Planning Committee Meeting

Agenda

**Joint Session – OC-PC-CIPC: June 6, 2017 | 10:00am – 12:00pm (PST) **
**Executive Committee Meetings: 8:00 – 10:00am (PDT) **

June 6, 2017 | 1:00 – 5:00pm (PST)
June 7, 2017 | 8:00am – 12:00pm (PST)

The Westin San Diego
400 West Broadway
San Diego, CA 92101

Tuesday, June 6

Administrative Items and Committee Updates

1. Administrative
   1:00 – 1:15pm
   a. Introductions – Brian Evans-Mongeon, Acting PC Chair
   b. Arrangements and Safety Briefing – Westin San Diego Staff
   c. NERC Antitrust Compliance Guidelines and Public Announcement – Elliott Nethercutt, PC Secretary
   d. Announcement of Quorum – Elliott Nethercutt, PC Secretary
   e. Consent Agenda – Brian Evans-Mongeon, Acting PC Chair
      i. March 7-8, 2017 Meeting Minutes
      ii. June 6-7, 2017 Meeting Agenda

2. Committee Updates
   1:15 – 1:45pm
   a. Opening Remarks and Committee Updates – Brian Evans-Mongeon, Acting PC Chair
      i. May NERC Board of Trustees Meeting Update*
      ii. RISC Update
      iii. Monthly Activity Schedule Email and Review Periods
      iv. Emerging Technology Efforts
      v. Standards Grading Exercise
   b. May SCCG Meeting Update – John Moura, NERC
   c. Future Meetings – Elliott Nethercutt, PC Secretary
      i. September 12-13, 2017 | Québec City, Québec
      ii. December 12-13, 2017 | Atlanta, GA
### Committee Subgroup Leadership Changes
- Brian Evans-Mongeon, Acting PC Chair
  
  i. Probabilistic Assessment Working Group (PAWG)
  
  ii. Demand Response Availability Data System Working Group (DADSWG)

### Committee Business

1. **PC Election | Report from Nominating Committee and Vote** – Elliott Nethercutt, PC Secretary  
   1:45 – 2:00pm

2. **2017-Q2 PC Work Plan | Review** – Elliott Nethercutt, PC Secretary  
   2:00 – 2:15pm

3. **Reliability Guideline: Forced Oscillations and Developing Load Model Composition Data | Update on Industry Reviews** – Elliott Nethercutt, PC Secretary  
   2:15 – 2:30pm

4. **Performance Analysis Subcommittee (PAS) and State of Reliability 2017 | Update and Approval** – Paul Kure, PAS Chair; David Till, NERC  
   2:30 – 2:45pm
   
   **Background/Objective:** Present the State of Reliability 2017 for approval; outline near term PAS activities.
   
   **Related PC Subgroup(s):** PAS  
   
   **Action:** Approval
   
   **Background Materials:** State of Reliability 2017
   
   **Meeting Notes:**

   **BREAK**  
   3:00 – 3:15pm

5. **Solar Resource Performance Task Force | Scope Approval** – Ryan Quint, NERC  
   3:15 – 3:30pm

   **Background/Objective:** As a result of the work of the Inverter Task Force (item 9a), a new joint OC/PC task force is being established to explore the performance characteristics of solar photovoltaic (PV) resources connected to the bulk power system (BPS). This task force will build off of the experience and lessons learned from the ad hoc task force created to investigate the loss of solar PV resources during the Blue Cut Fire event and other fault-induced solar PV resource loss events. The joint task force will address many of the recommendations from the Blue Cut Fire Disturbance Report, including additional system analysis, modeling, and review of inverter behavior under abnormal system conditions. Recommended performance characteristics will be developed along with other recommendations related to inverter-based resource performance, analysis, and modeling. The technical materials are intended to support the utility industry, Generator Owners with solar PV resources, and equipment manufacturers by clearly articulating recommended performance characteristics, ensuring reliability through detailed system studies, and ensuring dynamic modeling capability and practices that support BPS reliability. The objective is to review and approve the Solar Resource Performance Task Force Scope Document.

   **Related PC Subgroup(s):** N/A
   
   **Action:** Approve Scope Document
   
   **Background Materials:** Solar Resource Performance Task Force Scope Document*
   
   **Meeting Notes:**
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<tbody>
<tr>
<td>6. Geomagnetic Disturbance Task Force (GMDTF)</td>
<td>Update – Frank Koza, GMDTF Vice Chair</td>
<td>2:45 – 3:00pm</td>
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<td><strong>Background/Objective:</strong></td>
<td>Inform the PC on Standards Drafting Team (SDT) activities to draft revisions to the GMD planning standard (TPL-007) addressing directives in FERC Order No. 830. In the Order, FERC directed NERC to develop revisions to TPL-007 addressing the following: (i) modify the benchmark GMD event used in GMD Vulnerability Assessments; (ii) require entities to collect of geomagnetically-induced current (GIC) data; and (iii) require deadlines for Corrective Action Plans (CAP) and GMD mitigation. The SDT held a webinar with the GMD TF to discuss the initial draft TPL-007-2 in May.</td>
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<td><strong>Related PC Subgroup(s):</strong></td>
<td>GMDTF</td>
<td><strong>Action:</strong> Informational</td>
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<tr>
<td><strong>Background Materials:</strong></td>
<td>N/A</td>
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<tr>
<td><strong>Meeting Notes:</strong></td>
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| 7. Reliability Assessment Subcommittee (RAS) | Update – Phil Fedora, RAS Chair | 3:30 – 4:00pm |
| **Background/Objective:** | Status of major 2017 Reliability Assessment Subcommittee initiatives, including the 2017 Summer Reliability Assessment, development of the 2017 Long Term Reliability Assessment, liaison activities with the Essential Reliability Services Working Group (ERSWG) and Probabilistic Assessment Working Group (PAWG) activities. |   |
| **Related PC Subgroup(s):** | RAS, PAWG | **Action:** Informational |
| **Background Materials:** | N/A |   |
| **Meeting Notes:** |   |   |

| 8. Probabilistic Assessment Working Group (PAWG) | Update – Noha Abdel-Karim, NERC | 4:00 – 4:15pm |
| **Background/Objective:** | An update will be provided on activities underway at PAWG including preliminary results of Probabilistic Study Survey on probability-based evaluation and most common approaches used by NERC’s Regions, Assessment Areas, and industry at-large to assess resource adequacy. |   |
| **Related PC Subgroup(s):** | RAS, PAWG | **Action:** Informational |
| **Background Materials:** | PAWG Scope of Work |   |
| **Meeting Notes:** |   |   |

| 9. NERC Special Assessment: Gas-Electric Single Point of Disruption (SPOD) | Update – Tom Coleman, NERC | 4:15 – 4:45pm |
| **Background/Objective:** | Inform the PC on the latest special assessment by NERC, with support from the SPOD advisory group. |   |
| **Related PC Subgroup(s):** | N/A | **Action:** Informational |
| **Background Materials:** | N/A |   |
| **Meeting Notes:** |   |   |

| **Background/Objective:** | Mr. Underwood will provide an update on NATF planning-related activities, including recent projects in the System Protection Practice Group, a recent Geomagnetic Disturbance webinar, and a distributed energy resources project in the Modeling Practices Group. He will also discuss several documents which NATF has released or will soon release for public use, report on the Joint NERC/NATF Modeling Practices Workshop, and provide an update on the NATF Resiliency Initiative. |   |
| **Related PC Subgroup(s):** | N/A | **Action:** Informational |
| **Background Materials:** | N/A |   |
| **Meeting Notes:** |   |   |
Wednesday, June 7

11. **System Analysis and Modeling Subcommittee (SAMS) | Update – Michael Lombardi, SAMS Chair**
   **8:00 – 8:15am**
   
   **Background/Objective:** An update will be provided on activities underway at SAMS and its associated task forces pursuant with the SAMS 2017 Work Plan. The update consist of informational items. Items requiring PC action are include in separate PC agenda items.

   **Related PC Subgroup(s):** SAMS  
   **Action:** Informational  
   **Background Materials:** SAMS Work Plan

12. **MOD-032 Case Improvements Tracking | Update – Ryan Quint, NERC**
   **8:15 – 8:45am**
   
   **Background/Objective:** A update will be provided of NERC’s efforts working with the MOD-032 Designees to track their efforts on improving the quality of the interconnection-wide cases (application of NERC case quality metrics, implementation of the NERC List of Acceptable Models, case fidelity improvements, etc.).

   **Related PC Subgroup(s):** N/A  
   **Action:** Informational  
   **Background Materials:** N/A

13. **Essential Reliability Services Working Group (ERSWG) | Update – Brian Evans-Mongeon, ERSWG Co-Chair; Mark Ahlstrom, ERSWG Member**
   **9:00 – 9:30am**
   
   **Background/Objective:** The ERSWG has been moving forward with its planned activities for 2017. The team has been collecting data on frequency response and ramping from resources for all four interconnections and developing assessment tools to examine historical trends that will find their way into future SOR reports, as well as predictive forecasting for illustration in the LTRA. The presentation will highlight those actions. The ERSWG will also present its data analysis and recommendations to discontinue ERS Measure 7 for Voltage and support for the use of the recently approved Reactive Power Guideline. Lastly, the ERSWG will share the SAR it developed for acting upon the DER Report recommendation for modifying NERC Reliability Standard MOD-032. The SAR is being forwarded to the NERC Standards Committee for their consideration.

   **Related PC Subgroup(s):** ERSWG  
   **Action:** Informational; approval to discontinue Voltage Measure 7  
   **Background Materials:** N/A

14. **Preparing Eastern Interconnection Cases for Frequency Response | Update – Mohamed Osman, NERC**
   **8:45 – 9:00am**
   
   **Background/Objective:** Inform the PC on the Eastern Interconnection Modeling efforts involving dynamic models for the Frequency Response Study. The presentation entails the modeling improvements recommended by NERC System Analysis Department to be incorporated into the 2016 Series ERAG MMWG Dynamic Cases. The 2016 Series ERAG MMWG Dynamic case were than benchmarked and compared to the median FNET data for the outage of Millstone unit 2 & 3. The plots will show significant modeling improvements observed in the 2016 Series ERAG MMWG dynamic cases versus the 2015 Series ERAG MMWG dynamic cases.

   **Related PC Subgroup(s):** N/A  
   **Action:** Informational  
   **Background Materials:** N/A
9:30 – 10:00am

**Background/Objective:** As the penetration of DER continues to increase across the North American footprint, Transmission Planners (TPs) and Planning Coordinators (PCs) are faced with the challenge of representing these resources connected at the distribution system with relatively newer and evolving models. With a framework established for modeling DER, the purpose of this guideline is to provide information relevant for developing models and model parameters to represent different types of U-DER and R-DER in stability analysis of the BPS. This guideline brings together many different reference materials into a consolidated guidance document for industry’s use when modeling DER for interconnection-wide powerflow cases and dynamic simulations. More detailed, localized studies may require additional or more advanced modeling, as deemed necessary or appropriate. The modeling practices described here may also be modified to meet the needs of particular systems or utilities, and are intended as a reference point for interconnection-wide modeling practices.

**Related PC Subgroup(s):** SAMS, LMTF

**Action:** Approval to post for 45-day comment period

**Background Materials:** Draft Reliability Guideline: Distributed Energy Resource Modeling*

**Meeting Notes:**

**BREAK**
10:00 – 10:15am

10:15 – 10:30am

**Background/Objective:** This technical reference document is intended to provide technical reference material for Plant-level Control and Protection Modeling. This document focuses on studying the effects of plant-level, turbine, and boiler control and protection systems on power system stability. The report outline the impacts they have on system stability during grid disturbances. Eventually lead to development of models and modeling practices sufficient to capture the critical control functions.

**Related PC Subgroup(s):** SAMS; PCPMTF

**Action:** Approval vote of final Report

**Background Materials:** PCPMTF Technical Reference Document*

**Meeting Notes:**

17. Draft Reliability Guideline: Integrating VER into Weak Grids | Approval to Post for 45-Day Comment Period – Jason MacDowell, GE/SAMS Representative; Ryan Quint, NERC
10:30 – 11:00am

**Background/Objective:** This guideline provides the electric utility industry with background and useful reference information pertaining to the topics of identifying weak grid conditions and potential issues that may arise from weak grids when connecting or operating inverter-based resources. The goal is to proactively provide the industry with information for their consideration as they face this emerging issue and increasing penetrations of inverter-based resources.

**Related PC Subgroup(s):** SAMS

**Action:** Approval to post for 45-day comment period

**Background Materials:** Integrating Variable Energy Resources into Weak Power Systems*

**Meeting Notes:**

18. System Protection and Control Subcommittee (SPCS) | Scope Updates Approval – Richard Quest, SPCS Chair
11:00 – 11:15am

**Background/Objective:** Review proposed updates of the SCPS scope.

**Related PC Subgroup(s):** SPCS

**Action:** Approve Updated Scope

**Background Materials:** SPCS Updated Scope (with redlines)*

**Meeting Notes:**
19. Member Roundtable Discussion | Update – Open Discussion
11:15 – 11:45am

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<th>Background/Objective:</th>
<th>Action: Informational</th>
<th>Background Materials: N/A</th>
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<tbody>
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<td>a. Follow up on last meeting’s emerging concerns</td>
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<td>b. Perspectives from: Industry Segments; State and Federal agencies; Regions</td>
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<td>c. Benefits/consequences of having a single RC for an Interconnected and Synchronous System</td>
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Related PC Subgroup(s):

Meeting Notes:

Closing Remarks
1. Closing Remarks – Brian Evans-Mongeon, Acting PC Chair
11:45am – 12:00pm

*Background materials included in agenda package.
**Background materials will be provided in the agenda package prior to the meeting.
Purpose
The purpose of the Solar Resource Performance Task Force (SRPTF) is to explore the performance characteristics of utility-scale solar photovoltaic (PV) resources directly connected to the bulk power system (BPS). This task force will build off of the experience and lessons learned from the ad hoc task force created to investigate the loss of solar PV resources during the Blue Cut Fire event and other fault-induced solar PV resource loss events. The joint task force will address many of the recommendations from the Blue Cut Fire Disturbance Report, including additional system analysis, modeling, and review of inverter behavior under abnormal system conditions. Recommended performance characteristics will be developed along with other recommendations related to inverter-based resource performance, analysis, and modeling. The technical materials are intended to support the utility industry, Generator Owners with solar PV resources, and equipment manufacturers by clearly articulating recommended performance characteristics, ensuring reliability through detailed system studies, and ensuring dynamic modeling capability and practices that support BPS reliability.

Activities
The joint task force will focus primarily on the Findings, Actions, and Recommendations outlined in the Blue Cut Fire Disturbance Report. These activities include:

1. Review and document the frequency and voltage ride-through characteristics of solar PV resources and clearly articulate the intended performance of these resources to support BPS reliability. Clarify the frequency and voltage curves of PRC-024-2 such that operation outside the curves is a “may trip” area (if needed to protect equipment) rather than a “must trip” area.

2. Review and document recommended delays for the lowest levels of frequency to ensure transient/distorted waveform “ride through”.

3. Explore the development of a performance-based NERC Reliability Standard that clearly addresses the control of inverter-based resources, not to be confused with the protective relay functions as specified in PRC-024-2.

4. More clearly understand the potential limitations in early generation inverter technology to meet the proposed performance characteristics that support BPS reliability. Identify the extent to which these inverters may be modified to support BPS reliability, and articulate the limitations that may exist with today’s solar PV fleet.

5. Study the impacts that inverter momentary cessation (momentarily cease active power output) for voltage excursions could have on BPS reliability. Recommend performance characteristics related to momentary cessation, including the expected voltage levels and restore output characteristics.
6. Explore more detailed simulations of high penetration solar PV conditions and the impact that momentary cessation may have on BPS reliability criteria. Determine if momentary cessation should be allowed, and to what extent these conditions are allowable. Develop technical justification for these recommended performance characteristics. Account for technological advances and incorporate dynamic simulations of high penetration operating conditions as part of the justification.

7. Define an expected or recommended operation for solar PV resources during abnormal operating conditions. This should include the type of current (active or reactive, positive-negative-zero sequence) that should be injected across the full range of potential voltage levels.

8. Coordinate with FERC, IEEE, UL, NFPA and state jurisdictions to develop a solution to any relevant conflicting requirements with NERC Reliability Standards.

9. Coordinate with IEEE P1547 members to ensure a coordinated response of inverter-based resources connected to the BES and non-BES facilities. Align terms, practices, and requirements to the extent possible.

**Deliverables**
The task force may provide the following deliverables:

1. Reliability guideline on solar PV (and other inverter-based resource) performance addressing, at a minimum, the topics listed above

2. Recommendations on solar PV resource performance and any modifications to NERC Reliability Standards related to the control and dynamic performance of these resources during abnormal grid conditions

3. Detailed studies of any potential reliability risks under high penetration of solar PV given the findings from the Blue Cut Fire event and other related grid disturbances involving fault-induced solar PV tripping

4. Webinars and technical workshops to share findings, technical analysis, and lessons learned to support information sharing across North America

5. Other activities as directed by the NERC Planning Committee (PC) and Operating Committee (OC) in coordination with the Standards Committee

**Membership**
The task force will include the members from the original ad hoc task force as well as members selected by the NERC PC and OC. The majority of topics to be addressed have a focus on planning-related activities such as detailed stability simulations of the BPS, modeling capabilities, and inverter controls technologies; however, operational aspects to ensure grid reliability in the near-term time horizon will also be considered. Members should have expertise in the following areas:

- Understanding of inverter design, controls, and manufacturing for solar PV and other inverter-based resources
- Plant-level controls and the relationship between these controls and individual inverter controls
• Inverter-based resource performance characteristics, particularly performance under abnormal voltage and frequency conditions, phase angles changes, phase lock loop dynamics, and other performance characteristics

• Performing transient stability simulations and modeling of solar PV and other inverter-based resources, including modeling and model parameters for these resources

• Performing model verification testing for inverter-based resources

• BPS angular, frequency, and voltage stability, particularly under high penetration of inverter-based resources

NERC staff will be assigned as Task Force Coordinators. The task force will consist of two co-chairs who will each be appointed by the PC and OC, respectively, for the duration of the task force. Task force decisions will be consensus-based led by the co-chairmen and staff coordinators. Any minority views will be included in an appendix.

**Reporting & Duration**

The task force will jointly report to the NERC PC and OC. The task force is expected to exist no more than 18 months to develop the deliverables outlined. The task force will submit a work plan to the PC and OC, which must be approved by both technical committees.

**Meetings**

The task force is expected to have two to three in-person meetings, supplemented with conference calls to continue workload throughout the year.

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*Approved by the NERC PC on June ❘, 2017 and the NERC OC on June ❘, 2017.*
The NERC Planning and Operating Committees jointly created the Essential Reliability Services (ERS) Working Group to identify necessary services for reliability of the bulk power system (BPS). The group has been working on these issues since 2014 and previously proposed a measure related to reactive power capabilities that are essential for the management of voltage across the system (identified as Measure 7 in earlier reports). The original concept was to compile appropriate data on reactive capabilities by balancing authority (BA) and identify informative trends in those capabilities due to changes in the resource mix. This briefing summarizes the outcome of work on this measure and describes the path forward. This policy briefing distills results from other documents and does not create new findings or recommendations. References and links to the documents are provided and these original documents should be consulted for additional details when needed.

Voltage must be controlled to protect system reliability and move power where it is needed during normal operations and following system disturbances, and managing reactive power is the means by which system operations maintains the necessary voltage levels to ensure reliable operation. However, voltage issues tend to be local in nature, such as in sub-areas of the BPS. So, while the importance of reactive power is clear, the question was whether a measure of reactive power capability would be logical and useful for developing trends for larger areas such as a BA or interconnection.

The NERC System Analysis and Modeling Subcommittee (SAMS), with assistance from the NERC Performance Analysis Subcommittee (PAS), conducted a proof of concept data collection and subsequent analysis of the proposed Measure 7 data and reported their results in February 2017. Their findings show that at the level of a BA, the proposed measure would not provide useful, consistent and informative reactive capability trends related to a changing resource mix due to a variety of factors. SAMS further believes that the recent FERC Order 827 helps to alleviate BPS-level concerns of reactive deficiency due to a changing resource mix by requiring (consistent with earlier recommendations of the ERS Working Group) that all new resources connecting to the transmission system must have reactive power capability.

However, the ERS Working Group’s “Whitepaper on Sufficiency Guidelines” (Chapter 3) discussed the importance of sub-area treatment for reactive and voltage issues, and NERC SAMS reiterated that reactive power planning practices are best applied at a local level. SAMS developed the “Reliability Guideline for Reactive Power Planning” that provides a comprehensive overview of reactive power planning techniques and industry best practices. SAMS recommended the use of this guideline, in conjunction with interconnection studies, planning assessments and operational studies that are already done as part of established NERC planning and operating standards, rather than use of proposed ERS Measure 7. The ERSWG agrees and recommends that NERC’s Operating Committee and Planning Committee withdraw ERS Measure 7 from further consideration. The ERS Working Group recommends use of the Reliability Guideline for Reactive Power Planning, applied on a sub-area basis in conjunction with existing NERC planning and operating standards, to support the reactive power needs of the BPS, thereby ensuring sufficiency and reliability with a changing resource mix.

For Further Information

Reliability Guideline for Reactive Power Planning (December 2016) is strongly recommended to ensure locally-appropriate reactive power capabilities on an ongoing basis. Also refer to Chapter 3 of the ERS Whitepaper on Sufficiency Guidelines.

Measure 7 Analysis – System Analysis and Modeling Subcommittee (February 2017) provides details on the analysis that lead to the recommendations that are described above.
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Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC’s area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC’s jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map and corresponding table below.

<table>
<thead>
<tr>
<th>Acronym</th>
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<tr>
<td>FRCC</td>
<td>Florida Reliability Coordinating Council</td>
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<tr>
<td>MRO</td>
<td>Midwest Reliability Organization</td>
</tr>
<tr>
<td>NPCC</td>
<td>Northeast Power Coordinating Council</td>
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<tr>
<td>RF</td>
<td>ReliabilityFirst Corporation</td>
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<td>SERC</td>
<td>SERC Reliability Corporation</td>
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<td>Southwest Power Pool Regional Entity</td>
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<tr>
<td>Texas RE</td>
<td>Texas Reliability Entity</td>
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<tr>
<td>WECC</td>
<td>Western Electricity Coordinating Council</td>
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</table>
NERC, as the FERC-certified Electric Reliability Organization (ERO),¹ is responsible for the reliability of the Bulk Electric System (BES) and has a suite of tools to accomplish this responsibility, including but not limited to the following: lessons learned, reliability and security guidelines, assessments and reports, the Event Analysis program, the Compliance Monitoring and Enforcement Program, and Reliability Standards. Each entity, as registered in the NERC compliance registry, is responsible and accountable for maintaining reliability and compliance with the Reliability Standards to maintain the reliability of their portions of the BES.

It is in the public interest for NERC to develop guidelines that are useful for maintaining or enhancing the reliability of the BES. The NERC Technical Committees—the Operating Committee (OC), the Planning Committee (PC), and the Critical Infrastructure Protection Committee (CIPC)—are authorized by the NERC Board of Trustees (Board) to develop Reliability (OC and PC) and Security (CIPC) Guidelines per their charters.² These guidelines establish voluntary recommendations, considerations, and industry best practices on particular topics for use by users, owners, and operators of the BES to help assess and ensure BES reliability. These guidelines are prepared in coordination between NERC Staff and the NERC Technical Committees. As a result, these guidelines represent the collective experience, expertise, and judgment of the industry.

The objective of each reliability guideline is to distribute key practices and information on specific issues to support high levels of BES reliability. Reliability guidelines do not provide binding norms and are not subject to compliance and enforcement (unlike Reliability Standards that are monitored and subject to enforcement). Guidelines are strictly voluntary and are designed to assist in reviewing, revising, or developing individual entity practices to support reliability for the BES. Further, guidelines are not intended to take precedence over Reliability Standards, regional procedures, or regional requirements. Entities should review this guideline in conjunction with Reliability Standards and periodic review of their internal processes and procedures, and make any needed changes based on their system design, configuration, and business practices.

Purpose

The NERC Load Modeling Task Force (LMTF) published a Reliability Guideline on Modeling Distributed Energy Resources (DER) in Dynamic Load Models\(^3\), which laid a framework for modeling DER for dynamic simulations as well as in the powerflow base cases. The following definitions were created for the purposes of dynamic modeling\(^4\) specified in the guideline:

- **Utility-Scale Distributed Energy Resources (U-DER):** DER directly connected to the distribution bus\(^5\) or connected to the distribution bus through a dedicated, non-load serving feeder. These resources are specifically three-phase interconnections, and can range in capacity, for example, from 0.5 to 20 MW although facility ratings can differ.

- **Retail-Scale Distributed Energy Resources (R-DER):** DER that offsets customer load. These DER include residential\(^6\), commercial, and industrial customers. Typically, the residential units are single-phase while the commercial and industrial units can be single- or three-phase facilities.

The NERC Distributed Energy Resources Task Force (DERTF) developed a report\(^7\) that includes a chapter that also describes some DER modeling recommendations for bulk power system planning studies. In the report, the DERTF developed detailed, comprehensive definitions for DER; however, while the two definitions described above are not referenced in the DER report definitions, they directly support the needs of dynamic modeling of these distribution-connected resources. U-DER represents resources directly connected to, or closely connected to, the distribution bus that may have more complex controls associated with their interconnection. R-DER represents the truly distributed resources throughout the distribution system whose controls are generally reflective of IEEE 1547\(^8\) or other relevant requirements for the region they are being interconnected. This guideline follows the modeling practices recommended in the DER report that differentiate between types of generating resources (prime mover, synchronous/non-synchronous) by the location of their interconnection to the distribution system and by the vintage technical interconnection requirements they comply with.

As the penetration of DER continues to increase across the North American footprint, Transmission Planners (TPs) and Planning Coordinators (PCs) are faced with the challenge\(^9\) of representing these resources connected at the distribution system with relatively newer and evolving models. With a framework established for modeling DER, the purpose of this guideline is to provide information relevant for developing models and model parameters to represent different types of U-DER and R-DER in stability analysis of the BPS. This guideline brings together many different reference materials into a consolidated guidance document for industry’s use when modeling DER for interconnection-wide powerflow cases and dynamic simulations. More detailed, localized studies may require additional or more advanced modeling, as deemed necessary or appropriate. The modeling practices described here may also be modified to meet the needs of particular systems or utilities, and are intended as a reference point for interconnection-wide modeling practices.

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\(^3\) This guideline was approved by the NERC Planning Committee in December 2016, and can be found [HERE](#).

\(^4\) This guideline uses the composite load model to illustrate the recommended practices. Other load models could be used; however, the NERC Load Modeling Task Force (LMTF) is supporting the advancement, improvement, and use of the composite load model.

\(^5\) The distribution bus is connected to a transmission voltage bus via the transmission-distribution transformer. Resources not directly connected to this bus do not meet the criteria for this definition.

\(^6\) This also applies to community DER that do not serve any load directly but are interconnected directly to a distribution load serving feeder.

\(^7\) The DERTF report was approved by NERC Board of Trustees in February 2017 and is available [HERE](#).


\(^9\) This work should be conducted in coordination with distribution and DER generation entities, as applicable, to ensure sufficient data is available through interconnection agreements and relevant standards.
Chapter 1: DER Dynamic Load Modeling Framework

U-DER and R-DER should be accounted for in dynamic simulations as well as in the powerflow base case. Modeling the U-DER and R-DER in the powerflow provides an effective platform for linking this data to the dynamics records and ensuring that the dynamics of these resources are accounted for. This section discusses the recommended practices for both U-DER and R-DER modeling.

It is recommended that TPs and PCs, in conjunction with their DPs, identify MVA thresholds where U-DER should be explicitly modeled and R-DER should be accounted for in the powerflow and dynamics cases. DPs should provide information to TPs and PCs to support the development of representative dynamic load models including information pertaining to DER. TPs and PCs should differentiate between U-DER and R-DER in the models for the purposes outlined herein. This will assist in how these resources are modeled in the dynamic simulations as well as in the powerflow base case for contingency analysis and sensitivity analysis. The thresholds, for example, should be based on an individual resource’s impact on the system as well as an aggregate impact.

- Gross aggregate nameplate rating of an individual U-DER facility directly connected to the distribution bus or interconnected to the distribution bus through a dedicated, non-load serving feeder; and
- Gross aggregate nameplate rating of all connected R-DER that offset customer load including residential, commercial, and industrial customers.

Table 1 shows an example framework for modeling U-DER and R-DER, with thresholds determined based on engineering judgment applicable to the TP or PC electrical characteristics and processes.

- **U-DER Modeling**: Any individual U-DER facility rated at or higher than the defined threshold should be modeled explicitly in the powerflow case at the low-side of the transmission-distribution transformer. A dynamics record could be used to account for the transient behavior\(^{10}\) of this plant. U-DER less than the defined threshold should be accounted for as an R-DER as described below. Multiple similar U-DER connected to the same substation low-side bus could be modeled as an aggregate resource as deemed suitable by the TP or PC.

- **R-DER Modeling**: If the gross aggregate nameplate rating of R-DER connected to a feeder exceeds this threshold, these DER should be accounted for in dynamic simulations as part of the dynamic load model. While this may not require any explicit model representation in the powerflow base case, the amount of R-DER should be accounted for in the load record and/or integrated into the dynamic model.\(^{11}\)

---

\(^{10}\) Depending on complexity of the actual U-DER, for inverter coupled U-DER, more sophisticated models such as the second generation generic renewable energy system models may also be used (i.e. `regc_a`, `reec_b` and `repc_a`). Other U-DER (e.g. synchronous gas or steam-turbine generators) can also be modeled using standard models available in commercial software platforms.

\(^{11}\) The NERC DER Task Force recommends that all forms of DER be accounted for (no load netting) to the best ability possible. Therefore, it is recommended that the R-DER threshold be currently set to 0 MVA. This would account for all R-DER resources as part of the load record and distinctly capture the amount of R-DER represented within the load.
### Table 1.1: Example of U-DER and R-DER Modeling Thresholds

<table>
<thead>
<tr>
<th>Criteria</th>
<th>Description</th>
<th>Threshold</th>
</tr>
</thead>
<tbody>
<tr>
<td>U-DER Modeling</td>
<td>Gross aggregate nameplate rating(^{12}) of an individual U-DER facility directly connected to the distribution bus or interconnected to the distribution bus through a dedicated, non-load serving feeder</td>
<td>___ MVA(^{13})</td>
</tr>
<tr>
<td>R-DER Modeling</td>
<td>Gross aggregate nameplate rating(^{14}) of all connected R-DER on the feeder that offset customer load including residential, commercial, and industrial customers</td>
<td>___ MVA</td>
</tr>
</tbody>
</table>

Figure 1.1 shows the conventional powerflow representation of the load in a powerflow base case and the recommended representation that explicitly models U-DER above a given size threshold. Note that each U-DER above the threshold would be modeled explicitly via its own step-up transformer, as applicable, to the low-side bus. If the U-DER is connected through a dedicated feeder or circuit to the low-side bus, then that would also be explicitly modeled in the powerflow. The load is also connected to the low-side bus.

![Figure 1.1: Representing Utility-Scale DER (U-DER) in the Powerflow Base Case](image)

Once represented in the powerflow model in this manner, the data for the composite load model (CLM) should be modified to account for explicit representation of the U-DER and transmission-distribution transformer. Figure 1.2 shows the CLM where the distribution transformer impedance is not represented in the dynamic record, it is modeled explicitly in the powerflow to accommodate one or more U-DER. The transformer impedance is not represented in the CLM (impedance set to zero in the dynamic load model); therefore, any LTC modeling\(^{15}\) would be done outside the CLM such as enabling tap changing in the powerflow\(^{16}\) and using the \textit{ltc1} model\(^{17}\) in dynamic simulations. The motor load and distribution equivalent feeder impedance is modeled as part of the CLM\(^{18}\), and

\(^{12}\) This could be represented as a percentage of the sum of load serving capacity of all step-down transformer(s) supplying the distribution bus for that associated load record being modeled.

\(^{13}\) This is intentionally left blank as a template or placeholder for applying this in a particular TP or PC footprint.

\(^{14}\) This could be represented as a percentage of the sum of load serving capacity of all step-down transformer(s) supplying the distribution bus for that associated load record being modeled.

\(^{15}\) Utilities using transformers without ULTC capability but with voltage regulators at the head of the feeder could model this in the CLM with a minimal transformer impedance but active LTC to represent the voltage regulator.

\(^{16}\) For example, by specifying settings in the transformer record and enabling tap changing in the power flow solution options.

\(^{17}\) Software vendors are exploring the concept of applying an area-, zone-, or owner-based LTC model that could be applied to all applicable transformers to address LTC modeling.

\(^{18}\) In certain situations, for example where high R-DER penetration is expected, and where advanced “smart inverter functions” should be modeled, explicit modeling of the distribution transformer, equivalent feeder impedance, load bus, and DER models may be effective.
the R-DER are represented at the load bus based on the input in the powerflow load record while the load is fully accounted for rather than any net load reduction.

![Composite Load Model](image)

**Figure 1.2: Dynamic Load Model Representation with U-DER Represented in the Powerflow Base Case**

To capture the R-DER in the powerflow solution, the load records should have the capability to input the R-DER quantity in the powerflow. It is recommended that all software platforms adopt the same approach to unify this modeling practice and enable flexibility for capturing DER as part of the load records. Figure 1.3 shows an example of the R-DER included in the powerflow load records. The red box shows the R-DER specified, for example 80 MW and 20 Mvar of actual load with 40 MW and 0 Mvar of R-DER at Bus 2. The blue box shows the net load equal to the actual load less the R-DER quantity specified for MW and Mvar, defined as:

\[
Net MW = MW_{load} - Dist MW_{R-DER}
\]

\[
Net Mvar = Mvar_{load} - Dist Mvar_{R-DER}
\]

![Net Load Calculation](image)

**Figure 1.3: Capturing R-DER in the Powerflow Load Records [Source: PowerWorld]**

The R-DER represented in the powerflow would be based on the MVA threshold values established by the TP or PC in Table 1 for R-DER Modeling. It is also recommended that the software vendors include a DER input column representing the capacity of DER for each load. This should aid in accurate accounting of DER for sensitivity analysis and base case modifications.

---

19 Some software platforms have adopted this approach; NERC LMTF is working with all major software vendors to develop this capability.
Chapter 2: DER Modeling Practices and Model Parameters

This section provides recommended modeling practices and different DER modeling options to be considered when representing DER in stability simulations. Default parameters are also provided as a reference for situations where no further information is available. The models described here are based on those commonly available in commercial software tools as part of the standard model libraries. Parameter values are based on engineering judgment and experience modeling DER and BPS-connected resources, sourced from various industry references and testing.

The models described here are applicable to interconnection-wide modeling and the majority of positive sequence simulations. However, the PC or TP may determine that more detailed modeling may be necessary for special studies such as very high penetration of DER and/or low available short circuit systems. These studies may require the need for more complex and detailed models such as electromagnetic transient (EMT) type models.

DER Data Collection
TPs and PCs are required to develop steady-state and dynamic models for interconnection-wide base case creation. As part of this process, as outlined in MOD-032-1, each PC and each of its TPs jointly develop data requirements and reporting procedures for the PC’s planning area. In addition to the aggregate demand collected from the Load Serving Entity (LSE)\(^{20}\), accurate modeling of DER should also be included in the data collection process. Accurate modeling of DER as part of the overall demand and load composition is critical for accurate and representative modeling of the overall end-use load in both the powerflow and dynamics cases. DPs should coordinate with their respective TP and PC to provide sufficient steady-state and dynamics data to accurately represent the aggregate loads, aggregate R-DER and distinct U-DER for their system. At a minimum, TPs and PCs should have the following information related DER:

- **U-DER**
  - Type of generating resource (e.g., reciprocating engine, wind, solar PV, battery energy storage)
  - Distribution bus nominal voltage where the U-DER is connected
  - Feeder characteristics for connecting U-DER to distribution bus, if applicable
  - Capacity of each U-DER resource (Pmax, Qmax)
  - Control modes – voltage control, frequency response, active-reactive power priority

- **R-DER**
  - Aggregate capacity (Pmax, Qmax) of R-DER for each feeder or load as represented in the powerflow base case
  - Vintage of IEEE 1547 (e.g., -2003) or other relevant interconnection standard requirements that specify DER performance of legacy and modern DER (e.g., CA Rule 21)
  - As available, aggregate information characterizing the distribution circuits where R-DER are connected

This information will help both the DP, PC, and TP in more representative modeling of U-DER and R-DER. In situations where this data is not readily available, the DP in coordination with the TP and PC should use engineering judgment to map the model parameters to expected types of operating modes.

\(^{20}\) LSE is no longer a NERC registration; data should be collected in coordination with the DP.
Synchronous DER Models
Small, synchronous DER connected at the distribution level can be modeled using standard synchronous machine models. TPs and PCs should determine if any synchronous DER should be modeled, as applicable, and develop reasonable model parameters for these resources in coordination with the DPs as necessary. It is recommended to use the gentpj\(^\text{21}\) model, with \(K_{is} = 0\), for representing synchronous machines. This is the same representation as the gentpf model and requires the same list of parameters as the genrou model. The classical machine model, gencls, should not be used to model DER to avoid any unintentional poorly damped oscillations. In most situations, a generator model alone will capture the dynamic behavior of the machine in sufficient detail; however, if data is available and the PC or TP find it necessary, a suitable governor and excitation system may also be modeled. Table 2.1 shows examples of model parameters for a steam unit, small hydro unit, and gas unit for reference. It is noted that the inertia constant can range from around 2.0 to 5.0 for small synchronous DER and data may vary as available from the manufacturer.

| Table 2.1: Synchronous DER Default Model Parameters
<table>
<thead>
<tr>
<th>Parameter</th>
<th>Steam</th>
<th>Small Hydro</th>
<th>Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>MVA</td>
<td>14</td>
<td>32</td>
<td>15</td>
</tr>
<tr>
<td>(T'd_0)</td>
<td>6</td>
<td>6</td>
<td>6.5</td>
</tr>
<tr>
<td>(T''d_0)</td>
<td>0.035</td>
<td>0.027</td>
<td>0.03</td>
</tr>
<tr>
<td>(T'q_0)</td>
<td>1</td>
<td>0(^\text{22})</td>
<td>1</td>
</tr>
<tr>
<td>(T''q_0)</td>
<td>0.035</td>
<td>0.065</td>
<td>0.03</td>
</tr>
<tr>
<td>(H)(^\text{23})</td>
<td>3</td>
<td>1.7</td>
<td>4.2</td>
</tr>
<tr>
<td>(D)</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>(X_d)</td>
<td>1.8</td>
<td>1.45</td>
<td>1.6</td>
</tr>
<tr>
<td>(X_q)</td>
<td>1.7</td>
<td>1.05</td>
<td>1.5</td>
</tr>
<tr>
<td>(X'_d)</td>
<td>0.2</td>
<td>0.47</td>
<td>0.2</td>
</tr>
<tr>
<td>(X'_q)</td>
<td>0.4</td>
<td>1.05</td>
<td>0.3</td>
</tr>
<tr>
<td>(X''d)</td>
<td>0.18</td>
<td>0.33</td>
<td>0.13</td>
</tr>
<tr>
<td>(X''q)</td>
<td>0.18</td>
<td>0.33</td>
<td>0.13</td>
</tr>
<tr>
<td>(X_l)</td>
<td>0.12</td>
<td>0.28</td>
<td>0.1</td>
</tr>
<tr>
<td>(S(1.0))</td>
<td>0.2</td>
<td>0.2</td>
<td>0.1</td>
</tr>
<tr>
<td>(S(1.2))</td>
<td>0.6</td>
<td>0.6</td>
<td>0.4</td>
</tr>
<tr>
<td>(K_{is})</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

\(^{21}\) See NERC Modeling Notification – Use of GENTPJ Generator Model. Available: [HERE](#).

\(^{22}\) In many commercially available software platforms (not necessarily all), by setting \(T'q_0 = 0\) and \(X'_q = X_q\) in the gentpj model, then the appropriate changes are made to the model internally to represent a salient pole generator. In some software tools, this might have to be achieved by setting \(T'q_0 \) to a very large number.

\(^{23}\) For small DER synchronous generating units, the inertia constant can range from 2.0 to 5.0.
Second Generation Renewable Energy System Models

The second generation generic renewable energy system models\(^2\) were developed between 2010 and 2013 and have since been adopted by the most commonly used commercial software vendors\(^2\). The suite of models that have been developed can be used to model different types of renewable energy resources, including:

- Type 1 Wind Power Plants
- Type 2 Wind Power Plants
- Type 3 Wind Power Plants
- Type 4 Wind Power Plants
- Solar PV Power Plants
- Batter Energy Storage Systems (BESS)

These models were originally developed to represent large utility-scale resources connected to the BPS at transmission level voltage\(^2\), and provide the greatest degree of flexibility and modeling capability from the commercial software vendor tools using generic models. However, the flexibility also results in a significant number of settings and controls that must be modeled that may be cumbersome for representing DER. The following subsections describe how to model DER using the second generation models, if necessary, for specific studies such as generation interconnection system impact studies, large capacity resources relative to the local interconnecting network, or other special studies. The tables in those sections provide parameter values, or ranges of values, intended as an example or starting point when no further detailed information is available.

Where actual equipment is to be modeled, specific data should be sought from the equipment vendor or at least based on an understanding of the actual equipment control strategy and performance (e.g., constant power factor control vs. voltage control). The dynamic behavior of renewable energy systems that are connected to the grid using a power electronic converter interface (i.e., Type 3 and Type 4 wind turbine generators, solar PV, and battery storage) are dominated by the response of the power electronic converter. The converter is a power electronic device and its dynamic response is more a function of software programming than inherent physics as in the case of synchronous machines. Therefore, the concept of default and typical parameters is much less applicable to renewable energy systems than other technologies\(^2\). For example, lvplsw = 1 in Table 2.2 describes the flag that

---


\(^2\) Including Siemens PTI PSS® E, GE PSLF, PowerWorld Simulator, and PowerTech TSAT.


\(^2\) Generic models representing renewable energy systems include a common model structure that allows for representing different types of control strategies and characteristics. These models can be tuned or configured to represent specific vendor equipment by adjusting the model parameters.
turns on the so-called low voltage power logic and is used to emulate the behavior typical of some vendor equipment under low-voltage conditions. However, lvplsw = 1 may not be a typical value and should be set according to the respective vendor characteristics to be emulated, if that information is available. Thus, there is no typical value and it is a function of the software and vendor controls on the power converter.

The default example values for the models below assume a DER with constant power factor control, no reactive current injection during faults, P-priority on the current limits, and no frequency response capability. This is typical of most DER in-service to date. The models below do not include the lhvrt and lhfrt models, which should be used if low/high voltage and frequency ride-through capabilities are to be emulated.

**Recommendations:**

1. While the second generation renewable models are capable of representing DER in much more detail than other models, the complexity of these models is often not necessary for interconnection-wide modeling. Other models may be more suitable and easier to use for representing DER.
2. In situations such as detailed generation interconnection system impact studies, large capacity resources relative to the local interconnecting network, or other special studies, these more advanced models may be of value.
3. TPs and PCs should determine the appropriate situations where these complex models are useful for modeling DER to study the dynamic behavior of the BPS.

**Solar PV Plant Modeling**

A relatively large solar PV power plant connected to the distribution system (U-DER) can be modeled using the following three second generation renewable energy system models:

- **REGC_A:** renewable energy generator/converter model. Inputs real (Ipcmd) and reactive (Iqcmd) current command and outputs real (Ip) and reactive (Iq) current injection.
- **REEC_B (or REEC_A):** renewable energy electrical controls model\(^{28}\). Inputs real power reference\(^{29}\) (Pref), reactive power reference\(^{30}\) (Qref), terminal voltage reference\(^{31}\) (Vref0) and power factor angle reference\(^{32}\) (PFAref); and outputs real (Ipcmd) and reactive (Iqcmd) current command. All reference input values are for local control.
- **REPC_A:** renewable energy plant controller model\(^{33}\). Inputs either voltage reference (Vref) or regulated voltage (Vreg) at the plant level, or reactive power reference (Qrefp) and measure (Qgen) at the plant level, and plant real power reference (Plant_pref) and frequency reference (Freq_ref); and outputs reactive power command that connects to Qref of the REEC_A model and real power reference that connects to Pref of the REEC_A model.

\(^{28}\) Version b (or a).  
\(^{29}\) Can be externally controlled.  
\(^{30}\) Can be externally controlled.  
\(^{31}\) Initialized to generator terminal voltage if set to 0.0.  
\(^{32}\) Computed during model initialization, not a user-specified value.  
\(^{33}\) Version a.
Table 2.2 provides an example\(^{34}\) of modeling a solar PV facility using the second generation renewable models.

### Table 2.2: Default REGC_A Model Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Default Value or Range</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>lvplsw</td>
<td>0 or 1</td>
<td>Low voltage power logic (LVPL) switch(^{35})</td>
</tr>
<tr>
<td>Rrpwr</td>
<td>10</td>
<td>Ramp rate limit (pu)</td>
</tr>
<tr>
<td>Zerox</td>
<td>0.4</td>
<td>LVPL characteristic zero crossing (pu)</td>
</tr>
<tr>
<td>Brkpt</td>
<td>0.9</td>
<td>LVPL characteristic breakpoint (pu)</td>
</tr>
<tr>
<td>Lvpl1</td>
<td>1.22</td>
<td>LVPL breakpoint (pu)</td>
</tr>
<tr>
<td>vtmmax</td>
<td>1.2</td>
<td>Voltage limit used in high voltage reactive power logic (pu)</td>
</tr>
<tr>
<td>Lvpnt1</td>
<td>0.8(^{36})</td>
<td>High voltage point for low voltage active current management function(^{37,38}) (pu)</td>
</tr>
<tr>
<td>Lvpnt0</td>
<td>0.4(^{36})</td>
<td>Low voltage point for low voltage active current management function(^{37,38}) (pu)</td>
</tr>
<tr>
<td>qmin</td>
<td>-1.3</td>
<td>Limit in high voltage reactive power logic (pu)</td>
</tr>
<tr>
<td>Khv (accel)</td>
<td>0.7</td>
<td>Acceleration factor used in high voltage reactive power logic</td>
</tr>
<tr>
<td>tg</td>
<td>0.02</td>
<td>Time constant (sec)</td>
</tr>
<tr>
<td>tfltr</td>
<td>0.02</td>
<td>Voltage measurement time constant (sec)</td>
</tr>
<tr>
<td>iqrmax</td>
<td>99</td>
<td>Upward rate limit on reactive current command (pu/sec)</td>
</tr>
<tr>
<td>iqrmin</td>
<td>-99</td>
<td>Downward rate limit on reactive current command (pu/sec)</td>
</tr>
<tr>
<td>Xe</td>
<td>0(^{39})</td>
<td>Generator effective reactance (pu)</td>
</tr>
</tbody>
</table>

### Table 2.3: Default REEC_B Model Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Default Value or Range</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>mvab</td>
<td>0(^{40})</td>
<td>MVA Base</td>
</tr>
</tbody>
</table>

---

\(^{34}\) These values are adapted from the WECC Solar PV Dynamic Model Specification Document, September 2012.

\(^{35}\) Characteristic of active current response as voltage drops. Highly manufacturer-specific value.

\(^{36}\) The blocks associated with the parameters Lvpnt1 and Lvpnt0 are to a great extent also related to the numerical stability of the model during simulation of nearby faults. This functionality should be kept in mind while implementing a change in the values. A low value for Lvpnt0 could cause numerical instability.

\(^{37}\) Actual name for this block might differ across various software platforms.


\(^{39}\) Some vendors, particularly of Type 3 wind turbine generators, may recommend the use of a non-zero value for Xe.

\(^{40}\) If \(mvab \leq 0\), then MVA base used by REGC_A is also used in REEC_B.
Table 2.3: Default REEC_B Model Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Default Value or Range</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>v dip</td>
<td>-99</td>
<td>Voltage for activation of current injection logic</td>
</tr>
<tr>
<td>V up</td>
<td>99</td>
<td>Voltage for activation of current injection logic</td>
</tr>
<tr>
<td>Tr v</td>
<td>0.02</td>
<td>Transducer time constant (sec)</td>
</tr>
<tr>
<td>db d1</td>
<td>0</td>
<td>Deadband in voltage error (pu)</td>
</tr>
<tr>
<td>db d2</td>
<td>0</td>
<td>Deadband in voltage error (pu)</td>
</tr>
<tr>
<td>K q v</td>
<td>0</td>
<td>Reactive current injection gain (pu/pu)</td>
</tr>
<tr>
<td>i q h1</td>
<td>1.1</td>
<td>Maximum limit of reactive current injection (pu)</td>
</tr>
<tr>
<td>i q l1</td>
<td>-1.1</td>
<td>Minimum limit of reactive current injection (pu)</td>
</tr>
<tr>
<td>v re f0</td>
<td>1.0</td>
<td>Reference voltage</td>
</tr>
<tr>
<td>T p</td>
<td>0.02</td>
<td>Electrical power transducer time constant (sec)</td>
</tr>
<tr>
<td>q max</td>
<td>0.4</td>
<td>Reactive power maximum limit (pu)</td>
</tr>
<tr>
<td>q min</td>
<td>-0.4</td>
<td>Reactive power minimum limit (pu)</td>
</tr>
<tr>
<td>v max</td>
<td>1.1</td>
<td>Voltage control maximum limit (pu)</td>
</tr>
<tr>
<td>V min</td>
<td>0.9</td>
<td>Voltage control minimum limit (pu)</td>
</tr>
<tr>
<td>K q p</td>
<td>0</td>
<td>Proportional gain</td>
</tr>
<tr>
<td>K q i</td>
<td>1</td>
<td>Integral gain</td>
</tr>
<tr>
<td>K v p</td>
<td>0</td>
<td>Proportional gain</td>
</tr>
<tr>
<td>K v i</td>
<td>1</td>
<td>Integral gain</td>
</tr>
<tr>
<td>Ti q</td>
<td>0.02</td>
<td>Time constant (sec)</td>
</tr>
<tr>
<td>D p max</td>
<td>99</td>
<td>Up ramp rate on power reference (pu/sec)</td>
</tr>
<tr>
<td>D p min</td>
<td>-99</td>
<td>Down ramp rate on power reference (pu/sec)</td>
</tr>
<tr>
<td>P max</td>
<td>1</td>
<td>Maximum power reference (pu)</td>
</tr>
<tr>
<td>P min</td>
<td>0</td>
<td>Minimum power reference (pu)</td>
</tr>
<tr>
<td>I max</td>
<td>1.1</td>
<td>Maximum allowable total current limit (pu)</td>
</tr>
<tr>
<td>T p ord</td>
<td>0.05</td>
<td>Time constant (sec)</td>
</tr>
<tr>
<td>P f flag</td>
<td>1</td>
<td>Power factor control flag^41</td>
</tr>
<tr>
<td>V flag</td>
<td>1</td>
<td>Voltage control flag^42</td>
</tr>
<tr>
<td>Q flag</td>
<td>0</td>
<td>Reactive power control flag^43</td>
</tr>
<tr>
<td>P q flag</td>
<td>1</td>
<td>Power priority selection on current limit flag^44</td>
</tr>
</tbody>
</table>

^41 1 = Power factor control; 0 = Reactive power control.
^42 1 = Reactive power control; 0 = Voltage control.
^43 1 = Voltage/reactive control; 0 = constant power factor or reactive power control.
^44 1 = Active power priority; 0 = reactive power priority.
The REPC_A model typically should not be used with DER since this generic plant controller model provides the capabilities for controlling active and reactive power at the point-of-interconnection (typically not the terminals of the inverter(s)) by providing supervisory voltage control or Q-control, and primary frequency response functionality. As these are typically not available for most DER presently, this model need not be used\textsuperscript{45}. However, newer technologies may be able to provide all these features. In these cases, the equipment vendor should be consulted for appropriate parameters to be used in the REPC_A model.

### Table 2.4: Default REPC_A Model Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Default Value or Range</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>mvab</td>
<td>0\textsuperscript{46}</td>
<td>MVA Base</td>
</tr>
<tr>
<td>tfltr</td>
<td>0.02</td>
<td>Voltage or reactive power transducer time constant (sec)</td>
</tr>
<tr>
<td>kp</td>
<td>Vendor specific</td>
<td>Proportional gain</td>
</tr>
<tr>
<td>pi</td>
<td>Vendor specific</td>
<td>Integral gain</td>
</tr>
<tr>
<td>tft</td>
<td>0</td>
<td>Lead time constant</td>
</tr>
<tr>
<td>tfv</td>
<td>0.2</td>
<td>Lag time constant</td>
</tr>
<tr>
<td>refflg</td>
<td>See Table 2.6</td>
<td>Control mode flag\textsuperscript{47}</td>
</tr>
<tr>
<td>vfrz</td>
<td>0.7</td>
<td>State S2 freeze level (if Vreg &lt; vfrz)</td>
</tr>
<tr>
<td>rc</td>
<td>0</td>
<td>Line drop compensation resistance (pu)</td>
</tr>
<tr>
<td>xc</td>
<td>0</td>
<td>Line drop compensation reactance (pu)</td>
</tr>
<tr>
<td>kc</td>
<td>0</td>
<td>Droop gain (pu)</td>
</tr>
<tr>
<td>vcmpflg</td>
<td>1 or 0</td>
<td>Droop or LDC flag\textsuperscript{48}</td>
</tr>
<tr>
<td>emax</td>
<td>99</td>
<td>Maximum error limit (pu)</td>
</tr>
<tr>
<td>emin</td>
<td>-99</td>
<td>Minimum error limit (pu)</td>
</tr>
<tr>
<td>dbd</td>
<td>0.02-0.05</td>
<td>Deadband (pu)</td>
</tr>
<tr>
<td>qmax</td>
<td>Vendor specific</td>
<td>Maximum reactive power control output (pu)</td>
</tr>
<tr>
<td>qmin</td>
<td>Vendor specific</td>
<td>Minimum reactive power control output (pu)</td>
</tr>
<tr>
<td>kpg</td>
<td>0</td>
<td>Proportional gain for power control</td>
</tr>
<tr>
<td>kig</td>
<td>0.5</td>
<td>Integral gain for power control</td>
</tr>
<tr>
<td>tp</td>
<td>1.0</td>
<td>Lag time constant on Pgen measurement (sec)</td>
</tr>
<tr>
<td>fdbd1</td>
<td>-0.0006\textsuperscript{49}</td>
<td>Deadband downside (pu)</td>
</tr>
<tr>
<td>fdbd2</td>
<td>0.0006\textsuperscript{49}</td>
<td>Deadband upside (pu)</td>
</tr>
</tbody>
</table>

\textsuperscript{45} Without the use of the REPC_A model, reference parameters in the REEC_A model are set during initialization.

\textsuperscript{46} If \textit{mvab} \textless 0, then MVA base used by REGC_A is also used in REPC_A.

\textsuperscript{47} 1 = Voltage control; 0 = Reactive power control.

\textsuperscript{48} 1 = Line drop compensation; 0 = droop control

\textsuperscript{49} The NERC Guideline on Primary Frequency Control recommends a deadband not to exceed 36 mHz for BES resources. In IEEE P1547, deadband may be specified by the “Authority Governing Interconnection Requirements” for DER (e.g., state regulators); the latest draft of IEEE P1547 specifies a default value of 36 mHz with a range of adjustability from 17 mHz to 1 Hz.
<table>
<thead>
<tr>
<th>Parameter</th>
<th>Default Value or Range</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>femax</td>
<td>99</td>
<td>Maximum error limit (pu)</td>
</tr>
<tr>
<td>femin</td>
<td>-99</td>
<td>Minimum error limit (pu)</td>
</tr>
<tr>
<td>pmax</td>
<td>1</td>
<td>Maximum power (pu)</td>
</tr>
<tr>
<td>pmin</td>
<td>0</td>
<td>Minimum power (pu)</td>
</tr>
<tr>
<td>tlag</td>
<td>0.2</td>
<td>Lag time constant on Pref feedback (sec)</td>
</tr>
<tr>
<td>ddn</td>
<td>20</td>
<td>Downside droop (pu)</td>
</tr>
<tr>
<td>dup</td>
<td>0</td>
<td>Upside droop (pu)</td>
</tr>
<tr>
<td>frqflg</td>
<td>0</td>
<td>Pref output flag&lt;sup&gt;50&lt;/sup&gt;</td>
</tr>
<tr>
<td>outflag</td>
<td>0</td>
<td>Output flag&lt;sup&gt;51&lt;/sup&gt;</td>
</tr>
</tbody>
</table>

The model settings for various control strategies for active and reactive power are provided in Table 2.5 and Table 2.6, respectively<sup>52</sup>:

- **Active Power Control Options**: Most DER do not have the capability to provide governor-type frequency response (active power-frequency response) under the existing IEEE 1547 standard. However, the revision of IEEE 1547 currently underway will include active power-frequency response capability. However, DER will conventionally be dispatched at full active power capability (e.g., maximum power point tracking) and therefore will not have any headroom to be able to respond in the upward direction. DER may have frequency response capability to respond in the downward direction for overfrequency conditions.

- **Reactive Power Control Options**: Most DER under the existing IEEE 1547 will be dispatched at a constant unity power factor as a default, unless local electric power system (EPS) requirements differ. The revision to IEEE 1547 will enable more advanced voltage and reactive power control capabilities. The default setting for reactive power/voltage controls is shown in the tables above.

<sup>50</sup> 1 = Governor Response enabled; 0 = Governor Response disabled.

<sup>51</sup> 1 = Qref is voltage; 0 = Qref is reactive power.

**Recommendations:**

1. Consider the vintage of DER interconnected for each system (e.g., version of IEEE 1547 or other relevant interconnection requirements) and determine an acceptable level of representing the various vintages of DER (e.g., with different control settings or modification of control settings to account for aggregated differences in settings).

2. Use engineering judgment or data collection to determine the most reasonable control settings to use in the model.
   a. Legacy IEEE 1547 – no frequency response but unity power factor control, no frequency and voltage ride-through but tripping for abnormal frequency and voltage excursions.
   b. Revised (still under development) IEEE 1547 defaults – more advanced and flexible controls such as ride-through capability, voltage control, frequency response, etc.; local EPS capability to require these advanced controls.

3. Based on the preceding recommendations, set the DER controls in the model accordingly based on vintages of DER, data collection, and engineering judgment.
Most distributed resources, even with frequency response capability, do not have capability to provide upward regulation. Therefore, the dup parameter is set to 0. If this capability is available, then set dup parameter to > 0 at the appropriate droop characteristic.

<table>
<thead>
<tr>
<th>Table 2.5: Plant-Level Active Power Control Options</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Function</strong></td>
</tr>
<tr>
<td>No Governor Response</td>
</tr>
<tr>
<td>Governor Response</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Table 2.6: Plant-Level Reactive Power Control Options (Source: WECC)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Function</strong></td>
</tr>
<tr>
<td>Constant Local PF Control</td>
</tr>
<tr>
<td>Constant Local Q Control</td>
</tr>
<tr>
<td>Local V Control</td>
</tr>
<tr>
<td>Local Coordinated V/Q Control</td>
</tr>
<tr>
<td>Plant-Level Q Control</td>
</tr>
<tr>
<td>Plant-Level V Control</td>
</tr>
<tr>
<td>Plant-Level Q Control + Local Coordinated V/Q Control</td>
</tr>
<tr>
<td>Plant-Level V Control + Local Coordinated V/Q Control</td>
</tr>
</tbody>
</table>

<sup>53</sup> Most distributed resources, even with frequency response capability, do not have capability to provide upward regulation. Therefore, the dup parameter is set to 0. If this capability is available, then set dup parameter to > 0 at the appropriate droop characteristic.
Battery Energy Storage System (BESS) Modeling

A BESS can be modeled using the second generation renewable models using the following two or three models:

- **REGC_A**: renewable energy generator/converter model. Inputs real (Ipcmd) and reactive (Iqcmd) current command and outputs real (Ip) and reactive (Iq) current injection.

- **REEC_C**: renewable energy electrical controls model\(^{54}\). Inputs real power reference\(^{55}\) (Pref), reactive power reference\(^{56}\) (Qref), terminal voltage reference\(^{57}\) (Vref0) and power factor angle reference\(^{58}\) (PFAref); and outputs real (Ipcmd) and reactive (Iqcmd) current command.

- **REPC_A (Optional)**: renewable energy plant controller model\(^{59}\). Inputs either voltage reference (Vref) or regulated voltage (Vreg) at the plant level, or reactive power reference (Qrefp) and measure (Qgen) at the plant level, and plant real power reference (Plant_pref) and frequency reference (Freq_ref); and outputs reactive power command that connects to Qref of the REEC_C model and real power reference that connects to Pref of the REEC_C model.

A detailed description of modeling BESS can be found on the WECC website\(^{60}\). The same control tables (Tables 2.5 and 2.6) from the preceding section also apply to BESS controls for the REGC_A and REPC_A. The only difference is in the REEE_C model. Below is an example of the REEC_C parameters for a BESS with no plant level controls, constant power factor control, P priority current limits, and no frequency response controls. Most BESS technologies are capable of much more, but specific settings need to be sought from the vendor.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Default Value or Range</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mvab</td>
<td>0(^{61})</td>
<td>MVA Base</td>
</tr>
<tr>
<td>vdip</td>
<td>-99</td>
<td>Voltage for activation of current injection logic</td>
</tr>
<tr>
<td>vup</td>
<td>99</td>
<td>Voltage for activation of current injection logic</td>
</tr>
<tr>
<td>trv</td>
<td>0.02</td>
<td>Transducer time constant (sec)</td>
</tr>
<tr>
<td>dbd1</td>
<td>0</td>
<td>Deadband in voltage error (pu)</td>
</tr>
<tr>
<td>dbd2</td>
<td>0</td>
<td>Deadband in voltage error (pu)</td>
</tr>
<tr>
<td>kqv</td>
<td>0</td>
<td>Reactive current injection gain (pu/pu)</td>
</tr>
<tr>
<td>iqh1</td>
<td>1.1</td>
<td>Maximum limit of reactive current injection (pu)</td>
</tr>
<tr>
<td>iql1</td>
<td>-1.1</td>
<td>Minimum limit of reactive current injection (pu)</td>
</tr>
<tr>
<td>SOCini</td>
<td>e.g., 0.5</td>
<td>Initial State of Charge (user define)</td>
</tr>
</tbody>
</table>

\(^{54}\) Version c.

\(^{55}\) Can be externally controlled.

\(^{56}\) Can be externally controlled.

\(^{57}\) Initialized to generator terminal voltage if set to 0.0.

\(^{58}\) Computed during model initialization.

\(^{59}\) Version a.


\(^{61}\) If mvab ≤ 0, then MVA base used by REGC_A is also used in REEC_B.
### Chapter 2: DER Modeling Practices and Model Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>SOCmax</td>
<td>0.8</td>
<td>Maximum allowable state of charge</td>
</tr>
<tr>
<td>SOCmin</td>
<td>0.2</td>
<td>Minimum allowable state of charge</td>
</tr>
<tr>
<td>T</td>
<td>99999</td>
<td>Discharge time in seconds</td>
</tr>
<tr>
<td>tp</td>
<td>0.02</td>
<td>Electrical power transducer time constant (sec)</td>
</tr>
<tr>
<td>qmax</td>
<td>0.4</td>
<td>Reactive power maximum limit (pu)</td>
</tr>
<tr>
<td>qmin</td>
<td>-0.4</td>
<td>Reactive power minimum limit (pu)</td>
</tr>
<tr>
<td>vmax</td>
<td>1.1</td>
<td>Voltage control maximum limit (pu)</td>
</tr>
<tr>
<td>Vmin</td>
<td>0.9</td>
<td>Voltage control minimum limit (pu)</td>
</tr>
<tr>
<td>kqp</td>
<td>0</td>
<td>Proportional gain</td>
</tr>
<tr>
<td>kqi</td>
<td>1</td>
<td>Integral gain</td>
</tr>
<tr>
<td>kvp</td>
<td>0</td>
<td>Proportional gain</td>
</tr>
<tr>
<td>kvi</td>
<td>1</td>
<td>Integral gain</td>
</tr>
<tr>
<td>tiq</td>
<td>0.02</td>
<td>Time constant (sec)</td>
</tr>
<tr>
<td>dpmax</td>
<td>99</td>
<td>Up ramp rate on power reference (pu/sec)</td>
</tr>
<tr>
<td>dpmin</td>
<td>-99</td>
<td>Down ramp rate on power reference (pu/sec)</td>
</tr>
<tr>
<td>pmax</td>
<td>1</td>
<td>Maximum power reference (pu)</td>
</tr>
<tr>
<td>pmin</td>
<td>0</td>
<td>Minimum power reference (pu)</td>
</tr>
<tr>
<td>imax</td>
<td>1.1</td>
<td>Maximum allowable total current limit (pu)</td>
</tr>
<tr>
<td>tpord</td>
<td>0.05</td>
<td>Time constant (sec)</td>
</tr>
<tr>
<td>pfflag</td>
<td>1</td>
<td>Power factor control flag&lt;sup&gt;62&lt;/sup&gt;</td>
</tr>
<tr>
<td>vflag</td>
<td>1</td>
<td>Voltage control flag&lt;sup&gt;63&lt;/sup&gt;</td>
</tr>
<tr>
<td>qflag</td>
<td>0</td>
<td>Reactive power control flag&lt;sup&gt;64&lt;/sup&gt;</td>
</tr>
<tr>
<td>pqflag</td>
<td>1</td>
<td>Power priority selection on current limit flag&lt;sup&gt;65&lt;/sup&gt;</td>
</tr>
<tr>
<td>Vq1</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Iq1</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>Vq2</td>
<td>0.2</td>
<td></td>
</tr>
<tr>
<td>Iq2</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>Vq3</td>
<td>0.5</td>
<td></td>
</tr>
<tr>
<td>Iq3</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>Vq4</td>
<td>0.9</td>
<td></td>
</tr>
<tr>
<td>Iq4</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>Vp1</td>
<td>0</td>
<td></td>
</tr>
</tbody>
</table>

---

<sup>62</sup> 1 = Power factor control; 0 = Reactive power control.
<sup>63</sup> 1 = Reactive power control; 0 = Voltage control.
<sup>64</sup> 1 = Voltage/reactive control; 0 = constant power factor or reactive power control.
<sup>65</sup> 1 = Active power priority; 0 = reactive power priority.

**User defined current limit tables.**
<table>
<thead>
<tr>
<th>Ip1</th>
<th>1.1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vp2</td>
<td>0.2</td>
</tr>
<tr>
<td>Ip2</td>
<td>1.1</td>
</tr>
<tr>
<td>Vp3</td>
<td>0.5</td>
</tr>
<tr>
<td>Ip3</td>
<td>1.1</td>
</tr>
<tr>
<td>Vp4</td>
<td>0.9</td>
</tr>
<tr>
<td>Ip4</td>
<td>1.1</td>
</tr>
</tbody>
</table>
PV1 Model
The PV1 model represents a solar PV power plant and consists of two models:

- **PV1G**: PV converter model
- **PV1E**: PV converter control model

**Recommendations:**

1. The PV1 model was created as a temporary solution for bulk system solar PV generation prior to the 2nd generation renewable models being developed. The model is not implemented consistently across software platforms. Therefore, use of the PV1 model is not recommended.

2. For detailed solar PV modeling, the 2nd generation renewable models are recommended. For aggregated representation of DER, including solar PV, the PVD1 and future DER_A models are best suited.
**PVD1 Model**

The PVD1 model can represent distribution-connected small PV plants (U-DER) or an aggregate of multiple PV plants (R-DER). The model is a simple current injection with capability to represent basic control strategies. The model allows for two reactive power controls including constant reactive power and volt-var control at the generation terminals. It also allows for constant active power output or over-frequency response. It also includes voltage and frequency tripping characteristics that trip all or a portion of the generation and allows a certain percentage to restore output after the disturbance, effectively representing a mix of legacy (trip) and modern (ride-through) resources\(^{66}\).

The partial trip characteristic is implemented using a simple logic block that resembles a voltage versus current (VI) characteristic of the inverter. The use of this block has a different objective in the PVD1 model than the low voltage power logic block in the 2nd generation renewable models. It is being used here to represent the linear drop of voltage across a distribution network, thus it is being used to represent the aggregate tripping response of widely distributed resources across a distribution network, rather than the VI characteristic of the inverter. This leads to the following two notable differences in its implementation and choice of default values:

- The linear curve of the block is mirrored also for representing partial tripping for high voltage conditions.
- The parameters vt0 and vt1 (vt2 and vt3) for partial tripping during low voltage (high voltage) conditions may be set much closer to the nominal voltage than the default values recommended for the LVPL block implemented in the 2nd Generation Renewable Models used for representing single large inverter-based resources.

Table 2.8 provides default values for representing a solar PV DER for either IEEE 1547-2003\(^8\) and CA Rule 21\(^67\).

<table>
<thead>
<tr>
<th>Parameter</th>
<th>IEEE 1547-2003 Default</th>
<th>CA Rule 21 Default(^67)</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>pqflag</td>
<td>0</td>
<td>0</td>
<td>Priority to reactive or active current(^{68})</td>
</tr>
<tr>
<td>xc</td>
<td>0</td>
<td>0</td>
<td>Line drop compensation reactance (pu)</td>
</tr>
<tr>
<td>qmx</td>
<td>0</td>
<td>-0.44</td>
<td>Maximum reactive power command (pu)</td>
</tr>
<tr>
<td>qmn</td>
<td>0</td>
<td>-0.44</td>
<td>Minimum reactive power command (pu)</td>
</tr>
<tr>
<td>v0</td>
<td>0</td>
<td>0.98</td>
<td>Lower limit of deadband for voltage droop response</td>
</tr>
<tr>
<td>v1</td>
<td>1.3</td>
<td>1.02</td>
<td>Upper limit of deadband for voltage droop response</td>
</tr>
<tr>
<td>dqdv</td>
<td>0</td>
<td>0.06</td>
<td>Voltage droop characteristic</td>
</tr>
<tr>
<td>fdbd</td>
<td>-99</td>
<td>-0.0006(^49)</td>
<td>Overfrequency deadband for governor response (pu)</td>
</tr>
<tr>
<td>ddn</td>
<td>0</td>
<td>0.05</td>
<td>Down regulation droop gain (pu)</td>
</tr>
<tr>
<td>imax</td>
<td>1.2</td>
<td>1.2</td>
<td>Apparent current limit (pu)</td>
</tr>
</tbody>
</table>

---


\(^{67}\) The same values may be used to represent performance requirements currently specified in IEEE P1547/D6 (12/2016).

\(^{68}\) Reactive current = 0; active current = 1.
### Table 2.8: Default PVD1 Model Parameters
(Source: EPRI)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>IEEE 1547-2003 Default</th>
<th>CA Rule 21 Default</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>vt0</td>
<td>0.88&lt;sup&gt;69&lt;/sup&gt;</td>
<td>0.50&lt;sup&gt;70&lt;/sup&gt;</td>
<td>Voltage tripping response curve point 0 (pu)</td>
</tr>
<tr>
<td>vt1</td>
<td>0.90&lt;sup&gt;69&lt;/sup&gt;</td>
<td>0.52&lt;sup&gt;70&lt;/sup&gt;</td>
<td>Voltage tripping response curve point 1 (pu)</td>
</tr>
<tr>
<td>vt2</td>
<td>1.10&lt;sup&gt;69&lt;/sup&gt;</td>
<td>1.19&lt;sup&gt;70&lt;/sup&gt;</td>
<td>Voltage tripping response curve point 2 (pu)</td>
</tr>
<tr>
<td>vt3</td>
<td>1.20&lt;sup&gt;69&lt;/sup&gt;</td>
<td>1.21&lt;sup&gt;70&lt;/sup&gt;</td>
<td>Voltage tripping response curve point 3 (pu)</td>
</tr>
<tr>
<td>vrflag</td>
<td>0</td>
<td>1</td>
<td>Voltage tripping method&lt;sup&gt;71&lt;/sup&gt;</td>
</tr>
<tr>
<td>ft0</td>
<td>59.5</td>
<td>56.5</td>
<td>Frequency tripping response curve 0 (Hz)</td>
</tr>
<tr>
<td>ft1</td>
<td>59.7</td>
<td>57</td>
<td>Frequency tripping response curve 1 (Hz)</td>
</tr>
<tr>
<td>ft2</td>
<td>60.3</td>
<td>61.9</td>
<td>Frequency tripping response curve 2 (Hz)</td>
</tr>
<tr>
<td>ft3</td>
<td>60.5</td>
<td>62.1</td>
<td>Frequency tripping response curve 3 (Hz)</td>
</tr>
<tr>
<td>frflag</td>
<td>0</td>
<td>1</td>
<td>Frequency tripping method&lt;sup&gt;72&lt;/sup&gt;</td>
</tr>
<tr>
<td>tg</td>
<td>0.02</td>
<td>0.02</td>
<td>Inverter current lag time constant (sec)</td>
</tr>
<tr>
<td>tf</td>
<td>0.05</td>
<td>0.05</td>
<td>Frequency transducer time constant (sec)</td>
</tr>
<tr>
<td>vtmlax</td>
<td>1.2</td>
<td>1.2</td>
<td>Voltage limit used in high voltage reactive power logic (pu)</td>
</tr>
<tr>
<td>lvpnt1</td>
<td>0.8</td>
<td>0.8&lt;sup&gt;36&lt;/sup&gt;</td>
<td>High voltage point for low voltage active current management function&lt;sup&gt;37,38&lt;/sup&gt; (pu)</td>
</tr>
<tr>
<td>lvpnt0</td>
<td>0.4</td>
<td>0.4&lt;sup&gt;36&lt;/sup&gt;</td>
<td>Low voltage point for low voltage active current management function&lt;sup&gt;37,38&lt;/sup&gt; (pu)</td>
</tr>
<tr>
<td>qmin</td>
<td>-1.3</td>
<td>-1.44</td>
<td>Limit in high voltage reactive power logic (pu)</td>
</tr>
<tr>
<td>Khv (accel)</td>
<td>0</td>
<td>0.7</td>
<td>Acceleration factor used in high voltage reactive power logic (pu)</td>
</tr>
</tbody>
</table>

<sup>69</sup> Values may differ depending on feeder characteristics.

<sup>70</sup> Values may differ depending on feeder characteristics and DER performance settings. If partial voltage tripping of DER is of interest for the system planner, the values for parameters vt0 and vt1 may be chosen close to the trip threshold of interest, for example 0.5 pu. If the performance of DER during low voltage ride-through is of interest for the system planner, the values for these parameters may be chosen to vt1 = 0.88 pu and vt0 = 0.5 pu to replicate Mandatory Operation for abnormal voltage conditions below 0.88 pu and Momentary Cessation for abnormal voltage conditions below 0.5 pu as required by CA Rule 21 and P1547 Category III.

<sup>71</sup> Latching of legacy DER (trip) = 0; partially self-resetting with modern DER (ride-through) is > 0 and ≤ 1.

<sup>72</sup> Latching of legacy DER (trip) = 0; partially self-resetting with modern DER (ride-through) is > 0 and ≤ 1.
Recommendations:

1. Based on the existing set of models available in commercial software tools, the PVD1 model is the most flexible, easy to use, and appropriate model for representing aggregate solar DER such as R-DER.

2. The model is also a reasonable representation for larger U-DER resources, particularly when detailed information related to specific equipment and control settings is not available.

3. However, the PVD1 model may not be adequate for detailed system studies with very high DER penetration levels in certain regions or other special studies.

4. If the performance of legacy DER (tripping) and modern DER (ride-through) is modelled by use of a single instance of the `pvd1` model, values for the `vrflag` and `frflag` unequal to 0 and 1 may be used to represent partial tripping due to evolving interconnection standards.

5. If the performance of smart inverter functions like voltage control, frequency droop control, and ride-through is modelled, it is recommended to explicitly model legacy DER and modern DER in two instances of the `pvd1` model at a load bus with the parameters given in the two columns of the table.
DER_A Model

The DER_A model is a simplified version of the utility-scale generic PV model (regc_a, reec_b, repc_a) with a significantly reduced set of parameters. It is also an improvement over the pvd1 model in that it includes additional modeling flexibility for more advanced and representative capabilities being introduced in the updated version of the IEEE 1547 standard as well as California Rule 21. The model includes less parameters than other DER models while maintaining the following functional features73:

- Frequency control with droop control and asymmetric deadband
- Voltage control with proportional control and asymmetric deadband (may be used to either represent steady-state voltage control or dynamic voltage support, depending on chosen time constants)
- Constant power factor and constant reactive power control modes
- Inverter cutout at low and high voltage, including a four-point piece-wise linear gain used to model the aggregate response from a large number of resources
- Representation of a fraction of resources re-energizing following a low/high voltage condition (representation of legacy trip and modern ride-through resources in a single model)
- Representation of a fraction of resources re-energizing following a low or high frequency condition (representation of legacy trip and modern ride-through resources in a single model)
- Ramp rate limits and active power recovery limits following a fault or during frequency response
- Active-reactive power priority options (may be used to represent dynamic voltage support during abnormal voltage conditions)
- Capability to represent generating resource or inverter-based energy storage resources

This model is currently under final revisions and has not yet been implemented and tested in the commercial software platforms. It is expected that the model will be available in the commercial software platforms in late 2017 to early 2018.

Recommendations:

1. The DER_A model is the most flexible, ease of use, and capable generic model to represent most of the major control strategies for DER on an aggregate basis. For this reason, the DER_A model is the most appropriate for representing aggregated DER such as R-DER.

2. Once the DER_A model is finalized, commercial vendors will implement this model as part of their standard model libraries. Utilities should adopt this model for aggregated U-DER and applicable R-DER modeling, as appropriate.

3. Commercial software vendors should adopt the DER_A model as the DER component of the composite load model (CLM).

---

Chapter 3: U-DER and R-DER Modeling Capabilities

This section describes how the modeling options from the previous section can be applied for modeling R-DER and U-DER and provides recommendations to the utilities and software vendors for consistent modeling approaches.

U-DER Modeling Capabilities

The previous section describes dynamic models available for representing U-DER and the respective tables provide an example or starting point for more specific modeling as deemed appropriate by the TP or PC. Table 3.1 shows the software platforms’ capability to models each of the DER described as U-DER.

<table>
<thead>
<tr>
<th>Model</th>
<th>PSLF</th>
<th>PSSE</th>
<th>PW</th>
<th>PT</th>
<th>V&amp;R</th>
</tr>
</thead>
<tbody>
<tr>
<td>Synchronous Machine Models</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>2nd Generation Renewable Models</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>PV1</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>PVD1</td>
<td>X</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>DER_A(^{75})</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Recommendations:

1. Synchronous DER should be modeled using the gentpj model with Kis = 0. When equipment data is available, that data can be used to develop a representative dynamic model. If data is not available, engineering judgment may be applied and default parameters are provided in this guideline. The gencls model should not be used, to avoid any unnecessary instability issues in the interconnection-wide cases.

2. The 2nd generation generic renewable models can be used in specific situations where detailed modeling is deemed necessary by the TP or PC. However, these models are highly complex for modeling U-DER where detailed information is not available. Other models are better suited for these situations.

3. The PVD1 model is the most reasonable generic model representation of a U-DER resource(s) available in commercial software tools. This is particularly true in situations where detailed modeling information is not available. The model provides flexibility, modeling various control strategies, and is easy to use. This model is recommended over the PV1 model for these reasons.

4. The DER_A model is still under development and is expected to be available in commercial software tools in late 2017 or early 2018. This model will be an improvement to the PVD1 model and should be used to model the majority of U-DER.

---

\(^{74}\) TSAT supports the pv1g model in PSLF dynamic data.

\(^{75}\) The DER_A model is still under development.
R-DER Modeling Capabilities

The R-DER modeling is directly built into the dynamic load models, as specified in the framework presented. Therefore, R-DER modeling capability is available in the dynamic load models that include a DER resource. Table 3.2 shows the dynamic load models and their associated DER model, if applicable.

<table>
<thead>
<tr>
<th>Criteria</th>
<th>Modularized Approach</th>
<th>DER in CLM</th>
<th>DER Model in CLM</th>
</tr>
</thead>
<tbody>
<tr>
<td>GE PSLF</td>
<td>cmpldw276</td>
<td>cmpldw</td>
<td>Simplified version of PVD1</td>
</tr>
<tr>
<td>PTI PSSE</td>
<td>No</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>PowerWorld Simulator</td>
<td>Yes</td>
<td>DER can be used in conjunction with any load model, including CMPLDW</td>
<td>DGPV (simplified version of PVD1)</td>
</tr>
<tr>
<td>PowerTech TSAT</td>
<td>No</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>V&amp;R Energy POM</td>
<td>No</td>
<td>None</td>
<td>None</td>
</tr>
</tbody>
</table>

Composite Load Model with DER Included

The composite load model that includes DER as an element in the model (e.g., cmpldwg) uses a simplified version of the PVD1 model. The block diagram for this model is shown in Figure 3.1 and default parameter values for the DER parameters of the model are provided in Table 3.3.77

The block diagram centers around a current limit logic control that simply monitors the active and reactive current and determines if a limiter needs to apply. Terminal voltage and frequency are used for the tripping mechanisms that will trip a linear amount of generation between the thresholds where generation begins tripping and where generation is fully tripped. These tripping levels apply to high and low frequency and voltages. The reconnection settings allow for some fraction of the DER to reconnect after the voltage or frequency tripping, effectively allowing representing a mix of legacy (trip) and modern (ride-through) resources similar to the PVD1 model. This simplified modeling approach represents an aggregated response of many distributed resources on the distribution system and is not intended to represent a single unit or plant directly.

76 This is available in PSLF v21.
\[ \text{Current Limit Logic} \]

\[
\text{iaord} = (\text{ipord}'^2 + \text{iqord}'^2)^{\frac{1}{2}}
\]

\[
\text{If} (\text{iaord} > \text{ialim}) \quad \text{ratio} = \frac{\text{ialim}}{\text{iaord}}
\]

\[
\text{ipord} = \text{ratio} \times \text{ipord}'
\]

\[
\text{iqord} = \text{ratio} \times \text{iqord}'
\]

**Figure 3.1: Block Diagram of DER Component in Composite Load Model (cmpldwg) (Source: GE PSLF)**

**Table 3.3: Default in cmpldwg DER Model Parameters (Source: EPRI, GE)**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>IEEE 1547-2003 Default</th>
<th>CA Rule 21 Default</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>DGtype</td>
<td>0 or 1</td>
<td>0 or 1</td>
<td>Type of DER(^78)</td>
</tr>
<tr>
<td>Pflgdg</td>
<td>2</td>
<td>2</td>
<td>Data input method(^79)</td>
</tr>
<tr>
<td>Pgdg</td>
<td>0</td>
<td>0</td>
<td>DER active power(^80)</td>
</tr>
<tr>
<td>Pfdg</td>
<td>0</td>
<td>0</td>
<td>DER power factor(^81)</td>
</tr>
<tr>
<td>Imax</td>
<td>1.2</td>
<td>1.2</td>
<td>Maximum current (pu)</td>
</tr>
<tr>
<td>Vt0</td>
<td>0.88(^69)</td>
<td>0.50(^70)</td>
<td>Voltage (pu) below which all generation is tripped</td>
</tr>
<tr>
<td>Vt1</td>
<td>0.90(^69)</td>
<td>0.52(^70)</td>
<td>Voltage (pu) below which generation starts to trip</td>
</tr>
</tbody>
</table>

\(^78\) 1 = PV System; 0 = None.

\(^79\) 0 = Pgdg is specified as fraction of Pload; 1 = Pgdg is specified in MW; 2 = Use Pdgen and Qdgen from load table. It is recommended to use Pflgdg = 2, as specified in the NERC Reliability Guideline on DER Modeling.

\(^80\) Fractional value if Pflgdg = 0; MW value if Pflgdg = 1; ignored if Pflgdg = 2.

\(^81\) DER power factor if Pflgdg = 0 or 1; ignored if Pflgdg = 2.
### Table 3.3: Default in cmpldwg DER Model Parameters  
(Source: EPRI, GE)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>IEEE 1547-2003 Default</th>
<th>CA Rule 21 Default</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vt2</td>
<td>1.10&lt;sup&gt;69&lt;/sup&gt;</td>
<td>1.19&lt;sup&gt;70&lt;/sup&gt;</td>
<td>Voltage (pu) above which generation starts to trip</td>
</tr>
<tr>
<td>Vt3</td>
<td>1.20&lt;sup&gt;69&lt;/sup&gt;</td>
<td>1.21&lt;sup&gt;70&lt;/sup&gt;</td>
<td>Voltage (pu) above which all generation is tripped</td>
</tr>
<tr>
<td>Vrec</td>
<td>0</td>
<td>1</td>
<td>Fraction of generation that can reconnect after low or high voltage tripping&lt;sup&gt;82&lt;/sup&gt;</td>
</tr>
<tr>
<td>ft0</td>
<td>59.5</td>
<td>56.5</td>
<td>Frequency (Hz) below which all generation is tripped</td>
</tr>
<tr>
<td>ft1</td>
<td>59.7</td>
<td>57</td>
<td>Frequency (Hz) below which generation starts to trip</td>
</tr>
<tr>
<td>ft2</td>
<td>60.3</td>
<td>61.9</td>
<td>Frequency (Hz) below which generation starts to trip</td>
</tr>
<tr>
<td>ft3</td>
<td>60.5</td>
<td>62.1</td>
<td>Frequency (Hz) above which all generation is tripped</td>
</tr>
<tr>
<td>frec</td>
<td>0</td>
<td>1</td>
<td>Fraction of generation that can reconnect after low or high frequency tripping</td>
</tr>
</tbody>
</table>

The simplifying assumptions this model uses to represent an aggregated DER present some challenges. Namely, the following issues may exist using this model:

- No representation of reconnection time after tripping following a fault
- No representation of ramp rate limits and active power recovery limits following a fault or during frequency response
- No representation of frequency control modes
- No representation of steady-state nor dynamic voltage control modes
- No representation of constant power factor nor constant reactive power control modes
- No representation of inverter-based energy storage resources

A modularized approach to the dynamic load models will create flexibility for allowing the user to define its own set of load or DER components for each load or load classification. However, there is added complexity and implementation time required to get to that end goal. In the meantime, it is recommended that software vendors implement the DER_A model into the CLM, once the DER_A model specification is complete. This will ensure sufficient flexibility for modeling existing DER as well as some advanced features of newer DER, and will also ensure uniformity across software platforms for the CLM that includes a DER component.

**Recommendations:**

1. Continue development of a modularized load model for increased flexibility and capability of modeling distinct load components and DER.
2. Software vendors should implement the DER_A model into the CLM, once the DER_A model specification is complete, to ensure uniform implementation of the CLM model with a DER component.

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<sup>82</sup> Latching of legacy DER (trip) = 0; partially self-resetting with modern DER (ride-through) is > 0 and ≤ 1.
Plant-level Control and Protection Modeling Task Force
Task Force Report

Introduction
Model construction forms the foundation of all power system studies, periodic verification, and identification of power system components. Models are paramount in accurate calculations of operating limits, events analysis, planning studies, and performance assessments. Major issues in power systems analysis are modeling the large varieties of components that make up complex interconnected systems and using acceptable model parameter values. Analysis tools and techniques provide useful information only when models accurately reflect component behavior over the simulation time span.

As part of its Modeling Improvements Initiative, NERC formed the Plant-level Control and Protection Modeling Task Force (PCPMTF) to review the effects of plant-level turbine controls, boiler controls, and protection systems on the response of power plants and to what extent components may need to be modeled for interconnection-wide modeling cases. The PCPMTF consists of turbine manufacturers, Generator Owners, Generator Operators, and the North American Generator Forum (NAGF), subject matter experts in power system dynamics and control, and stability simulation software vendors. The PCPMTF collaborates on model identification and modeling practices for plant-level turbine protection and control functions in order to identify any gaps in obtaining accurate stability study results.

The power generation industry has boiler and turbine simulators for many of its generating units that emulate the control system logic and the boiler and turbine process. The purpose of these simulators is generally for operator training, but some have the ability to be used to validate control strategies and control system tuning to a limited extent. For performing forensic analysis of grid events or planning power system simulations, the associated fluid levels, flow, temperature, and pressure of the boiler and turbine simulation are not significant during the simulation time frame; however, the task force reviews the effects of these controllers to address the need for development of models and/or modeling practices sufficient to capture the critical control functions.

The reaction of a generating plant and the way it interacts with other elements comprising the bulk power system (BPS) depends on a wide array of operating modes dependent on choices made by plant control room operators as well as automatic limiters and control systems. Moreover, there are many aspects of power plant control, protection, and operation that require generating plants to act, ensuring the reliable operation of the BPS in the immediate time frame following an event.

The task force took a comprehensive look at the short- and mid-term post-disturbance behavior of control and protection systems and outlined the impacts on unit reliability and system stability during grid disturbances. Additionally, this report identifies requirements for high-level monitoring that uses simulation tools in order to provide the user with a warning message of a possible control or protection action.
Events Involving Turbine and Boiler Controls

Boiler and turbine controls are increasingly recognized as contributing elements to the severity of system disturbances. There has been a number of events where generators that survived transient dynamics are tripped moments after the disturbance, and the tripping was not through the action of protective relays on the generators but by their dynamics associated with the boiler and turbine controllers. Based on the available models today, there has been limited success in fully incorporating these controllers to recreate these events for forensic analysis. The goal of this task force is to have a comprehensive look at actions of boiler and turbine controllers and quantify their impact in power system simulation studies. Additionally, this examination will lead to development of models and/or modeling practices sufficient to capture the critical control functions as well as guidelines around these control functions. A summary of the moderate to severe system disturbances that the task force investigated are in Table 1.

<table>
<thead>
<tr>
<th>Event</th>
<th>Event Description</th>
<th>Boiler/Turbine Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Turbine hydraulic system pump tripped in part because of the acceleration detection circuit</td>
<td>Boiler/turbine controls could be improved to provide smooth transfer</td>
</tr>
<tr>
<td>2</td>
<td>Megawatt transducers were improperly scaled</td>
<td>Error in boiler/turbine controls scaling</td>
</tr>
<tr>
<td>3</td>
<td>Turbine PLU and transmission line protection schemes not tuned properly</td>
<td>Not a boiler/turbine control issue. PLU is a form of over-speed protection.</td>
</tr>
<tr>
<td>4</td>
<td>Turbine intercept valve logic in error</td>
<td>Error in boiler/turbine controls logic</td>
</tr>
<tr>
<td>5</td>
<td>Dynamic models overestimate generator governing response</td>
<td>Not a boiler/turbine control issue</td>
</tr>
<tr>
<td>6</td>
<td>Aux bus under voltage setting may not take into account grid disturbance</td>
<td>Not a boiler/turbine control issue</td>
</tr>
<tr>
<td>7</td>
<td>GT high rate of change causes a “blowout”</td>
<td>Boiler/turbine controls could be improved to reduce rate of change</td>
</tr>
<tr>
<td>8</td>
<td>Turbine tripped due to acceleration detection circuit</td>
<td>Boiler/turbine control (see Arizona-Southern California Outages section in this report)</td>
</tr>
<tr>
<td>9</td>
<td>Turbine hydraulic system pump tripped due to capacity limits</td>
<td>Boiler/turbine controls should include primary frequency response (PFR) limits</td>
</tr>
<tr>
<td>10</td>
<td>Drum level trip due to lag in starting second BFP</td>
<td>Boiler/turbine control should include PFR limits</td>
</tr>
</tbody>
</table>

Table 1: Events Investigated to Quantify Effects of Boiler and Turbine Controllers

For a grid event analysis, the simulation for a generating unit would only need to model active and reactive generator power output. A proposed block diagram of the generating unit sub-model is shown in Figure 1 along with the proposed inputs and outputs illustrated in Table 2. The inputs are a combination of real-time variables, unit-specific constants, and event-driven parameters.

---

1 Historically, simplified modeling was used to reduce computational burden associated with more detailed modeling. Commensurate with the increased computational power of today’s computers, more detailed power system models can be developed and used in power system studies.

2 Units capable of burning multiple fuels would also require inputs to the model based on the percentage of each type fuel being burned. Multiple models might be required for this purpose.
**Figure 1: Generating Unit Sub-model Input/output**

![Diagram of Generating Unit Sub-model](image)

**Table 2: Generator Unit Sub-Model Input/output**

<table>
<thead>
<tr>
<th>Input/output</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>ADS Target Megawatt Setpoint</td>
<td>A real variable in units of megawatts (MW) that represents the dispatcher megawatt setpoint to the generating unit</td>
</tr>
<tr>
<td>Unit Master Megawatt Setpoint</td>
<td>A real variable in units of MW that represents the local operator megawatt setpoint</td>
</tr>
<tr>
<td>Unit on ADS</td>
<td>A Boolean variable that indicates the generating unit’s operating mode. 0 = local (local operator provides setpoint), 1 = ADS (ADS provides setpoint)</td>
</tr>
<tr>
<td>Unit High Limit</td>
<td>A real variable in units of MW that represents the local operator set boiler/turbine high load limit</td>
</tr>
<tr>
<td>Unit Low Limit</td>
<td>A real variable in units of MW that represents the local operator set boiler/turbine low load limit</td>
</tr>
<tr>
<td>Unit Rate of Change</td>
<td>A real variable in units of megawatts/minute (MW/min) that represents the unit’s local operator set rate of change</td>
</tr>
<tr>
<td>Turbine PFR Deadband</td>
<td>A real variable in units of frequency (mHz) that represents the deadband of the turbine’s primary frequency bias</td>
</tr>
<tr>
<td>Turbine PFR Droop</td>
<td>A real variable in units of percent (%) that represents the droop response of the turbine’s primary frequency bias</td>
</tr>
<tr>
<td>Grid Frequency</td>
<td>A real variable in units of hertz (Hz) that represents the grid frequency</td>
</tr>
<tr>
<td>Acceleration High rate (optional)</td>
<td>A real variable in units of RPM/min that represents the trip value for the acceleration rate</td>
</tr>
<tr>
<td>Unit (internal) trip</td>
<td>A Boolean variable that initiates a unit trip: 0 = no trip, 1 = trip</td>
</tr>
<tr>
<td>Bus (external) trip</td>
<td>A Boolean variable that initiates a unit trip: 0 = no trip, 1 = trip</td>
</tr>
</tbody>
</table>
Figure 2 shows the functional requirement of the generating unit sub-model. Table 3 provides a brief description for each function.

Figure 2: Functional Generating Unit Sub-model
<table>
<thead>
<tr>
<th>Function</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>ADS Target Megawatt Setpoint</td>
<td>Signal should be developed by ADS sub-model</td>
</tr>
<tr>
<td>Unit Master Megawatt Setpoint</td>
<td>Signal is a constant (fixed) value or written by an event script</td>
</tr>
<tr>
<td>Unit on ADS</td>
<td>Signal is a constant (fixed) state or written by an event script</td>
</tr>
<tr>
<td>Unit High Limit</td>
<td>In practice, the boiler and turbine should have the same high load limit. If the load limits are different, then use the turbine high limit. If no high limits, then use 100 percent MCR value.</td>
</tr>
<tr>
<td>Unit Low Limit</td>
<td>In practice, the boiler and turbine should have the same low load limit if applicable. If the load limits are different, use the boiler low limit (For units that incorporate boilers rather than combustion turbines, the boiler low limit for combustion control automatic operation is normally between 40 and 50 percent of MCR. Steam turbine low limits are much lower than that).</td>
</tr>
<tr>
<td>Unit Rate of Change</td>
<td>Typically, a unit’s rate of change (ROC) is a constant value defined by the local operator, but the ROC is defined by the ADS or is a variable (function of load) based on external logic. For simplicity, a constant value is proposed.</td>
</tr>
<tr>
<td>Grid Frequency</td>
<td>Signal should be developed by existing simulation model. Note that the primary frequency bias is shown downstream of the unit limits as this is the current industry practice; however, new industry practices should consider having the limits applied downstream of the primary frequency bias. Per Table 1 Event 5, the actual turbine response is, in some cases, overestimated. The overestimation is due to the withdraw behavior defined by NERC’s Primary Frequency Response task force. While the actual primary frequency response will be slightly different for each unit (especially for mechanical turbine controls), developing a higher fidelity model might not be cost effective.</td>
</tr>
<tr>
<td>Acceleration High rate</td>
<td>Signal is a constant (fixed) value. This function should be updated based on this task force resolution to Recommendation 21 discussed below. If turbine controls do not include an acceleration high rate trip, then default constant should be a very large number.</td>
</tr>
<tr>
<td>Unit (internal) trip</td>
<td>A variable written by script. Default state is zero (no trip).</td>
</tr>
<tr>
<td>Bus (external) trip</td>
<td>A variable written by script. Default state is zero (no trip). An internal and external trip is proposed only for reports or script. These signals could be combined</td>
</tr>
</tbody>
</table>
Arizona: Southern California Outages

Recommendation 21: Acceleration Control Function

In April 2012, FERC and NERC issued the joint report, *Arizona-Southern California Outages on September 8, 2011.*

The sequence of events and causes of the Arizona–Southern California outages and 27 key findings and recommendations aimed at improving power system reliability are detailed in the joint report. Recommendation 21 of the joint report identified trips related to turbine control as an issue that exacerbated the consequences of that event, and it reads as follows:

“GOs and GOPs should evaluate the sensitivity of the acceleration control functions in turbine control systems to verify that transient perturbations or fault conditions in the transmission system resulting in unit acceleration will not result in unit trip without allowing time for protective devices to clear the fault on the transmission system.”

When the SONGS separation scheme operated, it resulted in the following:

- Having opened breakers within the San Onofre switchyard to leave SONGS Units 2 and 3 connected to the electric grid, five out of nine lines were disconnected from the SONGS units. The loss of the parallel lines increased the impedance seen by the generator and consequently reduced the power transfer according to the power-angle curve formula. This sudden change in the impedance of the electric grid caused both SONGS units to begin to oscillate as illustrated in Figure 3. The oscillation of Units 2 and 3 was strong enough that each turbine’s governor “rate of change of speed” logic detected an unacceptable acceleration, which then initiated turbine control actions.

---

*Figure 3: System Frequency Measured at SONGS Facility*

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3 *Arizona-Southern California Outages on September 8, 2011 – Causes and Recommendations.*

4 $P_e = \frac{OV}{X} \sin(\delta)$
• When digital turbine governor speed sensors measure an acceleration for a certain period of time, the high acceleration logic causes all of the high-pressure governor (steam admission) valves to close rapidly. This turbine control action made the SONGS main turbine speed governors react to the rapid increase in turbine speed; it closed all turbine main steam governor stop valves to prevent turbine shaft speeds above the over-speed trip set point.

• The heat energy produced by the nuclear fuel was no longer absorbed by steam flow into the main turbine. Primary system temperature increased rapidly, which caused primary system pressure to increase above the reactor protection system. The reactor protection system then sent trip signals to the reactor and the turbines at SONGS as they began to accelerate in excess of their control system settings and eventually caused both units to trip off-line.

The tripping of the SONGS units in this manner emphasized the importance of coordination between the sensitivity of the turbine control system’s settings and turbine capability during system events. The units are expected to withstand severe faults on the transmission system and allow the transmission protection systems to operate without the generators tripping off-line. The coordination required for this protection is not a traditional relay-to-relay coordination; rather, the setting for the acceleration function should be coordinated with capabilities of the turbine and with the system response anticipated following operation of transmission protection systems for faults under various system conditions. The turbine control system acceleration function coordination is paramount to avoid generating unit trips during activation of separation schemes or during system disturbances.

Generally, acceleration control functions in turbine control systems are established by the turbine manufacturer to coordinate with the physical capability of the turbine to withstand torques associated with rapid speed acceleration. Specifically, acceleration protection for large steam plants is important because of the need to handle the continued energy input when a system event occurs.

There are many aspects of power plant control, protection, and operation that require plants to act contrary to short-term grid needs to ensure the safety and integrity of the plant and to further long-term grid interests. Therefore, it is essential on the grid side to understand the realities of power plant operations.

It is helpful to separate conditions and events in a power plant into the following categories:

• Events and conditions where an immediate trip of a major plant component is mandatory, regardless of conditions on the transmission system outside the plant
• Events and conditions where the plant is unable to respond to grid conditions because of its inherent physical characteristics
• Events and conditions where the plant would be able to respond as grid control would expect, but only by taking elements of the plant into operational regimes
• Conditions where plant elements can continue to operate, and the plant can respond as the grid expects

Action for these conditions and events are always implemented by protective elements in the primary controls of the plant equipment. These protective actions are intended to be independent from the actions of operators’ control or external transmission grid conditions. When they are called upon, these protections act quickly and decisively. However, the Generator Owner shall provide and coordinate its applicable generator protection trip

5 Standard PRC-024-2 — Generator Frequency and Voltage Protective Relay Settings
6 Recognition of Power Plant Control, Protection, and Operation in Transmission System Simulation Studies
settings with the Planning Coordinator or Transmission Planner that models the associated unit. Examples of equipment protection limitations for the generator and prime mover type are summarized in Table 4.

<table>
<thead>
<tr>
<th>Heat Recovery Steam Generator / Balance of Plant</th>
<th>Steam Turbine</th>
<th>Gas Turbine</th>
<th>Generator</th>
</tr>
</thead>
<tbody>
<tr>
<td>• High HP &amp; Reheater Steam Temperature Trip/Runback</td>
<td>• High LP Exhaust Temperature Trip</td>
<td>• High Firing Temperature Trip/Runback</td>
<td>• Stator Cooling Water System Failure Trip</td>
</tr>
<tr>
<td>• Temperature Failure Trip</td>
<td>• High HP Exhaust Temperature Trip</td>
<td>• Partial Loss of Combustion Trip/Runback</td>
<td>• H2 Seal Oil Failure Trip</td>
</tr>
<tr>
<td>• High HRSG Pressure Trip</td>
<td>• High LP Stage L-1 Temperature Trip</td>
<td>• Compressor Operating Limit Trip</td>
<td>• Loss of H2 Purity Runback</td>
</tr>
<tr>
<td>• Stack Damper Not Open Trip</td>
<td>• Main /Reheat Steam Over-temperature Trip</td>
<td>• Compressor Start Bleed Failure Trip/Load Step</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Potential New Models for Use in Dynamic Simulations**

Modeling of the type used in analysis of grid dynamics cannot anticipate the pre-event operating conditions of all parts of a power plant at any given time; they cannot be relied on solely to determine how a plant will react to a given grid disturbance.

Regardless of the effort made on modeling, grid studies cannot rely solely on modeling of plant components and must always include judgments. These judgments must be based on experience as to how plants actually react to grid events. Sensitivity studies that examine varied scenarios of plant behavior are essential in considering grid disturbances in the close vicinity of power plants.

The task force thoroughly reviewed turbine controls, boiler controls, and protection systems that may affect the predicted behavior of generation during system disturbances. It is not practical nor necessary to model all such turbine or boiler controls. A plant’s behavior and the way it interacts with the grid during grid disturbances also depend on the status of a wide array of subsystems that have operating modes dependent on choices made by operators. These choices reflect factors like maintenance and temporary plant limitations. Many of these subsystems are not modeled in grid simulations largely because of the impracticality of maintaining the enormous database as well as simulation run times that would be required. If one considers the example list of events detailed in Table 1, which refers to units tripping due to various reasons that could not be modeled, it can be seen that these events can be broadly classified into the following categories:
• Equipment failure
• Expected protection action (correct action)
• Protection action that was not properly coordinated
• Complex dynamics of combustion/boiler systems

It is not possible to predict model equipment failure or practical to model all the nuances of the complex dynamics associated with combustion systems and boiler systems in thermal power plants. The additional modeling complexity for performing interconnection-wide planning studies would be insurmountable. Thus, the focus of the task force is to capture the potential actions of protection systems. Currently, a simple “generic” model of this nature exists in one commercial software tool called GP1/GP2 that can be expanded in other software platforms. The model representation of GP1 is depicted in Figure 4. This model has a basic representation of over- and under-voltage protections, over- and under-frequency protections, reverse power protection, and stator- and field-over-current protections. This model can be used to monitor generator models and warn the user if a generator appears to be entering regions of operation that may initiate a trip. The model can also be set to trip the generating unit if the unstable criteria is met. The task force recommends expansion of this model to include the following:

• Loss of field protection
• Under- and over-voltage and frequency protections (already included in the model)
• Turbine power and load unbalance protection
• Voltage restraint over-current protection (revise the stator-over current protection model)
• V/Hz Limiter and protection

Figure 4: GP1 Model Representation

To observe generator behavior, the following variables in Tables 5 and 6 will need to be monitored in the simulation. These are typically available in all commercial simulation platforms. This generic model could then be used in two possible ways:

1. Set with typical settings and applied globally to all synchronous generators in a simulation and set to “monitor” only and not trip any generators. Thus, warning messages can be given to the users to warn them of generators that appear to be encroaching on trip zones for a given simulation.

2. In detailed local studies where actual protection settings are available, those settings could be used with this model to either monitor or set the trip function to look at the potential behavior of the protection systems for various simulations.

Option 1 would be the most suitable for interconnection-wide studies, similar to the practice already used in some interconnections, so as to warn the user of possible conditions where generators may trip and might warrant further investigation.

### Table 5: Variables to be Monitored in Simulation Tools:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vt</td>
<td>Stator Terminal Voltage</td>
</tr>
<tr>
<td>Pe</td>
<td>Electric Real Power</td>
</tr>
<tr>
<td>Qe</td>
<td>Electrical Reactive Power</td>
</tr>
<tr>
<td>If</td>
<td>Field current, or in the case of a brushless unit the field of the pilot exciter</td>
</tr>
<tr>
<td>Speed</td>
<td>Mechanical Speed</td>
</tr>
<tr>
<td>Vx</td>
<td>Station level voltage – Aux bus voltage</td>
</tr>
<tr>
<td>Pm</td>
<td>Total Mechanical Power</td>
</tr>
</tbody>
</table>

### Table 6: Protection Systems and Limiters:

<table>
<thead>
<tr>
<th>Protection and Limiters</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>V/Hz</td>
<td>Volts per Hertz limiter and protection per unit frequency and per unit generator terminal voltage</td>
</tr>
<tr>
<td>Overspeed protection</td>
<td>Shaft speed</td>
</tr>
<tr>
<td>Power/Load Balance</td>
<td>Electrical real power and mechanical power</td>
</tr>
<tr>
<td>Overvoltage/Undervoltage</td>
<td>Generator terminal voltage</td>
</tr>
<tr>
<td>Overfrequency/Underfrequency</td>
<td>Frequency</td>
</tr>
<tr>
<td>Turbine valve rate of change limiters</td>
<td>How fast the unit is able to respond to a frequency deviation</td>
</tr>
</tbody>
</table>

---

8 Speed is not exactly the same thing as frequency, but speed is essentially the same thing at the generator terminals and easier to monitor and work with (it is a known fact that the calculation of frequency in positive sequence stability programs presents mathematical difficulties when a fault is applied nearby since it is based on calculating the derivative of the bus angle.)
Turbine-Governor Models with Representation of Plant-level DCS Controls

A recent IEEE task force document gives a comprehensive and detailed account of the existing models for turbine-governors. Detailed accounts are given of vendor-specific models, and some detailed models incorporate the dynamic models associated with the boiler of steam-turbine generators and fast-valving schemes. All the models described are in one or more commercial software platforms; however, as concluded in the report for large-interconnected power system simulations, the use of simplified models such as GGOV1, IEEEG1, etc. are recommended. A previous IEEE task force report showed that a reasonable match between actual and simulated interconnected power system frequency response can be achieved using simplified models in both WECC and ERCOT systems.

This section contains three brief summaries of the most common and widely used simplified models discussed in the IEEE task force document:

1. Turbine Load Controllers
   Several turbine-governor models in use include a representation of the turbine load controller that acts to maintain the active power (MW) output of a unit at a fixed value. The time constant of the turbine load controller is in the order of 10 to 30 seconds; therefore, the controller will initially allow the governor to adjust the unit’s active power output in response to frequency deviations but will counter those adjustments shortly afterward as it restores the output of the plant to a designated active power (MW) set point. Governor models that represent a turbine load controller include:
   - GGOV1
   - GGOV3
   - LCFB1 (this model represents only a turbine load controller and can be applied to most conventional turbine-governor models to represent a turbine load controller)

2. Turbine Control Modes
   Some models include the ability to represent the boiler dynamics and associated turbine control model. These are rarely used in interconnection-wide planning cases. Some examples are:
   - TGOV5 (in Siemens PTI PSS®E) or ccbt1 (in GE PSLF®) for large steam-turbines
   - UHRSG (in Siemens PTI PSS®E) or ccst3 (in GE PSLF®) for the heat-recovery steam generator in a combined-cycle power plant

3. Power-Load Unbalance
   There are models that include the effect of intentional fast-valving of the steam-turbine for the purposes of improving transient stability such as TGOV3 (in Siemens PTI PSS®E). Fast-valving is not very common. A more general (applied in many steam-turbine power plants) power-load unbalance (PLU) protection function can perhaps also be emulated with this model. The PLU function monitors both turbine mechanical power and electrical power. It sets an alert condition if the mechanical power is much larger than the electrical power that

---

9 Model names listed in ALL CAPS (e.g., GGOV1) indicates a model available in Siemens PTI PSS/E and possibly other programs (e.g., PowerWorld, DSATOOLS). A model name listed in lower case (e.g., ccbt1) indicates a model available in GE PSLF but not available in Siemens PTI PSS®E.
indicates a loss of turbine electrical load. If a PLU alert is issued, the turbine controller and stop valves are closed; however, it is not explicitly modeled in any of the simplified steam turbine models.
**Modeling Standards Review**

PRC-019-2\(^{12}\), PRC-025-1\(^{13}\), and PRC-027-1\(^{14}\) require each Generator Owner and Transmission Owner with applicable facilities to perform the following:

- coordinate the voltage regulating system controls with the equipment capabilities and settings of the applicable Protection System devices and functions;
- set load-responsive protective relays associated with generation at a level to prevent unnecessary tripping of generators during a system disturbance; and
- coordinate protection systems to detect and isolate faults on BES Elements such that those protection systems operate in the intended sequence during faults.

However, the above standards do not require coordination for turbine control system settings and protection devices. The Arizona–Southern California Outages section of this report highlighted the importance of the coordination between the turbine control settings and the turbine capability taking into consideration the anticipated system response following operation of transmission protection systems for faults under various system conditions. Any modifications to a NERC standard must be made through the NERC standards process under the *NERC Rules of Procedure*. Regarding PRC-019-2 the task force recommends modifications to the standard to include the coordination of turbine control system settings and protection devices with the turbine capability.

MOD-026\(^{15}\) and MOD-027\(^{16}\) require Generator Owners to provide:

- a verified generator excitation control system
- plant volt/var control function model
- turbine/governor and load control or active power/frequency control model

The automatic controls of the plant such as the automatic voltage regulator (AVR), governor, and power system stabilizer (PSS) that affect the performance of the electrical machine will respond accordingly. A review of the Eastern- Western- and Texas interconnections planning models built in 2015 (Table 7) indicate a very limited number of Volt/Hz, over excitation limiter, under excitation limiter, and reverse power dynamic models.

<table>
<thead>
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<th>Table 7: Model availability Percentages with Respect to Total Number of Machines in Each Interconnection</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Eastern Interconnection</strong></td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td><strong>Western Interconnection</strong></td>
</tr>
</tbody>
</table>

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\(^{12}\) PRC-019-2 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

\(^{13}\) PRC-025-1 — Generator Relay Loadability

\(^{14}\) PRC-027-1 — Coordination of Protection Systems for Performance During Faults

\(^{15}\) MOD-026-1 — Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

\(^{16}\) MOD-027-1 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions
The statistics show that the modeling practices and representations are incomplete. The task force recommends that the model builders, data owners, Planning Coordinators and Designee (per MOD-032) to incorporate and monitor processes for inclusion of such models in future year planning cases.

**Recommendations**

The task force took a comprehensive look at actions of boiler and turbine controllers by quantifying their impact to determine if there is value in modeling in grid dynamic analysis studies and what is needed to capture their influence if so.

The task force also reviewed recommendation 21 from the *Arizona-Southern California Outages on September 8, 2011* report. The recommendation is significant as it draws attention to the interaction between the plant-level, turbine, and boiler control and protection systems on power system stability. This task force report highlights the importance of modeling plant-level controls and protection systems that can influence a plant’s response to an event accurately and sufficiently. Understanding the interactions between plant-level, turbine, and boiler control and protections systems will lead to improved tools, techniques, and models to quantify their impact and to determine what is needed to capture their influence with regard to plant operational capabilities and limitations.

The task force recommendations focused on improving protection system representation in grid simulation studies are summarized below:

- Through ModelingNotifications,\(^{17}\) advise the industry to use the most accurate model representation of their generator. For instance, consider using models that represent PI controllers if such equipment is used in the plant. However, it is neither practical nor necessary to attempt to model all turbine and boiler controls.

- Encourage commercial software vendors to adopt a model similar to GP1 (and GP2) in GE PSLFTM that can monitor and provide warnings of potential unit tripping due to the generator encroaching on possible trip-zones of protection systems. The GP1 model should be revised or updated with the additional functions outlined in this report (e.g., the power-load unbalance protection).

- Modify PRC-019-2 standard to include the coordination of turbine control system settings and protection devices with the turbine capability due to recommendation 21 of the FERC and NERC issued joint Arizona-Southern California Outages report.

- The model builders, data owners, Planning Coordinators and designee (per MOD-032) are to incorporate and monitor processes for inclusion of Volt/Hz, over excitation limiter, under excitation limiter, and reverse power dynamic models in future year planning cases.

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\(^{17}\) NERC Modeling Notifications available on [NERC-MWG’s Webpage](https://www.nerc.com/mwg/modeling-notifications.html)
Integrating Variable Energy Resources into Weak Power Systems
Reliability Guideline
June 2017
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Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability and security of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC’s area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC’s jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map and corresponding table below.

The North American BPS is divided into eight RE boundaries. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

<table>
<thead>
<tr>
<th>FRCC</th>
<th>Florida Reliability Coordinating Council</th>
</tr>
</thead>
<tbody>
<tr>
<td>MRO</td>
<td>Midwest Reliability Organization</td>
</tr>
<tr>
<td>NPCC</td>
<td>Northeast Power Coordinating Council</td>
</tr>
<tr>
<td>RF</td>
<td>ReliabilityFirst</td>
</tr>
<tr>
<td>SERC</td>
<td>SERC Reliability Corporation</td>
</tr>
<tr>
<td>SPP RE</td>
<td>Southwest Power Pool Regional Entity</td>
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<tr>
<td>Texas RE</td>
<td>Texas Reliability Entity</td>
</tr>
<tr>
<td>WECC</td>
<td>Western Electricity Coordinating Council</td>
</tr>
</tbody>
</table>
Acknowledgments

This Reliability Guideline was developed in coordination with members and leadership of CIGRE WG B4.62 Connection of Wind Farms to Weak AC Networks. The goal is to share the key takeaways of the CIGRE technical brochure within the NERC footprint and relate these takeaways to the changing resource mix and BPS in North America.

NERC gratefully acknowledges the invaluable contributions and assistance of the following industry experts in the preparation of this guideline:

- Sebastian Achilles (General Electric)
- Andrew Isaacs (Electranix)
- Jason MacDowell (General Electric)
- Charlie Smith (UVIG)
Executive Summary

The electric utility industry is undergoing a rapid change in the way the BPS is planned and operated, predominantly driven by a changing resource mix and increasing penetration of renewable energy resources such as wind and solar. One aspect of this change is the fact that these newer technology resources are asynchronously connected to the grid through a power electronic interface, commonly referred to as inverter-based resources. The changing resource mix not only affects dispatch and essential reliability services such as voltage control, frequency response, and ramping, but also affects grid dynamics and controls. Grid planners and operators are faced with addressing these more complex engineering issues as they continue to see more of these resources connecting to the grid.

Grid strength is a commonly used term to describe how stiff or rigid the grid is to small perturbations such as changes in load or switching of equipment. While strong grids provide a strong source for resources to connect to, weak grids can pose challenges for connecting new resources and particularly for connecting inverter-based resources. These resources rely on a strong grid for synchronizing the power electronics. In addition, inverter-based resources do not provide significant levels of fault current. While these issues alone do not pose a reliability risk, existing control, and protection paradigms need to be adapted to accommodate these changing characteristics from the generation fleet.

This guideline provides the electric utility industry with background and useful reference information pertaining to the topics of identifying weak grid conditions and potential issues that may arise from weak grids when connecting or operating inverter-based resources. The goal is to proactively provide the industry with information for their consideration as they face this emerging issue and increasing penetrations of inverter-based resources.

Key takeaways discussed throughout the guideline include:

- **Increasing Penetration of VER and “Weak Grid” Conditions**: Variable energy resources (VER) such as wind and solar continue to be a significant component of new capacity additions. As the resource mix continues to evolve and technologies interconnecting to the BPS also continue to evolve, the electric power grid will undergo changes. Many utility-scale VER are often located in areas of the BPS with sparse transmission and few synchronous generating resources. These parts of the grid are generally considered “weak” parts of the system for these reasons.

- **Inverter Controls Affected**: The majority of inverter-based VER control systems rely on the voltage magnitude and angle at their terminals to not be largely affected by the current injection of the VER for stable operation. In this context, electrical system strength refers to the sensitivity of the VER terminal voltage to variations of VER current injections. In a strong system, this sensitivity is low; in a weak system, this sensitivity is higher.

- **Short Circuit Ratio (SCR) Based Metrics**: The SCR metric is most appropriate when considering a single VER interconnecting to the BPS. It does not account for the presence of other VER or power electronic based equipment. Additional SCR-based metrics have been developed by industry to address these conditions and should be considered accordingly for each system being studied. Each SCR-based metric has potential benefits and drawbacks in its application that are discussed herein. In general, SCR-based metrics should be used by planners, manufacturers, and developers to obtain a high level understanding of the relative impact the interconnecting generator(s) will have on the larger power system. Based on that information, and combined with specific knowledge of the equipment (from the manufacturers and developers), and specific knowledge of the network (from the planners), further studies may be required to confirm whether the plant will work correctly.
• **Weak Grid Issues:** A number of issues may manifest under weak grid conditions. These issues may include anything from classical voltage instability to control instability and control interactions. Examples of these types of issues are provided in this guideline to raise industry awareness of the issues and means by which to study these issues. The most important aspect of identifying and mitigating these issues is coordination and communication between the TP, GO, and manufacturer of the VER equipment.

• **Planning Considerations:** The increasing penetration of VER and potential weak grid issues drives the need to ensure accurate and representative models are available to planning engineers to study the impacts VER may have on grid reliability, and vice versa. Planners are recommended to use the screening methods outlined in this guideline to identify areas where weak grid conditions may be a concern. Once these areas are understood, modeling requirements should be put in place that clearly define the types of models, list of acceptable models, and intended use of these models. Transient stability models can be used by may have limitations to model detailed inverter-response, particularly under weak grid conditions. Detailed electromagnetic transient models may be needed to identify any weak grid issues that could arise.

• **Solution Strategies:** The TP, GO, and manufacturer have a number of solution options to explore to mitigate potential weak grid issues that may arise for interconnecting VER. These range from reinforcements or equipment that improve grid strength directly to controls improvements to enable more reliable operation under weak grid conditions.
Variable energy resources (VER) such as renewable generation like wind and solar continues to be a significant component of new capacity additions. The cumulative additions of these utility-level resources to the North American power system surpassed 100 GW in 2016 (Figure 1.1). While wind has been the predominant renewable resource, solar capacity additions are rapidly growing in many areas of the BPS. As the resource mix continues to evolve and the technologies interconnecting to the BPS also continue to evolve, the electric power grid will undergo changes. Many of the large utility-scale renewable generating resources are not located near major load centers. These resources are often in areas of the grid with sparse extra high voltage (EHV) transmission backbone and few synchronous generating resources to provide essential reliability services (ERS). These parts of the grid are generally considered “weak” parts of the system for these reasons.

There are engineering challenges when integrating VER into weak electric systems. More common challenges that planners and operators have had to face include:

- **Transmission overloading**: need for higher capacity transmission in the local area to accommodate higher penetrations of VER
- **Voltage profile or voltage deviation challenges**: additional reactive power compensation or VER controls to ensure acceptable voltage profiles across the system and sufficient reactive power available following major grid events
- **Low SCR**: no significant short circuit sources driving need to ensure sufficient levels of current for fault clearing and generator protection

There are additional challenges that can occur when interconnecting VER to weak parts of the system that are typically more complex and involve more advanced engineering analysis. A technical brochure was recently published by CIGRE WG B4.62, titled *Connection of Wind Farms to Weak AC Networks*, which describes some of these more advanced issues related to interconnecting wind power plants (WPPs). The technical brochure highlights the following areas:
Chapter 1: Introduction

- Technology overview describing types of wind turbine generator (WTG) technologies and controls
- Issues with connecting WPPs to weak systems
- Modeling summary including powerflow, short circuit, transient stability, small signal stability, electromagnetic transient, and islanding assessment
- Assessment techniques and possible mitigation solutions for some of the issues identified
- Quantification techniques for assessing weak grids
- Guidelines for interconnecting WPPs to the electric power system
- Case studies of actual operating experience around the world

The purpose of this guideline is to highlight some of the key takeaways from the CIGRE technical brochure, in coordination with CIGRE and the subject matter expertise that helped contribute to the brochure, and introduce some additional points that are relevant for the North American BPS. The focus is to provide utility planners, modelers, and operations engineers with useful tools, techniques, and recommendations around identifying weak grids and mitigating potential issues that could arise in weak grid conditions.

**Qualitative Description of System Strength**

Most VER are interfaced with the BPS using power electronic converters. Examples include WTGs with full converter technology (Type 4 WTGs), doubly-fed induction generators (Type 3 WTGs), and solar PV inverters. The vast majority of control systems for these resources rely on the voltage magnitude and angle at their terminals to not be largely affected by the current injection of the VER for stable operation. In this context, electrical system strength refers to the sensitivity of the VER terminal voltage to variations of VER current injections. In a strong system, this sensitivity is low; in a weak system, this sensitivity is higher.

VER connecting to a portion of the BPS with synchronous generation that is electrically close and/or relatively large is likely to be connecting to a strong system. If the size (rating) of VER connecting to this system increases or the electrical distance to the synchronous generation increases, then relative system strength becomes weaker. Technology and control advances in recent years has enabled certain VER technologies to perform satisfactorily in these weaker systems. Regardless, system strength continues to be a useful and simple indication to anticipate potential VER performance issues and facilitate discussions with VER developers and manufacturers regarding VER performance and issues that may require study.

A different definition of system strength is occasionally used to characterize the tolerance of system frequency to active power unbalances. While that aspect is relevant to BPS reliability, and is also an issue that will grow with increased penetration of VER, it is not related to the subjects discussed in this guideline.

**Variable Energy Resources**

The predominant reason the issues highlighted throughout this guideline are more prevalent with variable energy resources is that these resources are connected to the grid through power electronic controls. Inverter-based resources offer faster, more advanced control to be implemented and these controls provide additional flexibility for these resources but also add an additional layer of complexity to ensuring their reliable operation when
interconnected to the BPS. This section provides a high-level overview of the types of inverter-based resources described throughout this guideline; in particular, Type 3 and Type 4 wind turbine generating plants and solar photovoltaic plants.

**Wind Turbine Generator Technologies**

WPPs consist of many individual WTGs connected through a collector system to a WPP collector substation where the voltage is typically stepped up to same voltage as the BPS voltage in which it is connected to. The individual WTG ratings are usually in the range of 1 to 5 MVA, and are one of the four major technology types (Figure 1.2):

- **Type 1**: Fixed speed induction generator
- **Type 2**: Variable slip induction generator with variable rotor resistance
- **Type 3**: Variable speed doubly-fed induction generator
- **Type 4**: Variable speed full converter interface

![Figure 1.2: WTG Technologies and Grid Interfaces [Source: WECC]](https://www.wecc.biz/Reliability/WECC-Second-Generation-Wind-Turbine-Models-012314.pdf)

Type 1 and 2 WTGs are induction generators directly connected to the electric power system. Type 1 WTGs are induction generators with simple controls and a steep torque-speed characteristic so they operate at nearly constant speed and larger units use (relatively slow) blade pitch controls to aid in speed control. Type 2 WTGs vary the rotor resistance using power electronics. The (fast) rotor resistance control works with the blade pitch control.

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1 It is worth noting that the BPS is beginning to experience the introduction of battery energy storage systems that also make use of inverter-based equipment.
to control speed, improve stability following disturbances, and reduce mechanical stress. As induction generators, these WTGs consume reactive power and require shunt compensation to meet power factor requirements at the point of interconnection (POI). While these technologies may still exist, they are relatively older technologies and are not typically being installed in the North American market.

Type 3 and 4 WTGs are connected to the grid through some form of power electronic interface that includes an AC-DC-AC conversion. This inverter interface and fast electronics allow for a much more flexible control of speed vs. torque, enables independent control of active and reactive power, provides more efficient conversion of kinetic energy to electrical energy, and enables these resources to support steady-state and dynamic voltage control. The stator of a Type 3 WTG is directly interfaced with the electric power system while the rotor is connected through a power electronic interface allowing for variable speed of the machine and fast control response. Type 4 WTGs are connected through a full AC-DC-AC interface, asynchronously isolating the WTG from the system. This requires the converter to be fully sized to the rating of the WTG the electric machine which may be an induction generation, synchronous generator, or permanent magnet generator that operates at variable speeds.

WPPs, particularly WPPs with Type 3 and 4 WTGs, typically have a plant level control strategy where each individual WTG has its own controls to ensure some level of speed-torque, aerodynamic, pitch, and converter controls, and an overall plant controller coordinates these turbine level controls to ensure overall stable operation of the entire fleet of WTGs. The plant level controls generally use a voltage and/or MW/MVAR reference and distribute active and reactive power set points to each individual WTG, allowing the entire plant to operate with the grid in a coherent way. Figure 1.3 shows a block diagram of the overall wind plant control functions and how they operate together.

![Wind Plant Controller Block Diagram](https://www.wecc.biz/Reliability/WECC%20Wind%20Plant%20Dynamic%20Modeling%20Guidelines.pdf)
Solar Photovoltaic Generator Technologies
Utility-scale solar PV plants are built and designed in a similar fashion to Type 3 and 4 WPPs in that they consist of many individual inverter-based resources aggregated up to a central plant-level control system. The PV arrays are connected to the grid by a DC bus (capacitor) connected through power electronics and an isolation transformer (Figure 1.4). Being fully electronic, these resources also have increased flexibility in controls as a result of the capabilities of the power electronics driving the inverters. The other added benefit is that there are no rotating mechanical parts so any mechanical limitations of WPPs that may hinder their control capabilities are not present with solar PV resources. Plant-level controls operate in much the same fashion as a wind plant in sharing controls amongst the PV panels based on inverter capability, available irradiance, panel status, and grid operating conditions.

VER are particularly susceptible to weak grid conditions for several reasons. First, they have little or no inertia in their mechanical systems to provide the synchronizing power inherent in more traditional generation forms. Their ability to provide expected real and reactive power is dependent on the electronic controls which separate the power source from the grid. These controls in turn depend on a stable voltage reference from the grid. As the system is weakened, the voltage reference becomes less stable, and control dynamics and tuning become increasingly influential on overall system behavior. The specifics of some of the issues that may be encountered and the reasons for them will be covered later in this guideline.
Chapter 2: Quantifying a Weak Power System

The ability to identify “weak” systems helps to reliably plan and operate the BPS by understanding potential areas where weak grid issues could arise. Weak grids and the challenges associated with them are usually system-specific, making blanket interconnection standards or requirements often difficult to apply in a reasonable and fair manner. Therefore, it is often more appropriate for planners to use tools, techniques, and approaches to identify weak grid and determine if more detailed analyses are required for each interconnection or areas where weak grid issues and high penetration of inverter-based resources may occur. Similarly, transmission operators and operations engineers should understand, where applicable, the types of credible system conditions that could drive the grid into a weak state and result in weak grid issues.

There are a number of different methods in which system strength can be quantified. Each method has its benefits and drawbacks, which are described briefly in the following sections. However, some of these metrics are useful screening tools to determine potential weak grid conditions or areas.

As described before, the strength of a system is associated to the sensitivity of VER terminal voltage to VER current injection changes. Hence, the quantification of system strength is related to the equivalent impedance seen from VER terminals into the BPS for small voltage variations during normal or contingency conditions. The indices described in this section can be calculated using short circuit programs to estimate these equivalent impedance values. It should be noted that these estimations are not related to the operation of the system during any particular short circuit condition.

Short Circuit Ratio (SCR)
The most basic and easily applied metric to determine the relative strength of a power system is short circuit ratio (SCR). SCR is defined as the ratio between short circuit apparent power (SCMVA) from a 3LG fault at a given location in the power system to the rating of the VER connected to that location. Since the numerator of the SCR metric is dependent on the specific measurement location, this location is usually stated along with the SCR number.

\[
SCR_{POI} = \frac{SCMVA_{POI}}{MW_{VER}}
\]

Where \(SCMVA_{POI}\) is the short circuit MVA level at the POI without the VER current contribution and \(MW_{VER}\) is the nominal power rating of the VER being connected at the POI. This metric was developed as an aid in classical LCC HVDC design, and is commonly used by the utility industry to quantify system strength. A low SCR area (“weak system”) indicates high sensitivity of voltage (magnitude and phase angle) to changes in active and reactive power injections or consumptions. High SCR (“stiff”) systems have a low sensitivity and are predominantly unaffected by changes in active and reactive power injection. The SCR metric is most appropriate when considering a single VER operating into a relatively conventional power system (does not account for the presence of other VER or power electronic based equipment electrically close to the POI under study).

Key Takeaway:
The SCR metric is most appropriate when considering a single VER interconnecting to a power system. It does not account for the presence of other VER or power electronic based equipment.

Other SCR-Based Metrics
SCR, as defined above, cannot be easily applied to understand the strength of a grid when multiple VER are connected electrically close. More specifically, the use of SCR to estimate system strength for a VER connected close to other VERs can lead to overly optimistic results. Several methods have been proposed to estimate system...
strength for group of VER connected electrically close. These are described briefly below for reference. Refer to the CIGRE technical brochure for more detailed examples.

**Weighted Short Circuit Ratio\(^5\) (WSCR)**
The weighted short circuit ratio (WSCR) has been recently applied in Texas to assist in defining operational limits for total VER transmission across key power system interfaces. WSCR is defined as:

\[
WSCR = \frac{\sum_i^{N} SCMVA_i * P_{RMW_i}}{(\sum_i^{N} P_{RMW_i})^2}
\]

where SCMVA\(_i\) is the short circuit capacity at bus \(i\) without current contribution from nonsynchronous generation and \(P_{RMW_i}\) is the MW output of nonsynchronous generation to be connected at bus \(i\). \(N\) is the number of wind plants fully interacting with each other and \(i\) is the wind plant index.

**Composite Short Circuit Ratio (CSCR)**
Composite short circuit ratio (CSCR) estimates the equivalent system impedance seen by multiple VER by creating a common medium voltage bus and tying all VER of interest together at that common bus\(^6\). The composite short circuit MVA at the common bus without VER contribution, \(CSCMVA\), is then calculated. CSCR can then be calculated as

\[
CSCR = \frac{CSCMVA}{MW_{VER}}
\]

where \(MW_{VER}\) is the sum of the nominal power rating of all VER considered. This method calculates an aggregate SCR for multiple WPPs, rather than each WPP like the conventional SCR approach.

Both the CSCR and the WSCR calculation methods are based on the assumption of strong electrical coupling between nonsynchronous generation plants. This is equivalent to assuming that all nonsynchronous generation plants are connected to a virtual point of interconnection (POI). In practice, there is usually some electrical distance between each nonsynchronous generation plant’s POI, and the nonsynchronous generation plants will not fully interact with each other. The CSCR and WSCR values obtained with this method will typically give a more accurate estimate of the system strength compared to SCR values when more than one VER is present.

**Short Circuit Ratio with Interaction Factors (SCRIF)\(^7\)**
Other methods have been proposed which more directly account for impedances between the considered plants. This is done either through impedance matrix manipulation, or calculated changes in voltage at all other locations when reactive power is injected at each location. Although this method is more rigorous and allows consideration of each individual wind plant in the presence of the others, it is more difficult to apply as a screening method (for example, on the back of an envelope), and may be more difficult to determine what actions should be taken when used as an area wide operating screening tool.

SCR with Interaction Factors (SCRIF) has been proposed to capture the change in bus voltage at one bus corresponding resulting from a change in bus voltage at another bus. Electrically close VER buses will have a

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\(^6\) Details related to connection of medium voltage buses of different voltages and specifics of using short circuit programs for these estimations are described in: Report to NERC ERSTF for Composite Short Circuit Ratio (CSCR) Estimation Guideline, GE Energy Consulting: Fernandes, R., Achilles, S., MacDowell, J., January 2015.

\(^7\) This metric is titled “Equivalent SCR” in the Cigre brochure, which is distinct from the classical “Effective SCR” used in LCC HVDC design.
relatively higher Interaction Factor (IF) than VER buses that are electrically separated. When multiple VER are located very close to each other, they share the grid strength and short circuit level; hence, the grid strength is actually much lower than the overall short circuit level calculated at that bus or buses. SCRIF captures the voltage sensitivity between VERs as a screening tool for potential controls issues by using VER interaction factors, as follows:

$$SCRF_i = \frac{S_i}{P_i + \sum_j(IF_{ij} \cdot P_j)}$$

Where IF is the change in bus voltage at bus $i$ ($\Delta V_i$) for a change in bus voltage at bus $j$ ($\Delta V_j$), as follows:

$$IF_{ij} = \frac{\Delta V_i}{\Delta V_j}$$

An advantage of the use of SCRIF is that it can be readily amended to cater for any conceivable configuration for connection of multiple WPPs.

**Application of Metrics using MW vs. MVA**

SCR, WSCR, CSCR, and similar metrics should be carefully applied, understanding the assumptions and limits of each metric. For example, if a system is determined to be extremely weak, such that the VER is likely to have a problem, the equation for SCR immediately presents several mitigation solutions. Increasing the SCMVA at the interconnection (increasing the numerator) directly increases SCR. Synchronous condensers, lower impedance transformers, and additional interconnecting transmission all increase the short circuit level and generally improve weak system behavior. Conversely, decreasing VER output (decreasing the denominator) also directly increases SCR, and is also effective to improve weak system behavior.

However, in both cases care is needed. Adding synchronous condensers can introduce new modes of angular instability, and may also introduce protection and maintenance challenges. Reduction in active power from the wind plant (through curtailment) relieves stress on loaded lines and generally improves stability, but can leave a fully rated inverter (with associated voltage controls etc.) still actively connected to the same grid. Since SCR generally does not consider inverter capacity, but MW output, other inverter based equipment such as SVCs or FACTs are generally ignored in these calculations, even though they also require a stable voltage for their own power electronic controls.

It is clear that disconnecting half of the units in a VER plant may result in the same SCR increase as 50% active curtailment, the resulting electrical system is not the same and may respond differently in a weakened condition.

If applying such a metric as a generic operating procedure (for example, WSCR should stay above a given threshold), the threshold for WSCR calculated using MVA could be different from WSCR calculated using MW. In this case, the WSCR metric could be applied both in terms of MW and MVA, as expressed below.

$$WS_{CR_{MW}} = \frac{\sum_i^N SCMVA_i \cdot P_{RMW_i}}{(\sum_i^N P_{RMW_i})^2}$$

$$WS_{CR_{MVA}} = \frac{\sum_i^N SCMVA_i \cdot P_{RMVA_i}}{(\sum_i^N P_{RMVA_i})^2}$$

**Key Takeaway:**
The equations for SCR and other SCR-based metrics help illustrate how curtailment of VER under weak grid issues can be used as a mitigation strategy. As the active power injection (or capacity) to the system increases, the SCR and other metrics reduce. By limiting the injection (or capacity) into the system, this may help increase SCR.
Comparison of SCR Methods
Each of the methods described in the preceding sections has benefits and drawbacks as a screening tool to identify weak grid conditions and potential issues with inverter-based resources. Table 2.1 provides an illustrative description of the similarities, differences, benefits, and drawbacks of these metrics\(^8\). The Red ‘X’ represents that the metric cannot be applied for the described purpose. One * represents that the metric can be applied with some additional effort or processing, or can be applied to a limited extent, and two *s represents that the metric is easily or directly applied for these purposes.

<table>
<thead>
<tr>
<th>Metric</th>
<th>Simple calculation using short circuit program</th>
<th>Accounts for nearby inverter based equipment</th>
<th>Provides common metric across a larger group of VER</th>
<th>Accounts for weak electrical coupling between plants within larger group</th>
<th>Considers non-active power inverter capacity*</th>
<th>Able to consider individual sub-plants within larger group</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCR</td>
<td>Short Circuit Ratio</td>
<td>★★</td>
<td>★★</td>
<td>★★</td>
<td>★★</td>
<td>★★</td>
</tr>
<tr>
<td>CSCR</td>
<td>Composite SCR</td>
<td>★★</td>
<td>★★</td>
<td>★★</td>
<td>★★</td>
<td>★★</td>
</tr>
<tr>
<td>WSCR-MW</td>
<td>Weighted SCR using MW</td>
<td>★★</td>
<td>★★</td>
<td>★★</td>
<td>★★</td>
<td>★★</td>
</tr>
<tr>
<td>WSCR-MVA</td>
<td>Weighted SCR using MVA</td>
<td>★★</td>
<td>★★</td>
<td>★★</td>
<td>★★</td>
<td>★★</td>
</tr>
<tr>
<td>SCRF</td>
<td>Multi-Infeed SCR</td>
<td>★★</td>
<td>★★</td>
<td>★★</td>
<td>★★</td>
<td>★★</td>
</tr>
</tbody>
</table>

* e.g., STATCOMs or partial power VERs

Each metric has benefits and drawbacks in its application for assessing system strength and potential weak grid issues. These may include:

- **Simple calculation using short circuit programs**: Metric utilizes positive sequence short circuit program for primary results. Some simple additional manipulation or post-processing may be required.
- **Accounting for nearby inverter-based equipment**: Metric inherently considers the presence of nearby inverter based equipment, particularly if the equipment is very close.
- **Common metric across large group of VER**: Metric provides a single consolidated value for all the plants within the selected group.
- **Accounts for weak coupling between plants within larger group**: Metric is able to consider the isolating effect of impedance between VER plants, or to consider that each plant may be obtaining system strength from different sources. (As opposed to assuming plants are perfectly coupled - essentially a single plant).
- **Considers non-active power inverter capacity**: Metric accounts for capacity of inverters nearby which may require a strong system, but do not generate active power. Examples could be curtailed wind plants, STATCOMs, or SVCs.
- **Considers individual sub-plants within larger group**: Metric provides a system strength value at any number of individual buses within a group, accounting for the presence of the others.

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\(^8\) Note that WSCR-MW and WSCR-MVA are separated here to illustrate that consideration of MW vs. MVA rated metrics may have different benefits; however, this concept applies to all the metrics listed below.
Problems with Screening Metrics
There are some critical limitations when SCR based screening tools are used in power systems planning. First among these is the wide variety of problems which may be encountered under weak conditions. When the system is generally unable to support stable operation as well, the specific limits which will be encountered are very dependent on the precise nature of the interconnection. Specific control revisions within a vendor family of controls, specific system and outage conditions, and the precise nature of nearby equipment can all determine whether there will be a problem at a given SCR or not. The temptation for planners is to apply screening metrics in a general way to determine whether their system will operate correctly, while the reality is that weak system issues are usually not general but specific. Lower SCR typically increases the likelihood of issues, but often doesn’t predict the exact mode of failure or the precise point at which system stability will be compromised. This uncertainty means that usually SCR based metrics should be relegated to a high level of screening, and if specific knowledge is required regarding whether a given system will operate as expected, more rigorous study is required, often entailing electromagnetic transient (EMT) study tools.

Even when used purely as screening metrics, there is a temptation for planners to use SCR based tools to set “minimum system strength” criteria. The danger with this is that as equipment and control technology evolves, or as different types of equipment are mixed, the appropriate threshold becomes perilously difficult to set correctly. What is “weak” for one manufacturer may not be a problem for another. What was “weak” for one manufacturer two years ago may no longer be difficult to achieve. The addition of a new piece of equipment may (through poor controls, for example) suddenly destabilize otherwise very well controlled existing equipment.

Key Takeaway:
While lower SCR typically increases the likelihood of potential issues with inverter-based resources, these methods should be used as a screening tool. Weak grid issues are system- and equipment-specific and it is difficult to define a “minimum system strength” criteria that can be applied uniformly.

Appropriate use of SCR based metrics
In general, SCR based metrics should be used by planners, manufacturers, and developers to obtain a high level understanding of the relative impact the interconnecting generator(s) will have on the larger power system. Based on that information, and combined with specific knowledge of the equipment (from the manufacturers and developers), and specific knowledge of the network (from the planners), further studies may be required to confirm whether the plant will work correctly.
Chapter 3: Issues Associated with Weak Systems

A number of issues can occur under weak grid conditions. Once these potential conditions have been identified, it is useful to understand the different types of issues that have been observed and how these issues may be mitigated. All issues should be addressed in close coordination between the TP, PC, GO, and manufacturer of the generating resources under consideration. These issues are relatively complex and this close coordination helps ensure all entities develop the most effective and efficient solution to the problem(s). This chapter provides an overview of some of the issues that may be encountered under weak grid conditions, particularly for inverter-based resources. Appendix B provides some illustrative examples of actual weak grid interconnection issues.

Manufacturer Involvement
Manufacturers play an integral role in the design of WTG and plant performance and should be incorporated into any discussions around weak grid conditions. The following considerations are useful when interacting with manufacturers:

- **Short Circuit Thresholds:** The manufacturers should understand what a “weak grid” is for their equipment and controls, and should be able to clearly articulate this to the TP. TPs should request documentation and demonstration that the equipment to be installed on the system can meet the performance specifications under the expected low short circuit levels. The manufacturer may need additional information to understand how the SCR-based metric was used and applied. Detailed EMT simulations or comparable manufacturer information should be provided to the TP to clearly illustrate that the PV converter or WTG product has a stable performance in similar system strength conditions. This should include the ranges of system strength that the equipment can tolerate and operate as designed (e.g., ride-through). Prior to commercial operation and as part of the planning evaluation, TPs should have an understanding of the controls design, expected performance, and demonstrated results showing this performance. TPs should not simply ask for the ‘acceptable’ SCR level from manufacturers; rather, a bidirectional engineering conversation should address these consideration.

- **Control Design:** Operation of VER in weak grid conditions can be an important consideration in the control design for manufacturers. In the design process, manufacturers evaluate the capability to comply with performance requirements with different system strengths for predefined product configurations. It should be noted that at the product design stage, the specific BPS topology and characteristics of all future VER applications with this product are unknown. In this context, manufacturers can characterize applications with system strength levels that are well covered within the design processes. For example, strong and weak system strength may be well within the design verifications.

- **Additional VER Studies:** Manufacturers may also suggest low system strength levels where additional VER application studies may be required to complement the product performance design verifications. For example, for very weak system strength, a manufacturer (or TP) may recommend to evaluate the performance in a detailed EMT study, particularly early in the interconnection process.

- **Performance Requirements:** There is no industry standard for what strong, weak, or very weak system strength means. This characterization is useful for comparison with the design criteria of the product under consideration. The different control technologies used in the industry can result in a wide range of capabilities related to weak grids. Early dialogue with the manufacturers related to the application characteristics will typically reduce potential weak grid issues.
It is recommended that planners, developers, and consultants characterize the system strength of a VER application and discuss with the manufacturer potential performance concerns. The analysis and product configuration to mitigate issues integrating VER into very weak grids requires understanding of the power electronic controls and capabilities, operational understanding of how the platform will perform, and understanding of the specific equipment used in each application.

**Key Takeaway:**
TPs, PCs, and GOs should coordinate with the manufacturer of the inverter-based VER to characterize the system strength, understand potential performance concerns, and develop necessary solutions. The TP and PC should ensure sufficient justification from the manufacturer that any potential weak grid issues have been addressed prior to interconnection.

### Classical Voltage Stability in Weak Grids

Weak grid issues have been addressed by transmission planning engineers in different aspects for many years. One relatively well understood aspect of weak grids is steady-state voltage stability, which relates to how much the system voltage changes (dV) relative to changes in real or reactive power flow (dP or dQ) across the network. The change in system voltage compared to real or reactive power flow (dV/dP or dV/dQ) are well-known measures quantifying grid voltage stability. The amount of reactive loss in the network is proportional to the square of the current (I^2). The amount of voltage drop across the network is also based on the magnitude of current flowing through it. Network elements (e.g., transmission lines, transformers, and cables) are inherently lossy during periods of high power transfer due to their relatively high leakage and series reactance properties, ultimately lowering system voltage. During periods of light load, transmission line or cable shunt susceptance (also known as line charging) dominates and adds to the overall system reactive power supply, raising the voltage.

When the grid is strong, there are a relatively large number of online synchronous machines providing a substantial amount of available short circuit current and reactive support to the network. In a strong grid, the system series impedance is relatively low and the voltage is relatively constant vs. load level. That is, as power flow increases in a strong grid, dV/dP and dV/dQ is small. However, a weak grid has a comparably small availability of short circuit current (either due to fewer online synchronous machines or a higher network impedance due to long transmission lines and multiple voltage transformations). This low short circuit availability causes higher dV/dP and dV/dQ sensitivity, and these sensitivities increase as the electrical network becomes weaker (i.e., higher risk of voltage collapse).

The increased active power variability of VER, their integration into sparse electrical networks, and their inverter-based controls can bring potential weak grid issues that may not generally be studied or as closely considered as synchronous resources. Figure 3.1 shows two illustrations of grid strength and control modes and how they may impact voltage stability.

- The left figure illustrates the impact that control modes can have on grid performance in a relatively strong grid. For a given installed rating of the generating resource, the constant power factor (unity power factor in this example) is unable to maintain voltage as strongly as the same resource in voltage control mode. While this is expected, this is an important concept and similar to the requirements put forth in FERC Order 827\(^9\). In both cases, the voltage does not sag all that much in the strong grid case as load level is increased, but closed-loop dynamic voltage control of the point of interconnection and supply of reactive power factor to maintain voltages does a better job of supporting grid voltage during steady state operation. For VER power plants, closed-loop voltage regulation at the POI is an essential reliability service for the BPS.

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Chapter 3: Issues Associated with Weak Systems

- The right figure illustrates the impact of power transfer on voltage in weak grids and how the different control points enable more active power transfer and a more stable local power system. The plot shows the PV curves under voltage control mode (green) and power factor control mode with various setpoints. As more power is transferred across the system in this weak grid scenario, $\frac{dV}{dP}$ becomes larger. To support the grid voltage in these cases, shunt capacitor banks are switched on to discretely add reactive power and extend the power transfer capability, hence the spikes in the plots. As more capacitor banks are added, the voltage becomes generally more Voltage control mode is able to stably support the most active power transfer across the system and also maintains a steady system voltage at higher power transfers. Conversely, power factor control mode at unity causes a quick degradation in system voltage for increased power transfer since the system requires an exponentially higher amount of reactive power for this case. Decreasing power factor levels (i.e., $pf = 0.99, 0.98, 0.97$) delivers more reactive power to the grid and result in high voltage conditions since the system is unable to accommodate the increasing reactive output at higher active power levels. In all power factor modes, the steepness of the PV curve and instability points are at relatively higher voltages than the voltage control mode.

![Figure 3.1: Illustration of Grid Strength, Voltage Stability, and Wind Plant Control](Source: GE)

With VER, output variability (e.g., cloud cover, wind speed) may illuminate potential voltage issues that could arise in a classical voltage stability sense. Synchronous generation is typically held at constant active power output and ramped relatively slowly. Daily load changes can drive some instability issues, and those can be dealt with accordingly on a relatively slow basis. Individual VER, on the other hand, can ramp output very quickly depending on available input power. This variability, coupled with the load profile, can exacerbate voltage stability risks. This can be further complicated by network topology changes, planned or forced outages, etc. While the system is planned for N-1 security, weak grid issues can materialize under a wide range of conditions, particularly under outage conditions. Closed-loop voltage control is critical to have for all grid connected VER power plants, particularly in weak grids.

This issue of classical voltage stability is relevant and important to consider regardless of the source technology. However, it is not the only issue to be resolved. Separately, control stability is also an important issue to resolve in weak grids that have power electronic sources.
Control Interactions and Control Instability

Control interaction refers to any interaction of control systems between elements on the BPS. This term is typically associated with power electronic based generation interacting with other power electronic resources such as generators and FACTS devices, but also conventional generation and non-power electronic based devices such as series capacitors or switched shunt devices. Control interaction is more prominent in weak grid areas because each device attempting to control a specific electrical quantity or point on the BPS has more impact on other devices. Conversely, in strong (“stiff”) parts of the system, each device has little overall impact in changing that quantity and therefore little impact on other devices.

Small Signal Control Instability

“Control instability” encompasses a broad spectrum of phenomena when applied in power systems, but one of the important modes of instability in weak systems relates to interactions between fast, high gain controllers of power electronic resources such as wind (Type 3 and Type 4) or solar plants and relatively high impedances connecting the resources to the power system. In general, the open loop gain as experienced by the interacting controllers is higher when they are connected and operated in weak AC systems, making them more susceptible to control instability (sometimes referred to as “small signal” instability). These instabilities may result in growing or erratic oscillations that have negative consequences to grid reliability such as unit tripping, flicker or power quality concerns, and ultimately potential human safety concerns or damage to equipment. Small signal stability concerns such as these are usually functions of the linear control regions and the network impedance, and are often characterized by oscillations occurring in the absence of any disturbance.

Figure 3.2 shows an example of a wind turbine connected to a test system where the SCR is gradually decreased by increasing the system impedance. At some point, every conventionally controlled wind plant will reach a minimum SCR, below which its controls will experience instability.

10 “Small signal stability” term is often used to describe electromechanical oscillations that occur between synchronous machines or groups of synchronous machines in the BPS. In this guideline, “small signal stability” is used differently and refers to instabilities or oscillatory behavior of fast controls in PV converters, WTGs, VER plant controls, or dynamic compensation equipment. In this case, the instability is triggered by small perturbations associated to normal operation of the BPS (line switching, capacitor/reactor operation, etc.).
Figure 3.2: Example of Small Signal Control Instability at Wind Plant as Grid is Weakened
[Source: Electranix]

Other Modes of Control Instability

Other modes of instability become more common as the system is weakened, depending on specific control and protection configurations of individual plants. These can include non-linear controls or control-mode changes which activate during system disturbances or external events.

Figure 3.3 shows an example of control instability at a wind plant connected to a weak grid. Following a fault, the plant enters a separate ride-through control mode, where active power is reduced and quickly ramped back up following fault clearing. However, as the active power ramps, the reactive support available from the inverter is unable to support the voltage due to the high impedance between the plant and the larger grid, and voltage collapses. This causes the plant to re-enter ride-through mode and reduce its active power, which in turn allows the voltage to recover, and the cycle repeats, causing severe voltage oscillations to propagate through the system.
Figure 3.3: Example of Control Instability (Mode Cycling) at Wind Plant Connected to Weak Grid [Source: Electranix]

Figure 3.4 shows an example of control instability at a wind plant connected to a weak grid. Following a fault, the plant enters a separate ride-through control mode, where active power is reduced and quickly ramped back up following fault clearing, as in the prior example. However, the plant is unable to find a stable post-fault operating point in the weakened system, and following several severe oscillations, the plant trips.

Figure 3.4: Example of Control Instability at Wind Plant Connected to Weak Grid

These types of control interactions and instabilities are often not detectable using positive sequence simulation tools since these models usually do not represent the fast inner controllers that are responsible for the unstable modes. More complex studies using EMT tools may be required to identify control interactions or control instability for power electronic resources connected to weak grids. Furthermore, utilities with power electronic resources connected to weaker parts of the grid should be aware of these types of control interactions and should be proactive in identifying and mitigating these types of issues so as to ensure reliable operation of the BPS and avoid any unnecessary oscillatory behavior and/or plant tripping.
Disturbance Ride-Through Capability
Ensuring ride-through capability and coordinated controls during abnormal grid conditions is essential for effectively integrating VER into weak grids. Two aspects related to ride-through include meeting Reliability Standard requirements related to voltage and frequency protective relays, as well as stability of the phase lock loop (PLL) and VER response to any PLL issues.

Ride-Through Requirements
NERC Reliability Standard PRC-024-2 describes how generator protective relays should be set such that generating units remain connected during frequency and voltage excursions (see Figures 3.5 and 3.6). The curves specify a “No Trip Zone” where the BES resources should not trip within the specified time durations. Outside this specified region, BES resources may remain online to support grid reliability to the best extent possible. There is no explicit requirement for BES resource to trip; this is driven by plant protection requirements and local grid reliability issues.

Within the “No Trip Zone”, resources are not permitted to “trip” or disconnect from the grid. Inverter-based resources typically incorporate a Momentary Cessation (“block”) mode where they cease to supply current to the grid. “Blocking” should be used as sparingly as possible, and active grid support should resume immediately following fault clearing in most cases. Inverter-based resources should support the BPS reliability by providing active and reactive current to the best extent possible, within their inverter capability. Balancing the contribution of active and reactive current with the grid needs of voltage and frequency response may require detailed studies of inverter capability and coordination with the VER manufacturer. While, in general, priority should be given to reactive current to ensure local voltage stability and maintaining voltages within acceptable limits during the transient timeframe and post-contingency steady-state, this should be coordinated between the Transmission Planner, Planning Coordinator, Generator Owner, and manufacturer. Any blocking action should be reserved for severe fault (near zero voltage) conditions, and inverters should be capable of relatively fast resumption of active and reactive power control once the fault condition has been cleared, depending on the energy and frequency requirements for the area. Any local interconnection requirements should be met in addition to the PRC-024-2 requirements.

Voltage and frequency ride-through is critical under weak grid conditions for the following reasons:

- Weak grids experience a high sensitivity of voltage to changes in power (i.e., higher dV/dP, dV/dQ), and are more prone to potential voltage collapse conditions. Attempting to push real current during low voltage conditions could further degrade system voltage and result in collapse. Reactive current should be given priority during fault conditions in these weak grid conditions; however, studies should ensure that reactive current contribution during fault conditions does not cause voltage overshoot or other problems that could trip the inverters.
- Weak grids are indicative of a lack of synchronous generators and/or transmission in the local area. Tripping of inverter-based resources during abnormal voltage and frequency excursions would further exacerbate issues of grid support.
- Tripping of inverter-based resources could result in subsequent high voltage conditions due to loss of power transfer, which could result in cascading outage of inverter-based resources and further voltage rise.
Chapter 3: Issues Associated with Weak Systems

Figure 3.5: PRC-024-2 Voltage Ride-Through Curve

Figure 3.6: PRC-024-2 Frequency Ride-Through Curve
Phase Lock Loop Stability
The majority of inverter-based resources use a PLL to synchronize to the grid. Figure 3.7 shows a generic inverter schematic and how the PLL is a key component of the overall control system between the network and the inverter. The inverter operates in a “grid following” fashion by deriving the grid phase and frequency using a closed loop control system (Figure 3.8). The PLL voltage phase estimation is used to derive the d- and q-axis voltages and currents that are fed to the control algorithms. Similarly, the PLL voltage phase estimation is used to convert the control action (i.e., converter modulation) from d-q to phase quantities. Inaccurate PLL system voltage phase angle results in inaccurate control of VER active and reactive power. Following clearing of a fault, the PLL should regain synchronism sufficiently fast in order to control reactive power to maintain system voltage. In the short period (1-2 cycles following a fault), this critical PLL function becomes even more difficult in weak systems, as the phase angle may have shifted drastically, and the post fault voltages may be especially noisy. Inverter manufacturers should ensure PLL stability and the ability to withstand large changes in phase that are typically experienced under EHV fault conditions. Actual PLL functionality is often considered by manufacturers to be proprietary information, supported by internal research. However, this consideration should also be balanced against the requirement for TPs to understand the characteristics of the resources connected to the BPS. Transient stability models do not represent PLL in detail, and this is a major limitation for studying VER integration in weak systems. This issue supports the need for appropriate models to perform detailed EMT studies for weak grid conditions.

Figure 3.7: Generic Inverter Control Schematic [Source: EPRI]

Figure 3.8: Common PLL Structure – Synchronous Frame [Source: EPRI]
Chapter 4: Planning Study Considerations

The following sections describe useful considerations that TPs and PCs should make when studying integration of VER to the BPS.

Transient Stability Limitations

Transient stability simulation tools are widely used in planning applications to evaluate stability of the BPS. These tools are effective in predicting disturbance response, generator stability, voltage stability, load dynamics, and many other phenomenon for most applications. However, as VER penetration grows and the prevalence of weak grid interconnections becomes more important, these tools may encounter limitations which should be well understood by those who use them. Some considerations that should be made with respect to weak grids studies using transient stability tools include:

- **Validity for Phenomena Slower than 5 Hz**: "Transient stability programs use simplified generator models ignoring the dynamics of stator flux. In addition, the transmission network is modeled using a constant bus admittance matrix calculated for the power frequency. Due to these simplifications, any oscillations above the range of electromechanical oscillations (up to 5 Hz) produced by a transient stability program are not reliable."\(^{11}\) Subsynchronous phenomena or harmonic effects due to switching or controls are not accurately represented using these models.

- **Positive Sequence Based**: Positive sequence RMS quantities are typically calculated in these tools. The effect of DC current components, as well as zero and negative sequence components are usually neglected in these calculations. Some of the limitations of these approximations are commonly understood for unbalanced conditions (for example, the negative sequence aspects may become relevant for evaluating limitation of overvoltages in unfaulted phases during unbalanced faults). Zero sequence aspects may not be critical because the transformer connection group in the VER systems often isolates the zero sequence system in the VER from the BPS, but this may require additional review.

- **RMS Based**: Phasor-based tools require that the power system electrical quantities be represented as 3-phase rms quantities. The operation of protection systems is highly dependent on how measurement is modeled; there may be limitations in transient stability tools on measurement delays. Measurement, in general, must be approximated in these models, as the rms quantities are inherent to the transient stability tools (instantly available), while in the real controls they must be calculated from phase quantities. Additionally, the unique individual phase dynamics implicit in a severe contingency event such as a fault may not be captured, and this can result in different behavior from control elements which use these phase quantities, such as instantaneous phase-based protection circuits and synchronization controls (PLL details).

- **Large Simulation Time Step**: A typical power electronic converter contains control loops and algorithms with fast response times – faster than can be represented with the relatively large simulation time steps used in transient stability programs. These control loops include PLL controllers and inner current loop controllers, and are often key drivers of instability modes in weak systems (such as small signal instability modes), and govern the ability of the plant to quickly provide grid support.

- **Convergence Issues**: The iterative nature of the transient stability and powerflow calculations can be challenging in weak systems, manifesting in convergence problems as the system becomes very weak. This aspect in some cases is driven by limitations of specific models and not the tool itself, but can prevent proper analysis.

- **Limited Converter Electrical Representation**: Depending on the sophistication of the model, internal converter electrical representation is simplified. For example, the converter DC bus (including associated bus voltage protections, choppers, and controls) may be assumed to be infinitely strong. Likewise,

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interfaces and controls relating to the VER energy source are often approximated or ignored, where these elements can in some circumstances influence the converter behavior.

![Figure 4.1: Comparison of VER Fault Response between Transient Stability and EMT Models (Modified from public ERCOT Panhandle Study Report) [Source: Electranix, ERCOT]](image)

**Key Takeaway:**
The above approximations typically result in increasing differences between the positive sequence, phasor-based simulation methods, and the EMT simulations as the system strength becomes lower. This can lead to misrepresentation of ride-through performance, false stability evaluations, or failure to predict control interactions.

Manufacturers of modern VER equipment have in some cases gone to considerable lengths to overcome some of the above limitations and often use creative approximations to provide the best possible representation of their specific equipment using user-defined models. However, for some phenomena these tools are not appropriate, and as interconnecting systems become very weak, most manufacturers will recommend using EMT tools to confirm equipment behavior or validate the transient stability results.

**Electromagnetic Transient (EMT) Type Models**
In very weak system interconnections, planners and manufacturers may deem more detailed analysis to be necessary using Electromagnetic Transient tools. EMT simulation programs have in common a key distinction from phasor-based transient stability models. Power-flow and transient stability programs iteratively solve a system of equations to satisfy a set of constraints in the phase domain. EMT software solves systems of differential equations which describe the three-phase electrical network in the time domain, allowing unbalanced faults, harmonics, fast transients, and other effects to be modeled. In addition, extremely high levels of detail may be used in modeling the fast controllers which are used in real equipment converters, capable of capturing the very fast time constants used in current controls and switching algorithms. In many cases, the actual firmware code used in the power electronic devices may be inserted as-is into the model, eliminating most modeling approximations and approaching perfectly accurate control representation under transient conditions.
If it is determined that EMT studies are required, this very high level of detail is necessary, as the control modes which lead to the weak system issues described above are critically dependent on the specific control implementation (including PLL, inner current controls, specific protection implementation, etc.). Use of “generic” or “typical” EMT models is usually not recommended, as they cannot predict with accuracy the specific issues which may be encountered. If conventional transient stability models are not sufficiently accurate, detailed EMT models are required.

In some cases, it is useful to validate transient stability models using detailed EMT models (particularly in systems which are “marginally weak”, in order to provide comfort for planners that their standard transient stability models and studies are accurately predicting performance.

An example set of requirements for EMT models is shown in Appendix A.

### Study Model Requirements

The increasing penetration of VER and potential weak grid issues drives the need to ensure accurate and representative models are available to planning engineers to study the impacts VER may have on grid reliability, and vice versa. Planners are recommended to use the screening methods outlined in this guideline to identify areas where weak grid conditions may be a concern. Once these areas are understood, modeling requirements should be put in place that clearly define the types of models, list of acceptable models, and intended use of these models. The following concepts should be considered when developing these requirements:

- **Generic Positive Sequence Stability Model:** A generic model used for interconnection-wide modeling should be required for every resource seeking interconnection to the BES. Generic models are expected to accurately represent the general dynamic behavior of the VER, and should be benchmarked to more detailed models to the extent possible. These generic models should be part of the standard model library within the commercial software platforms, and should also conform to the data requirements specified by the TP and PC under MOD-032-1.

- **Detailed Positive Sequence Stability Model:** Interconnection stability studies (e.g., System Impact Studies) should use the most detailed model available for the study being performed. These studies are often positive sequence transient stability analyses. Detailed models from the VER manufacturer should be provided for these studies to ensure stability and security of the BES prior to connection of these resources. It is very important that these models be developed to a sufficient quality, with appropriate documentation, to allow for dependable use in system studies.

- **Electromagnetic Transient Model:** In the event that a weak grid condition has been identified, or a possible weak grid condition may occur in the future, EMT models should also be required from the GO. The EMT models should follow the considerations listed in Appendix A.

EMT usually require confidentiality agreements between the manufacturer and data owners and users. These types of models are used for detailed local studies; however, the data sharing and software support for these models create challenges from an interconnection-wide modeling perspective. Transient stability models typically do not have the same degree of confidentiality restrictions (i.e., user-defined transient stability models may still require a confidentiality agreement). Hence, these models, particularly the generic models, are used for larger system modeling purposes.
Potential Solution Options

There are a number of potential solutions that can be considered and deployed to address weak grid conditions. Some of the solutions can mitigate the weak grid condition from occurring entirely. Others help support the integration of VER under the weak grid conditions. In either case, the potential reliability risks described previously can be minimized. Similar to the weak grid issue, the solutions deployed are dependent on the system characteristics for each interconnection of VER as well as the manufacturer capabilities of the VER.

Potential solution options to mitigate issues associated with weak grids include:

- **Synchronous condenser:** Synchronous condensers are often the primary solution for weak grid issues, primarily due to the multifaceted benefits from these resources. Some of the benefits include large capability to supply fault current (higher short circuit capacity), increased system inertia, voltage capability and improved voltage stability, and other power quality improvements. This solution is particularly useful in situations where synchronous resources are being retired (or being considered for retirement) since there are a number of options that can be explored. New synchronous condensers can be installed or the existing unit(s) may be able to be used as synchronous condensers.

- **Plant Control Changes:** In some cases, changes to the plant control system(s) may alleviate weak grid issues. Time constants and gains may be adjusted to reduce the risks of unstable response under weak grid conditions. Voltage control strategies such as reactive droop can be deployed to minimize inter-plant control interactions. These changes are system specific and should be determined in close coordination between the TP, GO, and manufacturer. The evaluation of these changes can be time consuming, and may not be a viable option in the timeframe needed for maintaining grid reliability (e.g., interconnection study process, necessary maintenance outages, etc.).

- **Converter Control Changes:** In some cases, changes to the power electronic controls in WTG or PV converters may alleviate weak grid issues. These changes can consist of modifications to control parameter values and/or modifications to the control structures. These modifications may require complex engineering efforts, but can avoid the need to add equipment to the project. Not always weak grid issues can be fully addressed with converter control changes. In some cases the required changes may be significant and impractical modifications to the selected products. Terminal voltage control or PLL enhancements are examples of potential control modifications in weak grid systems. These changes should be determined in close coordination between the TP, GO, and manufacturer.

- **Reduction in Plant Capacity or Power Output:** Short circuit ratio and potential negative impact of a VER can have on the BPS can be improved by either reducing the plant capacity or limiting plant output. As the capacity or output reduces, the SCR will increase; similarly, any sensitivities to active or reactive power output will be reduced by the reduction in plant capacity or output. Other solution options may be more applicable in the planning stages; however, this may be the only viable short-term solution if weak grid conditions are encountered in real-time or near real-time. Restricting plant output under specific operating conditions may be used as a bridge strategy until a longer-term solution such as reinforcement or controls improvements can be implemented. In cases where the SCR is so low that the transfer of power is unfeasible during a particular N-1 condition (i.e., SCR well below unity), VER output may need to be reduced rapidly to avoid system instabilities. In such cases, the TP, GO, and manufacturer may need to agree on an operating plan that reduces the power output of the VER when the contingency occurs to a level that ensures stability and BPS reliability.

- **Transmission Reinforcement:** Transmission system reinforcement (e.g., line reconductoring, new transmission circuits, new or larger transformers) can increase SCR at the point of connection of the VER, particularly when coupled with system upgrades necessary to accommodate the capacity of the new generating resource in the weak system area.

- **FACTS Devices:** FACTS devices such as SVCs and STATCOMs can help control BPS voltages by providing dynamic reactive support. This may help in controlling voltage fluctuations under weak grid conditions as
well as help with transient ride-through capability. However, these devices have fast control loops that can interact with VER on weak grids, are limited in their contribution to fault current (similar to an inverter-based resource) and do not provide any system inertia. Series compensation can also mitigate some aspects of weak grid operation and can be an effective way of mitigating the need to build additional lines.
Chapter 5: Conclusion

Most inverter-based resource control systems rely on the voltage magnitude and angle at their terminals to not be largely affected by the current injection of the VER for stable operation. System strength refers to the sensitivity of the VER terminal voltage to variations of VER current injections. Weak grid conditions experience a higher sensitivity and this becomes a key consideration when integrating VER to the BPS.

Weak grids are typically system-specific and require system-specific studies and solutions. It is important for TPs to apply appropriate tools, techniques, and simulation approaches in weak grid systems and higher penetration of VER. To identify these systems, a number of SCR-based metrics have been developed by the industry. The benefits and drawbacks of each method, as well as a high-level description of how to apply the method, are provided in this guideline. There is no specific short circuit threshold one can consider as a “weak grid”, so understanding system short circuit levels, and engaging with the GO and manufacturer of the VER equipment is key to reliably planning and operation under these weak grid conditions.

Weak grid issues can manifest themselves in a number of different ways. Controls instability, control interactions, small signal instability, and classical voltage stability issues are more prominent in weak grids. This guideline provides a description of each phenomenon, as well as some illustrative examples of weak grid issues that have been experienced by grid operators across North America. Simulation tools and their inherent limitations should be understood by the planners identifying potential weak grid conditions. Conventional positive sequence, phasor-based simulation tools may not be able to capture some of the weak grid issues described in this guideline. More advanced EMT modeling may be required in certain situations, and these models should be provided by the GO to the TP for any potential weak grid area of the system.

Solutions to weak grid issues are also system specific and will depend on the weak grid issue identified, the local grid characteristics, and plant control capabilities. Potential solution options are described briefly in this guideline to provide TPs with a suite of options to explore in more detail.

The changing resource mix and increasing penetration of VER are driving parts of the BPS towards “weak grid” conditions. This guideline serves as a high-level overview of how to identify potential weak grid conditions, considerations TPs can make when studying these types of systems, and potential mitigation techniques to ensure a reliable BPS when interconnecting VER to weak grids.
Appendix A: Example Requirements for EMT Modeling

Specific modeling requirements for an EMT study depend on the type of study to be performed. An EMT study that may cover topics such as weak system interconnection, ride-through evaluation, voltage control and event response, control interactions with nearby devices, and islanding performance should require a model that has the characteristics described in the following sections.

Model Accuracy Features
For the model to be sufficiently accurate, it should:

- **Represent the full detailed inner control loops of the power electronics.** The model should not use the same approximations classically used in transient stability modeling, and should fully represent all fast inner controls as implemented in the actual equipment. It is possible to create models which embed the actual hardware code into an EMT model component, and this is the recommended type of model.\(^{12}\)\(^{13}\)\(^{14}\)

- **Represent all control features pertinent to the type of study being done.** This may include external voltage controllers, plant level controllers, customized PLLs, ride-through controllers, SSCI damping controllers, weak grid options, or other types of controls. Actual hardware code is recommended to be used for most control features. Operating modes that require system specific adjustment should be user accessible. In some cases, plant level voltage control should be represented along with adjustable droop characteristics. If the plant level controllers are very slow, these may be approximated using constant reactive power modes.

- **Represent all pertinent electrical and mechanical configurations.** This includes any filters and specialized transformers. There may be other mechanical features (e.g., gearboxes, pitch controllers, etc.) that should be modeled if they impact electrical performance.

- **Have all pertinent protection systems modeled in detail for both balanced and unbalanced fault conditions.** This typically includes various over- and under-voltage protections (individual phase and RMS), frequency protections, DC bus voltage protections, and overcurrent protection. Actual hardware code is recommended to be used for these protection features.

Model Usability Features
In order to allow study engineers to perform system analysis using the model, the EMT model should:

- **Have control or hardware options which are pertinent to the study accessible to the user.** These may include adjustable protection thresholds or real power recovery ramp rates, for example. Diagnostic flags (flags to show control mode changes or protection activations) should also be accessible to aid in analysis.

- **Be capable of running at a minimum time step of 10 us.** Most of the time, requiring a smaller time step means that the control implementation has not used the interpolation features of the EMT simulation, or is using inappropriate interfacing between the model and the larger network. Lack of interpolation support introduces inaccuracies into the model at higher time steps.

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\(^{12}\) More specialized studies may require additional features.

\(^{13}\) The model should be a full IGBT representation (preferred), or may use a voltage source interface that mimics IGBT switching (i.e., a firing pulse based model). A three phase sinusoidal source representation is not acceptable. Code that is actually programmed into the actual controller of the VER (e.g., C code) should be used in the model. Tools such as MATLAB can be used to generate the C code. Block diagram representations or other high-level code should not be used. The controller source code may be compiled into DLLs or binary if the source code is unavailable due to confidentiality restrictions.

\(^{14}\) If the model is assembled using standard blocks available in the EMT simulation library, approximations are usually introduced and specific implementation details for important control blocks may be lost. In addition, there is a risk that errors will be introduced in the process of manually assembling the model. Note that for this type of manually assembled model, (i.e., not using “real code”), validation is recommended.

\(^{15}\) There may be other types of protection that should be modeled based on the specific implementation.
• Include documentation and a sample implementation test case. Access to technical support engineers is desirable.

• Be capable of initializing itself. Model should initialize and ramp to full output without external input from simulation engineers.

• Accept external reference values. This includes real and reactive power reference values (for reactive power control modes), or voltage reference values (for voltage control modes).
Appendix B: Example Challenges with Weak Grid Issues

This section provides illustrative examples of challenges utilities have faced integrating VER into weak grid conditions. These examples are intended to be useful references for future awareness and understanding of the various issues that may be faced moving forward.

High Penetration of Wind in West Texas

The Panhandle region in West Texas is remote from synchronous generators and load centers and is considered a weak grid with a large amount of wind generation. Several system characteristics and challenges that were detected and or studied in a weak grid include:

- In a highly compensated weak grid, static voltage collapse can occur within the normal operating voltage range (0.95 to 1.05 pu) masking voltage stability risks in real time operations. Static var compensators contribute to this effect and have limited effectiveness for further increasing transfer capability.
- A grid with low short circuit ratios and high voltage sensitivity of dV/dQ requires special coordination of various complex control systems. Typical voltage control settings can result in aggressive but uncoordinated voltage support strategies, causing un-damped oscillations potentially leading to overvoltage cascading or voltage collapse.
- Wind projects connected to the Panhandle region are effectively connected to a common point of interconnection (POI) such that each wind plant control may interact with other wind plants controls strategies.

ERCOT identified the need to maintain adequate system strength using weighted short circuit ratio (WSCR) in the Panhandle region to avoid potential control inability problems. The WSCR is a measure of system strength and therefore stability that accounts for the lack of conventional generation or significant load in the Panhandle region, the low fault current contribution of the region’s wind units, and the mutual interactions between the power electronic converters through which these units are connected to the grid. To determine a proper threshold of WSCR, ERCOT conducted a detailed PSCAD Electromagnetic Transients Program (EMTP) analysis and assessment of the ERCOT Panhandle region and confirmed that a WSCR of 1.5 is appropriate for the Panhandle region for the proposed network topology. In addition, for Panhandle WSCR levels at 1.5 or higher, PSS/E dynamic models and PSCAD models performed adequately. As the WSCR drops below 1.5, the need for more detailed EMTP type models becomes more critical. System enhancements, including new added transmission circuit and two synchronous condensers, were verified to be adequate to improve the system strength and address weak grid issues.

It should be noted that WSCR is currently used to monitor the Panhandle region susceptibility to weak-grid problems and will require further analysis to evaluate applicability of such WSCR metrics in other regions. With the continued growth of renewable generation in the ERCOT system, periodic PSCAD studies should be considered to validate PSS/E studies and further develop WSCR planning guidelines.

16 Panhandle System Strength Assessment PSCAD Study. Available: HERE.
**Synchronous Condenser and Wind Farm Interactions**

The following example discusses the application of a synchronous condenser at a wind power plant. In the first steps of the interconnection study for the proposed wind facility, it was identified that the generator was interconnecting to a point on the system with low SCR through a long radial transmission line. In this case, the SCR was calculated using the standard SCR calculation methodology described earlier in this document. Because of the low SCR, EMT analysis was conducted for the project and confirmed that the project did not have stable response for certain credible contingencies. This unstable behavior was not observed using the positive sequence stability model. As a result of the unstable EMT performance, a synchronous condenser was proposed and sized to provide stable behavior for the conditions tested. As well as providing stable transient performance, the synchronous condenser can be used to help meet the interconnecting power factor and voltage control requirements for the facility. Figure B.1 shows a simplified one line diagram of the installation.

![Figure B.1: Simplified One-Line Diagram of Wind Generating Facility with a Synchronous Condenser](image)

Later, operations engineering studies identified further concerns. Stability analysis demonstrated that when the synchronous condenser was on-line, the limiting system condition was stead state post-contingency voltages. When the synchronous condenser was off-line, the limiting condition was actuation of the wind farm’s low voltage ride through protection, which would cycle in and out actuation. Tripping the plant would cause local voltage to rise enough to allow reconnection of the plant, which in turn caused actuation of the low voltage ride through protection. The resulting voltage variation and transients were unacceptable, as was the loss of the plant for the limiting transmission contingency.

There are some limitations that need to be considered with this type of installation:

- The synchronous condenser should be sized for a reasonable range of system conditions, considering facility outages or maintenance; however, it is not practicable to cover all possible operating conditions.
- Since the project response is unstable without the synchronous condenser, the output of the generating facility may have to be limited when the synchronous condenser is out of service. This presents additional complications to the calculations of operating limits.
- The protection for the synchronous condenser will be challenging to coordinate, especially for contingencies that island the facility from the system.
- Determining the actual lagging operating limits of the synchronous condenser is key, and behavior of the condenser when that lagging limit is reached can be critical for local system performance.
Weak Grid Voltage Stability Issues Interconnecting on Weak Circuits

BPA encountered classical voltage instability conditions caused by a high penetration of VER connected near the midpoint of a long (100+ mile) 230 kV transmission line. This relatively weak part of the network experienced high dV/dP and dV/dQ sensitivities. Figure B.2 shows a wind power hub with a Type 2 plant and Type 3 plant operating in power factor mode in late 2010. Illustrated differently, Figure B.3 shows a wind ramp at this location in December 2011, expressed as a classical PV plot. The wind plant and local network experienced a voltage collapse and inverter output problems due to the significant fluctuations in BPS voltage.

![Graphs showing voltage, power, and reactive power over time](source: BPA)

**Figure B.2: Classical Voltage Instability Issues for BPA Weak Grid VER Interconnection**

[Source: BPA]
To monitor plant performance in the future, BPA used V-Q plots to monitor VER modes of operation. Figure B.4 shows two examples of a plant’s operation along with the required dynamic voltage control on a reactive droop characteristic. The left figure shows the plant operating in voltage control mode with a fairly aggressive (i.e., low) droop characteristic where small changes in voltage result in large changes in reactive power output. In response to this, the plant operator switched to power factor mode without notifying the TOP. The right figure shows the power factor mode of operation, where reactive power output is held near 0 regardless of system voltage (no dynamic voltage support).

To mitigate the conditions shown in Figure B.5 where one VER at the wind hub is supplying reactive power and the other is consuming reactive power, BPA coordinated with the VERs to ensure correct voltage control (and reactive power) mode of operation and also devised a wind hub voltage control scheme. The goal of the scheme was to automatically control two 230 kV capacitors to aid operators in managing voltage in this area, maximize dynamic reactive reserves, and maintain acceptable pre- and post-contingency voltage levels.
Figure B.4: PV Curve for Wind Ramp Event [Source: BPA]

Figure B.5: PV Curve for Wind Ramp Event [Source: BPA]
Transformer Energization in Weak Grids

Energizing a transformer can cause it to draw significant initial inrush currents that are unbalanced in nature and that decay over time to much smaller steady state magnetizing currents. The main factors affecting the inrush current magnitude and duration include transformer design, initial conditions, and network factors. These inrush currents that can take several seconds to decay are supplied by the system, and flow through the network impedance which results in system voltage drop. In energizing transformers from weak grids, there is increased likelihood of resultant system voltage drops exceeding allowable limits or even the withstand level of any voltage-sensitive industrial loads or other inverter-based resources in the vicinity.

Power quality monitoring systems have captured significant voltage drops associated with energization of the transformers of several solar facilities (see Figure B.6 for illustration of typical interconnection) that have connected to the BPS. Figure B.7 shows the rapid voltage changes on the three phases measured at a 12 kV bus in response to energization of a solar facility connected to a nearby weak 46 kV bus. It can be seen that inrush caused 12 kV bus voltage to drop from pre-energization value of 1.02 pu to 0.87 pu for the worst phase and the recovery to pre-energization voltage took around five seconds. It may be noted that the voltage at the 46 kV bus dropped to an even lower value of 0.85 pu. Such rapid voltage changes easily exceed the typical limit of 5% (for up to four instances per day, IEEE 1453.1) at a PCC of a fluctuating facility connected to BPS.

Figure B.6: Illustration of Typical Solar Facility Interconnection to Utility System [Source: Southern Company]

Figure B.7: Example Rapid Voltage Change due to GSU Energization at a Solar Facility [Source: Southern Company]

Solutions being investigated to address these issues include:
Appendix B: Example Challenges with Weak Grid Issues

- **Pre-insertion Switching**: This solution involves use of a switching device that is equipped with a pre-insertion resistor. It is a very effective solution to mitigate the transient magnetizing currents and resultant system voltage drops. It may be noted that a comprehensive EMT study is recommended for each location where this is to be applied, to arrive at an optimal value for the pre-insertion resistor and insertion time.

- **Point-on-Wave (POW) Control Switching**: This solution involves using segregated pole breakers with special purpose point-on-wave control. It is another effective strategy but more complicated to implement in practice.

- **Moving interconnection**: In some cases, it may be possible to move the point of interconnection to a higher voltage level where the SCR is expected to be higher, resulting in smaller rapid voltage changes on the BPS.

- **Energizing Solar Facility Transformers in Stages**: Energizing the GSU along with all the inverter transformers yields the worst case scenario. Therefore, energizing the GSU first followed by various inverter transformers in stages may help minimize the rapid voltage changes caused by energization.
Appendix C: References


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<td>Andrew Isaacs</td>
<td>Electranix</td>
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<td>Jason MacDowell</td>
<td>General Electric</td>
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<td>Mohamed Osman</td>
<td>North American Electric Reliability Corporation</td>
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<td>Ryan Quint</td>
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<td>Jose Conto</td>
<td>Electric Reliability Council of Texas</td>
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<td>Shih-Min Hsu</td>
<td>Southern Company</td>
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<td>Hamody Hindi</td>
<td>Bonneville Power Administration</td>
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<td>Al McBride</td>
<td>ISO New England</td>
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### DRAFT System Protection and Control Subcommittee (SPCS) Scope

#### Purpose

The purpose of the System Protection and Control Subcommittee (SPCS), a subcommittee of the Planning Committee (PC), is to promote the reliable and efficient operation of the North American power system through technical excellence in protection systems and control system design, coordination, and practices.

#### Activities

1. Provide subject matter expertise for NERC Reliability Standards and technical guidelines, including, but not limited to, the following:
   - Protection systems and control systems, including local and wide area applications and synchrophasor applications
   - Remedial Action Scheme (RAS)
   - Power system monitoring

2. Provide subject matter expertise upon request on protection systems and control systems for NERC Critical Infrastructure Protection (CIP).

3. Provide subject matter expertise upon request on protection systems for the ERO Enterprise to NERC staff and the Performance Analysis Subcommittee (PAS) as follows:
   - Review summaries of misoperations associated with the top misoperation categories to identify trends, common factors, and root causes
   - Make recommendations for improvement where appropriate

4. Participate in developing reports to the Planning Committee concerning analysis, recommendations, and mitigation plans

5. Provide technical support to the NERC Event Analysis Program, including input and development of any lessons learned as needed from the Event Analysis Subcommittee (EAS).

6. Provide technical support to the NERC Alert System, including input and development of any lessons learned as needed from the Event Analysis group.

7. Provide technical support in the development of Implementation Guidance to the NERC Compliance Program.

8. Serve as the liaison to the IEEE Power and Energy Society (PES) committees associated with system protection slices and their associated subcommittees and working groups, and...
other industry protection groups, for collaborative promotion of technical excellence in system protection.

8.7. **Promote technical coordination between Regional Entity protection groups.**

9-8. Develop and maintain a NERC technical reference library on system protection and control.

10. Manage ongoing protection system programmatic reviews, as necessary.

Commented [FB21]: Nothing that I’m aware of, but some of the longer-tenured members may know.

Commented [MGG22]: Have we done anything in this area? Should we be?

Commented [SJ23]: Indirectly this is done by our participation of the regional representative and other members on the SPCS. I am not sure about formally requested input. I do know that we will reach out to the WECC RWG at times with questions.

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Other protection and control duties as determined by the SPCS and approved by the NERC Planning Committee.

Membership
The SPCS will generally follow the organizational structure and voting rights of the Planning Committee with the following additions:

- Additional non-voting industry subject matter experts may be added as determined by the SPCS.
- Additional voting members who are industry subject matter experts may be added as determined by the SPCS and approved by the PC.
- Non-voting members who are industry subject matter experts, as necessary for the work at hand may be added.
- Additional members may be added:
  - At the request of the System Protection and Control Subcommittee, and vote of approval by the SPCS.

A NERC staff member will be assigned as the non-voting Subcommittee Coordinator. The subcommittee chair and vice chair are appointed by the SPCS voting membership and approved by PC leadership chair of the NERC Planning Committee for one, two-year term. The vice chair should be available to succeed to the chair.

Reporting
The SPCS administratively reports to the Planning Committee and liaisons to the Operating Committee (OC) on pertinent technical issues.

Meetings
Four to six open meetings per year, or as needed. Emphasis will be given to conference calls and web-based meetings.

Approved by the NERC Planning Committee: December 14, 2011