NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Multiple Solar PV Disturbances in CAISO

Disturbances between June and August 2021
Joint NERC and WECC Staff Report

April 2022

RELIABILITY | RESILIENCE | SECURITY




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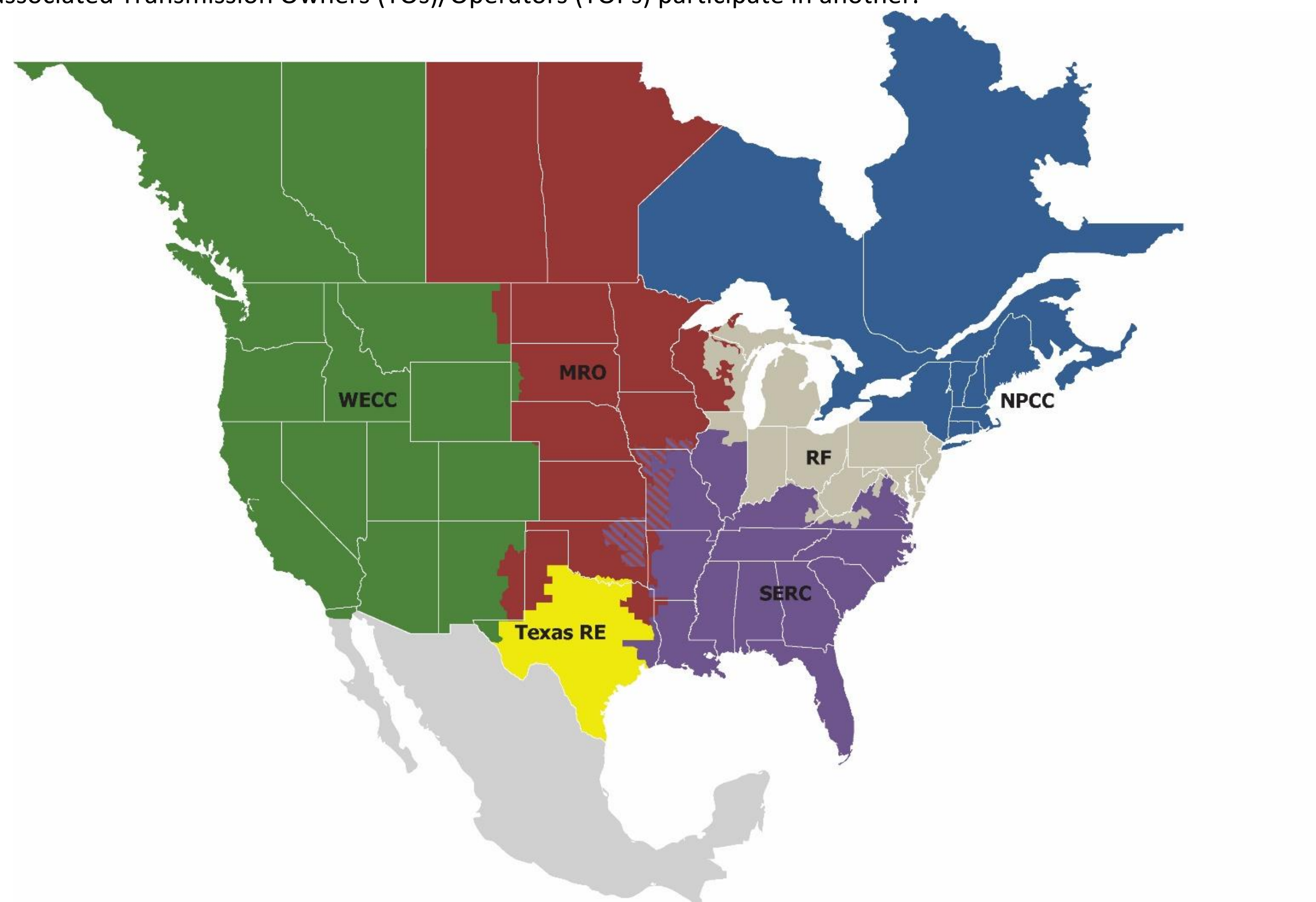
Preface

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, 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 made up of six Regional Entity boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners (TOs)/Operators (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	WECC

Executive Summary

NERC and the Regional Entities continue to analyze disturbances that involve widespread reductions of solar photovoltaic (PV) resources to identify any systemic reliability issues, to support affected facilities in developing mitigating measures, and to share key findings and recommendations with industry for increased awareness and action (see **Appendix A**). The ongoing widespread reduction of solar PV resources continues to be a notable reliability risk to the BPS, particularly when combined with the additional loss of other generating resources on the BPS and in aggregate on the distribution system. This report contains the ERO analysis of four BPS disturbances with widespread reductions of solar PV output that occurred in the California Independent System Operator (CAISO) footprint between June and August of 2021.

Each disturbance was categorized as a Category 1i event per the NERC Event Analysis Process[1] and involved widespread reductions of active power output from solar PV resources in the Southern California area (specifically in areas of high penetrations of solar PV and wind resources). Two of these events also involved tripping of synchronous generating resources, and three involved some degree of distributed energy resource (DER) tripping or reduction. All initiating faults were normally cleared with proper protection system operation. **Table ES.1** provides an overview of the four disturbances analyzed by NERC and WECC.

Table ES.1: Overview of Disturbances

Disturbance and Name	Initiating Fault Event	Description of Resource Loss*
June 24, 2021 “Victorville”	Phase-to-Phase Fault on 500 kV Line	Loss of 765 MW of solar PV resources (27 facilities) Loss of 145 MW of DERs
July 4, 2021 “Tumbleweed”	Phase-to-Phase Fault on 500 kV Line	Loss of 605 MW of solar PV resources (33 facilities) Loss of 125 MW at natural gas facility Loss of 46 MW of DERs
July 28, 2021 “Windhub”	Single-Line-to-Ground Fault on 500 kV Circuit Breaker	Loss of 511 MW of solar PV resources (27 facilities) Loss of 46 MW of DERs
August 25, 2021 “Lytle Creek Fire”	Phase-to-Phase Fault on 500 kV Line	Loss of 583 MW of solar PV resources (30 facilities) Loss of 212 MW at natural gas facility Loss of 91 MW at a different natural gas facility

* Solar PV loss quantities reported in this table are based on information provided by CAISO. Quantities used throughout this report may vary due to the resolution of data analyzed. As with the past disturbance reports that involve fault-induced solar PV reductions, the size of the disturbance (in MW) is difficult to calculate due to scan rate differences and other accounting factors; however, the reductions in solar PV output provide a relative indicator of the impact of these reductions compared to other disturbances.

These four disturbances further strengthen the need to ensure BPS-connected solar PV resources (and all BPS-connected inverter-based resources) are operating in a reliable manner to support the BPS. The persistent and systemic nature of these types of widespread solar PV loss events indicate an elevated level of risk to the BPS. NERC strongly recommends that industry take timely action to implement all of the recommendations set forth in this disturbance report, past disturbance reports, and related NERC reliability guidelines. The NERC Inverter-Based Resource Performance Subcommittee (IRPS) should continue driving implementation of the recommendations set forth in the NERC disturbance reports.

Chapter 1 provides details regarding the four initiating events, performance of the BPS-connected solar PV fleet during the events, and additional details around each event. **Chapter 2** documents the key findings from the analysis conducted. **Chapter 3** focuses on modeling and study findings based on NERC and WECC follow-up activities with

[1] NERC Event Analysis Program: https://www.nerc.com/pa/rrm/ea/Pages/EA-Program.aspx

CAISO. **Chapter 4** outlines recommendations specific to CAISO for improved performance validation of the solar PV fleet and improved practices related to the integration of solar PV resources in California. **Chapter 5** provides strong recommendations for the industry based on the key findings and technical basis defined in this report. **Appendix B** provides a detailed analysis of the affected facilities for all disturbances, and **Appendix C** provides a brief analysis of the synchronous generation tripping identified.

Recommendations for Industry Action

Chapter 5 outlines recommendations from the analyses conducted by NERC and WECC. The following are high-level recommendations documented throughout this report:[2]

- **Reinforcement of Recommendations from the *Odessa Disturbance Report*:** The NERC *Odessa Disturbance Report*[3] outlined a number of strong recommendations to address known reliability gaps or issues for reliable operation of BPS-connected inverter-based resources (mainly solar PV resources). NERC reiterates the need for industry action on those recommendations. The NERC IRPS developed a follow-up white paper[4] to the *Odessa Disturbance Report* that was approved by the NERC Reliability and Security Technical Committee (RSTC) and led to the IRPS adding multiple items to its work plan. NERC commends the RSTC and IRPS in being proactive to address identified reliability issues. NERC recommends the RSTC support the development of standards revisions (and future guideline development) to mitigate these reliability issues moving forward.
- **Reinforcing that Significant Updates and Improvements are Needed to the FERC Generator Interconnection Agreements:** All the performance issues identified in the NERC disturbance reports stem from a lack of performance requirements. These four events illustrate how the majority of affected facilities had minimal interconnection requirements applied to them and therefore introduced adverse impacts to the BES in aggregate. NERC guidelines highlight that TOs should establish detailed performance requirements, but those recommendations are not necessarily being comprehensively implemented. NERC recommends that the Federal Energy Regulatory Commission (FERC) update the *pro forma* interconnection agreements with all the necessary performance specifications covered in the NERC reliability guidelines to ensure that all resources are consistently and effectively being interconnected to the BPS. This will help ensure there are no gaps in performance for newly interconnecting resources. These updates should also be accompanied by clear requirements for accurate modeling and sufficiently detailed studies during time of interconnection, including electromagnetic transient (EMT) studies where necessary (most cases to ensure appropriate ride-through for BPS fault events). Lastly, plant commissioning should involve validation that the models used during the system impact studies reflect the equipment being commissioned; inconsistencies that affect the electrical output of the facility should require additional studies prior to commercial operation to ensure BPS reliability and stability.
- **Reinforcing that Improvements to NERC Reliability Standards are Needed to Address Systemic Issues with Inverter-Based Resources:** This disturbance report strongly reiterates the recommendations in the *Odessa Disturbance Report* regarding the need to modernize and update the NERC Reliability Standards. See **Chapter 5** for more details regarding areas for improvement. At a high level, these include the following:
  - **Performance-Based Requirements:** A number of NERC Reliability Standards require documentation that demonstrates compliance with the requirement (i.e., PRC-024-3); however, they do not specify a certain degree of performance that must be met. Therefore, any enforcement and auditing of these standards becomes poorly-defined and ineffective. This has led to unreliable operation of a large and growing number of solar PV facilities. A comprehensive review of NERC standards should be performed to identify any standards where the requirements do not align with the desired intent of the standard from a performance-based perspective. Future NERC Reliability Standard drafting teams should ensure that new

[2] As well as in the context of all past solar PV-related disturbances analyzed by NERC.
[3] https://www.nerc.com/pa/rrm/ea/Documents/Odessa_Disturbance_Report.pdf
[4] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_Odessa_Disturbance_Follow-Up.pdf

or modified requirements are written in a manner to ensure an adequate level of reliable operation of the BPS while minimizing the documentation burdens to demonstrate compliance (i.e., focus on the performance-based aspects of the standard).

- **Performance Validation Standard Needed:** NERC strongly recommends that a performance validation standard be developed that ensures that Reliability Coordinators (RCs), TOPs, or Balancing Authorities (BAs) are assessing the performance of interconnected facilities during grid disturbances, identifying any abnormalities, and executing corrective actions with affected facility owners to eliminate these issues. This requires entities to have strong interconnection requirements as NERC highlights in its reliability guidelines and disturbance reports. A lack of performance validation (validating that the facility is performing as expected) has led to large-scale and widespread disturbances with many affected facilities rather than addressing underlying systemic issues before they become larger events. RCs, TOPs, and BAs should be performing performance assessments and validation for their generation fleet, identifying any unreliable operation of connected resources, and addressing those issues in a timely manner. The IRPS has a work plan item to develop a standard authorization request (SAR) on this topic.
- **Ride-Through Standard In Lieu Of PRC-024-3:** NERC strongly recommends that PRC-024 be retired and replaced with a comprehensive ride-through standard focused specifically on the generator protections and controls (not the auxiliary systems). PRC-024 is not effectively addressing systemic performance issues with inverter-based resources, and this has led to misinterpretations that have resulted in poor performance from solar PV facilities. Many entities now have ride-through requirements in their local interconnection requirements, and a NERC Reliability Standard will help ensure that the growing number of BES inverter-based resources are supporting overall BES reliability during disturbances moving forward. The IRPS has a work plan item to develop a SAR on this topic.
- **Electromagnetic Transient Modeling and Model Quality Checks:** NERC strongly recommends that EMT modeling and studies be incorporated into NERC Reliability Standards to ensure that adequate reliability studies are conducted to ensure reliable operation of the BPS moving forward. Existing positive sequence simulation platforms have limitations in their ability to identify possible performance issues, many of which can be identified using EMT modeling and studies. As the penetration of inverter-based resources continues to grow across North America, the need for EMT modeling and studies will only grow exponentially. Furthermore, NERC Reliability Standards need enhancements to ensure that model accuracy and model quality checks are explicitly defined. While models have been provided by applicable entities in most cases, NERC has identified numerous and systemic modeling issues and believes these issues are due to a lack of model quality reviews that are taking place during model submittals. The IRPS has a work plan item to develop a SAR on this topic.
- **Other Reliability Standard Enhancements:** Chapter 5 describes a number of additional recommended enhancements to NERC Reliability Standards that are reiterations of the *Odessa Disturbance Report.*

Chapter 1: Disturbance Analyses

This chapter describes the initiating fault and an overview of the affected solar PV facilities for each of the four disturbances analyzed. Refer to **Appendix B** for more details regarding the affected solar PV facilities.

CAISO Predisturbance Operating Conditions

Figure 1.1 shows solar PV power profiles for each day that the disturbances occurred, and **Figure 1.2** shows the CAISO BPS-connected solar PV output reductions for each disturbance.[5] **Table 1.1** shows predisturbance operating conditions for each fault. BPS-connected inverter-based resource (i.e., wind, solar PV, and battery energy storage systems) output levels ranged from 33% to 51% of the CAISO internal net demand at the time of each fault. These predisturbance operating conditions illustrate the significant amount of inverter-based resource capacity in the CAISO footprint and highlight the importance of ensuring that all BPS-connected inverter-based resources are operating in a manner that supports reliable operation of the BPS.

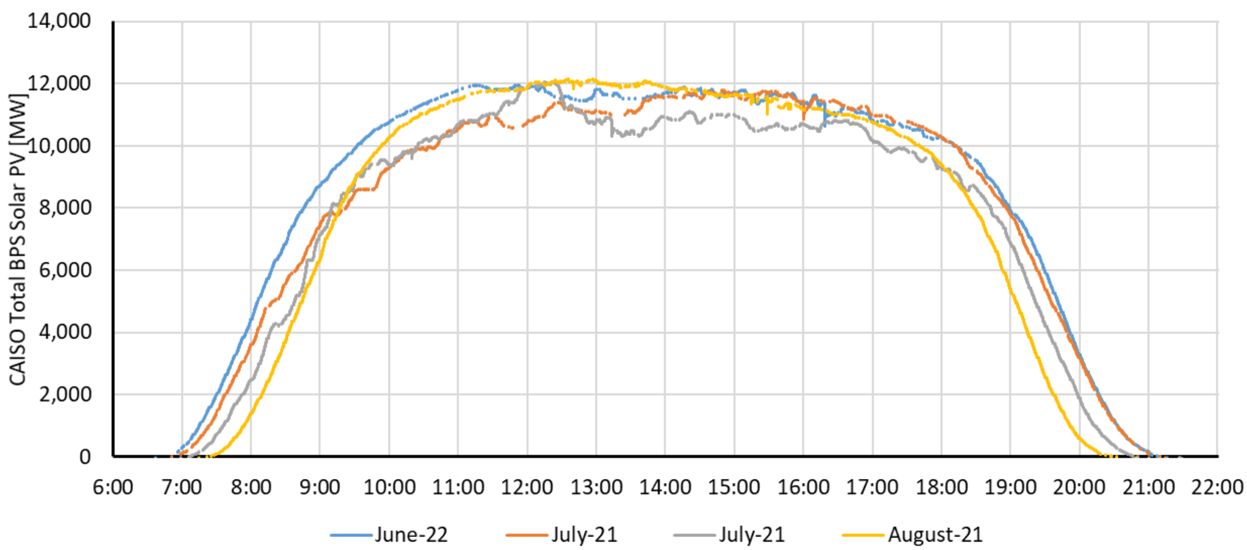


Figure 1.1: CAISO Total Solar PV Profiles for Each Day Events Occurred

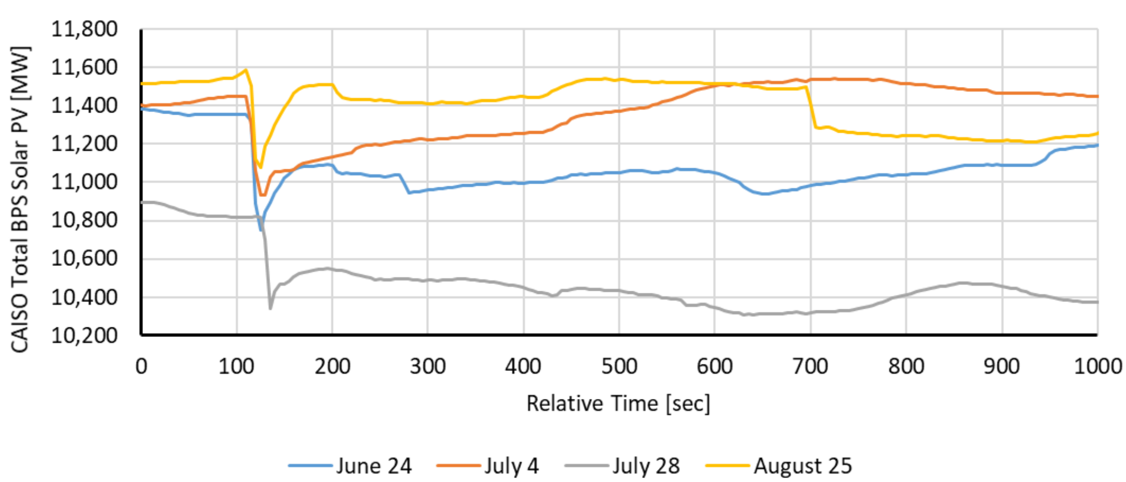


Figure 1.2: CAISO BPS-Connected Solar PV during Disturbance

[5] These plots were created with CAISO SCADA data and may not reflect actual reductions where higher resolution data may be available for certain plants.

Table 1.1: CAISO Predisturbance Operating Conditions [Source: CAISO]								
Operating Condition	June 24, 2021		July 4, 2021		July 28, 2021		Aug 25, 2021	
	Value	%	Value	%	Value	%	Value	%
CAISO Internal Net Demand	30,513	N/A	28,185	N/A	33,003	N/A	32,523	N/A
Solar PV Output [MW]	11,373	37.3%	11,404	40.5%	10,892	33%	11,526	35.4%
Wind Output [MW]	2,268	7.4%	3,156	11.2%	172	0.5%	1,407	4.3%
BESS Output [MW]	-115	-0.4%	-249	-0.9%	-169	-0.5%	100	0.3%

CAISO 2021 statistics[6] highlight that CAISO experienced a new record for peak renewables service load (94.5%) on April 24 for peak solar production (13,205 MW on May 27) and for wind peak production (5,754 MW on May 29). CAISO also added 2,359 MW of installed storage capacity in 2021. CAISO was unable to provide details regarding the amount of solar PV resources with signed interconnection agreements in the CAISO interconnection queue.

Description of Disturbances

This report analyzes the following four disturbances that occurred between June and August 2021 (refer to **Table ES.1** for an overview of the four disturbances):

- **June 24, 2021, "Victorville Disturbance":** At 15:19:35 (3:19 p.m. Pacific), a 500 kV line relayed due to a phase-to-phase fault (3.5 cycle clearing), resulting in a reduction of 765 MW of solar PV resources across the area. 730 MW of the reduction occurred in the CAISO BA footprint, and 35 MW of the reduction occurred in the LADWP BA footprint. CAISO identified 27 solar PV facilities that reduced output as a result of the fault.
- **July 4, 2021, "Tumbleweed Fire Disturbance":** The Tumbleweed Fire burned under some 500 kV transmission lines and heavy smoke caused faults on both the #1 and #2 lines. At 15:01:33 (3:01 p.m. Pacific), #1 kV line relayed out on a phase-to-phase fault. Nine seconds later at 15:01:42 (3:01 p.m. Pacific), the #2 line relayed due to a phase-to-phase fault (3-cycle clearing). The faults caused CT#2 at a combined-cycle power plant to trip while loaded at 125 MW and a 605 MW reduction of solar PV resources. CAISO identified 33 solar PV facilities that reduced output as a result of the fault.
- **July 28, 2021, "Windhub Disturbance":** At 12:14:48 (12:14 p.m. Pacific), a 500 kV line and the 500/230 kV transformer bank tripped on differential protection for a single-line-to-ground fault (3.5 cycle clearing) while closing disconnects on a 500 kV circuit breaker that faulted internally at the substation. The breaker was being returned to service after scheduled maintenance. A 500 kV series capacitor internally bypassed at a nearby facility. CAISO observed a 511 MW reduction of solar PV resources across 27 facilities.
- **August 25, 2021, "Lytle Creek Fire Disturbance":** At 14:15:11 (2:15 p.m. Pacific), a fire burning in Lytle Creek caused a 500 kV line to trip. Some solar PV resources reduced output during this initial fault. The transmission line was returned to service at 14:28:00 (2:28 p.m. Pacific) and then subsequently tripped again at 14:29:10 (2:29 p.m. Pacific) due to a phase-to-phase fault (3-cycle clearing). An LADWP 287 kV line tripped due to fire in the area as well. CAISO recorded 583 MW of solar PV reduction across 30 facilities. A natural gas turbine also tripped that was carrying 212 MW when a 220 kV line exceeded a remedial action scheme (RAS) threshold and tripped. In addition, another natural gas turbine at a combined cycle plant tripped while carrying 91 MW.

Figure 1.3–Figure 1.6 illustrate that all protection systems operated normally.

[6] http://www.caiso.com/Documents/2021Statistics.pdf

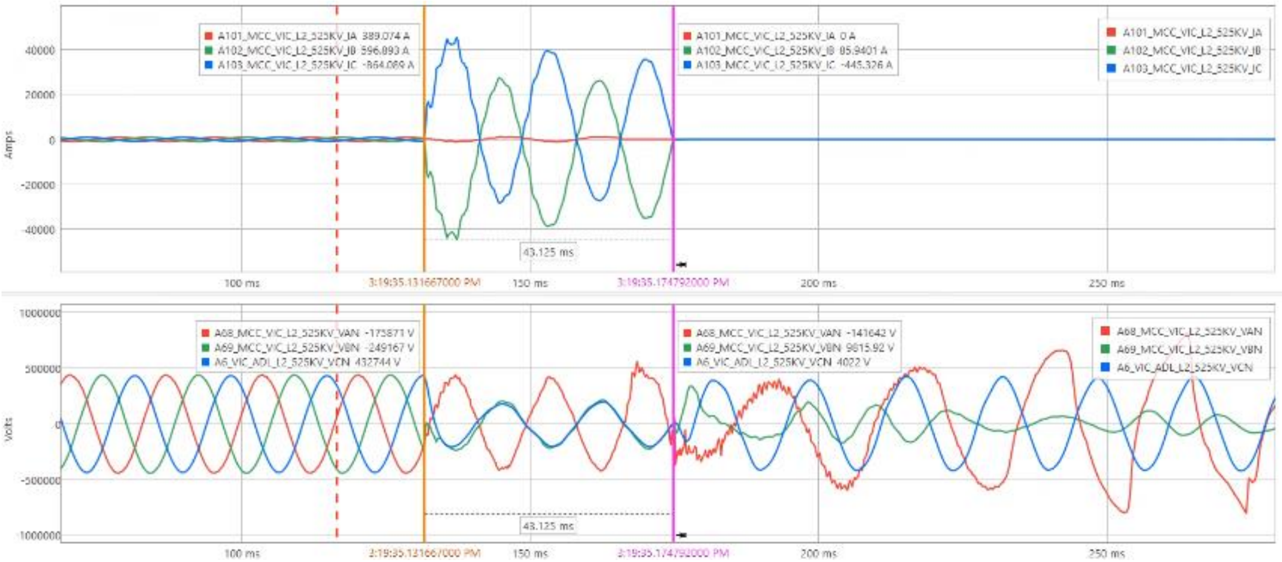


Figure 1.3: Fault Clearing for June 24 Disturbance

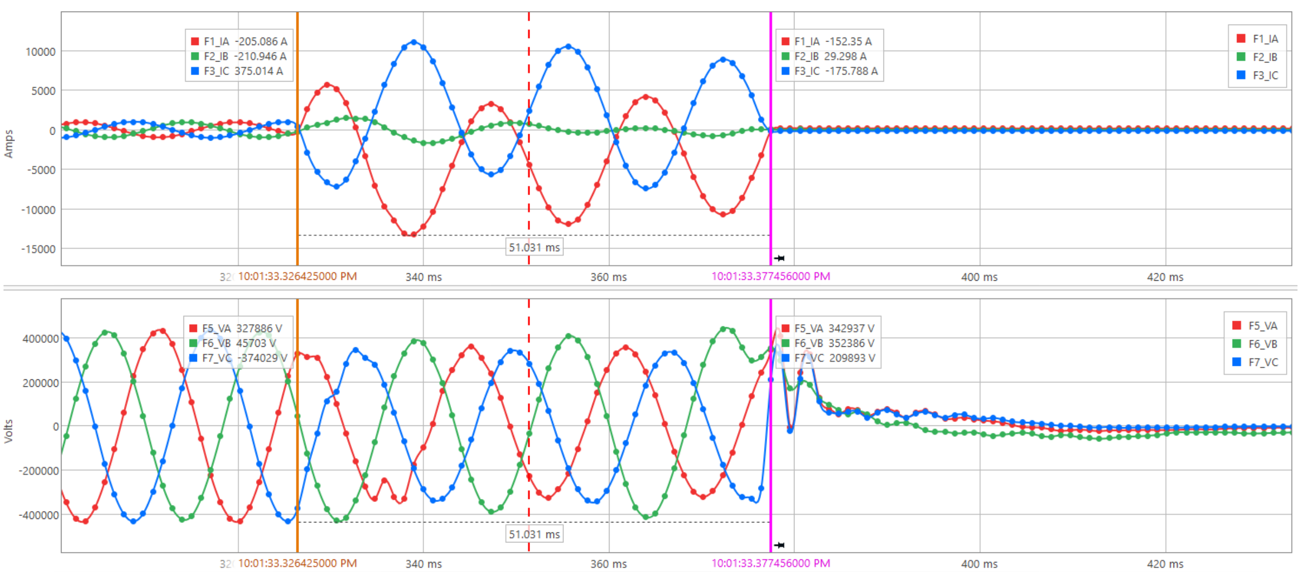


Figure 1.4: Fault Clearing for July 4 Disturbance

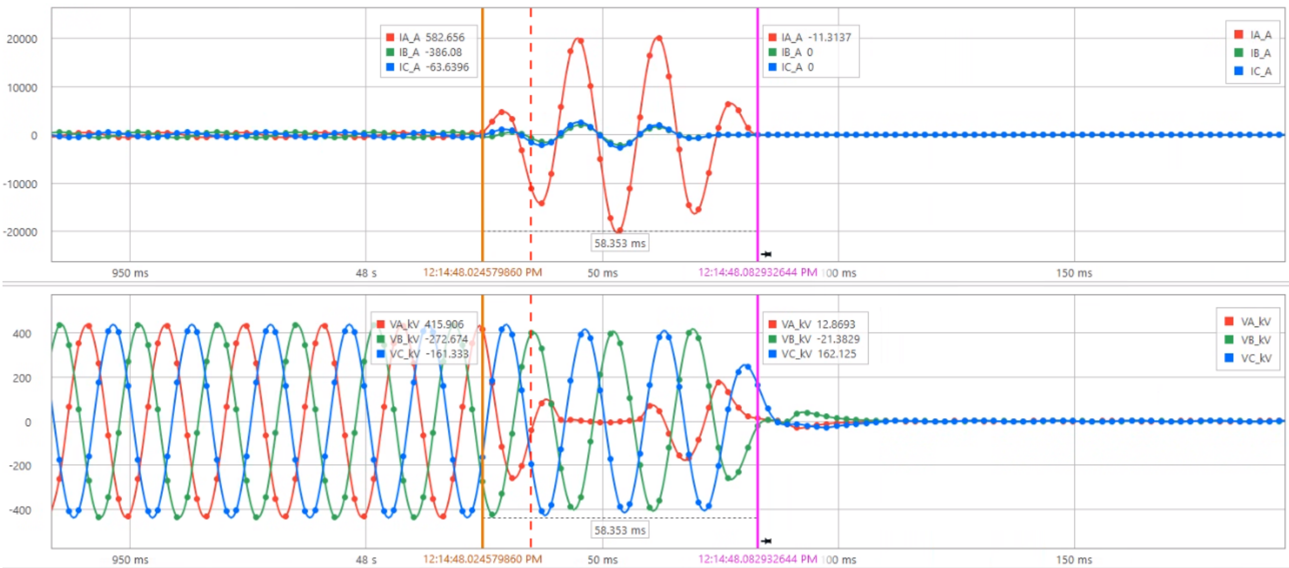


Figure 1.5: Fault Clearing for July 28 Disturbance

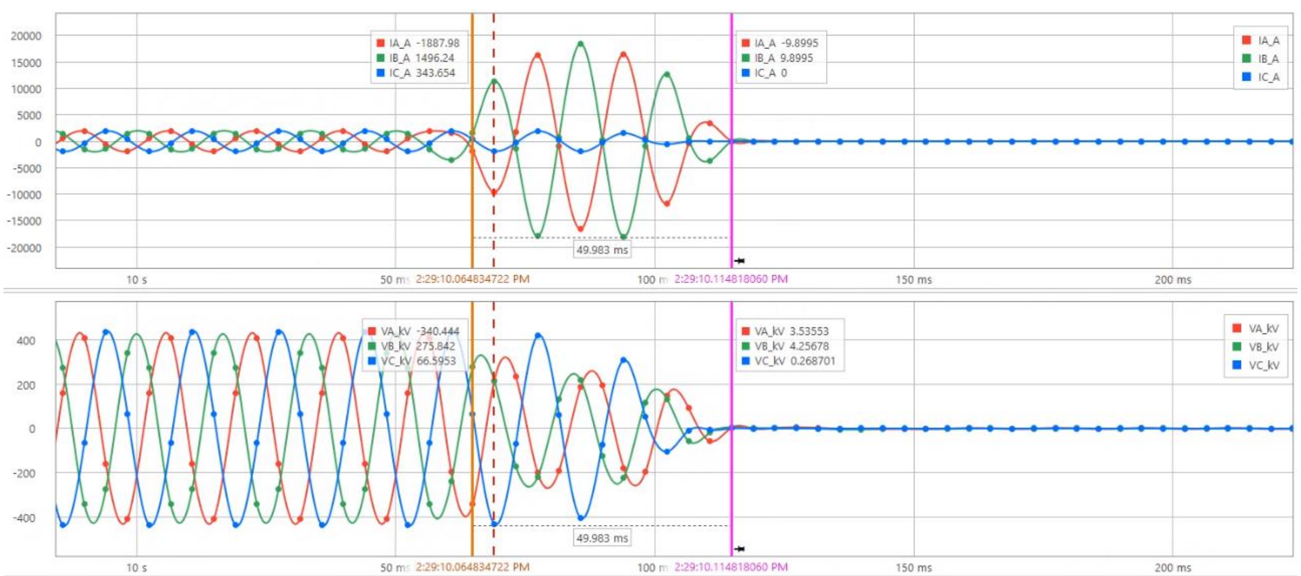


Figure 1.6: Fault Clearing for August 25 Disturbance

Location of Disturbances and Affected Facilities

Each fault occurred on a 500 kV BPS element in the Southern California area around the Los Angeles basin. Solar PV facilities that were identified as abnormally responding to the event were located up to 100 miles away from the fault location. **Figure 1.7**–**Figure 1.10** show the geographic locations of the fault and the affected facilities for each disturbance.

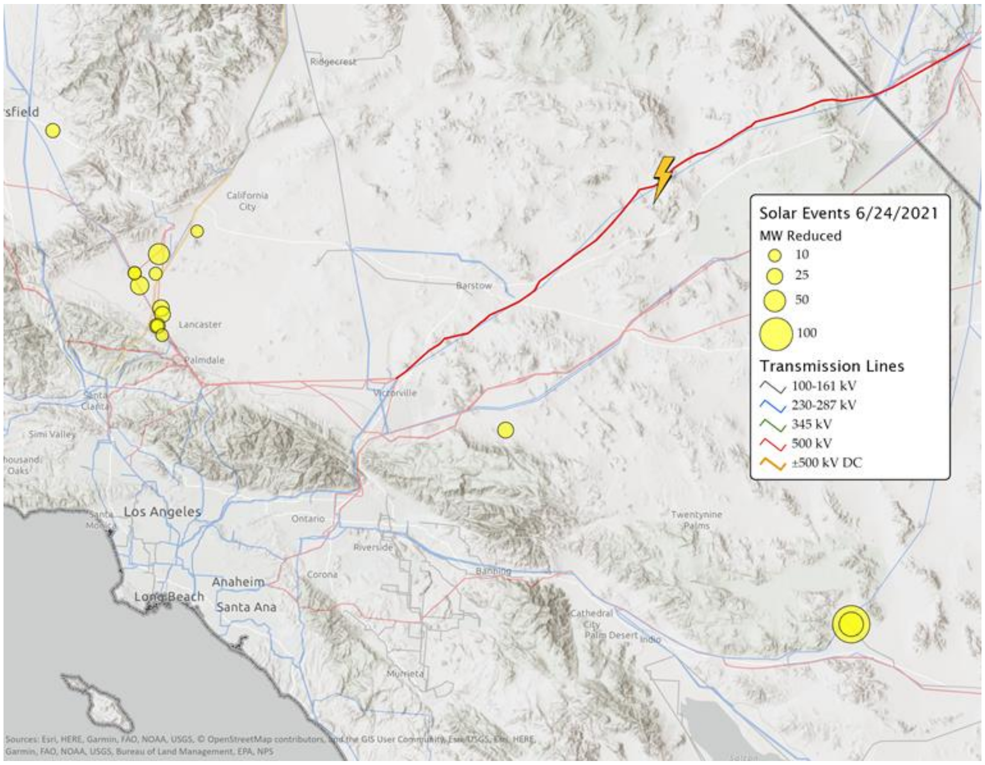


Figure 1.7: Map of Affected Facilities for June 24 Disturbance

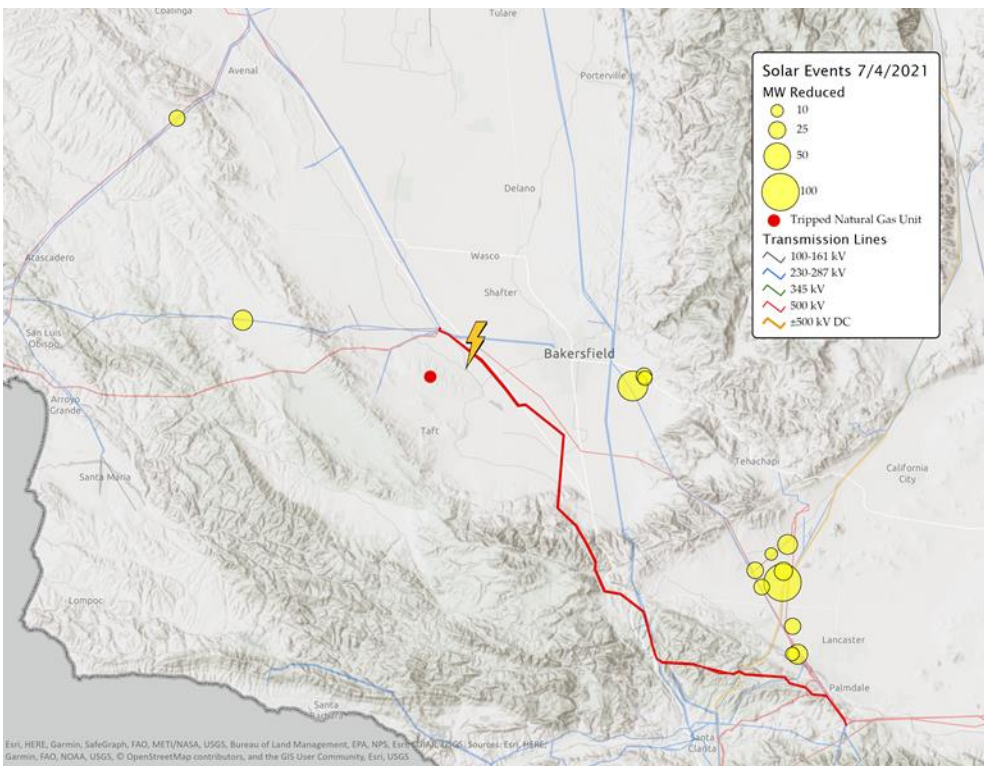


Figure 1.8: Map of Affected Facilities for July 4 Disturbance

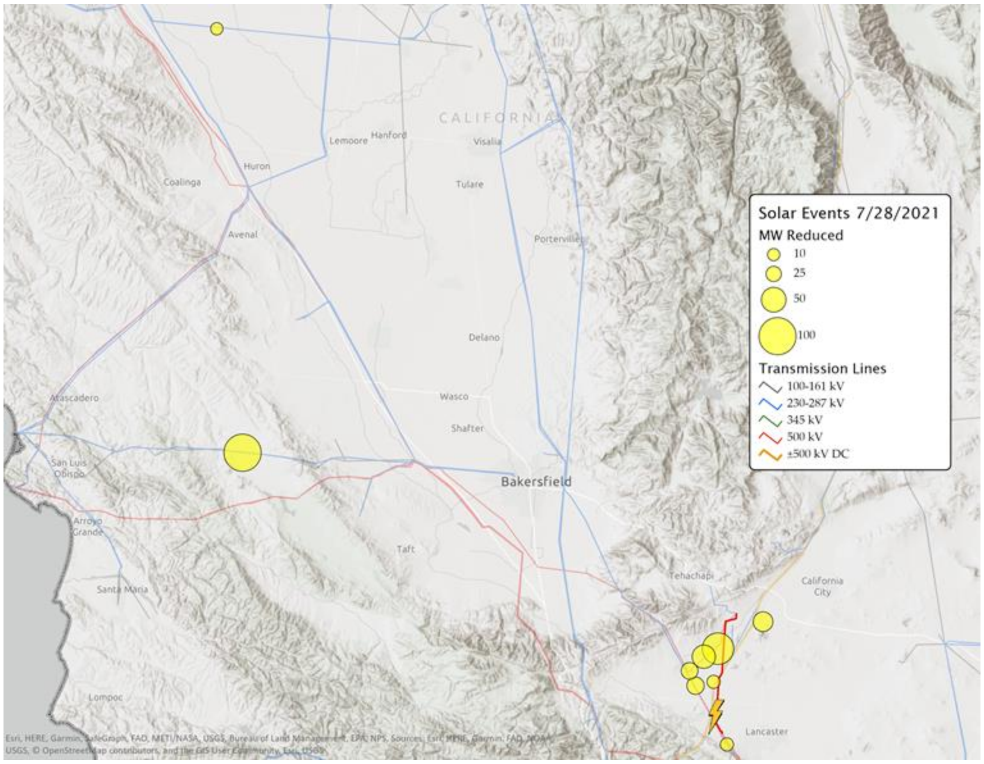


Figure 1.9: Map of Affected Facilities for July 28 Disturbance

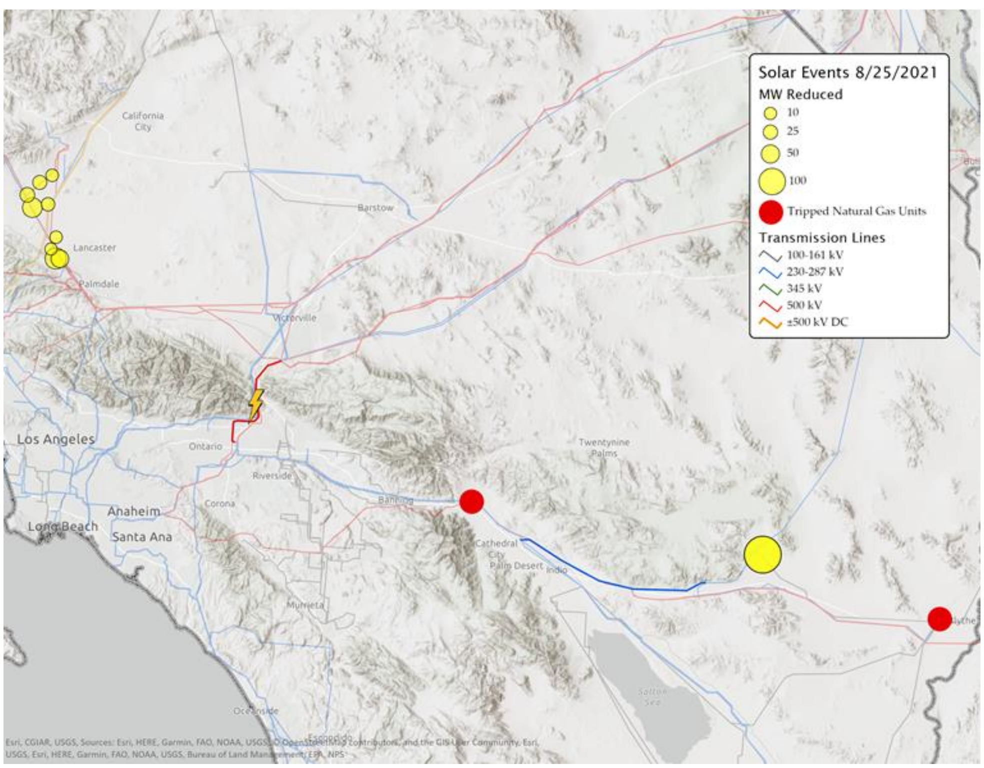


Figure 1.10: Map of Affected Facilities for August 25 Disturbance

System Frequency Response for Each Disturbance

Figure 1.11 shows the Western Interconnection frequency for each disturbance. The July 4, 2021, disturbance reached the lowest frequency nadir at 59.9125 Hz following two successive faults that each caused reductions of solar PV resources. As stated, the purpose of the ERO Enterprise analyzing these events is not due to the severity of the reductions on system conditions (i.e., significant deviations in system frequency); rather, the purpose is to identify any systemic adverse or abnormal performance issues across portions of the solar PV generating fleet that could be mitigated.

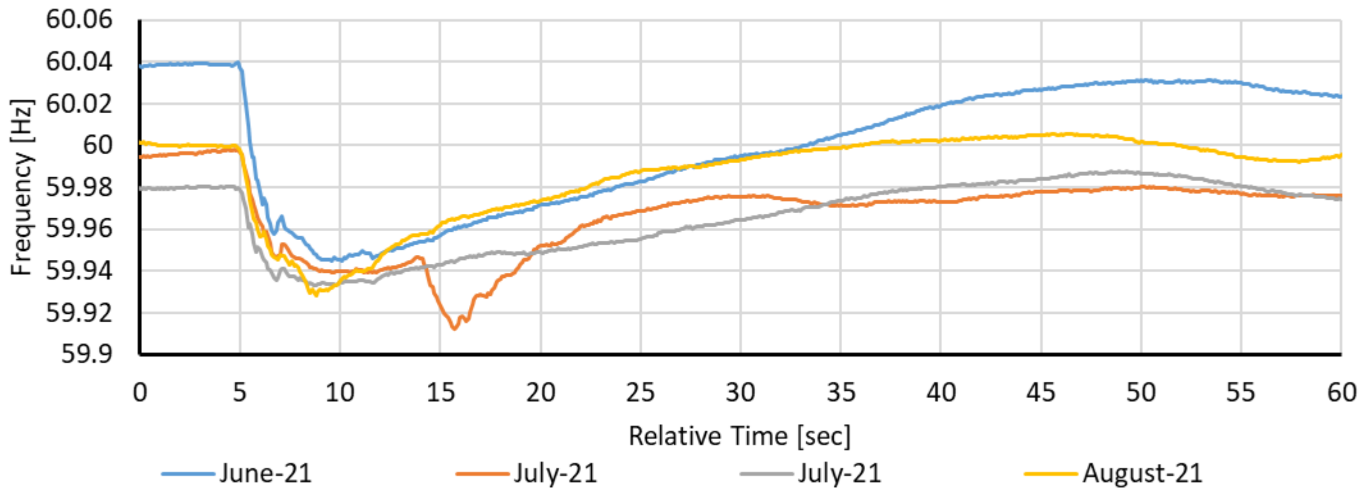


Figure 1.11: System Frequency Response for Each Disturbance [Source: UTK/ORNL]

Chapter 2: Detailed Findings from Disturbance Analysis

WECC requested data from solar PV generating facilities that reduced active power output by more than 10 MW. Information was collected regarding the reduction causes and the inverter characteristics at each site. NERC and WECC analyzed the information provided by the affected entities and held follow-up discussions with the owner/operators as necessary. This chapter describes the key findings and recommendations from these analyses.

Causes of Solar PV Resource Reduction

A significant number of solar PV resources responded to the BPS disturbances in a manner that does not support BPS reliability. There are multiple causes of reduction, ranging from inverter-level and plant-level controls to protection issues. **Table 2.1** shows the causes of solar PV reduction and the magnitude of reduction for each cause for each event. **Figure 2.1–Figure 2.4** illustrate the causes of reduction graphically.[7]

Table 2.1: Causes of Reduction

Cause of Reduction	June 24 [MW]	July 4 [MW]	July 28 [MW]	August 25 [MW]
Slow Active Power Recovery	111	193	184	91
Momentary Cessation	310	120	192	447
Cause Unknown	103	103	112	24
Inverter DC Voltage Unbalance	-	77	15	4
Inverter AC Overcurrent	49	74	17	13
Inverter DC Overcurrent	98	9	47	3
Inverter UPS Failure	-	4	-	-
Inverter Overfrequency	-	-	43	18
Inverter Underfrequency	14	-	-	-
Inverter AC Undervoltage	100	-	16	-
Total	**785**	**566**	**626**	**600**

* See explanations below.

[7] Note that the quantities shown in **Table 2.1** and **Figure 2.1–Figure 2.4** only represent the plants analyzed by NERC and WECC.

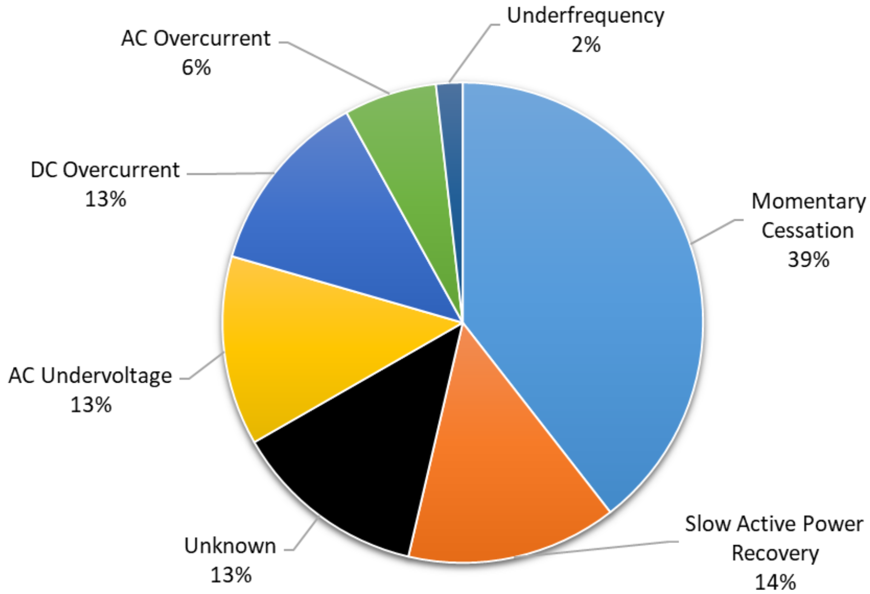


Figure 2.1: June 24 Disturbance Causes of Solar PV Reduction

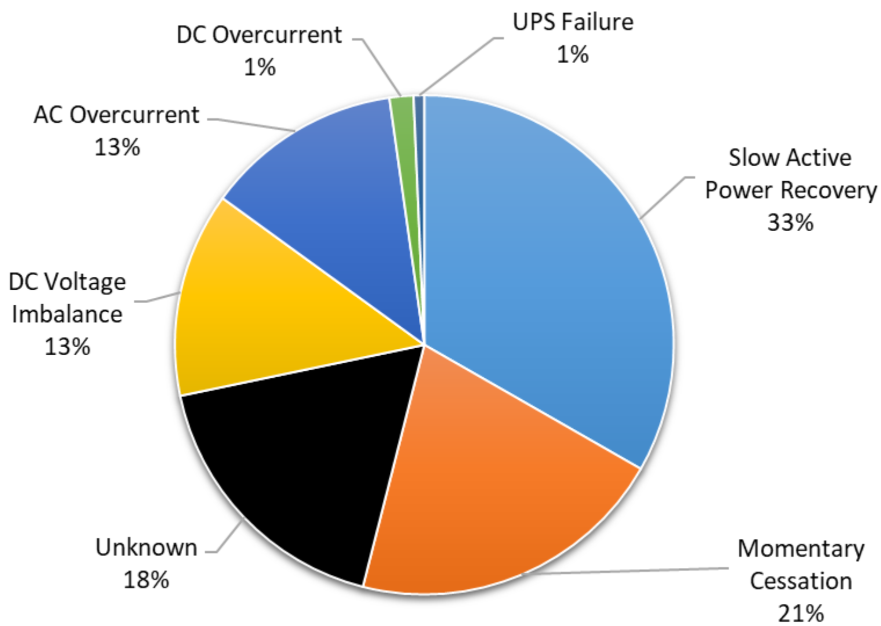


Figure 2.2: July 4 Disturbance Causes of Solar PV Reduction

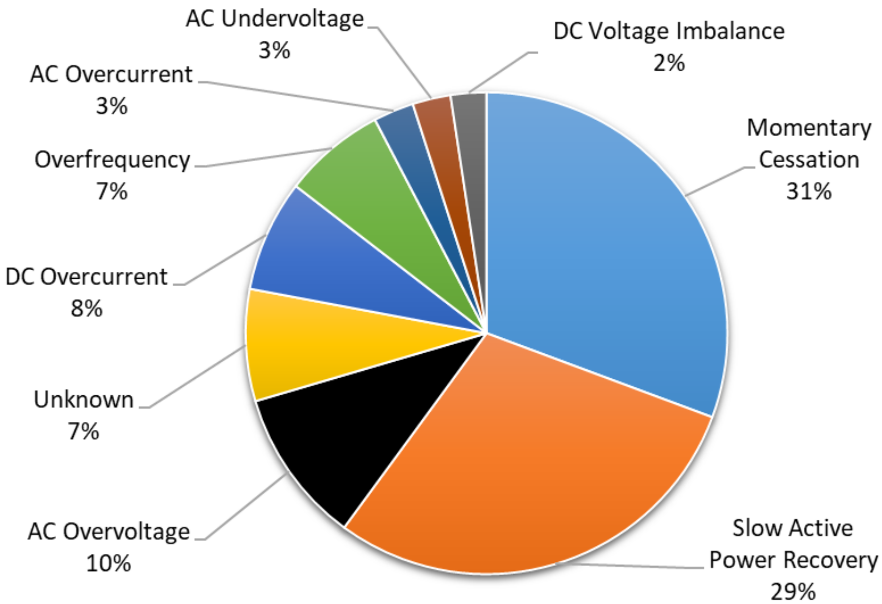


Figure 2.3: July 28 Disturbance Causes of Solar PV Reduction

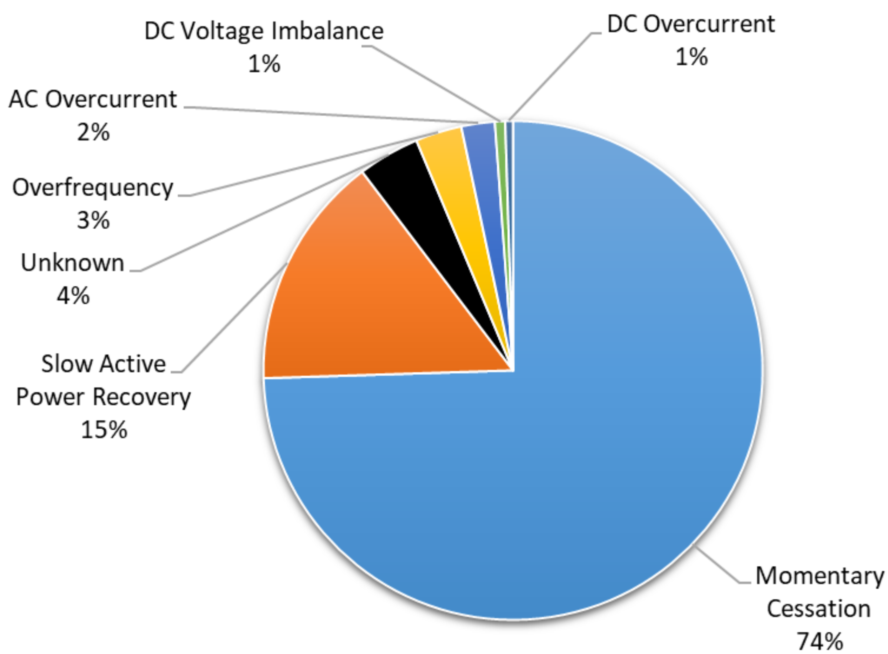


Figure 2.4: August 25 Disturbance Causes of Solar PV Reductions

The following are brief descriptions of the causes of solar PV reduction observed in these four disturbances:

- **Momentary Cessation and Plant Controller Interactions:** Momentary cessation continues to be a notable cause of BPS-connected solar PV reduction in the California region. This is primarily driven from solar PV facilities with legacy inverters that cannot eliminate momentary cessation or modify settings. These plants will continue to show up in NERC analyses of solar PV-related events and are documented for continuity purposes. NERC did note that a number of the facilities that tripped due to inverter protection (e.g., ac overcurrent protection) also stated that they have momentary cessation controls enabled; these are relatively large, newer facilities with these controls enabled that seems to conflict with existing interconnection requirements. Similarly, plant controller interactions with the inverters appear to be elongating the expected dynamic response from these resources based on the programmed ramp rates in the plant controller. This precludes the inverters from quickly returning to predisturbance output levels and degrades system stability. Some interactions slowed the plant recovery by many seconds while other slowed the recovery to many minutes. These issues are easily identifiable using various data sources (even Supervisory Control and Data Acquisition (SCADA) data) and should be mitigated immediately.

- **Slow Dynamic Response:** A number of facilities originally identified in the brief report as reducing power output actually responded dynamically (with dynamic voltage support) to the disturbance. However, the fault cleared in around 50 ms and voltage recovered immediately yet the recovery of active power to predisturbance levels extended many seconds or minutes beyond the recommendations specified in NERC reliability guidelines. These inverters are specifically programmed with momentary cessation disabled and some form of reactive current injection (e.g., K-factor control) enabled.
- **Cause Unknown:** A number of facilities that reduced output in these disturbances were unable to provide any useful information for root cause analysis. The inability of the facility owner to retrieve disturbance analysis data precludes the analysis team from conducting root cause analysis and prohibits the development of any possible mitigations or solutions to the issues observed. Causes for the inability to gather sufficient data to perform any analysis are described in more detail in the subsequent subsections of this chapter.
- **DC Voltage Imbalance:** Inverters from one manufacturer exhibited an imbalance in dc voltage conditions when the dc positive and negative voltages relative to the midpoint dc voltage exceeded a pre-defined threshold. The inverter manufacturer has stated that this may be attributable to the transient occurring during the fault or unstable negative sequence voltage plus the solar PV input at low power.
- **AC Overcurrent:** Across multiple facilities and three inverter manufacturers, ac overcurrent protection appeared in these disturbances. The issue was more pronounced for one particular inverter manufacturer; however, they have stated that this issue appears to be from some of their older inverter models and appears to not be an issue for newer inverters. Most commonly, the protection is set to 110–150% of rated inverter ac current (instantaneous peak).
- **DC Overcurrent:** At one large solar PV facility with legacy inverters, dc overcurrent protection tripped most inverters. These inverters have parallel-connected inverter insulated-gate bipolar transistor (IGBT) bridges (dc in, 3-phase ac out) and all parallel bridges initiated a dc overcurrent trip in most cases. This issue was identified in the Blue Cut Fire and led to this specific inverter manufacturer disabling fast dc current protection for all newer inverters; however, legacy inverters require the fast dc overcurrent protection remain enabled.
- **Uninterruptible Power Supply Unit Failure:** A few inverters tripped on uninterruptible power supply failure and remained off-line for the rest of the day. The plant owner was able to restore the inverters to service upon manual inspection; however, no additional details were provided regarding the failure.
- **Inverter Frequency Tripping:** Two facilities exhibited frequency-related tripping. One facility had inverters trip on overfrequency (61.7 Hz for 1 ms), and the other had inverters trip on underfrequency (59.3 Hz for 20 ms). Both trips involved a near-instantaneous trip timer that lead to false tripping caused by spikes in calculated frequency during voltage phase angle jumps at the time of the fault. These issues have been highlighted in the Blue Cut Fire, and the protection settings are not based on equipment limitations. NERC recommended that the plant owner work with the inverter manufacturer to expand settings to given equipment capabilities. NERC also recommended the inverter manufacturer proactively update settings at all existing facilities that may be prone to this spurious tripping.
- **AC Undervoltage:** Inverters at two facilities tripped on ac undervoltage protection. In particular, one non-BES facility had ac undervoltage protection set within the PRC-024-3 voltage boundaries and tripped due to

the relatively tight settings. NERC recommended that the facility owner consider extending those undervoltage trip settings, if possible, to help ensure resource ride-through for BPS faults.

The following sections describe key findings from these analyses in more depth.

Lack of Monitoring Data Available for Plants

Each affected solar PV facility was requested to provide plant- and inverter-level electrical measurement data at the highest resolution available. This included, at a minimum, the following quantities: plant root-mean-square (RMS) three-phase active power, plant RMS three-phase reactive power, plant RMS phase voltages, plant bus frequency, and inverter-level oscillography for inverters that tripped. The review team tracked the highest resolution of the data provided from each facility, and this information is provided in **Appendix B**.

NERC reliability guidelines strongly recommend all newly connecting BPS-connected inverter-based resources to be equipped with at least the following:

- SCADA data throughout the plant (1-second resolution)
- Sequence of events recording at all logging points within the plant and at inverters (1-ms resolution)
- Plant-level continuous recording from a phasor measurement unit or plant-level controller (1–2 cycle reporting resolution)
- Plant-level digital fault recorder (DFR) data from a digital relay or the plant-level controller (kHz resolution oscillography)
- Inverter-level oscillography data to capture inverter terminal behavior, at least from some inverters within the plant (kHz resolution)

Data availability and data quality issues continue be a significant area of concern for solar PV facilities in the CAISO footprint. This is particularly due to the commercial operation date of many of the affected facilities and the requirements they were subject to at the time of interconnection. While some of the recently interconnected facilities have dynamic disturbance and plant oscillography data, most facilities have very limited data for event analysis. Legacy plants installed prior to late-2019 (when the guidelines were published) have very limited on-site monitoring data and often report 5-minute resolution SCADA data that serves no value for forensic analysis. CAISO provided 5-second SCADA data that was needed to simply understand the magnitude of reduction in these cases since no useable data was available from the facility.

In multiple cases, the plant owner provided inverter trip functions with basic descriptions but did not include the associated settings—per the request for information (RFI)—to understand what trip function caused the reduction. In multiple cases, the plant owner stated that no further information was available due to limited information available or difficulty coordinating with the inverter manufacturer. These issues highlight a systemic gap in the capabilities of plant owners to analyze their facilities' dynamic response to grid disturbances.

CAISO updated their generator monitoring equipment requirements for facilities above 20 MW in February 2020. Those requirements mirror the NERC reliability guideline recommendations in terms of ensuring high-resolution plant-level data (including electrical quantities, statuses, and control points) as well as inverter-level signals, alarms, and fault codes. This data must all be time synchronized, have a resolution of 10 milliseconds or better, and be available for at least 30 days. Therefore, it is likely that data availability for newer facilities will improve over time; however, NERC and WECC in future event analyses will focus on whether this data is available from any affected newer facilities to ensure plant owners are able to deliver the required data specified by CAISO.

Lastly, NERC recommends that all existing facilities be retrofitted with SCADA data recording capability that records the information on an interval of no more than 2-4 seconds (ideally 1-second resolution). In many cases, this may be a software setting that can be modified rather than hardware replacements. SCADA historians are already installed and measuring electrical quantities at higher resolution, and the data is down-sampled when stored. Useful information is being deleted in this process; that data should be available for event analysis. Further, multiple plant owners and equipment manufacturers have stated that inverter-level oscillography data and high-resolution oscillography (typically available in digital relays) are available at the facility but currently "turned off." These features should be enabled when possible to improve forensic analysis and possibly improve performance at these facilities. However, there are no existing market rules or NERC Reliability Standards to enforce this recommendation. Industry should seek to improve monitoring capabilities at existing facilities when the ability to enable these features does not introduce significant cost burden for the facility owner. A NERC standard drafting team is making modifications to PRC-002 to account for these issues that are significantly hindering the ability to perform event analysis.

Persistent Challenges Performing Root Cause Analysis

The analysis team had significant difficulty gathering useful information for root cause analysis at multiple facilities for the four events analyzed. This led to an abnormally large number of "unknown" causes of power reduction for the plants analyzed. The goal of this analysis is to do the following:

- Help affected plants identify the causes of power reduction at their facilities and determine if any possible improvements can be made to their facilities (e.g., settings changes, firmware upgrades) that will help them remain operational during BPS fault events
- Help sharing information with the industry regarding any systemic performance issues observed during these analyses and any corrective actions that can be taken by the industry to mitigate any widespread risks moving forward

The primary causes for the inability to identify a root cause from affected solar PV resources includes the following:

- Plants lacked the necessary recording data to conduct any useful root cause analysis such as the following:
  - Poor resolution plant SCADA data leading to difficulties coordinating with plant personnel
  - No fault code data retrievable from the inverters due to inverter overwriting
  - No high-speed recording (e.g., DFR data) at the plant point of interconnection
- Plant personnel unaware that their facility was affected (i.e., entered momentary cessation, tripped, or reduced power output in another way)
- Plant personnel unable to access inverter information, such as fault codes, inverter oscillography, or inverter protection and control settings
- Affected inverters from manufacturers that are now out of business—no access to inverter information and no ability to make modifications to inverters
- Difficulties for plant personnel working with some inverter manufacturers due to workload, prioritization, and other factors (i.e., very long lead times for support)
- Plant underwent a change in ownership and therefore CAISO was unable to provide any contact information for the affected facility (i.e., analysis team unable to contact the facility)
- Non-BES facilities chose not to respond to the RFIs nor participate in any follow-up discussions to perform root cause analysis

- Challenges coordinating between the inverter manufacturer and plant-level controller manufacturer—commonly these are different entities whose controls are coordinated by a third-party consultant or contractor

Gathering useful data to perform root cause analysis has not been an issue in other NERC Regions.

Continued Momentary Cessation at Legacy Facilities

A notable portion of the overall power reduction for each event is attributed to momentary cessation from legacy facilities that cannot eliminate its use (75% of overall reduction for the August 25 event). NERC and WECC have worked closely with plant owners at these facilities to ensure that momentary cessation settings are set as wide as possible to avoid any unnecessary adverse impacts to BPS reliability from this response. However, these facilities will continue to reduce power output for an extended period of time since their settings often cannot be changed. While the response of these facilities will continue to drive possible Category 1i events per the NERC EA Program, NERC and WECC believe it is important to continue documenting the overall solar PV fleet performance for these types of events for the following reasons:

- These facilities may involve inverter tripping in addition to inverters entering momentary cessation that lead to a different set of key findings, recommendations, and mitigating measures. Useful information can be shared with industry by analyzing these facilities.
- Some facilities entering momentary cessation also involve plant-level controller interactions that further negatively affect overall BPS stability and reliability. While momentary cessation cannot be eliminated in these legacy facilities, eliminating plant-level controller interactions may be possible and should be pursued by the BA, RC, and plant owners/operators. These interactions are widely observed, pose a risk to BPS reliability, and are most often not identified in any reliability studies conducted by the Transmission Planner (TP) and Planning Coordinator (PC). This leads to plants being operated in an unplanned and unstudied operating state.

AC Overcurrent Protection

Multiple facilities had inverters trip on ac overcurrent protection. This issue is attributed to three inverter manufacturers. One inverter manufacturer in particular constituted the majority of ac overcurrent tripping. Most commonly, the ac overcurrent protection issues a fault code and trip signal when individual ac phase current on any one inverter module exceeds a pre-defined threshold value. The measurements typically use an instantaneous peak (rather than filtered RMS) measurement in order to protect the inverter components. Inverters are referred to as "current-limited" devices because they have semiconductor-based switches that are highly sensitive to overcurrent. However, when the inverter controls are unable to rapidly respond to changing ac-side grid conditions, the inverter is susceptible to briefly injecting uncontrolled currents that could lead to short spikes in inverter current and result in inverter tripping. The inverter manufacturers involved in these events use instantaneous peak ac current thresholds of 110–150% of nominal.

One inverter manufacturer had multiple facilities trip on ac overcurrent protection, and the manufacturer stated that the recurrence of ac overcurrent tripping is particularly an issues with "older" inverters installed in the 2016–2017 time frame. These inverters are more susceptible to ac overcurrent tripping due to the increased chance of its phase lock loop (PLL) losing synchronism, which controls the types of currents injected to the system. When the terminal ac voltage waveform becomes distorted and phase jumps during ac-side faults on the BPS, these older inverters are unable to adequately control ac current because they do not have fast modulation control. The inverter manufacturer stated "there is not much that can be done" for these inverters, so ac overcurrent tripping will continue to be a systemic issue for plants with this type of inverter installed.

NERC and WECC do not have a contact for the other inverter manufacturer and therefore were unable to contact them regarding the root cause of ac overcurrent tripping in their inverters, so these inverters (which are not widely used) will likely continue to trip on ac overcurrent protection for BPS faults moving forward.

All TOs should establish interconnection requirements that explicitly state that inverter tripping for studied ac-side faults is unacceptable and that inverter hardware and control protections (including ac overcurrent, dc voltage, and other protections related to the loss of PLL synchronism) should not operate to disconnect the plant for these studied faults. As stated in the NERC *Odessa Disturbance Report*,[8] the failure of solar PV facilities to ride through BPS fault events degrades BPS reliability and resilience. NERC PRC-024-3 does not address inverter overcurrent protection and should be overhauled to a ride-through standard focused on inverter-level and plant-level protection and controls for all BES inverter-based resources. All TPs and PCs should ensure that plant models accurately represent ac overcurrent protection, particularly in EMT studies, and any plant exhibiting this abnormal performance should be validated against its modeled performance. Discrepancies between actual and modeled performance should be addressed through a corrective action plan to ensure the facility does not operate in this unreliable manner during BPS faults.

DC Overcurrent Protection

One large solar PV facility with legacy inverters experienced consistent dc overcurrent protection that tripped most of the inverters for multiple faults analyzed. The inverters have three parallel-connected inverter IGBT bridges (dc in, 3-phase ac out) with three ac current sensors and one external dc current sensor. Any one sensor can initiate an overcurrent trip. In most cases, all IGBT bridges initiated a dc overcurrent trip. The dc overcurrent protection issues were first identified in the Blue Cut Fire, and this specific inverter manufacturer proactively analyzed this cause of tripping and disabled it for all newer inverters. None of the subsequent inverter models produced by this manufacturer include fast dc overcurrent protection. However, inverter tripping due to fast dc overcurrent protection will continue to be a possible cause of solar PV reduction during fault events for facilities with this legacy inverter model.

The inverter manufacturer stated that prior to being informed about these performance issues at this facility, they had not previously had such dc overcurrent protection reported for these types of inverters nor observed the cause of tripping in their laboratory testing. Presently, there is no test facility available or planned to do regression testing on these legacy inverters, so this is considered an “equipment limitation” and will remain a possible tripping issue in the future.

All inverter manufacturers are recommended to ensure that new inverters will not cause dc overcurrent tripping for external faults. This can be tested with rigorous factory tests that impose ac-side faults on the inverter and monitor dc-side current injection. As highlighted by working with this inverter manufacturer, this issue can be corrected for newer inverter models to eliminate the likelihood of any dc overcurrent tripping in the future. TOs should also ensure that interconnection requirements include specifications that dc overcurrent protection should not result in inverter tripping for studied BPS faults as this can be managed and mitigated by inverter controls.

Near-Instantaneous Inverter-Level Frequency Protection

Inverters at two solar PV facilities exhibited frequency-related tripping for these fault events: one facility tripped on measured overfrequency conditions and the other facility tripped on measured underfrequency conditions. In all events, BPS frequency never experienced a notable excursion that warrants any generator frequency protection to operate (see **Figure 1.11**). **Table 2.2** shows the frequency protection settings for the two facilities. Protection settings highlighted in red are those that tripped the inverters. One plant had inverters trip for measured overfrequency conditions (61.7 Hz) exceeding 1 ms; the other facility had inverters trip for measured underfrequency conditions (59.3 Hz) exceeding 20 ms.

[8] https://www.nerc.com/pa/rrm/ea/Documents/Odessa_Disturbance_Report.pdf

Table 2.2: Inverter Frequency Protection Settings			
Setting	Threshold and Timer	Setting	Threshold and Timer
OF1	61.7 Hz for 0.001 seconds	UF1	57.0 Hz for 0.0 seconds
OF2	61.6 Hz for 30 seconds	UF2	57 Hz for 0.02 seconds
OF3	60.6 Hz for 180 seconds	UF3	59.3 Hz for 0.02 seconds

The following observations are made:

- The overfrequency trip settings are directly on the PRC-024 frequency boundary and are not based on any actual equipment limitations.
- The underfrequency trip settings do not align with PRC-024-3 (i.e., they fall within the "no trip zone" of the curves). This facility is a non-BES resource and not subject to NERC Reliability Standards; however, this is likely not based on any equipment limitation and degrades BPS reliability due to the erroneous tripping on measured frequency during phase jumps.

Inverters calculate frequency from the measured phase angle at their terminals. Phase angle will shift (or "jump") during faults, so frequency measurements are often taken over a time window and then filtered to avoid erroneous frequency tripping issues. NERC *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance*[9] provides recommended practices for setting frequency protection following these same issues being identified as the primary cause of the Blue Cut Fire[10] and a NERC alert[11] was issued in 2017.

NERC PRC-024-3 allows for an "instantaneous" frequency trip setting; however, footnote 9 in Attachment 1 states the following:

> "Frequency is calculated over a window of time. While the frequency boundaries include the option to trip instantaneously for frequencies outside the specified range, this calculation should occur over a time window. Typical window/filtering lengths are three to six cycles (50–100 milliseconds). Instantaneous trip settings based on instantaneously calculated frequency measurement is not permissible."

Even with the footnote clarification, plants are still configured with very fast timers (i.e., 1 ms) that are causing inverters to erroneously trip for BPS fault events. The footnote simply provides a recommendation that is likely overlooked or ignored.

The sole inverter manufacturer involved in the Blue Cut Fire frequency-related tripping quickly and proactively responded by ensuring that all BPS-connected solar PV facilities changed their frequency protection settings to avoid future issues. However, these disturbances in 2021 involve different inverter manufacturers, illustrating that the issue is still not widely understood or addressed across all manufacturers and plant owner/operators.

NERC recommended both plant owners make changes to expand the window of inverter frequency protection based on equipment capabilities. Furthermore, NERC recommended that one inverter manufacturer proactively seek updates to these very fast frequency trip settings for all existing facilities. The inverter manufacturer informed NERC

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[9] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Inverter-Based_Resource_Performance_Guideline.pdf
[10] Blue Cut Fire Disturbance Report: https://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf
[11] Level 2 NERC Alert: Loss of Solar Resources during Transmission Disturbances due to Inverter Settings: https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20Loss%20of%20Solar%20Resources%20during%20Transmission%20Disturbance.pdf

and WECC that they agree that the frequency trip delay settings do not need to be set so tight (i.e., 1 ms) and that they can be modified. The inverter manufacturer stated that they have informed their regional service managers; however, it is unclear if this issue is being proactively updated. The inverter manufacturer did inform NERC that they are sometimes asked to set the protection settings to the PRC-024 curves (including near-instantaneous frequency tripping) to “match the dynamic model submitted” or for other reasons. The inverter manufacturer also stated that this issue is likely more prevalent in older projects; the default protection settings used since 2019 for these inverters involve a wide frequency window with a minimum of 1-second timer for any trip functions.

DC Voltage Imbalance Protection

Some inverters tripped on dc voltage imbalance, which triggers when a large voltage between positive and negative terminal voltages on the dc bus of the inverter is measured (|V(P)–V(N)| > Threshold). Unbalanced (negative sequence) voltage on the ac side of the inverter can cause a ripple on the dc bus that must be managed by inverter inner control loops. If those loops are not sufficiently fast enough to respond to grid fault events, the dc-side ripple may surpass the trip threshold and cause inverter tripping for ac-side faults.

In this case, the inverter manufacturer informed NERC and WECC that they have been field testing a firmware upgrade that is now available to be updated on existing solar PV facilities of this make and model type. The firmware upgrade reconfigures the way in which inner controls respond, enabling much faster and tighter control of inverter module currents in response to grid disturbances. The research team at the inverter manufacturer has stated that this firmware upgrade will likely reduce the tendency of inverters tripping on dc voltage imbalance issues if deployed.

This firmware upgrade should be deployed at all existing solar PV facilities for this specific inverter manufacturer. Firmware upgrades require the inverter manufacturer to be on-site at the facility to update each inverter with the new software. This will require time and coordination by each plant owner/operator, and it is unclear if and when those updates will take place. However, NERC strongly encourages applicable solar PV owner/operators to initiate firmware upgrades to mitigate unnecessary inverter tripping for future BPS fault events.

Recovery Time from Minor Fault Events

One plant owner/operator informed NERC that they are planning changes to their default return-to-service delay following minor faults. Minor faults are generally referred to as those faults where the inverters can initiate an automatic restart rather than require manual intervention or inspection. Inverters will typically attempt a restart, assuming a healthy grid voltage and frequency is detected following a restart timer. In the past, as an artifact of IEEE 1547, this restart timer has been set for 300 seconds; however, as identified in the *Odessa Disturbance Report*,[12] this default can be modified to be much faster. This plant owner/operator, in coordination with the inverter manufacturer, is planning to change the restart timer from the default 300 seconds to 0 seconds to help with recovery should any inverter trip for ac-side “minor faults” where an automatic restart can be initiated.

NERC recommends the plant owner/operator seek input and feedback from their BA and RC regarding appropriate return-to-service settings. NERC *Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources*[13] recommends that all TOs, in coordination with their BA, establish reconnection requirements for all BPS-connected inverter-based resources.

Tripping of Distributed Energy Resources

NERC has identified changes in net demand attributed to DER tripping during BPS fault events in the Angeles Forest, Palmdale Roost, and San Fernando disturbances.[14] As described in these reports, quantifying the aggregate dynamic DER response during these events can be challenging for a number of reasons. Area-wide load SCADA aggregation

[12] https://www.nerc.com/pa/rrm/ea/Documents/Odessa_Disturbance_Report.pdf
[13] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf
[14] https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx

points may be calculated using summations of tie-line interchanges and metered generation (i.e., *Area Load = Intertie + Metered Generation*) that may cause errors in the values reported during faults. This may be due to non-synchronized data scans capturing data pre- and post-fault quantities, not all generating units metered or remote terminal units sending data may be available, and area load nets unmetered generation with load—meaning that it is not possible to differentiate load response from unmetered generation.

Analysis of individual SCADA load points (e.g., power flow across a 230/66 kV transformer bank) provides a more reliable assessment of net load changes and possible DER tripping particularly because the data latency issues are not present but time alignment must be accounted for. However, this process is more time consuming since individual data points must be analyzed and subtransmission generation must also be accounted for appropriately. With these points in mind, Southern California Edison (SCE) conducted an analysis of possible DER tripping (or other reduction) to determine an estimate of the amount of DERs involved in the disturbances. SCE identified the following net load increases that are likely attributed to aggregate DER tripping:

- June 24 Disturbance: 145 MW
- July 4 Disturbance: 46 MW
- July 28 Disturbance: 46 MW
- August 25 Disturbance: 0 MW (no identifiable increase in net load)

Plant-Level Controller Interactions Persist Yet Solutions Exist

As observed in multiple past NERC analyses of disturbances involving solar PV resources, plant-level controllers can interact with the fast inverter controls immediately after BPS faults once voltage has recovered to within nominal ranges. This interaction precludes the inverters from fully recovering the predisturbance output levels. The issue appears to be more prominent when the inverter and plant-level controller are manufactured by different entities and integrated by a third-party consultant or contractor.

Plant controller interactions are a common and systemic issue because they cannot be identified with modeling prior to commercial operation and they can generally only be identified with event analysis and performance validation. As stated in this report and past NERC disturbance reports, most RCs, TOPs, and facility owners/operators are not conducting such analysis with sufficient technical depth and rigor to identify the root cause and implement a corrective action.

One large solar PV facility has been involved in multiple past events analyzed by NERC and WECC. This facility has legacy inverters with the following momentary cessation settings:

- Low voltage momentary cessation threshold (pu voltage) = 0.875 Vpu
- Time delay to recover active power upon voltage recovery (milliseconds) = 1,000 ms
- Active power recovery ramp rate (%/sec) = 8.2 %/sec

Therefore, if the plant enters momentary cessation, it should recover to predisturbance active power output levels in about 13 seconds (considering the time delay and active power ramp rate). However, it was observed in multiple disturbances analyzed that this plant took about 40–50 seconds to recover to predisturbance levels (see **Figure 2.5**), illustrating that some other form of ramp rate limiter was interacting with the inverter controls.

NERC and WECC worked collaboratively with the plant owner/operator to inform them of the issues observed. The plant owner worked with their internal controls team (this plant involves a legacy plant-level controller from an entity that is now out of business) and the inverter manufacturer to better understand the issue. It was determined that the slower response time was due to a set point change that the plant-level controller sends after the fault event that triggered the "normal" plant-level ramp rate rather than the faster 8.2%/second ramp rate expected from the inverters. As an outcome of this analysis, the plant owner/operator has added a latch to the plant-level controller that holds P and Q set points when voltage is outside of nominal (i.e., below 0.9 pu or above 1.1 pu). After voltage recovers and after a specified time delay (to allow the inverters to fully recover), the latch is released. This should allow the inverters to respond as fast as possible to fault events while maintaining the ability to control plant voltage within its schedule. These updates have been implemented, and NERC and WECC will monitor future performance of this facility to BPS faults.

Coordination between NERC, WECC, the plant owner/operator, and the equipment manufacturer(s) led to successful root cause analysis and the development of a corrective action to improve performance at this facility; other facilities with these interactions should explore similar updates to their controls to mitigate these types of issues, if identified.

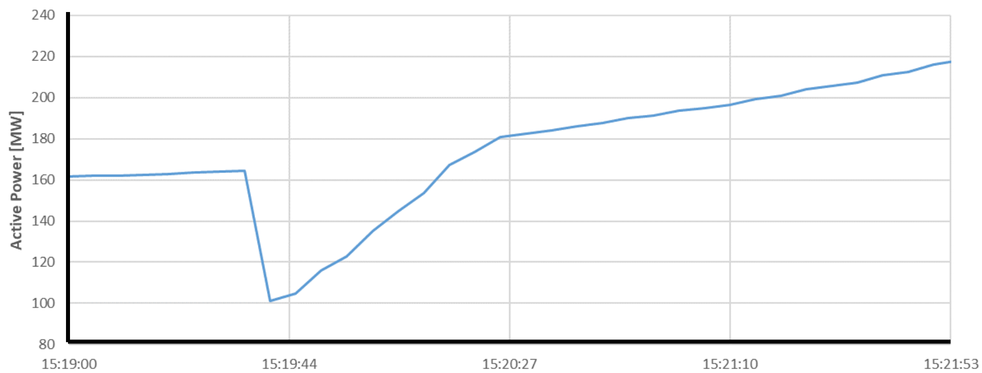

Figure 2.5: Example of Plant Prolonged Active Power Recovery Post-Fault

Slow Dynamic Recovery of Active Power after Faults

A number of the facilities identified by CAISO as being involved in these disturbances exhibited a response to the fault events that dynamically responded slower than expected. These facilities did not appear to have any abnormal plant controller interactions, had no inverters or feeders trip due to the fault, and did not have inverters configured with momentary cessation enabled. While all of these facilities were unable to provide any more information regarding their response (since no inverters tripped or provided any other fault code indicators), NERC and WECC believe that the facility, specifically the inverters or other controls, are simply programmed to respond post-fault relatively slowly. **Figure 2.6** shows an example of one facility that appears to have close to the desired performance with relatively fast recovery of active power to predisturbance levels; however, the plants takes about 25 seconds for this recovery to occur. Refer to NERC *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance*[15] for more details.

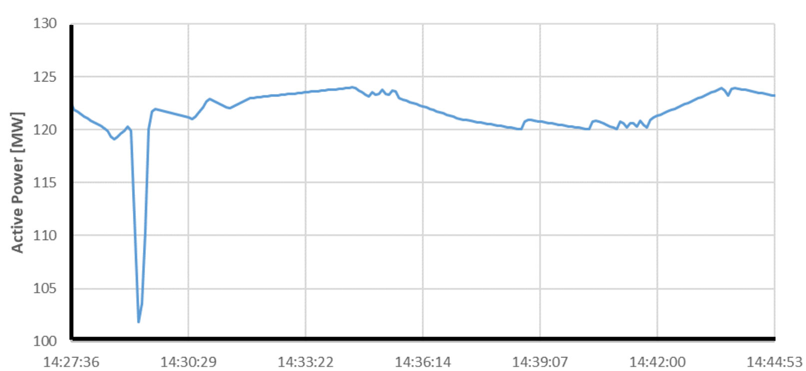

Figure 2.6: Example of Slow Active Power Recovery Following Fault

[15] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Inverter-Based_Resource_Performance_Guideline.pdf

Chapter 3: Review of Modeling and Study Practices

As identified in past NERC disturbance reports, there are significant and systemic modeling issues associated with BPS-connected inverter-based resources (particularly solar PV resources) that NERC has identified as not being rapidly addressed by industry, posing a reliability risk to the BES now and moving forward. This chapter explores existing practices and ways in which industry can enhance their requirements and processes to address these issues in a timely manner. NERC recognizes that these issues stem mainly from the need to modernize the interconnection process; however, each TP and PC need to ensure that resources connecting to the BPS have accurate and validated models during interconnection studies. Hence, NERC has provided strong recommendations that the FERC GIA/GIP be updated to address these known issues prior to commercial operation. However, the NERC FAC-001 and FAC-002 standards also require the TO, TP, and PC to ensure that suitable requirements, modeling practices, and studies are conducted during the interconnection process to ensure BPS reliability. CAISO uses its tariff and related documents to meet the obligations of the NERC FAC standards requirements (in coordination with its participating TOs in the CAISO footprint).

Positive Sequence and EMT Modeling Practices

NERC continues to raise significant concerns regarding positive sequence modeling practices and the need for industry to verify and validate the accuracy of the models being used for reliability studies. Having accurate models is essential for performing the reliability studies used to determine possible reliability risks and develop corrective action plans in the long-term planning horizon as well as to set system operating limits in the operations horizon. The following are key questions industry should be asking regarding modeling practices, modeling quality, and reliability studies as they pertain to positive sequence modeling, EMT modeling, and interconnection studies.

- **Positive Sequence Modeling**
  - Do TPs and PCs have positive sequence dynamic models for each interconnecting solar PV facility?
  - Have the positive sequence models been verified and validated as outlined in past NERC disturbance reports, reference documents, and guidelines? This includes not relying solely on the information provided for MOD-025, MOD-026, and MOD-027 standards compliance; rather, adequately verifying that sufficient documentation is provided to ensure the model matches actual equipment.[16]
  - Are the findings regarding abnormal performance of solar PV facilities used to inform the TP and PC of possible modeling issues that could result in model errors and inaccurate studies? This includes use of the correct control modes (momentary cessation versus ride-through performance), accurate gain and time constant settings, accurate representation of protection settings, and assurance that plant controller interactions will not affect plant dynamic response.
  - Are abnormal performance issues identified in past NERC disturbance reports used to identify possible positive sequence model limitations and drive the need for more detailed EMT studies?
  - How are abnormal performance issues identified in past NERC disturbance reports used to inform planning and operations studies regarding expectations of unexpected or abnormal tripping being modeled in stability studies in the long-term planning and operations horizons? Ongoing and systemic tripping or abnormal performance from solar PV resources should be analyzed and appropriately represented as part of the simulations (either accurately modeled or represented as part of the contingency definition).
  - Are the TP and PC leveraging the capabilities of MOD-032-1 Requirement R3 to require positive sequence models with known modeling issues to be addressed by the GO in a timely manner? Are the GOs delivering on these requests per the standard requirement?

[16] NERC presently has Standard Drafting Teams addressing known limitations in these standards to achieve the intended outcomes of verified and accurate models for planning studies.

- **EMT Modeling**
  - Do TPs and PCs have EMT models for each interconnecting solar PV facility?
  - Have the EMT models been verified and validated to ensure model quality? As identified in the *Odessa Disturbance Report*, the lack of model quality checks on EMT models pose a risk to the EMT models being insufficiently detailed to represent possible known causes of tripping.
  - Have EMT model quality checks been developed and comprehensively applied to existing EMT models to improve the quality of the models previously submitted that likely have known limitations?
  - Are the findings from past NERC disturbance reports being used to assess the quality of the EMT models provided? Are unexpected tripping issues being re-simulated or validated in the models provided to identify possible modeling deficiencies? Are the TP and PC requiring those models be updated and improved by the GO if and when they are identified?
  - Are EMT studies being conducted during the interconnection study process to ensure reliable operation of the BPS, particularly in situations where known positive sequence model limitations exist such as those highlighted in the *Odessa Disturbance Report*?
  - Are the TP and PC participating in plant performance validation, identifying possible modeling issues, and seeking corrective actions to those models in a timely manner?
- **Interconnection Studies**
  - Are the studies conducted during the interconnection process accurately demonstrating the performance issues that have been identified at the solar PV facilities?
  - What verification and validation requirements are in place during the interconnection study process to ensure that the models used in the system impact studies and any additional more detailed studies match the equipment installed in the field?
  - What checks are performed during plant commissioning to ensure that the studies conducted match the as-built settings such that the TP and PC can validate prior to commercial operation that the plant will reliably operate when connected to the BPS?
  - How has the TP and PC assessed possible discrepancies between models used in studies versus as-built settings for each interconnected facility?
  - How has the TP and PC ensured reliable operation of the BPS in situations where model discrepancies have been identified? Have the GOs provided model improvements in a timely manner for any identified issues by the TP and PC during and immediately after plant commissioning?

NERC has significant concerns that many of the reliability issues observed in real-time and identified in the numerous disturbance reports are not being captured in planning studies either during the time of interconnection (per FAC-002) or in long-term planning assessments (per TPL-001). Ongoing analysis continues to show numerous and systemic modeling errors that are not being addressed by industry, so studies relying on these models may not be accurately identifying possible reliability issues particularly under system conditions of heavy peak loading or high inverter-based resource penetrations.

CAISO's modeling requirements are established in its pro forma generator interconnection agreements, Section 10 of the *CAISO Transmission Planning Process Business Practices Manual (BPM)*,[17] its *New Resource Interconnection (NRI) Guide*,[18] and other supporting guidelines[19] and documents on its website. The following are observations and

[17] https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Transmission%20Planning%20Process
[18] http://www.caiso.com/Documents/NewResourceImplementationGuide.doc
[19] http://www.caiso.com/Documents/InverterBasedInterconnectionRequestsIBRDynamicModelReviewGuideline.pdf

recommendations to further enhance the requirements to ensure they are addressing known reliability issues (including modeling issues) for inverter-based resources:

- Section 10 of the BPM could be strengthened by ensuring consistency with other documentation CAISO uses to establish its requirements. For example, Section 10 describes model submittal requirements specific to one software vendor for positive sequence steady-state and power-flow modeling but points to other documents[20] for EMT and short-circuit modeling. Ensure all materials are consistent and clearly outlined so GOs understand the full suite of modeling requirements, the process for meeting those requirements, and any necessary details (e.g., level of detail, level of validation) throughout the process.
- Section 10.1.2.3 covers four categories of models for control and protection settings that shall be included in the dynamic models; however, this section does not address accurate representation of dynamic controls, such as inverter controls that are enabled during ride-through disturbances. The four categories appear to primarily focus on the slower-responding outer loop controls. Section 10 does point to a generator data template where modeling information is provided, including these additional components; however, the language in the section could be enhanced so that it does not appear comprehensive (i.e., it provides some examples only) to avoid any confusion. The section should clarify and strengthen the language such that "all controls and protection within the facility that affect the electrical response to a grid-side disturbance shall be represented in the dynamic models." Performance validation and model validation activities conducted by CAISO should then confirm that the model controls and protections match the performance of the plant during large grid disturbances. CAISO as the PC has the authority under existing NERC standards to address any modeling errors for BES resources.
- Section 10.1.2.4 mentions that inverter-based generation only need to provide maximum fault current data, but the *Generating Facility Data Attachment to Appendix 1*[21] includes a short-circuit section that is much more comprehensive regarding short-circuit data requirements for generating resources. Ensure consistency across these two areas to avoid any confusion by newly interconnecting resource owners and developers.
- Section 10.1.3.1 describes that Category 1 and 2 generators must provide test reports in accordance with WECC model validation requirements.[22] Small disturbance tests do not verify the accuracy of the model to large disturbances, such as faults, so should not be relied upon to verify or validate the vast majority of dynamic model parameters for inverter-based resources. This has been documented in multiple NERC reports, and a NERC standard drafting team is currently addressing shortcomings in the MOD-026 and MOD-027 standards to address this known risk. CAISO and all TPs and PCs should establish requirements to ensure that sufficient documentation is provided by the asset owner for the TP and PC to verify that the site-specific, tunable parameters of the actual hardware installed match the numerical parameters represented in the model. This should include attestations from equipment manufacturers, inverter specification sheets, control parameter settings, photos of settings panels, etc. The CAISO requirement focuses specifically on "excitation control system or plant volt/var" functions and does not address inverter controls (i.e., not suitable for inverter-based technology). Lastly, the first three sub-bullets do not address model accuracy and focus only on model usability and should be augmented with a requirement that the model (and its parameters) appropriately reflects the small and large disturbance behavior of the installed resource. WECC should also consider modifying their model validation policies to avoid confusion and align with or adopt future MOD-026 and MOD-027 revisions once approved.
- Section 10.1.3.2 describes active and reactive power capability requirements for modeling. The requirements mention that a test report from a staged test or operational data must be provided. However, NERC has shown that reactive power tests (per MOD-025) rarely result in test data that is appropriate to be used in models. A NERC standard drafting team is currently revising MOD-025 for this reason. CAISO requirements

[20] http://www.caiso.com/Documents/CaliforniaISOElectromagneticTransientModelingRequirements.pdf
[21] http://www.caiso.com/PublishedDocuments/GeneratingFacilityData-AttachmentAtoAppendix1.xlsm
[22] https://www.wecc.org/Reliability/WECC%20Generator%20Unit%20Model%20Validation%20Guideline.pdf

as well as the requirements for all TPs and PCs, should ensure that the active and reactive capability data provided for modeling purposes is a reasonable match to actual equipment capability, namely that a "composite capability curve," including generator capability and any limiters, is appropriately modeled. Sufficient documentation should also be provided for CAISO to verify that the modeling information is accurate. While CAISO operations may be helping support testing activities by adjusting nearby reactive resource outputs to facilitate generator testing to reach Qmax and Qmin and verify limiters, NERC strongly recommends making clear in the CAISO requirements that CAISO needs verified modeling data that is representative of the facility capabilities regardless of generator testing results. Also, current planning software tools allow for representation of multiple data points for active and reactive power (i.e., a "D curve") rather than just points for maximum values, and this information should be required by all generating resources for accurate modeling. Specific for inverter-based resources, this is important to understand the shape of the reactive capability of the facility; some facilities have artificial limits programmed into the plant-level controller to limit reactive power capability to a triangle-shaped curve rather than leveraging the full extent of the inverter capabilities.

- Section 10.1.3.4 outlines generator frequency and voltage protective relaying that must be modeled. NERC highlighted in the *Odessa Disturbance Report* that overreliance on NERC PRC-024 has resulted in poor ride-through performance of inverter-based resources since many other forms of protection can trip the facility or reduce its power output through inverter controls, so this section should be revised to ensure that all protective functions that can trip the inverter-based resource (inverter protections, feeder protection, etc.) are represented in the protection system models for the facility. CAISO has addressed this in its EMT modeling requirements, but these concepts are relevant to positive sequence dynamic models as well.
- Section 10.1.3.5 notes that all inverter-based resources are required to provide an EMT model at the time of interconnection and references the CAISO EMT modeling requirements document.[23] The EMT model requirements document focuses primarily on model documentation, usability, efficiency, and format. The EMT model requirements document could be enhanced by addressing model quality reviews and requirements for re-submittal of any model issues identified by CAISO during the interconnection study process. Furthermore, the EMT modeling requirements document contains many instances of "should" rather than "shall" and the requirements document highlights modeling "guidelines" that appear to be voluntary rather than actual requirements. CAISO has included explicit requirements regarding detailed modeling of controls and protection, and NERC strongly recommends all TPs and PCs make these types of requirements explicit regarding the models matching actual equipment controls, protections, and settings.
- Section 10.3 regarding the generator data template is written as a recommendation rather than a requirement. The CAISO *NRI Guide* defines requirements (although listed as recommendations) that link in many modeling requirements documents. However, NERC recommends clarifying what are considered requirements versus guidelines. Accurate and consistent reporting of generating data should not be a recommended practice, it should be a requirement. Having uniform submittal and processing of generator information following all required data formats, level of detail, etc., with sufficient supporting documentation to verify the validity of the model provided is necessary to address modeling deficiencies documented by NERC in past reports.
- Section 10.4.3 describes model checks to ensure "validation" is completed; however, these model checks do not explicitly state that CAISO requires that the model be accurate. Rather, the bulleted list of elements require data and information to be provided and for the model to initialize. CAISO should strengthen its model quality checks and model quality requirements to ensure that accurate models are provided and sufficient documentation is provided to verify and validate that the model is accurate. While large disturbance tests are generally not acceptable, CAISO (and all TPs and PCs) can require suitable verification documentation at each step in the interconnection process to ensure the models are accurate. Any

[23] http://www.caiso.com/Documents/CaliforniaISOElectromagneticTransientModelingRequirements.pdf

discrepancies or issues identified later in the process should be grounds for a re-study to identify any possible impacts the change may have to BPS reliability. These types of re-studies will often cause delays in the interconnection study process; therefore, developers and GOs are strongly recommended to avoid modifications during the interconnection process to mitigate these delays. Lastly, this section could also reference EMT models in addition to positive sequence models.

Model Quality Checks and Requirements

CAISO developed EMT modeling requirements back in 2018 and continues to enhance and refine those requirements for newly interconnecting inverter-based resources.[24] These modeling requirements mirror those of other TPs and PCs across North America and focus primarily on model data and documentation, modeling requirements, model usability requirements, and model efficiency requirements. NERC recommends that industry at-large continue to work collaboratively to keep EMT modeling requirements updated as technology evolves. One significant area of improvement, as identified in the Odessa disturbance, is model quality checks and model accuracy requirements. An EMT model does not necessarily result in a more accurate representation of the facility; that model must also be an appropriate representation of the installed equipment and be correctly parameterized. Furthermore, the EMT model must be of sufficient fidelity to include the controls and protections within the facilities.

NERC and WECC strongly recommend that CAISO and all TPs and PCs develop model quality requirements that explicitly define how model quality will be checked during the interconnection study process, during transmission planning assessments, and during real-time validation of plant performance. Any modifications or corrections to abnormal performance shall be accompanied by updated modeling information prior to the changes being made (so they can be studied per NERC FAC-002). Any abnormalities, inconsistencies, or concerns with model quality can be addressed within the construct of the NERC MOD-032 standard requirements. CAISO is strongly encouraged to explicitly document in its positive sequence dynamic modeling and EMT modeling requirements steps that CAISO will or may take to ensure model quality during each phase (i.e., the model quality checks) as well as the requirements set for the GOs to address any modeling errors identified.

The model quality requirements should include the following at a minimum:

- Attestations from equipment manufacturers that the model matches installed equipment settings, controls, and protections
- Explicit documentation of the types of protections that should be included in the EMT model, including all protection that have resulted in inverter tripping in these events and past events
  - Requirements that real-code models for protection systems be used in the model for both inverter-level and feeder-level protections
  - Requirements that model providing output channels for all measured signals by the inverter used for protection, such as voltage, current, frequency and rate-of-change-of-frequency

Plant Commissioning Challenges

NERC and WECC have identified that a significant number of inverter-based resources have models with known modeling errors, incorrect or obsolete models, or incorrect parametrization. These issues often stem from the plant commissioning process where final checks are made prior to commercial operation. However, validating that the installed settings (e.g., controls, protections, operating modes, gains, time constants) match the studies conducted during the system impact studies is often overlooked. Multiple TPs and PCs have highlighted that they are not often physically on-site during the commissioning process, so the process does not focus very much (if at all) on modeling-related comparisons. The TPs and PCs rely on post-commissioning requirement that the GO must provide an "as-built model" sometime after commercial operation. However, those requirements lack sufficient verification for the TP

[24] http://www.caiso.com/Documents/CaliforniaISOElectromagneticTransientModelingRequirements.pdf

and PC to confirm that the models are updated. More importantly, this leaves the TP and PC with little to no authority to demand corrections regarding facility performance if the models used in interconnection studies do not match the actual equipment. Transmission service providers have emphasized that this process results in model deficiencies that are not adequately addressed and resources connected to the system operating in a manner that was not adequately studied. Both issues present ongoing and systemic reliability risks to the BPS, particularly under the high pace of resource interconnection today and moving forward. **Chapter 4** provides two examples of significant modeling errors in the dynamic models of two facilities in the CAISO footprint.

As highlighted, improvements to the FERC Generator Interconnection Procedures can help mitigate these issues in the future. However, TPs and PCs are also strongly encouraged to improve their interconnection requirements and study processes per NERC FAC-001 and FAC-002 to eliminate these issues during the interconnection study process. This includes ensuring that any changes to equipment, controls, protections, modes of operation, or settings of any kind are updated in the model and re-studied to identify possible BPS reliability issues. All TPs and PCs are strongly encouraged to improve their commissioning process to ensure that the plant has controls, settings, and protections installed that match the models used during the interconnection studies prior to commercial operation. Otherwise, the TP and PC should require additional studies prior to commercial operation to ensure there are no adverse impacts to BPS reliability with the different settings and studies used. If any reliability issues are identified with the modified settings, appropriate corrective actions should be established by CAISO following its interconnection queue process. While large disturbance tests on the BPS to *validate* the performance against measurements are not generally feasible, gathering sufficient documentation for the TP and PC to *verify* that the model matches installed equipment is more than feasible during the commissioning and trial operation periods.

CAISO is strongly encouraged to conduct a detailed model quality review, both for positive sequence dynamic models and for EMT models, to ensure model accuracy based on past disturbance report findings and known modeling issues. While it is the responsibility of the asset owners to provide accurate modeling information, the TP and PC also have a responsibility to ensure the accuracy of models for the purposes of the reliability studies being conducted. CAISO is strongly recommended to perform system-wide model validation to understand the extent to which their dynamic models are or are not able to recreate real-world disturbances.

Lastly, CAISO and all PCs and RCs should ensure that their reliability studies in both the planning and operations horizons (interconnection studies per FAC-002 and operational planning analyses per IRO-008) are using models that are accurate and validated. It appears that the studies presently being conducted using models with known deficiencies could result in planning study assumptions that underestimate possible grid stability risks and may result in inaccuracies in the establishment of system operating limits.

Updates to Interconnection Requirements per NERC Guidelines

As outlined in the *Odessa Disturbance Report*, NERC has taken a three-pronged approach to developing recommendations for industry to address the known challenges facing the electric industry with growing levels of inverter-based resources. This includes the following items:

- Modernization of the FERC Generator Interconnection Agreements and Procedures
- Significant enhancements to the NERC Reliability Standards
- Industry incorporation of NERC guidelines into interconnection requirements to address known risks on an expedited basis

The interconnection study process is intended to identify reliability issues with the proposed interconnecting resource. This is the appropriate and most economical time to identify and develop solutions for reliability issues. Identifying any issues after the commercial operation date has taken place is not reliable nor cost effective. The most effective tools available to quickly address known reliability issues are the interconnection requirements established by TOs per the NERC FAC-001 Reliability Standard and the modeling and planning requirements established by TPs and PCs per the NERC FAC-002 Reliability Standard. NERC strongly recommends that all TOs, TPs, and PCs significantly enhance their interconnection requirements to address performance issues for inverter-based resources. NERC published *Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources*[25] to provide industry with clear technical guidance on making those improvements in a timely manner and encourages industry to adopt the recommendations contained in that guideline.

NERC conducted a cursory review of the CAISO interconnection requirements compared with the recommendations outlined in the above stated guideline (see **Table 3.1**). NERC acknowledges that CAISO has made recent improvements to their interconnection requirements and encourages comprehensive adoption of the guideline materials to support mitigation of ongoing risks to BPS reliability identified in NERC disturbance analyses. While the majority of affected facilities involved in the four disturbances are "legacy" facilities that connected to the CAISO system before significant enhancements to the CAISO interconnection requirements, NERC encourages proactive adoption of all the recommendations to avoid future possible reliability issues. In particular, the following recommendations are provided to CAISO and all TOs, TPs, PCs, TOPs, RCs, and BAs to help mitigate known risks through the interconnection requirements:

- Ensure that plant-level controller interactions are eliminated at all facilities, and that this type of performance is considered abnormal and subject to corrective actions if identified in real-time operations. These interactions are not easily identifiable in modeling and studies performed during the interconnection study process and should be analyzed after disturbances have occurred to ensure the correct performance.
- Consider NERC guidelines regarding speed of response during ride-through performance. Dynamic current injection requirements for ride-through performance that do not include a timing aspect pose a risk to BPS stability and can negatively impact protective relaying for increasing levels of inverter-based resources on the BPS. Relying on model accuracy to ensure the resource is meeting acceptable performance levels poses potential risks given that those models are often not reflective of the actual equipment installed in the field. Therefore, proof of dynamic performance, including current injection and magnitude requirements, should be considered as part of the interconnection requirements.
- Ensure that modeling requirements include accurate representation of the causes of tripping from these four disturbances and all past disturbances analyzed by NERC, not just voltage and frequency tripping. The positive sequence dynamic models and EMT models should accurately reflect all forms of tripping that could affect the electrical output of the facility. This includes, but is not limited to, PLL loss of synchronism, ac and dc overcurrent protection, dc bus protections (for EMT models), and feeder-level protections. These causes of tripping should be identified during interconnection studies and prohibited by CAISO ride-through requirements.
- Model quality is a significant issue facing many entities across North America. While modeling requirements may be in place, TPs and PCs are now strengthening their model quality checks to ensure that the models match actual equipment. Explicitly documenting the TP and PC model quality checks and ensuring that interconnection entities meet those model quality checks during the interconnection process and during commercial operation is critical to ensuring BPS reliability moving forward.

Table 3.1: CAISO Inclusion of NERC Recommendations

Recommended Requirement	CAISO Inclusion
Momentary Cessation	Yes
Phase Jump Immunity	Yes

[25] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf

Table 3.1: CAISO Inclusion of NERC Recommendations

Recommended Requirement	CAISO Inclusion
Capability Curve	Partially
Active Power-Frequency Control	Yes
Reactive Power-Voltage	Partially
Reactive Current-Voltage Control	Partially
Inverter Current Injection during Fault Conditions	Partially
Fault Ride-Through Capability	Yes
Grid Forming Capabilities	Not at this time
System Restoration and Blackstart Capability	Unknown**
Return to Service Following Tripping	Partially*
Balancing	Yes
Monitoring	Yes
Operation in Low Short-Circuit Strength Networks	Unknown
Power Quality	Yes
Steady-State Power-Flow Modeling	Yes; enhance model quality checks
Positive Sequence Stability Modeling	Yes; enhance model quality checks
Short-Circuit Modeling	Yes; enhance model quality checks
EMT Modeling	Yes; enhance model quality checks
Benchmarking Positive Sequence Stability and EMT Models	Yes

* CAISO has included a 2.5-minute threshold for reconnection for non-fatal trips; experience has shown that this can be significantly reduced (ERCOT follow-up from Odessa has changed this setting to 0 seconds on some facilities). CAISO should consider whether a quicker reconnection timer may help support the BPS for non-fatal inverter-tripping.

** Nothing precluding automatic restart of inverter-based resources during restoration activities if the plant main circuit breaker is closed.

Multiple transmission service providers have expressed serious concerns about their inability to actually enforce their interconnection requirements. NERC would like to reinforce that FAC-001 and FAC-002 provide the transmission service provider (i.e., the TO, TP, and PC) with the responsibility and authority to develop adequate interconnection requirements to ensure reliable operation of the BPS in their footprint. Entities not complying with those established interconnection requirements can and should be reported to NERC to ensure that resources are operating in a safe and reliable manner when connected to the BPS.

Chapter 4: Model Quality and Validation

NERC and WECC have analyzed BPS-connected inverter-based resource model quality for multiple years and published a detailed analysis of the Western Interconnection interconnection-wide positive sequence dynamics cases.[26] In that analysis, NERC and WECC raised significant concerns that many of the dynamic models are inaccurate and require improvements on an expedited basis. NERC is concerned that dynamic model issues persist and are not being addressed by industry. There are multiple NERC standards projects underway presently and SARs being developed by the NERC IRPS to address issues with existing standards. Furthermore, NERC has recommended standards improvements in the *Odessa Disturbance Report* in this area. This brief chapter provides examples to help illustrate the modeling quality concerns.

Validation Approach

Due to time constraints, NERC and WECC were not able to perform a system-wide model validation effort for these disturbances. However, WECC was able to run a couple dynamic simulations of a fault in the vicinity of some of the affected plants. The concerns are that the dynamic models are a vast misrepresentation of the actual performance of the facilities, so matching the fault impedance and the electrical conditions experienced at the facility exactly is not necessary. WECC simulated a bolted, 6-cycle fault on a transmission element near the affected facilities. This simulated disturbance is more severe than any of the faults experienced in the four events.

Example 1

Figure 4.1 shows a comparison of the simulated response versus the actual response to one of the four disturbances for one of the affected facilities. As the plots show, this facility experienced a 20+ MW reduction of active power that persisted with slow active power recovery well beyond 60 seconds after the fault. While the 5-second SCADA data does not provide high resolution, it does capture the overall trend of the reduction and recovery. A planner uses dynamic models to ensure reliable BPS operation and expects that the model, which includes inverter electrical controls models and a plant-level controller model, to match the actual response relatively closely.[27] In this case, the dynamic model shows the facility exhibiting minor jumps in active power during and immediately following the fault event with the plant returning to predisturbance output within 200 ms. These modeling errors are not minor issues regarding parameterization; they are vast modeling errors or gaps where the plant control modes and interactions are not captured with sufficient fidelity. This plant is being operated in an unplanned and unstudied operating state.

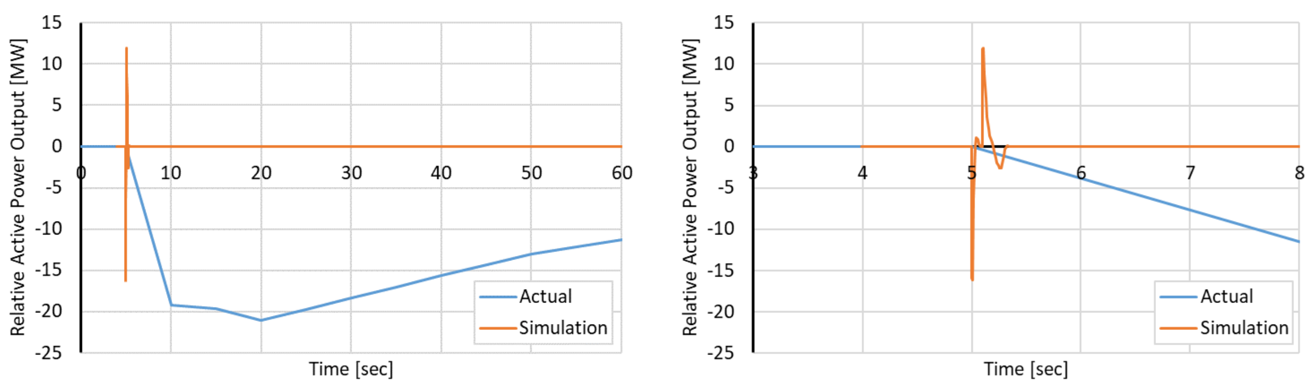

Figure 4.1: Simulated Versus Actual Response of Affected Facility

[26] https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/NERC-WECC_2020_IBR_Modeling_Report.pdf

[27] As mentioned, since the exact disturbance was not used (i.e., using a playback method) the results are not likely to match identically; however, the general trends should match closely.

Example 2

Figure 4.2 shows a similar comparison of a different facility that illustrates the vast difference between simulated versus actual response. As with the example above, this facility reduces power output by about 15 MW and recovers within about 30 seconds. The model shows a much more severe power reduction at the time of the fault (this is attributed to high fidelity simulation results and a more severe fault studied) but does not capture any of the delayed recovery of active power. The simulated response shows that the plant returns to predisturbance output within 1 second. This example again illustrates a plant with a dynamic model that performs very well whereas in actual operation the facility is operating in a manner that adversely affects BPS stability and reliability. Furthermore, the plant is being operated in an unstudied operating state because the model is vastly different from actual performance.

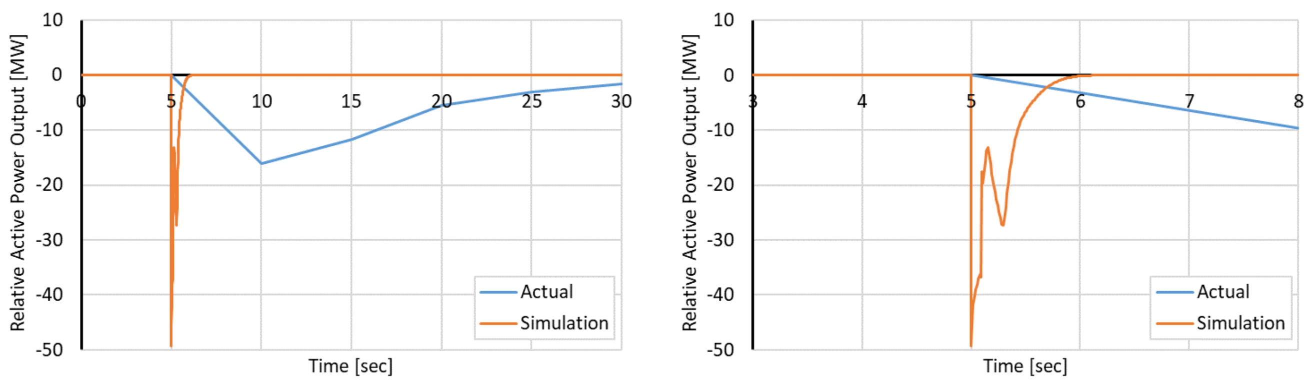

Figure 4.2: Simulated Versus Actual Response of Affected Facility

Key Takeaways to Systemic Modeling Issues

The following are key takeaways from this model validation analysis, the four disturbances analyzed, and known system modeling issues:

- Performance validation (i.e., analyzing the response of plants after BPS faults and other disturbances) is needed to identify possible model quality issues that may exist; sole reliance on models of BPS-connected solar PV resources is inadequate to ensure BPS reliability.
- EMT model benchmarking should be enhanced to ensure that protection system operations and plant-level controls are appropriately modeled.
- Model fidelity is critical to identify possible performance issues during studies. Without the model controls and protections accurately represented in the simulations, the TP and PC will not be able to identify possible issues in studies until they become real-time operational issues. Interconnection modeling and study requirements should be enhanced to ensure these issues are corrected prior to commercial operation. Plant commissioning should also ensure that the models match the as-built equipment (settings, controls, and protections).
- Model quality issues can be identified in many cases with SCADA data only. Grossly abnormal performance can be simply compared against the expected performance from the models, and any inconsistencies should be flagged by the TP and PC for immediate corrective actions until the issues are addressed.
- With the growing availability of plant-level DFR data, TPs and PCs can perform disturbance-based model validation with EMT models to ensure the plant dynamic response matches actual performance. In particular, the TP and PC should compare the active and reactive power response and recovery between the model and actual performance to ensure a reasonable match (and adherence to any performance requirements).

Chapter 5: Summary of Recommendations and Actions Needed

Table 5.1 contains recommendations based on key findings from this event and in the context of past events. The table also includes the applicable entities that should act on these requirements in a timely manner. Many recommendations are reiterations from the *Odessa Disturbance Report*[28] so are abbreviated here.

Table 5.1: Recommendations and Actions Needed	
Recommendation	**Applicability**
Reiterations of Odessa Disturbance Recommendations	
Adoption of Reliability Guidelines: NERC reiterates the strong need for industry to take action to comprehensively review and implement the recommendations contained in NERC reliability guidelines, technical reports, and white papers to mitigate known reliability issues related to BPS-connected solar PV resources. GOs, GOPs, developers, and equipment manufacturers should adopt the performance recommendations and all TOs should establish (or improve) clear and consistent interconnection requirements for BPS-connected inverter-based resources to support the implementation of the NERC FAC-001 and FAC-002 standards.	TOs, TPs, PCs, GOs, GOPs, developers, equipment manufacturers
Improvements to Interconnection Process: NERC reiterates the strong need for improvements in the interconnection process to address known reliability gaps in the interconnection of BPS-connected inverter-based resources. Significant improvements are needed to the FERC Generator Interconnection Process and Generator Interconnection Agreement, particularly around ensuring that accurate models are provided, sufficient reliability studies are conducted, plant commissioning validates that the studies match as-built equipment, and that requirements are clear and consistent for all resource types. BPS reliability is a critical factor during the interconnection process and presently plants are being interconnected in an unreliable manner based on studies that inadequately identify possible reliability issues prior to commercial operation. These issues need to be addressed in the GIP and GIA, and they should not be left up to individual interconnecting TOs to address with only the NERC FAC-001 requirements.	FERC
Significant Updates to NERC Reliability Standards Are Needed: NERC reiterates the strong need to enhance the NERC Reliability Standards to address systemic reliability issues related to inverter-based resources. NERC recommends that the RSTC facilitate and ensure the development of SARS to address each of the following issues: • **Performance Validation Standard Needed:** NERC recommends a performance validation standard be established such that TOPs, RCs, BAs (in coordination with their TP and PC) have the capability to seek corrective actions to plants that are not performing adequately based on the requirements imposed on them at the time of interconnection. Any abnormal performance identified in real-time should be compared against the models provided during time of interconnection (or any material modification to the facility), and model corrections should be required if discrepancies are identified. Abnormalities in plant performance should be	NERC RSTC and IRPS Project 2021-04 Standard Drafting Team Project

[28] https://www.nerc.com/pa/rrm/ea/Documents/Odessa_Disturbance_Report.pdf

Table 5.1: Recommendations and Actions Needed	
Recommendation	**Applicability**
reported to NERC and the Regional Entity and should be corrected by the GO. • **Ride-Through Standard to Replace PRC-024-3:** NERC recommends that PRC-024 be retired and replaced with a comprehensive ride-through standard focused specifically on generator ride-through performance.[29] Events analyzed by NERC regarding solar PV and wind plant reductions have identified issues with controls and protections that extend beyond voltage and frequency protection and pose risks to BPS reliability. Furthermore, industry continues to misinterpret PRC-024, seemingly setting unnecessary voltage and frequency protection within facilities "for compliance reasons." The retirement of PRC-024 and replacement with a ride-through standard should be developed and implemented on an expedited time line. • **Analysis and Reporting for Abnormal Inverter Operations:** PRC-004 should be modified to ensure that inverter-based resource power reductions of more than 75 MW in aggregate per facility are analyzed, reported, and corrected in a timely manner. The scope of the existing standard should be extended (or another standard introduced) if needed to ensure GOs and GOPs are analyzing their resource reductions. • **Monitoring Data:** Project 2021-04 has included findings from the Odessa disturbance in its SAR, and this report serves as another reference for improvements to PRC-002 necessary to gather sufficient data for event analysis purposes. NERC recommends the size thresholds for generating facilities to have recording data for event analysis be reduced significantly to ensure adequate data for the majority of BES wind and solar PV resources. Data should include plant-level high resolution oscillography data, plant SCADA data with a resolution of one second, sequence of events recording for all inverters that include all fault codes, and at least one inverter on each collector system configured to capture high resolution oscillography data within the inverter. • **EMT Modeling and Model Quality Checks:** NERC FAC-002, MOD-032, and TPL-001 should be revised to ensure that they adequately address the need for EMT modeling and studies during the interconnection study process and during annual planning assessments, as needed. As the penetration of inverter-based resources is growing across North America, all TPs and PCs should have clear requirements to gather EMT models at the time of interconnection and execute EMT studies to ensure proper ride-through performance for BPS fault events. Presently, the approaches taken by industry are leading to modeling and study gaps and consequently unreliable performance of inverter-based resources once interconnected. Furthermore, requirements specifically focused on model quality checks should be introduced to ensure that the TP and PC have validated the	

[29] The ride-through standard should focus specifically on generator protection and controls and does not need to include auxiliary systems within the facility. The standard should be a generator protection and control ride-through standard; it does not necessarily need to be a full facility ride-through standard.

Table 5.1: Recommendations and Actions Needed	
Recommendation	**Applicability**
models submitted by the GO with sufficient supporting documentation to demonstrate model quality. • **Inverter-Specific Performance Requirements:** Future NERC Reliability Standards should consider the inclusion of inverter-specific requirements or standards to ensure clarity and consistency for new technologies. NERC standards drafting teams presently underway are exploring these concepts to ensure that the requirements can be effectively implemented by the applicable entities. • **Gap Analysis of NERC Standards for Inverter-Based Resources:** NERC recommends that the IRPS conduct a comprehensive assessment that considers the unique performance characteristics of inverter-based resources and presents NERC standards enhancements needed to address any gaps identified. This assessment should be conducted by the NERC IRPS, and any necessary SARs should be produced through the RSTC.	
CAISO Recommended Actions	
CAISO Improvements to Interconnection Requirements Needed: CAISO should ensure that the recommendations in the NERC reliability guidelines are comprehensively reviewed and adopted to prevent these types of issues in the future. Examples for improvement include plant controller interactions, modeling and model quality enhancements, and return to service following trip requirements. These types of issues can be mitigated if appropriate performance requirements are established and interconnection studies are performed to ensure conformance with those requirements.	CAISO
CAISO Performance Validation and Follow-Up with Affected Facilities: CAISO should follow up with all affected facilities from these events to ensure that mitigating measures are implemented to improve performance. These mitigations should be reported to WECC and NERC as they occur as well as on a periodic basis. CAISO is also recommended to establish or advance a regional task force of owner/operators and transmission entities to analyze these types of events and correct performance issues as they occur. NERC and WECC should actively support these analyses and share best practices with all applicable entities.	CAISO
CAISO Event Analysis Process Improvements: In an effort to more effectively analyze these types of events as they occur, NERC and WECC have identified the following improvements that will help the timely solicitation of RFIs and analysis of affected facilities. These include the following: • **Brief Report Improvements:** The brief report list that all identified solar PV facilities entered momentary cessation; however, as the analysis has shown, a number of facilities had other performance issues identified, such as inverter tripping, plant controller interactions, or just delayed recovery of active power output. The brief report should help determine the type of reduction and the primary cause of the reduction to the greatest possible extent.	CAISO

Table 5.1: Recommendations and Actions Needed	
Recommendation	**Applicability**
• **Reporting Accuracy:** The CAISO brief report included a number of data points identified to be in error. This resulted in WECC soliciting RFIs to plants not involved in the disturbance. Original reporting numbers were not able to be recreated when data was later pulled from the data historian. • **Unit Naming:** All entities have specific reporting conventions that can be difficult as new projects or project phases are introduced; however, it is particularly difficult to identify the specific plants in the CAISO footprint due to naming conventions. The plants often include two or three identifiers or names in which the facility is referred to, often differing between CAISO and the plant owner/operator. This makes it difficult for NERC and WECC during event analysis based on information provided in the brief report. • **CAISO Involvement in Event Analysis:** CAISO is encouraged to be more active in the analyses conducted by NERC and WECC and is encouraged to be a partner in these activities. CAISO could be a great help with the following: ▪ Soliciting RFIs to affected plant owner/operators and coordinating follow-up activities with those entities ▪ Analyzing plant performance and helping identify the root causes of any abnormal performance ▪ Contributing to follow-up discussions and helping develop mitigating measures for any abnormal plant performance issues.	
CAISO Detailed Model Quality Review: CAISO should conduct a detailed model quality review for all inverter-based resources connected to the CAISO system. This should include both positive sequence and EMT model quality checks against as-built settings, specification sheets, one-line diagrams, past disturbance analyses, and any other information necessary to verify and validate that the model is a suitable representation of the installed facility. Models should include controls or protections that can trip the facility including (but not limited to) all the protections identified in this disturbance report and others published by NERC related to solar PV reductions. Model quality reviews should be conducted in the long-term planning horizon for interconnection studies and planning assessments as well as in the operations horizon for operational planning analyses and real-time analyses that use these same dynamic models.	CAISO

Appendix A: Overview of Past Solar PV Disturbances Analyzed

NERC and the Regional Entities continue to perform detailed analyses of solar PV disturbances due to the systemic nature of issues identified and to document key findings and recommendations for increased industry awareness. NERC works with its Regional Entities and industry to identify disturbances and works collaboratively to analyze these events. The events are then confirmed by the Regional Entities and industry, and the BA reports those events as part of the NERC Event Analysis Program.[30] At the time of writing this report, the Category 1i criteria for reporting events related to loss of solar PV resources is "a non-consequential interruption[31] of inverter type resources[32] aggregated to 500MW or more not caused by a fault on its inverters, or its ac terminal equipment." After receiving the initial brief report, NERC and the Regional Entities determine whether additional information is needed and send requests for information to the affected Generator Owners (GO) to gather that information. In all events analyzed to-date, the information provided in the brief reports has been insufficient to perform a comprehensive root cause analysis and additional information has been required.

List of Events and Relevant Activities

The ERO has previously published five disturbance reports related to the reduction of solar PV power output following BPS fault events:

- Blue Cut Fire disturbance[33] (August 16, 2016)
- Canyon 2 Fire disturbance[34] (October 9, 2017)
- Palmdale Roost and Angeles Forest disturbances[35] (April 20, 2018 and May 11, 2018, respectively)
- San Fernando disturbance[36] (July 7, 2020)
- Odessa disturbances[37] (May 9, 2021 and June 26, 2021)

[30] https://www.nerc.com/pa/rrm/ea/Pages/EA-Program.aspx

[31] Interruption of resources caused by action of control systems on the resources in response to perturbations in voltage and/or frequency on the Interconnection, not including the control actions of a RAS.

[32] In most cases, inverter-based generating resources refer to Type 3 and Type 4 wind power plants as well as solar PV resources. Battery energy storage is also considered an inverter-based resource. Many transmission-connected reactive devices, such as STATCOMs and SVCs, are also inverter-based. Similarly, HVDC circuit also interface with the AC network though converters.

[33] Blue Cut Fire Disturbance report, June 2017: https://www.nerc.com/pa/rrm/ea/Pages/1200-MW-Fault-Induced-Solar-Photovoltaic-Resource-Interruption-Disturbance-Report.aspx.

[34] Canyon 2 Fire Disturbance report, February 2018: https://www.nerc.com/pa/rrm/ea/Pages/October-9-2017-Canyon-2-Fire-Disturbance-Report.aspx.

[35] Palmdale Roost and Angeles Forest Disturbance report, January 2019: https://www.nerc.com/pa/rrm/ea/Pages/April-May-2018-Fault-Induced-Solar-PV-Resource-Interruption-Disturbances-Report.aspx

[36] San Fernando Disturbance report, November 2020: https://www.nerc.com/pa/rrm/ea/Pages/July_2020_San_Fernando_Disturbance_Report.aspx

[37] Odessa Disturbance Report: https://www.nerc.com/pa/rrm/ea/Pages/May-June-2021-Odessa-Disturbance.aspx

Following the Blue Cut Fire and Canyon 2 Fire disturbances, NERC issued alerts[38, 39] to the industry to gather additional information from BPS-connected solar PV resources and to provide recommendations for all BPS-connected solar PV facilities based on the key findings from the disturbance reports. The NERC IRPS has also published two foundational reliability guidelines that provide strong industry recommendations pertaining to reliable integration of BPS-connected inverter-based resources:

- *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance* (September 2018)[40]
- *Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources* (September 2019)[41]

Lastly, the Institute of Electrical and Electronics Engineers (IEEE) Standards Association recently approved IEEE Standard 2800-2022 (IEEE 2800),[42] which establishes "technical minimum requirements for the interconnection, capability, and performance of inverter-based resources interconnected with transmission and sub-transmission systems." The goal of IEEE 2800 is to ensure that future BPS-connected inverter-based resources are designed and installed with the equipment capabilities and functional parameters to mitigate some or all of the issues identified in past ERO disturbance analyses.

NERC believes that timely industry adoption of IEEE 2800 will help support reliable operation of the BPS with increasing levels of inverter-based resources and will help address some procedural challenges during the interconnection process. NERC recognizes that IEEE standards are voluntary in nature and require an authority governing interconnection requirements to enforce the standard effectively. Industry will need to develop a suitable strategy to ensure that the IEEE standard is adopted and implemented effectively and efficiently. This includes ensuring that the requirements become enforceable and that suitable coordination activities (i.e., specifying functional settings to configure performance, submitting and validating accurate models, performing system impact assessments, and assessing plant-level performance conformity prior to commissioning) occur in an effective manner.

NERC is working with IEEE 2800 leadership and industry partners to develop a strategy that will achieve this intended goal. However, the strategy will need to be put into action by industry for a widespread and successful implementation of IEEE 2800. The authorities governing interconnection requirements should begin developing plans to adopt IEEE 2800 now to avoid the risk of disturbances like those described in this report (and potentially larger events) as they recognize that the internal and external discussions needed to decide an adoption process and timeline can take many months. Transmission service providers will need to ensure an appropriate implementation time line for adopting IEEE 2800 that balances availability and cost effectiveness of conforming equipment with the potential BPS reliability issues that could continue to worsen until IEEE 2800 is enforced.

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[38] Blue Cut Fire Disturbance NERC Alert, June 2017: https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20Loss%20of%20Solar%20Resources%20during%20Transmission%20Disturbance.pdf.

[39] Canyon 2 Fire Disturbance NERC Alert, May 2018: https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC_Alert_Loss_of_Solar_Resources_during_Transmission_Disturbance-II_2018.pdf.

[40] *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance*: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf

[41] *Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources*: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf

[42] IEEE P2800: https://standards.ieee.org/project/2800.html

Appendix B: Detailed Review of Affected Facilities

This appendix provides a detailed review of the solar PV facilities that exhibited an active power reduction of more than 10 MW for the four disturbances analyzed. **Table B.1** provides an overview of these facilities, their size, interconnection date, and the events where they reduced output.

Table B.1: Overview of Affected Solar PV Facilities

Facility ID	Capacity [MW]	In-Service Date	April 20 2018	May 11 2018	July 7 2020	June 24 2021	July 4 2021	July 28 2021	Aug 25 2021
A	50	2016	X		X	X	X	X	X
B	100	2016	X	X		X	X	X	X
C	75	2016	X	X		X			
D	248	2012–2014		X	X	X	X	X	X
E	45	2014	X		X	X		X	
F	109	2013			X	X	X	X	X
G	300	2014			X	X			X
H	250	2014			X	X			X
I	40	2016	X			X	X		X
J	205	2016	X					X	
K	27	2015					X		
L	20	2014				X			
M	250	2016	X			X			
N	50	2018			X	X			
O	20	2019			X			X	
P	151	2019			X				X
Q	16.6	2015				X	X		
R	60	2014					X		
S	20	2014						X	
T	318	2014–2015	X		X	X	X	X	X
U	279	2014–2015	X		X	X	X		
V	85	2016			X		X		X
W	260	2016			X	X			
X	586	2013–2014					X	X	
Y	111	2019						X	X
Z	N/A*	N/A*							X
AA	20	2014				X			
AB	20	2016	X			X			X
AC	108	2019					X	X	X
AD	15	2015					X		

* Data unavailable.

June 24, 2021

Table B.2 provides a detailed review of each solar PV facility involved in the June 24, 2021, disturbance, including details of the facility, the magnitude of power reduction, and key findings from the NERC–WECC team review.

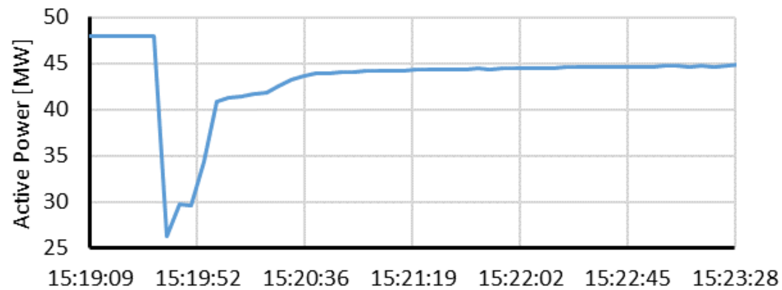
Table B.2: Review of Solar PV Facilities for June 24, 2021 Disturbance

Facility ID	Capacity [MW]	Reduction [MW]	POI Voltage [kV]	In-Service Date	Highest Data Resolution	NERC-WECC Review
A	50	22	230 kV	2016	5-min SCADA	Three inverters tripped on ac overcurrent above 150% of rated current. These inverters have momentary cessation enabled.
B	100	16	220 kV	2016	PMU	Dynamic reactive power support sacrificed active power output with slow recovery of active power after fault clearing.
C	75	11	220 kV	2016	PMU	Dynamic reactive power support sacrificed active power output with slow recovery of active power after fault clearing.
D	248	158	230 kV	2012–2014	PMU	Legacy inverters with momentary cessation enabled and no means of modifying. Thirteen inverters tripped on dc overcurrent protection.
E	45	42	66 kV	2014	1-min SCADA	Twenty-seven inverters tripped with no fault code provided; 11 inverters remained off-line for the remainder of the day.
F	109	49	500 kV	2013	SCADA	Dynamic active power response to fault with longer active power recovery than described in NERC reliability guidelines.
G	300	63	230 kV	2014	0.5-sec SCADA	Momentary cessation with plant controller interactions inhibiting recovery to predisturbance levels for 40 seconds.
H	250	124	230 kV	2014	0.5-sec SCADA	Momentary cessation with plant controller interactions inhibiting recovery to predisturbance levels for 50 seconds.
I	40	25	220 kV	2016	5-min SCADA	Seven inverters tripped on ac overcurrent above 150% of rated current. Other inverters entered momentary cessation yet required 15–20 seconds to recover to predisturbance levels.
L	20	15	33 kV	2014	6-sec SCADA	All inverters tripped on ac overcurrent above 150% of rated current. These inverters have momentary cessation enabled.
M	250	100	230 kV	2016	DFR	Inverters tripped on ac undervoltage protection. Plant owner unable to determine and provide voltage protection settings.
N	50	26	230 kV	2018		Unable to contact facility owner/operator. CAISO unable to provide contact information. Cause of reduction unknown.
Q	16.6	15	115 kV	2015	5-min SCADA	All inverters tripped on ac overcurrent above 110% of peak rated current. Inverters have momentary cessation enabled. Inverter manufacturer is out of business; facility cannot make modifications to eliminate risks.
T	318	36	230 kV	2014-2015	1-sec SCADA	Dynamic reactive power support sacrificed active power output with slow recovery of active power after fault clearing requiring one minute 35 seconds. Some inverters tripped for an unknown cause.
U	279	11	230 kV	2014-2015	2-sec SCADA	Dynamic reactive power support sacrificed active power output with slow recovery of active power after fault clearing requiring about one minute.
W	260	40	230 kV	2016	5-min SCADA	Multiple inverters entered momentary cessation. Some inverters also tripped for an unknown cause.

Table B.2: Review of Solar PV Facilities for June 24, 2021 Disturbance						
Facility ID	**Capacity [MW]**	**Reduction [MW]**	**POI Voltage [kV]**	**In-Service Date**	**Highest Data Resolution**	**NERC-WECC Review**
AA	20	14	66 kV	2014	5-min SCADA	Inverters erroneously tripped on underfrequency protection with settings of 59.3 Hz for 0.02 seconds.
AB	20	17	220 kV	2016	5-min SCADA	Three inverters tripped on ac overcurrent above 150% of rated current. Other inverters entered momentary cessation.
TOTAL		**784**				

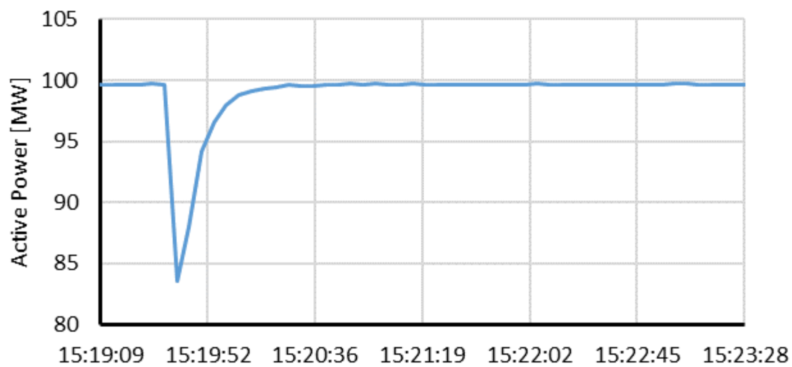
Plant A

Three inverters tripped on ac overcurrent protection at 150% of rated current. These inverters have momentary cessation settings at 0.9 pu voltage, 0.1 second delay to restart, and no programmed ramp rate (should return within one second); however, the inverters experienced a delayed recovery for about 30–45 seconds.



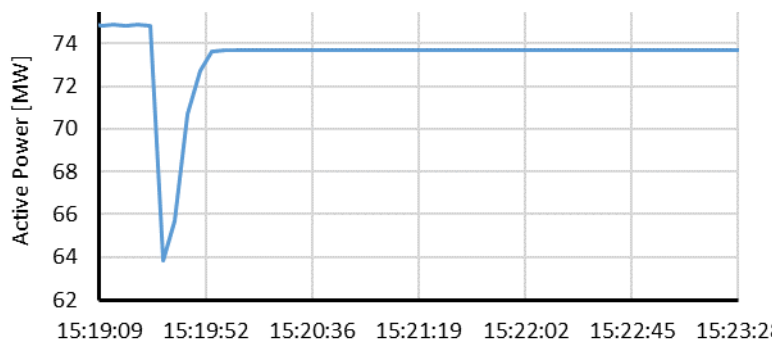
Plant B

This plant includes inverters that were initially programmed with momentary cessation; however, momentary cessation was disabled following the NERC alert. This plant now provides reactive power support during low voltage events, but active power is sacrificed and its recovery to predisturbance levels is relatively slow (i.e., does not meet the recommendations of the NERC reliability guidelines).



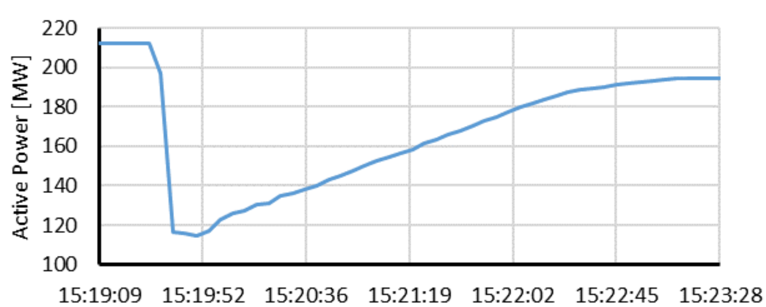
Plant C

This plant includes inverters that were initially programmed with momentary cessation; however, momentary cessation was disabled following the NERC alert. This plant now provides reactive power support during low voltage events but active power is sacrificed and its recovery to predisturbance levels is relatively slow (i.e., does not meet the recommendations of the NERC reliability guidelines).



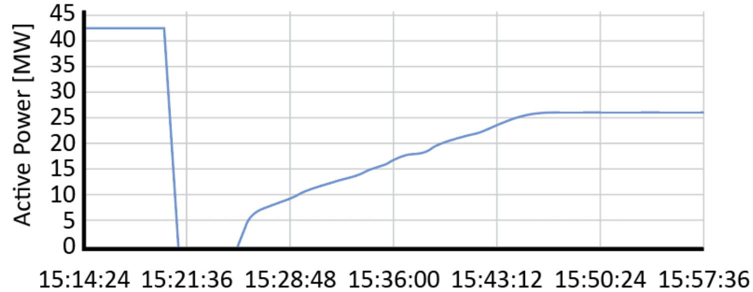
Plant D

This plant includes legacy inverters with momentary cessation enabled at 0.875 pu voltage, 1,020 ms delay to recover, and 8.2%/sec ramp rate to restore active power output. On dc overcurrent protection, 13 inverters tripped.



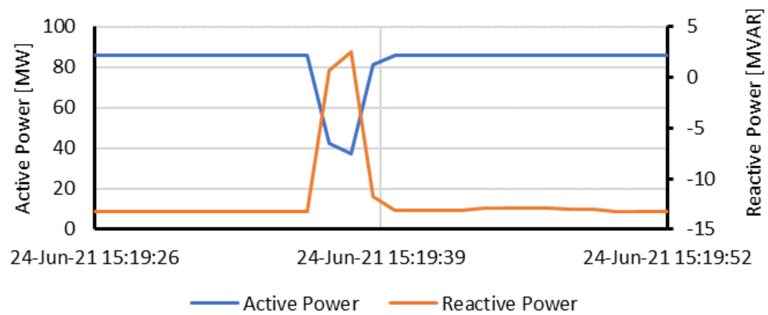
Plant E

Twenty-seven inverters tripped; however, the GO was not able to provide any information regarding the cause of the trip. The plant restored power output five minutes later. For the rest of the day, 11 inverters remained off-line.



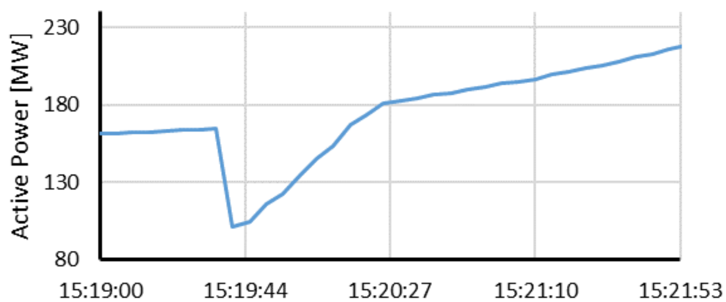
Plant F

Inverters provided reactive power support during the fault; however, they sacrificed active power output, which required about 5 seconds to recover. This recovery is relatively quick but is longer than recommendations from NERC reliability guidelines.



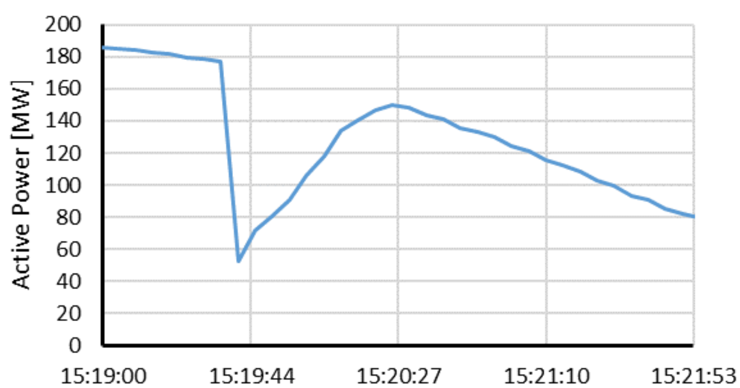
Plant G

This plant has been involved in past disturbances and includes legacy inverters with momentary cessation settings enabled of 0.875 pu voltage, 1,000 ms time delay to start active power recovery, and an active power ramp rate of 8.2%/second. The plant should return to predisturbance levels around 13 seconds after the fault; however, the facility took 40 seconds to predisturbance levels. This indicated that plant-level controller interactions are inhibiting the facility from recovering after faults. This issue has been identified in past events and has not been addressed by CAISO. However, NERC coordinated with the GO and they have made changes to the plant-level controller to mitigate this interaction in the future.



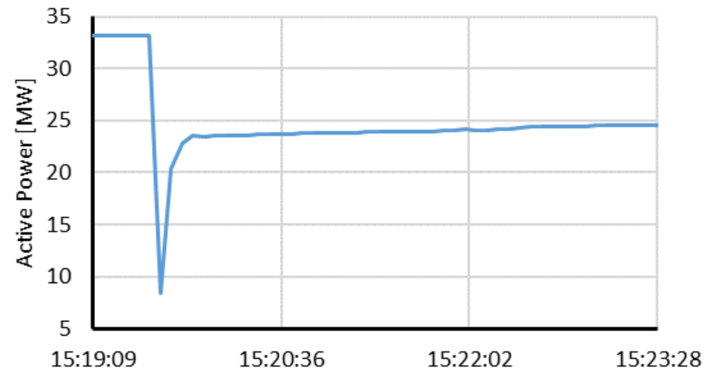
Plant H

This plant has been involved in past disturbances and includes legacy inverters with momentary cessation settings enabled of 0.875 pu voltage, 1,000 ms time delay to start active power recovery, and an active power ramp rate of 8.2%/second. The plant should return to predisturbance levels around 13 seconds after the fault; however, the facility took 50 seconds to predisturbance levels. This indicated that plant-level controller interactions are inhibiting the facility from recovering after faults. This issue has been identified in past events and has not been addressed by CAISO. However, NERC coordinated with the GO and they have made changes to the plant-level controller to mitigate this interaction in the future.



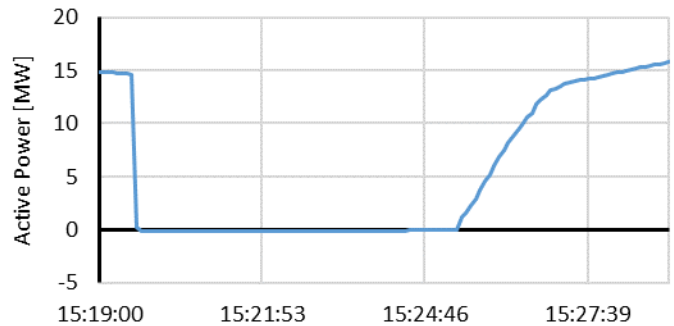
Plant I

On ac overcurrent protection, 7 inverters tripped at 150% of rated current. Other inverters entered momentary cessation and recovered within 15–20 seconds. Those inverters are set with momentary cessation settings of 0.9 pu voltage with 0.1 second delay to start active power recovery and "no programmed ramp rate (should return to full output in < one second)." These inverters are unable to eliminate momentary cessation or modify settings. The plant should recover around one second but recovers at a much slower rate.



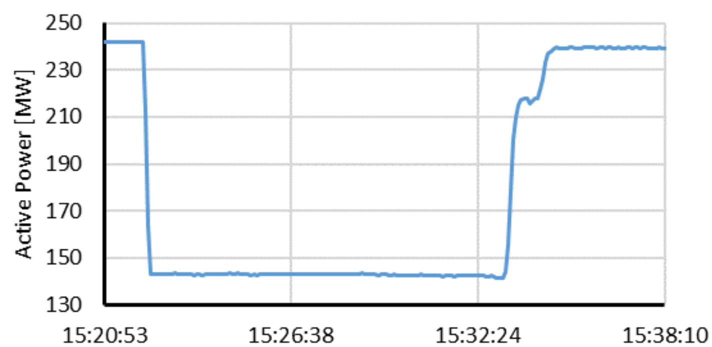
Plant L

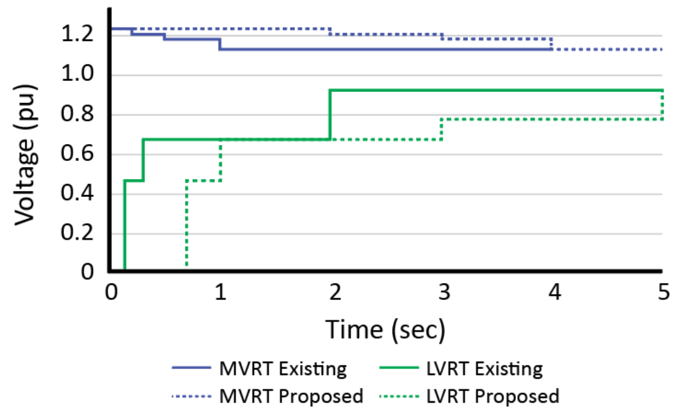
All on-line inverters tripped on ac overcurrent protection at 150% of rated current. Inverters returned to predisturbance levels in about seven minutes. These inverters have momentary cessation enabled with a low voltage threshold of 0.85 pu and a time delay before initiating active power recovery upon voltage restoration of 100 ms.



Plant M

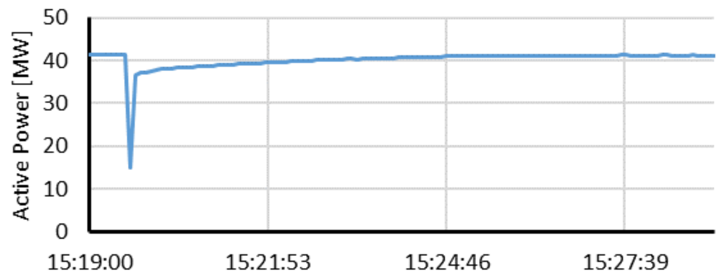
One hundred ninety-two inverters reduced power output for a total reduction of 100 MW. The inverters remained off-line for 11 minutes before returning to predisturbance levels. The reduction was initially indicated as "momentary cessation": however, this performance characteristic is not indicative of momentary cessation. Follow-up analysis identified that the plant tripped on "low voltage" although no further information is available. Since the plant personnel did not have access to in-service protection and control settings, the inverter manufacturer was engaged and informed the plant owner that voltage protection settings can be extended. The original settings were nearly identical to PRC-024-3 voltage trip curves whereas the proposed settings significantly improved the operational ride-through capabilities and are likely based on physical equipment limitations.





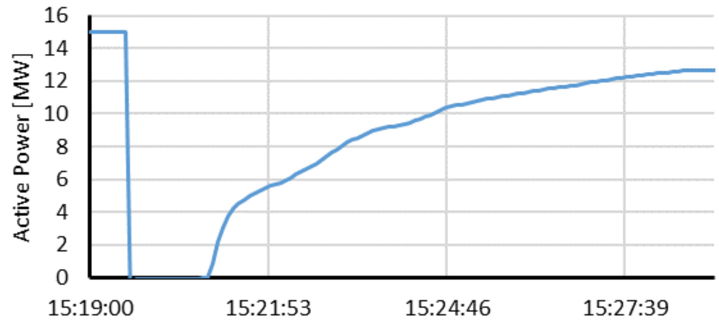
Plant N

The analysis team was unable to contact the plant owner/operator, and CAISO was unable to provide any contact information. Therefore, the cause of the reduction remains unknown.



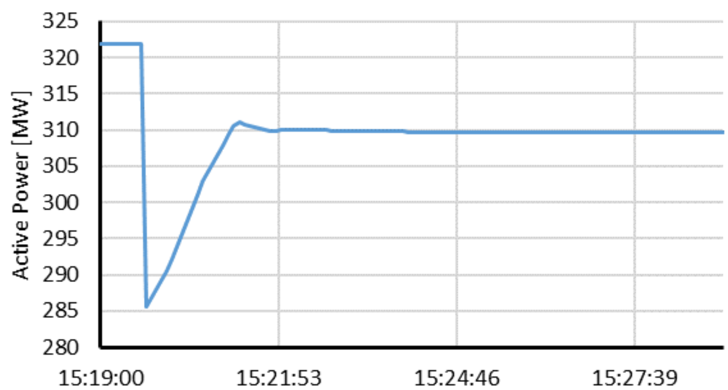
Plant Q

All inverters tripped on ac overcurrent above 110% of rated instantaneous peak current. These inverters all had momentary cessation enabled as well. The inverter manufacturer is out of business, so changes to inverter settings cannot be made to mitigate risks of tripping or momentary cessation. The plant returned to predisturbance levels in about 10 minutes, and one inverter remained off-line for an extended duration.



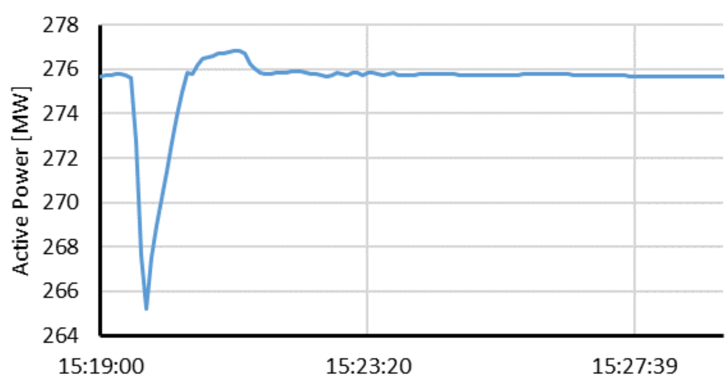
Plant T

The plant reduced active power output by 36 MW and increased reactive power output by 11 MVAR. However, active power recovery to predisturbance levels took one minute 35 seconds. Some inverters tripped, but the plant owner was unable to identify any fault codes that caused the trip. The inverter and plant-level controllers are from different manufacturers with a third-party having programmed the plant controller. The active power ramp rate in the plant-level controller is set to 0.167 %/sec. A global ramp rate limit also exists that limits plant ramps to 0–100% in 10 minutes. Inverters are set with a ramp rate of 0–100% in one minute. One or more of these ramp rates hindered the plant from returning to predisturbance levels following faults, degrading system stability, adversely affecting system frequency response, and failing to meet the recommendations set forth in NERC reliability guidelines.



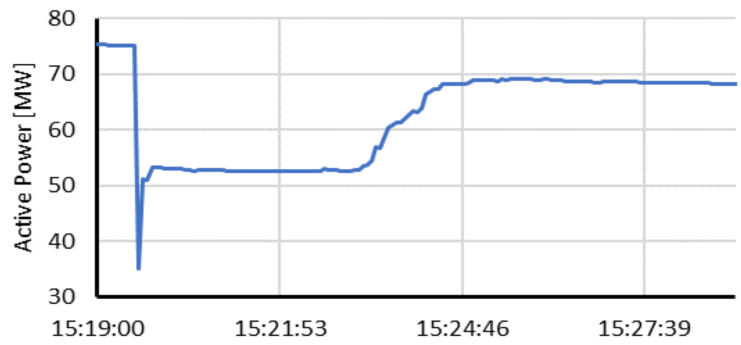
Plant U

This plant provided reactive power support during the fault but sacrificed active power (11 MW) and required over one minute to return to predisturbance levels. This does not meet the recommendations in the NERC reliability guidelines.



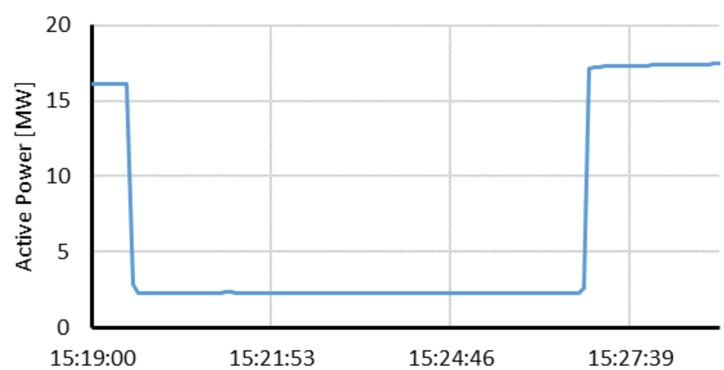
Plant W

This plant experienced both momentary cessation and inverter tripping. The plant owner provided 5-minute SCADA data that did not show the event. The 4-second SCADA data from the TOP identified that both momentary cessation and inverter tripping were involved. The plant owner indicated that only one inverter tripped; however, this is not true based on the SCADA data. It is suspected that inverters entered momentary cessation of which 40 MW of reduction was captured by SCADA. In addition, about 22.5 MW reduction is attributed to inverter tripping. The plant recovered to about 5 MW less than predisturbance levels in about five minutes; however, the remaining inverter had to be manually reset, which did not happen until the next morning. The inability of the plant owner to provide detailed information led to an inconclusive cause of tripping at this facility.



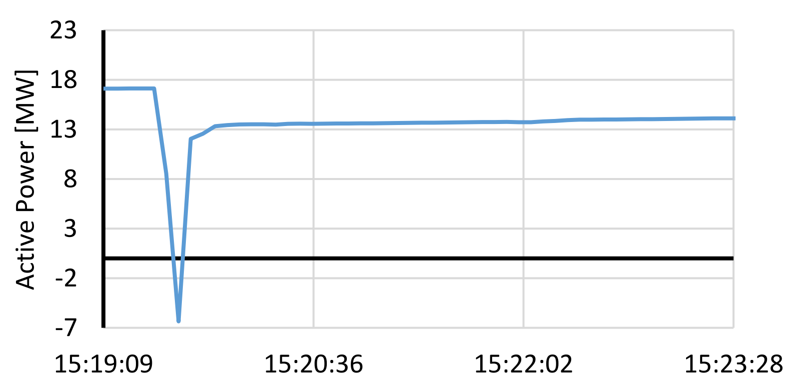
Plant AA

All inverters except one tripped on a "slow low frequency" fault code. The inverters have low frequency trip settings of 57 Hz for 0.0 seconds, 57 Hz for 0.02 seconds, and 59.3 Hz for 0.02 seconds. The plant owner was unable to identify which threshold initiated tripping. It is suspected that the 59.3 Hz for 0.02 seconds threshold initiated.[43] The plant returned to predisturbance output levels about 6.5 minutes later.



Plant AB

Three inverters tripped on ac overcurrent at 150% of rated current. Other inverters entered momentary cessation and recovered quickly (unable to identify exact timing due to poor data resolution). Those inverters are set with momentary cessation settings of 0.9 pu voltage (with 0.1 second delay to start active power recovery) and "no programmed ramp rate (should return to full output in < one second)." These inverters are unable to eliminate momentary cessation or modify settings.



[43] As observed in the Blue Cut Fire, instantaneous or near-instantaneous frequency trip settings will erroneously operate during faults. A filtered frequency measurement over a time window is needed to avoid unnecessary frequency protection operations. Protection settings should also be based on equipment capabilities. NERC has recommended the plant owner adjust frequency protection timers be set based on equipment capabilities and extended to at least 100 ms for the fastest trip timer (if not longer).

July 4, 2021

Table B.3 provides a detailed review of each solar PV facility involved in the July 4, 2021 disturbance including details of the facility, the magnitude of power reduction, and key findings from the NERC–WECC team review.

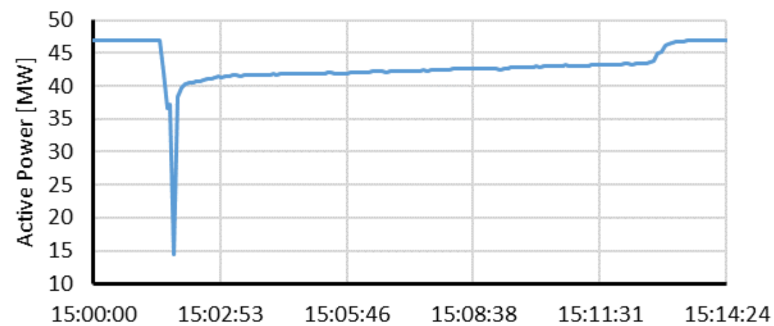
Table B.3: Review of Solar PV Facilities for July 4, 2021 Disturbance

Facility ID	Capacity [MW]	Reduction [MW]	POI Voltage [kV]	In-Service Date	Highest Data Resolution	NERC–WECC Review
A	50	33	230 kV	2016	5-min SCADA	Four inverters tripped on instantaneous ac overcurrent protection at 150% of rated current, and others entered momentary cessation.
B	100	100	220 kV	2016	PMU	Plant active power dropped to zero and plant-level controller interactions delayed recovery for 12–15 seconds.
D	248	80	230 kV	2012–2014	PMU	Legacy inverters entered momentary cessation, and six inverters tripped on dc overcurrent protection.
F	109	40	500 kV	2013	1-sec SCADA	There was a dynamic active power response to fault with a longer active power recovery period than described in NERC reliability guidelines. One inverter tripped on "overcurrent protection."
I	40	23	220 kV	2016	5-min SCADA	Eight inverters tripped on ac overcurrent protection at 150% of rated current, and others entered momentary cessation and recovered within 15–20 seconds.
K	27	22	115 kV	2015	5-min SCADA	Six inverters tripped on ac overcurrent protection at 110% of rated current, and others may have entered momentary cessation. Manufacturer out of business; no further details available.
Q	16.6	12	115 kV	2015	5-min SCADA	All inverters tripped on instantaneous ac overcurrent protection at 110% of rated current.
R	60	58	115 kV	2014	15-sec SCADA	Two inverters tripped on uninterruptible power supply failure and remained off-line for the rest of the day. Nearly all other inverters tripped but plant unable to provide details.
T	318	21	230 kV	2014–2015	1-sec SCADA	Dynamic response to fault and active power output drops. Recovery to predisturbance output in one minute 45 seconds.
U	279	28	230 kV	2014–2015	2-sec SCADA	Multiple inverters tripped for unknown reason. Plant unable to provide details.
V	85	25	220 kV	2016	5-min SCADA	Five inverters tripped on ac overcurrent at 150% of rated current. Three inverters tripped for unknown reason; other inverters entered momentary cessation.
X	586	33	230 kV	2013–2014	1-min SCADA	One inverter tripped for an unknown cause. Plant responded dynamically to fault and recovered relatively quickly; however, beyond time specified in NERC reliability guideline.

Table B.3: Review of Solar PV Facilities for July 4, 2021 Disturbance						
Facility ID	**Capacity [MW]**	**Reduction [MW]**	**POI Voltage [kV]**	**In-Service Date**	**Highest Data Resolution**	**NERC–WECC Review**
AC	108	77	230 kV	2019	DFR	Twenty-four inverters tripped on “unbalanced voltage” conditions. These inverters are on the only collector feeder with an underground portion. Some returned to service after 10 minutes, and others remained off-line for the rest of the day. All other inverters entered momentary cessation during the fault.
AD	15	14	115 kV	2015	5-min SCADA	All inverters tripped on instantaneous ac overcurrent at 110% of peak nominal current.
TOTAL		**566**				

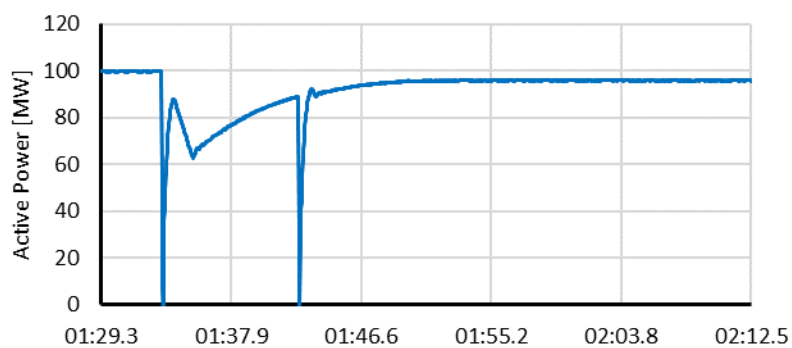
Plant A

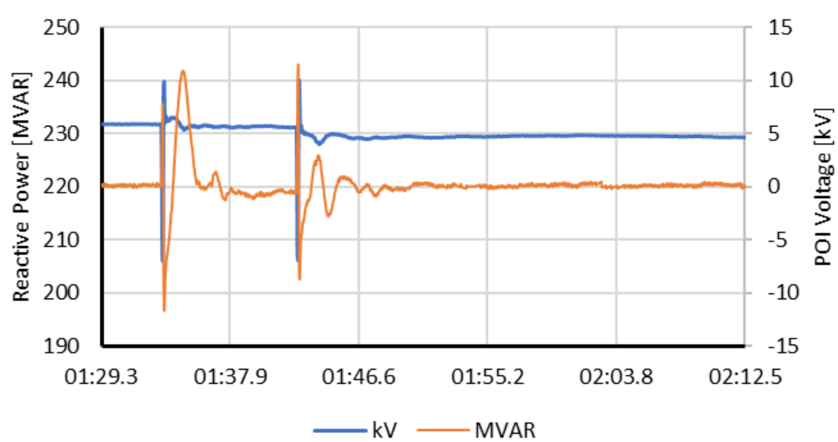
Four inverters tripped on instantaneous ac overcurrent protection at 150% of rated current. Other inverters entered momentary cessation with settings of a low voltage threshold of 0.9 pu (a 0.1 second delay to restart) and “no programmed ramp rate (i.e., should return within one second).”



Plant B

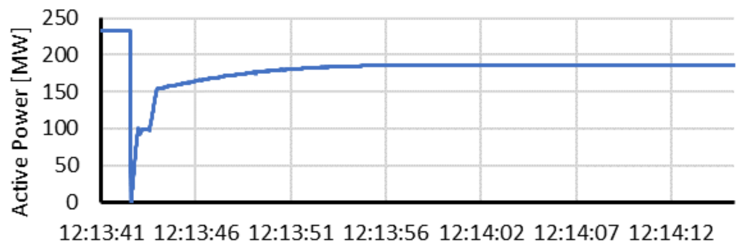
This plant includes inverters that were initially programmed with momentary cessation; however, momentary cessation was disabled following the NERC alert. This plant now provides reactive power support during low voltage events but active power is sacrificed and its recovery to predisturbance levels is relatively slow (i.e., does not meet the recommendations of the NERC reliability guidelines). For this event, active power goes to zero for both faults. In follow-up conversations with the inverter manufacturer, the active power response going to zero is not reasonable for the settings provided by the plant owner/operator, and this response appears to involve an abnormal interaction between the plant-level controller and the inverters. Active power also recovers but is then pulled back and then slowly recovers to predisturbance levels after about 12–15 seconds. This is not an expected response and does not support grid frequency stability. The plant-level controller is interacting with the inverter controls, resulting in a slower recovery than expected.





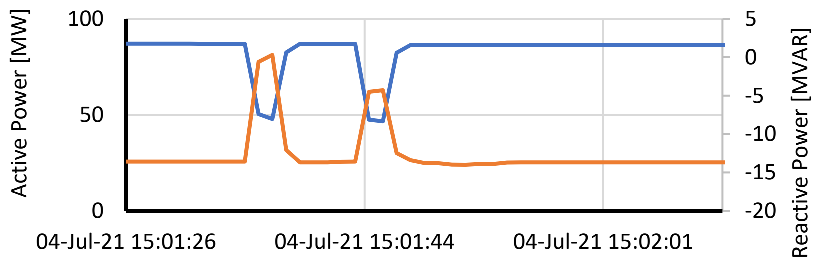
Plant D

This plant includes legacy inverters with momentary cessation enabled at 0.875 pu voltage, 1,020 ms delay to recover, and 8.2%/sec ramp rate to restore active power output. Six inverters tripped on dc overcurrent protection.



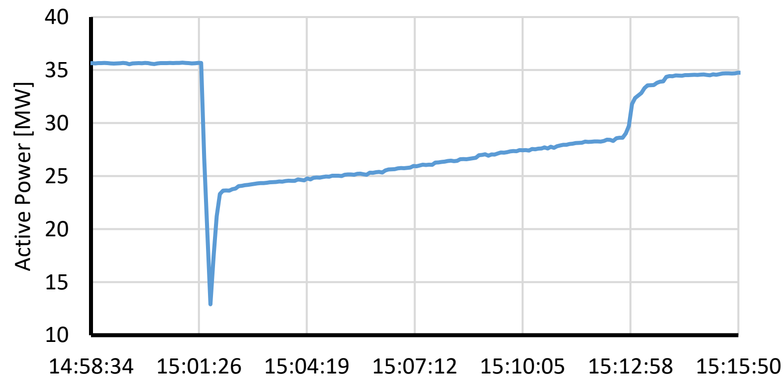
Plant F

Inverters provided reactive power support during the fault; however, they sacrificed active power output, which required about four seconds to recover. This recovery is relatively quick but is longer than recommendations from NERC reliability guidelines.



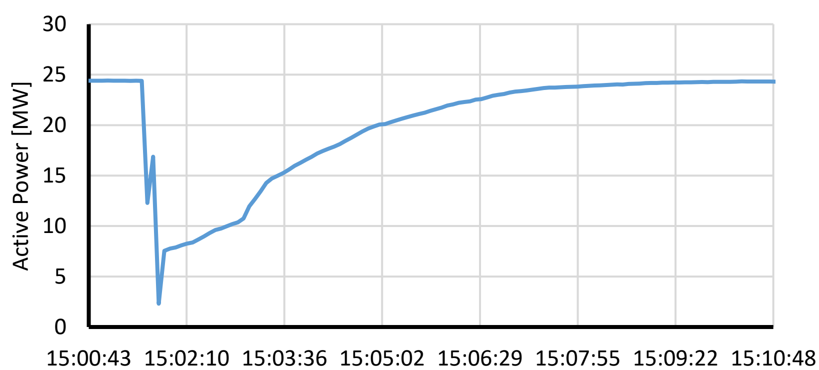
Plant I

Eight inverters tripped on ac overcurrent protection at 150% of rated current. Other inverters entered momentary cessation and had settings of 0.9 pu voltage, 0.1 second delay to start active power recovery, and "no programmed ramp rate (should return to full output in < one second)." These inverters were unable to eliminate momentary cessation or modify settings. However, the plant should recover to predisturbance levels within about one second but takes 15–20 seconds to recovery, indicating plant-level controller interactions.



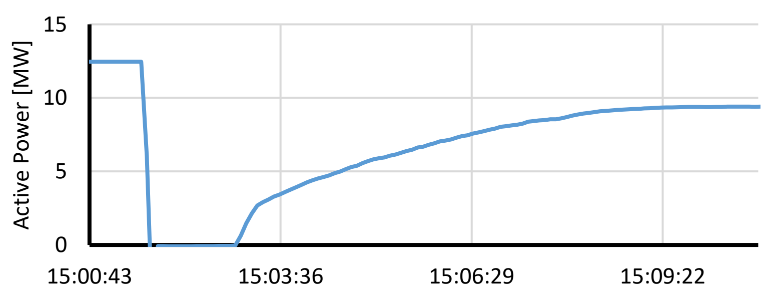
Plant K

Six inverters tripped on instantaneous ac overcurrent protection at 110% of peak nominal current. Other inverters at the facility likely entered momentary cessation. The inverter manufacturer is out of business, so additional details are unavailable and the plant is unable to make modifications to the inverter settings. The plant returned to predisturbance output levels in about six minutes.



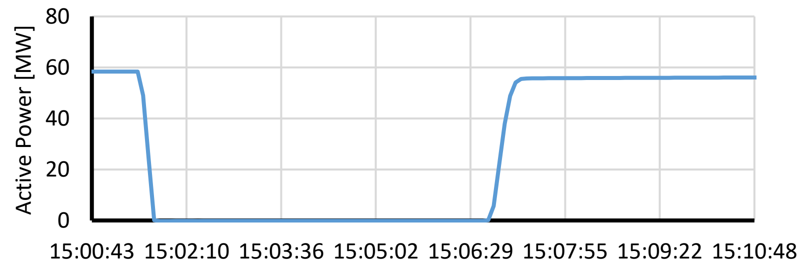
Plant Q

All inverters tripped on instantaneous ac overcurrent protection set at 110% of peak nominal current. The inverter manufacturer is out of business, so additional details are unavailable and the plant is unable to make modifications to the inverter settings.



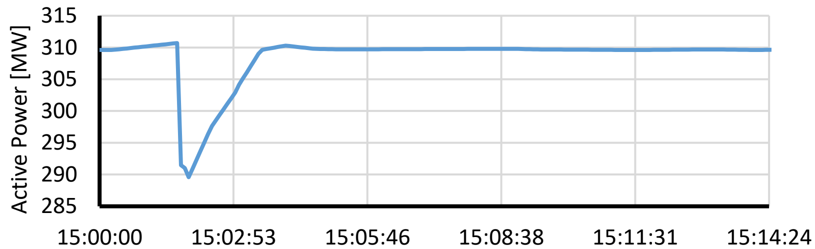
Plant R

Two inverters tripped due to uninterruptible power supply failure and remained off-line for the rest of the day. All other inverters tripped but the plant was unable to provide any details as to the cause of inverter tripping.



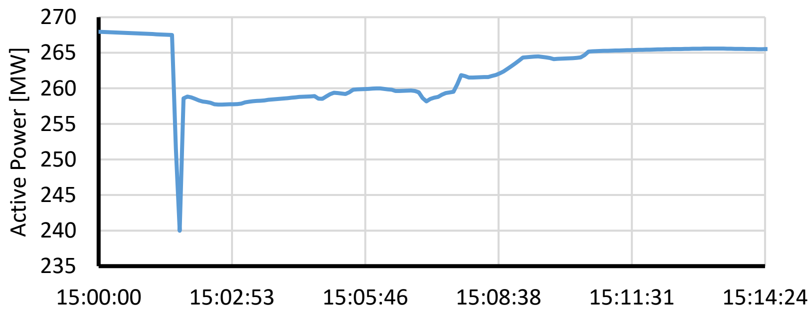
Plant T

The plant reduced power output by 21 MW and increased reactive power output by nine MVAR. However, the ramp back to predisturbance output is about one minute 45 seconds, indicating plant-level controller interactions are hindering inverter recovery of active power after the fault.



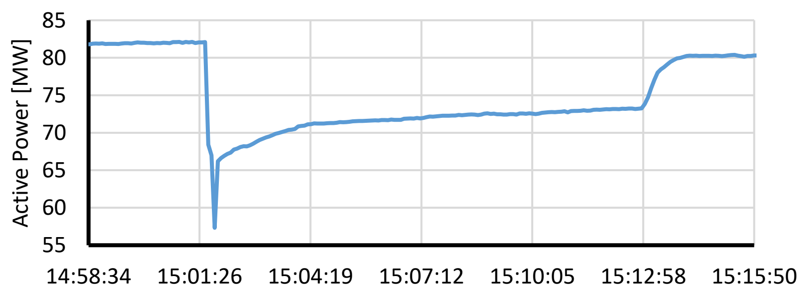
Plant U

The plant reduced power output by 28 MW and increased reactive power output by seven MVAR. However, the ramp back to predisturbance output took over nine minutes. Three inverters are suspected of tripping; however, fault code records were not recoverable by the plant owner.



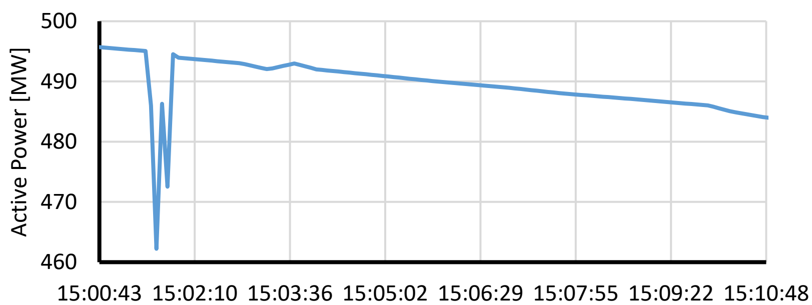
Plant V

Five inverters tripped on ac overcurrent protection at 150% of rated current. Three inverters logged no cause of tripping. These inverters are also configured with momentary cessation enabled.

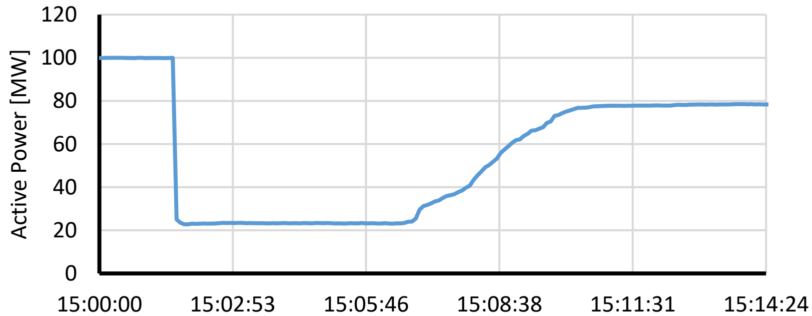


Plant X

One inverter tripped with no fault code. The remaining inverters responded dynamically to the fault event; no inverters at the facility are configured with momentary cessation enabled. According to SCADA data, the plant required about 30 seconds to fully recover to predisturbance output levels.

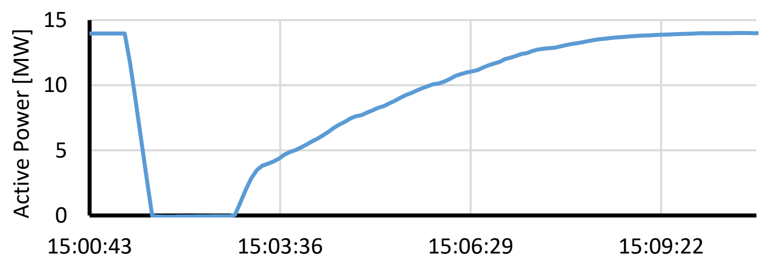


Plant AC



All inverters entered momentary cessation and started recovering 33 ms after fault clearing. Fourteen inverters restored output very quickly. The remaining inverters tripped, and sixteen returned in 10 minutes while eight did not return until later in the day. Inverter fault code records indicate that inverters tripped on “unbalanced voltage” conditions. There are three collector feeders in this plant. The inverters that tripped are all located on feeders that have an underground collector portion; the inverters that remained on-line are located on a fully-overhead collector system. The plant owner also stated that the voltage ride-through protection had been disabled in May 2021 unexpectedly during maintenance procedures and were restored at the end of August 2021. It is unclear if this was a contributor to this resource tripping abnormally for this event.

Plant AD



All inverters tripped on instantaneous ac overcurrent protection at 110% of peak nominal value. The plant returned to full power output in about nine minutes.

July 28, 2021

Table B.4 provides a detailed review of each solar PV facility involved in the July 28, 2021 disturbance, including details of the facility, the magnitude of power reduction, and key findings from the NERC-WECC team review.

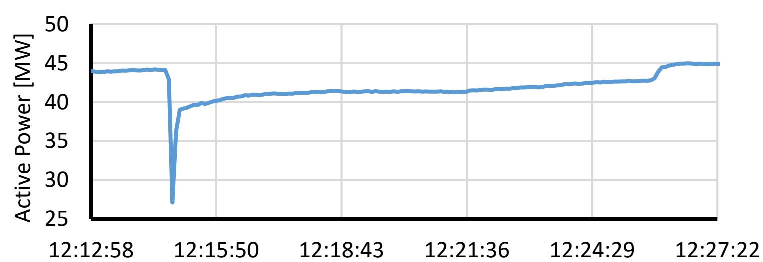
Table B.4: Review of Solar PV Facilities for July 28, 2021 Disturbance

Facility ID	Capacity [MW]	Reduction [MW]	POI Voltage [kV]	In-Service Date	Highest Data Resolution	NERC-WECC Review
A	50	17	230 kV	2016	5-min SCADA	Three inverters tripped on ac overcurrent at 150% of rated current; these inverters have momentary cessation enabled.
B	100	32	220 kV	2016	PMU	Dynamic reactive power support sacrificed active power output with slow recovery of active power after fault clearing.
C	75	11	220 kV	2016	PMU	Dynamic reactive power support sacrificed active power output with slow recovery of active power after fault clearing.
D	248	234	230 kV	2012–2014	PMU	Legacy inverters entered momentary cessation. Forty-one inverters tripped on dc overcurrent protection.
E	45	36	66 kV	2014	1-min SCADA	All inverters tripped for various reasons; plant owner unable to distinguish the primary cause of tripping. All but one inverter required manual restart.
F	109	68	500 kV	2013	SCADA	Dynamic active power response to fault with longer active power recovery than described in NERC reliability guidelines. One inverter tripped on “overcurrent protection.”

Table B.4: Review of Solar PV Facilities for July 28, 2021 Disturbance						
Facility ID	**Capacity [MW]**	**Reduction [MW]**	**POI Voltage [kV]**	**In-Service Date**	**Highest Data Resolution**	**NERC-WECC Review**
J	205	65	230 kV	2016	5-min SCADA	Inverters tripped on instantaneous ac overvoltage above 1.3 pu.
O	20	11	66 kV	2019	4-sec SCADA	Inverters tripped on ac undervoltage protection within the PRC-024-3 curve; remaining inverters entered momentary cessation.
S	20	11	66 kV	2014	5-sec SCADA	Cause of inverter tripping is unknown.
T	318	39	230 kV	2014–2015	1-sec SCADA	Active power drops in response to fault and requires 2 minutes 15 seconds to recover to predisturbance levels.
X	586	34	230 kV	2013–2014	1-min SCADA	Plant responded dynamically to event, reduced output by 34 MW and returned to predisturbance output in 15 seconds.
Y	111	48	500 kV	2019	1-sec SCADA & DFR	Fifteen inverters tripped on overfrequency protection with setting of 61.7 Hz for 1 ms. Two inverters tripped on ac undervoltage protection.
AC	108	20	230 kV	2019	DFR	All inverters entered momentary cessation; five subsequently tripped on “unbalanced voltage” conditions.
TOTAL		**626**				

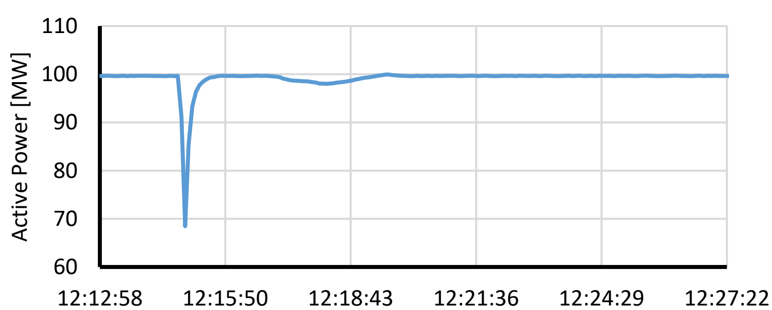
Plant A

Three inverters tripped on ac overcurrent protection set at 150% of rated current. Inverters at the facility also entered momentary cessation.



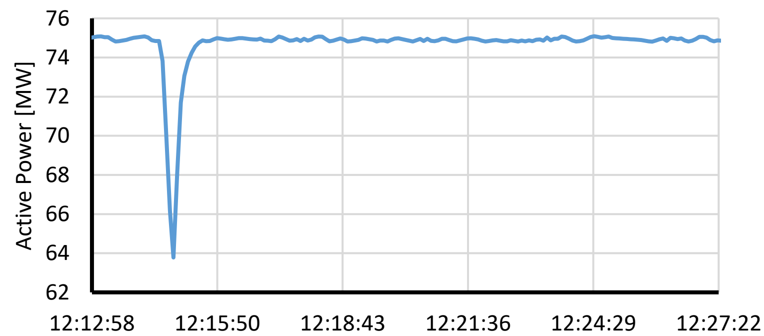
Plant B

This plant includes inverters that were initially programmed with momentary cessation; however, momentary cessation was disabled following the NERC alert. This plant now provides reactive power support during low voltage events but active power is sacrificed and its recovery to predisturbance levels is slower than recommended in NERC reliability guidelines.



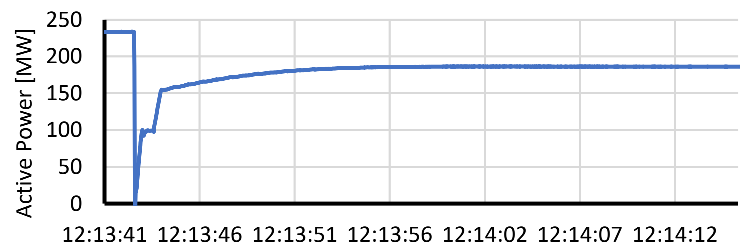
Plant C

This plant includes inverters that were initially programmed with momentary cessation; however, momentary cessation was disabled following the NERC alert. This plant now provides reactive power support during low voltage events but active power is sacrificed and its recovery to predisturbance levels is slower than recommended in NERC reliability guidelines.



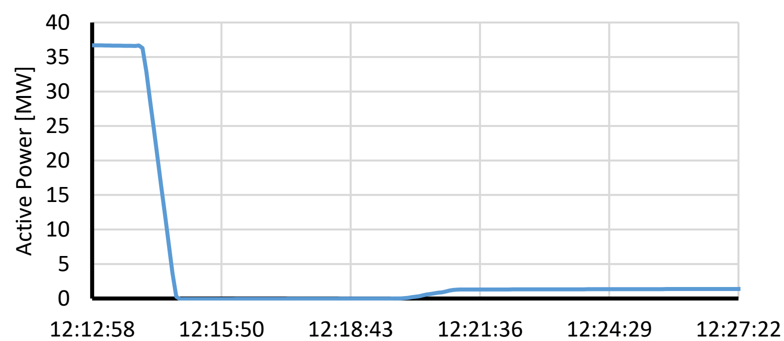
Plant D

This plant includes legacy inverters with momentary cessation enabled at 0.875 pu voltage, 1,020 ms delay to recover, and 8.2%/sec ramp rate to restore active power output. Forty-one inverters tripped on dc overcurrent protection.



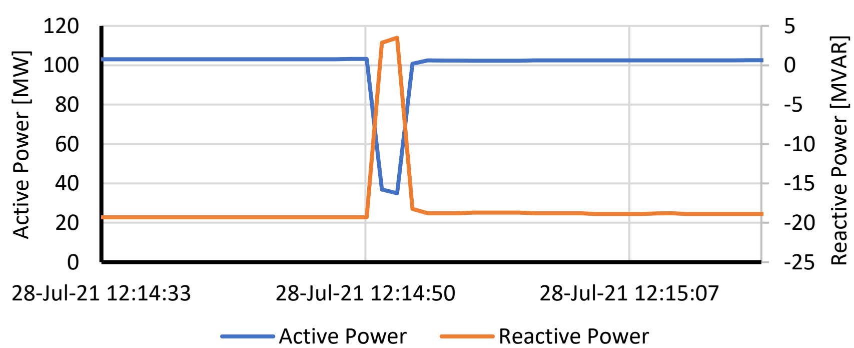
Plant E

The plant owner stated that all inverters at the facility tripped for the following reasons: instantaneous ac overvoltage, short time ac undervoltage, grid undervoltage, PLL loss of synchronism, grid overfrequency, and voltage phase jump. The plant owner was unable to provide additional details as to which fault code tripped each inverter. One inverter restored output in five minutes; the remaining inverters required manual restart.

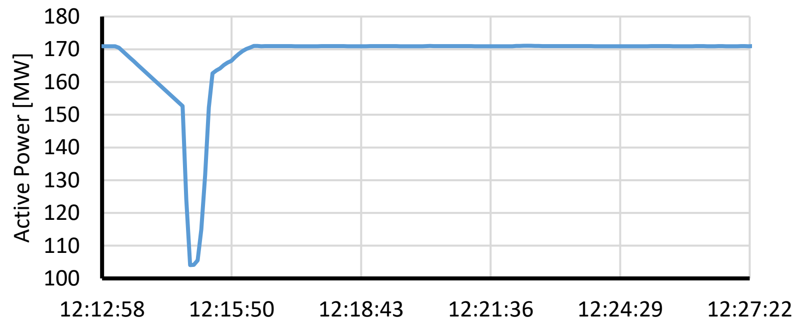


Plant F

Inverters provided reactive power support during the fault; however, they sacrificed active power output, which required about four seconds to recover. This recovery is relatively quick but still longer than recommendations from NERC reliability guidelines.

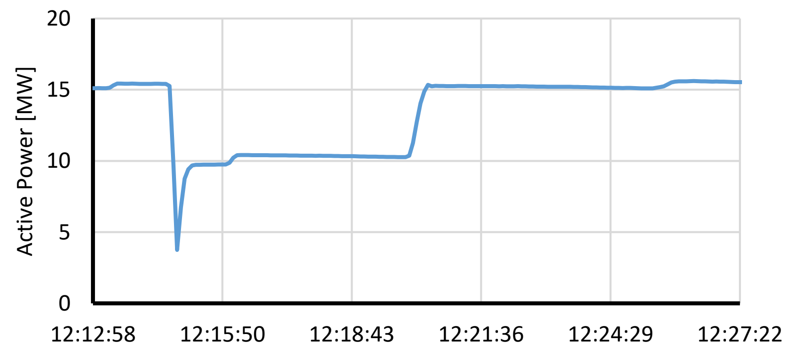


Plant J



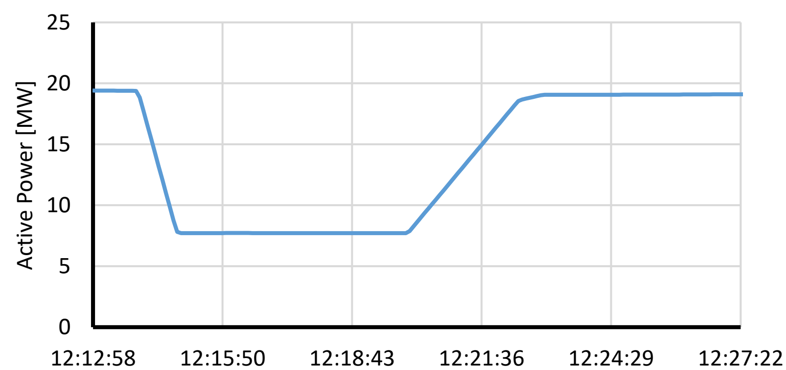
Multiple inverters tripped on instantaneous ac overvoltage at their terminals exceeding 1.3 pu. Those inverters returned to service automatically after a few minutes. Plant SCADA data was stored with five-minute resolution and therefore limited information was available to further understand the plant response to the event.

Plant O



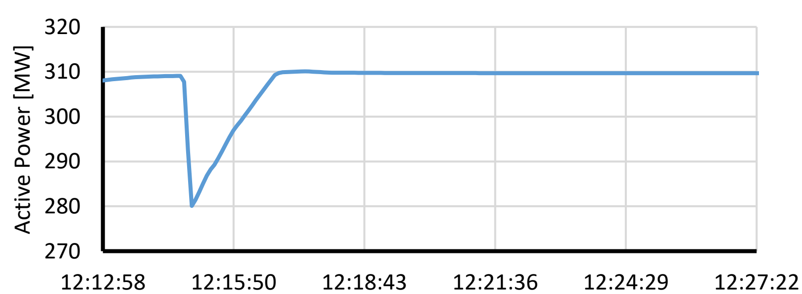
Eighteen inverters tripped on "fast ac minimum voltage percent for greater than 10 cycles (adjustable)" and restored output automatically five minutes later. The remaining inverters entered momentary cessation; settings are unknown for this plant. It was stated by the plant owner that inverter performance for the remaining inverters that did not trip "is not available due to SCADA communications failure" at the time of the event. Furthermore, it was stated that many of the inverters had no fault information because "the buffer capture clears the data when the auto-restart triggers." This plant is configured in a way where data is not being properly stored to capture any information for event analysis.

Plant S



The cause of reduction is unknown. The plant was unable to provide any useful information in response to the RFI nor during follow-up requests for additional information. The plant highlighted that they were waiting on additional information from the inverter manufacturer but were ultimately unable to provide any useable information for root cause analysis. The shape of the reduction and recovery is indicative of inverter tripping with automatic reconnection.

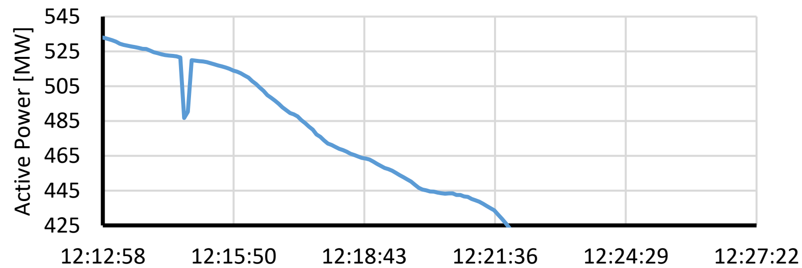
Plant T



The plant reduced power output by 39 MW and increased reactive power output by 14 MVAR. However, the ramp back to predisturbance output is about 2 minutes and 15 seconds, indicating plant-level controller interactions.

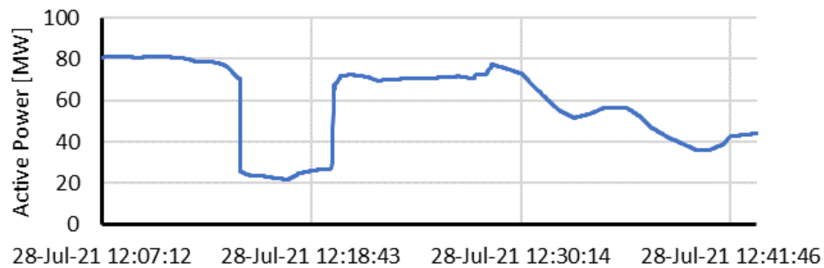
Plant X

The plant responded dynamically to the fault, reducing active power by 34 MW and returned to predisturbance output in about 15 seconds. This does not meet the recommended performance specified in NERC reliability guidelines.



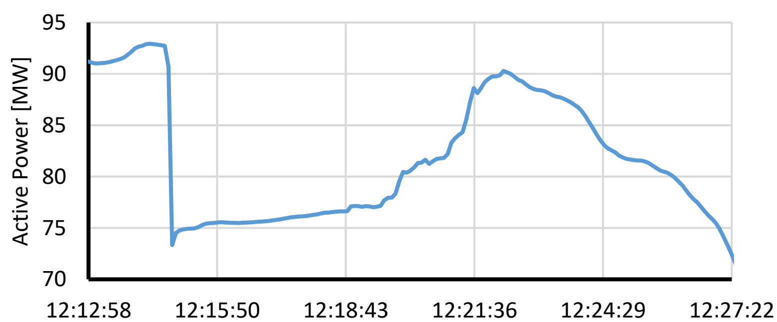
Plant Y

Fifteen inverters tripped on measured overfrequency caused by a very fast trip setting of 61.7 Hz for 1 ms. Two inverters tripped on ac low voltage, but the plant owner was unable to identify trip thresholds.



Plant AC

All on-line inverters entered momentary cessation for roughly 33 ms during the fault. Thirty-one inverters returned to service immediately while five inverters tripped on "unbalanced voltage" conditions.



August 25, 2021

Table B.5 provides a detailed review of each solar PV facility involved in the August 25, 2021 disturbance, including details of the facility, the magnitude of power reduction, and key findings from the NERC–WECC team review.

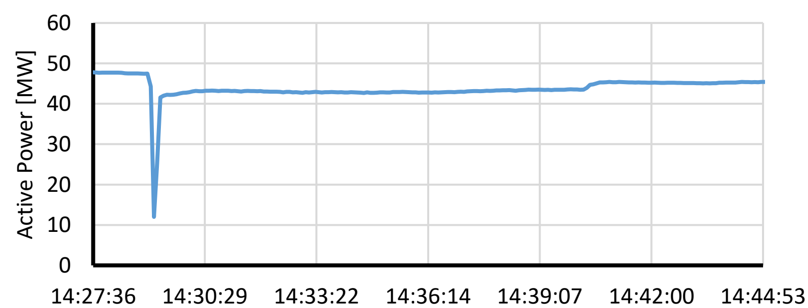
Table B.5: Review of Solar PV Facilities for August 25, 2021 Disturbance

Facility ID	Capacity [MW]	Reduction [MW]	POI Voltage [kV]	In-Service Date	Highest Data Resolution	NERC-WECC Review
A	50	35	230 kV	2016	5-min SCADA	One inverter tripped on ac overcurrent above 150% of rated current, and two tripped with no fault codes recorded. The remaining inverters entered momentary cessation.
B	100	24	230 kV	2016	DFR	The dynamic response to fault event was slightly slow to recover to predisturbance power output. No inverters tripped or entered momentary cessation.
D	248	54	230 kV	2012–2014	PMU	Legacy inverters entered momentary cessation; two tripped on dc overcurrent protection, and four tripped on ac overcurrent protection.
G	300	145	230 kV	2014	DFR	Legacy inverters entered momentary cessation with plant-level controller ramp rate interactions.

Table B.5: Review of Solar PV Facilities for August 25, 2021 Disturbance						
Facility ID	Capacity [MW]	Reduction [MW]	POI Voltage [kV]	In-Service Date	Highest Data Resolution	NERC-WECC Review
H	250	150	230 kV	2014	DFR	Legacy inverters entered momentary cessation with plant-level controller ramp rate interactions.
I	40	23	220 kV	2016	5-min SCADA	Two inverters tripped on instantaneous ac overcurrent above 150% of rated current; one tripped with no fault code recorded. The remaining inverters entered momentary cessation.
P	151	18	230 kV	2019	5-sec SCADA	The dynamic response to fault event was slightly slow to recover to predisturbance power output.
T	318	49	230 kV	2014–2015	1-sec SCADA	The dynamic response to fault event was slightly slow to recover to predisturbance power output.
V	85	48	220 kV	2016	5-min SCADA	Two inverters tripped on ac overcurrent above 150% of rated current, and one tripped with no fault code recorded. The remaining inverters entered momentary cessation.
Y	111	24	500 kV	2019	1-sec SCADA	Six inverters tripped on overfrequency protection with a trip setting of 61.7 Hz for 1 ms, and two inverters tripped with a non-descript “all modules have stopped” fault code, and one inverter tripped on dc bus voltage unbalance.
Z	-	14	-	-	-	Unknown; plant owner contact information unavailable due to change of ownership.
AC	108	16	230 kV	2019	DFR	Inverters entered momentary cessation, and plant-level controller interactions delayed recovery by seven minutes.
TOTAL		**600**				

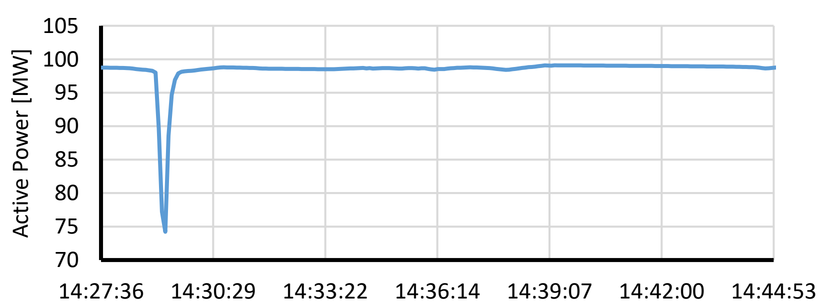
Plant A

One inverter tripped on instantaneous ac overcurrent above 150% of rated current and two inverters tripped with no fault code recorded. The remaining inverters entered momentary cessation (configured with 0.9 pu voltage threshold, a 0.1 second time delay to recover, and no defined ramp rate upon recovery).



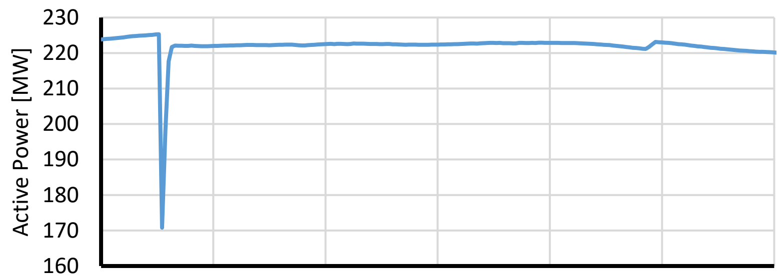
Plant B

The plant dynamically responded to the fault; however, active power recovery took about 40 seconds, which does not meet the recommended performance specified in NERC reliability guidelines.



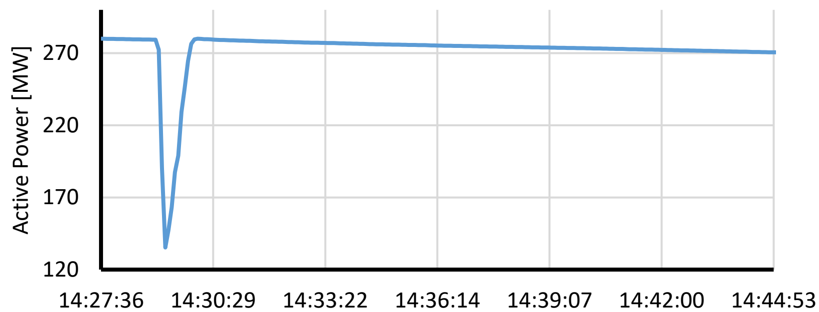
Plant D

This plant includes legacy inverters with momentary cessation enabled at 0.875 pu voltage, 1,020 ms delay to recover, and 8.2%/sec ramp rate to restore active power output. Two inverters tripped on dc overcurrent protection, and four inverters tripped on ac overcurrent protection.



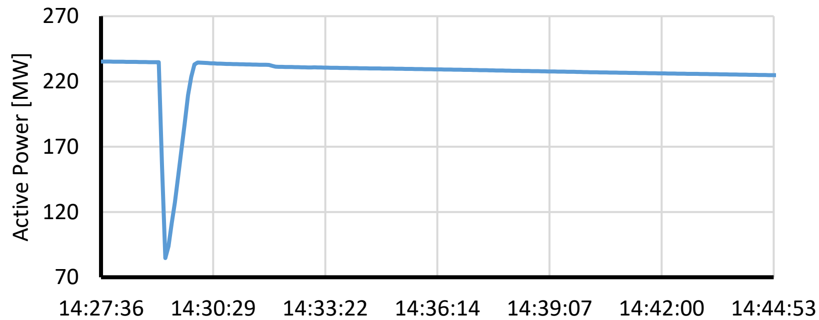
Plant G

Legacy inverters entered momentary cessation, and some minor plant controller interactions slightly inhibited recovery of active power to predisturbance output levels.



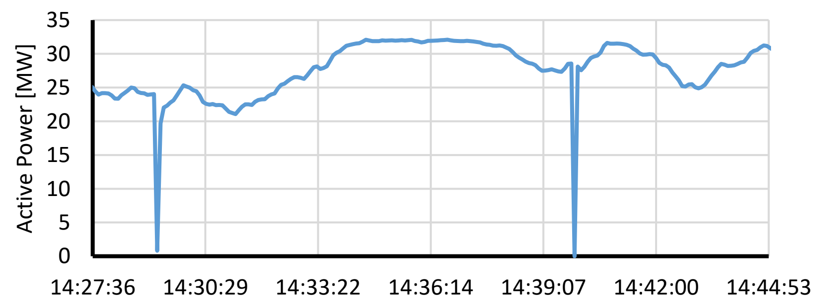
Plant H

Legacy inverters entered momentary cessation, and some minor plant controller interactions slightly inhibited recover of active power to predisturbance output levels.



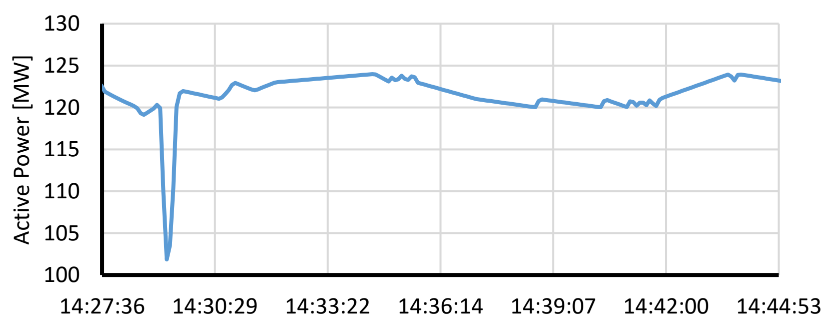
Plant I

Two inverters tripped on instantaneous ac overcurrent above 150% of rated current and one tripped with no fault code recorded. The remaining inverters entered momentary cessation (configured with 0.9 pu voltage threshold, a 0.1 second time delay to recover, and no defined ramp rate upon recovery).



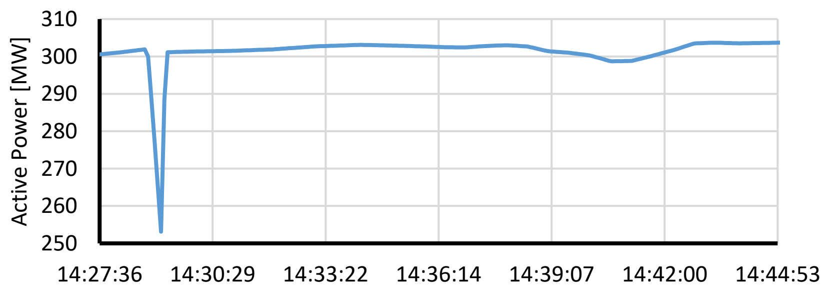
Plant P

The plant dynamically responded to the fault and recovered active power in about 25 seconds. No inverters tripped or entered momentary cessation. The delayed recovery does not meet the recommended performance specified in NERC reliability guidelines.



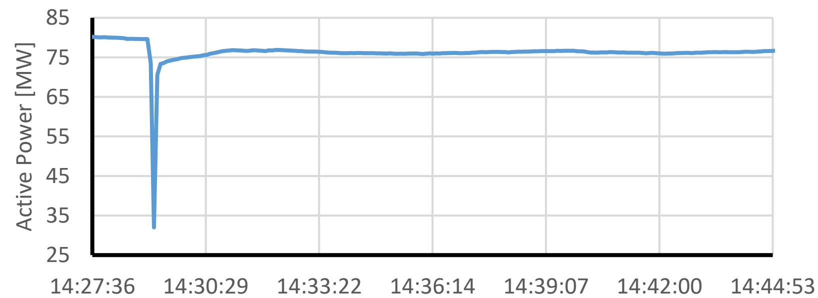
Plant T

The plant dynamically responded to the fault and recovered active power in about 30 seconds. No inverters tripped or entered momentary cessation. The delayed recovery does not meet the recommended performance specified in NERC reliability guidelines.



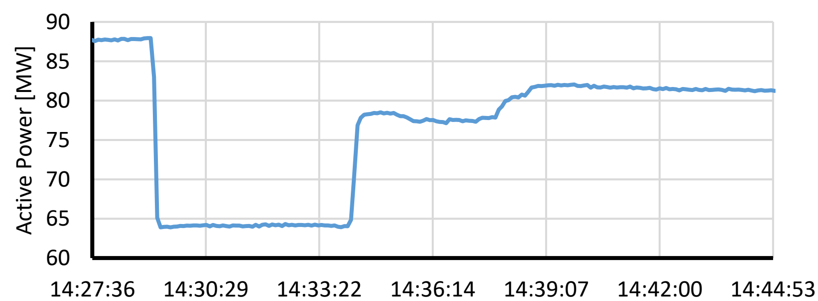
Plant U

Two inverters tripped on instantaneous ac overcurrent above 150% of rated current and one with no fault code recorded. Other inverters entered momentary cessation (configured with 0.9 pu voltage threshold, a 0.1 second time delay to recover, and no defined ramp rate upon recovery).



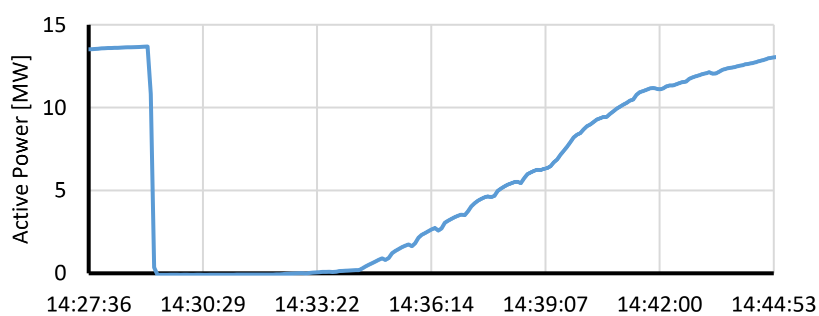
Plant Y

Six inverters tripped on overfrequency, and two inverters reported "all modules have stopped" with no additional details, and one inverter tripped on "voltage unbalance" between the high and low side of the dc bus. The inverters that tripped on overfrequency protection have trip settings of 61.7 Hz for 1 ms.



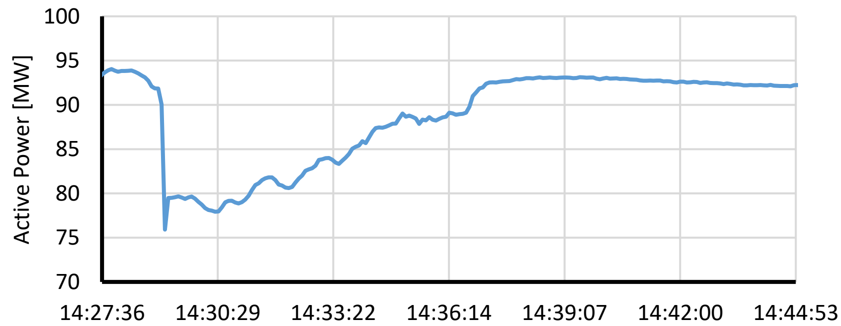
Plant Z

This plant reduced output to zero (by about 14 MW) for five minutes and then slowly ramped back to predisturbance levels by about 15 minutes after the fault. WECC requested contact information for this non-BES facility from CAISO; however, CAISO was unable to provide contact information because the plant was undergoing a change of ownership and had yet to provide the required documentation. Therefore, WECC and NERC were unable to perform any analysis on this facility; the cause of reduction is unknown.



Plant AC

All inverters entered into momentary cessation at the time of the fault. Inverter voltage ride-through settings were "disabled allowing momentary cessation to occur." This issue was corrected on September 1, 2021 and momentary cessation was subsequently disabled. The plant response to the event shows a significantly delayed recovery of about seven minutes back to predisturbance output levels.



Appendix C: Analysis of Synchronous Generator Tripping

The disturbances that occurred on July 4 and August 25 involved the loss of synchronous generating resources in addition to the widespread reduction of solar PV facilities. This section provides key findings regarding the loss of the synchronous resources.

Loss of Synchronous Generation on July 4

The fault on July 4 resulted in the loss of a combustion turbine at a combined-cycle power plant while loaded at 125 MW. The plant owner contacted the equipment manufacturer to analyze the alarm logs and provide an explanation of the trip. The turbine tripped because two sets of sensors were unhealthy: one power transducer and one dead fuel humidity sensor. This resulted in turbine controls operating incorrectly during the grid fault event and subsequently tripping the turbine for an external fault in which it should not have tripped.

Loss of Synchronous Generation on August 25

The fault on August 25 resulted in the loss of two separate synchronous generating resources that tripped for different reasons:

- **Unexpected/Unplanned RAS Operation:** A natural gas turbine tripped carrying 212 MW when a 220 kV line exceeded a RAS threshold. The RAS initiated a trip function to the generator during the power swing immediately upon fault clearing.
- **Combustion Turbine Tripping:** A natural gas turbine tripped while carrying 91 MW. This generator is not associated with the RAS described above. This unit tripped due to excitation system failure (failed diodes) that occurred at the time of the event. While the diodes are redundant, a failure can only be identified by manual inspection and was undetected prior to the event. Therefore, the response of the unit to the fault event likely led to the failure of the second diode, and the unit ultimately tripped. The plant has increased their inspection rate to avoid this issue in the future.

Analysis of RAS Operation

The RAS that operated is located about 130 circuit-miles from the fault location, illustrating how a centralized fault in a well-connected location can have far-reaching impacts on protection and controls of both generating assets and transmission assets. The RAS monitors three conditions involving two thermal overloads and a bus voltage and initiates generator tripping for monitored thermal overload conditions. The thermal overload arming point for the RAS uses phase instantaneous overcurrent elements on the monitored 220 kV lines set at a certain current threshold (i.e., the rating of the line). If the overload is detected, the RAS issues a trip signal to a combustion turbine generator within 15 cycles.

This RAS is specifically designed to mitigate a thermal overload reliability issue on the BPS. It uses a response-based monitoring scheme with inputs that use instantaneous elements (i.e., no time delay). They are also not supervised in any way by line status or other relevant localized measurements to avoid tripping on unexpected power swings.

In general, RASs should be armed based on precontingency conditions to protect against specific reliability issues studied ahead of time. RAS action should be based on specific post-contingency (or transient) conditions. In many cases, RASs are supervised by a triggering event (i.e., event-driven) to mitigate the possibility of unexpected RAS operations and unplanned cascading events like those that occurred in this situation. Thermal overloads are based on a time-based equipment rating that typically is on the order of many seconds to minutes, so the instantaneous overcurrent element used as a RAS input should be reviewed by SCE to determine whether this fast-acting control action is needed in this specific case. RASs that protect for thermal overload issues should generally incorporate a time delay to allow for automated control actions (such as reclosing) and to avoid over-tripping for power swings or other conditions for which the RAS is not designed to operate.

Recommendation
SCE should immediately conduct a thorough review of the RAS involved in this event and all response-based RAS to ensure that false tripping does not occur. In particular, SCE should consider whether possible supervisory functions (e.g., line status) should be used and whether instantaneous trip thresholds are necessary for a thermal overload issue. SCE should report their findings to WECC and NERC upon completion. Any operation of a RAS for a fault for which it is not designed should be considered a misoperation of the RAS and be analyzed and reported accordingly per NERC PRC-012-2.

Simulation of RAS Operation

SCE conducted a simulation of system operating conditions to analyze the contributing cause of the RAS operation (see **Figure C.1**). As the figure shows, the power swings reach very close (simulations do not exactly match actual system conditions) to the trip threshold[44] immediately after the fault that occurred around 130 circuit miles away.

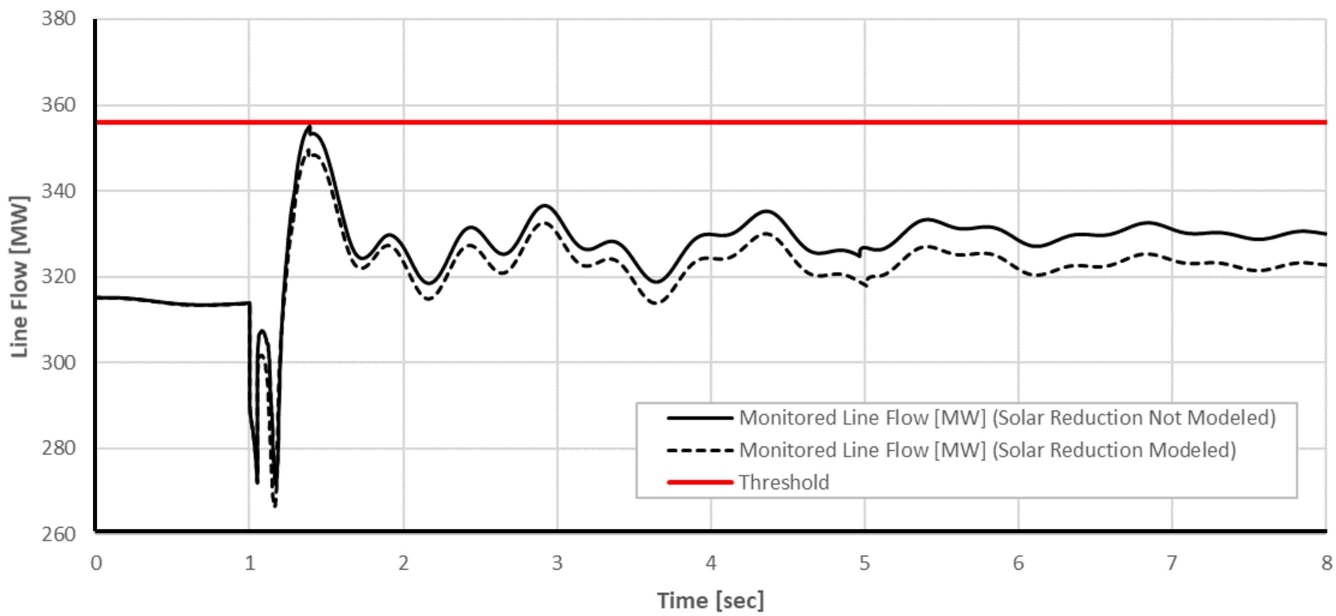


Figure C.1: Simulation of RAS Operation with and without Solar PV Modeled

As has been documented in multiple NERC technical reports[45] and alerts,[46] the dynamic models used by grid planners and operations engineers to develop corrective action plans or establish system operating limits do not accurately reflect the dynamic characteristics of solar PV resources. In particular, the vast majority of solar PV reduction (i.e., caused by solar PV tripping, controls interactions, and momentary cessation) are likely not correctly modeled in the dynamic models and lead to inaccuracies in simulations. SCE conducted two simulations: one involving the “as is” models used in operations studies that do not accurately model the reduction in solar PV resources identified in this event and one involving a manual reduction of those resources that were involved. As the simulation shows, the RAS operation is primarily attributed to the power swings immediately upon fault clearing; however, accurately representing the solar PV reductions changes simulation results. If some of the solar PV loss had been on the other side of this transfer path, the interactions could have been exacerbated.

[44] Note that the RAS operates on line current rather than on active power. Nominal voltage and current were used to illustrate a “threshold” in power quantities in the simulation.
[45] https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/NERC-WECC_2020_IBR_Modeling_Report.pdf
[46] https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC_Alert_Loss_of_Solar_Resources_during_Transmission_Disturbance-II_2018.pdf

Appendix D: Disturbance Analysis Team

This disturbance report was published with the contributions of the following individuals. NERC gratefully acknowledges WECC, CAISO, and the affected TOs, TOPs, GOs, and GOPs. Coordination between all affected entities was crucial for the successful analysis of this disturbance and publication of this report. NERC would also like to acknowledge the continued engagement and support of the inverter manufacturers to ensure that the mitigating measures being developed are pragmatic. Lastly, members of the NERC IRPS continue to support NERC in its mission to ensure reliable operation of the BPS, particularly as the BPS is faced with rapidly changing technology and evolving grid performance characteristics.

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Curtis Holland	WECC
Abe Rais	WECC
Tim Reynolds	WECC

Errata

April 8, 2022: Fixed language on page 57 that discussed solar PV reductions.