RECOMMENDED DISTRIBUTED ENERGY RESOURCE MODELING PRACTICES IN NORTH AMERICA

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ABSTRACT

Around the world, distributed energy resource modelling practices are evolving to meet the needs of rapidly growing DER penetrations. In North America, efforts are focused on improved and consistent steady-state and dynamic DER modelling. This paper describes a flexible DER modelling framework and recent developments in DER dynamic modelling. DER system impact studies in California using this modelling framework are also described.

INTRODUCTION

Distributed energy resources (DERs) are rapidly being deployed across North America, particularly due to mandated policy, favourable economics, and customer energy choices. In the United States, nonutility DER installations are expected to increase by 30 GW to nearly 51 GW by the end of 2023 (see Fig. 1) [1]. This is predominantly driven by the rise in distributed solar photovoltaic (PV) generation. Fig. 2 shows projections of behind-the-meter (BTM) solar PV for the California ISO (CAISO), driven by the state mandate that 33% of annual energy come from renewable sources [2]. This trend will likely continue, and widespread integration of DER will have significant impacts on the bulk power system (BPS).

The North American Electric Reliability Corporation (NERC) has focused on the impacts of aggregate DER on BPS reliability for many years [3][4]. In North America, DER is referred to as any resource that produces electricity and is located within the boundary of the distribution utility [4]. While DER can include distributed generation, BTM generation, energy storage, DER aggregators, and microgrids, the majority of existing and projected DER is inverter-interfaced (e.g., solar PV). Therefore, industry efforts are mainly focusing on studying the impacts and changing characteristics of these resources.

The increasing penetration of DER has an impact on BPS planning, operations, and design. Issues faced from a BPS perspective include lack of DER visibility and data, coordination between DER and BPS-connected resources, improved modelling for BPS reliability studies, uncertain impact of DER generation profiles on unit commitment and ramping of large generation plants, and increased complexity in load forecasting [5][6]. BPS planning studies involve steady-state, dynamic, and short-circuit simulations that focus on future conditions that include

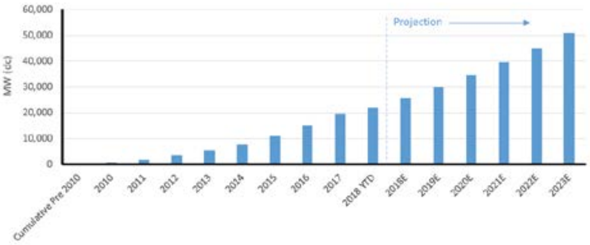


Fig. 1. U.S. Cumulative Solar PV DER – 2010 to 2023 [1]

Fig. 2. California BTM Solar PV Projections [2]

assumptions for DER. To have a reasonably accurate picture of DER behaviour, improved DER data sharing, modelling, and study approaches are the primary focus for BPS reliability studies.

Thus, a standardized framework was developed in North America that differentiates between utility-scale DER (U-DER) and retail-scale DER (R-DER) for BPS steady-state and dynamic modelling [7]. U-DER are typically three-phase installations directly connected to the distribution bus ranging from 0.5 to 20 MW. R-DER offsets customer load, including residential, commercial, and industrial customers, and are most commonly single-phase units. The framework, described in this paper, is applicable to interconnection-wide studies that use an approximation of the load and DER across a large footprint. It can be adapted to obtain various representations of DER, and serves as a common reference for DER modelling.

To accurately model DER for BPS studies, data must be collected and transferred between the distribution and transmission entities [5][6]. Data collection for U-DER should include type of generating resource (e.g., solar PV, battery storage), connecting distribution bus nominal voltage, connecting feeder characteristics (if applicable), capacity of each U-DER (P_{max}, Q_{max}), relevant control modes (active and reactive power controls and priority), and general power output profiles. Data collection for R-DER should include aggregate capacity (P_{max}, Q_{max}) of the total R-DER for each element represented in the base case, vintage of IEEE Std. 1547 (e.g., -2003 or -2018) or other relevant DER interconnection requirements (e.g., CA Rule 21), aggregate information characterizing the distribution circuits where R-DER are connected, and general power output profiles of the R-DER [7-10].

This paper presents latest efforts in North America to address DER modelling for BPS reliability studies.

STEADY-STATE DER MODELING

For BPS studies, aggregate loads are typically represented at the BPS bus (e.g., 115 kV, 230 kV), and represent an aggregation of loads (either a sub-transmission network or a specific transmission-distribution (T-D) transformer). With the inclusion of DER, steady-state gross and net load representation will need to evolve. Fig. 3 shows a framework for representing DER in powerflow cases [7]. Net load at the BPS bus (Fig. 3, left) can be reflected to the distribution side and the T-D transformer can be explicitly represented. U-DER (single U-DER, multiple U-DER, or a group of similar U-DER) can be represented by a generator model, and the R-DER can be represented as part of the load (Fig. 3, right). Most commercial software platforms now include a DER component as part of the load record. Fig. 4 shows an example load record, with the gross load modelled, the R-DER represented (red box), and then the net load calculated (blue box, right) [11]. From a powerflow solution perspective, the net active and reactive power are simply calculated as:

$$Net\ MW = MW_{load} - Dist\ MW_{R-DER} \quad (1)$$

$$Net\ Mvar = Mvar_{load} - Dist\ Mvar_{R-DER} \quad (2)$$

Any individual U-DER facility with a gross nameplate rating at or higher than a designated threshold should be modelled explicitly in the powerflow case at the low-side of the T-D transformer. This threshold is chosen by the utility. U-DER less than the designated threshold should be accounted for as part of the R-DER. Multiple similar U-DER connected to the same distribution bus could be modelled as an aggregate U-DER, if deemed acceptable by the study engineer.

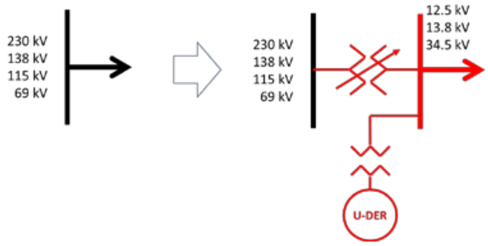


Fig. 3. Steady-State Representation of DER

For R-DER, if the gross aggregate nameplate rating of connected R-DER for a specific load element exceeds a given threshold, these DER should be accounted as R-DER. The recommended threshold for R-DER is 0 MVA, meaning that DER should not be netted with load. Utilities with very low DER penetration may choose to net the DER; however, this is not a recommended approach.

Explicitly representing U-DER and R-DER is important for accounting for the quantity of on-line DER and load in powerflow base cases. Keeping these quantities as separate entries is essential to allow for the application of individual load or DER scaling in order to develop different study cases. The primary benefit of representing DER explicitly rather than netting with the load is to capture and differentiate between the dynamic behaviour of DER and end-use loads. Recommended practices for dynamic modelling of DER are covered in the following sections.

DYNAMIC DER MODELING

The framework shown in Fig. 3 can be extended to dynamic simulations, as shown in Fig. 5. U-DER can be explicitly modelled with a standalone dynamic model(s) while R-DER can also be explicitly represented inside the composite load model [12]. Latest advancements in DER dynamic modelling focus on development, benchmarking, and utilization of the new *DER_A* dynamic model. This section covers these recent efforts.

The DER_A Model

The *DER_A* model was created to emulate the key dynamic performance that may be required from DER in the future, such as frequency and voltage control. At first sight, the 2nd generation generic renewable energy system (RES) models [13] that were developed for inverter-based generation may seem appropriate for modelling DER (i.e., *repc_a* + *reec_a* + *regc_a*). However, there are two drawbacks with this approach. First, the generic RES

	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

Fig. 4. DER Representation in Powerflow Load Records [10]

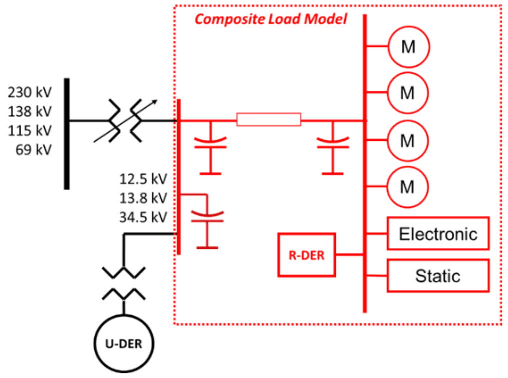


Fig. 5. Dynamic Representation of DER

models constitute well over one-hundred parameters and so are too complex for modelling aggregated DER. Second, the 2nd generation RES models were developed for modelling individual large wind, solar PV, and battery-energy storage plants and so may not provide a simple means to represent aggregated behaviour of many DER.

Starting with the model structures of the 2nd generation RES models (*repc_a* + *reec_a* + *regc_a*), a reduced version of the core functionality was developed to form *DER_A* [14]. Fig. 6 shows a block diagram of the *DER_A* model, with 48 parameters and 10 states which is roughly one-third the parameters of the full 2nd generation RES generic models [13]. However, it preserves a significant number of those features, namely frequency and voltage control emulation, with asymmetric deadband. For a detailed account of the model and its functionality see [14].

DER_A Model Testing and Benchmarking

Once the model was specified, five commercial software

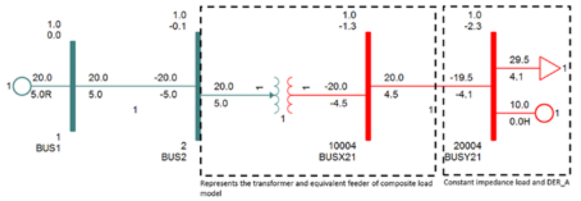


Fig. 7. Benchmarking Test Case Model

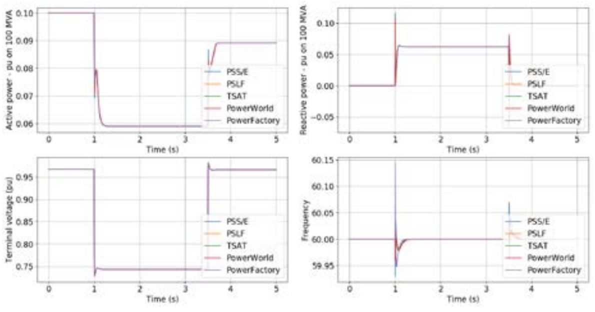


Fig. 8. Plots from Extended Voltage Sag Test

vendors implemented the model in their respective tools so that it could be tested. A beta version of the model was released by the software vendors and a set of test protocols were defined [15]. The tests aimed to ensure that all features of the model performed as expected. They also served to benchmark the model across the platforms to ensure consistent implementation and performance. A common test system was developed for these tests, as shown in Fig. 7. A complete list of all tests and initial results can be found in a report by the Electric Power Research Institute (EPRI) [15]. These tests, led and performed by EPRI, were focused on testing the *DER_A* model as a standalone model. During the testing, several issues were identified and rectified. Results of an extended duration undervoltage test are shown in Fig. 8.

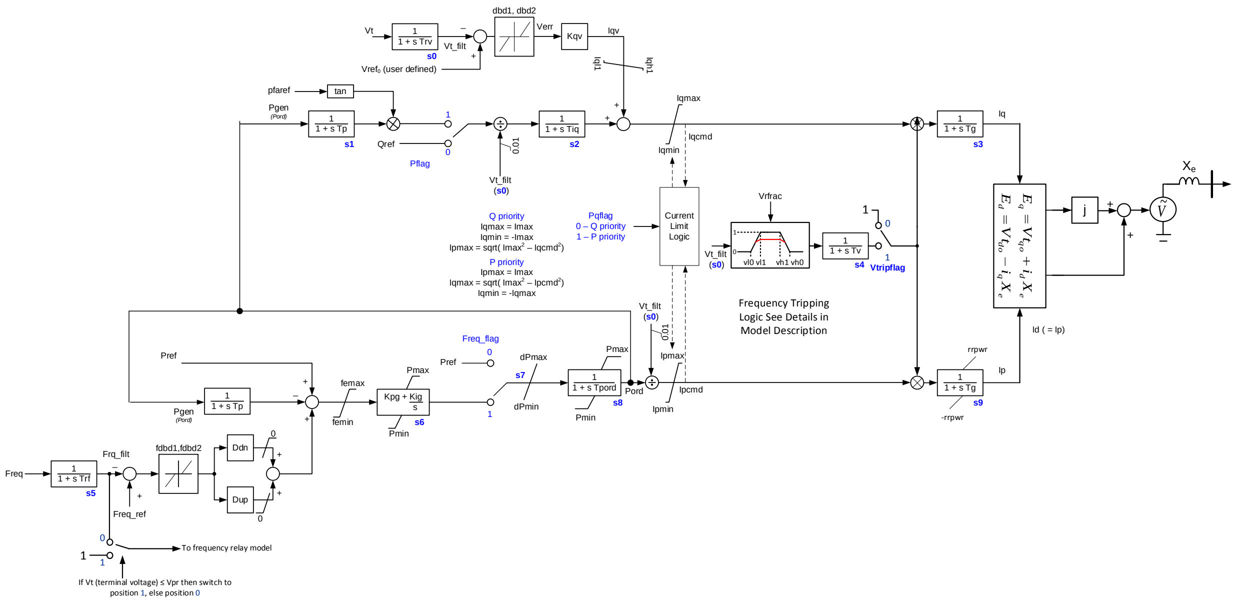


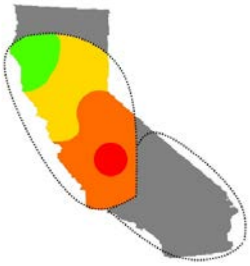
Fig. 6. DER Model Version A (*DER_A*)

CAISO SYSTEM IMPACT STUDIES WITH INCREASED PENETRATION OF DER

CAISO used the modelling framework described herein to reliability studies in the central California area, to understand the impacts that DER can have on the BPS. A 2020 peak summer case with high renewable generation dispatch, and accompanying dynamic models dataset including single-phase induction motor air-conditioning load, was used. DER information was gathered from existing installed BTM solar PV as well as forecast DER from the distribution resource plans of participating transmission owners. Vintage of DER was estimated and categorized as either legacy (installed BTM) or modern (or forecasted) inverters. Parameter values for the *DER_A* model were assumed to be the same for all units, U-DER and R-DER, and were based on information provided by EPRI and specifications in CA Rule 21 [10][16].

Simulations were run in a positive sequence RMS domain. A three-phase, 6-cycle bolted fault was applied on a 230 kV transmission line in the Fresno, CA area. Fig. 9 shows the area of study and amount of on-line DER. The colors denote sub-regions based on electrical distance to the fault. The following sensitivity studies were performed: (i) netting of DER with load versus explicit modelling, (ii) CA Rule 21 versus IEEE Std. 1547-2018 Cat II voltage ride-through settings, (iii) variations in voltage support settings, (iv) variations in DER recovery percentage (*vfrac*), and (v) active and reactive current priority.

Table I shows results of all sensitivities performed. A reduction in gross load is observed partially due to undervoltage tripping of portions of the load model and partially due to voltage dependency of load. A reduction in DER is due to the partial undervoltage trip characteristic of the *DER_A* model. Figs. 9-12 show results of each sensitivity study at a bus near the fault with 50 MW of gross load and 15 MW of DER (35 MW net load). The left plot of each figure shows net load (top) and DER (bottom) response; the right plot shows the 230 kV bus voltage.



Local area	DER installed capacity	DER output
Humboldt	19	19
North Valley North Coast/North Bay Greater Bay	254 388 1323	252 384 1310
Total	1965	1946
Central Valley Central Coast/Los Padres Kern	1037 324 431	1027 321 426
Total	1792	1774
Fresno	920	911
Total (northern California)	4696	4650

Fig. 9. Study Area and Amount of Modelled DER

Fig. 10 shows that almost all the DER is able to ride through the event when using IEEE Std. 1547-2018 Cat II voltage ride through settings, whereas around 5 MW of DER were unable to ride through when using CA Rule 21 settings. In both scenarios, voltage support functionality was disabled. The net load at the end of the event is seen to be around 20 MW when using the IEEE Std. 1547-2018 settings as compared to around 25 MW when using both CA Rule 21 settings and netting the DER with load. From these values, the amount of gross load at the end of the event can be calculated to be 35 MW with both the IEEE Std. 1547-2018 (20+15 MW) and CA Rule 21 (25+10 MW) settings. When the DER is netted with load and not modelled explicitly, it is difficult to differentiate between gross load loss and DER loss. It can thus be seen that when the DER is modelled explicitly, the impact of the standard to which the ride through settings have been set play a significant role in determining the net loading on the transmission system. While the transient bus voltage recovers more quickly using load netting, it is an optimistic result as the explicit modelling of DER shows the impact of trip settings on net load, which will by extension have an impact on the voltage magnitudes across the system.

Fig. 11 shows that with voltage/Q support (non-zero value of *Kqv* in the block diagram) and Q priority, the DER reach their current limit, I_{max}, in trying to support voltage post-fault, thereby causing the active current to reduce. This reduction in active current manifests as a prolonged

Table I. Loss of Load and DER in CAISO Impact Studies

Local area	Absent Model (DER netted)	CA Rule 21 Voltage Trip settings Q Priority	IEEE 1547-2018 Voltage Trip settings Q Priority	Gain=0 deadband=+/-99 vfrac = 0.2 Q Priority	Gain = 6 deadband = +/-0.02 vrfrac = 0.2 Q Priority	Gain = 0 deadband = +/-99 vrfrac = 0.5 Q Priority	Gain = 0 deadband = +/-99 vrfrac = 0.8 Q Priority	Gain = 6 deadband = +/-0.02 vrfrac = 0.5 Q Priority	Gain = 6 deadband = +/-0.02 vrfrac = 0.8 Q Priority	Gain = 20 deadband = +/-0.02 vrfrac = 0.2 Q Priority	Gain = 6 deadband = +/-0.02 vrfrac = 0.2 P Priority
Loss of Net Load, MW											
Humboldt	0	0	0	0	0	0	0	0	0	0	0
North Valley, Coast, Bay San Francisco Bay Area	-11	-21	-22	-21	-19	-24	-26	-19	-20	-18	-15
Central Valley, Coast, Los Padres, Kern	226	237	321	237	155	261	282	168	178	153	218
Fresno	418	362	553	362	405	446	516	477	540	378	365
Loss of Distributed Generation, MW											
Humboldt	0	0	0	0	0	0	0	0	0	0	0
North Valley, Coast, Bay San Francisco Bay Area	0	1	0	1	4	2	1	2	2	2	1
Central Valley, Coast, Los Padres, Kern	0	88	4	88	65	65	45	49	40	66	79
Fresno	0	192	20	192	165	118	51	100	43	191	189
Loss of Gross Load, MW											
Humboldt	0	0	0	0	0	0	0	0	0	0	0
North Valley, Coast, Bay San Francisco Bay Area	-11	-20	-22	-20	-15	-23	-25	-18	-18	-16	-14
Central Valley, Coast, Los Padres, Kern	226	325	325	325	220	326	326	217	217	219	297
Fresno	418	553	573	553	570	564	566	577	584	569	554
Net Load Loss Across Northern California, MW											
	633	577	852	577	541	683	771	626	698	514	567

reduction in DER MW output, and thus an increase in net load MW. A significant difference in net voltage recovery is not observed because the benefits of voltage support from the DER are to a large extent cancelled by the increase in net loading of the transmission system.

Fig. 12 shows a larger reduction in DER active power during transient conditions with Q-priority. Transient voltage with P-priority was slightly lower. After fault recovery, bus voltage and load were approximately the same in all cases. After fault recovery, with Q-priority the gross load loss area-wide was higher near the fault and lower farther from the fault than with P-priority. This behaviour seems counter-intuitive, as one would expect voltage support and Q-priority to support the load and reduce load loss. However, in Q-priority, due to preference to reactive current, net load on the system increases, which balances the voltage support provided by the DER, thereby resulting in lower voltages nearer the fault. This behaviour supports the claim that voltage support from DERs would be beneficial to surrounding load only if the fault was located farther away. Total net load loss in Northern California was higher with P-priority than with Q-priority.

FUTURE WORK

As shown above, for transmission planners, net load loss as a metric for defining DER impacts on the BPS could be deceptive. Improved DER ride-through settings allow DER to remain on-line while gross load trips, while other ride-through settings cause DER tripping along with tripping of load. There are pros and cons to both categories of ride-through settings, and their application for widespread use in the BPS should be further studied.

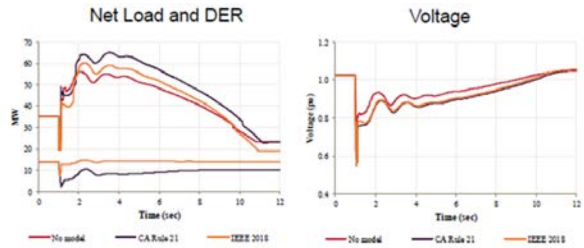


Fig. 10. Voltage Trip Settings Sensitivity

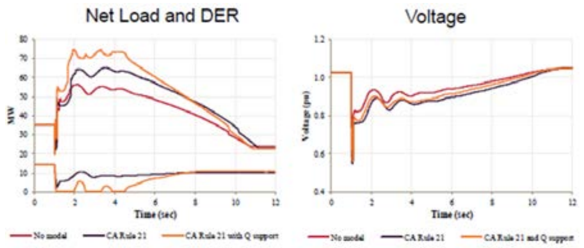


Fig. 11. Voltage Support Sensitivity

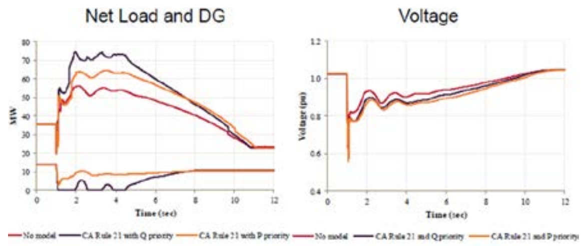


Fig. 12. P- and Q-Priority Sensitivity

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