Energy Storage—The Benefits of "Behind-the-Meter" Storage

Adding Value with Ancillary Services

FINAL REPORT | MAY 31, 2014

NRECA
A Touchstone Energy® Cooperative
CRN
Cooperative Research Network

Energy Storage—The Benefits of "Behind-the-Meter" Storage

Adding Value with Ancillary Services

FINAL REPORT | MAY 31, 2014

Prepared by

Douglas Danley, Dale Bradshaw,
and Peter Muhoro, Ph.D.
Cooperative Research Network
National Rural Electric Cooperative Association
4301 Wilson Boulevard
Arlington, Virginia 22203-1860

for

U.S. DOE/NETL
Morgantown Campus
3610 Collins Ferry Road
PO Box 880
Morgantown WV 26507-0880

PROJECT MANAGER: CRAIG MILLER, PHD

PRINCIPAL INVESTIGATOR: TOM LOVAS

The National Rural Electric Cooperative Association

NRECA is the national service organization for more than 900 not-for-profit rural electric cooperatives and public power districts providing retail electric service to more than 42 million consumers in 47 states and whose retail sales account for approximately 12 percent of total electricity sales in the United States.

NRECA's members include consumer-owned local distribution systems — the vast majority — and 66 generation and transmission (G&T) cooperatives that supply wholesale power to their distribution cooperative owner-members. Distribution and G&T cooperatives share an obligation to serve their members by providing safe, reliable and affordable electric service.

About CRN

NRECA's Cooperative Research Network™ (CRN) manages an extensive network of organizations and partners in order to conduct collaborative research for electric cooperatives. CRN is a catalyst for innovative and practical technology solutions for emerging industry issues by leading and facilitating collaborative research with co-ops, industry, universities, labs, and federal agencies.

CRN fosters and communicates technical advances and business improvements to help electric cooperatives control costs, increase productivity, and enhance service to their consumer-members. CRN products, services and technology surveillance address strategic issues in the areas:

- Cyber Security
- Consumer Energy Solutions
- Generation & Environment
- Grid Analytics
- Next Generation Networks
- Renewables
- Resiliency
- Smart Grid

CRN research is directed by member advisors drawn from the more than 900 private, not-for-profit, consumer-owned cooperatives who are members of NRECA.

Contact Information

National Rural Electric Cooperative Association
Cooperative Research Network ™
4301 Wilson Boulevard
Arlington, VA 22203-1860
703.907.5500

Table of Contents

List of Figures

List of Tables

FOREWORD

The National Rural Electric Cooperative Association (NRECA) has organized the NRECA-U.S. Department of Energy (DOE) Smart Grid Demonstration Project (DE-OE0000222) to install and study a broad range of advanced Smart Grid technologies in a demonstration that involved 23 electric cooperatives in 12 states. For purposes of evaluation, the technologies deployed have been classified into three major sub-classes, each consisting of four technology types.

Enabling Technologies:	Advanced Metering Infrastructure Meter Data Management Systems Telecommunications Supervisory Control and Data Acquisition
Demand Response:	In-Home Displays & Web Portals Demand Response Over AMI Prepaid Metering Interactive Thermal Storage
Distribution Automation:	Renewables Integration Smart Feeder Switching Advanced Volt/VAR Control Conservation Voltage Reduction

To demonstrate the value of implementing the Smart Grid, NRECA has prepared a series of single-topic studies to evaluate the merits of project activities. The study designs have been developed jointly by NRECA and DOE. This document is the final report on one of those topics.

DISCLAIMER
The views as expressed in this publication do not necessarily reflect the views of the U.S. Department of Energy or the United States Government.

1. Introduction

1.1 Background: The NRECA Smart Grid Demonstration Project

The benefits of behind-the-meter energy storage were evaluated through two closely related technology demonstration projects involving storage at several electric distribution cooperatives (co-ops) and Great River Energy (GRE), a generation and transmission (G&T) electric cooperative in Minnesota. The overall goals were to validate the technologies and determine their value in demand reduction and for providing such ancillary services as frequency regulation and synchronous reserves to the Midcontinent Independent System Operator[1] (MISO) electricity market.

These projects were undertaken through the National Rural Electric Cooperative Association (NRECA) Smart Grid Demonstration Project (SGDP) and funded by the U.S. Department of Energy (DOE) under an American Recovery and Reinvestment Act (ARRA) grant, with cost share provided from participating co-ops. The lead co-op on the battery energy storage project was Minnesota Valley Electric Cooperative (MVEC), a distribution co-op in Minnesota, with participation by Wright-Hennepin Cooperative Electric Association (WHCEA), Federated Rural Electric Association (Federated), and Meeker Cooperative Light and Power Association (Meeker). The lead co-op on the thermal storage project was GRE, which installed systems at a number of distribution co-ops within its membership.

1.2 Battery Energy Storage Project

The first project involved battery energy storage systems at MVEC, WHCEA, and two nearby distribution co-ops—Federated and Meeker. The specific technology used was a Silent Power (SP) "OnDemand™ Energy Appliance"—an integrated utility-controlled edge-of-grid battery energy storage system.[2]

Unfortunately, Silent Power became insolvent in early 2014 due to circumstances beyond its control. It should be noted that this does not sound the death knell for residential battery storage. There are other residential battery storage companies, such as Sunverge Energy in Stockton, California, very similar to SP. Also, Tesla Motors and Solar City are actively pursuing residential solar and battery storage solutions. Meanwhile, the work with SP has allowed electric cooperatives to gain a better understanding of the opportunities and challenges for battery storage.

The SP appliances in this test used sealed lead acid batteries. Lithium-ion batteries are a better fit for this type of application, albeit more expensive. However, NRECA CRN participated in the 31st International Battery Seminar and exhibit, during which a number of vendors and research organizations indicated that Lithium-ion battery prices would drop by 50% within the next 2–3 years. Cycle life (a cycle is the charge and discharge cycle of the battery) for 80% deep operating discharge will increase from 3,000 cycles to 5,000 cycles and be competitive with the shorter-lifetime lead acid batteries (450 cycles for an 80% deep operating discharge).

[1] See https://www.misoenergy.org/Pages/Home.aspx.
[2] See http://www.silentpwr.com/HomeOwner.htm.

The first project accomplished the following goals:

1. Eighteen SP battery storage appliances have been installed in the field to learn about and solve issues related to installation at members' homes and businesses.
2. The stated features of the SP battery storage appliances were tested and evaluated in the field, using sealed lead acid batteries. Feedback was provided to the vendor on product deficiencies and suggestions for improvements.
3. When aggregated, the SP battery storage appliances provided controllable demand reduction that could reduce the need for future natural gas peaking units. The immediate benefit is cost savings on wholesale power demand charges for the participating distribution co-ops. The benefit for the G&T co-ops is achieved not only through reduced need for new capacity in the future, but also reduced congestion costs on the transmission networks. It is important to understand that the value of "dispatchable battery storage" is greater than more traditional options, such as electric water heater thermal storage, dual fuel electric heating, or cycled air conditioner control.
4. Simultaneous control of battery storage units in multiple distribution co-ops was simulated/tested for the purpose of providing aggregated ancillary services—in this case, for MISO.
5. Battery storage for small residential and commercial consumers was used for instantaneous and dispatchable load management.
6. The whole-house load management tool was tested in a natural gas market.
7. WHCEA is prepared to use battery storage as the "dual fuel" for air conditioning. Dual fuel uses electric heat as the primary source, and a back-up heating source, such as liquefied petroleum (LP) gas or fuel oil, during peak load conditions. In this case, the battery storage energy would be injected into the grid to offset the A/C unit load during peak load conditions. The A/C unit would function as normal during the peak load condition. This provides demand reduction savings over the peak while eliminating "rebound" peaks when control ends. The SP units for these locations were not installed during summer 2013, but data should be available by the end of summer 2014.
8. MVEC and WHCEA SP units successfully provided back-up power for critical circuits.
9. A battery storage unit allowed continued solar energy production during a power outage at one location with a 2,000-watt solar photo voltaic array, while remaining isolated from the grid.[3]
10. The SP battery storage inverter (@ 48 volts DC) was integrated with a 2,000-watt residential solar photovoltaic (PV) (@48 volts DC), thus reducing cost for the solar PV/storage solution because the two units shared an inverter.
11. The ability to measure the amount and impact of battery storage load before and after load control was tested.

An anticipated implementation of localized volt-ampere reactive (VAR) control was not tested.

[3] Note: Solar panels generally will not function if grid power is lost because the inverters are required by UL-1741 / IEEE-1547 to operate only if the grid voltage and frequency are stable. With battery storage, the inverters can switch modes and operate isolated from the grid. This can provide grid resiliency.

1.3 Thermal Energy Storage Project

The second project was an extension of thermal energy storage systems that have been in use for demand-side management (DSM) by GRE. GRE provides wholesale electric service to 28 distribution co-ops in Minnesota and Wisconsin that distribute electricity to more than 650,000 member-consumers—about 1.7 million people. GRE offers more than 3,500 MW of generation capability, consisting of a diverse mix of baseload and peaking power plants, including coal, refuse-derived fuel, natural gas and fuel oil, and wind generation. As part of its DSM program, more than 70,000 hot water heaters have load management systems (LMSs) installed that will allow hot water heaters to be charged with low-cost off-peak energy from 11 PM to 7 AM. These hot water heaters generally are not allowed to contribute to the peak load that occurs during the day and early evening—generally between 7 AM and 11 PM.

The purpose of the project was to evaluate using a water heater to store thermal energy during off-peak hours and offset on-peak charging of hot water heaters, while providing frequency regulation to the MISO wholesale power market by varying the recharge rate during the off-peak hours. Successfully accomplishing this purpose meant deploying a new control technology for the water heaters. The controller has a fast, Internet Protocol (IP)-based connection back to the head-end system and the ability to vary the charge rate on the water heater between 0 and 100% of the appliances' maximum demand. Combining the fast connection with the ability to vary the charge rate technically provides a distributed resource capable of providing frequency regulation during off-peak hours to a wholesale power market such as MISO.

The overall project goals were accomplished:

1. Ten Steffes Water Heater Controls[4] with remotely configurable charge rates were deployed in the service territories of the participating member distribution cooperatives.
2. Two-way communication of the water heater controls was tested and evaluated.
3. The use of power-line carrier, 700-MHz wireless, and Wi-Fi were tested as possible communication technologies.
4. An economic model was developed for evaluating use of hot water heaters for frequency regulations.

2. Project Implementation and Results — Battery Energy Storage

2.1 Enabling Technology

The battery storage project used equipment from SP. The OnDemand™ system used advanced lead acid battery energy storage for this study; a dedicated grid battery charger; an inverter that can serve in either grid-connected or isolated, off-grid modes; and a monitoring and control system. Lithium-ion batteries were available but not included in this study. It was felt that lead acid batteries might work, based on the anticipated few hours of control (about 150) a year. The system includes an option for connection of a PV array through either a maximum-power, point-tracking controller provided by SP or an external controller. OnDemand™ Energy Appliance specifications are shown in **Table 1**.

[4] See http://www.steffes.com/offpeak.

Table 1. OnDemand™ Energy Appliance Specifications

Specification	Range
Inverter	
Input Battery Voltage Range	40 to 66 VDC
Nominal AC Output Voltage	120 or 120/240 Vrms ± 3%
Output Frequency	60 Hz ± 0.3%
Total Harmonic Distortion	< 5%
Continuous Power Output at 40° C	4,600 W/9,200 W
Continuous Input Battery Current	4.6kW-115A, 9.2kW-230A
Waveform	Pure Sine Wave (320 step)
Back-Up Power Features	
AC Pass-Through Current to Critical Circuits Panel	50A at 120 volts, 100A at 120/240 volts
Switching Time upon Grid Outage	Less than 30 milliseconds
Back-Up Switching Criteria	Per IEEE 1547
Continued Solar Production in Island Mode	Yes
Communications	
Consumer Interface	7" Touch Screen Display, Ethernet for Web-Based PC Interface
Utility Interface	RS232 for AMI, Ethernet for Broadband Internet, XML Protocol
Other	CAN Bus Communication Port, USB
Environmental	
OnDemand Operating Temperature*	-20° C to +55° C (-4° F to +131° F)
OnDemand Storage Temperature	-40° C to +70° C (-40° F to 158° F)
Recommended Battery Operating Temperature	-15° C to 45° C
Max Operating Altitude	15,000' (4,570m)
Operating Humidity	0 to 95% RH Non-Condensing
System Output	Operating Temperature 45°C 50°C 55°C Derating 83.3% 66.6% 50.0%
Safety	
Listing	Complies with UL 1741 and CSA 107.1 Complies with UL 1778 and CSA 107.3
Physical	
Dimensions and Weight Without Batteries	Standard XLT Cabinet 54.5"H x 27.0"W x 29.5"D - ~375lbs 73.0"H x 27.0"W x 29.5"D - ~400lbs
Clearance for Ventilation	See installation manual for workspace clearance

As shown in the table, the battery inverter is rated at 4.6 kW or 9.2 kW. The batteries installed during this demonstration by SP are GS-Yuasa 246 Amp-hour (AH) batteries that can produce 11.8 kWh or 23.6 kWh over a 20-hour discharge time. In discussions with WHCEA and MVEC, when the system is discharged over a quick 2 hours (WHCEA) and a 1-hour discharge time (MVEC), the peak output from the battery rated at 4.6 kW will be limited to less than 4.6 kW while also limiting the Depth of Discharge[5] (DOD) to <60% (WHCEA) or <80% (MVEC). This is because of Peukert's law, developed by the German scientist W. Peukert in 1897. He expressed the energy capacity of a lead acid battery as the rate at which it is discharged. As the rate increases, the battery's available energy capacity decreases (primarily from I^2R losses due to the

[5] The percentage of battery capacity that has been discharged, expressed as a percentage of maximum capacity. A discharge to at least 80% DOD is referred to as a deep discharge.

series resistance in the batteries). With a limitation on the percentage of depth of discharge, as the energy capacity of the battery decreases due to rate of discharge, its maximum kW output during the rapid discharge times also decreases.

Thus, when the MVEC unit discharges over a 1-hour time interval, the output has been less than 4.6 kW because of the following:

1. Increasing the nominal discharge time from 20 hours to 1 or 2 hours significantly increases the I^2R losses from the equivalent series resistance by a factor of 10 to 20 and the battery and the inverter by a factor of 100 to 400, which in turn significantly reduces the peak capacity of the GS-Yuasa 246 AH batteries.
2. The more cycles consumed and the more the batteries age, the more the voltage drops and the output from the batteries decreases.
3. For this research, WHCEA limited the degree of operating discharge to a conservative 60% DOD over 2 hours, which sets the limit on the peak output of the batteries but increases their life to a more conservative 700 cycles.
4. For this research, MVEC limited the degree of operating discharge to an aggressive 80% DOD, which shortens the life of the batteries to only 450 cycles.

Over time, MVEC has not been able to provide peak demand reduction of 4.6 kW or 9.2 kW; rather, the peak output is about 3.2 kW and 6.5 KW, respectively, for slightly more than 1 hour. WHCEA discharges its batteries to 60% DOD over a 2-hour time interval, which allows it to provide peak demand reduction of 2.7 KW and 5.5 kW, respectively, over the longer time interval of 2 hours. WHCEA and MVEC felt that Lithium-ion batteries would be a better option for storage because the battery output does not decrease significantly as the discharge time decreases.

2.2 Installation

The SP unit is designed to be installed "behind the meter" at the customer's premises. Installation involves physical placement of the equipment cabinet, installation of the batteries, and connection to the main load panel at two breakers (one for the charge circuit and one for the inverter-to-grid connection). Critical loads are connected through a separate "Critical Circuits Panel," typically by a selector switch that would allow the critical loads to be connected directly to the main panel and, in the event of outage, serve on the grid until the battery is discharged. If a PV array is to be attached, it is done either through an optional DC/DC charge controller or via a separate vendor-supplied charge controller. Communications are through customer-provided broadband Internet. The systems interact with the "On Command" software, hosted by SP.

Utility access to metering information also is provided via On Command. System performance data was collected by SP once per day and made available to the participating co-ops. Control over the units was provided through schedules, not by direct device control. Each cooperative managed its units separately through the On Command software service. Co-ops could set schedules specifying the time and magnitude of the discharge, and also the time and duration window for recharge.

Figure 1 shows a simplified installation wiring diagram.

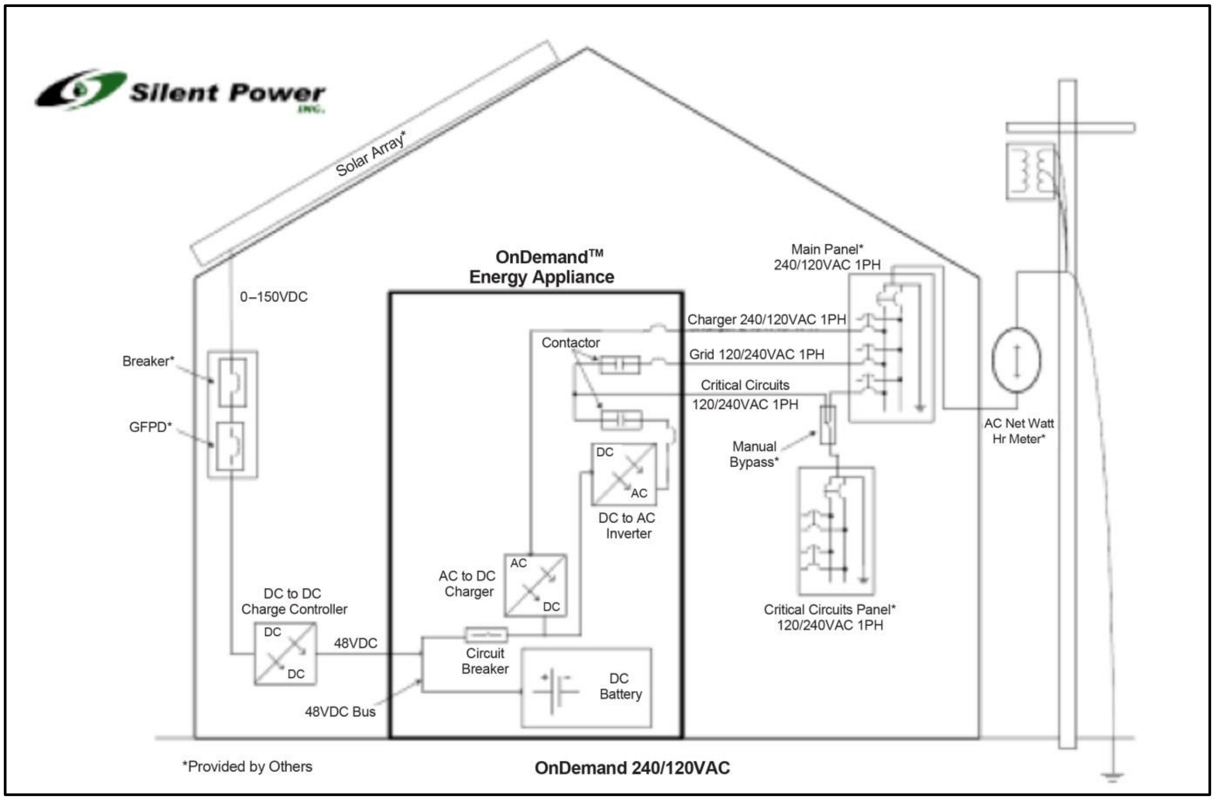

Figure 1. Simplified SP Installation Wiring Diagram

Project-Specific Installations

Table 2 shows the installation details for the units purchased for this project.

Table 2. Installation Details for the Units Purchased

Co-op	kW Rating	Solar?	Location
MVEC	4.6	Yes	Residential member location
MVEC	9.2	No	Residential member location
MVEC	9.2	No	MVEC headquarters
MVEC	4.6	No	MVEC headquarters
MVEC	4.6	No	MVEC headquarters
Federated	4.6	No	Federated headquarters
Meeker	4.6	No	Meeker headquarters
WHCEA	4.6	No	WHCEA headquarters-energy park
WHCEA	4.6	No	WHCEA headquarters-commercial building
WHCEA	4.6	No	Residential member location
WHCEA	4.6	No	Residential member location
WHCEA	4.6	No	Residential member location
WHCEA	9.2	No	Commercial member location
WHCEA	4.6	No	Residential member location
WHCEA	9.2	Wind	Residential member location
WHCEA	4.6	No	Residential member location
WHCEA	4.6	No	Residential member location
WHCEA	9.2	No	Residential member location

Federated installed three additional bi-directional meters on its unit. (See details under "Data Collection.)

WHCEA installed three large (9.2 kW net) battery storage units and eight small (4.6 kW net) units. One of the large units was installed in a small commercial location, one was at a residential location, and the third large unit was located at a residential site that included a small (20-kW) wind turbine. Otherwise, all units were placed in residential locations. Five units were installed with "critical circuits" panels. One of the MVEC installations includes integration with a 2,000-watt solar PV array, using the same inverter for the solar PV and the SP battery. The batteries provide voltage to the solar PV inverters, allowing operation of the solar PV if the grid has a short or extended outage. In addition, the batteries provide electricity to critical loads at night during an extended outage.

Experience

Installation of the SP units began in July 2012 and was completed by August 2013 (see **Figures 2 and 3**). The co-ops experienced delays in installation, due primarily to control software issues and communications problems with the SP systems. These eventually were resolved.

Figure 2. 9-kW SP Unit with Cover Removed

WHCEA noted some specific issues with the installations:

- "Installation of the equipment is fairly straightforward, and none of our electricians had any trouble with the installations. The one difficulty is the physical size and weight of the equipment and batteries, which require a two-person crew (at least for the initial installation)."
- "When installing the units in a critical-circuits configuration, the electricians have to use a manual bypass to allow operation of the critical circuits loads during maintenance or downtime of the SP unit. The manual bypass requires additional space and wiring and, in order to meet code, is fairly large, which adds some to the project costs."
- "The only means of communication with the device is through an Ethernet interface. Therefore, at each location, we've had external equipment that had to be added. Some could directly connect via Ethernet and communicate through the local broadband connection at the premises. However, the majority did not have direct Ethernet access. We used Linksys range extenders to convert Ethernet to Wi-Fi, so we could drop into the local Wi-Fi. However, this was not available at all locations. Where Wi-Fi was not available, we used cell modems with an Ethernet port. All of these items require external power."

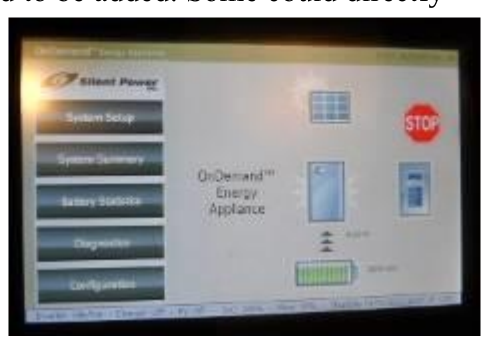

Figure 3. Display on SP Appliance

2.3 Operation

General Operation

In normal operation, the battery charge circuit is turned off; the majority of power flows directly "across" the SP inverter bus to the critical load panel. The only losses in this state are the self-discharge of the battery and the "tare losses" (parasitic losses)[6] required to run the control system. Periodically, the software is instructed to charge the battery. There are two stages to this charge—a bulk charge and an "absorption" charge. The MVEC nominally rated 4.6-kW units were recharged on a daily basis and drew an average of about 40 watts per hour during periods for the tare load, even if the unit was not dispatched. This would put the tare loss and battery maintenance at about 29 kWh per month, or a little more than $3 for the 4.6-kW unit and $6 for the 9.2-kW unit at retail rates. If a power outage occurs, the unit will disconnect from the grid and supply power directly to the Critical Circuits Panel, forming an intentional "island" that operates separately from the main power grid. This continues either until the battery is fully discharged (at which point the battery is disconnected) or grid power is restored and stable for five minutes, at which point the system will reconnect to the grid. If a PV array is used, the array can recharge the battery during sunlight hours during this "islanded" period.

If the unit is scheduled to "dispatch" to the grid, it will turn on and provide a targeted amount of power for a specific period of time. The maximum power available is limited by the size of the inverter (4.6 kW or 9.2 kW), and the discharge duration is limited by the power setting and the size of the battery. The discharge can be terminated either on a timer or a maximum DOD. The output power supplies the critical load, with any excess flowing back into the main panel. (Note that this "load sharing" occurs as a result of the laws of physics and not from any active control technology.) The "dispatch" results in a constant, verifiable, measured load reduction.

Project-Specific Operation

MVEC discharges its units at full nominal rated power (4.6/9.2 kW) until the battery is discharged to 80% battery DOD in the 1 hour it predicts will be the peak for the month. On average, it discharges the units about four or five times a month while attempting to hit the monthly peak demand. The battery is predicted to have a cycle life of about 450 cycles when operated at 80% DOD, as shown in **Figure 6**. Thus, if the units are discharged five times a month, the life of the battery will be about 90 months, or about 7.5 years. WHCEA discharges its units over a 2- to 3-hour period and usually discharges the batteries only down to 60% DOD, hoping to extend their life. The life of the battery when discharged down to 60% DOD is expected to be about 700 cycles, or about 12 years, if used five times a month. Federated discharges its unit at a 2.3-kW rate for one or two separate 1-hour periods, depending on the season. (Some winters may have two peaks; one in the morning and one in the afternoon or early evening; summers have afternoon peaks only.)

SP has been monitoring the operation for 16 of the units in service; nine currently are considered good and have been given a green status. Five batteries have been given a yellow status, as the batteries report a State of Charge (SOC) of 80% or lower and thus are considered as candidates for replacement. One battery had a charger drawer that needed repair; it was repaired but now is

[6] Loss caused by a charge controller.

reporting an SOC of 80% or lower and so is a candidate for replacement—its status is red. The last battery of the 16 is also in a red status and is a candidate for replacement.

Maintenance Requirements

The units use Valve-Regulated Lead Acid (VRLA) batteries that are sealed under normal operation, so the unit requires no regular maintenance. Depending on the use, number of cycles, and DOD of the batteries, they may need to be replaced one or more times over the course of the 10-year life of the system.

2.4 Data Collection

Data are collected for each unit via a web-hosted service provided by SP. Federated installed three additional bi-directional meters on its unit.

- One meter is between the main panel and the battery charger input.
- A second meter is between the main panel and the SP Inverter. This meter measures both power supplied from the panel to the unit (and through to the critical loads) and power supplied from the battery through the SP inverter and back onto the grid.
- A third meter is between the SP inverter and the critical loads panel.

2.5 Economic Evaluation

All four of the project co-ops purchase power through two G&T cooperatives. Their primary contract is through GRE and is fixed at their energy requirements from 2006. The balance of energy is purchased through Basin Electric Power Cooperative (Basin Electric). The co-ops pay a transmission charge to GRE, based on the coincident GRE system peak and a demand charge to Basin Electric, based on the peak demand at the individual co-op each month. The reduced demand cost can range from $20 to $25 per month per kW.

A detailed analysis that calculates payback for future commercial units based on using detailed assumptions regarding the components is shown in **Table 3** for WHCEA and **Table 4** for MVEC. The assumptions used include the following:

- Electricity is valued at 11.7 cents per kilowatt hour (kWh) when discharged into the grid; when recharging, the battery is charged 4.9 cents per kWh.
- The datasheet rating of the battery in the small system is 246 amp-hours at 48 volts, or 11.8 kWh at the 20-hour rate. As mentioned previously, however, the nominal ratings are assumed to be 4.6 kW and 9.2 kW; if discharged quickly over a 2-hour period, the ratings are assumed to be 2.7 KW and 5.5 kW, respectively. If discharged at the fast rate of 1 hour, the ratings are assumed to be 3.2 kW and 6.5 kW, respectively.
- As mentioned previously, the actual useful storage of the battery is diminished because of reduction in capacity due to high rate of discharge, conversion of energy from DC to AC, and reserving some capacity to prevent damage to the battery during excessive discharge.
- System round-trip efficiency is 60%, based on 85% efficiency for the electronics in each direction and 83% DC round-trip efficiency quoted for the GS Yuasa 260 amp-hr. battery. However, while both the inverter efficiency and DC efficiency of the battery decrease as the battery discharges faster, that effect has not been included in this analysis.
- For the nominally 4.6 kW rating of the GS Yuasa 260 amp-hr. battery, there is a 40-watt continuous tare load (a parasitic load), including maintenance charges on batteries when not in use.

- It is assumed that eight cycles per month currently are required to meet the two demand peaks; each cycle lasts for ≈1.2 hours, resulting in an 80% discharge. It is assumed that about five cycles per month are required to meet a single demand peak.
- The analysis assumes that the battery will last for 11.67 years if the battery system is discharged to 60% DOD or less or 4.69 years if discharged to 80% DOD.
- The net cost of the system each year is assumed to be a loan payment for the life of the battery at a 5% interest rate per year on the installed cost of the system over the life of the system.
- No allowance has been added for any operation and maintenance costs, replacement of batteries, or insurance on the installations. When the system becomes commercial, it is not clear who will bear the responsibility for insurance on the battery or the increased insurance the homeowner will require because of having the battery on the premises. DOE and stakeholders realize that unanswered safety questions exist and are developing best practices.
- The net benefit is the demand reduction cost benefit of about $20–25/kW per month.
- The probability of hitting the monthly hourly peak is assumed to be 100% for WHCEA when the battery is discharged over 2 hours and 90% when MVEC discharges the units in 1 hour.
- The net value received from the battery discharge is the demand reduction value times the peak rating for 1 or 2 hours, less the cost of charging the system, less the tare cost for the system, plus the value for the electricity sold during the peak hours.

Table 3. Battery Energy Storage Project Detailed Payback Analysis for WHCEA, Assuming 2-Hour Discharge, 5 Cycles per Month, 60% DOD

	Base 4.6-kW System	Base 9.2-kW System	Reduced-Cost 4.6-kW System	Low-Cost 9.2-kW System	
Unit cost	$13,000	$18,800	$9,000	$13,015	
Installation cost	$1,200	$1,200	$1,000	$1,000	
Nameplate rating	4.6	9.2	4.6	9.2	kW-AC
Actual rating for 2 hours, 60% DOD	2.7	5.5	2.7	5.5	kW-AC
Discharge hours per cycle	2	2	2	2	hours
Electric rate when discharging	$0.117	$0.117	$0.117	$0.117	$/kWh
Electric rate when charging	$0.05	$0.049	$0.049	$0.049	$/kWh
Demand value (average)	$23.51	$23.51	$23.51	$23.51	$/kW/mo.
Probability of hitting the peak (%)	100%	100%	100%	100%	%
Net average demand value	$23.51	$23.51	$23.51	$23.51	$/kW/mo.
Round-trip efficiency	60%	60%	60%	60%	%
Recharge energy per cycle or event	9.00	18.34	9.00	18.34	kWh
Number of cycles per month	5	5	5	5	per month
Recharge energy per month	45	92	45	92	kWh per month
Recharge cost	$2.21	$4.49	$2.21	$4.49	$ per month
Discharge energy per month	27	55	27	55	kWh per month
Value of discharge energy per month	$(3.16)	$(6.44)	$(3.16)	$(6.44)	$ per month
Tare load	40	80	40	80	watts per hour
Monthly tare load	29	58	29	58	kWh-AC/mo.
Tare energy cost	$3.42	$6.83	$3.42	$6.83	$ per event
Net cost energy for the ES (value for discharge energy less tare load and charge energy)	$2.46	$4.89	$2.46	$4.89	$ kWh/mo.
Demand charge savings	$63.48	$129.31	$63.48	$129.31	$ per month
Net monthly savings for ES	$61.01	$124.41	$61.01	$124.41	$ per month
Financing years	10	10	10	10	years
Interest rate per year	5%	5%	5%	5%	per year
Interest rate per month	0.42%	0.42%	0.42%	0.42%	per month
Monthly P&I payment factor	0.94%	0.94%	0.94%	0.94%	per month
Monthly payment for battery	$122.24	$176.77	$84.63	$122.38	$ per month
Monthly net benefit	$(61.22)	$(52.36)	$(23.61)	$2.03	$ per month
Lifetime net benefit	$(8,571.36)	$(7,330.53)	$(3,305.75)	$284.85	$ over lifetime
DOD	60%	60%	60%	60%	DOD
Cycle life	700	700	700	700	cycles
# of cycles per year	60	60	60	60	cycles per year
Battery life, in years	11.67	11.67	11.67	11.67	years
Battery life, in months	140.00	140.00	140.00	140.00	months

Table 4. Battery Energy Storage Project Detailed Payback Analysis for MVEC, Assuming 1-Hour Discharge, 8 Cycles per Month, 80% DOD

	Base 4.6-kW System	Base 9.2-kW System	Reduced-Cost 4.6-kW System	Low-Cost 9.2-kW System	
Unit cost	$13,000	$18,800	$9,000	$13,015	
Installation cost	$1,200	$1,200	$1,000	$1,000	
Nameplate rating	4.6	9.2	4.6	9.2	kW-AC
Actual rating for 1 hour, 80% DOD	3.2	6.5	3.2	6.5	kW-AC
Discharge hours per cycle	1	1	1	1	hours
Electric rate when discharging	$0.117	$0.117	$0.117	$0.117	$/kWh
Electric rate when charging	$0.05	$0.049	$0.049	$0.049	$/kWh
Demand value (average)	$23.51	$23.51	$23.51	$23.51	$/kW/mo.
Probability of hitting the peak (%)	92%	92%	92%	92%	%
Net average demand value	$21.55	$21.55	$21.55	$21.55	$/kW/mo.
Round-trip efficiency	60%	60%	60%	60%	%
Recharge energy per cycle or event	5.34	10.84	5.34	10.84	kWh
Number of cycles per month	8	8	8	8	per month
Recharge energy per month	43	87	43	87	kWh per month
Recharge cost	$2.09	$4.25	$2.09	$4.25	$ per month
Discharge energy per month	26	52	26	52	kWh per month
Value of discharge energy per month	$(3.00)	$(6.08)	$(3.00)	$(6.08)	$ per month
Tare load	40	80	40	80	watts per hour
Monthly tare load	29	58	29	58	kWh-AC/mo.
Tare energy cost	$3.42	$6.83	$3.42	$6.83	$ per event
Net cost energy for the ES (value for discharge energy less tare load and charge energy)	$2.51	$5.00	$2.51	$5.00	$ kWh/month
Demand charge savings	$68.96	$140.08	$68.96	$140.08	$ per month
Net monthly savings for ES	$66.45	$135.08	$66.45	$135.08	$ per month
Financing years	10	10	10	10	years
Interest per year	5%	5%	5%	5%	per year
Interest per month	0.42%	0.42%	0.42%	0.42%	per month
Monthly P&I payment factor	1.99%	1.99%	1.99%	1.99%	per month
Monthly payment for battery	$258.65	$374.05	$179.07	$258.95	$ per month
Monthly net benefit	$(192.20)	$(238.97)	$(112.62)	$(123.87)	$ per month
Lifetime net benefit	$(10,811.42)	$(13,442.00)	$(6,334.74)	$(6,967.60)	$ over lifetime
DOD	80%	80%	80%	80%	DOD
Cycle life	450	450	450	450	cycles
# of cycles per year	96	96	96	96	cycles per year
Battery life, in years	4.69	4.69	4.69	4.69	years
Battery life, in months	56.25	56.25	56.25	56.25	months

(The complete spreadsheets for the analysis of **Tables 3** and **4** are available upon request and posted on the NRECA CRN SharePoint.)

Some important observations and conclusions follow:

1. Battery storage has very limited (if any) payback when installed for peak load management or energy arbitrage (buying low-cost energy at night and redeploying it into the grid on peak). The only case that showed a small positive payback was the assumption of a lower-cost 10-kW SP battery system at $13,015 plus $1,000 for installation, compared to today's $18,800 for the SP battery system plus $1,200 for installation. All other cases had a negative net lifetime benefit, primarily because of the following factors:
   a. The demand charge savings alone are not enough to offset the capital cost of the equipment and installation.
   b. Lead acid batteries have a short life cycle if operated to a less than 60% DOD on a regular basis. Lithium-ion batteries were not tested in this study.
   c. The cost of equipment needs to come down. We feel this will happen for battery storage, as it did for solar panels. These dropped from $8/watt to under $1/watt once mass production and a competitive market developed. Companies like Tesla Motors and Solar City are working on bringing mass marketing of Lithium-ion batteries and solar PV to the U.S., and legislators and regulators are starting to provide incentives for solar. When lower costs and longer cycle life for batteries (probably Lithium-ion) are achieved, battery storage may have a return on investment for demand charge savings.
2. The case for battery storage is better if there is not only a peak load management application, but also usage in "premium power" applications, in which the customer is looking for better reliability and is willing to pay a monthly fee for the service—for example, $25−$30 per month.
3. The case for battery storage is best when combined with solar. In fact, solar should be combined with battery storage if the utility system peak is late in the day—after 6:00 PM, for example. Solar alone will cause cost-shifting to other members because it reduces kWh energy purchases but does not significantly reduce the kW demand. The effect is to reduce the utility's load factor, which could drive up the cost/kWh. **Figures 4** and **5** illustrate this issue.
4. Note that there is no assumption of any annual operation and maintenance costs. If the electric cooperatives have to send a technician out to each of the batteries once a year at a cost of $100 per visit, all cases will have a negative payback—even the one case that showed a positive payback here.

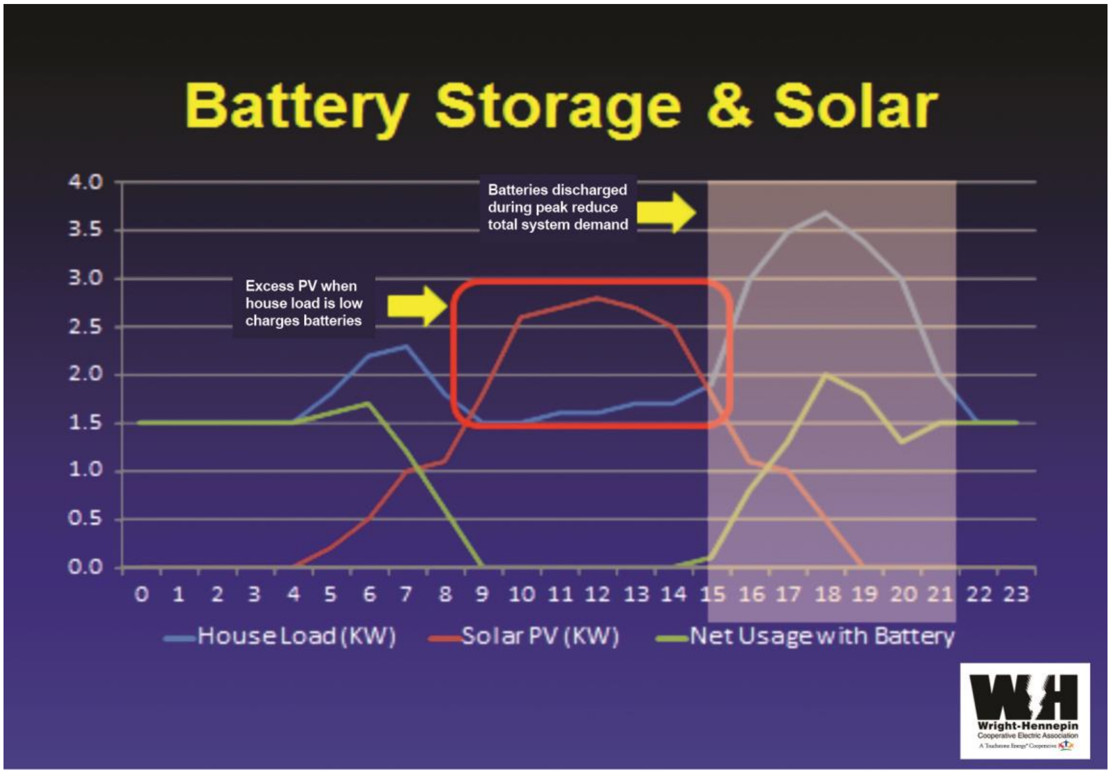

Figure 4. Battery Storage and Solar

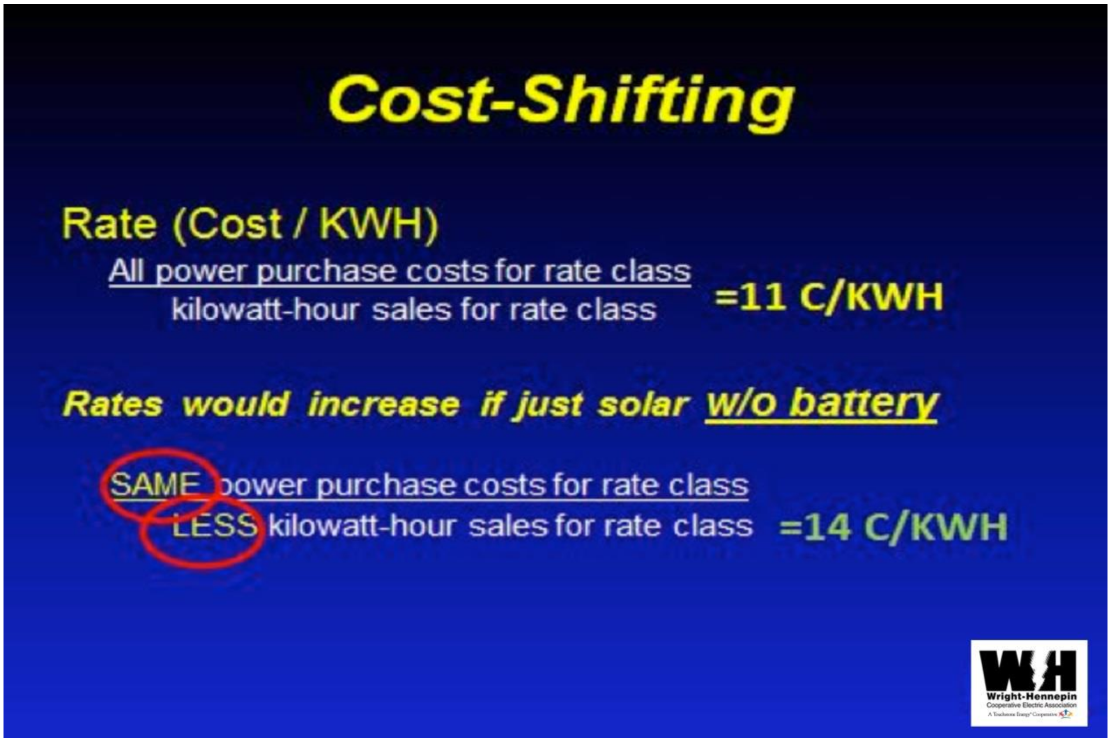

Figure 5. Cost-Shifting from Solar without Storage

Additional conclusions from the demonstration of the SP GS Yuasa batteries are as follows:

1. As noted in **Figure 6**, the capacity of a VRLA battery goes down as the discharge rate increases. Different lead acid batteries are designed to be optimum at differing discharge rates. It is important to understand the full performance characteristics of a particular battery when attempting to determine whether these batteries overall will be viable in any given application. Obviously, if the cost for technology such as Lithium-ion batteries can be reduced to \$500/kWh or (about \$14,000 total installed cost), these batteries will be the preferred option, as they have cycle lives of 3,000 cycles or more at 80% DOD and 125,000 cycles at 10–20% DOD. The electric cooperative then could have the option to bid Lithium-ion batteries into the frequency regulation market as well as for demand charge reduction; this would open up a second value stream, further strengthening the financial return of battery energy storage systems.

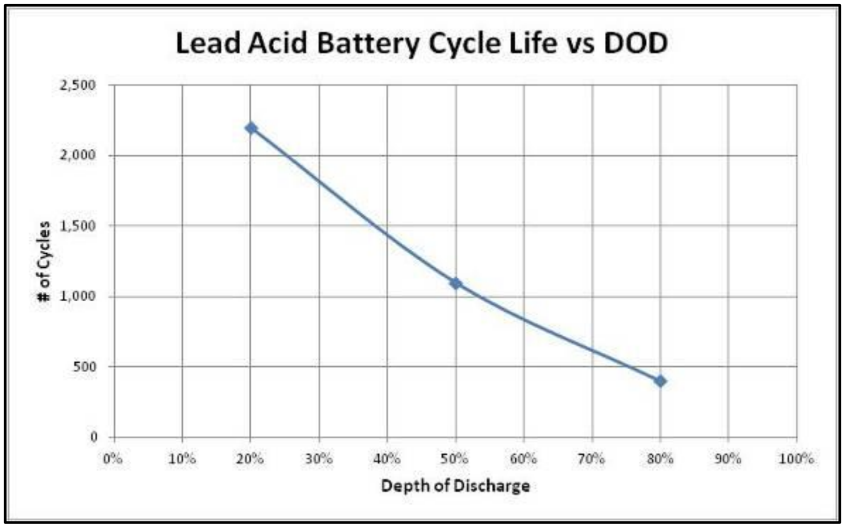

Figure 6. Lead Acid Battery Cycle vs. DOD

2. Many of the other applications envisioned by the co-ops—such as PV firming, wind energy load shifting, and commercial load management—will require additional cycling, thus putting additional strain on the batteries and requiring those with a significantly longer cycle life. The firming of PV potentially could require hundreds of cycles a year, which in turn would require the use of Lithium-ion batteries.
3. The typical discharge time for peak shaving is late in the afternoon and, in northern climates, might occur early in the morning during the winter. For the early morning peaks, it is conceivable that a utility could store wind or low-cost grid energy produced off peak at night.
4. A key benefit of an energy storage system could be to provide the voltage and frequency signal to the residential solar PV, so the PV can continue to operate when there is a power outage. This is accomplished by using the critical source on the battery storage system to power the solar array, which quickly and automatically disconnects from the grid if the main source power is lost. In this way, customers could continue to have a source of power for some critical loads during extended power outages, providing that the sun shines during the day—and major storms often are followed by sunny days.
5. The "certainty" of battery dispatch as a demand response solution has a significant value to cooperatives, as opposed to more probabilistic methods, such as hot water or air conditioner load control.

3. Project Implementation and Results − Thermal Energy Storage

3.1 Enabling Technology

Thermal energy storage using hot water heaters is a potentially low-cost and effective method of providing balancing services for the electric grid, usually referred to as "frequency regulation service" or just "regulation service." This service can be provided by "charging up" a water heater (i.e., heating water in a domestic water heater) in response either to an area control error (ACE) or automatic generator control (AGC) signal from a G&T, independent system operator (ISO), or regional transmission operator (RTO). The G&T, ISO, or RTO can request the hot water heater either to charge up (heat the water) from a mid-level charge of 1.5 kW to 3 kW (so as to last for 8 hours, from 11 PM to 7 AM), or stop the charge up by dropping the electric hot water heater to 0 kW. Thus, the hot water heater can respond to ACE or AGC signals for controlling frequency by providing frequency regulation up ("reg up") or frequency regulation down ("reg down"), providing the area balancing services.

In addition, by combining controls and communications with water heaters, the technology can interface with standard load management through the GRE DSM program to provide not only responsive regulation but also synchronous reserves and nearly instant "valley filling" during the off-peak hours. Effectively, hot water heaters can be "dynamically dispatched"; this technology is being developed by the Steffes Corporation to provide regulation service during the off-peak hours of heating water, thus valley filling load exactly so as to minimize the cost of charging and remove the hot water heater load from the morning or early evening peak hours. Such a configuration would qualify for a capacity credit or demand charge reduction if enough hot water heaters are aggregated.

As mentioned previously, the reliability of systems such as MISO or other ISOs/RTOs can be improved further by providing fast-response sources of generation, as required by FERC Order 755. The PJM RTO has found that the implementation of performance-based compensation for regulation resources has been successful (PJM RTO report of October 14, 2013 to FERC on analysis of performance-based regulation for frequency regulation). To support this need, the dynamic dispatch of the hot water heaters can provide response as fast as 4 seconds (often obscured by the 20- to 90-second latency time for reporting). PJM noted that fast-responding resources (like thermal energy storage in hot water heaters) can participate in the PJM regulation market when aggregated to provide more than 100 kW of regulation. This will provide the PJM system—and other ISOs/RTOs in the future—with control over regulation that is the same or better, as measured by North American Electric Reliability Corporation (NERC) Control Performance Standards 1 (CPS1) and Balancing Authority ACE Limit (BAAL) reliability criteria. PJM concluded that paying for performance of fast-response/fast-moving frequency regulation can provide significant benefits and reduce overall frequency regulation costs, as well as meet synchronous reserve requirements, thus reducing the total cost for providing frequency regulation.

The technology being deployed was developed by the Steffes Corporation and is referred to as the Grid-Interactive Energy Thermal Storage (GETS) system. It is a dynamic dispatch control system comprising a control panel with embedded microprocessor connected to current transformers and thermocouples in the hot water heater; it also has a high-speed Internet connection back to the head-end computer monitoring and control system. For this project, the water heaters were aggregated in the Microsoft Azure Cloud, and the head-end control system was located at GRE.

Currently, GRE has configured the GETS units charge during the off-peak hours each night (11 PM to 7 AM) to charge at an average of 1.5 KW for 8 hours, for a total of 12 kWhs. It can oscillate in response to the AGC or ACE signal by reg up from 1.5 KW to 3 kW or reg down from 1.5 kW to zero. The system is flexible enough that if the MISO regulation market clearing price (RMCP) during any hour is projected to be higher at any point during the charging time, the system could swing from 0 to 4.5 KW until the tank hits the temperature limits of 170°F. In doing so, it will limit the time to provide frequency regulation to less than 8 hours, depending on how long the tank heating element swings from 0 to 4.5 kW rather than from 0 to 3 kW.

As mentioned previously, the period between 11 PM and 7 AM coincides with the off-peak periods when MISO's locational marginal price (LMP) in the GRE region is at its lowest (averaging about $20/MWh for the year), thus avoiding the higher LMP prices during the day, which average about $40/MWh, with a peak of $45/MWh at 7 PM. During the charging time period, GRE communicates an AGC signal to simulate an ACE signal that GRE would receive in the future from MISO (presently, MISO does not recognize pilot efforts); this would be communicated to GRE's energy management system and the Steffes Corporation. The ACE signal would be more volatile than the AGC signal if the devices were enrolled in the MISO market to provide frequency regulation service but, as will be shown later, that will not be a problem for the Steffes GETS system. Currently, between 7 AM and 11 PM, the units are not allowed to charge or provide regulation service.

The advantages of this technology include the following:

1. Balanced and stable electric grid, offering improved reliability
2. Purchases of power when the MISO LMP is low ($20/MWh) during the off-peak time, and avoidance of buying power from MISO when the LMP is high ($45/MWh) during peak periods
3. Economic benefits from aggregating water heater controls responding to frequency regulation and obtaining payment for providing the service

3.2 Installation

The project initially planned to install 10 water heater controls. GRE installed 11 devices, 10 of which currently are operational. The one failure was a home that was struck by lightning, which damaged the control unit. The devices were installed in homes in and around Pelican Rapids, Minnesota.

The installation of the controllers was done by licensed electricians. While the installation work can be quick, complications arose with wiring the Ethernet cable to the control device. This was due to the water heaters typically being located in utility rooms, whereas Wi-Fi routers are found in home offices or living rooms. Making a physical connection between the modem and the controller often meant drilling through floors or finding other ways to route the cables. Having a wireless connection for the Steffes Corporation GETS controller would have made the installation easier and cheaper. Participating consumers generally were happy with the installation, and later queries revealed that they did not notice any difference in the operation of their hot water heaters.

A key lesson learned from the installations was that identifying locations with reliable Internet connectivity was more challenging than originally thought. It is important to note that a high percentage of GRE customers reside in rural parts of Minnesota.

3.3 Operation

Project-Specific Operation

In the systems installed, critical components monitored include the current temperature in the tank; upper, middle, and lower thermocouples; current charge status; and historical consumption in the home. Having temperature information permits a determination of the amount of charging, or heating of water, that still can be provided. The tank temperature is never allowed to exceed 170°F. There was one hot water heater that had an upper limit set-point of only 120°F. With the current charging status and control signal, the charging level can be manipulated and its response verified in near-real time, simulated 4-second data.

Tracking the historical temperature reduction and the time in which the reduction is occurring lets the application determine how much water/kWh is used on a typical weekday or weekend day. Weekend days and weekdays are tracked separately because of their different consumption patterns. This enables a forecast of how much energy can be expected to be put into the hot water heater the following day. GRE may want to offer these resources in the MISO market for regulation. Part of that offer would be providing MISO with the MWs that would be supplied in each hour of the following day. Tracking historical consumption for each water heater allows GRE to determine, with a high degree of certainty, the kWh of regulation that can be provided from the GETS. The application then aggregates these values to provide an energy and capacity value from the DSM and bid frequency regulation, as well as what would be provided to MISO.

Figure 7. Typical Example of a GETS System Integrated with a 105-Gallon Marathon Hot Water Heater, on display at the PJM RTO (courtesy of Steffes Corporation)

A typical example of a GETS system is on display at the PJM headquarters, as shown in **Figure 7**.

3.4 Data Collection

Data are collected via a system developed by Steffes (**Figure 8**).

Figure 8 shows the temperature of the top of the hot water heater in green (note that the temperature reaches a peak at about 170°F), the middle of the hot water heater in red, and the bottom of the hot water heater in blue. The yellow-gold line shows the total cumulative state of charge of the hot water heater. The x-axis time is in Universal Coordinated Time (UTC time), which currently is 6–7 hours ahead of the central time zone applicable in Minnesota (depending on standard or daylight savings time). The graph is a two-day plot, with the blue and gold lines on the bottom corresponding to the simulated ACE signal and the response of the GETS system heating element oscillating around 4 AM to 12 PM UTC or 11 PM to 7 AM central time.

Figure 8. Steffes Data on Temperature, Power, and Energy for an Individual Water Heater

The change in the kW output appears to be close to synchronous and coincident with the ACE signal in the 2.5 hours shown in this graph. Thus, the GETS system will qualify as a fast-response frequency response provider in accordance with FERC Regulation 755 (Frequency Regulation Compensation Organized Wholesale Power Markets). The final FERC Order 755 requires RTOs and ISOs to compensate frequency regulation resources based on the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service provided by a resource when that resource is following the dispatch signal accurately and quickly.

Initially, the plan by GRE and Steffes Corporation was to charge the hot water heaters at a 1.5-KW average heat-up during off-peak periods and swing up to 3 kW or down to 0 kW to respond to an ACE signal. However, as shown in **Figure 8** (the blue line) and **Figure 9**, the Steffes Corporation strategy is to charge using a valley-filling input strategy.

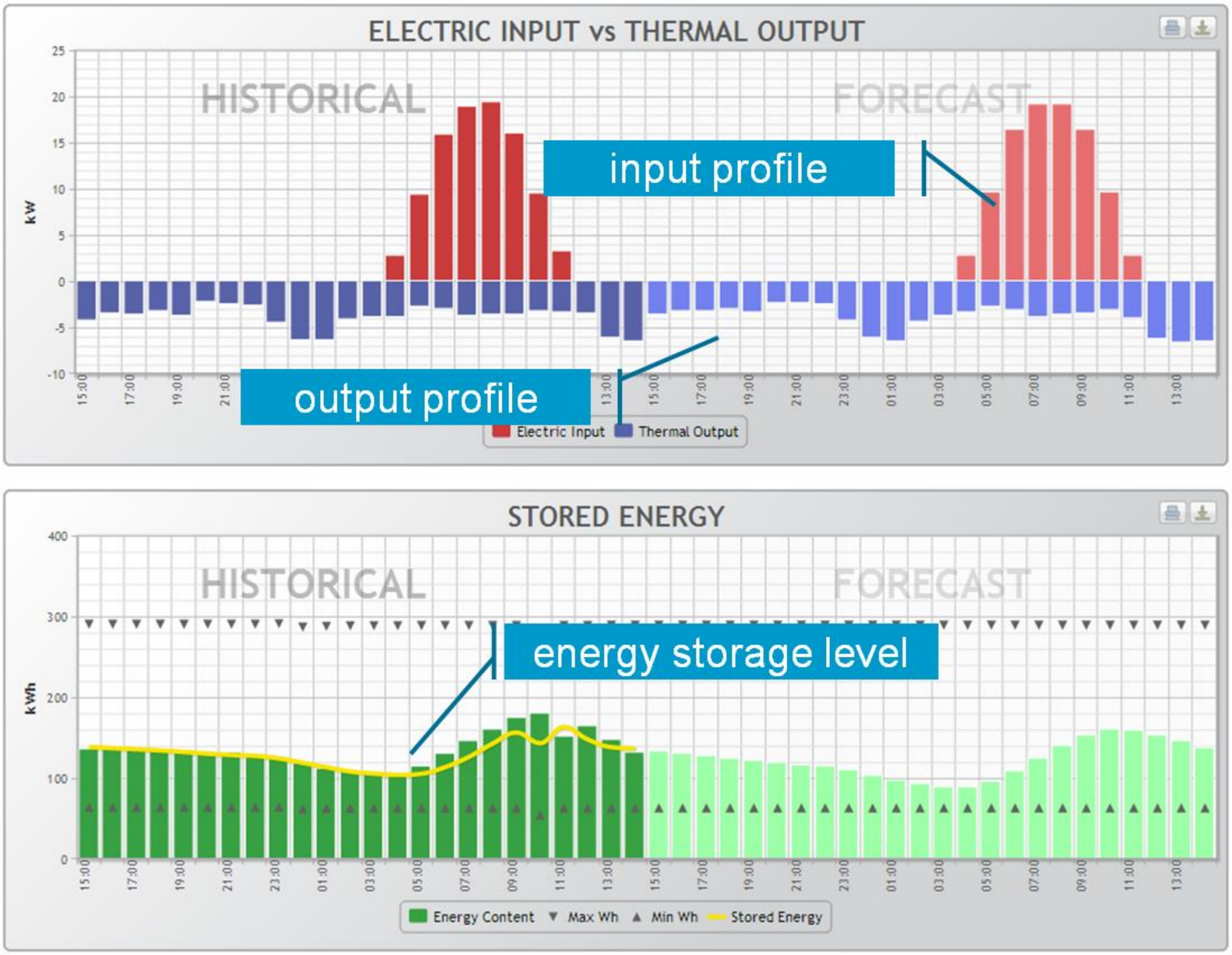

Figure 9. Steffes Corporation Valley-Filling Input Strategy

Steffes uses a valley-filling input strategy while simultaneously doing up and down fast regulation as needed for the aggregated 10 hot water heaters in the demonstration (as shown in **Figure 10**). Basically, the strategy is to begin slowly charging the hot water heater at 11 PM when the loads and the MISO LMP are still high (see **Figure 12** on LMP for MISO—$25/MWh at 11 PM) and then increase the average charge rate to 2 kW or more per hot water heater at 3 AM, when the loads and the LMP are lowest ($20/MWh) (shown as the red bars in Figure 9). This demonstrates valley filling of the off-peak loads and LMP. The average energy output profile is represented by the blue bars in **Figure 9**; the cumulative energy stored as thermal energy is shown in green and by the yellow line in the lower graph.

In **Figure 10**, the response to the simulated ACE signal from GRE is shown over a 2.5-hour time interval for the aggregated group.

In **Figure 10**, the load response from the GETS system is requested by the simulated ACE signal from GRE and plotted with the reported load. The plot occurs over a 2.5-hour time interval and shows near coincidence of the reported load relative to the requested load for frequency regulation.

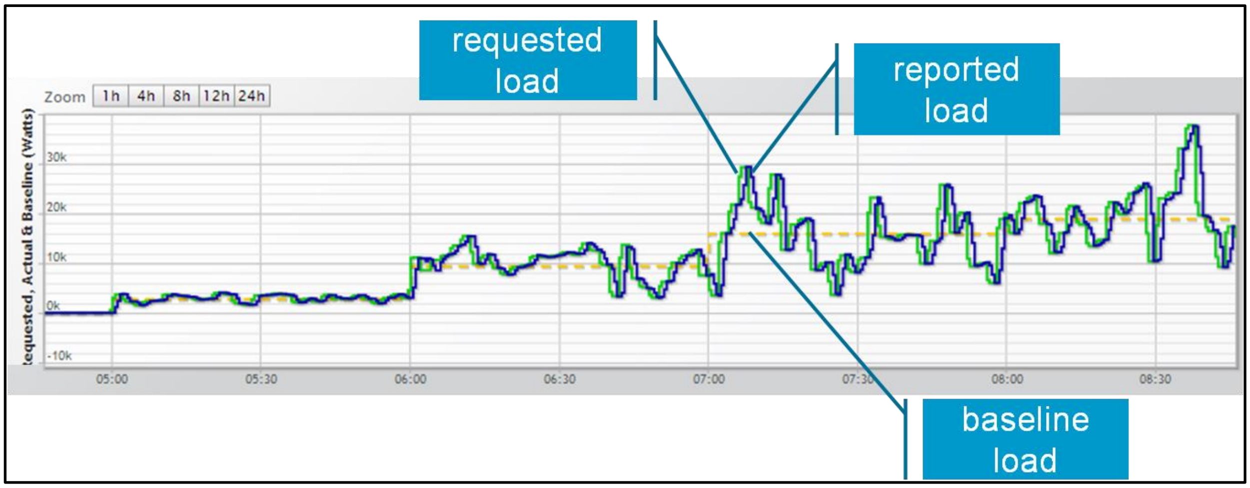

Figure 10. Near Coincidence of Requested vs. Reported Load from GETS System Aggregated Group in Response to Simulated ACE Signals for Frequency Regulation

A more detailed evaluation of the fast response of the GETS to a simulated ACE signal in the current demonstration is shown in **Figure 11**. The load response in the left-hand graph is a function of the current 90-second latency in reporting the results. However, the Steffes Corporation is developing a controller and monitoring system that will reduce the latency to less than 10 seconds, as shown in the right-hand graph in this figure. The latency includes the communications latency back to the Steffes controller and monitoring system, computer analysis, and web site, referred to as the head-end system.

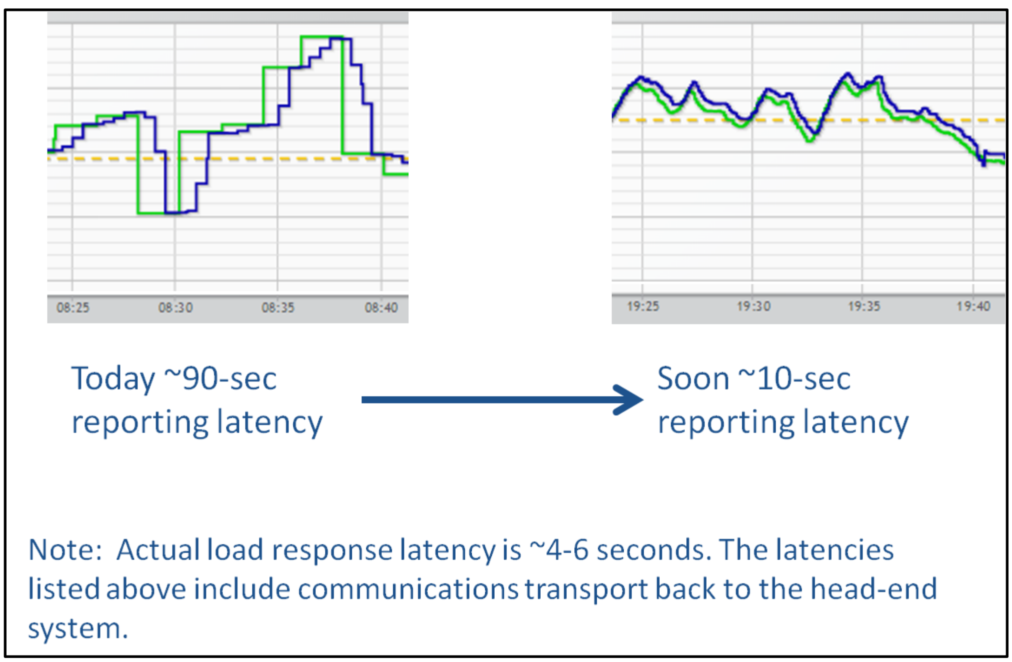

Figure 11. Detailed Steffes GETS System Load Response

3.5 Economic Evaluation

The total cost of the software modifications, project management fees, equipment, and other miscellaneous costs for this demonstration was $111,280. A total of $8,500 of this amount was for the GETS controllers and ancillary components ($850 per site). Future cost per site is estimated to be approximately $375 for the control and mixing valve. The cost of installation and operation still are pending final verification. Three distinct value streams arise from a system of this type:

1. Fast-response frequency regulation per FERC Order 755
2. Energy shifting—from low cost (night) to high cost (day)
3. Demand reduction—a passive method of lowering morning and/or afternoon peaks by eliminating electric water heater usage

Over time, the MISO RMCP may increase to pay for additional fast-response frequency regulation. Conversely, for performance, the PJM RTO is paying a much higher price for fast regulation by paying a Regulation Market Capability Clearing Price (RMCCP) *and* a Regulation Market Performance Clearing Price (RMPCP). In 2013, the MISO RMCP averaged about $8.55/MWh for the year for all of the hours in a day, as noted in **Figure 12**. The line LMP minus RMCP is the effective cost for heating hot water and averages only $10/MWh if the hot water heater utilizes the Steffes Corporation GETS system for providing frequency regulation.

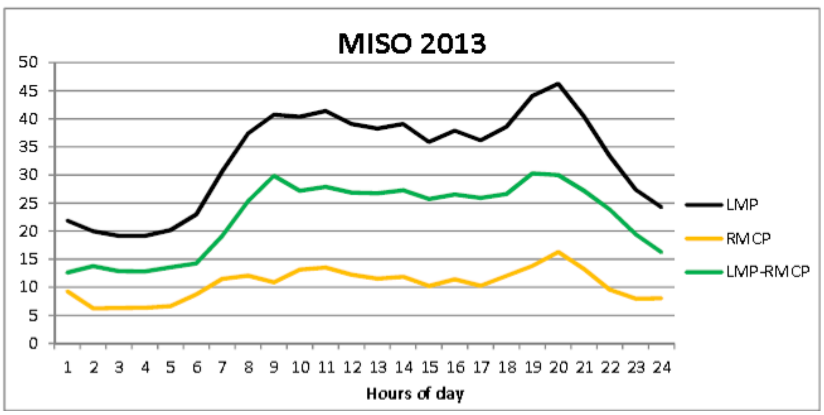

Figure 12. Average Hourly Prices in MISO in 2013 for LMP, RMCP, and LMP minus RMCP

Note: Although the annual average for the MISO RMCP is about $8.55/MWh, the Steffes Corporation GETS system in the demonstration was set to operate only from 11 PM until 7 AM, when the RMCP averaged only about $7/MWh.

Based on the MISO off-peak average price of $7/MWh, the equipment cost of $700 for the Steffes controller for this demonstration,[7] $75 for the mixing valve, $10 for shipping, and approximately $250 for installation (assuming no learning curve), the initial investment is not economical, given the current prices for MISO RMCP and the cost of acquisition and installation of the GETS system. **This assumes that the costs will be avoided for the current DSM**

[7] The Steffes controller currently is not being mass produced.

equipment cost of $85 and installation cost of approximately $200. These are avoided because the GETS system also will provide superior DSM by timing the charge of the hot water heaters to occur during the off-peak periods and valley filling while providing frequency regulation. If the current estimated MISO compensation structure continues into the future, the cost for the GETS system controller may drop to $300 per unit (assuming mass production), and the installation cost of $200 could move down due to a shorter learning curve (which would be possible if the GETS system controller were wireless, thus saving a time-consuming and expensive Ethernet installation). However, the investment in a GETS system still will not be paid back in the MISO (i.e., no payback). It should be noted that at the time of this report, there was still uncertainty regarding MISO's compensation for up and down regulation and mileage payments for fast-response regulation. Higher rates for pay-for-performance compensation in the future will improve the economics.

If it is assumed that the GETS dynamic dispatch provides for valley filling the off-peak charging period, which is valued conservatively at $5/MWh at 11 PM, $2/MWh at 6 AM, and $5/MWh at 7 AM, or $1.5/MWh credit for the full 8 hours of charging, the payback still is only 281 years.

If, in addition to the above cost decreases, there is a reduction in the monthly fee for the head-end aggregation and control services from $3 to $2 a month, the system will pay back the initial investment in about 26 years. If the monthly fee is dropped to $1/month, then the payback is 13 years, or a 4% return on investment.

However, when MISO begins to pay prices similar to the PJM RTO for fast-response frequency regulation service under the requirements for FERC Order 755 as well as a premium for fast-response resources such as the Steffes Corporation GETS system (which currently is being demonstrated on the PJM RTO), the rate of return will be very favorable.

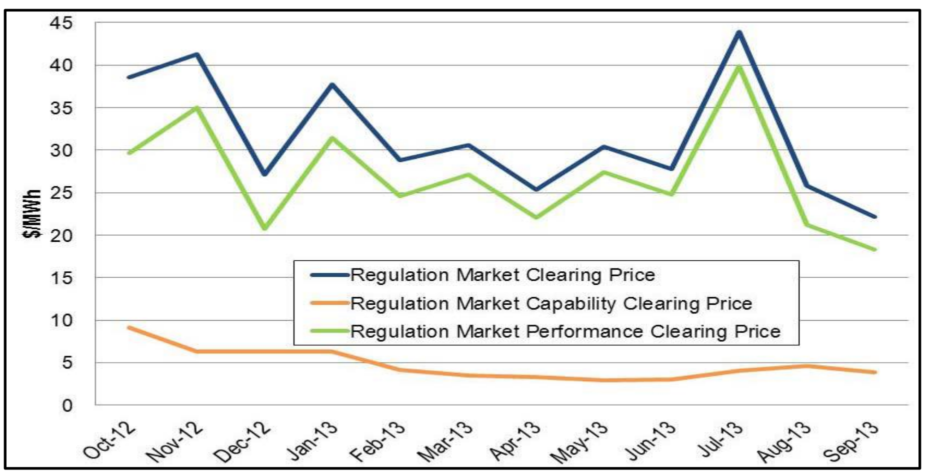

Figure 13. PJM Regulation Market Clearing Price, Oct 2012–September 2013. (Source: Oct 14, 2013 PJM RTO report to FERC on analysis of performance-based regulation for frequency regulation)

In **Figure 13**, the PJM RTO RMCP from October 2012 through September 2013 was about $31.64/MWh for all hours. This was significantly higher than the MISO RMCP of $8.55/MWh. Even the PJM RTO RMCCP of about $30/MWh was significantly higher than the MISO RMCP.

(Note that the PJM RTO RMCP is equal to the RMCCP + RMPCP—the pay-for-performance in accordance with FERC Order 755 for fast-response regulation.) If the MISO market prices for RMCP eventually evolve in the direction of the prices for RMCP in PJM RTO, a future MISO market price for RMCP could eventually be expected to average about $32/ MWh for all hours, and the MISO market price for RMCP to average about $27.75/MWh for the off-peak hours.

Figure 14 provides more detail on the PJM RTO RMCP, RMCCP, and RMPCP as a function of the time-of-day average for the entire year.

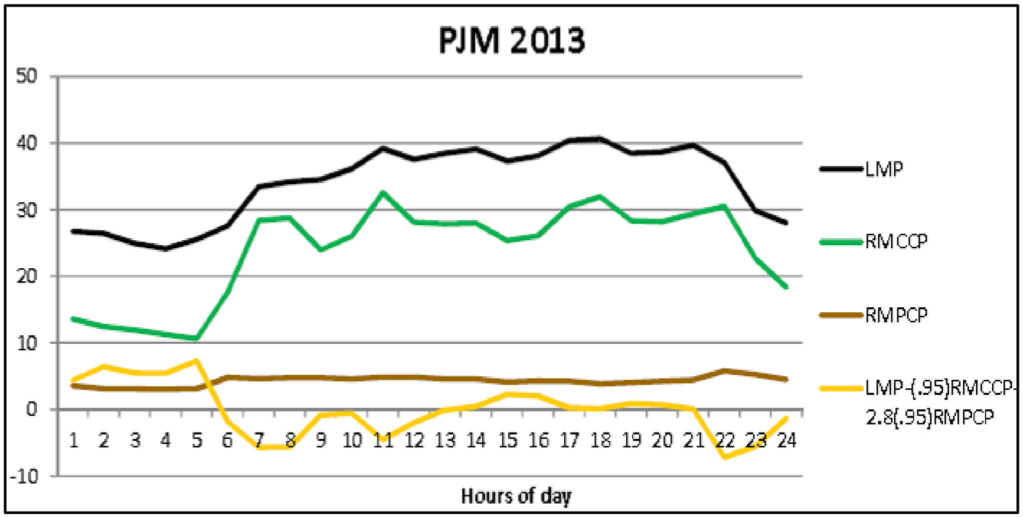

Figure 14. PJM RTO LMP, RMCCP, and RMPCP as a Function of the Time-of-Day Average for FY 2013

The equation and data for Locational Marginal Price developed by Steffes Corporation is LMP = (0.95*RMCCP) - (2.8*0.95*RMPCP), which represents an estimate of the average cost to heat a hot water heater providing frequency regulation. The "mileage factor" of 2.8 is calculated by the Steffes Corporation, which the PJM RTO calculates as a "marginal benefits factor" (discussed in more detail below). Of course, since the Steffes Corporation GETS system was set to operate only during the off-peak hours (11 PM to 7 AM), the average cost to heat the hot water was nearly zero (the yellow line). What is interesting and counterintuitive for the PJM RTO is that, with dynamic dispatch and an algorithm that would predict day-ahead LMP, RMCCP, and RMPCP (with mileage or marginal benefits factors), the lowest-cost time for charging the hot water heaters in the PJM RTO area would be the 3 hours between 6 AM and 9 AM, the 2 hours between 11 AM and 1 PM, and the 3 hours from 9 PM until midnight (for a total of 8 hours of charging throughout the day). Of course, in the case of MISO, the current optimum time for charging the hot water heaters is the 8 hours from 11 PM until 7 AM, as indicated in **Figure 12**. A great benefit of the Steffes GETS system is that it can be set to optimize the economics by weighing the compensation for frequency control against LMP prices and then selecting the combination that provides the best return.

3.6 More Detailed Discussion of Frequency Regulation Markets

In the October 14, 2013 PJM RTO report to FERC on analysis of performance-based regulation for frequency regulation, PJM reported the following: "Consistent with the clearing of the Performance Based Regulation Market, PJM Settlements compensates regulating resources with a capability and performance credit. For the regulation capability credit, PJM identifies each resource that supplied Regulation (both pool-scheduled and self-scheduled) with an hourly performance score greater than or equal to the applicable threshold for minimum hourly performance during an hour. PJM calculates the hourly Regulation Market Capability Clearing Price Credit for each applicable regulating resource by multiplying the individual resource's hourly Regulation megawatts by the Regulation Market Capability Clearing Price (RMCCP), and the resource's actual performance score. PJM calculates the hourly Regulation Market Performance Clearing Price Credit for each applicable regulating resource by multiplying the individual resource's hourly Regulation megawatts by the Regulation Market Performance Clearing Price (RMPCP) for that hour, **a performance multiplier**, and the resource's actual performance score for that hour."

FERC Order 755 refers to the performance multiplier as a "mileage factor" (calculated by Steffes as 2.8), which is multiplied by the RMPCP and added to the RMCCP for a total RMCP average for the year of $31.55/MWh. PJM also evaluated the possibility of over-penetration of fast-response systems for frequency regulation. It noted that the marginal benefits factor (the PJM measure of the mileage factor) is about 2.8, for a 1% penetration of fast-response resources into the total frequency regulation market (which would be about 6–7 MW for PJM and ~7,000 GETS-enabled water heaters). With a 3% penetration of fast-response resources for frequency regulation (about 18–24 MW for the RTO and 24,000 GETS-enabled water heaters), the marginal benefits factor drops to about 2.5. At a 40% penetration of fast-response frequency regulation (about 240–280 MW), the marginal benefits factor would drop to 1.0. Thus, there will be a limited penetration of fast-response frequency regulation; however, this will be after approximately 280,000 GETS-enabled water heaters are installed. It should be noted that even with a marginal benefits factor of 1.0, fast-response frequency regulation technology (such as the GETS system) still may be able to provide an adequate return on investment with a reduced RMCP price under the PJM system.

When the Steffes GETS system charges during the off-peak hours, 2.8 times the RMPCP yields about $13/MWh; the RMCCP of $14.75/MWh yields the off-peak RMCP for the PJM RTO of $27.75/MWh.

3.7 Summary of the Economic Evaluation

If MISO prices for fast-response frequency regulation during the off-peak periods rise to the levels of the PJM RTO of $27.75/MWh plus $1.50/MWh for valley filling, or $29.25/MWh, the payback for a full-priced GETS would be 8 years, or a very respectable 11% return on investment. With a lower-cost GETS system, the payback would be 4 years. It should be noted that at the time of this project and report, natural gas costs were between $2.25–$2.75 MMBtu in MISO and PJM RTO—averages near a 10-year low. The low cost of natural gas has driven down the cost of regulation for MISO, and hence the RMCP. Of course, this winter, the prices rose to $4.5/MBtu and, during the polar vortex, prices as high as $28/MBtu occurred in the PJM RTO for a few hours.

4. Conclusions

4.1 Effectiveness of Battery Energy Storage in Meeting Utility Needs

- This is a new commercial technology that presents a significant learning curve for both the manufacturer and the co-op. Presumably this learning curve will result in reduced "real" installation costs upon large-scale replication.
- At the present cost of equipment, both the 4.6 kW and the 9.2 kW systems have a negative net benefit.
- With present lead acid battery technology, accurate but limited use of the cycle life of the unit would be required to ensure that the battery would meet lifetime expectations. Such use would necessitate the ability to predict, as accurately as possible, the exact hour that the peak would occur for each month. This study did not evaluate Lithium-ion batteries. We feel that these batteries would meet performance requirements, but their cost currently is higher. This study attempted to see whether a utility could achieve the desired results using lower-cost sealed lead acid batteries. Our conclusion is that these batteries did not meet our standards. We expect that Lithium-ion batteries would perform better, although they would drive up the cost. During our research, we found Sunverge Energy, a company in Stockton, California, that is manufacturing utility-controlled battery storage units using Lithium-ion technology.
- The "certainty" of battery dispatch as a demand response solution has value for the co-ops, as opposed to more probabilistic methods, such as hot water or air conditioner load control.
- Initially, MVEC and WHCEA are looking for potential battery applications for small businesses and members with medical needs, where the advantages of continuous back-up power has a large benefit that can help offset the physical costs of the unit. As the cost comes down, we can look for more widespread applications. These would cover the power blinks (which cannot be managed by back-up diesel generators) and short-term (0−3 hours) outages for those customers that presently have no back-up power.
- Battery storage, when integrated with solar PV, can provide grid resiliency, which currently is not monetized. ("Grid resiliency" means operation of the solar PV when the grid has an outage by providing voltage and a frequency signal to the inverters that keep the solar PV on line and also ensuring that the batteries will be available to store solar PV for night-time loads during extended outages.)
- With significant increases in battery cycle life, additional applications, such as reduced loads on radial feeders, reducing peak loads on transformer banks, "soaking up excess renewable energy," or other economic dispatch applications, may become more feasible.
- The battery storage market is evolving quickly, especially as more solar energy is being dispatched into the electric distribution grids across the U.S. Utilities and regulatory agencies are implementing storage requirements after the fact, which is costly. The information gathered in this analysis will help others to understand the present economics and operating challenges. In addition, it is anticipated that other revenue streams or benefits will drive the battery storage industry, just as others have been discovered by adopting automated metering infrastructure (AMI) systems and system control and data acquisition (SCADA) systems. Many electric cooperatives and investor-owned utilities (IOUs) also wrestled with economic justification issues in the early stages of AMI and SCADA implementation, but these now have been implemented in a majority of cooperatives and IOUs.

4.2 Effectiveness and Benefits of Thermal Storage in Meeting Utility Needs

- As with battery storage, this is a new commercial technology that presents a significant learning curve for both the manufacturer and the co-op. Presumably, this learning curve will result in reduced "real" installation costs upon large-scale replication.
- Thermal energy storage has the ability to provide firm DSM during the most attractive and economical peak hours and fast-response frequency regulation during the off-peak hours.
- Current MISO market payments for regulation and high introductory costs of the Steffes GETS system have not provided a reasonable payback to GRE for frequency response. Scaled future production of the GETS system will reduce product costs substantially. Along with increased value for regulation services, this could provide a reasonable return for GRE and co-ops in the MISO footprint.
- GRE could have a rate of return >100% if (1) MISO frequency regulation market payments for fast-frequency regulation increase to prices similar to those paid by the PJM RTO, and (2) the Steffes Corporation reduces the price for its GETS system and installation as predicted.
- With the increased cost of natural gas, the price paid for RMCP will increase, making even more attractive those fast-responding products that can provide regulation services.
- GETS systems provide a very high round-trip efficiency (>95%).
- Hundreds of thousands of cycles and 10+ years of service could be received from GETS-enabled water heaters, even with DOD of >80%.
- Thermal systems are consumer friendly and safe, and there is no added cost for insurance or other similar factors.
- Steffes GETS systems have built-in kWh metering. This can eliminate the need for co-ops to add costly secondary services and metering into homes while still achieving all the economic benefits of demand reduction, LMP optimization, and frequency control.
- Comfort assurance features, if enabled, ensures hot water for the homeowner at all times. The GETS system monitors hot water heater temperatures and, only when needed, it will enable a temporary override to provide continuous hot water to a specific homeowner. Co-ops with traditional load management controls often will enable a permanent mid-day "bump" or recharge period, which then consumes higher-cost energy for a significant amount of its annual hot water heating requirements.
- Based on economics, an option for designating a block of time during the day can be used, during which a regulation signal can be provided to GETS and other water heaters that need it to allow limited recharging while also providing fast regulation services.
- The Steffes GETS system, along with its head-end aggregation control, provides great visibility and granularity, thus allowing co-ops to regroup endpoint control to better manage loading of substations and feeders. This can delay or eliminate the need for costly upgrades.
- The GETS communication system provides a complete and separate control system, and serves as an alternative to the aging and existing load management control system.
- The GETS system is a very flexible power management and storage resource. While GRE chose to limit the window for regulation from 11 PM–7 AM, the system has the ability to maximize benefit by selecting the best hours on a day-by-day or hour-by-hour basis.

4.3 Overall Assessment of the Storage Demonstration

- A well-designed thermal energy storage program can be used by utilities to shift their peak load while maintaining or even increasing energy sales, and potentially provide very valuable fast-response frequency regulation service. It is a technology that can benefit both the utility and the consumer.
- Cyber security issues have not been addressed for either the SP or the Steffes Corporation GETS systems. Both of these systems leverage and require existing broadband communications through the Internet.
- During the demonstration, there was a power quality issue with the operation of the GETS controller, and a probably minor issue with the SP advanced lead acid battery. At first, when there was an interruption in electric service to the home, the Internet modems had to be rebooted manually when service was restored. This initially was a problem, but it did not become an ongoing issue. Clearly, a robust Internet modem needs to be installed that reboots itself in the event of an interruption in electric service. An economic model to evaluate the GETS system via a simple Excel spreadsheet has been developed and is available from NRECA CRN upon request.

5. Recommendation for Further Study

As this project is ongoing, further data will be compiled, and additional studies of that data are recommended. Another "behind-the-meter" demonstration for residential and commercial energy storage could be developed when advanced battery energy systems are developed that (1) are 30–50% lower in cost than the current SP systems for 2 hours of storage, (2) have cycle lifetimes longer than 1,000 cycles for 80% DOD, and (3) do not show significant loss of capacity over time and use. A new demonstration would focus on peak shaving and demand charge reduction, firming up and managing the intermittency of distributed solar PV and providing grid resiliency, spinning reserve, and back-up power. Although the lowest-cost fast-acting energy storage today is the GETS system, this cost must be reduced further through manufacturing; at the same time, a wireless connection needs to be developed for the GETS controller that will make installation easier and less costly. Research into cost reduction mechanisms will be important for obtaining the full range of value from a GETS system.

Acknowledgments

We are grateful for the input from the following: Ryan Hentges – MVEC; Rod Nikula and Steve Nesbit – Wright-Hennepin; Chris Gallaway – Federated; Eddie Webster and Gary Connett – GRE; Doug Vermillion – Silent Power; Kelly Murphy, Paul Steffes, A. Takle, and A. Zeller – the Steffes Corporation; and DOE.