Attachment A: ENABLING SMART INVERTERS FOR DISTRIBUTION GRID SERVICES

Appendix

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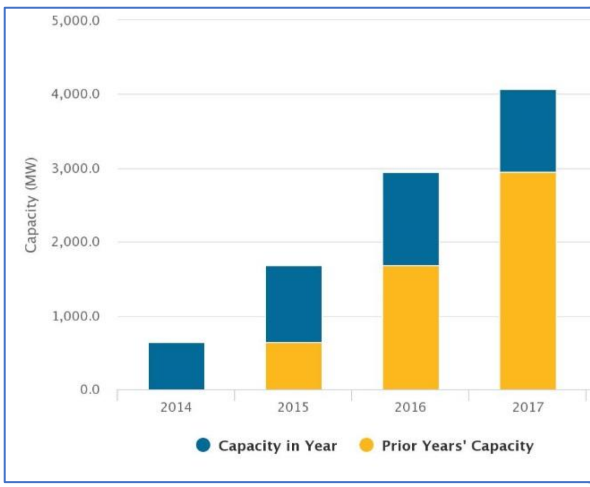
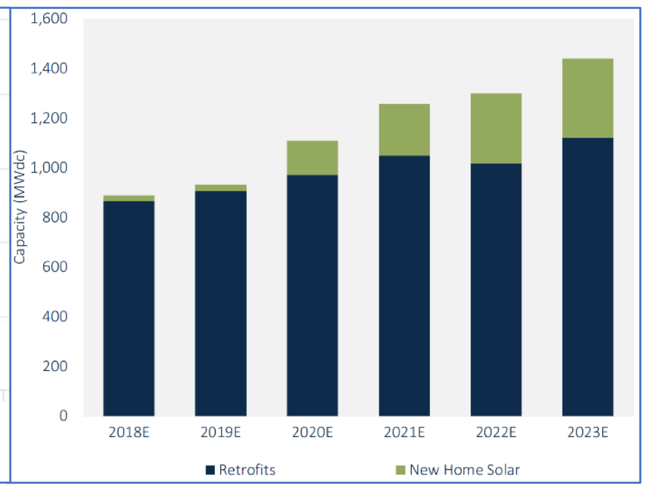
A. PV Growth in California





Source:www.californiadgstats.ca.gov *Source: www.greentechmedia.com/research*

Figure 1: CA NEM Solar PV Capacity and Residential Forecast, all IOUs

B. SIs and Hosting Capacity

Studies have shown that SIs can increase a distribution circuit's PV hosting capacity by minimizing the adverse impacts of each additional PV system to local distribution grid voltage. A modeling simulation based on feeders in Duke Energy's territory resulted in a 25% to 100%

increase in hosting capacity[1], and NREL has estimated that across the whole United States, SIs can approximately double existing hosting capacity just by voltage mitigation alone[2]. Through a modeling study that is part of the EPIC 2.03A demonstration, PG&E and EPRI are currently assessing SIs' ability mitigate the need for conventional upgrades for interconnection throughout PG&E's territory. The study's findings on SI capabilities to reduce PV-caused secondary voltage rise may allow PG&E to update its secondary voltage rise study process and associated mitigations for some new residential PV customers.

C. SI Working Group (SIWG)

In early 2013, the SI Working Group (SIWG) was formed to update Rule 21 Rulemaking R.11-09-011 to incorporate advanced SI technical capabilities. The IEEE 1547-2003 standard no longer met California's need at higher DER penetration levels, and the CPUC and IOUs decided to move forward on the Rule 21 requirements given the increasing penetration of renewables, predominately rooftop PV, before the penetrations reached a level that would put safe operation of the grid at risk. Some aspects of this advanced functionality were already available in inverters sold outside of the US, such as in Europe[3], and had demonstrated effectiveness at addressing operation of circuits with high DER penetration.

A key driver for the SIWG Phase 1 functions was to create grid-friendly inverters with extended frequency and voltage ride-through ranges that were designed to autonomously mitigate risks associated with sudden loss of distributed generation at high DER penetration levels. The SIWG work initiated the IEEE 1547 revision that became official in 2018, and functions in SIWG Phase 2 and 3 will be required starting in February 2019. On April 27th, 2018, resolution E-4898 updated the Volt-VAr requirements in Rule 21 to include reactive power priority, and resolution E-4920 established February 22nd, 2019 as the effective date for Phase 2 and 3 SIWG functions. The below table summarizes Phase 1/2/3 SIWG functions and in-effect dates.

Table 1: SI Working Group functions by phase

SIWG Phase I – Autonomous Functions *In effect 9/8/2017*	**SIWG Phase II – Communications** *Will be required Feb 22nd, 2019*	**SIWG Phase III – Advanced Functions** *Will be required Feb 22nd, 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

[1] On the Path to SunShot. Emerging Issues and Challenges in Integrating Solar with the Distribution System: https://www.nrel.gov/docs/fy16osti/65331.pdf

[2] Voltage Regulation with High-Penetration PV Using Advanced Inverters and a Distribution Management System: A Duke Energy Case Study: https://www.nrel.gov/docs/fy17osti/65551.pdf

[3] European Advanced SI and DER Functions Requirements: https://bit.ly/2OQxqCU

Fixed power factor to inject/absorb reactive power		Set real power mode*
Define default & emergency ramp rates		Frequency-Watt mode
Reconnect by "soft-start"		Volt-Watt mode
		Dynamic Reactive Current Support*
		Scheduling power values and modes

* These two functions were approved but IOUs need to file specific technical requirements for these two functions by Dec 26, 2018.

For Phase 2 (Communications), the requirement is that SIs must be *capable* of communicating with a utility system, though they will not be required to immediately do so in all California IOU regions. As DERs reach higher penetrations and the need and opportunity for coordinated control of SI-enabled DERs increases, the ability to coordinate individual assets through a utility aggregator system will be critical to providing grid services at scale in those areas where grid needs exist and can be cost-competitively met by DERs.

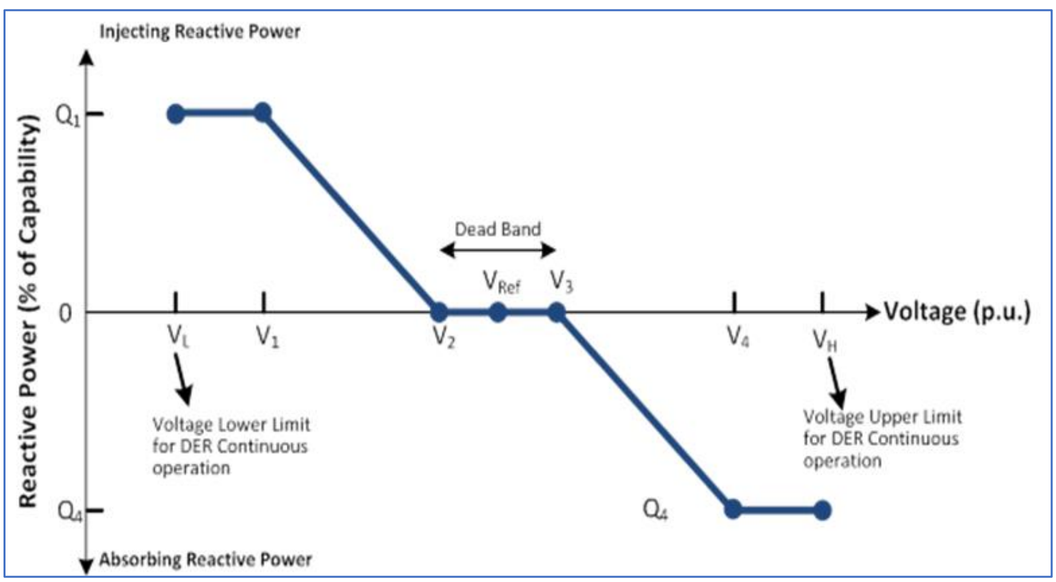


Figure 2: An example Smart Inverter Volt-VAr curve

D. SI Demonstration Projects Undertaken by the IOUs

SDG&E Smart Inverter Demo C: https://bit.ly/2OcQNGp

PG&E EPIC 2.03A Smart Inverter Interim Report (Location 1): https://bit.ly/2NyvgDp

PG&E EPIC 2.03A Smart Inverter Final Report (Location 2): Available Q1 2019

PG&E EPIC 2.19C Customer-Sited BTM Storage Report: https://bit.ly/2P7BE5q

SCE Smart Inverter Project: https://bit.ly/2RziE1A https://bit.ly/2OgNlLj https://bit.ly/2IJoyJJ

Table 2: Summary of IOU SI demonstration projects

No.	IOU	Project Name and Summary	Functions Tested	Key Findings
1	SDG&E	**SI Demo C** [2015] • Residential Demo with SolarCity • 47 PV sites, 400 kW nameplate ○ Interim findings evaluated data from 120 kW of PV • Autonomous SI management	• Three autonomous Volt-VAr/Volt-Watt curves • PV on/off effect on voltage • Fixed power factor	• Addition of PV increased average secondary voltage by 1%-2.5% • Enabling Volt-VAr reduced the voltage variability and brought the voltage closer to nominal • A Volt-VAr curve with no dead-band produced voltage with the lowest amount of variability
2	SCE	**SI Project with EPRI, SCE, and PG&E** [2018] A partnership to perform lab testing of SIs between SCE and PG&E.	Tested: • Autonomous curves ○ Volt/Watt Testing in progress: • Frequency-Watt • Voltage ride through • Frequency ride through • Volt-VAr controls • Ramp rates • Anti-islanding • Harmonics generation	• Naming conventions are not standardized in the SI display/GUI • Programming of smart functions is not user-friendly • Manuals are limited or non-existent on smart features • SIs not pre-programmed with California Rule 21 default functions • Smart functions are not enabled when delivered from mfr. • Complex procedures and very time consuming for installers
3	PG&E	**EPIC 2.03A: Behind-the-Meter SIs, Location 1** [2017] • Residential Demo with Tesla • 15 PV sites, 62.5 kW nameplate • Autonomous SI management with the ability to schedule settings on a day-ahead basis	• Single autonomous Volt-VAr/Volt-Watt curve • Fixed Active/Fixed Reactive Power • SI aggregation via a vendor-specific 2030.5 platform • Communications latency/reliability	• SIs were able to influence voltage on secondary systems • Targeted DER customer acquisition was challenging • Communication via residential internet/ZigBee was not reliable
4	PG&E	**EPIC 2.03A: Behind-the-Meter SIs, Location 2** [2018] • Commercial Demo with developer JKB Energy • 14 PV sites, 4.5 MW nameplate • Autonomous SI management with ability to schedule settings on a day-ahead basis (Kitu Systems) • Full report available in 2019	• Four autonomous Volt-VAr/Volt-Watt curves • Customer curtailment • SI aggregation via a vendor-agnostic 2030.5 platform • Communications latency and reliability • SI Lab testing/modeling	• SI voltage support must be coordinated with utility voltage regulation strategies • Test vendor's 2030.5-based SI aggregation technology is not yet a mature or "out-of-the-box" solution • Communication to DERs via satellite/cell was not reliable
5	PG&E	**PG&E EPIC 2.19C Behind-the-Meter Storage** [2017] • 240 kW commercial and 64.8 kW residential 2-hour storage • 20 residential and 2 commercial sites • Active control and scheduled commands using a DERMS	• Ability of SI-enabled BTM storage to reduce peak loading or absorb PV generation • Communications reliability • Ability of storage to simultaneously provide services to utility and on-site customer	• Pairing solar and storage is an effective way to "smooth" PV generation output • A DERMS-type platform is needed to enable utilization of BTM storage as a resource to manage the grid • The two vendors calculated state of charge differently, resulting in storage dispatch instructions not being followed consistently

6	**PG&E**	**PG&E EPIC 2.02 DERMS** [2015-2018] • Tested DERs participating in both the DERMS & wholesale markets • 27 residential customers with PV Only or PV + Storage: 124kW PV, 66kW-4hr storage • 3 Commercial Storage Sites: 360kW-2hr storage • 1 Utility Scale Battery: 4MW-7hr storage	• Ability to provide Situational Awareness to Operators regarding DER status • Automated IEEE 2030.5 aggregator interface built to communicate between DERMS and the 3rd Party Aggregators (No direct control of 3rd party SI by DERMS) • Market mechanisms to provide distribution services	• Critical mass of DERs needed to affect capacity & voltage where needed • Need for increased DER telemetry and status for distribution services • Managing 3rd party aggregations is technically complex for all parties • Custom extensions of IEEE 2030.5 required to implement market functions and distribution services

E. Technical Certification Activities

In February 2018, a major revision to IEEE Standard 1547-2018 *Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces*[4] was approved. This standard requires DERs to provide specific grid supportive functionalities per the California SIWG recommendations. In contrast with earlier standards that provided one set of requirements for all DERs, the new IEEE 1547-2018 lays out a set of options for deployment based on generator system characteristics (e.g. size) and grid reliability requirements.

Following the adoption of IEEE 1547-2018, work is underway to publish revisions to the accompanying IEEE Standard 1547.1, *IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems*[5], which will help manufacturers as they test and certify their products to the new 1547 standard. For example, solar PV and energy storage inverters are certified to UL 1741, *Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources*, which meets IEEE 1547/1547.1 testing requirements. After IEEE 1547.1 is published, likely in 2019, UL 1741 will be updated to reference the new 1547 and 1547.1 standards. From there, it may take up to 18 months for all products to comply with the updated requirements[6].

The next steps for CA Rule 21 is to align to IEEE 1547-2018 where differences exist (e.g. the Phase 3 Frequency-Watt function) as this will make it easier for inverter manufacturers to develop a product with consistent functionality and deploy those inverters across the United States. Allowing some time to pass to resolve these differences may reduce the amount of changes that need to be implemented at the design, manufacturing, and certification level, and stabilize deployed functionality. Upcoming challenges include alignment of industry players (manufacturers, installers and developers) to certification standards and consistent implementation and field verification that SIs are in compliance with Rule 21.

[4] IEEE 1547-2018 Standard: https://standards.ieee.org/standard/1547-2018.html

[5] IEEE 1547.1 Standard Conformance Test Procedures: https://ieeexplore.ieee.org/document/7100815

[6] IREC SI Update: New IEEE 1547 Standards and State Implementation Efforts: https://bit.ly/2mE9S4q

F. Distribution Planning Process

The typical utility distribution planning process goes through three steps:

1) Forecast electric demand – Use historical loading and load forecasting software to forecast the electric demand;
2) Identify the need – Use power flow modeling tools to simulate the electric grid under projected conditions and identify distribution capacity, voltage, and protection requirements; and
3) Determine the solution – Utilize engineering expertise to identify and propose projects that address the identified distribution capacity, voltage, or protection requirements.

This process has historically been done to serve one resource, customer load. Distribution circuits were designed to serve only loads in a radial configuration. A one-way power flow design has higher capacity at the substation that typically decreases as distance from the substation increases. While this design has proven to be an effective way to serve load over the past 100 years, the introduction of DERs makes distribution circuit power flow more complex, with multiple power flows at times within a single circuit.

As the grid continues to evolve and enable dynamic resources of flexible load and generation, making the most appropriate planning and operations decisions will increasingly require visibility into what each of these specific resources is doing. Planning and operations are moving away from basing their decisions on a single-point-in-time approach that only considers peak load. Instead, they are moving towards a more dynamic, time-series approach. Dynamic studies will add work and complexity for utilities, but they will need to be performed to ensure that the distribution system will be reliable and resilient with DER integration. Additionally, while Smart Inverter features will help alleviate some of the DER impacts and potentially provide new services, these benefits also comes with the need to model more complex controls.

The methodologies that were once used for studying only peak load must evolve. Part of the evolution involves integrating more data sources. Projects that integrate advanced metering infrastructure (AMI) information and forecasting into the tools of planning and operations are moving from pilot to production. Early demonstrations have highlighted that disaggregation is key to accurate forecasting. For example, during PG&E's Advanced DMS and DERMS Project (EPIC 2.02), a frequency regulating asset introduced a large source of error in the net load forecast due to the random nature of frequency regulation. When DERs report their monitoring information to the utility, it reduces the guess work and improves the accuracy of the models. The distribution planning process is becoming more complex, but new data sources can help assuage some of the new complexity.

G. References to SI Demonstrations by non-CA Utilities

Arizona Public Service Solar Partner Program SI project:	https://bit.ly/2yoKd59
HECO Voltage Regulation Operational Strategies (VROS) project:	https://bit.ly/2NwauUD

Duke Energy SI case study: https://bit.ly/2IK186M
Salt River Project Advanced Inverter study: https://bit.ly/2NyrQQy
DTE/National Grid SI project: https://bit.ly/2y9H8qn

H. SI Standards, Certifications and Testing Procedures

Table 3. SI Standards and Test Procedures for Interconnection and Communication

	Standard	Description / Purpose	Current State/Upcoming Milestone
Interconnection	IEEE 1547-2018 - Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power System Interfaces	An IEEE standard of interconnection requirements.	Published in 2018 after a multi-year revision process.
	IEEE P1547.1 - Draft Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces.	An IEEE test standard under revision that tests to the interconnection requirements in IEEE 1547-2018.	With IEEE 1547-2018 published, a published revision of IEEE 1547.1 is expected in 2019.
	UL 1741 - Standard for Safety - Inverters, Converters and Interconnection System Equipment for Use With Distributed Energy Resources	A UL standard that tests to the utility interactive inverter requirements of IEEE 1547 and IEEE 1547.1. The standard also includes product safety test procedures.	Revised in 2016 (Supplement A or "SA") to test to the inverter requirements of California and Hawaii. A future revision is expected following publication of the updated revision of IEEE 1547.1.
	Rule 21 - Generating Facility Interconnections	A California tariff that governs the interconnection requirements of the IOUs.	Updated as required by the California Public Utilities Commission (CPUC).
Communication	IEEE 2030.5-2018 - IEEE's Adoption of the Smart Energy Profile 2.0 (SEP2) Application Protocol Standard	An IEEE communication standard adopted by IEEE 1547-2018 as an eligible inverter communication protocol and adopted by the CA SI Working Group (SIWG) as the default communication protocol for inverters.	Updated revision published in 2018. A new project authorization request (PAR) was recently opened for a future revision.
	California Common SI Profile (CSIP)	An IEEE 2030.5 implementation guide and common communication profile for inverter communications developed to meet the needs of the IOUs.	CSIP 1.0 was issued in 2016 by the California SI Working Group (SIWG). CSIP 2.1 was issued in 2018 by SunSpec.
	SunSpec Common SI Profile Test Procedures	Verifies compliance with the IEEE 2030.5 functionality and options specified in CSIP.	Published in 2018.
	IEEE 1815-2012 – Standard for Electric Power Systems Communications-Distributed Network Protocol (DNP3)	An IEEE communication standard adopted by IEEE 1547-2018 as an eligible inverter communication protocol and adopted by SIWG as an alternate communication protocol that can be used upon mutual agreement.	Published in 2012.

	IEC 61850 – Communication networks and systems for power utility automation	An IEC communication standard adopted by SIWG as an alternate communication protocol that can be used upon mutual agreement.	The most recent relevant part was updated in 2015.

I. Phase Identification Requirements

Phasing data refers to mapping three-phase physical power system phase(s) (i.e. A, B, C) to transformers, customers, or devices. Some devices (e.g., line recloser) and customers are connected to all three phases, but some are only connected to one or two. Knowing phase connection allows for more accurate modeling and analysis of the distribution system, which is necessary to optimize DER asset utilization. For instance, suppose 1 MW of load reduction were needed across 3 phases (333 kW per phase) but that a single phase-connected SI were dispatched to meet the need; the risk would be 1 MW load reduction on one phase and persistent overload on the other two phases. To mitigate this risk in PG&E's EPIC Project 2.02 ADMS and DERMS, time- and labor-intensive SCADA device field verification was necessary in order to ensure phasing was accurately modeled, as a prerequisite to DERMS technology deployment. Single phase distribution modeling needs to evolve to enable accurate DER optimization to provide grid services and to increase efficiency of resource use. PG&E is exploring less cost-intensive methodologies for identifying phasing through its EPIC 2.14 project and other efforts/initiatives.

J. Using SIs for Synthetic Inertia (Frequency Support)

As deployment of renewables expands both on the distribution and transmission system, conventional generators are facing pressure to retire. The loss of rotating synchronous machines is expected to reduce the bulk power system's primary frequency response capability to remain stable in case of sudden frequency excursions from causes such as an unplanned outage of a large power plant. As inverters grow to provide more of the grid's energy, so too will they need to replace this loss of stability by means of new frequency response functions. The frequency-watt function is one fundamental approach where SIs could push or pull against frequency changes. However, the resource behind the inverter must have the power capacity reserve to provide additional energy in the case of a low frequency event. For PV assets, this could mean operating below maximum real power point to allow for a frequency response reserve. For energy storage, reserve may be easier to manage across the connected fleet. Beyond F-W capability, fast acting controls that emulate inertial response on sub-second time scales will demand inverter controllers to respond to measured Rate Of Change Of Frequency (ROCOF) as well. PG&E's EPIC 2.05 project[7] is an example of utility exploration of how to combine both frequency-watt (droop) and ROCOF (inertial) responses from inverters for optimal grid support, as well as investigating what thresholds of renewables growth will need such new solutions. Given that frequency is a system-wide parameter essential to maintain, broad and coordinated efforts across utilities, balancing authorities, and manufacturers will

[7] EPIC 2.05 Frequency Response and Short Circuit Current Contribution for DG Impact Improvement is planned to conclude in 4Q 2018.

need to align to determine which functions are best provided by which resources on which voltage levels and how to ensure they are available when needed as the grid evolves.

In this scenario, SI aggregators may need to play a role similar to large generators in maintaining system stability and reliability beyond voltage and frequency ride-through settings. The major difference is that the centralized generators are required to support the grid as a condition of interconnection whereas the DERs are not required to support the grid at this time.

SI support of grid reliability is a nascent area, and the IEEE-1547-2018 SI standard has begun to define functionality to enable SIs to be used for grid support going forward. IEEE-1547-2018 recognized that at higher penetration levels, DERs may be required to provide grid frequency support but may not be able to operate at maximum output at all times due to grid and hosting capacity constraints. The current PV SI operating mode relies on the existing grid operating margin to enable DERs to operate at maximum as-available output at all times. At high penetration levels, there may not be enough conventional generators to provide adequate frequency stability, requiring DERs to provide frequency support in the form of synthetic inertia. In order for intermittent DERs to have this ability, they may need to operate at less than 100% to reserve some capacity for system support or be coupled with storage.

K. Cybersecurity

Currently, the California Common SI Profile (CSIP) specifies IEEE 2030.5 as the communications protocol between the DER aggregator and utility. However, communication between the aggregator and individual SI Control Unit (SMCU) is specifically out-of-scope for the standard, and no mechanism currently exists to ensure end-to-end cybersecurity between the utility and SI-enabled DER. This is illustrated in the below diagram from the CSIP:

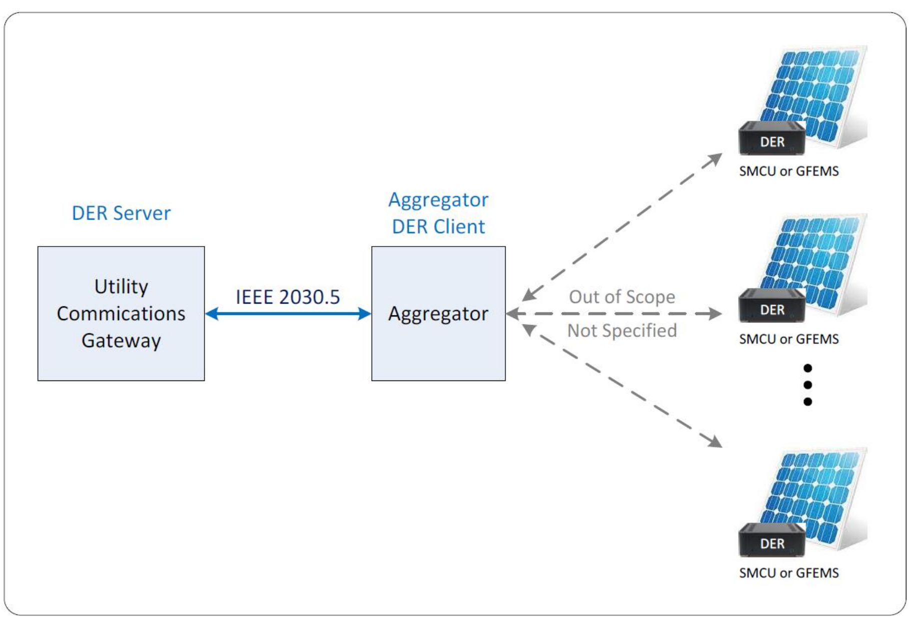


Figure 3: CSIP in-scope/out-of-scope communications paths

Furthermore, while the IEEE 2030.5 communications standard which covers utility-aggregator interactions does include a requirement for transport layer security (TLS), no certification or test procedures exist to guarantee that it is adequately implemented by vendors.

As SI-enabled DERs are increasingly aggregated and used for distribution grid services by utilities, utility telemetry and control requirements will necessitate the extension of the grid operations network to untrusted environments outside of the IOUs' cybersecurity control and protections. Under the current CSIP[8] and IEEE standards, potential threat scenarios include:

1) Falsification of SI telemetry and control signals from an unauthorized source.
2) Abuse of the SI-enabled DER connection by a 3rd party to gain access to the utility's networks and systems.
3) Uncertainty on the aggregators' security posture and controls leads to scenario 1) or 2).