# DTE Energy Advanced Implementation of Energy Storage Technologies

Technology Performance Report

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Key words: CES, Community Energy Storage, Microgrid, Distributed Energy Storage, Reliability, DERMS, Distributed Energy Resource Management System,

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# 1. Executive Summary

This report describes the implementation of 1-MW of distributed Li-ion energy storage on a distribution circuit in the DTE Energy service area. DTE Energy is a Michigan based diversified Energy Company that provides electric service to 2.1 million residential, business and industrial customers in southeast Michigan.

DTE Energy has worked with selected sub recipients, consultants, contractors and vendors to demonstrate the use and benefits of distributed energy storage, often referred to as Community Energy Storage (CES), in a utility territory and to test the ability to integrate secondary use electric vehicle (EV) batteries in the CES demonstration.

This is the first large scale utility community energy storage project with an aggregated capacity of 1-MW. Its 21 energy storage systems were managed by a Distributed Energy Resource Management System (DERMS). This DERMS was created to allow aggregation of any asset within the DTE Energy service territory using utility industry protocol (DNP3).

This project installed 18 S&C Electric (S&C) supplied 25kW/50kWh CES units, a 500kW Li-ion battery storage device integrated with a 500 kW solar system and two repurposed (secondary use) energy storage systems using Fiat Chrysler Automobile (FCA) 500e EV batteries. The first CES unit was installed at the DTE Energy Training and Development Center in Westland, MI for installation training, verification of work and operational procedures, and engineering design documentation. The remaining 17 CES units and the 500 kW battery are installed on a distribution circuit designated as TRINITY 9342 located near Monroe, MI. The repurposed batteries were installed at DTE Energy headquarter and at Next Energy Center in Detroit.

The project objectives are to integrate the CES units into the electric utility system, determine the performance of the CES and the control system, and the development and integration of CES devices from secondary-use battery. The analysis identified gaps, improvements, and suggestions on how devices and control systems can be standardized.

A number of project objectives were evaluated in this demonstration project, such as:

- Develop CES system for grid support
- Integrate energy storage into utility engineering standards
- Develop installation procedures
- Develop a DERMS and integrate CES operation and control
- Demonstrate the aggregation of distributed battery systems
- Determine performance improvements on the grid
- Determine economic value of energy storage at a utility in the MISO energy market
- Determine the multiple layered economic benefits of energy storage in MISO

- Demonstrate how to create a secondary use EV battery system
- Evaluate the cost of deploying repurposed EV battery system vs new batteries
- Perform sensitivity cost analysis on the application of CES in the DTE Energy distribution service area

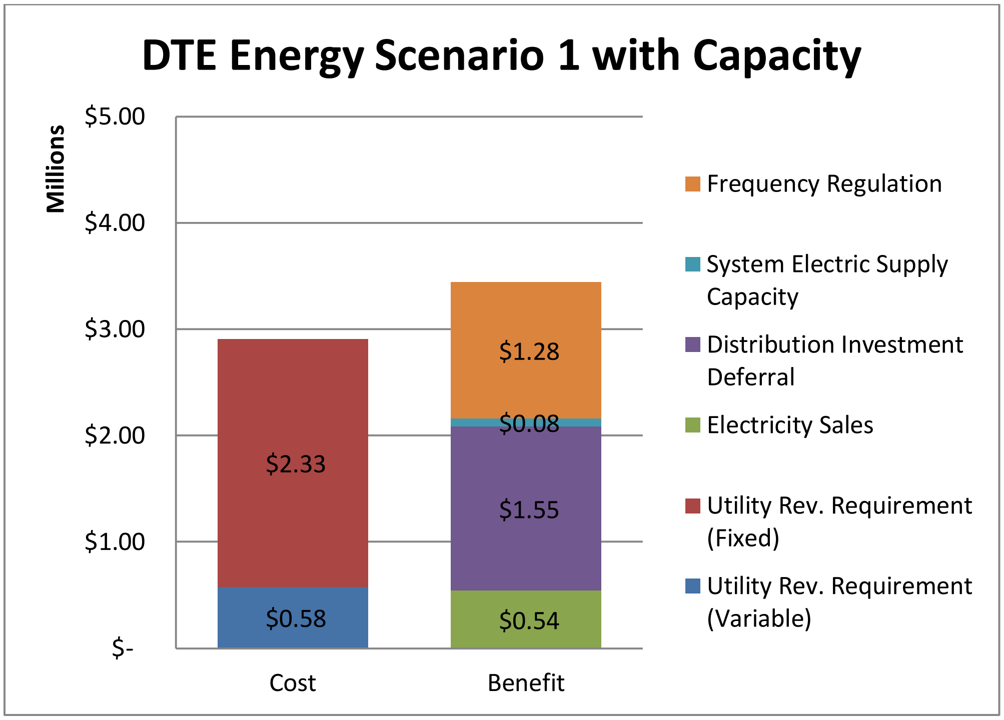
There were initial challenges due to a change in battery supplier in the project that caused delays in deployment the CES systems for the demonstration portion of the project. Once field installations started, additional anomalies that were not discovered in the factory testing. These materialized in the battery management system (BMS), and power conditioning system (PCS) software, and in various hardware components that were corrected. Some of those events caused outages to the customers fed from those battery systems. All know anomalies were corrected resulting in a more robust CES battery system. This is why it is so important to have field demonstration projects to identify product issues to help accelerate the adoption of new technology projects. Developing installation procedures, integrating the CESs into engineering design and training of field personnel was straightforward.

The refurbished batteries, due to lower cell cost, can be an economic solution as was shown by the DNV GL economic analysis. In this project, the EV battery modules were tested prior to them being repurposed without any signs of capacity degradation or failures. However, after commissioning and operating the systems a number of cell failures in the battery modules occurred questions the reliability and longevity of a battery system using used EV batteries. This project did not perform analysis on the bad battery cells, but the failures can be attributed to any number of causes. For example, the failures could be due to the EV packs being early prototype system or the harsh driving environment the EVs were subjected to when the prototype vehicles were being tested.

This project successfully used DNP3 protocol through the DERMS to test 23 use cases outlined in section 4.5. These use cases range from testing communication to individual CES units to testing of aggregation of all batteries based on distribution circuit model commands and dispatching due to high locational marginal pricing (LMP).

DNV GL performed two detailed cost effectiveness analyses on the test circuit to evaluate if the CES could be economically justified either as peak shaving deferral or as frequency regulation service. The analysis was performed using both new and repurposed battery packs to determine if low cost or free batteries would be an economic solution.

Theses analysis showed that on this particular circuit, the CES could not be economically justified in either peak shaving mode or in frequency regulation services mode in the MISO energy market. A sensitivity analysis of this circuit (using multiple value stream approach) was conducted with Electric Power Research Institute (EPRI) using their energy storage evaluation tool (EVST) in effort to determine at what price the CES needed to be for them to be cost effective on this particular test circuit. The sensitivity analysis is discussed in section 5.5.3. The scenario 1 graph below shows how the stacked benefits are needed to justify energy storage on the distribution system.




**Scenario 1: $1000/kWh; 1% growth; $5M Distribution Deferral**
**With Updated Financial and System Capacity Cost**

The table below is a matrix that summarizes the benefit to cost ratio (B/C) that shows how the effect of battery capital cost and distribution upgrade cost is clearly a dominant driver for the batteries economics in the distribution grid. For example a $1,000/kWh battery cost the break-even deferral cost is $3.3 M (Run 3) compared to a B/C = 1.3 when the capital upgrade cost is $5.5 M. For a $2 M capital deferral the break-even battery cost is $705/kWh. It should also be noted that higher growth rate diminishes deferral benefits as can be seen in Run 2 and 5.

| Run | Dist Def | Arbitrage | Freq Reg | Growth Rate | Capital Cost | Upgrade Cost | RT Price | B/C |
|---|---|---|---|---|---|---|---|---|
| 1 | Yes | Yes | Yes | 1% | 1000$/kwh | 5M | Avg | 1.3 |
| 2 | Yes | Yes | Yes | 1% | 1500$/kwh | 5M | Avg | 0.9 |
| 3 | Yes | Yes | Yes | 1% | 1000$/kwh | 3.3M | Avg | 1.0 |
| 4 | Yes | Yes | Yes | 1% | 705$/kwh | 2M | Avg | 1.1 |
| 5 | Yes | Yes | Yes | 2% | 1500$/kwh | 5M | Avg | 0.7 |

This project successfully demonstrated an early stage CES system and cleaned up most of the early stage failures that normally accompany new products. Even though the CESs successfully passed factory acceptance test and fixed all know issues (software and hardware), once the system was deployed in the field, many additional issues surfaced that needed to be addressed and fixed. The CES can now be acquired by utilities knowing that they will have higher reliable because of this project.

Energy storage will have a role to play in the distribution grid of the future. The cost benefit analysis shows that in the right situation, energy storage is a tool that can be justified on economics depending on its application. This is evident in the sensitivity analysis where a battery capital cost of $705/kWh can justify a distributed energy project. Because this demonstration project was using early development battery system cost over $2,000/kWh the economics could not be justified, but with decreasing cost, it's expect that by 2020 distributed energy storage will be an economical solution in certain projects.

DTE Energy will continue to use the CESs in the grid to gain additional operating data, especially customer reliability. Because of the high failure rate of the refurbished batteries, they will be decommissioned.

If repurposed EV batteries are to be considered in grid applications, additional research and demonstration projects need to be conducted to determine their reliability and system cost.

Below is a bullet list of some of the key lessons learned during this demonstration project:

- Circuit modeling tools for siting evaluation is important
- Layered benefits are required to justify energy storage projects
- An energy storage evaluation software is an important tool for performing cost analysis that can include multiple value streams
- Engaging all groups early within the utility, especially engineering and field resources is important
- Having a product that meets applicable IEEE standards is important
- Integrating distributed energy storage into DTE Energy was accomplished in a manner similar to any new technology being introduced
- It's important to have a DERMS to effectively manage distributed assets
- It's important to have a DERMS to optimally dispatch CESs to gain the greatest economic value for distributed energy storage
- A dispatch algorithm integrated into DERMS is required to gain greatest economic value for energy storage
- Autonomous dispatching using a DERMS and preferably a circuit model is required for day-to-day operation
- Repurposed EV batteries may not be an economic solution due to higher cell failure rate. This needs further studies

# 2. Overview/Background

## 2.1. Advancing the Development of Storage Technologies

The modern grid has several key characteristics that will benefit consumers, businesses, and utilities. These smart grid functional characteristics were identified through an industry collaborative effort and comprise the foundation of the DOE OE's smart grid program.

- Self-healing from power disturbance events
- Enabling active participation by consumers in demand response
- Operating resiliently against physical and cyber attack
- Providing power quality for 21st century needs
- Accommodating all generation and storage options
- Enabling new products, services, and markets
- Optimizing assets and operating efficiently

The energy storage systems demonstrated in this project can serve as an enabling technology for most of these functional characteristics. Self –healing is demonstrated with islanding functionality of the CES to continue serving the customers during a circuit disturbance. The enabling active participation by consumers is not demonstrated in this project due to the energy storage located on the utility side of the meter. If energy storage would be located on the customer side of the meter, they could actively participate in demand response. Operating resiliency is demonstrated by actively islanding if there is a physical disturbance and the cyber resiliency is demonstrated by the cyber security analysis performed in the project. The power quality aspect is demonstrated by the CES to actively manage voltage and ride through disturbances. The accommodating storage is covered by demonstrating that an electric utility can integrate distributed storage into the electric grid. Enabling new products, services and markets for storage is demonstrated in this project by showing that the distributed storage can respond to signal from the energy market (in this project it is MISO). Optimizing assets and efficiencies is demonstrated by dispatching the energy storage when it is needed by the circuit for load relive, for maintaining voltage and reactive power and managing solar production of the PV connected to the circuit.

## 2.2. Project Goals and Objectives

The goal of this project, as proposed in 2009, is a proof of concept to demonstrate the use and benefits of Li-ion battery Community Energy Storage systems in a utility territory and to test the integration of secondary-use electric vehicle batteries into the CES demonstration. A driver for this project in 2009 was the projected introduction of plug-in electric vehicle (PEV) into the market in 2010 (Li-ion battery pack ~$1,000/kWh) and mass manufacturing of Li-ion batteries with expected decrease in the cost of Li-ion batteries to $325/kWh[1] by 2020. Today (November 2015) projections by USABC[2] (UNITED STATES COUNCIL FOR AUTOMOTIVE RESEARCH LLC) are that EV battery system cost will be $125/kWh by 2020. With the continued decline in the cost of Li-ion batteries, they appear to be a good application for electric utility storage applications. It should be noted that the utility energy storage system cost in $/kWh will be higher than automotive battery system cost because the additional increase in balance of plant that is required to interconnect to the electric utility primary distribution system. The reason to include secondary-use-electric vehicle batteries in the project was to answer the question with regards the use of used EV batteries at the end of EV vehicle useful life. It is expected that used EV batteries will still have 75-80% of their original capacity at the vehicle end of life and that they may have an application in the utility industry. As part of this project, DNV GL (formerly KEMA) performed economic analyses of using secondary-use batteries versus new batteries.

This project installed 20 CES units and a 500kW storage device integrated with a 500 kW solar system that is managed centrally with a DERMS. The main phases of this project were:

- Design and construct a CES device that will serve as an essential component of grids
- Design a central communications control system to aggregate CES devices across DTE service territory (DERMS)
- Demonstrate the ability of the storage devices to provide:
  - Peak Shaving
  - Voltage Support
  - Integration of renewable generation & energy shifting
  - Islanding during outages
  - Frequency Regulation
- Demonstrate the utilization of secondary-use EV batteries for the storage systems
- Test the performance of the CES systems against baseline data
- Determine economic value of energy storage system in utility operation

## 2.3. Project Team

The project team members and roles are listed in Table 1. The original battery partner for the CES and larger (500 kW) system in this project was A123 System. A123 System was working with S&C Electric to integrate the A123 batteries to the S&C CES Power Conditioning System (PSC). With the design of the CES system well along (~1.5 years), including the underground vault and installation procedures, A123 decided to pull out of the CES portion of the project and not supply batteries. After researching CES battery replacement vendors, it was determined that the only viable Li-ion battery supplier with a battery management system (BMS) that could integrate to the S&C Electric PCS in the timeframe remaining on the project was Kokam.

A123 Systems was also the original supplier of the 500 kW battery and Dynapower PCS systems that was scheduled to be collocated with the DTE Energy owned 500 kW of solar. This part of the project was originally to be funded by a grant from the Michigan Public Service Commission, but due to a legal challenge to the funding mechanism, the funds were eliminated. At that time, DTE Energy stepped up and provided additional funding to be able to include the 500 kW battery in the project. In October of 2012, A123 System filed for bankruptcy causing them to fully exit the project as a battery supplier for the 500 kW battery. The challenge then was to find a new 500 kW battery supplier and PCS to meet the project time line to incorporate the 500 kW battery in the project with available funds. The only available PCS to meet the tight deadline was from S&C Electric and battery cells from Dow Kokam to be integrated by eCamion. When Dow Chemical backed out of it ownership of Dow Kokam, the new supplier of battery cells for the 500 kW battery became Kokam. The overall project experienced delays when A123 exited as a Li-ion battery cell supplier.

| Project Team Members & Roles | |
|---|---|
| **Team Member** | **Role** |
| DTE Energy | • Project lead<br>• Utility participant for CES field demo<br>• Project reporting |
| S&C; Ecamion | • CES Unit suppliers<br>• Factory acceptance testing<br>• Technical Support |
| DNV·GL | • CES functional testing<br>• Economic analysis and reporting<br>• Technical Support |
| edd | • Circuit model development for baseline<br>• Reliability & economic dispatch algorithm |
| FCA Fiat Chrysler Automobiles | • Durability & conditioning testing of EV battery<br>• Secondary use EV battery supplier<br>• Provide baseline data for EV battery |
| NextEnergy | • Investigation of regulatory issues surrounding energy storage and renewable energy<br>• DOD applications |
| nationalgrid | • Utility technical advisor |

**Table 1: Project Team and Roles**

## 2.4. Project Milestones and Target Dates

Table 2 shows the completion dates of the major milestones of this project. Within each major milestone, multiple tasks are not listed. Some of the original completion dates shifted when the new battery supplier needed to be integrated into the project and unforeseen technology issues surfaced that needed to be addressed which is not unusual for new technology projects.

| Milestone # | Description | Completion Date |
|---|---|---|
| 1 | Develop Project Management and Cyber Security Plan | 08/05/2011 |
| 2.1 | Baseline & Preliminary Plan, Design, Procure and Test – New Batteries | 07/26/2012 |
| 2.2 | Final Design of CES Complete – New Batteries | 02/28/2013 |
| 2.3 | Release, Install and Commission CES Equipment – New Batteries | 06/21/2013 |
| 2.4 | First CES Systems Operations Begins | 02/15/2014 |
| 2.5 | Integration of Chrysler Secondary-use Battery System into CES System | 12/31/2014 |
| 3.0 | Final Project Reporting | 12/31/2015 |

**Table 2: Major Milestones**

The final CES design milestone bore the brunt of the delay of about 1 ½ years. The CES field installation on the distribution circuit went well because of the training that was conducted at the DTE Energy Training and Development Center (TDC). Because all the CES installations were located in one service center, only the underground personnel associated with that service center needed to be trained. Figure 1shows the installation of the battery into the vault and figure 2 show a completed installation at TDC. The green box on the right is the pad-mounted transformer and the box on the left is the CES unit with the PCS sitting on top of the vault that houses the 50 kWh battery.

**Figure 1**: CES installation at DTE Energy Training and Development Center

**Figure 2: Completed CES installation at the Training and Development Center**

A delay in the start of the CES system operation milestone was due to operational issues that surfaced once the CES units were installed on the circuit. Even though the CES units went through a vigorous factory acceptance testing that included heat/cold chamber and one week of water immersion, once assets are installed in the field, additional issues arose that need to be addressed. Additional detail on this topic is covered in section 5.3 Storage System Performance. To keep the project on task, weekly project conference calls were conducted each Friday with all participants to review project tasks, time line and work through any issues that surfaced.

## 2.5. CES Energy Storage Applications

Community energy storage (CES) entails utility deployment of modular, distributed energy storage systems (DESS) located on the utility distribution system close to residential and business end customers. The Concept of CES is that a DESS can behave as a large battery system with additional reliability benefits to the end-use customer by creating a small microgrid for the customer downstream from the CES. See figure 3 CES Application Diagram.

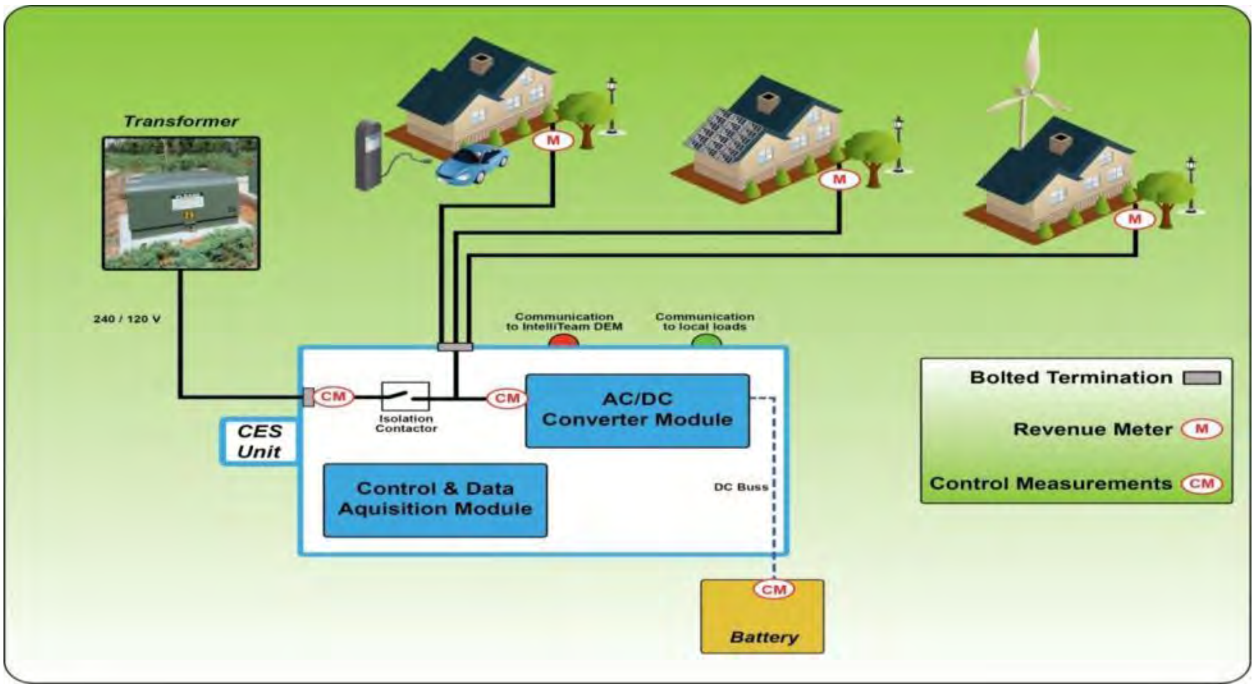



**Figure 3: CES Application Diagram**

By aggregating the distributed CES, the same benefits can be realized as a large single battery system with additional energy storage redundancy. Because there are so many storage units, it is unlikely that a substantial number of CES will be out-of-service at the same time. That is helpful from an energy storage reliability perspective. CES is also designed to electrically island which means that when a localized portion of the distribution system becomes electrically isolated from the rest of the grid, CES can serve the end-users demand while there is stored energy. Basically, the CES functions autonomously to provide back-up power in case of an outage.

The value of any specific CES deployment will vary significantly based on their applications, but important elements of the rationale for CES are that it can provide numerous benefits or multiple value streams, is a flexible solution for many existing and emerging utility reliability, and for the utility engineers an alternative in their growing toolkit of solutions and responses.

CES is expected to provide numerous benefits in many possible combinations. It can serve as a robust, fast-responding and flexible alternative to generation. It can store low priced energy and use that energy when the price is high. CES can also be used to provide most types of ancillary services needed to keep the electrical grid stable and reliable. Depending on the CES location, they can reduce the need for transmission and distribution (T&D) capacity upgrade because CES provides power locally to serve the local peak demand. CES can also improve the local electric service reliability and power quality. Of particular interest is CES used to maintain a stable voltage in the distribution system as well as provide backup power to und use customers due to an outage.

CES also plays an important role in the integration of renewable energy generation into the grid, including large remote wind and solar generation as well as distributed photovoltaics. CES addresses two notable variable renewable energy generation integration challenges. They can be charged with wind generation output, much of which occurs at night when the energy demand is low and when transmission systems are less congested and more efficient. In addition, CES can be used to manage localized power quality related challenges that occur due to high penetrations of photovoltaics systems, especially in residential areas. Of particular note is high voltage from local generation and voltage fluctuations due to rapid variations of photovoltaic output.

# 3. Technologies Demonstrated

## 3.1. Storage System Characteristics

Each new CES system deployed in this project consists of a 50 kWh battery, with associated BMS, that is connected to the DC bus. The PSC inverter then converts the DC voltage to AC that connects to the 120/240 volt system. See single line diagram in figure 4.

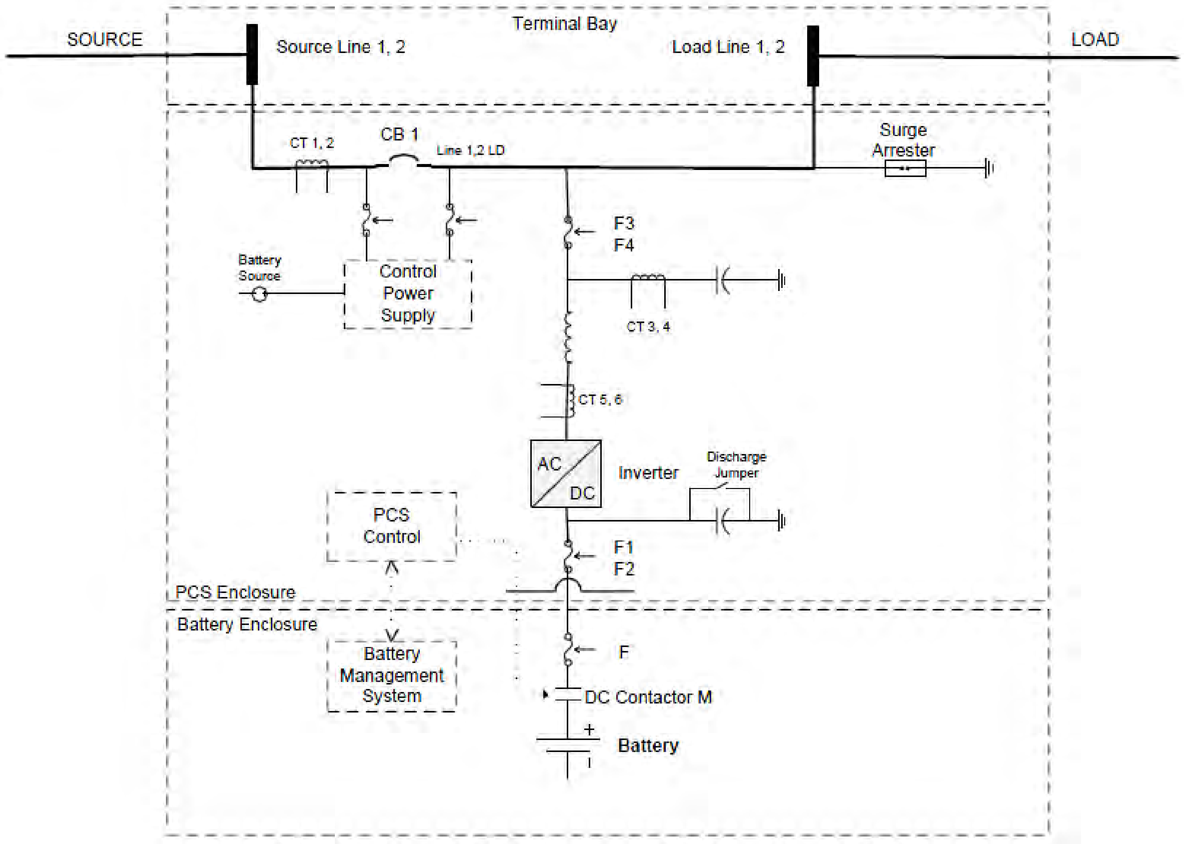



**Figure 4: CES Electrical One Line Diagram**

Both AC and DC circuit breakers, or contactors, (CB) are used to provide protection and islanding. For example, CB-1 in figure 4 opens when the source side voltage is zero, causing the CES to create a local microgrid that continues to serve the load (end use customers), until the source side voltage is restored or the battery energy is depleted which will cause the DC breaker to open to save the battery.

S&C Electric Company provided 20 CES systems to the project, 18 new units and 2 created with secondary-use EV batteries packaged by eCamion. The technical specifications of the new CES unit were as follows in table 3.

| **50kWh CES Specification** | | |
|---|---|---|
| Cell | 55 | Ah |
| Cell Voltage | 2.7~4.2 | V |
| Pack Energy | 2.85 | kWh |

| | | |
|---|---|---|
| Total Cell No. | 280 | |
| System Rated Energy | 50 | kWh |
| System Actual Energy | 57 | kWh |
| System Voltage | 380~590 | VDC |
| System Configuration | 14S x 10S x 2P | |
| Continuous Charge Power | 25 | kW |
| Continuous Discharge Power | 25 | kW |
| Peak discharge power | 150 | kW |
| Round-trip AC Efficiency | > 85% | |
| BIL | 30 | kV |
| Weight | 1100 | Kg |
| **Environmental Ratings** | | |
| Operating Ambient Temperature | -30ºC to 50ºC | |
| Survival Ambient Temperature | -40° to 60°C | |
| Storage Ambient Temperature | -30°C to 50°C for up to 6 months | |
| Humidity | 10% to 100% condensing | |
| Altitude | Sea level to 2,000 meters without kVA de-rating | |
| Seismic | Uniform Building Code Zone 4 | |

**Table 3: 50 kWh CES Specification**

Correspondingly, the Kokam battery characteristics are shown in table 4. The BMS inside the battery enclosure manages the battery charging and discharging based on commands from the CES PCS.

| | | | |
|---|---|---|---|
| **Primary Function** | **26.32 kW/ 52.64 kW-Hour (DC power/ energy) Battery Assembly** | | |
| **System Voltage** | | | |
| **Minimum Voltage** | VDC | 360 | |
| **Maximum Voltage** | VDC | 800 | |
| **Discharge Power** | | | |
| **Maximum Continuous Power at DC Terminals** | kW | 26.32 | Continuous constant-power discharge. |
| **Peak Discharge Power at DC Terminals** | kW | 78.96 | Repetitive surge power for three seconds. |
| **Charge Power** | | | |
| **Maximum Charge Power at DC Terminals** | kW | 26.32 | Continuous constant-power charge. |
| **Energy** | | | |
| **Rated Energy at DC Terminals** | kWh | 52.64 | Energy rating after 1000 Reference Duty Cycles in 25°C ambient at a constant-power discharge rate of 26.32 kW (DC power) beginning from 100% SOC. |
| Notes:<br>1. "Minimum SOC" is defined as the point during battery discharge at which:<br>a) at least one cell in the battery string has reached cut-off voltage;<br>b) the BMS system reports SOC as 0%; and,<br>c) Sufficient Reserve Energy remains in the battery to prevent self-discharge to an unrecoverable condition after being kept in the discharged state for a minimum of two weeks. | | | |
| **Repetition Rate of Consecutive Full Discharge/ Charge Cycles** | Cycles/ Day | 2 | The battery shall be capable of discharging from 100% SOC to 0% at rated discharge power, then immediately thereafter recharging to 100% at rated charge power, then immediately discharging a second time at rated discharge power, and then recharging to 100% at >0.5 rated charge power. |
| **Maximum Storage Temperature** | °C | +60 | Continuous. |
| **Minimum Storage Temperature** | °C | -40 | Continuous. |
| **Cooling** | Natural Convection | | |
| **Maximum Operating Altitude, above Sea Level** | m | 2000 | Without kVA derating. |
| **Relative Humidity** | % | 0 to 100 | Condensing or non-condensing, salt fog. |
| **Weatherproofing** | Battery shall function normally while completely and continuously submersed in groundwater to a depth of 15 cm [6 inches] above the top-most surface of the installed battery enclosure, throughout the specified operating life.<br>Enclosure shall be constructed of stainless steel; and of a suitable alloy, or painted, coated, or finished as necessary to prevent corrosion or deterioration of the enclosure in the presence of chlorides in the groundwater with surface temperature of the enclosure ≥50°C. | | |
| **Other** | Enclosure and interconnections must be resistant to insects, rodents, molds/ fungus, plant roots, birds, and other common flora and fauna.<br>The enclosure shall comply with the construction requirements of ANSI/ IEEE C57.12.25 Section 6. | | |
| **Seismic** | Zone | 4 | Uniform Building Code |
| **Operating Life** | Years | 10 | |

**Table 4: 50 kWh Battery Specifications**

By locating the battery and the BMS below grade, the need for active temperature regulation is eliminated by a moderate ground temperature. The BMS ensures that the batteries health and safety is maintained.

## 3.2. Distributed Energy Resource Management System - DERMS

The DTE Energy DERMS, also referred to as DR-SOC in this document, is a distributed energy resource management and control system that embodies the concept of a DERMS as defined in Argonne National Laboratory report titled "Advanced Distribution Management System for Grid Support, DMS Functions" (ANL/ESD -15/17). The DTE Energy DERMS is located outside of the traditional EMS/DMS system environment with a secure Inter Control Center Protocol (ICCP TASE.2) connection between the two systems as depicted in figure 5. There is also a link to the DTE Energy enterprise bus for bidirectional flow of data between systems. A DNP3 protocol engine within the DERMS was developed as part of this project to demonstrate the use of utility industry standard protocol communication to distributed energy storage systems.

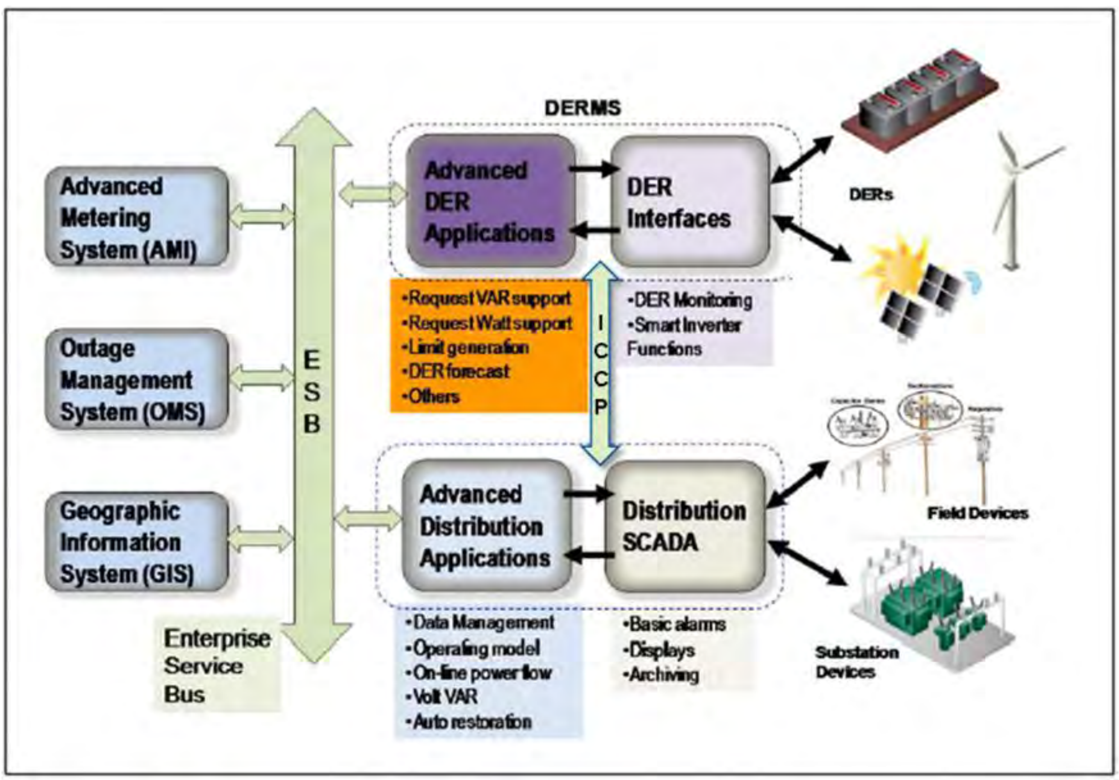



**Figure 5: DTE Energy DERMS**

The DERMS was improved to enable addressing of each CES unit individually or as a fleet of energy storage to demonstrate aggregation functionality in a distributed system. The concept is that CES units can reside anywhere in the utility service area and be aggregated to appear as single multi megawatt storage from a system level. In this project, the communication medium to the battery system was cellular APN Backhaul to demonstrate that a low cost communication medium can be used to manage a fleet of distributed energy storage.

## 3.3. Circuit Description

The 17 new CES systems and the large 500 kW battery are located on a distribution circuit, designated as Trinity 9342 in Monroe, Michigan. The circuit contains both overhead and underground construction with the CES units located in residential subdivisions served by pad-mounted transformers. The circuit primary distribution circuit voltage is 13.2 kV grounded wye with peak load of 10,300 kVA and summer rating of 12,500 kVA. The are 23 miles of primary overhead and 13 miles of underground circuit miles serving an area of about 6 by 3 miles. The circuit has 2,198 customer composed of 2,104 residential, 91 commercial and 3 industrial customers. The circuit primary electrical one-line diagram is shown in figure 6.

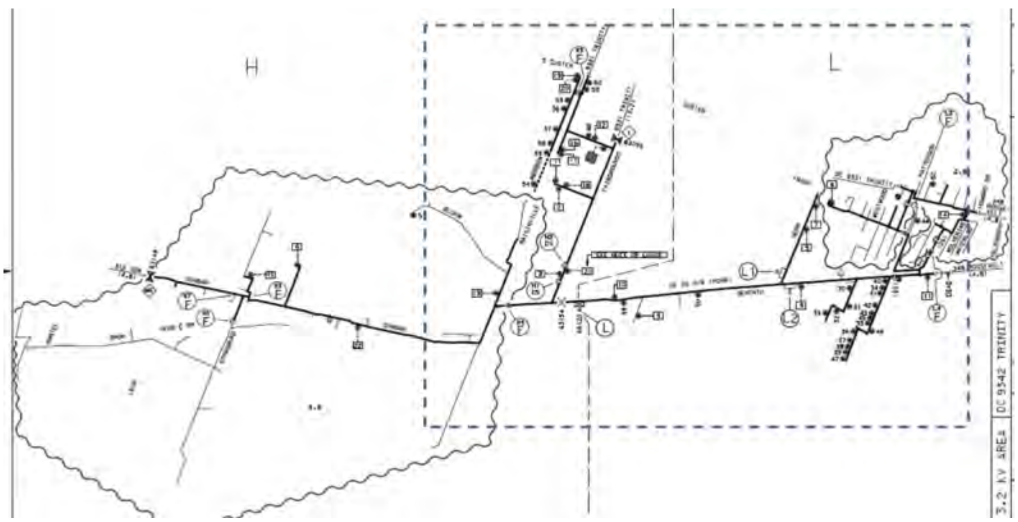



**Figure 6: Distribution Circuit Electrical One Line Diagram**

The circuit voltage is regulated at the substation with a load tap transformer (LTC) in addition to two capacitors and a voltage regulator out on the circuit. Figure 7 is an aerial view of the portion of the circuit (indicated by a dashed rectangular box in figure 6) where the battery systems are located. The CES are installed in two different underground fed subdivisions that are shown in figure 7.

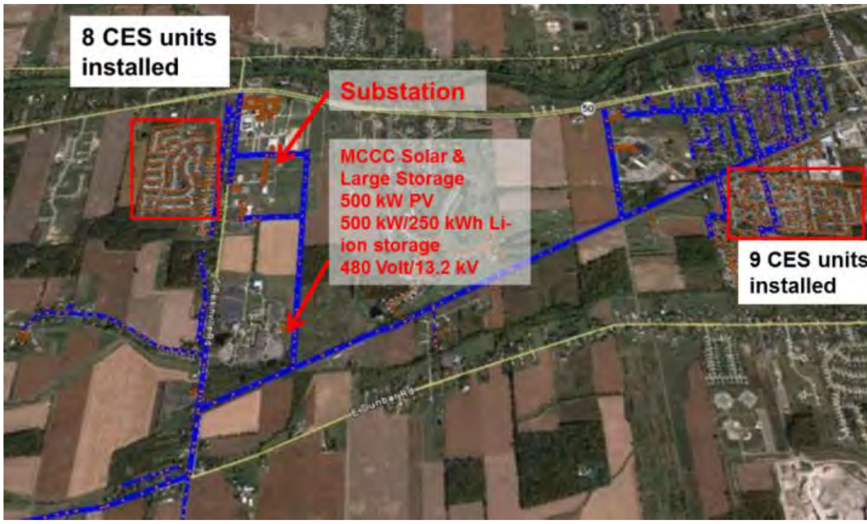



**Figure 7: Location of Energy Storage Systems on the Trinity Circuit**

The 500 kW battery is located at Monroe County Community College (MCCC) adjacent to a 500 kW photovoltaic (PV) system as shown in shown in figure 7. An aerial view of the 500 kW PV and 500 kW battery is shown in figure 8. The 500 kW battery PCS is connected to the same 480 volt PV electrical bus, which is then connected through a 500-kVA transformer to the 13.2 kV primary voltage. The site output is managed with the DERM to maintain maximum export of 625 kVA, which is the maximum 10-hour rating of the transformer.

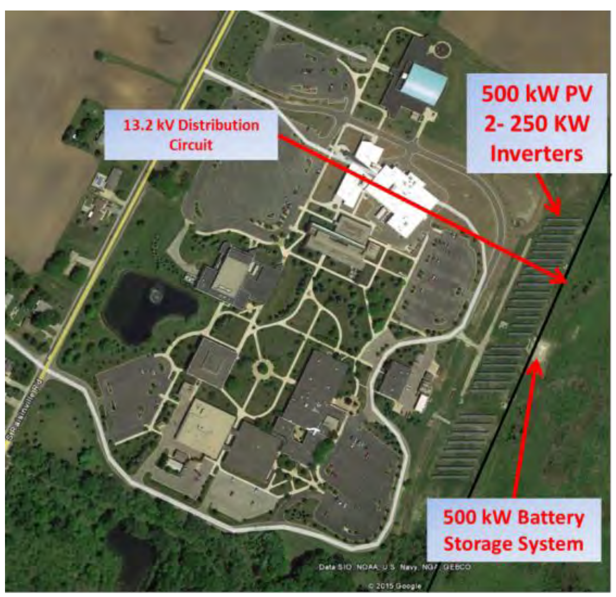



**Figure 8: Location of 500 kW PV and Storage at MCCC**

The MCCC battery and PCS is shown in figure 8 and figure 9 is a ground view of the 500 PV and battery system. In figure 9 the 500 kW battery container is on the left with the PCS on the right side of the pad.

**Figure 9: 500 kW Battery on the right and PCS at MCCC**

In figure 10, the gray container on the far right is the 500 kW storage system with the 500-kVA transformer (dark green container) to the left of the yellow bollards in the photograph.


**Figure 10: Ground View of 500 kW PV and Energy Storage at MCCC**

## 3.4. CES location Selection and Circuit Model Dispatching

A software application by Electric Distribution Design (EDD), called the Distributed Engineering Workstation (DEW), was used to model the distribution circuit to identify candidate locations for CES placement based on transformer loading, outage history and phase location. EDD also developed a model based control algorithm for dispatching set points based on real-time circuit conditions and economic parameters. The DEW engine provides the set points to the DERMS (DR-SOC Hub) for execution. The following two sections discuss these two topics in detail.

### 3.4.1. CES location Selection

DEW's Circuit modeling was use to provide technical input into where the CESs should best be placed. The included the following:

- Using DTE's Outage Plotting together with DEW's Outage Application enabled locating customers who had outages during the last five years. See Figure 11. This was done as part of the selection process since the CES could be used as a customer standby resource during outages.

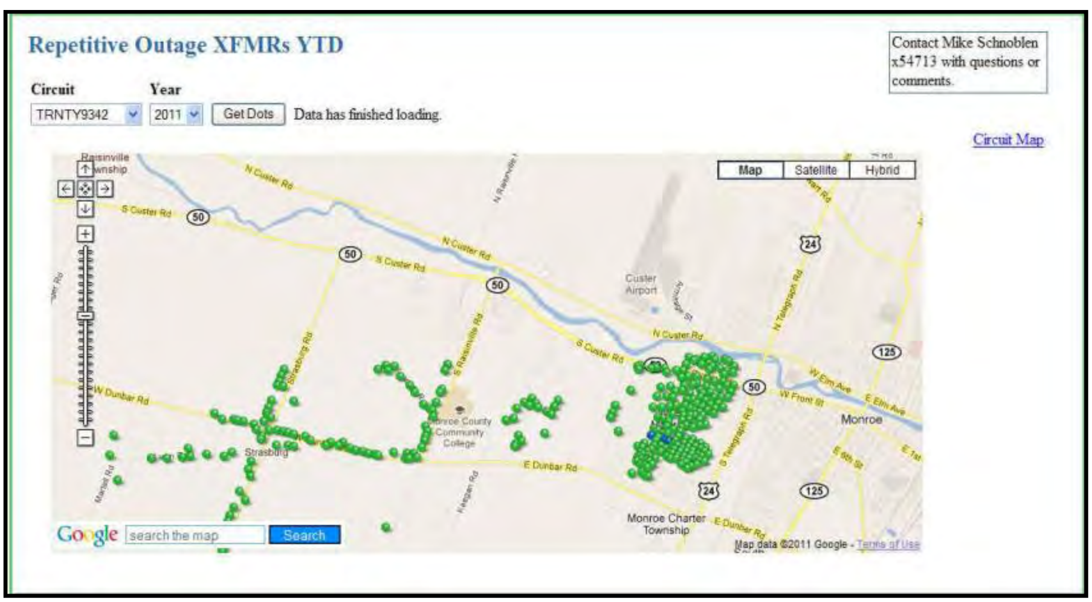


Figure 11: DTE's Outage Plotting Application Identifying Transformer Outages

- The DEW's Transformer Loading Analysis (TLA) was run to determine the minimum and maximum loading for each transformer. Since the application design was to maintain enough energy to provide 2 hours of standby power for each CES location, the TLA results indicate how much remaining battery capacity will be available for dispatching.
- To avoid overloading the transformer, the CES unit are not allowed to charge at a rate that, when added to the load, exceeds the transformer rating. The difference between the transformer rating and the load provides the headroom available for charging. The TLA results therefore allow for the selection of transformers with greater headroom for charging and thus greater opportunity for dispatching units for various technical demonstrations such as peak shaving.

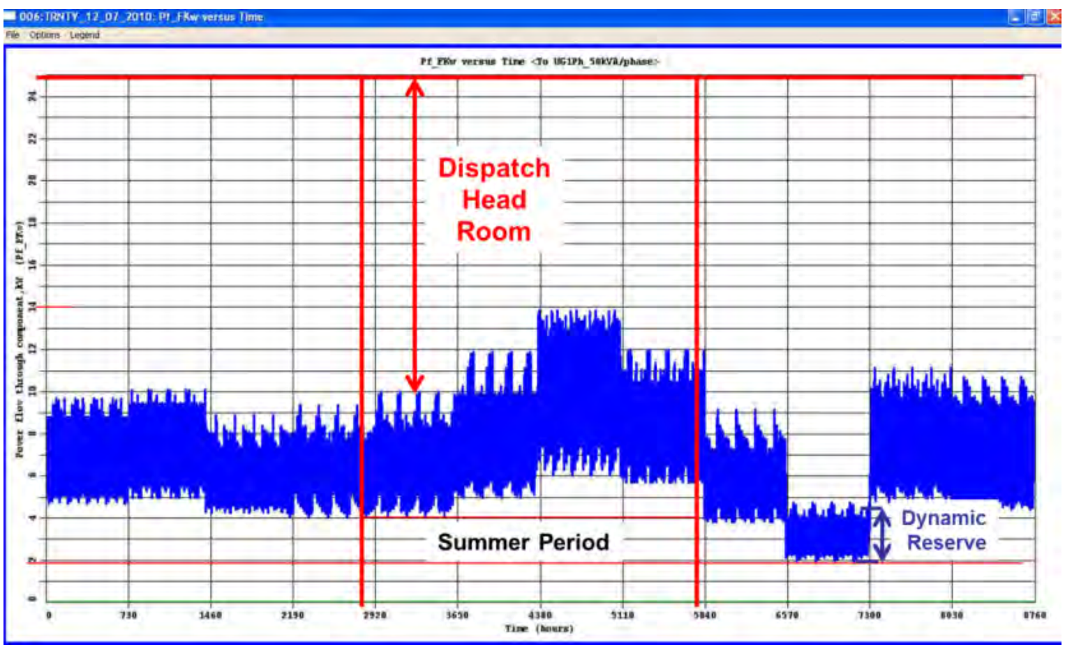



Figure 12: Transformer Loading Identifying Dispatch Headroom

- The DEW circuit model was used to examine customer voltages to determine where the CES could provide value to improve local voltage support if needed. See Figure 13.

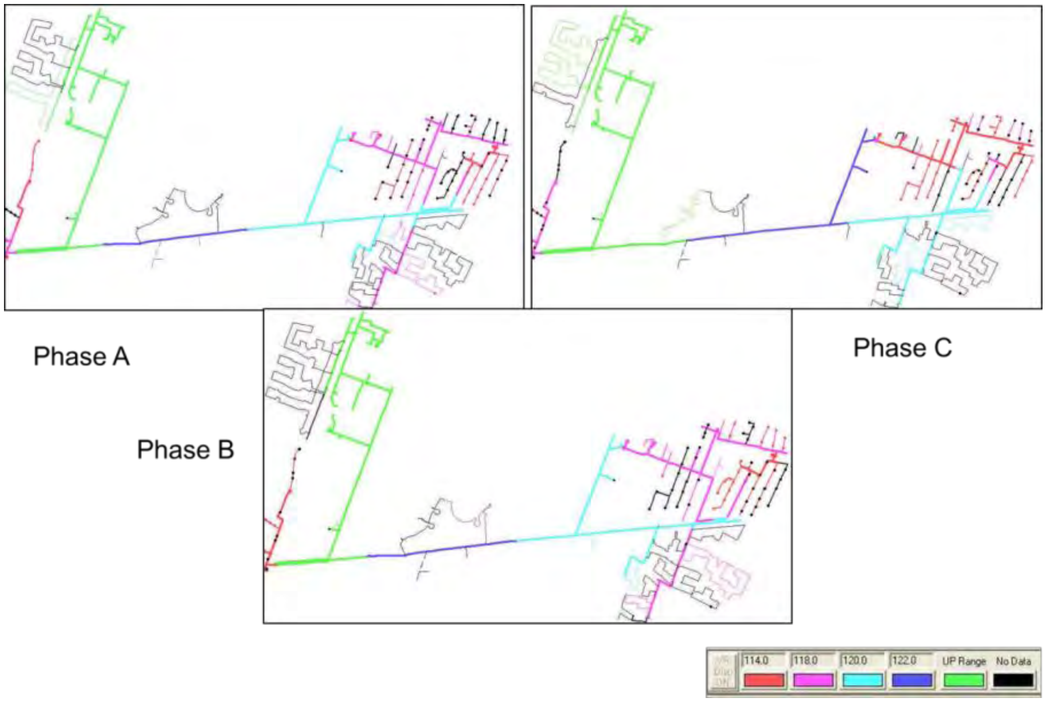



**Figure 13: Circuit Model Identifying Phase Voltage for CES Placement**

- The DEW circuit model was used to determine power factor at all single-phase attachment points to determine where the inverters reactive capability could be used to provide local power factor benefit. See Figure 15.


**Figure 14: Circuit Model Single Phase Power Factor for CES Placement**

- The DEW circuit model was used to simulate phase imbalance at all points where single phase laterals attached to the three phase mainline to determine points internal to the circuit where the placement of CES could improve phase balance. See Figure 15.

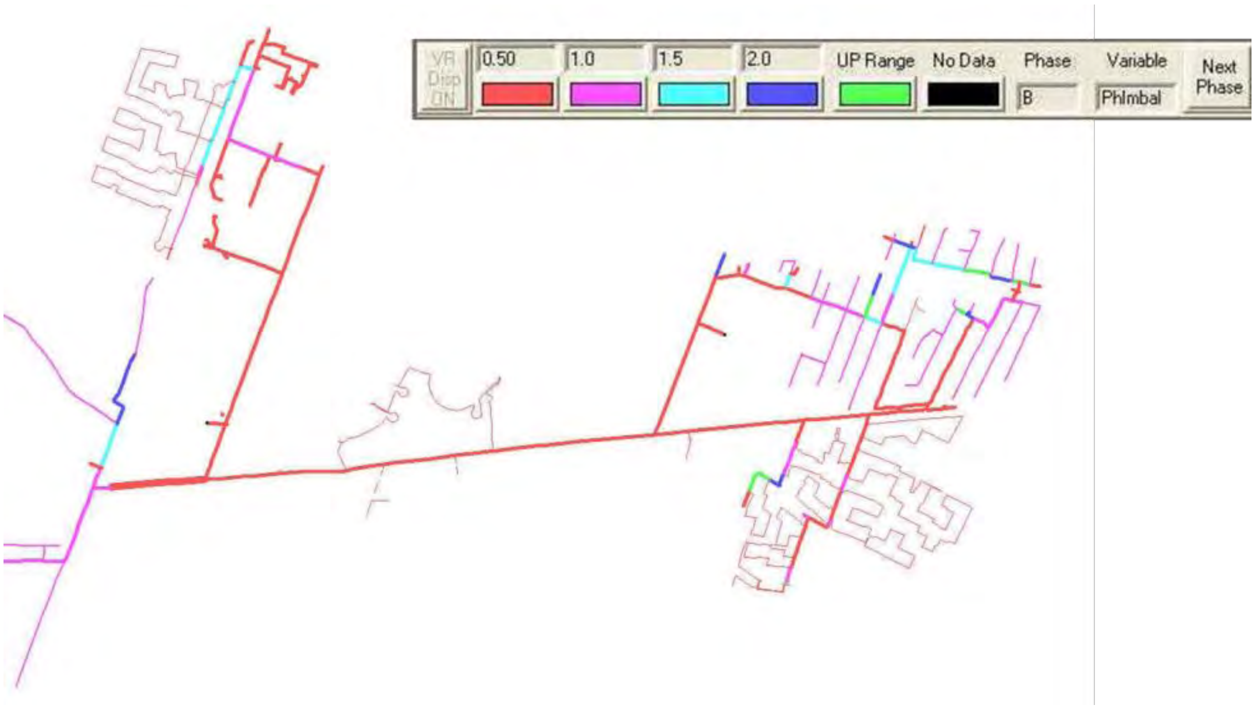



**Figure 15: Circuit Model Identifying Phase Imbalance**

- A strategy matrix was developed combining the elements of the technical summary shown in Figure 16, with the location accessibility and appearance to help in the choosing locations for placing the CES units. Figure 17 is the decision strategy matrix.

| | | Maximum Loading Data | | | Outages | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Local Name | UID | Analysis Time Point | kVA | Inter. Air | 2007 | 2008 | 2009 | 2010 | 2011 | Total | Cust. V. | P. F. (%) | Phase Imbalance | Ease of Access | Aesthetics |
| UG1Ph_50kVA/phase | 234813156209 | Friday-August@ 9PM | 21.336 | No | 1 | 0 | 0 | 1 | 0 | 2 | 124.2 | 86.20 | >100% | Easy | Nice |
| UG1Ph_50kVA/phase | 234620156289 | Saturday-December@ 6PM | 16.002 | No | 1 | 0 | 0 | 1 | 0 | 2 | 124.2 | 86.20 | >100% | Easy | Nice |
| UG1Ph_50kVA/phase | 234427156368 | Tuesday-July@ 9PM | 22.86 | No | 1 | 0 | 0 | 1 | 0 | 2 | 124 | 86.20 | >100% | Easy | Nice |
| UG1Ph_50kVA/phase | 234144156511 | Tuesday-July@ 9PM | 18.288 | No | 1 | 0 | 0 | 1 | 0 | 2 | 124 | 86.20 | >100% | Easy | Nice |
| UG1Ph_25kVA/phase | 233945156593 | Sunday-July@ 6PM | 3.81 | No | 1 | 0 | 0 | 1 | 0 | 2 | 124.1 | 86.20 | >100% | Hard | Nice |
| UG1Ph_25kVA/phase | 234022156785 | Friday-August@ 9PM | 5.334 | No | 1 | 0 | 0 | 1 | 0 | 2 | 124.1 | 86.20 | >100% | Hard | Nice |
| UG1Ph_50kVA/phase | 234241156752 | Friday-August@ 9PM | 3.81 | No | 1 | 0 | 0 | 1 | 0 | 2 | 124.1 | 86.20 | >100% | Hard | Nice |
| UG1Ph_50kVA/phase | 234511157147 | Sunday-July@ 6PM | 12.954 | No | 1 | 0 | 0 | 1 | 0 | 2 | 122.6 | 87.86 | >100% | Medium | Nice |
| UG1Ph_50kVA/phase | 234750157201 | Sunday-July@ 6PM | 16.764 | No | 1 | 0 | 0 | 1 | 0 | 2 | 122.6 | 87.86 | >100% | Easy | Nice |
| UG1Ph_50kVA/phase | 234119157057 | Wednesday-December@ 7PM | 1.524 | No | 1 | 0 | 0 | 1 | 0 | 2 | 122.8 | 87.86 | >100% | Medium | Nice |
| UG1Ph_50kVA/phase | 234783156726 | Sunday-July@ 6PM | 3.048 | No | 1 | 0 | 0 | 1 | 0 | 2 | 122.8 | 87.86 | >100% | Medium | Nice |
| UG1Ph_50kVA/phase | 234547157397 | Sunday-July@ 6PM | 10.668 | No | 1 | 0 | 0 | 1 | 0 | 2 | 122.7 | 87.07 | >100% | Medium | Nice |
| UG1Ph_25kVA/phase | 234402157454 | Sunday-July@ 6PM | 15.24 | No | 1 | 0 | 0 | 1 | 0 | 2 | 122.7 | 87.07 | >100% | Medium | Nice |
| UG1Ph_25kVA/phase | 234384157713 | Wednesday-November@ 8PM | 3.81 | No | 1 | 0 | 0 | 1 | 0 | 2 | 122.7 | 87.07 | >100% | Hard | Nice |
| UG1Ph_50kVA/phase | 235047157412 | Friday-August@ 9PM | 12.954 | No | 1 | 0 | 0 | 1 | 0 | 2 | 122.7 | 87.07 | >100% | Medium | Nice |
| UG1Ph_25kVA/phase | [illegible] | Sunday-July@ 6PM | 16.764 | No | 1 | 0 | 0 | 1 | 0 | 2 | 122.7 | 87.07 | >100% | Hard | Nice |
| UG1Ph_50kVA/phase | 234953157045 | Sunday-July@ 6PM | 18.288 | No | 1 | 0 | 0 | 1 | 0 | 2 | 122.8 | 87.07 | >100% | Medium | Nice |
| UG1Ph_50kVA/phase | 235257156991 | Tuesday-July@ 9PM | 22.098 | No | 1 | 0 | 0 | 1 | 0 | 2 | 122.8 | 87.07 | >100% | Easy | Nice |
| UG1Ph_50kVA/phase | 234604157893 | Sunday-July@ 6PM | 20.574 | No | 1 | 0 | 0 | 2 | 0 | 2 | 122.6 | 85.73 | >100% | Medium | Nice |
| UG1Ph_50kVA/phase | 234748157833 | Tuesday-July@ 9PM | 23.622 | No | 1 | 0 | 0 | 2 | 0 | 2 | 122.6 | 85.73 | >100% | Medium | Nice |
| UG1Ph_50kVA/phase | 235458157297 | Sunday-July@ 6PM | 9.144 | No | 1 | 0 | 0 | 2 | 0 | 2 | 122.8 | 85.73 | >100% | Easy | Nice |
| UG1Ph_50kVA/phase | 234973158121 | Tuesday-July@ 9PM | 16.764 | No | 1 | 0 | 0 | 1 | 0 | 2 | 122.9 | 85.80 | >100% | Medium | Nice |
| UG1Ph_50kVA/phase | 235666157811 | Tuesday-July@ 9PM | 23.622 | No | 1 | 0 | 0 | 1 | 0 | 2 | 123.1 | 85.80 | >100% | Hard | Nice |
| UG1Ph_25kVA/phase | 235077156395 | Friday-August@ 9PM | 9.906 | No | 1 | 0 | 0 | 1 | 0 | 2 | 124.3 | 85.88 | >100% | Easy | Nice |
| UG1Ph_50kVA/phase | 234912156437 | Friday-August@ 9PM | 9.144 | No | 1 | 0 | 0 | 1 | 0 | 2 | 124.3 | 85.88 | >100% | Easy | Nice |
| UG1Ph_50kVA/phase | 234566156570 | Friday-August@ 9PM | 5.334 | No | 1 | 0 | 0 | 1 | 0 | 2 | 124.3 | 85.88 | >100% | Medium | Nice |
| UG1Ph_50kVA/phase | 234418156645 | Sunday-July@ 6PM | 3.81 | No | 1 | 0 | 0 | 1 | 0 | 2 | 124.3 | 85.88 | >100% | Hard | Nice |
| UG1Ph_50kVA/phase | 236019158014 | Sunday-July@ 6PM | 14.478 | No | 1 | 0 | 0 | 1 | 0 | 2 | 124.5 | 85.88 | >100% | Medium | Nice |
| UG1Ph_50kVA/phase | 239684152896 | -July@ 6PM | 21.336 | No | 0 | 0 | 2 | 1 | 0 | 3 | 120.3 | 85.82 | No | Medium | Very Nice |
| UG1Ph_50kVA/phase | 240032153149 | -August@ 9PM | 16.002 | No | 0 | 0 | 2 | 1 | 0 | 3 | 120.4 | 85.82 | No | Easy | Very Nice |
| UG1Ph_50kVA/phase | 240250153386 | -August@ 9PM | 18.288 | No | 0 | 0 | 2 | 1 | 0 | 3 | 120.5 | 85.82 | No | Medium | Very Nice |
| UG1Ph_50kVA/phase | 244288150692 | -July@ 9PM | 20.574 | No | 1 | 0 | 2 | 2 | 0 | 5 | 118.0 | 85.91 | No | Easy | Really Bad |
| UG1Ph_50kVA/phase | 244057150603 | -July@ 9PM | 15.24 | No | 1 | 0 | 2 | 2 | 0 | 5 | 118.0 | 85.91 | No | Easy | Really Bad |

Figure 16: CES Location Strategy Matrix

| Legend | | |
|---|---|---|
| Color | Description | Total Xfrms |
| | Class 1, medium loading | 5 |
| | Class 1, heavy or light load | 7 |
| | Class 2, medium loading | 6 |
| | Class 2, heavy or light load | 12 |
| | Class 3, medium load | 2 |
| | Class 3, heavy or light load | 6 |
| | Class 4, medium load | 8 |
| | Class 4, heavy or light load | 4 |
| | Class 5, medium load | 3 |
| | Class 5, heavy or light load | 10 |
| | Unknown location | 1 |
| | | |
| | Total Xfrms | 64 |

| Classification | Description | Total Xfrms |
|---|---|---|
| Class 1 | Located in a Very Nice, Nice, or Bad area, with easy or medium access, having 3 or more total outages since 2007 with primary customer voltage below 121 | 12 |
| Class 2 | Located in a Very Nice, Nice, or Bad area, with easy or medium access, having less than 3 total outages since 2007 with primary customer voltage below 123 | 18 |
| Class 3 | Located in a Very Nice, Nice, or Bad area, with easy or medium access, having less than 3 total outages since 2007 with primary customer voltage above 123 | 8 |
| Class 4 | Located in a Really Bad Area with easy or medium access | 12 |
| Class 5 | Hard access | 13 |

Figure 17: CES Location Strategy Matrix Summary

- The strategy matrix was then combined with the circuit phasing which was used to maintain phase balance between the phases while picking the best candidates for installation. See Figure 18.

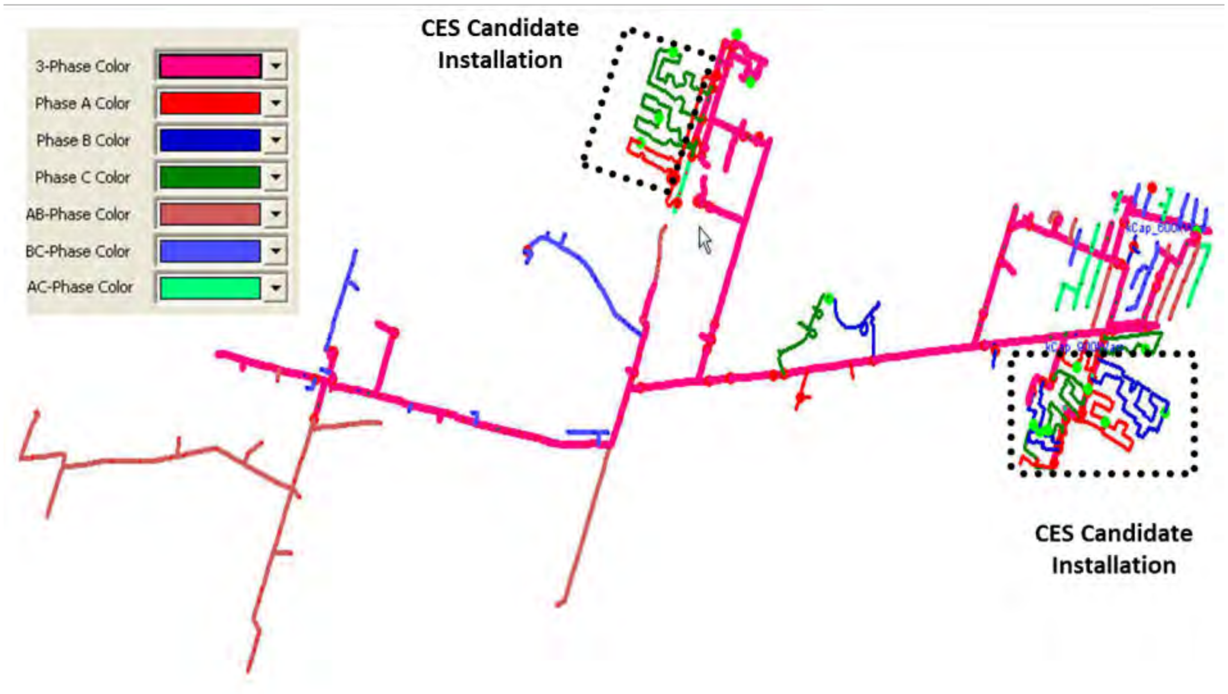



**Figure 18: CES Candidate Sites Selection using Strategy Matrix and Phase Balance**

### 3.4.2. Circuit Model Dispatching

DEW was used to determine dispatch set points based on real-time circuit conditions and economic parameters. This was demonstrated in the DERMS DEW Service Mode of Operation use cases 14 to 23, where recommendations were processed and dispatched by the DERMS DNP3 master to the CES. The uses cases are defined in section 4.3 with the results in section 5.2.

A DEW model-based real-time control algorithm was created for the CES DEW service dispatch. The DEW CES Economic Scheduling Application algorithm has as its objective maximizing profits subject to constraints arising from the CES specifications, dynamic reserve requirements, and system-level operating constraints such as voltage support and overload alleviation. This could be one CES or an entire fleet. Figures 19 and 20 show the control input and output concept of the CES economic scheduling.

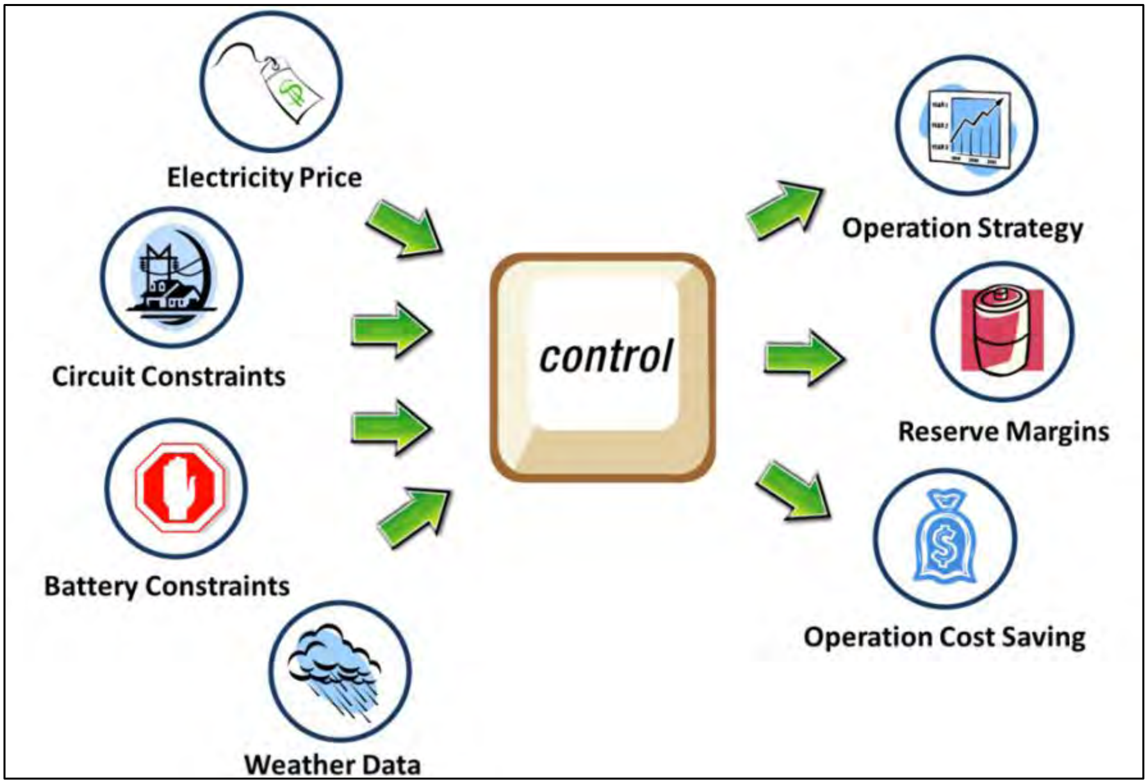



Figure 19: CES Economic Scheduling Control Algorithm

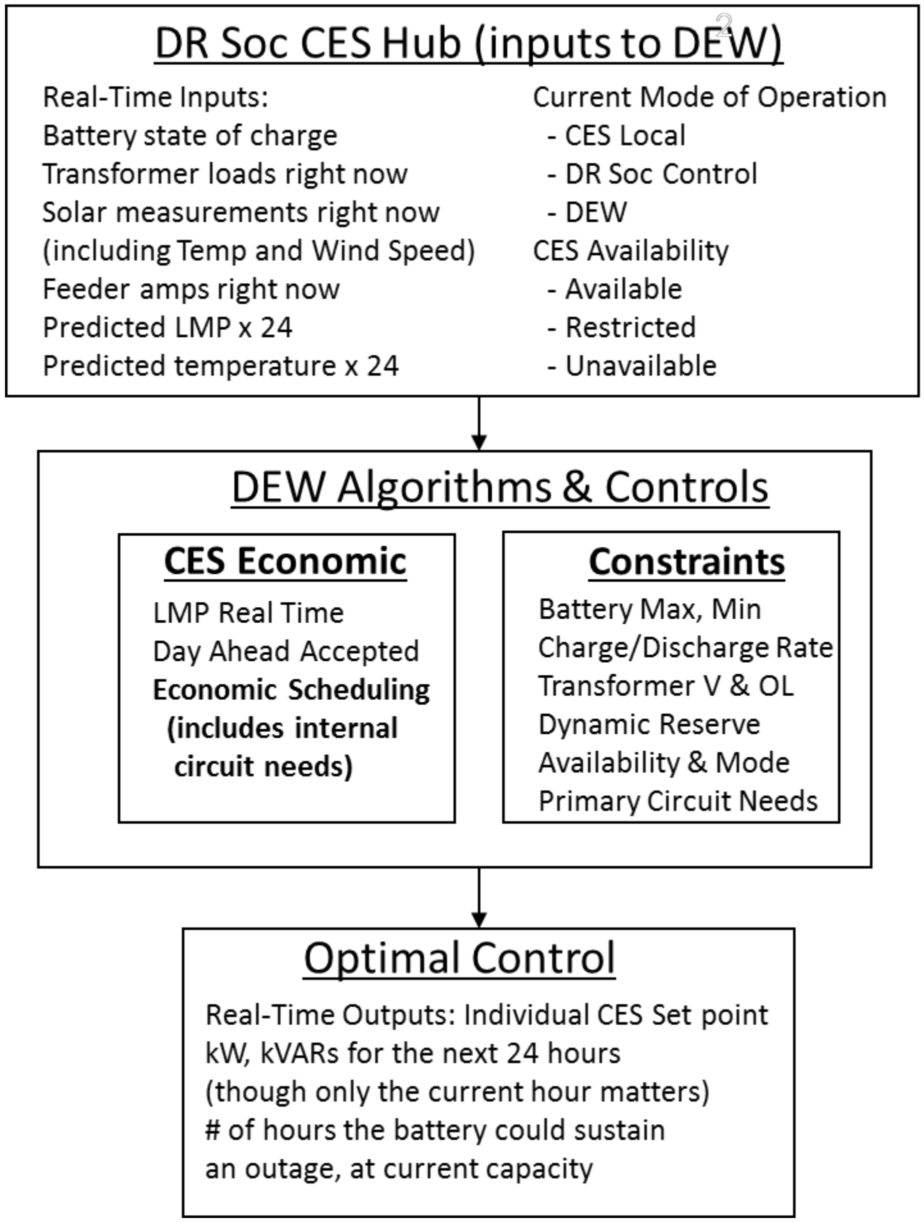



**Figure 20: DEW's CES Economic Scheduling Application Flow Diagram**

- DR-SOC delivers to the DEW CES Economic Scheduling Application all current parameters for each CES unit as well as MISO data and the Local Marginal Price (LMP). This data is used by the DEW algorithm to give dispatch information back to DERMS. This method establishes a set point for each CES unit in the CES Fleet. These measurements are typically updated every 5 minutes and include the following:

- Day ahead LMP
- Real-Time LMP
- Start of circuit current flows and voltages
- Battery status and current output
- Real-time loads at each CES location
- Solar Output
- Solar forecast

The objective of the DEW CES Economic Scheduling Application algorithm is to optimize energy cost savings over time by taking advantage of CES capacity in excess of the dynamic reserve capacity. Therefore, the two primary drivers of the optimization algorithm are the LMP prediction and the load forecast.

In electric energy markets, the Locational Marginal Price (LMP) is computed in real-time based on bids from energy producers and based on losses and line congestion. These prices are called the real-time LMPs and represent the incremental cost to supply load to a given region at a given time. In addition to the real-time LMP market, there is a day-ahead LMP market, wherein energy producers bid their expected costs one day ahead.

In order to determine the optimal charging and discharging schedule for the CES units, the price of energy at future hours is needed. The DEW CES Economic Scheduling Application uses both the real-time and the day-ahead LMP prices and calculates the profit attainable assuming that the day-ahead prediction is accurate. The real-time LMP provides continuous corrections to the day-ahead price forecast as the data is given to DEW.

The DEW modeling of the load and its forecast is the other primary driver of the economic optimization. In order to determine how much capacity is available currently and will be available in the near future for economic dispatch, the load must be forecasted. At each CES location, the transformer load is metered in real-time and reported to DEW. Thus, for these locations, DEW develops and continuously updates load models based on a rolling 2 weeks' worth of measurements. For all other transformers, and for the CES transformers until two weeks' worth of measurements are available, the forecast algorithm will use load research statistics and monthly kWh billing data. The load research statistics provide typical daily load curves for each month or season as well as each type of day (weekday or weekend) for the type of customer supplied by the transformer. These daily load curves are then scaled by the monthly kWh billing data.

The reliability constraints take precedence over the energy cost savings. The reliability constraint is calculated using a dynamic reserve capacity, meaning that the stored energy is kept at a sufficient level to serve an outage for a given duration based on the real-time load and near-term forecast. During peak load conditions the full capacity of the battery may be needed to provide energy during a two hour outage, but during light load conditions the battery may need to reserve only a small percentage of its maximum capacity to serve the load for the following two hours and can use the remaining capacity for economic dispatch.

The objectives and constraints described above can be evaluated for each CES unit independently. However, the DR-SOC Hub also provides start-of-circuit flows and voltages, PV output, and voltages at CES locations, which together can be used to identify overloads and high or low voltages on the primary system, which serve as additional constraints to CES scheduling, taking precedence over the economic objective and local reliability margin. Since these are primary system-wide constraints, the entire fleet of CES units is evaluated together when calculating the real power constraints to minimize restrictions to the individual CES unit schedules. Since the batteries supply power via inverters, which can provide reactive power support, the CES scheduling will first attempt to resolve the primary system constraints with reactive power support, which does not significantly affect the real power schedule. If reactive power support proves insufficient, then the CES scheduling algorithm modifies the real power (charge/discharge) schedule for the batteries until the primary system operating constraints are met or until the batteries reach state-of-charge or charge/discharge rate constraints.

The DERMS DEW Service dispatches operating set points and (on / off) commands. The DR-SOC Hub Operator validates the set points for each unit and compares the actual CES performance to the DEW forecast.

## 3.5. Repurposed EV Batteries

Two CES repurposed EV units were built by eCamion and integrated into the S&C PCS. During the project, it was decided to investigate two methods of using repurposed EV batteries. One was to use a whole battery pack and manage the batteries using the vehicle CAN message bus and the other to dismantle the battery pack and use the battery modules. It was also decided to build one container that could accommodate a whole packs or multiple battery modules. Because of technical challenges communicating with the battery pack message bus the whole pack concept was eliminated with both battery systems created using battery modules method. Another option considered but discarded, was to separate the battery modules into individual cells and create a repurposed pack composed using the individual cells. This method requires additional labor to disassemble the pack and reassemble. This is certainly not a cost effective method. Figure 22 shows the location of the Fiat 500e battery back in the vehicle and figure 22 is a photograph of the open pack showing the battery modules that contain individual cells and pack electronics.

**Figure 21: Fiat 500e Battery Pack Position (in Green)**

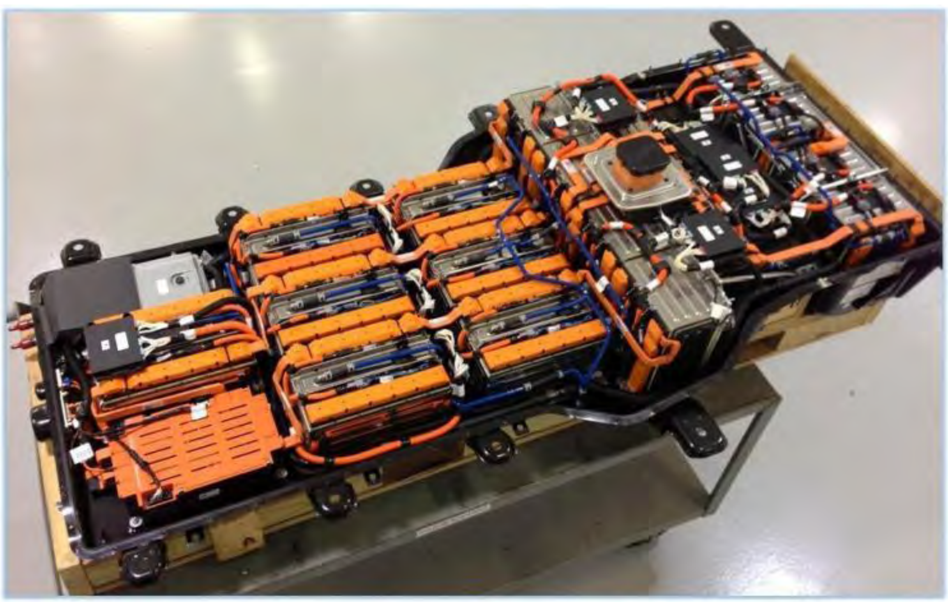


**Figure 22: Open Fiat 500e Battery Pack Showing the Battery Modules**

The two-battery packs built had a capacity of 48 kWh and 96 kWh.  A battery BMS supplied by eCamion as part of the packaging was used to manage the battery operation and communicate to the S&C PCS system.  The installation in figure 23 shows the 96 kWh configurations that is located at DTE Energy headquarters in Detroit.  The white container houses the battery and BMS and the green container to the right is the S&C CES PCS. This installation serves the six EV charging stations that are located along the fence behind the container.

Figure 23: Repurposed 96 kWh Battery Connected to the CES PCS

# 4. Technical Approach

## 4.1. Project Approach

The objective of energy storage project is to integrate 1-MW of distributed Li-ion energy storage into the electric utility system and to centrally control and aggregate them as a fleet. This project installed 20 CES units (500 kW total) and a 500kW storage device that is collocated with a 500 kW solar system that is managed centrally with a DERMS. The DERMS was expanded in this project, leveraging previous DOE funded work on the monitoring and control system at DTE Energy. Two of the 20 distributed CES storage system installed are secondary-use battery from electric vehicles. The main phases of this project were:

- Design and construct a CES device that will serve as an essential component of grids
- Develop installation procedures and integrate into engineering design
- Design a central communications control system to aggregate CES devices across DTE service territory (DERMS)
- Demonstrate the aggregation of distributed energy systems
- Using the DERMS, demonstrate the ability of the storage devices to provide:

    - Peak Shaving
    - Voltage Support
    - Integration of renewable generation & energy shifting
    - Islanding during outages
    - Frequency Regulation
- Determine the multiple layered economic benefits of energy storage in MISO
- Perform sensitivity economic analysis on the application of CES in the DTE Energy distribution service area
- Create a CES unit  with repurposed batteries form an electric vehicle
- Demonstrate the utilization of secondary-use EV batteries
- Evaluate the cost of deploying repurposed EV battery system vs new batteries

The benefit categories monitored and tracked for this project and reported in this final Technology Performance Reports are in table 5 below summarizes.

| Benefit Category | Benefit | Information Gathered | Process |
|---|---|---|---|
| Reliability and Power Quality | Reduced sustained outages (consumer)<br><br>Reduced momentary outages (consumer) | SAIFI<br><br>SAIDI, CAIDI, MAIFI | The DTE Energy team will be monitoring and recording project data through the DTE DERMS |
| Environmental | Reduced CO2 Emissions<br><br>Reduced Pollutant Emissions | DTE Environmental Affairs reports. DERMS data | An estimate of emissions performance will be included in the final TPR. We will attempt to include data for summer |
| Economic T&D O&M Savings | Reduced Equipment Maintenance Cost (utility /Ratepayer) | For Storage Equipment only – data will be gathered from project data base. | |

**Table 5: Project Benefit Categories**

## 4.2. Baseline Data

The Build and Impact metrics, along with descriptions of the types of data and their frequencies that are summarily provided in this section are based on discussion between the DOE team and DTE Energy Community Energy Storage project members. Discussions were held via teleconference calls on 1/20/2010 and 2/10/2011. During each call, the DOE team was represented by the Technical Project Officer and representatives from Navigant Consulting, Inc. The DOE provided a summary of the results of each discussion by revising the "Discussion of Data for Storage and Smart Grid Metrics and Benefits" document originally dated January 20, 2011. The revised Discussion Document serves as the basis of the Metrics and Benefits plan as described below.

The table 6 below contains Baseline calculation methods for each metric based on historical data, in conjunction with the assumptions described in the paragraph above. The final project baseline data is in a similar table in section 6.

| ID | Metric Name | Project Level Baseline and Commencement Value Calculation Method | System Level Baseline and Commencement Value Calculation Method |
|---|---|---|---|
| Build Metrics | | | |
| 1 | Distributed Generation Additional System Level | N/A | DTE will track the installation of a single PV/ Battery installation at Monroe County Community College (MCCC) which is on the same electric distribution circuit as the storage demonstration project |
| 2 | Energy Storage | No Energy Storage Systems initially installed on the project demonstration circuits -baseline is zero. As the PV / Battery installation comes on line, a new baseline will be established.<br>Value calculation- DTE will track the number (based on installation records) and connected output (based on installation records) of CES units installed on the project circuits.<br>Value at project commencement is zero. | DTE will limit the system level baseline per agreement with the DOE to the installation status and connected output of the PV/ Battery installation at Monroe County Community College (MCCC). This PV installation will be located on the demonstration circuits.<br>Value at project commencement is zero. |
| 3 | DER Interface | This will be a description only value report. Reporting will commence after design completion. | N/A |
| Impact Metrics - Storage System | | | |
| 4 | Annual Storage Dispatch | No Energy Storage Systems initially installed on the project demonstration circuits. - Baseline is zero. . As the PV/Storage Battery installation comes on line a new baseline will be established. Data reporting will commence in the quarter following the commissioning of the PV installation.<br>Value calculation method- DTE will t rack the kWh dispatched via the DERMS. | N/A |

| ID | Metric Name | Project Level Baseline and Commencement Value Calculation Method | System Level Baseline and Commencement Value Calculation Method |
|---|---|---|---|
| 5 | Average Energy Storage Efficiency | No Energy Storage Systems initially installed on the project demonstration circuits –baseline is zero. As the PV/Storage Battery installation comes on line a new baseline will be established. Data reporting will commence in the quarter following the commissioning of the PV/Battery installation. Value calculation method - DTE will track the kWh dispatched via the DERMS and will compare this with the energy required to operate the system and recharge the batteries. | N/A |
| 8 | Distribution Feeder or Equipment Feeder Overload Incidents | Use 2010 data as a baseline<br><br>Value at project commencement- Use 2010 - 2012 to calculate distribution equipment overloads | N/A |
| 9 | Distribution Feeder Load | Use 2010 data as baseline.<br>Value at commencement – use 2011-2014 to calculate distribution equipment overloads<br>Due to Michigan's current economy, there is no expected growth for these areas in the next five years. The growth rate will be zero. | N/A |
| 10 | SAIFI | Baseline data not available at the project distribution transformer level<br>Value at project commencement is zero. | 2012-0.83<br>2013-0.94 |
| 11 | SAIDI/CAIDI | Baseline data not available at the project distribution transformer level<br>Value at project commencement is zero. | 2012-108/130<br>2013-894/955 |
| 12 | MAIFI | Baseline data not available at the project distribution transformer level | N/A |

**Table 6: Project Baseline Data**

## 4.3. Test Plan/Use Cases (Modes of Operations)

The capabilities of the distributed energy storage systems were systematically demonstrated with a number of use cases in this project. These use cases started at the most basic level to establish communication to each CES unit to the more advanced use case using a circuit "model based" control and economic dispatching. This project created 23 unique use cases listed in table 7 below that are intended to test all of the functionalities of the CES system. The "Mode of Operation" is the type of operation being performed on the CES and are defined as follows:

- **Stand-by** – Local mode always active. Provides emergency power upon loss of utility power
- **Hub Command –** Set points to be written to CES by the DERMS Hub. Operator sends commands manually using web displays.
- **Schedule** – DERMS Hub retrieves set points from a table developed by DERMS personnel.
- **Peak Shaving** – DERMS Hub calculates kW needed to maintain max circuit kW at threshold. Needed kW is distributed among available CES units in this mode.
- **AGC** – DERMS Hub retrieves AGC set points and distributes kW among available CES units in this mode
- **DEW** – DERMS Hub obtains dispatch recommendations from the DEW model and sends commands to units.

| Requirement # | Test Performed | Component Tested | Mode of Operation |
|---|---|---|---|
| DRSOC-CES-001 | Data usage test | Cellular communications | Stand-by / Hub Command |
| DRSOC-CES-002 | CES maintains Minimum Reserve Margin | CES controller logic | Hub Command |
| DRSOC-CES-003 | CES unit will operate safely when unit is at 100% SOC and is given a charge command. | CES controller logic | Hub Command |
| DRSOC-CES-004 | CES unit will operate safely when kW and kvar setpoints cause unit to exceed discharge kVA rating. | CES controller logic | Hub Command |
| DRSOC-CES-005 | CES unit will operate safely when kW and kvar setpoints cause unit to exceed charge kVA rating. | CES controller logic | Hub Command |
| DRSOC-CES-006 | DRSOC Hub will dispatch a reasonable set-point when algorithms command a kW set-point that exceeds unit charge rating. | DRSOC Hub | Hub Command |
| DRSOC-CES-007 | DRSOC Hub will dispatch reasonable set-point when algorithms command a kW set-point that exceeds unit discharge rating. | DRSOC Hub | Hub Command |
| DRSOC-CES-008 | DERMS Hub will distribute fleet kW charge or discharge across all units based on SoC of each unit. | DRSOC Hub | Hub Command |
| DRSOC-CES-009 | CES Efficiency | CES Efficiency | Hub Command |
| DRSOC-CES-010 | DERMS Hub will issue commands per a set schedule to produce “Renewable Energy Time Shift” | DRSOC Hub | Schedule |
| DRSOC-CES-011 | DERMS Hub will issue commands per a set schedule to produce “Electric Energy Time Shift” | DRSOC Hub | Schedule |

| Requirement # | Test Performed | Component Tested | Mode of Operation |
|---|---|---|---|
| DRSOC-CES-012 | DERMS Hub will send commands to CES units based on simulated AGC signal | DRSOC Hub | AGC |
| DRSOC-CES-013 | DERMS Hub will discharge CES fleet to maintain a maximum kW at the circuit feeder. | DRSOC Hub | Peak-Shaving |
| DRSOC-CES-014 | Charge when needed for reserve capacity | DEW Service | DEW |
| DRSOC-CES-015 | Discharge when price is high and unit is not "needed" | DEW Service | DEW |
| DRSOC-CES-016 | Do not charge when doing so would cause overload | DEW Service | DEW |
| DRSOC-CES-017 | Maintain configured reserve capacity | DEW Service | DEW |
| DRSOC-CES-018 | Resolve transformer overload by discharging | DEW Service | DEW |
| DRSOC-CES-019 | Resolve low voltage by supplying vars | DEW Service | DEW |
| DRSOC-CES-020 | Resolve high voltage by absorbing vars | DEW Service | DEW |
| DRSOC-CES-021 | Resolve single-phase primary overload by discharging only batteries on that phase while charging others (low price) | DEW Service | DEW |
| DRSOC-CES-022 | Forecasted overload alert | DEW Service | DEW |
| DRSOC-CES-023 | Minimum profit margin test | DEW Service | DEW |

**Table 7: Project Uses Cases**

The test plan or use case results are in section 5.2.

## 4.4. Distributed Energy Management System Application

The DERMS was used to test all of the 23 CES project uses case that were defined in section 4.3 above. Testing of the DERMS or DRSOC Hub was performed against the CES Units installed on the Trinity circuit. DRSOC Hub parameters were set through the use of the DRSOC XML Poster tool. The hub in turn outputs the DNP3 commands for each CES Unit as appropriate for the mode of operation being tested. Figure 26 is a simplified schematic of the of the CES test setup. The Hub can address each CES individually or as a collective fleet. All data was collected and stored by the DERMS and is reported out in each of the 23 uses cases in section 5.1

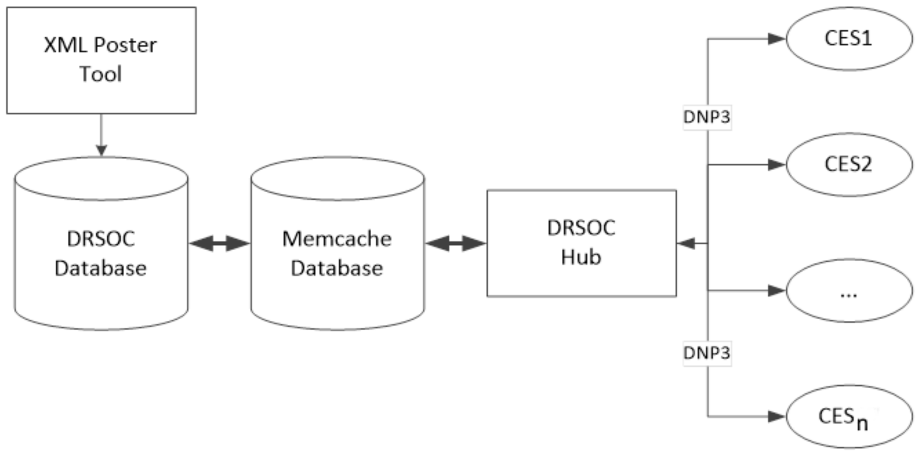



Figure 24: Schematic of CES Test Setup

## 4.5. Performance Testing and Analysis

In addition to demonstrating the use cases identified in Table 7, a number of functional test and analysis were performed as part of this demonstration project.

DNV GL performed CES functional tests in their energy storage test facility of new CES system prior to deployment and repurposed battery systems as well as degradation analysis of one of the oldest deployed battery pack. DNV GL also performed economic analysis on the application of distributed energy storage specific to the Trinity distribution circuit.

Next Energy investigated the regulatory issues surrounding energy storage and the application of distributed energy storage at the Department of Defense installations.

In the last year of this demonstration project, DTE Energy and EPRI worked together on additional economic analysis. The EPRI Energy Storage and Evaluation Tool (ESVT) was used to perform additional sensitivity on the application of distributed energy storage at DTE Energy.

The results of these analyses are discussed in section 5.9 of this report.

## 4.6. Cyber Security Approach

The challenge for the CES is to develop a smart grid system that provides end-to-end integration of a wide array of vendor products and systems while providing a robust, resilient and secured operational infrastructure. Interoperability and cyber security have common challenges for ensuring operational continuity of the smart grid system and adapting to change over time due to emerging standards and changing technology. Introducing new technologies to an already protected and sensitive network elevates the need to predict, evaluate, test, protect and react against threats and vulnerabilities.

Through experience and guidance from various industry standards authority and by leveraging the experiences from internal and other utilities, DTE Energy has developed many best practices for cyber security. Here are a few:

- Develop strategies for implementations to be “built-in” but not “bolted on”.
- Safety to public and customers and employees are paramount.
- Identify criteria for risks that could challenge the implementation of the project.
- Aim to fully meet or exceed industry standards for cyber security set forth by DOE, NIST, EPRI and the Smart Grid Consortium.
- Utility’s responsibility to find balance between grid reliability and cost for pilot projects, realizing permanent solutions may be too expensive for a particular research project.
- Vendor implementations do not always align with industry and internal corporate standards, and require DTE to investigate mitigation options.
- Presently using an unacknowledged protocol (UDP), DTE recommends using TCP, which is a more secure and interactive protocol.
- Any device installed should have the ability to monitor itself to operate safely. No remote operation should cause a device to cause a safety concern and shall pose no risk to surrounding environment.
- Leveraged the experience of AMI transmission across DTE's exclusive APN network with our cellular carrier AT&T. Plan to transmit CES information in a like manner.
- Engage with vendors early. Explicitly talk with the vendors early on, to ensure protocol/ product integration and security.
- Although security features may be available (example: password protection), the control may not meet industry or internal corporate standards (password controls: length, expiration, complexity).
- Product delayed due to safety concerns resulting from an incident due to an energy storage system malfunctioning.

Based on best practices the following communication activities were implanted in this project.

- Implemented APN with cellular provider
- Tested ICCP Protocol Security/Traffic Analysis application as a mitigation option
- Implemented hardened network communications

# 5. Results

This section reports on the results and data analysis of the demonstration project.

## 5.1. Impact Metrics Data

This section is the CES demonstration project final impact metrics. The metric table (Table 7) in section 4.2 is duplicated here with one additional column with the heading "Final Project Metrics" that includes the final metric and a brief discussion.

| ID | Metric Name | Project Level Baseline and Commencement Value Calculation Method | System Level Baseline and Commencement Value Calculation Method | Final Project Metrics |
|---|---|---|---|---|
| Build Metrics | | | | |
| 1 | Distributed Generation Additional System Level | N/A | DTE will track the installation of a single PV/ Battery installation at Monroe County Community College (MCCC) which is on the same electric distribution circuit as the storage demonstration project | On the Trinity circuit a 500 kW, PV system was installed at MCCC. |

| ID | Metric Name | Project Level Baseline and Commencement Value Calculation Method | System Level Baseline and Commencement Value Calculation Method | Final Project Metrics |
|---|---|---|---|---|
| 2 | Energy Storage | No Energy Storage Systems initially installed on the project demonstration circuits -baseline is zero. As the PV / Battery installation comes on line, a new baseline will be established.<br>Value calculation- DTE will track the number (based on installation records) and connected output (based on installation records) of CES units installed on the project circuits.<br>Value at project commencement is zero. | DTE will limit the system level baseline per agreement with the DOE to the installation status and connected output of the PV/ Battery installation at Monroe County Community College (MCCC). This PV installation will be located on the demonstration circuits.<br>Value at project commencement is zero. | Total energy storage installed capacity is 1,000 kW and 1,292 kWh of energy at 21 individual locations. |
| 3 | DER Interface | This will be a description only value report. Reporting will commence after design completion. | N/A | This is the DERMS as described in section 3.2 |
| Impact Metrics - Storage System | | | | |
| 4 | Annual Storage Dispatch | No Energy Storage Systems initially installed on the project demonstration circuits. - Baseline is zero. . As the PV/Storage Battery installation comes on line a new baseline will be established. Data reporting will commence in the quarter following the commissioning of the PV installation.<br>Value calculation method- DTE will track the kWh dispatched via the DERMS. | N/A | 90,551 kWh |

| ID | Metric Name | Project Level Baseline and Commencement Value Calculation Method | System Level Baseline and Commencement Value Calculation Method | Final Project Metrics |
|---|---|---|---|---|
| 5 | Average Energy Storage Efficiency | No Energy Storage Systems initially installed on the project demonstration circuits –baseline is zero. As the PV/Storage Battery installation comes on line a new baseline will be established. Data reporting will commence in the quarter following the commissioning of the PV/Battery installation. Value calculation method- DTE will track the kWh dispatched via the DERMS and will compare this with the energy required to operate the system and recharge the batteries. | N/A | The DERMS system did not have enough granular data collection system to calculate this metric. The DNV GL Kema battery test lab performed efficiency test as discussed in section 5.2.9. The roundtrip AC efficiency averaged 88%. |
| 8 | Distribution Feeder or Equipment Feeder Overload Incidents | Use 2010 data as a baseline<br><br>Value at project commencement- Use 2010 -2012 to calculate distribution equipment overloads | N/A | No known equipment overloads incidents occurred on the circuit feeder. |
| 9 | Distribution Feeder Load | Use 2010 data as baseline. Value at commencement – use 2011-2015 to calculate distribution equipment overloads<br>Due to Michigan's current economy there is no expected growth for these areas in the next five years. The growth rate will be zero. | N/A | No overload existed on the test feeder during the demonstration project test period. |
| 10 | SAIFI | Baseline data not available at the project distribution transformer level<br>Value at project commencement is zero. | 2012-0.83<br>2013-0.94 | 2014-0.73<br>2015-0 |
| 11 | SAIDI/CAIDI | Baseline data not available at the project distribution transformer level<br>Value at project commencement is zero. | 2012-108/130<br>2013-894/955 | 2014-210/288<br>2015-0/0 |
| 12 | MAIFI | Baseline data not available at the project distribution transformer level | N/A | N/A |

**Table 8: Final Impact Metrics**

## 5.2. Use Cases (Modes of Operations) Results

This section documents the execution of the 23 uses cases defined in section 4.5 and implemented using the method outlined in section 4.6. All of the use cases successfully executed with the details in the following pages.

Each use case is displayed in individual test sheets. Each test sheet header defines the mode of operation, the test performed (requirement) and use case number. Following the header information, the test assumptions and testing method are defined followed by the test results.

### 5.2.1. Data Usage Test: DRSOC-CES-001

All CES units communicated successfully with an average communication rate of 177 kB per day or 5.3 MB per month.

| | |
|---|---|
| **Mode of Operation:** Stand-By & Hub Command | |
| **Requirement: Data usage test** | **Requirement Number: DRSOC-CES-001** |

**Assumptions**

CES Units are online and are being polled and dispatched on a 5-minute basis. Cellular modems in use are Sierra Wireless Raven XE units. CES Unit charge levels are irrelevant in this test.

**Method of Testing**

The cellular modems used in the CES deployment have the ability of keeping a running tally of the amount of cellular bandwidth used. Each subtest requires the measuring of snapshots of these counters.

**Results:**

Data usage averaged 177 kB per day or 5.3 Mb per month.

**CES kB Usage Report July 9, 2014**

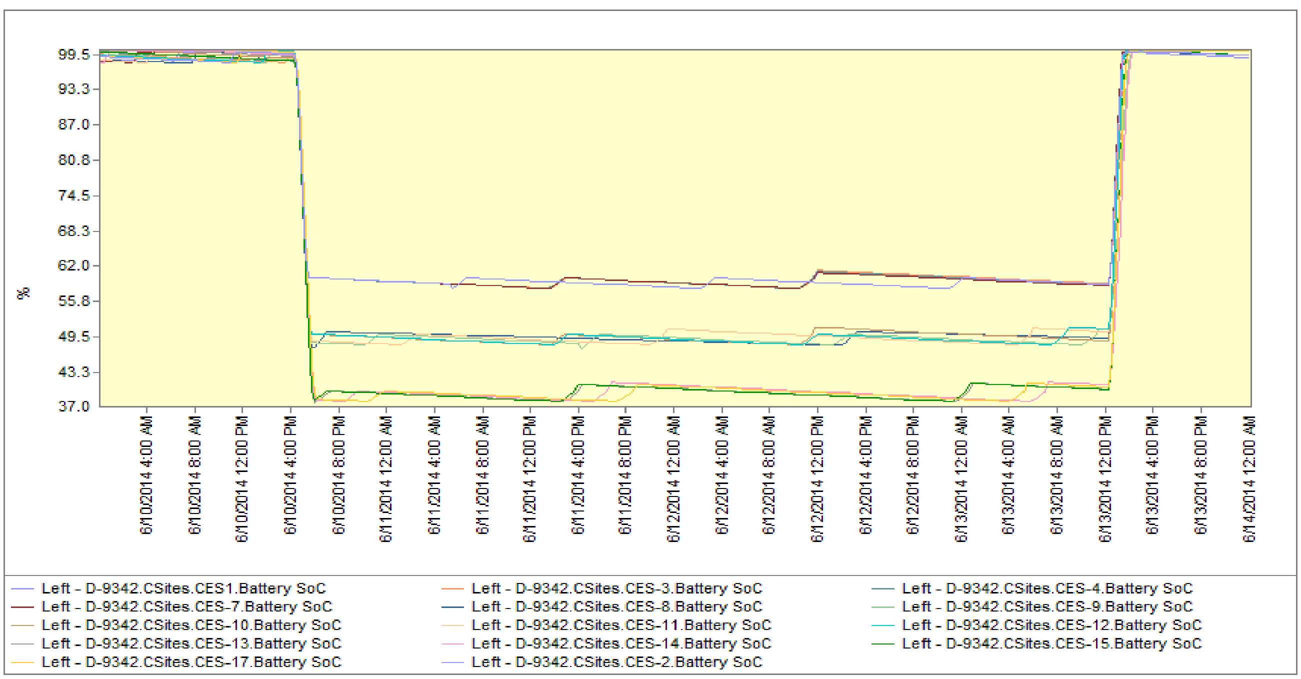
| | Previous day | Previous week | Avg/day | | Previous Month | Avg/day |
|---|---|---|---|---|---|---|
| **Unit #1** | 177 | 1259 | 180 | | 5 373 | 179 |
| **Unit #2** | 178 | 1270 | 181 | | 5257 | 175 |
| **Unit #3** | 174 | 1230 | 176 | | 5088 | 170 |
| **Unit #4** | 175 | 1230 | 176 | | 5085 | 170 |
| **Unit #5** | Unit not available during test | | | | | |
| **Unit #6** | Unit not available during test | | | | | |
| **Unit #7** | 181 | 1271 | 182 | | 5262 | 175 |
| **Unit #8** | 180 | 1315 | 188 | | 5294 | 176 |
| **Unit #9** | Modem replaced 7/3/2014 | | | | | |
| **Unit #10** | 177 | 1282 | 183 | | 5116 | 171 |
| **Unit #11** | 176 | 1241 | 177 | | 5127 | 171 |
| **Unit #12** | 171 | 1226 | 175 | | 5085 | 170 |
| **Unit #13** | 174 | 1224 | 175 | | 5243 | 175 |
| **Unit #14** | 65 | 1151 | 164 | | 5047 | 168 |
| **Unit #15** | 182 | 1269 | 181 | | 5262 | 175 |
| **Unit #16** | Unit not available during test | | | | | |
| **Unit #17** | 141 | 1225 | 175 | | 6857 | 229 |

**Test Date:** 7/9/2014

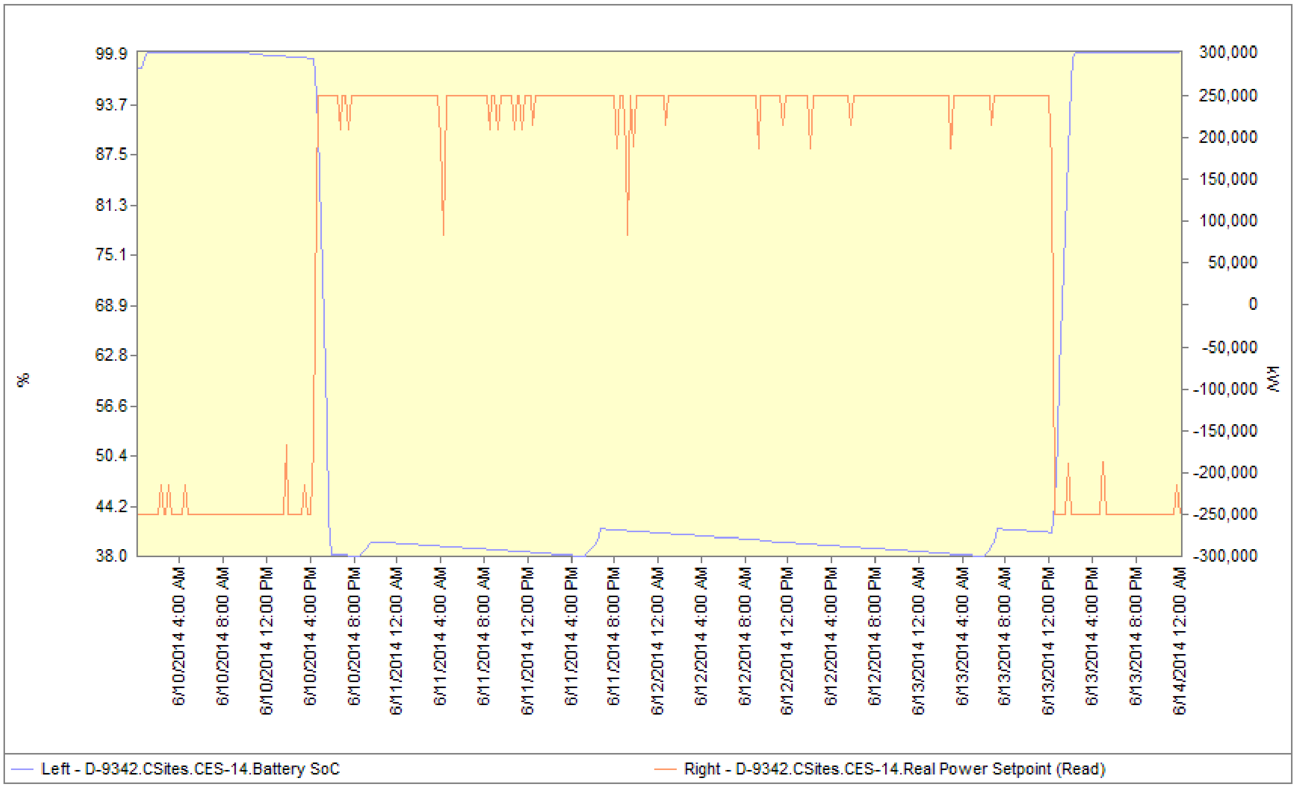
### 5.2.2. CES Maintains Minimum Reserve Margin: DRSOC-CES-002

All operating units properly stopped discharging when the battery SOC reached Minimum Reserve Margin set point.

| | |
|---|---|
| **Mode of Operation:** Hub Command | |
| **Requirement**: CES unit will maintain the set reserve margin | **Requirement Number:** DRSOC-CES-002 |
| | |
| **Assumptions** | |
| CES Units are online and are charged to a SoC above the minimum reserve margin.<br>Reserve margin set at 60% on CES 1, 2, 3, 4, 7<br>Reserve margin set to 50% on CES 8, 9, 10, 11, 12<br>Reserve margin set to 40% on CES 13, 14, 15, 17 | |
| **Method of Testing** | |
| Units participating in this test are to be sent a 25kW discharge command in Hub Command mode to get the battery down to the minimum reserve margin. Unit should no longer follow the discharge command once the minimum reserve margin has been reached. Observe the SOC over a 24-hour period. | |
| **Results:** | |
| All operating units properly stopped discharging when Battery SOC reached Minimum Reserve Margin set point. | |



The graph below shows the kW set point (scale factor is 10,000) on the right axis and Battery SOC on left axis of CES-14. On June 10, 2014 at approximately 16:14, the unit was requested to export 25 kW. The unit did produce 25 kW for about 1 ½ hours, at which time it reached the Minimum Reserve Margin. At that time, despite the continued 25 kW set point, the unit retained a Battery SOC of approximately 40%.




**Test Date: 6/10/2014 thru 6/13/2014**

## 5.2.3. CES Unit Will Operate Safely at 100% SOC and is Given a Charge Command: DRSOC-CES-003

| | |
|---|---|
| **Mode of Operation:** Hub Command | |
| **Requirement:** CES unit will operate safely when unit is at 100% SOC and is given a charge command. | **Requirement Number:** DRSOC-CES-003 |

**Assumptions**

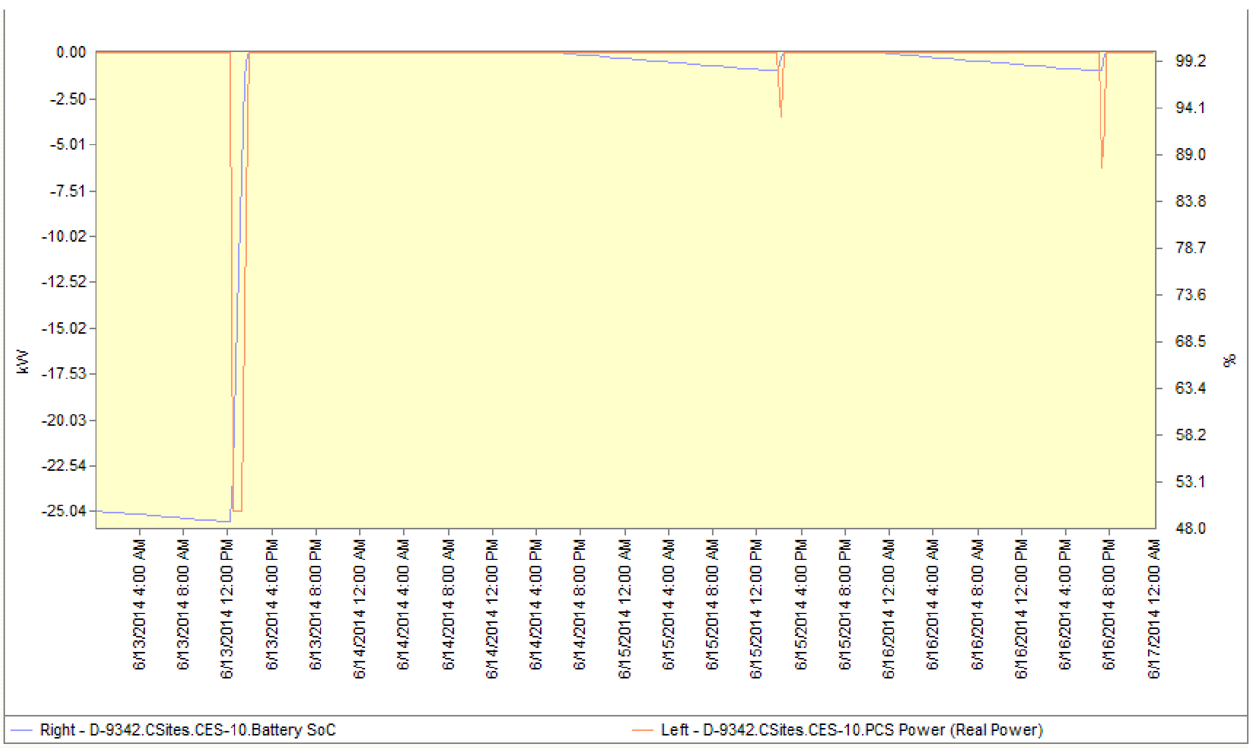
CES Units are online and are charged above minimum reserve margin.

**Method of Testing**

CES Units participating in this test are to be sent a 25kW charge command in Hub Command mode. The CES Units are expected to follow the command until the battery reaches 100%. At this point, the desired Unit behavior is maintaining a 100% charge as the Unit is still receiving charge commands.

**Results**

The graph below is typical of all operating CES units during this test. This unit started at 48% SoC. DR-SOC Hub sent a charge command of 25 kW. When the unit reached 100% SoC, it began to ignore the charge command. When the SoC dropped to a value of approximately 98%, the unit again responded to the charge command, and restored the SoC to 100%.




**Test Date: 6/13/2014 to 6/16/2014**

### 5.2.4. CES Unit Will Operate Safely when kW & kVAR Setpoints Cause Unit to Exceed Discharge kVA Rating: DRSOC-CES-004

| **Mode of Operation:** Hub Command | |
|---|---|
| **Requirement:** CES unit will operate safely when kW and kVAR setpoints cause unit to exceed discharge kVA rating. | **Requirement Number: DRSOC-CES-004** |

**Assumptions**

CES Units are online and are charged to a SoC above the minimum reserve margin.
Units have PowerOverVarsMode set (DNP Binary Input 130 is asserted).

**Method of Testing**

CES Units participating in this test are to be issued discharge commands that exceed their kVA rating by a significant margin. It is expected that the unit is to prefer producing watts over vars.
Example:

| Command kW | Command kvar | Command kVA | Expected kW | Expected kvar | Expected kVA |
|---:|---:|---:|---:|---:|---:|
| 18 | 18 | 25.455 | 18 | 17.349 | 25 |
| 20 | 18 | 26.907 | 20 | 15 | 25 |
| 25 | 15 | 30 | 25 | 5.5 | 25 |
| 30 | 15 | 33.541 | 25 | 0 | 25 |

**Results**

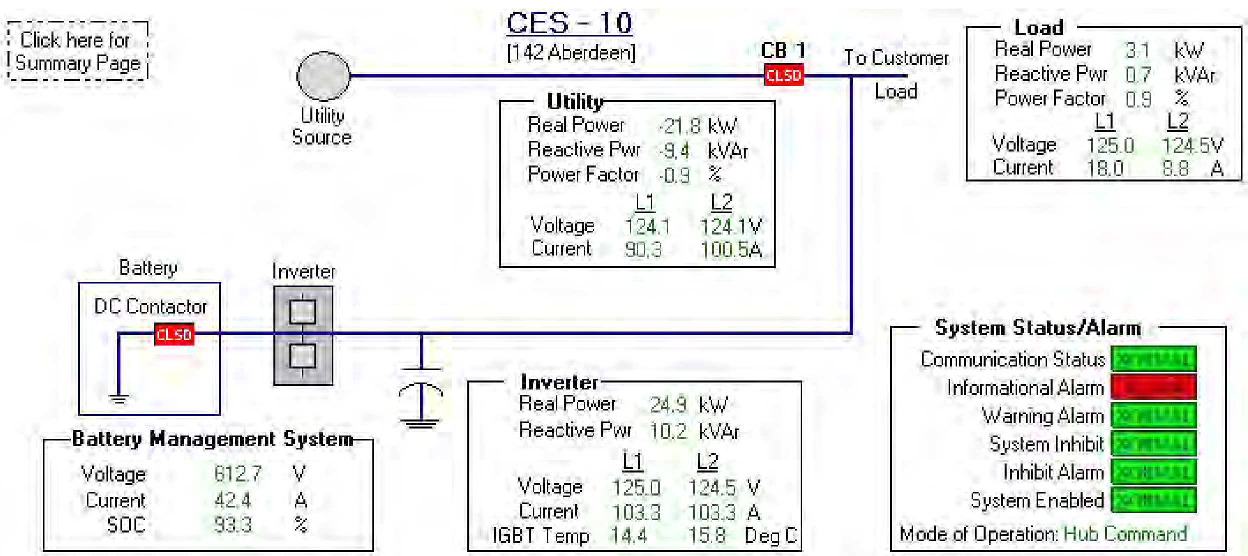
*See next page*

The fleet of CES units operated as expected, while slightly exceeding the kVA rating. Below are just a few example results.

CES-13

| Time stamp | CES-13.kW Setpoint | CES-13.kVAR Setpoint | kVA Setpoint (calc) | CES-13.PCS kW | CES-13.PCS kVARs | PCS kVA |
|---|---|---|---|---|---|---|
| 6/17/2014 13:15 | 25.00 | 15.00 | 29.15475947 | 24.11 | 5.42 | 24.71 |
| CES-10 | | | | | | |
| 2/3/2015 14:50 | 30.00 | 15.00 | 33.54101966 | 24.9 | 10.2 | 26.91 |

The screenshot below shows real time values for CES-10, with a command to discharge 30 kW and 15 kVAR.




**Test Date: 6/17/2014 & 2/3/2015**

## 5.2.5. CES Unit Will Operate Safely When kW & KVAR Setpoints Cause Unit to Exceed Charge Kva Rating: DRSOC-CES-005

| **Mode of Operation: Hub Command** | |
|---|---|
| **Requirement:** CES unit will operate safely when kW and kvar setpoints cause unit to exceed charge kVA rating. | **Requirement Number: DRSOC-CES-005** |

**Assumptions**

CES Units are online and are charged to a SoC above the minimum reserve margin. Units have PowerOverVarsMode set (DNP Binary Input 130 is asserted).

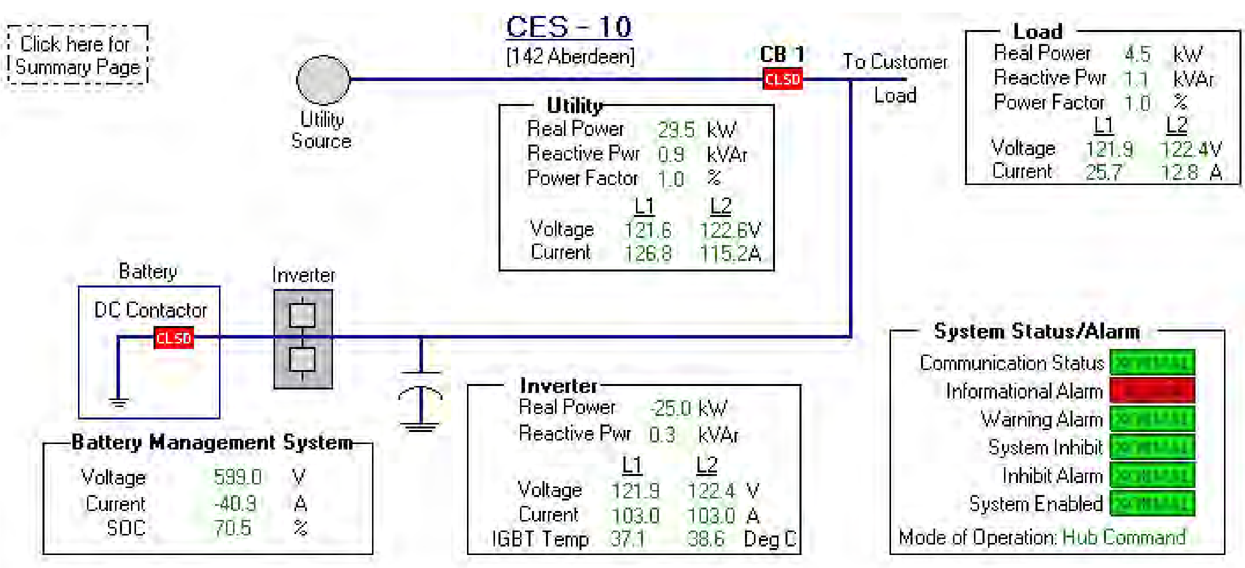
**Method of Testing**

CES Units participating in this test are to be issued charge commands that exceed their kVA rating by a significant margin. It is expected that the unit is to prefer producing watts over vars.
Example:

| Command kW | Command kvar | Command kVA | Expected kW | Expected kvar | Expected kVA |
|---|---|---|---|---|---|
| -20 | 18 | 26.907 | 20 | 15 | 25 |
| -25 | 18 | 30.805 | 25 | 0 | 25 |
| -30 | 15 | 33.541 | 25 | 0 | 25 |

**Results**

The fleet of CES units operated as expected, preferring charging kW over kVAR command. The command was -30 kW, 15 kVAR. The screenshot below is from 2/3/2015 at 15:40.
NOTE – As Battery SOC approaches full charge, the CES internal algorithm limits the charge kW, which gradually reduces the charge to 0 kW.




**Test Date:** 2/3/2015

### 5.2.6. DERMS Will Dispatch a Reasonable Set-Point when Algorithms Command a kW Set-Point that Exceeds Unit Charge Rating: DRSOC-CES-006

| **Mode of Operation: Hub Command** | |
|---|---|
| **Requirement:** DRSOC Hub will dispatch a reasonable set-point when algorithms command a kW set-point that exceeds unit charge rating. | **Requirement Number: DRSOC-CES-006** |

**Assumptions**

CES Units are online and are charged to a SoC above the minimum reserve margin.

**Method of Testing**

Issue a charge command (negative kW) that exceeds the total combined kW of all of the CES units combined. It is expected that each CES that is available for dispatch be issued a full kW charge command.

**Results**

This test was conducted in Peak-Shaving Mode.

Peak Shaving Threshold set at 4500 kW
DC 9342 load = 3,700 kW
HUB calculated kW available for charging = 800 kW

Total Max kW charge of available CES units = 350 kW
Actual kW commands sent:

| CES-1 | CES-2 | CES-3 | CES-4 | CES-5 | CES-6 | CES-7 | CES-8 | CES-9 | CES-10 |
|---|---|---|---|---|---|---|---|---|---|
| N/A | -25 | -25 | -25 | -25 | N/A | -25 | -25 | N/A | -25 |

| CES-11 | CES-12 | CES-13 | CES-14 | CES-15 | CES-16 | CES-17 |
|---|---|---|---|---|---|---|
| -25 | -25 | -25 | -25 | -25 | -25 | -25 |

The HUB algorithm did not send kW setpoints beyond the limits of each CES unit.

**Test Date:** 2/4/2015

### 5.2.7. DERMS Will Dispatch a Reasonable Set-Point When Algorithms Command a kW Set-Point that Exceeds Unit Discharge Rating: DRSOC-CES-007

| **Mode of Operation: Hub Command** | |
|---|---|
| **Requirement:** DRSOC Hub will dispatch reasonable set-point when algorithms command a kW set-point that exceeds unit discharge rating. | **Requirement Number: DRSOC-CES-007** |
| | |
| **Assumptions** | |
| CES Units are online and are charged to a SoC above the minimum reserve margin. | |
| **Method of Testing** | |
| Issue a discharge command (positive kW) that exceeds the total combined kW of all of the CES units combined. It is expected that each CES that is available for dispatch be issued a full kW discharge command that is not beyond the limit of 25 kW.. | |
| **Results** | |

This test was conducted in Peak-Shaving Mode.

Peak Shaving Threshold set at 3300 kW
DC 9342 load = 4,000 kW
HUB calculated kW required = 700 kW

Total Max kW charge of CES units = 350 kW
Actual kW commands sent:

| **CES-1** | **CES-2** | **CES-3** | **CES-4** | **CES-5** | **CES-6** | **CES-7** | **CES-8** | **CES-9** | **CES-10** |
|---|---|---|---|---|---|---|---|---|---|
| N/A | 25 | 25 | 25 | 25 | N/A | 25 | 25 | N/A | 25 |

| **CES-11** | **CES-12** | **CES-13** | **CES-14** | **CES-15** | **CES-16** | **CES-17** |
|---|---|---|---|---|---|---|
| -25 | 25 | 25 | 25 | 25 | 25 | 25 |

The HUB algorithm did not send kW setpoints beyond the limits of each CES unit.

**Test Date:** 2/4/2015

## 5.2.8. DERMS Will Distribute Requested kW Charge or Discharge Across All Units Based on SoC of Each Unit: DRSOC-CES-008

| **Mode of Operation: Hub Command** | |
|---|---|
| **Requirement:** DR-SOC Hub will distribute requested kW charge or discharge across all units based on SoC of each unit. | **Requirement Number: DRSOC-CES-008** |

**Assumptions**

CES units currently have various SoC values between 20% and 100%.

**Method of Testing**

Issue a Hub charge, or discharge, command that is within the kW capability of the available CES units.
When requesting kW discharge, the units with less SoC will be requested to provide less kW than units with higher SoC.
In contrast, when requesting kW charge, units with less SoC will be requested a higher charge kW than units with a higher SoC.

**Results**

DR-SOC Hub correctly dispatched CES units, based on their Battery SoC. Below are screenshots for 8/29/2014 showing results.

Command: -100 kW (charge)

**CES Site Summary**

| Site | | Battery SOC | Comm | PCS Power | PCS VARs | Load | DC Contactor | Inhibit Alarm |
|---|---|---|---|---|---|---|---|---|
| CES-1 | (1555 Featherwood Dr) | 80.80 % | NORMAL | -3.57 kW | 3.39 | 0.43 kW | CLSD | NORMAL |
| CES-2 | (1451 Herr Rd) | 55.90 % | NORMAL | -8.18 kW | 6.35 | 0.76 kW | CLSD | NORMAL |
| CES-3 | (1878 Magnolia Blvd) | 64.70 % | NORMAL | -6.55 kW | 3.92 | 1.66 kW | CLSD | NORMAL |
| CES-4 | (1824 Magnolia Blvd)) | 85.40 % | NORMAL | -2.72 kW | 3.48 | 1.98 kW | CLSD | NORMAL |
| CES-7 | (114 Aberdeen) | 77.70 % | NORMAL | -4.14 kW | 3.40 | 6.14 kW | CLSD | NORMAL |
| CES-8 | (122 Aberdeen) | 73.40 % | NORMAL | -4.96 kW | 3.66 | 7.90 kW | CLSD | NORMAL |
| CES-9 | (132 Aberdeen) | 84.80 % | NORMAL | -2.83 kW | 3.39 | 3.05 kW | CLSD | NORMAL |
| CES-11 | (3881 Ryans Ridge) | 66.50 % | NORMAL | -6.22 kW | 3.76 | 1.32 kW | CLSD | NORMAL |
| CES-12 | (1716 Meadowbrook) | 63.20 % | NORMAL | -6.83 kW | 3.78 | 0.68 kW | CLSD | NORMAL |
| CES-13 | (1713 Pinecroft Drive) | 72.80 % | NORMAL | -5.01 kW | 3.51 | 2.10 kW | CLSD | NORMAL |
| CES-14 | (1656 Meadowbrook) | 72.40 % | NORMAL | -5.12 kW | 3.45 | 2.57 kW | CLSD | NORMAL |
| CES-15 | (3819 David Landing) | 63.20 % | NORMAL | -6.83 kW | 3.78 | 0.75 kW | CLSD | NORMAL |

Command: 100 kW (discharge)

## CES Site Summary

| Site | | Battery SOC | Comm | PCS Power | PCS VARs | Load | DC Contactor | Inhibit Alarm |
|---|---|---|---|---|---|---|---|---|
| CES-1 | (1555 Featherwood Dr) | 27.90 % | NORMAL | 5.45 kW | 0.22 | 0.12 kW | CLSD | NORMAL |
| CES-2 | (1451 Herr Rd) | 61.70 % | NORMAL | 11.98 kW | 0.01 | 2.37 kW | CLSD | NORMAL |
| CES-3 | (1878 Magnolia Blvd) | 27.90 % | NORMAL | 5.47 kW | 0.19 | 11.38 kW | CLSD | NORMAL |
| CES-4 | (1824 Magnolia Blvd)) | 62.80 % | NORMAL | 12.24 kW | 0.44 | 3.72 kW | CLSD | NORMAL |
| CES-7 | (114 Aberdeen) | 25.90 % | NORMAL | 5.07 kW | 0.12 | 10.30 kW | CLSD | NORMAL |
| CES-8 | (122 Aberdeen) | 45.40 % | NORMAL | 8.87 kW | 0.31 | 5.65 kW | CLSD | NORMAL |
| CES-9 | (132 Aberdeen) | 40.90 % | NORMAL | 7.95 kW | 0.12 | 2.58 kW | CLSD | NORMAL |
| CES-11 | (3881 Ryans Ridge) | 24.90 % | NORMAL | -0.06 kW | 0.23 | 1.43 kW | CLSD | NORMAL |
| CES-12 | (1716 Meadowbrook) | 25.00 % | NORMAL | -0.05 kW | 0.28 | 0.58 kW | CLSD | NORMAL |
| CES-13 | (1713 Pinecroft Drive) | 70.30 % | NORMAL | 13.74 kW | 0.48 | 6.57 kW | CLSD | NORMAL |
| CES-14 | (1656 Meadowbrook) | 41.90 % | NORMAL | 8.12 kW | 0.19 | 2.40 kW | CLSD | NORMAL |
| CES-15 | (3819 David Landing) | 59.20 % | NORMAL | 11.48 kW | 0.04 | 0.73 kW | CLSD | NORMAL |

**Test Date:** 8/29/2014

### 5.2.9. CES Efficiency: DRSOC-CES-009

Because the archive data intervals available at the DERMS level were not sufficient to provide accurate efficiency data, the efficiency calculations caused some percentage to be greater than 100%. A more accurate efficiency analysis was performed by DNVGL in their laboratory as part of the functional testing as described in section 5.5.

| | |
|---|---|
| **Test Date:** | |
| **Mode of Operation: Hub Command** | |
| **Requirement:** CES Efficiency | **Requirement Number: DRSOC-CES-009** |
| | |
| **Assumptions** | |
| A number of units are currently holding an SOC of 100%. | |
| **Method of Testing** | |
| DR-SOC Hub will command a number of units that have an SOC value of 100%, to dispatch at 25 kW for 1 hour. The hub will then command the same units to charge at 25 kW. The kWh delivered will be compared to the kWh consumed to reach an SOC of 100% again. | |
| **Results** | |

Test #1 (5 minute scans / 15 minute archive)

| | kWh discharged | kWh charged | % |
|---|---|---|---|
| CES-8 | 25 | 31.83 | 78.54% |
| CES-9 | 24.99 | 28.15 | 88.77% |
| CES-10 | 25.01 | 28.05 | 89.16% |

Date: Nov. 26, 2013

Test #2 (5 minute scan / 15 minute archive)

| | kWh discharged | kWh charged | % |
|---|---|---|---|
| CES-5 | 27.02 | 24.96 | 108.25%* |
| CES-9 | 25.03 | 24.97 | 100.24%* |
| CES-13 | 27 | 27.96 | 96.57% |
| CES-17 | 26.99 | 27.74 | 97.30% |

Date: Dec. 6, 2013

*It was determined the archive data intervals available at DR-SOC are not sufficient to provide valuable efficiency data. DNVGL performed efficiency testing in their lab, and that data will be used to validate compliance with vendor specifications.

**Test Date:** 11/26/2013, 12/06/2013

### 5.2.10. DERMS Will Issue Commands per a Set Schedule to Produce "Renewable Energy Time Shift": DRSOC-CES-010

| | |
|---|---|
| **Mode of Operation: Schedule** | |
| **Requirement:** DR-SOC Hub will issue commands per a set schedule to produce "Renewable Energy Time Shift" | **Requirement Number: DRSOC-CES-010** |

**Assumptions**

The 500 kW PV system at Monroe County Community College (MCCC) is operational.
All available CES units are placed in "Schedule" Mode of Operation.

**Method of Testing**

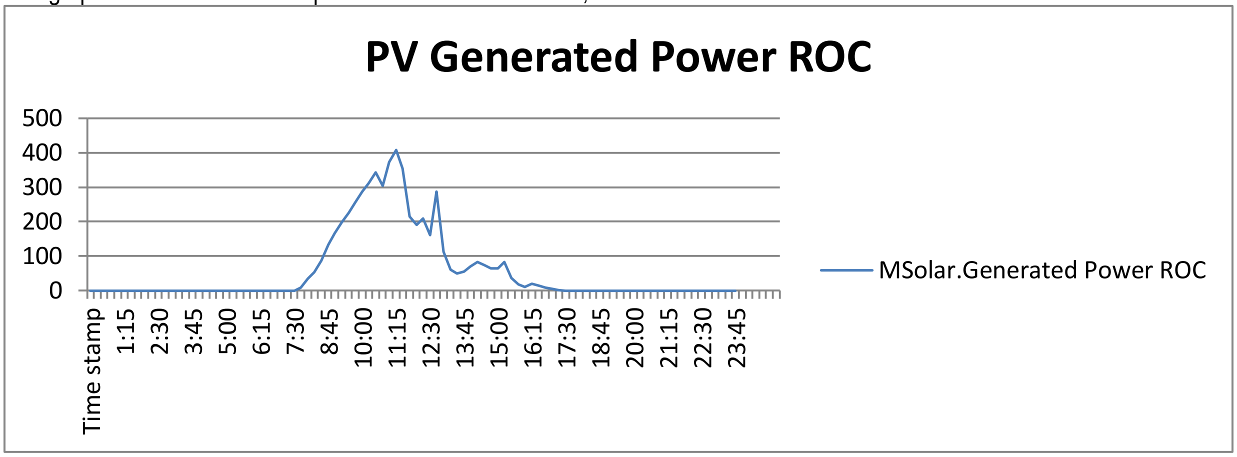
A schedule will be set for each available CES unit as follows to demonstrate the "**Renewable Energy Time Shift**" application for energy storage.

| Hour | kW |
|---|---|
| 9 | -1.5 |
| 10 | -3.5 |
| 11 | -3.5 |
| 12 | -3.5 |
| 13 | -3.5 |
| 14 | -3.5 |
| 15 | -3 |
| 16 | -1.5 |
| 18 | 11.75 |
| 19 | 11.75 |

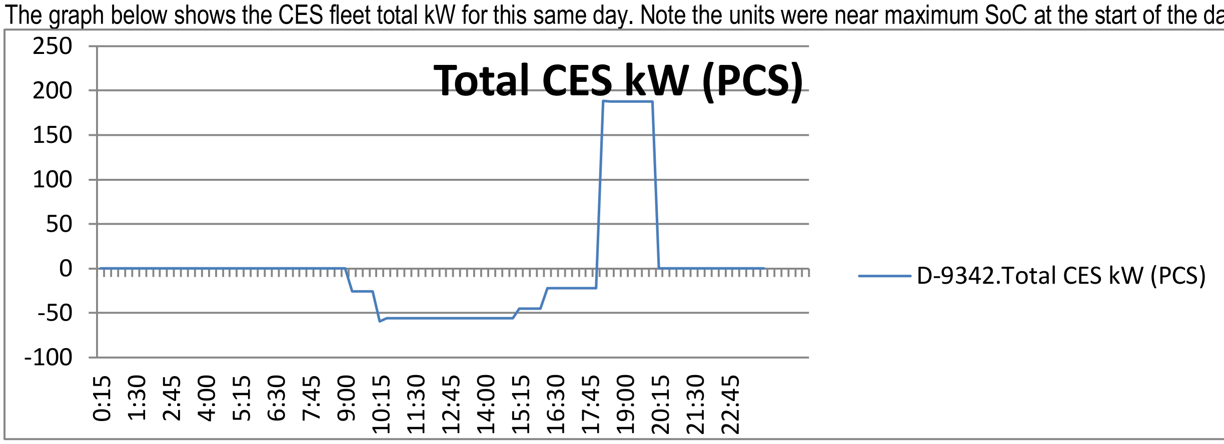
**Results**

The DR-SOC HUB successfully dispatched CES units per a configured schedule. The result was a shift of the energy produced by the 500 kW PV system from the middle of the day to the hours when the PV system would normally contribute very little kW to the distribution circuit (18:00 to 20:00)

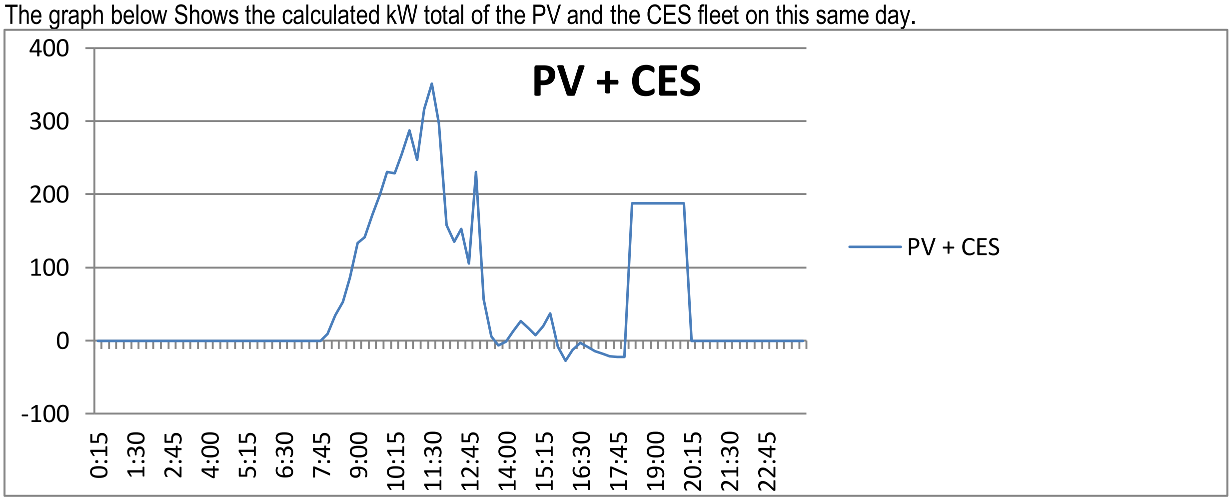
The graph below shows the PV production on November 14, 2014.




The graph below shows the CES fleet total kW for this same day. Note the units were near maximum SoC at the start of the day

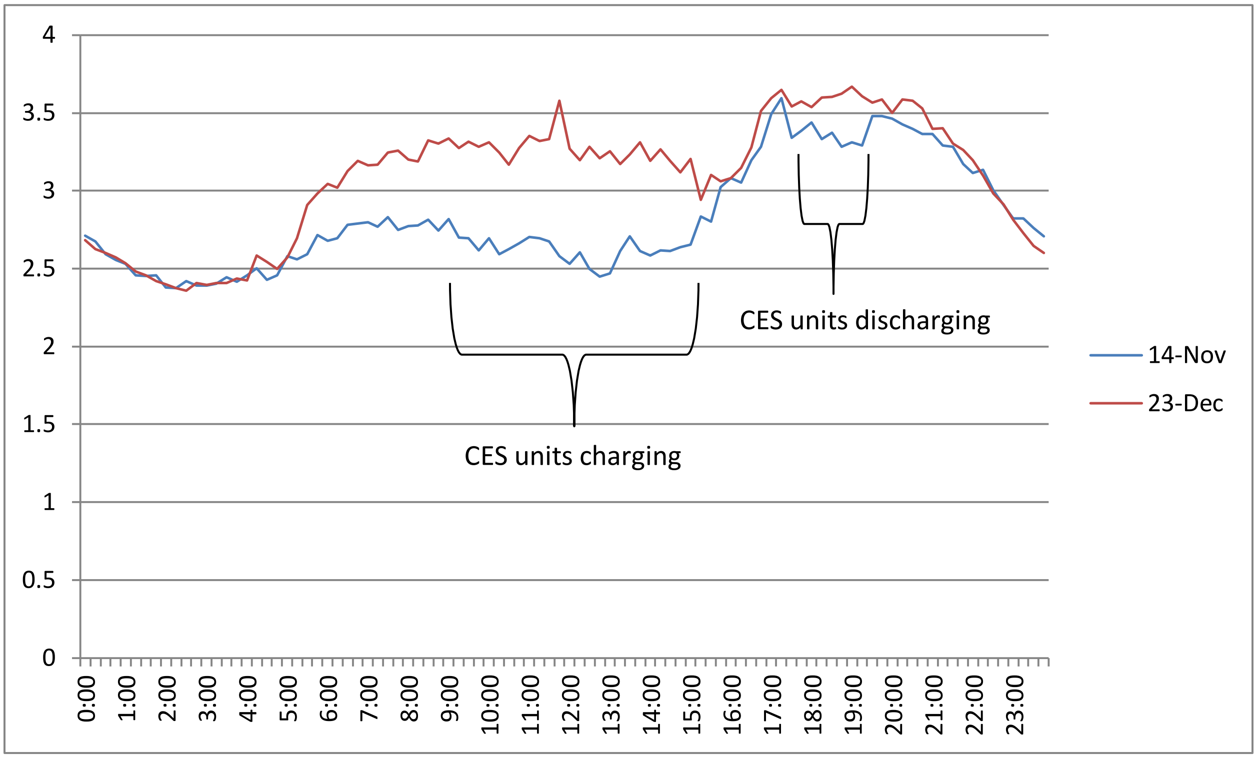



The graph below Shows the calculated kW total of the PV and the CES fleet on this same day.




The graph below shows the result to the overall circuit KW as seen by the substation. The brown line represents circuit load on December 23, a day the CES fleet was not scheduled to dispatch. It is important to note that on Dec. 23, the lack of sun energy minimized the output of the PV system. This caused higher circuit load seen by the substation on Dec. 23, when compared to Nov. 14.

The blue line represents November 14, a day the DR-SOC HUB schedule called for the CES units to charge/discharge per the above schedule.




Summary - The Renewable Energy Time Shift can be configured to shift a portion of the PV production to the time when the circuit peak normally occurs. The result is similar to a static peak shaving application.

**Test Date:** 11/14/2014

### 5.2.11. DERMS Will Issue Commands per a Set Schedule to Produce "Electric Energy Time Shift": DRSOC-CES-011

| | |
|---|---|
| **Mode of Operation: Schedule** | |
| **Requirement:** DR-SOC Hub will issue commands per a set schedule to produce "Electric Energy Time Shift" | **Requirement Number: DRSOC-CES-011** |

**Assumptions**

The 500 kW PV system on the distribution circuit is operating correctly.
All available CES units are placed in "Schedule" Mode of Operation.
This test will run for a minimum of 5 days.

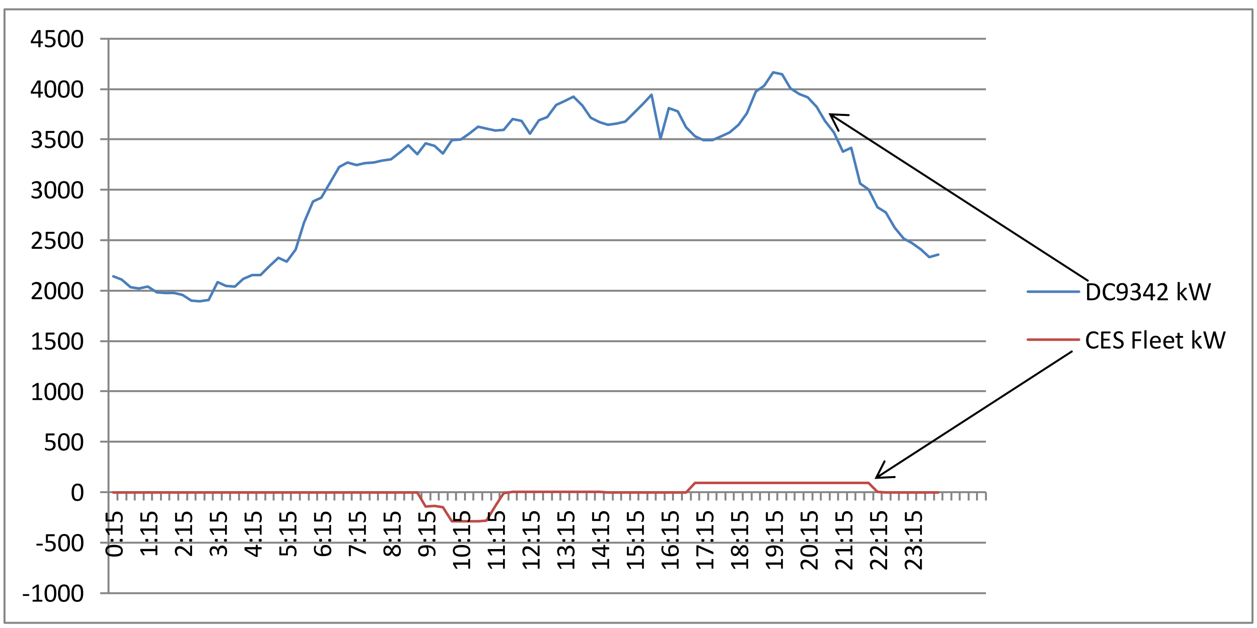
**Method of Testing**

A schedule will be set as follows to demonstrate the "**Electric Energy Time Shift**" application for energy storage.
Example:

| Charge Time ON | Charge kW | Discharge Time ON | Discharge kW (fleet) |
|---|---|---|---|
| 09:00 – 11:00 | 25 kW each CES | 17:00 – 22:00 | 7.5 kW each CES |

**Results**

The graph below shows energy being consumed by the available CES units early in the day, when circuit load is lower. The schedule then commands the fleet to produce kW in late afternoon. This essentially shifts kWh from one time of the day to another.




**Test Date: 10/3/2014**

### 5.2.12. DERMS Will Send Commands to CES Units Based on Simulated AGC Signal: DRSOC-CES-012

| | |
|---|---|
| **Mode of Operation: AGC** | |
| **Requirement:** DR-SOC Hub will send commands to CES units based on simulated AGC signal | **Requirement Number: DRSOC-CES-012** |

**Assumptions**

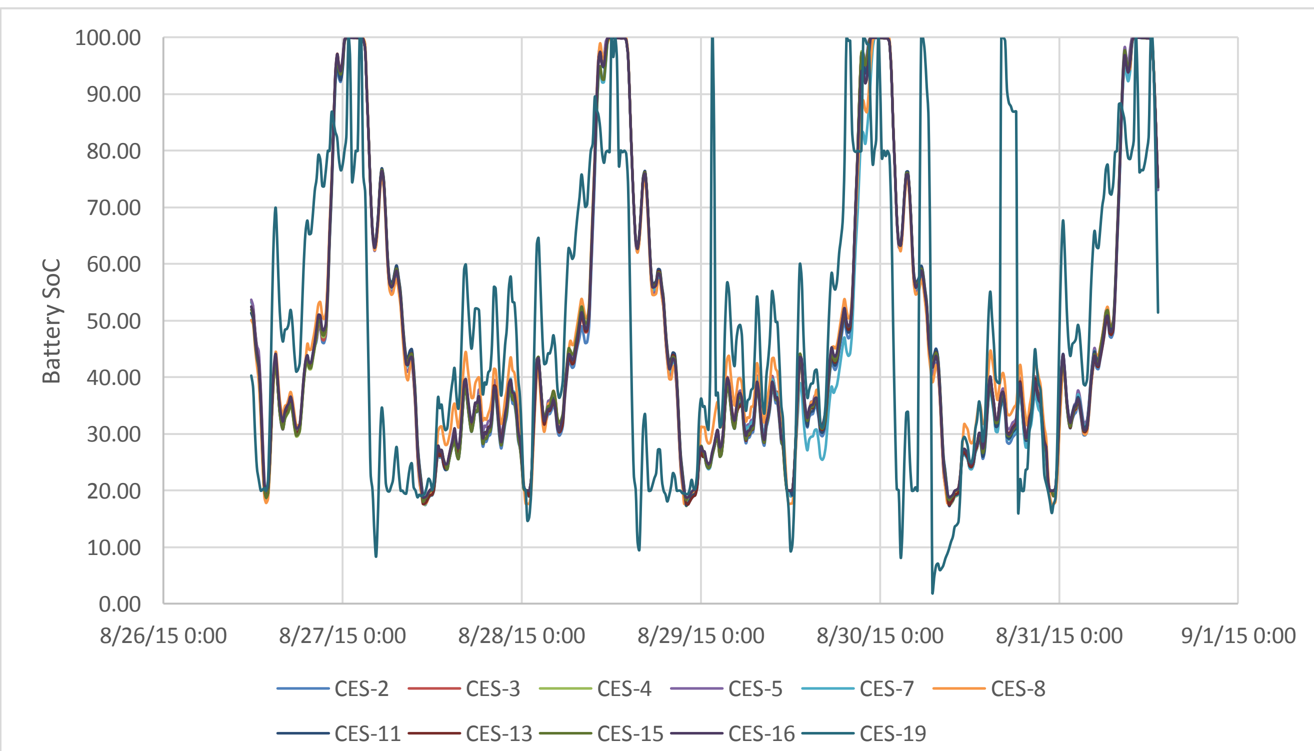
Simulated AGC signal will contain the same values used in KEMA's CES unit testing.
DR-SOC Hub will distribute AGC kW setpoint based on each CES unit's SoC as shown in Requirement Number: DRSOC-CES-008

**Method of Testing**

All available units are to be brought to 50% SoC and placed in AGC mode with the waveform played to them over the course of several days. This test will include CES-19, a unit utilizing repurposed batteries, located at Next Energy in Detroit (not on DC9342).

**Results**

All available units were placed in AGC mode. With the exception of CES-19, all units followed the commanded setpoint closely, as seen in the graph below.



CES-19's deviance appears to be the result of the way the SoC is computed in the repurposed battery. As with all of the CES units involved in this test, CES-19 was configured with a 20% reserve margin. Each time the repurposed battery reported a SoC value below this threshold, its inverter immediately started a maintenance charge. This behavior explains the downward spiking and the prompt recovery observed in the results.

CES Unit 19 also appears to have a resistance plateau at 80%, which is seemingly caused by suboptimal cell balancing inside its repurposed battery. When the battery controls detect that a single cell has reached its maximum voltage, the battery controls inhibit further charging of **ALL** cells and a SoC of 100% is passed to the CES inverter to prevent it from applying a charge. Individual cells causing the balancing issue were replaced to enable the battery system to continue to operate. After replacing the failed cells, additional cells failed causing the repurposed units to open up the DC contactor making the CES unit non-operational.

### 5.2.13. DERMS Will Discharge CES Fleet to Maintain a Maximum kW at the Circuit Feeder: DRSOC-CES-013

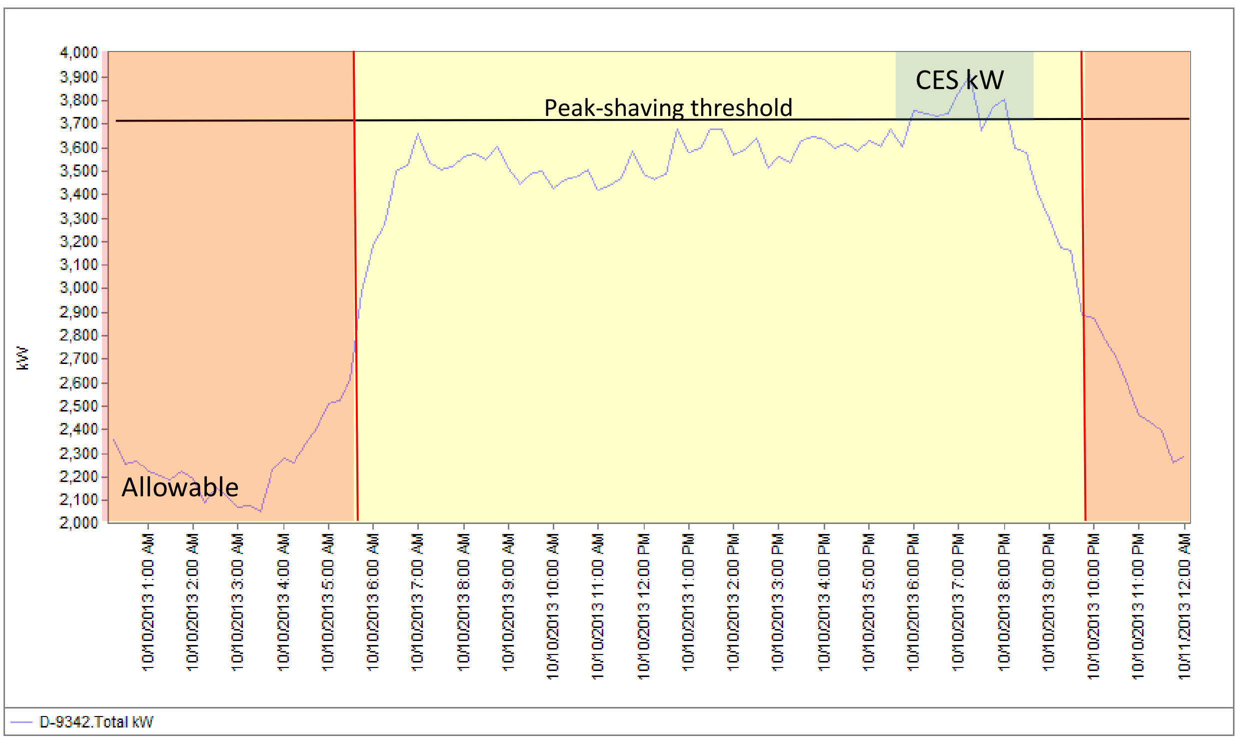
| | |
|---|---|
| **Test Date:** 8/26/2015 through 8/31/2015 | |
| **Mode of Operation: Peak Shaving** | |
| **Requirement:** DR-SOC Hub will discharge CES fleet to maintain a maximum kW at the circuit feeder. | **Requirement Number: DRSOC-CES-013** |

**Assumptions**

All available CES units are placed in “Peak Shaving” Mode of Operation.
DR-SOC Hub must charge the CES units when the total kW needed to charge will not cause the circuit to rise above the peak-shaving threshold.

**Method of Testing**

A peak-shaving threshold will be determined based upon recent circuit data.
Example:




*Graph 13-1*

### 5.2.14. Charge When Needed for Reserve Capacity: DRSOC-CES-014

| | |
|---|---|
| **Mode of Operation: DEW** | |
| **Requirement:** Charge when needed for reserve capacity | **Requirement Number: DRSOC-CES-014** |

**Assumptions**

DEW's *AppDefSettings.cfg* file is configured for at least a 4 hour minimum reserve capacity. Current load multiplied by this value added to the *minReserveCapacity* parameter should exceed CES configured minimum reserve margin kWh (default: 10kWh). Unit SoC values must be below this calculated minimum reserve. All available CES units are placed in "DEW" Mode of Operation.

**Method of Testing**

1. Set the "minReserveCapacity" parameter in AppDefSettings.cfg to **12.5**.
2. Set the "numberReserveCapacityHours" parameter in AppDefSettings.cfg to **8**.
3. Use Hub command mode to bring each unit's SoC below 60%.
4. Perform **load * minimum capacity** calculations to ensure that charge condition would be issued based on present loading conditions.
5. Place all available units in DEW Mode of Operation.
6. Ensure units are issued charge commands and record values.

**Results**

A series of Hub commands were issued to discharge the units down to acceptable levels for this test. The table below shows each unit's Battery SoC after discharge (Step 3).

| Site | | Battery SOC | Comm | PCS Power | PCS VARs | Load | DC Contactor | Inhibit Alarm |
|---|---|---|---|---|---|---|---|---|
| CES-2 | (1451 Herr Rd) | 28.50 % | NORMAL | 0.00 kW | 3.37 | 0.89 kW | CLSD | NORMAL |
| CES-3 | (1878 Magnolia Blvd) | 24.90 % | NORMAL | 0.00 kW | 3.47 | 6.90 kW | CLSD | NORMAL |
| CES-4 | (1824 Magnolia Blvd)) | 24.90 % | NORMAL | 0.00 kW | 3.41 | 1.22 kW | CLSD | NORMAL |
| CES-5 | (1817 Garden Drive) | 24.30 % | NORMAL | 0.00 kW | 3.35 | 1.07 kW | CLSD | NORMAL |
| CES-6 | (106 Aberdeen) | 28.30 % | NORMAL | 0.00 kW | 3.37 | 1.16 kW | CLSD | NORMAL |
| CES-7 | (114 Aberdeen) | 24.90 % | NORMAL | 0.00 kW | 3.40 | 2.02 kW | CLSD | NORMAL |
| CES-8 | (122 Aberdeen) | 25.30 % | NORMAL | 0.00 kW | 3.35 | 3.04 kW | CLSD | NORMAL |
| CES-10 | (142 Aberdeen) | 29.50 % | NORMAL | 0.00 kW | 3.40 | 0.69 kW | CLSD | NORMAL |
| CES-11 | (3881 Ryans Ridge) | 24.90 % | NORMAL | 0.00 kW | 3.41 | 1.09 kW | CLSD | NORMAL |
| CES-12 | (1716 Meadowbrook) | 24.90 % | NORMAL | 0.00 kW | 3.39 | 0.78 kW | CLSD | NORMAL |
| CES-13 | (1713 Pinecroft Drive) | 24.90 % | NORMAL | 0.00 kW | 3.46 | 1.78 kW | CLSD | NORMAL |
| CES-14 | (1656 Meadowbrook) | 29.20 % | NORMAL | 0.00 kW | 3.42 | 3.40 kW | CLSD | NORMAL |
| CES-15 | (3819 David Landing) | 23.70 % | NORMAL | -1.00 kW | 3.47 | 0.84 kW | CLSD | NORMAL |
| CES-16 | (1091 Cameron Circle) | 19.90 % | NORMAL | 0.00 kW | 3.44 | 0.82 kW | CLSD | NORMAL |

All available units were then placed in the DEW Mode of Operation and the resulting commands from DEW were observed. Fig. 14-1 shows a web page utilized by DR-SOC during the project, which provides an overview of real-time values key parameters of the fleet. Fig. 14-2 shows a graph of the Total Fleet kW for the day of the test.

| | | | | | |
|---|---|---|---|---|---|
| | **CES # SNC2 Charge 28.6%**<br>IN SCAN<br>PCS: -16.12 kW, 1.27 kvar<br>(Hub Command: -16.1 kW 0.8 kvar)<br>Current mode: DEW ECON | **CES # SNC3 Charge 24.9%**<br>IN SCAN<br>PCS: -23.34 kW, 4.08 kvar<br>(Hub Command: -25 kW 0 kvar)<br>Current mode: DEW ECON | **CES # SNC4 Charge 24.9%**<br>IN SCAN<br>PCS: -23.81 kW, 4.93 kvar<br>(Hub Command: -23.8 kW 0 kvar)<br>Current mode: DEW ECON | **CES # SNC5 Charge 24.4%**<br>IN SCAN<br>PCS: -23.32 kW, 4.73 kvar<br>(Hub Command: -25 kW 0 kvar)<br>Current mode: DEW ECON | **CES # SNC6 Charge 28.3%**<br>IN SCAN<br>PCS: -12.21 kW, 3.39 kvar<br>(Hub Command: -12.2 kW 0 kvar)<br>Current mode: DEW ECON |
| **CES # SNC7 Charge 24.9%**<br>IN SCAN<br>PCS: -24.97 kW, 4.91 kvar<br>(Hub Command: -25 kW 0 kvar)<br>Current mode: DEW ECON | **CES # SNC8 Charge 25.4%**<br>IN SCAN<br>PCS: -25.01 kW, 4.84 kvar<br>(Hub Command: -25 kW 0 kvar)<br>Current mode: DEW ECON | | **CES # SNC10 Charge 29.6%**<br>IN SCAN<br>PCS: -22.55 kW, 4.4 kvar<br>(Hub Command: -22.6 kW 0 kvar)<br>Current mode: DEW ECON | **CES # SNC11 Charge 24.9%**<br>IN SCAN<br>PCS: -24.98 kW, 0.38 kvar<br>(Hub Command: -25 kW -0.3 kvar)<br>Current mode: DEW ECON | **CES # SNC12 Charge 24.9%**<br>IN SCAN<br>PCS: -19.79 kW, 4.06 kvar<br>(Hub Command: -19.8 kW 0 kvar)<br>Current mode: DEW ECON |
| **CES # SNC13 Charge 24.9%**<br>IN SCAN<br>PCS: -25 kW, 3.43 kvar<br>(Hub Command: -25 kW 0 kvar)<br>Current mode: DEW ECON | **CES # SNC14 Charge 29.3%**<br>IN SCAN<br>PCS: -21.32 kW, 0.34 kvar<br>(Hub Command: -25 kW -0.4 kvar)<br>Current mode: DEW ECON | **CES # SNC15 Charge 23.9%**<br>IN SCAN<br>PCS: -21.99 kW, -3.69 kvar<br>(Hub Command: -22 kW -3.7 kvar)<br>Current mode: DEW ECON | **CES # SNC16 Charge 19.9%**<br>IN SCAN<br>PCS: -14.7 kW, 3.44 kvar<br>(Hub Command: -14.7 kW 0 kvar)<br>Current mode: DEW ECON | | |
| **CES # MCCC Charge 19.8%**<br>IN SCAN<br>PCS: 0 kW, 87 kvar<br>(Hub Command: 0 kW 0 kvar)<br>Current mode: DEW ECON | | | | | |

*Fig. 14-1*

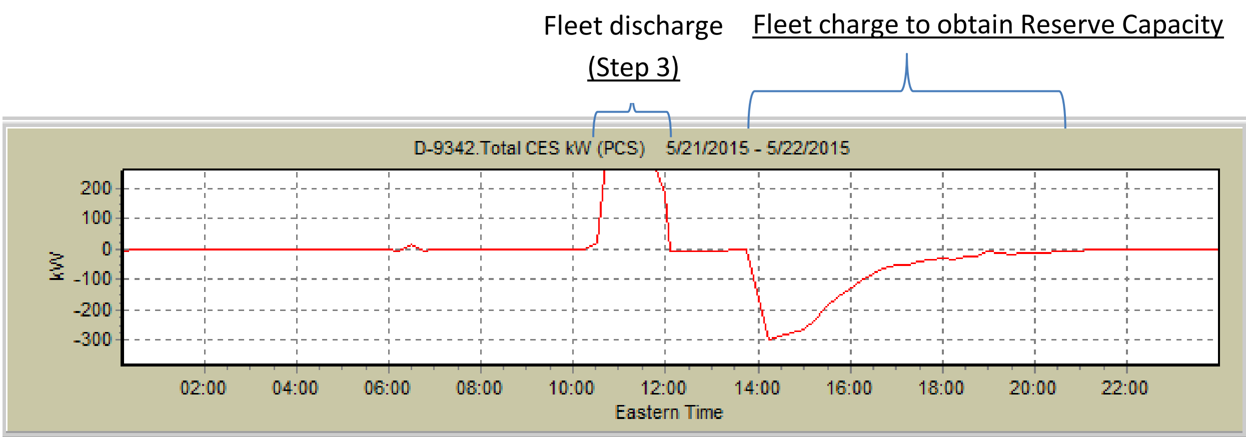
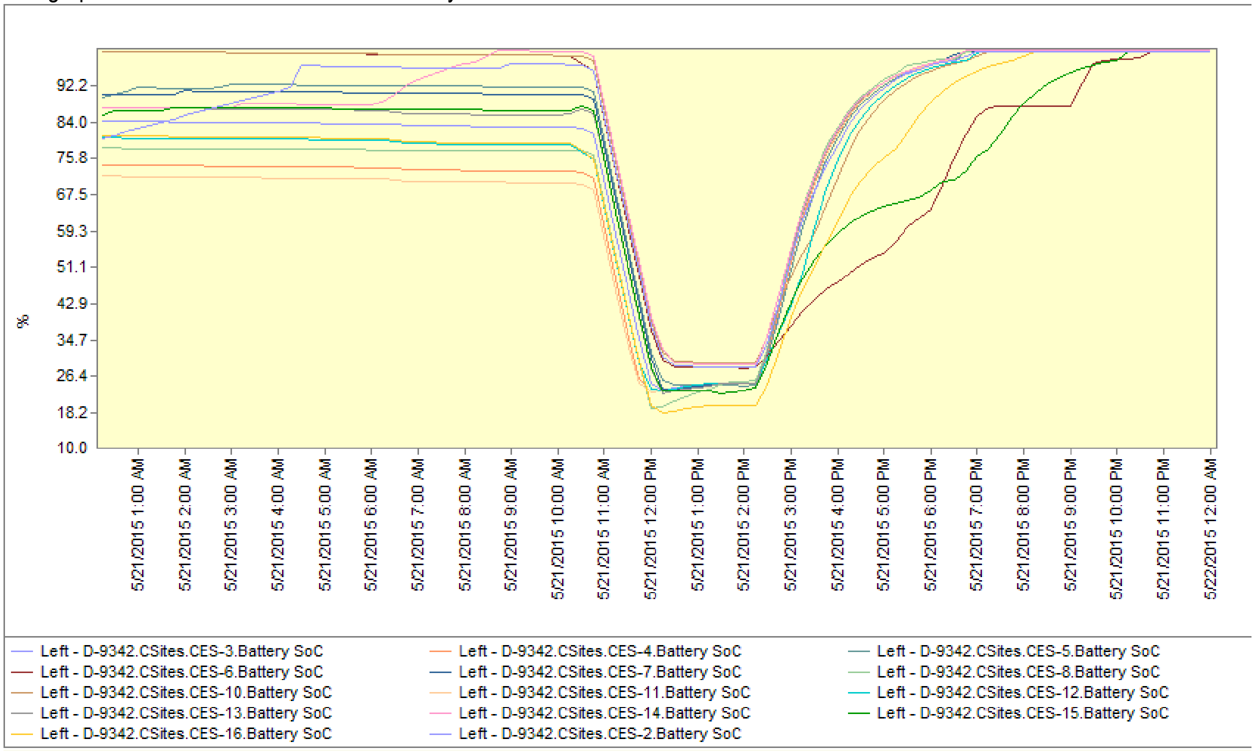



*Fig. 14-2*

The graph below shows individual CES Battery SoC for this date.

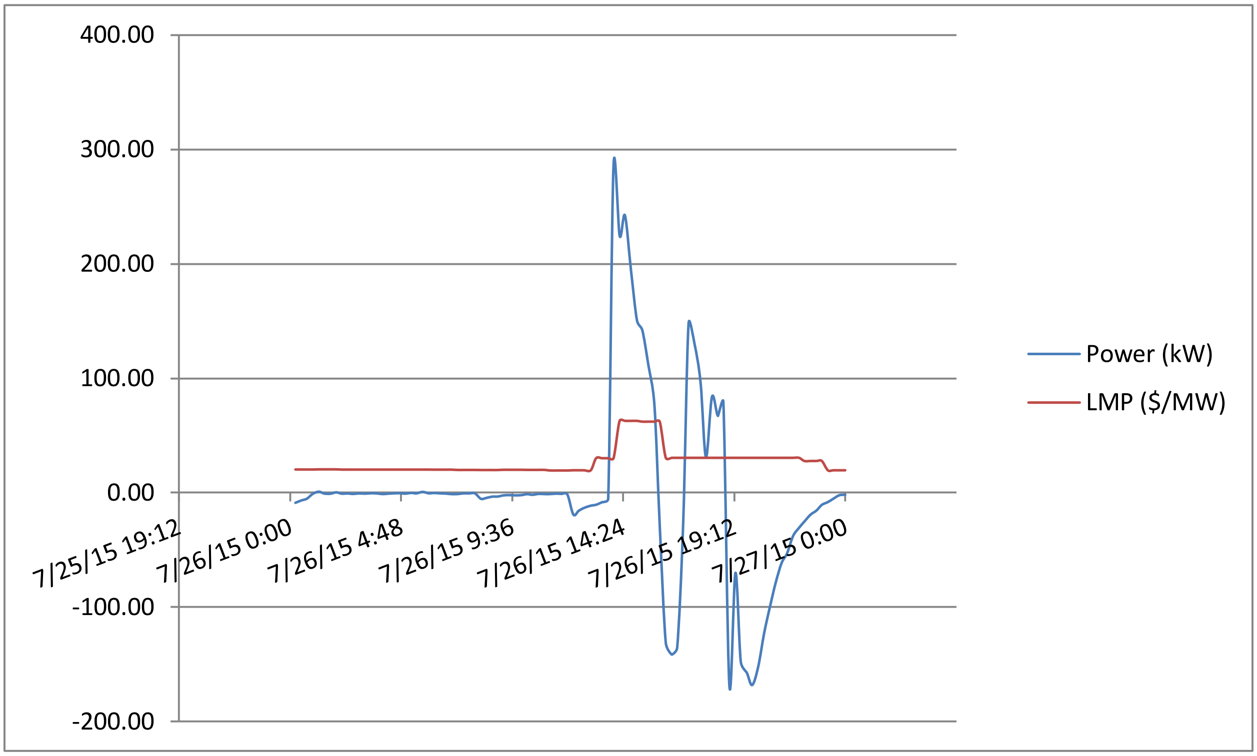



**Test Date:** 5/21/2015

### 5.2.15. Discharge When LMP Price is High and Unit is not Needed: DRSOC-CES-015

| **Mode of Operation: DEW** | |
|---|---|
| **Requirement:** Discharge when LMP price is high and unit is not "needed" | **Requirement Number: DRSOC-CES-015** |
| | |
| **Assumptions** | |
| Units participating are expected to be charged higher than the configured minimum reserve margin. AppDefSettings.cfg should have a *minimumProfitMargin_dollarsPerMWh* parameter lower than the current price minus future price after factoring losses (round-trip efficiency). Current LMP needs to be higher than the *minimumDischargePrice_dollarsPerMWh* parameter. All available CES units are placed in "DEW" Mode of Operation. | |
| **Method of Testing** | |
| 1. Restore the "*numberReserveCapacityHours*" parameter in AppDefSettings.cfg to 2.<br>2. Restore the "*minReserveCapacity*" parameter in AppDefSettings.cfg to 10.<br>3. Set the "*minimumProfitMargin_dollarsPerMWh*" parameter in AppDefSettings.cfg to $0.50/MWh.<br>4. Set the "*minimumDischargePrice_dollarsPerMWh*" parameter in AppDefSettings.cfg to $30/MWh and ensure that the price is below instantaneous LMP price for test to be valid.<br>5. Use Hub command mode to bring each unit's SoC above 60%.<br>6. Place all available units in DEW Mode of Operation.<br><br>**Ensure units are issued discharge commands.** | |
| **Results** | |
| *See next page* | |

The test was instrumented as described and yielded an interesting dataset. The LMP data shown in the graph below is the hourly average price and does not reflect the 5-minute LMP volatility that was fed to the DEW algorithm in real-time. This volatility is the reason behind the CES units charging shortly before what appears to be the end of the peak LMP. It is important to note that the LMP at the beginning of the hour was higher and as the price started leveling off, the DEW algorithm took the opportunity to charge the CES fleet.




**Test Date**: 8/5/2015 11:00AM – 8:00PM

### 5.2.16. Do Not Charge When Doing so Would Cause Overload: DRSOC-CES-016

| | |
|---|---|
| **Mode of Operation: DEW** | |
| **Requirement:** Do not charge when doing so would cause overload | **Requirement Number: DRSOC-CES-016** |

**Assumptions**

Current circuit/unit conditions are as such:

- CES-2 is configured in DEW with a transformer rating of 25 kVA
- CES-5 is configured in DEW with a transformer rating of 50 kVA
- CES batteries are below maximum state of charge by a significant margin.
- Current LMP price is negative.

**Method of Testing**

Send Hub commands to get units under test (CES-2 and CES-5) between 40% and 80% charge.
Using a test application, feed DEW a value of 25 for the load kW of each CES participating in the test, on a periodic basis.
Feed DEW the output of a calculation that multiplies the LMP by negative 1 to get a constant negative LMP. This ensures DEW would charge the units, based on economics, if the charge would not overload the transformer.

**Results**

Fig. 16-1 shows the results of CES-2. The load kW of CES-2, as seen by DEW, would oscillate between actual value (less than 5 kW), and the value fed from the test application (25 kW). While scan rates and archiving intervals caused a few exceptions, DEW would charge the unit when the charge would not cause a transformer overload, but would not charge when it would doing so would cause an overload.

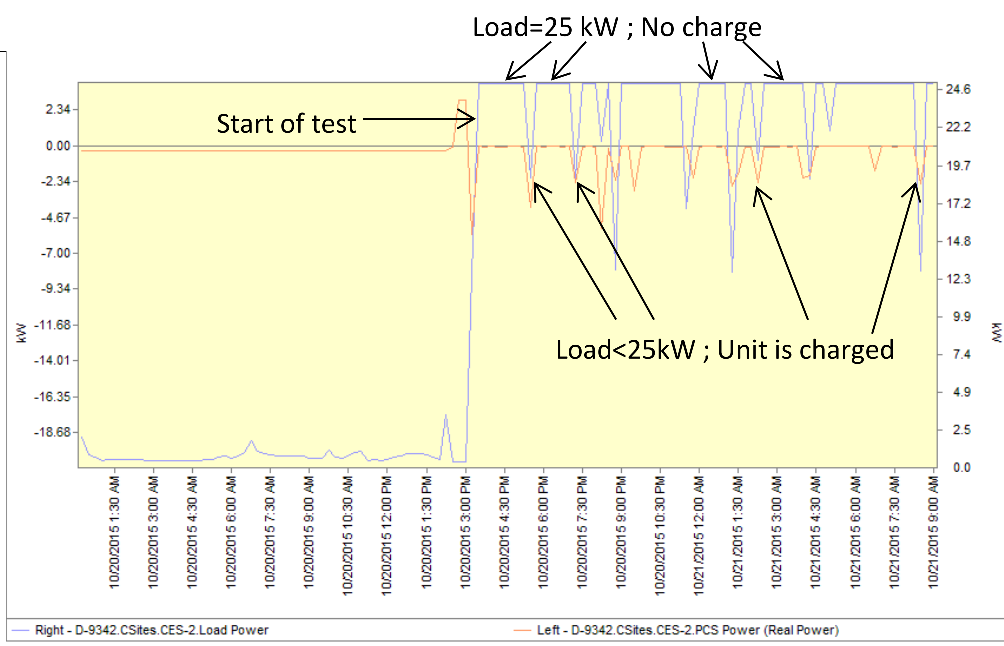



*Fig. 16-1*

Fig. 16-2 shows the results for CES-5. A load value of 25 kW did not affect the charging of CES-5, since it would not cause an overload. DEW continued charging the unit and it achieved 100% SoC within 3 hours.

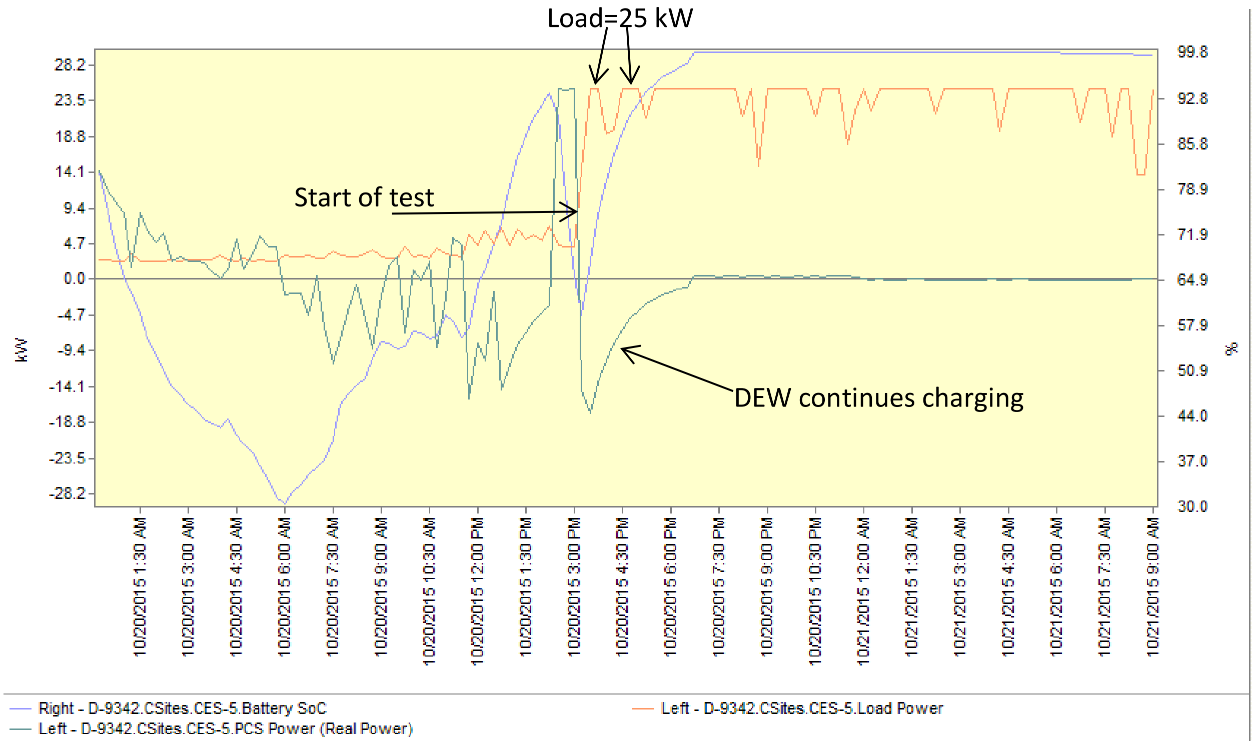



*Fig. 16-2*

**Test Date**: 8/20/2015-8/21/2015

## 5.2.17. Maintain Configured Reserve Capacity: DRSOC-CES-017

| | |
|---|---|
| **Mode of Operation: DEW** | |
| **Requirement:** Maintain configured reserve capacity | **Requirement Number: DRSOC-CES-017** |

**Assumptions**

Current circuit/unit conditions are as such:

- Unit under test has a reserve capacity configured in DEW for at least two hours of emergency power
- Unit SoC is above the minimum reserve capacity
- minimumProfitMargin_dollarsPerMWh has been met

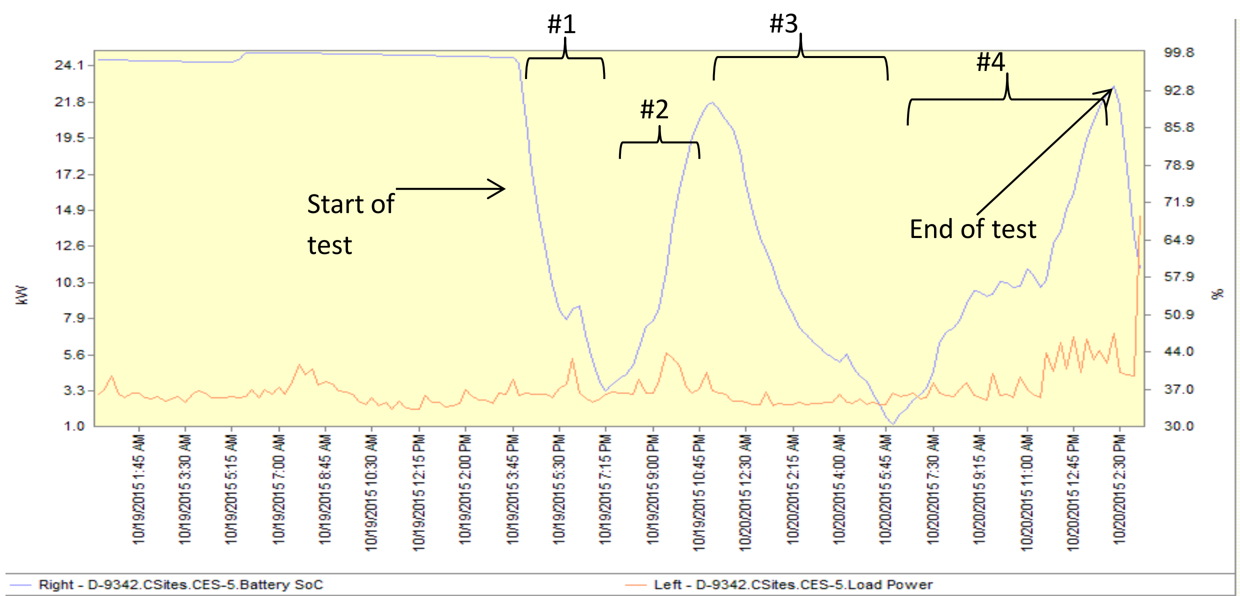
**Method of Testing**

Due to low loading, *numberReserveCapacityHours* was set to 8 hours
Battery SoC near 100%
Set minimumProfitMargin_dollarsPerMWh and minimumDischargePrice_dollarsPerMWh both set to $0.01
Place unit in DEW mode

**Results**

CES5 was selected as test unit. At the start of test, unit had 99% battery SoC.
The graph below contains four distinct time periods where DEW recommended commands indicate the algorithm was responding as expected, and maintained the required reserve capacity hours as a priority above profit margin. There was a slight lag time between the real-time Load kW and resultant change in the unit's SoC, caused by CES unit scan rates.

1. When real-time Load kW was low, the DEW algorithm discharged CES due to profit margin being met.
2. When real-time Load kW increased between 9:00 and 10:00 PM, DEW charged the unit in order to maintain the 8 hours of reserve capacity, despite the profit margin still being met
3. When Load kW was again low, after midnight, the unit was discharged for profit margin
4. As Load kW again increased around 6:00 AM, the unit was charged to attain the desired reserve capacity hours




**Test Date:** 10/19/2015

### 5.2.18. Resolve Transformer Overload by Discharging CES: DRSOC-CES-018

| **Mode of Operation: DEW** | |
|---|---|
| **Requirement:** Resolve transformer overload by discharging CES | **Requirement Number: DRSOC-CES-018** |

**Assumptions**

Current circuit/unit conditions are as such:

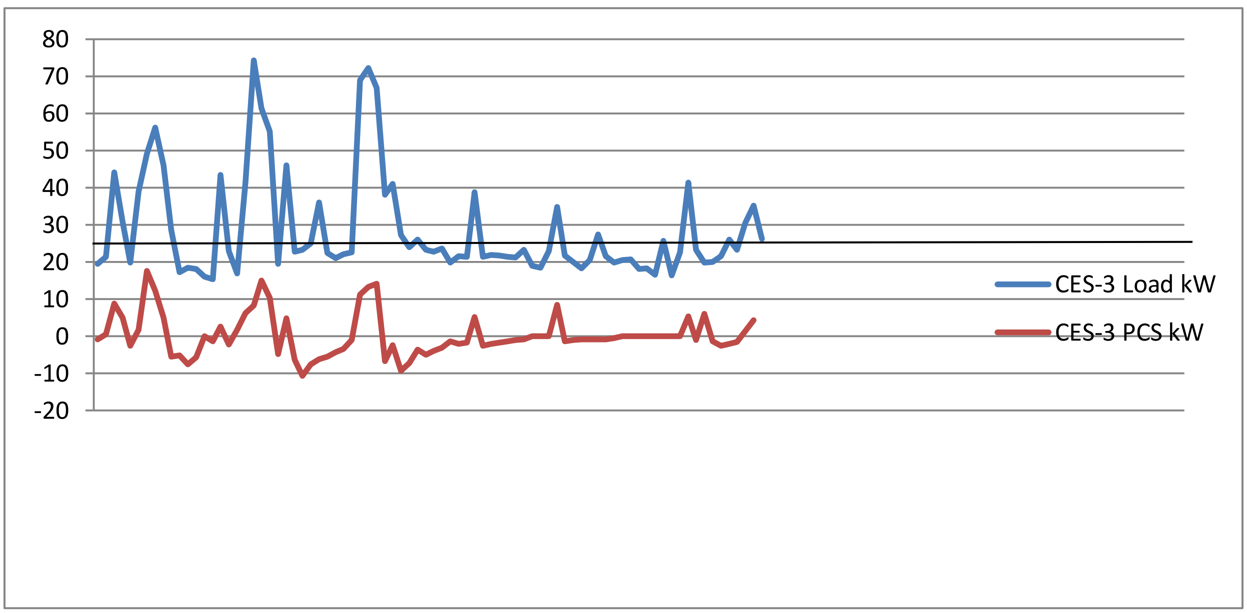
- CES unit in this test need to be placed in "DEW" Mode of Operation.
- CES battery is above minimum state of charge by a significant margin.
- Current LMP price is low, at zero or negative.

**Method of Testing**

- CES-3 used for this test. The transformer rating is 25 kVA
- Create new "test" Load kW point for CES-3, which will be calculated by multiplying the actual load by 12.5. This will periodically create an overload condition on the transformer
- Change PtID exchanged between DR-SOC Hub and DEW for CES-3 Load to new calculated point
- Utilize Negative LMP price in DEW configuration (ensures DEW will not discharge due to economics)

**Results**

The data indicates the DEW algorithm functioned properly. With a multiplier of 12.5, the "new" CES-3 load rose well above the transformer rating of 25 kVA. Even with the CES discharging, the "test" load value rose well above 25 kW. DEW took advantage of times the transformer was not overloaded to charge the CES.




**Test Date:** 10/22/2015

### 5.2.19. Resolve Low Voltage by Supplying KVAR: DRSOC-CES-019

| **Mode of Operation: DEW** | |
|---|---|
| **Requirement:** Resolve low voltage by supplying kvars | **Requirement Number: DRSOC-CES-019** |

**Assumptions**

Current circuit/unit conditions are as such:

- All CES units in this test need to be placed in "DEW" Mode of Operation.
- Circuit primary meter voltage is dipping below configured *minimumPrimaryVoltage_120Vbase* value.
- Current LMP price is not high enough to cause algorithm to discharge.
- Under normal conditions, each CES produces approximately 3.4 kvar's due to internal capacitor.

**Method of Testing**

1. Place all units in DEW Mode of Operation.
2. Set *minimumPrimaryVoltage_120Vbase* configuration parameter to **123.5**
3. Set *minimumDischargePrice_dollarsPerMWh* parameter to **1000**.

Voltage conditions on the circuit have been such that realistic low voltage testing was not possible as the substation transformer's load tap changer maintained voltage above 122 steadily. This test was performed with a value of 124 set for *minimumPrimaryVoltage_120Vbase* and backed off to 122.7, using CES-15.

**Results**

Fig. 19-1 shows the results. DEW successfully requested kVAR's from the CES to resolve a low voltage condition.

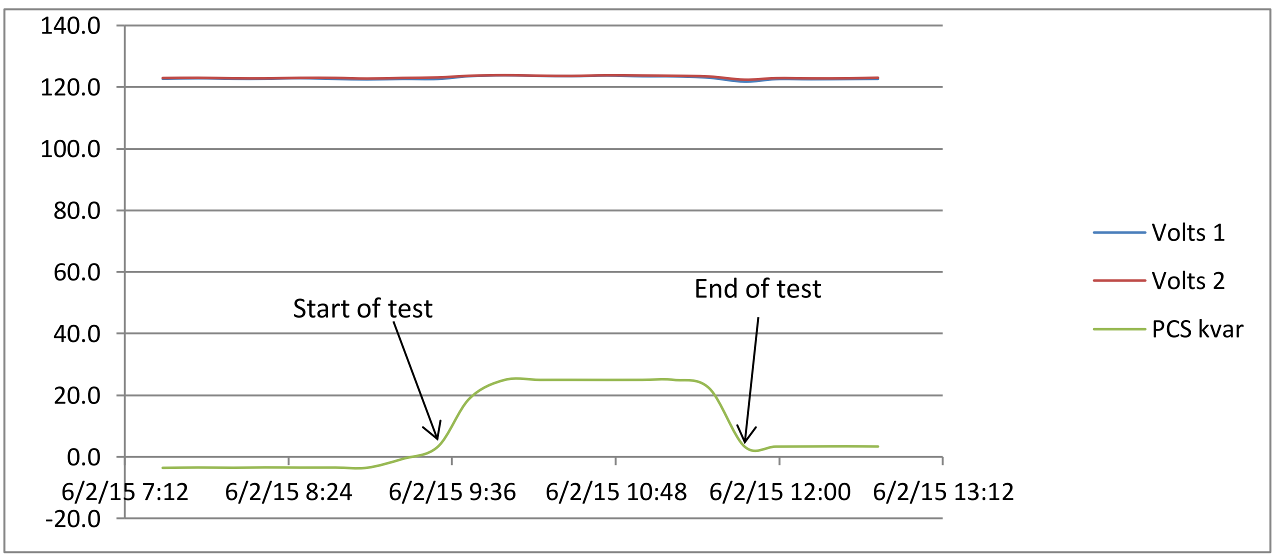



*Fig. 19-1*

Fig. 19-2 is the table representation of the chart in Fig. 19-1.

| Timestamp | Volts 1 | Volts 2 | PCS kvar |
|---|---|---|---|
| 6/2/15 7:28 | 122.7 | 122.9 | -3.55 |
| 6/2/15 7:44 | 122.9 | 123.0 | -3.43 |
| 6/2/15 7:59 | 122.7 | 122.9 | -3.50 |
| 6/2/15 8:13 | 122.7 | 122.8 | -3.40 |
| 6/2/15 8:29 | 122.9 | 123.0 | -3.45 |
| 6/2/15 8:44 | 122.6 | 123.0 | -3.45 |
| 6/2/15 8:58 | 122.5 | 122.8 | -3.50 |
| 6/2/15 9:14* | 122.7 | 123.0 | -0.65 |
| 6/2/15 9:29 | 122.6 | 123.1 | 3.32 |
| 6/2/15 9:43 | 123.5 | 123.7 | 18.89 |
| 6/2/15 9:59 | 123.8 | 123.9 | 25.00 |
| 6/2/15 10:14 | 123.6 | 123.7 | 25.00 |
| 6/2/15 10:28 | 123.6 | 123.6 | 25.01 |
| 6/2/15 10:44 | 123.7 | 123.8 | 24.98 |
| 6/2/15 10:59 | 123.5 | 123.8 | 25.00 |
| 6/2/15 11:13 | 123.5 | 123.7 | 25.00 |
| 6/2/15 11:29 | 123.0 | 123.4 | 22.30 |
| 6/2/15 11:44** | 121.8 | 122.4 | 3.38 |
| 6/2/15 11:58 | 122.6 | 122.9 | 3.36 |
| 6/2/15 12:14 | 122.5 | 122.8 | 3.40 |
| 6/2/15 12:29 | 122.6 | 122.9 | 3.44 |
| 6/2/15 12:43 | 122.7 | 123.0 | 3.38 |

*Fig. 19-2*

* Changed Nominal Voltage Setting to 124
** Changed Nominal Voltage Setting to 122.7

**Test Date:** 6/2/2015 8:30AM – 12:00PM

### 5.2.20. Resolve High Voltage by Supplying KVAR: DRSOC-CES-020

| | |
|---|---|
| **Mode of Operation: DEW** | |
| **Requirement:** Resolve high voltage by absorbing kvars | **Requirement Number: DRSOC-CES-020** |

**Assumptions**

Current circuit/unit conditions are as such:

- All CES units in this test need to be placed in "DEW" Mode of Operation.
- Circuit primary meter voltage is exceeding above configured *maximumPrimaryVoltage_120Vbase* value.
- Current LMP price is high enough to cause algorithm to discharge.
- DEW calculates high-side voltage using low side voltage plus an assumed voltage drop based on amount of load

**Method of Testing**

Set *maximumPrimaryVoltage_120Vbase* value to 126 while voltage on the load side of the selected CES units is above 124 volts.
NOTE – Each CES contains a capacitor that provides approximately 3 kVAR's under stand-by conditions.

**Results**

CES-4 was selected to perform this test. As the voltage started rising past the configured threshold, the CES unit switched off its capacitor and started absorbing vars. This brought the voltage down at the load below the configured threshold.
Fig. 20-1 shows a table of the results. Fig. 20-2 is the chart for this same dataset.

| Local Time | CES kVAR | Load Voltage 1 | Load Voltage 2 |
|---|---|---|---|
| 7/9/15 13:11 | 3.45 | 124.1 | 124.3 |
| 7/9/15 13:27 | 2.90 | 124.2 | 124.2 |
| 7/9/15 13:44 | 2.44 | 124.6 | 124.8 |
| 7/9/15 13:56 | 2.19 | 124.5 | 124.8 |
| 7/9/15 14:14 | 3.60 | 123.8 | 123.8 |
| 7/9/15 14:29 | 3.16 | 123.9 | 123.9 |
| 7/9/15 14:43 | -1.23 | 125.4 | 125.6 |
| 7/9/15 14:57 | -1.17 | 125.2 | 125.4 |
| 7/9/15 15:14 | 1.81 | 122.7 | 122.5 |
| 7/9/15 15:28 | 1.94 | 122.8 | 122.8 |
| 7/9/15 15:42 | 3.54 | 123.3 | 123.4 |

Although Load Voltage was < 126, DEW calculated >126 as it assumes a voltage drop across

*Fig. 20-1*

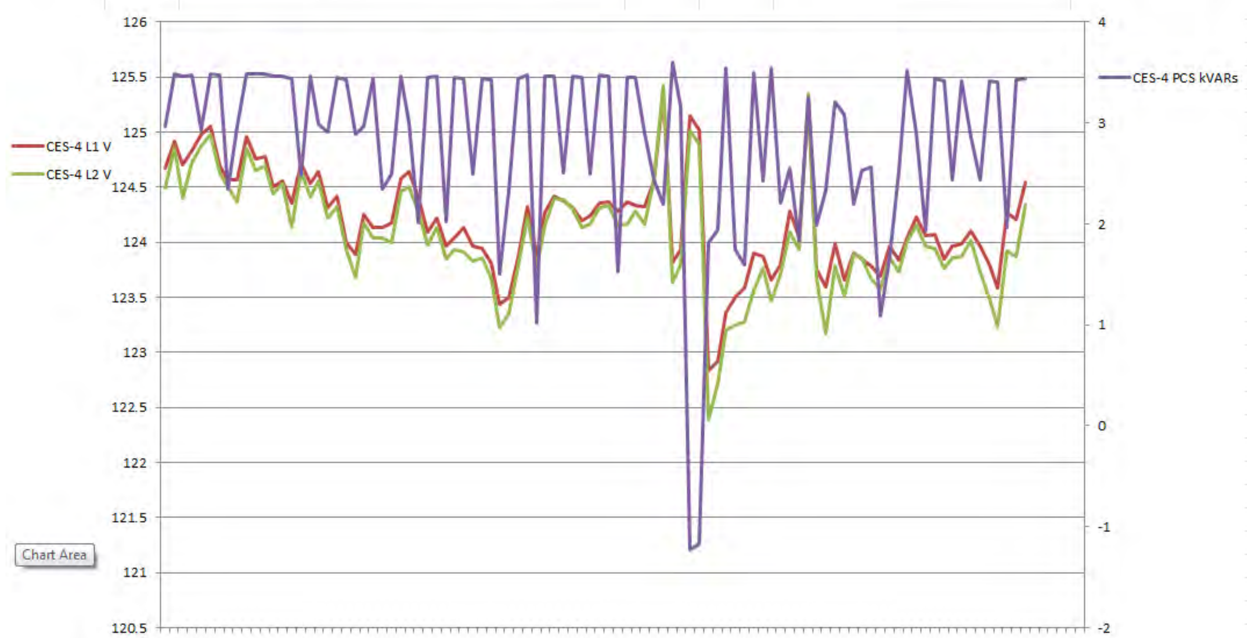



*Fig. 20-2*

**Test Date:** 7/9/2015

### 5.2.21. Resolve Single-Phase Primary Overload by Discharging Only Batteries on that Phase While Charging Others (Low Price): DRSOC-CES-021

| **Mode of Operation: DEW** | |
|---|---|
| **Requirement:** Resolve single-phase primary overload by discharging only batteries on that phase while charging others (low price) | **Requirement Number: DRSOC-CES-021** |

**Assumptions**

Current circuit/unit conditions are as such:

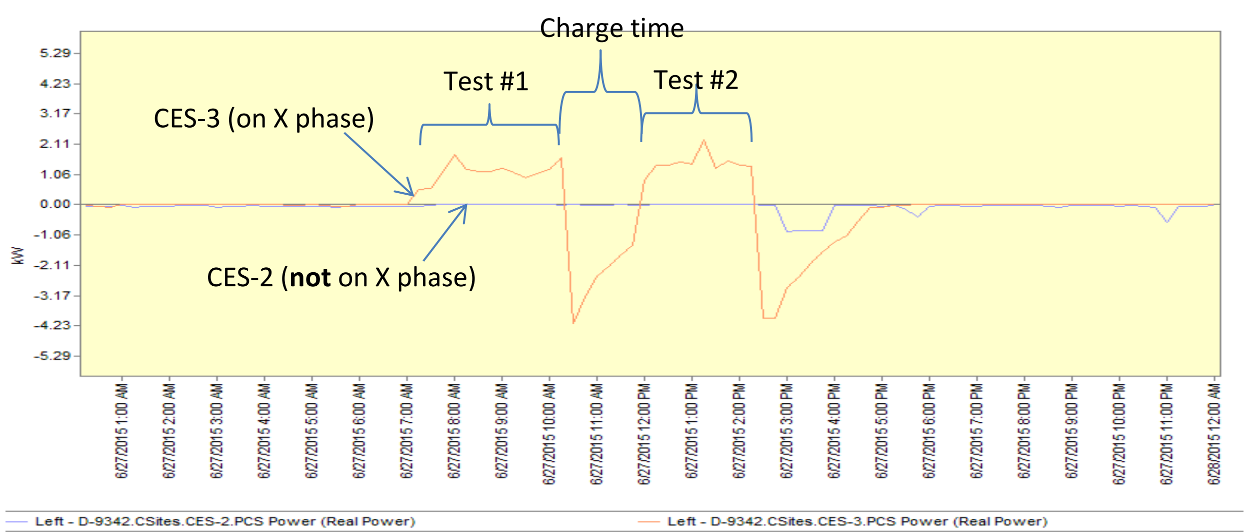
- All CES units in this test need to be placed in "DEW" Mode of Operation.
- Amp measurement on Phase A is higher than the rating of the exit cable in the DEW circuit model.
- Current LMP price is low, at zero or negative. DEW will prioritize reliability over economics.

**Method of Testing**

Insert a short run of significantly smaller conductor (#6) in the DEW circuit model on X phase at the start of circuit. This simulates a primary overload condition on a single phase.
CES-3 is on the affected phase, while CES-2 is on a different phase.

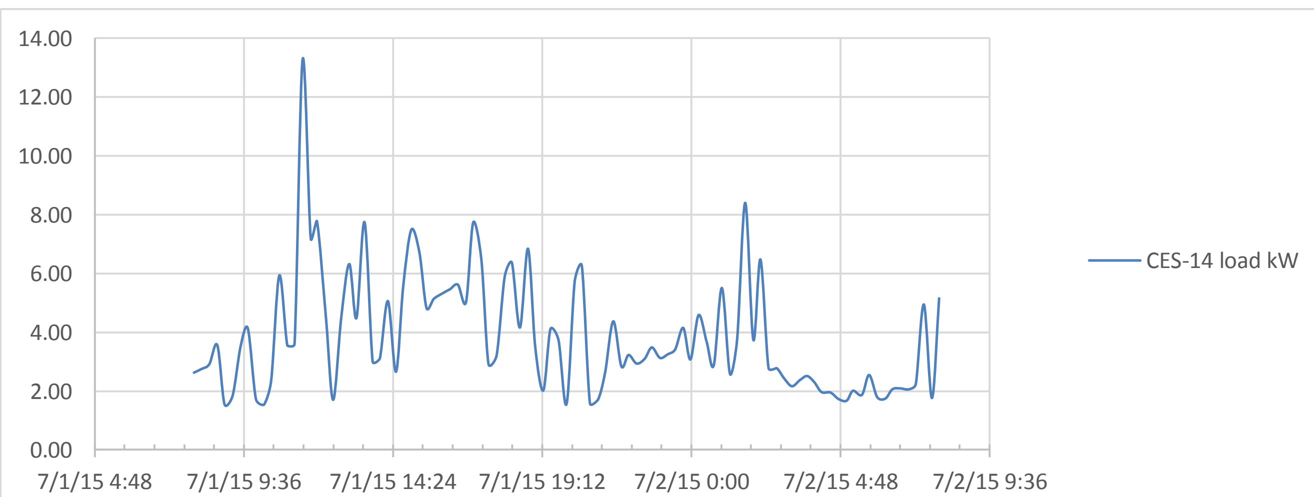
**Results**

The test was repeated twice with a charge issued between the two runs. The LMP pricing had no effect on the CES operations in this test and was only included to demonstrate DEW's prioritizing of reliability over economics. The chart below shows DEW only required power from the CES on the overloaded phase.




**Test Date:** 6/27/2015

### 5.2.22. Forecasted Overload Alert: DRSOC-CES-022

| **Mode of Operation: DEW** | |
|---|---|
| **Requirement:** Forecasted overload alert | **Requirement Number: DRSOC-CES-022** |
| | |
| **Assumptions** | |
| Current circuit/unit conditions are as such:<br>- All CES units in this test need to be placed in "DEW" Mode of Operation.<br>- Current time is just before customer/class load curve peak configured in DEW. The load is expected to increase in the next forecast period (hour).<br>- Present load is just under transformer rating. | |
| **Method of Testing** | |
| Look up results in XMLSent SQL table for the time interval matching the test. | |
| **Results** | |
| The overload alert message appears as expected for the affected units in the warnings="" XML attribute:<br><br><unit name="CES14" primaryOverride="1" anticipatedOverload="4.0" warnings="At hour 3: Reserve capacity greater than battery capacity; At hour 4: Reserve capacity greater than battery capacity; At hour 4: Reserve capacity will be violated to satisfy KW discharge requirement; At hour 5: Reserve capacity greater than battery capacity; At hour 5: Reserve capacity must be violated due to battery/inverter limitations; At hour 6: Reserve capacity greater than battery capacity; At hour 6: Reserve capacity must be violated due to battery/inverter limitations; At hour 7: Reserve capacity greater than battery capacity; At hour 8: Reserve capacity greater than battery capacity; At hour 10: Reserve capacity greater than battery capacity; At hour 23: Reserve capacity greater than battery capacity" outputkw="0.0" outputkvar="0.0" hoursStandby="3.5" /><br><br> | |
| **Test Date:** 7/1/2015 | |

### 5.2.23. Minimum Profit Margin test: DRSOC-CES-023

| Mode of Operation: DEW | |
|---|---|
| **Requirement:** Minimum profit margin test | **Requirement Number: DRSOC-CES-023** |

**Assumptions**

Current circuit/unit conditions are as such:

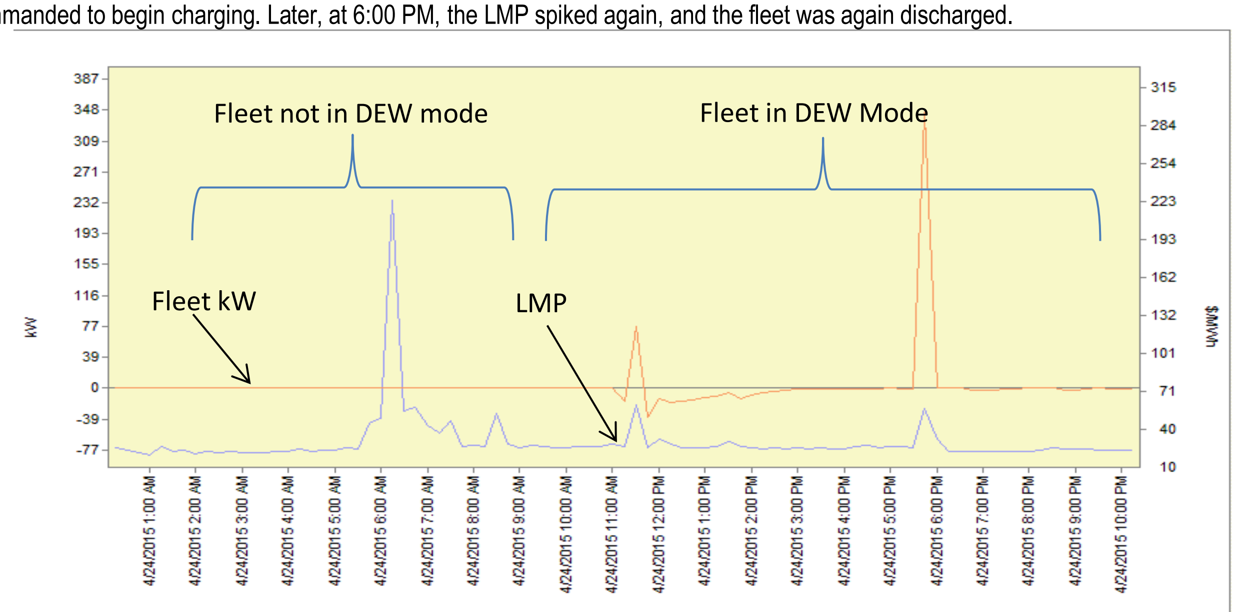
- All CES units in this test need to be placed in "DEW" Mode of Operation.
- Current LMP price is low, but expected to spike at times during the day

**Method of Testing**

1. All CES units participating in this test are to be charged up to 100%.
2. *minimumDischargePrice_dollarsPerMWh* set to $32/MWh.

**Results**

Fleet of available CES units placed into DEW mode at 10:00 AM. When the LMP rose above the set threshold (around 11:30 AM), DEW recommended the fleet to be discharged. DR-SOC Hub sent the appropriate DNP3 commands. When LMP price dropped, the fleet was commanded to begin charging. Later, at 6:00 PM, the LMP spiked again, and the fleet was again discharged.




**Test Date: 4/24/2015**

## 5.3. Storage System Performance

This section discusses in detail the development of the batteries and the balance of plant used in the project and the challenges that were overcome to create a CES unit that can be used in a utility application.

### 5.3.1. CES Technical Challenges

Several technical challenges were encountered in the design, validation and verification, and field deployment of the CES units. The first challenge was the design requirement of a single-phase, 240v/120v AC unit, a departure from S&C Electric typical primary high voltage (>4 kV), 3-phase type of equipment. The CES still needed to have utility grade performance, a compact design with a footprint similar to that of a residential pad mount transformer along with all of the safety requirements of utility-grade distribution equipment. These safety and quality features included passive cooling (no fans), poke and pry safe enclosure, highly corrosion resistant coatings, and quiet operation.

In addition to the overall packaging needs of a CES inverter, other utility functional specifications had to be met. These included voltage support, peak shaving, load shifting, anti-islanding, SCADA control via DNP3, and meeting industry standards such as IEEE 1547.

In order to achieve compliance with IEEE 1547, S&C sent a CES unit to Intertek Testing Laboratories in Rochester, NY. Intertek's technicians completed the various tests in accordance with IEEE 1547.1. The test results are outlined below showing that the CES complies to IEEE 1547 standard.

| IEEE 1547 | IEEE 1547.1 | Per UL 1741 Section 39.1 and 46.1.1 "A utility-interactive inverter or interconnection system equipment (ISE) shall comply with the Standard for Interconnecting Distributed Resources with Electric Power Systems, IEEE 1547…" | |
|---|---|---|---|
| | 5.1.2.1 | Operational Temperature | **Pass** |
| | 5.1.2.2 | Storage Temperature | **Pass** |
| 5.1.1 | 5.2 | Response to abnormal voltage | **Pass** |
| 5.1.1 | 5.3 | Response to abnormal frequency | **Pass** |
| 5.1.2 | 5.4 | Synchronization | **Pass** |
| 5.1.3 | 5.5 | *-- Interconnect Integrity tests (heading) --* | |

| | | | |
|---|---|---|---|
| 5.1.3.1 | 5.5.1 | Protection from EMI (IEEE C37.90.2) | **Pass** |
| 5.1.3.2 | 5.5.2 | Surge withstand (C62.45 and C62.41) Location Category A, B, or C | **Pass** |
| 5.1.3.3 | 5.5.3 | Paralleling Device | **Pass** |
| | 5.2 | *Response to abnormal voltage (Repeat)* | **Pass** |
| | 5.3 | *Response to abnormal frequency (Repeat)* | **Pass** |
| | 5.4 | *5.1.2 Synchronization (Repeat)* | **Pass** |
| 5.1.4 | 5.7 | Unintentional Islanding | **Pass** |
| 4.2.6 | 5.10 | Reconnection to Area EPS | **Pass** |
| 5.1.5 | 5.6 | Limitation of dc injection | **N/A** |
| 5.1.6 | 5.11 | Harmonics (current) | **Pass** |
| | 5.9 | Open Phase | **Pass** |

**Table 9: IEEE 1547 Test Results**

After units were installed and commissioned into service, some operational anomalies were discovered. Firmware updates to the BMS and PSC needed to be performed locally. During the update of the first unit, the AC contactor opened, resulting in an outage for the customers fed via the CES unit. Firmware updates on the remaining units required DTE line crews to install a hardwire bypass during the update process.

Another issue that was particularly problematic was the procurement of line inductors that could function properly and quietly with the S&C inverter. Different suppliers tried several variations of designs and potting materials to achieve operation meeting the temperature and sound level specifications.

There were additional component issues that were uncovered once the units were installed in the field that caused the AC contactor to open resulting in customer outages. DTE UGL crews responding to the outage would bypass the unit. The analysis performed by S&C indicated high resistance through an auxiliary contact on the AC contactor could cause the controls to inadvertently open the contactor. Replacement contact assemblies have been received by DTE, but have not been installed in the units. Installation, planned for in Spring 2016, requires two short outages for the customers.

Another procurement issue was related to circuit boards that were improperly cleaned during the soldering process that caused false readings due to leakage current on the circuit board. The false readings would inhibit the operation of the unit. These units were replaced.

All problems that were uncovered after the unit units were installed were resolved by S&C.

It is not unusual to uncover additional issues when new technology is deployed in field operation. Even though the factory testing uncovers most of the problems, there are always subsets of problems that are uncovered in field operation. This project most likely uncovered most of the anomalies making the CES a robust product. This is why demonstration projects of new technologies are so important to ensure that a product operates as designed in all environmental situations.

### 5.3.2. New Battery Technical Challenges

As the project evolved, many technical challenges with the storage batteries became known. The first of these was the stability of the supplier base. During the life of this project, two battery suppliers ceased operations causing S&C to contract with Kokam from South Korea for all of the new batteries. The first mechanical challenge was keeping the battery watertight. Since the batteries were installed beneath the CES in a vault about five feet deep, they were often exposed to water and in some cases, completely submerged. Maintaining a watertight seal proved difficult and seal designs changed a few times before the proper arrangement was determined. Verifying the integrity of the seal was also added to the testing regimen batteries underwent before being sent to the field. The battery was thermally cycled from -40°C to +50°C and then the seal was verified for integrity with a Helium leak test. If that test passed, the battery was submerged for two weeks in a water tank while under operation by a CES.

The Battery Management System (BMS) also required several iterations of changes, and testing to develop a BMS that would properly control the battery cells, dispatch power and correctly calculate and report the state of charge (SOC) to the CES PCS. The validation and verification of these changes took several months and caused some delays in final delivery of the CES systems.

### 5.3.3. Repurposed Battery Technical Challenges

Another deliverable by S&C were two CES units using end-of-life automotive batteries, or repurposed batteries. eCamion company was tasked with taking six Fiat 500e battery packs from pre-production test EVs and repurposing them into a CES battery that communicated with the CES PCS. The challenges here were significant.

First, eCamion attempted to use a whole battery pack "as-is" from the automotive application. To accomplish this, they would have to adapt their BMS to communicate to the battery CAN message bus and behave as the master controller and to sort out all of the information that an automotive battery normally delivers. This task proved not to be feasible. The CAN communication system was too unique to be adapted to eCamion's BMS system.

Since using a pack "as-is" was proven unfeasible, all battery packs were disassembled and each module was tested for capacity before integrating them into a custom battery pack. Testing modules resulted in approximately 5% to 10% of them being rejected for insufficient capacity. The good modules were assembled into two (2) packs, one with about a 47 KWh capacity and the other having a 94 KWh capacity. The different configurations were necessary due to the DC voltage range of the inverter.

In addition, a custom enclosure had to be designed and built to house these newly assembled packs. Because of the container size and the need have easy access to trouble shoot, these repurposed packs were not to be installed below grade.

### 5.3.4. Serviceability and Commissioning Challenges

The CES unit was not designed with any "user-replaceable" part so if a malfunction occurred, the solution was to remove and replace that unit with a repurposed one. While there was a procedure to electrically bypass the CES before removing it, DTE elected to forego the bypass procedure because of safety concerns in the tight working area and instead outage the customer while units were replaced due to a malfunction. Generally the change out was about a 15 to 20 minute outage while the units were replaced. Figure 25 shows the AC termination bay. S&C worked with DTE to improve the ease of bypassing the unit so the customer did not experience an outage during field replacement.


**Figure 25: AC Termination Bay**

The location of the units sometimes provided hindrances to servicing the units. If it had rained recently, the sites were not always accessible by the boom truck required to remove and reinstall the CES. In some cases, units had to be bypassed for several days until the location dried out enough to get a truck in.

Cold weather also affected the availability of the CES system. Although the battery was underneath the CES and somewhat sheltered from the cold, if the battery temperature fell below 10°C, the system BMS automatically reduced output to protect the battery cells.

## 5.4. DNV GL CES Functional Tests

Prior to CES field installations, the first production CES was sent to the DNV GL KEMA lab for functional testing and independent test verification. The purpose of the test was to confirm all operating modes for correct operation. This Includes: normal local operation, remote monitoring and control, abnormal operation, and safety related fault conditions which were performed and logged during performance testing. All alerts, warnings, and faults that occurred during performance testing were logged in the test log and discussed with the manufacturer. The CES responded without issue to commands through the HMI computer connected to the local Ethernet network port. Two HMI applications ran concurrently to monitor and control the CES. The local or browser based HMI monitored CES status and created a log file, updating every 10 seconds. The CES parameter view and edit HMI was used to control the power in and out of the system and to monitor BMS data. Screenshots were taken for documentation purposes during performance tests.

The following CES system performance tests were performed using IEEE 1547.1and IEEE 519 as a reference.

- Basic operation test
- Round trip efficiency both AC and DC
- Frequency regulation signal response
- Peak shaving
- Islanding electrically
- Basic Impulse Level (BIL)

**Figure 26: CES System Test Setup**

Testing of the CES to the IEEE 1547 standard was performed later by Intertek Laboratory as requested by S&C Electric and is reviewed in section 5.3.1. Having the CES conform to IEEE 1547 Standards makes it easier for electric utilities to install on the distribution system without detailed review by the system protection group.

The details of the performance tests are in appendix D showing that all tests passed per original specifications. Below is an example showing the AC efficiency of the CES system that is discussed in section 2.4 in appendix D. There are two data sources, CES PCS and KEMA data collection system.

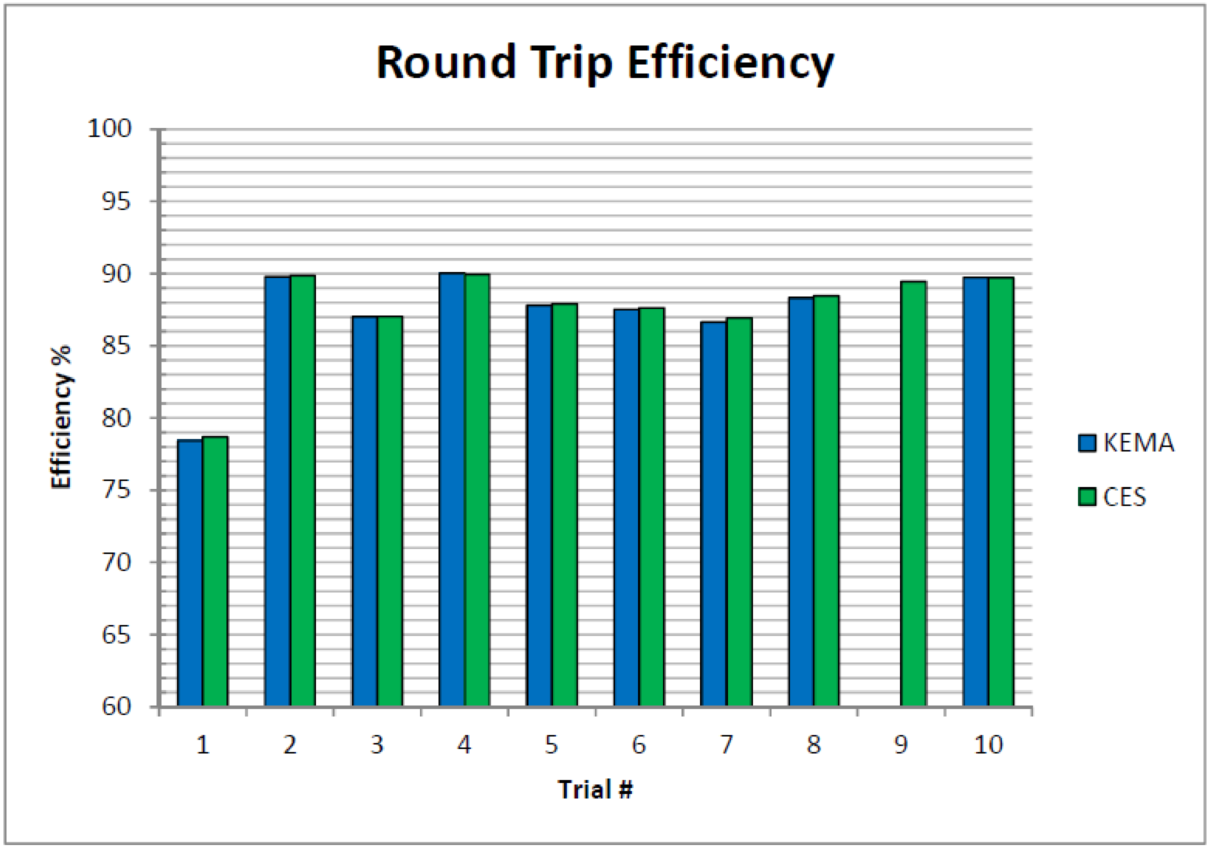



**Figure 27: CES AC Round Trip Efficiency**

KEMA data acquisition system (DAS) data for trial #9 was lost due to the data collection computer locking up before the system could store the data file. Trial #9 CES data is included. The average roundtrip AC efficiency over the 10 test is over 87% and if you exclude trial #1, the average is 88.5%. The tabular data is shown in the table below.

| Trial # | CES | KEMA |
|---|---|---|
| 1 | 78.68 | 78.43 |
| 2 | 89.86 | 89.78 |
| 3 | 87.04 | 87.02 |
| 4 | 89.95 | 90.02 |
| 5 | 87.91 | 87.8 |
| 6 | 87.62 | 87.51 |
| 7 | 86.93 | 86.64 |
| 8 | 88.44 | 88.31 |
| 9 | 89.43 | |
| 10 | 89.7 | 89.72 |
| | | |
| Average | 87.56 | 87.25 |
| Standard Deviation | 3.325 | 3.534 |

**Table 10: CES AC Round Trip Efficiency**

## 5.5. CES Economic Analysis

DNV GL performed two detailed cost effectiveness analyses on the test circuit to evaluate if the CES could be economically justified either as peak shaving deferral or as frequency regulation service. The DTE Energy financial numbers were used in these analyses. The first two sections below discuss each analysis with the full reports in the appendices. The analysis was performed using both new and repurposed battery packs to determine if low cost or free batteries would be an economic solution.

Theses analysis showed that on this particular circuit, the CES could not be economically justified in either peak shaving mode or in frequency regulation services mode in the MISO energy market. A sensitivity analysis of this circuit (using multiple value stream approach) was conducted with EPRI using their EVST tool in effort to determine at what price the CES needed to be at for them to be cost effective on this particular test circuit. The sensitivity analysis is discussed in section 5.5.3.

### 5.5.1. CES Peak Shaving Evaluation

The objective of this use case is to explore the cost-effectiveness of using CES units towards reducing the peak energy demand, or peak shaving with the purpose of deferring capital investment necessary to upgrade a substation. For the purpose of this study, the Trinity circuit was modelled because it features community energy storage (CES) fleet of 17 units aggregately rated at 425 kW / 850 kWh.

The primary benefits of reducing the peak demand are substation capacity upgrade deferral and reducing peak demand charges. Reducing peak demand will also reduce stress on power delivery assets, some of which may be critically loaded. In addition, the distributed CES units allow for more efficient distribution of power and utilization of distributed generation, reducing losses across the system and improving the network voltage profile. These benefits and the costs associated with deploying the CES units were evaluated over a 10-year horizon, considering the units are expected to have an operating life of 10 years. Four scenarios were analyzed as shown in the table 11 below. For each scenario, three configurations were analyzed: No CES units, a fleet of 17 new CES units and a fleet of 17 repurposed CES units.

| Scenario | Description |
|---|---|
| 1 | Default case with 15MVA substation transformer, peak load of 53% that capacity, and a load growth of 0.6%. |
| 2 | Illustrative case with 7.5MVA substation transformer, peak load of 99% that capacity, and a load growth of 0.3%. |
| 3 | Illustrative case with 7.5MVA substation transformer, peak load of 99% that capacity, and a load growth of 0.6%. |
| 4 | Illustrative case with 7.5MVA substation transformer, peak load of 99% that capacity, and a load growth of 0.9%. |

**Table 11: Peak Shaving Test Scenarios**

This report contains the results from analyzing the circuit based on actual load level and substation capacity, referred to as the "Default Case". In order to demonstrate the impact of a 425 kW / 850 kWh CES fleet (17units) deployed on a circuit with similar loading patterns and topology as Trinity along with the sensitivity of load growth to deferral opportunity, three "illustrative Cases" were developed. With everything being the same as the default case, these cases involved reducing the substation capacity by half to a 7.5 MVA unit, and calibrating the load to peak at 99% of that capacity. The same analysis as above was conducted for a load growth of 0.3%, 0.6%, and 0.9%, which is where these three cases differ from each other.

The Trinity test circuit was selected at the beginning of the project because it was the only circuit that had a 500 kW PV system that was required by the proposed project. The Trinity circuit is not a good candidate for substation deferral opportunities because the substation capacity is more than adequate to serve its load for years to come, particularly assuming a tame 0.6% load growth. The illustrative cases assumed a substation loading of roughly 99%. With this assumption in mind, these cases demonstrated the sensitivity of the deferral opportunity to load growth. None of the scenarios exhibited a promising return on investment, as illustrated for the new battery, the repurposed battery with free packs, and the repurposed battery with $3,000 pack.

| Scenario | Configuration | Benefit | Cost | Total NPV |
|---|---|---|---|---|
| 1 | New Pack | $139,342 | -$2,228,166 | -$2,088,824 |
| | $3k Pack | $136,018 | -$1,302,388 | -$1,166,370 |
| | Free Pack | $136,018 | -$992,380 | -$856,362 |
| 2 | New Pack | $563,486 | $2,228,166 | -$1,664,680 |
| | $3k Pack | $560,157 | $1,302,388 | -$742,231 |
| | Free Pack | $560,157 | $992,380 | -$432,223 |
| 3 | New Pack | $328,107 | $2,228,166 | -$1,900,059 |
| | $3k Pack | $324,776 | $1,302,388 | -$977,612 |
| | Free Pack | $324,776 | $992,380 | -$667,604 |
| 4 | New Pack | $232,154 | $2,228,166 | -$1,996,012 |
| | $3k Pack | $228,824 | $1,302,388 | -$1,073,564 |
| | Free Pack | $228,824 | $992,380 | -$763,556 |

**Table 12: Peak Shaving Results**

This analysis demonstrates the sensitivity to circuit load growth and CES cost as can be seen when repurposed batteries are used. In this case, the CES cannot be justified at current pricing for peak shaving only. The complete peak shaving report is in appendix E.

### 5.5.2. CES Frequency Regulation Services Evaluation

The objective of this use case is to explore the cost-effectiveness of using CES units to perform frequency regulation from the distribution system level. For the purpose of this study, the Trinity circuit was modelled because it features a CES fleet of 17 units aggregately rated at 425 kW / 850 kWh. These units were deployed by DTE Energy as a pilot project.

This use case provides a financial assessment of employing the Trinity CES fleet to participate in the Midwest Independent System Operator (MISO) and California Independent System Operator (CAISO) frequency regulation markets. The MISO and CAISO markets rules governing storage participation in the frequency regulation market were reviewed and the operating assumptions employed in the assessment of the Trinity CES fleet are presented. The computed market revenue of the fleet operating the conventional frequency regulation market will be provided along with the impact to network operational performance based on this dispatch. These benefits and the costs associated with deploying the CES units are evaluated over a 10-year horizon, considering the units are expected to have an operating life of 10 years.

The financial results for all cases analyzed for the MISO market are presented in table 13.

| Configuration | Benefit | Cost | Total NPV |
|---|---|---|---|
| New pack | $279,113 | $2,264,197 | -$1,985,085 |
| $3K pack | $279,113 | $1,338,419 | -$1,059,307 |
| Free pack | $279,113 | $1,138,251 | -$859,138 |

**Table 13: Comparison of Benefit/Cost for Use Cases for MISO Market**

There is again a large improvement in NPV when moving from the purchases a new units and moving towards free packs. However, for the given storage cost assumptions, market prices are too low to generate sufficient revenue to drive a positive NPV using the fleet for only market services. Therefore, valuing additional primary benefit streams, such as peak shaving or reliability, is required to produce a cost-effective case for the fleet. Frequency regulation services can be sold during periods when the fleet is not needed for these other applications. The market revenue can then be supplemental to those value streams, producing a cost-effective use case for the fleet. Additionally, as MISO market rules evolve with additional storage penetration, new regulation products may emerge for which storage is qualified. These new products may offer additional revenue opportunities for the fleet.

The financial results for all cases analyzed for the CAISO market are presented in table 14.

| Configuration | Benefit | Cost | Total NPV |
|---|---|---|---|
| New Pack | $366,392 | $2,280,026 | -$1,913,634 |
| $3K Pack | $366,392 | $1,354,248 | -$987,856 |
| Free Pack | $366,392 | $1,154,079 | -$787,687 |

**Table 14: Comparison of Benefit/Cost for Use Cases for CAISO Market**

There is again a large improvement in NPV when moving from the purchases a new units and moving towards free packs. However, similar to the MISO cases, for the given storage cost assumptions, market prices are too low to generate sufficient revenue to drive a positive NPV using the fleet for only market services. In the CAISO market, additional revenue can gained by using storage optimally in the regulation up and regulation down markets as well as spinning reserve. Participating in regulation down allows the storage system to obtain payments to offset charging cost or back off a day ahead energy commitment. This additional freedom allows flexible resources such as storage additional revenue opportunities. As in the MISO, case the revenue is not sufficient based on the costs for these early systems. Again, valuing additional primary benefit streams, such as peak shaving or reliability, may produce a cost-effective case for the fleet. The dual use application of both upgrade deferral and market services will be considered in the second round (2016) of the CA Energy Storage procurement targets. It is expected that business model demonstrated for these procurements will open doors in other markets for such arrangements. The market revenue can then be supplemental to those value streams, producing a cost-effective use case for the fleet. Additionally, as CAISO market rules evolve with additional storage penetration, new regulation products may emerge for which storage is qualified. These new products may offer additional revenue opportunities for the fleet. The complete frequency regulation report is in appendix F.

### 5.5.3. EPRI Distributed Energy Storage Sensitivity Analysis

In the last year of the project, DTE Energy collaborated with EPRI to perform sensitivity analysis on the CES project to determine what the CES capital cost needed to be for benefit-to-cost ratio to be break even or > 1. EPRI has developed an innovative method for quantifying the value of grid energy storage that takes into account layered benefits of energy storage. The EPRI Energy Storage Valuation Tool (ESVT) simulation software enables preliminary economic analysis prior to more resource-intensive analytical efforts. Several input sensitivities were tested for their impact on storage cost-effectiveness.

#### 5.5.3.1. ESVT Analysis Scope and Assumptions

The objective of this analysis is to examine and perform sensitivity analysis around the applications of CES or distributed energy storage at DTE Energy with the following conditions.

- Include regulation services, deferring capital (substation or distribution upgrade deferral) and some arbitrage based on an MISO LMP price
- Determine the optimal mix of applications and associated target price of storage to achieve benefit-to-cost ratio = 1
- The sensitivities should center on the following assumptions:
  - Initial cost of battery (was $2000-2500/kW, now lower )
  - Use a variety of costs and determine amount of benefits needed to achieve B/C = 1 (breakeven based on iterating deferral upgrade benefits)
  - Range of deferral costs ($2M- 5M)
  - Range of growth rates (1-2%)
  - Include capacity market costs
- The CES storage systems will be modeled as a group, acting as a single 1 MW system with agreed upon operating characteristics defined prior to modeling
- Input used 8760 system load data
- Input used forecasted capacity market number
- Frequency regulation uses 2014 MISO data

- Arbitrage uses 8760 LMP price data from MISO
- The DTE Energy applications run in ESVT will be prioritized as follows:
    - Substation deferral
    - Capacity market
    - LMP based arbitrage
    - Regulation service

#### 5.5.3.2. Model Scenarios

Below are the different scenarios that were run with the ESVT. Note that scenario 3 and 4 targets are to achieve a benefit to cost of approximately one.

| Run | Dist Def | Arbitrage | Freq Reg | Growth Rate | Capital Cost | Upgrade Cost | RT Price |
|---|---|---|---|---|---|---|---|
| 1 | Yes | Yes | Yes | 1% | 1000$/kwh | 5M | Avg |
| 2 | Yes | Yes | Yes | 1% | 1500$/kwh | 5M | Avg |
| 3 | Yes | Yes | Yes | 1% | 1000$/kwh | Target to B/C~1 | Avg |
| 4 | Yes | Yes | Yes | 1% | Target to B/C~1 | 2M | Avg |
| 5 | Yes | Yes | Yes | 2% | 1500$/kwh | 5M | Avg |

**Table 15: Sensitivity Analysis - ESVT Scenarios to Evaluate Benefit/Cost**

In these scenarios, the inputs are varied to determine sensitivities in these areas:

- Load growth rate on feeder
- Capital cost
- Deferral upgrade cost

- The two target B/C~1 scenarios are scenarios 3 and 4:
    - Using $1000/kWh Capital and changing Upgrade Cost – holding growth at 1%
    - Using a low end Upgrade Cost and changing Capital Cost – holding growth at 1% and

### 5.5.3.3. Characterization of the Modeled Feeder - Input Parameters

The two graphs below represent the 2014 load and LMP data used in the EVST analysis. The Trinity circuit is a summer peaking circuit with a peak load of 9 MW and average load of 3.42 MW.

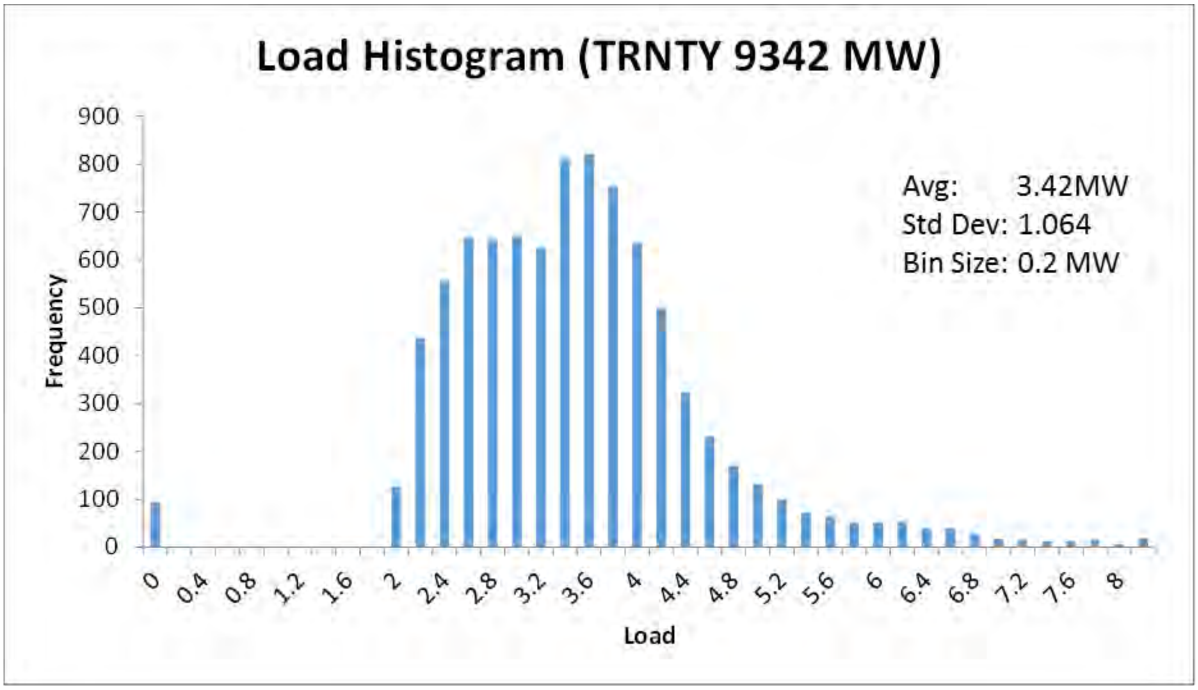



Figure 28: Trinity 2014 Load Histogram

Figure 29 is the 2014 detailed load curve in blue showing that the highest loading occurs in the summer period with a peak of just under 9 MW and average load of 3.42. The LMP curve overlays the load curve and it is interesting to note that the LMP price in 2014did not peak in the summer but rather in the winter. This reflects that the 2014 winter was quite cold and the summer was rather cool. Improvement in the sensitivity analysis can be achieved with temperature correlation taken into account. In this evaluation, temperature was not considered.

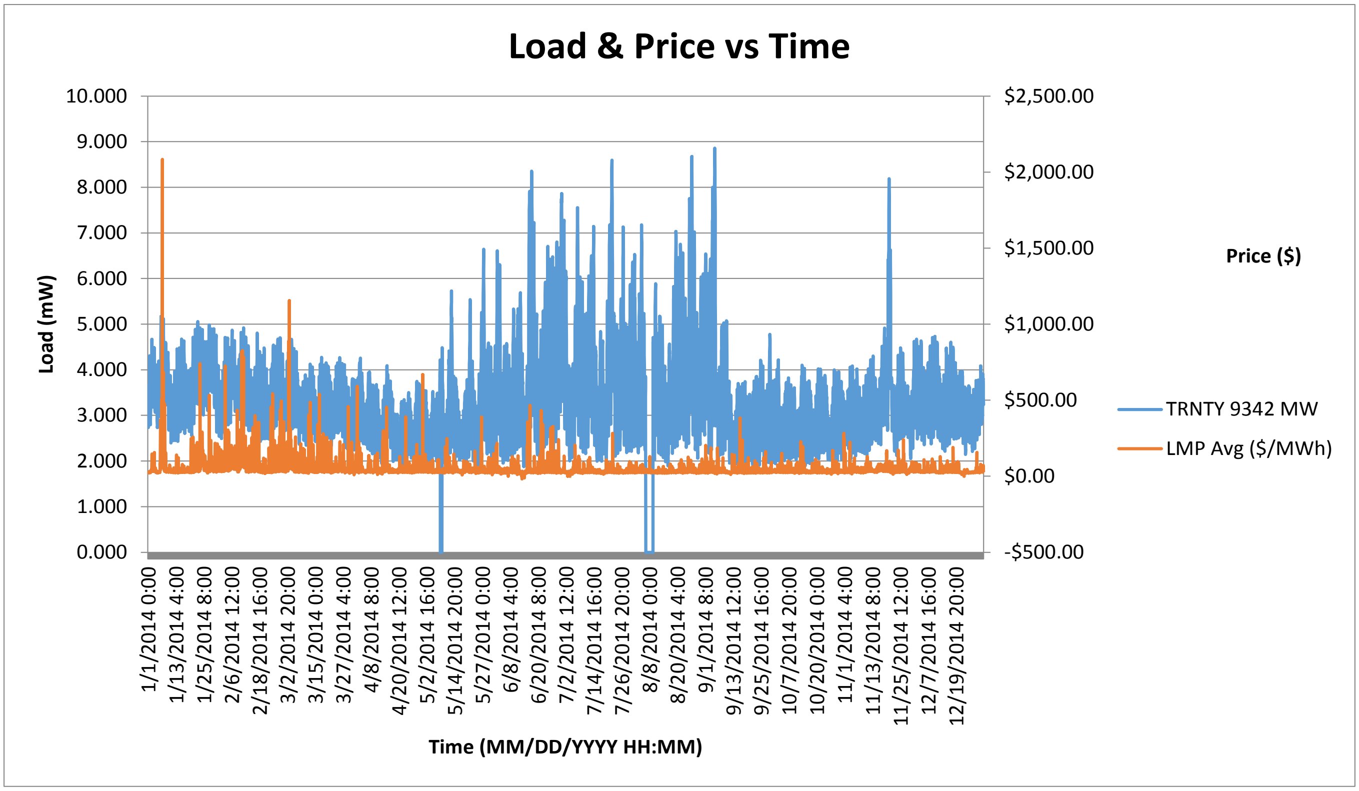



**Figure 29: Trinity 2014 Load (in blue) and LMP Price Graph**

The initial scenarios runs did not include the projected cost of capacity, but was included later. Because it is expected that the capacity market will tighten with retirements of coal plants and increase in renewable energy the forward looking system capacity market cost numbers for this region was included in later runs that are in section 5.5.3.5.

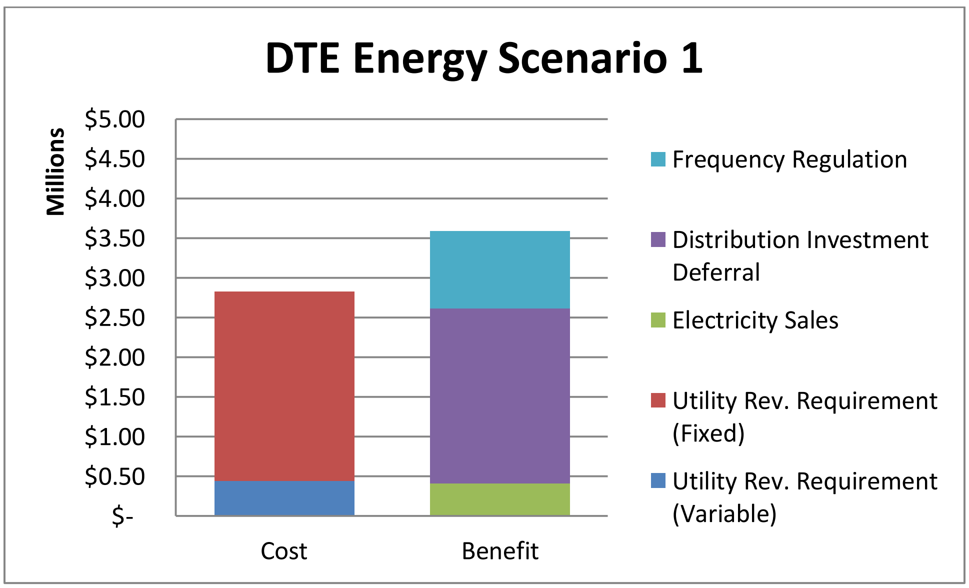
#### 5.5.3.4. Evaluation Result without System Capacity

The first two scenario results are provided below. These have fixed 1% growth rate, two different capital costs and $5M distribution upgrade cost. In run 1 with the capital cost at $1,000/kWh the benefit is greater than the cost while in run 2 where the capital cost is $1,500/kWh the cost is greater than the benefits.

| Run | Dist Def | Arbitrage | Freq Reg | Growth Rate | Capital Cost | Upgrade Cost | RT Price |
|---|---|---|---|---|---|---|---|
| 1 | Yes | Yes | Yes | 1% | 1000$/kwh | 5M | Avg |
| 2 | Yes | Yes | Yes | 1% | 1500$/kwh | 5M | Avg |

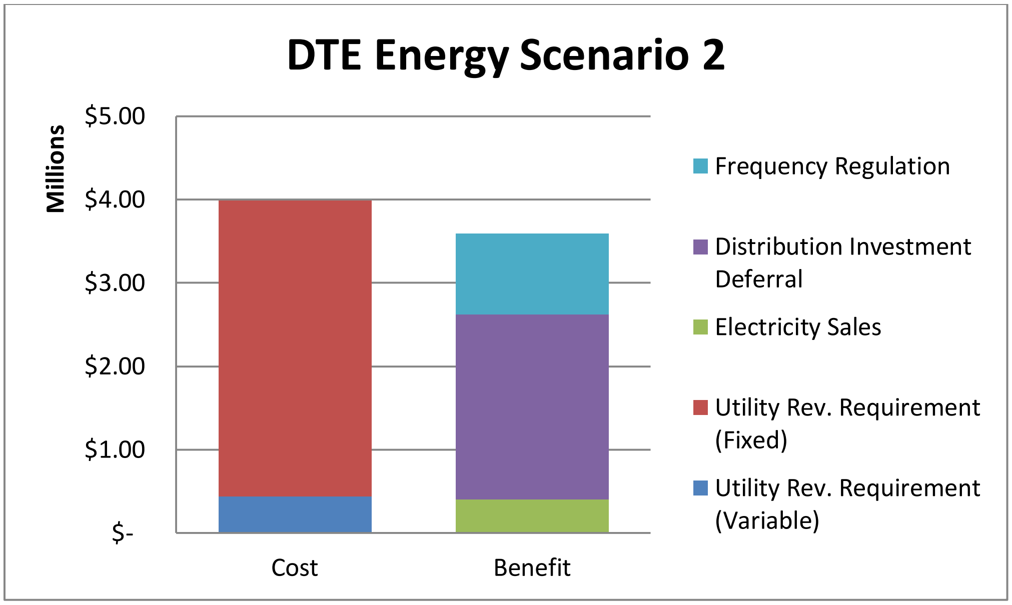
**Scenario 1 Results**

| $1000/kWh - $5M deferral - 1% growth | Cost | Benefit |
|---|---|---|
| Utility Rev. Requirement (Variable) | $ 440,235.01 | $ - |
| Utility Rev. Requirement (Fixed) | $ 2,387,745.67 | $ - |
| Electricity Sales | $ - | $ 406,876.40 |
| Distribution Investment Deferral | $ - | $ 2,213,116.31 |
| Frequency Regulation | $ - | $ 971,096.75 |
| Total | $ 2,827,980.68 | $ 3,591,089.46 |




**Scenario 2 Results**

| $1500/kWh - $5M defferal - 1% growth | Cost | Benefit |
|---|---|---|
| Utility Rev. Requirement (Variable) | $ 440,235.01 | $ - |
| Utility Rev. Requirement (Fixed) | $ 3,549,609.01 | $ - |
| Electricity Sales | $ - | $ 406,876.40 |
| Distribution Investment Deferral | $ - | $ 2,213,116.31 |
| Frequency Regulation | $ - | $ 971,096.75 |
| Total | $ 3,989,844.02 | $ 3,591,089.46 |

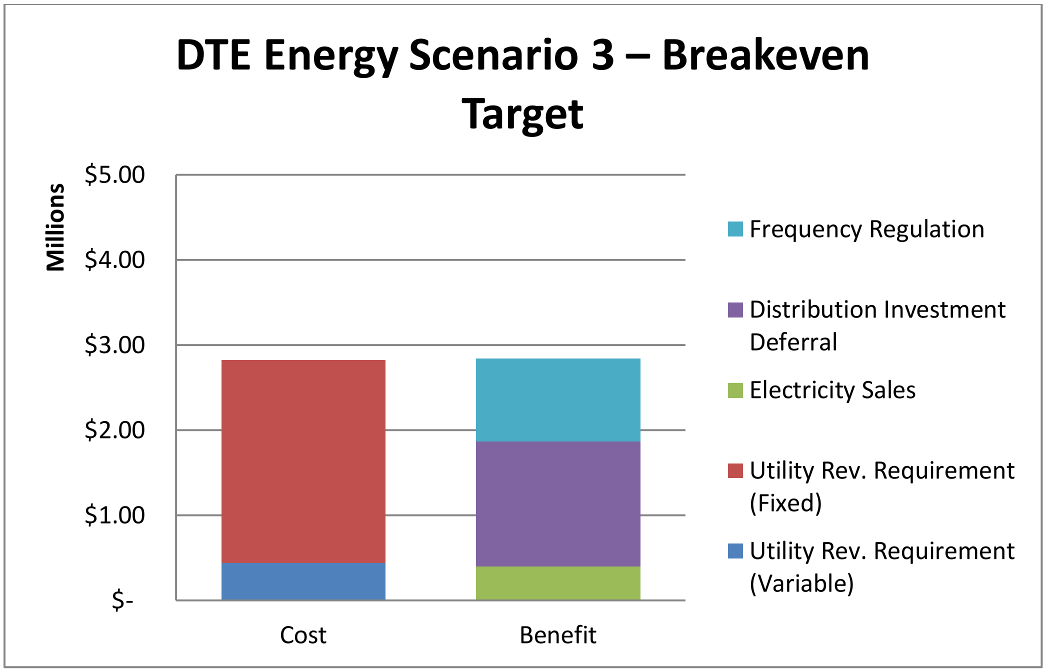



The next two scenarios, numbered 3 and 4, are attempting to identify where a benefit-to-cost (B/C) of ≥ 1 can be realized. These scenarios have fixed 1% growth rate, two different capital costs and distribution upgrade cost to identify how a B/C ≥ 1 can be achieved. In scenario 3, the capital cost is fixed at $1,000/kWh while varying the distribution upgrade cost. In scenario, 4 holding the upgrade cost to $2 M and varying the capital cost.

| Run | Dist Def | Arbitrage | Freq Reg | Growth Rate | Capital Cost | Upgrade Cost | RT Price |
|---|---|---|---|---|---|---|---|
| 3 | Yes | Yes | Yes | 1% | 1000$/kwh | Target to B/C~1 | Avg |
| 4 | Yes | Yes | Yes | 1% | Target to B/C~1 | 2M | Avg |

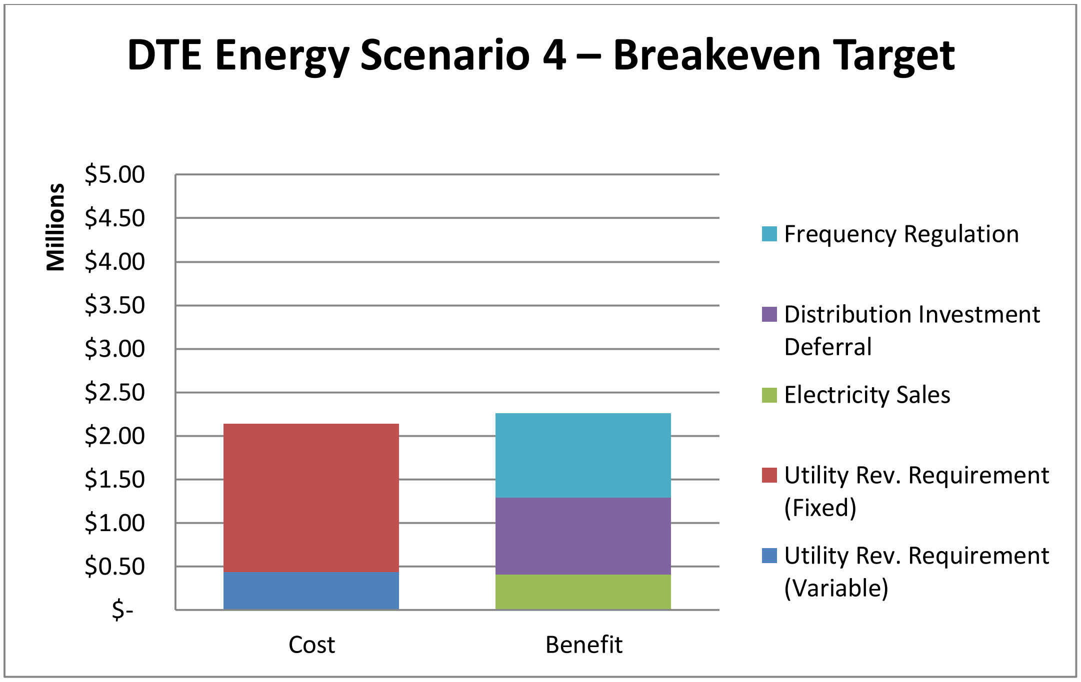
**Scenario 3**

| **$705/kWH - $3M deferral - 1% growth** | Cost | Benefit |
|---|---|---|
| Utility Rev. Requirement (Variable) | $ 440,235.01 | $ - |
| Utility Rev. Requirement (Fixed) | $ 2,387,745.67 | $ - |
| Electricity Sales | $ - | $ 406,876.40 |
| Distribution Investment Deferral | $ - | $ 1,460,656.77 |
| Frequency Regulation | $ - | $ 971,096.75 |
| Total | $ 2,827,980.68 | $ 2,838,629.91 |




**Scenario 4**

| **$750/kWh - $2M defferal - 1% growth** | Cost | Benefit |
|---|---|---|
| Utility Rev. Requirement (Variable) | $ 440,235.01 | $ - |
| Utility Rev. Requirement (Fixed) | $ 1,702,246.30 | $ - |
| Electricity Sales | $ - | $ 406,876.40 |
| Distribution Investment Deferral | $ - | $ 885,246.52 |
| Frequency Regulation | $ - | $ 971,096.75 |
| Total | $ 2,142,481.31 | $ 2,263,219.67 |

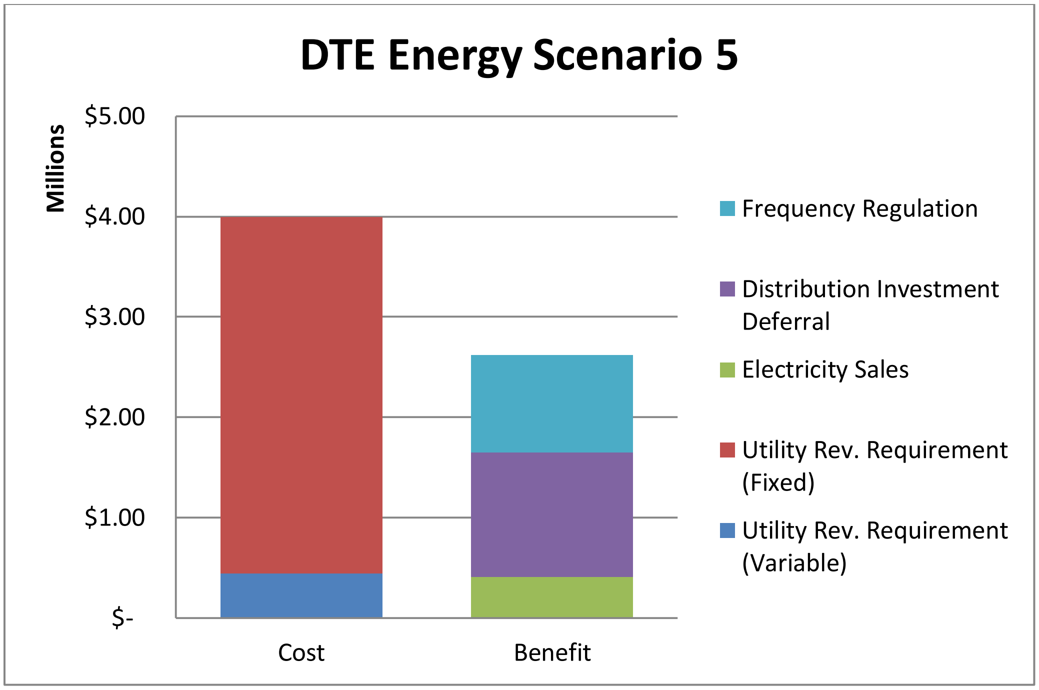



In scenario 5, the load growth rate is increased to 2% from 1% in the other scenarios to see what a more aggressive load growth may have on the economic analysis. The B/C is worse than in scenario 2 because the benefits are less.

| Run | Dist Def | Arbitrage | Freq Reg | Growth Rate | Capital Cost | Upgrade Cost | RT Price |
|---|---|---|---|---|---|---|---|
| 5 | Yes | Yes | Yes | 2% | 1500$/kwh | 5M | Avg |

**Scenario 5**

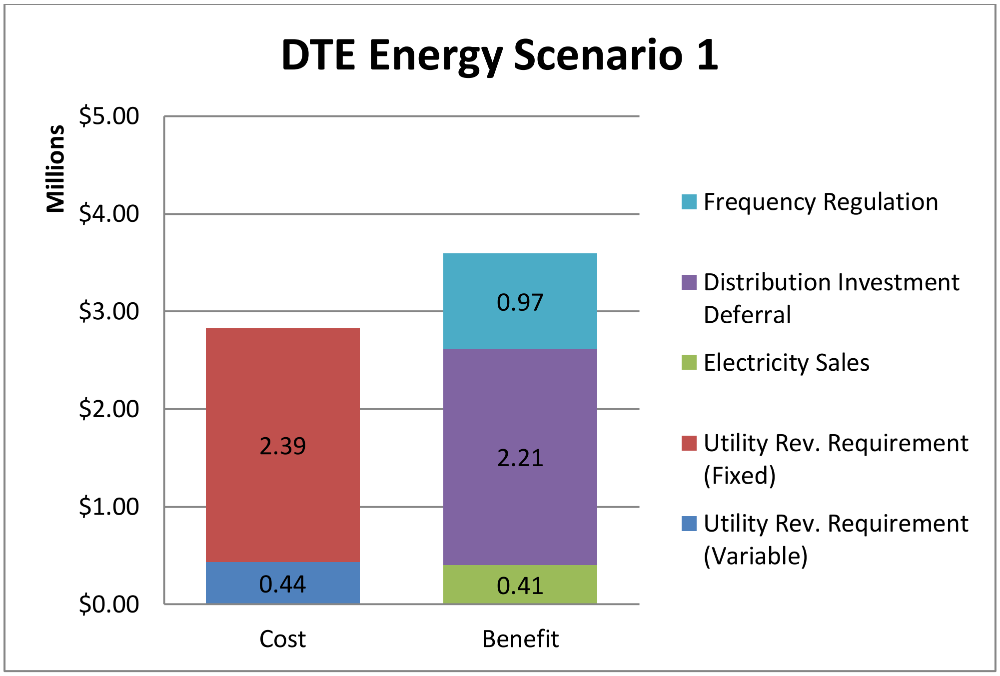
| **$1500/kWh - $5M defferal - 2% growth** | Cost | Benefit |
|---|---|---|
| Utility Rev. Requirement (Variable) | $ 443,045.47 | $ - |
| Utility Rev. Requirement (Fixed) | $ 3,549,609.01 | $ - |
| Electricity Sales | $ - | $ 409,520.23 |
| Distribution Investment Deferral | $ - | $ 1,235,237.30 |
| Frequency Regulation | $ - | $ 974,215.88 |
| Total | $ 3,992,654.49 | $ 2,618,973.41 |



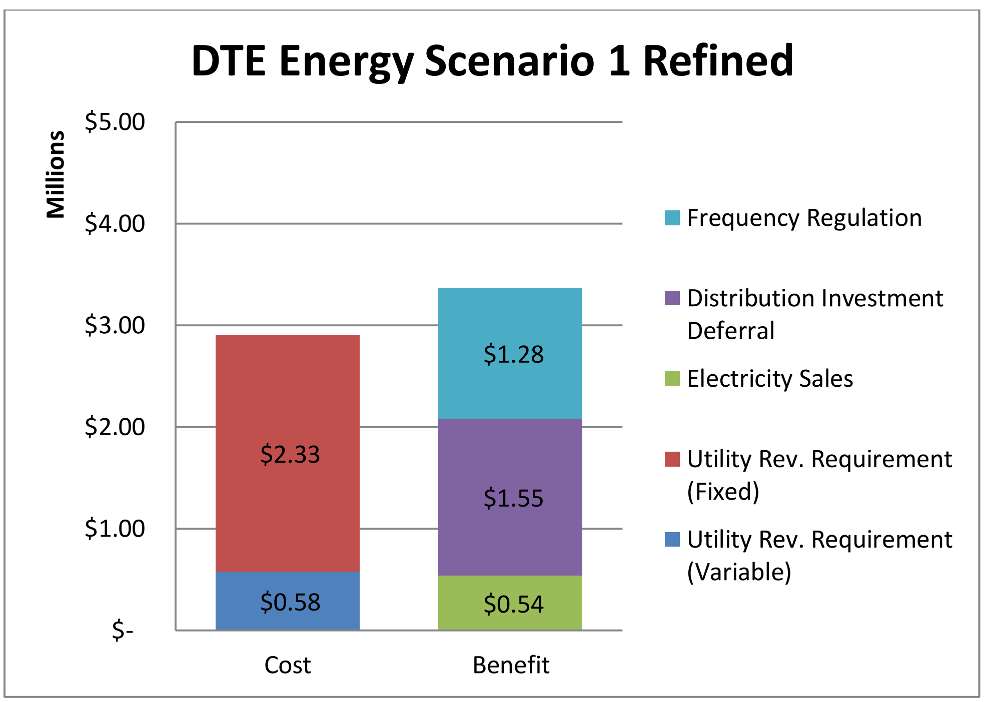

### 5.5.3.5. Evaluation Result with System Capacity

In this section analysis, the value of system capacity was added to the ESVT calculations in addition to a slight refinement in the DTE Energy financial numbers. The three graphs below show scenario 1 calculations. The first graph is a repeat of scenario 1in the previous section above, followed by a run using updated financial number and then the third graph with the cost of capacity added. In reviewing the three graphs, the updated financial graphs show a slight increase in cost and a slight decrease in benefits. There is not much change between those two analyses, but the main driver in the change was a lower discount rate in the financial analysis.

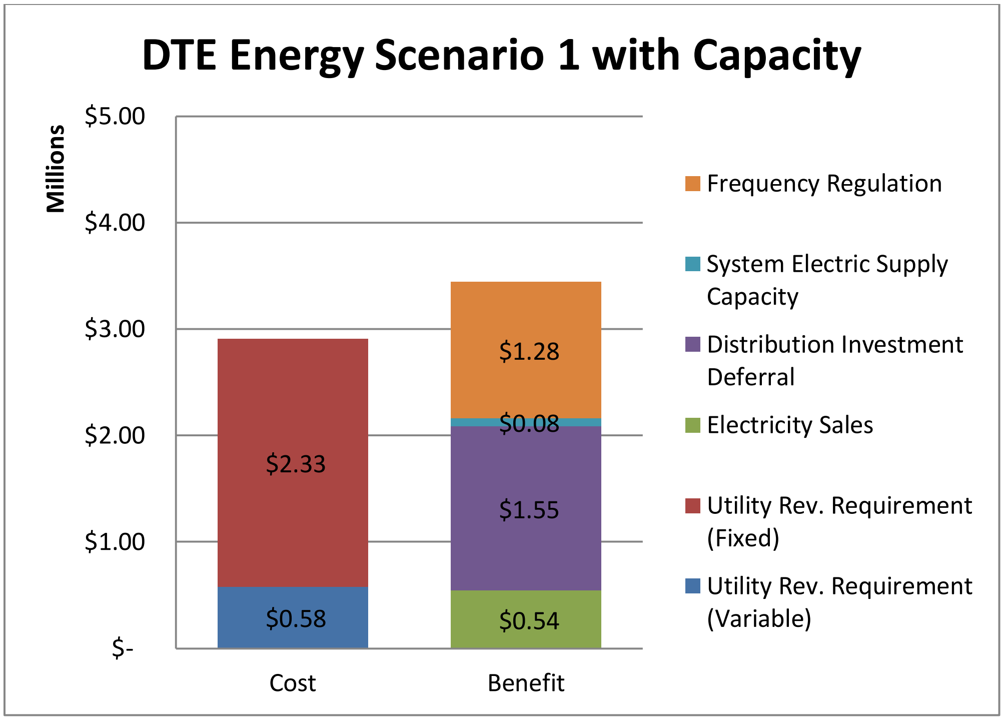
In the third graph below with the cost of capacity added to the financial calculations, you can see a slight increase in benefits shown in the narrow blue band with a value of $0.08M. This is a little surprising to me as I expected to see greater benefits with cost of capacity added.




**Scenario 1: $1000/kWh; 1% growth; $5M Distribution Deferral**




**Scenario 1: $1000/kWh; 1% growth; $5M Distribution Deferral With Update Financial Numbers**




**Scenario 1: $1000/kWh; 1% growth; $5M Distribution Deferral**
**With Updated Financial and System Capacity Cost**

In summary, table 16 below shows the benefit to cost ratio for the scenarios defined in table 15. For a $1,000/kWh battery cost the break even deferral cost is $3.3 M (Run 3) compared to a B/C = 1.3 when the capital upgrade cost is $5.5 M. For a $2 M capital deferral the break-even battery cost is $705/kWh. It should also be noted that higher growth rate diminishes deferral benefits as can be seen in Run 2 and 5. This table shows how the effect of battery capital cost and distribution upgrade cost is clearly a dominant driver for the batteries economics in the distribution grid.

| Run | Dist Def | Arbitrage | Freq Reg | Growth Rate | Capital Cost | Upgrade Cost | RT Price | B/C |
|---|---|---|---|---|---|---|---|---|
| 1 | Yes | Yes | Yes | 1% | 1000$/kwh | 5M | Avg | 1.3 |
| 2 | Yes | Yes | Yes | 1% | 1500$/kwh | 5M | Avg | 0.9 |
| 3 | Yes | Yes | Yes | 1% | 1000$/kwh | 3.3M | Avg | 1.0 |
| 4 | Yes | Yes | Yes | 1% | 705$/kwh | 2M | Avg | 1.1 |
| 5 | Yes | Yes | Yes | 2% | 1500$/kwh | 5M | Avg | 0.7 |

**Table 16: Sensitivity Analysis - ESVT Scenarios Results**

## 5.6. Next Energy Grid Storage Market Evaluation

The Next Energy Grid Storage Market Evaluation report reviews the energy storage "Value Chain" and applications for storage in the electric grid and how it relates to MISO specific analysis.

Throughout the report, several issues and barriers to implementing energy storage were highlighted including the low cost of natural gas, relatively high cost of battery storage, distributed nature of the benefits of storage on the grid and lack of clear benefit value for many of the storage benefits. Some recommendations for action and further concept development are listed below.

- Since it is difficult to get actual data demonstrating the value of energy storage at the community level, this Community Energy Storage demonstration project is critical in that it will supply some of that needed data.
- It would be valuable for the regulating bodies in the states to evaluate the requirements for generation reserve, the capability of storage to meet the requirements for reserve and to coordinate a consistent policy across the states in these areas.
- FERC is actively encouraging all of the ISOs to implement Energy Storage products and to appropriately value response time. This should help in the valuation of potential energy storage projects.
- The Behind the Meter Generation concept should be pursued at least as a concept. Allowing aggregation of assets in this area may allow electric vehicles to be aggregated and participate in this part of the market, but the four-hour requirement will make this difficult.
- Work with regulation bodies to evaluate the reduction of generation reserve requirements and/or allow some mechanism for energy storage to qualify for these requirements.
- Investigate the possibility of allowing energy storage assets to be charged and dis-charged in response to the hourly look-ahead price without the need for bidding as a load / generation device. The assumption here would be that the level of power associated with this activity would be below that which would change the price of power on the system.
- Investigate potential financing models for capitalizing energy storage assets on the grid, potentially similar to performance based energy efficiency contracts such are offered by Energy Service Companies (ESCOs).
- Pursue improved inverter functionality including durability, thermal management and efficiency to improve system performance and round-trip-efficiency of energy storage systems.

The full report is in Appendix B.

## 5.7. CES Application in Military Forward Operating Bases and CONUS

This report describes how advanced technologies, including energy storage and alternative energy generation as deployed in a Forward Operating Base (FOB), can improve base functionality and at the same time, conserve fuel. Application of these technologies to a Continental United States (CONUS) base is also feasible, and would demonstrate similar advantages. An analytical model is developed which integrates load profile data for several specific functions in the FOB environment, conventional generation assets, and "advanced technologies" including alternative generation and storage assets. Comparison of fuel usage is calculated for the initial base case, and for various implementations of storage and alternative generation assets which defines a "sensitivity analysis" for each of these parameters. Net Present Savings (NPS) is calculated for various implementations of "new technology" assets. For a very conservative set of assumptions, a NPS of $230,698 is demonstrated for implementing energy storage during a single six-month deployment in the FOB environment. The complete report is in appendix C.

## 5.8. Aged Battery Analysis

The main purpose of the test was to evaluate the performance of the aged battery against the results from the test of new battery. Since the battery pack is the same model Kokam battery as in the test in 2012, this test plan is tailored to focus on the key items that can be compared.

In 2012, there were 10 cycles of round trip efficiency test performed with both AC and DC side efficiency calculated. This test plan design is to repeat the exact procedure.

During the continuous cycling and peak shaving profile test, no issues or faults occurred. The battery nameplate states a 53 kWh rated capacity and testing showed that it was able to provide this capacity with over 95% DC and 87% AC efficiency. As for the peak shaving test, the battery also successfully maintained the discharge power for the intended duration without reaching 0% state of charge. Overall, there were no observed sign of aging or degradation. The full report is in appendix G.

# 6. Conclusions and Lessons Learned

This section is a high-level summary of the five-year CES project that successfully brought to market and demonstrated a 25 kW/50 kWh distributed energy system in a utility application. Some of the major challenges associated with this project included the maturity of the technology and the early stage technology companies assembled. First, because the battery industry is still relatively new, there are companies that are going through growing pains and failures as the market matures which is reflected in the change of suppliers in this project. Secondly, bringing an integrated energy storage system composed of battery cells and BMS that interfaces to a smart inverter system that can operate autonomously and communicate to a utility operation center for additional functionality is a complex task.

Even though all components were developed, the integrated system needed to be created, tested, and deployed in an electric utility grid and operate in all harsh environmental conditions ranging from severe winters to hot steamy wet lightning induced summers. This successful demonstration project created a complex CES system and demonstrated its installation and application at DTE Energy. One of the outcomes in this project is a robust marketable CES product that other electric utilities are able to deploy.

## 6.1. Cost Benefit Analysis

To achieve a benefit to cost ratio of greater than one when deploying distributed energy storage or CES is dependent on the energy storage location and its application. For a distribution utility, the application of distributed energy storage will be driven by improvements in reliability and deferral of distribution investment. To help justify the application of storage, having a market mechanism in place to gain additional economic value helps justify the energy storage investment

The cost benefit analysis showed that on this particular circuit, the CES could not be economically justified in either peak shaving mode or in frequency regulation services mode in the MISO energy market. This is due to the low growth rate and low cost of distribution upgrade of $100/kW in this scenario. A sensitivity analysis of this circuit (using multiple value stream approach) was conducted with EPRI using their Energy Storage Valuation Tool (ESVT) tool in effort to determine at what capital cost the CES needed to be at for them to be cost effective on this particular test circuit with range of distribution upgrade cost.

The EVST sensitivity analysis, taking into account layered benefits, determined what the CES capital cost needed to be for benefit-to-cost ratio to be break even or > 1. The table below is a summary of the ESVT run showing that in scenario 3 and 4 the benefit-to-cost ratio is ≥ 1.0.

| Run | Dist Def | Arbitrage | Freq Reg | Growth Rate | Capital Cost | Upgrade Cost | RT Price | B/C |
|---|---|---|---|---|---|---|---|---|
| 1 | Yes | Yes | Yes | 1% | 1000$/kwh | 5M | Avg | 1.3 |
| 2 | Yes | Yes | Yes | 1% | 1500$/kwh | 5M | Avg | 0.9 |
| 3 | Yes | Yes | Yes | 1% | 1000$/kwh | 3.3M | Avg | 1.0 |
| 4 | Yes | Yes | Yes | 1% | 705$/kwh | 2M | Avg | 1.1 |
| 5 | Yes | Yes | Yes | 2% | 1500$/kwh | 5M | Avg | 0.7 |

**Table 17: Summary of Sensitivity Analysis using EPRI's ESVT Tool**

The ESVT is the type simulation software that enables preliminary economic analysis to be performed by electric utility engineers as they evaluate solution to a problem they are trying to solve. One additional value that was not considered in this project is the value of reliability to customer. If electric utilities can put a value on reliability, it will increase the value of distributed energy storage because it is located close to its customers. The value of reliability can be included in tools like the ESVT

An interesting observation from the cost analysis is that the projected MISO cost of capacity did not add much to the benefit side of the analysis. This was evident in section 5.5.3.5 with the cost of capacity added to the financial calculations with only about 1% increase in benefits.

A tool like the EPRI energy storage evaluation tool (ESVT) is useful to perform analysis to determine how the layered benefits stack up on the benefits side of the equation. This invaluable tool allows the planning engineers to determine the economic value of using energy storage in the grid using individual companies' financial numbers.

## 6.2. Lessons Learned

This project successfully demonstrated an early stage CES system and cleaned up most of the early stage failures that normally accompany new products. Even though the CESs successfully passed factory acceptance test and fixed all know issues (software and hardware), once the system was deployed in the field, many additional issues surfaced that needed to be addressed and fixed. The CES that can now be acquired by utilities have become a more reliable product because of this project.

The refurbished batteries, due to lower cell cost, can be an economic solution but due to the number of cell failures in the battery modules, the reliability of the system is in question. A more complex repurposed battery system would need to be developed that could isolate individual battery modules, but at an increased cost. This project did not perform analysis on the bad battery cells, but the failures can be attributed to any number of causes. For example, the failures could be due to the EV packs being early prototype system or the harsh driving environment the EVs were subjected to when the prototype vehicles were being tested. It is interesting to note that FCA, DNV GL and eCamion tested all six EV packs prior to them being repurposed without any signs of unexpected capacity degradation or failures.

Below is a bullet list of some of the key lessons learned during this demonstration project:

- Circuit modeling tools for siting evaluation is important
- Layered benefits are required to justify energy storage projects
- An energy storage evaluation software is an important tool for performing cost analysis that can include multiple value streams
- Engaging all groups early within the utility, especially engineering and field resources is important
- Having a product that meets applicable IEEE standards is important
- Integrating distributed energy storage into DTE Energy was accomplished in a manner similar to any new technology being introduced
- It's important to have a DERMS to effectively manage distributed assets
- It's important to have a DERMS to optimally dispatch CESs to gain the greatest economic value for distributed energy storage
- A dispatch algorithm integrated into DERMS is required to gain greatest economic value for energy storage
- Autonomous dispatching using a DERMS and preferably a circuit model is required for day-to-day operation
- Repurposed EV batteries may not be an economic solution due to higher cell failure rate. This needs further studies

### 6.3. Conclusion and Future Plans

Energy storage will have a role to play in the distribution grid of the future. The cost benefit analysis shows that in the right situation, energy storage is a tool that can be justified on economics depending on where its application is. This is evident in the sensitivity analysis where a battery capital cost of $705/kWh can justify a distributed energy project.  Because this demonstration project was using early development battery system cost over $2,000/kWh the economics could not be justified, but with decreasing cost, I expect that by 2020 distributed energy storage will be an economical solution in certain projects.

DTE Energy will continue to use the CESs in the grid to gain additional operating data, especially with regards to reliability.

Because of the high failure rate of the refurbished batteries, they will be decommissioned. There has been interest by Michigan Universities in receiving the refurbished batteries for their energy storage laboratories to be used by engineering students.

If repurposed EV batteries are to be considered in grid applications, additional research and demonstration projects need to be conducted to determine their reliability and system cost.

# Appendix A: Glossary of Abbreviations

| | |
|---|---|
| AC | Alternate Current |
| AGC | Automatic Generator Control used in regulation services |
| AMI | Advanced Metering Infrastructure |
| APN | Access Point Network |
| B/C | Benefit to Cost ratio |
| BESS | Battery Energy Storage System |
| BMS | Battery Management System |
| Cal ISO | California Independent System Operator |
| CAN bus | Controller area network – message bused used in vehicles |
| CB | Circuit Breaker |
| CES | Community Energy Storage |
| DAS | Data Acquisition System |
| DC | Direct Current |
| DERMS | Distributed Energy Resource Management System |
| DESS | Distributed Energy Storage System |
| DEW | Distributed Engineering Workstation |
| DoD | Department of Defense |
| DOE | Department of Energy |
| DR-SOC Hub | Software to monitor and dispatch the fleet of CES units |
| DTE | DTE Energy Company |
| EDD | Electric Distribution Design |
| EEM Suite | The suite of software currently used by DR-SOC to monitor and control distributed generation assets |
| EPRI | Electric Power Research Institute |
| ESVT | Energy Storage Evaluation Tool |
| ICCP | Inter Control Center Protocol |
| Li-ion | Lithium ion |
| LMP | Locational Marginal Pricing |
| MCCC | Monroe County Community College |
| MISO | Midcontinent Independent System Operator |
| NPV | Net Present Value |
| OE | Office of Electricity |
| PCS | Power Conditioning System |
| PV | Photovoltaic |
| R.T. | Real Time |
| S&C | S&C Electric Company |
| SOC or SoC | State of Charge |
| TLA | Transformer Load Analysis |
| UDP | User Datagram Protocol |

# Appendix B: Grid Storage Market Evaluation Report

# Grid Energy Storage Market Evaluation Report

Prepared for DTE Energy

December 2012

DOE Recovery Act – Smart Grid Demonstration Project (DE-OE0000229)

Submitted by:

**NextEnergy Center (NEC)**
461 Burroughs Street
Detroit, MI 48202

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# Grid Energy Storage Market Evaluation Report

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# Grid Energy Storage Market Evaluation Report

## I. Introduction

The purpose of this Grid Energy Storage Market Evaluation Report is to assess the current market competitiveness of energy storage technologies/systems and to project market potential. Factors that significantly impact the market are considered, including the regulatory environment and other governmental policies that help or hinder the market. To develop this report research performed included a literature review of the existing, relevant body of work related to U.S. market status and potential for energy storage solutions, and conversations with several stakeholders in the energy storage, transmission and distributions sectors.

### A. Applications and Benefits of Energy Storage

Energy storage solutions assist in the efficient delivery of electricity to end-users. Applications for storage solutions range from small systems located at the user site to very large commercial installations located at the generation site. The technological benefit of storage associated with generation is its ability to equalize unscheduled variations in electricity generation, as with renewable energy generation dependent on availability of sunshine or wind. In the case of load related storage, the technological benefit is its ability to smooth out variations that occur either cyclically or randomly. In either case, generation must equal load, and a smooth power profile for both generation and load can reduce stress on the transmission and distribution system. Storage can also provide financial benefits such as arbitrage (buying/producing energy at a lower cost and selling electricity at a higher price).

Figure 1: Categorization of Storage Applications

| Category 1 — Electric Supply |
|---|
| 1. Electric Energy Time-shift |
| 2. Electric Supply Capacity |
| **Category 2 — Ancillary Services** |
| 3. Load Following |
| 4. Area Regulation |
| 5. Electric Supply Reserve Capacity |
| 6. Voltage Support |
| **Category 3 — Grid System** |
| 7. Transmission Support |
| 8. Transmission Congestion Relief |
| 9. Transmission & Distribution (T&D) Upgrade Deferral |
| 10. Substation On-site Power |
| **Category 4 — End User/Utility Customer** |
| 11. Time-of-use (TOU) Energy Cost Management |
| 12. Demand Charge Management |
| 13. Electric Service Reliability |
| 14. Electric Service Power Quality |
| **Category 5 — Renewables Integration** |
| 15. Renewables Energy Time-shift |
| 16. Renewables Capacity Firming |
| 17. Wind Generation Grid Integration |

Sandia National Laboratories studied the market potential for various energy storage applications in 2010.[1] The study's data offers a relevant picture of what have consistently been the most promising storage applications in recent years. Sandia categorized 17 storage applications into five groupings, as shown in Figure 1. This grouping is relevant for understanding the most appropriate

[1] Sandia Report "Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide" (SAND2010-0815)

uses of the various solutions. Figure 2, below, is also excerpted from this Sandia study and shows 10-year financial benefits and maximum U.S. market potential estimates for various energy storage applications.

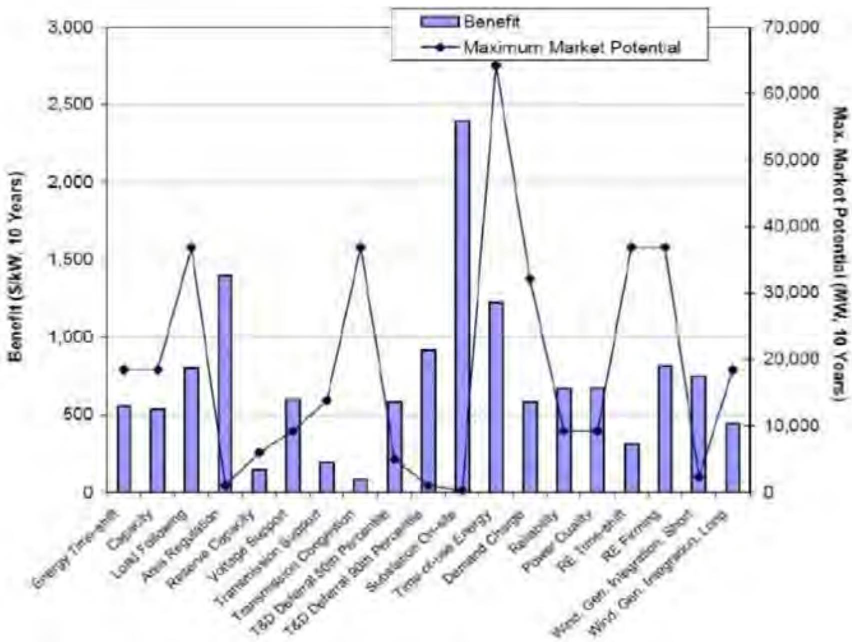



Figure 2: Market potential for different energy storage applications

The benefit indicates the value, or the present worth of the respective application, for 10 years (2.5% inflation, 10% discount rate). The maximum market potential is shown as the anticipated amount of capacity of various storage solutions based on the respective benefit over 10 years.

Major opportunities listed in order of market potential are:
(In $Millions which = average benefit * 10 year potential)

| | | |
|---|---|---|
| 1. | Time-of-use Energy Cost Management | 78,743 |
| 2. | Renewables Capacity Firming | 29,909 |
| 3. | Load Following | 29,467 |
| 4. | Demand Charge Management | 18,695 |
| 5. | Renewables Time Shift | 11,455 |
| 6. | Electric Energy Time Shift | 10,129 |

## B. Distributed and Community Energy Storage

Distributed and Community energy storage generally refer to storage on the load side of the grid but on the utility side of the meter. Distributed storage can be at the distribution voltage level or below while community storage is on the neighborhood side of the distribution transformer at the 120/240 volt level. The system benefit of community energy storage is in its ability to enhance reliability, compensate for the variability of distributed renewable resources (e.g. roof top solar PV), and provide a source of back-up power during grid events for residential, commercial and industrial customers. Its economic benefit lies in its ability to reduce required capital investment by flattening peak loads.

Summarized, #s 1, 3, 4, & 6 in the list above could be considered "community" storage. Distributed storage and some additional community energy storage applications in Figure 2, including Substation On-Site Power, Electric Service Reliability and Power Quality, Voltage Support, and Area Regulation are shown, for a total additional benefit of $19.83 Billion USD. In this report, Sandia also does point out that, "care must be used when aggregating specific benefits and market potential values because there may be technical and/or operational conflicts, and/or institutional barriers may hinder or even preclude aggregation." This is the case as stands in the US energy storage market, as will be discussed in section II, B.

## C. Energy Storage Technologies

A variety of energy storage technologies exist to meet specific needs for efficient management, and while energy storage adoption beyond pumped hydro storage is relatively small, several technologies have been successfully deployed. Note that the implementation of energy storage requires both the actual energy storage itself and the electrical interface to the grid at the appropriate voltage and frequency. The chart below[2] (Figure 3), lists various types of energy storage solutions generally regarded as appropriate for disparate grid applications.

[2] Figure 3 is excerpted from the EPRI White Paper "Electricity Energy Storage Technology Options" (EPRI 1020676)

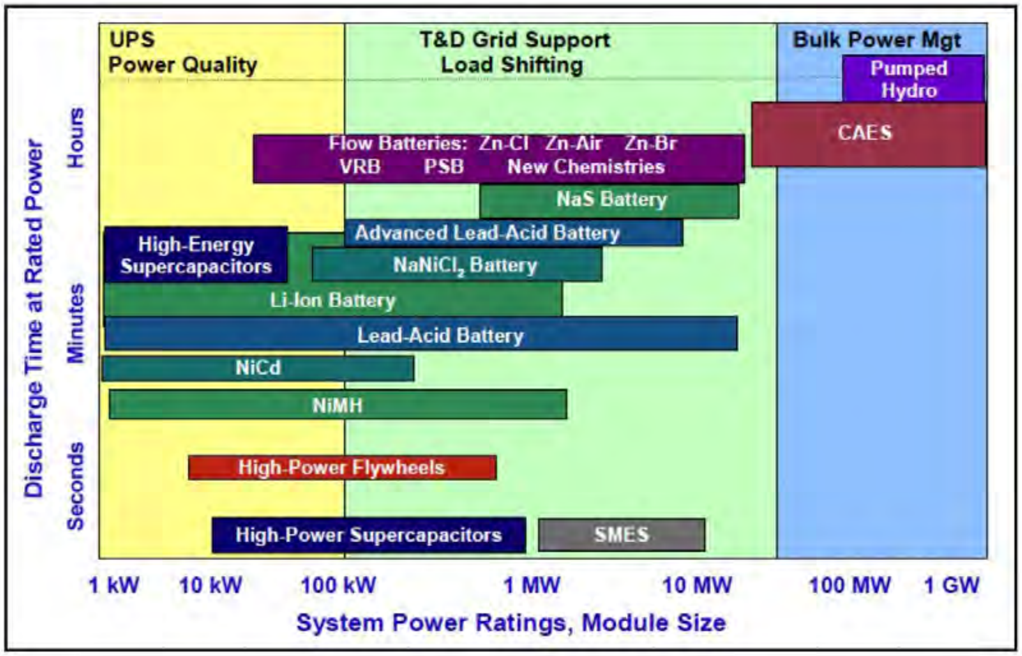



Figure 3: Positioning of Energy Storage Technologies

Figure 4 shows installed worldwide capacity of different energy storage technologies as of 2011. A 2012 EPRI summary lists several (>20) demonstration projects planned or implemented ranging in size from a 5kW Li-Ion installation to a 145MW CAES facility. Locations for these projects are distributed across the country, but are concentrated on the coasts.

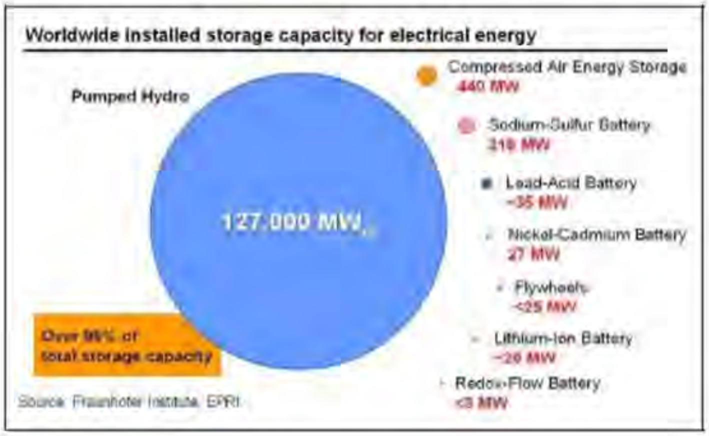



Figure 4: Installed energy storage capacity (Fraunhofer Institute, EPRI 2011)

## II. Obstacles to Energy Storage Implementation

One of the chief problems with widespread adoption of energy storage solutions on the grid is that in many cases a positive business case (cost vs. value) is lacking. Storage solutions must compete with non-storage alternatives that are often more economical. This poor business case is primarily a result of two types of obstacles:

A. Cost Obstacles
B. Regulatory Obstacles

### A. Cost Obstacles

Accurate, up-to-date evaluations of cost are critical to a defensible energy storage business case, but are difficult to obtain. A review of existing research on energy storage business case highlights the cost obstacle and acknowledges the challenges in appropriate evaluation, as well as the costs for status-quo technologies with which storage must compete.

Sandia National Laboratory, EPRI and others have done extensive cost analysis on various energy storage devices. Results from the Sandia 2010 study are shown in the table below.

Life-cycle cost factors included in the analysis of energy storage options are[3]:

- Capital cost of the energy storage and power conversion devices
- Energy loss due to round-trip inefficiency of the system
- Maintenance of the system including cycle life and replacement costs

These costs taken together with the benefits discussed earlier can produce a Net Present Value (NPV) for the investment. The table below describes the NPV ($/kW) of the asset, to both the grid and the customer. Service life is assumed to be 10 years.

| Technology/Use | Advanced Lead-acid Battery | Na/S (7.2 hr) | Zn/Br | V-redox | Lead-acid Battery with Carbon-enhanced Electrodes | Li-ion | CAES (8 hrs) | Pumped Hydro (8 hrs) | High-speed Flywheel (15 min) | Supercap (1 min) |
|---|---|---|---|---|---|---|---|---|---|---|
| Long-duration storage frequent discharge | 2839.26 | 2527.97 | 2518.03 | 3279.34 | 2017.87 | 2899.41 | 1470.10 | 2399.90 | | |
| Long-duration storage, infrequent discharge | 1620.37 | 2438.97 | 1617.62 | 2701.41 | 1559.57 | 2442.79 | | | | |
| Short-duration storage, frequent discharge | 1299.70 | | 905.53 | 1459.85 | 669.85 | 1409.99 | | | 965.73 | 834.62 |
| Short-duration storage, infrequent discharge | 704.18 | | 697.78 | 999.78 | 825.57 | 960.48 | | | 922.87 | 793.02 |

Table 1: Net present value ($/kW) of the asset based on use (Sandia National Labs - SAND2011-2730)

Note that in this assessment, net present value is positive, showing that costs compared to value suggest a positive business case for energy storage.

A cost comparison study by EPRI released in late 2010 both differentiates between applications and includes comparison to Combined Cycle Gas Turbine (CCGT) generation costs. Graphs from this study compare levelized costs of energy coming from storage devices to energy coming from CCGT (figures 5 and 6). To account for the challenges in appropriately evaluating cost for energy storage technologies, EPRI uses two separate graphs in comparing CCGT to certain storage applications (Renewable Integration/Time Shifting, Regulation, and Transmission & Distribution (T&D) Grid support).

EPRI's explanation of the differences in units between figures 5 and 6, highlight challenges in appropriately evaluating cost:

> *"An alternative basis for comparing different energy technologies is to divide the total costs to construct, finance, operate and maintain a plant by its useful output. The costs are levelized*

[3] Note that cost of equipment disposal at end of useful life is not considered in the Sandia report referenced.

*using the cost of capital or discount rate to calculate a flat cost for energy ($/kWh) and capacity ($/kW-Yr.) over the life of the plant. For generation assets, the primary basis for comparison is the levelized cost of energy in $/kWh. The cost or value of capacity is levelized on an annual basis and expressed as $/kW-Yr. Capacity cost represents the cost of a plant being available to provide electric generation whether or not it actually operates, analogous to an insurance premium."*

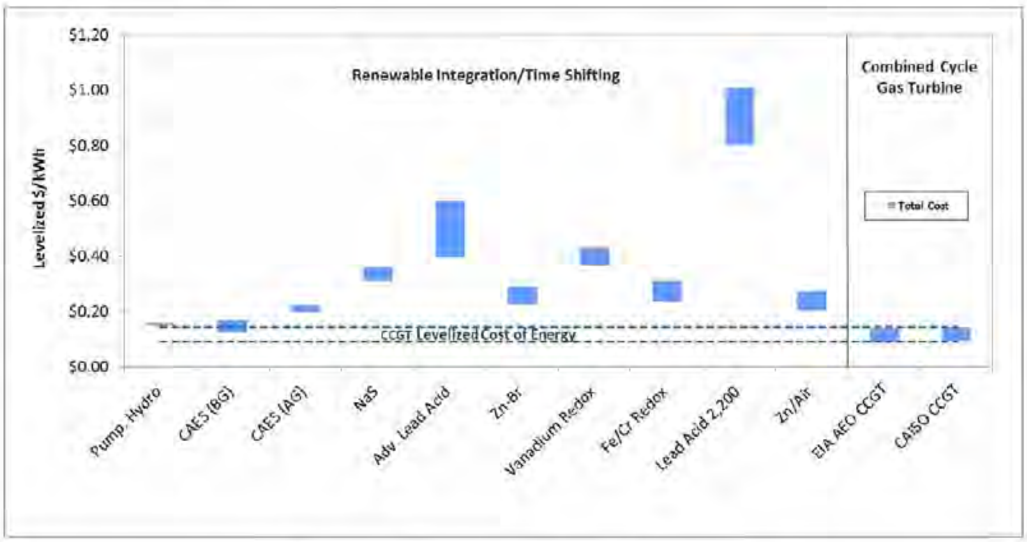



Figure 5: Cost comparison on ***energy*** basis (EPRI 1020676)

For the application of renewable integration and time shifting (arbitrage), the energy storage options do not compare favorably on a levelized cost of energy basis (figure 5). Many of the technologies closest to competing are well known, mature, large-scale technologies, such as pumped hydro and compressed air energy storage (Below Ground).

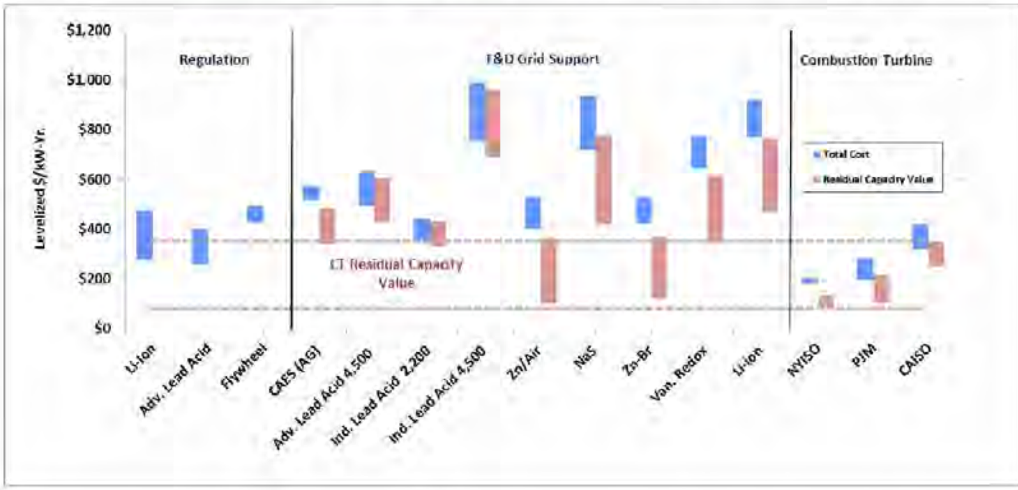



Figure 6: Cost comparison on *capacity* basis (EPRI 1020676)

Residual capacity refers to a plant earning additional revenue in energy and ancillary service markets throughout the year when it is economical to do so, and is calculated by subtracting the net revenues (or net margins) earned from other markets from the full cost of the plant. When examining the total cost and the residual capacity value for T&D Grid Support, immature battery technologies are the closest to combustion technologies. For regulation applications, mature Lithium Ion and Advanced Lead Acid technologies are the most cost competitive to combustion turbines, with flywheels as the most prominent non-battery technology. When comparing the cost of capacity and residual values of NYISO and PJM, there is little competition between combustion turbines and current, mature battery technologies.

Many of the battery technologies closest to being cost competitive are still immature and are being newly commercialized by a host of companies. These technologies include Zinc Air rechargeable batteries, Iron Chromium hybrid flow batteries and Zinc Bromine redox flow batteries. Examples of more mature battery technologies that are being used for renewables integration and time-shifting are Sodium Sulfur and other Sodium-based batteries, and Advanced Lead Acid. In addition to start-up companies, larger firms are investing into these Sodium-based batteries because of their relatively inexpensive material inputs and technological maturity. For example, General Electric has developed a new line of Sodium Metal Halide batteries that they have branded as Durathon, investing over $200 million dollars to develop for mass production.

For more on this subject, NextEnergy has compiled an analysis of next generation "unconventional batteries," that provides an overview of these battery technologies.

Furthermore, at the time this EPRI study was conducted, the cost of natural gas averaged near $6/Thousand Cubic Foot, about twice today's price (December 2012). The higher cost of natural gas in 2010 has the effect of making storage look more cost competitive with CCGT than it is today, with lower natural gas prices.

The business case for storage also depends on the ability to compete with non-storage alternatives. CCGT and combustion turbines are two alternatives, as illustrated in figures 5 and 6 above. Other alternatives are actual T&D investment, energy efficiency and demand side management.

An assessment by the Cleantech Group in 2011 illustrated the playing field between storage and non-storage alternatives by providing adoption forecast prices for various applications. When a specific technology reaches that forecast price, it will be competitive with current solutions for particular application segments, such as Frequency Regulation/Stability. Table 2 describes the results.

| Application Segment | Market Size (GW) | Cleantech Group Forecast Adoption Price | | Market Participants (storage) | Market Participants (non-storage) |
|---|---|---|---|---|---|
| | | ($/kW) | ($/kWh) | | |
| **Frequency Regulation/ Stability** | 3 | 500-1200[1)] | 500-4000[1)] | • Li-Ion<br>• Flywheel | • T&D Investment (ISO)<br>• Peaker<br>• Demand-Side (ISO and Retail) |
| **T&D Support** | 20 | 300-1100[2)] | 150-800[2)] | • Pb-Acid, Li-Ion, NaS<br>• Flywheel | • T&D Investment<br>• Demand-Side |
| **Renewables Integration** | 50 | 300-1200[3)] | 100-520[3)] | • Pb-Acid, Li-Ion, NaS<br>• CAES, Pumped Hydro<br>• Flow | • Peaker<br>• Other |
| **Arbitrage** | 30 | 100-500[4)] | 70-350[4)] | • Pb-Acid, NaS<br>• Flow<br>• CAES, Pumped Hydro | • Peaker |

Table 2: Adoption forecast prices for various energy storage and non-storage applications (Cleantech Group, 2011)

1) Low end of range applies to 1-hr regulation, high end to 15-min regulation. $/kWh highly skewed by 15-minute duration assumption
2) Investment deferral applications only. Low end applies to distribution, high end to
3) Forecast adoption price point based primarily on this benefit figure
4) Forecast adoption price point based completely on this potential benefit to end user.

Based on the CTG reports, frequency regulation/stability is the most likely early market for energy storage based on the current technology prices and the feasible adoption price of >$500/kW and $500 /kWh. This is also the market that the Federal Energy Regulatory Commission (FERC) has targeted for promotion via regulation, specifically by Order 755 (more in section III). Other markets seem unlikely in terms of present feasibility under all but the highest forecast adoption prices predicted.

The Cleantech Group analysis compares energy storage and demand side management (e.g. energy efficiency and demand-response) in terms of meeting the regulation market and T&D Support. Energy efficiency, on a levelized cost of energy basis, costs between 2.5-3.5 ¢/kWh saved, which is less expensive than any energy storage technology by a wide margin. It is one of the most cost-effective means of addressing electricity market needs in regulation and T&D support.

The indication from the EPRI and CTG reports is that the cost and competitive position of energy storage on the grid is still weak for most application segments and technologies. It is expected that research funding will bring these costs down in the following years. U.S. Department of Energy (DOE) has supported research that seeks the following cost and stability targets within the next 4 years (DOE 2011):

- System capital cost: under $250/kWh
- LCOE cost under 20 cents/kWh/cycle
- System efficiency over 75%
- Cycle life over 4,000 cycles
- Power capital cost under $1,750/kW

The DOE in early 2011 explained that, "As a utility asset, storage technologies are required for a life at least 10 years, often longer, and a deep cycle life (e.g., more than 4,000 cycles). Minimum or no maintenance is preferable." Although improving, long term reliability and durability have not been thoroughly tested. This lack of data is a powerful deterrent to grid adoption, and is currently being addressed by various regional and national pilot projects, including this current DTE energy storage project (see also Section IV).

## B. Regulatory Obstacles

There are elements of the regulatory structure that create obstacles to energy storage that are caused by electricity market construction in four areas:

- T&D deferral
- Ancillary services - Regulation markets
- Market access
- Renewables integration

T&D Deferral:

Currently, it is uncommon to incorporate purchasing new storage into rate-payer rules as an alternative to transmission and distribution upgrades. As discussed by EPRI, and the Boston Consulting Group (BCG) report (Figure 7), using energy storage as a means to defer or substitute investing in costly transmission and distribution upgrades constitutes a large market that exists today. Action on rule-making on this important issue, however, has lagged market value, limiting the ability of utilities to effectively pass-on the cost of purchasing energy storage as a tool to defer T&D investments. Without rule-making that accommodates energy storage, the business case for storage is hindered.

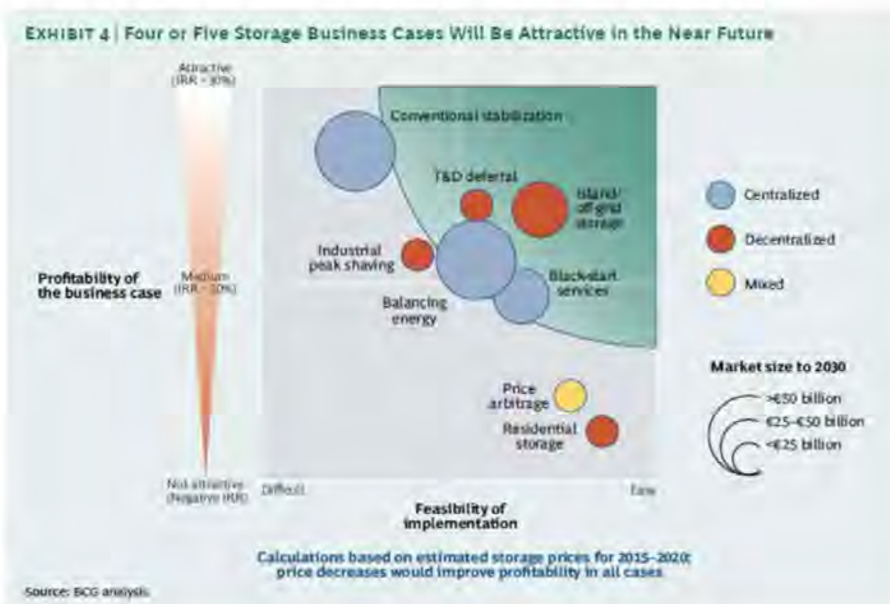



Figure 7: Market Profitability and Implementation Feasibility for Energy Storage Markets (Boston Consulting Group, 2011)

An attractive business case can be made for several storage applications, illustrated in Figure 7. One of these is the T&D Deferral market, which represents a global opportunity of approximately 25 billion euro (approx. $30 billion USD). By this estimation, it is highly profitable and feasible, and is almost entirely untapped in the United States. Regulatory barriers are currently preventing adoption. If addressed, it would represent a new domestic market for energy storage.

Ancillary Services - Regulation Markets:

Previously, a major regulatory barrier was that quick response to market signals in electricity regulation markets had not been compensated for premium performance. This has been addressed by FERC Order 755 in independent system operator (ISO) markets, but has not yet been fully implemented. Each ISO now has an implementation plan for Order 755, ranging from already implemented to implementation within two years (see also Section III). The benefits are not just higher performance in meeting current regulation requirements, but also lowering the total capacity of needed electricity regulation at any given point. Fast response can reduce the amount of regulation because frequency error is a function of the amount (MW) of imbalance and the time it takes to correct the imbalance. Thus, the sooner the frequency error (called Area Control Error or ACE) is corrected, the less amount of regulation is needed.

Market Access:

The regulatory structure also inhibits participation of some energy storage resources from certain markets. The relationship between regulatory restrictions and ISOs is discussed further in Section III. Furthermore, specific recommendations on lowering market access barriers for a more equal playing field will be discussed in the conclusion.

Renewables Integration:

Energy storage is effective in combination with renewable energy generation for two reasons. 1) Renewable resources are intermittent, and to ensure grid reliability, it is helpful to implement back-up assets that can ramp quickly to meet its high variability. 2) The combination of energy storage and renewables allows for maximum value extraction via arbitrage and other benefits.

While this combination is effective, the Renewable Portfolio Standards (RPS) in most states lack incentives for storage in combination with the installation of renewable energy generation. The majority of RPS policies do not prioritize renewable energy development bids based on optimized system implementation, which would benefit storage, but instead procurement processes tend to favor bids based on least cost. This is a major impediment to energy storage implementation in one of its most appropriate applications, renewable energy integration. A more environmentally sustainable solution that would ensure better grid reliability even with the onset of higher RPS would include renewables integrated with energy storage.

## III. Comparison of ISO current status and best practices in the US

### A. FERC Order 755

FERC Order 755 requires all grid operators (RTOs and ISOs) to modify their tariffs to provide for a two-part market-based payment to frequency regulation resources, incorporating the resource speed (performance) and capacity (size), as opposed to just capacity. The capacity (or option) payment is provided for keeping a resource's capacity in reserve in case it is needed to provide real-time frequency regulation. The performance (or movement) payment reflects the power contributed of each resource in real-time. Furthermore, all ISOs and RTOs have to calculate uniform clearing prices that include opportunity costs (reflects the foregone opportunity to participate in the energy or ancillary services market). Before FERC Order 755, a lower performing, slower "peaker" plant could be paid the same price as a fast acting flywheel or battery of the same capacity. FERC's market ruling allows for a more accurate accounting of the value of energy storage, and is considered essential to clarifying the business case for energy storage.

There are significant differences in ISO policies across the country, but nearly all target energy storage as regulating reserve. The policies will become more consistent in the near future as ISOs meet compliance requirements of FERC Order 755.

### B. Best Practices – ISOs / RTOs

Certain ISOs stand out in implementing best practices related to accommodating the participation of energy storage in their markets. Table 3, below, summarizes the major energy storage accommodation initiatives by ISOs.

ERCOT exempts energy storage resources from peak and retail distribution charges, which helps to improve economic viability of the resources. Energy storage resources are also allowed to charge and discharge at the same price while regulating frequency, which removes price risks when bidding into energy markets. Additionally, ERCOT is planning a pilot project, the Fast

Responding Regulation Service (FRRS) to begin in January 2013. In this project, FRRS would be deployed when the system frequency drops below 59.1 Hz or rises above 60.09 Hz. It requires a response time faster than frequency regulation (seconds to minutes) but slower than frequency response (tenths of seconds). FRRS resources must be able to deliver all of their megawatt capacity within one second. This pilot will assist ERCOT in developing market rules and settlement systems similar to the pay-for-performance rules in other ISOs. Note that ERCOT is not bound by FERC Order 755 as it doesn't have an "organized wholesale electricity market"[4].

In CAISO policy, energy storage resources with a minimum capacity of 500 kW are allowed to bid into the regulation markets (see table 3, below). Additionally, AB 2514 directs the California Public Utilities Commission (CPUC) to evaluate procurement targets for new storage capacity. CAISO recently enacted the Regulation Energy Management (REM), which allows greater storage participation in CAISO's ancillary services markets due to the low duration requirement of 15 min. CAISO is also considering implementing Energy Storage Portfolio Standards (ESPS). FERC approved CAISO's Order on Compliance Filing to Order No. 755 in September 2012 and the amendments (e.g. opportunity costs, two-part bidding) will become effective January 1, 2013. There is also grid energy storage testing in the CAISO area, for example a 50 kW / 1hr 40min Lithium-Iron-Phosphate distributed energy storage system that provides peak shaving and PV smoothing. This effort is a collaborative R&D project from EPRI and San Diego Gas & Electric to evaluate the performance and reliability of these grid-connected batteries.

NYISO offers an energy storage product called Limited Energy Storage Resource (LESR). LESRs have an energy output less than one hour and offer regulation as a stand-alone product. NYISO also has (as does MISO) an Energy Storage Tariff (EST), that allows energy storage resources to utilize the energy market to manage their state-of-charge (SOC) so that they can continuously provide regulation. Additionally, NYISO has a 20 MW/15 min flywheel energy storage plant operating in its service area to provide frequency regulation. NYISO's Order on Compliance Filing to Order No. 755 has not yet been accepted by FERC.

ISO-NE has offered a regulation opportunity cost, a capacity payment and a performance payment since 2005. The performance payment, or "mileage payment", reflects the sum of absolute values of movement up or down in response to regulation signals. FERC's required performance payment is largely based on this "mileage payment". Nevertheless ISO-NE's compliance filing with FERC Order 755 will not be implemented until January 2014, due to corresponding changes that will be needed in the energy and capacity markets. ISO-NE also has

[4] From FERC Order No. 755

a 3 MW flywheel pilot project operating in its service area to provide regulation.

PJM allows smaller scale energy storage resources (100 kW to 500 kW) to bid into frequency regulation markets and has demonstrated a high willingness to incorporate energy storage into its markets. The PJM compliance filing to Order 755 was accepted by FERC and became effective October 2012. PJM territory is home to the largest battery energy storage pilot program in the nation, which is a Lithium-Ion Battery energy storage with 32 MW capacity and 15 min duration operated by AES Wind Generation. This pilot has provided frequency regulation since September 2011. PJM also started a regulation services project with an ultra-battery of 3 MW/43 min. It provides frequency regulation services to the grid and it is used for peak demand management services to the local utility, Met-Ed.

MISO policies will be covered in detail in the next section.

Table 3 shows a summary of current energy storage policies in the different ISO's:

| | Size/duration limit for participation in market | Regulating reserve offers (AS Market) | Charge/ discharge | Pay – for - performance | Incentives | Outlook |
|---|---|---|---|---|---|---|
| **MISO** | 1 MW/1 hour | Two – part offer (performance and capacity)* EST[1] | separately | Yes* | Regulation opportunity cost* | |
| **ERCOT** | | | At same price | | exempt from peak / retail charges | FRRS[2] |
| **CAISO** | 500 kW<br>Day- Ahead Regulation up/down: 60 min<br>Real-time Regulation up/down(REM)[3]: 15 min<br>Spin & Non-Spin: 30 min | Two – part offer (performance and capacity)** | separately | Yes** | AB 2514 Regulation opportunity cost** | ESPS[4] |
| **NYISO** | LESR[5]: output ≤ 1hour | LESRs (regulation as stand-alone product) EST | LESRs: no pay for energy (netted against energy they use) | LESRs accuracy component | | |
| **ISO-NE** | | Two – part offer (performance and capacity) | | Yes | Regulation opportunity cost | |
| **PJM** | Frequency Regulation: 100kW to 500kW | Two – part offer (performance and capacity) | | Yes | Regulation opportunity cost | |

Table 3: Summary of current energy storage policies in the different ISO's (NextEnergy)

* Effective on Dec. 17, 2012
** Effective on Jan. 1, 2013

1) EST = Energy Storage Tariff;
2) FRRS = Fast Responding Regulation Service ( Pilot Project)
3) REM = Regulation Energy Management
4) ESPS = Energy Storage Portfolio Standards
5) LESR = Limited Energy Storage Resource

# IV. MISO Current Status

## A. Background

Several sources have indicated that, in the MISO area, there is more generation capacity than load. This "long on capacity" position affects the status of energy storage in many ways. It lessens the cost differential between base and peak generation times, therefore reducing the business case for arbitrage and for reducing peak power demand. Yet, it largely does not affect the business case for fast-response regulation and T&D deferral.

It remains to be seen what the effect will be of U.S. Environmental Protection Agency (EPA) emissions regulations on capacity oversupply in MISO, as coal plants will be taken off-line based on the inability to meet air emissions regulations. It is unlikely that new coal plants will directly replace decommissioned coal plants. If replacement generation capacity is to be developed, the source will be up to debate. Due to the low cost of natural gas, it is anticipated that Combined Cycle Gas Turbines will increase their market share; however to what extent they share this market with renewable energy is yet to be determined. Furthermore, reducing overall demand through demand response and energy efficiency could eliminate the need for full replacement of the decommissioned capacity. The role of energy storage in this transition has yet to be explored.

As an overview of the current status of energy storage on this MISO grid, there are approximately 2,500MW of pumped hydro storage registered in the MISO area, with no other storage technology close to that level of participation.

## B. Renewables Integration

Several industry observers contend that, since the MISO area is "long on generation capacity", renewable generation integration will be driven largely in response to RPS requirements on a state-by-state basis. RPS-driven renewable energy generation requirements in states that MISO serves average 13% by 2020. The current RPS in Michigan requires that all utilities must achieve 10% renewable energy-sourced electricity by 2015. For the largest utility companies in the state this represents: 300 MW renewables by 2013 and 600 MW by 2015 (DTE Energy), 200 MW renewables by 2013 and 500 MW by 2015 (Consumers Energy). As renewable generation increases in the MISO area in response to implementation of RPS requirements, additional energy storage may be required. As discussed earlier, combining energy storage with renewables allows for the highest value combination, if not the lowest initial upfront cost combination. Other options, albeit less cost efficient, exist for grids to back-up renewables. Spain, for example, has implemented a large amount of wind generation, but has deemed it necessary to back-up that "non-dispatchable" generation asset 100% with natural gas generators for times when wind generation is not available.

According to MISO, as of March 2012, 10,779 MW of name-plate rated wind generation existed within the MISO area. The capacity factor for wind generation over the last year has varied from 15% in August 2011 to 43% in January 2012 and averages to around 30% over the last year. If the average MISO load is 60MW, in order to meet the RPS energy generation requirements, and if wind were the only renewable energy source, wind generation capacity would need to increase to around 26GW. This level of intermittent generation may well require energy storage to implement some leveling. MISO does have a Dispatchable Intermittent Resource (DIR) provision for intermittent generation resources that can be automatically controlled in the downward direction.

### C. Current Energy Storage Products in MISO

MISO offers an "Energy Storage Product" as described in their Business Practice document (BPM-002-r11) effective January 13, 2012. This allows a Market Participant (MP) to bid into the Day-Ahead and Real-Time Energy and Operating Reserve Markets. Long-term and short-term assets are defined as >1 hour, or < 1 hour of duration capability, and a minimum of 1 MW capacity is required for the bid.

Parameters for the bid include:

- Hourly regulation minimum and maximum limits
- Hourly maximum charge and discharge rates
- Hourly maximum energy storage level
- Hourly bi-directional ramp rate
- Hourly energy storage loss rate
- Hourly full charge energy withdrawal rate

At least one obstacle to operating an energy storage system under the MISO tariff is that charging and discharging are treated separately. This means that the day-ahead offers for charging and discharging are not linked and this allows for the possibility that when the generation bid clears in the day-ahead market, but the load does not, the storage owner is left committed to provide power at an unknown cost. The cost of power to be supplied becomes unknown because the provider does not know at what price they will need to buy energy to charge the storage system.

For energy storage applications where fast response time is required, like load following, voltage and frequency support, there are new provisions allowing for a premium to be paid to the power provider for rapid response time of the storage asset under FERC Order 755. FERC approved MISO's compliance filing in September 2012, which will become effective on December 17, 2012.[5]

It remains to be seen what impact this new market mechanism will have on energy storage resources in MISO. However, analogous processes in multiple ISO regions (PJM for example) should lead to data and preliminary conclusions leading into 2013 that will provide insight.

As stated earlier, currently, the minimum power level that can be bid in the MISO energy storage product is 1MW. MISO has not planned to offer a "product" to address smaller-scale community energy storage directly. Distributed or Community level projects would be at the sub-station or distribution and feeder level and mostly would be below the power and energy levels at which MISO operates. Integration of these assets would be handled by the Load Servicing Entity (LSE) like DTE Energy or Consumers Energy. The pilot program (DE-OE0000229) for which this paper was funded is an example of what such a program would look like in MISO. DTE is installing 20 community energy storage devices (Li-Ion batteries) with a total capacity of 1 MW and 2 hr. duration. This aggregated system will serve several applications, for example renewables integration, peak shaving and demand response.

MISO BPM-011-r9 addresses Load Modifying Resources, which are classified as either Demand Resource (DR) or Behind the Meter Generation (BTMG). BTMG is defined as a generation resource that is used to serve wholesale or retail load that is located behind a Commercial Pricing Node. There are several requirements for qualifying such assets, including that the asset must be able to respond with less than 12 hour notification and be able to generate power for a minimum of four consecutive hours, but the minimum size is "only" 100 kW and aggregation of smaller resources is allowed. While this BPM is not aimed at energy storage assets, its parameters suggest that an energy storage asset could fulfill these requirements. Discussion with MISO to this end could be valuable.

[5] A full overview of the compliance proceedings can be found at: http://www.ferc.gov/whats-new/comm-meet/2012/092012/E-2.pdf

## V. Recommendations

Throughout the report, several issues and barriers to implementing energy storage have been highlighted. Recommendations for action and further concept development are listed below.

- We recommend MISO lower the capacity tariff to the point at which more market players, including storage, can participate in markets without damaging grid reliability. The current 1 MW capacity limit prevents most energy storage players from participation. Other ISO's have taken strong steps to lower their tariffs. For example, CAISO lowered their capacity limit to 500 kW, and PJM 100 kW for stability/regulation. We understand that the smaller a resource is that is bidding onto the market, the more difficult it is to manage the system. We have also explored another possibility, which is changing capacity rules to allow for greater amounts of aggregation of energy storage resources to bid into the market as a larger resource. Regardless of the particular solution, we think that MISO stakeholders should convene to discuss lowering this tariff in in 2013.
- We recommend that MISO lower the duration tariff for energy storage resources to participate in the market, specifically for frequency regulation. One of the most useful and cost effective applications for energy storage on the electricity grid is frequency regulation. However, the current requirement of 1-hour duration precludes that application, because frequency regulation occurs in short time intervals and acts on the level of seconds to minutes. With the onset of pay for performance requirements from FERC Order 755, we think that reducing this requirement will ensure higher levels of energy storage participation in support of better grid reliability.
- We recommend that for frequency regulation only, there be a provision to have no separate charge or discharge price. Allowing energy storage assets to charge and discharge (regulate up and down) at the same price (compare to ERCOT and NYISO policies) would remove price risks when bidding into energy markets, especially the day-ahead market.
- We recommend that with the implementation of Renewable Portfolio Standards in the state of Michigan, that energy storage be considered for project procurement on the basis of highest-value, in addition to lowest cost. NextEnergy would be interested in discussions to this end with DTE, Consumers Energy, and other stakeholders to research best practices from other ISO's. We consider this as a possibility for follow-up after initial submission of this report. We also believe that a pilot project to this end would be highly valuable in collecting data to demonstrate business model and cost/benefit analysis.
- We recommend MISO and MPSC enable the incorporation of storage into the rate base as a potentially lower cost alternative to transmission and distribution upgrades.

- We recommend that MISO examine the Behind the Meter Generation policy as an opportunity for energy storage participation in the market. Specifically considering aggregation of energy storage assets in vehicle to grid (V2G) power provision with electric vehicles could participate in this market segment. Any examination of this policy would require a re-evaluation of the current four hour requirement, as there would be an inability for V2G to participate.

# ACRONYMS

| | |
|---|---|
| CAISO | California Independent System Operator |
| CCGT | Combined Cycle Gas Turbine |
| DOE | Department of Energy |
| EPA | Environmental Protection Agency |
| EPRI | Electric Power Research Institute |
| ERCOT | Electric Reliability Council of Texas |
| FERC | Federal Energy Regulatory Commission |
| IRR | Internal Rate of Return |
| ISO | Independent System Operator |
| ISO-NE | Independent System Operator New England |
| LCOE | Levelized Cost of Energy/ Electricity |
| MISO | Midwest Independent System Operator |
| NYISO | New York Independent System Operator |
| PJM | Pennsylvania New Jersey Maryland Interconnection LLC |
| PNNL | Pacific Northwest National Laboratories |
| PV | Photovoltaics |
| RE | Renewable Energies |
| RPS | Renewable Portfolio Standards |
| RTO | Regional Transmission Organization |
| T&D | Transmission and Distribution |
| TOU | Time of Use |
| UPS | Uninterruptable Power Supply |

# APPENDIX

Complete "Economics" slide from the Sandia study SAND 2010-0815:

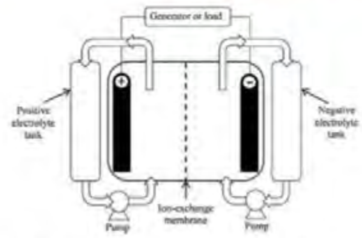
**Table ES-1. Summary of Key Assumptions and Results**

| | | Discharge Duration* | | Capacity (Power: kW, MW) | | Benefit ($/kW)** | | Potential (MW, 10 Years) | | Economy ($Million)† | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| # | Benefit Type | Low | High | Low | High | Low | High | CA | U.S. | CA | U.S. |
| 1 | Electric Energy Time-shift | 2 | 8 | 1 MW | 500 MW | 400 | 700 | 1,445 | 18,417 | 795 | 10,129 |
| 2 | Electric Supply Capacity | 4 | 6 | 1 MW | 500 MW | 359 | 710 | 1,445 | 18,417 | 772 | 9,838 |
| 3 | Load Following | 2 | 4 | 1 MW | 500 MW | 600 | 1,000 | 2,889 | 36,834 | 2,312 | 29,467 |
| 4 | Area Regulation | 15 min. | 30 min. | 1 MW | 40 MW | 785 | 2,010 | 80 | 1,012 | 112 | 1,415 |
| 5 | Electric Supply Reserve Capacity | 1 | 2 | 1 MW | 500 MW | 57 | 225 | 636 | 5,986 | 90 | 844 |
| 6 | Voltage Support | 15 min. | 1 | 1 MW | 10 MW | 400 | | 722 | 9,209 | 433 | 5,525 |
| 7 | Transmission Support | 2 sec. | 5 sec. | 10 MW | 100 MW | 192 | | 1,084 | 13,813 | 208 | 2,646 |
| 8 | Transmission Congestion Relief | 3 | 6 | 1 MW | 100 MW | 31 | 141 | 2,889 | 36,834 | 248 | 3,168 |
| 9.1 | T&D Upgrade Deferral 50th percentile†† | 3 | 6 | 250 kW | 5 MW | 481 | 687 | 386 | 4,986 | 226 | 2,912 |
| 9.2 | T&D Upgrade Deferral 90th percentile†† | 3 | 6 | 250 kW | 2 MW | 759 | 1,079 | 77 | 997 | 71 | 916 |
| 10 | Substation On-site Power | 8 | 16 | 1.5 kW | 5 kW | 1,800 | 3,000 | 20 | 250 | 47 | 600 |
| 11 | Time-of-use Energy Cost Management | 4 | 6 | 1 kW | 1 MW | 1,226 | | 5,038 | 64,228 | 6,177 | 78,743 |
| 12 | Demand Charge Management | 5 | 11 | 50 kW | 10 MW | 582 | | 2,519 | 32,111 | 1,466 | 18,695 |
| 13 | Electric Service Reliability | 5 min. | 1 | 0.2 kW | 10 MW | 359 | 978 | 722 | 9,209 | 483 | 6,154 |
| 14 | Electric Service Power Quality | 10 sec. | 1 min. | 0.2 kW | 10 MW | 359 | 978 | 722 | 9,209 | 483 | 6,154 |
| 15 | Renewables Energy Time-shift | 3 | 5 | 1 kW | 500 MW | 233 | 389 | 2,889 | 36,834 | 899 | 11,455 |
| 16 | Renewables Capacity Firming | 2 | 4 | 1 kW | 500 MW | 709 | 915 | 2,889 | 36,834 | 2,346 | 29,909 |
| 17.1 | Wind Generation Grid Integration, Short Duration | 10 sec. | 15 min. | 0.2 kW | 500 MW | 500 | 1,000 | 181 | 2,302 | 135 | 1,727 |
| 17.2 | Wind Generation Grid Integration, Long Duration | 1 | 6 | 0.2 kW | 500 MW | 100 | 782 | 1,445 | 18,417 | 637 | 8,122 |

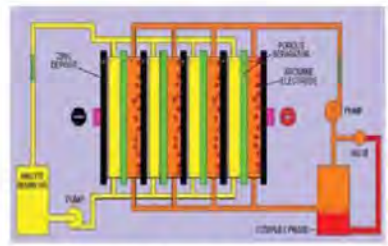
*Hours unless indicated otherwise. min. = minutes. sec. = seconds.
**Lifecycle, 10 years, 2.5% escalation, 10.0% discount rate.
†Based on potential (MW, 10 years) times average of low and high benefit ($/kW).
†† Benefit for *one year*. However, storage could be used at more than one location at different times for similar benefits.

Overview of NextEnergy's Research Work in Next-Generation Batteries – If interested in more of our work in this area, please contact us:

## Unconventional Batteries



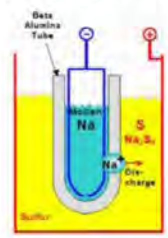

**Redox Flow Battery:** VRB, ICB



**Hybrid Flow Battery:** ZnBr, ZnCl, ZnMnO

**Metal-Air Battery:** Zinc, Lithium, Mg, Al


**Sodium-Based:** NaS, Sodium-Ion, Sodium Metal-Halide (ZEBRA)




Source (Figures - clockwise): UER 2012, Enervault 2011, DOE 2012, Zn-Air 2012

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NextEnergy Confidential

# Appendix C: CES Application in Military Forward Operating Bases

# Energy Storage Application in Military Forward Operating Bases

Prepared for DTE Energy

March 2013

DOE Recovery Act – Smart Grid Demonstration Project (DE-OE0000229)

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## Table of Contents

## List of Figures & Tables

## Executive Summary

This report describes how advanced technologies, including energy storage and alternative energy generation as deployed in a Forward Operating Base (FOB), can improve base functionality and at the same time, conserve fuel. Application of these technologies to a Continental United States (CONUS) base is also feasible, and would demonstrate similar advantages. An analytical model is developed which integrates load profile data for several specific functions in the FOB environment, conventional generation assets, and "advanced technologies" including alternative generation and storage assets. Comparison of fuel usage is calculated for the initial base case, and for various implementations of storage and alternative generation assets which defines a "sensitivity analysis" for each of these parameters. Net Present Savings (NPS) is calculated for various implementations of "new technology" assets. For a very conservative set of assumptions, a NPS of $230,698 is demonstrated for implementing energy storage during a single six month deployment in the FOB environment.

## Introduction

Energy storage in the civilian community environment offers advantages in several areas including backup power supply and peak load control. In the military base environment, similar advantages are available, but there are several variations in the requirements, implementation and "business case analysis" for the military application. In the Forward Operating Base environment, the single source of energy for both vehicle operations and electricity generation is typically liquid fuel, specifically JP8 (or diesel) fuel. As this fuel is expensive and difficult to transport to the forward base environment, it makes sense to minimize usage and energy storage can offer efficiency improvements in the areas of peak load control and backup power supply (critical load support). Also, any addition of energy generated from alternative sources such as solar power directly reduces the requirement for liquid fuel.

## Forward Operating Base

### Size and Scope of the base

#### Initial Base Configuration

The base model chosen for this report is a Standard Base Camp (SBC), Battalion Strength, as defined by the Department of Army [Ref. 1 & 2] and shown in Figure 1. Throughout the course of a given day, the SBC utilizes Command, Control, Communications, Computers, Infrastructure, Surveillance, and Reconnaissance (C4ISR), kitchen, dining hall, laundry, billeting, and administrative facilities, among others. Each facility requires a varying amount of continuous power and has a peak demand in order to supply the loads throughout a typical day. These individual facility loads have been aggregated to construct a total estimated base load profile.

This report starts with the power generation setup for a SBC by applying the U.S Army tactical and prime power principles. The U.S. Army prime power documentation [Ref. 1] indicates that two (2) 840kW generators can be used to support a SBC with a continuous operating capacity of 1,050 kilo-volt-amperes. It is also estimated that six (6) standby generators, rated 60kW each, would be required near the critical loads of the base for emergency backup in the event of a prime generator failure. These generators would serve the typical Load Profile of the SBC, as shown in Figure 1. As can be seen from the detailed table of the base load profile in the appendix [Appendix Table 5], during times of peak load, a single 840kW generator cannot support the load. Two generators are therefore required, and are usually operated at well below their power output capability and therefore at a sub-optimal efficiency point. Multiple smaller generators are distributed throughout the camp to serve as emergency back-up generation assets in case one or both of the larger generators fails.

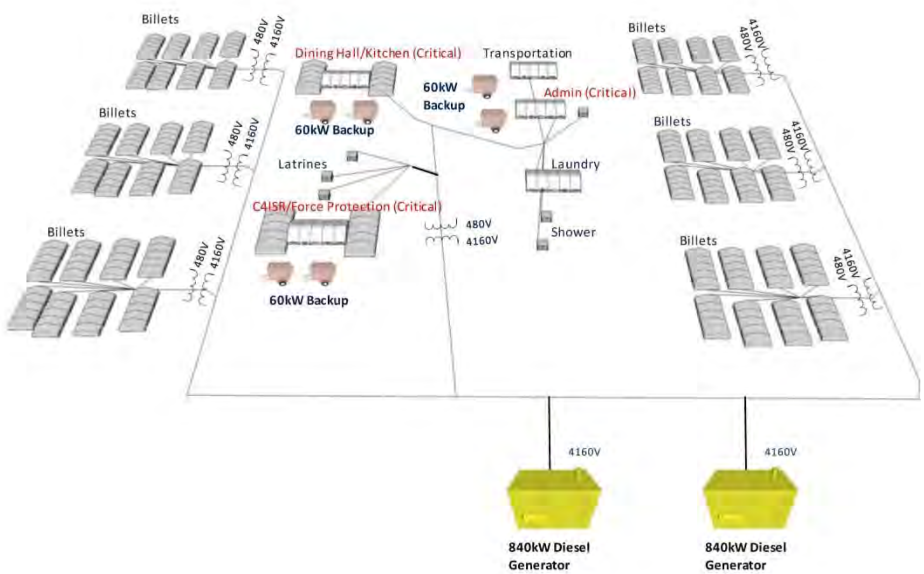


**Figure 1: 550-person Battalion: 2 840kW Generators**

## Base configuration with Storage and Alternative Energy Generation

An FOB with the addition of energy storage and alternative energy generation is shown in Figure 2. In this configuration, one of the 840kW generators has been removed and an energy storage battery bank and alternative energy generation in the form of Solar Photo Voltaic have been added. The integration of these assets is accomplished through the use of a Power Conditioning Module such as the Electronic Power Conditioning and Control (EPCC) module that NextEnergy has previously supplied to the DOD for evaluation. This analysis is agnostic to the exact form of the storage or PV cells. Other types of energy storage or generation could be used in the analytical model by using the appropriate temporal generation profiles, etc. Note that the number of the 60kW generators has been reduced as their UPS function is supplied by the energy storage. The reduced CAPEX for these generators offsets the cost of the Power Conditioning Module.

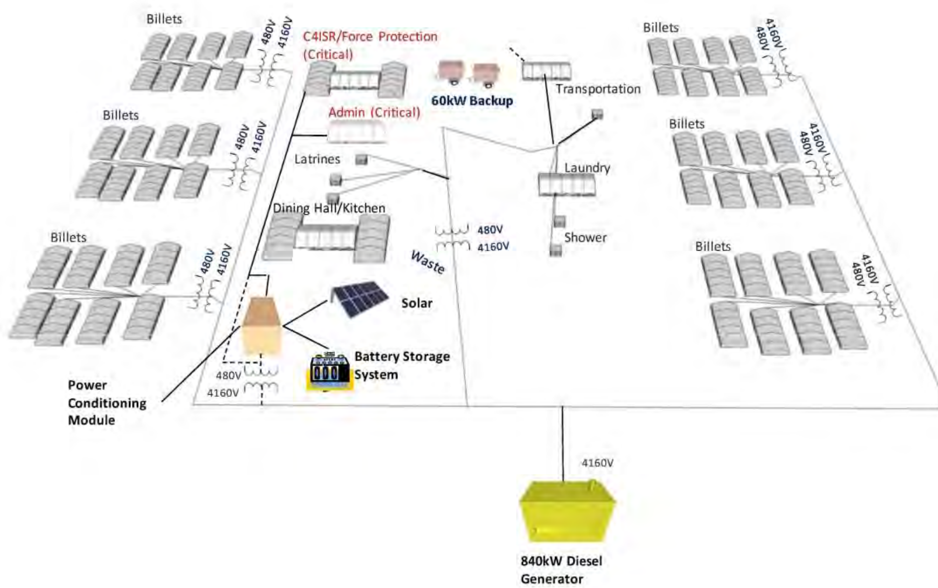


**Figure 2: 550-person Battalion: 1 Generator with energy storage and alternative energy generation**

## Load Profile for FOB

Graphical representation of the loads for the entire base is shown below in Figure 3 [also refer to Appendix Tables 2, 4&5]. Critical loads in the FOB for purposes of this report are assumed to be; C4ISR, Admin and Force Protection. Non-critical loads are the remainder and include Kitchen, Dining Hall, Latrines, Shower/Shave, RALS (remote lighting), Laundry, Billets, and Transportation. The definition of the power requirements for each of these items can be seen in the Base Load Profile in the appendix. These loads vary as a function of time of day for the FOB in a very similar way as the loads vary in any non-military grid environment. Specific values for these loads along with when those loads occur are shown in the "Base Load Profile" in the appendix.

Throughout the Net Present Savings (NPS) calculations, the average values are used for the Critical and Non-Critical loads. In the detailed sheet in the appendix, values for "Typical Peak" and "Total Peak" are given. These are for the highest 15 minutes during the hour, and absolute highest during the hour values respectively. Since we are calculating NPS based on energy usage during the hour, the average is the proper metric.

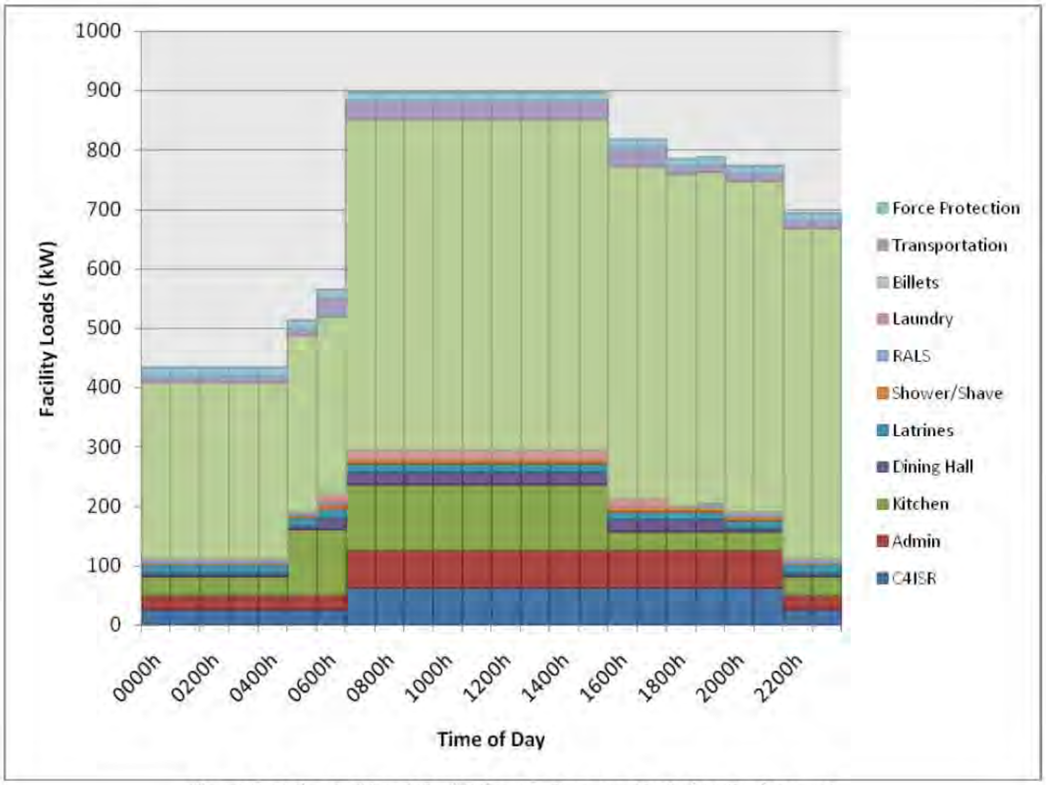


**Figure 3: Estimated Load Profile for a 550-person Battalion Deployment**

## Adding Storage

With the addition of storage, the possibility exists to use excess generation capacity from a single 840kW generator during the night to charge the batteries, and then during peak load time, the batteries can supply the additional load. Savings are realized by obviating the need for the second generator, and by running the existing generator at a more efficient operating point. Generator efficiency as a function of load is shown here in Figure 4 [Ref. 3]. The amount of energy storage capability that is required is the sum of the requirements for two uses, specifically critical load maintenance during generator outage and peak load support when peak load exceeds

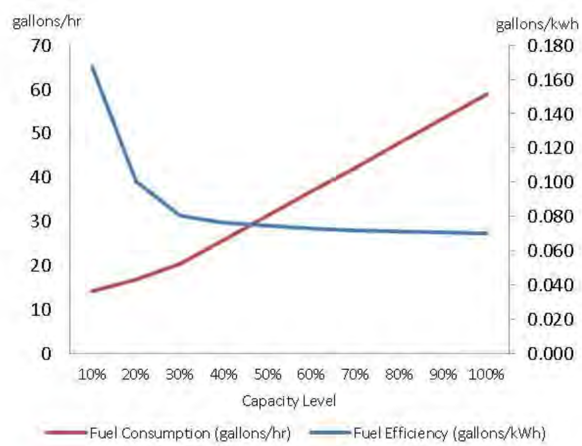


**Figure 4: Fuel consumption and efficiency of 840 kW generator**

generator capability.

### Critical Load Maintenance

Energy storage capacity to maintain critical loads is of course dependent on the power requirement of those critical loads, and how long those loads need to be maintained. Different sources have indicated that the required time can be as low as 30 minutes, and ranges upward from there. An initial estimate of two hours is used in the analysis. Loads that have been defined as "critical" include the C4ISR (Command, Control, Communications, Computers, Infrastructure, Surveillance, and Reconnaissance), Administration, and Force Protection for a total max load of 140 kW. Two hours of critical load maintenance defines an energy storage requirement of 280kWh.

### Peak Load Support

Energy storage capacity to support the peak load during times when the load exceeds the generation capacity can be defined by integrating the excess load over the time that it is required. Figure 2 shows the load profile for the FOB that is being considered. Note that the peak load exceeds the generation capacity for some part of the day. For this load profile and a generator capacity of 840kW, it is calculated that the battery size required to support peak load above generator capacity is 548kWh.

### Combined Requirements Analysis

Figure 5 shows the operation of the generator and state of charge of the battery in percent of maximum capacity over the first three days of operation starting at 00:00 hours and a completely discharged battery.

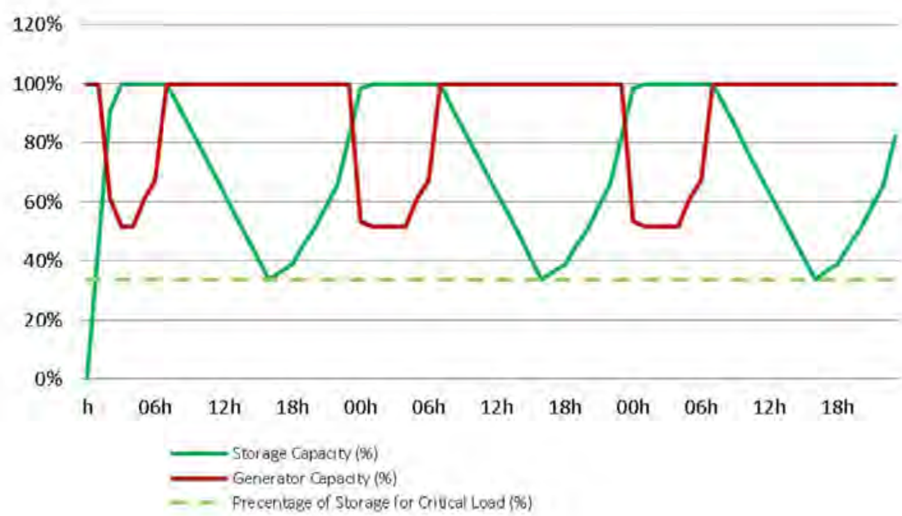


**Figure 5: Storage profile (First 72 hours)**

As can be seen, the generator runs @ 100% to charge the battery initially, drops back to only cover load conditions, and then ramps up with increasing load demand until the generator reaches its max

8

capacity. At that time, the battery starts to supply the additional load and discharges to the minimum allowable. This minimum is set by the requirements of supporting the critical load for two hours of a generator failure. The battery size is calculated so that the minimum state of charge (SOC) required to support the critical load is reached at the same time that the total base load has reduced enough to allow the generator to again cover the entire demand. At that time, re-charging can commence and full charge is again achieved sometime around 00:00 hours, and the cycle repeats except that the battery starts from a higher state of charge. There are several things of note: First, >60% of the battery capacity is used for peak load support, a "generator independent event" could be supported every day, and since the power/energy ratio of the battery will be at least 0.5 and there is over 800kWh of energy storage there will be more than enough power capability to supply the <100kW power requirement.

## Parametric Sensitivity Analysis

### Operating Assumptions

For the sensitivity analysis that follows, the initial operating point assumptions include:

- Time to sustain critical load (Generator independent time) — 2 hours
- Outage frequency — 1 time(s) per month
- Mission duration — 6 months [Ref. 4]
- # of deployments for the equipment — 1
- Cost of fuel (full burden) — $14/gal [Ref. 5]
- Cost of storage — $600/kWh [Appendix Table 4]
- Roundtrip efficiency of the storage: — 85%
- Cost of integrating power conditioning — offset by savings of 60kW generators
- Cost of PV generation — $3,000/kW [Appendix Table 4]
- Discount rate for NPS calculation — 6%
- Cycle life of battery > deployment demands

### Generator Independent Time

Battery capacity defined by generator independent time is a direct cost for which there is no variable cost savings. The longer the time required to sustain the load, the larger and more costly the battery becomes. The model can be used to explore the effects of variation in either the critical load or duration on the required size of energy storage and the resultant effect on the NPS.

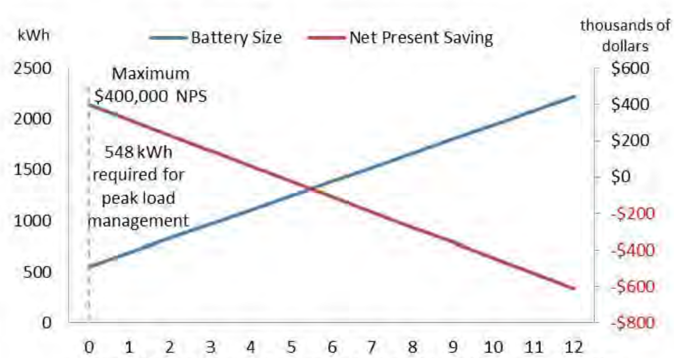

**Figure 6: Sensitivity Analysis - Generator Independent Time**

### Peak Load Support

Figure 6 shows an economic analysis of Net Present Savings as a function of total battery capacity. The min battery capacity required to support peak load is

548kWh, and as can be seen, this offers the maximum savings. If no critical load support were required, the NPS would be $400,000 but as capacity is added to support generator independent time, the savings are reduced. Savings come from the reduction of number of generators required in the field (from two to one) and from operating that single generator at a more efficient point. As battery capacity is added to support critical loads over time, the investment for energy storage increases linearly and results in a reduction of savings. With the given assumptions, the sizing and NPS calculations are as follows:

| Summary with Storage | | |
|---|---|---|
| Min Storage Capacity | **827** | kwh |
| CAPEX w/o Storage | **$913,128** | $ |
| CAPEX w/ Storage | **$952,626** | $ |
| Fuel Savings per Month | **3257** | gallons |
| Total Fuel Savings | **$273,577** | $ |
| Total NP Cost Savings | **$230,698** | $ |

**Table 1: Initial Case Savings Summary (2 hour generator independent time)**

For this set of operating assumptions, total battery storage capacity required is 827 kWh. This is the sum of 279kWh required for maintaining critical loads for 2 hours and 548kWh for supplying peak load above the capacity of the generator. Capital expenditure (CAPEX) with storage increases by $39,498 which represents the cost of the batteries less the cost of the redundant second 840kW generator. Total fuel savings is 3,257 gallons for a net savings of fuel costs of $273,577, and a NPS of $230,698 which is the net savings less the net present value of the additional investment over the duration, which in this case is 6 months.

### Outage Frequency per Month

As the number of outages per month increases, there is an increase of savings realized from the energy storage system. Specific values are shown in Figure 7. This is a result of the fact that during re-charging of the batteries, the generator is run at 100% load which is the most efficient operating point for the generator. More significant savings come however from the fact that during a generator outage, non-critical loads are not being serviced and therefore are not using energy. There may be some residual demand or catch-up effect for energy usage (ex. refrigeration that needs to catch up) that is not accounted for in the analysis.

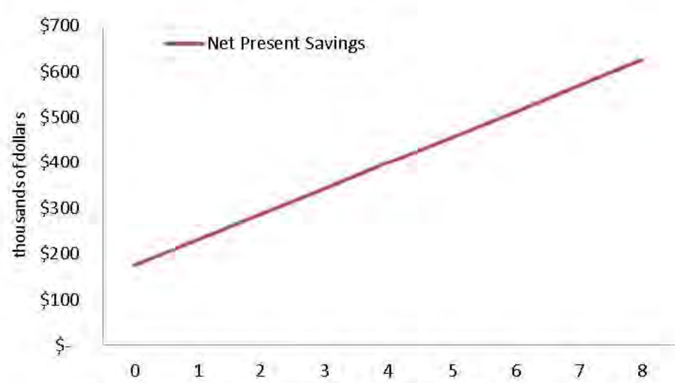

**Figure 7: Sensitivity Analysis – Outage Frequency per Month**

### Cost of Fuel

The U.S. military has documented that the cost impact of fossil fuel on present day deployments is very significant. The United States Army Materiel Command states that fuel and fuel handling costs now comprise nearly 25% of their total monthly operating cost. Present day military fuel consumption trends strongly indicate that future directed energy weapons, unmanned vehicles, and other emerging technologies will drive fuel usage almost exponentially. In the next decade, fuel consumption per soldier could equal 30 gallons/day, and at 100,000 deployed soldiers could equal 3.0 million gallons/day. It should be noted that the cost of fuel in the deployed environment is high, not only because of the economic cost of the logistics required to transport it to the FOB, but also because of the danger incurred by the forces required to get it there. Each fuel truck carries approximately 3,000 gal. of fuel per trip [Ref. 10] so the analysis above indicates that the savings in fuel is one full delivery truck per month. In as much as most of the electrical energy for a Forward Operating Base (FOB) is generated from fuel, this challenge creates a critical need to implement electrical power management innovations and technologies. These technologies will utilize alternative and renewable sources of energy as well as energy storage. These new and imaginative energy technologies are vital to bringing sustainability to military bases in the 21st century.

In order to equate fuel savings with dollar savings, it is beneficial to gain an understanding of the burdened cost of fuel. The Army Environmental Policy Institute [Ref. 5] cites that the fully burdened cost of fuel equates to $14.13 per gallon. This cost per gallon is derived from the fuel's base commodity cost of $3.14 per gallon, plus the effects of force protection and transportation. That is, in order for fuel to reach a forward operating military base, it has to be shipped in convoys, complete with air and ground support for safety. The fuel also needs to be supported in the field upon arrival to its place of deployment. Refer to Appendix Table 3 for more detailed information on the methodology used to calculate fuel costs. As seen in the table, the total annual fuel cost for a Standard Base Camp divided by the total gallons used equates to the overall $14.13 per gallon fuel cost. For this report, the rounded fuel cost is set at $14 per gallon and this cost is used throughout as a metric for estimating potential cost savings for a military base. However, the U.S. Rapid Equipping Force [Ref. 6] has indicated that the cost of fuel on a military base could range from $15 to $200 per gallon.

Figure 8 shows the sensitivity of NPS to the cost of fuel. Obviously, as the cost of fuel increases, any savings in fuel use directly translates into increased savings. It is interesting to note that using the assumptions outlined earlier there is a positive NPS even with fuel costs at levels significantly less than the base case assumption of $14/gal. Specifically, those assumptions were one deployment for six months. That means that the payback time for the energy storage in this

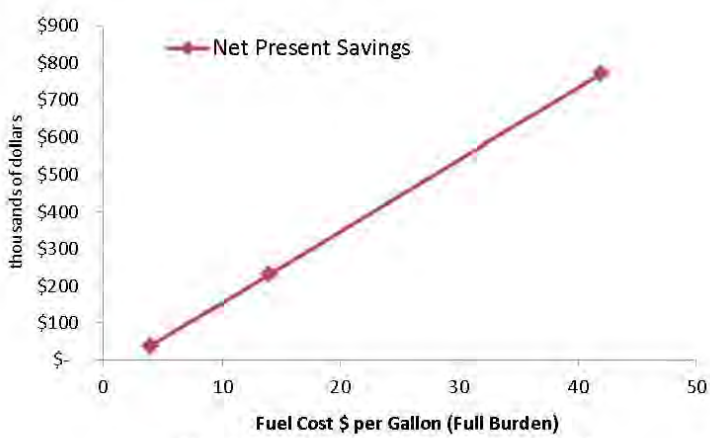


**Figure 8: Sensitivity Analysis – Fuel Cost $/gal.**

scenario is somewhat less than six months, which is very attractive. If it is decided that the second 840kW generator is still required, additional CAPEX would be needed, but fuel costs would not change. In this scenario, the NPS for a 6 month deployment and $14/gal fuel would be negative $225,866. However with only 12 month duration, the NPS becomes positive by $36,365.

### Mission Duration and Multiple Deployment Re-use

Since savings accrue over time and use as a direct function of fuel savings so the longer the equipment is in the field, the more savings will be realized. Increased use time can be achieved by either longer deployments per mission, or deployment on multiple missions. CAPEX would not be affected by either of these strategies.

## Adding Alternative Energy Generation

Having explored the savings afforded by energy storage, another analysis can be done to investigate the potential savings from electric energy generation from non-fuel using sources [Ref. 7]. Solar panels were chosen for analysis due to their relative ease of deployment compared to a wind turbine. For purposes of the analysis, these panels could be any type, but it is envisioned that for a FOB environment, a robust and flexible type would be preferred.

The generation profile for the array was assumed to be a sinusoidal function operating over 12 hours each day. A de-rating factor of 30% was applied (i.e. on average the panels produce 70% of the potential due to clouds cover, dirt, etc.). This de-rating factor could be more accurately assessed if a specific deployment location were known. Power generation values for a 20kW array are shown in Table 6 in the appendix. Since the energy storage capacity requirement is in part defined by the offsetting peak load which occurs during daylight hours, an argument could be made that this requirement is reduced by the addition of solar generation capacity. However, the assumption adopted was that the size of the batteries would not be affected by the potential of the PV array offsetting some of the peak load requirement as that eventuality cannot be relied upon. As we've heard so often, "The sun doesn't shine every day."

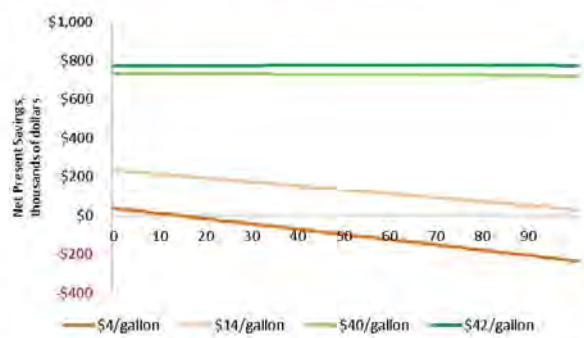


**Figure 9: NPS from solar generation Array size in kW**

Savings then comes exclusively from offsetting fuel usage by solar generation when it's available. The capital expenditure must be offset by this fuel savings to generate an NPS. Figure 10 shows the NPS of the entire upgraded system (including batteries) for array sizes starting at zero up through 100kW. As expected, for the $14/gal fuel price, at zero array size we again see the slightly over $200,000 NPS. Any increase in array size shrinks the NPS. At $40/gal however, the savings is significant. Again remember that this is for a one time, six month deployment. If the deployment time is for two years and $14/gal fuel, the NPS point would be $1,078,315.

For fuel values above $40/gal., it becomes possible to calculate an optimal array size. For example at the higher fuel value of $42/gal, the optimal size as shown in Figure 11 is around 85kW. The reduction in NPS at solar generation of greater than 85kW is due to the fact that the array is capable of generating more than enough power to handle the peak demand when it exceeds generation capacity. This causes the battery to be not fully utilized and so the cost savings offered by the battery is not fully realized.

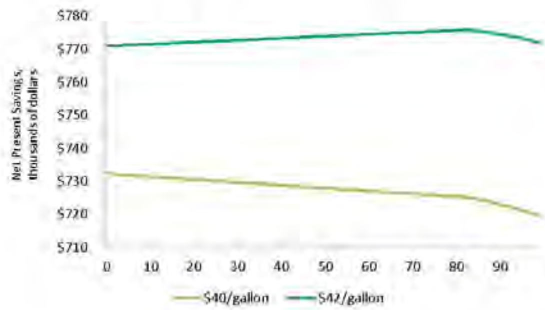

**Figure 10: Expanded scale for higher fuel values**

Solar panels then are a good investment for higher fuel costs and for longer deployment durations. The limiting factor of array size may be how much the deployment is willing to carry to the forward area.

## CONUS Base Analysis

A Continental United States base would have similar operational features as the Forward Operating Base in terms of cyclic energy use, the need for maintaining critical functions, the availability of energy storage options and access to alternative and renewable energy generation assets. U.S. Army Corps of Engineers [Ref. 4] estimated that the maximum power requirement in a military base is 3 kW per capita, so a Brigade base of 3000 people could need a generation capacity of as much as 9,000 kW. Each base however would have its own specific characteristics. Significant differences exist however in the assumptions of fuel costs, maintenance of critical loads, capital expenditure requirements etc.

With the proper salient information for each specific application, this model approach could be used to analyze the potential savings for implementation of these technologies. For this report, we listed some of the potential observations:

- Large battery size and the capital cost associated could become a barrier for implementation, given that a CONUS base might need to hold more critical load for a longer period of time and require a challenging peak shaving capacity.
- Longer deployment periods would potentially justify the huge capital investment. Additionally, more energy storage technologies with less capital requirements are viable based on specific configurations of the bases, for example, mobility is not required for a CONUS base application as it is in a FOB application.
- The full burdened fuel cost will not be as large of concern for the CONUS base as for the FOB, since the fuel transportation is not as high-risk and tedious, and the bases are very likely to be grid-connected.
- Alternative energy coupled with smart grid technologies may serve a more promising role at the CONUS base.

- Multi-function mobile energy storage systems such as electric vehicles might be a good substitution for bulk batteries.

## Conclusions

In the FOB environment described, fuel savings afforded by energy storage results in a positive NPS of over $200,000 for a single 6 month deployment. Longer or multiple deployments increase the savings. Implementing alternative energy generation (PV) has the potential to improve overall NPS, depending on the size of the array, length of deployment and cost of the fuel.

Technologies showcased in this report are easily scalable, allowing for application to larger or smaller bases and installations, such as U.S. Army Prime Power Platoon (1,600-man) and U.S. Air Force Harvest Falcon Brigade (3,300-man) sized bases. The force provider setup shown in this report serves as an example of how advanced technologies can benefit any military base.

## APPENDIX

### Load Profiles Constructed for Battalion-Strength SBC Serving 550 Soldiers

| Facility | Power Needs | Multiplier | Time of Use | Comments |
|---|---|---|---|---|
| C4ISR (Command, Control, Communications, Computers, Infrastructure, Surveillance, & Reconnaissance) | 100kWp / 50kWc (include ECU) | 1 | 0700 to 2200H | Extrapolated from HI Power Tactical C2 Cell @ 71kWp / 15kWc |
| | 40kWp / 20kWc | 1 | 2201 to 0659H | NEC Estimate |
| Administration/Supplies/Support | 100kWp / 50kWc (includes ECU) | 1 | 0700 to 2200H | Assumed to be the same as C4ISR |
| | 40kWp / 20kWc | 1 | 2201 to 0659H | NEC Estimate |
| Food Services | | | | |
| Kitchen | 120kWp / 108kWc (includes ECUs & RALS for entire Food Services Complex) | 1 | 0500 to 1600 | Load - USAF Harvest Falcon<br><br>Time – USA Force Provider (FM 42-424) |
| | 50kWp / 25kWc | 1 | 1601 to 0459 | NEC Estimate based on ECU load only |
| Dining Hall | 24kWp / 19kWc | 1 | 0600 to 2000 | Load - USAF Harvest Falcon<br><br>Time – USA Force Provider (FM 42-424) |
| | 10kWp / 4kWc | 1 | 2001 to 0559 | NEC Estimate |
| Hygiene Services | | | | |
| Latrines | 4.2kWp / 3.4kWc | 4 | 0700 to 0659 | Load - USAF Harvest Falcon<br><br>Time – USA Force Provider (FM 42-424) |
| Shower / Shave | 4.2kWp / 3.4kWc | 2 | 0600 to 2200 | Load - USAF Harvest Falcon<br><br>Time – USA Force Provider (FM 42-424) |
| | 1.7kWp / 1.36kWc | 2 | 2201 to 0559 | NEC Estimate |

| | | | | |
|---|---|---|---|---|
| RALS | 5.0kWp / 4.5kWc | 1 | 1900 to 0700 | Load - USAF Harvest Falcon<br><br>Time – USA Force Provider (FM 42-424) |
| Laundry | 17kWp / 14kWc<br><br>(includes ECU) | 1 | 0600 to 1800 | Load - USAF Harvest Falcon<br><br>Time – USA Force Provider (FM 42-424) |
| | 1.7kWp / 1.36kWc | 1 | 1801 to 0559 | NEC Estimate |
| Billeting | | | | |
| Billets | 13.5kWp / 11kWc<br><br>(includes ECUs, lights & receptacles) | 48 | 0700 to 2400 | Load - USAF Harvest Falcon<br><br>Time – USA Force Provider<br><br>(FM 42-424) |
| | 6.75kWp / 6kWc | 48 | 2401 to 0659 | NEC Estimate |
| Transportation | 42kWp / 28kWc<br><br>(includes ECU) | 1 | 0600 to 1800 | Load - USAF Harvest Falcon<br><br>Time – NEC Estimate |
| | 16kWp / 11kWc | 1 | 1801 to 0559 | NEC Estimate |
| Force Protection | 15kWp / 14kWc | 1 | 0001 to 2400 | Load - USAF Harvest Falcon<br><br>Time – NEC Estimate |

**Table 2: Load Profiles Constructed for Battalion-Strength SBC Serving 550 Soldiers**

## Fully Burdened Cost of Fuel Breakdown

| Cost Components | Annual Cost Base Case | % of FBCF | $ Per Gallon |
|---|---|---|---|
| Force Protection (Air) | $ 5,183,788.99 | 15.5% | $ 2.19 |
| Force Protection (Ground) | $ 2,823,413.83 | 8.5% | $ 1.20 |
| Transport | $ 11,189,210.80 | 33.6% | $ 4.75 |
| Resupply | $ 10,564,739.00 | 31.7% | $ 4.48 |
| Initial Deployment | $ 579,656.31 | 1.7% | $ 0.25 |
| Relocation | $ 44,815.50 | 0.1% | $ 0.02 |
| Return | | 0.0% | $ - |
| Fuel Support Military Personnel in SBCT | $ 5,737,231.63 | 17.2% | $ 2.43 |
| Fuel Support Equipment in SBCT | $ 432,488.07 | 1.3% | $ 0.18 |
| Sustainment Brigade/TSC | $ 571,155.90 | 1.7% | $ 0.24 |
| Fuel Commodity | $ 7,402,829.15 | 22.2% | $ 3.14 |

| Summary Statistic | Value |
|---|---|
| FBCF Annual Cost for SBCT | $ 33,320,118 |
| Annual Gallons Consumed by SBCT | 2,357,589 |
| FBCF per Soldier | $ 8,389 |
| FBCF per SBCT | $ 33,320,118 |
| FBCF per Gallon | $ 14.13 |

**Table 3: Fully Burdened Cost of Fuel Breakdown**

## Equipment Capital Costs

| Item | Capital Cost ($) | Comments |
|---|---|---|
| MEP-810B Generator (840kW) | $456,564 | [Ref. 8] |
| 60kW Generator | $48,000 | [Ref. 9] |
| Li-ion Battery | $600/kWh | NEC Estimate |
| Solar PV | $3000/kW | NEC Estimate |
| EPCC Module (250kW) | $295,000 | NEC Estimate |

**Table 4: Equipment Capital Costs**

## Initial Base Load Profile with conventional generation assets

| Loads (kW) | | 0000h | 0100h | 0200h | 0300h | 0400h | 0500h | 0600h | 0700h | 0800h | 0900h | 1000h | 1100h |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Hours | ^^Assuming 25% peak load duration | | | | | | | | | |
| C4ISR (Critical) | Continous | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 |
| | Peak | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 100 | 100 | 100 | 100 |
| Admin | Continous | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 |
| | Peak | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 100 | 100 | 100 | 100 |
| Kitchen | Continous | 31.25 | 31.25 | 31.25 | 31.25 | 31.25 | 111 | 111 | 111 | 111 | 111 | 111 | 111 |
| | Peak | 50 | 50 | 50 | 50 | 50 | 120 | 120 | 120 | 120 | 120 | 120 | 120 |
| Dining Hall | Continous | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 20.25 | 20.25 | 20.25 | 20.25 | 20.25 | 20.25 |
| | Peak | 10 | 10 | 10 | 10 | 10 | 10 | 24 | 24 | 24 | 24 | 24 | 24 |
| Latrines | Continous | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 |
| | Peak | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 |
| Shower/Shave | Continous | 2.89 | 2.89 | 2.89 | 2.89 | 2.89 | 2.89 | 7.2 | 7.2 | 7.2 | 7.2 | 7.2 | 7.2 |
| | Peak | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 | 8.4 | 8.4 | 8.4 | 8.4 | 8.4 | 8.4 |
| RALS | Continous | 4.625 | 4.625 | 4.625 | 4.625 | 4.625 | 4.625 | 4.625 | 0 | 0 | 0 | 0 | 0 |
| | Peak | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 0 | 0 | 0 | 0 | 0 |
| Laundry | Continous | 1.445 | 1.445 | 1.445 | 1.445 | 1.445 | 1.445 | 14.75 | 14.75 | 14.75 | 14.75 | 14.75 | 14.75 |
| | Peak | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 17 | 17 | 17 | 17 | 17 | 17 |
| Billets | Continous | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 558 | 558 | 558 | 558 | 558 |
| | Peak | 324 | 324 | 324 | 324 | 324 | 324 | 324 | 648 | 648 | 648 | 648 | 648 |
| Transportation | Continous | 12.25 | 12.25 | 12.25 | 12.25 | 12.25 | 12.25 | 31.5 | 31.5 | 31.5 | 31.5 | 31.5 | 31.5 |
| | Peak | 16 | 16 | 16 | 16 | 16 | 16 | 42 | 42 | 42 | 42 | 42 | 42 |
| Force Protection (Critical) | Continous | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 |
| | Peak | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| TOTAL Critical Avg. Load Profile | | 101 | 101 | 101 | 101 | 101 | 100.75 | 195.5 | 270.5 | 270.5 | 270.5 | 270.5 | 270.5 |
| TOTAL Critical Peak Load Profile | | 155 | 155 | 155 | 155 | 155 | 225 | 239 | 239 | 359 | 359 | 359 | 359 |
| Typical Critical Peak Load Profile | | 131.75 | 131.75 | 131.75 | 131.75 | 131.75 | 191.25 | 203.15 | 203.15 | 305.15 | 305.15 | 305.15 | 305.15 |
| TOTAL Non-Crit Avg. Load Profile | | 332.61 | 332.61 | 332.61 | 332.61 | 332.61 | 332.61 | 369.475 | 625.85 | 625.85 | 625.85 | 625.85 | 625.85 |
| TOTAL Non-Crit Peak Load Profile | | 366.9 | 366.9 | 366.9 | 366.9 | 366.9 | 366.9 | 413.2 | 732.2 | 732.2 | 732.2 | 732.2 | 732.2 |
| TYPICAL Non-Crit Peak Load Profile | | 311.865 | 311.865 | 311.865 | 311.865 | 311.865 | 311.87 | 351.22 | 622.37 | 622.37 | 622.37 | 622.37 | 622.37 |
| **WITHOUT EPCC** | | | | | | | | | | | | | |
| 840kW Generators w/o EPCC | | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Capacity per Generator (%) | | 26% | 26% | 26% | 26% | 26% | 31% | 34% | 53% | 53% | 53% | 53% | 53% |
| DSSI Fuel Consumption per Generator (gallons/hour) | | 18.78 | 18.78 | 18.78 | 18.78 | 18.78 | 21.53 | 23.31 | 34.74 | 34.74 | 34.74 | 34.74 | 34.74 |
| **Total Fuel Consumption (gallons /hour)** | | 37.55645 | 37.55645 | 37.55645 | 37.55645 | 37.55645 | 43.057 | 46.617351 | 69.473941 | 69.473941 | 69.473941 | 69.473941 | 69.473941 |

| Loads (kW) | | 1200h | 1300h | 1400h | 1500h | 1600h | 1700h | 1800h | 1900h | 2000h | 2100h | 2200h | 2300h |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| C4ISR (Critical) | Continous | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 25 | 25 |
| | Peak | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 40 | 40 |
| Admin | Continous | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 25 | 25 |
| | Peak | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 40 | 40 |
| Kitchen | Continous | 111 | 111 | 111 | 111 | 31.25 | 31.25 | 31.25 | 31.25 | 31.25 | 31.25 | 31.25 | 31.25 |
| | Peak | 120 | 120 | 120 | 120 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Dining Hall | Continous | 20.25 | 20.25 | 20.25 | 20.25 | 20.25 | 20.25 | 20.25 | 20.25 | 5.5 | 5.5 | 5.5 | 5.5 |
| | Peak | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 10 | 10 | 10 | 10 | 10 |
| Latrines | Continous | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 |
| | Peak | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 |
| Shower/Shave | Continous | 7.2 | 7.2 | 7.2 | 7.2 | 7.2 | 7.2 | 7.2 | 7.2 | 7.2 | 7.2 | 2.89 | 2.89 |
| | Peak | 8.4 | 8.4 | 8.4 | 8.4 | 8.4 | 8.4 | 8.4 | 8.4 | 8.4 | 8.4 | 3.4 | 3.4 |
| RALS | Continous | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 4.625 | 4.625 | 4.625 | 4.625 | 4.625 |
| | Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 5 | 5 | 5 | 5 |
| Laundry | Continous | 14.75 | 14.75 | 14.75 | 14.75 | 14.75 | 14.75 | 1.445 | 1.445 | 1.445 | 1.445 | 1.445 | 1.445 |
| | Peak | 17 | 17 | 17 | 17 | 17 | 17 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 |
| Billets | Continous | 558 | 558 | 558 | 558 | 558 | 558 | 558 | 558 | 558 | 558 | 558 | 558 |
| | Peak | 648 | 648 | 648 | 648 | 648 | 648 | 648 | 648 | 648 | 648 | 648 | 648 |
| Transportation | Continous | 31.5 | 31.5 | 31.5 | 31.5 | 31.5 | 31.5 | 12.25 | 12.25 | 12.25 | 12.25 | 12.25 | 12.25 |
| | Peak | 42 | 42 | 42 | 42 | 42 | 42 | 16 | 16 | 16 | 16 | 16 | 16 |
| Force Protection (Critical) | Continous | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 |
| | Peak | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| TOTAL Critical Avg. Load Profile | | 270.5 | 270.5 | 270.5 | 270.5 | 190.75 | 190.75 | 190.75 | 190.75 | 176 | 176 | 101 | 101 |
| TOTAL Critical Peak Load Profile | | 359 | 359 | 359 | 359 | 289 | 289 | 289 | 275 | 275 | 275 | 155 | 155 |
| Typical Critical Peak Load Profile | | 305.15 | 305.15 | 305.15 | 305.15 | 245.65 | 245.65 | 245.65 | 233.75 | 233.75 | 233.75 | 131.75 | 131.75 |
| TOTAL Non-Crit Avg. Load Profile | | 625.85 | 625.85 | 625.85 | 625.85 | 625.85 | 625.85 | 593.295 | 597.92 | 597.92 | 597.92 | 593.61 | 593.61 |
| TOTAL Non-Crit Peak Load Profile | | 732.2 | 732.2 | 732.2 | 732.2 | 732.2 | 732.2 | 690.9 | 695.9 | 695.9 | 695.9 | 690.9 | 690.9 |
| TYPICAL Non-Crit Peak Load Profile | | 622.37 | 622.37 | 622.37 | 622.37 | 622.37 | 622.37 | 587.265 | 591.515 | 591.515 | 591.515 | 587.265 | 587.265 |
| **WITHOUT EPCC** | | | | | | | | | | | | | |
| 840kW Generators w/o EPCC | | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Capacity per Generator (%) | | 53% | 53% | 53% | 53% | 49% | 49% | 47% | 47% | 46% | 46% | 41% | 41% |
| DSSI Fuel Consumption per Generator (gallons/hour) | | 34.74 | 34.74 | 34.74 | 34.74 | 31.99 | 31.99 | 30.86 | 31.02 | 30.51 | 30.51 | 27.78 | 27.78 |
| **Total Fuel Consumption (gallons /hour)** | | 69.473941 | 69.473941 | 69.473941 | 69.473941 | 63.973185 | 63.973185 | 61.727704 | 62.046713 | 61.029332 | 61.029332 | 55.558925 | 55.558925 |

**Table 5: Initial Base Load and Generation Configuration**

## Base Load Profile with Storage and Alt Energy Generation

Critical load grid independent (hrs) = 2 Critical Load = 278.50 KWh Storage Capacity = 827 KWh Roundtrip Efficiency= 0.85 One-way Efficiency = 0.925 Critical Capacity (%) = 34% Solar Size = 20

| Loads (kW) | | h | 01h | 02h | 03h | 04h | 05h | 06h | 07h | 08h | 09h | 10h | 11h | 12h | 13h | 14h | 15h | 16h | 17h | 18h | 19h | 20h | 21h | 22h | 23h |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| C4ISR (Critical) | Continous | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 25 | 25 |
| | Peak | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 40 | 40 |
| Admin (Critical) | Continous | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 62.5 | 25 | 25 |
| | Peak | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 40 | 40 |
| Kitchen | Continous | 31.25 | 31.25 | 31.25 | 31.25 | 31.25 | 111 | 111 | 111 | 111 | 111 | 111 | 111 | 111 | 111 | 111 | 111 | 31.25 | 31.25 | 31.25 | 31.25 | 31.25 | 31.25 | 31.25 | 31.25 |
| | Peak | 50 | 50 | 50 | 50 | 50 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Dining Hall | Continous | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 20.25 | 20.25 | 20.25 | 20.25 | 20.25 | 20.25 | 20.25 | 20.25 | 20.25 | 20.25 | 20.25 | 20.25 | 20.25 | 20.25 | 5.5 | 5.5 | 5.5 | 5.5 |
| | Peak | 10 | 10 | 10 | 10 | 10 | 10 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 10 | 10 | 10 | 10 | 10 |
| Latrines | Continous | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 | 14.4 |
| | Peak | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 |
| Shower/Shave | Continous | 2.89 | 2.89 | 2.89 | 2.89 | 2.89 | 2.89 | 7.2 | 7.2 | 7.2 | 7.2 | 7.2 | 7.2 | 7.2 | 7.2 | 7.2 | 7.2 | 7.2 | 7.2 | 7.2 | 7.2 | 7.2 | 7.2 | 2.89 | 2.89 |
| | Peak | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 | 8.4 | 8.4 | 8.4 | 8.4 | 8.4 | 8.4 | 8.4 | 8.4 | 8.4 | 8.4 | 8.4 | 8.4 | 8.4 | 8.4 | 8.4 | 8.4 | 3.4 | 3.4 |
| RAIS | Continous | 4.625 | 4.625 | 4.625 | 4.625 | 4.625 | 4.625 | 4.625 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 4.625 | 4.625 | 4.625 | 4.625 | 4.625 |
| | Peak | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 5 | 5 | 5 | 5 |
| Laundry | Continous | 1.445 | 1.445 | 1.445 | 1.445 | 1.445 | 1.445 | 14.75 | 14.75 | 14.75 | 14.75 | 14.75 | 14.75 | 14.75 | 14.75 | 14.75 | 14.75 | 14.75 | 14.75 | 1.445 | 1.445 | 1.445 | 1.445 | 1.445 | 1.445 |
| | Peak | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 17 | 17 | 17 | 17 | 17 | 17 | 17 | 17 | 17 | 17 | 17 | 17 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 |
| Billets | Continous | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 558 | 558 | 558 | 558 | 558 | 558 | 558 | 558 | 558 | 558 | 558 | 558 | 558 | 558 | 558 | 558 | 558 |
| | Peak | 324 | 324 | 324 | 324 | 324 | 324 | 324 | 648 | 648 | 648 | 648 | 648 | 648 | 648 | 648 | 648 | 648 | 648 | 648 | 648 | 648 | 648 | 648 | 648 |
| Transportation | Continous | 12.25 | 12.25 | 12.25 | 12.25 | 12.25 | 12.25 | 31.5 | 31.5 | 31.5 | 31.5 | 31.5 | 31.5 | 31.5 | 31.5 | 31.5 | 31.5 | 31.5 | 31.5 | 12.25 | 12.25 | 12.25 | 12.25 | 12.25 | 12.25 |
| | Peak | 16 | 16 | 16 | 16 | 16 | 16 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 16 | 16 | 16 | 16 | 16 | 16 |
| Force Protection (Critical) | Continous | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 | 14.25 |
| | Peak | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| Storage | Discharging | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 57.12 | 53.58 | 50.54 | 48.20 | 46.74 | 46.24 | 46.74 | 48.20 | 50.54 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Charging | 406.39 | 406.39 | 81.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 30.19 | 26.91 | 55.96 | 51.33 | 66.08 | 66.08 | 145.39 | 42.27 |
| Total Storage | kWh | 0.00 | 375.91 | 751.82 | 826.77 | 826.77 | 826.77 | 826.77 | 826.77 | 769.65 | 716.07 | 665.53 | 617.33 | 570.59 | 524.35 | 477.62 | 429.41 | 378.87 | 406.60 | 431.70 | 483.45 | 530.93 | 592.06 | 653.18 | 787.67 |
| Storage Capacity (%) | % | 0% | 45% | 91% | 100% | 100% | 100% | 100% | 100% | 93% | 87% | 80% | 75% | 69% | 63% | 58% | 52% | 46% | 49% | 52% | 58% | 64% | 72% | 79% | 95% |
| Solar | kW | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 3.51 | 6.79 | 9.60 | 11.76 | 13.12 | 13.58 | 13.12 | 11.76 | 9.60 | 6.79 | 3.51 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| TOTAL Critical Avg. Load Profile | | 64.25 | 64.25 | 64.25 | 64.25 | 64.25 | 64.25 | 64.25 | 139.25 | 139.25 | 139.25 | 139.25 | 139.25 | 139.25 | 139.25 | 139.25 | 139.25 | 139.25 | 139.25 | 139.25 | 139.25 | 139.25 | 139.25 | 64.25 | 64.25 |
| TOTAL Critical Peak Load Profile | | 95.00 | 95.00 | 95.00 | 95.00 | 95.00 | 95.00 | 95.00 | 95.00 | 215.00 | 215.00 | 215.00 | 215.00 | 215.00 | 215.00 | 215.00 | 215.00 | 215.00 | 215.00 | 215.00 | 215.00 | 215.00 | 215.00 | 95.00 | 95.00 |
| Typical Critical Peak Load Profile | | 80.75 | 80.75 | 80.75 | 80.75 | 80.75 | 80.75 | 80.75 | 80.75 | 182.75 | 182.75 | 182.75 | 182.75 | 182.75 | 182.75 | 182.75 | 182.75 | 182.75 | 182.75 | 182.75 | 182.75 | 182.75 | 182.75 | 80.75 | 80.75 |
| TOTAL Non-Crit Avg. Load Profile | | 369.36 | 369.36 | 369.36 | 369.36 | 369.36 | 448.11 | 508.73 | 757.10 | 757.10 | 757.10 | 757.10 | 757.10 | 757.10 | 757.10 | 757.10 | 757.10 | 677.35 | 677.35 | 644.80 | 649.42 | 634.67 | 634.67 | 630.36 | 630.36 |
| TOTAL Non-Crit Peak Load Profile | | 833.29 | 833.29 | 507.93 | 426.98 | 426.98 | 496.98 | 557.20 | 876.20 | 876.20 | 876.20 | 876.20 | 876.20 | 876.20 | 876.20 | 876.20 | 876.20 | 836.39 | 833.11 | 820.66 | 807.23 | 821.98 | 821.98 | 896.29 | 793.17 |
| TYPICAL Non-Crit Peak Load Profile | | 708.30 | 708.30 | 431.74 | 362.87 | 362.87 | 422.37 | 473.62 | 744.77 | 744.77 | 744.77 | 744.77 | 744.77 | 744.77 | 744.77 | 744.77 | 744.77 | 710.93 | 708.15 | 697.73 | 686.15 | 698.68 | 698.68 | 761.85 | 674.20 |
| **TOTAL Average Load Profile** | | 433.61 | 433.61 | 433.61 | 433.61 | 433.61 | 513.36 | 564.98 | 896.35 | 896.35 | 896.35 | 896.35 | 896.35 | 896.35 | 896.35 | 896.35 | 896.35 | 816.60 | 816.60 | 784.05 | 788.67 | 773.92 | 773.92 | 694.61 | 694.61 |
| **TOTAL Average Load Profile w Solar** | | 433.61 | 433.61 | 433.61 | 433.61 | 433.61 | 513.36 | 564.98 | 892.84 | 889.56 | 886.75 | 884.59 | 883.23 | 882.77 | 883.23 | 884.59 | 886.75 | 809.81 | 813.09 | 784.05 | 788.67 | 773.92 | 773.92 | 694.61 | 694.61 |
| **TOTAL Average Load Profile w Storage** | | 840.00 | 840.00 | 514.64 | 433.61 | 433.61 | 513.36 | 564.98 | 840.00 | 840.00 | 840.00 | 840.00 | 840.00 | 840.00 | 840.00 | 840.00 | 840.00 | 840.00 | 840.00 | 840.00 | 840.00 | 840.00 | 840.00 | 840.00 | 736.88 |
| 840kW Generators w/o EPCC | | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Capacity per Generator (%) | | 100% | 100% | 61% | 52% | 52% | 61% | 67% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 88% |
| Critical Storage Capacity (%) | | 34% | 34% | 34% | 34% | 34% | 34% | 34% | 34% | 34% | 34% | 34% | 34% | 34% | 34% | 34% | 34% | 34% | 34% | 34% | 34% | 34% | 34% | 34% | 34% |
| DSSI Fuel Consumption per Generator (gallons/hour) | | 61.76 | 61.76 | 39.32 | 33.73 | 33.73 | 39.23 | 42.79 | 61.76 | 61.76 | 61.76 | 61.76 | 61.76 | 61.76 | 61.76 | 61.76 | 61.76 | 61.76 | 61.76 | 61.76 | 61.76 | 61.76 | 61.76 | 61.76 | 54.65 |
| **Total Fuel Consumption (gallons/hour)** | | 61.76 | 61.76 | 39.32 | 33.73 | 33.73 | 39.23 | 42.79 | 61.76 | 61.76 | 61.76 | 61.76 | 61.76 | 61.76 | 61.76 | 61.76 | 61.76 | 61.76 | 61.76 | 61.76 | 61.76 | 61.76 | 61.76 | 61.76 | 54.65 |

**Table 6: Base Load Profile with storage and Alt. Energy Generation**

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### Other assumptions:

[A] The Force Provider SBC load profile assumes peak load duration of 25% (i.e. 15 minutes) in any given hour.

[B] Present generation scenario assumes no asset control and no automatic on/off control.

It is assumed that the peak facility loads will only occur in 85% of any facilities at any given time throughout a day. It is also assumed that any generators operating in parallel are equipped with a governor load sharing controller. The controller shall be provided to permit initial matching of governor paralleling circuits for sets operating in parallel. This controller is assumed to accomplish "load kW sharing adjustments". In addition, a voltage regulator paralleling controller is assumed to be provided to permit adjustment of division of the reactive kVA among sets operated in parallel. This controller is assumed to accomplish "reactive kVA current adjustments ".

[C] Ignore transformer losses throughout all Cases, including the step down from 4160V to 480V and the step down from 4160 to 208 required to serve the load from the 840kW generator in Case 2.

[D] Assume generator fuel consumptions are linear above 25% load [Ref. 3].

## References

[1] Department of the Army. Engineer Prime Power Operations, FM 3-34.480, April 2007.

[2] Department of the Army. Quartermaster Force Provider Company. August 1999.

[3] Diesel Service and Supply, Inc. "Approximate Fuel Consumption Chart." Accessed October 22, 2007.

[4] U.S. Army Corps of Engineers. "Base Camp Utility Technology Matrix." September, 2004.

[5] Army Environmental Policy Institute. "AEPI Report: Sustain the Mission Project: Energy and Water Costing Methodology and Decision Support Tool: Final Technical Report." July 2008.

[6] Dan Nolan, US Rapid Equipping Force, Worldwide Energy Conference April 14, 2008.

[7] Boswell, Major Randall J. Air Command and Staff College, Air University. "The Impact of Renewable Energy Sources on Forward Operating Bases." April, 2007.

[8] Wertz, Robert. Manager, Advanced Technical Programs, Concurrent Technologies Corporation, November 2008.

[9] Weiss, Gary. VP Marketing, Westwood Corporation, November 2008.

[10] Army Energy Security Task Force. "Army Energy Security – The Way Ahead." PowerPoint Presentation, given June 19, 2008. Sales and

# Appendix D: Community Energy Storage Functional Test Report

**DNV KEMA Energy & Sustainability**

**KEMA-Powertest, LLC,**

*Test Report # 20130040*

**Product Tested:**

Community Energy Storage System

Type: S&C Electric Purewave unit

with 25kW Kokam Li-ion battery

**Tested For:**

Basic Operation

Round Trip Efficiency

Frequency Regulation

Peak Shaving

Islanding

Basic Impulse Level

**Date of Tests:**

March 21, 2012 through October 3,2012

DNV KEMA Powertest, LLC 4379 County Line Road Chalfont PA 18914

T +1 215 822 4231 F +1 215 822 4267 www.kema.com

**REPORT OF PERFORMANCE NUMBER: 20130040**

| | |
|---|---|
| CLIENT: | DTE Energy<br>One Energy Plaza<br>Detroit, MI 48226 |
| PRODUCT TESTED: | Community Energy Storage System<br>S&C Electric Purewave unit<br>with 25kW Kokam Li-ion Battery |
| DATES OF TESTS: | March 21, 2012 – July 4, 2012 |
| TESTED FOR: | Basic Operation<br>Round Trip Efficiency<br>Frequency Regulation<br>Peak Shaving<br>Islanding<br>Basic Impulse Level |
| APPLICABLE STANDARD(S): | IEEE 1547.1and IEEE 519 as reference only. |

These tests have been carried out in accordance with the client's instructions based on the KEMA Client Test Plan agreed to by the Client and KEMA-Powertest, LLC.

This report contains the results of the tests performed at KEMA-Powertest Laboratory on the above noted equipment. Publication or reproduction of the contents of this report in any form other than a complete copy is not permitted without written approval of KEMA-Powertest.

Measurement uncertainty can be verified by reviewing the instrument calibration records. The instruments used are calibrated on a regular basis and are traceable to the National Institute of Standards and Technology.

The results apply only to the specific devices tested and are recorded on the enclosed tables, graphs, photographs, etc. A table of contents is included on page 3.

Alexander Feldman, VP of Engineering, KEMA-Powertest, LLC
Date: February 10, 2013

## TABLE OF CONTENTS

## Description of Test Product

| | |
|---|---|
| Name: | Community Energy Storage System |
| Manufacturer: | S&C Electric Company |
| Catalog number: | PEA-1429-4 |
| Type: | Utility Interactive with Charge Control |
| Name: | ESS Battery Assembly |
| Manufacturer: | Myungshin |
| Catalog number: | MA1428K |
| Type: | Lithium Ion Battery |

System Nominal Ratings:

Capacity: 25kW

Voltage: 240Vac Split Phase

Frequency: 60Hz

Test sample was received March 21, 2012 in good condition. The battery was replaced on May 1, 2012. All tests performed prior to this will not be part of this report.

## Identification of Test Device

One sample was used for testing:

CES Unit Serial Number: 1058

Battery Unit Serial Number: MCESA141FF11

**Test Equipment Used:**

| Equipment Use Log | | | | | |
|---|---|---|---|---|---|
| **Type** | **Manufacturer** | **Model Number** | **Serial Number** | **Calibration Code** | **Calibration Due Date** |
| High Precision Test Set | Omicron | 256+ | ME440G | MSC149 | 8/23/2013 |
| Voltage Divider | JMX | ICD-1400 | 121051245 | VDC24 | 7/19/2013 |
| CT Current Transformer | Pearson | 110 | 111060 | CTX131 | 4/20/2013 |
| Low Resistance Ohm Meter | Raytech | Micro Centurion 2 | 263117 | BRG16 | 1/22/2013 |

All measurements were taken with the KEMA DAS data acquisition system. The voltage current and temperature measurement system is calibrated before use using the Omicron 256+.

**Tests Witnessed by:**

| Name | Company |
|---|---|
| Brandon Zander | KEMA-Powertest, LLC |
| | |
| | |
| | |

**Tests Conducted by:**

| Name | Company |
|---|---|
| Kevin Lindenmuth | KEMA-Powertest, LLC |
| | |
| | |
| | |

**Report Prepared By:** Kevin Lindenmuth, KEMA-Powertest, LLC Engineering
Brandon Zander, KEMA-Powertest, LLC Engineering

# 1.0 Basic Operations Test

## 1.1 Summary, Basic Operations test:

The purpose of the test was to confirm all operating modes for correct operation. This Includes: normal local operation, remote monitoring and control, abnormal operation, and safety related fault conditions. The time required would be better spent on performance testing where the CES system logged data would be compared to the measured data from the KEMA DAS system. Therefore, it was decided not to perform a complete formal basic op test. All alerts, warnings, and faults that occurred during performance testing were logged in the test log and discussed with the manufacturer.

The CES responded without issue to commands through the HMI computer connected to the local Ethernet network port. Two HMI applications ran concurrently to monitor and control the CES. The local or browser based HMI monitored CES status and created a log file, updating every 10 seconds. The CES parameter view and edit HMI was used to control the power in and out of the system and to monitor BMS data. Screenshots were taken for documentation purposes during performance tests.

### 1.1.1 Local, Initial System Startup:

The only unexpected result encountered at startup was related to low line voltage. The battery was connected by the S+C field service technician and 120/240 Split phase 60Hz ac power was applied to the Source terminals of the CES. The incoming line voltage measured 112 Vac Line to Neutral and the CES alarmed for Undervoltage. The Minimum Vac and Stable Low Voltage parameters were changed from 115 to 110Vac for the remainder of the tests. The S+C PC was connected to the local network and the BMS data was monitored. The HMI screen showed that the battery was at 84.0%SOC. The CES was manually set real power to -25kW to charge to 100%SOC. When commanded the dc contactor closed and the battery charged without issue.

### 1.1.2 Remote Monitoring and Control:

Remote testing was performed and proven during the frequency regulation test. A script was written by DTE to represent an actual demand profile sending a power amplitude and direction command every 4 seconds through the remote network port using DNP3 protocol, simulating the utility dispatch signal from the control hub. No issues related to remote control were found during the Frequency Regulation test.

See section 3 Frequency Regulation Test of this report for more detail.

# 2.0 Round Trip Efficiency Test

## 2.1 Purpose of the Round Trip Efficiency test:

The purpose of the test was to determine the discharge/charge efficiency of the CES system while operating at full rated power through the normal operating range of 10 percent to 90 percent state of charge. This is as specified in Appendix A KEMA Client Test Procedure.

## 2.2 Description of Round Trip Efficiency test setup:

The CES will discharge and charge to the grid through the KEMA power transformer. There is no load connected. See Fig 1 in Appendix B for single line diagram of the test set up. The AC line voltage, current, and battery voltage and current will be measured with the KEMA DAS.

## 2.3 Round Trip Efficiency Test Procedure:

Prior to the RTE test, the fully charged CES unit was discharged until it reached 90 percent state of charge. The test started by discharged from 90 percent down to a 10 percent state of charge at its full power rating. Upon reaching the lower discharge limit, the unit was then recharged until it reached 90 percent state of charge again. The unit was then fully recharged and allowed to sit idle for several hours to allow the IGBT's to cool. The procedure was then repeated for a total of two round trip efficiency tests per day for five days. Measurements were taken at a rate of 1 kHz on the line voltages and currents as well as battery voltage, battery current, and several temperature readings.

Line voltage and current, along with elapsed time, were used to calculate the amount of energy in watt-hours that was discharged from and then subsequently recharged into the lithium ion battery pack. The calculation of watt-hours out of the battery divided by the watt-hours into the battery times 100 percent was used to determine the overall round trip efficiency. This calculation was performed on both the AC and DC sides of the unit. Round trip efficiencies were compared with those calculated using the internal measurements of the CES unit.

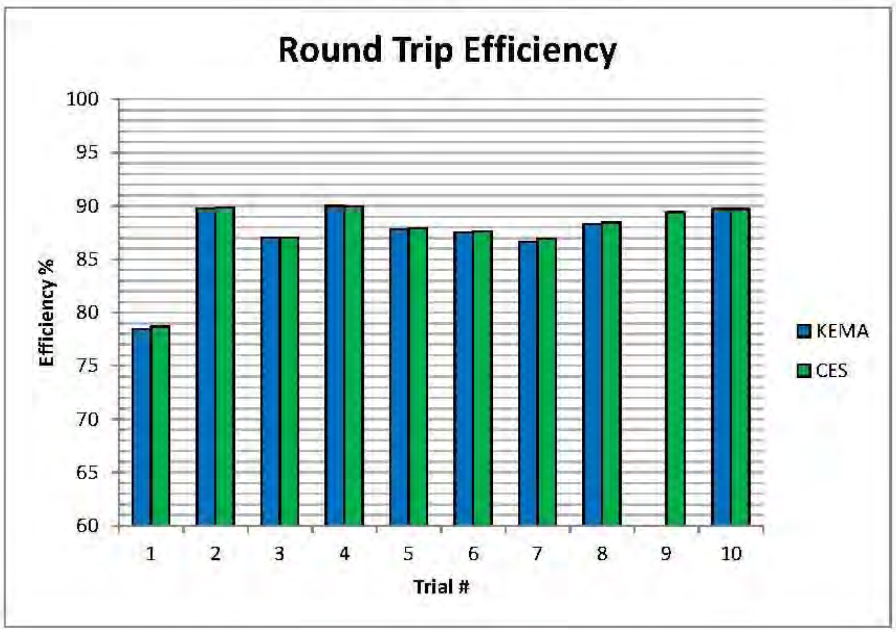
### 2.4 Results – Round Trip Efficiency Test:

Below is a summary of test results. The following page is a table of all RTE tests including CES recorded data and KEMA DAS recorded data.

Please note that Trial 1 had an issue with SOC jumping from 10% to 0% at the end of discharge. Consequently the subsequent charge was from 0% to 90% and the round trip efficiency calculation was affected. The client was notified of this.

KEMA DAS data for Trial #9 was lost due to the PC locking up before the system could store the file. Trial 9 CES data is included.

Chart 1 AC Round Trip Efficiency



## 2.4 Continued, Results – Round Trip Efficiency Test:

Table 2, AC Efficiency ($WH_{out}/Win$)

| Trial # | CES | KEMA |
|---|---|---|
| 1 | 78.68 | 78.43 |
| 2 | 89.86 | 89.78 |
| 3 | 87.04 | 87.02 |
| 4 | 89.95 | 90.02 |
| 5 | 87.91 | 87.8 |
| 6 | 87.62 | 87.51 |
| 7 | 86.93 | 86.64 |
| 8 | 88.44 | 88.31 |
| 9 | 89.43 | |
| 10 | 89.7 | 89.72 |
| Average | 87.56 | 87.25 |
| Standard Deviation | 3.325 | 3.534 |

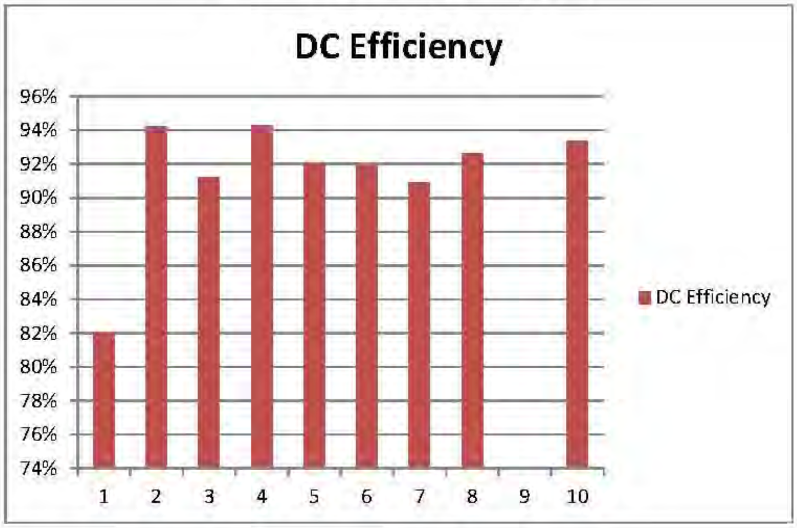
## 2.41 Continued, Results – Sound Level:

Sound level was not formally tested. The test plan asked that noise Levels be measured during several tests. The hand held sound meter directed toward the CES during the first round trip efficiency test measured above the 48dBA specified in the OEM manual. The manufacturer has identified the source and the inductive components producing excessive noise will be replaced with a different design in subsequent CES systems. It was agreed that measuring sound level on this CES test sample would provide no useful information.

## 2.42 Continued, Results – DC Efficiency

The following table shows DC efficiency calculating VAhours in and out of the battery measured during the Round Trip Efficiency tests. The current was measured using a Current transducer on the positive battery cable. DC voltage was measured at the bottom side + - terminals inside the CES enclosure. Efficiency is Discharge VAhours/ Charge VAhours.

Chart 2, DC Efficiency ($VAh_{out}/Vah_{in}$)



# 3.0 Frequency Regulation Profile Test

## 3.1 Purpose of the Frequency Regulation Profile Test:

The purpose of the test was to determine the ability of the CES system to perform a simulated frequency regulation profile. The power command signal will be received remotely through the DNP3 connection. This is as specified in the KEMA Client Test Procedure, Appendix A.

## 3.2 Description of the Frequency Regulation Profile Test Setup:

The CES will discharge and charge to the grid through the KEMA power transformer. There is no load connected. See Fig 1 in Appendix B for single line diagram of the test set up. The AC line voltage, current, and battery voltage and current will be measured with the KEMA DAS.

## 3.3 Frequency Regulation Profile Test Procedure:

The direction and amplitude of power is commanded from a DTE developed script. The commands were given through the remote (Utility) port using DNP3 protocol. The local S+C HMI was not needed to control the CES during this test.

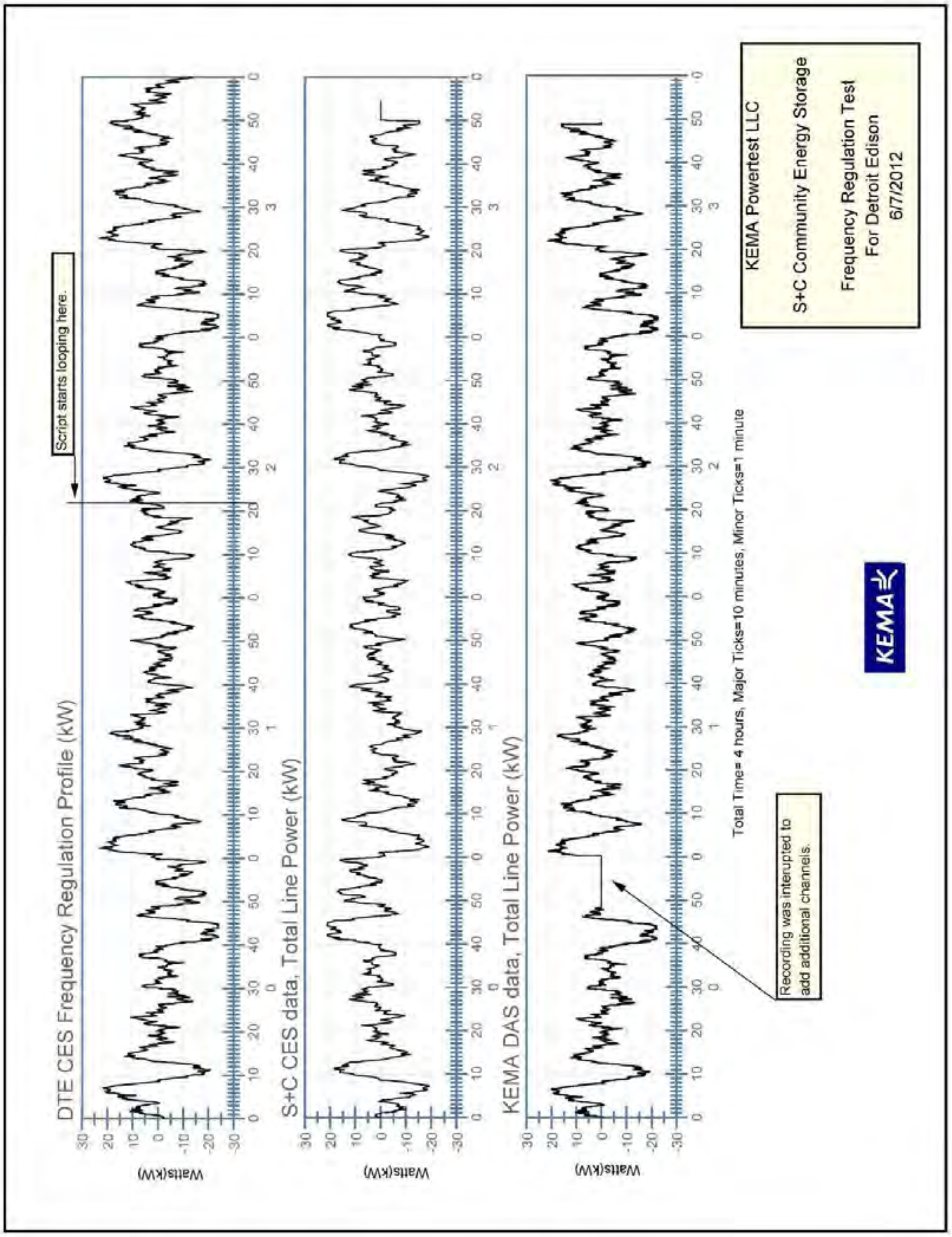
## 3.4 Results – Frequency Regulation Profile Test:

The first graph is the DTE CES Frequency Regulation Profile, extended to cover 4 hrs.

The second graph is the S+C CES recorded data, Total Line Power values x25 for KW. Note that the direction of the CES waveform is opposite that of the commanded profile. The Client was notified and investigating the cause.

The third graph is from the KEMA DAS data acquisition system. Note that the DAS recording was interrupted for 12 min near the end of the first hour to add more channels, specifically battery voltage and current sensors. The KEMA graph (VA) is L1 Current x L1 Voltage.

## 3.0 Continued, Frequency Regulation Profile Test:



# 4.0 Peak Shaving Profile Test

## 4.1 Purpose of the Peak Shaving Profile Test:

The purpose of the test was to determine the ability of the CES system to perform the Peak Shaving Profile without capacity or operation issues. This is as specified in the KEMA Client Test Procedure.

See Appendix A for KEMA Client Test Procedure.

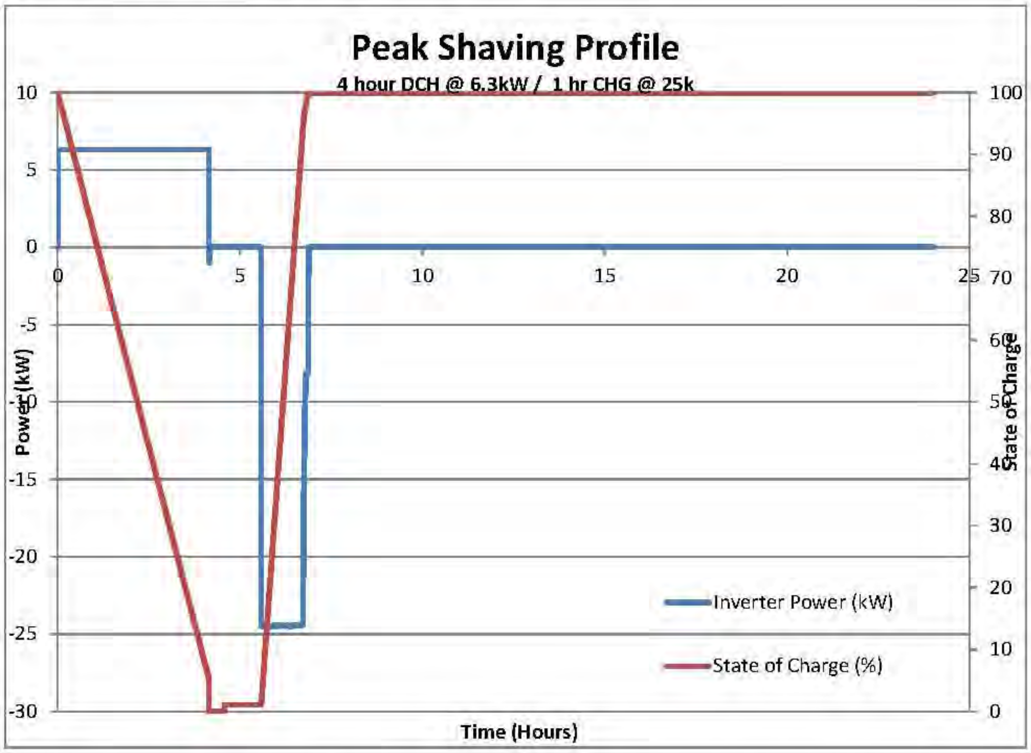
## 4.2 Description of Peak Shaving Profile test setup:

This test requires that the CES system be powered from the transformer with no load connected. The test control is performed manually through the S+C HMI pc connected to the local port. Measurements of line voltage, current and temperature were measured and recorded with the KEMA DAS system. The sampling rate was set at 1kHz.

## 4.3 Peak Shaving Profile Test Procedure:

A fully charged CES unit was discharged at a rate of 6.3 kW for four hours. The unit was allowed to rest for 2 hours and then was given a 25kW charge to 100 percent state of charge. Measurements were taken at a rate of 200Hz on the voltage and current of the CES unit. Voltage and current were used along with time to calculate the power discharged and charged by the unit as well as the units round trip efficiency.

## 4.4 Results – Peak Shaving Profile Test:




The unit was able to provide 6.3kW of power for 4 hours without reaching a zero percent state of charge. The unit was recharged at 25kW for about an hour. The overall efficiency of the unit was 85% over the duration of the test. This number would have been higher if the charge had taken place over a longer period of time at a lower rate. The BMS also recalculated state of charge following the discharge which reset the battery state of charge to zero. Had the SOC remained at 5 percent, less energy would have been required to recharge the battery which also would have increased efficiency.

# 5.0 Islanding Test

## 5.1 Purpose of the Islanding test:

The purpose of the test was to determine the ability of the test unit to perform the Islanding test. The CES test device must recognize a loss of line voltage and disconnect from the line and supply power from the battery through the inverter to the load within the specified time. This is as specified in Appendix A KEMA Client Test Procedure.

## 5.2 Description of Islanding test setup:

See Figure 2 in Appendix B for Single line diagram and photos of the test bed. The load bank was used during the tests. The CES was controlled through the S+C HMI connected through the CES local port. Data was recorded with the KEMA DAS system as well as the CES internal data logging.

## 5.3 Islanding Test Procedure:

A fully charged CES unit was paralleling the grid as it was used to power a load. While paralleling the grid, the external circuit breaker between the CES unit and the transformer was manually opened. The unit then transitioned into islanding mode where the inverter provided power to the load and CB-1 opened to isolate from the grid. After ten seconds the circuit breaker was manually closed, restoring power to the CES unit from the grid. After the CES unit had received stable power from the grid for five minutes plus its random time setting, CB-1 closed placing the CES unit in grid parallel mode. Line voltage, line current, load voltage, and load current were all measured at a rate of 20 kHz. The test was then repeated but grid power was only restored after all of the available energy in the battery had been depleted.

The time required to transition into islanding mode and the time required to transition back to grid parallel mode were recorded. The unit was also monitored to determine whether or not it transitioned in phase with the voltage and current being supplied from the grid.

## 5.4 Results – Islanding Test

Islanding tests were performed with resistive, inductive, and capacitive loads. See Figure 1 and Table 1 for results. The reactive load bank was adjusted to provide maximum phase shift and the commanded power was adjusted to provide maximum power without overloading the CES. The longest transition time was for the inductive load 23.35 milliseconds. IEEE states that the transition time must be below 2 cycles, 32ms.

1. Resistive Load: Voltage and current were in phase and the inverter produced the least distorted waveform. The Islanding transition measured 22.3ms.

2. Inductive Load: 250V Peak voltage of inductive ringing at 166 Hz measured during the transition. The Islanding transition measured 23.35ms. This is the longest time measured from all Islanding tests.

3. Capacitive Load: 100Vdc during the transition. The inverter produced a very distorted waveform. The Islanding transition measured 21.3ms.

Islanding tests were also performed while connected to the resistive load bank and the CES in 3 different operating modes with similar results.

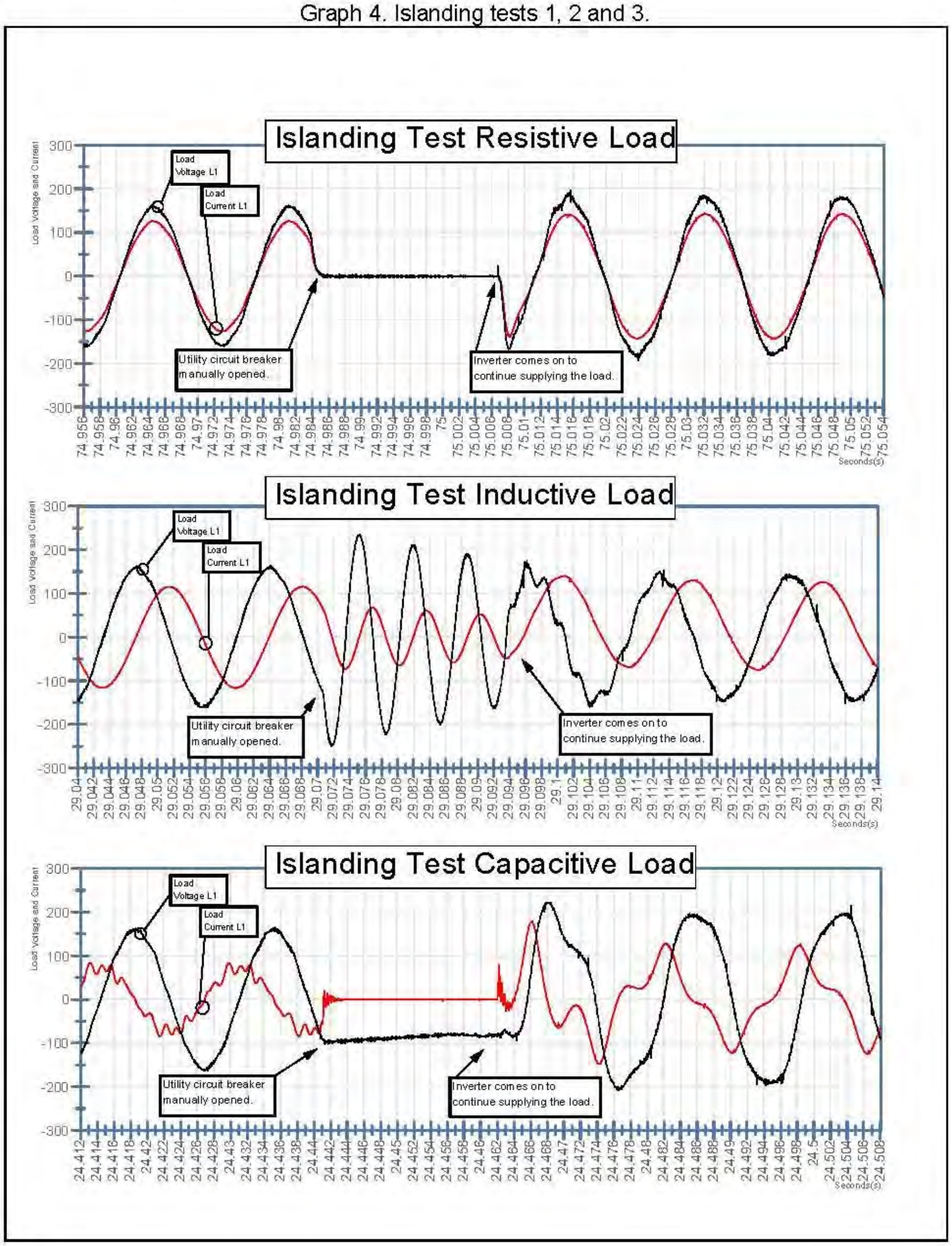
4.This test was performed with 0(zero) kW commanded. The CES transitioned into Islanding mode in 21.5milliseconds.

5. This test had 11kW from the utility and 10kW discharge commanded from the CES delivering 22 total kW to the load. When the utility was removed the CES changed from 10 to 22kW to make up for the lost utility.

6. This test had 22kW from the utility and no power commanded from the CES. When the utility was removed the internal ac breaker opened isolating the line. The inverter came on providing 22kW to the load. The CES was allowed to continue to discharge toward 0%SOC. The CES stopped discharging at 7%SOC and the message on the HMI: Minimum SOC reached.

## 5.4 Continued, Results - Islanding Test:

Graph 4. Islanding tests 1, 2 and 3.

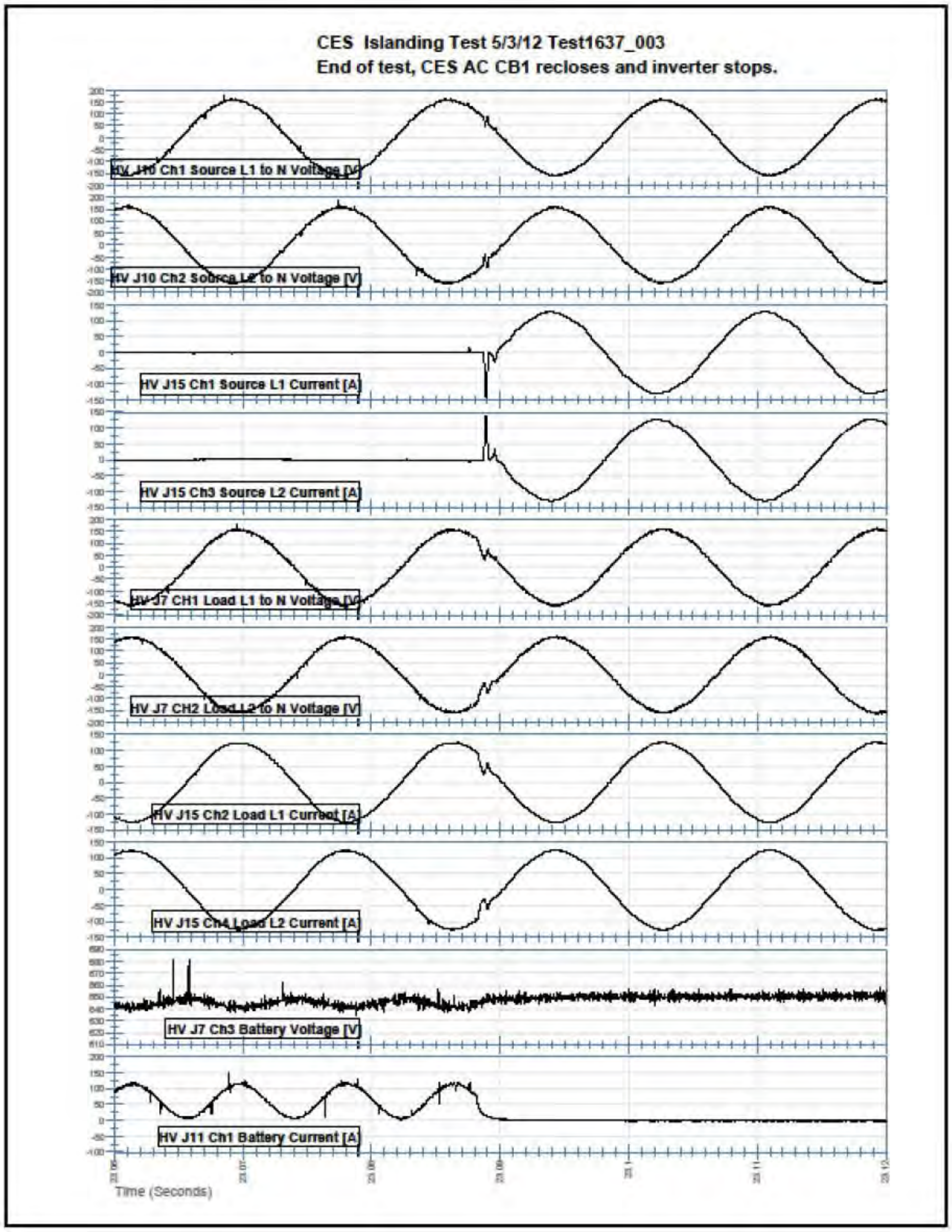


### 5.4 Continued, Results for Islanding tests 1,2, and 3.

| ISLANDING TEST | Utility Power | Inverter Power | Utility Power | Inverter Power | Utility Power | Inverter Power |
|---|---|---|---|---|---|---|
| | Resistive load | Resistive Load | Inductive Load | Inductive Load | Capacitive Load | Capacitive Load |
| KEMA DAS FILE | 1637 | 1637 | 1655 | 1655 | 1709 | 1709 |
| VrmsL1toN(V)= | 111.6 | 116.92 | 111.49 | 114.34 | 112.08 | 119.67 |
| VrmsL2toN(V)= | 111.6 | 116.52 | 111.46 | 114.44 | 112.04 | 119.52 |
| IrmsL1(A)= | 88.51 | 92.42 | 81.7 | 83.91 | 52.67 | 59.4 |
| IrmsL2(A)= | 87.91 | 91.74 | 81.13 | 83.3 | 52.32 | 58.97 |
| Power Apparent(VA)= | 19688.95 | 21494.76 | 18151.57 | 19126.89 | 11765.72 | 14156.54 |
| Phase Angle(deg)= | -0.1459 | 0.0503 | 87.7046 | 86.5749 | -89.5828 | -86.2194 |
| Current Lead/Lag= | In Phase | In Phase | Ind, C Lags V. | Ind, C Lags V. | Cap, V Lags C. | Cap, V Lags C. |
| Power Factor= | 0.9999 | 0.9999 | 0.0401 | 0.0597 | 0.0073 | 0.0659 |
| Power Real(W)= | 19688.88 | 21494.75 | 727 | 1142.7 | 85.67 | 933.42 |
| Power Reactive(VARs)= | 50.14 | 18.87 | 18137.01 | 19092.73 | 11765.41 | 14125.74 |
| | | | | | | |
| **Time (Milliseconds) Utility off, Inverter On.** | **22.3** | | **23.35** | | **21.3** | |
| | | | | | | |

## 5.4 Continued, Results for Islanding test

Graph 2 End of Islanding test. Minor disturbance to load current and voltage when internal CES breaker recloses. Note that the battery current drops to zero.



# 6.0 Harmonics Analysis

## 6.1 Summary:

Harmonic analysis was performed on the data recorded during 3 Islanding tests in section 4 of this report. The data was recorded at 20kHz sampling rate, the highest resolution available from the KEMA data acquisition system. The harmonic analysis uses National Instruments, Diadem Fast Fourier Transform FFT function and Total Harmonic Distortion and Total Demand Distortion were calculated using the IEEE Std. 519 standard for 3 tests where the CES was discharging into resistive, inductive, and capacitive loads.

The tables in the following section show each harmonic measured amplitude values in volts or amps and also the percent of fundamental where the fundamental frequency 60Hz is 100%.

Note that negligible values, mostly even harmonics, were omitted from the table.

Note that the values in red are above the limit set by IEEE Std. 519 Table 10-1 allowing for individual harmonics to be less than 1.0% of the fundamental.

The THD limit set by IEEE Std. 519 Table 10-2 allows 5.0%.

Note that 80$^{th}$ harmonic at 4800Hz is the switching frequency of the system.

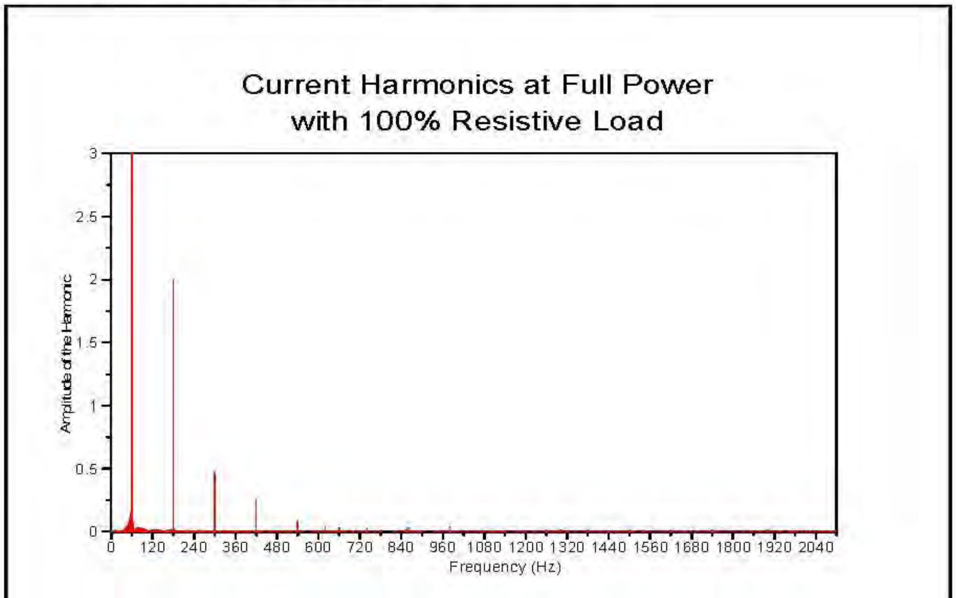
The graphs show amplitude vs. frequency curves and current and voltage vs. time curve for each load type. Be careful comparing the graphs. They are scaled differently to better show the amplitude of the harmonics and not the fundamental amplitude. The inverter running portion, second half, of Fig. 4 shows the same distortion.

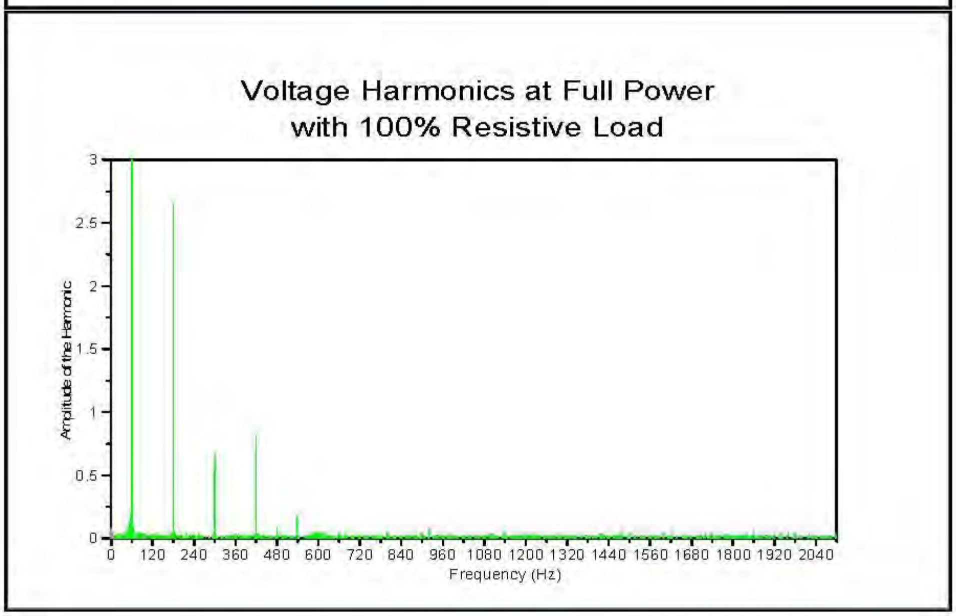
## 6.2 Harmonic Analysis Resistive Load:

| | Resistive Load, Voltage Harmonics | | | |
|---|---|---|---|---|
| | Line 1 | % of Fund. | Line 2 | % of Fund. |
| Fundamental | 162.2 | - | 161.7 | - |
| 2nd | | | | |
| 3rd | 2.65 | 1.63% | 2.48 | 1.53% |
| 4th | | | | |
| 5th | 0.654 | 0.40% | 0.543 | 0.34% |
| 6th | | | | |
| 7th | 0.812 | 0.50% | 0.337 | 0.21% |
| 8th | | | | |
| 9th | 0.171 | 0.11% | 0.135 | 0.08% |
| 10th | | | | |
| 11th | 0.0399 | 0.02% | 0.0274 | 0.02% |
| 80th | 1.185 | 0.73% | 1.192 | 0.74% |
| THD | 2.82% | | 2.71% | |

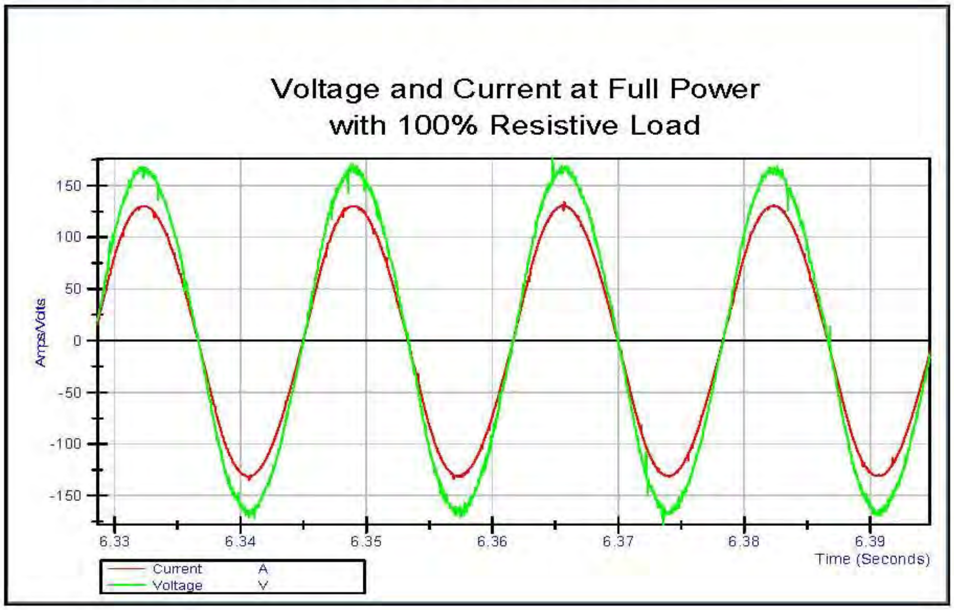
| | Resistive Load, Current Harmonics | | | |
|---|---|---|---|---|
| | Line 1 | % of Fund. | Line 2 | % of Fund. |
| Fundamental | 128.3 | | 127.3 | |
| 2nd | | | | |
| 3rd | 2 | 1.56% | 1.98 | 1.56% |
| 4th | | | | |
| 5th | 0.473 | 0.37% | 0.469 | 0.37% |
| 6th | | | | |
| 7th | 0.248 | 0.19% | 0.245 | 0.19% |
| 8th | | | | |
| 9th | 0.0828 | 0.06% | 0.0838 | 0.07% |
| 10th | | | | |
| 11th | 0.0305 | 0.02% | 0.0326 | 0.03% |
| THD | 2.21% | | 2.20% | |
| TDD | 0.71% | | 0.70% | |

## 6.2 Continued, Harmonic Analysis Resistive Load:



### 6.2 Continued, Harmonic Analysis Resistive Load:

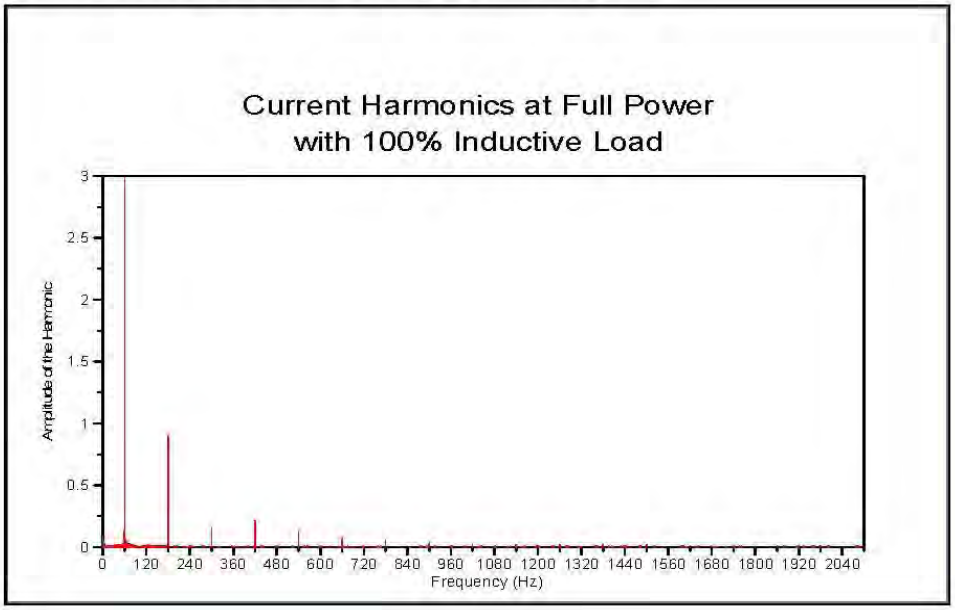


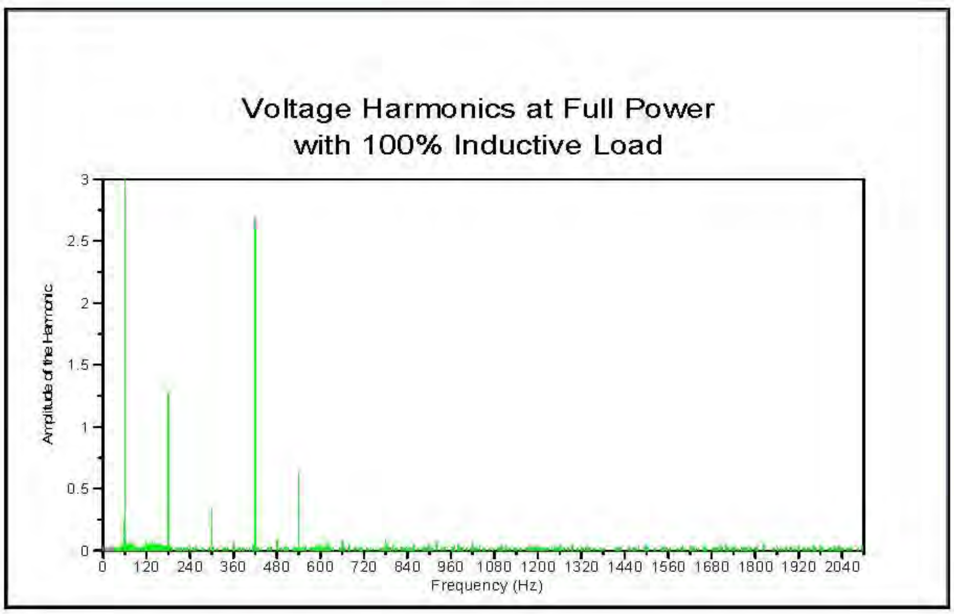
### 6.3 Harmonic Analysis Inductive Load:

| | Inductive Load, Current Harmonics | | | |
|---|---|---|---|---|
| | Line 1 | % of Fund. | Line 2 | % of Fund. |
| Fundamental | 117.1 | | 116.3 | |
| 2nd | | | | |
| 3rd | 0.902 | 0.77% | 0.897 | 0.77% |
| 4th | | | | |
| 5th | 0.159 | 0.14% | 0.157 | 0.13% |
| 6th | | | | |
| 7th | 0.208 | 0.18% | 0.212 | 0.18% |
| 8th | | | | |
| 9th | 0.13 | 0.11% | 0.129 | 0.11% |
| 10th | | | | |
| 11th | 0.0721 | 0.06% | 0.0708 | 0.06% |
| THD | 1.46% | | 1.49% | |
| TDD | 0.43% | | 0.43% | |

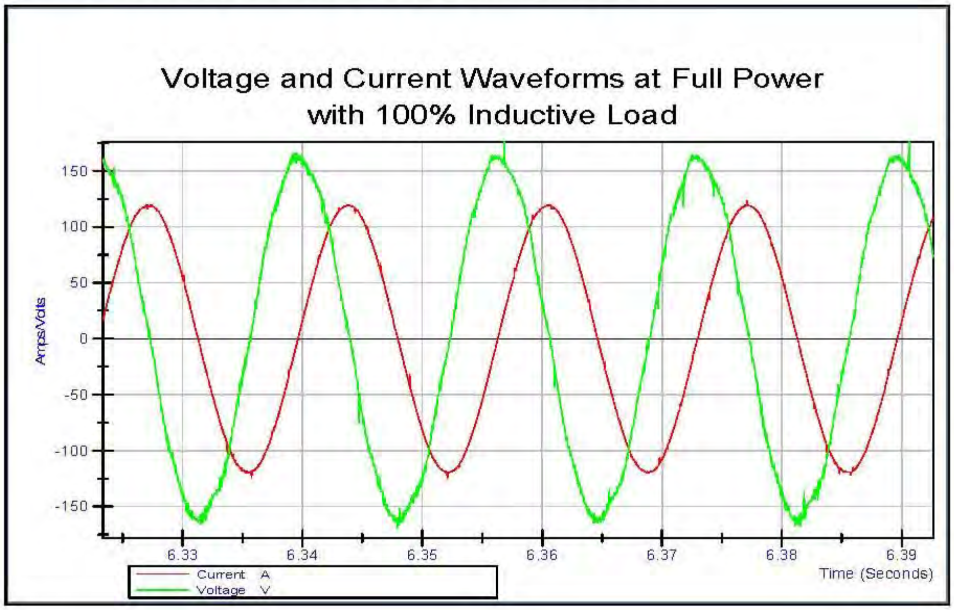
| | Inductive Load, Voltage Harmonics | | | |
|---|---|---|---|---|
| | Line 1 | % of Fund. | Line 2 | % of Fund. |
| Fundamental | 159.5 | | 159.6 | |
| 2nd | | | | |
| 3rd | 1.27 | 0.80% | 1.2 | 0.75% |
| 4th | | | | |
| 5th | 0.356 | 0.22% | 0.452 | 0.28% |
| 6th | | | | |
| 7th | 2.69 | 1.69% | 2.9 | 1.82% |
| 8th | | | | |
| 9th | 0.628 | 0.39% | 0.672 | 0.42% |
| 10th | | | | |
| 11th | 0.0814 | 0.05% | 0.08 | 0.05% |
| 80th | 1.38 | 0.87% | 1.39 | 0.87% |
| THD | 2.92% | | 3.00% | |

## 6.3 Continued, Harmonic Analysis Inductive Load:



## 6.3 Continued, Harmonic Analysis Inductive Load:

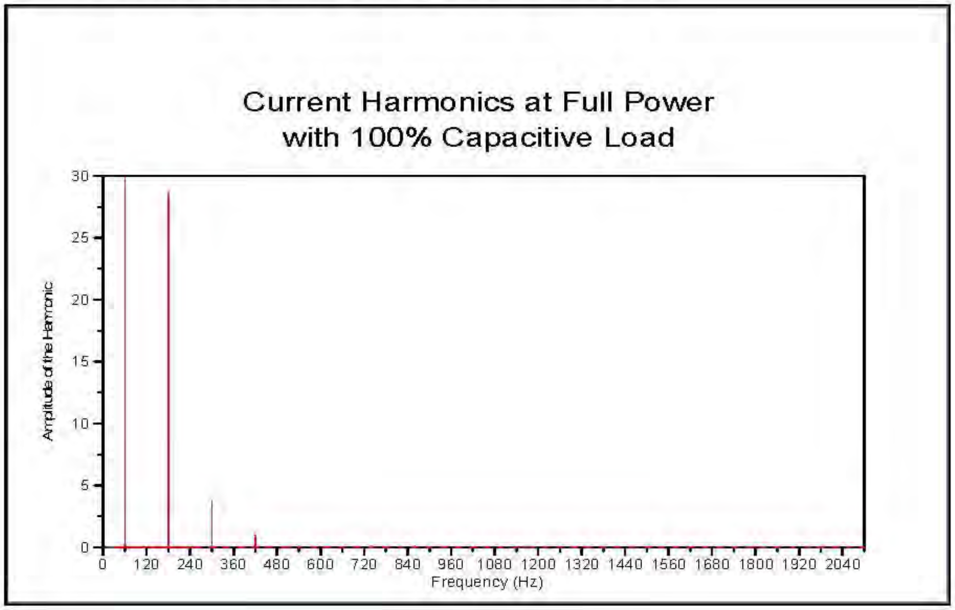


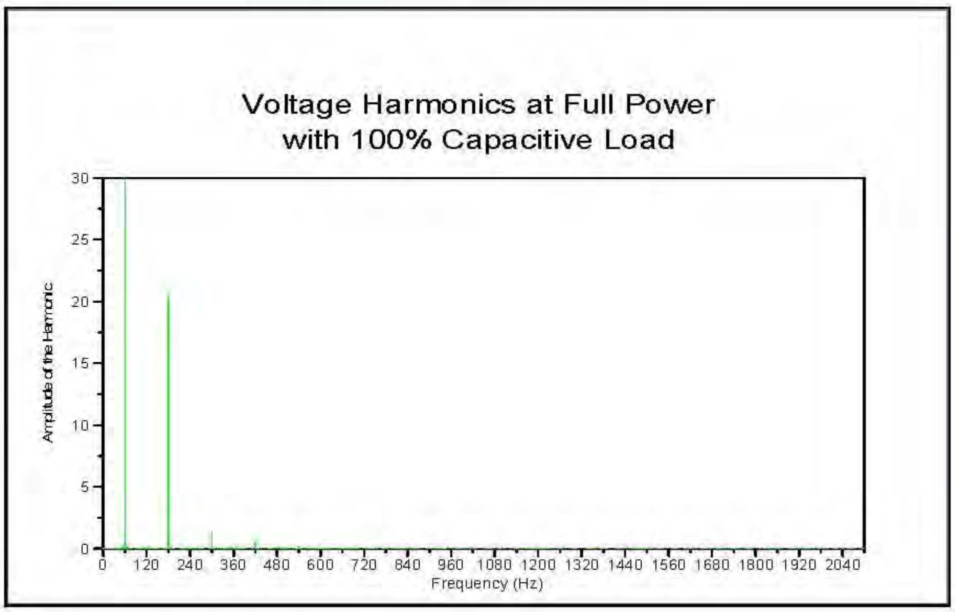
## 6.4 Harmonic Analysis Capacitive Load:

| | Capacitive Load, Current Harmonics | | | |
|---|---|---|---|---|
| | Line 1 | % of Fund. | Line 2 | % of Fund. |
| Fundamental | 57.9 | | 57.5 | |
| 2nd | | | | |
| 3rd | 28.6 | 49.40% | 28.4 | 49.39% |
| 4th | | | | |
| 5th | 3.7 | 6.39% | 3.67 | 6.38% |
| 6th | | | | |
| 7th | 0.937 | 1.62% | 0.934 | 1.62% |
| 8th | | | | |
| 9th | 0.0646 | 0.11% | 0.0648 | 0.11% |
| 10th | | | | |
| 11th | 0.0332 | 0.06% | 0.0342 | 0.06% |
| THD | 49.95% | | 49.95% | |
| TDD | 7.23% | | 7.17% | |

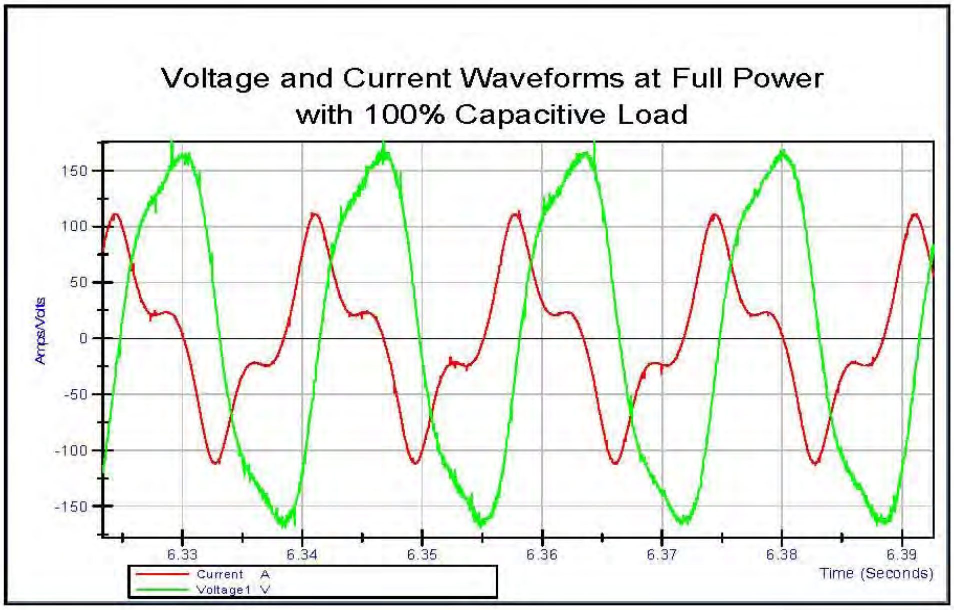
| | Capacitive Load, Voltage Harmonics | | | |
|---|---|---|---|---|
| | Line 1 | % of Fund. | Line 2 | % of Fund. |
| Fundamental | 124.8 | | 124.6 | |
| 2nd | | | | |
| 3rd | 20.4 | 16.35% | 20.3 | 16.29% |
| 4th | | | | |
| 5th | 1.31 | 1.05% | 1.65 | 1.32% |
| 6th | | | | |
| 7th | 0.541 | 0.43% | 0.519 | 0.42% |
| 8th | | | | |
| 9th | 0.137 | 0.11% | 0.0282 | 0.02% |
| 10th | | | | |
| 11th | 0.0199 | 0.02% | 0.049 | 0.04% |
| 80th | 1.54 | 1.23% | 1.56 | 1.25% |
| THD | 16.80% | | 16.78% | |

## 5.4 Continued, Harmonic Analysis Capacitive Load:



### 6.4 Continued, Harmonic Analysis Capacitive Load:



# 7.0 BIL Test

## 7.1 Purpose of the BIL test:

Verify that the basic lightning impulse level of the test device is as stated by the manufacturer.

## 7.2 BIL Test Set up:

See appendix C for photos of test set up. The angle iron CES test stand was designed to locate the CES unit above the battery similar to their position when installed. The battery terminals along with J7 and J8 connections were connected. The battery case is grounded to the CES ground point inside the terminal bay and also the low side of the Impulse generator is grounded.

The KEMA lightning impulse generator was connected to a calibrated voltage divider and the system was adjusted to discharge at 30kV maximum. An open circuit test was performed to verify the instrumentation and the actual open circuit voltage measured was 29.6kV. The IG output cable was then attached to the CES test device, location specified by Table 1 in the test procedure.

## 7.3 BIL Test Procedure:

Prior to any BIL testing the HMI pc network cable was connected to the CES local port and the CES selector switch in the Local position. 24Vdc was applied to the hot start terminals and the red hot start PB pressed. Led lights and HMI communication confirmed operation. The status screen shows a fault condition for Battery Cell Over/Under Voltage and the Battery BMS screen showed the battery at 0%SOC. The customer is aware of the self discharge issue and the fault will not affect the BIL test. Proper operation before and after every test will be indicated by establishing communications and observing the data being retrieved and displayed.

The test was performed in accordance with the KEMA Test Procedure. The following table was used to identify test number and terminal connection.

| BIL TEST | Source Line 1 | Source Line 2 | Source Neutral | Load Line 1 | Load Line 2 | Load Neutral |
|---|---|---|---|---|---|---|
| Num | Connect to: | Connect to: | Connect to: | Connect to: | Connect to: | Connect to: |
| 1 | IG High Voltage | Ground | Ground | Ground | Ground | Ground |
| 2 | Ground | IG High Voltage | Ground | Ground | Ground | Ground |
| 3 | Ground | Ground | Ground | IG High Voltage | Ground | Ground |
| 4 | Ground | Ground | Ground | Ground | IG High Voltage | Ground |
| 5 | IG High Voltage | Ground | Ground | Open | Ground | Ground |
| 6 | Ground | IG High Voltage | Ground | Ground | Open | Ground |

**TABLE 1**

## 7.4 BIL (Basic Impulse Level) Test Results

The following Table 2 is a summary of each test. Refer to Table 1 for the test connection. The voltage was measured at the high voltage test device connection to ground. The current is DC and was measured using a CT in the ground cable.

| Trial | Peak Voltage | Peak Current |
|---|---|---|
| Pretest | 29.6 kV | 0.01 kA |
| 1 | 2.1 kV | -0.27 kA |
| 2 | 2.0 kV | -0.28 kA |
| 3 | 2.0 kV | -0.28 kA |
| 4 | 2.0 kV | -0.27 kA |
| 5 | 2.0 kV | -0.21 kA |
| 6 | 2.0 kV | -0.28 kA |

**TABLE 2**

Each test produced very similar results. The current measurement trace clipped during test 5. The scale was adjusted for test 6. The wave shape appeared identical so step 5 was not repeated.

The test device internal resistance was measured with the Raytech low resistance ohmmeter.

Source Line 1 to Load 1 with CB closed : 618.05 micro ohms

Source Line 2 to Load 2 with CB closed : 653.70 micro ohms

The 30kv was applied to the high voltage cable was clipped to ground bypassing the test device. The drop across the short circuit 900V and short circuit current 280A was measured.

Without knowledge of the CES internal circuitry it is difficult to evaluate where the paths to ground occur.

## 7.4 Continued, BIL Test Results:

The following waveform is from the open circuit pretest condition, without the CES connected. The voltage measured was 29.6kV Open Circuit Voltage.

# Impulse Waveform Data Sheet

***DNV-KEMA / KEMA-Powertest, LLC***

Impulse 2010 V10.0.0.16 | JMX Services, Inc. | 10/02/1212:13 PM

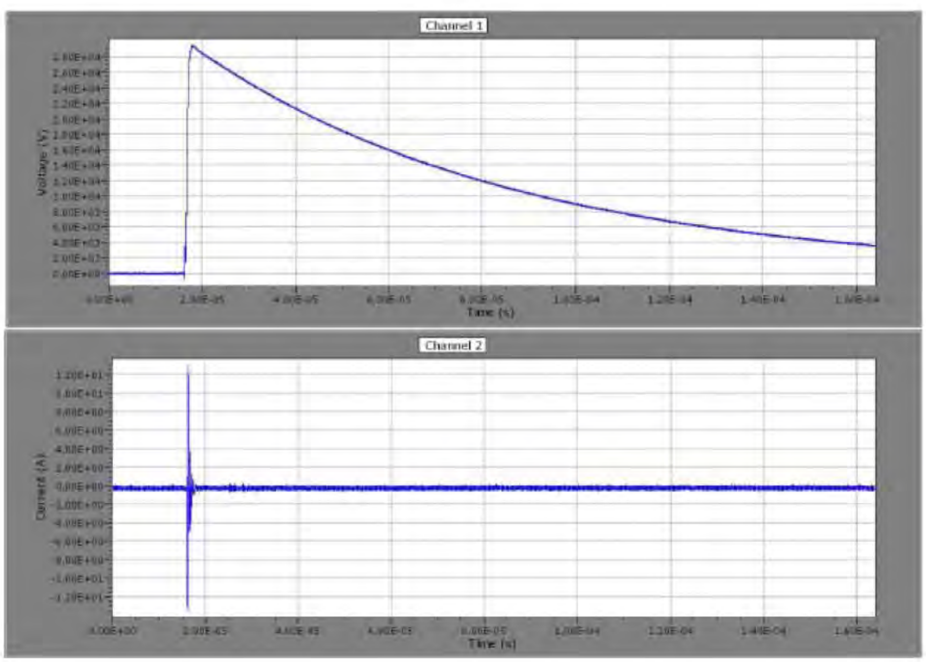
Temperature - 18°C Barometric Pressure - 746 mmHg Humidity - 67%

Job/Project - 12181-D
Job/Project Description - Comunity Energy Storage System
Pulse Description - New Digitizer Acquisition
Waveform Filename - 12094.jmx

Customer Name - Kevin Lindenmuth for S & C Electric Co
Comment -
Pulse Description - 10/2/2012 10:46:53 AM

Ch1 Waveform Type: Full Voltage
Ch1 Desc. - Channel 1
Ch1 Peak = 29.6 kV
Ch1 Front (T1) = 1.002 us
Ch1 Tail (T2) = 49.2 us
Ch1 Os = 3.2 %
Ch1 Os Dur. = 3.00 us
Ch1 Os Freq. = 40.0 kHz

Ch2 Waveform Type: Current
Ch2 Desc. - Channel 2
Ch2 Peak = 0.01 kA
Ch2 Front (T1) = 0.050 us
Ch2 Tail (T2) = 0.1 us
Ch2 Os = 0.0 %
Ch2 Os Dur. = 0.00 us
Ch2 Os Freq. = 0.0 kHz



## 7.4 Continued, BIL Test Results:

The following waveform is 30kv applied to the CES Load Line 2 with all other terminals grounded. The voltage clamped at 2kV. This waveform is typical of all tests.

# Impulse Waveform Data Sheet

***DNV-KEMA / KEMA-Powertest, LLC***

Impulse 2010 V10.0.0.16 | JMX Services, Inc. | 10/02/1212:09 PM

Temperature - 18°C Barometric Pressure - 746 mmHg Humidity - 67%

Job/Project - 12181-D

Job/Project Description - Comunity Energy Storage System

Pulse Description - New Digitizer Acquisition

Waveform Filename - 12099.jmx

Customer Name - Kevin Lindenmuth for S & C Electric Co

Comment -

Pulse Description - 10/2/2012 12:04:37 PM

Ch1 Waveform Type: Front Chopped Voltage

Ch1 Desc. - Channel 1

Ch1 Peak = 2.0 kV

Ch1 Front (T1) = 0.284 us

Ch1 Chop (Tc) = 0.31 us

Ch1 Steepness = 0.00 MV/us

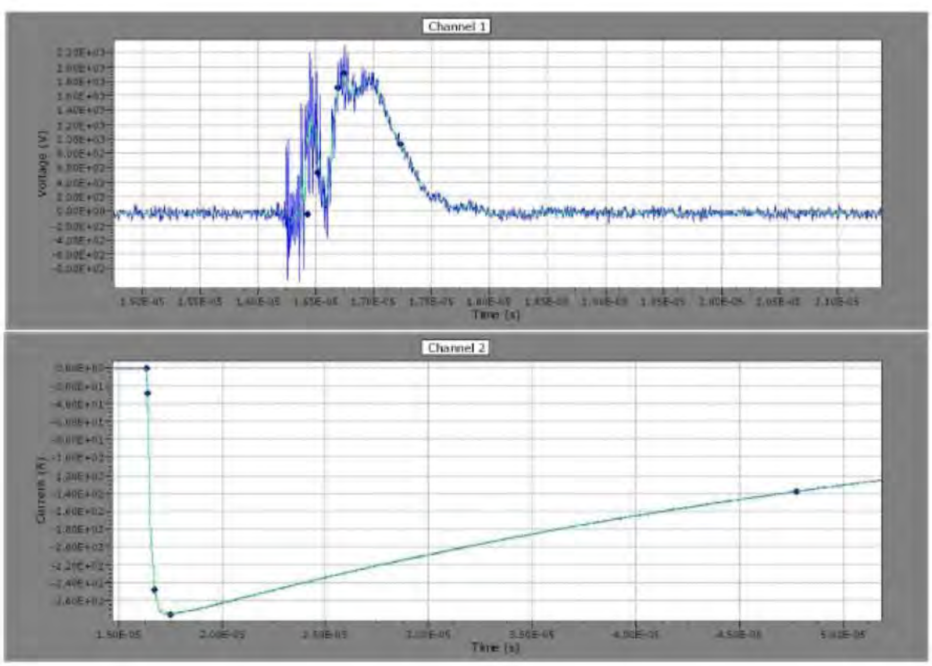
Ch2 Waveform Type: Current

Ch2 Desc. - Channel 2

Ch2 Peak = -0.27 kA

Ch2 Front (T1) = 0.444 us

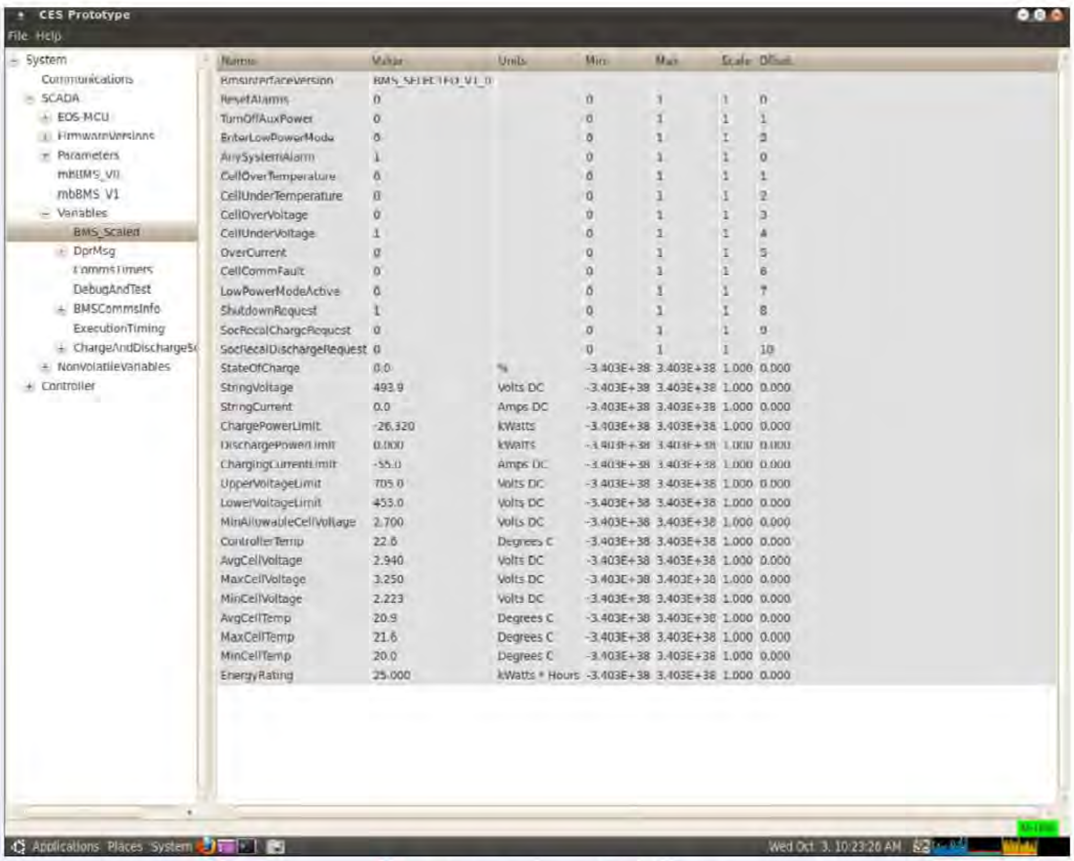
Ch2 Tail (T2) = 31.4 us



![KEMA DNV]

## 7.4 Continued, BIL Test Results:

CES Prototype HMI screen after the last test (test 6). This screenshot is typical of all 6 tests. The indicator in the lower right corner shows green when communications is established and the BMS reported data is displayed. Please note that the battery is at its minimum capacity as described above and is no concern to the BIL test results.




| Name | Value | Units | Min | Max | Scale | Offset |
|---|---|---|---|---|---|---|
| BmsInterfaceVersion | BMS_SELECTED_V1_0 | | | | | |
| ResetAlarms | 0 | | 0 | 1 | 1 | 0 |
| TurnOffAuxPower | 0 | | 0 | 1 | 1 | 1 |
| EnterLowPowerMode | 0 | | 0 | 1 | 1 | 2 |
| AnySystemAlarm | 1 | | 0 | 1 | 1 | 0 |
| CellOverTemperature | 0 | | 0 | 1 | 1 | 1 |
| CellUnderTemperature | 0 | | 0 | 1 | 1 | 2 |
| CellOverVoltage | 0 | | 0 | 1 | 1 | 3 |
| CellUnderVoltage | 1 | | 0 | 1 | 1 | 4 |
| OverCurrent | 0 | | 0 | 1 | 1 | 5 |
| CellCommFault | 0 | | 0 | 1 | 1 | 6 |
| LowPowerModeActive | 0 | | 0 | 1 | 1 | 7 |
| ShutdownRequest | 1 | | 0 | 1 | 1 | 8 |
| SocRecalChargeRequest | 0 | | 0 | 1 | 1 | 9 |
| SocRecalDischargeRequest | 0 | | 0 | 1 | 1 | 10 |
| StateOfCharge | 0.0 | % | -3.403E+38 | 3.403E+38 | 1.000 | 0.000 |
| StringVoltage | 493.9 | Volts DC | -3.403E+38 | 3.403E+38 | 1.000 | 0.000 |
| StringCurrent | 0.0 | Amps DC | -3.403E+38 | 3.403E+38 | 1.000 | 0.000 |
| ChargePowerLimit | -26.320 | kWatts | -3.403E+38 | 3.403E+38 | 1.000 | 0.000 |
| DischargePowerLimit | 0.000 | kWatts | -3.403E+38 | 3.403E+38 | 1.000 | 0.000 |
| ChargingCurrentLimit | -55.0 | Amps DC | -3.403E+38 | 3.403E+38 | 1.000 | 0.000 |
| UpperVoltageLimit | 705.0 | Volts DC | -3.403E+38 | 3.403E+38 | 1.000 | 0.000 |
| LowerVoltageLimit | 453.0 | Volts DC | -3.403E+38 | 3.403E+38 | 1.000 | 0.000 |
| MinAllowableCellVoltage | 2.700 | Volts DC | -3.403E+38 | 3.403E+38 | 1.000 | 0.000 |
| ControllerTemp | 22.6 | Degrees C | -3.403E+38 | 3.403E+38 | 1.000 | 0.000 |
| AvgCellVoltage | 2.940 | Volts DC | -3.403E+38 | 3.403E+38 | 1.000 | 0.000 |
| MaxCellVoltage | 3.250 | Volts DC | -3.403E+38 | 3.403E+38 | 1.000 | 0.000 |
| MinCellVoltage | 2.223 | Volts DC | -3.403E+38 | 3.403E+38 | 1.000 | 0.000 |
| AvgCellTemp | 20.9 | Degrees C | -3.403E+38 | 3.403E+38 | 1.000 | 0.000 |
| MaxCellTemp | 21.6 | Degrees C | -3.403E+38 | 3.403E+38 | 1.000 | 0.000 |
| MinCellTemp | 20.0 | Degrees C | -3.403E+38 | 3.403E+38 | 1.000 | 0.000 |
| EnergyRating | 25.000 | kWatts * Hours | -3.403E+38 | 3.403E+38 | 1.000 | 0.000 |

## Appendix A

### KEMA Client Test Procedure Summary page 1

| Test category | Tests | Procedure | Data Recorded |
|---|---|---|---|
| **Set Up** | Basic Operation | 1. Receive unit and ensure no damage during shipping. | Condition of unit upon receipt |
| | | 2. Set up unit in test lab. | None |
| | | 3. Operate unit to ensure proper basic ON/OFF function and data exchange and operation. | Does the unit operate, YES/NO |
| | | | |
| **Cycling** | Electrical Ratings | 1. Unit will run 10 full cycles. A cycle is defined as a unit that begins at a 90% state of charge (SOC) and then discharged to a 10% SOC and then charged back to 90% SOC. With a C rate of 25 kW. | 1. Round trip efficiency as defined as power in vs. power out at the point of common coupling. DC level efficiency will also be calculated and compared to AC. |
| | | | 2. Output voltage, power and energy ratings will be compared to those claimed |
| | | | 3. Harmonics levels will be recorded including total demand distortion and levels during charge and discharge actions |
| | | | 4. Noise levels at night time will be recorded |
| | Communication | 1. Unit data will be monitored to through DPN3 communications port. | 1. Data to be compared includes: Voltage (cell, battery module, ans system), current, temperature, harmonics, and efficiency. |
| | | 2. Unit data will be monitored through KEMA's data acquisition system (DAS) | |
| | | 3. Comparison of CES unit data and DAS data will be made | |

KEMA Client Test Procedure Summary page 2

| Test category | Tests | Procedure | Data Recorded |
|---|---|---|---|
| **Applications** | Peak Shaving | 1. Unit will operate in peak shaving application. Unit will operate in charge/standby mode for a period of 20 hours and will operate in discharge mode for a period of 4 hours. | 1. Round trip efficiency as defined as power in vs. power out at the point of common coupling |
| | | | 2. Output voltage, power and energy ratings will be compared to those claimed |
| | | 2. Unit will operate to DTE parameters regarding DOD | 3. Harmonics levels will be recorded including total demand distortion and levels during charge and discharge actions |
| | | | 4. Noise levels at night time will be recorded |
| | Frequency Regulation | 1. Unit will operate in frequency Regulation application. Unit will receive a charge/discharge command every 10 seconds. The duration of the test cycle will be 2 hours. In the 2 hour period the unit will receive 720 charge/discharge commands. A total of 36 consecutive cycles will be run | 1. Round trip efficiency as defined as power in vs. power out at the point of common coupling |
| | | | 2. Output voltage, power and energy ratings will be compared to those claimed |
| | | | 3. Harmonics levels will be recorded including total demand distortion and levels during charge and discharge actions |
| | | | 4. Noise levels at night time will be recorded |

### KEMA Client Test Procedure Summary page 3

| Test category | Tests | Procedure | Data Recorded |
|---|---|---|---|
| **Applications** | Islanding | 1. Unit will operate properly in Islanding mode. Line power will be shut off to unit simulating a grid outage. Unit will transition to islanding mode in a maximum of 3 cycles Power will be restored and unit will switch back to grid parallel mode. | 1. Time to change modes and voltage and current |
| | | 2. Line power will be shutoff to simulate power outage. Power will not be restored. CES unit will continue to provide power to load until it reaches its 100% DOD (or other predetermined level). Power will then be restored and unit will switch back to grid parallel mode | 2. Record when unit stops providing power and compare to the intended settings |
| | Communication | 1. Unit data will be monitored to through DPN3 communications port. | 1. Data to be compared includes: Voltage (cell, battery module, ans system), current, temperature, harmonics, and efficiency. |
| | | 2. Unit data will be monitored through KEMA's data acquisition system (DAS) | |
| | | 3. Comparison of CES unit data and DAS data will be made | |

## KEMA Client Test Procedure Summary page 4

| Test category | Tests | Procedure | Data Recorded |
|---|---|---|---|
| **Protection** | Utility Voltage Variation | 1. Unit will be placed in grid parallel mode. | 1. All voltage, current, temperature levels. |
| | | 2. Unit will be given signal that an overload condition exists. (the specific overload level will need to be determined) | 2. Monitor and record time and condition. Record if the unit responds as expected |
| | | 3. Unit will be given signal that an overvoltage condition exists (overvoltage level to be determined) | 3. Grid parallel tests will be run in a method which is in conformance with IEEE 1547.1 |
| | | 4. Unit will be given signal that an under voltage condition exists (under voltage level to be determined) | 4. Islanding tests will run where minimum voltage is 91.7% of nominal voltage and maximum voltage is 105.8% of nominal voltage. |
| | | 5. Unit will be given signal that an under load and overvoltage condition exists ( levels to be determined) | |
| | | 1. Unit will be placed in islanded mode. | |
| | | 2. Unit will be given signal that an overload condition exists. (the specific overload level will need to be determined) | |
| | | 3. Unit will be given signal that an overvoltage condition exists (overvoltage level to be determined) | |
| | | 4. Unit will be given signal that an under voltage condition exists (under voltage level to be determined) | |
| | | 5. Unit will be given signal that an under load and overvoltage condition exists ( levels to be determined) | |

## KEMA Client Test Procedure Summary page 5

| Test category | Tests | Procedure | Data Recorded |
|---|---|---|---|
| **EMI** | EMI | 1. Unit will operate in grid parallel mode | 1. EMI shall be measured to not exceed limits set by FCC code |
| | | | 2. Unit shall have the capability to withstand EMI in accordance with IEEE C37.90.2-1995. |
| | | | |
| **High Voltage/High Current** | Basic Impulse Level | 1. Unit will withstand 30 kV | |
| | Surge Protection | 1. Unit control shall meet the applicable test requirements of IEEE C37.90.1 Surge Withstand Capability (SWC) Tests for Relays and Relay Systems Associated with Electric Power Apparatus. | |
| | Load Interrupting | 1. Isolating contactor continuous current rating and load interrupting capability shall be at least 400 Amps. Fault duty is 50 kA for 2 cycles. All associated terminations and wiring in the source to load side path must also meet this requirement. This ampacity is necessary because the CES Unit may be associated with transformers up to 100 kVA. | |

## Appendix B

### Test Set up

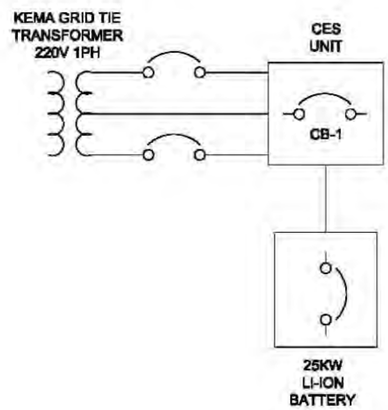



Fig 1. Test Set up with no load bank connected..

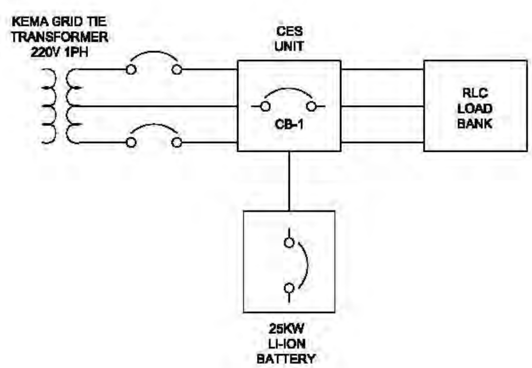



Fig 2. Test Set up with load bank.

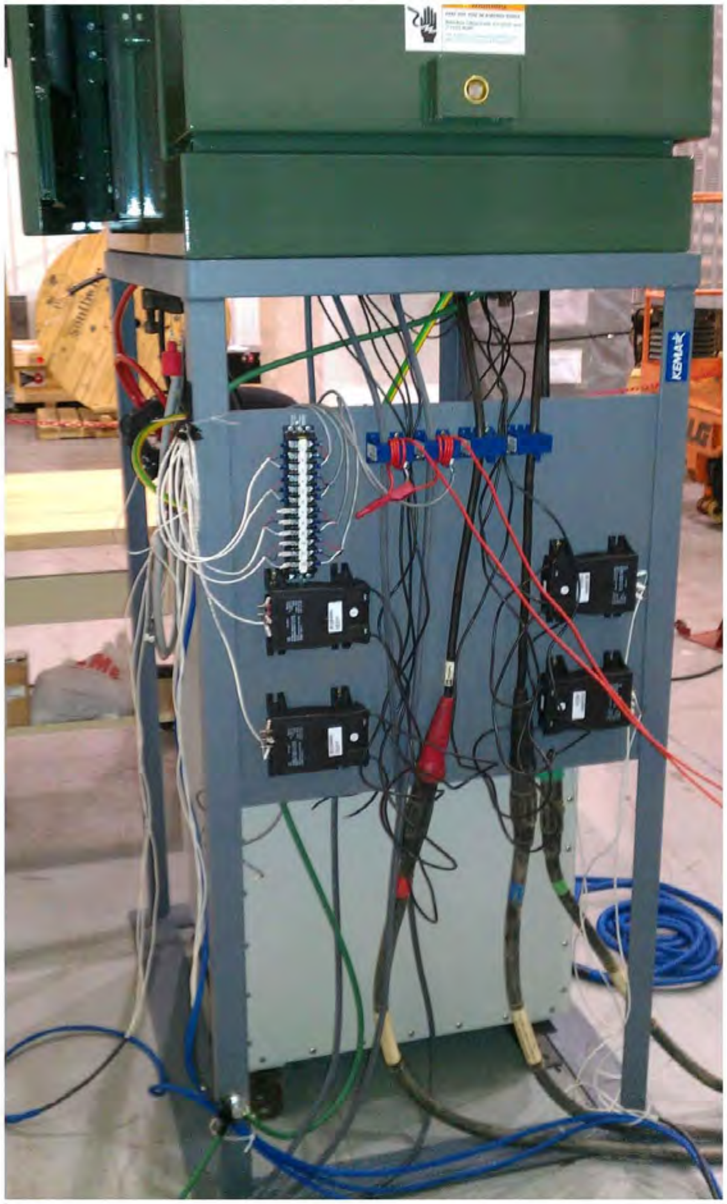
# Appendix C

**Photos of Test Setup**

CES on stand with battery under. KEMA Power transformer in back. DAS, Blue cables to V and C transducers.

CES test stand, Opposite view. Load bank to the right

## Appendix C continued, Photos of Test Setup




KEMA CES test stand. Source current(blue) and source voltage(black) transducers to the left and load current and voltage transducers to the right. Large power cables go to load bank.

## Appendix C continued, Photos of Test Setup

Inductive load bank connections

Appendix C continued, Photos of Test Setup

Resistive load bank connections.

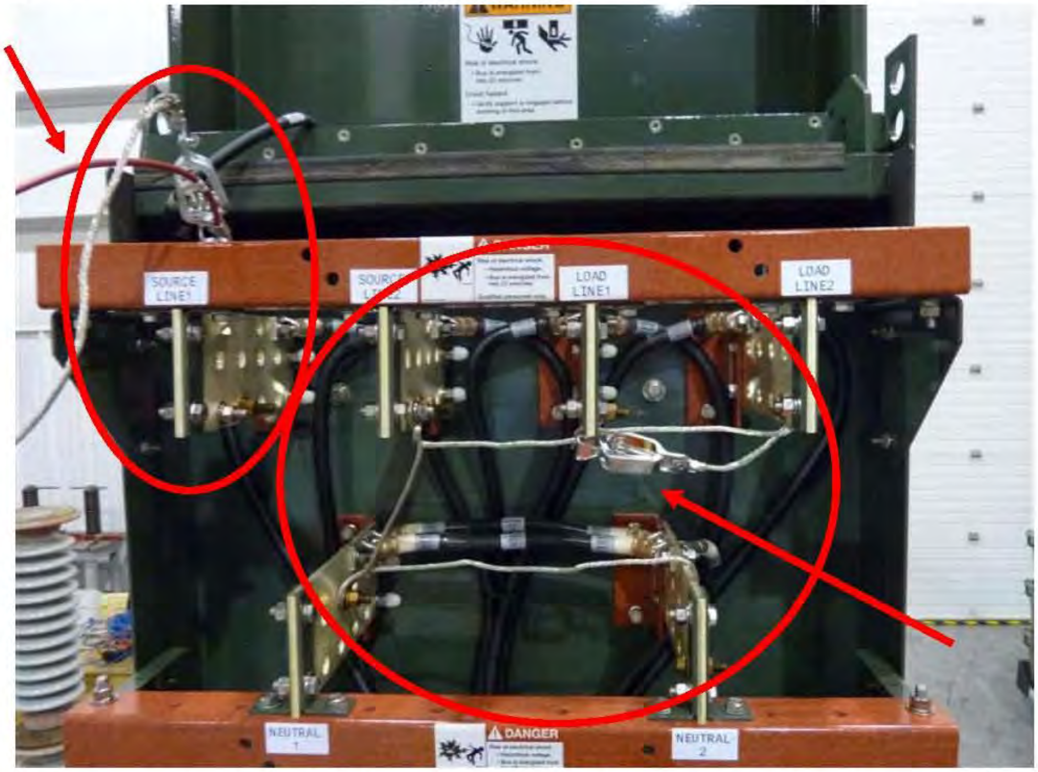
Appendix C continued, Photos of Test Setup

Capacitive load bank connections

## Appendix C continued, Photos of Test Setup

Set up for BIL test. CES unit and battery on test stand. KEMA Impulse generator is the blue rack to the right and white voltage divider on the left.

Appendix C continued, Photos of Test Setup




Typical connection for BIL test. CES source line 1 tied to the red high voltage clip and all other terminals to ground through the un-insulated stranded wire. The second clip attached to the CES source line 1 is for the voltage divider.

END OF REPORT

# Appendix E: CES Peak Shaving Evaluation

DNV·GL

DTE CES ENERGY STORAGE DEMONSTRATION COST-EFFECTIVENESS ANALYSIS

# Peak Shaving Evaluation

## DTE Energy

**Report No.:** Final, Rev. 2
**Date:** August 14, 2015

| | | |
|---|---|---|
| Project name: | DTE CES Energy Storage Demonstration Cost-Effectiveness Analysis | DNV GL Energy Advisory |
| Report title: | Peak Shaving Evaluation | [Office Post 1] |
| Customer: | DTE Energy | [Office Post 2] |
| Contact person: | Dennis Flinn | [Office Post 3] |
| Date of issue: | August 14, 2015 | [Office Post 4] |
| Project No.: | | Tel: [+00 000 000 000] |
| Organization unit: | | [Company Reg No] |
| Report No.: | Final, Rev. 2 | |
| Document No.: | | |

Applicable contract(s) governing the provision of this Report:

Objective:
Present the technical and financial analysis of simulation results of the CES fleet dispatched for Peak Shaving purposes.

| Prepared by: | Verified by: | Approved by: |
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# 1 EXECUTIVE SUMMARY

The objective of this use case is to explore the cost-effectiveness of using CES units towards reducing the peak energy demand, or peak-shaving with the purpose of deferring capital investment necessary to upgrade a substation. For the purpose of this study, the Trinity circuit was modelled because it features community energy storage (CES) fleet of 17 units aggregately rated at 425 kW / 850 kWh. These units were deployed by DTE Energy as a pilot project.

This report contains the results from analyzing the circuit based on actual load level and substation capacity, referred to as the "Default Case". In order to demonstrate the impact of a 425 kW / 850 kWh CES fleet (17 units) deployed on a circuit with similar loading patterns and topology as Trinity along with the sensitivity of load growth to deferral opportunity, three "illustrative Cases" were developed. With everything being the same as the default case, these cases involved reducing the substation capacity by half to a 7.5 MVA unit, and calibrating the load to peak at 99% of that capacity. The same analysis as above was conducted for a load growth of 0.3%, 0.6%, and 0.9%, which is where these three cases differ from each other.

# 2 INTRODUCTION

DTE Energy has deployed 17 new CES units manufactured by the S&C Electric Company. These units are rated at 25 kW / 50 kWh and are centrally controlled by DTE's Distributed Resource System Operation Center (DR-SOC). DNV GL worked closely with DTE Energy to model a fleet of 17 CES using ES-Grid, a proprietary cost-effectiveness model used to assess the technical impact of deploying energy storage on a distribution circuit through power flow analyses. This model processes results from OpenDSS, an open-source power flow analysis software.

The primary benefits of reducing the peak demand are substation capacity upgrade deferral and reducing peak demand charges. Reducing peak demand will also reduce stress on power delivery assets, some of which may be critically loaded. In addition, the distributed CES units allow for more efficient distribution of power and utilization of distributed generation, reducing losses across the system and improving the network voltage profile. These benefits and the costs associated with deploying the CES units were evaluated over a 10-year horizon, considering the units are expected to have an operating life of 10 years.

# 3 TECHNICAL ANALYSIS

The technical analysis consisted of hourly simulations performed for 20 sample days over a period of 10 years. These sample days were chosen through a pre-analysis of the base case scenario with the purpose of representing the seasonal differences associated with systems operations. An initial analysis was conducted on the Trinity circuit provided by DTE using observed SCADA data. It was observed that the circuit loading and growth level compared to the substation transformer capacity did not offer an opportunity for capacity deferral since the substation transformer capacity would not be met within 10 years.

In order to demonstrate the impact of a 425 kW / 850 kWh CES fleet (17 units) deployed on a circuit with similar loading patterns and topology as Trinity and to demonstrate the sensitivity of capacity deferral opportunity to load growth three illustrative cases were developed. These consisted of a 0.3%, 0.6%, and 0.9% load growths. These profiles are illustrated in Figure 3-1.


**Figure 3-1 Load Growth Profiles for Scenarios 1, 2, 3, & 4**

The scenarios analysed will be referred to as show in Table **3-1** throughout this report.

| Scenario | Description |
|---|---|
| 1 | Default case with 15MVA substation transformer, peak load of 53% that capacity, and a load growth of 0.6%. |
| 2 | Illustrative case with 7.5MVA substation transformer, peak load of 99% that capacity, and a load growth of 0.3%. |
| 3 | Illustrative case with 7.5MVA substation transformer, peak load of 99% that capacity, and a load growth of 0.6%. |
| 4 | Illustrative case with 7.5MVA substation transformer, peak load of 99% that capacity, and a load growth of 0.9%. |

Table 3-1 Scenario Descriptions

For each scenario, the following three configurations were analysed:

- No CES units
- Fleet of 17 new CES units
- Fleet of 17 repurposed CES units

The principal technical difference between the new and repurposed CES units is how quickly they are expected to degrade.

## 3.1 Modelling

The circuit and CES models are detailed in the following subsections.

### 3.1.1 Circuit Model

The circuit model and load curves were provided in DEW format and converted to an OpenDSS format, an open-source power flow analysis tool developed by EPRI. The base scenario involved simulating the system without CES units and it features a 490 kW photovoltaic site with a 500 kW energy storage backup. The Trinity circuit diagram is illustrated in Figure **3-2**.

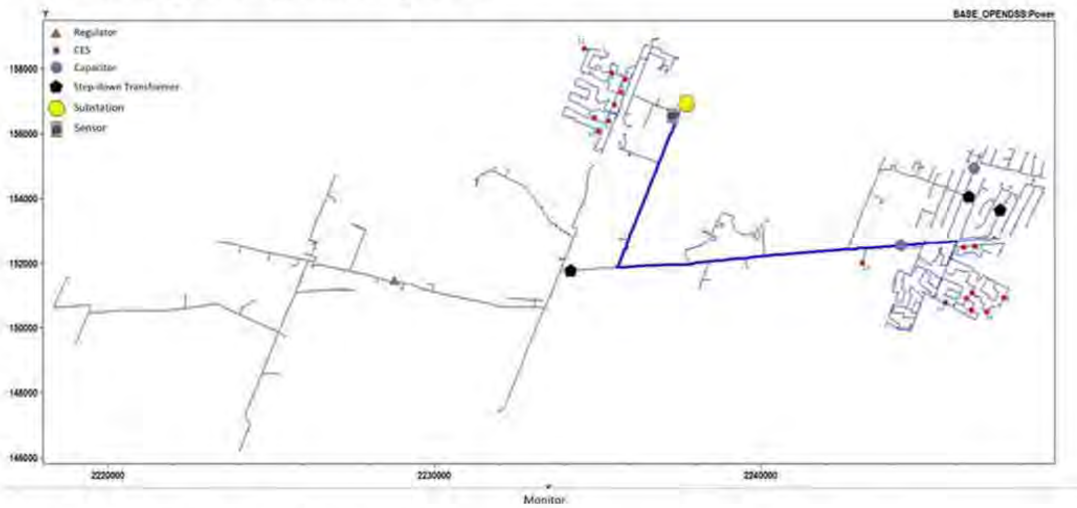



Figure 3-2 OpenDSS Trinity Circuit Diagram

The test scenarios were essentially the same as the base case scenario with the addition of the 17 CES units distributed across two regions as shown in **Error! Reference source not found.**. The first test scenario featured CES units modelled to illustrate the degradation of new battery modules, and the second test scenario featured CES units modelled to illustrate the degradation of repurposed battery modules.

### 3.1.2 CES Model

#### 3.1.2.1 CES Unit Ratings

The CES units were modeled taking into account the physical limits of the units as observed in the field and laboratory environment, and heeding S&C's usage recommendations, such as maximum depth of discharge, acceptable charge and discharge rates, and expected round trip efficiency.

The algorithm also ensured that the CES units in the model respected their maximum charge and discharge magnitudes and durations as observed in laboratory experiments:

- Backup reserve was 20%, meaning up to 40 kWh of energy is available for dispatch for each unit

- Maximum charge rate was 22.5 kW
- Maximum discharge rate was 22.5 kW
- Round trip efficiency was 88%
- Idling losses were .25 kWh/hr

#### 3.1.2.2 Controls

DNV GL consulted closely with DTE Energy to ensure the CES units were dispatched in a way as to model real-life operations. For peak-shaving purposes, the monitored voltage and current points were located on the low-side of the substation transformer. The energy storage operations were determined as follows assuming perfect foresight of the load profile.

The units were charged and discharged taking into account the dispatch magnitude and the CES units respective state of charge (SOC) as compared to the SOC of the entire fleet regardless of the distance from the substation.

##### Charging Strategy

The algorithm used to optimize the charging of the CES units ensured the fleet is fully charged before meeting peak demand hours. The rate and aggressiveness of charging varied depending on the load profile. All units charge at roughly the same rate

##### Discharging Strategy

The CES units were restricted in their discharge rate by their respective SOC, and the physical limitations of the battery. Each battery dispatch signals were processed as follows:

1. The total power request was limited by the total amount of discharge capacity available in the CES fleet.
2. The total energy request was limited by the total amount of energy capacity available in the CES fleet.
3. The signal was split amongst each battery based on their respective SOC as follows:

$$\boldsymbol{P_{out_n}} = P_{demand} * \frac{SOC_{CES_n}}{\sum_{j=1}^{m} SOC_{CES_j}} \text{, } where$$

$$\boldsymbol{P_{out_n}} = Power\ dispatch\ of\ unit\ n$$

$$\boldsymbol{P_{demand}} = Total\ power\ requested\ for\ peak - shaving$$

$$\boldsymbol{SOC_{CES_j}} = SOC\ of\ unit\ j$$

$$\boldsymbol{m} = Total\ number\ of\ CES\ units$$

#### 3.1.2.3 Degradation

The degradation in energy capacity of the battery modules over time was determined by analyzing expected duty cycles for lithium ion batteries based on the operations described above. This analysis assumes that Nickel-Cobalt Manganese (NCM) cells were used as a proxy because of DNV GL's expertise in testing this type of chemistry in laboratory experiments. Additionally, it was assumed that temperature was maintained by an active cooling system at around 25°C.

Based on the operational profile used for time shifting applications, using the DNV-GL BatteryXT application, the resulting degradation curves were calculated. These curves assume a 'best case' scenario where all cells are perfectly balanced, and no single cell deteriorates more rapidly than others. Thusly, they are built to represent the continual degradation of the original units and thus do not incorporate provision for maintenance or repurposing. This also assumes that the battery management system (BMS) is able to compensate for capacity loss and adjust operation such that accelerated degradation would not occur as the battery ages. Mathematically, the degradation curve for a new battery module can be defined as follows:

$$\boldsymbol{Capacity}\ (\%) = 100 - 0.2788 * \sqrt{time}, \quad where\ time\ is\ in\ days$$

The degradation for the repurposed battery modules is expected to degrade slightly faster, considering component mismatches. The time factor was increased by 10% to represent this slight increase degradation. These curves are illustrated over 10 years in Figure **3-3**.

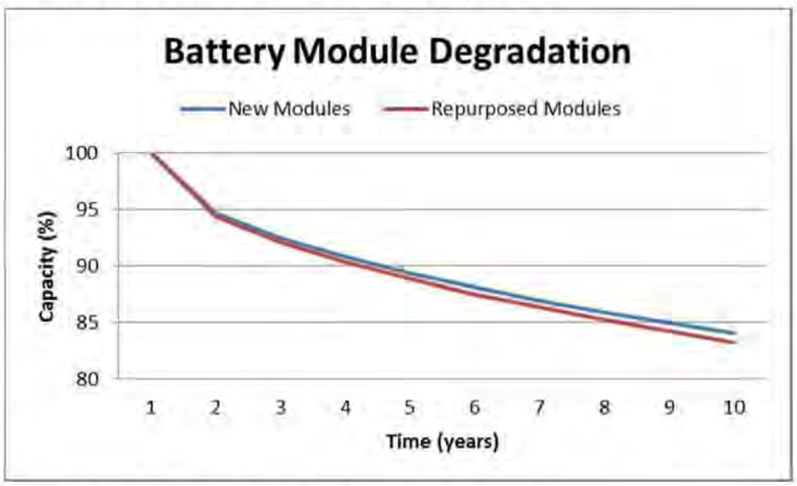



Figure 3-3 Battery Module Degradation for Peak-Shaving

The impact of degradation can be seen in the difference in peak demand reduction for the new and repurposed modules in Figure **3-4**.

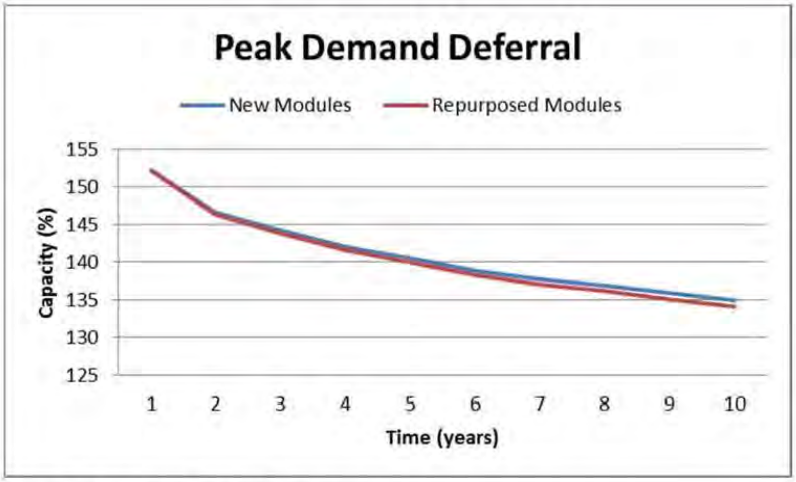


Figure 3-4 Peak Demand Reduction

## 3.2 Scenario 1

This case involved modelling the Trinity circuit under its actual conditions, meaning modelling a 15MVA substation transformer, a peak load of roughly 53% that capacity, and a load growth of 0.6%.

The annual peak demand results for the various CES configurations are presented in kW in Table 3-2.

| Configuration | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| No CES | 7675 | 7714 | 7754 | 7794 | 7834 | 7874 | 7915 | 7956 | 7996 | 8037 |
| New CES | 7522 | 7568 | 7610 | 7652 | 7693 | 7735 | 7777 | 7818 | 7859 | 7901 |
| Repurposed CES | 7522 | 7568 | 7610 | 7652 | 7694 | 7735 | 7777 | 7819 | 7860 | 7902 |

Table 3-2 Scenario 1 - Annual Peak Demand (kW)

This case does not show benefits from capital investment deferral over the 10 years project analysis period, therefore no financial benefit is expected from the CES fleet on the Trinity circuit. This is illustrated in Figure **3-5** where the peak demand, represented as solid column series, never exceeds the substation capacity, represented as a red line, for the base or test cases. Note that both test cases are modelled as the same peak demand profiles because the difference between the new and repurposed batteries would not be evident on this scale.

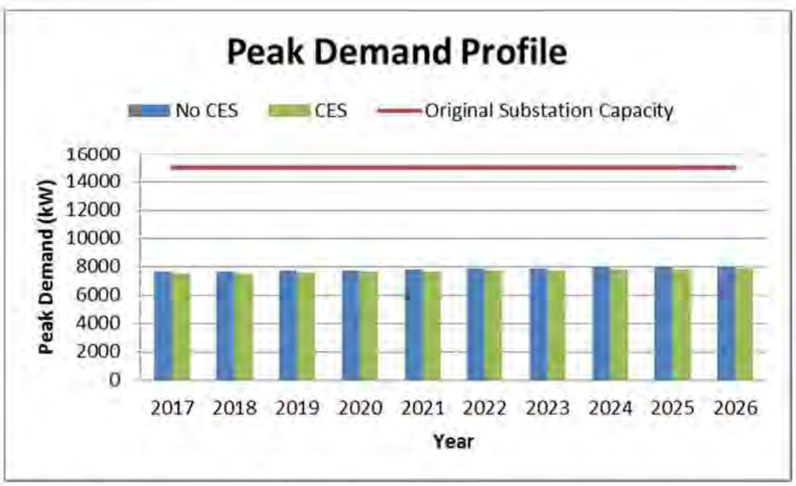



Figure 3-5 Scenario 1 - Deferral Opportunity

The annual consumption results for the various CES configurations are presented in MWh in Table 3-3.

| Configuration | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| No CES | 35254 | 35482 | 35709 | 35856 | 36170 | 36398 | 36632 | 36780 | 37097 | 37328 |
| New CES | 35282 | 35510 | 35738 | 35885 | 36199 | 36427 | 36660 | 36809 | 37125 | 37357 |
| Repurposed CES | 35282 | 35510 | 35738 | 35885 | 36199 | 36427 | 36660 | 36809 | 37125 | 37357 |

Table 3-3 Scenario 1 - Annual Consumption (MWh)

The energy consumption was increased for the test cases because operating the CES unit's required additional energy due to charging and discharging inefficiencies and idling losses. The total energy consumption, accounting for the inefficiencies from the CES units, was increased by 29 MWh for the first year.

The annual technical loss results for the various CES configurations are presented in MWh in Table 3-4.

| Configuration | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| No CES | 4178 | 4198 | 4218 | 4229 | 4260 | 4280 | 4302 | 4313 | 4345 | 4367 |
| New CES | 4178 | 4198 | 4218 | 4229 | 4260 | 4280 | 4302 | 4313 | 4345 | 4367 |
| Repurposed CES | 4178 | 4198 | 4218 | 4229 | 4260 | 4280 | 4302 | 4313 | 4345 | 4367 |

Table 3-4 Scenario 1 - Annual Technical Loss (MWh)

The losses were slightly decreased due to reducing the peak, and increased to a lesser extent during the charging period. The total technical loss, which consists only of the energy loss contribution from the conductors, over the distribution circuit, excluding the inefficiencies from the CES units, was reduced by 144 kWh for the first year, which is negligible.

## 3.3 Scenario 2

With everything being the same as in scenario 1, this case involved reducing the substation transformer capacity by half to a 7.5 MVA unit, and calibrating the load to peak at 99% of that capacity, and a load growth of 0.3%.

The annual peak demand for the various CES configurations are presented in kW in Table 3-5.

| Configuration | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| No CES | 7436 | 7457 | 7477 | 7498 | 7519 | 7539 | 7560 | 7581 | 7602 | 7622 |
| New CES | 7284 | 7310 | 7333 | 7356 | 7378 | 7400 | 7422 | 7444 | 7466 | 7487 |
| Repurposed CES | 7284 | 7311 | 7334 | 7356 | 7379 | 7401 | 7423 | 7445 | 7466 | 7488 |

Table 3-5 Scenario 2 - Annual Peak Demand (kW)

The annual consumption results for the various CES configurations are presented in MWh in Table 3-6.

| Configuration | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| No CES | 33948 | 34067 | 34186 | 34220 | 34427 | 34544 | 34666 | 34698 | 34905 | 35022 |
| New CES | 33977 | 34096 | 34215 | 34249 | 34456 | 34573 | 34694 | 34727 | 34934 | 35051 |
| Repurposed CES | 33977 | 34096 | 34215 | 34249 | 34456 | 34573 | 34694 | 34727 | 34934 | 35051 |

Table 3-6 Scenario 2 - Annual Consumption (MWh)

The annual technical loss results for the various CES configurations are presented in MWh in Table 3-7.

| Configuration | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| No CES | 4057 | 4066 | 4076 | 4076 | 4095 | 4104 | 4114 | 4114 | 4133 | 4142 |
| New CES | 4057 | 4066 | 4076 | 4076 | 4094 | 4104 | 4113 | 4113 | 4133 | 4142 |
| Repurposed CES | 4057 | 4066 | 4076 | 4076 | 4094 | 4104 | 4113 | 4113 | 4133 | 4142 |

Table 3-7 Scenario 2 - Annual Technical Loss (MWh)

The deferral opportunity result for this case was 6 years for both the new and repurposed modules, and is illustrated in Table 3-6.

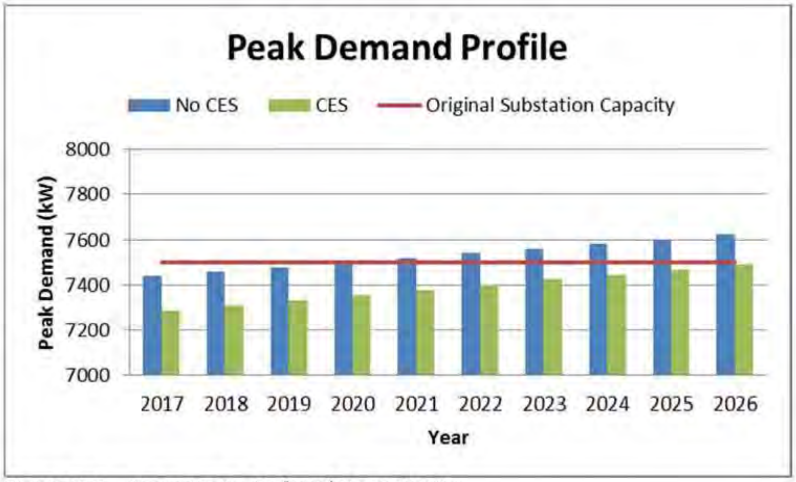


Figure 3-6 Scenario 2 - Deferral Opportunity

## 3.4 Scenario 3

The annual peak demand for the various CES configurations are presented in kW in Table 3-8.

| Configuration | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| No CES | 7436 | 7475 | 7515 | 7554 | 7594 | 7633 | 7673 | 7713 | 7752 | 7792 |
| New CES | 7284 | 7329 | 7371 | 7412 | 7453 | 7494 | 7535 | 7575 | 7616 | 7657 |
| Repurposed CES | 7284 | 7329 | 7371 | 7413 | 7454 | 7494 | 7535 | 7576 | 7617 | 7658 |

Table 3-8 Scenario 3 - 3Annual Peak Demand (kW)

The annual consumption results for the various CES configurations are presented in MWh in Table 3-9.

| Configuration | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| No CES | 33948 | 34168 | 34389 | 34525 | 34838 | 35059 | 35284 | 35429 | 35737 | 35962 |
| New CES | 33977 | 34197 | 34418 | 34554 | 34867 | 35088 | 35313 | 35458 | 35766 | 35991 |
| Repurposed CES | 33977 | 34197 | 34418 | 34554 | 34867 | 35088 | 35313 | 35458 | 35766 | 35991 |

Table 3-9 Scenario 3 - Annual Consumption for (MWh)

The annual technical loss results for the various CES configurations are presented in MWh in Table 3-10.

| Configuration | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| No CES | 4057 | 4076 | 4094 | 4104 | 4133 | 4152 | 4171 | 4182 | 4211 | 4231 |
| New CES | 4057 | 4075 | 4094 | 4104 | 4132 | 4152 | 4171 | 4182 | 4211 | 4231 |
| Repurposed CES | 4057 | 4075 | 4094 | 4104 | 4132 | 4152 | 4171 | 4182 | 4211 | 4231 |

Table 3-10 Scenario 3 - Annual Technical Loss (MWh)

The deferral opportunity result for this case was 4 years for both the new and repurposed modules, and is illustrated in Figure **3-7**.

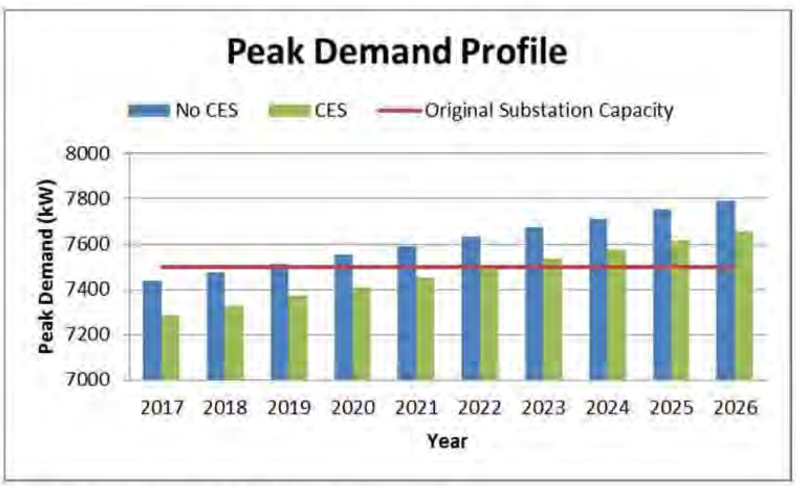



Figure 3-7 Scenario 3 - Deferral Opportunity

## 3.5 Scenario 4

The annual peak demand results for the various CES configurations are presented in kW in Table 3-11.

| Configuration | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| No CES | 7436 | 7494 | 7552 | 7610 | 7669 | 7727 | 7786 | 7845 | 7905 | 7964 |
| New CES | 7284 | 7348 | 7408 | 7468 | 7528 | 7588 | 7648 | 7708 | 7768 | 7829 |
| Repurposed CES | 7284 | 7348 | 7409 | 7468 | 7528 | 7588 | 7648 | 7708 | 7769 | 7829 |

Table 3-11 Scenario 4 - Annual Peak Demand (kW)

The annual consumption results for the various CES configurations are presented in MWh in Table 3-12.

| Configuration | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| No CES | 33948 | 34269 | 34593 | 34831 | 35250 | 35579 | 35912 | 36165 | 36584 | 36921 |
| New CES | 33977 | 34298 | 34623 | 34860 | 35279 | 35608 | 35941 | 36194 | 36613 | 36949 |
| Repurposed CES | 33977 | 34298 | 34623 | 34860 | 35279 | 35608 | 35941 | 36194 | 36613 | 36949 |

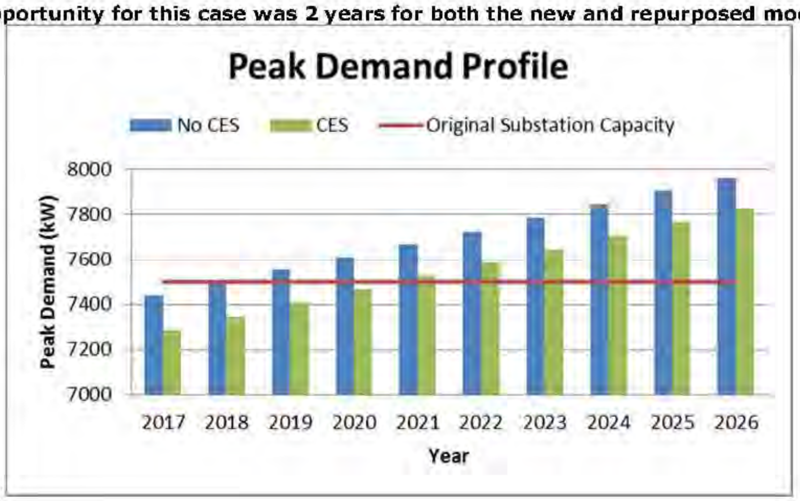
Table 3-12 Scenario 4 - Annual Consumption (MWh)

The annual technical loss results for the various CES configurations are presented in MWh in Table 3-13.

| Configuration | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| No CES | 4057 | 4085 | 4113 | 4132 | 4171 | 4201 | 4231 | 4253 | 4294 | 4326 |
| New CES | 4057 | 4085 | 4113 | 4132 | 4171 | 4201 | 4231 | 4252 | 4294 | 4326 |
| Repurposed CES | 4057 | 4085 | 4113 | 4132 | 4171 | 4201 | 4231 | 4252 | 4294 | 4326 |

Table 3-13 Scenario 4 - Annual Technical Loss (MWh)

**The deferral opportunity for this case was 2 years for both the new and repurposed modules, and**




**is illustrated in** Figure **3-8**.

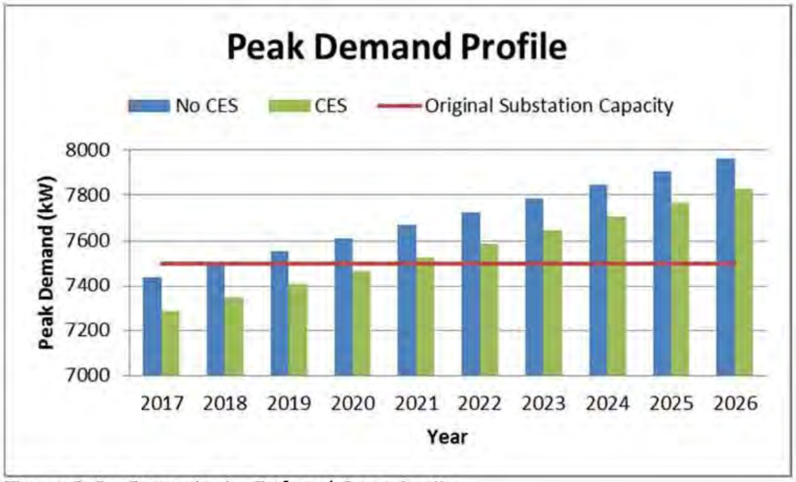


Figure 3-8 Scenario 4 - Deferral Opportunity

# 4 FINANCIAL ANALYSIS

The parameters presented in Table 4-1 along with technical results from the simulations were used to evaluate the financial impact of the CES system for the case various scenarios.

| Data Type | Parameter Description | Value | Unit |
|---|---|---|---|
| General | Calendar life | 10 | years |
| | Project analysis period | 10 | years |
| | Substation transformer capacity | 15 | MVA |
| | Substation transformer upgrade factor | 100 | % |
| | Installation cost of distribution upgrade | 100 | $/kW |
| Financial | Inflation rate | 2.0 | % |
| | Discount rate | 7.0 | % |
| | Electricity price escalation rate | 3.0 | % |
| | Equity financed | 50.0 | % |
| | Debt financed | 50.0 | % |
| | WACC | 7.6 | % |
| | Property taxes and insurance | 1.5 | % |
| | Marginal income tax rate | 43.8 | % |
| | Debt rate | 6.2 | % |
| | Equity rate | 11.5 | % |
| | Insurance | 0.4 | % |
| Battery specification | Annual decline rate of battery capital cost | 3.3 | % |
| | Fixed O&M cost | 16 | $/kW |
| | O&M cost escalation rate | 0.0 | % |
| | Total power capacity | 425 | kW |
| | Duration | 2.00 | hours |
| | One-way efficiency | 93.8 | % |

Table 4-1 Financial Parameters

The benefits and cost categories are detailed in the following two subsections. The scenario results are presented in the last section.

## 4.1 Benefits

Energy storage benefits considered in the analysis include the following components:

- **Substation upgrades deferral**. This benefit represents the ability to delay substation transformer upgrades for one or more years. An annual fixed charge rate is calculated and applied to the total installed cost of the upgrade and valued as a benefit for the number of years deferral is possible with energy storage. The number of years that the substation upgrade is deferred is calculated by counting the number of years between the times that peak demand exceeds 90 percent of circuit capacity in the base and test cases.
- **Distribution loss reduction**. Changes in system losses are calculated via engineering simulations. Annual time series data for electricity wholesale prices are used to estimate the value of loss changes.
- **Cost of energy.** Although deploying a CES fleet on the system increases the amount of energy used due to their inefficiencies, the overall cost of energy to the utility is expected to be reduced due to the difference in pricing between peak demand time, when the units are discharging, and off-peak demand time, when the units are charging. This holds true under the assumption that the peak

demand and off-peak demand times on the distribution circuit coincide with the peak and off-peak demand time across the utility territory.

## 4.2 Costs

Energy storage costs considered in the analysis include the following components:

- **Capital Investment cost of energy storage.** The energy storage unit's capital cost is calculated as a function of the size of the unit and the battery type. During the analysis period, storage units are replaced based on estimated actual life. Energy storage actual life is calculated as a function of the number of charge/discharge half-cycles and the amount of energy that is charged/discharged in each half-cycle, and its calendar life. (The engineering simulation tracks storage charges and discharges). A fixed charge rate is used to level the total cost. The total cost, which includes the battery modules, the inverter, and the installation cost, for the three systems under evaluation are as follows:
    - New system: $133,575
    - Repurposed system with free battery packs: $66,075
    - Repurposed system with $3,000 battery packs: $78,075
- **Cost of replacement.** The cost of replacing energy storage at the end of its actual life is assumed to be a fraction of initial investment cost. The number of replacements during the project analysis period depends on the energy storage actual life. The replacement cost for the three systems under evaluation, which only include the battery modules, are as follows:
    - New system: $85,000
    - Repurposed system with free battery packs: $17,500
    - Repurposed system with $3,000 battery packs: $29,500
- **Operation and maintenance cost.** Annual operation and maintenance costs are assumed to be proportional to energy storage power capacity.

## 4.3 Scenario 1

The technical results gathered from the simulations were analysed over the 10 year period and yielded an NPV for the various benefits and cost categories ranging from -$2,088,824 to -$856,361 in 2013 dollars.

The NPV for the new battery use case is presented by component in Table **4-2** and illustrated in Figure **4-1**.

| Categories | Discounted Value |
|---|---|
| Substation upgrades deferral | $0 |
| Additional energy costs | $112,855 |
| Loss reduction | $26,486 |
| **Total benefit** | **$139,342** |
| Storage capital investment | $2,228,123 |
| Fixed O&M | $43 |
| Storage replacement | $0 |
| **Total cost** | **$2,228,166** |
| **NPV** | **-$2,088,824** |

Table 4-2 Scenario 1 - NPV Component Breakdown for New Battery

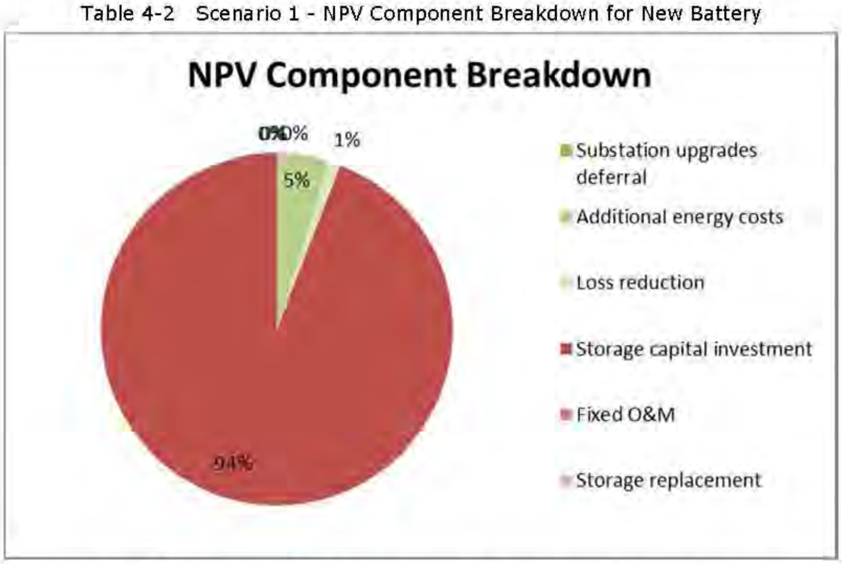



Figure 4-1 Scenario 1 - NPV Component Breakdown for New Battery

The NPV for the repurposed battery with free packs use case is presented by component in Table **4-3** and illustrated in Figure **4-2**.

| Categories | Discounted Value |
|---|---|
| Substation upgrades deferral | $0 |
| Additional energy costs | $109,839 |
| Loss reduction | $26,179 |
| **Total benefit** | **$136,018** |
| Storage capital investment | $1,102,176 |
| Fixed O&M | $43 |
| Storage replacement | $0 |
| **Total cost** | **$992,380** |
| **NPV** | **-$856,361** |

Table 4-3 Scenario 1 - NPV Component Breakdown for Repurposed Battery with Free Pack

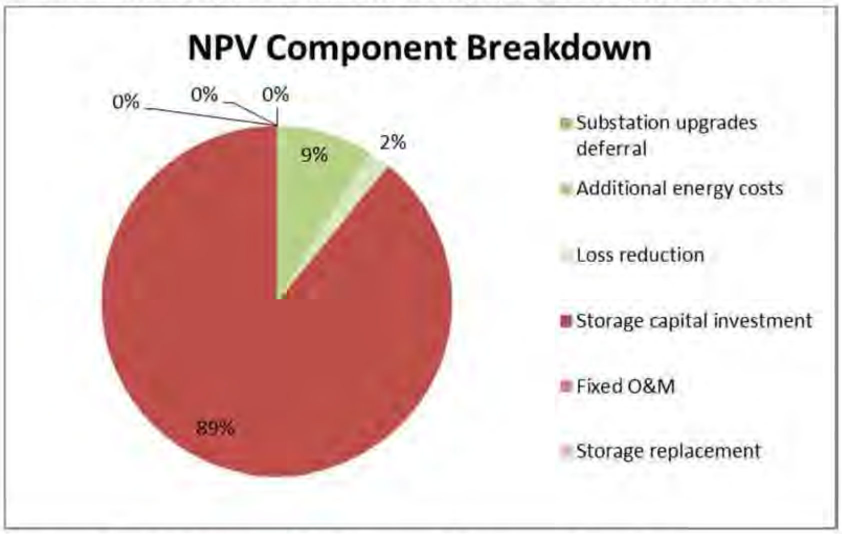



Figure 4-2 Scenario 1 - NPV Component for Repurposed Battery with Free Pack

The NPV for the repurposed battery with $3,000 packs use case is presented by component in Table 4-4 and illustrated in Figure **4-3**.

| Categories | Discounted Value |
|---|---|
| Substation upgrades deferral | $0 |
| Additional energy costs | $109,839 |
| Loss reduction | $26,179 |
| **Total benefit** | **$136,018** |
| Storage capital investment | $1,302,345 |
| Fixed O&M | $43 |
| Storage replacement | $0 |
| **Total cost** | **$1,302,388** |
| **NPV** | **-$1,166,370** |

Table 4-4 Scenario 1 - NPV Component Breakdown for Repurposed Battery with $3,000 Pack

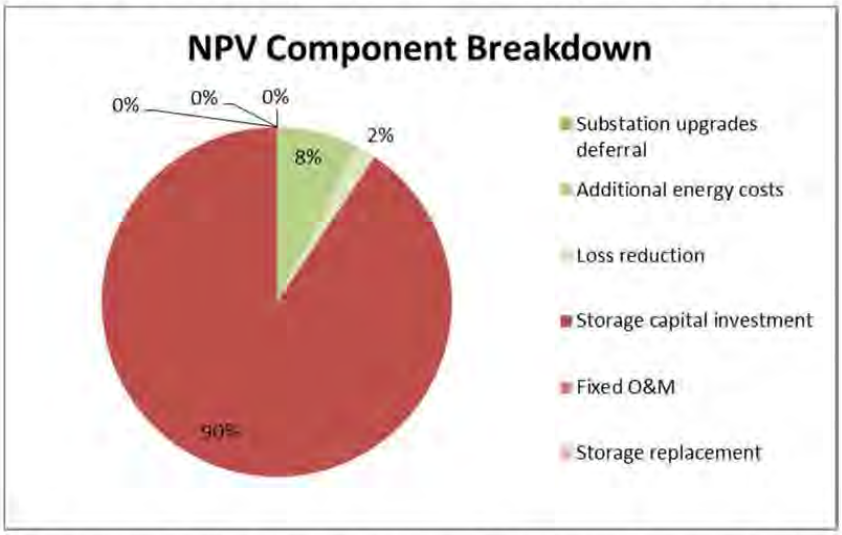



Figure 4-3 Scenario 1 - NPV Component Breakdown for Repurposed Battery with $3,000 Pack

## 4.4 Scenario 2

The technical results gathered from the simulations were analysed over the 10 year period and yielded an NPV for the various benefits and cost categories ranging from -$1,664,681 to -$432,223 in 2013 dollars.

The NPV for the new battery use case is presented by component in Table **4-5** and illustrated in Figure **4-4**.

| Categories | Discounted Value |
|---|---|
| Substation upgrades deferral | $387,068 |
| Additional energy costs | $110,927 |
| Loss reduction | $65,490 |
| **Total benefit** | **$563,486** |
| Storage capital investment | $2,228,123 |
| Fixed O&M | $43 |
| Storage replacement | $0 |
| **Total cost** | **$2,228,166** |
| **NPV** | **-$1,664,680** |

Table 4-5 Scenario 2 - NPV Component Breakdown for New Battery

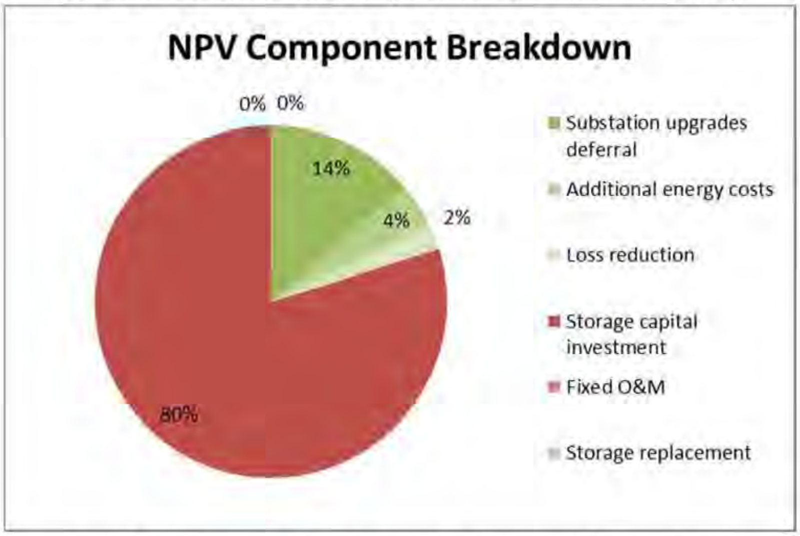



Figure 4-4 Scenario 2 - NPV Component Breakdown for New Battery

The NPV for the repurposed battery with free packs use case is presented by component in Table **4-6** and illustrated in Figure 4-5.

| Categories | Discounted Value |
|---|---|
| Substation upgrades deferral | $387,068 |
| Additional energy costs | $107,885 |
| Loss reduction | $65,204 |
| **Total benefit** | **$560,157** |
| Storage capital investment | $1,102,177 |
| Fixed O&M | $43 |
| Storage replacement | $0 |
| **Total cost** | **$992,380** |

| Categories | Discounted Value |
|---|---|
| **NPV** | **-$432,223** |

Table 4-6 Scenario 2 - NPV Component Breakdown for Repurposed Battery with Free Pack

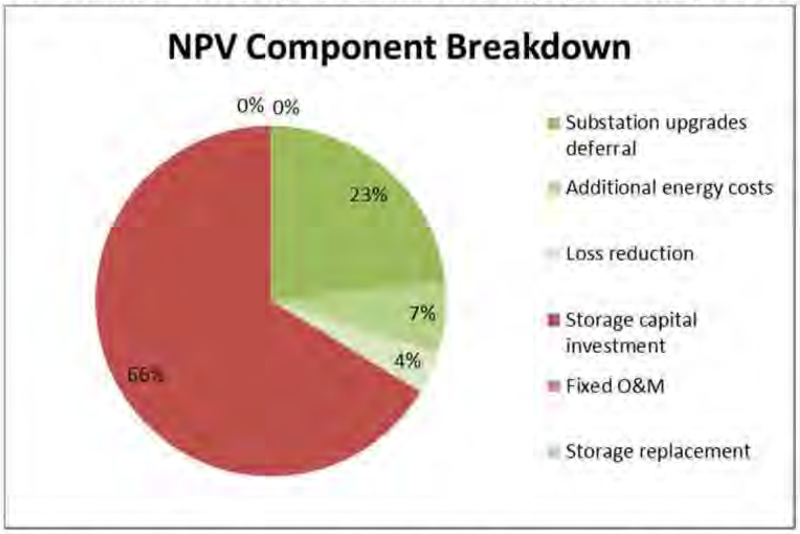



Figure 4-5 Scenario 2 - NPV Component Breakdown for Repurposed Battery with Free Pack

The NPV for the repurposed battery with $3,000 packs use case is presented by component in Table 4-7 and illustrated in Figure 4-6.

| Categories | Discounted Value |
|---|---|
| Substation upgrades deferral | $387,068 |
| Additional energy costs | $107,885 |
| Loss reduction | $65,204 |
| **Total benefit** | **$560,157** |
| Storage capital investment | $1,302,345 |
| Fixed O&M | $43 |
| Storage replacement | $0 |
| **Total cost** | **$1,302,388** |
| **NPV** | **-$742,231** |

Table 4-7 Scenario 2 - NPV Component Breakdown for Repurposed Battery with $3,000 Pack

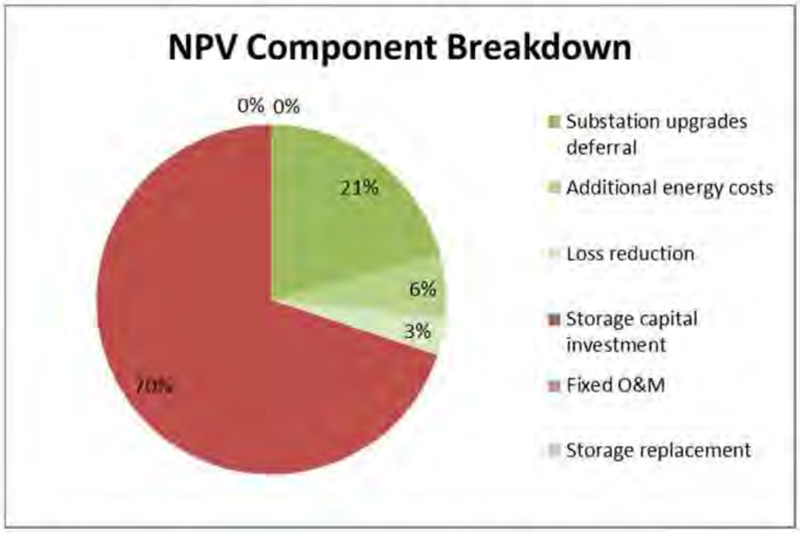



Figure 4-6 Scenario 2 - NPV Component Breakdown for Repurposed Battery with $3,000 Pack

## 4.5 Scenario 3

The technical results gathered from the simulations were analysed over the 10 year period and yielded an NPV for the various benefits and cost categories ranging from -$1,900,060 to -$667,604 in 2013 dollars.

The NPV for the new battery use case is presented by component in Table 4-8 and illustrated in Figure **4-7**.

| Categories | Discounted Value |
|---|---|
| Substation upgrades deferral | $159,820 |
| Additional energy costs | $112,191 |
| Loss reduction | $56,096 |
| **Total benefit** | **$328,107** |
| Storage capital investment | $2,228,123 |
| Fixed O&M | $43 |
| Storage replacement | $0 |
| **Total cost** | **$2,228,166** |
| **NPV** | **-$1,900,059** |

Table 4-8 Scenario 3 - NPV Component Breakdown for New Battery

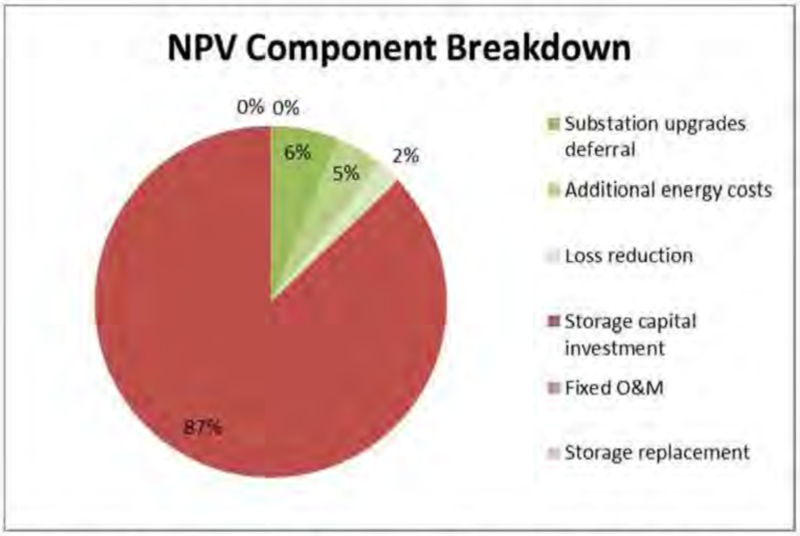



Figure 4-7 Scenario 3 - NPV Component Breakdown for New Battery

The NPV for the repurposed battery with free packs use case is presented by component in Table **4-9** and illustrated in Figure 4-8.

| Categories | Discounted Value |
|---|---|
| Substation upgrades deferral | $159,820 |
| Additional energy costs | $109,147 |
| Loss reduction | $55,809 |
| **Total benefit** | **$324,776** |
| Storage capital investment | $1,102,177 |
| Fixed O&M | $43 |
| Storage replacement | $0 |
| **Total cost** | **$992,380** |
| **NPV** | **-$667,604** |

Table 4-9 Scenario 3 - NPV Component Breakdown for Repurposed Battery with Free Pack

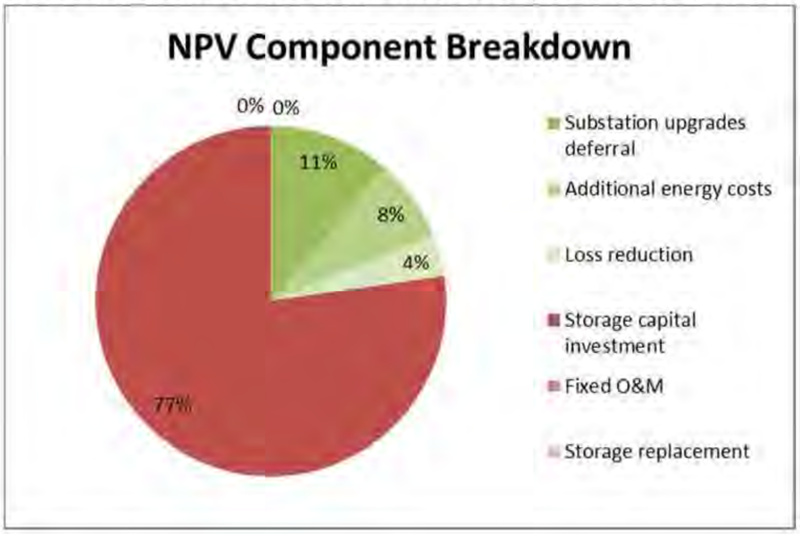



Figure 4-8 Scenario 3 - NPV Component Breakdown for Repurposed Battery with Free Pack

The NPV for the repurposed battery with $3,000 packs use case is presented by component in Table 4-10 and illustrated in Figure 4-9.

| Categories | Discounted Value |
|---|---|
| Substation upgrades deferral | $159,820 |
| Additional energy costs | $109,147 |
| Loss reduction | $55,809 |
| **Total benefit** | **$324,776** |
| Storage capital investment | $1,302,345 |
| Fixed O&M | $43 |
| Storage replacement | $0 |
| **Total cost** | **$1,302,388** |
| **NPV** | **-$977,612** |

Table 4-10 Scenario 3 - NPV Component Breakdown for Repurposed Battery with $3,000 Pack

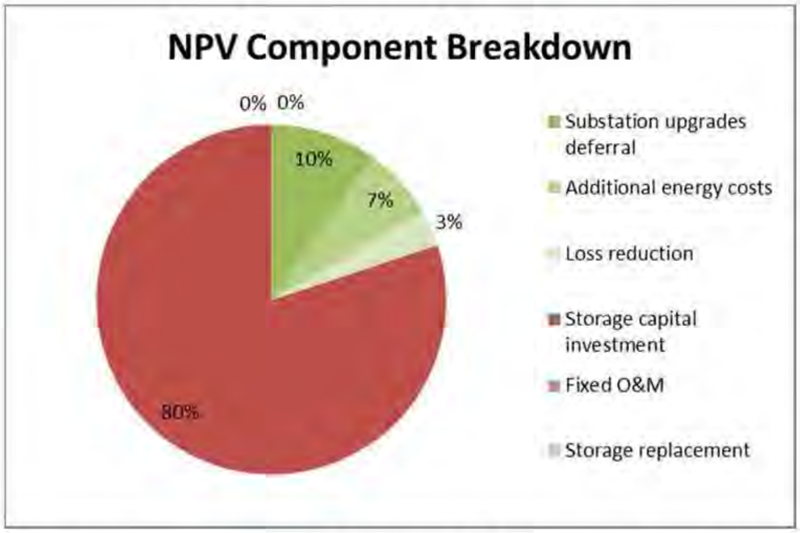



Figure 4-9 Scenario 3 - NPV Component Breakdown for Repurposed Battery with $3,000 Pack

## 4.6 Scenario 4

The technical results gathered from the simulations were analysed over the 10 year period and yielded an NPV for the various benefits and cost categories ranging from -$1,996,012 to -$763,556 in 2013 dollars.

The NPV for the new battery use case is presented by component in Table 4-11 and illustrated in Figure **4-10**.

| Categories | Discounted Value |
|---|---|
| Substation upgrades deferral | $85,308 |
| Additional energy costs | $111,956 |
| Loss reduction | $34,890 |
| **Total benefit** | **$232,154** |
| Storage capital investment | $2,228,123 |
| Fixed O&M | $43 |
| Storage replacement | $0 |
| **Total cost** | **$2,228,166** |
| **NPV** | **-$1,996,012** |

Table 4-11 Scenario 4 - NPV Component Breakdown for New Battery

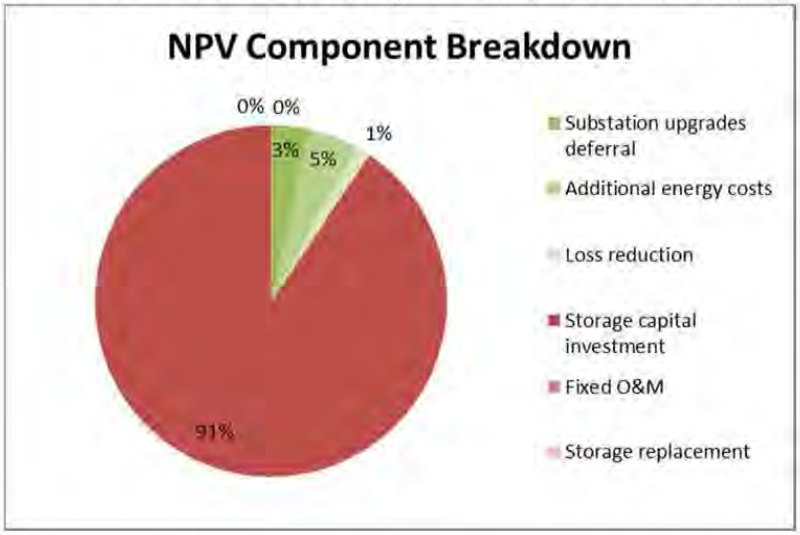



Figure 4-10 Scenario 4 - NPV Component Breakdown for New Battery

The NPV for the repurposed battery with free packs use case is presented by component in Table 4-12 and illustrated in Figure **4-11**.

| Categories | Discounted Value |
|---|---|
| Substation upgrades deferral | $85,308 |
| Additional energy costs | $108,923 |
| Loss reduction | $34,593 |
| **Total benefit** | **$228,824** |
| Storage capital investment | $1,102,177 |
| Fixed O&M | $43 |
| Storage replacement | $0 |
| **Total cost** | **$992,380** |
| **NPV** | **-$763,556** |

Table 4-12 Scenario 4 - NPV Component Breakdown for Repurposed Battery with Free Pack

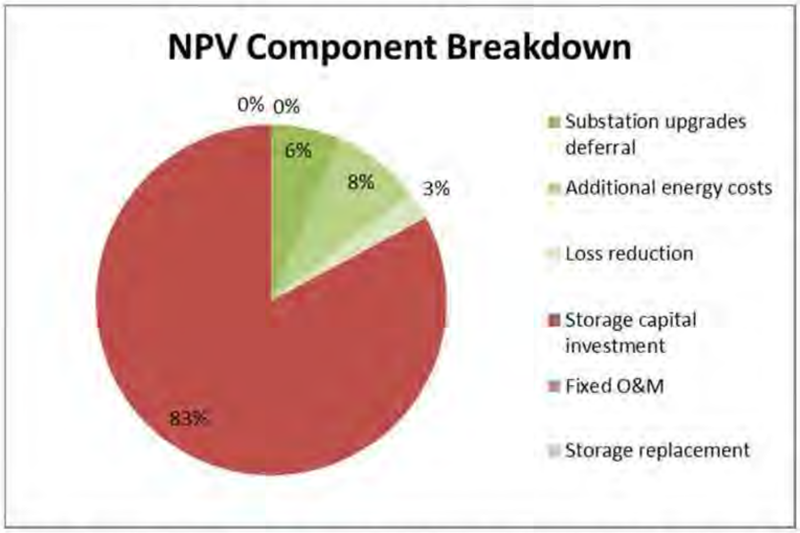



Figure 4-11 Scenario 4 - NPV Component Breakdown for Repurposed Battery with Free Pack

The NPV for the repurposed battery with $3,000 packs use case is presented by component in Table 4-13 and illustrated in Figure **4-12**.

| Categories | Discounted Value |
|---|---|
| Substation upgrades deferral | $85,308 |
| Additional energy costs | $108,923 |
| Loss reduction | $34,593 |
| **Total benefit** | **$228,824** |
| Storage capital investment | $1,302,345 |
| Fixed O&M | $43 |
| Storage replacement | $0 |
| **Total cost** | **$1,302,388** |
| **NPV** | **-$1,073,564** |

Table 4-13 Scenario 4 - NPV Component Breakdown for Repurposed Battery with $3,000 Pack

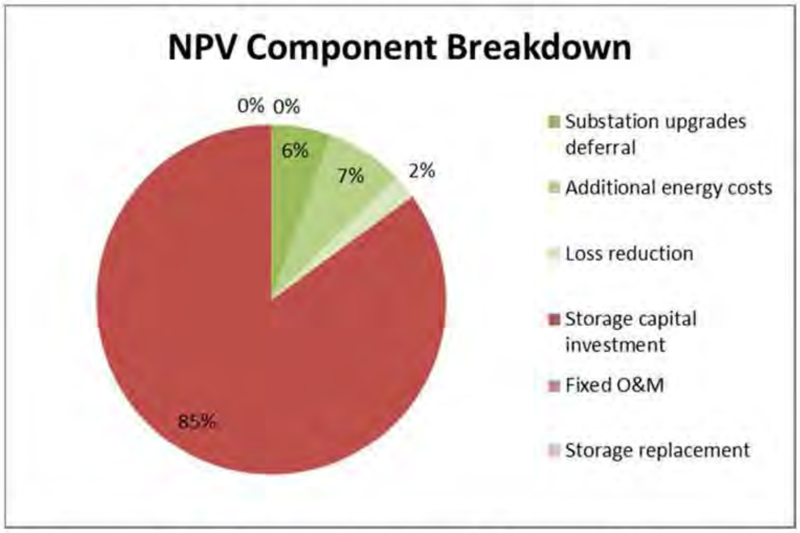



Figure 4-12 Scenario 4 - NPV Component Breakdown for Repurposed Battery with $3,000 Pack

# 5 CONCLUSIONS

The NPV for all cases analysed are presented in Table **5-1**.

Table 5-1 Comparison of Benefit/Cost for Use Cases

| Scenario | **Configuration** | **Benefit** | **Cost** | **Total NPV** |
|---|---|---|---|---|
| 1 | New Pack | $139,342 | -$2,228,166 | -$2,088,824 |
| | $3k Pack | $136,018 | -$1,302,388 | -$1,166,370 |
| | Free Pack | $136,018 | -$992,380 | -$856,362 |
| 2 | New Pack | $563,486 | $2,228,166 | -$1,664,680 |
| | $3k Pack | $560,157 | $1,302,388 | -$742,231 |
| | Free Pack | $560,157 | $992,380 | -$432,223 |
| 3 | New Pack | $328,107 | $2,228,166 | -$1,900,059 |
| | $3k Pack | $324,776 | $1,302,388 | -$977,612 |
| | Free Pack | $324,776 | $992,380 | -$667,604 |
| 4 | New Pack | $232,154 | $2,228,166 | -$1,996,012 |
| | $3k Pack | $228,824 | $1,302,388 | -$1,073,564 |
| | Free Pack | $228,824 | $992,380 | -$763,556 |

The Trinity circuit is a poor candidate for substation deferral opportunities because the current substation capacity is more than adequate to serve its load for years to come, particularly assuming a tame 0.6% load growth.

The illustrative cases assumed a substation loading of roughly 99%. With this assumption in mind, these cases demonstrated the sensitivity of the deferral opportunity to load growth. None of the scenario exhibited a promising return on investment, as illustrated for the new battery, the repurposed battery with free packs, and the repurposed battery with $3,000 packs in Figure **5-1**, Figure **5-2**, and Figure **5-3** respectively.

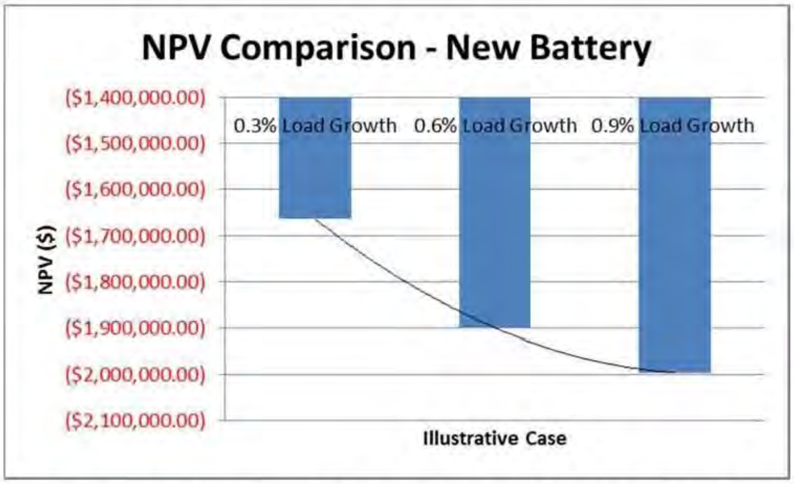



Figure 5-1 NPV vs. Load Growth Trend for Illustrative Scenarios with New Battery

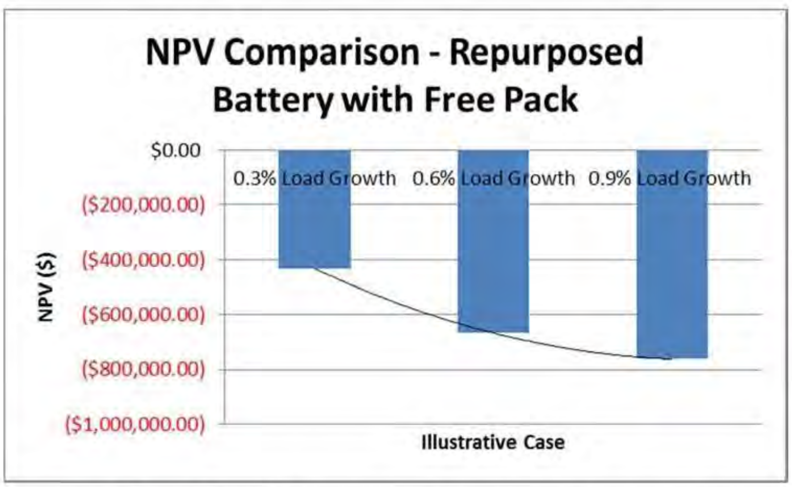



Figure 5-2 NPV vs. Load Growth Trend for Illustrative Scenarios with Repurposed Battery and Free Packs

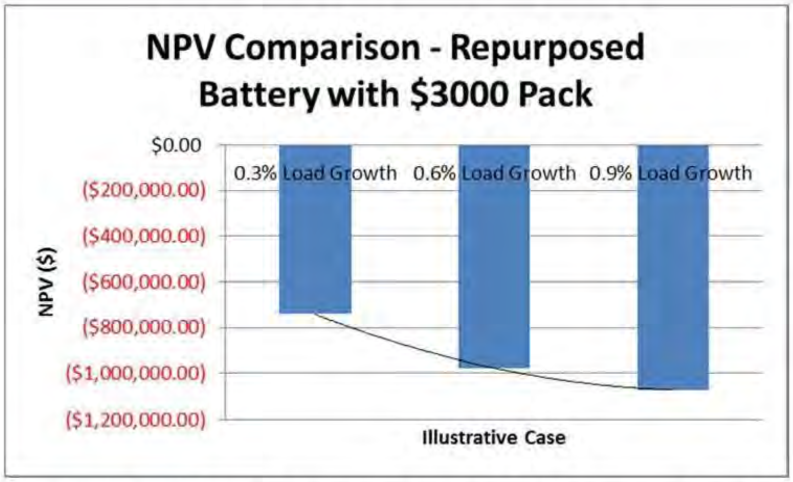



Figure 5-3 NPV vs. Load Growth Trend for Illustrative Scenarios with Repurposed Battery and $3,000 Packs

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# Appendix F: CES Frequency Regulation Evaluation

DNV·GL

DTE CES ENERGY STORAGE DEMONSTRATION COST-EFFECTIVENESS ANALYSIS

# Frequency Regulation Evaluation

DTE Energy

**Report No.:** Final, Rev. 2
**Date:** August 14, 2015

| | | |
|---|---|---|
| Project name: | DTE CES Energy Storage Demonstration Cost-Effectiveness Analysis | DNV GL Energy Advisory |
| Report title: | Frequency Regulation Evaluation | [Office Post 1] |
| Customer: | DTE Energy | [Office Post 2] |
| Contact person: | Dennis Flinn | [Office Post 3] |
| Date of issue: | August 14, 2015 | [Office Post 4] |
| Project No.: | | Tel: [+00 000 000 000] |
| Organization unit: | | [Company Reg No] |
| Report No.: | Final, Rev. 2 | |
| Document No.: | | |

Applicable contract(s) governing the provision of this Report:

Objective:
Present the technical and financial analysis of simulation results of the CES fleet dispatched for Frequency Regulation purposes.

| Prepared by: | Verified by: | Approved by: |
|---|---|---|
| Mike Kleinberg<br>Senior Consultant | Frederic Dubois<br>Consultant | Dennis Flinn<br>Principal Consultant |
| Niloufar Mirhosseini<br>Consultant | | |



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- ☐ Secret

Keywords:
CES, Peak Shaving, Distribution Deferral

| | | | | | |
|---|---|---|---|---|---|
| 0 | 2014-05-09 | Original Issue | Frederic Dubois | Mike Kleinberg | Dennis Flinn |
| 1 | 2015-06-17 | Include battery degradation | Mike Kleinberg<br>Niloufar Mirhosseini | Frederic Dubois | Dennis Flinn |
| 2 | 2015-08-14 | Final Report | | | |

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# 1 EXECUTIVE SUMMARY

The objective of this use case is to explore the cost-effectiveness of using CES units to perform frequency regulation from the distribution system level. For the purpose of this study, the Trinity circuit was modelled because it features a community energy storage (CES) fleet of 17 units aggregately rated at 425 kW / 850 kWh. These units were deployed by DTE Energy as a pilot project.

This use case provides a financial assessment of employing the Trinity CES fleet to participate in the Midwest Independent System Operator (MISO) and California Independent System Operator (CAISO) frequency regulation markets. The MISO and CAISO markets rules governing storage participation in the frequency regulation market were reviewed and the operating assumptions employed in the assessment of the Trinity CES fleet are presented. The computed market revenue of the fleet operating the conventional frequency regulation market will be provided along with the impact to network operational performance based on this dispatch. These benefits and the costs associated with deploying the CES units are evaluated over a 10-year horizon, considering the units are expected to have an operating life of 10 years.

## 2 INTRODUCTION

DTE Energy has deployed 17 new CES units manufactured by the S&C Electric Company. These units are rated at 25 kW / 50 kWh and are centrally controlled by DTE's Distributed Resource System Operation Center (DR-SOC). DNV GL worked closely with DTE Energy to model a fleet of 17 CES using ES-Grid, a proprietary cost-effectiveness model used to assess the technical impact of deploying energy storage on a distribution circuit through power flow analyses. This model processes results from OpenDSS, an open-source power flow analysis software.

The objective of this use case is to explore the cost-effectiveness of using CES units performing frequency regulation in MISO market. Additional results are provided also demonstrating dispatch and valuation results for the system if it were located in the CAISO market. The use case will explore the first and repeated costs of using a fleet of CES units to perform these operations, and assess the financial benefits of doing so. The computed market revenue of the fleet operating the conventional frequency regulation market will be provided along with the impact to network operational performance based on this dispatch. These benefits and the costs associated with deploying the CES units were evaluated over a 10-year horizon, considering the units are expected to have an operating life of 10 years.

# 3 TECHNICAL ANALYSIS

The technical analysis consisted of hourly simulations performed for 20 sample days over a period of 10 years. These sample days were chosen through a pre-analysis of the base case scenario with the purpose of representing the seasonal differences associated with systems operations. An initial analysis was conducted on the Trinity circuit provided by DTE using observed SCADA data.

## 3.1 Circuit Model

The circuit model and load curves were provided in DEW format and converted to an OpenDSS format, an open-source power flow analysis tool developed by EPRI. The base scenario involved simulating the system without CES units and it features a 490 kW photovoltaic site with a 500 kW energy storage backup. The Trinity circuit diagram is illustrated in Figure 3-1.

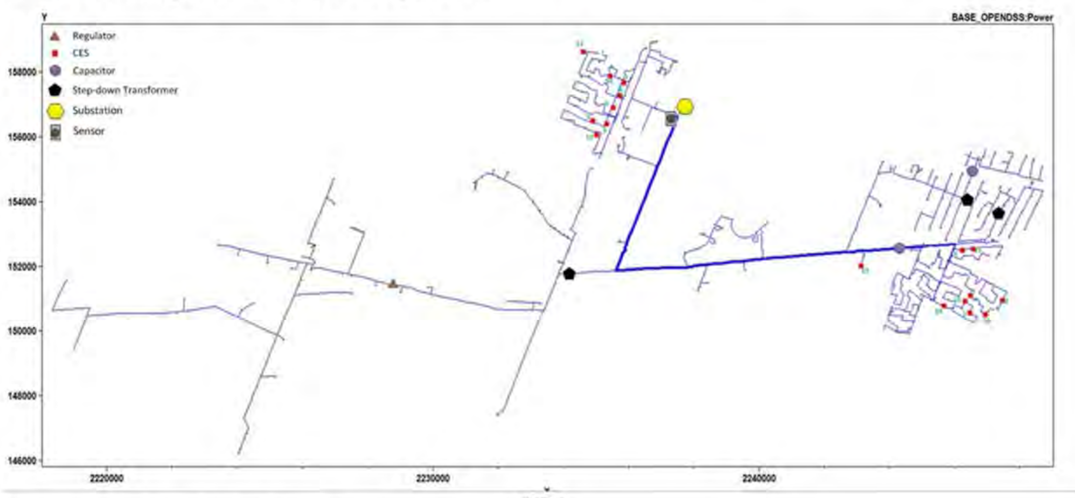


**Figure 3-1 OpenDSS Trinity Circuit Diagram**

The test scenarios were essentially the same as the base case scenario with the addition of the 17 CES units distributed across two regions as shown in Figure 3-1. The first test scenario featured CES units modelled to illustrate the degradation of new battery modules, and the second test scenario featured CES units modelled to illustrate the degradation of repurposed battery modules.

## 3.2 CES Model

The CES units were modeled taking into account the physical limits of the units as observed in the field and laboratory environment, and heeding S&C's usage recommendations, such as maximum depth of discharge, acceptable charge and discharge rates, and expected round trip efficiency.

The algorithm also ensured that the CES units in the model respected their maximum charge and discharge magnitudes and durations as observed in laboratory experiments:

- Backup reserve was 20%, meaning up to 40 kWh of energy is available for dispatch for each unit
- Maximum charge rate was 22.5 kW

- Maximum discharge rate was 22.5 kW
- Round trip efficiency was 88%
- Idling losses were .25 kWh/hr

Based on MISO regulations presented in the following section, the TRINITY CES fleet is assumed to operate in the conventional MISO regulation market. The fleet is dispatched by storage operator based on the hourly commitments to the regulation market. Hourly commitments are computed based on forecasts of the day-ahead market prices. Operation of the fleet is then simulated with the ESGRID to capture the network performance during these operations. The underlying assumptions of the operational optimization are:

- Operation of the fleet is simulated on an hourly basis to optimize the revenue from frequency regulation market participation.
- The fleet operates as a price taker on day-ahead markets. Day-ahead forecasts of market prices are assumed perfect. The price taker assumption implies that the size of the fleet is small enough such that its participation will not affect the market prices.
- Over any hour, the fleet commits optimal capacity to regulation which can result in either net charge or discharge.
- The optimal market participation dispatch is determined by solving a series of Mixed Integer Linear Program (MILP) problems.
- The optimization focuses solely on operational costs and benefits and does not take into consideration the capital costs or fixed Operations and Maintenance (O&M) costs the system.
- Optimal operation is computed on an hourly time scale over a time-horizon of one day. Annual results are obtained by simulating one day at a time.
- The fleet is dispatched to participate in MISO's conventional day-ahead energy and regulation markets – day-ahead energy (DAE) and regulation (REG).

## 3.3 Frequency Regulation Dispatch

### 3.3.1 MISO Market

Frequency Regulation market rules vary depending on the ISO. To capture the specifics of the territory that DTE is part of, DNV GL met with representatives from MISO to discuss the specific bid limitations and valuation of centrally controlled CES fleets. Some important findings used to drive the financial analysis and operating assumptions are listed below:

**General Guidelines**

- Multiple Stored Energy Resources can be aggregated under an Elementary Pricing Node (Epnode), which is a bus where energy is injected and/or withdrawn from the Transmissions System. For the purpose of this project, the DR-SOC qualifies as an Epnode, and therefore the capacity of all CES units can be aggregated as one.

- No bids are accepted for resources smaller than 1MW. Bids from Stored Energy Resources between 1 and 5MW are evaluated on a case-by-case basis. For the purpose of this assessment it is assumed that the TRINTY fleet qualifies at 750kW. However, the fleet would need an additional 250kW of capacity at minimum to be deemed adequately sized.
- Stored Energy Resources do not qualify as a Spin Qualified Resource, and therefore cannot bid in the Spinning Reserve market.[1]
- There are no restrictions on duration, however the device is required to be dispatchable at the committed power capacity for at least 5 minutes in order to follow MISO's real-time AGC signal.
- There are two markets in which an electric storage asset might participate – the conventional regulation market for which resources such as turbine generators and pumped hydro plants are eligible and qualifying storage resources and the short term storage market in which fast response, energy constrained resources are eligible.

**Conventional Regulation Markets**

- A resource bids into the regulation market over an hour and provides the regulation service if the bid is accepted. The regulation service must be provided over the entire hour.
- MISO operates a consolidate regulation market, i.e. there are not separate regulation up and regulation down market products. The device must then be able to perform equal regulation up and down from its set-up for a given set-up.
- The MISO regulation signal averages an up-regulation bias implying there is a net energy supply to the grid from a storage device for a regulation commitment.
- Resources participating in regulation are paid the hourly market clearing price for the capacity committed.
- Energy transactions while providing regulation are assessed at the spot market price of energy, i.e. charging to perform regulation down requires purchasing energy at the spot market price.
- Disparate resources such as turbine generators and pumped hydro plants may bid into this market.
- Devices can provide regulation while charging or discharging. A regulation up signal can be followed by increasing the rate of discharge or decreasing the rate of charge. A regulation down signal can be followed by decreasing the rate of discharge or increasing the rate of charge.

**Fast Regulation Markets**

- The devices committed to this market are dispatched by the market operator according to optimal market requirements. The device operator specifies on a day-ahead basis, the hours on which the device will be available to MISO to provide regulation.
- Devices operating in the fast regulation market are required to have an instantaneous power capacity greater than 5 MW. Systems between 1 and 5 MW may be allowed to participate on a case-by-case basis with an absolute minimum capacity of 1 MW.

[1] MISO Energy and Operating Reserve Markets Business Practices Manual, Section 4.2.1.2

- Devices have to be registered as 'short term storage devices'. Onus on operator to register responsibly. Devices specify (on day-ahead basis) the hours of availability for regulation. There is no state of charge specification for the device to be eligible at any hour. A short term storage device is not eligible to participation in any other market when committed to fast regulation.
- The regulation signal is not guaranteed to be net-zero over a given time interval. MISO's AGC signal tends to deviate to the positive direction, or has a regulation up trend.
- Stored Energy Resources committed to this market are directly controlled by MISO. Devices receive capacity payment for regulation, energy clearing price for buying and selling, and mileage payments for cycling.
- MISO controls the charging and discharging operation of the storage device on the hours the device has been committed for regulation. The state of charge of the device is measured every ten minutes and an appropriate regulation up or down signal is supplied.
- The charging and discharging energy is settled at the spot market price of energy. The payment for regulation is assessed on a day-ahead basis as:
- $/MW regulation payment = $/MW capacity payment + Mileage ratio * $/MW mileage payment.
- The mileage ratio is a constant fixed by the ISO at the beginning of the month and is a metric for estimating the number of cycles moved by the state of charge of the storage device over an hour. The mileage ratio is measured at the time of providing the service and any discrepancy from the monthly mileage ratio is compensated at the spot price of mileage.

### 3.3.2 CAISO Market

As a supplement to the performance in the MISO market, DNV GL has also modeled the CAISO regulation market and will present valuation results which simulate the Trinity fleet being dispatch into the CAISO market with projected CAISO prices. As stated for MISO market, the frequency regulation markets rules vary by ISO. DNV GL has modeled the CAISO market rules over the past two years while supporting California storage RFO evaluations. Some of the key differences for operating in the CAISO regulation market rather than the MISO market are listed below:

**Key CAISO Market Differences**

- The CAISO market offers separate regulation up and regulation down market products, counter to MISO's consolidated regulation market. In CAISO both the regulation up and regulation down market prices will vary in different ways on an hourly basis. When optimizing dispatch for these separate regulation products, the corresponding hourly price for each, along with the commitment impact on the storage state-of-charge must be considered.
- The fleet resource commits to combined regulation up and regulation down markets separately. At the smallest interval over which the regulation signal is transmitted by the market operator (4 s), the signal is either up or down.
- Following a regulation up signal, corresponding to a given committed capacity over an hour, results in a non-zero production of energy in excess of the nominal energy production set point. The resource is compensated for this energy production at the spot-market price of energy.

- Following a regulation down signal, corresponding to a given committed capacity over an hour, results in a non-zero deficit in delivering the energy committed to the day-ahead market. The resource compensates for the deficit by buying energy at the spot-market price.

- The energy off-set from a set point by following a regulation signal is 10% of the capacity committed to regulation. For example, if 1 MW is committed to the regulation market over an hour, the resource will deliver 100kWhr in excess of the energy set point, over the hour.

- Regulation can be sold while the device is charging or discharging, this is illustrated in Figure 3-2:
  - Regulation up implies either increasing rate of discharge or decreasing the rate of charge.
  - Regulation down implies decreasing the rate of discharge or increasing rate of charge.

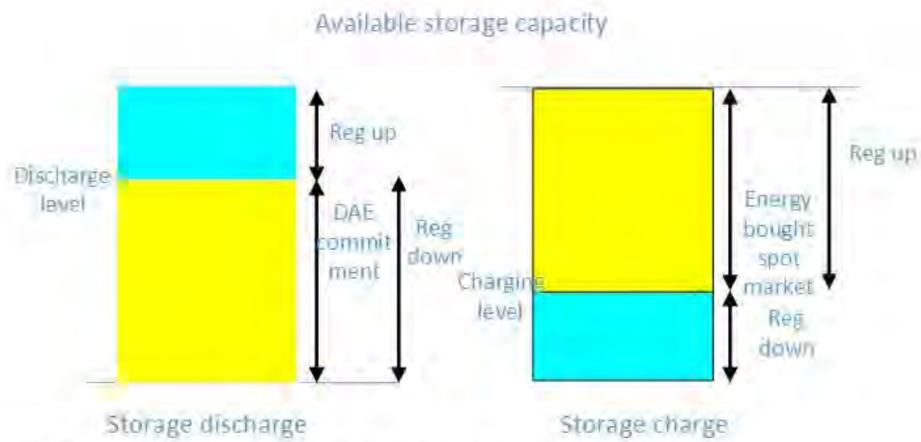


**Figure 3-2 Regulation up and down during charging and discharging**

- The mean spot market price of energy is assumed to be a multiple of the day-ahead energy price at that hour.

- In CAISO, energy limited devices can participate in conventional spinning reserve markets. This is different from MISO which does not allow for these bids.

- Beyond conventional regulation, other markets exist or are emerging in CA which permit energy storage. The existing Regulation Energy Management market is designed for shorter duration devices, like flywheels, and operates on a 15 minute commitments. An emerging Fast Ramping product is also close to being approved and has been targeted at fast responding devices to regulate the "duck curve" phenomena in California.

### 3.3.3 Conceptual Dispatch

For both markets, the output of the market optimization is the daily commitment schedule of the CES fleet. Given the computed commitment and the assumptions listed, the fleet is assumed to be dispatched according to the high level control methodology, as provided by DEW, seen in Figure 3-3.

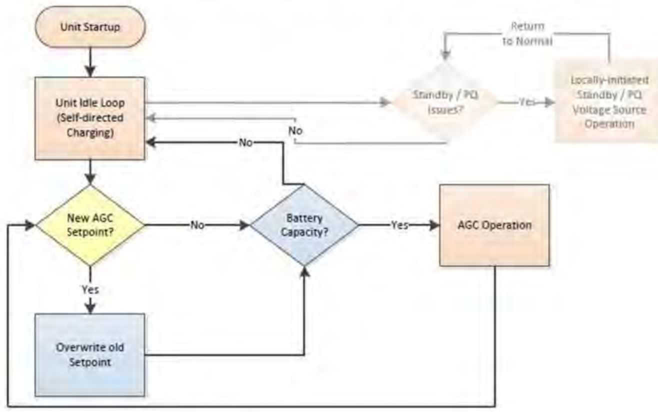


**Figure 3-3 Frequency Regulation control logic**

The corresponding charge or discharge command is distributed amongst each CES unit is based on the DTE Flex logic, using the SOC of each unit as follows:

$$\boldsymbol{P_{out\_n}} = P_{demand} * \frac{SOC_{CES_n}}{\sum_{j=1}^{m} SOC_{CES_j}}, where$$

$$\boldsymbol{P_{out_n}} = Power\ dispatch\ of\ unit\ n$$

$$\boldsymbol{P_{demand}} = Total\ power\ requested\ for\ peak - shaving$$

$$\boldsymbol{SOC_{CES_j}} = SOC\ of\ unit\ j$$

$$\boldsymbol{m} = Total\ number\ of\ CES\ units$$

# 4 FINANCIAL ANALYSIS

The parameters presented in Table 4-1 along with technical results from the simulations were used to evaluate the financial impact of the CES system for the two scenarios evaluated.

**Table 4-1 Financial Parameters**

| Data Type | Parameter Description | Value | Unit |
|---|---|---|---|
| General | Calendar life | 10 | years |
| | Project analysis period | 10 | years |
| | Substation transformer capacity | 15 | MVA |
| | Load Growth | 6.0 | % |
| | Substation transformer upgrade factor | 100 | % |
| | Installation cost of distribution upgrade | 100 | $/kW |
| Financial | Inflation rate | 2.0 | % |
| | Discount rate | 7.0 | % |
| | Electricity price escalation rate | 3.0 | % |
| | Equity financed | 50.0 | % |
| | Debt financed | 50.0 | % |
| | WACC | 7.6 | % |
| | Property taxes and insurance | 1.5 | % |
| | Marginal income tax rate | 43.8 | % |
| | Debt rate | 6.2 | % |
| | Equity rate | 11.5 | % |
| | Insurance | 0.4 | % |
| Battery specification | Annual decline rate of battery capital cost | 3.3 | % |
| | Fixed O&M cost | 16 | $/kW |
| | O&M cost escalation rate | 0.0 | % |
| | Total power capacity | 425 | kW |
| | Duration | 2.00 | hours |
| | One-way efficiency | 93.8 | % |

The benefits and cost categories are detailed in the following two subsections. The scenario results are presented in the last section.

The analyses of the MISO and CAISO markets are presented in the following subsections.

## 4.1 Benefits

Energy Storage benefits considered in the analysis include:

- **Market Revenue Generation.** The dispatch of storage units in the conventional regulation market as compensated by MISO or CAISO.
- **Distribution Loss Reduction.** Changes in system losses are calculated via engineering simulations. Annual time series data for electricity wholesale prices are used to estimate the value of loss changes. Discharging the CES units will reduce the current on the feeder upstream, while charging will have the opposite effect.

## 4.2 Costs

Energy Storage costs considered in the analysis include:

- **Capital Investment cost of energy storage.** The energy storage unit's capital cost is calculated as a function of the size of the unit and the battery type. During the analysis period, storage units are replaced based on estimated actual life. Energy storage actual life is calculated as a function of the number of charge/discharge half-cycles and the amount of energy that is charged/discharged in each half-cycle, and its calendar life (The engineering simulation tracks storage charges and discharges). The total cost, which includes the battery modules, the inverter, and the installation cost, for the three systems under evaluation are as follows:
    - New system: $133,575
    - Repurposed system with free battery packs: $66,075
    - Repurposed system with $3,000 battery packs: $78,075
- **Cost of replacement.** The cost of replacing energy storage at the end of its actual life is assumed to be a fraction of initial investment cost. The number of replacements during the project analysis period depends on the energy storage actual life. The replacement cost for the three systems under evaluation, which only include the battery modules, are as follows:
    - New system: $85,000
    - Repurposed system with free battery packs: $17,500
    - Repurposed system with $3,000 battery packs: $29,500
- **Operation and maintenance cost.** Annual operation and maintenance costs are assumed to be proportional to energy storage power capacity.

## 4.3 MISO Market Use Case

Given the assumptions in section 3.2, the CES fleet is dispatched optimally to generate revenue in the MISO day-ahead energy and regulation markets. Hourly energy and regulation price data for the full year 2013 was obtained and used as input for the day-ahead optimal storage dispatch. Based on the dispatch assumption in section 3.2, the market operations for two sample days are presented below: July 5th, 2013 and June 8th, 2013.

### 4.3.1 New Battery Modules

The dispatch results for July 5th are shown in Figure 4-1. Storage charging and regulation operations are optimized against the hourly day-ahead energy and regulation prices. As seen in on July 5th, the storage device charges during one hour in the morning to capture the low day-ahead energy price in order to be available for operation at all other hours in the regulation market. Based on the assumptions of net-energy discharge during regulation operations, the state-of-charge of the fleet decrease during each hour of commitment to the regulation market at seen in Figure 4-2.

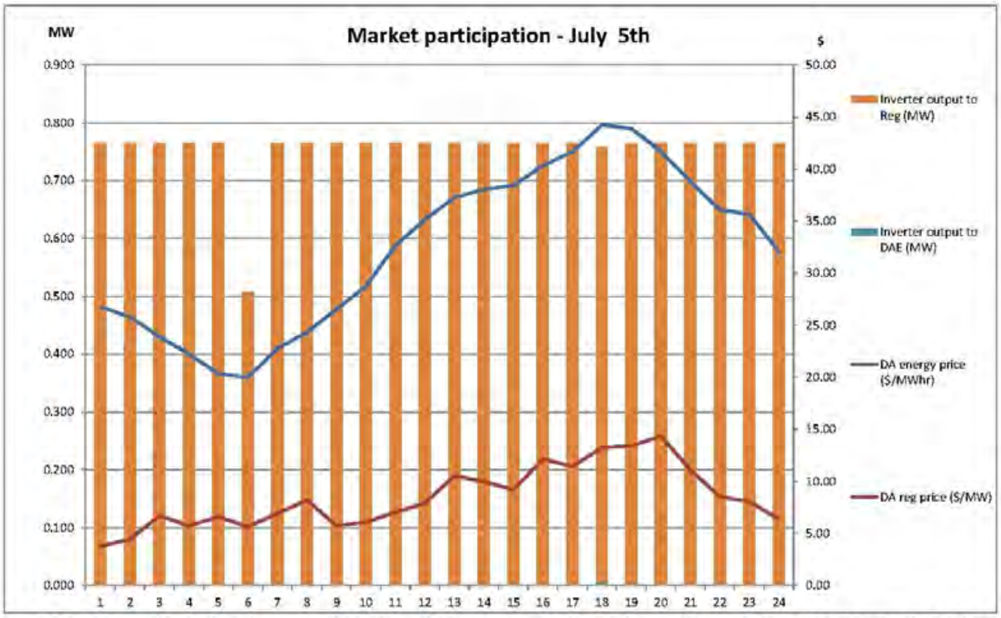


**Figure 4-1 Day-Ahead Prices and Optimal Storage Market Commitment for MISO Market Case with New Battery Modules – July 5th**

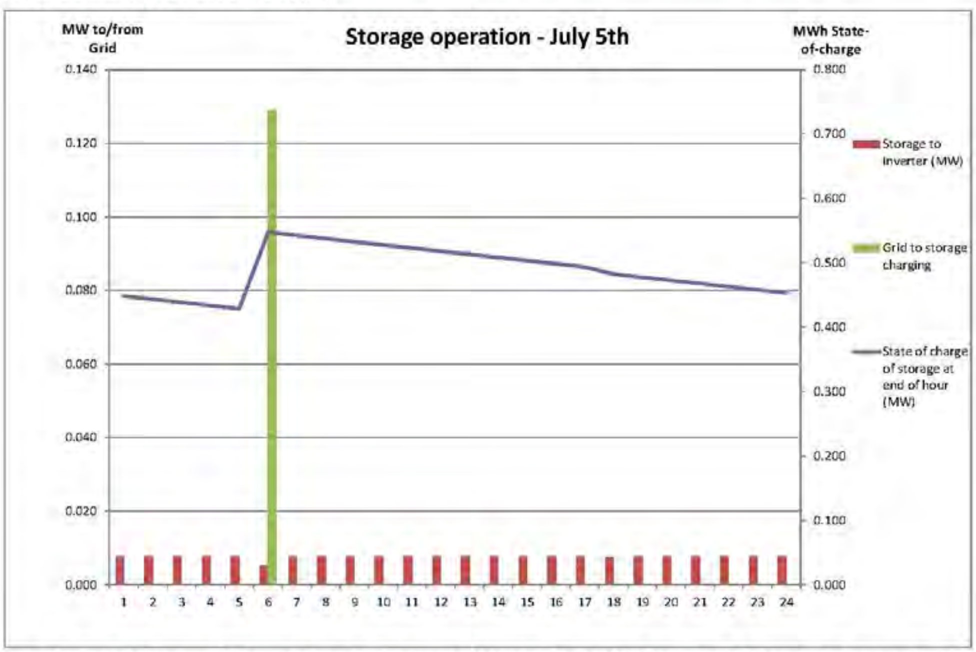


**Figure 4-2 Net Storage Dispatch and State-of-Charge for MISO Market Case with New Battery Modules – July 5th**

The dispatch results for June 8th are shown in Figure 4-3. Storage charging and regulation operations are optimized against the hourly day-ahead energy and regulation prices. The fleet now spreads charging over multiple hours to optimize against the lower day-ahead energy prices and to be available for regulation during other hours of the day and for a small arbitrage opportunity at hour 19. Based on the assumptions of net-energy discharge during regulation operations, the state-of-charge of the fleet decreases during each hour of commitment to the regulation market at seen Figure 4-4.

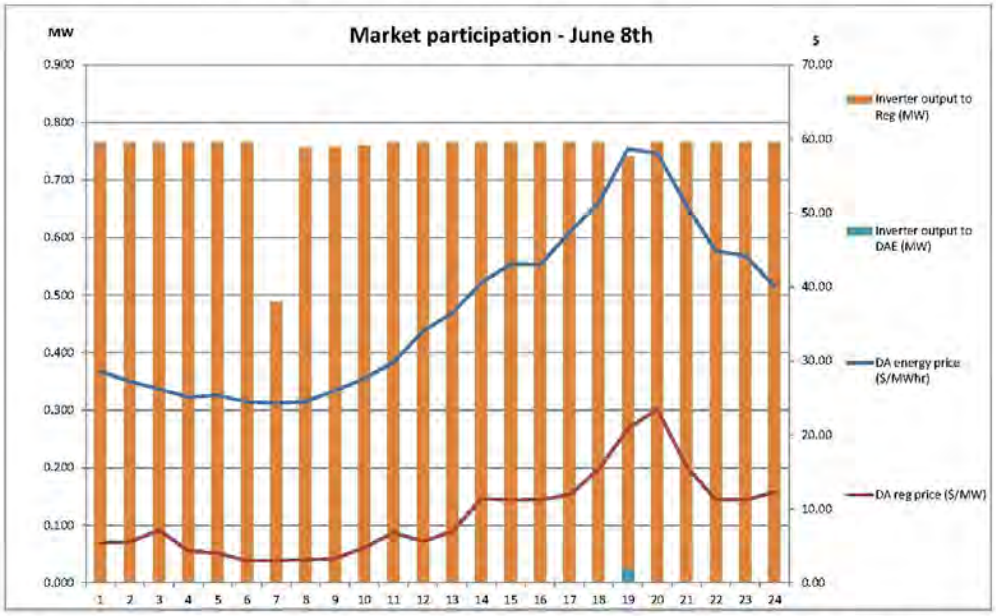


**Figure 4-3 Day-Ahead Prices and Optimal Storage Market Commitment for MISO Market Case with New Battery Modules – June 8th**

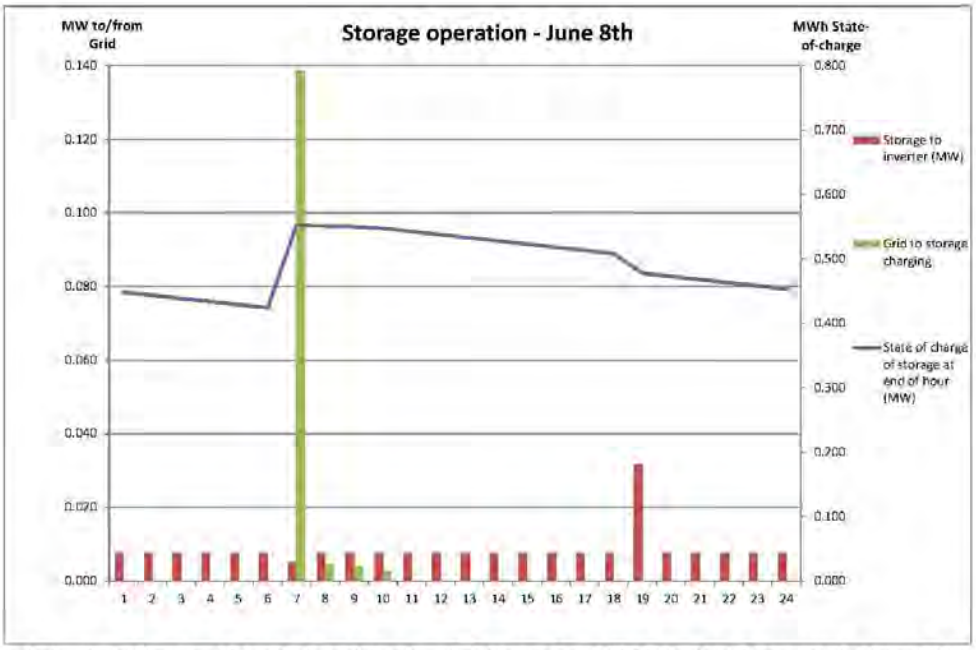


**Figure 4-4 Net Storage Dispatch and State-of-Charge for MISO Market Case with New Battery Modules – June 8th**

Considering the financial benefits of market revenue generation and network loss reduction, and the associated storage costs including investment cost, battery replacement, fixed O&M and storage charging, the financial analysis of this use case results in a negative net present value (NPV) of (-$1,985,085) and a benefit-cost ratio of approximately 0.12. This result is primarily driven by the cost of the fleet vs. the potential market revenue achievable based on historical 2013 prices. A breakdown of the discounted cost and benefits can be seen in Table 4-2.

**Table 4-2 NPV Component Breakdown for MISO Case with New Battery**

| Categories | Discounted Value |
|---|---|
| Market revenue | $282,541 |
| Loss reduction | -$3,428 |
| **Total benefit** | **$279,113** |
| Storage investment | $2,228,123 |
| Storage replacement | $0.00 |
| Fixed O&M | $43 |
| Charging costs | $36,031 |
| **Total cost** | **$2,264,197** |
| **NPV** | **-$1,985,085** |

The undiscounted cash flow for each of the revenue and cost streams is shown in Figure 4-5 below.

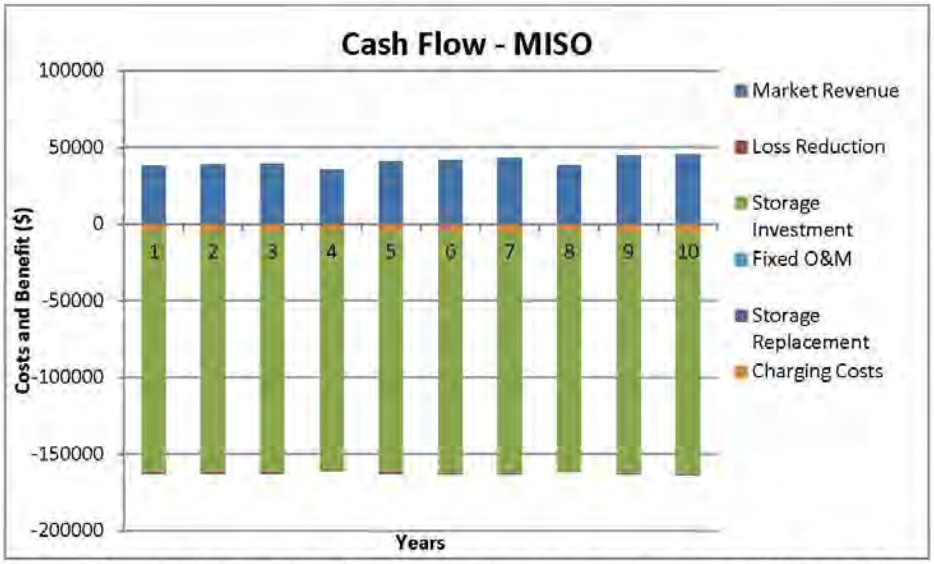


**Figure 4-5 10 Year Cash Flow of Market Services Cost and Benefits for MISO Market Case with New Battery Modules**

### 4.3.2 Repurposed Battery Modules

Considering the financial benefits of market revenue generation and network loss reduction, and the associated storage costs including investment cost, battery replacement, fixed O&M and storage charging, the financial analysis of this use case results in a negative net present value (NPV) of (-$1,059,307) and a benefit-cost ratio of approximately 0.21 for $3,000 packs and a negative net present value (NPV) of (-$859,138) and a benefit-cost ratio of approximately 0.25 for free packs. This result is primarily driven by the cost of the fleet vs. the potential market revenue achievable based on historical 2013 prices. A breakdown of the discounted cost and benefits can be seen in Table 4-3 for repurposed battery modules with $3,000 packs, and in Table 4-4 for repurposed battery modules with free packs.

**Table 4-3 NPV Component Breakdown for MISO Case with Repurposed Battery and $3,000 Packs**

| Categories | Discounted Value |
|---|---|
| Market Revenue | $282,541 |
| Loss Reduction | -$3,429 |
| **Total benefit** | **$279,113** |
| Storage Investment | $1,302,345 |
| Storage Replacement | $0 |
| Fixed O&M | $43 |
| Charging Costs | $36,031 |
| **Total cost** | **$1,338,419** |
| **NPV** | **-$1,059,307** |

**Table 4-4 NPV Component Breakdown for MISO Case with Repurposed Battery and Free Packs**

| Categories | Discounted Value |
|---|---|
| Market revenue | $282,541 |
| Loss reduction | -$3,429 |
| **Total benefit** | **$279,113** |
| Storage investment | $1,102,177 |

| Categories | Discounted Value |
|---|---|
| Storage replacement | $0 |
| Fixed O&M | $43 |
| Charging costs | $36,031 |
| **Total cost** | **$1,138,251** |
| **NPV** | **-$859,138** |

The undiscounted cash flows for each of the revenue and cost streams are shown in Figure 4-6 and Figure 4-7 below.

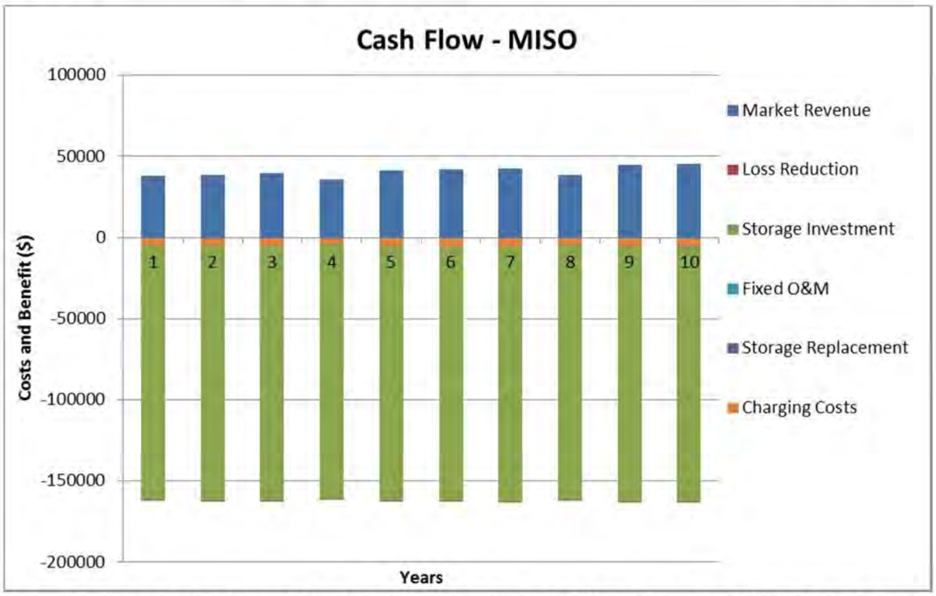


**Figure 4-6 10 Year Cash Flow of Market Services Cost and Benefits for MISO Market Case with Free Repurposed Battery Modules**

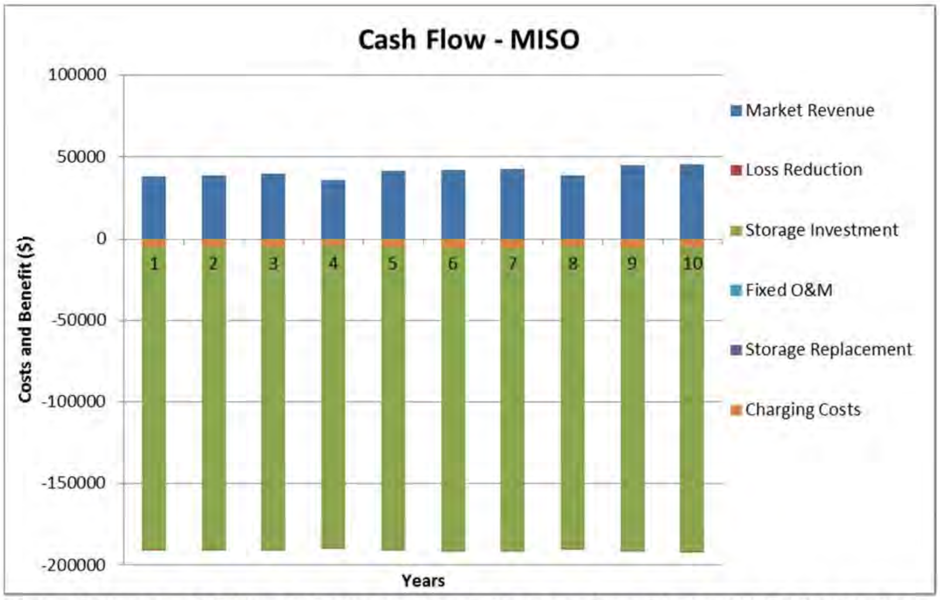


**Figure 4-7 10 Year Cash Flow of Market Services Cost and Benefits for MISO Market Case with $3,000 Repurposed Battery Modules**

### 4.3.3 Conclusions

The financial results for all cases analyzed for the MISO market are presented in Table 4-5.

**Table 4-5 Comparison of Benefit/Cost for Use Cases for MISO Market**

| Configuration | Benefit | Cost | Total NPV |
|---|---|---|---|
| New pack | $279,113 | $2,264,197 | -$1,985,085 |
| $3K pack | $279,113 | $1,338,419 | -$1,059,307 |
| Free pack | $279,113 | $1,138,251 | -$859,138 |

There is again a large improvement in NPV when moving from the purchases a new units and moving towards free packs. However, for the given storage cost assumptions, market prices are too low to generate sufficient revenue to drive a positive NPV using the fleet for only market services. Therefore, valuing additional primary benefit streams, such as peak shaving or reliability, is required to produce a cost-effective case for the fleet. Frequency regulation services can be sold during periods when the fleet is not needed for these other applications. The market revenue can then be supplemental to those value streams, producing a cost-effective use case for the fleet. Additionally, as MISO market rules evolve with additional storage penetration, new regulation products may emerge for which storage is qualified. These new products may offer additional revenue opportunities for the fleet.

## 4.4 CAISO Market Use Case

Given the assumptions in section 3.2, the CES fleet is dispatched optimally to generate revenue in the CAISO day-ahead energy and regulation markets. Hourly energy, regulation up, regulation down, and spinning reserve price data for the full year 2013 was obtained and used as input for the day-ahead optimal storage dispatch. Based on the dispatch assumption in section 3.2, the market operations for two sample days are presented below: July 7th, 2013 and January 25th, 2013.

### 4.4.1 New Battery Modules

The CAISO dispatch results for July 7th are shown in Figure 4-8. Storage dispatch is optimized against the hourly day-ahead energy, regulation up, regulation down, and spinning reserve prices. The fleet commits capacity to each market based on the prices and impact to state-of-charge. It can also be observed that regulation prices for this July 7th summer day follow expected behaviour in response to emerging high-renewable penetration scenarios, with regulation prices rising in the late day when PV productions drops but high demand persists until the early evening. The storage dispatch follows these prices, committing to regulation up in the late day as prices increase. Regulation down is favoured when regulation up and down prices are similar because this represents a charging operation or reduction of a day ahead energy commitment. Based on the assumptions of net-energy impact resulting from regulation up and down operations, the state-of-charge of the fleet fluctuates based on the commitments of each hour of as seen in Figure 4-9. This figure also show the hours denoted for storage charging from the grid.

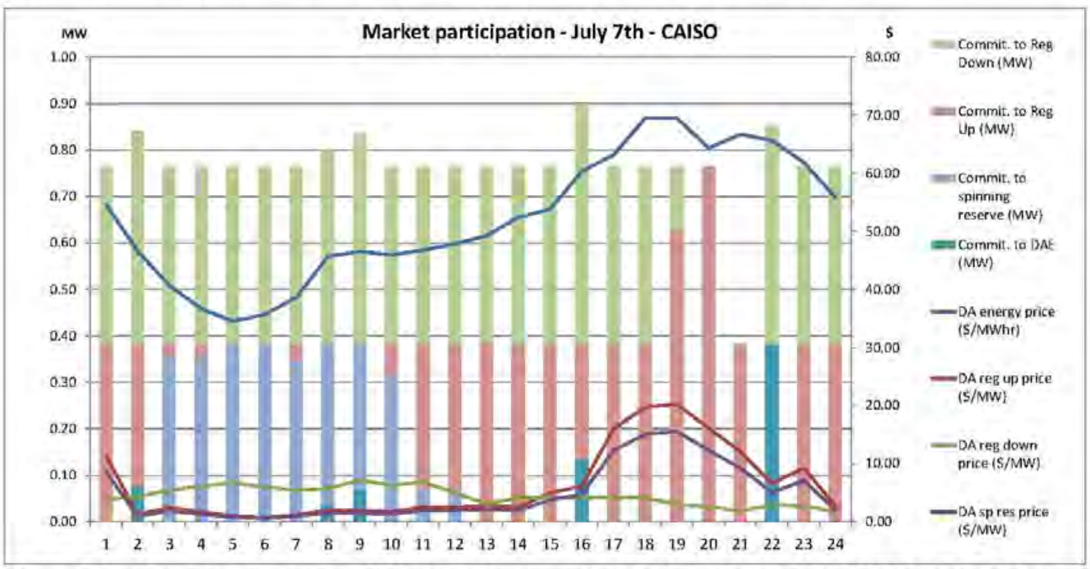


**Figure 4-8 Day-Ahead Prices and Optimal Storage Market Commitment for CAISO Market Case with New Battery Modules – July 7th.**

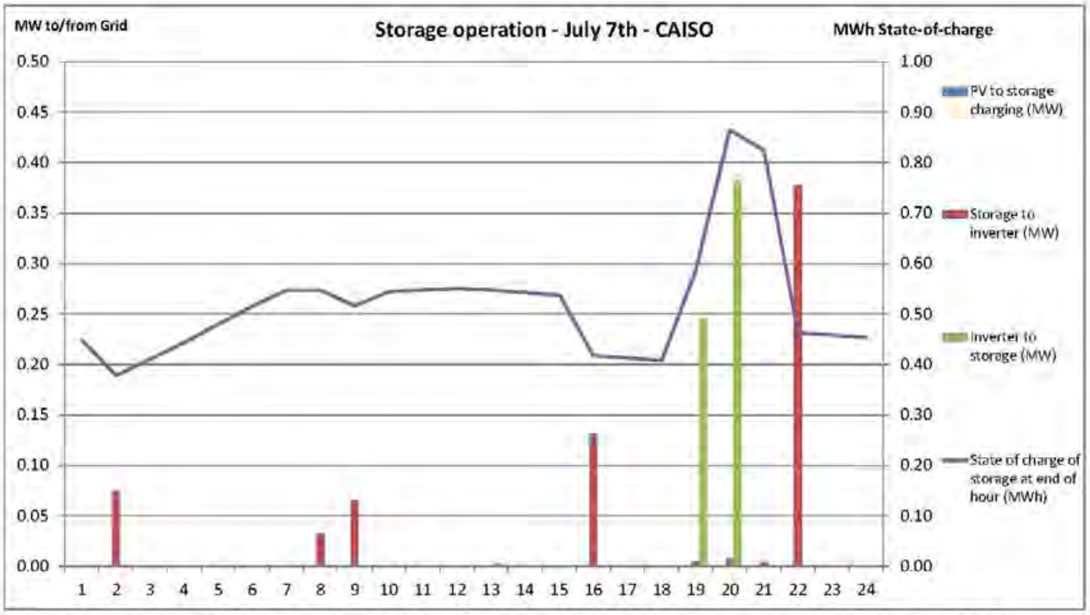


**Figure 4-9 Storage Dispatch and State-of-Charge for CAISO Market Case with New Battery Modules - July 7th**

An additional CAISO example is shown in Figure 4-10 below. Here, a winter season day, January 25 is selected. Storage charging and regulation operations are again optimized against the hourly day-ahead energy, regulation up, regulation down, and spinning reserve prices. Regulation up and down prices are generally lower than the summer day, and the fleet typically commits equally to regulation up and regulation down. The net dispatch of the storage device at each hour can be seen in Figure 4-11. The larger swings in state-of-charge compared to the MISO results are due to the commitments to selling day-ahead energy which results in a larger energy commitment for a given hour.

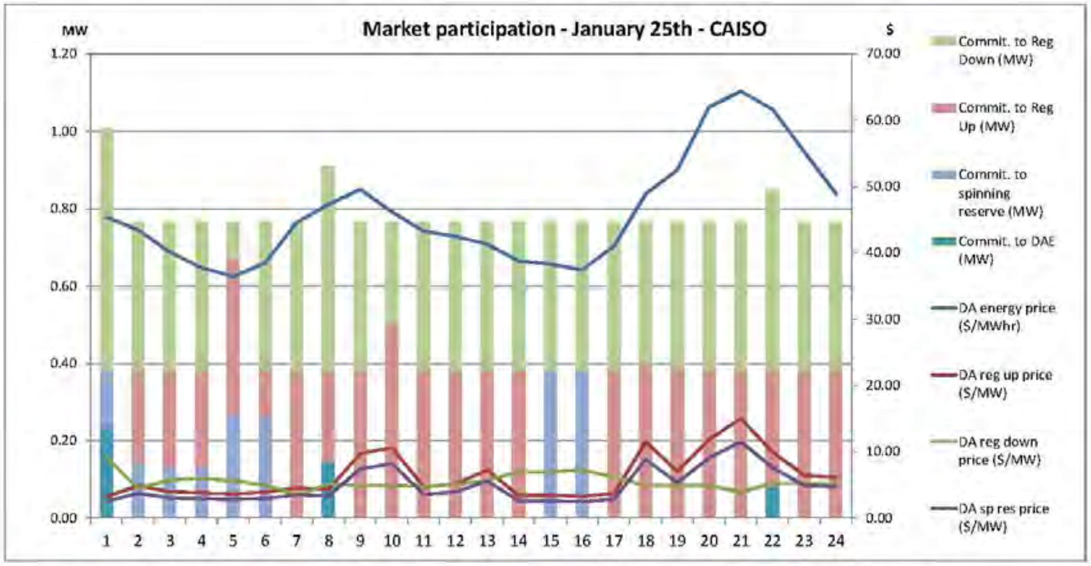


**Figure 4-10 Day-Ahead Prices and Optimal Storage Market Commitment for CAISO Market Case with New Battery Modules - January 25th**

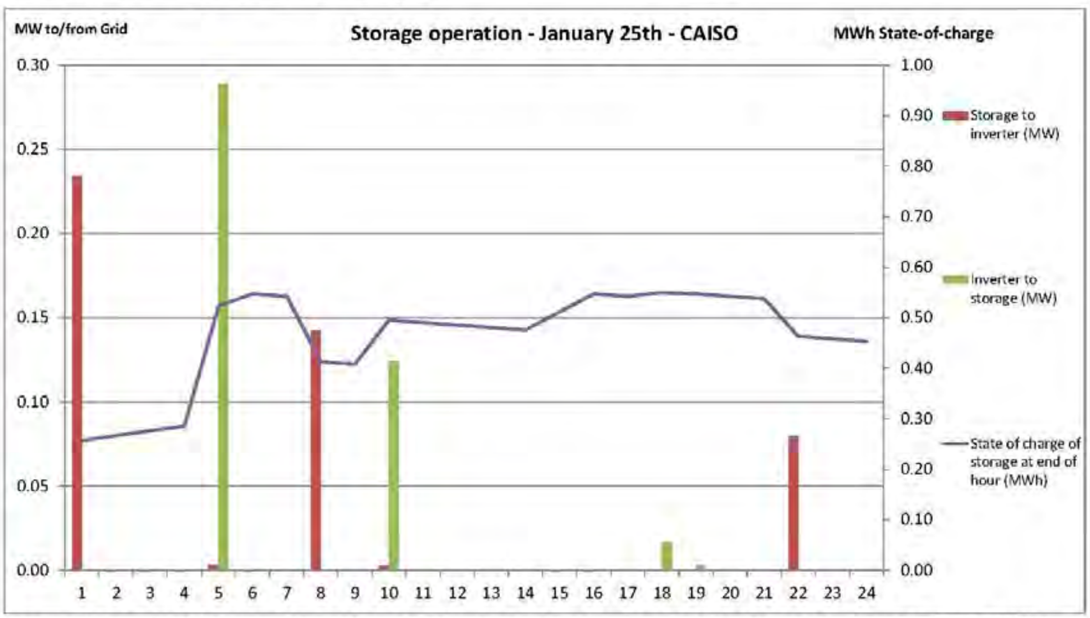


**Figure 4-11 Net Storage Dispatch and State-of-Charge for CAISO Market Case with New Battery Modules - January 25th**

Considering the financial benefits of market revenue generation and network loss reduction, and the associated storage costs including investment cost, battery replacement, fixed O&M and storage charging, the financial analysis of this use case results in a negative net present value (NPV) of (-$1,913,634) and a benefit-cost ratio of approximately 0.16. This result is primarily driven by the cost of the fleet vs. the potential market revenue achievable based on historical 2013 prices. A breakdown of the discounted cost and benefits can be seen in Table 4-6.

**Table 4-6 NPV Component Breakdown for CAISO Case with New Battery**

| Categories | Discounted Value |
|---|---|
| Market revenue | $368,412 |
| Loss reduction | -$2,020 |
| **Total benefit** | **$366,392** |
| Storage investment | $2,228,123 |
| Storage replacement | $0 |
| Fixed O&M | $43 |
| Charging costs | $51,860 |
| **Total cost** | **$2,280,026** |
| **NPV** | **-$1,913,634** |

The undiscounted cash flow for each of the revenue and cost streams is shown in Figure 4-12 below.

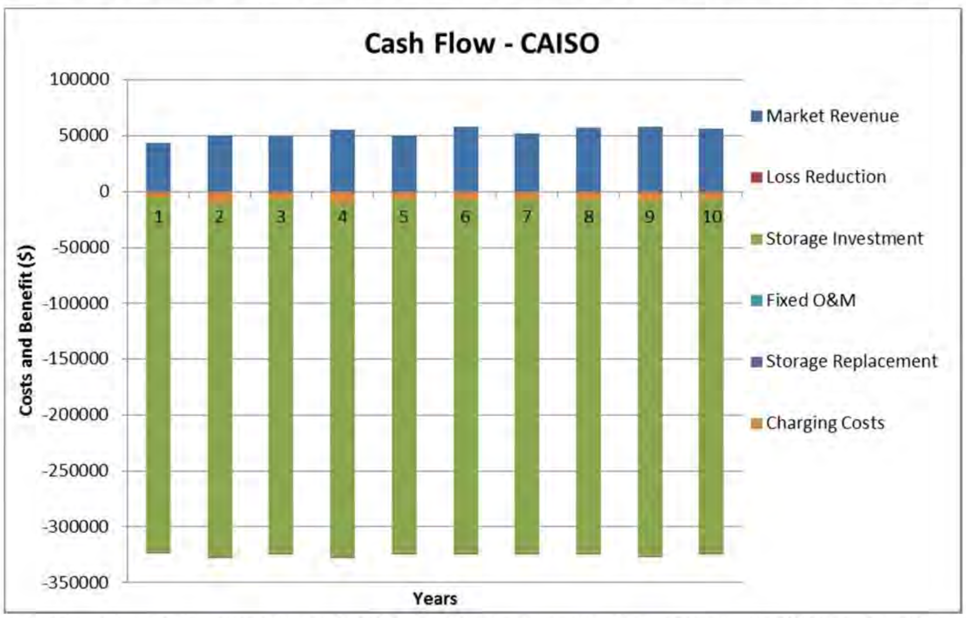


**Figure 4-12 10 Year Cash Flow of Market Services Cost and Benefits for CAISO Market Case with New Battery Modules**

## 4.4.2 Repurposed Battery Modules

Considering the financial benefits of market revenue generation and network loss reduction, and the associated storage costs including investment cost, battery replacement, fixed O&M and storage charging, the financial analysis of this use case results in a negative NPV (-$987,856) and a benefit-cost ratio of approximately 0.27 for $3,000 packs and a negative net present value (NPV) of (-$787,687) and a benefit-cost ratio of approximately 0.32 for free packs. This result is primarily driven by the cost of the fleet vs. the potential market revenue achievable based on historical 2013 prices. A breakdown of the discounted cost and benefits can be seen in Table 4-7 for repurposed battery modules with 3000 packs, and in Table 4-8 for repurposed battery modules with free packs.

**Table 4-7 NPV Component Breakdown for CAISO Case with Repurposed Battery and $3,000 Packs**

| Categories | Discounted Value |
|---|---|
| Market revenue | $368,412 |
| Loss reduction | -$2,020 |
| **Total benefit** | **$366,392** |
| Storage investment | $1,302,345 |
| Storage replacement | $0 |
| Fixed O&M | $43 |
| Charging costs | $51,860 |
| **Total cost** | **$1,354,248** |
| **NPV** | **-$987,856** |

**Table 4-8 NPV Component Breakdown for CAISO Case with Repurposed Battery and Free Packs**

| Categories | Discounted Value |
|---|---|
| Market revenue | $368,412 |
| Loss reduction | -$2,020 |
| **Total benefit** | **$366,392** |
| Storage investment | $1,102,177 |
| Storage replacement | $0 |
| Fixed O&M | $43 |
| Charging costs | $51,860 |
| **Total cost** | **$1,154,079** |
| **NPV** | **-$787,687** |

The undiscounted cash flows for each of the revenue and cost streams are shown in Figure 4-13 and Figure 4-14 below.

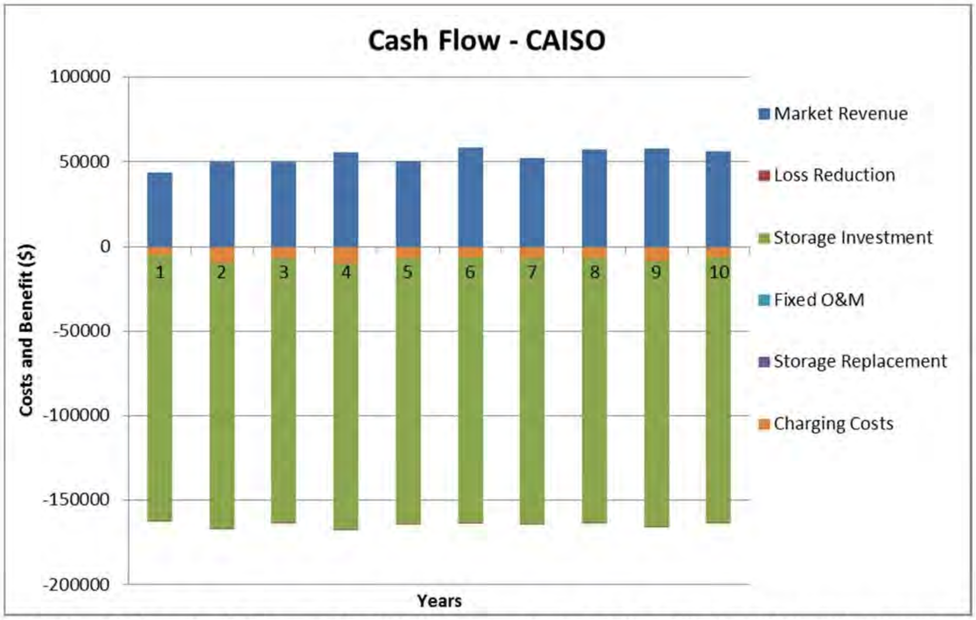


**Figure 4-13 10 Year Cash Flow of Market Services Cost and Benefits for CAISO Market Case with Free Repurposed Battery Modules**

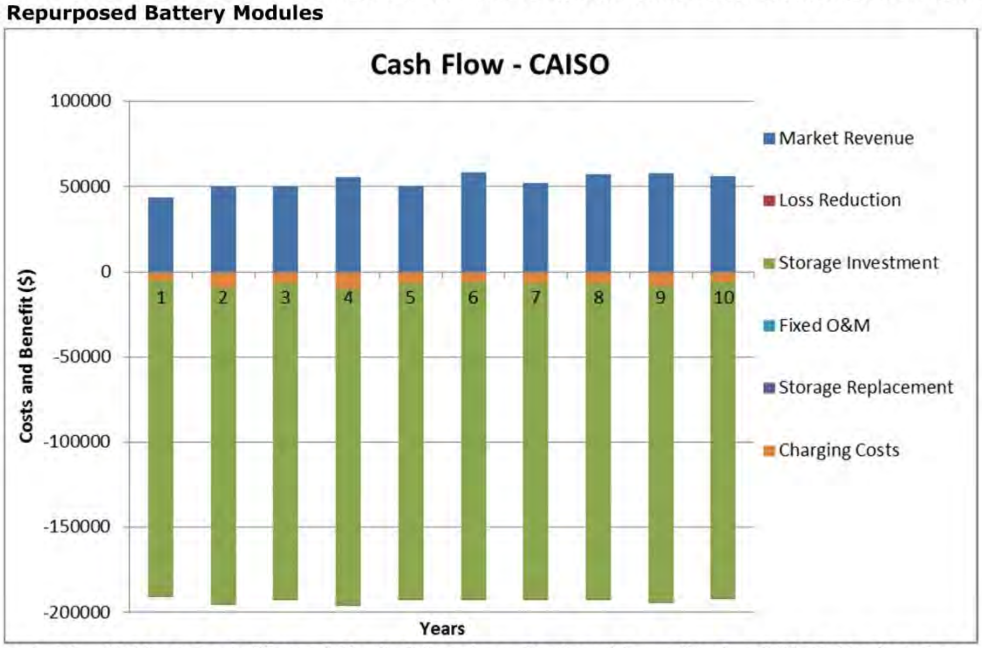


**Figure 4-14 10 Year Cash Flow of Market Services Cost and Benefits for CAISO Market Case with $3,000 Repurposed Battery Modules**

### 4.4.3 Conclusions

The financial results for all cases analyzed for the CAISO market are presented in Table 4-9.

**Table 4-9 Comparison of Benefit/Cost for Use Cases for CAISO Market**

| Configuration | Benefit | Cost | Total NPV |
|---|---|---|---|
| New Pack | $366,392 | $2,280,026 | -$1,913,634 |
| $3K Pack | $366,392 | $1,354,248 | -$987,856 |
| Free Pack | $366,392 | $1,154,079 | -$787,687 |

There is again a large improvement in NPV when moving from the purchases a new units and moving towards free packs. However, similar to the MISO cases, for the given storage cost assumptions, market prices are too low to generate sufficient revenue to drive a positive NPV using the fleet for only market services. In the CAISO market, additional revenue can gained by using storage optimally in the regulation up and regulation down markets as well as spinning reserve. Participating in regulation down allows for the storage system to obtain payments to offset charging cost or back off a day ahead energy commitment. This additional freedom allows flexible resources such as storage additional revenue opportunities. As in the MISO, case the revenue is not sufficient based on the costs for these early systems. Again, valuing additional primary benefit streams, such as peak shaving or reliability, may produce a cost-effective case for the fleet.

The dual use application of both upgrade deferral and market services will be considered in the second round (2016) of the CA Energy Storage procurement targets. It is expected that business model demonstrated for these procurements will open doors in other markets for such arrangements. The market revenue can then be supplemental to those value streams, producing a cost-effective use case for the fleet. Additionally, as CAISO market rules evolve with additional storage penetration, new regulation products may emerge for which storage is qualified. These new products may offer additional revenue opportunities for the fleet.

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Driven by our purpose of safeguarding life, property and the environment, DNV GL enables organizations to advance the safety and sustainability of their business. We provide classification and technical assurance along with software and independent expert advisory services to the maritime, oil and gas, and energy industries. We also provide certification services to customers across a wide range of industries. Operating in more than 100 countries, our 16,000 professionals are dedicated to helping our customers make the world safer, smarter and greener.

# Appendix G: CES Aged Battery Test Report

DNV·GL

# KEMA TEST REPORT

**R15008**

| | |
|---|---|
| **Object** | S&C PureWave® CES With Aged Battery Pack |
| **Type** | Utility-Interactive with Charge Control Li-ion battery — **Serial No.** 1069, MDTEC 132BK01 and MDTEC 132BK02 |
| **Client** | DTE Energy<br>Detroit, MI, USA |
| **Manufacturer** | S&C Electric Company<br>Chicago, Il, USA [*)]<br><br>Myungshin Engineering Company<br>South Korea [*)] |
| **Tested by** | KEMA Powertest, LLC.<br>2301 Mt. Read Blvd. Suite 104<br>Rochester, NY 14615<br>USA |
| **Date of tests** | 6/17/2015 to 7/17/2015 |
| **Test specification** | The tests have been carried out in accordance with the client's instructions. |
| **Remarks** | |

This report applies only to the object tested. The responsibility for conformity of any object having the same type references as that tested rests with the Manufacturer.
[*)] as declared by the manufacturer

This report consists of 24 pages in total.

Elizabeth Mayo
Head of Department, Energy Advisory Laboratory Services
Date : December 9, 2015

Frank Cielo
Operations Manager, KEMA-Powertest, LLC
Date : December 9, 2015

KEMA Laboratories

# INFORMATION SHEET

**1 KEMA Type Test Certificate**

A KEMA Type Test Certificate contains a record of a series of (type) tests carried out in accordance with a recognized standard. The equipment tested has fulfilled the requirements of this standard and the relevant ratings assigned by the manufacturer are endorsed by DNV GL. In addition, the test object's technical drawings have been verified and the condition of the test object after the tests is assessed and recorded. The Certificate contains the essential drawings and a description of the equipment tested. A KEMA Type Test Certificate signifies that the object meets all the requirements of the named sub clauses of the standard. It can be identified by gold-embossed lettering on the cover and a gold seal on its front sheet.

The Certificate is applicable to the equipment tested only. DNV GL is responsible for the validity and the contents of the Certificate. The responsibility for conformity of any object having the same type references as the one tested rests with the manufacturer.

Detailed rules on types of certification are given in DNV GL's Certification procedure applicable to KEMA Laboratories.

**2 KEMA Report of Performance**

A KEMA Report of Performance is issued when an object has successfully completed and passed a subset (but not all) of test programs in accordance with a recognized standard. In addition, the test object's technical drawings have been verified and the condition of the test object after the tests is assessed and recorded. The report is applicable to the equipment tested only. A KEMA Report of Performance signifies that the object meets the requirements of the named sub clauses of the standard. It can be identified by silver-embossed lettering on the cover and a silver seal on its front sheet.

The sentence on the front page of a KEMA Report of Performance will state that the tests have been carried out in accordance with ...... The object has complied with the relevant requirements.

**3 KEMA Test Report**

A KEMA Test Report is issued in all other cases. Reasons for issuing a KEMA Test Report could be:

- Tests were performed according to the client's instructions.
- Tests were performed only partially according to the standard.
- No technical drawings were submitted for verification and/or no assessment of the condition of the test object after the tests was performed.
- The object failed one or more of the performed tests.

The KEMA Test Report can be identified by the grey-embossed lettering on the cover and grey seal on its front sheet.

In case the number of tests, the test procedure and the test parameters are based on a recognized standard and related to the ratings assigned by the manufacturer, the following sentence will appear on the front sheet. The tests have been carried out in accordance with the client's instructions. Test procedure and test parameters were based on ..... If the object does not pass the tests, such behavior will be mentioned on the front sheet. Verification of the drawings (if submitted) and assessment of the condition after the tests is only done on client's request.

When the tests, test procedure and/or test parameters are not in accordance with a recognized standard, the front sheet will state the tests have been carried out in accordance with client's instructions.

**4 Official and uncontrolled test documents**

The official test documents of DNV GL are issued in bound form. Uncontrolled copies may be provided as loose sheets or as a digital file for convenience of reproduction by the client. The copyright has to be respected at all times.

**5 Accreditation of KEMA Laboratories**

The KEMA Laboratories of DNV GL are accredited in accordance with ISO/IEC 17025 by the respective national accreditation bodies. The KEMA Laboratories in the Netherlands are in the RvA register under nos. L020, L218, K006, K009 and I049. The KEMA Laboratory in the United States is accredited by the A2LA under no. 0553.01. The KEMA Laboratory in the Czech Republic is accredited by CAI under no. 1035.

# TABLE OF CONTENTS

# 1 IDENTIFICATION OF THE OBJECT TESTED

## 1.1 PureWave CES™ Community Energy Storage System

Manufacturer: S&C Electric Company
Catalogue number: PEA-1429-4
Type: Utility-Interactive with Charge Control
One sample was used for testing:
CES Unit Serial Number: 1069

Table 1. CES unit technical specifications

| **AC input/output rating:** | |
|---|---|
| Inverter real power (kW) | 25 |
| Inverter apparent power (kVA) | 25 |
| Inverter energy (kW-Hr) | 25 |
| Inverter power factor | 0.1 to 1.0, Lead or Lag |
| Frequency (Hz) | 60 |
| Phase configuration | 2φ, split-phase |
| Input voltage range ($V_{RMS}$) | 108-132/216-264 |
| Through-circuit current ($A_{RMS}$) | 400 |
| Inverter voltage ($V_{RMS}$) | 120/240 |
| Inverter current ($A_{RMS}$) | 104.2/104.2 |
| Max inverter current 3 seconds ($A_{RMS}$) | 260.5 |
| AC input short-circuit Current, symmetrical ($kA_{RMS}$) | 50 |
| BIL (kV) | 30 |
| **DC input ratings** | |
| Max voltage ($V_{DC}$) | 800 |
| Max current ($A_{DC}$) | 73 |

## 1.2 Aged Battery Pack

Manufacturer: Myungshin Engineering Company
Model: MA1325K
Rated Voltage: 577 VDC
Rated Capacity: 53 kWh
Rated Power: 26.5 kW
Rated Current: 52 A
Operation Voltage: 422-655 VDC
Two battery packs connected in parallel were tested as one unit
Serial Numbers: MDTEC 132BK01 and MDTEC 132BK02

# 2 GENERAL INFORMATION

Testing was performed on a S&C Electric Company PureWave® Community Energy Storage (CES) unit connected to a battery pack manufactured by Myungshin Engineering Company, South Korea. The S&C CES unit was delivered on January 30, 2015 in good condition. The battery pack was received on May 28, 2015 with no damage to the battery itself; however, there was some damage to the pallet it was sitting on causing the two connected units to bend towards each other at the bottom (See appendix A for as received photographs). Testing was conducted in accordance with *CES unit with aged batteries - Testing plan V4 06022015* document provided by Kevin Chen, senior engineer at DNV GL, Raleigh, NC (See appendix B). Testing consisted of initial capacity checks, cycling test, charge/discharge (Peak Shaving Profile) test and final capacity checks.

Testing was performed by Mehdi Hosseinifar, test engineer at KEMA Powertest, Rochester, NY between 6/17/2015 and 7/17/2015.

# 3 TEST EQUIPMENT

The S&C CES unit was connected to the grid using the 480V, 60A outlet of the test center. A 480/240 step down transformer (Table 2) provided the power to the CES unit. The 240V output of the transformer was split into two 120V lines that fed the CES unit. The Bloomy data acquisition system (DAS) was used to measure AC voltage and current on line 1 and line 2 between the transformer and the CES input. In addition the DC voltage of the battery and the DC current applied by CES were recorded. The DAS configuration is defined in table 3. An end to end calibration was performed on each channel before starting the test.

Table 2. technical specifications of the transformer

| **SORGEL® Single phase general purpose transformer** | |
|---|---|
| Manufacturer | Schneider Electric / Square D |
| Catalogue Number | EE50S3H |
| Serial Number | 1052714006 |
| Power Rating (kVA) | 50 |
| Primary Voltage ($V_{AC}$) | 240/480 |
| Primary Current ($A_{AC}$) | 208/104 |
| Secondary Voltage ($V_{AC}$) | 120/240 |
| Secondary Current ($A_{AC}$) | 416/208 |
| Phase | 1-phase |
| Frequency | 60 |
| %IZ | 5.8 |
| Class | AA |

Table 3. Data acquisition system description

| DAS Connection | Transducer Type | Manufacturer | Model # | Serial # | ID # |
|---|---|---|---|---|---|
| J7-1 | AC/DC Voltage | LEM | DV 1200/SP2 | 1102450014 | DV 1200-12 |
| J7-2 | AC/DC Voltage | LEM | DV 1200/SP2 | 1102450008 | DV 1200-2 |
| J8-2 | AC/DC Current | LEM | LF 2005S | LF 2005S-4 | LF 2005S-4 |
| J8-3 | AC/DC Current | LEM | LF 2005S | LF 2005S-6 | LF 2005S-6 |
| J15-1 | AC/DC Voltage | LEM | DV 1200/SP2 | 1102450009 | DV 1200-3 |
| J15-2 | AC/DC Current | LEM | LF 2005S | LF2005S-13 | LF2005S-13 |

# 4 TEST PROTOCOL SUMMARY

A sequence of five tests was described in test protocol:

1. *System setup, basic operation test*; to ensure proper basic ON/OFF function and data exchange and operation and verify that the HMI and data acquisition system are working properly.
2. *Capacity check*; to benchmark the state of health of the battery prior to cycling test.
3. *Cycling test*; to verify the system integrity and functionality under continuous charging and discharging operation.
4. *Charging and discharging (peak shaving profile) test*; to determine the energy capacity of the battery under different charging and discharging power levels, and to determine the ability of the CES system to perform the Peak Shaving Profile without capacity or operation issues.
5. *Capacity check*; to benchmark the state of health of the battery after cycling test.

# 5 TEST DATA SUMMARY

For each test, AC and DC voltages and currents were recorded at 1k Hz and power and energy were calculated using the raw data. The CES unit also recorded current, voltage, power and SOC of the battery every 10 seconds. These recordings were used to calculate charge/discharge energies and round trip efficiencies and compared to the DAS data. Snapshots of the HMI were also taken before and after each charge and discharge step.

## 5.1 System setup, basic operation test

The battery was connected to the CES unit and data communication was tested and no issues were encountered. The S&C's Ilink6 (a Windows based device manager software) installed on a laptop (HMI computer) was used to control and operate the CES unit. Using Ilink6, charge/discharge steps can be initiated by requesting a desired power or by setting a "target SOC". The applied power during a "target SOC" controlled step can be adjusted in Ilink6 settings.

An initial charge test run revealed that the full 25 kW power of the CES unit is not utilized between 0% and 2% SOC and also between 95% and 100% SOC (Figure 1). S&C conformed that the lower charge power is requested by the BMS to protect the battery at the extremes of the SOC. Charge power deration was also noticed when "target SOC" command was used for control. A lower power was used in the last 5% SOC no matter what the target was. Similarly, discharge was done at a lower power within the last 5% SOC before reaching the target. The "target SOC" control was used for cycling tests where the battery was charged to 90% SOC and discharged to 10% SOC.

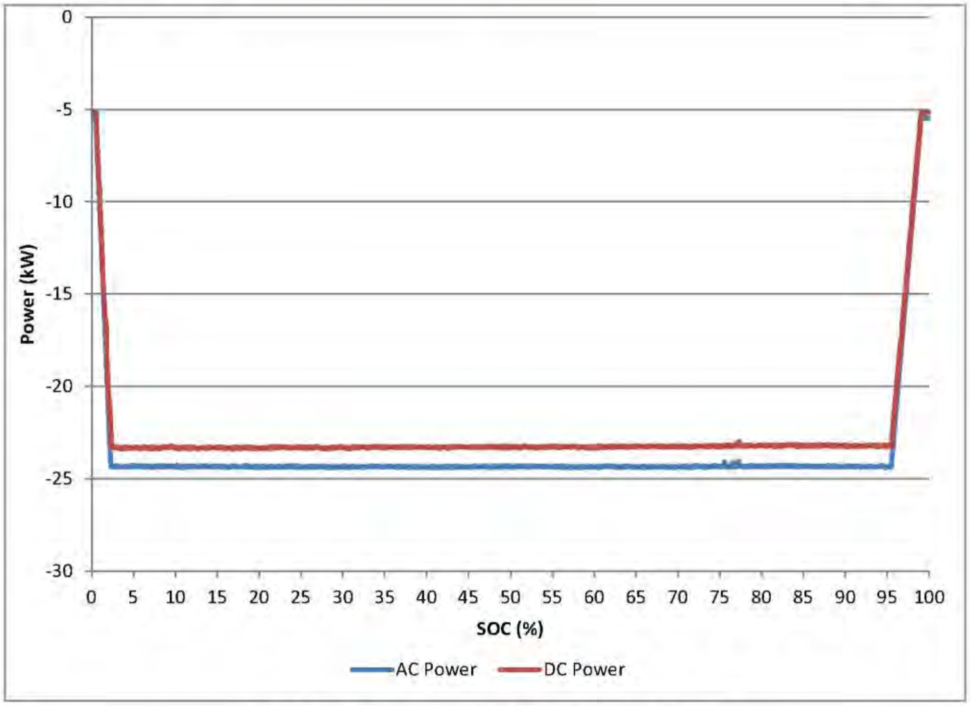



Figure 1. Charge power vs. battery state of charge

## 5.2 Capacity Check

Four capacity check (two before cycling and two post cycling and peak shaving tests) were performed on the battery. A 25 kW power was applied to charge and discharge the battery. The battery was discharged to 0% SOC from a fully charged state and then recharged to 100% SOC and left to idle overnight.

Charge/discharge capacities in terms of kWhr are presented in Table 4. Round trip energy efficiencies (RTE) were calculated by dividing the discharge energy by the charge energy and multiplying the result by 100. It is seen that the battery has close to 54 kWhr of discharge energy and exhibits over 95% of DC efficiency. On the AC side, the CES unit demonstrates over 87% efficiency.

Table 4. Charge/discharge energies and round trip efficiencies for pre and post-test capacity checks[1]

| Test | CES Charge Energy (kWh) | | CES Discharge Energy (kWh) | | CES RTE (%) | | DAS Charge Energy (kWh) | | DAS Discharge Energy (kWh) | | DAS RTE (%) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | AC | DC | AC | DC | AC | DC | AC | DC | AC | DC | AC | DC |
| Pre Test Capacity 1 | 59.1 | 56.5 | 51.5 | 53.6 | 87.2 | 94.8 | 58.0 | 56.7 | 51.5 | 53.9 | 88.9 | 95.1 |
| Pre Test Capacity 2 | 59.5 | 56.8 | 52.0 | 54.0 | 87.5 | 95.1 | 58.4 | 57.1 | 51.3 | 53.8 | 87.8 | 94.2 |
| Post Test Capacity 1 | 59.4 | 56.7 | 51.8 | 53.9 | 87.2 | 95.0 | 58.1 | 57.3 | 51.7 | 53.6 | 89.0 | 93.6 |
| Post Test Capacity2 | 59.4 | 56.7 | 51.9 | 54.0 | 87.4 | 95.2 | 58.2 | 57.3 | 51.6 | 53.7 | 88.7 | 93.8 |
| Average | 59.3 | 56.7 | 51.8 | 53.9 | 87.3 | 95 | 58.2 | 57 | 51.7 | 53.9 | 88.6 | 94.1 |

## 5.3 Cycling Test

Ten charge/discharge cycles were performed on the battery. The cycling was done at the rated 25 kW power between 10% SOC and 90% SOC. There was no rest period in between discharge and charge steps. The battery remained idle overnight. Figure 2 show the AC round trip efficiency of the unit calculated from both CES and DAS data. The DC round trip efficiencies are presented in Figure 3. The charge/discharge energies and efficiencies are summarized in table 5. On average the battery has been able to provide over 43 kWhr of energy with 96% efficiency (CES data). The average AC efficiency is 88% (CES Data).

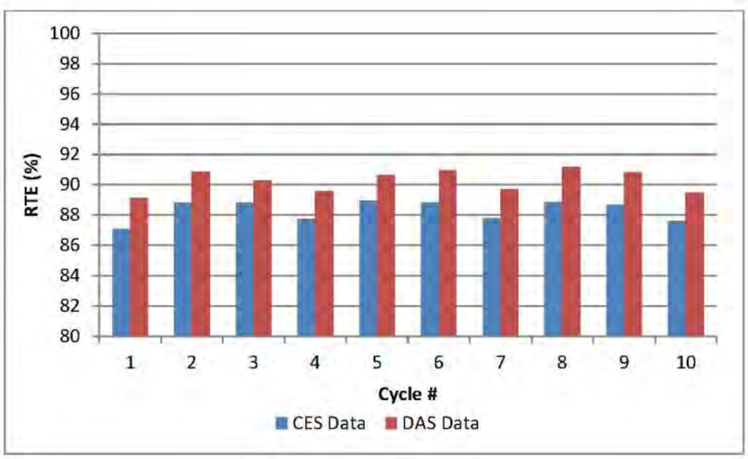



Figure 2. AC round trip efficiency

[1] See Appendix C for AC and DC energy calculation notes

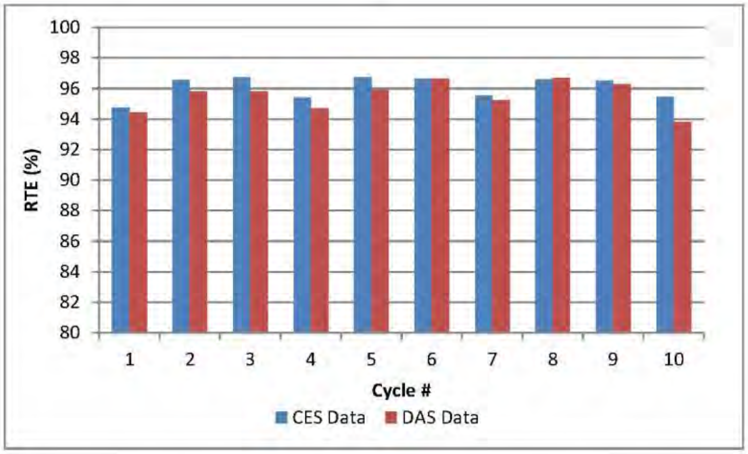



Figure 3. DC round trip efficiency

Table 5. Charge/discharge energies and round trip efficiencies for cycling tests

| Cycle # | CES Charge Energy (kWh) | | CES Discharge Energy (kWh) | | CES RTE (%) | | DAS Charge Energy (kWh) | | DAS Discharge Energy (kWh) | | DAS RTE (%) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | AC | DC | AC | DC | AC | DC | AC | DC | AC | DC | AC | DC |
| **1** | 47.8 | 45.6 | 41.6 | 43.2 | 87.1 | 94.7 | 46.7 | 45.8 | 41.7 | 43.2 | 89.1 | 94.4 |
| **2** | 47.0 | 44.8 | 41.7 | 43.3 | 88.8 | 96.6 | 45.9 | 45.2 | 41.7 | 43.3 | 90.8 | 95.8 |
| **3** | 46.9 | 44.8 | 41.6 | 43.3 | 88.8 | 96.7 | 46.0 | 45.1 | 41.5 | 43.2 | 90.3 | 95.8 |
| **4** | 47.5 | 45.4 | 41.7 | 43.3 | 87.7 | 95.4 | 46.5 | 45.7 | 41.7 | 43.3 | 89.6 | 94.7 |
| **5** | 46.8 | 44.8 | 41.7 | 43.3 | 89.0 | 96.7 | 46.0 | 45.1 | 41.7 | 43.2 | 90.6 | 95.9 |
| **6** | 46.9 | 44.8 | 41.6 | 43.3 | 88.8 | 96.6 | 45.8 | 44.9 | 41.6 | 43.4 | 91.0 | 96.7 |
| **7** | 47.5 | 45.4 | 41.7 | 43.4 | 87.8 | 95.5 | 46.4 | 45.5 | 41.6 | 43.4 | 89.7 | 95.2 |
| **8** | 46.9 | 44.8 | 41.7 | 43.3 | 88.9 | 96.6 | 45.8 | 44.9 | 41.7 | 43.4 | 91.2 | 96.7 |
| **9** | 47.0 | 44.9 | 41.7 | 43.4 | 88.7 | 96.5 | 45.9 | 45.1 | 41.7 | 43.4 | 90.8 | 96.3 |
| **10** | 47.5 | 45.4 | 41.6 | 43.3 | 87.6 | 95.4 | 46.5 | 45.9 | 41.6 | 43.1 | 89.5 | 93.8 |
| **Average** | 47.2 | 45.1 | 41.7 | 43.3 | 88.3 | 96.1 | 46.2 | 45.3 | 41.6 | 43.3 | 90.3 | 95.5 |

## 5.4 Charging and Discharging (Peak Shaving Profile) Test

The Fully charged battery was discharged at 6.3 kW, 8.4 kW and 12.6 kW for 8, 6 and 4 hours respectively. Each discharge rate was performed two times. The unit was allowed to rest for 2 hours and then was given a 25kW charge to 100% SOC. The battery was able to provide the requested power for the specified duration in all tests. The discharge power and duration and the SOC of the battery at the end of discharge are given in Table 6. The charge/ discharge power throughout the test along with the SOC of the battery are provided in figures 4a – 4f.

Table 6. Peak shaving profile test results summary

| Discharge Power Set point (kW) | Discharge Duration (hr) | Final SOC (%) |
|---|---|---|
| **6.3** | 8 | 5.7 |
| **6.3** | 8 | 6 |
| **8.4** | 6 | 5.8 |
| **8.4** | 6 | 5.9 |
| **12.6** | 4 | 5.4 |
| **12.6** | 4 | 5.3 |

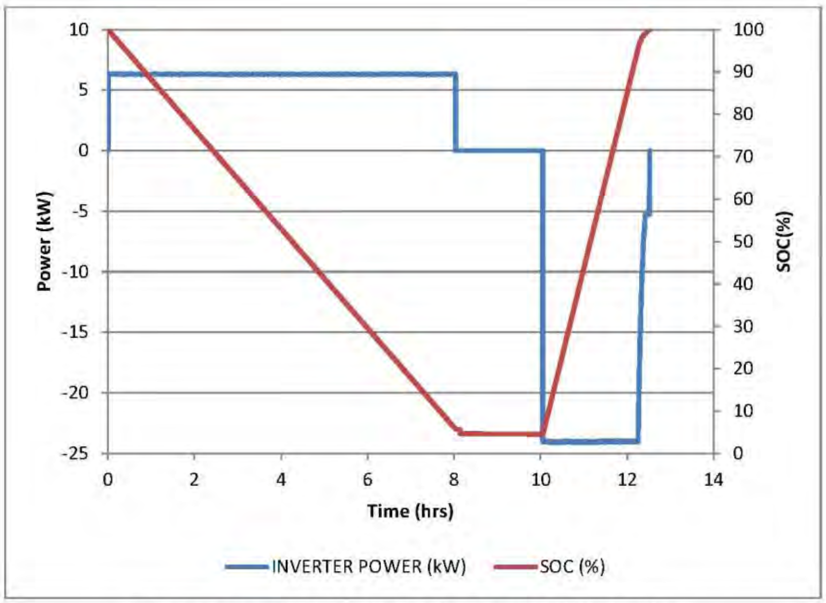



Figure 4a. First peak shaving profile test at 6.3 kW discharge

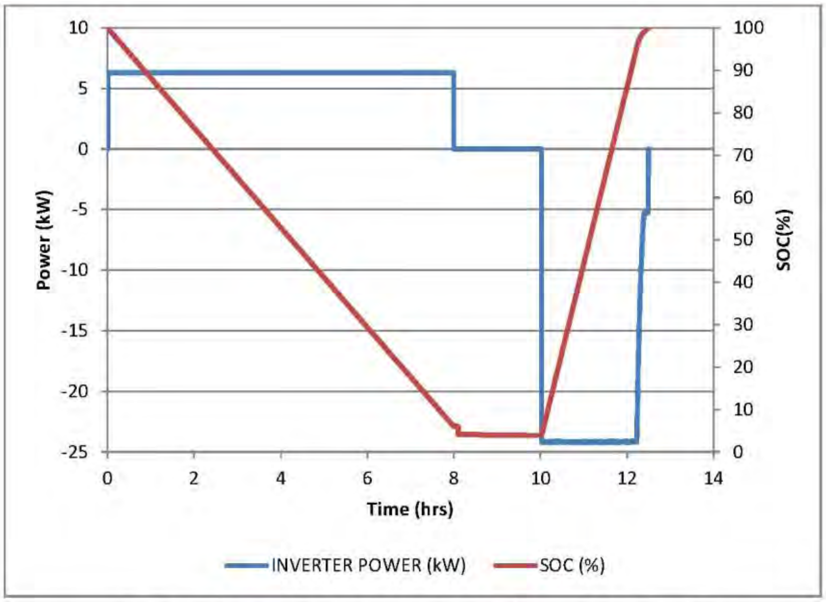



Figure 4b. Second peak shaving profile test at 6.3 kW discharge

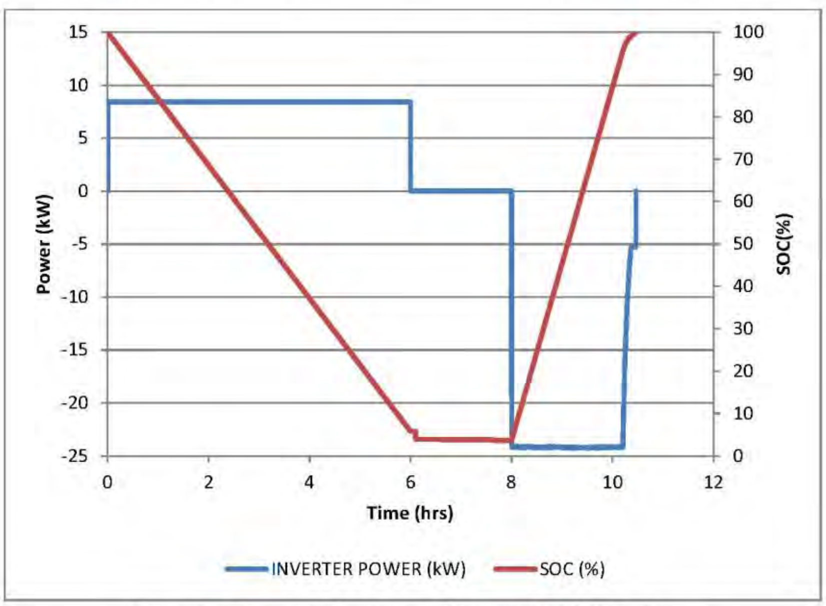



Figure 4c. First peak shaving profile test at 8.4 kW discharge

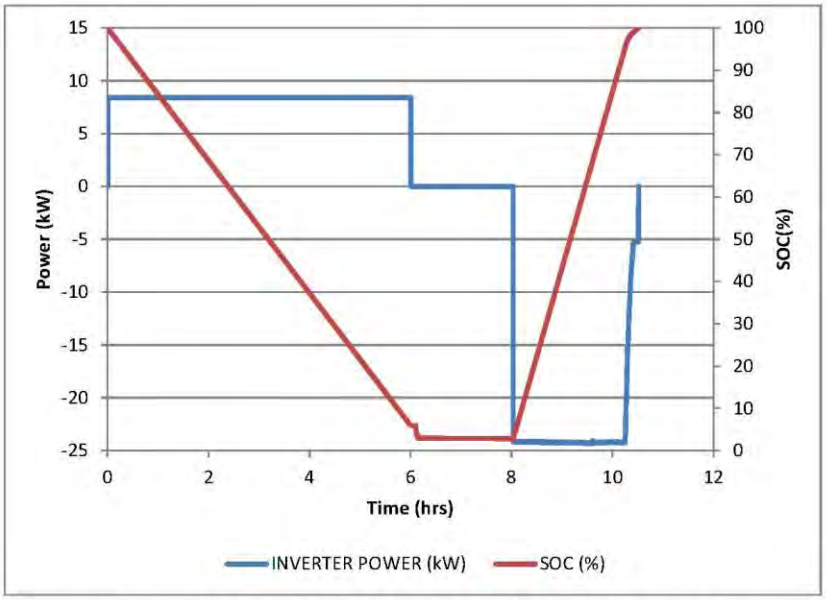



Figure 4d. Second peak shaving profile test at 8.4 kW discharge

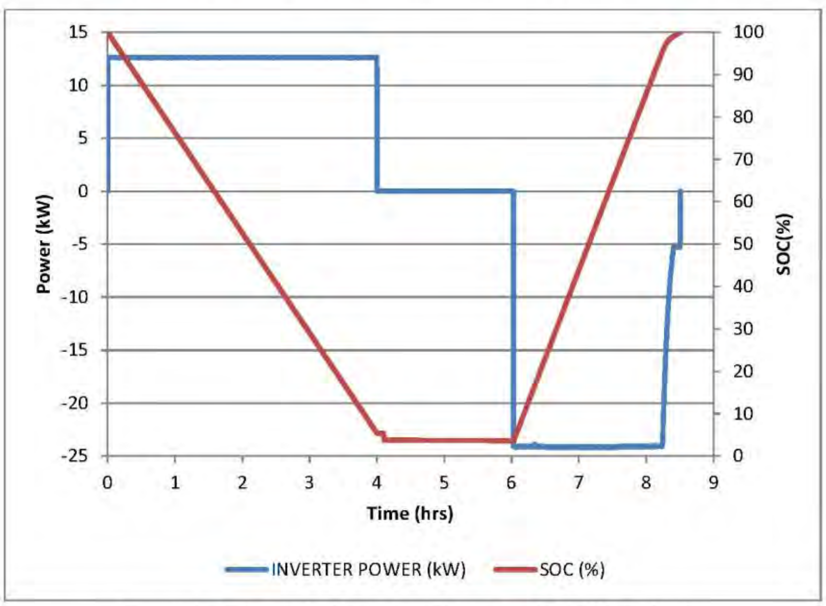



Figure 4e. First peak shaving profile test at 12.6 kW discharge

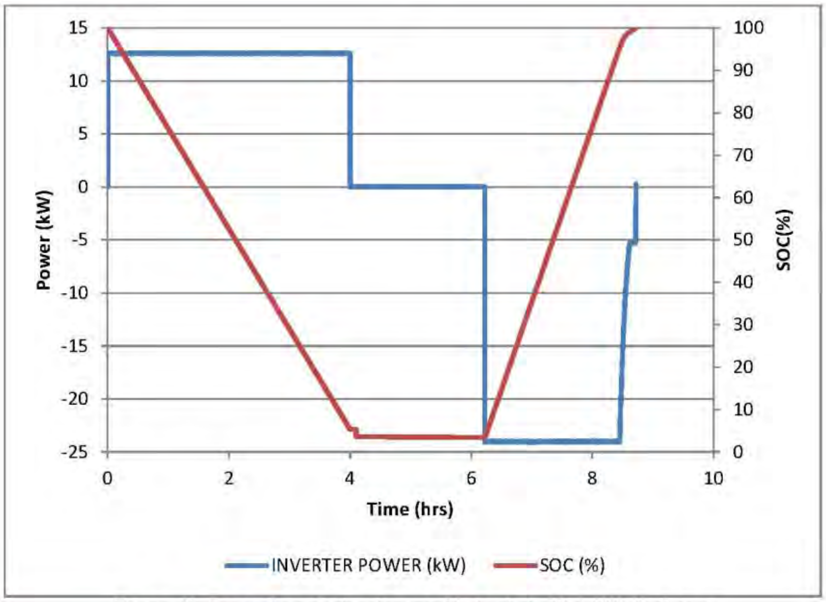



Figure 4f. Second peak shaving profile test at 12.6 kW discharge

## 6 SUMMARY AND OBSERVATIONS

No issues or faults were observed during the unit performance under continuous cycling and peak shaving profile tests. The battery nameplate states a 53 kWhr rated capacity and testing showed that it was able to provide this capacity with over 95% efficiency. As for the peak shaving test, the battery also successfully maintained the discharge power for the intended duration without reaching 0% SOC. Overall, no signs of aging or degradation were observed.

## APPENDIX A – PHOTOGRAPHS

Figure 5. As received battery condition

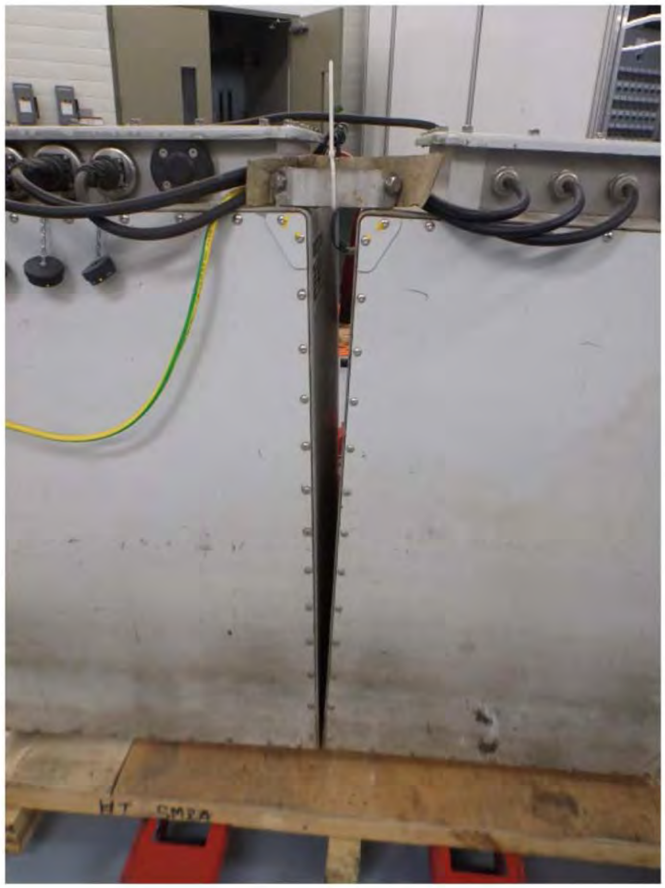


Figure 6. As received battery condition

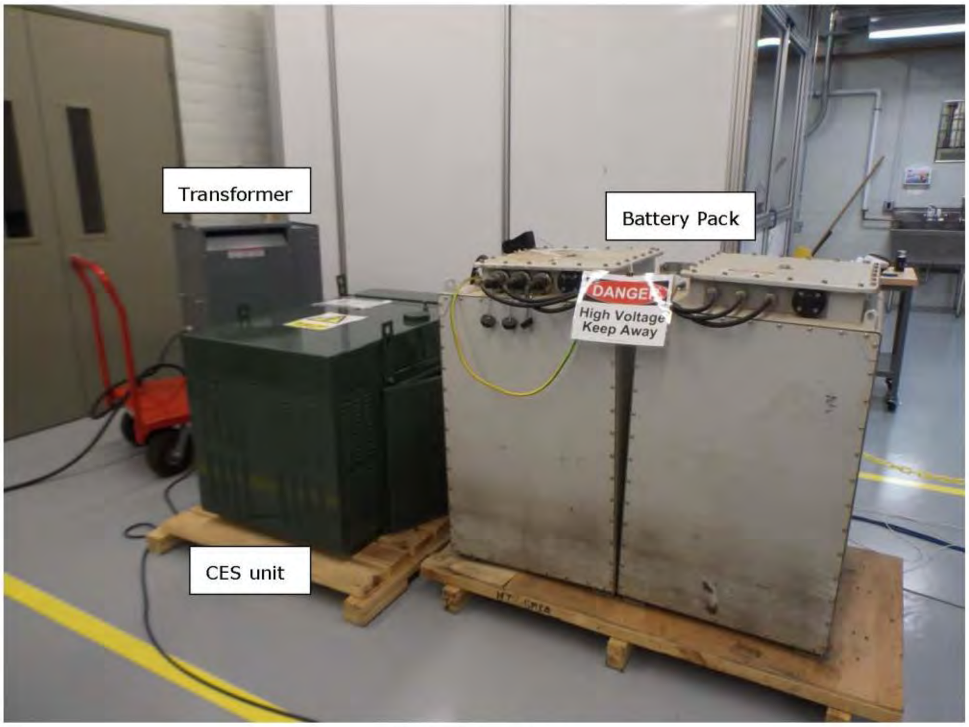



Figure 7. Test Setup

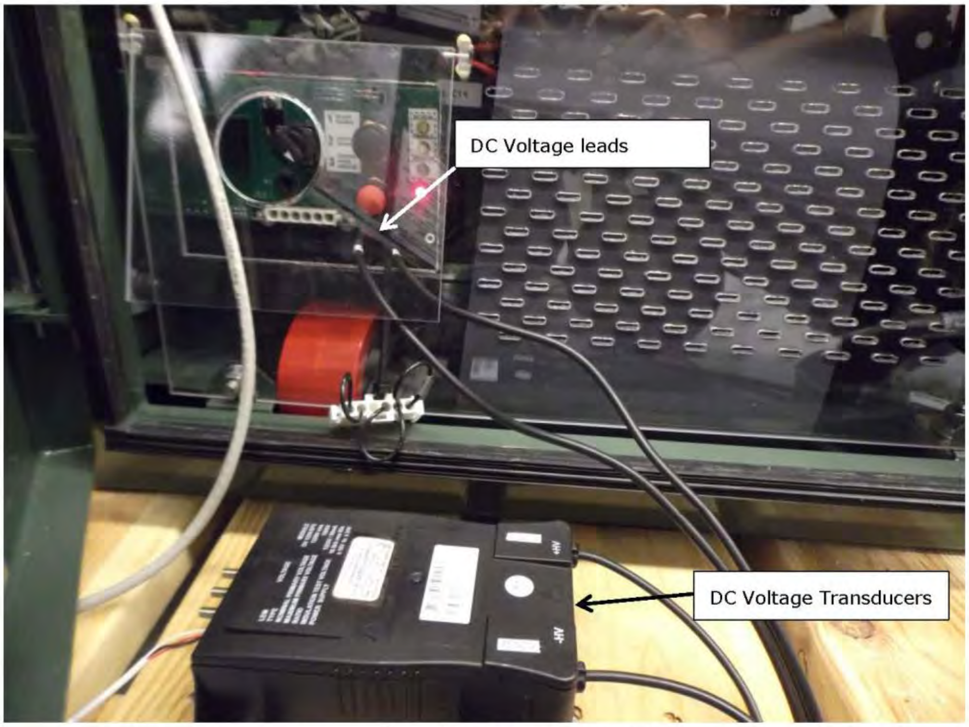



Figure 8. DC voltage measurement setup

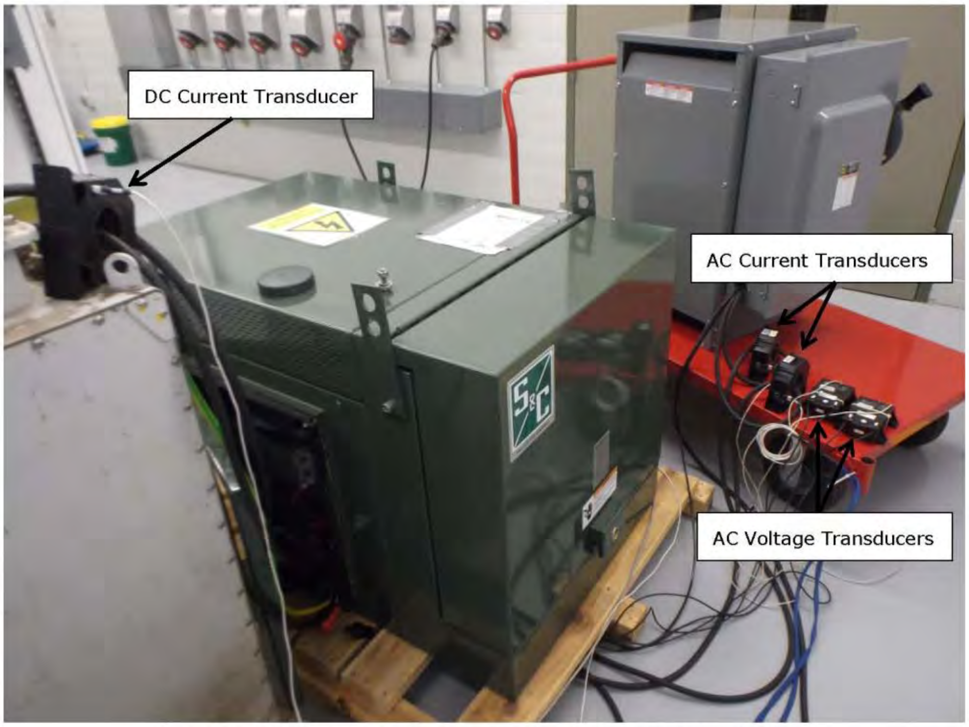



Figure 9. DC current and AC current and voltage measurement setup

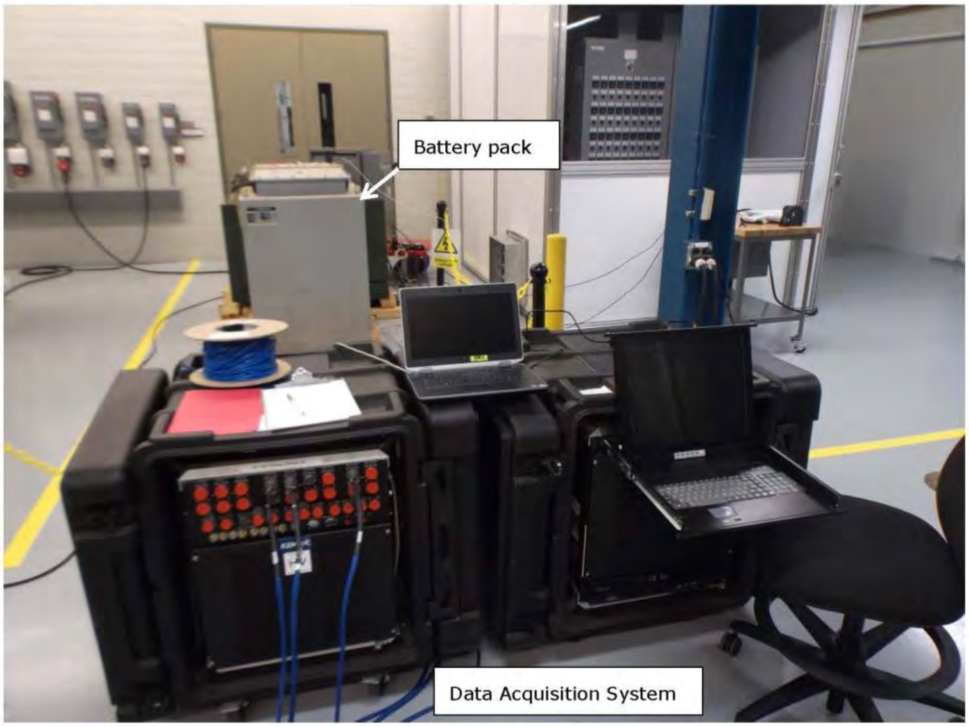



Figure 10. Data acquisition system

# APPENDIX B – TEST PROTOCOL

## CES with Aged Batteries Testing (V4)

### Product to be tested:

Community Energy Storage (CES) System

1. S&C Electric Purewave unit with aged Kokam Li-ion battery pack 25kW/53kWh (2 x 26.5 kWh)

### Planned testing schedule:

Early June, 2015 – Mid July, 2015

Approximately 6 weeks

### Testing location:

DNV GL's BEST Test & Commercialization Center (BEST T&CC)

Address: 2031 Mount Read Blvd, Ste 103, Rochester NY 14615, United States

### Highlights of This Test Plan:

There are 2 Kokam battery units, coupled together in parallel as a pack, delivered to Rochester lab. According to S&C, this battery pack cannot be separated. This test plan is updated to test the pack instead of individual battery unit.

The main purpose of the test is to evaluate the performance of the aged battery against the results from the test of new battery. Since the battery pack is the same model Kokam battery as in the test in 2012, this test plan is tailored to focus on key items which can be compared.

There were 10 cycles round trip efficiency test performed in 2012, with both AC and DC side efficiency calculated. This test plan intends to repeat the exact procedure.

There was a peak shaving profile test in 2012 which verified the CES unit could provide 4 hours energy at 6.3kW discharging power. This test plan intends to repeat the peak shaving profile test with various power levels included.

### 1. System Setup, Basic Operations Test

The purpose of the test is to confirm ensure proper basic ON/OFF function and data exchange and operation. The battery will be connected by contractor electrician with help from the S&C field service technician.

Verify the HMI communication, data acquisition system are working properly. IntelliLink software shall be provided by S&C and used in this test.

**Expected duration**

2 days

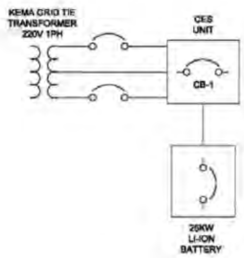
## 2. Capacity Check (before cycling)

### Purpose

The purpose of this test is to benchmark the state of health of the battery prior to cycling test.

### Test setup

The CES will discharge and charge to the grid through the power transformer. There is no load connected. See the diagram below.




### Test procedure

1. The CES shall be charged at rated power (25kW) to 100% SOC.
2. Then it shall be discharged at rated power (25kW) to the minimum SOC (0% or other value which is the lowest allowed by the BMS).
3. The CES shall be charged back to 100% SOC using rated (25kW) power.
4. Let the CES rest overnight, and then repeat above steps next day.

### Data reporting

Following data shall be recorded (or calculated) by CES HMI and DNV GL data acquisition system (DAS):

1. Current (A) and voltage (V) vs time (s)
2. Charge and discharge power (kW) vs time
3. Charge and discharge energy (kWh)
4. Charge and discharge time (hrs)
5. Snapshot of BMS monitor after each charging and discharging
6. Snapshot of S&C HMI after each charging and discharging

### Expected duration

2 days

## 3. Cycling Test

### Purpose

The purpose of this test is to verify the system integrity and functionality under continuous charging/discharging operation for minimum 10 cycles.

**Test setup**

The test setup is the same as in the capacity check test.

**Test procedure**

1. The CES shall be charged at rated power (25kW) to 90% SOC.
2. Then it shall be discharged at rated power (25kW) to the 10% SOC.
3. The CES shall be charged back to 90% SOC using rated (25kW) power.
4. Let the CES rest for 2 hours. (Or let the unit rest overnight if CH/DCH time is too long.)
5. Perform the 2nd discharging at rated (25kW) power to 10% SOC.
6. Perform the 2nd recharging at rated (25kW) power to 90% SOC.
7. Let the CES rest overnight and repeat above steps next day. Check the SOC before each discharging. **Charging may be necessary if the overnight loss of SOC is significant, especially if the unit stays over weekend.**

**Data reporting**

Following data shall be recorded (or calculated) by CES HMI and DNV GL data acquisition system (DAS):

1. Current (A) and voltage (V) vs time (s), both AC and DC.
2. Charge and discharge power (kW) vs time, both AC and DC.
3. Charge and discharge energy (kWh), both AC and DC.
4. Charge and discharge time (hrs)
5. Snapshot of BMS monitor after each charging and discharging
6. Snapshot of S&C HMI after each charging and discharging
7. Round trip efficiency, both AC and DC.

**Expected Duration**

2 weeks

### 4. Charging and Discharging (Peak Shaving Profile) Test

**Purpose**

The purpose of the test is to determine the energy capacity of the battery under different charging and discharging power levels, and to determine the ability of the CES system to perform the Peak Shaving Profile without capacity or operation issues.

**Test setup**

The test setup is the same as in the capacity check test. The power command signal will be issued using CES HMI.

**Test procedure**

1. The CES shall be charged at rated power (25kW) to full, 100% SOC.
2. Then it shall be discharged at 6.3kW for 8 hours.
3. Let the unit rest for 2 hours.
4. The CES shall be charged back to 100% SOC using rated (25kW) power.

5. Let the CES rest overnight and repeat above steps next day.
6. Repeat above steps with different discharging power levels and duration: 8.4kW for 6 hours, 12.6kW for 4 hours. **Each power level has at least 2 discharges.**

**Data reporting**

Following data shall be recorded (or calculated) by CES HMI and DNV GL data acquisition system (DAS):

1. Current (A) and voltage (V) vs time (s)
2. Charge and discharge power (kW) vs time
3. Charge and discharge energy (kWh)
4. Charge and discharge time (hrs)
5. Snapshot of BMS monitor after each charging and discharging
6. Snapshot of S&C HMI after each charging and discharging
7. Round trip efficiency

**Expected Duration**

8 days

### 5. Capacity Check (after cycling)

The purpose of this test is to benchmark the state of health of the battery after cycling and peak shaving test.

The test setup, procedure and data to be recorded are the same as in the capacity check before cycling.

**Expected duration**

2 days

## APPENDIX C – ENERGY EFFICIENCY CALCULATIONS

When DC round trip efficiencies were initially calculated, DAS data showed higher values compared to CES data (on average 2% higher). In order to find the cause of this difference the raw current and voltage data out of the DAS system were investigated. Figure 11 presents $dI = I_{DAS}-I_{CES}$ and $dP = P_{DAS}-P_{CES}$. It is seen that the DAS measure DC current is about 0.5A lower than the CES values (in discharge, the absolute DAS current value becomes greater than CES current). As a result the measured DC power is lower than CES data during charge and higher than CES data during discharge. This translates into the same trend when the power data is integrated over time to calculate energies resulting in higher RTEs.

Reviewing the calibration data on the DC current channel it was found that the DAS data were on average about 0.45A less than the set point of the calibrator (this is within the acceptable deviation range based on the channel accuracy). This baseline value was added to the DC current data and power and energies were recalculated. The DC RTE data provided in table 4, table 5 and figure 2 are calculated taking into account the baseline current.

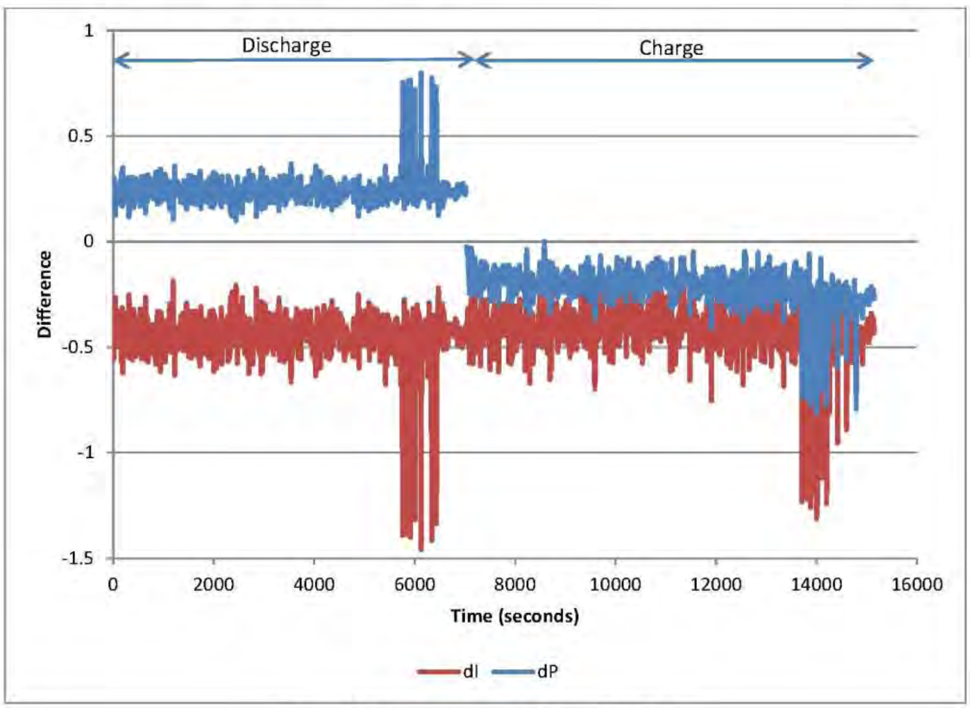



Figure 11. Comparison of DAS and CES data

Higher AC RTEs are also measured using the DAS. In this case the discharge energies are rather close to the CES data and the higher DAS RTEs result from lower calculated charge energies. The raw data of the DAS were examined and no specific trend was observed. Moreover, most of the calibration data for the AC measurement transducers showed minimal deviation from the set points. The difference between DAS and CES data can very well be within measurement uncertainties of both devices.