NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Guideline

Modeling Distributed Energy Resources in Dynamic Load Models

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RELIABILITY | ACCOUNTABILITY

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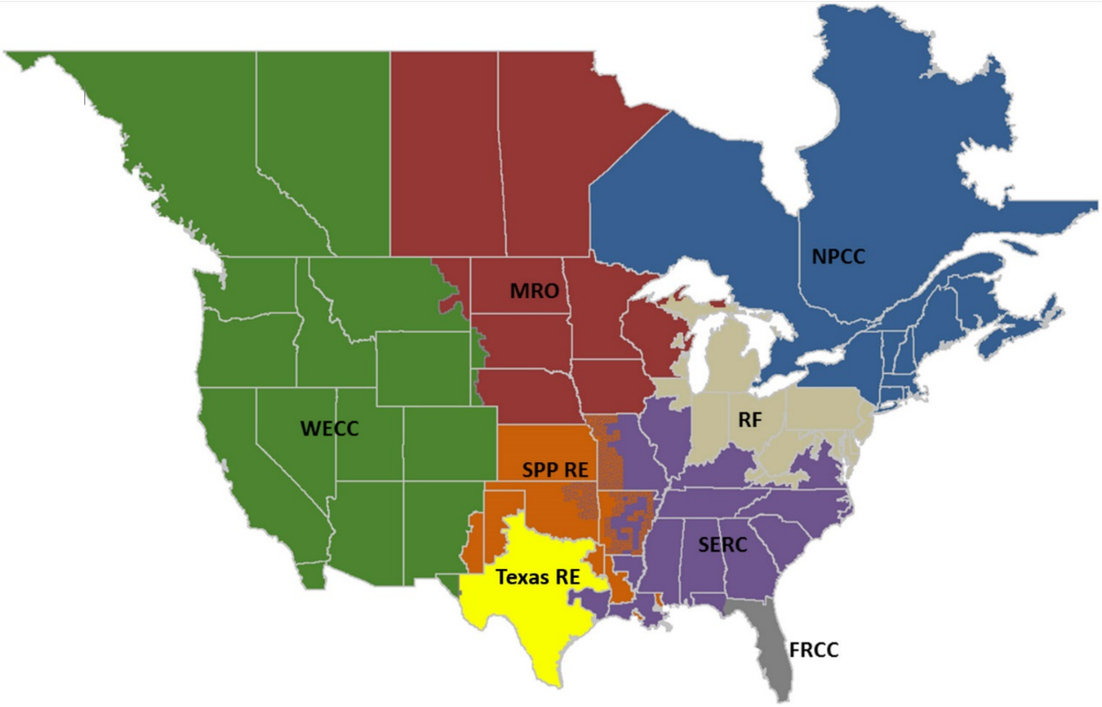
Preface

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

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



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

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

Preamble

NERC, as the FERC-certified Electric Reliability Organization (ERO),[1] is responsible for the reliability of the Bulk Electric System (BES) and has a suite of tools to accomplish this responsibility, including but not limited to the following: lessons learned, reliability and security guidelines, assessments and reports, the Event Analysis program, the Compliance Monitoring and Enforcement Program, and Reliability Standards. Each entity, as registered in the NERC compliance registry, is responsible and accountable for maintaining reliability and compliance with the Reliability Standards to maintain the reliability of their portions of the BES.

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

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

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[1] http://www.ferc.gov/whats-new/comm-meet/072006/E-5.pdf

[2] http://www.nerc.com/comm/OC/Related%20Files%20DL/OC%20Charter%2020131011%20(Clean).pdf
http://www.nerc.com/comm/CIPC/Related%20Files%20DL/CIPC%20Charter%20(2)%20with%20BOT%20approval%20footer.pdf
http://www.nerc.com/comm/PC/Related%20Files%202013/PC%20Charter%20-%20Board%20Approved%20November%202013.pdf

Purpose

With the proliferation of distributed energy resources (DER), modeling capabilities and practices should be adapted and refined so that transmission planning and operations planning engineers can differentiate between actual end-use loads and DER resources. In the past, and at lower penetrations of DER integrating into the distribution system, net load reduction has been used. Net load reduction is the result of the same or greater demand with an offset due to DER. However, these practices may not be sustainable moving forward as the distribution system continues to integrate more DER. Increasing DER penetration will impact the BES, resulting in changes in transmission loading levels, voltage regulation, and determination of operating limits. It is important to accurately represent the total end-use load and its composition, and model the amount of DER as a separate resource. This will allow entities to adequately represent the impact of future DER integration as well as the performance of DER during transmission system events. Distribution Providers (DPs) should coordinate with their Transmission Planners (TPs) and Planning Coordinators (PCs) to ensure sufficient data for load composition and DER resources is provided, as necessary, for reliable planning and operation of the BES. While many of these resources are not considered BES, sharing of this information is important for developing representative models and performing system studies.

The purpose of this guideline document is to provide a common framework for entities to consider for modeling DER in transient stability and powerflow simulations. The framework recommended in this guideline is expected to be particularly useful for interconnection-wide studies where a reasonable approximation of the load and resources across a large footprint will behave. More detailed, localized studies may require additional or more advanced modeling, as deemed necessary or appropriate. The modeling practices described here may also be modified to meet the needs of particular systems or utilities, and are intended as a reference point for interconnection-wide modeling practices. The recommendations in this guideline do not create any requirements or new obligations.

The NERC Distributed Energy Resources Task Force (DERTF) is developing a report[3] that will provide definitions for DER including different types of DER such as distributed generation (DG), behind the meter generation (BTMG), and others. These definitions will be used as the prevailing definition of DER; however, for the purposes of modeling DER and the guidance provided herein, a simplified set of definitions are used. The DERTF report also includes a chapter with recommendations on DER modeling in various bulk system planning studies. Please refer to the DERTF report, in addition to this guideline, after it is issued. The recommended practices in the DERTF report differentiate between types of generating resources (prime mover, synchronous/non-synchronous) by the location of their interconnection to the distribution system and by the technical interconnection requirements they comply with. For the purposes of dynamic load modeling[4] specified in this guidance, the following definitions are used:

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

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[3] The DERTF Final Report will be completed by end of year 2016 and available here.

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

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

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

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[6] This also applies to community DER that do not serve any load directly but are interconnected directly to a distribution load serving feeder.

Discussion of Modeling Practices

This section describes modeling practices for the powerflow and dynamics cases and how U-DER and R-DER can be represented to effectively capture their performance.

Simple Powerflow Modeling

Aggregated loads are commonly modeled in the powerflow base cases at the high side of the distribution transformer, with no representation of the transmission-distribution transformer that steps the voltage down to feeder levels (Figure 1). This is generally done to simplify modeling for studying the impacts on Bulk-Power System (BPS) performance.

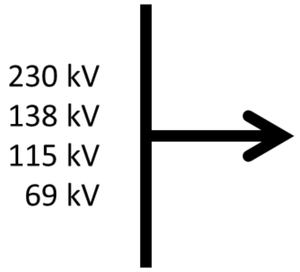

Figure 1: Powerflow Representation of Aggregated Loads

Modeled Distribution Transformer

One form of modeling loads is to represent each transmission-distribution transformer as a point of connectivity and represent that in the powerflow base case. In this situation, the distribution transformer is modeled explicitly, capturing the electrical impedance as well as any under-load tap changing (ULTC) impacts the transformer may have in steady-state pre- and post-contingency operating conditions. This is particularly important for voltage stability analysis where the transformer impedance and ULTC operation can impact longer term dynamics[7]. Figure 2 shows an example of this representation.

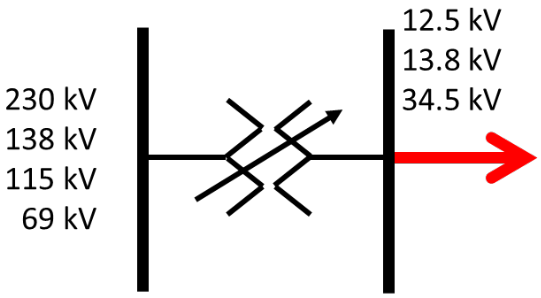

Figure 2: Transmission-Distribution Transformer Representation

Composite Load Model Representation in Stability Programs

The most detailed representation of end-use load for dynamic simulations and transient stability assessment available in commercial software platforms is the Composite Load Model (CLM). This model is used in this guidance document to explain how U-DER and R-DER can be incorporated into a dynamic load model and general modeling practices. The CLM includes different types of induction motor models, electronic load, and static load. It also includes representation of the transmission-distribution transformer, shunt compensation at the distribution

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[7] Constant power loads have been used as a surrogate to LTC action for power flow based long-term voltage stability analysis.

level, and a distribution feeder equivalent impedance. Lastly, protective tripping can be modeled for each machine as well as the ULTC action.

The CLM in the form shown in Figure 3 does not allow for representation of U-DER or R-DER. This is the current implementation of the CLM model structure in at least four major commercial software platforms in North America. The model is not well suited for breaking out U-DER or R-DER and separating the amount of net load reduction (U-DER and R-DER) versus gross load modeled as various forms of induction motors and other types of load.

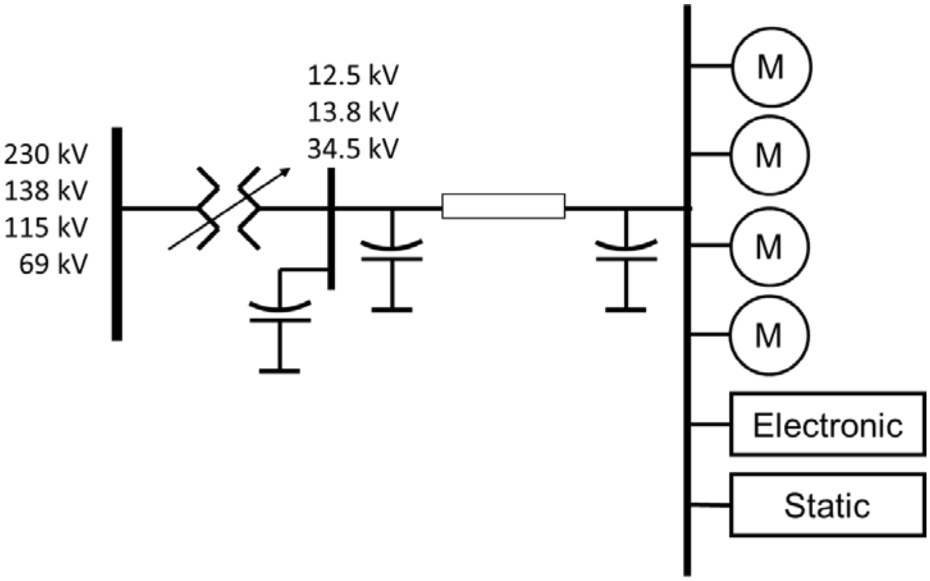

Figure 3: Composite Load Model

DER in the Composite Load Model

One option is to include DER directly into the dynamic load model, as shown in Figure 4. This capability is included in a modified version of the CLM presently in one commercial software platform.[8] In this case, the DER model represents an aggregate of all U-DER and R-DER on the distribution feeder and is located at the load-bus end of the feeder. An equivalent "average" impedance[9] is included in the model between the low-side bus and the load bus where all the loads (and DER) on the feeder are located. While this may be a reasonable modeling assumption at low penetration levels, the U-DER and R-DER would be represented by a uniform control strategy ("DER" model).

In this case, the powerflow base cases should separately represent the load and amount of DER. One option to accomplish this is to include DER in the load record fields to account for the output and capacity of "DER". Increasing DER will result in net load reduction; however, the gross load will be broken out in the dynamic simulations such that a more accurate amount of induction motor load and other loads will be represented as well as a closer representation of DER transient performance. Again, the latest versions of several commercial software platforms used in North America presently have this feature of separate fields in the powerflow load records for specifying active and reactive power associated with aggregated DER for each load modeled in the powerflow.

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[8] *cmpldw* in GE PSLF™.

[9] Some studies have shown that modeling more than one "average" impedance to reflect DER and load located near the substatioin and DER interconnected further down the feeder were effective for recreating system events.

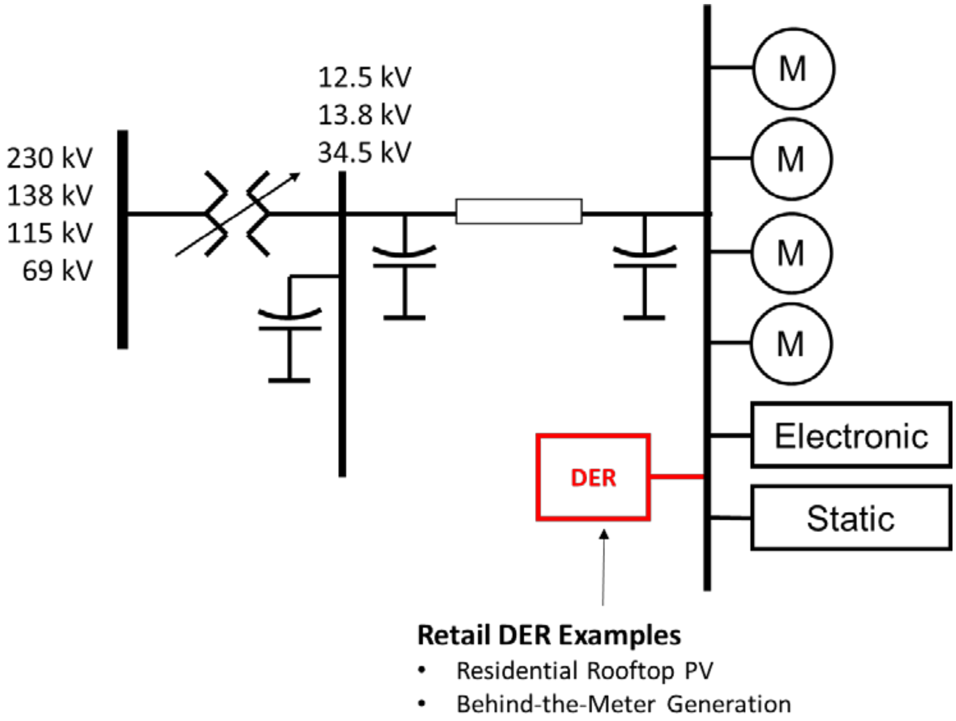

Figure 4: Inclusion of DER in the Composite Load Model

U-DER and R-DER in the Composite Load Model

Another option is to include U-DER and R-DER in the dynamic load model, as shown in Figure 5. In this case, the U-DER and R-DER are separated into different aggregate models with R-DER represented at the load bus of the feeder model and U-DER represented at the distribution substation.

The benefits of this approach include:

- **Effects of locationality of U-DER and R-DER:** The equivalent feeder impedance results in several percent (e.g., typically around 5%) voltage drop between the low-side bus and load bus. During transient conditions, that voltage difference may cause some DER to trip offline while others may ride through.
- **Control strategies:** Interconnection requirements for U-DER may differ from R-DER. Larger-scale installations (primarily U-DER) may have more complex controls such as low voltage ride through, voltage control, and other plant level controls. On the other hand, small-scale (primarily R-DER) likely have simpler control features (e.g., present installations likely adhere to the original IEEE 1547 requirements, which were essentially constant power factor control with no frequency or voltage ride through capability).

The drawbacks of this approach are:

- **Complicated Data Entry:** The powerflow base case would need to include the U-DER and R-DER separately or a fractional differentiation would have to be accounted for in the dynamic load model. This would result in complications in data management and for running sensitivity studies.
- **Dynamic Load Model Complexity:** In addition to the complexity introduced in the powerflow solution, the composite load model records would also become increasingly complicated by multiple types of U-DER and R-DER.

- **Burdensome Modeling:** There are limits to dimensions (memory allocation) in the software platforms and adding excessive dynamic data and state variables may slow down simulation runs significantly.

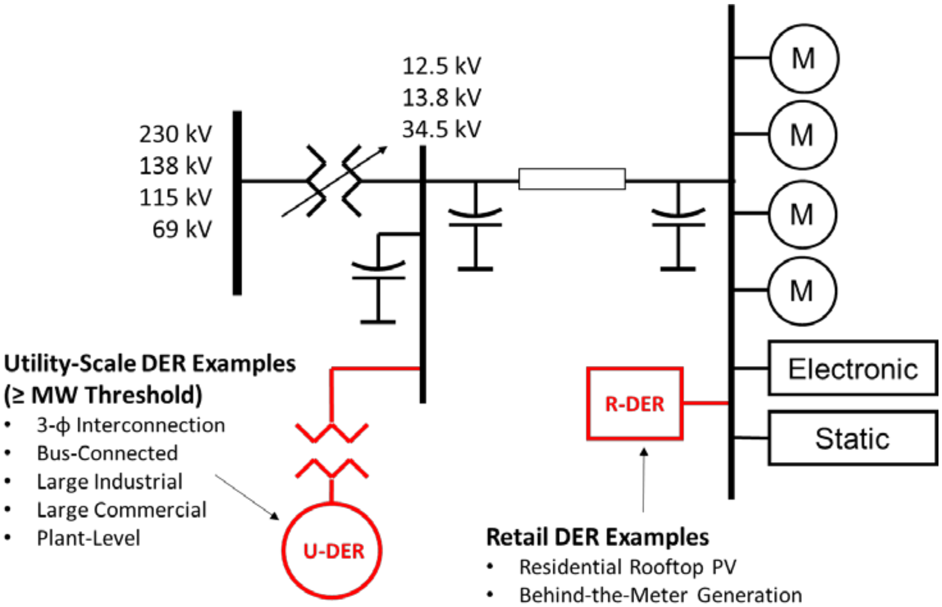

Figure 5: Inclusion of U-DER and R-DER in the Composite Load Model

Recommended Modeling Practice for U-DER and R-DER in the Dynamic Load Models

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

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

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

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

- **U-DER Modeling:** Any individual U-DER facility rated at or higher than the defined threshold should be modeled explicitly in the powerflow case at the low-side of the transmission-distribution transformer. A dynamics record, such as *PVD1*[10] or the second generation renewable energy model, could be used to account for the transient behavior[11] of this plant. U-DER less than the defined threshold should be accounted for as an R-DER as described below. Multiple similar U-DER resources 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 an R-DER exceeds this threshold, these DER should be accounted for in dynamic simulations as part of the dynamic load model. While this may not require any explicit model representation in the powerflow base case, the amount of R-DER should be accounted for in the load record and/or integrated into the dynamic model.[12]

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[10] The *PV1* is a generic dynamic model for a photovoltaic inverter system. This model is currently being expanded to a PVD2, or DER_A, model with advanced capabilities.

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

[12] The NERC DER Task Force recommends that all forms of DER be accounted for (no load netting) to the best ability possible. Therefore, it is recommended that the R-DER threshold be currently set to 0 MVA. This would account for all R-DER resources as part of the load record and distinctly capture the amount of R-DER represented within the load.

Table 1: Example of U-DER and R-DER Modeling Thresholds

Criteria	Description	Threshold
U-DER Modeling	Gross aggregate nameplate rating[13] of an individual U-DER facility directly connected to the distribution bus or interconnected to the distribution bus through a dedicated, non-load serving feeder	___ MVA[14]
R-DER Modeling	Gross aggregate nameplate rating[15] of all connected R-DER resources on the feeder that offset customer load including residential, commercial, and industrial customers	___ MVA

Figure 6 shows the conventional powerflow representation of the load in a powerflow base case and the recommended representation that explicitly models U-DER above a given size threshold. Note that each U-DER above the threshold would be modeled explicitly via its own step-up transformer, as applicable, to the low-side bus. If the U-DER is connected through a dedicated feeder or circuit to the low-side bus, then that would also be explicitly modeled in the powerflow. The load is also connected to the low-side bus.

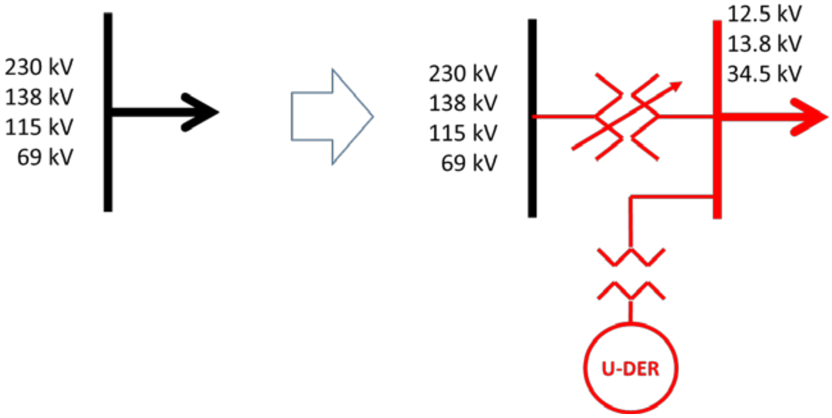

Figure 6: Representing Utility-Scale DER (U-DER) in the Powerflow Base Case

Once represented in the powerflow model in this manner, the data for the composite load model should be modified to account for explicit representation of the U-DER and transmission-distribution transformer. Figure 7 shows the composite load model where the distribution transformer impedance is not represented in the dynamic record, it is modeled explicitly in the powerflow to accommodate one or more U-DER. The transformer impedance is not represented in the CLM (impedance set to zero in the dynamic load model); therefore, any LTC modeling[16] would be done outside the CLM such as enabling tap changing in the powerflow and using the *ltc1* model[17] in dynamic simulations. The motor load and distribution equivalent feeder impedance is modeled as part of the

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[13] This could be represented as a percentage of the sum of load serving capacity of all step-down transformer(s) supplying the distribution bus for that associated load record being modeled.

[14] This is intentionally left blank as a template or placeholder for applying this in a particular TP or PC footprint.

[15] This could be represented as a percentage of the sum of load serving capacity of all step-down transformer(s) supplying the distribution bus for that associated load record being modeled.

[16] Utilities using transformers without ULTC capability but with voltage regulators at the head of the feeder could model this in the CLM with a minimal transformer impedance but active LTC to represent the voltage regulator.

[17] Software vendors are exploring the concept of applying an area-, zone-, or owner-based LTC model that could be applied to all applicable transformers to address LTC modeling.

CLM[18], and the R-DER are represented at the load bus based on the input in the powerflow load record while the load is fully accounted for rather than any net load reduction.

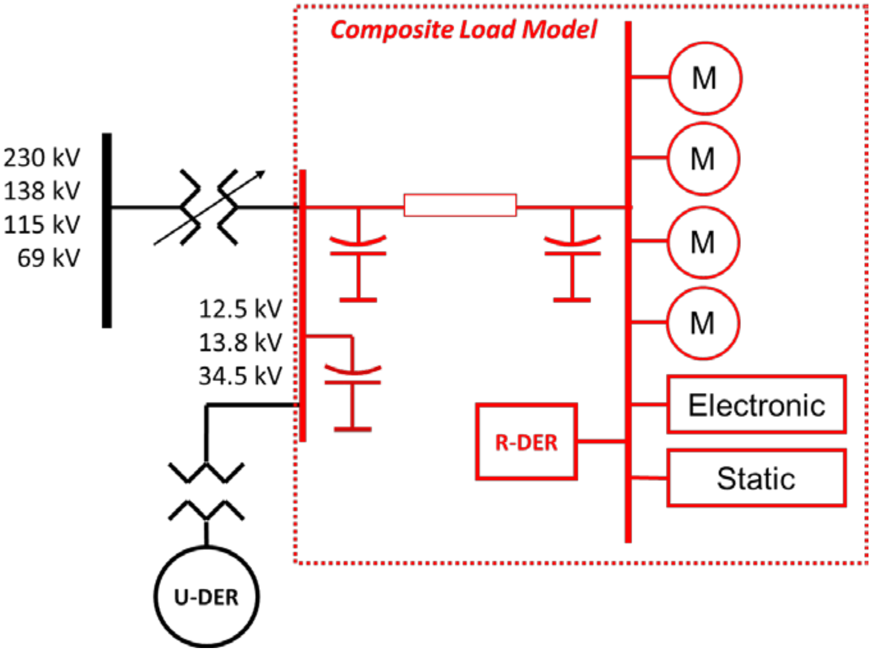

Figure 7: Dynamic Load Model Representation with U-DER Represented in the Powerflow Base Case

To capture the R-DER in the powerflow solution, the load records should have the capability to input the R-DER quantity in the powerflow. It is recommended that all software platforms adopt[19] the same approach to unify this modeling practice and enable flexibility for capturing DER as part of the load records. Figure 8 shows an example of the R-DER included in the powerflow load records. The red box shows the R-DER specified, for example 80 MW and 20 Mvar of actual load with 40 MW and 0 Mvar of R-DER at Bus 2. The blue box shows the net load equal to the actual load less the R-DER quantity specified for MW and Mvar, defined as:

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

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

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

Figure 8: Capturing R-DER in the Powerflow Load Records [Source: PowerWorld]

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

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[18] In certain situations, for example where high R-DER penetration is expected, and where advanced "smart inverter functions" should be modeled, explicit modeling of the distribution transformer, equivalent feeder impedance, load bus, and DER models may be effective.

[19] Some software platforms have adopted this approach; NERC LMTF is working with all major software vendors to develop this capability.