UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection	**)))**	**Docket No. RM21-17-000**

COMMENTS OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION, MIDWEST RELIABILITY ORGANIZATION, NORTHEAST POWER COORDINATING COUNCIL, INC., RELIABILITYFIRST CORPORATION, SERC RELIABILITY CORPORATION, TEXAS RELIABILITY ENTITY, INC., AND WESTERN ELECTRICITY COORDINATING COUNCIL ON
THE ADVANCE NOTICE OF PROPOSED RULEMAKING

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On July 15, 2021, the Federal Energy Regulatory Commission ("FERC" or the "Commission") issued an Advance Notice of Proposed Rulemaking ("ANOPR") introducing potential proposals intended to holistically reform regional transmission planning and cost allocation and generator interconnection procedures. While many aspects of the ANOPR focus on cost allocation and investments, the Commission also highlights the need for continued reliability of the Bulk-Power System ("BPS") while the resource mix evolves.[1]

The North American Electric Reliability Corporation ("NERC"), as the Commission-certified Electric Reliability Organization ("ERO"),[2] and the Regional Entities[3] hereby submit comments to:

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1 *See, e.g.*, ANOPR at PP 3-4, 14, and 31-32.

2 *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC 61,104 (2006), *order on reh'g*, Order No. 672-A, 114 FERC 61,328 (2006). NERC was certified by the Commission as the ERO, pursuant to § 215(c) of the Federal Power Act ("FPA"), by Commission order issued July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006) [hereinafter Certification Order].

3 The Regional Entities are (i) Midwest Reliability Organization ("MRO"); (ii) Northeast Power Coordinating Council, Inc. ("NPCC"); (iii) ReliabilityFirst Corporation ("ReliabilityFirst"); (iv) SERC Reliability Corporation ("SERC"); (v) Texas Reliability Entity, Inc. ("Texas RE"); and (vi) Western Electricity Coordinating Council ("WECC"). NERC and the Regional Entities comprise the ERO Enterprise.

(i) Propose enhancements for modeling and studies under *pro forma* generator interconnection procedures, particularly through the inclusion of electromagnetic transient ("EMT") modeling and studies;

(ii) Propose enhancements to the Commission's *pro forma* interconnection agreements to incorporate recommendations from NERC Reliability Guidelines pertaining to integration of inverter-based resources; and

(iii) Support the Commission's exploration of better coordinated transmission planning.

For the reasons set forth in these Comments, the ERO Enterprise proposed enhancements to the Commission's *pro forma* interconnection procedures and interconnection agreements would be a just and reasonable, targeted, approach to efficiently ensure continued reliability of the BPS as increasing levels of inverter-based resources interconnect with the grid.

I. <u>EXECUTIVE SUMMARY</u>

The ANOPR explores reforms or revisions to Commission regulation to improve regional electric transmission planning and generator interconnection procedures under a transforming electricity sector with a changing resource mix. As the Commission-certified ERO, NERC must conduct periodic assessments of the reliability and adequacy of the BPS in North America.[4] During the course of event analysis and assessments, the ERO has identified improvements to modernize Commission generator interconnection procedures and agreements and help ensure continued reliability as greater levels of inverter-based resources interconnect with the BPS.

With decarbonization of the resource mix, it is vitally important that renewable, and often variable, energy resources be integrated in a way that sustains reliable operation of the BPS. This will maximize the amounts of resources that can be incorporated, while at the same time addressing the changing characteristics of the transformed grid. As detailed in Section IV.A. below, transmission planner and planning coordinator studies under the Commission's present

4 16 U.S.C. § 824o(g).

interconnection procedures have failed to identify performance issues from inverter-based resources (particularly solar photovoltaic ("PV") resources). These studies mostly rely on positive sequence models which have limited ability to accurately reflect many causes of power reduction observed by NERC event analysis. Evidence shows that these positive sequence studies are failing to identify potential performance issues that could negatively affect reliability of the BPS due to their limitations and due to modeling simplifications associated with inverter and plant protection systems and controls. The attached Odessa Report (**Attachment 1**) provides ERO Enterprise event analysis of a scenario where performance issues that could have been identified during the interconnection process led to a Category 1i event on the BPS.[5]

In addition to improved positive sequence dynamic models,[6] modern EMT studies would provide an opportunity for transmission service providers to both (i) identify and (ii) work with resources to address, potential performance issues and impacts to reliability before interconnection and commercial operation. To ensure continued reliability of the BPS under a changing resource mix and successful integration of inverter-based resources, the ERO Enterprise proposes the following enhancements to the Commission's interconnection procedures to require that:

1) Resources seeking to interconnect with the BPS provide accurate data enabling EMT modeling and studies during the interconnection process; and

2) Transmission service providers perform EMT studies for all inverter-based resources, unless determined unnecessary, and consider EMT studies for other resources.

See infra, Section IV.A. for more discussion.

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[5] A Category 1i event is understood as a "non-consequential interruption of inverter type resources aggregated to 500MW or more not caused by a fault on its inverters, or its ac terminal equipment." *See*, *Electric Reliability Organization Event Analysis Process,* Version 4 (Dec. 2019), available at https://www.nerc.com/pa/rrm/ea/ERO_EAP_Documents%20DL/ERO_EAP_v4.0_final.pdf.

[6] The ERO Enterprise encourages clear and consistent improvements to the modeling practices for positive sequence dynamic models as these models play a crucial role in interconnection-wide planning, notwithstanding their limitations.

The ERO Enterprise has similarly identified enhancements to the Commission's *pro forma* interconnection agreements. NERC's disturbance reports explain how a lack of performance requirements for interconnected resources is contributing to performance issues during real-time operations and may impact multiple footprints and interconnections. The *pro forma* interconnection agreements should be equipped with clear and consistent requirements for newly interconnecting inverter-based resources. Therefore, in addition to NERC's evaluation of potential modifications to Reliability Standards, the ERO Enterprise proposes that the Commission incorporate recommendations from Inverter Based Resource Performance Working Group ("IRPWG") Reliability Guidelines related to the integration of inverter-based resources into the *pro forma* interconnection agreements. These Reliability Guidelines are widely downloaded and relied upon by industry, in varying degrees. The Guidelines, for example, specifically recommend improved monitoring capability from BPS connected inverter-based resources. Thus, the ERO Enterprise recommends that the Commission incorporate performance requirements in IRPWG Reliability Guidelines into the *pro forma* interconnection agreement. *See infra,* Section IV.B.

Finally, the ERO Enterprise supports the Commission's attention to better coordinated transmission planning. Greater coordination and certainty would improve industry's ability to assess reliability of a changing grid. NERC and the Regional Entities look forward to reading comments regarding the concept of an independent transmission monitor. In addition, NERC and the Regional Entities appreciate the Commission's attention to managing potential issues associated with multiple interconnection requests by a resource. *See infra*, Section IV.C.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[7]

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[7] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2020), to allow the inclusion of more than two persons on the service list in this proceeding.

III. STATUTORY FRAMEWORK

A. Introduction to the ERO Enterprise.

NERC's mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. In enacting the Energy Policy Act of 2005[8] and section 215 of the Federal Power Act ("section 215") thereunder,[9] Congress entrusted the Commission with: (i) approving and enforcing rules to ensure the reliability of the BPS; and (ii) with certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval, and assessing reliability and adequacy of the BPS in North America.[10]

Congressional and Commission statute and regulation reflect certification of an ERO subject to Commission oversight under various avenues. In 2006, the Commission certified NERC as the ERO pursuant to section 215.[11] Prior to that, Order No. 672 established regulations implementing section 215, including a process for periodic Performance Assessments that would examine how well the ERO is accomplishing its responsibilities.[12] The initial Performance Assessment was due three years after certification, with subsequent ones due on a five-year cycle. Order No. 672 also required that NERC and the Regional Entities submit a detailed annual budget and business plan filing each year for Commission approval, 130 days in advance of the ERO fiscal year.[13] The Commission also reviews and approves the Regional Delegation Agreements

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8 Pub. L. 109–58, title XII, §1211(b), Aug. 8, 2005, 119 Stat. 946.

9 16 U.S.C. § 824o [hereafter section 215].

10 Section 215(a)(2). *See also* Section 215(c) (providing the ERO certification criteria). *See also* Pub. L. 109–58, title XII, §1211(b), Aug. 8, 2005, 119 Stat. 946 (clarifying, "[t]he Electric Reliability Organization… and any regional entity delegated enforcement authority… are not departments, agencies, or instrumentalities of the United States Government.").

11 Certification Order.

12 Order No. 672, PP 183-191.

13 18 C.F.R. §39.4.

("RDAs") between NERC and the Regional Entities every five years.[14] Through oversight conducted pursuant to the RDAs and NERC Rules of Procedure ("ROP"), NERC evaluates Regional Entity performance and compliance with the ROP, Commission directives, RDAs, NERC policies or procedures, and guidance and directions issued by the NERC Board of Trustees ("Board").

B. NERC Reliability Standards and Commission Interconnection Procedures Operate Together to Ensure Reliability of the BPS as New Resources Interconnect.

NERC Reliability Standards define the reliability requirements for planning and operating the North American BPS and are developed using a results-based approach that focuses on performance, risk management, and entity capabilities. NERC and the Regional Entities have the obligation to identify and register all entities that meet the criteria for inclusion in the NERC Compliance Registry ("NCR")[15] and are therefore subject to the Reliability Standards.[16]

NERC's suite of Reliability Standards include requirements applicable to responsible entities on NERC's NCR and which address potential risks associated with the interconnection of resources to the BPS. For example, Reliability Standard FAC-001-3 states that, "[t]o avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection requirements available so that entities seeking to interconnect will have the necessary information."[17] Reliability Standard FAC-002-2 requires entities "[t]o study the impact of interconnecting new or materially modified

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[14] 18 C.F.R. §39.8. A delegation agreement shall not be effective until it is approved by the Commission.

[15] The NCR identifies the owners, operators, and users of the BPS that are responsible for complying with approved reliability standards applicable to the functions for which each entity is registered.

[16] Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher (while also considering any Inclusions or Exclusions as detailed in the NERC Glossary of Terms, available here https://www.nerc.com/files/glossary_of_terms.pdf).

[17] Available at https://www.nerc.com/pa/Stand/Reliability%20Standards/FAC-001-3.pdf.

Facilities on the Bulk Electric System."[18] These Reliability Standards apply to registered entities and their requirements operate in partnership with the Commission's interconnection procedures and interconnection agreements for efficiency, comprehensiveness, and effectiveness.

The Commission's *pro forma* interconnection procedures and agreements serve as a key function in the regulatory framework. The Commission has interconnection procedures and agreements for both large[19] and small[20] generators and these provide uniformity for both transmission providers and interconnection customers. The Commission's procedures help prevent undue discrimination and preserve reliability, building on the Reliability Standard obligations applicable to Transmission Providers in FAC-001-3 and FAC-002-2 referenced above.[21] These procedures, moreover, have the advantage that they may apply to resources prior to their operation and therefore prior to registration on NERC's NCR after which Reliability Standards become mandatory and enforceable. As a result, the Commission's interconnection procedures and agreements complement NERC Reliability Standards to help ensure continued reliability of the BPS as the North American resource mix evolves.

IV. COMMENTS

As discussed below, NERC disturbance reports[22] and Reliability Guidelines[23] have identified two material enhancements to the Commission's *pro forma* interconnection procedures

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18 Available at https://www.nerc.com/pa/Stand/Reliability%20Standards/FAC-002-2.pdf.

19 A Generating Facility having a Generating Facility Capacity of more than 20 MW.

20 A Generating Facility that has a Generating Facility Capacity of no more than 20 MW.

21 *See* Order Nos. 2003 and 2006 (regarding large and small generators, respectively). *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC 61,103 (2003); *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, 111 FERC 61,220 (2006).

22 Major Event Analysis Reports, available at https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx (including, the Blue Cut Fire, Canyon 2 Fire, Palmdale Roost and Angeles Forest Disturbances, San Fernando Disturbance, and Odessa Disturbance reports).

23 Available at https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx.

and interconnection agreements to help maintain reliability under a transforming grid. The ERO Enterprise proposes: (i) modernizing the interconnection procedures to ensure accurate positive sequence and EMT modeling of newly interconnected resources; and (ii) updating the interconnection agreements to include performance requirements for inverter-based resources, reflecting recommendations in Reliability Guidelines developed by the NERC IRPWG and related to the integration of inverter-based resources with the BPS.

These proposals would reflect a just and reasonable, tailored, approach to help maintain reliability of the BPS by responding to issues identified by NERC event analysis and reliability assessments in an efficient and streamlined manner. *See* Sections IV.A. and B. below. The ERO Enterprise also takes this opportunity to support the Commission's attention to better coordinated transmission planning. *See* Section IV.C. below.

A. Interconnection Procedures Should Require EMT Modeling and Studies.

The ANOPR requests comments on potential modeling and study enhancements which would support reliability during the interconnection of new generation resources. The Commission states:

> We also seek comment on which inputs and assumptions transmission providers would need to model to represent new generation sources, such as renewable resources, in order to reflect their actual performance, such as active power-frequency control, reactive power-voltage control, and fault ride-through capabilities, in the planning study cases and any additional studies in order to ensure that transmission planning solutions result in operating reliability for the future.[24]

NERC and the Regional Entities propose that the Commission's *pro forma* interconnection procedures include modern EMT modeling and studies, in addition to improved positive sequence

[24] ANOPR at P 50.

dynamic models,[25] to support a new and changing grid. ERO Enterprise event analysis over the past several years demonstrates that relying solely on conventional studies to evaluate potential reliability ramifications of inverter-based resources is too limited.[26] As detailed in NERC and Texas RE's recent Odessa Report, event analysis disturbance reports and NERC Alerts since 2016 have documented performance abnormalities and challenges by inverter-based resources (particularly PV facilities) during faults on the system.[27] In the past several years, NERC has published five disturbance reports analyzing seven events. Two of these disturbances resulted in NERC Alerts.[28] The second Alert focused on the modeling deficiencies of inverter-based resources, specifically modeling deficiencies with PV solar facilities. Root cause analysis highlighted limitations of interconnection studies due to issues with generator models used during the interconnection study process.

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25 These improvements should include requirements for accurate models and updates to any proposed modifications to the facility as part of the interconnection process to permit accurate modeling, modeling updates, and any re-study as determined necessary.

26 Major Event Analysis Report Webpage, available at https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx (providing NERC disturbance reports). *See also* White Paper: Fast Frequency Response Concepts and Bulk Power System Reliability Needs, available at https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf; Technical Report: BPS-Connected Inverter-Based Resource Modeling and Studies, available at https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/IRPTF_IBR_Modeling_and_Studies_Report.pdf; and NERC-WECC Joint Report: WECC Base Case Review: Inverter-Based Resources, available at https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/NERC-WECC_2020_IBR_Modeling_Report.pdf.

27 Odessa Report at vii.

28 Loss of Solar Resources during Transmission Disturbances due to Inverter Settings (June 2017), available at https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20Loss%20of%20Solar%20Resources%20during%20Transmission%20Disturbance.pdf; and Loss of Solar Resources during Transmission Disturbances due to Inverter Settings – II (May 2018), available at https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC_Alert_Loss_of_Solar_Resources_during_Transmission_Disturbance-II_2018.pdf.

The performance issues identified in ERO Enterprise disturbance reports could have been discovered during the interconnection process through EMT studies and more accurate positive sequence studies. Today's interconnection procedures do not require either: (i) that interconnecting resources provide modeling data needed for EMT studies; or (ii) that transmission service providers perform EMT studies. The ERO Enterprise proposes that the Commission's interconnection procedures require modeling data to support EMT studies and that transmission service providers evaluating a resource (i) perform EMT studies for proposed inverter-based resources facilities, unless it is determined unnecessary in light of facts and circumstances presented; and (ii) consider EMT studies for other resources, as appropriate. These enhancements to *pro forma* interconnection procedures would introduce some additional complexity to the study process (at least at first), however, better studies would serve as a tailored approach to balancing efficient due diligence regarding interconnecting resources with a quick pace towards interconnection.

The Odessa Report was prepared by NERC and Texas RE, in coordination with the Electric Reliability Council of Texas ("ERCOT"), after a BPS disturbance in Texas on May 9, 2021, referred to as the "Odessa Disturbance." While the ERO Enterprise has analyzed similar events in California, the Odessa Disturbance was the first disturbance involving widespread reduction of solar PV resources in the Texas Interconnection. The event involved facilities across a large geographic area of up to 200 miles from the location of the initiating fault, and information was gathered from ERCOT and the affected generator owners whose facilities experienced a notable reduction in power during the event. The fault was caused by a failed surge arrester at the combustion turbine for a combined-cycle power plant near Odessa, Texas during startup for testing, and it also affected a number of solar PV and wind plants connected to the BPS. None of the affected inverter-based resources were tripped consequentially by the fault itself. Rather, all reductions were due to inverter-level or feeder-level tripping or control system behavior within the resources. The Odessa Report documents analysis of the disturbance, summarizes takeaways from prior disturbance reports and Alerts, and provides key findings and recommendations for industry. The Odessa Report is posted on NERC's website and included as **Attachment 1**.

EMT studies would be capable of modeling all forms of tripping and abnormal performance during faults. Multiple types of inverter tripping were identified during the Odessa Disturbance and past solar PV resource loss events evaluated by NERC. Figure 1.1 of the Odessa Report presents causes of solar PV power reduction during the disturbance and associated inverter characteristics.[29]

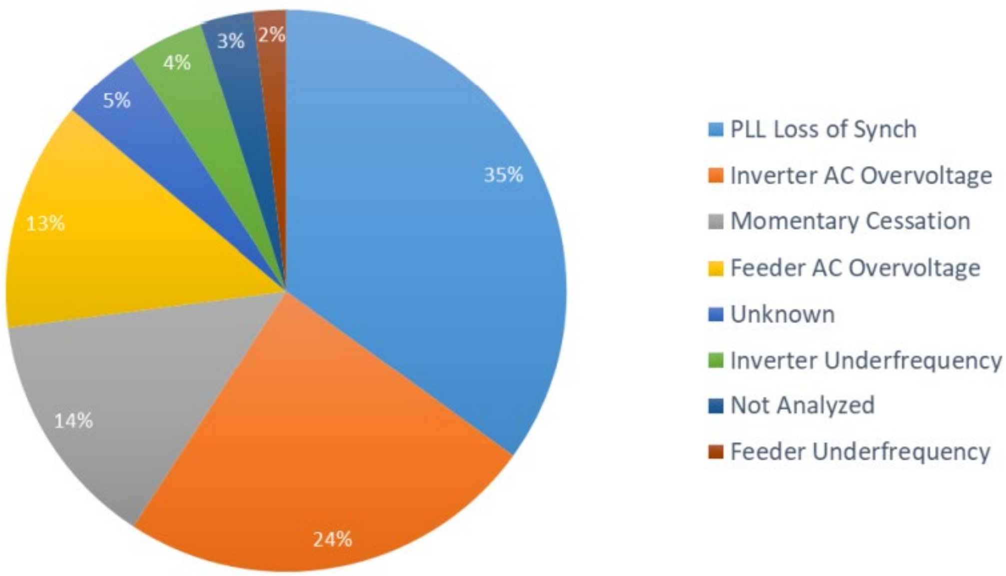

Table 2.1 of the Odessa Report also presents the various causes of inverter tripping identified in these events and whether these can be modeled in positive sequence simulations and EMT simulations.

[29] Odessa Report at p. 7. *See also, id.* at pp. 7-9 (describing these causes of power reduction in more detail).

Table 2.1: Solar PV Tripping and Modeling Capabilities and Practices		
Cause of Tripping	Can Be Accurately Modeled in Positive Sequence Simulations?	Can Be Accurately Modeled in EMT Simulations?
Erroneous frequency calculation	No	Yes
Instantaneous* ac overvoltage	No	Yes
PLL loss of synchronism	No	Yes
Phase jump tripping	Yes	Yes
DC reverse current	No	Yes
DC low voltage	No	Yes
AC overcurrent	No	Yes
Instantaneous* ac overvoltage—feeder protection	No	Yes
Measured underfrequency—feeder protection	No	No**

* Sub-cycle ** Due to very limited protective relay models in EMT today

The majority of tripping identified cannot be accurately simulated in positive sequence studies most commonly performed by transmission planners and planning coordinators, due to limitations of positive sequence simulations (RMS, quarter-cycle time step simulations) and modeling simplifications associated with the inverter and plant protection systems and controls. In contrast, these aspects of abnormal tripping and inverter behavior can be identified in EMT simulations.[30]

As the penetration of inverter-based resources grows across North America: (i) interconnecting resources should be required to provide accurate EMT models (and update those models as needed); and (ii) transmission service providers should be required to execute EMT studies to ensure reliable operation of the BPS, unless determined unnecessary in light of the particular facts and circumstances presented. EMT models should support reliable interconnection through their ability to reflect ride-through performance issues for normal balanced and

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30 Odessa Report at pp. 22-23.

unbalanced fault events. In light of potential for tripping, reduction of power, and possible intra-plant or inter-plant interactions, the ERO Enterprise proposes that the Commission revise its interconnection procedures to leverage EMT modeling and studies to support high penetrations of inverter-based resources moving forward. NERC and the Regional Entities understand that as higher levels of inverter-based resources integrate with the BPS, there is a delicate tradeoff between expedited interconnection and due diligence to address potential reliability concerns. Potential reliability concerns include, for example, ride-through performance, operation in low short-circuit strength network, and sub-synchronous resonance and control interactions. Modernizing the Commission's interconnection procedures to include EMT modeling and studies would be a just and reasonable, tailored, approach that balances speed and diligence, to help ensure efficient and reliable interconnection of resources under the changing resource mix.

B. Interconnection Agreements Should Incorporate Recommendations from NERC Reliability Guidelines Pertaining to Interconnecting Inverter-Based Resources.

The ERO Enterprise also proposes that the Commission update the *pro forma* interconnection agreements for newly interconnecting inverter-based resources to reflect recommendations in NERC Reliability Guidelines. In particular, NERC Reliability Guidelines developed through the IRPWG[31] of the Reliability and Security Technical Committee provide guidance addressing performance issues such as, phase lock loop ("PLL") loss of synchronism, ac overvoltage, high-speed recording and retention, time to restart, and other relevant topics. The following Reliability Guidelines are particularly instructive:[32]

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31 *See* NERC IRPWG Webpage, available at https://www.nerc.com/comm/RSTC/Pages/IRPWG.aspx (presenting work accomplished by the IRPWG).

32 Odessa Report at p. vi, 10.

- Reliability Guideline: BPS-Connected Inverter-Based Resource Performance[33]
- Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources[34]
- Reliability Guideline: Integrating Inverter-Based Resources into Low Short Circuit Strength Systems[35]
- Reliability Guideline: Performance, Modeling, and Simulations of BPS-Connected Battery Energy Storage Systems and Hybrid Power Plants[36]

ERO Enterprise disturbance reports advocate for more detailed monitoring data from BPS-connected inverter-based resources. Better monitoring capability should enable the ERO Enterprise, the transmission service provider, and the generator owner to work together to identify abnormal performance issues and develop effective mitigations for those issues to the extent necessary. NERC has had success working with a number of affected facility owners, when sufficient data is available, to help perform analysis, identify the relevant issue, and work collaboratively to develop a solution.

For example, NERC Reliability Guidelines recommend that newly interconnecting BPS-connected inverter-based resources 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 data from a digital relay or the plant-level controller (kHz resolution oscillography); and

33 Available at https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Inverter-Based_Resource_Performance_Guideline.pdf.

34 Available at https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf.

35 Available at https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Item_4a._Integrating%20_Inverter-Based_Resources_into_Low_Short_Circuit_Strength_Systems_-_2017-11-08-FINAL.pdf.

36 Available at https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_BESS_Hybrid_Performance_Modeling_Studies_.pdf.

- Inverter-level oscillography data to capture inverter terminal behavior, at least from some inverters within the plant (kHz resolution).

NERC disturbance reports explain how a lack of performance requirements for interconnected resources are contributing to performance issues. In addition, ERO Enterprise event analysis of the Odessa Disturbance discussed in Section IV.A. above revealed that although the IRPWG Reliability Guidelines cited above are among the most downloaded Guidelines produced by NERC and most widely used by industry, there has been incomplete adoption of their recommendations. This lack of comprehensive adoption contributes to inefficiencies during the interconnection process and contributes to gaps in performance by BPS-connected inverter-based resources which may impact multiple footprints and interconnections.

Therefore, the Odessa Report recommends consideration of modifications to NERC Reliability Standards to address potential risks associated with increasing integration of inverter-based resources and highlights the opportunity to similarly update the Commission's interconnection procedures and agreements. The ERO Enterprise's Odessa Report states that:

> [B]ased on the growing evidence and findings from these disturbance reports and efforts within the NERC [IRPWG], the recommended approach is for FERC to 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.[37]

As discussed in Section III above, the Commission's interconnection procedures and *pro forma* interconnection agreements occupy a key role within the regulatory framework in ensuring reliable interconnection and operation of new resources, and complement NERC Reliability Standards and Guidelines. As a result, NERC and the Regional Entities propose that the Commission incorporate NERC Reliability Guideline recommendations pertaining to inverter-based resources within *pro forma* interconnection agreements.

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[37] Odessa Report at p. vi.

C. The ERO Enterprise Supports Enhancements to Coordinated Transmission Planning.

The ANOPR requests comment on proposals to support better coordinated transmission planning. Two proposals include, for example, the Commission's requests for comment on: (i) an independent transmission monitor; and (ii) ways to manage speculative interconnection requests. With regard to an independent transmission monitor, the Commission "seek[s] comment on which potential measures the Commission could take to ensure that there is appropriate oversight over how new regional transmission facilities are identified and paid for."[38] The ANOPR later notes, "We seek comment on what role can or should an independent transmission monitor play in facilitating enhanced coordination."[39] Separately, the Commission highlights the challenges posed in transmission planning where entities submit multiple speculative requests. The ANOPR states, "Because of the changing interconnection landscape since Order No. 2003, the Commission's interconnection pricing policy, and in particular participant funding, now may result in a situation where interconnection customers have a financial incentive to submit multiple speculative projects."[40] The Commission subsequently, "encourage[s] commenters to discuss how to address concerns regarding uncertainty, including speculative projects, in planning for anticipated future generation."[41]

Without discussing matters associated with cost allocation, funding, or investments, the ERO Enterprise generally supports the Commission's exploration of avenues to enhance coordinated transmission planning. Coordination and better certainty around anticipated future

[38] ANOPR at P 163.

[39] *Id.* at P 171.

[40] *Id.* at P 41.

[41] *Id.* at P 67.

resource mix during transmission planning and interconnection studies could improve reliability assessments associated with the changing resource mix.

The ERO Enterprise appreciates the role that transmission planning may continue to have under a transforming grid which includes greater integration of inverter-based resources as well as what might be considered more emerging technologies, such as offshore wind powered generation, energy storage resources, and electric vehicle charging stations. Along these lines, the ERO Enterprise appreciates the goals aimed at better coordinated transmission planning articulated by the recently formed Joint Federal-State Task Force on Electric Transmission.

V. CONCLUSION

The ERO Enterprise looks forward to the Commission's continued efforts to modernize generator interconnection procedures, interconnection agreements, and transmission planning under an evolving resource mix with increasing integration of inverter-based resources. NERC and the Regional Entities take this opportunity to propose initial enhancements to the Commission's *pro forma* generator interconnection procedures and interconnection agreements which reflect the results of ERO Enterprise event analysis and assessments over the past several years. In addition, the ERO Enterprise appreciates the Commission's evaluation of measures, such as an interconnection-wide transmission monitor, to improve coordinated transmission planning.

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Date: October 12, 2021

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Attachment 1

Odessa Report
September 2021

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Odessa Disturbance

Texas Events: May 9, 2021 and June 26, 2021
Joint NERC and Texas RE Staff Report

September 2021

RELIABILITY | RESILIENCE | SECURITY




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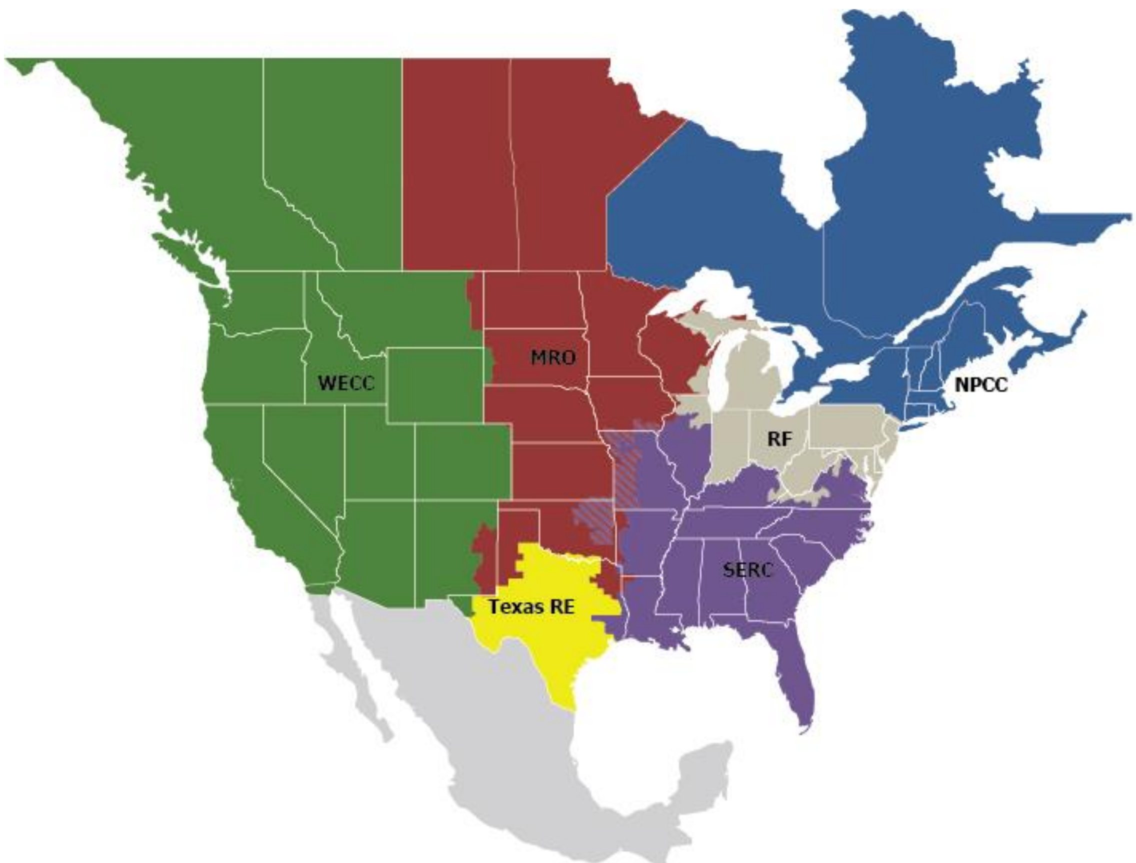
Preface

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

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one RE 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

This report contains the ERO analysis of the BPS disturbance that occurred in Texas on May 9, 2021, referred to herein as the "Odessa Disturbance." While the ERO has analyzed multiple similar events in California, this is the first disturbance involving a widespread reduction of solar photovoltaic (PV) resource power output observed in the Texas Interconnection. The event involved solar PV facilities across a large geographic area of up to 200 miles away from the location of the initiating event. The Electric Reliability Council of Texas (ERCOT) provided Texas RE and NERC with a brief report as the disturbance was categorized as a Category 1i event.[1]

In coordination with ERCOT, NERC and Texas RE gathered additional information from affected Generator Owners (GO) whose facilities experienced a notable reduction in power during the event. In addition, NERC and Texas RE worked collaboratively with ERCOT and the impacted transmission service providers to gather additional information and corroborate incoming data with other sources. The purpose of this report is to document the analysis of the disturbance and provide key findings and recommendations for industry.

The **Introduction** provides details regarding the initiating event, performance of the BPS-connected solar PV fleet during the event, and additional details around the event. **Chapter 1** provides a detailed review of the key findings and establishes the supporting evidence and technical basis for the recommendations that are laid out in **Chapter 3**. In addition, **Chapter 2** focuses on modeling and study findings that support the recommendations in **Chapter 3**. **Appendix B** provides a detailed analysis of the affected facilities. **Appendix C** describes analysis of a smaller event that subsequently occurred on June 26, resulting in solar PV resources tripping.

Description of Disturbance

At 11:21 a.m. Central time on May 9, 2021, a single-line-to-ground (Phase A) fault occurred on a generator step-up (GSU) transformer at a combined-cycle power plant near Odessa, Texas. The fault was caused by a failed surge arrester at the combustion turbine (CT) during startup for testing. The circuit breaker for CT1 operated and cleared the fault within three cycles and the #2 unit experienced a partial trip followed by a run back for a total loss of 192 MW. The fault caused voltages in the area to drop to 0.72 pu at the 345 kV connecting station for the generation facility, 0.84 pu around Fort Stockton at a 138 kV station, and as low as 0.54 pu at a 69 kV bus near Alpine, Texas. Voltage in the area recovered to near predisturbance levels very quickly (within a couple electrical cycles) after the fault cleared.

In addition to the generation loss at the combined cycle plant, a number of solar PV and wind plants connected to the BPS also exhibited active power reductions caused by the fault event. None of the affected inverter-based resources were tripped consequentially by the fault itself. Rather, all reductions were due to inverter-level or feeder-level tripping or control system behavior within the resources. Active power reductions by resource type are shown in **Table ES.1**.

Table ES.1: Reductions of Output by Unit Type

Plant Type	Reduction [MW]
Combined Cycle Plant	192
Solar PV Plants	1,112
Wind Plants	36
Total	**1,340**

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

Key Findings and Recommendations

Refer to **Chapter 1** and **Chapter 2** for key findings from the event analysis and refer to **Chapter 3** for specific recommendation outlined throughout this report. The following are high-level recommendations from the report:[2]

- **Industry Not Sufficiently Implementing Recommendations from NERC Reliability Guidelines—Further Action Is Needed:** Conversations with GOs and Generator Operators (GOPs) of affected solar PV facilities and ERCOT[3] have highlighted that industry is aware of the guidance materials published by NERC yet are not comprehensively adopting the recommendation contained in those materials. In most cases, the GO and GOP are aware of the guidelines that have been published but are not following the guidance. Issues (such as phase lock loop (PLL) loss of synchronism, ac overvoltage, high-speed recording and retention, time to restart, and many other relevant topics) are all covered in the guidelines. TOs, Transmission Planners (TPs), and Planning Coordinators (PCs) have considered the guideline content and have adopted some recommendations; however, the guidelines are not being widely and comprehensively adopted. This leaves gaps in their implementation and has led to gaps in performance from BPS-connected inverter-based resources across multiple footprints and Interconnections.
- **Significant Updates and Improvements Needed to the FERC Generator Interconnection Agreements:** All of the performance issues identified in the NERC disturbance reports stem from a lack of performance requirements. In most cases, the identified affected facilities are performing in an unreliable manner, but there are either no or unclear performance requirements for how the resource is obligated to perform. Issues (e.g., PLL loss of synchronism, sub-cycle transient ac overvoltage, frequency control interactions) are not specifically addressed in the NERC Reliability Standards. The NERC guidelines highlight that TOs should establish detailed performance requirements, but those recommendations are not being implemented. At this point, based on the growing evidence and findings from these disturbance reports and efforts within the NERC Inverter-Based Resource Performance Working Group (IRPWG), the recommended approach is for FERC to 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.[4] 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).
- **Improvements to NERC Reliability Standards Needed to Address Systemic Issues with Inverter-Based Resources:** Ongoing analysis of abnormal performance of BPS-connected solar PV facilities continues to highlight gaps in the NERC Reliability Standards that need to be addressed by industry. Refer to **Chapter 3** for more detailed recommendations. However, the following should be improved at a high level:
  - **Improvements to Performance-Based Requirements:** A number of NERC Reliability Standards require documentation that demonstrates compliance with the requirement (e.g., PRC-024-3); however, they do not directly specify that the performance must be met. Therefore, any enforcement and auditing of these standards becomes poorly-defined and ineffective. For example, PRC-024-3 requires documentation that the facilities voltage and frequency protective relaying is set outside the "no trip zone" curves. Vendors, GOs, and GOPs gather documentation to demonstrate this, but facilities continue to trip for point of interconnection (POI) voltages within the "no trip zone" in real-time. Those facilities are audited on their documentation, not on their performance. This has led to ongoing abnormal and inadequate performance from BPS-connected resources and should be addressed comprehensively with standards revisions.

[2] As well as in the context of all past solar PV-related disturbances analyzed by NERC.

[3] Along with discussions within the NERC IRPWG and with GOs, GOPs, TOs, TPs, PCs, BAs, and RCs in past disturbance analyses.

[4] ERCOT is also strongly encouraged to update their corresponding regional rules (e.g., ERCOT protocols).

- **Performance Assessment and Mitigation:** There is presently no NERC Reliability Standard that obligates or that gives appropriate authority for Reliability Coordinators (RCs), TOPs, or Balancing Authorities (BAs) to assess the performance of an interconnected facility, identify abnormalities, and execute corrective actions to eliminate this abnormal performance. In most cases, the systemic underlying issue is that performance requirements are not established or are not clear. The lack of performance validation (validating that the facility is performing as expected) leads to these large-scale and widespread events 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.
- **Ride-Through Standard In Lieu Of PRC-024-3:** The PRC-024 standard is not effectively or efficiently addressing a systemic reliability gap of inverter-based resources tripping for POI voltages within the "no trip zone" curves. Updates were recently made to PRC-024-3 to add clarity to the expectations; however, newly interconnecting resources are being installed with hidden protections within the inverter that will trip for local inverter terminal conditions regardless of POI voltage conditions. This has been shown to be a systemic issue in nearly all past disturbances analyzed and is not expected to be addressed in existing facilities since these limits are hard-coded into the inverters.[5] Furthermore, PLL loss of synchronism, dc reverse current, wind turbine failures,[6] and many other issues exist that are not directly related to voltage and frequency protection. Lastly, facilities most commonly have their voltage and frequency protection set "for compliance with PRC-024" rather than based on equipment ratings within the facility. Multiple GOs/GOPs have been unable to identify what is actually being protected and have stated that they are set based on compliance. This is a misinterpretation of the standard and has led to degraded performance due to unnecessary tripping events. Based on the growing evidence and ongoing work to investigate poorly performing resources during fault events, NERC recommends that a comprehensive generator ride-through standard be implemented either as a NERC Reliability Standard or as part of the FERC Generator Interconnection Agreement.
- **Analysis and Reporting of Inverter-Based Resource Reductions:** All of the abnormal performance analyzed by NERC and the Regional Entities are not presently being reported to NERC (i.e., as any form of a misoperation). However, the performance for these affected facilities is unreliable and unexpected for these types of faults. There are no standards where these types of issues must be reported to facilitate industry analysis of the performance and/or seek mitigating actions proactively or preemptively. This has led to underlying performance issues remaining unknown until they are systemic across a large number of resources and subsequently investigated by the ERO Enterprise. This has inherently led to degraded system performance and should be mitigated by requiring GOs and GOPs of generating resources to report abnormal performance issues to the RC, TOP, and BA in a timely manner. This should include unexpected tripping or controls that reduce power output at inverter-based resources by a pre-determined threshold amount (e.g., 75 MVA or 105 of inverters at a site). Not all inverter tripping necessarily needs to be reported; however, large-scale tripping (or sustained reductions in power) needs to be reported. NERC should ensure that abnormal power reductions from inverter-based resources (e.g., tripping, momentary cessation, abnormal controls) are analyzed, similar to how misoperations are reported in PRC-004, and reported in a timely manner.
- **Electromagnetic Transient Modeling and Studies for All Newly Interconnecting Inverter-Based Resources:** All the performance issues identified in this report and all past NERC disturbance reports involving solar PV resources should have been identified during interconnection studies and addressed as a mitigating measure prior to the resource being interconnected. All forms of tripping or abnormal

[5] This is a significant area of concern for one solar PV inverter equipment manufacturer, whose facilities continue to trip off-line for normal BPS fault events due to voltage-related issues.

[6] These include, but are not limited to: crowbar failures, turbine vibration trips, and universal power supply failures.

performance can be modeled in EMT simulations and should be studied during the interconnection study process. However, these studies are not widely conducted. Conventional positive sequence dynamic simulations do not model inverter-based resources with enough resolution to represent all the different controls and protection that could cause the plant to trip, disconnect, or abnormally perform. Therefore, these performance issues are going unnoticed until after the time of interconnection. At that time, the TO, TOP, RC, TP, and PC have limited capability to address these abnormal performance issues after the interconnection agreements have been signed. Industry has expressed significant concerns with these types of issues after-the-fact. However, these issues should have been studied prior to interconnection and are a result of insufficient studies conducted at the time of interconnection. EMT models should be provided for all newly interconnecting inverter-based resources and EMT studies should be conducted to ensure that performance requirements (once established) are being sufficiently met.

Introduction

Background

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

- Blue Cut Fire disturbance[7] (August 16, 2016)
- Canyon 2 Fire disturbance[8] (October 9, 2017)
- Palmdale Roost and Angeles Forest disturbances[9] (April 20, 2018, and May 11, 2018, respectively)
- San Fernando disturbance[10] (July 7, 2020)

Following the Blue Cut Fire and Canyon 2 Fire disturbances, NERC issued alerts[11, 12] 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 IRPWG 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)[13]
- *Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources* (September 2019)[14]

Lastly, the Institute of Electrical and Electronics Engineers (IEEE) Standards Association Project 2800 (IEEE P2800)[15] is underway to "establish recommended interconnection capability and performance criteria for inverter-based resources interconnected with transmission and networked sub-transmission systems." IEEE P2800 is expected to ensure that future interconnections of BPS-connected inverter-based resources are designed and installed with the equipment and functional performance capabilities to mitigate some or all of the issues identified in past ERO disturbance analyses.

Description of Analysis Process

The Texas RE Event Analysis and Situational Awareness team identified a grid disturbance by using their situational awareness tools that alerted them to a low frequency (59.817 Hz) and the deployment of operational reserves in response to the low frequency. NERC Situational Awareness staff also detected the disturbance with the Frequency

7 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.
8 Canyon 2 Fire Disturbance report, February 2018: https://www.nerc.com/pa/rrm/ea/Pages/October-9-2017-Canyon-2-Fire-Disturbance-Report.aspx.
9 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
10 San Fernando Disturbance report, November 2020: https://www.nerc.com/pa/rrm/ea/Pages/July_2020_San_Fernando_Disturbance_Report.aspx
11 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.
12 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.
13 *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance*: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf
14 *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
15 IEEE P2800: https://standards.ieee.org/project/2800.html

Monitoring Network FNET monitoring tool. Texas RE analyzed the solar PV output as part of its situational awareness monitoring and noted a large reduction of solar PV resources for this disturbance. Texas RE reached out to ERCOT that was already analyzing this grid disturbance. ERCOT confirmed the solar generation loss coincided with a transmission fault in the area. Initial correspondence identified that this event may meet the NERC Event Analysis Program Category 1i criteria. ERCOT was very responsive throughout, confirmed observations made by the Texas RE, and initiated requests for information (RFI) to the involved entities. An interim ERCOT report was provided about seven weeks following the disturbance. The ERCOT report identified over 30 individual facilities that experienced a change in active power output due to the fault.

NERC, Texas RE, and ERCOT determined that follow-up activities were needed to further understand the root causes of abnormal performance from a large number of resources after reviewing responses from the RFI. NERC and Texas RE formed a small team to work closely with ERCOT and engage with the affected GOs for facilities that reduced power output by more than 10 MW. Follow-up coordination calls were held with all impacted GOs to discuss the responses to the initial ERCOT RFI and discuss any questions pertaining to resource performance during this event.

NERC and Texas RE are publishing this report to document the key findings and recommendations from the analysis of this disturbance.

Predisturbance Operating Conditions

Figure I.1 shows the total ERCOT solar PV profile for May 9, 2021. The disturbance occurred at 11:21:36 a.m. Central time when solar was still ramping up. The disturbance is clearly visible in the total solar PV power output; however, the magnitude of reduction is not the primary concern. The unexpected reduction of power output across many solar PV resources is the primary focus of this analysis. Most of the affected facilities were located in the West Texas area with one affected facility near the Texas Panhandle.

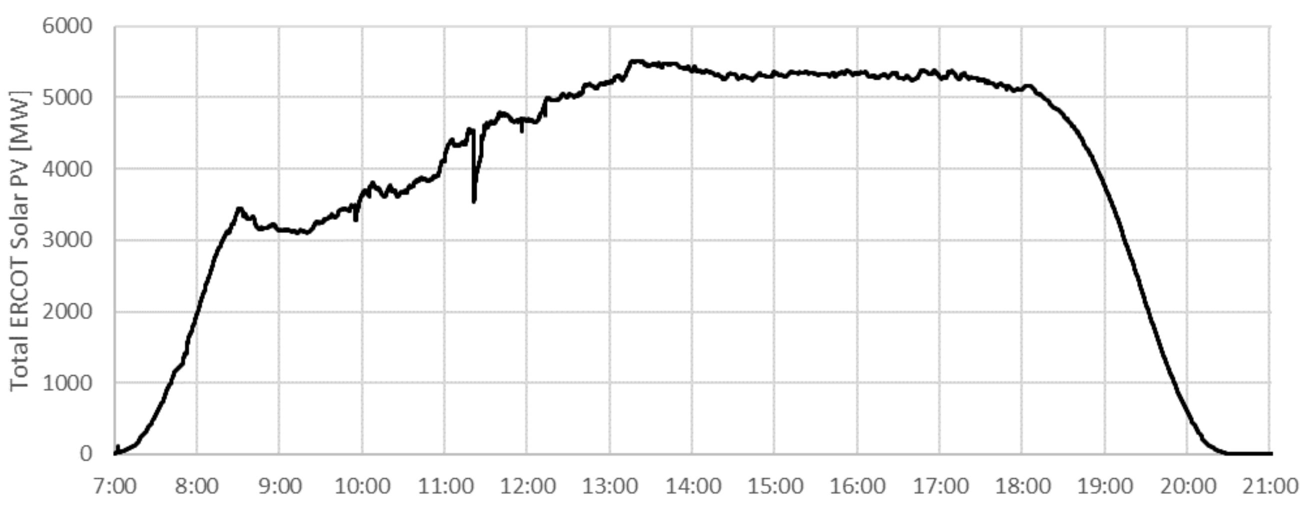


Figure I.1: ERCOT Solar PV Profile for May 9, 2021

Wind and solar PV resources comprised 34% and 9% of the total generation prior to the disturbance, respectively (see Table I.1). These predisturbance operating conditions illustrate the significant amount of wind and increasing capacity of solar PV resources in the ERCOT footprint. The magnitude of reduction highlights the importance of ensuring that all BPS-connected inverter-based resources are operating in a manner that ensures reliable operation of the BPS. At the time of the event, the ERCOT footprint included about 7,200 MW of solar PV resources with an additional nearly 790 MW in the commissioning process. As of the end of August 2021, there is now 8,900 MW of solar PV resources in the ERCOT footprint and an additional 1,000 MW in the commissioning process. There is also around 25,000 MW of solar PV resources with signed interconnection agreements in the ERCOT generation interconnection queue between now and 2023.

Table I.1: Predisturbance Resource Mix		
BPS Operating Characteristic	**MW**	**%**
Internal Net Demand	47,434	-
Solar PV Output	4,533	9%
Wind Output	15,952	34%
Synchronous Generation	26,383	56%

*ERCOT was importing 566 MW through dc ties

Figure I.2 shows the share of BPS-connected solar PV resources by inverter original equipment manufacturer. The vast majority of plants involved in this disturbance were from the four largest inverter manufacturers by ERCOT market share.

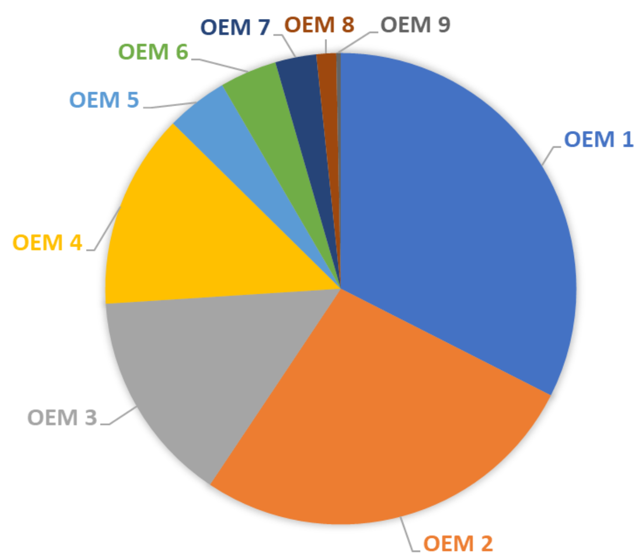


Figure I.2: Capacity Share of BPS-Connected Solar PV Resources by Inverter Original Equipment Manufacturer

Fault Analysis

An A-phase-to-ground fault occurred on a CT GSU transformer at a combined-cycle power plant during turbine startup for testing. The fault was caused by a failed surge arrestor. Protective relaying cleared the fault on the 18/345 kV GSU in three cycles (see Figure I.3). At the combined cycle plant where the fault occurred, the faulted CT was tripped off-line, consequentially, by protective relay operation. In addition, the neighboring unit at the facility experienced a natural gas turbine runback and consequent steam turbine power reduction. The total loss of generation at the plant was 192 MW.

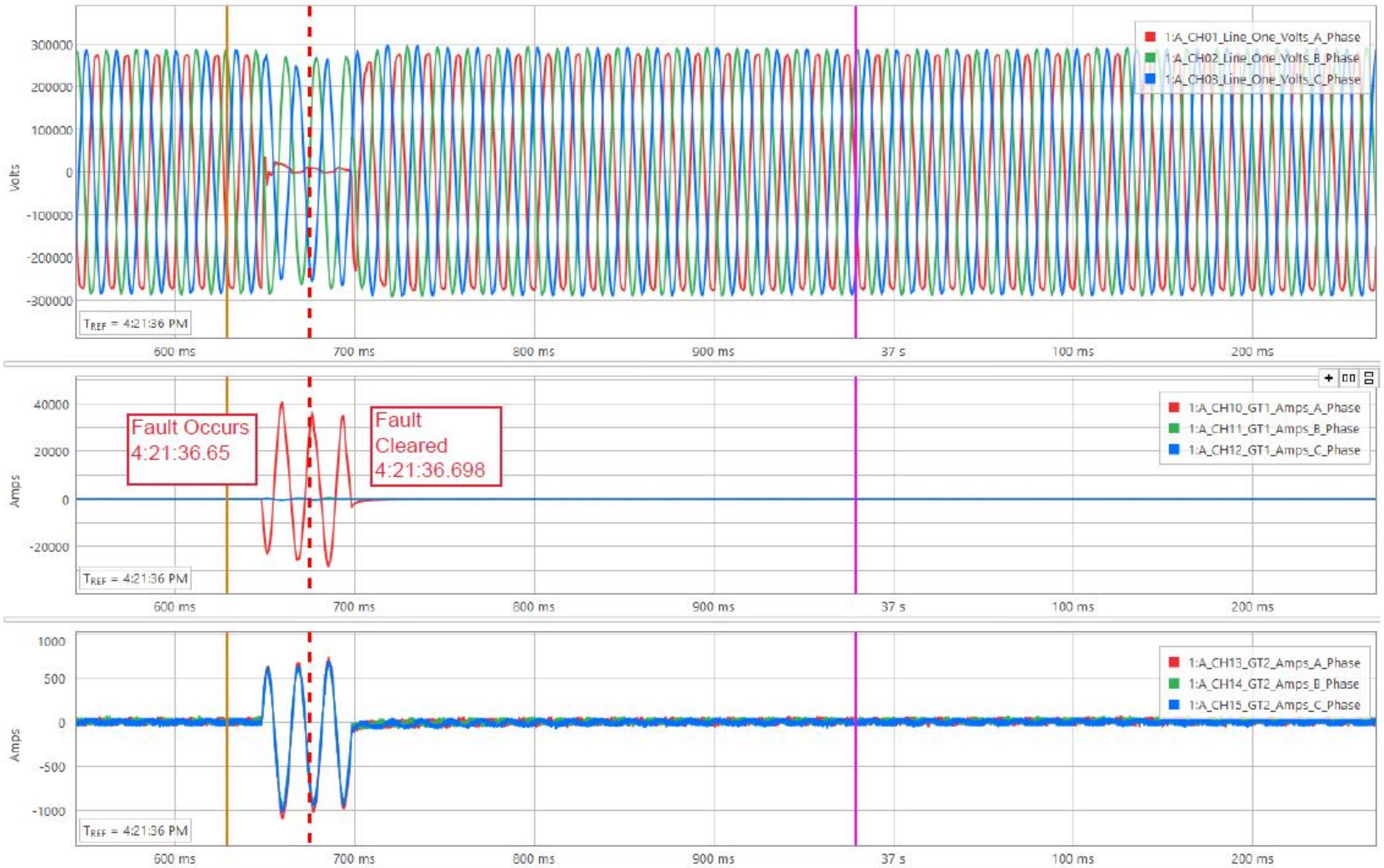


Figure I.3: A-Phase-to-Ground Fault on Combined Cycle Combustion Turbine GSU

As a result of the fault, voltages in the area were depressed on the 345 kV, 138 kV, and 69 kV networks during the on-fault conditions. The perturbation in system voltages and phase angles resulted in widespread reduction of BPS-connected solar PV resources as well as the reduction of some wind power plants in the area. No solar PV or wind resources were de-energized as a direct consequence of protective relaying removing the faulted BPS element from service. Rather, controls and protection within the plant caused the reduction in output for all affected inverter-based facilities.

Location of Disturbance and Affected Facilities

The fault event occurred in the Odessa, Texas, within the ERCOT footprint. Solar PV and wind facilities that were identified as abnormally responding to the event were located up to 200 miles away from the fault location. **Figure I.4** shows the geographic location of the fault (red) as well as the affected solar PV facilities (blue) and wind facilities (orange).

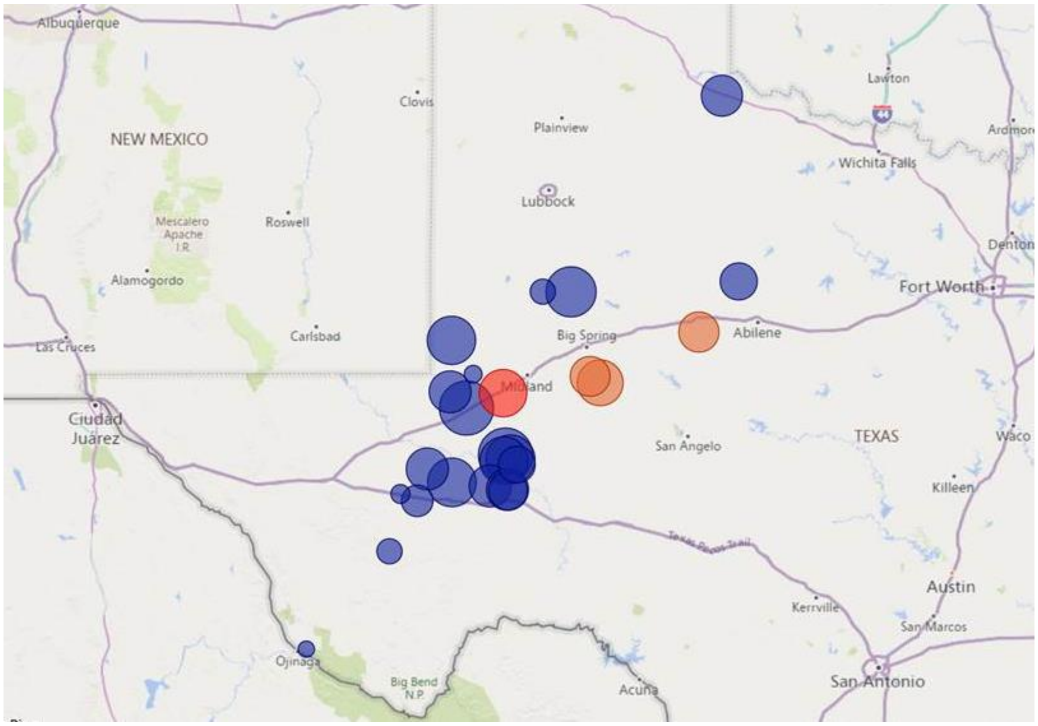


Figure I.4: Map of the Fault Location and Affected Facilities

Figure I.5 shows the reduction in solar PV resources reported by ERCOT supervisory control and data acquisition (SCADA) data. As with the past disturbance reports involving fault-induced solar PV reductions, the size of the active power reduction is determined using SCADA data from the affected BA (i.e., ERCOT) in addition to analyzing data provided by individual facilities. Due to SCADA scan rate differences, different metering points, different accounting practices, and other factors, small discrepancies may exist between the values; however, the reductions in solar PV output provide a relative indicator of the impact of these reductions compared to past disturbances.

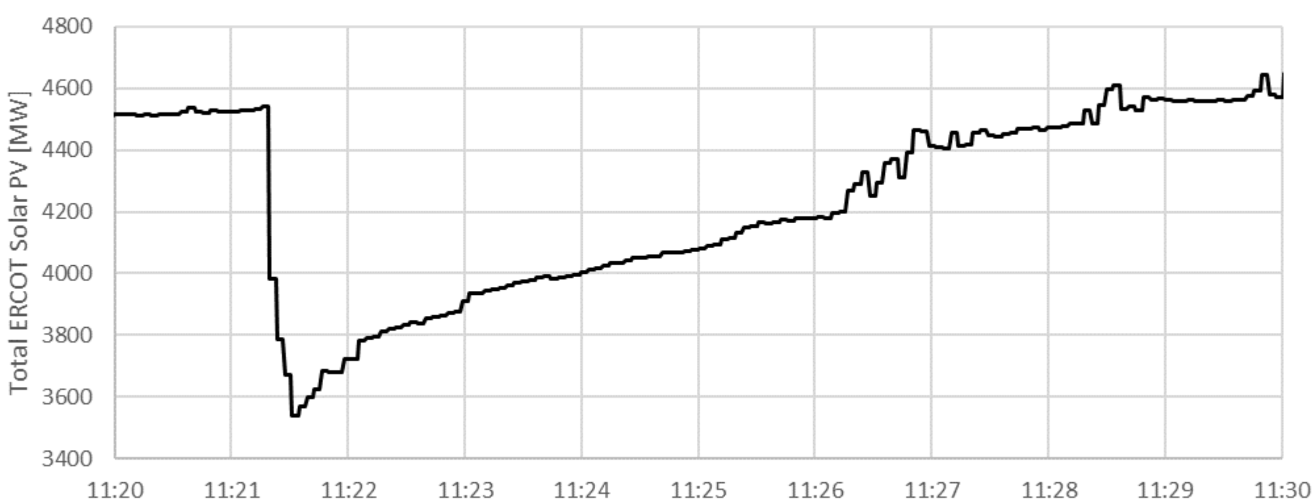


Figure I.5: ERCOT BPS-Connected Solar PV during Disturbance [Source: ERCOT]

NERC has identified changes in net demand during BPS fault events in the Angeles Forest, Palmdale Roost, and San Fernando disturbances. These changes in net demand were attributed to the tripping of distributed energy resources.[16] For this fault event, the analysis team reviewed net load quantities, particularly any possible net load increases that could be attributed to DER tripping, and did not identify any abnormalities in load response for a BPS fault.

Lastly, **Figure I.6** shows system frequency measurements for the event. Pre-disturbance frequency was very close to 60 Hz and the frequency nadir occurred at around 59.805 Hz at 3.3 seconds after the initiation of the event.

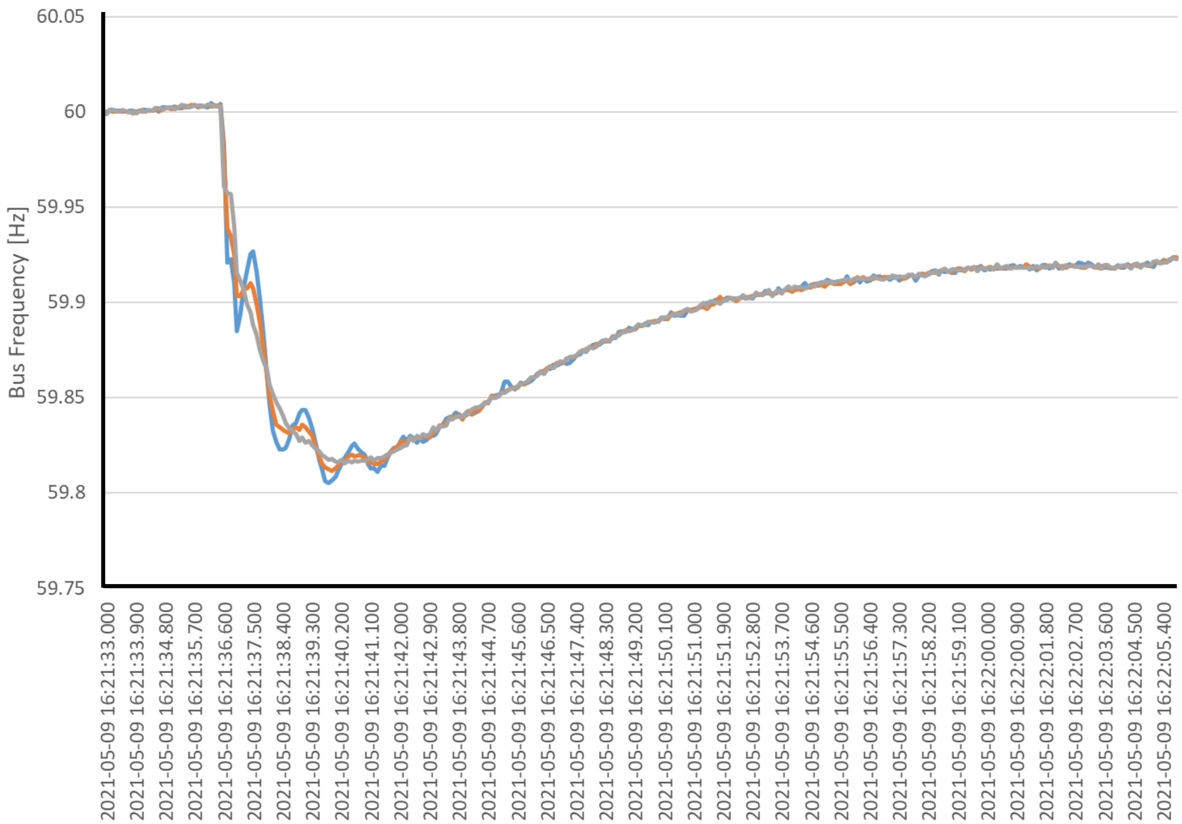


Figure I.6: System Frequency during Event [Source: UTK/ORNL]

[16] *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

Chapter 1: Detailed Findings from Disturbance Analysis

Texas RE and ERCOT requested data from all affected solar PV generating facilities, and this analysis focused specifically on those that abnormally changed active power output greater than 10 MW. The primary causes of active power reduction and inverter characteristics were gathered at each site. This chapter describes the findings from the analysis.

A significant number of solar PV resources responded to the BPS fault event in an abnormal manner. Many of the solar PV resources are large BES facilities with affected resources over a significantly large geographic area within the Texas footprint (over 200 miles away). **Figure 1.1** and **Table 1.1** show the causes of reduction including both momentary cessation and tripping within the facilities.

Table 1.1: Causes of Reduction

Cause of Reduction	Reduction [MW]
PLL Loss of Synchronism	389
Inverter AC Overvoltage	269
Momentary Cessation	153
Feeder AC Overvoltage	147
Unknown	51
Inverter Underfrequency	48
Not Analyzed	34
Feeder Underfrequency	21

* See explanation below.

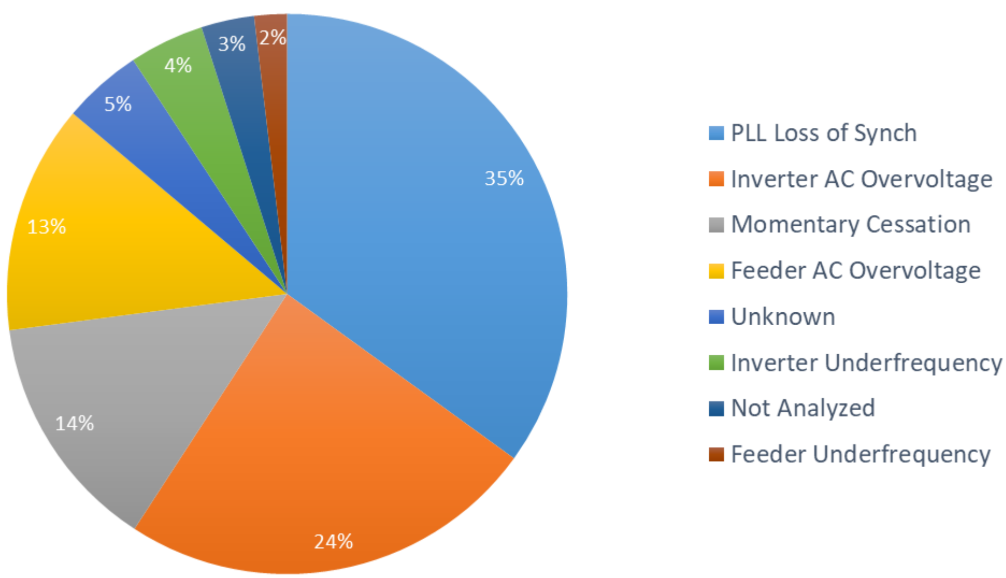


Figure 1.1: Causes of Solar PV Reduction

The following briefly describes causes of power reduction:

- **PLL Loss of Synchronism (389 MW):** PLL loss of synchronism was the largest contributor to the reduction of solar PV output in this event. Two large BES facilities reduced output by 239 MW and 150 MW. This cause of tripping is specifically attributable to one inverter manufacturer and has been identified in multiple prior events analyzed by NERC. It is a systemic concern for facilities with this inverter type. Existing facilities are likely set with inverters that will trip when their voltage phase angle experiences a shift during fault events (i.e., 10 degree vector shift); the inverters issue a fault code and shut down. This trip function is completely separate from any voltage-related tripping most commonly referred to as "ride through settings." There is a default 5-minute restart timer once the fault occurs before the inverter will return to operation. The equipment manufacturer has stated that they are removing this trip function from inverters at existing facilities only upon request and are shipping newer inverters with this function disabled. The equipment manufacturer has stated that other protective functions in the inverter will be adequate to protect it from conditions that would cause equipment damage. The inverter manufacturer has also stated that the 5-minute restart timer is a default setting for existing inverters; however, newer inverters are being shipped with a 5 second restart timer if the trip is still enabled.
- **Inverter-Level Instantaneous AC Overvoltage (269 MW):** A lack of inverter-level oscillography data significantly limits the ability to conduct analysis on this type of tripping. The inverters log trip codes attributed to ac overvoltage; however, oscillography data is generally available only at the POI and not at the individual inverters. In most cases, the POI voltage is within the PRC-024-3 voltage "no trip" curves. Furthermore, this trip mechanism is using instantaneous peak measurements at 1.3 pu rather than using RMS fundamental frequency measurements, as stated in the standard. So the inverters are much more prone to tripping on those instantaneous spikes that occur on the order of a few milliseconds during fault events. PRC-024-3 is not an adequate protection to ensure BPS-connected inverter-based resources do not trip for normal BPS fault events. This form of tripping has been identified in nearly all large-scale solar PV tripping events analyzed by NERC. Plant POI voltage conditions are not a suitable criteria for establishing trip settings within the inverter. Furthermore, instantaneous trip thresholds either need to be modified to reflect those recommended in the NERC reliability guidelines or some time delay for tripping needs to be established. Lastly, it appears that some plants experience reactive power injections post-fault that exacerbate these types of tripping issues.
- **Momentary Cessation with Plant-Level Ramp Rate Interactions (153 MW):** One plant includes legacy inverters that use momentary cessation when the voltage falls below 0.9 pu.[17] The inverters should recover back to predisturbance output relatively quickly when voltage recovers; however, the plant-level controllers interacted with the active power recovery and slowed the recovery to the limits established for meeting BA ramping requirements in this case. This is not the appropriate application of these limits and is negatively impacting system stability nor is meeting the recommended performance recommendations in the NERC reliability guidelines.
- **Feeder-Level Instantaneous AC Overvoltage (147 MW):** One facility had all feeder-level protection trip on instantaneous phase ac overvoltage 59 targets set at 1.2 pu. These settings are directly on the PRC-024-3 curves. The review team questioned the need for this protection on the feeders and the plant owner/operator was unable to clarify what these feeder-level voltage relays are protecting.
- **Unknown Cause (51 MW):** One facility had insufficient data to perform any useful root cause analysis; the cause of reduction remains unknown.
- **Inverter-Level Underfrequency (48 MW):** One facility had all inverters trip, and the majority of the inverters in the facility recorded tripping on measured "grid underfrequency" conditions; however, frequency did not

[17] These inverters that entered momentary cessation also had alarms stating PLL loss of synchronism was an issue. However, it was determined that the momentary cessation trigger was the primary cause of reduction.

fall outside of the PRC-024-3 boundaries, so these inverters likely erroneously tripped on a poorly measured or calculated frequency signal.

- **Not Analyzed (34 MW):** A total of 34 MW of solar PV facilities reduced power output yet were below the threshold for a detailed review by NERC and Texas RE.
- **Feeder Underfrequency (21 MW):** One plant had one feeder-level relay operate on underfrequency, tripping 21 MW of inverters. The relay manufacturer indicated that the relay performs the frequency measurement over a 3 cycle window. Analyzing the waveforms during the disturbance from the relay, it was determined that the relay measured the frequency correctly over the 3 cycle window. However, the manufacturer recommends a minimum time delay for frequency tripping to be 5 cycles. The relay was set for zero delay. This reinforces previous disturbance reports recommendations to not use an instantaneous trip setting for frequency protection.

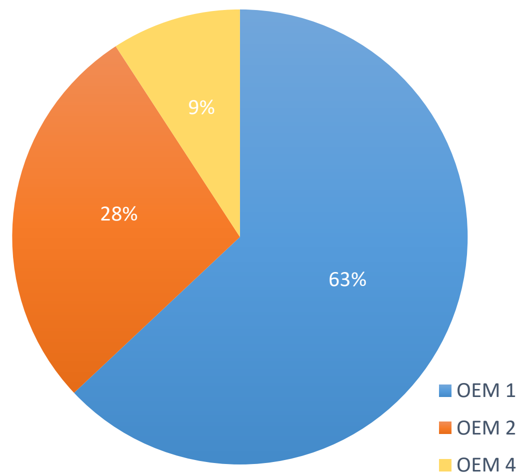


Figure 1.2: Inverter Manufacturers Involved in Disturbance

Figure 1.2 shows the share of inverter manufacturers involved in the solar PV reductions. Only three different types of inverter manufacturers were involved in this event. The inverter manufacturer with only 9% of the total reduction is no longer in the business of manufacturing large-scale inverters. The other two manufacturers are actively involved in the production of inverters for large-scale solar PV power plants.

The following sections of this chapter provide technical details behind these causes of solar PV reduction and any other abnormal behavior observed during this event.

Gaps in Plant Performance Analysis and Performance Requirements

The majority of plant owner/operators are not conducting regular analysis of abnormal performance of inverters or plant-level controls within their facility. In most cases, the plant owner/operator is unaware of the abnormalities in plant performance to grid fault events until an RFI is administered and follow-up discussions take place. Performance analysis is critical to proactively identifying anomalous behavior both within the plant and by the TOP or RC on a wider basis. Responses in multiple RFIs highlighted lack of understanding of inverter response and controls to grid fault events.

There are no regulations that require any type of performance analysis, and there is only indirect ability for the TOP or RC to seek corrections to any abnormal performance issues identified. Many of the TOs, in coordination with their TP, PC, TOP, and RC, are still in the process of improving their interconnection requirements per NERC FAC-001-3. Discussions between NERC and various independent system operators/regional transmission organizations (ISO/RTOs) have identified gaps in established performance requirements that would not capture the abnormal behavior trends observed and documented in NERC disturbance report and NERC reliability guidelines.[18] Through the analysis of this event and follow-up activities with plant owner/operators, it is clear that industry is not adhering to the recommendations within these guidelines to the extent needed to mitigate known reliability issues; other tactics are needed to properly ensure reliable operation of the BPS with such a rapidly changing resource mix.

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

The vast majority of plants stated that they are not performing any mitigating actions after the solicitation of the RFI nor are any mitigating actions planned in the future (ERCOT will be following up with all affected facilities). Furthermore, multiple plant owner/operators stated that their facility "operated as designed" for grid fault events, clearly illustrating limited understanding of the expected performance of these facilities. This is a systemic issue that NERC has identified in every event analyzed to-date that involved solar PV resources.

Key Finding
In many cases, industry is not proactively identifying abnormal performance issues of inverter-based resources. Furthermore, the recommendations outlined in NERC reliability guidelines are not being adequately adopted to ensure reliable operation of the BPS with a changing resource mix to inverter-based technology. Plants stated that no mitigating actions are being done (or planned) to improve the performance of the resources involved in the event.

Improved Monitoring Data yet Still Challenges to Identify Root Causes

Each affected solar PV facility was requested to provide plant- and inverter-level electrical measurement data at the highest resolution available. This included the following quantities at a minimum: 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. Per the NERC reliability guidelines, each BPS-connected inverter-based resource should 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)

Section 6.1 and Section 8 Attachment M of the ERCOT Operating Guides identify disturbance monitoring requirements.[19] Some requirements may not be fully effective until July 1, 2022. The following are possible improvements that could be made to the ERCOT guides to ensure effective data collection:

- Triggering conditions (Section 6.1.2.1(1)(a)) should consider adding phase over-voltage thresholds.
- Limits on generating resource MVA (i.e., 100 MVA) may need to be reduced to capture smaller inverter-based resources experiencing ride-through issues.
- Retention and reporting requirements may need to include filtered .CEV file format (or similar) in addition to CSV/COMTRADE.
- The location of the measurements for generators (e.g., high side of main power transformer, inverter terminals) may need to be more clearly specified.
- Inverter oscillography should be required at newly installed inverter-based resources, at least at some inverters within the facility.

[19] http://www.ercot.com/mktrules/guides/noperating/current

The review team tracked the highest resolution of the data provided from each facility, and this information is provided in **Appendix B** (**Table B.1**). The following observations are made based on the data available for each facility and the analysis conducted by the review team:

- A number of facilities captured high resolution DFR data at the point of interconnection that was extremely valuable to perform analysis of plant performance and coordinate with plant owner/operators to identify possible causes of any abnormal response. DFR data is essential to understand the unique operational characteristics and response of inverter-based resources; PMU data does not record electrical quantities at a high enough sampling rate to sufficiently capture electrical quantities for root cause analysis.
- Many plants have SCADA recordings at a resolution of 1-second data. This appears to be a common industry practice and is strongly recommended by NERC and the review team. Data at lower resolution misses key performance characteristics that are useful for event analysis and performance validation.
- Only one facility was able to provide oscillography data from individual inverters that tripped during this event. This data was extremely useful in understanding the conditioned experienced at the inverter terminals that resulted in inverters tripping throughout the facility. Without this information, it is essentially impossible to fully understand what the individual inverters may have experienced at their terminals as compared to the POI conditions. This is the most valuable data available and provides the most useful insights for inverter-level tripping and performance. The NERC reliability guidelines strongly encourage inverter-based resources to have this type of monitoring data to support event analysis and performance improvement. Equipment manufacturers have stated that "minor faults" (such as ac overvoltage) are not set by default to trigger oscillography data; however, they can be configured to capture oscillography data if requested by the plant owner. This is not a mandatory requirement and therefore the vast majority of GOs will not enable this feature.
- The recommendations set forth in the NERC reliability guidelines related to monitoring data for inverter-based resources are not being implemented by GOs of newly interconnecting inverter-based resources. Furthermore, TOs (in coordination with their RC and TOP) are not establishing interconnection requirements based on the recommendations laid out for improving those requirements for these resources. Specifically, the monitoring capability at solar PV facilities is not comprehensive enough to effectively perform root cause analysis and is leading to unreliable operation of these resources due to the inability to effectively develop mitigations for abnormal performance.

Key Finding

Data provided by affected solar PV facilities for this event is significantly improved from past events analyzed by NERC and the Regional Entities. This is likely due to ERCOT establishing some monitoring and measurement requirements in its interconnection requirements and market rules. 1-second SCADA data resolution appears to be a common industry practice and helps aid in initial analysis. PMU data at the POI is also helpful for overall plant analysis; however, DFR data at the POI is essential for performing plant-level event analysis. Only one plant provided inverter-level oscillography data which significantly limited the ability of the review team to conduct adequate root cause analysis. TOs are not improving interconnection requirements based on the recommendations set forth in the NERC reliability guidelines.

PLL Loss of Synchronism Tripping Continues

PLL loss of synchronism resulted in the largest reduction of solar PV output in this event (two large plants tripped entirely for this reason). One of the affected facilities was also the furthest plant from the fault identified in this event, showing the potential widespread nature of this cause of tripping.

The NERC reliability guidelines[20] published by IRPWG have provided clear recommendations for addressing PLL loss of synchronism as it has been identified in multiple NERC-analyzed events. The initial guideline published by IRPWG stated that "PLL loss of synchronism should not result in inverter tripping" mainly because "the PLL is able to resynchronize to the grid within a couple electrical cycles and should be able to immediately return to expected current injection." Furthermore, the inverter "current limits should ensure that overcurrent protective functions do not operate during PLL loss of synchronism conditions." The subsequent IRPWG guideline stated that "TOs should establish a dialogue with interconnecting GOs to understand the means in which the inverters may trip on instantaneous changes in phase either due to fault events or line switching events. TOs may perform system studies to identify possible worst-case phase jumps at the POI of the interconnecting resources, may consider identifying worst case balanced phase jump limits, or state that inverter-based resources should not trip for studied credible contingency events."

Follow-up activities during this disturbance analysis highlight that TOs (in coordination with the ISO/RTO) have not adopted the recommendations set forth in the guidelines. TOs are not establishing clear limits or requirements for phase jump or PLL loss of synchronism to mitigate this issue, and they are expected to persist since no requirements are in place. Furthermore, this tripping mechanism is not a consideration or requirement in PRC-024-3, leaving a significant gap in inverter-based resource ride-through requirements and capabilities, as has been observed across many large-scale events.

The NERC RSTC should direct the NERC IRPWG to develop a Standard Authorization Request (SAR) that ensures that resources are not prone to PLL loss of synchronism and that also ensure sufficient capability to ride through normal BPS fault events.

Protection Disabling

One inverter manufacturer that has experienced multiple facilities tripping on PLL loss of synchronism has stated that this protection is being disabled for future rollout of inverters and can be disabled on existing facilities only if those facilities request this from the equipment manufacturer. The inverter manufacturer has stated that other protections (such as ac- and dc-side voltage and current protection) can suitably protect the inverter and that PLL loss of synchronism protection can be disabled.

The review team noted that one facility was making updates to its inverters between the May 9 and June 26 events (refer to **Appendix C** for information on the related June 26 event) and tripped on both events for different reasons. The cause of tripping in the May 9 event was PLL loss of synchronism; the cause of tripping in the June 26 event was inverter ac overcurrent. This leads the review team to question whether eliminating this form of tripping will mitigate the unreliable performance. It appears that other forms of protection will simply trip the inverter for BPS fault. Overcurrent protection is not addressed in PRC-024-3, leading to unreliable performance with no mitigating measure in place to address this issue.

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

Key Finding
Solar PV plants continue to trip on PLL loss of synchronism, and these issues are not being properly mitigated. TOs, in coordination with their RC, BA, TP, and PC, are not establishing interconnection requirements to prohibit plants from tripping on PLL loss of synchronism. This form of tripping is not addressed in PRC-024-3 but it is the most significant cause of solar PV reduction in this event. This has led to unreliable performance of a number of large BES solar PV resources that lack sufficient ride-through capability to support the BPS for normal BPS fault events. This reliability issue is persistent, growing in the number of resources prone to this issue, not being mitigated appropriately, and warrants mitigating actions to address. The NERC RSTC should direct the NERC IRPWG to produce a SAR to mitigate this issue effectively.

Momentary Cessation and Plant-Level Control Interactions Persist

As experienced in the past NERC analyses of disturbances involving solar PV resources, one facility had legacy inverters programmed to enter momentary cessation when voltage falls below 0.9 pu. After fault clearing, voltage recovered to normal operating ranges quickly (within a few cycles) and the inverter attempted to return to pre-disturbance levels. The inverter manufacturer for this facility stated that there are no inverter-level controls that would slow the inverter response to the levels seen in **Figure 1.3**. Rather, once voltage recovers, the inverters return to responding to plant-level set point values. The plant-level controller has ramp rate limits that limit how quickly inverters can change active power output to support BA balancing activities. However, these limits should not interfere with the inverters' ability to recover to pre-disturbance output levels within under about one second. This is documented in NERC reliability guidelines.[21]

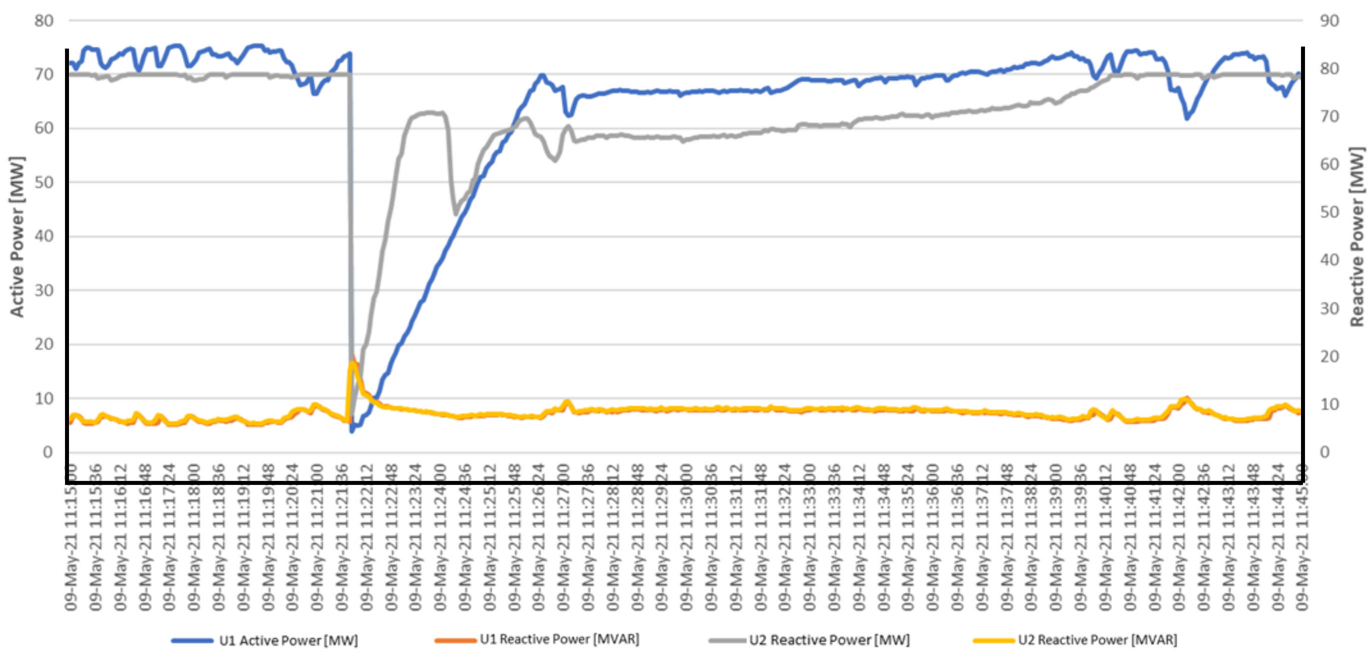


Figure 1.3: Momentary Cessation with Ramp Rate Interaction

These types of interactions should be detected in the dynamic models submitted to the TP and PC during the interconnection study process, and the interactions can be easily identified by the TP and PC for normal fault events studied during the interconnection process. However, it is apparent that these interactions were not properly identified in the interconnection studies; this has resulted in the plant operating in an unreliable manner while connected to the BPS.

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

Key Finding
Plant-level controller interactions with inverter response after fault events continue to be an issue for BPS solar PV facilities. These two layers of controls are not properly tuned with each other and are resulting in unreliable performance of these resources once connected to the BPS. Furthermore, these interactions are not properly being identified in the interconnection study process.

Inverter Controls Leading to Facility Tripping

In multiple plants, the root cause of solar PV reduction of active power was attributed to inverter controls driving conditions that led to the plant tripping. Most commonly, the inverter controls during and after the fault lead to voltages within the plant that exceed protection settings on either the inverter or on feeder protection.

Figure 1.4 shows high-resolution data from a digital relay oscillography record captured on one of the feeders within a plant. Prior to the fault, the plant is injecting active power into the system and operating near a unity power factor. At the time of the fault, phase voltages fall and current quickly drops to near zero.[22] Upon fault clear and voltage recovery, the inverters are programmed arbitrarily to delay resumption of current injection for 100 ms. After this time, the inverters ramp up current at about a 45° angle between voltage and current (equal injection of active and reactive power). However, voltage is operating high post-fault and the inverters should be consuming reactive power at this time. This leads to further overvoltage conditions that will ultimately trip the feeder-level phase overvoltage protection elements. This happens on all feeders within the plant, and output power goes to zero.

Upon further analysis and discussion with the inverter manufacturer, this issue is believed to be caused by poor coordination between the inverter controls and the plant-level controller. Immediately upon voltage recovery, the inverters begin responding to the plant-level controller set points. Their last received set point is an injection of reactive power, creating the overvoltage condition that ultimately tripped the plant. This behavior is solely based on the logic programmed into the controls for the inverter and plant-level controller.

[22] Current near zero is attributed to the inverter gate blocking the electronics, prohibiting it from injecting current, while the inverter output capacitors remain on-line and connected to the ac network.

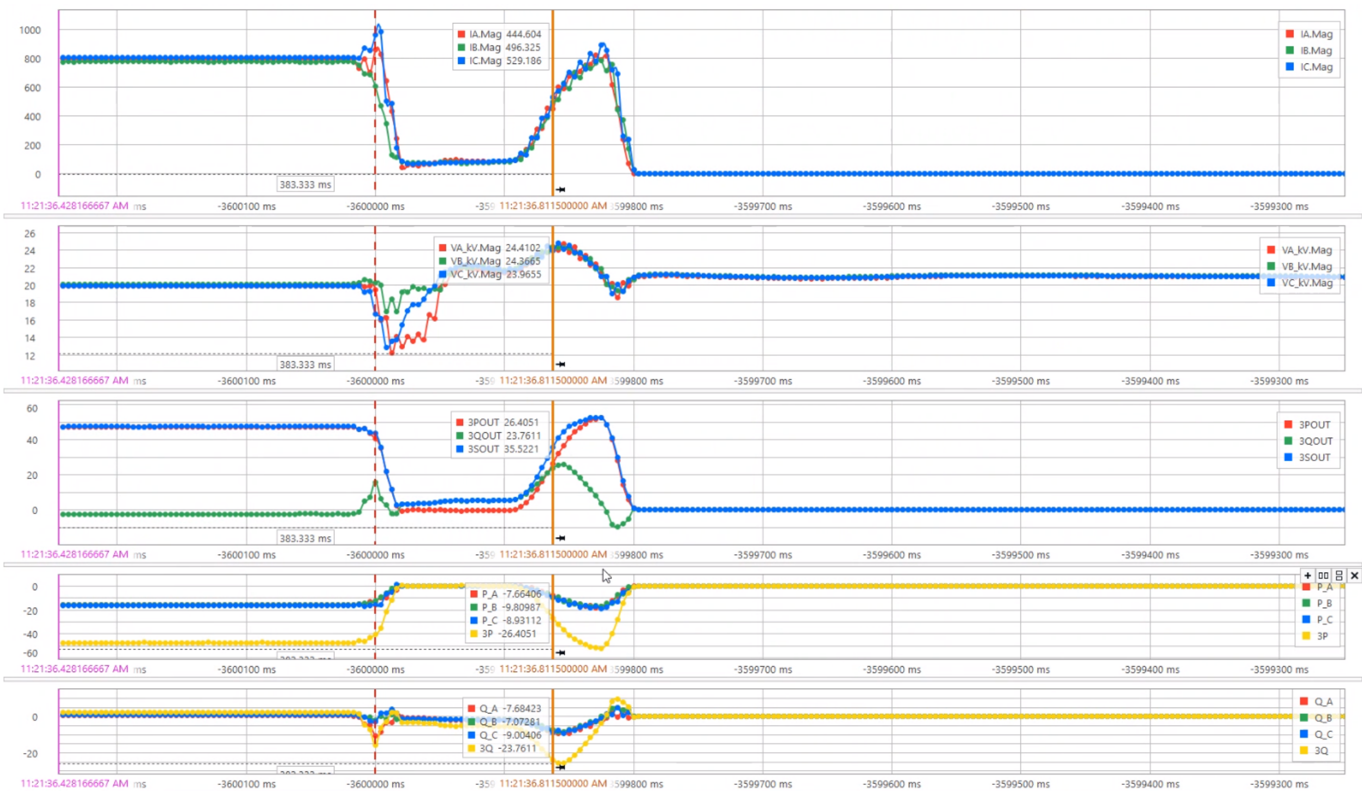


Figure 1.4: Current Injection at Time of Trip

As mentioned previously, these types of interactions should be identified during the interconnection study process. However, this requires that detailed and accurate models are provided during the time of interconnection that represent the equipment and controls that will be installed in the field. NERC, in coordination with industry stakeholders and the NERC IRPWG, has identified numerous times that detailed models of equipment are not being provided during the interconnection study process, and inverter-based resources are being interconnected in an unreliable manner due to poor modeling and inadequate studies being conducted during the interconnection process.

Key Finding
Multiple solar PV plants tripped on inverter terminal or feeder-level protection caused by inverter and plant-level controls driving voltage conditions above trip settings to some degree. The electrical response of the facility is based solely on the logic programmed into the inverter and plant-level controls. These issues should have been identified during interconnection studies, yet the plant was able to connect in an unreliable manner.

Inverter Transient AC Overvoltage Tripping Persists

As experienced in the past NERC analyses of disturbances involving solar PV resources, resources tripped on ac overvoltage conditions. One facility was able to capture inverter-level oscillography data (see Figure 1.5) to help the review team more comprehensively understand the tripping mechanism for these inverters. When the fault occurs, the inverters follow a K-factor injection of reactive current due to the low voltage measured during on-fault conditions. Upon fault clearing, voltage returns to normal operating ranges and the inverters continue to inject a large amount of reactive current into the normal voltage and ultimately drive voltage to above 1.3 pu. This leads to the inverter tripping to protect itself from the high voltage conditions. The 1.3 pu trip threshold is hard-coded by the inverter manufacturer and entirely separate from the overvoltage protection settings configurable by plant personnel used to meet PRC-024-3 requirements. This hard-coded voltage trip threshold is based on instantaneous peak measurements, not RMS measurements of voltage. Therefore, these settings cannot be modified for any existing facilities and likely will continue to invoke tripping for normal grid fault events unless plants are tuned accordingly to appropriately ride through these types of events.

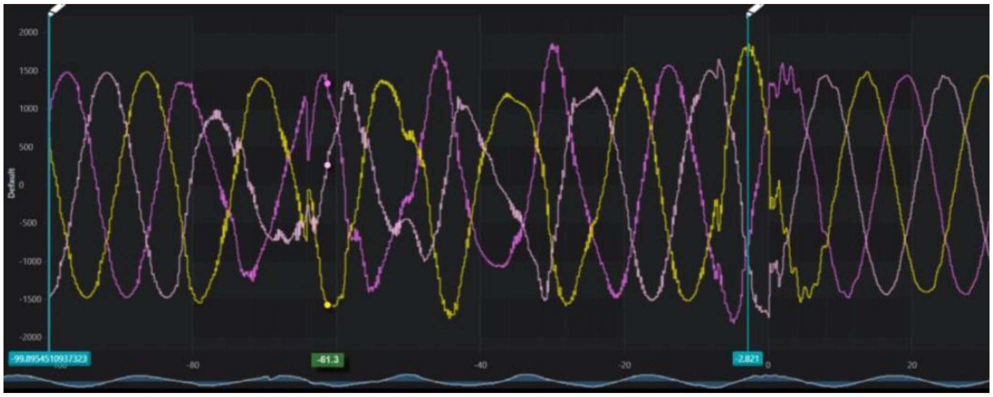


Figure 1.5: Inverter Oscillography of Transient AC Overvoltage Tripping

Note that PRC-024-2 was modified and updated to PRC-024-3, and one of the main clarifications added to this standard was that the "voltages in the boundaries assume RMS fundamental frequency phase-to-ground or phase-to-phase per unit voltage."[23] However, inverters are being installed on the system with trip setting that use instantaneous rather than RMS fundamental frequency measurements and will likely continue to result in plants tripping on ac overvoltage conditions. The modifications made to PRC-024-3 will not address this growing and persistent issue with solar PV resources, particularly from this one manufacturer.

Key Finding

Inverter-level ac overvoltage protection has caused a significant amount of tripping across multiple fault events. The trip threshold is set by the inverter manufacturer and is hard-coded into the inverter at 1.3 pu. This setting is non-configurable and unavailable to plant personnel. The peak overvoltage conditions occur because the inverter is injecting reactive current into the ac network when the fault clears, and ultimately the inverter drives its terminal voltage above the threshold and trips itself off-line (as mentioned above). The updates made to PRC-024-3 will not remedy these issues, and sub-cycle ac overvoltage tripping will likely persist and possibly grow in occurrence unless a mitigating measure is put in place.

Settings for Protection Set on or Near Curve

In discussions with multiple solar PV plant owner/operators, the review team expressed concerns that protection system settings were programmed directly on the PRC-024-3 boundaries. Further discussions highlighted that the plant personnel were unsure of the justification for feeder-level protection and were unsure of whether inverter-level protection was set to the equipment capabilities or to the PRC-024-3 curves. Figure 1.6 shows the snippet of the "grid protection" function set in the inverters at one facility. The overvoltage (OVR) and undervoltage (UVR) protection settings are programmed directly on the PRC-024-3 boundaries, illustrating that the protection settings within this facility are not set to equipment capabilities. Furthermore, this illustrates that the inverter-level protection is not coordinated with conditions at the POI (per requirements in PRC-024-3).

[23] https://www.nerc.com/files/PRC-024-3.pdf

```
<GRID PROTECTION> (1/3)

LEVEL & TIME
      OVR4:    125.0%                     ENABLE
         3:    118.0%       2.00sec
         2:    116.0%       3.00sec
         1:    112.0%       5.00sec
      UVR1:     88.0%      20.00sec       ENABLE
         2:     70.0%      10.00sec
         3:     60.0%       5.00sec
         4:     45.0%       1.00sec
```

Figure 1.6: Inverter Protection Set to PRC-024-3 Boundaries

PRC-024-3 was specifically modified to ensure clarity around the fact that these types of protection are not required by the standard, but the voltage- and frequency-related protections must be set to withstand certain conditions at the POI if they exist. However, it is clear from this analysis that there are systemic and significant misinterpretations of how the standard should be applied. In most cases, some form of consultant is hired to design station protection and they are not interpreting the standards appropriately. Numerous plant owner/operators have stated that they do not have sufficient technical staff on hand to interpret the results and will simply install what the consultant recommends. This is leading to poorly coordinated protection systems within the facility, causing unreliable performance from BPS-connected solar PV facilities in multiple interconnections.

Key Finding

Multiple solar PV plants include protective functions either within the inverters or in feeder-level protection that are set directly to the curves specified in PRC-024-3. The purpose of the standard is to establish requirements for performance when using voltage and frequency protective relaying. However, PRC-024-3 was recently updated to explicitly clarify that these type of protection are not mandatory nor is protection necessary unless it is based on an equipment rating or limitation. PRC-024-3 does not require any specific type of protection be enabled nor does it specify that protection should be set directly on the curve. This is a systemic issue with solar PV resources across multiple interconnections, as highlighted in past disturbance reports.

PFR Controls Interactions and Abnormalities

Frequency declined due to the loss of resources following the fault event. However, about six minutes later, frequency returned to nominal and actually reached the upper end of the frequency deadband. For inverter-based resources in Texas per ERCOT requirements, this is 60.017 Hz. The review team identified a number of resources that experience abnormal performance when frequency reached this upper deadband threshold.

For example, in this event, frequency reached 60.028 Hz momentarily, which is 0.011 Hz outside the upper deadband threshold. On a 5% droop characteristic based on nameplate rating, this equates to a reduction in plant output by only 0.37% (i.e., 0.37 MW for a 100 MW facility). However, as illustrated in **Figure 1.7**, facilities began reducing power output significantly for these minor frequency deviations. The plot on the left shows a plant with interactions between the ramping controls and the PFR controls; the plot on the right shows a plant where the PFR controls are reducing power abnormally. Such large swings in active power output from inverter-based resources will actually degrade the ability of the BA (i.e., ERCOT) to control frequency in a smooth and stable manner.

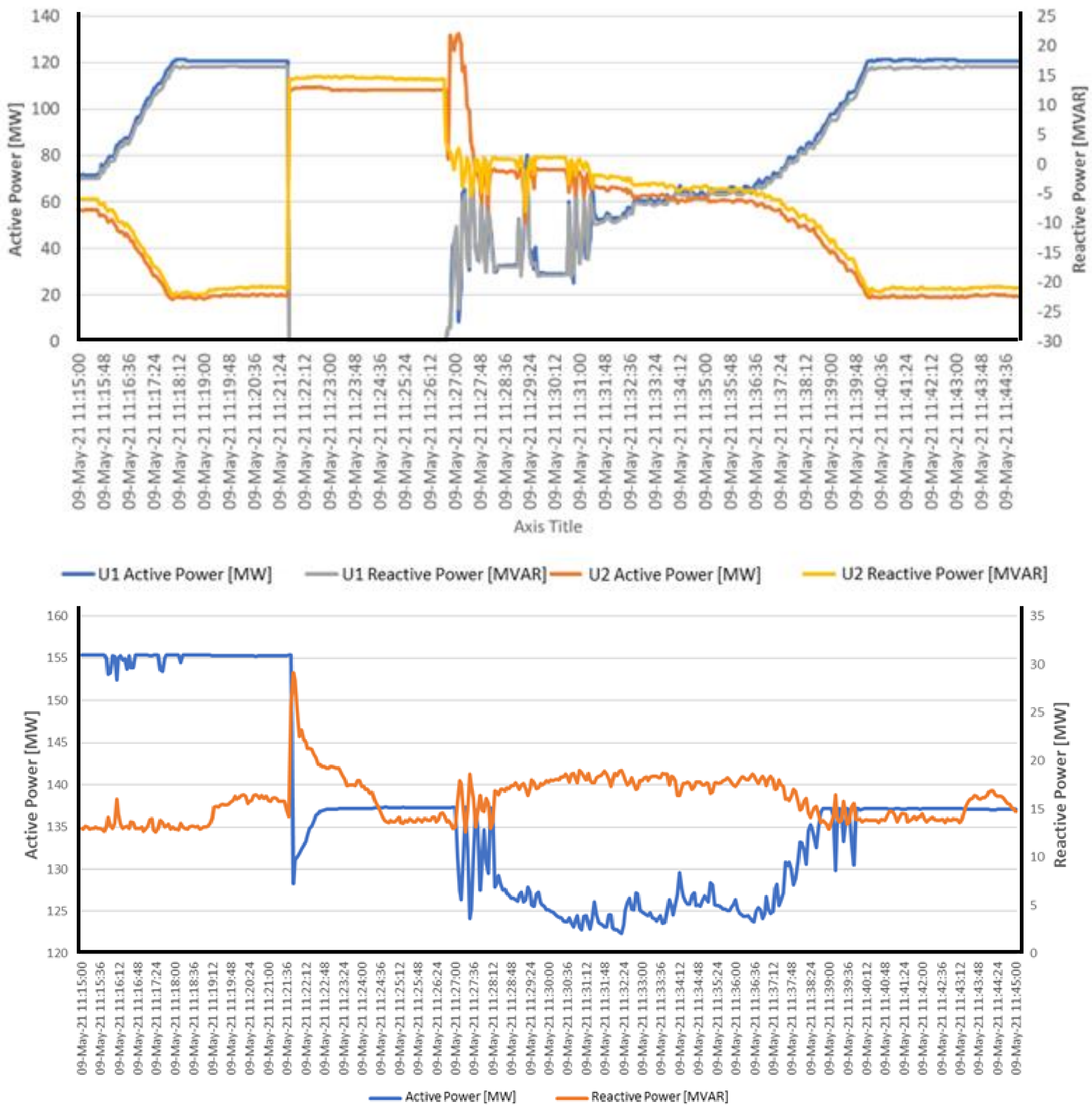


Figure 1.7: Examples of Poorly Coordinated Primary Frequency Response Controls

This finding highlights the need for a comprehensive analysis of all plants participating in the ERCOT frequency response market to ensure performance that is appropriately tuned to the requirements and expectations of the BA.

> **Key Finding**
>
> After the fault event and recovery of system frequency, frequency reached the upper deadband of 60.017 Hz. At that time, the review team identified a number of solar PV resources rapidly changing active power output in response to this condition. However, the magnitude of active power reduction to these overfrequency conditions does not match the expected performance following the requirements set forth by ERCOT. Therefore, it appears that interactions and abnormalities may exist with the implementation of PFR controls in these facilities and that this may be a more systemic issue than only the plants analyzed.

Reactive Power Injection While Inverters Gate Block

During the analysis of multiple facilities for this event, the review team noticed abnormal reactive power response upon inverter tripping. Figure 1.8 provides an example of the performance at a plant that tripped on PLL loss of synchronism. Before the disturbance, the plant is on automatic voltage control and injecting around 9 MVAR to the system at the POI. At the time of the fault, all inverters at the facility trip off-line, plant reactive power injection increases to 16 MVAR, and the POI voltage rises slightly due to this increase in reactive power production from the facility. Immediately upon inverter re-start, the plant pulls its reactive power injection down to about 4 MVAR after a ramping period where it appears that voltage control may be disabled.

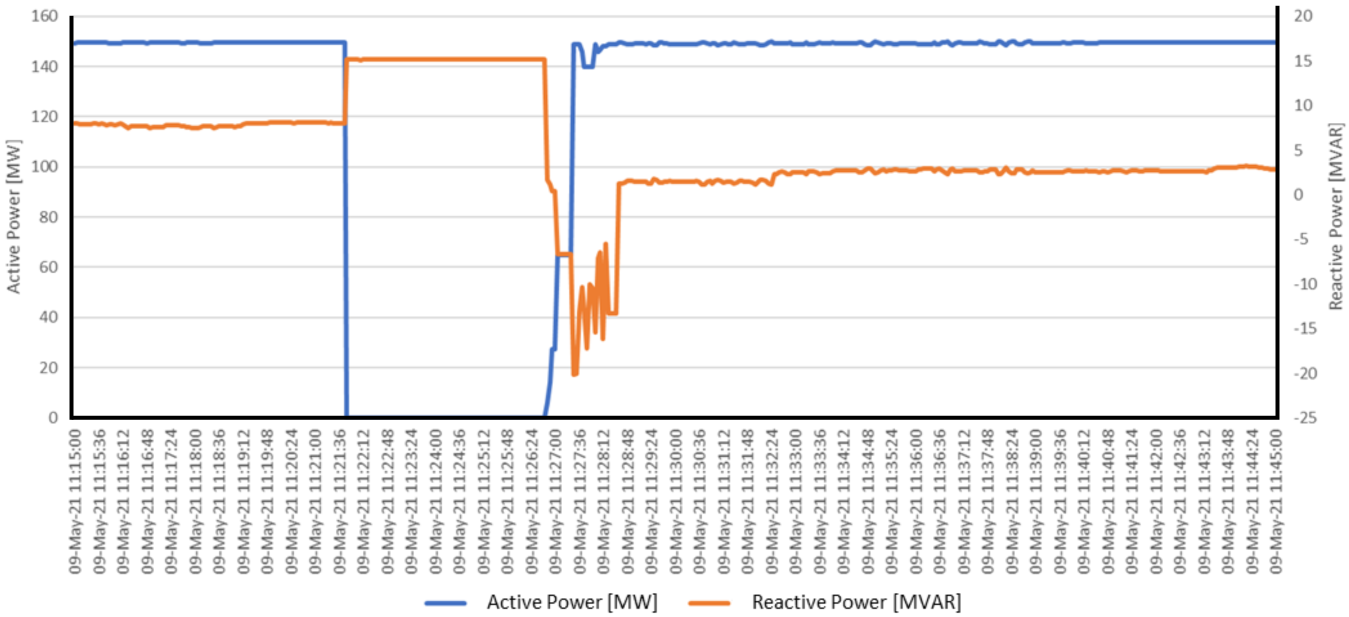


Figure 1.8: Example of Reactive Power Injection during Inverter Gate Blocking

ERCOT analyzed the production of reactive power during nighttime operations and noted only a minor reactive power injection during these conditions. NERC corroborated this finding with a model-based approach by analyzing reactive power injection with all inverters off-line in the model. NERC then noticed that the affected facilities exhibiting this behavior had a common inverter manufacturer, and NERC coordinated with this manufacturer to get additional information. The manufacturer stated that, upon tripping (often referred to as "idle"), the inverters gate blocked[24] "to prevent overuse of the inverter ac circuit breaker," but the inverter output capacitors remain on-line. The capacitors in this situation are 1,800 µf/phase and installed in a delta configuration on the ac-side of the inverter on the 630 V level. Figure 1.9 shows an illustration of the configuration. The capacitance values for each inverter aligned closely with the expected reactive power injection of the facilities that experienced gate blocking (cessation of current). This also helps partly explain some possible ac overvoltage experienced during these inverter tripping conditions.

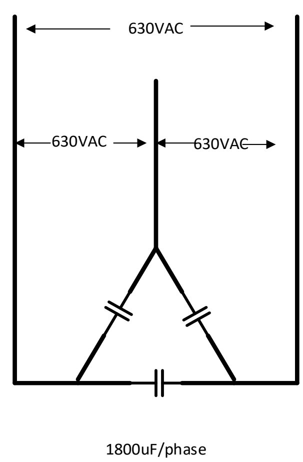


Figure 1.9: Inverter Output Capacitor Configuration

[24] This is another name for momentary cessation where the inverter power electronics gating is blocked to keep the inverters on-line yet not producing any current.

With the output capacitors remaining connected to the system once the inverters ceased current injection, the plant was not providing any voltage support and was injecting an unexpected amount of reactive power into the BPS. This was not previously known by ERCOT, is not a desired response from inverter-based resources,[25] and should not be allowed without prior consent from the TO, TOP, and RC. Furthermore, this should be appropriately modeled and studied by the TP and PC as well.

Key Finding

Inverters from one manufacturer are programmed to gate block (a form of momentary cessation) rather than open the inverter ac circuit breaker for fault events in order to prevent overuse of the breaker. However, this leads to the inverter output capacitors remaining connected to the BPS when the inverter current injection is ceased. This leads to a fixed reactive power injection during these times with no ability to control voltage post-contingency. This type of behavior was not known by ERCOT prior to the event analysis nor is this type of behavior supporting the BPS post-fault.

Modifications to Default Time to Restart Upon Trip

Most commonly, solar PV facilities that experience a "minor fault" event, such as these abnormal responses to BPS faults, will undergo a five minute disconnection with an automatic restart timer and ramp back to pre-disturbance levels. The five minute restart has been observed across all solar PV disturbances analyzed by NERC. However, in this event, some facilities experienced a trip and were able to return to service following the trip in a relatively short time period (e.g., around 30 seconds to a couple minutes). This demonstrates that these timers can be modified and are being modified by some asset owners. However, ERCOT does not have any requirements or specifications for returning to service following a trip, and therefore, solar PV plant owners stated that the default timers are most commonly used in absence of any further guidance.

The NERC reliability guidelines specifically cover this issue and state that "TOs, in coordination with their BA, should specify the expected performance of inverter-based resources following a tripping event. This may include automatic reconnection after a predefined period of time or may include manual reconnection by the BA. Ramp rates during return to service conditions should be specified as well. Following "system black" conditions, inverter-based resources should not attempt to automatically reconnect to the grid (unless directed by the BA) so as to not interfere with blackstart procedures." However, ERCOT has not implemented any return to service specification following these recommendations outlined in the reliability guideline.

Key Finding

In the absence of return to service specifications for inverter-based resources, these facilities are using default automatic reconnection times most commonly on the order of five minutes. However, some facilities are able to return to service much faster by modifying these timers. The TO (and BA) did not have any return to service requirements and therefore plants are making assumptions on the preferred performance. These types of specifications should be clear for all BPS-connected resources to ensure the BA has sufficient capability and flexibility to balance the system during normal and emergency grid conditions.

Updates Needed to Misoperation Analysis

The purpose of NERC PRC-004-6 is to "identify and correct the causes of misoperations of protection systems for BES elements" and is the one NERC Reliability Standard that drives the analysis of protection system misoperations and corrections to any identified abnormalities. The requirements focus specifically on misoperations where the protection system fails to operate. The requirements apply to TOs, GOs, and distribution providers; however, the

[25] Both the unexpected tripping and the unexpected reactive power injection upon tripping.

requirements ultimately do not cover situations where protection operates unexpectedly due to external faults. For example, a number of facilities analyzed for this event report that their inverters all tripped within the facility, but this was "correct operation" based on the inverter controls. However, these abnormal responses from the protection and control systems of inverter-based resources result in systemic and widespread reduction in power output from these facilities with ultimately no follow-up analysis to mitigate its occurrence. This leads to a widespread lack of understanding of inverter response to fault events, possible abnormal tripping issues, and very few plant owner/operators performing any post-event forensic analysis of their inverter and plant-level control behavior. Many facilities were unaware that their inverters had responded abnormally until ERCOT administered the RFI and the review team held one-on-one follow-ups with each facility.

Industry needs to improve the mandatory analysis and reporting of these types of abnormal tripping issues. The protection and controls within BPS-connected inverter-based resources should be analyzed after fault events when protection results in the tripping of individual inverters or protection systems in the facility that trip more than 75 MVA of aggregate resources. This should also be analyzed for any control systems that cause that same reduction of power output for more than 1–2 minutes. Presently, there is no standard requirement for any of this analysis to be performed, and this is leading to performance gaps and unreliable operation of these facilities. The NERC RSTC should direct an appropriate stakeholder group to develop a SAR to address this gap and require analysis of large reductions of BPS-connected resources by GOs and report those findings to the BA, RC, TOP, and Regional Entity for further awareness. This analysis should be linked to model quality analyses conducted by the TP and PC who should have the ability to correct any modeling deficiencies identified by this type of performance assessment. This is particularly important for any possible abnormal tripping issues that cannot be corrected.

Key Finding

The majority of BPS-connected solar PV plant owners and operators are unaware of the abnormal behavior of their inverter and plant-level controller responses to BPS fault events until the RC, BA, TOP, Regional Entity, or NERC identifies a more widespread issue. This is leading to more common widespread solar PV reductions to fault events than is necessary or warranted. PRC-004-6 does not require any analysis or reporting of large reductions in inverter-based resource facilities caused by either the protection or controls. The RSTC should direct its technical sub-groups to develop a SAR to address this gap to ensure that mitigating actions are developed to eliminate abnormal tripping and response of inverter-based resources to BPS fault events. Without any further action, these issues will continue to persist. Furthermore, the analyses should also be reported to the TP and PC, who should perform model quality checks to ensure their dynamic models accurately capture these unexpected performance issues.

Chapter 2: Modeling and Studies Assessment

This chapter analyzes the modeling and interconnection study activities both generally and within the Texas Interconnection. A number of the key findings and recommendations in this report highlight that significant modeling issues and challenges face the electric utility industry, especially for newer technologies, such as wind, solar PV, battery energy storage, and hybrid plants. NERC has been working in this area to support industry efforts to assess model quality, recommend modeling and study requirements per NERC FAC-001 and FAC-002 standards, and identify gaps in the interconnection process.

This chapter highlights that, under high inverter-based resource penetrations, there is a delicate tradeoff between an expeditious interconnection process (timelines, costs, scheduling, etc.) and due diligence to address reliability concerns, such as ride-through performance, operation in low short-circuit strength networks, subsynchronous resonance and control interactions, and other issues that may arise. Industry is challenged with recognizing that having both a quick interconnection process and addressing these reliability issues is a significant challenge not realistic and in many cases due to the types of analyses needed under these conditions. NERC recognizes that improvements to the FERC generator interconnection process are likely needed to balance these issues and is committed to working with FERC to develop solutions that can help industry both achieve effective interconnection processes while still ensuring reliable operation of the BPS. NERC also recognizes that ERCOT will need to implement similar updates by using their corresponding market rules and protocols.

Model Limitations and Updates to Modeling Requirements

Multiple types of inverter tripping have been identified in this event and past NERC disturbance reports on solar PV resource loss events.[26] **Table 2.1** shows the various causes of inverter tripping that have been identified in these events and whether these can be modeled in positive sequence simulations and EMT simulations.

Table 2.1: Solar PV Tripping and Modeling Capabilities and Practices

Cause of Tripping	Can Be Accurately Modeled in Positive Sequence Simulations?	Can Be Accurately Modeled in EMT Simulations?
Erroneous frequency calculation	No	Yes
Instantaneous* ac overvoltage	No	Yes
PLL loss of synchronism	No	Yes
Phase jump tripping	Yes	Yes
DC reverse current	No	Yes
DC low voltage	No	Yes
AC overcurrent	No	Yes
Instantaneous* ac overvoltage—feeder protection	No	Yes
Measured underfrequency—feeder protection	No	No**

* Sub-cycle ** Due to very limited protective relay models in EMT today

As **Table 2.1** illustrates, the majority of tripping that has been identified in this event and in past events cannot be accurately simulated in positive sequence studies most commonly performed by TPs and PCs. In particular, this is due

[26] https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx

to the limitations of positive sequence simulations (RMS, quarter-cycle time step simulations) and modeling simplifications associated with the inverter and plant protection systems and controls. However, all these aspects of abnormal tripping and inverter behavior can be identified in EMT simulations.[27] Considering the potential for tripping, reduction of power, and any possible interactions of intra-plant or inter-plant interactions, EMT studies should be conducted prior to resources being interconnected to the BPS.

Recommendation
Most of the causes of solar PV reduction identified in this event and past events analyzed by NERC cannot be properly represented in positive sequence dynamic models. High quality, vendor-specific EMT models are required to identify these causes of tripping. EMT studies should be required as part of the interconnection study process to ensure that all resources can reliably operate once connected to the BPS prior to the resource being interconnected. Resources that experience abnormal performance once connected should be subject to performance validation against the submitted models. Any discrepancies should be reported to the TP, PC, BA, RC, and NERC. A performance validation feedback loop should be incorporated into a NERC Reliability Standard to ensure reliable operation of the BPS with growing levels of inverter-based resources moving forward.

The combination of both EMT studies conducted during the interconnection process and a performance validation feedback loop after the plant has been commissioned would help mitigate the reliability issues that are presently going unnoticed prior to and during commercial operation of these facilities.

ERCOT Model Type Review

ERCOT reviewed the positive sequence dynamic models and the EMT models of the affected wind and solar PV facilities. **Table 2.2** and **Table 2.3** show an overview of the positive sequence and EMT models, respectively. One wind plant was represented using standard library models and two were modeled with more detailed user-defined models. For the solar PV facilities, 16 plants were modeled using standard library models and two were modeled using user-defined models.

Table 2.2: Positive Sequence Models for Affected Facilities

Resource	Standard Library Model	User-Defined Model
Wind	1	2
Solar PV	16	2

Table 2.3: EMT Models for Affected Facilities

Resource	Available EMT Model	No EMT Model
Wind	2	1
Solar PV	15	3

ERCOT stated that most of the available EMT models for these facilities were provided prior to ERCOT implementing a more detailed set of modeling requirements; therefore, these models require a model quality review and possible correction by the GOs in coordination with the plant equipment manufacturers.

[27] Most positive sequence dynamic models do not represent the PLL and other fast internal control and protection dynamics; therefore, EMT simulations are required to identify this cause of tripping in studies.

ERCOT Model Quality and Validation Process

ERCOT Planning Guides[28] Section 5 (Generator Resource Integration or Change Request) and Section 6 (Data/Modeling) describe the commissioning process and model validation processes for the ERCOT area. A *Resource Integration Handbook*[29] is also available that provides an overview of the entire process. The commissioning process involves three stages at a high level:

- Stage 1 performs several studies, gathers initial information, and executes a Generator Interconnection Agreement between the TO and GO.
- Stage 2 continues to gather additional modeling data that includes verification that model performance is reasonable and as expected.
- Stage 3 contains processes to begin final telemetry and data validation as well as executing a commission checklist.

Most model parameters are checked for reasonability against a set of validation rules. Since May 2020, ERCOT has implemented additional positive sequence dynamic model checks in an attempt to improve the quality and accuracy of dynamic models. The ERCOT Dynamics Working Group procedure manual provides a summary of these checks in Section 3.1.5 (Dynamic Model Quality Test Guideline).[30]

Model quality gaps are partly related to the applicability of recent requirement changes. The updated requirements were implemented for newly connecting facilities in May 2020. Dynamic models for most generators installed prior to May 2020 did not undergo such testing and review. The Planning Guide Revision Request (PGRR-085) (effective March 1, 2021) implemented additional requirements that include an EMT model validation, EMT model quality tests, consistency tests between EMT and positive sequence models, and verification of tunable field settings with model parameters. For both the positive sequence and EMT models that ERCOT has obtained, the dynamic response and tripping from several solar PV facilities during this May 9 event were not evident in the HVRT or phase angle jump tests conducted in the model quality tests.

ERCOT has not validated the EMT models yet, but the positive sequence models did not identify the observed issues as expected. The observed inverter protection systems, threshold, time limits, and hardcoded response logic do not appear to be included in the current models provided by the GO (in coordination with the equipment manufacturer). This is a significant modeling gap, particularly in the EMT models, as these models are expected to provide such detail in order to identify these potential tripping issues during ride-through simulation tests conducted during interconnection studies.

Recommendation

EMT models are expected to be the most accurate representation of a resource for use in detailed reliability studies. Assessments demonstrate that EMT models are lacking key protection and control functions within the models and that they are unable to demonstrate the response of the equipment in the field, and this poses significant reliability risks (particularly in areas of rapidly growing penetrations of inverter-based resources). Industry should develop EMT-focused modeling and study requirements and implement them in a timely manner, particularly in areas of high inverter-based resource penetration.

28 http://www.ercot.com/mktrules/guides/planning/current

29 http://www.ercot.com/content/wcm/lists/168284/Resource_Interconnection_Handbook_v1.91_01082021.docx

30 http://www.ercot.com/content/wcm/key_documents_lists/27301/DWG_Procedure_Manual_Revision_16_ROS_Approved_060321.DOCX

EMT Model Quality Requirements Improvements

ERCOT has required submission of an EMT model for inverter-based resources since 2016. Models provided by the GO prior to this date were generally not reviewed for quality or fidelity.[31] Furthermore, the model was generally not validated against any as-built setting information nor used unless needed for a sub-synchronous resonance study or other ad hoc study used in voltage-sensitive areas or low short-circuit strength areas. Planning Guide Revision Request (PGRR-085) (effective March 2, 2021) implemented additional requirements, including EMT model validation, EMT model quality testing, consistency tests between the EMT and positive sequence models, and verification of tunable field settings with model parameters.

Those requirements are not retroactive and only apply to newly interconnecting facilities. Entities have had significant difficulty coordinating with equipment manufacturers to submit acceptable model validations, and this is significantly more challenging for older plants and models. ERCOT continues to work on improvements to modeling requirements through their stakeholder process.

Recommendation

While the improvements put in place by ERCOT related to model quality testing and validation are a significant step towards properly identifying ride-through issues, ERCOT is encouraged to further enhance those requirements to ensure that the causes of tripping can be accurately represented in studies prior to interconnection. Models lacking quality or fidelity should be updated as quickly as possible and reliability studies should be conducted with those unreliable performance issues accurately represented if they cannot be mitigated appropriately. This same recommendation applies to all TPs and PCs performing interconnection studies and all TOs establishing interconnection requirements, per NERC reliability guideline recommendations. ERCOT is one of the leading PCs in North America in establishing these types of requirements and improving them to meet the changing resource mix; other TPs and PCs are encouraged to adopt similar types of modeling and study requirements.

ERCOT Model Quality Check for May 9 Event

ERCOT was requested to provide details regarding whether the abnormal performance for each affected plant in the May 9 event is accurately represented both in the positive sequence and EMT models provided by the GOs at the time of interconnection (and any subsequent annual modeling data collection activities). Due to time limitations and other priorities, ERCOT was unable to provide this assessment for this report but is actively working on this topic. NERC recommends that ERCOT follow up with this assessment and provide a detailed review of model quality for its BPS-connected solar PV fleet. In particular, the model quality assessment should determine whether the primary cause of tripping or abnormal performance is accurately represented in the EMT models provided. Any discrepancies should be corrected and studied for impacts of this unreliable operation of resources in the future.

ERCOT did note that many of the EMT models provided were not tested for model quality. Again, this is due to the effective date of the requirements that have been put in place recently relative to the interconnection date of the affected plants.

[31] Model fidelity generally refers to whether the model sufficient represents the various functions (controls, protection, etc.) within the resource. Model quality refers to whether the model parameters sufficiently reflect the as-built settings and controls of the equipment installed in the field.

Recommendation
All TPs and PCs should be assessing the quality and fidelity of the positive sequence and EMT models provided during the interconnection study process. Model quality checks, test, and validations should be conducted per the recommendations set forth in the NERC reliability guidelines. Any model quality concerns should be addressed prior to the studies being conducted and resources should be held accountable for any modeling errors that do not suitable represent the installed equipment in the field.

ERCOT Interconnection Study Process Assessment

As stated, some of the modeling gaps can be attributed to the lack of applicability of requirements that were implemented in May 2020 and March 2021. Most generators installed prior to May 2020 did not undergo detailed model quality testing and review.

ERCOT is planning to review the findings from this event analysis and identify improvements to their generator interconnection agreements and process in an effort to take mitigating measures to prevent such abnormal performance in the future. ERCOT is undergoing some plant-level model validation for voltage ride-through events and determining if the models provided can actually identify the abnormal performance experienced for these events. ERCOT plans to work with the affected GOs to make corrective actions to prevent and/or mitigate similar behavior to the extent possible based on the equipment limitations and vendor cooperation. Those changes will require the GOs to implement, and may include, but are not limited to, the following:

1. Review and/or make adjustments to HVRT/LVRT set points
2. Review and/or make changes to disable or loosen frequency trip set points
3. Review and/or make changes related to VRT mode recovery timers and ramp rate limitations
4. Review and/or update models

Additionally, ERCOT intends on meeting with vendors that were primarily affected to determine additional modeling and or setting adjustments that can be standardized for new equipment.

ERCOT Interconnection Study Process Improvements

Multiple solar PV plants tripped for a normally cleared BPS fault event within the ERCOT footprint. These causes of tripping should be identified in the interconnection study process and should be flagged as unacceptable performance by ERCOT planning staff. While performing EMT simulations is an intensive process, the penetration of inverter-based resources in the ERCOT footprint raises concerns that a significant portion of the connected resources are operating in a potentially unreliable manner and were not previously studied with detailed EMT studies prior to interconnection.

PLL loss of synchronism and ac overvoltage tripping will likely not be identified by using positive sequence models (either user-defined or standard library models) and will require an EMT study. Furthermore, the protection mechanisms need to be properly represented by the equipment manufacturer, particularly since the standard “HVRT” and “LVRT” protections are not the cause of tripping in this event—it is the detailed, hard-coded, unconfigurable protections set by the inverter manufacturer. Therefore, detailed EMT models using real-code representations of the facilities are needed to accurately identify these trip mechanisms.

Recommendation
ERCOT should conduct a comprehensive modeling assessment of both the positive sequence models and the EMT models as well as benchmark the models against each other to ensure that all models are reflective of the as-built settings, controls, and protections that are installed at these facilities.

System Model Validation Needed

Based on the magnitude of solar PV reduction for a normally cleared BPS fault, NERC and Texas RE strongly recommend ERCOT to conduct a system-wide model validation effort to identify models that may not match expected performance of the facilities. This effort should include detailed event recreation for both the May 9 and June 26 events. The modeling and studies conducted should be able to indicate possible performance issues based on the findings of this report. Therefore, it is strongly recommended that ERCOT develop a system-wide EMT study for this effort. This study should accurately represent the system elements, end-use load models, and generating resources. Tripping due to PLL loss of synchronism, inverter-level and feeder-level instantaneous ac overvoltage protection, and other sub-cycle tripping mechanisms should be appropriately modeled in the solar PV facilities.

The study should identify the following:

- Modeling deficiencies in the previously submitted models
- Performance issues where the modeled performance is not meeting the performance requirements established by ERCOT
- Gaps in performance requirements where abnormal performance is not previously addressed by existing performance requirements

Aggregate findings from this study should be made available to NERC, Texas RE, and to industry stakeholder groups, such as the NERC IRPWG, so that other areas within North America can learn from these modeling findings in more detail.

NERC acknowledges that a system-wide EMT simulation would be a significant undertaking for a system the size of the Texas Interconnection. Improved tools and processes as well as additional personnel may be needed to conduct these types of analyses. However, ERCOT (and other ISO/RTOs) will need to start working towards this type of system representation as the ongoing and growing amount of abnormal performance of inverter-based resources continues to be an issue, particularly for ride-through performance. The findings published in multiple NERC disturbance reports and now clearly observed on a wide-scale in the Texas Interconnection justify the need for this type of analysis, validation, and improvement to system-wide models as well as identification of any unreliable performance from the resource base.

Recommendation

ERCOT should conduct a system-wide model validation effort to identify models that do not match actual performance of the installed facilities. This study should include event recreation for both the May 9 and June 26 events. The studies should be able to indicate performance issues identified in this report. Otherwise, model improvements are needed immediately. ERCOT should develop a system-wide EMT model for this study that accurately represent system elements, end-use load models, and generating resources. Tripping due to PLL loss of synchronism, inverter-level and feeder-level instantaneous ac overvoltage protection, and other sub-cycle tripping mechanisms should be appropriately modeled in the solar PV facilities. The study should identify any modeling deficiencies, performance issues once models are corrected, and gaps in performance requirements that could lead to unreliable performance of these resources in the future. Aggregate findings should be made publicly available and should be shared with Texas RE, NERC, and the NERC IRPWG.

Relation to ERCOT Operations Models

ERCOT Operations team runs quarterly stability assessments (QSAs) that identify potential instability in the operations time horizons. These studies use the same models that long range planning uses for a similar study. While there have been several studies that evaluate contingencies, such the 1-phase fault that occurred in the May 9 event, the loss of resources observed in the event have not been identified with the real-time or long-term planning models (same set of models) used in studies. The QSAs typically use positive sequence models. If instability (or questionable results) is identified, then a coordinated EMT study with additional planning staff may be conducted. On-line voltage stability studies are run on a subset of stability limits and real-time dynamic stability studies are not presently performed for real-time or next-day operations. Rather, system operating limits (SOL) are derived from stability studies conducted as part of the QSA. Those SOLs are then established and operated within in real-time. Reviews and revisions to those limits in the SOL tables are conducted as needed for a next-day study.

As ERCOT continues to make improvements to their planning models, those improvement should then be reflected in the operational models used for establishing SOLs. Presently, the known modeling gaps identified in this report may pose real-time reliability limits, particularly for fault events where both the positive sequence and EMT models may not be accurately reflecting the possibility of tripping of solar PV resources.

Chapter 3: Recommendations and Actions Needed

Based on the key findings from analyzing this event and in the context of prior grid events, NERC is providing the following recommendations contained in **Table 3.1**. The table also includes the applicable entities that should act on these requirements in a timely manner.

<table>
<tr><th colspan="2">Table 3.1: Recommendations and Actions Needed</th></tr>
<tr><th>Recommendation</th><th>Applicability</th></tr>
<tr><td colspan="2">Improved Requirements and Processes</td></tr>
<tr><td>Adoption of Reliability Guidelines: While the IRPWG reliability guidelines are some of the most downloaded guidelines produced and most widely used across the industry, it is clear that industry is not adopting the recommendations contained within NERC reliability guidelines. GOs, GOPs, developers, and equipment manufacturers should adopt the performance recommendations provided in the NERC reliability guidelines. 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-001-3 and FAC-002-2 standards.</td><td>TOs, TPs, PCs, GOs, GOPs, developers, equipment manufacturers</td></tr>
<tr><td>Improvements to Interconnection Process: As stated, the NERC reliability guidelines are not being widely adopted in a comprehensive manner, leaving gaps in reliable interconnection of BPS-connected inverter-based resources. Significant improvements are needed to the FERC Generator Interconnection Process and Generator Interconnection Agreement that include comprehensive requirements that must be met during the interconnection process. These requirements should be clear, consistent, and ensure reliable operation of these resources prior to commercial operation of the facility. Presently, plants are being interconnected in an unreliable manner with inadequate studies to appropriately identify these issues ahead of 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 using only the NERC FAC-001-3 requirements.</td><td>FERC</td></tr>
<tr><td colspan="2">NERC Standards Updates Needed to Address Performance Gaps in Inverter-Based Resources</td></tr>
<tr><td>Significant NERC Reliability Standard Updates Needed Related to Performance: The systemic nature of these events across multiple interconnections and a wide range of facilities, many of which are recently energized, warrants significant enhancements to the NERC Reliability Standards to address gaps in BES inverter-based resources. As reported in this disturbance report (and building on past reports published by NERC), the following recommendations are provided. The NERC RSTC should facilitate and ensure the development of SARS to address each of the following issues:
Performance Validation Standard Needed: TOPs, RCs, BAs (in coordination with the TP and PC) should 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) as well as based on a comparison of any applicable interconnection requirements in place. Abnormalities in plant performance should be reported to NERC and the Regional Entity and should be corrected by the GO in a timely manner. Persistent deviations of performance from expectations are not acceptable.
Ride-Through Standard to Replace PRC-024-3: The original intent of the PRC-024 standard was to ensure that plants remain connected to the BPS during frequency and voltage excursions. This was approved only as a protective relaying standard, but then caused significant confusion for inverter-based resource controls and protection within the individual inverters. Additionally, the events analyzed by NERC regarding fault-induced reductions in solar PV output and wind output have identified issues with controls and protections unrelated to voltage and frequency. For example, PLL loss of synchronism, sub-cycle ac overvoltage protection, dc reverse current, and wind converter crowbar failure are all examples of widespread tripping that are not addressed by PRC-024-3. Furthermore, industry continues to misinterpret PRC-024-3 and continues to set seemingly unnecessary voltage and frequency protection within facilities "for compliance reasons" even though the</td><td>NERC RSTC and NERC IRPWG, Project 2021-04 Standard Drafting Team</td></tr>
</table>

Table 3.1: Recommendations and Actions Needed	
Recommendation	**Applicability**
standard was updated to address this confusion. The growing evidence leads NERC to recommend that a ride-through standard focusing specifically on generator ride-through performance[32] should be developed and implemented on an expedited timeline. • **Analysis and Reporting for Abnormal Inverter Operations:** Inverter-based resource power reductions of more than 75 MW in aggregate per facility should be analyzed and reported. While this may not be the present intent of the PRC-004 standard, the standard scope should be extended (or another standard introduced) to ensure that abnormal power reductions are analyzed, reported, and corrected in a timely manner. Ongoing, persistent tripping or reductions in inverter-based resources is the present situation and should not be considered acceptable. • **Monitoring Data:** NERC should ensure that recording at all BES inverter-based resources includes 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. These are standard features for modern inverters that should be enabled within all facilities to better understand their response to grid events and improve overall fleet performance. The Project 2021-04 standard drafting team should consider whether these recommendations are within scope and adopt them where possible. Otherwise, a future standards project should address this issue. • **Inverter-Specific Performance Requirements:** The NERC IRPWG conducted an assessment of existing NERC Reliability Standards that should be updated to ensure clarity and consistency for inverter-based resources; however, the assessment did not comprehensively consider performance characteristics specific to inverter-based resources that should be addressed by a NERC Reliability Standard. This assessment should be conducted by the NERC IRPWG and any necessary SARs should be produced through the RSTC: ▪ As one example, the absence of return to service timing requirements established consistently by BAs, has introduced unexpected and anomalous behavior from inverter-based resources when returning from “minor faults” that trip the facility off-line. Furthermore, the lack of specifications around return-to-service could introduce challenges and complexity for RCs and TOPs in the event of a widespread outage conditions during blackstart recovery. Industry is not adhering to the recommendations in the NERC guideline and this should be addressed in a standard or within the FERC GIA. ▪ Having inverter-specific requirements or standards has been considered by the SAR drafting teams focused on revisions to MOD-025, PRC-019, MOD-026, and MOD-027 given there are differences and unique characteristics of inverter-based resources that do not directly relate to synchronous generation.	
NERC Standards Updates Needed to Address Modeling and Studies Gaps for Inverter-Based Resources	
Requirements for Accurate EMT Models at Time of Interconnection: The existing NERC FAC-001 and NERC FAC-002 standards provide too much leverage and have led to inconsistency in how TPs and PCs are gathering modeling information and conducting interconnection studies. 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. The FAC-001 and FAC-002 standards more clearly align with the FERC GIP and GIA to clearly specify the models required and the studies to be conducted at the time of interconnection.	NERC RSTC and NERC IRPWG

[32] 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 3.1: Recommendations and Actions Needed	
Recommendation	**Applicability**
Update to NERC MOD-032 to Include EMT: The NERC MOD-032 standard is used by TPs and PCs to ensure appropriate models for performing system studies are provided by equipment and data owners. Presently, it is unclear how EMT models are treated in this standard and this lack of clarity needs to be addressed with a standard revision. EMT models should be made available by GOs to ensure system studies are conducted in the planning horizon for growing levels of inverter-based resources, not just for newly interconnecting facilities. Larger-scale EMT studies will likely be needed in the future as penetration levels continue to rise.	NERC RSTC and NERC IRPWG
Updates to Ensure Model Quality Checks and Model Improvements: GOs need to provide accurate models to the TPs and PCs based on existing requirements. A feedback loop to ensure model accuracy (for any type of model) is only an optional specification in the existing MOD-032 standard. Model quality checks should be conducted by all TPs and PCs, and any modeling errors should be addressed by the equipment owner (i.e., the GO) in a timely manner. Model quality reviews should include more than just model usability—they should check for model parameterization issues or inconsistencies against plant performance to real events.	NERC RSTC and NERC IRPWG
ERCOT Recommended Actions	
ERCOT Adoption of Reliability Guideline Content: ERCOT should ensure that the recommendations contained within the NERC reliability guidelines are comprehensively reviewed and adopted to ensure mitigating actions are put in place to prevent these types of issues in the future. May of the performance issues in this event could have been mitigated if appropriate performance requirements were established for these resources and interconnection studies were performed to ensure conformance with those requirements.	ERCOT
ERCOT Follow-Up with all Solar PV Resources in Texas Interconnection: ERCOT should conduct outreach and education for all GOs and GOPs with solar PV resources in the Texas Interconnection. This should include follow-ups with the affected facilities to develop mitigating measures for any abnormal performance issues identified in this event. The follow-up should also include an educational outreach effort (e.g., workshop, webinar series, etc.) that provides the details of this analysis, understanding of ERCOT performance requirements and expectations, ERCOT planning and modeling requirements, and key areas of focus for newly interconnecting resources.	ERCOT
ERCOT Detailed Model Quality Review: ERCOT should conduct a detailed model quality review for all inverter-based resources connected to the ERCOT system. This should include both positive sequence and EMT model quality checks against as-built settings, specification sheets, one-line diagrams, and any other information provided to validate that the model is a suitable representation of the installed facility. Models should include any control or protection function that can trip the facility, including (but not limited to) all the protections identified in this disturbance report and all others published by NERC related to solar PV reductions.	ERCOT
ERCOT System Model Validation Effort: ERCOT should conduct a system-wide model validation effort using both positive sequence and EMT models to ensure that those models do not include any deficiencies and can accurately recreate system events. This activity will help ensure that the models can identify future performance issues on the ERCOT system, both for balanced and unbalanced phenomena.	ERCOT
ERCOT Gap Analysis of Interconnection Study Process: ERCOT should conduct a comprehensive gap analysis of its interconnection study process to identify areas of improvement to address the shortcomings identified in this report. As stated, the interconnection study process should ensure reliable performance from all interconnecting plants and any performance requirements not met should have mitigating actions before proceeding in the interconnection queue. With the growing level of inverter-based resources, particularly in Texas, this should include detailed EMT modeling for ride-through assessments. Clear interconnection requirements should be in place such that any plant performance issues for facilities not meeting those requirements can be mitigated through effective means.	ERCOT

Appendix A: Disturbance Analysis Team

This disturbance was analyzed by the following individuals. NERC gratefully acknowledges Texas RE, ERCOT, 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 IRPWG 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.

Name	Company
Rich Bauer	North American Electric Reliability Corporation
Howard Gugel	North American Electric Reliability Corporation
Mark Lauby	North American Electric Reliability Corporation
Matt Lewis	North American Electric Reliability Corporation
John Moura	North American Electric Reliability Corporation
Ryan Quint	North American Electric Reliability Corporation
John Paul (JP) Skeath	North American Electric Reliability Corporation
Jule Tate	North American Electric Reliability Corporation
David Penney	Texas Reliability Entity
Bob Collins	Texas Reliability Entity
Freddy Garcia	Electric Reliability Council of Texas
Abhilash Massana Gari	Electric Reliability Council of Texas
Patrick Gravois	Electric Reliability Council of Texas
Fred Huang	Electric Reliability Council of Texas
Alex Lee	Electric Reliability Council of Texas
John Schmall	Electric Reliability Council of Texas
Stephen Solis	Electric Reliability Council of Texas
Xiaoyu Wang	Electric Reliability Council of Texas

In Memoriam

This disturbance report is dedicated to Jule Tate, who passed away in 2021. Jule was instrumental in the success of the NERC Event Analysis Program due to his deep involvement and led the ERO Enterprise analysis of many major disturbances. Jule was a dear friend to the analysis team, a trusted colleague to many across the North American electrical ecosystem, and an exceptional engineer and leader in the electricity sector.

Jule W. Tate, III

Appendix B: Detailed Review of Affected Facilities

This appendix provides a detailed review of the affected generating facilities that exhibited an active power reduction during the event. For the solar PV plants, only those facilities with a reduction of more than 10 MW are covered in this detailed analysis. The affected wind power plants are documented in this section, but NERC and Texas RE did not conduct any detailed analysis of the power reductions. The combined cycle facility is also documented in this section.

Affected Solar PV Facilities

Table B.1 provides a high-level overview of the involved facilities, and each subsection describes the facility in more detail. Note that "Reduction" values in the table are based on a comparison of both the ERCOT data and data provided by GOs. Values are based on engineering judgment by NERC and Texas RE after reviewing data sources with varying resolutions. Other information was collected through the data requests sent out to affected facilities and from Texas RE.

Table B.1: Review of Solar PV Facilities

Facility ID	Capacity [MW]	Reduction [MW]	POI Voltage [kV]	In-Service Date	Highest Data Resolution	NERC-Texas RE Review
Plant A	180	28	138	June 2018	PMU	A lack of data leaves the root cause unidentifiable.
Plant B	152	150	138	June 2020	PMU	All inverters at site tripping on PLL loss of synchronism. Anomalous reactive power injection after inverter tripping.
Plant C	126	64*	345	November 2020	DFR	Some inverters at plant tripped on ac overvoltage. Inverters injected reactive current during fault conditions. Inverter voltage reached trip settings of 1.25 pu and tripped instantaneously. POI voltage experienced voltage below nominal at this time.
Plant D	132		345	November 2020		
Plant E	162	21	138	May 2021	1-sec	One medium voltage feeder breaker tripped instantaneously on measured underfrequency of 57.5 Hz, disconnecting 25 inverters.
Plant F	50	48	69	September 2017	1-sec	All inverter at facility tripped off-line. Those that indicated a fault code tripped on "grid underfrequency" conditions.
Plant G	121	239	345	December 2019	PMU	All inverters at the facility tripped. The vast majority tripped on PLL loss of synchronism while the others had an unidentified cause for tripping.
Plant H	119					
Plant I	154	205	345	June 2020	Inverter High-Speed	Inverter instantaneous ac overvoltage tripping over 1.3 pu. Induced by inverter injection of reactive current into high voltage conditions post-fault.
Plant J	150		345	June 2020		
Plant K	78.75	153	138	September 2016	DFR	Legacy inverter momentary cessation setting with plant-level controller ramp rate interactions prohibited quick active power recovery.
Plant L	78.75		138	September 2016		
Plant M	155	147	138	March 2018	DFR	Plant injected reactive current into high voltage condition that caused all feeder breakers to trip on instantaneous ac overvoltage.
Plant N	110	23	138	March 2017	2-sec	There was an unknown cause of reduction in active power reduction (increase in reactive power output); interactions of primary frequency response controls with plant recovery.

Table B.1: Review of Solar PV Facilities						
Facility ID	Capacity [MW]	Reduction [MW]	POI Voltage [kV]	In-Service Date	Highest Data Resolution	NERC-Texas RE Review
Plant O	50		138	November 2016		Reduction in active power output caused by inverter controls; response to pre-disturbance in about 20–30 seconds does not meet NERC guidelines.
Other		34				Not analyzed.
TOTAL		1,112				

* Modified from ERCOT brief report

Plant A

Plant A is a 180 MW facility connected to the 138 kV network that went into commercial operation in June 2018. The facility is actually a hybrid resource that includes a battery energy storage system component within the facility. The plant reduced output by 28 MW during the event (see Figure B.1) and started recovering after about 6.5 minutes. The plant returned to pre-disturbance output about 12 minutes later. According to the facility, 6 of 90 inverters reduced output "to idle operation" due to a "voltage deviation at the POI," and plant staff stated that no protection functions operated. Plant staff were unable to identify a cause of tripping for any of the inverters and stated that they do not have "enough knowledge on site at these facilities to get the data needed" to identify a root cause for the abnormal behavior (within the timing required by the ERCOT RFI and follow-up discussions with NERC and Texas RE). Therefore, the plant has no identified cause of tripping due to lack of information provided.

The plant had a PMU located at the interconnection point and measured POI voltage of around 0.63 pu followed by a slight voltage overshoot upon fault clearing—well within the PRC-024-2 curve. The plant was operating near maximum active power output and also consuming a significant amount of reactive power prior to the fault event.

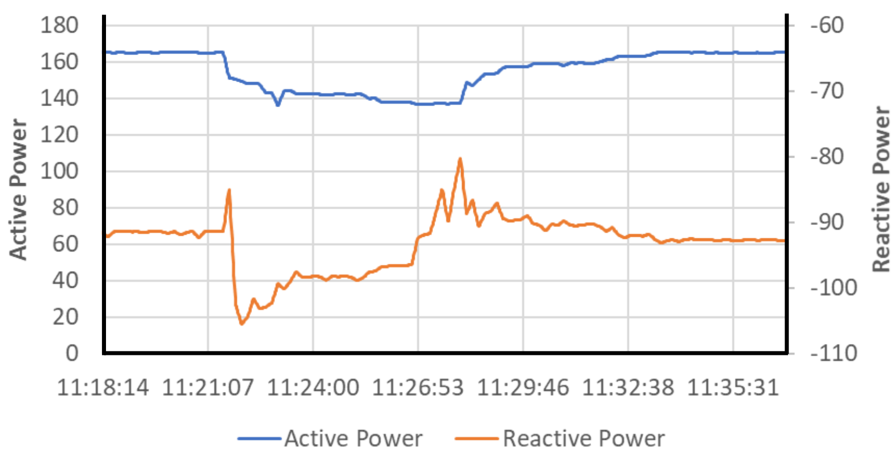


Figure B.1: Plant Active and Reactive Power Output

Plant B

Plant B is a 152 MW facility connected to the 138 kV network that went into commercial operation in June 2020. The plant reduced output by 150 MW during the event (see Figure B.2). All 50 inverters in the plant tripped on PLL loss of synchronism. After a five-minute auto-restart timer, the plant returned to full output.

NERC identified anomalous behavior in reactive power output when the inverters shut down due to loss of synchronism. Reactive power increases during this time to about 15.5 MVAR while the inverters were in an "idle" mode. NERC raised this issue with the inverter manufacturer, and they stated that the inverters will "gate block" the power electronics (same mechanism as momentary cessation) and power output will go to zero. However, the inverter ac circuit breaker did not operate and the inverter output capacitors remained connected to the system. This results in an unexpected injection of reactive power while the inverters sat idle connected to the system but blocked from supporting the grid. Upon recovery of active power after the auto-restart, the resource experiences abnormal reactive power injection during inverter restoration before reaching a new steady-state condition.

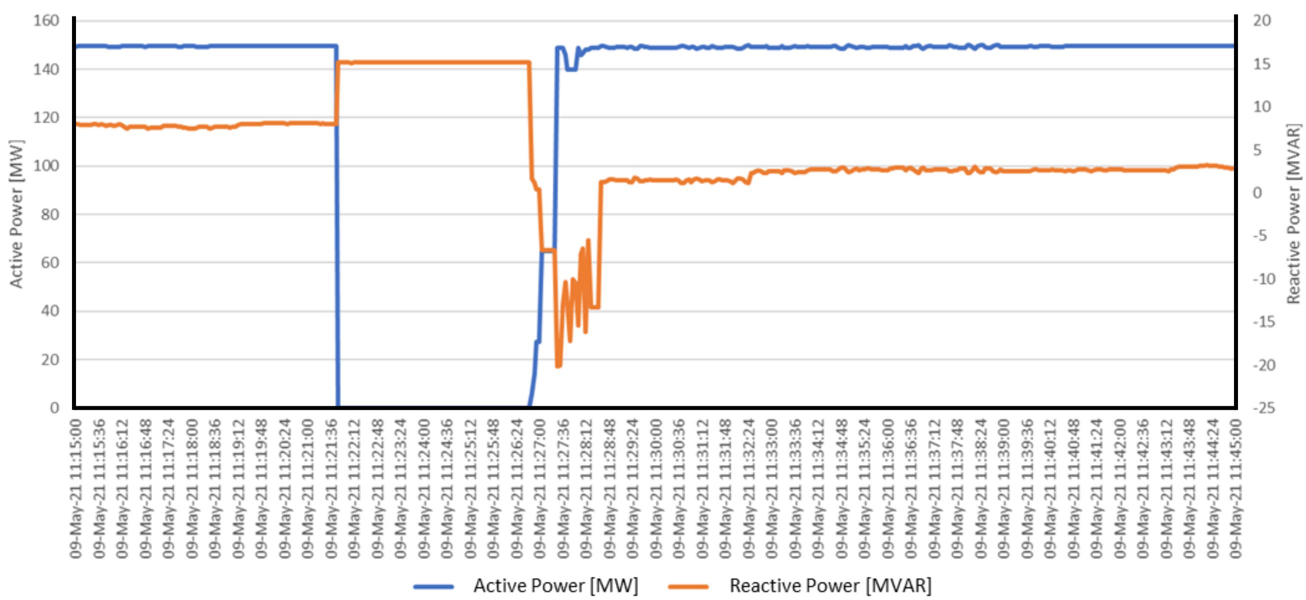


Figure B.2: Plant Active and Reactive Power Output

Plant C and Plant D

Plant C and Plant D are a combined 255 MW facility connected to the 345 kV network that went into commercial operation in November 2020. Prior to the event, this facility had experienced a down ramp due to curtailment and was in the process of ramping up power output when the fault occurred. During the fault, the overall plant reduced output by about 64 MW. A total of 15 inverters tripped on instantaneous ac overvoltage protection. Inverters that did not trip reacted to the frequency excursion by providing frequency response appropriately. Active power at the POI returned to predisturbance output after 10 seconds, and it actually increase above predisturbance levels to about 215 MW and settled at 200 MW due to the active-power frequency controls. Figure B.3 shows the response of the facility around the fault event.

This response of this facility includes a number of unique findings:

- **Inverter Fault Current Injection and Tripping on Instantaneous AC Overvoltage:** The inverters are programmed to provide reactive current injection for low voltage conditions. As voltage fell during the fault, the inverters injected reactive current by using K-factor control. The inverters are set to trip at 1.25 pu instantaneously, and 15 inverters tripped at that level. Voltage data provided by the plant does not show POI voltage above 1.25 pu (see Figure B.4), so the POI voltage and the individual inverter voltages are likely significantly different during ride-through conditions. It is believed that the inverters responding to the undervoltage by injecting reactive power ultimately drove their terminal voltage to above the inverter trip setting limit. Figure B.4 illustrates these points using DFR data captured at the POI around the fault event.

- **Facility Current Injection Post-Fault:** After the fault cleared and voltages returned to within normal operating ranges, the current injection at the POI oscillated between all active current and all reactive current injection. **Figure B.4** also shows this in the phasor diagrams for the latter three time frames. Immediately after fault clearance when voltages are slightly high (around 1.09 pu), the facility starts injecting entirely active current. About two cycles later, the facility is injecting entirely reactive current.[33] Finally, about 100 ms later, the facility is again injecting entirely active current. It is believed that the anomalous injection of entirely active and reactive current may be due to coordination issues between the plant controller and inverter controls.
- **Rapid Return to Service by Tripped Inverters:** The 15 inverters that tripped on instantaneous ac overvoltage began recovery back to pre-disturbance levels after 10 seconds (see **Figure B.5**). This type of tripping is commonly followed by a 5-minute auto-restart timer. This facility was able to bring the inverters back significantly faster; this should be explored for all existing inverters from this manufacturer.
- **Primary Frequency Response due to Curtailment:** Due to the previous curtailment of the facility prior to the fault, the facility was operating with headroom[34] to provide frequency response capability. When frequency declined, many of the inverters within the facility that remained on-line responded by increasing their active power output in response to the declining system frequency (see **Figure B.5**).

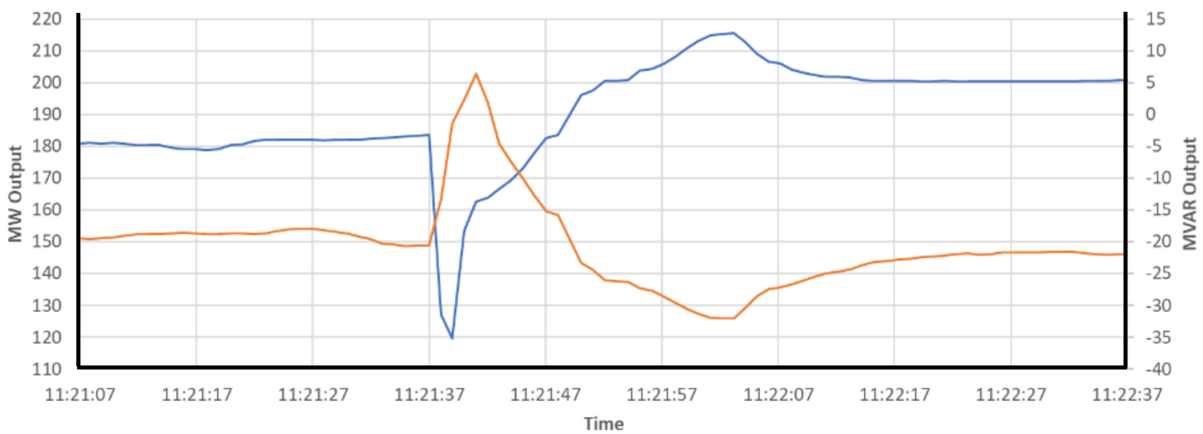


Figure B.3: Plant Active and Reactive Power Output

[33] Note current polarity is reversed in the phasor diagrams.

[34] Operating at an active power output level below the maximum available power at that time.

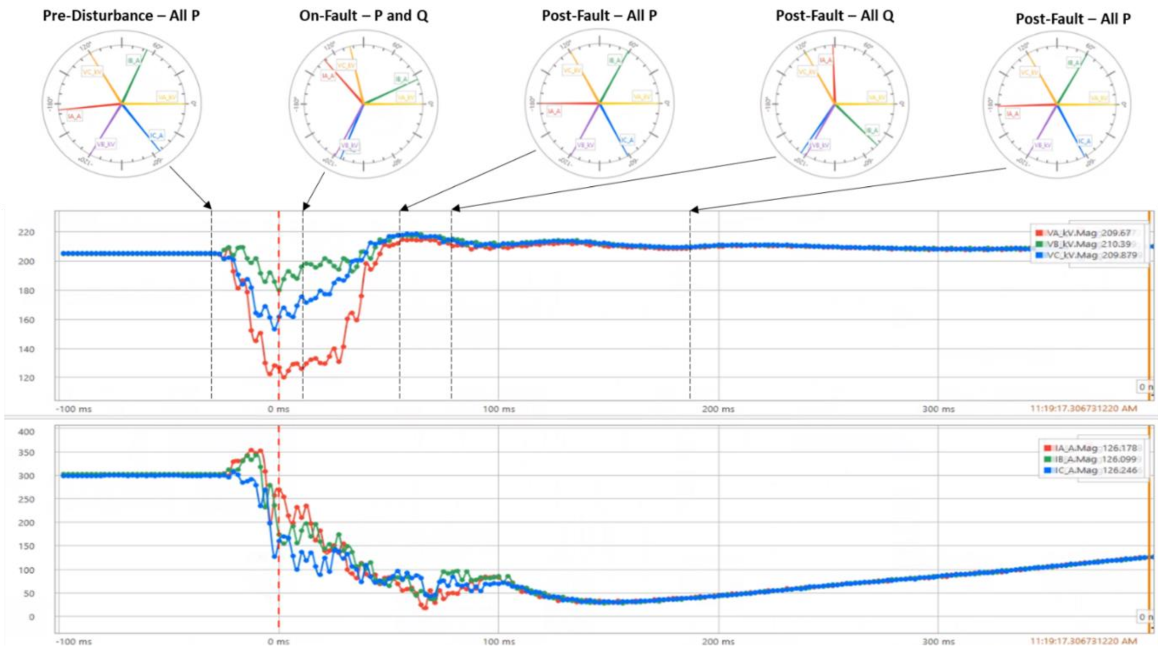


Figure B.4: High-Resolution Point-on-Wave Data Captured at POI

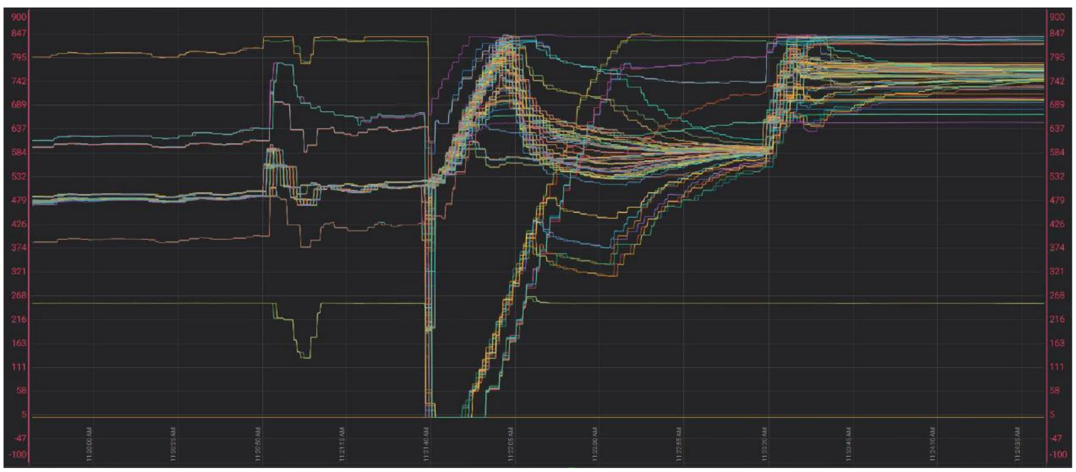


Figure B.5: Inverter Active Power Output per Skid

Plant E

Plant E is a 162 MW facility connected to the 138 kV network that went into commercial operation in May 2021. During the event, the overall plant reduced output by about 21 MW (see **Figure B.6**). A total of 25 inverters disconnected when a medium voltage feeder breaker tripped on measured underfrequency conditions. Frequency protective relaying was set to trip at 57.5 Hz instantaneously, and settings were programmed to match the PRC-024-3 curves exactly (see **Figure B.7**). The inverters were off-line for five days for root cause analysis.

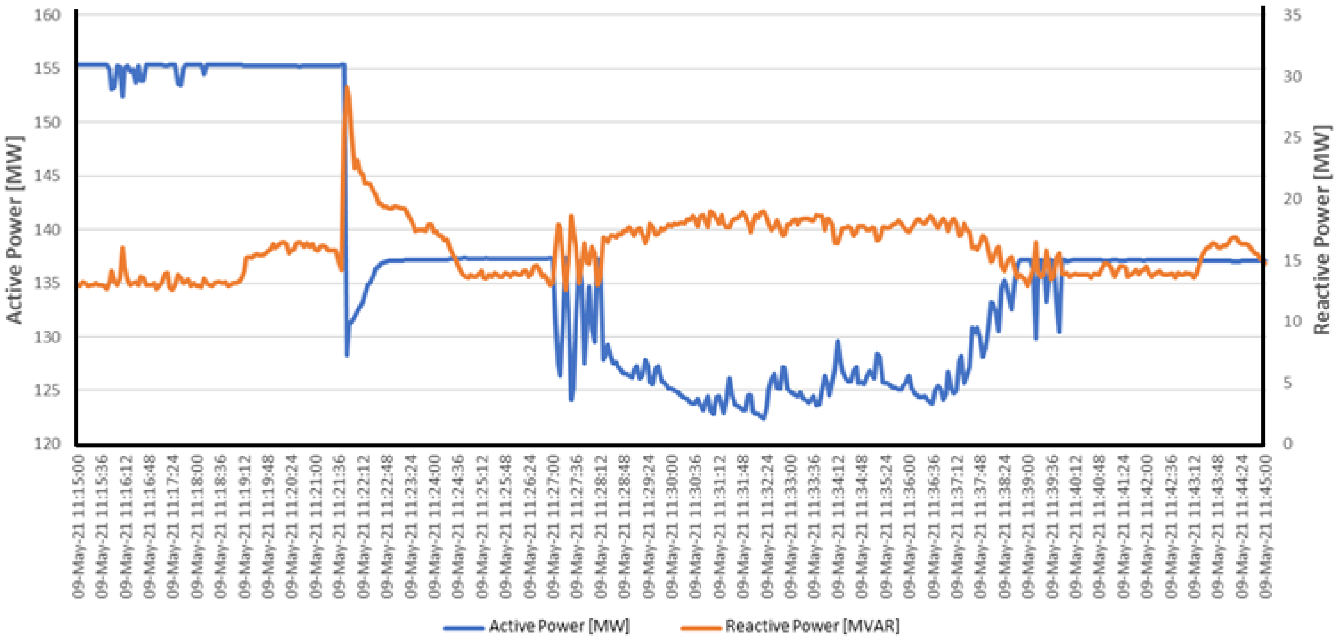


Figure B.6: Plant Active and Reactive Power Output

Frequency Range	Delay to Trip
Above 59.4 Hz	No automatic tripping (Continuous operation)
Above 58.4 Hz up to And including 59.4 Hz	Not less than 9 minutes
Above 58.0 Hz up to And including 58.4 Hz	Not less than 30 seconds
Above 57.5 Hz up to And including 58.0 Hz	Not less than 2 seconds
57.5 Hz or below	No time delay required

Figure B.7: Plant Frequency Protection Settings

There are two key findings that should be highlighted from analyzing this facility:

- **Frequency Protection Set Directly on PRC-024-3 Curves:** Frequency protection was programmed into relays on the collector system feeders to match the PRC-024-3 curves exactly. NERC stressed with the plant owner/operators that the area outside the boundaries of that curve are not a "must trip zone;" they are a "may trip zone." This is stated in every curve of PRC-024-3, as illustrated in **Figure B.8**. Furthermore, Footnote 2 on the Facilities section of PRC-024-3 clarifies that "it is not required to install or activate the protections described" in that section. NERC highlighted that protection should be based on equipment ratings and that protection is not required solely for compliance with PRC-024-3. The plant owner/operator stated that they would work with their design engineering firm to better understand if this protection was implemented mistakenly or it there are actual equipment limitations. The fact that the protection settings match the PRC-024-3 curves exactly raises concerns that the protection is not based on actual equipment ratings.

*** The area outside the "No Trip Zone" is not a "Must Trip Zone."***

Frequency Boundary Data Points – ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Minimum Time (Sec)	Frequency (Hz)	Minimum Time (sec)
≥61.8	Instantaneous[9]	≤57.5	Instantaneous[9]
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

Table 4

Figure B.8: NERC PRC-024-3 Frequency Boundary Points—ERCOT

- **Erroneous Relay Tripping on Measured Underfrequency:** Inverters in the Blue Cut Fire erroneously tripped on measured underfrequency, and this issue was corrected fleet-wide by the equipment manufacturer. Until this event, no inverter-based resources had tripped on underfrequency protection captured by a protective relay, so this event was anomalous in that this was unexpected since frequency only fell to 59.8 Hz (nowhere near the 57.5 Hz protection setting). However, frequency was measured by the protective relay at 56.9 Hz and caused a trip. **Figure B.9** shows the waveforms captured by the relay for this event. The relay manufacturer indicated that the relay performs the frequency measurement over a 3 cycle window. Analyzing the waveforms during the disturbance from the relay, it was determined that the relay measured the frequency correctly over the 3 cycle window. However, the manufacturer recommends a minimum time delay for frequency tripping to be 5 cycles. The relay was set for zero delay. This reinforces previous disturbance reports recommendations to not use an instantaneous trip setting for frequency protection.

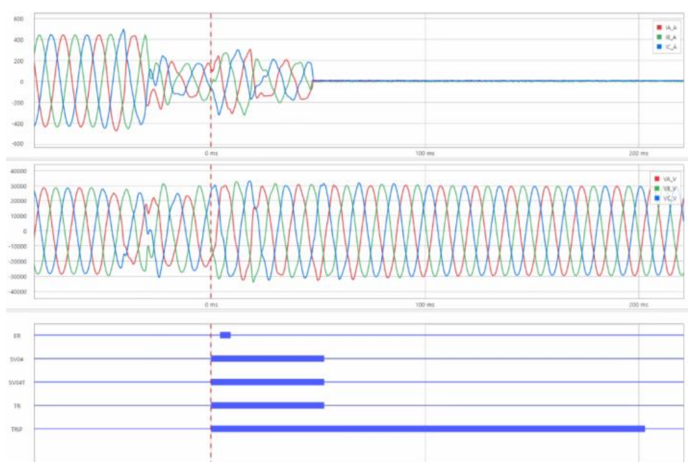


Figure B.9: Raw Unfiltered Waveforms at Feeder that Tripped

Plant F

Plant F is a 50 MW facility connected to the 69 kV network that went into commercial operation in April 2017. The plant reduced output by 48 MW during the event (see Figure B.10). All 26 inverters in the plant tripped off-line during the fault; however, only 17 of the 26 inverters recorded the cause for tripping. Those inverters indicated a “grid underfrequency” event. The plant informed the team that the underfrequency trip settings for 59.4 Hz, 58.4 Hz, and 58.2 Hz were all set to three-cycle tripping. Plant staff stated that specifically the 58.2 Hz trip setting is what triggered inverter tripping. This plant is connected to 69 kV and less than the bulk electric system size threshold, so this facility is not subject to NERC requirements. The team wanted to reach out to the facility to help improve performance regardless.

The inverters came back on-line after 7 minutes; however, the plant did not return to predisturbance output levels for 50 minutes.

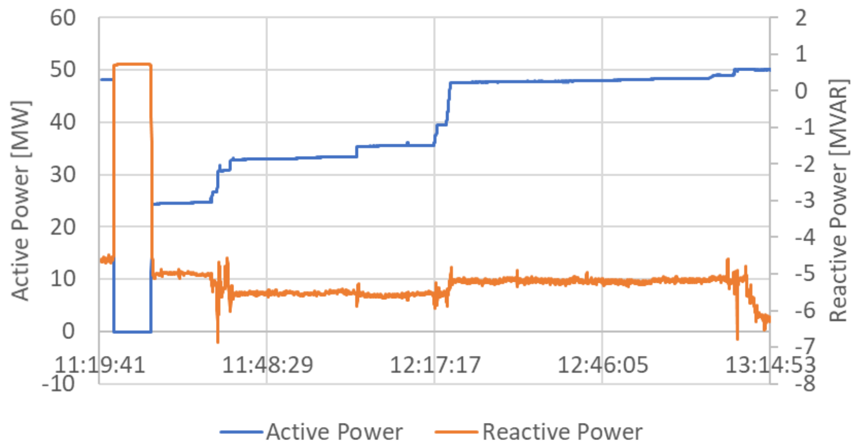


Figure B.10: Plant Active and Reactive Power Output

Plant G and Plant H

Plant G and Plant H are 121 MW and 119 MW resources, respectively, connected to the 345 kV network and went into commercial operation in December 2019. These facilities are the furthest from the fault (over 200 miles away) that responded abnormally. Plant G tripped off-line while carrying 120.9 MW and Plant H tripped off-line while carrying 118.1 MW (see Figure B.11). The GO and GOP identified that 80 of the 83 inverters reported a loss of synchronism trip code; these are indicated as “minor faults” by the inverter manufacturer. The remaining 3 inverters also tripped but did not record and trip codes. It is believed that all inverters within the facility tripped due to inverter loss of synchronism. This inverter trip is caused when the voltage phase angle change exceeds a predefined threshold (e.g., 10 degrees) and the inverter then shuts down.

> **Key Takeaway**
> In coordination with the inverter manufacturer, the plant GO/GOP was able to eliminate loss of synchronism tripping while still protecting their inverters for the entire fleet of inverters for this facility.

NERC has observed this same cause of tripping in multiple past disturbance analyses that involved BPS-connected solar PV resources, particularly from this specific inverter manufacturer. NERC has had extensive conversations with the inverter manufacturer and requested that this abnormal performance be corrected for their entire fleet. The inverter manufacturer has previously stated that the settings associated with loss of synchronism are not tunable and the issue is not correctable for existing facilities. However, the plant operator worked with the inverter manufacturer and disabled this trip function on all 83 inverters at the facility. This was completed in June 2021.

The inverters automatically reconnected and resumed power output after a five-minute automatic restart timer (likely an artifact of IEEE 1547 and set by the inverter manufacturer and GO/GOP rather than based on a performance requirement set by ERCOT). The plant stated that they can modify the automatic restart timer down to the order of 5–10 seconds if advised to do so.

Lastly, the plant appears to have exhibited abnormal oscillatory behavior during inverter reconnection and ramping upon returning to service after the fault. This was identified as an interaction between the ramping and the primary frequency response logic in the plant-level controller. The ramping logic did not register the zero-output of the inverters and expected them to stay at 240 MW. The inverters therefore followed their internal ramping limit. The large difference between the PFR logic reference and the ramping reference set points created a logic loop that caused an over-response to the frequency deviation. When the frequency returned within the dead band, the ramping logic set point was still above the plant output allowing the inverters to ramp per their internal ramp rate, trigger the cycle again. This continued until the ramping set point and PFR set points where within a range that allow the logic loop to collapse and the inverters to follow the ramping logic.

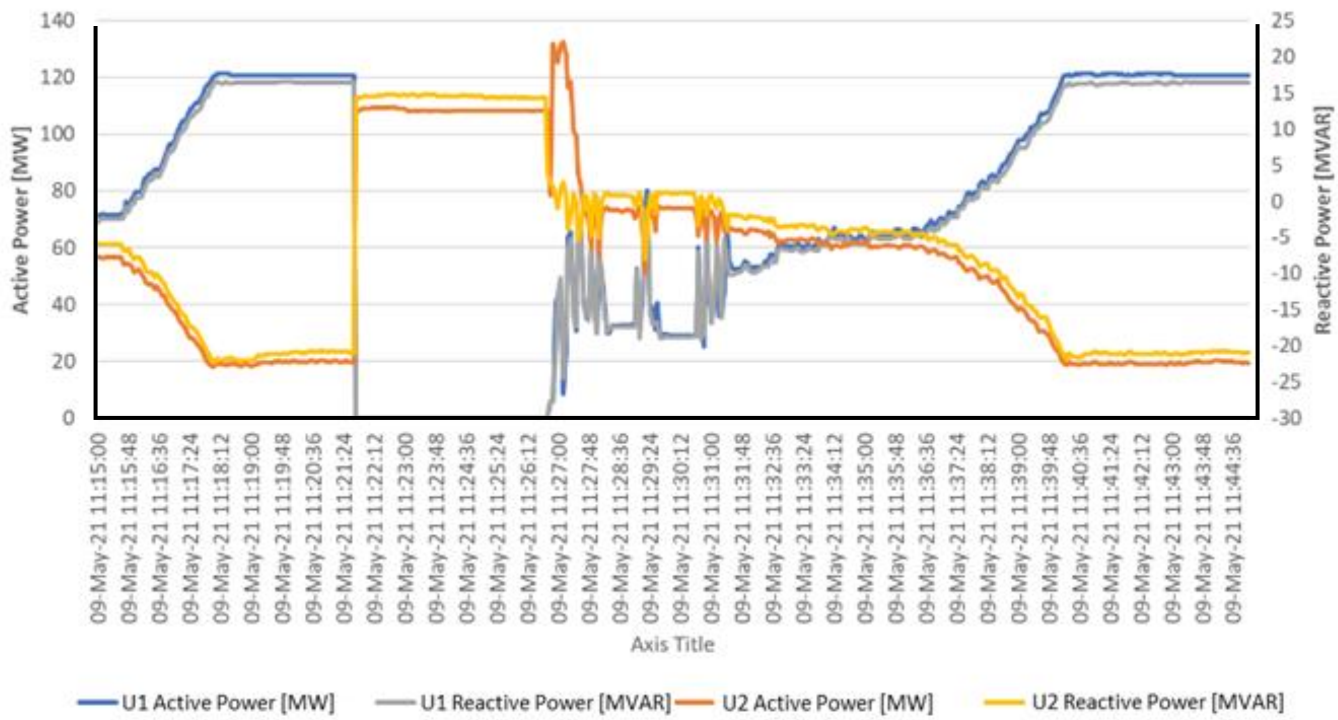


Figure B.11: Plant Active and Reactive Power Output

Plant I and Plant J

Plant I and Plant J are 154 MW and 150 MW resources, respectively, connected to the 345 kV network and went into commercial operation in June 2020. The combined reduction of active power at the time of the disturbance was 205 MW (see **Figure B.12**). Both facilities utilize the same inverter make and model and are connected to the same POI bus; however, Plant I reduced output by 152 MW while Plant J reduced output by only 53 MW.

In both cases, the inverters began injecting reactive current during the fault for ride-through operation. However, the inverters then tripped on "instantaneous AC overvoltage" set to 1.3 pu. PMU data (30 samples/second) showed that POI voltage dropped to 0.8 pu during the fault and then experienced a slight overshoot to 1.08 pu. The plant was able to retrieve inverter-level oscillography data that showed that the inverters injected reactive current into high voltage and drove inverter terminal voltages above their peak threshold values. The 1.3 pu magnitude value is a hard-coded trip threshold in the inverter that is not available to plant personnel and is separate from the RMS-based "ride-through settings" used to demonstrate PRC-024-3 compliance.

POI voltage was well within the PRC-024-2 ride-through curve, but the individual inverters experienced much higher voltages caused by their dynamic performance that essentially caused themselves to trip. The inverters are using a measurement for voltage protection that is not a filtered, fundamental-frequency RMS quantity; they are using instantaneous peak measurements that is causing the inverters to trip for normal grid fault events. This issue has been identified in multiple past NERC analyses and is a systemic issue for this inverter manufacturer.

A coordination analysis between the reactive current injection controls at the inverters and the overvoltage protection settings needs to be conducted by this facility to ensure it remains connected to the BPS for POI voltages within the PRC-024-2 curves. This facility did not meet the performance requirements laid out in PRC-024-2 and may have equipment limitations that may hinder its ability to do so.

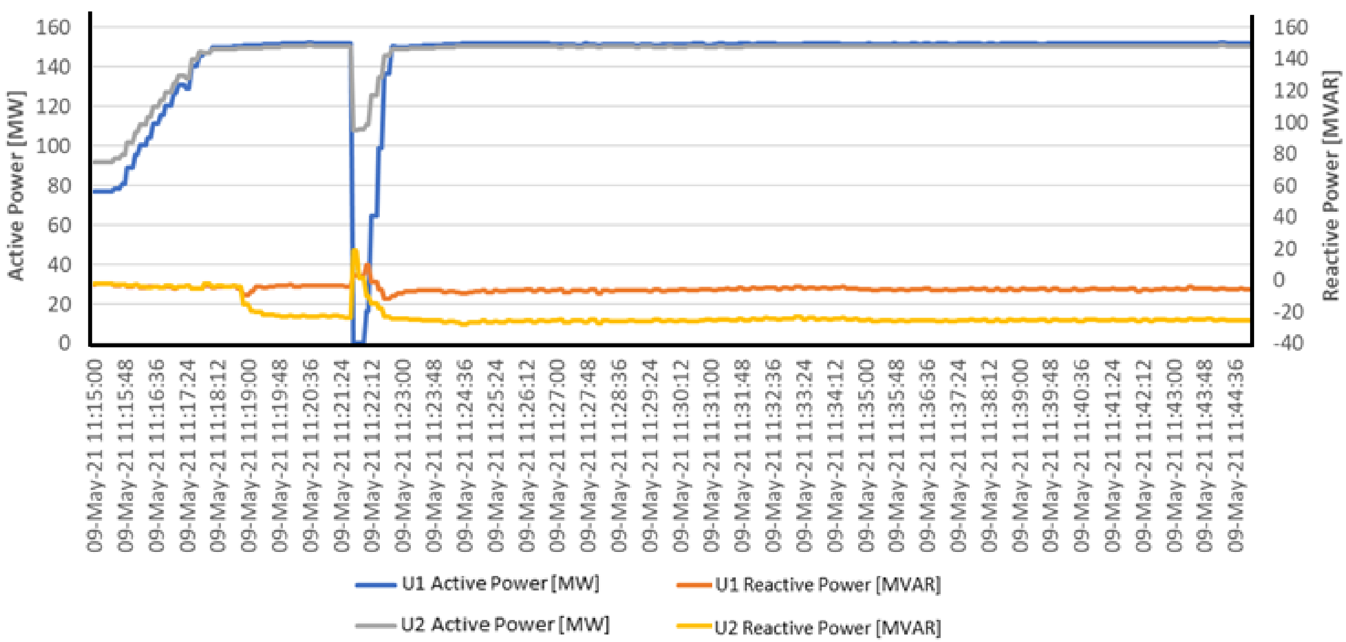


Figure B.12: Plant Active and Reactive Power Output

Plant K

Plant K is a 155 MW facility connected to the 138 kV network that went into commercial operation in March 2018. During the fault, the plant inverters responded by reducing active current to zero and injecting a small amount of reactive current[35] for 100 ms. After a 100 ms time delay and post-fault clearing, the inverters injected a combination of active and reactive current (see **Figure B.13**). The increased reactive power injection after fault clearing drove feeder voltages above 1.2 pu, tripping the feeders on instantaneous phase overvoltage (59) trip conditions. This opened all feeder breakers and the shunt capacitor breaker in the plant and caused power output to drop by 147 MW during the event (see **Figure B.14**). The plant was off-line for 1 hour 49 minutes.

There are two important findings from this analysis:

[35] The reactive current injection may be due to the inverter output capacitors remaining on-line when active current is blocked by the inverter controls. The analysis team was unable to ascertain the exact cause of the reactive current injection during this time.

- **Relay Records and DFR Data Critical for Event Analysis:** The availability of high-resolution point-on-wave data from relay event records at the POI in combination with relay sequence of events logs enabled the review team to perform the analysis for this plant and fully understand a root cause of tripping at this facility.
- **Feeder Protection:** The feeder relays were set to trip at 1.2 pu instantaneously (directly on the PRC-024-3 voltage no-trip boundary). The review team stressed to the plant owner/operator that the PRC-024 voltage trip curves are "may trip" curves, and there is no requirement for plants to trip at those levels. The review team questioned the need for instantaneous voltage protection at 1.2 pu and requested the plant follow up with their protection engineers to consider revising these settings. However, PRC-024-3 allows for instantaneous tripping above 1.2 pu when POI voltage exceeds that level.
- **Current Injection during Inverter Dynamics:** Figure B.13 shows the current injection from the facility as measured at the POI during and immediately following the fault. Prior to the fault, the plant was injecting nearly all active current. As the fault occurred, the plant began injecting mostly reactive current as voltage declined. However, active current went to zero and remained there for 100 ms, which appears to be a programmed response in the inverter controls. After 100 ms, the facility began injecting about equal levels of active and reactive current. However, at this time, voltage had fully recovered and is actually higher than predisturbance levels. At the time of tripping, the facility attempted to inject reactive current into high voltage (around 1.23 at POI), which is exacerbating the problem and leading to high voltage conditions that ultimately result in plant tripping. This clearly illustrates that this facility has coordination issues between its controls, limiters, and protection that should have been identified during the interconnection study process and mitigated prior to commercial operation. Dynamic simulation should have identified the incorrect injection of reactive current at this facility and corrected this behavior prior to allowing the facility to interconnect.

The combination of these two findings raises concerns by NERC that the existing standards and interconnection requirements do not mitigate reliability risks appropriately. Plants are being commissioned with improperly tuned and coordinated controls and protection settings. Plants are abnormally responding to BPS disturbance events and ultimately tripping themselves off-line. These issues are not being properly detected by the models and studies conducted during the generator interconnection study process nor during annual planning assessments. Improvements to the generator interconnection procedure, agreements, and study processes are strongly recommended.

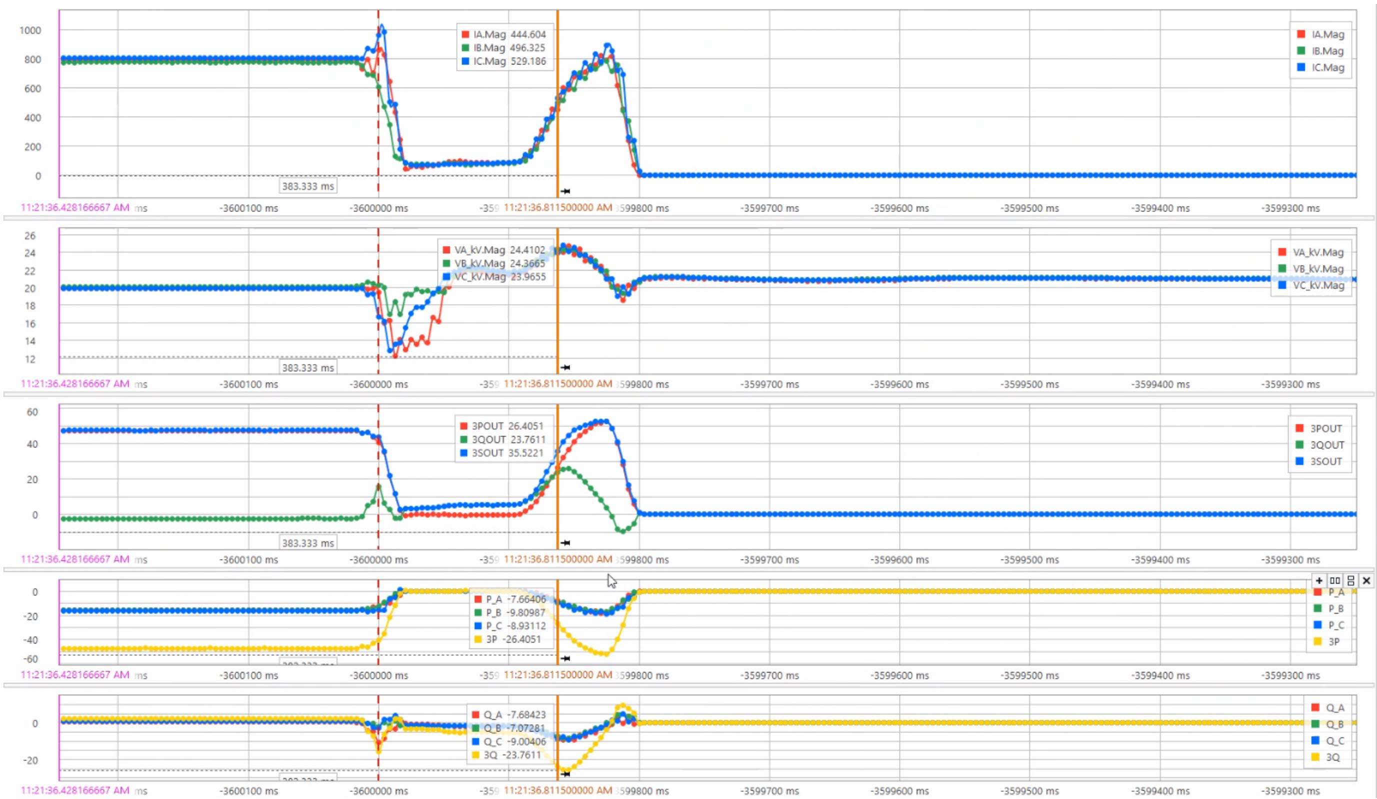


Figure B.13: Current Injection at Time of Trip

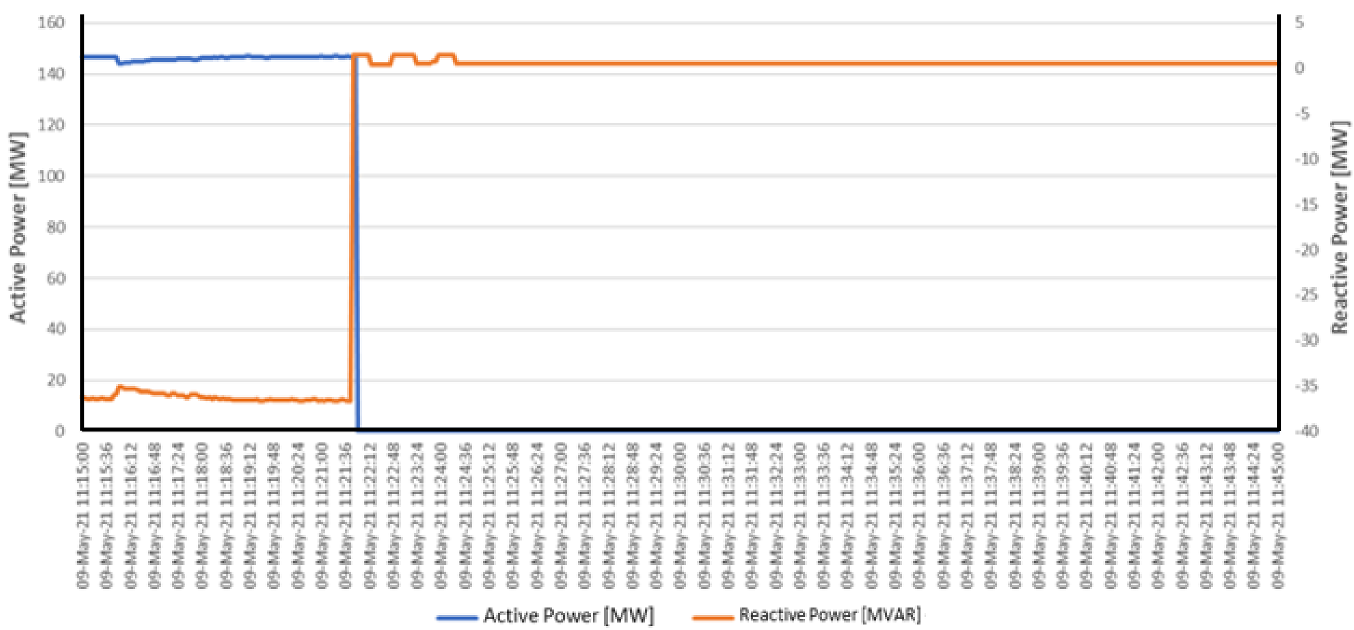


Figure B.14: Plant Active and Reactive Power Output

Plant L and Plant M

Plant L and Plant M are a combined 157.5 MW facility connected to the 138 kV network that went into commercial operation in September 2016. The plant owner/operators stated[36] that nearly all of the inverters at both sites lost synchronization at the time of the fault on the BPS (see **Figure B.15**). However, these inverters also have momentary cessation settings of 0.9 pu with a 200 ms delay to start recovery with a 500%/second recovery ramp rate.

Upon fault clearing, the inverter power output began ramping back to predisturbance levels. However, the response of these plants, particularly their return to predisturbance output levels, does not meet the recommended performance specified in the NERC reliability guidelines. Plant L took nearly 5 minutes and Plant M took about 1.5 minutes to return to near predisturbance output. However, both plants exhibited an anomalous recovery behavior that appears to have limited them from returning to full predisturbance levels until nearly 18 minutes later. Plant controller ramp rates (set at around 8 MW/minute upward ramp and 16 MW/minute for emergency ramps) interacted with the inverter-level recovery, precluding the inverter ramp rate (500%/second) from fully recovering within 0.5 seconds. This is a systemic issue observed across multiple BPS-connected solar PV plants in both the WECC and Texas RE regions. The inverter controls should fully recover power output back to pre-disturbance levels rather than being limited by the plant controller, which is set based on BA ramp rate requirements.

The plant responded to questions regarding mitigating measures to eliminate the plant controller ramp rate interactions with “N/A” so no further modifications to improve performance are expected from this facility. It will continue to not meet the recommendations set forth in the NERC reliability guidelines.

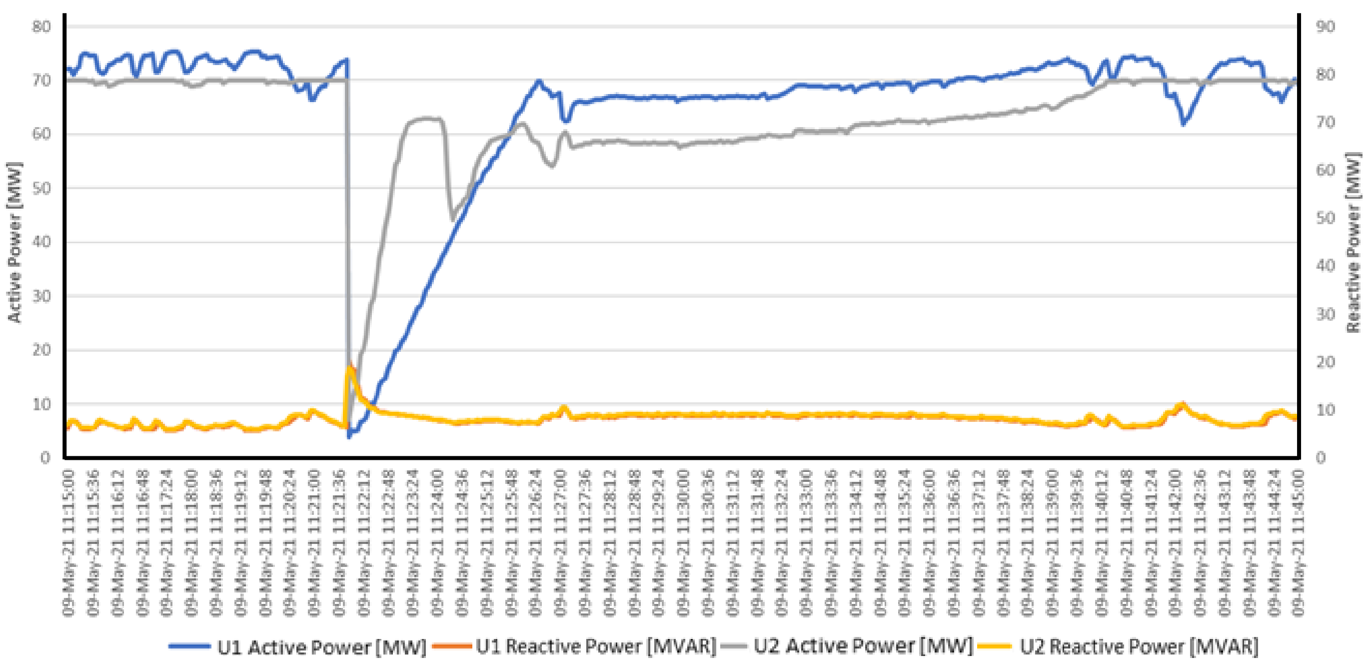


Figure B.15: Plant Active and Reactive Power Output

Plant N and Plant O

Plant N is a 110 MW facility that went into commercial operation in March 2017. Plant O is a 50 MW facility that went into commercial operation in November 2016. The combined plant active power output dropped by 23 MW during the event (see **Figure B.16**).

[36] Reported that a phase jump at the inverter terminals exceeding 20˚ cases inverter PLL loss of synchronism, which can invoke momentary cessation to protect the inverter power electronics for this specific inverter manufacturer.

During the fault, the inverters responded by providing reactive power to the system, as expected (reactive power polarity in **Figure B.16** is reversed). Steps in reactive power injection after the fault appear to be from the facility maintaining voltage schedule on the BPS; however, no additional information or data was available. The plants did not indicate any cause for inverter tripping.

Plant O returned to predisturbance output in about 20 seconds while Sirius #1 required about 6 minutes to recover. However, Plant N exhibited anomalous oscillations during recovery with power swings for about 15 minutes that reached about 9 MW. Furthermore, the post-fault oscillations are similar to other facilities for this event and are likely due to improperly configured active power-frequency controls or other controls instability or oscillatory instability issues.

The occurrence of this level of oscillatory behavior warrants immediate detailed analysis by ERCOT and the affected facilities. This should include a detailed EMT study of this facility, the local interconnecting transmission system, and all neighboring facilities (as deemed necessary by ERCOT).

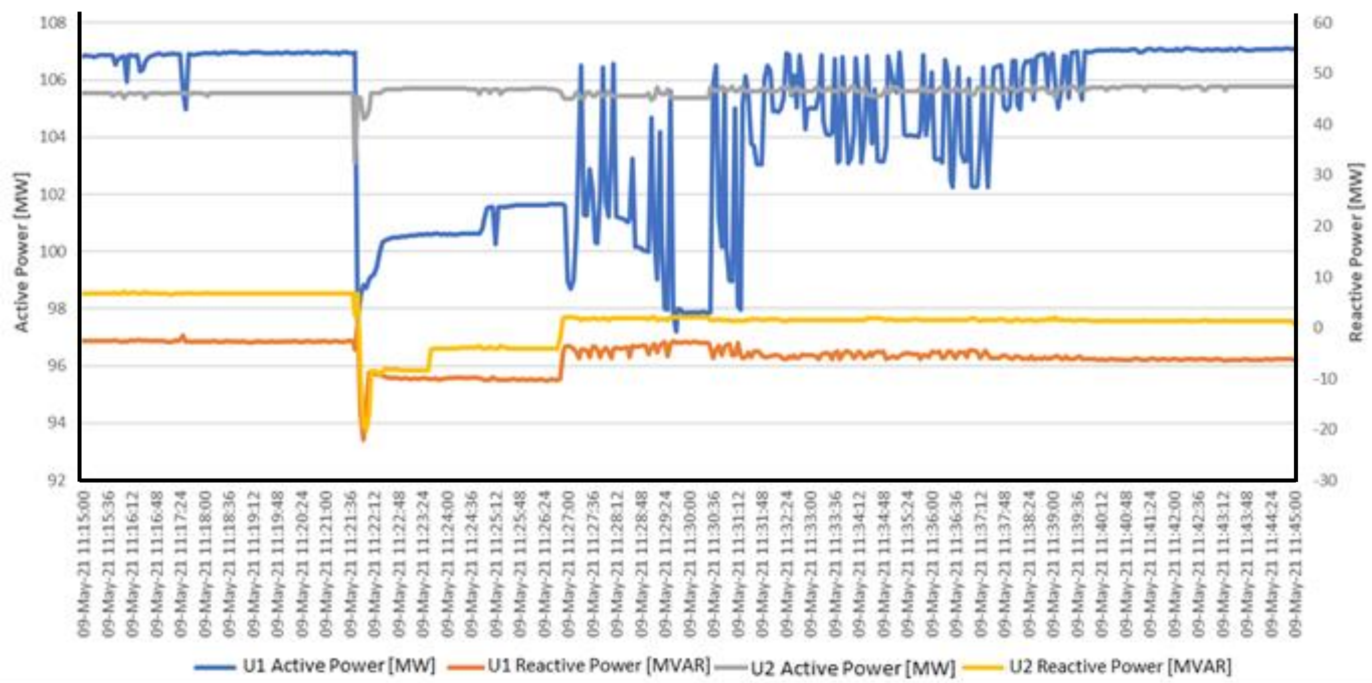


Figure B.16: Plant Active and Reactive Power Output

Affected Wind Power Plants

Table B.2 shows the wind power plants that reduced power output during this fault event. A detailed analysis of the causes of wind plant reduction was not conducted by NERC or Texas RE. The combined wind power reduction for this event was 36 MW. All affected wind plants consist entirely of Type 3 wind turbines. Figure B.17–B.20 show the response of each affected plant.

Table B.2: Review of Wind Facilities

Facility ID	MW Capacity	Reduction	POI Voltage	In-Service Date	Data Resolution	NERC-Texas RE Review
Plant W1	37.5	13.8	345	November 2003	4-second (ERCOT SCADA Data)	NERC and Texas RE did not conduct a detailed analysis of the causes of reduction of wind power output from these resources.
Plant W2	105	7.3	345	November 2003		
Plant W3	142.5	6.5*	345	July 2008		
Plant W4	115.5	8.3	345	July 2008		
TOTAL		**35.9**				

* Modified by NERC and Texas RE from ERCOT brief report.

Figure B.17: Plant W1

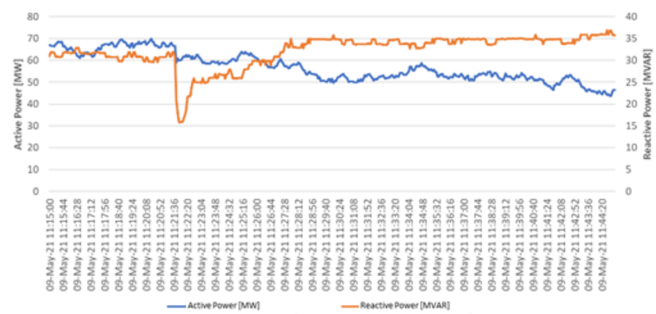


Figure B.18: Plant W2

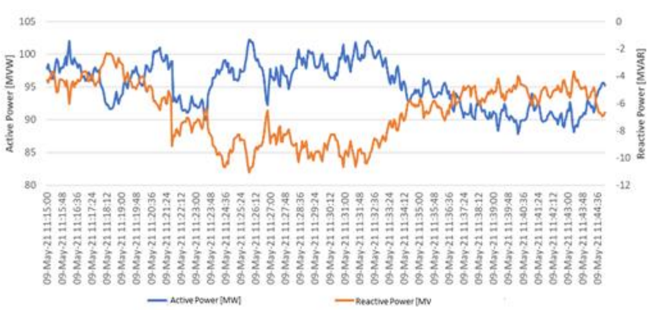


Figure B.19: Plant W3

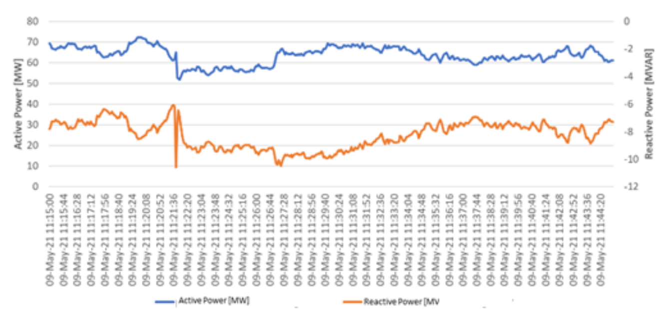


Figure B.20: Plant W4

Affected Combined-Cycle Facility

The combined cycle plant is a 1,356 MVA facility connected to the 345 kV network that went into commercial operation in June 2001. The plant consists of two 2x1 combined-cycle (CC) blocks that consist of two CTs and one steam turbine (ST). Prior to the event, CT11 was in startup. Table B.3 shows the predisturbance operating conditions, the lowest power output reached for each unit, and the cause of reduction. The fault occurred on the 345 kV high-side of the GSU for CT11. CT11 tripped consequentially due to the fault. CT21 ran back power output for an unknown reason,[37] and ST20 experienced a decaying power output due to CT21 tripping. In total, the plant reduced output by 192 MW. Figure B.21 shows the net power output from each on-line unit in the facility.

Table B.3: Review of Combined Cycle Plant Tripping

Unit	Nameplate Capacity [MW]	Pre-Disturbance Output [MW]	Reduction [MW]	Cause of Tripping
CT11 (CC1)	176	12	12	Consequential tripping from fault on 345 kV surge arrestor
CT12 (CC1)	176	0	0	N/A
ST10 (CC1)	224	0	0	N/A
CT21 (CC2)	176	142	131	Turbine-generator runback for unknown reason
CT22 (CC2)	176	0	0	N/A
ST20 (CC2)	224	72	49	Steam turbine power decay from CT runback
TOTAL			**192**	

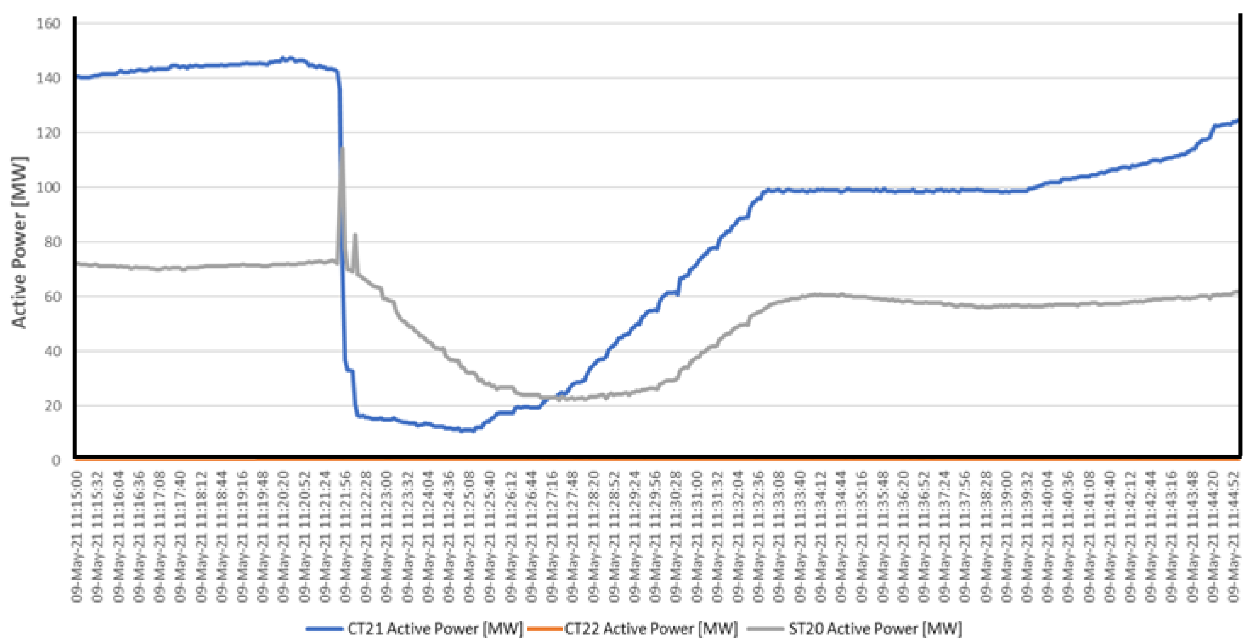


Figure B.21: Combined Cycle Plant Unit 2 Active Power Output

[37] The turbine controller manufacturer does not allow the generator owner/operator to access their relay, protection, or controls logs; therefore, the owner/operator must contract the equipment manufacturer to access the records which is taking a significant amount of time due to manufacturer prioritization.

Appendix C: ERCOT June 26, 2021 Solar Plant Tripping Event

At approximately 11:14:27 on June 26, 2021, an A-phase-to-ground fault occurred on a 345 kV circuit about 40 miles north of Odessa, Texas. The H-frame structure experienced a failure (see **Figure C.1**). Line differential protection cleared the fault normally in about three cycles. This fault caused several solar PV resources to have reduced active power output for a loss of approximately 518 MW. Frequency dropped to 59.927 Hz and began to recover. About one second later, one end of the faulted line attempted a reclose and experienced an A-C-ground fault and cleared in about 3.5 to 4 cycles. Then about 30 seconds later, the other end of the line attempted a reclose and experienced a three-phase-to-ground fault that cleared in 4.5 cycles. This fault resulted in the loss of around 179 MW of solar PV resources. Frequency then dropped to 59.935 Hz and recovered to 60 Hz within 1 minute and 15 seconds. **Figure C.2** shows the ERCOT solar PV output during the faults and **Figure C.3** shows system frequency. **Table C.1** shows the predisturbance operating conditions at the time the events occurred.

Figure C.1: Failed H-Frame

NERC and Texas RE analyzed the event in coordination with ERCOT and focused specifically on solar PV resources that reduced power output by more than 15 MW for either fault event. **Table C.2** shows a comparison of the magnitude of power reduction and the causes of reduction for the May 9 and June 26 events.

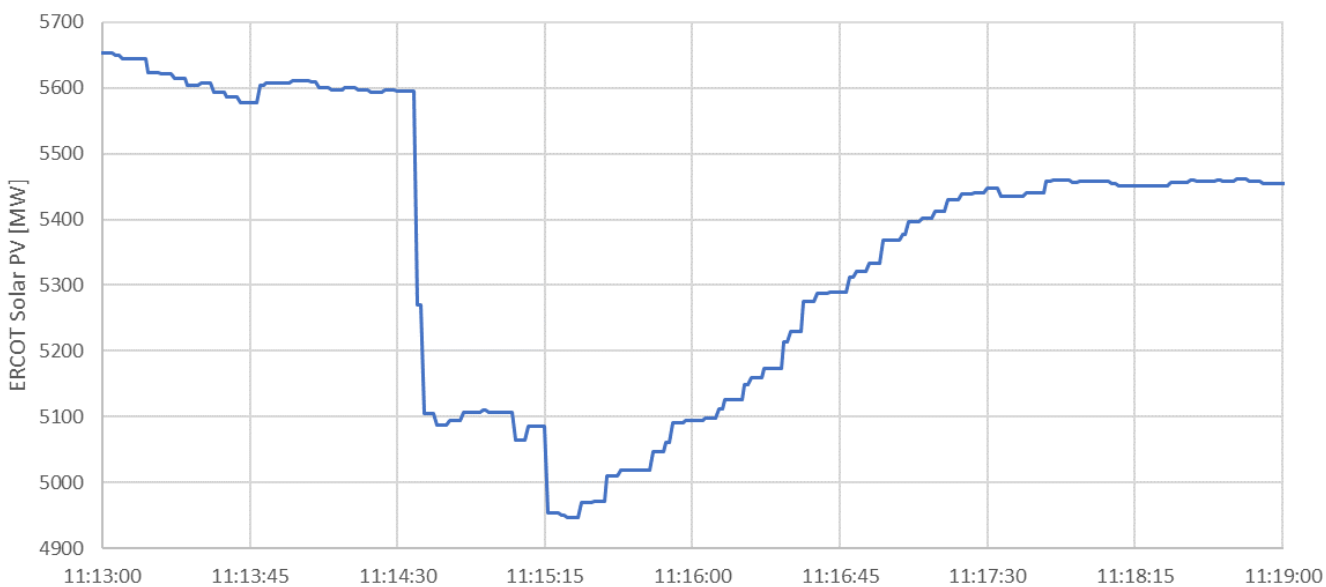


Figure C.2: ERCOT Solar PV Profile during Fault Events

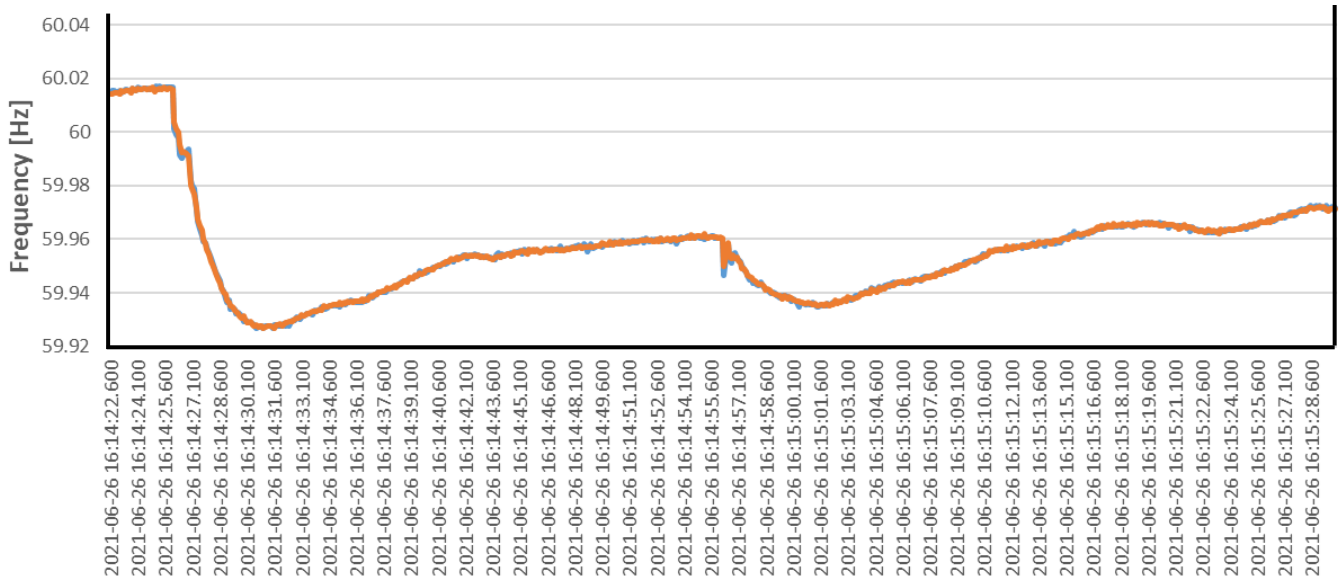


Figure C.3: June 26 Event System Frequency

Table C.1: Predisturbance Resource Mix		
BPS Operating Characteristic	**MW**	**%**
Internal Net Demand	56,985	-
Solar PV Output	5,594	10%
Wind Output	12,033	21%
Synchronous Generation	39,348	69%

*ERCOT Interchange was 10 MW (importing)

Table C.2: Comparison of Events					
Facility ID	**MW Capacity**	**Cause of Reduction – May 9**	**May 9 Reduction [MW]**	**Cause of Reduction – June 26**	**June 26 Reduction [MW]**
Plant I	154	Inverter tripping on instantaneous ac overvoltage	205	Inverter tripping on ac overcurrent and ac undervoltage	131
Plant J	150				129
New Plant 1	126.5	No reduction.	0	"No Modules" Fault Code – Unknown Cause	113
New Plant 2	126.5				110
Plant M	155	Feeder breaker tripping on instantaneous ac overvoltage	147	Inverter tripping on instantaneous ac overvoltage tripping	143*

* Tripped for second fault event; all other facilities tripped on first fault event for June 26 event.

The following sections provide a brief description of each facility's performance in the June 26 event and any relevant comparisons with the May 9 event.

Plant I and Plant J

In the June 26 event, this facility tripped on inverter-level ac overcurrent and ac undervoltage protection. The combined facility (Plants I and J) output decreased by 260 MW (see **Figure C.4**). **Figure C.5** shows high-resolution point-on-wave oscillography data at the POI during the fault event. POI voltage is within the PRC-024-3 voltage boundaries.

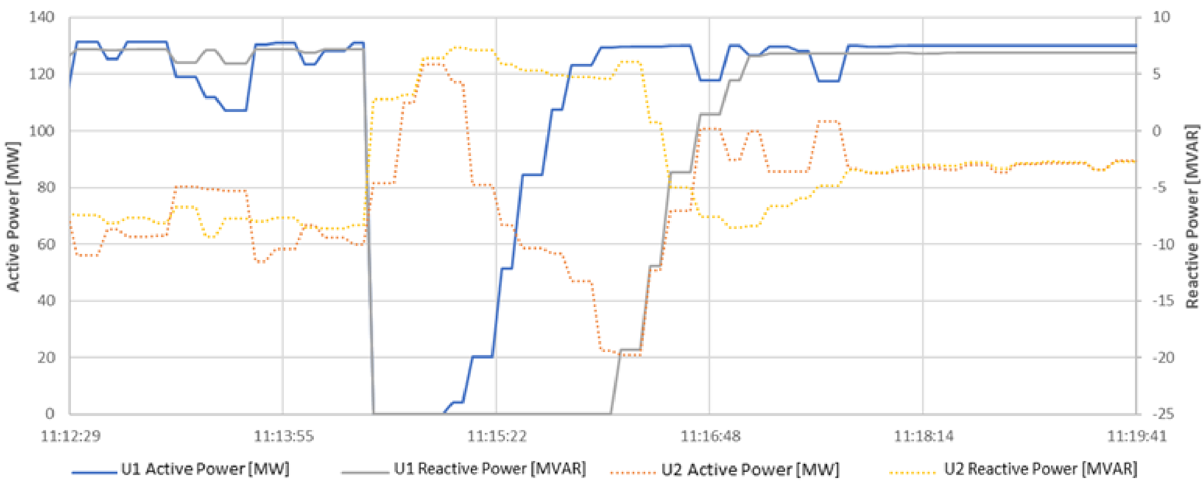


Figure C.4: Plant I and Plant J Active and Reactive Power Output

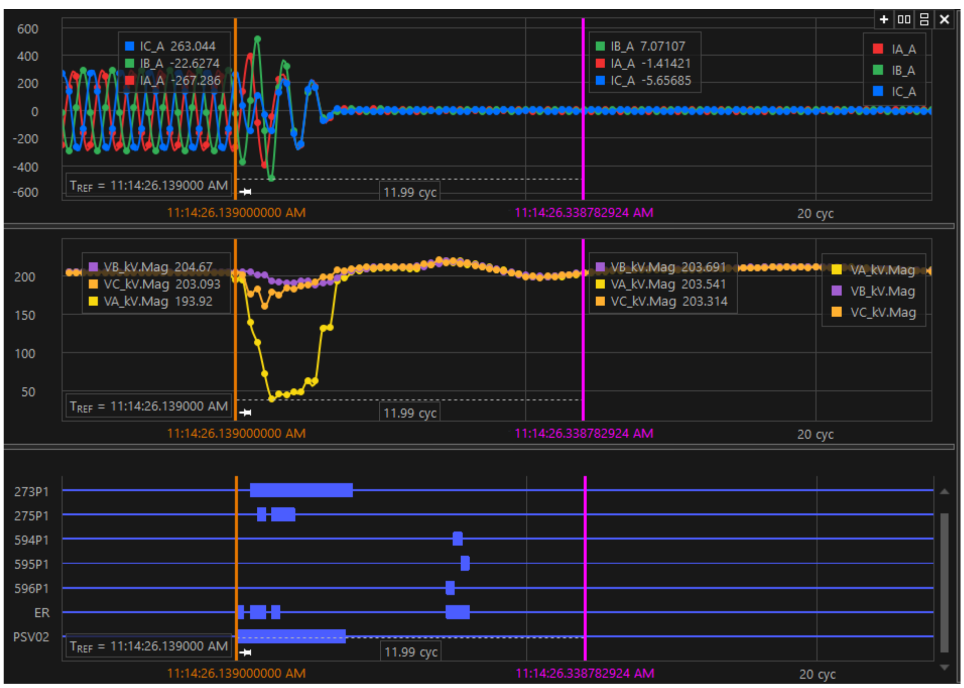


Figure C.5: June 26 Event System Frequency

In the May 9 event, this facility tripped on inverter-level instantaneous ac overvoltage conditions while the POI voltage remained within the PRC-024-3 voltage boundaries. For the June 26 event, the facility tripped on a different tripping mechanism: ac overcurrent and ac undervoltage. The ac overcurrent is a peak (instantaneous) measurement also hard-coded into the inverter. This setting is set by the equipment manufacturer at 150% of rated value. Between these two events, it is likely that the equipment manufacturer had disabled the inverter loss of synchronism tripping (as mentioned previously in this report) and that another form of protection then triggered for the latter event. This raises concerns that the disabling of PLL loss of synchronism tripping does not mitigate the potential of tripping for these inverters; rather, another form of tripping will still trip the facilities for future events.

The important commonality between these events is that the POI voltage remained within the PRC-024-3 voltage boundaries while inverters throughout the plant experienced significantly different terminal conditions. All causes of inverter tripping—instantaneous ac overvoltage, ac overcurrent, and dc undervoltage—are equipment protections set by the inverter manufacturer that are hard-coded into the inverter and not made available to nor modifiable by the plant owner/operator.

New Plant 1 and 2

In the June 26 event, this facility was in the commissioning process. The facility tripped on an unknown fault code of "no modules." No further information was available from the plant or inverter manufacturer. The combined facility (New Plant 1 and New Plant 2) output decreased by 223 MW (see **Figure C.6**).

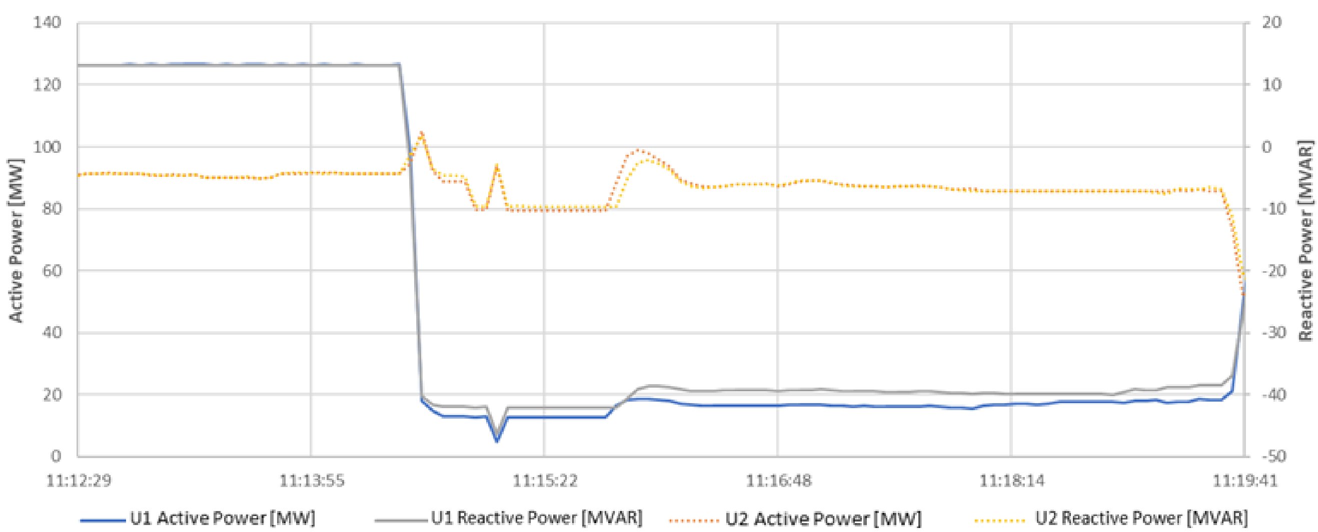


Figure C.6: New Plant 1 and New Plant 2 Active and Reactive Power Output

This facility was off-line for the May 9 event.

Plant M

In the June 26 event, this facility tripped on inverter-level instantaneous ac overvoltage protection. **Figure C.7** shows the trip and reconnection that occurred five minutes later. For the May 9 event, the facility tripped on ac overvoltage protection that operated the feeder breakers rather than the individual inverters.

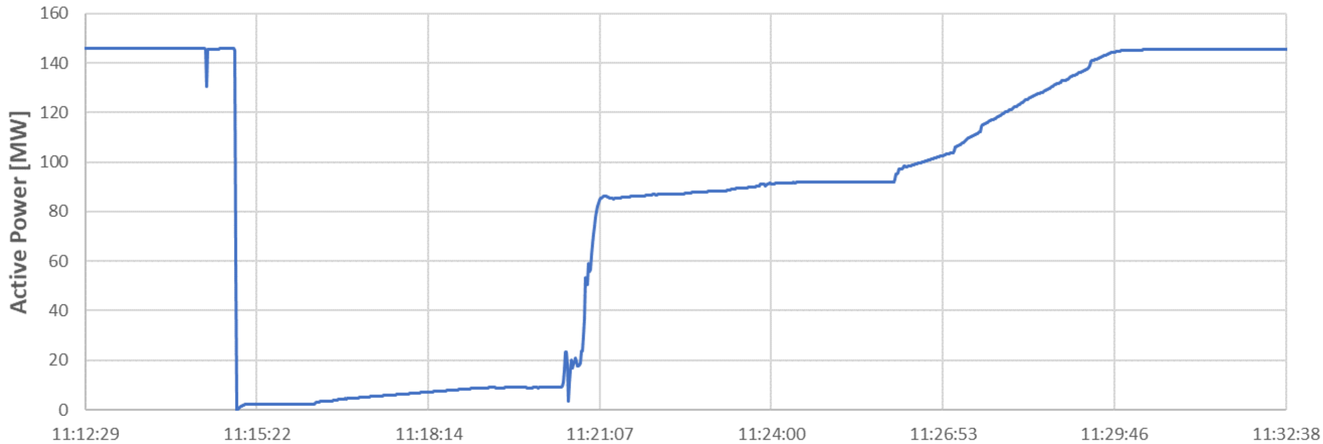


Figure C.7: Plant Active Power Output

The combination of these two events, both with plant-wide overvoltage conditions, highlights the risk this facility poses to systemic voltage-related tripping during fault conditions on the BPS. The plant is not properly coordinated to ride-through normal voltage excursions experienced during BPS fault events, and a coordination study should be conducted immediately.

The risk of this facility tripping during normal fault events on the BPS should have been identified during the interconnection study process using the dynamic models provided to ERCOT. As described throughout this report, this highlights a significant gaps in the interconnection study process that is allowing facilities to interconnect to the BPS in an unreliable manner. A comprehensive model review and analysis of the interconnection studies conducted to-date should be conducted.