NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

Parameterization of the DER_A Model

September 2019

RELIABILITY | RESILIENCE | SECURITY




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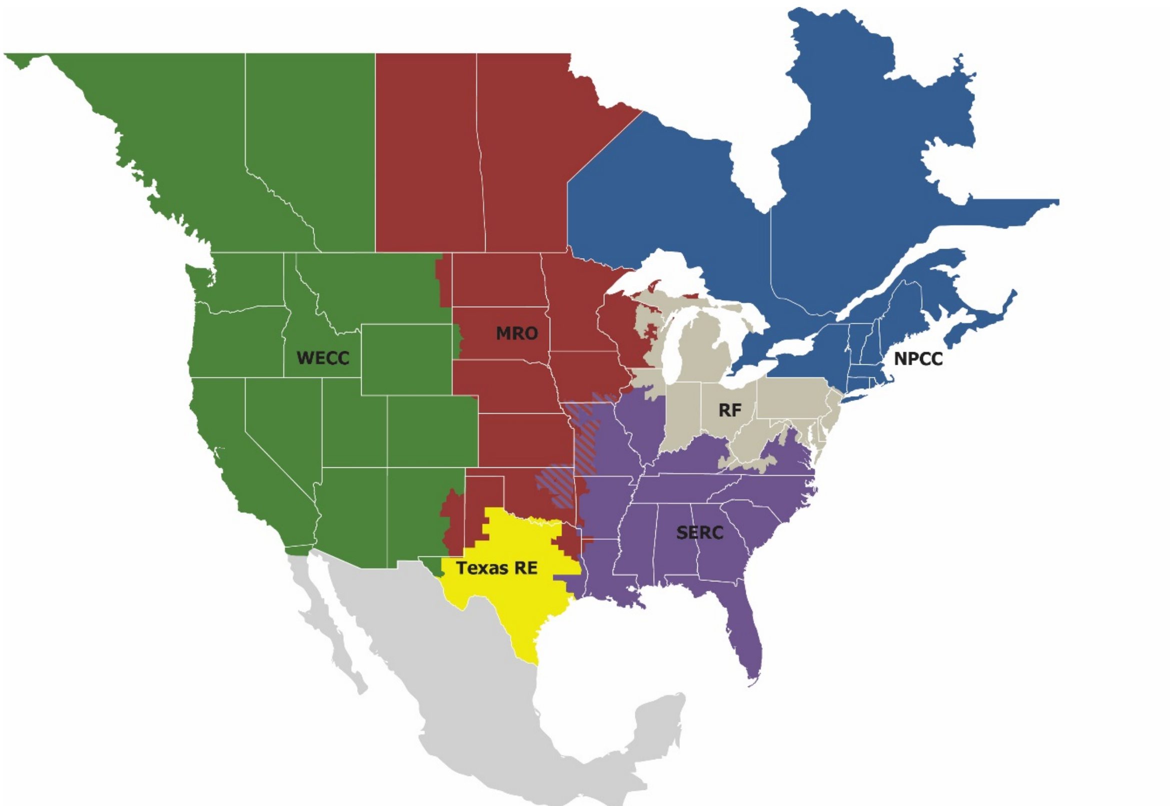
Preface

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

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

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



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

Preamble

It is in the public interest for NERC to develop guidelines that are useful for maintaining or enhancing the reliability of the Bulk Electric System (BES). The NERC technical committees (the Operating Committee (OC), the Planning Committee (PC), and the Critical Infrastructure Protection Committee (CIPC)) are authorized per their charters[1] by the NERC Board of Trustees (Board) to develop reliability (OC and PC) and security guidelines (CIPC). These guidelines establish a voluntary code of practice on a particular topic for consideration and use by BES users, owners, and operators. These guidelines are coordinated by the technical committees and include the collective experience, expertise, and judgment of the industry. The objective of this reliability guideline is to distribute key practices and information on specific issues critical to maintaining the highest levels of BES reliability. Reliability guidelines are not to be used to provide binding norms or create parameters by which compliance to standards is monitored or enforced. While the incorporation of guideline practices are strictly voluntary, reviewing, revising, or developing a program using these practices is highly encouraged to promote and achieve the highest levels of reliability for the BES.

NERC, as the FERC certified ERO,[2] is responsible for the reliability of the BES and has a suite of tools to accomplish this responsibility, including, but not limited to, lessons learned, reliability and security guidelines, assessments and reports, the Event Analysis Program, the Compliance Monitoring and Enforcement Program, and mandatory reliability standards. Each entity as registered in the NERC compliance registry is responsible and accountable for maintaining reliability and compliance with the mandatory standards to maintain the reliability of their portions of the BES. Entities should review this guideline in detail in conjunction with the periodic review of their internal processes and procedures and make any needed changes to their procedures based on their system design, configuration, and business practices.

[1] 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
http://www.nerc.com/comm/PC/Related%20Files%202013/PC%20Charter%20-%20Board%20Approved%20November%202013.pdf
[2] http://www.ferc.gov/whats-new/comm-meet/072006/E-5.pdf

Executive Summary

The NERC Load Modeling Task Force (LMTF)[3] worked in coordination with the NERC Distributed Energy Resources Task Force (DERTF) and published two detailed guidelines on modeling distributed energy resources (DERs) as either stand-alone generating resources or as part of the composite load model (CLM). These guidelines include the following:

- The *Reliability Guideline: Modeling DER in Dynamic Load Models*,[4] published in December 2016, established a framework for modeling DERs in steady-state powerflow and dynamic simulations.
- The *Reliability Guideline: Distributed Energy Resource Modeling*,[5] published in September 2017, utilized the framework established in the aforementioned guideline, and provided default parameter values for various DER dynamic models.

At the time of development of the latter guideline, the DER_A dynamic model was still under development and therefore only briefly mentioned. The DER_A model is now implemented and tested across the commonly used commercial simulation software platforms, and this guideline provides guidance on parameterizing the DER_A model for representing aggregate or stand-alone inverter-based DER resources in stability studies. The DER_A model has the capability to model DERs with advanced features as well as legacy DERs currently installed across North America.[6]

This guideline provides background material on the recommended DER modeling framework, including the concepts of retail-scale DERs (R-DERs) and utility-scale DERs (U-DERs), information on relevant interconnection standards (IEEE Std. 1547-2003, IEEE Std. 1547a-2014, IEEE Std. 1547-2018, and CA Rule 21), and how the DER_A model parameters can be modified to account for a mixture of vintages of inverter-interfaced DER.

The recommendations developed in this guideline are based on extensive testing of the DER_A dynamic model in the Western Electricity Coordinating Council (WECC) Modeling and Validation Work Group (MVWG) as well as industry expertise and studies discussed in detail in the NERC System Planning Impacts of DER Working Group (SPIDERWG) modeling subgroup.

This guideline is intended for use by Planning Coordinators (PCs), Transmission Planners (TOs), Transmission Operators (TOPs), Reliability Coordinators (RCs), and other entities performing positive sequence stability simulations of the BPS where an aggregate representation of DERs is needed. It also serves as a useful reference for building DER models and selecting representative DER model parameters in situations where more detailed information is not yet available.

[3] https://www.nerc.com/comm/PC/Pages/Load%20Modeling%20Task%20Force%20(LMTF)/Load-Modeling-Task-Force.aspx.
[4] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Modeling_DER_in_Dynamic_Load_Models_-_FINAL.pdf
[5] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_DER_Modeling_Parameters_-_2017-08-18_-_FINAL.pdf
[6] P. Pourbeik, "Proposal for DER_A Model," June 19, 2019. [Online]: https://www.wecc.org/Reliability/DER_A_Final_061919.pdf.

Background

The NERC DERTF published a report[7] in February 2017 that focused on connection modeling and reliability considerations for DER. The report provided definitions of DERs, an overview of data and modeling needs, characteristics of nonsynchronous DERs, and potential reliability impacts of DERs on the BPS.

The NERC LMTF[8] worked in coordination with the NERC DERTF, and published two detailed guidelines on modeling DERs as either stand-alone generating resources or as part of the CLM:

- The *Reliability Guideline: Modeling DER in Dynamic Load Models*, published in December 2016, established a framework for modeling DERs in steady-state powerflow and dynamic simulations.
- The *Reliability Guideline: Distributed Energy Resource Modeling*, published in September 2017, utilized the framework established in the preceding guideline, and provided default parameter values for various DER dynamic models.

At the time of development of that guideline, the DER_A model was still under development and testing and was therefore only briefly mentioned. With the DER_A model now implemented and tested across the major commercial software vendors, this guideline provides background and guidance on parameterizing the DER_A model for representing aggregate or stand-alone inverter-based DER resources.

The following section briefly describes the DER modeling framework and the definitions and terminology used in that framework. Refer to the modeling guidelines (mentioned above) for more details.

DER Modeling Framework

For the purposes of steady-state and dynamic modeling of DERs in BPS reliability studies, DERs can be defined as either utility-scale DERs, U-DERs, or R-DERs, which the previous guidelines have defined as follows:

- **U-DER:** DERs directly connected to, or closely connected to, the distribution bus[9] or connected to the distribution bus through a dedicated,[10] non-load serving feeder. These resources are typically three-phase interconnections and can range in capacity (e.g., 0.5 to 20 MW).
- **R-DER:** DERs that offset customer load, including residential,[11] commercial, and industrial customers.[12] Typically, the residential units are single-phase while the commercial and industrial units can be single- or three-phase facilities.[13]

Both U-DERs and R-DERs can be differentiated and should be accounted for in powerflow base cases and dynamic simulations. Modeling U-DERs and R-DERs in the powerflow provides an effective platform for linking this data to the

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7 https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf.

8 https://www.nerc.com/comm/PC/Pages/Load%20Modeling%20Task%20Force%20(LMTF)/Load-Modeling-Task-Force.aspx.

9 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.

10 In some cases, U-DERs may not be located on a dedicated feeder; rather, U-DERs may be installed on the load-serving feeders near the head of the feeder. In either case, the framework presented here can and should be adapted to each TP and PC needs. In this case, these larger DER installations can still be represented as U-DERs. In other cases, they may be better suited to be modeled as R-DERs. Engineering judgment should be used to determine which modeling approach is most appropriate.

11 This also applies to community DERs that do not serve any load directly but are interconnected directly to a distribution load serving feeder.

12 This often includes behind the meter generation but may also include individually metered DERs and systems that export beyond customer load at a particular site boundary.

13 For the purposes of modeling, some larger utility-scale U-DER may exist along the load-serving distribution feeder and may be electrically distant from the distribution substation. In these cases, they may be represented as R-DERs since they offset customer load. The aggregate power output can potentially exceed the total load demand of the distribution feeder.

dynamics records and ensuring that the dynamics of these resources are accounted for. U-DERs are typically relatively large, stand-alone installations that may have more complex controls or requirements associated with their interconnection. R-DERs represent the truly distributed resources throughout the distribution system whose controls are generally reflective of IEEE Std. 1547[14] vintages or other relevant requirements for the region they are being interconnected.

TPs and PCs should identify thresholds where U-DERs should be explicitly modeled and R-DERs should be accounted for in the powerflow and dynamics cases. The thresholds should be based on either the individual or aggregate impact of DER on the BPS: [15]

- 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
- Gross aggregate nameplate rating of all connected R-DERs that offset customer load including residential, commercial, and industrial customers

The thresholds for modeling U-DERs and R-DERs, determined using engineering judgment, can be defined as follows:

- **U-DER Modeling:** Any individual U-DER facility rated at or higher than the defined U-DER modeling 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[16] of this plant. U-DERs less than the defined threshold should be accounted for as an R-DER (as described below). Multiple similar U-DERs 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-DERs connected to a feeder exceeds the defined R-DER modeling threshold, these R-DERs 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-DERs can be accounted for as part of the powerflow load record and integrated into the dynamic model as an explicit DER component. The threshold for modeling R-DER should be 0 MVA, meaning that all forms of DERs be accounted for (not netted with the load) to the extent possible.

Figure B.1 shows the recommended powerflow representation for accounting for U-DERs. The left side of **Figure B.1** shows the conventional powerflow representation of the load record. This has conventionally included both load and DERs (representing a net load quantity as opposed to a gross load quantity). However, the right side of **Figure B.1** shows how the transmission–distribution (T–D) transformer can be modeled explicitly and the gross load can be moved to the low side distribution bus. U-DERs above the specified threshold can be modeled explicitly via their own step-up transformers as applicable. If the U-DERs are connected through a dedicated feeder or circuit to the low-side bus, then that would also be explicitly modeled in the powerflow.

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[14] IEEE Std. 1547-2003, Standard for Interconnecting Distributed Resources with Electric Power Systems, July 2003: https://standards.ieee.org/standard/1547-2003.html.
IEEE Std. 1547a-2014, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems – Amendment 1, May 2014: https://standards.ieee.org/standard/1547a-2014.html,
IEEE Std. 1547-2018, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, April 2018: https://standards.ieee.org/findstds/standard/1547-2018.html.
IEEE Std. 1547-2018, 6/4/2018: Errata to IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces: http://standards.ieee.org/findstds/errata/1547-2018_errata.pdf.

[15] This may include many different types of DERs, including distributed solar PV, energy storage, synchronous generation, and other types of DERs. Including synchronous generation in the CLM as a component of R-DERs may not be possible across all software platforms.

[16] 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-DERs (e.g., synchronous natural gas or steam-turbine generators) can also be modeled using standard models available in commercial software platforms.

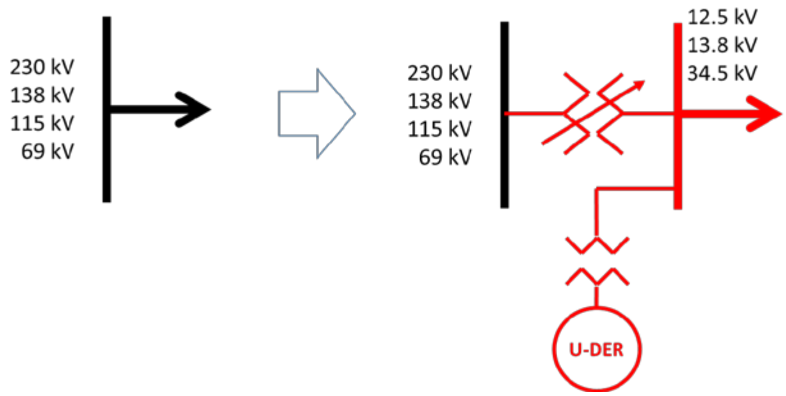

Figure B.1: Representing a U-DER in the Powerflow Base Case

To capture the R-DER in the powerflow, the load records now[17] have the capability to input the R-DER quantity along with the gross load amount. **Figure B.2** shows an example of the R-DERs included in the powerflow load records. The red box shows the R-DERs specified and the blue box shows the net load equal to the actual load minus the R-DERs. For example 80 MW and 20 MVar of actual load with 40 MW and 0 MVar of R-DER at Bus 2.

	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 B.2: Capturing a R-DER in the Powerflow Load Records [Source: PowerWorld]

Once represented in the powerflow base case, data for the CLM can be modified to account for explicit representation of the DERs and the T/D transformer. **Figure B.3** shows the dynamic representation of the CLM, where the distribution transformer impedance is not represented in the dynamic load record. Rather, it is modeled explicitly in the powerflow to accommodate one or more U-DER.[18] Any load tap changer (LTC) modeling[19] would be done outside the CLM, such as enabling tap changing in the powerflow[20] and using the *ltc1* model in dynamic simulations. Motor load and the distribution equivalent are modeled as part of the CLM, and the R-DERs are represented at the load bus based on the data entered in the load record table.

[17] All commonly used commercial simulation software platforms now have the ability to represent DERs as part of the powerflow load record in an attempt to standardize and unify modeling practices for representing DERs in powerflow base cases.
[18] If only R-DERs are represented at a bus (no U-DERs), then the T–D transformer does not necessarily need to be explicitly modeled in the powerflow since it can be accounted for in the CLM dynamic record, including LTC action. However, if LTC action needs to be modeled in the steady-state analyses in any way, then explicit modeling of the T–D transformer in the powerflow may be needed.
[19] Utilities using transformers without under-load tap changers (ULTCs) capability but with voltage regulators at the head of the feeder could model this in the CLM with a minimal transformer impedance but active LTCs to represent the voltage regulator.
[20] For example, by specifying settings in the transformer record and enabling tap changing in the powerflow solution options.

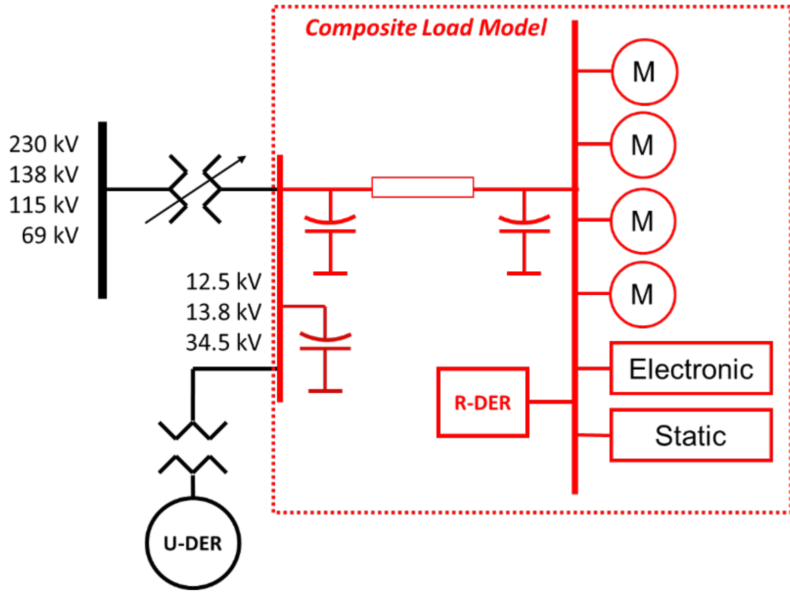

Figure B.3: CLM Representation with U-DER Represented in the Powerflow Base Case

Background and Overview of the DER_A Model

The DER_A model is a simplified version of the second generation generic renewable energy system models (i.e., regc_a, reec_b, repc_a, lhvrt, lhfrt) used to represent inverter-based DERs (i.e., utility-scale wind, solar photovoltaic (PV), and battery energy storage resources). The DER_A model uses a reduced set of parameters meant to represent the aggregation of a large number of inverter-interfaced DERs. It is also an improvement over the pvd1 model in that it includes additional modeling flexibility for more advanced and representative capabilities introduced in IEEE Std. 1547-2018 and California Rule 21. The DER_A model can be used to represent U-DERs (individual DER resources, or a group of similar U-DERs) and can also be used to represent R-DERs as either a standalone DER dynamic model or as part of the CLM. The DER_A model includes the following features:

- Constant power factor and constant reactive power control modes (allows voltage control to be active along with PF/Q control, depending on whether voltage is within the deadband or not)
- Active power-frequency control with droop 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)
- Representation of a fraction of resources tripping or entering momentary cessation[21] at low and high voltage, including a four-point piece-wise linear gain (partial tripping includes a timer feature as well)
- Representation of a fraction of resources that restore output following a low or high voltage or frequency condition (representation of legacy trip and modern ride-through capabilities in a single model)
- Active power ramp rate limits during return to service after trip or enter service following a fault or during frequency response
- Active-reactive current priority options (used to represent dynamic voltage support during fault events)

[21] Momentary cessation is a mode of operation during which no current is injected into the grid by the inverter during low or high voltage conditions outside the continuous operating range. This leads to no current injection from the inverter, and therefore, no active or reactive current (and no active or reactive power). Refer to the NERC R*eliability Guideline: BPS-Connected Inverter-Based Resource Performance.* The concept applies to both BPS-connected inverter-based resources and DERs: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf.

- The capability to represent generating or energy storage resources[22] (The model allows for absorption of active power; however, charging and discharging as modeled in reec_c is not included. Therefore, the DER_A model should not be used for devices with only a few seconds of energy injection (e.g., flywheel energy systems)

The overall block diagram for the DER_A model can be found in **Appendix B**.

[22] This guideline focuses mostly on using the DER_A model to represent generating resources, primarily distributed solar PV generation. However, the DER_A model can be used to represent energy storage, and future guidelines may be developed on this topic as necessary.

Chapter 1: Annotated DER_A Block Diagram

This chapter briefly describes the functional sections of the DER_A model and provides a high-level overview of what the various blocks represent. Refer to the DER_A specification document[23] for more detailed information regarding implementation. The sections below describe the general control aspects of the different functional sections of the model.

Active Power-Frequency Controls

The active power-frequency controls portion of the DER_A model are shown in **Figure 1.1**. The frequency input signal feeding the active-power frequency controls is first passed through a frequency measurement time constant, *Trf*. The filtered voltage is compared against a reference signal. The *fdbd1* and *fdbd2* parameters represent the active power-frequency control deadband for overfrequency and underfrequency, respectively. The *Ddn* and *Dup* parameters represent the overfrequency and underfrequency droop gains, respectively. *Tp* represents an active power measurement time constant. When active power-frequency control is enabled, *Freq_flag* is set to 1. To disable active power-frequency control of the model, set *Freq_flag* to 0. The frequency error is limited by *femax* and *femin* and goes through a PI controller with *Kpg* and *Kig* parameters. The *dPmax* and *dPmin* parameters limit active power upward and downward ramp rates. *Pmax* and *Pmin* represent the maximum and minimum power output, respectively. *Tpord* is the power-order time constant, and it can be used to represent the small time lag for changing the power reference (when *Freq_flag* = 0) or the open-loop time constant associated with the full controls (when *Freq_flag* = 1), as specified in IEEE Std. 1547-2018. Active current command (*ipcmd*) is calculated using power-order (*Pord*) divided by filtered terminal voltage (*Vt_filt*), and it is limited by *Ipmax* and *Ipmin*.

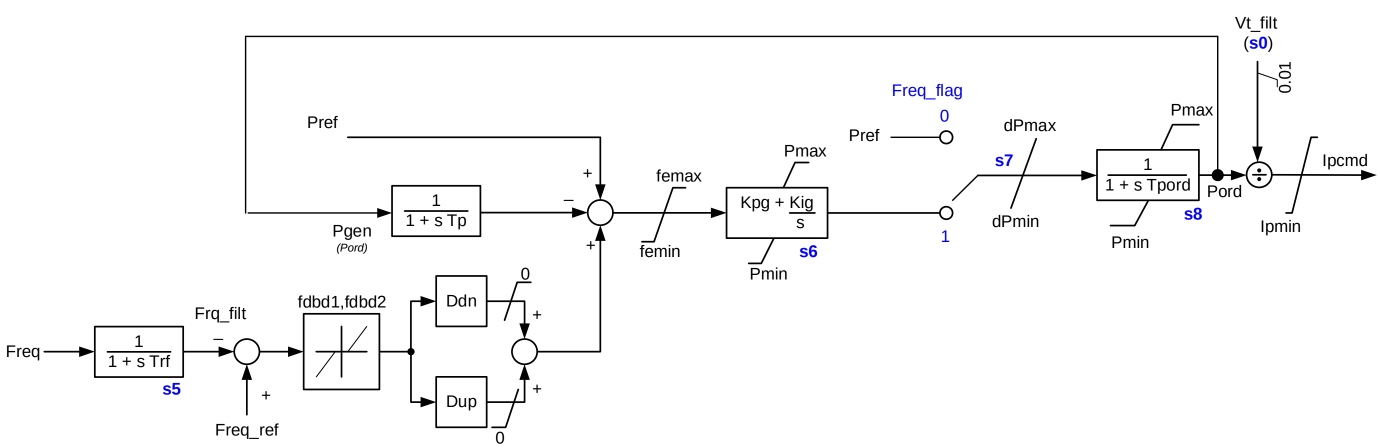

Figure 1.1: Active Power-Frequency Controls

Frequency Tripping Logic Input

The frequency input signal feeding the active-power frequency controls is first passed through a frequency measurement time constant, *Trf*. A low voltage inhibit logic was added to the model, which is shown in **Figure 1.2**. When voltage falls below a threshold (*Vpr*), then the frequency relay model is bypassed. This is common in frequency protective functions, to avoid spurious tripping during transients. In numerical simulations, this low voltage inhibit is also used to avoid tripping on numerical spikes during discontinuities.[24]

[23] P. Pourbeik, "Proposal for DER_A Model," June 19, 2019: https://www.wecc.org/Reliability/DER_A_Final_061919.pdf.
[24] https://www.wecc.biz/Reliability/WECC_White_Paper_Frequency_062618_Clean_Final.pdf

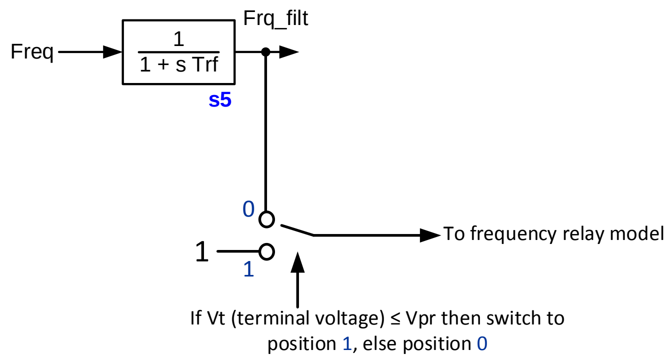

Figure 1.2: Frequency Tripping Logic Controls

Reactive Power-Voltage Controls

The reactive power-voltage controls portion of the DER_A model are shown in **Figure 1.3**. Setting *pflag* to 0 or 1 selects either constant reactive power control or constant power factor control, respectively. The *pfaref* parameter is internally calculated to achieve the necessary reactive power order for the current active power order. Reactive power is then divided by filtered terminal voltage (*Vt_filt*) and passed through a reactive current calculation time constant (*Tiq*). Voltage control is included in the model. Terminal voltage (*Vt*), after a measurement time constant (*Trv*), passes through a lower (*dbd1*) and upper (*dbd2*) deadband and proportional control gain (*Kqv*). Respectively, Iqh1 and Iql1 specify maximum and minimum limits of reactive current injection. To disable the reactive power-voltage control function of the model, set *Kqv* to 0.

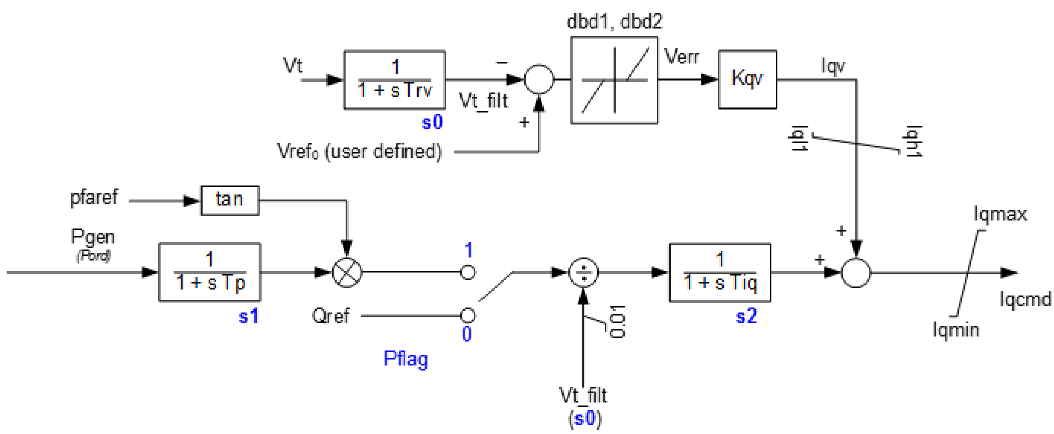

Figure 1.3: Reactive Power-Voltage Controls

Active-Reactive Current Priority Logic

With the active and reactive command values established in the active power-frequency and reactive power-voltage control elements, the command values are passed through maximum (*Ipmax*/*Iqmax*) and minimum (*Ipmin*/*Iqmin*) active and reactive current limits. **Figure 1.4** shows the current limit logic and how that logic interacts with the limiters. When the *typeflag* parameter is set to 0, this denotes a DER that is a generating unit with *Ipmin* = 0 while setting it to 1 denotes a DER that is an energy storage device with *Ipmin* = -*Ipmax*.

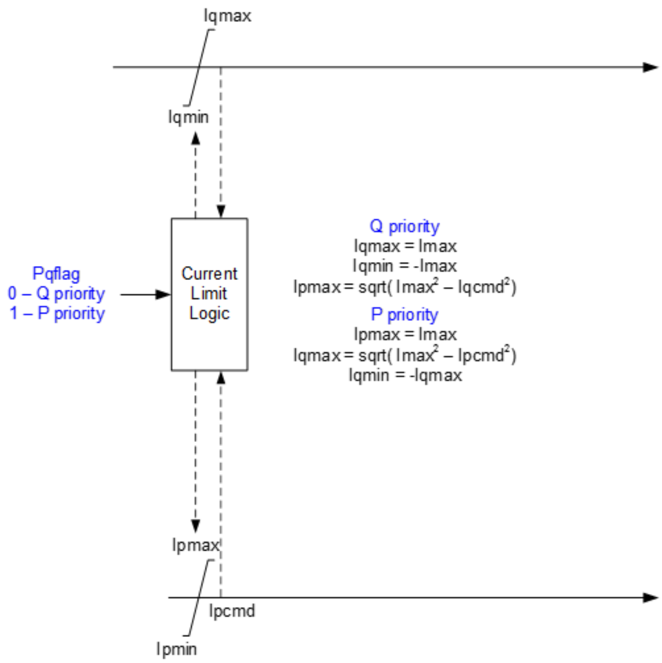

Figure 1.4: Active-Reactive Current Priority Controls

Current limits, particularly in inverter-based resources, determine how the resource response to large grid disturbances, such as faults on the BPS. The current limit logic is determined based on whether the resource is operated in active or reactive current priority and dictated by the *pqflag* parameter. The priority logic controls *Iqmax* and *Iqmin* based on the priority setting and maximum total current of the inverter (*Imax*). **Figure 1.4** also shows the equations used for this control. For example, if reactive current priority is selected, then *Iqmax* and *Iqmin* are limited to *Imax* and -*Imax*, respectively. Based on the reactive current ordered from the controls, the active current limit is then simultaneously calculated to utilize the remaining amount of total apparent current capability (*Imax*). A circular capability curve is assumed.

Example Consideration of Q Priority and P Priority

As an example, if the magnitude of current is limited to 1.2 pu (*Imax*), and the priority scheme is defined by reactive current priority, then a maximum limit of 1.2 pu is imposed on the reactive portion of current. The maximum active current (at this reactive current limit) will be $0.0 \text{ pu} = \sqrt{1.2^2 - 1.2^2}$. However, this does not imply that the active current will always be zero. This is the limited value of active current only when the reactive current is at its limit. However, if a reactive current of 1.0 pu is sufficient for the system, as decided by the reactive power-voltage controls, then the maximum active current can be $0.66 \text{ pu} = \sqrt{1.2^2 - 1.0^2}$. Hence, the reactive power-voltage controller not only decides the amount of reactive current to be injected but also the maximum amount of active current that can be injected for the decided value of reactive current. The active current controller then decides the actual value of active current to be injected. An opposite situation occurs when an inverter is in active current priority.

Prior to approval of IEEE Std. 1547-2018, all DERs on the system were not required to have reactive power-voltage control capability. Thus, the vintage of inverters that conform to this standard should have a P priority setting. With the approval of IEEE Std. 1547-2018, which requires inverters to have reactive power-voltage control capability (with preference to reactive current), it is expected that this capability will be used by the inverter, so the current priority setting should be set to Q priority. However, the impact of setting DER to P priority versus Q priority should be assessed with detailed studies since both settings could have a positive impact.

For example, upon the occurrence of a fault, a larger percentage of gross load can trip if located electrically close to the fault and if adjacent DERs are in Q priority, compared to when adjacent DERs are in P priority. However, at locations located electrically farther away from the fault, a larger percentage of gross load can trip when adjacent DERs are in P priority compared to when adjacent DERs are in Q priority. Closer to the fault, when in Q priority and with voltage control enabled, the DER reactive current would hit *Imax* and active current reduces to zero. The intention behind this is to try and support local voltage and prevent tripping of gross load. However, when the DER's active current contribution reduces to zero due to full output of reactive current (bear in mind that this is not to be confused with momentary cessation), the net load at the load substation bus increases, which can result in voltage reducing at nearby non-DERs causing load to trip. Now, when the DER is in P priority, the net load at the load bus would be lower (assuming that the DERs have not gone into momentary cessation mode), and thus, the voltage wouldn't fall as much at nearby non-DER buses, and as a result, a trip of gross load is lesser. Farther away from the fault, due to the initial higher voltage levels (as compared to the voltage levels closer to the faults), voltage support in Q priority has a greater effect and so even though the net load may increase (due to decrease in active current contribution from DER to accommodate injection of reactive current) the voltage drop (due to increase in net load) does not counterbalance the voltage support from the DER. Therefore, there is less gross load tripping.[25] It should be noted that this behavior may not be the norm, but it is a possibility; therefore, setting DER priority settings should be conducted based on detailed system studies.

Fractional Tripping

The DER_A model includes a fractional tripping control that is intended to represent a portion of the DER tripping on low or high voltage[26] as shown in **Figure 1.5**. The *vtripflag* controls voltage tripping and the *ftripflag* controls frequency tripping separately.[27] *Vrfrac* defines the fraction of DERs that recover after voltage returns to within acceptable limits after dropping below or above the threshold values. For frequency tripping, a single low (*fl*) and high (*fh*) frequency cutout breakpoint is implemented since frequency variation along the distribution feeder is relatively constant (as compared with voltage). Hence, there is no partial tripping due to frequency.[28] *Tv* is a time constant representing the time delay for voltage related partial tripping (shown in **Figure 1.5**).

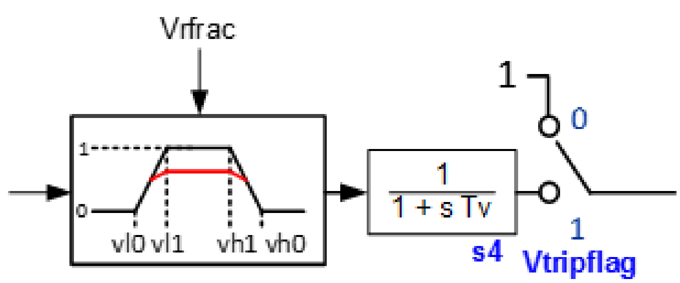

Figure 1.5: Fractional Tripping Controls

The *vl0* and *vl1* parameters are the low voltage cutout breakpoints and the *vh0* and *vh1* parameters are the high voltage cutout breakpoints. For example, when voltage falls below *vl1*, a fraction of the DERs will cutout, with a linearly increasing amount of DERs experiencing cutouts down to *vl0* where all DERs will have cut out. The output of the fractional tripping block is the value that gets applied to *ipcmd* and *iqcmd*.[29] If voltage falls outside the specified thresholds for the predefined amount of time (below *tvl0* or *tvl1* or above *tvh0* or *tvh1*), then the recovery of

[25] R. Quint, I. Green, D. Ramasubramanian, P. Pourbeik, J. Boemer, A. Gaikwad, D. Kosterev, C. DuPlessis, M. Osman, "Recommended DER Modeling Practices in North America," *25th International Conference and Exhibition on Electricity Distribution (CIRED) [under review]*.

[26] There is no partial tripping due to frequency in the DER_A model. If there is a frequency trip, then the entire amount of DER trips.

[27] GE PSLF does not have these flags; however, Siemens PTI PSS®E, PowerWorld Simulator, and Powertech TSAT do have these flags.

[28] If there is a frequency trip, then the entire amount of DER trips.

[29] Refer to the DER_A Model Specification document for a detailed pseudo code explanation of how the fraction/partial tripping is calculated: https://www.wecc.biz/Reliability/DER_A_Final.pdf.

resources changes from the black line to the red line. This is intended to represent only a fraction of resources recovering from the decrease in voltage (*Vrfrac*); Those resources are expected to trip off-line and return to service some time beyond a typical transient simulation.

The fractional tripping logic does not represent any actual controls but is rather an attempt at emulating the fact that not all R-DERs will necessarily experience the same terminal voltage on a feeder and therefore they may not trip at the same time and for the same level of voltage excursion at the head of the feeder. Thus, this is an attempt based on much deliberation among many participants and stakeholders to come up with a method to emulate such behavior. As experience is gained with the model, this and perhaps other aspects may be refined over time.

Refer to the model specification document for more details related to model implementation and pseudo code.[30]

Fractional Tripping Derivation

Specific data related to DERs tripping is often not available, and engineering judgment must be used to determine reasonable tripping values. These values should be based on the expected vintage of DERs and the distribution circuit characteristic. Each interconnection standard (e.g., IEEE Std. 1547-2003, IEEE Std. 1547a-2014, IEEE Std. 1547-2018) may have different ride-through and trip settings for abnormal voltage and frequency, with multiple magnitude/time duration pairs. Refer to **Table 2.1**and **Table 3.1** for details on setting these parameter values. TPs should coordinate with their Distribution Providers (DPs) to attempt to track the proportion of DERs that could be expected to fall within each category. The proportion of DERs within each category may be inferred by DPs by assessing the date of each DER installation. The DER_A model does not include multiple points; however, these are likely not needed for stability studies in most cases. Typically, it is recommended to model the trip thresholds that relate to the shorter trip times[31] since this scenario is what covers most stability simulations. The thresholds are selected to account for the varied response of aggregate DERs tripping across a distribution system while taking into account the voltage drop (V_{DROP}) across the feeder.

> **Key Takeaway:**
> The DER_A model does not include multiple points; however, these are likely not needed for stability studies in most cases. Typically, it is recommended to model the trip thresholds that relate to the shorter trip times since this scenario is what covers most stability simulations.

Fractional trip settings are based on how the DERs are represented in powerflow and dynamics. There are multiple modeling options for how to set these fractional trip settings including the following (see **Figure 1.6**):

- **Option 1 (Recommended for U-DERs):** The U-DER is represented in the powerflow base case as a generator, and has an associated DER_A model in dynamics. The modeled U-DER is intended to represent one or multiple U-DERs connected directly to or very close to the distribution substation. In this case, load modeling is unrelated, since the U-DER model explicitly represents a single or group of U-DERs. Partial tripping is not applied, and the DER trip settings can mirror those specified in the respective interconnection requirements. Parameters *vl0*, *vl1*, *vh0*, and *vh1* have a direct relation to those interconnection requirements. *Vrfrac* can be set to 1 or 0 depending on the vintage of DER.
- **Option 2 (Recommended for R-DERs):** An aggregate amount of R-DERs spread throughout the distribution system is represented in the powerflow base case as a DER component of the load record. In dynamics, this information is integrated into the CLM with DER representation (e.g., cmpldwg). The equivalent distribution impedance is then represented in the CLM as well, with both load and DER represented at the load bus across the equivalent feeder impedance. Voltage drop (V_{DROP}) across the feeder is accounted for explicitly ($V_{DROP} = V_{SUB} - V_{LOAD}$. The Electric Power Research Institute (EPRI) has shown that a V_{DROP} of 2–8% is typical for most distribution feeders; a value around 5% is a reasonable assumption for DER (and load) modeling. Assuming a

[30] P. Pourbeik, "Proposal for DER_A Model," June 19, 2019: https://www.wecc.org/Reliability/DER_A_Final_061919.pdf.
[31] As in, if the specification includes multiple trip magnitude-duration points, use the shortest duration point.

trip setting of 0.5 pu (see **Figure 1.6**), then DERs start tripping when the load bus voltage reaches 0.5 pu. All DERs have tripped when the substation bus voltage reaches 0.5 pu, meaning that the load bus voltage is at 0.45 pu. Therefore, *vl1* equals 0.5 pu and *vl0* equals 0.45 pu in this example. This concept can be used to determine trip settings for other standards as well.

- **Option 3:** An aggregate amount of R-DERs spread throughout the distribution system can also be represented in the powerflow base case as a stand-alone generator. This does not necessarily follow the recommended framework described above; however, it is a modeling option. In this case, the same concept as presented in Option 2 applies with some minor modifications. In this case, the DERs are connected to the substation bus. The DERs start tripping when the implied load-side bus (distribution feeder impedance not represented) reaches 0.5 pu (so $V_{SUB} = V_{LOAD} + V_{DROP} = 0.55$ pu) and all are tripped when the substation bus voltage reaches 0.5 pu, so *vl1* equals 0.55 pu and *vl0* equals 0.5 pu in this example. Again, this concept can be applied to determine trip settings for other standards as well.

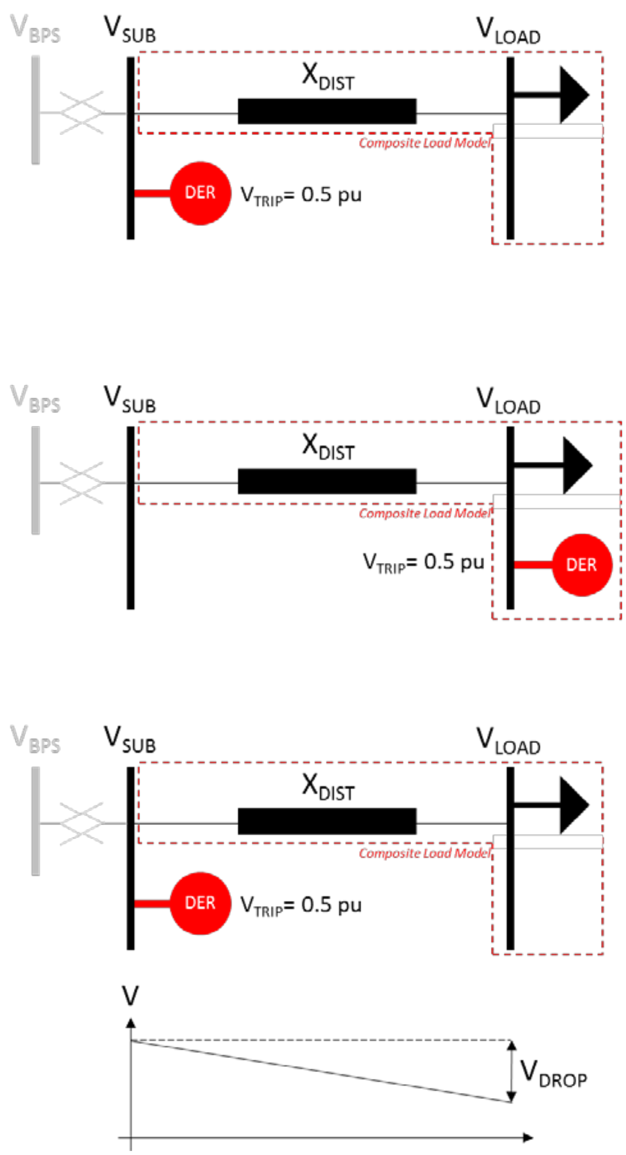

Figure 1.6: Fractional Trip Derivation Examples

The fractional trip settings can be used to model momentary cessation, if needed, in a relatively crude manner. For example, setting *vl1* and *vl0* to the momentary cessation settings will result in cessation of current below the specified thresholds. Selecting times *tvl0* and *tvl1* should be done with care to ensure the resources appropriately return following voltage recovery.[32] Note that momentary cessation is not required for Category II resources in IEEE Std. 1547-2018; however, the permissive operation range does allow for momentary cessation. TPs should consider sensitivity studies to understand the impact that this may have on studies.[33]

Voltage Source Representation

In the DER_A model, a voltage source representation[34] is implemented at the network interface to support numerical stability of the model in the simulation tools (see **Figure 1.7**).[35] In reality, all modern inverters used on the grid-side of power electronic interfaced energy sources use a voltage source converter (VSC), specifically, a dc voltage source behind a full four-quadrant controlled dc to ac power electronic converter.[36] The current through the VSC is strictly controlled by the controls of the inverter. This can thus be represented as a voltage source behind an impedance. In order to develop the value of the voltage behind the impedance, the values of *ipcmd* and *iqcmd* are used to evaluate the voltage drop across the impedance and thereby develop the complex voltage. The representation is a voltage behind an reactance, *Xe*. Typical values for *Xe* are in the range of 0.25 pu.[37]

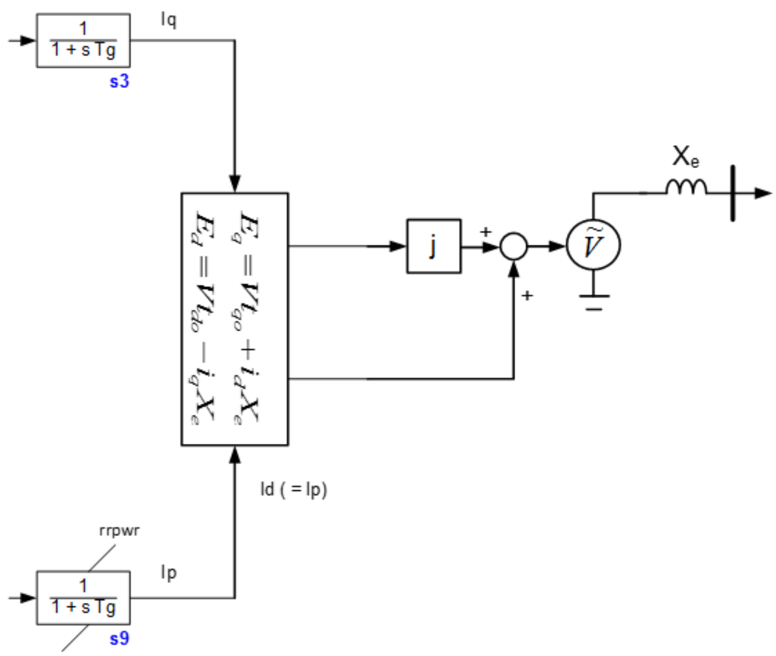

Figure 1.7: Voltage Source Representation

[32] The settings *tvl0* and *tvl1* are related to the trip characteristics, and they do not apply to momentary cessation. Parameter *vl0* can be set to the highest undervoltage point in which momentary cessation starts occurring.

[33] The fractional trip settings are not intended to match the IEEE Std. 1547 trip characteristics exactly; the DER_A model is intended to represent an aggregate behavior of DERs.

[34] D. Ramasubramanian, Z. Yu, R. Ayyanar, V. Vittal and J. M. Undrill, "Converter Model for Representing Converter Interfaced Generation in Large Scale Grid Simulations", IEEE Trans. PWRS, April 2016.

[35] The *PVD1* and second generation renewable energy system models use a current source representation, which has proved to cause numerical issues in simulations—particularly at increased penetration levels of these models.

[36] A *typeflag* parameter exists in the model to denote whether the model is representing a generator or a battery energy storage system (BESS). The model does not explicitly represent four-quadrant control, as it does not represent a single BESS but rather an aggregated model. If the model is used to represent BESS, the model can operate with both positive and negative injection of active and reactive current.

[37] Resistance is neglected, and the reactance value (*Xe*) is also a default value for numerical stability. A value of *Xe* of around 0.25 pu seems reasonable for this model.

Chapter 2: Parameterization of the DER_A Model

A challenge with any DER model is developing a reasonable set of parameters to represent an aggregate response of many individual resources spread across a distribution system or feeder. Table 2.1 provides a list of parameter values to represent different vintages of Interconnection standards. These include IEEE Std. 1547-2003, IEEE Std. 1547a-2014, IEEE Std. 1547-2018 Category II[38] defaults, and CA Rule 21 defaults. Refer to the DER_A specification document[39] or the simulation software model libraries for a description of the model parameters.

Table 2.1: Default DER_A Model Parameters

Param[40]	IEEE Std. 1547-2003 Default	IEEE Std. 1547a-2014 Default	CA Rule 21 Default	IEEE Std. 1547-2018 Category II Default	Notes
trv	0.02	0.02	0.02	0.02	† Note 1
dbd1	-99	-99	-99	-99	† Note 1
dbd2	99	99	99	99	† Note 1
kqv	0	0	0	0	† Note 1
vref0	0	0	0	0	† Note 2
tp	0.02	0.02	0.02	0.02	†
tiq	0.02	0.02	0.02	0.02	†
ddn	0	0	20	20	Note 3
dup	0	0	20	20	Note 3
fdbd1	-99	-99	-0.0006	-0.0006	Note 3
fdbd2	99	99	0.0006	0.0006	Note 3
femax	0	0	99	99	Note 3
femin	0	0	-99	-99	Note 3
pmax	1	1	1	1	† Note 4
pmin	0	0	0	0	Note 4
dpmax	99	99	99	99	†
dpmin	-99	-99	-99	-99	†
tpord	0.02	0.02	5	5	Note 3
Imax	1.2	1.2	1.2	1.2	† Note 4
vl0	0.44	0.44	0.49	0.44	Note 5
vl1	$0.44+V_{DROP}$	$0.44+V_{DROP}$	$0.49+V_{DROP}$	$0.44+V_{DROP}$	Note 5
vh0	1.2	1.2	1.2	1.2	Note 5
vh1	$1.2–V_{DROP}$	$1.2–V_{DROP}$	$1.2–V_{DROP}$	$1.2–V_{DROP}$	Note 5
tvl0	0.16	0.16	1.5	0.16	Note 5
tvl1	0.16	0.16	1.5	0.16	Note 5
tvh0	0.16	0.16	0.16	0.16	Note 5
tvh1	0.16	0.16	0.16	0.16	Note 5

[38] In IEEE Std. 1547-2018, the abnormal operating performance Category II "covers all BPS stability/reliability needs and is coordinated with existing reliability standards to avoid tripping for a wider range of disturbances of concern to BPS stability."

[39] P. Pourbeik, "Proposal for DER_A Model," June 19, 2019. [Online]: https://www.wecc.org/Reliability/DER_A_Final_061919.pdf.

[40] Refer to the DER_A model specification for parameter names: https://www.wecc.biz/Reliability/DER_A_Final.pdf.

Table 2.1: Default DER_A Model Parameters					
Param[40]	IEEE Std. 1547-2003 Default	IEEE Std. 1547a-2014 Default	CA Rule 21 Default	IEEE Std. 1547-2018 Category II Default	Notes
Vrfrac	0	0	1	1	Note 5
fltrp	59.3	59.5 OR 57.0	58.5 OR 56.5	58.5 OR 56.5	Note 6
fhtrp	60.5	60.5 OR 62.0	61.2 OR 62.0	61.2 OR 62.0	Note 6
tfl	0.16	2.0 OR 0.16	300.0 OR 0.16	300.0 OR 0.16	Note 6
tfh	0.16	2.0 OR 0.16	300.0 OR 0.16	300.0 OR 0.16	Note 6
tg	0.02	0.02	0.02	0.02	†
rrpwr	0.1	0.1	2.0	2.0	Note 8
tv	0.02	0.02	0.02	0.02	†
Kpg	0	0	0.1	0.1	Note 3
Kig	0	0	10	10	Note 3
xe	0.25	0.25	0.25	0.25	† Note 8
vpr	0.8	0.8	0.3	0.3	Note 6
iqh1	0	0	1	1	Note 1
iql1	0	0	-1	-1	Note 1
pflag	1	1	1	1	† Note 7
frqflag	0	0	1	1	Note 7
pqflag	P priority	P priority	Q priority	Q priority	Note 7
typeflag	1	1	0 OR 1	0 OR 1	Note 7

Parameterization Notes

The following notes describe considerations and background on the parameter values selected in **Table 2.1**. Refer to each respective interconnection standard for more information.

NOTE †: Default Parameters Not Typically Subject to Change

These parameters do not typically change across different implementations of the DER_A model. Any modification from the recommended default values should be carefully analyzed and justified.

NOTE 1: Voltage Control Parameters

In most existing applications, DERs do not control voltage. In such cases, the voltage control function should be disabled by setting the voltage control gain, *Kqv*, to 0. The lower and upper voltage deadbands, *dbd1* and *dbd2*, should be set large values (e.g., -99 and 99), respectively. However, interconnection standards state that the voltage control "capability" must be provided in the DER. If the capability is being utilized or required by the local utility, this setting should be modified accordingly.

When DERs are controlling voltage, the dynamic model needs to be adapted to account for this. As the model is not able to simultaneously represent both steady-state voltage control (Clause 5.3.3. voltage-reactive power mode in IEEE Std. 1547-2018) and dynamic voltage control (Clause 6.4.2. dynamic voltage support in IEEE Std. 1547-2018), a modeling compromise must be made. Therefore, it is recommended that the dynamic voltage support settings be implemented since most simulations involve fault-type conditions with large voltage fluctuations. Reasonable default values are *trv* = 0.02, *kqv* = 5,[41] *dbd1* = –0.12, *dbd2* = 0.1, *iqh1* = 1, and *iql1* = –1.[42] Any situation where *Kqv* is non-zero (dynamic voltage control is enabled), care should be taken to ensure that the corresponding deadband is not too small, which would lead to voltages possibly jumping across deadband thresholds each simulation iteration.

NOTE 2: Voltage Reference
The recommended setting for *Vref0* is 0. Setting *Vref0* equal to 0 allows the model to set its own terminal voltage reference based on the initial conditions. This is consistent with the language in IEEE Std. 1547-2018 and in 5.3.3 (voltage-reactive power mode), which require that DERs shall be capable of autonomously adjusting reference voltage (*Vref*) with *Vref* being equal to the (low pass filtered) measured voltage.

NOTE 3: Active Power-Frequency Control
In IEEE Std. 1547-2003 and IEEE Std. 1547a-2014, active power-frequency control is not specified. Therefore, the gains *Ddn* and *Dup* as well as the frequency errors *femax* and *femin* are set to 0. This disables the active power-frequency controls in the model for these two standards. In CA Rule 21 and IEEE Std. 1547-2018, the capability for resources to have active power-frequency controls installed and enabled (as default) are specified. Therefore, per the standard *Dup* and *Ddn* should be set to 20 (representing a 5% droop characteristic).[43] Default deadband for both standards is set to ±0.0006 pu, or ±36 mHz. *Tpord* is used to represent the specified open loop time constant of five seconds per IEEE Std. 1547-2018 and CA Rule 21, and it is set to a small value (0.02 sec) when these controls are disabled in previous IEEE Std. 1547 versions.[44] Parameters *Kpg* and *Kpi* are not directly mapped to the interconnection standards; values describe in **Table 2.1**were used in benchmark testing of the DER_A model are based on engineering judgment and were found to provide satisfactory response. Note that if the DERs are assumed to be operating at maximum available power, the *Dup* should be set to 0. This is explained further in **Chapter 3**

NOTE 4: Active Power Capability
Maximum active power output is set to a default of 1 pu. Minimum active power output is assumed to be 0 pu for generating resources but can be negative (i.e., -1 pu) for energy storage resources. These maximum and minimum active power capability values can be modified if more detailed information is known about specific DERs. Inverter-based DERs have an overload capability of around 110–120%, and therefore *Imax* is set to 1.2 pu. Other types of DERs may have a different current limit, and this can be adjusted carefully if additional information is known. However, for most inverter-based installations (e.g., solar PV), a value of 1.2 pu is a reasonable approximation.

NOTE 5: Partial Tripping
Vrfac, the ratio of DERs that restore output upon voltage recovery, should be set to 0 for legacy[45] DERs (i.e., no DER restore output following a ride-through event), 1.0 for modern DERs (i.e., all DERs restore output following a ride-through event), and some value in between for a mix of a legacy and modern DERs based on the assumed vintage of the DER deployed. A value of *Vrfrac* = 0 is a conservative assumption and should be used if no detailed DER information is available. Since CA Rule 21 and IEEE Std. 1547-2018 are relatively new standards, it can be expected that, for now, *Vrfrac* can be set at or near 0.

The interconnection standards include different levels of trip settings: typically a longer duration trip time with magnitude closer to nominal and a shorter duration trip time with lower (or higher) magnitude away from nominal. **Table 2.1** includes values for the shorter duration trip thresholds since these values are likely the most useful and relevant settings for stability studies. Consult the relevant interconnection standards and requirements for more

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41 Allows for maximum reactive current injection when voltage falls below around 0.7 pu, taking into consideration the voltage deadband.

42 Again, note that the values in Table 2.1 do not use these settings because the respective interconnection agreements do not require dynamic voltage control to be used. Hence, *kqv* is set to 0.

43 See Chapter 3 on recommended settings. Since most DER will be operated at maximum available power, and will not have available generating capability to respond in the upward direction for underfrequency events, *Dup* should be set to 0, from a practical standpoint.

44 Setting *tpord* should be studied on an individual system basis.

45 Use of the term “legacy” generally refers to DER compliant with IEEE Std. 1547-2003 and IEEE Std. 1547a-2014, which typically involve limited or no controls and ride-through capability.

information on longer duration trip settings. Higher magnitude with longer duration trip settings may need to be studied in simulations involving delayed voltage recovery.

V_{DROP} should be set to a reasonable equivalent voltage drop across the distribution system in the range of 2–8% (reasonable default of 5%) if no detailed information is available. Voltage trip thresholds include a 0.01 pu offset from the interconnection standard values to correctly account for the beginning and completion of partial tripping.

The values specified in the **Table 2.1** represent R-DERs as part of the CLM. If individual or multiple similar U-DERs are represented, trip settings should be equal and set to the corresponding value in the interconnection standard. If aggregate R-DERs are to be represented by a generator record, use the methodology described in **Chapter 1** to determine correct trip settings.

In cases where momentary cessation of inverter-based resources needs to be represented, use *vl1* and *vl0* with extended trip times. Note that this may hinder the ability to capture any tripping effects due to existing model limitations. Engineering judgment and sensitivity studies should be used when applying these types of settings.

NOTE 6: Frequency Trip Levels

High (*fhtrp*) and low (*fltrp*) frequency tripping has different thresholds in a few of the interconnection standards, as described in **Table 2.1** Again, each has a specified time threshold. The frequency thresholds closer to nominal frequency have a longer duration while the thresholds further from nominal have a shorter duration.

In simulations where frequency does not fall below under-frequency load shedding (UFLS) levels, the setting values for CA Rule 21 and IEEE Std. 1547-2018 are not significant.[46] However, the settings representing IEEE Std. 1547-2003 and IEEE Std. 1547a-2014 are relevant, particularly for the thresholds closer to nominal frequency. IEEE Std. 1547-2003 has only one magnitude and time value. IEEE Std. 1547a-2014 has two thresholds, but most commonly only the 59.5 Hz and 60.5 Hz thresholds, with two second timers, are applicable.

Disabling tripping on frequency during low voltage is implemented in almost all relay models as the relay needs a sufficient voltage waveform to measure frequency. Under fault conditions, due to the large change in voltage, the frequency calculation can result in a spurious spike, and thus, frequency tripping should be disabled. IEEE Standard C37.117[47] recommends disabling the frequency trip when the voltage is below 50–70% of nominal. For DERs, this voltage levels was increased to 80% to account for further inaccuracies in frequency calculation that may arise in positive sequence simulations.[48]The first sentence of IEEE Std. 1547-2018, Clause 6.5.1, states that when frequency meets a certain criteria and “the fundamental-frequency component of voltage on any phase is greater than 30% of nominal” then the DER can respond. However, if the frequency is outside acceptable range but voltage is less than the 30% threshold then the DER should not trip. This represents a low voltage inhibit function in the frequency tripping, and it is represented by parameter *Vpr*.[49] Regardless, study engineers should monitor for false trips by the DER_A model that may not be realistic; rather, they are an artifact of positive sequence stability simulation calculation of frequency. Close review of any frequency-related tripping is strongly recommended.

NOTE 7: Control Flags

The parameter *pflag* sets power factor control. If set to 1, then the power factor angle reference is used based on initialization of the model. Otherwise, if set to 0, then the reactive power reference (*Qref*) will be used.

The parameter *frqflg* sets the active power-frequency control capability. If set to 0, then active power reference (*Pref*) is used. Otherwise, if set to 1, then the active power-frequency control loop is enabled. If *frqflg* is set to 1, the resource

[46] Unless specific studies are being performed to configure UFLS systems.
[47] IEEE C37.117-2007, IEEE Guide for the Application of Protective Relays Used for Abnormal Frequency Load Shedding and Restoration.
[48] https://www.wecc.biz/Reliability/WECC_White_Paper_Frequency_062618_Clean_Final.pdf.
[49] *Vpr* may also be referred to as *Vfth*.

will response to over- and under-frequency disturbances. However, if the user sets *Dup* to 0, the resource will not respond to underfrequency. This configuration emulates the unit(s) operating at maximum available power output.

The parameter *pqflag* specifies whether to use active or reactive current priority, which is effective when the current limit logic is in effect. This is particularly used during response to large disturbances (i.e., faults).

The parameter *typeflag* specifies whether the resource is a generating resource (set to 1) or an energy storage device (set to 0). Setting as an energy storage device allows absorption of active power, and it emulates distributed energy storage. This does not, however, emulate charging and discharging of the resource.

NOTE 8: Voltage Source Representation

The *rrpwr* specifies the active current ramp rate. IEEE Stds. 1547-2003 and 1547a-2014 do not specify an active current ramp rate; however, IEEE Std. 1547-2018 and CA Rule 21 use a 80% recovery within 0.4 seconds that can be approximated with a gain of 2 pu/sec, which equates to full recovery within 0.5 seconds. The voltage source impedance also uses a default values for *Xe* of 0.25, based on robustness testing of the DER_A model during its development.

Future Model Implementation Improvement

Commercial simulation software vendors should consider adding a new global flag for inverter-based resources (particularly renewable energy resources) that sets the maximum available power to the current power output (*Pgen*) upon initialization of the inverter-based models. This can then be changed by the user on a case-by-case basis during the simulation if necessary (e.g., to represent curtailing). For example, simulations with renewable generation dispatched at less than maximum capacity (*Pmax*) may represent less solar irradiance or lower wind speed. However, this is the maximum available power output for the assumed conditions. As more resources are being installed with the capability to provide active power-frequency control, the ability to distinguish whether units are operating at maximum available power output will be increasingly important. This parameter is similar to the baseload flag for synchronous generating resources.

Chapter 3: Practical DER_A Model Implementation

Table 2.1 in the previous chapter provides parameter values that relate to specific interconnection standards and requirements; however, many systems are faced with aggregate DERs that encompass many vintages of interconnection requirements and settings. Table 3.1 provides a set of default parameter values for different systems based on the penetration of different IEEE Std. 1547 vintages, ranging from a system dominated by IEEE Std. 1547-2003 interconnections to a system of modern IEEE Std. 1547-2018 interconnections.[50] Also shown are default values for penetrations at 70% for 2003 vintage and 30% for 2018 vintage, as well as 30% for 2003 vintage and 70% for 2018 vintage. These default values are based on engineering judgment and intended to be used as a starting point for more detailed studies and sensitivities.[51] Note that, in addition to the IEEE Std. 1547 default settings, individual utilities or jurisdictions may have additional or more stringent requirements that should be considered when developing a set of DER modeling parameters. TPs and PCs should consider any modifications to the default IEEE Std. 1547 parameters as well as local requirements and should adapt the models accordingly.

Parameter values that are subject to changes across interconnection vintages are highlighted in red in Table 3.1 and described in this chapter. Note that some of the parameter values subject to change are a linear interpolation based on the penetration of specific vintages of DERs. Sensitivity studies should be performed by the TP and PC to understand the impacts of these parameter values to system study results.

Table 3.1: Default Parameter Selection for Mixed Vintages of DER

Param	Early Vintage DER System IEEE Std. 1547-2003	70% of -2003 30% of -2018	30% of -2003 70% of -2018	Newer Vintage DER System IEEE Std. 1547-2018 (Category II)
trv	0.02	0.02	0.02	0.02
dbd1	-99	-99	-99	-99
dbd2	99	99	99	99
kqv	0	0	0	0
vref0	0	0	0	0
tp	0.02	0.02	0.02	0.02
tiq	0.02	0.02	0.02	0.02
ddn	0	6	14	20
dup	0	0	0	0
fdbd1	-99	-0.0006	-0.0006	-0.0006
fdbd2	99	0.0006	0.0006	0.0006
femax	0	0	99	99
femin	0	0	-99	-99
pmax	1	1	1	1
pmin	0	0	0	0

[50] Note that application and enforcement of IEEE Std. 1547-2018 for newly interconnecting inverters is likely to take time to implement in many jurisdictions, often requiring regulatory updates to enable enhanced capabilities. Some degree of verification and alignment with these implementation timelines should be performed by each TP and PC when representing DER in BPS reliability studies.

[51] Transmission–distribution co-simulation techniques may be used to help further parameterize DER_A models based on specific distribution feeder configurations and DER penetration levels.

Table 3.1: Default Parameter Selection for Mixed Vintages of DER				
Param	**Early Vintage DER System IEEE Std. 1547-2003**	**70% of -2003 30% of -2018**	**30% of -2003 70% of -2018**	**Newer Vintage DER System IEEE Std. 1547-2018 (Category II)**
dpmax	99	99	99	99
dpmin	-99	-99	-99	-99
tpord[52]	0.02	0.02	5	5
Imax	1.2	1.2	1.2	1.2
vl0	0.44	0.44	0.44	0.44
vl1	0.49	0.49	0.49	0.49
vh0	1.2	1.2	1.2	1.2
vh1	1.15	1.15	1.15	1.15
tvl0	0.16	0.16	0.16	0.16
tvl1	0.16	0.16	0.16	0.16
tvh0	0.16	0.16	0.16	0.16
tvh1	0.16	0.16	0.16	0.16
Vrfrac	0	0.3	0.7	1.0
fltrp	59.3	58.5	57.5	56.5
fhtrp	60.5	61	61.5	62.0
tfl	0.16	0.16	0.16	0.16
tfh	0.16	0.16	0.16	0.16
tg	0.02	0.02	0.02	0.02
rrpwr	0.1	0.6	1.4	2.0
tv	0.02	0.02	0.02	0.02
Kpg	0	0.1	0.1	0.1
Kig	0	10.0	10.0	10.0
xe	0.25	0.25	0.25	0.25
vfth	0.8	0.3	0.3	0.3
iqh1	0	1.0	1.0	1.0
iql1	0	-1.0	-1.0	-1.0
pfflag	1	1	1	1
frqflag	0	1	1	1
pqflag	P priority	P priority	Q priority	Q priority
typeflag	1	1	1	1

[52] The active power-frequency response from DERs, if utilized in studies, should be tuned to achieve and ensure a closed-loop stable control. This parameter may need to be adapted based on this tuning.

The following considerations are made in the development of these default parameter values and intended to provide transparency and understanding of how these parameters were devised. However, they are intended as default values that may be subject to change if more detailed information is known.

- **Upward Frequency Responsiveness for Underfrequency Conditions (*Dup, Pmax*):** In this set of default parameters, it is assumed that the vast majority (if not all) DERs are operated at maximum available[53] power and thus cannot provide frequency response for underfrequency conditions.[54] To model the inability to provide response in the upward direction, the *Dup* parameter value is set to 0. This disables upward movement regardless of where the DER resource(s) is dispatched relative to *Pmax* in the dynamics data. This allows for easy manipulation of DER output levels without needing to modify additional parameter values for each sensitivity case. Another option is to set the *Dup* parameter value according to the expected performance and then modifying *Pmax* value in the dynamics data to match the predisturbance output for each operating conditions studied. However, this requires an additional step and may lead to unexpected frequency responsiveness from DER if not adequately handled when changing DER dispatch levels.
- **Downward Frequency Responsiveness for Overfrequency Conditions (*Ddn*):** *Ddn* is modified across the different penetration levels to represent an effective droop characteristic, or a response from a fractional DER value based on the penetration of modern inverters. The 5% droop (*Ddn* = 20) is multiplied by a linear factor based on this penetration (e.g., 70% of 20 equals 14).
- **Frequency Deadband and Error Limits (*fdb1, fdb2*):** When frequency response is enabled in the model, the deadband settings of *fdb1* and *fdb2* as well as the frequency error settings of *femax* and *femin* need to be modified to enable accurate representation of these controls. A default value is used in all cases where control is enabled.
- **Voltage-Related Trip Settings and Times:** Refer to the **Chapter 1** for the derivation of the partial trip values. Note that trip thresholds and times may vary if applying CA Rule 21. Values assume a voltage drop, V_{DROP}, of 5%.
- **Fraction of Resources Recovering (*Vrfrac*):** The parameter *Vrfrac* represents the fraction of resources that recover upon voltage recovery following abnormal voltage conditions. It is expected that resources meeting IEEE Std. 1547-2018 will recover from abnormal voltages and ride through disturbances while IEEE Std. 1547-2003 resources will likely trip and remain disconnected for the duration of stability simulations. A linear multiplier is used based on the fraction of resources connected to the system. For example, for a 70% IEEE Std. 1547-2018 system, *Vrfrac* equals 0.7.
- **Frequency-Related Trip Settings (*fltrp, fhtrp*):** Frequency-related trip settings of *fltrp* and *fhtrp* are assumed to slightly vary based on the aggregate vintage of connected DERs. For the shorter-term tripping, IEEE Std. 1547-2003 has trip settings at 59.3 Hz and 60.5 Hz while IEEE Std. 1547-2018 has trip settings at 57.5 Hz and 62 Hz. For mixed penetrations, a linear multiplier is used to vary the level of DER tripping. This is an approximate; yet, these trip settings are below the first stage of UFLS, and they are therefore not likely to make a substantive impact in most stability simulations.[55] More detailed studies should consider identifying more accurate information for these settings.
- **Active Current Recovery Ramp Rate (*rrpwr*):** The parameter *rrpwr* is modified across different penetration levels to represent the fraction of resources that recover from abnormal voltage conditions. A 2.0 pu/sec (recovery in 0.5 seconds) is used for IEEE Std. 1547-2018 resources, and a linear multiplier is used for the mixed penetration conditions. For example, 70% of 2.0 pu/sec equals 1.4 pu/sec.

[53] If studies are assuming that DERs are curtailed for any reason, IEEE Std. 1547-2018 vintage DERs will have the capability to respond to underfrequency events.

[54] This statement relates to DERs that are generating resources; this may not be the case for energy storage. Energy storage, not injecting maximum power, will be able to respond to underfrequency events following a droop characteristic.

[55] Stability studies for establishing UFLS set points, where simulated frequency can fall well below UFLS, should ensure reasonable frequency-related trip settings are used for DER.

- **Frequency Response PI Controls (*Kpg, Kig*):** When frequency response controls are enabled in the model, default parameter values of *Kpg* = 0.1 and *Kig* = 10 are used.
- **Type Flag (*typeflag*):** In these default data sets, the *typeflag* is set to 1 representing a generating resource. This flag, and relevant parameter values, can also be modified to represent an energy storage resource.

Chapter 4: DER_A Model Benchmarking and Testing

To ensure that a model is usable for industry-wide studies, some form of model benchmarking and testing is typically performed by industry partners. DER_A model development and testing was led by the WECC Renewable Energy Modeling Task Force (REMTF) and NERC LMTF with EPRI providing the model benchmarking support.

EPRI performed extensive DER_A model benchmarking while working with the major commercial software vendors[56] following their implementation of the standalone DER_A model. A test system with a play-in voltage source model at the transmission bus with constant impedance load adjacent to the DERs was used for the testing. A suite of 19 tests was used to apply small and large disturbances of voltage and frequency, and then the model's active and reactive power response and set points were observed. The response of the DER_A model was compared for each test across all platforms to determine whether the models match the same general trend in response (i.e., they are considered suitably benchmarked). Refer to an EPRI white paper on this topic (reference 11 in **Appendix A**).[57] **Figure 4.1** shows an example benchmarking simulation, and it demonstrates how the DER_A model in each of the software platforms matches the same general performance characteristic.

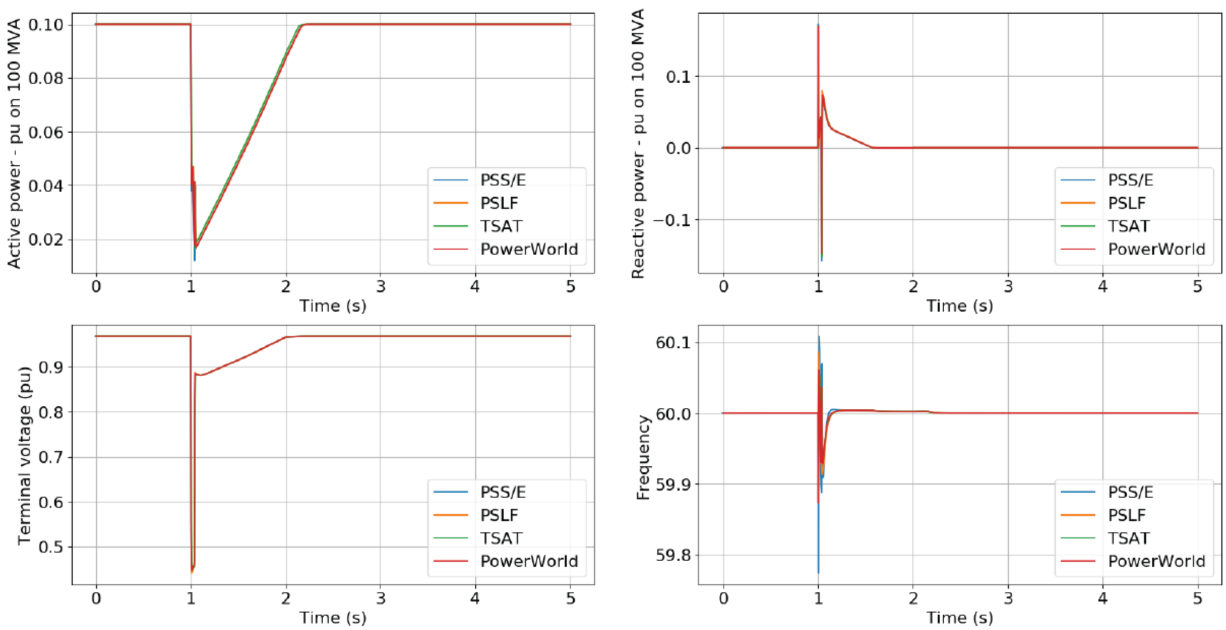

Figure 4.1: Voltage Sag Benchmarking Test Result [Source: EPRI]

To ensure that the model is numerically robust and usable in system studies on a large-scale case, CAISO has been testing the DER_A model on WECC-wide base cases for their reliability studies. **Figure 4.2** shows one example of the types of sensitivity studies performed by CAISO. CAISO has been testing the model with different parameter values, including CA Rule 21 and the new IEEE Std. 1547-2018 default settings. The model has performed well and is numerically robust in these studies using GE PSLF™.[58]

[56] Including GE-PSLF™, Siemens PTI PSS®E, PowerWorld Simulator, and Powertech Labs TSAT.

[57] The New Aggregated Distributed Energy Resources (der_a) Model for Transmission Planning Studies. 2019 Update. White Paper. 3002015320. Electric Power Research Institute (EPRI). Palo Alto, CA (https://www.epri.com/#/pages/product/000000003002015320/?lang=en-US).

[58] CAISO, "CMPLDWG Composite Model with Distributed Generation DER_A CAISO Assessment," NERC LMTF Meeting, May 2018: https://www.nerc.com/comm/PC/LoadModelingTaskForceDL/CMPLDWG_DER_A_CAISO_NERC.pdf.

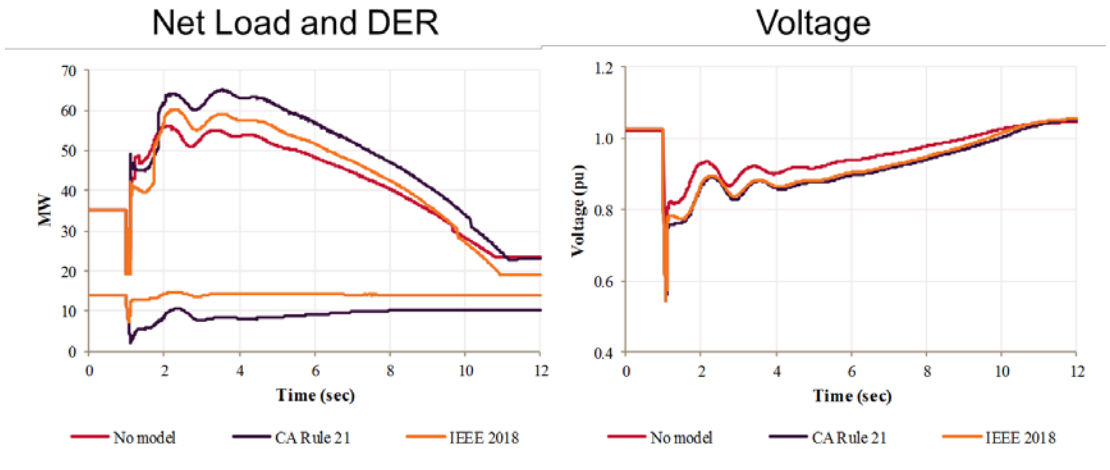

Figure 4.2: CAISO DER Study Example including DER_A Model [Source: CAISO]

EPRI has also performed system studies on the full Eastern Interconnection base case in coordination with Duke Energy. These studies implemented the DER_A model on 138 U-DER installations with a capacity of 1,300 MW. **Figure 4.3** shows the DER response from an example simulation using these models. It shows that some of the DER_A models near the fault location respond to the disturbance with active and reactive power response, and those further away from the disturbance do not provide a significant response. Again, the implemented DER_A models are numerically robust.[59]

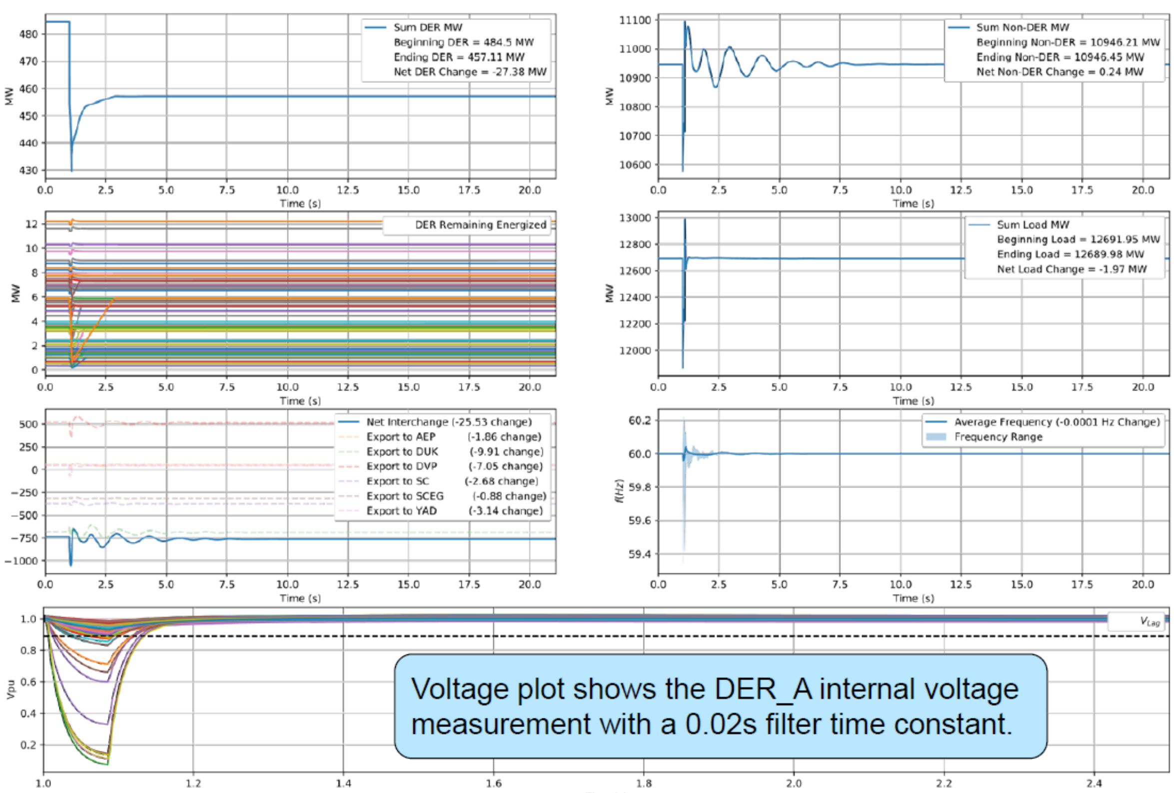

Figure 4.3: DER Study Example including DER_A Model [Source: EPRI]

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59 EPRI, "Preliminary results of DER_A model parameterization", NERC LMTF Meeting, July 2018: https://www.nerc.com/comm/PC/LoadModelingTaskForceDL/Parameterization_of_DER_A_Model_v1_DR.pdf.

Appendix A: References

DER_A Model Specification Document

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Relevant Interconnection Standards

[2] IEEE Std. 1547-2003, Standard for Interconnecting Distributed Resources with Electric Power Systems, July 2003. [Online]: https://standards.ieee.org/standard/1547-2003.html.

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Appendix B: DER_A Block Diagram

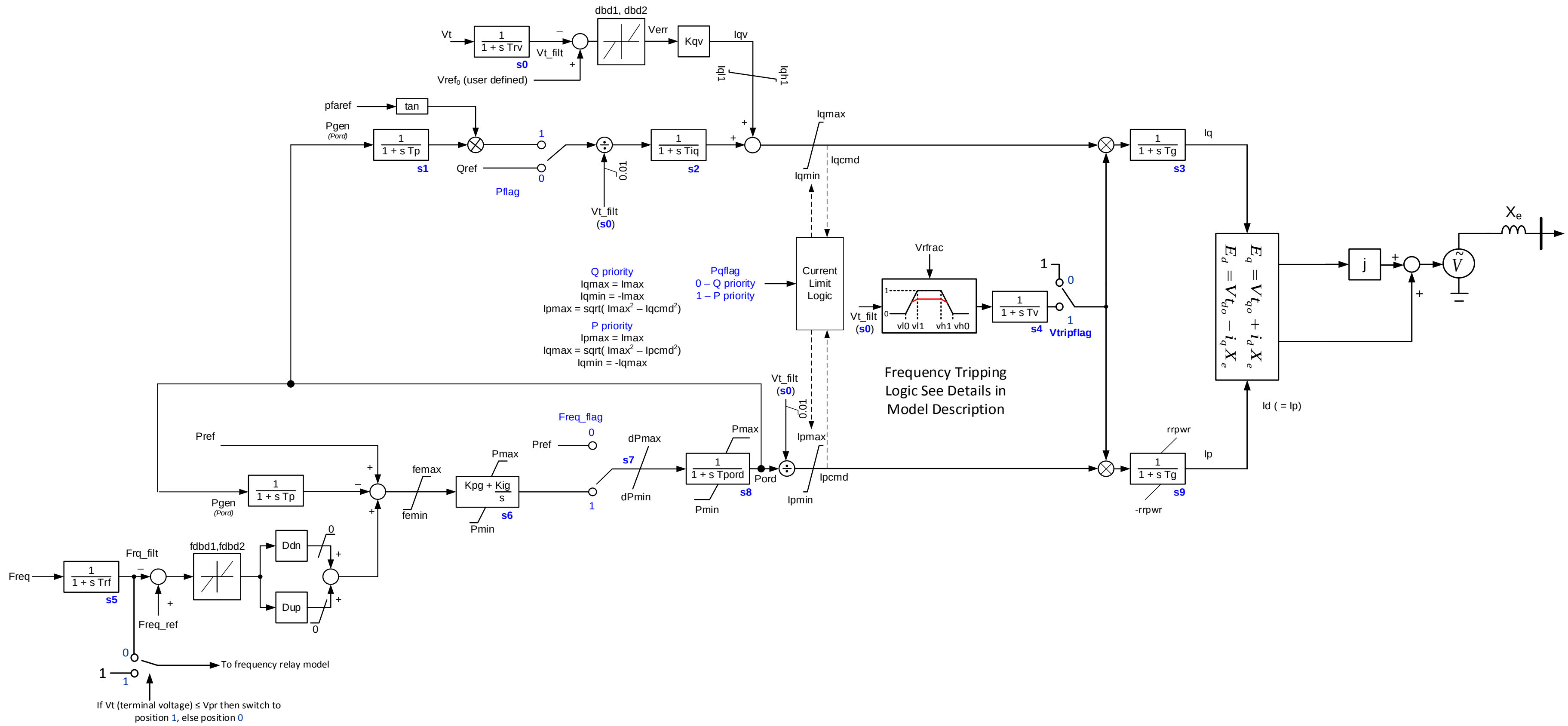

Figure B.1: DER_A Model Block Diagram

Contributors

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