Pacific Gas and Electric Company

EPIC Final Report

Program	***Electric Program Investment Charge (EPIC)***
Project	***EPIC Project 1.02 – Demonstrate Use of Distributed Energy Storage for Transmission and Distribution Cost Reduction***
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Table of Acronyms

Acronym	Description
AB	Assembly Bill
BESS	Battery Energy Storage System
CAISO	California Independent System Operator
CPUC	California Public Utilities Commission
EPC	Engineering, Procurement and Construction
EPIC	Electric Program Investment Charge
EPRI	Electric Power Research Institute
GHG	Green House Gas
IOU	Investor-Owned Utility
kW	kilowatt
LMM	Load Management Mode
MW	megawatt
MWh	megawatt-hour
QA	Quality Assurance
PG&E	Pacific Gas and Electric Company
RFO	Request for Offer
RFP	Request for Proposal
RTDECS	Real-Time Distributed Energy Control System
SCADA	Supervisory Control and Data Acquisition
SIS	System Impact Study
SOC	State of Charge
TD&D	Technology Demonstration and Deployment
UBAT	user acceptance beta testing

1 Executive Summary

This report summarizes the project objectives, technical results and lessons learned for the Electric Program Investment Charge (EPIC)-funded *Project 1.02 Demonstrate Use of Distributed Energy Storage for Transmission and Distribution Cost Reduction*, also referred to in short as *Energy Storage for Distribution Operations,* as listed in the EPIC Annual Report.

For EPIC Project 1.02, the California Public Utility Commission's (CPUC or Commission) Decision (D.) 13-11-025 approved Pacific Gas and Electric Company's (PG&E) EPIC 1 portfolio, and noted the following: "If successful, PG&E Project No. 2 (EPIC Project 1.02) will demonstrate, among other things, the ability to use energy storage more broadly to delay capacity expansions while maintaining or improving reliability" (page 26). Consistent with the Decision, PG&E deployed a 500 kilowatt (kW) / 2 megawatt-hour (MWh) energy storage system at the Browns Valley substation and integrated the energy storage system control into PG&E's Supervisory Control and Data Acquisition (SCADA) system to deliver autonomous distribution peak shaving functionality.

Challenges Addressed

In 2010, California passed Assembly Bill (AB) 2514, "Energy Storage Systems" noted that "there are significant barriers to obtaining the benefits of energy storage systems." In response to AB 2514 guidance, the CPUC issued the Decision Adopting Proposed Framework for Analyzing Energy Storage Needs,[1] which identified the following nine key barriers to energy storage deployment:

- Lack of definitive operational needs
- Lack of cohesive regulatory framework
- Evolving markets and market product definition
- Resource Adequacy accounting
- Lack of cost-effectiveness evaluation methods
- Lack of cost recovery policy
- Lack of cost transparency and price signals at wholesale and retail levels
- Lack of commercial operating experience
- Lack of well-defined interconnection processes

Two of these nine barriers applied to EPIC Project 1.02 and were addressed in the demonstration, including: (1) "Lack of Definitive Operational Needs," and (2) "Lack of Commercial Operating Experience. EPIC Project 1.02 was designed to improve the technical understanding of these barriers in the context of distribution-reliability applications and to design innovative systems and processes to directly and indirectly address these barriers.

Key Project Objectives

To help address these barriers, EPIC Project 1.02 Energy Storage for Distribution Operations established the following objectives:

- Demonstrate the ability of a utility-operated energy storage asset to address capacity overloads on the distribution system and improve reliability;
- Evaluate energy storage controls systems for deployment with this project and develop learnings to inform future controls deployment for utility operated energy storage; and

1 D. 12-08-016.

- Integrate energy storage functionality with existing Distribution Operations protocols, roles and responsibilities based on use-cases deployed.

Key Accomplishments

The following summarizes some of the key accomplishments of the project over the project duration:

- Identified energy storage site based on project objectives and site selection criteria: the availability of land, the availability of SCADA at the nearby substation, the presence of a residentially driven load profile and the presence of a small capacity overload;
- Deployed a 500kW/2MWh energy storage system at the Browns Valley substation in Browns Valley, CA to demonstrate the ability of an energy storage system to autonomously shave load peaks in a real-world operational context;
- Developed, tested and proved peak-shaving energy storage control application, and deployed controls successfully in field;
- Tested fully deployed energy storage system using a test protocol based on early versions of the Electric Power Research Institute (EPRI) Energy Storage Test Manual and analyzed results. Tests included measurement of max power input, max charge power, roundtrip efficiency under various duty cycles, standby power consumption and the system's ability to follow a frequency-regulation-like signal, amongst other functionalities;
- Confirmed system capability of autonomous peak load shaving as needed for distribution deferral energy storage use case; and
- Addressed inverter-grid interaction issues and demonstrated system capability to address peak overload conditions during multiple heat waves in summer of 2017.

Key Takeaways

The following findings are the key takeaways and lessons learned from this project:

- **Utility-operated energy storage can provide peak-shaving functionality:** The primary goal of EPIC Project 1.02 was to demonstrate an energy storage resource to autonomously provide up to 500kW of loading relief on the Browns Valley substation transformer bank for up to four hours. The project was sized based on a 10-year projection of peak loading at the Browns Valley substation compared to the 2.4 megawatt (MW) rating of the substation transformer bank. The four-hour system duration was determined to be appropriate through load data analysis and is exemplary of what would be needed for a typical residential distribution circuit. The Browns Valley energy storage resource has proven capable of providing just this peak-shaving functionality as it can output the energy necessary to address projected peak loading conditions on the substation transformer bank. This functionality was proven most notably during two heat wave events in Summer 2017 where the system kept peak loading at the substation below 2.3MW.
- PG&E's test protocol provides a robust assessment of energy storage facility use case capabilities, which will be leveraged for future Energy Storage Request for Offers (RFO): The test protocol developed for this project was based on early versions of the EPRI Energy Storage Test Manual. As described in Section 4.1.4 and detailed in Appendix A, the test protocol measured max power input, max charge power, roundtrip efficiency under various duty cycles, standby power consumption and the system's ability to follow a frequency-regulation-like signal, amongst other functionalities. The protocol proved successful at fully characterizing the capabilities of the system and PG&E will leverage this protocol and general project learnings in future Energy Storage RFOs.

Recommendations

For stakeholders considering energy storage deployments, PG&E provides a variety of recommendations as an outcome of this project:

- **Define unique energy storage control requirements upfront:** To date, energy storage controls have generally been built for commercial applications, and utility environments may require different functionalities and protocols.
- **Test energy storage use case control capabilities in a lab before controls implementation is on the critical path:** Energy storage controls are still far from standardized. Testing control capabilities in a lab in parallel with project deployment will ensure desired project use cases can be realized most efficiently.
- **For demonstration projects with significant operational impact, engage planning and operational teams at the concept stage:** The ultimate, long-term success of demonstration projects requires buy-in from both planning and operational teams; therefore, engaging with these teams early on sets foundation for a smooth transition from design through construction to day-to-day operations. This is especially critical for distribution deferral type energy storage systems, which provide reliability services on the distribution system.
- **Include robust use case functionality requirements in the form of test protocols for RFOs:** PG&E's energy storage test protocol as detailed in Appendix A provided a robust way to characterize system use case functionality. Stakeholders considering energy storage deployments can leverage PG&E's protocol as appropriate and modify as needed for particular applications.

Conclusion

EPIC Project 1.02 represented PG&E's first energy storage system deployed as a distribution, peak-shaving resource. A 500kW/2MWh energy storage project was deployed at the Browns Valley substation to provide capacity relief for a substation transformer bank, which represents a potentially attractive use case for future energy storage deployments. The facility was tested in a variety of control modes as part of system commissioning and proved its ability to reliably follow real-time control signals as well as to deliver and consume real and reactive power as instructed. Ultimately, the project was operational during multiple heat waves during the summer of 2017 and proved the ability for such an energy storage system to address peak overload conditions via an autonomous, SCADA-based control mechanism.

During project implementation, a variety of challenges were encountered and overcome. Nearly all challenges directly related to the relative newness of the energy storage deployments. As energy storage standards crystalize over time, and as procurement requirements become better defined, deployments across the industry as a whole will become streamlined.

Energy storage resources hold significant promise to help California address a variety of renewable integration challenges, both today and in the future. The implementation and operational challenges associated with this project resulted in learnings that will inform PG&E's procurement of future energy storage resources, both utility-owned and utility-contracted, through compliance with the Investor-Owned Utility (IOU) energy procurement targets as set forth in CPUC D.10-03-040 and beyond.

2 Introduction

This report documents the achievements, highlights key learnings that have industry-wide value, and identifies future opportunities for PG&E and other industry stakeholders to leverage the results of the EPIC Project 1.02 Energy Storage for Distribution Operations. This project was funded by the EPIC based on the below noted regulatory framework.

The CPUC passed two decisions that established the basis for this pilot program. D.11-12-035, *Decision Establishing Interim Research, Development and Demonstrations and Renewables Program Funding Level,* was initially issued to establish the EPIC on December 15, 2011. Subsequently, on May 24, 2012, the CPUC issued D.12-05-037, *Phase 2 Decision Establishing Purposes and Governance for Electric Program Investment Charge and Establishing Funding Collections for 2013-2020,*[2] which authorized funding in the areas of applied research and development, technology demonstration and deployment (TD&D), and market facilitation. In this later decision, CPUC defined TD&D as "the installation and operation of pre-commercial technologies or strategies at a scale sufficiently large and in conditions sufficiently reflective of anticipated actual operating environments to enable appraisal of the operational and performance characteristics and the financial risks associated with a given technology."[3]

The decision also required the EPIC Program Administrators[4] to submit Triennial Investment Plans to cover 3-year funding cycles for 2012-2014, 2015-2017, and 2018-2020. On November 1, 2012, in Application 12-11-003, PG&E filed its first triennial EPIC Application at the CPUC, requesting $49,328,000 including funding for 26 Technology Demonstration and Deployment Projects. On November 14, 2013, in D.13-11-025, the CPUC approved PG&E's EPIC plan, including $49,328,000 for this program category. Pursuant to PG&E's approved EPIC triennial plan, PG&E initiated, planned and implemented the following project: EPIC Project 1.02 Demonstrate Use of Distributed Energy Storage for Transmission and Distribution Cost Reduction, referred to in short as Energy Storage for Distribution Operations. Through the annual reporting process, PG&E kept CPUC staff and stakeholder informed on the progress of the project. The following is PG&E's final report on this project.

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2 http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/167664.pdf.

3 D.12-05-037, p. 37.

4 PG&E, SDG&E, SCE, and the California Energy Commission (CEC).

3 Project Summary

This report summarizes the project objectives, technical results, lessons learned and recommendations for EPIC Project 1.02 Energy Storage for Distribution Operations.

EPIC Project 1.02 was designed as a complement to PG&E's EPIC Project 1.01 Demonstrate Energy Storage End Uses. EPIC Project 1.01 focused on the potential energy market values for energy storage, while EPIC Project 1.02 focused on the non-market, distribution functionality of energy storage assets. CPUC D.13-11-025[5] approved PG&E's EPIC 1 portfolio, and noted the following: "If successful, PG&E Project No. 2 (EPIC Project 1.02) will demonstrate, among other things, the ability to use energy storage more broadly to delay capacity expansions while maintaining or improving reliability." This is precisely what has been demonstrated by EPIC Project 1.02. PG&E identified a project site, conducted a Request for Proposal (RFP) for project deployment, finalized designs, deployed the facility, commissioned the equipment, and tested facility performance for effective autonomous "peak shaving" operations.

3.1 Issues Addressed

In 2010, California passed AB 2514, "Energy Storage Systems." AB 2514 required investigation of the benefits and feasibility of energy storage systems. The bill noted that "there are significant barriers to obtaining the benefits of energy storage systems, including inadequate evaluation of the use of energy storage to integrate renewable energy resources into the transmission and distribution grid through long-term electricity resource planning, lack of recognition of technological and marketplace advancements, and inadequate statutory and regulatory support."

In response to AB 2514 guidance, the CPUC issued Decision Adopting Proposed Framework for Analyzing Energy Storage Needs (D.12-08-016), which identified nine key barriers to energy storage deployment, as listed below:

- Lack of definitive operational needs
- Lack of cohesive regulatory framework
- Evolving markets and market product definition
- Resource Adequacy accounting
- Lack of cost-effectiveness evaluation methods
- Lack of cost recovery policy
- Lack of cost transparency and price signals at wholesale and retail levels
- Lack of utility operating experience
- Lack of well-defined interconnection processes

Those barriers addressed directly in EPIC Project 1.02 were a: (1) "Lack of Definitive Operational Needs;" and (2) a "Lack of Commercial Operating Experience." EPIC Project 1.02 was designed to improve technical understanding of these barriers and to design innovative systems and processes to directly and indirectly address these barriers as described below.

3.1.1 Lack of Definitive Operational Needs

CPUC D.12-08-016 mentions a "Lack of Definitive Operational Needs" as one barrier to energy storage deployment. This suggests that energy storage system deployments are hindered because potential

5 Page 26.

system operators do not yet know how to adequately define energy storage system performance requirements to meet a given operational need (e.g., distribution peak shaving, distribution feeder voltage regulation, among others).

The concept of "distribution deferral" (also referred to herein as "peak shaving") is frequently used in discussions of energy storage value as a key non-market energy storage use case. The concept of "peak shaving" reflects a capacity issue in a particular part of the electrical delivery system and the potential applications to using energy storage in this fashion are not limited to only distribution facilities. The type of "peak shaving" demonstrated in EPIC Project 1.02 could be deployed in a variety of locations in the grid, including the transmission system. The operational requirements are very similar across many conceptual capacity overload scenarios. PG&E pursued this project for its applicability to a variety of future energy storage deployment deferral scenarios.

3.1.2 Lack of Utility Operating Experience

At the start of the project in 2014, PG&E had recently deployed the Vaca Dixon and Yerba Buena Battery Energy Storage Systems (BESS). EPIC Project 1.01 Demonstrate Energy Storage End Uses brought these resources into the California Independent System Operator (CAISO) Non-generator Resource Market and the reported the results and lessons learned of the commercial operating experience in its final report.[6] EPIC Project 1.02 sought to develop operating experience focused on energy storage as a non-market, distribution resource. The requirements and challenges associated with operating a CAISO market resource are distinct from the requirements and challenges associated with operating a distribution resource. For example, no daily bidding and scheduling of a distribution resource is required as there is no CAISO market functionality; however, considerations for seasonal loading of the local distribution system need to be considered in the case of a distribution deferral project like that deployed in EPIC Project 1.02. This project sought to "learn by doing" to inform future deployments. Specifically, PG&E seeks to combine learnings from EPIC Project 1.01 and EPIC Project 1.02 to deploy multi-use (distribution deferral plus CAISO market participation) energy storage resources at future sites.

3.2 Project Objectives

To accomplish the objectives for EPIC Project 1.02 Energy Storage for Distribution Operations, the following key objectives were developed:

- Evaluate energy storage controls systems for deployment with this project and develop learnings to inform future controls deployment for utility operated energy storage;
- Demonstrate the ability of a utility-operated energy storage asset to address capacity overloads on the distribution system and to improve reliability; and
- Integrate energy storage functionality with existing Distribution Operations protocols, roles and responsibilities based on distribution deferral/peak shaving functionality.

6 PG&E, Energy Storage End Uses EPIC Final Report: https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-1.01.pdf, September 13, 2016

3.3 Scope of Work and Project Tasks

To accomplish the objectives for EPIC Project 1.02 Energy Storage for Distribution Operations the following key scope items were developed:

- **Develop:** Identify a suitable site for project deployment;
- **Procure:** Conduct an RFP to identify suitable solutions and vendors;
- **Design and Deploy:** Complete design and deployment of facility;
- **Test Controls:** Develop, test and release a peak-shaving “bank load management” functionality for PG&E’s Real-Time Distributed Energy Control System (RTDECS) energy storage controller;
- **Integrate:** Develop organizational roles and responsibilities for efficiently operating battery resources as a distribution resource; and
- **Implement:** Demonstrate energy storage facility capabilities and prove “bank load management” functionality in the field.

3.3.1 Tasks and Milestones

Table 3-1 below includes the tasks and milestones that were achieved by the project:

Table 3-1: Project Tasks and Milestones

Phase	Task	Milestone
Develop	Identify site for energy storage deployment	Reach internal approval on project site at Browns Valley substation
Procure	Administer competitive solicitation to select vendor for an energy storage system	RFP released
		RFP proposals due
		EPC agreement executed
Design and Deploy	Develop acceptable project designs and deploy facility	Released major equipment for fabrication
		Project designs finalized
		All major equipment delivered on site
Design and Deploy	Testing the integration of the SCADA control application	Benchtop integration testing of SCADA + site controller complete
Design and Deploy		PG&E user acceptance testing of bank load management mode functionality complete
Integrate	Conduct trainings to integrate system into operations	Training with Distribution Control Centers complete
Integrate		Training with local fire department (Loma Rica) complete
Implement	Test the system to prove functionality and ability to meet project objectives	Project initial energization
		Project performance testing complete
		Initial phase data collection and analysis complete
		Collect operational data during peak loading conditions

4 Project Activities, Results, and Findings

4.1 Technical Development and Methods

4.1.1 Develop

Identifying the proper site for deployment was essential for the success of EPIC Project 1.02. PG&E developed a list of key criteria for sites to ensure the appropriate characteristics were present in the ultimate site chosen.

Site Selection and Project Sizing

PG&E considered seven potential sites for this project before choosing the ultimate site, the Browns Valley substation. Site selection focused on four main criteria:

1. **Minor overload on substation bank:** PG&E sought to deploy a small energy storage resource between 500kW-1MW for this demonstration project. The projected overload of the substation had to be less than this size of the installed system to be addressable by such a resource;
2. **PG&E-owned land:** PG&E sought to build on PG&E-owned land to save EPIC program implementation costs and to expedite project implementation;
3. **Residentially-driven load profile:** Residentially driven distribution circuits typically exhibit a shorter duration peak load (lower load factor) compared to commercial or industrial circuits. All else equal, a shorter duration peak makes energy storage a relatively more viable solution as energy storage project deployment cost scales with the required energy storage system discharge duration; and
4. **SCADA availability:** PG&E has SCADA installed in many of the transformers in its distribution substations; however, there are cases where analog metering is still in place. To save EPIC program implementation costs and to expedite project implementation, only substations with SCADA metering already in place were considered.

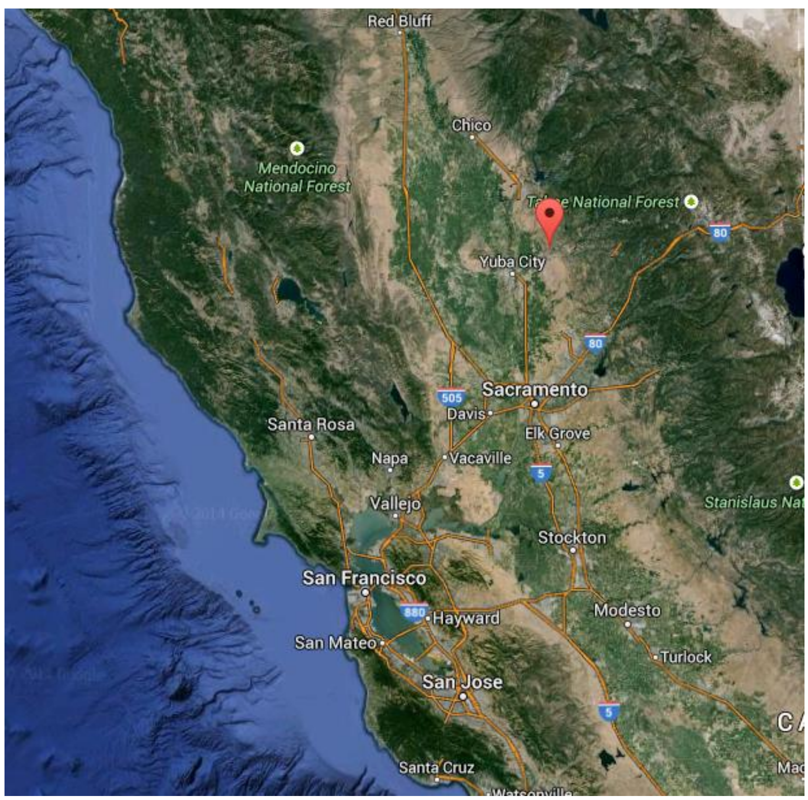
PG&E ultimately selected the Browns Valley site for its best alignment with the four-site selection and project sizing requirements. First, there was a very minor overload projected in the future years on the substation transformer bank. Second, PG&E owned land immediately adjacent to the existing substation. Third, the Browns Valley circuit is residentially driven and features a short duration summer peak, which is ideal for addressing with a targeted energy storage facility. Lastly, the Browns Valley substation transformer already had SCADA in place so the right infrastructure was already in place for the planned "bank load management" battery energy storage scheme. Table 4-1 describes the alternate sites that were considered, but ultimately not selected for the reasons listed in the "Considerations" column. It is notable that after all short listed sites were analyzed for the criteria above, only the Browns Valley site met all requirements, suggesting sites like this are not ubiquitous across PG&E's territory. Such siting criteria could be consistently applied across future projects to ensure the balance of deployment needs is considered in concert with cost-effective solutions for customers.

Table 4-1: Alternative Sites Considered

Potential Site	Considerations
Upper Lake	SCADA metering on bank not planned until 2017
Rough & Ready	Land leased and insufficient in size
Lemoore	Land insufficient in size
Merced Falls	Requirements for deferral likely too costly for project budget (1 MW, 4 hours for 1-2 year deferral)
Half Moon Bay	Land insufficient in size
Bogue	Very minor projected overload could be addressed with load transfers
Lammers	Land insufficient in size with overhead lines on property

A map of the project location, which is in Browns Valley, CA, is included inFigure 4-1 below.

Figure 4-1: Browns Valley Energy Storage Location

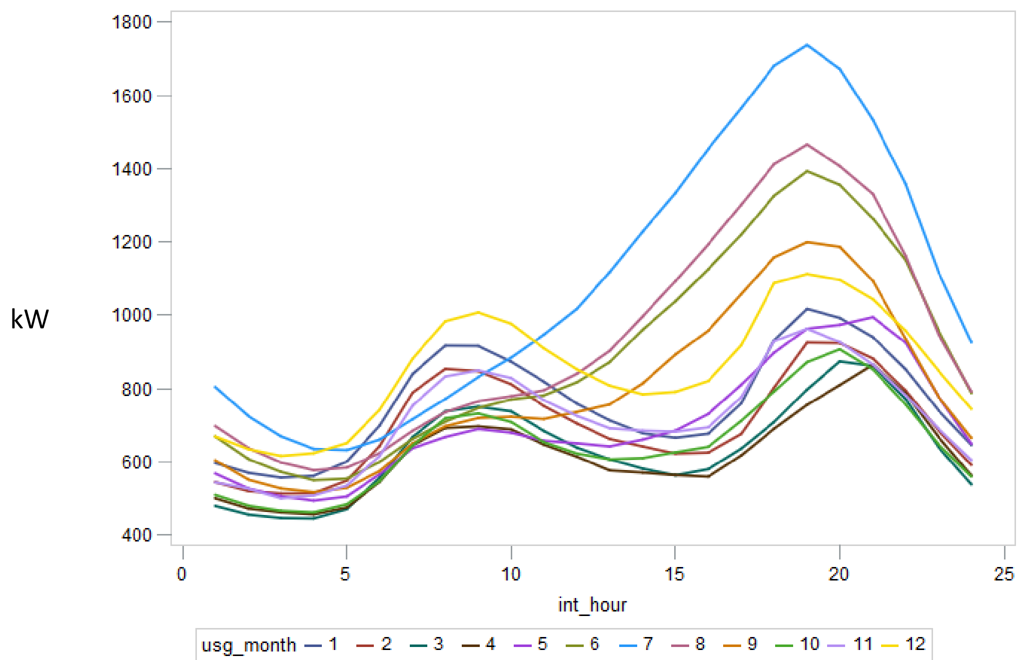


Project Sizing

In order to appropriately size the energy storage facility, PG&E utilized SCADA data, supplemented with aggregated SmartMeter$^{\text{TM}}$ loading data to obtain a robust baseline measurement of existing load on the Browns Valley substation transformer bank. After establishing a baseline, a growth rate was projected based on local economic factors as well as known new load interconnections. This load growth rate was utilized along with the baseline data to develop a ten-year projection of loading at the substation. This projection methodology was analogous to that used for PG&E's 2014 Energy Storage

Request for Opportunity in sizing the Distribution Deferral energy storage sites. As mentioned above, the Browns Valley area features mostly residential load and peaks in late summer (August-October) with loads driven by home cooling. Based on the ten-year load forecast, a transformer rating of 2.4MW[7] and projected lifetime system degradation losses, an appropriate size for the energy storage system was determined to be a nominal 500kW/2MWh. A graphic illustrating the portion of the load curve served by the energy storage system is included in Figure 4-2 below.

Figure 4-2: Average Daily Load Shape at Browns Valley Substation by Month[(a)]



(a) Note that Figure 4-2 represents the average, not maximum daily load shape.

Challenges

As noted above, finding an appropriate site for EPIC Project 1.02 represented a significant challenge early in project implementation. Finding a site with all the particular criteria required significant diligence and planning research. Distribution peak shaving scenarios in the style represented by the Browns Valley site are not straightforward to find—even in an environment like PG&E that contains approximately 900 substations. Each substation and each local community is unique and the electrical system design and load characteristics at each require individual study to determine the appropriate approach. The “site-specific” nature of the grid is why facility specific interconnection studies must be carried out as part of distributed energy resources (DER) interconnection requests and why costs for interconnection can vary widely from resource to resource.

7 “Transformer rating” refers to the maximum amount of power a substation transformer can handle under normal conditions without accelerating the degradation of the transformer.

Recommendations

Data sources are the key to successful implementation of energy storage project development efforts. For energy storage project identification, land databases, such as geographic information systems, may need to be paired with various data sources such as SCADA data, engineering drawings and historical asset records. In this particular case, PG&E also utilized data from PG&E's SmartMeter™ devices to supplement existing SCADA data. Those interested in deploying energy storage resources should consider streamlining and integrating data tools in advance to make siting and development tasks more manageable.

4.1.2 System Design and Deployment

In order to achieve the objectives of EPIC 1.02 at the Browns Valley substation, PG&E needed to deploy an energy storage system, including switchgear, energy storage batteries, and communication shelter, which met certain key design requirements and develop the proper controls functionality.

Design Intent

PG&E's overall design intent for the Browns Valley energy storage facility was to:

- Deploy a 500kW/2MWh energy storage system connected to the PG&E distribution system.
- Control energy storage system via autonomous control in order for the system to "shave peaks" on the distribution system without manual intervention.

Facility Telecommunications Design

The telecommunications design was critical to enabling the desired autonomous distribution peak shaving functionality and real-time operational visibility of the planned energy storage system. Originally, PG&E specified a satellite based communications system for the SCADA server on site. Unfortunately, after the technical team gathered detailed design requirements, it was realized that the requirement for remote access to the server would render satellite-based communications infeasible. The time required for satellite-based round trip verification before remoting in to the server was actually long enough that the request would time out. This level of service was deemed unacceptable; therefore, PG&E considered multiple options, specifically microwave and fiber based communications. After investigating options, PG&E decided to leverage fiber-based communications based on reliability, price and ease of deployment.

Controls Development: RTDECS Bank Load Management Mode

PG&E had to ensure the Browns Valley BESS could be dispatched in an efficient way to provide the required power at the time of peak loading. To accomplish this project objective, PG&E and its SCADA vendor partnered together to build the requisite functionality into the existing RTDECS.

As described in PG&E's EPIC Project 1.01 Demonstrate Energy Storage End Uses report, PG&E's electric distribution SCADA system vendor developed Smart Grid software that allows PG&E to automate and control energy storage resources under a variety of operating scenarios. The software is provided as a "bolt on" application to the base SCADA platform. The specific applications relevant to energy storage include RTDECSs and Real-Time Automated Dispatch System.

There was, however, a need to develop separate functionality, not already existing, to autonomously shave load peaks on the Browns Valley substation bank; therefore, PG&E met with the SCADA vendor and initiated design discussions. The final result was a new "bank load management" mode created in RTDECS that autonomously polled the real-time loading on the substation transformer bank, performed calculations to determine the amount of charge or discharge needed to keep the transformer bank within operational limitations and sent a corresponding real power set point to the Browns Valley energy storage system.

Controls Development: Algorithm Testing

PG&E configured a test server to allow user acceptance beta testing (UABT) of the RTDECS product enhancements prior to formal release for comprehensive PG&E Information Technology and SCADA Quality Assurance (QA) and integration testing. PG&E performed the initial UABT of the new RTDECS Load Management Mode (LMM) to confirm that the new functionality developed by the SCADA vendor operated as required to dispatch an energy storage resource in a manner that maintained transformer bank load below a user specified limit.

The UABT leveraged historical bank load data from the Browns Valley substation, along with commonly observed anomalous behaviors and tuning parameters associated with DER to create a series of test scripts that could be run using the test server. The objective was to compare the dispatch solution generated by the RTDECS LMM to a predetermined desired solution in a simulated test environment. This would identify any findings and recommendations that needed to be addressed before proceeding with more formal QA and pre-production testing and ultimately implementing RTDECS LMM in the field.

PG&E completed this testing in two phases. Phase I resulted in initial findings that were communicated to PG&E's SCADA vendor to address. In response to the Phase I UABT results, the SCADA provider addressed each of the findings through various software revisions and provided a new beta version for Phase II UABT and validation. After updates, both normal and abnormal operating scenarios were simulated successfully and LMM calculated the proper solution, generating the desired dispatch instruction under all cases. User configurable options functioned as expected including new options for ramp rate, settle time, and time out. The SCADA vendor also completed a bug fix to allow the charge time configuration to wrap across midnight and added RTDECS application engine alarming capabilities through the use of a heartbeat calculation point. As a result, Phase II UABT was successful with all previously identified issues resolved and no new problems observed. At the end of Phase II UABT, LMM functionality of RTDECS was released for field use with the Browns Valley energy storage facility by PG&E.

Controls Development: DNP3 Conformance Testing

PG&E deployed similar controls architecture in this project as was utilized in EPIC Project 1.01, with an onsite PG&E SCADA server that communicates directly with the vendor supplied site controller. This communication is carried out via a utility-standard DNP3 protocol[8] and the overall architecture of a PG&E managed device communicating with a site controller is indicative of a control architecture that could be rolled out for both utility-owned and utility-controlled (third-party owned) DER projects. This project represented one of the first DNP3 implementations for the energy storage vendor, and as a result, PG&E initiated discussions and collaboration between the SCADA vendor and the energy storage vendor early on in the project implementation timeline to avoid integration being tested for the first time in the field.

PG&E initiated discussions with both the SCADA vendor and the energy storage vendor and the two firms then collaborated to work out the finer points of implementing controls over DNP3 protocol. A variety of physical, desktop-based tests were conducted and the systems were then proved fully functional in the lab. These tests culminated in a formal DNP3 conformance test for the vendor

8 DNP3 is "Distributed Network Protocol 3," an automation protocol used in electric utility environments.

controller which proved compatibility with the DNP3 protocol standard. Passing this test in the lab paved the way for smooth deployment in the field.

Challenges

The requirement for remote access to the SCADA server on site presented issues for the originally proposed satellite-based telecommunications design. After operational requirements were fully understood, the right design was selected.

Although PG&E's SCADA system vendor and the BESS vendor had extensive experience in monitoring and controlling energy storage resources, neither of them had an off-the-shelf solution that could be applied to meet the objectives of this project. This is common in the energy storage industry as the flexible nature of an energy storage resource allows deployments to be monitored and controlled in a nearly infinite number of ways so some level of project specific customization will always be required. As energy storage use case definitions, testing and certification standards develop over time, the need for customization will decrease.

Recommendations

Before soliciting for energy storage resources, PG&E recommends that owners discuss and decide upon the required design criteria. It is obvious to focus on the energy storage technology component of the project, but time to develop detailed design requirements for the balance of plant facilities, such as medium-voltage electrical switchgear, should be allotted as well. For utilities, discussions of where energy storage assets fit within the existing organization should take place early on in the process to avoid alignment issues becoming on the project critical path. Lastly, since energy storage assets are only valuable to the extent they can respond to commands, telecommunications capabilities are absolutely crucial for functionality. To ensure smooth a project implementation, telecommunications requirements, including discussions of remote connectivity capabilities should be defined early in the scoping phase.

PG&E recommends further work on energy storage standards, including but not limited to, use case and application driven monitoring and control standards and minimum acceptable communication protocols for integration in a utility environment. Where appropriate, standard development should be flexible to ensure the utility grid of the future can effectively monitor and control energy storage resources consistently regardless of asset ownership or deployment location.

In addition, PG&E will require bidders in future solicitations to provide a copy of their communication protocol certification along with the proposed points register to determine whether additional protocol-testing related effort is required for project deployment. Where certification for the desired utility communication protocols is unavailable, or where the points register does not conform to minimum utility specifications, PG&E recommends requiring the bidder to furnish a contractually binding roadmap to achieve certification within the project budget and timeline.

4.1.3 Integrate

Integration with PG&E Roles and Responsibilities:

Prior to the deployment of the Browns Valley energy storage facility, PG&E already had two energy storage systems in the field: the Vaca Dixon and Yerba Buena sodium sulfur (NAS) BESSs, which were featured in EPIC Project 1.01 Demonstrate Energy Storage End Uses. The Browns Valley BESS is only a distribution peak shaving resource and does not participate in the CAISO market, thus PG&E's roles and responsibilities are different.

Prior to initially energizing the Browns Valley energy storage system, PG&E held a variety of trainings with the local distribution operations team to brief key members on the project background, project functionality and operational roles and responsibilities. Given the autonomous nature of the peak shaving functionality, the operations team doesn't have a minute-to-minute operational functionality, but the team is still responsible for responding to alarms, leading emergency response as needed and manually controlling the resource under atypical distribution topologies.

Outside of the PG&E operations team, the technical operations team also reached out to the local community, specifically the Loma Rica Fire Department. A first briefing was held in person at the fire department where PG&E reviewed the draft fire pre-plan with the team. Based on feedback received on site, PG&E improved the document, subsequently finalized the document with final vendor information and rolled out training to the fire department team at a subsequent on-site training. This same safety preparedness approach was deployed successfully for PG&E's NAS batteries and it worked equally well for EPIC Project 1.02.

Challenges

Although PG&E has experience interacting with PG&E's existing NAS batteries, their roles are reserved primarily to notifications, emergency response, and select scripted operating tasks to respond to and resolve critical alarms. Actual day-to-day operations for the NAS batteries are dictated by CAISO market needs. As a result, new notification processes and operating procedures were required for EPIC Project 1.02 along with various contingency plans for how to effectively manage the resource in abnormal distribution topologies or in the event an operator needed to take manual control and command set points in real-time to serve an emerging distribution system need.

Recommendations

PG&E recommends that all energy storage procurement teams define how to manage the resource under both normal and abnormal conditions upfront and before project deployment so key operational teams can be trained before the online date. In addition, PG&E has found that periodic refresher trainings and regularly occurring hands-on drills for common scenarios and two best practices.

4.1.4 Implement

<u>Initial Energization and Performance Testing</u>

After initially energizing the facility and proving basic remote control capabilities, PG&E set about testing the Browns Valley BESS according to the contractual requirements and project objectives. These testing protocols are the same protocols PG&E plans to use in current and future Energy Storage RFOs. The objective of these tests was to identify and remedy any observed performance deficiencies and to assess contractual compliance with the project deployment contract. In addition, the test results were also archived to establish first year baseline performance metrics to serve as a benchmark for future annual performance testing.

Given the tests were completed in the winter, which is a low load period for the Browns Valley area, there was a risk that ill-timed full discharges could lead to reverse power flow through the Browns Valley substation. From a system operations perspective, this is not desirable. To address this risk, PG&E conferred to determine the appropriate limitations for dispatching the system during the initial performance testing time period. Ultimately, full discharge commands at 500kW were only allowed between the hours of 4pm and 10pm to mitigate reverse power flow risk.

As there are a large number of variables that impact operational performance of any BESS facility, a simplified set of technical performance metrics were chosen based on industry guidelines, including early versions of the EPRI Energy Storage Test Manual. These metrics were defined in the Engineering, Procurement and Construction (EPC) contract with some categorized as minimum guarantees with direct contractual implications, and others categorized as informational only for purposes of establishing performance expectations. A summary of these metrics and the EPC vendor's stated or guaranteed values are included in Table 4-2.

Table 4-2: Key Technical Performance Metrics

Metric	Description	Guaranteed
Dmax	The maximum steady state power the Facility can continuously discharge from 100% State of Charge (SOC) to 0% SOC	0.475 MW
Discharge Duration	Time from 100% SOC to 0% SOC at Dmax	4 hrs.
Cmax	The maximum steady state power the Facility continuously draws over its charge duration	-0.500 MW
Charge Duration	Time from 0% SOC to 100% SOC at Cmax (It is understood that ESS may curtail charge as SOC approaches 100%. This measurement should be interpreted as fastest charging time under normal operation.)	5.08 hrs
Daily Efficiency (%)	Efficiency measured over a 24-hour period that includes 1 full duty cycle	Yr. 0 – 77.0% Yr. 2 – 76.0%
Standby Self Discharge	Difference between starting SOC at 75% and ending SOC over 24 hour period while Facility is idle but ready for immediate operation.	0.06%
Standby Energy Consumption	Average hourly consumption of energy by Facility, measured over 24 consecutive hours when Facility is idle but ready for immediate operation.	25kWh

Project performance testing measured max power input, max charge power, roundtrip efficiency under various duty cycles, standby power consumption and the system's ability to follow a frequency-regulation-like signal, amongst other functionalities. A complete list of the tests is presented in Table 4-3. Detailed, step-by-step descriptions of the tests are presented in Appendix A: Performance Test Protocol and Results.

Table 4-3: Performance Test Descriptions

Test Name	Test Description[a]
Maximum Power/Full Duty Cycle Efficiency/Daily Efficiency	Starting at 100% state of charge, a duty cycle is a full system discharge, followed by a full system charge. Goal: Determine whether maximum power and discharge duration performance meets minimum specifications and confirm charge duration and full duty cycle efficiency meets manufacturer's stated values
Stored Energy Capacity	Goal: Characterize general facility performance and determine usable capacity at various discharge and charge rates.
Partial Duty Cycle	Starting at 100% state of charge, a partial duty cycle is a less the full discharge (to level greater than 0% state of charge), followed by a less than full charge. Goal: Confirm partial duty cycle performance and partial duty cycle efficiency meet manufacturer's stated values.
Standby Self-Discharge	Goal: Measure system's loss of state of charge while sitting idle
Standby Energy Consumption	Goal: Measure system's energy consumption while sitting idle
Response Time, Power Factor (Real/Reactive Power), and Frequency Regulation	Goal: Measure system's time to respond to set points, characterize the system's ability to produce and consume both real and reactive power and confirm system's ability to follow a frequency regulation-like[b] set point
Substation Bank Load Management (SCADA Control Application)	Goal: Confirm and characterize system's ability to follow SCADA input of substation bank loading and respond accordingly to shave peaks per pre-established threshold

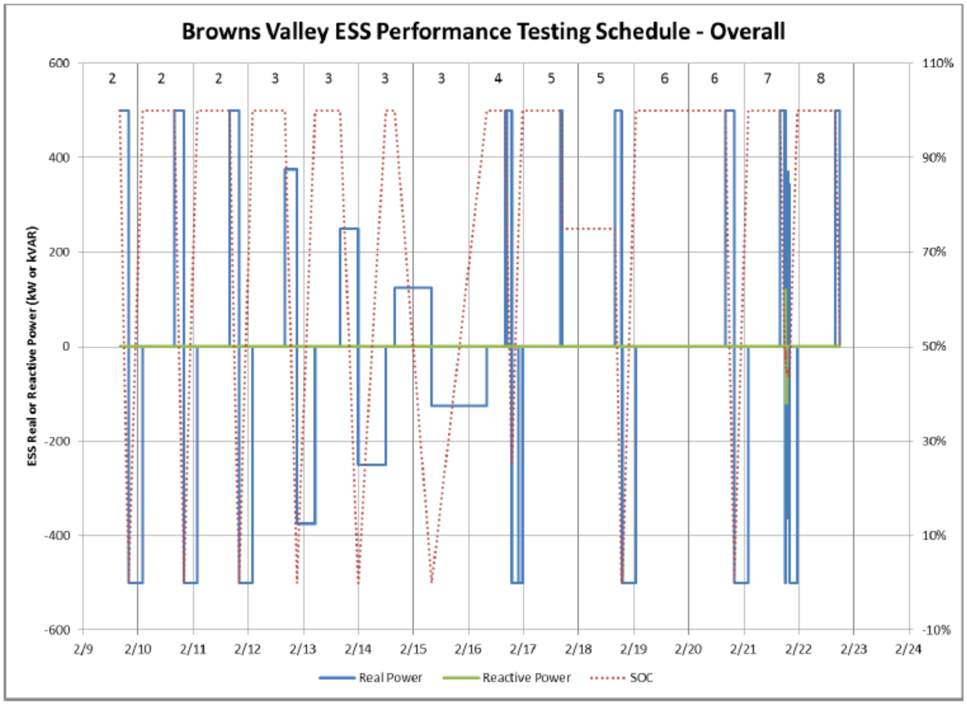
(a) See Appendix A for more thorough descriptions of each test.

(b) PG&E utilized flat data input files containing exemplary frequency regulation signals based on learnings developed through EPIC 1.01. The Browns Valley facility did not become certified for frequency regulation in the CAISO market, which would have required a formal CAISO interconnection agreement, completion of the CAISO New Resource Implementation process and installation of the associated Remote Intelligent Gateway controls for Automatic Generation Control capabilities.

Performance Test Findings:

The performance testing approach and results are described in detail in Appendix A: Performance Test Protocol and Results and shown graphically in Figure 4 3 below.

Figure 4-3: Browns Valley Performance Testing Schedule – Overall



Over the course of the tests, detailed data on battery system performance was collected via a supplemental metering installed specifically for this purpose. The test data was downloaded and analyzed for conformance with the system contractual obligations. A summary of the performance data collected is shown in Table 4-4.

Table 4-4: Data Collection Summary

Data Collected	Measurement Device	Data Interval
Ambient Temperature	Browns Valley Regional Weather Station	1-hour
Ambient Humidity	Browns Valley Regional Weather Station	1-hour
Battery State of Charge	Vendor Site Master Controller	5-minute
Real Power (480V)	Vendor Battery Meter	1-second
Current (12kV)	PG&E Supplemental Test Meter	1-second
Voltage (12kV)	PG&E Supplemental Test Meter	1-second
Real/Reactive Power (12kV)	PG&E Supplemental Test Meter	1-second
Power Factor (12kV)	PG&E Supplemental Test Meter	1-second
Current THD (12kV)	PG&E Supplemental Test Meter	1-second
Voltage THD (12kV)	PG&E Supplemental Test Meter	1-second

Table 4-5 provides a summary of the testing results compared to the EPC vendor's stated or guaranteed values for various technical performance metrics as measured by the 12 kilovolt (kV) meter.[9] Parameters in Table 4-5 marked as "N/A" either could not be validated due to low bank loading, metering resolution, or because the values would be quantified at a later date as part of extended reliability testing. General electrical performance behavior was trended for each of the tests conducted. These trends are presented graphically in Appendix A: Performance Test Protocol and Results along with concise descriptions of the tests and associated findings.

9 Note that due to real power measurement reporting resolution associated with the 12kV meter, real power indicated is based on a calculation using the underlying current, voltage, and power factor measurements.

Table 4-5: Key Technical Performance Metric Comparison – 12kV Meter

Metric	Brief Description	Vendor Guaranteed	Actual Measured
Dmax (Discharge MW)	Maximum system discharging power	0.475[a]	0.472[b]
Discharge Duration (hours)	The amount of time required to fully discharge system from 100% state of charge	4	4
Cmax (Charge MW)	Maximum system charging power	0.500	0.477[c]
Charge Duration (hours)	The amount of time required to fully discharge system from 100% state of charge	5.08	5.07
Full Duty Cycle Efficiency (%)	Ratio of the energy output to the grid compared to the energy consumed under various cycling scenarios[d]	83.50%	82.62%
Partial Duty Cycle Efficiency (%)		83.50%	82.79%
Site Specific Duty Cycle Efficiency (%)		83.50%	N/A
Daily Efficiency (%)		77.00%	82.62%
Standby Self-Discharge (%)	Measurement of the amount of energy lost while system idles	0.06%	1.00%[e]

(a) The Browns Valley energy storage facility is designed for 500kW at the output of the inverters. This value, measured at the point of interconnection with the grid is slightly lower than 500kW due to losses and auxiliary loads. The sizing of the storage resource to meet the projected peak loading took this discrepancy into account.

(b) The difference of 3kW is within the accuracy of the measurement equipment used for testing, thus this delta between "Guaranteed" and "Actual Measured" was deemed compliant.

(c) Consistent with the requirements utilized in PG&E's Energy Storage RFOs, the contract called for CMax to be at least 90 percent of the guaranteed value and the "Actual Measured" CMax value met this requirement.

(d) See Appendix A for a more detailed description of each efficiency test.

(e) Explanation: The 'Vendor Guaranteed" value of 0.06 percent was provided on a state-of-charge basis and the "Actual Measured" value was based on measurements taken at 12kV. As a result, the "Actual Measured" value captures losses associated with the transformer and other appurtenant systems during the test period due to the test methodology (using kWh instead of SOC as a proxy), which explains the discrepancy.

Results of the performance tests indicate that the Browns Valley BESS met or exceeded all of the applicable performance criteria within contractually allowed performance bands after accounting for the expected accuracy of the measurement devices used. Key highlights from these performance testing results include the BESS total power output (Dmax) measured as 0.472MW of the guaranteed 0.475MW for a minimum discharge duration of four hours. This key result confirms the system's ability to shave the projected peak on the transformer bank at the Browns Valley substation. In addition, the maximum steady state power that the Facility continuously drew over its charge duration (Cmax) was measured as 0.477MW over approximately 5 hours. This finding confirmed the system's ability to recharge in a manner quick enough to ensure the system met operational requirements.

Lastly, the performance tests were successful in confirming system efficiency over 82 percent across a number of different duty cycles.

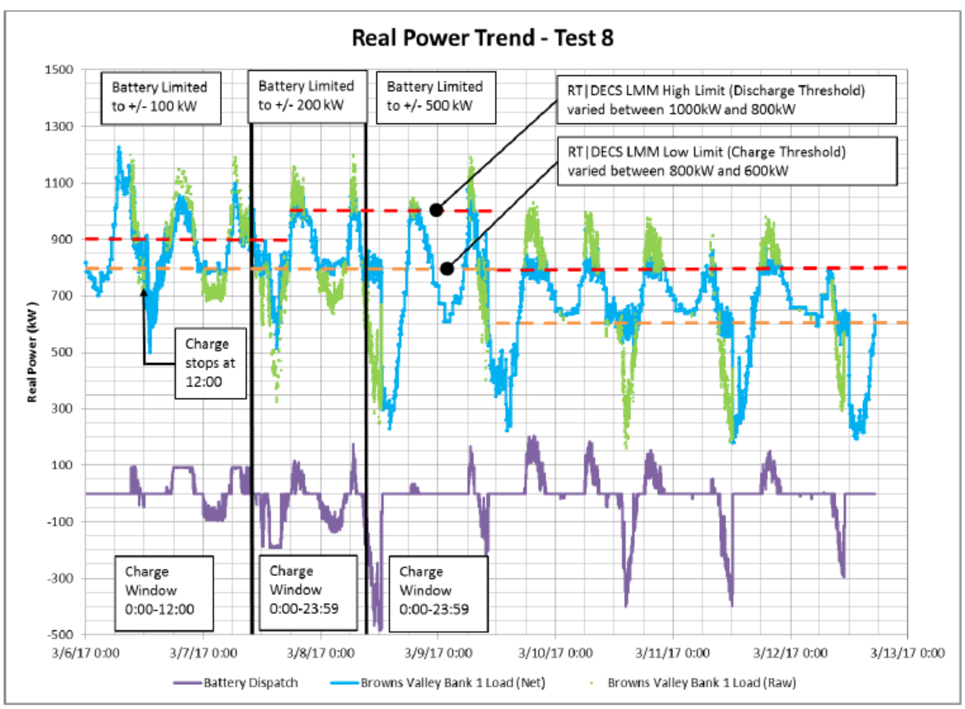
Proving Bank Load Management Functionality

After the initial performance tests were complete, PG&E initiated bank load management tests to prove the ultimate project objective of an energy storage system that autonomously shaved distribution load peaks. Given the lower seasonal loading on the bank during the testing window, loading observed on the substation was lower than the substation transformer bank rating of 2.4MW. However, to prove the bank load management functionality, PG&E adjusted the bank load limit as the value in RTDECS is entirely configurable. Over the course of one week, PG&E implemented different load limits between 0.8-1MW to test autonomous peak shaving functionality.

The results of the bank load management tests are shown below in Figure 4-4. The green series represents the gross load on the substation, with the blue series representing the net load observed after energy storage dispatch. The red and orange dotted lines show the upper and lower bank load management load limits, respectively. The technical team employed a phased testing approach and limited energy storage charge/discharge to ± 100kW for the first 36 hours, followed by a ± 200kW limit for the next 48 hours. After the first 84 hours, PG&E removed the system limitations and allowed dispatches up to the full range of ± 500kW.

Once the ± 100kW limit was lifted, the blue series never crosses above the dotted red line. This is the ultimate proof of the success of the RTDECS bank load management control scheme in the field. Since this initial week of peak shaving testing, PG&E has continued operating the system in autonomous bank load management mode and has observed similarly successful results. The best test of the system will be in the summer months of August through October when high, cooling driven loads drive Browns Valley substation loading near the 2.4MW transformer threshold.

Figure 4-4: Browns Valley Bank Load Management Mode Test Results



Challenges

As mentioned above, low Browns Valley substation loading imposed unforeseen constraints on field performance testing. In most cases these constraints could be managed, but in some cases it was impossible to validate compliance with certain non-critical performance metrics.

In addition, the current RTDECS load management mode load limits are configured using a custom application configuration editor interface where limits are set manually and then left unchanged until conditions warrant changes to the load limits. For purposes of this project, load limits were changed as needed by the project engineer, but the process was a bit cumbersome and entirely manual in nature.

Recommendations

PG&E recommends that energy storage procurement policy considers whether all critical performance criteria can be validated under all normal operating conditions in advance of contract award. In addition, teams should provide appropriate contingency plans and secondary compliance paths for validating non-critical performance criteria.

In addition, procurement teams deploying similar distribution deferral energy storage resources should consider options for dynamic adjustment of load management mode load limits to allow the optimal use of the resource during non-peak loading periods with minimal need for manual reconfiguration. Specifically, teams should evaluate the opportunity for controls that can accept either an operator direct command or an external signal to reset the load management load limits in real-time. Possible examples of external signals could be inputs derived from local weather or load forecasts.

Lastly, as noted above, the current RTDECS load management mode load limits are configured using a custom application configuration editor interface where limits are set manually. Simply setting the load limits based on the absolute peak summer loading conditions will cause the battery to sit idle for much of the year, so PG&E will desire to change these inputs at least seasonally. Though the load limit updating process is not particularly time consuming, a more dynamic load limit input capability, perhaps a date based formula approach, would enable a more cleanly-packaged and streamlined solution.

4.1.5 Operate

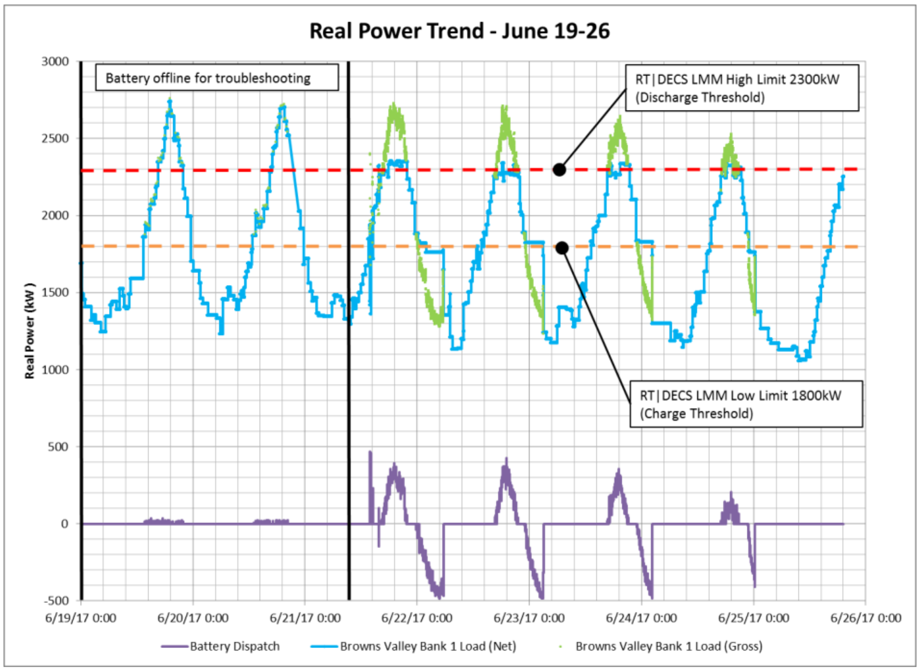
<u>Characterization of Operations</u>

Upon the conclusion of the initial performance characterization testing, the facility was released to full operations. As Browns Valley is a summer peaking substation, the most substantial system tests took place in the summer.

California experienced two significant heat waves over June and July 2017, which drove peak loading for the Browns Valley substation transformer above its normal rating threshold of 2.4MW. The first round of significant heat occurred the week of June 19. Figure 4-5 shows the results of the Browns Valley BESS providing peak shaving functionality with the bank load management threshold set at 2.3MW. As noted above, the green series shows the substation loading as it would have been without the energy storage system supporting distribution system operations. The blue series shows the net loading at the substation after accounting for BESS dispatch. The purple series shows the BESS real power dispatch and the dotted red line demarcates the 2.3MW threshold. Readers will note that on the days of 6/19 and 6/20 the total loading briefly surpassed the transformer rating of 2.4MW while the system was offline for troubleshooting. The emergency rating of the Browns Valley transformer bank is 3.1MW and loading on these days did not cross this threshold. Additional detail on the issues that caused the system to be offline on 6/19 and 6/20 is provided below.

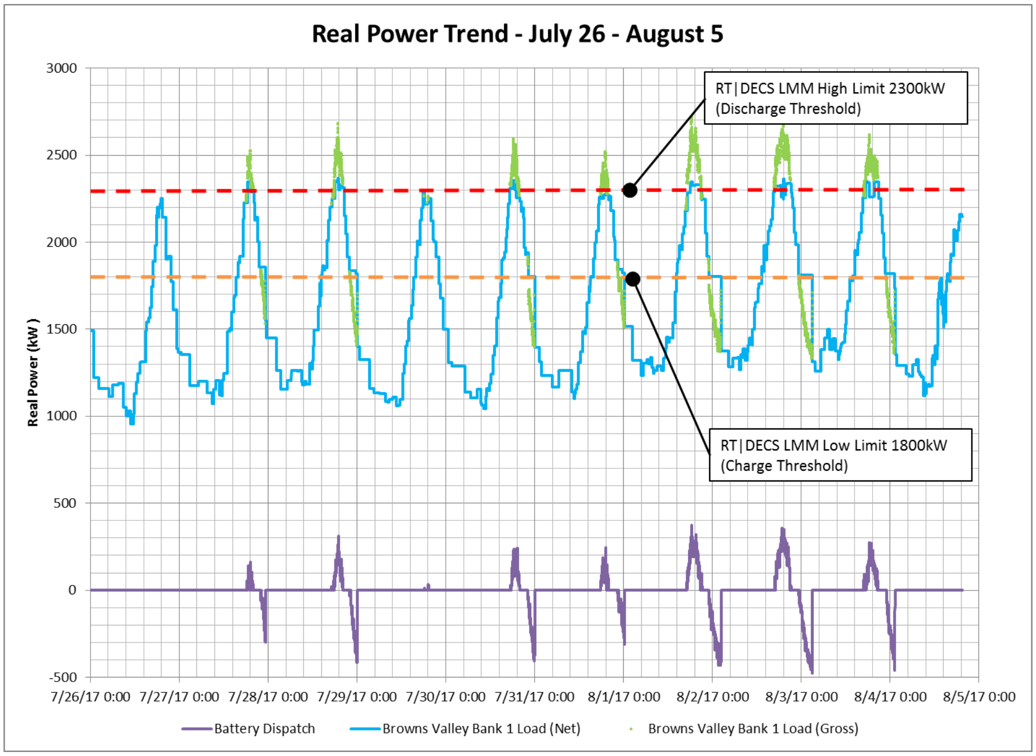
After 6/20, the fact that the blue series comes up to the red line but does not continue following the green series is a direct result of the BESS discharging on peak to alleviate overload conditions on the substation transformer bank.

Figure 4-5: Browns Valley Bank Load Management Mode Results (June 19-June 26)



Another heat wave arrived the week of July 24, 2017 and the BESS had another opportunity to keep loading below the Browns Valley substation transformer threshold. Fortunately, the system experienced no issues and was online for the entirety of this heat wave. Figure 4-6 shows the system loading results during the timeframe of July 26 through August 5 with the same color-coded legend.

Figure 4-6: Browns Valley Bank Load Management Mode Results (July 26-August 5)



Challenges

PG&E experienced some intermittent issues with the BESS inverters during two months of testing. In total, four hard fault events tripped the inverters on site requiring a physical resetting of the inverter circuit breaker. As noted above, one of the inverter tripping events happened right before the heat wave of the week of 6/19 and the project team was unable to complete troubleshooting in time before the bank loading temporarily went above the normal rating of 2.4MW on the days of 6/19 and 6/20. Ultimately, troubleshooting efforts determined that temperature-triggered line capacitor switching was causing voltage waveform disturbances significant enough to trip the inverters.

For background, PG&E installs line capacitors across the distribution system to support the delivery of reliable voltages at customer service points under a variety of system conditions. Many capacitors are switched on and off based on ambient temperature as temperature is a good proxy for load, and high loads can, if not adequately compensated for, cause voltage issues. This is the case with the three line capacitors on the Browns Valley circuit and the high temperature trigger is the reason the issues started in the spring.

Line capacitor switching typically causes no issues for a generic residential customer, since typical residential appliances and loads are not overly sensitive. However, for sensitive power electronics, such as inverters, certain arrangements can cause issues as the physical act of switching in and out the capacitor bank often leads to sub-cycle waveform disturbances. Under the right circumstances, these disturbances can be of sufficient magnitude that they can trip sensitive power electronic equipment, as was the case with the Browns Valley BESS inverters.

PG&E worked with the inverter manufacturer to identify the root cause, and the inverter settings were adjusted on site to temporarily halt operation on the occasional wave form distortions caused by line capacitor switching, and reconnect five minutes later. These settings are entirely configurable and PG&E continues to work with the inverter manufacturer to fine tune the system configuration. As of the publishing of this report, no inverter tripping events that required manual intervention have happened in over two months, since the new settings were deployed on site.

This anecdote describing inverter issues goes to show that DER-based solutions, which are almost always some type of inverter-based generation, still have some uncertainty associated with their operational deployments on the grid. Reliability is at the core of grid operations, and while inverter technologies are far from an "emerging technology," the truth is that the grid is becoming ever more reliant on this technology which is not yet fully understood across the industry. A timely example of the industry collectively working to advance this understanding is the June 2017 North American Electric Reliability Corporation (NERC) report chronicling the loss of nearly 1,200MW of inverter-based generation in Southern California on August 16, 2016.[10] The development of this report was supported by utilities, NERC, Western Electricity Coordinating Council, CAISO, key inverter vendors and various renewable energy developers. As the grid becomes more and more dependent on inverter-based generation, industry understanding of inverter-grid interactions will need to improve. The progression of collective understanding can be advanced through current and future demonstration projects like those implemented through the EPIC Program.

Recommendations

As of the writing of this report, PG&E reviews line capacitor settings as part of the development of distribution generator interconnection System Impact Studies (SIS), but the framing is in the context of voltage excursions at the customer end point, not from the perspective of potential line capacitor driven impacts to the generator. To date, sub-cycle level interaction between distribution-connected inverters and existing PG&E line capacitors has not been explicitly part of the SIS review.

PG&E coordinated to proactively address similar issues arising in the future, which could happen for any number of future distribution generation interconnections. While it is not anticipated at this time that sub-cycle-level analysis will become an upfront component of the SIS due to complexity and the often unknown specifications of inverters at that point in the interconnection process, this knowledge sharing will enable the more timely resolution of future issues should they arise in the field.

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10 http://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf.

5 Value Proposition

The purpose of EPIC funding is to support investments in technology demonstration and deployment projects that benefit the electricity customers of California. EPIC Project 1.02 Energy Storage for Distribution Operations has demonstrated that an energy storage system can be used to autonomously and effectively shave distribution load peaks. This same functionality and use case can be deployed more broadly to delay capacity expansions on both the transmission and distribution systems while maintaining and improving reliability.

5.1 Primary and Secondary Principles

5.1.1 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 two of these three primary principles in the following ways:

- Greater reliability and lower costs: The promise of energy storage systems is to provide greater system reliability at lower costs by deploying BESSs in high-value grid locations. Through this EPIC Project 1.02, and its sister project (EPIC Project 1.01), PG&E has deployed energy storage resources demonstrating two key energy storage use cases: distribution deferral and CAISO market participation. Using the knowledge gained and looking forward, PG&E seeks to deploy energy storage facilities in locations that have the ability for both use cases to be deployed in a single site, thus improving effectiveness.

5.1.2 Secondary Principles

EPIC also has a set of complementary secondary principles, including societal benefits, greenhouse gas (GHG) emissions reduction, the loading order, low-emission vehicles/transmission, economic development; and efficient use of ratepayer funds. This EPIC project contributes to the following secondary principles:

- GHG emissions reduction: To the extent energy storage resources can be used to replace natural gas based generation for peak power generation, and to the extent those energy storage resources are charged with low-carbon electricity, energy storage systems can reduce the net GHG emissions from the electricity sector. This project did not seek to quantify GHG or additional societal impacts.

5.2 Key Accomplishments

The following summarize the key accomplishments of the project over its duration:

- Identified energy storage site based on project objectives and site selection criteria: the availability of land, the availability of SCADA at the nearby substation, the presence of a residentially driven load profile and the presence of a small capacity overload.
- Deployed a 500kW/2MWh energy storage system at the Browns Valley substation in Browns Valley, CA.
- Developed lessons learned regarding procurement of utility-scale battery storage technology.
- Developed autonomous peak-shaving energy storage control application and tested in lab setting.

- Tested fully deployed energy storage system using a test protocol based on early versions of the EPRI Energy Storage Test Manual and analyzed results. Tests included: measurement of max power input, max charge power, roundtrip efficiency under various duty cycles, standby power consumption and the system's ability to follow a frequency-regulation-like signal, amongst other functionalities.
- Confirmed system capability of autonomous peak load shaving as needed for distribution deferral energy storage use case.
- Developed lessons learned regarding procurement of utility-scale battery storage technology.

5.3 Key Recommendations

For industry stakeholders considering energy storage procurement, PG&E provides a variety of recommendations:

- **Define unique energy storage control requirements upfront:** To date, energy storage controls have generally been built for commercial applications, and utility environments may require different functionalities and protocols.
- **Test energy storage use case control capabilities in a lab before controls implementation is on the critical path:** Energy storage controls are still far from standardized. Testing control capabilities in a lab in parallel with project deployment will ensure desired project use cases can be realized without project delay.
- **For demonstration projects with significant operational impact, engage operational teams at the concept stage:** The ultimate, long-term success of the project requires buy-in from operational teams; therefore, engaging with operations early on sets foundation for a smooth transition from construction to day-to-day operations. This is especially critical for distribution deferral type energy storage systems which aim to provide reliability services on the distribution system.
- **Include robust use case functionality requirements in the form of test protocols for RFOs:** PG&E's energy storage test protocol, as detailed in Appendix A, provided a robust way to characterize system use case functionality. Stakeholders considering energy storage deployments can leverage PG&E's protocol as appropriate and modify as needed for particular applications.

5.4 Technology Transfer PlanIOU'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:

- DistribuTECH 2017: San Diego, California | February 2, 2017
- Benchmarking conference call with Puget Sound Energy | April 17, 2017
- EPRI Energy Storage Integration Council meeting: Denver, Colorado | April 21, 2017
- Benchmarking conference call with San Diego Gas & Electric Company | April 27, 2017

5.4.2 Adaptability to Other Utilities and Industry

The following findings of this project are relevant and adaptable to other utilities and the industry:

- **Utility-operated energy storage can provide peak-shaving functionality:** The primary goal of EPIC Project 1.02 was to deploy an energy storage resource to autonomously provide up to 500kW of loading relief on the Browns Valley substation transformer bank for up to four hours. The project was sized based on a 10-year projection of peak loading at the Browns Valley substation compared to the 2.4MW rating of the substation transformer bank. The four-hour system duration was determined to be appropriate through load data analysis and is exemplary of what would be needed for a typical residential distribution circuit. The Browns Valley energy storage resource has proven capable of providing just this peak-shaving functionality as it can output the energy necessary to address projected peak loading conditions on the substation transformer bank.
- **Testing energy storage controls in the lab, prior to field deployment, leads to a smooth project:** First time field integration of energy storage controls is a recipe for project delays. Building on PG&E's learnings with previous energy storage installations, PG&E, PG&E's SCADA vendor and the energy storage system vendor vetted the energy storage controls functionality in a lab setting prior to field deployment. The lab testing took multiple months as numerous control intricacies were worked through. By the time of field deployment, all known issues were resolved and operations were not held up by system control issues.
- **PG&E's test protocol provides a robust assessment of energy storage facility use case capabilities which will be leveraged for future Energy Storage RFOs**: The test protocol developed for this project was based on early versions of the EPRI Energy Storage Test Manual. As described in Section 4.1.4 and detailed in Appendix A, the test protocol measured max power input, max charge power, roundtrip efficiency under various duty cycles, standby power consumption and the system's ability to follow a frequency-regulation-like signal, amongst other functionalities. The protocol proved successful at fully characterizing the capabilities of the system and PG&E will leverage this protocol and general project learnings in future Energy Storage RFOs.

In addition, the implementation and operational challenges associated with this project resulted in learnings that will inform PG&E's procurement of future energy storage resources, both utility-owned and utility-contracted through compliance with the IOU energy procurement targets as set forth in D. 10-03-040. Operational experiences gained from this project can also inform outstanding policy and implementation issues as identified in the Energy Storage Order Instituting Rulemaking (Rulemaking 15-03-011).

5.5 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.

6 Metrics

The following metrics in Table 6-1 were identified for this project and included in PG&E's EPIC Annual Report as potential metrics to measure project benefits at full scale.[11] Given the proof of concept nature of this EPIC project, these metrics are forward looking.

Table 6-1: Project Metrics

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
1. Potential energy and cost savings	
a. Number and total nameplate capacity of distributed generation facilities	See Table 4-2
b. Total electricity deliveries from grid-connected distributed generation facilities	See Table 4-5
c. Avoided procurement and generation costs	See Section 5
i. Nameplate capacity (MW) of grid-connected energy storage	See Section 5
3. Economic benefits	
a. Maintain / Reduce operations and maintenance costs	See Section 5
b. Maintain / Reduce capital costs	See Section 5
c. Reduction in electrical losses in the transmission and distribution system	See Section 5
4. Environmental benefits	
a. GHG emissions reductions (MMTCO2e)	See Section 5
5. Safety, power quality, and reliability (equipment, electricity system)	
b. Electric system power flow congestion reduction	See Section 5
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 (Public Utilities Code(Pub. Util. Code) §8360)	See Section 0
c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (Pub. Util. Code §8360)	See Section 0
d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (Pub. Util. Code §8360)	See Section 0
h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (Pub. Util. Code §8360)	See Section 0
k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (Pub. Util. Code §8360)	See Section 0
8. Effectiveness of information dissemination	
d. Number of information sharing forums held	See Section 5
9. Adoption of EPIC technology, strategy, and research data/results by others	
d. Successful project outcomes ready for use in California IOU grid (Path to market)	See Section 5

11 2015 PG&E EPIC Annual Report. Feb 29, 2016. http://www.pge.com/includes/docs/pdfs/about/environment/epic/EPICAnnualReportAttachmentA.pdf

7 Conclusion

For EPIC Project 1.02, the CPUC D.13-11-025 approved PG&E's EPIC 1 portfolio, and noted the following: "If successful, PG&E Project No. 2 (EPIC Project 1.02) will demonstrate, among other things, the ability to use energy storage more broadly to delay capacity expansions while maintaining or improving reliability." Consistent with the Decision, PG&E deployed a 500kW/2MWh energy storage system at the Browns Valley substation and integrated the energy storage system control into PG&E's SCADA system to deliver autonomous distribution peak shaving functionality.

EPIC Project 1.02 addressed two of the nine key barriers inhibiting energy storage deployment as identified in D.12-08-016: (1) "Lack of Definitive Operational Needs," and (2) "Lack of Commercial Operating Experience." EPIC Project 1.02 was designed to improve the technical understanding of these barriers in the context of distribution-reliability applications and to design innovative systems and processes to directly and indirectly address these barriers. Projects such as EPIC Project 1.02 represent a potentially attractive use case for future energy storage deployments.

EPIC Project 1.02 project performance testing measured max power input, max charge power, roundtrip efficiency under various duty cycles, standby power consumption and the system's ability to follow a frequency-regulation-like signal, amongst other functionalities. Results of the performance tests indicate that the Browns Valley BESS met or exceeded all of the applicable performance criteria within contractually allowed performance bands after accounting for the expected accuracy of the measurement devices used. Ultimately, the project was operational during multiple heat waves during the summer of 2017 and proved the ability for such an energy storage system to address peak overload conditions via an autonomous, SCADA-based control mechanism.

The RTDECS bank load management control scheme, which enables autonomous peak load shaving for distribution deferral use case, ultimately proved successful in the field and PG&E will continue operating the battery for future, continued learnings.

During project implementation, a variety of challenges were encountered and overcome. Nearly all challenges directly related to the relative newness of the energy storage deployments, such as the issues experienced with anomalous inverter tripping. As energy storage standards crystalize over time and as procurement teams better define requirements, deployments across the industry as a whole will become streamlined.

Energy storage resources hold significant promise to help California address a variety of renewable integration challenges, both today and in the future. The implementation and operational challenges associated with this project resulted in learnings that will inform PG&E's and other utilities' procurement of future energy storage resources, both utility-owned and utility-contracted, through compliance with the IOU energy procurement targets as set forth in D.10-03-040 and beyond.

8 Appendix A: Performance Test Protocol and Results

Chart legend note: For all charts that follow with the exception of Test #8,[12] the blue series represents the real power set points passed from the controller to the energy storage system. The purple series represents the metered real power output (discharging) or input (charging). The dark green series represents the reactive power set points passed from the controller to the energy storage system. The light green series represents the metered reactive power output (producing volt-ampere reactive (VARs)) or input (consuming VARs). The dotted red series represents the state of charge trend over the course of the tests.

Performance Testing Protocol:

1. General

1.1 This document describes the minimum performance tests required to ascertain compliance with minimum performance specifications, determine conformance with manufacturer's stated values, and provide general characterization for the Facility at beginning of life.

1.2 Variations to the test plans, including additional testing and or measurement above and beyond what is described herein, may be required depending on the Facility technology and manufacturer's stated features and will be evaluated on a case by case basis.

1.3 All performance tests defined herein require the use of Facility instrumentation and balance of plant digital multi-function meter for measurement and reporting of data.

1.4 Select performance tests may require the use of separate calibrated field instrumentation for measurement and reporting of data not available through the use of Facility instrumentation and balance of plant digital multi-function meter or at the discretion of PG&E.

1.5 Facility performance testing will be conducted via the PG&E SCADA interface or where specifically indicated via the resource level control/optimization application by sending real and reactive power set points to the Facility Site Master Controller.

1.6 Where specified herein, idle refers to leaving the Facility in a ready state but without any supplemental power being provided to maintain SOC.

1.7 Where specified herein, float refers to leaving the Facility in a ready state with supplemental power being provided to maintain SOC.

1.8 Ambient conditions (temperature and humidity) shall be recorded for reference as independent variables for all performance testing.

2. Maximum Power/Full Duty Cycle Efficiency/Daily Efficiency/Power Quality (3 full cycles, 3 days)

2.1 Set Facility Data Historian and balance of plant digital multi-function meter to log current date/time, Alternating Current (AC) real and reactive power, Root Mean Square (RMS) voltage and current for each phase, voltage and current harmonic magnitude for the first 50 harmonics, and voltage and current total harmonic distortion (THD) at minimum 10-second intervals.

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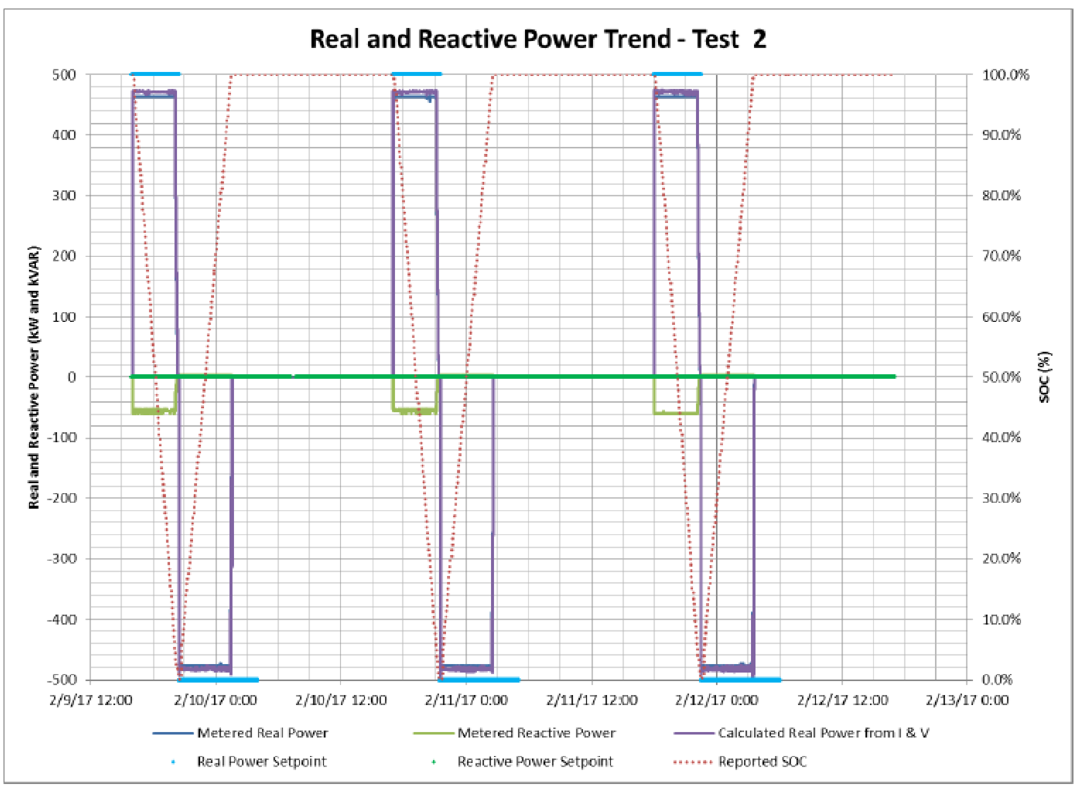
[12] See Test #8 description for a description of the Test #8 legend.

2.2 Set Energy Storage System (ESS) Data Historian to log ESS thermal parameters as applicable for the technology at the same logging frequency or as a minimum at 5-minute intervals.
2.3 Set the ESS Local/Remote switch to Remote to enable SCADA operation of the ESS.
2.4 If not at 100 percent SOC, charge the ESS until available charge power is reported as 0kW according to the manufacturer's standard charge profile at Cmax.
2.5 Allow the ESS to idle at 100 percent SOC according to the manufacturer's recommendations or for a minimum of one minute where undefined.
2.6 Discharge the Facility at Dmax until available charge power is reported as 0kW.
2.7 Allow the Facility to idle at 0 percent SOC according to the manufacturer's recommendations or for a minimum of one minute where undefined.
2.8 Charge the Facility until available charge power is reported as 0kW according to the manufacturer's standard charge profile at Cmax.
2.9 Set the Facility to idle at 100 percent SOC and resume testing the following day.
2.10 Repeat steps 2.5 through 2.9 four more times to complete five full cycles.
2.11 Set the Facility to idle at 100 percent SOC until the next test.
2.12 Data collected will be used to determine whether Maximum Power and Discharge Duration performance meets minimum specifications and to confirm Charge Duration and Full Duty Cycle Efficiency meets manufacturer's stated values.

Figure A-8-1: Performance Test #2 Results – Maximum Power/Full Duty Cycle Efficiency/Daily Efficiency/Power Quality

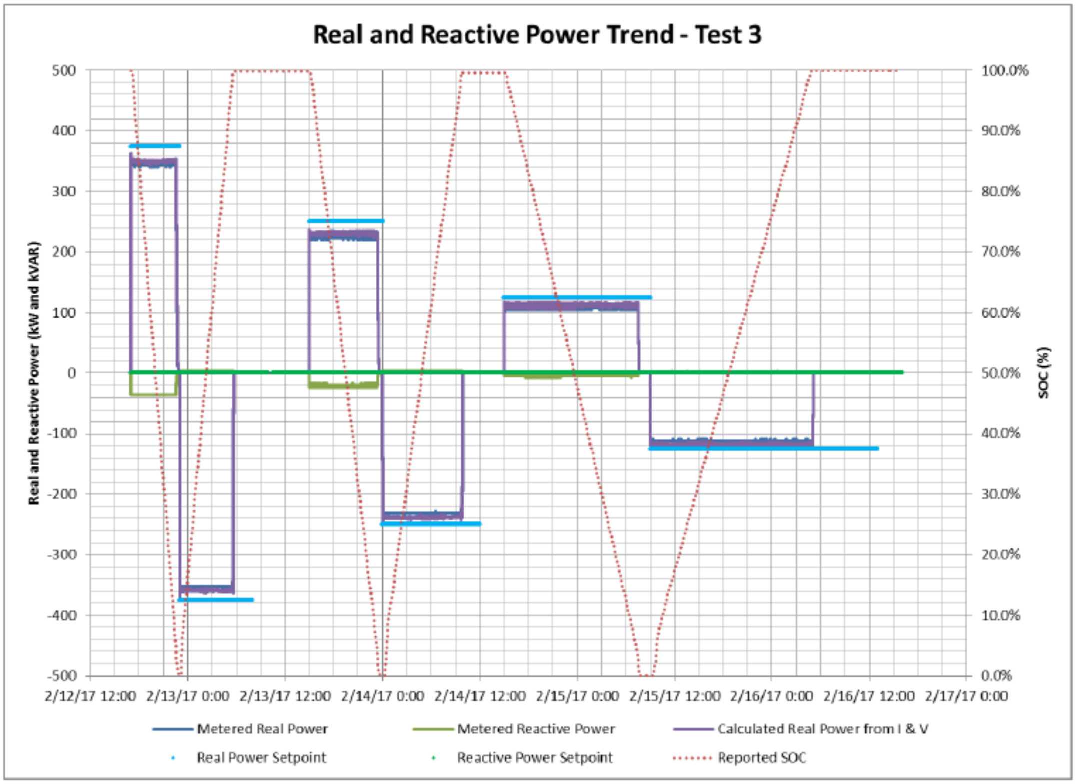


Description: The blue and purple trends show the system successfully followed the Dmax and CMax real power set points passed from the controller across the range of state of charge. The efficiency values were calculated based on this data.

3. Stored Energy Capacity (3 days)

3.1 Set Facility Data Historian and balance of plant digital multi-function meter to log current date/time, AC real and reactive power, and RMS voltage and current for each phase at minimum 10-second intervals.
3.2 Set Facility Data Historian to log Facility thermal parameters as applicable for the technology at the same logging frequency or as a minimum at 5-minute intervals.
3.3 Set the Facility Local/Remote switch to Remote to enable SCADA operation of the Facility.
3.4 If not at 100 percent SOC, charge the Facility until available charge power is reported as 0kW according to the manufacturer's standard charge profile at Cmax.
3.5 Allow the Facility to idle at 100 percent SOC according to the manufacturer's recommendations or for a minimum of one minute where undefined.
3.6 Discharge the Facility at 0.75*Dmax until available charge power is reported as 0kW.
3.7 Allow the Facility to idle at 0 percent SOC according to the manufacturer's recommendations or for a minimum of one minute where undefined.
3.8 Charge the Facility until available charge power is reported as 0kW according to the manufacturer's standard charge profile at 0.75*Cmax.
3.9 Allow the Facility to idle at 100 percent SOC according to the manufacturer's recommendations or for a minimum of one minute where undefined.
3.10 Discharge the Facility at 0.5*Dmax until available charge power is reported as 0kW.
3.11 Allow the Facility to idle at 0 percent SOC according to the manufacturer's recommendations or for a minimum of one minute where undefined.
3.12 Charge the Facility until available charge power is reported as 0kW according to the manufacturer's standard charge profile at 0.5*Cmax.
3.13 Allow the Facility to idle at 100 percent SOC according to the manufacturer's recommendations or for a minimum of one minute where undefined.
3.14 Discharge the Facility at 0.25*Dmax until available charge power is reported as 0kW.
3.15 Allow the Facility to idle at 0 percent SOC according to the manufacturer's recommendations or for a minimum of one minute where undefined.
3.16 Charge the Facility until available charge power is reported as 0kW according to the manufacturer's standard charge profile at 0.25*Cmax.
3.17 Set the Facility to idle at 100 percent SOC until the next test.
3.18 Data Collected will be used to characterize general Facility performance and determine usable capacity at various discharge and charge rates.

Figure A-8-2: Performance Test #3 Results – Stored Energy Capacity



Description: The blue and purple trends show the system successfully followed the real power set points passed from the controller at a range of levels (75% DMax, 50% DMax, 25% DMax, etc.) across a range of state of charge.

4. Partial Duty Cycle (1 day)

4.1 Set Facility Data Historian and balance of plant digital multi-function meter to log current date/time, AC real and reactive power, and RMS voltage and current for each phase at minimum 10-second intervals.

4.2 Set Facility Data Historian to log Facility thermal parameters as applicable for the technology at the same logging frequency or as a minimum at 5-minute intervals.

4.3 Set the Facility Local/Remote switch to Remote to enable SCADA operation of the Facility.

4.4 If not at 100 percent State of Charge (SOC), charge the Facility until available charge power is reported as 0kW according to the manufacturer's standard charge profile at Cmax.

4.5 Allow the Facility to idle at 100 percent SOC according to the manufacturer's recommendations or for a minimum of one minute where undefined.

4.6 Discharge the Facility at Dmax to 75 percent SOC.

4.7 Allow the Facility to idle at 75 percent SOC according to the manufacturer's recommendations or for a minimum of one minute where undefined.

4.8 Discharge the Facility at Dmax to 25 percent SOC.

4.9 Allow the Facility to idle at 25 percent SOC according to the manufacturer's recommendations or for a minimum of one minute where undefined.

4.10 Charge the Facility to 75 percent SOC according to the manufacturer's standard charge profile at Cmax.

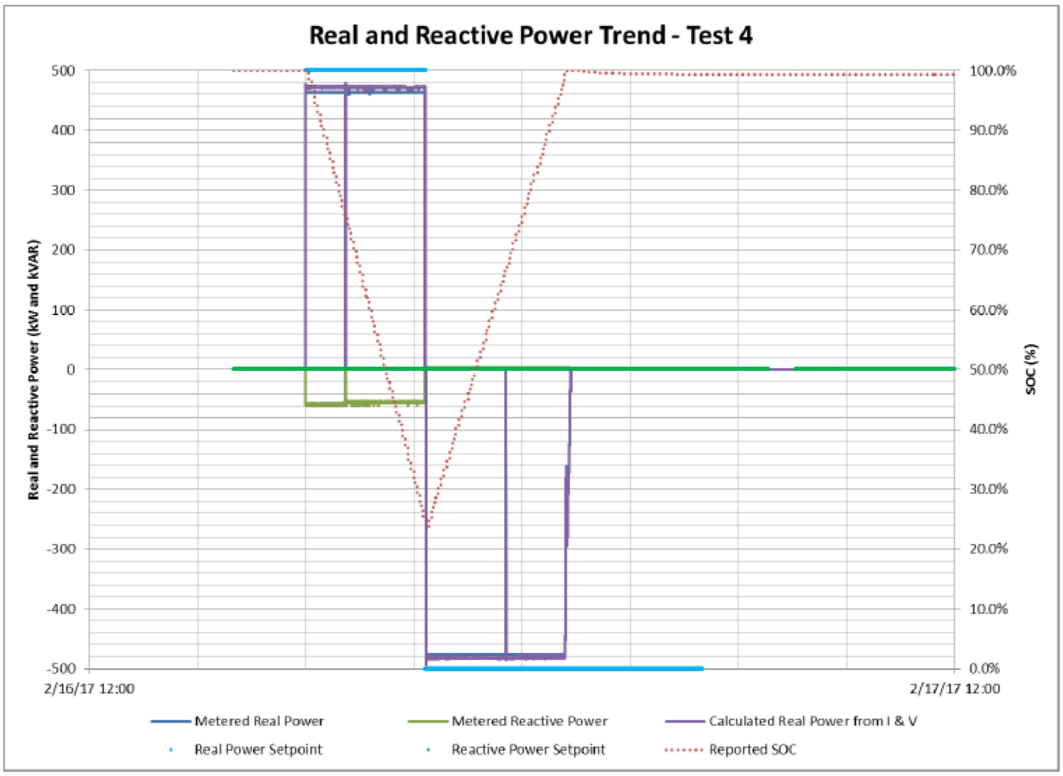
4.11 Allow the Facility to idle at 75 percent SOC according to the manufacturer's recommendations or for a minimum of one minute where undefined.

4.12 Charge the Facility until available charge power is reported as 0kW according to the manufacturer's standard charge profile at Cmax.

4.13 Set the Facility to idle at 100 percent SOC until the next test.

4.14 Data collected will be used to confirm Partial Duty Cycle performance and Partial Duty Cycle Efficiency meet manufacturer's stated values.

Figure A-8-3: Performance Test #4 Results – Partial Duty Cycle



Description: A partial duty cycle was completed from 100 percent state of charge to ~25 percent state of charge, with pauses at 75 percent state of charge. The efficiency was calculated based on the total energy input and output over the course of this test.

5. **Standby Self-Discharge (1 day)**

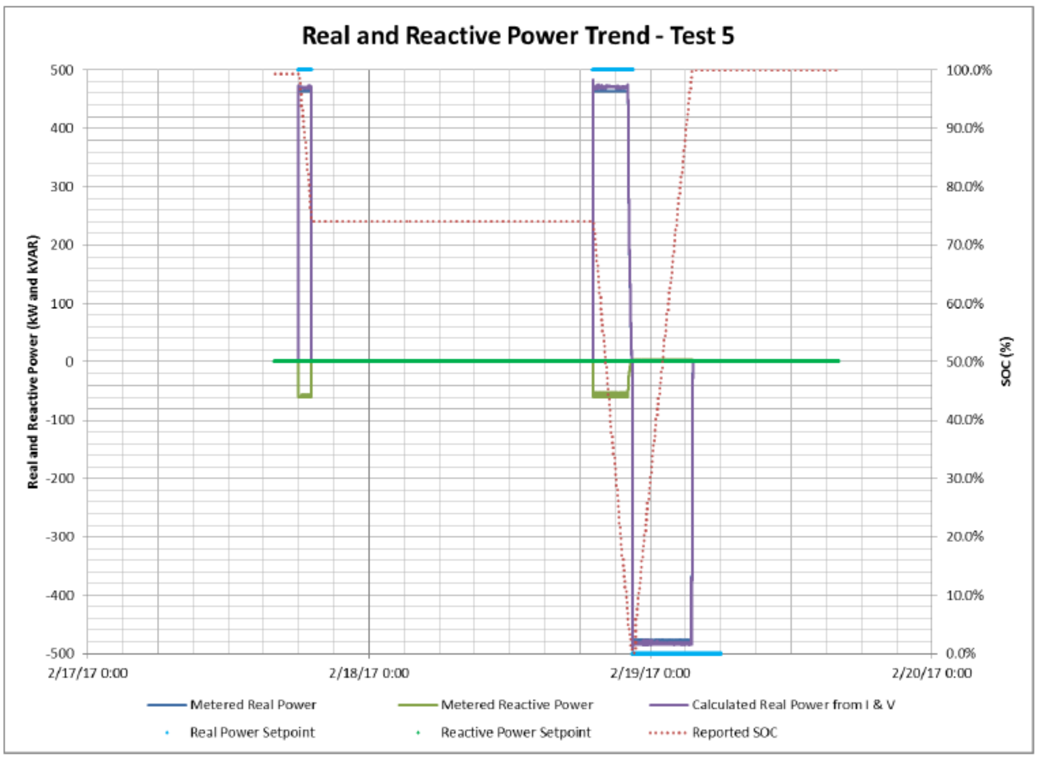
5.1 Set Facility Data Historian and balance of plant digital multi-function meter to log current date/time, AC real and reactive power, and RMS voltage and current for each phase at minimum 10-second intervals.

5.2 Set Facility Data Historian to log Facility thermal parameters as applicable for the technology at the same logging frequency or as a minimum at 5-minute intervals.

5.3 Set the Facility Local/Remote switch to Remote to enable SCADA operation of the Facility.

5.4 If not at 100 percent State of Charge (SOC), charge the Facility until available charge power is reported as 0kW according to the manufacturer's standard charge profile at Cmax.
5.5 Allow the Facility to idle at 100 percent SOC according to the manufacturer's recommendations or for a minimum of one minute where undefined.
5.6 Discharge the Facility at Dmax to 75 percent SOC.
5.7 Allow the Facility to idle at 75 percent SOC for a period of 24 hours.
5.8 Discharge the Facility at Dmax until available charge power is reported as 0kW.
5.9 Allow the Facility to idle at 0 percent SOC according to the manufacturer's recommendations or for a minimum of one minute where undefined.
5.10 Charge the Facility until available charge power is reported as 0kW according to the manufacturer's standard charge profile at Cmax.
5.11 Set the Facility to idle at 100 percent SOC until the next test.
5.12 Data collected will be used to confirm Standby Self-Discharge performance meets manufacturer's stated values.

Figure A-8-4: Performance Test #5 Results – Standby Self-Discharge

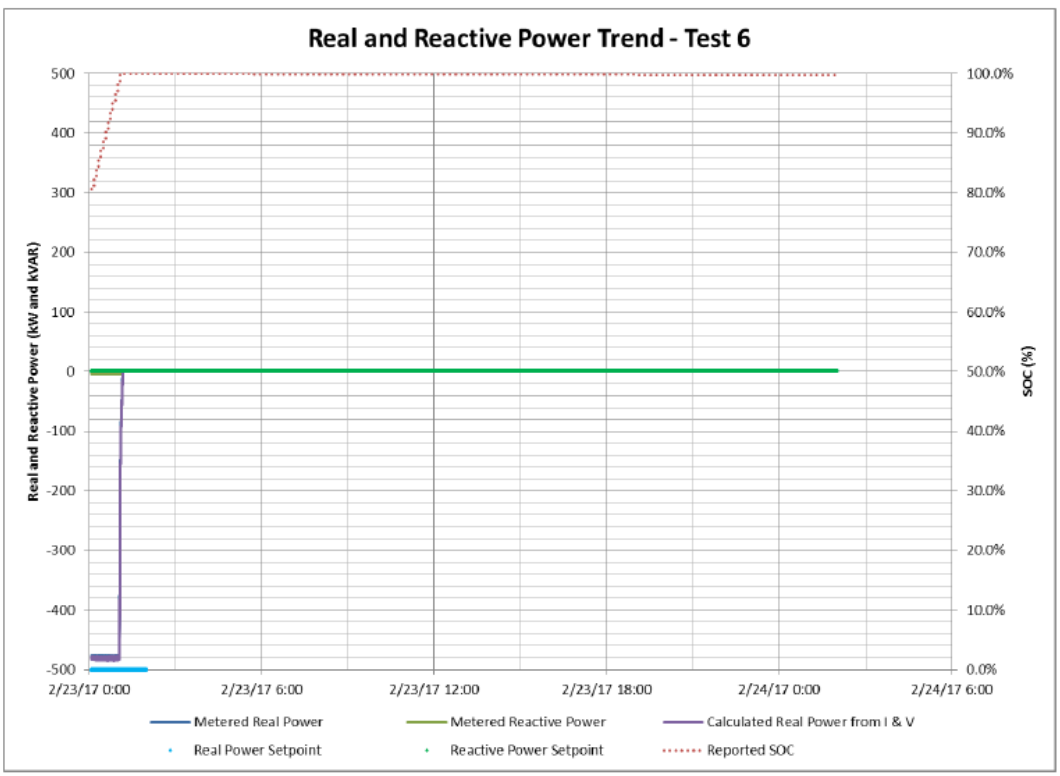


Description: The system starts at 100 percent state of charge and is discharged to 75 percent state of charge and then left idle for 24 hours. The system is then fully discharged and subsequently fully charged. The purpose of this test is to measure the self-discharge that occurs over the 24 hours idling at 75 percent state of charge.

6 Standby Energy Consumption (1 day)

6.1 Set Facility Data Historian and balance of plant digital multi-function meter to log current date/time, AC real and reactive power, and RMS voltage and current for each phase at minimum 10-second intervals.
6.2 Set Facility Data Historian to log Facility thermal parameters as applicable for the technology at the same logging frequency or as a minimum at 5-minute intervals.
6.3 Set the Facility Local/Remote switch to Remote to enable SCADA operation of the Facility.
6.4 If not at 100 percent State of Charge (SOC), charge the Facility until available charge power is reported as 0kW according to the manufacturer's standard charge profile at Cmax.
6.5 Allow the Facility to float at 100 percent SOC for a period of 24 hours.
6.6 Discharge the Facility at Dmax until available charge power is reported as 0kW.
6.7 Allow the Facility to idle at 0 percent SOC according to the manufacturer's recommendations or for a minimum of one minute where undefined.
6.8 Charge the Facility until available charge power is reported as 0kW according to the manufacturer's standard charge profile at Cmax.
6.9 Set the Facility to idle at 100 percent SOC until the next test.
6.10 Data collected will be used to confirm Standby Energy Consumption performance meets manufacturer's stated values.

Figure A-8-5: Performance Test #6 Results – Standby Energy Consumption



Description: The system is charged to 100 percent state of charge and left to float at 100 percent state of charge for a period of 24 hours. The purpose of this test is to quantify the standby energy required to keep the system at 100 percent state of charge.

7. Other Tests for Response Time, Power Factor (Real and Reactive Power), and Frequency Regulation (1 day)

7.1 Set Facility Data Historian and balance of plant digital multi-function meter to log current date/time, AC real and reactive power, and RMS voltage and current for each phase at 1-second intervals.

7.2 Set Facility Data Historian to log Facility thermal parameters as applicable for the technology at the same logging frequency or as a minimum at 5-minute intervals.

7.3 Set the Facility Local/Remote switch to Remote to enable SCADA operation of the Facility.

7.4 If not at 100 percent State of Charge (SOC), charge the Facility until available charge power is reported as 0kW according to the manufacturer's standard charge profile at Cmax.

7.5 Allow the Facility to idle at 100 percent SOC according to the manufacturer's recommendations or for a minimum of one minute where undefined.

7.6 Discharge the Facility at Dmax to 50 percent SOC.

7.7 Allow the Facility to idle at 50 percent SOC according to the manufacturer's recommendations or for a minimum of one minute where undefined.

7.8 Discharge the Facility at Dmax for five minutes.

7.9 Allow the Facility to idle according to the manufacturer's recommendations or for a minimum of one minute where undefined.

7.10 Charge the Facility at Cmax for five minutes.

7.11 Allow the Facility to idle according to the manufacturer's recommendations or for a minimum of one minute where undefined.

7.12 Discharge the Facility at Dmax for five minutes.

7.13 As permissible per manufacturer's recommendations, without any idle time immediately charge the Facility at Cmax for five minutes.

7.14 As permissible per manufacturer's recommendations, without any idle time immediately discharge the Facility at Dmax for five minutes.

7.15 Allow the Facility to idle according to the manufacturer's recommendations or for a minimum of one minute where undefined.

7.16 As permissible per manufacturer's recommendations, discharge the Facility at the appropriate real and reactive power set points for a minimum of five minutes for each set point combination to achieve leading and lagging power factor values within the manufacturer's stated values.

7.17 Allow the Facility to idle at 50 percent SOC according to the manufacturer's recommendations or for a minimum of one minute where undefined.

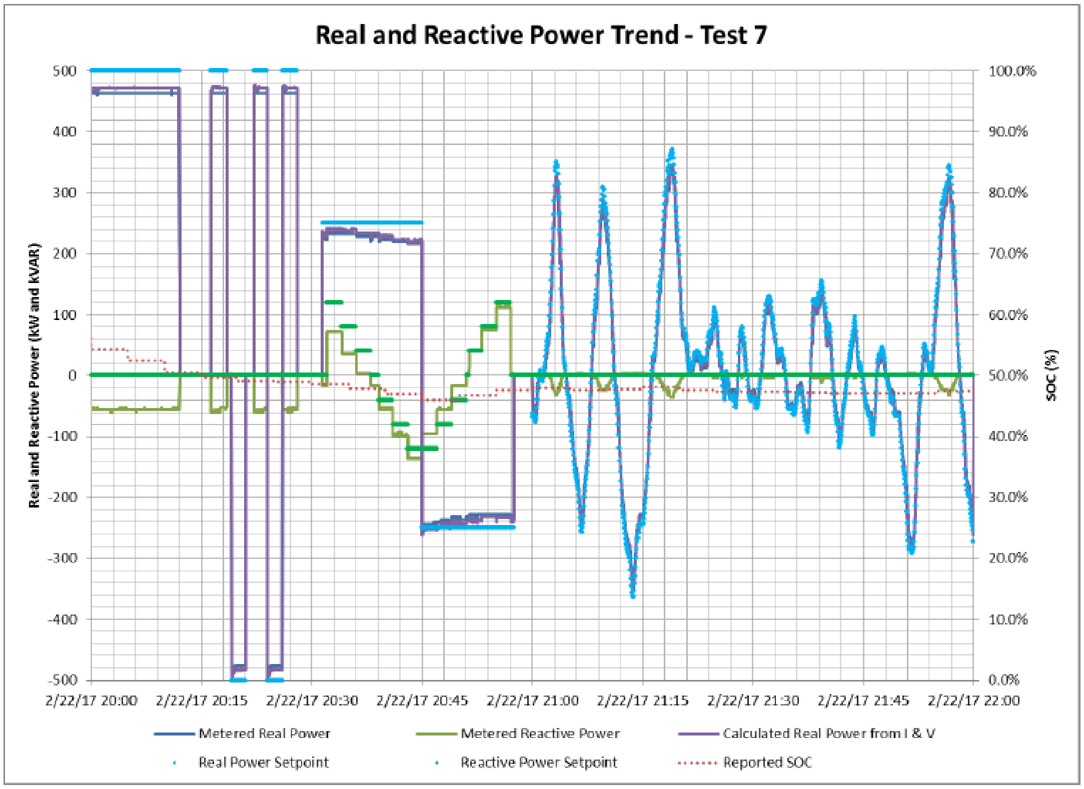
7.18 Discharge the Facility in accordance with a frequency regulation profile provided by PG&E.

7.19 Charge the Facility until available charge power is reported as 0kW according to the manufacturer's standard charge profile at Cmax.

7.20 Set the Facility to idle at 100 percent SOC until the next test.

7.21 Data collected will be used to confirm Power Factor performance meets manufacturer's stated values.

Figure A-8-6: Performance Test #7 Results – Other Tests for Response Time, Power Factor (Real and Reactive Power), and Frequency Regulation



Description: PG&E developed a variety of other tests to gauge system performance. Moving from left to right, the system was passed a variety of real power set points based on a CAISO frequency regulation signal to measure responsiveness. Second, the system was passed a variety of real and reactive power set points to measure the system's ability to discharge or charge at different power factors. Lastly, the system was passed a series of real point set points consistent with a wind renewable integration signal as developed by PG&E through prior energy storage testing work.

8. Substation Bank Load Management (SCADA Control Application) (2 days)

8.1 Set Facility Data Historian and balance of plant digital multi-function meter to log current date/time, AC real and reactive power, and RMS voltage and current for each phase at 1-second intervals.

8.2 Set Facility Data Historian to log Facility thermal parameters as applicable for the technology at the same logging frequency or as a minimum at 5-minute intervals.

8.3 Set the Facility Local/Remote switch to Remote to enable SCADA operation of the Facility.

8.4 If not at 100 percent State of Charge (SOC), charge the Facility until available charge power is reported as 0kW according to the manufacturer's standard charge profile at Cmax.

8.5 Allow the Facility to idle at 100 percent SOC according to the manufacturer's recommendations or for a minimum of one minute where undefined.

8.6 Discharge the Facility at Dmax to 50 percent SOC.

8.7 Allow the Facility to idle at 50 percent SOC according to the manufacturer's recommendations or for a minimum of one minute where undefined.

8.8 Configure the SCADA control application with high and low substation bank load limits and predefined time windows as provided by PG&E.

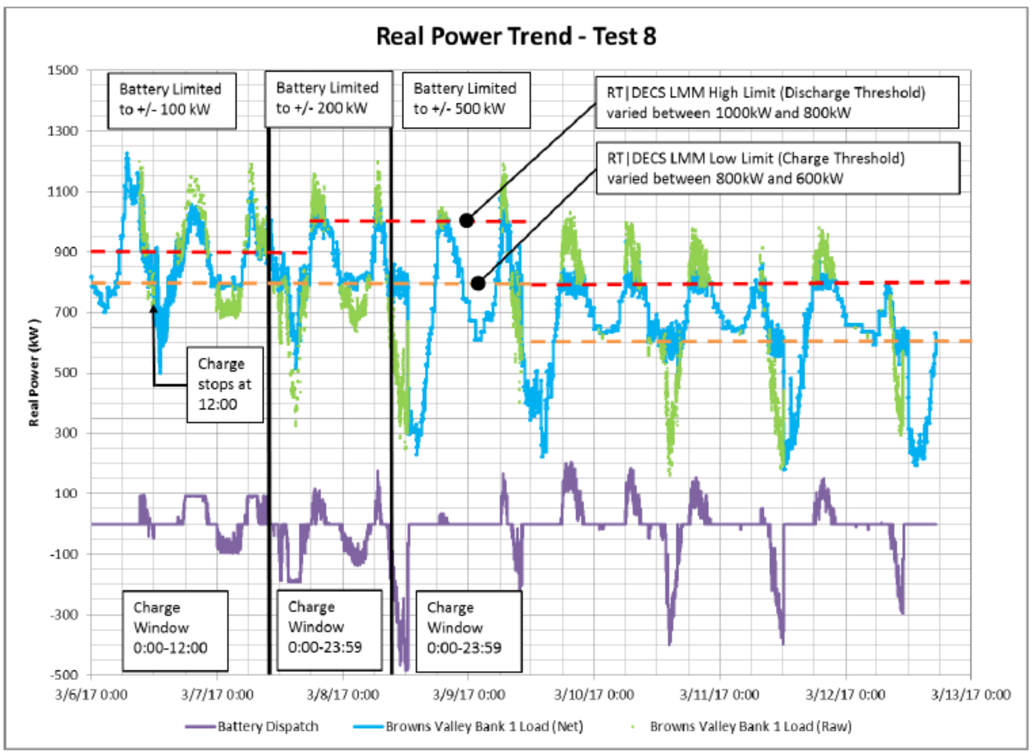
8.9 Enable the resource level control/optimization application and dispatch the Facility to manage substation bank load based on SCADA bank load measurements for up to 48 consecutive hours.

8.10 Charge the Facility until available charge power is reported as 0kW according to the manufacturer's standard charge profile at Cmax.

8.11 Set the Facility to idle at 100 percent SOC until the next test.

8.12 Data collected will be used to characterize general substation bank load management performance using the SCADA control application.

Figure A-8-7: Performance Test #8 Results – Substation Bank Load Management



Description: For this chart, the green series represents the raw, or gross, loading on the substation. The purple series represents the battery system dispatch profile. The blue series represents the net loading at the substation after accounting for battery charge/discharge. The red and orange dotted lines represent the upper and lower thresholds entered into the bank load management control scheme. The proof of the peak-shaving system working is that the blue series does not go beyond the red threshold.