EPIC Final Report

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Administrator	**San Diego Gas & Electric Company**
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Module Name	**Pre-Commercial Demonstration of Methodologies and Tools for Energy Storage Integration into Smart Distribution Circuits**
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Attribution

This comprehensive final report documents work done in this EPIC activity.

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EXECUTIVE SUMMARY

This executive summary overviews the work performed in EPIC-1, Project 5, Module 2 on Smart Distribution Circuit Demonstrations. It is a companion to other activities in that project.

Project Objectives and Chosen Focus

The objective of EPIC-1, Project 5 was to perform pilot demonstrations of smart distribution circuit features and associated simulation work to identify best practices for integrating new and existing distribution equipment in these circuits.

Energy storage systems are key components of smart distribution circuits with variety of applications that can enhance performance and provide superior value proposition in future distribution circuits.

The chosen focus of this specific project module was on Pre-Commercial Demonstration of Methodologies and Tools for Energy Storage Integration into Smart Distribution Circuits. The work included:

- Assessing the present state of energy storage systems (ESS) at SDG&E, including assessment and design approaches utilized, application selection processes applied and final selections, as well as areas for potential enhancements.
- Identifying candidate methodologies and tools that could be used in future energy storage projects as part of distribution circuit modernization programs, based on examination of available tools and methodologies utilized by SDG&E and/or other utility practices and state-of-the-art in the industry.
- Selecting a series of use cases to evaluate ESS solutions and to perform overall economic analysis of the solution versus conventional approaches based on comparative capital costs and market benefits. The use cases included examination of the benefits of stacking applications of the ESS. The use cases were aligned with SDG&E ESS strategic planning needs.
- Demonstrating state-of-the-art methodologies and tools for structured and consistent assessment of energy storage projects, to cover both technical studies (planning and design) and business evaluation.
- Preparing a comprehensive final report, including findings, conclusions, and recommendations on which methodologies and tools should be used commercially in routine planning by SDG&E.

Key Findings

- The methods and tools discussed can significantly improve the benefit/cost analysis results when stacking of application, reliability and other benefits offered by ESS are considered.
- The process for implementing distribution ESS in the markets has multiple hurdles to overcome. Included are regulatory approval of the evaluation framework and establishing the tools and process to ensure the ESS is ready to perform its distribution system value when needed.
- Detailed ESS distribution application evaluation require time-series analysis. However, commercial tools available today do not use time-series analysis and have limitations in the

accuracy of the assessments possible when analyzing distribution system issues in conjunction with ESS applications and solutions.

- A major shortcoming of the existing tools and models is that most tools use one type of "generator" representation (typically synchronous generator model) as a proxy for an energy storage system during the discharge mode, and load models as a proxy for energy storage in a charge mode.
- Most tools focus on single application analysis such as peak shaving, generation shifting, or congestion management. None of the available tools can analyze stacking of applications and/or added value of market participation in conjunction with distribution reliability applications.
- Distribution planning software tools have limited or no capabilities in performing power flow analyses on part of a distribution circuit that is separated from the main source (substation) in an isolated (island) mode.
- The methodology for performing distribution planning studies should incorporate the addition of newly developed time-based power flow analytics and time-series load/resource data for enabling hosting capacity analysis.
- Energy storage system models that incorporate accurate characteristics of the power conversion systems, the energy storage technology, and controls with considerations for operating constraints of real world utilization need to be developed.
- ESS benefit/cost analysis that relies solely on capital upgrade deferral or renewable smoothing is unlikely to provide cost-effective applications based on current ESS costs and operation and maintenance (O&M) charges. Adding market applications, especially ancillary services, can significantly improve the economics of ESS. However, market participation will add complexity into the analysis and evaluation process. The ESS sizing and technology selection has to be also carefully examined based on the operating constraints and impact on power quality of distributions systems.
- There are multiple challenges to achieve the potential benefits of ESS deployment but all are expected to be manageable and become more mainstream as new installations and ESS applications are deployed

Key Recommendations and Next Steps

- It was recommended that analysis methodologies and ESS evaluation tools similar to the ones investigated and demonstrated in this project should be considered in assessment of future ESS projects. Incorporating a commonly applied analysis tool that can evaluate various ESS applications to quantify benefits and various value-added opportunities will significantly improve the economics of the projects and will increase benefits to ratepayers.
- It would be beneficial to utilize an integrated analytical platform and associated methodologies across various business units that are involved in ESS projects from planning to operation, to ensure that estimated benefits would be properly realized in the field and during operation.
- Further standardization of the deployment aspects (engineering and controls) and proper site integration into distribution management systems for automated control and operation should also be emphasized as next critical steps.

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AB	Assembly Bill
AES	Advanced Energy Storage
AGC	Automatic Generation Control
AMI	Advanced metering Infrastructure
ANSI	American National Standards Institute
ASET	Automated Security Enhancement Tool
BESS	Battery Energy Storage System
BOP	Balance of Plant
CAIDI	Customer Average Interruption Duration Index
CAISO	California Independent System Operator
CAM	Computer Aided Manufacturing
CAPEX	Capital Expenditure
CCUD	Circuit for Capacity Upgrade Deferral
CC	Cycle Charging
CD	Capital Deferral only
CDA	Capacity Deferral and Arbitrage
CDAAM	Capacity Deferral, Arbitrage and Ancillary Service Market
CEC	California Energy Commission
CIS	Customer Information System
COE	Cost of Energy
CMG	Circuit for Microgrid
CPUC	California Public Utilities Commission
CPVIM	Circuit for PV Impact
DA	Day Ahead
DBE	Diverse Business Enterprise
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DNI	Direct Normal Irradiance
DOE	Department of Energy
D-SCADA	Distribution SCADA
DVC	Distributed Voltage Control
EOL	End of Line
EPIC	Electric Program Investment Charge
EPS	Electric Power System
EMTDC	Electromagnetic Transient and Direct Current
ESCT	Energy Storage Cost Template
ESP	Expedited Storage Projects

ESS	Energy Storage System
EV	Electrical Vehicle
FAT	Factory Acceptance Test
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location, Isolation and Services Restoration
GHI	Global Horizontal Irradiance
GRC	General Rate Case
HA	Hour Ahead
HOMER	Hybrid Optimized Model for Electric Renewables (Software)
IEEE	Institute of Electrical and Electronics Engineers
ISO	Independent System Operator
kW	Kilowatts
kWH	Kilowatt Hour
LACC	Levelized Annual Cost of Capital
LF	Load Following
LMP	Locational Marginal Price
MIP	Mixed Integer Programming
MG	Microgrid
MVA	Mega Volt Ampere
MW	Megawatts
MWH	Megawatt Hour
NASA	National Aeronautics and Space Administration
NGR	Neutral Grounding Resistor
NODES	Network Optimized Distributed Energy Systems
NOPR	Notice of Proposed Rulemaking
NPC	Net Present Cost
NREL	National Renewable Energy Laboratory
NO	Normally Open
NPV	Net Present Value
OH	Overhead
OPEX	Operating Expense
OPF	Optimal Power Flow
PEV	Plug-in Electric Vehicle
POC	Point of Connection
PSCAD	Power System Computed Aided Design (Software)
PSLF	Positive Sequence Load Flow (Software)
PPA	Power Purchase Agreement
PV	Photovoltaic
R&D	Research and Development

RACI	Responsible-Accountable-Consulted-Informed
RFP	Request for Proposal
ROC	Rate of Charge
ROCP	Rate of Change of Active Power
ROI	Return on Investment
ROR	Rate of Return
RT	Real Time
RTP	Real Time Pricing
SAIDI	System Average Interruption Duration Index
SAM	System Advisor Model (Software)
SCADA	Supervisory Control and Data Acquisition
SCC	Short Circuit Capacity
SCUC	Security Constrained Unit Commitment
SDG&E	San Diego Gas and Electric
SOC	State Of Charge
SRE	Sempra Energy
T & D	Transmission and Distribution
TMY	Typical Meteorological Year
TOU	Time of Use
TOV	Temporary Overvoltage
UG	Underground
VAF	Vanadium Redox Flow Battery
VAR	volt-ampere reactive
VBA	Visual Basic for Applications
VOM	Variable Operation and Maintenance

1 INTRODUCTION

1.1 Objective

This project module was part of EPIC-1, Project 5 on smart distribution circuit demonstrations. The objective of EPIC-1, Project 5 was to perform pilot demonstrations of smart distribution circuit features and associated simulation work to identify best practices for integrating new and existing distribution equipment in these circuits. Simulation studies were utilized to optimize a particular circuit and the desired features in that circuit to assess their suitability for widespread commercial adoption.

The focus of the project module covered in this report was to demonstrate methodologies and tools for use in enhanced technical analysis of distribution circuits and the application of energy storage systems (ESS) to resolve identified issues. Identification of potential storage projects will be enhanced by the implementation of these tools that can more effectively model the distribution system and the complex nature of ESS value propositions. Additionally, the economics can now be evaluated by using methodology and tools that maximize the ESS value by taking into account capacity upgrade deferral opportunities and CAISO market benefits, thereby "stacking" the benefits in a financial manner. Proper stacking of ESS benefits can significantly improve the cost effectiveness analysis results.

An additional objective was to make recommendations on which methodologies and tools should be used commercially by SDG&E as best practices in its future power system planning for assimilation of ESS. Recommendations were also provided towards successful deployment of ESS. These overall results will enhance and streamline both the identification and evaluation of ESS in the distribution system.

1.2 Issues/Problems Being Addressed

With the significant growth of Distributed Energy Resources (DER) and ESS on distribution systems in California, the analytical tools for circuit modeling and analysis require further modernization. Current tools used for distribution planning have typically performed static analysis dealing with loading or voltage issues during peak periods. In recent years, some of the distribution planning analysis has transitioned to an hourly analysis. Software tools that can improve this hourly analysis to a more granular level can improve the results by more accurately finding issues and solutions as well as finding unexpected distribution problems. An example of an unexpected issue is PV caused flicker. Sometimes flicker related problems are found due to customer complaints rather than analysis. It is best for the utility and the customer if problems are effectively predicted and resolved before they occur.

The overall benefit/cost analysis process for ESS needs to be enhanced so that it becomes more thorough thus helping ESS opportunities expand. When ESS is identified as a potential solution, currently the typical evaluation will be a comparison of the traditional upgrade cost versus the cost of ESS. Software tools that can also evaluate the potential CAISO market benefits and properly sum those benefits will better demonstrate the potential value of ESS. Some of the roadblocks towards wider scale deployment of ESS is the belief by some that ESS is many years from being cost effective thus receive a low priority as compared to other day to day challenges. Demonstrating the significance of the combined value can help expedite the resolution of challenges to use storage on the distribution system and in CAISO markets.

ESS installations have many similarities to traditional electric utility infrastructure, but there are also significant differences that provide opportunities for enhancements which would help maximize their value and avoid eventual problems. Many of those challenges are related to the integration of the processes, engineering standards, and day-to-day operations. Identifying and improving those situations will also help improve the value of ESS systems.

1.3 Project Tasks and Deliverables Produced

The project was performed in two phases. The first phase incorporated the initial preparation tasks of the project which included development of the project plan and selection of the project team and contractors. Phase 2 of the project dealt with technical parts.

The tasks included in phase 1 were:

1.3.1 Phase 1 - Task 1: Team Formation and Project Plan

The SDG&E EPIC program manager identified the technical lead for the project based on experience and technical expertise. Later, the internal project team was formed by identification of technical skills and expertise available within the organization. After forming the internal project team task to develop the project plan was given to the technical lead. The technical lead with the help of the project team wrote the project plan as per the guidance provided by the SDG&E EPIC program manager adhering to EPIC guidelines.

1.3.2 Phase 1 - Task 2: Procurement of Contractor Services

Scope of the work was identified and written for the part of the project needed to be contracted out to engineering consulting firm. Standard company practices were followed for contractor selection and procurement.

The phase 2 of the project included the following major tasks (Figure 1-1):

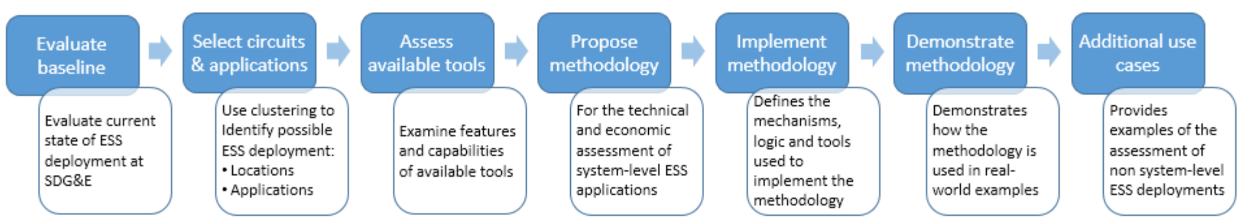


Figure 1-1. Primary project tasks

1.3.3 Phase 2 - Task 1: Evaluate baseline

This task assessed the present state of energy storage systems at SDG&E and the applications in use, as well as determination of potential areas for utilization enhancement.

1.3.4 Phase 2- Task 2: Identify circuits and applications

This task proposed a framework for identifying which distribution circuits could potentially benefit from future deployment of ESS and which applications should be considered. Using the framework, 28 feeders and 5 applications were identified and these results used in subsequent tasks to demonstrate the use of the assessment methodology developed as part of this project.

1.3.5 Phase 2 - Task 3: Assess available tools

This task assessed a number of Energy Storage Analysis tools used in the industry. The investigation covered technical analysis as well as the economics related to capital deferral and markets benefits. The results were used to select the tools used for the remainder of the project.

1.3.6 Phase 2 - Task 4: Propose methodology

This task proposed a methodology to be used to analyze the technical and economic viability of deploying ESSs on the SDG&E distribution system.

1.3.7 Phase 2 - Task 5: Implement methodology

This task provided a detailed description of the mechanics involved in applying the various steps of the methodology developed in the preceding task, for three different types of system applications.

1.3.8 Phase 2 - Task 6: Demonstrate methodology

Using some of the circuits identified in Phase 2 - Task 2, this task demonstrated how the methodology can be applied to real-world cases.

1.3.9 Phase 2 - Task 7: Additional use cases

This task analyzed three additional use cases that utilized portions of the methodology on single facility end use (non-system) related applications.

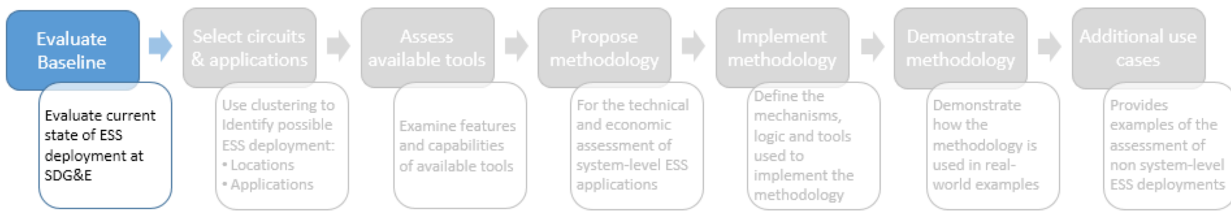
1.3.10 Phase 2 - Task 8: Final Report and Tech Transfer of Project Results

This was the final project task and included two key activities: a) Preparation of the draft and final report for the project, and b) Knowledge transfer plan and demonstration session for utilization of the methodology and tools.

2 ANALYSIS AND ASSESSMENTS

This section provides a summary of the tool evaluation performed and development of methodology to analyze ESS applications.

2.1 Task 1: Baseline Evaluation and Analysis of Energy Storage Systems Applications in Use



Early in the project, a series of brainstorming sessions were held with multiple SDG&E groups and stakeholders. Additional follow-up sessions were conducted with specific organizations who were determined to have more direct involvement and critical roles in ESS projects in the future. The sessions were used to understand the current process for ESS selection and deployments, as well as to identify their ESS related responsibilities and to discuss suggestions and opportunities to improve the process and value received from ESS. The groups interviewed included:

- Electric Generation
- Market Operations
- Advanced Technology
- Distributed Energy Resources
- Electric Distribution Operations
- Distribution Planning
- Substation Engineering
- Distributed Energy Management Systems
- Customer Generation
- Distribution Reliability
- Facilities
- Customer Services

The findings from the interviews were utilized in the assessment of the tools required and also in the development of a viable methodology comprehensive enough to address various key aspects of the ESS project life cycle.

Through June 2017, SDG&E has installed a significant amount of ESS in its service territory, primarily driven by regulatory requirements and reliability improvement needs.

There are two types of ESS connected to the distribution system:

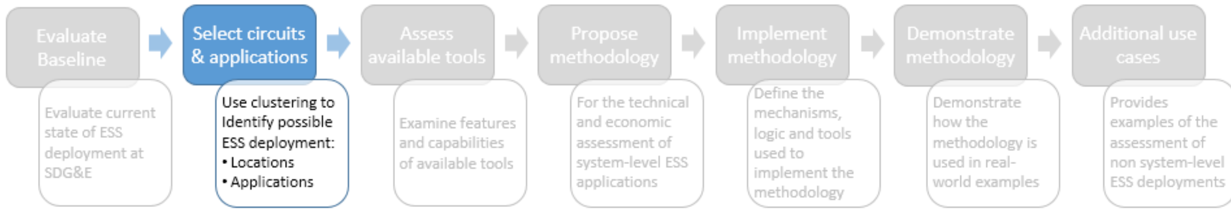
- Seven large ESS site ranging in size from 1 MW to 30 MW, connecting to 12 kV substation buses or across the circuits.
- Community type ESS sites ranging in size from 25 kW to 200 kW.

Overall SDG&E has 30+ battery systems in operation, with a combined capacity of 104 MW. This 104 MW of energy storage achieves 63% of a CPUC approved Assembly Bill (AB) 2514 requirement of 165 MW. While 104 MW of ESS is in place, SDG&E-owned storage is about 44.5 MW (43%) with most going operational in 2017. There are two large ESS Projects in progress that will achieve the overall 165 MW requirement by adding an additional 70 MW combined ESS at two different substations.

These installations have provided excellent experience on the procurement, installation and operation of ESSs.

Besides the expected reliability benefits, much of the early deployments were implemented with expectations towards significant learnings about the technological capabilities, installation requirements, and operational opportunities towards resolving distribution system issues. The recent ESS projects were also targeted toward participation and experience with wholesale market.

2.2 Task 2: Select Circuits and Applications



The objective of this task was to develop a framework for identifying which distribution circuits could potentially benefit from future deployment of ESS, analyzing which applications should be considered and then creating a list of actual circuits to be used elsewhere in the project. It did this by:

- Identifying common parameters and characteristics that could be used as criteria to group circuits together into clusters that shared similar attributes.
- Identifying the ESS applications most suitable for use with these different clusters of distribution circuits.
- Using the framework to select a number of representative circuits that could potentially benefit from the deployment of ESS and which were used in the remainder of the project to test the concepts, tools and methodologies proposed.

The benefit of performing detailed analysis on the technical and cost/benefit implications of ESS deployment on a small representative sample of the different clusters is that it becomes a relatively simple matter to extrapolate the impacts of ESS deployment on a much larger scale.

2.2.1 Clustering Criteria

The approach to defining the criteria used to group circuits together into clusters that shared similar attributes involved two steps:

- Step 1: Identify typical distribution system issues that can be mitigated by an ESS,
- Step 2: Determine key circuit characteristics from an ESS deployment perspective

Working with distribution planning groups, the findings from each step were discussed and ultimately several representative circuits and potential sites were selected for each target application. The two steps utilized in this process is described below.

Step 1: Identify System Issues that an ESS can mitigate

System Issues that can be mitigated by the deployment of an ESS include:

- **Load management,** to flatten the profile and reduce peak load durations that can exceed thermal limits of conductors or circuit/substation apparatus (circuit breakers, switches, line reclosers, circuit ties, voltage regulation devices, transformers, etc.).
- **PV generation management**, to better correlate load and generation time locally and avoid excessive reverse power flow that can affect the operation of voltage control devices or cause power quality issues (voltage, flicker, harmonics, etc.).

- **Voltage and reactive power support**, to prevent significant over/under voltage situations due to excess generation or fast-changes beyond the regulation capability of feeder voltage control devices.
- **Intermittency and ramp rate management**, to improve firm capacity of PV systems and control ramp rate.
- **Circuit reliability enhancement,** to avoid sustained outages in areas without circuit ties and alternative solutions for supplying customers during outages caused by equipment/cable failure (with minimum time to repair of 8 to 10 hours typically), and any areas with CAIDI more than 100 minutes. This incorporates customers on radial circuits, branches and boundary areas.
- **Backup supply for mission-critical utility services and infrastructure,** such as communication towers in back-country , or utility infrastructure in Fire Prevention zones
- **Backup supply for critical customers,** such as military bases, hospitals, government buildings, data centers, etc.
- **Any others known distribution impacts of DERs**, such as protection coordination issues and unintentional islanding scenarios.

Step 2: Determine key circuit characteristics

Key circuit characteristics from an ESS deployment perspective that can be used to group the circuits and ESS sites as clusters with common characteristics and behavior, include:

- List of circuits with known voltage or power quality issues, or prone to show power quality problems, such as:
  - Circuits with customer complaints
  - Very long circuits (over 20 miles)
  - Circuits with major load center away from substations
  - Circuits with large PV/DG toward the end of line
  - Circuits that have more than 3 sets of voltage regulator on one backbone
  - Circuits with Short Circuit Capacity (SCC) less than 150 MVA at substation or less than 35 MVA at the end of line (EOL)
  - Circuits with minimum day-time load less than 1 MW (very lightly loaded)
  - Circuits with peak to minimum load ratio more than 10
  - Others relevant criteria.
- List of circuits serving critical customers such as: water treatment facilities, military/navy bases/facilities, airports, hospitals, etc.
- List of circuits with large customers (more than 3 MW peak load)
- List of distribution substations with radial supply (one major feeder)
  - Distribution substations at the end of a radial feeder with no alternative supply path
  - Substations that will be on critical operator watch list during maintenance, when they have no alternative feeder during schedule maintenance or contingency events with one feeder out (abnormal condition)
- List of circuits with existing high PV penetration (% PV rating to the circuit kV rating > 50%) – nameplate
- List of circuits approaching maximum hosting capacity for DER interconnections by limiting category:

    - Steady state voltage limit (Vpu < 0.93 or Vpu > 1.07)
    - Temporary voltage limit (TOV > 1.8 pu for more than 5 cycles)
    - Thermal limit (current > 600 A)
    - Flicker limit (ΔV > 3%)
    - High generation to minimum load ratio (Gen(rated)/L(min) > 0.75)
    - Significant change in short circuit capacity on the circuit (SSC(with DER) / SSC (without DER) > 150%)
    - Other relevant criteria
- List of circuits or substations with large load growth, approaching thermal limit in the next 2-5 years
- List of circuits suggested for re-conductoring in the next 5 years
- List of circuits known with high percentage losses or low power factor
- List of circuits with overhead conductor more than 80% of circuit length
- List of circuits with FLISR schemes activated on them (for re-configuration)
- List of circuits with no-tie to any other circuit for re-configuration
- List of boundary circuits/substation in areas with limitations in circuit extension
- List of circuits with high adoption rate of Electric Vehicles
- List of circuits on CPUC emergency load curtailment list (rotational outage list during emergency)
- List of worst performing circuits or circuits with CAIDI more than 100 minutes or CAIFI more than 0.5 (and main root-cause of outage)

2.2.2 Applications

ESS applications considered in this project fall into one of five categories:

- Wholesale
- Transmission
- Generation
- Distribution
- Behind-the-meter

And within each of these domains, there are multiple sub-domains of applications. Those storage applications which are being pursued today in commercial or pilot projects are tabulated in Table 2-1 below. There are other potential applications such as the provision of synthetic governor or inertial response and putative distribution system ancillary services that are nascent and not listed.

Table 2-1. ESS Applications

Domain	Sub-Domain	Applications
Wholesale	Energy Markets	Day Ahead Markets
		Hour Ahead Markets
		Real Time Energy
	Ancillary Service Market	Regulation
		Ramping
		Spinning Reserve
		Quick Start Reserve
		Black Start
Transmission	Congestion Relief	N-0 Congestion Relief
		N-1 Congestion Relief
	Capacity /Operability	VAR Support
Generation	Scheduling	Curtailment Management
		Self Firming
		Smoothing
	Market Participation	Time Shifting / Arbitrage
		Wholesale Products per Above
Distribution	Capacity	Upgrade Deferral
	Renewable Integration	Back Feed Prevention
		Voltage Control
		PV Smoothing (Flicker Control)
	Local Resiliency	Islanded Circuit Operation
Behind the Meter	Bill Management	Demand Charge/Peak Shaving
		Time Shifting (TOU or RTP) / arbitrage
	Reliability	Islanding / Off Grid

Outside of project scope – non-distribution

The distribution-focused ESS applications are described in the sections that follow:

2.2.2.1 Wholesale

- Day Ahead Energy – arbitraging prices across time or time shifting energy. (called DA henceforth)
- Hour Ahead Energy – same issue, but performed as part of the hour ahead hourly energy bidding/award process instead of the Day Ahead process. (called HA henceforth)

- Real Time Energy – same issue, but performed against the intra hour dispatching process. (called RT henceforth)
- Regulation – providing regulation service and the ability to respond to 4 second AGC signals from the grid operator. (Called REG henceforth)
- Fast ramping. This is a product particular to California today although under consideration elsewhere.
- Spinning Reserve – ability to provide rapid response to the grid operator against a large generator contingency and to provide that energy for sufficient time for the grid operator. While requirements for DA, HA, RT products vary in detail from one market to another, requirements for "reliability" products such as spinning reserve are determined ultimately by NERC, note.
- Non-spin or quick start reserve – a product with slightly slower response requirements than spin which is aimed at hydroelectric and gas turbine generation, among others, than can reliably be started in minutes.
- Blackstart – Generators which normally require power from the grid in order to start can qualify as able to provide black start services with the installation of energy storage sufficient to power them through startup. This accesses a revenue stream for these units and also helps the state with maintaining black start capacity in the face of plant retirements.

2.2.2.2 Capacity Deferral

The capacity deferral application uses the storage discharging to reduce upstream circuit load where the loading is projected to exceed ratings in the near term. In other words, capacity deferral shaves peaks by discharging on peak and then to charging off peak.

Centralized model

In many circuits the circuit element affected first by load growth is the station exit cable, which may be underground. Aerial space over the station apparatus is frequently in short supply and a short underground cable to a riser pole is a typical solution. This cable often has a rating that is more restrictive than the overhead conductors, and replacing it is costly. In this instance, the battery can be located adjacent to the station and is referred to as a "centralized" capacity deferral application. Such a location can also help with capacity issues at the station transformer level when the N-1 rating after an outage of one of 2 or 3 units causes overloads at peak hours.

Decentralized model

When the ratings issues are with the overhead or underground conductors, then storage must be located along the feeder downstream of the overloaded section. Such a solution is a "distributed storage" capacity upgrade deferral application. Analyzing this application really requires a distribution load flow with a time series solution so that the effect of storage discharging and the control algorithm that each battery employs can be validated along with the sizing. It is also possible in this application to gain some additional capacity by power factor correction to unity on a time varying basis, which can be done with inverter based storage as opposed to switched capacitors.

When the BESS is far down the feeder, and on the secondary, it has the potential to relieve overloads/peak shave all along the feeder back to the station and at the station. However, the size of a BESS located on the secondary is necessarily much smaller than a BESS in the station or on the MV feeder. Consequently, to achieve capacity deferral with such BESS it will be important to exploit multiple BESS.

Capacity deferral is only needed at peak hours – so is not used year-round. It is a natural extension to use the peak shaving year round and also to optimally discharge and recharge the battery to minimize the costs of wholesale energy as delivered to the feeder, that is, at the appropriate locational marginal price. It is also possible to estimate potential revenues from using the battery in the more lucrative ancillary markets, if and when this is allowed by state and federal regulators and by the ISO. Because capacity deferral is reducing peak loads, it "fits" or is compatible with market applications in general although regulation services are typically most valuable at peak as well so the allocation of battery capacity for regulation has to take a second position behind the mandatory peak shaving usage.

2.2.2.3 Renewables Integration

The Renewable Integration application set has three parts:

- One is to perform a form of peak shaving on the net circuit flow in the other direction, to prevent back feed or the condition where net flow from the feeder is back into the station. This may or may not be an issue for the utility, depending upon the particulars of the protection equipment.
- A second is to ensure that the absolute voltage level along the circuit is within ANSI standards. This is best accomplished by using excess capacity from the battery inverter to supply and withdraw VAR from the circuit.
- A third is to avoid flicker caused by excessive rate of change of voltage due to PV variability.

Back feed Prevention

Back feed prevention is performed similarly to capacity deferral, except that storage charging is used to increase feeder load and avoid negative load (back feed) at off peak hours when PV production is highest (i.e. weekend afternoons on moderately hot/cool days in April/May). The algorithms for managing the battery are similar to that for managing capacity deferral. Depending upon the ISO market back feed prevention may or may not be compatible with optimizing wholesale energy costs. At high PV penetration in the market, prices may be low when PV production is peaking, and back feed prevention is then compatible with optimizing market costs. But in other situations, this may not be the case. The same potential constraints with providing ancillaries exist as with other applications – there are hours where charge/discharge capabilities are limited and ancillary services offers must be limited.

Voltage Control

The control of voltage level is best done by using the battery inverter to inject/withdraw VAR at the circuit location. The control algorithm looks at the filtered circuit voltage that is being controlled (typically and best at the battery as then no communications are required) and controls the VAR output. The VAR output will impose limits on the kW charge discharge, which in turn limits the amount of capacity available for other applications. By increasing the inverter size beyond the battery power rating this capability can be provided without limiting battery usage for other applications. While it is theoretically possible to perform the same function by varying battery power output, this will interfere with other applications and might be incompatible with them. The use of the inverter and reactive output is generally preferable and less costly as well as no additional energy storage capability is needed. To maximize the benefit, the battery should be as close to the focus of PV production or where the circuit voltages are most affected, but this only affects inverter sizing somewhat.

Because PV production may cause overvoltage for hours at a time, controlling this with battery charging would require longer duration batteries, running up the costs. Unless justified by price / time arbitrage as with capacity deferral, this is uneconomical as compared to using VAR for voltage control.

Sizing the battery for this in general requires running a time series of load and PV profiles on a distribution load flow, with an external algorithm controlling the inverters (on a 10 second time step, typically) so as to manage the absolute voltage level. The control algorithm has to be coordinated with the control algorithm that is providing flicker control as well. Less effective measures can include:

- Performing the circuit analysis at on and off peak loads and at peak and nil PV production to attempt to measure worst case voltages, and then determining the amount of VAR injection required to maintain acceptable voltage levels. This approach can work but can be in error as the worst voltages may be at the point when local PV production versus local load is maximum or some other combination. In other words, the sampling approach is not guaranteed to find the worst case. This is especially true if different circuit locations have radically different load profiles (customer types) as well as concentrations of PV.
- Attempting to estimate circuit voltage impact by considering the amount of PV production minus load and the local circuit short circuit impedance. This estimates the voltage effect of a given power injection. As with estimating PV hosting capacity, this approach has proven inaccurate in practice. Spreadsheet based approaches that use circuit length and voltage, peak load, and PV penetration to estimate battery sizing (and costs) for voltage control are therefore rough estimates only and not valid for business case much less engineering estimates.

Flicker Control (PV Smoothing)

Flicker is defined as a rate of change of voltage up or down that exceeds ANSI standards and which would cause lighting to noticeably vary. Voltage flicker is caused /aggravated by PV variability due to scattered cloudiness. The flicker phenomenon can be controlled via rapid variation of local battery charging/discharging so as to slow the rate of the combined PV/battery power injection to within limits. That is, when the PV production is dropping, the battery discharges at a rate so as to temporarily smooth the PV variation and reduce the rate of change of voltage to within limits. Because the rate of change calculation is “noisy” (i.e., Differencing voltage samples across time steps) some filtering is needed but the filter design cannot itself mask effects that must be controlled. Because the level of power charge/discharge is only as great as the PV itself, and the duration short (minutes at most) the battery size is modest. This makes this a cost-effective application when the alternative is re-conductoring to stiffen the circuit voltage response.

As with controlling voltage level, it is conceivable to develop rules of thumb instead of performing time series analysis to size the battery. And as with voltage control and PV hosting, such sampling or rule of thumb estimates will be inaccurate.

2.2.2.4 Local Resiliency – Microgrids / Islanding

There are instances when “normal” circuit N-1 measures (normally open ties to adjacent circuits) are not available or would be prohibitively expensive and so circuit sections near the end of a circuit cannot be switched to alternate supply in the event of an upstream outage. Such instances can be found at the "edges" of a network where adjacent circuits are not convenient. When the edges are imposed by physical/geographic factors such as rivers, bodies of water, mountains/canyons, forests, etc., poor reliability at the end of the circuit may be the case and lack of an N-1 alternative aggravates the situation. Pilot projects as at Borrego Springs have demonstrated that battery storage, possibly in conjunction with local Distributed Generation, may be a viable alternative in these cases. The size of the battery is determined by the amount of load, net of DG and Demand Response, which must be carried. The energy/duration of the battery is determined by the load profile over time and the expected time to repair.

Because the battery must be available for islanded duty whenever an outage might occur, a minimum state of charge to meet the outage energy needs and restoration times must be maintained. This puts constraints on other uses for the battery. Depending upon circuit load profiles across the year and load factor, as much as 50% of battery capacity could be available for market participation on different days / at different times. Also, depending upon circumstances, at some times during the year it may make operational sense to completely restrict battery usage to islanding – as during forest fire season, during a hurricane watch, and so forth.

2.2.3 Selecting representative circuits from the clusters for further study

The clustering results and circuit/substation selected list were used to:

1. Collect data for representative circuits per cluster and evaluate information such as:
   - Historical load profiles, – at least 1 year for circuits associated with each circuit
   - Available/expected DG capacity and potential impact or possible penetration limitations
   - Site representative PV profiles (high resolution) and historical generation levels
   - Historical power quality and reliability data and/or any records of major outages or reliability issue associated with a circuit or cluster.
2. Obtain up-to-date planning model for each circuit
3. Identify load growth in the area/circuit,
4. Identify existing and expected amount (and distribution) of DERs (PVs , Wind, etc.) on each corresponding circuit,
5. Investigate circuit maps and planning models showing all critical devices, sections with thermal limits, and methods of voltage and reactive power management,
6. Examine any known circuit restrictions or operation difficulty,
7. Document any special operating procedures and circuit conditions that can affect ESS installation or operation,
8. Identify ESS applications that should be evaluated per cluster,
9. Determine the number, capacity and potential locations for ESS deployment by application categories and usage per cluster and to rank the clusters
10. Prepare a summary report on clustering criteria and methods, as well as findings from the system characterization in terms of any system impact that requires mitigation and the gaps in the measurement, monitoring and operation to support the assessments
11. Evaluate the SCADA monitoring and field connectivity for the cluster circuits.

By applying the clustering criteria, candidate circuit and substations were ranked and and/or locations for possible ESS deployment identified for each of the following application areas:

• Capacity upgrade deferral	3 circuits
• Community microgrid applications	4 circuits
• PV impact analysis and potential voltage issues	8 circuits
• Whole sale market analysis	2 locations (one at substation, one on a circuit)
• Single facility energy storage	2 locations
• Multiple family housing	4 locations

Table 2-2, Table 2-3, and Table 2-4 list the parameters of the shortlisted circuits for capacity upgrade deferral, community microgrids and PV Impact which were the results of identifying representative circuits and locations from the clustering analysis. The actual circuit identifiers have been replaced with generic identifiers; Circuit Capacity Upgrade Deferral (CCUD x), Circuit Microgrid (CMG x) and Circuit PV Impact (CPVIM x).

Table 2-2. Summary table of the selected circuits for the upgrade deferral application

Circuit ID	2019 forecasted load (A)	Average forecasted load growth per yr 2019 to 2021	SDG&E Ampacity (A)	Distribution Planning Tool 4 Ampacity (A)	Circuit PV Size (kW)	Number of Capacitors	Number of Voltage Regulator	10 yrs Capacity (MVA)
CCUD 1	369	3.30%	408	395	981	1	0	10.4
CCUD 2	564	1.30%	600	580	580	1	0	13.5
CCUD 3	558	1.40%	600	580	935	1	0	13.5

Table 2-3. Summary table of the selected circuits for the microgrid application

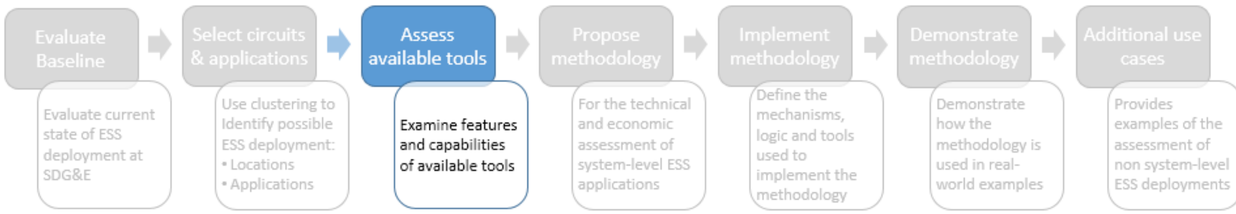
Circuit ID	# customers in MG Area	Peak load for MG [kW]	Minimum load for MG [kW]	MG Resources	# of Capacitors	# of Voltage Regulator
CMG 1	Whole circuit: 263 Recloser 1: 55 Recloser 2: 146	700	0	ESS only	1	0
CMG 2	255	712	0	ESS + PV	0	2
CMG 3	281	616	6	ESS only	0	1
CMG 4	837	2,064	0	ESS only	1	6

Table 2-4. Summary table of the selected circuits for the PV impact mitigation application

Circuit ID	PV Size (kW)	Dominant PV Type	Peak Circuit Load (A)	Minimum Day Time Circuit Load (A)	# of Capacitors	# of Voltage Regulator
CPVIM 1	8,955	Centralized	407	-5.38	5	3
CPVIM 2	7,128	Centralized	254	-5.23	2	2

Circuit ID	PV Size (kW)	Dominant PV Type	Peak Circuit Load (A)	Minimum Day Time Circuit Load (A)	# of Capacitors	# of Voltage Regulator
CPVIM 3	4,918	Distributed	470	-0.82	3	0
CPVIM 4	4,188	Distributed	479	-0.2	3	0
CPVIM 5	4,066	Distributed	454	-0.74	2	0
CPVIM 6	4,045	Distributed	467	-0.92	2	0
CPVIM 7	3,725	Distributed	490	-0.17	0	1
CPVIM 8	3,710	Distributed	501	0.9		

2.3 Task 3: Assessment of Energy Storage Analysis Tools



A list of Energy Storage Analysis tools in common use in the industry was compiled and the individual tools assessed. The results were used to select the tools utilized in the remainder of the project.

2.3.1 Evaluation Methodology

A comprehensive review of literature, publications, reports, and any information on available ESS tools and ESS assessment approaches in the public domain and/or from previous SDG&E projects was performed. Several ESS tools were identified and evaluated: such as tools developed by Vendor 12, Vendor 1, Vendor 6, and a few ESS assessment tools that are considered as integral parts of commercial planning software tools. Where information was available on proprietary tools used by consulting/ engineering companies and storage developers these were also considered.

The different tools were characterized by tool types and their intended purpose(s) itemized. A set of high level functional requirements for different purposes was developed. The focus was placed on the use of storage tools for (a) actual project design and evaluation and (b) developing a roadmap and business case for a system level portfolio of storage projects. A gap analysis against the needs of these two purposes was performed.

In addition, the task also included the investigation of any SDG&E in-house developed tools and/or any ESS analyzing tools used by major US Investor Owned Utilities such as Southern California Edison, Commonwealth Edison, Duke Energy, or others - to the extent that information was available - to facilitate selection and/or enhancement of an ESS planning and analysis tool that can support development of an ESS utilization roadmap.

For the purposes of this report, the tools were evaluated along several dimensions:

- The range of storage applications and technologies covered
- Degree of rigor in modelling and analysis
- Ease of achieving specificity to particular geographies, utilities, jurisdictions
- Ease of achieving specificity to a particular project and basing storage project design on tool results

This is shown graphically in Figure 2-1. The vertical axis, “integration and ease of use,” measures the extent to which the tool can utilize data from other analytical tools such as commercial production costing or distribution load flow software, and to how easy it is to make use of that data. The horizontal axis, range of applications addressed, characterizes which set of storage applications a tool covers. Some tools focus on a particular domain such as wholesale market benefits whereas others purport to cover all applications. The third axis, rigor, accuracy, and specificity address whether a tool will provide engineering level quantitative results for a specific storage implementation on a specific circuit or is simply a broad range of estimated benefits for a class of applications/locations.

As examples to illustrate these characterizations, the Vendor 5/6 tool, Technology Selection Tool 1, purports to cover all applications but only gives a broad range of potential benefits for each, and does not integrate with any other tools. The Vendor 12 tool Cost Calculation Tool 6 addresses multiple applications and can be made to be specific to a particular location and implementation, but it does not directly integrate with other tools and requires user effort to import relevant data from circuit analysis tools, for instance.

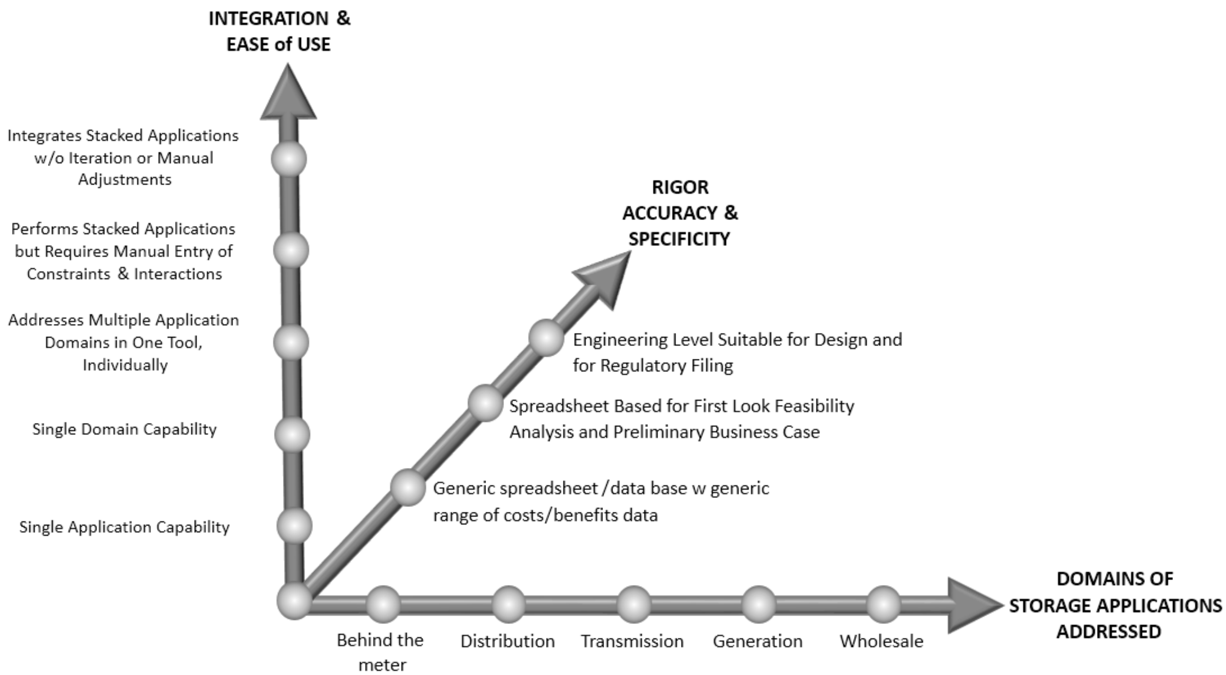


Figure 2-1. Characterizing Storage Assessment Tools

2.3.2 Degrees of complexity

In some cases, it is straightforward to estimate the "value" of a storage resource against a single application. For instance, to estimate the value of a battery that is dedicated to wholesale regulation services, it is possible to simply load historical hourly cleared regulation prices into a spreadsheet and sum the potential revenues for providing a MW of regulation up/down for a year. With a little more effort, some more complex applications can be similarly valued. For instance, the avoidance of retail demand charges can be estimated in a spreadsheet by loading the particular load profile (for a year) into a spreadsheet and computing the energy above the threshold every day, then using that to both size the battery and estimate the savings.

Other applications and combinations of applications require something more sophisticated than a simple spreadsheet. For instance, a typical question would be "determine the value of a storage asset in the wholesale markets" This requires determining how to co-optimize the use of the battery in the different energy and ancillaries markets across each day, considering the limitations on battery power rating and energy rating/duration. Doing this across an entire year may be beyond the capabilities of the embedded EXCEL SOLVER and it may be desirable to access a more capable optimization engine, perhaps in a different formulation in a tool such as Matlab.

The market applications pose one degree of difficulty in assessing the economics of a storage project. The storage costs are known, and the market prices are known so that it is only necessary to determine the best use of the storage asset and compute the market revenues from that use. In other domains, the problem is more complicated as the valuation involves comparing the cost of the storage asset to the cost of addressing the problem by other means.

For example, the distribution capacity deferral can be a straightforward task in terms of determining the size and charge/discharge profile of the battery, using a spreadsheet against the circuit load profile and rating as with the retail demand management example. Then the cost of the storage project can be estimated. However, this must be compared to the avoided cost of the deferral, and then a decision made as to how long the upgrade is deferred (which may affect the battery size if load continues to grow). The amount of conventional distribution investment needed to accommodate a given future load growth may vary widely according to the type of circuit (overhead, underground, urban underground secondary network), its voltage level, the length of the circuit, and whether there are adjacent circuits with spare capacity available. While it may be possible to estimate this avoided cost with rules of thumb, that may only be usable for a feasibility study and the actual business case will require the actual engineering design and costing to be done. Finally, the avoided cost is a regulatory asset so the details of how a given utility values regulated capital projects has to be mirrored in any analysis.

The industry uses the term "stacked applications" to refer to the case when a given storage resource is performing multiple applications across domains. Examples of this include a battery that is primarily performing a distribution application such as capacity deferral but which is also used (conceptually, today) to realize revenues from providing wholesale market ancillary services. In general, we employ the term stacked applications to refer to combinations of applications which cross domains in the taxonomy above. Distribution storage could be used to participate in a scheme for transmission congestion relief. Behind the meter storage could conceivably provide wholesale services or distribution capacity deferral. Valuing stacked applications is typically complex and few tools today do this with any pretense of analytical rigor. None do it easily from a user perspective. In order to do this accurately the tool must:

- Have a priority for which application takes precedence over others or which application imposes constraints on others. For instance, the distribution capacity deferral application takes precedence over market applications, or maintaining sufficient state of charge for an expected outage in a local resiliency application takes precedence over other applications.
- Assess the value in both domains (as in wholesale and distribution) with a degree of analytical rigor and accuracy appropriate to that domain. This means, in general, that at least two sets of tool types must be applied in an integrated way – combinations such as distribution load flow and market optimization, or optimal power flow and production costing.
- Where a tool in one domain may not currently support storage as an object or model element in the tool with any detail, some external simulation of storage may be required to gain fidelity. The means by which this can be accomplished and the user friendliness and flexibility of doing so are then key issues.

2.3.3 Types of tools

For the purposes of comparison, the different tools available in the market were categorized based on two parameters:

- Domain(s) served
- Area(s) of focus

In addition, in broad strokes, the different tools trace their lineage back to one of six areas:

- Feasibility analysis
- Technology selection
- Cost calculations
- Distribution studies
- Transmission studies
- Production costing

The combination of these attributes is shown graphically in the categorization matrix below (Figure 2-2).

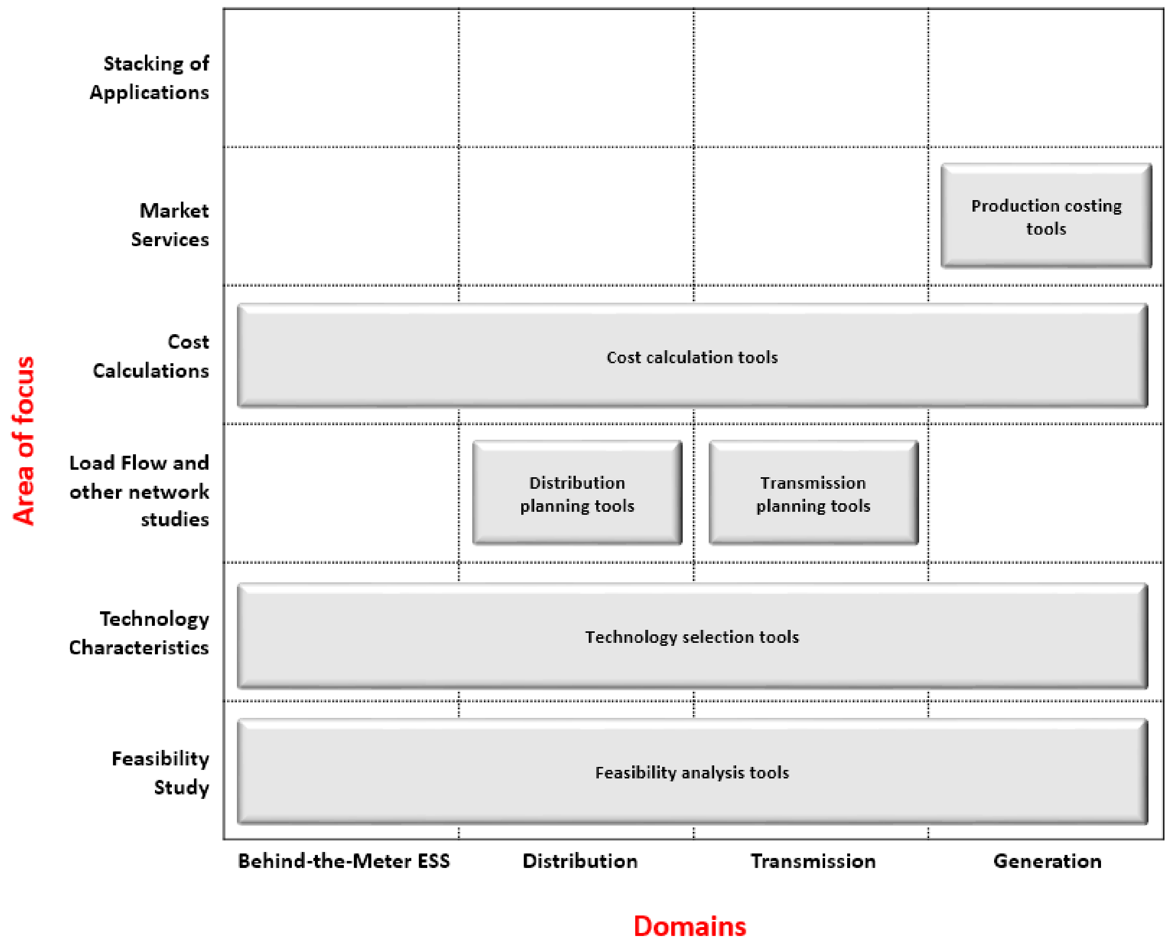


Figure 2-2. ESS Tool Categorization Matrix

One final tool characteristic is whether the tools are commercially available (marketed and sold), publicly available (available for free download and use), or custom (in use by their creators, but not available to others).

One danger of trying to compare and contrast software tools is that their features and functions are dynamic, making any comparison almost immediately stale. The populated matrix that follows (Figure

2-3) must therefore be viewed in that context. Furthermore, there are several tools that are briefly described in the sections that follow that are not shown on the matrix because they fall into the category of not available to anyone other than their creators.

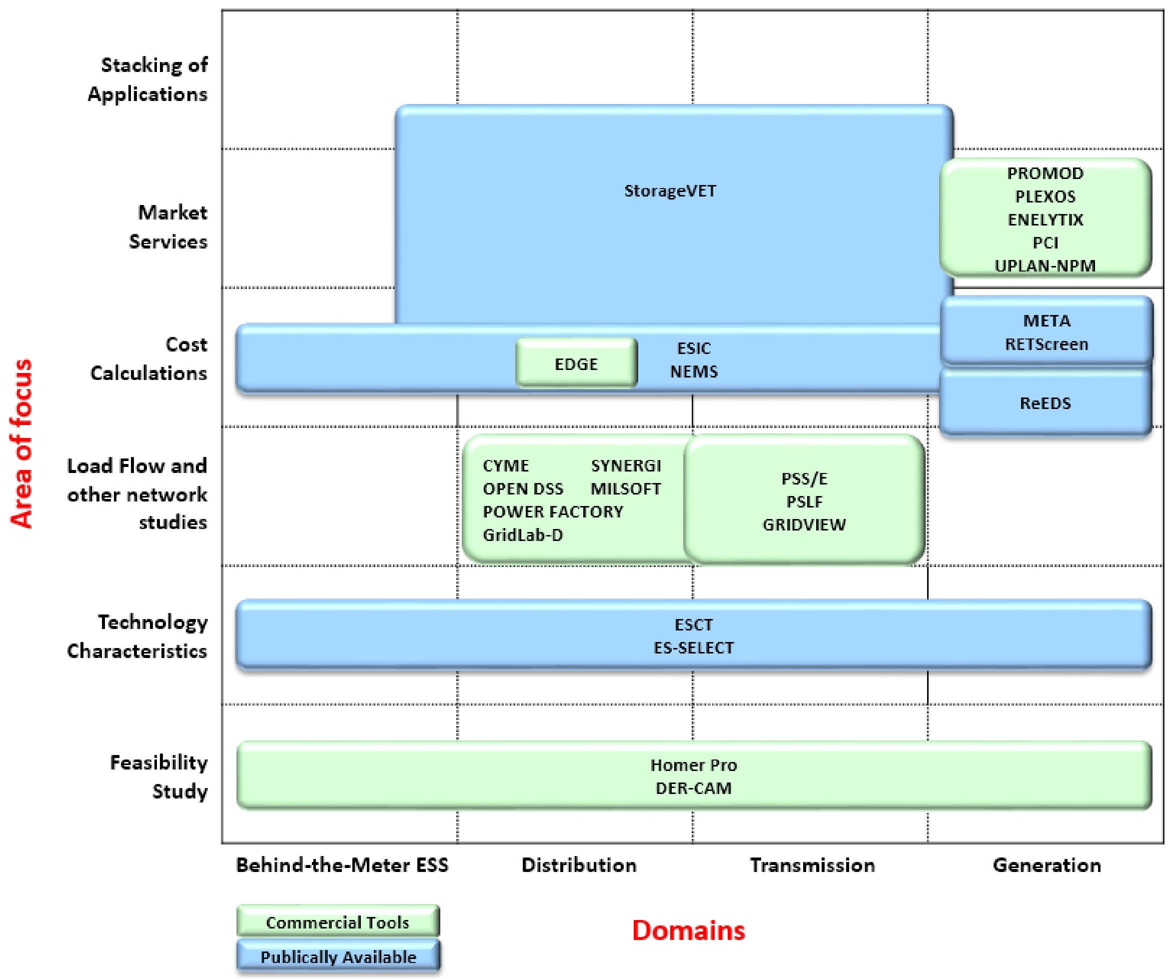


Figure 2-3. ESS Tool Categorization Matrix - populated

Since ESS is still a relatively nascent technology, the available tools that address aspects of ESS deployment have typically added these as ancillary functions to the tool's primary function and there are often trade-offs that result. These are discussed in sections that follow.

__Feasibility analysis tools__

Feasibility Analysis Tool 1: Feasibility Analysis Tool 1, originally developed by Vendor 1 and then enhanced and distributed by Vendor 2, is a microgrid optimization tool, which is able to model a power system's physical behavior and its life-cycle cost, which incorporates the total cost of installing and operating the system over its life span. Feasibility Analysis Tool 1 uses the total net present cost to represent the life-cycle cost of the system. The advanced storage module includes the Modified Kinetic Battery Model to represent the rate dependent losses, changes in capacity with temperature, variable depth of discharge for cycle life, and increased degradation rate at higher temperatures. With these features, users are able to create new batteries and add them to the existing Feasibility Analysis Tool 1 battery library. It is assessed in more detail in a separate section below.

Feasibility Analysis Tool 2: Feasibility Analysis Tool 2, developed by Vendor 3, performs investment modeling and optimal modeling of DER integration for microgrids. The objective of Feasibility Analysis Tool 2 is to minimize the cost of operating on-site generation and CHP systems. Feasibility Analysis Tool 2 model determines what technologies should be adopted for DERs and how the DER should be operated based on the site load profile and market price information. Feasibility Analysis Tool 2 is capable of modeling ESS in microgrids and in its more advanced (proprietary, not publicly available) version can incorporate distribution circuits within the microgrid and can determine the sizing of DER components.

Feasibility Analysis Tool 3: Feasibility Analysis Tool 3, developed by Vendor 4, is an energy management software system used for energy efficiency and renewable energy and cogeneration project feasibility studies. This tool can perform clean energy modeling, cost, emission, financial, and sensitivity and risk analysis.

<u>Technology selection tools</u>

Technology Selection Tool 1: Technology Selection Tool 1 was created by Vendor 5 in collaboration with Vendor 6, licensed for public use. This tool provides a visual platform to compare energy storage technologies and their feasibility for specific applications. This tool is designed to work with the uncertainties of storage and application characteristics, costs, and benefits using Monte Carlo analysis. The output of this tool includes cumulative costs and benefits, comparison of different technologies, and feasibility scores. The tool supports 19 different energy storage technologies with 23 different applications. It is useful as a first examination of BESS possibilities. However, the performance and cost data of emerging BESS technologies change rapidly, and the data base behind Technology Selection Tool 1 is not updated as frequently as might be desired, so results have to be considered in that light. Technology Selection Tool 1 should be seen as an introduction to Energy Storage and a source of general information, but not as a tool to begin the design or financial evaluation of a project.

Technology Selection Tool 2: Technology Selection Tool 2 was developed by Vendor 7 at the request of a federal agency to identify and quantify the benefits accrued through the service provided by storage projects. This tool identifies 18 applications and their benefits categorized as economic, reliability or environmental. This tool performs cost/benefit analysis on the energy storage systems regardless of who the likely benefactor is.

<u>Distribution planning tools</u>

Distribution Planning Tool 1: Distribution Planning Tool 1 was developed by Vendor 8 to perform a daily or weekly unit commitment and hourly or sub-hourly dispatch, recognizing both generation and transmission impacts & market performance. Distribution Planning Tool 1 is an industry accepted simulation approach in the Western Electric Coordinating Council territory. The Distribution Planning Tool 1 analysis methodology combines generation, transmission, loads, fuels, and market economics intone integrated framework for location dependent market analysis, reliability and market performance indices.

Distribution Planning Tool 2: Distribution Planning Tool 2, developed by Vendor 9, is mostly suited for ESS technical and planning studies. This tool provides time series power flow analysis for ESS in distribution level. Distribution Planning Tool 2 utilizes some default dispatch strategies, however requires a higher level of software for control and automation purposes.

Distribution Planning Tool 3: Distribution Planning Tool 3, developed by Vendor 10, is a power flow analysis tool that can be suited for ESS studies in distribution level for the purpose of planning and technical studies. Distribution Planning Tool 3 can be utilized to perform detailed power system studies on ESS on each node of system. The dispatch models in Distribution Planning Tool 3 can be defined by user based on the load profile of circuit under study.

Distribution Planning Tool 4: Distribution Planning Tool 4, developed by Vendor 5, is a power flow analysis tool that can be suited for ESS studies in distribution level for the purpose of planning and technical studies. Distribution Planning Tool 4 can be utilized to perform time series analysis on ESS on each node of system. Extra modules can be developed to study ESS for different applications (e.g., PV smoothing, capacity deferral, etc.)

Distribution Planning Tool 5: Distribution Planning Tool 5, developed by Vendor 11, is a power system analysis tool that can be utilized in both transmission and distribution level. The ESS study tools for this software are need to be customized and developed by the user via some pre-existing modules in software platform.

Distribution Planning Tool 6: Distribution Planning Tool 6, developed by Vendor 12, is power system simulation tool for distribution systems. This tool utilizes time series analysis and supports nearly all frequency domain analyses performed on electric utility power distribution systems. Distribution Planning Tool 6 can be suited to support the analysis of distributed generation and ESS units interconnected to distribution systems.

Distribution Planning Tool 7: Distribution Planning Tool 7, developed by Vendor 13, is a power system planning tool that can be utilized for ESS analysis in transmission level. The ESS study tools for this software are not readily available and should be customized and developed by the user through some pre-existing modules in software platform.

<u>Transmission planning tools</u>

Transmission Planning Tool 1: Transmission Planning Tool 1, developed by Vendor 14, is a power transmission system planning tool software that can be utilized for ESS analysis in transmission level. The ESS study tools for this software are not readily available and should be customized and developed by the user through some pre-existing modules in software platform.

Transmission Planning Tool 2: Transmission Planning Tool 2, developed by Vendor 15, is a comparable and competing product to Transmission Planning Tool 1.

<u>Other specialty tools</u>

Specialty tools are utilized to perform special studies that are outside of the scope of T&D planning and system protection analysis. Below are the list of specialty tools investigated.

Specialty Tool 1: Specialty Tool 1, developed by Vendor 16, is a power system electromagnetic transient simulation tool mainly designed for analyzing transients. Specialty Tool 1 utilizes Electromagnetic Transient (EMTDC) as the simulation engine which facilitates simulating time domain instantaneous responses (electromagnetic transients) of electrical systems. Specialty Tool 1 can be utilized to study the grid integration impacts of ESS units, such as power quality issues, harmonic studies, stability analysis, transient analysis, etc.

Specialty Tool 2: Specialty Tool 2 is not shown on the graphic as it is somewhat unique in its application, although other power system dynamic tools such as Transmission Planning Tool 2 can approach some of its capabilities. Specialty Tool 2 was developed by Vendor 5 in Matlab-Simulink platform. This tool primarily targets transmission applications for ISO needs and is suited to perform frequency response and balancing energy studies of renewable and distributed energy resources and storage energy resource in 1 sec to 24 hour timeframe. It is primarily used for analyzing future system performance, designing Automatic Generation Control algorithms, and other control area problems.

Cost calculation tools

Cost Calculation Tool 1: Cost Calculation Tool 1, developed by Vendor 17, provides a comparative assessment of the economic costs of more than 40 electricity generation and delivery technologies, including conventional generation options such as thermal, renewable options including hydroelectric and wind, and emerging options such as energy storage. One of the features of Cost Calculation Tool 1 is that it allows for integration of environmental externalities, such as local pollution and greenhouse gas emissions.

Cost Calculation Tool 2: Cost Calculation Tool 2 was developed by Vendor 1. This tool is a long-term capacity-expansion model for the deployment of electric power generation technologies and transmission infrastructure. Cost Calculation Tool 2 uses a linear programming approach to minimize the capital, fuel, and operation costs of energy storage systems.

Cost Calculation Tool 3: Cost Calculation Tool 3 was developed by Vendor 18. This tool determines the optimal energy storage system characteristics using different modules such as Electricity Market Module, Electricity Capacity Planning, and Electricity Load and Demand. The objective of planning module is to minimize the total, discounted present value of the costs associated with meeting demand complying with environmental regulations. The planning module allows planners to analyze new capacity additions, construction costs, computation of avoided costs, emission banking, pollution control retrofits, and capacity requirements.

Cost Calculation Tool 4: Cost Calculation Tool 4 was developed by Vendor 12. This tool is mainly intended to perform business studies for distribution system applications in Excel platform. This tool enables utilizes and suppliers to indicate the scope for an energy storage system or project and helps buyers to clarify what they need. The main output of this tool is the total cost of ownership of energy storage system. This tool is openly available for public use.

Cost Calculation Tool 5: Cost Calculation Tool 5, developed by Vendor 19, is a MATLAB-based simulation tool designed to comprehensively assess the DER value proposition in different regulatory and utility business model environments based on a detailed assessment of the technical and operational implications. This tool utilizes Distribution Planning Tool 6 for running time series power flow simulations.

Cost Calculation Tool 6: Cost Calculation Tool 6 was developed by Vendor 12 and is mainly intended for energy storage system business studies. Cost Calculation Tool 6 has a web-based platform, performs cost/benefit analysis of energy storage projects and analyzes life degradation. Cost Calculation Tool 6 can perform electricity market analysis (suited for CAISO). Cost Calculation Tool 6 is not capable of analyzing stacked applications directly. Cost Calculation Tool 6 was developed jointly by Vendor 12 and a state energy commission with approximately $1M of funding, and is heavily tailored towards state-specific ESS applications. It is assessed in more detail in a separate section below.

Production costing tools

Production Costing Tool 1: Production Costing Tool 1 was developed by Vendor 8 to perform generation and transmission system studies. This tool performs a daily or weekly unit commitment and hourly or sub-hourly dispatch, recognizing both generation and transmission impacts at the nodal and zonal level. The output of this tool includes a detailed production cost modeling. Production Costing Tool 1 is widely used for renewable curtailment studies, for valuing a new generation project or a new transmission project. Production Costing Tool 1 has limited capabilities to model energy storage and cannot co-optimize storage charging and discharging or ancillaries' provision.

Production Costing Tool 2: Production Costing Tool 2 is a production cost model from Vendor 20. This tool is object oriented and allows the user to develop specific resource models to some extent. It is able to co-optimize storage charging and discharging (originally used for pumped hydro modelling). Regulation reserves are held in a regulation raise (and lower) reserve category and cannot contribute to energy or other ancillary services. Production Costing Tool 2 addresses the losses due to the inefficiencies of charging and discharging by adding an auxiliary load to the energy storage resource model. Production Costing Tool 2 is widely used within WECC for analyzing renewable penetration impacts, cost of additional ancillary services, and so on.

Production Costing Tool 3: Production Costing Tool 3 is a production costing simulation available from Vendor 21. It is cloud based (runs on Amazon Cloud Services) and has capabilities similar to Production Costing Tool 2.

There is a category of unit commitment tools that are used by generation market participants to determine bidding strategies. Unit Commitment Tool 1 by Vendor 22 is an example of this. These tools today do not accommodate storage as the generation owners have not as yet had to incorporate these into their operations. Large storage operators no doubt have proprietary tools but these were not accessible for evaluation.

Production Costing Tool 4: Production Costing Tool 4, by Vendor 23, simulates the electricity market using security constrained unit commitment and security constrained economic dispatch. This tool integrates the electricity market with a full transmission network model. Production Costing Tool 4 is a powerful tool to co-optimize energy and ancillary services market products and produce information on the projected hourly operation of generators, ancillary service revenue, costs, and net income. It is not known if Production Costing Tool 4 has been enhanced to incorporate ESS.

2.3.4 Tool Limitations

2.3.4.1 Using "Educational" Tools

Tools designed for "educational" purposes include tools developed by US DOE in the past decade– Technology Selection Tool 1 and Technology Selection Tool 2. These tools are Excel-based and employ an internal data base of storage technology parameters and costs, plus some parameters around the performance requirements of different applications. These tools typically provide benefits analyses with a wide range, appropriately given the simple nature of the calculations and lack of geography/site/application specificity. As such they are useful for introducing energy storage to stakeholders and corporate management. They are relatively useless for evaluating specific projects or portfolios, and it was not the intent of the tool developers that they be used for those purposes. A weakness of this category of tool is that the internal data bases may not be current. Cost and performance data for different storage technologies may be out of date, and projected performance of laboratory/pre-commercial technologies may not have been realized. These tools typically include numerous technologies in a research and development phase which may not ever be commercially viable. Any use of these tools must include caveats about the data currency and realism issues.

Some of the Excel-based tools may be useful for evaluating initial business case feasibility before performing more rigorous analysis. But given the wide range of estimated benefits, results have to be interpreted as very rough estimates and only that.

As noted above, general high level "survey" tools are more valuable today for educational and introductory purposes than for realistic project analysis. Technology Selection Tool 1, for instance, cannot be used to evaluate a project feasibility. Technology Selection Tool 2 and Cost Calculation Tool 4 can be used to get a first estimate of a storage project's likely costs, but the currency of the data in these tools must be verified and industry surveys from Vendor 7, Vendor 24, and others will provide more up to date information.

2.3.4.2 Using planning tools

The major distribution and transmission planning tool sets either do not have storage object models or have limited capabilities in terms of using these for particular applications or for assessing sizing requirements. This is expected to change rapidly as the software companies move to incorporate storage in their capabilities. Tools that employ distribution planning load flows for storage sizing typically do so with external time series control of the storage using python, Matlab, or other coded algorithms.

In the distribution space, the tools typically found for distribution planning are Distribution Planning Tool 3, Distribution Planning Tool 4, Distribution Planning Tool 2, Distribution Planning Tool 7, and Distribution Planning Tool 6. Any can be used to evaluate samples (as in peak load, minimum load, peak PV production) with storage added as a user specified injection/withdrawal. Using these tools for storage applications in distribution this way is labor intensive.

Distribution Planning Tool 3, Distribution Planning Tool 6, and Distribution Planning Tool 4 support a Python license and this allows time series simulation with the external Python code actually simulating the storage asset and its control algorithms. Distribution Planning Tool 6 and Distribution Planning Tool 3 have been used in previous utility ESS assessments in state or utility storage roadmap and valuation projects. For this project the Python code was also ported to Distribution Planning Tool 4 so that that tool could be used. All three of these distribution planning tools will perform well for use in storage sizing and evaluation efforts, with idiosyncrasies unique to each around issues of high PV penetration. All three have PV hosting capacity analysis capabilities under development or released, note.

The effectiveness of the particular Python storage applications is therefore more a determinant of the capabilities of the tool than of the distribution load flow to which it is mated. From published work, the

Vendor 5 application performs capacity deferral. The Python code used in the project supports capacity deferral and it also supports the PV integration applications, which were demonstrated in this project.

It is normally the case that one storage resource can provide all the renewable integration applications in conjunction. In some cases, the capacity deferral application may be combined with renewable integration. However, renewable integration is very locational which may make this impractical.

Local resiliency is not a problem of analyzing the distribution circuit but is one of ensuring that the storage resource in conjunction with other energy resources is capable of meeting load within the microgrid for the duration required. This is similar to the behind the meter microgrid application and addressable with the same tool kits. Feasibility Analysis Tool 1 is widely used for this purpose; there are other tools with similar capability available from several vendors. Feasibility Analysis Tool 2 tool is another one.

There is also a stacked application for the local islanding application. The storage must be sized to carry the peak loading day for enough hours to allow business as usual repairs. This means that in off peak seasons there may be sufficient energy storage capacity to enable participation in wholesale market products so long as state of charge is sufficient for the outage energy needs.

Distribution applications are very much in a pilot/demonstration stage today and there are few examples of stacked applications in commercial operation. Uncertainty is one obstacle, lack of integrated controls for stacked applications another.

2.3.4.3 Using production costing tools

All production costing tools are set up to evaluate generation resources against these products and to co-optimize participation in the different markets. However, not all are set up to include “energy limited” resources such as storage, other than possibly pumped hydroelectric. And even if they do accommodate pumped hydroelectric, common shortcomings include easy handling of multiple storage resources or the ability to optimally schedule charging as well as discharging.

Some production costing tools are able to address the real time market explicitly or indirectly. Explicit representations reduce the time step from 1 hour to the real time market time step of 5 or 15 minutes. This produces exact results at significant increases in computer time. Others may approximate the representation to retain use of an hourly time step and then co-optimize the ability to be in the RT market as well as DA and ancillaries. None of the production costing tools represent the actual energy flow in charging or discharging in the regulation market which may be a factor for storage depending upon the details of the ISO regulation product.

The California ISO market has unique features of the regulation market that are not duplicated in other ISO markets. The production costing tools may not capture the details of these at a level that works for energy storage planning. The regulation product has separate up and down components so that a resource can be in one or the other or both. There is a special regulation product for storage where the ISO biases the setpoint in a subsequent 15 minute time step so as to “repay” the energy net charge/discharge of the prior time period. This allows a storage resource with a shorter duration (nominally 15 minutes but certainly 30 minutes) to play in this market. Today, resources in this market cannot be in the energy markets.

The problem of engineering validation of schedules derived from production costing models or other models is a different problem. Here the storage resource needs to be simulated with reasonable fidelity in a simulation appropriate to the application. For energy products this is not an issue. For regulation where system control area performance is an issue, then dynamic simulations such as Transmission Planning Tool 2 or proprietary tools such as Specialty Tool 2 or similar tools from Vendor 15 and Vendor 1 are required.

When physical validation with a dynamic simulation tool such as Transmission Planning Tool 2 or Specialty Tool 2 is required, then a day at a time is typically simulated and a means of annualization by extrapolation has to be developed if needed. More typically extreme scenarios are defined and days selected against this set of characteristics as performance, not annualized cost is the objective.

When an existing storage project has been in the wholesale markets for some time, it is straightforward to calculate the performance of the project against the theoretical best as one metric of how well the project has performed, or better said, as a metric of how well original projections compare to actual. It is also possible to assess the impact of different factors: actual vs historical prices (a major factor), project availability, accuracy of forecast prices used in daily decision making, and so on.

Production costing tools in general are able to assess generation and to some extent storage resource revenues in the wholesale markets across a range of products. All the production costing tools mentioned incorporate transmission network models and constraints (usually not AC models, note) so can model transmission N-0 and N-1 congestion and compute nodal prices. However, their network models are not suitable for distribution networks so that the tools cannot be used to assess wholesale market services revenues for distributed or behind the meter ESS. Table 2-5 presents a comparison of some features of commonly used production costing tools.

Table 2-5. Observations on Tools for Valuing Storage in the Wholesale Markets

Tool	Has Storage Object	Co-optimizes charge & discharge DA schedule	Co optimizes HA storage schedule	Co-optimizes ancillaries	Allows user object definitions (e.g., degradation, self-discharge)
Generation Management Tool (Vendor 22)	No	No	No	No	No
Production Costing Tool 1 (Vendor 8)	No	Discharge only	Discharge	With discharge	No
Production Costing Tool 3 (Vendor 21)	Yes	Yes	Yes	Yes	Unknown
Production Costing Tool 2 (Vendor 20)	Yes	Yes	Yes	Yes	Yes

2.3.4.4 Using specialty tools

There are a number of tools available that can co-optimize storage participation in the wholesale markets given a time series of hourly prices as inputs. These can be spreadsheet based, written in a high-level language such as Matlab, or developed in a coding language such as Python. The formulation of the problem – objective function of maximizing revenues and constraints on capacity, state of charge, etc., can be written in the language of the chosen platform and then an available/native optimization "solver" package or more capable 3rd party code can be used to perform the optimal scheduling. Other "tools" may approximate this via less rigorous approaches, using averaging or other approximations, but there are multiple organizations with true optimization capabilities today. These tools typically work on an hourly resolution (only) and must ignore or approximate the Real Time market revenues.

All such "price taker" tools use historical ISO prices for market products and determine an optimal schedule against those prices. This is valid for DA prices if the storage resource can act as a passive non-participant and vary its charging and discharging on a Real Time Pricing (RTP) basis. It is not valid if the resource must be in the market as at a minimum the resource must schedule or bid the charging and then offer the charging so must determine which hours to target, as the ISOs do not co-optimize this for the storage resource. For the RT market and the ancillaries market the resource must be an active participant and must submit offers in order to be awarded product delivery at market price. Thus, the resource operator is dependent upon price forecasting tools or similar in order to develop a bidding strategy. This means that the optimal strategy developed in the storage valuation tool is a theoretical optimum which cannot be realized in practice and must be discounted to some extent.

These tools exhibit the same characteristics with regard to annualization as the production costing tools. Hourly analysis can be carried out on an 8760 basis. Sub hourly analysis may require sampling and extrapolation although some tools can perform it on an 8760 basis as well.

Vendor 12, and some consultants have developed specialized tools for assessing various storage applications at higher fidelity using engineering grade network analysis coupled with co-optimization of the ESS for wholesale market services. These include tools that use Python and/or Excel to set up and simulate ESS for capacity deferral, renewable integration, and local microgrid applications. These tools interface to Distribution Planning Tool 3, Distribution Planning Tool 6, and Distribution Planning Tool 4 to perform AC distribution network simulations and are capable of assessing stacked applications including wholesale market services.

2.3.5 Stacked Applications

Stacked Applications is the term used to describe a situation where the storage resource is used for more than one domain of applications. The normal case is one where one storage resource is used for multiple renewable integration applications, or to accesses wholesale markets in addition to its primary mitigation function projects, i.e. when the wholesale market applications and T&D applications are allowed to be performed by the same storage resource.

Generally speaking, the T&D "reliability" applications take precedence over "wholesale market participation" in that the applications that ensure safe operation of the T&D system will come first, and market operations cannot be allowed to interfere with the instantaneous requirements of the reliability application. This means that the source of the information about the T&D application must provide constraints on how much storage capacity is available for other applications on a basis that is usable by the tool being used for market valuation.

Unfortunately, market valuation tools are all based to some extent on hourly analysis (or more granular) of price time series or market simulations. This means that the T&D constraints must be similarly posed to be useful. When the T&D sizing/valuation/validation process does not produce this data, something must be done with load profile shapes, PV shapes, and the like to approximate it.

Tools that use generic factors to reduce capacities, etc. fall into the educational class and will be essentially useless for this purpose.

Once the T&D constraints are available, the storage capacities available for market purposes must be modified on an hourly / daily basis so that the market valuation can respect the T&D application requirements.

The constraint transfer can be manual, possibly with simplifications, or automated to some degree via file transfer/upload, etc.

As of this draft, there are no tools available that completely automate this process although some approach it in terms of anticipating the need and preparing the constraint data from the T&D analysis ready for input to the market valuation analysis.

The use of different circuit analysis tools with different storage valuation tools is discussed below. The tools listed are the ones primarily used by large utilities in California. There is good body of experience on utilizing Distribution Planning Tool 3, Distribution Planning Tool 4, Distribution Planning Tool 6, and Distribution Planning Tool 5 for similar projects, and the observations are based on those experience in the context of California. It should be noted that software vendors are continuously improving the models and features of the existing tools based on the feedback and request from utilities and industry user. For that reason, the information in Table 2-6 should not be considered exhaustive and final. There are always newer versions of the tools that may provide additional features and need to be evaluates on the case by case basis.

Table 2-6. Comparison of major capabilities of tools available for evaluating energy storage applications in distribution systems and stacked benefits

	User Interface & Models			ESS Distribution Applications				ESS Market Applications			Stacking
Tools / Vendor	**Supporting External Scripts (API)**	**Open Source**	**Energy Storage Model?**	**Capacity Upgrade Deferral**	**PV Integration Impact**	**Voltage & Flicker Mitigation**	**Islanding (Microgrid)**	**Hourly Energy**	**Real Time Energy**	**Regulation**	**Application Co-Evaluation**
Distribution Planning Tool 3	YES	NO	Basic, Some controls	YES	YES	Voltage Control	No	N/A	N/A	N/A	N/A
Distribution Planning Tool 4 (Vendor 5)	YES	NO	Basic, Scheduling Charge and Discharge	Single location (using scheduling)	No	No	No	N/A	N/A	N/A	N/A
Distribution Planning Tool 6 (Vendor 12)	YES	YES	Possible[1]	Possible[1]	Possible[1]	Possible[1]	Possible[1]	N/A	N/A	N/A	N/A
Distribution Planning Tool 2 (Vendor 9)	YES	NO	Possible[1]	Possible[1]	Possible[1]	Possible[1]	Possible[1]	N/A	N/A	N/A	N/A
Distribution Planning Tool 5 (Vendor 11)	YES	NO	Possible[1]	Possible[1]	Possible[1]	Possible[1]	Possible[1]	N/A	N/A	N/A	N/A
Vendor 5 ESS	NO	NO	Explicit[2]	YES	Unknown	Voltage only	YES	YES	YES	YES	Unknown
Cost Calculation Tool 6 (Vendor 12)	NO	No, but planned	Explicit[2]	YES	NO	Voltage only	NO	YES	YES	YES	Limited
ESS-ASET	YES	Semi	Explicit[2]	YES	YES	YES	YES	YES	YES	YES	YES

1: Complex approach; User needs to develop custom model
2: Including an object model for energy storage (equations, constraints, and parameters)

2.3.6 Storage Portfolio Determination

For utilities and for state policy makers, an important question today is “how much storage do we need?” and related to that “what is a no regrets figure for storage?” Variations on this question can get to the level of “for what purpose and where” as well.

Determining the characteristics of desirable portfolios is also sometimes called a “roadmap” process that may also address the rate at which this storage is implemented, and what indicators along the way (such as PV penetration, storage costs, and energy prices) inform the process.

As of today, there is not even a widely agreed process for conducting such an exercise. Several utilities have proceeded down this path.

At the wholesale level, iterations using a production cost program are a valid way to address the question, including the question of how much is needed to integrate a specified renewable portfolio or to address how different storage portfolios will address the costs of renewable integration in terms of production costs and ensuring that sufficient reserves and system flexibility is maintained. Such an analysis would not, however, address the question of whether conventional plant revenues are sufficient and what capacity payments or equivalent might be required from that perspective.

At the transmission level, there have been as yet no studies to examine total storage portfolios for congestion management.

At the utility distribution level, there have been several such studies. These basically repeat the distribution application assessment for a circuit or station across the population of utility circuits and stations, or find a way to parameterize these results based on a sample and then extrapolate this to the entire population based on those parameters.

If these studies include stacked applications, then they are vulnerable to the wholesale market price taker problem. They use historical price time series as inputs. However, if a particular T&D utility were to deploy wholesale level storage in total (as in > 1000 MW) and all of it were doing stacked applications, then the assumption of wholesale price time series is not valid and probably optimistic, as that much storage will act to depress high prices.

2.3.7 Vendor 12 Cost Calculation Tool 6 Assessment

The Vendor 12 Cost Calculation Tool 6 tool is a major, integrated tool which can assess all the various applications described and which has been extensively customized to the California situation. As such, it merits a more in-depth discussion than most other tools considered.

This assessment is based on a review of the documentation set Vendor 12 Cost Calculation Tool 6 1.0 and the on-line cloud-based version.

Cost Calculation Tool 6 is based on the Analytical software platform. This is a heavy duty commercial simulation/optimization platform that uses EXCEL as a GUI and allows users the benefit of a variety of sophisticated and powerful optimization engines/solvers that would otherwise be expensive to access. This gives Cost Calculation Tool 6 capabilities beyond those available from EXCEL and VBA based tools

Cost Calculation Tool 6 is tailored to the California system and markets, and has incorporated CA ISO historical prices for use in valuations. This greatly facilitates use of it for storage assessments in California. As such, it is not intended for nor suitable for use in other regions when wholesale prices must be factored in. It also has pre-loaded load profiles for use in assessing various T&D applications, so is again California specific and not suitable for geographies with significantly different weather, etc.

The Cost Calculation Tool 6 modeled Services are shown in Figure ES-1 of the Vendor 12 documentation (Table 2-7):

Table 2-7. Cost Calculation Tool 6 modeled applications with source of market price, retail rate or avoided cost [11]

	CAISO Markets/ Tariff Rates	Bilateral Markets or Internal Utility Dispatch Costs	Utility Rates/ Customer-sited Applications	T&D Investment and Operations
Resource Adequacy Capacity	✓	✓		
Day Ahead Energy Time Shift	✓	✓		
Real Time Energy Dispatch	✓	✓		
Flexible Ramping Product	✓			
Frequency Regulation	✓	✓		
Spinning Reserve	✓	✓		
Non-Spinning Reserve	✓	✓		
Black Start	✓	✓		
T&D Investment Deferral				✓
Transmission Congestion Relief	✓			✓
Transmission Voltage/Reactive Power Support	✓			✓
Equipment Life Extension				✓
Losses Reduction	✓			✓
Voltage Control	✓			✓
Retail Demand Charge Reduction			✓	
Retail Energy Time Shift			✓	
Power Quality			✓	
Backup Power			✓	
Demand Response Program Participation	✓		✓	✓
PV Self-Consumption (FITC Eligibility)			✓	✓

Vendor 12 describes the following limitations of Cost Calculation Tool 6:

- It models storage as a price taker in the market and uses historical prices as given. Thus it assumes perfect foreknowledge of prices in establishing day ahead scheduling for the time series optimization. This is typical of storage (and other resources in the market) valuation approaches and is in effect state of the art. Without knowledge of what price forecasting/scheduling tool a user might have access to this is the best that could be done.

- Because it models storage as a price taker it is appropriate (only) for assessing incremental individual storage project revenues and returns in the wholesale markets. This means, by extension of this point, that Cost Calculation Tool 6 as it is – is *not* a suitable tool for assessing impacts of storage profiles on the state markets, answering questions such as "what is the no-regrets level of storage in the state?" and so on. It was not the intent of Cost Calculation Tool 6 to provide this capability. Advanced Production Costing tools such as Production Costing Tool 2 are better suited for this purpose.
- Cost Calculation Tool 6 does not model effects such as AC voltage effects. Thus in valuing storage as a VAR resource on a distribution system, it requires external inputs obtained from a distribution circuit analysis tool. This is typical of the state of the art today.
- It does not address emissions benefits. Again, this is best done via an advanced production costing tool which typically has this capability.
- The details of the co-optimization of energy and ancillaries across time are not transparent. The documentation states that some approximations are taken to avoid the creation of non-linear or integer variables in the tool. This is not surprising, as large numbers of integer variables or non-linear functions can tax the optimization. Without further work to compare Cost Calculation Tool 6 results with those of a more rigorous formulation the impact of these approximations cannot be determined. It may well be that during the tool development this was examined and determined to be unimportant.
- Cost Calculation Tool 6 does not explicitly address the distribution micro grid or local circuit resiliency application. However, use of the behind the meter backup generation capability can achieve results for this application with the correct data entries so long as circuit constraints do not enter the problem.

2.3.8 Conclusions

The state of energy storage in the electric power industry has developed rapidly and is variously at the stage of pilot projects to commercially viable businesses depending upon the application and the geography/jurisdiction. Early storage tools which were aimed at "education" and "introduction" were useful at the time but have not kept pace with the need to perform true engineering and detailed financial modelling.

As with every other technology in use in electric power, rule of thumb or simplified analyses have their place in terms of "first look" at technology viability for meeting needs or estimating market revenues. However, actual project planning and financial evaluation before proceeding cannot depend upon such approaches, and rapidly evolves to detail engineering simulations and analyses coupled with sophisticated financial analyses. A perfect example of this is the wind industry that has long relied on 8760-hour time series analysis of wind production and then state of the art production costing/security constrained unit commitment analyses of market revenues and potential curtailment as a condition of securing project finance. Energy storage is reaching similar states of sophisticated analysis rapidly for the same reasons.

Even when the storage investments are driven by grid reliability needs and will be rate based at the start, the role that market revenues can play in the economic viability of a project is crucial. Analyzing these finances requires levels of sophistication as with the wind farm example. Storage is more complicated than most technology investments in that it lends itself to stacked applications and revenues that encompass one or more reliability applications as well as multiple sources of market revenues.

The survey of the different tools available indicated that (as shown in Figure 2-4) today the engineering tools routinely used in distribution planning have not, for the most part, accommodated storage technologies at fidelity for reliability applications, and are not at all able to address market application revenues. For this reason, a combination of storage specific application software wrapped around commercial distribution planning software is the only realistic alternative.

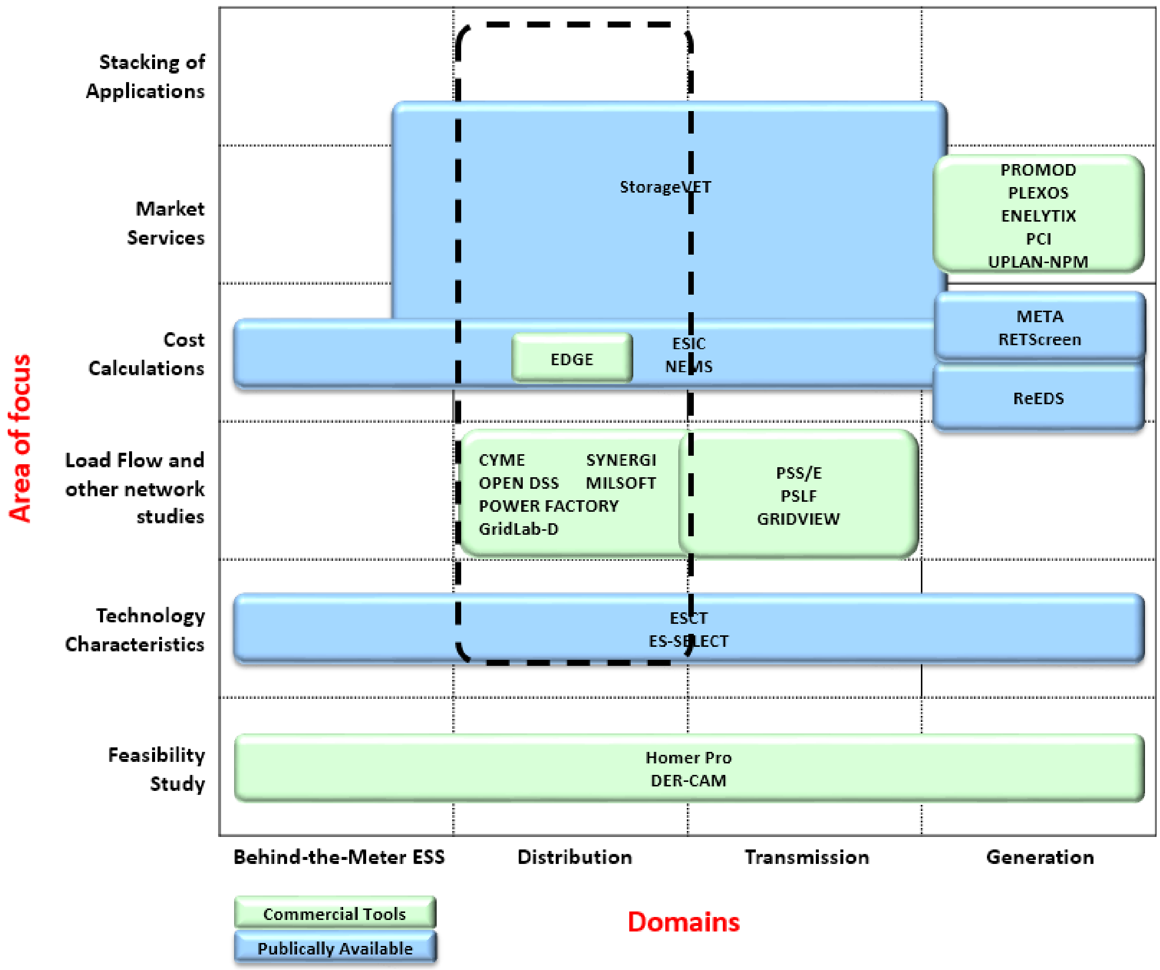
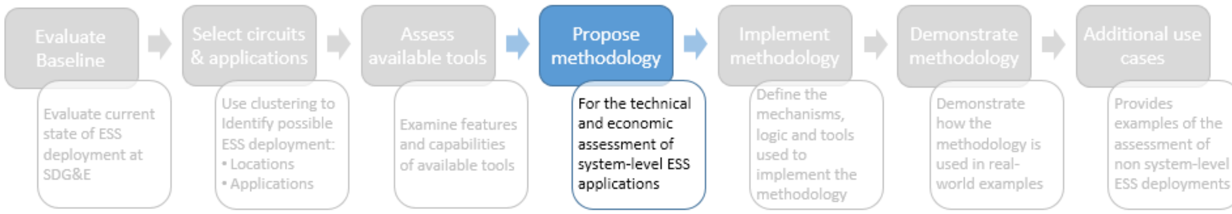


Figure 2-4. Gap in available tool set for Distribution applications

2.4 Task 4: Propose methodology

This task proposed a methodology to be used to analyze the technical and economic viability of deploying ESSs on the SDG&E distribution system.



There are two categories of applications to be considered; system applications where the ESS is deployed as a grid asset, and end-use applications where the ESS is deployed as a pure market asset or for the end-use customer specific purpose. The methodology for evaluating these two categories of applications differs. The methodology discussed in this section, and implemented and demonstrated in the next two sections, is designed for performing energy storage value evaluation for system applications. The methodology consists of the four steps shown in Figure 2-5 below.

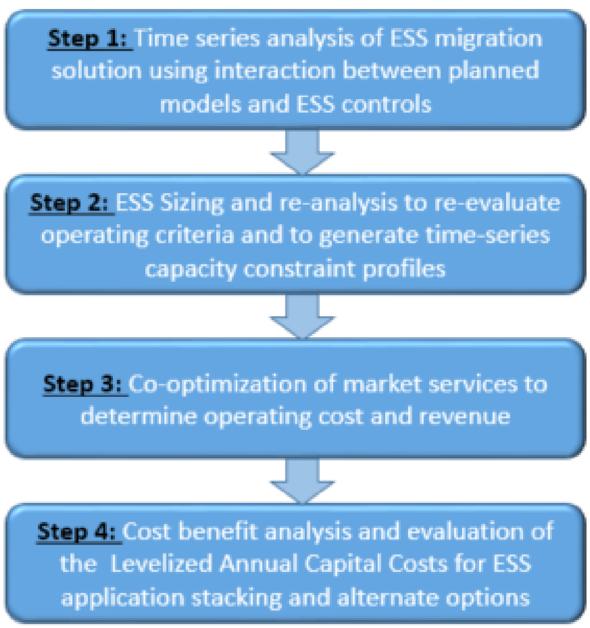


Figure 2-5. ESS analysis approach for system applications

- In Step 1, typical planning tools are used to determine the proper size and location of single or multiple energy storage units that can mitigate the specific issue addressed by that application. In the case of SDG&E, a combination of Distribution Planning Tool 4 planning model and Python coding is used to represent and analyze specific energy storage functions as part of the circuit-based power flow studies. It should be noted that similar study approach has been applied in conjunction with other planning tools (common to other IOUs in California). Distribution Planning Tool 4 is used to perform the circuit load flow at each time step. Python code simulated the BESS and its control algorithms for each application and controls the time step.

- In Step 2, the ESS size and capacity obtained from Step 1 analysis is assessed to select a realistic rating from available commercial technologies. The time series analysis of Step 1 are repeated for the final ESS size and capacity to capture the operating constraints of the BESS and to determine available capacity and/or operating conditions under which the BESS unutilized capacity or time-frame of operation can be offered for other services.
- In Step 3, once the energy storage sizes (both power and energy capacity ratings) and constraints are obtained, optimization and analysis of various applicable market participation services are performed to estimate revenue for stacking market services with distribution reliability application as primary functions. Certain operating constraints are applied to ensure energy storage system can always meet the distribution reliability application considered. For instance, circuit loading mitigation thresholds are used for capacity upgrade deferral and/or maintaining state of charge requirements at all times are applied to ensure enough capacity to serve customer loads if a planned or unplanned outage occurs. The market analysis is on an hourly basis for 8760 hours a year and factors in load growth to analyze future years.
- Step 4 focuses in cost benefit analysis and evaluation of the Net Present Value for the ESS approach versus the more conventional approach of distribution system upgrade and enhancements.

The time series analysis approach using Python/Distribution Planning Tool 4 power flow and/or circuit loading processes was developed for this project using available algorithms and control functions from similar prior studies that can produce appropriate setpoints for BESS active and reactive power contributions in an attempt to mitigate the issue under study (such as circuit overloading, or excessive reverse power flow, or steep power changes, or significant voltage problems).

For this project, a custom design mixed integer programing (MIP) based tool was used for evaluating BESS revenues in wholesale markets and for evaluating the wholesale revenues from distribution system and microgrid stacked applications. This tool was used to perform detailed evaluations of the Escondido and El Cajon BESS participation in the wholesale markets; it was also used to evaluate the stacked-application revenues for the energy storage system sized and sited for distribution reliability applications such as capacity upgrade deferral and for PV integration mitigation, as well as for the proposed microgrid (local reliability) applications. CA ISO 2016 historical data was used to perform the theoretically optimal revenue evaluations.

It is important to recognize that real world operations cannot realize 100% of the projected theoretical best case revenues; there are several reasons for this:

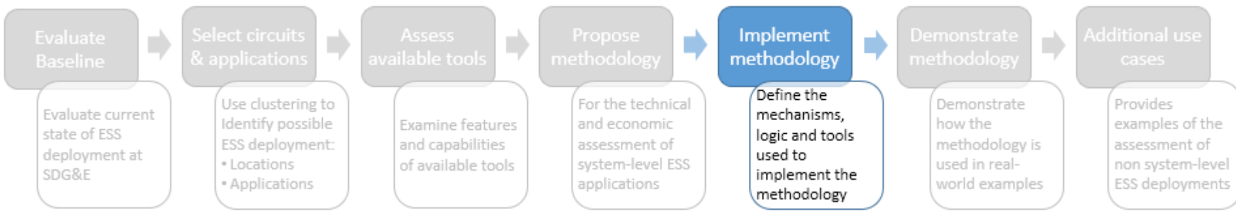
- Market prices going forward may not behave identically to historical prices. Changes in the resource mix, weather, and fuel prices as well as possible changes in market products and rules can all affect prices. Most studies nonetheless use historical prices for these analyses, although when forward gas market prices are notably different these can be factored in. Similarly, growth in renewable penetration, plant retirements, and similar trends can be factored in. This study did not include production costing analysis or future energy price forecasting. The 2016 historical prices – extracted from CAISO website - are used “as is.”
- When it is necessary to actively participate in the market by making offers, the BESS operator has to determine the price for each market product to use in submitting a bid. This requires the use of a tool such as Generation Management tools to forecast DA energy and ancillaries prices and to determine a bidding strategy, as SDG&E does today. A BESS, which is declared as a generation resource or an NGR, can participate in DA energy and ancillary markets, and in the RT market; it must make offers in order to do so. BESS located “below the take-out point” or on the distribution

system can participate passively by responding to DA energy prices – this then affects the Unaccounted for Energy account of SDG&E; the energy cost savings get passed on to SDG&E ratepayers. In order to participate in RT and ancillaries markets, distributed BESS seeking stacked applications will have to be active market participants with the same work required in developing daily bidding strategies; thus, the stacked applications revenue calculations are somewhat hypothetical today. When a rule-based bidding strategy is determined, (as might be the case for distributed storage), then this can be simulated and evaluated using the same approach as in the theoretically optimal analysis. Simulations such as these could also be used to test different rule-based strategies, ultimately including price uncertainty.

- As more energy storage systems enter the market in California, it can be expected that market prices will be impacted and that the ISO market products and rules may adapt to storage penetration.

2.5 Task 5: Implementing the methodology

This task converted the theoretical four step process proposed in the preceding task into an executable model for analysis of the three system-based ESS applications shortlisted in the section entitled Task 2: Select Circuits and Applications.



The short-listed system-based ESS applications are:

- Circuit upgrade deferral
- Reliability Enhancement for Customers by using ESS in Microgrids
- PV Integration Mitigation

The sections that follow describe how the four step methodology of performing Time Series Analysis, ESS sizing, co-optimization and cost benefit analysis are implemented for these three system applications.

2.5.1 Circuit upgrade deferral application

The circuit upgrade deferral function of ESS deals with mitigating thermal rating issues on distribution circuits and therefore deferring the distribution system upgrades for a specific period of time. Thermal limiting cases can be at: transformer bank level, circuit level, section level (further away from substation) or branch level – especially at tie-lines with limited capacity for load transfer (e.g. places where 100A tie switches were used but the load has grown beyond 100 A overtime).

The analysis is focused on estimating ESS size/capacity for providing at least 5-year capacity support and upgrade deferral for the circuit. ESS may be installed downstream of the location where upgrade is required, such as circuit head, mid-circuit and/or on a branch.

2.5.1.1 Step 1 - Perform time series analysis

Some planning related information was received from SDG&E and the rest were extracted from Distribution Planning Tool 4 models. Since the ampacity ratings from Distribution Planning Tool 4 models are lower, the project considered these numbers in capacity upgrade deferral studies in order to perform the studies for the worst case.

Based on information from SDG&E, the main cases of thermal limit issues identified for this project were at the substation level. The limiting factor is typically conductor size for the first section of the backbone that have to carry out almost the entire circuit load.

Two approaches are suggested for mitigation of thermal limits with the use of ESS:

- Centralized
- Decentralized

2.5.1.2 Step 2 - Calculate ESS sizing

The sizing calculations performed in Step 2 differ depending on the approach.

Centralized:

In this approach, a single battery energy storage system is installed close to the substation for upgrade deferral application. The battery energy storage is sized appropriately to ensure the upgrade requirements of the distribution system in a 5-year time frame will be deferred. Therefore, the following approach is applied to each potential circuit in order to size the ESS for upgrade deferral application:

1. **Size determination**: Historical load profile (2016) are used to estimate a projected load profile for a 5-year upgrade deferral analysis:
   - Considering year 2019 as the analysis start year, a projected load profile for study year (2024) is created by escalating the load growth based on the historical load profile of 2016, and the resultant maximum loading of the circuit determined.
     - Load growth % is an input provided by SDG&E per circuit identified for capacity upgrade deferral
     - If load growth % information was not available, a 0.5%-1% growth factor per year was assumed
   - The number of hours/days that there would be a violation of thermal loading of the circuit is determined
   - Based on the maximum MW thermal loading violation and also the number of hours the service required, the ESS MW size and MWh capacity per year and on 5-year basis are calculated.
2. **Size verification**: Distribution Planning Tool 4 – Python combination is used to run the circuit load flow with the battery installed close to substation. In this analysis the projected annual load profile (year 2024) is used with 15 minute resolution to verify the satisfactory performance of the ESS with specified kW and kWh sizing.

Decentralized:

In this approach, two or more energy storage systems are installed on the circuit, further away from the substation and closer to load centers. Similar to the centralized approach, the distributed approach attempts to reduce the maximum loading of the circuit below the thermal ampacity in the analysis year and therefore deferring distribution system upgrades. However, dividing the ESS and installing them at different location helps manage the distribution congestion more efficiently throughout the circuit.

The main advantage of the distributed ESS approach is to reduce the size of ESS by dividing it among multiple units, as well as enabling additional stacking applications for voltage and reactive power support on the circuits.

The sizing approach is very similar to the centralized approach,

1. **Size determination**: Historical load profile (2016) are used to estimate a projected load profile for a 5-year upgrade deferral analysis:
   - Considering year 2019 as the analysis start year, a projected load profile for study year (2024) is created by escalating the load growth based on the historical load profile of 2016 and the maximum loading of the circuit determined.
     - Load growth % was an input provided by SDG&E per circuit identified for capacity upgrade deferral
     - If load growth % information was not available, a 0.5%-1% growth factor per year was assumed
   - The number of hours/days there is a violation of thermal loading of the circuit is determined
   - Thermal limiting points (TLPs) of the circuit downstream of the substation are determined and the effect of installing multiple ESSs downstream of TLPs assessed on ESS sizing and applications.
   - The geographical map of the area is investigated to finalize the multiple ESS locations based on space availability to install the ESS.
   - Based on the aforementioned analysis, the ESS locations, MW size and MWh capacity per year on 5-year basis are determined.
2. **Size verification**: Distribution Planning Tool 4 – Python combination is used to run the circuit load flow with the multiple ESS installed downstream of the substation, close to load centers. In this analysis the projected annual load profile (year 2024) is used with 15 minute resolution to verify the satisfactory performance of the ESS with specified kW and kWh sizing and modify the kW and/or the kWh capacity of the ESS if required.

2.5.1.3 Step 3 - Co-optimization of market services

Capacity upgrade deferral only requires the use of an energy storage system (ESS) during peak months at most. The rest of the year the ESS asset is not used for this core distribution reliability function (primary application). The peak shifting effect of capacity upgrade deferral necessarily provides some savings in wholesale energy costs via time arbitrage depending upon the ratio of on peak to off peak prices; these savings flow to the ratepayers (or so it is assumed). During the period of the year when the storage asset is not required for deferral; this time arbitrage is still possible. This service results in additional ratepayer savings when the asset is assumed to be utility owned with all energy cost savings passed on to ratepayers. The ability to fully utilize the storage this way adds to the business case and economic assessment (Secondary application).

Many analyses also examine “shared applications” or “hybrid application” meaning that the storage is also used for ancillary services provision. The recent FERC NOPR (Docket No. PL17-2-000January 2017) on storage in the wholesale markets encourages the aggregation of distributed storage resources for market participation and would open the door for ancillary service provision. However, this is definitively a market function and a regulated utility in a restructured environment in general today cannot act as a market participant. In order to achieve the shared applications model, the storage asset must be “shared” on some basis between the utility (for reliability functions) and a market participant (for market functions). This implies that the full benefits of market participation for ancillary services would not necessarily flow to ratepayers, depending upon whether the utility owns the storage and “rents” it out to participants when not needed or the utility contracts for its use via a kind of PPA agreement, with a developer owning the storage and using it in the markets. The FERC NOPR would suggest that this could change to allow regulated utilities to exploit stacked applications for the benefit of ratepayers.

This project analyzes three different variations of the hybrid application:

- Capacity Deferral Only (CD): Utility owned storage used for capacity upgrade deferral only. All arbitrage gains flow to ratepayers but when the storage is not needed for capacity deferral it sits idle. This generally justifies the smallest amount of storage and results in the weakest business case.
- Capacity Deferral and Arbitrage (CDA): Utility owned storage used for capacity upgrade deferral as a priority and for time arbitrage with "smart" charging to optimize energy wholesale costs throughout the year, with all savings passed to ratepayers. This model justifies somewhat larger storage installations and results in more feeders having storage as a viable business case.
- Capacity Deferral, Arbitrage and Ancillary service Market (CDAAM): Storage used for capacity upgrade deferral as a priority, with wholesale arbitrage and ancillary services provision (regulation and ancillaries) co-optimized as would be done by a sophisticated market participant. All economic benefits are assumed passed to ratepayers on some basis for the purposes of this roadmap. This case results in the most number of circuits justifying storage with the largest amounts of storage.

In each case, detailed technical, economic, and market operations analysis are required to understand not only whether storage is viable on a given circuit or location, but also exactly how much storage and for how long it is deployed before the circuit is upgraded.

Another important variation is the disposition of the storage after the deferral period. Many analyses assume that the storage is simply disposed of after the deferral period. This is uneconomic as the storage may have 50% or more of its useful life remaining. Here, we examines two variations:

- The storage is relocated to a new feeder (Out) for capacity upgrade deferral at the end of the deferral period (which means its remaining capital value after depreciation is transferred to a new feeder application), or
- The storage is left in place (In) and used purely for wholesale energy arbitrage. Both alternatives may result in positive business cases depending on cost of T&D upgrades, storage cost and storage market participation.

An overview of the capacity deferral valuation process as used to evaluate sample SDG&E circuits in this project is shown in Figure 2-6 below.

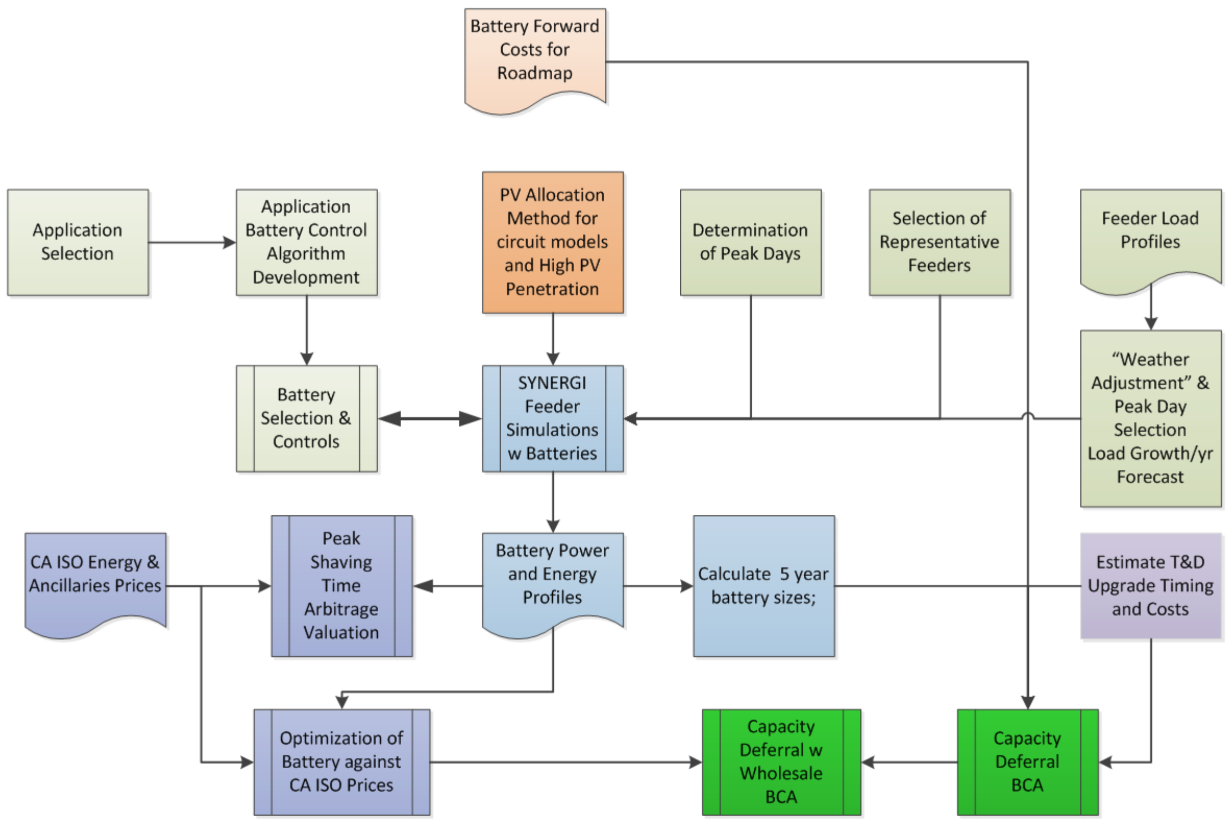


Figure 2-6. Overview of the capacity deferral valuation process as used to evaluate sample SDG&E circuits

2.5.1.4 Step 4 - Cost benefit analysis

The cost benefit analysis is accomplished by the following steps:

- What is the size of storage needed to address a given situation
- What is the cost of that storage
- What is the cost of the "traditional" distribution construction/upgrade alternative
- What is the Net Present Value of the difference in costs of the two approaches

The size of the storage has the two parameters of power capacity and energy capacity or duration – each of which influence the battery cost.

The cost of the traditional solution can be a generalization as in FERC Form 1 data on the cost of a MW of distribution capacity or can be an entry for each case.

For each circuit, the economics of T&D capacity upgrade deferral (5 year deferral) are evaluated. In this analysis it is assumed that year 0 is 2019. The "base case" is a distribution capacity upgrade in the first year (2020). It was assumed that when capacity expansion is done, the circuit will be upgraded to accommodate 10 years of load growth, and a generic cost per MW of upgrade (to cover transformer, circuit breaker, exit cable, conductor, switchgear – all in) is applied. Storage is being used as an alternative to defer upgrade for 5 years.

Battery costs in future years can originate from industry surveys, from vendor quotations, or from applications of costing tools such as the Argonne National Laboratories Bat-Pac tool[1].

The upgrade resulted in a cash cost in the year of deployment, plus an ongoing OPEX cost and financing cost to the utility. It is also assessed for ratepayer impact in terms of ongoing revenue requirement. Table 2-8 provides a sample of typical assumptions made in the model.

Table 2-8. Sample of typical assumptions and parameters

Parameter	Value	Comment
Battery MW cost $k/kW	$300	cost of inverter
Battery MWH cost $k/kWh	$200	cost of container
installation cost / kWh	$150	cost related to any work required to pick up the equipment at site and place it on the foundation, secure it on the foundation
Battery depreciation / yr	10.00%	Book Depreciation
Opex on Battery	5.0%	Service and maintenance

Each storage alternative is evaluated as follows:

- The storage is deployed instead of the T&D upgrade and the T&D upgrade delayed to the end of the deferral period (2025).
- The storage incurs cash costs for the installation (engineering, cost of battery, power converter, and balance of system, and erection), ongoing OPEX costs, and removal costs at the end of the deferral period.
- It also incurs depreciation during its deployment.
- At the end of the deployment the assumption is made that the storage will be relocated to another application and the particular feeder deferral "credited" with the depreciated value of the storage.

For each of the capacity upgrade deferral (CD), capacity upgrade deferral plus time arbitrage (CDA), and capacity upgrade deferral plus time arbitrage plus ancillary market (CDAAM) cases the economic benefits (all assumed going to ratepayers) are set against the annual costs of the storage and the ultimate T&D upgrade. These time series of costs and ratepayer benefits can then be compared to the base T&D upgrade on an ongoing and on aggregated cash flow basis.

2.5.2 Reliability Enhancement for Customers – ESS in Microgrid Application

Battery Energy Storage Systems (ESS) provide excellent opportunities to improve system reliability. Depending on the application implemented, ESS can reduce a sustained outage to a momentary outage or potentially completely avoid the momentary. ESS can provide opportunities for reliability improvement in areas where traditional upgrades are expensive, such as in areas with no circuit ties

[1] http://www.cse.anl.gov/batpac/about.html

capabilities. These can occur in rural areas or even in urban areas with limited access by other circuits. Areas with high PV penetration can also be evaluated to integrate with ESS for Microgrid applications.

For the purpose of customer-based reliability enhancement, the priority is to utilize ESS to serve the load of a selected area on the circuit during outages (islanded microgrid). In the microgrid application, ESS would be the primary source of grid-forming and supplying loads during outages. For this purpose, ESS should be equipped with appropriate control framework to provide voltage and reactive power control and frequency regulation. The area under ESS coverage (microgrid boundaries) should be bordered by reclosers or SCADA switches to isolate the area subsequent to islanding in upstream grid.

Beside from the microgrid application, the ESS can be also utilized for some secondary applications such as market participation and voltage support during normal operation. However, the utilization of ESS for these secondary applications should be limited such that there is always enough State of Charge (SOC) available in there battery to be utilized for customer support during unplanned outages.

2.5.2.1 Step 1 - Perform time series analysis

The ESS sizing was performed by time-series analyzing of maximum demand and reserve capacity (kW, KWh) required to supply customers within the designated microgrid territory during the worst case outage. Three sets of ESS sizing were identified based on evaluating worst case outage time of the year for 4-hour, 6-hour, or 8-hour durations, respectively

2.5.2.2 Step 2 - Calculate ESS sizing

The ESS sizing methodology for microgrid application is shown in Figure 2-7. As seen in this figure, the ESS sizing process is categorized into three main categories, namely:

- Identifying candidate locations for ESS installation
- Determine load allocation
- Calculate ESS sizing for candidate locations

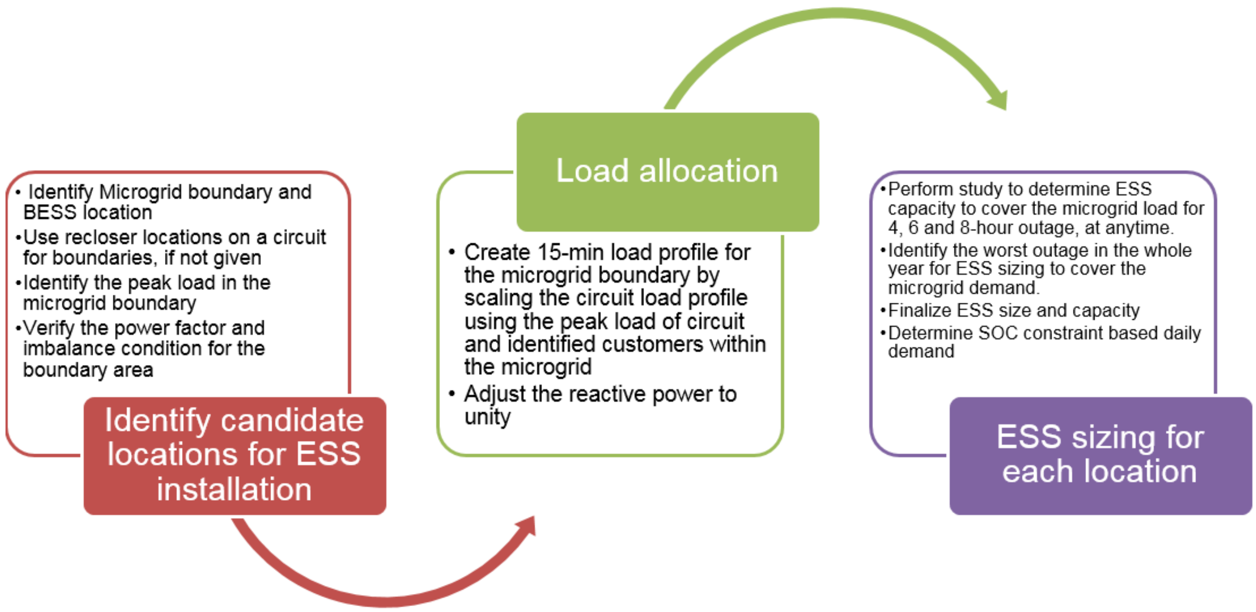


Figure 2-7. ESS sizing methodology for microgrid application

To determine the ESS size, the 15 minute load profile of circuits are utilized. The ESS size is calculated for three different outage durations, 4-hour, 6-hour, and 8-hour. The outage window is moved along the whole year starting from the first hour in January 1st of year under study to the hour 8760. The ESS is sized to cover the microgrid load during the worst outage window. It is assumed that ESS is fully charged before the outage occurs (control scheme based on initial SOC =100%). Additionally, the minimum allowable SOC of ESS is assumed to be 5%.

2.5.2.3 Step 3 - Co-optimization of market services

The objective of this study is evaluating the additional potential benefits of Battery Energy Storage Systems (ESS) by participating in CAISO wholesale and ancillary markets.

Market participation is considered as secondary application where the primary application is reliability enhancement by utilizing ESS to serve the load of a selected area – on a circuit- during outages.

In this analysis, the optimization used the DA prices for charging and the RT prices for discharging, to simulate the strategy described by SDG&E in which charging load is bid into the day ahead markets and discharging withheld from the day ahead (2016 nodal LMP prices are considered). Discharging is offered into the Real Time markets. As an additional step, the strategy of offering RegUp and RegDown services into the CAISO ancillary service markets was evaluated, again at 2016 historical prices. Each day, the optimization would co-optimize the energy and ancillary service participation across the day so as to maximize revenues subject to BESS operational constraints. Adding regulation services to the product portfolio accessible to the Escondido BESS increases revenues as would be expected.

For market participation analysis two alternatives are considered. These are

- Only participation in wholesale market, and

- Participation in both wholesale and regulation markets.

The analysis considers different outage durations and summarizes the market participation benefits for these outage scenarios. An Energy Credit is calculated for each scenario using the discharging revenues less the charging payments when only wholesale energy participation is considered. These energy credits in the wholesale and regulation case also include an estimate of the settlement of regulation revenues at RT prices. Generally, energy credits decrease as regulation capacity increases, as less battery capacity is then available for arbitrage.

In regulation market benefits calculations the mileage payment is a straight forward computation using the CA ISO 2016 historical data for up and down mileage factors and battery accuracies. The ISO data does not appear to facilitate the direct calculation of the energy credit for RegUp and RegDown energy. (The mileage factor is related to the length of the curve of AGC dispatch signals, not to the area under the curve). For purposes of this estimate, a figure of ½ of the Reg Capacity in each 15-minute period was used to estimate the RegUp and RegDown energy. This then became an increment/decrement to the BESS state of charge beginning the next 15 minute period, and was used to calculate regulation energy credits.

Annual market benefits are calculated as a summation of energy, Regulation Up and down Capacity, mileage credits less the variable O&M (VOM). Note: VOM of 0.00579 $/kWH is considered for both charging and discharging of the battery.

Utilization of ESS for some secondary applications (e.g., voltage support and market participation) should be subjected to some constraints to ensure the availability of energy required to serve the load if outage happens anytime during the day. For this purpose, the following energy constraints are calculated:

- SOC Day Long: The minimum required SOC for BESS to be armed for possible outage happening during the day.
- SOC Day End: The required BESS SOC at the end of the day.

2.5.2.4 Step 4 – Cost/benefit analysis

In order to perform cost/benefit analysis for ESS in microgrid application, the cost of alternative (wire-base) solutions were establishes as follows,

- Cost of doing nothing option: For each microgrid, the 5-year historical outage data and customer demography information were used to perform ICE Calculation to determine loss of business cost for various customers.
- For microgrid on circuits that are in boundary areas (there is no alternative path) the 20 years NPV of that cost was assigned to the business case.
- For microgrid on other circuits, cost of extending an additional circuit and/or upgrading a tie line to serve the area through an alternative path was determined. The lowest alternative option cost was assigned to the business case
- For all microgrid cases, the revenue estimate for participation in the wholesale market with capacity constraint was used as the direct revenue for the business case.

2.5.3 PV Integration Mitigation

High penetration of PV systems (both centralized and distributed) across a distribution circuit can cause significant over/under voltage conditions, visible flicker events, and possibly excessive ramping up and down. Active and reactive power produced from the PV system can have an effect on the steady-state circuit voltage (Even if the PV system does not produce reactive power, the high real power flows will induce reactive power in the circuit reactance.). Moreover, fluctuations in the PV output would cause voltage fluctuations on the circuit. BESS can be used to mitigate the aforementioned issues by controlling active and reactive power on the circuit at pre-determined locations.

The impacts of high PV penetration is highly pronounced when the feeders are lightly loaded and at the same time a large amount of PV is connected. Thus, for each of the selected circuits the day with the minimum loading in the year 2016 was chosen as the desired study day. A combination of the aforesaid chosen day and the PV profile scaled to the maximum installed PV size of the circuit provides the worst case scenario for the PV impact analysis.

2.5.3.1 Step 1 - Perform time series analysis

The system is first modelled without a BESS to produce baseline results, and then again after the BESS is deployed to verify the issues have been mitigated. The approach is as follows:

PV only, no BESS

- For selected circuits, time series analysis is performed to determine whether the existing (or expected) PV penetration level can introduce any voltage or power quality issue.
- 10 second solar radiation profiles are used for the PV production estimation.
- The existing/expected PV systems are identified in Distribution Planning Tool 4 model to incorporate variable profiles.
- 15 minute annual load profile extracted from SCADA system at the circuit head is used to perform load allocation at given steps of analysis.
- Based on resolution of load and PV profiles, 10-second time steps are used for Distribution Planning Tool 4 time series analysis. At every time step, PV system outputs are updated and a power flow is performed. At every 15 minutes, a load allocation is performed to re-assign the total circuit load (from SCADA) to the distributed and spot loads on the circuit.
- Time series analysis are performed on daily basis, and for the entire year.
- At each time step, voltage and power flow values at pre-selected metering locations on the circuit model are captured and saved in a file. The locations of interest are typically: at circuit head, at PV interconnection points, on secondary of line voltage regulators, at shunt capacitor locations, and toward the end of circuits or major branches.
- Voltage and power flow data are analyzed to determine any potential for flicker events or ramp rate issues.
- Figure 2-8 below shows an example of the flicker calculation curve for a circuit that includes a large PV system. As shown, the flicker level is above the visibility level in several instances, close to or below the irritation level (based on old GE flicker curve), or below the IEEE flicker curve; and would therefore require mitigation.

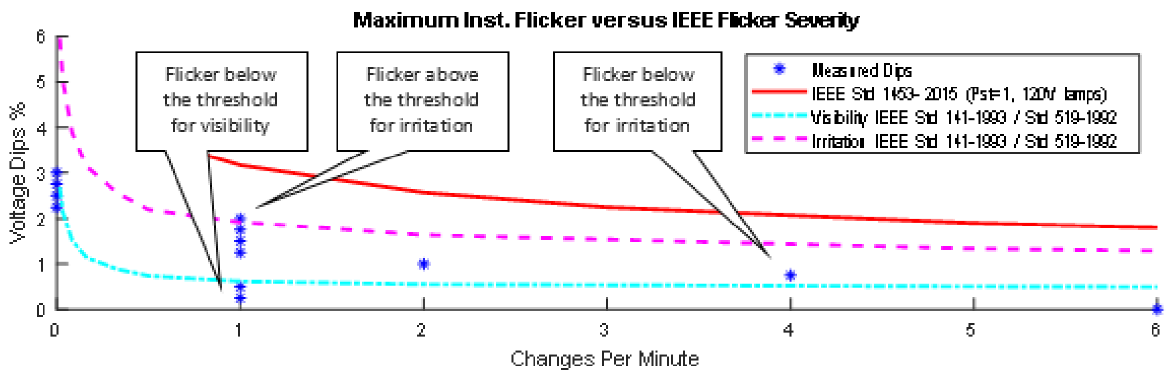


Figure 2-8. Sample flicker calculation curve

Figure 2-9 illustrates the flowchart of the Distribution Planning Tool 4 – Python interface. As shown, the first step is to input the PV and loading profiles of the chosen circuit. As it was previously mentioned, the resolution of the PV and loading profile are 10 seconds and 15 minutes, respectively. Thus, the load allocation is done every 15 minutes while the load flow analysis is done every 10 seconds and for each PV data. Moreover, it must be mentioned that in order for the load allocation function of Distribution Planning Tool 4 to work properly, all the loads and generators in the circuit must be turned off. Hence, after updating the power output of the PVs as a percentage of their corresponding ratings, the simulation time is checked to see whether 15 minutes has passed or not, if yes, all the generators and loads are turned off, the load allocation is done, and then the aforesaid generators and loads in the circuit are turned back on. Further, the load flow analysis is done and the results are stored for further analysis.

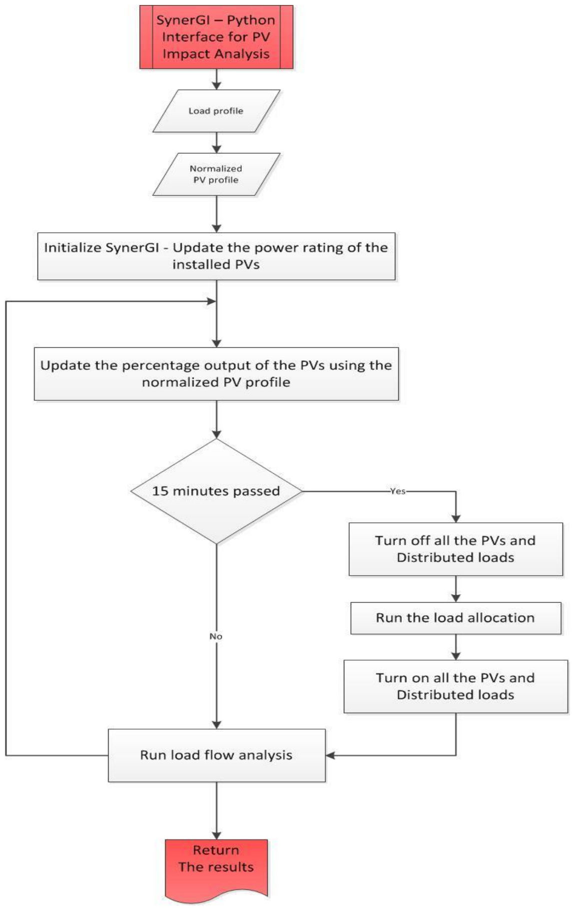


Figure 2-9. Distribution Planning Tool 4 – Python interface flowchart without the battery

PV and BESS

For the cases where a mitigation solution is required, a BESS model is incorporated in the Distribution Planning Tool 4 model close to the mitigation point. Two algorithms are used to determine BESS setpoints for active and reactive power exchange with the grid.

- In one case, (and technically when there is no ramp rate issue), voltage control function is used to determine reactive power setpoint of the BESS at every step. Time series analysis is performed to regulate voltages.
- In a case where voltage control through reactive power control is not effective and/or active power contribution from the battery is needed to manage the ramp rate below a given threshold, the BESS control function for P setpoint is also applied. The time series analyses are performed with new P and Q setpoints for the BESS.
- The new voltages and power flow values are captured and re-assessed.

The Distribution Planning Tool 4 – Python combination along with daily 15 minute load profile and PV data (10 second time steps) are used for final assessment of the PV impact mitigation with Energy Storage System (ESS) on the chosen circuits. Figure 2-10 illustrates the flowchart of the Distribution Planning Tool 4 – Python interface in presence of the battery model in Distribution Planning Tool 4. After inputting load and PV profiles, the Distribution Planning Tool 4 model is initialized and load allocation is done (with PVs turned off) every 15 minutes. The load flow is run (with PVs turned on in the model) and the load flow results are input to the battery function. The voltage control function of the battery is called and the battery charge/discharge to control the voltage (both intermittency smoothing and voltage droop control) is calculated. Based on the battery output, the battery model parameters are set in Distribution Planning Tool 4 and the load flow will be run for the second time to capture the results with the battery performance.

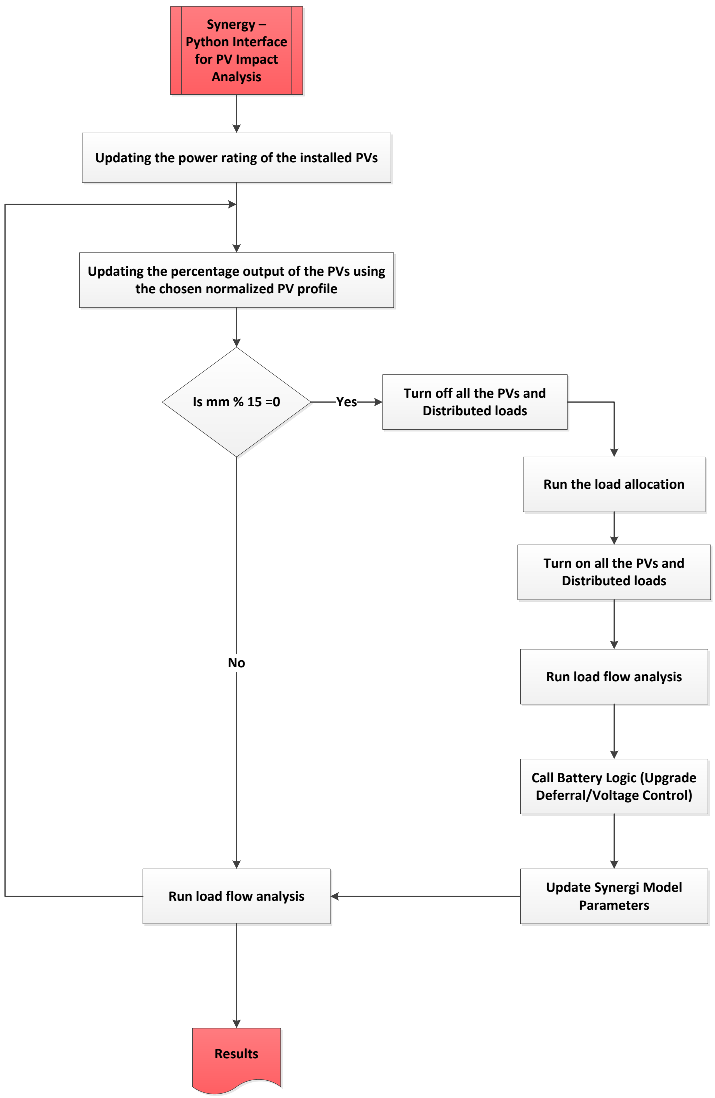


Figure 2-10. Distribution Planning Tool 4 – Python interface flowchart with the battery

2.5.3.2 Step 2 - Calculate ESS sizing

The maximum BESS P size and the maximum cumulative energy during the charge or discharge are used to calculate BESS size and capacity.

2.5.3.3 Step 3 - Co-optimization of market services

The CAISO market participation is considered as secondary application when the primary ESS application is PV smoothing. The process of calculating ESS charge/discharge constraints for CAISO frequency regulation market participation is summarized as follows:

1. First, rate of change of active power generation (RCOP) limits at the location of ESS are calculated according to the flicker limits. The flicker limits represent the maximum acceptable voltage change per minute (dVm). For example, dVm is 2.72% for one change per minute (applicable to real time market) and 1.5% for frequency regulation based on 4 second reg up and down CAISO signals. RCOP can be positive and negative depending on the impact on the voltage deviation. For example, a positive RCOP would increase the voltage at the point of connection (POC) of ESS, while a negative RCOP would decrease the voltage level at POC. To ensure that POC voltage always remain in the flicker limits (i.e. ±dVm from the nominal voltage). The maximum and minimum RCOP limits at the POC (RCOP_max and RCOP_min) are calculated using the equivalent circuit model at POC. The equivalent circuit at POC is modeled using the circuit model in Distribution Planning Tool 4.
2. The rate of change of power flow at POC is calculated using the time series analysis on the minute-by-minute load and PV profile.
3. At each time instant, the minimum ESS charge/discharge limits required for PV smoothing are calculated using the rate of change of power flow and the RCOP_max and RCOP_min calculated above. For example, if PV minus load at a specific time has a sudden ramp up that violates RCOP_max, the voltage at POC would have a sudden increase that violates (1+dVm) pu flicker limit. To avoid the violation, ESS should have a minimum charging rate. This charge rate is considered as the minimum ESS charge limit at that specific time.
4. At each time step, the maximum ESS charge/discharge limits are calculated using the rate of change of power flow, the minimum charge/discharge limits, and the RCOP_max and RCOP_min calculated above. For example, if a minimum charging limit is calculated for ESS to keep the POC voltage below (1+dVm) pu, the maximum ESS charging should be also limited to ensure that POC voltage does not fall below (1-dVm) pu.

The minimum and maximum PV smoothing charge/discharge limits for market participation are calculated for one of the SDG&E sample circuits. The market studies for this sample circuit considering the minimum and maximum PV smoothing charge/discharge limits are summarized in following sections.

2.5.3.4 Step 4 – Cost/benefit analysis

In case of PV related voltage and flicker impact mitigation, the cost of alternative (wire-based) option was calculated based on deploying localized or distributed secondary voltage control devices on all affected service transformers, using the following approach:

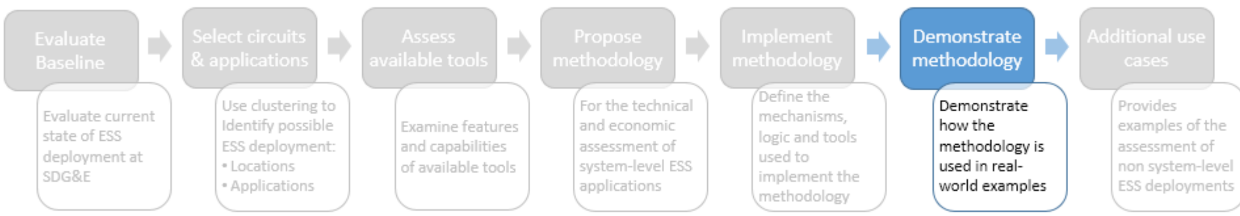
- For each circuit with PV impact, the circuit nodes affected by PV systems were identified.
- Using GIS database and circuit map, the number and size of service transformers in the affected region were determined
- Total cost of deploying secondary devices were determined by multiplying the cost of deploying each secondary device (about $15k per 50 kVA size device installed) with the number of devices required.

- Note that 50kVA is the only commercially available size. The number of devices required per service transformer need to be calculated on this basis.

3 SUMMARY OF THE PROJECT RESULTS

3.1 Task 6: Demonstrating the methodology

This task demonstrated examples of how the ESS analysis tools can be applied and how the results can be used in selection of project sizes, locations and applications as well as business case development and justification of ESS projects.



3.1.1 Capacity Deferral

The initial analysis targeted the circuits close to their thermal capacity which will be dealing with over-loading conditions in a 5-year time frame. Three circuits were identified (Table 3-1).

Table 3-1. Summary table of the selected circuits for the upgrade deferral application

Circuit ID	2019 forecasted load (A)	Average forecasted load growth per yr 2019 to 2021	SDG&E Ampacity (A)	Distribution Planning Tool 4 Ampacity (A)	Circuit PV Size (kW)	Number of Capacitors	Number of Voltage Regulator	10 yrs Capacity (MVA)
CCUD 1	369	3.30%	408	395	981	1	0	10.4
CCUD 2	564	1.30%	600	580	580	1	0	13.5
CCUD 3	558	1.40%	600	580	935	1	0	13.5

***Note**: In the sections that follow only the data for CCUD 2 are presented. However, the same analysis was performed for CCUD 1 and CCUD 3, and these data are provided in the Appendix.*

3.1.1.1 BESS Sizing

3.1.1.1.1 Study results for the centralized approach on CCUD 2

For CCUD 2, centralized deferral approach, the battery was installed at the beginning of the feeder. The battery was initially sized as 0.5 MW, 0.75 MWh (see Figure 3-1).

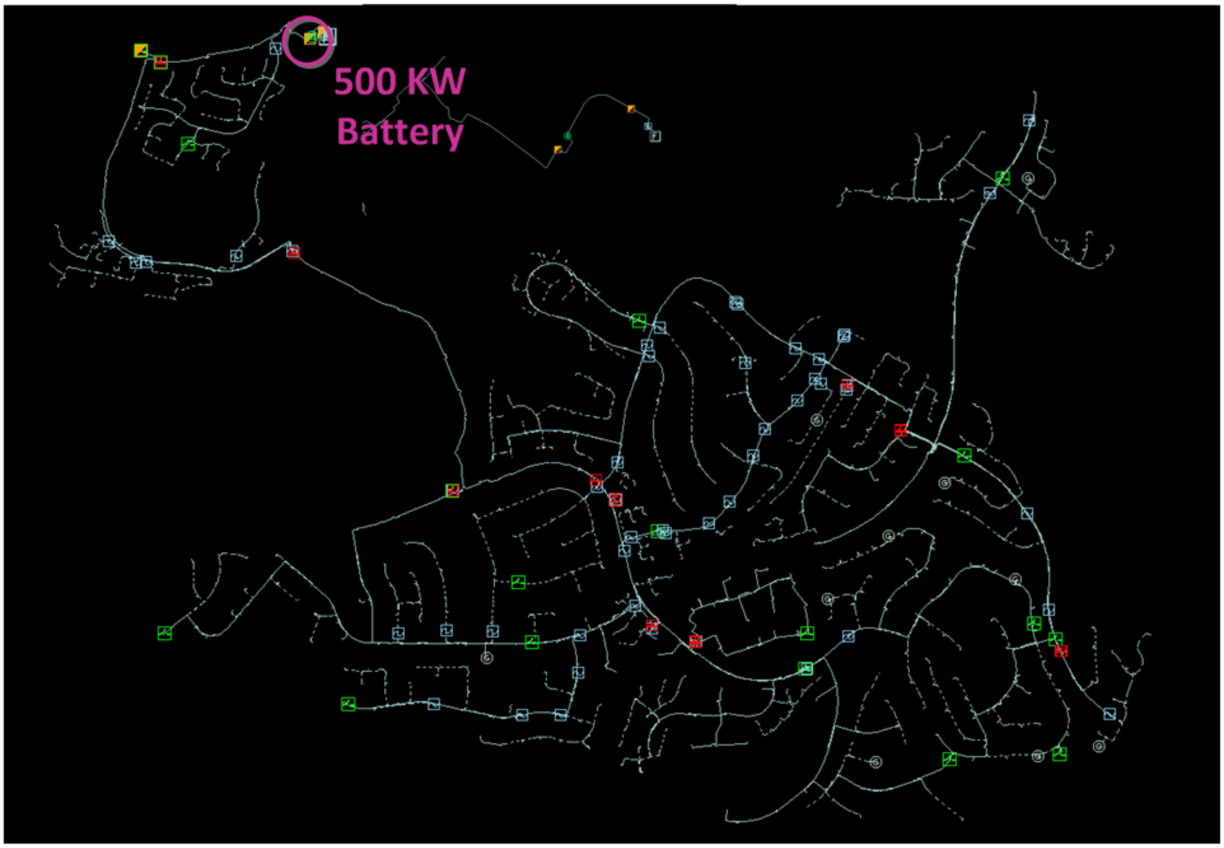


Figure 3-1. Location of the battery for circuit CCUD 2

The circuit under study has a thermal loading limit of 580 (A) determined in Distribution Planning Tool 4 model. This limit was used as the upper threshold of the circuit for peak shaving purposes. For the lower threshold zero was used to make sure that the reverse power flow is prevented. Also, the battery is scheduled to charge between 0:45 am – 5:00 am up to 95% in order to provide enough energy for discharging throughout the day.

In order to consider the worst-case scenario, the maximum peak day of year was determined for the projected (year 2024) load profile and the PV systems have been turned off during the analysis.

Figure 3-2 demonstrates the feeder power flow before and after the upgrade deferral application. The battery was charging during the scheduled charging zone up to 95% SOC and then maintained the feeder power below 12,055 kW during the day.

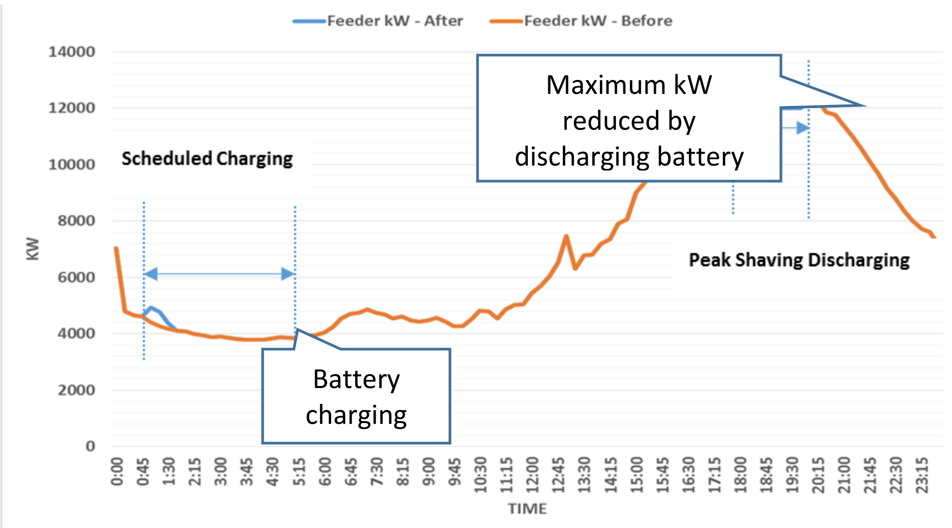


Figure 3-2. Power Flow (Centralized Upgrade Deferral) for CCUD 2

As illustrated in Figure 3-3 below, the battery charges/discharges up to the maximum rate of ~**500 kW**.

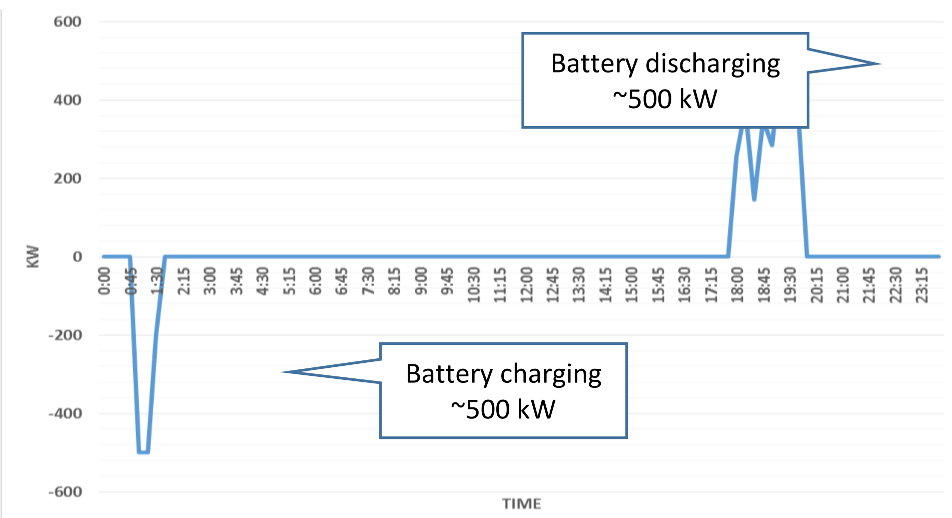


Figure 3-3. Battery Output Power (Centralized Upgrade Deferral) for CCUD 2

Figure 3-4 illustrates the battery state of charge for the day.

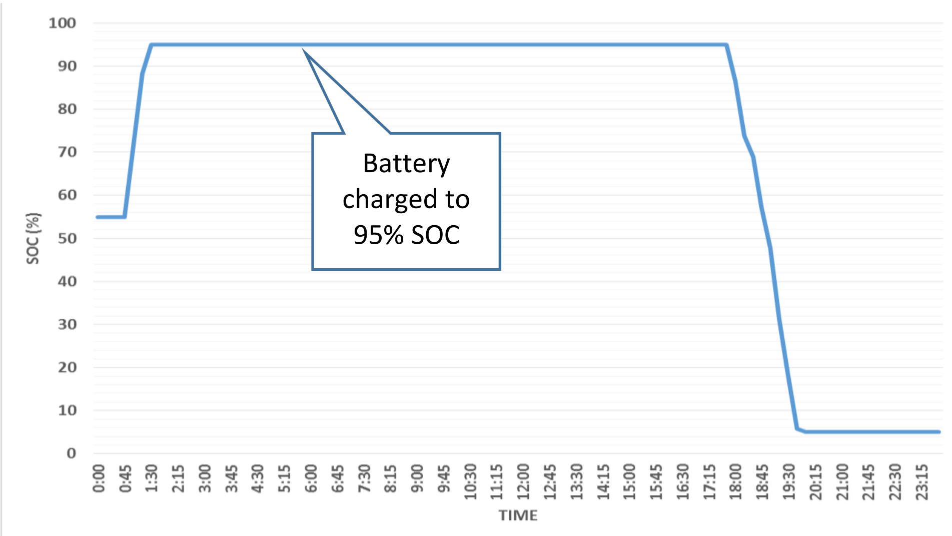


Figure 3-4. Battery State of Charge (Centralized Upgrade Deferral) for CCUD 2

The accumulative discharge of the battery by the end of the day, is almost 700 kWh (Figure 3-5) which reflects the maximum amount of energy required from the battery and justifies using a **750 kWh** battery.

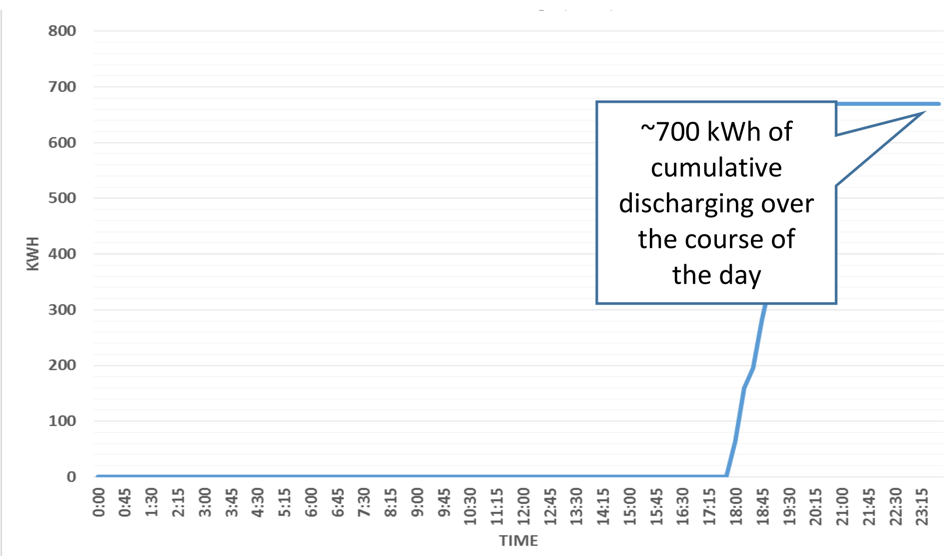


Figure 3-5. Accumulative Discharge (Centralized Upgrade Deferral) for CCUD 2

Using the analysis above, the BESS for the centralized approach was sized as **500 kW / 750 kWh**

3.1.1.2 Study results for the decentralized approach on CCUD2

For CCUD 2, distributed deferral approach, the battery was installed at two locations (see Figure 3-6) based on the thermal limiting points of the feeder as well as the space availability for battery installation. The proposed locations of two batteries have been shown in. The batteries have been initially sized as 0.4 MW, 1 MWh.

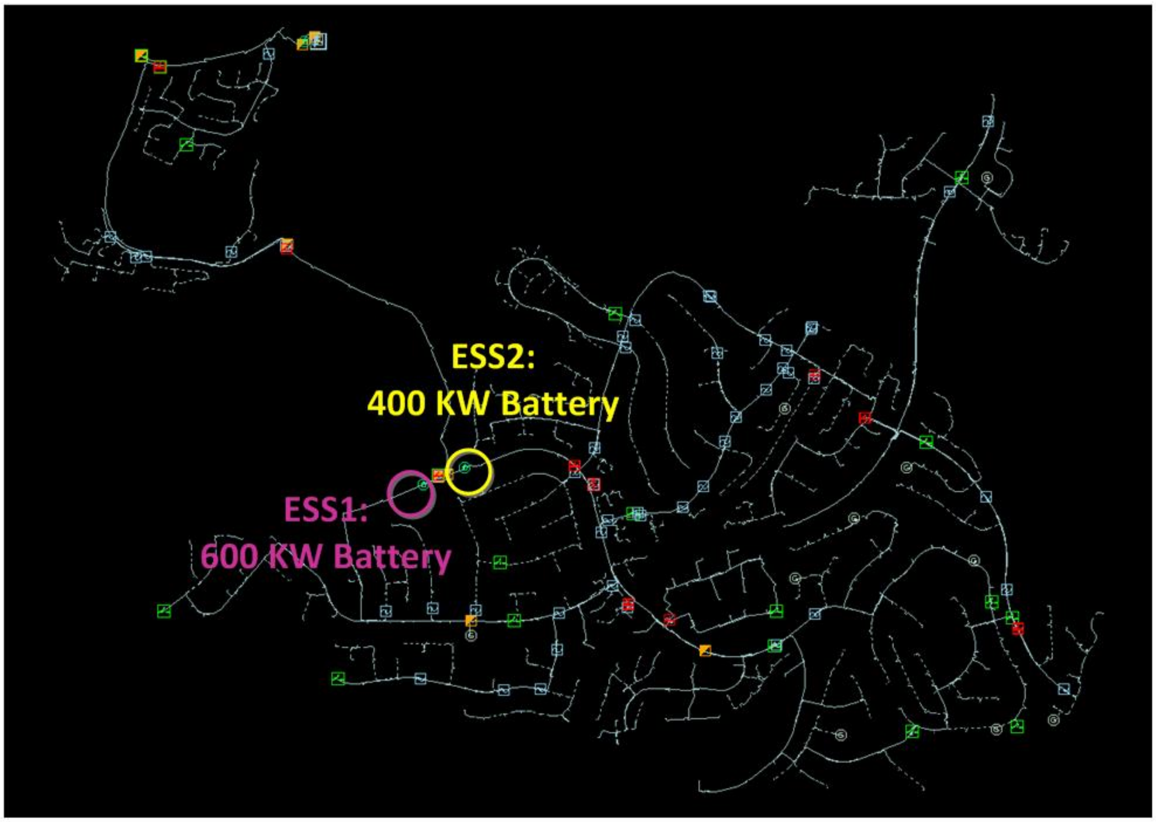


Figure 3-6. Battery Locations for CCUD 2

The circuit under study has a thermal loading limit of 580 (A) determined in Distribution Planning Tool 4 model. This limit was used as the upper threshold of the circuit for peak shaving purposes. For the lower threshold zero was used to make sure that the reverse power flow is prevented. Also, the battery is scheduled to charge between 0:45 am – 5:00 am up to 80% in order to provide enough energy for discharging throughout the day. In order to consider the worst-case scenario, the maximum peak day of year was determined for the projected (year 2024) load profile and the PV systems have been turned off during the analysis.

The excess feeder power to be provided from two batteries is divided between the batteries with respect to their kW rated ratios.

Figure 3-7 demonstrates the feeder power flow before and after the upgrade deferral application. The battery was charging during the scheduled charging zone up to 80% SOC and then maintained the feeder power below 12,055 kW during the day.

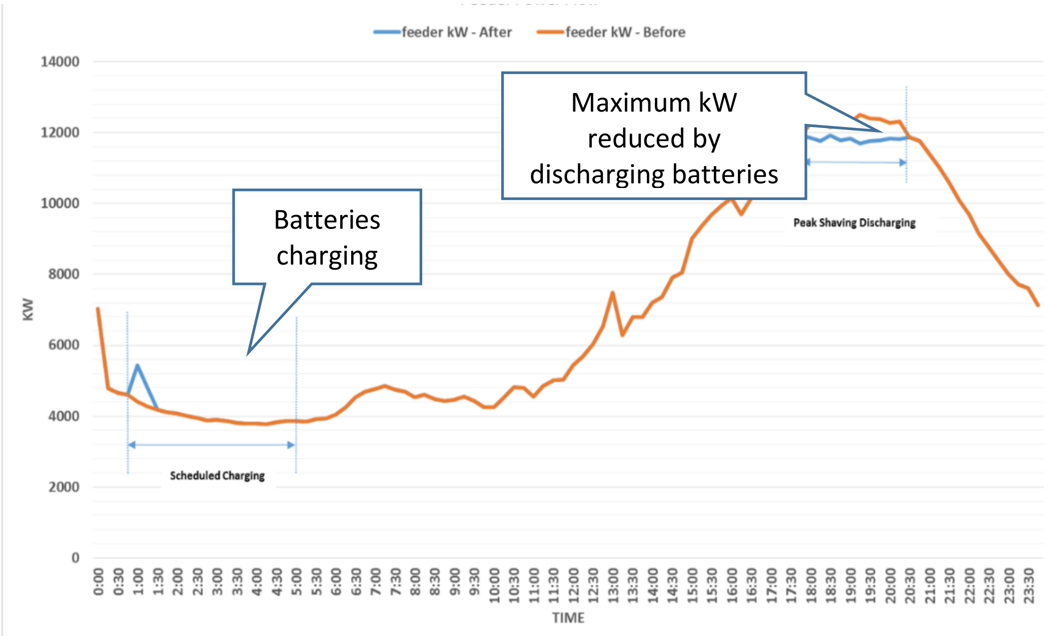


Figure 3-7. Power Flow (Distributed Upgrade Deferral) for CCUD 2

As illustrated in Figure 3-8, ESS1 and ESS2 charge/discharge up to the maximum kW rate of **600 kW and 400 kW** respectively.

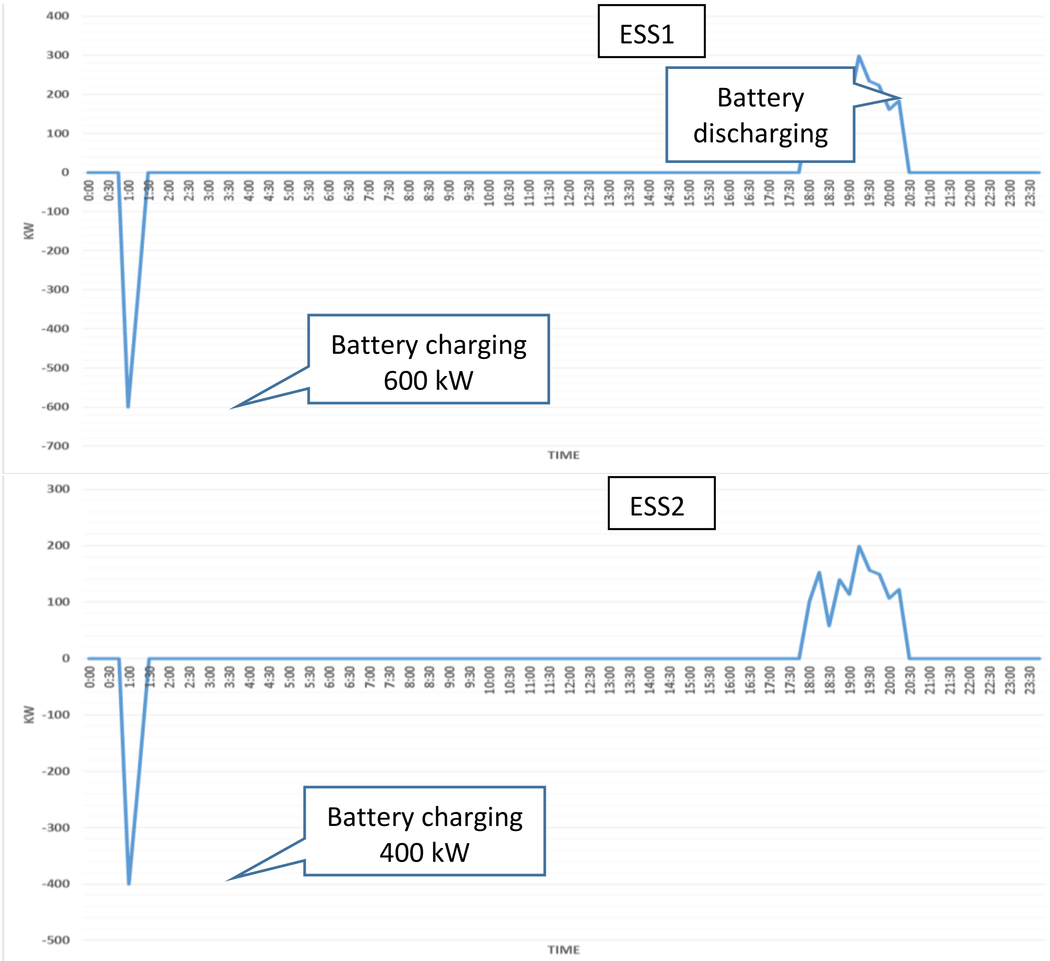
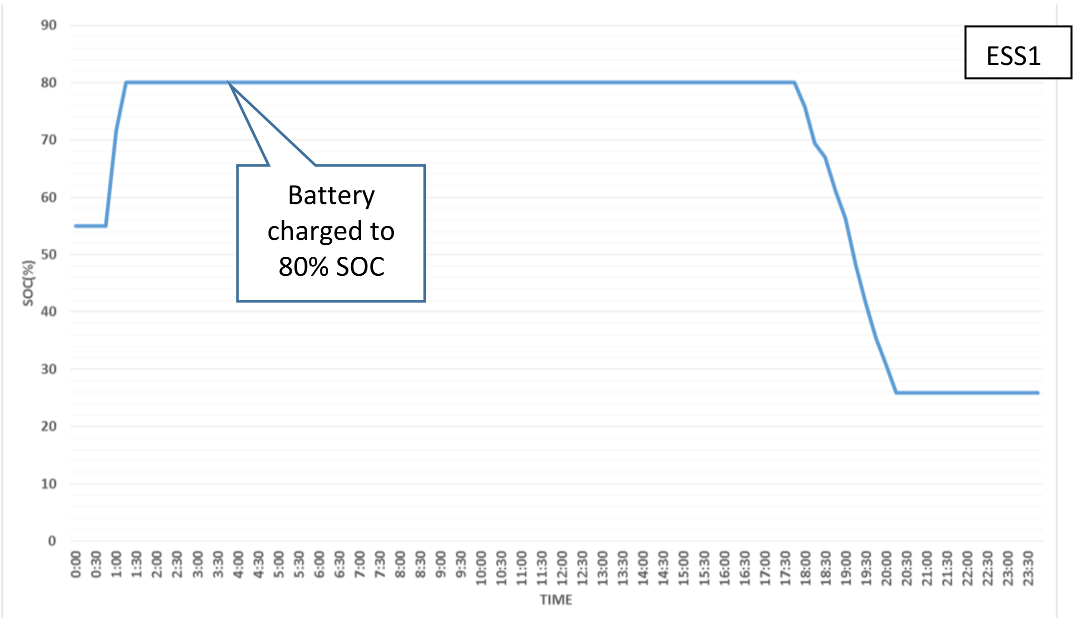


Figure 3-8. ESS1 and ESS2 Output Power (Decentralized Upgrade Deferral) for CCUD 2

Figure 3-9 illustrates the state of charge for the two BESS during the day.



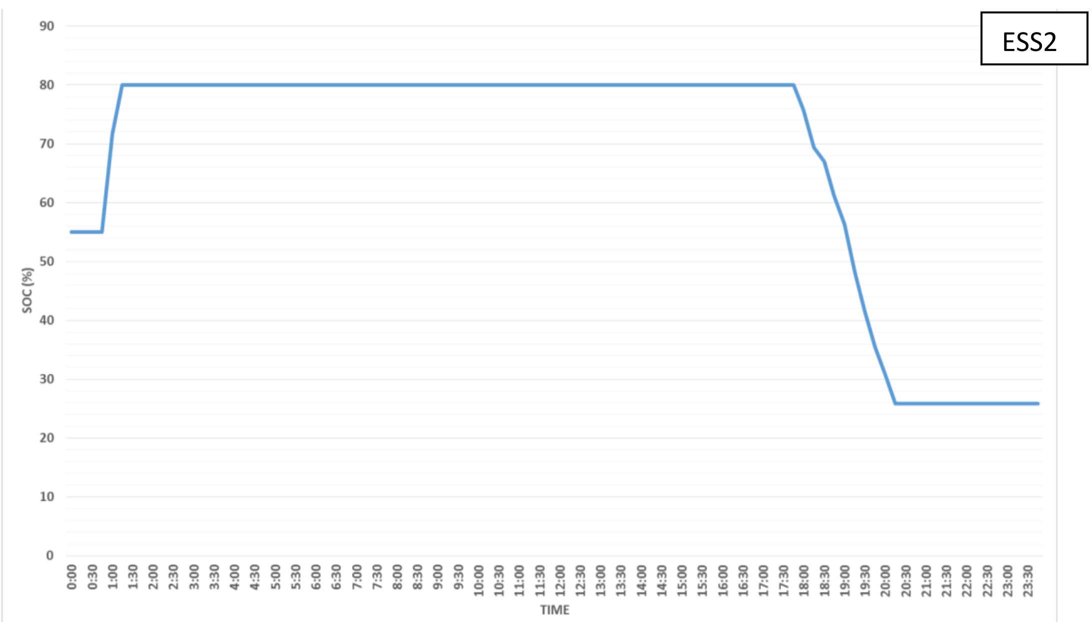


Figure 3-9. ESS1 and ESS2 State of Charge (Distributed Upgrade Deferral) for CCUD 2

The accumulative discharge of the battery by the end of the day, is almost 500 kWh for ESS1 and 320 kWh for ESS2 (Figure 3-10) which reflects the maximum amount of energy required from the battery and justifies using a one hour battery for each (**600 kWh for ESS1 and 400 kWh for ESS2**).

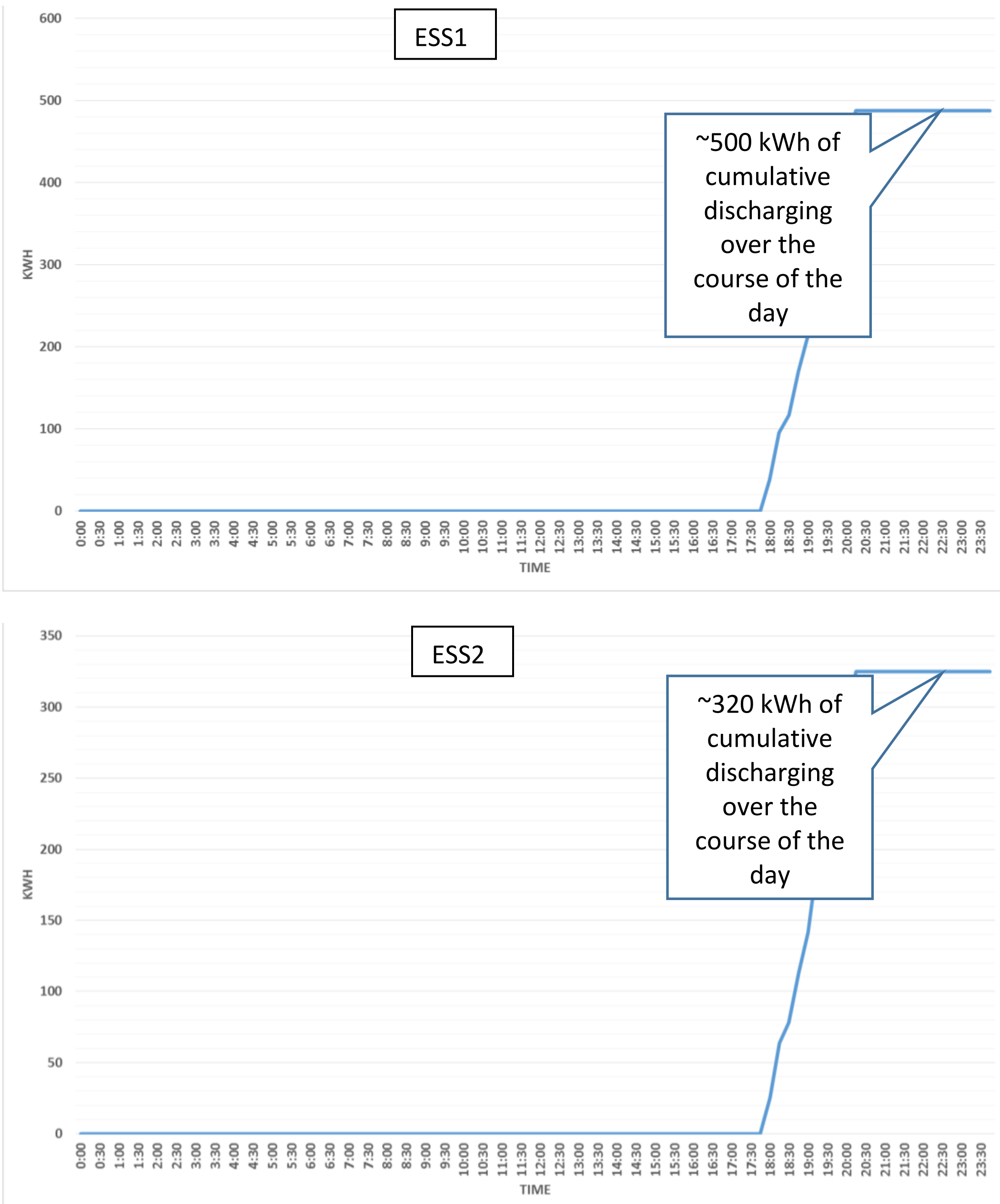


Figure 3-10. ESS1 and ESS2 cumulative discharge (Distributed Upgrade Deferral) for CCUD 2

Using the analysis above, the two BESS for the decentralized approach were sized as **600 kW / 600 kWh** and **400 kW / 400 kWh.**

3.1.1.3 Cost/benefit analysis

A mixed integer programming (MIP) optimizer formulated for optimizing storage participation in energy and ancillary service markets was used to optimize storage discharging and charging against annual load profile time series for the three circuits simulated in Distribution Planning Tool 4.

The size of the storage used for the required peak shaving in 2024 was taken from the Distribution Planning Tool 4 simulations (as shown in Table 3-2 below that tabulates both storage sizes[2] and capital costs).

Table 3-2. Required Battery Size and Projected Capital Cost

Circuit ID	Storage Power Rate (MW)	Storage Energy Capacity (MWh)	Projected Battery Cost in 2019 ($K)
CCUD 1	0.7	3.5	$1,435
CCUD 2	0.5	0.75	$413
CCUD 3	0.5	1.0	$500

The MIP algorithm then optimizes the charging and discharging for each day in the year to achieve the peak shaving goal (CD). Furthermore, MIP optimizes arbitrage benefits as a secondary application of storage in CDA case, as well as co-optimizing wholesale and ancillary market participation in CDAAM scenario.

Table 3-3 summarizes annual market benefits (revenues) for three circuits. CAISO 2016 nodal day-ahead and real-time prices as well as day-ahead regulation market prices are applied for market benefits calculation. Annual CDA and CDAAM market benefits (revenues) beyond 2024 (only for battery in) are assumed to be identical to the 2024 values, note.

Table 3-3. Annual Market Revenue ($)

Annual Market Benefits						
Circuit	Operation Strategy	2020	2021	2022	2023	2024
CCUD1	CD	$ -	$ -	$ -	$ 250	$ 838
	CDA	$ 48,742	$ 48,742	$ 48,742	$ 48,728	$ 48,330
	CDAAM	$ 115,003	$ 115,003	$ 115,003	$ 114,990	$ 114,626
CCUD2	CD	$ -	$ -	$ 0	$ 25	$ 77
	CDA	$ 26,955	$ 26,955	$ 26,953	$ 26,918	$ 26,865
	CDAAM	$ 76,302	$ 76,302	$ 76,300	$ 76,265	$ 76,213
CCUD3	CD	$ -	$ -	$ -	$ 10.19	$ 60.78
	CDA	$ 30,350.59	$ 30,350.59	$ 30,350.59	$ 30,313.12	$ 30,267.91

[2] The results for CCUD 2 were calculated in the preceding section; the results for CCUD 1 and CCUD 3 are calculated in the appendix.

	CDAAM	$ 79,060.14	$ 79,060.14	$ 79,060.14	$ 79,030.39	$ 78,986.39

Table 3-4 summarizes cost NPV and aggregated cash flows (revenue requirements) for the immediate T&D upgrades for feeders under the study. This includes annual T&D depreciation, Capex ROI, property & income taxes, and OPEX. A T&D upgrade cost of $921K/MW is assumed.

Table 3-4. Immediate T&D Upgrades NPV Costs and Revenue Requirements (in $K)

Feeder	Feeder Load Growth Rate	Peak load in 2019	Existing Feeder Rating (MW)	Immediate T&D upgrade cost NPV	Immediate T&D upgrade revenue requirements – aggregated cash flows
CCUD1	3.3%	7.5	8.2	$2,099	$4,626
CCUD2	1.3%	11.7	12.05	$2,099	$4,626
CCUD3	1.4%	11.6	12.05	$2,099	$4,626

As is illustrated, CCUD1 has the highest cost NPV for T&D upgrades. This is mainly due to the significant growth load of the circuit compared to the other two circuits, which requires greater T&D MW upgrades. All reported NPV and aggregated cash flows are calculated for a 20 year horizon.

In Table 3-5 and Table 3-6, T&D deferral NPV costs as well as revenue requirements are provided for battery “in” and “out” scenarios, respectively. This includes annual depreciation, Capex ROI, property & income taxes, and OPEX for both battery and T&D upgrades plus potential market benefits.

It should be noted that CCUD1 requires the highest T&D deferral costs mainly due to the large size of the battery and consequently highest capital investment compared to the other two circuits.

Table 3-5. T&D Deferral Costs and Revenue Requirements (in $K) – Battery Disposition Scenario: Out

Feeder	T&D Deferral cost NPV			T&D Deferral revenue requirements – aggregated cash flows		
	CD	**CDA**	**CDAAM**	**CD**	**CDA**	**CDAAM**
CCUD1	$2,622	$2,412	$2,126	$5,528	$5,236	$4,838
CCUD2	$1,790	$1,673	$1,460	$4,411	$4,249	$3,953
CCUD3	$1,861	$1,730	$1,520	$4,506	$4,324	$4,032

Table 3-6. T&D Deferral Costs and Revenue Requirements (in $K) – Battery Disposition Scenario: In

Feeder	T&D Deferral cost NPV			T&D Deferral revenue requirements – aggregated cash flows		
	CD	CDA	CDAAM	CD	CDA	CDAAM
CCUD1	$3,498	$3,047	$2,434	$7,673	$6,698	$5,373
CCUD2	$1,969	$1,720	$1,263	$4,890	$4,351	$3,364
CCUD3	$2,100	$1,819	$1,368	$5,129	$4,522	$3,547

In Table 3-7 and Table 3-8, summery of overall benefits are provided for battery in and out scenarios, respectively. In each table ΔNPV benefits as well as Ratepayers benefits are provided for different storage operation strategies. ΔNPV benefits are calculated as NPV costs of immediate T&D upgrades less the NPV costs of T&D deferrals. Ratepayers benefits are calculated as aggregated cash flows of immediate T&D upgrades less the aggregated cash flows of T&D deferrals.

Table 3-7. Overall Benefits comparing Deferral to Immediate T&D upgrades ($K) – Battery Disposition Scenario: Out

Feeder	ΔNPV Benefits			Ratepayers Benefits (Δ Aggregated Cash Flows)		
	CD	CDA	CDAAM	CD	CDA	CDAAM
CCUD1	**-$523**	**-$313**	**-$27**	**-$902**	**-$610**	**-$212**
CCUD2	$310	$426	$639	$215	$377	$673
CCUD3	$238	$369	$580	$120	$302	$594

Table 3-8. Overall Benefits comparing Deferral to Immediate T&D upgrades ($K) – Battery Disposition Scenario: In

Feeder	ΔNPV Benefits			Ratepayers Benefits (Δ Aggregated Cash Flows)		
	CD	CDA	CDAAM	CD	CDA	CDAAM
CCUD1	**-$1,399**	**-$948**	**-$335**	**-$3,046**	**-$2,072**	**-$746**
CCUD2	$130	$380	$836	**-$264**	$275	$1,262
CCUD3	**-$1**	$280	$731	**-$502**	$105	$1,079

Conclusions:

From the above examples, it can be observed that one of the circuits (CCUD1) is not a viable candidate for capacity deferral under any scenario, mainly because relatively large battery size requirement and significant up- front cost.

The second circuit (CCUD2) is a viable candidate for capacity deferral using a BESS under the scenarios where time arbitrage (CDA) or time arbitrage plus ancillaries (CDAA) are allowed. However, this case has also negative ratepayer benefits under a peak shaving only scenario, even though the cash flow NPV is favorable.

The third circuit studied (CCUD3) is even less favorable without the time arbitrage or ancillary service revenues.

For the two latter circuits, an assumption that the BESS may be relocated to another location in 5 years can enhance the financial outcomes. The relocation would occur after the need for capacity upgrade deferral is resolved, and the circuit finances credited with the battery residual value remaining.

The fact that the three circuits have different outcomes illustrates the need for detailed engineering and financial analysis to evaluate the real financial outcomes.

3.1.2 Reliability Enhancement for Customers – ESS in Microgrid Application

To study the microgrid application of ESS in SDG&E, four candidate circuit were selected. The information related to these circuits and the number of customers in the microgrid area are summarized in Table 3-9 below.

Table 3-9. Summary table of the selected circuits for the microgrid application

Circuit ID	# customers in MG Area	Peak load for MG [kW]	Minimum load for MG [kW]	MG Resources	# of Capacitors	# of Voltage Regulator
CMG 1	Whole circuit: 263 Recloser 1: 55 Recloser 2: 146	700	0	ESS only	1	0
CMG 2	255	712	0	ESS + PV	0	2
CMG 3	281	616	6	ESS only	0	1
CMG 4	837	2,064	0	ESS only	1	6

***Note**: In the sections that follow only the data for CMG 1 are presented. However, the same analysis was performed for CMG 2, CMG 3 and CMG 4, and these data are provided in the Appendix.*

3.1.2.1 BESS Sizing

3.1.2.1.1 Study Results for CMG 1

The microgrid studies for this circuit were conducted for two different scenarios. The microgrid topology is shown in Figure 3-11. In the first scenario, two separate microgrids were considered that could be isolated from the upstream grid through two reclosers. The ESS units were located at the location of these reclosers. In the second scenario, one ESS unit was used to support the whole circuit load during outages. This ESS unit was located at the main substation.

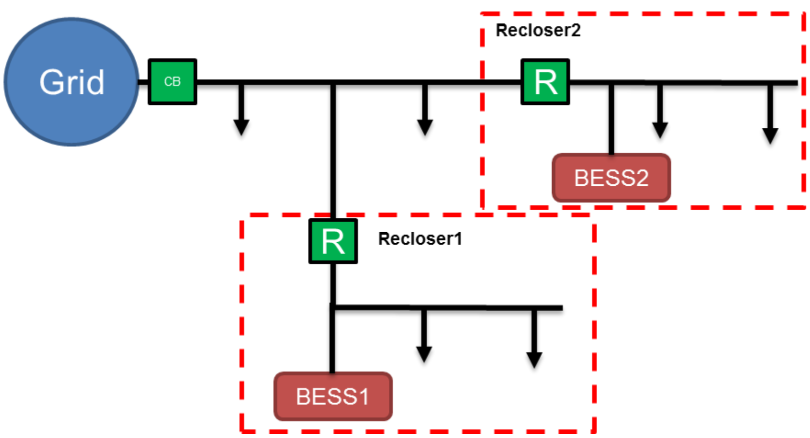


Figure 3-11. CMG1 - Microgrid Topology

The summary of recommended ESS sizes for Scenario 1 and 2 is provided in Table 3-10. These ESS sizes were recommended based on simulation results of 8-hour outages occurring any time during the year on the microgrid area. Based on the simulation results, the required size of battery (kW and kWh) for each of the simulated 8-hour outages was determined and the ESS sized to cover the maximum required kW and kWh. The required size of ESS units for the batteries listed in Table 3-10 for different outage times are illustrated in Figure 3-12 to Figure 3-14.

Table 3-10. Recommended ESS sizes for CMG1

Scenario	ESS Location	Covered Area	Number of customers	Peak Load (kW)	Recommended ESS Size
1	Recloser 1	Branch downstream of Recloser 1	40	230	450 kW – 3 Hrs
1	Recloser 2	Branch downstream of Recloser 2	89	388	550 kW – 4 Hrs
2	CMG1 Substation	Whole circuit	164	770	1100 kW – 4 Hrs

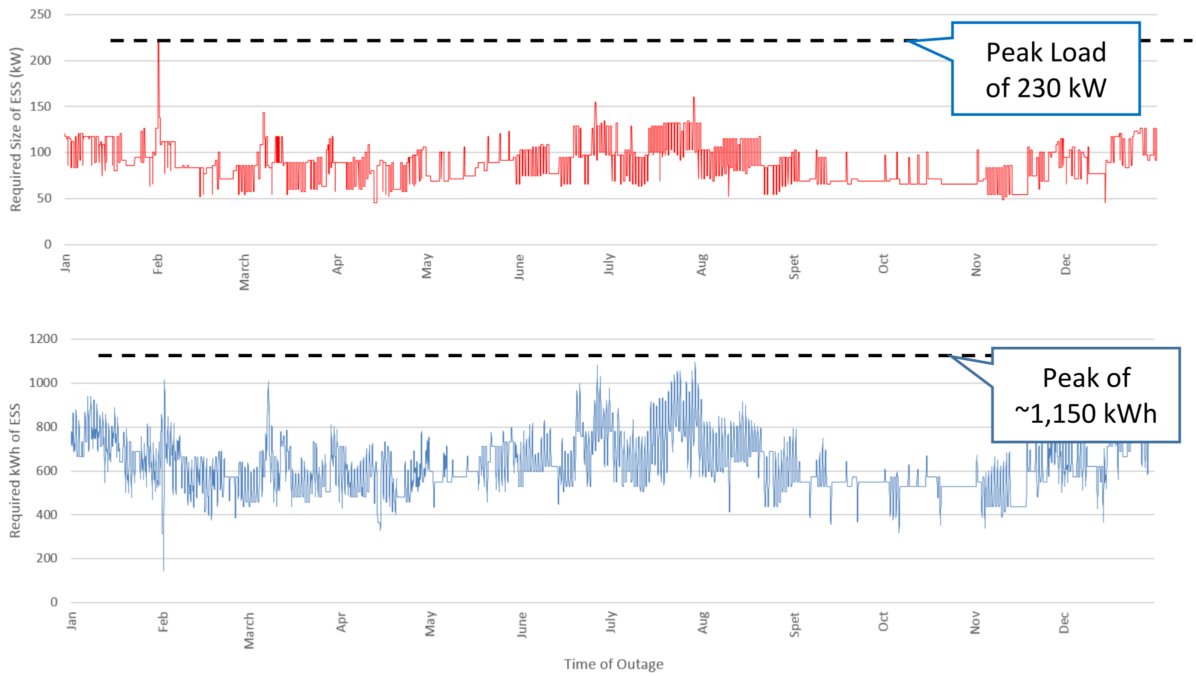


Figure 3-12. Required kW and kWh of ESS to support load downstream of Recloser 1 for an 8 hour outage at different times of year

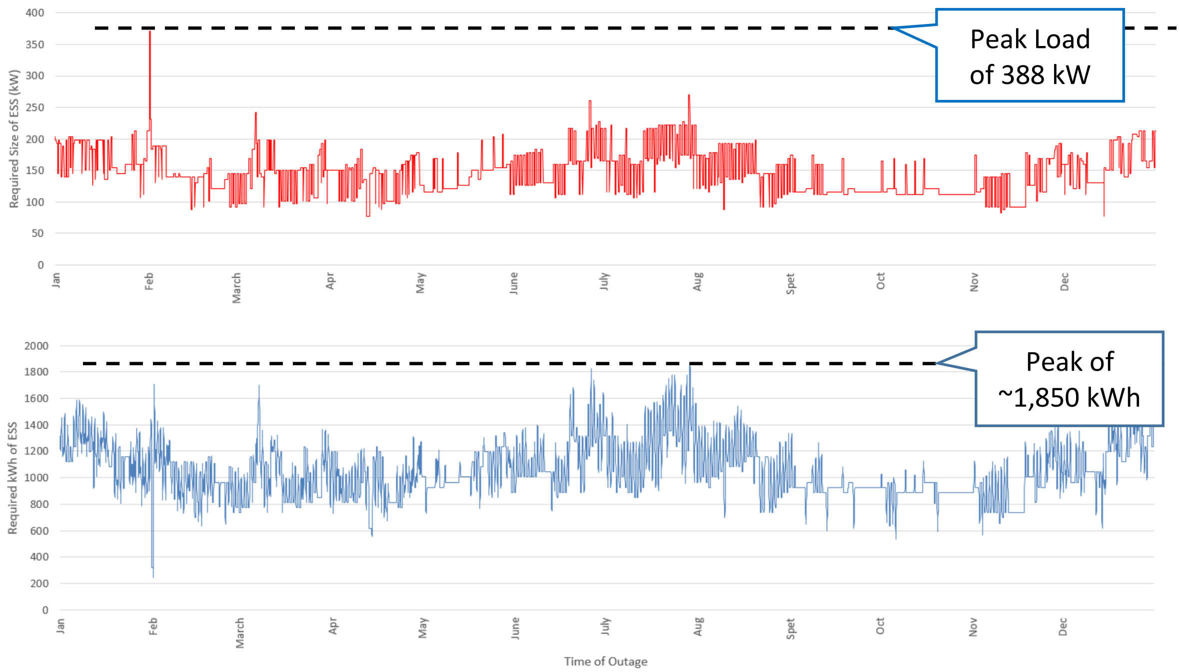


Figure 3-13. Required kW and kWh of ESS to support load downstream of Recloser 2 for an 8 hour outage at different times of year

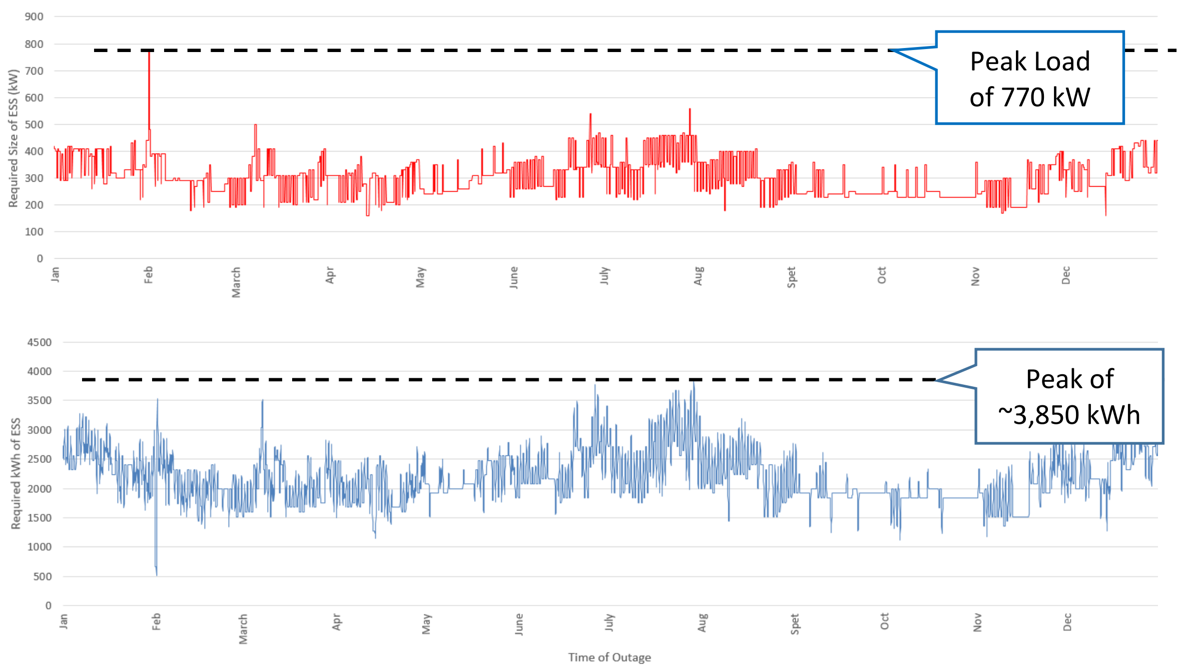


Figure 3-14. Required kW and kWh of ESS to support CMG1 circuit load for an 8 hour outage at different times of year

3.1.2.2 Cost benefit analysis

The objective of this study is evaluating the additional potential benefits of Battery Energy Storage Systems (ESS) by participating in CAISO wholesale and ancillary markets. Four microgrids, namely CMG1, CMG2, CMG3, and CMG4[3], are investigated in this analysis.

A mixed integer programming (MIP) optimizer formulated for optimizing ESS participation in energy and ancillaries markets. MIP maximizes the utilization of the excess battery capacity (based on constraints) via market participation.

3.1.2.2.1 CBA for CMG 1

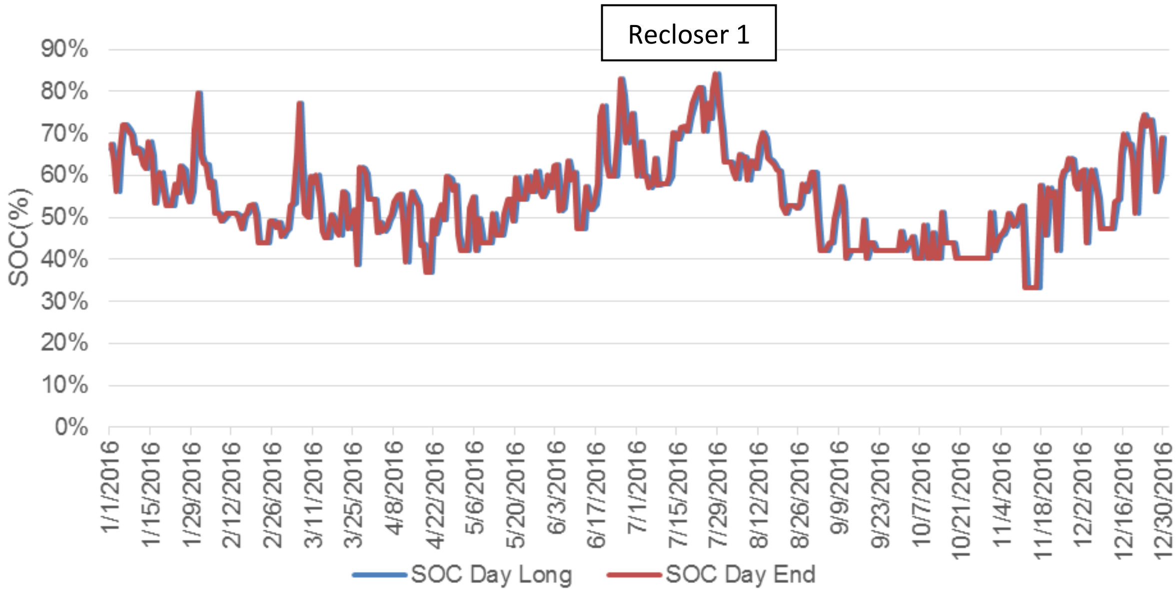
Market analysis is conducted for two ESSs located on reclosers 1, and 2 and sized in a way to manage 8-hour outages as tabulated in Table 3-11 below.

Table 3-11. ESS sizes for CMG1

Reclosers	ESS Power (kW)	ESS Energy (kWh)
Recloser 1	450	1,350
Recloser 2	550	2,200

For the ESSs at the two reclosers, hourly SOC constraints are calculated via Distribution Planning Tool 4. The SOC constraints determine the total energy required to serve the load if an 8-hour outage happens anytime during the day. SOC constraints are provided in Figure 3-15 below.

[3] The results for CMG 1 were calculated in the preceding section; the results for CMG 2, CMG 3 and CMG 4 are calculated in the appendix.



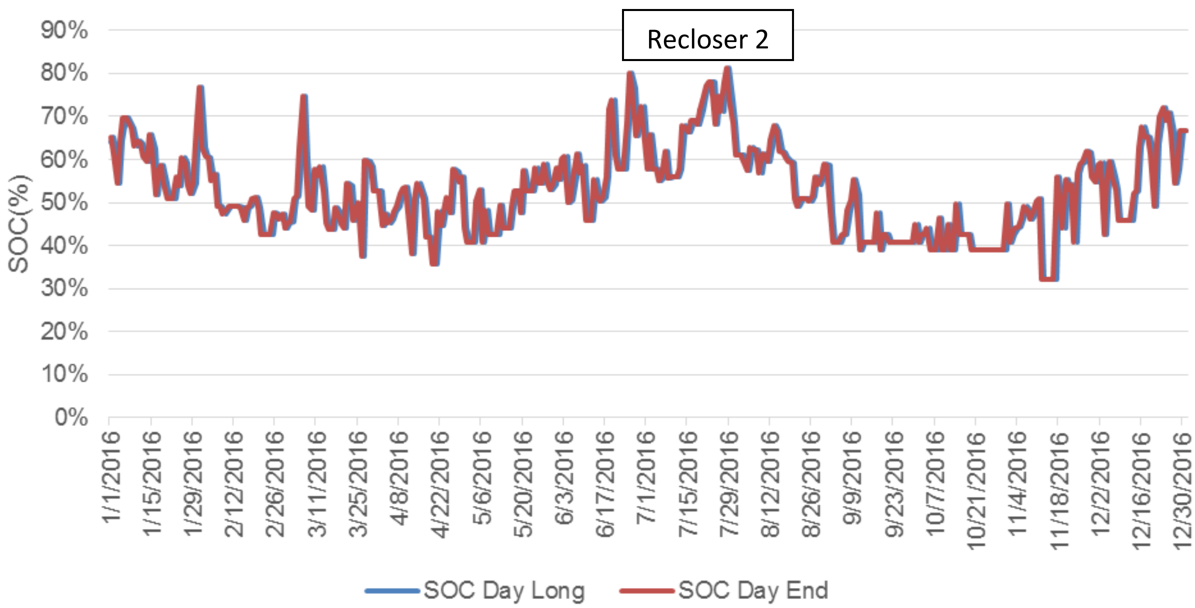


Figure 3-15. Recloser 1 and 2 - SOC constraints for 8-hr outage

Table 3-12 and Table 3-13 summarize the market participation benefits for the two ESSs. In these tables, the Energy Credit is the discharging revenues less the charging payments when only wholesale energy participation in considered. These energy credits in the regulation case include an estimate of the settlement of regulation revenues at RT prices.

In regulation market benefits calculations the mileage payment is a straight forward computation using the CA ISO 2016 historical data for up and down mileage factors and battery accuracies. Here, a figure of ½ of the Reg Capacity in each 15 minute period was used to estimate the RegUp and RegDown energy.

Annual market benefits are calculated as a summation energy, Regulation Up and down Capacity, mileage credits less the VOM. VOM of 0.00579 $/kWH is considered for both charging and discharging of the battery.

Table 3-12. CMG1: ESS: 450 kW, 1,350 kWh on Recloser 1

ESS: 450 kW, 1350 kWh on 280R	Energy Credit	Regulation Up Capacity Credit	Regulation Down Capacity Credit	Mileage UP Credit	Mileage Down Credit	VOM	Annual Market Benefits
Wholesale Energy Only	$ 26,971	$ -	$ -	$ -	$ -	$ 3,134	$ 23,837
Wholesale Energy and Ancillary	$ 24,568	$ 22,348	$ 19,563	$ 2,484	$ 4,740	$ 5,985	$ 67,720

Table 3-13. CMG1: ESS: 550 kW, 2,200 kWh on Recloser 2

ESS: 550 kW, 2200 kWh on 262R	Energy Credit	Regulation Up Capacity Credit	Regulation Down Capacity Credit	Mileage UP Credit	Mileage Down Credit	VOM	Annual Market Benefits
Wholesale Energy Only	$ 35,623	$ -	$ -	$ -	$ -	$ 4,389	$ 31,233
Wholesale Energy and Ancillary	$ 32,243	$ 27,317	$ 23,830	$ 3,068	$ 5,804	$ 7,600	$ 84,663

3.1.3 PV Integration Mitigation

To study the application of ESS to address PV Integration issues at SDG&E, eight candidate circuits were selected. The information related to these circuits is summarized in the Table 3-14 below.

Table 3-14. Summary table of the selected circuits for the PV impact mitigation application

Circuit ID	PV Size (kW)	Dominant PV Type	Peak Circuit Load (A)	Minimum Day Time Circuit Load (A)	# of Capacitors	# of Voltage Regulator
CPVIM 1	8,955	Centralized	407	-5.38	5	3
CPVIM 2	7,128	Centralized	254	-5.23	2	2
CPVIM 3	4,918	Distributed	470	-0.82	3	0
CPVIM 4	4,188	Distributed	479	-0.2	3	0
CPVIM 5	4,066	Distributed	454	-0.74	2	0
CPVIM 6	4,045	Distributed	467	-0.92	2	0
CPVIM 7	3,725	Distributed	490	-0.17	0	1
CPVIM 8	3,710	Distributed	501	0.9		

***Note**: In the sections that follow only the data for CPVIM 1 are presented. However, the same analysis was performed for CPVIM 2 to 8, and these data are provided in the Appendix*

For the ease of comparison, a single PV profile with high fluctuations was chosen and used for the PV impact analysis of all the circuits. The profile was first normalized and then scaled to the maximum installed PV size of each circuit. The normalized PV profile is shown in Figure 3-16.

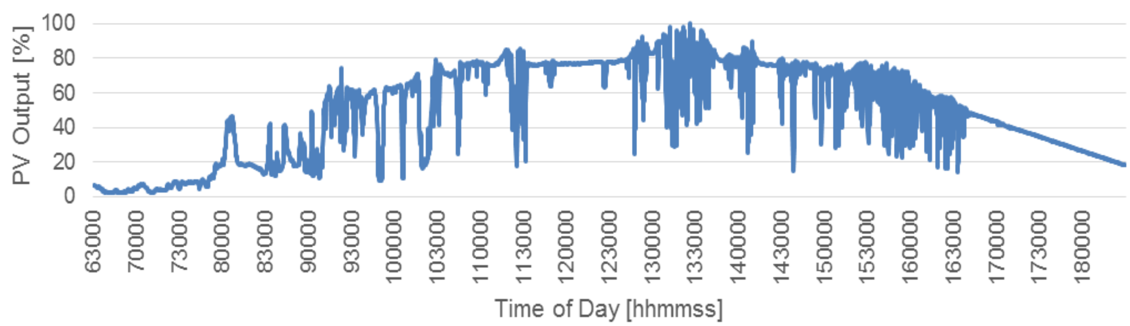


Figure 3-16. Selected PV profile for PV impact analysis

3.1.3.1 BESS Sizing

3.1.3.1.1 Study results for CPVIM 1 without BESS

Figure 3-17 presents a reference diagram of CPVIM 1.

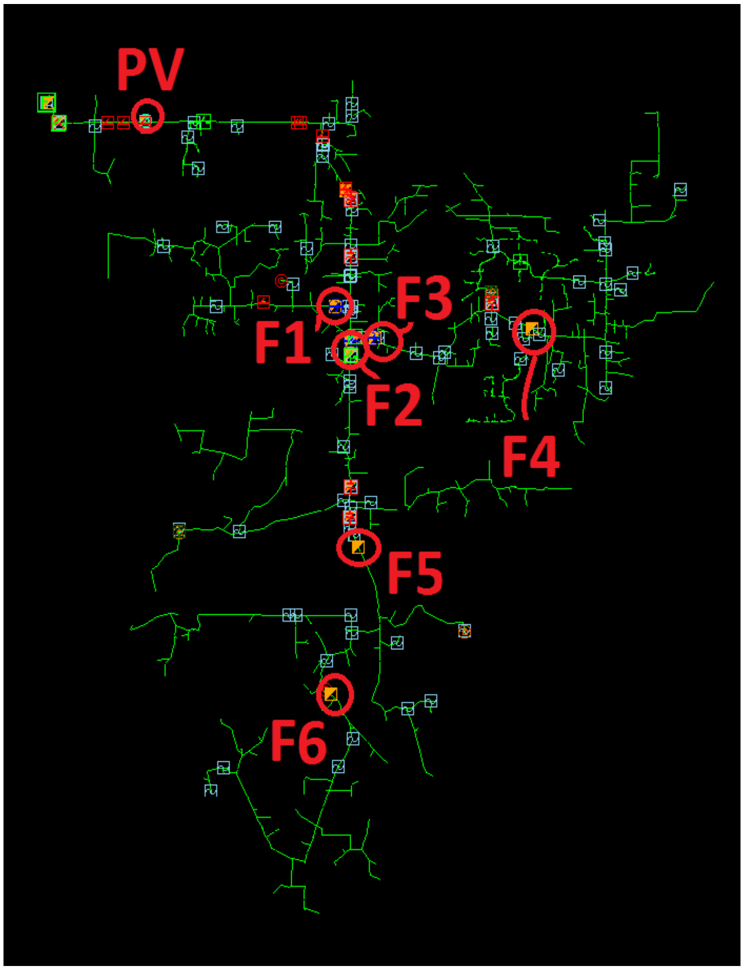


Figure 3-17. Reference diagram of CPVIM 1

Figure 3-18 below shows the phase A voltages of the meters at the locations of PV, F1, and F3 respectively. Locations F1 and F3 were selected for detailed analysis because they showed the highest incidence of flicker amongst the six locations (F1 through F6).

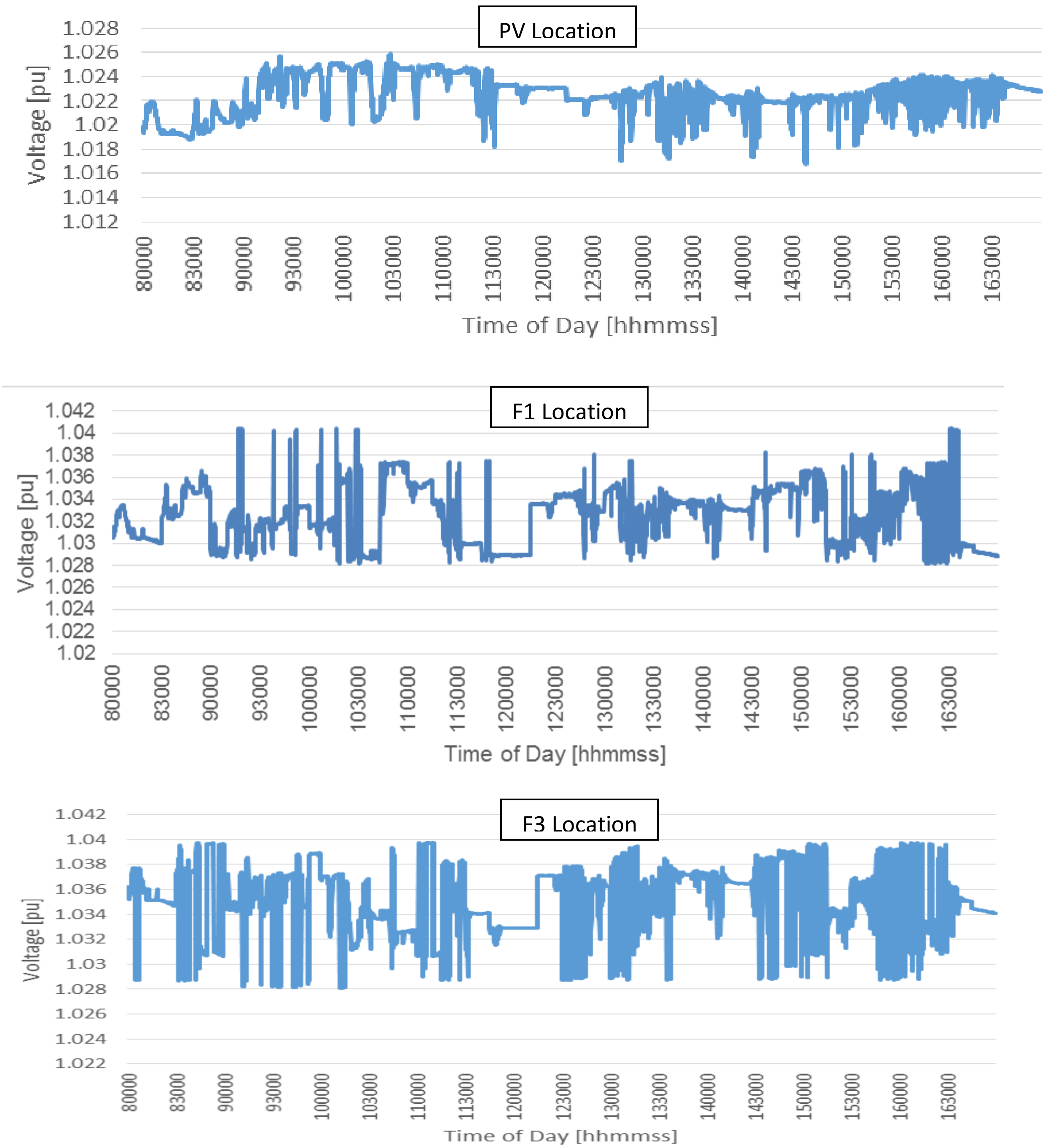


Figure 3-18. Voltage profiles at the PV, F1 and F3 location on CPVIM 1

Figure 3-19 below shows the flicker calculation curve for the meter at the PV location of CPVIM 1. As shown, the flicker level is always below the visibility level, which indicates that there is no flicker associated issues with CPVIM 1 at this location.

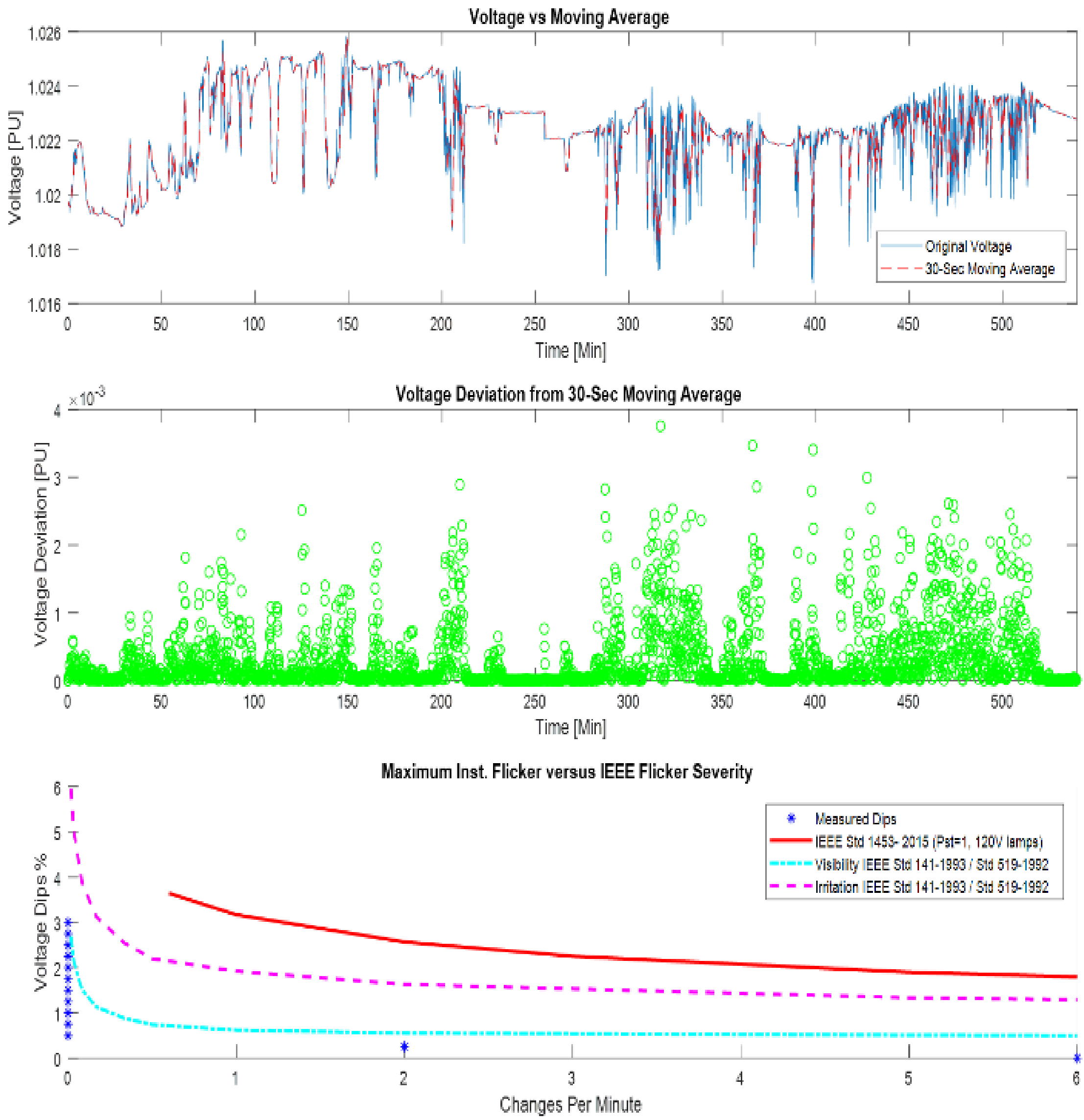


Figure 3-19. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 1 at PV location

Figure 3-20 below shows the flicker calculation curve for the meter at the PV location of CPVIM 1. As shown, the flicker level is always below the irritation level. However, there are instances when the flicker level is higher than the visibility level.

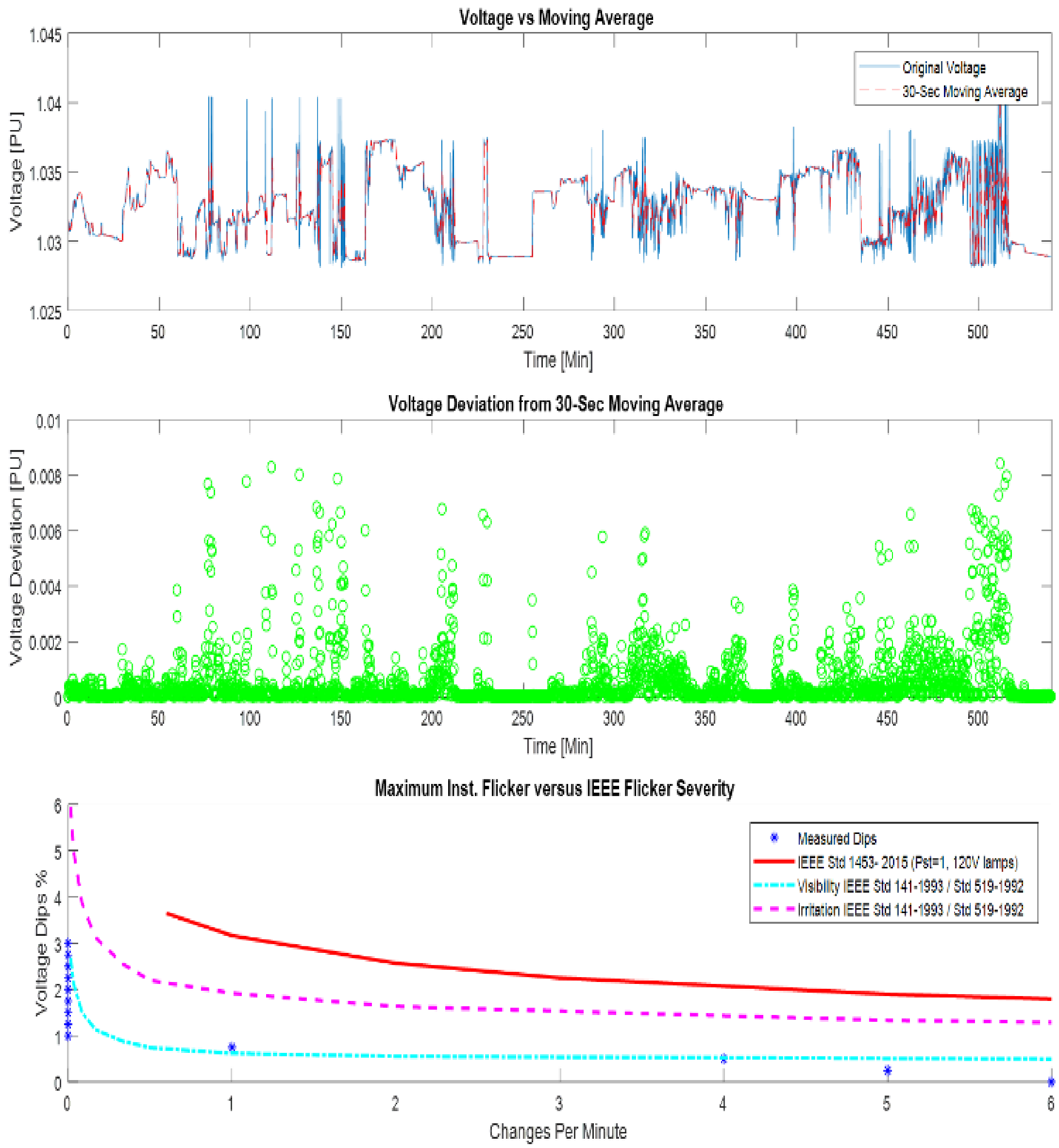


Figure 3-20. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 1 at the F1 location

Figure 3-21 below shows the flicker calculation curve for the meter at the F3 location of CPVIM 1. As with F2, the flicker level is always below the irritation level but there are instances when the flicker level is higher than the visibility level.

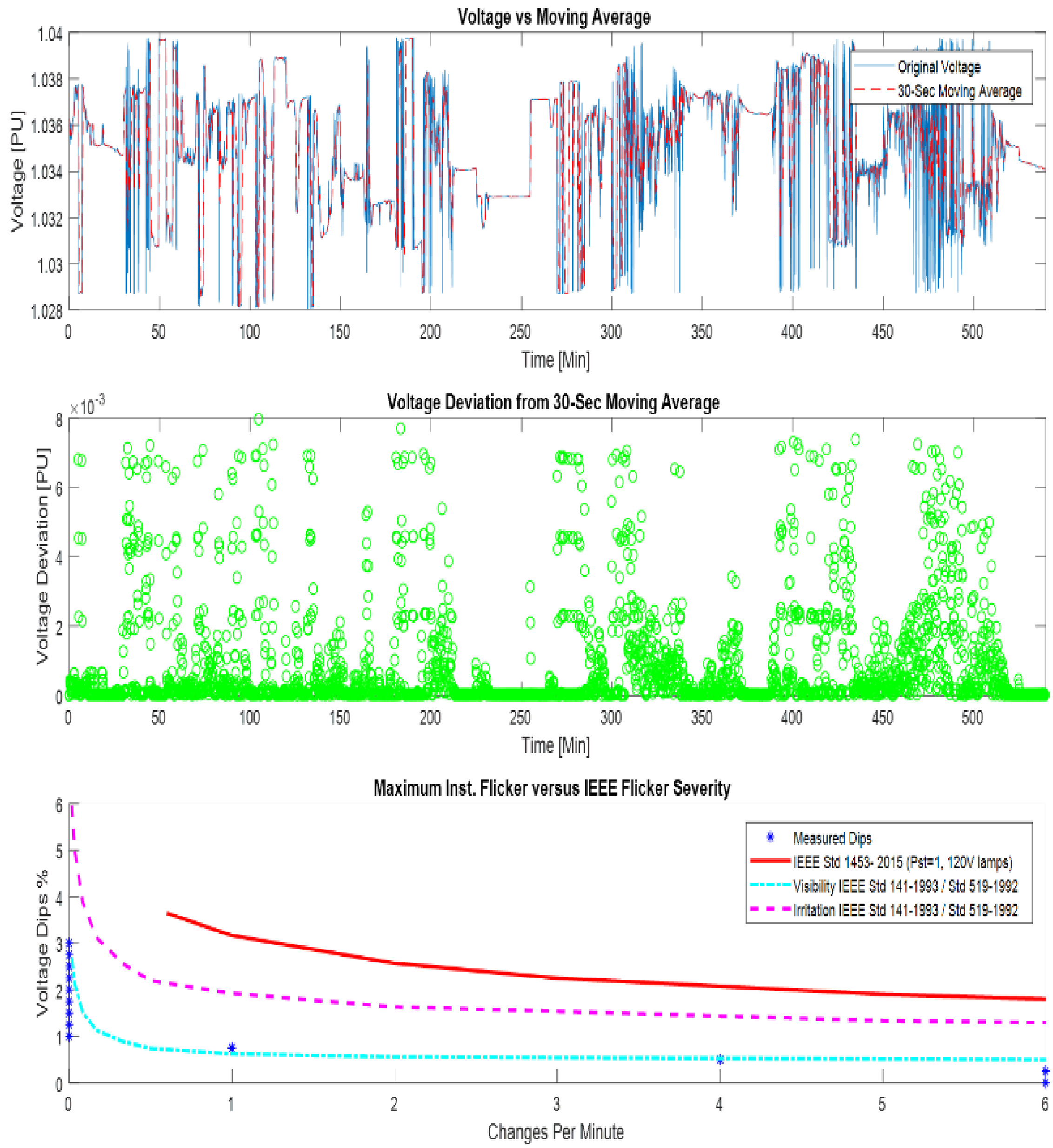


Figure 3-21. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 1 at the F3 location

3.1.3.1.2 Study results for CPVIM 1 after BESS deployment

The PV impact mitigation was evaluated for select circuits with Python-Distribution Planning Tool 4. In this case, a battery was installed at the beginning of CPVIM 1, close to the large PV location (Figure 3-22).

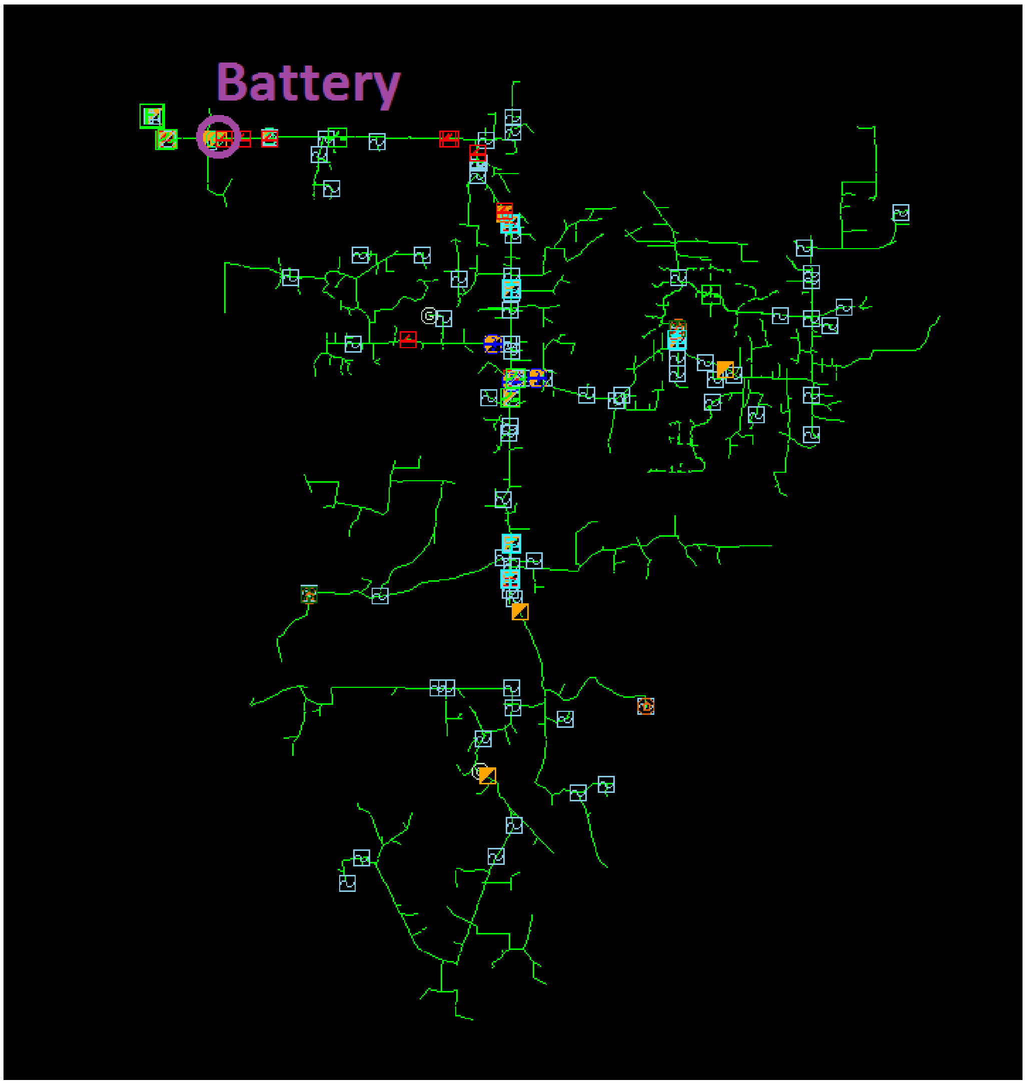


Figure 3-22. Location of the battery for CPVIM 1

A 3 MW, 6 MWh battery was initially selected and modeled in Distribution Planning Tool 4. The smoothing and voltage control logic was implemented in Python script. For PV smoothing, the battery looks at the average of power in a two minute moving average window and injects/absorbs active power to follow the average power value. This smooths out the power flow upstream of the battery. For voltage control, the logic consisting of two parts.

- Based on the voltage at a reference location (battery location in this case), the battery looks at the changes of voltage and injects/absorbs reactive power to smooth out the output voltage and mitigates the sudden changes in the voltage. This smoothing take place based on a moving average with a one-minute time frame.

- The battery makes sure that the output voltage is within the acceptable voltage limits.

Figure 3-23 shows the flicker analysis for the three locations (PV, F2 and F3) after the BESS is deployed and in all three cases the voltage dips are now all below the limits which means that battery was able to mitigate the voltage flicker issues previously observed.

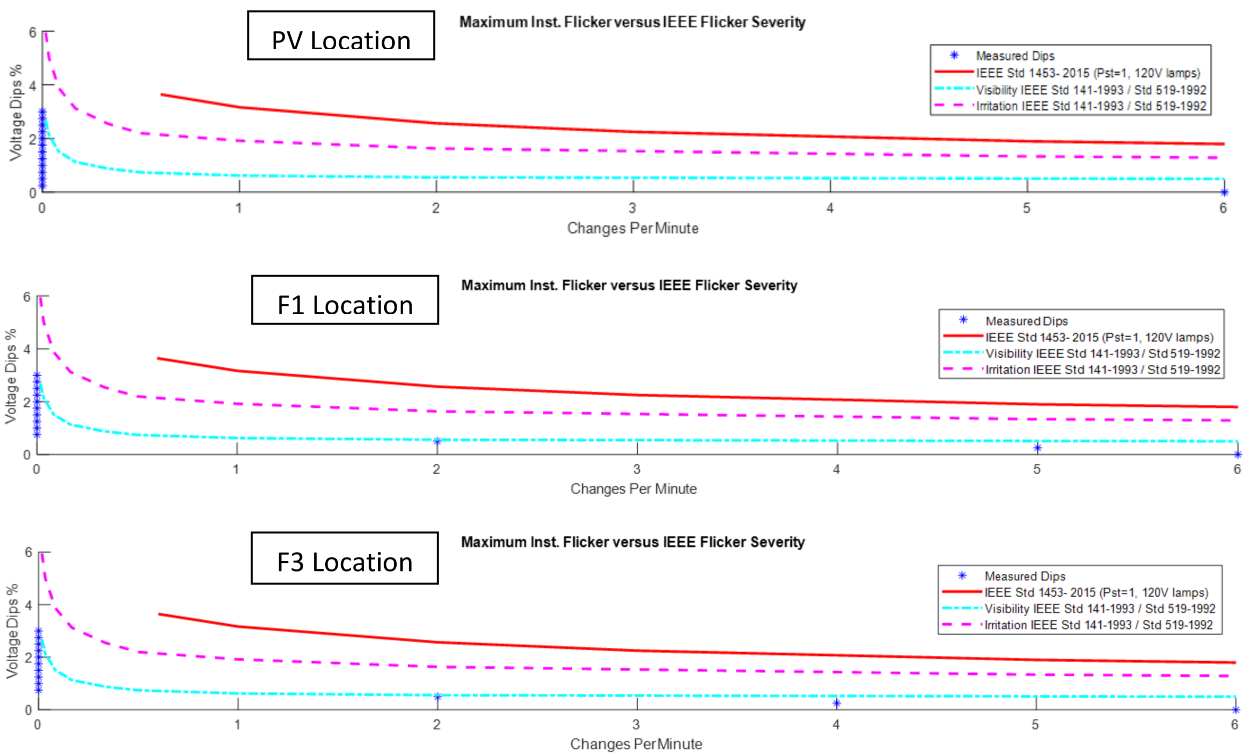


Figure 3-23. Flicker calculation curves for CPVIM 1 at PV, F2 and F3 locations after BESS installation

The results of the power smoothing are shown in Figure 3-24 where the circuit breaker power flow upstream and downstream of the BESS are compared over a nine-hour period. However, at that resolution, it is difficult to observe the impact of the BESS, so the results are repeated in Figure 3-25 over a one-hour time-frame and the ability of the BESS to smooth out the power by injecting/absorbing active power is clearly visible.

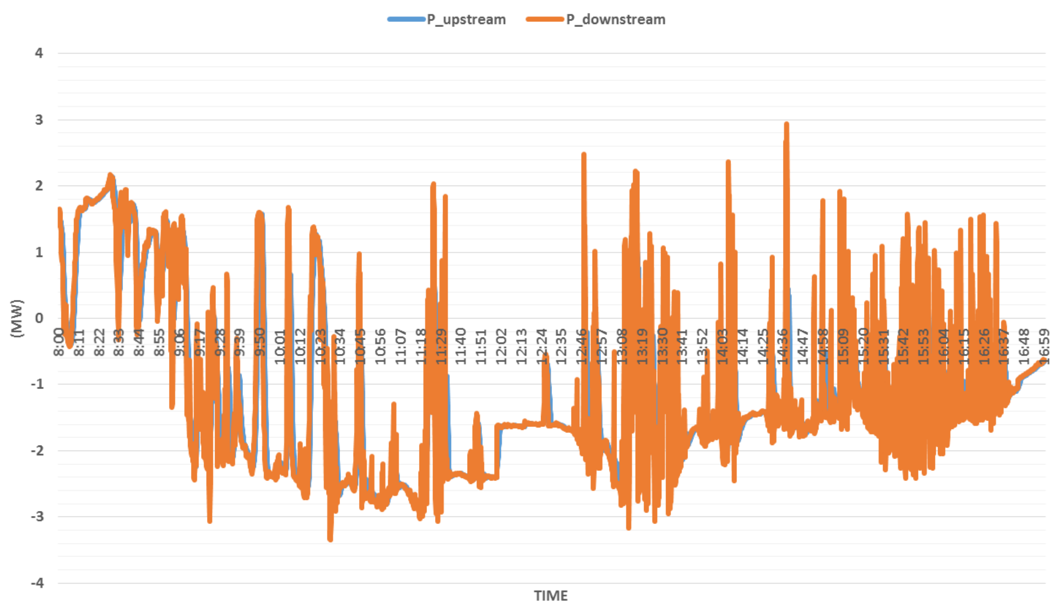


Figure 3-24. Power Flow Comparison upstream vs. downstream of BESS for CPVIM 1 (9 hours)

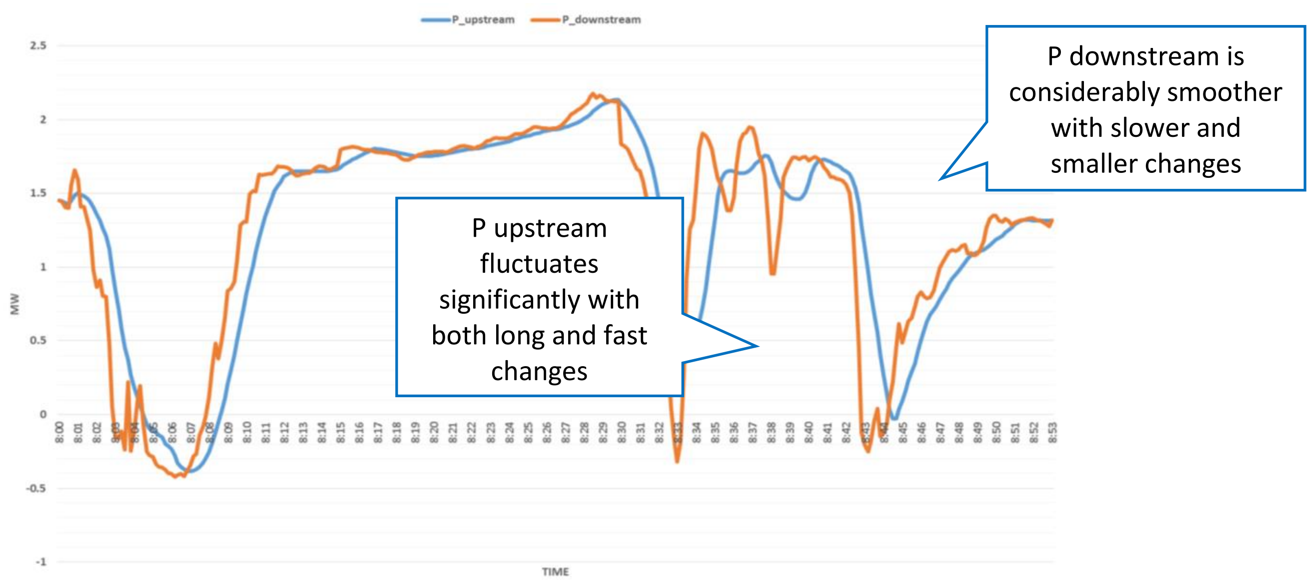


Figure 3-25. Power Flow Comparison upstream vs. downstream of BESS for CPVIM 1 (1 hour)

The battery active power output has been illustrated in Figure 3-26. As is evident, the battery kW goes up to 3,000 kW.

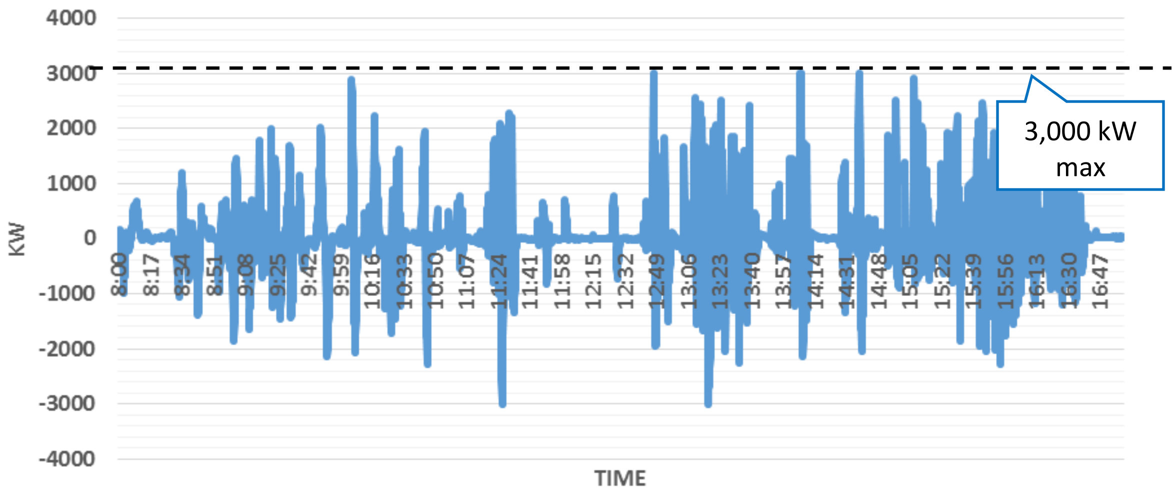


Figure 3-26. Battery active power for CPVIM 1

For voltage control, the battery looks at the voltage at the battery location and smooths out the rate of change of voltage (ROC); it also guarantees that the output voltage is within the acceptable limits. Figure 3-27 compares the voltage before and after the battery installation at the PV, F2 and F3 locations. As shown, the battery manages to reduce the voltage ROC during the sudden changes in the voltage and smooths out the output voltage by injecting/absorbing reactive power.

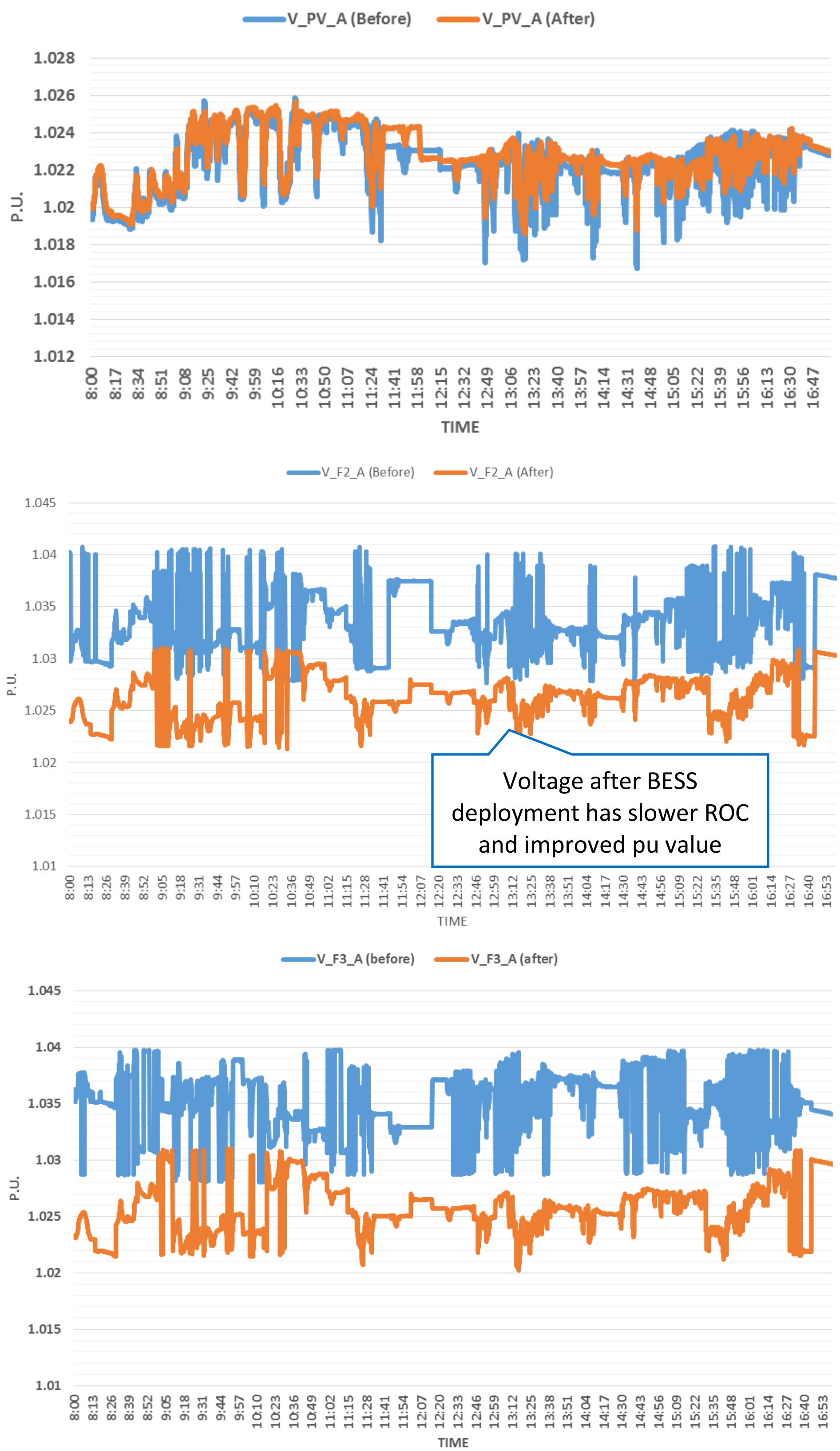


Figure 3-27. Voltage comparison at PV, F2 and F3 locations before and after Battery Installation for CPVIM 1

Finally, the accumulative charge and discharge of the battery are shown in Figure 3-28 and Figure 3-29, respectively. In general, the battery needs almost 2,000 kWh for the PV impact mitigation. Therefore, a 3,000 kW, 3,000 kWh battery would be satisfactorily performing PV smoothing application, and the remaining energy could be used for further applications.

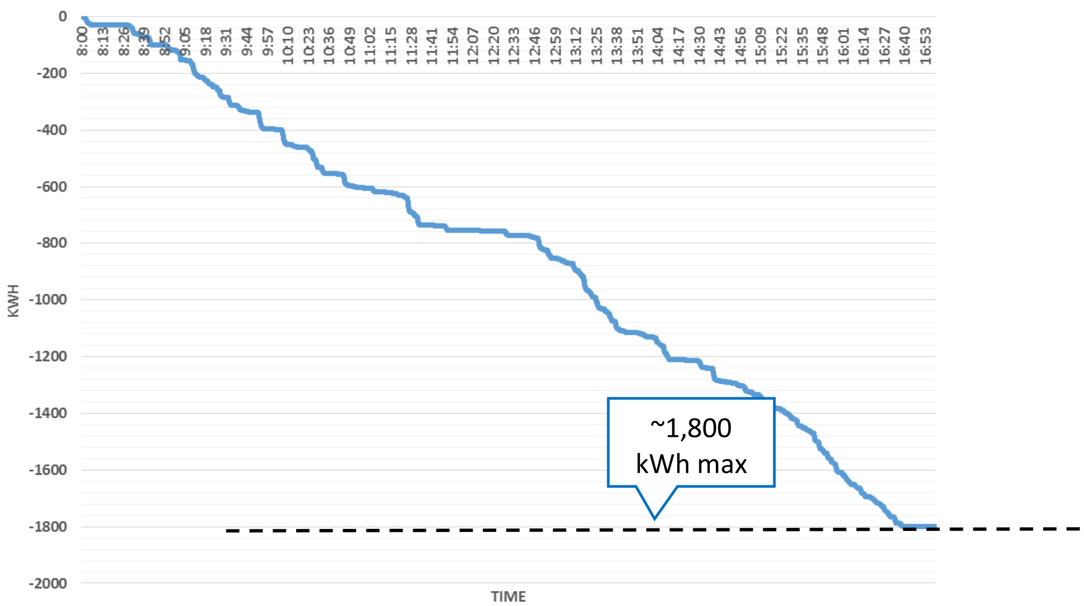


Figure 3-28. Battery accumulative charge for CPVIM 1

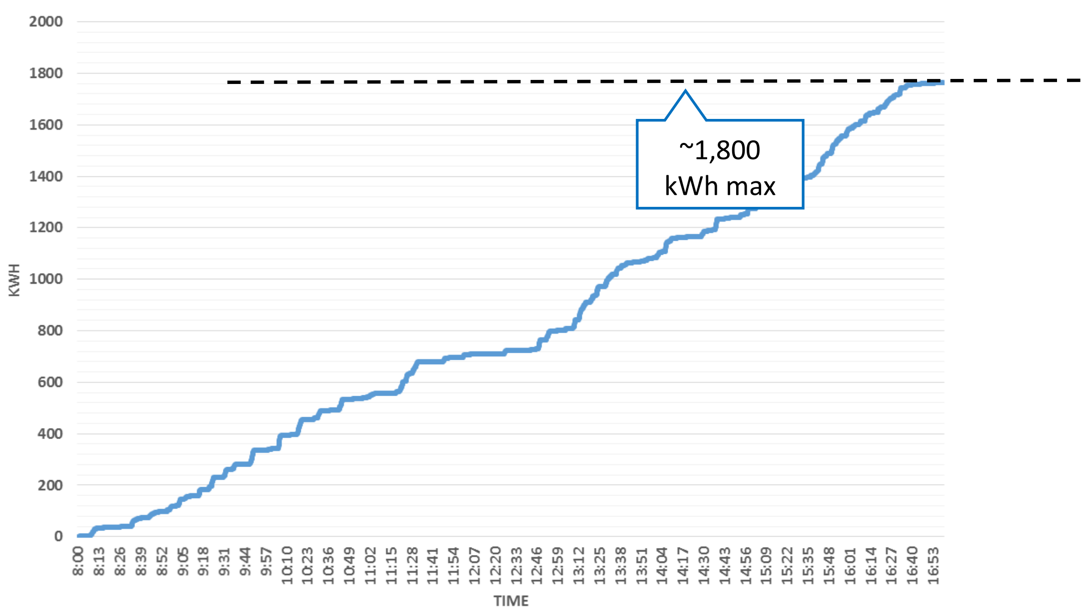


Figure 3-29. Battery accumulative discharge for CPVIM 1

3.1.3.2 Cost benefit analysis for CPVIM 2

The objective of this study is evaluating the potential benefits of Battery Energy Storage Systems (ESS) by participating in CAISO wholesale and ancillary markets. CAISO market participation is considered as secondary application where the primary ESS application is PV smoothing.

A mixed integer programming (MIP) optimizer formulated for optimizing ESS participation in energy and ancillaries markets. MIP maximizes the utilization of the excess battery capacity (based on constraints) via market participation.

In this analysis, the optimization used the DA prices for charging and the RT prices for discharging, to simulate the strategy described by SDG&E in which charging load is bid into the day ahead markets and discharging withheld from the day ahead (2016 nodal LMP prices are considered). Discharging is offered into the Real Time markets. As an additional step, the strategy of offering RegUp and RegDown services into the CA ISO ancillary service markets was evaluated, again at 2016 historical prices. Each day, the optimization would co-optimize the energy and ancillary service participation across the day so as to maximize revenues subject to BESS operational constraints. Adding regulation services to the product portfolio accessible to the BESS increases revenues as would be expected.

Market analysis was conducted for ESS sized at 2000 kW, 2000 kWh designed to smooth PV.

ESS Operation Constraints for Market Participation

According to previous section, maximum and minimum charge/discharge limits for CPVIM2 in real-time energy market and regulation market are shown in Figure 3-30 to Figure 3-35.

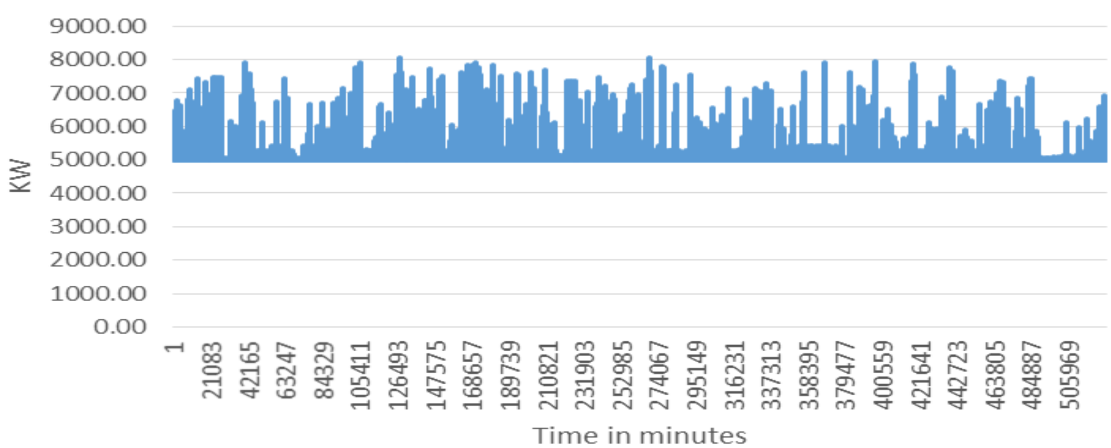


Figure 3-30. Maximum discharge (Real-time energy market)

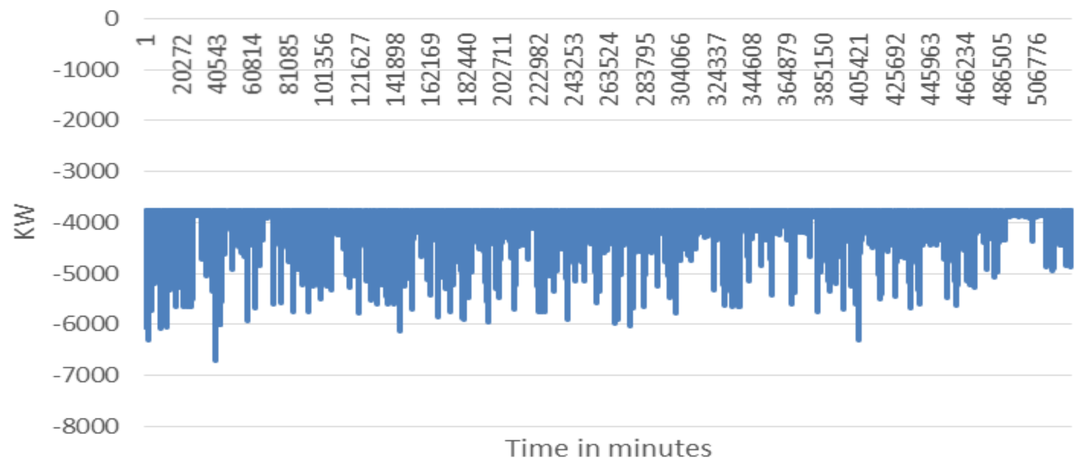


Figure 3-31. Maximum charge (Real-time energy market)

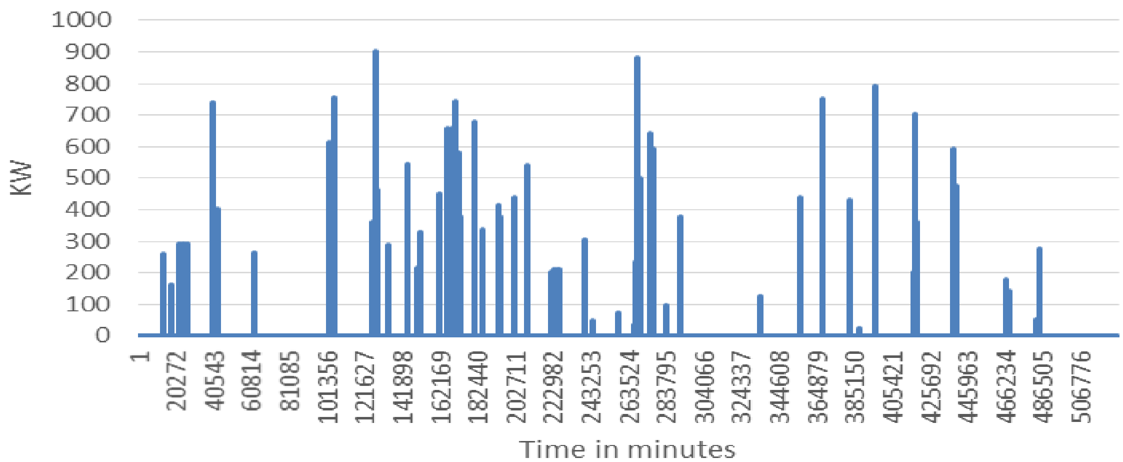


Figure 3-32. Minimum discharge (Regulation market)

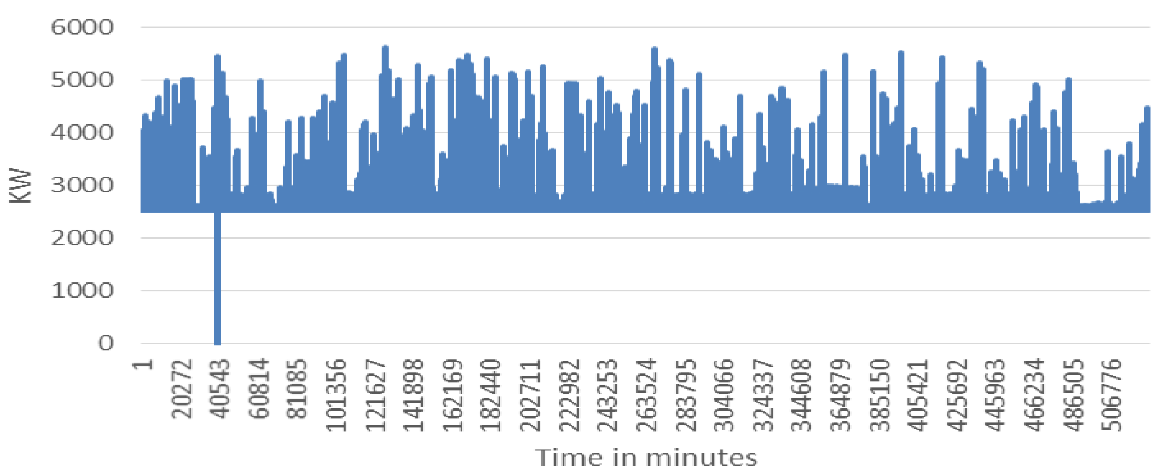


Figure 3-33. Maximum discharge (Regulation market)

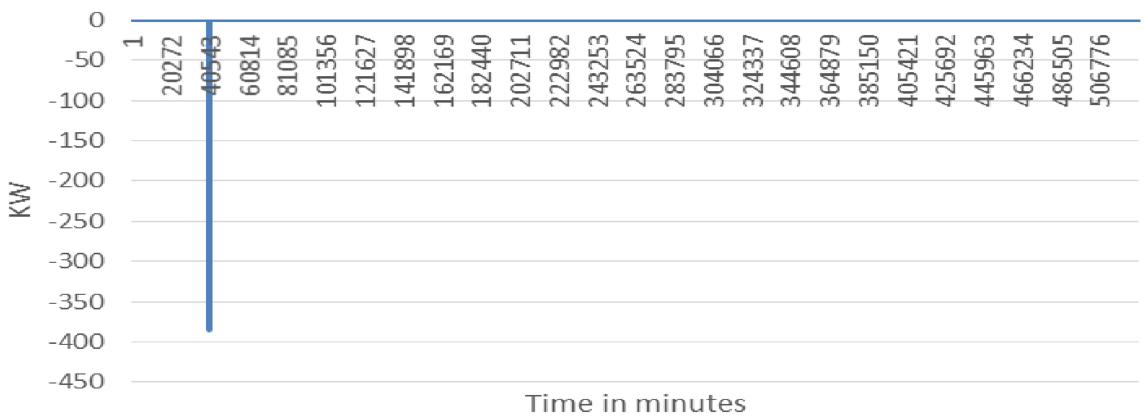


Figure 3-34. Minimum charge (Regulation market)

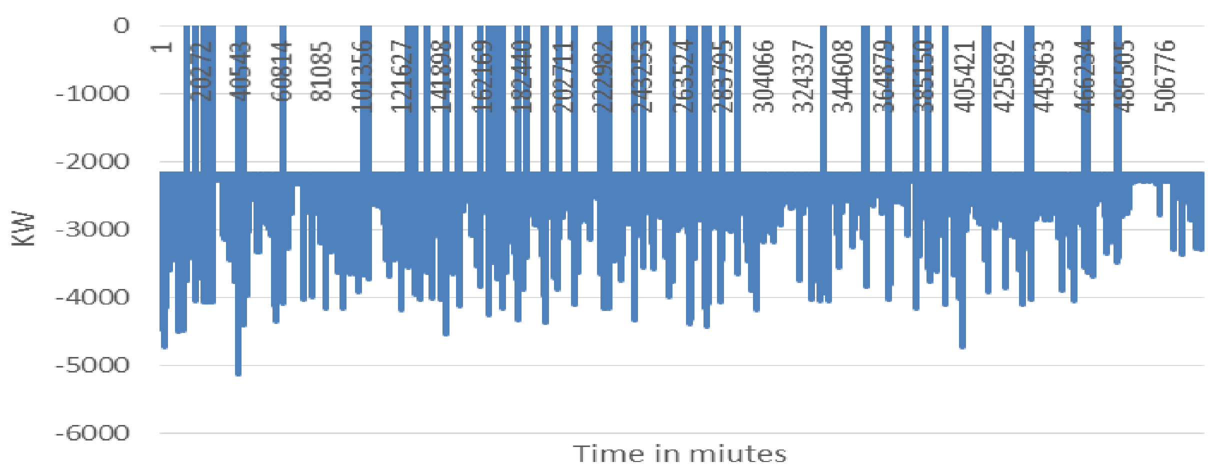


Figure 3-35. Maximum charge (Regulation market)

To create constraint profiles for market analysis, minute by minute charge and discharge limits were converted to hourly constraints. This is necessary due to hourly nature of regulation DA markets. In order to avoid violations, the most conservative approach was applied to convert minute-by-minute constraints to hourly constraints. The method was based on:

- Taking maximum of 1-minute minimum values (minimum charge/discharge) within each hour,
- Taking minimum of 1-minute maximum values (maximum allowable charge/discharge) within each hour.

It was shown that by utilizing the excess capacity of the BESS for market participation, the case resulted in a positive NPV for ESS deployment on CPVIM 2 as summarized in Table 3-3-15 below. The additional revenue was calculated by considering the operation/application constraints to ensure the primary application for the BESS (i.e. PV smoothing) was accomplished.

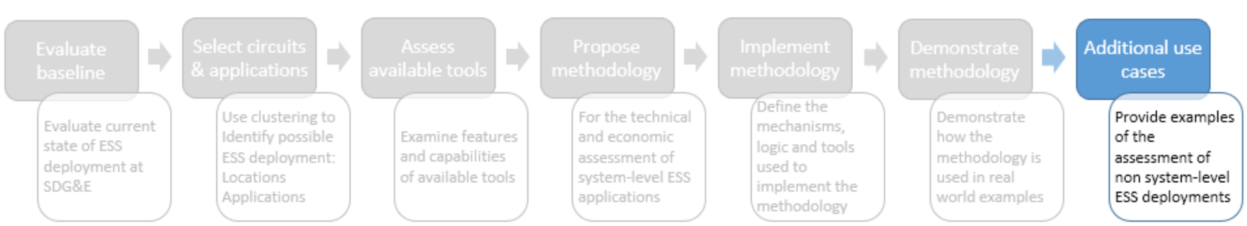
Table 3-3-15. NPV Table for CPVIM 2

Parameter	$ thousands
Battery Size	2 MW / 2 MWH
Battery Initial Cost	$1,248
Annual Depreciation	$130
Capital Return	$56
Opex	$62
Market Benefits	$230
T&D Upgrade Cost	$515
Annual Depreciation	$17
Capital Return	$23
Opex	$16
20 yr NPV of Battery vs T&D Upgrade	$1,273

Conclusions:

The use of energy storage for PV integration alone may not be financially attractive. However, by determining hourly constraints on the use of the battery to be included in regulation services, additional revenues can be obtained which make the business case viable. Note that a time base scheme for enabling regulation services will likely not produce the same benefits, as the most restrictive hourly constraint on a monthly or seasonal basis would have to be applied, which would greatly reduce revenues.

3.2 Task 7: Summary Results for Additional Use Cases



The previous sections focused on the methodology and tools for evaluating ESS deployment for system-level applications. This section examines three different uses cases for end-use applications:

- Whole sale market participation
- Demand Management in Commercial Buildings

- Hybrid Applications for Residential and Commercial Buildings

3.2.1 Whole Sale Market Analysis

For this use case a comparison of the wholesale market analysis and the potential performance of two 10 MW / 40 MWh Battery Energy Storage System (BESS) in the California ISO (CA ISO) market was performed.

Each of the two units was installed on 12 kV systems, however, one of them (Location A) was connected at substation level with a step-up transformer to 66 kV, versus the second one which was connected at circuit level, remote from the substation (Location B).

The unit at location A was connected to the sub-transmission system by a dedicated transformer, so that there were no limitations on charging/discharging power flow imposed due to other circuit/transformer loading concerns.

The evaluation for location B included limitations of the BESS charging rate due to thermal loading of the circuit and rating of the circuit at a given time of day. This resulted in varying hourly limitations on BESS charging which were additionally considered in the scheduling optimization. Because of load variation during the day and throughout different months or seasons, the load changes impose different levels of charge limitations on BESS charging on a daily basis across the year.

Neither study circuit had any significant amount of PV systems. For circuits with reasonable PV amounts, during days with high PV production, wholesale prices may be low at peak PV production hours and BESS charging might be scheduled for these hours. However, depending upon the circuit load profiles and PV penetration this may or may not coincide with peak loading. When it does, the BESS charging will be impacted and unable to fully take advantage of low prices.

After investigating available (commercial) tools for BESS market assessments, it was decided to use a proprietary storage evaluation tool from the consultant for this analysis – as one option. Another study was also suggested to compare the results with Vendor 12 Cost Calculation Tool 6 tool. The Vendor 12 Cost Calculation Tool 6 tool has identical capabilities for optimizing Day Ahead (DA), Real Time (RT), and Ancillary service revenues and can additionally factor in fast ramping services to the ISO. However, the Cost Calculation Tool 6 tool did not have the particular LMP prices for the locations of the BESS studied as pre-loaded data which would create inaccuracies at peak pricing. This report outlines the analysis and findings by using the former tool.

The theoretical best revenues obtainable against 2016 historical CAISO market prices were computed.

In the optimizations, the stated SDG&E strategy of offering charging load in the day ahead energy market and discharging energy in the Real Time market was used. The headline results from this analysis showed that the theoretical best performance against 2016 prices would be a net benefit of $725,906 for the 10 MW unit for the entire year. This net benefit is the net of receipts for discharged energy, payments for charging energy, and variable operating and maintenance costs estimated. The fixed operating cost were not included.

As a future case, the economics of the 10 MW BESS for also participating in the CA ISO ancillary service market, specifically the Regulation Up and Regulation Down markets, were assessed using the same tool and 2016 prices. If one 10MW BESS were employed to optimally charge in the Day Ahead market and discharge in the Real Time market, the theoretical best results come to $725,906 as stated above. If the entire capacity of the BESS were to be available for regulation, a co-optimization of day ahead energy, real time energy, and regulation service across 2016 using historical prices indicates that the benefits for one 10MW BESS would be as much as $ 1,872,000. This is a theoretical best value against historical prices. However, the more than doubling of economic benefits indicates that pursuit of the ancillary service markets is well worth the effort.

3.2.1.1 Approach

This evaluation was carried out using a proprietary optimization tool previously developed by the consultant for evaluating storage projects economics. This tool methodology and mathematical formulation are developed for solution as a Mixed Integer Programming (MIP) problem. The co-optimization of storage resource participation in energy and ancillary service markets is similar to that performed by the CA ISO in its market clearing.

The baseline evaluation of the 10 MW BESS economics used 2016 CA ISO market prices for day ahead (DA), Real Time (RT), and Regulation UP (RU) and Down (RD) products. The tool computes the optimal allocation of BESS capacity to the different markets each hour, while observing constraints imposed by the BESS characteristics and capabilities. This is done for the 8760 hours of the year and the total revenues computed.

In this analysis, the optimization used the DA prices for charging and the RT prices for discharging, to simulate the strategy described by SDG&E in which charging load is bid into the day ahead markets and discharging is offered into the Real Time markets. The strategy is based on the observation that RT prices are usually higher than DA prices, sometimes significantly so.

As alternatives, strategies of offering both charging and discharging into the DA markets or alternatively offering both into the RT markets were evaluated. Results from these tended to confirm that the SDG&E strategy is valid.

As an additional step, the strategy of offering RegUp and RegDown services into the CA ISO ancillary service markets was evaluated, again at 2016 historical prices. Each day, the optimization would co-optimize the energy and ancillary service participation across the day so as to maximize revenues subject to BESS operational constraints. Adding regulation services to the product portfolio accessible to the 10 MW BESS increases revenues as would be expected.

Because the BESS has a daily limit of one deep discharge cycle, the optimization was done with various limits on the amount of the BESS capacity available for regulation. The impact of charge/discharge cycles from regulation, given the CA ISO NGR-REM protocols which manage BESS state of charge (SOC) by calculating net regulation energy in a 15 minute period and “repaying” it with Real Time energy dispatch in the next, should not be material. However, other operational issues might cause SDG&E to restrict the amount of BESS capacity available for regulation. While no operational constraints were described in the context of the 10 MW BESS in meetings with SDG&E staff, it is possible that other large BESS systems could see constraints on total regulation for reasons similar to the restrictions on charging load studied in the second part of this case study. For illustrative purposes, the analysis was carried out with, limits on maximum regulation participation of 25%, 50%, 75%, and 100%. Another reason to study limits on regulation participation is the warranty contractual limit of one deep discharge cycle per day. 100% regulation service could well violate this.

The 10 MW BESS was considered to be a NGR REM resource, meaning it participates in the energy and ancillary service markets with energy charging scheduled hourly against day ahead prices and discharge at 15 minutes scheduled duration against real time prices. Real time prices were averaged for each hour for use in hourly optimization. The ISO biases each 15 minute schedule for NGR-REM resources in the regulation service so as to “pay back” the net energy charged/discharged for regulation in the previous hour. This was factored into the simulation/optimization.

When the RT operations result in charging/discharging that varies from the DA charging schedule in the Charge DA / Discharge RT case, there is a secondary effect that the net energy for the deviation from the DA schedule will pay/be paid for the difference in the DA and RT cases. This is called the “charging DA-RT compensation” in the chart below. It is a secondary effect but not insignificant. It only occurs in this case.

The summary results of the three sets of optimizations for all of 2016 with different strategies for charging and discharging in the Day Ahead and Real Time markets are shown in the tables below.

Table 3-3-16 shows that the SG&E strategy today of charging in DA and discharging in RT provides considerable benefits over charging/discharging in the DA markets; the benefits are nearly 6 times as great. The increment to charge and discharge both in the RT markets is only 25% and it is far from clear that this increment is realizable or that the calculations are that precise. As said, this analysis validates the SDG&E strategy.

Table 3-3-16. The 10 MW BESS in the Day Ahead and Real Time Energy markets for 2016 data

Operational Strategy	Annual cost of charging	Annual revenue from discharging	Annual VOM	Charging DA-RT Compensation	Annual Benefits
Charge DA - Discharge DA	$206,744	$441,196	$114,999	$0	$119,453
Charge DA - Discharge RT	$144,706	$925,139	$85,995	$31,468	$725,906
Charge - Discharge RT	$38,924	$1,030,404	$126,792	$0	$864,688

Table 3-3-17 calculates the benefits of the 10 MW BESS participating in the Regulation market. In case there are other operational constraints that prevent the full power capacity of the BESS from being utilized, four cases where capacity was restricted to 9 MW were also analyzed.

Table 3-3-17. Evaluating the 10 MW BESS Participation in Ancillary service Markets (Regulation) for 2016 data

MW Cap avail	Reg Cap %	Energy credit (total DA and RT)	Reg Up capacity credit	Reg Down capacity credit	Mileage Up credit	Mileage Down credit	Variable O&M (VOM)	Reg Energy credit	Total Benefit
10	0	$811,901					$ 85,995		$ 725,906
10	20	$709,245	$132,323	$116,016	$15,021	$ 29,162	$112,760	$ (3,904)	$ 889,007

MW Cap avail	Reg Cap %	Energy credit (total DA and RT)	Reg Up capacity credit	Reg Down capacity credit	Mileage Up credit	Mileage Down credit	Variable O&M (VOM)	Reg Energy credit	Total Benefit
10	50	$678,755	$329,751	$289,337	$37,315	$ 72,834	$132,674	$ (10,143)	$1,275,317
10	75	$647,164	$491,787	$431,929	$55,354	$109,105	$145,081	$(16,640)	$1,590,259
10	100	$614,557	$637,215	$554,806	$73,353	$145,030	$152,580	$ (22,168)	$ 1,872,381
9	20	$646,392	$118,882	$104,288	$13,496	$ 26,210	$104,028	$ (3,472)	$ 805,239
9	50	$617,043	$296,293	$260,377	$33,408	$ 65,523	$ 120,738	$ (9,786)	$ 1,151,904
9	75	$587,405	$442,223	$388,172	$49,884	$ 98,161	$ 131,264	$ (15,115)	$ 1,434,581
9	100	$ 557,911	$573,279	$498,585	$66,147	$ 130,520	$138,045	$ (19,982)	$1,688,397

In the third column of the chart, the Energy Credit is the Discharging Revenues less the Charging Payments. Given that the charge–DA / discharge–RT strategy is simulated, the $725,906 from the first table of energy-only strategies is the baseline for comparison with the regulation simulation results once the Variable O&M (VOM) costs are deducted. These energy credits in the regulation case include an estimate of the settlement of regulation revenues at RT prices. Energy credits decrease as regulation capacity increases, as less battery capacity is then available for arbitrage.

In these calculations the mileage payment is a straight forward computation using the CA ISO 2016 historical data for up and down mileage factors and battery accuracies. The ISO data does not appear to facilitate the direct calculation of the energy credit for RegUp and RegDown energy. (The mileage factor is related to the length of the curve of AGC dispatch signals, not to the area under the curve). For purposes of this estimate, a figure of ½ of the Reg Capacity in each 15 minute period was used to estimate the RegUp and RegDown energy. This then became an increment/decrement to the BESS state of charge beginning the next 15 minute period, and was used to calculate regulation energy credits. Because the RegUp energy and RegDown energy more or less cancel each other out, based on hourly participation, the regulation energy credit is minor. As can be seen in the table, it is a small negative figure that grows as regulation capacity increases.

Because the 10 MW BESS has warranty terms stipulating a limit on daily discharge cycles, the impact of regulation service on cycling has to be considered. The mileage factor alone is insufficient to do this as it does not indicate separate measures of number of regulation cycles in a period versus size of cycles. In order to properly assess this impact a more detailed analysis would need to be done using actual CA ISO regulation instructions or a time series simulation of such at 4 second intervals. The difference in revenues are sizable and the possible impacts on battery life potentially a factor, so this analysis may be a next step prior to developing a bidding strategy for regulation services.

Overall, the results offer some obvious relationships. Making more capacity available for regulation decreases the energy credits slightly as less state of charge is allocated to DA and RT energy arbitrage –

the regulation capacity and mileage payments are greater. Regulation payments increase with added regulation capacity almost linearly.

3.2.1.2 Sample Results of Daily Scheduling

The following three examples are results obtained when limiting the regulation participation to 50% of capacity: first, the day when RegUp and RegDown prices were highest, May 21st 2016; second, the day when Day Ahead prices were highest, June 20th; and third, the day when Real Time prices were the highest, Aug. 20th.

To illustrate the complexities of these operations, consider the following sets of daily plots (Figure 3-36) of operations showing market prices, charge and discharge activities, and regulation services provision. The elements shown on the series of charts that follows are described below.

Table 3-3-18. Chart Elements

Chart Element	Description
Reg UP	BESS capacity offered to Regulation Up (KW)
Reg Down	BESS capacity offered to Regulation Down (KW)
RU CLR P	Regulation Up market clearing price ($/KW)
RD CLR P	Regulation Down market clearing price ($/KW)
RMU CLR P	Regulation Mileage Up market clearing price ($/KW)
RMD CLR P	Regulation Mileage Down market clearing price ($/KW)
DA	Day-ahead wholesale energy clearing price ($/KWh)
RT	Real-time wholesale energy clearing price ($/KWh)
Charge Down	Required Charge for Regulation Down Participation (KWh)
Discharge UP	Required Discharge for Regulation Up Participation (KWh)
Charge ENM	Charge bid in Day-ahead wholesale energy market (KWh)
Discharge ENM	Discharge offered in Real-time wholesale energy market (KWh)

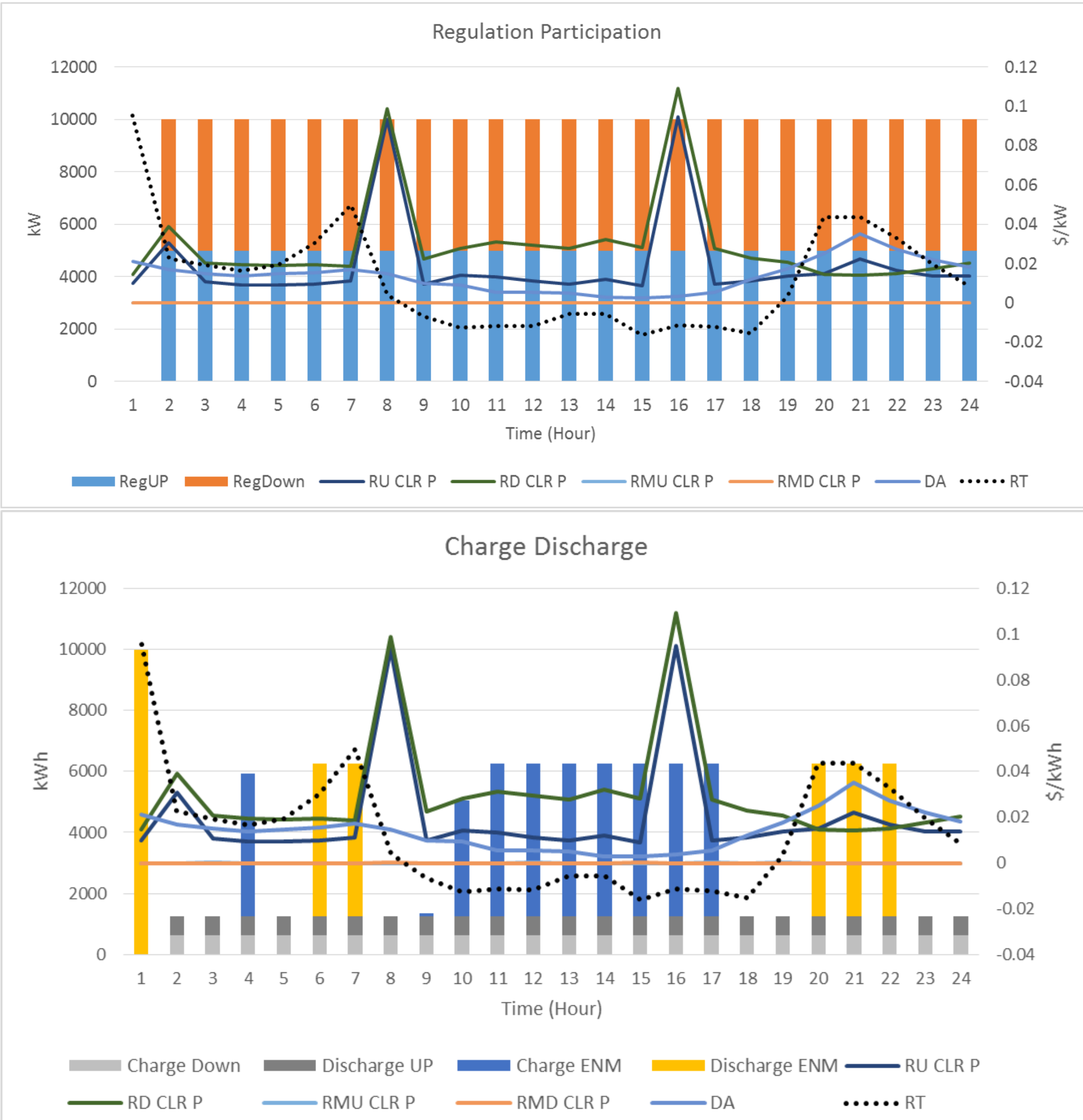
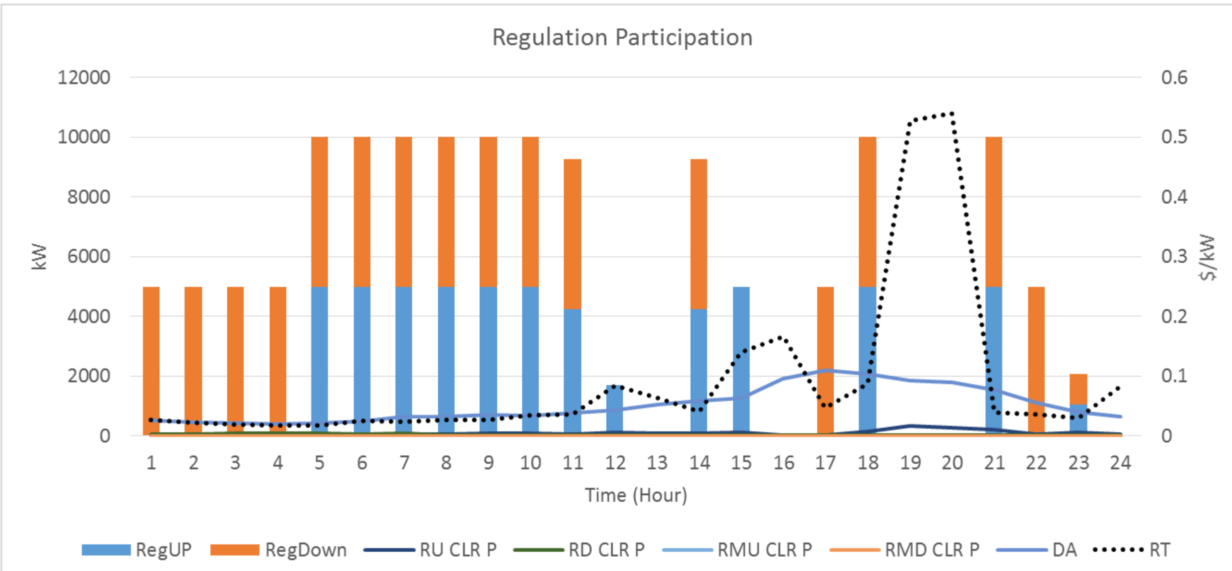


Figure 3-36. May 21, 2016 analysis (Location A)

Figure 3-36 above shows May 21 2016 simulated operation, a day with high RegUp and RegDown prices. RegUp and RegDown are sold almost continuously through the day, which limits the capacity available for charge / discharge arbitrage. Charging occurs between when DA prices are low.

By contrast, a June day with higher DA prices and spikes in RT prices shows (Figure 3-37) that the operations shift towards maximizing revenues from charge-discharge activities, following the RT prices for discharge.



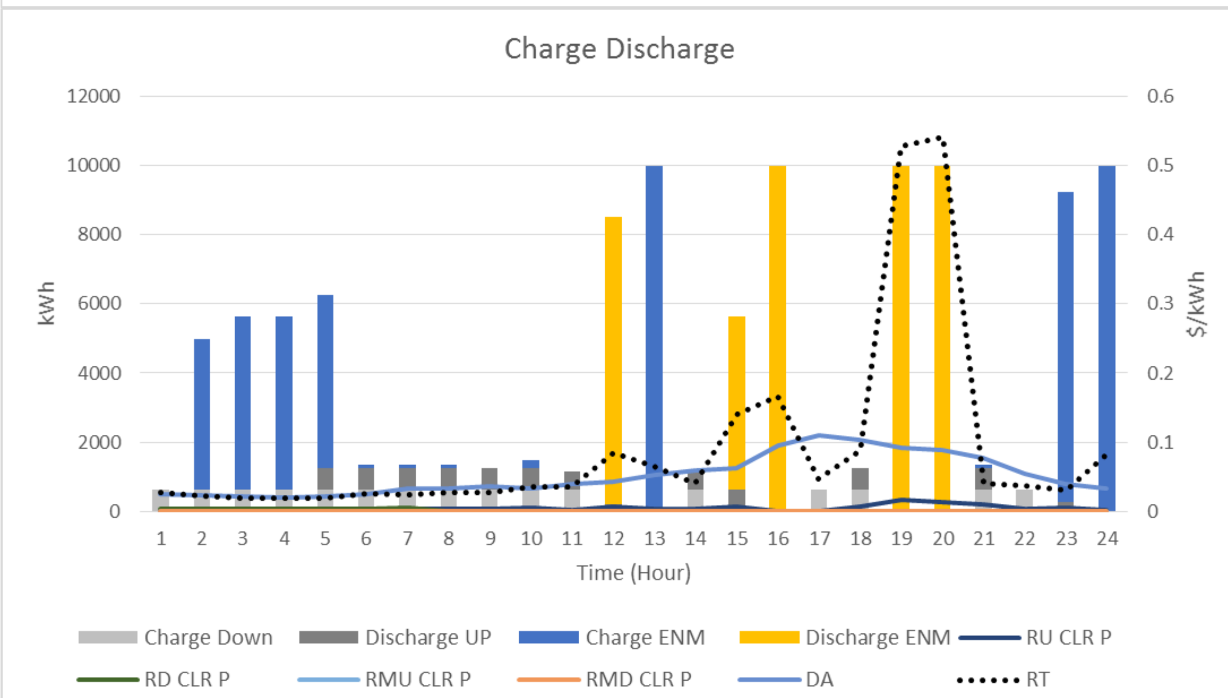


Figure 3-37. June 20 2016 analysis (Location A)

Finally, a day in August with high real time prices results in a yet different pattern (Figure 3-38):

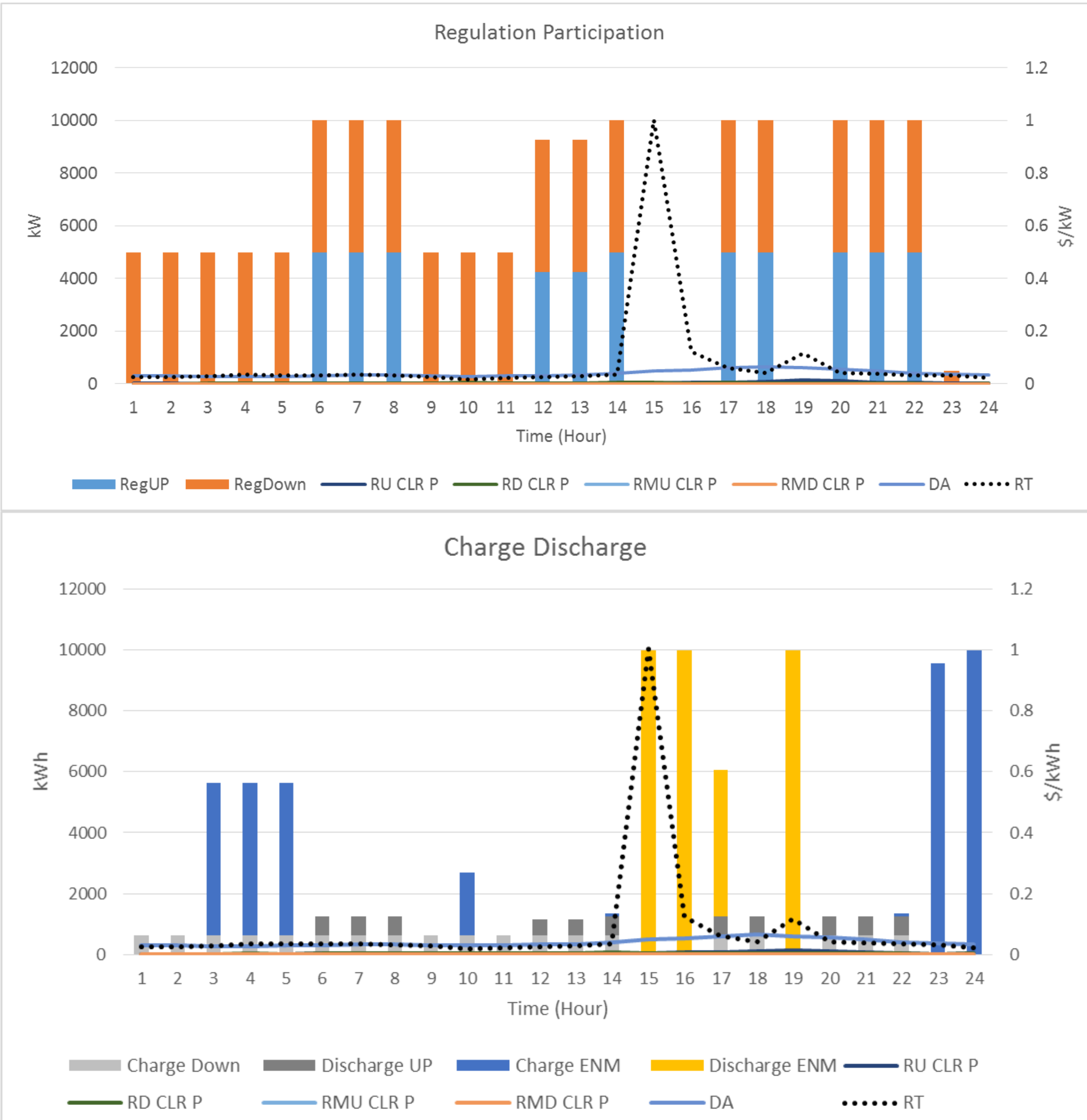


Figure 3-38. A day in August 2016 analysis (Location A)

Increasing the allowable regulation participation to 20% and 50% alters the daily pattern of participation considerably. Comparable charts to those above for different levels of regulation participation are shown in the appendix.

Similar analyses of any day in the year, with focus on aspects such as “lowest DA prices” or “highest RT prices” are possible in the tool used for this analysis. The conclusion from examining the results of the optimization of the 10 MW BESS in the energy and ancillaries markets should be that optimal scheduling is quite complex – more so than that of a conventional resource given the limited 40 MWH of energy available and the need to manage that during the day. The asymmetric nature of the CA ISO RegUp and RegDown pricing and mileage/energy usage creates additional complexities and interactions between regulation service and energy arbitrage.

Whether a tool such as Generation Management tool (Vendor 22) can effectively manage these interactions given its lack of storage representation is a question to be answered. It may be that SDG&E bidding strategy for the 10 MW Bess also needs to be informed by a detailed simulation of BESS charging and discharging as well as Generation Management tool (Vendor 22) price forecasts. The considerable additional revenues from participating in regulation service can only be realized by careful consideration of all the BESS constraints and regulation-energy interactions, so an investment in addressing these questions is worthwhile. It is also worth noting that the bulk of the large BESS in ISO markets today as merchant storage are dedicated to the regulation market where they can function as price takers without the need to anticipate DA prices. Mixing regulation, DA energy, and RT energy requires price forecasting and bidding with sophisticated strategies.

3.2.1.3 Imposing Hourly Limits on BESS charging (Location B)

As stated earlier, a second case was analyzed for the case when the BESS is connected on distribution circuits (Location B). The BESS size was kept the same (10MW / 40 MWh). This means that the total of circuit loadings and BESS charging must be within the circuit thermal limit of 600 A (12MW).

The relative size of the BESS as compared to the total circuit thermal rating and the total circuit peak loading becomes an important factor in how much the loading limits will impact BESS charging flexibility and overall market revenues.

Table 3-3-19. The 10 MW BESS in the Day Ahead and Real Time Energy markets for 2016 data with limits imposed on hourly charging at Location B

Operational Strategy	Annual cost of charging	Annual revenue of discharging	Annual VOM	Charging DA-RT Compensation	Annual Benefits
Charge DA - Discharge RT NO LIMITS	$144,706	$925,139	$85,995	$31,468	$725906
Charge DA - Discharge RT with Station Limits	$141,038	$917,865	$82,221	$31,163	$725,768

There are small differences in the charging and discharging revenues, but they net to a nearly insignificant difference in the net annual benefits. There are a number of factors at work. The limits normally will be imposed when the net load (circuit native load total – total PV production) is greatest. This tends to correlate with the periods of highest market prices, when the BESS would normally be discharging, not charging. The BESS would normally be charging when market prices are lowest, this correlates with periods when the net load is lowest which is either after midnight or in the early afternoon when PV production is highest, and this is when market prices are lowest. The limits do not have a major impact. Another factor is that the MIP optimization may not be accurate to the 0.2% difference in net benefits that is shown in this comparison, over the 8760 hours with all the variables and constraints in the problem.

Figure 3-39 and Figure 3-40 below show the June 23 day comparing the BESS dispatch with and without the station limits imposed. With the limits, the charging level in the early hours of the day is more restrictive. This forces the total charging to take longer – to spill into later hours. But the BESS is still fully charged by the time the sun comes up and the day starts. The impact on discharging is minor.

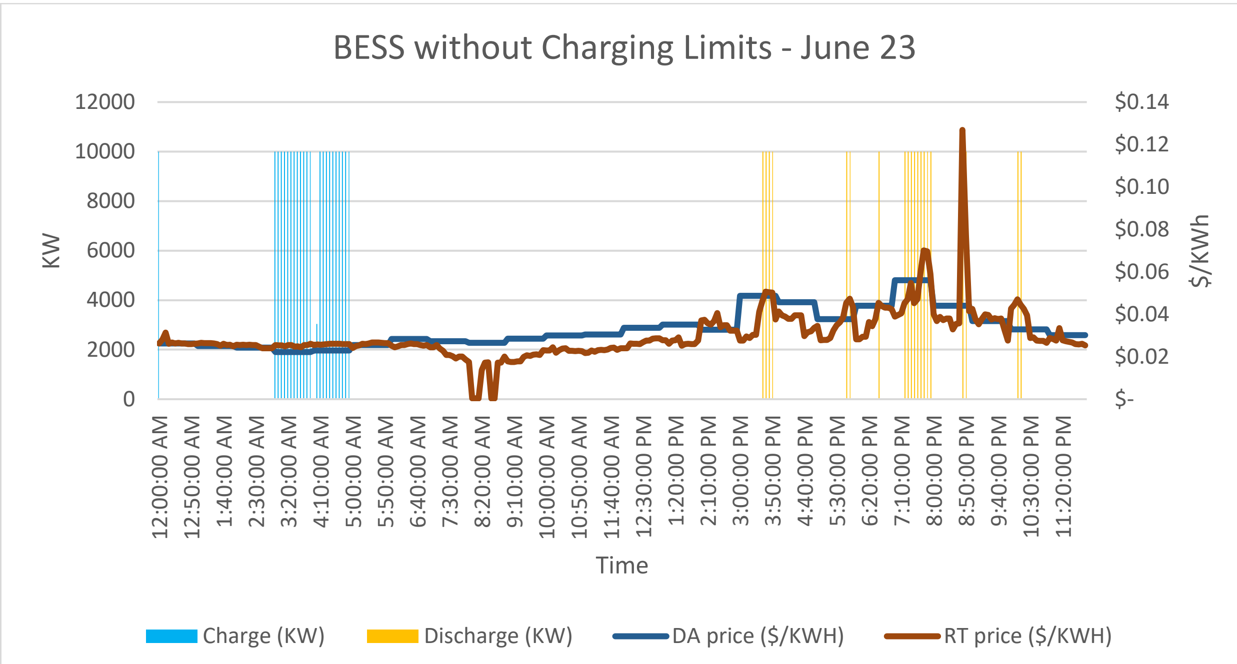


Figure 3-39. June 23 BESS Behavior with No Charging Limits

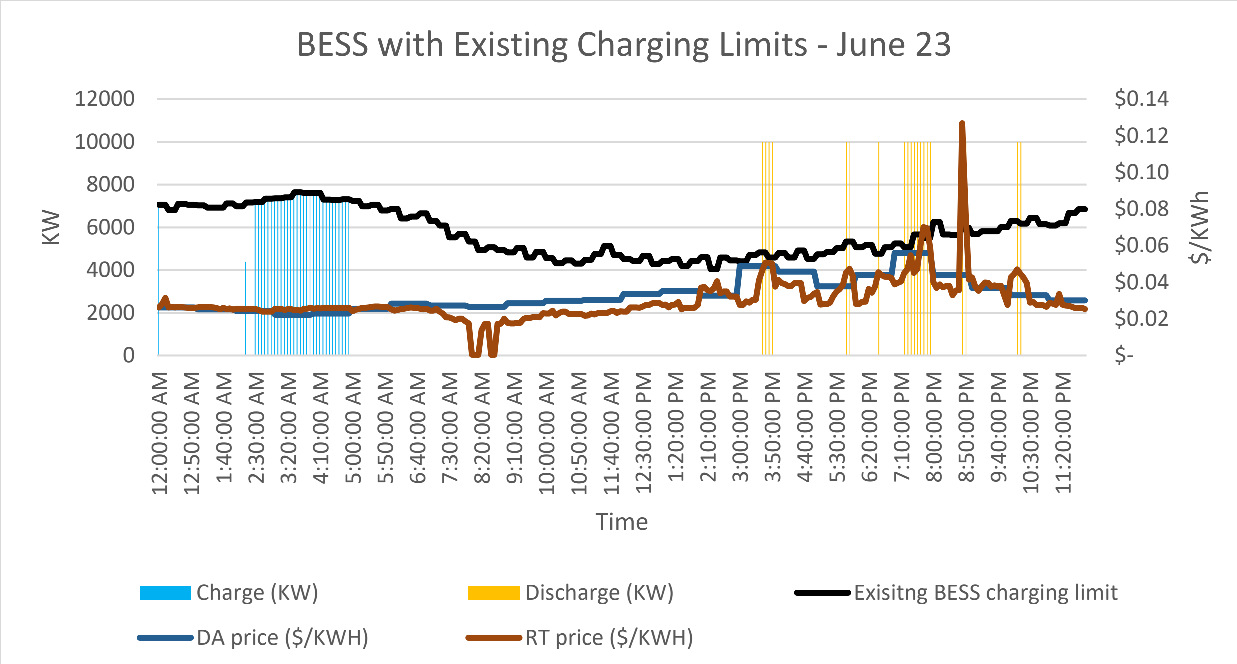


Figure 3-40. BESS behavior with Charging Limits

If the limits on charging were to be reduced to 75% of their value in the above case, then the impacts are more visible. The net benefits drop from $725,000 to $680,000 as shown in Table 3-3-20 below.

Table 3-3-20. Economics with limits reduced (Location B)

Annual cost of charging	Annual revenue of discharging	Annual VOM	Charging compensation
$ 115,367	$ 831,336	$ 55,935	$ (20,153)
Annual Benefit W/O VOM cost			$ 736,122
Annual Benefit with VOM cost			$ 680,187

Some changes are visible in the June 23 behavior as well (Figure 3-41):

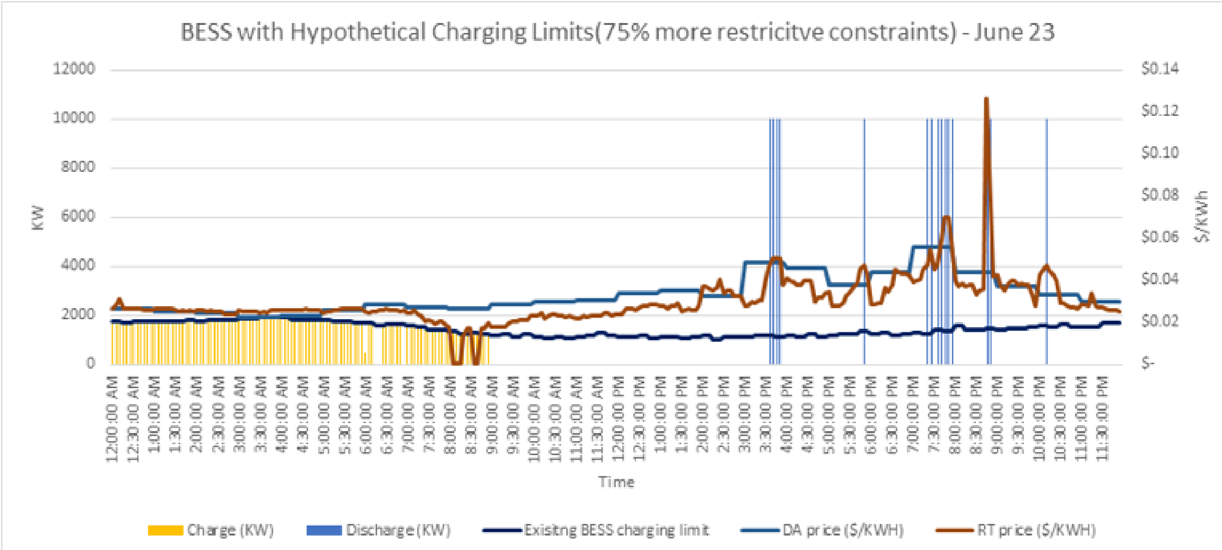


Figure 3-41. June 23 BESS with Hypothetical Charging Limits

This suggests that the cost of modifying a station configuration and providing a separate transformer for BESS interconnection should be compared to the incremental market value that can be realized by removing potential constraints. In this example, the incremental benefits are only $45,000 – how that compares to the incremental cost of bus work and a station transformer needs examination.

3.2.1.4 Shortcomings in this Analysis as a Predictor of Outcomes

It is important to recognize that real world operations cannot realize 100% of the projected best case revenues; there are several reasons for this:

- Market prices going forward in general will not behave identically to historical prices. Changes in the resource mix, weather, and fuel prices as well as possible changes in market products and rules can all affect prices. Most studies nonetheless use historical prices for these analyses, although when forward gas market prices are notably different these can be factored in. Similarly, growth in renewable penetration, plant retirements, etc., can be factored in. This study did not include production costing analysis or future energy price forecasting, and 2016 historical prices are used "as is." While production cost simulations using tools such as Production Costing Tool 1 or Production Costing Tool 2 are routinely used to simulate future hourly prices for energy and ancillaries to value new wind farms or other new resources, they are generally not used to simulate Real Time prices and valuing a BESS under hypothetical future market conditions against RT prices is a challenge.
- There may be additional operational constraints not reflected in the simulation. It would be helpful to understand those and add them to the model if possible;
- When it is necessary to actively participate in the market by making offers, the BESS operator has to determine the price for each market product to use in submitting a bid. This requires the use of a tool such as Generation Management tool (Vendor 22) to forecast DA energy and ancillaries prices and to determine a bidding strategy, as SDG&E does today. BESS which is declared as a generation resource can participate in DA energy and ancillary markets, and in the

RT market. It must make offers in order to do so. BESS located "below the take out point" or on the distribution system can participate passively by responding to DA energy prices – this then affects the Unaccounted For Energy account of SDG&E and the energy cost savings get passed on to SDG&E ratepayers. In order to participate in RT and ancillaries markets, distributed BESS seeking stacked applications will have to be active market participants with the same work required in developing daily bidding strategies. Thus the stacked applications revenue calculations are somewhat hypothetical today. When a rule based bidding strategy is determined (as might be the case for distributed storage) then this can be simulated and evaluated using the same approach as in the theoretically optimal analysis.

- As more storage enters the market in California, it can be expected that market prices will be impacted and that the ISO market products and rules may adapt to storage penetration.
- As more capacity is allocated for regulation service, the ability to achieve best case results improves. A BESS that is offering regulation service as a price taker will realize near-optimal revenues as it is not necessary to use price forecasts to determine when to schedule energy or which energy market to schedule in.

3.2.2 Application of Energy Storage for Demand Management in Commercial Buildings

The objective of this use case was to investigate application of Energy Storage Systems, ESS, for demand management in commercial building. A key assumption is that the commercial building under investigation would require energy storage to serve building load during grid outages – in a microgrid application.

Feasibility Analysis Tool 1 was used to model and optimize energy storage system along with other microgrid components. The analysis was performed by running a benchmark case using both assumed and realistic data, and by evaluating the microgrid model and the associated software tool (Feasibility Analysis Tool 1) from different technical aspects such as: input data, control settings, usability, analyzability, result generation, comparison and reporting.

3.2.2.1 General Description of Feasibility Analysis Tool 1

Feasibility Analysis Tool 1 for optimization and decision analysis for hybrid renewable microgrids including Energy Storage Systems. Feasibility Analysis Tool 1 can be utilized to size project components from a single building or household to a region both with the main grid connected and separated from it – in "islanded" mode. Feasibility Analysis Tool 1 provides solution of best reliable and more economical combination of renewable energy sources versus grid expansion option.

Feasibility Analysis Tool 1 is capable of combining multiple energy and storage sources, such as wind with solar photovoltaics and batteries and offers optimized decision analysis based on both financially and complex engineering feasibility solutions.

3.2.2.2 Approach

The approach was to find applications for, and optimize the size of, the ESS based on the demand and PV generation profile for a commercial building. During the course of this study, we also evaluated the Feasibility Analysis Tool 1 software capabilities

3.2.2.3 System parameters

Feasibility Analysis Tool 1 utilizes a wide range of data for a specific project including geographical location of project, historical time series data for weather, electrical components and economic data of project and its components, etc.

In this section, we briefly explain what is required to model a sample project including a load (building demand), grid (utility), solar photovoltaic and energy storage systems.

Figure 3-42 shows the single line of the benchmark case along with its geographical location which Feasibility Analysis Tool 1 uses to download historical data for weather including solar irradiance, wind and temperature from available resources (such as NREL or NASA).

This study was applied on a commercial building as a benchmark. The study goal was to design and size PV/ESS system components to supply demand during any grid outages, as well as optimizing the electricity bill during normal operation for more economic supply.

Figure 3-42. Single Line of Benchmark Study and its Geographical Location

3.2.2.3.1 Load Data

The building demand for an entire year (2016) was applied as a time-series data with an hour resolution to the Feasibility Analysis Tool 1 load data. The average daily kWh consumption for this load is 725 kWh/day with average annual load of 30.21 kW and peak load of 105.6 kW, which occurred at 9/26/2016 at 5 PM. Annual load profile and statistical information are shown in Figure 3-43.

For multi-year analysis, a load increase of 0.5% annually was considered for the building demand.

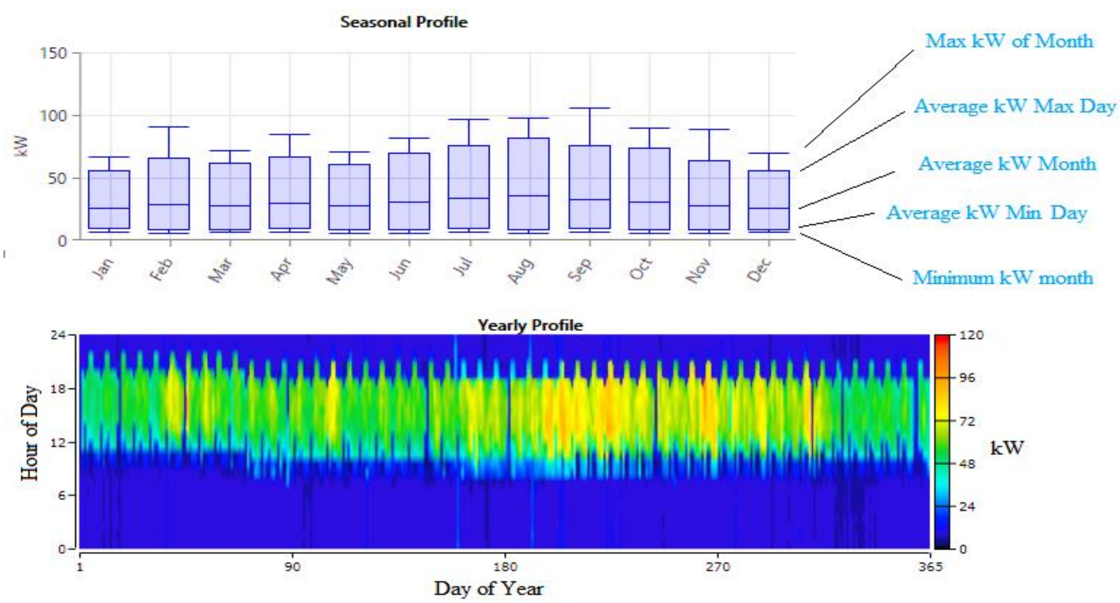


Figure 3-43. Load Annual Demand Data

3.2.2.3.2 Grid Data

The grid can utilize different rate structure (Time of Use - TOU) including Simple Rates, Real Time Rates, and Scheduled Rates. Based on the utility rate structure, the Scheduled Rates were used by defining 6 categories of TOU as shown in Table 3-21 below.

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Table 3-21. Scheduled Rates for Utility

Rate Category	Price $/kWh	Weekday Hours	Weekends Hours	Controls applied under this rate period
Summer On-Peak	0.1276	11 AM to 6 PM	N/A	Prohibited any battery charging Prohibited any grid sales
Summer Semi-Peak	0.1178	6 AM to 11 AM 6 PM to 10 PM	N/A	Prohibited any battery charging and discharging Prohibited any grid sales
Summer Off-Peak	0.0870	10 PM to 6 AM	All Day	Prohibited any battery discharging Prohibited any grid sales
Winter On-Peak	0.1157	5 PM to 8 PM	N/A	Prohibited any battery charging Prohibited any grid sales
Winter Semi-Peak	0.1001	6 AM to 5 PM 8 PM to 10 PM	N/A	Prohibited any battery charging and discharging Prohibited any grid sales
Winter Off-Peak	0.0787	10 PM to 6 AM	All Day	Prohibited any battery discharging Prohibited any grid sales

In addition, the demand rate was defined based on the utility TOU rate as shown in Table 3-22.

Table 3-22. Demand Rates for Utility

Rate Category	Demand $/kW/month	Weekday Hours	Weekends Hours
Summer On-Peak Demand	45.64	11 AM to 6 PM	N/A
Winter On-Peak Demand	32.08	5 PM to 8 PM	N/A
Non-Coincident Demand (non-peak)	24.51	Rest	All Day

For the project lifetime (assumed 30 years), a multi-year analysis was applied by assuming the energy prices will increase 0.5% annually. No emission data was considered.

It was also assumed that the building could experience up to three outages per year with repair time of eight hours as a worst case scenario. These outage assumptions were made for demonstration purposes, the actual circuit reliability was extremely good (SAIDI < 1 minute).

Also, net purchased capacity for the building was calculated annually, considering a maximum monthly purchase capacity of 150 kW.

3.2.2.3.3 Solar Data

Solar DNI (Direct Normal Irradiance) data was captured from a local weather station and was applied to Feasibility Analysis Tool 1. It has 15 minute time resolution with 5.05 kWh/m2/day annual average. Solar GHI (Global Horizontal Irradiance) was downloaded from "National Renewable Energy Lab" resource data by Feasibility Analysis Tool 1 for the location of study. Its annual average is 5 kWh/m2/day.

3.2.2.3.4 PV/Inverter Data

The PV system was treated as a generic, roof-mount type with the following parameters:

- Capital Cost: 2300 $/kW
- Replacement Cost (after 20 years): 1750 $/kW
- Operation and Maintenance Cost: 37 $/kW
- Lifetime: 20 years
- Derating Factor: 80%
- Ground Reflectance: 20%

Other aspects for the model were: No tracking system, default slope and azimuth, and no temperature effect.

For multi-year study, PV degradation of 1% per year was considered. For optimization purpose, a search space of 0 to 100 kW with 10 kW steps was applied.

3.2.2.3.5 Energy Storage Data

The BESS was configured as follows:

- Nominal Capacity: 210 kWh, 553 Ah
- Roundtrip Efficiency: 88%
- Maximum Charge Current: 131 A
- Maximum Discharge Current: 131 A
- Capital Cost: 450 $/kWh
- Replacement Cost (after 10 years): 350 $/kWh
- Operation and Maintenance Cost: 13.5 $/kWh
- Lifetime: 10 years
- Initial State of Charge: 80%
- Minimum State of Charge: 5%

For optimization, a search space with maximum 7 battery strings was considered.

3.2.2.3.6 DC/AC Converter (Battery Charger/Discharger)

A generic model of a power converter with the following parameters was used:

- Nominal Capacity: 150 kW
- Capital Cost: 500 $/kW
- Replacement Cost: 350 $/kW
- Operation and Maintenance Cost: 15 $/kW
- Inverter Lifetime: 12 years
- Inverter Efficiency: 98%
- Rectifier Efficiency: 92%

3.2.2.3.7 Project Settings

The project lifetime was considered to be 30 years. Therefore, all the economic aspects and cost calculations were based on multi-year analysis. If the lifetime of any piece of equipment was less than 30 years, it had to be replaced.

Below are additional economic factors applied in the analysis:

- Discount Rate: 7.79%
- Inflation Rate: 2.90%
- System fixed O&M cost annual increase: 0.5%/year

3.2.2.4 Energy Storage Control Strategy

There are two control approaches in Feasibility Analysis Tool 1 for optimization of an ESS: Load Following (LF), and Cycle Charging (CC). This section provides an explanation of each approach and distinctive features of these two approaches.

3.2.2.4.1 Load Following (LF) Approach

The load following strategy is a dispatch strategy whereby whenever a generator/utility operates, it produces only enough power to meet the primary load. Charging the storage bank or serving the deferrable load are left to the renewable power sources and are lower-priority objectives in this approach. Under the load following strategy, Feasibility Analysis Tool 1 dispatches the system's controllable power sources (generators, grid, storage bank) so as to serve the primary loads at the least total cost in each time step, while satisfying the operating reserve requirement.

3.2.2.4.2 Cycle Charging (CC) Approach

The cycle charging strategy is a dispatch strategy whereby whenever a generator needs to operate to serve the primary load, it operates at full output power. Surplus electrical production goes toward the lower-priority objectives such as serving the deferrable load and charging the storage bank. When using the cycle charging strategy, Feasibility Analysis Tool 1 dispatches the controllable power sources (generators, storage bank and grid) for each time step of the simulation in a two-step process:

- Step1; selecting the optimal combination of power sources to serve the primary load, while satisfying the operating reserve requirement. To accomplish this, Feasibility Analysis Tool 1 calculates the fixed and marginal cost of each dispatchable power source. This step is identical to the load-following strategy (LF).
- Step2; Feasibility Analysis Tool 1 ramps up the output of each generator/utility in that optimal combination to its rated capacity. If a set point state of charge is applied to the cycle charging strategy, then when the storage state of charge is below the set point and the storage was not discharging in the previous time step, controller will avoid discharging the storage in this time step. A generator/utility will likely be called upon to serve the primary load and produce excess electricity to charge the storage bank. So, once the system starts charging the storage bank, it continues to do so until it reaches the set point state of charge.

For this benchmark study, the Cycle Charge approach is applicable to charge the ESS bank during the lower electricity rate hours of simulation. Therefore, this approach is recommended for this kind of ESS applications and hence we used the approach with considering a 90% State of Charge set point.

Figure 3-44 shows how the Cycle Charging approach controls ESS charging/discharging for a sample week based on the grid power price for the optimum solution. The case shown is for the weekend days of October 27th and 28th, when the electricity price is low and constant all day long; no ESS was utilized and the demand was met by shared PV and Utility powers.

During the weekdays, the utility rate structure were slightly higher during semi-peak and further on-peak hours. Therefore, ESS was discharged during those hours and was started to be charged back during off-peak hours to reach its target SOC of 90% at the end of the day.

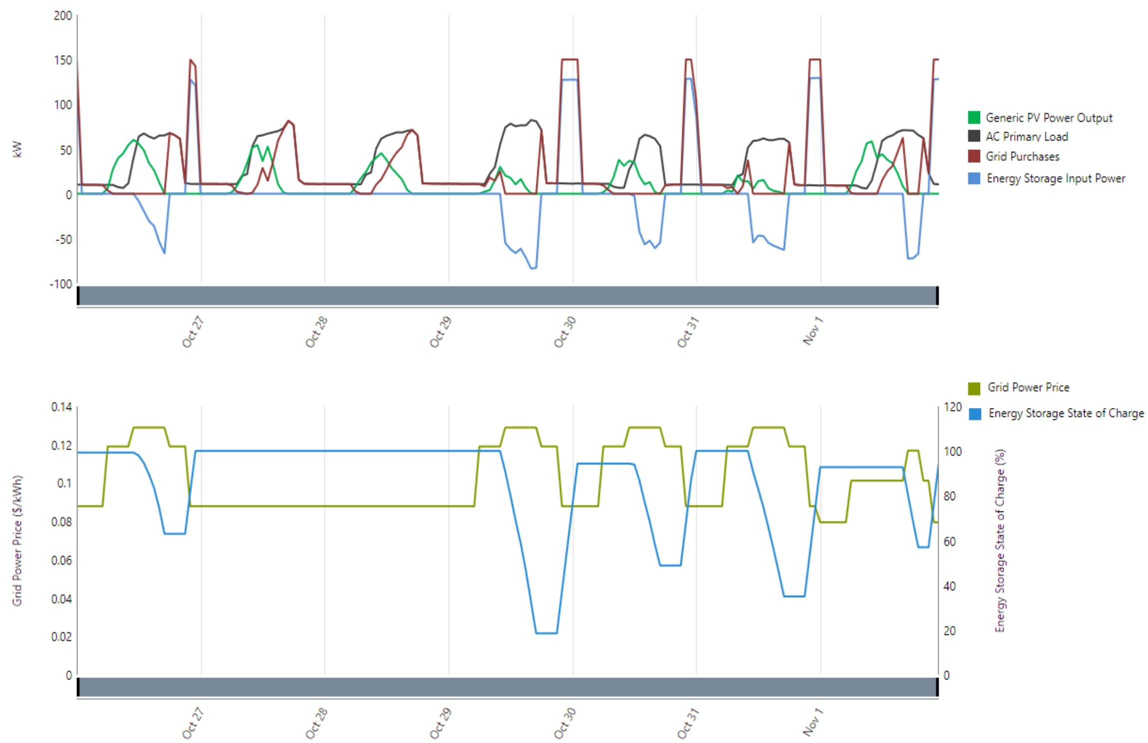


Figure 3-44 - Sample week simulation results for the sample case

Figure 3-45 shows how a simulated grid outage happening in Oct 1 is handled with both PV and ESS. The ESS is discharged deeply in the day when utility is disconnected from the building.

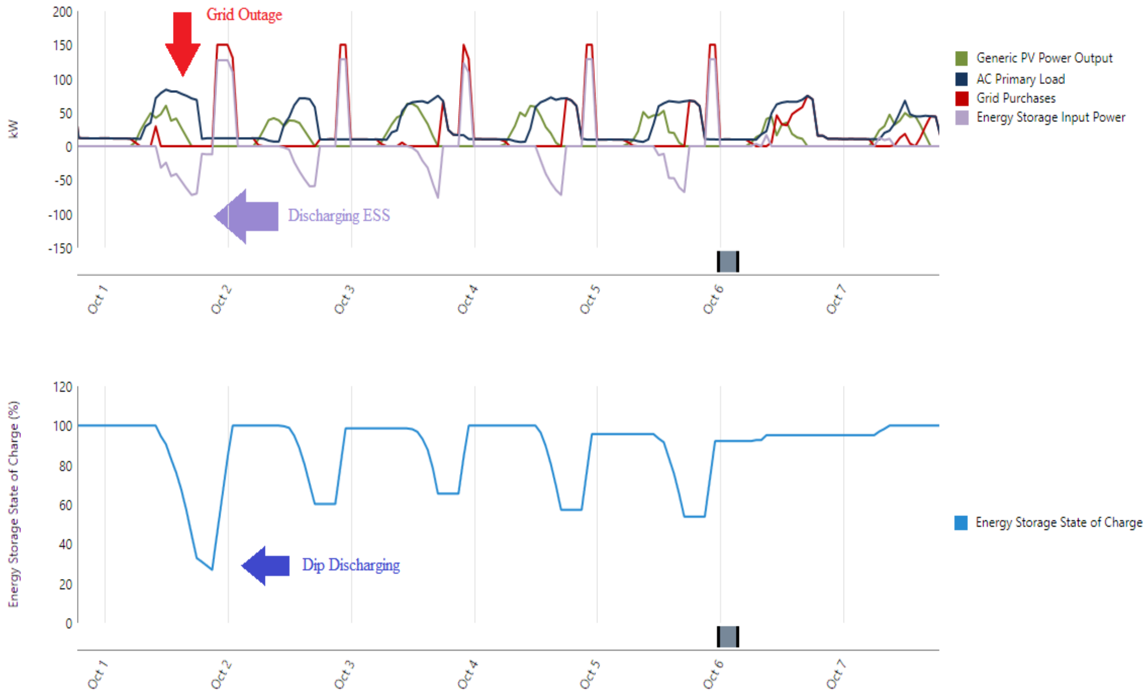


Figure 3-45. Outage simulation results on October 1st

3.2.2.5 System Sizing

Based on the preset model and data, the sizes of the PV and ESS units were evaluated for optimization. The PV system was considered to be between 0 to 100 kW with 10 kW steps. The energy storage was sized in increments of 210 kWh, with a maximum size of 7 strings (i.e. 7×210=1470 kWh).

Executing the optimization and after running both LF and CC approaches for the entire year, data was calculated for every scenario of ESS and PV size combination inside their search space.

The objective function is based on optimizing Total Net Present Cost (NPC) for the entire project life time. A solution would be provided if the least NPC as an optimized PV/ESS combination can be identified.

Table 3-23 provides the overall results for all feasible solutions which are ranked from top to bottom based on their economic value. Based on this table, the optimization solution is to utilize 70 kW of Photovoltaic along with 3×210=630 kWh of Energy Storage system. This solution has the lowest NPC of $2,156,915 and the lowest Cost of Energy (COE) of 0.479 $/kWh.

Table 3-23. Feasible optimization results

PV (kW)	ESS # Strings (×210 kWh)	AC/DC (kW)	Cost/COE ($)	Cost/NPC ($)	Cost/Operating cost ($)	Cost/Initial capital ($)	Cost/O&M ($)	System/Ren Frac (%)	PV/Capital Cost ($)	PV/Production (kWh)	ESS/Autonomy (hr)	ESS/Annual Throughput (kWh)	Grid/Energy Purchased (kWh)
70	3	150	0.479	$2,156,915	$103,526	$519,500	$87,537	23%	$161,000	106,188	18	89,589	218,434
80	3	150	0.480	$2,162,409	$102,420	$542,500	$85,615	27%	$184,000	121,358	18	84,869	208,083
60	3	150	0.481	$2,165,899	$105,549	$496,500	$90,553	19%	$138,000	91,019	18	94,513	229,630
90	3	150	0.483	$2,176,865	$101,879	$565,500	$84,618	30%	$207,000	136,528	18	80,468	198,795
50	3	150	0.486	$2,190,207	$108,540	$473,500	$94,545	15%	$115,000	75,849	18	99,581	241,587
100	3	150	0.487	$2,192,340	$101,404	$588,500	$83,549	33%	$230,000	151,698	18	76,470	190,668
40	3	150	0.498	$2,242,160	$113,279	$450,500	$100,346	11%	$92,000	60,679	18	104,604	254,296
30	4	150	0.500	$2,249,516	$109,223	$522,000	$88,821	6%	$69,000	45,509	25	114,000	269,067
20	4	150	0.501	$2,255,580	$111,061	$499,000	$91,254	0%	$46,000	30,340	25	120,478	284,080
40	4	150	0.503	$2,264,246	$108,700	$545,000	$87,872	11%	$92,000	60,679	25	107,734	254,905
50	4	150	0.505	$2,273,981	$107,862	$568,000	$86,748	15%	$115,000	75,849	25	101,827	241,825
10	4	150	0.507	$2,282,112	$114,192	$476,000	$94,956	0%	$23,000	15,170	25	127,202	300,050
100	2	150	0.507	$2,285,063	$113,241	$494,000	$102,025	33%	$230,000	151,698	12	70,620	189,752
60	4	150	0.508	$2,288,893	$107,350	$591,000	$85,909	19%	$138,000	91,019	25	96,199	229,588
90	2	150	0.510	$2,294,387	$115,285	$471,000	$104,162	31%	$207,000	136,528	12	73,640	197,519
80	2	150	0.512	$2,304,718	$117,392	$448,000	$106,389	28%	$184,000	121,358	12	76,808	206,415
50	2	150	0.512	$2,304,903	$121,766	$379,000	$111,574	16%	$115,000	75,849	12	85,564	238,220
70	4	150	0.512	$2,305,387	$106,939	$614,000	$85,189	23%	$161,000	106,188	25	90,860	218,183
70	2	150	0.512	$2,305,621	$118,903	$425,000	$108,158	24%	$161,000	106,188	12	80,008	216,313
60	2	150	0.513	$2,306,983	$120,443	$402,000	$109,870	20%	$138,000	91,019	12	82,968	226,945
30	3	150	0.515	$2,319,497	$119,622	$427,500	$107,189	6%	$69,000	45,509	18	109,715	268,017
80	4	150	0.515	$2,319,900	$106,402	$637,000	$84,237	27%	$184,000	121,358	25	85,846	207,601
	4	150	0.516	$2,324,181	$118,306	$453,000	$99,812	0%			25	133,710	316,743

PV (kW)	ESS # Strings (×210 kWh)	AC/DC (kW)	Cost/COE ($)	Cost/NPC ($)	Cost/Operating cost ($)	Cost/Initial capital ($)	Cost/O&M ($)	System/Ren Frac (%)	PV/Capital Cost ($)	PV/Production (kWh)	ESS/Autonomy (hr)	ESS/Annual Throughput (kWh)	Grid/Energy Purchased (kWh)
90	4	150	0.520	$2,340,513	$106,251	$660,000	$83,751	30%	$207,000	136,528	25	81,222	198,245
100	4	150	0.524	$2,361,348	$106,114	$683,000	$83,235	33%	$230,000	151,698	25	77,099	190,034
20	3	150	0.528	$2,378,206	$124,789	$404,500	$111,519	1%	$46,000	30,340	18	114,670	282,591
	5	150	0.538	$2,422,067	$118,520	$547,500	$94,014	0%			31	135,811	317,252
10	3	150	0.539	$2,425,303	$129,220	$381,500	$116,058	0%	$23,000	15,170	18	119,032	297,967
10	5	150	0.539	$2,429,212	$117,518	$570,500	$92,629	0%	$23,000	15,170	31	128,363	300,328
20	5	150	0.542	$2,438,818	$116,671	$593,500	$91,461	0%	$46,000	30,340	31	121,205	284,222
30	5	150	0.544	$2,449,995	$115,924	$616,500	$90,393	6%	$69,000	45,509	31	114,416	269,090
40	5	150	0.547	$2,462,503	$115,260	$639,500	$89,406	11%	$92,000	60,679	31	108,008	254,795
	3	150	0.549	$2,470,610	$133,539	$358,500	$120,248	0%			18	123,015	314,031
50	5	150	0.550	$2,476,621	$114,699	$662,500	$88,523	15%	$115,000	75,849	31	102,011	241,544
60	5	150	0.553	$2,492,061	$114,221	$685,500	$87,722	20%	$138,000	91,019	31	96,337	229,137
70	5	150	0.557	$2,508,847	$113,828	$708,500	$87,004	24%	$161,000	106,188	31	90,970	217,580
80	5	150	0.561	$2,527,018	$113,522	$731,500	$86,370	27%	$184,000	121,358	31	85,927	206,893
90	5	150	0.566	$2,547,051	$113,335	$754,500	$85,849	31%	$207,000	136,528	31	81,305	197,416
100	5	150	0.570	$2,568,900	$113,262	$777,500	$85,442	34%	$230,000	151,698	31	77,178	189,145
	6	150	0.585	$2,635,578	$126,045	$642,000	$96,717	0%			37	135,984	317,298
10	6	150	0.587	$2,643,796	$125,110	$665,000	$95,464	0%	$23,000	15,170	37	128,428	300,343
20	6	150	0.589	$2,653,393	$124,263	$688,000	$94,295	0%	$46,000	30,340	37	121,223	284,219
30	6	150	0.592	$2,664,501	$123,511	$711,000	$93,223	6%	$69,000	45,509	37	114,421	269,037
40	6	150	0.594	$2,676,927	$122,843	$734,000	$92,231	11%	$92,000	60,679	37	108,010	254,678
50	6	150	0.598	$2,690,891	$122,271	$757,000	$91,338	15%	$115,000	75,849	37	102,011	241,316
60	6	150	0.601	$2,706,139	$121,781	$780,000	$90,525	20%	$138,000	91,019	37	96,337	228,764
70	6	150	0.605	$2,722,652	$121,371	$803,000	$89,792	24%	$161,000	106,188	37	90,970	217,032

PV (kW)	ESS # Strings (x210 kWh)	AC/DC (kW)	Cost/COE ($)	Cost/NPC ($)	Cost/Operating cost ($)	Cost/Initial capital ($)	Cost/O&M ($)	System/Ren Frac (%)	PV/Capital Cost ($)	PV/Production (kWh)	ESS/Autonomy (hr)	ESS/Annual Throughput (kWh)	Grid/Energy Purchased (kWh)
80	6	150	0.609	$2,740,603	$121,052	$826,000	$89,144	28%	$184,000	121,358	37	85,964	206,211
90	6	150	0.613	$2,760,464	$120,853	$849,000	$88,612	31%	$207,000	136,528	37	81,969	196,757
100	6	150	0.618	$2,782,074	$120,765	$872,000	$88,192	34%	$230,000	151,698	37	79,791	188,829
	7	150	0.633	$2,850,158	$133,637	$736,500	$99,552	0%			43	135,996	317,299
10	7	150	0.635	$2,858,379	$132,703	$759,500	$98,299	0%	$23,000	15,170	43	128,428	300,345
20	7	150	0.637	$2,867,970	$131,855	$782,500	$97,130	0%	$46,000	30,340	43	121,223	284,214
30	7	150	0.639	$2,879,047	$131,101	$805,500	$96,056	6%	$69,000	45,509	43	114,421	269,012
40	7	150	0.642	$2,891,401	$130,428	$828,500	$95,060	11%	$92,000	60,679	43	108,010	254,603
50	7	150	0.645	$2,905,238	$129,849	$851,500	$94,158	15%	$115,000	75,849	43	102,011	241,143
60	7	150	0.648	$2,920,345	$129,350	$874,500	$93,335	20%	$138,000	91,019	43	96,337	228,479
70	7	150	0.652	$2,936,656	$128,927	$897,500	$92,590	24%	$161,000	106,188	43	90,970	216,608
80	7	150	0.656	$2,954,431	$128,596	$920,500	$91,932	28%	$184,000	121,358	43	86,550	205,815
90	7	150	0.660	$2,973,955	$128,376	$943,500	$91,380	31%	$207,000	136,528	43	84,524	196,631
100	7	150	0.665	$2,995,395	$128,278	$966,500	$90,947	34%	$230,000	151,698	43	84,354	189,057

The data tabulated above can also be shown graphically in a "heat map" which simplifies the assessment of the various options. Figure 3-46 below shows the "Total Net Present Cost" of the project based on PV size and ESS string numbers – with the dark-blue color representing the lowest cost. If the installed PV size was planned to be more than 40 kW then three battery strings (i.e. 3×210 kWh) would be a reasonable solution (see left box on the picture). But, for a wider range of PV installation, the best ESS size would be 4 battery strings (i.e. 4×210 kWh) as shown with the right box.

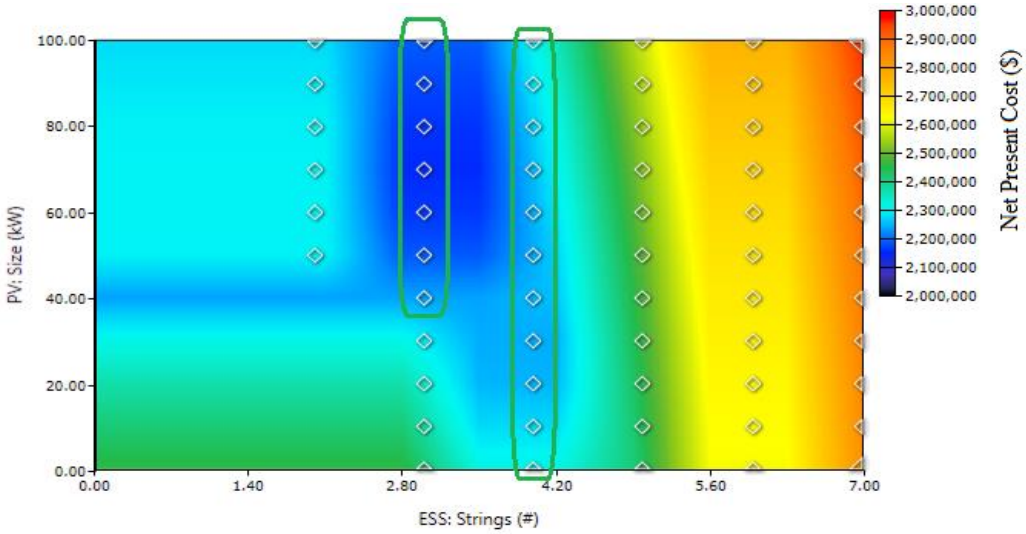


Figure 3-46. Net present cost of project based on PV/ESS size

In the Capacity Shortage percentage plot in Figure 3-47 below, the darker portion of the plot represents no capacity shortage and, hence, a feasible solution. By evaluating the plot, it is evident that at least three ESS strings are required to avoid power shortage during outages. Based on the PV size, 3 battery strings (for PV size more than 50 kW) and 4 battery strings (all PV ranges from 0 to 100 kW) would be adequate.

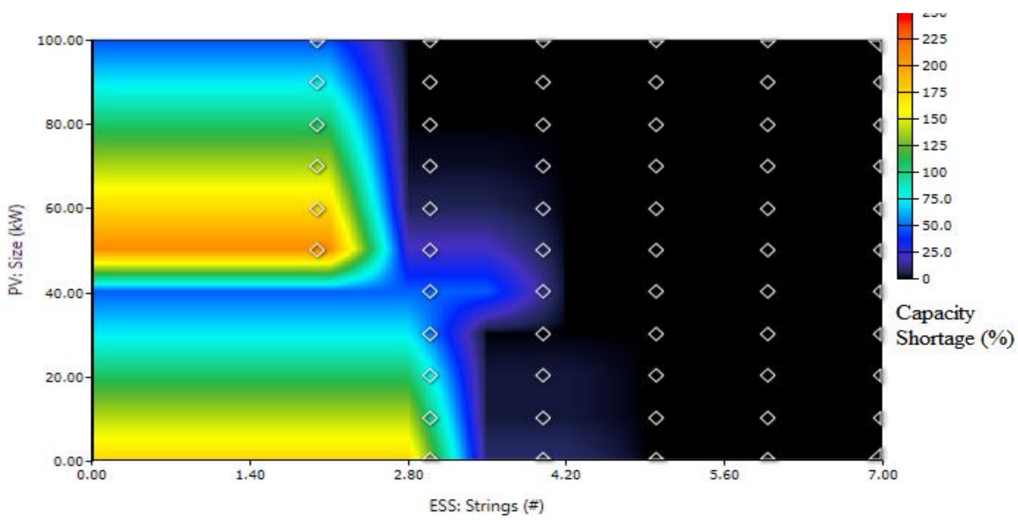


Figure 3-47. Capacity Shortage (%) based on PV/ESS size

3.2.2.6 Financial analysis

For the optimized case with PV=70 kW and ESS=3×210=630 kWh, a summary of the results are presented below. Figure 3-48 and Table 3-24 show the cost summary based on Capital, Operating, Replacement, and salvage cost as net-present values.

Table 3-25 shows the same costs annualized.

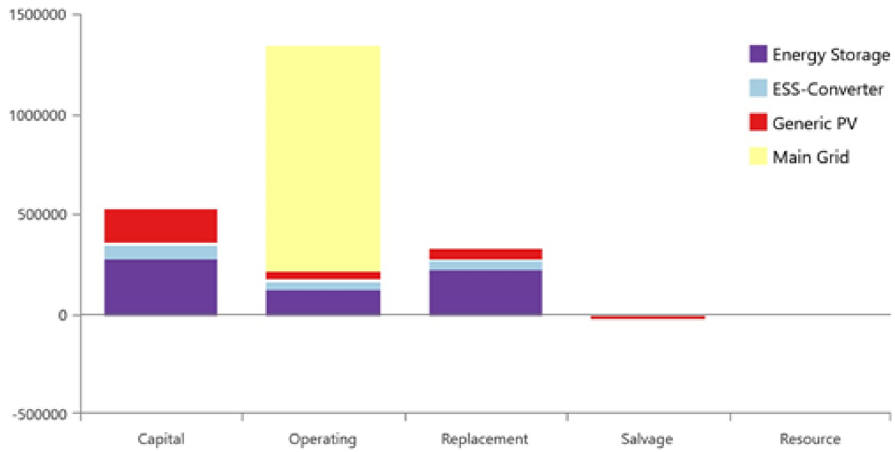


Figure 3-48. Cost Summary for Energy Resources under different cost categories

Table 3-24. Net Present Costs under different cost categories

Name	Capital	Operating	Replacement	Salvage	Resource	Total
Energy Storage	$283,500	$134,519	$225,730	$0.00	$0.00	$643,749
ESS-Converter	$75,000	$35,587	$47,303	-$6,520	$0.00	$151,370
Generic PV	$161,000	$40,965	$48,403	-$15,213	$0.00	$235,155
Grid serving	$0.00	$1.13M	$0.00	$0.00	$0.00	$1.13M
Total System	$519,500	$1.34M	$321,437	-$21,733	$0.00	$2.16M

Table 3-25. Annualized Costs under different cost categories

Name	Capital	Operating	Replacement	Salvage	Resource	Total
Energy Storage	$17,924	$8,505	$14,272	$0.00	$0.00	$40,701
ESS-Converter	$4,742	$2,250	$2,991	-$412.22	$0.00	$9,570
Generic PV	$10,179	$2,590	$3,060	-$961.85	$0.00	$14,868
Grid Serving	$0.00	$71,232	$0.00	$0.00	$0.00	$71,232
Total System	$32,846	$84,577	$20,323	-$1,374	$0.00	$136,372

Figure 3-49 show 30-years cash flow for the different cost categories.

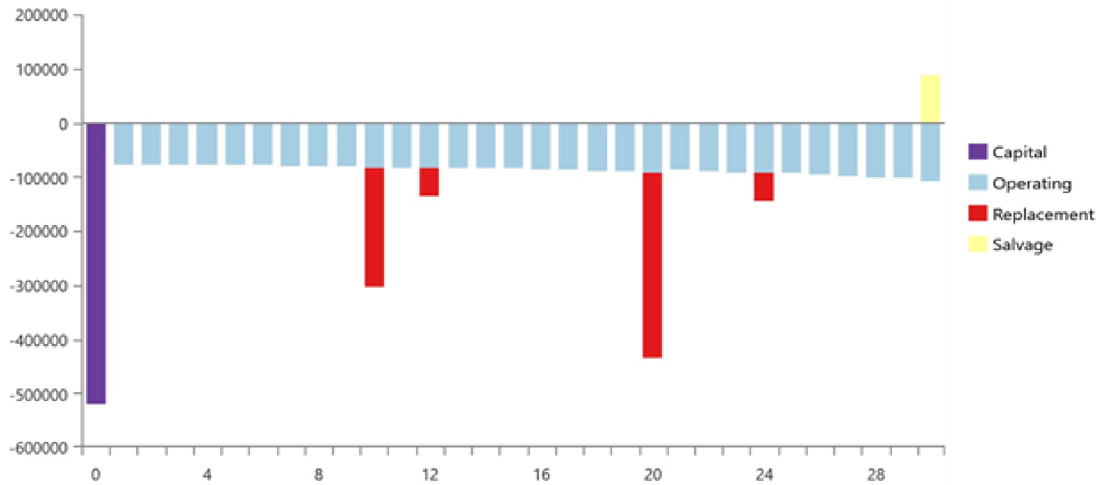


Figure 3-49. 30-Year Cash Flow under different cost categories

Utilizing the ESS system decreases the total utility bill payment from $1.612 million to $ 1.13 million in 30-years compared to the case where PV and Utility-supply are the sole resource of energy. Table 3-26 shows the project economic metrics with the payback of 5.43 years.

Table 3-26. Project Economic Metrics (Comparing with and without ESS cases, both cases including PV)

Net Present Value ($)	$313,695
Annual saving ($/yr)	$27,314
Return on investment (%)	%19
Internal rate of return (%)	%18.5
Simple payback (yr)	5.43 Year
Discounted payback (yr)	6.39 Year

3.2.2.7 Observations

The use case investigated the viability of using a hybrid system comprising of PV and ESS units to optimize electricity usage and also to serve building load during grid outages. Feasibility Analysis Tool 1 was used to generate results for a large search space incorporating mixed combination of various sizes for PV system and ESS units. The software proved adept at analyzing and optimizing both PV and ESS in a commercial building application.

Other observations include:

- Design and sizing of the PV and ESS are very sensitive to load data. The accuracy of this data and its year-to-year growth therefore plays a critical role in the optimization procedure.
- In a similar fashion, accurate weather time-series data, as well as carefully selected economic data will affect the outcome of the optimized solution.
- Grid outages require the BESS to be sized to carry the load for the duration of the outage. Feasibility Analysis Tool 1 defines outages in a random manner for the specified duration which does not always coincide with peak demand hours. It is therefore necessary to perform several sensitivity analysis to size the ESS during a worst case outage scenario with maximum load.

3.2.3 Hybrid ESS Applications for Residential and Commercial Buildings

3.2.3.1 Introduction

This use case outlines utilization of hybrid PV with battery energy storage systems in residential and commercial buildings. The objective of the use case is to investigate the economic benefit of offsetting some or all of the time of use peak energy and/or demand consumption from a battery with the intention of lowering the customer's bill to a meaningful extent. The battery would be charged using available surplus onsite PV electricity together with supplementary electricity drawn from the grid during off-peak periods. In other words, this case evaluates the merits of charging a battery using "free" solar PV power along with off peak grid-supplied power, and discharging the battery to offset higher priced energy and demand charges.

3.2.3.2 Properties Assessed

For the benchmark purpose (hypothetically), four building locations were selected as representative residential / commercial buildings for the study.

- Residential building 1 (RB1) is a multi-family building complex in Chula Vista, CA. At approximately 50,000 square foot space, the multi-family home sits on a 2.1 acre lot. From on-line information, it appears to include 5 (plus a small) buildings and maybe 60-80 apartments in total. It has 2 laundry rooms and swimming pools. There is potential to install a solar shade parking structure to generate PV. The peak annual demand for the building complex is 29.6 kW (hourly data) and the average hourly demand was 13 kW. The hybrid system evaluated for this building included 20 kW PV with a 60 kWh battery. The solar PV panels could potentially be installed on the rooftop or outdoor parking structure. This system was also evaluated using 2 potential time of use electric pricing schedules.
- Residential building 2 (RB2) is a 7,200 square foot multi-family building with 9 units in Chula Vista, CA. It has a flat roof, a peak annual demand of 14.4 kW and an average hourly demand of 4.4 kW. The hybrid system evaluated included a 10 kW rooftop solar PV system with 25 kWh of battery storage. This system was also evaluated using 2 potential time of use electric pricing schedules.
- Commercial Building 1 (CB1) is 21,000 square foot building in El Cajon, CA. It operates seven days per week, generally from mornings to late evenings and visitors are members of the general public. The building has an existing 45 kW rooftop PV system. Not factoring the contribution from the PV system, the building is estimated to have a peak annual demand of 113.5 kW and an average demand of 44.3 kW. A potential commercial sector time of use rate schedule factoring energy and demand was used for the evaluation. The hybrid system cases evaluated would use the existing PV system with 100 kWh or 150 kWh batteries.
- Commercial Building 2 (CB2) is a 25,000 square foot building in San Diego, CA. Visited by the general public, it is open seven days per week and operates from morning to early evening. The building has

a peak annual demand of 105 kW and average demand of 30.4 kW. It was evaluated for a 36 kW solar PV system with options for 90 kWh and 180 kWh battery storage capacities. A potential commercial sector time of use rate schedule factoring energy and demand was used for the evaluation.

Table 3-27 illustrates the combination of properties and systems that were assessed for the analysis.

Table 3-27. Representative residential and commercial buildings for the Hybrid ESS analysis

Address	PV Only	PV + Battery	Residential TOU-DR 2 Rate	Residential TOU-DR 3 Rate	Commercial Rate >20 kW
Residential building 1 (RB1)	✓	✓	✓	✓	
Residential Building 2 (RB2)	✓	✓	✓	✓	
Commercial building 1 (CB1)	✓	✓			✓
Commercial building 2 (CB2)	✓	✓			✓

3.2.3.3 Approach

Figure 3-50 illustrates the method used to determine the cost to benefit of adding a battery to a solar PV system for a given building. The modeling was performed using the widely available System Advisor Model (SAM) software developed by Vendor 1.

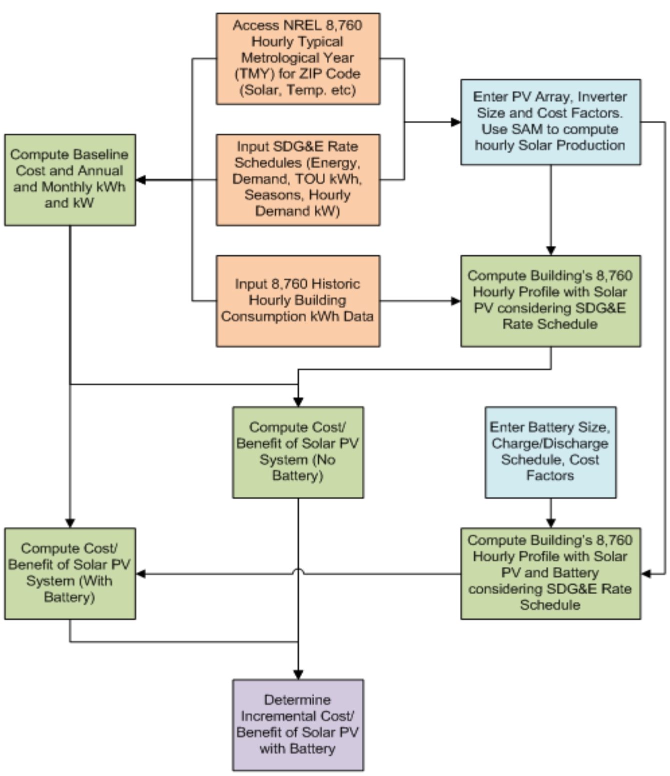


Figure 3-50. Flowchart of the proposed study approach for hybrid system evaluation

The key inputs to the SAM include:

1. 8,760 hourly historic energy consumption for the specific building,
2. The associated electricity Tariff schedule, and
3. The Typical Meteorological Year data for the building's ZIP code.

The model was used to compute the building's Baseline energy cost. Next, a solar PV Array and Inverter (building roof-top installation) were added to the model, and the cost and benefit of this system, together with the impact on the Baseline electricity bill were calculated. In the third step, a battery energy storage system was added to the model.

The battery model included the battery's degradation factors, and a schedule for charging and discharging based on the variations in the electricity prices according to the time-of-use Tariff schedule. The model was set to charge the battery using off-peak time (lowest electricity price) and PV-generated power, and to discharge to offset peak kWh and peak kW demand charges. The incremental cost and benefit of the adding the battery was then computed.

PV system sizes were selected based on performing an assessment of the available roof-top area for installing typical roof-top PV systems. The PVWatts Calculator tool from NREL[4] was used for this purpose.

Battery ESS sizing was performed according to the analysis of the historical hourly demand of the buildings and the peak load.

3.2.3.4 SAM Software

The System Advisor Model (SAM) is a performance and financial model developed by NREL. It performs hour-by-hour calculations of a power system's electric output, generating a set of 8,760 hourly values that represent the system's electricity production over a single year.

The current version of the SAM includes performance models for Photovoltaic systems together with Battery storage for photovoltaic systems.

SAM accepts inputs for the technical specifications and performance degradation associated with solar PV modules, inverters and batteries.

A variety of residential retail electricity rates and commercial retail and power purchase agreement rates can be incorporated into SAM's financial model. The financial model calculates financial metrics for various kinds of power projects based on a project's cash flows over a specified analysis period. The financial model uses the system's electrical output calculated by the performance model to calculate the series of annual cash flows.

[4] http://pvwatts.nrel.gov/

3.2.3.5 Weather Data

Figure 3-51 shows 8,760 hourly Typical Meteorological Year (TMY) data for a selected ZIP code. The SAM software uses this solar insolation and ambient temperature (among other factors) to compute the solar PV production.

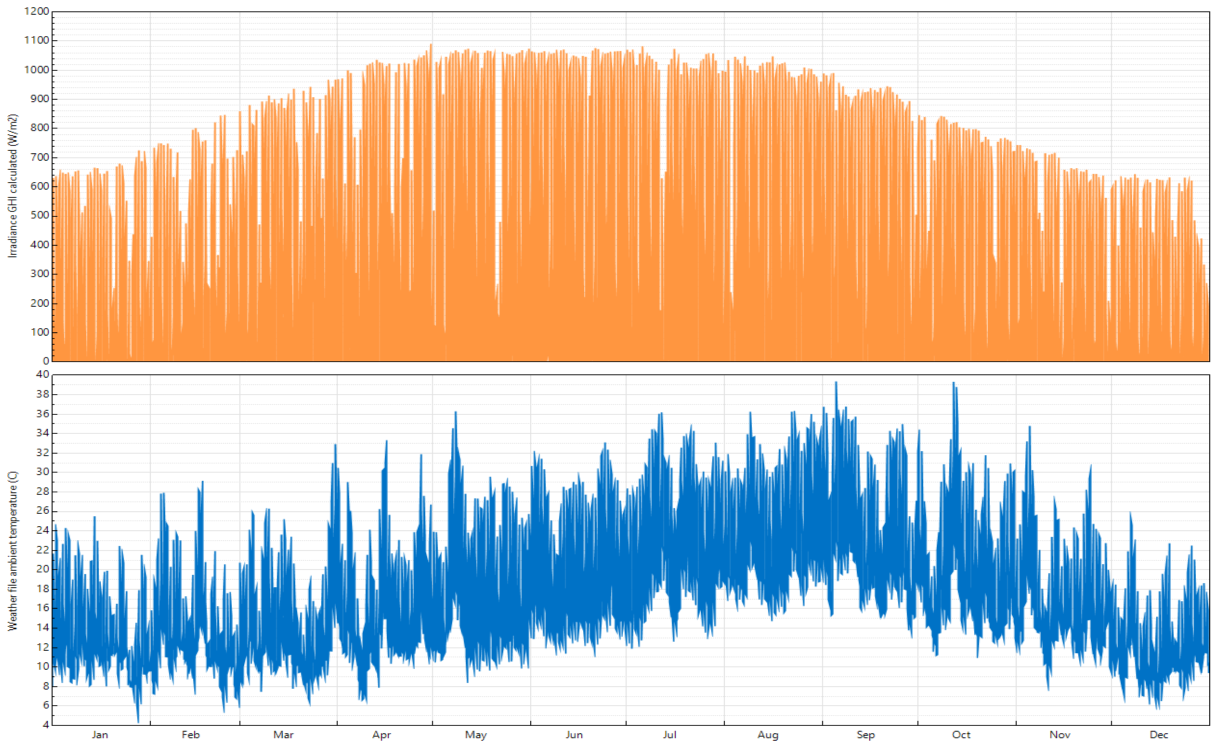


Figure 3-51. Solar radiation and temperature profiles for a selected location in the study area

3.2.3.6 Electricity Rate Data

In "Resolution E-4848. Adoption of San Diego Gas & Electric Company's residential default time-of-use pricing pilot pursuant to Decision 15- 07-001" two residential time of use rates TOU-DR2 and TOU-DR3 (referred to DR2 and DR3 in this report) were filed with the Public Utilities Commission of the State of California. [5] (Note that rates are out for decision and the analysis are only for assessment purpose).

As an example, for TOU-DR2 (see Figure 3-52) the weekday and weekend time blocks are shown. Proposed time of use rates included:

- Summer On-peak
- Summer Off-Peak
- Summer Super Off-Peak
- Winter On-peak
- Winter Off-Peak

[5] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M183/K383/183383395.PDF (Accessed 20 September 2017)

- Winter Super Off-Peak

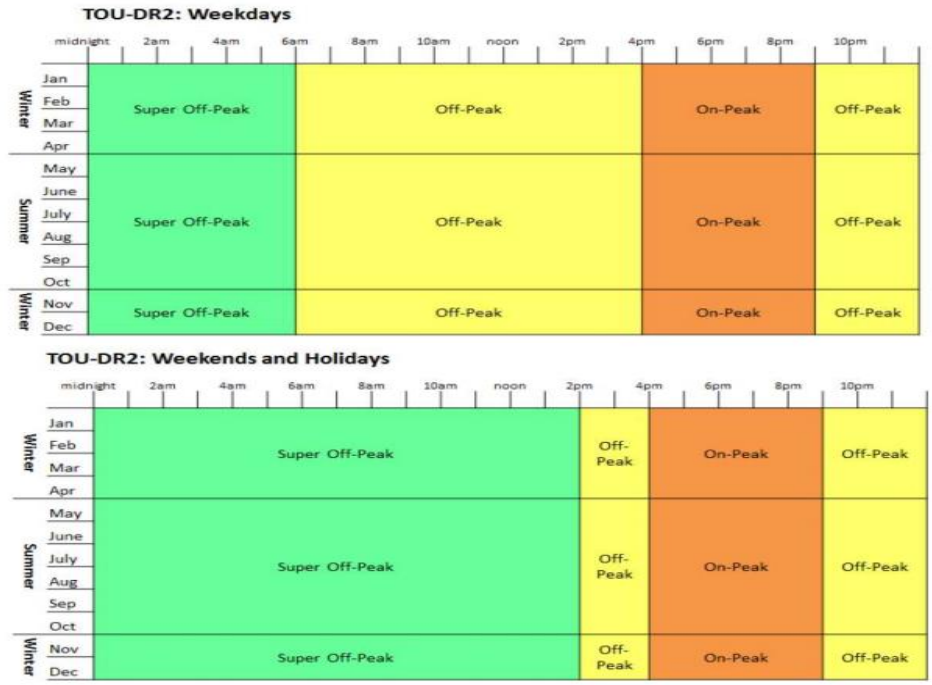


Figure 3-52. Proposed TOU-DR2 Time of Use Hourly Schedule

This is typically for 6 time blocks illustrated by 1 to 6 in the Table 3-28.

Table 3-28. TOU-DR2 Time of Use Rate Designations

Time of Use Period for TOU-DR2	Numeric Designation in SAM Model
Summer On-peak	1
Summer Off-Peak	2
Summer Super Off-Peak	3
Winter On-peak	4
Winter Off-Peak	5
Winter Super Off-Peak	6

The SAM model accepts a numeric designator for entering time of use energy (kWh) and demand (kW) data as illustrated in Figure 3-53. In order to provide more precise instructions for the SAM model, 2 additional placeholder rates (7 and 8) were created to properly control the battery discharge hours, where rate for 8 is identical to 6 and rate for 7 is identical to 3.

Weekday

	12am	1am	2am	3am	4am	5am	6am	7am	8am	9am	10am	11am	12pm	1pm	2pm	3pm	4pm	5pm	6pm	7pm	8pm	9pm	10pm	11pm
Jan	6	6	6	6	6	6	5	5	5	5	5	5	5	5	5	5	4	4	4	4	4	8	8	8
Feb	6	6	6	6	6	6	5	5	5	5	5	5	5	5	5	5	4	4	4	4	4	8	8	8
Mar	6	6	6	6	6	6	5	5	5	5	5	5	5	5	5	5	4	4	4	4	4	8	8	8
Apr	3	3	3	3	3	3	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	7	7	7
May	3	3	3	3	3	3	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	7	7	7
Jun	3	3	3	3	3	3	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	7	7	7
Jul	3	3	3	3	3	3	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	7	7	7
Aug	3	3	3	3	3	3	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	7	7	7
Sep	3	3	3	3	3	3	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	7	7	7
Oct	6	6	6	6	6	6	5	5	5	5	5	5	5	5	5	5	4	4	4	4	4	8	8	8
Nov	6	6	6	6	6	6	5	5	5	5	5	5	5	5	5	5	4	4	4	4	4	8	8	8
Dec	6	6	6	6	6	6	5	5	5	5	5	5	5	5	5	5	4	4	4	4	4	8	8	8

Weekend

	12am	1am	2am	3am	4am	5am	6am	7am	8am	9am	10am	11am	12pm	1pm	2pm	3pm	4pm	5pm	6pm	7pm	8pm	9pm	10pm	11pm
Jan	6	6	6	6	6	6	6	6	6	6	6	6	6	6	5	5	4	4	4	4	4	8	8	8
Feb	6	6	6	6	6	6	6	6	6	6	6	6	6	6	5	5	4	4	4	4	4	8	8	8
Mar	6	6	6	6	6	6	6	6	6	6	6	6	6	6	5	5	4	4	4	4	4	8	8	8
Apr	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2	1	1	1	1	1	7	7	7
May	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2	1	1	1	1	1	7	7	7
Jun	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2	1	1	1	1	1	7	7	7
Jul	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2	1	1	1	1	1	7	7	7
Aug	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2	1	1	1	1	1	7	7	7
Sep	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2	1	1	1	1	1	7	7	7
Oct	6	6	6	6	6	6	6	6	6	6	6	6	6	6	5	5	4	4	4	4	4	8	8	8
Nov	6	6	6	6	6	6	6	6	6	6	6	6	6	6	5	5	4	4	4	4	4	8	8	8
Dec	6	6	6	6	6	6	6	6	6	6	6	6	6	6	5	5	4	4	4	4	4	8	8	8

Figure 3-53. Daily and monthly electricity rate schedules

For the commercial buildings, proposed time of use rates[6] (see Table 3-29) for peak kW demand charges were input in the model, and the operating strategy was to use the battery to reduce the peak demand charges. Table 3-30 presents the commercial time of use and demand price.

Table 3-29. Commercial time of use and demand rates

Rate Category	Price $/kWh	Weekday Hours	Weekends Hours
Summer On-Peak	0.1276	11 AM to 6 PM	N/A
Summer Semi-Peak	0.1178	6 AM to 11 AM 6 PM to 10 PM	N/A
Summer Off-Peak	0.0870	10 PM to 6 AM	All Day
Winter On-Peak	0.1157	5 PM to 8 PM	N/A
Winter Semi-Peak	0.1001	6 AM to 5 PM 8 PM to 10 PM	N/A
Winter Off-Peak	0.0787	10 PM to 6 AM	All Day

[6] docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M195/K586/195586830.PDF

Table 3-30. Commercial time of use and demand price

Rate Category	Demand $/kW/month	Weekday Hours	Weekends Hours
Summer On-Peak Demand	45.64	11 AM to 6 PM	N/A
Winter On-Peak Demand	32.08	5 PM to 8 PM	N/A
Non-Coincident Demand	24.51	Rest	All Day

3.2.3.7 Battery Impact

The SAM model was set to dispatch during periods of highest energy and/or demand prices and to recharge using off-peak and/or minimum demand price electricity supplemented by the surplus power produced by the solar PV system.

Figure 3-54 shows the annual hourly impact of using the solar PV with battery combination on a sample commercial building (CB1) used for the analysis. The upper portion shows the historic hourly energy consumption of the building. The lower graph uses a different scale, and shows the charging of the battery (from lower cost hours plus available excess solar PV), and discharge of the battery during peak hours.

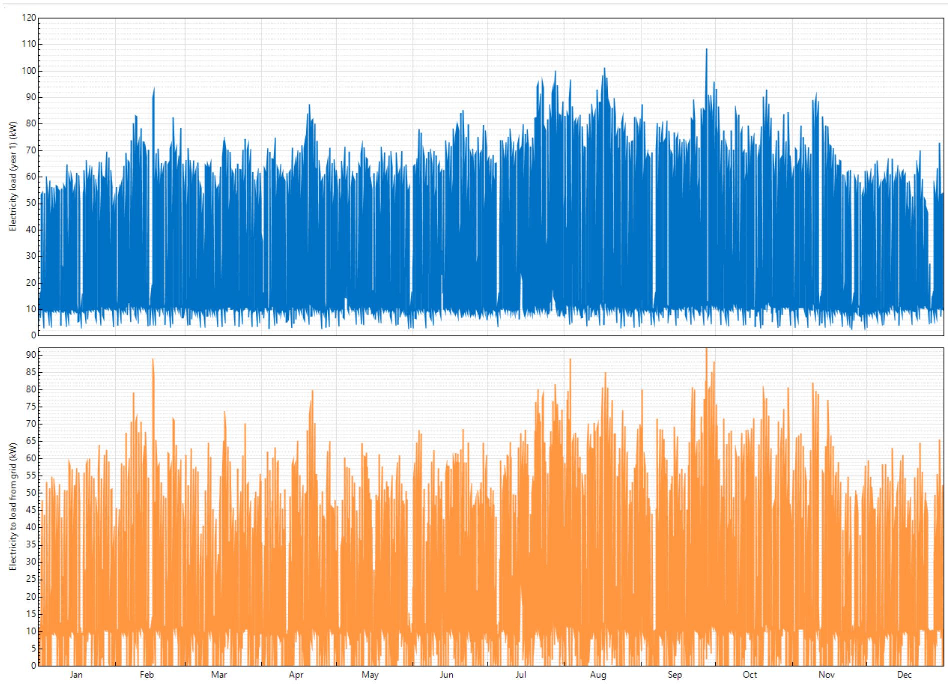


Figure 3-54. Annual View of Hourly impact of using battery

The impact of the battery can be seen in Figure 3-55 where according to the proposed Commercial time of use rates, the battery discharges during the 3 peak winter weekday hours, and recharges during the day.

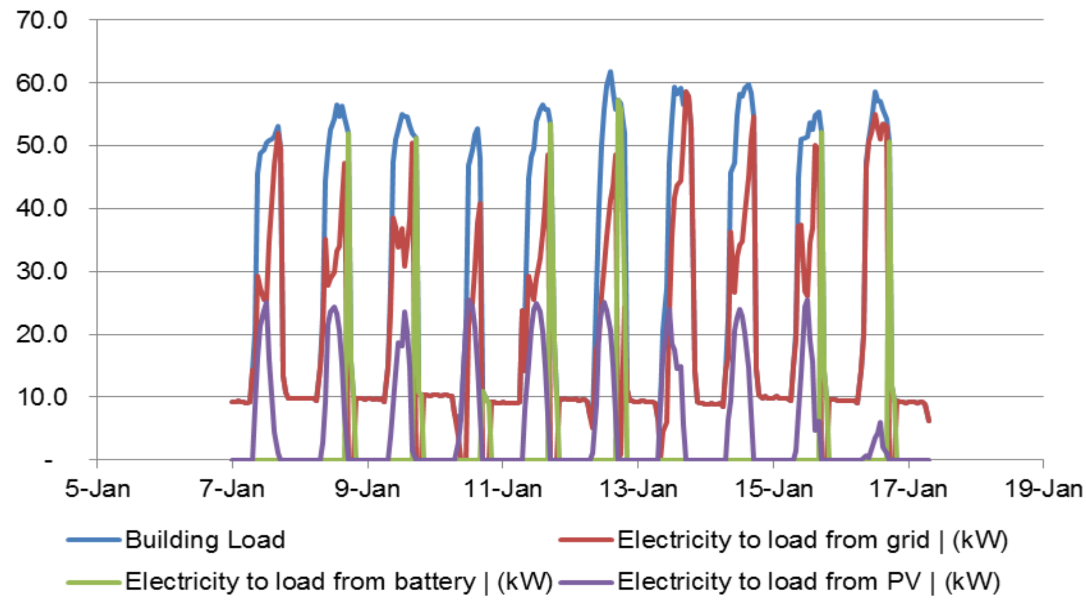


Figure 3-55. Hourly impact of using battery

Figure 3-56 shows the impact of adding a 180 kWh battery and 36 kW PV array to building CB1. The battery is charged using off peak/low demand power and surplus solar PV generated power. It can be seen that approximately 10% of the building's power consumption flows through the battery.

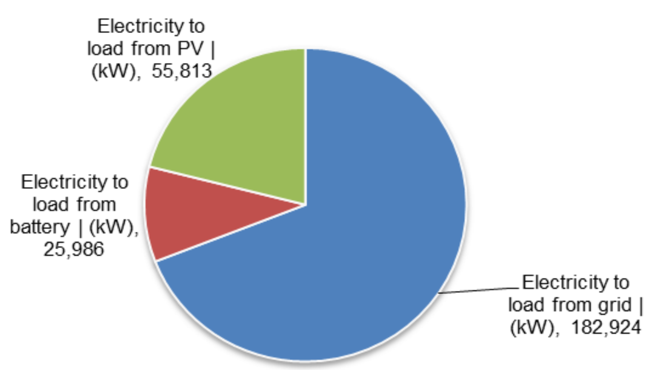


Figure 3-56. Flow of Annual Power to Building CB1 (Total 246,723 kWh)

3.2.3.8 Battery Degradation Factor

The default SAM battery degradation factors were revised to reflect actual experience with batteries of this nature and are presented in Figure 3-57.

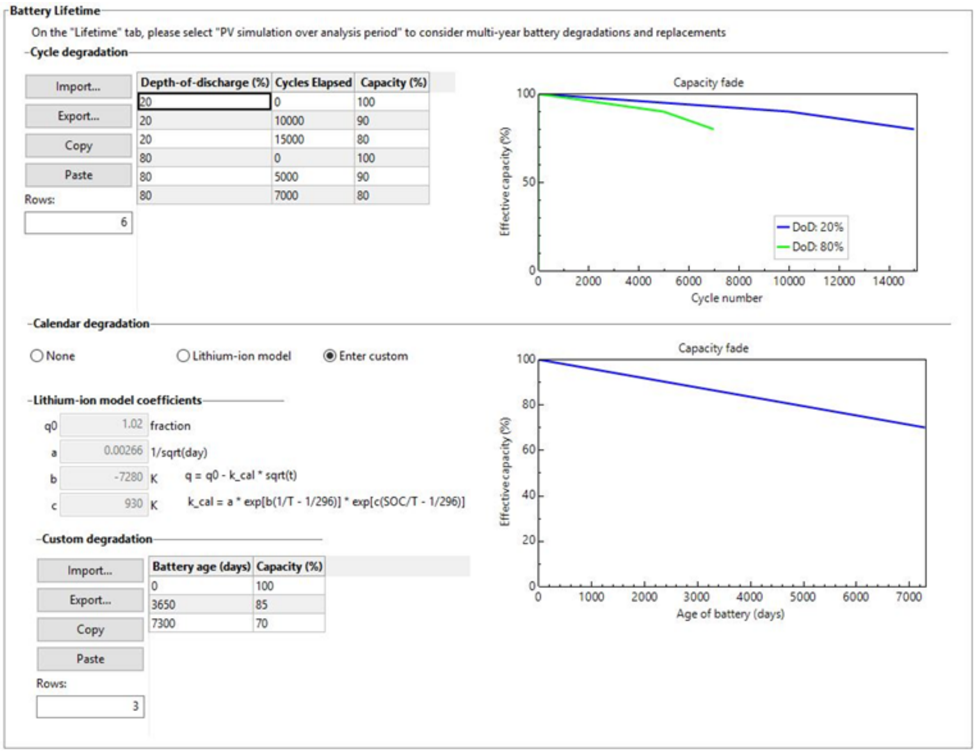


Figure 3-57. Assumption for battery degradation model

3.2.3.9 Economic Parameters Used in the SAM Model

Other economic parameters used for the model included:

- Discount Rate: 7.79%
- Inflation Rate: 2.9%
- Solar PV Modules : $0.64 per W DC
- Inverter: $0.21 per W DC
- DC to AC Ratio : From 1.15 to 1.20
- Battery Bank: $420 per kWh DC
- Balance of System: $0.36 per W DC
- Installation Labor: $0.30 per W DC
- Installer Margin and Overhead: 25%
- Permitting and Environmental Studies: $0.10 per W DC

3.2.3.10 Results Summary

Table 3-31 shows the average electricity rate per kWh expected to be paid by a customer for 100%, grid supplied, Grid supplied with Supplementary PV, and Grid supplied with PV and Battery.

- Four cases (Case 1 to Case 4) are analyzed for representative multi-family low-income residential housings in the context of rates TOU-DR2 and TOU-DR3.

- Four representative cases (Cases 5 to Case 8) incorporated commercial buildings designated as cool zones in disadvantage communities. The cases used the Commercial time of use rate but varied the battery size.

Table 3-31. Average Cost per kWh with Time of Use Rates and Supplementary PV and Battery

CASE	Applicable Rate	100% Grid Supplied ($/kWh)	Grid Supplied with PV ($/kWh)	Grid Supplied with PV and Battery ($/kWh)
Case 1 RB1	TOU-DR2	$ 0.2901	$ 0.2112	$ 0.2016
Case 2 RB1	TOU-DR3	$ 0.2939	$ 0.2149	$ 0.2095
Case 3 RB2	TOU-DR2	$ 0.2885	$ 0.2059	$ 0.1972
Case 4 RB3	TOU-DR3	$ 0.2929	$ 0.2101	$ 0.2058
Case 5 CB1	Commercial	$ 0.3413	$ 0.2952	$ 0.2789
Case 6 CB1	Commercial	$ 0.3413	$ 0.2952	$ 0.2828
Case 7 CB2	Commercial	$ 0.2926	$ 0.2461	$ 0.2446
Case 8 CB2	Commercial	$ 0.2926	$ 0.2461	$ 0.2437

Table 3-32 shows 6 cases of the cost and benefit and payback of the Solar PV systems. The first four cases are for Residential buildings RB1 and RB2 where the time of use rates are varied from TOU-DR2 and TOU-DR3. These rates have marginal impact on the solar PV simple payback which is 3.5-3.6 years. The last two cases are for buildings CB1 and CB2 and use the Commercial time of use with demand rate. The solar PV Systems are expected to have paybacks in the 4.3 to 5.2 year range.

Table 3-32. Cost and Benefit of Solar PV

Rate	PV Array Size (kW)	Study Locations (Hypothetical)	Annual Building Load kWh	Gross Electricity to Load from Grid (kWh)	Electricity to Load from PV	Electricity bill without system (year 1)	Net savings with PV Only (year 1)	PV Only Payback period
RB1 DR2	20	Chula Vista	114,279	83,592	30,687	$ 33,154	$ 9,020	3.5 years
RB1 DR3	20	Chula Vista	114,279	83,592	30,687	$ 33,589	$ 9,035	3.5 years
RB2 DR2	10	Chula Vista	47,477	35,190	12,287	$ 13,697	$ 3,921	3.6 years
RB2 DR3	10	Chula Vista	47,477	35,190	12,287	$ 13,905	$ 3,928	3.6 years
CB1 Commercial	36	San Diego	264,723	208,916	55,807	$ 90,339	$ 12,199	5.2 years
CB2 Commercial	45	El Cajon	388,696	311,690	77,005	$ 113,715	$ 18,075	4.3 years

As shown in Table 3-32, it was noted that the incremental payback for the additional battery-based hybrid ESS equipment is more than 10 years. In the case of residential customers who do not pay for peak kW demand, the cost savings are expected to be in the 1.5-3% range and the incremental payback for the battery storage is uneconomic. For commercial time of use customers with peak energy and demand charges, the benefit of adding energy storage was between 0.5- 4.8 %. In general terms the incremental cost of adding additional battery storage greater than the expected energy and demand bill savings of avoiding peak energy at the rate schedules assessed.

Table 3-33 summarizes the results of analysis for the eight cases.

Table 3-33. Summary of the Hybrid ESS benefit/cost analysis

Case and Building	Electricity Rate Schedule	PV Array Size (kW)	Battery Size (kWh)	Location	Baseline Electric Bill (No PV or Battery)	Baseline Average Cost per kWh	Incremental Bill Savings with Battery	Percent Savings of Baseline Bill	Incremental Cost to Add Battery	Simple Payback for Battery (years)
Case 1 RB1	TOU-DR2	20	60	Chula Vista	$33,154	$0.29	$1,099	3.30%	$25,850	23.5
Case 2 RB1	TOU-DR3	20	60	Chula Vista	$33,589	$0.29	$609	1.80%	$25,850	42.4
Case 3 RB2	TOU-DR2	10	25	Chula Vista	$13,697	$0.29	$414	3.00%	$10,750	26
Case 4 RB3	TOU-DR3	10	25	Chula Vista	$13,905	$0.29	$205	1.50%	$10,750	52.4
Case 5 CB1	Commercial	36	180	San Diego	$90,339	$0.34	$4,311	4.80%	$77,551	18
Case 6 CB1	Commercial	36	90	San Diego	$90,339	$0.34	$3,278	3.60%	$38,800	11.8
Case 7 CB2	Commercial	45	150	El Cajon	$113,715	$0.29	$577	0.50%	$64,650	112
Case 8 CB2	Commercial	45	100	El Cajon	$113,715	$0.29	$919	0.80%	$43,100	46.9

3.2.3.11 Conclusions

The only way that a Hybrid ESS can be cost effective is to utilize ESS for other stacked applications such as Reliability Enhancement during grid outage situations (for scheduled utility maintenances and/or as a result of natural disasters). The added value of customer load serving during grid outages, or any possibility to aggregate smaller size ESS units and incorporate them in wholesale market applications (energy market or ancillary services) can bring in additional revenue to make the case cost effective.

It was however shown that addition of PV to each of these building can effectively reduce the electricity cost and the return on investment under either Time of Use structure (DR2 or DR3) will be tangible enough.

4 KEY FINDINGS AND RECOMMENDATIONS

This section describes findings of the project and provides a series of unique implementation considerations particular to the tools and methodologies for analysis of ESS applications. Based on the findings and observations, several recommendations are also provided to close the gap in study tools and analytical methodologies that will enhance the project planning, application selection and operation.

4.1 Findings and Recommendations Related to Assessment of Existing Applications and Tools

Utilities all have standards for distribution planning and engineering/design in place. Beginning with IEEE and ANSI standards, they develop specific practices and design approaches based on their historical practices and on the particulars of their service territory such as customer base and energy costs. The analyses and business case presentations build on these practices and are tailored to meet the needs of the local regulatory bodies as well. These standards and practices may include (but are hardly limited to):

- Philosophies on issues such as lateral fusing, employment and implementation of N-1 contingencies, including with no ties to other sources from engineering and design practices,
- Implementation of distribution automation technologies,
- Standards for monitoring and control,
- Protection setting standards,
- Design standards such as minimum levels of reserve capacity/maximum loading,
- Design standards such as normal levels of capacity upgrade to achieve,
- Selection of particular vendor products (both software tools and apparatus) to be used in design engineering.

Energy storage for utility applications in today environment will challenge all these practices.

Presently, there are no ANSI or IEEE standards that would specifically define the ESS controls and expected performance characteristics for T&D applications such as capacity upgrade deferral, distribution reliability enhancement, and/or renewable resource impact mitigation (i.e. smoothing). Available standards address type testing, device level performance and interconnection testing of ESS sites [5], [6]. New IEEE working groups, as part of IEEE 1547 and IEE 2030 family of standards are established to focus on characterization and parameterization of storage models and interaction with area electric power system (EPS). Expectation is that the new effort will aim to standardize the application definition and control aspects.

Standardization of practices in construction practices, communication infrastructure, operating practices, and safety is needed for ESS, as for all other power system infrastructure.

The software tools used in planning and design are in general not capable of optimizing storage system design and in some cases cannot analyze the effectiveness of a particular asset and design.

Some storage technologies pose life cycle risks that are difficult to assess in business cases. Degradation models are a subject of ongoing R&D.

Storage siting and local permitting are site specific and need to be addressed on a project by project basis. Federal, state, and local standards for the safe siting, installation, inspection, and maintenance of storage are being addressed across the industry.

4.1.1 Gap analysis and needs

In the production costing space there are at least two tools (Production Costing Tool 2 and Production Costing Tool 3) that can model storage adequately for annual production costing and price impact studies.

With storage as a price taker there are several tools available that can assess storage in the ISO DA, HA, RT, and ancillary markets. One of them, Cost Calculation Tool 6, is focused only on the California market, but has superior detail in the modeling of that market.

Whether the issues of integer variable creation in Cost Calculation Tool 6 and others performing product co-optimization are that significant with technologies other than Li-Ion will have to be determined over time. If the particular tool can accept alternate solvers or if the performance impacts are tolerable, additional integer variables should not be a major issue in the future. However, introducing constraints for stacked applications may make this kind of approximation more problematic.

In the distribution space, the consultant tools can analyze time series of load, PV, etc., using external Matlab or Python code and Distribution Planning Tool 6, Distribution Planning Tool 3, or Distribution Planning Tool 4. The Cost Calculation Tool 6 tool requires external distribution circuit analysis to supply it with data.

These tools can also perform stacked applications. One tool was able to demonstrate semi-automated interfaces between the circuit analysis/sizing and the market and applications cost benefits calculations. However, it is again a semi-manual process. These tools in general are suitable for the evaluation of pilot projects and for engineering a limited number of storage projects by personnel that have been trained in or exposed to the methodologies, generally in close contact with the organizations that developed them. They are not as yet suitable for general use in the T&D planning organizations by all staff.

4.1.2 Deployment and operational challenges

In order for storage projects to move from a “pilot” stage to “commercial” the planning and operations processes will have to mature and address all the process/capabilities gaps identified in previous sections. This means that tools and methodologies for planning, engineering, and operations must be coordinated across a given utility such that overall processes can be standardized, and training for all involved staff can be conducted. Additionally, the methodology for developing a business case must be communicated to and accepted by the regulatory bodies so that planning can be conducted consistent with methods and cost benefit thresholds that will meet regulatory approval.

Up till now this report has addressed evaluation methodologies and tool capabilities. Additional planning standards need to be addressed in order for any methodology to succeed. These critically revolve around (a) the question of ‘how much storage is appropriate?” and “how to manage the risks in storage deployment decisions?”

The methodologies for determining storage sizes for a given application have focused on "how much is required?" or determining a minimum size for a given application, and then for assessing stacked applications for that application and particular implementation. This is not the same as addressing "how much is appropriate?" which would take into account uncertainties in future load growth, uncertainties in energy costs, and (especially) uncertainties in storage costs and performance. The latter might well favor more flexible / modular designs capable of accepting incremental additional capacity in the future; might favor mobile storage that can be moved to a new location (at higher initial costs); and might favor "throw away" storage in some instances. None of the tools available today address this question directly; there are not published results of studies that examine more than a few dimensions of these questions. These questions are the next stage in developing planning and operational guidelines for storage.

Because storage technology is developing rapidly, there will possibly be cases of technical failures after a couple year's operations for reasons not anticipated today, and cases where newer technology is superior at lower costs, rendering plans to move older storage to a new location uneconomic. In other words there will be risks associated with a rapid adoption of new technologies. One solution has been that utilities can specify very tight and long duration warranties in order to ensure performance from manufacturers. Manufacturers may respond by pricing large amounts of additional/replacement battery pack modules as a result, greatly increasing initial costs. Different models that share risks may be more cost effective.

Methodologies to assess these risks realistically and account for them are lacking today.

4.1.3 Recommendations

Utilities should develop plans for making the transition from "pilot" or "proof of concept" status to "commercial" status with the following key steps

- Standardize the framework for calculating benefits, avoided costs, and cost benefit analysis of storage including various combinations of stacked applications.
  - Ensure that the framework adopted for a particular utility is consistent with the system engineering and design philosophy of that utility. The framework should take advantage of the state of the art in assessing storage valuation on distribution systems without venturing into R&D territory for problems as yet unaddressed (such as incorporating stochastics into valuations)
  - Obtain regulatory approval for the framework via worked examples and filings
  - The benefits methodology should be integrated with the actual procedures and tools for system operations incorporating storage so that the benefits are realizable in practice
- Identify available methodologies and tools that can perform assessments consistent with the framework, even if manual steps are necessary at the current state of tool development. The appropriate methodologies and tools should be comprehensive enough to incorporate various aspects of ESS applications and deployment environment. In addition, tools should follow and build upon existing distribution planning and operation platform (beyond a single department) to ensure sustainability in the utilization, as well as trust and support in applying them.
  - Identify gaps and forward tool development to close the gaps as part of this step. (see section on evaluation of tools)

- Acquire selected tools and arrange desirable integration steps with company data bases and existing commercial tools in use. This may involve procurements, licensing, or consulting agreements to modify existing tools in various combinations.
- Train staff in the use of the tools and embed the consideration of storage as a routine step in system planning and engineering.
- In parallel develop procedures for system operations incorporating storage and develop tool requirements for system operations. Plan operational system upgrades, procurements, and training to realize these planned tools.

4.2 Findings and Recommendations Related to Methodologies and Tools for Assessment of Future Projects

This section addresses the need to improve methodologies for assessing future projects in the short term, before new tools can be made ready. It describes how best to attack valuing storage projects on the distribution system going forward making use of tools available today. Compared to the processes used in identifying and planning projects in the period immediately after the CPUC mandate for the first year of storage deployment, it will be necessary to have a valid business case as part of planning any project and it will also be “wise” to anticipate changes in the regulatory environment and the CA ISO market rules as possible under the current FERC NOPR on distributed storage in the markets and the current CA ISO stakeholder process on DG and Distributed Storage. This section is written in the context of the evaluation of SDG&E storage projects and planning processes so generalization to other California utilities would require a mapping of their current capabilities and plans to the recommendations. This section also focuses on storage projects on the distribution system – in distribution stations or connected to distribution feeder circuits. It does not address larger storage projects that are transmission connected nor does it discuss behind the meter storage.

4.2.1 Tools and methodologies

California investor-owned utilities are required to file plans for valuing DER as well as to complete and publicize PV hosting capacity analysis on the entire distribution system. New storage projects on the distribution system should be planned in light of these requirements, and ideally storage project identification should include consideration of needs identified in the hosting capacity analysis. Near-term steps that utilities could take include:

- Using demonstrated tools that can assess distribution applications and stacked applications to screen the feeder population and identify potential storage projects to be planned in 2018-2019 against expected or possible conditions over the period 2018-2025. These applications would include:
  - Capacity deferral (station and circuit or centralized and distributed)
  - PV integration
    - Back feed prevention
    - Voltage Control
    - PV smoothing
  - Local Resiliency (distribution microgrid)
- The stacked applications should definitely include Day Ahead (hourly) energy time shifting/arbitrage and should consider Real Time energy and Ancillaries as options depending upon the outcome of the

FERC NOPR and the CA ISO stakeholder process, as these issues greatly affect potential valuations. (and also impact the costs of controls and market participation)

- This screening could be built upon the tools demonstrated and assessed during this project that already have the ability to assess distribution and stacked applications with manual integration of data and steps. The screening would be at most an annual process with updates for particular feeders / stations when conditions changes significantly.
- Given the rapid improvements in storage technology and costs, scenarios should be examined in this screening that reflect better than forecast improvements.
- Following the screening, identified circuits with potential storage applications should be examined in more detail using the methodologies demonstrated in this report to determine engineering requirements and engineering level feasibility of storage projects. In this process, combinations of distribution and stacked applications need to be examined in depth as individual applications may not have favorable cost benefit ratios where combined applications do.
- One of the largest obstacles to performing storage assessment on a given circuit is obtaining time series data for load profiles and for PV production forecast that is “clean” and without missing data and bad data. This is a general issue that affects PV hosting as well, although not the same degree (as 8760 data is not required). But this should be considered a highly desired process – to clean the data – as then all planning functions benefit.
- Another obstacle in the screening process is that detailed engineering cost estimates for avoided cost (circuit and station upgrades) may be unavailable. For initial evaluations, the utility should determine rule of thumb numbers to be used against simple categorizations of feeders (voltage level, load growth, rating vs current peak, length, etc.). Final evaluations will need detailed cost estimates.
- Agreement should be reached internally and ultimately with the CPUC on how to “derate” the estimated stacked applications benefits given the reliance on historical profiles, market prices, and perfect dispatch. This should include an assessment of how realistic projected benefits are given current operations and control room capabilities. Otherwise too optimistic a business case will be developed using unrealizable but theoretically “perfect” benefits
- Plans for DERMS applications should be reviewed in light of the planned use of storage for operations, reliability, and market benefits.
- Because the tools are not “commercial” nor at an easy to use stage, the utilities will have to consider developing a focused team within distribution planning and engineering to conduct screening and studies in this time period, possibly in conjunction with external assistance (ideally from organizations/people experienced with the tools and the problems)

4.2.2 Gaps in commercial tools and industry practices related to technology assessment approaches

Section 5.1.1 identified gaps in the capabilities of tools available today. For planning in the distribution space, the largest gap is the ease of integrating the results of time series simulations with Distribution Planning Tool 4 and external Python code with stacked applications analyses in other external tools offered by consulting firms.

Because SDG&E is standardized on the Distribution Planning Tool 4 distribution planning tool set, plans in the 2017-2019-time frame have to be built around Distribution Planning Tool 4 capabilities and short-term release plans. (Distribution Planning Tool 4 data base porting to other planning tools such as

Distribution Planning Tool 3 and Distribution Planning Tool 6 are also limited, excluding those possibilities for this purpose). Discussions with Distribution Planning Tool 4 about desired enhancements and capabilities to facilitate the integration with external scripts/applications for time series analyses and then exports to other analytical tools should be organized so that planning can be informed about Distribution Planning Tool 4 plans.

Second, the three tools capable of some degree of stacked applications benefits analysis should be examined for adaptations to the FERC NOPR and the CA ISO stakeholder process, as well perhaps as some enhancements to reflect errors in day ahead PV and market price forecasts in the optimization and benefits calculation.

4.2.3 Standardization and regulatory compliance

The CPUC should be informed about issues such as developing standards, standards gaps, and benefits assessment methodologies. While immediate regulatory objections may be unlikely, indications of possible objections might be identified in time to develop adjustments and accommodations.

Utilities should prepare a list of existing and developing standards that it will require storage proposals to comply with for use in RFPs, and revisit this periodically as standards evolve. This list should not be limited to electrical performance and interconnection but should include siting, safety, and environmental issues.

An analysis should be performed of the cost-risk-reward tradeoff between requiring strict and long-term warranties versus more relaxed terms and internal risk acceptance. RFPs may be modified to reflect multiple options for longer term warranty and maintenance agreements so that the risk-reward can be evaluated. These issues should be revisited frequently as technology and vendor terms evolve. To the maximum extent possible, procurements should drive towards standardized storage configurations, sizes, and interconnections. Procurements for higher volumes of storage at one time will result in more favorable pricing and warranty terms and this is a key factor.

4.2.4 ESS Projects Responsibilities

SDG&E ESS projects have been for both transmission system support and also for distribution system support, with both processes having differences and similarities. Recent Transmission system ESS support projects have been driven by the CPUC-directed Expedited Storage Projects (ESP) as a result of the Aliso Canyon incident. The effort was primarily managed by the Advanced Technology section including RFPs and installation contracts. These projects were identified quickly and installed amazingly well especially considering the short time frame.

ESS is relatively new to the industry and many issues continue to be resolved. It is beneficial to acknowledge the need to learn. As multiple projects move forward these lessons learned are clarified and lead to proper improved standards. For the distribution system, although the planning approach of a project is similar to traditional projects as shown in Figure 4-1, the action needed is typically unlike traditional electric utility infrastructure projects. It is important early in the process to ensure responsibilities are clear through the various stages of the project. It is best to start the collaboration early.

Figure 4-1. Planning approach

4.2.4.1 Potential Project Implementation

Distribution system identification of ESS applications would normally be done by groups responsible for circuit capacity, voltage, or reliability planning. As part of that process the size, capacity, and operational parameters would be identified and used as the project moves forward through specifications, procurement, commissioning, and operations. The planning phase is not just distribution/reliability planning but also the planning required to achieve the expected benefits. Requirements include operations controls, ESS system performance (including related metrics), communications & controls, and site requirements.

4.2.4.2 Project Evaluation- Benefit/Cost

A key challenge for ESS implementation has been the overall cost effectiveness. Current applications across the industry were at times installed as demonstration projects to learn about the overall process and economics. As ESS applications move forward, the economics have become more critical in the project applications. Economic analyses needs to determine the overall value and preliminary project approval. Besides typical capacity deferral benefits, with ESS the markets value should be included. The Market value should be integrated with the constraints to achieve the distribution system needs.

4.2.4.3 Project Approval

When traditional projects seek approval, they are normally approved based on the significance of the issue, estimated cost, the evaluation that has occurred, and available budget. For ESS projects, the approval process is similar although for large systems, regulatory approval may be required. For projects requiring regulatory approval, that may not occur until after the RFP process.

The approval process needs to include the additional evaluation towards achieving applicable regulatory ESS mandates. In addition, the methodologies and tools provided in this report can enhance the benefit cost analysis, especially the inclusion of related market benefits

4.2.4.4 Project Implementation

Procurement

The ESS Procurement process is relatively new with a much lower number of installations as compared to traditional infrastructure. The plan should be to improve and standardize the process in a similar fashion.

Technical requirements should be owned by Engineering to ensure internal oversight. In the requirements development, RFP specifications require extensive collaboration across multiple organizations. Although the categories may be similar to typical infrastructure projects, the content would be unique to ESS. RFP categories include [7], [8]: minimum qualification requirements; system performance requirements; RFP schedule and selection criteria; RFP response requirements; scope of work; and technical specifications. Technical sub specifications include ESS performance, installation, interconnection, controls and communication, environmental, safety, commissioning, and operations.

Other issues to consider in the development of the RFP is clarity on the work to be performed to complete the installation and commissioning which includes space, physical interconnection, and communication and control integration. Maintenance requirements performed via the contract or utility need to be clarified. Once installed, the RFP must include testing to validate it meets the requirements and can perform as needed to achieve the project objective and benefits.

Installation:

Prior to installation, site considerations that require evaluation and resolution include permitting, seismic, noise, physical access, flooding, fire barriers, and spill containment. As part of the ESS installation, considerations to also include are the connection requirements to the utility grid including transformers, switches, protection system, and communications and control. The communications and control can include requirements for the ESS and the integration with the utility's control system.

New systems require extensive testing to ensure it is capable of performing as required. Testing includes factory acceptance tests (FAT), site acceptance testing as well as testing on specific pieces of equipment. Site acceptance testing is part of commissioning and overall is intended to ensure the ESS operates as required, is integrated effectively with the utility grid, the controls systems operated as required, and the system has been properly installed to maintain safety and long term performance.

4.2.4.5 ESS Operations

Since ESS installations are relatively new, operation and maintenance is another key area undergoing lessons learned as experience is gained. It is important that personnel responsible for both operations and maintenance be prepared to undertake that responsibility. Operators should have the software tools needed to facilitate monitoring ESS status as well as the information and tools needed to take action when needed- such as to use the ESS to restore load during outages. Appropriate BESS management systems applications should be required in development of operating systems that will manage DER. Clarity between requirements and constraints in support of Distribution Operations and Market Operations/Trading for the daily scheduling of BESS must be established, especially if routine distribution operations will be encountering BESS during circuit maintenance activities.

Related to maintenance requirements, the industry is still in the learning stage with much of the maintenance for large systems handled through the resultant RFP contract. Even when the maintenance is performed via the RFP contract, the utility should be knowledgeable about the required maintenance to ensure compliance. Maintenance requirements should be established and cycle inspections should be documented. Reference [9] provides the CPUC document regarding the Safety Energy Division Safety Inspection Items for Energy Storage – February 2017. Overall safety requirements related to ESS has gaps which are being addressed across the industry [10]. The gaps are largely related to the evolving nature of ESS systems.

The impact of both planned and forced maintenance on the distribution system needs to be taken into consideration. For other systems, maintenance requirements should be established and cycled inspections should be performed and documented.

4.2.4.6 RACI Matrix

Based on the results of the brainstorming sessions and the ESS project responsibilities described above, a RACI (Responsible-Accountable-Consulted-Informed) model was developed to identify the relationship between various ESS functions and organizational departments. The model is illustrated in Figure 4-2. The model was originally used to determine types of tools and methodology needed for the ESS projects and required by various departments.

	Business Unit																		
	Customer Services	Markets Operations	Regulatory Affairs	Finance/ Accounting	Safety	Environmental	Security (Physical & Cyber)	Information Technology	Advanced Technology Integration		Electric System Planning			Elec. Trans. & Dist Eng.			Electric System Operation		
Functions (Grouped)	Customer Services	Markets Operations	Regulatory Affairs	Finance/ Accounting	Safety	Environmental	Security (Physical & Cyber)	Information Technology	Business	Technology assessment & Pilot projs. (DER)	Reliability	Electr. Distrib. Planning	Grid (transmission) Planning	Standards & Power quality	Protection & Automation Control	Substation Engineering & Design	Distribution Operation (Control Center & Field)	Transmission Operations (Control Center & Field)	Generation Operations
Business Planning	I	C	C	C	I	I	I	I	A/R	C	C	C	C	C	C	C	C	C	C
Preliminary Studies (NOTE 1)	I	C	C	c	I	I	C	I	C	C	A/R	A/R	A/R	C	C	C	C	C	C
Regulatory Approvals	C	C	A/R	C	C	C	C	I	R	I	C	C	C	I	I	I	I	I	I
Specification Development / Application selection (NOTE 1)	C	C	C	C	C	C	C	R	A/R	R	R	R	R	R	R	R	C	C	C
Safety Compliance (NOTE 1)	I	I	C	I	A/R	I	C	I	A/R	C	C	C	C	R	R	R	R	R	R
Procurement Process	I	I	C	C	C	C	C	C	A/R	C	R	R	R	C	C	C	I	I	I
Zone and site selection	C	I	I	I	C	C	C	I	A/R	C	R	R	R	C	I	C	I	I	I
Detailed Engineering Design	I	I	I	I	C	C	C	R	A/R	C	C	C	C	R	R	R	C	C	C
ESS Installation and integration to control center	I	I	I	I	C	I	C	R	A/R	R	C	C	C	C	R	C	R	R	R
Commissioning and Acceptance Testing	I	I	I	I	C	I	C	R	A/R	R	C	C	C	C	C	C	R	R	R
O&M Procedures	I	I	I	I	C	I	C	R	A/R	R	I	I	I	R	C	R	R	R	R
Ongoing Operations	I	R	I	I	I	I	I	I	A/R	C	C	C	C	I	I	I	R	R	R
Ongoing Maintenance & upgrade	I	C	I	I	C	I	C	R	A/R	C	I	I	I	C	C	C	R	R	R
Market Services	I	A/R	C	C	I	I	I	I	A/R	C	C	C	C	I	I	I	C	C	C

NOTES

1. Each organization may have responsibility for certain parts of the business function, thus the reason for multiple "R" or "A/R" assignments

R = Responsible (can do it, actually doing work)
A = Accountable (ultimate authority for a function being completed)
C = Consulted (has input to the process)
I = Inform (notify)

Figure 4-2. RACI (Responsible-Accountable-Consulted-Informed) model

4.2.5 Approach Towards Markets Participation

Market analysis was performed on potential ESS sites for projects such as capacity deferral and microgrids. That analysis has provided CD, CDA, and CDAA benefit analysis. Certainly the analysis has shown sufficient potential benefits that can significantly impact the benefit-cost justification for the ESS installation.

To achieve those benefits, multiple hurdles need to be resolved in time to maximize the market benefits when the ESS goes operational. Some of the key hurdles are:

- Regulatory
- Software Tools for Integrating Market and Distribution Benefits
- Collaboration Between Markets Operations and Distribution Operations
- Advanced Distribution Management System Enhancement

Software Tools for Integrating Market and Distribution Benefits

Market participation tools are currently available and in use. However, those tools typically do not handle distribution constraints. Those constraints result from ensuring that the ESS is readily charged to perform the discharge required for the distribution benefit. Those constraints need to be modeled on a daily basis throughout the year. The distribution constraints model must be integrated with the markets participation model for proper use of the ESS. It is recommended that a tool to perform this task be pursued.

Collaboration Between Markets Operations and Distribution Operations

Traditionally, there has been no need for collaboration between a utility's Market Operations and Electric Distribution Operations. Now, with the joint use of distribution system ESS, those two groups need to collaborate on how the ESS will be scheduled and deployed. Although the modeling tool described above can deal with scheduled charge/discharge and forecasted distribution requirements, the real world cannot be fully scheduled. The maximum ESS market benefits tend to be related to real time prices and distribution system forced outages cannot be forecasted. Distribution Operations will need to deploy the ESS as required during conditions such as forced outages, especially if the ESS is part of a microgrid. The collaboration requirements need development but should be assumed that Distribution Operations will deploy the ESS as needed but will be dependent on the real-time State of Charge (SOC). It is recommended that as the use cases for ESS are developed, this collaboration and related requirements be pursued.

4.3 Findings and Recommendations Related to Implementation of Methodology and Tools in Assessment of Future Distribution Circuits Design Practices

This section addresses recommended enhancements to project selection and design practices in the near and mid-term future, including improvements in methodologies and tools as recommended in sections 5.1 and 5.2 as well as certain other enhancements that would allow the realization of greater value from storage on the distribution system.

4.3.1 Tools and assessment methodologies

Assuming that the recommendations of section 5.2 are followed for the screening of the distribution system and the evaluation of storage benefits in detail for targeted feeders, there are then additional improvements in the detailed planning and design of particular storage projects. These are addressed in this section.

4.3.1.1 Value of time-series analysis in assessment of other technologies

This project demonstrated clearly the value of employing time series analysis of the storage resource and the control algorithms for the storage resource in conjunction with distribution circuit analysis. Whether or not this degree of rigor is applied to the business case development, it is critical to the engineering and design of the storage project. Due to PV integration, this methodology should be standardized and used for all distribution projects in future, whether or not storage is planned. It is also a superior way to assess flicker issues from PV and other problems that can arise under high DER penetration. Just as renewables have made time series analysis mandatory in assessing, planning, and operating grid scale generation resources, the same will be true for distribution level BESS in future.

Critical aspects of using the time series analysis approach to consider in future include:

- Adjusting the control algorithm and storage performance characteristics to determine the best algorithm and parameters/tuning as well as to assess the value of different levels of storage performance (rate limit, etc.). When procurement decisions for a technology type/product are being made (as in a selection of storage systems for a number of distribution projects) then the particular characteristics and algorithm can be simulated in the time series analysis as part of the evaluation. Such time series analyses are relatively new to the distribution domain but have become routine in applications such as wholesale market and grid operations, and wind farm interconnection studies. The advent of high DER penetration plus the use of some DER such as storage to facilitate DG integration and hosting capacity will demand that time series analysis become routine.

4.3.1.2 Evaluating other sizing possibilities for best cost benefits

The sizing calculations and market value assessments performed should incorporate a study of the modular sizes available closest to the values determined in the time series analysis. That is, if the time series analysis results in a 714 kW battery system the impact of using a 700 and a 750 kW system should be evaluated.

4.3.1.3 Incorporating uncertainty

The studies performed in this project used historical load profiles, PV profiles, load growth, and market prices to assess storage projects. In the future, all these variables as well as DER adoption become subject to greater uncertainty over future years. This is particularly true of PV adoption, possibly EV adoption, and possibly PV production and load profiles given the uncertainties of climate change.

A major value in energy storage systems that has not been assessed so far or published is the protection that can be provided against uncertainty, especially if the storage can easily be re-located to another location, reprogrammed for different applications, and/or resized as conditions change. Once a circuit is reconductored, for example, that cost is sunk and the decision cannot be reversed or the value of it transferred somehow or repurposed. If load growth fails to materialize as projected, the cost may be incurred needlessly. Storage can be repurposed, resized, and relocated with only marginal costs, if plans and allowances for such are made as part of engineering design.

In other fields, the 'optionality value" of more flexible planning is recognized and factored into plans. The utility industry is not, in general, accustomed to thinking this way about projects although some generation portfolio assessments consider the optionality value in generation plant flexibility. Storage introduces the very real possibility of more flexible planning and adaptability to distribution engineering and an effort should be made to take advantage of this. The best way forward may be a subsequent EPIC or other R&D oriented project to demonstrate methodologies and benefits, or a simple first step based on probabilistic scenarios and evaluations using current approaches may be a way to explore this.

4.3.2 Applications of other similar emerging technologies in distribution systems

This study examined applications that are possible with today's technologies and for which there is a current market or perceived value. Additional new technologies/applications to consider include:

- Provision of synthetic governor response. There is a FERC NOPR which proposed to require governor response from inverter based resources, in order to compensate for decreased system primary response due to conventional generation displacement by wind and solar generation. Many respondents to the NOPR suggested making primary response a market based ancillary product as is the case in the United Kingdom. Distribution level storage could easily provide this capability with local autonomous controls for smart inverters so this should be considered in future applications. A FERC decision in late 2017 or early 2018 and a follow up CA ISO stakeholder process would bring this about sooner, not later.
- Provision of synthetic inertial response or response to rate of change of frequency. This is a current R&D topic in several DOE SHINES or NODES program projects and DOE ARPA-E projects. Smart inverters can provide this capability as well as primary governor response. If system level studies show a benefit from this, it could be a candidate for deployment in California before long.
- Continuous assessment of new storage electro-chemistries. On the one hand, Lithium Ion technology continues to improve with a focus on lowering cost, increasing energy densities, and increasing lifetime cycles. Beyond this, there are potential improvements in Vanadium-Redox Flow (VRF) technologies that could improve costs and improve cycle charge/discharge losses. This could make VRF more attractive for applications with frequent cycling duties. Other technologies that are not as commercialized (zinc air) bear monitoring because of low cost and/or intrinsic safety that facilitates siting.
- Integration of utility distribution storage roadmaps with state level planning. As storage penetrates the distribution system it will have impacts on wholesale markets and bulk power operations that can both benefit the state overall while altering the local value of storage, perhaps unfavorably. Some effects include:
    - Increased distributed storage that is performing peak shifting and energy time shifting will act to counter swings in day ahead prices due to macro-level load and renewable profiles. Decreasing this volatility will decrease the value of distributed storage market participation somewhat but also will benefit the state greatly overall. Such a macro level portfolio assessment and more integrated planning is indicated as distributed storage penetration goes. Ultimately, a way to apply some of the state level benefits to fund distributed storage or incent market participation may be desirable.

- Use of storage to manage PV interconnection will also have the effect of decreasing voltage regulation requirements due to PV volatility. An assessment of the potential impact here and the state level benefits is indicated.
- How distributed storage will impact real time energy requirements and the requirements for balancing headroom in day ahead schedules is unclear.

4.3.3 Voltage and VAR compensation assessments

As investigated and discussed in previous sections, ESS can provide reactive power compensation and voltage control. A valid question can be raised regarding the use of energy storage system for the sole purpose of voltage control on distribution systems, as compared with other technologies such as Dynamic Voltage Controller (DVC) or similar reactive power compensation devices. DVC type devices have been also introduced in the utility to manage adverse impact of high penetration of solar PV systems.

A sample case study was performed to compare the effectiveness of DVC and an ESS on the voltage control under the influence of a 2MW PV system installed toward the end of a very long radial distribution line. Based on the minimum day time loading in the area downstream of an in-line voltage regulator, on a sunny day, the reverse power flow caused by the 2 MW PV is about 0.75 MW. The significant reverse power causes the voltage to increase up to 1.08 per units, exceeding the 1.05 pu permissible threshold. Changing the voltage regulator mode to co-generation helps to resolve the voltage problem, however, because of the speed time of an electromechanical tap changer and delays built into the voltage regulator control logic, the high voltage condition will remain in effort on the circuit for a few minutes before getting resolved. In addition, fast fluctuations in PV production, due to alternating clouds, will have significant impact on the number of tap operation and maintenance life cycle.

The study determined that a 2 MVA DVC installed downstream of the voltage regulator can reduce the overvoltage conditions, however, it is less effective in mitigating the number of tap operation of the voltage regulator. The main reason has been associated with interaction of voltage regulator and DVC.

The equivalent impedance at the target location is R = 5.03 ohms, and X = 8.56 ohms (X/R = 1.7). Because of the large resistive impedance, a major part of the overvoltage is caused by voltage gain on resistive impedance during reverse power flow.

If an ESS was installed at the DVC location instead, ESS can help reduce the reverse power flow, and therefore avoid sudden change in power flow direction during intermittency. It was noted that the ESS size for the location of interest has to be 2 MW / 4 MWh, which is almost 3 times costlier than the DVC. Table 4-1 presents ESS size requirements for worst case reverse power flow.

Table 4-1. ESS size requirements for worst case reverse power flow

Day hour	10	11	12	13	14	15
*Solar irradiance [pu]	0.83	0.95	0.997	1	0.9	0.791
MWh charge per hour	0.6225	0.7125	0.74775	0.75	0.675	0.59325

Total MWh	~ 4.0					

Hence, utilizing ESS for the voltage/reactive power control application would need to be evaluated side by side with other technologies on the case by case basis. If the location of interest is highly resistive, and/or there are considerable outage scenarios, or fast flicker issues due to high level of intermittency, an ESS solution can be proposed and justified. Yet, additional stacking application for the ESS should be considered and evaluated to make the technology cost effective.

In this case, ESS should be introduced as part of a portfolio of the mitigation technologies.

4.3.4 Conclusions

The main conclusions from this project are:

- ESS applications need to be evaluated in the context of smart distribution circuits and by considering other emerging technologies that may have capabilities to achieve similar goals. An example technology examined was the use of Dynamic Voltage and Reactive Power Compensation devices versus installation of energy storage systems on circuits with high PV penetration.
- As a complimentary step in the evaluation process, standardization of the framework for calculating sizes, benefits, avoided costs, and cost benefit analysis of emerging technologies incorporating various combinations of stacked applications should be performed. The studies reported in previous sections showed that single applications would not be cost effective.
- In addition, it would be advantageous to provide planning engineers a comprehensive list of technologies and tools and their key application areas for mitigation of system impacts. Planning engineers and designers of smart distribution circuits of the future should take advantage of the state of the art in assessment and analyses tool to evaluate various possible conventional and emerging solutions.
- The benefit evaluation methodology and tools should be integrated with the actual procedures and tools for system operations incorporating emerging technologies so that the benefits are realizable in practice and after deployment in the field. This requires development of day-to-day operating procedures and guidelines for inclusion of energy storage and other emerging technologies for system operations. In addition, there should be plans in place for operational system upgrades, procurements, and training to realize full benefit of these solutions.

Some of the other key findings are listed below:

- Economic comparison of traditional infrastructure versus ESS has typically been solely based on capital, operating, and maintenance costs. Market benefits have not been included.
- The distribution planning process has used Distribution Planning Tool 4 for circuit modeling and is satisfied with its capabilities. Modeling enhancements are desirable.
- A new microgrid application is under consideration for an area in the back country
- As future ESS sites are identified, improved collaboration across organizations would improve the decision, engineering, deployment, and operations processes.
- Initial ESS sites installed years ago have had maintenance and operation challenges. Future installations need performance and maintenance requirements in contracts.

- Certain existing ESS sites are being enhanced to enable microgrid deployment during outages.
- The upcoming change in the Time of Use Rates for the On-Peak period from 11 AM -6 PM to 4 PM to 9 PM will likely increase customers' behind the meter interest in ESS.

5 SUMMARY OF RECOMMENDATIONS AND NEXT STEPS

A summary of the key recommendations from this project is given below:

- Implement tools and standardize the process for calculating benefits, avoided costs, and cost/benefit analysis of ESS,
- Improve standards and processes for co-utilization of ESS with distribution system benefits and the wholesale market. Acquire as needed regulatory approval for distribution ESS participation in the markets.
- Implement ESS control systems that can manage stacking of applications in cooperation with ESS vendors and ESS integrators.
- The ESS tools should be compatible with existing distribution planning models and study approaches to ensure on-going support and utilization by the engineers and stakeholders. Various interfacing schemes are available to add the functionalities and analysis approach to the existing software tools through APIs and drivers similar to the ones introduced and demonstrated in this project.
- Develop procedures for utilizing storage in daily system operations by acquiring and applying enhanced tools to ensure benefits are achieved.
- Communicate accountable, responsible, consulted, informed (RACI) sections' role in ESS project assessments, procurement of technologies and operation to enhance collaboration so that it can be effectively integrated with day to day business across the organization.

6 TECHNOLOGY/KNOWLEDGE TRANSFER FOR APPLYING THE RESULTS INTO PRACTICE

6.1 Information Sharing Forum

The following meetings and workshops were held to share the information with various stakeholders and the public:

- Stakeholder workshop (May 25, 2017): Over 30 people from various SDG&E departments attended the workshop
- Brainstorming sessions (May 30, 2017 to July 30, 2017): Over 10 brainstorming sessions were held with individual groups and key stakeholders within SDG&E
- IEEE PES General Meeting – panel session (July 18, 2017): Frank Goodman presented state of the ESS technology and assessment methodology at IEEE conference.
- Presentation by SDG&E to Green Team meeting (June 2017): SDG&E presentation to the Green Team members regarding the storage sites and applications
- Demonstration workshop of the tools and methodology (Oct 2017): workshop and knowledge transfer session at SDG&E on the project findings and recommendations

In addition, to further benefit the public, there are plans to submit papers and presentations for conferences and/or journals on the project results. These items, along with this comprehensive final report, will be posted on the SDG&E public website at www.sdge.com/epic.

6.2 Particular to SDGE's internal technology transfer

The results of this project were shared with the appropriate organizations within SDG&E. Key organizations included:

- Distributed Energy Resources
- Distribution Planning
- Engineering
- Advanced Technology
- Distribution Operations
- Market Operations

In addition, based on the findings and recommendations, the project team has proposed several training sessions on applications of ESS evaluation tools and utilization of the methodology targeted toward specific groups and stakeholders that will be held in upcoming months.

SDG&E is also assessing the applicability of the ESS study tools and methodologies and how best they can be integrated into existing processes to support engineering and business needs. ESS strategic taskforces are formed to further follow up and coordinate this matter among stakeholders.

6.3 Adaptability to other utilities and/or the broader industry

A key limiting factor in ESS deployment and utilization across the electric utility industry is the proper economic evaluation of ESS values. As stated previously, traditional economic evaluation has focused on the value of capital deferral. This project demonstrated the value of market participation that can enhance the business case. It also demonstrated the significant increase where ancillary services are available for participation. It is critical for the industry to expedite resolution of hurdles that limit the participation of ESS in these markets.

However, the main challenge is to have engineering tools and study methodologies that can co-analyze both distribution applications and market services. Several tools and associated analytical methodology were introduced and demonstrated in this project that can be utilized by other electric utilities to perform similar co-analysis of the stacked applications. The approach was based on enhancing existing distribution planning tools and incorporating ESS controls and market optimization as add-on analytical modules through external interfaces. This approach will ensure sustainability in use and will facilitate expedited knowledge gain and acceptance among utility engineers.

7 METRICS AND VALUE PROPOSITION

7.1 Metrics

The metrics in the Table 7-1 were identified for this project and are reference to the appropriate section.

Table 7-1. Project Metrics

List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area in applied research, technology demonstration, and market facilitation) – See EPIC document for reference.	Remark & Reference
1. Potential energy and cost savings	
c. Avoided procurement and generation costs	Included & verified; The demonstrated ESS investigation approach can be used to properly identify the projects and reduce the cost. For more information, refer to sections: 2.1, 2.2, 2.5, 3.2,
i. Nameplate capacity (MW) of grid-connected energy storage (target ESS size for each application)	Included & verified; The demonstrated ESS investigation approach provides methods for proper sizing ad selection of ESS locations based on the applications. For more information refer to section: 2.1
3. Economic benefits	
b. Maintain / Reduce capital costs (by proper sizing and increase in utilization factor)	Included & verified; The demonstrated method provides sizing and location selection methods to precisely select ESS and manage the capital cost. The method also target, the increase in utilization factor by combining applications with manage the maintenance cost and benefit to cost ratio. For more information refer to sections: 2.2, 2.5, 3.1, 4.2, 7.2
e. Non-energy economic benefits	The propose method utilizes the ancillary market participation that ties to Power rather than energy capacity. Grid support

List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area in applied research, technology demonstration, and market facilitation) – See EPIC document for reference.	Remark & Reference
	applications are also included that targets Power. For more information refer to sections: 2.2, 2.5, 3.1, 4.2, 7.2
5. Safety, Power Quality, and Reliability (Equipment, Electricity System)	
a. Outage number, frequency and duration reductions	Included & verified; Study method incorporates the assessment of grid supporting applications for outage management. Constraint calculations taps into the capacity for outage support. For more information refer to sections: 2.5, 3.1, 7.2
b. Electric system power flow congestion reduction	Included & verified; One of the ESS applications that can be assessed with the demonstrated analysis method. For more information refer to sections: 2.2, 3.1, 4.3, 7.2
c. Forecast accuracy improvement	Included & verified; Time-series analysis utilizes the forecasted load change and solar PV to reduce the error. For more information refer to sections: 2.4, 2.5, 4.3
d. Public safety improvement and hazard exposure reduction	Included & verified; One of the parameters in the assessment process is the safety consideration of the ESS. For more information refer to sections: 4.2, 7.2
f. Reduced flicker and other power quality differences	Included & verified;

List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area in applied research, technology demonstration, and market facilitation) – See EPIC document for reference.	Remark & Reference
	Renewable smoothing and grid support applications incorporate the flicker and power quality indices. For more information refer to sections: 2.2, 3.1, 4.3
7. Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy	
a. Description of the issues, project(s), and the results or outcomes	Included & verified; The project process flowchart deals with the standard approach and evaluation of the outcomes. For more information refer to section: 4.2
b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)	Included & verified; ESS control system requirement metrics address the safety and reliability of technology and sizing accordingly. For more information refer to sections: 4.2, 4.3
f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360)	Included and verified; Metrics were used in comparing the ESS with other smart grid technologies such as DVR. For more information, refer to sections: 4.1, 4.3
l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360)	Included and verified; Project process flowchart incorporates methodologies for streamlining the process and avoiding unnecessary costs. For more information, refer to section: 4.1
8. Effectiveness of information dissemination	
d. Number of information sharing forums held	Included and Performed;

List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area in applied research, technology demonstration, and market facilitation) – See EPIC document for reference.	Remark & Reference
	Multiple meetings and workshop held with stakeholders and team. For more information, refer to section: 6.1
e. Stakeholders attendance at workshops	Included and performed; Stakeholder from various departments and group related to ESS project life cycle were selected and invite to workshops. For more information, refer to sections: 2.1, 6.1
f. Technology transfer	Plan was made for knowledge transfer through open forum and conferences. For more information, refer to section: 6.2

7.2 Value Proposition

EPIC provides project funding for applied research and development, technology demonstration and deployment, and market facilitation for clean energy resources. This project has provided multiple values by supporting benefits related to improved reliability, lower costs, safety improvement, and environmental benefits. In addition, this project has provided value by demonstrating tools and methodologies that will support future ESS evaluations.

7.2.1 Primary Principles

- Improved Reliability

  PV growth on distribution circuits has resulted in the need for improved analytical tools. Circuit analysis solely based on the peak hour is not sufficient. As demonstrated in this report, higher level of time-based granularity will more effectively simulate potential problems and potential solutions. This granular predictive analysis models the circuit load and voltage, while helping to effectively determine the amount of ESS that can resolve the problem.

  The types of problems that ESS can prevent include circuit overloads, high or low voltage, voltage flicker, and outages. If overloads are not prevented, they can result in infrastructure damage or outages, or both. Voltage flicker caused by PV systems is a relatively new problem since the distribution planning process would normally prevent it when large customers or large DER are connected. However, with a high quantity of small PV systems, sudden changes caused by clouds can result in unusual voltage fluctuations especially where small conductors are involved. The legacy distribution system was not engineered and constructed with this type of expectation. The study methodology proposed and evaluated in this project can effectively predict the issues described above thereby preventing those problems, either with ESS or other solutions.

In addition, the simulation supports the development of ESS microgrids by properly determining the ESS kW and kWh. By supplying customer load during forced or planned outages, ESS microgrids have great potential in improving reliability when properly designed and operated as described in this report. These types of applications can significantly improve circuit SAIDI.

- Lower Costs

  Opportunities are provided in this report to reduce costs to the utility and its customers.

  The improved analysis process will enable the utility to identify potential problems sufficiently in advance to pursue the most cost-effective solution.

  In addition, the integrated modeling of the capacity deferral and markets benefits allows the utility to properly compare the NPV of traditional infrastructure versus capacity deferral based on ESS applications and related market benefits.

  Ultimately, the ESS cost effectiveness is dependent on the specific use case and resultant model inputs such as required capacity upgrade cost, ESS kW/kWh/cost, load growth rate, and distribution constraints that limit market participation.

- Increased Safety

  The modeling process provided in this report improves the economics of potential ESS applications thus enhancing safety. The improved economics will help justify the application of ESS across the utility system. Providing ESS microgrids for customers such as fire stations can improve public safety by maintaining their power during outages. In addition, the current state of safety requirements, challenges, and implementation recommendations are provided in this report.

7.2.2 Secondary Principles

- Enhanced Environmental Sustainability

  ESS can reduce the need for CAISO to curtail PV generation and instead store the excess energy to utilize it when natural gas generation would otherwise be used to supply load. The economic modeling results indicate that energy storage systems can be cost effective, thus supporting additional applications.

- Efficient Use of Ratepayer Funds

  This project's enhanced analytics techniques can provide the proper evaluation for future ESS applications, including maximizing the benefits and improving the cost effectiveness. This project's tool and methodology evaluation can also help support others in their research. This research support will save future evaluators time and resources.

8 REFERENCES

[1] SDG&E Energy Storage System – 2016 Distribution Reliability/Power Quality Program Request for Proposal

[2] ESIC Energy Storage Implementation Guide- 2016

[3] California Public Utilities Commission- SED Safety Inspection Items for Energy Storage- February 2017

[4] EPRI & Sandia- Energy Storage Safety- 2016- Guidelines Developed by the Energy Storage Integration Council for Distribution-Connected Systems

[5] http://standards.ieee.org/findstds/standard/2030.3-2016.html

[6] https://smartgrid.ieee.org/resources/standards/ieee-approved-proposed-standards-related-to-smart-grid/704-p1547-8-recommended-practice-for-establishing-methods-and-procedures-that-provide-supplemental-support-for-implementation-strategies-for-expanded-use-of-ieee-standard-1547

[7] https://www.sdge.com/sites/default/files/00%20-%202016%20ESS%20RFP%20-%20Final%283%29.docx

[8] https://www.epri.com/#/pages/product/000000003002008899/

[9] https://www.epri.com/#/pages/product/000000003002008308/

[10] http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Safety/Risk_Assessment/ESS%20Inspection%20Guidelines.doc

[11] CEC report, " Validated and Transparent Energy Storage Valuation and Optimization Tool", - CEC-500-2017-016-APC, March 2017

9 APPENDIX

9.1 Additional study results for Capacity Deferral Application

9.1.1 BESS sizing - Centralized Upgrade Deferral for CCUD 1

For CCUD 1, centralized deferral approach, the battery was installed at the beginning of the feeder (Figure 9-1). The battery was initially sized as 0.7 MW, 3.5 MWh.

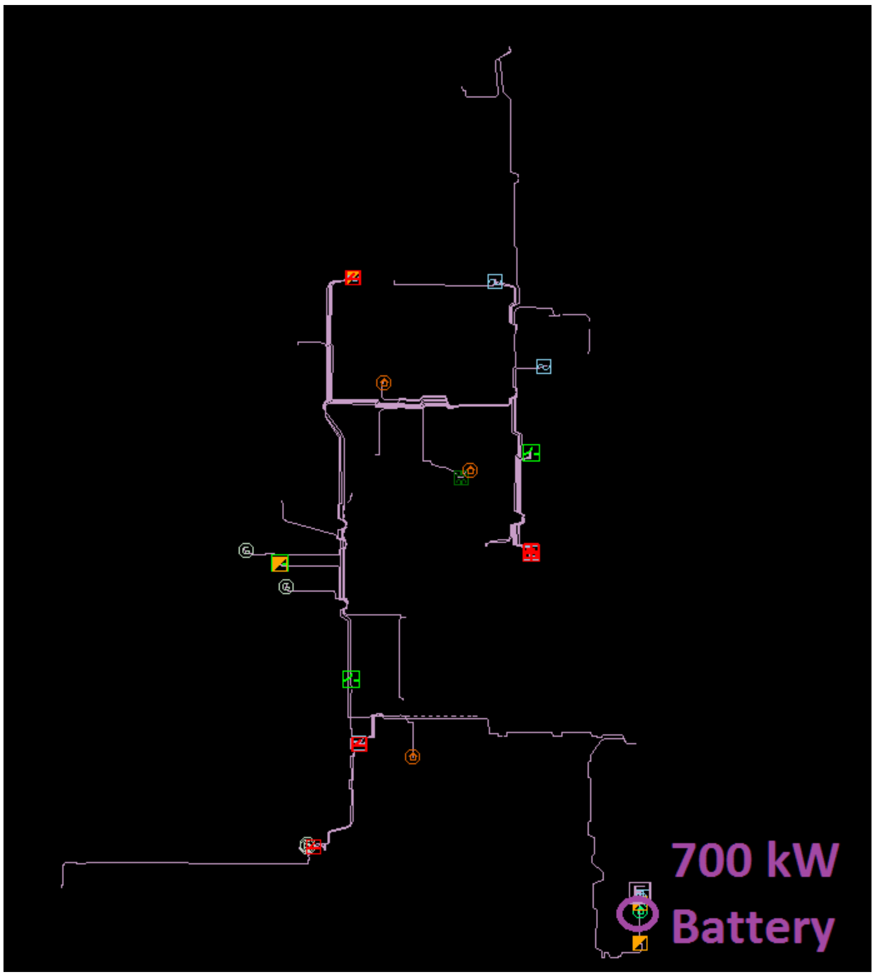


Figure 9-1. Location of the battery for circuit CCUD 1

The circuit under study has a thermal loading limit of 395 (A) determined in Distribution Planning Tool 4 model. This limit was used as the upper threshold of the circuit for peak shaving purposes. For the lower threshold zero was used to make sure that the reverse power flow is prevented. Also, the battery is scheduled to charge between 0:45 am – 5:00 am up to 95% in order to provide enough energy for discharging throughout the day.

In order to consider the worst case scenario, the maximum peak day of year was determined for the projected (year 2024) load profile and the PV systems were turned off during the analysis.

Figure 9-2 demonstrates the feeder power flow before and after the upgrade deferral application. The battery was charging during the scheduled charging zone up to 95% SOC and was then able to maintain the feeder power below 8,210 kW during the day. Figure 9-3 shows the expected power flow before and after the ESS applications.

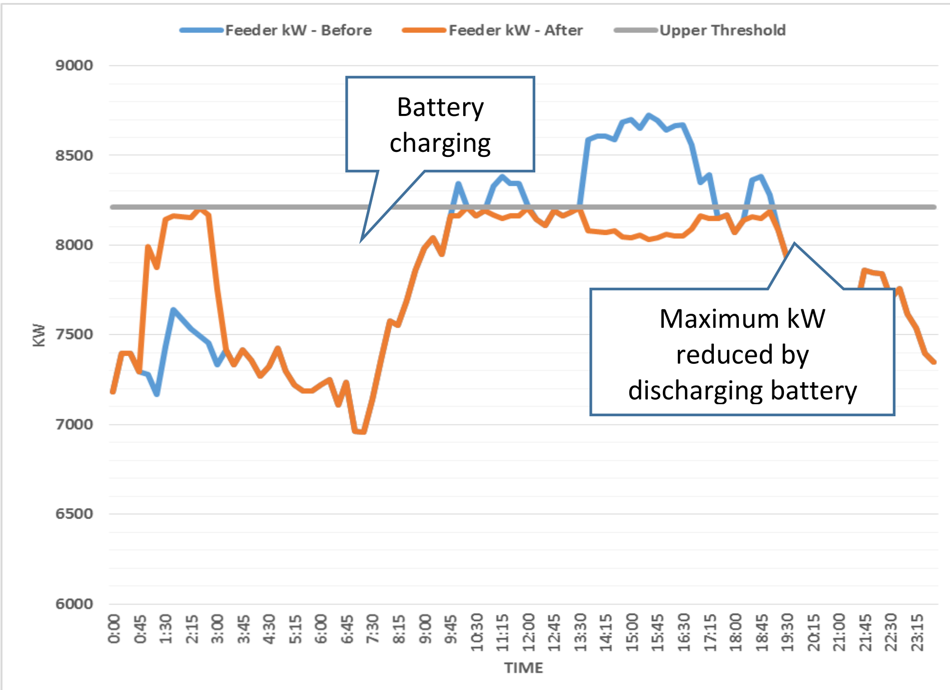


Figure 9-2. Power Flow (Centralized Upgrade Deferral) for CCUD 1

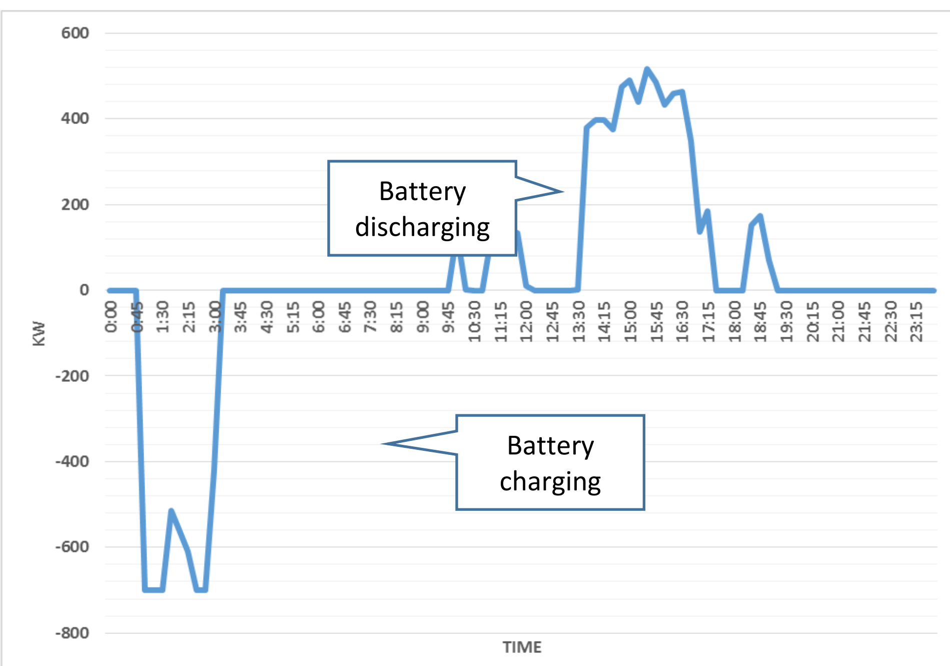


Figure 9-3. Battery Output Power (Centralized Upgrade Deferral) for CCUD 1

As illustrated in Figure 9-4, the battery charges/discharges up to the maximum rate of 700 kW. The accumulative charge of the battery by the end of the day is almost 1,400 kWh, while the discharge of the battery by the end of the day, is almost 1,800 kWh which reflects the maximum amount of energy required from the battery and justifies using a 750 kWh battery.

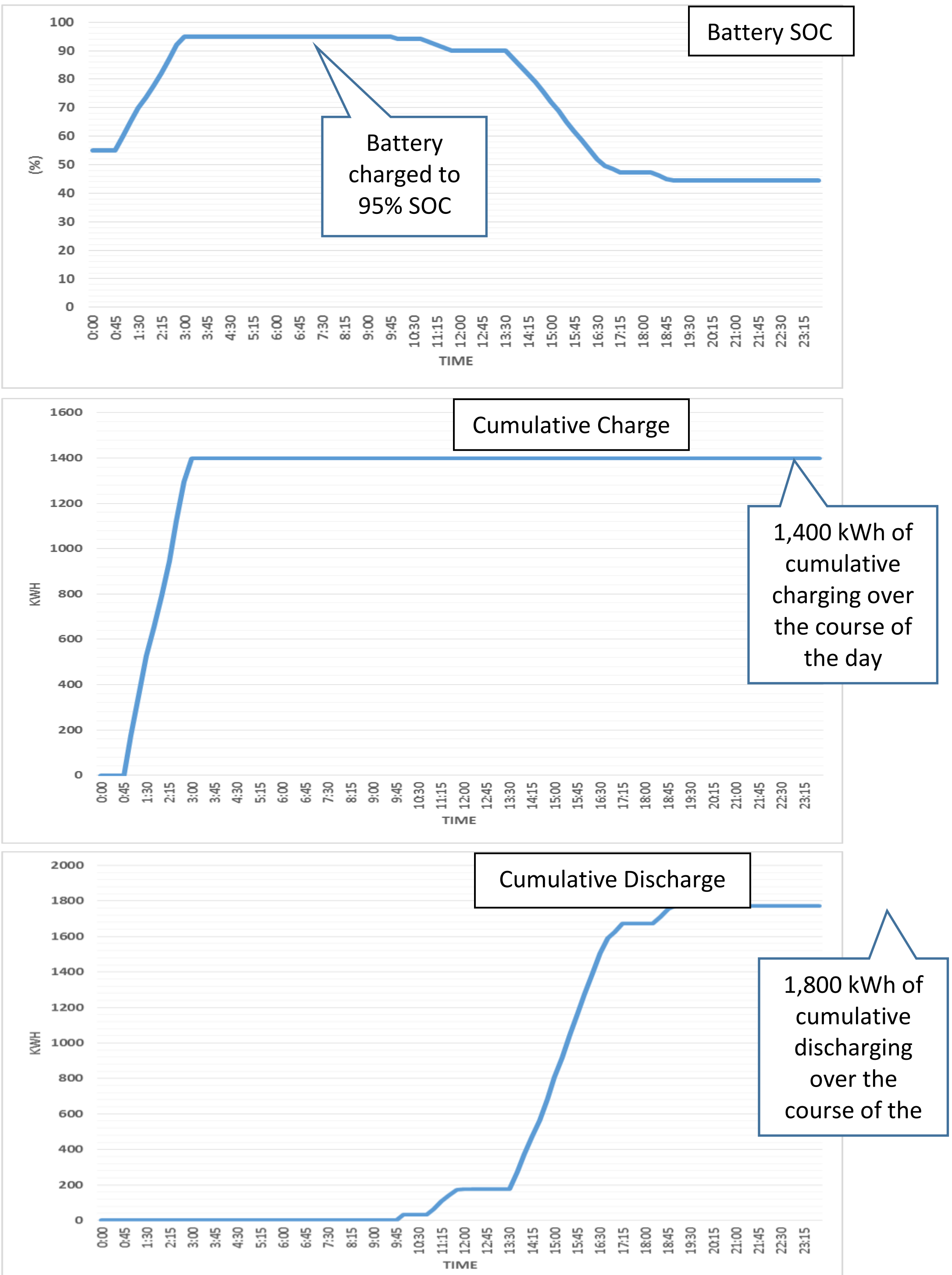


Figure 9-4. Battery SOC, cumulative charge and discharge for CCUD 1 (centralized)

9.1.2 BESS sizing - Centralized Upgrade Deferral for CCUD 2

For CCUD 2, centralized deferral approach, the battery was installed at the beginning of the feeder (Figure 9-5). The battery was initially sized as 0.5 MW, 0.75 MWh.

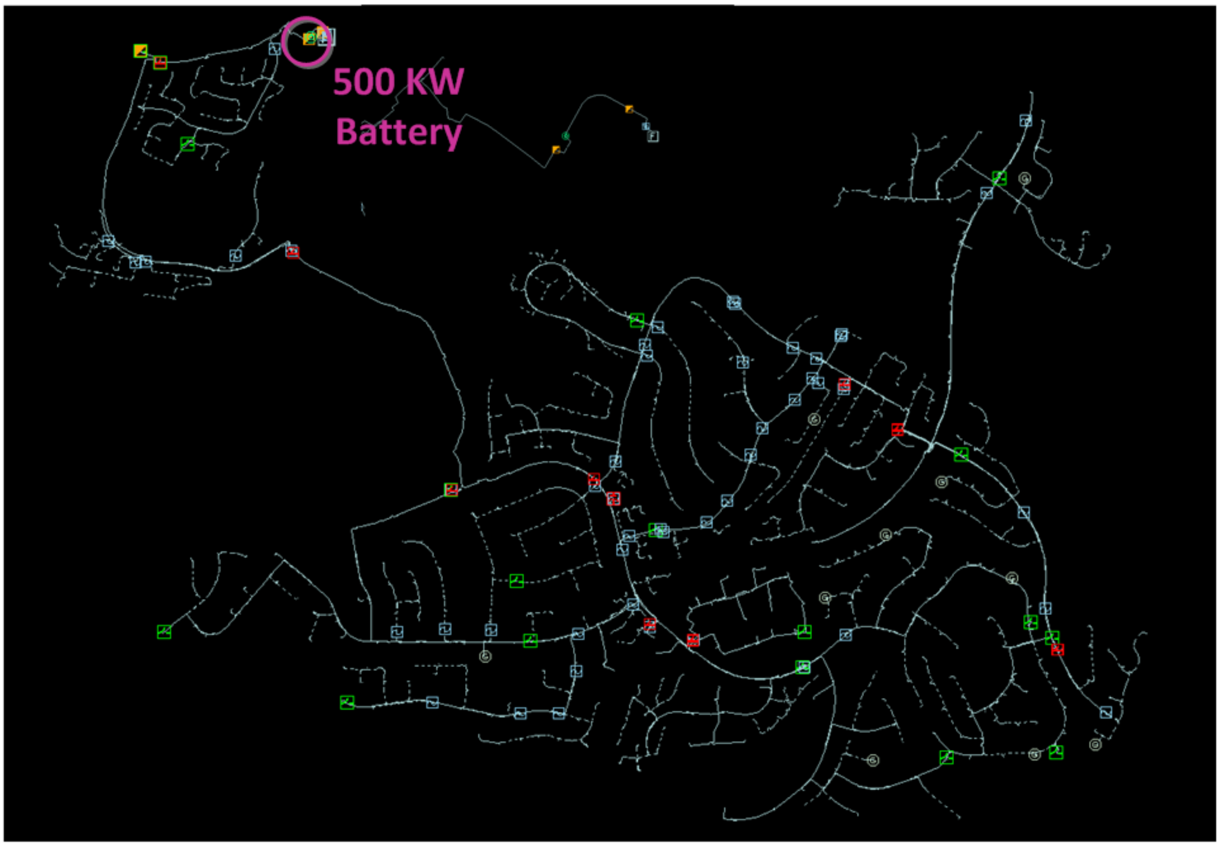


Figure 9-5. Location of the battery for circuit CCUD 2

The circuit under study has a thermal loading limit of 580 (A) determined in Distribution Planning Tool 4 model. This limit was used as the upper threshold of the circuit for peak shaving purposes. For the lower threshold zero was used to make sure that the reverse power flow is prevented. Also, the battery is scheduled to charge between 0:45 am – 5:00 am up to 95% in order to provide enough energy for discharging throughout the day.

In order to consider the worst case scenario, the maximum peak day of year was determined for the projected (year 2024) load profile and the PV systems have been turned off during the analysis.

Figure 9-6 demonstrates the feeder power flow before and after the upgrade deferral application. The battery was charging during the scheduled charging zone up to 95% SOC (Figure 9-7) and then cutting the feeder power below 12055 kW during the day. As illustrated in Figure 9-8, the battery charge/discharge up to the maximum kW rate of 500 kW. The accumulative discharge of the battery by the end of the day, is almost 700 kWh (Figure 9-9) which reflects the maximum amount of energy required from the battery and justifies using a 750 kWh battery.

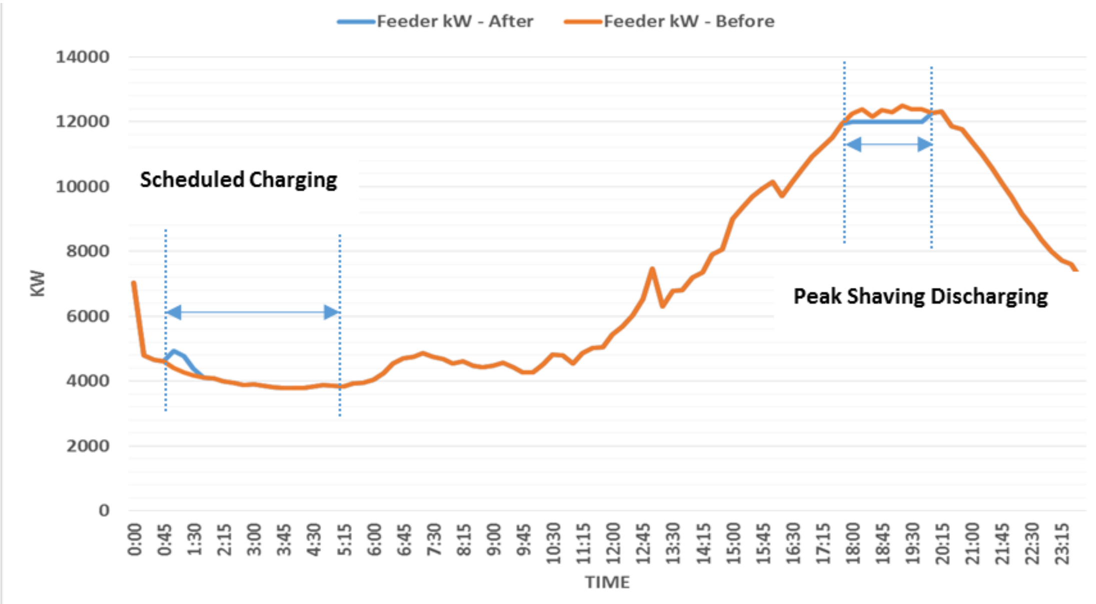


Figure 9-6. Power Flow (Centralized Upgrade Deferral) for CCUD 2

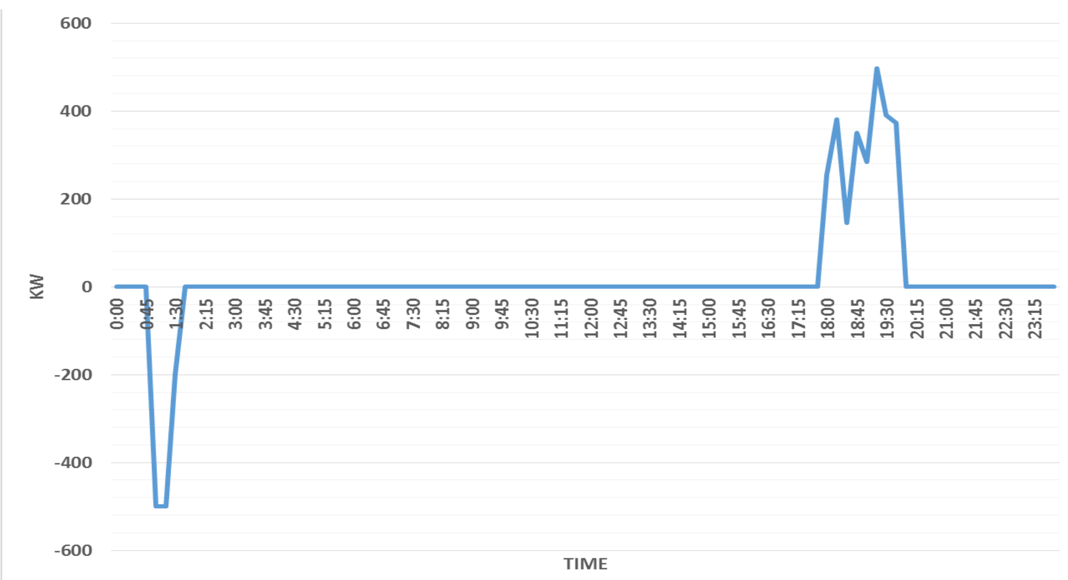


Figure 9-7. Battery Output Power (Centralized Upgrade Deferral) for CCUD 2

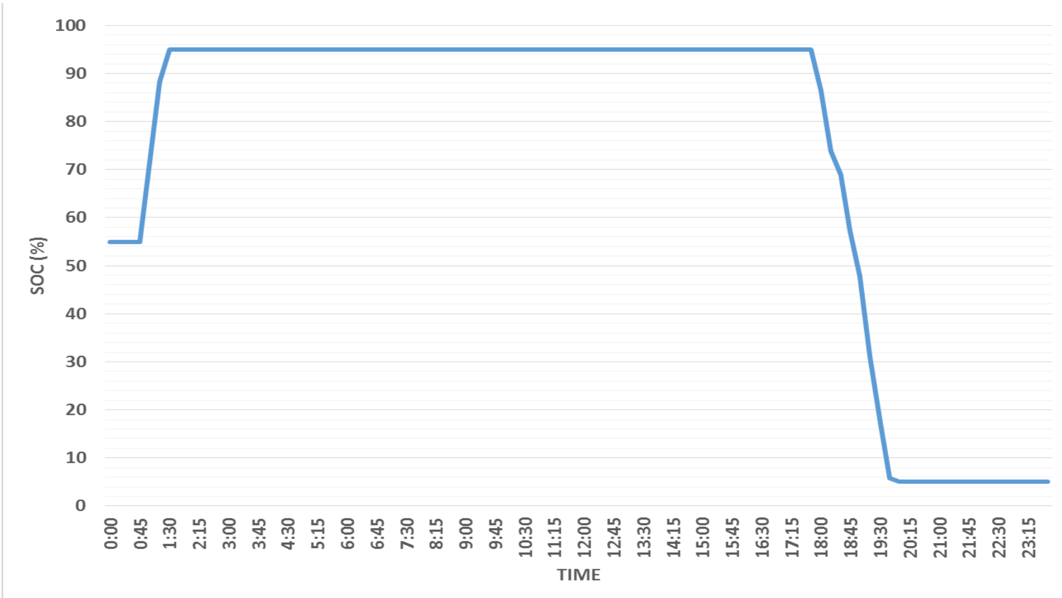


Figure 9-8. Battery State of Charge (Centralized Upgrade Deferral) for CCUD 2

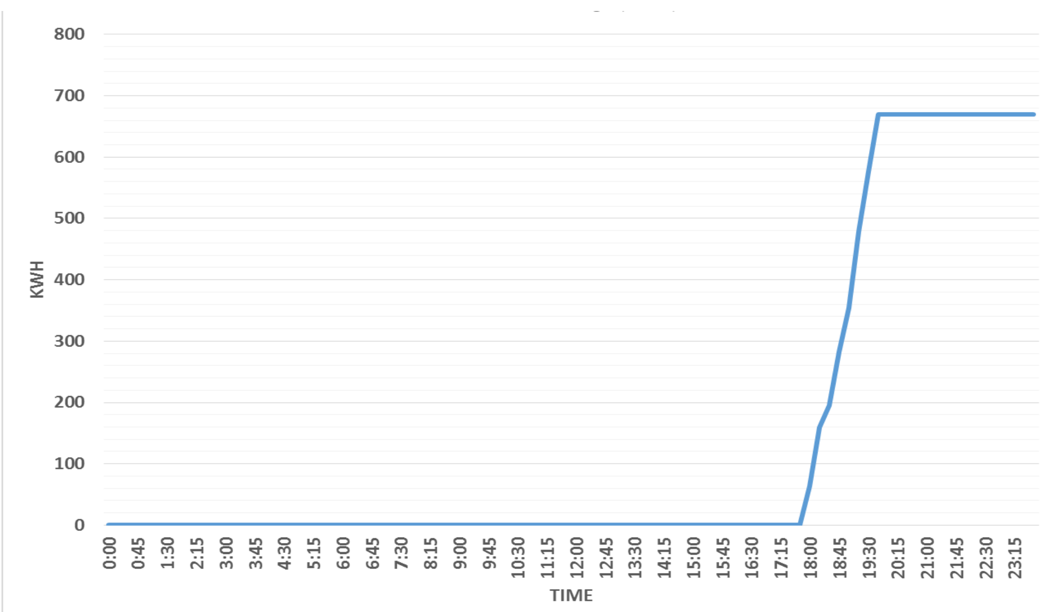


Figure 9-9. Accumulative Discharge (Centralized Upgrade Deferral) for CCUD 2

9.1.3 BESS sizing - Centralized Upgrade Deferral for CCUD 3

For CCUD 3, centralized deferral approach, the battery was installed at the beginning of the feeder (Figure 9-10). The battery was initially sized as 0.5 MW, 1 MWh.

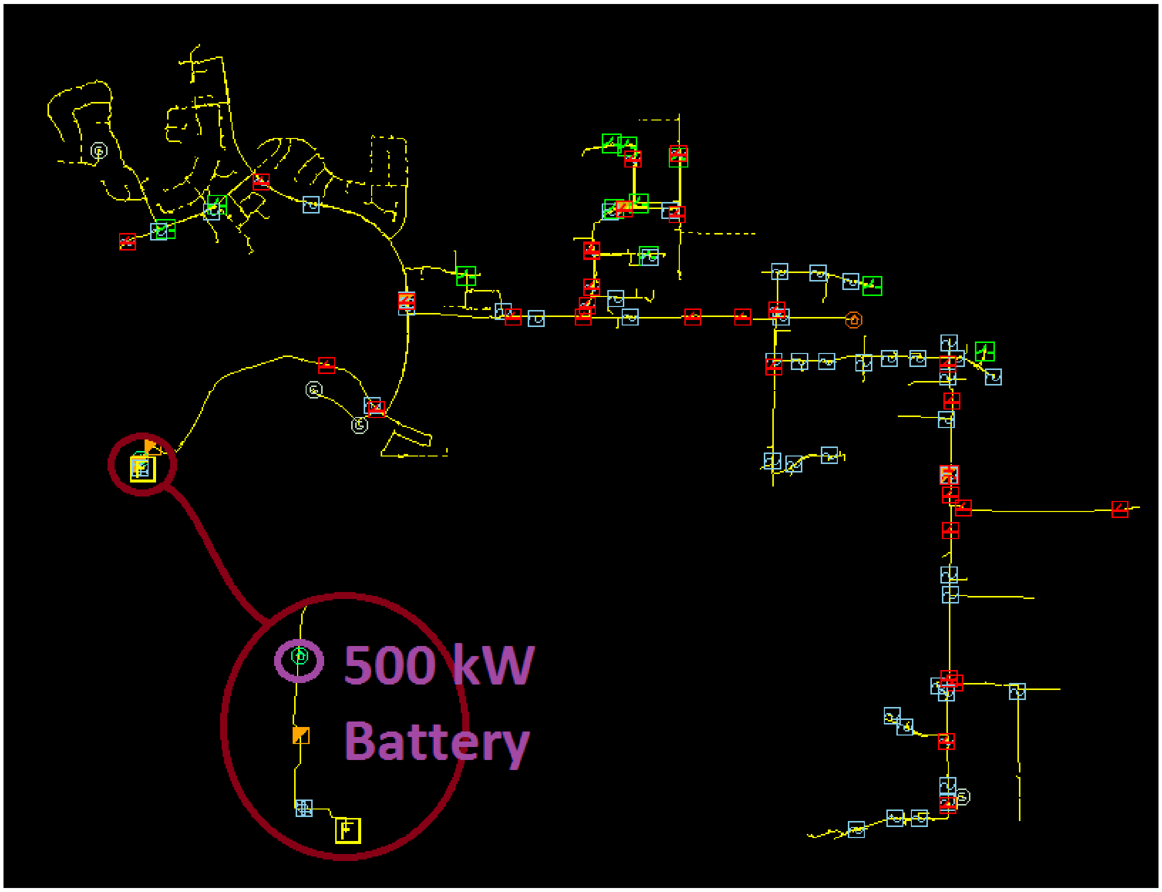


Figure 9-10. Battery Location for CCUD 3

The circuit under study has a thermal loading limit of 580 (A) determined in Distribution Planning Tool 4 model. This limit was used as the upper threshold of the circuit for peak shaving purposes. For the lower threshold zero was used to make sure that the reverse power flow is prevented. Also, the battery is schedules to charge between 0:45 am – 5:00 am up to 95% in order to provide enough energy for discharging throughout the day.

In order to consider the worst case scenario, the maximum peak day of year was determined for the projected (year 2024) load profile and the PV systems have been turned off during the analysis.

Figure 9-11 demonstrates the feeder power flow before and after the upgrade deferral application. The battery was charging during the scheduled charging zone up to 95% SOC (Figure 9-12) and then cutting the feeder power below 12055 kW during the day. As illustrated in Figure 9-13, the battery charge/discharge up to the maximum kW rate of 500 kW. The accumulative discharge of the battery by the end of the day, is almost 800 kWh (Figure 9-14) which reflects the maximum amount of energy required from the battery and justifies using a 1000 kWh battery.

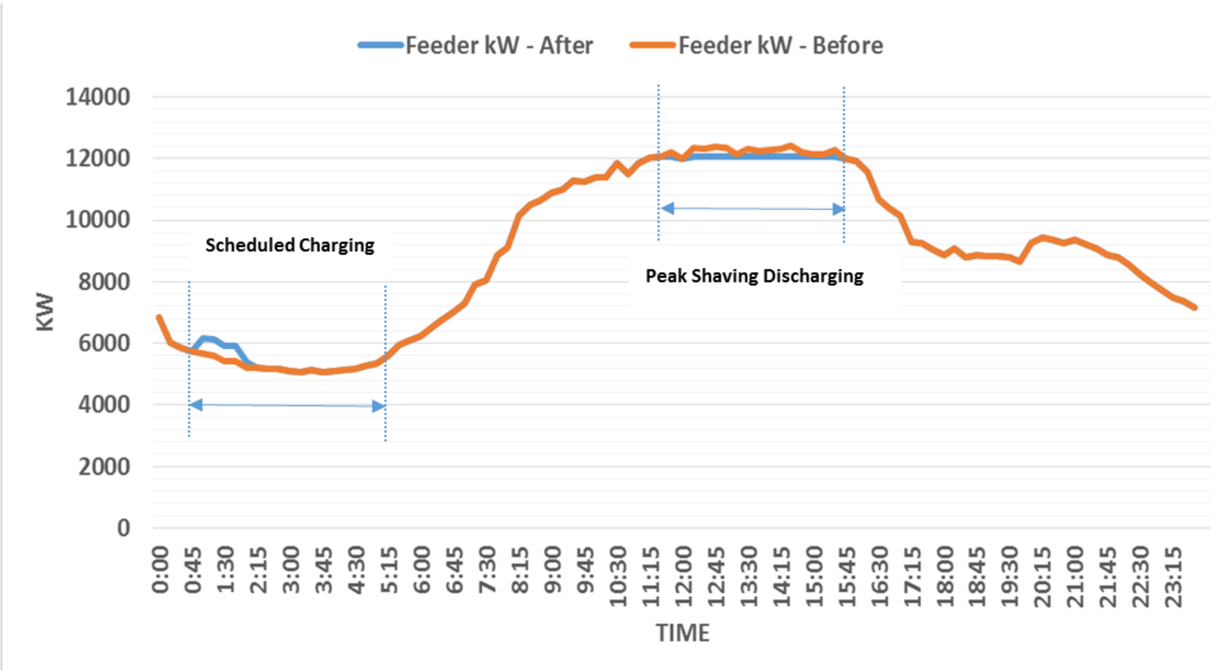


Figure 9-11. Power Flow (Centralized Upgrade Deferral) for CCUD 3

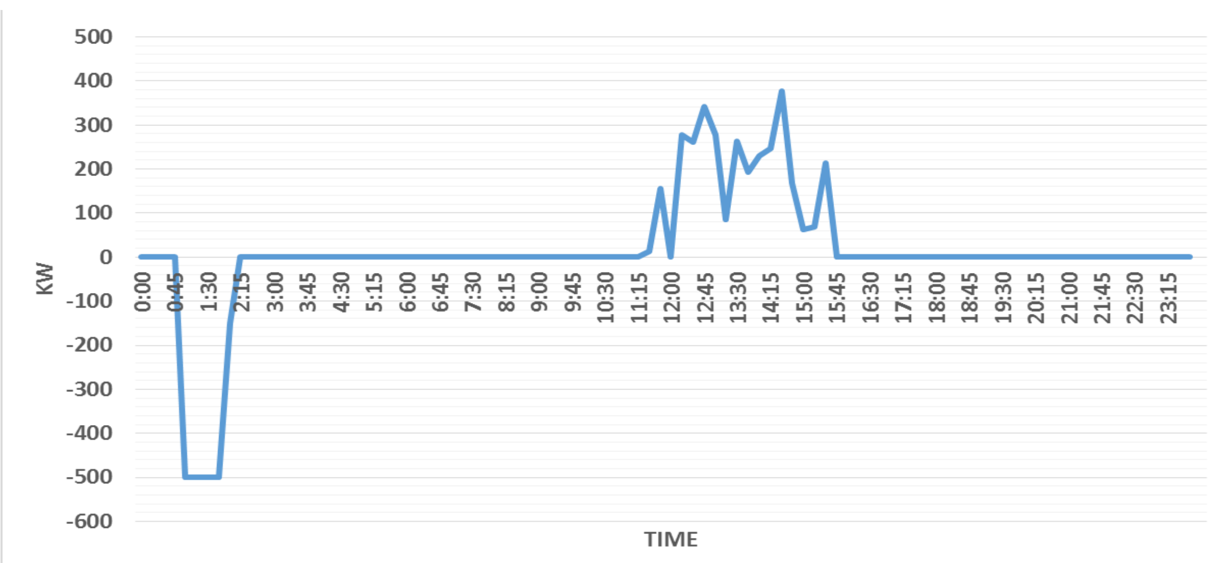


Figure 9-12. C1202 Battery Output Power (Centralized Upgrade Deferral) for CCUD 3

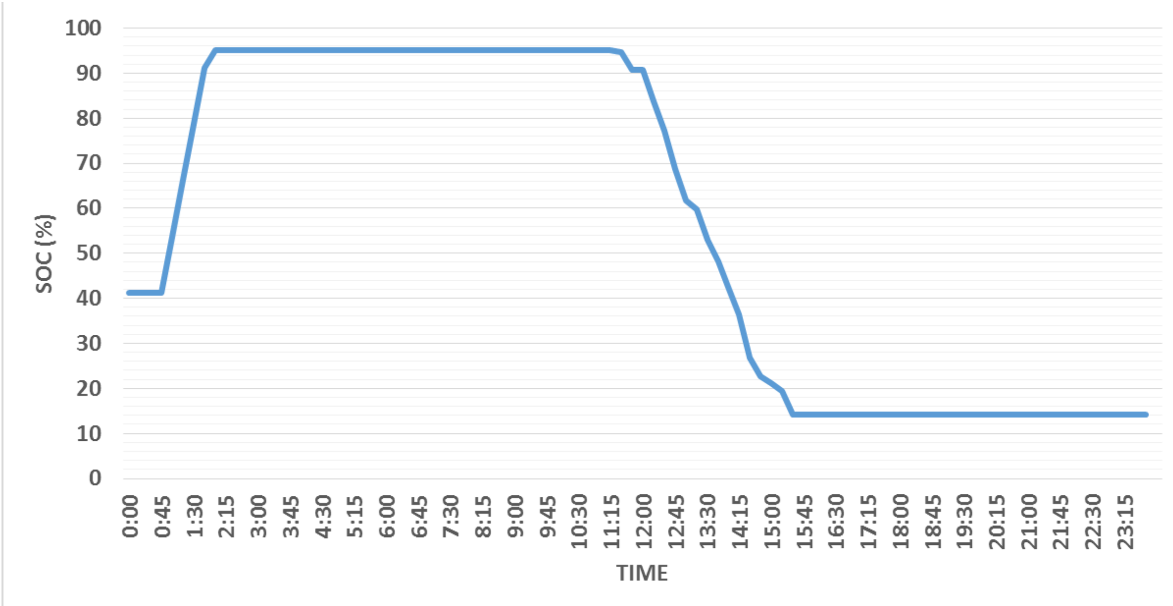


Figure 9-13. C1202 Battery State of Charge (Centralized Upgrade Deferral) for CCUD 3

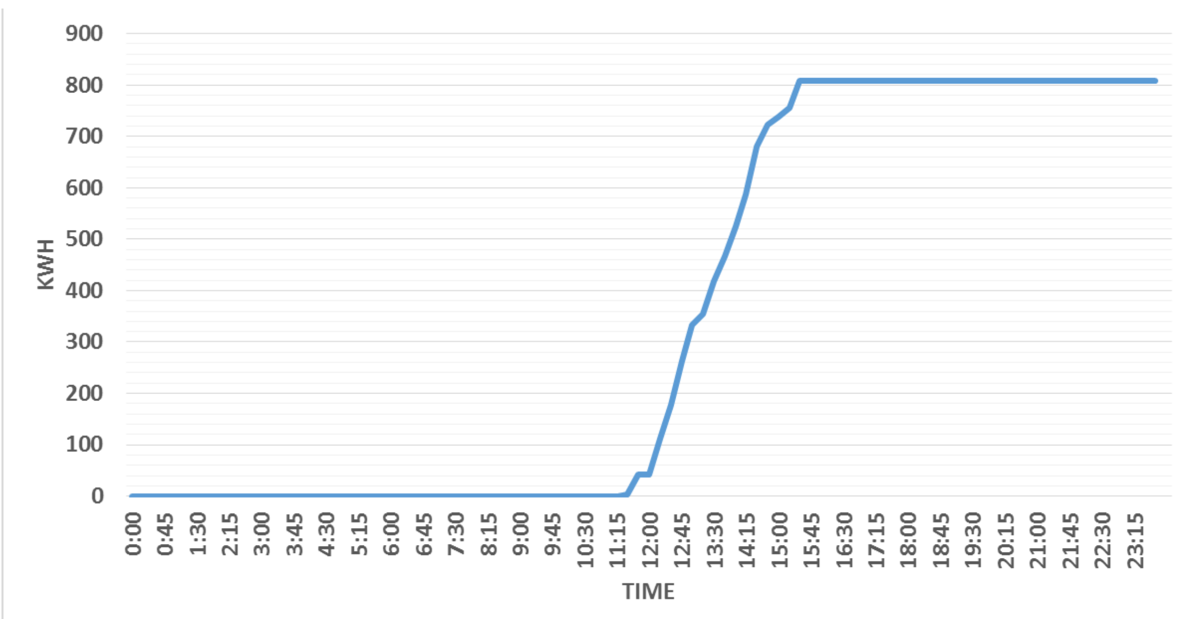


Figure 9-14. C1202 Accumulative Discharge (Centralized Upgrade Deferral) for CCUD 3

9.2 Additional study results for Microgrid Application

9.2.1 BESS sizing for CMG2

The microgrid topology and location of PV and ESS are shown in Figure 9-15.

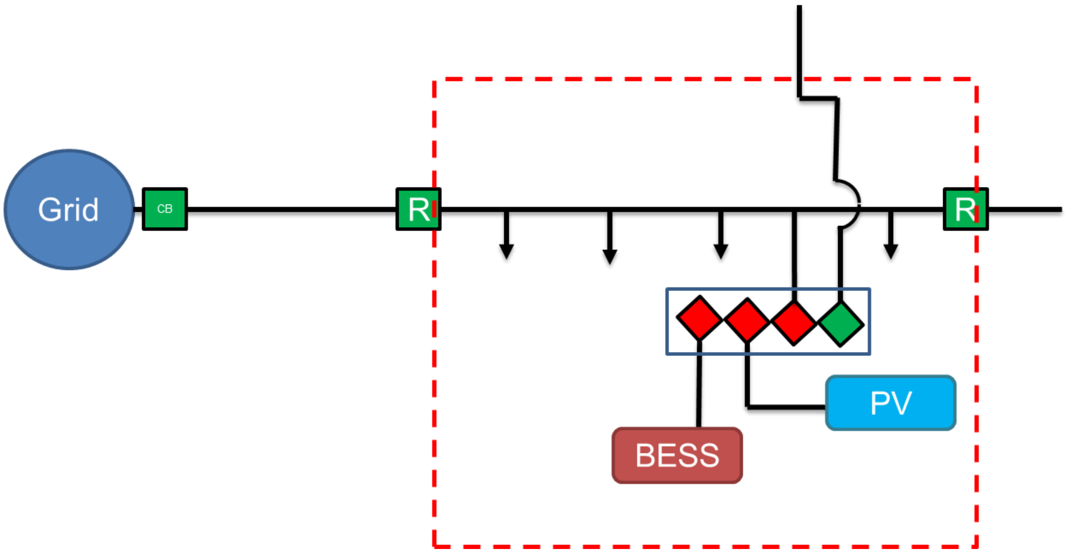


Figure 9-15. CMG2 - microgrid topology

The summary of recommended ESS sizes for is provided in Table 9-1. These ESS sizes are recommended based on simulation results of 4-hour, 6-hour, and 8-hour outages occurring any time during the year on the microgrid area. Based on the simulation results, the required size of battery (kW and kWh) for each of the simulated outages are gathered and ESS is sized to cover the maximum required kW and kWh. The required size of ESS unit for 4-hour, 6-hour, and 8-hour outages occurring at different times during 2016 are illustrated in Figure 9-16, Figure 9-17, and Figure 9-18.

Table 9-1. ESS size recommendations for CMG2

Outage Duration	Maximum Energy Required (kWh)	Peak Load (kW)	Recommended ESS Size
4 hours	2743	711	**750kW – 4.0 Hrs**
6 hours	4048	711	**1100kW – 4.0 Hrs**
8 hours	5300	711	**1400kW – 4.0 Hrs**

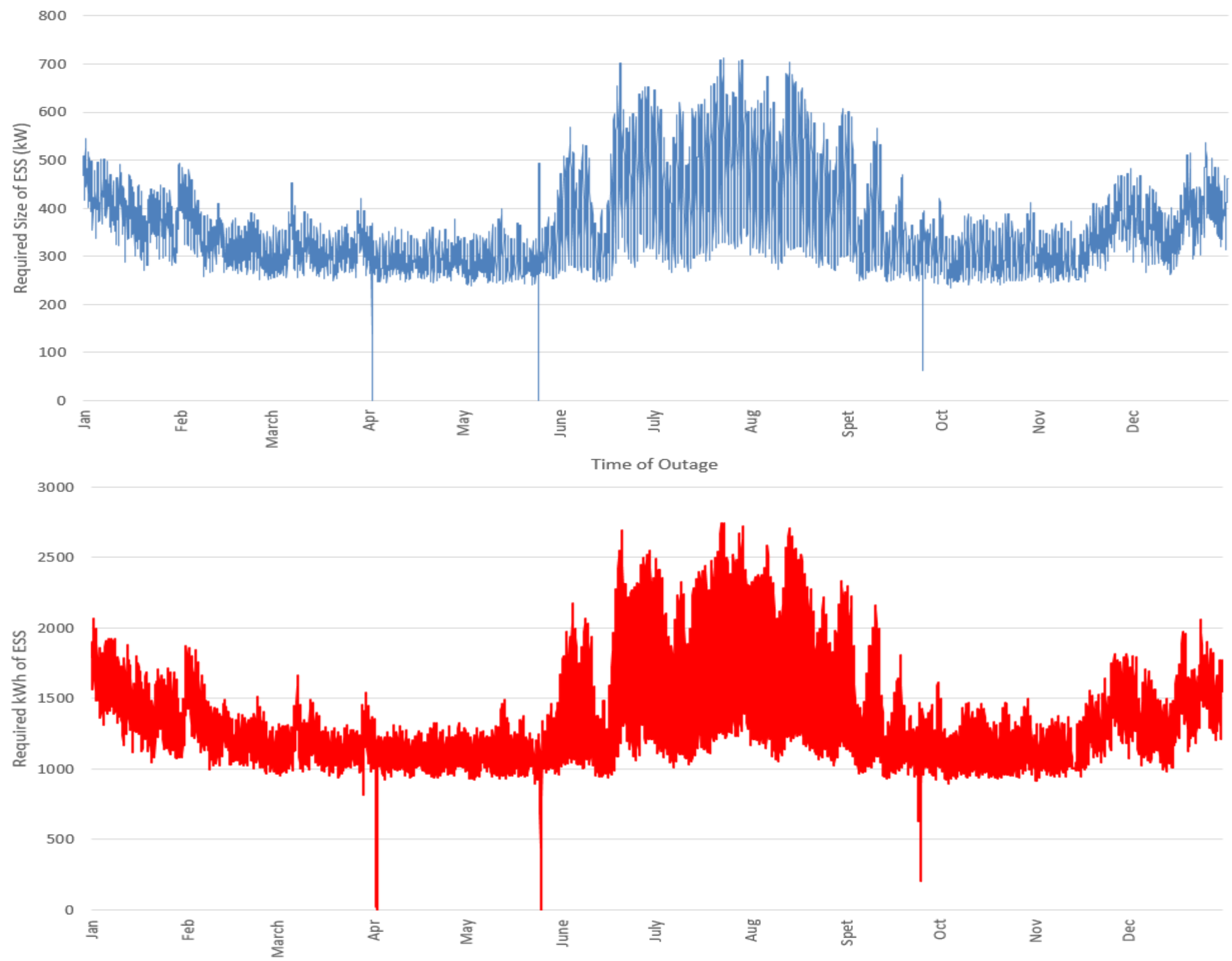


Figure 9-16. Required kW and kWh of ESS to support CMG2 microgrid load for 4-hour outages

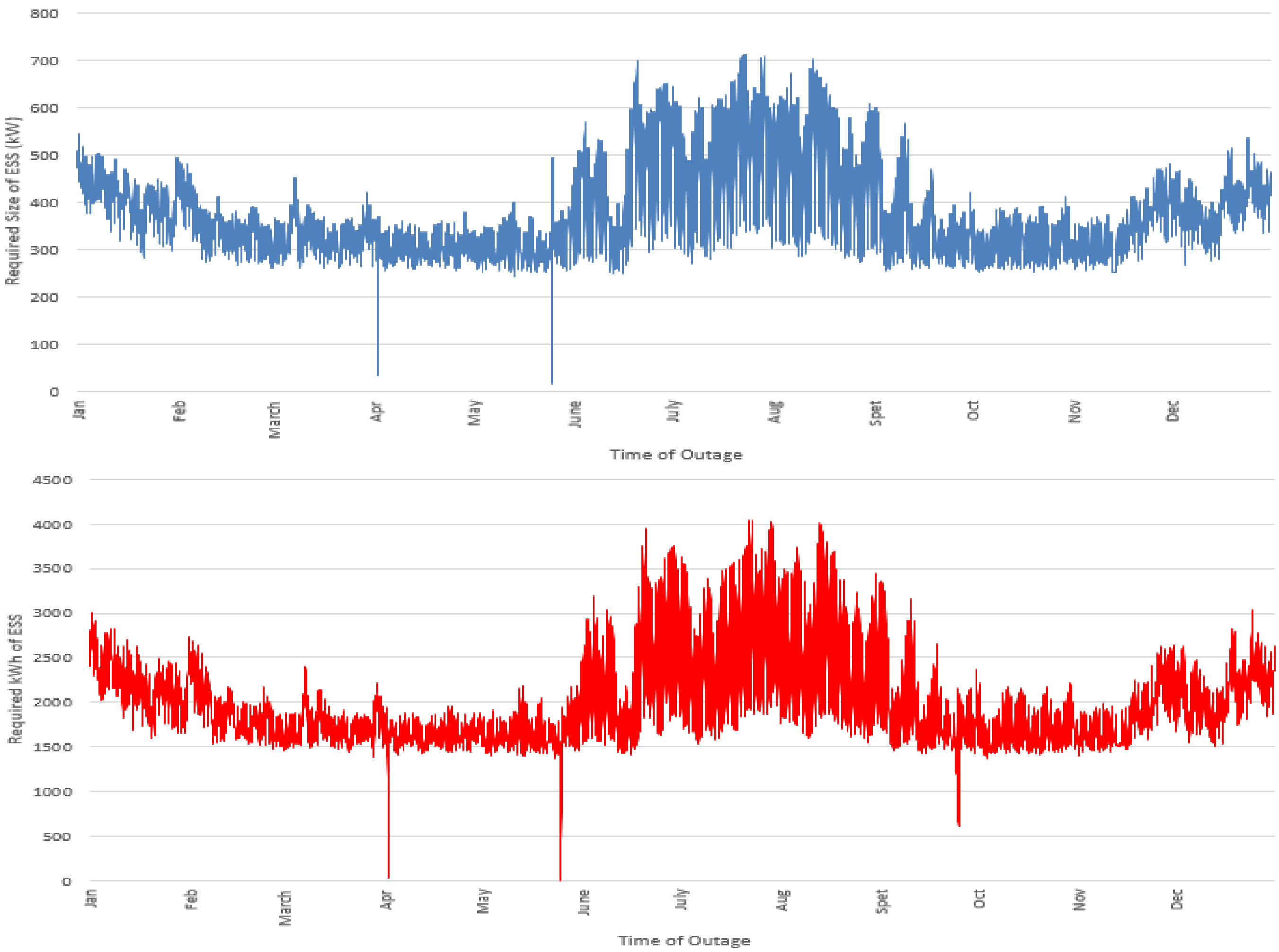


Figure 9-17. Required kW and kWh of ESS to support CMG2 microgrid load for 6-hour outages

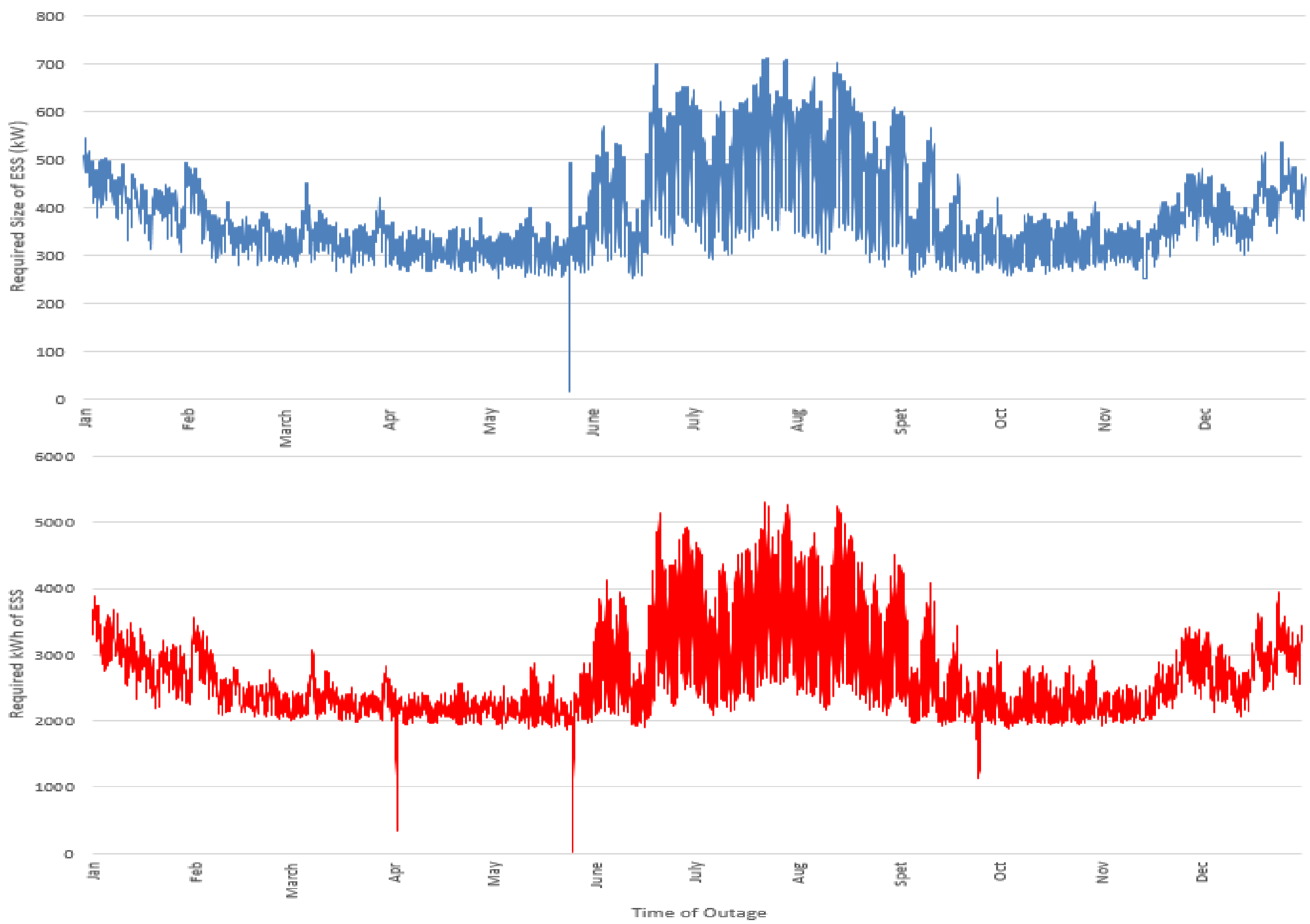


Figure 9-18. Required kW and kWh of ESS to support CMG2 microgrid load for 8-hour outages

9.2.2 BESS sizing for CMG3

The microgrid topology and location of ESS are shown in Figure 9-19. The ESS is planned to be located very close to a library as a cool zone.

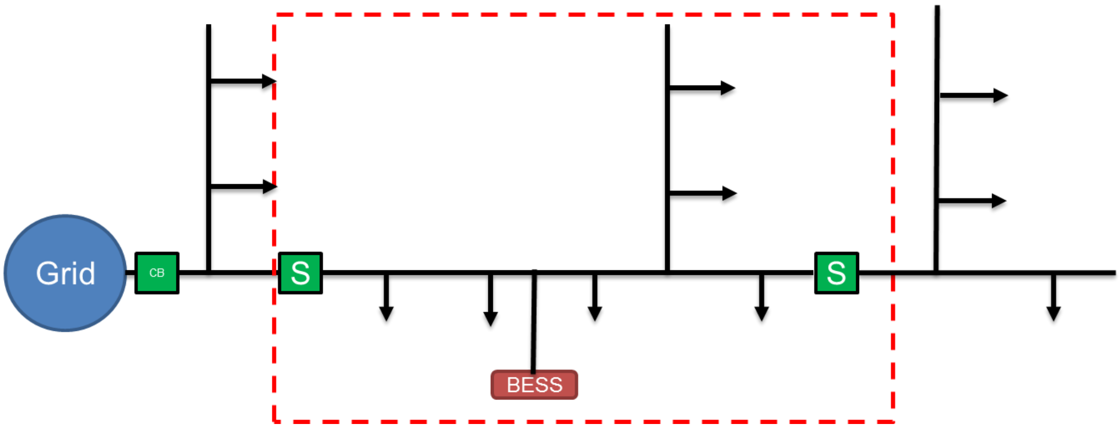


Figure 9-19. CMG3- microgrid topology

The summary of recommended ESS sizes is provided in Table 9-2. These ESS sizes are recommended based on simulation results of 4-hour, 6-hour, and 8-hour outages occurring any time during the year on the microgrid area. Based on the simulation results, the required size of battery (kW and kWh) for each of the simulated outages are gathered and ESS is sized to cover the maximum required kW and kWh. The required size of ESS unit for 4-hour, 6-hour, and 8-hour outages occurring at different times during 2016 are illustrated in Figure 9-20, Figure 9-21, and Figure 9-22.

Table 9-2. Recommended ESS sizes for CMG3

Outage Duration	Maximum Energy Required (kWh)	Peak Load (kW)	Recommended ESS Size
4 hours	2465.95 kWh	616.5kW	**800 kW – 4.0 Hrs**
6 hours	3698.93 kWh	616.5kW	**1100 kW – 4.0 Hrs**
8 hours	4931.91 kWh	616.5kW	**1400 kW – 4.0 Hrs**

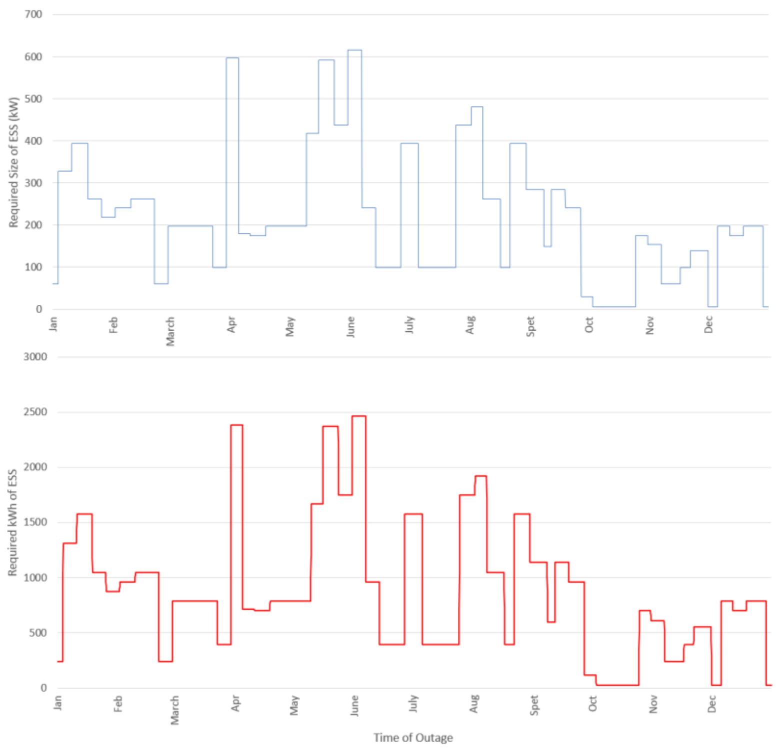


Figure 9-20. Required kW and kWh of ESS to Support CMG3 Microgrid Load for 4-hour Outages

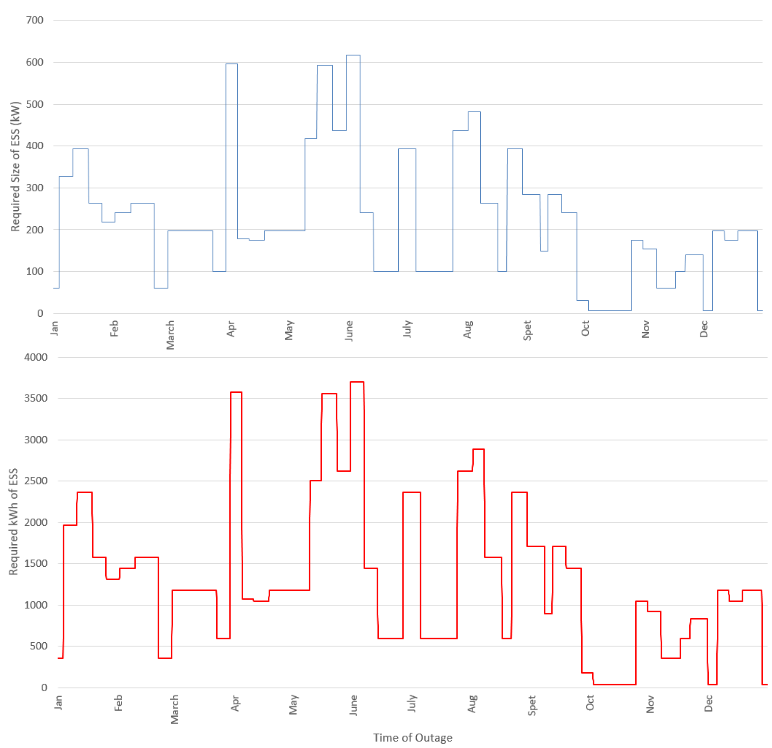


Figure 9-21. Required kW and kWh of ESS to support CMG3 microgrid load for 6-hour outages

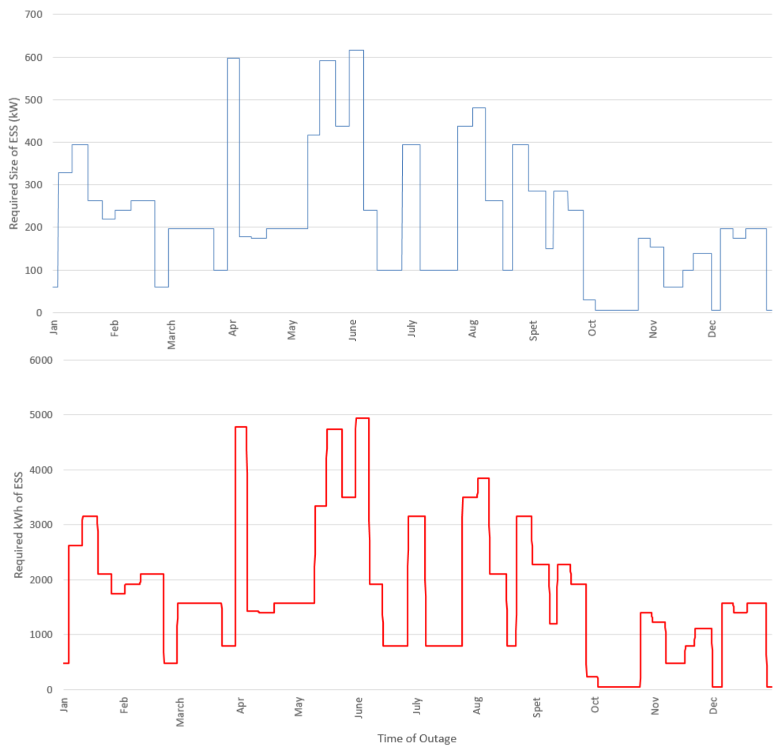


Figure 9-22. Required kW and kWh of ESS to support CMG3 microgrid load for 8-hour outages

9.2.3 BESS sizing for CMG4

The microgrid topology and location of ESS are shown in Figure 9-23. The ESS is planned to be co-located with one of the critical customers (a library) which is also utilized as a “cool zone” for the community.

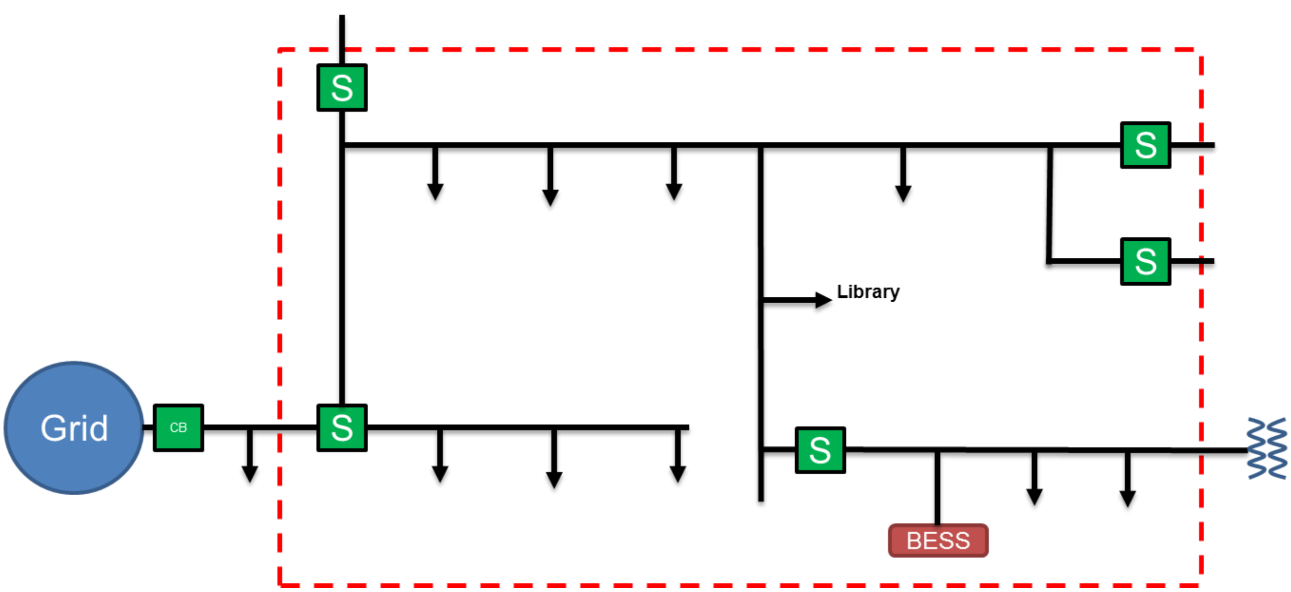


Figure 9-23. CMG4 - microgrid topology

The summary of recommended ESS sizes for is provided in Table 9-3. These ESS sizes are recommended based on simulation results of 4-hour, 6-hour, and 8-hour outages occurring any time during the year on the microgrid area. Based on the simulation results, the required size of battery (kW and kWh) for each of the simulated outages are gathered and ESS is sized to cover the maximum required kW and kWh. The required size of ESS unit for 4-hour, 6-hour, and 8-hour outages occurring at different times during 2016 are illustrated in Figure 9-24, Figure 9-25, and Figure 9-26.

Table 9-3. Recommended ESS sizes for CMG4

Outage Duration	Maximum Energy Required (kWh)	Peak Load (kW)	Recommended ESS Size
4 hours	8005.76 kWh	2063.94 kW	**2500 kW – 4.0 Hrs**
6 hours	11748 kWh	2063.94 kW	**3200 kW – 4.0 Hrs**
8 hours	15211.56 kWh	2063.94 kW	**4100 kW – 4.0 Hrs**

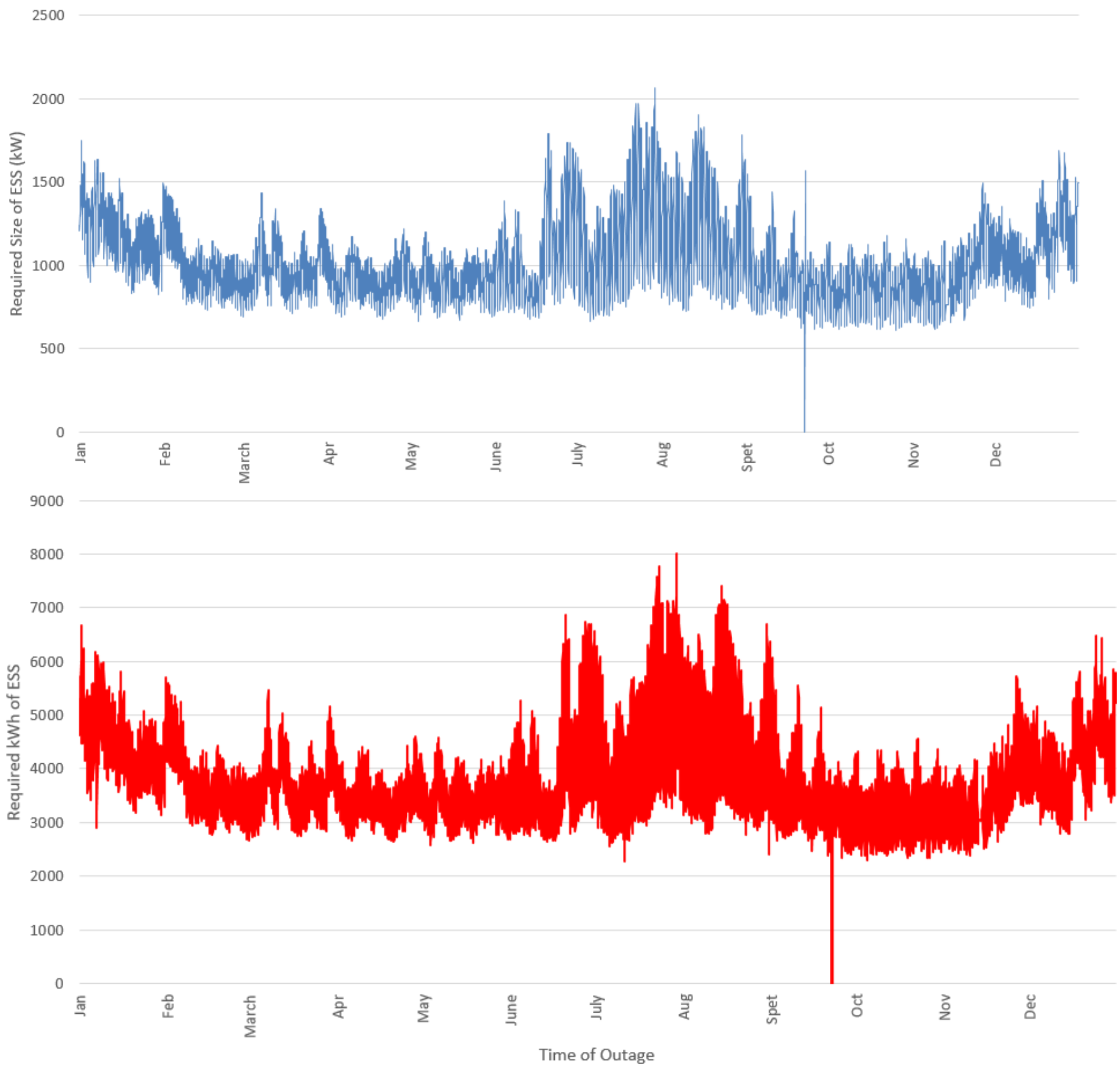


Figure 9-24. Required kW and kWh of ESS to support CMG4 microgrid load for 4-hour outages

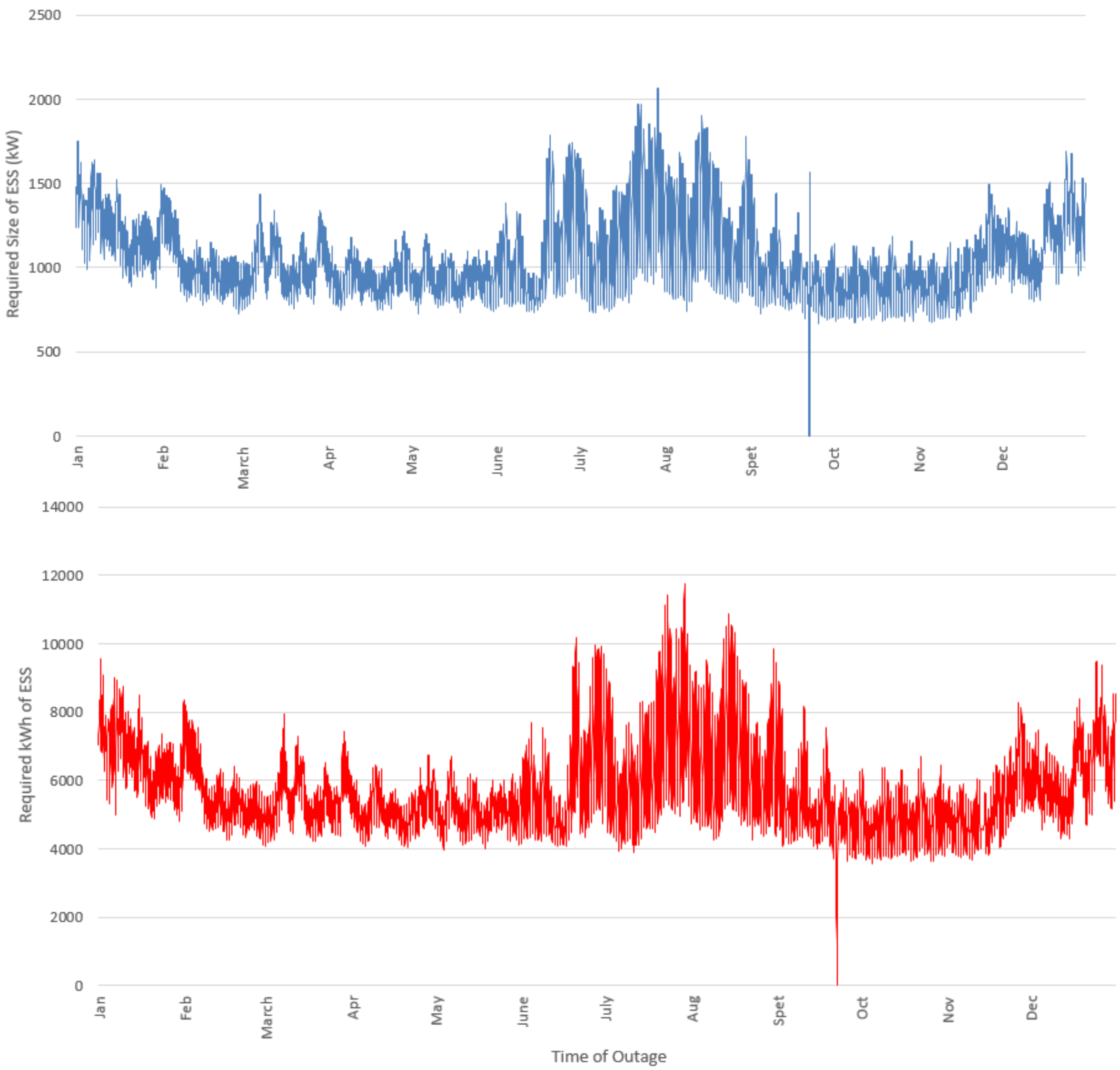


Figure 9-25. Required kW and kWh of ESS to support CMG4 microgrid load for 6-hour outages

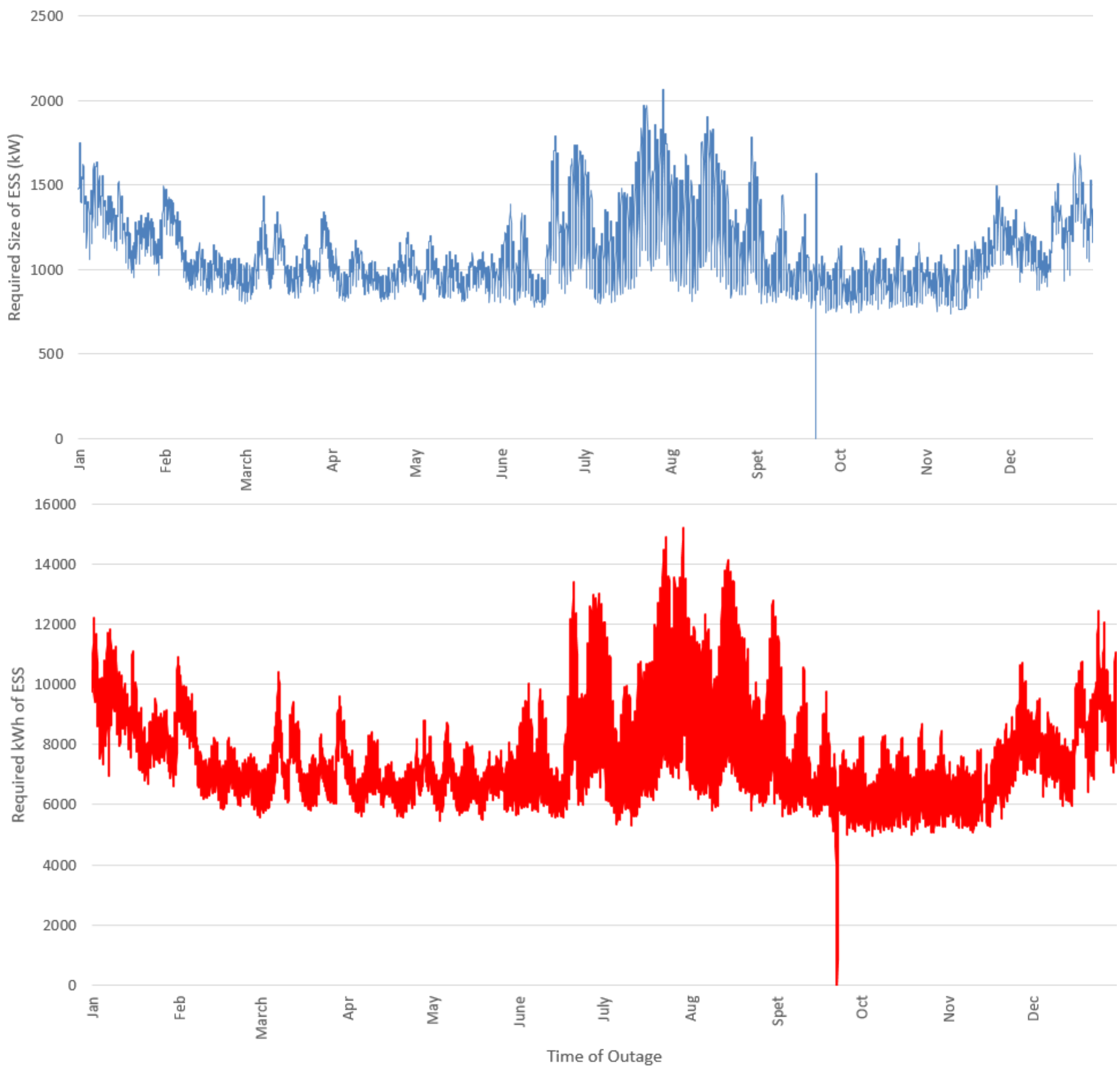


Figure 9-26. Required kW and kWh of ESS to support CMG4 microgrid load for 8-hour outages

9.2.4 CBA for Circuit CMG2

Market analysis is conducted for three ESS sizes designed to manage 4, 6, and 8 hour outages. For each scenario, two variations are considered; with and without PV. Table 9-4 summarizes ESS sizes.

Table 9-4. ESS sizes for CMG2

Outage Duration	ESS Power (kW)	ESS Energy (kWh)
4-hr	750	3,000
6-hr	1,100	4,400
8-hr	1,400	5,600

SOC constraints throughout the year for given outage scenarios are provided in Figure 9-27 to Figure 9-32. SOC constraints limit the capacity of ESS which can participate in the market as secondary application. As seen in the below figures, the SOC constraints are relatively lower in the presence of PV system. The reason is that for the outages during day time PV system can also support a portion of the microgrid load beside ESS.

Without PV:

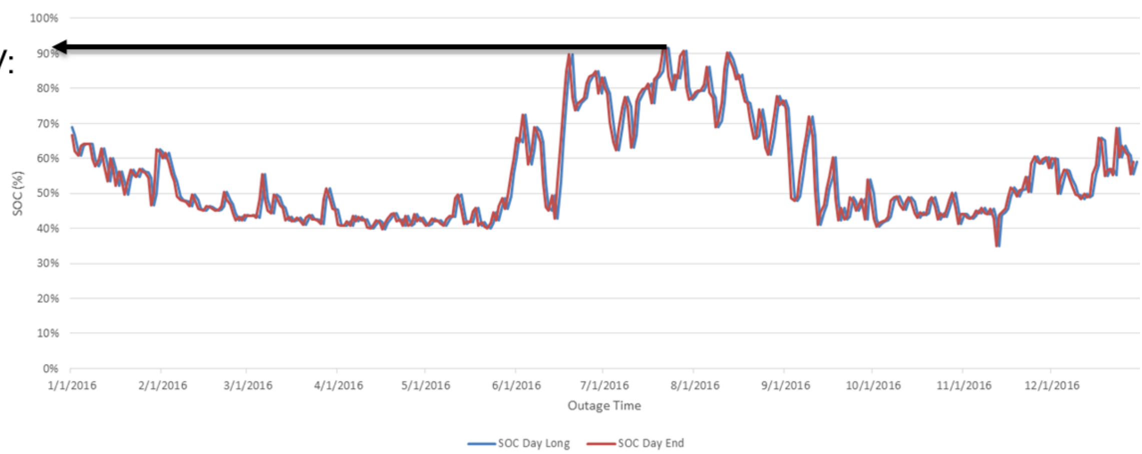


Figure 9-27. SOC constraints for 4-hr outage (without PV)

With PV:

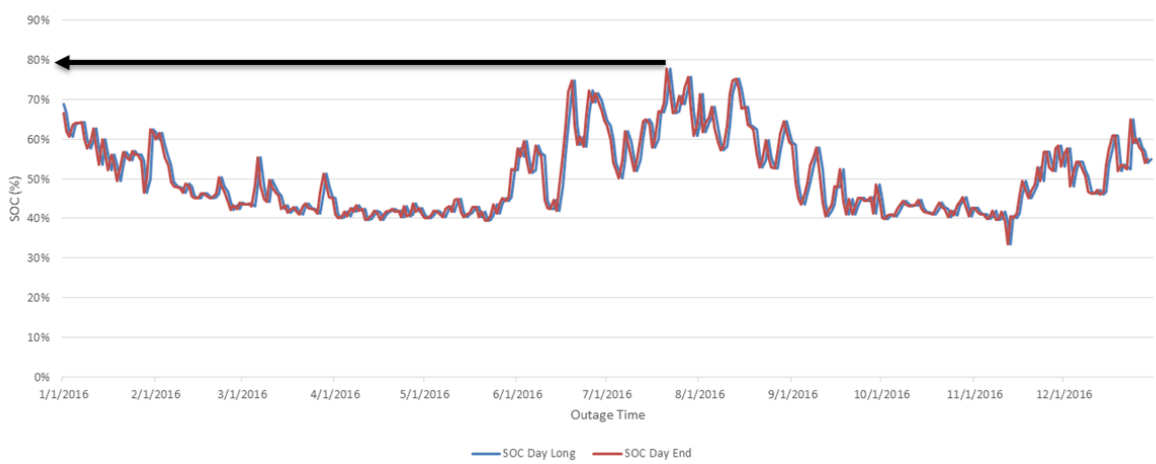


Figure 9-28. SOC constraints for 4-hr outage (with PV)

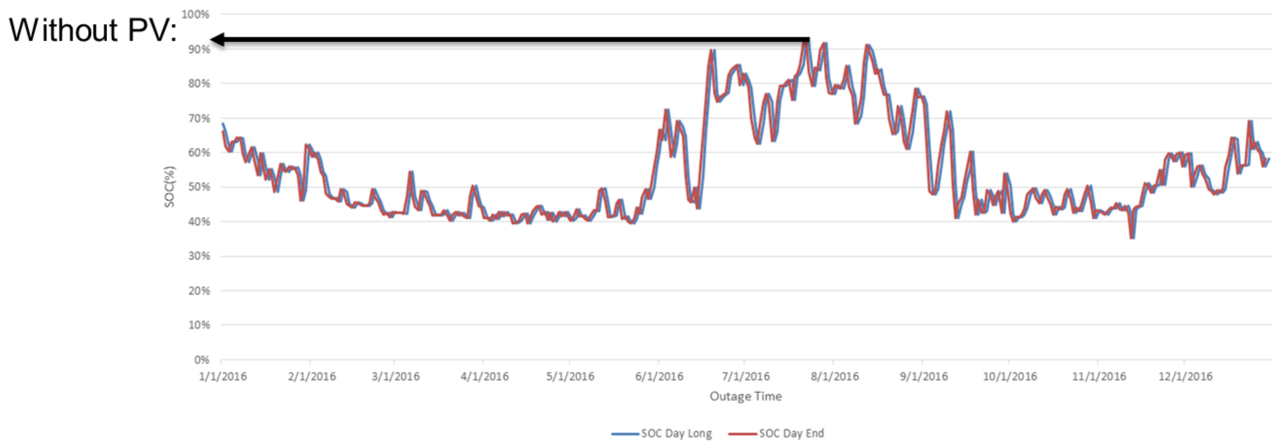


Figure 9-29. SOC constraints for 6-hr outage (without PV)

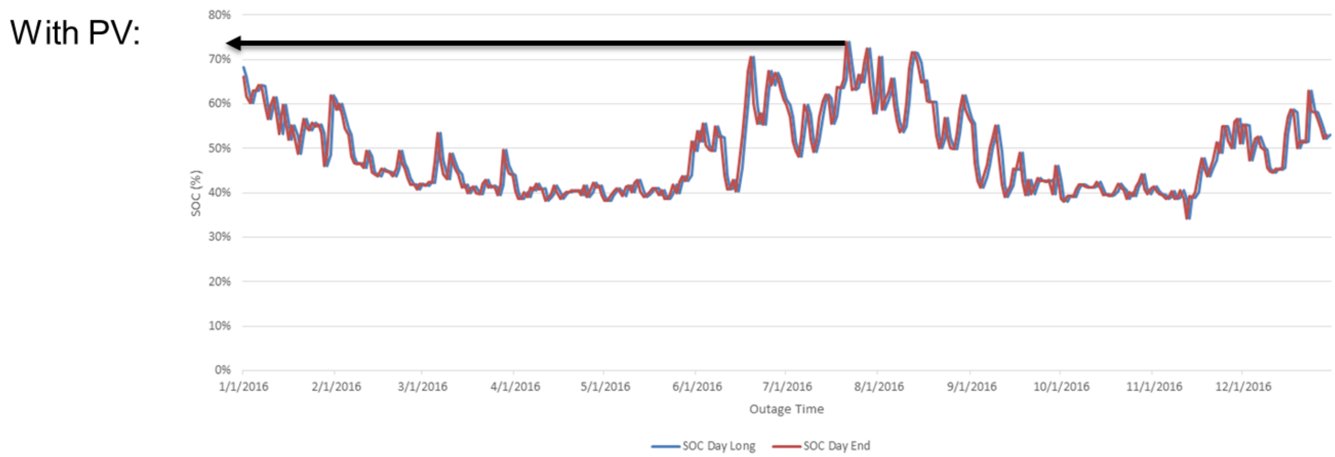


Figure 9-30. SOC constraints for 6-hr outage (with PV)

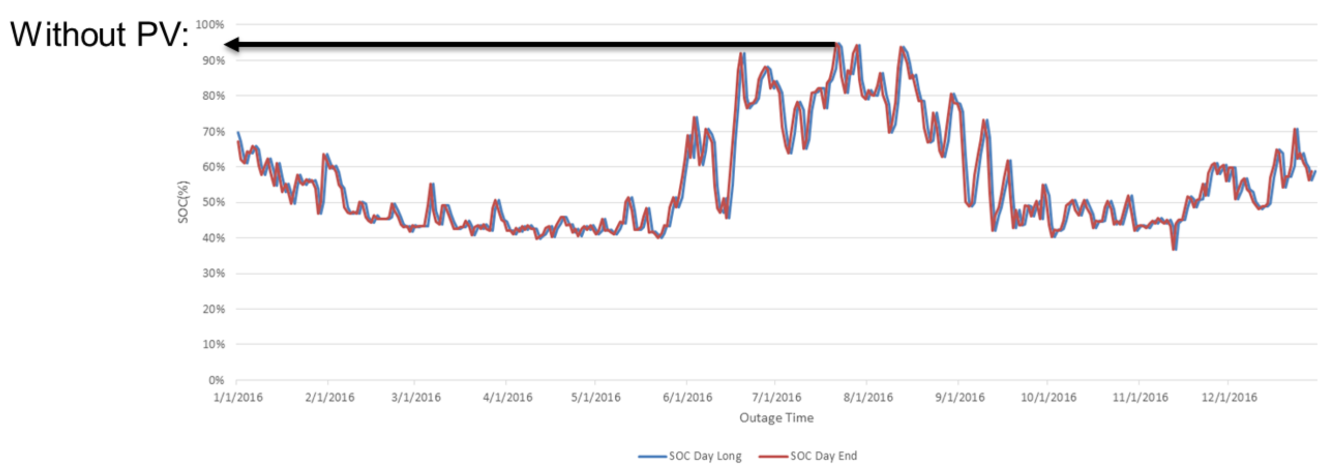


Figure 9-31. SOC constraints for 8-hr outage (without PV)

With PV:

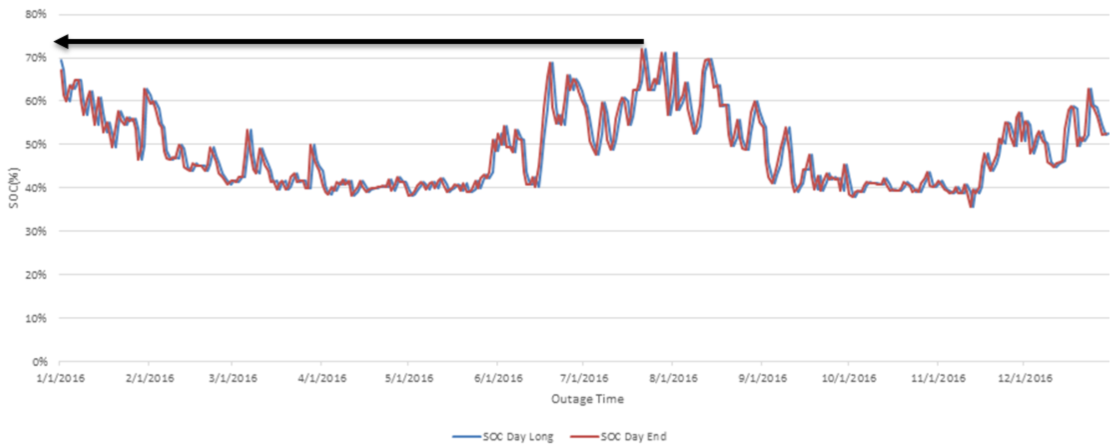


Figure 9-32. SOC constraints for 8-hr outage (with PV)

Annual market benefits are calculated as a summation of energy, Regulation Up and down Capacity, mileage credits less the variable O&M (VOM). It should be noted that VOM of 0.00579 $/kWH is considered for both charging and discharging of the battery. Table 9-5 through Table 9-10 present the results of market analysis for ESS in a microgrid.

Table 9-5. CMG2: 4-hr outage (ESS: 750 kW, 3000 kWh) without PV

4-hr outage (ESS: 750 kW, 3000 kWh) without PV	Energy Credit	Regulation Up Capacity Credit	Regulation Down Capacity Credit	Mileage UP Credit	Mileage Down Credit	VOM	Annual Market Benefits
Wholesale Energy Only	$ 41,764	$ -	$ -	$ -	$ -	$ 5,564	$ 36,200
Wholesale Energy and Ancillary	$ 37,351	$ 37,368	$ 32,557	$ 4,274	$ 8,171	$ 10,011	$ 109,710

Table 9-6. CMG2: 4-hr outage (ESS: 750 kW, 3000 kWh) with PV

4-hr outage (ESS: 750 kW, 3000 kWh) with PV	Energy Credit	Regulation Up Capacity Credit	Regulation Down Capacity Credit	Mileage UP Credit	Mileage Down Credit	VOM	Annual Market Benefits
Wholesale Energy Only	$ 45,078	$ -	$ -	$ -	$ -	$ 5,999	$ 39,078
Wholesale Energy and Ancillary	$ 40,342	$ 37,134	$ 32,506	$ 4,240	$ 8,168	$ 10,232	$ 112,158

Table 9-7. CMG2: 6-hr outage (ESS: 1100 kW, 4400 kWh) without PV

6-hr outage (ESS: 1100 kW, 4400 kWh) without PV	Energy Credit	Regulation Up Capacity Credit	Regulation Down Capacity Credit	Mileage UP Credit	Mileage Down Credit	VOM	Annual Market Benefits
Wholesale Energy Only	$ 61,275	$ -	$ -	$ -	$ -	$ 8,176	$ 53,100

Wholesale Energy and Ancillary	$ 54,793	$ 54,807	$ 47,746	$ 6,270	$ 11,983	$ 14,692	$ 160,907

Table 9-8. CMG2: 6-hr outage (ESS: 1100 kW, 4400 kWh) with PV

6-hr outage (ESS: 1100 kW, 4400 kWh) with PV	Energy Credit	Regulation Up Capacity Credit	Regulation Down Capacity Credit	Mileage UP Credit	Mileage Down Credit	VOM	Annual Market Benefits
Wholesale Energy Only	$ 66,943	$ -	$ -	$ -	$ -	$ 8,972	$ 57,970
Wholesale Energy and Ancillary	$ 59,836	$ 54,422	$ 47,650	$ 6,214	$ 11,978	$ 15,084	$ 165,017

Table 9-9. CMG2: 8-hr outage (ESS: 1400 kW, 5600 kWh) without PV

8-hr outage (ESS: 1400 kW, 5600 kWh) without PV	Energy Credit	Regulation Up Capacity Credit	Regulation Down Capacity Credit	Mileage UP Credit	Mileage Down Credit	VOM	Annual Market Benefits
Wholesale Energy Only	$ 76,595	$ -	$ -	$ -	$ -	$ 10,220	$ 66,375
Wholesale Energy and Ancillary	$ 68,489	$ 69,853	$ 60,790	$ 7,996	$ 15,253	$ 18,605	$ 203,776

Table 9-10. CMG2: 8-hr outage (ESS: 1400 kW, 5600 kWh) with PV

8-hr outage (ESS: 1400 kW, 5600 kWh) with PV	Energy Credit	Regulation Up Capacity Credit	Regulation Down Capacity Credit	Mileage UP Credit	Mileage Down Credit	VOM	Annual Market Benefits
Wholesale Energy Only	$ 85,436	$ -	$ -	$ -	$ -	$ 11,448	$ 73,988
Wholesale Energy and Ancillary	$ 76,341	$ 69,253	$ 60,646	$ 7,926	$ 15,254	$ 19,204	$ 210,215

9.2.5 CBA for Circuit CMG3

Market analysis is conducted for ESS sized at 800 kW: 3,200 kWh. ESSs is sized in a way to manage 8 hour outages. Hourly SOC constraints are calculated via Distribution Planning Tool 4. The SOC constraints determine the total energy required to serve the load if 8-hour outage happens anytime during the day. SOC constraints are provided in Figure 9-33.

Table 9-11 presents a summary of market analysis results for the ESS in the microgrid.

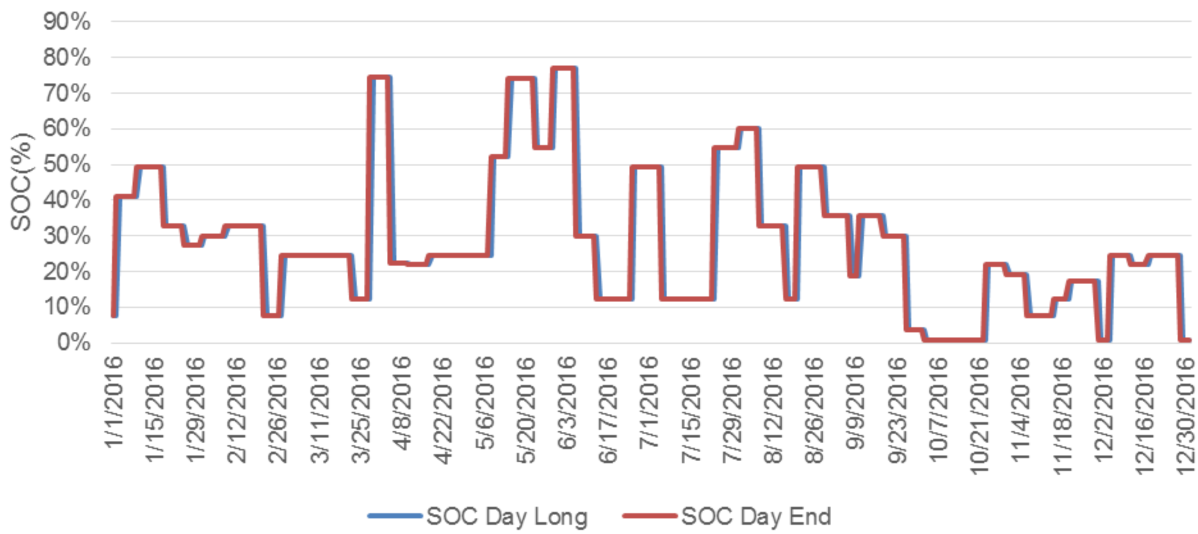


Figure 9-33. CMG3- SOC constraints for 8-hr outage

Table 9-11 CMG3: ESS: 800 kW, 3200 kWh

(ESS: 800 kW, 3200 kWh)	Energy Credit	Regulation Up Capacity Credit	Regulation Down Capacity Credit	Mileage UP Credit	Mileage Down Credit	VOM	Annual Market Benefits
Wholesale Energy Only	$ 59,965	$ -	$ -	$ -	$ -	$ 8,037	$ 51,928
Wholesale Energy and Ancillary	$ 53,337	$ 39,353	$ 34,353	$ 4,457	$ 8,734	$ 11,725	$ 128,510

9.2.6 CBA for Circuit CMG4

Market analysis is conducted for ESS sized at 2,500 kW: 10,000 kWh. ESSs is sized in a way to manage 8 hour outages. Hourly SOC constraints are calculated via Distribution Planning Tool 4. The SOC constraints determine the total energy required to serve the load if 8-hour outage happens anytime during the day. SOC constraints are provided in Figure 9-34.

Table 9-12 presents a summary of market analysis results for the ESS in the microgrid.

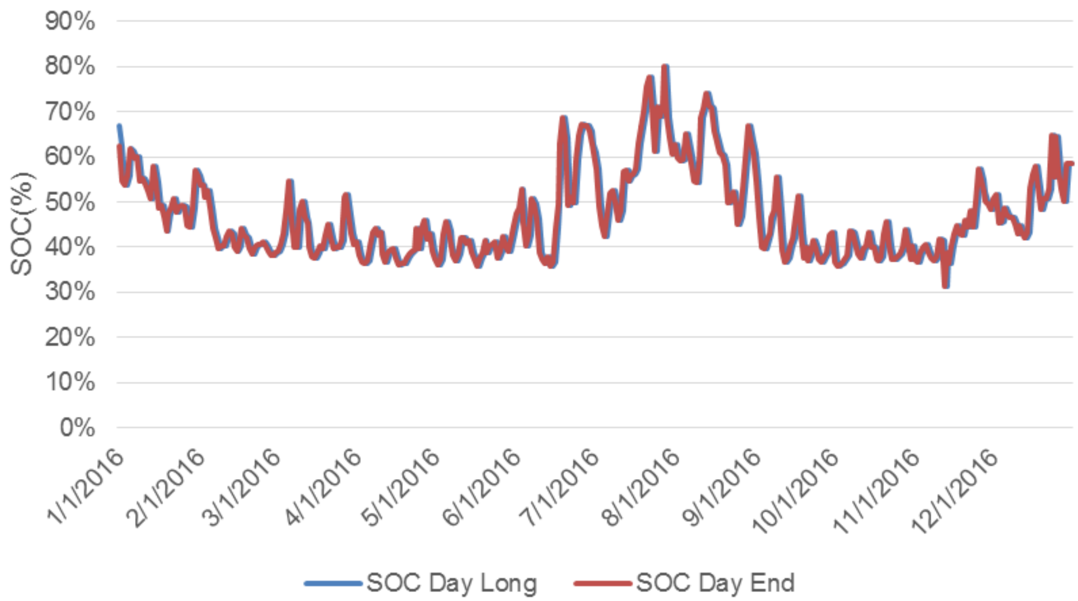


Figure 9-34. CMG4- SOC constraints for 8-hr outage

Table 9-12 CMG4: ESS: 2,500 kW, 10,000 kWh

ESS: 2500 kW, 10000 kWh	Energy Credit	Regulation Up Capacity Credit	Regulation Down Capacity Credit	Mileage UP Credit	Mileage Down Credit	VOM	Annual Market Benefits
Wholesale Energy Only	$ 173,284	$ -	$ -	$ -	$ -	$ 21,990	$ 151,294
Wholesale Energy and Ancillary	$ 155,539	$ 123,787	$ 108,026	$ 14,068	$ 27,354	$ 35,370	$ 393,405

9.3 Additional study results for PV Intermittency Application

9.3.1 Load profile selection and daily analysis

The impacts of high PV penetration is highly pronounced when the feeders are lightly loaded and at the same time a large amount of PV is connected. Thus, for each of the PV impact circuits the day with the minimum loading in the year 2016 was chosen as the desired study day. A combination of the aforesaid chosen day and the PV profile scaled to the maximum installed PV size of the circuit provides the worst case scenario for the PV impact analysis. Figure 9-35 to Figure 9-41 illustrate the load profile for the PV impact analysis circuits presented in Table 3-5.

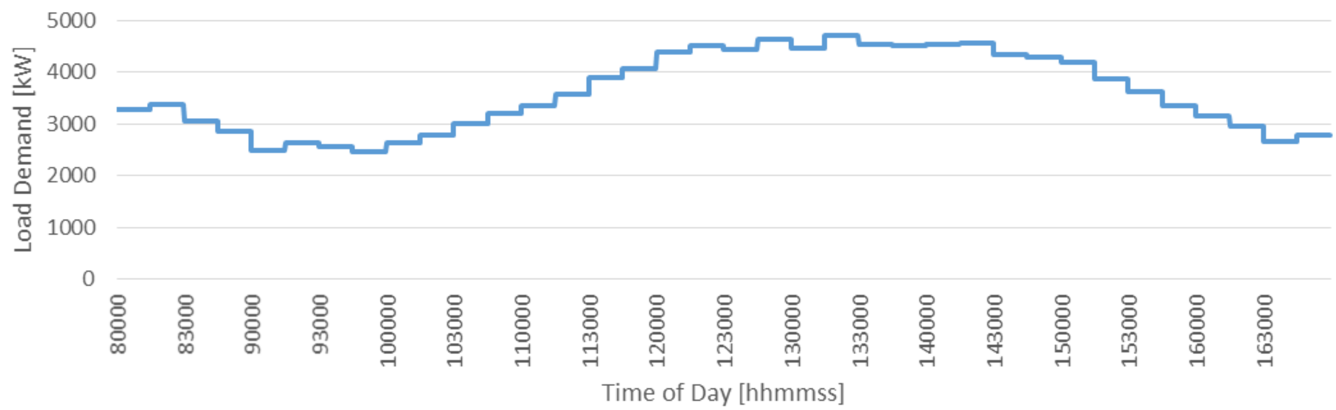


Figure 9-35. Load profile for CPVIM 1

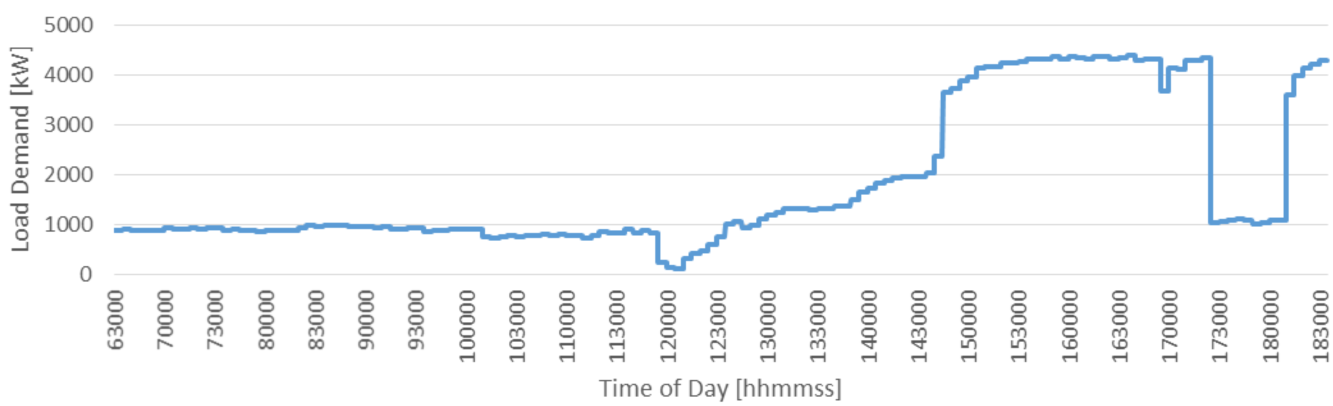


Figure 9-36. Load profile for CPVIM 2

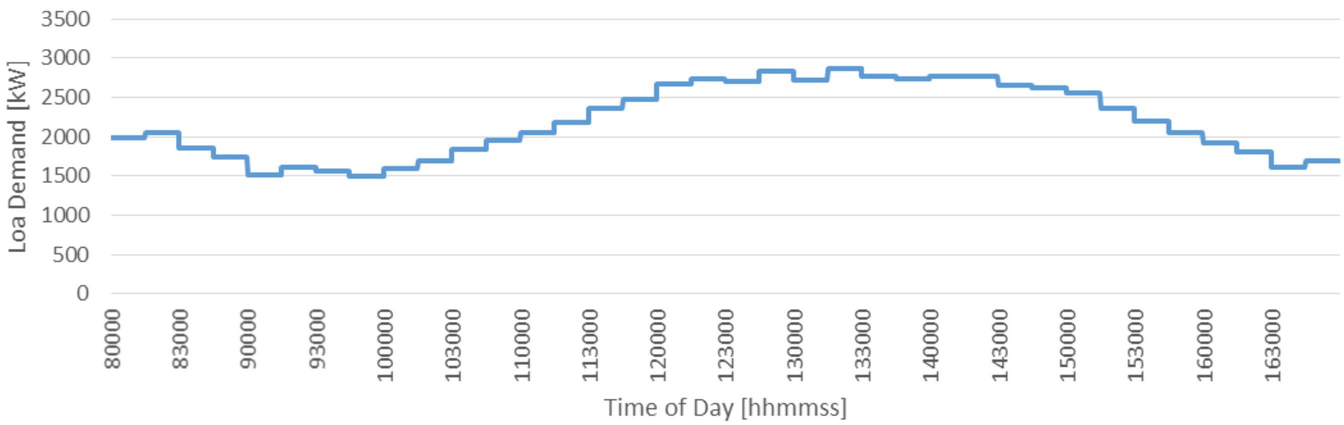


Figure 9-37. Load profile for CPVIM 3

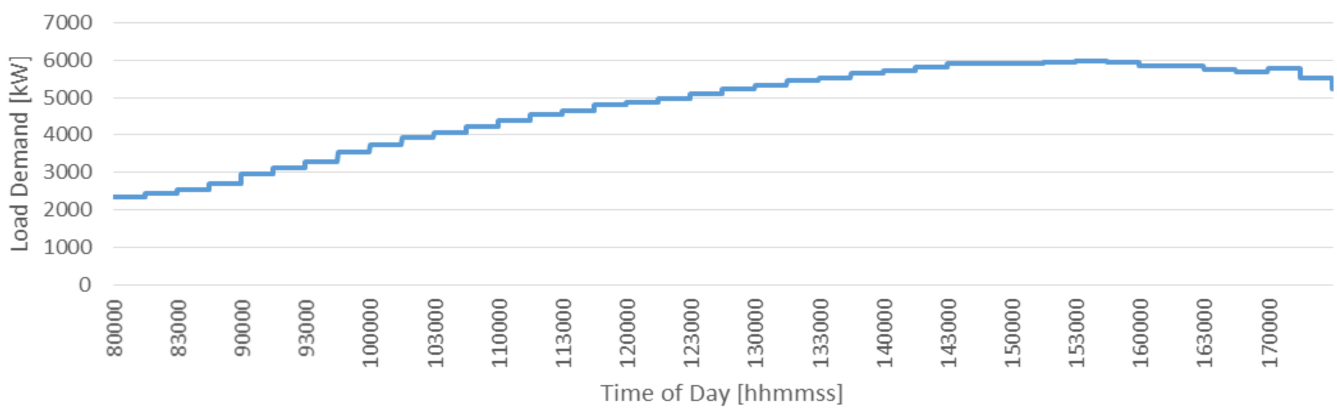


Figure 9-38. Load profile for CPVIM 4

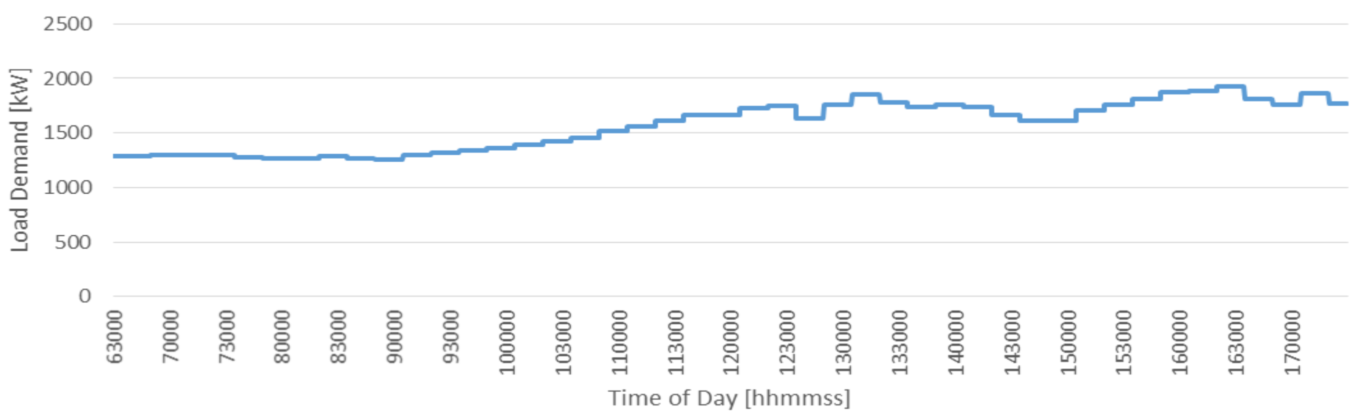


Figure 9-39. Load profile for CPVIM 5

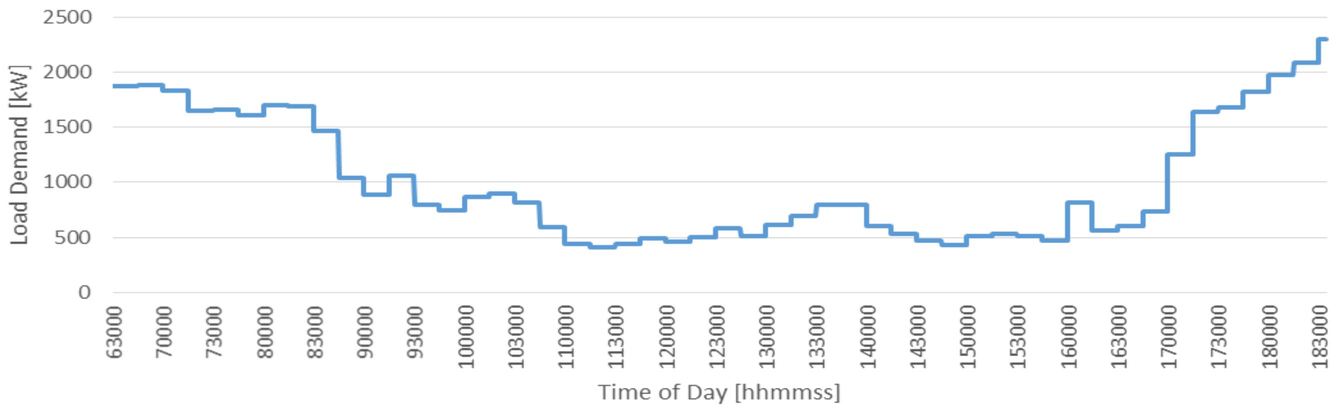


Figure 9-40. Load profile for CPVIM 6

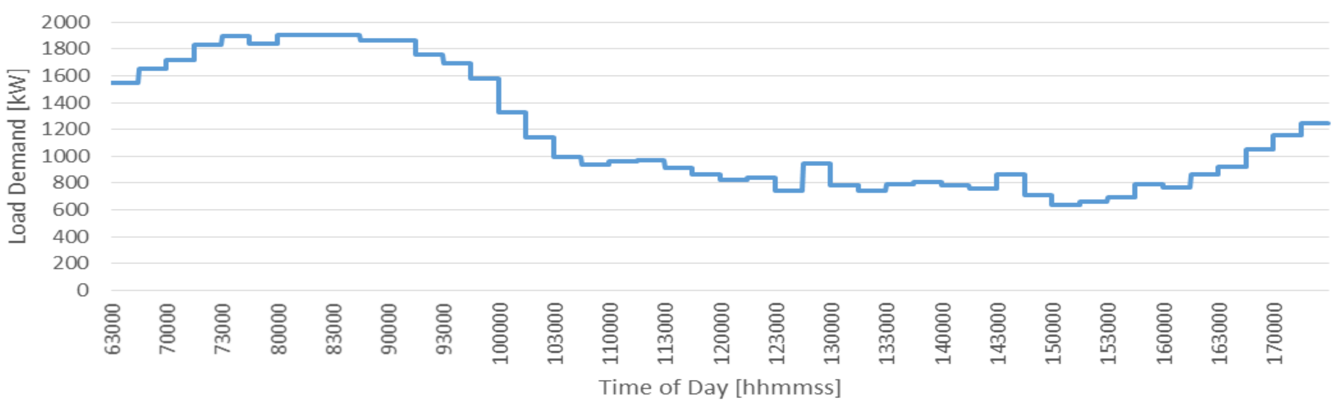


Figure 9-41. Load profile for CPVIM 7

9.3.2 Flicker summary results for all circuits (table format)

Table 9-13 to Table 9-19 illustrate the flicker analysis results of CPVIM 1, CPVIM 2, CPVIM 3, CPVIM 4, CPVIM 5, CPVIM 6, and CPVIM 7, respectively. As it can be seen from the tables, CPVIM 2, CPVIM 3, CPVIM 5, and CPVIM 7 do not have any flicker issues. CPVIM 1 and CPVIM 6 have visible voltage drops. Furthermore, CPVIM 4 has the most flicker issues associated with it, i.e., exceeding the visibility and irritation ranges.

As a result, CPVIM 1, and CPVIM 4 were chosen as the target circuits for further PV impact studies. It should be mentioned that the meters were chosen based on their locations and the availability of the measured voltage values in the model. Example locations are: PV1 (a node close to the PV1), PV2 (a node close to PV2), F1 (first measured node), F2 (second measured node), and so on. The locations that exceed each of the flicker thresholds are marked in the tables with a black triangle symbol.

Table 9-13. Flicker analysis summary for circuit CPVIM 1 (Fx is the monitoring point)

Voltage Signal	Visible Voltage Dips	Irritative Voltage Dips
V_PV1_A	-	-
V_F1_A	▲	-
V_F3_A	▲	-

Table 9-14. Flicker analysis summary for circuit CPVIM 2

Voltage Signal	Visible Voltage Dips	Irritative Voltage Dips
V_PV1_A	-	-
V_PV2_A	-	-
V_F3_A	-	-
V_F6_C	-	-

Table 9-15. Flicker analysis summary for circuit CPVIM 3

Voltage Signal	Visible Voltage Dips	Irritative Voltage Dips
V_PV1_A	-	-
V_PV2_A	-	-
V_F3_A	-	-
V_F6_C	-	-

Table 9-16. Flicker analysis summary for circuit CPVIM 4

Voltage Signal	Visible Voltage Dips	Irritative Voltage Dips
V_F2_A	▲	-
V_F6_A	▲	-
V_F7_A	▲	▲
V_F8_A	▲	▲
V_F9_A	▲	▲
V_F10_A	▲	▲

Table 9-17. Flicker analysis summary for circuit CPVIM 5

Voltage Signal	Visible Voltage Dips	Irritative Voltage Dips
V_F1_A	-	-
V_F2_A	-	-
V_F3_A	-	-
V_F6_A	-	-
V_F8_A	-	-
V_F9_A	-	-

Table 9-18. Flicker analysis summary for circuit CPVIM 6

Voltage Signal	Visible Voltage Dips	Irritative Voltage Dips
V_F1_A	-	-
V_F3_B	▲	-
V_F6_A	-	-

Table 9-19. Flicker analysis summary for circuit CPVIM 7

Voltage Signal	Visible Voltage Dips	Irritative Voltage Dips
V_F1_A	-	-
V_F2_A	-	-
V_F3_A	-	-
V_F4_B	-	-

CPVIM 4: Figure 9-42 illustrates the circuit diagram and the location of the meters used in analysis of CPVIM 4. The meters' data at the F1, F2, F6, F7, F8, F9, and F10 are analyzed to determine any potential for flicker events or ramp rate issues.

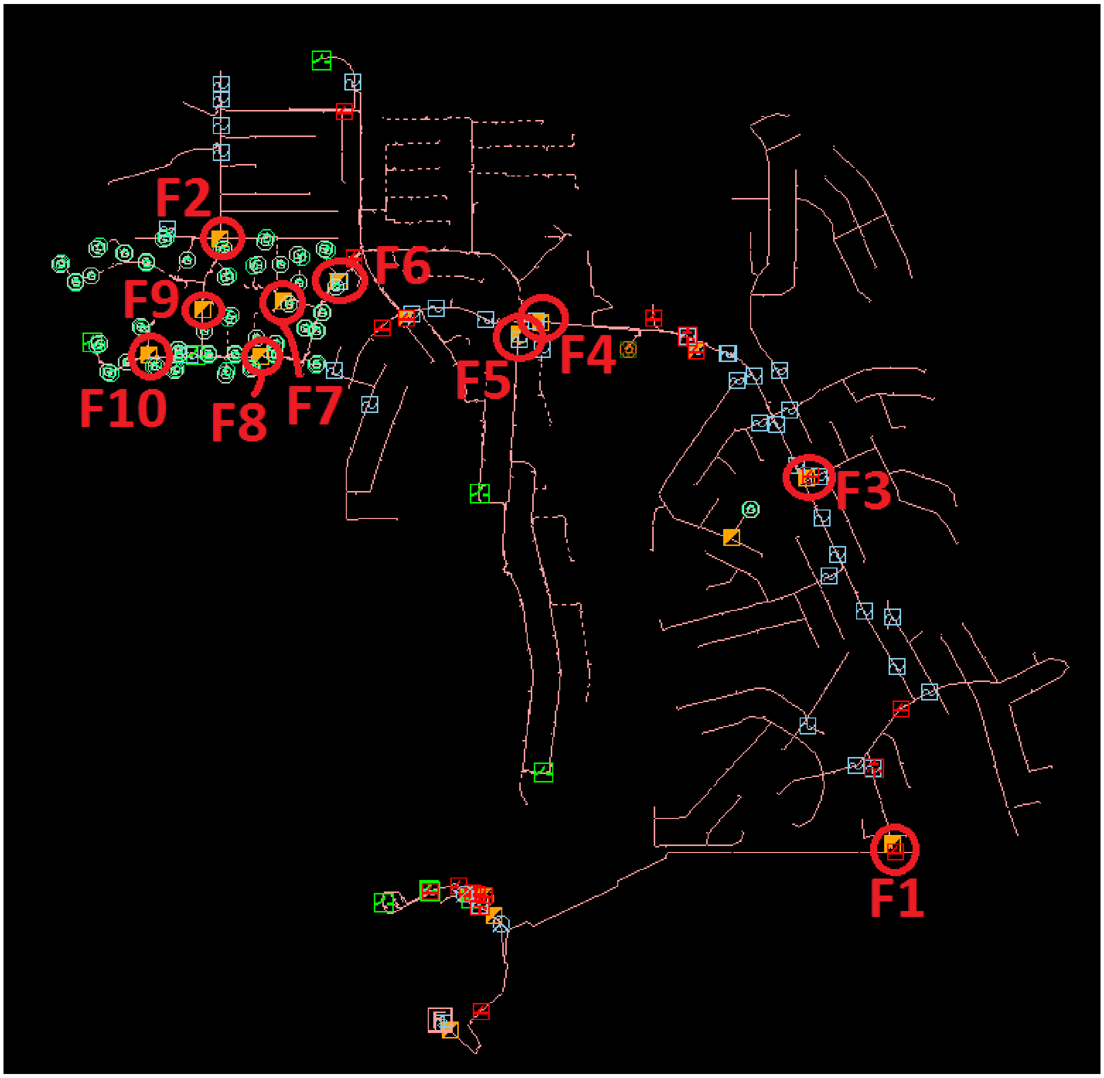


Figure 9-42. Reference diagram of CPVIM 4

Figure 9-43 below shows the flicker calculation curve for the meter at the F1 location of CPVIM 4. As can be seen from Figure 9-43, the flicker level is always below the visibility and irritation level, which indicates that there are no flicker issues at the aforementioned location.

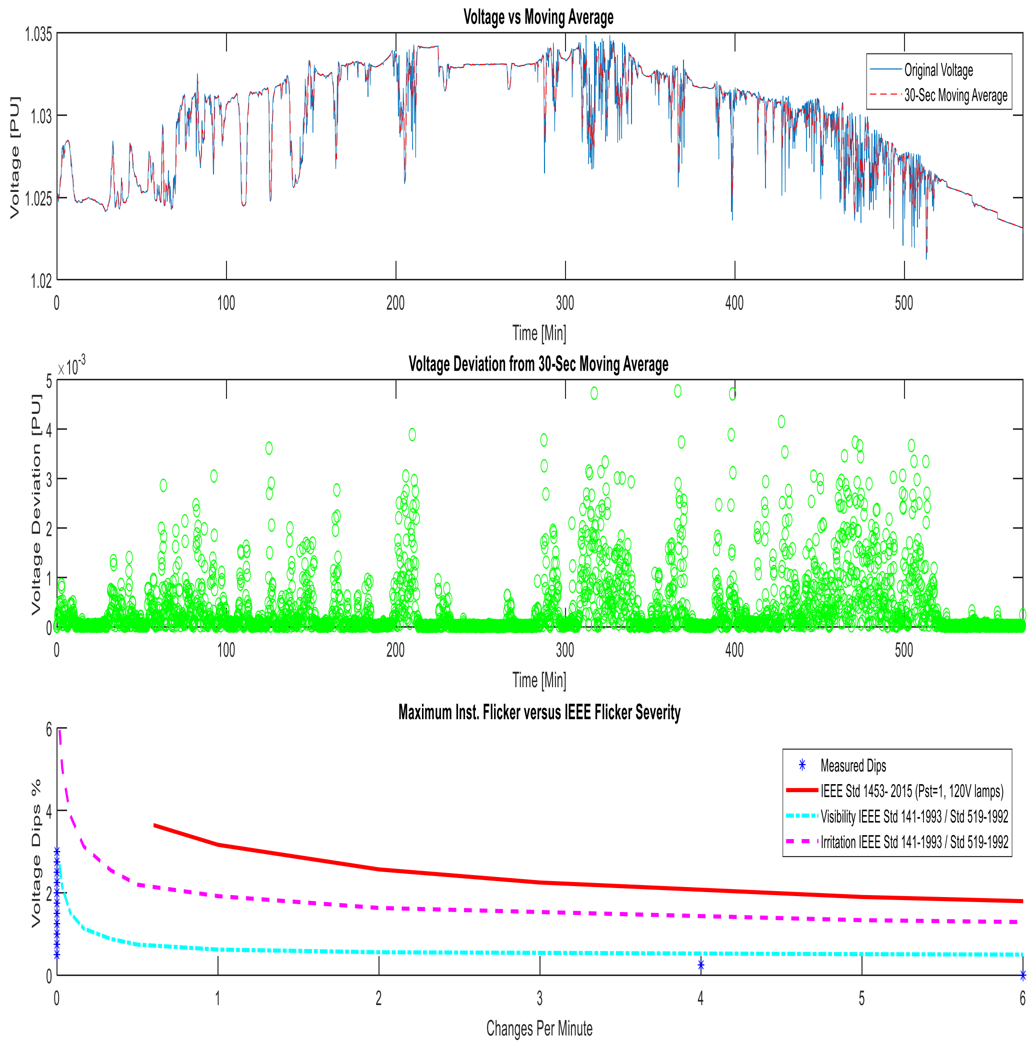


Figure 9-43. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 4 at the F1 location

Figure 9-44 below shows the flicker calculation curve for the meter at the F2 location of CPVIM 4. As can be seen from, the flicker level is above the visibility level in several instances, but almost close to or below the irritation level (based on old GE flicker curve), or below the IEEE flicker curve.

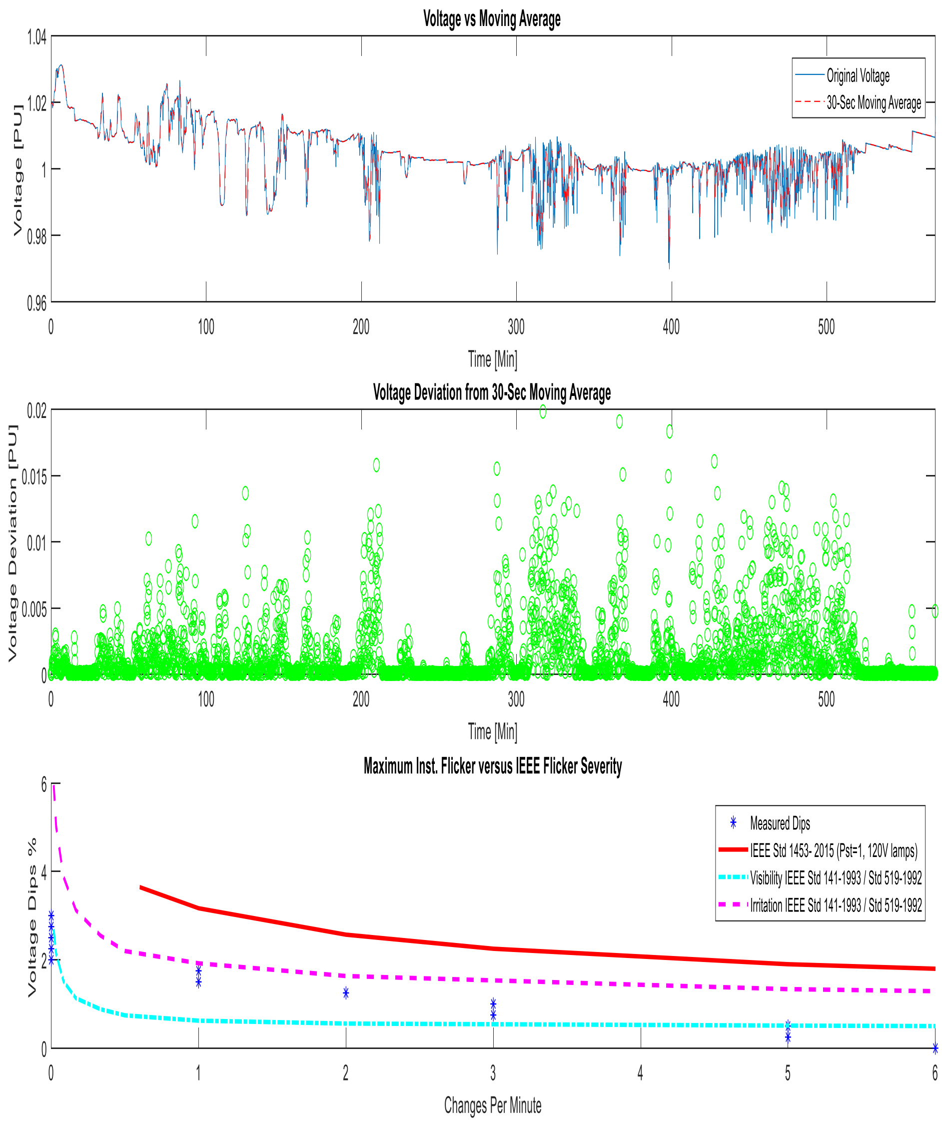


Figure 9-44 – Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 4 at the F2 location

As can be seen from Figure 9-45, the flicker level is above both the visibility and the irritation level in several instances, but below the IEEE flicker curve; this indicates that the location F6 in CPVIM 4 can be an appropriate choice for installing the energy storage system.

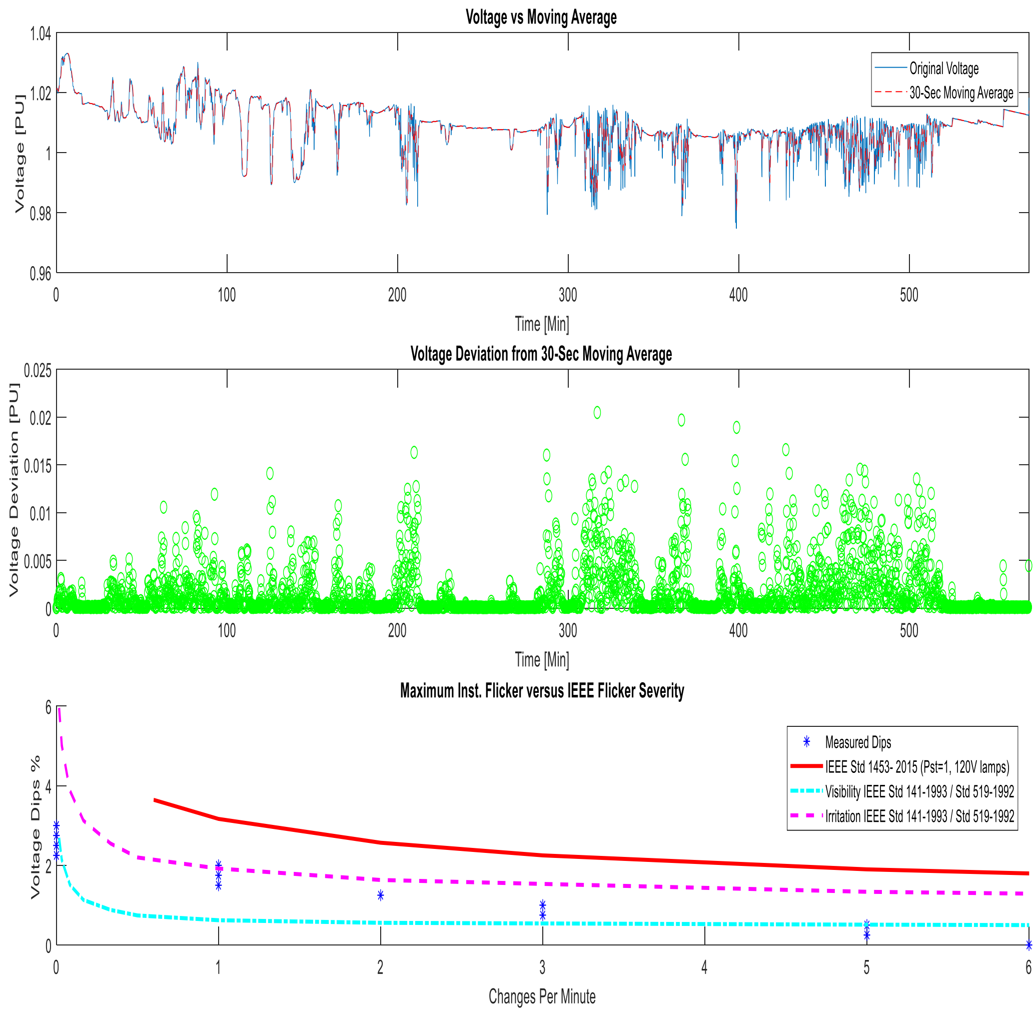


Figure 9-45. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 4 at the F6 location

As can be seen from Figure 9-46, the flicker level is above both the visibility and the irritation level in several instances, but below the IEEE flicker curve; this indicates that the location F7 in CPVIM 4 can be another appropriate location choice for installing the energy storage system.

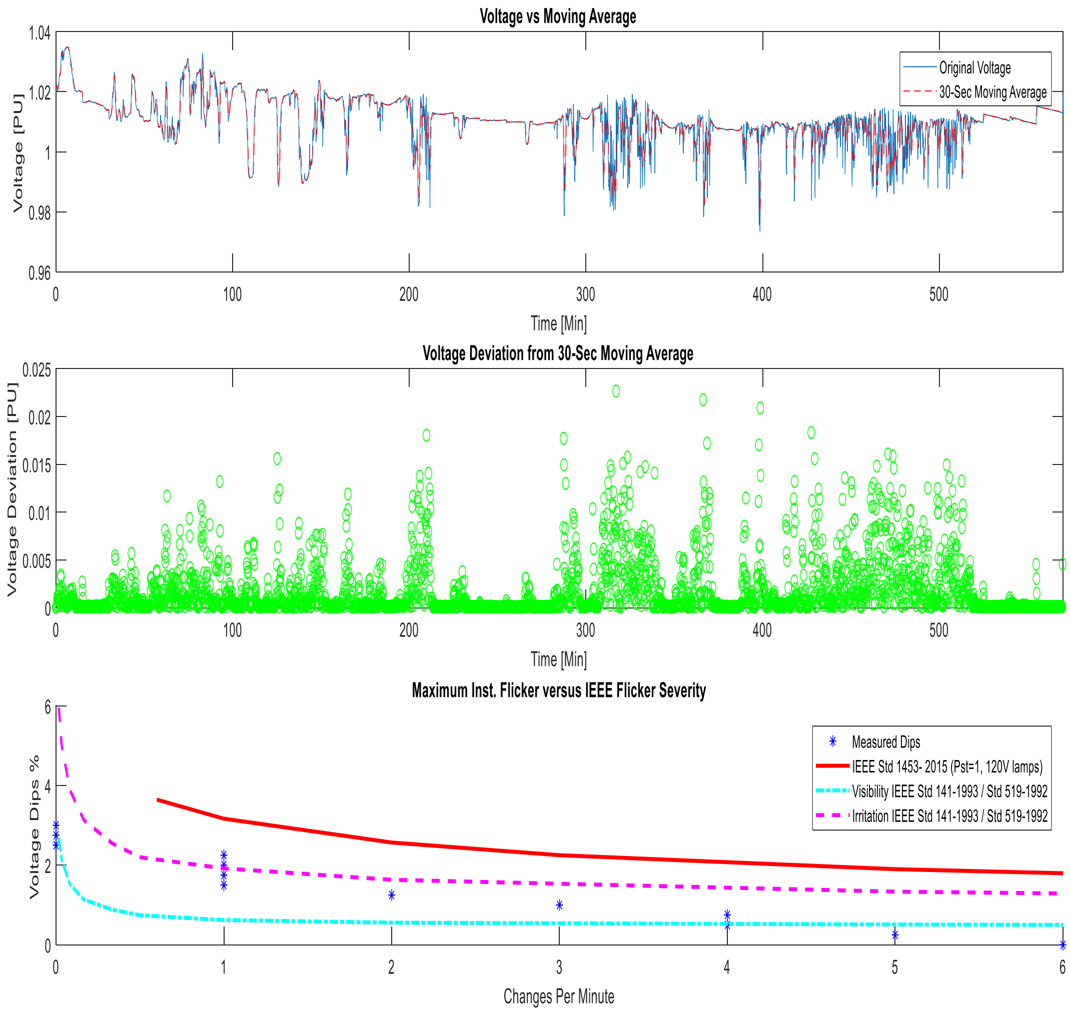


Figure 9-46. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 4 at the F7 location

As can be seen from Figure 9-47, the flicker level is above both the visibility and the irritation level in several instances, but below the IEEE flicker curve; this indicates that the location F8 in CPVIM 4 can be another appropriate location choice for installing the energy storage system.

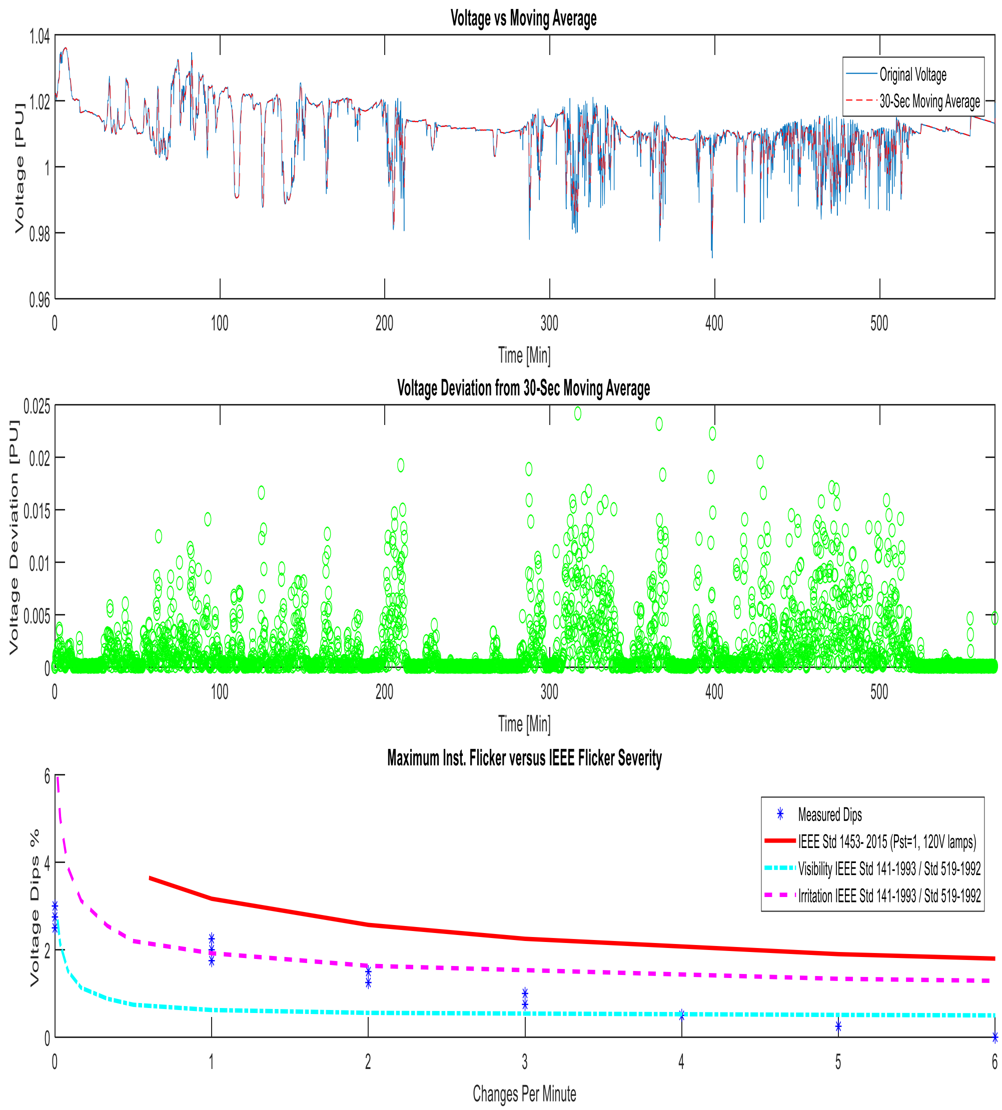


Figure 9-47. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 4 at the F8 location

As can be seen from Figure 9-48, the flicker level is above both the visibility and the irritation level in several instances, but below the IEEE flicker curve; this indicates that the location F9 in CPVIM 4 can be another appropriate location choice for installing the energy storage system.

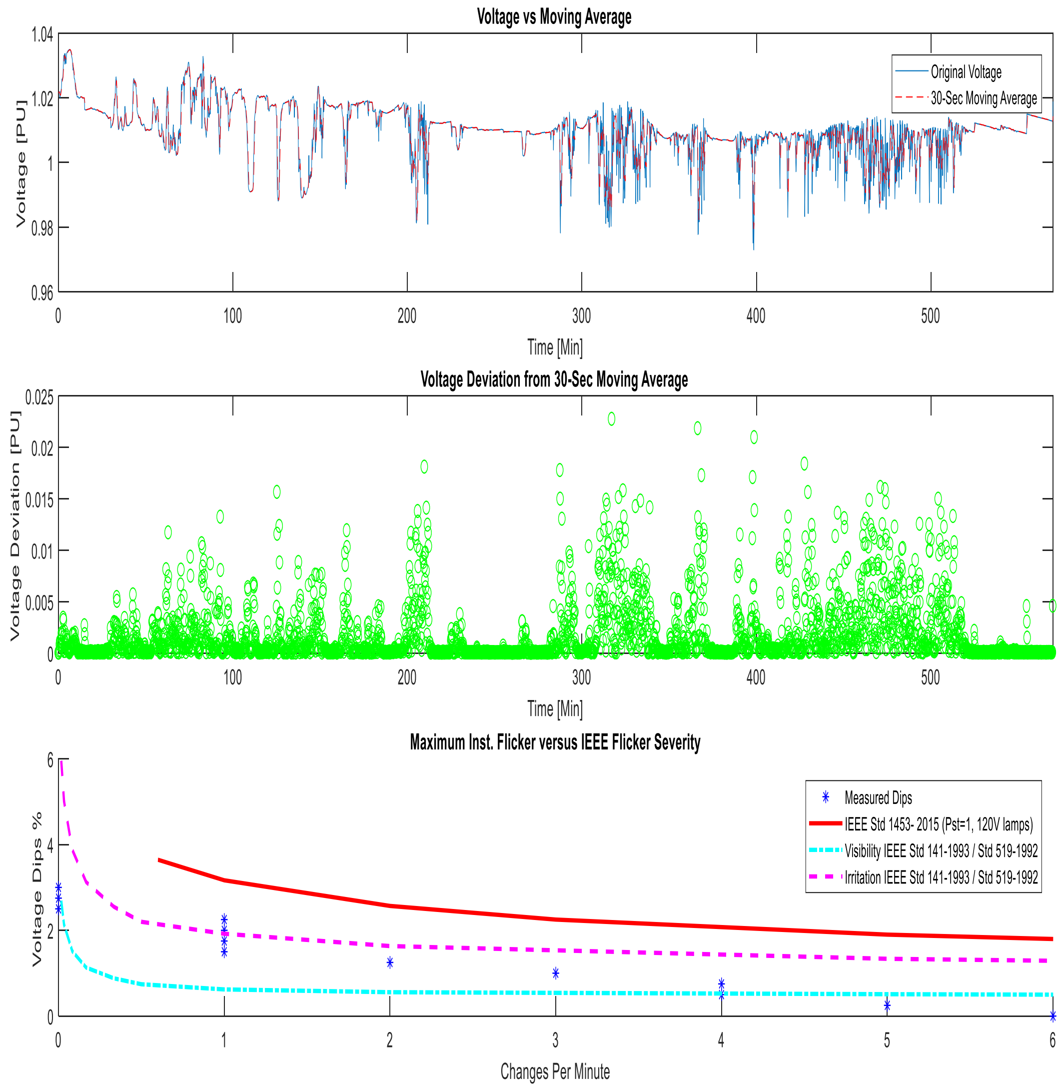


Figure 9-48. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 4 at the F9 location

As can be seen from Figure 9-49, the flicker level is above both the visibility and the irritation level in several instances, but below the IEEE flicker curve; this indicates that the location F10 in CPVIM 4 can be another appropriate location choice for installing the energy storage system.

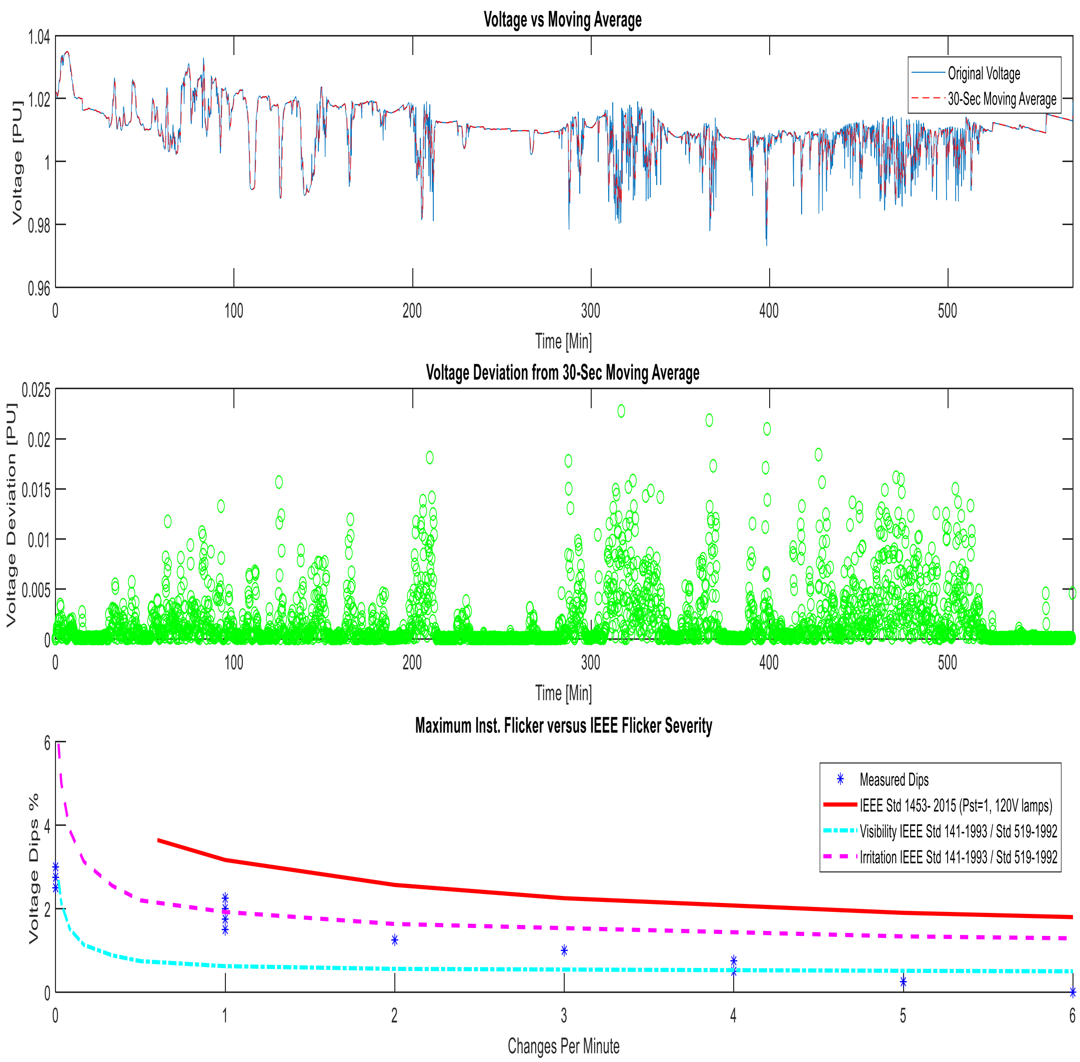
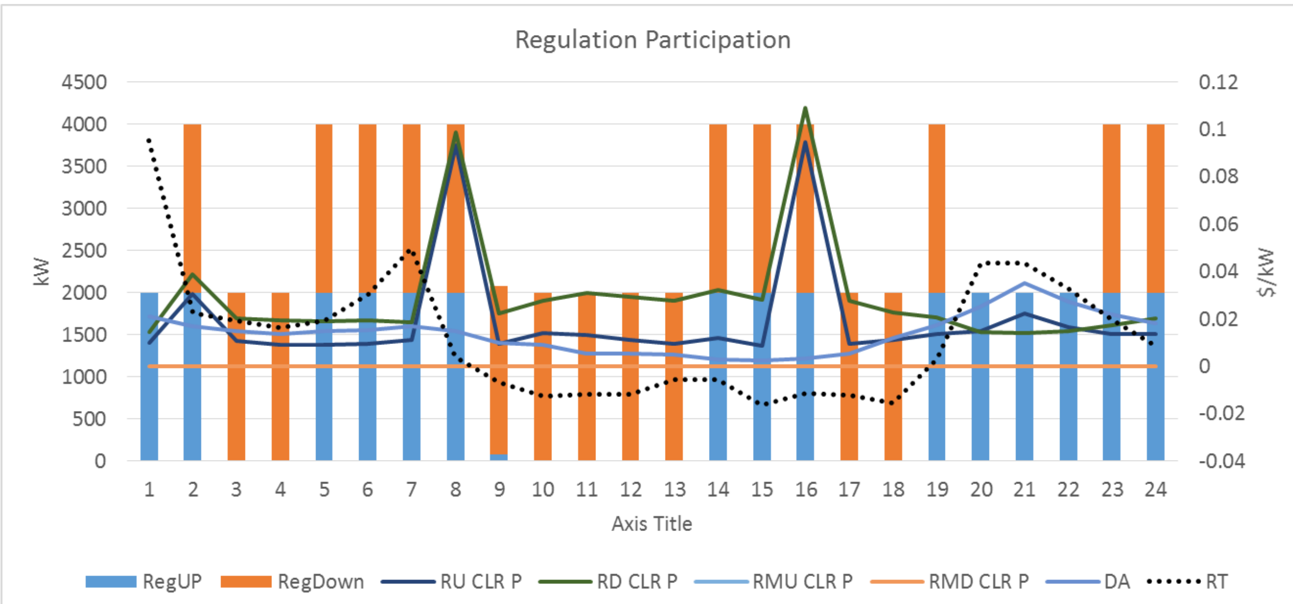


Figure 9-49. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 4 at the F10 location

9.4 Additional study results for wholesale market participation

May 21st 2016 is the day with the highest regulation prices. We can see the change in regulation participation and charge/discharge patterns as the limit on regulation participation changes from 20% to 50% and 100% (Figure 9-50)

At 20% of capacity available for regulation:



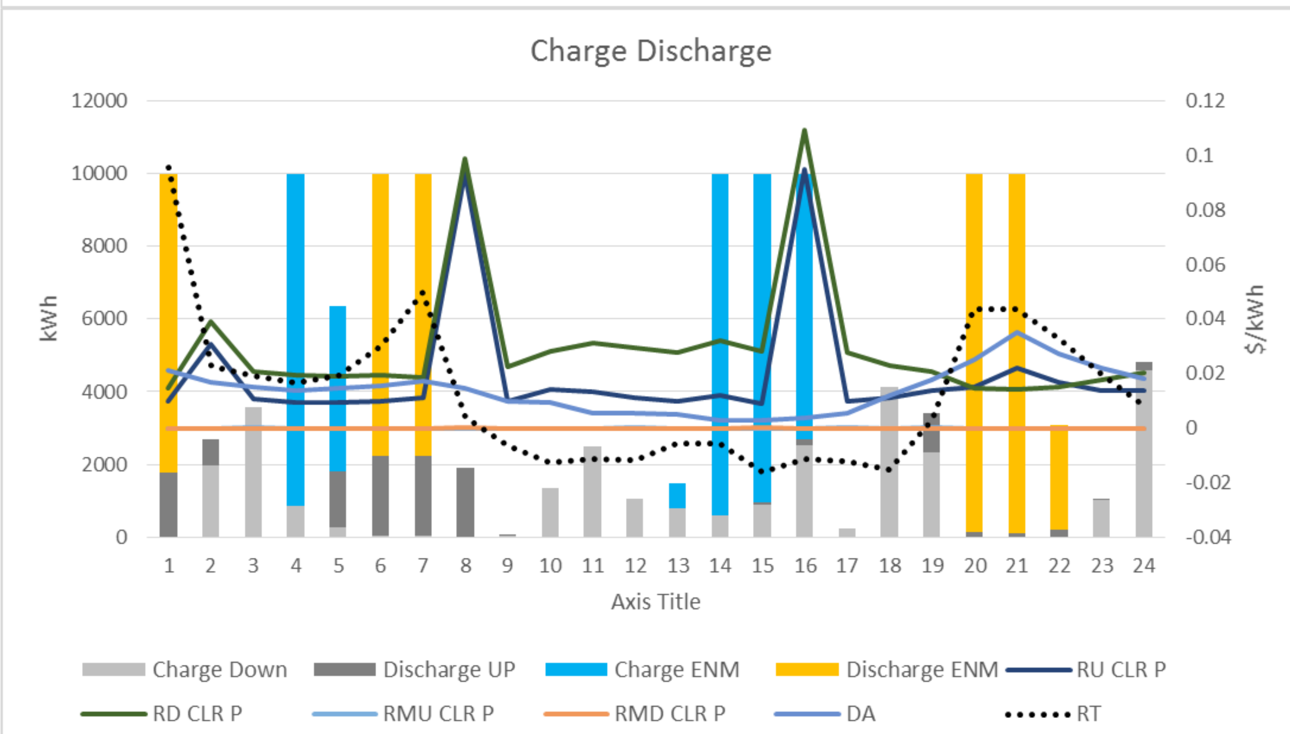


Figure 9-50. May 21st, 2016 analysis with 20% assumption (Location A)

The regulation participation is always 2 MW or 20% in the RegUp, RegDown, or both directions.

At 50% (Figure 9-51), the example results were:

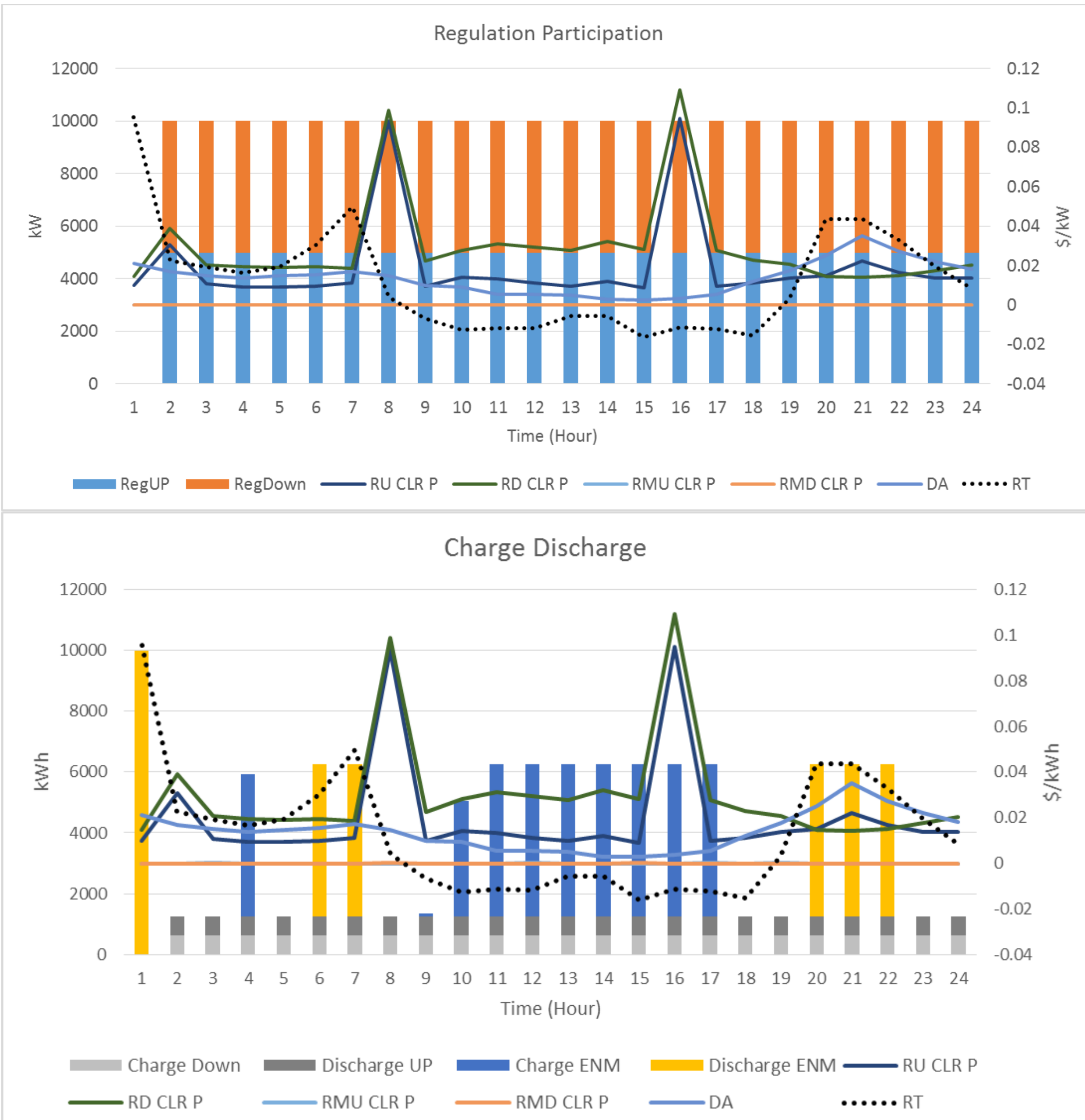


Figure 9-51. May 21st, 2016 analysis with 50% assumption (Location A)

The hourly pattern of regulation participation is nearly identical but the amount of participation is now 5 MW in every hour except hour 24 (when it is necessary to meet day ending state of charge constraints).

The pattern of energy market charging / discharging is similar on an hourly basis but the levels are different, to accommodate the charging / discharging energy for regulation.

At 100% (Figure 9-52), example results were:

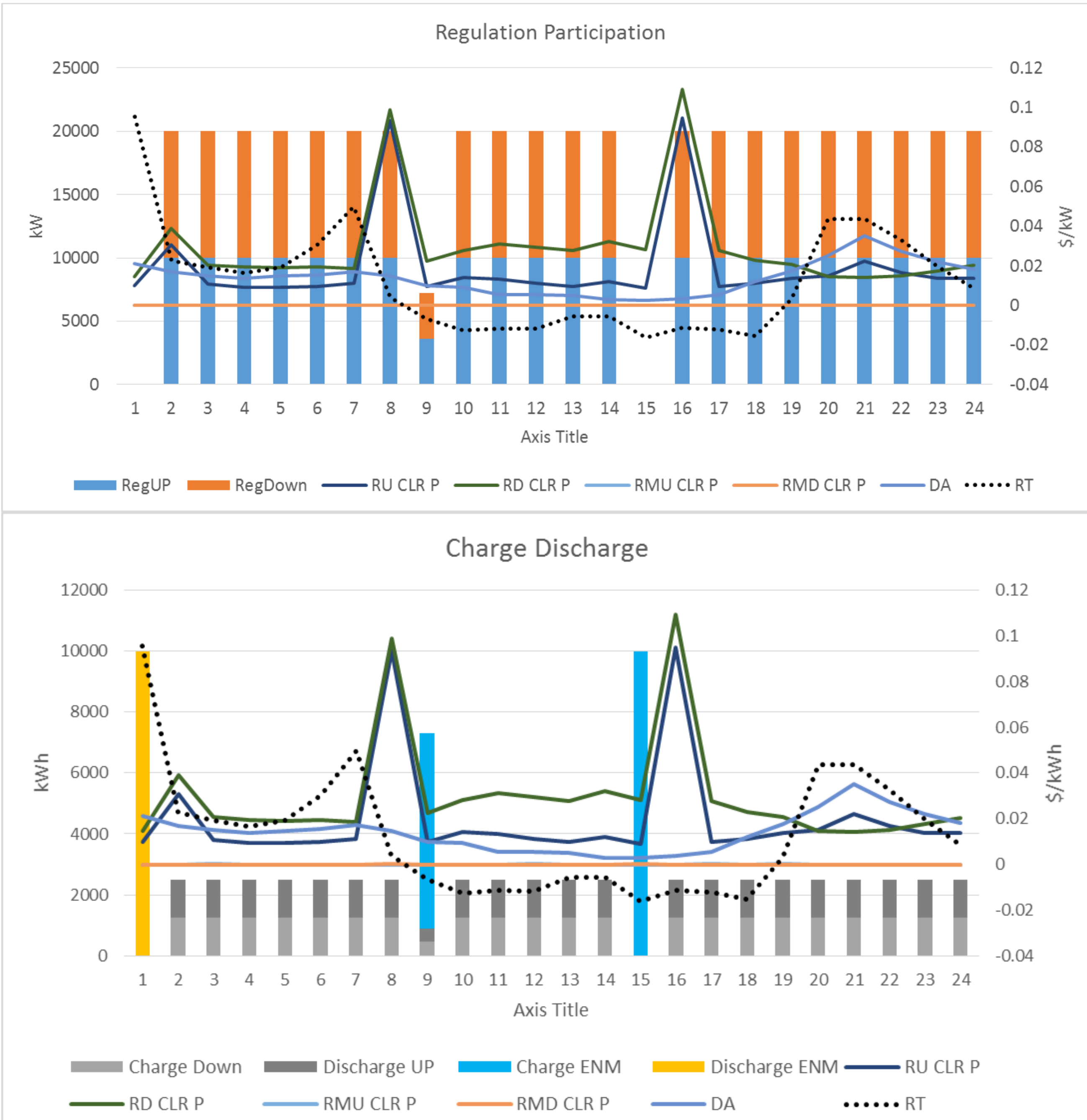
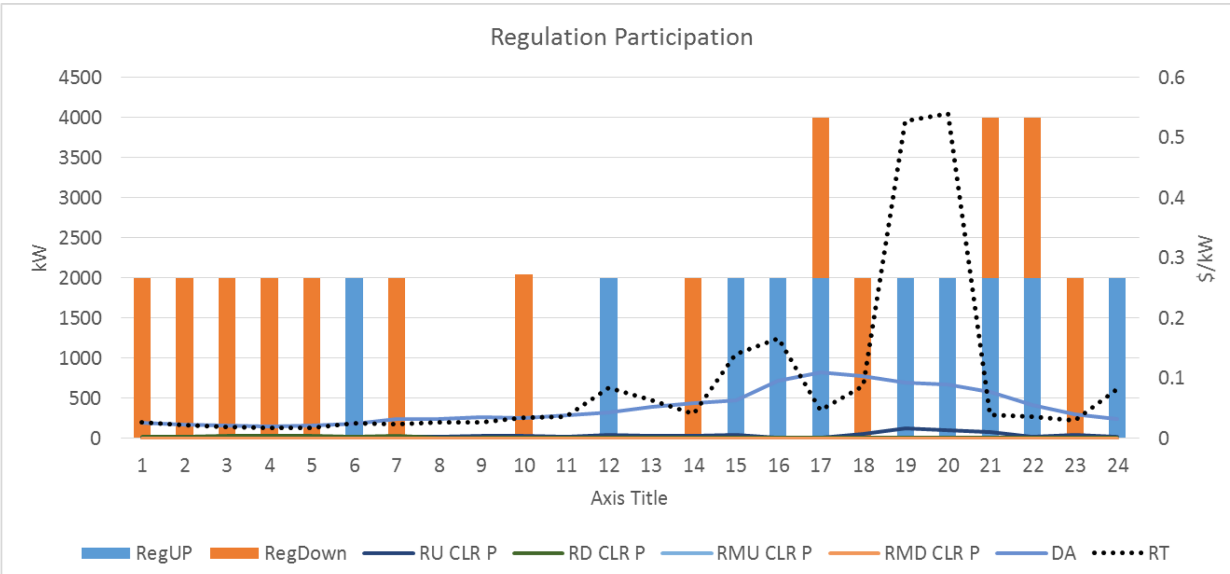


Figure 9-52. May 21st, 2016 analysis with 100% assumption (Location A)

In this case, the pattern of regulation participation has altered, and the level reaches 10 MW but not at all times. The pattern of energy market charging is quite different. The optimization is trading off regulation capacity payments against the balance of RegDown and energy market charging, and still maintaining the energy market discharging in the early evening hours when prices are highest.

If we examine the June 20th day (Figure 9-53) when DA prices are the highest, we see different behaviors:



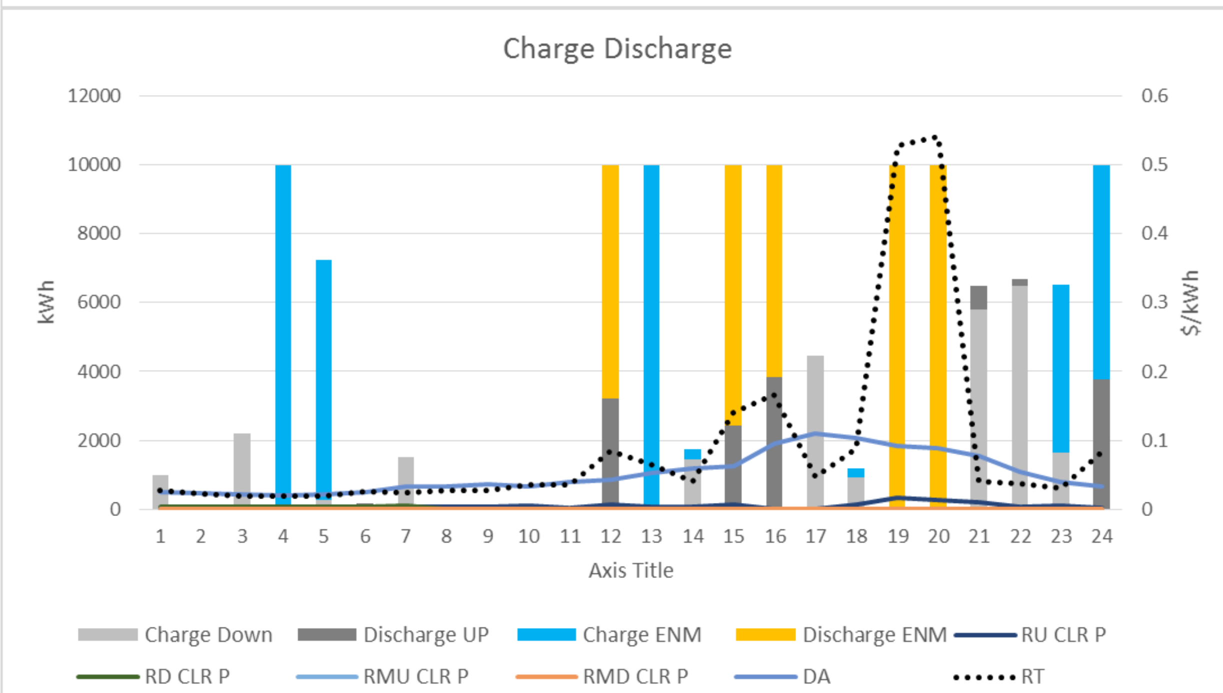


Figure 9-53. June 20th analysis for 20% assumption (Location A)

At 20% regulation capacity allowed, above, the participation in the morning is limited to RegDown. The RegUp participation and Energy discharge are focused in the afternoon when prices are highest. (Note that the RT prices, while not the highest of any day in the year, are still quite high in the early evening.)

At 50% of capacity available for regulation (Figure 9-54):

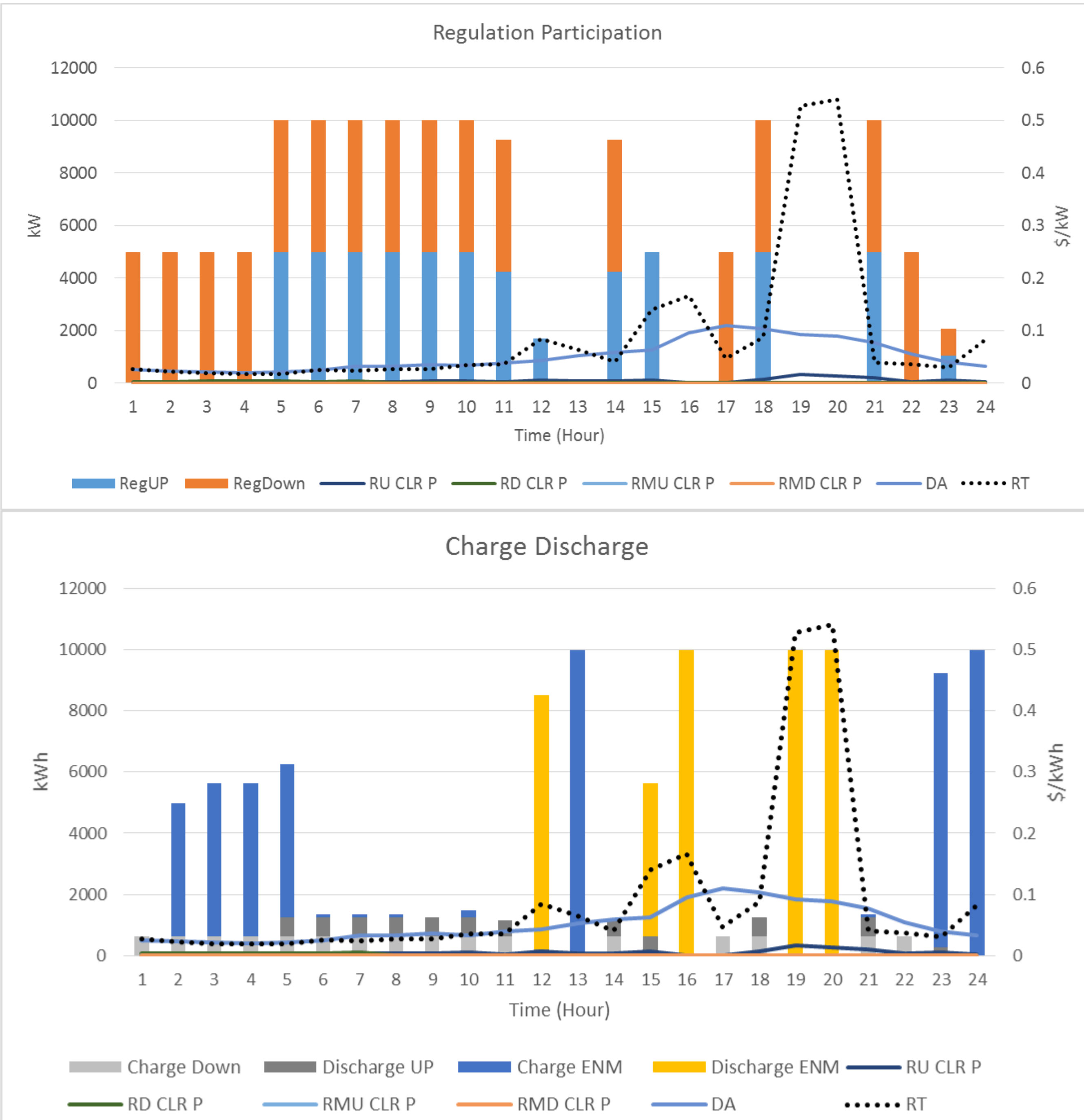


Figure 9-54. June 20th analysis for 50% assumption (Location A)

The pattern of behavior is similar to the pattern at 20% but not identical, and the RegUp / RegDown levels are usually although not always 5 MW. The energy discharge pattern is identical, but the energy charge pattern is different as the RegDown energy charging has supplied more of the charging energy needed.

At 100% (Figure 9-55), example results were:

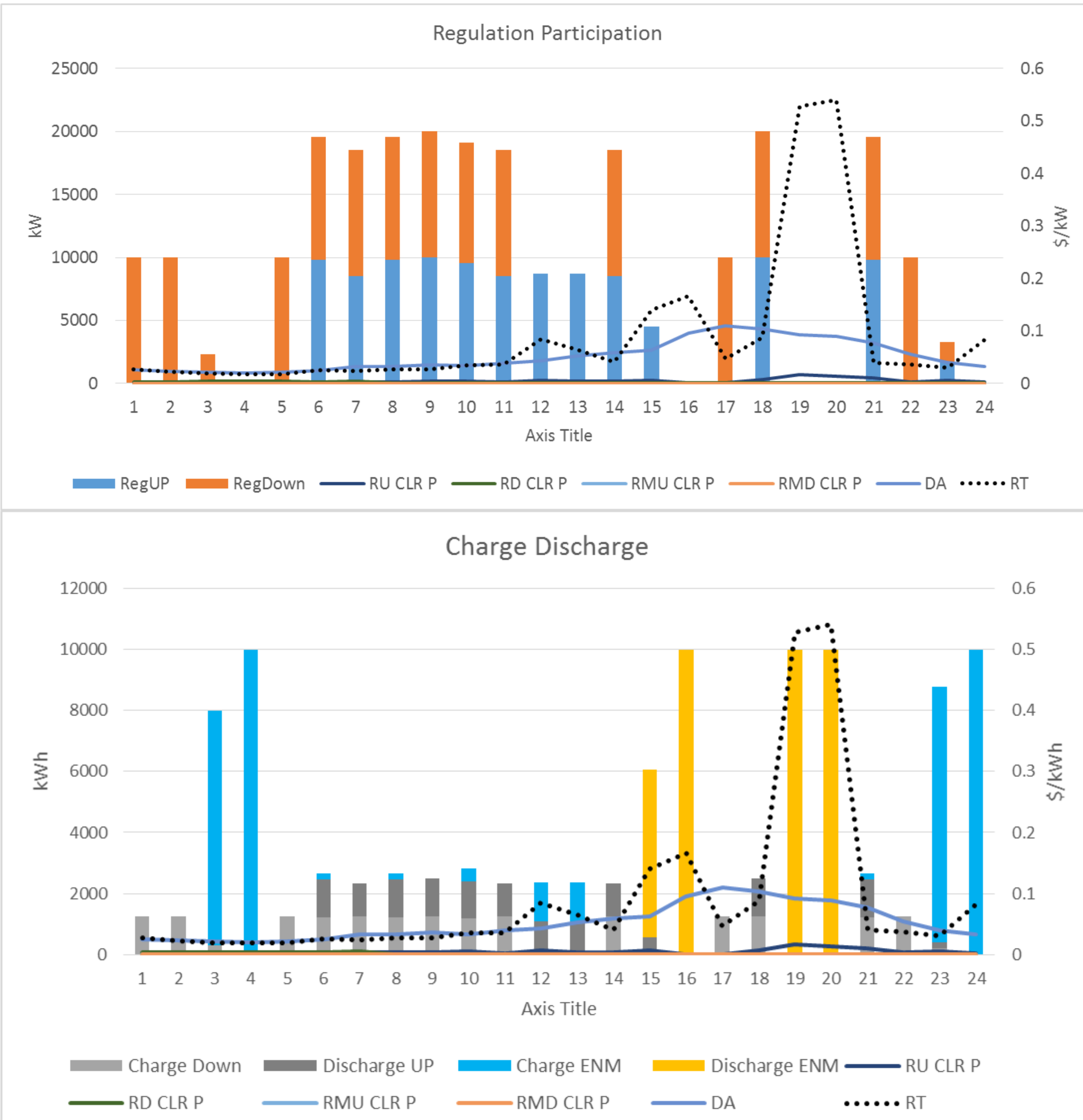


Figure 9-55. June 20th analysis for 100% assumption (Location A)

The patterns continue to evolve in the same way as from 20% to 50% but with periods of 5 MW of RegUp (but not always the 5 MW max) and energy market discharging is displaced in the afternoon hours by RegUp discharging.