NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

Distributed Energy Resource Modeling

September 2017

RELIABILITY | ACCOUNTABILITY

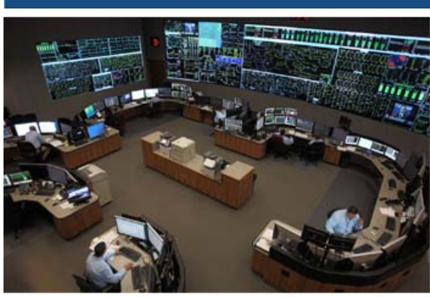

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Table of Contents

Preface iii

Preamble iv

Executive Summary 1

Chapter 1: DER Dynamic Load Modeling Framework 2

Chapter 2: DER Modeling Practices and Model Parameters 5

- DER Data Collection 5
- Synchronous DER Models 6
- Second Generation Renewable Energy System Models 8
  - Solar PV Plant Modeling 9
  - Battery Energy Storage System (BESS) Modeling 15
- PV1 Model 17
- PVD1 Model 18
- DER_A Model 21

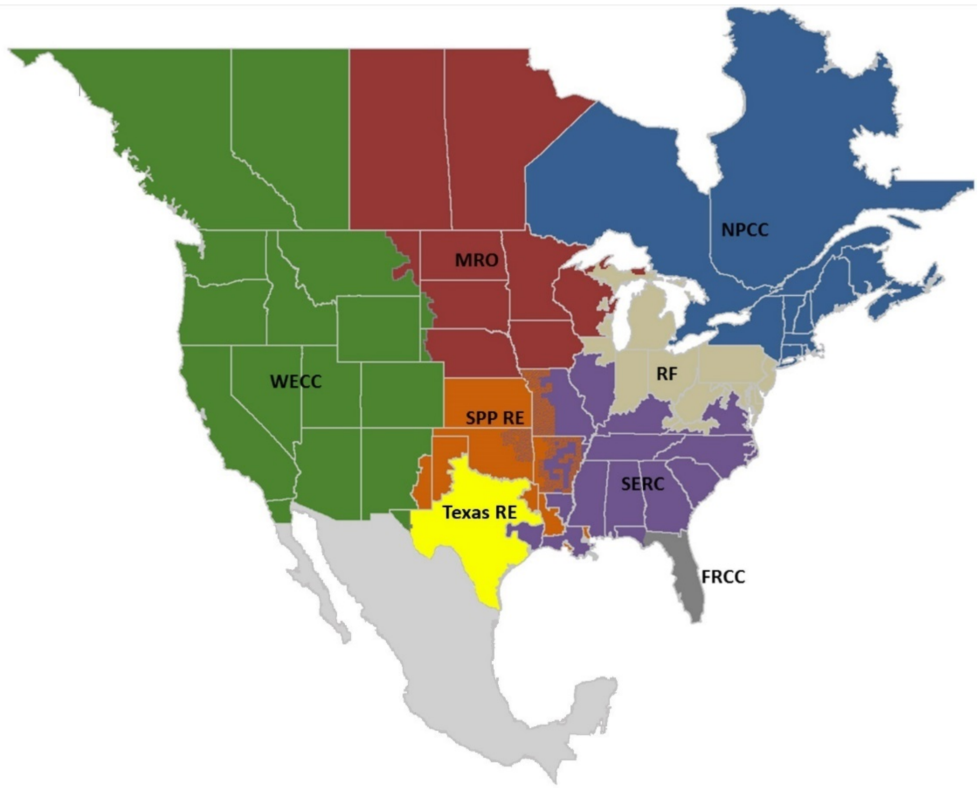
Chapter 3: U-DER and R-DER Modeling Capabilities 22

- U-DER Modeling Capabilities 22
- R-DER Modeling Capabilities 23
  - Composite Load Model with DER Included 23

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.



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

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst Corporation
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Preamble

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, the Planning Committee, and the Critical Infrastructure Protection Committee—are authorized by the NERC Board of Trustees (Board) to develop Reliability and Security 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.

[1] http://www.ferc.gov/whats-new/comm-meet/072006/E-5.pdf
[2] http://www.nerc.com/comm/OC/Related%20Files%20DL/OC%20Charter%2020131011%20(Clean).pdf
http://www.nerc.com/comm/CIPC/Related%20Files%20DL/CIPC%20Charter%20(2)%20with%20BOT%20approval%20footer.pdf
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Executive Summary

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 on DER modeling recommendations for BPS 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 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 Std. 1547[8] or other relevant requirements for the region they are being interconnected (e.g., California Rule 21). 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 North America, Transmission Planners (TPs) and Planning Coordinators (PCs) are faced with the challenge[9] of collecting information from their Distribution Providers (DPs) (and Resource Planners (RPs), if applicable) for resources connected to the distribution system and representing them with relatively newer and evolving models. With a framework established for modeling DER, the purpose of this guideline is to provide information relevant for collecting the data needed by TPs and PCs to sufficiently represent and model different types of U-DER and R-DER in stability analyses of the BPS. As a growing component of the overall load characteristic, it is important the TPs and PCs are able to assess how DER performance impacts 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.

[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.
[8] IEEE Std. 1547-2003, "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems," IEEE, July 2003.
[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 identify MVA thresholds where U-DER should be explicitly modeled and R-DER should be accounted for in the powerflow and dynamics cases. The thresholds, for example, should be based on an individual resource's impact on the system as well as an aggregate impact of many DER, including:

- 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 1.1 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 facility. 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 load 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		
Criteria	**Description**	**Threshold**
U-DER Modeling	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	___ MVA[13]
R-DER Modeling	Gross aggregate nameplate rating[14] of all connected R-DER on the feeder that offset customer load including residential, commercial, and industrial customers	___ MVA

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.

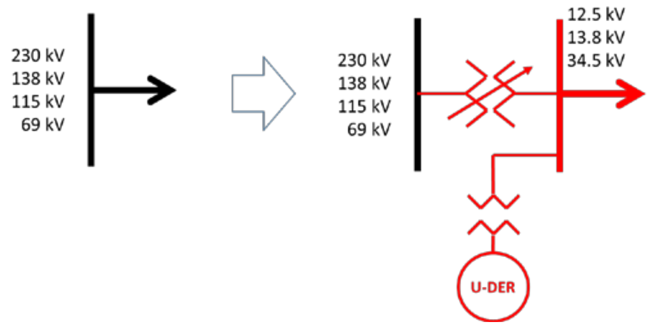

Figure 1.1: Representing Utility-Scale DER (U-DER) in the Powerflow Base Case

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 R-DER and the 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 *ltc1* model[17] in dynamic simulations. The motor load and distribution equivalent feeder impedance is modeled as part of the CLM[18], and 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.

[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.

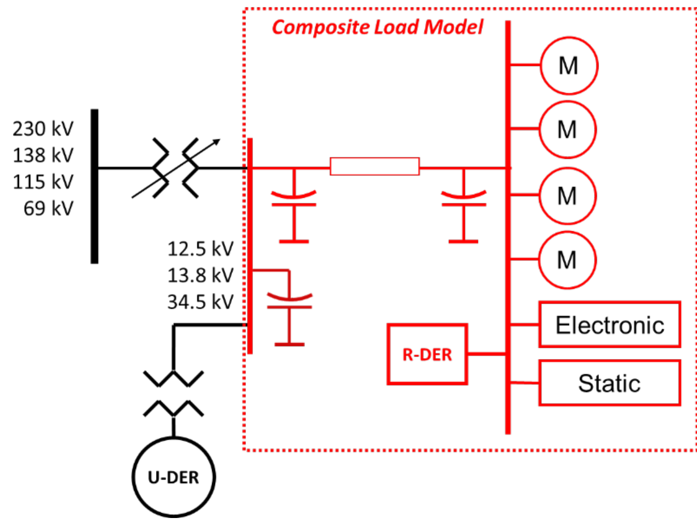

Figure 1.2: Dynamic Load Model Representation with U-DER Represented in the Powerflow Base Case

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[19] 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:

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

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

	Number of Bus	Name of Bus	Area Name of Load	Zone Name of Load	ID	Status	MW	Mvar	MVA	S MW	S Mvar	Dist Status	Dist MW Input	Dist Mvar Input	Dist MW	Dist Mvar	Net Mvar	Net MW
1	2	Two	Top	1	1	Closed	80.00	20.00	82.46	80.00	20.00	Closed	40.00	0.00	40.000	0.000	20.000	40.000
2	3	Three	Top	1	1	Closed	220.00	40.00	223.61	220.00	40.00	Open	110.00	0.00	0.000	0.000	40.000	220.000
3	4	Four	Top	1	1	Closed	160.00	30.00	162.79	160.00	30.00	Closed	80.00	0.00	80.000	0.000	30.000	80.000
4	5	Five	Top	1	1	Closed	260.00	40.00	263.06	260.00	40.00	Open	130.00	0.00	0.000	0.000	40.000	260.000
5	6	Six	Left	1	1	Closed	400.00	0.00	400.00	400.00	0.00	Closed	200.00	0.00	200.000	0.000	0.000	200.000
6	7	Seven	Right	1	1	Closed	400.00	0.00	400.00	400.00	0.00	Closed	200.00	0.00	200.000	0.000	0.000	200.000

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 1.1 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.

Recommendations:

1. All software platforms should adopt a unified approach to modeling R-DER as part of the the load records in the powerflow.
2. Software vendors should include R-DER inputs for active and reactive power generation, and active power capacity of DER for each load. DER zone should also be considered.

[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.

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 (and RPs, if applicable) 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, rated MVA, rated power factor, capability curve of U-DER reactive output with respect to different real power outputs down to Pmin)
  - 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)
  - Actual plant control modes in operation – voltage control, frequency response, active-reactive power priority
- R-DER
  - As available, aggregate information characterizing the distribution circuits where R-DER are connected
  - Aggregate capacity (Pmax, Qmax) of R-DER for each feeder or load as represented in the powerflow base case and a reasonable representation of the aggregate "capability curve" of reactive output with respecet to different real power outputs down to Pmin
  - 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)

[20] LSE is no longer a NERC registration; data should be collected in coordination with the DP.

Table 2.1: Data Collection Applicability to U-DER and R-DER		
Description	**U-DER**	**R-DER**
Type of generating resource (e.g., reciprocating engine, wind, solar PV, battery energy storage)	X	
Distribution bus nominal voltage	X	
Information characterizing the distribution circuits (X, R)	X	X (aggregate/ equivalent)
Capacity and capability (Pmax, Qmax, reactive capability with respect to real power output)	X (individual)	X (aggregate)
Rating (rated MVA, rated power factor)	X	
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)	X	X
Control modes – voltage control, frequency response,	X	

Note: The technical capabilities and default settings of R-DER for frequency response, volt/var control, and P/Q priority as specified by the revised IEEE Std 1547 should also be considered.

This information will help the PC, and TP in more representative modeling of U-DER and R-DER. In situations where this data is not readily available, the entities should use engineering judgment to map the model parameters to expected types of operating modes. The technical capabilities and default settings of R-DER for frequency response, volt/var control, and P/Q priority as specified by the revised IEEE Std 1547 should also be considered.

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[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 2.2 shows examples of model parameters for a steam unit, small hydro unit, and gas unit for reference.

[21] See NERC Modeling Notification – Use of GENTPJ Generator Model. Available: HERE.

Table 2.2: Synchronous DER Default Model Parameters			
Parameter	**Steam**	**Small Hydro**	**Gas**
MVA	14	32	15
T'd0	6	6	6.5
T''d0	0.035	0.027	0.03
T'q0	1	0[22]	1
T''q0	0.035	0.065	0.03
H[23]	3	1.7	4.2
D	0	0	0
Xd	1.8	1.45	1.6
Xq	1.7	1.05	1.5
X'd	0.2	0.47	0.2
X'q	0.4	1.05	0.3
X''d	0.18	0.33	0.13
X''q	0.18	0.33	0.13
Xl	0.12	0.28	0.1
S(1.0)	0.2	0.2	0.1
S(1.2)	0.6	0.6	0.4
Kis	0	0	0

Recommendations:

1. Synchronous DER should be modeled using the gentpj model with *Kis* = 0. This is the same representation as the gentpf model and requires the same list of parameters as the genrou model.
2. If modeling information is provided from the generating resource, that data can be used to develop the gentpj model parameters. Otherwise, engineering judgment should be used to develop reasonable model parameters based on the type of synchronous DER.

[22] In many commercially available software platforms (not necessarily all), by setting T'qo = 0 and X'q = Xq 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'qo to a very large number.

[23] For small DER synchronous generating units, it is common for the inertia constant to range from 1.5 to 5.0.

Second Generation Renewable Energy System Models

The second generation generic renewable energy system models[24] were developed between 2010 and 2013 and have since been adopted by the most commonly used commercial software vendors[25]. 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
- Battery Energy Storage Systems (BESS)

These models were originally developed to represent large utility-scale resources connected to the BPS at transmission level voltage[26], 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 (e.g., large capacity resources relative to the local interconnecting network) or other special studies. Tables 2.3-2.9 in the following 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 from the equipment vendor or at least an understanding of the actual equipment control strategy and performance (e.g., constant power factor control vs. voltage control) should be used. 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[27]. For example, lvplsw = 1 in Table 2.3 describes the flag that 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 is a function of the software and vendor controls in the power converter, and should be set according to the respective vendor characteristics to be emulated, if that information is available.

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.

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[24] Electric Power Research Institute, "Model User Guide for Generic Renewable Energy System Models," Report No. 3002006525, June 2015.

[25] Including Siemens PTI PSS®E, GE PSLF, PowerWorld Simulator, and PowerTech TSAT.

[26] P. Pourbeik, J. Sanchez-Gasca, J. Senthil, J. Weber, P. Zadehkhost, Y. Kazachkov, S. Tacke, J. Wen and A. Ellis, "Generic Dynamic Models for Modeling Wind Power Plants and other Renewable Technologies in Large Scale Power System Studies", IEEE Transactions on Energy Conversion, published on IEEE Xplore 12/13/16, DOI 10.1109/TEC.2016.2639050.

[27] 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.

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, the second generation renewable models may be of value and should be considered.
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 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. Inputs real power reference[28] (Pref), reactive power reference[29] (Qref), terminal voltage reference[30] (Vref0) and power factor angle reference[31] (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. 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.

Table 2.2 provides an example[32] of modeling a solar PV facility using the second generation renewable models.

Table 2.3: Default REGC_A Model Parameters

Parameter	Default Value or Range	Description
lvplsw	0 or 1	Low voltage power logic (LVPL) switch[33]
Rrpwr	10	Ramp rate limit (pu)
Zerox	0.4	LVPL characteristic zero crossing (pu)
Brkpt	0.9	LVPL characteristic breakpoint (pu)
Lvpl1	1.22	LVPL breakpoint (pu)
vtmax	1.2	Voltage limit used in high voltage reactive power logic (pu)

[28] Can be externally controlled.
[29] Can be externally controlled.
[30] Initialized to generator terminal voltage if set to 0.0.
[31] Computed during model initialization, not a user-specified value.
[32] These values are adapted from the WECC Solar PV Dynamic Model Specification Document, September 2012.
[33] Characteristic of active current response as voltage drops. Highly manufacturer-specific value. Connect = 1, disconnect = 0.

Table 2.3: Default REGC_A Model Parameters		
Parameter	**Default Value or Range**	**Description**
Lvpnt1[34]	0.8	High voltage point for low voltage active current management function[35] (pu)
Lvpnt0	0.4[33,34]	Low voltage point for low voltage active current management function[35] (pu)
qmin	-1.3	Limit in high voltage reactive power logic (pu)
Khv (accel)	0.7	Acceleration factor used in high voltage reactive power logic
Tg	0.02	Time constant (sec)
Tfltr	0.02	Voltage measurement time constant (sec)
Iqrmax	99	Upward rate limit on reactive current command (pu/sec)
Iqrmin	-99	Downward rate limit on reactive current command (pu/sec)
Xe	0[36]	Generator effective reactance (pu)

Table 2.4: Default REEC_B Model Parameters		
Parameter	**Default Value or Range**	**Description**
Mvab	0[37]	MVA Base
vdip	-99	Voltage below activation of current injection logic
vup	99	Voltage above activation of current injection logic
Trv	0.02	Transducer time constant (sec)
dbd1	0	Deadband downside in voltage error (pu)
dbd2	0	Deadband upside in voltage error (pu)
Kqv	0	Reactive current injection gain
iqh1	1.1	Maximum limit of reactive current injection (pu)
iql1	-1.1	Minimum limit of reactive current injection (pu)
vref0	1.0	Reference voltage
Tp	0.02	Electrical power transducer time constant (sec)
qmax	0.4	Reactive power maximum limit (pu)

[34] Actual name for this block might differ across various software platforms.

[35] WECC, "Second Generation Wind Turbine Models," Salt Lake City, Jan 2014. Available: https://www.wecc.biz/Reliability/WECC-Second-Generation-Wind-Turbine-Models-012314.pdf

[36] Some vendors, particulalrly of Type 3 wind turbine generators, may recommend the use of a non-zero value for Xe.

[37] If mvab ≤ 0, then MVA base used by REGC_A is also used in REEC_B.

Table 2.4: Default REEC_B Model Parameters		
Parameter	**Default Value or Range**	**Description**
qmin	-0.4	Reactive power minimum limit (pu)
vmax	1.1	Voltage control maximum limit (pu)
vmin	0.9	Voltage control minimum limit (pu)
Kqp	0	Reactive power regulator proportional gain
Kqi	1	Reactive power integral gain
Kvp	0	Voltage regulator proportional gain
Kvi	1	Voltage regulator integral gain
Tiq	0.02	Time constant (sec)
Dpmax	99	Up ramp rate on power reference (pu/sec)
Dpmin	-99	Down ramp rate on power reference (pu/sec)
Pmax	1	Maximum power reference (pu)
Pmin	0	Minimum power reference (pu)
Imax	1.1	Maximum allowable total current limit (pu)
Tpord	0.05	Time constant (sec)
Pfflag	1	Power factor control flag[38]
Vflag	1	Voltage control flag[39]
Qflag	0	Reactive power control flag[40]
Pqflag	1	Power priority selection on current limit flag[41]

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.

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[42]. 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.

[38] 1 = Power factor control; 0 = Reactive power control.
[39] 1 = Reactive power control; 0 = Voltage control.
[40] 1 = Voltage/reactive control; 0 = constant power factor or reactive power control.
[41] 1 = Active power priority; 0 = reactive power priority.
[42] Without the use of the REPC_A model, reference parameters in the REEC_A model are set during initialization.

Table 2.5: Default REPC_A Model Parameters		
Parameter	**Default Value or Range**	**Description**
mvab	0[43]	MVA Base
tfltr	0.02	Voltage or reactive power transducer time constant (sec)
kp	Vendor specific	Proportional gain
pi	Vendor specific	Integral gain
tft	0	Lead time constant
tfv	0.2	Lag time constant
refflg	See Table 2.7	Control mode flag[44]
vfrz	0.7	State S2 freeze level (if Vreg < vfrz)
rc	0	Line drop compensation resistance (pu)
xc	0	Line drop compensation reactance (pu)
kc	0	Droop gain (pu)
vcmpflg	1 or 0	LDC or droop flag[45]
emax	99	Maximum error limit (pu)
emin	-99	Minimum error limit (pu)
dbd	0.02-0.05	Deadband (pu)
qmax	Vendor specific	Maximum reactive power control output (pu)
qmin	Vendor specific	Minimum reactive power control output (pu)
kpg	0	Proportional gain for power control
kig	0.5	Integral gain for power control
tp	1.0	Lag time constant on Pgen measurement (sec)
fdbd1	-0.0006[46]	Deadband downside (pu)
fdbd2	0.0006[46]	Deadband upside (pu)
femax	99	Maximum error limit (pu)
femin	-99	Minimum error limit (pu)
pmax	1	Maximum power (pu)
pmin	0	Minimum power (pu)
tlag	0.2	Lag time constant on Pref feedback (sec)
ddn	20	Downside droop (pu)

[43] If mvab ≤ 0, then MVA base used by REGC_A is also used in REPC_A.
[44] 1 = Voltage control; 0 = Reactive power control.
[45] 1 = Line drop compensation; 0 = droop control
[46] The NERC Guideline on Primary Frequency Control recommends a deadband not to exceed 36 mHz for BES resources. Available: http://www.nerc.com/comm/OC/Reliability%20Guideline%20DL/Primary_Frequency_Control_final.pdf.

Table 2.5: Default REPC_A Model Parameters		
Parameter	**Default Value or Range**	**Description**
dup	0	Upside droop (pu)
frqflg	0	Pref output flag[47]
outflag	0	Output flag[48]

The model settings for various active and reactive power control strategies are provided in Table 2.6 and Table 2.7, respectively[49]:

- **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 1547-2003 standard. However, the revision of IEEE P1547 currently underway will include active power-frequency response capability. Regardless, 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, are 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.

The constant and local control options are most common for DER; however, some larger or more advanced U-DER may employ plant-level controls in certain situations. This will be application specific.

Table 2.6: Plant-Level Active Power Control Options				
Function	**Required Models**	**frqflag**	**ddn**	**dup**
No Governor Response	REGC_A + REEC_B	0	N/A	N/A
Governor Response	REGC_A + REEC_B + REPC_A	1	> 0	0[50]

[47] 1 = Governor Response enabled; 0 = Governor Response disabled.
[48] 1 = Qref is voltage; 0 = Qref is reactive power.
[49] Western Electricity Coordinating Council, "WECC Solar PV Dynamic Model Specification," Salt Lake City, UT, September 2012. Available: https://www.wecc.biz/Reliability/WECC%20Solar%20PV%20Dynamic%20Model%20Specification%20-%20September%202012.pdf.
[50] 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 2.7: Plant-Level Reactive Power Control Options (Source: WECC)[35]					
Function	**Required Models**	**pfflag**	**vflag**	**qflag**	**refflag**
Constant Local PF Control	REGC_A + REEC_B	1	N/A	0	N/A
Constant Local Q Control	REGC_A + REEC_B	0	N/A	0	N/A
Local V Control	REGC_A + REEC_B	0	0	1	N/A
Local Coordinated V/Q Control	REGC_A + REEC_B	0	1	1	N/A
Plant-Level Q Control	REGC_A + REEC_B + REPC_A	0	N/A	0	0
Plant-Level V Control	REGC_A + REEC_B + REPC_A	0	N/A	0	1
Plant-Level Q Control + Local Coordinated V/Q Control	REGC_A + REEC_B + REPC_A	0	1	1	0
Plant-Level V Control + Local Coordinated V/Q Control	REGC_A + REEC_B + REPC_A	0	1	1	1

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 1547-2003 – 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 P1547 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. Set the DER controls in the modelbased on estimated vintages of DER, data collection, and engineering judgment.
4. The REPC_A model should not typically be used to model DER since this models a plant-level controller and advanced capabilities of POI control of active and reactive power.

Battery Energy Storage System (BESS) Modeling

A BESS can be modeled using the following second generation renewable 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. Inputs real power reference[51] (Pref), reactive power reference[52] (Qref), terminal voltage reference[53] (Vref0) and power factor angle reference[54] (PFAref); and outputs real (Ipcmd) and reactive (Iqcmd) current command.
- **REPC_A (Optional):** renewable energy plant controller model. 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 BESS modeling can be found on the WECC website[55]. The same control tables (Tables 2.6 and 2.7) 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. Table 2.8 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 have additional capabilities, and specific settings and modeling parameters should be gathered from the vendor.

Table 2.8: Default REEC_C Model Parameters

Parameter	Default Value or Range	Description
Mvab	0[56]	MVA Base
vdip	-99	Voltage below activation of current injection logic
vup	99	Voltage above activation of current injection logic
trv	0.02	Transducer time constant (sec)
dbd1	0	Deadband downside in voltage error (pu)
dbd2	0	Deadband upside in voltage error (pu)
kqv	0	Reactive current injection gain
iqh1	1.1	Maximum limit of reactive current injection (pu)
iql1	-1.1	Minimum limit of reactive current injection (pu)
SOCini	e.g., 0.5	Initial State of Charge (user-defined)
SOCmax	0.8	Maximum allowable state of charge

[51] Can be externally controlled.
[52] Can be externally controlled.
[53] Initialized to generator terminal voltage if set to 0.0.
[54] Computed during model initialization.
[55] See: Western Electricity Coordinating Council, "REEC_C Modeling Specification," WECC REMTF, Salt Lake City, March 2015. [Online]. Available: https://www.wecc.biz/Reliability/REEC_C_031815_rev3%20Model%20Spec.pdf
Also see: Western Electricity Coordinating Council, "WECC Battery Storage Dynamic Modeling Guideline," WECC REMTF, Salt Lake City, Nov 2016, accessed Jan 2017. [Online]. Available: https://www.wecc.biz/Administrative/WECC%20Battery%20Storage%20Guideline%20V02.docx
[56] If mvab ≤ 0, then MVA base used by REGC_A is also used in REEC_B.

Table 2.8: Default REEC_C Model Parameters

Parameter	Default Value or Range	Description
SOCmin	0.2	Minimum allowable state of charge
T	99999	Discharge time in seconds
tp	0.02	Electrical power transducer time constant (sec)
qmax	0.4	Reactive power maximum limit (pu)
qmin	-0.4	Reactive power minimum limit (pu)
vmax	1.1	Voltage control maximum limit (pu)
vmin	0.9	Voltage control minimum limit (pu)
kqp	0	Reactive power regulatory proportional gain
kqi	1	Reactive power regulator integral gain
kvp	0	Voltage regulator proportional gain
kvi	1	Voltage regulator integral gain
tiq	0.02	Time constant (sec)
dpmax	99	Up ramp rate on power reference (pu/sec)
dpmin	-99	Down ramp rate on power reference (pu/sec)
pmax	1	Maximum power reference (pu)
pmin	0	Minimum power reference (pu)
imax	1.1	Maximum allowable total current limit (pu)
tpord	0.05	Time constant (sec)
pfflag	1	Power factor control flag[57]
vflag	1	Voltage control flag[58]
qflag	0	Reactive power control flag[59]
pqflag	1	Power priority selection on current limit flag[60]
Vq1	0	User-defined current limit tables.
Iq1	1	
Vq2	0.2	
Iq2	1	
Vq3	0.5	
Iq3	1	
Vq4	0.9	

[57] 1 = Power factor control; 0 = Reactive power control.
[58] 1 = Reactive power control; 0 = Voltage control.
[59] 1 = Voltage/reactive control; 0 = constant power factor or reactive power control.
[60] 1 = Active power priority; 0 = reactive power priority.

Table 2.8: Default REEC_C Model Parameters		
Parameter	**Default Value or Range**	**Description**
Iq4	1	
Vp1	0	
Ip1	1.1	
Vp2	0.2	
Ip2	1.1	
Vp3	0.5	
Ip3	1.1	
Vp4	0.9	
Ip4	1.1	

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

This model was created as an interim solution for modeling BPS-connected solar PV power plants prior to the release of the 2nd generation renewable models. PV1 is not implemented consistently across software platforms and is not recommended for use to represent DER.

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[61].

The partial trip characteristic in PVD1 is implemented using a 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 also used to represent partial tripping for high voltage conditions.
- The parameters vt0 and vt1 used for modeling partial tripping during low voltage conditions, or the parameters vt2 and vt3 for high voltage, 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 since PVD1 is modeling aggregated response of many inverter-based resources.

The partial tripping voltage response curve points 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.

Table 2.9 provides default values for representing a solar PV DER for either IEEE 1547-2003[8] and CA Rule 21[62].

Table 2.9: Default PVD1 Model Parameters (Source: EPRI)

Parameter	IEEE 1547-2003 Default	CA Rule 21 Default[62]	Description
pqflag	0	0	Priority to reactive (pqflag =1) or active (pqflag=0) current
xc	0	0	Line drop compensation reactance (pu)
qmx	0	-0.44	Maximum reactive power command (pu)
qmn	0	-0.44	Minimum reactive power command (pu)
v0	0	0.98	Lower limit of deadband for voltage droop response

[61] Western Electricity Coordinating Council, "WECC Solar Plant Dynamic Modeling Guidelines," Salt Lake City, April 2014, accessed January 2017. [Online]. Available: https://www.wecc.biz/Reliability/WECC%20Solar%20Plant%20Dynamic%20Modeling%20Guidelines.pdf.

[62] The same values may be used to represent performance requirements currently specified in IEEE P1547/D6 (12/2016).

Table 2.9: Default PVD1 Model Parameters (Source: EPRI)			
Parameter	IEEE 1547-2003 Default	CA Rule 21 Default[62]	Description
v1	1.3	1.02	Upper limit of deadband for voltage droop response
dqdv	0	0.06	Voltage droop characteristic
fdbd	-99	-0.0006[46]	Overfrequency deadband for governor response (pu)
ddn	0	0.05	Down regulation droop gain (pu)
imax	1.2	1.2	Apparent current limit (pu)
vt0	0.88[63]	0.50	Voltage tripping response curve point 0 (pu)
vt1	0.90[63]	0.52	Voltage tripping response curve point 1 (pu)
vt2	1.10[63]	1.19	Voltage tripping response curve point 2 (pu)
vt3	1.20[63]	1.21	Voltage tripping response curve point 3 (pu)
vrflag	0	1	Voltage tripping method[64]
ft0	59.5	56.5	Frequency tripping response curve 0 (Hz)
ft1	59.7	57	Frequency tripping response curve 1 (Hz)
ft2	60.3	61.9	Frequency tripping response curve 2 (Hz)
ft3	60.5	62.1	Frequency tripping response curve 3 (Hz)
frflag	0	1	Frequency tripping method[65]
tg	0.02	0.02	Inverter current lag time constant (sec)
tf	0.05	0.05	Frequency transducer time constant (sec)
vtmax	1.2	1.2	Voltage limit used in high voltage reactive power logic (pu)
lvpnt1	0.8	0.8[33]	High voltage point for low voltage active current management function[34,35](pu)
lvpnt0	0.4	0.4[33]	Low voltage point for low voltage active current management function[34,35](pu)
qmin	-1.3	-1.44	Limit in high voltage reactive power logic (pu)
Khv (accel)	0	0.7	Acceleration factor used in high voltage reactive power logic (pu)

[63] Values may differ depending on feeder characteristics.
[64] Latching of legacy DER (trip) = 0; partially self-resetting with modern DER (ride-through) is 0 < vrflag ≤ 1.
[65] Latching of legacy DER (trip) = 0; partially self-resetting with modern DER (ride-through) is 0 < frflag ≤ 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 R-DER.
2. The PVD1 model is a reasonable representation for U-DER, particularly when specific equipment and control settings are not available.
3. 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 v*rflag* and *frflag* between 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, then explicitly model two instances of the PVD1 model at a load bus (one for legacy DER and one for modern DER) starting with the parameters listed in Table 2.9.

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 will be 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 and California Rule 21. The model includes less parameters than other DER models while maintaining the following functional features[66]:

- 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 piecewise linear gain used to model the aggregate response from a large number of resources
- Representation of a fraction of resources that re-energize 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 that re-energize following a low/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 fully benchmarked and available in the commercial software platforms in late 2017 to early 2018.

Recommendations:

1. The DER_A model is the most appropriate model for representing aggregated R-DER based on its flexibility in modeling DER controls and its ease of use.
2. Once the DER_A model is finalized, commercial vendors will implement this model as part of their standard model libraries. Once available, entities should adopt the DER_A model for modeling U-DER and applicable R-DER, as appropriate.
3. Commercial software vendors should adopt the DER_A model as the DER component of the composite load model (CLM).

[66] P. Pourbeik, "Proposal for DER_A Model," WECC Renewable Energy Task Force Memo, Rev. 3, March 2017.

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

This section provides recommendations as to how the modeling options from the previous section can be applied for consistent modeling of R-DER and U-DER.

U-DER Modeling Capabilities

Table 3.1 shows the software platforms' capability to models each of the DER described as U-DER.

Table 3.1: U-DER Modeling Options					
BPS Model Options					
Model	**PSLF**	**PSSE**	**PW**	**PT**	**V&R**
Synchronous Machine Models	X	X	X	X	X
2nd Generation Renewable Models	X	X	X	X	X
PV1	X	X	X	X[67]	-
PVD1	X	-	X	-	-
DER_A[68]	-	-	-	-	-

Recommendations:

1. Synchronous DER should be modeled using the gentpj model with Kis = 0.
    a. When equipment data is available, that data can be used to develop a representative dynamic model.
    b. If data is not available, engineering judgment may be applied and default parameters are provided in this guideline.
    c. 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. It is is particularly useful in situations where detailed modeling information is not available. This model is recommended over the PV1 model for these reasons.
4. The DER_A model, when made available, should be used to model the majority of U-DER. This model is under development and expected in commercial software tools in late 2017 or early 2018.

[67] TSAT supports the pv1g model in PSLF dynamic data.
[68] The DER_A model is still under development.

R-DER Modeling Capabilities

R-DER modeling is integrated into the dynamic load models, and therefore R-DER modeling capability is available in the dynamic load models that include a DER component. Table 3.2 shows the dynamic load models and their associated DER model, if applicable.

Table 3.2: R-DER Modeling Capability

Criteria	Modularized Approach	DER in CLM	DER Model in CLM
GE PSLF	cmpldw2[69]	cmpldwg	Simplified version of PVD1
PTI PSSE	No	None	None
PowerWorld Simulator	Yes	DER can be used in conjunction with *any* load model, including CMPLDW	DGPV (simplified version of PVD1)
PowerTech TSAT	No	None	None
V&R Energy POM	No	None	None

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.[70]

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.

[69] This is available in PSLF v21.

[70] Western Electricity Coordinating Council, "WECC Specifications for Modeling Distributed Generation in Power Flow and Dynamics," Salt Lake City, Feb 2015, accessed January 2017. [Online]. Available: https://www.wecc.biz/Reliability/WECC%20Specifications%20for%20Modeling%20Distributed%20Generation%20in%20PF%20and%20DY.docx.

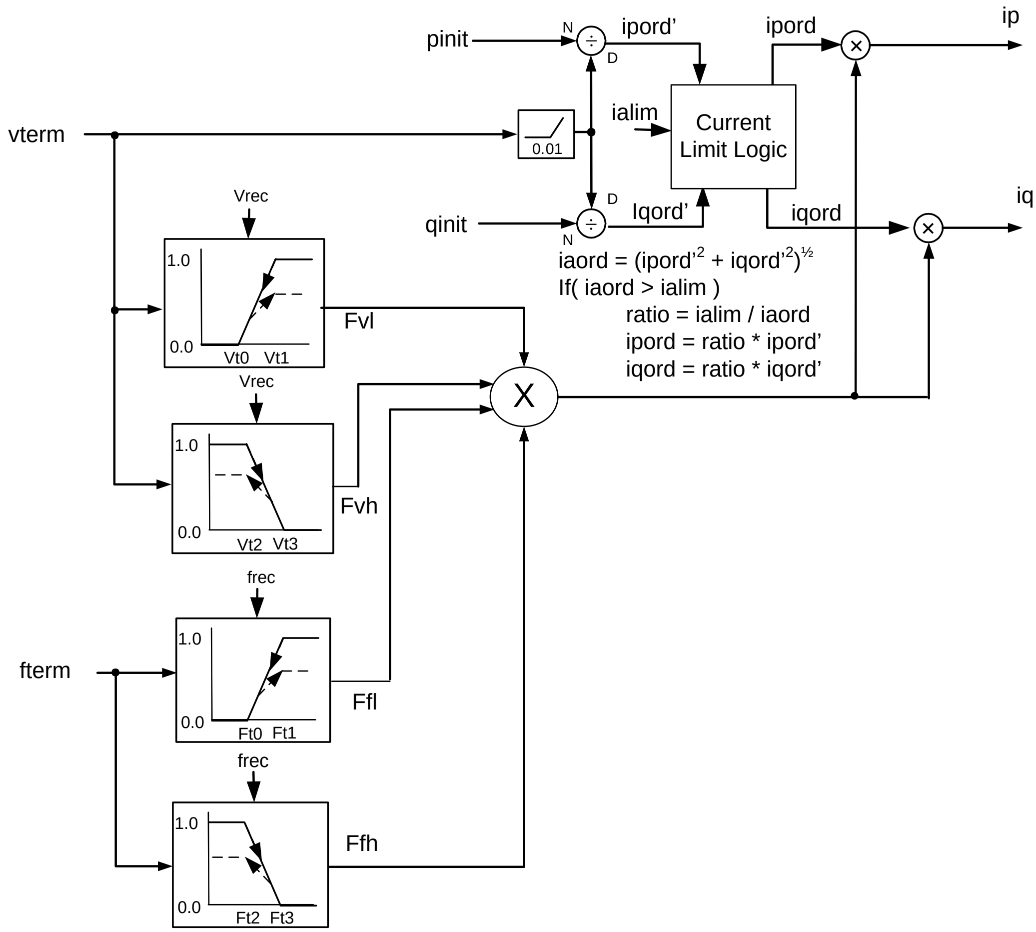

Figure 3.1: Block Diagram of DER Component in Composite Load Model (cmpldwg) (Source: GE PSLF)

Table 3.3: Default in cmpldwg DER Model Parameters (Source: EPRI, GE)			
Parameter	**IEEE 1547-2003 Default**	**CA Rule 21 Default[62]**	**Description**
DGtype	0 or 1	0 or 1	Type of DER[71]
Pflgdg	2	2	Data input method[72]
Pgdg	0	0	DER active power[73]
Pfdg	0	0	DER power factor[74]
Imax	1.2	1.2	Maximum current (pu)
Vt0	0.88[63]	0.50[60]	Voltage (pu) below which all generation is tripped
Vt1	0.90[63]	0.52[60]	Voltage (pu) below which generation starts to trip

[71] 1 = PV System; 0 = None.
[72] 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.
[73] Fractional value if Pflgdg = 0; MW value if Pflgdg = 1; ignored if Pflgdg = 2.
[74] DER power factor if Pflgdg = 0 or 1; ignored if Pflgdg = 2.

Table 3.3: Default in cmpldwg DER Model Parameters (Source: EPRI, GE)			
Parameter	**IEEE 1547-2003 Default**	**CA Rule 21 Default**[62]	**Description**
Vt2	1.10[63]	1.19[60]	Voltage (pu) above which generation starts to trip
Vt3	1.20[63]	1.21[60]	Voltage (pu) above which all generation is tripped
Vrec	0	1	Fraction of generation that can reconnect after low or high voltage tripping[75]
ft0	59.5	56.5	Frequency (Hz) below which all generation is tripped
ft1	59.7	57	Frequency (Hz) below which generation starts to trip
ft2	60.3	61.9	Frequency (Hz) above which generation starts to trip
ft3	60.5	62.1	Frequency (Hz) above which all generation is tripped
frec	0	1	Fraction of generation that can reconnect after low or high frequency tripping

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 achieve that goal. In the meantime, it is recommended that software vendors implement the DER_A model into the CLM once that model specification is complete. This will ensure sufficient flexibility for modeling existing DER and 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.

[75] Latching of legacy DER (trip) = 0; partially self-resetting with modern DER (ride-through) is $0 < \text{Vrec} \leq 1$.