# Grid Impacts from Distributed Energy Resources

Research & Development Priorities

A Technical Update

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# ABSTRACT

As distributed energy resources (DERs) have increased and created stresses on the electrical grid, distribution planners have used traditional mitigations, hosting capacity analysis, and interconnection requirements to help. As the move on climate change proceeds and DERs come to define the grid, distribution planners are encountering a set of significant grid impacts associated with the widespread customer adoption of DERs. There are four cases of particular concern: dynamic DER design & location, DER concentration, unsatisfactory DER performance, and unsatisfactory DER interoperability and integration. This study focuses on research and development priorities to address these cases.

**Keywords**

- Distributed Energy Resource (DER)
- Distribution Planning
- Demand Response (DR)
- Energy Efficiency (EE)
- Zero Net Energy (ZNE)
- Research and Development (R&D)

# ACRONYMS & ABBREVIATIONS

| | |
|---|---|
| AB | Assembly bill |
| ABC | artificial bee colony |
| AC | alternating current |
| ACS | alternate convex search |
| ADMS | advanced distribution management system |
| ADN | active distribution network |
| AE | active element |
| AEIC | Association of Edison Illuminating Companies |
| AHJ | authority having jurisdiction |
| AKA | also known as |
| AMS | asset management system |
| BTM | behind the meter |
| CSI | California Solar Initiative |
| CEC | California Energy Commission |
| CPUC | California Public Utilities System |
| CSIP | California smart inverter profile |
| CVR | conservation voltage reduction |
| DC | direct current |
| DA | distribution automation |
| DER | Distributed Energy Resource |
| DERMS | distributed energy resource management system |
| DG | distributed generation |
| DLSE | distribution linear state estimation |
| DMS | distribution management system |
| DNP | distributed network protocol |
| DOE | department of energy |
| DPV | distributed photovoltaic |
| DR | demand response |
| DRP | distribution resource planning |
| DSIP | distributed system implementation plans |
| DSO | distribution system operators |
| DTT | direct transfer trip |
| EDD | electrical distribution design |
| EPIC | electric program investment charge |
| EPRI | Electric Power Research Institute |
| ESIF | Energy Systems Integration Facility |

| | |
|---|---|
| FERC | Federal Energy Regulatory Commission |
| FACTS | flexible AC transmission systems |
| GHG | greenhouse gas generation |
| GIS | geographic information system |
| HCA | hosting capacity analysis |
| HECO | Hawaiian Electric Company |
| HIL | hardware in the loop |
| HVAC | heating/ventilating air conditioning |
| Hz | hertz |
| ICA | integration capacity analysis |
| IEC | International Electrotechnical Commission |
| IES | integrated energy system |
| INL | Idaho National Laboratory |
| ISO | International Standards Organization |
| IEEE | Institute of Electrical and Electronic Engineers |
| kV | kilovolt |
| LBNA | locational net benefits analysis |
| LBNL | Lawrence Berkeley National Laboratories |
| LTC | line tap changer |
| MECO | Maui Electric Company |
| MPPT | maximum power point tracking |
| MW | megawatt |
| NEM | net energy metering |
| NREL | National Renewable Energy Laboratory |
| NWA | non-wires alternative |
| OCCP | open charge point protocol |
| OEN | overload energy |
| OLTC | on-load tap changers |
| PDN | passive distribution network |
| PFM | power flow modeling |
| PWM | pulse width modulation |
| PG & E | Pacific Gas & Electric |
| PMU | phasor measurement unit |
| PPC | point of plant control |
| PQEN | poor quality energy |
| PSPS | public safety power shutoff |
| PV | photovoltaic |
| REV | Reforming the Energy Vision |
| RL | resistor-inductor |
| RoCoF | rate of change of frequency |
| RPS | renewable portfolio standard |
| SADN | semi-active distribution network |
| SCADA | supervisory control and data acquisition |
| SCE | Southern California Edison |
| SDG&E | San Diego Gas & Electric |
| SEAMS | System to Edge of Network Architecture |

| | |
|---|---|
| SEPA | Smart Electric Power Alliance |
| SGIP | Small Generation Interconnection Procedures |
| SIWG | smart inverter working group |
| SMUD | Sacramento Municipal Utility District |
| SOP | soft open point |
| SVCE | Silicon Valley Clean Energy |
| TLS | traffic light system |
| VAr | volt-ampere reactive |
| VOC | virtual oscillator control |
| UFLS | under-frequency load shedding |
| UL | Underwriters Laboratory |
| VGI | vehicle-to-grid integration |
| VSC | voltage source converter |
| VVI | voltage variation index |
| ZIP | constant impedance, current and power |
| ZNE | Zero-Net Energy |

# EXECUTIVE SUMMARY

Distributed Energy Resources (DERs) are a new and significantly evolving source of stress on the electric grid. The project defines grid stress as grid conditions outside normal operating bounds, which call for maintenance, repair, or upgrading of the grid. Serious grid stress occurs when these conditions damage the grid, interfering with further normal operations, and potentially cascading into catastrophic problems.

Distribution planners are focusing on DERs in three main tasks: (1) preparing to host customer-sited DERs on the grid, as potentially useful, but a challenge to be managed; (2) aiming to manage DERs by introducing interconnection requirements, seeing DERs as everyday grid components that need to be controlled and standardized; and (3) deploying DERs to combat climate change, in response to legislated renewable energy mandates to limit greenhouse gas (GHG) emissions.

Grid planners encounter a set of significant grid impacts associated with DERs. There are four cases of particular concern:

- Dynamic DER Design & Location
- DER Concentration
- DER Performance
- DER Interoperability and Integration

Earlier work put DERs in the context of the California housing market and identified DER deployment scenarios for the next several years. The work in this report (1) describes the cases when DERs may have severe impacts on the grid, as distribution planners work on their three main tasks; and (2) helps distribution planners by providing examples of research & development that has been completed, and near-term research & development requirements.

The hosting capacity analysis (HCA) movement helped enable DERs to be hosted on the grid. Hosting views DERs at best as “guests” on the grid, and at worst as intrusions. From the hosting perspective, DERs are special components under examination that without changing grid operations, may be tolerated under certain circumstances. HCA is a good starting point, and has confirmed DERs’ significant grid impacts, but can’t forecast these impacts, hasn’t been standardized, and lacks sufficient data. Today, HCA faces substantial challenges in becoming dynamic and effective.

The adoption of more rigorous interconnection requirements for smart inverters improved DER management. It had to, because legislated climate change mandates, such as

California’s AB 32, mean that DERs are required, rather than merely encouraged or accepted. California also asks DERs to be economic and reliable. Generation will be distributed and variable as load has been, and like load, will be optimized with climate metrics in mind.

The symptoms and causes of grid stresses differ. The symptoms are a range of voltage and frequency disturbances; the causes are system imbalances (e.g., intermittent, variable, and unanticipated power flows). These imbalances stress the grid if the grid lacks sufficient resilience. The four DER-related serious grid stresses are:

- Dynamic DER Design & Location
- DER Concentration
- Unsatisfactory DER Performance
- Unsatisfactory DER Interoperability and Integration

Dynamic DER design and location stress is multidimensional, beginning as a baseline, spanning resource and load, extending up from the feeder level to the enterprise, and extending out over time as the grid develops. DER concentration intensifies the grid impacts that DER location and design deliver, stressing the grid to a greater degree as DER penetration, intensity, and activity increase. Unsatisfactory DER performance stresses the grid when DER performance is unreliable, compromised, or falls to zero as they fail. Unsatisfactory DER interoperability and limited integration with other grid components will also result in grid constraints and additional stress.

Traditional mitigations can’t address all these grid stresses from DERs as they arise. SCE’s zero-net energy (ZNE) demonstration community at Fontana revealed major grid stresses from DERs that are only mitigated with major grid reinforcement. Other projects have indicated that transportation electrification and building electrification policies will also create major stresses. Deploying DERs to fight climate change calls for DERs to be deployed as rapidly as possible, setting aside past constraints, and entailing new risks. DER design and location must be much better understood, particularly as DERs are concentrated.

The proposed research and development priorities for dynamic DER design and location are more data, basic analysis, and dynamic modeling. For DER concentration, the research and development priorities are edge case identification, bulk power system interactions, and stronger forecasting models. For unsatisfactory DER performance the research and development priorities are DER performance metrics, failure analysis, and HCA and interconnection reexamination. For unsatisfactory DER interoperability and integration, the research and development priorities are interoperability and integration confirmation, the constraints and risks of communications choices, and the reexamination of grid design assumptions.

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# 1 BACKGROUND ON THE ASSIGNMENT

## A - Introduction

Government policies addressing climate change have brought new priorities to electric distribution planning. Both state agencies and customers are addressing many of these new priorities by expanding the adoption and use of behind the meter distributed energy resources (DERs), including photovoltaic (PV) solar generation, wind generation, battery storage, and demand response (DR). In turn, the expanded use of DERs is bringing its planning challenges to utilities.

DERs stress the grid: the researchers define grid stress as grid conditions outside normal operating bounds, which call for maintenance, repair, or upgrading of the grid. Serious grid stress occurs when these operations damage the grid, interfering with further normal operations, and potentially cascading into catastrophic problems.

DERs arose literally at the margins of distribution planning when early opponents of a fossil-fueled generation made new central power plants difficult to site. Even though solar and wind resources were expensive at the time, utilities stressed by peak loads had to consider distributed generation as an alternative. Peak-shaving distributed renewables found a modest place in utility conservation and efficiency programs.

Then a steady decline in renewable generation costs coincided with the policy advocacy that fossil fuels posed mortal risks for the global climate. At that moment, DERs became a priority in their own right and began to replace large-scale fossil-fueled power plants. However, distribution planners found that DERs and the grid-edge concepts they foster don't integrate easily with familiar models of the centralized grid. The grid impacts of DERs at scale are significant, and still coming into focus. This investigation aims to sharpen that focus.

One example of the novel concepts DERs have fostered is Zero-Net Energy (ZNE). ZNE began among the traditions of energy efficiency and conservation, with a focus on limiting electric load in the built environment. ZNE advocates that individual buildings should use as much energy as they produce. In ZNE buildings, energy efficiency is the first priority, followed by DR and DER. The grid would become more efficient through new construction, project by project, as the energy impact on the grid could be "zero net."

ZNE has proven to be an inspiring and impractical concept, as both developers and distribution planners have found it challenging to design the grid by each building. ZNE has fascinated architects, highlighted the advantages of DERs, and inspired innovative designs for several thousands of new buildings. But ZNE has not become a new template for construction and has not been widely adopted in California.

Instead, the concept of ZNE has now become absorbed in a broader policy movement aiming to expand the use of residential and multifamily storage, renewables, electric transportation, and energy efficiency. ZNE advocates now include “nearby” DERs in their projects, and aim for “near-zero” net energy use, or “net-zero emissions,” rather than net-zero energy. Even though it didn’t become a new standard, ZNE has joined a chorus of concepts advancing DERs within distribution planning.

The policy movement that enveloped ZNE moved many utilities’ focus away from improving efficiency toward limiting harmful emissions. Utilities who were unable to site a new generation a decade ago have now begun to develop new renewable resources as rapidly as possible. Load increases from electric transportation and gas-to-electric conversion are accepted and encouraged if powered by new renewable resources. Some of these new resources are arising in utility-scale facilities, but many new renewable resources are arriving as DERs.

Because climate change is now a leading priority for many utilities, emission-free DERs are no longer merely an alternative to traditional resources. DERs are into service in all forms: large and small, proven and novel, utility-sponsored, and sponsored by others[1]. Ready or not, distribution planners see more and more DERs interconnected to the grid. From a grid planning perspective, DERs have now become essential, either as a grid resource or customer asset.

The rise of DERs has found many energy industry professionals lacking the experience to accurately assess DER installation, interconnection, operations, and maintenance. While the distribution planning focuses on digitizing the grid, DERs (though considered digital), add layers of complexity to the operations, control, and communications when compared to the traditional devices and systems. Many planners aren’t ready for DERs to take on significant roles. Planners’ hesitation increases as they note that DER design continues to evolve rapidly, resetting utility assumptions at every turn. The most forward-thinking jurisdictions (e.g., in California, Hawaii, Arizona, and Massachusetts) have revised their DER policies repeatedly. The reward for learning about DERs is the opportunity to learn even more about them.

In this uncertain environment, utilities have been at work on three main tasks related to DERs. Each of these activities has a different focus:

- First, many planners are still preparing to host DERs on the grid. Most utilities in North America are focused on this activity, seeing DERs as potentially useful, but as a challenge to be managed.

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[1] See for example the list of 23 utility-led DER projects included below in the Appendix to this report, from *Expanding PV Value: Lessons Learned from Utility-led Distributed Energy Resource Aggregation in the United States*, a National Renewable Energy Laboratories (NREL) Technical Report, NREL/TP-6A20-71984, November 2018, pp. 27-28

- Second, some planners aim to manage DERs by introducing interconnection requirements for smart inverters. Many utilities are involved in efforts to codify advanced inverter functions, seeing DERs as everyday grid components that need to be controlled and standardized.
- Third, utilities are deploying DERs to combat climate change. Many utilities with legislated renewable energy mandates aim to use DERs in their responses, much as they earlier turned to a wide variety of resources to limit load.

These three tasks will eventually lead utilities to face a bigger challenge of redesigning the grid based on DERs. Utilities will come to recognize distribution rather than centralization as the dominant mode of design for the digital grid. Resources, communications, and control will be distributed, much as customers, loads, and operations are already distributed today. Grid planning will take advantage of local conditions rather than merely coping with them. Software, communications, and DERs will enable this redesign.

However, until that major redesign begins, today's grid still must be managed based on its centralized model. Today's grid planners will seek to host DERs on the grid, introduce smart inverters, and deploy DERs to fight climate change. As they address these three tasks, today's grid planners will continue to encounter a set of significant grid impacts that are associated with DERs. There are four cases of particular concern:

- Dynamic DER Design & Location
- DER Concentration
- Unsatisfactory DER Performance
- Unsatisfactory DER Interoperability and Integration

Our work is neither a comprehensive treatment of these types of DER grid impacts nor an engineering analysis of them. Demonstrating or resolving these impacts is also beyond our scope. Instead, the researchers describe these cases when DERs may have serious impacts on the grid, so we can help distribution planners to identify near-term research & development requirements. This report also serves as a background for dialogue with utility distribution planners[2].

In earlier reports, the researchers profiled the California housing market to provide context for DER deployment and analyzed various scenarios for the scale and timing of DER deployment across the next several years. These earlier reports indicated that in most scenarios, DER deployments would accelerate rapidly in California.

This report discusses the three main tasks distribution planners have been working on regarding DERs. The researchers give examples of the research & development that has been completed and describe the next steps of research and development to manage DERs' grid impacts. These next steps are naturally experimental and diverse. Planners

[2] Originally this work was intended to validate the DER grid impact research & development priorities of distribution planners at a major utility, but a reorganization intervened. Priorities were under revision. This report can now serve as the platform for later validation discussions.

are trying to identify state of the art, specify what aspects require further attention, and rethink everything that seems obvious and previously demonstrated.

# 2 PREPARING FOR DERS

To be realized, policy concepts like ZNE depend upon DERs, which have impacts on the grid. Research and development to address DER grid impacts have arisen in the three tasks of estimating how to host DERs on the grid, introducing smart inverters, and deploying DERs to fight climate change. The progress is as follows:

## A- ZNE

The researchers noted above that ZNE has become absorbed in a broader climate-oriented policy movement aiming to expand the use of electricity in general and DERs in particular. Also, utilities are greatly expanding the use of utility-scale renewables and storage across both bulk power and distribution systems, including microgrids. But ZNE is more than a transitory concept now bypassed by events. ZNE illustrates a fundamental principle of how grid impacts arise.

The concept of ZNE began and continues as an approach to the design and construction of individual buildings. Achieving energy efficiency and conservation is a complex challenge in individual buildings, only partly met in the design and construction stages, and more difficult to achieve once the building is occupied. However, the design and construction of individual buildings offer energy management, that advocates the change to come together around specific projects. In contrast, policy, legislation, and regulation usually have to wait for broader compromise and consensus. ZNE continues to arise building by building, as an aspiration that can galvanize project teams.

Across the last decade in North America, hundreds of individual project teams have invoked ZNE as they designed and built buildings, often as they pursued various Energy Star standards in the same projects. Individual buildings and projects have always differed in their demands on the grid, and these demands have been tightly specified by building codes and utility regulation, specifying interconnections, and allocating costs. The few new buildings with ZNE aspirations met these requirements one way or another, and they localized the impact of DERs, while current flowed in one direction and followed load. These much-admired, ZNE-inspired buildings rarely achieved strict ZNE metrics once occupied, and they are a tiny fraction of the total number of new buildings, but they have invoked the concept.

In California, the presence of these “ZNE” buildings helped a dedicated group of ZNE advocates to make their aspirations mandatory across the construction industry. A simple and attractive concept, ZNE fits well into California’s tradition of elaborate, aspirational building codes. A construction industry battered by the Great Recession of 2008 was slow to respond to a drive for radical change. ZNE leaped from a notion with some prospects in progressive municipalities, to a broadly-defined state policy.

However, the bridge from broad policy to firm building codes proved to be a bridge too far for ZNE. When considering how to translate ZNE into California State Building Codes, policymakers came to recognize ZNE's difficulties. Buildings had different sites and different uses over time. There was little agreement about how to measure or allocate energy costs. An entire grid might be managed with ZNE in mind, but ZNE was impractical for many buildings. New construction was recovering, already burdened by regulation and failing to meet demands, and a revived industry pushed back against ZNE metrics.

Building code policymakers then realized that ZNE had always been based on two sets of measures: (1) on-site electricity supply provided through rooftop solar and stationary-battery energy storage, and (2) on-site electricity demand reduced through rigorous design and materials specifications for intense energy efficiency (EE). These measures had been combined into ZNE's simple "net-zero" outcome metric, but policymakers realized the measures could be decoupled from the metric.

ZNE advocates and the construction industry both accepted revisions for the 2020 California Building Code, setting aside the ZNE metric, while preserving the underlying measures (e.g., mandatory solar generation, mandatory energy efficiency in design, optional energy storage). The code revisions focused on building design and construction, rather than renovation or energy use. As a set of minimum standards to be implemented over time for all new buildings, the new code allowed more ambitious developers to aim for ZNE if they wished. A few have done so.

From the perspective of the California electric grid, the California Building Code changes are far more impactful than ZNE ever was on its own. ZNE had led to a few buildings of radically-unusual construction. The new building code will lead to many buildings of significantly-unusual construction. In 2020 alone, SCE will add 60,000-80,000 new solar residential interconnections, 30,000-40,000 in new residential construction.

The code compromise between the construction industry and the environmental community decoupled ZNE measures from ZNE metrics, but in doing so fostered the deployment of DERs, and left the measures' grid impacts in place. Under the new code, the grid impacts of DERs will scale up and register across the grid. Some of these grid impacts are risks, and some are opportunities, and as indicated below, they vary in nature, scale, intensity, duration, locations, and contingencies. What they have in common is that they are the legacy of aspirational concepts like ZNE.

Furthermore, including DERs in every new building across the years to come not only scales up the total of individual grid impacts, and broadens them across all classes of buildings, it also introduces regional and grid-wide concerns. Individual buildings, circuits, and the grid as a whole, experience's loads, weather, and market conditions differently. Aggregation may not be straightforward. Maintaining reliable and resilient performance is much more complex when sources of bidirectional and volatile current flow are everywhere.

Outside of California, although few regulators are ready to revise building codes on behalf of ZNE, ZNE advocates are still active. These advocates are led by the U.S. Green Building Council and the New Building Institute (NBI). NBI compiles a useful catalog of ZNE buildings, and in 2017 announced the GridOptimal© model, which aims to tie individual buildings' energy use to their grid impacts. The complex assessment system has a few sponsors and has completed a few field trials. NBI is also sympathetic with electrification, which recasts ZNE as zero-net *emissions*, and with another creative repositioning with marketing appeal, e.g., "ZNE-ready" and "near-ZNE."

It may be that as microgrids aim to achieve local reliability and resilience, they will inherit ZNE's aspirations for on-site energy management. It may be that utility-scale investments in renewables and energy storage will be the DERs with the impacts on the centralized grid. However, in the meantime, California grid planners will be preoccupied with how the California building codes (especially ZNE) affect the grid impacts.

## B- Hosting DERs on the Grid

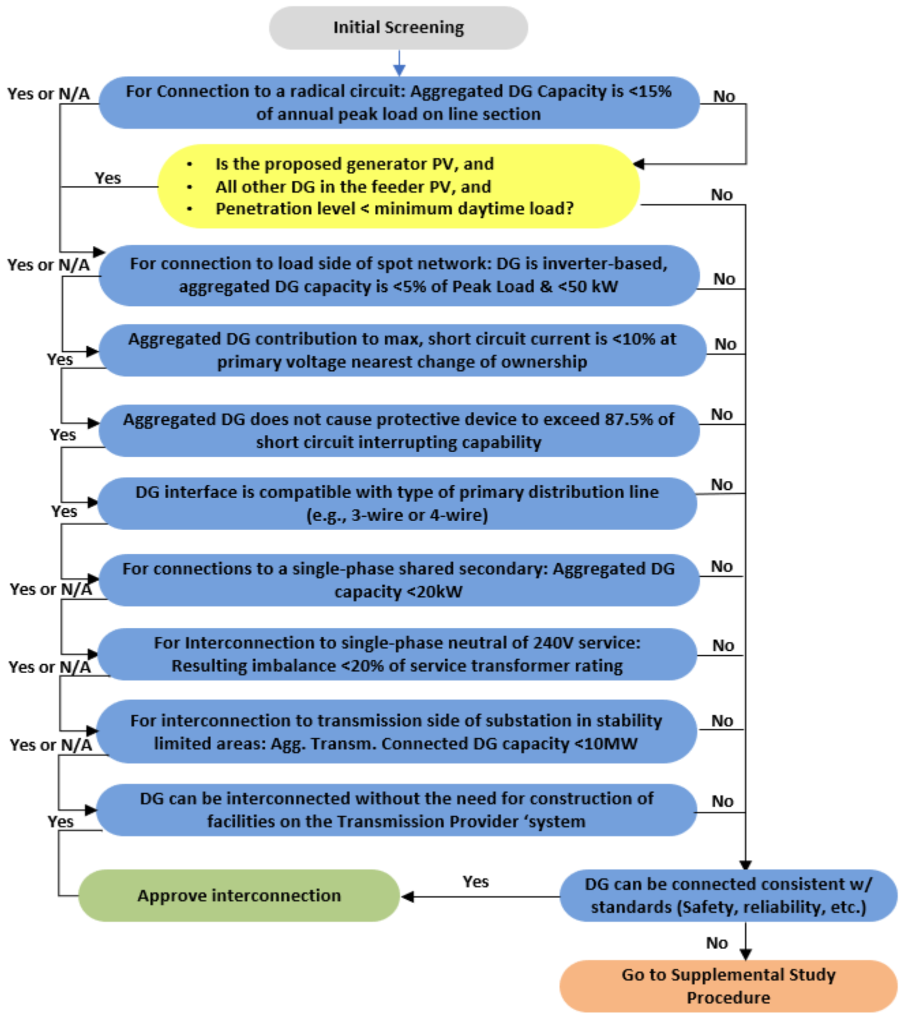
The first of the three tasks utility grid planners took on to account for DERs' grid impacts was <u>DER hosting</u>. The question: given the standard centralized grid design, operating under normal conditions, where could DERs be accommodated, and to what degree? Many utilities in North America are still focused on this question, seeing DERs as potentially useful with a challenge to manage on the grid.

Hosting views DERs at best as guests on the grid, and at worst as intrusions. From the hosting perspective, DERs are systems under examination that, without changing grid operations, may be tolerated under certain circumstances. The history of distributed generation (DG) explains planners' approach to DER hosting.

### 1. Regulation and Standardization

Forty years ago, with the rise of deregulation and DG, the Federal Energy Regulatory Commission (FERC) began to standardize how distributed energy resources (DERs) would be hosted on the nation's electric grid. Utilities were familiar with interconnecting central generation plants, and independent generation had long been a feature of remote and private locations. As deregulation began, significant new facilities aimed to join the grid, many of them based on renewable resources.

In 2003, FERC offered a set of 10 SGIP[3] (Small Generator Interconnection Procedures) review screens (see figure below):[4]




Source: FERC SGIP Technical Screens Summary, including the additional considerations for PV (Yellow box) from Coddington 2012

**Figure 1:**
**FERC Small Generator Interconnection Procedure Screens**[5]

[3] FERC's Small Generator Interconnection Procedures (SGIP) , http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp#skipnav, are independent of California's eponymous Self-Generation Incentive Program (SGIP).

[4] These screens include many well-known requirements (see Table) FERC has reexamined these screens several times since 2003. As NREL notes, FERC has recently edited its supplemental review list to three screens: (1) a penetration screen, set at 100% of minimum load, (2) potential voltage and power quality impacts and/or (3) safety and reliability impacts. In most cases, a proposed facility below 100% of the minimum load measured at the time the generator will be online, will have minimal risk of power back-feeding beyond the substation, and there is a good possibility that power quality, voltage control, and other safety and reliability concerns will be below the thresholds for a full study.

[5] Peterson, Zac, Michael Coddington, Fei Ding, Ben Sigrin, Danish Saleem, Kelsey Horowitz, Sarah E. Baldwin, et al. 2019. *An Overview of Distributed Energy Resource (DER) Interconnection: Current Practices and Emerging Solutions*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-72102.

IEEE 1547-2003 was issued the same year, essentially codifying FERC's approach to DER interconnection. Most of the new small generators were covered by the SGIP's 10 kW inverter process or the 2-5 MW fast track process. Larger and more complicated projects entered the study process, which would classify the project by interconnection type and costs, analyze any adverse system impacts and mitigation strategies, and assess the mitigation costs. The FERC SGIP screens offered a reasonable approach to appraising DERs arriving in small numbers, at dispersed locations.

In whole or in part, the FERC screens were adopted by most states as an approach to accommodating new DG facilities. These new DG facilities generally operated at the edge of the grid and could impact local distribution facilities (>50kV, primarily-radial facilities, serving retail customers in a local geographical area)[6]. Potential adverse system impacts included equipment-thermal overload, voltage violations, protection requirements violations, and power quality disturbances.

Utility engineers could generally recognize circumstances where the screens were applicable and indicated further study was required. Sizing and placing wire, devices, resources, and other grid elements based on local conditions was fundamental to distribution planning. FERC and FERC's experts believed that the grid would not be harmed by DG penetration below 15%, even though little data existed about whether or not 15% of the annual peak load on a line section was a proper general limit for aggregated DG capacity. The screens based on the judgments about how DG would be used, how much DG the grid could tolerate, and where it could be tolerated.

In 2003, California was developing interest in DG, due to restrictions on new utility generation, increasing peak loads, and general public support for renewable power sources. The focus was on large-scale wind and solar resources, which were beginning to display acceptable economics. Every proposed DER interconnection could be evaluated in detail, if necessary, for interconnection feasibility, system impacts, and facility costs. Smaller-scale behind-the-meter (BTM) resources such as photovoltaic (PV) solar, small-scale wind, and small-scale hydropower were generally isolated and marginal special cases. Energy storage was experimental.

Even as FERC's initial screens were being implemented, DERs were scaling rapidly. In 2003, fewer than 100 MW of solar resources were connected to the U.S. grid: in 2013, the total exceeded 12,000 MW. In 2005, U.S. developers and utilities connected 79 MW of grid-connected solar resources; in 2013, the developers and utilities connected 4,600 MW. Much of this ramp-up occurred in California, where projects queued up for interconnection. Some circuits began to feature not only multiple DG projects but many smaller-scale DER sites. The smaller-scale DERs were too small individually to support detailed studies, but in the aggregate that was significant in their numbers and locations.

[6] As defined in FERC's Order 888 (1998).

California distribution planners began to recognize that DERs were going to challenge both the "15% rule" and their assumptions about local impacts[7].
One answer to the interconnection queuing problem seemed to be establishing individual circuits' hosting capacity[8] and allowable penetration levels, to expedite harmless projects and identify the upgrades that could allow more stressful projects to proceed. Planners reasoned that hosting capacity analysis (HCA) might also identify those cases where smaller projects might be enough to put a circuit at risk.

In California, Minnesota, and New York utilities launched significant efforts to evaluate different methods of HCA. On the one hand, there were resource-intensive and demanding methods that required running power flow simulations at each node until constraints were reached. These heavy-duty methods offered relative precision about the local impacts of DER. On the other hand, more streamlined methods required fewer data and approximate system variables but offered less precise results[9]. California has generally favored the more demanding HCA methods.

To date, HCA has demonstrated that hosting capacity varies widely from place to place, from time to time, and DER to DER. Distribution planners aim to identify conditions where DER could be hosted while avoiding adverse grid impacts, significant infrastructure upgrades, and interconnection delays. However, HCA is dependent on both specific, current data about individual locations and powerful, general assumptions about DER impacts. Where these are lacking, the results of HCA are equivocal. In many cases, the granularity of HCA analysis quickly approaches the level of effort required for supplemental project studies.

The effort to standardize HCA has helped many distribution planners model DER grid impacts for the first time, consider the importance of aggregation, and develop improved maps of their grid. Contending HCA models have raised issues, required better data, and invited more investigation. Both planners and developers have learned about DERs' potential impacts on the grid as a result. As HCA models improve, they promise to identify positive grid impacts as well as adverse impacts, characterize DERs more effectively, and provide clearer results. EPRI has taken the lead in this regard by working with dozens of utilities and improving its DRIVE tool. But to date, HCA has not been standardized.

[7] So-called integrated distribution planning quickly arose in California and Hawaii, and was followed by work in New York, Minnesota, Massachusetts, Maryland, Iowa, Illinois, and Ohio.

[8] California refers to "integration capacity analysis" rather than HCA. In this report we use the more widespread term.

[9] There are at least four major methods for HCA: (1) stochastic, (2) iterative, (3) streamlined, and (4) the hybrid EPRI DRIVE method. Stochastic analysis increases DERs randomly across a circuit model, examining power flows in each instance, while iterative analysis increases DERs at a specific location and examines power flows at each increase. These two methods consume considerable resources and time analyzing each scenario. The streamlined method gains efficiency by examining fewer power flows and few scenarios. EPRI's Distribution Resource Integration and Value Estimation (DRIVE) is a hybrid stochastic approach that offers ranges of results for individual feeders based on sampled feeder data and a wide range of constructed scenarios.

## 2. Guiding Concepts & Investigations

The concept guiding DER deployment in its initial stage was **hosting capacity**. As a starting point for interconnection analysis, hosting capacity is intended to alert distribution planners to the potential impact incremental DERs may have when sited and operated on a particular circuit. Hosting capacity assumes that a snapshot of a circuit's current configuration, and a description of that circuit's typical range of operating conditions, can indicate the circuit' ability to host DERs without significant upgrades or operating risks.

Hosting capacity presumes a *status quo* definition of the grid, grid operations, and acceptable stress levels on circuit-level grid components. Significantly, the variables in HCA are first the number, type, and locations of DERs on the circuit, and second any project-specific grid reinforcements. HCA is designed to indicate what the *status quo* grid can accept, and does not rise to the more significant questions of how DERs would need to change to be more acceptable, or how the grid would need to change to be more accepting.

HCA is also an approach to assessing the incremental impact of a project regarding boundary limits across a circuit. The analysis is only as good as the data regarding the specifications of the circuit, the incremental DERs, and the DERs' operations. Furthermore, because the actual impacts of DERs are specific both to circuit location and operating circumstances, HCA may not be conclusive.

FERC's "15% rule" served as an initial reference point for DER distribution planners, but once they began to realize that this heuristic was limited, they needed a new approach. The planners inferred that the challenge to the "15% rule" would be local: hosting capacity would be exceeded in certain instances, and characterizing those exceptional instances would identify where DERs should not be installed.

The planners further assumed that establishing individual circuits' hosting capacity[10] and allowable penetration levels could expedite harmless projects and identify the upgrades that could allow more stressful projects to proceed. Finally, the planners acknowledged that even if the DER grid impacts would be local, they would be widespread, and they called for a DER planning baseline that would be system-wide.

However, system-wide hosting capacity models have proven difficult to perfect. The complexities of dynamic bidirectional grid modeling far exceed those of previous distribution system modeling. Hosting capacity has reference to standards, tariffs, metering, protection, and grid devices in addition to solar and storage. Assets and the services provided by them are taking on new forms (e.g., in microgrids).

Despite these difficulties, ambitious research & development initiatives have helped the industry move forward. The researchers briefly describe examples of these to highlight future research directions.

[10] California refers to "integration capacity analysis" rather than HCA. In this report we use the more widespread term.

In 2013, Maui Electric Company Ltd. (MECO) planned to replace the aging fossil-fueled power plant serving the 23 kV Pukalani feeder with flexible, fast-ramping units at the more distant Waena plant (Ref: MECO: Pukalini Curtailment Reduction Plan Impact Study (2014)[11]). The Pukalani feeder was projected to host 128 MW of PV solar and 72 MW of wind resources by 2019. MECO aimed to understand how the planned project could affect Pukalani feeder operations. Typical at the time of the iterative work undertaken to cope with the proliferation of DERs, the MECO Pukalini project was essentially an effort to identify hosting capacity in the absence of an enterprise model. For such an ambitious project, FERC's heuristics would no longer suffice. MECO needed an iterative HCA based on circuit data.

The Pukalani study solved for an operating solution, showing that line conditions required 5.5 MW/minute ramping to maintain system frequency. Still, even with transmission upgrades, the project could only support fast-ramping of 5.0 MW/minute. Intensive and specific use of DERs and demand response as ramping resources would be required to support system frequency. Voltage regulation would also need to be expanded through additional capacitors, STATCOM, and tap changers.

The transmission upgrades required were significant as well because a transmission fault could trigger frequency variation and a severe loss of solar generation along the line. To mitigate the problems, the study proposed requiring (1) all new solar interconnections to use extended ride-through settings for voltage and frequency variability, (2) high-speed communications along all 69 kV transmission lines, and (3) increasing the number of circuits on automatic under-frequency load shedding (UFLS). Only by combining these three remedies, and using them all exactly as modeled, could the project succeed.

The MECO study revealed that solar PV tripping had become the utility's dominant contingency, with a 6X greater impact than the prior largest contingency. System collapse could follow a single contingency event, even if the event were cleared within four cycles. In the study's simulations, daytime peak loads easily pushed system frequency over the 60.5 Hz solar PV trip setting.  Preventing solar PV tripping required significant system improvements as well as rewriting the operating rules for the DERs themselves.

The study recommended further research into UFLS design because over shedding load risked system collapse. Modeling energy storage resources was crucial: without energy storage, loss of a single fossil-fueled unit on the system could lead to the loss of legacy PV solar, and system collapse. Furthermore, faults near the proposed Waena units could desynchronize the system, and risk system collapse, unless rapidly cleared.

The study indicated that moving to a lighter-inertia system with narrower security margins had consequences. The activity of individual DERs became dramatically more critical. As the number of DERs increased, it became more and more significant that Hawaii's ride-through requirements for solar PV were inadequate, and that some solar PV installations

[11] John D. L. Hieb, James W. Cote Jr., David W. Burlingame of Electric Power Systems, Inc.; Maui Electric Company Ltd. Curtailment Reduction Plan Impact Study; June 30, 2014.

were out of compliance even with these inadequate provisions. MECO also recognized that increasing ride-through requirements might limit penetration to protect feeders from high voltages following isolation.

The study's recommendations required fine-tuning generation and transmission, which in turn required significantly upgraded and reinforced communications. Failed relaying protection could result in a delayed clearing, and system collapse. The study also recommended upgrading the MECO under-frequency load shedding (UFLS) system so it could survive large contingencies and control 55-65% of the MECO load. The recommendations focused on carefully operating a reinforced centralized grid.

Hawaii hosted several other DER experiments and demonstrations, e.g., the well-publicized MECO JumpStart Maui experiment that included electric vehicles and stationary batteries. In comparison, the MECO Pukalini analysis was practical, and worrying, indicating as it did that DERs had serious impacts in specific situations, and there were upper-limits to the DER hosting capacity on the *status quo* grid. The Pukalani study also revealed that characterizing the combined performance of operating grid devices under diverse conditions was very difficult. HCA was essential, and much more complex than it had seemed initially.

### EPRI Feeder DER Control Comparison: DMS vs. Autonomous (2018)

EPRI has worked with many utilities that are developing HCA policies and practices and has led efforts to bridge iterative and stochastic approaches to HCA through its DRIVE approach. A 2018 EPRI Technical Brief[12] takes a more in-depth look at how various impact factors can interact to determine DER hosting capacity.

The EPRI study examined data from two 12 kV feeders and control, each of the two experimental feeders with three possible locations for a single large-scale DER (i.e., a solar PV installation). According to peak and off-peak load snapshots, and OpenDSS analysis of thermal and voltage constraints, one of the experimental feeders had three regulators and a high DER hosting capacity, and the other had no regulators and a low DER hosting capacity.

Feeder 683, the low-hosting line, had a 5.5 MW peak capacity, a three-phase line-tap changer (LTC) at the feeder head, three-line regulators located near its midpoint and a single 1200 KVar capacitor located upstream of the line regulators. Feeder 420, the high-hosting line, also had a 5.5 MW peak capacity, three single-phase line regulators at the feeder head, and a single 1200 KVar capacitor located on a lateral near its midpoint. Both lines were assumed to have an off-peak load 20% of peak, a maximum DER size of 10 MW of solar PV, and the smart inverter ability to provide reactive power at maximum DER output.

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[12] *Value of a Distribution Management System for Increasing Hosting Capacity: Centralized vs. Autonomous Control of Distributed Energy Resources.* EPRI, Palo Alto, CA: 2018. A Technical Brief

Each of the two feeders could control its DERs through LTC/regulator taps, capacitors, and -- for volt/VAR and power factor control -- reactive power. OpenDSS indicated tap, capacitor, and PV reactive power control settings for local autonomous control. Centralized control was modeled in three forms: (1) for all control devices, (2) for distribution assets only (regulators and capacitors), and (3) for PV reactive power control alone. Under the various control schemes, the study solved for the maximum PV size that did not cause voltage violations or thermal overloads.

In a 2017 presentation in Hawaii, “Hosting Capacity Methodologies and Relevant Use Cases,”[13] EPRI’s Mathew Rylander summarized hosting capacity impact factors considered at the time:

[13] “Hosting Capacity Methodologies and Relevant Use Cases,” a presentation to “Pathways to an Open Grid,” Oahu, Hawaii. EPRI, Palo Alto, CA: 2017.

| Impact | | Hosting Capacity Impact Factor |
|---|---|---|
| High | DER | Location |
| High | DER | Type/Technology/Portfolio |
| High | DER | Smart Inverter |
| High | DER | Communication and Control |
| High | DER | Aggregation |
| Medium | DER | Efficiency |
| Medium | DER | Single-Phase |
| Low | DER | Vendor |
| Low | DER | Plant Layout |
| Medium | DER | Local weather patterns (renewables) |
| Medium | DER | Panel orientation (PV) |
| High | Distribution | Voltage control scheme |
| High | Distribution | Configuration/Reconfiguration |
| High | Distribution | Load Level and allocation |
| High | Distribution | Phasing information (load/laterals) |
| Medium | Distribution | Protection system design |
| Medium | Distribution | Granularity of MV models (# of nodes) |
| High | Distribution | Grounding practices |
| High | Misc | Time |
| Medium | Misc | Modeling of service transformers |
| Medium | Misc | Modeling of services/secondaries |
| Low | Misc | Planning software platform |
| Medium | Misc | Transmission constraints |
| Medium | Misc | Transmission grid configuration/dispatch |

**Figure 2: Hosting Capacity Impact Factors**[14]

The researchers note that while all of the distribution factors are rated as medium or high impact, the distribution perspective is based on modeling (i.e., schemes, allocations, designs, models, and practices) rather than actual operating conditions.

The technical brief addresses explicitly three of the high-impact factors EPRI had identified in its Hawaii presentation: DER location, DER communication and control, and voltage control schemes. The researchers will return to these factors again and again in our report. The study investigated the effects on hosting capacity of two different control methods: the use of a Distribution Management Control (DMS) system, and local autonomous control.

The technical brief analysis portrays a variety of operating outcomes, depending on the siting of the DERs, the feeder itself, and the control schemes. The *status quo* grid is still strongly represented by the peak and off-peak metrics, the performance of control

[14] "Hosting Capacity Methodologies and Relevant Use Cases," *ibid*, p.7.

devices, and the DERs' performance. The results for each of the two feeders at three different locations were as follows[15]:

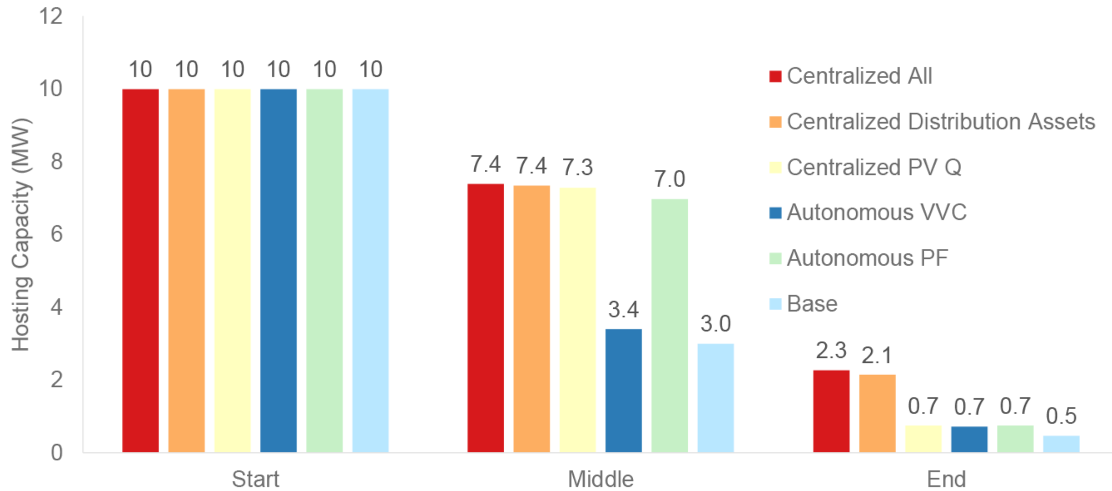



**Figure 3:**
**Hosting Capacity for Three Locations: Feeder 683**

Thermal constraints under complete centralized control limited the end-of-feeder hosting capacity of Feeder 683, and by voltage constraints in all other cases. In contrast, the end-of-feeder hosting capacity on Feeder 420 was limited by thermal constraints in every case except autonomous volt/VAR, which was constrained by voltage.

[15] EPRI, *Ibid*

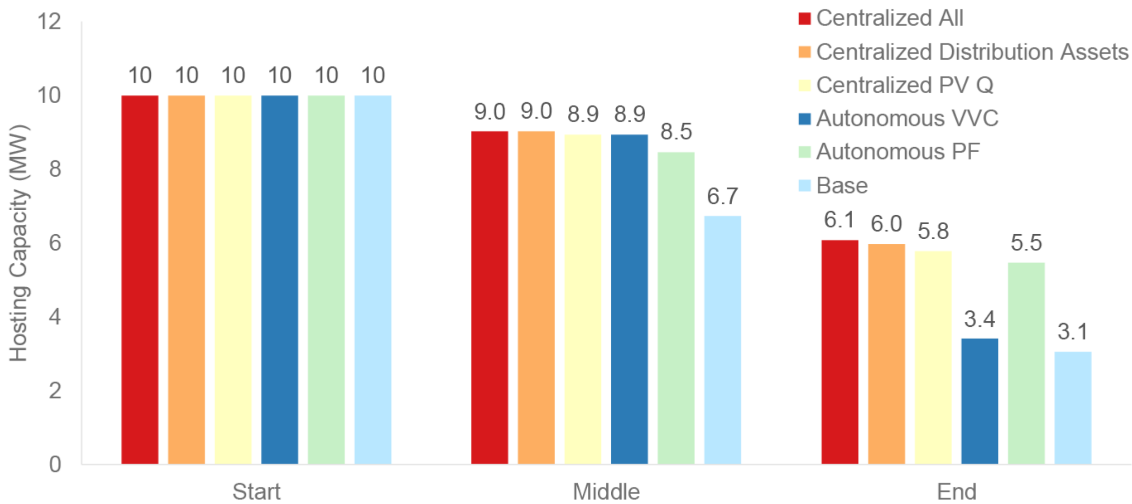



**Figure 4:**
**Hosting Capacity for Three Locations: Feeder 402**

The results indicate that in many cases, control schemes can significantly influence hosting capacity. Hosting capacity is influenced by where assets are, but it is also influenced by how assets act individually and in aggregate.

**Table 1: Percentage Increase in Hosting Capacity for Each Case Over the Base Case**

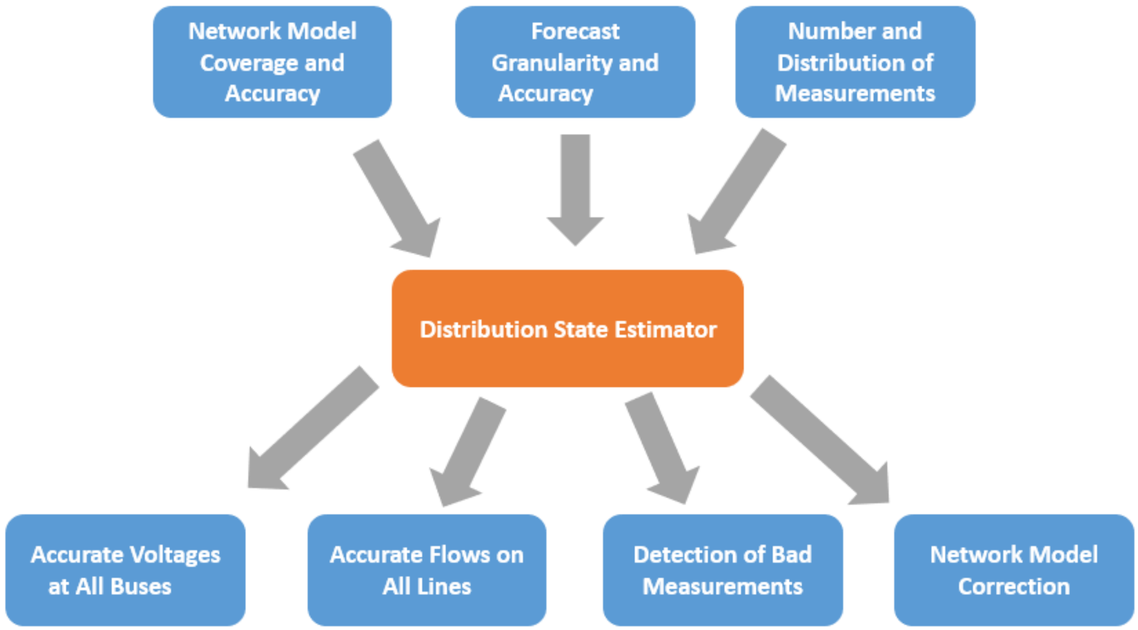
| | | Centralized all | Centralized Distribution Assets | Centralized PV Reactive Power | Autonomous volt- var | Autonomous Power Factor |
|---|---|---|---|---|---|---|
| Feeder 683 | Start | 0% | 0% | 0% | 0% | 0% |
| | Middle | 147% | 147% | 143% | 13% | 133% |
| | End | 360% | 320% | 40% | 40% | 40% |
| Feeder 420 | Start | 0% | 0% | 0% | 0% | 0% |
| | Middle | 34% | 34% | 33% | 33% | 27% |
| | End | 97% | 94% | 87% | 10% | 77% |

Note that the hosting capacity estimates in each case are not optimized but are set to remain within constraints during short-term variances. Because DER location and use interact in their grid impacts, and because feeders differ, HCA is complex even in a single instance. Because these circumstances change as DERs, grid devices, loads, and control systems change, HCA results will change. In other words, the hosting capacity of the grid directly depends on grid operations.

### ComEd: Distribution Linear State Estimation (DLSE)

While EPRI was working to improve HCA models for immediate application in Hawaii and California, ComEd, a leading Chicago-based Illinois utility and Exelon subsidiary, was preparing for its future by completing a comprehensive baseline assessment of its system-wide hosting capacity. Many prior HCA studies had been project-based, aimed at validating interconnection proposals. With relatively few DERs being installed, ComEd had little urgency around resolving the differences in the structure and outputs of leading HCA models. Instead, ComEd was among a few utilities that sought to improve planning and strategy through larger-scale HCA modeling.

After substantial time and investment, ComEd's initial HCA supported operating scenarios atop individual feeder models and provided maps and planning guidance.
However, while ComEd's grid information was substantially accurate, like many utilities, ComEd had few sources of feeder data and almost no data beyond its substations. Determining and monitoring DER hosting capacity requires mapping data measurements to grid state variables. The lack of suitable data meant that the state estimation tools previously applied in the transmission sector could not be easily extended to distribution. NYSERDA describes the situation:




Source: *Fundamental Research Challenges for Distribution State Estimation to Enable High-Performing Grids: Final Repo*rt, NYSERDA Report Number 18-37 | May 2018[16]

**Figure 5:**
**Input Quality Versus Possible Outputs to a Distribution State Estimator**

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Typical state estimation tools for distribution currently make the most of SCADA data, PMU data, and GIS-supplied topology information. But distribution state estimates are also critically dependent on so-called "pseudo-measurements" (AKA estimates) of factors such as load forecasts at distribution transformers or interconnections. Third-party distribution planning tools are also dependent on these inputs, which have an uncertainty of +/- 50%. HCA cannot be better than the state estimation it is based on, and state estimation cannot be better than its inputs.

Addressing these limitations directly, ComEd's approach to DER hosting focused on DLSE development. To define the instances hosting capacity must satisfy, feeder by feeder across the 8,760 hours in a year, DLSE will be required to leap static system modeling and mapping to the dynamics of effective and secure system operations.

[16] New York State Energy Research and Development Authority (NYSERDA): 2018. "Fundamental Research Challenges for Distribution State Estimation to enable High-Performing Grids," NYSERDA Report Number 18-37. Prepared by Smarter Grid Solutions, New York, NY. p. 133. Available at: nyserda.ny.gov/publications

ComEd has built out its Grid of the Future Lab in large part to develop and test its stochastic DLSE approach and has partnered with a software vendor to test simulations of several feeders. The partners continue to refine the model and a set of related hosting capacity tools[17]. Field tests are anticipated. To help populate the DLSE model, and identify suspect data, ComEd's software partner has customized the three-phase, near-real-time DLSE to accept phasor measurement unit (PMU) signals from ComEd's Bronzeville Community Microgrid cluster. ComEd has been deploying PMUs for field testing across several substations, in anticipation of DER growth.

ComEd has used its DLSE to test DER control. Although the system has been challenged by feeder model flaws, missing data, and model run times in its work, it has helped deliver a series of system-wide hosting capacity maps. It is helping ComEd plan future investments in DERMS and Advanced Distribution Management Systems (ADMS) software.

ComEd's DLSE project indicates how dependent managing DER grid impacts will be on software development, and how much development remains to be done. It also indicates how dependent HCA will remain on estimation. The grid will never be directly and accurately monitored at all times in all places, even though engineers will improve their understanding of the grid through indicators (e.g., voltage) captured at intervals in selected locations. Grid indicators will never be communicated instantly and completely at all times to all of the places where they might be needed, even though engineers and software designers will continue to identify which communications are most important.

### California Distributed Resource Plans

In California, HCA was accelerated by the California Public Utilities Commission (CPUC) Rulemaking (R.14-08-013), requiring the regulated utilities to participate in a Distribution Resource Planning (DRP) process to incorporate DERs into the grid better. The CPUC was focused on (1) accommodating two-way energy and energy services flows, (2) reducing greenhouse gas emissions while improving reliability and reducing costs; and (3) creating opportunities for DERs to supply grid services. While the incremental DRP process remained within the centralized grid model, it emphasized that utilities find significant roles for DERs within it. The DRP process also moved DER planning and rulemaking squarely into a collaborative process based on informal dialogue in working groups and tool development rather than rate making.

While California is deploying more DERs than any other jurisdiction, and while California distribution planners have spent more time considering hosting capacity than the rest of North America combined, PG&E, SDG&E, and SCE have all approached HCA cautiously. The IOUs rechristened the concept as "integration capacity analysis" (ICA), and generally favor more intensive iterative approaches. The CPUC is pressing the California IOUs to

[17] L. Garcia-Garcia and D. Apostolopoulou, "State Estimation in Distribution Systems, Commonwealth Edison Company," in *Grid of the Future Symposium*, Chicago, IL, 2015.

base their interconnection decisions and process designs on their ICA work; to date, the utilities have been willing to incorporate ICA as guidance for these activities.

ICA became part of "Track 1" within the California DRP proceedings, alongside Locational Net Benefits Analysis (LBNA)[18]. Utilities were directed to form joint Working Groups and to conduct individual demonstration projects at each utility (for Track 1, these are Demo A and Demo B). In 2016, based on the initial findings of the ICA Working Group, the CPUC supplied more specific guidance on ICA methodology, going beyond the original PG &E-derived baseline ICA approach to pose nine functional requirements for ICA. Among these were to "quantify the capability of the distribution system to host DERs," and "determine thermal ratings, protection limits, power quality (including voltage), and safety standards."[19] After more discussion and guidance, the ICA Working Group submitted its final report in 2018.

The California IOUs have produced hosting capacity maps but have been reluctant to establish DER hosting policies based on them. No streamlined, iterative, or stochastic method has emerged as a preferred California standard, despite CPUC direction. All three utilities have signaled that they anticipate new versions of ICA to emerge based on practical experience. In a familiar practice, the next stages of analysis will include a broad set of stakeholders, and to consider price signals along with the grid data. PG&E has stated that new visibility and monitoring capabilities in distribution management systems should precede any standard use of HCA.[20]

Without reviewing the entire course of ICA development in California's DRP process, the researchers would note three points. First, no complete "California solution" has yet emerged for ICA. Second, the CPUC's broad ambitions for DRP are still in sight[21] but aren't close to realization, and there is no indication that the collection of California research & development projects (e.g., Demos A-E), will fulfill these ambitions. Third, the scale of DER deployment in California will soon have grid impacts like those that have led Hawaii to innovative and even radical DER plans.

### Other HCA Investigations

In the past decade, many distribution planners outside of California have taken up HCA, with the help of EPRI and other experts. A complete review of these efforts is beyond the

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[18] ICA and LBNA were intended to support one another, but the LBNA efforts struggled to achieve working methods to value DERs in place.

[19] CPUC – California Public Utilities Commission. 2016: *Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769; In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769*. Rulemaking 14-08-013. San Francisco, California. Accessible at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M161/K474/161474143.PDF.

[20] Mark Esguerra, PG & E Director, quoted in "*Why are the newest distribution system buzzwords 'hosting capacity analysis'*", Utility Dive: 17 January 2018 and confirmed in private conversation.

[21] CPUC Decision 18-02-004 (2018) requires Grid Needs Assessments and Distribution Deferral Opportunity Reports from utilities. CPUC Decision 18-03-023 (2018) provided guidance for utility grid modernization plans.

scope of this study, but examples include work in New York State, Minnesota, and the Pepco Holdings (Exelon) territory (including Washington D.C., and parts of New Jersey, Maryland, and Delaware).

In New York state, the New York Public Utilities Commission included hosting capacity in its 2014 Reforming the Energy Vision (New York REV) initiative. In New York REV, HCA was one aspect of the Distributed System Implementation Plans (DSIPs) utilities were required to jointly develop as they created Distribution System Operators (DSOs). New York regulators did not set parameters for HCA accuracy, precision, or effectiveness.

The New York utilities turned to EPRI and its DRIVE tool to help create HCAs that could inform interconnection, planning, and DERs' locational value. However, working with a relatively narrow set of stakeholders, the New York regulated utilities focused only on siting large-scale solar projects along a gradual path to introducing HCA, with no particular use cases specified at the outset.

The New York utilities are gradually moving from distribution indicators to iterative and advanced hosting capacity evaluations. However, they are still far from the goal of fully-integrated DER value assessments. The exclusion of storage, electric vehicles, and small-scale solar from the DSIP HCA work has become an increasingly significant limitation of the New York HCA work.

Motivated by Minnesota regulations mandating grid modernization to support DERs, Xcel also approached HCA in partnership with EPRI. Xcel's focus was on feeder hosting readiness as indicated by its aspirational data requirements:[22]

- Granular: capture unique feeder-specific responses
- Repeatable: as distribution feeders change
- Scalable: system-wide assessment
- Transparent: clear and open methods for analysis
- Proven: validated techniques
- Available: utilize readily-available data and tools

Xcel's HCA work has achieved regulatory compliance, but Xcel acknowledges that its HCA maps, based as they are on EPRI's streamlined DRIVE approach, have different assumptions, data, and criteria than Xcel's iterative interconnection studies. Work remains to be done to integrate the two perspectives. It is also very significant that Xcel has switched its HCA focus from accommodating small-scale DERs, to reducing the time and costs of interconnecting new large-scale DER projects.

Xcel's HCA included a variety of voltage and thermal constraints, as well as deviations in feeder and breaker relay fault currents. Xcel's HCA indicated that approximately ¾ of feeder DER limits were caused by voltage constraints, and ¼ by thermal constraints. As expected, shorter feeders with more concentrated loads and higher voltage had higher

[22] "*Minnesota Hosting Capacity Analysis*", by Chris Punt, MIPSYCON, Xcel: Minneapolis, MN: 2017, p. 4

DER capacity. While 17% of feeders seemed to have no DER hosting capacity, 59% had 1 MW capacity or more, and the average minimum hosting capacity was 1.5 MW. In an artifact of modeling, very few feeders showed DER hosting capacities above 10 MW, while dozens clustered at the 10 MW level.

Pepco had an early interest in the grid impact of distributed resources[23], and with the aid of a federal Department of Energy (DOE) grant assembled a system-wide HCA in 2015 across their franchise territory in New Jersey, Maryland, Washington D.C., and Delaware. Pepco's internally-developed stochastic HCA method used scenarios to indicate where DERs could be and might be located without violating hosting constraints (thus indicating further study), and where adding DERs would violate hosting constraints.

Pepco employs power flow modeling (PFM) and electrical distribution design (EDD) in automated tools to evaluate interconnection applications. While it may take the applicant some time to gather the required data, the applications themselves can be evaluated within minutes.

Pepco uses its HCA results to bypass or require specific interconnection studies on designated "restricted circuits," depending on the size of the DERs under consideration (<50 kW, <250 kW, >250 kW). The interconnection studies specify the distribution infrastructure investment required to permit individual DER projects. Pepco has undertaken its HCA effort in the absence of any regulatory direction or stakeholder review, to define DER interconnection as clearly as possible. To date, the focus has been primarily on solar projects.

While Pepco's approach is modern and streamlined, its HCA voltage and thermal constraints and impact mitigation requirements are very conservative.[24] Regulators across the Pepco franchise have taken an interest in Pepco's HCA work, reviewing Pepco's procedures and cost assumptions as part of larger-scale efforts to improve distribution planning.

In summary, planners in Hawaii, Illinois, California, and other regions have used HCA as a generally-accepted starting point for understanding the impacts of DERs on the grid. But HCA hasn't been standardized, and it can't yet replace interconnection studies. In some situations, HCA work has confirmed that DERs can have severe impacts on the *status quo* grid. But not all of these situations can be easily forecast or located. Changes in weather; the deployment of solar, storage, and electric transportation; and grid operating protocols can alter HCA results significantly. Most important, available grid data is insufficient to accurately model and characterize the combined impacts of operating DERs. State estimation models are incomplete, and they struggle to support location-based impact and value assessment. HCA development continues.

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[23] Pepco Holdings, Inc., *Model-Based Integrated High Penetration Renewables Planning Control and Analysis*, pp. 7-10 (Dec. 14, 2015); see also EPRI, Stochastic Analysis to Determine Feeder Hosting Capacity for Distributed Solar PV (Dec. 2012).

[24] Steve Steffel, Pepco Holdings, private conversation.

## C- Introducing Smart Inverters

In their second task, planners are preparing to manage DERs by introducing interconnection requirements with smart inverters. Many utilities and other industry experts are involved in efforts to codify advanced inverter functions, seeing DERs as everyday grid components that need to be standardized. Standardized inverters could control DER operations and produce more grid data and communicate in real-time.

As noted above, moving past the 15% heuristic to an effective baseline for DER operations has required distribution planners to estimate hosting capacity. But DERs have delivered too little data and operated in too many modes for HCA to absorb. DER grid impacts cannot be understood, let alone managed, through hosting maps alone. HCA has indicated when more detailed DER interconnection studies may be required to permit a project, but these intensive studies are prohibitively expensive for deploying smaller DERs. Small DER projects often receive streamlined approval, as long as the HCA indicates the feeder should have the capacity for them. Even for larger DER projects, the interconnection studies analyze only a limited range of conditions.

Early on, these limitations once seemed to be acceptable for isolated, passive DERs with simple roles: i.e., just here, under familiar conditions, this DER or that seemed unlikely to get into too much trouble. Early DERs had only a limited range of functions. They lacked sensor and communications capabilities. They couldn't document and report on their circumstances, they weren't aware of their grid impacts, and they couldn't receive or execute central instructions about how to behave. Most of the string and microinverters for these DERs converted AC power to DC power and automatically disconnected from the grid when they detected a significant local fault (e.g., a significant voltage or frequency deviation), but they did little else. By remaining simple, economical, and "dumb," DER inverters didn't add much to the costs and operating risks of solar power.

But as the costs and risks of solar power fell, DERs proliferated, and the roles of DERs expanded. The lack of data and control began to stress grid planning and operations. Automatic DER disconnection wasn't always so automatic, didn't scale well on feeders hosting many DERs, and could amplify minor incidents into severe outages. Especially in concert, DERs could get into a lot of trouble after all. The grid impacts of DERs derived not only from *where* they were, but from *what* they were, and what they were was primitive.

Complex, expensive, and customized inverters had been available, and they included some reasonably-reliable two-way communications and control capabilities. But these inverters were unusual and limited. EPRI worked with many utilities on Smart Grid demonstrations, including DERs, and recognized that the functionality and communications of these early smart inverters would need to be upgraded. EPRI recognized that inverters were ubiquitous control devices that could serve as the logical starting point for standardizing DER functionality. Still, first, the industry would need standard functions, information models, open protocols, grid models, and compliance tests. Beginning in 2008, EPRI organized over 600 experts from manufacturers, integrators, utilities, universities, and research organizations in a multi-year effort to identify smart inverter features and functions.

The ongoing dialogue EPRI fostered industry development and led directly to the IEEE 1547 and California Rule 21 interconnection standards. In jurisdictions where DERs were multiplying, communicating smart inverters became suitable components to consider. By 2015, “smart” inverters tested by HECO and SolarCity[25] in Hawaii proved they could provide suitable ride-through during disturbances. The introduction of smart inverters became the second major task on the way to managing DER grid impacts.

### 1. Regulation and Standardization

The Hawaii smart inverter tests occurred as DER penetration levels in Hawaii and California were rapidly exceeding the penetration levels FERC had anticipated. Both FERC’s screens and the states’ supplemental reviews proved inadequate.

In response, with many of the same participants as EPRI’s collaborative, California created Rule 21 and rewrote Net Energy Metering (NEM) rules. California’s Rule 21 is a mandatory DER interconnection tariff developed by the Smart Inverter Working Group (SIWG), a broad set of stakeholders spanning utilities, regulators, manufacturers, developers, associations, and advocates. SIWG’s effort began in 2013; Rule 21 was adopted in 2017. Rule 21-compliant inverters are now listed on a California Energy Commission (CEC) database and are generally UL-1741-SA-listed as well. Rule 21 also requires that installers enable certain inverter features (e.g., smooth disconnection/ reconnection in an outage (anti-islanding), damping voltage deviations via reactive power management)[26].

The first phase of Rule 21 addressed voltage and frequency ride-through and reactive power control. The second phase, addressing Internet communications, was introduced in January 2020. The third phase of Rule 21, regarding data monitoring, remote grid connection and disconnection, and maximum power controls, has been delayed several times and has yet to be completely specified and scheduled.

Both the second and the third phase of Rule 21 have been controversial. The second phase sets quite demanding and complex communications, testing, and documentation requirements. The third phase must address controlling customer energy use and storage to meet the utility grid and climate objectives. Substantive revisions to Rule 21 are

[25] “Can Smarter Solar Inverters Save the Grid?” by Benjamin Kropolski, IEEE Spectrum, October 2016; test reports in www.NREL.gov/docs/fv15osti/63510.pdf

[26] A range of frequency regulation, power quality and voltage management functions are specified in IEEE 1547-2018. While the frequency regulation and power quality functions are required to be turned on by default, the voltage management functions are not, due to concerns about customer impacts depending on location.

ongoing, particularly regarding compatibility with IEEE 1547-2018, communication certification, and cybersecurity.

The IEEE revised IEEE 1547, eventually released IEEE 1547-2018[27], and follow-up conformance and testing provisions, in parallel with the California Rule 21 work. IEEE 1547-2018 (IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces), requires all inverter-based DERs have a range of specific grid-supporting inverter functions. Also, IEEE 1547-2018 requires all other DERs to support these functions as well.

Grid-interconnected DERs must ride through voltage and frequency variances; be able to provide voltage regulation, frequency regulation, and power quality support; manage reactive power; and meet communications and control standards. DER interconnection itself is standardized. IEEE 1547-2018 provides a range of options for DER deployment requirements across the range of DER types. Product specifications are arriving in IEEE Standard 1547.1, IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems,

One of the most important aspects of IEEE 1547-2018 is the distinction between DERs' Normal Operating Performance and Abnormal Operating Performance. Normal Operating Performance specifies the level of reactive power a DER must be capable of supplying to regulate voltage locally during normal conditions. Assigning DERs to several categories, Abnormal Operating Performance specifies the level of voltage and frequency ride-through a DER must display in the event of disturbances. The distinction acknowledges that in abnormal conditions, the impacts of DERs can be positive as well as harmful.

An example of DERs' positive impacts is the mandatory role in voltage control IEEE 1547-2018 assigns to DERs within normal operations. Voltage variances will impact a DER's location due to distance from a substation or regulation devices, feeder design, utility practices, and the presence of other DERs. Smart inverters enable alternative DER power modes to manage voltage by applying reactive power: constant power factor, voltage-reactive, active power-reactive, and constant reactive. Smart inverters also enable voltage-active power mode (AKA volt-watt), which decreases voltage through active power. Utilities will have to decide when and how to activate these different capabilities.

The normal/abnormal distinction and smart inverters' function definitions have boundary cases and consequences that have yet to be fully evaluated. For example, inverter-based voltage regulation will increase DER hosting capacity. But due to reactive power requirements and use of the voltage-active power mode, the application of inverter-based voltage regulation will reduce customer generation, and as a result, customer revenue. One view maintains that these reductions are suitable to protect the grid. Another view maintains that these reductions result from device constraints not envisioned in tariffs. Both positions are correct.

[27] https://standards.ieee.org/standard/1547-2018.html

Smart inverters initiatives have also arisen in other locations. In Arizona, Hawaii, Massachusetts, Nevada, Vermont) utilities and standards organizations are examining these DER standardization initiatives and planning to update their inverter specifications. Hawaii created rule 14-H and prohibited export from residential DERs to the grid. UL, MESA, SunSpec, and the IEC worked on DER-related standards. North American distribution planners also noted the decision in Germany to replace more than 300,000 traditional inverters with smart inverters.

Meanwhile, NREL was assessing smart inverters for help with another grid impact from DER proliferation: the loss of inertia. The mechanical inertia delivered by the rotating mass of traditional power plants naturally dampens frequency and voltage disturbances, but DERs are frequency-following and don't supply inertia to the grid. Frequency and voltage disturbances are more intense and harder to manage because droop control is difficult. The droop control methods capable of balancing inertial forces across multiple plants are slow and computationally-intensive when applied to inverter-based systems. NREL has begun to test virtual oscillator control (VOC) to align inverter responses better than droop control, working toward software that could manage the inverters in real-time[28].

Today, smart inverters have taken on many roles beyond converting DC to AC power: e.g., reporting, monitoring, and scheduling; supporting grid frequency, real power, power factor, and voltage. Smart inverters have added real-time visibility, communications, and control to DERs. Inverters for solar PV systems have a different function set than inverters for storage systems, but many of the basics are similar. These inverter functions focus on the Point of Plant Control (PPC),[29]e.g., in its simplest case where an individual residential electric panel and individual inverter connect in a residential PV solar system. The inverter's activity impacts both the DER and the grid from the PPC, where control may be by the operator (e.g., connect/disconnect), by the inverter itself (volt, watt, VAR, power factor functions), or by data streams (e.g., electrical, pricing, temperature, time).

Today's DER smart inverter design has also influenced the design of both DER Management Systems (DERMS) software and the DERs themselves. DERMS software allows distribution planners to aggregate DERs (e.g., as Virtual Power Plants (VPPs), and combine them with other grid resources (e.g., battery storage, microgrids, demand response), to coordinate a response to grid conditions. Inverter standardization has helped individual utilities (with the support from standards and research organizations) find some common ground in their DERMS requirements. Through the SIWG, the smart inverter movement also helped identify gaps in individual DER capabilities, recommend new DER specifications, and standardize many DER functions.

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[28] See for example "Laboratory Testing of a Utility-Scale PV Inverter's Operational Response to Grid Disturbances," presented by NREL at the IEEE Power & Energy Society General Meeting, August, 2018.
[29] Device specifications may also note the Point of Common Coupling (PCC) and the Electrical Connection Point (ECP). Complexities arise in commercial systems and in systems combining solar and storage resources. See *Common Functions for DER Group Management*, *Third Edition*. EPRI, Palo Alto, CA: 2016. 3002008215.

Smart inverters encouraged the deployment of DERs, in part because they made DERs simpler to add, and feasible at many new sites. Smart inverters also aimed to make DERs more acceptable to the *status quo* grid. Power can reverse flow from time to time in manageable ways. Industry authorities can turn their attention to field demonstrations of the new management processes defined in the standards. They can continue to work on the difficult challenges of inverter communication and control.

But smart inverter design is not finished: the rise of behind the meter energy storage paired with solar photovoltaics as a “bundled” DER promises an even larger disruption of the *status quo* than bidirectional power did. Beyond short-duration batteries, the potential for energy storage is for loads to become resources, allowing energy to be produced and consumed almost anywhere, anytime, at will. The grid, the electric power industry, and energy use all transform under these conditions. The continued development of inverter design will be part of this transformation. To begin that work, EPRI engineers and other experts have begun to combine storage integration with DER standardization and extend IEEE 1547-2018 and IEEE 2030.5-2018 (Standard for Smart Energy Profile Application Protocol) to energy storage.

## 2. Guiding Concepts & Investigations

The second task distribution planners addressed as DER deployment accelerated was requiring smart inverters.

As noted, IEEE 1547-2018 and California’s Rule 21 require grid-interconnected DERs to ride through voltage and frequency variances; be able to provide voltage regulation, frequency regulation, and power quality support; manage reactive power; and meet communications and control standards. DER interconnection itself is also standardized. These requirements and their relationships to grid impacts have been illustrated in many investigations.

Inverter and DER manufacturers are now recertifying their products under IEEE 1547.1 and UL 1741[30], and are aiming to have compliant products in commercial markets in 2021. Under IEEE 1547.1, DER manufacturers must be validated at the unit, system, and composite levels across type, production, design, and periodic tests. Under UL 1741, interconnection equipment must receive safety and performance certifications. The procedures and metrics for these many examinations are now under debate. IEEE 1547.2, the application guide for IEEE 1547.1, is now under active development. As expected, inverter manufacturers are concerned that the options and profiles they provide should align with the state-by-state requirements that are emerging (e.g., the requirements for SEP 2.x, DNP3, or SunSpec ModBus communications).

[30] “Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources”. Available at https://standardscatalog.ul.com/standards/en/standard_1741_2

Hundreds of professionals are engaged in diverse processes related to IEEE 1547, but as a July 2019 workshop[31] illustrated, a consensus is still some distance away. As noted above, in California, the Rule 21 debates continue similarly, with Phase 2 postponements and slow progress on Phase 3. Smart inverters are arriving, with functions that are locally-autonomous and centrally-controlled, applicable as alternatives, and applicable together, mandatory, and optional. But what these functions will be asked to do, and how they will do it is still in question.

Several investigations illustrate how smart inverters have arrived, and may be applied in the future:

### Enabling Smart Inverters for Distribution Services (2018)

The Joint IOU Smart Inverter White Paper*, "Enabling Smart Inverters for Distribution Services,"*[32] was prepared by the three California IOUs and collaborating industry stakeholders such as the Association of Edison Illuminating Companies (AEIC), EPRI, NREL, ICF International, and DER vendors. The paper addressed three questions:

- What considerations need to be addressed for Smart Inverter-enabled DERs to become an effective technology to maintain and enhance distribution grid safety, reliability, and customer affordability?
- What are the key learnings that the IOUs have gained on Smart Inverters through demonstration projects?
- What questions remain unanswered?

The perspective of this research is valuable as it was based on the implicit assumption that managing DERs' negative grid impacts would be accomplished through smart inverter design, and DERs' positive grid impacts have become the priorities to be addressed. HCA struggled to identify and localize the negative grid impacts and generally regarded positive grid impacts as a bonus. The movement to smart inverters regarded DERs' negative grid impacts as manageable costs and moved on. California Rule 21 illustrates this perspective, defining a smart inverter as:

> an "inverter that performs functions that when activated, can autonomously contribute to grid support during excursions from normal operating voltage and frequency system conditions by providing: dynamic reactive/real power support, voltage and frequency ride-through, ramp rate controls, communication systems with the ability to accept external commands, and other functions.[33]"

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[31] Distributed Generation Integration Collaborative Workshop, Overcoming Challenges for DER Interconnection, IEEE Standards Association, Washington, D.C.: July 29, 2019.

[32] "Enabling Smart Inverters for Distribution Grid Services," White paper by PG&E, San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE), Oct. 2018. Available at: https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/Joint-IOU-SI-White-Paper.pdf.

[33] PG&E Rule 21 interconnection tariff: https://bit.ly/2pRY540

The examples of grid services cited in the White Paper included

- capacity deferral, including managing both DERs and loads to limit the investment in distribution infrastructure,
- voltage support, including the injection and absorption of reactive power, and the limiting of active power,
- resiliency (e.g., microgrid), including outage recovery for intentionally-islanded customers through the operation of an *ad hoc* microgrid, and
- reliability (e.g., back-tie), reducing the frequency and duration of outages by transferring capacity from feeders with spare capacity to feeders in need.

The White Paper acknowledged that traditional devices, as well as DERs, could provide these grid services, and it admitted that these grid services would come at a cost: DERs have their impacts. PV systems can increase voltage and voltage variability on service transformer (low-voltage) secondaries and primary (medium-voltage) systems, depending on local conditions. Thermal problems can arise from high reverse power flows. DERs can interfere with protection systems and mask load. But enabling Volt-VAR and volt/watt functions through smart inverters could address these issues, and help ensure reliability and safety for DER operations.

Drawing from SIWG analysis and the Rule 21 definition, the white paper distinguished autonomous and active inverter control modes. Autonomous modes, resembling capacitor and grid voltage regulator operations, act when automatically triggered by DER-detected conditions. Autonomous DER capabilities may help avoid grid reinforcement, ride through momentary frequency or voltage disturbances, inject or absorb reactive power to support voltage, limit real power output, aid in a start-up after an outage, and increase DER hosting capacity.

Active modes, resembling sectionalized operations, act when SCADA data leads a DMS or a grid operator to communicate with the DER. Active DER capabilities can provide validation of local conditions and DER operations, trigger DER operations deliberately, and can also enable battery storage. Active modes are particularly important for grid services when a DER's performance is dictated by the distant requirement as well as local conditions.

The White Paper identified six key considerations limiting the ability of smart inverter-enabled DERs to become competent and reliable grid resources: (1) DER location and volume; (2) synchronization of grid needs and DER responses; (3) grid-level availability and assurance of DER responses; (4) data coordination, measurement, and verification between utilities, DERs, and DER aggregators; (5) utility capabilities and systems for awareness, analysis, and response; and (6) the availability of standard, certified and tested inverters and trained installers.

All of these considerations remain research & development priorities today:

- DER location and volume limit the potential for smart inverter-based grid services simply because scale and scope are important. Capacity deferral and outage-related services (i.e., resiliency and reliability) are only feasible as grid services with significantly-high local penetration of DERs in stressed locations. The usefulness of voltage support is most dependent on local conditions.

- The synchronization of grid needs and DER responses is a limit because not all DERs (e.g., EVs, PV at night) are always available to meet the grid's needs, and the grid does not always need them. More energy storage and better grid software may help.

- The grid-level availability and assurance of DER responses is a limit because unlike demand response, smart inverter-based grid services have specific, consistent performance requirements that require SCADA-level communications to achieve. The consequences of inadequate performance are more than economic. Voltage and frequency deviations can be damaging.

- Data coordination, measurement, and verification between utilities, DERs, and DER aggregators limit grid planning and economic settlement with customers and third-parties.

- Utility capabilities and systems for awareness, analysis, and response limit control and dispatch, especially where vendors and third-party owners are involved. Internal utility communications across systems (e.g., distribution management, work management, customer information) limit effectiveness, especially in outages. Utilities will need robust power flow modeling, phase identification, and system visibility to manage the DERs.

- The availability of standard, certified, and tested inverters and trained installers are limits to replicating design and simulation results in the field.

The White Paper stressed that utility grid modernization investments would be required to realize the potential of smart inverter-based grid services. These investments include ADMS and DERMS software, grid sensors, communications infrastructure and extended protocols, and in particular, cybersecurity. IEEE 1547-2018 was silent on cybersecurity standards, and the California Common Smart Inverter Profile (CSIP) did not include aggregator-DER communications, thus providing a broad and unexamined threat surface.

The White Paper also emphasized that the potential for smart inverter-based grid services was limited in practice by customer acquisition, communications reliability, and the inconsistent operations of DER aggregation software. Utility distribution strategies were difficult to translate into DER operations. Smart inverters were standardized but still differed in system user interfaces and programming. Smart inverters were capable but lacked documentation and required expert installers.

Finally, the White Paper concluded that utilities should continue to assess the competitiveness of smart inverter-enabled grid services as DER penetration increased across the grid. Demonstrations and tests could certify smart inverters for certain services (e.g., frequency regulation). Research and development could identify methods for DERs to interact with other local grid-support devices, independent of central systems, thereby reducing response times, reducing vulnerability to communications outages, and bolstering DER control.

### PG&E EPIC Smart Inverter Tests (2018)

In 2018, PG&E completed an in-depth analysis of smart inverters as an Electric Program Investment Charge (EPIC) project: "EPIC 2.03A: "*Test Capabilities of Customer-Sited Behind-the-Meter Smart Inverters.*"[34] PG&E's work paralleled the higher-level consensus building in the utility White Paper, the EPRI consortium, and the Rule 21 groups. Based on the assumption that widespread deployment of DERs with smart inverters would be required to meet California's clean energy goals and expand consumer choices, the PG & E study demonstrated the field performance of BTM smart inverters.

The project aimed to demonstrate the functionalities and grid impacts of BTM smart PV inverters, through smart inverter modeling and testing of smart inverters in the laboratory followed by field demonstrations. PG&E believed that autonomous smart inverters could address islanding, voltage, and frequency disturbances; and could provide soft-start after outages, autonomous reactive (Volt-VAR), and active (Volt-Watt) power output control. Actively-managed smart inverters could also send and receive reactive power setpoints.

With these broad aims in mind, the project focused on a few aspects of SIWG's vision (bolded in the table below):

[34] "EPIC 2.03A: "*Test Capabilities of Customer-Sited Behind-the-Meter Smart Inverters"* The series of reports is available at: [https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-2.03a.pdf](https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-2.03a.pdf)

**Table 2: Smart Inverter Working Group Functions by Phase**

| **SIWG Phase I – Autonomous FX**<br><br>In effect 9/8/2017<br><br>(except for Volt-VAR, effective 7/25-26/2018) | **SIWG Phase II – Communications**<br><br>*Will be required in 2019* | **SIWG Phase II – Advanced FX**<br><br>*Will be required in 2019* |
|---|---|---|
| Support anti-islanding | Utilities to DER systems | **Monitor key DER data** |
| Ride through of low/high voltage & frequency | Utilities to Facility Energy Management Systems | DER cease to energize and return to service request |
| **Volt-Var control through reactive power injection/absorption** | **Utilities to Aggregators** | **Limit maximum real power** |
| Fixed power factor to inject/absorb reactive power | | Set active power mode |
| Define default and emergency ramp rates | | Frequency-Watt mode |
| Reconnect by “soft-start” | | **Volt-Watt mode** |
| | | Dynamic reactive current support |
| | | Scheduling power values and modes |

Source: Interim Report, p. 18, citing SIWG recommendations[35]

The modeling effort considered six representative PG&E feeders to study voltage violations across a range of typical operating scenarios. The study required exceptional levels of modeling for feeders, conventional upgrade practices, and violation mitigation practices (e.g., Volt-VAR mitigation through VAR priority rather than watt priority).

35 http://www.energy.ca.gov/electricity_analysis/rule21/documents/phase3/SIWG_Phase_3_Working_Document_March_31_2017.pdf

Consistent with the White Paper's perspective, the PG&E study regarded DERs' negative grid impacts as issues to be managed or accepted on the way to achieving positive benefits. For example, the study did not distinguish between voltage violations arising from DERs, and voltage violations arising from other sources, and did not consider thermal violations.

The smart inverter modeling in the project was notable in that it directly compared the technical and economic performance of (1) smart inverter Volt-VAR and Volt-Watt functions, too (2) regular distribution infrastructure upgrades. Smart inverter operations were modeled hypothetically and were limited to the two functions. Conventional upgrades were modeled as triggered by PG&E's prevailing design and engineering practices, which were recognized as imperfect.

The modeling indicated smart inverter operations reduced overvoltage, and often performed better technically than conventional upgrades, but did not entirely suppress violations. Active power was triggered very rarely. The study indicated that high levels of PV penetration would trigger a high level of transformer replacements and secondary voltage rise studies under conventional practices; many of these could be avoided through smart inverter operations. Smart inverter deployment was comparable in addressing voltage violations to the conventional upgrades occasioned by secondary voltage rise studies. Overall, the smart inverter approach was economically preferable to a minor degree.

The study's other significant modeling findings ranged broadly. Inadequate facility wiring (smart inverter to customer panel) was shown to impact smart inverter operations to a large degree. PG & E's preventive service transformer replacement process was demonstrated to be effective. Employing DERs to mitigate voltage violations resulted in bill increases of 3% or more for 0.74% of customers, indicating that their DERs happened to be in locations experiencing high levels of voltage violations, and confirming that DER utilization comes at a cost.

Significant field findings included these:

- Customer acquisition is a demanding and time-consuming task for field tests
- Smart inverters can help regulate local voltage through autonomous active or reactive power support
- Volt-VAR and volt-watt smart inverter functions can be executed as programmed for some inverters (if manufacturers' specifications permit)
- The real-time communications requirements for smart inverter operations exceed the asset availability, and uptime residential Wi-Fi and Zigbee can provide

- Passive, automatic smart inverter control addresses some grid constraints, but active operator intervention will be required in some instances (e.g., establishing power setpoints)[36]

- Across large numbers of widespread DERs, utility systems were unable to fully integrate operations, provide real-time control, or access full capabilities

- Vendor hardware and software was not ready for field testing and required replacement, costly integration and downgrading of communications standards
-
- Provoking voltage violations through custom and inflexible Volt-Watt curves yielded artificial results

The project demonstrated that smart inverters might help DERs overcome the problems that came with them (e.g., thermal and voltage violations, power quality issues, adverse impacts on protection systems due to reverse power flow[37]). PG&E concluded that smart inverters might also demonstrate other benefits, but more smart inverter field tests would be required, at higher DER penetration levels.

**Other Smart Inverter Projects**

In Hawaii, from 2011 until 2016, MECO partnered with HECO, Hitachi, and others to pioneer smart inverter applications as part of the JumpStart Maui project. The project was intended to develop an approach to DER proliferation while maintaining power quality, providing customers with access and control, and managing aggregated DERs.

Among its other innovations, JumpStart Maui included ten smart inverters on PV rooftops, controlled by experimental Hitachi software. The inverters responded to voltage signals from local transformers, and Hitachi set related signals to 80 electric vehicles and two medium-scale stationary batteries (153 KwH and 576 KwH). In the absence of prevailing smart inverter standards at the time, the customized devices proved challenging to develop in accord with local permitting and safety standards. Eventually, they were delivered capable of operating in limited use cases.

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[36] The project Interim Report notes that "active control (the ability to dispatch commands in response to real-time grid conditions) could potentially extend SI benefits to use cases such as on-demand curtailment by a grid operator or instances where SI-controlled DERs may be providing distribution grid services," however "most utilities, including PG&E, do not currently have the foundational capability to actively monitor or control DERs. Such applications would require SI-controlled DER solutions to be integrated with the utility DER management platform and customized to specific grid conditions, configurations and needs." Interim Report, p.7.

[37] "Emerging Issues and Challenges in Integrating Solar with the Distribution System" NREL. Accessible at https://www.nrel.gov/docs/fy16osti/65331.pdf. See also "High-Penetration PV Integration Handbook for Distribution Engineers," NREL. Accessible at https://www.nrel.gov/docs/fy16osti/63114.pdf

An ambitious project, JumpStart Maui, demonstrated the importance of smart inverter product standards, and the importance of network communications across different kinds of DERs.

Also, in Hawaii, NREL's partnership with HECO has continued to support the development of statewide DER policies based on smart inverter functions. First, NREL successfully field-tested frequency-watt activation, an autonomous smart inverter function that reacts to grid frequency by modulating output power. In response, the Hawaii Public Utilities Commission has required systemwide activation of frequency-watt activation.

Second, NREL/HECO voltage-regulation studies demonstrated that improving the voltage profile of a DER-laden feeder would require a critical mass of volt/watt and volt/VAR capabilities. Under IEEE 1547-2018, voltage-regulating functions (e.g., reactive power functions such as power factor, volt/VAR, watt/VAR, constant VAR, and active power function volt-watt) are required to be built into smart inverters but are not required to be activated. In response, HECO is now seeking these capabilities from its customers.

Third, HECO and NREL have early-stage tests underway (e.g., the GO-Solar project) to optimize DER control through smart inverter operation. In many projects underway at its Energy Systems Integration Facility (ESIF), NREL is aiming for inverter controllers to be grid-forming rather than grid-following, as grids become inverter-based. In parallel, HECO is procuring grid services from aggregated DER resources, on the theory that suppliers will be able to fulfill these contracts reliably.

In Sacramento, at the Sacramento Municipal Utility District (SMUD), NREL tested its PRECISE technology for streamlined solar PV interconnection. Since 2016, SMUD had experienced high volumes of BTM solar interconnection applications, putting voltage control and grid reliability in question as applications were expedited. NREL had been exploring preconfiguring smart inverters with settings accounting for clustered locations and seasonal weather patterns, eliminating much of the application-specific analysis and validation interconnection could demand.

SMUD field tests in 2018 demonstrated that as part of a real-time operations platform, PRECISE (PREconfiguring and Controlling Inverter SEtpoints) could reduce the utility's interconnection backlog from 10-15 days to 5 days. Constraining inverters to certain modes enabled DER hosting for limited purposes. Defining cases for these constraints allowed the utility to assign constraints by address. Preconfiguring the inverters enabled the constraints to be established without further intervention by installers.

The modest SMUD PRECISE test illustrates the industry's renewed focus on avoiding problems from DER deployment, with a new conviction that smart inverter set points could be established in advance. By implication, the test also demonstrated the importance of developing remote programming methods for DERs, at installation, or during grid-stressed conditions.

To summarize, the smart inverter movement standardized the grid impacts of DERs through IEEE 1547 and Rule 21 and occasioned a shift in perspective towards positive grid impacts. DERs negative grid impacts were reset as issues to be managed or accepted, at a cost. Field tests in California and Hawaii indicated that many other resources would have to be in place to realize the benefits smart inverters offered, and these benefits would arise in some operating conditions, but not others. The California utility White Paper confirmed that much work remained to be done.

## D- Deploying DERs to Fight Climate Change

In their third task, utilities are facilitating the deployment of DERs to fight climate change. Many utilities with legislated renewable energy mandates need to use DERs in their responses, much as they earlier turned to a wide variety of demand-side management resources to limit energy use. While HCA tries to indicate where DERs could be tolerated with limited grid impact, and smart inverters try to let DERs have the best impact they can on the grid, the fight against climate change is oriented toward climate impact metrics for DER deployment, particularly the reduction of greenhouse gases (GHGs) and carbon in the environment.


- Procure & Maintain a sustainable, affordable and carbon-free supply
- Electrify the built environment and mobility
- Promote energy efficiency & successful grid integration

Source: Silicon Valley Clean Energy, 2019.

**Figure 6:**
**Silicon Valley Clean Energy Deep Decarbonization Strategy**

As illustrated above, the DER-related climate impact metrics connect most closely to three strategies, as Silicon Valley Clean Energy (SVCE) identifies in their strategy for the war against climate change.

These strategies are:

1) Grid Decarbonization: The replacement of fossil-fueled pre-energy generation with renewable resources, which has been legislated in an increasing number of jurisdictions and is feasible.
2) Transportation Electrification: Transportation electrification has barely begun, is still largely voluntary, and is driven by programs, incentives, and technical innovation.
3) Building Electrification: Building construction is gradually being transformed by new codes, materials, and practices. Most of these changes are incremental, and many are voluntary. The challenge: electrifying loads intensifies demand peaks.

Grid decarbonization's objectives are to convert generation to carbon-free sources while supporting the rise of both transportation and building electrification. Meeting these objectives will lead the grid to radically new load shapes and a completely reconfigured supply mix. Meeting these objectives all at the same time will require new levels of grid flexibility and resiliency. The grid impacts of the DERs required to support grid decarbonization only add to these demands.

Transportation electrification is accelerating but is still at an early stage. Despite the war on climate change, electric transportation is still a voluntary option, supported to a modest degree by programs, incentives, and technical innovation. Electric transportation directly impacts the grid through incremental load from residential, commercial, and public recharging, and the operation of charging systems (especially those including energy storage). As a result, transportation electrification is directly connected to building remodeling and construction.

Building electrification is a very traditional concept and has been aided recently by developments in solar arrays, water heaters, heat pumps, and induction cooking. Despite the war on climate change, building electrification (e.g., ZNE) is still a voluntary option in most jurisdictions. Building electrification directly impacts the grid through reshaping loads previously met by natural gas. As a result, building electrification is directly connected to grid planning.

The three strategies are interrelated and involve many complex technical challenges. Both the mandatory transition to renewable generation and transportation electrification are carbon-driven imperatives arising outside of the utility industry. Both of these strategies are immense, expensive, and stressful for the grid. Both strategies directly involve building construction in the siting and operation of DERs (e.g., rooftop PV, electric vehicle charging), and both strategies ask building construction to support a much higher degree of load management. DERs are crucial elements of all three strategies, mainly since DERs now include energy storage. The researchers will refer to the three strategies collectively as grid decarbonization.

In North America, there is little debate remaining about whether or not to pursue grid decarbonization. However, there is considerable debate regarding the appropriate pace, intensity, risks, and costs of moving in that direction. Research & development will inform that debate and is urgent for the utility industry because grid decarbonization advocates regard climate change as an existential threat, and ask utilities to bear whatever grid impacts may arise in the battle.

As climate change legislation becomes increasingly demanding, with higher percentages of renewable generation achieved sooner, utility cost/benefit thinking is shifting. Typically, utilities wait for their technology vendors to demonstrate affordability, safety, and grid performance. Promising technologies may receive the benefit of the doubt, but the acceptance process is gradual. Positive impacts are weighed against negative impacts and uncertainties. Pilots are followed by competitive bidding and proof-of-concept testing.

Grid decarbonization has become a more urgent requirement. California took the lead in North America's fight against climate change, passing AB 32 into law in 2002, requiring a statewide reduction in greenhouse gas generation (GHG) to 1990 levels by 2020. California regulators then established an early Renewable Portfolio Standard (RPS) for utility resource procurement. They created the California Solar Initiative (CSI), a $2.3 billion initiative to enable 1,940 MW of small-scale PV installations. Today, California aims to have 60% of its energy supply from renewable energy by 2030, and 100% carbon-free electricity by 2045.

While HCA focused on the negative grid impacts of DERs, and smart inverters shifted the focus to the positive impacts of DERs, grid decarbonization implies that DERs' grid impacts are byproducts of deploying DERs as rapidly and broadly as possible. Utilities understand that rapid and broad deployment means that DERs will be in place at scale, yielding grid impacts as intended and unintended consequences, before these impacts have been modeled, verified, and understood.

### 1. **Regulation and Standardization**

Legislated climate change mandates, such as California's AB 32, laid the groundwork so that DERs are required, rather than merely encouraged or accepted. Regulators judge where the tradeoffs come across climate impact, affordability, safety, and grid performance. Regulators indicate how utilities must comply with the legislation: neither utilities nor their customers can ignore requirements. Customers can still choose what kind of car they drive, but they cannot individually choose how much climate impact they pay to mitigate, and what risks they bear. Instead, utilities are required to meet specific grid decarbonization objectives and are compensated for meeting them. Customers are permitted to live with the results.

By 2014, the older mandates for net energy metering (NEM) had expanded in California, and utilities across the state struggled to streamline PV interconnection across tens of thousands of applications every quarter. Planners and regulators came to believe that DERs were more and more cost-effective as solar and storage costs fell; 'qualified' DERs could be cost-effectively integrated into ongoing distribution plans. As DER penetration passed 35% on some circuits, the grid stresses attendant on-grid decarbonization was coming into view.

In the face of those mandates, utilities had thought it prudent to require at least a modicum of interconnection analysis for every DER. However, with the government mandates for mitigating climate change increasing, California accelerated its timetable for its renewable energy conversion. DERs wouldn't wait. Utilities were pressured to streamline DER interconnection and deal with DERs' technical risks through the analyses like those attendants on AB 327. Californians saw DERs as inevitable: their DER question had become not *when*, but *how fast*.

As noted above, the CPUC DRP Rulemaking (R.14-08-013) reached even further, requiring two-way energy and energy services flows, demanding opportunities for DERs to supply grid services, and insisting on "reducing greenhouse gas emissions while improving reliability and reducing costs." Meeting all of these objectives at once has been challenging for California's IOUs. Just as DERs have become old enough to fight, the war against climate change has consumed California. As DERs have been called upon to be life-saving, they have been asked to be economical and reliable as well. DERs have shown continual technical and cost improvements (energy storage in particular), but the climate needs even more.

In the third stage of DER development, large-scale DERs have been proposed in unprecedented numbers and scale. The grid needs widespread deployment at high penetration levels while avoiding grid collapse. DERs must be deployed even in those locations where HCA indicates they may entail significant grid reinforcement. DERs will need to operate on climate-friendly routines, and the grid will need to support them in doing so. The challenge is immense, yet it is not unprecedented. Distribution planners have always responded to load dynamics in this fashion, adjusting the grid continually as new demand-side requirements emerged. Now generation will be just as distributed and just as variable, and both load and generation will have to be optimized with climate metrics in mind.

Even with their similar experience with load, California distribution planners are understandably concerned about risk mitigation given the scale, concentration, and urgency of DER deployment. The grid has been asked to host DERs to fight climate change, even if these DERs pose other issues, and even if significant investment and reconfiguration is required. These DERs will be hosted, and they will have smart inverters, and they will need to function well on the grid. The question for distribution planners is how the grid can best cope with all of the DERs that are coming.

One major source of risk is a lack of clarity about where DERs need to go and what they need to do once they are there. DER standards and regulations don't yet specify roles for DERs in the fight against climate change, nor how to deal with DERs' grid impacts. The CPUC did ask ICA planners to "quantify the capability of the distribution system to host DERs," and "determine thermal ratings, protection limits, power quality (including voltage), and safety standards." Still, the final 2018 report of the ICA Working Group lacked consensus on many operating issues.

Smart inverters are marching to decarbonization in better order: Rule 21 Phase 1 required DER voltage and frequency ride-through, and reactive power control. Rule 21 Phase 2 defined DERs' Internet communications. But Rule 21 Phase 3, regarding data monitoring, remote grid connection and disconnection, and maximum power controls, has not been specified and scheduled. Phase 3 aims to address controlling customer energy use and storage to meet utility grid and climate objectives.

The second source of risk for distribution planners is the lack of control they have over the growth and deployment of transportation electrification and building electrification. These key strategies in the war against climate change are defined outside of the utility industry, but they are broad, expensive, and stressful for the grid. Both strategies directly involve the siting and operation of DERs (e.g., rooftop PV, electric vehicle charging), and both strategies ask building construction to support a much higher degree of demand management. DERs are crucial elements of all three strategies, mainly since DERs now include energy storage.

Electric transportation and building electrification arrive on the grid In the form of new load and radically-new load shapes. DERs are being asked to help the grid support larger loads, particularly during early evening peaks. Mainly in the form of solar + storage, DERs are also being called into service to address the changes in load shapes. As electrification accelerates, these revisions in load will have more and more impact on the grid. As Hawaii discovered and California is learning, it is one thing to host a residential PV array near the end of a feeder, it is another thing to host many PV arrays along a feeder, and it is something else altogether to host PV and storage, electric vehicles, electric heat pumps, and residential energy storage systems on a hot summer evening along a carbon-free feeder.

The third source of risk for distribution planners is the requirement for seamless grid enhancement to realize the policymakers' ambitions. For example, the integrated DER (IDER) demonstrations were intended to replace cost-effectively or defer distribution upgrades (so-called "non-wires solutions"), but few solicitations have led to projects. The project locations were difficult, the requests had strict requirements, and value-stacking[38] was restricted. A few large-scale storage-based bids to replace generation and

[38] In a particular sense, DER value-stacking may have direct grid impacts. DER use cases have been suggested for rate optimization, demand response, energy efficiency, emissions reduction, self-resiliency, customer choice & control, smart home, ancillary services, emerging markets, power quality management, unregulated energy services, and non-wire alternatives. Obviously, DER value could increase with multiple applications. Obviously not every application can be run by the same DER concurrently for the life of the DER.

distribution have moved forward, based on more flexibility in location and design, but many more are needed. Neither the grid impacts nor the economic impacts of DER deployments have been resolved.

The risks of distribution planning during the war on climate change are arising in California and Hawaii first. These two states have moved forward with grid decarbonization, moving as fast as they can, enlisting DERs in the cause. Even in California and Hawaii, as recently as fifteen years ago, DERs were a curiosity for most distribution planners. Today, legislation has designated DERs as indispensable warriors in the battle to save human civilization. Distribution planners can see that more and more DERs will be called to action, straining the practical bounds of affordability, safety, and grid performance.

These bounds differ from place to place. Hawaii has exceptionally high costs, long feeders, and a unique island environment. California also has high costs and some long feeders, but it is part of the nation's bulk power system. New York and other states have renewable energy mandates but have smaller-scale grids, or less urgent schedules, or different weather, or different markets. Some states have weak climate change mitigation standards or none. ComEd, for example, has chosen to explicitly exclude climate impact as a factor in DER integration planning, because to do so "could lead to the task of planning and operating the grid in an overly expensive way, because the utility would be required to offer incremental services."[39]

As California utilities have realized, both the positive and the negative DER grid impacts intensify with scale and concentration. California's grid and its renewable energy mandate are immense. No other state is likely to host so many electric vehicles in close proximity any time soon. No other state faces climate change with such urgency and commitment. No other state will be so determined to replace fossil fuels with DERs. As a result, the future of DER grid impacts will be defined in California, and these grid impacts will be the product of the fight against climate change.

The call to arms is clear, and the risks of responding are evident, mainly because it is unclear how to site, operate, and maintain DERs effectively within a carbon-free grid. As distribution planners have observed, the objective function of organizing the grid to best fight climate change has yet to be defined.

## 2. Guiding Concepts & Investigations

The third task distribution planners are addressing as DER deployment accelerates employing DERs in the war against climate change.

As noted above, decarbonization includes the conversion of fossil-fueled energy generation to carbon-free electricity, support for transportation electrification, and support for building electrification. Notable research projects to date have often involved more than one of these ambitions, in efforts to identify and manage the scale of DER

[39] "ComEd Values DER," by Shay Bahramirad, T & D World, September 5, 2019.

deployment required for decarbonization. Simply because of their scale, building and transportation electrification are immense challenges for decarbonization, as the Aspen Institute has noted:[40]

> "Even if California reaches 100% clean electricity…it would still miss its greenhouse gas reduction goals by a lot. Electricity is responsible for only about 17% of California's GHG emissions. Natural gas in buildings and industry accounts for more than a quarter. Transportation represents about 40%, and emissions from transportation have increased over the last few years, in part because of bad housing policy; the lack of affordable housing means working families have to drive for hours to get to work."

To the degree that building and transportation electrification can be achieved, electric loads will rise substantially, and therefore greatly increase the scale of DERs required for meeting these decarbonization end uses. Building electrification produces load peaks from heating, while transportation electrification produces load peaks from recharging. While energy storage may help, it too produces load peaks when recharging.

As the fight against climate change expresses itself in increased load, DERs have handicaps in responding to these new demands on the grid. Both building electrification and transportation electrification produce new end-use load shapes, varying by time of day and season. DERs supply power intermittently: wind and solar power are not always available during variable weather, and they are not as available as they need to be during evening load peaks or any other new peaks. As a result, the task of peak management further increases the scale of DERs required for decarbonization.

These scale effects that SCE's ZNE Demonstration at Fontana helped identify (see below) have implications across the electric industry, including in the residential sector, that is, our focus in this report. One of the most significant implications is that DERs need more management than smart inverters can provide. Smart inverters are essential system components to help ensure that DERs operate reliably, but their capabilities are limited and local. The DER scale-up of DERs has brought attention to the telecommunications and information technologies required to aggregate and coordinate these resources.

Many utilities with legislated renewable energy mandates aim to use DERs in their responses, much as they earlier turned to a wide variety of resources to limit load. While HCA tries to indicate where DERs could be tolerated with limited grid impact, and smart inverters try to let DERs have the best impact they can on the grid, the fight against climate change is oriented toward climate impact metrics for DER deployment, particularly the reduction of greenhouse gases (GHGs) and carbon in the environment.

Several initiatives illustrate how DERs are active in grid decarbonization, transportation electrification, and building electrification, with grid stresses arising as a result:

[40] Decarbonizing the Electricity Sector and Beyond, The Aspen Institute Energy and Environment Program, Winter 2019, p. 10.

### SCE ZNE Demonstration at Fontana (2015)

In 2015, looking ahead to the current California state residential building code, SCE, EPRI, and Meritage Homes launched a field test in Fontana, California, outfitting 20 new homes with advanced DERs, energy efficiency, and energy conservation technologies. The Fontana trial was a small-scale residential experiment outfitting homes with PV solar systems, all-electric space heating and water heating, LED lighting, smart thermostats, high-efficiency insulation, and ZNE-level building envelope construction. Of the 20 experimental homes, nine also had residential storage systems. The Fontana trial also included 11 other new homes as controls. The development in Fontana is in climate zone 3B (warm and dry), with peak annual temperatures of 114° F in the summer, so cooling-related summer peaks are to be expected. The Fontana trial homes displayed peaks above 10 kW.

The Fontana results helped provide input for the development of multiple scenarios of DER operation for SCE's planning engineers though a detailed analysis of the performance of the homes. They helped support the development of the SCE decarbonization roadmap[41]. SCE anticipated the rollout of ZNE-based Building Codes (January 2020) mandatory time-of-use (TOU rates (October 2020), electric vehicle adoption, all-electric homes, and municipalities with "reach" codes mandating an even stronger battle against climate change. SCE says that its "long-term vision is to transform its distribution grid into a flexible, networked platform that optimizes DER value through advanced grid management and empowers customers with options to be reliability partners."[42]

SCE believes that economic signals will organize optimal, grid-harmonized DER deployment and dispatch. DERs will be "leveraged" as they work with automated grid assets, earning customers who host DERs the status of reliability and decarbonization partners. SCE acknowledges that load will be more challenging to manage, due to bidirectional consumption and production, and much higher peaks driven by behavior, appliances, and electric vehicles. However, SCE also believes that through rates, demand response, and energy storage, the load can also be more controllable and flexible.

SCE's vision assumes DERs will be where they need to be, in the types and quantities they need to be, controlled as they need to be to achieve grid decarbonization and to be "leveraged" as they work in concert with other automated grid assets. The vision assumes that these DERs will have side effects (e.g., bidirectional consumption and higher peaks), but these side effects will be manageable.

SCE's vision effectively calls for a new version of HCA, one that begins with a model of the decarbonized grid, and populates DERs as appropriate. SCE's vision also effectively calls for a new version of inverter operating protocols, to enable grid optimization, DER

[41] "Decarbonization and the Grid," by Jun Wen, SCE, CalPlug, October, 2019.

[42] Wen, *ibid* p. 3

leverage, and cooperation with other automated grid assets (as these operations are defined). SCE's vision assumes there is a "flexible networked platform" of advanced grid management that will optimize the value of DERs, allocate the value that results, and manage those side effects.

The Fontana trial was operating as a limited residential experiment, while SCE developed its vision for decarbonization. The Fontana homes in the trial did not host electric vehicles, which would have increased household load an additional 10-20 kWh daily, and would have increased peaks above 15 kW. The trial wasn't ready to program PV solar and residential energy storage systems to mitigate load peaks best. The novel technologies deployed in Fontana had many issues in design, installation, and operations. But even within these limits, the Fontana trial still identified significant DER impacts for the grid, both in modeling and in operations.[43]

In modeling, loads in the Fontana trial homes didn't match prevailing residential load models. They indicated the need for improved models based on better data about weather, appliance operation (e.g., water heaters), residential energy storage, and customer behavior. In operations, the residential energy storage systems installed in Fontana were code-compliant but proved too small to manage household peak loads effectively or prevent reverse power flow. The DERs in the Fontana homes also combined with having substantial impacts on the 50 kvA and 75 kvA transformers connected to them.

In its analysis, EPRI noted that distribution planning focuses on assessing the current capacity (ampacity) of lines, on avoiding thermal stresses. Voltage is a significant but secondary concern. Residential distribution planning recognizes that ambient exterior temperature is highly-correlated with HVAC loads, which drive peak electric use, and current flow. Using heat pumps for space heating reinforces these relationships. As a result, residential load modeling can be broadly guided by construction activity and weather.

However, loads from homes hosting DERs behave differently. Electric water heating is less correlated with ambient exterior temperature than to household behavior, especially when the household is active in demand response. Solar PV generates due to irradiance rather than temperature, to the point that it can cause reverse power flow during solar peaking hours. Residential energy storage also has its control strategy that shifts load. These additional factors and variances can be further influenced by TOU rates, which may shift load neither according to grid health nor decarbonization, but rather according to economics. Load from homes hosting DERs is likely to have more range, more determining factors, and require more sophisticated modeling.

The Fontana results indicated that DER-intensive neighborhoods have the potential for significant impacts on the grid. If they are controlled, these impacts provide valuable flexibility; if they are uncontrolled, they provide dangerous variation. The Fontana results also indicate that the DER operations will reflect their environment and their instructions.

[43] **Grid Integration of Zero Net Energy Communities**. EPRI, Palo Alto, CA: 2016. 3002009242.

The root cause of DER grid impacts maybe the weather, maybe customer behavior, or maybe automated programs. Any effort to manage DER grid impacts will require sufficient data on all three, and a sufficient understanding about how all three interact.

DER grid stresses might be addressed through restrictions on DER operations, load management, grid operating routines, regulation and protection devices, reconductoring lines or a mix of these methods. Rather than analyze all of these options for managing Fontana's grid stresses, and then account for whether or not the Fontana location is typical of the grid, the EPRI report opts for recalibrating the Fontana stresses' impacts into reconductoring requirements, i.e., what incremental wiring would be required if the project's grid impacts were to be wholly addressed through adding more wire locally. This recalibration is possible because grid wire comes in different ratings:[44]

**Table 3: Circuit Segment and Typical Line Ratings**

| Circuit Segment | # Residential Cust. (avg) | Rating* (typical kVA) |
|---|---|---|
| Feeder | 1200 | 10,000 |
| Load Block | 24 | 1,500 |
| Lateral | 60 | 375 |
| Transformer | 10 | 50-75 |

*These ratings are characteristics of the region that was under evaluation and not representative of the range of ratings in California's 10,000+ distribution circuits.

Source: **Grid Integration of Zero Net Energy Communities**. EPRI, Palo Alto, CA: 2016. 3002009242.

The recalibration indicates the order of magnitude of grid impacts from DERs in normal operations. The Fontana DERs' load impacts were challenging to the model given the data sources, but EPRI's simulations identified highly-probable peak load scenarios for the project's feeders, load blocks, laterals, and transformers. The analysis specified these peak loads as percentages of nominal ratings for the lines and emergency limits for the transformers.

While the Fontana analysis involved a host of modeling assumptions, the necessary conclusion was evident: the Fontana project generally overloaded transformers (17% and 40%), laterals (16%), and load blocks (10%). In cases with energy storage controlled to maximize self-consumption or to manage TOU peaks,[45] this overloading was reduced, but not eliminated. The scale of these residential DER impacts in normal grid operations is enough to indicate grid reinforcement would be prudent.

[44] **Grid Integration of Zero Net Energy Communities**. EPRI, Palo Alto, CA: 2016. 3002009242, p. 7-6.

[45] The TOU rates prevailing at the time of the Fontana analysis have since been changed to align more with utility costs, and utility grid stresses. The Fontana results about DER performance under TOU rates are still notable, however, because they indicate that rate-motivated load shifting and recharging can result in serious grid stresses in normal operating conditions.

When deployed in quantity and proximity, as might well be required for decarbonization, DERs will require improved coordination, improved visibility, and upgraded distribution relays to handle the bidirectional current. Morning hot water and heating use becomes a typical and challenging load peak to manage in winter and spring. An increase in solar PV resources is non-coincident with the load increases. Significant grid reinforcement is indicated, especially if electric transportation arrives in a similar quantity and proximity.

The reason Fontana's limited, experimental, and residential results are so important for SCE's distribution vision lies in the simplicity of the field trial. A few homes on a couple of transformers were deliberately built as most code-compliant homes would have to be built in the future, and the loads projected from these new homes stressed the local grid significantly. The model for future new residential construction carried the grid past its DER hosting capacity, and smart inverters wouldn't be enough to resolve all of the issues that resulted.

Even within hosting capacity, controlling DERs and their smart inverters might require significant investments in control and communications systems. DERs deployed within hosting capacity might also have substantial economic impacts on both utilities and their customers, especially if the grid required specific operating protocols. But the Fontana trial showed that an even more fundamental consideration would be the essential reinforcements needed for the grid to operate appropriately, once hosting capacity was bypassed in the interests of decarbonization.

The Fontana reconductoring results illustrate the nature and scale of local investment required to cope with the side effects of deploying a decarbonizing level of DERs on the grid. While not every section of every SCE feeder would register the same impacts that this set of new Fontana homes entailed, DER grid impacts would be significant and relevant for SCE. Just as Hawaii found that a high penetration of residential DERs could lead to risks in grid operation, so California can foresee similar risks as transportation and building electrification proceed. The risks are large, and managing them is essential for any utility committed to decarbonization.

### Other Grid Decarbonization Projects

Beyond Fontana, many research and development projects have been active recently regarding the conversion of fossil-fuel resources to renewables, transportation electrification, and building electrification. Projects considering grid impacts have often focused on energy storage, although most of these projects have emphasized utility-scale, commercial-scale, or transportation-based resources.

Some projects include the telecommunications and information technologies required to aggregate and coordinate DERs, as deployed in software, e.g., Automated Metering Infrastructure (AMI) Advanced Distribution Management Systems (ADMS), Distributed Energy Resource Management Systems (DERMS), and various line sensor systems.

These projects address decarbonization indirectly by working to make the DER scale-up manageable.

In a DOE SHINES-funded project, HECO tested System to Edge-of-Network Architecture (SEAMS) as a means of increasing visibility, control, and grid response for distribution system operators. Through SEAMS' innovative systems logic, plug-and-play residential DERs (PV and storage assets) provided enhanced communications to improve situational awareness and forecasting. The project also helped HECO understand the cost-effectiveness of upgrading DER systems.

The scale-up of transportation electrification includes vehicle-to-grid integration (VGI) and smart charging feasibility projects working to identify customer value propositions, bidirectional charging and equipment requirements, and potential services available from connecting vehicles to the grid. The results are only preliminary and indicative, because DERs, electric vehicles (EVs) are far from standardized, in their design, charging requirements, and charging behavior. Today, VGI is generally one-way, small-scale, and cost-prohibitive.

In a parallel study to the smart inverter work noted above,[46] PG&E examined electric vehicles connected to the grid through residential connections and demonstrated that interconnected vehicle batteries could support the grid much as residential stationary batteries do. Lawrence Berkeley National Laboratories (LBNL) testing at Los Angeles Air Force Base demonstrated that EV batteries could be used for demand response and frequency regulation. Little work has been done on assessing the grid impacts of electric transportation at scale.

Similar to VGI, the scale-up of building electrification aims to use assets outside the grid to support the grid. But while VGI offers batteries as short-term resources, buildings can offer larger-scale and longer-term load management in the form of demand response. Buildings could conceivably support voltage, deliver reactive power, and provide other grid services. However, buildings have even more variation in design and load than vehicles, and buildings have owners, occupants, and systems with multiple agendas. While buildings have been active in traditional demand response, demand response programs have their issues, and adding DER's doesn't solve any of them: e.g., program and rate design, customer recruitment, equitable compensation of those customers, cost allocation, bulk power conflicts with distribution management, and in particular, operating management of assets at a distance. Virtual power plants (VPPs) based on DERs in buildings have been discussed for a decade, but few commercial VPPs have been assembled.

In summary, fighting climate change is scaling up the presence of DERs on the grid substantially. While converting fossil-fueled electric generation to carbon-free generation

[46] "EPIC 2.03B: "*Test Smart Inverter Enhanced Capabilities – Vehicle to Home"* The series of reports is available at: https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-2.03a.pdf

is a process mainly within the utility industry, transportation, and building electrification and are processes dependent on assets owned and operated outside of the utility industry. This distinction is proving decisive in the effort to manage the grid impacts of DERs. Through new load and changes in load, grid impacts from fighting climate change will continue to increase. In turn, these changes in load will call for more and more DERs, which will further increase grid impacts.

Decarbonization strategies span conversion of the grid to renewable power, building electrification, and transportation electrification. These initiatives radically reconfigure load shapes and grid operations as DERs are widely deployed. SCE's envisions its distribution system for the decarbonized grid as a "flexible networked platform" heavy with DERs, the DERs' grid impacts managed through close cooperation with other grid assets. Load management, energy storage, and grid software will help optimize grid operations, but the challenge will continue to grow.

# 3 DER-RELATED SERIOUS GRID STRESSES

## A - Grid Stresses from DERs

The researchers define grid stress as grid conditions outside reasonable operating bounds which call for maintenance, repair, or upgrading of the grid. Serious grid stress occurs when these operations damage the grid, interfering with further normal operations, and potentially cascading into catastrophic problems.

DERs provide intermittent, variable, and unanticipated local power flows. In particular, energy storage can provide intermittent and unpredictable bidirectional local power flows. These variations are reflected in voltage and frequency. These symptoms arise because DERs are what they are. The symptoms of grid stress are what is detected, but the symptoms are not the same things as the causes of grid stress. There is a need to seek the underlying causes of the grid stresses to resolve them.

First, the researchers observe that under certain grid conditions, standard DERs in normal operations (as well as substandard DERs and DERs operating abnormally) will have voltage impacts on the grid. These violations and faults may result in local overvoltage, or overvoltage at isolated feeders and substations, or local undervoltage from a unit trip, with damaging consequences that may be aggravated by a low-inertia environment with narrow security margins and rapid clearing requirements.

These damaging consequences can follow from both overvoltage and undervoltage. Overvoltage, and sustained load or current creating heat, can result in thermal overload, which can ruin insulation, components, and equipment after temperature exceeds ratings for a few cycles, or over time (e.g., annealing of an overloaded conductor). The conductive path can melt. In some cases, overvoltage can create a severe loss of DER generation and load in a cascade, with fault clearance too slow to prevent system collapse. Voltage variability can lead to significant equipment wear from increased operations to manage variability (e.g., regulator or LTC cycling, battery charging/ discharging). Loss of load may also result in additional voltage violations.

Voltage deviation is a common issue for distribution planners, who often add, relocate, or reset voltage regulation resources (e.g., regulators, tap changers, capacitors, STATCOMs). After interconnection analysis, the planners may also reconductor lines, revise DER power factor settings, or attend to smart inverter management of local power flows (e.g., volt-VAR, volt-watt). The planners know that voltage violations can be symptoms with serious consequences and that the root causes of these violations can be DERs.

Second, planners observe that under certain grid conditions, the intermittent, variable, and unpredictable local power flows from DERs in normal operations (as well as substandard DERs and DERs operating abnormally) can contribute to frequency impacts on the grid. A remote fault from a unit trip can lead to underfrequency, or a transmission fault can lead to over frequency. A low-inertia environment can also aggravate these frequency problems with narrow security margins and rapid clearing requirements.

Frequency issues can be severe and immediate. In some cases, severe loss of DER generation and load can cascade, and frequency decay can’t be cleared in time to prevent system collapse. To prevent these problems, distribution planners will increase the ramp rate of resources, add ramping resources (e.g., storage, demand response), improve DER ride-through, and employ smart inverters to manage local power flows.

Beyond these familiar voltage and frequency challenges, the intermittent, variable, and unpredictable local power-flows from DERs give rise to other symptoms. UL 1741-compliant inverters may still interact to island, and planners may respond with Direct-Transfer Trip (DTT).

The researchers can observe these symptoms of grid stress, and the standard steps distribution planners take to deal with them. To appreciate how these stresses lead to grid impacts, it is important to consider the electric grid as a system. The grid is a dynamic system maintaining itself in normal operation by constantly balancing stresses as its tasks and conditions change. Much stress can be absorbed, but some stress impacts performance impacts the system itself, requires costly mitigation, damages the grid, or even causes the grid to collapse. Deliberate and reliable stress balancing is preferable to accidental and unreliable stress balancing.

To balance stresses, material properties are more reliable than devices; devices are more reliable than management; automation is more reliable than manual intervention. To design responses to stress and choose among responses, the balancing relationships defining the system, the stress, and our options for response has to be understood.

A balanced system will provide reliable (normal) local and pervasive performance across a discrete range of (normal) conditions. System stress arises when conditions impact the system. Environmental changes (e.g., wildfires) alter conditions, and technical changes (e.g., DERs) alter systems and conditions. Stress also rises as norms fade and change. Stressed systems can perform differently, be damaged, recover, or transform to ‘new normal’ performance; of these options, recovery is most efficient and least stressful to other systems. If the system can cope with stress -- if the stress can be avoided, accepted, assigned, or addressed -- the grid continues to perform adequately. If the system can’t cope with stress, it wears down, performs poorly, shuts down, or collapses.

Resilience is the system’s ability to recover to normal from stress impacts or transform.
Reliability and resilience arise in material properties, system design, device design, enforced requirements and regulations, and consistent operations, but are influenced by conditions. One major condition for the electric grid’s resilience is the presence of DERs.

Every circuit varies overtime in size and location of DERs, DER generation, customer loads, technologies, weather, grid infrastructure and equipment, controls. But wherever they are, DERs create distributed variable current flows (some beneficial, some not) that are challenging to detect and manage reliably, and may unbalance the grid locally and generally. When enough DERs or large-enough DERs are added to the grid in particular locations, the grid may require reconductoring, new equipment, and new control systems.

In the presence of DERs, the grid may require more than reinforcement. The DERs themselves (e.g., inverters), protection equipment, other grid components, and the grid itself (e.g., hosting capacity) may need to be respecified and redesigned. The operating protocols of operating the grid may need to be adjusted or replaced. Grid costs and benefits may need to be reallocated through charges and rates. These many impacts may be positive or negative, significant or trivial, depending on the grid design and operating protocols. The result may be more resilience or less.

So DERs are associated with many symptoms of grid stress, and these symptoms have many mitigations. When looking for the causes of grid stress beneath these various symptoms, the common aspects of DERs, DER operations are under normal operation while providing intermittent, variable, and unanticipated local power flows. Flexibility isn't a flaw in the grid; after all, the grid was designed for routine loads, but it also accepts intermittent, variable, and unanticipated loads. But flexibility in local power flows wasn't part of the plan.

The changes in the plan, that Grid system components and performance have been redesigned: current flows are reversed, variable, and intermittent from generation and storage; diverse generation and storage sources require remote and active management (e.g., operations, maintenance). The loads these resources serve have been changed by the electrification of heating and transportation, the rise of energy storage, new energy, information technology, and transportation technologies are evolving and the arrival of climate-related performance metrics. The DERs and their impacts on the grid is changing.

The grid is a system of dynamic balance that has maintained its equilibrium through margins of capacity and resilience extending down through its feeders. DERs introduce distributed sources of local disturbance (i.e., intermittent, variable, and unanticipated power flows); in many cases, the disturbance is unobserved, and the response to it is uncoordinated. HCA has indicated where modest levels of disturbance can be accommodated, and smart inverters have provided a measure of management and control, but there are levels of disturbance that range beyond these measures, and seriously stress the grid.

## B – Mitigating Typical DER-Related Grid Stresses

Before considering the edge cases of serious DER-related grid stresses, a review on how our industry has coped with typical DER-related grid stresses. As known that DERs were disturbing: the development of HCA and smart inverters were spurred by the recognition that DERs were coming, and DERs create grid stresses. HCA helped identify and locate many of these stresses and indicated when interconnection work was needed.

Smart inverters directly control some of the most common DER-related grid stresses by managing DER active power and providing or absorbing reactive power. The Volt-Watt function limits active power voltage at the point of connection and across a volt-watt curve, and can also prevent reverse power flow and simultaneous thermal violations. The Volt-Var function uses reactive power to maintain voltage within a range. Other smart inverter functions include Watt-Power Factor (PF), which reacts to DER active power by moderating the inverter's PF, and Fixed-PF, which maintains a fixed inverter PF. These built-in capabilities are ready to manage many local grid stresses.

At times of peak generation (e.g., full PV irradiance), or moderate voltage violations, even a smart inverter will probably need to limit either its active power generation or its reactive power absorption capabilities. These limits may be significant, even if the inverter is oversized.

However, as EPRI notes, DER-related grid stresses can also be addressed by grid enhancements and operational changes.[47] Beyond smart inverters, typical grid enhancements to address stresses include upgrading transformers, relays, and regulators to enhance control; and upgrading wire (reconductoring) to raise current ratings and lower impedance. Reconductoring also mitigates thermal stresses. Typical operational changes to address grid stresses (e.g., voltage variability) include adjusting the settings on regulators, capacitors, and relays, reconfiguring feeders, and uprating feeder voltage. All of these steps are familiar from ordinary work required to adapt the grid to changes in load.

These steps may be familiar, but they have their limits, costs, and side effects, as seen in the three examples. First, shutting down a capacitor bank is a robust and blunt tool for managing feeder voltage. The shutdown can reduce the increase upstream local reactive power and reduce overvoltage, but it can also induce undervoltage. Capacitor location and size determine the effect. To size and locate the mitigation, each overvoltage location must be assessed against individual capacitor settings.

Second, lowering voltage regulator settings manages feeder voltage beginning with the first regulator upstream from the violation, and can be effective within that zone, but not downstream, and not in another regulator's zone. To size the mitigation, each overvoltage location must be assessed against individual regulator settings and the full range of voltage, DER, and load conditions in the regulation zone.

[47] "Mitigation Methods to Increase Feeder Hosting Capacity," EPRI, Palo Alto, CA, December, 2018

Third, if resetting existing equipment doesn't resolve over voltages, new regulators can also be added upstream of the overvoltage (and any over voltages on branches) but downstream from any existing regulator. A new higher-rated wire can be added, replacing lines as indicated by voltage, DER, and load conditions. Designing, installing, and testing these improvements can be expensive, and isn't practical to repeat for every DER added to the grid.

For larger-scale DER proposals, feeder assessment and solution identification still require modeling the feeder across its normal range of operating conditions, incrementally modeling the feeder with the DER included, identifying voltage and thermal violations, and then modeling solutions like those described above. Eventually projects can proceed, but the combinations among solutions, and the tradeoffs across solutions, are complex. For example, Watt-PF and Fixed-PF lead to lower feeder voltage profiles than other solutions but may have thermal side effects. Traditional grid planners would admit that smart inverters, grid enhancements, and operational changes can be complicated, but they do eliminate many violations.

## C - NREL's Perspective

NREL has recently addressed DER-related grid issues from a similar perspective. As indicated in the table below, the effects of DERs on distribution systems have been acknowledged for some time and treated through a set of standard mitigations. But almost all of these effects and their mitigations are considered from the perspective of specific projects.

These mitigations may seem to be a diverse set of options, but they are similar in many respects. Most of them are grid enhancements based on equipment (e.g., inverters, regulators, relays) and operational changes arising in response to voltage violations. The implicit assumption is that violations can be identified, diagnosed, and treated by adding equipment or adjusting equipment settings. Reconductoring is a similar solution, consisting of wire as the equipment involved[48]. These equipment-based solutions are similar to the peaker-plants constructed to address load peaks, which provide system resiliency that is only occasionally needed, but is essential when it is needed. If these solutions can be reliably and effectively stress-triggered, and if they are tested and maintained, the system can ride through stresses.

[48] Note the EPRI/SCE Fontana field test, which was able to estimate DER grid stresses and quantify the substantial amount of reconductoring required to mitigate them. *(reference)*

**Table 4: Typical Solutions Used Today to Mitigate Effects of DER on-Distribution Systems**

| Typical Solutions Used Today to Mitigate Effects of DER on Distribution Systems | | |
|---|---|---|
| **Mitigation Solution** | **Applicable Violations** | **Key Considerations and Notes** |
| Use alternative PF set points for the DER, for example, non-unity PF or advanced inverter functions for var and watt control | • High or low voltage<br>• Voltage flicker at PCC | • Low to no cost if set at install<br>• Ability to mitigate voltage problems depends on the fraction of advanced inverters on the system. Retrofits of old inverters are typically prohibitively expensive<br>• At high penetrations, advanced inverters may need to be used in concert with other voltage-regulation solutions to fully mitigate DER Impacts<br>• Legal and commercial constraints should be considered<br>• Utility ownership and/or control of advanced inverters is possible, being piloted |
| Modify capacitor and/or voltage-regulator controls | • Reverse power flow<br>• High or low voltage<br>• Voltage flicker at the device<br>• Excessive device movement | • Bidirectional or co-generation mode for desired operation with reverse power flow.<br>• Modifying device bandwith may help with voltage flicker |
| Move voltage-regulating devices | • Voltage flicker at the device<br>• High or low voltage | • Need to balance high and low voltage conditions |
| Install new voltage regulators | • High or low voltage | • If adding new regulators, include bidirectional functionality |
| Modify load tap changer (LTC) tap set point | • High or low voltage<br>• Excessive device movement | • Need to balance high and low voltage conditions |
| Install LTC at the substation | • High or low voltage | |
| Direct transfer trip (DTT) | • Anti-islanding<br>• Voltage supervisory reclosing relaying | • UL 1741 inverters pass anti-islanding tests, but interaction between inverters may not be tested<br>• DTT is required by utilities under certain circumstances, but not universally |
| Reconductoring | • Thermal overload<br>• Voltage flicker | |
| Upgrade protection coordination schemes | • Protection | |
| Move protective devices | • Protection | |

Source: Peterson, Zac, Michael Coddington, Fei Ding, Ben Sigrin, Danish Saleem, Kelsey Horowitz, Sarah E. Baldwin, et al. *Ibid.*

While the equipment-based solutions NREL cites are common mitigations for voltage violations, they are also inefficient: even if rarely used or used to only a small degree, equipment requires investment, installation, inspection, maintenance, and eventually replacement. Reconductoring or supplying a feeder with improved devices can be a major project. The economic temptation is great to supplement equipment-based solutions with more efficient software-based and service-based solutions.

Software-based solutions add new equipment capabilities (e.g., the “smart” in smart inverters) or adjust equipment setting automatically in real-time. Software-based solutions assume not only that violations can be identified, diagnosed, and treated by existing or additional grid devices; they also assume suitable device communications and control to execute new operating protocols. As a general rule, it is still more challenging to provide, validate, and maintain consistent performance through software than equipment, because equipment takes advantage of the properties of physical materials. But robust software can perform just as consistently as equipment, and software can offer remarkable performance and deployment at scale. In doing so, the software can streamline equipment requirements.

A third approach to mitigating grid stresses (e.g., voltage violations) adds services to equipment and software. Services are forms of accepting grid stresses (e.g., forbidding net PV export from households, requiring Public Service Power Shutoffs when weather conditions indicate wildfire risks, imposing peak load “brownouts”). Service-based solutions structure grid performance to operate within certain service specifications that software can manage and equipment can support.

NREL doesn’t distinguish equipment, software, and service components in the cited solutions, but the solutions NREL cites have these components. These components also underlie NREL’s observations about the maturity of knowledge and standards regarding DER management[49]. It is important to keep in mind that NREL remains focused on deploying DERs as rapidly as possible for grid decarbonization. The grid stresses that result are not NREL’s focus. This report summarizes NREL’s views on the key challenges of knowledge and standards here:

- <u>Forecasting DER Deployment</u>: There is no established standard or best practice. Options differ on resource requirements (e.g., data, time, and money), costs, risks, and abilities to cope with higher DER penetration levels. Regulators and utilities have their own needs, preferences, and assumptions (e.g., about the circumstances that would lead to DERs being deployed). Models are not yet validated. The tradeoffs between forecast accuracy and forecast costs (time and money) are unknown.

- <u>Applying to Install DERs</u>: The best available applications are online, streamlined, easily navigable, and clear, whether based on third-party or in-house platforms. Options differ based on resource requirements (e.g., data, time, and money), costs, risks, and abilities to cope with very low and very high DER penetration levels.

[49] Peterson, Zac, Michael Coddington, Fei Ding, Ben Sigrin, Danish Saleem, Kelsey Horowitz, Sarah E. Baldwin, et al. *Ibid.*

- Screening DER Applications: FERC's SGIP screens have been the standard practice to fast-track DER interconnection. These screens are heuristics that only address selected DER effects and leave individual DER grid impacts on safety and reliability to be assessed as individual utilities see fit. The screens don't apply equally well to all utilities, Models (e.g., power-flow modeling) are not yet validated. Sidetracked applications face further resource-intensive supplemental tests or full-scale reviews. The best screening approach to use and the tradeoffs between screening accuracy and screening costs (time and money) are unknown.

- Modeling and Interconnecting DERs: Online, automated, and streamlined interconnection is the current best practice. Options differ on resource requirements (e.g., data, time, and money), costs, risks, and abilities to cope with very low and very high DER penetration levels. Regulators, utilities, developers, and customers all have needs and preferences.

- Specifying Advanced Inverters: IEEE 1547-2018, California Rule 21, and Hawaii Rule 14H are new inverter standards based on recent research indicating how advanced inverters can facilitate DER interconnection. Additional research is underway about how best to implement these standards, and how advanced inverters can influence DER impacts.

- Allocating DER Costs: There is no established standard or best practice. Cost-causer pays the current practice, but maybe inequitable. Other practices are under test, but their effectiveness and impacts are not yet clear.

- Providing Cybersecurity for DERs: There is no established standard or best practice. Models, standards, and methods are still under development.

- Upgrading Distribution Systems for DERs: There is no established standard or best practice. Upgrade strategies are determined system by system, case by case. Options differ on resource requirements (e.g., data, time, and money), costs, risks, and abilities to cope with higher DER penetration levels. Regulators, utilities, developers, and customers all have needs and preferences. DER power factors, capacitor set points, or voltage regulator setpoints may influence DER impacts.

NREL also cited other concerns regarding DER interconnection without commenting on the maturity of knowledge and standards. As DER's proliferate, the issues are faced:

- System and organizational flexibility must be maintained in the face of ongoing technological change and policy and market uncertainty. It is unclear how much of what kinds of flexibility is worthwhile. It is unclear how much of what kinds of technical, policy, and market change to expect.

- System impacts from concentrated and aggregated smaller DER systems (e.g., DPV on new housing developments and third-party-owned aggregations) have not been investigated in detail. There is no established standard or best practice. Models, standards, and methods are still under development.

- Storage issues span missing interconnection standards; unclear AHJ and inspection/process requirements; NEM requirements; control, connection, and operational configurations; and metering/billing system integration. While there are many established standards and practices, there is no consensus on best practice. Models, standards, and methods are still under development.

- Generation metering must improve, but the cost of more sophisticated meters, billing system reconfiguration and customer site aesthetics are unclear.

- Data issues span integrity, standardization, validation, availability, and integration (e.g., the lack of reliable, standardized data from the load, DPV inverters, capacitors, voltage regulation devices, utility distribution systems, DERs, and other utility sources). There are no established standards or best practices for what counts as adequate data. Models, standards, and methods are still under development.

- Data operations issues span collection, management, tool development (e.g., maps, software systems), privacy, cybersecurity, and online standards and processes for distribution and DERs. There are no established standards or best practices for utilizing DER data. Models, standards, platforms (e.g., DERMS) and methods are still under development.

NREL's assessment indicates the progress in determining how to connect DERs to the grid. Our forecasts indicate why and how the DERs would proliferate. Given these forecasts, new software and services have accelerated application, application review, and interconnection. DERs are deployed faster than ever before.

But NREL also emphasizes that a consensus about DERs regarding cybersecurity software or distribution system upgrade requirements (e.g., for aggregated DERs), or storage or metering, or data. To fight climate change, connecting many more DERs to the grid, but NREL acknowledges that a lot have to be learnt about DERs once they are connected to the grid.

NREL's work suggests that help might lie in DER data from the explosion of DER interconnections, and the field experiences leading to IEEE 1547-2018. After all, the lessons learned about load impacts in part through meter data, which is collected, validated, and maintained properly for billing. Learnings about other grid impacts through SAIDI and SAIFI data, which is similarly curated for regulatory reporting. But DER data isn't compiled similarly. The DER data is still raw, heterogeneous, and largely based on low levels of DER penetration. It would take decades of DER field operations to yield robust conclusions simply by observation.

The DER data sufficed for modest levels of DER penetration. could assemble forecasts, design procedures, and manage DER deployment across our centralized grid. DER deployment under 15% doesn't generally disrupt the distribution and can be remedied locally when it does. Smart inverters avoid typical voltage and active/reactive power issues as DER penetration rises, and both TOU rates and energy storage can help nudge DER performance. DER grid stresses could be addressed project by project.

But the fight against climate change has increased DER utilization well beyond levels previously forecast. The roles of DERs in grid operation are becoming so pervasive and significant that central visibility, control, and communications are reaching their limits. NREL's emphasis on the grid effects from specific projects misses these grid effects from general DER proliferation.

We have reached the point where we can connect DERs to the grid much faster than we can assess their impacts.

## D - Grid Standardization vs. Grid Adaptability

Moving from typical DER-related grid stresses to the more serious grid stresses that are beyond the capacity of HCA and smart inverters to manage, note the central role of reversible, variable, intermittent again, and unanticipated local power flows. Also note that the typical mitigations employed to manage the symptoms of DER grid stresses are topical rather than systematic. Experience with single, modest cases, but not with large-scale, general effects. These general effects arise from each of the four DER-related severe grid stresses considered in the next section:

- Dynamic DER Design & Location
- DER Concentration
- Unsatisfactory DER Performance
- Unsatisfactory DER Interoperability and Integration

Mitigating these stresses is beyond the reach of adding or recalibrating equipment, reconductoring lines, or adjusting operating protocols. More research and development are needed for each of them.

To understand why these enterprise-level grid stresses remain to be dealt with, need to recognize that while DERs are individual resources in specific locations, their effects on the grid may be aggregated, distributed, and widespread. Very much like load, a DER is a nodal source of variation on the grid. The variation may be as eccentric as the weather or as cyclical as the time of day, it may be driven by customer behavior or automated programming, but in all cases the variation will impact the DER's site, feeder, and beyond as the DER's performance aggregates into grid activities.

As might be indicated for any source of variation on the grid, as climate change spurs the proliferation of DERs, many industry authorities have argued for standardizing DER grid-impact modeling across power system criteria, distribution system design, DER types and locations, and specific DER performance. Standardization manages variation while constraining volatility. For example, standardized grid patches (e.g., deploying regulators under certain circumstances) could be based on a few particular solutions individual utilities understand and accept.

Our work indicates that these aspirations for standardization are shared across many utilities, vendors, research organizations, and regulators. While the hard-won progress in establishing smart inverter standards is encouraging, the effort to standardize DER deployment faces several challenges:

- First, many DERs are procured, financed, tested, operated, and maintained outside utility management and control. Large-scale renewable projects and household energy storage systems originate outside the utility and insist on interconnection. These DERs may be specified within standards and initially interconnected within utility processes. Still, in most cases, subsequent operating responsibility falls upon third parties, whose obligations may not extend beyond replacing malfunctioning equipment in an initial period after commissioning. Quality and performance challenges are particularly strong for storage assets.

- Second, even to the degree utilities are involved, utilities differ in their approaches to DERs. These differences extend far beyond technology preferences. Utilities may own and operate DERs, or they may not. Utilities may limit DER locations and operations, or the market and renewable power mandates may guide them. Utilities may solicit widely across a range of DER project types (e.g., utility-scale, commercial/industrial, residential), or they may have few projects and narrow requirements. Utilities may proceed from demonstrations through pilots and internal development, or they may proceed from rates and regulations to project solicitations and contracts.

- Third, customers and a diverse array of third parties are stakeholders in DERs and expect their fair share of control and economic returns as a result. The study has noted how California stakeholders have been unable to agree on the locational value of DERs, in part because the California proceedings had direct implications for whose costs would be covered, and whose returns would be provided. Rate and RFP design reflect considerations well beyond technical performance. The DER-related grid stresses a utility decides to tolerate will be strongly influenced by the economic consequences for various parties, from customers to developers to the utilities themselves. Engineering may provide alternatives, but economics will dictate choices.

- Fourth, different DERs are deployed differently: some deployments are systems, some are contracted and aggregated sets of assets, some are dedicated grid resources. Inverter standardization provided DERs with a standard array of functions, but DER requirements are far from standardized. As a result, when DERs are combined in projects, programs, or utility grids, their roles differ greatly.

The simplest circumstances may be a utility-scale, utility-owned & operated DER project. But even in this case, the deployment order and utilization of this asset will be influenced by all of the utility's other DER projects.

These challenges caution us that while smart inverter deployment has been standardized across the industry, DER deployment will be coordinated to a lesser degree. DER-related grid stresses will be addressed by operational changes and grid enhancements, but they will also be addressed by a myriad of different design decisions, tailored to individual locations. The grid will need to adapt to resources as it has adapted to loads.

DERs are resources that behave like load, in many respects. Load requires utilities to plan for contingencies they do not create and to provide resiliency for situations they could not anticipate. The load is distributed in time, scale, variability, volatility, awareness, and interconnection with other loads, merely in location. Utilities have designed the grid to be adaptable to load in its variety, and as load continues to grow and change (e.g., in transportation and building electrification), grid design continues to evolve. Through all the changes, utilities work to provide affordable, reliable, and safe power, as demanded. The advent of DERs at scale means utilities will need to regard resources as being as a variable, as determined by outsiders, and as necessary to understand as load.

And yet, beyond the kaleidoscopic array of individual loads a utility needs to manage, there is the grid, functioning as a single integrated enterprise. Plug loads, data centers, and ports cooperate to the degree necessary to operate on the grid. The grid lets the loads vary, and even move from place to place. Customers and asset owners make their own choices within a framework. Similar integrated-grid planning will be necessary to let the resources vary and move. If entire programs of equipment, software, and services were necessary to manage load (e.g., demand response), perhaps similar programs will be necessary to manage resources and manage resources in coordination with the load.

The solutions to DER-related serious grid stresses are unlikely to be standardized DERs. Instead, there will be flexibility: many ways the grid adapts to a wide variety of DERs. As the grid adapts, decarbonization, and the DERs that arrive on the grid, as a result, may accomplish what deregulation has not. The biggest grid impact of DERs may be the opening of the grid to outside influences.

## E – Serious DER-Related Grid Stresses

As LCA and interconnection analysis improve, and smart inverters become standard, many traditional grid stresses attributed to DERs can be managed. For example, voltage deviation, frequency deviation, and islanding originate as local grid issues which can cascade to much larger problems if left unmanaged as they originate, but can be specified by HCA and interconnection analyses, and mitigated through smart inverters, operational changes, and grid enhancements. In most cases, typical DER-related grid stresses have practical resolutions.

However, there are several DER-related grid stresses with serious impacts where the mitigations are less obvious, scaling is questionable, and further research and development are indicated. These serious grid stresses become prevalent with the opening of the grid to DERs in large numbers.

Below is the description of these four fundamental DER-related serious grid stresses. Each of these four stresses has the potential to interfere with the large-scale rollout of DERs required to support grid decarbonization, transportation electrification, and building electrification. Each of these four stresses calls for additional research & development to address concerns beyond the scope of traditional mitigations.

In several respects, the discussion of DER-related serious grid stresses isn't definitive:

- The four stresses discussed are among many grid symptoms and stresses attributed to DERs. The study does not discuss flicker, Ferro resonance, harmonics, LTC cycling, islanding, and other concerns that usually have minor, merely theoretical, or easily managed grid impacts.

- The future holds new types of severe DER-related grid stresses. The impacts of transportation and building electrification are only beginning to come into focus. Storage may also reset the situation.

- This study was intended to provoke a dialogue with utility distribution planners, and in its present form, could suffice in that role. But much more work would be required to establish budgets and priorities for research and development.

Despite these limitations, an investigation of severe DER-related grid stresses should consider the four stresses identified.

These four stresses are:

- Dynamic DER Design & Location
- DER Concentration
- Unsatisfactory DER Performance
- Unsatisfactory DER Interoperability and Integration

The researchers define each of these severe DER-related grid stresses in turn.

### 1. Dynamic DER Design & Location

**Nature of the Stress**

Dynamic DER design and location stress arise because by design, DERs are resources (not connecting to distribution through a managed bulk power system) and distributed by location (and even mobile). Dynamic DER design and location stress is multidimensional, beginning as a baseline, spanning resource and load, extending up from the feeder level to the enterprise, and then extending out over time as the grid develops.

Grid stress due to the mere presence of DERs is, first of all, baseline stress of grid design. As incremental resources (and load, in the case of storage), DERs stress the grid merely by being distributed energy resources, and merely by being located where they are. Because they are resources connected outside of the bulk power system, DERs have impacts never envisioned in the initial design of the distribution system. We can broadly characterize the baseline stress of DER location and grid design as variability, e.g., reverse power flow. The baseline stress due to DER variability has been mitigated at one level by HCA, interconnection planning, and smart inverters. However, these mitigations function project by project, usually as increments to the *status quo* grid, and they don't scale.

Second, in the forms of storage, solar+ storage systems, and electric transportation, DERs function as resource and load. Typical distribution planning has accounted for load growth project by project, has also included real estate development forecasting at intervals, and has occasionally been combined at a high level with resource planning. The alternation of storage between resource and load poses particular planning challenges. As illustrated in Hawaii, DERs call for resource and load planning and design to be integrated more carefully than ever before.

Third, DER grid impacts can be cumulative in a location, along a feeder, and across the grid. Enterprise grid modernization planning has a considerable distance scaling in detail down to feeder-level upgrades. Feeder-level interconnection studies have a similar distance scaling up to identify enterprise implications. Even the evaluations of so-called "non-wires alternatives", which often examine entire feeders or sets of feeders, usually examine a limited range of proposed alternatives. We noted earlier that when attempted, enterprise HCA has been able to serve as an indicator for utilities, rather than as a framework for grid management.

Fourth, the grid stress DERs entail as dynamic grid components add to the stresses resulting from their nature as both resource and load, and their impacts locally and cumulatively. While DER design is becoming more standardized, the performance sought from DERs is not. As DERs are added to a location, feeder, or system, grid performance and grid requirements change. As DERs age, their performance changes, and grid requirements change. As loads change, the roles of individual DERs change, and grid requirements change. Transportation and building electrification add further dynamics rarely anticipated in HCA and interconnection studies, as does storage, whether considered as a resource or as load. The grid with DERs is much more dynamic than it has ever been before.

Because DERs are what they are, individual DER designs and operating routines may have severe impacts on voltage and frequency, and these impacts are multiplied in scale and complexity in clusters and aggregations of DERs across several dimensions. The multidimensional stress of dynamic DER design and location require distribution planning that differs in kind from previous planning.

DER performance that is variable, both resource and load, cumulative, and dynamic have many opportunities to violate grid constraints. In a dense DER deployment aiming for decarbonization and electrification, these violations can occur more often and in greater variety. Severe grid stress arises as a direct consequence.

**Traditional Mitigations**

The local nature of traditional mitigations for DER grid impacts generally assumed relatively stable grid operations, perhaps across daily or seasonal patterns. As the interconnected loads and resources change, feeder performance, and requirements change. In some cases, voltage regulation resources (e.g., regulators, tap changers, capacitors) can be added or reset. Eventually, substations might change.

Once DERs arrive in quantity, the distribution grid becomes more dynamic in the configuration as well as operations, and the DERs have their own grid impacts. Project-by-project HCA work can indicate how the distribution grid should be reconfigured or reinforced for these new resources, just as traditional distribution planning has done for a new load. These traditional mitigations require resources and may need modifications as new DERs or loads arrive, e.g., solar PV, energy storage, and electric transportation.

In Hawaii and elsewhere, DER location has shown distribution planners that unmanaged DER deployment can lead to voltage and frequency violations, and reverse power flow, especially further down feeder lines. Unless DERs are managed carefully, sudden faults can amplify, and crash the system. Grid enhancements and smart inverters may constrain DERs from following this path.

In the near term, traditional mitigations will constitute the bulk of the response to the severe grid stresses caused by DERs. Project by project, HCA, smart inverters, and grid reinforcement will be deployed, based on standard assumptions about DER deployment, performance, and activity. The gaps in response these traditional mitigations leave reveal themselves over time, as DERs are designed differently, become pervasive, and are used differently.

**Gaps Remaining**

Grid stress due to dynamic DER design and location is unlikely to be resolved merely by advances in HCA and inverter standardization. As noted above, further progress in HCA depends on overcoming barriers in state estimation analysis. However, even if these barriers are overcome, the analysis would only provide awareness and not mitigation. Further progress in inverter standardization would make inverters simpler to model individually and might allow DERs to help manage their own grid impacts, but in doing so would foster more modes of DER activity (e.g., bidirectional power flow), and would require careful management.

In addition, the impacts of solar location are understood to a degree, but the impacts of storage and electric transportation location are not, particularly given that electric transportation location is dynamic. Smart inverters have reined in the grid impacts of solar PV design, but storage design and electric transportation design still require definition. The grid stresses from DERs are also unfamiliar under the new conditions the grid itself is experiencing, i.e., steep ramps from afternoon generation peaks to evening load peaks, and weather driven by climate change.

In the face of all of these new challenges, it is a further concern that DER designs in combination, are preliminary. Inverter functions may have been standardized for solar systems, but not for storage, so solar + storage remains customized. Battery systems differ in many respects, whether stationary or in electric vehicles. “Community solar” remains a concept without consistent specifications.

### Summary

Grid impacts from grid stress due to dynamic DER design and location present themselves as variability in operations (e.g., reverse power flow, resource and load alternating, daily, and weather-related changes). These symptoms are diagnosed by measuring current and voltage. Left untreated, the prognosis for grid stress due to dynamic DER design and location is accelerated grid damage in unanticipated locations.

Grid stress due to dynamic DER design and location could be prevented by requiring detailed HCA for each incremental DER while holding grid operations constant; this mitigation is impractical. Preparation for grid stress due to dynamic DER design and location would include reliable models for improved HCA and early identification of location-specific issues. Operational tests and measurements upon DER commissioning could help lead to a timely response.

The treatment options are (a) returning the grid to normal by identifying individual problems and rectifying them one by one, and (b) transforming the grid by reinforcing feeders individually or by region. The initial treatment for grid stress due to dynamic DER design and location needs to be administered through effective HCA and validated through interconnection testing. The treatment is contraindicated or unsuitable without detailed local grid models, updated for changes in load. The side effects of these treatments are an increase in time and effort around DER deployment (balanced against the urgency of climate change mitigation).

## 2. DER Concentration

### Nature of the Stress

DER concentration intensifies the grid impacts that DER location and design deliver, stressing the grid to a higher degree as DER penetration, intensity, and activity increase. Concentration across one or more of these three dimensions may cloud the identification of DER-related stresses, magnify the effects of DERs, and complicate the mitigation of these effects.

In the transition to grid decarbonization, DER concentration stress becomes notable where LCA DER location and level recommendations are reached or exceeded. More DERs, more concentrated DERs in individual locations, and more DERs utilized more often have more grid impacts and more serious grid impacts. Grid impacts that might be tolerable at low concentration levels can become intolerable at high concentration levels. Past a certain point of DER concentration, the rest of the grid has to be managed with DERs in mind, rather than the DERs managed to work within the *status quo* grid.

DER concentration stress can be thought of as a particularly severe type of DER location, and design stress, when properly-designed and acceptably-located DERs are tipped into serious grid stress either by the addition of a modest incremental DER (penetration), or by a modest change in circumstances of an individual location (intensity) or by an unanticipated edge operating case, (activity). For example, electric transportation operating after streamlined interconnection procedures could fulfill any or all of these conditions.

DER concentration stress arises as grid conditions range outside local management and grid operating protocols, and then amplify into serious problems. DER concentration stress will be focused, usually emerging in cases of uneven DER proliferation across the system (e.g. solar, battery storage, electric transportation), intense local clustering of DER resources on particular feeders (e.g., large individual and community projects), concentration of DER activity at particular times (e.g., ramping or peaking), or concentration of DER use in aggregation.

As noted above, by its nature, DER performance can be variable, both resource and load, cumulative, and dynamic. In a dense DER deployment aiming for decarbonization and electrification, DER-related grid stresses become common, concentrated, and serious.

### Traditional Mitigations

There are no traditional mitigations for DER concentration stress because these levels of DER penetration are not traditional. However, Hawaii's experience with anticipating extremely high levels of DER penetration are relevant. HECO's interconnection analysis of larger DER projects identified some impacts of concentrated DERs, which could be mitigated to a degree, and in certain local respects, by reconductoring and adding equipment (e.g., voltage regulators, energy storage), or by programs such as demand response.

HECO saw that for its unusual grid, traditional mitigations were necessary but insufficient. Capacity additions weren't enough and couldn't respond quickly enough to feeder conditions. To address the gaps remaining, major storage projects and reconfigured grid operations would be needed. In addition, HECO has also prohibited DER export to the grid, provided for extensive grid reinforcement, and identified the need to redefine its requirements for grid services (e.g., fast frequency response, capacity) from the ground up.

**Gaps Remaining**

While many utilities are looking to Hawaii to pioneer the solutions to DER concentration stress, Hawaii's approach may not be suited to utilities connected to a bulk power system. HECO's grid, grid modeling, and grid management software are all unusual.

The impacts of small-scale but high-level DER penetration on a feeder, and the impacts of high-level DER penetration across a number of related feeders, are unclear. Cases of DER penetration stress may arise in the wake of fast-track interconnection approvals, particularly as feeders near their HCA limits. Operating edge-cases (e.g., storms at night, outages during peaks, multi-day temperature extremes) are also serious, and little examined from what we can determine.

**Summary**

Grid impacts from DER concentration stress present themselves in symptoms like reverse power flow, voltage disturbances, and frequency violations. These symptoms are diagnosed through sensors or observation of problems. Left untreated, the prognosis for DERs operating in excessive concentration is thermal degradation. Violation cascade can also result, which can be catastrophic.

DER concentration stress could be prevented simply by limiting the interconnection of DERs, or inhibiting DER operations, as has been done in the past, but today's goals to limit climate change will require DERs to be more concentrated than ever before. Additional mitigations will be required.

Preparation for DER concentration stress would include improved HCA for early identification, and improved line sensors for timely identification and response. The treatment options are (a) returning the grid to normal by curtailing DER operations, or (b) transforming the grid by reinforcement. Reinforcement needs to be administered by traditional measure and validated across grid operating protocols and a range of emergency edge cases. Reinforcement has few side effects, but is contraindicated where prohibitively expensive, or where even with reinforcement local grid conditions are still unsustainable.

### 3. Unsatisfactory DER Performance

**Nature of the Stress**

DERs stress the grid when their performance is unreliable, their performance is compromised (e.g., due to a cyber-vulnerability), or they fail. The grid stress of unsatisfactory DER performance can arise from to shortfalls and failures in construction and operations, initially and over time. Devices may be poorly manufactured; plant and field inspections may miss some of these defects. Even after operating properly for some time, properly-manufactured DERs can still degrade and fail. With age, PV systems may cloud, fray, and degrade. On-premise and vehicle batteries will all eventually fatigue and break down. Inspection and maintenance will miss some of these problems. DER performance also can be compromised when cyber-tampering alters DER data, operations, or control.

The grid stress from unsatisfactory DER performance is serious because the grid is in continuous operation, and usually copes with defective or failed components by workarounds until replacement. Grid operation depends upon awareness of the problem, the ability to contain the stress caused by the problem, and the ability to resolve the problem, all of which may be lacking. Not all of these shortfalls and failures can be detected, much less assessed and remedied, prior to grid impacts. Due to lack of access and control, these stresses may arise and amplify unnoticed. Even once they are noticed, responses may be very difficult. Warranties are only relevant if they are accompanied by detection and repair.

Forecasting grid stress from unsatisfactory DER performance would depend upon the availability of data from DER testing and operations. This data is insufficient at present, especially given ongoing changes in DER design and operation.

The grid stress from unsatisfactory DER performance would reveal itself as DERs malfunctioned, and failed to perform properly (e.g., deliver reactive power, charge and discharge evenly). In a dense DER deployment aiming for decarbonization and electrification, these symptoms would arise more often.

### Traditional Mitigations

Device performance is a well-understood source of grid stress, and most grid components have received decades of attention in this regard. Device lifetimes, operating conditions, failure modes, maintenance requirements, and repair procedures are documented. Competitive manufacturers have worked to improve their products.

But DERs haven't yet received this attention: not only is the category relatively new, but basic DER technology and DER fabrication methods are still changing rapidly, as demands on DERs are evolving. Smart inverters have compounded the issue rather than resolved it, because they are the basis for requiring DERs to be active, and active more precisely, than they have ever been before.

Unsatisfactory device performance can be addressed in individual projects through conservative operating assumptions, but where data is lacking, these assumptions are difficult to establish.

## Gaps Remaining

Performance modeling across the various types of DERs and systems including DERs are limited. Device lifetimes, operating conditions, failure modes, maintenance requirements, and repair procedures all need to be documented, and incorporated into both device design and grid modeling.

Apart from inverters, few DERs have been designed based on grid use cases. Few distribution system plans have been developed reflecting input from DER designers. Even in the case of inverters, more work remains to be done to align operations of DERs and the grid.

## Summary

Grid stress from unsatisfactory DER performance presents itself as device misbehavior and failure. Some accumulate over time, and some are sudden. Some of these problems are acute, and some are chronic. Left untreated, the prognosis for unsatisfactory DER performance ranges from insufficient capacity when called on, to inability to supply grid support. The seriousness of the grid stress depends upon factors such as the number and size of DERs involved, the suddenness of the impacts, and the abilities to foresee and detect the impacts.

Stress from unsatisfactory DER performance could be prevented by replacing the DERs at issue, or changing their performance requirements. Preparation for unsatisfactory DER performance would include design for purpose, and performance monitoring once in place for early identification and timely response. Treatment for unsatisfactory DER performance includes replacing the DERs involved or recalibrating the DERs' performance requirements (either through system design or operation). While replacing the individual DERs may often solve the problem, care should be taken to ensure the stress isn't resulting instead from unsuitable specifications.

### 4. Unsatisfactory DER Interoperability and Integration

**Nature of the Stress**

DERs stress the grid when their interoperability with other grid components is limited, or when their integration with other grid components is constrained. As every solar + storage developer has come to learn, a properly-designed, properly-functioning DER may not play well with others. The grid stress from unsatisfactory DER interoperability and integration develops when DER communications or control have issues (e.g., latency, gaps) that have not been anticipated in project design and development.

Of course, there is stress involved when interoperability is limited or integration is costly and projects are set aside as a result, but grid stress arises only when a project proceeds and the result stresses the grid. Thus grid stress from unsatisfactory DER interoperability and integration may be taken as a particular type of unsatisfactory DER performance, when properly-designed and acceptably-located DERs are tipped into serious grid stress either by the addition of an incremental DER, a new system or system operations, or by an unanticipated edge operating case, e.g., a wildfire.

As devices, most DERs are in fact systems: components combined into standard products with operations depending upon internal sensors and software for communications and control. Individual DERs may combine into larger-scale systems, e.g., a solar array, a stationary storage appliance, an electric vehicle. These systems interconnect with the electric grid.

Interoperability is a challenge of compatibility: the ability of system components in combination to work with one another properly. Interoperability may be limited by component design, communications or control. Integration is the combination of system components into a larger system, often accomplished by software. For a century and more, the electric grid has been a vast exercise in interoperability and integration, highly dependent on exercises like smart inverter standardization. We have now reached the most critical phase of this exercise.

**Traditional Mitigations**

DERs (e.g., solar systems, battery systems, electric vehicles) are relatively new categories, which operated relatively independently within the grid until recently. As basic DER technology and DER fabrication methods changed rapidly, HCA and smart inverter design have combined to help DER interoperability and integration to improve.

However, as demands on DERs have evolved, ever more sophisticated interoperability and integration is required. For example, smart inverter specification has eased many challenges of interoperability and integration, while at the same time increasing demands on DERs for more exacting performance. Improved interconnection procedures have aided integration with the grid but have increased calls for DERs to be active (e.g., residential storage resources during Public Service Power Shutoffs).

Grid reinforcement could assist DER interoperability and integration, particularly in the form of DERMS (Distributed Energy Resource Management Systems). While DERMS has been discussed for a decade, it is still not yet standardized, and it only qualifies as a traditional mitigation in the loosest sense. Even the best DERMS carried its own burden of communications and control requirements and operates across a limited set of DERs. However, one common purpose of DERMS software is to enable the interoperability of disparate DERs without requiring integration beyond APIs (Application Programming Interfaces).

In individual projects, interoperability and integration constraints may be addressed through careful specification and custom work (e.g., in the SCE Fontana project). In some cases, the gaps will be too large (e.g., in the PG & E project cited above).

**Gaps Remaining**

Grid stress from unsatisfactory DER interoperability and integration is now arising in solar + storage projects, in inverter design, and in larger-scale utility DER programs. The root cause of this grid stress is inconsistent or incomplete grid use cases incorporating DERs as well as other grid components and software. Software in particularly limited, across DERMS, distribution automation (DA) systems, and advanced distribution management systems (ADMS), which have been developed separately and integrated sparingly. As a result, both DERs and the communications and control software linking them to the rest of the grid are limited.

Much more work is required across communications and control protocols, messaging requirements, use cases, and operations.

**Summary**

Grid stress from unsatisfactory DER interoperability and integration presents itself in suboptimal grid performance. It may require detailed analysis to recognize that these DER limitations lead to grid stress. Left untreated, the prognosis for grid stress from unsatisfactory DER interoperability and integration is often serious dysfunction (see the PG & E test example described above).

Grid stress from unsatisfactory DER interoperability and integration could be prevented at the grid design and planning stage through improved modeling and testing, especially during development of communications protocols, messaging requirements, use cases and operating protocols. Preparation for grid stress from unsatisfactory DER interoperability and integration would include better commissioning for early identification and use case testing against performance requirements for timely response when performance problems arise. Because this grid stress arises at a system level, the treatments require rebuilding what was intended to be grid modernization or reinforcement.

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# 4 RESEARCH & DEVELOPMENT NEEDS

In the first three sections of this report, the work described the HCA and smart inverter initiatives that responded to grid stresses from DERs and profiled the remaining sources of grid stress that become more serious as the society fights climate change with grid decarbonization, building electrification, and transportation electrification.

These four sources of serious grid stress are:

- Dynamic DER Design & Location
- DER Concentration
- Unsatisfactory DER Performance
- Unsatisfactory DER Interoperability and Integration

In this final section, for each of these serious grid stresses, the researchers broadly review the gaps remaining to be filled by research and development and cite some instances of work in those respects. These studies are not cited as examples of curated insight, instead they are taken as indications of activity and interest in the area, which might provoke discussion when considered by distribution planners.

Based on the interviews the researchers have conducted in this assignment, internal analysis, and guidance from other initiatives[50], this project also describes a near-term research and development plan for utilities.

## A - Dynamic DER Design & Location

### 1. Gaps Identified

On the distribution grid, the researchers are unable to anticipate voltage and frequency variability, and react to it fast enough and reliably enough. Our traditional interconnection

[50] For the California Energy Commission, Navigant and Gridworks led the development of California's DER Research Roadmap, which recently set three top priorities for urgent DER research: (1) valuing operational flexibility, (2) demonstrating DER grid balancing services, and (3) creating a VGI data program. The initiative prioritized urgency based on climate commitments, customer safety, and customer economics, rather than grid stress. However, the group also identified other grid-related priorities: local distribution impact and optimization; communications and layered controls; validation and large-scale demonstrations; customer and critical infrastructure resiliency; operational flexibility potential and value; and data, analytics and planning. See . Liet Le, Distributed Energy Resources (DER) Roadmap Presentation, Navigant and Gridworks, (19-MISC-01, TN# 229805) 9/20/2019.

solutions are case by case or based on reinforcing the grid substantially, but even these steps leave us short of data to anticipate, assess, and react to grid conditions.

As noted above, the joint White Paper from the three California IOUs identified utility capabilities and systems for awareness, analysis, and response as a research and development priority. Utility capabilities and systems for awareness, analysis, and response limit control and dispatch, especially where vendors and third-party owners are involved. Internal utility communications across systems (e.g., distribution management, work management, customer information) limit effectiveness, especially in outages. To manage DERs, utilities will need robust power flow modeling, phase identification, and system visibility.

## 2. Examples of Current Research

The researchers have seen in the research cited above (e.g., Pukalani, Fontana, PG & E) that field experiments and tests with DERs can substantially revise our performance expectations. It should give us pause that our hypotheses are not being validated in good order, and even standing up projects proves very difficult. Several examples of other recent research and development illuminate these challenges.

### Characterizing DER Performance for Frequency Management

Much current work on microgrids anticipates problems that will arise for a grid with a high level of DERs. For example, DERs replace the energy from traditional resources but do not replace the inertia. In microgrids, the relative lack of inertial dampening causes the rate of change of frequency (RoCoF) to accelerate from a conventional grid average of 0.2 to 4 Hz/s[51]. Given the lack of inertia, inverters must supply frequency response instead, and if the inverters don't respond well enough or fast enough, a fault can cause protection resources to respond to the extreme break frequency by disconnecting resources in a cascade. Storage resources can also occasion these problems through their operations.

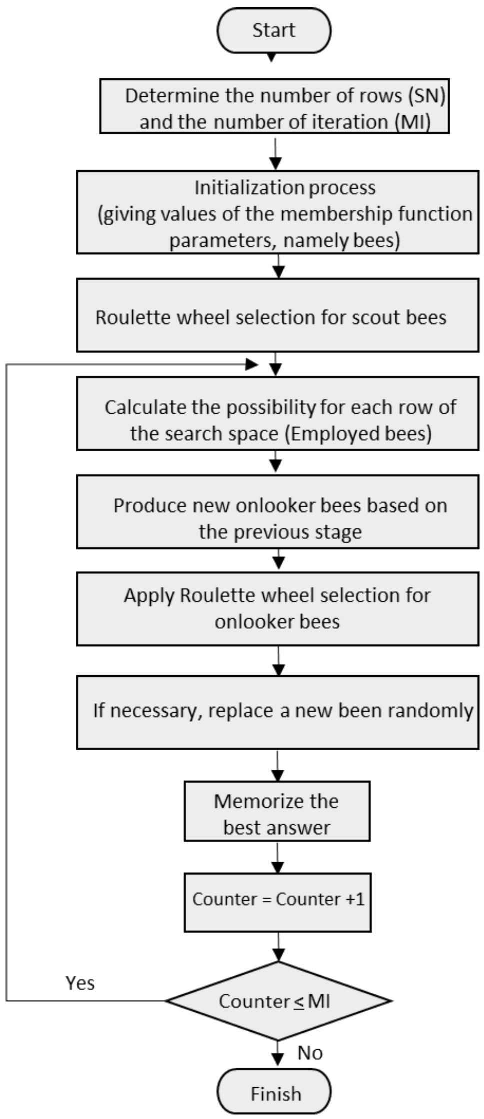
To pursue novel generation strategies for robust, flexible, and sophisticated controllers, researchers have had to reexamine resource models, and coordinate models across resources (wind turbines, PV arrays, flywheels, fuel cells, diesel-powered generators, storage devices, and controllable loads). DERs require time to operate and incur their own stresses as they operate. Frequently switching on and off has consequences. Intelligent, adaptive, and model-predictive controllers are becoming as important for DERs as smart inverters.

In their work, Abazari, Monsef, and Wu focus on improving load frequency control strategies by active power injection. For example, they create a dynamic small-signal

[51] Ahmadreza Abazari, Hassan Monsef, Bin Wu, "Coordination Strategies of Distributed Energy Resources Including FESS, DEG, FC and WTG in Load Frequency Control (LFC) Scheme of Hybrid Isolated Micro-grid," *Journal Citation*

fuzzy-droop model for wind turbines that helps to create virtual inertia, using the artificial bee colony (ABC) algorithm for self-tuning and adaptive membership specifications. In other words, the control system accepts a wide range of signals, adapts to them, and reacts to them according to the nature of the specific DERs addressed. Some messages trigger resources, some messages scout for resources, and some messages confirm the utilization of resources.

The bee analogy is powerful and applicable:




Source: Abazari, Monsef, and Wu, *ibid*, p. 15

**Figure 7:**
**Flowchart of Artificial Bee Colony Algorithm**

In their work, individual (virtual) bees share information at the hive about pollen sources and the costs of accessing them. Individual bees are then provided with individual missions based on the total of the hive's information at the time. The information is dynamic and updated in real-time. Bees depart for the next best available mission, which may be back to where they just were and maybe to a new resource. DERs are accessed similarly in the study, taking into account the requirements of access, the resources available, and the net intended result.

This study illustrates the importance of ongoing work to understand the different types of DERs and how they operate alone and in combination. Local, momentary circumstances are only one level of consideration. Weather, load, and overall grid conditions influence control as well. Characterizations of heterogeneous DERs accessed for fast frequency response have been uncommon, but are becoming essential (e.g., in the recent HECO procurement of fast frequency response resources). Our industry needs more of them.

Abazari *et al.* recognize that sophisticated modeling of DERs in dynamic operation will be required to anticipate performance. Note that they are directly focused on translating DERs' design parameters into the design of valuable operating protocols. In a real sense, the DERs aren't completely designed until their operations are specified.

## Characterizing Flow Batteries as DERs Contributing to Resilience

Energy storage is a particularly important type of DER because of its ability to serve both as resource and load. As a type of energy storage, flow batteries hold the promise of delivering these services for longer durations. The advanced distribution grid that includes DERs, such as flow batteries, will also include remote sensing, smart reconfiguration, volt-VAR control, advanced control and protection, automation, optimization, and other means of putting long-duration storage to work. These capabilities combine to provide grid resilience, which is the ability of the grid to withstand stress and recover from stress.

Validating DER performance beyond modeling is often conducted through Hardware-In-the-Loop (HIL) testing, where a device (or its sub-second data) interfaces within a real-time simulation of a power system. An example is examining battery life under different conditions of temperature, age, inverter operation, and charge/discharge cycling[52].

At Idaho National Laboratory (INL), Panwar *et al.* quantified a network-based resilience metric, evaluated the network-topological resilience. This was conducted by establishing the nodes' percolation thresholds (the probability of each node being functional at all after a stress event), among other factors (e.g., connectedness and heterogeneity). The network's resilience arises from these mutually-dependent factors; hence the network as

[52] Mayank Panwar, Sayonsom Chanda, Manish Mohanpurkar, Yusheng Luo, Fernando Dias, Rob Hovsapian, and Anurag K. Srivastava, "Integration of flow battery for resilience enhancement of advanced distribution grids," *International Journal of Electrical Power & Energy Systems* (Volume 109, July 2019, pp. 314-324).

a whole cannot always be improved by an improvement in a single factor but instead requires a multi-factor solution. Grid reconfiguration in the event of stress is one example, often implemented automatically.

The presence of DERs complicates the reconfiguration algorithms, but also provides new solutions; flow batteries provide many new solutions. The INL experiments used HIL testing of a ViZn flow battery, varying voltage and frequency in grid feeder simulations of sudden load loss, and providing battery data back for inclusion in the network model. Battery response protocols (e.g., varying power-to-energy ratios) were developed in a microgrid framework. The tests also added data simulating a solar resource. The flow battery responded in 600 ms, changed modes from charging to discharging in 1300 ms, and restored grid resilience within one second. Without the flow battery, the base case simulation took 27 seconds for restoration. The flow battery consistently improved grid resilience across the test cases[53].

The INL work indicates how complex and rewarding it can be to understand DER-related grid stresses. While DERs can cause stresses and complicate mitigation, they can also ease stresses, especially when flow battery storage is involved. Notably, Panwar *et al.* persisted in standing up their project to provide a rich data set, allowing them to understand variable DER performance. The projects' sophisticated modeling and testing are also important, as it helps distribution planners take advantage of advanced network mathematics. Our industry needs more tests of DERs within disciplined resilience frameworks.

## 3. Near-Term Research & Development Agenda for Utilities

To anticipate voltage and frequency variability on the distribution grid, and react to it fast enough and reliably enough, requires understanding DER performance in the grid. The inherent variability of DER performance on the grid means utilities need much more data, fundamental analysis, and dynamic modeling than they have needed for other grid components.

It is not enough to merely understand whether or not a proposed DER project might have specific consequences under "normal conditions." HCA needs to consider a very broad set of conditions, including edge cases. Our traditional interconnection solutions are case by case or based on reinforcing the grid substantially, but even these steps leave us short of data to anticipate, assess, and react to grid conditions.

[53] Similar advanced work on frequency regulation using Li-ion batteries is reported in Zhi Yuan Tang, Yun Seng, Lim, Stella Morris, Jia Liang Yi, Padraig F. Lyons, and Phil C. Taylor, "A comprehensive work package for energy storage systems as a means of frequency regulation with increased penetration of photovoltaic systems," *International Journal of Electrical Power and Energy Systems*, Vol. 110, September 2019, pp. 197-207.

Utilities need better data to indicate not just how large a DER project would be suitable at a given location, but what kind of project would be suitable[54]. The gap between HCA and interconnection studies needs to be bridged through better data about how to profile locations, across a greater number of factors, with improved modeling of both the grid and DERs. At present, much of the limited DER performance data that has been collected is proprietary to vendors, project developers, or other third parties.

The research & development agenda begins with utilities collecting and reviewing more data about what is actually happening with the DERs already installed on their grids, as ComEd is beginning to do. That data can be supplemented by deliberately generating that data, as Panwar *et al.* have done, and as HECO has had to do.

Modeling for DER performance also needs to move beyond the traditional approaches that sufficed for stable one-way power flow. The researchers don't yet know what risks and opportunities lie beyond the HCA and inverter protocols the researchers have in place, and the researchers don't yet know how to model the grid stresses or the mitigations. Abazari *et al.* and HECO show us that modeling DERs in use can progress service by service.

There is precedent for deploying utility sensors widely for modeling. Today, utility load research departments use a comprehensive set of automated meter reads not only for billing, but also to populate utility load models. For decades before automated metering arrived at every customer site, these departments deployed an array of meters to sample data across the franchise, and they still use data from individual meters in special situations. The utility's load research department might become the utility's *resource* research department, modeling DERs and load and how they interact.

To better manage dynamic DER design and location, the researchers recommend these kinds of utility tests and pilots in the near term:

- <u>More data</u>: inventory installed DERs, the data available from them, and the sources (e.g., the grid, buildings, vehicles), channels, and storage of this data. Assess the reliability and accessibility of this data. Identify useful validation routines and supplemental data—Benchmark with other utilities.

- <u>Basic analysis</u>: identify cases where DER data would call for a reaction. Define and test the available utility analytics for reaction speed and reliability—Benchmark with other utilities.

- <u>Dynamic modeling</u>: Identify the modeling currently in use for interconnection and hosting analysis. Assess the models for relevance, reliability, accuracy, and dynamic flexibility. Adjust the models as indicated, and test them.

[54] "Characterizing the Costs of DR Automation in New Buildings" was among the top five priorities in the recent California DER Research Roadmap work. Liet Le, Distributed Energy Resources (DER) Roadmap Presentation, Navigant and Gridworks, (19-MISC-01, TN# 229805) 9/20/2019, p. 24.

# B - DER Concentration

## 1. Gaps Identified

Instances of DER concentration surpassing HCA recommendations, or causing particular problems, are important special cases of severe dynamic DER design and location stress. These cases should be anticipated in development, and they must be mitigated in the field, despite the demands of the war on climate change. To do so, utilities must be able to correlate DER penetration, intensity, and activity with voltage, frequency, and other metrics. Mitigation may well be avoidance, i.e., DERs cannot generally be constrained, but they need to be constrained in these particular instances.

DER concentration stresses can be identified individually and assessed incrementally as DER penetration, intensity, and activity increase. They will be associated with edge cases, arising in some instances or in all instances. They may arise as DER deployments change, or other aspects of the grid change. They cannot yet be avoided merely by design, because our DER and grid modeling isn't robust enough.

As noted above, the joint White Paper from the three California IOUs identified DER location and volume as a top research and development priority. Scale and scope are important. Capacity deferral and outage-related services (i.e., resiliency and reliability) are only feasible as grid services with significantly-high local penetration of DERs in stressed locations. The usefulness of voltage support is most dependent on local conditions. Utilities need the right degree of DER penetration in the right places, to be both useful and safe.

## 2. Examples of Current Research

### Rooftop PV Concentration and Grid Stresses

Work in Hawaii and California across the last decade has highlighted the challenges posed by the growth of rooftop PV generation. A study from Spain[55] indicates that those challenges remain. Tevar *et al.* catalog the advantages and disadvantages of rooftop PV proliferation to meet a renewable mandate, given a distribution grid designed for traditional operations. The increased penetration of PV is related to "rapid voltage fluctuations, imbalanced between phases, the appearance of harmonics and flicker, the de-coordination of protections, the premature aging of assets, and other impacts on network operations.[56]" They note PV is more helpful than the wind in reducing technical

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[55] Gabriel Tevar, Antonio Gomez-Exposito, Angel Arcos-Vargas, Manuel Rodriguez-Montanes, "Influence of rooftop PV generation on net demand, losses, and network congestions: a case study," *Electrical Power and Energy Systems* (106), 2019, pp. 68-86.

[56] Gabriel Tevar*, ibid*, p. 69.

losses, and PV arrays in some locations can reduce technical grid losses much more than others.

The grid impact of PV arrays is determined by the time, their activity (i.e., number, size, operations) and their location. Their locations differ in their physical and technical position on the grid (more nearby laterals, connection points, and groups can increase losses and other problems). PV arrays also differ in the load conditions they experience at their locations. Even given these differences, through an extensive analysis of Barcelona data, Tevar *et al.* note that 30% PV concentration on a distribution feeder is generally the milestone when losses begin to accelerate past standard levels. Voltage violations arise in 20-30% penetration scenarios, and ampacity (saturation) problems increase in 30-40% penetration scenarios, clustered wherever PV is concentrated. These violations and problems can occur at lower penetration levels, and much more often when the grid is imbalanced or weather conditions are extreme.

Most important, while PV penetration levels of 25% still may be beneficial overall (reducing technical losses), penetration levels of 66% or higher increase technical losses over 50%, and cause the distribution grid to export daily, year-round. At a minimum, these stresses call for grid reinforcement (e.g., storage).

The basic variability and volatility of DER performance has long been recognized and gave rise to HCA, Tevar *et al.* remind us that despite the operational mitigations explored in Hawaii and California, the grid impacts are real, and increase with DER concentration. Their findings regarding penetration levels over 66% are sobering and need validation. Our industry needs much more research on the scaling and costs of DER grid impacts.

## Integrating Conservation Voltage Reduction (CVR) With DERs

Ranamuka *et al.* have[57] examined the integration of CVR with DERs, specifically CVR across a distribution grid with a high penetration of PV systems. CVR has become a popular approach for utilities in North America and elsewhere to reduce peak demand and improve energy savings, simply by reducing the voltage across certain portions of the distribution system under certain peak load conditions, and in sites where reactive power loads can trigger upgrades. To the degree that DERs impact voltage, they can support or undermine CVR operations.

Essentially a specific and automatic method of volt/VAr control, CVR, isn't suited for every utility. Most utilities have the necessary substation on-load tap changers (OLTC) to implement CVR, but some have volt/VAr control devices that are incompatible with CVR, or they lack the control and communications networks to validate CVR performance. CVR requires that active and reactive power down the line need to be managed in coordination with OLTC voltage corrections at the substation, which can be demanding because the

[57] D. Ranamuka, A.P. Agalgaonkar, K.M. Muttaqi, "Conservation voltage reduction and VAr management considering urban distribution system operation with solar-PV," *Electrical Power and Energy Systems,* (105), (2019), pp.856-866.

generation of a PV array is influenced by not only influenced by its operating instructions, its inverters, and its controls, but also by its own VAr generation, nearby protection equipment, and the weather.

Ranamuka *et al.* examined a series of CVR case study simulations across solar penetrations of 16-30%, comparing energy savings, losses, tap operations, and the voltage variation index (VVI). The target CVR was 10%. Several case studies showed so-called “green-solar CVR” at work, with PV arrays supporting CVR if peak load profiles coincide with periods of high solar generation. Solar intermittency was an issue, with the CVR results following the level of solar generation, and the OLTC operating frequently. In other cases, when the OLTC operations were reduced, VVI increased, reducing the voltage at the remote end bus. The introduction of capacitor banks helped stabilize VVI but also reduced CVR effectiveness in certain cases.

In some cases, high solar penetration affected downstream voltage, energy savings, and peak demand reductions, and CVR was less effective. In still other cases, using the PV resources to provide local VAr support could aid CVR, but only if the Volt/VAr control mechanism was carefully designed. The complex case study results showed how two programs that both influence line voltages (CVR and PV solar) interact, and require careful joint management.

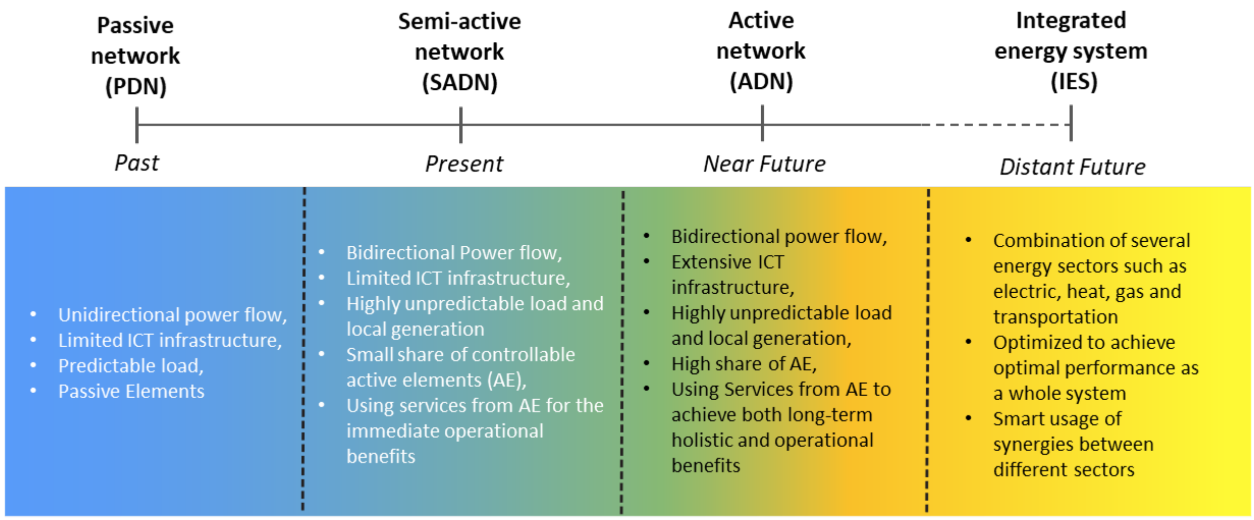
The detailed case studies also suggest that local DERs may have focused impacts on many utility programs and that these impacts will change as DERs proliferate. DER operations will need to be integrated and interoperable with a wide range of other utility programs. Understanding how DERs affect these programs’ results is the first step.

## Improve Distribution Planning to Recognize DER Concentration

It is important to recognize that HCA, the smart inverter initiative, and HECO’s fundamental redefinition of grid services all occurred outside the normal framework of utility distribution planning, Before the serious grid stresses from DERs can be managed; they have to be recognized and understood within established utility processes.

Klyapovskiy *et al.* have[58] worked in a European context, transitioning from passive distribution planning to planning for an Active Distribution Network (ADN). As shown in the table below, an ADN is characterized by an increased level of active elements (e.g., DERs, demand response participants):

[58] Sergey Klyapovskiy, Shi You, Hanmin Cai, Henrik W. Bindner, “Incorporate flexibility in distribution planning through a framework solution” *Electrical Power and Energy Systems*, Vol. 111, (2019), pp. 66-78.




Source: Klyapovskiy *et al*, *ibid*, p. 67

**Figure 8:**
**Evolution of Distribution Networks from Passive to Active and Integrated**

For passive networks, distribution planning begins as an exercise in load forecasting and then extends across the grid's resources. PDF plans often consider contingencies (e.g., N-1), and aim to reinforce the grid for worst cases, leading to inefficient, oversized investments. In contrast, ADN plans often expect AEs to deliver flexibility services, reducing investment requirements, but increasing the burden on operations. Unless network and operating planning are synchronized (which may require revising network plans considerably in the even that operating solutions are unavailable), ADN planning can lead to inadequate, undersized investments. ADN planning also has to acknowledge that AEs operate intermittently and imperfectly, whether as resources or loads, introducing a further uncertainty that puts a premium on accurate forecasting and field data.

Where DERs are concentrated, it becomes particularly important for ADN planning to understand the context of the DERs' operations: e.g., design, environment, location, activity, condition, performance. Operating solutions will be vital and may have their own side effects that need to be mitigated. The Load can reverse, the voltage can deviate, and equipment can fail. Congestion and malfunctions can increase. Because uncertainties are present at every stage, validation is necessary after network planning, operations planning, and field implementation.

ADN planning is more rigorous than PDN planning and involves much more data, analysis, and revision. ADN planning is complicated no matter how many times it is repeated, is uncertain, and involves its own risks. But ADN planning is mandatory: the nature of the grid has changed. Klyapovskiy *et al.* help us recognize that the change is fundamental and demanding.

## The Spatial Uncertainty of Renewable Resources

DER concentration can arise in time, activity (i.e., number, size, operations) and location. Given that almost every utility has a Geographic Information System (GIS) and an Asset Management System (AMS), it might seem that the location of DERs can be specified adequately. There will be instances of mistaken or missing database entries, but the utility inventory should be relatively complete. However, knowing the physical location of DERs is essential, but insufficient; grid modeling and grid operations require at least an estimation of the DER's activity at a point in time. Even at the most advanced utilities, the ADMS and DERMS systems aren't fast enough or integrated enough to support complete state estimation, as Exelon has found.

An active distribution network (ADN) has few measurement units across its many buses and branches. For power flow calculations, transmission planners have made do with ADN load models assuming ZIP: (constant-impedance (Z)), constant-current (I), and constant-power (P)). The variability of DER operations was acknowledged in passing as an uncertainty but rarely calculated. Shang *et al.* provide an approach to modeling this uncertainty,[59] with particular attention to the location of DER resources.

The location of concentrated DER resources greatly influences the grid. The resources PV, wind, and storage resources may not be mobile in themselves, but their grid impacts are mobile as their activity varies. Just as a stadium influences a feeder's role on the grid during a big game, or a recharging electric vehicle influences a household's role on a feeder, DERs' impacts can rise or fall in different locations across the grid. Location matters for resource and load, and forecasting power flow matters for grid operations, so the ability to better specify the location of DER impacts is very important.

Shang *et al.* demonstrate that meteorological data from DER sites and operating data from DERs can help build a learning model that yields improved power flow estimates with real-time applicability in dispatch and control. Their work introduces a new approach to considering the location of resources in distribution planning, which has long considered the location of the load. Most important, their work demonstrates that the variability of DERs across locations can impact the distribution grid as a whole, in its transmission relationships.

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[59] Xioya Shang, Zhigang Li, Jiehui Zheng, Q.H. Wu, "Equivalent modeling of active distribution network considering the spatial uncertainty of renewable energy resources," *Electrical Power and Energy Systems* (112), 2019, pp. 83-91.

### 3. Near-Term Research & Development Agenda for Utilities

Identifying and avoiding untenable edge cases, where DER concentration results in serious grid stresses, is considerably more complex than case-by-case interconnection studies can address. The cumulative effects of DER concentration, when combined with extremes of weather, load, and other grid operations, can create problems very quickly. DER performance is variable, but these other factors are also variable, and the incidence of high-impact/low-probability instances is difficult to anticipate.

However, it is exactly these cases utilities need to anticipate as they operate ADNs. HECO has found it necessary to model and plan for DERs in great detail. While few utilities have experienced HECO's level of DER penetration, few utilities can control as many elements of their situations as HECO can. Most utilities will need to take into consideration how extreme weather, a storage-rich bulk power system, and a host of electric vehicles might combine to stress their grids.

Utility distribution planners need much stronger forecasting models to cope with the rise of DERs. These forecasting models need to support better interconnection studies, which in turn need to support grid-wide HCA.

To better manage DER concentration, the researchers recommend these kinds of utility tests and pilots in the near term:

- Edge case identification: identify existing relevant edge cases specified in interconnection and hosting analysis and experienced recently by the utility. Specify the grid stresses experienced. Identify where the variables (e.g., weather, load, grid operations) involved could feasibly reach levels intensifying grid stresses.

- Bulk power system interactions: identify and model typical and edge case utility interactions with the bulk power system, with particular attention to planned storage expansions. Identify instances of grid stress. Examine existing utility planning models with regard to these cases. Identify improvements to bulk power system interactions and test them.

- Stronger forecasting models: Identify the modeling currently in use for forecasting, including new DERs.[60] Assess the models for relevance, reliability, accuracy, and dynamic flexibility. Adjust the models as indicated and test the revisions.

[60] "V2Bus for Resiliency" was among the top five priorities in the recent California DER Research Roadmap work, because of the lack of data and modeling for electric vehicles. . Liet Le, Distributed Energy Resources (DER) Roadmap Presentation, Navigant and Gridworks, (19-MISC-01, TN# 229805) 9/20/2019, p. 24.

## C - Unsatisfactory DER Performance

### 1. Gaps Identified

Voltage and frequency violations due to unsatisfactory DER performance are very difficult to anticipate, detect, identify, assess and remedy. Many other grid components have design features and established maintenance routines to provide performance awareness, because engineers have long known the stresses the components would cause and endure. DER designs are newer and are very limited in the data they collect and transmit. Data from DER testing and field experience is also lacking, so the signatures of impending problems or unsatisfactory performance may not be recognized. The performance data may be insufficient, unreliable, compromised, or missing.

DERs can be vital to grid operations: in the absence of warning systems, the risk of unsatisfactory performance risks seriously stressing the grid. The industry's catalog of failure modes and cases is also very limited, and is obsolete in some respects, as DER designs have changed. DER standards have increased in number and detail, but design and performance measurements are still developing.

Utilities who are authorizing interconnection of DERs or even procuring DERs may lack even basic proof-of-concept or field data to guide commissioning and oversight. Utilities have had to streamline their processes and rely on authorities having jurisdiction (AHJs) to vouch for results. For many DERs, price competition, foreign sourcing third-party ownership, and untrained installers have left utilities dependent on unproven DERs.

As noted above, the joint White Paper from the three California IOUs identified data coordination, measurement, and verification between utilities, DERs, and DER aggregators as a research and development priority. Data coordination, measurement, and verification between utilities, DERs, and DER aggregators limits grid planning and economic settlement with customers and third-parties. The PG & E EPIC project demonstrated that smart inverters might help DERs overcome operating variability, but more smart inverter field tests would be required, at higher DER penetration levels.

### 2. Examples of Current Research

**Diagnosis and Mitigation of PV System Sensor Malfunctions**

To connect a PC array to the grid, required components include a DC-DC boost power electronic converter, a three-phase voltage source converter (VSC), a maximum-power point tracking (MPPT) control, vector control, a pulse width modulation (PWM) pulse generator and a resistor-inductor (RL) filter.[61] The MPPT algorithms extract the maximum possible power given weather conditions, and then the VSC flows power through a

[61] S. Saha, M.E. Haque, C.P. Tan, M.A. Mahmud, M.T. Arif, S. Lyden, N. Mendis, "Diagnosis and mitigation of voltage and current sensors malfunctioning in a grid-connected PV system," *Electrical Power and Energy Systems*, (115) 2020, 105381.

common DC-link capacitor into the grid, transferring maximum power with unity power factor. The process depends upon accurate sensor measurements of these VSC/grid currents, as well as the voltage and current output of the PV array, in that these are used for converter switching signals.

Inaccurate sensor measurements can arise from many sources (e.g., the current transformer, various current sensors, their connectors). These components can age, be damaged, or can simply malfunction. The sensor readings can cease or be in error. Sensor failures are difficult to detect when they first occur, may also be difficult to detect and quantify as they are occurring, and may be almost impossible to anticipate. In practice, these sensor faults are discovered indirectly by measuring PV performance against weather-corrected output estimates.

Sensor faults in larger inverter-based systems are well-researched, but these models do not translate well to PV systems. Fault-tolerant PV control systems are known, but are rare, and may require additional circuitry. Saha *et al* suggest an approach to diagnosing and mitigating these PV sensor faults, and they test it in simulations and experiments. Offline, the potential faults are specified, modeled, implemented in a microcontroller, and checked against the actual measurements of the PV array. Because the modeling is thorough enough, the mitigation approach can rectify the measurements to the degree they indicate faults, and then supplies the rectified measurements to PV array controllers.

PV array sensor faults are common enough to be well-known as sources of suboptimal system performance. Even with nominal internal function, PV arrays are subject to weather-related variability. Improvements in the performance and reliability of PV arrays are assumed to be proceeding apace as the solar industry evolves; in this study the researchers see one example of the detailed analysis required to deliver that progress. Saha *et al* do not include data on the prevalence or impact of PV array sensor faults. The researchers cite their study to indicate how DERs are each themselves systems that include devices, components, and software. Mitigating unsatisfactory DER performance is complex, and worth more research and development.

### Assessing Risk in DER Investments

Mitigating unsatisfactory DER performance depends on defining the gap between typical DER performance, and typical DER requirements. Much current work in this area occurs in so-called “non-wires” investigations, where the capabilities of DERs are assessed against those of traditional distribution grid enhancements.

Solar + storage offers a combination of new capabilities that highlights DER performance. Both the solar assets and the storage assets must perform properly within the combined resource. The basic concept is that solar assets’ intermittency and variability can be overcome through pairing with storage, to meet sizing requirements dictated by load and location. The solar + storage system can then be employed as a resource to meet peak load, minimize total cost, minimize losses, or defer investment.

In a recent example[62] of this analysis, Samper *et al* explored the technical and economic performance of solar + storage. Notably, the study uses financial metrics to assess alternatives' comparative risk per unit of investment, moving toward risk-based distribution planning. Performance uncertainties are introduced by stochastic Monte Carlo simulation, and the traditional Sharpe and Sortino cost ratios are simplified to consider only costs (e.g., the penalty costs of supplying poor-quality energy, the costs of violating feeder and distribution transformer ratings), and not potential income streams.

The objective function of the optimization problem works within constraints (e.g., capacity, power balance), and considers the PV and the storage as resources, and the storage as load. The conventional alternatives include feeder upgrades, capacitor banks, and new distribution lines. The timing of the potential investments is also considered, because an upgrade may occur over time. Power flow simulations are run on EPRI's OpenDSS* tool, particularly to calculate energy losses, the energy supplied with poor quality (PQEN) and the overload energy (OEN). Because the decision variables are complex, heuristic optimization (e.g., Evolutionary Particle Swarm Optimization) is suitable to obtain near-optimal solutions.

Samper *et al* consider data from San Juan province in Argentina for a 13.2 kV three-phase balanced network with four feeders and 20 MW of non-coincident peak load. Upgrades are considered for two of the feeders, one with even proportions of residential, commercial, and industrial load, another with 74% residential load and 26% commercial load. As an alternative, solar + storage is sized and costed. Weather, load growth, PV efficiency improvements, and PV penetration (across a 10%-60% range) are considered across a ten-year investment horizon in the simulations. It is significant that the study considers the storage investment as an alternative incremental to a base that includes solar resources expanding of their own accord.

The study compares traditional reinforcement (largely the additional of a new transformer at the substation), with storage system investment across two years, and flexible storage system investment (aligned to growth in solar resources and load) across three years. All options have similar expected costs, but the flexible investment has significantly lower risk, and is generally preferable.

Samper *et al* offer evidence that performing properly, solar + storage may offer economical and prudent alternatives to traditional grid reinforcement. The modeling also indicates that modest shortfalls in either solar or storage performance can significantly influence the analysis. It must be noted that the modeling did not account for the likelihood of these shortfalls, which could arise through design, unfamiliarity with the systems, or operations.

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[62] Mauricio E. Samper, Fathalla A. Eldali, Siddharth Suryanarayanan, "Risk Assessment in planning high penetrations of solar photovoltaic installations in distribution systems," *Electrical Power and Energy Systems*, (104), 2019, pp. 724-733.

Because DER performance has the potential of these positive contributions to distribution system planning, DERs will play larger and larger roles in these plans. Understanding the risk of these roles will be crucial.

## 3. Near-Term Research & Development Agenda for Utilities

Utility engineers need a complete and up-to-date catalog of DER failure modes and cases, which depends in turn upon a set of well-defined, standard DER use cases. From this foundation, utilities and vendors can develop a set of well-defined standard procedures to anticipate, detect, identify, assess and remedy unsatisfactory DER performance. The catalog and use cases can be updated as DERs change. Vendors now provide some of this information, but many vendor claims are partial and lack validation. Vendors would admit much more comprehensive information is available about grid components other than DERs.

In the interim, utilities need to appreciate the risks they are running experimenting with DERs in the field, across the grid. Utilities seek safe, reliable and affordable performance from grid components, but validation is often limited to confirming the contractual responsibilities for specific potential problems, should they arise. In addition, utilities need to anticipate outcomes. Problems and failures can be modeled, simulated and analyzed in advance of their occurrence. Cooperative studies across utilities are the best avenue for these analyses.

Utilities also need to look past commissioning to the grid impacts of what might go wrong. As the primary line of defense, HCA and interconnection studies need to be reexamined, reinforced, and extended, rather than abbreviated. The Fontana results indicated how easily standing up a project can become an experiment in how to stand up a project. Impactful DER projects are multiplying, and the demands for utility oversight prior to commissioning are increasing.

Streamlining interconnection and valuing resource performance properly are both worthy and urgent goals; they can be pursued successfully once performance is sufficiently understood. Utilities need to develop better and faster analyses, particularly for commercial projects.

To better manage unsatisfactory DER performance, the researchers recommend these kinds of utility tests and pilots in the near term:

- <u>DER performance metrics</u>: inventory installed DERs, their performance metrics, and the data available to assess performance against these metrics. Assess the reliability and accessibility of these DERs. Identify useful validation routines and supplemental data. Benchmark with other utilities.

- Failure analysis: catalog failure instances among installed DERs and their performance metrics. Identify root causes as possible. Identify useful validation routines and supplemental data. Profile failure cases. Test these analyses.

- HCA and interconnection reexamination: Identify the modeling currently in use for hosting and interconnection hosting analysis. Assess the models for success, identifying instances of failure. Benchmark with other utilities. Adjust the models as indicated, and reevaluate.

## D - Unsatisfactory DER Interoperability and Integration

### 1. Gaps Identified

Limited DER interoperability with other grid components, or constrained DER integration with other grid components are problems based in DER communications or control. These problems may be missed in project design and commissioning, because they arise as DERs become active, and as DER performance changes.

Utilities need much more analysis of the information technology in their DER projects. DERs' performance variability translates directly into more intensive communications and control requirements, and more sophisticated protocols to execute and confirm. Utilities need to anticipate when properly-designed and acceptably-located DERs might tip into serious grid stress either by the addition of an incremental DER, a new system or system operations, or by an unanticipated edge operating case. Interoperability and integration need to be confirmed prior to project commissioning, as part of interconnection analysis.

Utilities also need to understand the constraints and risks that their communications and control choices impose on grid operations. These choices are often embedded in software, and software integration. Developing suitable software depends in turn upon stable use cases, distribution systems, and component design (e.g., inverters). Utilities need to develop operating models for the distribution grid accordingly. To the degree that DERs are similar to load, and require a flexible and dynamic grid, a host of design assumptions about the distribution grid need to be reexamined.

As noted above, the joint White Paper from the three California IOUs identified synchronization of grid needs and DER responses as a research and development priority. The joint White Paper also identified grid-level availability and assurance of DER responses as a research and development priority, because unlike demand response, smart inverter-based grid services have specific, consistent performance requirements that require SCADA-level communications to achieve. The consequences of inadequate performance are more than economic. Voltage and frequency deviations can be damaging.

## 2. Examples of Current Research

### Joint Control of New Grid Enhancements to Support DERs

Throughout our work, the researchers have referred to types of distribution grid reinforcement or grid enhancement to support DERs, the most advanced of which include hardware, software, and services. Some of these distribution system enhancements have previous applications on the transmission grid. One important example is the set of power electronic devices known as flexible AC transmission systems (FACTS). These devices need to be reconfigured to be operable with distribution networks, and then integrated into the networks.

Among these devices, Soft Open Points (SOPs) provide notable operating reliability and feeder flexibility under conditions of high renewable penetration[63]. SOPs replace normally open points, and have begun to be used back-to-back in voltage conversion, loss reduction, and balancing. In particular, once their control variables and optimization can be described, coordinated SOPs and smart inverters offer new strategies for voltage control. Back-to-back SOPs can decouple real power exchange and reactive power support. Other SOPs (Static Series Synchronous Compensators, Unified Power Flow Controllers, and electric springs) can control the reactance between pair points to influence network power flows.

Of course, there are many devices available to address these distribution grid stresses: as Zheng *et al* argue, what is needed is a coordinated approach to applying them together, based on comprehensive modeling and analytics of joint control. Zheng *et al* offer evidence that their voltage control algorithms and strategies are practical, timely, and valid across systems with different numbers of compensators, reversed power flow at light loads, and high DG penetration at heavy loads (i.e., 48%, 79%, 96%).

The project viewed the optimization as a biconvex problem, and applied an alternate convex search (ACS) algorithm successfully in a number of trials. Their work coordinates power injections and line impedances efficiently for a single snapshot, however it is not yet general across multiple objectives for individual devices across multiple periods.

The study illustrates that new devices, in new combinations, offer new operating possibilities once modeling and testing can be completed. But unless the new devices are considered in the first place, and considered in combination, grid stress mitigation decisions may these opportunities. Our industry would benefit from more research & development across these topics.

[63] Yu Zheng, Yue Song, David Hill, “A general coordinated voltage regulation method in distribution networks with soft open points,” *Electrical Power and Energy Systems*, (116), 2020, 10557.

## Managing DERs for Remote and Enterprise Purposes

As DERs scale to support grid decarbonization and electrification, to a large extent their local use can be managed and monitored by smart inverters. But DER use for remote or enterprise purposes will depend on significant progress in DER integration and interoperability.

As HECO has recognized, aggregated DERs can provide significant grid balancing services if they can avoid violating distribution grid operating requirements. To date, DERMS and other communications and control systems have offered limited functionality and scalability. Central control of distributed assets is a classic challenge, and a distribution grid with diverse DERs has to orchestrate timely participation based on a large array of constraints, requirements, and interactions, often in dynamic conditions. Recognizing current and potential conditions, assessing how to react to them, reacting effectively, and documenting results is a continual cycle.

The capabilities to enable safe activation of flexibility products are being field-tested in Portugal and Slovenia, in the European Union's Horizon 2020 InteGrid project. The capabilities are referred to as the "traffic light system" (TLS) because they are a scalable, automatic, non-discriminatory signaling scheme reacting reliably to local and enterprise conditions (like traffic lights). DER management requires prequalification and central control based on information about current grid status, and defining "a set of interactions and responsibilities between the market participants and the network operators for the use of flexibility located on the distribution network.[64]" Underway for several years, TLS work has now included successful distribution grid simulations, and has scaled across more market participants.

Ongoing TLS work will consist of communications and control research and development. Field work will involve implementing the system in the communications and control framework already in place across the electricity distribution network. Insight into electrical engineering will inform the parameters of TLS design and operation, but the primary focus lies in information science. The major challenges are familiar: overcoming latency and missing data; modeling and testing decision rules; creating algorithms and use cases.

Many researchers, utilities and DERMS vendors have been engaged in modeling and analysis of individual DER communications and control systems under limited conditions. Simulations of complete grids are few, and field tests like the InteGrid project are rare. Our industry needs more successful field tests of DER communications and control across entire utility grids.

[64] Julien Le Baut, Fabian Leimgruber, Clemens Korner, "The Traffic Light System to Exploit Flexibility Exploitation from Stressed Distribution Grid," Paper No. 1893, presented at the 29th International Conference on Electricity Distribution (CIRED), Madrid, Spain (June 2019).

**Preventing DER Chaos: A Guide to Selecting the Right Protocol for DER Management[65]**

The researchers noted above that Phase 3 of California Rule 21 implementation, addressing smart inverter communications, has been much delayed. James Mater and Mark Osborn of QualityLogic have been major participants in those discussions. They recently summarized their observations in a webinar, indicating how much work remains to be done.

Mater and Osborn are focused on the messaging protocols, use cases, and control architecture used by DERs communicating in the distribution system. The leading messaging protocols are OpenADR, IEEE 2030.5-2018, DNP 3, and IEC61850. Only OpenADR was created for DER management, as part of demand response. DERMS is usually compatible with all of these protocols, and perhaps ModBus as well. ADMS usually employs DNP-3 and may also be compatible with IEEE 2030.5-2018 for DERs. DNP-3 is used for SCADA, and occasionally for control of utility-owned DERs. IEEE 2030.5-2018 was recently updated to reflect IEEE and California smart inverter standards. IEC61850 is based on substation system engineering as well as communications.

None of the four messaging protocols are completely suited for DER grid stress management, and all of them back into proprietary software : e.g., SCADA, DERMS, ADMS, and demand-response management systems (DRMS) from a variety of software vendors. DER communications use cases include linking with SCADA, demand response programs for peak management, and a host of specific control cases (e.g., solar smoothing, peak load curtailment, black start, DERMS linking under Rule 21, vehicle-to-grid operations).

Many proceedings, including an OpenADR-EPRI Workshop, have labored to define DER messaging requirements across the range of control messages required. SCADA control, IEC61968.5, voltage and frequency support, alarms and notifications, load management, and emergency dispatch are particularly important for the grid, but ordinary operating, administration, security, pricing, and electric-vehicle messages are also significant.

Unfortunately, OpenADR and IEEE2030.5 are not yet effective for real-time control, and while DNP-3 and IEC61850 are effective at SCADA and real-time DER control, they haven’t been completely implemented for many of the other DER messaging requirements (e.g., demand response), and extending them to do so isn’t a simple challenge. Mater and Osborn’s protocol recommendations for development differ by use case:

[65] James Mater, Mark Osborn, “Preventing DER Chaos: A Guide to Selecting the Right Protocol for DER Management,” Quality Logic and Triangle MicroWorks, March 2020.

**Table 5: Summary Matrix – DER Communications Applications and Protocols**

| Use Case/Application | Recommended Protocol(s) | Alternative Protocols |
|---|---|---|
| Utility Scale Solar/SCADA Control | DNP3, IEC 61850 | IEEE 2030.5 |
| DR: Utility to EMS/Aggregator | OpenADR | IEEE 2030.5 |
| Solar Smoothing | DNP3, IEC 61850 | IEEE 2030.5 |
| Duck Curve Mitigation | IEEE 2035.5 | DNP3, IEC 61850 |
| Black Start – Wildfire Prevention | IEEE 2035.5 | DNP3, IEC 61850 |
| CA Rule 21 Solar and Storage | IEEE 2035.5 | DNP3, IEC 61850 |
| V2G Applications: Utility to EVSE/PEV/Gateway | IEEE 2035.5 | DNP3, IEC 61850, Open ADR, OCCP, ISO 15118 |

Source: Mater and Osborn, *ibid*, p. 33

In California, Rule 21 has required inverter manufacturers to demonstrate communications capability with at least one of three protocols: SunSpec ModBus, DNP3, or IEEE 2030.5. But as QualityLogic emphasizes, capability with one protocol may not translate well to another, and the capabilities that must be demonstrated are limited to a spot check of standard cases. To be confident about DER interoperability and integration, a utility needs disciplined testing programs of their own, built around their own use cases and software environment.

Absent such testing, communications and control issues can easily lead to system malfunctions, and serious grid stresses, even when the components are properly designed and manufactured. As DERs develop and new DERs emerge, the interoperability and integration challenges will multiply, unless utilities insist on specific requirements.

### 3. Near-Term Research & Development Agenda for Utilities

DER interoperability and integration depends on DER communications and control, which have been limited in design and demonstration. Inverters are only now becoming standardized in communications design and operation, and storage inverters are not yet standardized. If DERs are to become as versatile as they are variable, DERs will need to meet more intensive communications and control requirements, especially in edge operating cases. "Low Cost Telemetry for Aggregated DER" was the highest-ranking priority in the recent California DER Research Roadmap work. Also among the top five priorities were “Secure Communications for DER”, and “PSPS Grid Support Fuel Research.[66]

Utilities need much more detailed analysis of the information technology in these cases, confirming interoperability and integration prior to project commissioning, as part of interconnection analysis. It is not enough merely to confirm DERs can be safely interconnected to the grid. DERs need to be able to perform on the grid, and that performance needs to be reliable and verified over time.

Utilities also need to identify the constraints and risks that their communications and control choices impose on grid operations. The devices and the software have to perform, and work together, within operating models for the distribution grid. Today, there isn’t yet consensus about what kind of software system should control DERs.

To enable a flexible and dynamic grid, a host of design assumptions about the distribution grid need to be reexamined. Substations will need to become communications hubs. Feeder control and software intelligence will be distributed. Microgrids will be common. Most important, resources (including DERs) will be located where they need to be to support the grid. Some DERs will be located where they need to be to enable the deployment of other DERs (e.g., solar + storage).

As noted above, the joint White Paper from the three California IOUs agreed that grid needs and DER responses need to be synchronized, and grid-level availability and assurance of DER responses need to be assured. These are research and development priorities, ultimately requiring SCADA-level communications to achieve.

To better manage DER interoperability and integration, the researchers recommend these kinds of utility tests and pilots in the near term:

- Interoperability and integration confirmation: Identify the DERs in place, and the most important use cases where they need to interoperate with the grid and integrate with other utility systems. Model these cases, identifying the data that would confirm acceptable operations. Document earlier validation, if any. Check for this data and confirmation. Identify instances of variance, violation, or lack of confirmation. Identify novel methods of overcoming these issues, simulate and test them.

- Constraints and risks of communication choices: Identify the communications protocols in use across the DERs in place, and anticipated. Assess performance, interoperability and risks (e.g., cybersecurity). Identify potential grid stresses, and methods of recognition, identification, and mitigation. Test these methods.

- Reexamination of grid design assumptions: Document how the utility’s grid design would change to become a flexible and dynamic ADN. Catalog the performance

[66] Liet Le, Distributed Energy Resources (DER) Roadmap Presentation, Navigant and Gridworks, (19-MISC-01, TN# 229805) 9/20/2019, p. 24.

standards for DERs to be available and reliable, and compare to current utility practices. Identify and quantify the value of redesigning specific grid elements. Test these analyses.

## D – The Way Forward

The research and development agenda outlined above is the starting point for dialogue with distribution planners about serious DER-related impacts on the grid. There are literally hundreds of completed studies on that topic that the researchers have not cited in this report, many of which should be considered in establishing a research and development plan for any particular utility. EPRI itself has completed many relevant studies (see in the Appendix). SCE has major strategy, planning, and procurement exercises underway which would influence research and development priorities.

And yet, the researchers can see the outlines of the research and development agenda every utility ought to consider. DER design and location must be much better understood, particularly as DERs are concentrated. DER performance must be much better understood, particularly with regard to communications and control. As DERs come to define the grid in the war against climate change, proliferating throughout the grid, transportation, and buildings, a lack of understanding could be expensive and even catastrophic for the grid. As things stand, these risks fall to the utilities.

The remaining momentum in the HCA and smart inverter movements is limited, and won't mitigate these risks. HCA faces substantial challenges in becoming dynamic. Smart inverters have to bridge to storage. Nor will a new generation of software manage DERs on its own, at least not until the many systems, types of systems, and protocols coordinate properly. Utilities and regulators continue to assume a widely-successful DERMS platform will emerge, yet none has to date. Nor will industry hesitation about the war on climate change hold back the tide of cost-effective DERs. The auto industry is retooling for EVs without asking permission from utilities. Loads and resources are changing far more than ever imagined when the smart grid was first envisioned.

It also won't work to simply deploy traditional mitigations to address grid stresses from DERs as they arise. In an era of wildfires and pandemics it is simply too expensive to build peak line capacity to replace peaker plants. The grid can't be tailored with devices to be completely reversible. Solar PV arrays can't be located merely due to grid requirements. Infrastructure can't be moved every time EVs become popular in a neighborhood. Like the simple analog solutions, the researchers relied on before the complex digital age, the traditional grid simply can't support the new technologies

The researchers need to understand the grid not merely as a fluid system of flowing electrons, but also as a conversation between intelligent nodes. Load is one kind of signal, and resource is another. Some of these intelligent nodes will be DERs, and some of them will be customers, and some of them will be buildings and vehicles and microgrids. The intelligent nodes will have roles to play, and they will make decisions.

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## Other Sources

## Relevant EPRI Studies

EPRI has conducted a number of relevant proprietary studies that were unavailable for our review, because they were funded by individual EPRI members. Among others, these studies include:

1. *Method for Calculating Low-Voltage Hosting Capacity: North American Use Case*. EPRI, Palo Alto, CA: 2012. Product ID: 3002010278.

2. *Benchmarking Utility Best Business Practices and Processes for Managing High Penetration PV: Case Studies and Lessons Learned.* EPRI, Palo Alto, CA: 2013. Product ID: 3002001255.

3. *Integration of Variable Generation Forecasting into System Operations: Probabilistic Scenario Development and Assessing Forecast Value.* EPRI, Palo Alto, CA: 2015. Product ID: 3002005769.

4. *Application of Active Power Management to Increase Hosting Capacity*. EPRI, Palo Alto, CA: 2018. Product ID: 3002013440.

5. *Exploring DER Interconnection Cost Allocation Approaches and Tradeoffs.* EPRI, Palo Alto, CA: 2018. Product ID: 3002012961.

6. *Hosting Capacity Impact of DERMS Reactive Power Control*. EPRI, Palo Alto, CA: 2018. Product ID: 3002013383.

## Identified Utility-led DER Aggregation Programs by Year

| Project Name | Launch Year | State | Lead Utility | Technology Summary |
|---|---|---|---|---|
| **Pacific Northwest Smart Grid Demonstration Project** | 2009 | Oregon | Bonneville Power Administration | Batteries, EVs, home appliances, PV |
| **JumpSmart Maui** | 2011 | Hawaii | Maui Electric Company | Batteries, EVs, home appliances, PV |
| **Distributed Energy Resource Management System** | 2013 | California | San Diego Gas & Electric | Batteries, PV |
| **NA** | 2013 | South Dakota | NorthWestern Energy | Batteries, PV |
| **Preferred Resources Pilot** | 2013 | California | Southern California Edison | Batteries, PV |
| **2500 R Midtown** | 2014 | California | Sacramento Municipal Utility District | Batteries, home appliances, PV |
| **Energy Storage Program** | 2015 | Washington | Snohomish County Public Utility District | Batteries |
| **Distributed System Platform Demonstration Project** | 2015 | New York | National Grid | Batteries, fossil generators |
| **Clean Virtual Power Plant Demonstration Project** | 2015 | New York | Consolidated Edison | Batteries, PV |
| **Solar Partner Program** | 2015 | Arizona | Arizona Public Service | PV |
| **Residential Solar Program** | 2015 | Arizona | Tucson Electric Power | PV |
| **Glasgow Smart Energy Technologies** | 2016 | Kentucky | Glasgow Electric Power Board | Batteries, home appliances |
| **Austin SHINES** | 2016 | Texas | Austin Energy | Batteries, PV |
| **McKnight Lane Project** | 2016 | Vermont | Green Mountain Power | Batteries, PV |
| **San Jose Distributed Energy Resource Demonstration Project** | 2016 | California | Pacific Gas & Electric | Batteries, home appliances, PV |
| **Advanced Inverter Pilot** | 2017 | Arizona | Salt River Project | PV |
| **Community Storage Project** | 2017 | Colorado | Xcel Energy | Batteries, PV |
| **HECO DR Portfolio** | 2017 | Hawaii | Hawaiian Electric Company | Batteries, EVs, home appliances, PV |
| **Keystone Solar Energy Future Project** | 2017 | Pennsylvania | PPL Electric Utilities | TBD |
| **NA** | 2017 | Minnesota | Great River Energy | Batteries, EVs, home appliances, PV |
| **CleanstartDERMS** | 2018 | California | City of Riverside Public Utilities | TBD |
| **Distributed Energy Resource Management System** | 2018 | Tennessee | Chattanooga Electric Power Board | TBD |
| **Battery Storage Pilot Program** | 2018 | New Hampshire | Liberty Utilities | Proposed, TBD |

Source: *Expanding PV Value: Lessons Learned from Utility-led Distributed Energy Resource Aggregation in the United States*, a National Renewable Energy Laboratories (NREL) Technical Report, NREL/TP-6A20-71984, November 2018, pp. 27-28