ENABLING SMART INVERTERS FOR DISTRIBUTION GRID SERVICES

October 2018

Notice

This understanding of what will be required to enable Smart Inverter technology to become a reliable grid resource was made possible by the technical research to-date undertaken by California utilities, AEIC member utilities and utilities across the U.S. This research has been supported by collaboration and engagement with industry stakeholders such as Distributed Energy Resource (DER) vendors/aggregators, equipment manufacturers, and research institutions such as the Electric Power Research Institute (EPRI) and the National Renewable Energy Laboratories (NREL). Through execution of Smart Inverter demonstration projects in our respective service territories, the Investor Owned Utilities (IOUs) and other utilities have learned about the potential of Smart Inverters and also the remaining barriers to fully realizing their value. In particular, much of the research was enabled by California's Electric Program Investment Charge (EPIC) in its two past cycles (EPIC 1, 2012-15 and EPIC 2, 2015-18). With continuing commitment by regulators to fund this important research, development and demonstration (RD&D) work in the current EPIC cycle (EPIC 3 2018-2020), the IOUs can continue to develop capabilities, define system requirements, and generate technical, process, and human capital learnings related to how Smart Inverter technology can provide benefits to California.

Acknowledgements

California IOUs: Pacific Gas & Electric Company, Southern California Edison Company, San Diego Gas & Electric Company

External Organizations: ICF International, The Association of Edison Illuminating Companies (AEIC) Distributed Energy Resource (DER) Sub-Committee, National Renewable Energy Laboratory (NREL), Electric Power Research Institute (EPRI)

List of Acronyms

ADMS	advanced distribution management system(s)
AMI	advanced metering infrastructure
BESS	battery energy storage system(s)
BTM	behind-the-meter
CAISO	California Independent System Operator
CPUC	California Public Utilities Commission
DER	distributed energy resource
DERMS	distributed energy resource management system(s)
DMS	distribution management system
EPIC	Electric Program Investment Charge
EV	electric vehicle(s)
IEEE	Institute of Electrical and Electronics Engineers
IOU	investor owned utility
kW	kilowatts
kVAr	kilovolt amperes reactive
MUA	multiple use applications
PV	photovoltaic(s)
SCADA	supervisory control and data acquisition
SI	smart inverter
SIWG	smart inverter working group
TOU	time of use

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Executive Summary

The presence of Distributed Energy Resources (DERs) on the electric grid has been increasing in recent years, especially in California, and this trend is expected to continue[1]. DERs such as electric vehicles (EV), solar photovoltaics (PV), and battery energy storage systems (BESS) represent an important part of the resource portfolio needed to address California's clean energy goals and expand consumer choices. At the same time, DER integration into the distribution grid presents both challenges and opportunities for grid planning and operations. Recent utility experience demonstrates that Smart Inverters have the potential to enable DERs to support grid needs when combined with new capabilities that enable full integration of DERs into the utility's grid planning and operations. This experience has identified multiple factors for allowing Smart Inverter-enabled DERs to minimize potential grid impacts at higher DER penetration levels and, when cost competitive, to provide distribution grid benefits such as deferral of utility investments, increased capacity, improved power quality, enhanced reliability, and greater resiliency.

This white paper is a joint collaborative effort of Pacific Gas & Electric (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison (SCE), collectively the California IOUs, and member utilities in the Association of Edison Illuminating Companies (AEIC) DER Sub-Committee. It is intended to inform electric utilities, regulators and DER industry stakeholders nationwide by addressing the following questions through results and learnings achieved in demonstration projects:

- What considerations need to be addressed for Smart Inverter-enabled DERs to become an effective technology to maintain and/or 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 to be answered?

Recent California utilities' experience has highlighted the following six (6) key considerations for Smart Inverter-enabled DERs to become an effective and reliable distribution grid resource:

1. Location and volume of Smart Inverter-enabled DERs on the distribution grid is important

- For most distribution grid services, the distribution system will require location-specific services to address specific system constraints or needs[2]. Significant distribution service needs that require investment do not exist everywhere.

[1] SEIA Solar Market Insight Report 2018 Q2: https://bit.ly/2JyMH9f

[2] Integrated Distribution Planning, Paul De Martini, ICF, for Minnesota PUC: https://bit.ly/2N4Zihn

- The effectiveness of Smart Inverter-enabled DERs to support locational grid services is highly dependent on DER penetration levels and feeder characteristics.

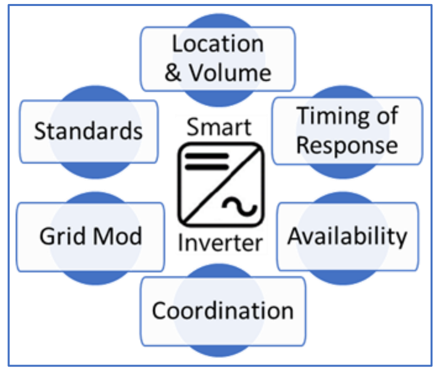

Figure 1: Six factors for Smart Inverter-enabled DER grid value

2. **Timing of Smart Inverter-enabled DER response should align with distribution grid need**
   - The distribution system has dynamic needs that can occur at various times within a day, month, or season
   - Currently, output of most customer-sited Smart Inverter-enabled DERs (e.g. PV, batteries, or EVs) is not coordinated with dynamic grid conditions.

3. **Availability and assurance of Smart Inverter-enabled DERs to provide grid response is needed for critical distribution services that support grid safety and reliability**
   - For Smart Inverter-enabled DERs to successfully provide critical distribution services such as voltage support, capacity and reliability, they should provide distribution services with a comparable level of performance as traditional utility "wires" infrastructure.
   - IOU demonstration experience suggests communications to DER assets requires additional research, development and demonstration.

4. **Coordination between the utility and DERs or DER aggregators is important**
   - Smart Inverter-enabled DERs and their data must be visible and available to the utility and/or aggregator for these resources to be fully utilized by the Distribution Operator.
   - Standardization of communication and operational procedures is necessary between utilities and DER providers to ensure instructions are received, interpreted and executed consistently by different aggregators.

5. **Capabilities provided by grid modernization technology deployments will enable Smart Inverter-enabled DERs to provide distribution grid services beyond autonomous Smart Inverter functions**
   - Utility operational capabilities and systems that automatically analyze grid conditions, determine optimized solutions, and communicate signals to aggregators and DER assets are needed to enhance the value of DERs to the grid.
   - The management systems and communication infrastructure used to integrate DERs are as critical as the DERs themselves and must have reliability and redundancy comparable to traditional utility "wires" infrastructure.

6. **Unified standards, comprehensive testing and certification, and training for DER installers are needed to ensure safe, reliable and resilient Smart Inverter operation, communication and cybersecurity**
   - Phased implementation of standards for advanced Smart Inverter functions has created complexity for manufacturers in getting Rule 21-compliant Smart Inverters to market

and for Nationally Recognized Testing Laboratories (NRTLs) to certify and test Smart Inverters.

- Improved manufacturer product documentation and standardization of Smart Inverter feature names and user interfaces is needed to facilitate proper configuration during field installation.
- Cybersecurity standards need to be adopted by the industry and integrated into relevant communication standards for Smart Inverter interconnection. Existing methods to ensure end-to-end cybersecurity between the utility and Smart Inverter-enabled DERs need significant improvement.

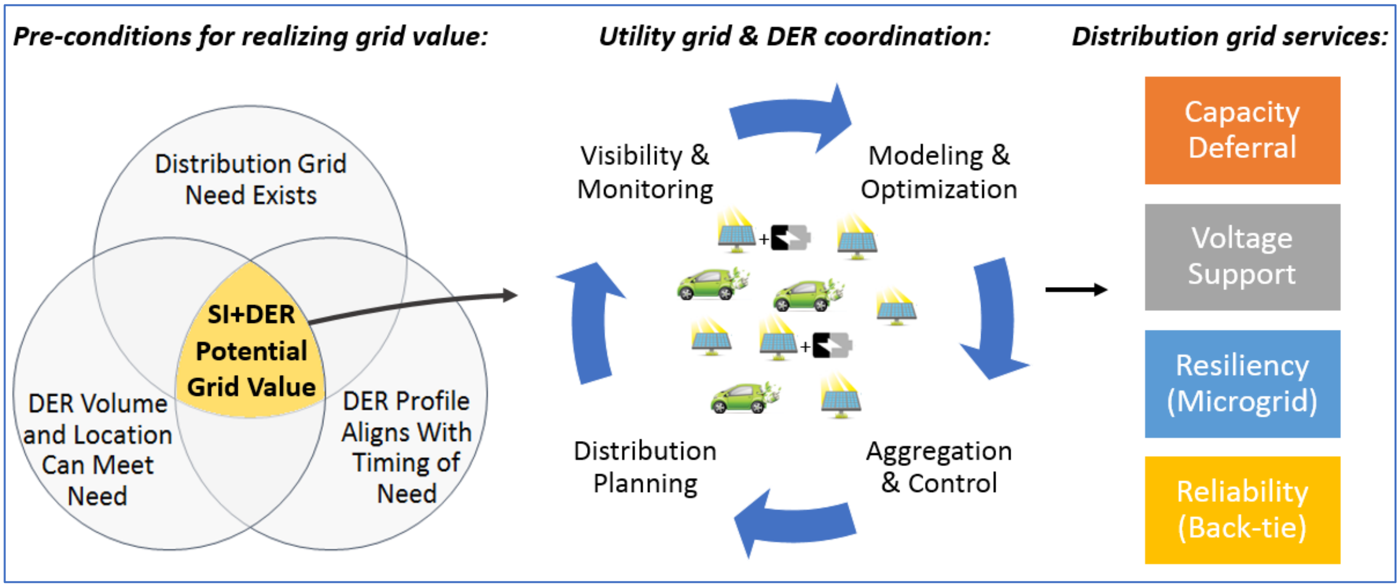

Figure 2: Components of Smart Inverter-enabled DER coordination for distribution grid services

To fully realize the value of Smart Inverter-enabled DERs, utilities need to continually improve methodologies to identify locations where grid needs exist and to assess capabilities and cost-competitiveness of DERs to meet those needs. Standards and utility investments that support interoperability between aggregators and utilities can allow Smart Inverter-enabled DERs to be “good citizens” of the distribution grid at high penetrations and evolve the electric system to be more reliable, resilient, and affordable.

1. Background on Smart Inverters and DERs

The presence of Distributed Energy Resources (DERs) on the electric grid has been increasing in recent years, and DERs are expected to continue to be rapidly interconnected onto the distribution grid[3]. While this trend has been experienced nationwide, it is particularly pronounced in sunny states like California, Arizona and Hawaii where policy, regulation and progressive consumer preferences have, in combination with evolution in DER technology and a subsequent reduction in costs, driven accelerated adoption of DERs[4]. In February 2015, the California Public Utilities Commission (CPUC) issued the Distribution Resources Plan (DRP) Rulemaking R.14-08-013[5], which foresaw incorporation of DERs into day-to-day grid operations and long-term distribution grid planning and investment decisions.

Distributed solar PV and other DERs such as battery storage systems and EVs represent an important part of California's clean energy portfolio and an avenue for customer choice[6]. However, incorporation of DERs onto the distribution grid raises challenges for the electric system, where the primary goals will continue to be delivering safe, reliable and affordable electricity for its customers. Technical grid challenges related to high DER penetration in certain instances include thermal violations, protection system impacts related to bidirectional power flow, and power quality issues[7].

1.1. What is a Smart Inverter?

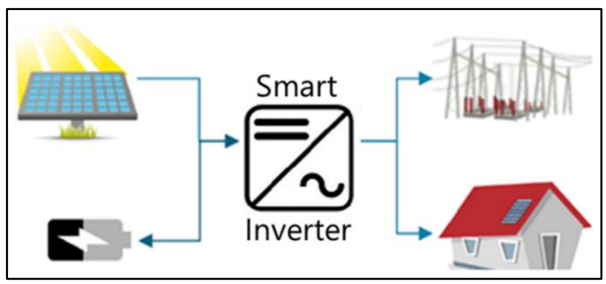

Figure 3: Smart Inverters convert DER output for use in homes and the grid

The basic function of a standard inverter is to convert the direct current (DC) output of an energy source such as a PV system to alternating current (AC) that can be fed into the electric grid or used onsite. California's Rule 21[8], the tariff under which Smart Inverter (SI)-enabled DERs can interconnect to the California IOUs distribution grids, defines a SI 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

[3] See Appendix A, "PV Growth in California"

[4] These include CA Senate Bills 350, X1-2, and 100, and energy metering (NEM) policies and federal tax subsidies incentivizing residential and commercial PV adoption (Solar Investment Tax Credit: https://bit.ly/2zDmwYE)

[5] Distribution Resources Plan (R.14-08-013) https://bit.ly/2pRY540

[6] EPRI Integrated Grid report: https://bit.ly/2RJuq9O

[7] Emerging Issues and Challenges in Integrating Solar with the Distribution System: https://bit.ly/2xNqfBt

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

controls, communication systems with ability to accept external commands and other functions."

DER interconnection rules requiring SIs, such as California's Rule 21, can help the grid to host more DERs, can minimize the negative impact of DERs on grid power quality and can potentially lower interconnection costs. IOU experience has shown that when a customer installs solar PV, the PV system offsets their load and sends power to the grid, which may increase voltage levels and variability on the secondary (e.g. low voltage system) of the service transformer[9]. The exact increase is dependent on the amount of DER capacity installed relative to load as well as electrical conditions in the distribution line. This local increase of voltage can not only affect that DER customer's voltage but also raise voltage for neighboring customers served by the same electric service system. Consequently, at high penetrations, DERs can elevate voltage levels on the secondary and primary (medium voltage) systems.

In addition to elevated voltages, high penetrations of DERs can cause thermal problems due to high reverse power flows, can interfere with the operation of protection systems, and can result in issues such as electrical load masking. All of these challenges lead to increased complexity of day-to-day distribution grid operations and can impact electric service reliability and safety.

To address some of these concerns, the electric utilities nationwide have been actively supporting the evolution of SIs. Updated interconnection standards incorporating autonomous SI functions such as Volt-VAr and Volt-Watt are a first step to ensuring that customer-sited DERs do not cause adverse impacts to grid safety, reliability, and power quality. These SI functions can also help delay or avoid some distribution upgrade costs that may otherwise be passed on to the interconnecting customer or rate-based, and lay a foundation for DERs to potentially provide distribution grid services.

1.2. Smart Inverter Functions and Capabilities

Beyond autonomous functions, SIs can also enable active or real-time control of DERs through a Distributed Energy Resource Management System (DERMS) and an Advanced Distribution Management System (ADMS). This distinction between autonomous and active control is illustrated below:

Table 1: Autonomous vs. active control use cases for SI-enabled DERs

Smart Inverter Operating Mode		Use Cases
Autonomous	Pre-programmed parameters that run independent of any additional external control signals, and that may be locally or remotely changed infrequently.	• Help customers avoid paying for distribution upgrades for DER interconnection (for example, upgrading a dedicated customer transformer) • "Ride through" momentary disturbances to frequency or voltage

[9] SDG&E SI Demonstration C Project: In the specific configuration tested in Demo C, SDG&E found that 120 kW of solar PV resulted in a 6 volt increase in voltage at 12pm over the no PV scenario: https://bit.ly/2InkePW

Smart Inverter Operating Mode		Use Cases
	Analogous to a grid voltage regulator or capacitor, which is programmed to automatically respond to a range of grid voltage conditions.	• Inject or absorb reactive power into or from the grid (Volt-VAr) to support voltage within mandated levels • Limit real power output when voltage is high (Volt-Watt) • Provide a "soft start" after power outages • Increase DER hosting capacity[10]
Active Control	The ability to receive and execute remote commands to address dynamic grid conditions using a DERMS/ADMS platform. Analogous to today's grid operator using a DMS to remotely operate a SCADA device such as a sectionalizer to re-balance load across adjacent circuits.	In addition to autonomous capabilities, potential to provide: • Additional capacity (peak load shaving) – example: SI-enabled battery storage dispatched to relieve substation congestion during peak loading hours • Enhanced reliability and resilience – example: PV + storage designed for microgrid operation used to more quickly restore customers following an outage

California's Smart Inverter Working Group (SIWG) has been instrumental in defining the above capabilities including current and upcoming California Rule 21 requirements for SIs. For additional background on the SIWG's activities, Phases 1, 2 and 3 SI functions and evolution of the IEEE 1547 interconnection standard, see Appendices C and E.

1.3. What are Distribution Grid Services?

Electric utilities' distribution planning process evaluates and specifies projects to ensure availability of sufficient capacity and operating flexibility for the distribution grid to maintain a reliable and safe electric system[11]. This process is focused on identifying and implementing "least cost-best fit" solutions to provide four key grid services: 1) Distribution Capacity, 2) Voltage Support, 3) Reliability (Back-Tie) and 4) Resiliency. Distribution Grid Services can be provided by a host of solutions, ranging from traditional hardware (generators, transformers, voltage regulators, capacitors) to newer technologies such as a portfolio of SI-enabled DERs. These DERs could operate in an autonomous or actively-controlled manner, depending on the use case and type of service needed. An overview of the four distribution grid services in the DER context is provided below in Table 2:

Table 2: Potential distribution grid services provided by SI-enabled DERs

Distribution Capacity	Load-modifying or supply services that DERs could provide via the dispatch of generators or reduction in load that can reliably and consistently reduce net loading on desired distribution infrastructure. These capacity services could be provided by **autonomous DERs** or more likely **actively-controlled DERs** that meet an identified operational need in response to a control signal from the utility.

[10] For more detail, see Appendix B, SIs and Hosting Capacity

[11] For a more detailed description of this process, see Appendix F, Distribution Grid Planning Process

Voltage Support and/or Reactive Power Support	Voltage management services that could be provided by **autonomously or actively-controlled DERs** capable of dynamically correcting excursions outside of voltage limits. A Smart Inverter can support this capability by absorbing or injecting reactive power (Volt-VAr) as well as by controlling real power output (Volt-Watt) to maintain local voltage within Rule 2 limits[12]. Only the ability to support voltage beyond simply mitigating voltage rise caused by the DER itself would be considered a distribution grid service.
Reliability (Back-Tie)	Load-modifying or supply services capable of reducing the frequency and duration of outages. Specifically, the back-tie reliability service provides a fast reconnection from one feeder with an identified operational need to one or more backup feeders that have excess capacity reserves (including those provided by DERs) to restore customers during an outage. This service could be provided by **autonomously** or **actively-controlled DERs**.
Resiliency (Microgrid)	Load-modifying or supply services capable of improving the local distribution system's ability to quickly recover from an outage. This service provides power to intentionally-islanded end-use customers through an ad-hoc microgrid when central power is not supplied, reducing the duration of outages. These resiliency services could be provided by **actively-controlled DERs** meeting an identified operational need in response to a control signal[13]. See section 2.5, *Grid Modernization* for utility investments that would be needed to enable this service.

For SI-enabled DERs to successfully provide distribution services, they must meet similar technical and operating standards as the rest of the distribution system such that when DERs are interconnected and operated in grid support modes, they can maintain the safety and reliability of the distribution grid.

2. Key Considerations and Insights Achieved in Smart Inverter Pilots

2.1. Smart Inverter Demonstrations Undertaken by Distribution Utilities

Recent demonstration projects at the California IOUs and other U.S. utilities have shown that SI-enabled DERs have the potential to respond to certain grid needs. By partnering with DER vendors/aggregators and SI manufacturers, the IOUs have demonstrated that SI-enabled DERs can help with local secondary voltage regulation and provide distribution capacity services, and that remote change of autonomous SI settings using an aggregation platform is possible. Some of the IOU SI findings are also supported by the Arizona Public Service (APS) Solar Partner Program, which performed the largest and most comprehensive SI field deployment to date[14]. However, the IOU demonstrations have revealed challenges that must be overcome for SI-enabled DERs to consistently provide distribution grid services. These challenges include: difficult targeted customer acquisition, unreliable communication to SIs, and inconsistent

[12] CPUC Rule 2 describes electric service requirements, which includes the acceptable secondary voltage ranges of electric service to electric customers.

[13] In a microgrid application it is necessary for a system to match generation to load while maintaining voltage, frequency, and power quality within appropriate limits.

[14] Arizona Public Service Solar Partner Program: Advanced Inverter Demonstration Results: https://bit.ly/2yoKd59

application of SI commands via aggregation platforms. Figure 4 below summarizes the California IOU demonstrations and key findings[15,16]:

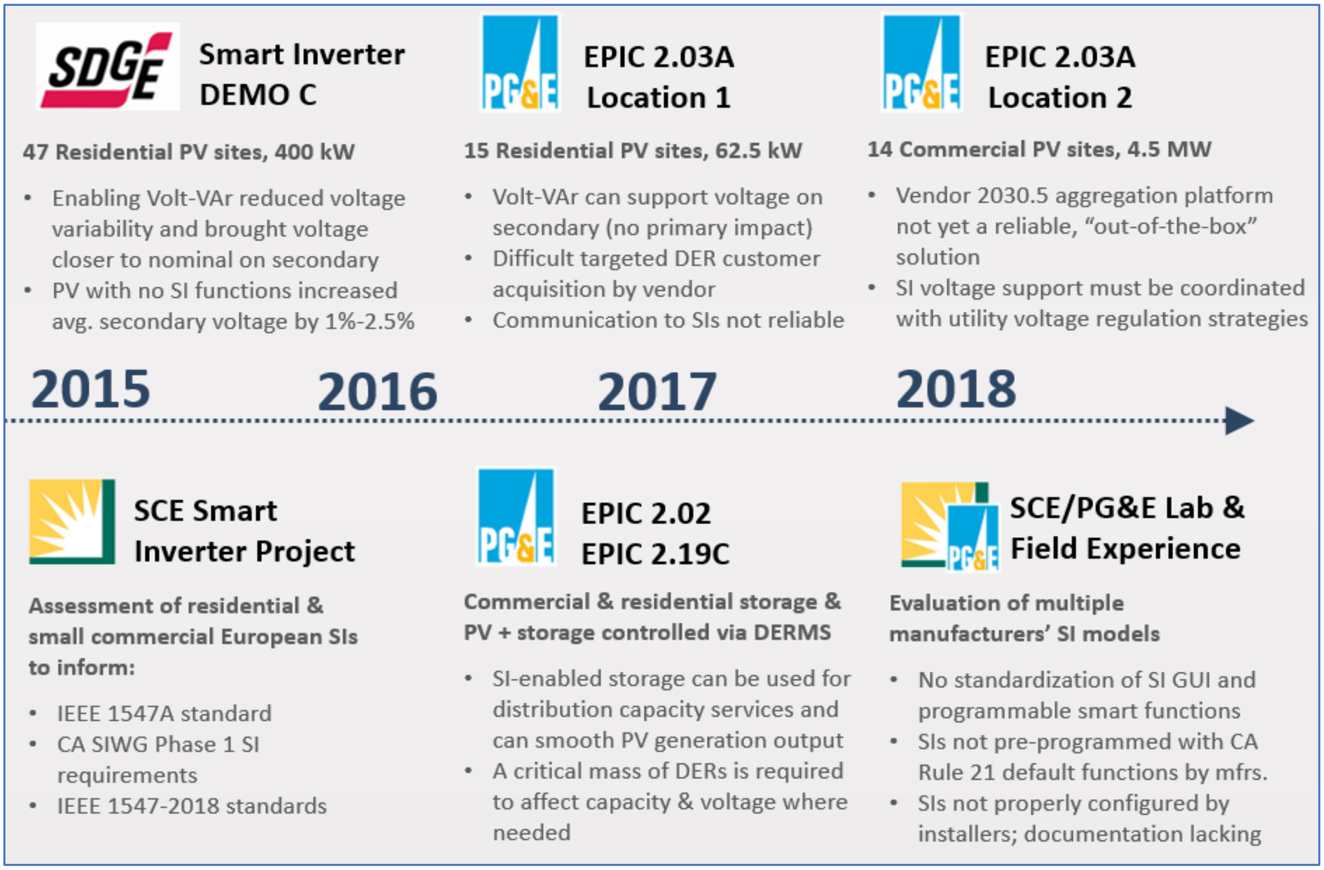

Figure 4: Key Learnings from Smart Inverter Demonstrations Undertaken by California IOUs

SI demonstrations have also been completed by utilities outside of California and Arizona, such as by the Hawaiian Electric Companies (HECO), Duke, and National Grid, references to which are available in Appendix G. Outside of the U.S., European experience also supports the need for advanced inverter functions. In 2013, Germany was forced to retrofit 300,000 BTM PV inverters with updated frequency ride-through settings, at significant cost to German electric ratepayers[17]. The adoption of communications capability that allows for remote change of autonomous SI settings will prevent such scenarios from occurring in the future.

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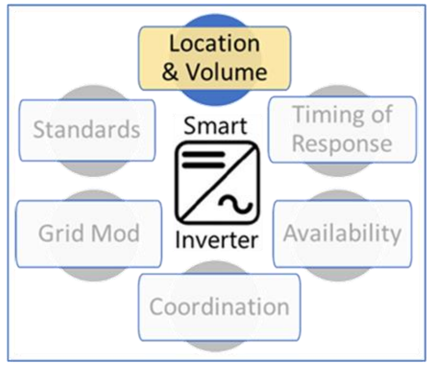
[15] SDG&E Smart Inverter Demo C Report: https://bit.ly/2OcQNGp; PG&E EPIC 2.03A Interim Report/EPIC 2.19C Final Report: https://bit.ly/2NyvgDp, https://bit.ly/2P7BE5q; PG&E EPIC 2.03A Smart Inverter Final Report (Location 2) and EPIC 2.02 Report: Available Q1 2019; SCE Smart Inverter Project Reports: https://bit.ly/2RziE1A, https://bit.ly/2OgNlLj, https://bit.ly/2IJoyJJ

[16] For more detail on each of the projects summarized in Figure 5, see Appendix D

[17] IEEE: The Impact of Distributed Solar on Germany's Energy Transitions: https://bit.ly/2EcJsSD

2.1. Location and Volume of Smart Inverter-enabled DERs on the Distribution Grid is Important



Significant grid infrastructure needs that require investment do not exist everywhere. Where needs do exist, the distribution system will require location-specific services to address them[18]. For example, the need to replace an undersized substation transformer that could overload may be met with DERs interconnected on the distribution feeder downstream of that transformer. A deficiency on a certain section of a distribution feeder would require that DERs interconnected to the overloaded section operate to ensure that the overload issue is mitigated[19].

California' Rule 21 tariff began requiring SIs with Phase 1 SIWG functions on new inverter-based DER installations in California IOU territories in September 2017. Since these changes to Rule 21 are still relatively new, SI-enabled DER penetration is still low relative to peak load on most California distribution circuits, as illustrated below in Figure 5[20].

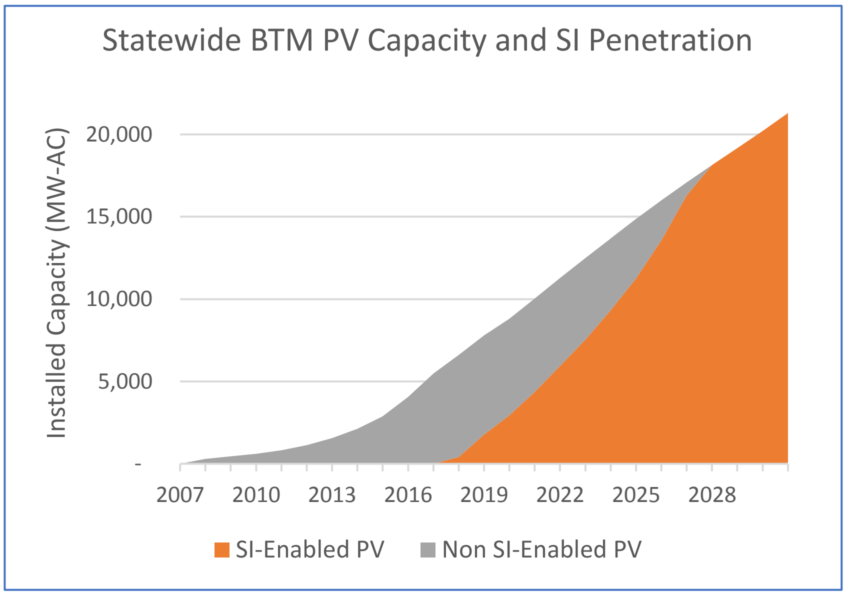


Figure 5: Statewide BTM PV Capacity and Smart Inverter Penetration

With organic growth over the next several years, SI-enabled DERs may begin to reach penetration levels where they can be considered as a solution for distribution grid services in some locations. In the meantime, the CA IOUs encourage the replacement of standard inverters with SIs for existing DERs to reach these penetration levels more quickly.

In the SI field demonstrations completed to-date by the California IOUs and other utilities[21], it was observed that at low penetration levels it may be difficult to see aggregate

[18] Integrated Distribution Planning, Paul De Martini, ICF, for Minnesota PUC: https://bit.ly/2N4Zihn

[19] The Distribution Resources Plan (DRP) proceeding is developing a Locational Net Benefit Analysis (LNBA) framework to identify locations for DERs to benefit the distribution grid: https://drpwg.org/sample-page/drp/

[20] Data source: CEC historical data for CA installations from 2007-2017; CEC mid-mid forecast for 2018-2030

[21] See appendices D and H for a full list of utility SI demonstration projects completed to date

effects of SIs for improving power quality or increasing hosting capacity[22]. Simulations, such as in HECO's Voltage Regulation Operational Strategies (VROS) project[23] and the Duke Energy Case study[24], have shown the benefits of SIs at higher penetration levels and minimal curtailment due to Volt-Watt curves, but this has yet to be demonstrated on a residential feeder in the field.

Field demonstrations by SDG&E and PG&E evaluated the aggregate effects of 400 kW and 62.5 kW of SI-enabled BTM PV, which comprised approximately 6% and <1% of the test feeders' peak demand, respectively. Due to these low penetrations, aggregate SI functions were observed to have little to no measurable impact on the distribution grid. Specifically, there was no measurable effect on the primary (e.g. medium voltage) system and there were small effects on the secondary service (e.g. low voltage) system. It is also important to note that the electric distribution feeders (e.g. lines) that were used for this demonstration were robust or less prone to voltage disturbances based on their design, making them less likely to be influenced by SI reactive power support[25].

As observed by the IOUs and in the additional utility SI demonstrations cited above**,** the effectiveness of SIs depends on DER penetration levels and distribution system design characteristics at a given location[26] as well as customer load and customer generation operating profiles. Given that SI impacts are highly dependent on penetration and location, the ability of SI-enabled DER aggregations to provide grid services reliably and where needed is currently limited by existing penetration levels, but this capability is expected to grow as SI-enabled DERs proliferate.

2.1.1. Targeted Customer Acquisition Challenges

A related challenge to SI penetration and location is the ability to deploy new SI-enabled DERs or retrofit existing DERs with SIs in a targeted fashion, which may be necessary as localized grid needs are identified. In its EPIC 2.03A SI project, PG&E relied on vendors to acquire new residential customers to participate in the demonstration. Vendors encountered significant challenges in meeting customer acquisition objectives, leading to penetration targets ultimately not being met. The challenges may have been related to limited access to customer information, customer fatigue from door-to-door solar outreach, and existing DERs being ineligible for SI retrofit due to residential solar system ownership structure and restrictions on curtailment. These customer acquisition challenges were not unique to PG&E. SCE, in its

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[22]In SDG&E's DRP Demo C/PG&E's EPIC 2.03A projects, the limited amount of Smart Inverter-enabled PV was only able to impact secondary voltages and not the primary distribution where voltage regulation schemes are in place.

[23] Simulation of HECO Feeder Operations with Advanced Inverters: https://bit.ly/2NwauUD

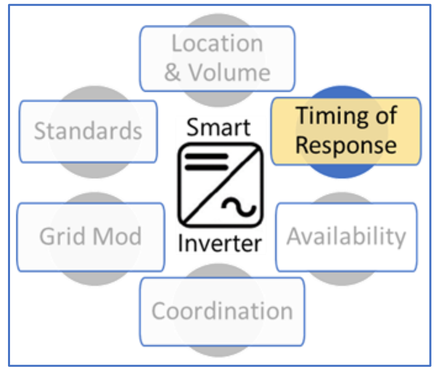
[24] Feeder Voltage Regulation with High-Penetration PV Using Advanced Inverters: https://bit.ly/2IK186M

[25] PG&E is currently evaluating a feeder where SI-enabled PV represent a greater percentage of that feeder's peak load (35% penetration of DERs participating in the demo vs. peak load) and voltage excursions above 105%.

[26] For example, the ratio of system reactance to system resistance (X/R) at a given point, and the location and number of capacitors and voltage regulators. Reactive power support is most effective where X >> R.

Integrated Grid Project EPIC 1 results[27], also encountered difficulty regarding customer participation in a program to monitor Smart Inverter-enabled DER data. More work is needed in this area to develop potential solutions to overcome these challenges.

2.2. Timing of Smart Inverter Response Should Align with Distribution Grid Need



The distribution system has dynamic needs that can occur at various times within a day, month, or season and may change over time. For example, the electric demand loading profile of one distribution feeder may reveal that high loading occurs for a few hours in the evening during the summer months, while another feeder may exhibit high loading in the early afternoon. Similarly, one feeder may experience low voltage in the morning while another has low voltage in the evening. These variations can be attributed to differences in customer types, geography, weather, and other factors.

Currently, the output and/or charging behavior of most customer-sited SI-enabled DERs (e.g. PV, batteries, or electric vehicles (EVs)) is not coordinated with or optimized for these constantly-changing grid conditions. For example, PV supplies peak power onto the grid at mid-day, which may be a time of low loading for many evening-peaking residential feeders. Consequently, an evening capacity constraint on such a feeder would not be lessened by the presence of distributed PV; in this example, the grid need, and DER profile are effectively mismatched as shown in Figure 6.

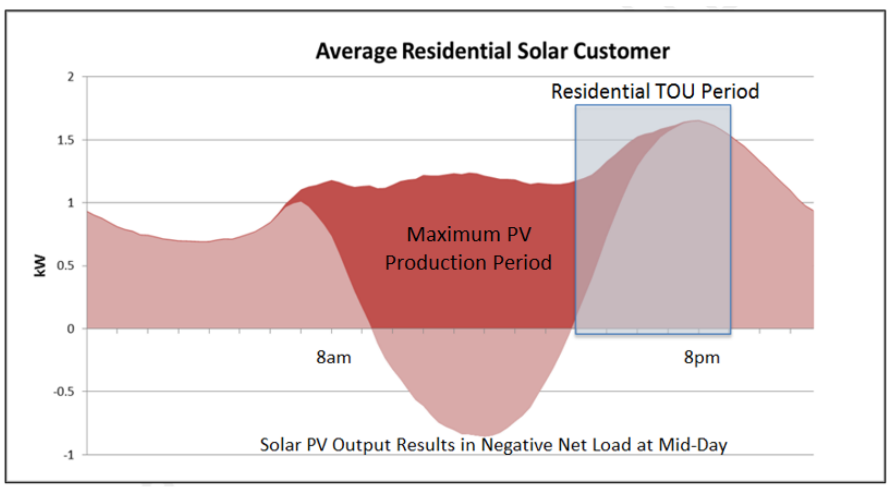


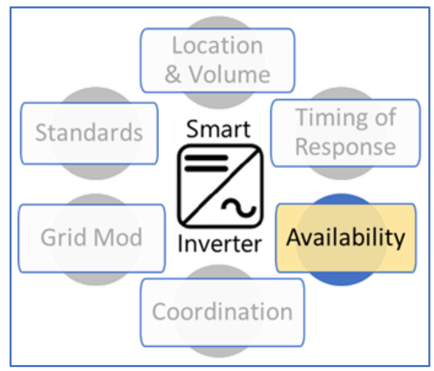
Figure 6: Net load of average residential SDG&E solar customer

By and large, today's customer-owned DER operating profiles are optimized for consumer needs as opposed to local distribution grid conditions and needs; BTM PV production is maximized to offset customer bills and BTM storage is typically charged/discharged for time-of-use (TOU) rate arbitrage or peak demand

[27] SCE Integrated Grid Project EPIC 1 Presentation: https://on.sce.com/2R6Wu6C

shaving[28]. As Smart Inverter capabilities mature beyond autonomous functions, the ability to control DERs in coordination with a DER-aware distribution operations system such as a DERMS and ADMS will improve the potential to match DER capabilities more closely with dynamic grid needs[29]. These systems will consider the specific DER types, sizes, concentrations and locations relative to localized grid needs and will require foundational utility technology deployments to operationalize.

2.3. Availability and Assurance of Smart Inverter-enabled DERs to Provide Response is Needed for Critical Distribution Services that Support Grid Safety and Reliability



For SI-enabled DERs to successfully provide critical distribution services such as voltage support, capacity and reliability, they should meet performance requirements similar to the rest of the distribution system. DERs should be readily available to provide distribution services with a comparable level of certainty that a traditional "wires" upgrade provides today. For example, if an aggregation of SI-enabled PV + storage is used to defer a traditional "wires" upgrade for a capacity constraint on a feeder, it must perform reliably during all hours of the year that the capacity constraint exists and at other agreed-upon times. It must also be able to consistently address the worst-case distribution planning scenario (e.g. a prolonged heatwave resulting in record loading due to concurrent air conditioner usage). Scenarios such as a communications outage that prevents the DERs from receiving commands or relaying data to the utility or aggregator must be considered.

Based on experiences to-date in working with DER aggregators, the IOUs have identified areas for the utility and industry to tackle to enable greater DER value. In PG&E's EPIC 2.03A Location 2 demo, the IEEE 2030.5 SI aggregator solution routinely failed to recover from temporary satellite and cellular communications outages, requiring a manual reset to restore visibility and control of SI-enabled PV systems. Similarly, SDG&E's SI Demo C experience and PG&E's EPIC 2.19C/EPIC 2.03A Location 1 demos showed that the reliability of SI communications was well below the average communication reliability for Supervisory Control and Data Acquisition (SCADA)-enabled devices, such as line reclosers[30]. For distribution services, this creates challenges associated with performance since customer needs require a high degree of distribution system reliability.

In general, the reliability of a DER or DER aggregation should follow the criticality of the specific grid service that is provided. Certain use cases may not require a guarantee of near-100% uptime as, for example, a bulk generator, while others may be absolutely critical where the

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[28] "Who Should Own and Operate DERS?" https://bit.ly/2NMFvIR

[29] EPRI "Understanding DERMS" White Paper: https://bit.ly/2OV0J3J

[30] PG&E's average communication reliability for SCADA-enabled devices, such as line reclosers is above 96%.

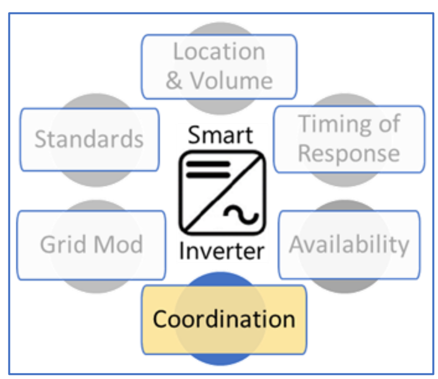
uptime of both the DER assets and their communication systems is equally important. In certain cases, rules, processes, or penalties may be needed to address situations where DERs fail to meet an obligation to provide grid services.

2.3.1. Reliable Measurement and Verification for DER Services is Needed

As opportunities for SI-enabled DERs to provide grid benefits beyond autonomous functions begin to be realized by utilities, customers and aggregators, a robust methodology for validating the DER's grid impact must be established. This capability will be needed for purposes of settlement to verify compliance with a contract, and will also allow grid operations and planning to more fully account for the impact of DERs on the distribution system. Components/principles that need to be further explored include:

1) The SI resource and its data must be visible to the utility and/or aggregator[31]. Currently, most utilities do not have adequate visibility into the impact of DERs on local voltage and capacity. Utility access to DER data should be included in DER interconnection agreements, since even small DERs can have significant grid impact at high aggregate penetrations.
2) The utility must have the systems in place to integrate DER data with its grid monitoring and control platform. Such a system must be capable of performing validation to verify that the SI provided a grid service (e.g. voltage support) beyond simply mitigating the adverse impact of high DER penetration.
3) For non SI-enabled DERs (e.g. legacy systems) where data monitoring is unavailable, utilities will need to develop new forecasting capabilities in order to account for the grid impacts of those DERs.
4) In active control use cases and some autonomous use cases, the DER must be able to be coordinated/controlled to provide the grid service, such as by a grid operator through an ADMS or DERMS.

2.4. Coordination Between the Utility and Aggregator is Important



As SI-enabled DERs play an increasingly important role on the distribution grid, coordination between utilities and aggregators will be critical to ensuring that grid needs and the ability of DERs to meet those needs are communicated in a timely and accurate manner. For example, for a fleet of BTM batteries to meet a temporary capacity constraint on a given circuit, the aggregator will need to reliably communicate the availability and state of charge of those batteries to the utility. The utility will need the capability to accurately model the amount of capacity required and translate that need into a dispatch signal to the aggregator or individual SI-enabled battery assets.

[31] Phase 2 SIWG function – DER to utility communications and Phase 3 function – monitor key DER data.

Alignment and standardization is also necessary between the utility and DER operators to ensure instructions are interpreted consistently by different aggregators, especially if multiple aggregator platforms take different approaches to SI management. Examples include how to handle multiple schedules and/or overlapping control modes, how to measure key operating metrics, and how to interpret instructions. While some of these scenarios are specifically addressed in standards, experience to-date has shown that different vendors may interpret the same command differently. In PG&E's EPIC 2.02 DERMS Project, when a DER was given a dispatch command beyond its capability, one vendor would dispatch as much as possible, while another vendor cancelled the command and did nothing. In SDG&E's Demo C pilot, the fixed power factor setting responses activated by the aggregator were the opposite of requested settings, e.g. producing VArs instead of absorbing VArs[32].

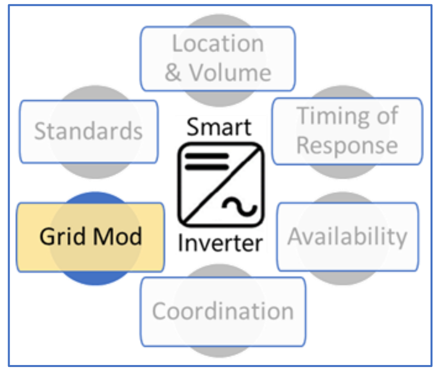
PG&E's EPIC 2.19C project, "*Customer Sited and Behind-the-Meter Storage*", demonstrated both technical potential of SI-enabled BTM energy storage to provide grid reliability support and highlighted next steps required to enable scalability. PG&E found that communication between the storage aggregators and individual SI-enabled storage assets was an ongoing challenge. In some cases, dispatch signals were not followed because a communications outage prevented the storage asset from receiving it. The ability of both participating aggregators to reliably drop load as instructed was compromised due to frequent loss of communications link with the storage assets.

In addition to accurate aggregator communication of DER states and availability, clear utility signals related to loading, voltage, and as-switched grid configurations are equally important. Specific coordination challenges are posed by the dynamic operating conditions of each distribution feeder, frequent rerouting of power to minimize the duration and magnitude of local outages (switching), and the need for work clearances (planned outages) to ensure the safety of the public and utility crews[33]. Operational capabilities and systems that can automatically analyze grid conditions, determine optimized solutions, and communicate signals to aggregators and DER assets are needed to enhance the value of DERs to the grid operator and planner.

[32] Since this demo, the Common Smart Inverter Operating Profile (CSIP) was established and would likely help prevent such issues.

[33] Coordination of T&D in a high DER Electric Grid: https://bit.ly/2qEf8Gw

2.5. Grid Modernization Initiatives are Necessary for Smart Inverter-enabled DERs to Provide Distribution Grid Services Beyond Smart Inverter Autonomous Functions



Utility investments in systems that can integrate SIs into distribution grid operations are foundational to full realization of DER potential. While SI-enabled DER penetration on the distribution grid is still relatively low overall, investment should begin today to prepare for a high DER penetration future, if utilities and DER customers are to derive maximum value from SI deployment.

First, utilities will need new modeling and distribution power flow capabilities to better forecast the operations of and impacts from SI-enabled DERs, in order to utilize the full benefits of SI functionality. PG&E experienced this need in the EPIC Project 2.02 DERMS demonstration, where software was deployed to allow distribution load flow and state estimation for the demonstration feeders in question. These capabilities enabled advanced modeling and forecasting of distribution grid constraints and automated optimization of DER dispatches in concert with traditional distribution operations equipment to resolve real-time and forecasted issues[34]. SCE is also exploring these advanced capabilities in its EPIC 1 Integrated Grid Project, which will demonstrate power flow optimization with DER participation and DER operational data integration into operations[35]. Advanced DMS software deployments will be key to safely and reliably accounting for DERs in distribution grid operations, and to laying the foundation for active DER management to enable distribution grid services.

Second, regardless of DER integration needs, phase identification improvements will be necessary to enable phase balancing with SI-enabled DERs and improve situational awareness for the grid operator[36]. These improvements will rely on investments in hardware, communications infrastructure, and analytical software to produce the required phasing data.

Third, additional hardware devices will be required to complement the deployment of SIs as complexity of power flows increases with DER penetration. These include distribution grid devices such as additional line sensors to augment visibility and monitoring of end devices like SIs and Smart Meters.

Finally, current utility operational systems are not yet capable of using advanced SI technology available today, such as SIWG Phase 3 functions, to its fullest extent. Utility investment in ADMS and DERMS software would provide visibility and control of SI-enabled DERs to the utility

[34] This functionality included the ability to calculate forecast DER contributions, to anticipate day-ahead capacity and voltage violations, and to suggest DER re-dispatch mitigation plans.

[35] SCE EPIC 1 Report, Pages, 64-139: https://on.sce.com/2CSLVAv

[36] For more detail, see Appendix I, “Phase Identification Requirements”

and allow DERs to fully realize their value through dynamic management for distribution grid services.

2.5.1. Enhanced Communication Infrastructure and Interoperability is Critical

To ensure grid safety and reliability, SI communications should be designed for reliable, durable and secure operation. California IOU experience has uncovered challenges to SI integration in two key areas related to communication:

1) Communication Infrastructure: Communications to DER assets at the grid edge currently may not provide the necessary reliability or availability for utilities to rely on these assets for distribution grid services at scale.
2) Communication Protocols: Utility demonstration experience has highlighted that for some DER use cases beyond current Rule 21 requirements, communication protocols such as IEEE 2030.5 may need to be customized with additional capabilities when implementing utility and aggregator interactions.

In multiple IOU residential demonstrations, communication to residential SIs via customers' home internet in combination with ZigBee was not always reliable[37]. Similarly, satellite and cell communication to commercial SIs in PG&E's EPIC 2.03A Location 2 experienced frequent and prolonged outages that led the aggregation software to fail, resulting in an inability to remotely change SI settings or download DER data. While several factors contributed to these challenges, more reliable and standardized communication performance would be recommended for SI-enabled DERs to participate actively in grid services at scale (e.g. if the use cases require active control, such as sending real or reactive power set points).

One potential approach to account for unreliable communication in some DER assets could be to build in a probabilistic expectation for asset availability. Since no network consisting of many geographically dispersed nodes (e.g. AMI or SCADA) will have 100% uptime, it may be unrealistic to expect that an aggregation of SI-enabled DERs will be as reliable as a bulk generator[38]. A probabilistic approach could factor in the likelihood that some proportion of assets will not be able to respond to a grid need, and adjust an aggregator or utility DER dispatch signal accordingly. Any communication reliability and performance standards that emerge should also factor in the use case: are the DER assets primarily operating autonomously (with infrequent remote settings changes), or do they need to be available on-demand for active control cases such as capacity or reliability?

While protocols for communicating to SI-enabled DERs exist, they are still evolving, and there is not yet an "out-of-the-box" aggregator solution that allows seamless interoperability between DERs, aggregators, and utilities. The IOUs have found that the IEEE 2030.5 protocol is a

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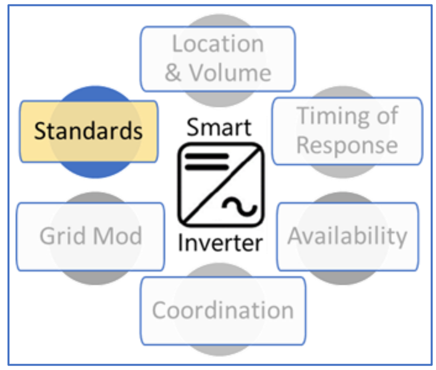
[37] SCE's Irvine Smart Grid Demonstration also found that communication to other home area network (HAN) devices via Zigbee was challenging: https://bit.ly/2q2xaCv

[38] Bulk generators on the transmission system are typically designed with redundant systems for high reliability.

powerful tool for implementing advanced SI functions as defined by Rule 21. However, extensions to 2030.5 were required in IOU demonstrations for certain active control (DERMS) use cases, for example bidding DER capabilities into a test-scale distribution capacity market[39]. Such customization when implementing DER control functions beyond the current Rule 21 requirements could be a barrier to scalability and interoperability and may contribute to differing interpretations of the same instruction or command between utilities and aggregators. As SIs and DER use cases continue to evolve and DER aggregations begin responding to dynamic grid needs, testing and certification procedures for the 2030.5 protocol should continue to be updated to move the industry towards a more standardized "plug-and-play" state.

2.6. Standards, Certifications, and Field Implementation are Critically Important



As many U.S. regions transition to a high DER penetration world, the standardization of SI technical functions, software and hardware can provide certainty to utilities and aggregators that the devices can be operated safely and consistently across a range of grid conditions. Consistent standards across geographic regions have allowed for reduced cost and complexity for manufacturers, and helped streamline the interconnection process.

As requirements for new advanced functions like communications, Volt-Watt and Frequency-Watt go into effect, it is critical that certification and testing procedures are clear and rigorous and that SIs are properly configured to comply with Rule 21 upon installation. As advanced SI functionality is phased in over 2017-2019, separate standards have emerged for certifying and testing different Smart Inverter functions[40]. This phased implementation has created complexity for manufacturers in getting Rule 21-compliant SIs to market and for Nationally Recognized Testing Laboratories (NRTLs) to certify SIs[41]. The IOUs recognize that with time and subsequent standard revisions, the certification and testing process will become more streamlined.

After a SI-enabled DER is interconnected per Rule 21 with all required default settings, it is equally important to ensure that the default settings are not subsequently changed in unexpected or unapproved ways so as to invalidate the interconnection agreement. California IOU lab and field experience has shown that more consistent manufacturer product

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[39] Specifically, PG&E's EPIC 2.02 DERMS and EPIC 2.03A SI demos found that 2030.5 lacked the ability to support market functions, scheduling, and confirmation that SI curves were running after command execution.

[40] The SunSpec Common Smart Inverter Profile (CSIP) provides testing procedures for the Phase 2 and 3 SIWG functions while UL 1741 defines test standards to the Phase 1 utility interactive inverter requirements of IEEE 1547. IEEE 1547.1 and UL 1741 for 1547.1 will likely not be issued until January 2020. Certification of SIWG Phase 1 functions is still covered by the UL 1741-SA test specification.

[41] Appendix H summarizes the complex landscape of SI standards and test procedures.

documentation, user-friendly SI user interfaces, and field verification by installers are also needed to ensure SIs are correctly configured when installed.

In both field and lab settings, the California IOUs have observed variability in different manufacturers' software and hardware performance[42]. Challenges encountered by the IOUs include differences in performance among products for pre-defined Volt-VAr/Volt-Watt curves, implementation of function priority, and SI response to remote commands and variable grid conditions. For example, recent IOU lab testing found that one manufacturer's new SI unit failed to initialize, another stopped functioning upon executing the latest Rule 21 firmware update, and a third shut down unexpectedly under normal operating conditions. IOU field experience also shows that many installers have not been able to properly set all SI parameters to comply with Phase 1 SIWG SI requirements that came into effect in September 2017. Manufacturers should standardize SI feature names in user interfaces and improve documentation to facilitate proper configuration by installers.

Overall, the results from IOU SI demonstrations are promising. However, certain aspects of SI performance require further testing to ensure that manufacturers comply with standards. Prior to implementation of any DER-based distribution grid services or reliability programs, it is essential that aggregator and DER operational and performance requirements are validated to be in place.

2.6.1. Cybersecurity Standards Need to be Developed for Smart Inverters

No national standards currently exist to ensure end-to-end secure implementation of SIs, and aggregator-specific communication protocols for control and coordination are highly variable in their level of security offerings. As such, further testing is required to develop and validate cybersecurity requirements which safeguard against various threat scenarios intended to maliciously operate SIs outside of their expected manner. Cybersecurity requirements should also include the protection of data at rest and in transit, secure over-the-air update procedures, access, authentication and authorization.

While the decision was made to specifically exclude cybersecurity standards from IEEE 1547-2018, cybersecurity standards should be adopted by the industry and integrated into the appropriate SI standards. As other grid-interactive hardware devices (e.g. smart thermostats and IoT routers/gateways) proliferate, these standards should be extended to any such non-SI device that enables communication and control between a DER and a utility or aggregator.

[42] Some of the functions tested were not yet formally required/certified in California. While some of the Smart Inverters tested were compliant with the September 2017 Rule 21 Phase 1 requirement, none had yet been certified to UL-1741SA for Rule 21 Phases 2 and 3 since those requirements go into effect in February 2019.

A key challenge with the current California Common SI Profile (CSIP) is that standards for aggregator communication to SI-enabled DERs are currently out of scope[43]. DER aggregators' highly variable proprietary communications methods are likely to have cybersecurity vulnerabilities that could put both the aggregator and utility (and ultimately the stability of the distribution grid) at risk. New standards to test and certify these proprietary methods for cybersecurity conformity should be developed.

3. Conclusions and Recommended Next Steps

This white paper identifies key factors for the scaled deployment of SI-enabled DERs as an effective and reliable distribution grid resource. These factors include recognizing that distribution service needs that can be cost-competitively met by DERs do not exist everywhere and that DER location and penetration must coincide with those needs when and where they do exist. To realize the full benefits of SI functionality beyond autonomous functions, utilities will need new modeling, control and communication capabilities to better characterize and forecast the operations of SI-enabled DERs, which will require investments in both software and hardware solutions.

To date, the CA IOUs have demonstrated that SI-enabled DERs have the capability to autonomously support secondary voltage and provide some capacity services. This can help to mitigate the impacts of high DER penetration and potentially increase DER hosting capacity in certain areas, avoiding distribution system upgrades and PV-caused voltage violations. The IOUs have found that maturity in SI testing and certification, more robust communication between aggregators and DERs, and improved utility-aggregator coordination are key next steps to support the deployment of SI-enabled DERs as a reliable grid resource in the future.

Future Directions

1) Utilities should continue to assess the capability and cost-competitiveness of SI-enabled DERs to meet distribution grid needs[44]. Additional SI demonstrations at higher DER penetrations are needed to assess SI capability to support voltage and provide other grid services.

2) As DER penetration increases and provides higher levels of bulk system support (displacing existing centrally-controlled generators), national performance certifications should be explored for certain types of DERs that can provide essential reliability services such as frequency regulation[45].

[43] The CSIP currently only covers utility-aggregator communications. For a more detailed discussion of the CSIP/IEEE 2030.5 and potential cybersecurity threat scenarios, see Appendix K

[44] PG&E's EPIC 2.22 "Demand Reduction through Targeted Analytics" project is applying the utility's data resources and industry-leading analytical skills to identify cost-competitive DER portfolios to meet distribution system needs.

[45] See Appendix J "Using SIs for Synthetic Inertia" for more detail.

3) Future SI research and development could explore the capability to interact with other nearby grid support devices independent of a centralized coordination system. Such intelligent, localized control capability could limit DERs' vulnerability to communication outages, increase response time, and otherwise augment autonomous or DERMS/ADMS-enabled active DER control at the grid edge.

With the advancements described in this white paper, continued collaboration between the IOUs and industry partners, and in situations where they are cost-competitive relative to traditional grid upgrades, SI-enabled DERs have the potential to become an effective technology to maintain and potentially enhance the reliability of the electric grid.