Ensuring Bulk Power System Reliability with Increasing Penetration of Distributed Energy Resources

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Distributed energy resources (DERs) are unlocking new opportunities, and the grid is undergoing a dramatic transformation with unprecedented change. Yet as DERs continue to grow in North America and around the world, it is apparent that the aggregate amount of DERs is having an impact on bulk power system (BPS) planning and operation. The effects of DER can be attributed to the uncertainty, variability, and lack of visibility of these resources at the BPS level. From a BPS perspective, the key grid planning impacts generally include:

- Transmission-distribution coordination and data exchange
- Visibility, dispatchability, and controllability
- DER ride-through capability
- Impacts to load shedding programs
- Aggregate DER modeling and changing reliability study approaches

The industry is learning from prior experience, and taking actions in anticipation of future DER penetration levels. Waiting for the effect of DER to manifest before developing solutions may be extremely costly and even risk BPS reliability. However, proactive development and coordination of requirements can ensure reliable operation of the BPS moving forward. The electric industry needs to address these challenges with innovative solutions earlier rather than later.

DER Impacts to Hawai'i Grid Operation

The islands of Hawai'i, Oahu, and Maui have among the highest penetration levels of DERs in the United States, in terms of installed capacity relative to system size. Under favorable policies and the right economic circumstances, rapid deployment of DERs can occur in an extremely short period of time. In only 6 years, average distributed solar PV (D-PV) contribution to meeting gross peak daytime demand (net peak plus D-PV) increased from 12% to 37% on Hawai'i Island (see Figure 1). The instantaneous D-PV penetration can exceed 71% of daytime demand today, and provides around 11% of annual energy. With increasing DER penetration levels comes rapidly increasing levels of variability and uncertainty. Hawai'i is now seeing more D-PV systems with battery energy storage systems, and is anticipating the effect these combined systems will have on the islanded grid. Needless to say, the long-term planning studies performed ten years ago never anticipated such a major change.

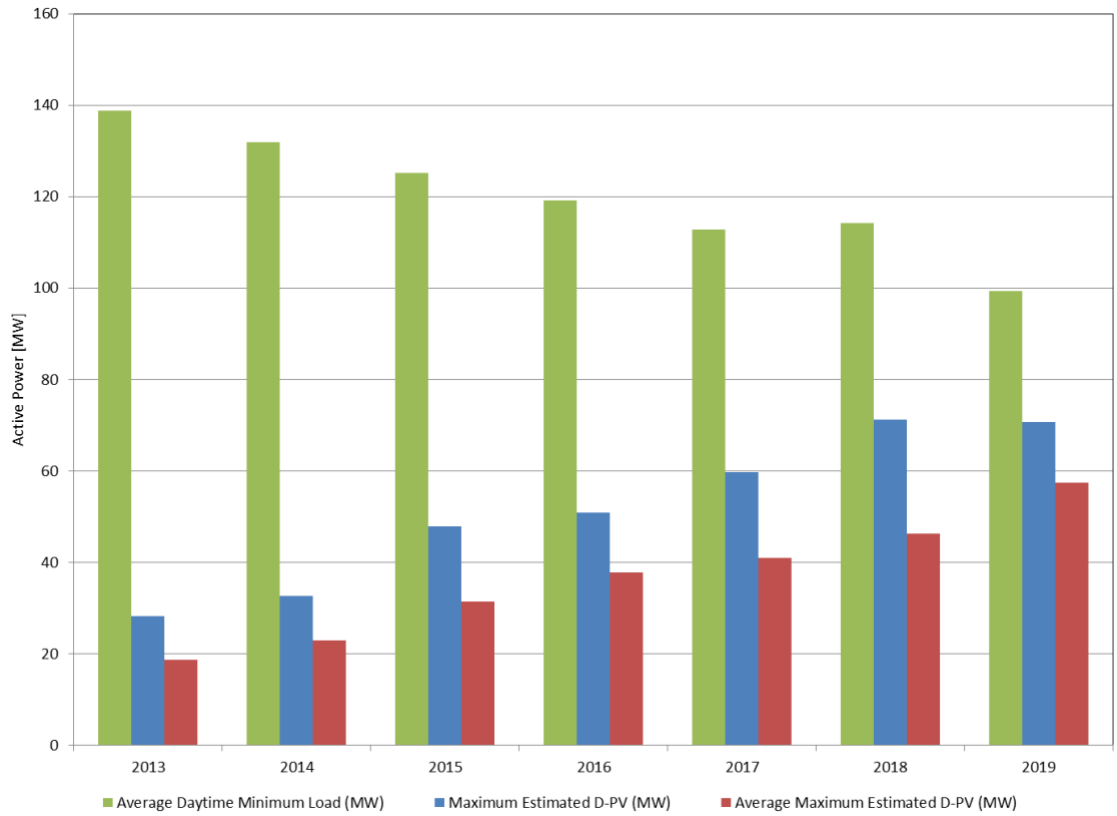

Figure 1. Rapid Deployment of Distributed Solar PV for Hawai'i Island

Performance requirements needed for high DER penetration levels on island grids were not initially supported by the requirements in IEEE Std. 1547-2003 or IEEE Std. 1547a-2014. Hawai'i's DER interconnection standard (Rule 14H) eventually deviated from IEEE Std. 1547 to support continued integration of DERs. However, the new IEEE Std. 1547-2018 includes requirements that are beyond Rule 14H, and are currently under consideration for inclusion in a revised Hawai'i standard. Based on Hawai'i's experience, robust interconnection requirements need to be in place well in advance of high penetration levels to support BPS reliability. It is extremely challenging and expensive to retroactively enhance equipment installed with minimal performance requirements and capabilities to meet changing BPS needs.

For the Hawai'ian grid, the following aspects of DER integration are top priority:

- Balancing solar PV variability with flexible energy resources capable of fast ramping and cycling, and ensuring regulation resources do not fall below minimum allowable dispatch levels.
- Managing frequency stability with sufficient frequency responsive reserves, and ensuring newly installed DERs have active power-frequency controls enabled to assist primary frequency response.
- Improving DER estimation techniques since nearly all DERs are behind-the-meter (BTM) with no visibility or control by the system operator. D-PV output is estimated using field irradiance measurements provided to the operator via SCADA.

- Ensuring effective system restoration with variable DER auto-reconnection, and possibly adjusting reconnection criteria (although this will not address situations of high solar PV periods where DER control is necessary).
- Studying adverse impacts of DER tripping during BPS faults, and working with existing DER installations to modify trip settings and improve ride-through capability, where possible.

In addition to these issues, there are two additional issues related to frequency stability worth highlighting. These include the use of fast-responding battery energy storage to mitigate legacy DER tripping and the development of an adaptive underfrequency load shedding (UFLS) program to ensure system security during severe resource loss events.

Storage to Mitigate Loss of DER

Some legacy DERs do not have robust ride-through capability, and are therefore subject to aggregate loss during over/under frequency and voltage excursions. The behavior of D-PV is determined by the standard requirements at the time of interconnection, with different possible aggregate loss during these frequency and voltage excursions. The largest contingency concern for Hawai'i Island is the loss of legacy DER tripping at 60.5 Hz, as a large majority of existing D-PV is subject to trip at or near this frequency. The second largest vulnerability is the loss of DER during large voltage excursions. On an island system like Hawai'i, 60.5 Hz is possible after delayed fault clearing (due to transient swings following fault clearing) and major loss of load events, which can occur with transmission outages (both N-1 and N-1-1). The potential aggregate loss of D-PV during high solar production periods is about double the largest single generator contingency, resulting in severe underfrequency conditions and possible risk of system failure. The loss of D-PV also exacerbates other loss of generation events with some additional D-PV loss during the underfrequency situation. To address this concern, a battery energy storage study was conducted, analyzing the effect of legacy DER tripping for low voltage during transmission faults, low frequency following generating unit trips, and high frequency following a transmission line fault. The study found that retrofitting legacy DERs to full ride-through capability was the most effective solution, yet also too costly and impractical. The study also found that:

- Storage can replace DER energy lost during transient voltage and frequency conditions, preventing excessive underfrequency protection and reducing risk of system failure for disturbances during high solar PV production.
- The size of storage necessary to mitigate reliability issues depends on the amount of legacy DERs installed.
- Increased amounts of spinning reserves could reduce the size of storage necessary but could not eliminate the need. Increasing reserves also exacerbates excess energy concerns. D-PV protection systems are not consistently implemented, and performing sensitivity studies around the uncertainty of this DER behavior is critical.

Based on the studies, a battery energy storage system (BESS) of 18 MW capacity with 30-minute duration was able to arrest frequency excursions and provide sufficient time to bring standby generation on-line. Increasing the duration to one hour enables the BESS to respond to over-frequency conditions. Studies

showed that two BESS geographically and electrically separated from one another provided the best performance and grid resilience.

Adaptive Underfrequency Load Shedding

The reliable operation of the Hawai'ian island systems heavily relies on underfrequency load shedding (UFLS) that trips distribution circuits at pre-established frequency thresholds. However, as the penetration of DERs rapidly increases, variability in net loading on any given feeder poses significant challenges to conventional UFLS design, which means static UFLS arming is no longer effective. An adaptive UFLS program has been implemented to address this variability. Figure 2 shows a dashboard of the adaptive UFLS program, including six instantaneous stages of UFLS arming between 59.1 Hz and 57.6 Hz, and two kicker stages that operate with time delays at 59.3 Hz and 59.5 Hz. The target MW value is calculated based on system net loading at the time, and available distribution circuits are automatically armed every 15 minutes to achieve the target net load level. An arming tolerance percentage and value is depicted, as well as the difference between the available MW arming and the target MW value. Stages 1–2 sum to 15% and Stages 1–4 sum to 40% of system net load based on the maximum allowable load shedding for N-1 and N-1-1 unit trips, respectively. Each stage operates with an 8-cycle relay time plus breaker operation time. A rate-of-change-of-frequency (ROCOF) load shedding element was also included in Stages 1 and 2, with a 0.5 Hz/sec set point and 9-cycle relay time plus breaker operation time.

Over 40 substations were modified, including relay and communications upgrades, and 78% of customer circuits (up to 70% of peak load) are participating. The adaptive UFLS program has performed well during N-1 and N-1-1 events at various times of day, and is proving to be an effective reliability improvement. Figure 3 shows an example of a severe N-1-1 generator loss disturbance where Stages 1-4 operated successfully to arrest frequency and mitigate a potential large scale outage.

UFLS STAGE DATA

Change to MONITOR

MODE: ACTIVE

Reset and Calculate

System Load:	151.629
Total Target:	120.559
Total Available:	127.133

Stage	Frequency	Percent	Target MW	Avail MW	Tol %	Tolerance	Delta MW
STAGE1	59.100	5.00	7.53492	7.68113	5.000	0.377	-0.146
STAGE2	58.800	10.00	15.06984	14.93933	5.000	0.753	0.131
STAGE3	58.500	10.00	15.06984	15.45847	5.000	0.753	-0.389
STAGE4	58.200	15.00	22.60476	22.63691	8.000	1.808	-0.032
STAGE5	57.900	10.00	15.06984	14.63551	8.000	1.206	0.434
STAGE6	57.600	20.00	30.13968	30.76797	25.000	7.535	-0.628
KICKER1	59.300	5.00	7.53492	7.90598	5.000	0.377	-0.371
KICKER2	59.500	5.00	7.53492	7.72132	5.000	0.377	-0.186

Figure 2. Adaptive UFLS Arming Dashboard

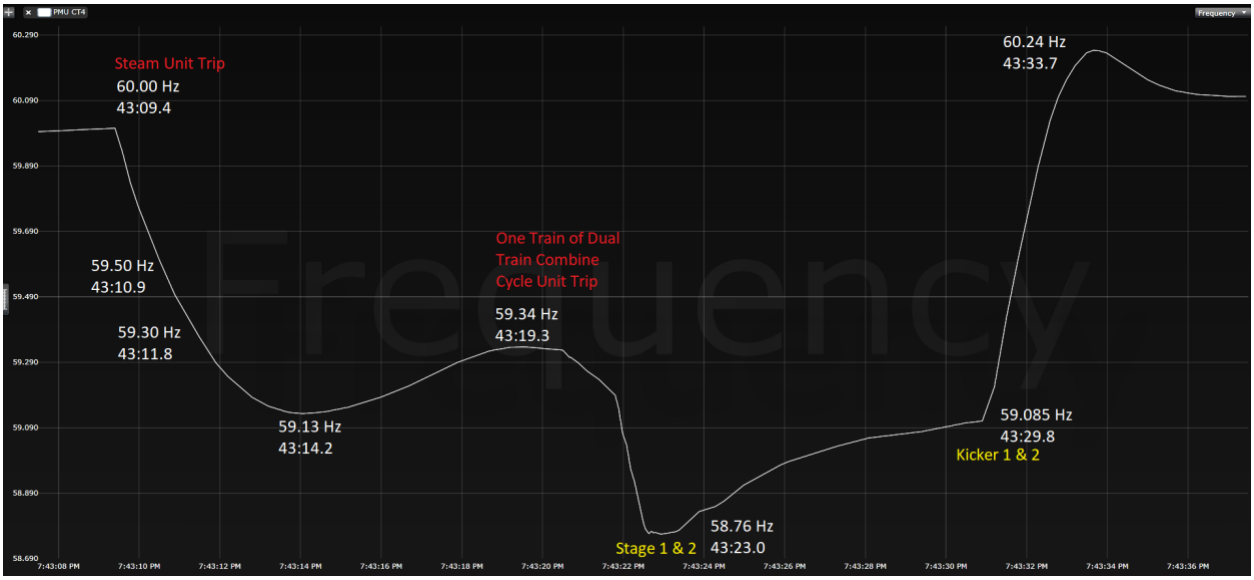

Figure 3. Operation of Adaptive UFLS for Multiple Contingency Event

CAISO Experience amidst Growing Rooftop Solar PV Deployment

California has a state mandate that 33% of annual energy come from renewable energy sources by 2020 with a target of 60% by 2030 established by SB100, which came into effect in September 2018. However, on some days, instantaneous output from the renewable sources already exceeds 50% of total generation output. A large portion of that penetration consists of BTM D-PV, and the rapid deployment of D-PV is driving changes in the CAISO transmission planning, forecasting, and grid operations.

Figure 4 shows an example of the effect that D-PV is having on the Pacific Gas & Electric (PG&E) net load profile, driving the need for different study times and net load levels from the CAISO's 2018-2019 transmission planning process. The blue curves show the net load after subtraction of the D-PV output called managed load. The figure clearly shows a shift in the peak net load time, which in many parts of the state is shifted outside the times when solar PV is available. D-PV penetration levels are also causing a drastic change in minimum net load levels, which need to be carefully studied. Sensitivity analysis is also needed to operate and plan for ramping periods. All these issues are compounded by load modifiers such as energy efficiency, demand response, time of use rates, and electric vehicle charging.

The uncertainty in net load forecasting, including D-PV, is a concern for BPS reliability studies. The CAISO coordinates its load forecasts with and relies upon long-term forecasts produced by the California Energy Commission (CEC). The CEC energy demand forecast includes an hourly forecast of the consumption load and load modifiers to develop the managed forecast to which the transmission system is planned.

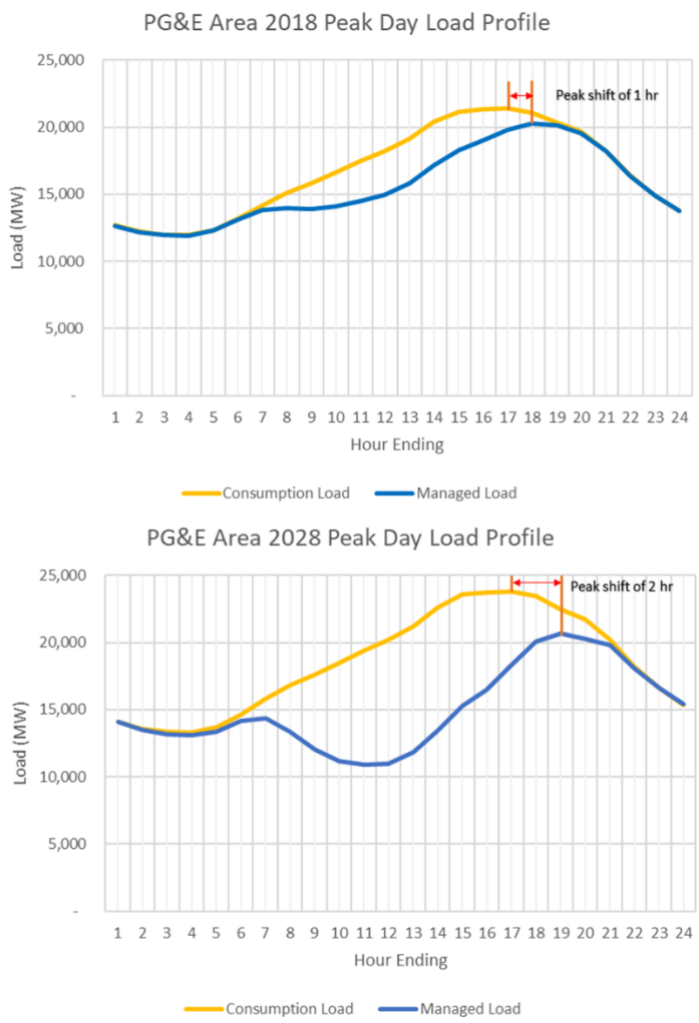

Figure 4. PG&E Net Load Impacts of DERs

Since D-PV is shifting net peak load periods, selection of critical study conditions also needs to change. Planning standards require assessment of peak and off-peak conditions; however, with large amounts of DERs, critical system conditions may not occur at either of these periods. This requires even greater amounts of sensitivity studies of varying dispatch and load scenarios, including peak gross load, peak net load (at the transmission-distribution interface), and minimum net load conditions (e.g., spring weekend during off-peak load conditions). Figure 5 shows how DERs were incorporated into the CAISO study scenarios of the 2018-2019 transmission planning process. In these tables, AAEE is the Additional Achievable Energy Efficiency. In addition to these sensitivities, consideration for BPS-connected generation dispatch and assumptions for neighboring planning areas are critical as they impact local or wide-area reliability issues. This leads to the need for wider coordination across planning coordinators.

Baseline scenarios and DER contributions

Scenario	Day/Time			BTM-PV			AAEE			Driver
	2020	2023	2028	2020	2023	2028	2020	2023	2028	
Summer Peak	8/10 HE 18	8/14 HE 19	8/14 HE 19	18%	3%	3%	90%	81%	76%	Hour of maximum managed load
Spring Off Peak	4/5 HE 12	4/6 HE 13	4/16 HE 13	79%	84%	85%	58%	56%	49%	Hour of minimum managed load
Winter Off Peak			2/13 HE 4			0%			28%	Hour of minimum consumption
Winter Peak	10/15 HE 19	10/3 HE 18	10/3 HE 19	0%	1%	0%	77%	76%	72%	Hour of maximum managed load in winter

Sensitivity scenarios and DER contributions

Scenario	Starting Baseline Case	BTM-PV		AAEE	
		Baseline	Sensitivity	Baseline	Sensitivity
Summer Peak with high CEC forecasted load	2023 Summer Peak	3%	3%	81%	0%
Off Peak with heavy renewable output and minimum gas generation commitment	2023 Off Peak	84%	99%	56%	56%
Summer Peak with heavy renewable output and minimum gas generation commitment	2020 Summer Peak	18%	99%	81%	81%

Figure 5. Incorporating DERs into Study Scenario Development in the CAISO Transmission Plan

With the increasing penetration of DERs, the CAISO has incorporated the forecasted DERs explicitly in power flow and stability studies for the last three planning cycles to account for their unique operational characteristics that are different from the end-use load behavior. This is especially important for stability studies, since study results with DERs netted with load versus modeled explicitly are significantly different. With a large penetration of DERs in California, study results would be inaccurate if DERs were only netted with load, and may lead to erroneous conclusions. Retail-scale BTM DERs are modeled in the power flow and dynamic stability studies as a part of a composite load model, and utility-scale DERs are modeled as aggregated generators on the transmission buses. Figure 6 illustrates these impacts on transient voltage response following a simulated BPS fault event. The results are different because modeling the DER characteristics explicitly (including DER tripping of legacy equipment) allows the simulation to differentiate between DERs' response and gross load response. This is critical as penetration levels of DERs increase, yet have a study impact in all cases even at low penetration levels.

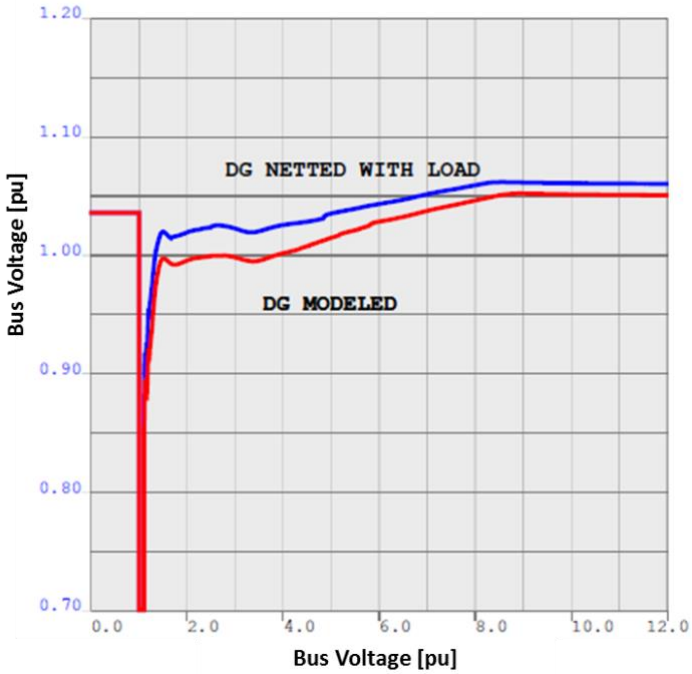

Figure 6. 230 kV Bus Voltage Close to Three-Phase Fault – With and Without DER Modeled

CAISO currently uses parameter values for the DER models based on the Western Electricity Coordinating Council (WECC) and North American Electric Reliability Corporation (NERC) guidelines, and performs multiple sensitivity studies to determine the impact that variations in these DER parameters have on BPS performance. Parameters that are the most sensitive are DER undervoltage trip settings, the fraction of DERs that recover upon voltage recovery, and whether DERs provide voltage regulation (and characteristics of this regulation). Figure 7 illustrates net load and DER response on a 230 kV bus, and BPS voltage for a three-phase fault close to the BPS bus. The plots show the DERs netted with load as well as two cases of DERs modeled explicitly with different voltage trip settings. One set uses the IEEE Std. 1547-IEEE Std. 1547-2018 settings and the other uses California Rule 21 settings. These DER are on the different feeders and aggregated to the 230 kV bus. System performance differences are dominated by the different response of gross load and DERs. Although for one bus the difference is not that significant, the aggregate effect across a large portion of the system has a significant impact on study results.

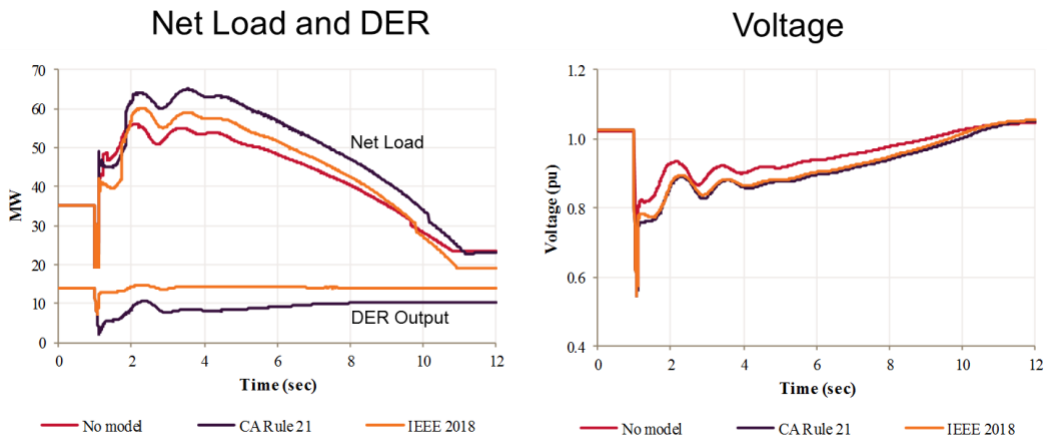

Figure 7. Sensitivities of Net Load, DER Output, and BPS Bus Voltage to DER Modeling Settings

New York ISO's Management of DER

New York is on the cusp of transformation, expecting a significant penetration of DERs. New York's Reforming the Energy Vision and Clean Energy Standard initiatives, combined with efforts to expand transfer capability on the BPS, offer a comprehensive energy strategy to achieve the NY State goals of 50% of electricity delivered by renewable energy sources by 2030. New York has also established policy to achieve 1,500 MW of energy storage by 2025 and 3,000 MW by 2030.

The New York Independent System Operator (NYISO) expects DERs to play a significant role in achieving New York State's goals. Due to the expected growth of DERs in the near future, NYISO is developing market-based mechanisms to integrate DERs into the wholesale electricity markets it administers. The NYISO's DER market design is expected to be implemented in 2021. The proposed design recognizes the unique characteristics of DERs. For example, the market design acknowledges that individual DERs may be small in size yet aggregate to a large capacity; can be fast-acting yet with limited capability to deliver energy for long durations. The proposed market design considers DERs that may have capability to provide services to wholesale markets, retail markets, and end-use customers (see Figure 8).

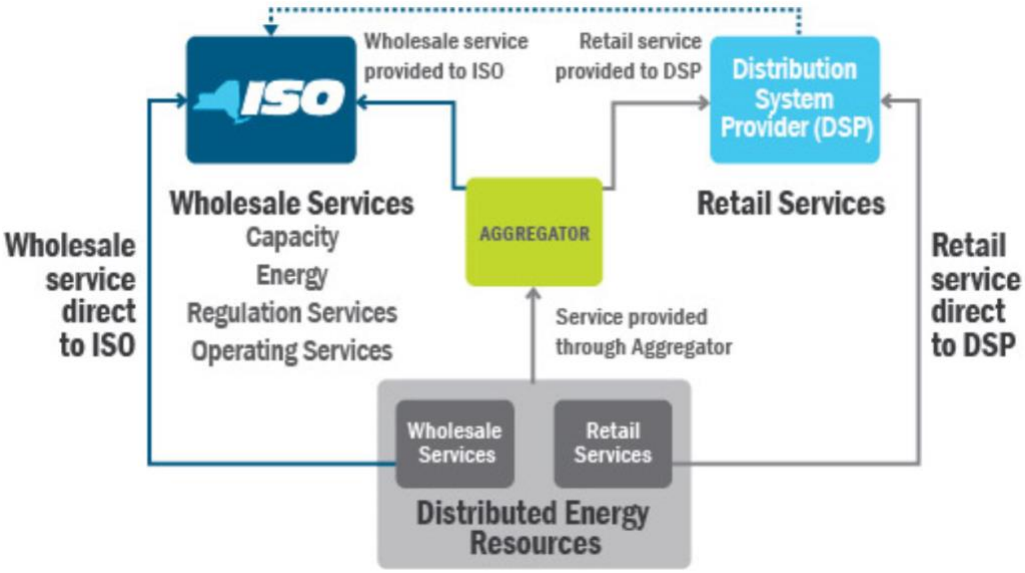

Figure 8. Concept of NYISO Wholesale and Retail Market Designs Incorporating DERs

The NYISO's DER integration proposal focuses on enhancing operational coordination among BPS and distribution system operators, and on developing market rules that allow DERs to aggregate to provide wholesale market services. Individual DERs that do not have sufficient capability to participate in the wholesale markets can aggregate with other DERs as a larger virtual resource. NYISO is lowering its minimum participation threshold from 1 MW to 100 kW for DERs. Aggregators can enroll many DERs of different technologies at different physical locations (so long as they are behind the same BPS transmission node), and choose to use DERs in the aggregation, or a subset of those DERs, to respond to NYISO market dispatch instructions. The DER aggregators can submit offers to provide energy, regulation, operating reserves, and capacity. To determine the least cost resource dispatch, the NYISO will evaluate these offers along with offers from other BPS supply resources in its multi-interval security constrained economic dispatch to co-optimize energy, regulation, and operating reserves. Dispatch instructions from NYISO will be directed to the entire aggregation. DER aggregators will be responsible for:

- Receiving the aggregation-level dispatch instructions from the NYISO in real-time
- Identifying the dispatch of individual DERs within the aggregation
- Transmitting dispatch instructions to individual DERs
- Collecting the response from individual DERs
- Consolidating the response to an aggregation level
- Communicating the aggregation-level response back to the NYISO with real-time telemetry

Performance will be measured for the DER aggregation rather than individual DERs. As NYISO encounters transmission constraints, NYISO market dispatch signals can effectively dispatch the aggregation of DERs to address reliability issues at lowest cost. This approach allows aggregators flexibility to meet NYISO dispatch using DERs within the aggregation based on availability, costs, and other factors.

Enhanced operational coordination among the wholesale system operator, distribution system platform (DSP) operator, aggregator, and individual DERs is necessary to ensure reliability of the transmission and

distribution systems. DERs may provide services to the wholesale and retail markets and to end-use customers (see Figure 8). Individual DERs that make up an aggregation may be located on different distribution feeders and have different impacts on each of those feeders. Enhanced coordination ensures that DSPs have situational awareness of the impacts of NYISO dispatch signals across the transmission-distribution system interface. In the event of conflicts between the transmission and distribution system reliability needs, under the NYISO's proposed rules, priority will be given to maintaining transmission system reliability. DER aggregators must work with the DSPs to meet local reliability criteria and coordinate with NYISO to deliver the expected services.

Enhanced operational coordination starts two days prior to the operating day, when the DSP communicates any potential or expected outages to the DER aggregator. One day prior to the operating day, aggregators use this information to assess availability of the overall aggregation and submit DER aggregation offers into the NYISO day-ahead market. NYISO will evaluate DER aggregation offers along with offers from other BPS suppliers, and schedule day-ahead market resources. Aggregators report to the DSP their intended dispatch of individual DERs to meet the NYISO day-ahead market schedule. DSPs can use this information to identify any potential reliability impacts on their systems, and communicate any restrictions on individual DER dispatch to the aggregators. Ongoing communication will be necessary among the DSPs, DERs, and aggregators after the NYISO day-ahead market is posted, and will continue into real-time to identify and address changes in the distribution system conditions and potential impacts to individual DERs. Aggregators will be required to communicate aggregation-level changes to NYISO so that those changes are reflected in the real-time dispatch. DSPs can also request NYISO operations to dispatch DER aggregations to address reliability issues. This enhanced operational coordination framework recognizes the transmission–distribution system interface and allow DERs to effectively provide services to both the BPS and DSP.

Experiences Managing DERs in Australia

The installed capacity of DERs, particularly D-PV, is rapidly growing in Australia's National Electricity Market (NEM), with more than 6,000 MW installed and a projected increase to 10-17 GW by 2030 (with peak demand around 35 GW). The South Australian region of the NEM has been a focus for analyzing D-PV integration. This region is geographically about the size of Texas, yet with a demand of 600–3,000 MW has already experienced periods where more than half of its demand has been supplied by D-PV. By 2026-27, the Australian Energy Market Operator (AEMO) predicts that D-PV capacity may be high enough to periodically supply the region's entire demand. This region is connected to the rest of the NEM via a single double-circuit AC interconnector, with an expectation that South Australia continue to operate as an island if it is separated from the rest of the NEM. This raises challenges and questions about how to successfully operate when the majority of load is supplied by D-PV. To explore these challenges, AEMO launched a program to identify and implement actions required to maintain security and operability of this system.

One of the key focus areas in this program is understanding and managing the behavior of DERs during grid disturbances. If a large capacity of DER disconnects during a disturbance, this exacerbates the disturbance and can possibly lead to instability. AEMO has been gathering data on DER response during grid disturbances, and identified the following:

- D-PV is more prone to tripping during grid disturbances than end-use loads.
- Net demand post-fault is higher than pre-disturbance levels, indicative of D-PV disconnection.
- Data from actual grid disturbances in Victoria, South Australia, and New South Wales estimates that as much as 30-40% of aggregate D-PV may disconnect during a disturbance.
- Laboratory inverter testing showed multiple reasons for inverter tripping, including voltage phase jumps greater than 30°, ROCOF levels exceeding 0.4 Hz/s, and inability to meet ride-through requirements specified in standard AS/NZ4777.2-2015.
- Laboratory testing also showed sluggish responses for control modes (frequency-watt and volt-watt) that are compliant with the standard yet provide little support to the grid.

These findings highlight a number of potential security risks that AEMO is trying to address. It also suggests a need to review Australian standards to more explicitly specify required responses.

Collecting suitable data related to D-PV has been one of the main challenges that AEMO has faced in this program. Feeder-level monitoring captures aggregate DERs and load behavior but does not separate the two. Furthermore, disturbances during high D-PV output periods are rare (e.g., voltage disturbances are often associated with lighting strikes where cloud cover impacts D-PV output). AEMO has been working with Solar Analytics and University of New South Wales (UNSW) Sydney to develop new techniques to analyze DER responses. Solar Analytics provided AEMO with one-minute resolution data on 5,000 D-PV systems during a disturbance on 25 August 2018. A fault occurred at the Queensland-New South Wales interconnector (QNI), causing a voltage dip across the northern part of New South Wales. Figure 9 shows D-PV responses for systems installed prior to October 2015 (AS/NZ4777.3-2005 compliant), after October 2016 (AS/NZ4777.2-2015 compliant), and during the transition period (could meet either standard). Almost 45% of pre-2015 D-PV in zone 1 (540 km diameter area) disconnected. The newer standard appears to have improved voltage disturbance ride-through capabilities, especially in zone 2 where the voltage dip was less severe. Future versions of DER standards can build on this improvement in capabilities, minimizing risks to power system security.

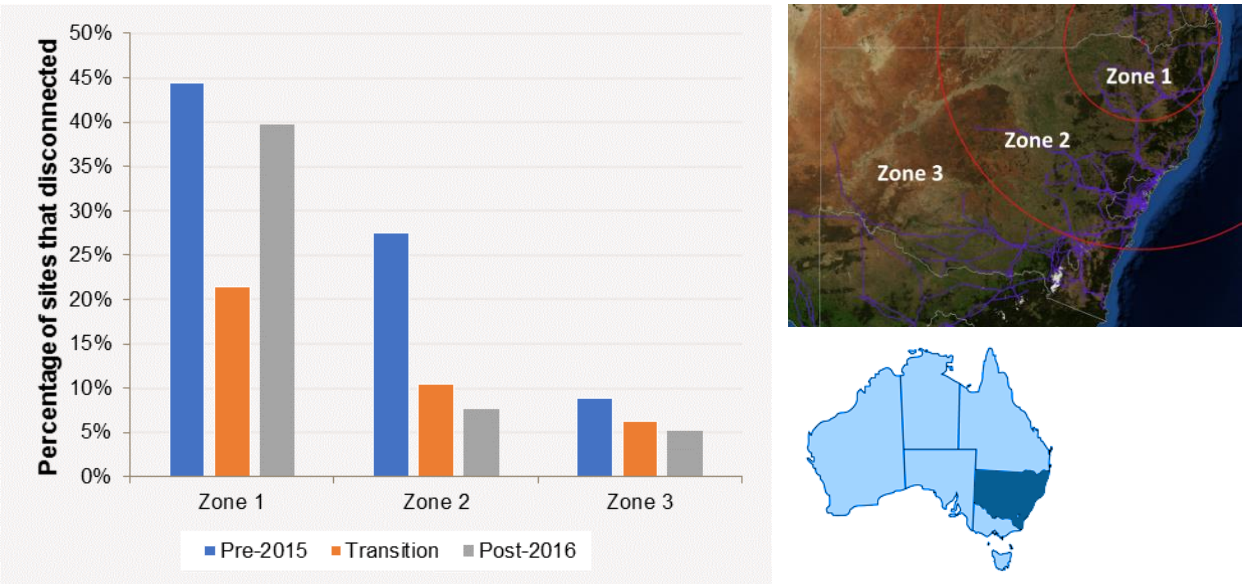

Figure 9. Geographic Distribution of Monitored D-PV Sites Disconnecting in New South Wales during the 25 August 2018 Event

D-PV can also provide valuable grid support. AS/NZ4777.2-2015 specifies that D-PV should provide overfrequency droop response when frequency exceeds 50.25Hz, with a linear ramp to zero generation by 52 Hz. This was observed during the event on 25 August 2018, as illustrated in **Error! Reference source not found.**10. The fault led to separation of Queensland and South Australia from the rest of the NEM, causing overfrequency in those regions. Many D-PV systems behaved according to the standard, and reduced output to assist with managing frequency during the event. However, more than 15% of D-PV in Queensland and more than 30% in South Australia did not behave according to the standard, suggesting issues with compliance.

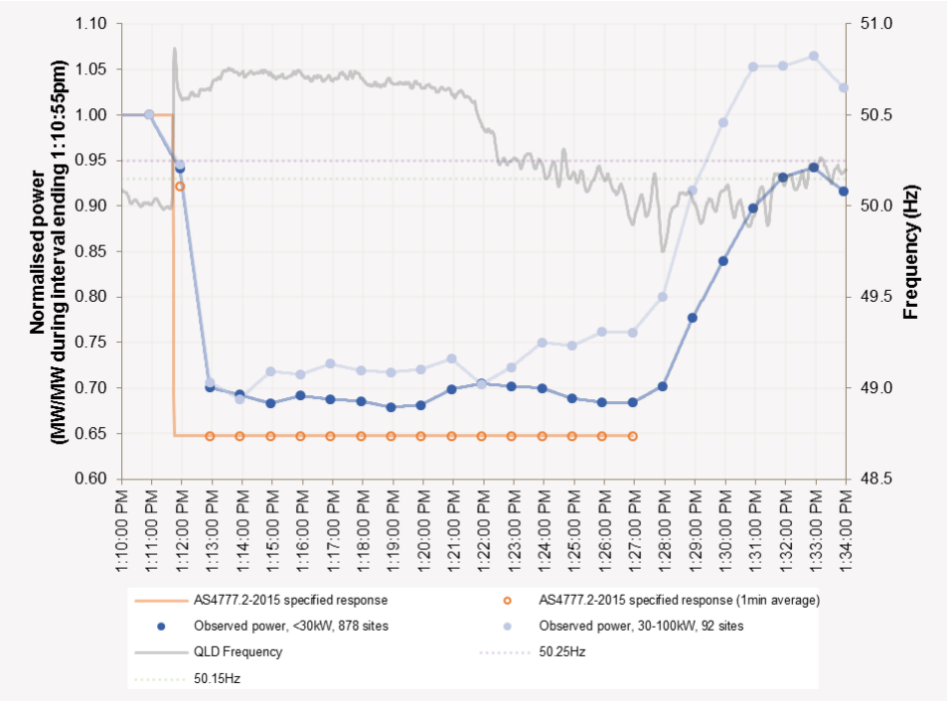

Figure 10. Behavior of post-2016 D-PV inverters in Queensland on 25th August 2018

These findings demonstrate a range of areas in which the DER standards in Australia need review to ensure reliability of the BPS. Review and implementation of advanced DER standards should be pursued years in advance of significant DER penetration due to extensive stakeholder consultation required and the need for transition periods for manufacturers to implement new capabilities. Further, dynamic models that represent DER behavior during grid disturbance also need to adapt quickly to these changes since these studies are of paramount importance for grid reliability.

Duke Energy Progress Experience with DER

Solar PV has grown significantly in North Carolina in the last five years due to government policies, avoided cost of energy, available land, and falling costs of solar technology. Approximately 3,100 MW of solar PV capacity was connected in North Carolina (NC) as of January 2019 across the Duke Energy North Carolina balancing areas. About 2,300 MW of that capacity is located in the Duke Energy Progress (DEP) region, with a winter peak demand of approximately 15,000 MW. About two-thirds of the solar PV capacity is utility-scale DERs, with the most common DER capacity being 5 MW due to past incentives. The rest is transmission-connected, with sizes ranging from 20 to 80 MW. Very little solar PV is co-located with customer load in NC. As such, D-PV in NC is modeled as a stand-alone generating resource at the distribution level. Location is critically important, and some areas of the transmission grid are saturated with generation and need upgrades to accommodate additional generation of any type. DER back-feeding onto transmission is common, but even without back-feeding, DERs are having an impact.

Traditionally, utilities have understood and been able to predict with good accuracy the daily and seasonal fluctuations of customer demand. Unplanned generation or transmission outages have long been incorporated into planning and operating practices. Significant growth of solar PV generation has added a new and independent dimension to planning and operating the BPS. Solar output does not follow load and is generally non-dispatchable. Fig. 11 shows an example daily load curve for generation and customer load in DEP on a mild winter day. The top orange line represents a typical winter customer load shape, with dual peaks in the morning and evening. Generation resources are separated into baseload nuclear, regulating resources such as gas and coal generation, and solar PV. Solar is further split into distribution- and transmission-connected. As the figure shows, customer load is at a minimum when solar generation is at its maximum on a winter day. Regulating resources that need to be on-line for the peaks have a minimum output represented by the red line, and are potentially forced off midday due to solar PV generation. However, many regulating resources have startup and shut-down times of hours or days. The only solutions on some days are to sell energy to neighboring Balancing Areas at low cost, buy peak energy from neighbors at high cost, or curtail solar PV generation.

Determining conditions for which to plan the BPS requires understanding how the grid operates, which as discussed has become more complicated. Transmission planners examine the worst realistic conditions, which in NC have been summer and winter peak load and valley load. With the addition of DERs, new operating hours are becoming the most limiting or worst case. As shown in Figure 11, generation output can vary significantly throughout the day. While the annual minimum customer load may occur at night, light load conditions on a mild Sunday afternoon in spring can closely correlate with maximum solar PV output, which can result in minimum net customer load. BPS voltages can be high and power flow patterns may occur that have never been observed before in operating practice. In summer, while customer load may peak at 5 PM, high solar PV output earlier in the day may increase flows on the transmission system.

Worst case conditions can occur at non-traditional planning hours, and DEP is frequently reviewing actual operating conditions to ensure that planners are focusing on the worst realistic conditions for the BPS. DEP is currently planning for various combinations of customer load and solar output, focusing on the following situations of stressed system conditions:

- 100% summer peak load, 50% solar output (summer peak hour)
- 90% summer peak load, 100% solar output (1 PM on summer peak day)
- 90% summer peak load, 0% solar output (sunset on summer peak day)
- 100% winter peak load, 0% solar output (winter peak hour)
- 35% load, 0% solar output (mild night in spring)
- 40% load, 100% solar output (noontime on mild spring Sunday)

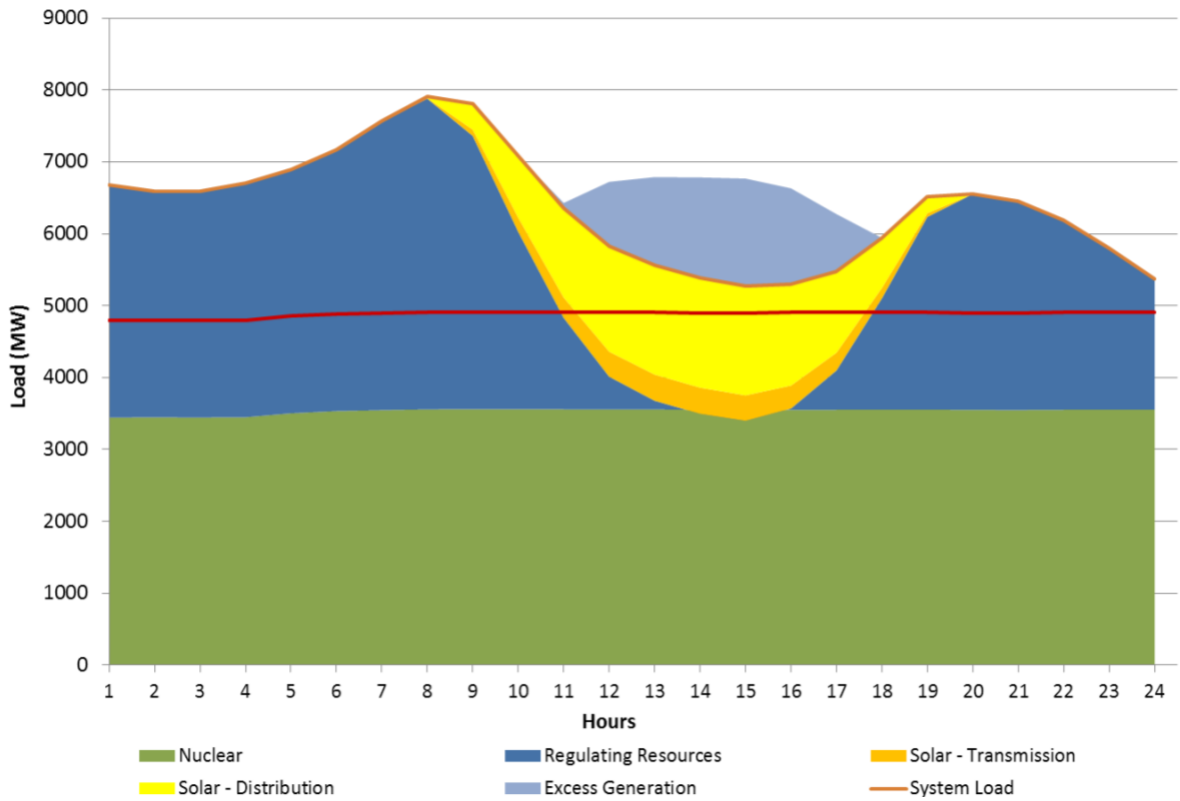

Figure 11. Example of mild winter load curve and resource stack in DEP

NERC System Planning Impacts of DER Working Group

The North American Electric Reliability Corporation (NERC), in coordination with its stakeholders, has been studying the effect that increasing penetration of DERs have on the BPS. The focus of these efforts is ensuring that the BPS has sufficient essential reliability services (ERSs) – inertial response and stability, frequency control and balancing, and reactive power capability and voltage support. While modern inverter-based resources can be equipped with these capabilities and controls, changes in planning and operating paradigms must occur to utilize these capabilities. A BPS with increasing amounts of inverter-based resources, including DERs, presents new challenges that must be addressed to ensure a reliable grid.

NERC has recently strengthened its focus on DER impacts to the BPS and formed the System Planning Impacts of DER Working Group (SPIDERWG), which is developing guidance to address the planning and

modeling challenges with increasing penetration of DERs across North America. NERC SPIDERWG membership spans distribution and transmission entities across North America, and is focusing on four primary topics – advancing aggregate DER modeling capabilities, verification of DER models and performance, developing study techniques with increasing penetration of DERs, and coordination across industry stakeholders.

Summary

While some may argue that the BPS is becoming obsolete in the face of DERs, others believe that the BPS has never been more critical for reliable delivery of power to end-use customers. However, we can all agree that the breadth of impacts that DERs are having on BPS reliability are immense. For now, we are focused on ride-through capability, evolving modeling and study techniques, changing control strategies and requirements, adjusting market designs, and the impending growth of energy storage. Interconnection standards are rapidly evolving to keep up with the transition from centralized control to truly distributed and decentralized architectures. Requirements for grid connection are more important now than ever before, and engagement from transmission providers and grid operators is essential for maintaining BPS reliability. Proactive improvements to interconnection requirements are imperative since retrofitting legacy DERs is cost-prohibitive.

DERs pose one of the biggest evolutions in BPS planning and operation since the inception of polyphase AC power systems over 130 years ago. Anyone who generates, transfers, controls, delivers, or utilizes electric energy should commit to these reliability efforts as we move towards an integrated energy system. Historically, these resources acted passively, and were even required to trip off-line during disturbances. But these resources are becoming a major component of the grid, and must actively support the grid as a whole including mitigation of variability impacts and maintain adequate levels of reliability at reasonable cost. The successful path forward involves collaboration, communication, and coordination among these groups, breaking down barriers that have existed for many years.

For Further Reading

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