NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Technical Report

BPS-Connected Inverter-Based Resource Modeling and Studies

May 2020

RELIABILITY | RESILIENCE | SECURITY




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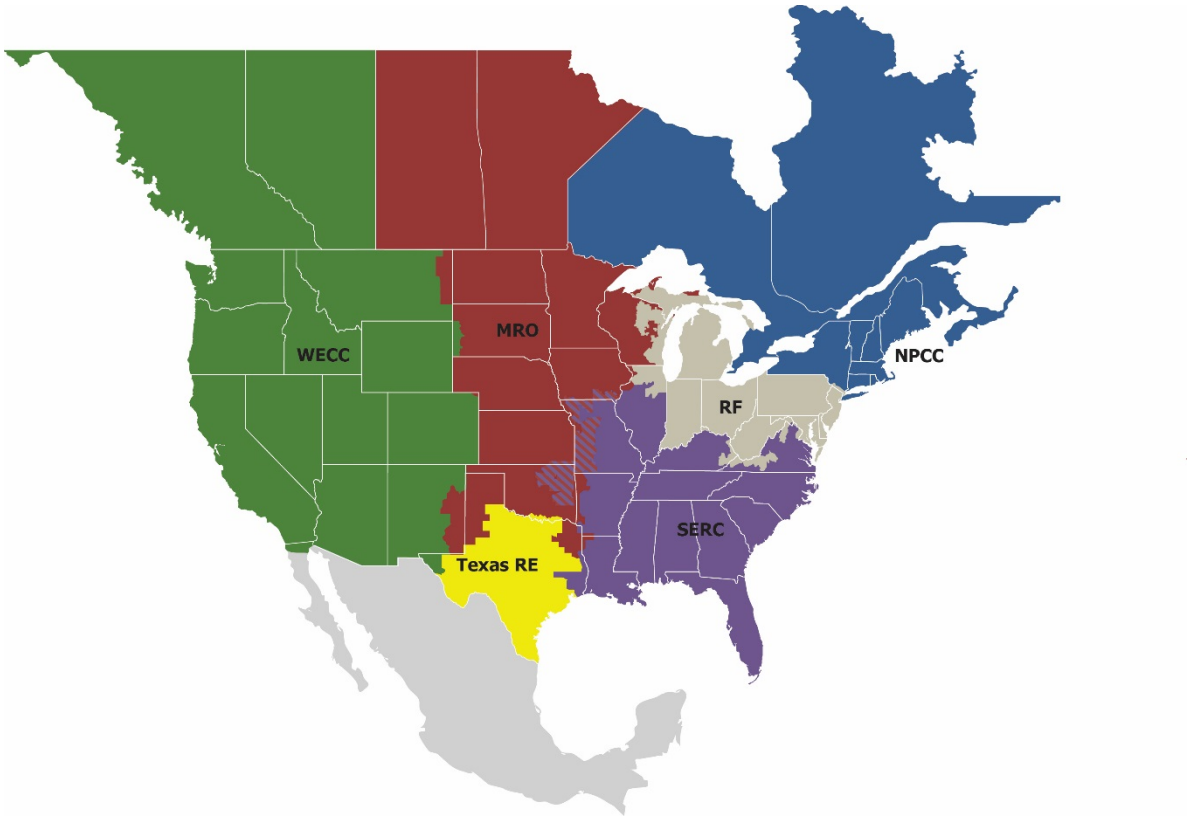
Preface

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

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

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



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

Executive Summary

The NERC Inverter-Based Resource Performance Task Force (IRPTF) and the industry have been working diligently on modeling and simulation activities to accurately represent inverter-based resources in dynamic stability analyses and explore the impacts of inverter-based resources on BPS reliability. This report outlines the activities of the IRPTF related to inverter-based resource modeling and studies. These activities are based on the following items:

- NERC staff activities related to disturbance analyses, NERC Alerts, and response data from the NERC Alerts
- Transmission Planner (TP) and Planning Coordinator (PC) efforts to improve the accuracy of RMS[1] positive sequence dynamic models for inverter-based resources
- IRPTF modeling sub-team activities to perform interconnection-wide stability analyses
- IRPTF technical discussions and work product developments

Table A.1 of **Appendix A** provides a list of key findings and recommendations from all the industry and IRPTF activities that have occurred in the past couple years. These findings are separated into three distinct categories: items A1–A6 focus on NERC alert findings, items S1–S6 are associated with IRPTF studies, and items D1–D7 are based on technical discussions and industry work related to dynamic modeling needs. The following list is an abbreviated version of **Table A.1**, highlighting the modeling issues identified and study results obtained:

- **NERC Alert Findings:** These findings highlight systemic modeling issues with BPS-connected solar photovoltaic (PV) resources in the interconnection-wide base cases. Many of the dynamic models do not match the data that was provided by Generator Owners (GOs) responding to the NERC Alert. Furthermore, many GOs failed to provide dynamic models as requested in the NERC Alert. Many of the dynamic models that were supplied by GOs as part of the NERC Alert process had modeling errors or inaccuracies and were unusable to the TP and PC. Many entities stated they could eliminate or reduce the use of momentary cessation (MC) but did not provide any updated dynamic model to initiate these changes to be studied by the TP and PC. Therefore, NERC staff and the IRPTF concluded that, due to the numerous modeling issues discovered and entities not following the NERC Alert process, the accuracy of the interconnection-wide base cases is unknown at this time.[2] The accuracy and reasonability of dynamic model parameterization may be overlooked by TPs and PCs due to lack of understanding of the dynamic models, insufficient processes to assure that they have obtained the best available models, and lack of tools to effectively check their validity. These issues illustrate the need to update the interconnection-wide base cases as quickly as possible with accurate dynamic modeling information for BPS-connected solar PV resources to ensure reliability studies are accurately identifying potential reliability issues.
- **IRPTF Studies Findings:** Initial stability studies highlighted degradation of BPS performance when MC was assumed to be used by all BPS-connected solar PV resources. Potential BPS voltage and transient instability issues were noted when models incorporating MC were applied in the studies. Solar PV resources entering MC also interacted with existing high voltage dc (HVDC) circuit controls and remedial action scheme (RAS) actions. This highlighted the need to widely eliminate MC to the most possible extent. However, when studies were performed using more accurate modeling information collected following the Canyon 2 NERC Alert with not all resources currently utilizing MC, results showed that the BPS remained stable but BPS performance was still degraded. The studies performed required applying extensive user-defined models that overlay onto the existing models to accurately capture the large disturbance behavior from solar PV resources on the BPS. Sensitivity studies were performed that showed that reactive current priority with voltage control enabled is the preferred default configuration for BPS-connected solar PV resources in the studied areas; however, detailed interconnection studies should be performed to determine tuning of control systems for each BPS-

[1] Root-mean-square
[2] Particularly for the Western Interconnection base cases.

connected inverter-based resource. Lastly, IRPTF studies highlighted the need for more accurate protection system modeling to identify any potential interactions with inverter controls that would need to be considered.

- **Technical Discussion Findings:** The IRPTF and industry technical discussions have highlighted an array of modeling issues that need to be addressed in a timely manner. These modeling issues are likely leading to some of the systemic challenges identified in this report. NERC MOD-026-1 and MOD-027-1 verification and testing activities are not adequately verifying the dynamic models relative to actual installed equipment performance for large disturbance response, leading to false expectations that these models are actually representative of installed performance. Incorrect parameterization of the dynamic models is likely caused by inaccurate modeling data provided by the GO and lack of information sharing between the original equipment manufacturer (OEM), GO, TP, and PC, and it is a contributor to many of the modeling issues. Similarly, Attachment A of Appendix 1 of the FERC *Large Generator Interconnection Procedures*[3] (LGIP) does not mention solar PV resources and only briefly mentions wind power resources. Lack of specificity of modeling information may be leading to a lack of detailed studies prior to interconnection. Furthermore, it is unclear in these procedures what constitutes a "material modification" and how the technological change procedures should apply. Interconnection requirements should be broadly improved to ensure adequate modeling information is provided during interconnection and that any changes affecting the electrical performance of the facility are studied prior to implementation by the GO. Interconnection-wide case creation practices will also need to evolve as instantaneous penetrations of inverter-based resources continues to increase. Many entities are experiencing a need for more advanced electromagnetic transient (EMT) modeling in areas of high penetrations of BPS-connected inverter-based resources, and EMT simulations are becoming standard practice during the interconnection processes.

Without attention to the recommendations described in **Appendix A**, TPs and PCs are limited in their ability to ensure reliable operation of the BPS in the face of increasing penetrations of BPS-connected inverter-based resources. The efforts of the NERC IRPTF have illustrated a need for TPs, PCs, GOs, equipment manufacturers, and developers to take timely actions to correct the modeling issues identified. A shift in the study approaches and tools may also be warranted in many cases. This technical report provides industry with sound technical steps to address these issues and provides clear recommendations throughout. All points have been thoroughly vetted by IRPTF members. This ensures that the perspectives of TPs, PCs, RCs, GOs, GOPs, and equipment manufacturers have been considered and addressed. As new technologies continue to connect to the BPS, there will be a continued need to work out these issues in this manner.

Chapter 1 of this technical report focuses on modeling activities and issues related to BPS-connected inverter-based resources; **Chapter 2** describes system reliability studies performed by the IRPTF, focusing on the Western Interconnection and including sensitivity analyses on various inverter controls considerations. **Appendix A** provides a complete list of key findings and recommendations from this report, **Appendix B** discusses model verification issues regarding large disturbance behavior of inverter-based resources, and **Appendix C** describes follow-up findings after the Canyon 2 disturbance NERC Alert.

This report is applicable for TPs, PCs, RCs, and GOs of BPS-connected inverter-based resources (particularly solar PV resources). Each entity is encouraged to review the key findings of this report and implement the recommendations set forth as applicable.

[3] https://www.ferc.gov/industries/electric/indus-act/gi/stnd-gen/LGIP-procedures.pdf

Introduction

The rapid growth in inverter-based resources connected to the BPS across North America has challenged TPs, PCs, RCs, GOs, and inverter manufacturers with ensuring the models used to represent these resources in steady-state power flow, dynamics, and short circuit studies sufficiently represent the actual behavior of these resources. NERC activities have initiated an extensive industry-wide focus on model improvements for inverter-based resources, including efforts within NERC, in the NERC IRPTF, and by industry to improve modeling and simulation practices.

NERC IRPTF Modeling and Studies Sub-Group

NERC IRPTF has been working on modeling and dynamic simulations of BPS reliability and various inverter-based resource modeling issues over the past few years since the studies related to the Blue Cut fire. The group was initially formed to analyze the potential of widespread MC possibly affecting frequency stability in the Western Interconnection.[4] Following that work, the team concluded that frequency stability was not at risk; however, transient stability issues could possibly arise across all Interconnections if MC continued to be used as a predominant form of ride-through operation moving forward. This led to recommendations that MC be eliminated or mitigated to the most possible extent. Subsequent studies identified that most BPS-connected solar PV resources do not have their large disturbance behavior accurately modeled (specifically not accurately representing MC or disturbance ride-through). The group also supported the development of the NERC Alert following the Canyon 2 fire disturbance. Most recently, the group has been analyzing the data and information received from their respective GOs following the Canyon 2 fire NERC Alert. The discussions and analyses that have transpired since then have identified a number of modeling and study recommendations that are captured in this report.

NERC Disturbance Analyses and NERC Alerts

Following the Blue Cut fire[5] and Canyon 2 fire[6] disturbances, NERC issued Alerts[7] to gather data to understand the extent of the conditions regarding inverter operating modes and to recommend mitigating actions to address potential reliability issues related to inverter-based resource performance. In particular, the NERC Alert[8] following the Canyon 2 fire disturbance focused primarily on modeling issues. Specifically, the Alert provided recommendations for modeling MC for existing solar PV resources as well as accurately modeling updated controls for potential changes to eliminate MC. In particular, the NERC Alert stated that GOs should perform the following recommendations:

> **Recommendation 1a:** Ensure that the dynamic model(s) being used accurately represent the dynamic performance of the solar facilities. Refer to the Modeling Notification[9] published on this topic. If the inverters at the solar facility use MC, update the dynamic model(s) to accurately represent MC and provide the model(s) to the TP and PC (to support NERC Reliability Standard TPL-001-4 studies) and to the RC, TOP, and Balancing Authority (in accordance with NERC Reliability Standards TOP-003-3 and IRO-010-2). If no change is required in the model(s), a written notification that the previously provided model(s) accurately captures the dynamic behavior of the solar PV facility should be provided.
>
> **Recommendation 1b:** Work with their inverter manufacturer(s) to identify the changes that can be made to eliminate MC of current injection to the greatest extent possible, consistent with equipment capability. For inverters where MC cannot be eliminated entirely (i.e., by using another form of ride-through mode), identify the changes that can be made to MC settings that result in the following:
>
> - Reducing the MC low voltage threshold to the lowest value possible

[4] https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/IRPTF_RLPC_Assessment.pdf
[5] https://www.nerc.com/pa/rrm/ea/Pages/1200-MW-Fault-Induced-Solar-Photovoltaic-Resource-Interruption-Disturbance-Report.aspx
[6] https://www.nerc.com/pa/rrm/ea/Pages/October-9-2017-Canyon-2-Fire-Disturbance-Report.aspx
[7] https://www.nerc.com/pa/rrm/bpsa/Pages/Alerts.aspx
[8] https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC_Alert_Loss_of_Solar_Resources_during_Transmission_Disturbance-II_2018.pdf
[9] http://www.nerc.com/comm/PC/NERCModelingNotifications/Modeling_Notification_-_Modeling_Momentary_Cessation_-_2018-02-27.pdf

- Increasing the MC high voltage threshold to the highest value possible, at least higher than the NERC Reliability Standard PRC-024-2 voltage ride-through curve levels
- Reducing the recovery delay (time between voltage recovery and start of current injection) to the smallest value possible (i.e., on the order of 1–3 electrical cycles)
- Increasing the active power ramp rate upon return from MC to at least 100% per second unless specific reliability studies have demonstrated otherwise

Provide these proposed changes, and an accompanying proposed dynamic model, to their TP and PC. GOs should provide these proposed models, according to their TPs'/PCs' procedures for modifying existing facilities as soon as possible.

The NERC Alert subsequently requested that the TP, PC, TOP, and RC who are receiving the recommendations in the NERC Alert perform the following actions:

Recommendation 6a: Track, retain, and use the updated dynamic model(s) (and any other pertinent information gathered from this NERC Alert) of existing resource performance that are supplied by the GOs to perform assessments and system analyses to identify any potential reliability risks related to instability, cascading, or uncontrolled separation as soon as possible.

Recommendation 6b: Track, retain, and analyze the proposed dynamic model(s) supplied by the GOs that indicate their proposed changes (based on Recommendation 1b) to eliminate MC to the extent possible. Based on the analysis, approve or disapprove the potential changes based on reliability risks related to instability, cascading, or uncontrolled separation as soon as possible.

The NERC Alert sought to address two key aspects of modeling inverter-based resource dynamic performance:

- Ensuring that the currently used dynamic models accurately represent the actual behavior of the inverter-based resources; and
- Ensuring that the GO is coordinating with the TP and PC to make changes to inverter controls to eliminate MC by providing an updated dynamic model to the TP and PC for study and acceptance of the proposed changes (aligning with FAC-002-2)

Modeling Notification for NERC Alert

To support the Canyon 2 fire NERC Alert recommending actions to accurately model existing controls of inverter-based resources as well as proposed changes to controls (through updated modeling and studies) to support BPS reliability, the NERC IRPTF modeling sub-group developed a modeling notification regarding recommended practices for modeling MC.[10] While the NERC Alert recommended eliminating MC to the extent possible, it also highlighted the immediate need to accurately model solar PV large disturbance controls correctly (namely, the widespread use of MC). The modeling notification provided clear guidance on how to update models and key parameter values in the models to reasonably represent MC in RMS positive sequence stability programs. Refer to the modeling notification for more details.

[10] Modeling notification: Recommended Practices for Modeling Momentary Cessation, February 2018: https://www.nerc.com/comm/PC/NERCModelingNotifications/Modeling_Notification_-_Modeling_Momentary_Cessation_-_2018-02-27.pdf

Chapter 1: Inverter-Based Resource Modeling Activities

A significant amount of activities focusing on reliable integration of BPS-connected inverter-based resources, particularly on the modeling aspects, have taken place in the NERC IRPTF over the past two years. These activities have led to improvements to TP and PC modeling practices, identified systemic modeling challenges facing the industry, and led to recommended improvements[11] to modeling and studies required per NERC FAC-001-3 and FAC-002-2 Reliability Standards. This chapter documents many of these activities as well as the key findings and recommendations moving forward.

Canyon 2 Fire NERC Alert Findings

As described, a NERC Alert was issued following the Canyon 2 fire disturbance that required mandatory data reporting and recommended specific changes to performance and modeling of BPS-connected solar PV resources. Following the submittal of data from GOs regarding large disturbance performance, NERC was particularly focused on ensuring that the TPs and PCs received the data as well (per the recommendations of the NERC Alert) and were taking actions to ensure that the interconnection-wide planning models were being updated to reflect actual installed equipment. Furthermore, NERC was interested in the types of studies being performed by TPs and PCs to ensure that the proposed changes to solar PV inverters were being made accordingly by the GOs that reported this capability.

Prior to the NERC Alert, in many cases, TPs and PCs had insufficient information to determine whether the modeling data provided was a reasonable representation of the behavior of the resource. For example, most submitted models for resources employing MC in the field did not capture MC in the dynamic models; however, TPs and PCs were unaware of the discrepancy because there was no means of verifying this modeling data without the NERC Alert data gathered.

Upon completion of the time lines used in the NERC Alert for data submittal to NERC and modeling information submittal to the TPs and PC, NERC followed up with each TP and PC that should have received data from their respective GOs of solar PV resources. **Appendix C** provides a detailed anonymous review of a selection of entities that provided follow-up information. The key takeaways from these responses include the following:

- The majority of TPs and PCs stated that they received little or no updated dynamic models for the existing solar PV resources following the NERC Alert process. Similarly, nearly no solar PV facilities provided dynamic models of the proposed changes that could be made to improve performance. Key points made included the follow:
  - TPs and PCs stated that because the updated models were not provided by the GO, no further action was taken to perform system studies to ensure reliability.
  - Some TPs and PCs also stated that no follow-up actions were taken to request or collect the updated dynamic models from the GO to proactively address the known modeling issues. However, some TPs and PCs were very diligent about these follow-ups outside of the NERC Alert process (i.e., using market rules and other requirements).
- Some TPs and PCs stated that they did additional outreach to GOs of solar PV facilities but were met with either unwillingness to support such initiatives or no concrete timelines as to when the updates would be performed. Very few entities mentioned utilizing MOD-032-1 Requirement R3 to get the dynamic models updated even with known modeling issues present (based on the discrepancies between NERC Alert data and previously provided dynamic models). Entities that did additional outreach nearly all stated that a significant amount of effort and education was needed during these follow-ups to ensure the correct models and parameters were provided by the GO.

[11] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf

- Nearly every TP and PC that did receive updated dynamic models from solar PV resources following the NERC alert stated that the models provided had errors or deficiencies that made them unusable. These issues included the following:
  - The dynamic models provided were not the appropriate models to represent the resource being modeled or are considered obsolete models.
  - The electrical controls model submitted was reec_b; however, the resource currently uses MC. The reec_b dynamic model is not able to reasonably represent MC with sufficient detail.[12]
  - The dynamic model parameters did not match the information provided following the NERC Alert (i.e., the spreadsheet for MC performance required to be submitted by the GO to NERC did not match the modeling data provided to the TP or PC).
  - The dynamic models would not initialize properly or provide a flat run simulation for no disturbance.
- Multiple TPs and PCs stated that they received updated dynamic models and that those models were reasonable. However, upon further vetting by NERC it was determined that the dynamic models had incorrect parameterization or were not a reasonable representation of the MC characteristic (i.e., the models submitted were reec_b even though the resource uses MC). This identified a systemic lack of verification of the parameterization of the dynamic models by TPs and PCs as well as possible systemic issues regarding the understanding of these dynamic models compared to actual performance of solar PV resources.
- Some TPs and PCs stated that they rely solely on the MOD-026-1 and MOD-027-1 processes to update dynamic models for their base case submittals. However, as described in this report, this may lead to systemic modeling issues for verifying the accuracy of these models for large disturbance behavior of inverter-based resources. At the time of writing this report, IRPTF is in the process of creating a standard authorization request proposing changes to NERC MOD-026-1 and MOD-027-1 to address gaps with not verifying the large disturbance behavior of inverter-based resources.
- A small group of TPs and PCs were being very proactive in addressing known modeling issues using either MOD-032-1 Requirement R3 or other mechanisms, such as market rules in annual modeling submittal requirements; these examples, while rare, are good illustrations of how TPs and PCs should be proactively pursuing GO verification of their respective dynamic models and parameters against actual installed equipment settings.
- Most BPS-connected solar PV resources owners stated in their response to the data request for the NERC alert that they could eliminate MC or that the MC settings could be changed to improve performance. However, little to no dynamic models were provided for those proposed changes. Therefore, it is unclear, based on the information at hand, whether those changes were made, and whether the dynamic models have been updated to adequately reflect either the existing or proposed settings.
- Information from only about one-half of the installed capacity of BPS-connected solar PV resources (in the Western Interconnection) was collected as part of the NERC Alert process based on the size of resources and their designation as Bulk Electric System (BES) or non-BES resources. The extent of model accuracy for those resources that did not respond to the NERC Alert is unknown.

These findings from reviewing and analyzing the responses provided by GOs during the NERC Alert and by TPs and PCs as part of follow-up activities by NERC following the NERC Alert illuminate some major challenges to modeling of BPS-connected inverter-based resources (particularly solar PV resources). Known modeling issues exist and may continue to exist, and they may be attributable to issues related to modeling submittals during the interconnection

[12] The reec_b dynamic model was intended to represent solar PV resources with a simplified control block diagram structure relative to reec_a that did not fully capture the large disturbance behavior of some resources, particularly the voltage-dependent current logic; therefore, the model was later identified through IRPTF activities as being deficient and is currently not recommended for BPS-connected solar PV resources.

study process or annual base case creation process. It is clear that there is a lack of verification of reasonable parameterization of the dynamic models and likely a lack of understanding of these models by industry.

Industry Efforts to Update Dynamic Models

Prior to the activities following the Canyon 2 fire disturbance and the subsequent NERC Alert, Southern California Edison (SCE) and the California Independent System Operator (CAISO) attempted to collect updated generation dynamic models in 2017. This was in response to the unexpected performance observed by solar PV facilities during disturbances that occurred on SCE's system in 2016. The disturbances brought to light that the existing models provided by the GOs were not accurate for large disturbance behavior. To address this issue, SCE in coordination with the CAISO sent GOs data requests seeking updated or revised generation model data. To seek compliance with the data request, the request letters referenced MOD-025-2, MOD-026-1, MOD-027-1, MOD-032-1, PRC-024-2, CAISO's business practice manuals, and CAISO's Fifth Replacement FERC Electric Tariff Section 24.8.2. SCE sent approximately 120 data request letters to GOs. However, most of the data received from the GOs corresponding to the data request were deficient. During this process, SCE observed the following challenges:

- GOs stated that the data request caused financial burden since they had to hire engineers or consultants to collect the data and develop the dynamic models.
- GOs stated that some of the data required field verification testing that would not be performed until the next maintenance schedule.
- GOs that own non-BES facilities and therefore are not subject to NERC Reliability Standards for those facilities were reluctant to provide any updated data given that it was not enforceable.

In addition to the GOs being reluctant to submit updated generation model data, SCE also experienced data quality issues. GOs were able to meet MOD-032-1 requirements by providing minimum amounts of data and data that does not meet the quality expected and requested by SCE.

CAISO, in coordination with SCE, Pacific Gas and Electric (PG&E), and San Diego Gas and Electric, started a model update process in 2018 following the Canyon 2 fire NERC Alert. This process is seeking modeling improvements for all generation within the CAISO market. **Figure 1.1** shows an example of the process for updating the modeling data, specifically illustrating SCE process. The process includes the following:

- **Data Package Creation:** CAISO and its participating Transmission Owners (PTOs) create a package that is sent to each GO to gather updated modeling data with specified model data details and data formats.
- **GO Data Gathering:** GOs collect the necessary modeling information and provide this data to CAISO within 120 days from receiving the request per each facility.
- **CAISO and PTO Review:** CAISO and its PTOs perform a detailed review of the data collected to ensure that the model initializes correctly, the model performs acceptably under large disturbance conditions, all model parameters match the data provided in the NERC Alert, and all model parameters pass reasonability checks. When deficiencies in the submitted data are identified, CAISO will send feedback to the GO within 90 days.
- **GO Deficiency Cure:** Where applicable, the GO has 60 days to address the deficiencies identified by CAISO and its PTOs. Failure to resolve deficiencies during the 60-day period results in an accumulating financial penalty.
- **Second CAISO and PTO Review:** Following resubmission of the modeling data, CAISO and its PTOs have 90 days to again review the modeling data.

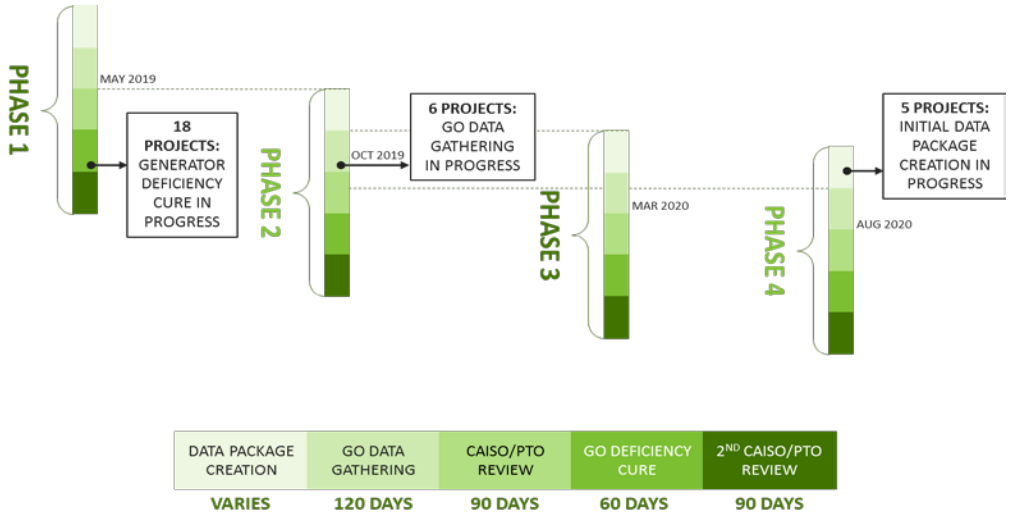


Figure 1.1: Illustration of Modeling Improvements Process Used by CAISO

All generating resources operational on or before September 1, 2018, and participating in the CAISO market are scheduled to provide updated modeling data in eleven phases.[13] **Table 1.1** shows the schedule and composition of resources in each phase. Resources utilizing MC and larger capacity resources were included in earlier phases due to the critical nature to address any modeling deficiencies for those resources. **Figure 1.2** shows the status of submissions received as of September 25, 2019. As of that date, CAISO had received updated models from 109 resources, constituting 13,915 MW of capacity. A total of 39 of those facilities (3,844 MW) are solar PV resources, and 21 of those facilities use MC (2,672 MW). A total of 101 submissions were reviewed by the time of documenting this report. Only 6 model submissions were accepted. A total of 95 facilities were identified as deficient, and 85 (10,923 MW) of those are still seeking a correction to the deficiency.

Table 1.1: CAISO Model Updates Schedule

Group	Phase	Submission Deadline	Solar		Wind		Other		Total	
			# Sites	MW	# Sites	MW	# Sites	MW	# Sites	MW
1	1	May 31, 2019	28	3,337	20	2,532	32	6,248	**80**	**12,117**
	2	October 30, 2019	19	1,925	3	408	61	8,046	**83**	**10,380**
	3	March 30, 2019	5	220	9	711	58	13,006	**72**	**13,937**
	4	August 30, 2020	22	2,171	18	1,204	72	11,397	**112**	**14,771**
2	5	January 1, 2021	40	763	6	311	60	1,895	**106**	**2,970**
	6	June 30, 2021	34	626	9	165	55	1,886	**98**	**2,677**
3	7	September 30, 2021	26	79	3	12	52	183	**81**	**274**
	8	December 31, 2021	29	97	9	46	36	171	**74**	**314**
	9	March 31, 2022	20	67	1	9	49	187	**70**	**263**
4	10	June 30, 2022	40	192	14	132	35	801	**89**	**1,125**

[13] All generating resources operational after September 1, 2018, are required to provide as-built models within 120 days of commercial operation.

Table 1.1: CAISO Model Updates Schedule

Group	Phase	Submission Deadline	Solar		Wind		Other		Total	
			# Sites	MW	# Sites	MW	# Sites	MW	# Sites	MW
5	11	September 30, 2022	26	166	4	19	28	114	**58**	**299**
Total			**289**	**9,645**	**96**	**5,549**	**538**	**43,933**	**923**	**59,128**

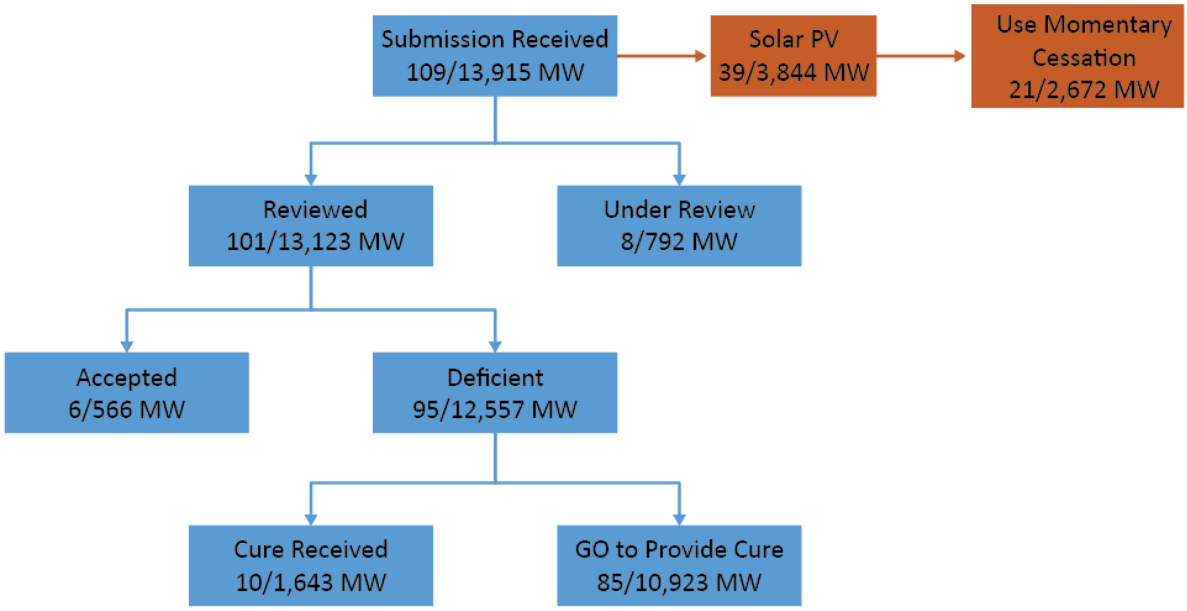


Figure 1.2: Status of Modeling Improvements at CAISO (September 25, 2019)

A similar review was performed by SCE, shown in **Figure 1.3**. A total of 29 (3,707 MW) solar PV facilities meet the criteria for the modeling assessment. Data requests have been received from 18 (1,928 MW) facilities. Of those, 15 (1,867 MW) use MC and all those models were reviewed. Every model submitted had deficiencies identified and SCE and CAISO provided that feedback to the GOs to address within the time lines described above. The review identified the following most common modeling deficiencies:

- The GO submitted the reec_b dynamic model instead of reec_a model. The reec_b model is unable to accurately model MC and is considered an obsolete model in WECC (i.e., reec_b is no longer approved and should be converted to reec_a).
- The GO submitted dynamic models with parameters for MC that did not match the actual settings data submitted as part of the NERC Alert.
- The GO did not provide a dynamic model that included MC even though the GO provided data following the NERC Alert stating that the resource did utilize this feature.

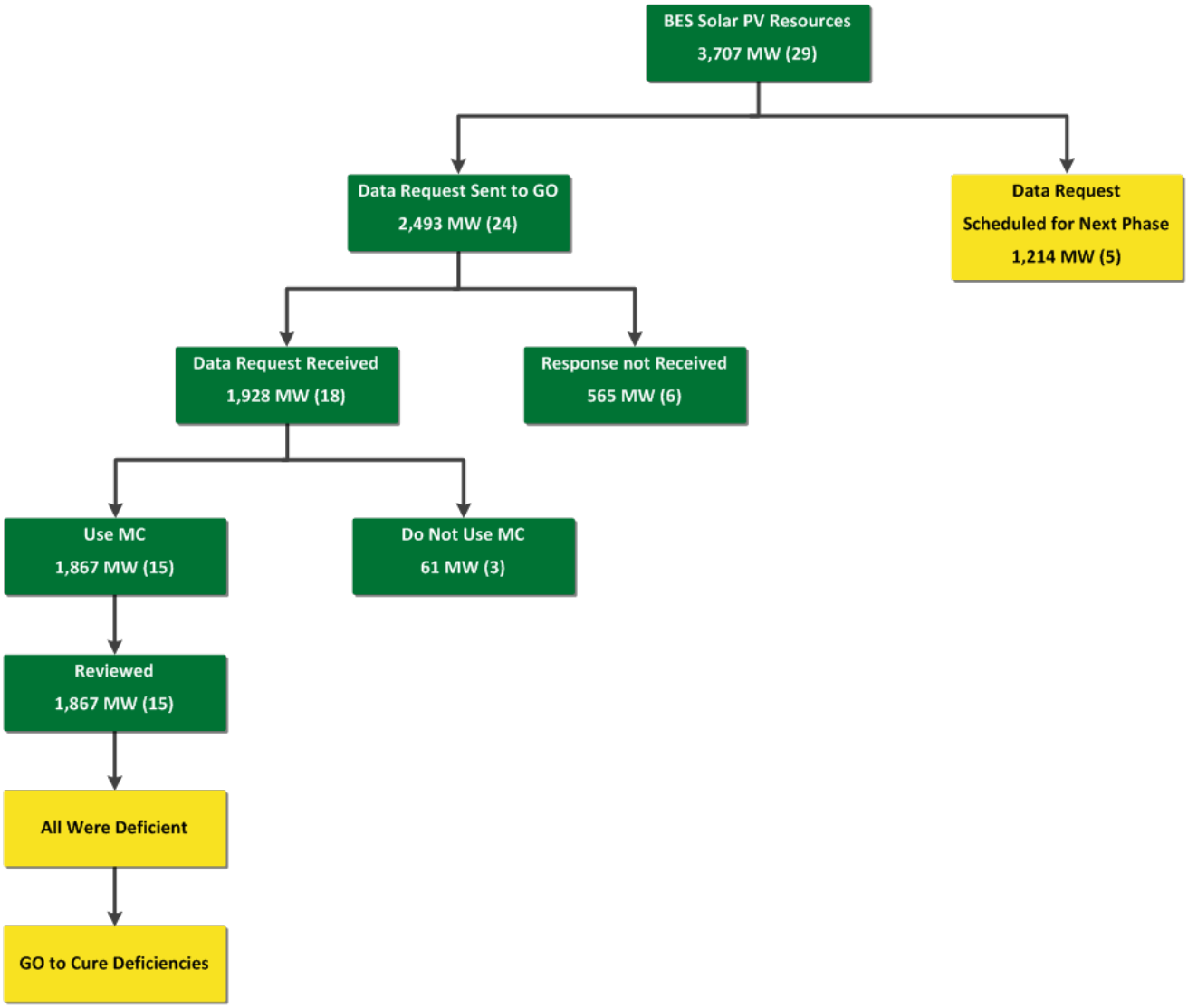


Figure 1.3: SCE Status Update for Modeling Improvements

PG&E is also actively participating in the review of the modeling data supplied by GOs in regards to the CAISO data requests. **Figure 1.4** shows a time line of all phases and the status of PG&E review in each. During report-outs at IRPTF meetings, PG&E highlighted that these analyses are resource demanding, considering that each generator data sheet has 190 equipment data items for review and cross-checking. The model data reviewers need to fill out a comprehensive checklist for each generator.

The PTOs are identifying any data quality deficiencies in the GO data submissions. These data quality deficiencies include, but are not limited to, deviations from applicable reliability standards, PTO interconnection handbook, expected steady-state or dynamic performance results, and reasonable values for generator technology type and size.

As CAISO gathers updated data and information for modeling, they are reporting the updated model data to WECC as the MOD-032 designee for creating the interconnection-wide base cases in the Western Interconnection. Until the full process is completed, potential modeling discrepancies for BPS-connected inverter-based resources may exist in the WECC base cases.

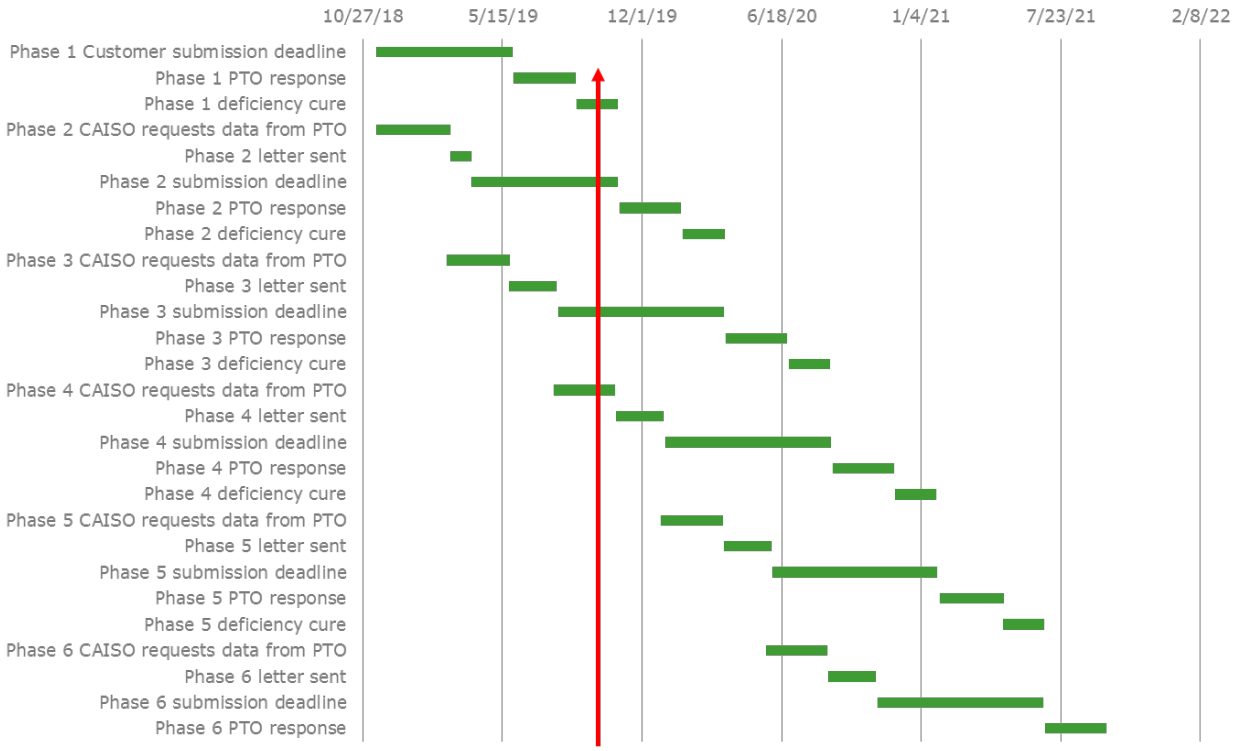


Figure 1.4: PG&E Timeline for Modeling Improvements [Source: PG&E]

WECC Solar Modeling Advisory Group

In April 2019, NERC and WECC jointly held a meeting with transmission entities to coordinate activities related to modeling and system analysis for increasing penetrations of BPS-connected inverter-based resources. One of the outcomes of this meeting was a request for WECC to form an ad-hoc group consisting of the meeting attendees to review the results from the NERC Alert data following the Canyon 2 fire disturbance. The WECC Solar Modeling Advisory Group was formed to focus on accurate modeling of existing inverter-based resources and to ensure that all BPS-connected solar PV resources modeled in the WECC Master Dynamics File for interconnection-wide base cases accurately represent the installed resources; the goal of this activity is to coordinate modeling improvements across TP and PC footprints to ensure all updates get integrated in the base case creation process.

As of the time of writing this report, the WECC Solar Modeling Advisory Group had not verified the validity of dynamic models for any BPS-connected inverter-based resources in the WECC base cases. One entity has reviewed the data in their footprint and identified modeling errors needing attention.

Challenges with Relying on MOD-026-1 and MOD-027-1

NERC MOD-026-1 focuses on verification of data for generator excitation control system or plant volt/var control functions, and MOD-027-1 focuses on verification of data for turbine-governor and load control or active power-frequency control functions. These standards are only applicable to an "individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 75 MVA[14] (gross aggregate nameplate rating)." One of the major challenges industry faces is that most solar PV resources have capacities lower than these thresholds and therefore the standards do not apply to them. IRPTF sees great value in ensuring that the large disturbance behavior of inverter-based resources is verified in some manner on a semi-regular basis. This can be accomplished with other means beyond small disturbance verification activities and does

[14] Note that the MVA size threshold for applicability of inverter-based resources is 75 MVA in the Western and Texas Interconnections and 100 MVA in the Eastern and Quebec Interconnections.

not necessarily warrant a large disturbance test that is generally not feasible. Verification of key controller parameters, specification sheets, type tests, and other methods can be used to perform verification for large disturbances.

Another issue facing MOD-026-1 is Footnote 1, which states that the excitation control system for aggregate generating plants (i.e., wind and solar PV) includes the volt/var control system including the voltage regulator and reactive power control system controlling and coordinating plant voltage and associated reactive capable resources. This language is slightly ambiguous on whether the verification activities include the inverter-level parameter values of the dynamic models. Various testing engineers and entities have stated that they are uncertain as to whether the standard applies to the plant-level parameters or the aggregate representation of the inverter-level settings.

Most commonly, verification test reports for inverter-based resources involve a small set of small disturbance tests that include, but are not limited to, the following:

- Capacitor switching test
- Plant-level voltage or reactive power reference step test
- Plant-level frequency reference step test
- Plant-level frequency play-in or step test

These tests do not perturb the generating resource such that the parameter values that dictate the large disturbance behavior[15] of the resource are verified in any way. In conjunction with the size thresholds that preclude many solar PV resources from being subject to these standards, this issue is the predominant challenge with the standards. While obviously incorrect model parameters may be identified during these tests, the tests do not verify that the parameters selected for the model accurately capture the dynamic behavior of the resource. Refer to **Appendix B** that shows the common suite of generic library dynamic models used to represent solar PV and Type 4 wind plants. The tables in **Appendix B** list the parameters for each model and describe whether the parameters can be verified using commonly applied verification tests (i.e., tests that demonstrate a match between simulated and actual response). The **Appendix B** materials show that the majority of parameters are not verified by these tests directly (i.e., large disturbance behavior is overlooked).

This may give a false impression to TPs and PCs that the full set of parameters are verified for use in planning studies. Improvements are needed to the NERC MOD standards to ensure that critical parameter values are verified in some meaningful way and that documentation is provided that justifies all parameter values; for example, testing engineers could document inverter-level settings, provide specification sheets (when available), perform and demonstrate engineering calculations, and perform other activities to demonstrate verification of parameters beyond testing activities only. However, these actions are not requirements in MOD-026-1 and MOD-027-1. Thus, these additional steps are often not documented or proven in MOD-026-1 and MOD-027-1 test reports for inverter-based resources, leading to the problems previously mentioned.

This issue is one of the predominant reasons why ride-through operation modes, such as MC, were able to persist and promulgate throughout BPS-connected inverter-based resources for so long.[16] The dynamic models did not accurately represent this large disturbance behavior since certain key parameters that govern the response under a large disturbance were incorrectly parametrized; however, the same plants were able to provide verification reports that demonstrated that the small disturbance behavior driven mainly by plant-level control settings reasonably matched.

[15] Large disturbance behavior involves large changes to terminal voltage, frequency, or phase. These conditions occur during fault events, the most commonly studied contingencies for planning assessments and interconnection studies.

[16] In addition to the reec_b (rather than reec_a) model initially being recommended for BPS-connected solar PV resources (not including the ability to accurately model MC)

Recommended Questions to Ask when Receiving Dynamic Models

As described throughout the paper thus far, systemic modeling issues have been identified by NERC and the IRPTF during disturbance analyses involving solar PV resources and their dynamic behavior during large disturbance events. Many of these issues stem from insufficient questions being asked by TPs and PCs when receiving dynamic modeling information for inverter-based resources. For this reason, IRPTF has developed a list of questions that should be asked for any modeling submittal provided by GOs of inverter-based resources. These questions involve validating, to some degree, through corroboration with additional data sources and confirming with the inverter manufacturer or other procurement contractor setting up the plant level controller or other control systems that the dynamic models accurately represent the behavior of the installed equipment. Questions that should be asked include, but are not limited to, the following:

- What type of BPS-connected inverter-based resource facility is being represented (i.e., a solar PV, wind, battery energy storage, or hybrid facility)?
- Do the steady-state and dynamic models provided meet the list of acceptable models established by the TP and PC, and do the models provided reasonably represent the resource?
- Is a one-line diagram provided to validate that the steady-state power flow model is a reasonable representation of the equivalent generating resource and associated components within the plant? Does the power flow model meet the recommended modeling practices used by the TP and PC?
- What make, type, and models of inverters and other relevant controls equipment are represented by these dynamic models? Were the inverter specification sheets and settings used to develop these dynamic models?
- Do the control modes set in the installed inverters and plant-level controls match the flags and settings configured in the dynamic models (e.g., voltage control versus reactive power control, current priority, and active power-frequency controls)?
    - Do the settings or configuration of these modes ever change in the installed equipment? If so, when and why? Do the dynamic models provided match all the expected settings and configurations for major performance capabilities?
    - Can the models adequately represent the performance of the plant for all these modes by switching the flags and settings, or is the model only valid for the indicated control mode?
- Are appropriate protection and control models, settings, or functions provided to the TP and PC to fully understand the potential ways in which the resource may trip or cease injection of current during abnormal operating conditions?
    - Are any of these settings out of the ordinary or restrictive beyond expected performance requirements set by the TO or by other relevant requirements?
    - Does the TP and PC have full understanding of all the possible protections and associated settings that may operate to trip the inverters?
    - Does the TP and PC have full understanding of any aspects of equipment performance and operation not captured by the dynamic models provided or available to the TP and PC?
- Is information provided that describes how the resource returns to service following any cessation of current from the BPS or following a trip?

This list of questions is not intended to be comprehensive; rather, it is intended to help TPs and PCs facilitate sufficient data collection such that BPS-connected inverter-based resources can be adequately modeled in system planning

studies to ensure BPS reliability into the future. TPs and PCs are encouraged to adopt these types of questions into their interconnection process or annual case creation process.

Predominant Issues for Modeling Inverter-Based Resources

Over the past few years, as IRPTF has continued to review modeling data and support the NERC Alert process, a number of modeling issues have arisen. These have been documented by the IRPTF here as a reference for future activities to improve modeling practices in the future. The predominant modeling issues for BPS-connected inverter-based resources (specifically solar PV resources) include, but are not limited to, the following:

- The dynamic models provided often do not meet basic model quality checks. These include acceptable dynamic model initialization in the interconnection-wide base case, flat performance during a no-disturbance simulation, and positive damping for an otherwise stable simulation. These issues are caused mainly by incorrect parameterization of the dynamic models.
- The dynamic models provided are often in the incorrect format as specified by the TP and PC in their modeling requirements; for example, the wrong simulation platform model structure may be used, or data may be provided in a tabular format rather than the actual dynamic model setup.
- The dynamic models or model parameters that have been provided for use in the interconnection study process and annual interconnection-wide base case creation sometimes do not match the information provided by the GO regarding the actual installed control settings for large disturbance behavior; for example, the reec_a model was provided, but the dynamic model parameters for representing MC do not match the data provided by the GO per the NERC Alert.
- The dynamic models use reec_b rather than reec_a even though the resource uses MC during large disturbance behavior. The reec_b model does not reasonably capture MC response characteristics and the reec_a model is recommended for BPS-connected inverter-based resources at this time. WECC has published a white paper describing the steps to convert the dynamic models from reec_b to reec_a; however, these recommendations are not being applied widely by industry.[17]
- The dynamic models provided appear "suspicious" because they are either using exactly the same parameter values used as default values in the simulation software manuals or using model parameters that exactly match a wide array of other plants modeled in the base case. It is unlikely that every control setting is exactly the same for a large number of plants; each control system should be tuned during the interconnection process and during commissioning to provide the optimal response for the locally connected network to which it is connected.
- The dynamic models are incorrectly parameterized with parameter values that are not coordinated appropriately; for example, coordinating the Vdip parameter with other MC parameters and VDL table values is critical for achieving the appropriate response. Furthermore, coordinating the reactive current controls and Ip and Iq prioritization settings are essential to avoid spurious overvoltage conditions post-fault. Parameterization of these models is extremely complex and requires experts in this area to make changes to model settings due to all these interactions between parameter values and models.
- Anecdotally, IRPTF members and NERC staff have heard multiple times of plants making changes to control settings without providing a dynamic model to the TP and PC nor requesting approval from the applicable transmission entities before these changes are made.[18] The GOs and GOPs have stated that these changes are not considered "material modifications" in their opinion; therefore, the GOs and GOPs believe they can be made without prior approval or notification.

[17] https://www.wecc.org/Reliability/Converting%20REEC_B%20to%20REEC_A%20for%20Solar%20PV%20Generators.pdf
[18] This applies to both BPS-connected synchronous generators as well as inverter-based resources.

- There is a lack of information available for TPs and PCs to verify whether the dynamic models are a reasonable match to actual installed equipment. TPs and PCs have stated that, while the commonly used small-disturbance tests are performed for MOD-026-1 and MOD-027-1 compliance, the TP and PC do not receive detailed reports that describe how each model parameter was or was not verified. Therefore, there is little to no data to use to verify that the dynamic models are set appropriately. Until the NERC Alert recommended GOs to provide data to TPs and PCs regarding large disturbance behavior of the actual installed equipment, multiple TPs and PCs expressed that this data was not readily available.
- While the interconnection process often states that as-built settings must be provided some time period after the commercial operation date of the resource, multiple transmission entities have stated that they are very challenged in enforcing those requirements once the plant has entered commercial operation and that receiving updated dynamic models through additional data requests have proved fruitless.
- For many entities, EMT models are not provided as part of the interconnection study process. EMT models are extremely difficult to acquire after-the-fact once the resource has been in service for a period of time. This is for many different reasons and poses a challenge to systems that are experiencing a rapid evolution of generation technologies. Without receiving EMT models up-front during the interconnection process, some TPs and PCs are faced with using significant assumptions for resource performance while performing EMT simulations unless other requirements, such as market rules, are enforced.
- Detailed studies with the most up-to-date available data for both BPS-connected inverter-based resources as well as distributed energy resources (DERs) are not being widely performed. While the IRPTF studies manually updated the dynamic models for BPS-connected solar PV resources, DERs were not considered in those studies. Conversely, studies of DERs using the most accurate data available are likely using the dynamic models for BPS-connected inverter-based resources provided in the interconnection-wide base cases that have systemic modeling issues identified in this report. Similarly, entities performing annual planning studies are required to use the data provided per MOD-032-1 that may include the systemic modeling issues mentioned.
- Many of the more common stability issues observed during high-penetration inverter-based resource conditions are not easily detectible using the existing state-of-the-art RMS positive sequence stability simulations. Issues with controls interactions, controls instability, subsynchronous control interactions (SSCI), and other issues during low short-circuit strength conditions require detailed EMT simulations that are not commonly performed during the annual planning process.
- The commercially available simulation tools most commonly used by TPs and PCs lack the reporting tools and capabilities to easily deduce necessary metrics for an increasingly variable and inverter-based generation mix. These may include the amount of on-line contingency reserves, the amount of on-line frequency responsive reserves, the amount of total on-line resources by type, the amount of on-line resources with certain performance characteristics (e.g., MC), total system inertia, short-circuit ratio-based metrics, and other useful indicators.
- Modeling issues are addressed in silos by one organization that may or may not be sharing their updated dynamic models and parameterization of those models with neighboring entities. Issues identified in **Chapter 2** illustrate how modeling issues in one area could have a significant impact on neighboring areas and that these issues need to be communicated to all neighboring entities, particularly if the controls begin interacting with each other.

Modeling Issues and the Interconnection Study Process

Discussions during IRPTF meetings and modeling team meetings focused on identifying potential root causes to the modeling errors from the start of newly interconnecting resources to the BPS. This led IRPTF to review at a high level the FERC interconnection process and identify some key factors that may be attributed to some of the modeling

deficiencies observed to-date. For the purposes of this discussion, the LGIP and *Large Generator Interconnection Agreement* (LGIA) are used; however, similar concepts would apply to the *Small Generator Interconnection Procedures* (SGIP) and *Small Generator Interconnection Agreement* (SGIA) and may have parallels in areas not subject to the FERC interconnection process.

The LGIP specifies that an interconnection request is in the form of Appendix 1 to the LGIP, and initiating an interconnection request includes a monetary deposit, demonstration of site control and also a completed application in the form of Appendix 1. Furthermore, Section 6.1 states that the interconnection customer must provide the "technical data called for in Appendix 1, Attachment A."

Attachment A to Appendix 1 of the LGIP is the Large Generating Facility Data section of the interconnection request and defines the technical data required for an interconnection request. For synchronous generators, the required technical information is fairly comprehensive and will provide a reasonable amount of information to inform and verify the dynamic models provided for those resources. However, for wind generators, the only information requested is shown in **Figure 1.5**, and there is no specified technical data for solar PV resources in the attachment.

WIND GENERATORS

Number of generators to be interconnected pursuant to this Interconnection Request: _____

Elevation: _____ _____ Single Phase _____ Three Phase

Inverter manufacturer, model name, number, and version:

_____

List of adjustable setpoints for the protective equipment or software:

_____

Note: A completed General Electric Company Power Systems Load Flow (PSLF) data sheet or other compatible formats, such as IEEE and PTI power flow models, must be supplied with the Interconnection Request. If other data sheets are more appropriate to the proposed device, then they shall be provided and discussed at Scoping Meeting.

Figure 1.5: Appendix 1 Attachment A of FERC LGIP

While it is understood that only limited technical detail may be known for the interconnecting resource during the feasibility study phase of interconnection, detailed modeling information should be available for stability studies per the system impact study phase of interconnection. Section 7 of the LGIP specifies this process and associated requirements. Section 7.1 states the following:

> If the "Interconnection Customer does not provide all such technical data when it delivers the Interconnection System Impact Study Agreement, [the] Transmission Provider shall notify the Interconnection Customer of the deficiency within five (5) Business Days of the receipt of the executed Interconnection System Study Agreement and Interconnection Customer shall cure the deficiency within ten (10) Business Days of receipt of the notice…"

It is unclear whether this statement specifically applies to the modeling data needed to execute the study in an appropriate data format with sufficient technical detail. If it does cover the modeling data, these time lines are likely too tight for the TP to do a thorough review of the dynamic models and their parameters and for the interconnection customer to engage necessary stakeholders (e.g., the inverter and plant-level controller manufacturers).

Section 24.3 of the pro forma LGIA states that the interconnection customer must provide updated information, including manufacturer information, no later than 180 days prior to trial operation. The section states the following:

> "…Large Generating Facility data requirements contained in Appendix I to the LGIP…[and] it shall also include any additional information provided to the Transmission Provider for the Feasibility and Facilities Study. Information in this submission shall be the most current Large Generating Facility design or expected performance data. Information submitted for stability models shall be compatible with Transmission Provider standard models. If there is no compatible model, Interconnection Customer will work with a consultant mutually agreed to by the Parties to develop and supply a standard model and associated information."

Section 24.3 also states the following:

> "data is materially different from what was originally provided to the Transmission Provider pursuant to the Interconnection Study Agreement…then Transmission Provider will conduct appropriate studies to determine the impact of Transmission Provider Transmission System based on the actual data submitted…The Interconnection Customer shall not begin Trial Operation until such studies are completed."

While the process outlined here in Section 24.3 of the LGIA is relatively clear in terms of providing the most up-to-date information and models for stability studies, discussions within and between NERC and TPs and PCs have stressed the tight time lines and pressure from TP management to expeditiously move the interconnection requests through the process for fear of complaints from interconnection customers regarding unfair requests. Entities have indicated that studies may not be revisited and fully vetted upon receiving updated dynamic modeling information. Furthermore, TPs and PCs have stressed that the data supplied by the interconnection customer may not even be accurate or reflective of the actual performance of the resource until well past the interconnection process and after commercial operation. For example, the majority of dynamic models for BPS-connected solar PV resources did not accurately reflect MC, and this finding was not widely known until after the NERC Alert process. TPs and PCs have stressed that they have limited authority to demand additional information during the interconnection process and take the dynamic models and information provided by the interconnection customer as credible and accurate.

Per FERC Order 845, TPs must develop a technological change procedure to outline what technological changes would be permitted without restudy. If the technological changes are equal to or better than the existing technology, no restudy should be required according to FERC Order 845. The question raised is "who makes the determination that the technological advancement is equal to or better than the previous performance?" In many cases, changes to control settings, control features, etc. require detailed studies to ensure no unknown control interactions or anomalous behavior occurs from the resource during large disturbance events. It is unclear to TPs when they can require restudy due to models not being correct or accurate. Blanket determinations of what constitutes an acceptable change without sufficient study may put the BPS in potential situations of elevated reliability risk as the penetration of inverter-based resources continues to increase.

For the reasons stated in this section, it is recommended that the interconnection study procedures be reviewed and possibly improved to ensure clarity and consistency for inverter-based resources. Specifically, it should be made clear the types of data required to be provided during the interconnection request and throughout the entire study process as well as when changes to equipment, controls, technology, settings, and other characteristics that could change the electrical response of the resource should be restudied.

Growing Need for Electromagnetic Transient Modeling

As inverter-based resources continue to interconnect to the BPS across North America, TPs and PCs are faced with challenges relying solely on the RMS positive sequence dynamic models to ensure reliable operation of the BPS. The following challenges have been identified in an increasing number of networks across North America and around the world:

- The RMS positive sequence simulation platforms, by design, are generally not suitable for capturing the dynamic response of inverter-based resources for unbalanced fault conditions.
- Due to the aforementioned point, any individual phase-based controls or protection cannot generally be modeled to complete accuracy in an RMS positive sequence simulation platform. For this reason, the RMS positive sequence dynamic models have limitations in precisely assessing ride-through performance during unbalanced faults often performed during interconnection studies. Approximations and engineering judgment can be applied after extensive detailed simulations. However, applicability of these approximations is still uncertain.
- In areas of high penetrations of inverter-based resources or low short-circuit strength networks, the existing state-of-the-art generic RMS positive sequence dynamic models may encounter numerical issues that pose challenges for TPs, and PCs to trust the results obtained from these studies. There are, however, beta versions of new generic RMS positive sequence models that have shown numerical robustness in low short-circuit networks and are being introduced in the various simulation platforms. In addition, spurious spikes in electrical quantities in positive sequence RMS simulations can occur at any bus. This is caused by sudden changes in inverter terminal voltage phase angle due to the network bus voltages being algebraic variables instead of differential equations (as they are in EMT programs). These limitations need to be well understood by planning engineers.
- The RMS positive sequence dynamics models do not include the real-code behavior of inverter-based resources and often involve engineering judgment based on controller block diagrams used in representing the actual performance of these complex power electronic resources. In the generic models, these simplifications are based on ensuring that the trend of the response is still captured accurately. However, a gap exists in identifying the exact thresholds at which inverter and plant protection would activate that could be dependent on knowledge of the real code within the control systems.
- Due to the numerical issues and simplified modeling assumptions described above, the existing state-of-the-art generic RMS positive sequence dynamic models are often unable to identify controls instability or controls interactions with neighboring facilities[19] or sub-cycle inverter tripping. SSCIs are not identifiable by these models by design of the simulation platform (i.e., fundamental frequency positive sequence simulations). Therefore, the most commonly used planning tools are not able to capture phenomenon like SSCIs.
- The existing[20] state-of-the-art generic RMS positive sequence dynamic models do not represent phase lock loop dynamics and other inner loop (small time constant) controls that often dictate the dynamic behavior and changes in control modes for inverter-based resources. Due to the lack of phase lock loop dynamics and inner control loop modeling in the RMS positive sequence dynamic models, these models are unable to accurately represent the on-fault current contribution from inverter-based resources as well as any fast controls issues that may arise under low short-circuit strength conditions. This can, however, change once the new generation of generic positive sequence models become part of the standard library of models.

The combination of these modeling challenges drives the growing need for EMT modeling[21] and studies for inverter-based resources, particularly in areas of growing penetration of inverter-based resources or low short-circuit strength. These areas may be wider areas of the BPS or may be local pockets of inverter-based resources that often do not include any nearby synchronous generation or loads. The NERC *Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources*[22] recommends including real-code EMT modeling requirements for all newly interconnecting inverter-based resources to the BPS and also recommends

[19] As with other inverter-based resources, series compensated transmission circuits, and HVDC facilities.
[20] There are, however, beta versions of new generic RMS-positive sequence models that have representation of these controls and have shown accurate behavior.
[21] There are challenges with migrating towards large-scale EMT modeling and studies. Therefore, it is important to understand which situations may warrant EMT modeling and to have suitable information and models available to perform EMT simulations when needed.
[22] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf

benchmarking the RMS positive sequence dynamic models with those EMT models. Documentation should be provided during the interconnection process such that the interconnection studies performed by the TP and PC can identify any BPS reliability issues at the time of interconnection and also into the future.

All the issues described in this chapter are dependent on accurate parameterization of the models to match the installed equipment in the field. Inaccurate parameterization of any model (RMS positive sequence or EMT) can lead to misidentification of potential BPS reliability issues via studies. TPs and PCs can help ensure accurate parameterization of dynamic models by asking the GO and OEM for data regarding the type of facility, inverter modes of operation, control settings, ride-through performance, unusual or restrictive protection settings, reconnection and recovery times, etc.

Chapter 2: Reliability Studies of Inverter-Based Resources

The NERC IRPTF developed a sub-group that focuses on modeling and reliability studies in the Western Interconnection since the majority of grid disturbances have occurred in this area. The sub-group performed many system studies using RMS positive sequence simulations[23] to understand potential reliability issues that may be attributed to different inverter-based resource performance issues. These studies, their findings, and recommendations based on the study results are provided in this chapter.

A range of studies were performed by IRPTF in phases as the industry continued to expand its knowledge and understanding of inverter performance during large disturbance events. These phases included the following:

- **Phase 1:** Phase 1 used a light winter base case that was adapted to represent minimum inertia and minimum reserves. IRPTF study engineers considered this to represent a heavily stressed, unrealistic operating case, but it served as the worst case scenario from an inertia and reserves standpoint. The goal of this study was to review the resource loss protection criteria impacts caused by potential widespread MC. Phase 1 studies applied a user-written model as described in the following section.
- **Phase 2:** Phase 2 used a light summer base case intended to represent a mid-day condition where CAISO is preparing for ramping[24] later in the afternoon. This case included more on-line reserves in preparation for that ramp and was deemed more realistic from a dispatch perspective. The case was compared against real-time operating conditions and deemed suitable. Phase 2 studies applied the same user-written model described in Phase 1.
- **Phase 3:** Phase 3 studies used the same base case as Phase 2. If the actual MC settings were provided by the GO to the TP and PC per the NERC Alert following the Canyon 2 fire disturbance, then the actual MC settings were updated in the dynamic models supplied by the GOs.

Development of User-Written Model to Represent Momentary Cessation

Data from the NERC Alert following the Canyon 2 Fire disturbance showed that the vast majority of BPS-connected solar PV inverters use MC during large voltage disturbances. However, the IRPTF reviewed the WECC base cases and determined that few of the dynamic models used in the interconnection-wide base case accurately represented MC behavior. Therefore, the IRPTF determined that the best modeling approach for the purposes of the Phase 1 and Phase 2 studies was to use the models supplied by the equipment owners and introduce a user-written model that interacted[25] with the existing models to capture the MC. This decision was made to ensure consistency with the models submitted by the equipment owners (i.e., the GOs) while also ensuring the large disturbance behavior more accurately reflected the actual installed performance. The goal was to minimize any changes to the GO-supplied models while also enabling the ability for IRPTF to effectively study different assumptions for MC and its use across the BPS to the greatest possible extent.

The user-defined model was developed to represent MC for BPS-connected solar PV resources. The model is invoked by a model entry in the dynamic model file with the following MC parameters:

- *Vblk*: MC low voltage threshold [pu]
- *Delay*: recovery delay [s] once the voltage recovers above *vblk*
- *rrpwr*: active current ramp rate [pu/s] during the recovery period

[23] IRPTF studies focused primarily on BPS reliability impacts of widespread use of MC using interconnection-wide study cases. MC can be identified by using RMS positive sequence models, and therefore more detailed EMT simulations were not needed for these purposes.
[24] Ramping caused by the drop-off of solar PV resources in the late afternoon due to the sun setting.
[25] The user-written model created by IRPTF overlaid the existing models in the base case and allowed for more accurate representation of MC. Refer to the following publication for more details: S. Zhu, D. Piper, D. Ramasubramanian, R. Quint, A. Isaacs and R. Bauer, "Modeling Inverter-Based Resources in Stability Studies," 2018 IEEE Power & Energy Society General Meeting (PESGM), Portland, OR, 2018, pp. 1–5.

- *lockout*: number of successive MC events before the inverters are permanently locked out

These parameters were applied by the user-defined model to all generators in the base case with a turbine type set to 31.[26] For the purposes of this study, the model was configured such that any generator with the third owner value set to 999 would be excluded from applying these MC controls. During initialization, the user-defined model saves the list of generators applying the model.

At each simulation step, the user-defined model applied to each individual generator monitors for conditions that trigger MC. A generator operates in one of the following modes:

- **Normal mode:** Voltage is above *vblk* and the generator is not in recovery mode; the user-defined model does not apply any additional controls to the supplied models. All original parameters in the supplied models are in effect.
- **Block mode:** Voltage is below *vblk*; the user-defined model forces active and reactive current command to zero, and zero current is injected from the resource.
- **Delay mode:** Voltage dropped below *vblk* and is now above *vblk* for less than *delay* seconds; the user-defined model continues forcing both active and reactive current command to zero (i.e., remaining in MC).
- **Recovery mode:** Voltage dropped below *vblk* and is now above *vblk* for more than *delay* seconds and less than recovery period (*1/rrpwr*); the user-defined model replaces the active current ramp rate in the supplied models to *rrpwr*.

The user-defined model approach is suitable for these types of exploratory studies to understand different assumptions on inverter behavior and their impacts to BPS performance (i.e., varying MC settings for voltage threshold, delay, and ramp rate recovery). Application of the user-defined model is not suitable for production-level reliability studies (i.e., establishing system operator limits, annual transmission planning assessments, and operations planning assessments) since the user-defined model applies the same settings to all generators in which the model is applied. Furthermore, the model affects the performance of the GO-supplied models. In this case, it is believed that these changes actually better-reflect the actual behavior of the resources; however, these models need to be updated by the GO and supplied to the TP and PC for them to enter the interconnection-wide base cases.

Phase 1: WECC Resource Loss Protection Criteria Assessment

Initial analysis of the Blue Cut fire disturbance identified MC as a widely used form of ride-through during large disturbances on the BPS. The initial concern regarding the momentary loss of active power was frequency instability and the potential triggering of underfrequency load shedding (UFLS). The IRPTF performed stability studies and published a report on this subject.[27] The key takeaway was that frequency stability due to MC was not a significant issue with the assumption of a reasonable return-to-service behavior from inverter-based resources. However, it was also determined that BPS transient stability could be affected if MC was widely applied across the BPS with certain settings. Based on the limited data available at the time, it was determined that "typical" MC settings were as described in **Table 2.1**. Preliminary studies were performed and the team determined that the combination of thresholds in **Table 2.1** may result in system instability if widely applied to solar PV resources connected to the BPS. At that point, the Resource Loss Protection Criteria assessment was complete, but the focus turned toward assessing transient and voltage stability issues.

[26] Turbine type is a field provided in GE PSLF software to represent different types of generating resources in the power flow base case. The WECC Base Case Preparation Manual requires all BPS-connected solar PV resources to be modeled using turbine type value set to 31.

[27] https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/IRPTF_RLPC_Assessment.pdf

Table 2.1: MC Default Settings	
Characteristic	**Default Setting**
Low Voltage Threshold	0.9 pu
Recovery Delay	0.5 s
Active Current Recovery Ramp Rate	1.0 pu/s

Phase 2: Initial WECC Stability Simulations

A large instantaneous active power change in one part of the BPS will cause large changes to bus voltage angles and subsequent power swings across the BPS. This has conventionally been an issue with the loss of large synchronous generators or tie lines and been a relatively minor issue for normally cleared BPS faults. However, with solar PV resources utilizing MC, voltage depressions caused by BPS faults may result in widespread MC across a large geographical area. For bolted three-phase close-in faults, terminal voltage may drop to almost zero for local generators, causing even synchronous machine power output to be close to zero. However, for synchronous machines, this is a relatively local phenomenon, and resources on the BPS electrically farther away from the fault should be significantly less affected. IRPTF studies, on the other hand, showed that the "typical" MC settings applied to many BPS-connected solar PV resources could also invoke angular swings on the BPS and therefore needed closer examination. MC settings shown in **Table 2.1** were applied to all solar PV resources (roughly 12,000 MW of on-line capacity) since, at the time, no further information was available or easily applicable to the case dynamics data. These simulations are described here as Phase 2 studies.

Extent of Possible Momentary Cessation

Initial stability simulations explored the extent of BPS buses that could potentially have voltage low enough to elicit MC from solar PV resources during on-fault conditions. These studies used a normally-cleared (4 cycle), three-phase bolted fault[28] on a BPS bus in Southern California. **Figure 2.1** and **Figure 2.2** show the results plotted geographically. BPS buses across a large area of the Western Interconnection can experience voltage less than 0.9 pu during on-fault conditions (blue area of **Figure 2.1**). Conversely, very low voltage (e.g., less than 0.4 pu as shown in the blue area of **Figure 2.2**) during on-fault conditions is only observable in a small geographic regional around the fault. Thus, lowering the MC low voltage threshold exponentially decreases the risk of widespread MC and the potential risk of stability issues. **Figure 2.1** and **Figure 2.2** illustrate the risk of BPS system instability caused by widespread use of MC with a relatively high value for the MC low-voltage threshold. Eliminating the use of MC by inverter-based resources in favor of providing dynamic reactive support that is commonly available in modern inverter designs significantly minimizes the risk of BPS instability issues.

[28] Typical assumption for TPL-001 stability simulations for P1 contingencies.

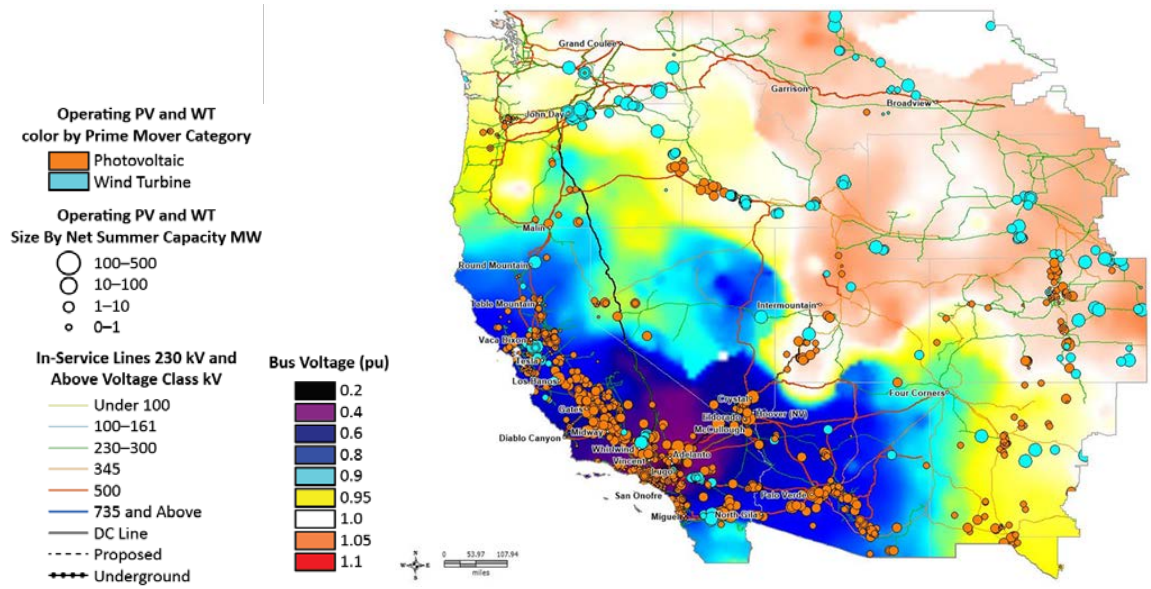


Figure 2.1: BPS Bus Voltages during On-Fault Conditions for Fault in Southern California

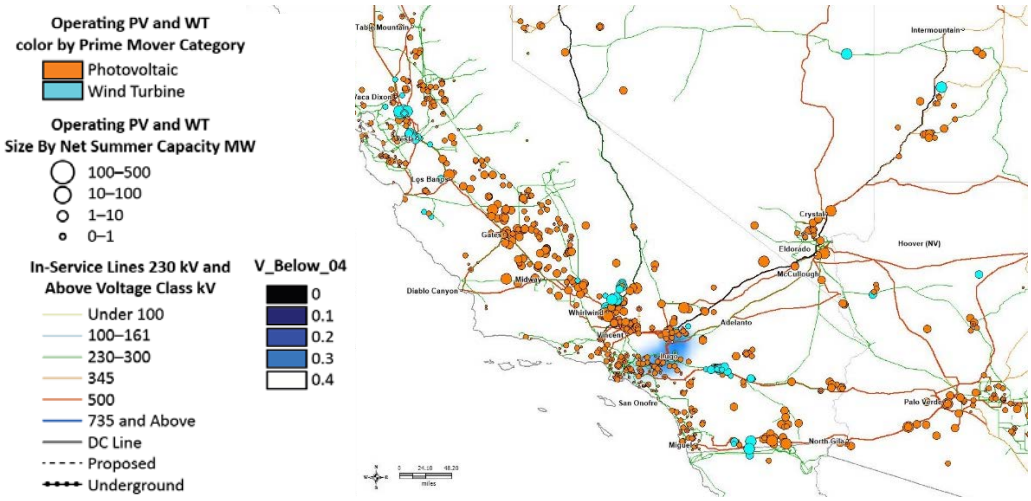


Figure 2.2: BPS Bus Voltages less than 0.4 pu during Same On-Fault Conditions as Figure 2.1

Identified Potential Instability Events

To identify fault locations that could result in instability or unacceptable system performance, normally-cleared three-phase bus faults were simulated near major 500 kV buses across the Western Interconnection. The MC settings shown in **Table 2.1** were applied to all BPS-connected solar PV resources as a conservative assumption based on the data available at the time of simulations. While varying levels of system performance were identified, only two potential instabilities were identified—an N-1 fault event and an N-1-1 fault event with no system redispatch between contingencies. These two simulations are described below to illustrate the analysis of the instability and identify key drivers of the instabilities.

N-1 Fault Simulation

A normally-cleared bolted three-phase fault was applied on a transmission circuit near a 500 kV bus in the PG&E footprint. The simulation results showed system instability caused by MC that was attributed to a lack of dynamic reactive support during and immediately following the fault. When the fault is applied, about 7,000 MW of solar PV resources across California and neighboring areas exhibit MC, see **Figure 2.3** (left). MC occurs instantaneously upon voltages falling below the MC threshold value (i.e., 0.9 pu), so this would occur for a normally-cleared fault. Upon fault clearing, voltages remained depressed below the MC voltage threshold in the Northern California region, and

the inverters therefore did not return to predisturbance output (i.e., remained in MC after fault clearing). The lack of reactive power support in the area following fault clearing caused transient voltage collapse along a major transmission corridor within a couple seconds. **Figure 2.3** (right) also shows different BPS bus voltage magnitudes in California and the sustained low voltage after fault clearing prohibiting active and reactive current recovery of solar PV resources to predisturbance levels.

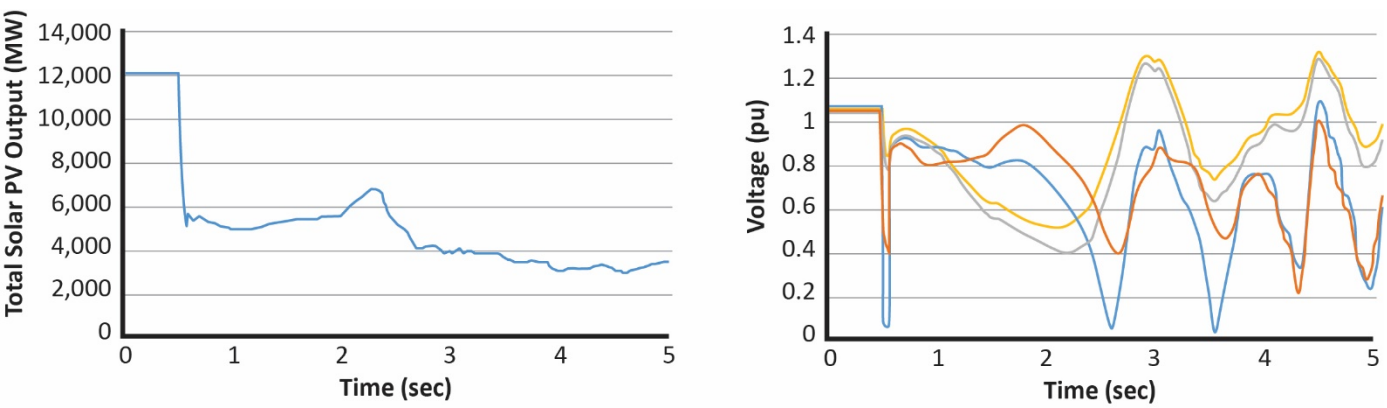


Figure 2.3: Total Solar PV Output (left) and BPS Bus Voltages in California (right) for N-1 Fault Event

Widespread MC that results in the zero current injection from solar PV resources removes a significant amount of reactive power support from these resources during and immediately following fault clearing. As BPS voltages begin to recover upon fault clearing, insufficient dynamic reactive power support is available to bring BPS bus voltages back to a stable operating point. This is primarily caused by the solar PV resources not resuming current injection following fault clearing because voltage remains below the MC low voltage threshold. This sequence of events occurs immediately upon fault clearing as a large power swing is picking up across the Western Interconnection due to the deficit of power in the California region. Voltages along the interties collapsed about 1 second after fault clearing. The primary driver of voltage collapse in this local region is the inability of solar PV resources to recover from MC due to reduction of reactive power support.[29]

During the N-1 contingency, interactions with widespread MC and HVDC circuit behavior played a critical role in BPS stability. Line-commutated converter (LCC) HVDC circuits often have controls that will block thyristor firing when voltages fall below a predetermined threshold.[30] On the inverter end (in Southern California) of this HVDC circuit, that threshold is around 0.9 pu ac voltage for a predefined period of time. Consider **Figure 2.4** (left), which shows the inverter-side ac bus voltage as well as the HVDC circuit power flow. Voltage falls below 0.9 pu due to the fault and remains depressed below this level due to the widespread MC of solar PV resources. This triggers thyristor blocking and power flow immediately being reduced to zero on the HVDC circuit. That power is transferred to the ac system and picked up across key ac transmission interties as seen in **Figure 2.4** (right). The blocking of the HVDC circuit caused by widespread MC and insufficient reactive power support near the inverter-end of the HVDC terminal further exacerbate the ac system power swings and further drives voltage collapse along major ac circuits.

Voltages at the midpoint of this large power transfer (as shown in **Figure 2.3**) decay the fastest and collapse within 1.5 seconds after the fault. During the fast voltage decay in the first swing, synchronous generators within PG&E lose synchronism at about 0.5 second after the fault. Following PG&E, other synchronous generators in the Southern California area lose synchronism within 1.0 second after the fault.

[29] Widespread MC also causes induction motor loads to slow down and draw more reactive current from the system.
[30] This is the expected performance of the HVDC circuit to protect from commutation failure and is modeled accordingly in stability simulations.

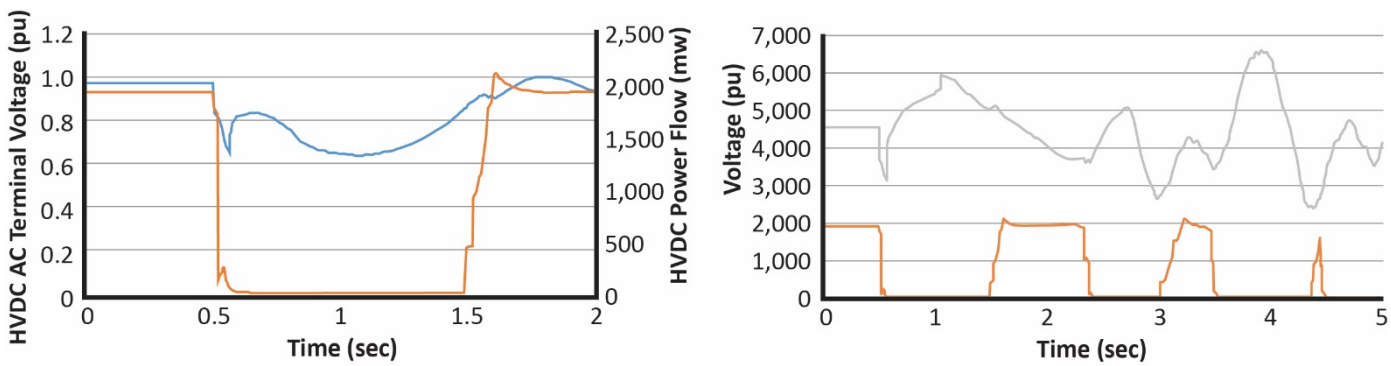


Figure 2.4: HVDC AC Voltage and Power Flow (left) and AC and DC Intertie Flows (right)

Upon identifying this instability, the HVDC circuit controls were further studied. This HVDC circuit includes a RAS that trips a large amount of synchronous generation in the Pacific Northwest when flows exceed a predefined threshold. The RAS is designed to support BPS voltage stability for situations where major ac interties experience significant power swings that drive transient voltage performance issues (as described above). The RAS is event-driven (i.e., using line loss logic) for specific contingencies in the Pacific Northwest region and was not designed for prolonged voltage depressions in the Southern California footprint causing sustained blocking of the HVDC circuit. Therefore, it was important to simulate this RAS in more detail (simulations above did not include the RAS action to trip generation) and understand its impacts on BPS performance with the HVDC circuit blocking and widespread MC.

Delayed voltage recovery lasting more than 1 second with voltage below the predetermined threshold at the inverter-end (receiving-end) of the HVDC circuit caused the HVDC RAS to trigger generator tripping actions. About 2,000 MW of generation in the Pacific Northwest would be tripped by the RAS actions based on the ac and dc circuit flows in the base case. Generation tripping initiated by the RAS action reduced the large power swing on the ac interties (as expected) and stabilized the BPS for this N-1 contingency. **Figure 2.5** shows HVDC and ac intertie flows with the RAS actions modeled.

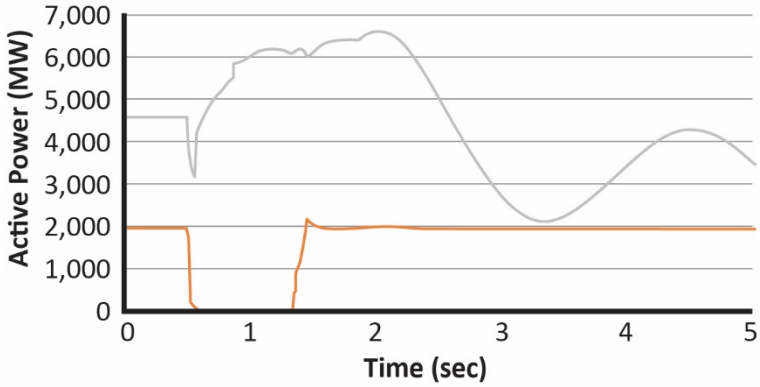


Figure 2.5: AC and DC Intertie Flows for N-1 Fault with RAS Modeled

With the RAS modeled appropriately, bus voltage magnitudes along the ac interties recover to acceptable levels following fault clearing. **Figure 2.6** (left) shows bus voltages with the RAS modeled (solid line) and without the RAS modeled (dashed line). Reactive power deficiency along the ac intertie in Northern California caused by solar PV MC still exists; however, the RAS action offloads the ac intertie and allows voltage to recover and solar PV resources to return to predisturbance output. However, bus frequencies fall close to UFLS levels, something not intended for a normally-cleared N-1 contingency (see **Figure 2.6**, right). The combination of loss of solar PV resources due to MC and the generation tripped in the Pacific Northwest due to RAS action are the primary drivers for the large frequency excursion. In addition, the amount of generation lost exceeds Balancing Authority requirements for this type of contingency and could increase the operating reserve requirements if not mitigated.

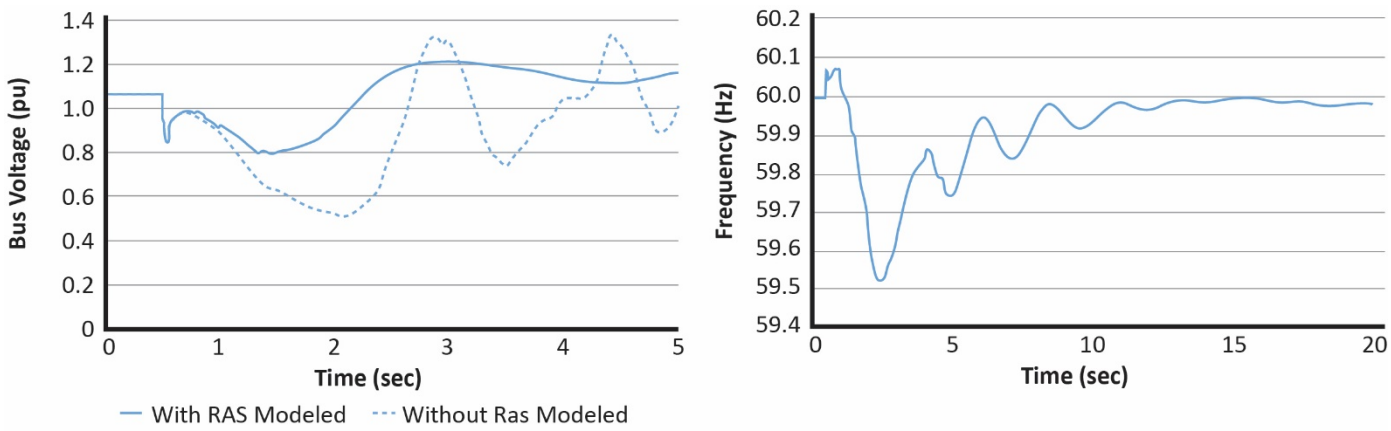


Figure 2.6: AC Intertie Bus Voltage with and without RAS (left) and System Frequency with RAS (right)

Key Takeaway

Widespread use of MC from BPS-connected solar PV resources following a fault event in the Northern California region could interact with HVDC controls. This interaction could result in inadvertent operation of RAS actions that were not designed for this type of contingency. While the system remained stable for the simulated contingency and performance of the BPS-connected solar PV fleet, system performance was not acceptable. Therefore, the IRPTF determined that the elimination (or mitigation) of MC was needed to improve BPS stability performance now and into the future. These studies did not, however, identify a known stability issue since the default settings for MC were used rather than actual equipment settings (since this data was not available).

N-1-1 Fault Simulation

One other instability was identified during the screening studies: an N-1-1 contingency with no system redispatch between contingencies. With one line taken out of service in the power flow base case (first N-1), a high-penetration wind area in Southern California was radially connected to the grid via one 500 kV transmission circuit. No voltage violations or thermal overloads existed after the first N-1, so no redispatch was needed. A line fault on the 500 kV line was applied. The fault caused widespread MC from solar PV resources and the HVDC circuit to block (again initiating the Pacific Northwest RAS action). In addition, wind generation consequentially tripped[31] due to the permanent fault removing the plant's only remaining grid tie to the BPS. **Figure 2.7** shows the HVDC and ac intertie power flows in addition to total BPS solar PV and wind power output. **Figure 2.8** (left) shows BPS bus voltages along the ac intertie and **Figure 2.8** (right) shows system frequency. While the system remains stable, performance is marginal and would not be deemed acceptable. Transient voltage swings along the ac intertie are severe, and key bus voltages in that area are marginally stable but approach the instability point. System bus frequencies fall to near or below the first stage of UFLS operations, which is unacceptable BPS performance. These significantly degraded

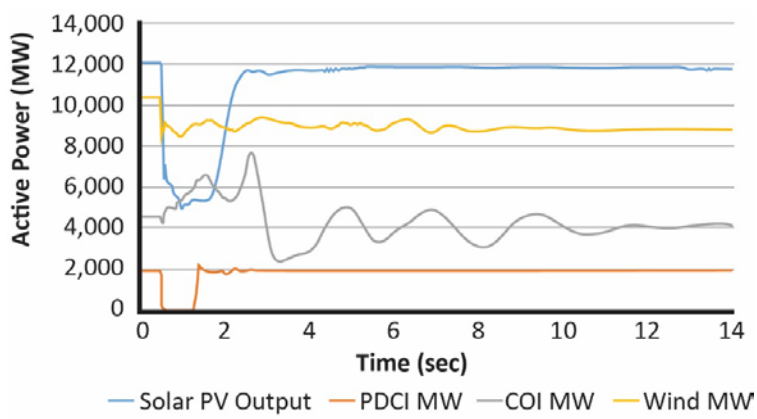


Figure 2.7: Total Solar PV and Wind Output and Intertie Flows for N-1-1 Fault (with RAS Action)

[31] "Consequentially tripped" refers to the wind plant being removed from service upon the permanent fault being cleared by protective relaying in this case. With only a single radial connection to the BPS, this is the expected contingency definition.

performance metrics are caused by the widespread use of MC. Therefore, it is not suitable to address them with generation redispatch; rather, the recommendation is to eliminate MC to the greatest possible extent.

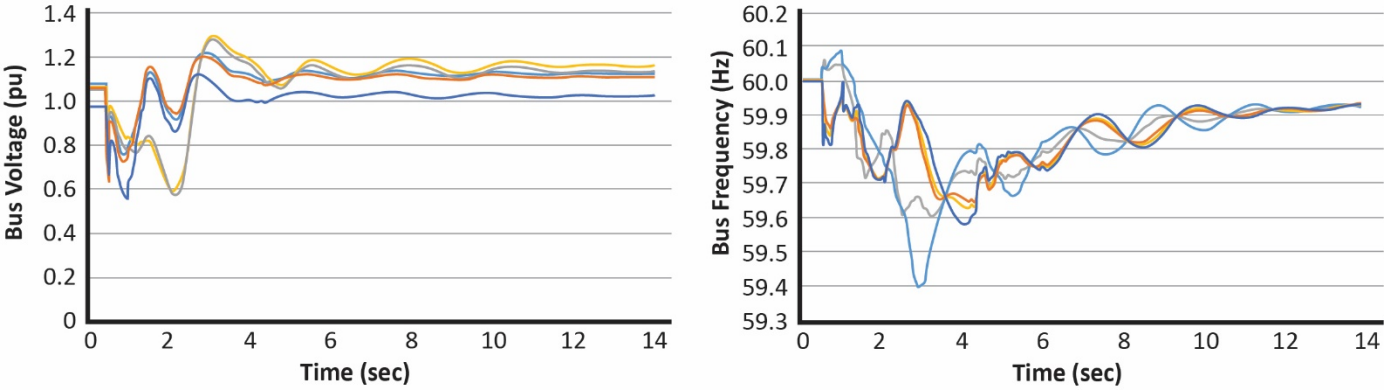


Figure 2.8: BPS Bus Voltages (left) and System Frequency (right) for N-1-1 Contingency (with RAS Action)

Mitigation of Potential Instability Conditions

With the two instability cases identified, IRPTF studies focused on high-level considerations for the various solutions that could be employed to address the instabilities observed. The goal of this exercise was to understand the extent to which these solutions could mitigate the potential instability cases caused by the widespread use of MC. **Table 2.2** shows an overview of the considerations explored by the IRPTF that are based partly on simulation results and partly on engineering judgment from the IRPTF study team. The most effective solution option included eliminating MC to the greatest possible extent. Obviously, completely eliminating MC will correct the problem; however, marginal improvements to MC settings and partially eliminating MC also greatly improves BPS performance. Refer to the Phase 3 studies described below for more details.

Table 2.2: Overview of Mitigation Option for Instability Conditions

Mitigation Option	Instability Mitigated	Acceptable BPS Performance	Discussion
Eliminate MC	Yes	Yes	Eliminating MC greatly improves BPS performance, including angular stability, voltage stability, and frequency stability; interaction with HVDC controls and RAS eliminated; all alternative options for inverter controls provided adequate BPS performance; active current priority had local performance issues.
Operating Limit Restrictions	Yes	Yes	Stability issues are mitigated if operating limits are restricted; no operation of RAS if ac and dc intertie flows are limited; MC still causes adverse impacts on system performance, although performance requirements are met; costly solution due to economic impacts of curtailment.[32]

[32] Instability could be mitigated through generation redispatch by bringing 500 MW of generation on-line in the PG&E area near the ac intertie and reducing 500 MW of generation in the Pacific Northwest. The system remains stable; however, transient performance is marginal with a severe voltage dip during the first swing. Any use of system redispatch as a preventive measure should include extensive, detailed studies under various system operating conditions to define the stability boundary in terms of path flows and generation dispatch.

Table 2.2: Overview of Mitigation Option for Instability Conditions			
Mitigation Option	**Instability Mitigated**	**Acceptable BPS Performance**	**Discussion**
Reactive Power Support	Marginal	Marginal	Multiple STATCOM locations were explored; a significantly large amount of reactive power was needed to mitigate transient voltage collapse along corridor and depressed voltage at inverter-end of HVDC circuit; ineffective solution for this specific problem.
Additional RAS Actions	Unlikely	Unlikely	The only additional RAS action suitable to address this issue would be load tripping in Southern California, an unacceptable solution for N-1 contingency events. This solution would have significant economic impacts and load service degradation.
Transmission Reinforcement	Likely	Possibly	Significant EHV network improvements needed to eliminate need for RAS; extremely costly solution option, and likely not possible due to permitting, expense, and regulations; not recommended.

Phase 3: Detailed Stability Studies using NERC Alert Data

As described in **Chapter 1,** the NERC Alert following the Canyon 2 fire disturbance gathered detailed information regarding MC from currently installed BES solar PV resources. The NERC Alert recommended GOs to provide updated dynamic models that reflect the actual installed equipment in the field (since the currently submitted models in the interconnection-wide base cases were widely deemed to not match actual inverter settings). The NERC alert also recommended that GOs review their inverter capabilities and determine if MC could be eliminated and to submit updated dynamic models to their TP and PC for study prior to material changes being made to installed equipment.

Since most of the models provided by GOs following the NERC Alert were either not usable or did not match the data provided in the NERC Alert, the IRPTF study team updated the dynamic models manually to more accurately reflect the expected performance for existing inverter-based resources. The IRPTF study team used the information provided from the NERC Alert process to update the models and then perform the same simulations that were performed in Phase 2 studies. The goal of Phase 3 studies was to understand the BPS performance based on dynamic models that more closely resemble actual installed equipment. The results from these simulations are provided in this section.

Studies using Existing and Proposed Momentary Cessation Settings

As mentioned, the dynamic models were updated by TPs and PCs on the IRPTF study team to reflect the data provided following the NERC Alert.[33] A flowchart of the updates to the dynamic models for solar PV resources is shown in **Figure 2.9**. About 14,500 MW of BPS-connected solar PV resources are represented in the WECC base case. GOs representing approximately 7,200 MW submitted data during the NERC Alert process. Of the remaining 7,300 MW of

[33] As described in **Chapter 1**, the models received by the TPs and PCs from the GOs owning solar PV resources were largely unusable and inaccurate (i.e., did not match the information supplied in the NERC alert).

solar PV resources that did not submit data as part of the NERC Alert,[34] the default MC settings from **Table 2.1** were assumed (and updated in the dynamic data file) as a conservative yet reasonable assumption. For those resources that submitted data, about 6,000 MW stated they use MC and their dynamics data was updated accordingly. For the remaining 1,200 MW of solar PV resources stating they do not use MC, their dynamics data was left unchanged from what is currently used in the WECC base case.

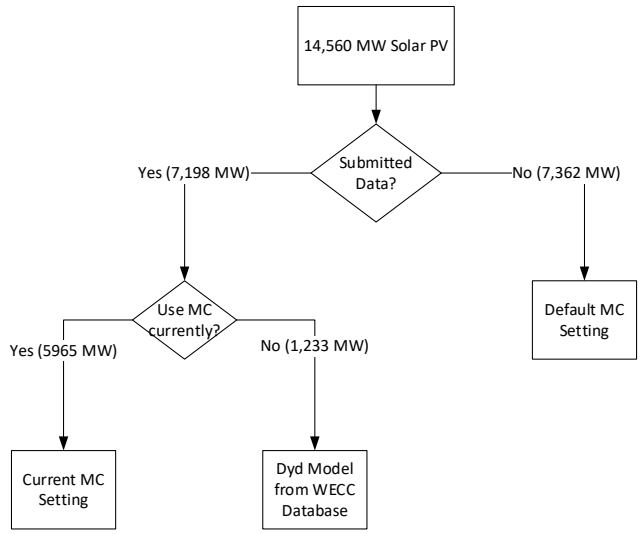


Figure 2.9: Flowchart of Current MC Settings

The NERC Alert following the Canyon 2 Fire disturbance also requested GOs owning BPS-connected solar PV facilities to identify possible improvements to controls to eliminate MC, to the greatest possible extent. In situations where it could not be eliminated, modifications to control settings were recommended (where possible). As stated in **Chapter 1**, very few dynamic models were provided by GOs regarding proposed improvements to inverter performance during large disturbances. Therefore, the IRPTF study team again used the NERC Alert data provided by GOs to update the dynamic models to reflect the proposed changes. **Figure 2.10** shows a flowchart of the data collected from the NERC Alert and the ways it was used to model the proposed settings. Of the nearly 6,000 MW of resources that currently use MC, GOs of about 3,250 MW of these resources stated that they could eliminate its use while 2,700 MW stated they could not. If settings could be changed to eliminate MC, the original dynamics data file records were used that do not model MC. Where MC could not be eliminated, the settings were updated manually by the IRPTF study engineers to reflect the current or proposed changes to MC settings provided in the NERC Alert data.

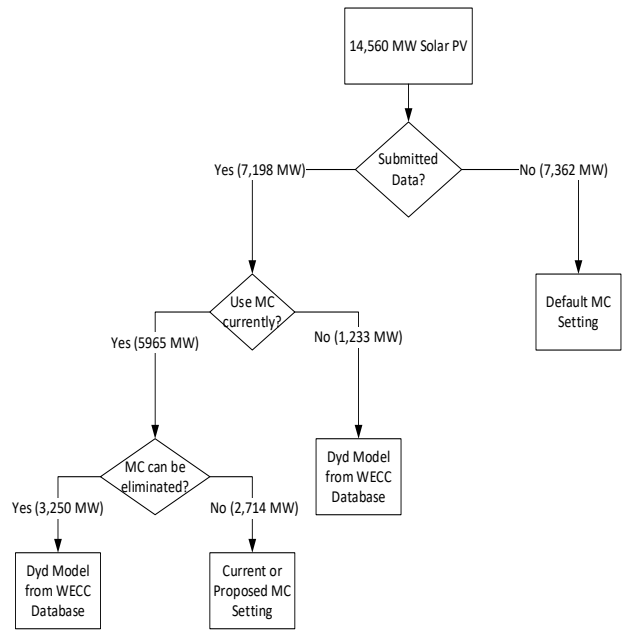


Figure 2.10: Flowchart of Proposed MC Settings

With the updated settings modeled, a comparative analysis was performed between what was the current settings in the field and proposed settings based on the information collected in the NERC Alert and the process described above **Table 2.3** compares performance among different MC settings without simulating the RAS action versus simulating the RAS actions. With the current or proposed MC settings, the system was stable even without RAS action with frequency remaining above the UFLS threshold. The duration of the HVDC circuit blocking was shortened by using the proposed MC settings; however, HVDC RAS would still be triggered in all simulations, something undesirable for these contingencies. With the RAS actions modeled appropriately, the system was also stable with the frequency nadir reaching 59.6 Hz and 59.71 Hz for current MC and proposed MC settings, respectively. The UFLS threshold is generally 59.5 Hz for the Western Interconnection.

[34] While entities owning non-BES resources were requested to provide data, only BES resources are required to respond to the data requests in the NERC alert. This explains why modeling assumptions were made on roughly half of the solar PV resources in the WECC base case.

Table 2.3: Performance Comparison for Different MC Settings for N-1 Contingency (without and with RAS Action)			
System Response	**Default MC**	**Current MC**	**Proposed MC**
RAS Actions Not Modeled			
Initial HVDC blocking duration [s]	0.93	0.90	0.84
Successive HVDC Blocking	Yes	No	No
System Stable	No	Yes	Yes
System Frequency Nadir [Hz]	N/A (Unstable)	59.63 Hz	59.78 Hz
RAS Actions Modeled			
Successive HVDC Blocking	No	No	No
System Stable	Yes	Yes	Yes
System Frequency Nadir [Hz]	59.52	59.6	59.71

For the N-1-1 contingency, the system was still unstable when using the MC settings for currently installed solar PV resources without the RAS modeled (see Table 2.4). With the RAS modeled, all MC settings were stable; however, the frequency nadir remained above the first stage of UFLS operation only for the proposed MC settings. Unintended load shedding may have been caused by the combination of generation tripping from RAS action, MC from BPS-connected solar PV resources, and consequential tripping of wind generation due to the contingency. This scenario would likely require a system operating limit or other curtailment to the wind facility to mitigate the potential for unacceptable BPS performance for this N-1-1 contingency.

Table 2.4: Performance Comparison for Different MC Settings for N-1-1 Contingency (without and with RAS Action)			
System Response	**Default MC**	**Current MC**	**Proposed MC**
RAS Actions Not Modeled			
Successive HVDC Blocking	Yes	Yes	No
System Stable	No	No	Yes
System Frequency Nadir [Hz]	N/A (Unstable)	N/A (Unstable)	59.76
RAS Actions Modeled			
Successive HVDC Blocking	No	No	No
System Stable	Yes	Yes	Yes
System Frequency Nadir [Hz]	59.39	59.47	59.59

Figure 2.11, (left) shows a noticeable improvement to the amount of solar PV resources entering MC when the proposed MC settings are applied; however, it is still observable that about 5,000 MW of solar PV resources enter into MC.[35] **Figure 2.11**, (right) shows system frequency for the different MC settings.

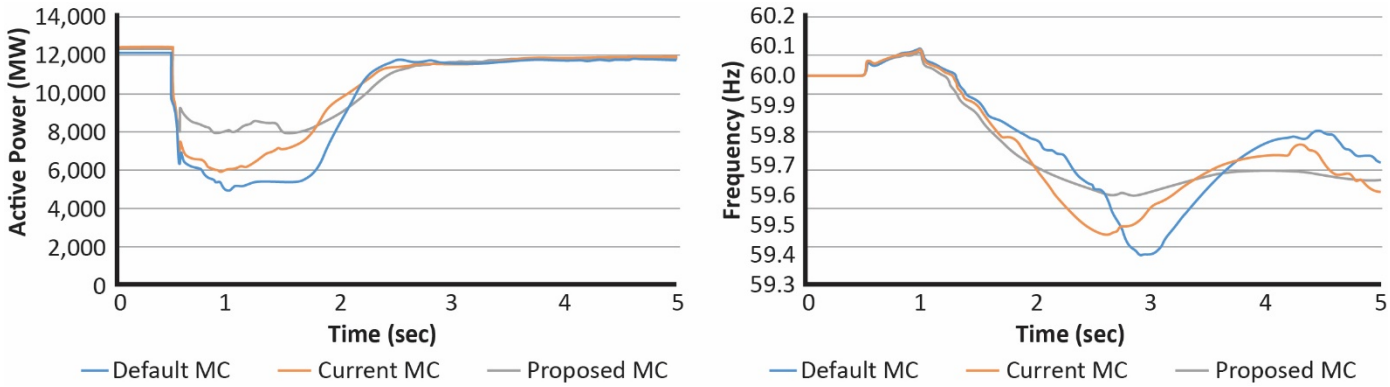


Figure 2.11: Total Solar PV Output (left) and System Frequency (right) for N-1-1 with RAS

Impacts to Key Protection Systems

Due to the large power swings induced on the BPS caused by large amounts of BPS-connected solar PV resources entering MC, the IRPTF study team focused on including relay models on some of the ac major interties across the Western Interconnection to ensure this performance did not adversely impact BPS protection system operations. In particular, the farthest reaching forward distance elements and out-of-step (OOS) relaying on one of the key ac interties was of primary interest since this was identified as one location where transient voltage collapses could occur in some of the study scenarios. Load encroachment blinders were included to show where the distance elements would be blocked. **Figure 2.12** and **Figure 2.13** show the OOS and distance elements on one of the key transmission circuits on one of the ac interties, respectively. These impedance trajectories are plotted for instructional purposes only; these plots do not provide the complete picture for relay response to large power swings.[36] Relay operation is much more complex and is ultimately determined by additional items, such as the impedance rate of change, time delay, frequency, minimum current threshold, and communications from the remote end. In both the N-1 and N-1-1 scenarios, the apparent impedances are outside of the OOS blinders and are therefore unlikely to cause an OOS trip. The apparent impedances enter the Zone 3 quad element but are blocked by load encroachment. No other distance element zones were entered. Therefore, it is unlikely that either scenario would cause a trip of the protection systems on this major ac intertie.

[35] This is predominantly caused by the lack of data for non-BES solar PV resources. So the assumption was made that those resources use the default MC settings used in previous studies as a conservative assumption.

[36] The best way to determine how a relay will respond is to test it on hardware in the loop test bench with simulated events created from system models. This would require bus voltage magnitude (volts), voltage magnitude (volts), bus voltage angle (deg or rad), line current magnitude (A-rms), line real three phase power (MW), line reactive three phase power (Mvar), and bus frequency (Hz).

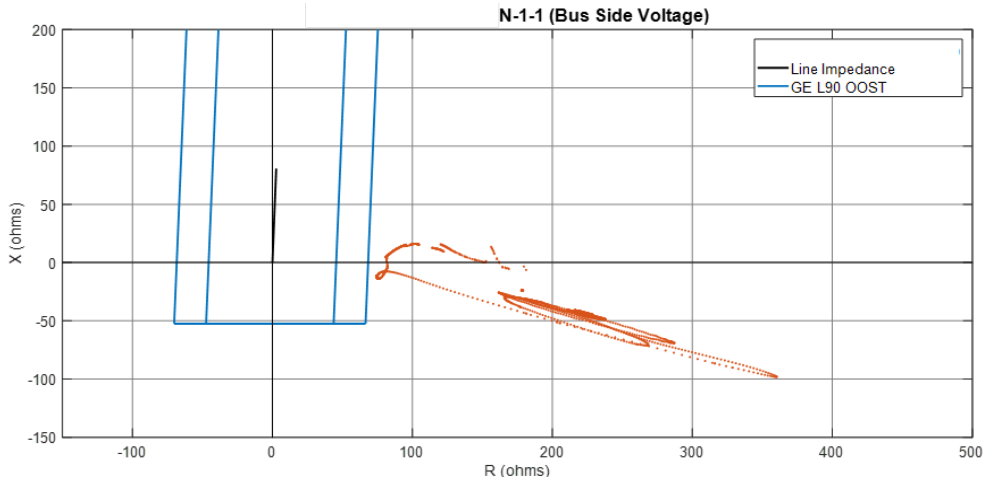


Figure 2.12: OOS Characteristic for 500 kV Line Swing Impedance

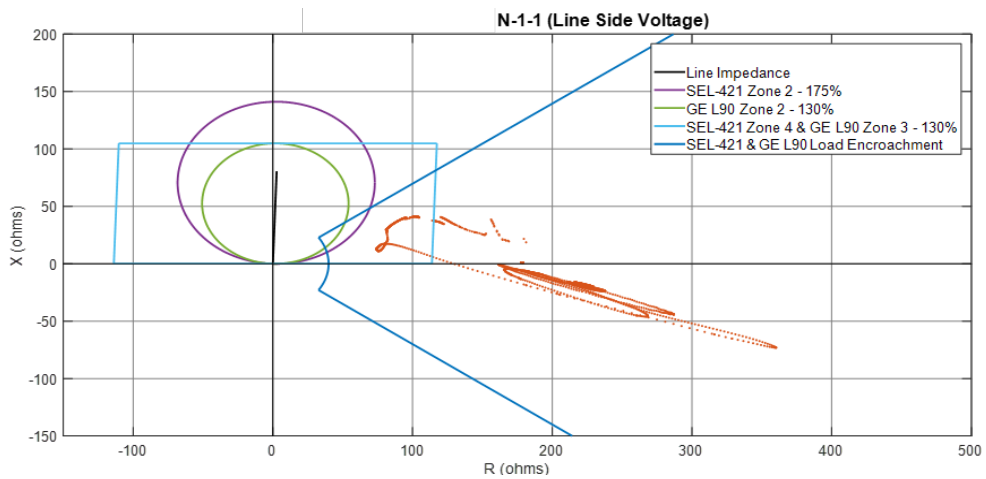


Figure 2.13: Forward Reaching Relay Characteristic with 500 kV Line Swing Impedance

For severe contingencies with conservative assumptions for MC settings for solar PV resources that did not provide NERC Alert data, the apparent impedance swings still do not enter any zone of protection to cause potential tripping for one of the major ac interties most affected by the large power swings. In addition, information regarding BPS protection system settings was not readily available in the dynamic models and required engagement between protection engineering and transmission planning engineering departments across multiple organizations. This type of engagement is likely not occurring on a broad scale for standard TPL planning assessments. Relay information and at least high-level relay models should be available to TPs when performing system stability studies. While actual installed protection is likely much more complex, standard protection models working in "monitoring mode" could help inform planners to any potential trips. Incorporating these types of protection models into stability simulations and the interconnection-wide base cases should continue to be a

Key Takeaway:
Including standard protection models in stability simulations (at least in "monitoring mode") can help inform planners of any possible interactions between BPS-connected inverter controls and potential BPS protection system operation. These models were not readily available for this study and required a significant amount of coordination across different organizations and departments. Incorporating these types of protection models into stability simulations and the interconnection-wide base cases should continue to be a priority for industry moving forward. Training may also be needed to enable planning engineers to properly interpret the "monitoring mode" results.

priority for industry moving forward. Training may also be needed to enable planning engineers to properly interpret the "monitoring mode" results.

Current Control Sensitives if Eliminating Momentary Cessation

With the IRPTF recommendation to eliminate MC for BPS-connected solar PV resources, the IRPTF study team focused on the various types of inverter controls during ride-through operation that could impact BPS stability both locally and on a wide-area basis. The current injection from these resources during and immediately following BPS fault events were analyzed to understand the sensitivities that different control strategies may have on BPS performance. Inverters were assumed to continue current injection during low voltage conditions (rather than use MC), and sensitivities focused on active current priority (Ip priority) or reactive current priority (Iq priority).[37] A combined Ip-Iq priority was also studied where Ip and Iq priorities adapt to terminal voltage conditions, entering Iq priority when voltage falls below 0.9 pu and remaining in Ip priority otherwise. **Table 2.5** shows a comparison of inverter control strategies tested.

Table 2.5: Inverter Control Sensitivity Analysis

Inverter Control Strategy	Description
P-Priority	Preset all PQflag to P priority
Q-Priority	Preset all PQflag to Q priority
Q-0.9	Q-priority if voltage < 0.9; original PQflag if voltage ≥ 0.9[38]
P-Q-0.9	Preset all PQflag to P priority; Q priority when voltage < 0.9[39]

System-wide stability and acceptable dynamic performance was maintained in all of the cases studied. The only notable difference between simulation results on a wide-area basis was the reduction of total solar PV output using Ip priority (see **Figure 2.14**); this is due to one solar PV plant tripping due to sustained low voltage. In that case, the solar PV resource did not contribute sufficient reactive power output during and immediately following the fault event and entered a sustained low voltage condition, causing tripping.[40] During and immediately after a BPS fault, the injection of reactive current from all resources helped support and raise voltage to predisturbance levels. The higher voltage resulted in more available active current injection from the inverter-based resource. Thus, reactive current priority also helped raise the level of active power output from inverter-based resources during the fault. Therefore, based on the simulations performed, the IRPTF study team believes that Iq priority is the preferred inverter control strategy for this area due to the ability to support BPS voltage during and immediately after the fault, enabling active current from inverter-based resources to quickly and reliably return to predisturbance levels. Detailed system studies may identify in some regions that Ip priority may be the preferred strategy; however, simulation results should be used to provide a technical basis for this decision.

Key Takeaway:
Simulations performed by the IRPTF study team demonstrate that Iq priority is the preferred inverter control strategy due to the ability to support BPS voltage during and immediately after the fault, enabling active current from inverter-based resources to quickly and reliably return to predisturbance levels. Detailed system studies may identify in some regions that Ip priority may be the preferred strategy; however, simulation results should be used to provide a technical basis for this decision.

[37] Note that these active and reactive prioritizations are only in effect once the inverter has reached its maximum current output (Imax). If the inverter is not limited by Imax, the inverter controls will seek to provide the commanded Ip and Iq necessary based on the programmed controls in the inverter. Therefore, Ip and Iq priority are only applicable for large disturbance behavior of inverter-based resources located close to the fault condition. Ip and Iq priority are also often referred to as "P priority" and "Q priority," respectively.
[38] Done through additional EPCL scripting language in GE PSLF.
[39] Done through additional EPCL scripting language in GE PSLF.
[40] Some reactive power is provided; however, voltage remains below 0.8 pu for a sustained period that causes the resource to trip.

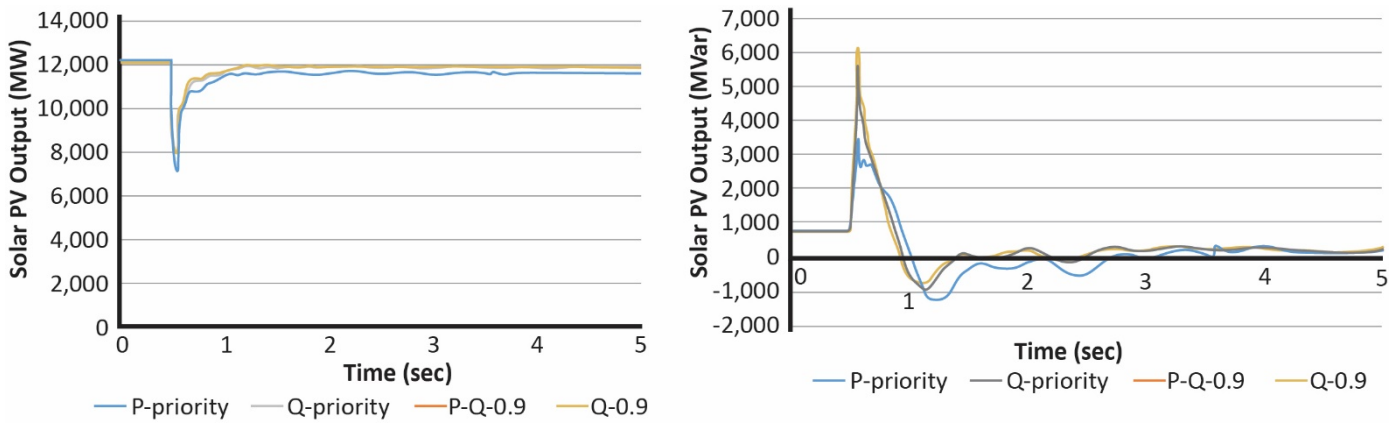


Figure 2.14: Total Solar PV Active and Reactive Power Output for Ip and Iq Control Strategies

To obtain further insight into the application of Ip and Iq settings at an individual plant level, the performance of a 250 MW solar PV plant was examined with different Ip and Iq strategies and control settings. A few different scenarios were devised to study the performance of the different controls to different types of BPS contingencies and operating conditions, listed as follows:

- **Scenario 1:** A fault on a 500 kV transmission circuit causes inverter terminal voltage to drop to 0.50 pu. Figure 2.15 – Figure 2.17 show the performance under Ip priority, Iq priority with voltage control disabled, and Iq priority with voltage control enabled, respectively.
  - **Results:** Iq priority with voltage control enabled provides the optimal control strategy tested, avoiding degradation in on-fault voltage drop and post-voltage transient overvoltage conditions. The following observations are made:
    - With Ip priority, a slight degradation in on-fault and post-fault voltage recovery is observed. Ip takes priority and limits the available Iq during the fault. This results in a slower voltage recovery as well as recovery of active power due to inverter controls.
    - With Iq priority with Imax equal to 1.3 and dynamic voltage control disabled, post-fault overvoltage is observed. Plant-level voltage control and local coordinated Q/V control is applied, driven by the Kvi parameter equal to 40. Iq command rises to 1.3 pu during the fault. Ip command drops as Iq command ramps up to attempt to provide reactive support. Kqv is disabled and Vdip and Vup are -99 and 99, respectively. Hence, there is a slower response characteristic.
    - With Iq priority and dynamic voltage control enabled (Kqv equal to 2), there is no observed post-fault voltage overshoot. The Kqv control loop has fast proportional gain response to clamp voltage down in response to the change in Iqcmd. Kqv set to 2 prevents overshoot since Iq command only rises to 0.5 pu during the fault. Ip command is only slightly clamped since the voltage drop is not drastic. Fast recovery in active power occurs since Ip command is able to quickly respond and provide additional voltage support.

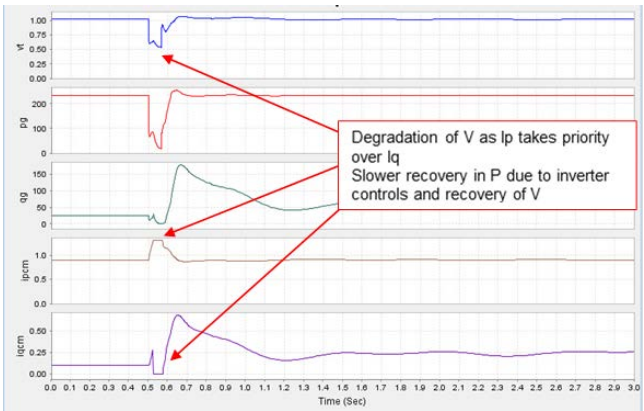


Figure 2.15: Ip-Priority with Imax = 1.3, Kqv disabled

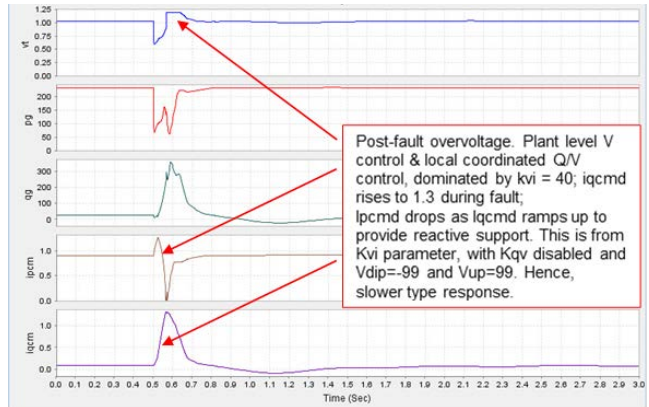


Figure 2.16: Iq-Priority with Imax = 1.3, Kqv disabled

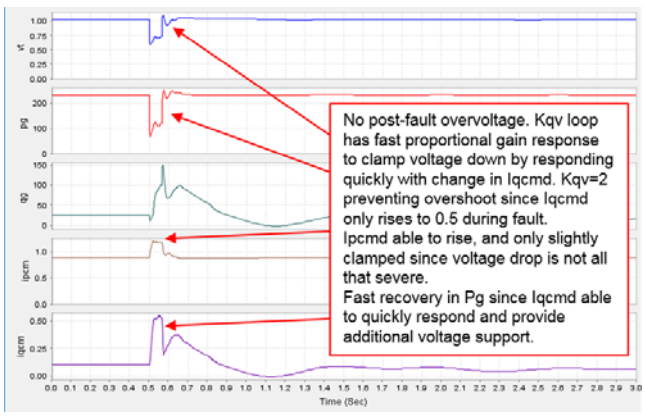


Figure 2.17: Iq-Priority with Imax = 1.3, Vdip=0.9, Kqv=2

- **Scenario 2:** A nearby fault causes the inverter terminal voltage to drop to 0.2 pu. **Figure 2.18** – **Figure 2.20** show the performance under Ip priority, Iq priority with voltage control disabled, and Iq priority with voltage control enabled, respectively.
  - **Results:** Same as described above, Iq priority with voltage control enabled provides the optimal control strategy tested, avoiding degradation in on-fault voltage and post-voltage transient overvoltage. The following observations are made:
    - With Ip priority, again a slower voltage recovery is observed. During the fault, Ip command is clamped to Imax and Iq command is limited to 0. Upon fault clearing, controls respond to return active and reactive power to predisturbance levels.
    - With Iq priority, again an ac overvoltage occurs after the fault is cleared. The Kvi parameter of 40 and plant controls drive this behavior. Iq command rises quickly to 1.3 pu during the on-fault conditions. After the fault, 1.2 pu voltage is observed. The slower plant-level controls seek to slowly return voltage to acceptable levels about 130 ms after fault clearing.
    - With Iq priority and dynamic voltage control enabled (Kqv equal to 2), again, the ac overvoltage is mitigated due to the fast inverter-level controls being able to bring voltage down immediately upon fault clearing. Ip command is only slightly clamped during the fault and not impacted upon fault clearing. Plant active power returns to predisturbance levels very quickly.

These sensitivity studies illustrate how voltage control parameters can be adjusted and coordinated to achieve the desired performance. Multiple control parameters can be tuned, and different combinations of these parameters can all meet the performance requirement under one specific condition. Tuning parameters under as many scenarios as possible is necessary. Performance also depends on the interaction with the system itself. The same inverters installed at a different location would need to be tuned differently. It is critical that the dynamic models used to represent BPS-connected resources actually reflect the installed equipment in the field and are provided to the TP and PC during the interconnection studies process as well as during interconnection-wide case creation processes.

Key Takeaway:
Dynamic models used to represent BPS-connected resources should accurately reflect the actual installed equipment in the field and should be provided to the TP and PC during the interconnection studies process as well as during interconnection-wide case creation processes. Each specific resource and its controls (including inverter controls) should be tuned for the specific interconnected system. Therefore, the TP and PC should ensure that the appropriately tuned parameters are provided in each dynamic model.

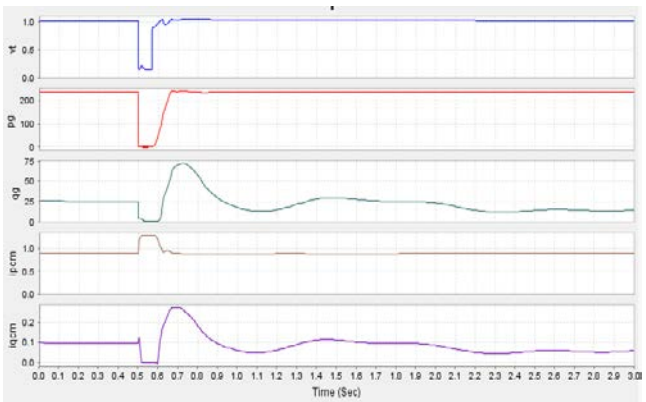


Figure 2.18: Imax = 1.3, Kqv disabled

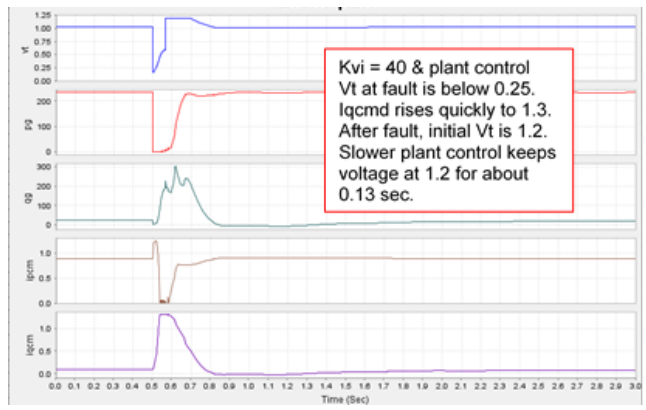


Figure 2.19: Iq-Priority with Imax = 1.3, Kqv disabled

Figure 2.20: Iq-Priority with Imax = 1.3, Vdip=0.9, Kqv=2

Appendix A: Key Findings and Recommendations

Table A.1 provides the key findings and recommendations from the activities documented throughout this report related to BPS-connected inverter-based resource modeling and studies. These key findings and recommendations cover the following areas:

- Analysis of the NERC Alert data and industry follow-up activities
- Simulations and studies performed by the IRPTF of Western Interconnection dynamic performance
- IRPTF modeling work and technical discussions

Table A.1 is separated into three sections to mirror these three topic areas. Items A1–A6 focus on NERC Alert findings, items S1–S6 are associated with IRPTF studies, and items D1–D7 are based on technical discussions and industry work related to dynamic modeling needs.

Table A.1: Key Findings and Recommendations from IRPTF Modeling and Studies Work

#	Key Findings and Recommendations
From NERC Alert Analysis…	
A1	**Key Finding:** A significant number of inverter-based resources, particularly solar PV resources, have submitted RMS positive sequence dynamic models for the interconnection-wide case creation process (i.e., MOD-032-1) that do not accurately represent the control settings programmed into the inverters installed in the field. This was identified[41] due to discrepancies between NERC alert data and the dynamic models used in the interconnection-wide base cases. **Recommendation:** GOs should submit updated models to the TPs and PCs as quickly as possible to accurately reflect the large disturbance behavior of BPS-connected solar PV resources in the interconnection-wide base cases used for planning assessments. This applies to BES resources as well as non-BES resources connected to the BPS.
A2	**Key Finding:** Many of the updated dynamic models submitted during the NERC Alert that were intended to represent the existing settings and controls currently installed in the field either did not match the data provided by the GO for actual settings or did not meet TP and PC requirements for model performance (i.e., incorrect models used, incorrect parameters, or inability of model to initialize). **Recommendation:** TPs and PCs should proactively work with all BPS-connected solar PV resources connected to their system to ensure that the dynamic models correctly represents the large disturbance behavior of the actual installed equipment. GOs should verify the dynamic model parameters with actual equipment and control settings. These activities should occur on a regular basis.

[41] A significant number of resources utilize MC for disturbance ride-through, but the provided models showed current injection behavior during the same large disturbance operating mode.

Table A.1: Key Findings and Recommendations from IRPTF Modeling and Studies Work	
#	**Key Findings and Recommendations**
A3	**Key Finding:** A significant number of GOs submitted NERC Alert data indicating that they could eliminate the use of MC for existing resources; however, either no model of proposed changes was provided or the provided model did not meet TP and PC requirements for model performance. **Recommendation:** TPs and PCs should proactively work with all GOs of BPS-connected solar PV resources in their footprint to review the NERC alert data provided, develop an updated dynamic model of their system with the proposed changes that can be made to eliminate MC, study the impacts of making these changes to controls, and provide recommendations to the GO to make appropriate changes based on the study results.
A4	**Key Finding:** GOs responded to the NERC Alert by providing the requested data and information about their facilities; however, very few GOs provided acceptable dynamic models that matched the data provided. Some TPs and PCs were proactive seeking corrections to these deficiencies, but these activities are occurring outside the NERC Alert process. The NERC Alert itself did not remedy the issues associated with inaccurate dynamic model representation of BPS-connected inverter-based resources. **Recommendation:** IRPTF should continue to monitor for systemic modeling issues and make appropriate recommendations on future actions. Additional actions needed to address systemic modeling issues identified during the NERC Alert process may require another method of engaging or requiring industry to make these changes to the dynamic models will need to be implemented.
A5	**Key Finding:** TPs and PCs are still becoming familiar with the relatively new dynamic models for inverter-based resources. These models are significantly more complex than synchronous generator dynamic models and documentation on their parameterization and correct utilization is limited. For this reason, experience has shown that many TPs and PCs are not familiar with how to perform suitable reasonability tests during model submittal processes either during the interconnection process or during MOD-032-1 data reporting. Currently limited material is available and often requires expert input. In-house expertise on these models is fairly limited within many TP and PC engineering staffs. This allows either incorrect or inappropriate dynamic models to enter the interconnection-wide base cases. **Recommendation:** Industry should develop adequate technical guidance and reference materials on how to parameterize the RMS positive sequence dynamic models for BPS-connected inverter-based resources. Training should be provided to planning engineers to educate them on the structure and parameterization of these models for use in planning and operations reliability studies.

Table A.2: Key Findings and Recommendations from IRPTF Modeling and Studies Work	
#	**Key Findings and Recommendations**
A6	**Key Finding:** The NERC MOD-032-1 standard[42] does not prescribe the details that the modeling requirements must cover; rather, the standard requirements leave the level of detail and data formats up to each TP and PC to define. Many TPs and PCs have developed detailed data requirements; however, little validation of the data provided by GOs is performed. In many cases, "usability testing" is performed that covers model initialization, data format correctness, and numerical robustness during simulated disturbance events. Assessments on the accuracy or reasonableness of the parameter values are not typically performed. Standardized validity testing for dynamic models of newer generation inverter-based resources is not readily available to TPs and PCs; this is a contributor to inaccuracies in the interconnection-wide base cases. While some entities have leveraged the capability of identifying "technical concerns" with data submittals per MOD-032-1 Requirement R3, experience has shown that entities are not utilizing this capability suitably nor following up with these requests with regional compliance groups when data continues to not meet requirements. **Recommendation:** See A2 recommendation.
From IRPTF Studies…	
S1	**Key Finding:** Early stability studies using assumptions regarding the use of MC based on data provided from the first NERC Alert illustrated that widespread use of MC could cause system instability issues for N-1 contingencies if not mitigated. MC at high voltage thresholds caused a lack of reactive power support in key voltage-sensitive areas and resulted in large power swings across the BPS in the Western Interconnection. Furthermore, the MC actions interacted with existing HVDC controls and RAS actions in the Pacific Northwest. **Recommendation:** These findings served as the technical justification that MC should be disallowed for newly interconnecting BPS-connected solar PV resources and should be eliminated to the greatest possible extent for existing resources. Industry should be taking actions to eliminate the use of MC for existing resources to the greatest possible extent, and TOs should update their interconnection requirements to disallow[43] its use for newly interconnecting resources.
S2	**Key Finding:** More detailed studies using models modified to reflect the actual MC settings of BPS-connected solar PV resources (when data was available[44] following the Canyon 2 Fire disturbance NERC Alert showed that the BPS remains stable[45] for the aforementioned contingencies. However, BPS performance is degraded by the use of MC, particularly when the recovery from MC is delayed or the recovery ramp rate is slowed. Elimination of MC or improvements to the MC voltage threshold (i.e., lowering the voltage threshold to the lowest possible value) or recovery characteristic had the greatest impact on improving BPS performance. Interactions with HVDC controls were still present, and the combination of solar PV MC, RAS actions due to HVDC controls, and consequential loss of additional active power due to certain fault events resulted in frequencies falling close to or below UFLS thresholds. **Recommendation:** See S1 recommendation.

[42] MOD-032-1 requires each TP and PC to jointly develop data requirements and reporting procedures for the collection of modeling data used in planning studies.
[43] If reliability studies demonstrate that performance of the BPS-connected inverter-based resource is improved using MC for very low inverter terminal voltages, then the TP and PC (in coordination with the TO) should consider allowing its use on a case-by-case basis.
[44] The NERC Alert gathered information regarding MC from about half of the BPS-connected solar PV resources. Conservative modeling assumptions regarding MC were used for the remaining resources.
[45] This finding on acceptable performance should not degrade the criticality of getting the dynamic modeling issues addressed in a timely manner.

Table A.2: Key Findings and Recommendations from IRPTF Modeling and Studies Work	
#	**Key Findings and Recommendations**
S3	**Key Finding:** Solution options to mitigate poor BPS performance for widespread MC were explored, and it was determined that none of the system-level solutions (e.g., transmission reinforcement, widespread use of transmission-connected reactive devices, curtailment) proved to be an effective means of ensuring reliability. The best solution to the widespread use of MC to improve BPS performance was to eliminate its use to the greatest possible extent. **Recommendation:** See S1 recommendation.
S4	**Key Finding:** User-defined models were used to modify the dynamics model data provided by the GOs for the interconnection-wide base cases. These models updated the simulated response of resources that were identified as using MC per the NERC Alert data to more accurately capture their large disturbance behavior. The use of these user-defined models was necessary since the majority of BPS-connected solar PV models in the interconnection-wide base case provided by the GOs were either the wrong model or were not parameterized to accurately reflect the large disturbance behavior of the actual installed resources. These user-defined models are not intended as a long-term solution nor should they be used in planning assessments. They were used in IRPTF studies as a workaround to widespread modeling deficiencies in the planning base cases. The interconnection-wide base cases need to be updated as quickly as possible with accurate dynamic models to ensure reliability studies are able to identify potential reliability issues. **Recommendation:** See A1 recommendation.
S5	**Key Finding:** With the recommendation to eliminate MC to the greatest possible extent, the next question raised was which large disturbance operating mode provides the best BPS performance. All forms of active and reactive current priority for current injection during large disturbances provide better BPS performance than MC; however, reactive current priority with voltage control enabled provided the most optimal form of ride-through performance for the studied area based on the sensitivity studies performed. Timely recovery and control of inverter voltage allows active current to resume to predisturbance output immediately following a severe fault event without causing overvoltage or delays in response. **Recommendation:** GOs should tune the controls and dynamic response of BPS-connected inverter-based resources to meet BPS reliability criteria and support the BPS during normal operation and during contingency events. The dynamic models representing these resources should be updated to reflect the specific control settings and parameters used in the field. Refer to NERC *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance*[46] for details on recommended performance.
S6	**Key Finding:** Protection system models were not widely available in the planning models, so it was a challenge to study whether the large power swings caused by MC and other inverter behavior were having a potential impact on BPS protection system operation. Concerted efforts were taken to model key transmission paths; however, these models were not readily available to transmission planning engineers. **Recommendation:** TPs and PCs should require a reasonable representation of protection systems and functions be included in the interconnection-wide base cases. The models used to represent these protection systems and functions can be used in "monitor only" mode to flag potential operation of protection systems or functions. TPs and PCs should perform detailed analyses to identify any potential inadvertent operation of protection systems or functions during contingency events.

[46] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf

Table A.2: Key Findings and Recommendations from IRPTF Modeling and Studies Work	
#	**Key Findings and Recommendations**
From Ongoing IRPTF Discussions and Technical Analysis…	
D1	**Key Finding:** NERC MOD-026-1 and MOD-027-1 verification and testing activities do not adequately verify the accuracy of the dynamic models relative to actual installed equipment performance for large disturbance response. Small disturbance testing does not capture the large disturbance behavior of inverter-based resources and therefore does not verify dynamic model parameter values.[47] This issue may be a contributor to the systemic modeling challenges of accurately modeling BPS-connected solar PV resources in planning studies. **Recommendation:** The IRPTF performed a detailed review of the NERC Reliability Standards and identified MOD-026-1 and MOD-027-1 as needing revisions to more accurately serve the intent of the standard for BPS-connected inverter-based resources. Changes should ensure that large disturbance behavior of inverter-based resources is verified. Verification activities beyond matching simulated response with actual response to a small disturbance test should be a mandatory step in the model verification process. This is implicit in MOD-026-1 and MOD-027-1 and should be made an explicit step. TPs and PCs should be required to verify the appropriateness of all dynamic model parameters to ensure suitability of these parameters to match actual performance for all operating conditions. This may include verification of inverter-level and plant-level controller settings, OEM specification sheets, etc.
D2	**Key Finding:** A disconnect exists in transferring knowledge about actual controls installed in the field and how they are accurately parameterized in the dynamic models provided to TPs and PCs. This issue appears to stem partly from the inverter manufacturers and consultants who prepare the dynamic models of their equipment and submit those models to the GOs. For example, inverter manufacturers stated that they were not aware of the issues with reec_b not accurately representing MC and recovery of current injection for large disturbance events. This model has been widely used by industry under the assumption that it accurately represented the installed equipment. Furthermore, WECC has disallowed the use of the model due to its inability to represent voltage-dependent current logic;[48] however, this has not become a practice across North America yet. Not until actual responses of solar PV resources were analyzed by NERC and IRPTF did industry become aware of these shortcomings in the dynamic models. **Recommendation:** GOs should provide appropriate training and guidance to personnel who parameterize the models that are submitted for the interconnection-wide base cases. Also, see A2 recommendation.

[47] For example, a GO could submit a REEC_B dynamic model that has no capability to represent MC, and small disturbance verification testing could identify a suitable dynamic model match between simulated and actual response during testing. However, the tests in no way test the large disturbance behavior. Therefore, there is no comparison of actual response and modeled response for large disturbance response.

[48] The issues associated with representing voltage-dependent current injection are applicable both to MC but also to current injection during ride-through operation.

Table A.2: Key Findings and Recommendations from IRPTF Modeling and Studies Work	
#	**Key Findings and Recommendations**
D3	**Key Finding:** Attachment A of Appendix 1 in the FERC LGIP does not mention solar PV resources and only briefly mentions wind power resources. The lack of specificity of information that is used for modeling and studying these resources during the interconnection process may be leading to lack of detailed studies prior to interconnection. Furthermore, it is unclear in the LGIP and the LGIA what constitutes a material modification and how the technological change procedures should apply when changes (relative to the initial configurations) to the controls, settings, equipment, or other features of a newly interconnecting inverter-based resource will change the electrical response of the resource to disturbance events on the BPS. **Recommendation:** The FERC LGIP and LGIA should be reviewed in detail to identify the changes necessary to ensure clarity and consistency for inverter-based resources. The material modification and technological change procedures should be updated to ensure that changes to any equipment that change the electrical response of a resources warrant additional interconnection studies to ensure that response is stable under all expected operating conditions.
D4	**Key Finding:** As the system continues to evolve towards increasing penetrations of inverter-based resources, it is incumbent upon TPs, PCs, and TOs to ensure that interconnection requirements (specifically pertaining to modeling and system studies) are updated to ensure that adequate models (i.e., steady-state, dynamic, short circuit, and EMT) are provided and benchmarked.[49] Refer to NERC *Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources*.[50] **Recommendation:** TOs, TPs, and PCs should ensure that the interconnection requirements are updated to ensure that GOs provide adequate models for reliability studies during the interconnection studies process. Requirements should be clear and consistent as to what is required to be provided for BPS-connected inverter-based resources.
D5	**Key Finding:** As the instantaneous penetration of BPS-connected inverter-based resources (in combination with DERs) continues to increase, it is becoming increasingly difficult to develop interconnection-wide base cases that meet renewable portfolio standard levels while maintaining acceptable system performance. For example, dispatch conditions of wind and solar PV resources combined with other assumptions in the power flow base case led to intertie flows never previously experienced. These assumptions also impact neighboring footprints and should be established collaboratively with all parties. **Recommendation:** TPs and PCs responsible for interconnection-wide case creation practices should consider how to manage very high penetration inverter-based resource operating assumptions and also determine any necessary steps or practices to handle previously unexpected operating assumptions that may be leading to system performance issues. Case assumptions should be established collaboratively with all parties. Entities should develop credible operating assumptions, particularly in the planning horizon with significant amounts of additional variable energy resources dispatched in the case. Additionally, TPs and PCs should establish communication practices to share relevant modeling and simulation issues and knowledge across footprints within an interconnection.

[49] Benchmarking is particularly important between the dynamic stability models and the EMT models

[50] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf

Table A.2: Key Findings and Recommendations from IRPTF Modeling and Studies Work	
#	**Key Findings and Recommendations**
D6	**Key Finding:** The challenges related to planning-models are equally a challenge for the stability studies performed during the near-term planning or operations planning time horizons. However, it appears that assumptions are also made in these studies and the modeling improvement efforts in the planning realm by TPs and PCs may not be widely shared with TOPs and RCs. Accurate models are particularly important for studying the "fringe" operating conditions (e.g., high path flows with high renewables conditions) that are relatively unlikely to occur (and may be overlooked in the long-term planning horizon) but may appear in the operations horizon due to outage conditions or other factors. These low-likelihood, high impact operating conditions may pose risks to BPS reliability during certain operating hours. **Recommendation:** Transmission planning and operating entities should be coordinating to ensure that any modeling improvements identified in either time frame are shared and communicated to other entities. Modeling improvements for inverter-based resources should be accounted for in both the planning and operations studies to the greatest possible extent. Centralized modeling repositories for planning and operations may help ensure accurate models are being applied to both types of studies.
D7	**Key Finding:** The generic RMS positive sequence dynamic models for inverter-based resources connected to the BPS can generally model MC behavior with known limitations on modeling the recovery delay. Inaccurate modeling of recovery delay causes inaccuracies in the dynamic simulation results, particularly regarding false voltage overshoot when active current recovery is delayed but reactive current is not. Furthermore, the reec_b model has limitations on capturing voltage-dependent current logic and its use is discouraged moving forward. **Recommendation:** The generic RMS positive sequence dynamic models should be enhanced by model development groups[51] as soon as possible. Once the model enhancements are benchmarked and approved for use in planning assessments, TPs and PCs should notify GOs in their planning footprint that these updated models are available and should be used for any necessary modeling improvements regarding MC and other improvements to modeling disturbance ride-through performance.

[51] Likely the WECC Renewable Energy Modeling Task Force

Appendix B: Model Verification Review

Technically, model verification of individual elements[52] inside an inverter-based resource may be necessary to reach the desired level of detail in these dynamic models. However, this level of verification or testing has proved too complex and costly, and most inverter-based resources dynamic simulations are modeled as an aggregate equivalent. The Applicability section of MOD-026-1 and MOD-027-1 add some confusion to this, stating that "verification for individual units less than 20 MVA…may be performed using either individual unit or aggregated unit model(s)," but it is unclear which actual versus simulated responses should be compared. The focus should be on ensuring that the overall plant response[53] matches between model and actual rather than the response of specific units or aggregated units within an inverter-based resource.

Furthermore, as stated in the body of this report, the comparison of modeled response and actual response to staged tests or recorded disturbance events on the BPS are a requirement of MOD-026-1 and MOD-027-1; however, these comparisons fail to capture the large disturbance behavior of inverter-based resources. Therefore, the dynamic models can be provided to meet compliance with the standards without actually ensuring that that the modeled response actually matches any large disturbance behavior. These gaps in the existing standards should be considered during any development of improved standard requirements.

To illustrate these issues, **Table B. 1** shows the model parameters for the *regc_a*, *reec_a*, and *repc_a* dynamic models and describes whether these parameters can be directly verified using commonly applied MOD-026-1 and MOD-027-1 verification tests.

Table B. 1: Dynamic Model Parameters Verified by Testing Procedures

Parameter	Verified by Test?	Comments
REGC_A Electrical Generator Model		
lvplsw	No	
rrpwr	No	
brkpt	No	
zerox	No	
lvpl1	No	
vtmax	No	
lvpnt1	No	
lvpnt0	No	
qmin	No	
accel	No	
tg	Maybe	Observability of inverter time constant depends on tuning of the active power and volt/var control loops. Inverter time constants are usually small, so tuning of the system must be fast in order to validate this parameter with confidence. It may be difficult to distinguish this parameter from other similar parameters for an aggregate model unless the control system's internal signals are available.
tfltr	N/A	
iqrmax	No	
iqrmin	No	
xe	No	

[52] For example, individual turbines in a wind plant or individual inverters in a solar PV facility.
[53] As measured at the Point of Measurement (i.e., high-side of the plant substation transformer(s)).

Table B. 1: Dynamic Model Parameters Verified by Testing Procedures		
Parameter	**Verified by Test?**	**Comments**
REEC_A Electrical Control Model		
mvab	Maybe	If this parameter is set erroneously, this may show up in test verification because the per-unitized values of the various quantities would be wrong and this will affect even small disturbance test results.
vdip	No	
vup	No	
trv	No	
dbd1	No	
dbd2	No	
kqv	No	
iqh1	No	
iql1	No	
vref0	N/A	
iqfrz	No	
thld	No	
thld2	No	
tp	No	
qmax	Maybe	In cases where this value limits power factor range, it can be quite evident during testing. However, verification of accuracy is unlikely.
qmin	Maybe	
vmax	No	
kqp	Maybe	
kqi	Maybe	
kvp	Maybe	
kvi	Maybe	
vref1	N/A	
tiq	No	
dpmax	No	
dpmin	No	
pmax	No	
pmin	No	
imax	Yes, maybe	When performing vref step tests at full load, the maximum current limit may be reached.
tpord	No	
pfflag	N/A	
vflag	Yes, maybe	The plant response to small disturbances created by capacitor switching tests may reveal incorrect flag settings associated with v/q control mode.
qflag	Yes, maybe	Same reason as above.
pflag	N/A	
pqflag	Yes, maybe	When performing vref step tests at full load, the maximum current limit (Imax) may be reached. P/Q priority may be verified by checking which of the two currents (Iq or Ip) was limited first.
vq1	No	
iq1	No	
vq2	No	
iq2	No	
vq3	No	
iq3	No	

Table B. 1: Dynamic Model Parameters Verified by Testing Procedures		
Parameter	**Verified by Test?**	**Comments**
vq4	No	
iq4	No	
vp1	No	
ip1	No	
vp2	No	
ip2	No	
vp3	No	
ip3	No	
vp4	No	
ip4	No	
REPC_A Plant-Level Control Model		
mvab	Yes, maybe	If this parameter is set erroneously, this may show up in test verification because the per unitized values of the various quantities would be wrong, and this will affect even small signal test results.
tfltr	Yes	Observability of inverter time constant depends on tuning of the active power and volt/var control loops. Inverter time constants are usually small, so tuning of the system must be fast in order to validate this parameter with confidence. It may be difficult to distinguish this parameter from other similar parameters for an aggregate model unless the control system's internal signals are available.
kp	Yes	
ki	Yes	
tft	Yes	
tfv	Yes	
refflg	Yes	
vfrz	No	
rc	Yes, maybe	
xc	Yes, maybe	
kc	Yes	
vcmpflg	Yes	
emax	Maybe	These parameters may be used to replicate ramp behavior during step response tests. Therefore, they may be verified in some cases (but not all).
emin	Maybe	
dbd	No	
qmax	No	In cases where this value limits power factor range, the impacts can be evident during testing. However, verification of accuracy is unlikely. This depends on if these limits are applied at the plant-level controller or at the individual inverters. Documentation would be required to identify where limits are applied.
qmin	No	
kpg	Yes	
kig	Yes	
tp	Yes	
fdbd1	Yes	
fdbd2	Yes	
femax	No	These parameters may be used to replicate ramp behavior during step response tests. Therefore, they may be verified in some cases (but not all).
femin	No	
pmax	No	
pmix	No	
tlag	Yes	
ddn	Yes	
dup	Yes	

Table B. 1: Dynamic Model Parameters Verified by Testing Procedures		
Parameter	**Verified by Test?**	**Comments**
frqflg	N/A	
outflag	N/A	
puflag	N/A	

Appendix C: Canyon 2 Fire Disturbance NERC Alert Follow-Up

This appendix provides a brief summary of the observations made while reviewing the follow-up information provided to NERC by each entity. These responses identify potential systemic issues with modeling practices for BPS-connected solar PV resources.

Entity 1 Response

Entity 1 did not receive any updated dynamic models from solar PV resources in their footprint following the NERC alert. Entity 1 stated that they rely on MOD-026-1 and MOD-027-1 model submittals for verifying the dynamic models before using those models in the MOD-032-1 case building process. However, as this report highlights, these verification tests likely do not sufficiently verify the large disturbance behavior of inverter-based resources to the degree necessary for TPs and PCs to ensure accurate models are provided. This highlights a potential challenge for this entity regarding BPS-connected inverter-based resource modeling if the entity is solely relying on MOD verification tests to ensure that the dynamic models adequately capture large disturbance behavior.

Entity 2 Response

Entity 2 stated that they are using data for one solar PV facility last supplied in 2015. The entity did not receive any updated dynamic modeling information following the NERC alert. The dynamic models being used include *reec_b*, and the plant stated that they use MC below 0.6 pu voltage. As previously explained throughout this report, the *reec_b* model is insufficient to capture MC. The entity did not clarify whether they were proactively addressing this modeling issue with the applicable GO. Therefore, it is unclear if this modeling issue will be addressed.

Entity 3 Response

Entity 3 responded that no modeling data from any solar PV resources was received following the NERC alert. However, this entity has over 800 MW of solar PV resources in its footprint that provided alert data (responses to actual settings, not modeling data) to NERC following the NERC alert. All facilities except one use MC during large voltage disturbances. The entity stated that a follow-up inquiry was made with seven facilities that did not produce any additional results. The entity stated that the response provided by the GO for those facilities was that they did not need to take any further action. Upon NERC spot-checking the dynamic models used for these facilities, all facilities use the *reec_b* dynamic model that is unable to represent MC appropriately. Entity 3 did not provide any additional information regarding future follow-up activities to address these modeling issues. Therefore, there is no indication that these modeling deficiencies have been addressed. Entity 3 should seek immediate model improvements by utilizing MOD-032-1 Requirement R3.

Entity 4 Response

Entity 4 received data from 42%[54] of its installed solar PV generation fleet (as reported in the 2018 summer base case) and implemented actual data in its simulations for approximately 6,900 MW of solar PV plants. For solar PV sites where data was not submitted, generic parameters were used for representing MC based on IRPTF simulation activities. Stability simulations were performed, and the result identified that maximum risk of potential instability occurs when system demand is lowest, solar PV output is highest, and major intertie flows are also high. While these conditions are quite rare, such conditions have occurred in the past. Upon reviewing historical data in 2017 and 2018, it was determined that these conditions occurred 10 hours and 38 hours of the year, respectively. The simulations showed that the system remains stable for fault events and subsequent MC of a wide area of solar PV generating resources. Under light load conditions, a significant frequency event occurs (although does not reach UFLS activation levels); under high transfer conditions, a significant transient voltage swing occurs along the major interties. In addition, it is unclear whether Entity 4 will be following up with the other 58% of the solar PV fleet to incorporate actual data in future simulations.

[54] This represents many thousands of MW of solar PV.

Entity 5 Response

Entity 5 stated that they did not receive any updated models following the NERC alert for existing solar PV facilities nor any models of proposed changes to equipment. For this reason, Entity 5 stated that no reliability studies were performed due to the lack of model submittals. Entity 5 also stated that the existing models do not adequately represent MC behavior. They expressed that risk exposure is likely limited due to the fact that BES solar PV resource penetration is relatively low and is less than the generation loss for their largest single contingency. Entity 5 stated that upon receipt of any updated models, reliability simulations would be performed to study any potential instability conditions. They offered to continue providing support to GOs regarding updating and supplying their dynamic models; however, there was no concrete time line or description of a proactive effort to get these modeling issues addressed. As the penetration of solar PV continues to grow in this region, Entity 5 will need to be more proactive in addressing known modeling issues.

Entity 6 Response

Entity 6 stated that they had one applicable facility regarding the NERC alert and that no modeling changes were needed because the dynamic model represents the expected behavior of the facility. However, NERC reviewed the dynamic model for this resource in the latest interconnection-wide base case, compared the model with the submitted NERC alert data, and identified that they are not consistent. The resource utilizes MC for large disturbance behavior; however, the GO submitted a *reec_b* model that does not have the capability to accurately represent MC. Therefore, it is concerning that the entity provided such response that stated no further action is needed. This identifies a potential lack of understanding of the dynamic models for BPS-connected inverter-based resources for this entity. The entity stated that no proposed changes were needed and that no follow-up activities are planned. Further analysis by NERC identified that this specific inverter manufacturer is able to eliminate MC for its fleet of inverters. Again, this identifies a lack of effort by the entity to drive improvements in performance of their applicable solar PV facilities.

Entity 7 Response

Entity 7 failed to respond to the NERC request for follow-up activities; additional outreach by NERC led to informal responses from the entity. Three solar PV facilities (a couple hundred MW) in their footprint use MC that was not originally captured by the dynamic models. The GO provided updated dynamic models for these facilities that were determined to accurately capture MC. Entity 7 also requested the GO to update their inverters to eliminate MC and provide updated models. As a result, the models representing MC were not incorporated into the area-wide base case and the models using the other forms of ride-through were used instead. The entity notified their PC and RC when the GO completed upgrades to eliminate MC. Subsequently, the entity has now modified their interconnection requirements to prohibit MC within the PRC-024 No Trip zone for all new plants.

Entity 8 Response

Entity 8 stated that they identified discrepancies between the submitted data and the dynamic models provided as part of the NERC alert. Specifically, most issues were associated with the GOs using default model parameters or parameters that did not reflect the expected performance (as confirmed with the GO). These issues were resolved through an iterative process of data exchange between the entity, the GO, and often with their OEMs. Reliability studies performed by the entity used a high inverter-based resource output under light load conditions. Two solar PV facilities with updated dynamic modeling data exhibited questionable behavior after fault clearing and contributed to both overvoltage conditions and subsequent resource tripping. Although this response did not exhibit MC and did not trigger instability, cascading, or uncontrolled separation, it was considered unacceptable dynamic behavior. The entity communicated these findings to the respective GOs, and the GOs are in the process of reviewing the model data provided.

Entity 9 Response

Entity 9 stated that they only have one applicable BES solar PV facility in their footprint and that the facility does not use MC, so no changes were made. The entity stated that they reviewed the data submitted by the GO to resolve

issues pertaining to the large disturbance logic and settings in the dynamic model (e.g., V_{dip}, V_{up}, V_{frz}, I_{qrmax}, I_{qrmin}) to avoid erroneous behavior for large disturbances. This was a positive response with the TP being proactive in ensuring appropriate dynamic modeling and parameterization of the models beyond a simple cursory review of the submittals.

Entity 10 Response

Entity 10 stated that they received NERC alert data (spreadsheet) from 65 solar PV facilities. While the NERC alert data was only required for BES resources, they did receive information for some non-BES resources (but not many). The total capacity of the 65 facilities is over 7,000 MW. Most of the inverters currently use MC as a means of voltage ride-through, and more than half can eliminate the use of MC according to the NERC alert data provided.

Although the NERC alert recommended that updated dynamic models be provided by the GOs, only 13 submissions of dynamic models were received by Entity 10. Deficiencies were identified in every submitted model (i.e., no submitted models were deemed acceptable). Most commonly, the GO provided a dynamic model in the wrong format or with parameter values that did not match the NERC alert data submitted. No dynamic models were received for proposed changes in settings.

Due to the lack of information and updated models provided during the NERC alert process, Entity 10 has initiated a comprehensive modeling improvement effort over the course of multiple years to receive accurate and updated dynamic model information for all its market participants. Entity 10 will notify the GOs of model improvement requirements that must be met by the GOs within a set time frame. Entity 10 is also working with the GOs to ensure approval of changes to inverter settings to improve solar PV performance during large disturbance events. After the changes are implemented in the field, GOs are required to submit the updated dynamic models to Entity 10 and their applicable TPs. Entity 10 will follow up with the GOs following the model submission and review process to track, retain, and use the updated models.

Entity 10 proactively updated the dynamic modeling errors described above by using the received NERC alert data. These updates were made to each facility, and stability simulations were performed to ensure reliability criteria was met using the updated models. Model updates were only made to solar PV facilities in the Entity 10 footprint; no models were changed outside their footprint since data was not available (i.e., not shared amongst PCs). Stability studies on light load and peak load cases were performed. No reliability concerns caused by existing MC settings were identified. A few parameter values associated with a large solar PV facility in one part of their planning area could have an impact on load bus voltages in a neighboring TP area in their footprint. While acceptable performance was met, this strengthened the importance of model accuracy for the entity. Studies of proposed changes identified improvements to BPS performance following fault events (i.e., less MC, faster power output recovery, less impacts to system frequency).

Since so many model deficiencies were identified and incomplete modeling data was supplied by GOs, the studies do not adequately assess the individual facilities' dynamic characteristics. Therefore, the studies do not provide the information needed to support approval of the proposed settings. However, NERC recognizes that minimizing the impacts of MC is an imminent concern. Given that the proposed setting changes align with the NERC recommendation to improve the reliability, Entity 10 recommended to GOs to make the proposed changes to equipment settings. Entity 10 has also improved its procedures for collecting modeling data from generating resources by improving its modeling requirements to provide clarity and consistency to the model submittals.

The entity stressed the criticality of accurate models for ensuring BPS reliability; this includes models of existing installed equipment in the facilities, and ensuring that any changes to such equipment are accurately reflected in updated dynamic models. The entity also stressed that the vast number of modeling deficiencies identified highlights a systemic modeling challenge for the industry moving forward. While Entity 10 is proactively trying to address these known modeling issues, they recommend industry-wide efforts to correct these modeling errors as quickly as possible.

Entity 11 Response

Entity 11 stated that they have utilized MOD-032-1 Requirement R3 to gather representative modeling information after identifying issues with the submitted data for solar PV facilities. The most common issue with the submitted models was the use of models that are no longer approved by the MOD-032 designee and hence the TP. Specifically, the *reec_b* model was submitted multiple times for different solar PV facilities. This required back-and-forth feedback between the entity and the GOs to convert these to acceptable models. Most of the updated dynamic model data was deemed acceptable by the entity; several submittals are still pending confirmation by the entity. One solar PV facility failed initialization testing and is being re-evaluated. A couple of the solar PV resources were previously represented using the Type 4 wind plant models (first generation models) with no associated protection models. These are being updated to the latest generation of renewable energy system models.

Entity 12 Response

Entity 12 received initial data from one BES solar PV facility that utilizes MC. Over the course of two months, the entity had several communications with the solar PV facility to clarify information and address data formats and model parameter issues from the initial submittal. The entity stated that they are stressing that solar PV resources should be designed to eliminate or minimize MC. However, there was no mention of improving interconnection requirements to reflect this recommended performance specification. The entity also stated that no proposed model was provided to eliminate MC, so no further studies have been performed. They stated that since no model was provided, no follow-up activities have occurred and did not describe any plans to do so.

Entity 13 Response

Entity 13 stated that no updated data was provided from the applicable GOs following the NERC alert; however, the entity stated that they did not identify an issues with the existing data (i.e., the models previously supplied by the GOs are accurate and sufficient). However, NERC reviewed at least one of the applicable units and identified that the inverters use MC for voltage less than 0.45 pu (based on NERC alert data provided) but the GO submitted the *reec_b* model (and the TP accepted the model) that cannot accurately capture MC. Furthermore, it was noted that the data supplied during the NERC alert for this solar PV facility stated that the plant uses a 10%/second ramp rate recovery, requiring 10 seconds to recover to predisturbance current injection following MC. Such performance does not meet the recommended performance as specified by the IRPTF. Furthermore, after reviewing the NERC alert data, NERC identified that the proposed settings provided by the GO actually result in degraded performance from the inverters for large disturbance events. Entity 13 stated that they did not receive any proposed model and therefore did not perform any studies related to these proposed settings. Therefore, it is unclear the extent of this modeling gap and this example also illustrates a lack of review and potential system modeling issue for this entity.

Entity 14 Response

Entity 14 stated that it commonly identified that solar PV and wind facilities do not pass dynamics data checks, including the following:

- Models often have initialization errors that preclude their use in dynamic simulations.
- Models often do not have a flat dynamic response for no disturbance simulations up to 30 seconds.
- Models often do not exhibit positive damping for normally cleared fault events.
- Models often do not have proper vetting against data provided by the inverter manufacturer (i.e., the data provided does not match the dynamic model parameters).
- Models are often netted or disabled in the interconnection-wide base case due to system modeling errors that cannot be easily addressed by the MOD-032 designee during base case creation processes.

This entity has over 600 MW of solar PV facilities in its footprint. The entity did not receive an updated dynamic model from any of its solar PV GOs following the NERC alert for either existing equipment or proposed changes.

NERC reviewed the information submitted by the GOs in the area of Entity 14. The largest solar PV facility in this area, consisting of multiple phases of different inverter types, stated that the facility utilizes MC below around a 0.9 pu voltage threshold for different inverter types. The data provided also stated that MC can be eliminated for all types of inverters at this facility. Furthermore, the existing models include *reec_b*, which cannot represent MC suitably. Entity 14 did not state that any follow-up activities were planned to correct these issues.

The lack of updated dynamic models and no models provided for proposed settings in combination with the lack of activities to proactively or reactively address these modeling issues is identified as a systemic modeling and procedural issue for Entity 14.

Entity 15 Response

Entity 15 stated that, upon receipt of the NERC alert, they held conference calls with each of the GOs with solar PV facilities to discuss the answers provided; however, no dynamic models were provided by the GOs regarding existing equipment or proposed changes. The entity stated that their planning engineers updated some of the dynamic model voltage trip settings based on the provided NERC alert data; however, these updated models did not come from the GOs directly.

The entity stated that no models of proposed changes in equipment were provided by the GOs, so no follow-up studies or activities were planned by the entity. This shows a lack of proactive action to address potential modeling issues by this entity. NERC reviewed the NERC alert data for applicable solar PV facilities and noted that multiple facilities currently use MC with a low voltage threshold around 0.9 pu and that those facilities stated they could eliminate MC. However, with the lack of follow-up by this entity, it is unclear if the changes were made and if the dynamic models actually reflect behavior of the installed resources.

Contributors

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