Pacific Gas and Electric Company

EPIC Final Report

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Table of Acronyms:

AC	Alternating Current
ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
ATS	Applied Technology Services
BTM	Behind-The-Meter
C&I	Commercial & Industrial
CPUC	California Public Utilities Commission
CSIP	Common Smart Inverter Profile
DC	Direct Current
DCFC	Direct Current Fast Charger
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DRP	Distribution Resources Plan
DSS	distribution system simulator
EIC	Engineering, Installation, and Commissioning
EPIC	Electric Program Investment Charge

EPRI	Electric Power Research Institute
EV	Electric Vehicles
EVSE	Electric Vehicle Service Equipment
GHG	greenhouse gas
HECO	Hawaiian Electric Company
IDER	Integrated Distributed Energy Resources
IEEE	Institute of Electrical and Electronics Engineers
IOU	Investor-Owned Utility
IT	Information Technology
kVA	kilovolt-ampere
kVAR	kilovolt-ampere-reactive
kW	kilowatt
LR	Line Recloser
LTC	Load Tap Changer
M&C	Monitoring and Control
MW	megawatt
NRTL	National Recognized Testing Laboratory
OIR	Order Instituting Rulemaking
PCC	Point of Common Coupling
PG&E	Pacific Gas and Electric Company
PQM	Power Quality Meter
PV	Photovoltaic
QSTS	Quasi-Static Time Series
SCADA	Supervisory Control and Data Acquisition
SI	Smart Inverter
SIWG	Smart Inverter Working Group
SM	Smart Meter
THD	Total Harmonic Distortion
VVO	Volt-VAR Optimization

1 Executive Summary

This report summarizes the project objectives, technical results and lessons learned for EPIC Project 2.03A - Test Smart Inverter Enhanced Capabilities –PVs, as listed in the Pacific Gas and Electric Company's (PG&E) EPIC Annual Report, also referred to as EPIC 2.03A – Smart Inverters. This EPIC 2.03A project Final Report is a follow-on to the EPIC 2.03A project Interim Report. The EPIC 2.03A project Interim Report[1] was published in July 2018 and documented the achievements and lessons learned in EPIC 2.03A projects Location 1, while the EPIC 2.03A project Final Report documents the achievements and lessons learned in EPIC 2.03A projects Location 2.

This report highlights key learnings gained from the project that have industry-wide value and urgency to share given recent changes to the California Rule 21 Tariff[2], which pertains to Distributed Energy Resources (DER) deployment and interconnection requirements.

The presence of DERs on the electric grid has been increasing in recent years, especially in California, and this trend is expected to continue[3]. DERs such as Electric Vehicles (EV), solar PV, and Battery Energy Storage Systems 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. EPIC 2.03A focuses on the challenges and opportunities for grid operations. As industry stakeholders and the California utilities converge on a set of standards for Smart Inverter (SI)[4] operation, communication, and interconnection[5], it is important to highlight these observations on SI technology's key capabilities as well as note areas for improvement.

The EPIC 2.03A project demonstrated the functionality of customer-sited Behind-The-Meter (BTM) solar PV SIs and the grid impacts of their use. To date, PG&E has demonstrated the use of residential and commercial and industrial customer-sited PV SI technologies and communication

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[1]   The EPIC 2.03A Interim report 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

[2]   On April 27th, 2018, CPUC resolution E-4898 updated the Volt-VAR requirements in Rule 21 to include reactive power priority, and resolution E-4920 established February 22, 2019 as the effective date for Phase 2 and 3 SIWG functions.

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

[4]   A SI is an advanced version of a standard inverter, both of which convert the variable Direct Current (DC) output of a solar PV system to Alternating Current (AC) that can be fed into the electric grid or used onsite by normal AC loads. In addition to this standard inverter function, Sis have the capability to communicate (receive remote operation instructions and communicate measurements/status), and to make autonomous decisions to maintain grid stability and power quality.

[5]   See the California Joint Investor-Owned Utility (IOU) White Paper "Enabling Smart Inverters for Distribution Grid Services" for a broader discussion of IOU learnings on SI technology and industry recommendations: 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.

infrastructure to mitigate potential local grid issues related to high penetration of customer-sited DERs on two electrical distribution feeders ("Location 1" and "Location 2"), with the latter exhibiting greater SI-enabled PV penetration. An interim report detailing findings from the Location 1 EPIC 2.03A SI field demonstration was published in July 2018 and is available on PG&E's EPIC website[6].

Table 1: EPIC 2.03A Key Activities.

Activity	Covered in this Final Report?
Location 1 Residential SI Field Testing	No – Covered in Interim Report
Location 2 Commercial SI Field Testing	Yes
SI Lab Testing	Yes
SI Modeling Study	Yes

The project activities covered in this report targeted high voltage issues attributed to Location 2's high PV penetration[7] as well as an evaluation of a vendor-agnostic aggregation platform that allowed for the remote change of settings and monitoring of SI assets. This report details the results of Location 2 activities and also includes findings from SI laboratory testing and 3rd-party SI modeling performed by the Electric Power Research Institute (EPRI) in conjunction with PG&E.

Related to the objectives of EPIC 2.03A, PG&E concurrently aimed to demonstrate the ability of SI-enabled PV and BTM storage to be monitored and dispatched remotely by a DER Management System (DERMS). For the results of that demonstration please see the forthcoming report on EPIC Project 2.02 – Distributed Energy Resource Management System (DERMS)[8]. PG&E also completed EPIC Project 2.19 – Enable Distributed Demand-Side Strategies & Technologies, which tested the use of customer-sited energy storage technologies to reduce peak loading and absorb DERs generation[9]. Past PG&E work on reactive power optimization also includes the Voltage and Reactive Power Optimization Smart Grid Project[10].

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[6] The EPIC 2.03A Interim report 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.

[7] 35% penetration of participating demo DERs by nameplate vs. feeder peak load

[8] Once published, the Final EPIC reports of this project will be found at: https://www.pge.com/en_US/about-pge/environment/what-we-are-doing/electric-program-investment-charge/closeout-reports.page.

[9] The EPIC 2.19 Final Project Report 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-2.19.pdf

[10] The PG&E VVO project final report can be found here: https://tinyurl.com/ya2x7ta7.

Overall, the project established that successful SI deployment and remote monitoring and management is contingent on the following factors:

1. Unified standards, comprehensive testing and certification, and improved manufacturer product documentation and standardization of SI feature names and user interfaces;
2. SI communications solutions that are designed for reliable, durable and secure operation;
3. Rigorous pre-deployment testing of SI aggregation platform software and firmware to ensure reliable behavior under degraded communication and grid power conditions;
4. Coordination of SI settings with existing utility voltage regulation equipment settings; and
5. Utility grid modernization technology deployments such as Advanced Distribution Management System (ADMS) and DERMS (for enablement of active control SI use cases, such as for provision of distribution grid services).

1.1 EPIC 2.03A Key Objectives

The overall EPIC 2.03A key project objectives are described below in Table 2.

Table 2: EPIC 2.03A Key Objectives.

Objective and Description	Covered in this Final Report?
A. Evaluate the technical ability of SIs to influence secondary and primary voltage through field studies in two distinct locations, by adjusting reactive and real power output autonomously.	Yes – Location 2 evaluated SI impact to secondary and primary voltage. Note: Location 1 evaluated SI impact to secondary voltage. This was covered in the EPIC 2.03A Interim Report.
B. Measure customer curtailment from Volt-VAR/Volt-Watt function activation.	Yes
C. Demonstrate and evaluate the reliability of communications to provide visibility, monitoring and change settings for SI-equipped PV using both a vendor-specific aggregation platform and a vendor-agnostic utility aggregation platform.	Yes – Location 2 evaluated a vendor-agnostic aggregation platform. Note: Location 1 evaluated a vendor-specific aggregation platform. This was covered in the EPIC 2.03A Interim Report.
D. Clarify SI technology requirements to integrate and operate SIs, and characterize challenges to deployment at scale relative to today.	Yes (this was also covered in the EPIC 2.03A Interim Report)
E. Through lab testing, understand SI performance under a range of distribution grid conditions.	Yes
F. Through a vendor-led modeling study, evaluate the impact of BTM residential PV and PV + Storage with and without SIs and perform an economic analysis of SIs on PG&E's system as compared to traditional distribution grid upgrades.	Yes

1.2 Differences Between Field Testing at Location 1 and Location 2

For clarity, key differences between field testing at Location 1 and Location 2 of the project are highlighted in Table 3.

Table 3: EPIC 2.03A Smart Inverter Project Location 1 and Location 2 Differences.

Project Parameters	EPIC 2.03A Location 1[11]	EPIC 2.03A Location 2
Voltage impacts demonstrated from controlling BTM customer-sited SI-equipped PV	Local (secondary) voltage impacts	Local (secondary) voltage impacts
Customer type	Residential	Commercial/Agricultural
# of PV sites, # of SIs and PV capacity	15 PV sites, 15 SIs, 62.5 kilowatts (kW) nameplate capacity (New customers acquired and SI assets installed)	14 PV sites, 179 SIs, 4.5 megawatts (MW) nameplate capacity (Existing SI assets retrofitted with new SI firmware)
Feeder penetration of PV assets included in project (nameplate/peak feeder demand)	Less than 1% of peak feeder demand (2 feeders); overall, test feeders had a moderate level of BTM PV penetration	35% of peak feeder demand (1 feeder); overall, test feeder has a high level of BTM PV penetration (~70% of peak feeder demand)
Feeder stiffness and power quality issues	Stiff feeders (less prone to voltage disturbances based on loading and impedance) no observed voltage/power quality issues or reverse flow	Feeder with prior voltage and capacity constraints as well as observed reverse power flow
Volt-VAR/Volt-Watt curves evaluated	Custom curves (non-default) designed to ensure active/reactive power functions activated	Rule 21 curve, Hawaiian Electric Company (HECO) curve and 2 additional curves tested on existing high voltage conditions
Type of remote control of assets evaluated (autonomous/passive or active/on-demand)	Autonomous/passive with the ability to schedule settings on a day-ahead basis using a **vendor-specific** aggregation platform	Autonomous/passive with the ability to schedule settings on a day-ahead basis using a **vendor-agnostic** aggregation platform

The EPIC 2.03A Interim report detailing findings from the Location 1 SI field demonstration was published in July 2018 and is available on PG&E's EPIC website[12].

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[11] The Location 1 EPIC 2.03A demonstration was co-located on feeders in San Jose with two other related projects (EPIC 2.02 – DERMS and EPIC 2.19 – Enable Distributed Demand-Side Strategies & Technologies), to efficiently use EPIC funds and build collective learnings.

[12] The EPIC 2.03A Interim report 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.

Location 2 field testing involved 14 individual PV sites, with each site containing between 4 and 41 SIs. Three stages of field testing were executed as shown in
Figure 1:

Figure 1: PIC 2.03A Location 2 SI Field Testing Timeline
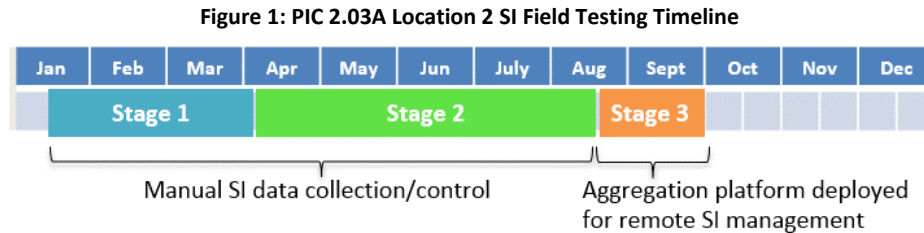
1. <u>Stage 1 (2.5 months)</u>: A manual effort to update firmware, load SI curves, and retrieve performance data on-site. Stage 1 was terminated by the conclusion of reconductoring activities that occurred on the feeder (planned independently from this project) and the kick-off of SI Volt-Watt and Volt-VAR curve cycling.
2. <u>Stage 2 (4.5 months)</u>: After reconductoring of the feeder was completed, *manual* loading of specific SI curves and *manual* retrieval of data continued as an automated control and data interaction solution (the vendor-agnostic aggregation platform) was deployed. Whereas Stage 1 tested the effects of running a single Volt-Watt and Volt-VAR curve set, Stage 2 involved weekly cycling of 5 different curve sets.
3. <u>Stage 3 (1.5 months)</u>: Characterized by remote interaction with the sites through the vendor-agnostic aggregation platform, this stage permitted loading of multiple curves and automated retrieval of performance data.

The field demo tested a limited set of the California Electric Rule 21 ("Rule 21") functions that were currently implemented during the planning and execution of the project (Phase 1 Autonomous Functions) or were being developed (Phase 2 Communications and Phase 3 Advanced Functions). It is important to note that despite the focus of testing on the Rule 21 functions, none of the inverters in the <u>field component</u> of this project were UL-certified to meet any of the SI functions of Rule 21, as ratification of Phase 1/2/3 functionality occurred after installation of these inverters, resulting in their being grandfathered and exempt from Rule 21 Phase 1 functions. On the other hand, the inverters tested in the lab were models that were newly purchased in mid-2018 and were thus certified to meet UL 1741-SA requirements for Phase 1 functions[13] (though several models did not perform to certain components of this standard – see section 4.3 for more detail).

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[13] California Rule 21 specifications for Volt-VAR and Volt-Watt curves differ slightly from what is specified in IEEE 1547.1. UL 1741-SA specifies SI testing procedures to IEEE 1547.1, and not specifically to California Rule 21.

1.3 Project Milestones

The following summarizes the key accomplishments of the demonstration project as they relate to Location 2, Lab Testing, and the Modeling Study:

1. Conducted manual Volt-VAR and Volt-Watt testing at 14 of 14 commercial SI-enabled PV sites using a common set of curves (Stages 1/2/3).
2. Measured customer curtailment from Volt-VAR/Volt-Watt function activation (Stages 1/2/3).
3. Demonstrated and evaluated the reliability of communications to provide visibility, monitoring, and control for SI-equipped PV using both a vendor-specific aggregation platform and a vendor-agnostic utility aggregation platform (Stage 3).
4. Clarified SI technology requirements to integrate and operate SIs, and to characterize barriers to deployment at scale relative to today (Stages 1/2/3).
5. Designed and implemented data architectures to support satellite and cellular interaction with remote sites (Stages 2/3).
6. Implemented automated Volt-VAR and Volt-Watt curves, with a quantification of ability to perform different grid services (Stages 2/3).
7. Lab-tested Electric Vehicle Service Equipment (EVSE) performance under a large range of harmonic content, to identify any chance of poor behavior.
8. Lab-tested the performance of SIs during loss of phase due to opening of a Line Recloser (LR).
9. Lab-tested the compliance of various brands of SIs to be properly configured for Rule 21 operation.
10. Completed a vendor-led power flow modeling study evaluating the impact of BTM residential PV and PV + Storage with and without SIs and performed an economic analysis of SIs on PG&E's system as compared to traditional distribution grid upgrades.

1.4 EPIC 2.03A Key Learnings and Recommendations

The following are the key lessons learned in the Location 2 field demonstration, the SI lab testing, and in performance of 3rd-party modeling activities:

1. **SIs can enable BTM PV to help with local secondary voltage support through autonomous real (Volt-Watt) and reactive (Volt-VAR) power support. Volt-Watt/Volt-VAR did not have any clear effect on average primary voltage** (Key Objectives A and D).
   - In this demonstration, SIs showed an impact to voltage on the secondary system, resulting in fewer voltage violations[14] correlated with high PV penetration on the test feeder.
   - Properly configured SIs successfully executed the Volt-Watt and Volt-VAR curve settings within tolerances, with a negligible percent of data points falling outside the tolerances.
   - Volt-VAR curve sets with greater reactive power absorption had a larger effect on the percent reduction of secondary voltage violations at the Point of Common Coupling (PCC).
   - The site with the largest aggregated nameplate kW/kilovolt-ampere-reactive (kVAR) experienced a more significant reduction in voltage violations with Volt-Watt/Volt-VAR deployed than sites with smaller aggregate nameplate kW/kVAR.
   - The effect of Volt-Watt/Volt-VAR observed at the largest site was significant and reduced secondary voltage violations from 10% to effectively 0%.
   - **Recommendations:**
     - For Volt-Watt and Volt-VAR implementations, larger SI-enabled PV sites will provide greater ability to affect voltage on the secondary at the PCC, all other parameters remaining constant.
     - Additional characterization of the size of the SI-enabled PV site relative to feeder characteristics, including net loading levels at the PCC, should be performed.

2. **Technical evidence from field and lab testing suggests that certain aspects of SI configuration and performance require further testing and development to ensure that manufacturers comply with standards and SI certification procedures.** (Key Objectives A, D, E).
   - While the SIs used in the field demo offered the option of voltage management at night using reactive power support ("VARs at night"), this feature proved to be unreliable due to implementation inconsistencies by the inverter manufacturer[15].

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[14] A voltage violation is defined as voltage above 105% or below 95% of nominal voltage. CPUC Rule 2 describes electric service requirements, which includes the acceptable secondary voltage ranges of electric service to electric customers.

[15] At the time of the project, the "VARs at Night" function was not a requirement for the project nor was it required per California Rule 21. The working implementation utilized the inverter manufacturer's

- o Individual SIs within a field site did not always execute the curve set that was deployed via the aggregation platform and occasionally reported incorrect curve settings, largely due to synchronization and command verification issues.
- o Lab testing[16] confirmed that SI vendor adoption and deployment of Rule 21 SI functions is still evolving. Some manufacturers have a complex field upgrade process that may not be followed by the installers, resulting in inverters not running Rule 21 SI functions, or possibly running the functions but with improper settings.
- o SI lab testing was heavily hindered by SI equipment failures and poor product readiness on part of the vendors, specifically with their implementation of Rule 21 autonomous SI functions. For example:
  - One vendor's product was defective out of the box (would not power up) and could not be tested until a replacement was received.
  - A second vendor's product did not function when the Rule 21 SI functions were applied, and three units from this vendor were replaced after successive electrical failure (units would not convert power but showed no error messages).
  - A third vendor's product shut down at 107% p.u. voltage although it was within the expected Volt-VAR/Volt Watt operating curves and not outside ride-through thresholds.
  - Despite the fact that tested SIs were certified to UL-1741 SA, it is possible that manufacturing or quality control issues were responsible for the observed performance issues out of the box.
- o **Recommendations:**
  - Improved manufacturer product documentation and standardization of SI feature names and local user interfaces is needed to facilitate proper configuration during installation and commissioning.
  - Standardization of SI feature names and functions across inverter manufacturers would significantly facilitate verification of configuration. Vendor-specific implementations are not scalable to system-wide operations with the current configurations available from inverter manufacturers.
  - "VARs at Night" behavior was not comprehensively tested due to an inability of the field SI models to consistently apply the setting, and future work should include evaluation of "VARs at Night" capabilities.
  - SI vendor preparedness regarding Rule 21 Phase 1 Autonomous Function implementation needs improvement. Further progress needs to be made

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proprietary site controller and not the IEEE 2030.5 controller developed for this project. Consequently, full compliance testing using this function was not performed by the SI manufacturer and field performance was not guaranteed during the project time period.

[16] As opposed to field testing, which used inverters that were manufactured prior to Phase 1 Rule 21 requirements (and were thus not certified to UL-1741 SA).

on capabilities to automate verification of deployed SIs against expected configurations so that the last known state of PV and energy storage inverter assets can be determined.

3. **The aggregation platforms and communication infrastructure used to integrate SI-enabled DERs are as critical as the DERs themselves, if DERs are to be reliably deployed for active control use cases by distribution grid operations** (Key Objectives C and D).
    o Issues related to gateway firmware, vendor aggregators, and cellular carrier communications adversely affected system reliability as well as the ability to consistently apply settings changes to SIs as well as to receive DER data back from SI assets in the field. The project developed customized tools to mitigate system failure and increase system reliability over time.
    o In this project, satellite communications proved significantly more reliable than cellular communications.
    o In this project, carrier (satellite and cellular) loss of communication issues were minimal in relation to other system issues such as aggregation platform firmware/software issues.
    o Round-trip latency for cellular communications averaged 0.2 seconds, and 1.8 seconds for satellite.
    o **Recommendations:**
        ▪ Tools to identify and mitigate system failure (to increase end-to-end system reliability) need to be developed to have a situational view of individual assets, aggregations of assets, interconnected communication pathways, and back-office server-side processing. Scalability will require the ability to identify and correct the offending assets when site performance is less than optimum.
        ▪ Degraded communication link quality testing should be included as part of any Engineering, Installation, And Commissioning (EIC) process for SI-enabled DER aggregations to determine the robustness of controls, data and alarms.
        ▪ More reliable communications behavior needs to be specified by the utility and implemented by aggregation platforms regarding the sending of commands to fielded assets, the response of fielded assets to those commands, and verification of actual configuration against expected configurations.
        ▪ Cybersecurity standards are critical and need to be adopted by the industry and integrated into relevant communication standards for SI interconnection.

4. **There is not yet an off-the-shelf SI vendor-agnostic aggregation solution that allows seamless interoperability between DERs, aggregators, and utilities. Aggregation platforms will need to be tailored and customized to specific DER communication infrastructure and DER use cases** (Key Objectives C and D).

- o This project drew from the latest standards and best practices for implementation[17], but the project's use cases required additional functionality above existing standards which resulted in a non-standard Institute of Electrical and Electronics Engineers (IEEE) 2030.5 implementation.
- o Customization of software and firmware was required by all parties to reach a fully functional end-state: the SI manufacturer (SI firmware), PG&E (data analysis and verification of SI function activation), aggregation platform vendor (on-site gateway firmware and aggregator server software).
- o Satellite bandwidth and monthly usage limitations and cellular data usage restrictions required further modifications to the IEEE 2030.5 implementation, resulting in novel data compression techniques.
- o Non-standard Modbus configuration at the SIs complicated the communications architecture design.
- o Despite lab testing that was performed by the aggregation platform vendor, the as-deployed aggregation firmware required many iterations of updates to attain reliable operation, significantly delaying the project timeline.
- o **Recommendations:**
    - Although approved industry standards will always lag new implementations of technologies, technical implementation of standards to address use cases needs to be planned with all stakeholders and should include the inverter manufacturer, communications representatives, aggregation platform developers, and communications security personnel.
    - Laboratory testing by aggregation platform vendors in a configuration that represents fielded assets should continue to be a priority for fielded deployments.

5. **While the SI Volt-VAR and Volt-Watt functions are an important component of voltage regulation, the project has also highlighted that SIs should be viewed as one component of a larger strategy referred to as integrated voltage regulation** (Key Objectives A and D).
    - o Traditional utility equipment such as substation Load Tap Changers (LTC), distribution line regulators and distribution capacitors remain the most effective devices at regulating the primary, medium voltage distribution system. SIs were shown to be effective in regulating the secondary, low voltage distribution system.
    - o The sum of all of these different devices optimized together is greater than the capabilities of the individual parts.
    - o **Recommendations:**
        - Further work should be conducted to better understand the impact of SI Volt-Watt/Volt-VAR performance in context of location of the asset, or grouping of assets, within a voltage zone. The location of the SI PCC on

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[17]   Standards referenced in the design and execution of this project included the IEEE 2030.5 communication protocol, SunSpec Common Smart Inverter Operating Profile (CSIP), IEEE 1547, and UL 1741-SA

the voltage profile within a voltage zone is not yet well understood and most likely has an impact on SI performance on secondary voltage.

- Interoperability of SIs within an ADMS-enabled Volt-VAR Optimization (VVO) platform combined with Supervisory Control and Data Acquisition (SCADA)-enabled voltage regulating devices should be examined in greater detail. As an example, adjustment of autonomous voltage regulation settings may not solve for all voltage violations in higher penetration scenarios.

6. **Curtailment of customer generation due to activation of Volt-VAR and Volt-Watt functions on a test feeder with persistent voltage violations and via the SI modeling study was found to be minimal** (Key Objectives B and F).
    o The SI Stage 2 & 3 field testing of Volt-VAR/Volt-Watt settings on average resulted in 0.4% curtailment at the SIs as compared to a baseline SI running no Volt-VAR/Volt-Watt settings for the demonstration sites.
    o In the SI modeling study, active power curtailment resulting from the activation of SI functions appeared extremely limited: across all combinations of feeders, functions, inverter densities, and PV and load conditions considered, only 45 of the 8,414 PV installations modeled experienced active power curtailment greater than 1% across any of the analyzed 24-hour periods[18].
    o In both the field testing and SI modeling study, activation of SI functions resulting in curtailment was primarily due to elevated voltage from high PV penetration on the feeder(s) and not from pre-existing voltage issues.

7. **Capabilities provided by grid modernization technology deployments such as ADMS and DERMS could allow SI-enabled DERs to provide distribution grid services beyond autonomous SI functions, and to provide value to Distribution System Operations** (Key Objective D).
    o Robust operator feedback mechanisms, such as knowing the status of what SI curve is deployed, whether it is active, and other control settings along with the integrity of the incoming data, were paramount to the success of the SI field demonstration.
    o **Recommendations:**
        - To be actionable by a Distribution Operator, SI data needs to be reliable, timely, and integrated into the context of dynamic Distribution System states via grid operator tools and platforms.
        - Utility operational capabilities and systems that automatically analyze grid conditions, determine optimized solutions, and communicate signals to aggregators and SI-enabled DER assets are needed to enhance the value of DERs to the grid.

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[18] SI Modeling studies by HECO (https://bit.ly/2NwauUD) and Duke (https://bit.ly/2IK186M) found similarly small amounts of curtailment resulting from Volt-VAR and Volt-Watt function activation.

8. **The 3-phase SIs tested in the lab were found to operate in accordance with standards with regard to loss of phase and out of phase recloser operation** (Key Objective D).
   o Testing revealed that the lab-tested SIs met the requirements outlined in IEEE 1547-2018, specifically sections pertaining to ride-through of high/low voltage disturbances and consecutive high/low voltage disturbances.
   o All three vendors' SI products tripped/disconnected within 0.16s (9 cycles) upon opening of a LR, within IEEE 1547-2018 requirements.

9. **For the lab tested EV charger models, line-side harmonic interaction with proper EV charger operation did not exceed standardized limits** (Key Objective E).
   o EVSE, when presented with abnormal line-side harmonic content, operated without error despite extraordinarily high levels of line interference, well in excess of limits established by IEC 60204-1, IEC 61000-4-13, and with respect to guidance provided by IEEE 1547-2018 section 7.3.
   o Although laboratory test equipment limitations precluded extremely high levels of harmonic injection (e.g. beyond 20%), harmonic levels as stipulated by IEC 60204-1, IEC 61000-4-13, and IEEE 1547-2018 were easily met by installed test equipment and levels stipulated by the standards (< 4% for all harmonics) were successfully met.

10. **A modeling study[19] on six PG&E distribution feeders showed that using autonomous SI functions to mitigate the grid impacts of high PV penetration yielded a small, but positive economic impact for ratepayers ("total ratepayer cost") compared to cases where conventional secondary system upgrades were performed to address voltage violations from high PV penetration** (Key Objective F).
   o The modeled use of autonomous SI functions was shown to reduce, but not entirely suppress overvoltage conditions arising from high PV penetration. The reduction observed was generally comparable, and sometimes superior to the level of performance obtained with conventional upgrades such as new secondary (service) transformers.
   o The SI modeling study was not able to demonstrate a scenario in which autonomous SIs mitigated a conventional upgrade on the primary, medium voltage system.
   o The benefits of activating autonomous SI functions generally increased at higher PV penetration levels, due in part to a reduction in count of replacement of service transformers and elimination of voltage rise studies.

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[19] EPIC 2.03A Modeling Report 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

- o HECO's Rule 14H curve was slightly more effective at mitigating over-voltage conditions, but all three curves were on average more effective than conventional upgrades.
- o **Recommendations:**
  - Results for the modeled six distribution feeders indicate that PG&E can eliminate its secondary voltage rise study process for residential projects when Volt-VAR and Volt-Watt are activated and only replace service transformers when their thermal rating is exceeded. The cost savings resulting from this process change are expected to benefit electric ratepayers, interconnecting customers, and PV developers.
  - Future SI modeling work that explores the ability of higher SI-enabled PV penetrations to mitigate distribution upgrades on the primary should be considered.

1.5 Implementation Challenges and Resolution

1.5.1 Location 2 Field Demonstration Challenges and Resolutions

A number of challenges exist with a project of this magnitude. In no particular order, the following are "firsts" and had to be carefully thought through to realize the project objectives:

1. The inverter vendor's SIs used in the Location 2 field demonstration were installed pre-Rule 21 Phase 1 Autonomous function certification requirements, as well as those requirements related to the Common Smart Inverter Profile (CSIP), so implementation of any Phase 1 functionality was not certified by a National Recognized Testing Laboratory (NRTL). Despite this, the project vendor's SIs did meet specific requirements of UL 1741 SA (anti-islanding). While the project SI vendor updated the firmware to provide the necessary functionality, nuances in implementation were slightly different than what was anticipated by the vendor-agnostic aggregation platform vendor.
2. IEEE 2030.5, which was accepted as the communication specification for Rule 21 Phase 2 in March 2018, has limitations with respect to the data model and associated functional use cases. This means that there are implementation gaps between understanding how functions are enacted at the inverter and how they are established at the server, and these had to be worked through between various vendors.
3. Although the satellite communications link is a robust medium, actual commissioning and testing via satellite with remote assets is challenging using the IEEE 2030.5 framework. This required considerable creativity on the part of PG&E and the aggregation vendor to leverage unused portions of the IEEE 2030.5 data model to embed commands to remote assets to facilitate test mode vs. normal operations mode.
4. Limitations exist with the aggregator platform user interface, which was provided to PG&E to interact with assets, specifically to configure, test, and retrieve data. While the vendor worked to establish a baseline interactive capability, much more work is required to make it a useable system.
5. Limitations on data rate, data payload, and other characteristics associated with the satellite link forced a significant amount of creativity on the part of the PG&E and vendor teams. For example, data rates/payloads were constructed to ensure that no one site exceeded 3 GB of data transmission in a month. This required development of preprocessing capabilities at the remote site controller, an effort which was not part of the original project scoping.
6. SI "sensitivity" at PCC is unknown. Smaller SI aggregations have minimal impact on voltage at the PCC, but determining the exact value for this is difficult because it is a multi-variate influence. For example, load absorption of PV output has a profound impact on the ability of the SI to influence voltage at the PCC, yet exact values of load were not quantified at every PCC. Ambient temperature also has an impact as it affects the efficiency of production, line losses, etc., and this impacts how generation will influence voltage at the PCC.

1.5.2 Laboratory Testing Challenges and Resolutions

1. SI lab testing was heavily hindered by SI equipment failures and poor product readiness on the part of some SI vendors, specifically with their implementation of Rule 21 autonomous SI functions (see Key Learning #2 in Section 1.3 above). Laboratory testing confirmed that SI vendor adoption and deployment of Rule 21 SI functions is still evolving.
2. Some manufacturers have a complex SI upgrade process that may not be followed by installers, resulting in inverters not running Rule 21 SI functions. It presently is not possible to verify the magnitude of this potential deficiency due to limited accessibility to SI settings in BTM field deployed units which makes lab product testing and establishment of documented processes/procedures even more critical in advance of larger scale rollouts.
3. Direct Current Fast Chargers (DCFC) tolerated voltage harmonics that produced up to 10% Total Harmonic Distortion (THD) using a 3 Phase 480V input supply, well in excess of the 4% maximums permitted by standards, but could not be taken to higher-order harmonics due to test equipment limitations. It is recommended that an alternative method be developed if testing above 10% is required.

1.5.3 Feeder Modeling Challenges and Resolutions

The modeling component of the EPIC 2.03A project had several challenges related to both setting up the model and performing the simulations. While these challenges were overcome, they were a significant hurdle within the project.

1. PG&E's existing model does not include components of the secondary electric distribution system[20]. For the purposes of this project, secondary, low voltage systems were mapped through a manual process and single customer Advanced Metering Infrastructure (AMI) load profiles were incorporated within the models. This was of particular importance to the project as the output of SI functions is heavily influenced by the secondary system and individual load profiles, and the inclusion of the secondary models allowed for a full evaluation of the impacts of DERs through different loading/generation conditions.

2. The presence of thousands of individually controlled assets made modeling convergence a challenge. In addition to convergence increasing simulation time, there was a large number of permutations that had to be simulated. As a result of efforts related to this project, improvements to the OpenDSS modeling software were implemented that will benefit future releases for the research community.

3. In some instances, there was the requirement to make manual changes to the model. In certain circumstances, such as voltage regulation settings changes, manual decisions had to be made. This process disrupted automation and significantly slowed down simulation time, but ultimately resulted in a more accurate output to the project.

The challenges identified above are specific to the vendor-provided SI technology, the configurations tested, and the "state-of-the-art" at the time of deployment and testing in 2018. As with any new technology, SI solutions will require additional standardization and investment over time to reach maturity, and evolving standards will often lag implementation requirements because new use cases using the same standards are constantly being evolved. Overall, PG&E believes that the industry is on the right track to make SIs a reliable and scalable grid resource over time, with the understanding that some of the above issues may have already been addressed since the time of EPIC 2.03A Location 2 project.

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[20] Secondary voltage is currently accounted for in PG&E's primary distribution model by maintaining primary voltage within certain tolerances. PG&E's service planning department performs secondary level calculations as needed, limiting maximum voltage drop in the secondary system.

1.6   Conclusions

EPIC 2.03A findings demonstrated basic technical functionality of SI autonomous functions designed to mitigate local voltage issues associated with high DER penetration and characterized remaining hurdles to scaled SI deployment for grid support. Efforts undertaken within the project were not able to establish that individual or aggregations of SIs were able to substantially affect *primary voltage*. Despite this, the project has established that there is significant potential for local voltage support from SIs to help mitigate local *secondary voltage challenges* caused by high PV penetration in a cost-effective manner. SI ability to impact secondary voltage demonstrates that, with necessary improvements to the technology and processes related to its deployment, SI technology represents a promising avenue to address California's goals for DER integration.
The project established that successful SI deployment and remote monitoring and management is contingent on the following factors:

1. Unified standards, comprehensive testing and certification, and improved manufacturer product documentation and standardization of SI feature names and user interfaces;
2. SI communications solutions that are designed for reliable, durable and secure operation;
3. Rigorous pre-deployment testing of SI aggregation platform software and firmware to ensure reliable behavior under degraded communication and grid power conditions;
4. Coordination of SI settings with existing utility voltage regulation equipment settings; and
5. Utility grid modernization technology deployments such as ADMS and DERMS (for enablement of active control SI use cases, such as for provision of distribution grid services).

These findings on the potential use of SI autonomous capabilities to support local voltage are expected to be valuable for distribution grid operations, electric generation interconnection, distribution planning, and customer programs. Learnings from this technology demonstration can inform process changes and utility requirements needed to successfully integrate renewable resources controlled by SIs, specifically during the interconnection process. Learnings can also inform the Distribution Resources Plan (DRP) and Integrated Distributed Energy Resource (IDER) proceedings, including Distribution Infrastructure Deferral Framework, Competitive Solicitation Framework, ongoing Rule 21 Order Instituting Rulemaking (OIR), and Grid Modernization Planning filings.

The EPIC 2.03A Project enhanced understanding of the potential of SIs for electric utilities, regulators, adjacent industries, policy makers, and SI vendors. PG&E plans to continue to champion this effort through continued support and presentations at industry meetings and to seek opportunities to continue to assess use of this technology.

2   Introduction

This project Final Report documents the project objectives, technical results and lessons learned in PG&E's EPIC Project 2.03A - Test SI Enhanced Capabilities – PVs, also referred to as EPIC 2.03A – SIs. This report is a follow-on to the EPIC 2.03A project Interim Report[21] that was published in July 2018. The EPIC 2.03A project Interim Report documented the achievements and lessons learned in EPIC 2.03A projects Location 1, while the EPIC 2.03A project Final Report documents the achievements and lessons learned in the EPIC 2.03A projects Location 2, SI lab testing, and SI modeling. This report highlights key learnings gained from the project that have industry-wide value and urgency to share given recent changes to California Rule 21[22], which pertains to DER interconnection requirements. As the industry and California stakeholders converge on a set of standards for SI operation[4], communication and interconnection[5], PG&E feels that it is important to highlight these observations on SI technology's key capabilities as well as note areas for improvement.

The project demonstrated the functionality of customer-sited BTM SI-enabled PV systems and the grid impacts of their use. To date, PG&E has demonstrated the use of residential and commercial and industrial customer-sited PV SI technologies and communication infrastructure to mitigate potential local grid issues related to high penetration of customer-sited DERs on two electrical distribution feeders ("Location 1" and "Location 2"), with the latter exhibiting greater SI-enabled PV penetration. These ongoing project activities targeted high voltage issues attributed to Location 2's high PV penetration as well as an evaluation of a vendor-agnostic aggregation platform that functioned to remotely control and monitor the SI assets. This report details the results of Location 2 activities, as of late 2018, and includes findings from SI laboratory testing and as well as a modeling study.

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[21]   The EPIC 2.03A Interim report 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.

[22]   CPUC Draft Resolution E-4920 issued on 4/26/18 sets the power priority mode as *reactive power priority* mode

2.1 Rationale

In recent years in California, distributed solar PV penetration has increased and growth is expected to continue. As of October 2018, PG&E has over 390,000 solar customers and is adding approximately 5,000 each month. This trend is driven in part by consumer preferences and in part by complementary legislative and regulatory actions. These include California's Renewable Portfolio Standard (33% renewable[23] by 2020, 50% renewable by 2030[24], and 100% carbon emission-free by 2045[25]), Net Energy Metering policies, and federal tax subsidies incentivizing residential and commercial PV adoption[26]. In February 2015, the California Public Utilities Commission[27] (CPUC) issued the DRP Rulemaking R.14-08-013, which foresees incorporation of DERs into day-to-day grid operations and long-term distribution grid planning and investment decisions.

While distributed PV and other DERs represent an important part of the resource portfolio needed to reach California's clean energy and DER integration objectives, high levels of distributed solar penetration have been linked to grid reliability issues. Industry experience and studies have suggested that in some instances, high levels of distributed solar penetration can cause thermal violations, power quality issues, such as voltage violations, and adverse impacts on protection systems due to reverse power flow[28,29]. High levels of distributed solar penetration are also associated with decreasing ability of the distribution grid to host additional solar resources without traditional distribution grid upgrades, such as reconductoring or new voltage regulation equipment.

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[23] Senate Bill X1-2: http://www.energy.ca.gov/portfolio/documents/sbx1_2_bill_20110412_chaptered.pdf.

[24] Senate Bill 350: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350.

[25] Senate Bill 100: https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB100.

[26] Solar Investment Tax Credit: https://www.energy.gov/eere/solar/downloads/residential-and-commercial-itc-factsheets.

[27] Distribution Resources Plan (R.14-08-013) http://www.cpuc.ca.gov/General.aspx?id=5071.

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

[29] High-Penetration PV Integration Handbook for Distribution Engineers: https://www.nrel.gov/docs/fy16osti/63114.pdf.

PG&E forecasts that by 2021, roughly half of all BTM PV in California will be equipped with SIs and predicts nearly 100% SI penetration in California by 2028. Since most of the early PV inverter deployments did not have SI capabilities, the proportion of PV inverters with *intrinsic* functions, initially starting low, will progressively grow over time as older inverters are retired and new Sis are interconnected[30].

Figure 2 shows the past and projected BTM PV capacities and SI densities in
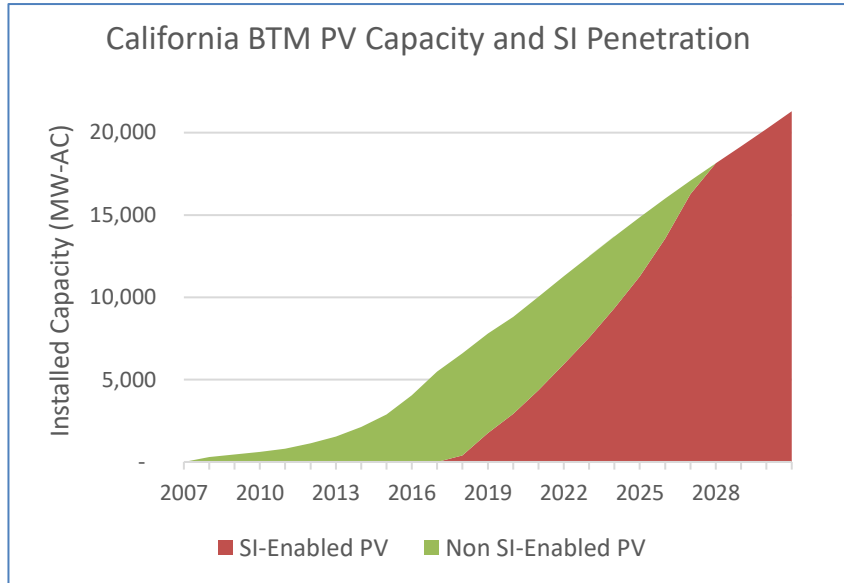
Figure 2: California Statewide BTM PV Capacity and SI Penetration

California. A deeper understanding of SI functions and potential will enable PG&E and other utilities to incorporate SI-equipped DERs into distribution grid planning and operations at scale. This demonstration's objectives focused on exploring several SI functionalities recently adopted by the CPUC. In early 2013, the Smart Inverter Working Group (SIWG) was formed to update Rule 21[31] Rulemaking R.11-09-011, to incorporate advanced SI technical capabilities. Since September 8, 2017, all new PV interconnections are required to have SIs compliant with Rule 21 Phase I autonomous functions, including Volt-VAR control with active power priority. Volt-VAR control with reactive power priority was required starting July 26, 2018. Furthermore, at the time of writing this report, Rule 21 requires all new PV systems interconnected after February 22, 2019 to comply with Rule 21 Phase 2 communications, and Rule 21 Phase 3 advanced functions including Volt-Watt mode[32]. Standardized, industry-certified SIs that are fully Phase 1, Phase 2, and Phase 3 compliant are expected no later than February 2019, although some of this functionality is already available and has been leveraged in the performance of this project.

This demonstration provides several actionable findings, discussed below, which will enable California to make investments needed to leverage the capabilities of the newly adopted SI

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[30]   It should be noted that there is no requirement to replace legacy inverters with SIs.

[31]   Rule 21 is the interconnection tariff that governs DER interconnection; PG&E Rule 21 tariff https://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf.

[32]   For a table of the Phase 1, 2 and 3 SI functions, see Appendix A.

functionalities as a tool to mitigate the distribution grid issues associated with high DER penetration and as a resource to support grid stability[33].

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[33] PG&E has also recently completed a project (EPIC 2.05: Synthetic Inertia) to further explore how SI-based generation could provide frequency and fault response for the bulk electric system as rotating synchronous generators are retired. The report will be available on PG&E's EPIC website.

2.2   The Role of Smart Inverters

SI functionality can help mitigate distribution grid issues associated with high DER penetration. Autonomous SI functions such as anti-islanding, voltage and frequency disturbance ride-through, and "soft-start" after an outage can help to maintain grid stability and reliability. Additionally, the use of autonomous reactive (Volt-VAR) and real (Volt-Watt) power output control is a way for SIs to enable DERs to support grid voltage and to be "good citizens" of the distribution grid at high penetrations. While autonomous SI settings and remote change of autonomous settings may address some grid constraints, active management of advanced SI functions (e.g. sending real or reactive power set points in a more interactive manner, such as through a DERMS) is likely to be needed in other instances, such as for provision of distribution grid services.

Table 4: 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. Analogous to a grid voltage regulator or capacitor, which is programmed to automatically respond to a range of local grid voltage conditions.	• 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 • 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
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 distribution grid services such as: • 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

The project activities documented in this report demonstrate the technical potential of SIs to enable BTM PV to support local (secondary) voltage and highlight next steps to enable scalability and to fully realize their ability to mitigate issues associated with high DER penetration and their potential value as a grid resource. With additional utility investments that enable the distribution

grid operator to achieve better utility situational grid awareness, visibility, coordination and control capabilities, SIs have the potential to play a key role in shaping California's energy future.

3   Project Summary

3.1   Project Objectives

- This project explored the use and impact of aggregated customer-sited SIs to help inform emerging industry standards, as well as define the operational and communication requirements to support the advancement and deployment of new inverter technologies.

- This project addresses CPUC proceeding, Distribution Resources Plan R.14-08-013, by informing DERs modeling by incorporating SIs. The findings of this report will also support and inform PG&E's position within the Rule 21 open proceeding.

3.2 Project Milestones

The following summarizes the key accomplishments of the demonstration project as they relate to Location 2, Lab Testing, and the Modeling Study:

1. Conducted manual Volt-VAR and Volt-Watt testing at 14 of 14 commercial SI-enabled PV sites using a common set of curves (Stages 1/2/3).
2. Measured customer curtailment from Volt-VAR/Volt-Watt function activation (Stages 1/2/3).
3. Demonstrated and evaluated the reliability of communications to provide visibility, monitoring, and control for SI-equipped PV using both a vendor-specific aggregation platform and a vendor-agnostic utility aggregation platform (Stage 3).
4. Clarified SI technology requirements to integrate and operate SIs, and to characterize barriers to deployment at scale relative to today (Stages 1/2/3).
5. Designed and implemented data architectures to support satellite and cellular interaction with remote sites (Stages 2/3).
6. Implemented automated Volt-VAR and Volt-Watt curves, with a quantification of ability to perform different grid services (Stages 2/3).
7. Lab-tested EVSE performance under a large range of harmonic content, to identify any chance of poor behavior.
8. Lab-tested the performance of SIs in the presence of recloser activities.
9. Lab-tested the compliance of various brands of SIs to be properly configured for Rule 21 operation.

3.3   Project Overview

The portion of the EPIC 2.03A project covered in this report involved three major sub-projects:
1) **Location 2 Field Testing**: Demonstration of SIs with BTM customer-owned PV sites, as well as back-office integration and operation of a vendor-agnostic aggregation platform by the lead project engineer.
2) **Laboratory Testing and Research**: a broad range of activities that included testing SIs and electric vehicle charging equipment, as well as furthering understanding of these technologies in context of grid operations and adverse power quality.
3) **Residential SI Modeling**: a study performed by the EPRI in conjunction with PG&E that focused on a limited number of residential distribution feeders, comparing SIs with non-SIs.

Each of these areas, with additional detail, is presented below. Immediately following these descriptions are key learnings for the project.

3.4   Location 2 Field Testing Activities

3.4.1 Location 2 Goals and Objectives

The following were goals of the Location 2 field-test effort, and refer to the Key Objectives as listed in Section 1.1:

- Inform telemetry requirements for SI assets in various modes of functionality (Key Objective C);
- Explore the efficacy of various Volt-VAR and Volt-Watt curves at regulating secondary (local) voltage/addressing voltage issues while minimizing customer curtailment (Key Objectives A and B);
- Determine cost of upgrading existing non-communicating or non-Rule 21-functioning units to those that are Rule 21 compliant with respect to impact on timeline and multiple stakeholder costs (e.g. utility and customer costs, Key Objective D);
- Quantify voltage changes on primary side of transformer that are directly caused by changing Volt-VAR/Volt-Watt settings on the SIs (Key Objective A);
- Inform PG&E SI management strategies for distribution voltage regulation, grid modernization, and SI visibility for distribution operations based on demonstration learnings (Key Objective D)

3.4.2 Location 2 Activities Overview

Location 2 activities field tested Commercial & Industrial (C&I) SI integration and operational challenges. Several use cases and research questions were formulated and addressed through field testing of large-scale SI-enabled PV systems.

3.4.3 Location 2 Scope of Operational Testing

Location 2 testing involved a field demonstration of SIs for C&I customers in the Central Valley from January through September 2018. The project sought to further learnings from Location 1, which was conducted in San Jose, California, to obtain better understanding of SI implementation and management on a rural, radially distributed feeder with high voltage issues and high PV penetration.

In Location 2, PG&E worked with a local PV installer-developer (the project "Asset Manager") to upgrade firmware on existing SIs/existing customer-owned PV sites to evaluate the effectiveness of Volt-VAR and Volt-Watt curves in delivering primary and secondary voltage support. These upgrades allowed PG&E to deploy SI Volt-Watt and Volt-VAR curves and to monitor effects at the SI, PCC, and primary.

Location 2 activities involved 14 individual PV sites owned by 4 individual customers, with each site containing between 4 and 41 SIs. Three stages of testing were created:

1. Stage 1 (January 18 – April 4, 2018): A manual effort to update firmware, load SI curves, and retrieve performance data on-site. Stage 1 was terminated by the conclusion of reconductoring activities that occurred on the feeder (planned independently from this project) and the kick-off of SI Volt-Watt and Volt-VAR curve cycling.
2. Stage 2 (April 5 – August 19, 2018): After reconductoring of the feeder was completed, *manual* loading of specific SI curves and *manual* retrieval of data continued as an automated control and data interaction solution (the vendor-agnostic aggregation platform) was deployed. Whereas Stage 1 tested the effects of running a single Volt-Watt and Volt-VAR curve set, Stage 2 involved weekly cycling of 5 different curve sets.
3. Stage 3 (August 19 – October 1st): Characterized by remote interaction with the sites through the vendor-agnostic aggregation platform, this stage permitted loading of multiple curves and automated retrieval of performance data.

Spanning these phases of testing was a series of capabilities that were intended to inform the objectives of this project. Location 2 activities tested a limited set of the CPUC Rule 21 functions that are currently implemented (Phase 1 Autonomous Functions) or are being developed (Phase 2 Communications and Phase 3 Advanced Functions). See Appendix
Appendix A: SIWG Functions by Phase for a table of all SIWG functions. Within this context, "Primary Function" and "Alternate Function" have been designated on specific inverter functions; each is specified below:

The following CPUC Rule 21 Phase 1, Phase 2, and Phase 3 functions were considered in-scope with respect to testing:
(1) (Primary Function) (Fn 4) Volt-VAR Mode (Phase 1)

(2) (Primary Function) Communications: Utilities to DER Systems (via Aggregator) (Phase 2)[34]
(3) (Primary Function) (Fn 6) Voltage/Watt Mode (Phase 3)
(4) (Primary Function) (Fn8) Scheduling Power Values and Modes (Phase 3)
(5) (Alternate Function) (Fn 1) Monitor Key DER Data (Phase 3)

Testing of the following CPUC Rule 21 Phase 1 functions was considered out-of-scope[35]:
(1) Anti-Islanding
(2) Low/High Voltage Ride Through
(3) Low/High Frequency Ride Through
(4) Ramping
(5) Fixed Power Factor
(6) Reconnect on Restoration

Testing of the following CPUC Rule 21 Phase 2 function was considered out-of-scope:
(1) Communications: Utilities to Facility Energy Management Systems

Testing of the following CPUC Rule 21 Phase 3 functions was considered out-of-scope:
(1) (Fn2) DER Disconnect and Reconnect (Cease to Energize)
(2) (Fn4) Set Active Power Mode
(3) (Fn5) Frequency/Watt Mode
(4) (Fn7) Dynamic Reactive Current Support

Volt-Watt and Volt-VAR were the primary functions for Location 2 field testing activities. During the planning phase, the alternate function "(Fn 3) Limit Maximum Active Power" was considered as a stretch goal for this program. In the end, (Fn 3) Limit Maximum Active Power was not tested due to resource constraints.

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[34]   Phase 2 functionality was not yet defined in CSIP at the time the study was designed, so the communications solution deployed did not match the current definition of Phase 2 functions but accomplished many of the same goals (send DER data, change SI settings remotely, etc.
[35]   These functions were intentionally out of scope to reduce test complexity as well as to focus the aggregator vendor on supporting the in-scope functions. Additional programs may examine the out of scope functions to ascertain their applicability to establishing value for multiple stakeholders.

3.4.4 Location 2 Prerequisites

1. **Identify Feeder Locations:** The project team worked with Distribution Planning Engineers to identify a cross-section of desired feeder locations (residential, C&I, and a mix of residential/C&I customers) with known voltage issues. These feeders were further down-selected to meet a minimum requirement of 30-50% PV penetration as a function of feeder peak load. The project team targeted firmware retrofits of existing SI customers versus new customer acquisition to meet field demonstration timelines.
2. **Identify Field Installer-Developers:** Identifying the "top 5" installers on the down-selected feeder list was a key next step, recognizing that working with too many installers for a small demonstration project would not be feasible from a contract and work management perspective.
3. **Identify a Vendor-Agnostic Aggregation Platform:** IT and Business teams worked together to determine the requirements for how best to monitor and manage field assets for this demonstration. In Location 1 of EPIC 2.03A, SI assets were monitored through a *vendor-specific* aggregation platform, but direct management of all settings by PG&E was not possible. The desired functionality for Location 2 was the ability to directly manage autonomous SI settings (Volt-VAR and Volt-Watt) through a *vendor-agnostic* aggregation platform.

There were a number of key prerequisites that needed to be in place before all stages of field testing activities could begin using all available assets:
1. The individual inverters needed to be upgraded with firmware that had the required capabilities;
2. Three (3) sites needed to be rewired to a common PCC so that the assets could be included in the project.

A number of key prerequisites and resolution milestones needed to be in place before Stage 3 field-testing could commence:
3. The communications gateway, located at each of the 14 test sites, needed to be capable of receiving/aggregating all inverters at the individual site, and
4. The communications gateways needed to be fully compatible with the satellite or cellular uplink/downlink telecommunication capabilities specific to each site.

Items (3) and (4) were verified as installation progressed. An additional prerequisite item that needed to be in place was that the information required by the PG&E technical lead (e.g. the team member who monitored and managed the SI settings) needed to be provided from the individual sites as well as from the aggregator function. This was validated once the interface gateways were installed and operational.

3.4.5 Location 2 System Configuration Overview

Two Location 2 system configurations were developed, the first characterized by manual interaction with SI resources, and the second characterized by use of electronic interfaces, removing the need for on-site, local curve configuration and data collection from the SI resources. The first configuration is grouped as the Stage 1 and Stage 2 configuration, and the overall people, processes, and technologies are unchanged in each of these stages. In this first configuration, the SI assets were locally configured and data was manually retrieved from each of the 14 sites, to be post-processed and analyzed by PG&E.

As previously stated, the conclusion of Stage 1 was initiated by reconductoring activities on the feeder. A new voltage regulator was also installed as part of this distribution upgrade project. Upon completion of the reconductoring activity, Stage 2 activities began.

The second Location 2 system configuration was termed "Stage 3" and was characterized by the use of digital interfaces, removing the need for any local, on-site interaction with the SI assets to configure curves or retrieve data. The configuration used a third-party, vendor-agnostic aggregator platform and existing satellite and cellular communications infrastructure to relay information from each of the 14 sites to the aggregator, where it was formatted and sent to PG&E.
The high-level system configuration that was implemented during the Stage 3 portion of the project is provided below. There were four primary stakeholders in the overall system configuration:

- Multiple Customer Sites:
  - There were 14 individual customer PV sites (owned by a total of 4 customers) associated with this specific feeder
  - Each customer site had between 4 and 41 individual PV SIs for a total of 179 SIs
  - The majority of inverters were 24 kilovolt-ampere (kVA) or 30 kVA maximum output with the ability to support power factor ranges of 0.8 leading/lagging
  - 4,496 kVA full production capacity (4520 kW PV nameplate) was available with all assets online and all sites fully operational

- Aggregator: A third-party aggregator provided the SI interfacing capability and telemetry for the individual site assets during the Stage 3 activities, as well as server assets to provide data to PG&E and the Asset Manager.

- Asset Manager (the PV installer-developer): Each of the end-customers in this pilot is managed by a common Asset Manager. The Asset Manager had the primary responsibility to ensure that the customer was achieving the appropriate levels of production as agreed upon between the Asset Manager and the end-customer. The Asset Manager facilitated data retrieval and SI configuration during Location 2 Stage 1 and Stage 2 activities.

- <u>PG&E</u>: During Location 2 Stage 1 and Stage 2 activities, PG&E directed the Asset Manager on the specific curves to load. During the same period, the Asset Manager retrieved data from the sites and forwarded this data to PG&E. During the Stage 3 period, PG&E worked through the third-party aggregator interface to remotely configure the SI assets in various modes as well as to retrieve data, ultimately determining the impact of various test cases on specific feeder behavior.

Location 1, Stage 1 & 2 Configuration

Figure 3: Location 2 Stage 1 & 2 Configuration, Characterized by Manual Interaction With the SI Assets
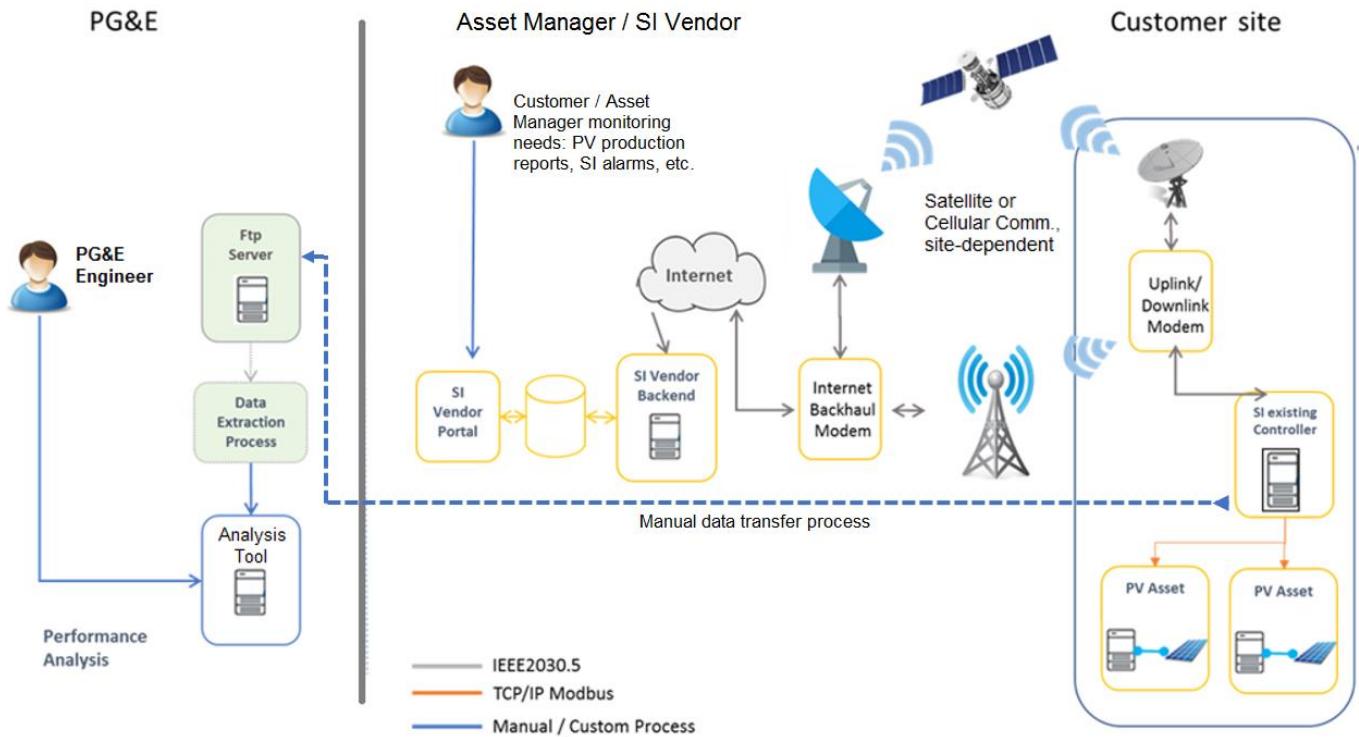
The figure above reveals a manual process that existed between the Asset Manager and PG&E. Data was generated on the right side of the figure, at each of the PV assets, and was collected by a SI Controller. This data was recorded locally and downloaded locally for physical handoff (on a USB drive) to PG&E. Simultaneously, data was provided via a communications link to the SI Vendor and this link provided overall site performance data for the Asset Manager/Customer, but unfortunately, was unsuitable for performance analysis by PG&E (left side of figure). While the configuration met contractual obligations between the Customer and Asset Manager, manual data retrieval is not a viable solution for SI monitoring and management at scale.

Figure 4: Location 2 Stage 3 Configuration That Leveraged the Aggregator Platform Deployment, Allowing for Remote Monitoring/Management of SI Assets by PG&E

Location 2, Stage 3 Configuration
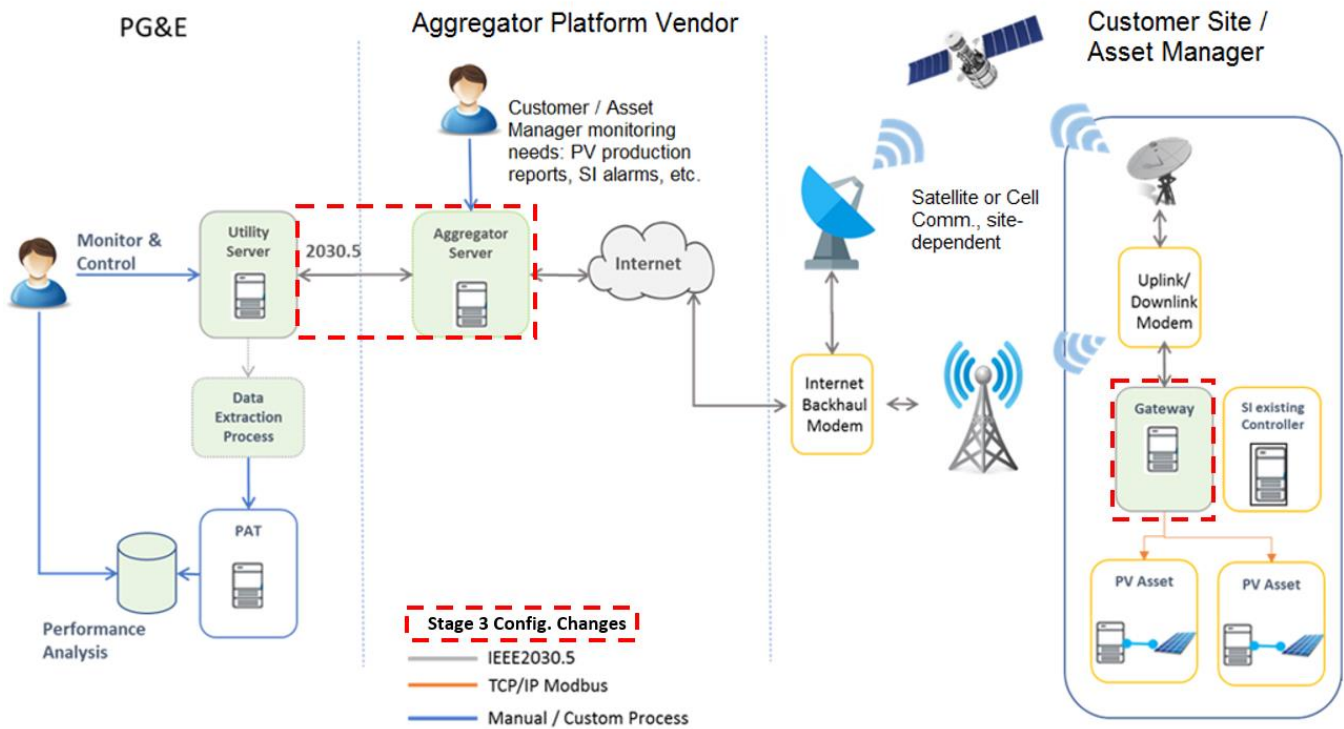
Figure 4 reflects the Stage 3 configuration, which facilitated end-to-end communications and bidirectional control and monitoring data exchange. Measurement data was provided by the individual SI-enabled PV arrays to a newly-installed gateway, which was interfaced to the site communications modem. Independent of whether the medium was satellite or cellular, information was provided to the aggregator platform vendor's server, where it was interfaced via IEEE 2030.5 to PG&E's utility server. Hence, no requirements existed for physical, on-site interaction with system components; configuration of fielded assets (curve settings) and data acquisition was able to be done remotely using the vendor-agnostic aggregation platform.

3.4.6 Location 2 Site-Specific Configuration

14 sites comprised the overall pilot. Each site had between 4 and 41 SIs for a total of 179, and these were connected to a communications gateway to provide individual data collection from each asset as well as individual device addressing. The communications gateway functions as each site's primary interface, and relays remote monitoring information to PG&E as well as distributes control commands to individual SI assets.

The following are the identified test sites, number of SI assets per site, size of the assets, and the total production capacity for each site aggregation:

Table 5: List of Test Sites, Composition of Each Test Site, and Total Production Capacity Per Site

Test Site	Number of SI Assets	Site SI Composition (#SIs, rating)	Total Site Production Capacity (kVA)
LC2	9	Qty 1 (24 kVA) , Qty 8 (30 kVA)	264 kVA
LC4	7	Qty 7 (30 kVA)	210 kVA
LC5	8	Qty 1 (12 kVA), Qty 7 (30 kVA)	222 kVA
LC6	7	Qty 7 (30 kVA)	210 kVA
OR3	9	Qty 1 (24 kVA), Qty 8 (30 kVA)	264 kVA
OR4	9	Qty 1 (24 kVA), Qty 8 (30 kVA)	264 kVA
J16	4	Qty 1 (12 kVA), Qty 3 (30 kVA)	102 kVA
GRE	11	Qty 11 (24 kVA)	240 kVA
GRW	10	Qty 10 (24 kVA)	240 kVA
SVD	41	Qty 41 (24 kVA)	984 kVA
VVE	6	Qty 1 (12 kVA), Qty 5 (24 kVA)	132 kVA
SVW	26	Qty 1 (20 kVA) , Qty 25 (24 kVA)	620 kVA
V6A	16	Qty 1 (12 kVA), Qty 15 (24 kVA)	372 kVA
V6B	16	Qty 1 (12 kVA), Qty 15 (24 kVA)	372 kVA

3.4.7 Location 2 Site Baseline Inverter

One SI asset at each site functioned as a baseline device and did not participate in the settings changes deployed to the remaining site devices. This design was formulated so that a control baseline was present and would provide the differential measurements that were necessary to determine the amount of curtailment at a particular site.

3.4.8 Location 2 Site-Specific Data

Data gathered per site came from two locations and three measurement devices. Table 6 shows the measuring locations, their respective measuring devices, and their measured values.

Table 6: Site-Specific Measuring Locations, Measuring Devices, and Measured Values

Measuring Location	Measuring Device	Total Devices Deployed	Measured Values
PV Site (14 Sites)	SI	179	Total Yield 3-phase Active Power 3-phase Voltage 3-phase Current
PCC	Smart Meter (SM)	8	3-phase Voltage
PCC	Power Quality Meter (PQM)	6	3-phase Active Power 3-phase Reactive Power 3-phase Voltage 3-phase Current

Data at the PCC was provided by SMs or PQMs. The criteria for determining which measuring device was used were whether the meter at the PCC provided voltage data. There were six sites (of the 14 total) that had MV-90 meters, which could not capture voltage data. In these cases, a PQM was used to record data. Figure 5 shows a map with the demonstration sites indicated by a circle sized relative to the site nameplate and colored by the measuring device installed at the PCC. Eight sites used SM data at the PCC; six sites used PQM data at the PCC.

Figure 5: Map of Demonstration Sites and Cressey Substation, With Circle Size Reflective of PV Size, Colored by Recording Device at the PCC
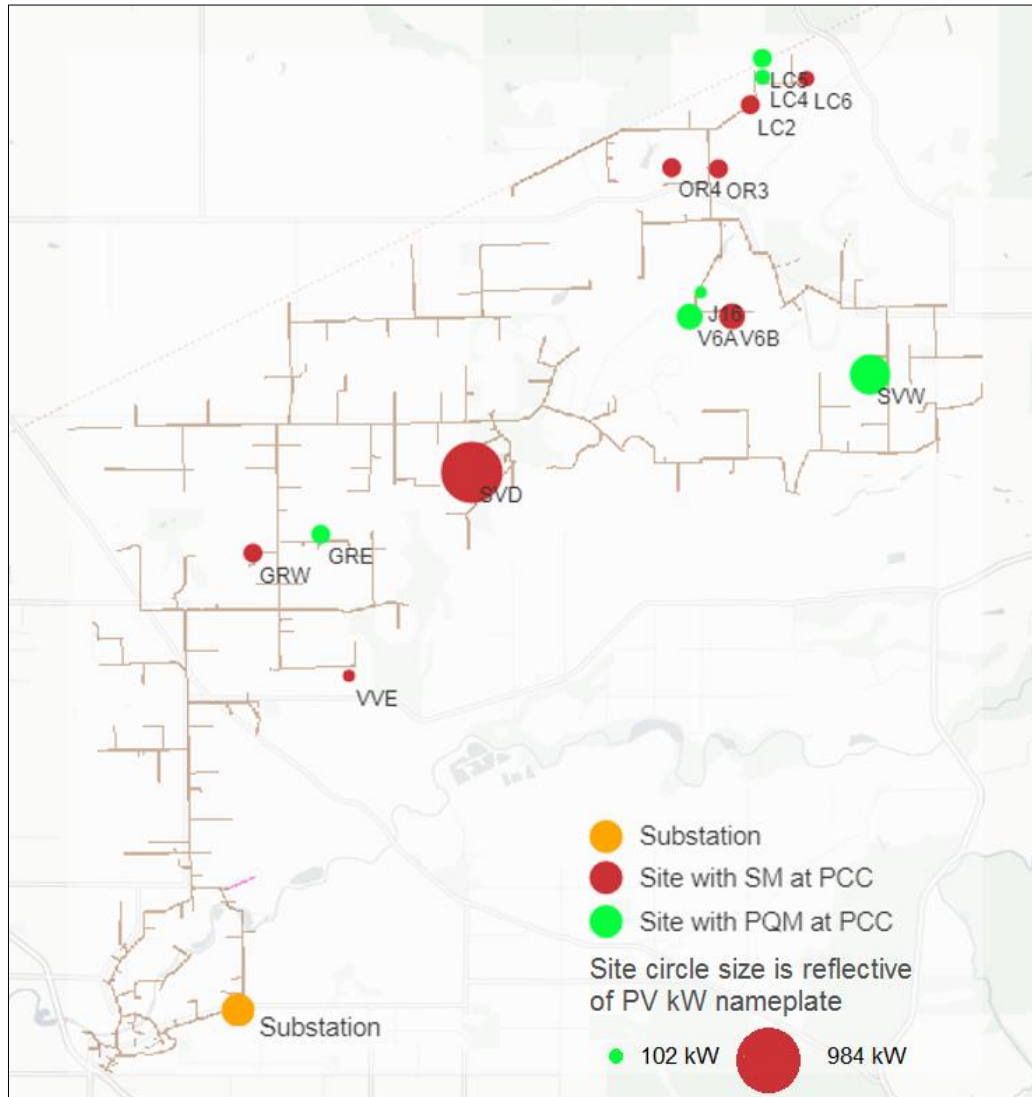
3.5   Laboratory Testing

PG&E has conducted significant testing with SIs in the EPIC 2.03 Project and in the Advanced VVO Smart Grid Pilot. Further, under the EPIC 2.02 DERMS program, a centralized utility control system was interfaced to fielded SI assets, via 3rd party aggregators, to establish Monitoring and Control (M&C) capabilities. While a number of lessons were learned through these efforts, gaps related to knowledge regarding the impact of the distribution grid upon distributed energy resource operation, as well as considerations concerning scaling, configuration, and commissioning remain. Laboratory testing efforts were undertaken to understand potential grid-side issues, specifically existing power quality (harmonics) issues that present themselves to the SI as well as EVSE and provide additional understanding regarding the potential impact of protection operations on SI operation. The effort examined the issues surrounding configuration of SIs, specifically examining their behavior within the California Electric Rule 21 ("Rule 21") autonomous Volt-VAR and Volt-Watt modes, and the difficulty of configuration of the basic functions across multiple vendor assets.

There were three main objectives with respect to laboratory testing:

1. Characterize and understand SI performance under various configurations surrounding Volt-VAR, Volt-Watt, and harmonic performance.
2. Characterize and understand SI performance in context of loss of phase and LR action, with the intent to have SIs under various configurations and establish how SIs respond to dynamic operational conditions that may occur on the utility grid and how this response subsequently impacts both the utility grid and the customer, and
3. Characterize and understand harmonic performance of Level 2 Electric Vehicle Supply Equipment (EVSE) and DCFC and establish how EVSE and DCFC respond to dynamic operational conditions that may occur on the utility grid and how this response subsequently impacted both the utility grid and the customer.

Formal results are presented in Section 5 of this report.

3.6 Residential SI Modeling

In the modeling component of EPIC 2.03 the EPRI performed detailed time series simulations in OpenDSS[36] on six PG&E distribution feeder models. Simulations were focused on the SI Volt-VAR and Volt-Watt functions. High-level questions within the study included:

- When compared to scenarios without SIs, do SIs help mitigate primary, medium voltage upgrades?
- Can PG&E update its interconnection process as it relates to secondary voltage rise studies and replacing service transformers on potential overvoltage?
- Is one Volt-VAR curve more effective than another?
- What are the customer generation curtailment impacts of the Volt-VAR and Volt-Watt functions?
- When compared to scenarios without SIs, what is the economic impact of SIs in both avoided equipment replacement and installation, as well as avoided labor performing voltage rise studies?

Due to the scope of the modeling study, it is important to acknowledge some of the caveats:

- The modeling study only focused on six distribution feeders[37], representing less than 0.2% of PG&E's system. This makes it difficult to extrapolate system-wide conclusions.
- The modeling study only focused on residential installations. Penetration was based on number of residential customers with PV, not as a percentage of peak load. As a result, any conclusions assume that PV penetration is highly distributed across each circuit.
- The modeling study focused on comparing scenarios without SIs to scenarios with SIs. If an upgrade was required in both scenarios, such as a voltage regulator replacement or a service transformer replacement, it was excluded from the economic analysis. Therefore, results may incorrectly imply a high integration/hosting capacity.
- The modeling study's scope was limited to the Volt-VAR and Volt-Watt function. Therefore, any integration/hosting capacity conclusions can only be compared to the thermal and voltage components and the previously stated caveats must be acknowledged.
- The modeling study included models of the secondary, low voltage system. This contrasts most common planning modeling methodologies that more commonly focus on only the primary, medium voltage system.

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[36] An open-sourced, research-grade distribution system simulator (DSS) software developed by EPRI.
[37] The modeling component of this project leveraged, and enhanced feeder models previously used under the California Solar Initiative (CSI3). Refer to the main modeling report for more information on feeder selection: 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

Formal results are presented in Section 5 of this report.

4   Testing Methodology

Testing methodology spanned three separate subprojects:

1) Location 2 Activities
2) Laboratory Testing and Research
3) Residential SI Modeling

The following is a high-level description of how testing was accomplished, or considerations with respect to testing, in each of the subprojects.

4.1   Descriptions of the Curve Sets

The following are brief descriptions of the curves that were used throughout this project. A detailed accounting of the curves, with figures of exact breakpoints, can be found in Appendix B. These figures may be helpful in visualizing the actual curves that were implemented.
The primary goal with these 5 different curve sets was to provide a calibration methodology (Curve Set A) as well as to better understand the impact of Volt-Watt and/or Volt-VAR on primary and secondary voltage (Curve Sets B-E).

Table 7 below lists the Curve Sets that were implemented in the project with various characteristics. Specific similarities and differences are noted below:

1. For Curve Set A, the Volt-Watt and Volt-VAR curves are flat, zero-sloping lines with no breakpoints. This was done to provide a reference for measurement of system parameters for which to compare (due to anticipated changes in load, seasonality, and production levels). The result is that no curtailment results at any voltage (Volt-Watt) nor does any VAR production/absorption occur at any voltage (Volt-VAR).
2. **Volt-Watt** Curves A and E utilize a "flat line", e.g. no breakpoints, in the curves. The rationale for Curve Set A was previously explained. For Curve E this was done to isolate the VAR component of Curve E, e.g. no Volt-Watt curtailment occurred while Curve Set E was enacted, hence any effect on the voltage was due purely to VAR production/absorption.
3. **Volt-Watt** Curve Sets B, C, and D all began curtailment at 1.06 Vpu and reached 100% curtailment at 1.10 Vpu. This was done to align with proposed SIWG and enacted Hawai'i Rule 14 parameters.
4. **Volt-VAR** Curve Sets B and E were identical in VAR generation and absorption. The only difference between these two Curve Sets was that Curve Set E did not have a Volt-Watt curtailment – it was effectively disabled when Curve Set E was running. This was to specifically isolate pure VAR impact on voltage on the feeder. Curve Set C absorbed VARs up to 1.07 Vpu for purposes of testing overlap with the Volt-Watt curve; Curve Set D allowed for the greatest VAR absorption/injection at 44% of Pmax vs. 30% for the other curves.

Please refer to Appendix B for visualization of each of the curves and various breakpoints.

Table 7. Curve Sets Implemented in the EPIC 2.03A Project

	Set A (Baseline)	Set B (Alt. Prop CA Rule 21)	Set C (CA Rule 21)	Set D (HECO)	Set E (Set B with Volt-VAR Only)	Acceptance Test
Volt-Watt Characteristic Curve						
Adjustm time characteristic curve operating point	10	0	0	0	10	0
Number of points to be used	2	2	2	2	2	2
X-axes reference	Voltage in percentages of Un	Voltage in percentages of Un	Voltage in percentages of Un	Voltage in percentages of Un	Voltage in percentages of Un	Voltage in percentages of Un
X value 1	100	106	106	106	100	92
X value 2	100	110	110	110	100	110
Y-axes reference	Power in Percentages of Pmax (Prated)	Power in Percentages of Pmax (Prated)	Power in Percentages of Pmax (Prated)	Power in Percentages of Pmax (Prated)	Power in Percentages of Pmax (Prated)	Power in Percentages of Pmax (Prated)
Y value 1	100	100	100	100	100	3
Y value 2	100	0	0	0	100	3
Volt-VAR Characteristic Curve						
Adjustm time characteristic curve operating point	10	5	5	5	5	5
Number of points to be used	4	4	4	4	4	4
X-axes reference	Voltage in percentages of Un	Voltage in percentages of Un	Voltage in percentages of Un	Voltage in percentages of Un	Voltage in percentages of Un	Voltage in percentages of Un
X value 1	100	92	92	94	92	92
X value 2	100	96.7	96.7	97	96.7	96.7
X value 3	100	103.3	103.3	103	103.3	103.3
X value 4	100	106	107	106	106	106
Y-axes reference	Var in percentages of Pmax	Var in percentages of Pmax	Var in percentages of Pmax	Var in percentages of Pmax	Var in percentages of Pmax	Var in percentages of Pmax
Y value 1	100	30	30	44	30	1
Y value 2	100	0	0	0	0	-5
Y value 3	100	0	0	0	0	-5
Y value 4	100	-30	-30	-44	-30	-5

Curves B, C, D, and E all contain varying values of where Volt-Watt or Volt-VAR impact outputs. Of particular interest is the lower portion of the table, specifically X value 2 and X value 3, which are discrete at 96.7% and 97% as well as 103% and 103.3%.

4.2 Location 2 Testing Methodology

4.2.1 Location 2 Testing Cadence & Methodology

The testing methodology was split into three primary sequences due to the new functionality of software, hardware, communications path, data parsing, and data visualization necessary at multiple steps or locations throughout the overall configuration. The methodology aligns with the stages:

1. Stage 1: Curve Set B
2. Stage 2: Curve Sets A – E
3. Stage 3: Curve Sets A – E

Location 2 Stage 1, which utilized only Curve Set B, was enacted during the pre-reconductoring phase of the project (through April 4 and was the only Curve Set that was deployed. This approach was taken in order to capture as much data as possible using the smaller conductor. No changing of Curve Sets occurred during the Location 2 Stage 1 period.

Location 2 Stage 2 utilized all Curve Sets on a weekly basis. Curve Sets B-E were interleaved with the baseline Curve Set A, resulting in the ability to compare / contrast the individual Curve Sets B-E with a baseline, which provided visibility into the impact of seasonality and extended weather events. The Location 2 Stage 2 effort ran from the beginning of April to August 2018, while individual sites were being upgraded and certified for remote operation.

Stage 3 utilized all Curve Sets, as in the Stage 2 effort, but with two notable changes. First, because of expected third-party aggregator automation and remote communication pathways to the assets, cadence of curve changes was daily, including changes on weekends.

4.2.2 Location 2 Stage 1 Testing

Stage 1 of the project involved on-site visits to update firmware, physically loading SI settings, and manually retrieving performance data. Stage 1 kicked off on 1/18/2018 and concluded on 4/4/2018. Events that occurred over this time included:

- Area 1 reconductoring was completed
- Pilot sites were accepted for testing
- A single SI Volt-Watt and Volt-VAR setting was deployed to sites
- The SI setting for reactive power generation at night was activated
- Area 2 reconductoring began
- Area 2 reconductoring was completed
- The SI Volt-Watt and Volt-VAR setting was removed

Figure 6 shows the Stage 1 timeline along with high-level events that occurred within that timeline. Most of the sites were configured with Curve Set B for the majority of February and March 2018.

Figure 6: Stage 1 Timeline and Events
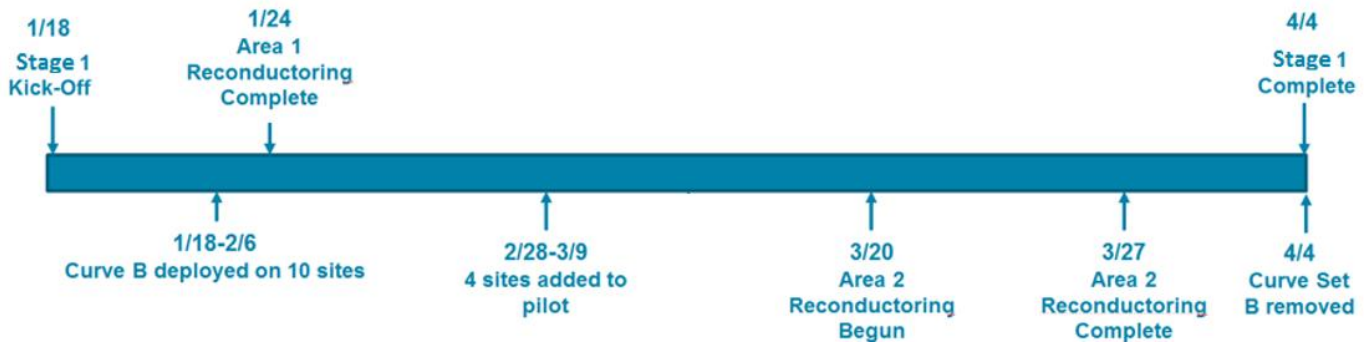
4.2.3 Location 2 Stage 2 Testing

Stage 2 of the project involved on-site visits to update firmware, physically load SI settings, and manually retrieve performance data. Stage 2 kicked off on 4/5/2018 and concluded on 8/15/2018. Events that occurred over this time included:

- Five SI Volt-Watt and Volt-VAR Curve Sets were cycled on the sites
- SI settings were initially deployed using P_{pre}, and then modified to use P_{rated}
- The vendor-agnostic aggregation platform was deployed for acceptance testing leading up to Stage 3
- The vendor-agnostic aggregation platform was accepted with minimal requirements passing

Figure 7 shows the Stage 2 timeline along with high-level events that occurred within that timeline.

Figure 7: Stage 2 Timeline and Events
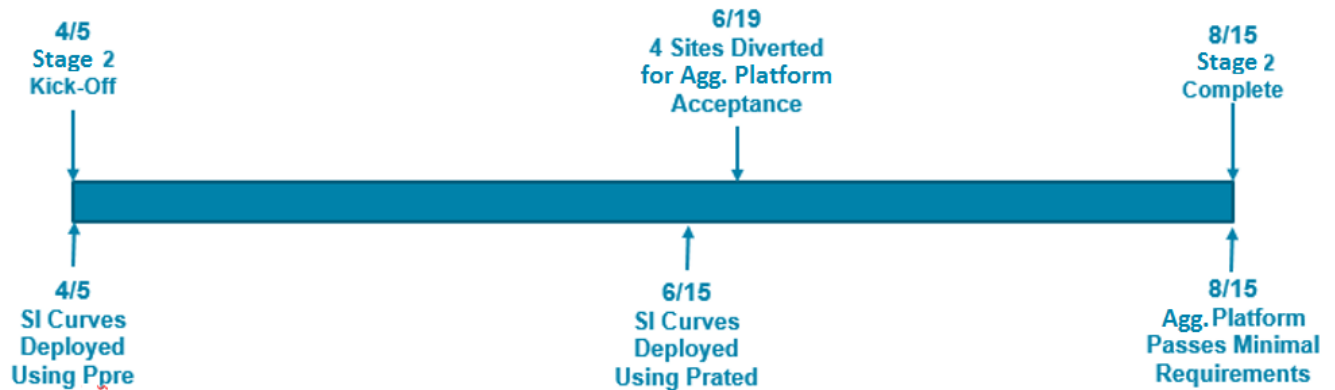
Five different Volt-Watt, Volt-VAR Curve Sets were deployed during Stage 2. Initially, the inverters were programmed to use P_{pre} in following the Volt-Watt curve, and later modified to use P_{rated}. The five Curve Sets were designated: A0, B0, C0, D0, and E0. Upon modifying the inverter setting to use P_{pre} instead of P_{rated}, the five Curve Sets were designated: A1, B1, C1, D1, and E1. The sections below present the curves and the criteria used in selecting each. Table 8 documents the deployment dates for each Curve Set across the demonstration sites. The curves ran from 4/5/2018 through 8/15/2018. While the intent of the project was to cycle curves weekly, there were instances where this was not possible due to rainy conditions limiting site access, and delays related to vendor platform acceptance.

Table 8: Stage 2 Curve Set Deployment Schedule

Curve Deploy Date	4/5	4/13	4/27	5/4	5/11	5/18	6/1	6/8	6/15	6/22	6/29	7/6	7/13	7/20	7/27
Curve Deploy Duration	7 days	14 days	7 days	7 days	7 days	14 days	7 days	7 days	7 days	7 days	7 days	7 days	7 days	7 days	20 days
Curve Set	A0	D0	A0	E0	A0	B0	A0	C0	A1	C1	A1	B1	D1	A1	E1

While the majority of the sites followed the schedule outlined in Table 8, there were instances where an individual inverter or an individual site did not follow this schedule. These instances are documented in Table 9.

Table 9: SI Curve Set Exceptions

Site	Date Range	Desired Curve	Actual Curve	Explanation
GRE, GRW, VVE, SVD	6/19-8/15	N/A	N/A	These sites were diverted for vendor acceptance testing and were removed from Stage 2
LC4	7/20-7/26	A1	D1	Site was experiencing a power outage and field technician was unable to change SI settings
LC5	7/20-7/26	A1	D1	Site was experiencing a power outage and field technician was unable to change SI settings
LC6	7/20-7/26	A1	D1	Site was experiencing a power outage and field technician was unable to change SI settings
V6B	7/13-7/19	D1	B1	Upon attempting curve change from B_1 to D_1, field technician found that a subset of the inverters at this site were not accepting curve changes. All inverters at the site were reverted back to B_1.
V6B	7/20-7/26	A1	B1	Upon attempting curve change from B_1 to A_1, field technician found that a subset of that a subset of the inverters at this site were not accepting curve changes. All inverters at the site were reverted back to B_1.

In addition to the exceptions listed in the table above, data loss was experienced at the demonstration sites. No data was recorded at SVD from 4/13/18 to 4/26/18 due to malfunctioning site controller hardware.

4.2.4 Location 2 Stage 3 Testing

Stage 3 of the project involved remotely loading SI curves and remotely retrieving SI data using a third-party vendor-agnostic interface platform. PQM data, captured at six PCC locations, continued to be manually retrieved during this stage. Stage 3 kicked off on 8/19/2018 and concluded on 9/30/2018.

The same curves that were used in Stage 2 were used in Stage 3. Table 10 documents the curve set deployment schedule across the demonstration sites. All curve sets end in "1", indicating that they use P_{rated} as their power configuration.

Table 10: Stage 3 Curve Set Schedule

	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday
Week of 8/19	B1	D1	A1	E1	C1	A1	D1
Week of 8/26	E1	A1	C1	B1	A1	E1	C1
Week of 9/02	A1	B1	D1	A1	E1	B1	A1
Week of 9/09	C1	E1	A1	D1	B1	A1	E1
Week of 9/16	D1	A1	B1	C1	A1	D1	B1
Week of 9/23	A1	C1	E1	A1	D1	C1	A1
Week of 9/30	C1						

The remote-configuration capabilities of the system had a dramatic impact on testing methodology by permitting different curves to be loaded on a daily basis. This allowed curves to be tested against the ever-changing production and load values that were presented to the feeder.

Curves were applied to all 14 sites during Stage 3.

4.3 Laboratory Testing

4.3.1 Laboratory Testing Overview

Lab testing as part of EPIC 2.03A was conducted on multiple SIs and Electric Vehicle (EV) chargers to characterize equipment performance under various test conditions and assess SI conformance with Rule 21 SI functional requirements. Specifically, tests were structured to characterize and understand Volt-VAR, Volt-Watt, and harmonic performance of SIs under various configurations and characterize and understand harmonic performance of Level 2 Electric Vehicle Supply Equipment (EVSE) and DC Fast Chargers (DCFC). In addition, lab testing sought to characterize the behavior of loss of phase due to opening of a LR that supplied power to commercial grade SIs connected in a traditional Delta-Wye transformer configuration.

4.3.2 Laboratory Testing Scope

The following table lists the in-scope/out-of-scope test matrix for the equipment that was tested under laboratory conditions.

Table 11: Residential SI and EV Chargers Test Matrix

	Unit 1, Vendor 1	Unit 2, Vendor 1	Unit 1, Vendor 2	Unit 1, Vendor 3	Unit 2, Vendor 3	Unit 1 Level 2 EVSE, Vendor 4	Unit 1 Level 2 EVSE, Vendor 5	Unit 1, DCFC, Vendor 6	Unit 1, DCFC, Vendor 7
Rule 21 Applied	X	X	X	X	X				
Volt -VAR Rule 21 Curve	X	X	X	X	X				
Volt-Watt Rule 21 Curve	X	X	X	X	X				
Volt-VAR and Volt-Watt Rule 21 Curve	X	X	X	X	X				
Volt-VAR and Volt-Watt Alternate Curve	X	X	X	X	X				
Harmonic Immunity	X	X	X	X	X	X	X	X	X

4.4   Modeling

An overview of the EPRI SI modeling study is provided above in Section 3.6. For a detailed description of the modeling methodology, [follow this link to the full online report](#).

5   Technical Findings

The following section details findings as found in the three subprojects within the program. The subprojects presented are:

1) Location 2 Findings
2) Laboratory Testing and Research Results
3) Residential SI Modeling Results

5.1.1 Location 2 Volt-Watt and Volt-VAR Findings

The following are the results learned in the Location 2 field demonstration as well as in the SI lab testing and 3rd-party modeling activities. It is important to note that Location 2 stages, specifically Stage 1, Stage 2, and Stage 3, build upon each other as capabilities expanded, and have been consolidated to reflect overall project results.

A number of use cases were developed as part of the Location 2 effort and these use cases, with associated questions, guided the overall project and performance of activities. Table 12 identifies the use cases as documented in the EPIC 2.03A SI Test Plan that apply to Volt-Watt and Volt-VAR performance. A separate table is provided in this section that provides the Telemetry use cases and questions. Exploration of the Volt-Watt/Volt-VAR use cases have been covered in fine detail in separate Measurement & Verification reports prepared by PG&E ATS; higher-level summaries of findings follow.

Table 12: Volt-Watt and Volt-VAR Measurement and Verification Use Cases and Questions

Use Case # and Description	Question #	Question
UC 1: Volt-VAR / Volt-Watt Testing	Q1	Is the inverter, and are the aggregations of inverters able to follow Volt-VAR and Volt-Watt curves without interaction/interference?
	Q2	What is the ability of a SI, or grouping of SIs at a site, to move voltage as measured at the PCC using each of the individual Volt-VAR or Volt-Watt functions? Characterize in terms of curtailment (Volt-Watt) as well as reactive production (Volt-VAR). Separate functions if possible; if not, characterize as a function of the simultaneous combined curve performance.
	Q3	What is impact at the substation in context of moving voltage on the feeder as a function of individual inverter Volt-VAR or Volt-Watt functions? Characterize in terms of curtailment (Volt-Watt) as well as reactive production (Volt-VAR). Separate functions if possible; if not, characterize as a function of the simultaneous combined curve performance.
	Q4	What are the economics associated with the use of a SI, or grouping of SIs at a site, relative to customer production? Is there a clear preferred mode of operation that does not impact customer economics but does provide an electrical benefit to PG&E (SIWG Phase 3 10.3.8: Should Volt-VAR take precedence over Volt-Watt)? Separate functions if possible; if not, characterize as a function of the simultaneous combined curve performance.
	Q5	What Curve Set is most effective at moving voltage and minimizes curtailment?
	Q1	[Monitoring] What are the explicit minimum requirements for monitoring the reactive components of production on an

Use Case # and Description	Question #	Question
UC4: Volt-Watt and Volt-VAR M&C Analysis		individual SI or group of SIs? Representative response areas include: • Requirements associated with the SI manufacturer to provide measurements related to reactive power production/absorption as measured at the output terminals of each of their devices; • Accuracy and resolution requirements associated with measuring the reactive components of production and electrical parameters at the PCC; • Sampling requirements associated with measuring the reactive components of production and electrical parameters at the PCC.
	Q2	[Monitoring] What are the explicit minimum requirements for monitoring the real components of production on an individual SI or group of SIs? Representative response areas include: • Requirements associated with the SI manufacturer to provide measurements related to real power production as measured at the output terminals of each of their devices; • Accuracy and resolution requirements associated with measuring the real power components of production and electrical parameters at the PCC; • Sampling requirements associated with measuring the real power components of production and electrical parameters at the PCC.

5.1.2 UC1, Q1: SI Ability to Follow Volt-VAR and Volt-Watt

Use Case 1, Question 1 investigated whether the inverter and the aggregation of inverters were able to follow Volt-VAR and Volt-Watt curves without interaction and/or interference. Addressing this question required forming a tolerance around which adherence to the SI Volt-Watt/Volt-VAR curves was deemed acceptable. This was based on the "Technical Data" section of the SI installation manual for the demonstration SIs. For these tests, the limits of accuracy for voltage measurement was specified at 2% of nominal voltage for the limits of accuracy for power (active/reactive) measurement were established at 5%.

Figure 8 shows the SIs' effectiveness in executing Curve Set B1 and uses all data available across all sites for the stated curve. As expected, all data points fell within the Volt-Watt and Volt-VAR tolerance bands. The figure include data from all active SIs across all the demonstration sites. Baseline SIs have been excluded from this figure. Additional figures for Curve Sets A1, C1, D1, and E1 can be found in Appendix C: SI Measurements Across All Sites and Curve Sets.

Figure 8: SI Measurements Across All Sites Plotted Against Curve Set B1 Volt-Watt and Volt-VAR Settings Along With the Tolerance Bounds Around the Curve Settings
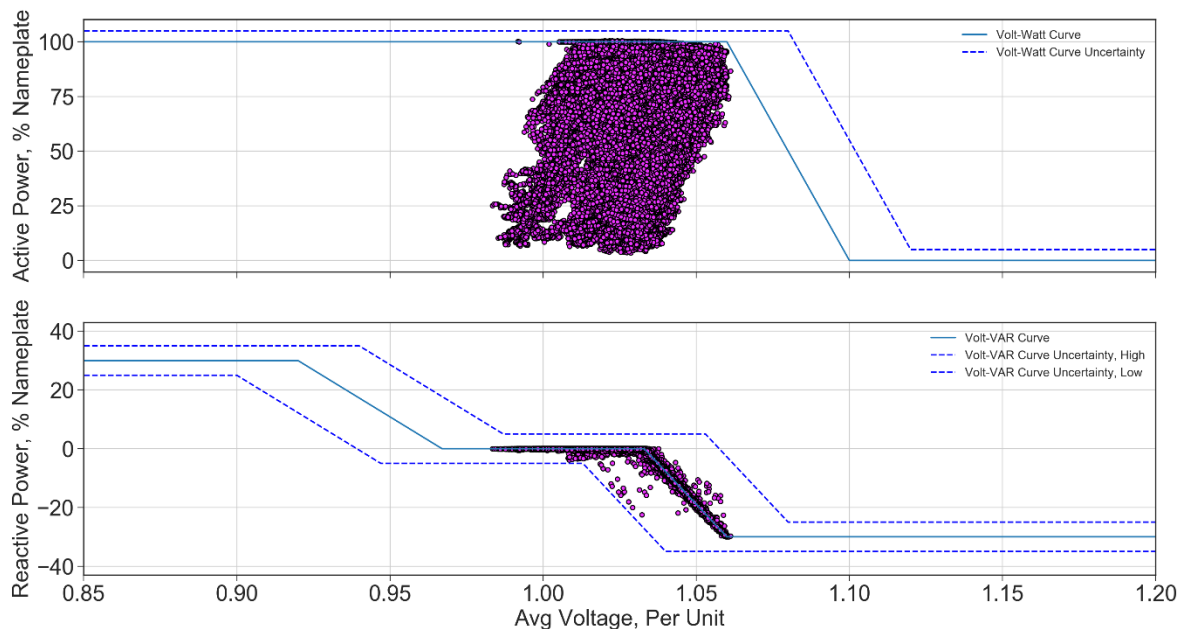
Key Learning: The demonstration SIs successfully executed the Volt-Watt and Volt-VAR curve settings within tolerances in adherence with proposed Rule 21 requirements.

5.1.3 UC1, Q2 and Q5: SI Ability to Affect Secondary Voltage at the PCC

Use Case 1, Question 2 investigated whether the inverter and the grouping of inverters at a site were able to move secondary voltage as measured at the PCC using the Volt-VAR and Volt-Watt functions. Use Case 1, Question 5 asks what curve set was most effective at moving voltage at the PCC.

Voltage at the PCC was measured by either a smart meter or a PQM. The data for each site was grouped by curve set and then plotted as a histogram of the percent occurrence of each voltage bin (bin width = 0.0015 Vpu). As an example, Figure 9 shows this histogram for Site SVW. The orange vertical line indicates 1.05Vpu, the upper bound of the California Rule 2 limit. For each of the active Volt-Watt, Volt-VAR curve sets B1, C1, D1, and E1, the data shows a significant decrease in the percentage of voltage violations (fewer than 0.2%) as compared to the period with no Volt-Watt, Volt-VAR i.e. curve set A1 (11.7%).

Figure 9: SVW: Percent of Occurrences of Voltage "Bins" and Percentage of Violations by Curve Set
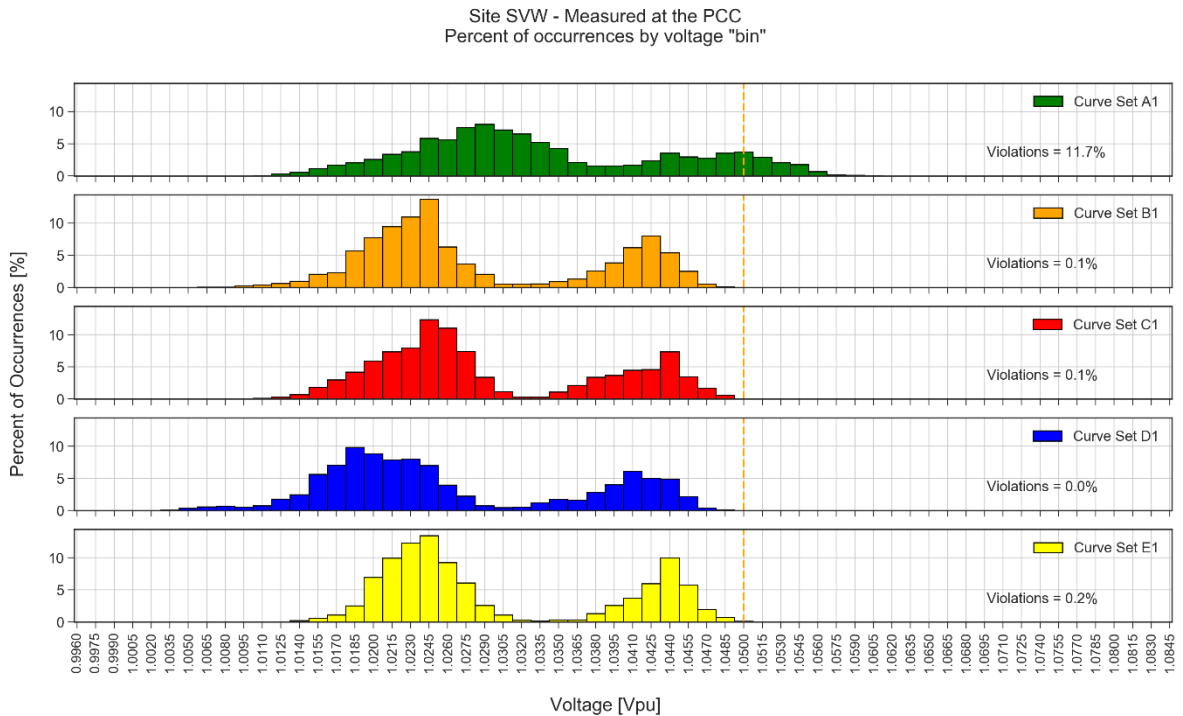
While it is visually apparent that use of the curve sets significantly reduced the number of violations, ensuring compliance with Rule 2, further analysis was required to determine individual characteristics of the curves and their efficacy to produce the desired change.

Figure 10 shows the percentage of voltage violations for each of the curve periods as experienced at site SVW, one of the largest PV sites that was near the end of the test feeder and also

experienced the most voltage violations of any test site. A clear drop in voltage violations (normalized by site production) was seen across the curve periods that deployed a Volt-Watt/Volt-VAR Curve Set as opposed to the curve periods running no SI curves. This is another visual indication that the SIs at a site were able to move voltage as measured at the PCC using the Volt-VAR and Volt-Watt functions.

Figure 10: Site SVW: Percent of Voltage Violations Versus Curve Period

Site SVW: % kWh Normalized Voltage Violations by Curve Period
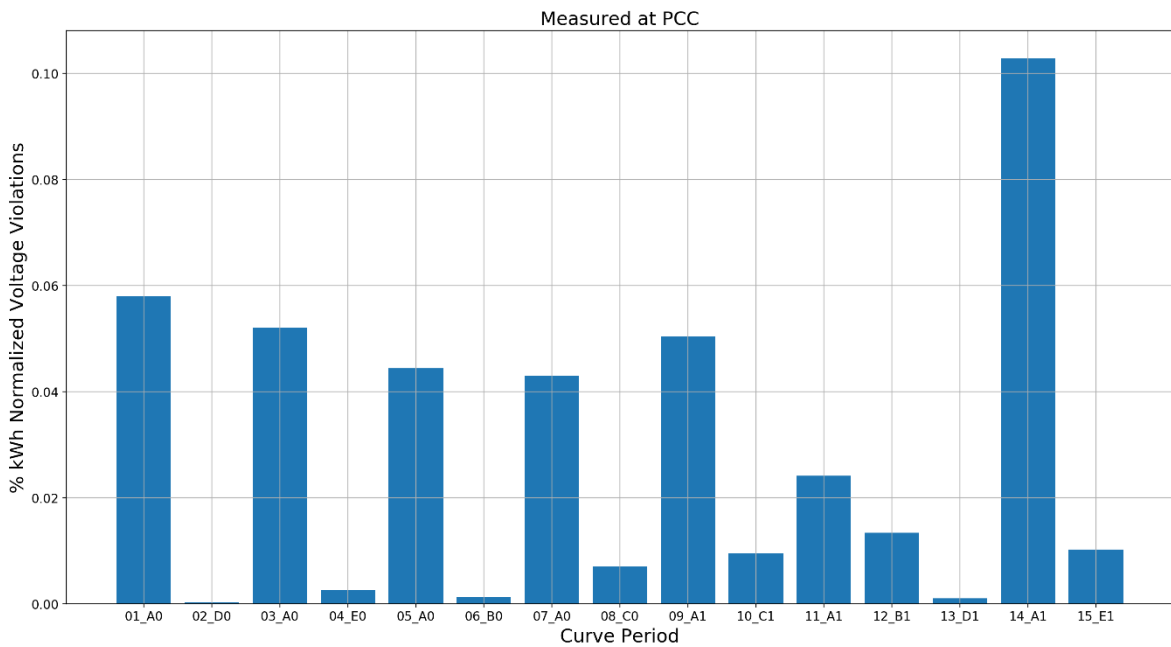
Building upon the results presented in Figure 10, Table 13 presents this analysis as a heatmap across all sites and curve periods. The heatmap includes the 10 sites in Voltage Zone E (see the discussion in the next section regarding voltage zones) that experienced voltage violations through Stage 2, and the sites are organized by decreasing site nameplate.

Table 13: Stage 2 Heatmap of Percent Reduction in Voltage Violations by Curve Set and Site

Site	Nameplate kW	% Change in $\frac{\# Voltage\ Violations}{Peak\ kW}$			
		B1	**C1**	**D1**	**E1**
SVW	620	48	76	98	87
V6A	372	98	-17	99	88
V6B	372	29	20		
LC2	264	-3	20	100	96
OR3	264	0	10	95	100
OR4	264	92	18	100	57

LC5	222	15	36		
LC4	210	39	38		
LC6	210	0	29		
J16	102	-9	-2	7	-39

The heatmap provides the following observations:

1. The site with the largest aggregate nameplate (SVW) experienced a larger effect on percent change in voltage violations when an SI Volt-Watt/Volt-VAR curve setting was active compared to when one was inactive.
2. Curve sets with more reactive power input/output had a larger effect on the percent reduction of voltage violations at the PCC.
3. Sites located at the end of the feeder experienced more voltage violations than sites closer to the feeder head.

Whereas the heatmap provides one methodology to view the change in violations from Stage 2, the following table provides another view of the same data from Stage 3.

Table 14 shows the percent of voltage violations experienced at each site organized by curve set. The sites are grouped by voltage zone and sorted by descending nameplate kW. Sites LC4 and J16 have been excluded because PQM data from this site was corrupted. Site V6A has been excluded because this site executed an incorrect curve setting for a large part of Stage 3 activities.

The sites in Voltage Zone B experienced fewer violations than those in Voltage Zone E when running no SI curve set, and no violations when executing a curve set (Figure 11 below shows the test feeder voltage zones). The sites in Voltage Zone E experienced approximately 10% voltage violations with no SI curve set, with every site showing a reduction in voltage violations when running with a Volt-Watt, Volt-VAR curve set. In the case of SVW, the largest site, the reduction in voltage violations was significant, going from 11.7% down to 0.2%. While the reduction in voltage violations was apparent in the smaller sites, the improvement was not as significant as with the largest site, suggesting that the size of the site has a direct impact on the reduction of violations.

Table 14: Stage 3 Percent Voltage Violations by Curve Set and Site, Organized by Descending Nameplate kW and Voltage Zone

Voltage Zone	Site	Nameplate kW	% Voltage Violations by Curve Set				
			A1	B1	C1	D1	E1
B	SVD	984	3.7	0	0	0	0
	GRE	264	0	0	0	0	0
	GRW	240	0.1	0	0	0	0
	VVE	132	0	0	0	0	0
E	SVW	620	11.7	0.1	0.1	0	0.2
	V6A	372	NA	NA	NA	NA	NA
	V6B	372	9.9	2.5	0.5	1.1	2
	LC2	264	7.9	6	0.1	3.2	3.5
	OR3	264	9	5.7	1.7	3.1	3.2
	OR4	264	7.7	1.8	2.3	4	0

LC5	222	8.6	5.1	1.4	4.2	2.8
LC4	210	NA	NA	NA	NA	NA
LC6	210	9.5	7.5	2.7	5.1	4.6
J16	102	NA	NA	NA	NA	NA

Figure 11: Demonstration Feeder Voltage Zones and SCADA Equipment Locations
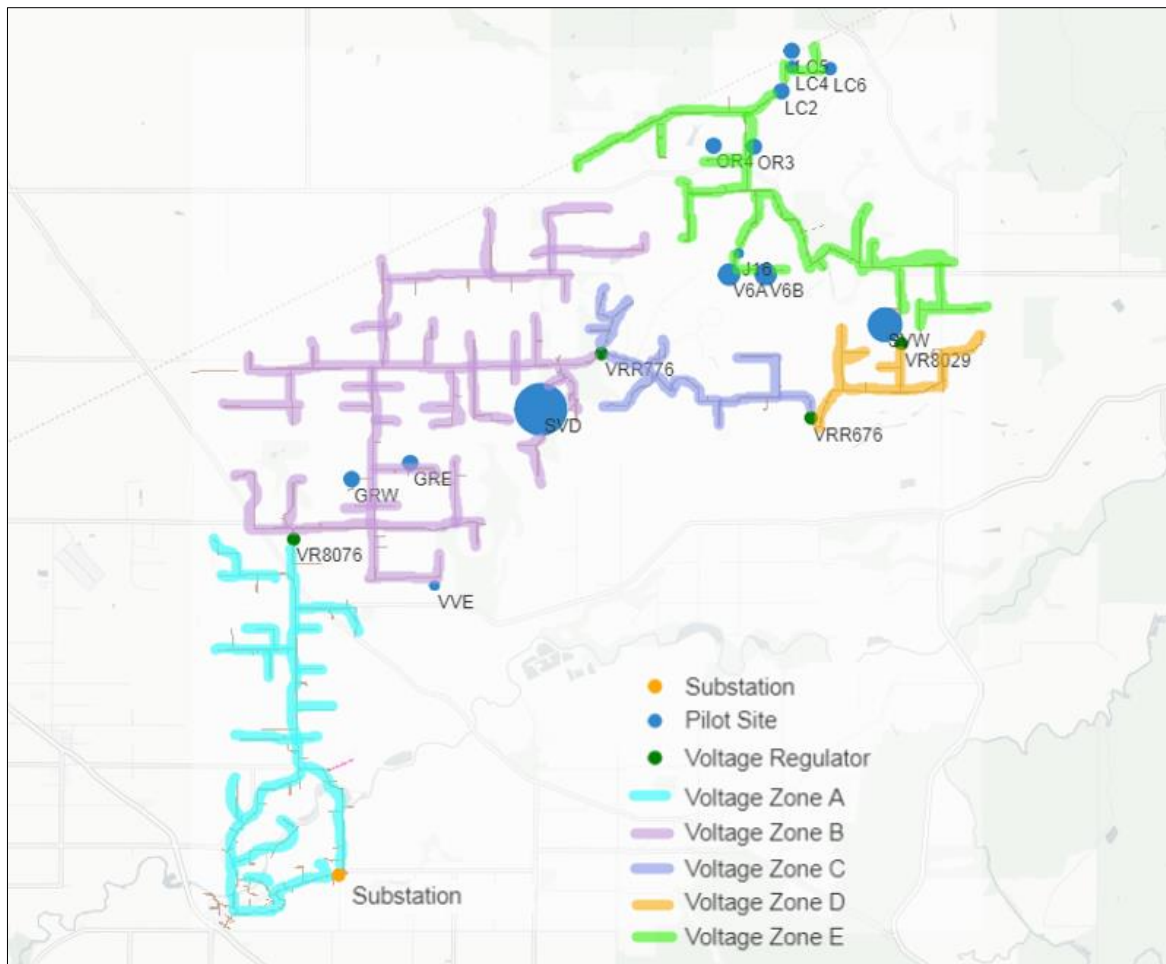
Key Learning: The SIs at a site can move secondary voltage as measured at the PCC using the Volt-VAR and Volt-Watt functions.

Key Learning: The largest PV site by aggregate nameplate experienced a more significant reduction in voltage violations with Volt-Watt/Volt-VAR deployed than sites with smaller aggregate nameplate kW.

Key Learning: The effect of Volt-Watt/Volt-VAR observed at the largest site was significant and reduced secondary voltage violations from 10% to effectively 0%.

5.1.4 UC1, Q3: SI Effect on Primary Voltage on the Feeder

Use Case 1, Question 3 investigates the impact of inverter settings on primary voltage on the feeder.

In order to study the SI effect on primary voltage on the feeder, a study of the health of feeder devices versus the timeline of the demonstration was required. The test feeder has four LR that provide 3-phase voltage and four capacitors that provide voltage on a single phase. The individual phases that these devices report is undocumented and unconfirmed. During the course of the demonstration, it was determined that three of the LRs were not configured to measure the voltage; this was corrected during the performance of the project. It was also determined that the capacitors were not reporting voltage data; this too was corrected during performance of the project. Table 15 shows the feeder devices available to the project, the device type, the voltage zone that they fell within, and the date that they were available to the project.

Table 15: Feeder Devices With Voltage Recording

Voltage Zone	Device Number	Device Type	Date Available
A	LR 9880	Line Recloser	6/22/18
B	LR 9410		6/12/18
C	LR 551990		6/12/18
E	LR 947844		1/1/18
B	C705	Capacitor	7/18/18
B	C404		7/18/18
C	C88065		7/18/18

Of the feeder devices available, only those that fell in voltage zones B and E were useful as these were the voltage zones applicable to the test sites. Table 16 shows the details for those two voltage zones.

Table 16: Voltage Zones Applicable to the Test Sites

Voltage Zone	Device Number	Device Type	Date Available
B	LR 9410	Line Recloser	6/22/18
E	LR 947844	Line Recloser	1/1/18

The timeline below shows the Phase 2 period along with the dates at which feeder devices with voltage recording became available to the project. The four sites diverted to the aggregator vendor acceptance on 6/19 all fell in Voltage Zone B and LR 9410 became available on 6/22. This effectively left LR 947844 as the only device available for studying SI effect on voltage on the feeder.

Figure 12 shows the voltage as measured at LR 947844 during hours 07:00 to 17:00 over the course of Stage 2 performance, organized by curve period. It was difficult to see any clear pattern in the feeder voltage behavior in response to either running with or without Volt-Watt/Volt-VAR or to the different curve sets.

Figure 12: Feeder Vpu as Measured by the LR in Voltage Zone E for Hours 7 to 17, Broken Down by Curve Period

LR 947844: Vpu at SCADA Device, Hours = 7 to 17
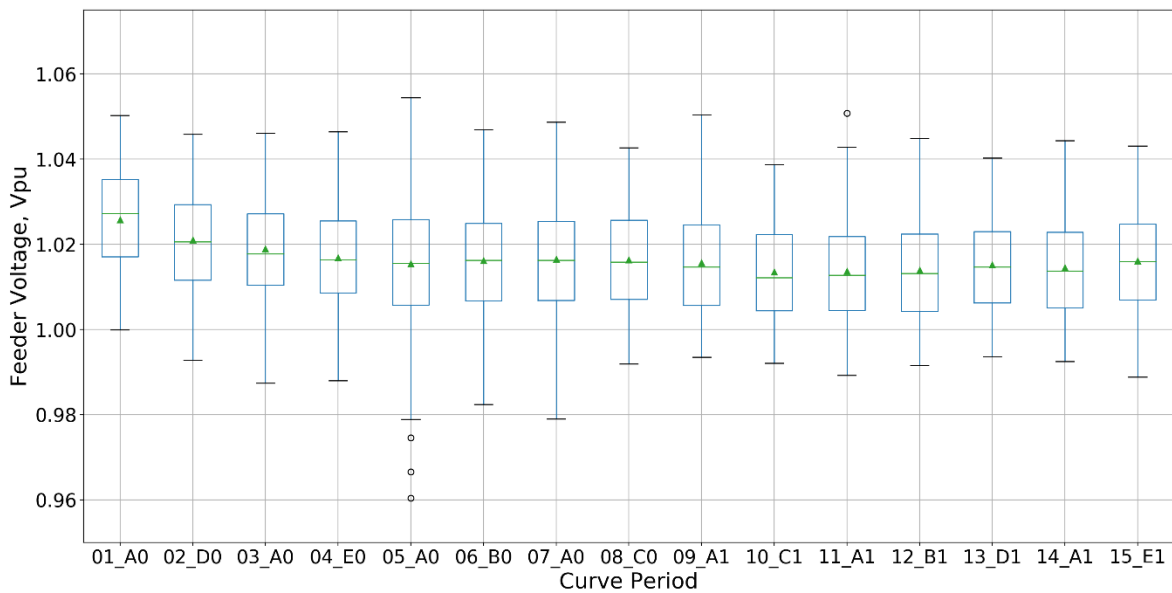
Figure 13 shows the voltage as measured at LR 947844 during hours 11:00 to 14:00 over the course of Stage 2 organized by curve period, with the intent that these would be periods of high active power generation and hence potential Volt-Watt/Volt-VAR execution. It was again difficult to see any clear pattern in the average feeder voltage behavior in response to either running with or without Volt-Watt/Volt-VAR or to the different curve sets.

Figure 13: Feeder Vpu as Measured by the LR in Voltage Zone E for Hours 11 to 14, Broken Down by Curve Period

LR 947844: Vpu at SCADA Device, Hours = 11 to 14
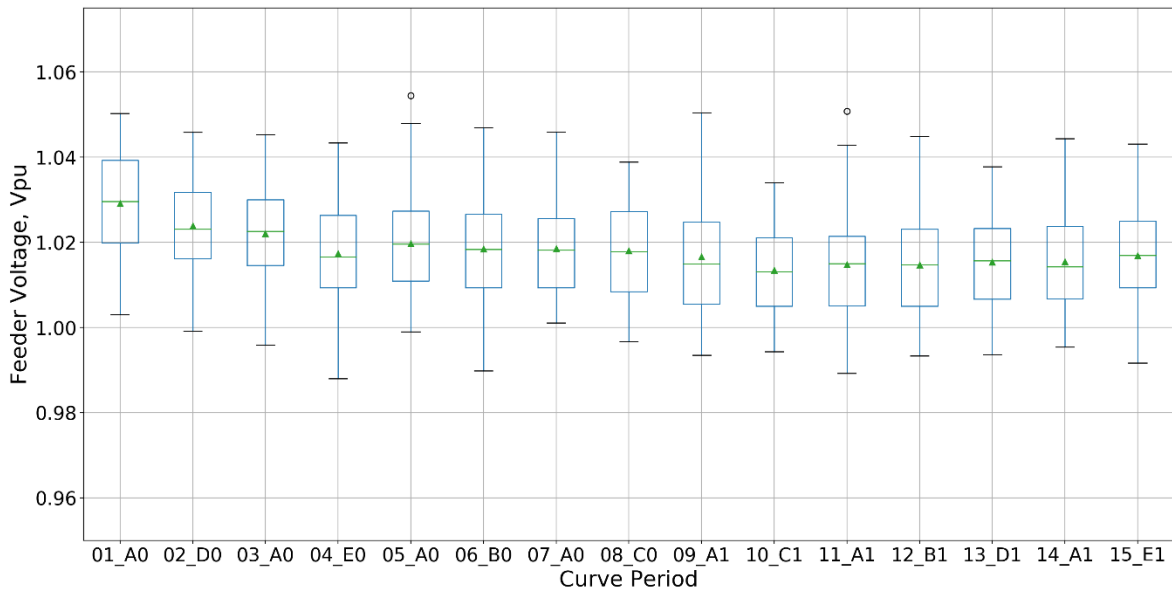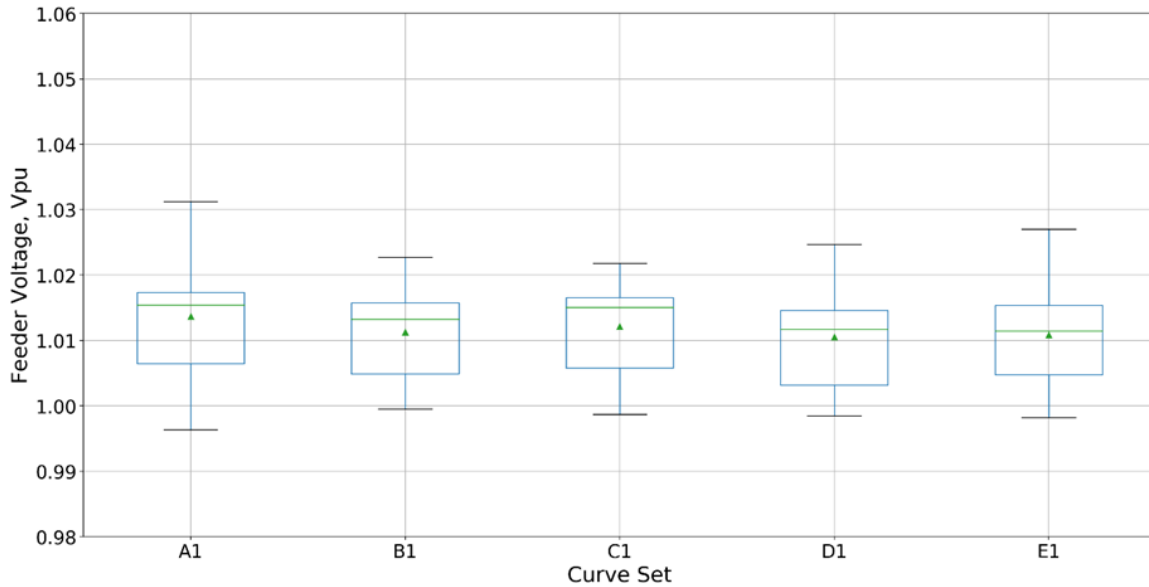
However, data from both Stage 2 and Stage 3 showed that the range voltage values (max/min) when using Curve Set A1 was larger than that experienced when Volt-Watt/Volt-VAR was in effect, indicating a potential beneficial effect of the SI curves. Figure 15 shows the voltage as measured by LR 9410 during hours 11:00 to 14:00 over the course of Stage 3, organized by curve set.

Figure 14: Feeder Vpu as Measured by the LR in Voltage Zone B for Hours 11 to 14, Broken Down by Curve Set

Key Learning: Volt-Watt/Volt-VAR did not have any clear effect on average primary voltage at the PV penetrations tested in the field.

Key Learning: Active Volt-Watt/Volt-VAR curves may have a potential beneficial effect in terms of reducing the range voltage values (max/min) on the primary relative to no active curves.

5.1.5 UC1, Q4: SI Effect on Customer Production

Use Case 1, Question 4 investigated the impact of inverter settings on customer production i.e. curtailment. Curtailment was calculated at each of the demonstration sites by comparing the total yield (Wh) as measured by the active SIs to that measured by the baseline SI, and by applying a correction factor to total yield in an attempt to normalize differences in production between the SIs. As the SIs at each site were not necessarily of the same size, the active versus baseline total yield comparison was corrected for SI size. The DC/AC ratios across all the inverters within the individual sites were constant, except for Site SVW where 1 out of the 26 inverters had a lower DC/AC ratio as compared to the other inverters. This matching DC/AC ratio meant that normalizing by inverter nameplate was appropriate. The single inverter with a lower DC/AC ratio at Site SVW was excluded from the curtailment analysis. The curtailment calculation methodology is presented below.

Each curve period was designated either as a "baseline" curve period (i.e. one in which a Volt-Watt/Volt-VAR curve was not executed) an "active" curve period (i.e. one in which a Volt-Watt/Volt-VAR curve was executed). Table 17 shows the curve periods broken down by their types.

Table 17: Curve Period and Curve Period Type

Curve Period Type	Curve Period
Baseline	01_A0, 03_A0, 05_A0, 07_A0, 09_A1, 11_A1, 14_A1
Active	02_D0, 04_E0, 06_B0, 08_C0, 10_C1, 12_B1, 13_D1, 15_E1

Certain days were excluded from the analysis. These days and the reasoning behind exclusion are documented in Table 18.

Table 18: Dates Excluded From the Curtailment Analysis and Reason for Exclusions

Dates Excluded from Curtailment Analysis	Field Situation Resulting in Exclusion
9/1, 9/2	The aggregator vendor aggregator reboot resulted in lost data from multiple sites
8/29, 9/1	Power outage occurred resulting in all inverter clients restarting

For each day within a curve period, the Wh growth [Wh] per SI was calculated by subtracting minimum Wh from maximum Wh:

$$Wh_{\Delta,day} = Wh_{max} - Wh_{min}$$

The Wh growth was normalized by SI size [Wh/W]:

$$Wh_{\Delta,day,norm} = \frac{Wh_{\Delta}}{SI_{size}}$$

Normalized Wh growth [Wh/W] was identified for the baseline SI and for the active SIs:

$$Wh_{\Delta,day,norm,baseline}$$
$$Wh_{\Delta,day,norm,active}$$

A correction factor was calculated by comparing the active SI normalized Wh growth to that of the baseline SI:

$$corr\ factor_{day} = \frac{Wh_{\Delta,norm,baseline}}{Wh_{\Delta,norm,active}}$$

The mean of the correction factors for each day across the curve period was calculated and used as that curve period's correction factor.

$$corr\ factor_{curve\_period} = \frac{\sum corr\ factor_{day}}{count\ (corr\ factor_{day})}$$

The normalized Wh growth for each SI across the curve period was calculated and corrected using the curve period's correction factor:

$$Wh_{\Delta,curve\_period,norm,baseline} = \sum Wh_{\Delta,day,norm,baseline}$$
$$Wh_{\Delta,curve\ period,corr,norm,active} = \sum Wh_{\Delta,day,norm,active} \times corr\ factor_{curve\_period}$$

Corrected, normalized curtailment relative to the baseline SI [Wh/W] was calculated:

$$Curtailment_{curve\_period,corr,norm,rel\ to\ baseline\ SI}$$
$$= Wh_{\Delta,curve\ period,corr,norm,active} - Wh_{\Delta,curve\ period,norm,baseline}$$

Percent corrected curtailment relative to the baseline SI [%Wh] was calculated:

$$Pct\_Curtailment_{corr,rel\ to\ baseline\ SI}$$
$$= \frac{Wh_{\Delta,curve\_period,norm,active} - Wh_{\Delta,curve\_period,norm,baseline}}{Wh_{\Delta,curve\_period,norm,baseline}} \times 100$$

Corrected curtailment relative to the baseline SI [Wh] was calculated by multiplying by SI size:

$$Curtailment_{corr,rel\ to\ baseline\ SI}$$
$$= Curtailment_{curve\_period,corr,norm,rel\ to\ baseline\ SI} \times SI_{size}$$

It was also observed that inverters at each site experienced periods where they tripped offline. In order to remove the skew on curtailment that an offline inverter introduced to the site calculation, inverters that recorded fewer than 95% data points as compared to the inverter with the maximum number of data points recorded over the test period were removed from consideration in the analysis. If the inverter that was offline was the site's baseline inverter, a curtailment calculation for the period being checked was not executed. If more than 50% of the inverters at a site were offline over a given curve period, a curtailment calculation was not executed.

Table 19 documents the percent curtailment experienced during Stage 3 at each site for each curve set execution.

Table 19: Stage 3 Percent Curtailment Due to Volt-Watt/Volt-VAR Execution, Presented by Site and Curve Set

Test Site	PV Site Size (kW)	% Production Curtailment by Curve Set			
		Curve B1	Curve C1	Curve D1	Curve E1
SVD	984	0.45	0.6	0.46	0.57
SVW	620	0.6	0.16	0.49	0.27
V6B	372	0.49	0.71	0.46	0.38
LC2	264	0.45	0.5	0.28	0.32
OR3	264	1.01	0.71	0.49	0.38
OR4	264	0.45	0.61	0.25	0.09
GRE	264	0.33	0.47	0.17	0.42
GRW	240	0.67	0.61	0.7	0.36
LC5	222	0.37	0.9	0.38	0.7
LC4	210	0.61	0.68	0.5	0.26
LC6	210	0.28	0.18	0.35	0.12
VVE	132	0.45	0.57	0.56	0.73
J16	102	0.66	0.6	0.53	0.71
Avg. Curtailment (%):		0.48			

Key Learning: The Stage 3 Volt-Watt/Volt-VAR settings on average resulted in less than .5% curtailment at the SIs as compared to a baseline SI running no settings for the demonstration sites, and a maximum worst-case curtailment of 1%. Stage 2 curtailment findings were nearly identical (.4% average and 1.2% maximum curtailment).

5.1.6 UC4, Q1 and Q2: Minimum Requirements for Monitoring Real and Reactive Power Production

Use Case 4, Question 1 sought to determine whether reactive power monitoring is a requirement, and if so, to determine the specific requirements surrounding reactive power monitoring. It has been clearly established in UC1, Q2 that VAR production had a measurable (and significant) impact on reducing secondary voltage violations. Measurement error for active and reactive power was specified by the manufacturer as 5% at the inverter and within 1% for each of the PQMs.

Of importance is the ability for the inverter to provide both active and reactive power levels as measured at its terminals. Not all inverter manufacturers provide reactive power output values, so having this value will significantly contribute to understanding PCC sensitivity to interconnected complex generation and loading (e.g. four-quadrant charging and discharging capabilities).

Key Learning: Minimally, requiring installed SIs to provide both active and reactive power measurements with no greater than 5% error is sufficient to understand a specific inverter's role in affecting secondary voltage at the PCC.

5.1.7 Additional Finding: Reactive Power at Night

Reactive power at night is a capability available with the SI vendors equipment and was not part of the original test plan. The ability to produce or absorb VARs at night, when PV systems are not illuminated, was deemed to be of value to the project and could have benefit to the utility. Reactive power at night utilizes a separate power supply to produce or consume VARs. Essentially, the internal power electronics generates or absorbs VARs, according to settings, to stabilize voltage. Hence, if line voltage is too low once PV production has ceased, it is possible to generate a limited number of VARs and support voltage, ideally restoring it to within range.

The reactive power at night setting was turned on via a setting change on 3/9/18 on all the sites. In Stage 2 of the demonstration, VARs at night could not be studied as reactive power from the SIs was being calculated rather than being reported by the SIs. The reactive power calculation was dependent on active power, voltage, and current as reported by the SI, and active power at night equaled zero. The project team, however, was able to review reactive power production at the sites diverted to testing the vendor-agnostic aggregator platform in preparation for Stage 3. In studying this data, it became evident that reactive power generation by the inverters was unreliable and that this feature could not be used for analysis of the system during the Location 2 demonstration.

Key Learning: While the demonstration SIs offered the option of voltage management at night using reactive power support, this feature proved to be unreliable.

5.2 Location 2 Telemetry Findings

As stated in the previous section, a number of use cases were developed as part of the Location 2 effort and these use cases, with associated questions, guided the overall project and performance of activities. Table 20 identifies the use cases as documented in the EPIC 2.03A SI Test Plan that apply to the Telemetry portion of this project. Exploration of the Telemetry use cases have been covered in fine detail in separate reports; higher-level summaries of findings follow.

Table 20: Telemetry Use Cases and Questions

Use Case # and Description	Question #	Question
UC 2: Telemetry	Q1	What is the availability of the satellite uplink/downlink to ensure continuous communications with fielded assets (are there periods were the satellite link is simply not available)?
	Q2	Does the use of satellite uplink/downlink methods impact distribution operations in any manner?
	Q3	What is the availability and reliability of the satellite uplink/downlink in terms of first packet Tx/Rx versus retransmission rates (directly impacts average latency)?
	Q4	What are the explicit minimum requirements for conveying measurements from the field to an expert system (e.g. what is the minimum acceptable frame rate)? Representative response areas include: - Requirements associated with a **minimum transmission rate** of information to a utility back-office system that requires updating every N minutes. - Requirements associated with **maximum transmission size** of information to a utility back office system.
	Q5	What are the payload size vs. costs associated with transmission of field measurements to the utility back office? Representative responses include: - General monitoring payloads average $X/MB or $Y/day of operation for N fielded assets. - Remote configuration payloads average $Z/MB or $ZZ per event for N fielded assets.
	Q6	[Monitoring] What are the link reliability requirements for providing fielded information to a utility back office system (includes end-to-end considerations; can disaggregate into individual components if necessary)?
	Q7	[Monitoring] How do we think about costs in context of this satellite telemetry platform vs. a 3rd party platform vis-à-vis hardline SCADA connectivity, etc.?

Use Case # and Description	Question #	Question
	Q8	What are minimum total latency and bandwidth requirements for assets (related to UC2 Q3 and UC2 Q4)?

Telemetry analysis focused on specific use case questions related to PG&E telemetry requirements associated with EPIC 2.03A. Telemetry in the context of this analysis refers to the collection of SI monitoring data and the setting of curves and controls that were needed for the successful performance of operational use cases. The analysis examines in detail the communication networks and their ability to satisfy the use case telemetry requirements.

Communication link performance across both cellular and satellite sites was tested towards the end of the data gathering phase of the project. Testing involved the use of both customized transport layer and standardized network layer internet control message protocol (ICMP) tools. Testing was performed on the network, transport and application layers only. Protocol analysis using a Wireshark™ type tool was done only in the laboratory and not in the field.

5.2.1 UC2, Q1: Availability of the Satellite Uplink/Downlink for Interacting With Fielded Assets?

Use Case 2, Question 1 asked to determine the availability of the communications link.
The satellite link provided almost 100% uptime during the four months of operation. However, there was a period of about 4 hours on August 15, 2018 when a satellite carrier hub went down affecting all satellite sites. Aside from this service-provider related outage, telemetry testing confirmed satellite transmission to be 100% reliable with zero packet loss and consistent throughput. PG&E developed communication monitoring tools that alerted the operator when communications went down. The operator was immediately notified when the satellite carrier hub went off line.

Communication link health is an important operational feature that should be included in any future CSIP requirements. Out-of-band methodologies need to be developed to notify operators when the communication resources go off line.

Key Learning: Before deploying future SI networks, communication availability with carrier providers should be thoroughly defined.

Key Learning: Aside from one service-provider related issue, satellite transmission was nearly 100% reliable.

5.2.2 UC2, Q2: Does the Use of the Satellite Impact Distribution Operations?

Use Case 2, Question 2 asked whether the use of satellite uplink/downlink methods impact distribution operations in any manner. Satellite communications is characterized by the complete end-to-end system configuration, and as a result, latencies additively build as additional systems are inserted in the overall path. Correspondingly, the specific use case that is being implemented by distribution operations, specifically temporal requirements of that use case, will play a key role in determining the suitability of satellite communications to provide the necessary information for operators or distribution engineers. Link latencies, buffered transmission and reception, and the inherent serialization of data will play a significant role in communicating and configuring remote assets.

Key Learning: Depending on the use case, satellite links can be a suitable option for real-time situational information from fielded assets and for real-time interaction for configuration or other control purposes but may have disadvantages relative to other communications methods (e.g. equipment costs and data plan charges- see section 5.2.5).

5.2.3 UC2, Q3 and Q6: Is Satellite Transmit and Receive Signal Quality Good? What Are Link Requirements?

Use Case 2, Question 3 asked to quantify satellite link availability and reliability and Use Case 2 Question 6 asks specifically to provide any additional reliability requirements.
In general, satellite transmit and receive quality is extremely good. 12 of the 14 project sites were linked via satellite (the other two were cellular), and communications quality was extremely reliable for the 12 sites, independent of weather or other conditions.

The satellite uplink throughput was measured at 98 kbps for a 100kB file and the downlink was measured at 304 kbps. The original uplink bandwidth was estimated at 128 kbps, which was about 25% faster than the actual measured bandwidth. Note that the measured bandwidth varied depending on the size of the data payload. The larger the payload, the greater the bandwidth throughput (to a limit).

Most of the data uses the uplink speed since the data is being transferred from the field to the utility server. The available throughput speed was adequate to handle the amount of traffic generated from the largest SI site.

The link reliability is a subset of the overall reliability requirements necessary to maintain a robust data monitoring system.

Key Learning: The satellite performance, both uplink and downlink proved to be more reliable than the cellular solution.

5.2.4 UC2, Q4 and Q8: Determine Minimum Requirements for Conveying Measurements From the Field to the Back Office

Use Case 2, Question 4 and Use Case 2, Question 8 asked to provide minimum requirements for satellite links, the latter in context of latency and bandwidth requirements.

There are several fundamental questions to ask when determining the minimum transmission rate:

- What are the transmission bandwidth options? It is important to compare advertised and actual values, as they differ.
- If the bandwidth is too small for data to be exchanged, can the speed be increased?
- How much data needs to be sent over the link?
- How much time do is available to send the data over the link?

Based upon calculations, for this specific project, the minimum bandwidth required to send all data from the largest site over a 24-hour period is 8.4 kbps. Note that traffic transmission requirements are consistent around the clock and that some data may have to get to the utility server in a specific period.

The satellite had a measured round-trip latency time of 1.8 seconds while the cellular link had a 0.2 second delay.

The bandwidth requirements are determined by the largest amount of data sent over a specific time-period and will ultimately be determined by the utilities use case requirements. For example, so not to exceed monthly data utilization limits in EPIC 2.03A, the largest data requirement occurred every two hours.

Key Learning: It is important to establish total data exchange requirements early in the project in order to determine minimum latency and bandwidth requirements.

5.2.5 UC2, Q5: Determine Costs of Satellite Utilization

Use Case 2, Question 5 asked to provide costs for telemetry using satellite systems.
Costs can be separated into fixed costs and variable costs. Fixed costs are costs associated with infrastructure – hardware, software, and tools necessary to operate and maintain the system to acceptable performance specifications. Variable costs are almost entirely attributed to data utilization – the more inverters that are in the system, the greater the overall costs for communications.

Fixed costs were not detailed on the EPIC 2.03A project because they were considered a sunk cost and would be roughly equivalent for back-office implementation, independent of the actual communications infrastructure selected.

Of particular interest to the project are variable costs, as these represent the ongoing costs associated with interacting with remote assets. The overall program utilized satellite (12 sites) and cellular (two sites) communications, for a combined monthly charge of approximately $1,300. This was based on a 3 GB/month/site uplink restriction ($100 per month per site) and unlimited cellular usage ($50 per site per month).

The cost per MB of data for all sites using both cellular and satellite for the EPIC 2.03A project was $0.63 per MB, but this is averaged across all sites, data, and variable project costs. Note that site sized ranged from 26 inverters to 4 inverters, so smaller sites will see a higher cost allocated. The best-case cost per MB for the largest 26-inverter site for cellular was $0.25/MB and $0.27/MB dollars for satellite, and for the smallest inverter site, the data cost was $1.87/MB.

Key Learning: Although satellite costs are higher than cellular costs, the margin between the two is less than $0.02/MB. Careful consideration of project requirements as well as negotiation with communication service providers could reduce the cost of satellite to below traditional cellular methods.

5.2.6 UC2, Q7: Is the Use of Satellite a Good Alternative in Context of Other 3rd Party Platforms?

Use Case 2, Question 7 asked to provide a cost comparison of the use of satellite systems to competing alternatives.

The operational use cases drive the determination of the suitability of satellite communications vis-à-vis other 3rd party communications platforms. Key to this is establishing requirements for data monitoring resolution, as indicated in the following graphic:

Figure 15: Qualitative Relationship of Data Resolution for The EPIC 2.03A Project
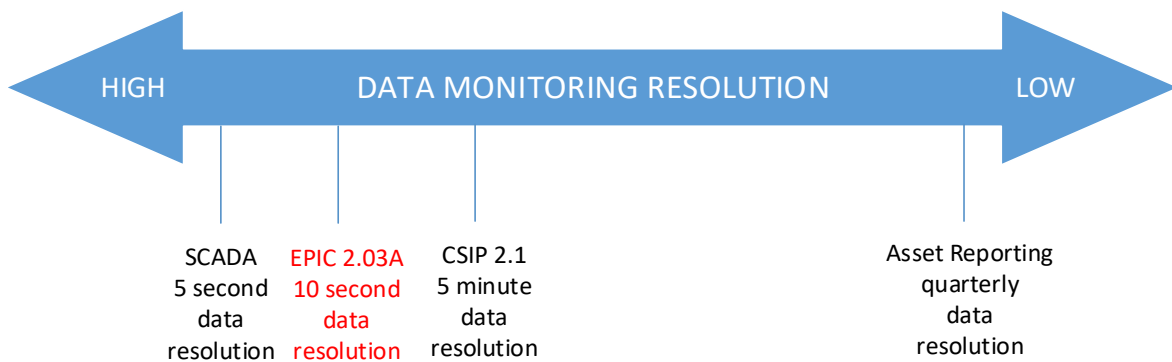
SCADA telemetry, which is characterized as a fast-acting, quasi-real-time system, brackets communications capabilities with approximately 5 seconds of measurement and reporting resolution. Latency in a SCADA system is low, and tolerance for latency is virtually zero. Contrasting, there are use cases where equipment is interfaced and only periodically sampled, often as infrequently as once per quarter of a year. The difference is important as project requirements determine the suitability of a given communications solution to address operational use cases.

In EPIC 2.03A, there was a requirement to sample, as fast as the equipment would allow, inverter voltage to detect (and report) voltage violations. While data monitoring *resolution* requirements were high, data *reporting* requirements were not as strict. To maintain monthly limits on total data utilization (limited to 3 GB/month/site for this project), data was compressed, and reporting requirements of every two hours was successfully implemented.

Key Learning: The use of any communication methodology for utility operations must be analyzed in context of data resolution (how fast to measure data), reporting requirements (how often to present data to operators, including link latencies), and constraints imposed by costs associated with total data utilization per a block of time. Use cases determine the suitability of a communications link.

5.3   Location 2 Distribution Operations Notifications Findings

The EPIC 2.03A project sought an improved understanding on how the telemetry associated with the project would affect Distribution Operations. One specific question was sought:
Use Case 3, Q1: What information is required in distribution operations related to the commanding of SI assets, or groups of SI assets, to achieve a desired outcome?
To address this question, areas of consideration with respect to Distribution Operations use cases were developed:

- Ability to configure remote assets and observe that the configurations were accepted
- Ability to interact with fielded assets as necessary (change parameters to affect a test)
- Ability to acknowledge and address alarm conditions
- Ability to visualize, in real time, production and/or simultaneous limitations of performance
- Actionable alarms for the Department of Energy or end-use stakeholders from these systems

5.3.1 Distribution Operations Smart Inverter Use Cases

The following section outlines Distribution Operations responsibilities that would benefit from visibility and configurability of SIs on the grid:

1. **Power Quality Investigations** – Distribution Operations is the first line of defense against power quality issues, specifically issues that relate to steady-state voltage, voltage fluctuation, and voltage regulating device operation. SI data and control would help Distribution Operations investigate and resolve both historic and developing power quality issues. Key benefits can be grouped into two main categories of visibility (A) and configurability (B):

   A) Visibility – When investigating a power quality issue, granular voltage data at the SI level will allow operations to observe historic voltage trends at a SI and either pinpoint it as the source of the power quality issue, eliminate it as a suspect, or isolate the issue to a specific geographic area. If available in real time, this data could be used to create alerts for emerging issues for proactive mitigation.
   B) Configurability – If a DER is causing a power quality problem for a customer or their neighbors, Distribution Operations may be able to adjust the SI's configuration to resolve the issue. This ensures that DERs are acting as good citizens of the grid. Even if the DER is not the cause, it may provide another tool for Distribution Operations to use in coordination with traditional mitigation methods, while realizing benefit from DERs.

2. **Planned Switching** – Distribution Operations is responsible for creating planned switching logs, and SIs could be an input into this work.

   A) Visibility – Distribution Operations needs to understand the loading trends of a feeder in order to plan switching and SI data would provide real time and historical insight into the SIs in the area. This visibility would also help to uncover masked load. Additionally, operations could monitor SIs during abnormal switching and receive alerts if unforeseen conditions are created.
   B) Configurability – SI settings are optimized for normal switching and may need to be adjusted during abnormal switching to avoid introducing power quality or loading issues. Such a setup could allow a SI to operate that would otherwise have to be shutoff during abnormal switching. This could be done by applying a different Volt-VAR/Volt-Watt curve or setting an active power limit to better suit the new conditions.

3. **Emergency Switching** – Distribution Operations is also responsible for emergency switching efforts and could use SIs as a resource.

   A) Visibility – It is essential for operations to be able to see what is happening on the grid in real time during emergency switching so that they can make informed decisions for safe restoration. SIs could provide valuable insight into the state of DERs on the grid.

Additionally, SI data could be used to create alerts if DERs are introducing problems in abnormal configurations.

B) Configurability – Distribution Operations need to be able to take action to address unsafe situations. In the future, they may need to be able to disable SIs on line sections that are switched abnormally to ensure safe restoration, and similar to planned switching, they may need to be able to reconfigure or curtail inverters that cause issues in abnormal switching.

In addition to supporting Distribution Operations responsibilities, SI data could improve the tools the engineers and operators use. For example, SI data would add robustness to alarm, state estimation, forecasting, and situational awareness calculations within an ADMS. Future controls and configurations of SIs are being defined and implemented through candidate distribution investment deferral projects as well as upcoming research and demonstration projects.

5.3.2 Implications for Distribution Operations and EPIC 2.03A

This project confirmed the capabilities of and uncovered the limitations of current SI technology. The following sections summarize current curve setting and alarm functionality and highlight gaps that will need to be addressed moving forward in order to enable the Distribution Operations use cases outlined above.

In this project, Volt-VAR and Volt-Watt curves were set correctly if they were scheduled in advance and restricted to a single curve per day. Actions beyond this were limited for the following reasons:

1. This project drew from the latest standards and best practices for implementation, but the project's use cases required additional functionality which resulted in a non-standard IEEE 2030.5 implementation. Satellite bandwidth limitations and cellular data restrictions required further modifications to the IEEE 2030.5 implementation for data compression purposes. Finally, non-standard Modbus configuration at the SI complicated the communications architecture design.
2. If these limitations are addressed, polling requirements and latency still impact the ability to set curves. The IEEE 2030.5 CSIP 1.0 polling interval is once per hour with curve changes limited to twice per day. Additionally, the gateway to DER control transfer specification is 10 minutes (15 minutes for aggregators). This means curves are checked for only once per hour and there is up to a 15-minute delay once a new curve is detected with a limit of two curve changes in a day. (Note: IEEE 2030.5 CSIP 2.1 updates polling from a default of hourly to every ten minutes but could be more stringent depending on a utility's interconnection requirements. This would allow more flexibility for Distribution Operations.)
3. Cellular signal strength impacted the reliability of curve setting.

These restrictions may inhibit Distribution Operations' ability to control SIs in real time in response to changing grid conditions as outlined in the initial use cases. Additionally, the following implementation recommendations were made to improve asset configuration:

1. The IEEE 2030.5 CSIP 1.0 curve overlay setting allows the utility to define a "base" curve that is reverted to in all cases. This caused unintended consequences when scheduling more than one curve in a day. For example, a curve (different from the base curve) was scheduled for a day and another curve was scheduled (days in advance in one case and day of in another case) to temporarily replace that day's set curve. Once the interrupting curve's scheduled time was complete, the "base" curve was enabled as specified in CSIP 1.0 rather than returning to the scheduled curve as the user intended. To return the curve originally scheduled for that day, it would need to be scheduled as a new curve and counts towards the twice per day curve change limit. Distribution Operations needs the ability to temporarily overlay a curve in response to changing grid conditions and will need training on how to implement it as intended using the protocol.

2. The curve acceptance implementation lacked robustness. There were cases where new curves were not implemented and remained on the previous curve set or were disabled completely. In a couple cases, the settings did not form a designated curve. Automatic retries should be built in as well as alarms and logging to for troubleshooting if unsuccessful. In general, timely notifications of curve request acknowledgement and implementation acceptance would improve user trust in the system.

This project's minimum viable product implementation had limited ability to address alarm conditions both in terms of operational alarms related to grid conditions and state of heath alarms regarding inverter functionality. Real time alarms were not available in this project's implementation. End of day logs were emailed out every day covering in detail events and alarms from that day. These logs provided valuable insight needed to resolve an issue; however, the logs were incomplete and could not be relied on in all cases because it used a RESTful polling architecture as specified in IEEE 2030.5 CSIP 1.0. In this design, the polling window is ten seconds and the Modbus is limited to one alarm in the register at a time. If multiple alarms occur during that window, only one alarm will be transmitted, and any additional alarms will be ignored. The inverters were designed with an event-based architecture where the inverter transmits the alarm when it occurs, capturing all alarms. (Note: More robust push architectures have been considered by IEEE 2030.5 but have not been enacted thus far due to potential security concerns.)

5.3.3 Distribution Operations Conclusions

This project confirmed the capabilities of current SI technology: they can be configured remotely, and they can return alarm and production information. In order for Distribution Operations to fully utilize SIs as a resource for visibility into and control of the grid, standardization limitations uncovered during this project will need to be addressed and implementation recommendations will need to be considered.

Key Learning: The project was able to configure remote assets with a single curve per day, scheduled in advance. More complex configuration was limited by cellular data and satellite bandwidth constraints and IEEE 2030.5 polling and latency specifications. Increased robustness in the implementation and clarity in curve overlay requirements would improve configuration reliability and troubleshooting capabilities.

Key Learning: End of day logs provided valuable information but were incomplete due to the polling architecture. Real time alarms were not easily interpretable, making them unactionable.

Key Learning: The project collected granular voltage and production data, but the data was not available to the end user in real time. Additionally, data gathering standards between the gateway and inverters lacked clarity.

Key Learning: If available in a timely manner, visibility of grid conditions from SI data and control of SIs to address grid issues could be an asset to Distribution Operations for power quality investigations and planned and emergency switching situations. However, utilization of this data would require grid modernization technology deployments such as ADMS and/or DERMS.

5.4   Laboratory Testing Scope and Findings

5.4.1 Laboratory Testing Scope

The following table provides an overview of tested residential SI assets and relevant outcomes associated with laboratory testing. The notes field below each table provides the overall classification of outcomes.

Table 21: Residential SI and EV Chargers Test Matrix

	Unit 1, Vendor 1	Unit 2, Vendor 1	Unit 1, Vendor 2	Unit 1, Vendor 3 SB3.8-1 SP-US-40	Unit 2, Vendor 3	Unit 1 Level 2 EVSE, Vendor 4	Unit 1 Level 2 EVSE, Vendor 5	Unit 1, DCFC, Vendor 6	Unit 1, DCFC, Vendor 7
Rule 21 Applied	1	1	2, 4	2, 7	2, 7	3	3	3	3
Volt -VAR Rule 21 Curve	1	1	2	2	2	3	3	3	3
Volt-Watt Rule 21 Curve	2, 5	2, 5	2	2	2	3	3	3	3
Volt-VAR and Volt-Watt Rule 21 Curve	2	2	2	2	2	3	3	3	3
Volt-VAR and Volt-Watt Alternate Curve	2	2	2	2	2	3	3	3	3
Harmonic Immunity	1	1	2	1, 8	2	1	1	1	1

Legend:
1. Testing completed
2. Testing not completed due to inability to complete test pre-requisite within timeline
3. Testing out of scope and therefore not applicable
4. Defective out of the box
5. Failed at 1.07% p.u. voltage
6. California Rule 21 not provided as a default configuration, instead configuration was manually applied
7. Waiting for production Rule 21 firmware/software
8. Tested using default UL 1741/210V/120V "country data set" since Rule 21 SI functions software was unavailable at the time of testing.

The following table provides an overview of tested commercial SI assets and relevant outcomes associated with laboratory testing.

Table 22: Commercial 3-Phase SI Test Matrix

	Unit 1, Vendor 1	Unit 2, Vendor 2	Unit 3, Vendor 3
Loss of Phase	1	1	1
Out-of-phase Reclosing	1	1	1, 2

Legend:
1. Testing completed
2. Rule 21 SI Functions not provided as a default configuration, instead configuration was manually applied

5.4.2 Laboratory Testing Findings/Discussion

5.4.2.1 Laboratory Smart Inverter Findings

SI lab testing was heavily hindered by SI equipment failures and poor product readiness on part of the vendors, specifically with their implementation of Rule 21 autonomous SI functions. As examples, one vendor's product was defective out of the box (would not power up) and could not be tested until a replacement was received. A second vendor's product did not function when the Rule 21 SI functions were applied, and three units from this vendor were replaced after successive electrical failure (units would not convert power and showed no error messages). As of this writing, PG&E is still waiting on the production version of Rule 21 SI functions firmware/software from this second vendor. Manufacturing defects in electrical components are suspected as the root cause. Additionally, a third vendor's product shut down at 107% Vpu although it was within the expected Volt-VAR/Volt-Watt operating curves and not outside ride through thresholds. Because of these challenges and lack of preparedness from vendors, limited harmonic and Rule 21 autonomous function testing could be performed.

Testing confirmed that SI vendor adoption and deployment of Rule 21 SI functions is still evolving. Some manufacturers have a complex field upgrade process that may not be followed by the installers, resulting in inverters not running Rule 21 SI functions. PG&E cannot verify the magnitude of this potential deficiency due to limited accessibility to SI settings in BTM field deployed units which makes lab product testing and establishment of documented processes/procedures even more critical in advance of larger scale rollouts.
With respect to out-of-phase recloser operation, for the tested models, operational units met the requirements outlined in IEEE 1547-2018, specifically: "The DER shall cease to energize and trip within 2.0 s of the open phase condition" by two of the vendors. Vendor 2's default setting was found to be set at 21 seconds and therefore, did not meet the requirements out of the box (a manufacturer factory setting issue). All three vendors' products tripped/disconnected within 0.16s (9 cycles) upon opening of the LR, preventing an unintended islanding condition being sustained.

Key Finding: PG&E presently has no methodology or authority to ensure and verify that the autonomous functions in SIs are properly configured and are operating within known parameters.

Key Finding: The 3-phase SIs tested in the lab were found to operate in accordance with standards with regard to loss of phase and out of phase recloser operation.

5.4.2.2 Laboratory EVSE Findings/Discussion

Contrasting, EV charger lab testing was more successful than SI testing as no major equipment hardware or software issues were encountered – the units tested performed relatively well to high levels of harmonics. The baseline current and voltage harmonics were well within the IEC 61000-4-13 limits for internally generated harmonics by the device under test. Two Level 2 EVSEs and two DCFCs were tested. One Level 2 EVSE vendor tolerated voltage harmonics that produced up to 18% THD while the second Level 2 EVSE vendor tolerated up to 22% THD. The two DCFCs tolerated voltage harmonics that produced up to 10% THD on 3 Phase 480V input supply. In all cases, EV chargers operated within these ranges, up to the stated limits, without any real time operating performance impact.

EVSE, when presented with abnormal line-side harmonic content, operated without error despite extraordinarily high levels of line interference. While not an exhaustive test, the line levels necessary to cause interference with charger operation are extraordinary and are not indicative of normal power quality conditions in distribution.

Key Learning: For the lab tested EV charged models, line-side harmonic interaction with proper EV charger operation did not exceed standardized limits.

5.5   Modeling Findings

High level findings:

- This modeling study was not able to demonstrate a scenario in which SIs mitigated a conventional upgrade on the primary, medium voltage system. This is likely a result of the caveats mentioned in Section 3.6 above.
- Results for the feeders studied indicate that PG&E can eliminate its voltage rise study process when Volt-VAR and Volt-Watt are activated and only replace transformers when their thermal rating is exceeded.
- HECO's Rule 14H curve was slightly more effective at mitigating overvoltages, but all three curves were on average more effective than conventional upgrades.
- The curtailment impact of the Volt-VAR and Volt-Watt functions was small, allowing them to mitigate at minimal curtailment cost the secondary system upgrades that would otherwise be a condition of PV interconnection.
- Compared to cases where conventional upgrades were performed to interconnect PV, the activation of SI functions yielded a small, but positive economic impact to ratepayers.

The six feeders were chosen due to their use in a previous project. This leveraged work already undertaken to convert the models from CYME, PG&E's primary distribution power flow simulation software, to OpenDSS. The converted feeder models did not previously have secondary, low voltage models. Since the operation of the Volt-VAR and Volt-Watt function is highly dependent on voltage measurements within the secondary system, a significant effort was undertaken to incorporate into each feeder model a representative set of secondary models and a representative set of load profiles. This additional effort resulted in over 2,000 transformers, 11,500 lines, 9,000 single customer load profiles, and 9,000 PV profiles total being incorporated into the six feeder models.

Once the feeder models were updated, the simulation portion of the study was broken into three sections--**baseline PV assessment**, **conventional upgrade analysis**, and **SI analysis**. Each of these three sections studied a wide range of scenarios including:

- 3x Load Day Types (Peak, Minimum, and Average)
- 5x PV Day Types (Summer Sunny, Winter Sunny, Overcast, Changeable, and Cloudy)
- 3x Energy Storage System Levels (0%, 20%, and 40% of PV Customers)
- 5x PV Penetration Levels (0%, 25%, 50%, 75%, and 100% of Residential Customers[38])

In all analyses, settings changes to existing voltage regulation equipment were assessed at each penetration level. Results indicated that changes to the voltage regulation settings considerably

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[38]   For example, a PV penetration of 50% on a feeder with 100 residential customers would mean that 50 of the residential customers have PV and the other 50 do not.

reduced voltage violations on all feeders. Since adding bidirectional capability is not an upgrade that can be mitigated by the Volt-VAR or Volt-Watt functions, all three analyses assumed that all voltage regulating equipment had bidirectional capability. This assumption may incorrectly suggest a high integration/hosting capacity.

In the **baseline PV assessment**, the impact of PV without conventional upgrades or SI functions was assessed. It was determined how much PV could be accommodated before violations occur. Figure 16 summarizes the results of the baseline PV assessment. While some feeders could accommodate a higher penetration level, all feeders had significant voltage and thermal violations at least at one of the penetration levels.

Figure 16: Baseline PV Assessment Results
(False Indicates No Significant Violations; True Indicates at Least One Significant Violation)

Feeder	PV Level	ES Level	Significant Voltage Violation	Overload	Feeder	PV Level	ES Level	Significant Voltage Violation	Overload
Feeder B	PV1	ES0	FALSE	TRUE	Feeder N	PV1	ES0	FALSE	FALSE
		ES1	FALSE	TRUE			ES1	FALSE	FALSE
		ES2	FALSE	TRUE			ES2	FALSE	FALSE
	PV2	ES0	FALSE	TRUE		PV2	ES0	FALSE	FALSE
		ES1	FALSE	TRUE			ES1	FALSE	FALSE
		ES2	FALSE	TRUE			ES2	FALSE	FALSE
	PV3	ES0	TRUE	TRUE		PV3	ES0	FALSE	FALSE
		ES1	FALSE	TRUE			ES1	FALSE	FALSE
		ES2	TRUE	TRUE			ES2	FALSE	FALSE
	PV4	ES0	TRUE	TRUE		PV4	ES0	FALSE	TRUE
		ES1	TRUE	TRUE			ES1	FALSE	TRUE
		ES2	TRUE	TRUE			ES2	FALSE	TRUE
Feeder L	PV1	ES0	FALSE	FALSE	Feeder S	PV1	ES0	TRUE	FALSE
		ES1	FALSE	FALSE			ES1	TRUE	FALSE
		ES2	FALSE	FALSE			ES2	TRUE	FALSE
	PV2	ES0	FALSE	FALSE		PV2	ES0	TRUE	FALSE
		ES1	FALSE	FALSE			ES1	TRUE	FALSE
		ES2	FALSE	FALSE			ES2	TRUE	FALSE
	PV3	ES0	FALSE	FALSE		PV3	ES0	TRUE	TRUE
		ES1	FALSE	FALSE			ES1	TRUE	TRUE
		ES2	FALSE	FALSE			ES2	TRUE	TRUE
	PV4	ES0	TRUE	TRUE		PV4	ES0	TRUE	TRUE
		ES1	TRUE	TRUE			ES1	TRUE	TRUE
		ES2	TRUE	TRUE			ES2	TRUE	TRUE
Feeder M	PV1	ES0	FALSE	TRUE	Feeder W	PV1	ES0	FALSE	TRUE
		ES1	TRUE	TRUE			ES1	FALSE	TRUE
		ES2	TRUE	TRUE			ES2	FALSE	TRUE
	PV2	ES0	TRUE	TRUE		PV2	ES0	FALSE	TRUE
		ES1	TRUE	TRUE			ES1	TRUE	FALSE
		ES2	TRUE	TRUE			ES2	TRUE	TRUE
	PV3	ES0	TRUE	TRUE		PV3	ES0	TRUE	TRUE
		ES1	TRUE	TRUE			ES1	TRUE	TRUE
		ES2	TRUE	TRUE			ES2	TRUE	TRUE
	PV4	ES0	TRUE	TRUE		PV4	ES0	TRUE	TRUE
		ES1	TRUE	TRUE			ES1	TRUE	TRUE
		ES2	TRUE	TRUE			ES2	TRUE	TRUE

In the **conventional upgrade analysis**, upgrade measures required to accommodate each PV penetration level were determined. On the primary system, only one upgrade was required, a new

regulator to correct primary voltage violations on one feeder. On the secondary system, service transformers were replaced when the aggregate inverter nameplate exceeded the thermal rating or, following a secondary voltage rise study, when there was potential for an overvoltage. Figure 17 summarizes the upgrade results for the secondary system, categorizing transformers replaced due to potential voltage and thermal violations. As can be seen in the figure, the conventional upgrade analysis also flagged scenarios where this existing process would miss some potential overvoltages. PG&E's existing process performs secondary voltage rise studies when the aggregate inverter nameplate is greater than the service transformers kVA nameplate, but below the thermal rating. Due to this existing process, there may be scenarios where potential overvoltages are missed as they occur before the aggregate inverter nameplate exceeds the service transformer's kVA nameplate.

Figure 17: Conventional Upgrade Analysis Results for the Secondary System

	L1	L2	L3	L4	L1	L2	L3	L4	L1	L2	L3	L4	L1	L2	L3	L4	L1	L2	L3	L4	L1	L2	L3	L4
		Burlingame				LosGatos				Middletown				Newark				Shafter				Westley		
Missed-VoltageRise	0	0	5	3	0	3	4	4	1	6	9	9	0	0	0	0	2	4	8	13	1	1	1	2
Upgraded-VoltageRise	0	3	4	15	0	1	5	4	1	0	0	2	0	0	0	0	0	0	0	4	0	0	0	1
Upgraded-Thermal	0	1	5	10	0	0	2	6	1	2	3	8	0	0	0	0	0	0	0	0	0	0	0	0
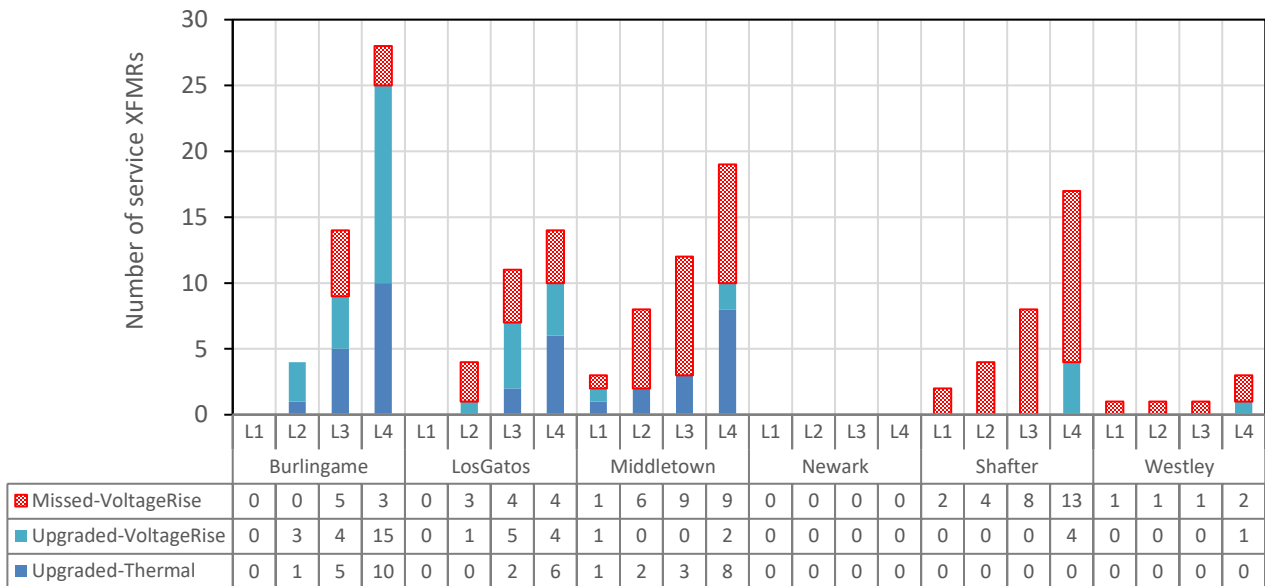
In the **SI analysis**, simulations were performed only with autonomous SI functions activated, specifically Volt-VAR and Volt-Watt. In addition to the scenarios noted on Page 105, the SI analysis also studied:

- 4x SI Densities (25%, 50%, 75%, and 100% of PV Customers)
- 3x SI Functions
  - PG&E Rule 21 Volt-VAR Only ("VV-R21")
  - PG&E Rule 21 Volt-VAR and Volt-Watt Combined ("Combi-R21")
  - HECO Rule 14h Volt-VAR and Volt-Watt Combined "Combi-R14")

Conventional upgrades were performed on the primary system when violations were identified. Similar to the conventional upgrade analysis, only one primary upgrade was required, a new regulator on one feeder. As a result, this modeling study was not able to demonstrate a scenario in

which SIs mitigated a conventional upgrade on the primary system. The only significant improvement in medium voltage overvoltage duration compared to baseline was on Feeder M and can be attributed to the installation of a new regulator. A similar improvement was seen in the conventional scenarios. This report is not stating that SIs cannot mitigate conventional primary upgrades. Instead, the previously stated caveats likely contribute to the study not being able to demonstrate a conventional upgrade mitigation.

On the secondary system when SI functions were enabled, voltage rise studies were not performed and transformers were no longer replaced on potential overvoltage. Instead, transformers were replaced only when a thermal violation occurred. Figure 18 compares the maximum number of transformers with secondary overvoltages of all scenarios and across the three different analyses. Figure 19 similarly compares the maximum secondary overvoltage. Cases with SI Volt-VAR and Volt-Watt functions enabled performed similarly to cases with conventional secondary system upgrades; however, cases with SI functions enabled required significantly less labor and capital spent to perform voltage rise studies and replace transformers on potential secondary overvoltage. Results for these six feeders suggest that PG&E can eliminate its voltage rise study process and only replace transformers when their thermal rating is exceeded. Note that PG&E can still replace transformers reactively when overvoltage violations are identified.

Figure 18: Maximum Transformer Count With Secondary Overvoltages
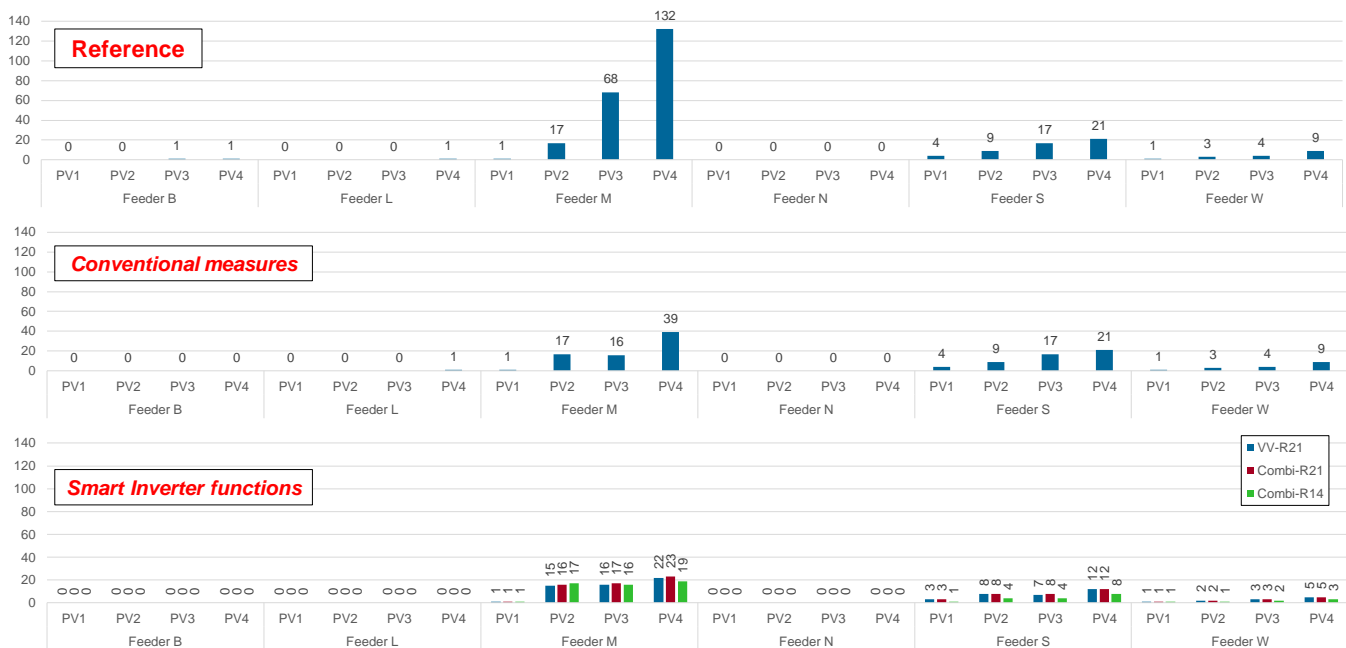
Figure 19: Maximum Secondary Overvoltage

Figure 18 and Figure 19 also demonstrate that the HECO Rule 14H curve is slightly more effective at mitigating overvoltages. Data further supporting this conclusion can be found in the modeling study's main report[39]. HECO's Volt-VAR curve's increased effectiveness over PG&E Rule 21 is likely a result of a higher maximum VAR requirement and a more aggressive slope.

The SI analysis also assessed the curtailment impact of the Volt-VAR and Volt-Watt functions. Figure 20 compares the 99th percentile individual PV system energy difference to the maximum individual PV system energy difference per feeder and SI function. 99th percentile curtailment was less than 2% and maximum energy curtailment was less than 5% across all feeders and scenarios. While this level of curtailment may seem large to PV system owners and developers, the curtailment percentage does not represent annual curtailment and is based on the worst case 24-hour scenario. For example, while the most extreme single-system, 24-hour period PV curtailment across all 8,438 residential customers resulted in a 4.83% reduction in kWh produced by the PV system, this same customer's annual PV curtailment was a 2.16% reduction in kWh produced. This demonstrates that the curtailment impact of these functions is small, allowing them to mitigate at minimal curtailment cost the secondary system upgrades that would otherwise be a condition of PV interconnection.

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[39] EPIC 2.03A modeling report 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.

Figure 20: 99th Percentile and Maximum Energy Difference Per SI Function
(Results Based on the Single Worst Case 24-Hour Period)
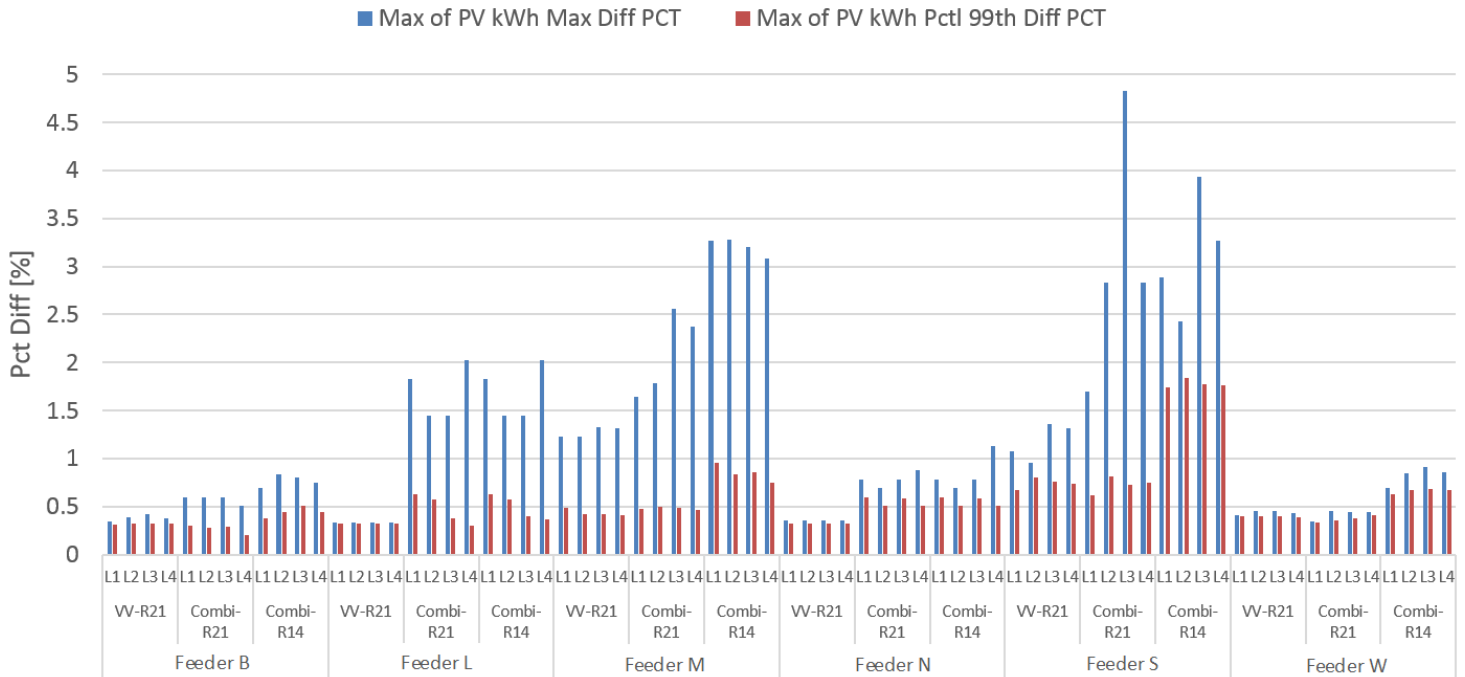
The economic analysis looked at four cost categories—increased electricity cost, bill increases to customers (curtailment), avoided replacement of service transformers on potential overvoltage, and avoided voltage rise studies. These cost categories were applied to four different cost tests. Compared to cases where conventional upgrades were performed to interconnect PV, the activation of SI functions yielded a small, but positive economic impact to ratepayers. This means that any bill increases to customers was less than the avoided cost of service transformer upgrades and voltage rise studies. While inverter utilization was not a cost category that was quantifiable within the scope of this project, increased inverter utilization was also analyzed and found to be negligible.

Overall, this study successfully demonstrated the effectiveness of the SI Volt-VAR and Volt-Watt function at mitigating secondary system upgrades for residential PV systems. Labor and capital attributed to secondary voltage rise studies and any associated transformer upgrades can be mitigated at minimal cost. While a scenario in which a primary system upgrade was not demonstrated, mitigating the secondary system upgrades allows PV systems to interconnect at a reduced cost to ratepayers and PV system owners. Future work in the area of this study could look into 1) use cases involving the control of SIs, 2) expanding the study to a more representative set of feeders or begin piloting the new approaches identified, and 3) expanding the study beyond just residential customers. When considering these future areas, it is important to consider whether they should be done through another modeling study or with a field pilot.

Key Learning: This modeling study was not able to demonstrate a scenario in which SIs mitigated a conventional upgrade on the primary, medium voltage system. This is likely a result of the caveats outlined in section 3.6.

Key Learning: Results for the feeders studied indicate that PG&E can eliminate its secondary voltage rise study process for residential projects when Volt-VAR and Volt-Watt are activated and only replace transformers when their thermal rating is exceeded.

Key Learning: HECO's Rule 14H curve was slightly more effective at mitigating secondary overvoltages, but all three curves were on average more effective than conventional upgrades.

Key Learning: The curtailment impact of the Volt-VAR and Volt-Watt functions was small, allowing them to mitigate at minimal curtailment cost the secondary system upgrades that would otherwise be a condition of PV interconnection.

Key Learning: Compared to cases where conventional upgrades were performed to interconnect PV, the activation of SI functions yielded a small, but positive economic impact to ratepayers.

5.6   Integrated Voltage Regulation

The field and modeling components of the EPIC 2.03A project have highlighted the important role SIs and specifically the role that the Volt-VAR function[40] will play in utility voltage regulation going forward. While the Volt-VAR function is an important component of voltage regulation, the project has also highlighted that SIs should be viewed as one component of a larger strategy referred to as **integrated voltage regulation**. Substation LTCs, distribution line regulators, distribution capacitors, and SIs all provide both overlapping and unique value to voltage regulation on the utility distribution system. The sum of these different devices optimized together is greater than the capabilities of the individual parts.

Distribution voltage regulation is managed today through autonomous settings on LTCs, regulators, and capacitors. Planning studies are performed on an annual basis and the critical points in time and/or loading are identified. These critical points are used to develop autonomous LTC, regulator, and capacitor settings. In the future, distribution voltage regulation will be managed through a combination of autonomous settings and active control[41], both based on Quasi-Static Time Series (QSTS) analysis and real time operating conditions. Active control decisions will likely be made through an ADMS-based[42] VVO platform combined with SCADA-enabled voltage regulating devices. Such a platform will control the present operating state of voltage regulation equipment or their autonomous settings.

The points below highlight key learnings from the EPIC 2.03A project that will inform future voltage regulation strategy.

1. LTCs, regulators, and capacitors remain the most effective devices at regulating the primary, medium voltage distribution system. SIs, due to their location at the grid edge, have been found to be effective in regulating the secondary, low voltage distribution system.[43]

2. There exists a push and pull in how these devices interact. SI reactive power consumption is necessary to reduce and avoid high voltage violations. This may increase the need for

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[40]   The SI Volt-Watt function is viewed a protective function to prevent overvoltages before an inverter trips offline. It is not viewed as a voltage regulation function.

[41]   This project did not answer any questions related to active control of SIs. However, in the future, some SIs will be actively controlled through ADMS and DERMS platforms.

[42]   PG&E filed its 2020 GRC on December 13th, 2018. Chapter 19 on the Integrated Grid Platform Program and Grid Modernization Plan requests funding to implement an ADMS platform. The program also requests funding to expand PG&E's communication infrastructure to support the increased deployment of SCADA-enabled devices.

[43]   Both the modeling and field components of the study showed that, while the SI functions had a minimal impact on the primary system, they did have a material impact on the secondary system.

capacitors to offset SI reactive power consumption. LTCs and regulators are necessary to provide voltage headroom for the operation of both the capacitors and SIs. If this higher-level strategy is not considered, these devices may end up fighting with each other. Instead, the settings of these devices need to be optimized to work in concert as a part of integrated voltage regulation.

3. SI Volt-VAR and optimizing autonomous voltage regulator settings both reduce the number of high voltage violations. If only one type of device is considered, the optimal, most effective solution will likely not be achievable.[44],[45]

4. Integrated voltage regulation involves changes in the autonomous setting strategy of traditional voltage regulation.

    a. LTCs and regulators need cogeneration capability with reverse power settings that provide voltage headroom. This is done by setting a lower base voltage and using inverse resistive compensation[46]. Just as primary voltage drop is considered in the forward direction, primary voltage rise needs to be considered in the reverse direction. Additionally, the interaction between multiple stages of regulation needs to be considered in the voltage regulation design of both directions.

    b. As the daily voltage profile of high penetration circuits becomes increasingly dependent on solar output, switching capacitors on time and voltage may be inadequate in regulating voltage. Additionally, switching on reactive power may not be an appropriate capacitor switching strategy when there is a high penetration of inverters.[47] Capacitors need the updated capability to switch on directional active power and/or directional current.

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[44] The field component of this study demonstrated that small changes to the cogen settings of voltage regulating devices could reduce primary voltage violations. In the modeling component, EPRI states in their final report that "Such manual setting changes, relatively cost-effective to perform since they leverage existing feeder voltage regulation equipment, can be very effective at addressing adverse voltage impacts caused by PV".

[45] EPRI found that the two critical 24-hour periods that influenced voltage regulation settings the most were peak load/peak generation and minimum load/peak generation.

[46] The modeling component of the project identified that, when developing cogeneration regulator settings, the changes were more dependent on the voltage base and less dependent on resistive and reactive compensation. This is likely due to the distribution of generation being similar to the distribution of load in the modeling component of this study.

[47] Several capacitors on the feeder in the field demonstration had a reactive power switching strategy and are used for both voltage and reactive power support. On high penetration feeders, the voltage profile becomes increasingly dependent on the active power profile of the circuit. With a reactive power switching strategy, capacitors do not necessarily turn on and off at the right times for voltage support.

    c.   Determining the autonomous settings of LTCs, regulators, and capacitors will become increasingly complex and rely more heavily on QSTS simulations to develop the optimal autonomous settings. This project has highlighted that, after overcoming this complexity, some distribution circuits can handle a high penetration of inverters by only adjusting the settings on existing equipment.

5.   While optimizing autonomous voltage regulator settings reduces the number of voltage violations, some modeling results suggest that an ADMS-based VVO platform combined with SCADA-enabled voltage regulating devices may be able to further reduce voltage violations by actively managing voltage regulation equipment. Notable scenarios of VVO benefit include:

    a.   At a more fundamental level, the autonomous settings of SCADA-enabled voltage regulating devices can be more actively managed compared to those that are not SCADA-enabled. For example, voltage regulators today only have a forward and reverse or cogen setting. Remote settings management could allow a voltage regulator to have a multiple forward, reverse, and cogen settings. This would enable a regulator to be run in reverse by both DERs or abnormal switching. Advanced remote settings maintenance decisions can also be made in real time or seasonally to tune the distribution voltage profile.

    b.   When the circuit's voltage profile shows an opportunity to eliminate a voltage violation, but any change to autonomous settings would increase the number of violations at other times of day or year. For example, a settings change solves the one voltage violation while creating two more violations at a different point in time. A VVO platform would allow for the one violation to be corrected without creating more violations at other times.

    c.   When voltage violations would otherwise occur when a voltage regulator transitions from forward mode to cogeneration (reverse) mode, and vice versa. For example, the autonomous settings that eliminate the violation may be the forward settings, but the load profile has not quite changed enough and is still operating in cogeneration mode. A VVO platform does not have to rely on forward or reverse autonomous settings. Instead, the platform would determine the regulator tap position that results in the least number of voltage violations for that point in time.

Traditional voltage regulation needs to evolve, and SIs are an important tool within integrated voltage regulation. When paired with updated capabilities and optimized settings to traditional voltage regulation equipment, the optimal voltage regulation solution is achievable in the distribution grid that is becoming increasingly bidirectional.

6   Value proposition

The purpose of EPIC funding is to support investments in technology demonstration and deployment projects that benefit the electricity customers of PG&E, San Diego Gas & Electric Company, and Southern California Edison Company. Project 2.03A, Test SI Enhanced Capabilities – PVs, successfully tested and demonstrated the use of customer-sited SI technologies and communication infrastructure to provide local grid support to lessen the impacts related to high DER penetration and to potentially facilitate the continued growth and integration of DERs. The project also evaluated SI performance in a lab setting and carried out a modeling study to assess the economics of using autonomous SI functions vs. traditional distribution upgrade measures to address impacts related to high PV penetration.

6.1 Primary Principles

The primary principles of EPIC are to invest in technologies and approaches that provide benefits to electric ratepayers by promoting greater reliability, lower costs, and increased safety. This EPIC project contributes to these primary principles in the following ways:

- **Greater reliability**: EPIC 2.03A explores SI capabilities to improve grid reliability by mitigating the impact of renewable resources on secondary (Location 1) and primary (Location 2) system voltage. As of this writing, PG&E has interconnected a total of 390,000 retail BTM PV sites and is adding an average of 5,000 additional sites every month. In its current form, today's grid—especially its distribution system—was neither designed nor equipped to accommodate such a high penetration of DER while sustaining high levels of electric quality and reliability. PG&E forecasts that by 2021, roughly half of all BTM PV in California will be equipped with SIs and predicts nearly 100% SI penetration in California by 2028. Since most of the early PV inverter deployments did not have SI capabilities, the proportion of PV inverters with intrinsic functions, initially starting low, will progressively grow over time as older inverters are retired and new SIs are interconnected This growing penetration of SI-enabled DER presents an opportunity to use advanced SI functions to proactively address these DER-caused reliability issues.

- **Lower costs**: Conventional mitigation measures (transformer upgrades, reconductoring, additional voltage regulation equipment, etc.) provide a possible path towards accommodating more distribution-connected DER in PG&E's service territory. CPUC Electric Rule 21 mandating the use of SIs with autonomous functions provides new, alternative solutions that may perform equally well with potential for improved ratepayer benefits. Specific 2.03A activities targeting cost reductions included 1) the Location 2 field demonstration, which evaluated SI ability to help mitigate voltage problems resulting from high PV penetration on a distribution feeder and 2) the modeling study, which performed an economic analysis of SI capability vs. traditional grid upgrades across multiple PG&E distribution feeders and evaluated the potential to update PG&E standards for performing voltage rise studies when new BTM DERs are interconnected.

- **Increased safety and/or enhanced environmental sustainability:** SIs can help to better integrate renewables, and, therefore, advance California energy policy to increase the amounts of renewable and distributed generation on the grid. By assessing SIs' ability to address DER-caused voltage issues through both the Location 2 field demonstration and modeling, this technology demonstration has shed light on SIs' potential to increase hosting capacity, potentially allowing for faster and more affordable interconnection of additional DERs onto PG&E's distribution system. Additionally, lab testing activities evaluated SI responses to extreme grid conditions, which may result in updates to SI standards.

6.2   Secondary Principles

EPIC also has a set of complementary secondary principles. This EPIC project contributes to the following four secondary principles: societal benefits, greenhouse gas (GHG) emissions reduction, and low-emission vehicles/transportation.

- *Societal benefits:* By evaluating SIs' potential to cost-effectively mitigate power quality issues caused by high DER penetration, this project supports California's clean energy policy goals and advances PG&E's mission to "reliably deliver affordable and clean energy to our customers...while building the energy network of tomorrow."

- *Greenhouse gas (GHG) emissions reduction*: SI technologies can help integrate more renewable resources while enhancing the reliable operation of the grid, resulting in fewer fossil-fuel plants required to remain online. By reducing fossil-fuel generation, there will be a reduction in emissions from the residual fossil-fuel fleet, including GHG emissions.

- *Low-emission vehicles/transportation*: EVs and their infrastructure are becoming an increasingly significant source of DERs on the grid. By evaluating the behavior of electric vehicle chargers when presented with abnormal line-side harmonic content, this project evaluated potential safety and reliability concerns of EV chargers operating on distribution circuits having high penetration of PV and other harmonic-generating equipment.

- *Efficient use of ratepayer funds*: The project performed an economic analysis of SI functions vs. traditional distribution grid upgrades to mitigate issues caused by high DER penetration. As a result, the recommendation has been made that PG&E eliminate its secondary voltage rise study for some new DER interconnections, which, if implemented, would result in a small but positive economic net benefit to PG&E's customers.

7 Accomplishments and Recommendations

7.1 EPIC 2.03A Key Learnings and Recommendations

The following are the key lessons learned in the Location 2 field demonstration, the SI lab testing, and in performance of 3rd-party modeling activities:

1. **SIs can enable BTM PV to help with local secondary voltage support through autonomous real (Volt-Watt) and reactive (Volt-VAR) power support. Volt-Watt/Volt-VAR did not have any clear effect on average primary voltage** (Key Objectives A and D).
   - In this demonstration, SIs showed an impact to voltage on the secondary system, resulting in fewer voltage violations[48] correlated with high PV penetration on the test feeder.
   - Properly configured SIs successfully executed the Volt-Watt and Volt-VAR curve settings within tolerances, with a negligible percent of data points falling outside the tolerances.
   - Volt-VAR curve sets with greater reactive power absorption had a larger effect on the percent reduction of secondary voltage violations at the PCC.
   - The site with the largest aggregated nameplate kW/kVAR experienced a more significant reduction in voltage violations with Volt-Watt/Volt-VAR deployed than sites with smaller aggregate nameplate kW/kVAR.
   - The effect of Volt-Watt/Volt-VAR observed at the largest site was significant and reduced secondary voltage violations from 10% to effectively 0%.
   - **Recommendations:**
     - For Volt-Watt and Volt-VAR implementations, larger SI-enabled PV sites will provide greater ability to affect voltage on the secondary at the PCC, all other parameters remaining constant.
     - Additional characterization of the size of the SI-enabled PV site relative to feeder characteristics, including net loading levels at the PCC, should be performed.

2. **Technical evidence from field and lab testing suggests that certain aspects of SI configuration and performance require further testing and development to ensure that manufacturers comply with standards and SI certification procedures.** (Key Objectives A, D, E).
   - While the SIs used in the field demo offered the option of voltage management at night using reactive power support ("VARs at night"), this feature proved to be unreliable due to implementation inconsistencies by the inverter manufacturer[49].

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[48] A voltage violation is defined as voltage above 105% or below 95% of nominal voltage. CPUC Rule 2 describes electric service requirements, which includes the acceptable secondary voltage ranges of electric service to electric customers.

[49] At the time of the project, the "VARs at Night" function was not a requirement for the project nor was it required per California Rule 21. The working implementation utilized the inverter manufacturer's

- o Individual SIs within a field site did not always execute the curve set that was deployed via the aggregation platform and occasionally reported incorrect curve settings, largely due to synchronization and command verification issues.
- o Lab testing[50] confirmed that SI vendor adoption and deployment of Rule 21 SI functions is still evolving. Some manufacturers have a complex field upgrade process that may not be followed by the installers, resulting in inverters not running Rule 21 SI functions, or possibly running the functions but with improper settings.
- o SI lab testing was heavily hindered by SI equipment failures and poor product readiness on part of the vendors, specifically with their implementation of Rule 21 autonomous SI functions. For example:
  - One vendor's product was defective out of the box (would not power up) and could not be tested until a replacement was received.
  - A second vendor's product did not function when the Rule 21 SI functions were applied, and three units from this vendor were replaced after successive electrical failure (units would not convert power but showed no error messages).
  - A third vendor's product shut down at 107% p.u. voltage although it was within the expected Volt-VAR/Volt Watt operating curves and not outside ride-through thresholds.
  - Despite the fact that tested SIs were certified to UL-1741 SA, it is possible that manufacturing or quality control issues were responsible for the observed performance issues out of the box.
- o **Recommendations:**
  - Improved manufacturer product documentation and standardization of SI feature names and local user interfaces is needed to facilitate proper configuration during installation and commissioning.
  - Standardization of SI feature names and functions across inverter manufacturers would significantly facilitate verification of configuration. Vendor-specific implementations are not scalable to system-wide operations with the current configurations available from inverter manufacturers.
  - "VARs at Night" behavior was not comprehensively tested due to an inability of the field SI models to consistently apply the setting, and future work should include evaluation of "VARs at Night" capabilities.
  - SI vendor preparedness regarding Rule 21 Phase 1 Autonomous Function implementation needs improvement. Further progress needs to be made

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proprietary site controller and not the IEEE 2030.5 controller developed for this project. Consequently, full compliance testing using this function was not performed by the SI manufacturer and field performance was not guaranteed during the project time period.

[50] As opposed to field testing, which used inverters that were manufactured prior to Phase 1 Rule 21 requirements (and were thus not certified to UL-1741 SA).

on capabilities to automate verification of deployed SIs against expected configurations so that the last known state of PV and energy storage inverter assets can be determined.

3. **The aggregation platforms and communication infrastructure used to integrate SI-enabled DERs are as critical as the DERs themselves, if DERs are to be reliably deployed for active control use cases by distribution grid operations** (Key Objectives C and D).
   o Issues related to gateway firmware, vendor aggregators, and cellular carrier communications adversely affected system reliability as well as the ability to consistently apply settings changes to SIs as well as to receive DER data back from SI assets in the field. The project developed customized tools to mitigate system failure and increase system reliability over time.
   o In this project, satellite communications proved significantly more reliable than cellular communications.
   o In this project, carrier (satellite and cellular) loss of communication issues were minimal in relation to other system issues such as aggregation platform firmware/software issues.
   o Round-trip latency for cellular communications averaged 0.2 seconds, and 1.8 seconds for satellite.
   o **Recommendations:**
     ▪ Tools to identify and mitigate system failure (to increase end-to-end system reliability) need to be developed to have a situational view of individual assets, aggregations of assets, interconnected communication pathways, and back-office server-side processing. Scalability will require the ability to identify and correct the offending assets when site performance is less than optimum.
     ▪ Degraded communication link quality testing should be included as part of any EIC process for SI-enabled DER aggregations to determine the robustness of controls, data and alarms.
     ▪ More reliable communications behavior needs to be specified by the utility and implemented by aggregation platforms regarding the sending of commands to fielded assets, the response of fielded assets to those commands, and verification of actual configuration against expected configurations.
     ▪ Cybersecurity standards are critical and need to be adopted by the industry and integrated into relevant communication standards for SI interconnection.

4. **There is not yet an off-the-shelf SI vendor-agnostic aggregation solution that allows seamless interoperability between DERs, aggregators, and utilities. Aggregation platforms will need to be tailored and customized to specific DER communication infrastructure and DER use cases** (Key Objectives C and D).

- o This project drew from the latest standards and best practices for implementation[51], but the project's use cases required additional functionality above existing standards which resulted in a non-standard IEEE 2030.5 implementation.
- o Customization of software and firmware was required by all parties to reach a fully functional end-state: the SI manufacturer (SI firmware), PG&E (data analysis and verification of SI function activation), aggregation platform vendor (on-site gateway firmware and aggregator server software).
- o Satellite bandwidth and monthly usage limitations and cellular data usage restrictions required further modifications to the IEEE 2030.5 implementation, resulting in novel data compression techniques.
- o Non-standard Modbus configuration at the SIs complicated the communications architecture design.
- o Despite lab testing that was performed by the aggregation platform vendor, the as-deployed aggregation firmware required many iterations of updates to attain reliable operation, significantly delaying the project timeline.
- o **Recommendations:**
  - Although approved industry standards will always lag new implementations of technologies, technical implementation of standards to address use cases needs to be planned with all stakeholders and should include the inverter manufacturer, communications representatives, aggregation platform developers, and communications security personnel.
  - Laboratory testing by aggregation platform vendors in a configuration that represents fielded assets should continue to be a priority for fielded deployments.

5. **While the SI Volt-VAR and Volt-Watt functions are an important component of voltage regulation, the project has also highlighted that SIs should be viewed as one component of a larger strategy referred to as integrated voltage regulation** (Key Objectives A and D).
   - o Traditional utility equipment such as substation LTCs, distribution line regulators and distribution capacitors remain the most effective devices at regulating the primary, medium voltage distribution system. SIs were shown to be effective in regulating the secondary, low voltage distribution system.
   - o The sum of all of these different devices optimized together is greater than the capabilities of the individual parts.
   - o **Recommendations:**
     - Further work should be conducted to better understand the impact of SI Volt-Watt/Volt-VAR performance in context of location of the asset, or grouping of assets, within a voltage zone. The location of the SI PCC on

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[51] Standards referenced in the design and execution of this project included the IEEE 2030.5 communication protocol, SunSpec Common Smart Inverter Operating Profile (CSIP), IEEE 1547, and UL 1741-SA.

the voltage profile within a voltage zone is not yet well understood and most likely has an impact on SI performance on secondary voltage.

- Interoperability of SIs within an ADMS-enabled VVO platform combined with SCADA-enabled voltage regulating devices should be examined in greater detail. As an example, adjustment of autonomous voltage regulation settings may not solve for all voltage violations in higher penetration scenarios.

11. **Curtailment of customer generation due to activation of Volt-VAR and Volt-Watt functions on a test feeder with persistent voltage violations and via the SI modeling study was found to be minimal** (Key Objectives B and F).
    - The SI Stage 2 & 3 field testing of Volt-VAR/Volt-Watt settings on average resulted in 0.4% curtailment at the SIs as compared to a baseline SI running no Volt-VAR/Volt-Watt settings for the demonstration sites.
    - In the SI modeling study, active power curtailment resulting from the activation of SI functions appeared extremely limited: across all combinations of feeders, functions, inverter densities, and PV and load conditions considered, only 45 of the 8,414 PV installations modeled experienced active power curtailment greater than 1% across any of the analyzed 24-hour periods[52].
    - In both the field testing and SI modeling study, activation of SI functions resulting in curtailment was primarily due to elevated voltage from high PV penetration on the feeder(s) and not from pre-existing voltage issues.

12. **Capabilities provided by grid modernization technology deployments such as ADMS and DERMS could allow SI-enabled DERs to provide distribution grid services beyond autonomous SI functions, and to provide value to Distribution System Operations** (Key Objective D).
    - Robust operator feedback mechanisms, such as knowing the status of what SI curve is deployed, whether it is active, and other control settings along with the integrity of the incoming data, were paramount to the success of the SI field demonstration.
    - **Recommendations:**
        - To be actionable by a Distribution Operator, SI data needs to be reliable, timely, and integrated into the context of dynamic Distribution System states via grid operator tools and platforms.
        - Utility operational capabilities and systems that automatically analyze grid conditions, determine optimized solutions, and communicate signals to aggregators and SI-enabled DER assets are needed to enhance the value of DERs to the grid.

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[52] SI Modeling studies by HECO (https://bit.ly/2NwauUD) and Duke (https://bit.ly/2IK186M) found similarly small amounts of curtailment resulting from Volt-VAR and Volt-Watt function activation.

13. **The 3-phase SIs tested in the lab were found to operate in accordance with standards with regard to loss of phase and out of phase recloser operation** (Key Objective D).
    o Testing revealed that the lab-tested SIs met the requirements outlined in IEEE 1547-2018, specifically sections pertaining to ride-through of high/low voltage disturbances and consecutive high/low voltage disturbances.
    o All three vendors' SI products tripped/disconnected within 0.16s (9 cycles) upon opening of a LR, within IEEE 1547-2018 requirements.

14. **For the lab tested EV charger models, line-side harmonic interaction with proper EV charger operation did not exceed standardized limits** (Key Objective E).
    o EVSE, when presented with abnormal line-side harmonic content, operated without error despite extraordinarily high levels of line interference, well in excess of limits established by IEC 60204-1, IEC 61000-4-13, and with respect to guidance provided by IEEE 1547-2018 section 7.3.
    o Although laboratory test equipment limitations precluded extremely high levels of harmonic injection (e.g. beyond 20%), harmonic levels as stipulated by IEC 60204-1, IEC 61000-4-13, and IEEE 1547-2018 were easily met by installed test equipment and levels stipulated by the standards (< 4% for all harmonics) were successfully met.

15. **A modeling study[53] on six PG&E distribution feeders showed that using autonomous SI functions to mitigate the grid impacts of high PV penetration yielded a small, but positive economic impact for ratepayers ("total ratepayer cost") compared to cases where conventional secondary system upgrades were performed to address voltage violations from high PV penetration** (Key Objective F).
    o The modeled use of autonomous SI functions was shown to reduce, but not entirely suppress overvoltage conditions arising from high PV penetration. The reduction observed was generally comparable, and sometimes superior to the level of performance obtained with conventional upgrades such as new secondary (service) transformers.
    o The SI modeling study was not able to demonstrate a scenario in which autonomous SIs mitigated a conventional upgrade on the primary, medium voltage system.
    o The benefits of activating autonomous SI functions generally increased at higher PV penetration levels, due in part to a reduction in count of replacement of service transformers and elimination of voltage rise studies.

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53   EPIC 2.03A modeling report 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

- o HECO's Rule 14H curve was slightly more effective at mitigating over-voltage conditions, but all three curves were on average more effective than conventional upgrades.
- o **Recommendations:**
  - Results for the modeled six distribution feeders indicate that PG&E can eliminate its secondary voltage rise study process for residential projects when Volt-VAR and Volt-Watt are activated and only replace service transformers when their thermal rating is exceeded. The cost savings resulting from this process change are expected to benefit electric ratepayers, interconnecting customers, and PV developers.
  - Future SI modeling work that explores the ability of higher SI-enabled PV penetrations to mitigate distribution upgrades on the primary should be considered.

7.2   Implementation Challenges and Resolution

7.2.1 Location 2 Field Demonstration Challenges and Resolutions

A number of challenges exist with a project of this magnitude. In no particular order, the following are "firsts" and had to be carefully thought through to realize the project objectives:

1. The inverter vendor's SIs used in the Location 2 field demonstration were installed pre-Rule 21 Phase 1 Autonomous function certification requirements, as well as those requirements related to the CSIP, so implementation of any Phase 1 functionality was not certified by a NRTL. Despite this, the project vendor's SIs did meet specific requirements of UL 1741 SA (anti-islanding). While the project SI vendor updated the firmware to provide the necessary functionality, nuances in implementation were slightly different than what was anticipated by the vendor-agnostic aggregation platform vendor.
2. IEEE 2030.5, which was accepted as the communication specification for Rule 21 Phase 2 in March 2018, has limitations with respect to the data model and associated functional use cases. This means that there are implementation gaps between understanding how functions are enacted at the inverter and how they are established at the server, and these had to be worked through between various vendors.
3. Although the satellite communications link is a robust medium, actual commissioning and testing via satellite with remote assets is challenging using the IEEE 2030.5 framework. This required considerable creativity on the part of PG&E and the aggregation vendor to leverage unused portions of the IEEE 2030.5 data model to embed commands to remote assets to facilitate test mode vs. normal operations mode.
4. Limitations exist with the aggregator platform user interface, which was provided to PG&E to interact with assets, specifically to configure, test, and retrieve data. While the vendor worked to establish a baseline interactive capability, much more work is required to make it a useable system.
5. Limitations on data rate, data payload, and other characteristics associated with the satellite link forced a significant amount of creativity on the part of the PG&E and vendor teams. For example, data rates/payloads were constructed to ensure that no one site exceeded 3 GB of data transmission in a month. This required development of preprocessing capabilities at the remote site controller, an effort which was not part of the original project scoping.
6. SI "sensitivity" at PCC is unknown. Smaller SI aggregations have minimal impact on voltage at the PCC, but determining the exact value for this is difficult because it is a multi-variate influence. For example, load absorption of PV output has a profound impact on the ability of the SI to influence voltage at the PCC, yet exact values of load were not quantified at every PCC. Ambient temperature also has an impact as it affects the efficiency of production, line losses, etc., and this impacts how generation will influence voltage at the PCC.

7.2.2 Laboratory Testing Challenges and Resolutions

1. SI lab testing was heavily hindered by SI equipment failures and poor product readiness on the part of some SI vendors, specifically with their implementation of Rule 21 autonomous SI functions (see Key Learning #2 in Section 1.3 above). Laboratory testing confirmed that SI vendor adoption and deployment of Rule 21 SI functions is still evolving.
2. Some manufacturers have a complex SI upgrade process that may not be followed by installers, resulting in inverters not running Rule 21 SI functions. It presently is not possible to verify the magnitude of this potential deficiency due to limited accessibility to SI settings in BTM field deployed units which makes lab product testing and establishment of documented processes/procedures even more critical in advance of larger scale rollouts.
3. DCFC tolerated voltage harmonics that produced up to 10% THD using a 3 Phase 480V input supply, well in excess of the 4% maximums permitted by standards, but could not be taken to higher-order harmonics due to test equipment limitations. It is recommended that an alternative method be developed if testing above 10% is required.

7.2.3 Feeder Modeling Challenges and Resolutions

The modeling component of the EPIC 2.03A project had several challenges related to both setting up the model and performing the simulations. While these challenges were overcome, they were a significant hurdle within the project.

1. PG&E's existing model does not include components of the secondary electric distribution system. For the purposes of this project, secondary, low voltage systems were mapped through a manual process and single customer AMI load profiles were incorporated within the models. This was of particular importance to the project as the output of SI functions is heavily influenced by the secondary system and individual load profiles.
2. The presence of thousands of individually controlled assets made modeling convergence a challenge. In addition to convergence increasing simulation time, there was a large number of permutations that had to be simulated. As a result of efforts related to this project, improvements to the OpenDSS modeling software were implemented that will benefit future releases for the research community.
3. In some instances, there was the requirement to make manual changes to the model. In certain circumstances, such as voltage regulation settings changes, manual decisions had to be made. This process disrupted automation and significantly slowed down simulation time, but ultimately resulted in a more accurate output to the project.

The challenges identified above are specific to the vendor-provided SI technology, the configurations tested, and the "state-of-the-art" at the time of deployment and testing in 2018. As with any new technology, SI solutions will require additional standardization and investment over time to reach maturity, and evolving standards will often lag implementation requirements because new use cases using the same standards are constantly being evolved. Overall, PG&E believes that the industry is on the right track to make SIs a reliable and scalable grid resource over time, with the understanding that some of the above issues may have already been addressed since the time of EPIC 2.03A Location 2 project.

8   Technology Transfer Plan

8.1 IOU's Technology Transfer Plans

A primary benefit of the EPIC program is the technology and knowledge sharing that occurs both internally within PG&E, and across the other IOUs, the CEC and the industry. In order to facilitate this knowledge sharing, PG&E will share the results of this project in industry workshops and through public reports published on the PG&E website. Specifically, below is information sharing forums where the results and lessons learned from this EPIC project were presented or plan to be presented:

8.2   Information Sharing Forums Held

- *DistribuTECH; San Antonio, Texas | Jan 23-25, 2018*
- *CIGRE Grid of the Future Symposium; Reston, VA | October 28, 2018*
- *CEC EPIC Symposium; Sacramento, California | February 7th, 2018*

8.3   Information Sharing Through Papers and Working Groups

- *Smart Inverter Working Group*
- *Rule 21 Working Groups*
- *Joint California IOU Whitepaper: Smart Inverters*
- *Greentech Media Article: What California Utilities Have Learned from Smart Inverter Pilots*

PG&E plans on continuing to share the results and lessons learned from this EPIC project in the future.

8.4   Adaptability to other Utilities and Industry

The key takeaways and recommendations provided by this demonstration are applicable to all utilities and industry partners integrating renewables into their electric grids using SI technology. While states like California have specific drivers fueling DER growth, these trends and related challenges are expected to grow in the future.

8.5 PG&E Applied Technology Services for SI Testing

In this project, PG&E used its ATS facilities and personnel to design, set up, and execute SI performance testing. ATS services are available on a contract basis to the DER and SI industry to evaluate SI performance across Phase 1 autonomous functions, Phase 2 communications functions, and Phase 3 advanced functions. For more information, contact jason.pretzlaf@pge.com.

9 Data Access

Upon request, PG&E will provide access to data collected that is consistent with the CPUC's data access requirements for EPIC data and results.

10 Metrics

The following metrics were identified for this project and included in PG&E's EPIC Annual Report as potential metrics to measure project benefits at full scale.[54] Given the proof of concept nature of this EPIC project, these metrics are forward looking.

D.13-11-025, Attachment 4. List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area)	Reference
3. Economic benefits	
a. Maintain / Reduce operations and maintenance costs	See Section 4.4 (Modeling Findings)
b. Maintain / Reduce capital costs	
e. Non-energy economic benefits	
5. Safety, Power Quality, and Reliability (Equipment, Electricity System)	
f. Reduced flicker and other power quality differences	See Section 5.1.1 (Location 2 Volt-VAR and Volt-Watt Findings)
7. Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy	
b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)	See Section 5 (Technical Findings)
d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360)	

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54 2015 PG&E EPIC Annual Report. Feb 29, 2016.
http://www.pge.com/includes/docs/pdfs/about/environment/epic/
EPICAnnualReportAttachmentA.pdf.

11 Conclusions

EPIC 2.03A findings demonstrated basic technical functionality of SI autonomous functions designed to mitigate local voltage issues associated with high DER penetration and characterized remaining hurdles to scaled SI deployment for grid support. Efforts undertaken within the project were not able to establish that individual or aggregations of SIs were able to affect average primary voltage, though a potential benefit of reduced voltage variability was observed. Despite this, the project has established that there is significant potential for local voltage support from SIs to help mitigate local secondary voltage challenges caused by high PV penetration in a cost-effective manner. SI ability to impact secondary voltage demonstrates that, with necessary improvements to the technology and processes related to its deployment, SI technology represents a promising avenue to address California's goals for DER integration.

The project established that successful SI deployment and remote monitoring and management is contingent on the following factors:

1. Unified standards, comprehensive testing and certification, and improved manufacturer product documentation and standardization of SI feature names and user interfaces;
2. SI communications solutions that are designed for reliable, durable and secure operation;
3. Rigorous pre-deployment testing of SI aggregation platform software and firmware to ensure reliable behavior under degraded communication and grid power conditions;
4. Coordination of SI settings with existing utility voltage regulation equipment settings; and
5. Utility grid modernization technology deployments such as ADMS and DERMS (for enablement of active control SI use cases, such as for provision of distribution grid services).

These findings on the potential use of SI autonomous capabilities to support local voltage are expected to be valuable for distribution grid operations, distribution planning, and customer programs. Feedback from this technology demonstration can inform process changes and utility requirements needed to successfully integrate renewable resources controlled by SIs, specifically during the interconnection process. Learnings can also inform the DRP and IDER proceedings, including Distribution Infrastructure Deferral Framework, Competitive Solicitation Framework, ongoing Rule 21 OIR, and Grid Modernization Planning filings.

The EPIC Project 2.03A enhanced understanding of the potential of SI for electric utilities, regulators, adjacent industries, policy makers, and prospective vendors, toward building a broader solution to the ultimate benefit of utility customers. PG&E plans to continue to champion this effort through continued support and presentations at industry meetings and to seek opportunities to continue to assess use of this technology.

11.1 Location 2 Field Demonstration Conclusions

11.1.1 Volt-Watt / Volt-VAR Conclusions

The following is a concise listing of key learnings related to the Location 2 Volt-Watt and Volt-VAR portion of this project:

Key Learning: The demonstration SIs successfully executed the Volt-Watt and Volt-VAR curve setting within tolerances.

Key Learning: The Smart Inverters at a site can move secondary voltage as measured at the PCC using the Volt-VAR and Volt-Watt functions.

Key Learning: The largest PV site by aggregate nameplate experienced a more significant reduction in voltage violations with Volt-Watt/Volt-VAR deployed than sites with smaller aggregate nameplate kW.

Key Learning: The effect of Volt-Watt/Volt-VAR observed at the largest site was significant and reduced secondary voltage violations from 10% to effectively 0%.

Key Learning: Volt-Watt/Volt-VAR did not have any clear effect on average primary voltage at the PV penetrations tested in the field.

Key Learning: Active Volt-Watt/Volt-VAR curves may have a potential beneficial effect in terms of reducing the range voltage values (max/min) on the primary relative to no active curves.

Key Learning: The Stage 3 Volt-Watt/Volt-VAR settings on average resulted in less than .5% curtailment at the SIs as compared to a baseline SI running no settings for the demonstration sites, and a maximum worst-case curtailment of 1%. Stage 2 curtailment findings were nearly identical (.4% average and 1.2% maximum curtailment).

Key Learning: Minimally, requiring installed SIs to provide both real and reactive power measurements with no greater than 5% error is sufficient to understand a specific inverter's role in affecting secondary voltage at the PCC.

Key Learning: While the demonstration SIs offered the option of voltage management at night using reactive power support, this feature proved to be unreliable.

11.1.2 Telemetry Conclusions

The following is a concise listing of key learnings related to the Location 2 telemetry portion of this project:

Key Learning: Before deploying future SI networks, communication availability with carrier providers should be thoroughly defined.

Key Learning: Aside from one service-provider related issue, satellite transmission was nearly 100% reliable.

Key Learning: Depending on the use case, satellite links can be a suitable option for real-time situational information from fielded assets and for real-time interaction for configuration or other control purposes but may have disadvantages relative to other communications methods (e.g. equipment costs and data plan charges- see section 5.2.5).

Key Learning: The satellite performance, both uplink and downlink proved to be more reliable than the cellular solution.

Key Learning: It is important to establish total data exchange requirements early in the project in order to determine minimum latency and bandwidth requirements.

Key Learning: Although satellite costs are higher than cellular costs, the margin between the two is less than $0.02/MB. Careful consideration of project requirements as well as negotiation with communication service providers could reduce the cost of satellite to below traditional cellular methods.

Key Learning: The use of any communication methodology for utility operations must be analyzed in context of data resolution (how fast to measure data), reporting requirements (how often to present data to operators, including link latencies), and constraints imposed by costs associated with total data utilization per a block of time. Use cases determine the suitability of a communications link.

11.1.3 Distribution Operations Notifications Conclusions

The following is a concise listing of key learnings related to interaction requirements from Distribution Operations, as related to this project:

Key Learning: The project was able to configure remote assets with a single curve per day, scheduled in advance. More complex configuration was limited by cellular data and satellite bandwidth constraints and IEEE 2030.5 polling and latency specifications. Increased robustness in the implementation and clarity in curve overlay requirements would improve configuration reliability and troubleshooting capabilities.

Key Learning: End of day logs provided valuable information but were incomplete due to the polling architecture. Real time alarms were not easily interpretable, making them unactionable.

Key Learning: The project collected granular voltage and production data, but the data was not available to the end user in real time. Additionally, data gathering standards between the gateway and inverters lacked clarity.

Key Learning: If available in a timely manner, visibility of grid conditions from SI data and control of SIs to address grid issues would be an asset to Distribution Operations for power quality investigations and planned and emergency switching situations. However, utilization of this data would require grid modernization technology deployments such as ADMS and/or DERMS.

11.2 Lab Testing Conclusions

The following is a concise listing of key learnings related to the laboratory testing portion of this project:

Key Finding: PG&E presently has no methodology or authority to ensure and verify that the autonomous functions in SIs are properly configured and are operating within known parameters.

Key Finding: The 3-phase SIs tested in the lab were found to operate in accordance with standards with regard to loss of phase and out of phase recloser operation.

Key Learning: For the lab tested EV charged models, line-side harmonic interaction with proper EV charger operation did not exceed standardized limits.

11.3 Modeling Conclusions

The following is a concise listing of key learnings related to the EPRI modeling portion of this project:

Key Learning: This modeling study was not able to demonstrate a scenario in which SIs mitigated a conventional upgrade on the primary, medium voltage system. This is likely a result of the caveats outlined in section 3.6.

Key Learning: Results for the feeders studied indicate that PG&E can eliminate its secondary voltage rise study process for residential projects when Volt-VAR and Volt-Watt are activated and only replace transformers when their thermal rating is exceeded.

Key Learning: HECO's Rule 14H curve was slightly more effective at mitigating overvoltages, but all three curves were on average more effective than conventional upgrades.

Key Learning: The curtailment impact of the Volt-VAR and Volt-Watt functions was small, allowing them to mitigate at minimal curtailment cost the secondary system upgrades that would otherwise be a condition of PV interconnection.

Key Learning: Compared to cases where conventional upgrades were performed to interconnect PV, the activation of SI functions yielded a small, but positive economic impact to ratepayers.

12 Appendix

12.1 Appendix A: SIWG Functions by Phase

Table 23: SIWG 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
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.

12.2   Appendix B: Curve Set Design / Implementation

12.2.1 Descriptions of the Curve Sets

The following are brief descriptions of the curves that were used throughout this project. A detailed accounting of the curves, with pictures, can be found in the Appendix.

The primary goal with these 5 different curve sets was to provide a calibration methodology (Curve Set A) as well as to better understand the impact of Volt-Watt and/or Volt-VAR on primary and secondary voltage (Curve Sets B-E).


12.2.2 Curve Sets A0 and A1

Curve Sets A and A1 (both shown as A in the following figures) were intended to provide a baseline where no Volt-Watt and Volt-VAR control was in effect. This allowed the project team to compare observations from each Curve Set versus a baseline and evaluate the impact of Curve Settings on voltage. Curve Sets A0 and A1 resulted in zero curtailment (Volt-Watt) and zero reactive power management (Volt-VAR). Figure 21 identifies the Volt-Watt and Volt-VAR curves that make up Curve Set A0; Curve Set A1 is identical and is not shown. Curve Set A0 used P_{pre} in following the Volt-Watt curve while Curve Set A1 used P_{rated}.[55]

Figure 21: Representative Curves for the "A" Designation Curvesets. These Are Calibration (Reference) Curve Sets and Are Not Meant to Impact Inverter Output.

Curve Set A: Volt/Watt and Volt/VAR

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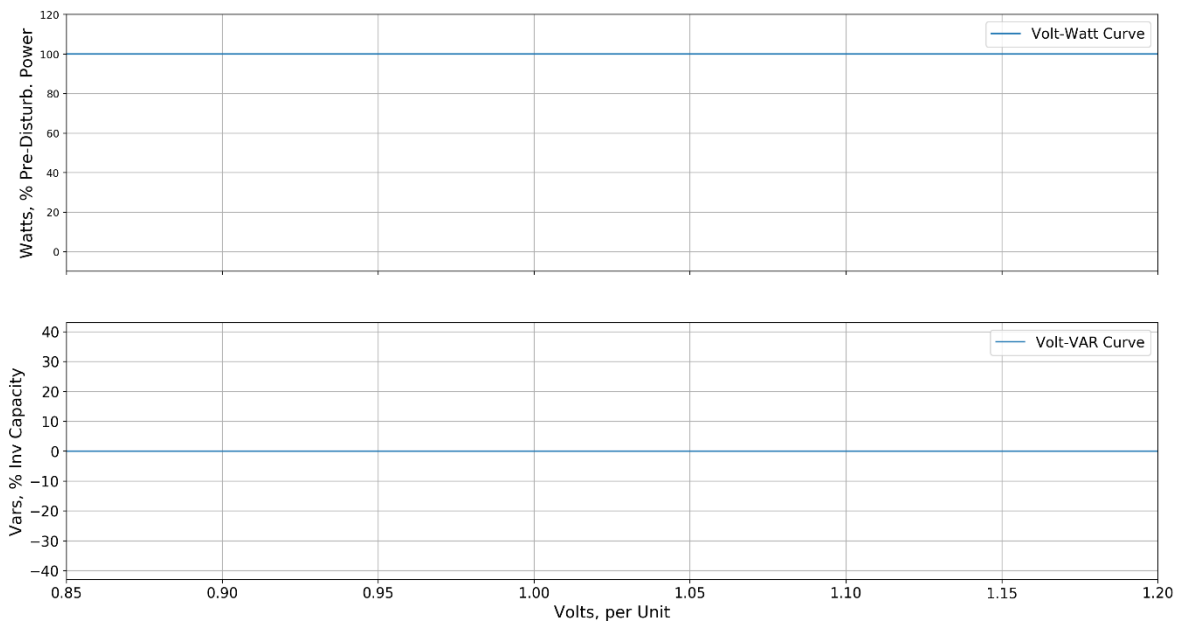
[55]   There are two methodologies for reducing active power as a function of voltage (Volt-Watt): P_{pre} and P_{rated}. P_{pre} reduces active power based on the value prior to the voltage changing, while P_{rated} reduces active power as a function of the nameplate active power rating. P_{rated} has been adopted in IEEE 1547-2018 as the recommended methodology for the Volt-Watt function.

12.2.3 Curve Sets B and B1

Curve Sets B and B1 were the alternate curves proposed by the SIWG as the Volt-Watt and Volt-VAR Curve Settings under Rule 21 at the time the project was scoped, though Curve Set C/C1 is the final adopted curve in CA. Figure 22 identifies the Volt-Watt and Volt-VAR curves that make up Curve Set B; Curve Set B1 is identical and is not shown. Curve Set B used P_{pre} in following the Volt-Watt curve while Curve Set B1 used P_{rated}. These Curve Sets are distinguished by having no overlap in the sloped regions between the two curves with Volt-Watt kicking in at 1.06 Vpu once Volt-VAR has maximized VAR absorption at 1.06 Vpu. This configuration is done so that voltage measurements and outcomes could be uniquely assigned to specific curve behaviors, and helps to address the question "which curve has the greatest impact at addressing voltage as measured at the PCC?"

Figure 22: Representative Curves for the "B" Designation Curvesets. Note the Knee Points for Volt-Watt and Volt-VAR, Specifically That There Is No Overlap.

Curve Set B: Volt/Watt and Volt/VAR
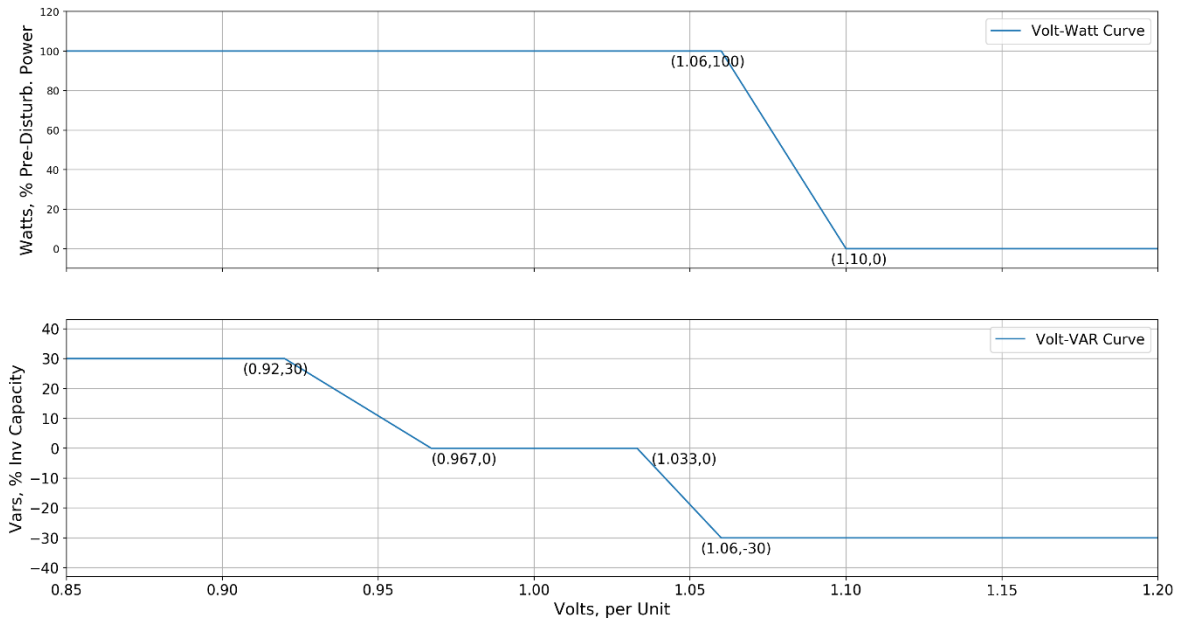
12.2.4 Curve Sets C and C1

Curve Sets C and C1 consisted of a combination of the Volt-VAR curve accepted by Rule 21 at the time of project kick-off along with the proposed Volt-Watt curve that was under consideration for Rule 21; this is the curve that is now required by Rule 21 in CA. Figure 23 identifies the Volt-Watt and Volt-VAR curves that make up Curve Sets C; Curve Set C1 is identical and is not shown. These Curve Sets are characterized by an overlap between Volt-Watt, which starts at 1.06 Vpu, which is enacted simultaneously with the Volt-VAR curve, the latter which flattens at 1.07 Vpu. This is the primary difference between Curve Set B and Curve Set C, and was implemented to improve understanding of dual, simultaneous interaction of the two curves. Curve Set C addresses the "what is the simultaneous behavior of Volt-Watt and Volt-VAR on voltage support, knowing that the two are simultaneously operating for part of their voltage ranges?" As before, Curve Set C used P_{pre} in following the Volt-Watt curve while Curve Set C1 used P_{rated}.

Figure 23: Representative Curves for the "C" Designation Curvesets. Note the Knee Points for Volt-Watt and Volt-VAR, and How They Contrast With Curve Set B.
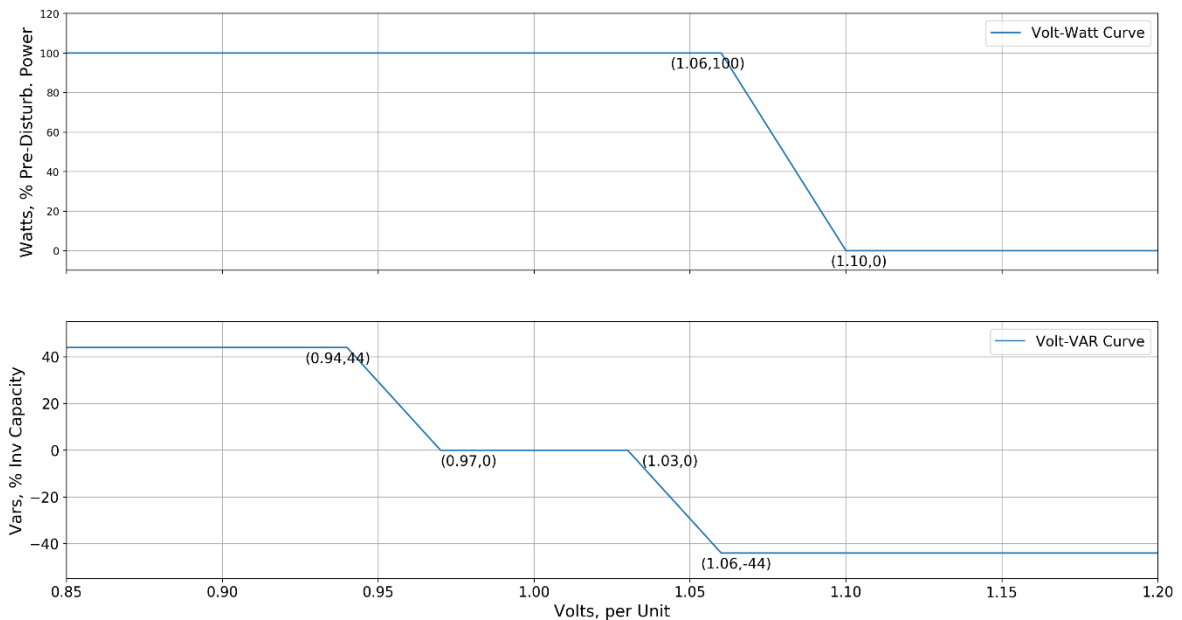
Curve Set C: Volt/Watt and Volt/VAR
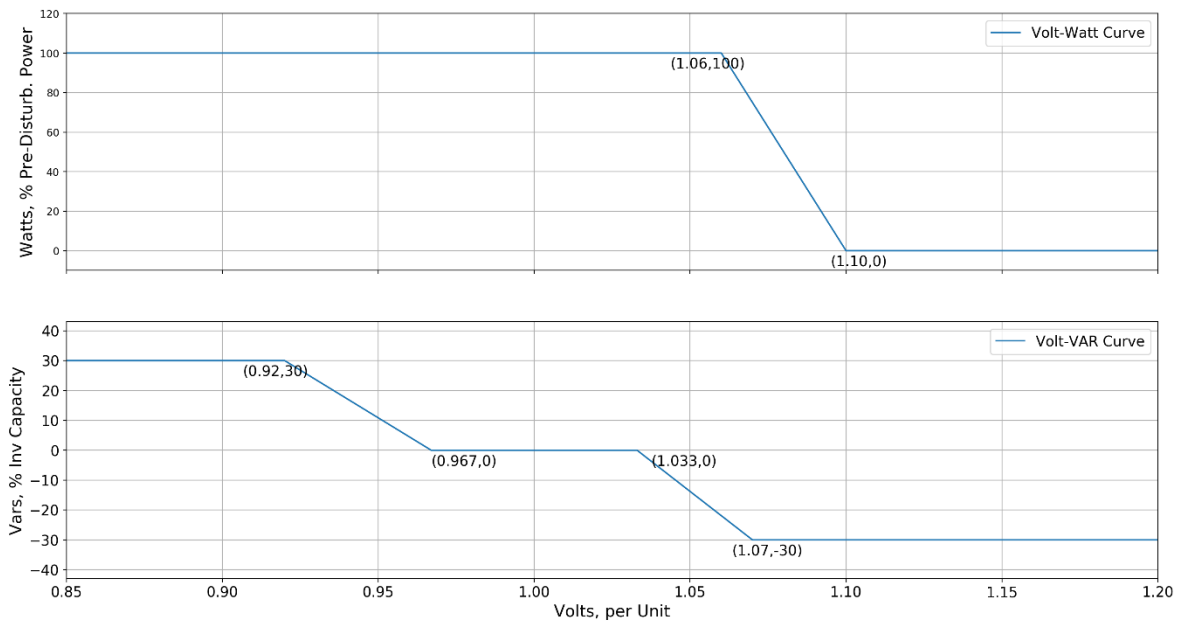
12.2.5 Curve Sets D and D1

Curve Sets D and D1 were the curves in place at the HECO at the start of the project. While the Volt-Watt curve matched the one executed in Curve Sets B and C, the Volt-VAR curve covered more reactive power support, increasing from +/- 30% nameplate to +/- 44% of the inverter capacity. Curve Set D and D1 do not have any overlap in the Volt-VAR and Volt-Watt curves. The intent was to evaluate the effectiveness of additional VAR support in voltage management. Figure 24 identifies the Volt-Watt and Volt-VAR curves that make up Curve Sets D; Curve Set D1 is identical and is not shown. As with the previously described curves, Curve Set D used P_{pre} in following the Volt-Watt curve while Curve Set D1 used P_{rated}. Curve set D addresses the question "what is the impact of a larger VAR support component in the presence of established curtailment criteria?"

Figure 24:   Representative Curves for the "D" Designation Curvesets. Volt-Watt Is Unchanged in Knee Points From Curve Sets B and C; Volt-VAR Expands Reactive Power Support to +/- 44% of Nameplate.
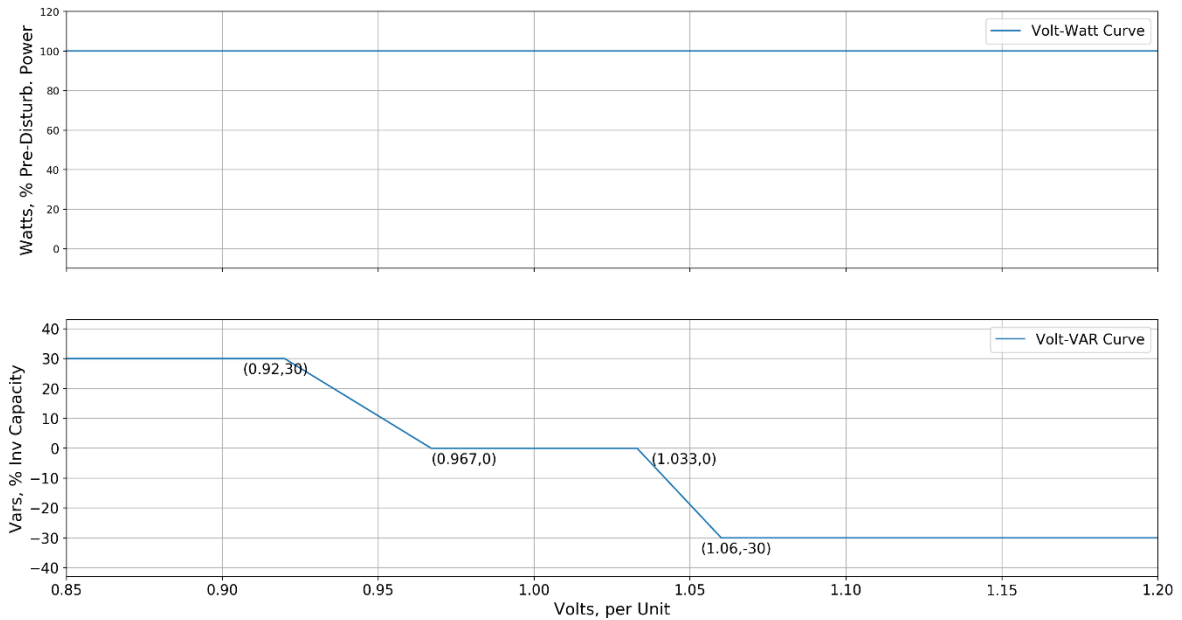
Curve Set D: Volt/Watt and Volt/VAR

12.2.6 Curve Sets E and E1

Curve Sets E and E1 included a flat Volt-Watt curve with zero active power curtailment at any measured voltage and the Volt-VAR curve that was proposed by the SIWG for Rule 21. The intent was to evaluate the effectiveness of managing voltage using Volt-VAR alone without Volt-Watt. Figure 25 identifies the Volt-Watt and Volt-VAR curves that make up Curve Sets E; Curve Set E1 is identical and is not shown. Curve Set E used P_{pre} in following the Volt-Watt curve while Curve Set E1 used P_{rated}. Curve Sets related to "E" address the specific question "What is the impact of VAR-only support at each inverter site?"

Figure 25: Representative Curves for the "E" Designation Curvesets. Volt-Watt Has No Impact on Measured Voltage (e.g. It Has no Knee Points so Has no Curtailment), While the Volt-VAR Curve Has the Same Volt-VAR Characteristics as Curve Set B

Curve Set E: Volt/Watt and Volt/VAR

12.3 Appendix C: SI Measurements Across All Sites and Curve Sets

The following figures show the SIs' effectiveness in executing the Volt-Watt and Volt-VAR curves within the tolerance bounds determined using the voltage and power measurement data from the inverter manufacturer. These figures include data from all active SIs across all the demonstration sites. Baseline SIs have been excluded from these figures.

Figure 26 shows the SIs' effectiveness in executing Curve Set A1 and uses all data available across all sites for the stated curve. This is the reference/calibration curve, and no impact on production was expected. Correspondingly, there was zero curtailment of active power and the inverters achieved 100% active power production. There was zero reactive power produced or absorbed.

Figure 26: SI Measurements Across All Sites, Plotted Against Curve Set A1 Volt-Watt and Volt-VAR Settings Along With the Tolerance Bounds Around the Curve Settings
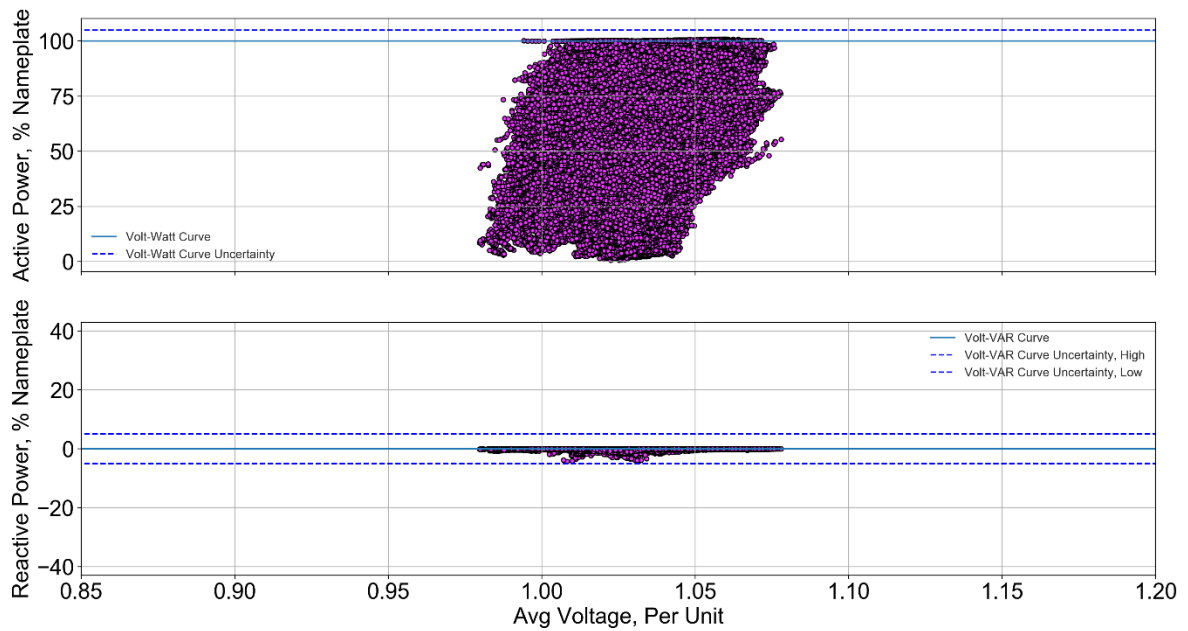
Figure 27 shows the SIs' effectiveness in executing Curve Set C1 and uses all data available across all sites for the stated curve. As expected, all data points fell within the Volt-Watt and Volt-VAR tolerance bands.

Figure 27: SI Measurements Across All Sites, Plotted Against Curve Set C1 Volt-Watt and Volt-VAR Settings Along With the Tolerance Bounds Around the Curve Settings

Curve Set C1 : SI P and Q Measurements with Active Volt/Watt and Volt/VAR
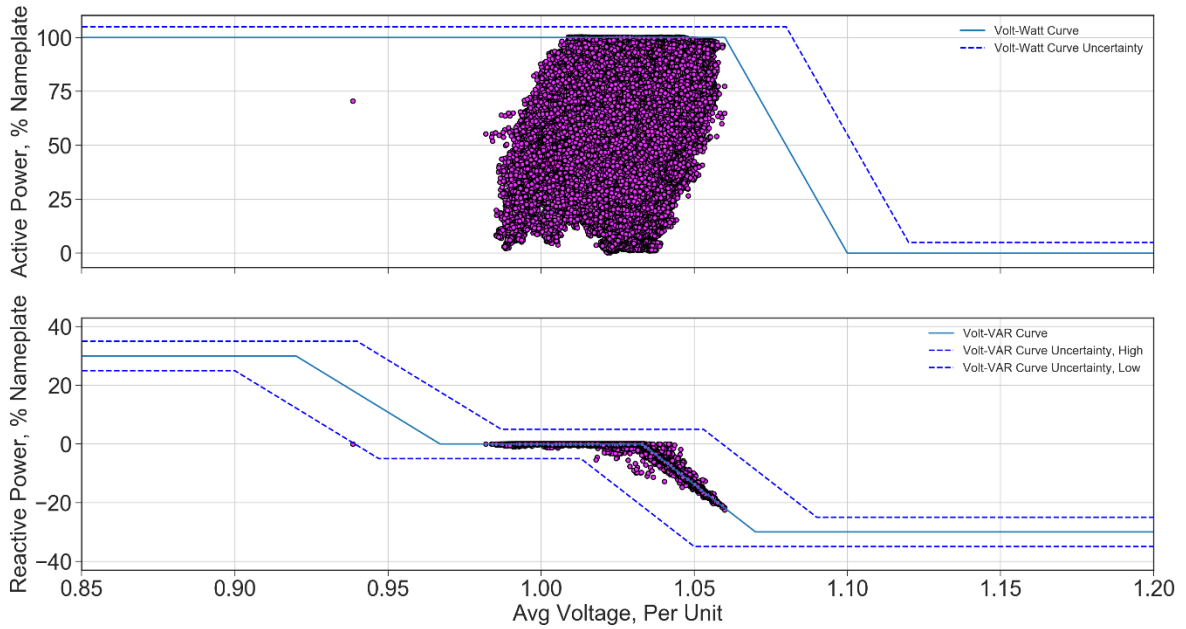
Figure 28 shows the SIs' effectiveness in executing Curve Set D1 and uses all data available across all sites for the stated curve. All data points fell within the Volt-Watt and Volt-VAR tolerance bands.

Figure 28: SI Measurements Across All Sites, Plotted Against Curve Set D1 Volt-Watt and Volt-VAR Settings Along With the Tolerance Bounds Around the Curve Settings

Curve Set D1 : SI P and Q Measurements with Active Volt/Watt and Volt/VAR

Figure 29 shows the SIs' effectiveness in executing Curve Set E1 and uses all data available across all sites for the stated curve. All data points fell within the Volt-Watt and Volt-VAR tolerance bands.

Figure 29: SI Measurements Across All Sites, Plotted Against Curve Set E1 Volt-Watt and Volt-VAR Settings Along With the Tolerance Bounds Around the Curve Settings

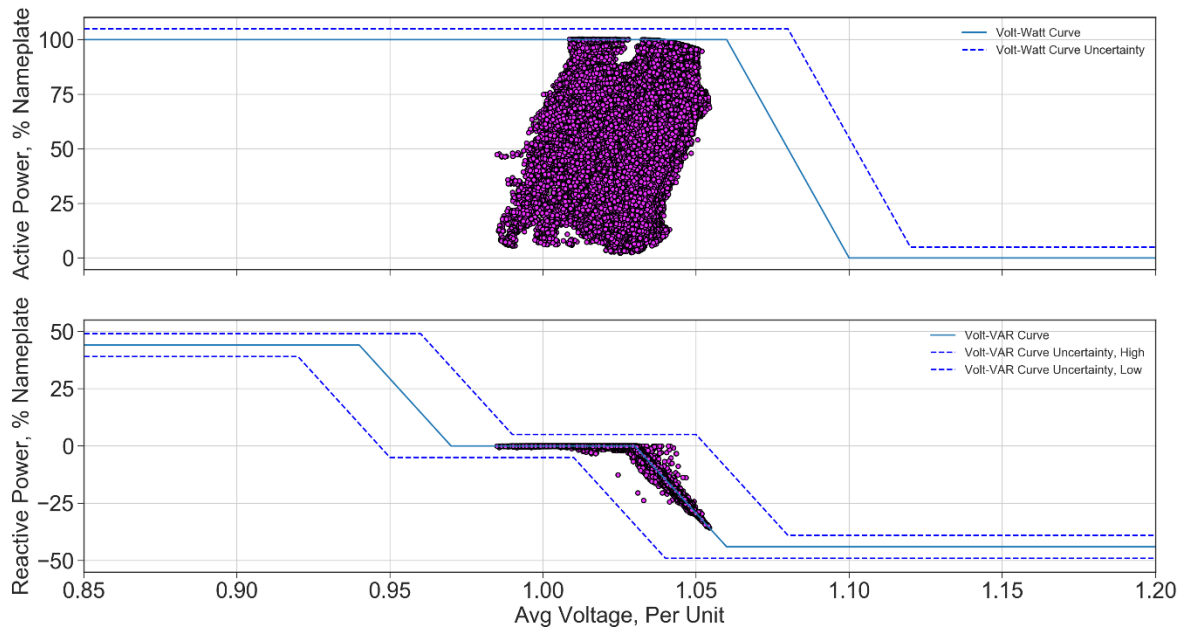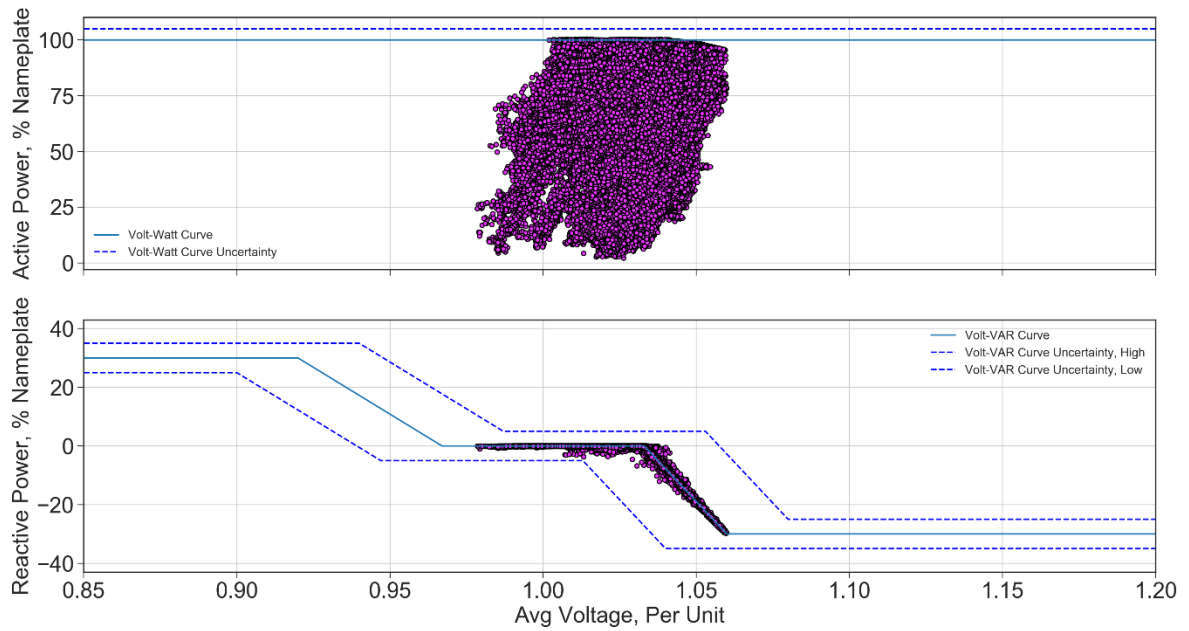Curve Set E1 : SI P and Q Measurements with Active Volt/Watt and Volt/VAR

12.4 Appendix D: Satellite Telemetry Data Calculation Design

12.4.1 Satellite Telemetry Data Calculation Design Overview

The primary question to be addressed on this project is whether multiple, co-located inverters that are connected to the test feeder can be used in an autonomous manner to ensure Rule 2 compliance. This is to be accomplished through the application of various Volt-Watt or Volt-VAR curves and then measuring voltage at the individual inverter terminals to control the individual inverter.

A secondary question to be addressed on this project is how to utilize a witness inverter that is co-located on each site to infer the amount of energy reduction due to implementation of Volt-Watt (and potentially) Volt-VAR curves. This is accomplished through normalizing each Volt-Watt or Volt-VAR-enabled inverter to the witness inverter, and then tracking differences in total watt-hour production.

These two project questions must be addressed with data that is available from the field. Affecting this, there is a significant constraint with respect to automated data transmission from each of the sites. 12 of the 14 test sites utilize a satellite link with 128 kbps upload link rate, which ultimately limits the type of and amount of information that can be captured from each test inverter as well as site.

12.4.2 Satellite Telemetry Data Calculation Design Constraints

12.4.2.1 Constraint by Uplink Rate

The satellite uplink maximum rate is limited to 128 kbps. Translating to bytes, this is 16 kBps. This will ultimately limit the amount of data that can be sent via the satellite link.

Each register must be wrapped in IEEE 2030.5 protocol. Benchmarking from the aggregator vendor indicates that for a single U32 register, the total payload size is 416 bytes and for 16 U32 registers, such as a time series, we generate a payload requiring approximately 1612 bytes. This suggests that transmitting time series values for each register maximizes data throughput by reuse of the IEEE 2030.5 headers and wrapping information.

Total register reads per unit time will be limited by the uplink data rate, a chosen retransmit data rate, and the size of the IEEE 2030.5 wrapper for the register value. Worse case estimates give the following rough-order of magnitude values for the total number of registers/engineering values that can be uploaded in various time frames, resuming that 1 retransmission is required for all data, as shown in Table 24.

Table 24: Uplink Data Rate

128	kbps uplink rate
16	kBps uplink rate
1	Retransmit Attempt
416	Total Bytes per Register/Engineering Value (estimate)
0.052	secs to upload one Register/Engineering Value
19	Total Number of Registers/Engineering Value per second
1153	Total Number of Registers/Engineering Value per minute
5769	Total Number of Registers/Engineering Value per 5 minutes

These values are based on a single inverter. The number of inverters per site will directly impact (reduce this value, e.g. for a site with 26 inverters, divide the values per unit time by 26).

12.4.2.2 Constraint by Data Plan

Another major constraint is related to the overall total uplink traffic that is permitted. The site owner is in a contractual relationship with the satellite provider, and the current plan they have chosen allowed for 12 GB/month download and 3 GB/month upload. This is an aggregated amount that is shared with all inverters at each site. The most populated site contains 41 inverters but according to the site owner, this site is on a cellular modem with an unlimited data plan and is not a concern for this discussion. The next most populous site contains 26 total SI assets, and this sets the maximum-and-not-exceed levels for total data allowance.

Maximum data allowance estimates per inverter, per unit time, are shown in Table 25 below, presuming 26 inverters as well as a 12 GB/month download and 3 GB/month upload data plan.

Table 25: Maximum Data Allowance Estimates Per Inverter

26 Number of Total SI Assets		MB Per Day per Asset	KB Per Hour per Asset	KB / 15 Min per Asset	KB / 5 Min per Asset
	Download	14.9	620	155	51.7
	Upload	3.72	155	38.8	12.9

Given the same worse-case scenario for register/engineering value packing requirements due to IEEE 2030.5 overhead, the following limitations for the existing data plan as imposed at a site that has 26 inverters are enacted are shown in Table 26 below.

Table 26: Existing Data Plan Limitations

	Registers/Engineering Values Per Day Per Asset	Registers/Engineering Values Per Hour Per Asset	Registers/Engineering Values / 15 Min per Asset	Registers/Engineering Values / 5 Min per Asset
Upload	8,948	373	94	32

Conclusion: Although the uplink data rate supports over 5,700 values being uploaded per 5 minutes, the data plan chosen by JKB only allows us to export 32, single-valued registers/engineering values within the IEEE 2030.5 protocol, and within the 5-minute window. Note: The same caveat as stated above exists – the more we can reuse the IEEE 2030.5 header/wrapper by constructing the values as a time series, the greater the number of register reads / engineering values that can be uploaded from the most populous site. As an example,

constructing a 16-element time series using the same IEEE 2030.5 header/wrapper for that series results in the improvement shown in Table 27 below.

Table 27: Improved Data Plan Limitations With IEEE 2030.5 Header/Wrapper Reuse

	Registers/Engineering Values Per Day Per Asset	Registers/Engineering Values Per Hour Per Asset	Registers/Engineering Values /15 Min per Asset	Registers/Engineering Values /5 Min per Asset	
Upload	14,972	624	156	52	

12.4.3 Satellite Telemetry Data Calculation Design Approach (Data Plan Limited to 3 GB / Month)

12.4.3.1 Data Compression through Histogram Analysis

To address the first question, whether embedded curves can autonomously regulate voltage to ensure Rule 2 compliance, voltage data from each inverter is required. The application of different curves is expected to change the voltage at the terminals. Specifically, during baseline activities (no curve applied), normal voltage variations need to be captured. It is expected that there will be periods where voltages exceed thresholds established in Rule 2. Contrasting, during curve-active activities (a test curve applied), voltage various above the thresholds relating to the specific curves should be reduced in count or eliminated altogether.

The basic approach to quantify this difference is to sample individual phase voltages as rapidly as possible and assign to a given bucket with a known voltage width (bin width). Bin widths are to be determined as a function of payload: narrower bin widths provide greater resolution but also increase the data payload size. Larger bin widths provide lower resolution but reduce data payload size. Ideally, bin widths should allow for comparison between the curves to be fully analyzed. Refer to Table 7. Curve Sets Implemented in the EPIC 2.03A Project

Curves B, C, D, and E all contain varying values of where Volt-Watt or Volt-VAR impact outputs. Of particular interest is the lower portion of the table, specifically X value 2 and X value 3, which are discrete at 96.7% and 97% as well as 103% and 103.3%. Because the differentials are 0.3%, this suggests that in order to properly ascertain differences in performance with respect to each curve that we should have a minimum of one-half of this span as the default bin width (bin width = 0.15%).

An additional component of the table is that the span of the voltage ranges is from a minimum of 92% to a maximum of 110%. This is the span of the transition ranges for the control input and suggests that we minimally need a range of 92% - 110% to fully capture the ability of the curves to influence voltage.

In practical application, we are not seeing this wide range of voltages on this feeder. The following plots are representative of the measured ranges that we are seeing on the feeder:

Figure 30: Results From All Sites Running Volt-VAR and Volt-Watt
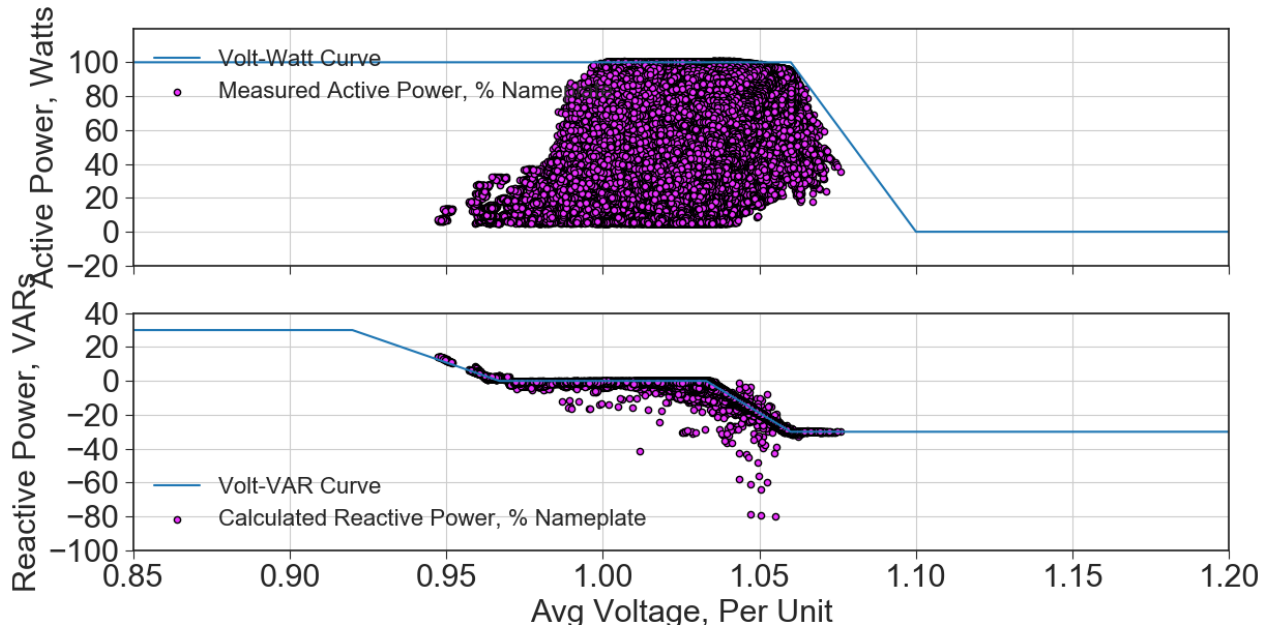
Given the real-world response, a minimum range for the data is approximately 98% to 107% (to capture the ranges shown) and the recommend ranges are at 95% to 110%, to capture the majority of observable data that will be seen on the feeder.

A constraint that we have with data elements within the IEEE 2030.5 wrapper / the aggregator vendor implementation is that we need the number of bins to fall as an n-multiple of 32 (e.g. 32, 64, 96, 128, etc.). This suggests the structure shown in Table 28 below.

Table 28: Proposed Voltage Bin Structure

0.15	% Bin Width
110	% Ending Point
128	# Bins
90.80	Projected Starting % Point

As you can see above, a starting voltage of 90.8% P.U. significantly captures the expected low range of the anticipated measurement range, and 110% P.U. is the upper cut-off.
The aggregator vendor process will be to run various counters for the different bins – if a measured voltage meets a bin criteria the counter is incremented. This will build an X-Y array of bin values vs. counts, which is a histogram. Because the X-array is stationary, there is no need to send it up the satellite stream and it can be inferred. It would be added back to the data stream on the server side.

Multiple histograms will be continually generated. It is proposed that each histogram be aligned with a clock boundary, e.g., 5-minute, 15-minute, etc. Although individual time of a specific measurement will not be known, the interval in which the measurement was made will be known. The approximate size of this histogram (128 bins) is estimated at 4 x 2804 = 11,216 bytes, per benchmarks conducted by the aggregator vendor. In an unlimited bandwidth scenario we would want to capture all three individual phases of information as a histogram, but in fallback (limited bandwidth) mode, we would average the three line voltages and write the average to the appropriate bin[56].

Internally, it is desired to scan the voltage registers as fast as possible to build the voltage histograms.

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[56]   This latter method of writing the average voltage to the histogram should be discussed. The pros with this approach is that this is what the SI vendor does to actually command/control the inverter with respect to watt output or VAR production/consumption. The negative with this approach is that averaging "washes out" any visibility that a particular phase may be out of compliance at the time of measurement, especially if the other two phases are significantly lower than the one that is much higher.

12.4.3.2 Replicating the Volt-Watt and Volt-VAR Data Plots

Additional data is required to answer the primary question of the amount of power output per inverter (y-axis) as a function of voltage (x-axis) as well as the amount of VAR production (y-axis) as a function of voltage is possible. This effectively builds a major portion of the plots that were previously listed (see above).

The key information in these plots is not the full data (shown in blue points in Figure 30 above) – but is the maximum value registered for each voltage measurement. Ultimately, this maximum value, and ensuring that it stays under the respective curve, is what assures us that the system is in compliance with Rule 2.

To generate these plots, the same concepts can be employed that were used to build the voltage histogram. The basic approach is to sample voltage for the histogram as well as simultaneously sample power output and VAR production, sorting each value into an appropriate voltage bin. This will self-produce the maximum power-output and VAR plots, allowing a direct measurement of each of the inverter systems. What will be lost in this method is the multiple values that are measured at a given voltage (e.g. solar ramp up and solar ramp down at various voltages.). The data underneath the maximum value, while interesting, is not necessary to determine if line voltage is in compliance.

It is reasonable to use the same resolution as was used in the voltage histogram for bin reporting. Although not required, this would permit the x-axis to be omitted from the data stream and be assumed/known without ambiguity for all downloaded series. Like the voltage histogram, data would be captured at the fastest rate deemed possible and compiled into the appropriate voltage bin. The maximum value would be written (e.g. maximum power output, maximum absolute VAR value, etc.).

Each of these watt-plots and VAR plots would be sent as an array of 128 points. The X-axis (voltage) would be added on the server side or during analysis.
The size requirements for each array are the same as the voltage histogram, approximately 11,216 bytes per array. Table 29 shows the possible number of array transmissions per unit time, and the remaining balance of remaining, un-used data.

Table 29: Possible Number of Array Transmissions Per Unit Time

	# of Arrays per 5 Minutes / Remaining Data	# of Arrays per 15 Minutes / Remaining Data	# of Arrays per 20 Minutes / Remaining Data	# of Arrays per 60 Minutes / Remaining Data

General Utilization	1	3	4[57]	13[58,59]
	12.9 KB − 11.3 KB ≅ 1.6 KB	38.8 KB − 3*11.3 KB ≅ 5.1 KB	52.0 KB − 4*11.3 KB ≅ 6.8 KB	155 KB − 13*11.3 KB ≅ 9.3 KB

An analysis of the amount of data that can be generated per unit time suggests that 5-minute intervals are simply NOT realistic – we can only generate one histogram, one volt/max watt plot, or one volt/max VAR plot in this interval. This is deemed unacceptable.

Conceptually, generation of 3 arrays per 15 minutes is possible. This would permit an AVERAGED voltage array to be generated (to generate the voltage counts histogram), and then a totalized volt/max watt plot as well as a totalized volt/max VAR plot. The remaining bandwidth of ≅ 5.1 KB could be used to read other instantaneous values, and would include time stamps, unique identifiers, etc.

The same argument for 20-minute intervals can be made at 10 with a 33% increase in unused remaining data. The major detriment to this interval is that it amounts to 24 fewer array-sets per day (down from 96 on the 15-minute interval to 72), a decrease of 25%. This interval could be useful if a higher value on the remaining data is presumed. More on the use cases associated with the remaining data set below.

Sending the data on a 60-minute boundary opens a significant amount of bandwidth for raw data, while permitting us to capture three different sets of phase data, specifically individual voltage histograms, individual volt/max watt, and individual volt/max VAR values. While only 24 of these 9 data sets would be captured on a daily basis, there would be over 19 KB available for raw data capture.

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[57] 4 arrays are not useful so 3 arrays containing average values would be built. This would leave an additional 11.3 KB available, making a total of 11.3 + 6.8 KB = 18.1 KB available for instantaneous readings.

[58] 13arrays13 arrays are more than what is needed. If we sample each phase and construct independent plots on phase for voltage counts (the histogram), wattage, and VARs, the maximum we need is 9. With a bandwidth budget of 155 KB per hour, 155 KB − 9*11.3 KB ≅ 53.3 KB remaining.

[59] It is possible to decrease this value to a total of 12 − 9 individual phase arrays and 3 averaged arrays. In doing so, we would have the same maximum rate per hour of 155 KB, but the remaining balance is 155 KB − 12*11.3 KB ≅ 19.4 KB.

12.4.3.3 Raw Data Capture

The overhead to read, package with the IEEE 2030.5, and transmit an individual register in the inverter is large – approximately 416 bytes. 4 values is more efficient, dropping the total to 760 bytes. A 1x32 array of values, which is a limitation for our implementation, is an efficient 2,804 bytes. It is highly desirable to package values in 1x32 arrays, per unit time, to maximize efficiency. The following table discusses some of the options available with use of the remaining bandwidth as functions of time.

Table 30: Remaining Bandwidth as a Function of Time

	Remaining Data per 5 Minutes	Remaining Data per 15 Minutes	Remaining Data per 20 Minutes	Remaining Data per 60 Minutes
Remaining Data	$\cong$ 1.6 KB	$\cong$ 5.1 KB	$\cong$ 6.8 KB (4 arrays) $\cong$ 18.1 KB (3 arrays)	$\cong$ 9.3 KB (13 arrays) $\cong$ 19.4 KB (12 arrays) $\cong$ 53.3 KB (9 arrays)

Registers that are of interest are the following:

- Line voltage (3 phases) and/or an average line voltage value
- Real Power Output (3 phases) and/or a total real power value
- Reactive Power (3 phases) and/or a total reactive power value
- Housekeeping / configuration registers (TBD).

As previously discussed, 5-minute intervals do not provide the desired number of sets of voltage histogram, volt/max watt, and volt/max VAR arrays. Consequently, it's not being considered as an option.

15- and 20-minute data do not offer a full set of 3 averaged, 1x32 values over either time frame. If a minimum requirement of sending averaged line voltage values as well as total real/reactive power values (in a 3x16 array size are desired), the following applies:
3 averaged values x 16 readings $\cong$ 1,614 bytes:

- 15 minutes (900 sec) / 16 = 56 second scans
- 20 minutes (1200 sec$\cong$) / 16 = 75 second scans

Consequently, in addition to the voltage histogram array, the volt/max watt array, and the volt/max VAR array, it would be possible to read about 16 values per the chosen interval at the indicated periodicity.

On the other hand, if an hourly periodicity is desired with 9 phase values chosen, a considerable amount of data can be transmitted. Here are examples:

- 3 averaged values x 64 readings $\cong$ 3 x 5608 bytes = 16,824 bytes, over 32 KB remaining, 60 minutes (3600 sec) / 64 = 56 second scans.
- 3 averaged values x 128 readings $\cong$ 3 x 11,216 bytes = 33,648 bytes, over 20 KB remaining, 60 minutes (3600 sec) / 128 = 28 second scans.
- 9 <u>instantaneous phase</u> values x 32 readings $\cong$ 9 x 2804 bytes = 25,236 bytes, over 27 KB remaining, 60 minutes (3600 sec) / 32 = 112.5 second scans
- 9 <u>instantaneous phase</u> values x 64 readings $\cong$ 9 x 5608 bytes = 50,472 bytes, with 3 KB remaining for miscellaneous data.

There are obviously many permutations on a theme. What is needed is to decide the following:

1. Whether 20 minutes or 60 minutes frame rate (data reporting interval is desired)
2. Whether 3 averaged values (voltage, real power, reactive power) or 9 individual phase values (same measurands) are required (individual phase only available for the hourly frame rate)
3. Whether ~ 60 seconds or ~ 112 seconds are acceptable in terms of sampling.

12.4.4 Final Satellite Telemetry Data Calculation Design Requirements

12.4.4.1 High-Resolution Voltage, Volt-Watt, and Volt-VAR Arrays

Three high-resolution arrays are specified:
1) Voltage Histogram
2) Volt-Max Wattage
3) Volt-Max VARs

Each of these arrays has an x-axis that is measured in normalized voltage (per unit, 277VAC LN nominal). The x-axis values are exactly the same for each of the arrays specified. Because of this, there is no requirement to report the x-array values, because they can be reconstructed on the server side once the data is processed from the aggregator vendor.

The x-axis details are as follows:
- Starting bin: 90.8% PU
- Ending bin: 110% PU
- Bin Width: 0.15% PU
- Total number of bins: 128

It is highly desired that these high-resolution arrays sample the appropriate values as fast as possible without adversely impacting system performance. The expectation is at least once per 15-seconds but this should be discussed and quantified.

Details for constructing each of these arrays is as follows:

12.4.4.2 Voltage Histogram

The voltage histogram has an x-y relationship that is quantified in voltage (p.u.) vs. counts. The algorithm uses the individual grid voltage line registers 30783, 30785, and 30789 to form three voltage histograms for data transmission.

The pseudo code for this follows this line of execution:

1. At the beginning of the frame, zero the count accumulators (qty 128) for each of the voltage histograms.
2. Sample the three voltage registers as close to the same time as possible (within the same Modbus scan).
3. Measure each of the voltage registers to determine which bin of the 128 that the value belongs. Increase the count value by 1 for the appropriate measurement.
4. Repeat until the end of the frame period.
5. At the end of the frame, package the individual 128 count observations as 4 packages of 32 observations. Uniquely identify these 1x32 arrays so that they can be reconstructed on the server side.

There will be three voltage histograms per frame, one per phase.

12.4.4.3 Maximum Volt-Watt

The maximum volt-watt has an x-y relationship that is quantified in voltage (p.u.) vs. maximum measured value of inverter output in real-power watts. The quantification of the x-axis is the same as the voltage histogram so there is no requirement to report the x-array values.
The algorithm uses the individual grid power L1/2/3 registers 30777, 30779, and 30781 to form three separate maximum-watt arrays.

The pseudo code for this follows this line of execution:

1. At the beginning of the frame, zero the maximum-watt registers (qty 128) for each of the real power measurements.
2. Sample the three active power registers as close to the same time as possible and within the same Modbus scan as previous values.
3. Using the voltage for a specific phase (you should know the bin number from the voltage histogram), determine whether the new power reading is greater than the previous value stored in that bin or if the new value should be written.
4. Repeat until the end of the frame period.
5. At the end of the frame, package the individual 128 maximum-wattage observations as 4 packages of 32 observations. Uniquely identify these 1x32 arrays so that they can be reconstructed on the server side.

There will be three maximum-wattage arrays per frame, one per phase.
The sample interval for maximum volt-watt should be conducted in the same Modbus scan as the voltage histogram. This is because the output voltage is directly controlled by the average of the measured line voltages, so it is expected that there will be a direct correlation.

12.4.4.4 Maximum Volt-VAR

The maximum volt-VAR has an x-y relationship that is quantified in voltage (p.u.) vs. maximum measured value of inverter output in reactive power (volt amperes reactive). The quantification of the x-axis is the same as the voltage histogram as well as the maximum volt-watt array so there is no requirement to report the x-array values.

The algorithm uses the individual reactive power L1/2/3 registers 30807, 30809, and 30811 to form three separate maximum-VAR arrays.

The pseudo code for this follows this line of execution:

1. At the beginning of the frame, zero the maximum-VAR registers (qty 128) for each of the reactive power measurements.
2. Sample the three reactive power registers as close to the same time as possible and within the same Modbus scan as previous values.
3. Using the voltage for a specific phase (you should know the bin number from the voltage histogram), determine whether the new reactive power reading is greater than the previous value stored in that bin or if the new value should be written.
4. Repeat until the end of the frame period.
5. At the end of the frame, package the individual 128 maximum-VAR observations as 4 packages of 32 observations. Uniquely identify these 1x32 arrays so that they can be reconstructed on the server side.

There will be three maximum-VAR arrays per frame, one per phase.
The sample interval for maximum VAR should be conducted in the same Modbus scan as the voltage histogram. This is because the output voltage is directly controlled by the average of the measured line voltages, so it is expected that there will be a direct correlation.

12.4.4.5 Instantaneous or "Snapshot" Values

Instantaneous or "snapshot" values refer to the instantaneous values that are captured in addition to the previously-described high-speed array data. Presently, the following registers are being considered as part of individual instantaneous snapshots:

```
*30531 Total yield        kWh    U32
*30537 Daily yield        kWh    U32
30777  Power L1           W      S32
30779  Power L2           W      S32
30781  Power L3           W      S32
30783  Grid voltage phase L1   V      U32
30785  Grid voltage phase L2   V      U32
30787  Grid voltage phase L3   V      U32
30807  Reactive power L1       VAR    S32
30809  Reactive power L2       VAR    S32
30811  Reactive power L3       VAR    S32
```

Shown are the project Vendor's register numbers, the descriptor, the units on the value, and the size of the inverter register and whether the value is signed (S) or unsigned (U).
It is desired that each of these values be reported on in blocks of 1x32 arrays, per frame, so that the data-to-overhead ratio associated with the IEEE 2030.5 protocol can be maximized. For example, if the frame rate is every 60 minutes, the sample rate of the snapshots will be 60/32 = 1.875 minutes or every 112.5 seconds.

It is a requirement that this snapshot interval be a parameter that can be adjusted on the EZ-Server and pushed down to the gateway clients.

*Note that the first two values do not need to have periodic sampling, as these are accumulator values. It needs to be discussed on specifics of how to obtain this data outside of the instantaneous / snapshot process.

12.4.4.6 Alarms

Report by exception.

12.4.4.7 Link Calculations

There are two important parameters for satellite communications: uplink/downlink data rates, as well as uplink/downlink data allowance. Data rates are typically measured in bits per second (bps); data allowance is typically measured in GB per month.

12.4.4.8 Determine if there is a Constraint on Data Rate

The satellite uplink maximum rate is limited to 128 kbps.
Each register must be wrapped in IEEE 2030.5 protocol. Benchmarking (using Wireshark) from the aggregator vendor indicates the following:

- for a single U32 register the total payload size is 870 bytes,
- for 32 U32 registers, such as a longer time series, we generate a payload requiring approximately 3,304 bytes.

This suggests that transmitting time series values for each register maximizes data throughput by reuse of the IEEE 2030.5 headers and wrapping information.
Total register reads per unit time will be limited by the uplink data rate, a chosen retransmit data rate, and the size of the IEEE 2030.5 wrapper for the register value. Worst-case estimates (one wrapper per engineering value) give the following rough-order of magnitude values for the total number of registers/engineering values that can be uploaded in various time frames, assuming that 1 retransmission is required for all data:

Table 31: Total Number of Registers/Engineering Values That Can Be Uploaded in Various Time Frames

128	kbps uplink rate
16	kBps uplink rate
1	Retransmit Attempt
870	Total Bytes per Register/Engineering Value (estimate)
0.10875	secs to upload one Register/Engineering Value
9	Total Number of Registers/Engineering Value per second
551	Total Number of Registers/Engineering Value per minute
2758	Total Number of Registers/Engineering Value per 5 minutes
26	Number of Total SI Assets per Site
106	Total Number of Registers/Engineering Values per 5 minutes for the SITE

Shown are numbers for a single inverter, as well as a site containing 26 inverters.
There does not appear to be a significant constraint on data rate with the stated parameters.

12.4.4.9 Determine if there is a Constraint on Data Allowance

The existing satellite data plan that is in force for the project permits a 12 GB / month downlink allowance and a 3 GB / month uplink allowance. We are concerned about the 3 GB / month limitation; little data is being deployed to the field on the downlink.

Each site is constrained to the 3 GB / month limitation. Presuming a 31-day month, the data allowances per unit time are as follows:

Table 32: Data Allowances Per Unit Time

		MB Per Day	MB Per Hour	MB / 30 Min	MB / 20 Min	MB / 15 Min	KB / 5 Min
3	GB Uplink Total per Month	Upload	97	4.0	2.0	1.3	1.0	336

There are 14 sites that have varying numbers of inverter assets. 12 of these sites have satellite-only coverage; 2 of the sites have AT&T cellular unlimited plans.

The maximum number of inverters across the 12 satellite-enabled sites is 26. The data allowances, per asset at the site containing 26 inverters, are as follows:

Table 33: Data Allowances Per Asset at Site With 26 Inverters

		MB Per Day per Asset	KB Per Hour per Asset	KB / 30 Min / Asset	KB / 20 Min / Asset	KB / 15 Min per Asset	KB / 5 Min per Asset
26	Maximum # of Total SI Assets per Site	Upload	3.72	155	78	51.7	38.8	12.9

Recall that the worse-case scenario, where individual IEEE 2030.5-wrapped engineering values are measured, each are about 870 bytes in size. Further benchmarking indicates that the high speed arrays, which will each be comprised of 4, 32-observation blocks (4x32), will occupy 4 x 3,304 = 13,216 bytes each. This suggests that in order to send 3 high-speed arrays per frame we have a limitation that will be realized on available remaining data:

Table 34: Remaining Bandwidth for Instantaneous / Overhead / Retransmit

	One Frame / Day	One Frame / Hour	One Frame / 30 Min	One Frame / 20 min	One Frame / 15 min	One Frame / 5 min	
Remaining Bandwidth for Instantaneous + Overhead + Retransmit	3.682	115.439	37.895	12.048	-0.876	-26.724	
	(MB)	(KB)	(KB)	(KB)	(KB)	(KB)	

The values in red, which are the "One Frame / 15 min" and "One Frame / 5 minute" values, are negative, showing that the sending of high-speed data at the 26-inverter site will result in total consumption of available monthly data.

The instantaneous "snapshot" values, in order to maximize the data-to-IEEE 2030.5 wrapper overhead, need to be 32 observations in length. Values less than this are not efficient and do not provide optimal usage of bandwidth.

The following are other considerations that have been applied:

- One frame per day is deemed unacceptable – risk of data loss has been cited, as well as lack of overall resolution.
- Sufficient margin is necessary for overhead operations – acknowledgements, alarms, etc. Size must be allocated for this and tested experimentally in the laboratory.
- It is presently unknown how much the end-of-day (EOD) site configuration report will occupy, but it is presumed to be some portion of the allowed 97MB per day, as much of this bandwidth will be used on the 26-inverter site.

Given these observations, and with the 11 1x32 "snapshot" observations that are being made, the following shows the amount of remaining bandwidth, in KB, for the site containing 26 inverters.

Table 35: Remaining Bandwidth for Site With 26 Inverters

Total Bytes	Include in Total (1 = Yes, 0 = No)	One Frame / Hour	One Frame / 30 Min	One Frame / 20 Min	32 Obs / Hour = Min / Sample ?	32 Obs / 30 Min = Min / Sample?
Remaining Bandwidth for Overhead & Retransmit		79.09485	1.551424	-24.2964	1.875	56.25
		(KB)	(KB)	(KB)	min / sample	SEC / sample

One frame per hour provides the greatest margin for overhead and retransmit operations. One frame per 30 minutes provides some thin margin for the site with 26 inverters, and this margin improves significantly for sites with 16 inverters or less (the next smaller site from the 26-site is 16 and the system reduces in inverter count from there).

As can be seen, one frame per 20 minutes is unacceptable for the 26-inverter site, resulting in a negative balance on data plan usage.

Conclusion: At a minimum, the fastest possible rates to send the high-speed arrays and have available bandwidth for instantaneous "snapshot" and overhead are reduced frame rates that are once per hour or once per 30 minutes. The final frame rate value needs to be tested and evaluated.

12.5 Appendix E: Joint IOU Smart Inverter White Paper, White Paper Appendix

12.6 Appendix F: PG&E EPIC 2.03A Smart Inverter Interim Report

12.7   Appendix G: PG&E EPIC 2.03A Modeling Report