Distributed Energy Resources

Technical Considerations for the Bulk Power System

Staff Report

Docket No. AD18-10-000

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Executive Summary

Traditionally, distributed energy resources (DERs) referred to small, geographically dispersed generation resources, such as solar or combined heat and power (CHP), installed and operated on the distribution system at voltage levels below the typical bulk power system levels of 100kV. In recent years, DER installations have increased significantly in some regions of the United States due in part to technology advances and state energy policies. This report considers how the increasing penetration and integration of DERs in specific regions may affect bulk power system reliability. This report focuses primarily on the technical considerations for DERs as they are currently operated, and does not necessarily address how DERs may participate in the markets operated by the regional transmission organizations and independent system operators (RTOs/ISOs).

To this end, FERC staff performed a series of technical assessments using industry power system models and commercially available power system simulation software to identify the potential reliability issues and likely benefits to the bulk power system resulting from an increased penetration of DERs.

Staff's work identified, at a high level, several key topics that are addressed in this report and can be summarized as follows:

- The impact of the current common industry modeling practice of netting DERs with load,[1] which may mask the effects of DER operation;
- DER capabilities for voltage and frequency ride through during contingencies;
- The potential for improved customer-level voltages due to the unloading of the bulk power system associated with the location of DERs at or near customer loads;
- Potential effects on system-wide transmission line flows and generation dispatch due to changing load patterns; and
- The sensitivity of voltage or power needs to different types of DER applications (i.e., the provision of energy, capacity, or ancillary services).

Overall, the results of this analysis suggest that increasing DER capacity, if not properly accounted for, could cause reliability concerns for the bulk power system.[2] Further industry discussion is needed to improve and refine the data that is available for

[1] Such as described in NERC Reliability Standard MOD-032-1 — Data for Power System Modeling and Analysis, requiring Load Serving Entities to aggregate Demand at each bus.

[2] DER capacity modeling was based on current trends for technology types, operational capabilities, and deployment distributions.

DERs that will be incorporated into planning and operating models. Collecting and using the most current and accurate data is key to getting a complete picture of how DERs affect the bulk power system.

In addition, further discussion and study is needed regarding other issues, such as sensitivities with higher DER penetration levels, changes in siting patterns, and potential impacts to the system's response to events, disruptions and outages, including frequency events. Further exploration in these areas will help the Commission to track and assess the impact of changing conditions on the bulk power system to identify emerging trends and address potential future reliability challenges.

1. Background

DER adoption is growing in the United States, due in part to state, local, and federal policies. In 2016, DERs accounted for about two percent of the installed generation capacity in the United States, but distributed solar photovoltaic (PV) installations alone represented over 12 percent of new capacity additions.[3] Certain regions have experienced disproportionately greater growth in the installed capacity of DERs. For example, California currently has over 7,000 MW of installed DER capacity[4] as shown in Figure 1, and has set a target to integrate 12,000 MW[5] of DERs by 2020.[6]

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[3] Twenty-four gigawatts of new utility-scale generating capacity and 3.4 gigawatts of new distributed small scale photovoltaic were added in 2016 according to the U.S. Energy Information Administration. *See Renewable Generation Capacity Expected to Account for Most 2016 Capacity Additions*, the U.S. Energy Information Administration, (January 2017), *available at* https://www.eia.gov/todayinenergy/detail.php?id=29492 and *Electric Power Monthly – Chapter 6: Capacity*, the U.S. Energy Information Administration, (February 2016 with data for December 2016), *available at* https://www.eia.gov/electricity/monthly/current_year/february2017.pdf.

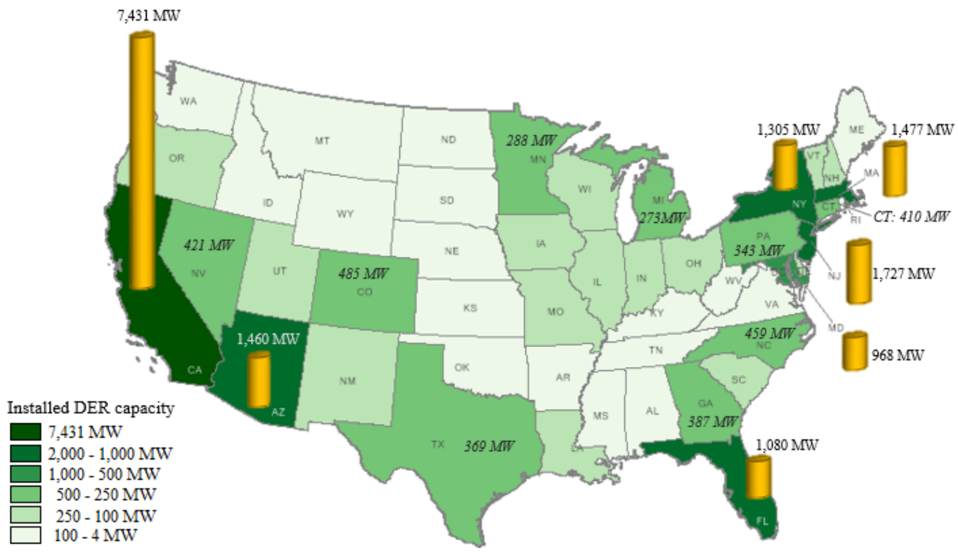
[4] *See Electric Power Sales, Revenue, and Energy Efficiency - Form EIA-861*, the U.S. Energy Information Administration, Release Date: October 6, 2016 with final 2015 data, Next Release date: October 2017, *available at* https://www.eia.gov/electricity/data/eia861/index.html and *Form EIA-861M (formerly EIA-826)*, the U.S. Energy Information Administration, Release Date: February 2017 for December 2016 data, *available at* https://www.eia.gov/electricity/data/eia861m/.

[5] The 12,000 MW goal does not include energy storage. The energy storage procurement target is set in Assembly Bill 2514 (California's investor owned utilities must procure 1,325 MW of energy storage by 2020) and Assembly Bill 2868 (California's investor owned utilities must procure up to 500 MW of additional distributed energy storage). *See* Energy Storage Systems, A.B. 2514, Skinner. (2009-2010), *available at* http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100AB2514 and Energy Storage, A.B. 2868, Gatto. (2015-2016), *available at* https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160AB2868. (2015-2016), *available at* https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160AB2868.

[6] *See* Clean Energy Job Plans, Office of the Governor Edmund G. Brown Jr., at 3 (September, 2011), available at https://www.gov.ca.gov/docs/Clean_Energy_Plan.pdf.

Further, even without regional policies encouraging DER growth, factors such as customer desire for self-supply, environmental considerations, and declining acquisition costs of DER technologies suggest continued DER growth, and the experience in other countries illustrates the rapid pace at which deployment can occur.[7]

Figure 1 – U.S. DER Deployments



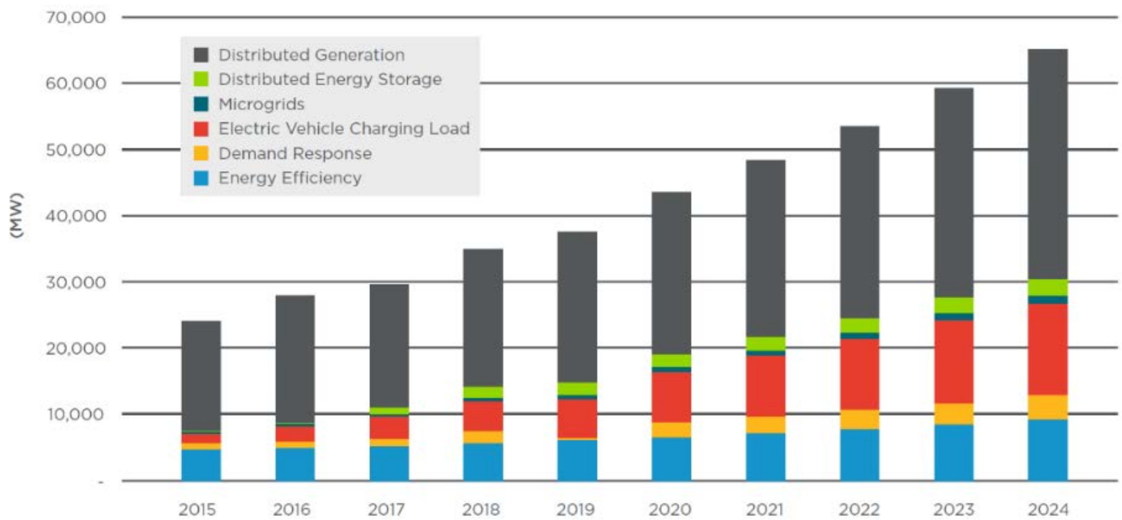
Source: The U.S. Energy Information Administration[8]

Figure Figure 2 below illustrates the estimated and projected annual installed DER capacity additions for the United States during 2015-2024. With several states setting high renewable energy procurement targets, installed capacity could rise rapidly.

[7] Germany added 7,400 MW of solar PV on its low-voltage distribution grid in one year. *See* Martin Braun, *Integrating PV in Local Distribution Systems – Germany*, (December 2010), *available at* http://iea-pvps.org/index.php?id=9&eID=dam_frontend_push&docID=423.

[8] *See Electric Power Sales, Revenue, and Energy Efficiency - Form EIA-861*, the U.S. Energy Information Administration, Release Date: October 6, 2016 with final 2015 data, Next Release date: October 2017, *available at* https://www.eia.gov/electricity/data/eia861/index.html and *Form EIA-861M (formerly EIA-826)*, the U.S. Energy Information Administration, Release Date: February 2017 for December 2016 data, *available at* https://www.eia.gov/electricity/data/eia861m/.

Figure 2 – U.S. Annual Installed DER Power Capacity Additions by DER Technology, 2015-2024



Source: Navigant analysis[9]

2. Defining DERs

Although "distributed energy resource" is a common term in the energy industry, no uniform DER definition exists. Traditionally, DERs referred to small, geographically dispersed generation resources, such as solar or CHP, located on the distribution system.[10] Depending on their size and configuration, distributed energy generation resources could partially or completely offset consumer electrical demand. They could also feed surplus energy back into the distribution system or, in some cases, the transmission system.[11] However, the definition of DERs has evolved to include not only

[9] *See* Navigant, Take Control of Your Future, Part II: The Power of Customer Choice and Changing Demands, May 9, 2016, *available at* https://www.navigantresearch.com/blog/take-control-of-your-future-part-ii-the-power-of-customer-choice-and-changing-demands.

[10] *See* NARUC, *Distributed Energy Resources Rate Design and Compensation* (Nov. 2016), https://pubs.naruc.org/pub.cfm?id=19fdf48b-aa57-5160-dba1-be2e9c2f7ea0 (NARUC DER Manual) at 44.

[11] PJM has been facing reverse power flows to the transmission system as a result of DER output for some time. In 2012, the Net Energy Metering Task Force reported that 20 out of the 8,096 load buses had negative loads of 10 MWh or more in more than 350 instances during the Jan-Mar 2012 period. *See* Net Energy Metering Senior Task Force, *1st Read - Final Report and Proposed Manual Revisions* at 4-5, (June 2012), *available at* http://www.pjm.com/~/media/committees-groups/task-

generation resources, but also energy storage, energy efficiency and demand response resources. Indeed, distributed generation resources are often co-located with, for example, demand response resources, and may be bundled into net demand such that a utility may not be able to measure nor have specific information on the characteristics and/or performance of DERs in its service area.

In a recent proposed rule on electric storage and DER participation in wholesale markets, the Commission proposed to define a DER as:

A source or sink of power that is located on the distribution system, any subsystem thereof, or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, thermal storage, and electric vehicles and their supply equipment.[12] NERC's working definition of DER, as provided in a report from the NERC DER Task Force, is "any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System."[13] Some entities, such as the California Public Utility Commission (CPUC), have a more narrow definition of distributed generation that includes only renewable resources.[14]

NARUC uses a broad DER definition:

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forces/nemstf/postings/20120628-first-read-item-04-nemstf-report-and-proposed-manual-revisions.ashx. This trend has continued into 2016. *See* Ken Schuyler, *Net Energy Injections at Load Busses* at 3, (May 2016), *available at* http://www.pjm.com/~/media/committees-groups/committees/mrc/20160617-special/20160617-item-02-pjm-net-energy-injections-quarterly-review.ashx.

[12] *See Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157 FERC ¶ 61,121, at P 1 (2016) (Storage NOPR). The Commission received several comments on this proposed definition. Staff cites this definition as an example and notes that the instant report does not choose a specific definition for DERs.

[13] See NERC, *Distributed Energy Resources: Connection Modeling and Reliability Considerations* (Feb. 2017), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf (NERC DER Task Force Report) at 1.

[14] *See California Public Utilities Code § 769 (a) (2015)*, CPUC, *available at* http://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?lawCode=PUC&sectionNum=769.

> A resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load. Examples of different types of DER include solar PV, wind, CHP, energy storage, demand response (DR), electric vehicles (EVs), microgrids, and energy efficiency (EE).[15]

NARUC's report further argues that defining DERs should be a collaborative effort between utilities and state and federal entities because of the potential applications across the entire electric power system and energy markets.

While it is possible to define DERs as a single class of assets, it is also important to recognize differences within this asset class. For example, bulk power system reliability issues associated with DERs may differ depending on whether DERs participate directly in the RTO/ISO markets, or participate in retail compensation programs, such as net metering. DERs that participate directly in the RTO/ISO markets provide greater visibility of the resources to system operators because they generally provide their physical and operational characteristics to the RTO/ISO and are modeled and dispatched as part of the market's economic clearing mechanism.[16] As discussed further below, while it is possible for DERs that are participating in retail compensation programs to be modeled, dispatched and metered, we understand that the reporting of such information to bulk power system operators is limited, which in turn limits the operational awareness about those DERs that are not participating directly in the RTO/ISO markets.

DERs also comprise a number of different technologies, and the operational characteristics of those different technologies and how they are modeled, dispatched and metered must be considered when evaluating their potential reliability impacts on the bulk power system. Some DER technologies, like electric storage, are completely controllable, and their controllability offers opportunities for resolving operational constraints on the transmission and distribution systems. Variable DERs, like solar and

[15] NARUC DER Manual at 45.

[16] See, e.g., Docket No. ER16-1085-001, 155 FERC ¶ 61,229 (Order conditionally accepting CAISO's tariff revisions to facilitate participation of aggregations of DERs in CAISO's energy and ancillary services markets); and ER16-1085-001 (Letter order accepting CAISO's filing to comply with 155 FERC ¶ 61,229).

wind generation, require operators to forecast accurately their output to identify their potential effects on system constraints and other operational challenges. However, the advent of smart inverters, as discussed below, and the aggregation of DER technologies with complementary capabilities, can help mitigate some of the operational limitations posed by certain technologies.

3. Bulk Power System Reliability Considerations for DERs

The electric industry has recently conducted several analyses to better understand the unique characteristics of DERs, how they respond to system conditions, and how they may be deployed as compared to bulk power system generators. This section presents a survey of several of these findings and conclusions on how those unique characteristics may translate into potential reliability issues and benefits as DER penetration increases.

3.1 Potential DER Reliability Issues

The potential impact of DERs, in aggregate, on the bulk power system has captured the electric industry's attention in recent years.[17] NERC has asserted that greater levels of DERs highlight the "need to ensure reliability of the bulk power system during both normal operation and in response to disturbances."[18] While industry has identified several potential reliability issues such as impacts to operations and planning including modeling, ramping and load forecasting,[19] many of these issues can be managed with adequate DER data and visibility. As the ISO/RTO Council's (IRC) Emerging Technology Report explains, "data is a common theme running through the DER issue."[20] However, as discussed below, ensuring the provision of appropriate data to bulk power system planners and operators can be complicated.

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[17] *See* NERC, *Special Report: Potential Bulk System Reliability Impacts of Distributed Resources* (Aug. 2011), http://www.nerc.com/docs/pc/ivgtf/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011.pdf (2011 NERC Report) at 1.

[18] NERC DER Task Force Report at 3.

[19] 2011 NERC Report at 19-20.

[20] ISO/RTO Council, *Emerging Technologies* (Mar. 2017), http://www.iso-rto.org/Documents/NewsReleases/PUBLIC_IRC_Emerging_Technologies_Report.pdf. (Emerging Technologies Report) at 11.

In this section, staff presents the following potential reliability issues identified by industry that may arise from increased DER penetration:

- The lack of DER data and the resulting implications for the operation, planning, and design of the bulk power system;
- The need for coordination between the settings and capabilities of resources connected to the bulk power system and DERs;
- The need for improved modeling practices and capabilities for DERs;
- The effect of DER daily generation profiles on system unit commitment and ramping needs; and
- The effect of distribution connected variable PV and wind output on day-ahead load forecasts.

3.1.1 The Lack of DER Data and the Implications for the Bulk Power System

Without adequate data, many bulk power system models and operating tools will not fully represent the effects of DERs in aggregate.[21] For example, the IRC has argued that North American ISOs and RTOs should have access to basic data about DERs in their respective territories, and that the location, size, and technological capabilities of DERs are examples of critical and reliable data needed to formulate a "comprehensive strategy for managing an increasingly distributed electricity system."[22] For example, in projecting the reliable and efficient management of an increasingly distributed grid, ERCOT highlights the need for the detailed collection of static DER data[23] from distribution service providers and transmission service providers to support various ERCOT grid monitoring functions.[24]

In most regions, there is no process in place to provide static DER data to bulk system operators and planners.[25] In many states with net metering programs, certain

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[21] NERC DER Task Force Report at 3.

[22] *Id*. at 11.

[23] Data which is set, typically upon installation, such as the physical and electrical location of the device as well as its capacity, type and capabilities.

[24] ERCOT, *Distributed Energy Resources: Reliability Impacts & Recommended Changes* (Mar. 2017), http://www.ercot.com/content/wcm/lists/121384/DERs_Reliability_Impacts_FINAL.pdf (ERCOT DER Impacts Report) at 5.

[25] *Id*. at 20.

static DER data may be collected through the customer registration process, but additional effort would be needed for operators and planners to obtain that data. NERC has identified the need to further study what specific, static DER data is needed for operators and planners and whether the data to be shared can be standardized or are subject to regional variation.[26]

3.1.1.1 DER Visibility

In its 2016 Long-Term Reliability Assessment, NERC states that many utilities lack "sufficient visibility" of DERs.[27] This lack of visibility could present certain issues for bulk power system reliability, including a lack of situational awareness.[28] NERC has defined situational awareness as "ensuring that accurate information on current system conditions is continuously available to operators."[29] This information should include the potential impact of contingencies and must be comprehensive enough for operators to "rapidly and fully understand actual operating conditions and take corrective action when necessary to maintain or restore reliable operations."[30]

In addition to the need for static DER data noted above, DER telemetry data (such as output) can allow transmission system operators to gain real-time visibility and situational awareness of behind-the-meter generation. Today, this visibility is limited

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[26] NERC, *DER Data Collection Guideline Presentation* (Aug. 2017), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSWG_Meeting_Presentations_-_August_2-3_2017_Atlanta_GA.pdf at 13.

[27] NERC, *2016 Long-Term Reliability Assessment* (Dec. 2016), http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20Long-Term%20Reliability%20Assessment.pdf at viii.

[28] CAISO, *Coordination of Transmission and Distribution Operations in a High Distributed Energy Resource Electric Grid* (June 2017), http://morethansmart.org/wp-content/uploads/2017/06/MTS_CoordinationTransmissionReport.pdf at 8.

[29] *See* NERC, *Real-Time Tools Survey Analysis and Recommendations* (Mar. 2008), http://www.nerc.com/comm/OC/Realtime%20Tools%20Best%20Practices%20Task%20Force%20RTBPTF%2020/Real-Time%20Tools%20Survey%20Analysis%20and%20Recommendations.pdf at 9.

[30] *Id*.

because DERs are generally not required to supply telemetry data.[31] PJM explains that, while the telemetry data for some DER units may be available, "the process for obtaining the data varies based on the local distribution company."[32] Furthermore, PJM asserts that, depending on the level of penetration, DERs could require increased de-commitment/re-dispatch of centrally dispatched resources to meet balancing obligations.[33] The IRC supports the development of a framework by which "increasingly comprehensive operational data from the distribution system is provided as DER penetrations reach different thresholds."[34] A counter-balancing consideration when assessing the need for more DER information, including the granularity of the data, is the associated cost that DER owners will incur to provide the information. Requiring metering or telemetry equipment will impose a cost on DER resources, and that cost will need to be considered against the benefit of providing the additional information. Further, the degree to which statistical methods could use static data and telemetry data from a sample of DER may offer a cost effective real-time visibility without burdening every DER resource with the cost of telemetry equipment.

The CAISO region provides an example of how a lack of DER data can affect bulk power system operations such as unit commitment and dispatch. In 2016, distributed PV totaled 4,903 MW and represented over 10 percent of CAISO's peak load.[35] Behind-the-meter DERs are not typically metered unless participating in a

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[31] *See* PJM, *PJM's Evolving Resource Mix and System Reliability* (Mar. 2017), , http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx (PJM Reliability Report) at 21.

[32] *Id.*

[33] *Id.*

[34] Emerging Technologies Report at 11.

[35] NERC DER Task Force Report at 33.

wholesale market program,[36] and can have the effect of reducing the measured load.[37] In CAISO, for example, a distribution circuit with a 10 MW load may see 5 MW of load at the circuit breaker, assuming a 50 percent penetration of solar PV. However, the underlying 10 MW load is still present, and as solar production declines in the late afternoon and evening, or as a result of cloud cover, this underlying load will remain high.[38] From the perspective of the bulk power system operator, the net load translates into lower than expected loads during the day with much faster increases of load through the late afternoon and evening than would be the case without DERs.[39] This results in low bulk power system unit commitment during the day, but very fast resource and ramping requirements in the late afternoon and evening.[40] These conditions may challenge the operational capacity of the system during some operating hours.[41]

As a result of netting DERs with load, CAISO has stated that it only becomes aware of the impact of rooftop solar when clouds block the sun and the demand previously served by rooftop solar suddenly appears.[42] On a clear sunny day, solar PV systems exhibit consistent energy output; however, when solar panels experience passing clouds, the solar PV exhibits intermittent energy production, as illustrated in Figure 3. Transmission operators have identified cloud cover as an issue in areas that have a large penetration of rooftop solar. It can cause a need for sudden ramping of other generation

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[36] A behind-the-meter DER is "metered" if an electric meter collects data for the DER generation separately from the total net customer load. Usually this is not the case, and a single electric meter collects data for both the load and any DER generation behind the meter (for example small roof top PV have a single meter with the local load). This translates to an aggregate of all loads and DERs on a distribution circuit as a single net load from the perspective of the bulk power system. See ERCOT, *ERCOT Concept Paper on Distributed Energy Resources in the ERCOT Region* (Aug. 2015), , https://energy.gov/sites/prod/files/2016/02/f29/ERCOT_DER_Whitepaper_082015.pdf (ERCOT Concept Paper on DERs) at 34.

[37] *Id*. at 33-34.

[38] *Id*. at 34.

[39] *Id*.

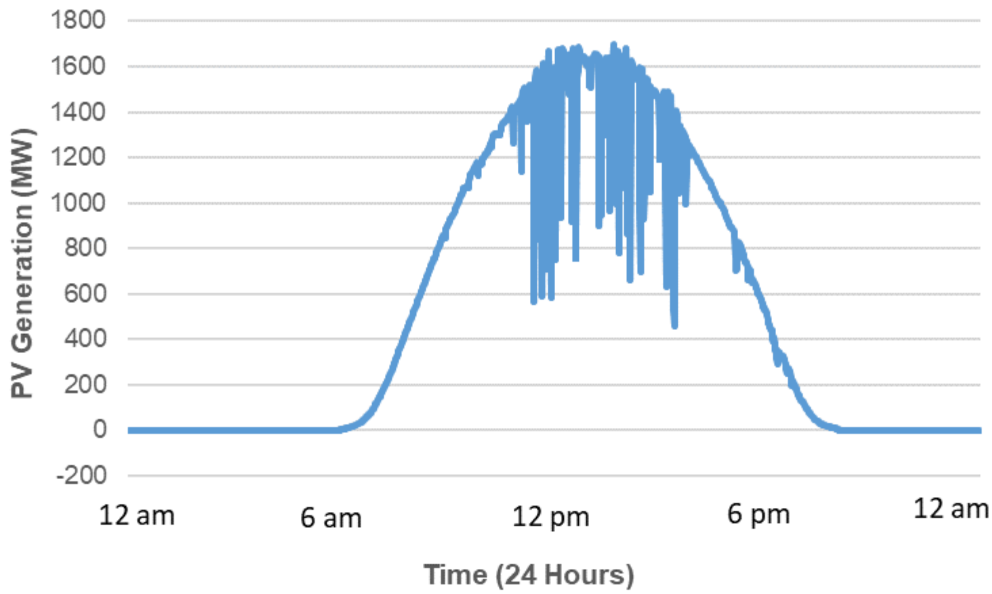
[40] *Id*.

[41] *Id*.

[42] Larson, *How are Distributed Energy Resources Affecting Transmission System Operators* (May 2016), http://www.powermag.com/distributed-energy-resources-affecting-transmission-system-operators/?printmode=1.

resources to balance the system load, as shown by the staff study summarized in Section 4.1 of this report.

Figure 3 – One-minute PV Generation during a Cloudy Day[43]



3.1.2 Coordination between the Bulk Power System and Distribution System

On November 4, 2006, one of the largest and most severe disturbances in Europe led to a blackout for more than 15 million European households. The Union for the Coordination of Transmission of Electricity (UCTE) prepared a Final Report[44] on the event, which contains information and analysis on the underlying causes of the November 4 disturbance, as well as lessons learned and recommendations to avoid a

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[43] *See* EPRI, *Distributed PV Monitoring and Feeder Analysis*, http://dpv.epri.com/feeder_j.html.

[44] The UCTE is the association of Transmission System Operators in continental Europe. It aims at providing a reliable market place through the co-ordination of the operation of electric "power highways" over the entire European mainland. Union for the Co-ordination of Transmission of Electricity, *Final Report – System Disturbance on 4 November 2006* (Jan. 2007), https://www.entsoe.eu/fileadmin/user_upload/_library/publications/ce/otherreports/Final-Report-20070130.pdf (UCTE Report) at 12.

similar event in the future. The report discusses the contributions of DERs to the event, and offers DER-specific recommendations.

Analysis of the event showed that the proliferation of generating units connected to the distribution system increased the event's severity. During the event, cascading outages and tripped lines caused the UCTE grid to split into three separate systems. Without imports from the east, the western area of the split faced a supply-demand imbalance of about 8,940 MW.[45] This imbalance caused the frequency to drop to 49 Hz from the normal 50 Hz.[46] Immediately following the frequency drop, a significant amount of DERs, mostly consisting of wind and CHP units, tripped offline, which exacerbated the supply-demand imbalance and, by increasing the frequency deviation, led to further outages which increased the size of the event.[47] Furthermore, a lack of sufficient situational awareness meant that the transmission system operators did not have access to real-time data for DERs, preventing a better evaluation of system conditions.[48] Ensuring the visibility and situational awareness of DERs, as well as accurately modeling their response to events to avoid unforeseen tripping, could help prevent similar events in the United States as DER penetration levels increase. Further, new revisions to the Institute of Electrical and Electronics Engineers (IEEE) 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems are expected to leverage recent technology updates by requiring ride through capabilities in newly interconnecting DERs, which would help to avoid a parallel event in the United States.[49]

The final UCTE Report recommended several steps be taken to address the different disconnection requirements between generators connected to the transmission system and those connected to the distribution system, in light of the role of DERs in the November 4 event. Specifically, the UCTE Report recommended that "requirements to

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[45] *Id*. at 25.

[46] *Id*. at 25.

[47] Since DERs are connected to the distribution grid, the relevant standards for their performance during a frequency drop are less constraining than those connected to the transmission grid. At the time of the event they typically would have to withstand a frequency drop to 49.5 Hz. A significant amount of DER units tripped during the event because the frequency dropped below the predefined threshold of 49.5 Hz. *Id.* at 25.

[48] *Id*. at 7.

[49] Staff notes that while the IEEE 1547 provides a uniform standard for the interconnection of distributed resources, it must be adopted by a jurisdiction to have effect.

be fulfilled by generation units connected to the distribution grid should be the same in terms of behavior during frequency and voltage variations as for the units connected to the transmission network…these requirements should be applied also to units already connected to transmission and distribution grids."[50] The UCTE Report also recommended that transmission system operators receive on-line data of generation connected to the distribution provider[51] grids (in at least one-minute increments).[52]

In the U.S., the topic of interconnection requirements has received attention as well. In a 2013 report, NERC found that a lack of coordination between small generating facilities and the bulk power system can lead to events where system load imbalance may increase during frequency excursions or voltage deviations, due to the disconnection of DERs, which in turn may exacerbate a disturbance on the bulk power system.[53] Relevant to that issue, in Order No. 828,[54] the Commission revised the *pro forma* Small Generator Interconnection Agreement (SGIA) to harmonize voltage and frequency ride through requirements for newly interconnecting small generating facilities (no larger than 20 MW) with those already in place for large generating facilities (larger than 20 MW). Order No. 828 requires newly interconnecting small generating facilities to meet the same requirements as large generating facilities to ride through abnormal frequency and voltage events (i.e., to not disconnect during such events).[55] While Order No. 828 applies only to generating facilities interconnecting to Commission-jurisdictional facilities through an SGIA, the Commission communicated its hope that the rule would be helpful to states when updating their own rules for interconnection to the distribution system,

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[50] *Id*. at 62.

[51] As defined by the *NERC Glossary of Terms* (Aug. 2017), http://www.nerc.com/files/glossary_of_terms.pdf.

[52] *Id*. at 62.

[53] *See* NERC, *Integration of Variable Generation Task Force Draft Report: Performance of Distributed Energy Resources During and After System Disturbance* (Dec. 2013), http://www.nerc.com/comm/PC/Integration%20of%20Variable%20Generation%20Task%20Force%20I1/IVGTF17_PC_FinalDraft_December_clean.pdf.http://www.nerc.com/comm/PC/Integration%20of%20Variable%20Generation%20Task%20Force%20I1/IVGTF17_PC_FinalDraft_December_clean.pdf.

[54] *Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities*, 156 FERC ¶ 61,062 (year) (Order No. 828).

[55] *Id.* at P 21.

while acknowledging that states are under no obligation to adopt the provisions of the Commission's proposal.[56] As discussed below, technical DER interconnection standards, such as the IEEE 1547 Standard, are increasingly incorporating advanced features and grid friendly services such as ride through capabilities. However, in regions where clusters of DERs have already been installed without ride through requirements, NERC's 2013 observation remains relevant.

3.2 Potential Reliability Benefits of DERs

As DER penetration increases, there may be several associated reliability benefits to the bulk power system. For example, by providing power close to the customer, DERs can serve to reduce grid losses and reduce system peak load.[57] Several efforts are underway to better understand the full range of potential reliability benefits associated with DERs.[58]

3.2.1 Communication and Technological Capabilities of DERs

New revisions to the IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems are expected to mandate communication capability from all DERs and standardize the related communication interfaces, protocols, and information models. NERC has commented that the revisions to IEEE 1547, coupled with smart inverter technology, could have substantial benefits for operations of distribution and transmission grids. NERC stated:

> Current work […] on enhancements to the IEEE 1547 interconnection requirements and how capabilities of DER are used will present opportunities for improving [bulk power system] reliability. Technology advances have the potential to alter DER from a passive "do no harm" resource to an active "support reliability" resource. From a technological

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[56] *Id*. at P 12.

[57] *See* NYISO, *A Review of Distributed Energy Resources*, (Sep. 2014), http://www.nyiso.com/public/webdocs/media_room/publications_presentations/Other_Reports/Other_Reports/A_Review_of_Distributed_Energy_Resources_September_2014.pdf at 18.

[58] *See, e.g.*, EPRI, *The Integrated Grid, A Cost-Benefit Framework* (Feb. 2015), http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002004878.

perspective, modern DER units will be capable of providing ERS [essential reliability services] and supporting [bulk power system] reliability.[59]

These revisions, once effective, would apply to new but not to existing DERs. However, the U.S. Department of Energy (DOE) estimates that the average life of small inverters is seven years, and thus inverter turnover will bring these new capabilities to an increasing proportion of deployed DERs. If the new revisions to IEEE 1547 mandate communication capability from all DERs, it would be the responsibility of the utility to build the required communication infrastructure to make use of this capability.[60] While transmission system operators may not presently be able to leverage all of these new features due to a lack of infrastructure, a great deal of work is underway at the Electric Power Research Institute (EPRI), the National Labs, NERC, and the National Institute of Standards and Technology's Smart Grid Interoperability Panel to develop ways to harness these new technical capabilities of DERs.

3.3 Developments at the Transmission-Distribution Interface: The DSO Model

Distributed System Operators (DSOs) are one of several different operational and business models that have been proposed and analyzed as a structure for distribution utilities in the future, especially with higher DER deployment.[61] DSOs have been proposed as a means to address the parallel needs of an efficient and reliable distribution system and an intermediate entity between the RTO/ISO and DER owners due to the limited visibility and control of DERs.[62] Paul De Martini of Newport Consulting Group and Lorenzo Kristov of CAISO outlined the potential functions of a "distribution system operator," including the ability to coordinate the interchange of power to other markets, physically coordinate DER schedules, aggregate DERs for wholesale market participation, and control resource output.[63] The DSO could be the medium by which RTOs/ISOs are provided with net load forecast and dispatchable DER products,

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[59] NERC DER Task Force Report at 4.

[60] *Id*.

[61] DER Task Force Report at vi.

[62] *See Distribution Systems in a High DER Future: Planning, Market Design, Operation and Oversight*, Paul De Martini and Lorenzo Kristov, Lawrence Berkeley National Laboratory, October 2015, (De Martini and Kristov).

[63] De Martini and Kristov at 21-23; *see also*, Apostolopoulou, *et al.*, *The Interface of Power: Moving Toward Distribution System Operators* (May 2016), http://ieeexplore.ieee.org/document/7452714/ (Apostolopoulou) at 3.

schedules and bids, metering, and telemetry. In turn, the RTO/ISO would send the DSO schedules, dispatch instructions, prices, and settlements for individual DERs or DER aggregations.[64] To enable these functions, the current distribution system may require certain upgrades to provide for better modeling, including upgrades to the data measurement and collection schemes to model existing DERs, as well as upgrades providing the capability to switch protection settings online and to communicate with DER resources.[65]

While a fully developed DSO as outlined by DeMartini and Kristov has yet to be implemented, several states are exploring regulatory and policy changes to overhaul the distribution system. Through its Reforming the Energy Vision (REV) initiative, the New York Public Service Commission has implemented changes through a series of orders to the structure of its electric system, including the development of distribution system platform (DSP) providers,[66] and has required distribution utilities in the state to file distribution system implementation plans. Other states, such as California, New Hampshire, Maryland, Massachusetts, and Ohio are also examining reforming the role of distribution utilities, particularly distribution system planning, during grid modernization proceedings, but not at the level being conducted in New York. Still other states, such as Rhode Island, are examining distribution system planning in much greater detail.

In addition, to explore the expanded role and responsibilities of DSOs and distribution utilities, DOE, in collaboration with the CPUC and the New York Public Service Commission, is developing a comprehensive set of functional requirements for a next-generation distribution system platform to enable participation of DERs in the provision of electricity services.[67] The project intends to engage key stakeholders to obtain a critical review of its efforts and aspires to provide guidance for the development

[64] Apostolopoulou at 3.

[65] *Id.* at 3.

[66] The DSP providers will be tasked with modernizing electric distribution systems to create a flexible platform for new energy products and services, and incorporating DERs into planning and operations to achieve the optimal means for meeting customer reliability needs. *See The Energy to Lead*, New York State Energy Planning Board, at 49 (2015), *available at* https://static1.squarespace.com/static/576aad8437c5810820465107/t/5797fc52f5e231d942a2d79b/1469578322990/2015-state-energy-plan-pf.pdf.

[67] *See Overview of DSPx*, DOE-OE, http://doe-dspx.org/.

of future planning, operations, and market tools needed to support distribution system platform implementation.

4. Technical Studies and Results

The need to study both the transmission and distribution systems becomes more important as DER penetration increases, because increasing DER penetration changes how the two systems interact. To assess the impacts of increasing penetration levels of DERs, Commission staff performed several technical studies using power flow, production cost, and distribution models to evaluate the potential reliability issues and benefits associated with DERs.

The power flow models provide information on the DER impacts to bus voltages and changes in power flows across the bulk power system following a contingency (such as the loss of bulk power system generation or DER generation). Production cost modeling offers information on the changes to dispatch and production costs of generation given various DER penetrations. OpenDSS[68] allows modeling of the distribution system and facilitates the analysis of the distribution system for a period of time such as a day. Several sources of data were used to reach consistent levels of DER penetration across the different study types and models to allow for comparison of results despite differences in modeling tools.

This section describes these studies, including the assumptions, methodology, and conclusions.

4.1 Role of Distribution Models in Planning Studies (Distribution Modeling)

Unlike typical power flow studies, this study uses the OpenDSS modeling tool to analyze the effects of DER installations on the distribution system over a period of a day and allows for extrapolation of potential impacts to the transmission system. Typical power flow studies assume a balanced three phase system, while distribution models typically portray individual phases[69] because many DER installations and distribution

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[68] OpenDSS is a publicly available software modeling tool provided by EPRI. EPRI provides the tool and related distribution feeder models and sample data sets at no cost as part of their ongoing analyses of the impact of the variability of solar generation. This software has also been used for other industry studies, including multiple studies published with IEEE.

[69] Alternating electrical current circuits typically have three phases to efficiently move power. To minimize losses on bulk power system facilities these phases are

loads are single phase. It is important to consider the effects of DERs over a period of 24 hours to capture the influence of DER generation on feeder performance because DERs and load vary independently.

4.1.1 Study Purpose

The objective of the distribution feeder model study is to compare the potential impact of different types of feeder modeling on the effectiveness of planning studies, and therefore grid reliability. Feeders with DERs can be modeled three different ways: (1) as net demand (so the generation from the DER is cancelled by the load of customers); (2) as the aggregated generation of the DER independent of the aggregated load at the feeder connection; and (3) as a detailed model of the feeder. This is shown in Figure 4 below.

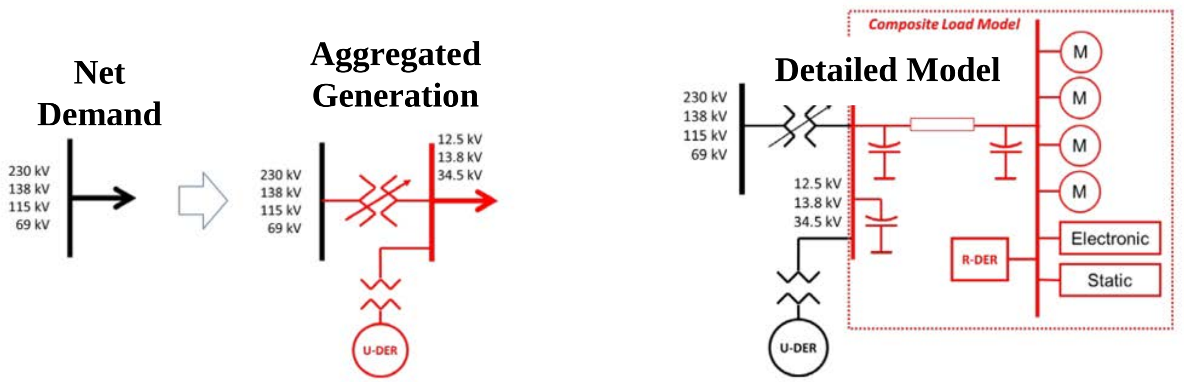

Figure 4: Types of DER Modeling[70]

In this study, staff evaluated the real and reactive power and voltages at the transmission and distribution interconnection points using the different types of DER models to assess whether different model types such as netted load or aggregated load and generation provide sufficient detail to assess reliability. Review of detailed models also provides insight into how DERs may behave during a variety of system conditions.

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balanced, i.e. each phase carries the same amount of power. But on a lower voltage distribution circuit loads can be connected to single phases which often results in unbalanced power flow across the three phases.

[70] *See Reliability Guideline Distributed Energy Resource Modeling DRAFT*, NERC, Page 3 and 4, *available at* http://www.nerc.com/pa/RAPA/rg/ReliabilityGuidelines/Item_14._Reliability_Guideline_-_DER_Modeling_Parameters_-_2017-05-09_-_FINAL_DRAFT.pdf.

4.1.2 Assumptions and Data

For the distribution feeder modeling, the distribution feeder models provided by EPRI[71] were used in combination with OpenDSS. This was not an attempt to model a full distribution system. The Feeder J1,[72] located in the northeastern United States, was selected because 1.7 MW of customer-owned PV systems already exist on the feeder. With a peak load of approximately 6 MW, this 12 kV feeder serves approximately 1,300 residential, commercial, and light industrial customers. While not a heavily loaded feeder, it requires the use of a load tap changer, voltage regulators, and switched capacitor banks to provide voltage regulation. Volt-Volt-Ampere Reactive (VAR) control was added to all PV units to assess the potential impact of the smart inverter functionality on both distribution and transmission operations.

The J1 feeder model used in the analysis consists of all primary and secondary power delivery elements from the substation transformer to the individual customers. Control elements such as load tap changers, capacitors (aqua marks in Figure 5) and voltage regulators (red marks in Figure 5) are included with fully implemented control algorithms using set-points, delays, and bandwidths. Load is allocated to each individual customer. The feeder peak load is about 6 MW and the substation peak load is 11 MW. Solar PV units (yellow marks in Figure 5) are interconnected at the customer service level (0.416 kV and 0.24 kV). Installed solar PV capacity is 1.7 MW or 28 percent of the peak feeder load and 15 percent of the substation load.

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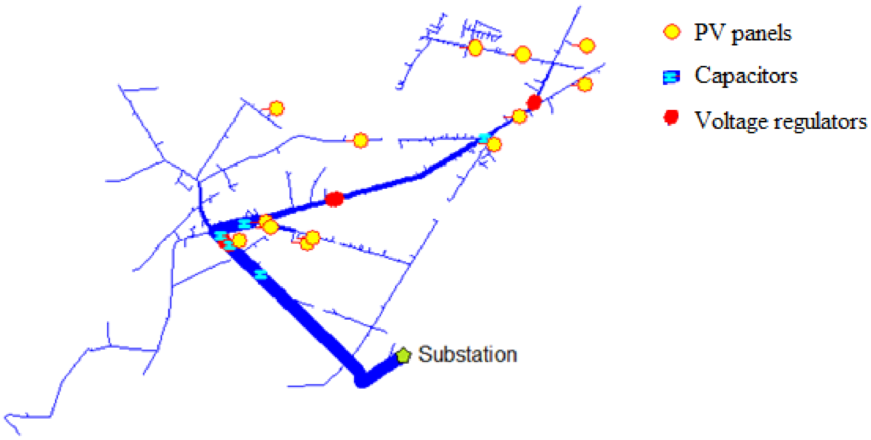
[71] Since 2010, EPRI has been conducting analyses to assess the variability of solar generation and its potential impact on utility operations and planning. As a part of the project, EPRI provides OpenDSS distribution feeder models and sample data sets at no cost. This software has also been used for other industry studies, including multiple studies published with IEEE.

[72] *See Distributed PV Monitoring and Feeder Analysis*, EPRI, *available at* http://dpv.epri.com/feeder_j.html.

Figure 5: Feeder J1 – location of voltage regulators, capacitors and PVs



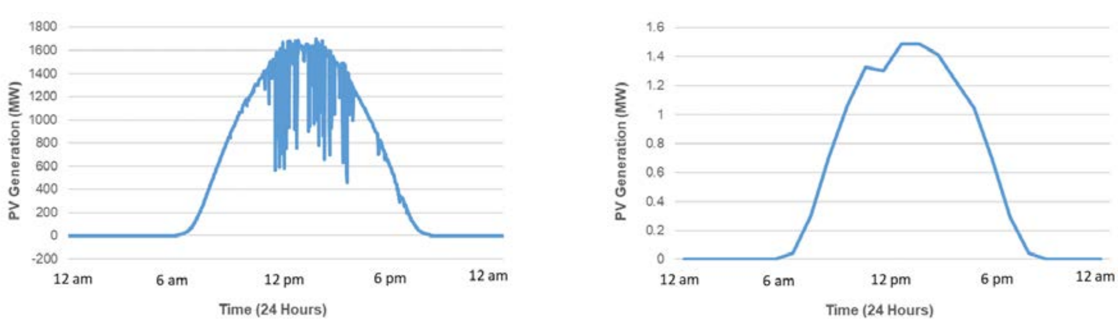
The J1 feeder model includes one year of the substation hourly real and reactive power measurement data and nine days of the measured solar PV generation data. Solar PV generation data is given for one-second, one-minute, fifteen-minute and one-hour time intervals.

4.1.3 Methodology

The study included models both with and without assumed distribution system voltage controllers, i.e., load tap changers, line regulators and capacitors. Staff also conducted a power flow analysis for both cases, and assessed the results using loading and voltage analyses.

Then, for the time series analysis results were generated for every minute during a 24-hour period, and the study considered three different cases of the feeder model: a full detailed model, an aggregated model, and a netted model. In each case, load was modeled using SCADA data and PV data was based on one minute EPRI data before being aggregated as needed to create the three different feeder models.

Figure 6: Hourly PV Diagrams



a) One-minute PV Generation Data b) Hourly average PV generation data

First, for the full detailed model both load and PV generation were modeled separately. For load, staff generated an hourly daily load diagram from the substation SCADA measurements by selecting a day when the peak demand occurred. Since the substation meters measure hourly net load, staff modified the measured values by adding an hourly solar PV generation profile. The hourly PV generation profile was calculated averaging one-minute PV data provided by EPRI over one hour (Figure 6). PV reactive power was neglected because a very small amount (less than 50 kVAr) was generated.

Second, staff aggregated the same load as a single load in the substation and aggregated the solar PV units as a single solar PV installation interconnected in the substation. In this case, staff derived the normalized hourly load data from multiple load profiles to represent "typical" hourly load data using statistical methods and incorporated it by replacing the entire feeder model with one aggregated demand and one aggregated solar PV installation in the substation.

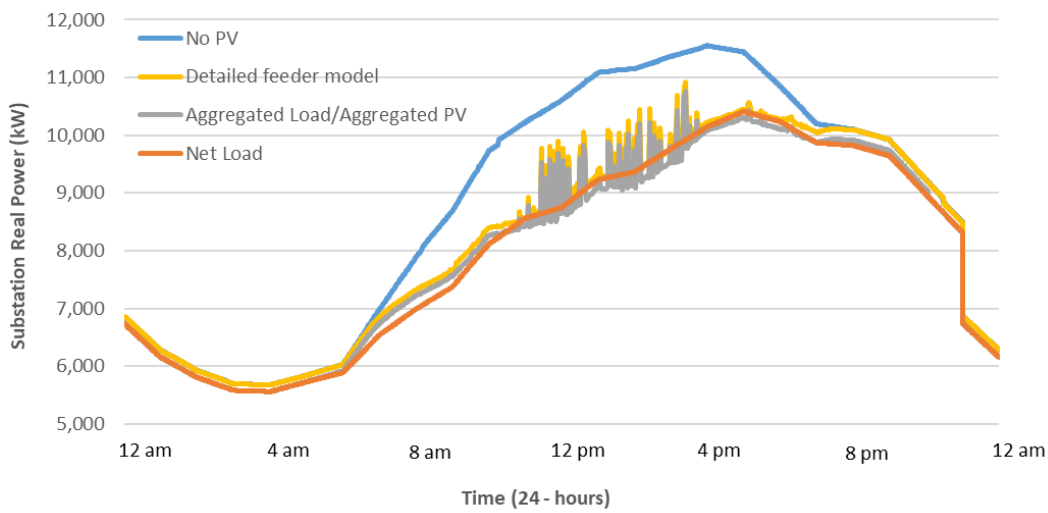
Finally, both load and solar PV installations were netted as one load located in the substation. The case used the normalized hourly SCADA data for the peak day to represent the net demand and solar PV generation as already included.

For all three cases, staff ran the time series analysis for every minute during a 24-hour period.

4.1.4 *Results*

The analysis found that DERs will modify the feeder load such that the variability of the load (both magnitude and frequency of change) will significantly increase relative to having no DER resources. However, this is only fully captured in the detailed model and partially captured in the aggregated models. It further found that based on the time series analysis results, the peak load change due to DERs may not be proportional to the installed capacity of DERs because the maximum DER generation may not be coincident with the feeder peak load. This demonstrates the need to develop planning processes that capture more detailed models of DERs and allow for modeling of the interface between the transmission and distribution systems to enable information exchange and more accurate calculations of the DER impact. The following figures illustrate how the current practice of netting DERs with load rather than using more detailed models may result in inaccurate estimates of power flowing on the system.

Figure 7: Substation Real Power

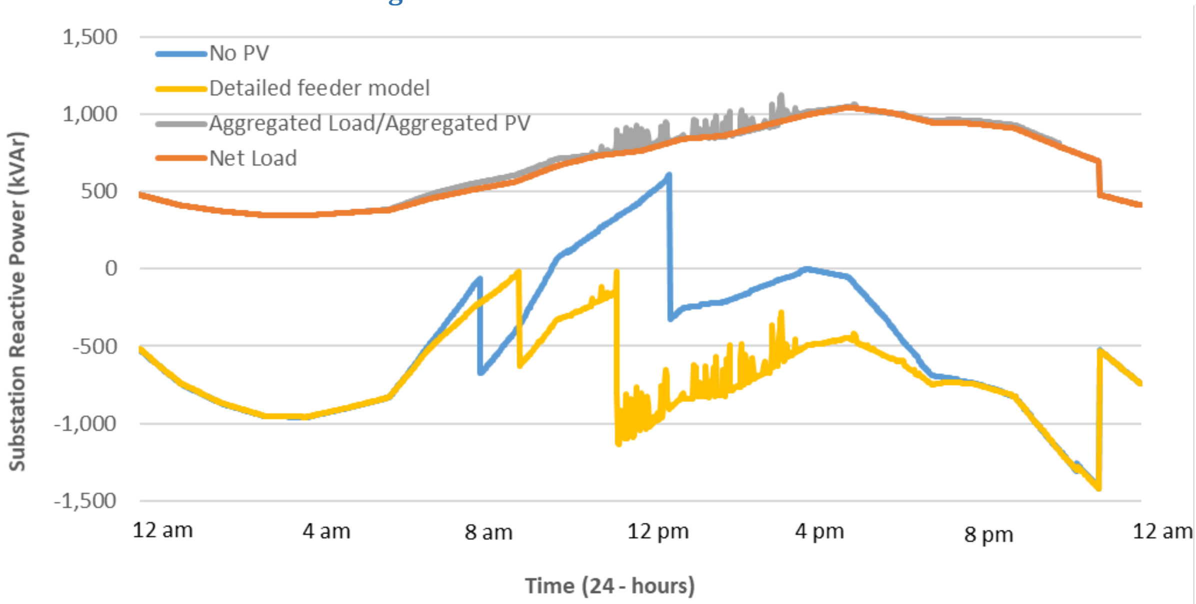


As shown in Figure 7, when the feeder is modeled as a net load, information about solar PV generation variability is not captured because the net load is usually an hourly average of the feeder load. The yellow line, representing the detailed model, shows significant variation. The grey line, representing aggregated load and solar PV data, shows less variation. The orange line, representing the net load model, shows none of the variation caused by the solar PV generation.

Therefore as shown here, when the solar PV aggregation is modeled separately from the load aggregation, the variability of the solar PV generation can be preserved. For the given feeder, when net load modeling is used, information on variability of PV operation is lost, causing a 12-percent difference in modeled load in comparison with the full feeder model. Because the load and generation data is combined when the feeder is modeled as an aggregated load and aggregated solar PV generation, the difference is much smaller (about 3 percent) or “smoother” as shown in Figure 6.

Figures 7 and 8 illustrate the difference between the detailed, aggregated and netted models and the limitations of the netted models.

Figure 8: Substation Reactive Power



4.2 DERs and System Performance Following Generator Outages (Power Flow Study)

4.2.1 Study Purpose

The objective of the power flow study was to assess how DERs, in a system with high DER penetration, may impact system power flows and bus voltages following a contingency. As DERs proliferate throughout the system, outages of DERs could have increasing impacts on the bulk power system, comparable to an outage of conventional generation. For example, a system disturbance causing DERs without ride through capabilities to automatically disconnect may exacerbate the initial system disturbance.

4.2.2 Assumptions and Data

The study utilized the FERC Form 715 planning cases for WECC and ERCOT.[73] Staff adjusted the 2017 peak load and low load cases for both regions to represent, as closely as possible, current DER penetration levels as reported by publicly available data

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[73] These cases were used because they provide perspective on both interconnections, and their content and development process are familiar to most in the electric industry.

(approximately 12 percent penetration level in WECC and 0.02 percent in ERCOT).[74] However, because DER definitions vary and DERs are not yet explicitly modeled in WECC's FERC Form 715 power flow cases, staff made a few key assumptions and estimates regarding the amount and location of existing DER installations to identify load points for probable sites for the additional DER capacity to reach consistent penetration levels.

First, using commercially available data as a basis,[75] staff determined that the DER penetration in the WECC power flow case should be increased by approximately four percent (about 2,265 MW) over the amount determined to be included in Form 715 data to reflect a total of about 9,400 MW of DERs as currently reported within California.[76] Second, to determine where to place the additional DER capacity in the WECC power flow case, staff assumed that buses which included "aggregated generation and load models,"[77] also known as "complex loads," would constitute reasonable DER locations. These complex loads are modeled throughout the California electric system, and roughly match the location of DERs found in the PROMOD models. Therefore, staff added a total of 2,265 MW of DER capacity (as compared to the amount determined to be in the Form 715 data) to 1,010 load points throughout California in the WECC 2017 peak and low load planning cases to bring estimated modeled DER generation in line with capacity estimates prepared by the California Energy Commission.[78]

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[74] Data sources, such as existing commercially available production cost and power flow models, and data collected by relevant public utility commissions and reported to the EIA were used to approximate both capacity and location of current DER facilities.

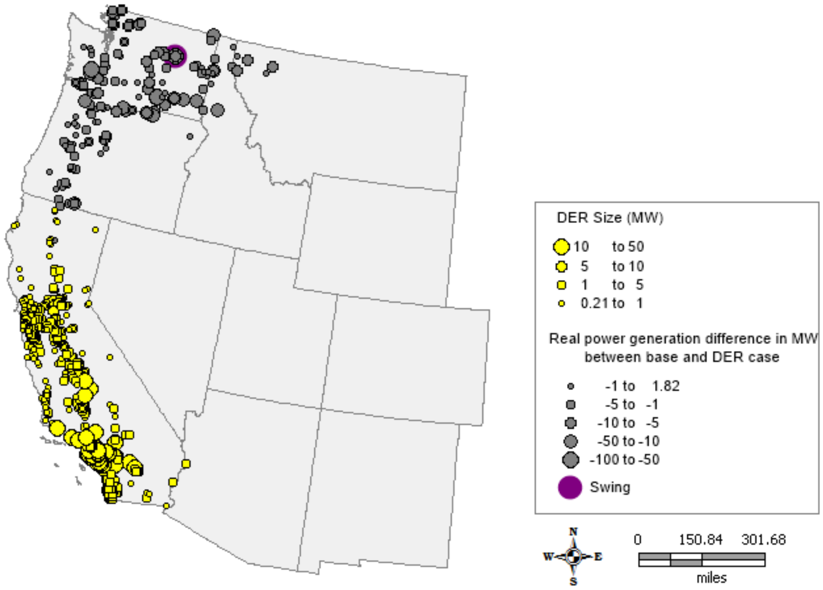
[75] This data was provided as part of the PROMOD databases developed by ABB.

[76] In WECC, the most detailed public DER data is collected by the California Energy Commission, which defines DERs as projects that are 20 MW or smaller, including both self-generation and projects for market participation. *See Renewable Energy Tracking Report 2016*, California Energy Commission, (last updated on December 22, 2016), *available at* http://www.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf.

[77] *See* Reliability Guideline Distributed Energy Resource Modeling DRAFT, NERC, Page 3 and 4, *available at* http://www.nerc.com/pa/RAPA/rg/ReliabilityGuidelines/Item_14._Reliability_Guideline_-_DER_Modeling_Parameters_-_2017-05-09_-_FINAL_DRAFT.pdf.

[78] *See Renewable Energy – Overview*, California Energy Commission, *available at* http://www.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf.

Figure 9: Modeled Change in Generation in WECC



The location of these load points is shown in Figure 9. To maintain the generation and load balance across the entire WECC system, the team performed a production cost modeling study with similar levels of DER penetration to adjust generation.

In ERCOT, DERs are defined as an electrical generating facility that is located at a point of common coupling, 10 MW or less, connected to a bus voltage level less than or equal to 60 kV.[79] ERCOT has locational information for DERs with installed capacity greater than 1 MW that export energy into the distribution system because they are required to register with ERCOT, but it does not have detailed information for DER installations that do not meet that threshold. Based on this definition, and to match other data sources, staff determined that a total of 179 MW of DER capacity had to be added in the ERCOT 2017 peak and low load planning cases, as compared to the Form 715 data, to bring estimated modeled DER generation in line with the capacity estimates prepared by ERCOT.[80] To maintain the load and generation balance, an equivalent amount of generation from several large generating units was scaled down.

In order to determine the location of the DER installations, staff leveraged data from commercially available databases to site the DERs in the ERCOT power flow model based on their geographical proximity to the nearest distribution generator bus.

[79] *See Distributed Generation*, ERCOT, (2017), *available at* http://www.ercot.com/services/rq/re/dgresource.

[80] *See Distributed Generation*, ERCOT, *available at* http://www.ercot.com/services/rq/re/dgresource.

The data for the unregistered component of the DER installations in ERCOT is available on an aggregate level by primary fuel type and load zone.[81] Staff divided the total capacity value of unregistered DERs proportionally among the buses identified by staff as probable DER locations. Table 1 shows the unregistered DER capacity as reported by ERCOT.

Table 1: Unregistered DER Totals[82]

Aggregate by Primary Fuel Type (MW) for Reporting Quarter 2016 Q4					
Load Zone	**Solar**	**Wind**	**Other Renewable**	**Other Non-Renewable**	Total
AEN	13.91	0.00	0.00	0.00	13.91
CPS	7.14	0.00	0.23	0.00	7.37
Houston	8.03	0.39	0.11	4.33	12.86
LCRA	0.64	0.00	0.00	0.00	0.64
North	68.46	1.66	0.00	0.63	70.74
Rayburn	0.00	0.00	0.00	0.00	**0.00**
South	11.27	0.67	0.00	0.00	11.94
West	5.93	0.82	0.00	0.33	7.08
Total	115.37	3.54	0.34	5.28	124.53

In additional sensitivity studies, staff also scaled DER generation by factors of two and three to test the effects of higher penetrations. To accommodate this additional generation, the existing generation fleet was re-dispatched based on dispatch results from a production cost modeling study with similar levels of DER penetration.

4.2.3 Methodology

The power flow study considers two fundamental system loading conditions: (1) high load, which typically occurs in the hot summer months; and (2) low load, which

[81] *Unregistered DER Capacity Quarterly Report*, ERCOT (last updated Quarter 1 2017) *available at* http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13544&reportTitle=Unregistered%20DG%20Installed%20Capacity%20Quarterly%20Report&showHTMLView=&mimicKey.

[82] *Unregistered DER Capacity Quarterly Report*, ERCOT (last updated Quarter 1 2017) *available at* http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13544&reportTitle=Unregistered%20DG%20Installed%20Capacity%20Quarterly%20Report&showHTMLView=&mimicKey.

typically happens during the spring or fall. The studies monitored for transmission facility loadings above 100 percent of Rating Set A (used for normal operations) and for bus voltages below 90 percent, below 95 percent, and above 105 percent of the standard operating voltage.

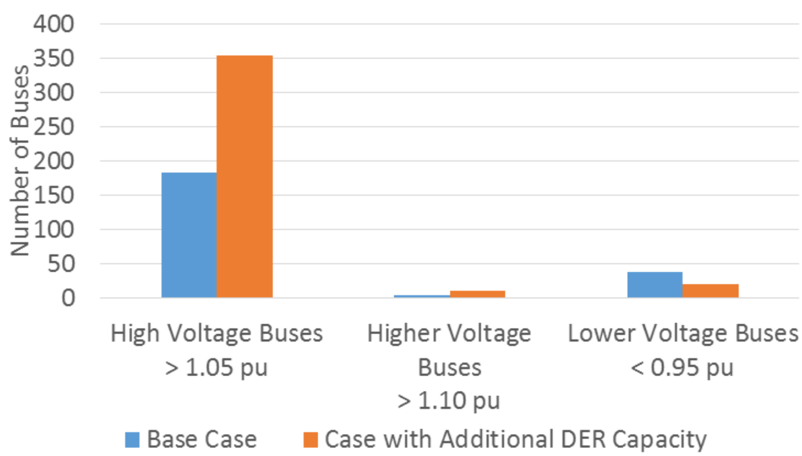
Finally, staff performed a selective contingency analysis to determine any violations to the thermal and voltage criteria. The contingencies examined included the loss of DER capacity, the loss of a large generating facility, and a combination of both. Staff also evaluated these contingencies at different DER penetration levels. The following contingencies were analyzed:

- Loss of bulk power system generation equal to one or two nuclear units
- Loss of levels of DER generation equal to one or two nuclear units
- Loss of both the one or two nuclear units on the bulk system and DER generation

4.2.4 Results

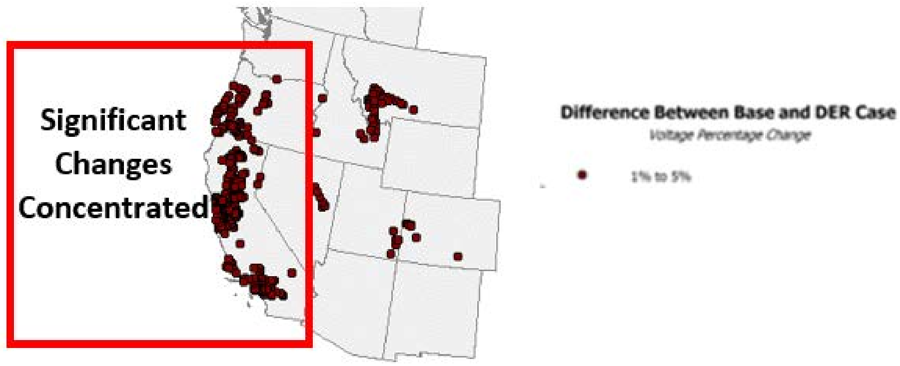
As shown in Figure 10 below, analysis of the WECC system found that in most cases, higher DER penetrations resulted in fewer buses with low voltages and thermal overloads but a greater number of buses with high voltages when compared to the base case. The increased voltages may be helpful on buses that tend to have low voltage issues, but potentially challenging to those with voltages that are already high. Bus voltages can in some cases increase with DER generation because it reduces loads and relieves loading on some transmission facilities.

Figure 10: Change in California Voltage Levels in WECC Cases



Voltages changed throughout WECC, with voltages generally increasing in load pockets closest to the additional DER capacity and varying in direction and magnitude of change elsewhere. Figure 11 shows that the most significant changes are close to the new DER capacity, but due to changes in power flows, there are smaller voltage changes throughout the system. Voltage changes are also influenced by the ability of some transformers to adjust their voltage output based on system conditions.[83]

Figure 11: Significant Voltage Changes Concentrated near DER Resources[84]



The small changes in voltage can ripple through the entire WECC interconnection in response to a change in any part of the system (for example, the loss or addition of generation) that might affect the voltage at a transformer. The resulting changes in voltage highlight the need for additional study to define and articulate: ride-through requirements for deviations in voltage; voltage support required from DER at the point of interconnection or appropriate point on the system; voltage support strategies throughout the interconnections to define steady state and dynamic reactive resources that may be needed; and the need for detailed/accurate/validated modeling of the behavior of DER.

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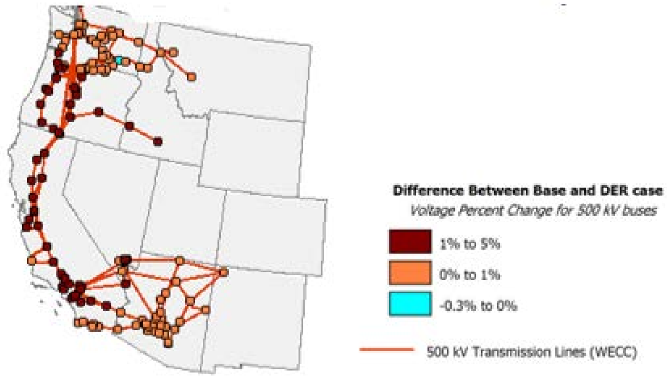
[83] Transformers with tap adjustors can change the number of core windings that determine the primary to secondary voltage relationship, in order to maintain a more consistent voltage output. Typically, the tap position on the primary side will adjust based on the voltage delivered there so that the secondary voltage remains constant.

[84] The analysis also observed effects in Canada, which are not reported here.

Figure 12: Changes on the 500kV System[85]



As shown in Figure 12, the large number of small changes in voltage that occurred in the modeled scenarios (between 0 and five percent) throughout the 500 kV system likely resulted from changes in flow patterns due to variations in load levels and generation re-dispatch to accommodate DERs. Due to the increase in DERs, staff decreased generation imports from the Northwest as well as load in California in the WECC power flow model to mimic the changes in dispatch identified in production cost modeling studies. As a result, in the model voltages on the 500 kV buses increased and smaller voltage shifts on lower voltage lines and buses also occurred. Power flow changes are also influenced by the ability of some transformers to adjust[86] their power output based on system conditions. The results shown in Figure 6 indicate that a closer look at the dispatch of reactive resources is needed to assess whether these changes in reactive support will need to be addressed in the future, e.g., with operating procedures or additional reactive equipment. The results mimic those identified in the production cost study below in Section 4.3, with similar levels of DER penetration. These effects are further shown in Figure 13 below.

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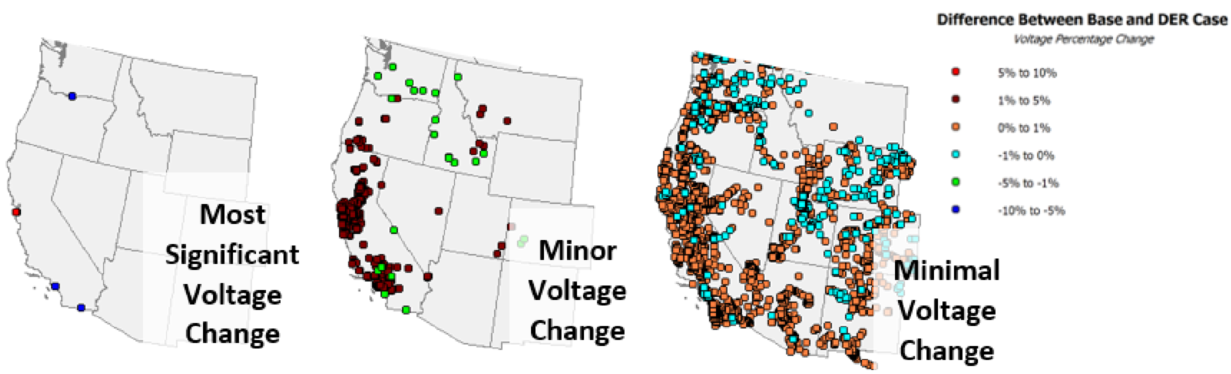
[85] The analysis also observed effects in Canada, which are not reported here.

[86] Transformers with phase shifters are able to change the phase displacement between the input and the output voltage in order to control the active power passing through.

Figure 13: Buses with Large and Small Voltage Changes (Voltage Level Less than 100 kV)[87]



By comparison, analysis of the ERCOT system, with its lower levels of DER penetration, showed no significant variation in reliability impacts for voltages and thermal overloads under different contingencies. There was a slight increase in the number of thermal overloads, likely as a result of the clustering of DER capacity in a smaller number of locations on the system. Appropriate interconnection studies, curtailment procedures, and DER models will be needed to resolve these overloads in order to integrate large amounts of DER reliably into the ERCOT system.

After making changes to the settings as part of the power flow analysis, such as locking tap changers and switched shunt adjustments,[88] the percent change in bus voltages across the DER buses was no greater than 6 percent as increasing DER penetration levels were studied. This is due to the overall low penetration levels of DER capacity in ERCOT. However, while the average bus voltage increased at higher DER penetration levels similarly to the percentage changes found in WECC, increasing the DER penetration levels beyond a factor of three to a total penetration level of 0.05 percent at the identified set of DER buses prevented the case from converging, making further analysis impossible without broadening the electrical location of DERs throughout the model. Further studies taking into account alternative variables, such as changes in siting, may need to be conducted on the system to determine the impact of increasing DER penetration levels beyond a factor of three.

[87] The analysis also observed effects in Canada, which are not reported here.

[88] These are types of settings used in the power flow model to control how different devices respond to changes in voltage.

4.3 Impact of DERs on Dispatch (Production Cost Modeling)

4.3.1 Study Purpose

Staff performed production cost studies for WECC and ERCOT at both current and future DER penetration levels to evaluate the impact of DERs on generation dispatch and transmission constraints. Production cost modeling can simulate the operation of an electric system, within or outside of a market, as a least-cost optimization of unit commitment and dispatch to serve load while accounting for generator, system, and transmission constraints. This allows for the assessment of some high level reliability implications.

This analysis allowed staff to monitor the impact of different levels of DER penetration on generator dispatch, and congestion, to help identify common conditions that may create system stress.

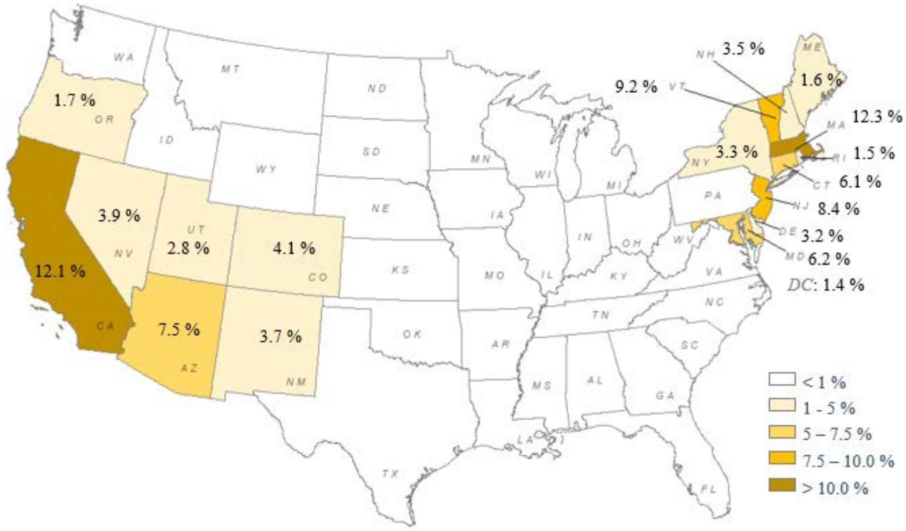
4.3.2 Assumptions and Data

The study modeled both WECC and ERCOT using the most recent nodal PROMOD databases. The models were prepared for a 2017 study year using escalations and recent forecasts included in the model for variables such as prices and load and set up to track emergency energy deployment and key generator characteristics, such as reserve participation and LMPs.[89]

Assumed DER capacity was increased by a total of 4,855 MW in the WECC model and 55 MW in the ERCOT model, as compared to the original models developed by ABB for the PROMOD production cost mode. These changes result in a penetration level of 12.5 percent for WECC in the updated model, rather than the three percent level in the original model.

[89] Staff notes that LMPs in this case are a proxy for the values associated with relieving transmission constraints, even though LMPs are not used throughout the WECC region.

Figure 14: Net Metering as a Percentage of State Peak Load[90]



This penetration level matches the 12.1 percent penetration level for California shown in Figure 14, which was calculated based on EIA data. Staff also evaluated a second future scenario with a 25-percent penetration level. More capacity could be incorporated into the system, but additional supporting infrastructure or other changes, such as new DER locations, may be needed.

For the ERCOT system, where there is a much lower amount of existing DER capacity, the original model included a penetration level of 0.01 percent. The updated model increased this penetration level to 0.02 percent, and two future-case scenarios were developed to evaluate penetration levels of 0.13 percent and one percent.

In both interconnections, the assumed DER capacity was sited and proportionally assigned hourly profiles to match existing installations in the models. Staff simulated randomized forced outages of both traditional and DER generators to assess the impact of different DER penetrations and dispatch capabilities on total system costs, LMPs, congestion, and loss of load expectation.

4.3.3 Methodology

Staff performed a one-year simulation for each scenario. Results were then reviewed on a monthly, and where possible, hourly basis. Results assessed included: generation dispatch changes, increases and decreases in production costs at the unit and regional level, variation in LMPs throughout the year, changes in congestion costs at flow gates over the year, monitoring of excess generation or any instances of unserved load to

[90] Data Source: EIA - Form EIA-826 detailed data files - Net Metering (December 2016) and Velocity Suite – Estimated State Load (Hourly).

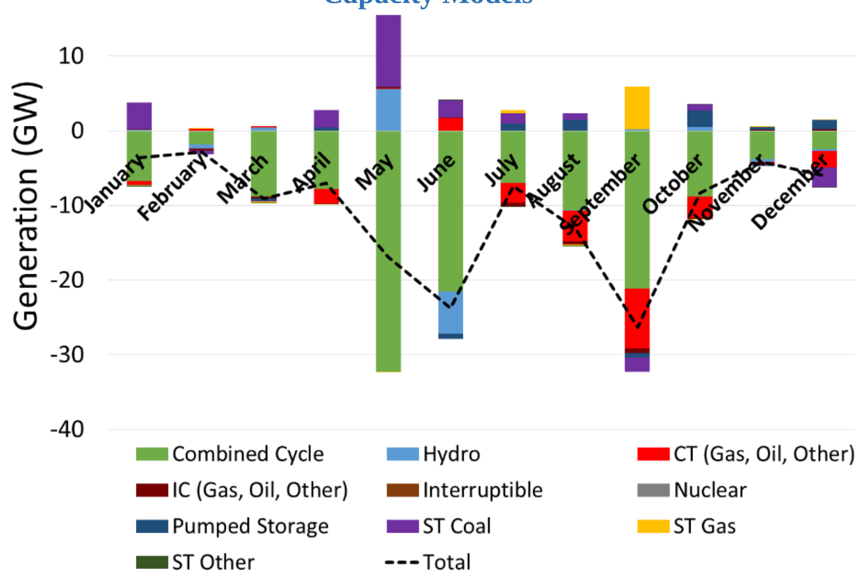
test for deliverability issues, and finally monitoring of reserve participation. Staff also reviewed these results at the nodal and area levels.

4.3.4 Results

In ERCOT, the scenario with 0.01 percent DER penetration level resulted in minimal changes in the dispatch of generation over the modeled year. In WECC, however, changes in LMPs, congestion costs, and therefore generator dispatch occurred frequently throughout the simulated year. The magnitude of these changes was limited due to the level of DER penetration and did not result in any loss of load hours or deployment of emergency energy.

As shown in Figure 15 below, increased DER capacity in WECC offset existing generation in the dispatch throughout the year, with the most significant changes occurring in late spring and fall. Increased DER capacity primarily replaced combined cycle gas generation, which is typically on the margin in WECC. However, it also caused minor increases in the dispatch of some steam coal and natural gas units, and affected the timing of the hydro dispatch. It is important to note that the PROMOD production cost model does not model forecast errors for either load or renewable generation. Therefore, the results do not provide insight into the impact of daily forecast uncertainty caused by variation in output from DERs such as variations in daily weather.

Figure 15: Monthly Generation Results for WECC Comparing Base Case and Additional DER Capacity Models



While the maximum and minimum LMPs changed slightly in the spring, the average LMP did not show a significant change overall, consistent with the other results and suggesting that the changes, while numerous, remain limited in magnitude at this time. These changes were consistent with the relative increases and decreases in the dispatch of different generators.

In addition to the frequent dispatch variations, the effects were widespread throughout the WECC system even though the DER installations were largely located within California. The effects also changed depending on system conditions within the model for a given hour. This was particularly noticeable in generation dispatch, line flows, and congestion. Units were offset by DERs throughout WECC, and these changes caused both increases and decreases in congestion during the year.

Overall, transmission lines outside of California saw a decrease in congestion while those within California, especially near high concentrations of DERs, saw both increases and decreases. The increases in congestion could be caused by increased imports to areas with diminished use of some combined cycle units. However, given that the changes in congestion and dispatch were spread throughout the system and occurred at a wide variety of load levels and hours, additional sensitivities may need to be assessed in other studies to examine specific system conditions.[91] Because the model assumes the existing transmission system, effective planning for DER integration using accurate models could address any increases in congestion, though further study would be needed to confirm this conjecture.

4.4 Ancillary Services Provided by Energy Storage (Distribution Modeling)

4.4.1 Study Purpose

The energy storage study evaluates the impact of ancillary services provided by energy storage devices, such as regulation services, on markets, and transmission and distribution systems. Energy storage may be able to provide grid level services such as regulation, reserves and voltage support. However, the provision of these services from energy storage devices can result in sudden variations in output, affecting voltage and power quality on the distribution system, and potentially on the transmission system as well.

This study assesses whether a storage resource needs to be modeled separately from other DER installations due to the possibility of different impacts from the operation of a storage resource. The study also assesses what specific operational characteristics of the storage resource may be necessary in specific operational situations. If the storage resource has the potential to provide grid level services at a location valuable to the bulk energy system, but the distribution infrastructure is unable to

[91] For example, power flow studies typically focus on particular seasonal conditions such as peak summer conditions or a winter dispatch.

accommodate the resource reliably, this may have market implications at the bulk energy system level if the operator is forced to procure that service elsewhere. Accurate studies during the interconnection process could help to identify and mitigate such concerns.

4.4.2 Assumptions and Data

This study continues to use the Feeder J1 model, as previously described. Staff analyzed two applications of energy storage: (1) using energy storage for frequency regulation services and (2) using energy storage for load leveling.

In each case, staff added one energy storage device to the model. Adding a single energy storage system instead of several distributed units does not significantly change the results from the transmission operator standpoint because transmission system operators only see the impact of aggregated energy storage, such as a change in substation power flows and voltages. The difference in the results is mostly due to different patterns of distribution system losses.

In order to compare the impact of similar size aggregated DERs with different applications, staff selected the energy storage size (1.7 MW and energy of 6.8 MWh) based on the installed capacity of the existing solar PVs. The location of the largest solar PV units was selected as the energy storage system location. To model the operation (charging and discharging intervals) of the energy storage system for the regulation service, staff used one day of PJM RegD[92] (a fast regulation signal that is sent every two seconds to the devices participating in regulation service).

For the load leveling application, staff developed a 24-hour charging/discharging energy storage profile such that the energy storage system charges during the night and discharges during the day.[93] Since the efficiency of an energy storage system is not 100 percent, the amount of energy charged is larger than energy discharged.

4.4.3 Methodology

Staff added one energy storage system to the detailed feeder model. For the frequency regulation application, staff performed a time series analysis over a 24-hour

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[92] *See Ancillary Services: Market-Based Regulation - RTO Regulation Signal Data*, PJM, *available at* http://www.pjm.com/markets-and-operations/ancillary-services.aspx.

[93] *See Energy Storage Projects in AEP*, Ali Nourai, page 7, (October 2009), *available at* *https://energy.gov/sites/prod/files/ESS%202009%20Peer%20Review%20-%20Energy%20Storage%20Projects%20in%20AEP%20-%20Ali%20Nourai%2C%20AEP.pdf.*

period with a two-second time step in order to simulate the frequency of the regulation signal. For the load leveling application, staff ran the time series analysis over a 24-hour period with a 15-minute time step. To focus only on the impact of energy storage, the model disconnected existing solar PV units from the system. Staff assessed changes in the real and reactive power in the substation and changes in voltage on the high voltage side of the substation transformer.

4.4.4 Results

When an energy storage system is used to provide frequency regulation service, peak demand on the affected feeder may increase if the charging of the energy storage system is coincident with the occurrence of the feeder peak load. If this happens, the increase in the peak load on that affected feeder may be larger than the installed storage capacity (in MW) because of the increase in the feeder power losses. Since the regulation signal is volatile with very frequent changes, the probability that this may happen is high. Energy storage is a very specific technology because it can consume and generate power, meaning that it may increase or decrease the feeder loading.

Figure 16: Substation Real Power

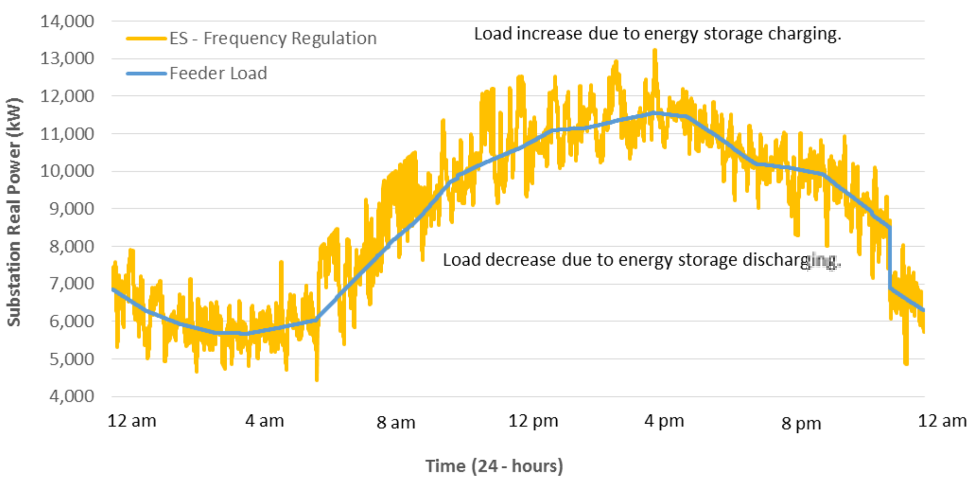


Figure 16 illustrates substation real power as seen by the transmission operator during a 24-hour period. The feeder peak demand increased from 11,558 kW to 13,241 kW. The substation load change ranged from a 30 percent decrease to a 27 percent increase compared to the substation load without the storage. Hence, additional load on the feeder due to the operation of the storage system may reduce the overall available supply from resources on the feeder. If a DER owner is planning to participate in the ancillary services market, the distribution system operator may want to be informed because the distribution feeder elements are sized based on the estimated peak demand, and any additional loading can cause an overloading of the lines. In addition to changes in the substation/feeder load, using an energy storage system located on a distribution system for regulation service will cause sudden changes in the voltage and potential issues with power quality. Some of these effects may also impact the transmission system.

Figure 17: Substation Voltages - Phase A

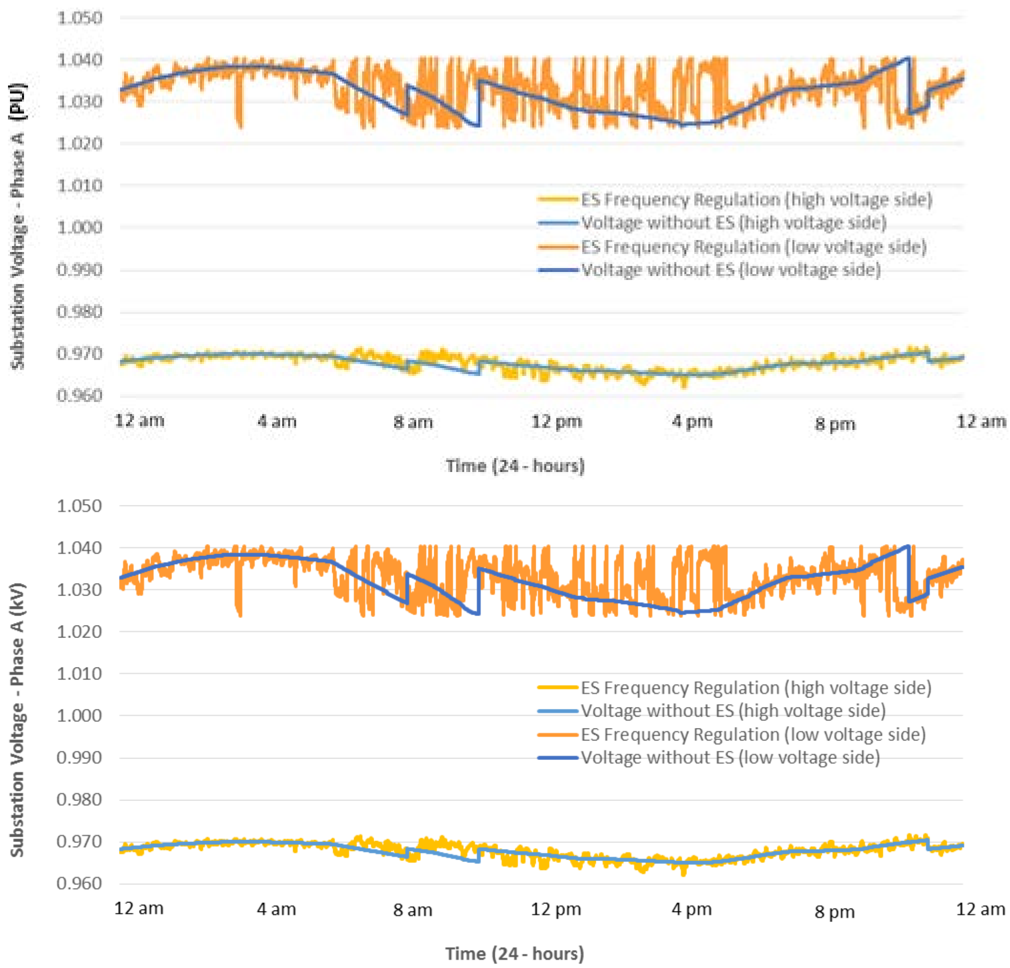


Figure 17 illustrates the substation voltage (light blue and yellow lines), the feeder voltage (dark blue and orange lines), and the frequent changes caused by the energy storage system. In the given example, the change on the high voltage side of the substation transformer ranges from a 0.4 percent decrease to a 0.3 percent increase compared to the voltage without energy storage, which ranges from a 1.6 percent decrease to a 1.5 percent decrease on the low voltage side. Depending on the energy storage system power capacity (in MW) participating in the market, these changes can be higher or lower.

In the case of load leveling, the changes introduced are much smoother. Figure 18 illustrates substation real power over 24 hours. Since the energy storage system is charging during the night, off-peak load increases, and since the energy storage system is discharging during the peak time, the peak load is reduced. The energy storage system, charges/discharges with constant power. This profile can be changed based on the feeder/substation load profile. Voltage changes (Figure 19) are also much smoother because there is no sudden change in the load.

Figure 18: Substation Real Power – Load Leveling

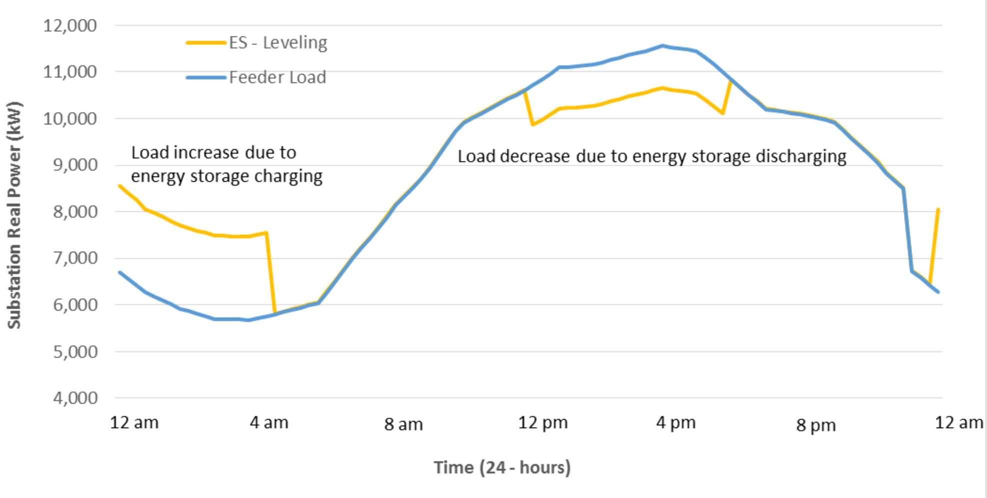
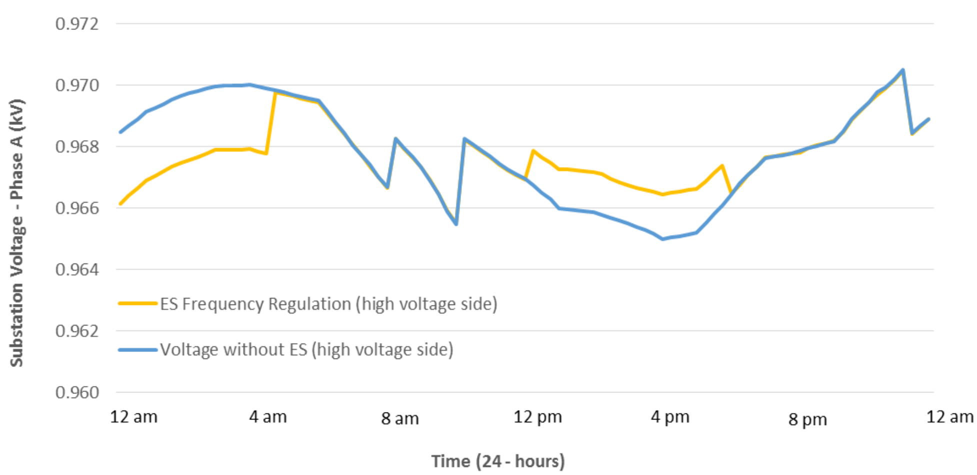


Figure 19: Substation Voltage – Phase A – Load Leveling



As demonstrated above, when DER resources provide services such as frequency regulation, and if the distribution infrastructure is unable to accommodate this type of operation, there could be potential market and reliability impacts. This potential impact to reliable operation of the distribution system infrastructure could affect distribution resources participating in wholesale markets by providing energy, capacity or ancillary services if these services cannot be provided with a reasonable assurance of expected performance. The distribution system operator may need to be allowed to assess the impact on its system of the participation of energy storage systems or any other DERs in wholesale markets, and may need to provide feedback on upgrades to the infrastructure necessary to support this wholesale participation. The distribution provider may also be able to provide recommendations on the resource size (in MW) during the installation process so that the reliability of the distribution system remains intact.

4.5 Assessing the Benefit of Smart Inverters to Reliability (Distribution Modeling)

This study assesses whether smart inverters on the distribution system provide greater benefits than regular inverters used in some DER installations. Smart inverters have controls that provide additional capabilities, such as allowing DERs to provide voltage and frequency control. This study examines the potential impacts of smart inverters providing volt-VAR control; it does not include frequency control.

4.5.1 Study Purpose

The smart inverter study assesses whether smart inverters on the distribution system provide significant benefits compared to regular rooftop solar inverters. Smart inverters have the potential not only to provide real power, but also to assist in providing reactive power and voltage regulation, which increases the number of PVs that can be installed reliably on a distribution feeder. Therefore, smart inverters may be able to address some of the operational issues associated with increased DER penetration. The study assesses their impact on reliability using line loading, voltages, and voltage control equipment. It focuses primarily on the distribution system, and also explores the potential for a transfer of benefits to the transmission system.

4.5.2 Assumptions and Data

Staff used Feeder J1 for the simulation and analysis. All existing solar PVs were equipped with smart inverters that could provide volt-VAR control. The volt-VAR control function allows each individual solar PV system to provide a unique VAR response according to the voltage at the point of connection (0.416 kV and 0.24 kV). All the solar PVs were set to use the same volt-VAR curve such that the inverter provided the maximum possible reactive power if the voltages were smaller or larger than 0.95 and 1.05, respectively, and slightly less if the voltage was within that range. Staff conducted a time series analysis on a 30-minute interval.

4.5.3 Methodology

To examine the impact of smart inverters, staff modeled two cases with rooftop solar installations: (1) one with regular inverters and (2) one with smart inverters. The impact on reliability was assessed by monitoring variability in line loading, voltages, and voltage control equipment operation. While this study focused primarily on the distribution system, it also reviewed the data to determine whether benefits can be transferred to the transmission system by analyzing voltages and real and reactive power at the transmission-distribution interconnection point.

4.5.4 Results

EPRI previously showed that using smart inverters can increase the amount of solar PVs that can be reliably installed on the feeder (i.e., increase the hosting capacity of the feeder)[94] and can potentially lead to higher penetration levels of PV DERs in the future. Adding smart inverters with volt-VAR control capability to the PV installations improved the reactive power and voltage at the local and substation level in this analysis. Based on the volt-VAR curve, the maximum voltage at the PV interconnection point was reduced from 1.032 down to about 1.025 pu (as shown in Figure 20) by absorption of VARs from the grid (as shown in Figure 21) following the volt-VAR curve and control algorithm. Voltage levels at the substation also dropped but by a much smaller amount (about 0.2 percent).

[94] *See Distributed PV Monitoring and Feeder Analysis – Hosting Capacity Method*, EPRI, *available at* http://dpv.epri.com/hosting_capacity_method.html.

Figure 20: Voltage at PV location and at Substation – Phase A

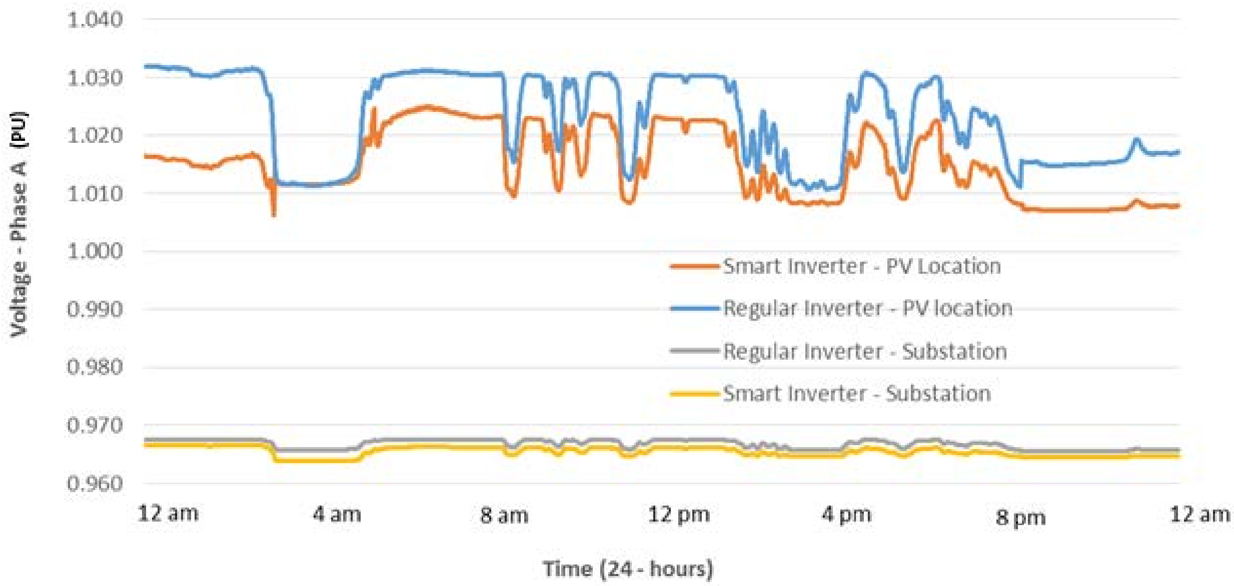
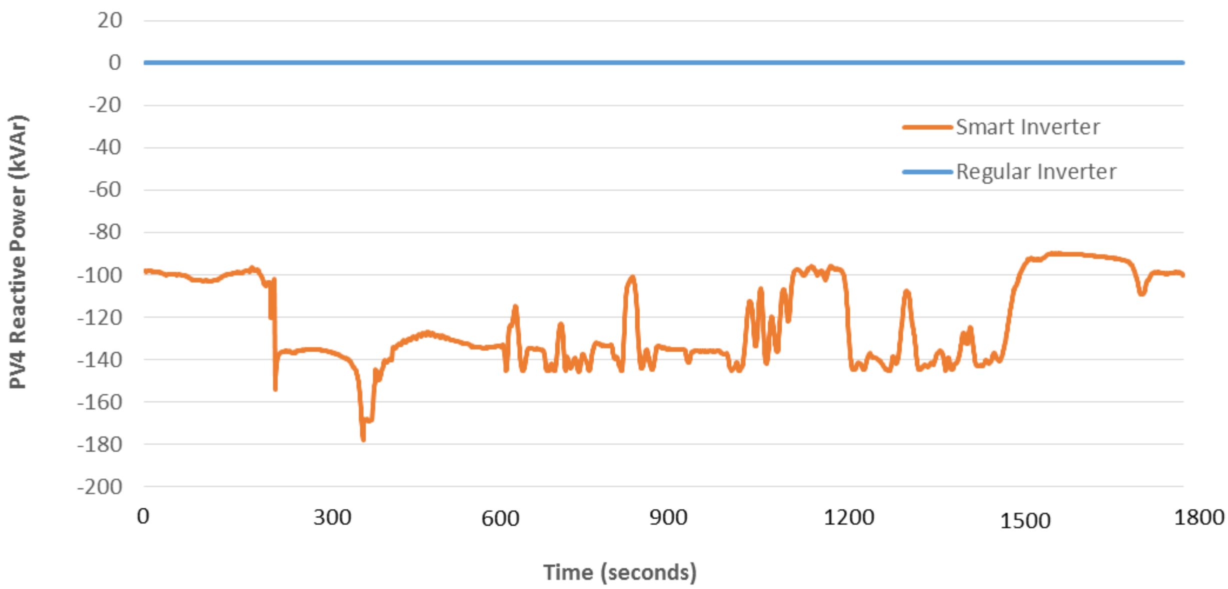


Figure 21: PV Generation of Reactive Power with and without Smart Inverter



This case illustrates a situation in which the local and substation voltage controls have opposite objectives. If the local voltage were 1.03 pu, the objective would be to bring this voltage closer to 1.0 pu or below so that additional PVs could be installed on the feeder. In contrast, if the substation voltage level were about 0.965 pu, the objective would be to increase it. However, by decreasing the local voltage, the substation voltage decreases as well.

If solar PV with smart inverters were used to support voltage at the substation level, this control would need to be coordinated between the market operator, the transmission system operator and the distribution system operator. Similarly, as in the energy storage system analysis, smart inverters may be used to support the operation of the transmission power system. However, use of smart inverters to support the operation of the transmission system without consideration of distribution system requirements would be unwise because the operation of PVs or any other DER technology with a smart inverter could impact distribution system reliability or power quality.

5. Conclusions

As demonstrated by this technical assessment, given the growing adoption of DERs in the United States, there are a number of key bulk power system reliability topics to explore, including:

- The impact of the current common industry modeling practice of netting DERs with load, which may mask the effects of DER operation;
- DER capabilities for voltage and frequency ride through during contingencies;
- The potential for improved voltages due to the unloading of the bulk power system associated with the location of DERs at or near customer loads;
- Potential effects upon system-wide transmission line flows and generation dispatch due to changing load patterns; \
- The sensitivity of voltage or power needs to different types of DER applications (i.e., providing energy, capacity, or ancillary services); and
- The need to develop planning processes that capture more detailed models of DERs and allow for modeling of the interface between the transmission and distribution systems to enable information exchange and more accurate calculations of the DER impact on the bulk power system.
- The advantages and disadvantages of allowing DERs to participate directly in the organized wholesale electric markets.

Further discussion also is needed on potential means to improve modeling practices with respect to DERs, including options for improving available data and the incorporation of detailed DER models into existing industry models. In addition, further dialogue is needed to identify other areas for additional analysis, such as additional study types and sensitivities which could provide further insight into the potential local and system-wide impacts of future growth in DER capacity. Efforts such as these could help track and assess the impact of changing conditions on the bulk power system to identify emerging trends and address potential future reliability challenges.