AN INTRODUCTION TO COMPLETING NERC MOD STUDIES FOR INVERTER-BASED RESOURCES

Publication Details

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Abstract

NERC MOD standards have been implemented to ensure that the mathematical models used to evaluate bulk electric system (BES) reliability accurately represent the generation resources installed. This is part of NERC's initiative to implement modeling improvements to ensure that the steady-state and dynamic cases used for planning studies have a high degree of accuracy. Accurate models are critical to maintaining and improving grid stability. MOD-025 is intended to verify the gross and net real and reactive power capability of an applicable generating facility. MOD-026 is intended to verify that the plant volt/var control behavior is accurate by comparing model simulation output to real-world testing. Similarly, MOD-027 is intended to verify plant active frequency control behavior by comparing model simulation output to real- world testing. Finally, MOD-032 defines the modeling data documentation requirements and reporting procedures for generation plant owners to provide consistent data for submission to the respective transmission planners and planning coordinators. This paper provides an overview of the NERC MOD standards and highlights control and model deficiencies uncovered during MOD testing that plant owners were unaware of and provides other lessons learned from performing MOD studies for inverter-based resource plants. The deficiencies discussed in this paper are examples of some of the issues that the standards were developed to address, which highlights the criticality and importance of these standards. This paper is intended to serve as a reference to aid electric utilities and independent power producers comply with the NERC MOD standards mentioned above.

Introduction

Power system planning and operation requires accurate dynamic models that represent the transient behavior of the system during both normal operations and grid disturbances. In August 1996 a sequence of power system events led to a small signal instability at the California-Oregon Intertie (COI). Resulting undamped oscillations caused blackouts in California.[1] However, the system model used to evaluate this scenario at the time did not exhibit a similar response, instead showing damped oscillations. This resulted in Western Systems Coordinating Council (WSCC) launching an initiative to improve the quality of transient stability models. The initiative improved the power plant model validation process that led to the development of MOD standards. The WSCC required all generators >20 MVA to be tested for model validation. It was found that many dynamic models needed data revisions and control settings corrections, thus underscoring the need for model validation efforts. The MOD standards were developed to make model validation a criterion for ensuring compliance with the enforcing entities. Model-based validation involves testing the accuracy of dynamic models by comparing the simulated response versus baseline tests. If the response does not match, the model parameters are adjusted or tweaked until the simulated response matches the field response.

NERC MOD Standards

NERC MOD Standards apply to both synchronous and inverter-based generating resources. Synchronous generators use a governor to provide frequency response and an excitation system to provide voltage response. Inverter-based resources have analogous, though very different, controls to provide reactive power/voltage response and active power/frequency response. This section covers the applicability of NERC MOD Standards to inverter-based resources. There are four MOD standards:

- **MOD-025-2:** Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability
- **MOD-026-1:** Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions (MOD-026-2 expected in 2023)
- **MOD-027-1:** Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions
- **MOD-032-1:** Data for Power System Modeling and Analysis

NERC MOD-025-2

According to NERC MOD-025-2, its purpose is "to ensure that accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability."[2] The standard establishes criteria for the facilities to which MOD-025-2 applies and what needs to be verified. Generation owners (GO) and transmission owners (TO) who use traditional and inverter-based resources are required to demonstrate compliance for BES generating facilities under their control. The standards apply to the generation units and generating plants (consisting of multiple generation units) that are directly connected to a BES:

- Individual generating unit greater than 20 MVA (gross nameplate rating)
- Synchronous condenser greater than 20 MVA (gross nameplate rating)
- Generating plant or facility greater than 75 MVA (gross aggregate nameplate rating)

The standard outlines three requirements:

- Requirement R1 states that the GO shall provide its Transmission Planner (TP) with verification of real power capability of the generation units in accordance with the directions in Attachment 1. Submit a completed documentation form, Attachment 2 to its Transmission Planner within 90 calendar days of either the date of recording data from a staged test or the date the data is selected for verification if using historical data.
- Requirement R2 states that the GO shall provide its TP with verification of reactive power capability of the generation units and synchronous condenser units in accordance with the directions in Attachment 1. Submit a completed documentation form Attachment 2 to its TP within 90 calendar days of either the date of recording data from a staged test or the date the data is selected for verification if using historical data.
- Requirement R3 states that the TO shall provide its TP with verification of reactive power capability of the synchronous condenser units in accordance with the directions in Attachment 1. Submit a completed documentation form Attachment 2 to its TP within 90 calendar days of either the date of recording data from a staged test or the date the data is selected for verification if using historical data.

- Verification - the first verification must be a staged test. The periodicity of the verification is at least every 5 years; or within 12 months of discovery of a change affecting the real or reactive power capability that is greater than 10% and expected to last for more than 6 months. New units must be verified within 12 months of commercial operations date (COD).

The GO and TO shall retain the latest MOD-025 Attachment 2 and the supporting data for the time period since the last audit.

NERC MOD-026-1

According to NERC MOD-026-1 standard, its purpose is “to verify that the generator excitation control system or plant volt/var control function model (including the power system stabilizer model and the impedance compensator model) and the model parameters used in dynamic simulations accurately represent the generator excitation control system or plant volt/var control function behavior when assessing Bulk Electric System (BES) reliability.”[3]

The standard establishes criteria for the facilities to which MOD-026-1 applies and what needs to be verified. Traditional and inverter-based resources GOs and qualifying units identified by TPs are required to demonstrate compliance for BES generating facilities under their control. The standards apply to the following generation units and generating plants (consisting of multiple generating units) that are connected to the BES:

- Individual generating units or generating plants greater than 100 MVA in the Eastern or Quebec interconnection
- Individual generating units or generating plants greater than 75 MVA in the Western interconnection region
- Individual generating units greater than 50 MVA or generating plant greater than 75 MVA in the ERCOT region
- If the TP can demonstrate that a simulated unit or plant response does not match measured responses of units that meet NERC registry criteria, but are otherwise excluded from the above criteria per interconnect, can be deemed subject to compliance at the request of the TP.

The standard outlines six requirements:

- Requirement R1 states that the transmission planner shall provide instructions on how to obtain the list of excitation control or plant volt/var control function models, block diagrams, data sheets, and model data for any of the GO’s existing applicable units.
- Requirement R2 states that each GO shall provide for each applicable unit, a verified generator excitation control system or plant volt/var control function model, GO must also provide supporting documentation and data to its TP in accordance with the periodicity specified in MOD-026-1 Attachment 1. The documentation must demonstrate that the applicable unit’s model response matches the recorded response from a staged test or a measured system disturbance. The data should include manufacturer name, model number (if applicable), type of excitation control system, model structure and data including details of compensation setting, details if a voltage regulator or power system stabilizer is equipped, other generator parameters and plant volt/var function parameters.
- Requirement R3 states that each GO shall provide a written response to its TP within 90 calendar days of receiving notification or comments from its TP identifying technical concerns with the plant volt/var control function model or if the plant control model response did not match the recorded response to a transmission system event.

- Requirement R4 states that each GO shall provide revised model data or plans to perform model verification for an applicable unit to its TP within 180 calendar days of making changes to the excitation control system or plant volt/var control function that alters the response characteristic.
- Requirement R5 states that each GO shall provide a written response to its TP within 90 calendar days following receipt of a request from the TP to perform a model review of a unit or plant. The response may include either details of plans to verify the model or request for corrected model data along with the source of the revised model data.
- Requirement R6 states that each TP shall provide a written response to the GO within 90 calendar days of receiving the verified plant excitation control system or plant volt/var control function model information that the model is usable or is not usable. The model is deemed usable if the excitation control system or plant volt/var control function model initializes without error, no-disturbance simulation results in negligible transients, and a disturbance simulation results in excitation control system and plant volt/var control function model exhibits positive damping.

All transmittal from the GO and TP including model, documentation, and other correspondence shall be dated for evidence. The GO and TP shall retain the applicable information/data request and provided response evidence for three calendar years from the date the document was provided.

Upcoming Changes to NERC MOD-026-1

The new MOD-026-2 standard is expected to be effective from 2023.[6]

NERC MOD-027-1

According to NERC MOD-027-1 standard, its purpose is "to verify that the turbine/governor and load control or active power/frequency control model and the model parameters, used in dynamic simulations that assess Bulk Electric System (BES) reliability, accurately represent generator unit real power response to system frequency variations."[4] The standard establishes criteria for the facilities to which MOD-027-1 applies to and required verification. GOs and TPs of traditional and inverter-based resources and qualifying units identified by TPs are required to demonstrate compliance for BES generating facilities under their control. The standards apply to the generation units and generating plants that are connected to the BES:

- Individual generating units or generating plants greater than 100 MVA in the Eastern or Quebec interconnection
- Individual generating units or generating plants greater than 75 MVA in the Western interconnection region
- Individual generating units greater than 50 MVA or generating plant greater than 75 MVA in the ERCOT region

The standard outlines five requirements:

- Requirement R1 states that the TP shall provide instructions on how to obtain the list of turbine/governor and load control or active power/frequency control function models, block diagrams, data sheets and model data for any of the GO's existing applicable units.
- Requirement R2 states that each GO shall provide, for each applicable unit, a verified turbine/governor and load control or active power/frequency control function model, including documentation and data, to its TP in accordance with the periodicity specified in MOD-027 Attachment 1. The documentation should demonstrate that the applicable unit's model response matches a recorded response from a staged test or a measured system disturbance from

a frequency excursion, speed governor reference change with the unit online, or a partial load rejection test. The data should include manufacturer name, model number, generator, turbine/governor data, model data, active power/frequency control function parameters, and representation of the real power effects of outer loop controls (part of inverter controls, outer loop typically includes voltage, real, and reactive power).

- Requirement R3 states that each GO shall provide a written response to its TP within 90 calendar days of receiving notification from its TP identifying technical concerns with the turbine/governor and load control or active power/frequency control function model or if the active power/frequency control model response did not match the recorded response to a transmission system event three or more times.
- Requirement R4 states that each GO shall provide revised model data or plans to perform model verification for an applicable unit to its TP within 180 calendar days of making changes to the turbine/governor and load control or active power/frequency control system.
- Requirement R5 states that each TP shall provide a written response to the GO within 90 calendar days of receiving the turbine/governor and load control or active power/frequency control system verified model information that the model is usable. For the model to be deemed usable, the model should initialize without error, have negligible transients during a no- disturbance run, and result in positive damping during a disturbance simulation.

NERC MOD-032-1

According to NERC MOD-032-1 standard, its purpose is "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."[5] The standard outlines four requirements:

- Requirement R1 states that the Planning Coordinator (PC) and TP shall develop steady-state, dynamics, and short-circuit modeling data requirements and reporting procedures for the PC's planning area per the data listed in Attachment 1 of MOD-032.
- Requirement R2 states that each Balancing Authority (BA), GO, Load Serving Entity, Resource Planner, TO, and Transmission Service Provider shall provide steady- state, dynamics, and short-circuit modeling data to its TP and PC according to the data requirements and reporting procedures developed per Requirement R1.
- Requirement R3 states that upon receipt of written notification from its PC or TP regarding technical concerns with the submitted data, each BA, GO, Load Serving Entity, Resource Planner, TO, and Transmission Service Provider shall provide within 90 calendar days of receipt, updated data, or a technical explanation for maintaining the current data.
- Requirement R4 states that each PC shall provide their models representing their planning area to the Electric Reliability Organization (ERO) or its designee to support the creation of interconnection-wide case(s).

The applicable entity shall keep data or evidence to show compliance with requirements R1 through R4, and measures M1 through M4, since the last audit or for a longer period of time as directed by a compliance enforcement authority. If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved.

Study Methodology

This section covers NERC MOD study methodology and each of the steps involved: data collection, identifying approved dynamic models, modeling, field-testing, and report preparation.

Data Collection

The first step in performing MOD studies is collecting the necessary data. The following data is typically required for inverter-based generator studies:

- Electrical single-line and three-line drawings
- Collector system equivalent from existing system planning models (if collector system drawings are not available)
- Generator capability curves
- User manual
  - » Inverters
  - » Wind turbine generator (WTG) controller
  - » Plant controller
  - » VAR controller
- Pad-mount or generator step-up (GSU) transformer data
- Collector station power transformer data (nameplate info, test reports, etc.)
- Utility system point of interconnect data (short circuit MVA, X/R ratio)
- Dynamic models from manufacturer
  - » Photovoltaic (PV) and battery energy storage system (BESS) inverters
  - » WTG
  - » VAR system (eg: D-VAR)

Approved Dynamic Models

It is important to ensure the dynamic model(s) provided by the equipment manufacturer will be accepted by the TP for the region where the plant is located. For example, when studying plants in the West, WECC's approved model list should be checked. This has been particularly important for older sites, as we have encountered models which WECC would not accept. In these cases, conversion to acceptable replacement models was required.

Field Testing Overview

Field testing is typically required for MOD-025, MOD-026, and MOD-027 to verify the real/reactive power capability, the volt/var response, and the real power/frequency response of the generating unit(s). The field testing needs to be carefully planned to provide sufficient data to compare to dynamic model simulations to validate the dynamic models. Section IV covers the field-testing aspects in detail.

Modeling Overview

System modeling involves building a steady-state model of the plant, reviewing the dynamic model(s) provided by the manufacturer, running simulations to match the field results, and updating the steady-state and dynamic parameters until a matching response is obtained. Section V of this paper covers modeling in detail.

Report Preparation

The final step in the completion of the MOD study is preparing a report that clearly depicts agreement between real-world plant response and model response that can be submitted to the compliance authorities during a compliance audit. The report must include plant details, including the number of inverters or WTGs, GSU (pad-mount) transformers, collector system topology, main power transformer, transmission tie-line data, and utility Thevenin equivalent at the point of interconnection (POI). The report should include a discussion of the field testing and model validation approach and results. The report appendices should include all data used in the analysis, dynamic model values, a description of the dynamic model parameters, block diagram, etc. The steady-state, short-circuit, and dynamic data needed to satisfy MOD-032-1 requirements should be submitted along with the report.

Field Testing

To meet NERC's model validation requirements, the real- world response of the generating unit(s) being studied must be recorded. The following subsections describe methods for performing field testing.

Test Equipment Used

The goal of the test setup is to record three-phase currents and voltages at the point of interconnection of the plant, during prescribed plant stimulus. During our testing, current measurements are taken using clamp-on current transformers (CTs) applied to line relay CTs or plant metering CTs. Plant voltage measurements are taken by direct connection to the secondary of plant potential transformers (PTs), typically at the PT fusing in the meter or line relaying panel. The data is recorded in a lab-grade, analog data acquisition device. From the recorded instantaneous currents and voltages, root-mean-square (RMS) currents, RMS voltages, frequency, and active and reactive power values are calculated. The data acquisition device used in POWER Engineer's testing has a sample rate of up to 50,000 samples/sec which provides detailed dynamic response data. Test recording devices must be carefully chosen because many plant data historians and SCADA historians do not have a sufficient sampling rate to provide detailed dynamic response recordings.

Pre-Requisites for Testing

One of the initial steps to be completed before performing a field test is preparing a test plan. The test plan should detail the CT and PT connection points for the data logging equipment, CT and PT ratios, and the actions to be taken with the plant controller or reactive power devices for each test. The test plan should be reviewed by plant operational authorities to ensure that the tasks outlined in the test plan can be carried out without any challenges. The test plan should usually be reviewed and approved by the transmission planning authority which governs the point of interconnect.

When performing tests at a wind farm, it is important to plan the testing during a period of historically reliable wind and check for the availability of wind by checking the weather reporting tools as the testing date approaches to ensure the testing can be carried out successfully. It is also important to ensure there are no scheduled outages or maintenance activities planned at the generating plant during the testing dates.

While performing MOD-025 tests, if the substation transformer is equipped with a load tap changer (LTC), it is recommended that the testing be performed with the tap setting in its normal operating condition.[7] Similarly, the in- plant reactive devices (i.e., shunt capacitors, shunt reactors, STATCOMs, SVCs, or synchronous condensers) in the plant should be set at their normal operating mode.

MOD-025 requires that at least 90% of the wind turbines or photovoltaic inverters are online during testing. If 90% of the plant units are not online during the test effort, the standard requires documentation of the reasons why 90% could not be achieved. It should be noted that this does not mean the plant should be producing 90% of the MW rating—rather, 90% of the turbines should be online and producing power. If 90% of the units are not online, the test is required by the standard to be rescheduled within 6 months of reaching the 90% availability threshold. To avoid testing multiple times, this emphasizes that the testing should be planned in such a way that there are no planned outages or maintenance schedules that would result in less than 90% of the units online.

MOD-025 Tests

PV/Wind Farms

The following information is recorded before beginning the test:

- Ambient temperature, humidity
- Nominal operating voltage
- Approximate plant auxiliary load real and reactive power
- Voltage ratio of the collector station power transformer and any auxiliary transformer(s)
- Tap setting of the collector station power transformer
- Pre-test plant operating voltage, real power output and reactive power production
- Count of number of turbines or inverters online

After the test equipment CT and PT leads are connected to their previously identified sources, the currents and voltages are recorded continuously during testing to calculate the real power and lagging reactive power capability (over-excited) at the plant's normal expected maximum real power output. The following data are recorded for verification during the test:

- Voltage and current used to calculate P (real power) and Q (reactive power)
- Scheduled voltage
- Voltage at the high-side and low-side of the GSU transformer
- Date and time of verification (start and end times)

If measurements are taken on the transmission side of the collector station power transformer, the transformer losses calculated based on GSU impedance needs to be accounted for while calculating the gross real power capability. The full reactive capability of the inverter-based resource may not be achieved during testing conditions since the maximum reactive power output may push the collector system or transmission line voltages to unacceptably high levels. The voltage protection settings may also prevent the plant from reaching its maximum reactive power limits. Therefore, the maximum reactive power output that can be achieved during testing will be determined by the normal operating conditions of the plant. The plant model can then be verified by extrapolating the field measurements obtained during the testing.

BESS

Unlike wind turbines and PV generators, BESS systems can operate on all four quadrants. The following scenarios are tested for the BESS:

- BESS charging - Max P, lagging Q
- BESS discharging - Max P, lagging Q
- BESS charging - Max P, leading Q
- BESS discharging - Max P, leading Q

MOD-026 Tests

MOD-026 tests involve measuring the volt-var response of the plant by switching capacitor banks in or out of service, or by changing the voltage or reactive power reference in the power plant controller.

- Capacitor Switching - Capacitor switching is done to induce a wind turbine or inverter voltage control response. Consequently, we capture any changes in the reactive power injected into the system and the corresponding voltage changes. This is typically done by switching a capacitor bank on- or offline a few minutes into the testing to capture the system response before and after switching the capacitor bank. **Figure 1** and **Figure 2** show the response to capacitor switching from a field test.

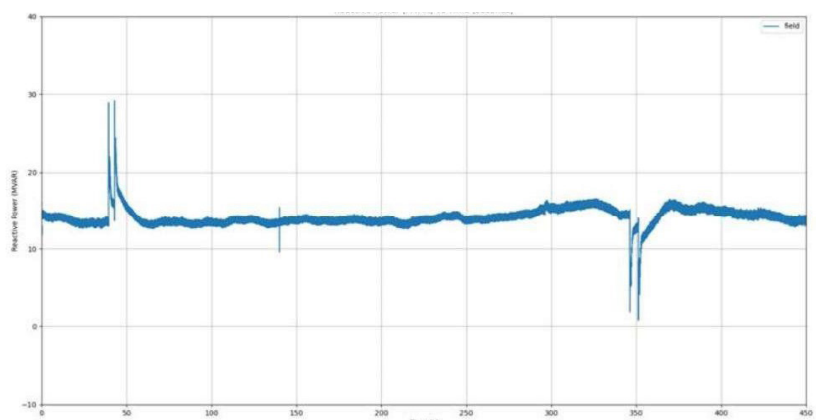

Figure 1: Measured reactive power response to capacitor bank switching

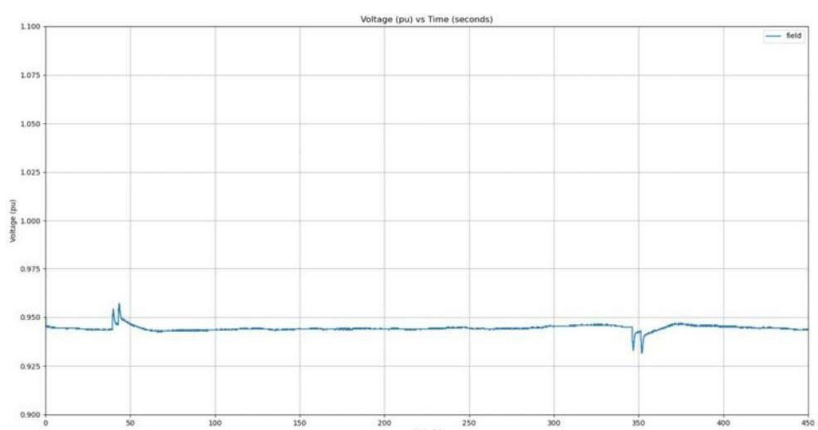

Figure 2: Measured voltage response to capacitor bank switching

- Step Change in Plant Controller Voltage Reference - For inverter-based resources, the following are the typical operating modes: voltage control, power factor, or constant var control. When a voltage step reference is provided to the plant controller (typically 2% to 3% step), the plant controller sends reactive power or voltage set point commands to the inverters or WTGs to adjust their reactive power output to modify the voltage at the POI. The voltage reference should be held for several minutes for the transients to settle. For plants that operate in constant reactive power mode or constant power factor mode, a reactive power reference step is set in the plant control. The reactive power step should be small and should not result in voltages exceeding operating or protection limits at the POI or the collector station. **Figure 3** and **Figure 4** show the response to plant controller step change in voltage during a field test.

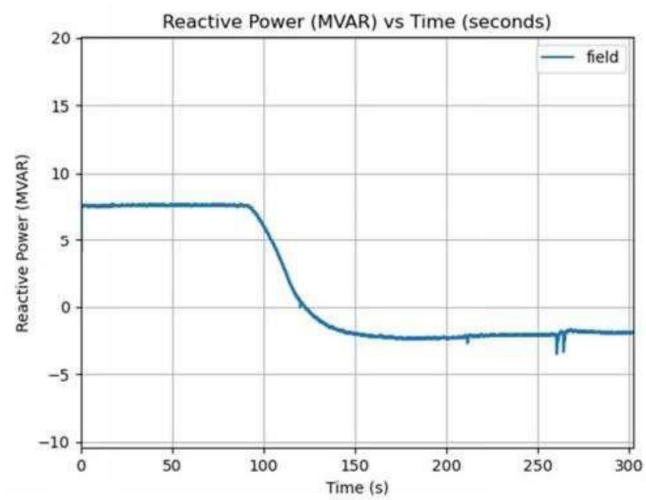

Figure 3: Measured reactive power response to plant step change in voltage

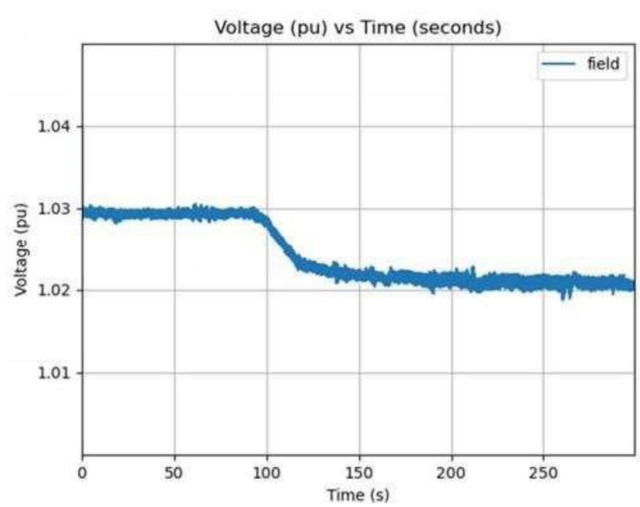

Figure 4: Measured voltage response to plant step change in voltage

MOD-027 Tests

MOD-027 testing requires measuring the real power- frequency response of the system by changing the frequency reference in the power plant controller.

- Step Change in Frequency Reference - This test is performed by adding a frequency offset that exceeds the governor dead-band value to the measured frequency signal. This creates a step change in the measured frequency signal. This is tested at a load level that allows the generating plant to increase or decrease load without hitting the operating limits. **Figure 5** shows the response to a frequency reference step change during a field test.

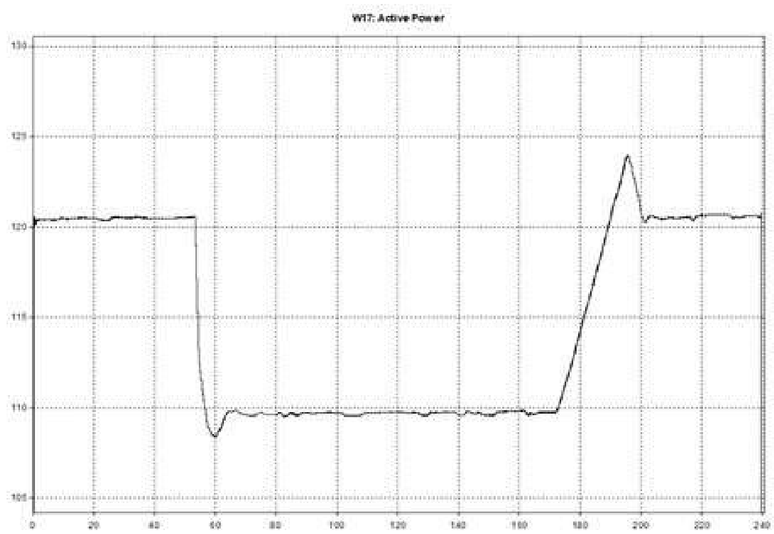

Figure 5: Measured real power response to plant step change in frequency

Alternate Model Validation Methods

Model validation can be performed using system event data captured by digital fault recorders (DFR), protective relays, and phasor measurement units (PMUs). While obtaining measurements from DFR or PMU sources during planned testing, sufficient data should be captured covering the steady- state response pre-disturbance and system response post- disturbance until steady-state is reached. If actual system event data is retrieved from DFR, PMU, or protective relay event records, careful selection of appropriate data sets showing sufficient pre-event, event and post-event values is critical. For performing model validation using PMUs, the typical approach includes the following steps:

- Monitor for any major grid disturbances that evoke a transient response from the generator.
- Convert the disturbance data into a format sufficient for playback and comparison to model data. The measurement data should be at least 30-60 samples per second with time synchronization.
- The playback voltage magnitude should be positive sequence bus (or line voltage) reported in kV or per unit. The playback frequency should be the frequency of the voltage phasor reported in hertz. The active and reactive power should be reported on a three-phase basis (total POI line flow), in megawatts and megavars.
- Update the plant dynamic model to simulate the plant operating conditions at the beginning of the field test or system event.
- Run the model with the PMU data to generate the simulated output.
- Compare simulated response model output to the actual response from PMU output.
- Update model parameters to get a matching response.

Advantage of PMU disturbance recording:

PMUs capture plant response to actual transmission-level grid disturbances, such as loss of equipment, faults, or breaker operations. This helps obtain data that captures a much wider range of events than can be captured in a planned test. Since PMUs may capture grid disturbances on a relatively regular basis, it may be possible to perform model validation more frequently, resulting in better power system models. Instead of reducing production to conduct generator testing, PMU model validation allows asset owners to continue operating plants and avoid lost revenue by collecting continuous data about generator operation under actual grid conditions.

Disadvantages of PMU disturbance recording:

Some plants are connected to strong systems where frequency and voltage events aren't common, or to systems that aren't subject to regular disturbances, such as open areas with few trees and little to no lightning. For those plants, DFR, PMU, or protective relay data may not be available at intervals sufficient to rely on them for regular compliance evaluation.

Modeling

After field testing is complete, the next step is to build the steady-state model of the system along with the dynamic models of the generating unit to study the model response under different conditions. The next subsections cover the various aspects of developing the model for the MOD studies.

Software Used

The software packages primarily used for MOD studies are Siemens PTI's PSS®E and GE PSLF. ERCOT and PJM require that the model files be submitted in PSS®E format, while

WECC requires model files in PSLF format. For engineers, consultants who are used to working in one software (PSS®E or PSLF), it is often possible to convert the steady-state and dynamic files from PSLF to PSS®E using the WECC conversion tools. PowerWorld, another power system planning software, is a useful tool to help with conversions between PSS®E and PSLF.

Steady-State Model Development

Building the steady-state model is the first step in the model development process. The typical approach for these studies is to develop aggregate models for the generating units, GSU transformer, and collector system. The collector feeders are modeled as a single collector system equivalent. **Figure 6** shows the one-line of a model in PSS®E.

The steady-state model consists of the following:

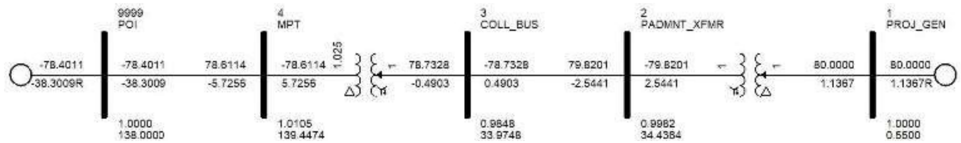

Figure 6: Aggregated single line diagram

Project Generator

This refers to the aggregated model representing the total number of WTGs or inverters. For example, if the generating facility consists of fifty 2 MW inverters, they are modeled as a single 100 MW equivalent.

GSU Transformer

The GSU transformers step-up the generator or inverter voltage (typically 240-1000 V) to the collector system voltage (typically 34.5 kV). Each WTG has its own pad-mount (or up-tower) transformer and hence the pad-mounts are modeled as a lumped unit similar to WTGs. For example, fifty 2.2 MVA pad-mount transformers are modeled as a single 110 MVA pad-mount transformer equivalent. The PV collector systems are modeled without DC collection systems and modeled in a similar fashion to WTGs.

Collector System Equivalent

The collector system constitutes the medium voltage cables that collect power from the inverters or turbines to be transferred to the substation. There can be multiple feeders, with each feeder consisting of a string of GSUs and generators. The multiple feeders are modeled as a single feeder equivalent in PSS®E and PSLF. If the feeder data is available—including the cable type and length—the equivalent collector system impedance can be calculated using the 'NREL method'.[8] If the collector system drawings are not available, typical collector system impedance can be used.

Static and Dynamic Reactive Resources

Inverter- based plants often have capacitor banks installed to maintain the required power factor at the POI and to meet the volt/var demands of the system. It is important to model these reactive resources as well.

Main Power Transformer or Substation Transformer

The main power transformer refers to the substation transformer that gets power from the collector feeders and is used to step-up the collector system voltage to a high voltage for transfer to the grid.

Gen-Tie Line
The gen-tie line refers to the trans- mission line that transfers the power from the substation transformer to the utility at the POI. The line impedance data for the gen-tie can be found either from the existing system models or calculated based on cable type, line configuration, and total length.

Utility Source Equivalent
The utility side of the plant's POI is modeled as a Thevenin equivalent or modeled based on the available short circuit MVA and X/R ratio at the POI with the plant off-line.

Dynamics Model Update

The dynamic model for the generating units in the plant must be obtained from the inverter or WTG manufacturer as part of the data collection effort for the study. The dynamic file used in PSS®E has the format .dyr while GE's PSLF uses the format .dyd. The manufacturer should be able to provide the dynamic file in any of the requested formats (PSS®E, PSLF). Once the dynamic file is obtained, it needs to be updated with the appropriate bus numbers for the generators. Typically, but not always, a power plant controller (PPC) exists and that will often need to be added to the dynamic file and the control flags set based on the type of reactive control implemented in the plant. The dynamic file may also need to be updated with additional channels to capture the response in the system (e.g., active, reactive power flows through the line). For example, to monitor branch current and power flow in PSLF, a model called 'imetr' needs to be added in the dynamic file to view the line active and reactive power flow results after dynamic simulation is complete.

EMT Validation

Electromagnetic transient (EMT) modeling is not currently required for NERC MOD studies but is often required for new and existing facilities based on the total nameplate capacity and interconnection voltage. An EMT model can be built using various software platforms (PSCAD, MATLAB/Simulink, ATP, EMTP-RV, PowerFactory, etc.). In the United States, PSCAD is the most requested and supported format for transmission planning studies.

Building a plant model in EMT software is very similar to building the steady-state model and should have the same general components that were described earlier in the Steady- State Model Development section. Each steady-state component will have a similar component and parameterization in the EMT model (transformers, lines, shunts, source equivalent, generator equivalent). Additionally, an EMT model should include a power plant controller (PPC) if one exists. The PPC manages real and reactive power flow at some point in the project and needs to be configured for site specific ratings/settings. For the generator equivalent, the IBR manufacturer should be contacted regarding availability of a detailed model of the inverter at the facility. Newer equipment will often have a manufacturer specific EMT model, but older equipment rarely does. Therefore, a generic representation will have to be used and adjusted for the specific inverter it needs to represent.

While most system operators and utilities request similar EMT modeling details be incorporated into the model, there is a wide range of documentation and validation requirements. It is highly recommended to retrieve the latest requirements from the specific entity requesting the model. Following these requirements will minimize the time needed to generate an acceptable EMT model and associated documentation.

Modeling Validation and Submission

The crucial step in the model validation process after field testing is subjecting the model to the same disturbances tested in the field. The following simulations are typically performed:

- No-disturbance Run - The no-disturbance run is performed in PSS®E or PSLF to verify if the dynamic models are stable before performing other tests. The no-disturbance run involves running the model without applying any disturbances for a duration of at least 20 seconds. The generators are set to operate at full real and reactive power output. Since no disturbance is applied, the voltage, real/reactive power, and frequency plots should demonstrate a flat response with negligible transients. If there are transients, it could point to discrepancies in the model and will need to be investigated. **Figure 7** shows the simulated voltage, real and reactive power output of the generator for a no- disturbance run in PSLF.
- Tests to Verify MOD-026 - Capacitor switching and/or plant controller step change are simulated using PSS®E or PSLF to compare against the field response. **Figures 8 and 9** show the simulated reactive power and voltage response to capacitor switching from a field test (corresponding to Figures 1 and 2). **Figures 10 and 11** show the simulated reactive power and voltage response to step change in plant controller voltage reference (corresponding to Figures 3 and 4).
- Tests to Verify MOD-027 - the change in active power output due to percentage droop change (frequency reference change) is shown in **Figure 12**.

Based on how the simulated response compares against the field test results, the steady-state and dynamic parameters are adjusted to achieve a closely matching response between the field and simulated results. Although NERC standards do not specify any metrics to compare field and model results, the model response should follow the field response with a reasonable level of accuracy. Some of the metrics to determine a reasonable level of accuracy would be low percentage errors in magnitude levels pre- and post-disturbance, similarity in stepped responses, etc. In most cases, the simulation will not exactly match the actual response of the plant. However, we consider a good match to be similar curve shapes, similar ramp rates, and similar magnitudes. NERC does not provide definite direction on what is an acceptable level of match and what is left to the judgment of the regional enforcing entities.

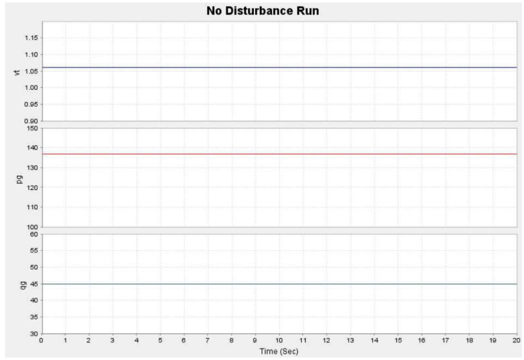

Figure 7: Simulated no-disturbance run

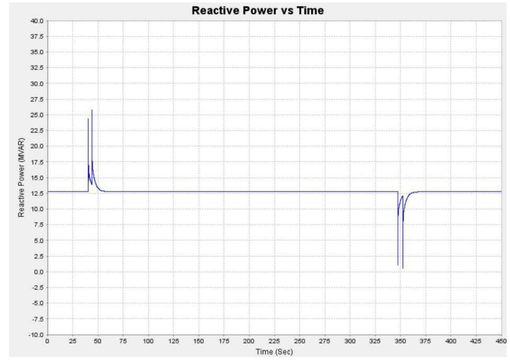

Figure 8: Simulated reactive power response to capacitor switching

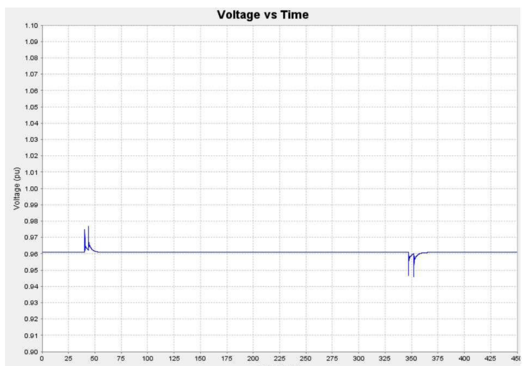

Figure 9: Simulated voltage response to capacitor switching

Figure 10: Simulated reactive power response to plant step change in voltage

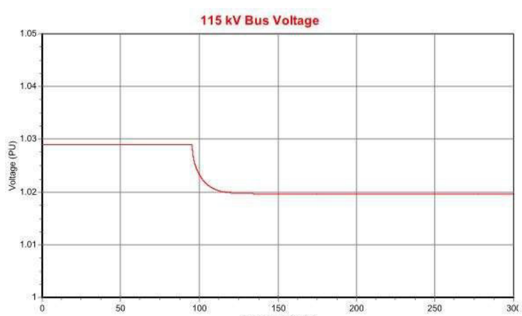

Figure 11: Simulated voltage response to plant step change in voltage

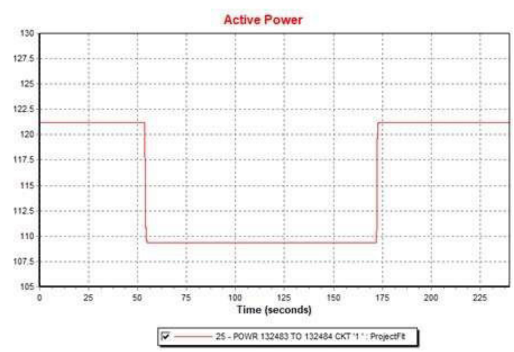

Figure 12: Simulated response to plant step change in frequency

Discrepancies Between Model And Field Response

The following should be taken into consideration when trying to determine the reason for discrepancies between the field and model response:

- Fluctuating input power - Unlike conventional generators, the power output from wind farms and PV farms may vary continuously due to changing wind speed or solar irradiance. To minimize fluctuations in the source, the starting simulation time is set closer to the disturbance itself. The variable power output is particularly challenging for MOD-027 tests.
- Lower sampling rates - Modern power electronics- based inverter resources have quickly responding controls. Some recording devices such as SCADA logs and data historians may not be able to capture the dynamic responses effectively due to lower sampling rates.
- Low MW output - When using the playback option to evaluate events from disturbance recording devices, it is important to note that some of the turbines may have tripped offline for a variety of reasons: nearby faults, turbines not producing power due to being yaw-locked based on the direction of wind, lack of wind or maintenance. In such cases the MVA output should be changed to represent the number of turbines online.
- Sub-cycle interactions - Type 3 and Type 4 turbines, which have power electronic interfaces, incorporate sub-cycle interactions within the plant that may not be sufficiently represented using positive sequence models.
- Disturbance events based on unbalanced faults - When fault events are used for verification testing, unbalanced faults may not be correctly represented in positive sequence simulation tools. The inverter-based resource controls may act on measured phase quantities while software like PSS®E or PSLF is limited to positive sequence quantities. Positive sequence models do not capture the dynamics from the inverter controls very well.

When performing model validation using dynamic events, Requirements R3 and R5 for standards MOD-026-1 and MOD- 027-1 create feedback loops between the GO and TP. It is important that the two work together collaboratively to develop a model that represents reality.

Satisfying MOD-032-1 Requirements

The purpose of the MOD-032-1 standard is to help develop interconnection-wide base cases and dynamic models through standardized data submission. To satisfy MOD-032-1 requirements, steady-state, short-circuit, and dynamic parameters of the project must be submitted to the planning coordinator. The submitted data typically includes the following:

- Steady-state model in PSS®E (.raw) or PSLF format (.epc)
- Dynamic model in PSS®E (.dyr) or PSLF format (.dyd)
- Short-circuit data (positive sequence, negative sequence, and zero sequence)
- PSS®E IDEV file to construct collector system, transformer, and grid equivalent (an IDEV file is a response file similar to a batch input file, which when run in PSS®E, takes inputs from the response file and executes the commands as it would in an interactive mode)
- PSS®E and PSLF formatted generator real and reactive capability curve data
- Appendices in the model validation report list the following:
    - » Steady-state – turbine/inverter rating, plant MVA, GSU and substation transformer voltage, impedance, winding connection, gen-tie line impedance and length
    - » Dynamic – dynamic model parameters and block diagrams for each of the dynamic models

Ensuring Compliance

After performing field tests and completing the requisite studies, the last step is to complete any additional documentation needed to show compliance with the standards before submitting to enforcement entities. Additional documentation may vary depending on the governing entities charged with compliance enforcement in each region. For example, CAISO requires filling the "Generating and Interconnection Facility Data" spreadsheet that contains the steady-state, dynamic, and facility data required for the site. Here is a summary of the key points related to ensuring compliance.

- MOD-025-2 submission involves completing the MOD-025 Attachment 2.
- The documentation should include a reactive capability curve provided by the manufacturer in a P-Q format.
- The capability determined during MOD-025-2 test conditions should not be used for the data submitted to MOD-032-1 if the full capability was not reached during the testing. The MOD-032-1 data supplied by the GO should include the full reactive power capability of the generator.
- For MOD-026-1 and MOD-027-1, a report should be submitted along with the steady-state and dynamic files in the required format (PSS®E, PSLF). The data to satisfy MOD-032-1 requirements may be attached as well.
- It is also important to make sure all the reports, model data, and additional documentation are submitted on time. Any follow-up correspondence from the entities requesting additional information should be promptly addressed to avoid fines or penalties.

Challenges and Lessons Learned

- **Proper Documentation** – One of the main challenges with completing the MOD studies is the availability of accurate documentation. This is common with older generating plants and plants whose ownership has changed. In our experience, plant documentation is often lost during site hand off(s). Locating the correct data can become time consuming. In some cases, the data must be recreated or approximated, particularly when the manufacturer no longer exists. It is important to allocate additional study time to account for any delays in gathering all data.
- **Expect the Unexpected** – Early in our MOD work, we followed a test plan which called for capacitor bank switching at a wind plant that was intended to create a voltage rise and fall as the capacitor bank was switched into service and out of service. During testing, we noticed that the bus voltage was not changing appreciably. We reviewed the data offsite and found no WTG response to our varied bus voltage. After confirming the bus voltage indeed exceeded the WTG control bandwidth that should have resulted in a WTG voltage control response, we decided to retest the site. The model for that site clearly indicated our voltage excursions should have caused WTG voltage control action. With the test data and a working dynamics model in hand, we aided the GO in discussing the plant response with the WTG manufacturer. Through a series of data and control settings reviews, the WTG manufacturer discovered the voltage control module in the plant controller had not been configured properly for the site. While this was a rather extreme example, this site was a poster child for why the MOD standards were created. The site had been modeled in WECC dynamics models with functioning dynamic voltage control, while in the real world, the site provided no dynamic voltage control.
- **Proprietary Controls** – Asynchronous generation sources rely on a variety of inverter, converter, and machine controls that are highly proprietary and closely guarded by their manufacturers. This can make writing a test plan difficult as it is often not clear what settings, reference inputs, or even control modes are

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available. As such, it is often critical or mandatory to include a representative from the generator manufacturer in the test planning and/or testing process.

- **Pay Attention to Weather** – One important requirement of MOD-025 for IBRs is that 90% of the units must be online. On one testing trip for two PV sites, there were scattered rain showers in the forecast for part of the testing window. This was not much of a concern until dense fog set in after the showers had cleared out. Fortunately, the fog eventually cleared mid-afternoon leaving a small but manageable window of time to complete the testing.
- **Knowledge of Site** – One of the things that needs to be considered is the age and condition of the site. A wind farm that was tested for MOD-025 had quite old wind turbines in various stages of functionality. The wind conditions didn't look great, but were expected to be at least strong enough to bring the turbines online at low production levels to meet the 90% online requirement for MOD-025. What we didn't know until arriving on site was that many turbines were "yaw-locked" to face the direction of the prevailing wind, and some of the turbines were broken beyond repair. This produced confusion as to the total turbine count required. In the end, the 90% threshold was unachievable to meet the MOD-025 requirement, so a retest was required.
- **Confirm Plant Controller Manipulation** – When dealing with plants that do not need regular plant controls adjustments, it is crucial to confirm plant operators can follow the tasks outlined in the test plan. On a recent MOD-025 test trip, it was discovered in the middle of testing that the plant controller was unresponsive to changes in the reactive power setpoint. This plant had operated at the same setpoint for years and no documentation existed on how to properly modify the setpoint. The result was an unsuccessful test that had to be delayed to a future date after the manufacturer and plant operators collaborated on the proper sequence to manipulate the setpoint. Requiring a pre-test test of the plant controller setpoint manipulation is now being implemented on sites where plant controllers are not frequently manipulated.

Conclusions

With the US Federal and State governments pushing toward renewable energy to combat climate crises and accommodate the proliferation of inverter-based resources, unforeseen events on the BES are expected to increase. NERC MOD Standards were drafted to minimize risk by improving the standard level and accuracy of representation of transient stability models. These standards will be revised in the future based on lessons learned and knowledge gained from BES events. It is important for engineers and personnel responsible for compliance to familiarize themselves with these standards and keep themselves up to date on future modifications to these standards.

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