Costs and Benefits of Conservation Voltage Reduction

CVR Warrants Careful Examination

INITIAL FINDINGS | NOVEMBER 15 2013

NRECA
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NRECA-DOE SMART GRID DEMONSTRATION PROJECT | DE-OE0000222

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CVR Warrants Careful Examination

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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.

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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 involves 23 electric cooperatives in 11 states. For purposes of evaluation, the technologies deployed have been classified into three major sub-classes, each consisting of four technology types, the status of which have been reported in the Interim Technology Report of April 2013:

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 initial report on one of those topics, based upon the progress of the activity to date. The project team will be monitoring the progress of the various cooperative activities during the remaining term of the demonstration to close identified information gaps and identify additional information that will be of benefit to the merit evaluation. This document and the other single-topic studies then will be updated, as appropriate, for consideration in the final Technology Performance Report at the close of the Smart Grid Demonstration Project.

ACKNOWLEDGMENTS

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- James Bridges, VP of Engineering, Owen Electric Cooperative
- Robert Emgarten, Manager of Engineering, Iowa Lakes Electric Cooperative
- Jason Fuller, Senior Research Engineer, Pacific Northwest National Laboratory
- Gerald Schmitz, Electrical Engineer, Adams-Columbia Electric Cooperative

ABSTRACT

This report investigates the deployment experience at four rural electrical cooperative utilities of conservation voltage reduction (CVR) technology. Data from these field studies are used in the development and calibration of a hybrid powerflow-economic model. We derive a cost-benefit analysis methodology for conservation voltage reduction from this model and validate it against field data.

EXECUTIVE SUMMARY OF RESULTS

Volt/VAR optimization (VVO) via power factor correction was preferred strongly to CVR via active voltage regulation. CVR schemes were primarily SCADA actuated but were initiated by human operators. Simple paybacks for these projects were generally in the 0–2 year range.

Model data are not always detailed enough for time series powerflow. Model results were not informative if the underlying data that inform the model were lacking. Heuristics based on historical CVR factors, single point-in-time voltage drop, and annual energy use estimates can be used for estimates of CVR effectiveness. Calibration of dynamic load models is still a manual and labor-intensive process.

Many schemes are in common use for verifying CVR results. A central problem is how we pair control and CVR-influenced data. Use of correlated feeders is a faster and clearer method than alternate day comparison with weather correction.

RESEARCH QUESTIONS

- Field Trials:
  - In the co-ops that installed hardware, what were the expected and realized benefits?
  - What are the planning requirements for a successful CVR deployment?
  - What are best practices and common “gotchas” across all deployments?
  - What is the best method for verifying results?
  - How do energy savings and demand savings impact revenue for the co-op and its members?
  - What feeder characteristics are correlated with benefits?
- Model Extensions:
  - How can the CVR algorithm be tuned to a tradeoff between costs and benefits?
  - How much engineering design (e.g., capacitor sizing and siting) can be automated?
  - Are model results comparable to human-led planning studies?

TECHNOLOGY DESCRIPTION

The key principle of CVR operation is that the ANSI standard voltage band between 114 and 126 volts can be compressed via regulation to the lower half (114–120) instead of the upper half (120–126), producing considerable energy savings at low cost and without harm to consumer appliances. Decades of field research have found that for each 1% reduction in distribution service voltage, mean energy consumption for residential and commercial loads is reduced by 0.8%. Furthermore, these energy savings can be highly economical to capture. Variation in results depends on load mix and distribution system configuration.

As an illustrative example, one of the earliest CVR pilot projects was done in 1987 by Snohomish PUD, which concluded that, across three test substations, a levelized 2.1% voltage reduction was achievable, as well as reduced energy requirements by approximately the same amount. System loss effects of voltage reduction were favorable, with the bulk of the reduction resulting from an improvement in distribution transformer efficiency. Customer bills, after a rate adjustment to accommodate fixed operations costs, were approximately $6.28 lower per customer per year. These savings were available at a cost of $0.008/kWh for additional line drop compensator and capacitor application.

"CVR factor" is the term commonly used to refer to the ratio between voltage reduction and energy load consumption for a particular part of a distribution system (load, feeder, substation, or utility):

$$F_{CVR} = \frac{\Delta E}{\Delta V}$$

Factors vary widely from substation to substation, feeder to feeder, and especially load to load. Contributions to the overall factor for a utility include consumers' load mix, transformer and conductor characteristics, voltage control schemes as moderated by voltage regulators, line drop compensators, and switched capacitor banks. Because of the large number of components involved, CVR factors for feeders and substations typically are measured experimentally, not theoretically generated. An excellent overview of measured feeder CVR factors is included in DSTAR's evaluation of CVR [18].

Progress is being made in calculating CVR factors theoretically, with an eye toward predicting control scheme performance before installation. In this report, we investigate heuristic and load model-based approaches.

Load behavior is a large contributor to feeder CVR factor. Many load modeling studies have been completed; a good recent study is the 2010 report by the Pacific Northwest National Laboratory (PNNL), which evaluated CVR on a national level and built models that divided loads into two primary classes: those with and without thermal cycles. In the first category, lighting loads, for example, will consume energy as a function of voltage when on. In the second category, loads with thermal cycles, such as a hot water heater, will vary their duty cycles depending on the supply voltage. Moreover, inside each of these classes, loads' response can be described by their ratio of constant power, impedance and current characteristics—ZIP models. ZIP models can be constructed from experimental results on load behavior under changing voltage conditions.

Key goals of conservation voltage reduction are peak power demand reduction and energy conservation. These benefits are available at different prices, depending on the distribution system; in general, however, CVR is seen as very cost-effective. In a planning study performed by the Bonneville Power Administration (BPA) across 150 utilities in its service area, BPA found 170 to 268 MWh of energy conservation opportunity (and hence generation capacity increase deferment) priced at between 0.01 and 5 cents/kWh [3].

Feeder characteristics that correlate with CVR are of interest for planning purposes and are addressed later in this report. BPA's findings in the study cited above were that short feeders with large numbers of customers were the most economical to use when applying CVR techniques; however, later studies have challenged this result [5].

Hardware choices for improved volt/VAR optimization boil down to capacitor banks, voltage regulators, and improved measurement and control systems. Other upgrades to the distribution system that improve the voltage profile—such as reconductoring, load balancing, and transformer upgrades—also can be helpful, in combination with the more technically sophisticated approaches mentioned above. Existing research on the effectiveness of these various methods has singled out the cost effectiveness of improved VAR support and better voltage regulation schemes; reconductoring and adding completely new regulators is more expensive.

FIELD DEPLOYMENTS

Four cooperatives completed volt/VAR optimization projects. Descriptions of the deployments follow.

Adams-Columbia Electric Cooperative

Motivation

Adams-Columbia Electric Cooperative (ACEC) is a utility serving 36,000 members around Friendship, Wisconsin. The cooperative's main goal in implementing CVR was to reduce monthly coincident peak demand charges from its power supplier, Alliant Energy. ACEC also sought to improve system power factor and voltage profile.

Installation Description

ACEC installed 30 voltage monitoring sites, along with 10 distribution regulators. The CVR activity included installation of 10 capacitor banks with controller and 40 Varentec solid state variable capacitors. Capacitor banks allow for a flattening of the system voltage profile, improving the abilities of substation regulators to perform conservation voltage reduction. The CVR control algorithm currently is triggered manually by employees when they deem the system's peak will coincide with a power supplier peak. A regulation activity, when triggered, reduces substation voltage for 4–5 hours and then restores the original voltage level.

The Varentec devices are transformer-mounted edge-of-network devices, described by the vendor as "voltage optimizers." The devices each include 10 kVAR switched capacitor banks, monitoring sensors, and cellular modems. Although quite expensive per kVAR when compared to traditional switched capacitor banks, the devices offer more advanced controls, the possibility of more precise sizing and location, and monitoring functionality. This hardware deployment also was motivated by the cooperative's desire to study and pilot a unique and cutting-edge technology.

Total hardware and software costs for this project were $176,000.

Planning Experience

ACEC contracted with a third-party engineering firm, Power Systems Engineering (PSE), to perform a planning study to determine the suitability of each of its feeders for CVR. Each feeder was modeled using Milsoft's Windmil engineering analysis software, and recommendations of estimated potential one-year savings for each feeder were generated. Approximately half of the studied feeders were found to have 0- to 2-year estimated simple paybacks for project hardware, based on lower peak demand charges.

Deployment Status

ACEC's Varentec hardware is fully installed and operational, but data collection is on hold pending a firmware upgrade to fix a communications issue, in which the devices would not join the correct cellular data network. ACEC so far has seen a 10% failure rate for these devices.

The substation regulators for the more traditional CVR implementation have been installed, and the radio for end-of-line voltage measurement was deployed, but the supervisory control and data acquisition (SCADA) control algorithm had not been implemented as of September 17, 2013. The capacitor controls also need some additional work.

Deployment Lessons Learned

ACEC was concerned that cap banks would block AMI signals on its power line carrier system by sending signals to ground. To avoid this problem, the cooperative used line-to-ground capacitors, with blockers installed on the neutral phase, to maintain signal integrity. No signal degradation has been found so far.

Installation problems comprised typical administrative, legal, and construction issues, and were not specific to the smart grid technology being installed. Weather head additions to coax cable termination resulted in damage to low-density foam (LDF) cables, which needed replacement. For a communications upgrade, ACEC proposed building a 70-foot steel pole on land owned by another utility. Obtaining easement proved to be a multi-month process; to stay on schedule, the tower instead was deployed on a farmer's land, resulting in additional site engineering.

Realized Benefits

ACEC did a session-initiation protocol (SIP) programming test on a regulator substation, lowering voltage and achieving a resultant load reduction. However, this is too small a sample to come to any conclusions at this point. Full verification methodology and data are described later in this study.

Owen Electric Cooperative

Motivation

Owen Electric Cooperative (OEC) is a utility serving approximately 58,000 consumer-members around Owenton, Kentucky. The purpose of the project is to gain enhanced knowledge of the effects of optimizing OEC's system voltage and kVAR profiles with respect to peak electrical demand and energy usage.

Installation Description

Substations that serve Owen Electric Cooperative are configured for bus regulation. OEC currently requires its power provider, Eastern Kentucky Power Cooperative (EKPC), to set the bus voltage regulators to 125 volts +/- 1 volt (referenced to 120 volts). Line voltage regulators (VRs) are used on the OEC distribution system to support the system voltage. VRs typically are set to 125 volts +/- 1 volt (referenced to 120 volts) and can raise and lower line voltage levels up to 10%. (The 125-volt setting can allow up to an 8-volt drop on the system past the VR.) Voltage-level adjustments of less than a volt are typical of VRs. Auto-booster transformers (ABs) also are used for voltage support when tight voltage bandwidths are not necessary. Auto-booster transformers have less capability than line voltage regulators to react to and compensate for voltage fluctuations. ABs typically are set to 125 volts, with a 4-volt bandwidth. Typical voltage-level adjustments are 1.5 volts. Since ABs are limited in their ability to maintain tight voltage bandwidths, they were not recommended for this project.

EKPC currently requires its member cooperatives to maintain a power factor of 90% (lagging) or better at the distribution station transformer level. EKPC assesses financial penalties monthly when the power factor falls below this level. EKPC does not assess penalties for leading power factor. To maintain power factor levels at or above 90% lagging, OEC historically has utilized fixed capacitor banks. These capacitor banks have been furnished by EKPC to its member cooperatives as an incentive to maintain compliant power factor. Typical fixed capacitor banks are sized at 300 and 600 kVAR.

To improve voltage regulation and power factor, OEC's Advanced volt/VAR Control activity is being implemented in phases at two substations:

- **Phase 1:** Verify and correct system data so that the engineering model is accurate in all critical areas.
- **Phase 2:** Analyze and optimize feeders for phase balancing and power factor.
- **Phase 3:** If voltage optimization is possible, test and evaluate the effects of reducing voltages on the feeders.
- **Phase 4:** If cost beneficial, deploy an Integrated Volt/VAR Control (IVVC) system at one or both test substations.
- **Phase 5:** Conduct data collection and verification.

Deployment Status

OEC is in Phase 3 of its four-phase project. This measurement phase will indicate whether regulation changes are possible and if they are valuable to consumer-members. OEC is in the process of changing its system design to use alternate voltage monitors. The original equipment had functional problems and was returned to the manufacturer.

Iowa Lakes Electric Cooperative

Motivation

Iowa Lakes Electric Cooperative (ILEC) is a utility serving 12,289 customers around Estherville, Iowa. ILEC's primary goals for conservation voltage reduction were to reduce demand charges from power suppliers and improve power factor.

Installation Description

Four substations (Gar, Range, Miles Nelsen, and Milford) were set up for 2.5% or 3-volt reduction at monthly coincident peak times. The three voltage regulator panels at each substation are controlled and monitored through the SCADA system. The 2011 summer demands on these substations were 5,900 KW at Gar sub; 2,228 KW at Milford sub; 1,290 KW at Range sub; and 2,208 KW at Miles Nelsen sub. At the project planning stage, it was projected that a 2.5% drop in voltage would yield a 2% drop in the current KW demand on the substation, based on historical results of comparable CVR installations. The planning was restricted to residential substations.

KVAR capacitor bank controls also were deployed in two substations (Rembrandt and Gilmore City) that historically had power factor averaging around 70%. These were improved with a 150-kVAR bank at Gilmore City substation and a 1,200-kVAR bank at Rembrandt substation. These kVAR capacitor banks reduced the overall KVA demand on each substation transformer and improved the voltage levels, reaching a target power factor of 85%. Each of these units has a controller that can energize the bank either by time or voltage levels, and current operation is based on a time-of-day schedule.

Two municipal utilities (Pocahontas and Estherville) are a part of ILEC's sale-for-resale accounts, and each wanted to reduce its monthly coincident demand. Each needed to be able to monitor its demand as it compares to the wholesale power supplier and enable the control of its monthly demand at coincident billing peaks. The project included communication equipment at each municipal substation to allow real-time load demand monitoring at city hall and also required communication at each substation to enable control of load management devices. Due to the municipal utilities' lack of approval to go ahead with the project, this effort was cancelled.

Planning Experience

Planning at this cooperative was conducted by Bob Emgarten. Prior experience in deploying CVR controls at four Minnesota cooperatives led Mr. Emgarten to investigate CVR as a demand management technique for ILEC. Design parameters and hardware choices from this experience informed the demonstration project planning, including the deployment of CVR controls at main residential substations, with monitoring and control via SCADA.

Existing substation voltage regulator panels had active voltage control capabilities, which led to significant cost savings over turnkey CVR solutions. The main substation expense came from modifying the SCADA display to include control signals for the voltage regulators.

Deployment Status

The hardware is deployed and functioning correctly in the field. CVR operation was started under SCADA control on January 1, 2012.

Verification and Realized Benefits

ILEC does not have a requirement to keep a historical database of SCADA readings. Because of this constraint, the verification procedures described in the Verification section of this report were not applied to this project.

The original CVR plan called for a 5% instead of a 2.5% voltage reduction. ILEC has implemented a smaller voltage reduction thus far to guard against power quality issues. Further voltage reduction can be implemented in the SCADA system if there are no problems with the current program.

Voltage reduction has been verified via a SCADA display upgrade, and a matching load reduction is observable. In **Figure 1**, Gar substation voltage reduction, note the voltage and load reductions. The top graph shows voltage level, with scheduled reduction at 2 p.m. The bottom graph shows KW demand. The load spikes are from a demand response program operated by the power producer, not a product of the CVR regulation.

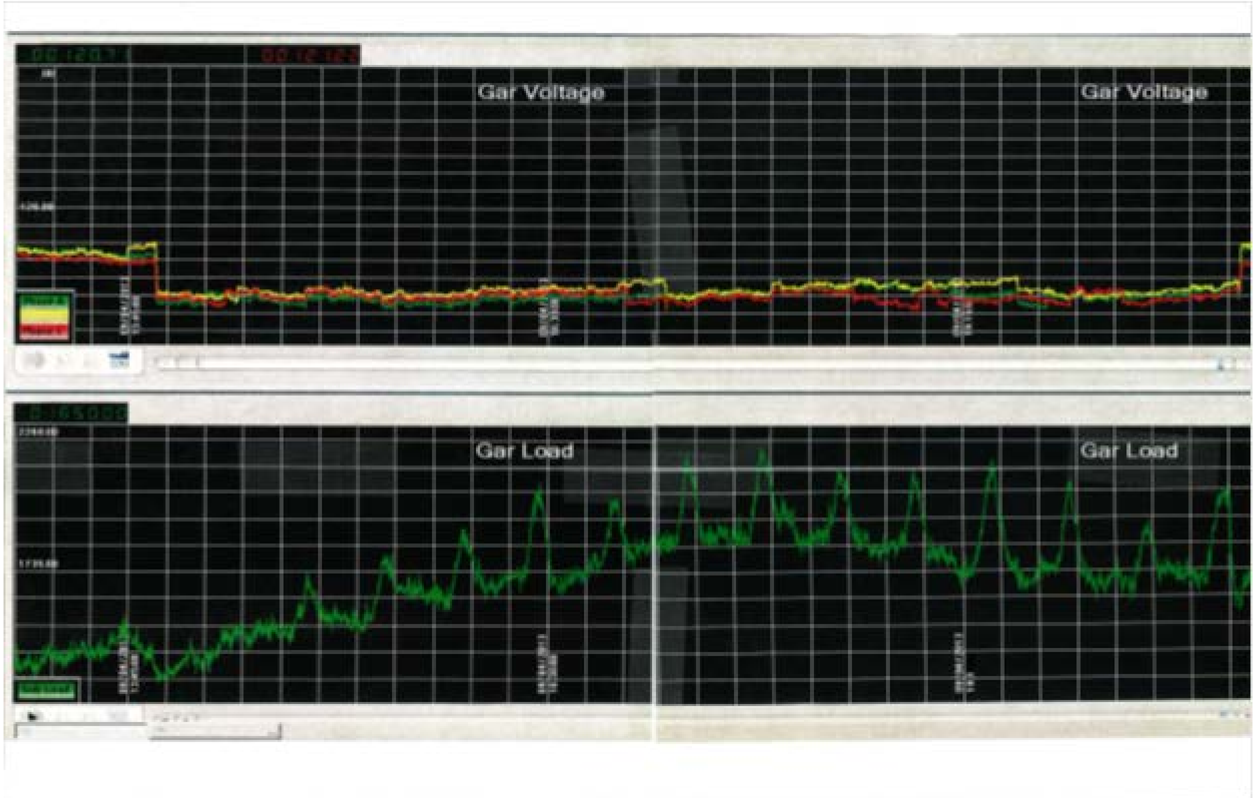

Figure 1. Gar Substation Voltage Reduction

VERIFICATION

Verification of the benefits of volt/VAR optimization is a difficult problem. Load changes occur for many reasons and are hard to separate from the changes to the powerflow due to volt/VAR optimization. There are two verification approaches commonly described in the literature: comparison of strongly correlated feeders (correlated feeder method) and comparison of one feeder across time with weather correction (alternate day method). The alternate day method typically is practiced by applying the CVR scheme on alternate days to factor out seasonal load changes [5].

We base our verification scheme on testing across correlated feeders. There are some key advantages to this approach. The pairing algorithm is uniquely defined and simple to implement. Weather and day-of-week load correction is not necessary because the pairs of SCADA measurements under comparison are taken at the same time. This method also has operational benefits, since feeder regulation schemes do not need to be changed frequently, as is the case in the single-feeder verification methods cited in the literature. With ACEC, we found that, for each of the features for which CVR was implemented, there were multiple other feeders in the system whose load behavior was strongly correlated (R^2 > 0.9), which we could use as controls.

In cases for which, due to the system design, highly correlated feeders do not exist, we propose an alternate day treatment verification protocol.

The full source code for our verification scheme is available in Appendix A, along with interspersed example data from ACEC. As of November 15, 2013, the CVR installations were all complete, but data collection had just begun. To accurately evaluate CVR, a year’s worth of

SCADA data is required to capture the effects of seasonal Heating, Ventilation, and Air Conditioning (HVAC) loads. We foresee collecting and running these data through our analysis code in late 2014.

A dataflow diagram for the verification procedure is shown in **Figure 2**. From a set of SCADA data for the target feeder substations (typically provided as tab-separated value flat files), we derive a standard form (meter ID, timestamp, power, voltage, power factor); produce a correlation matrix for each pair of feeders based on a subset of the data as a control; select the most strongly correlated feeder for each treated CVR feeder; and then measure the relevant quantities ($\Delta E, \Delta Demand, F_{CVR}$) from these pairs.

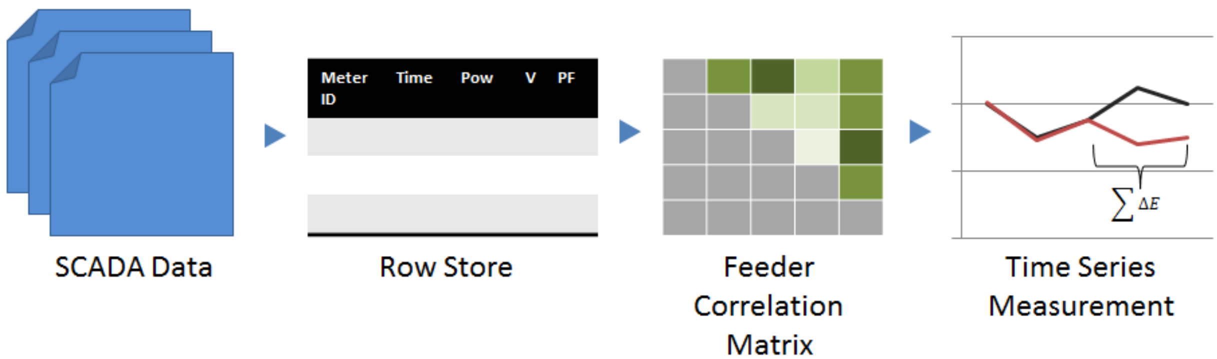

Figure 2. Verification Procedure Dataflow

Future work to compare the sensitivity and specificity of the correlated feeder method with that of the alternate day method would be beneficial in determining the ideal verification protocol. To do so via a dynamic powerflow model would be straightforward. To test in the field would require disaggregated, high-resolution (hourly) load data from AMI. For the systems studied in this report, load data at this resolution were not available, due to communications network limitations (ILEC) or because meter data management software was not yet available (ACEC).

We also foresee AMI data as having some importance in CVR verification, although clearly this is not a requirement, as proven by these study cooperatives' success and the history of the technology. There is some demand for AMI data in exception reporting for meters out of the ANSI voltage limits as an indicator of power quality issues.

MODELING CVR POWER SYSTEM BEHAVIOR

In this section, we derive computational model-based results for the CVR behavior on the studied systems. We model at three distinct levels of load detail and compare the results. Models are built at the level of the feeder due to the feeder-by-feeder planning and investment decision process used by the study participants and volt/VAR optimization projects in general.

The key problem that any computational model of CVR must solve is powerflow. Given a description of the hardware on the feeders (lines, transformers, capacitor banks, etc.) and a description of the loads on the system, we must solve for the total power consumption across all of the loads and power dissipated in the distribution system (losses). Changing the operating conditions (source voltage) to reflect the behavior of the CVR hardware allows us to judge those systems' efficacy. Aggregating the powerflow results over time gives us total energy delivered and lost and peak demand, which are the key variables of interest for economic analysis.

We rely on the National Rural Electric Cooperative Association's (NRECA's) Open Modeling Framework (OMF, accessible at http://omf.coop/) to perform our analysis. The OMF is an open source framework for performing analysis with models of the electrical grid. Faced with numerous models created by the research community, vendors, and utilities, the OMF provides a structure for running, comparing, reporting on, and monetizing the results. This is managed via a web interface, enabling collaboration and sharing of the results.

The OMF incorporates GridLAB-D, a state-of-the-art feeder simulator developed by PNNL and released to the public as open source software. The OMF relies on GridLAB-D to perform powerflow calculations and as a means to describe controls schemes and load-weather interactions.

At its core, GridLAB-D has an advanced algorithm to simultaneously determine the state of millions of independent devices, each described by models and equations relevant to the particular domain. GridLAB-D does not require the use of reduced-order models to describe the aggregate behavior of the system (but may do so when appropriate). Rather, it relies on advanced physical models to describe the interdependencies of each of the devices. This helps to avert the danger of erroneous or misapplied assumptions. The advantages of this algorithm over traditional, finite difference-based simulators are that (1) it handles unusual situations much more accurately; (2) it handles widely disparate time scales, ranging from sub-seconds to many years; and (3) it is very easy to integrate with new models and third-party systems. This unique approach to power-system modeling has enabled industry, utilities, and others to use the tool to evaluate new distribution-automation designs (e.g., VVO, feeder reconfiguration, fault-detection identification and restoration); new rate structures in concert with new smart technologies (e.g., real-time pricing and automated controls, direct load control); optimization of distributed-energy resource usage (e.g., maximizing the value of battery storage for peak-load shaving, arbitrage, and regulation); benefits and effects of new technologies (e.g., voltage control issues with high penetration of photovoltaics); and a number of other studies designed to maximize the potential of new technologies.

All of the system models in this study were translated into OMF standard format from Milsoft Utility Solutions' Windmil software system. Among the 23 co-ops that participated in NRECA's Smart Grid Demonstration Project, 80% had Windmil models of their entire system. Milsoft reports an 80%–90% market share among electric distribution cooperatives.

Static Peak and Mean Powerflow Method

Of the three methods we consider, the one that is computationally simplest, fastest to evaluate, and the current standard for planning studies in the cooperatives reviewed is a static monthly peak and mean powerflow calculation.

As described above, we bring study feeder distribution hardware descriptions into the OMF from Windmil. Each base feeder then is duplicated, and the duplicate is modified using the OMF GUI to include any capacitor banks, line drop compensators, or other circuit elements installed as part of the project that would impact system losses or loads. An example of this editing process is shown in **Figure 3**.

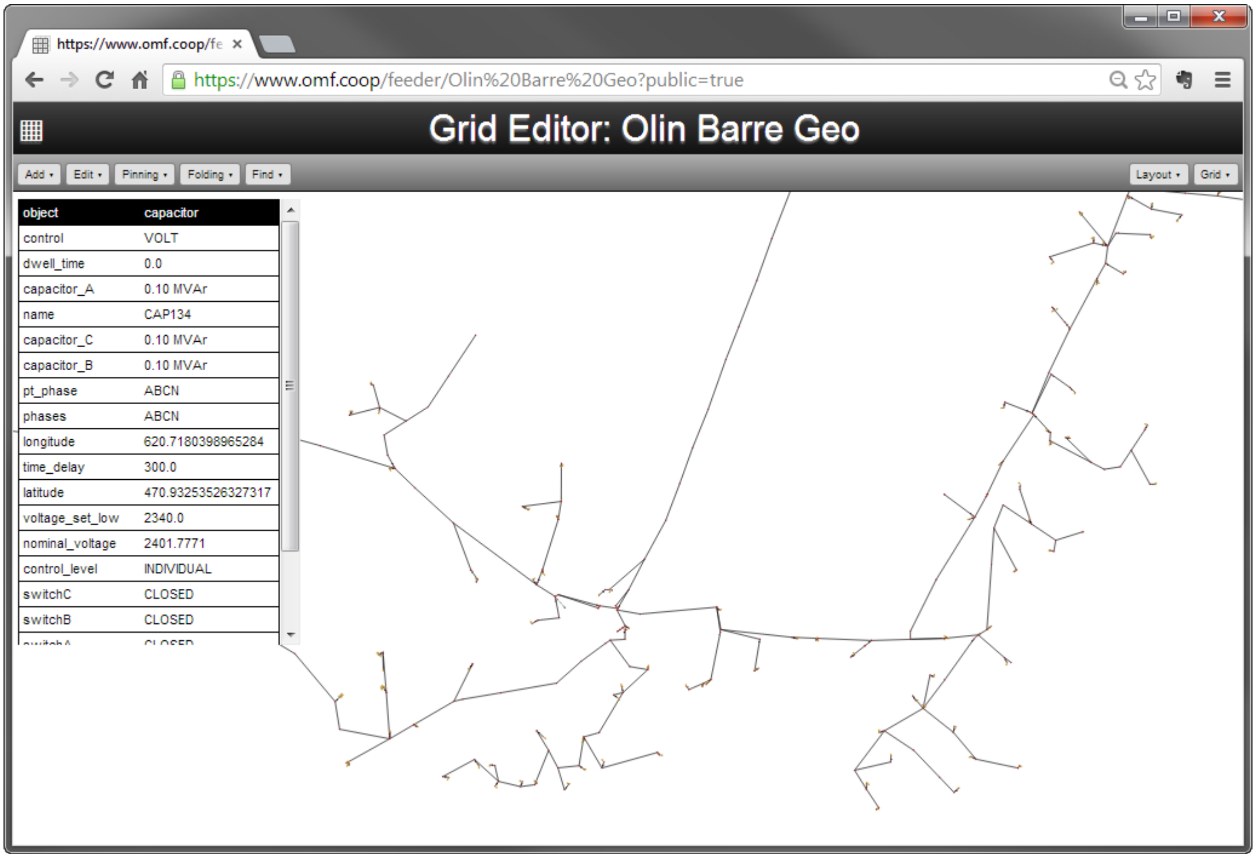

Figure 3. Specifying Capacitor Bank Properties in the OMF

Load data also are imported from Windmil. For each meter on the system, real and imaginary load as a percentage of historical annual consumption is allocated based on billing data via Milsoft's load allocation algorithm. In the OMF, these loads are translated into ZIP models—load circuit elements that provide or consume a combination of constant impedance (Z), current (I), and power (P). Because the feeders under study were primarily residential feeders, we modeled loads as 50% constant impedance and 50% constant power, in line with industry practice and published examples [19].

A year's worth of historical SCADA data for the test feeder is used to determine peak and mean load levels for each month. The ZIP models then are scaled to 10 different load levels that can be used to linearly approximate all of the historical levels. Powerflow is run twice at each level: once at the current substation voltage and once at a substation voltage that is as low as possible with no meters outside of the ANSI voltage band (116–124 volts). The difference in consumption between the two voltage levels then gives the maximum possible savings that could be achieved via CVR. Model output for one example feeder is shown in **Table 1**.

Table 1. Powerflow Results for Test Co-Op Feeder

Load Level (W)	CVR Opp.	CVR Factor	CVR Active	High Meter (V)	Low Meter (V)	Sub (V)	Losses (W)	PF	Power Cons
1.0E+06	5.91E+04	1.04	FALSE	125	122	124	2.4E+04	96%	9.72E+05
			TRUE	118	115	116	2.3E+04	97%	9.13E+05
1.6E+06	6.29E+04	1.05	FALSE	124	120	124	5.2E+04	100%	1.55E+06
			TRUE	120	115	119	5.2E+04	100%	1.48E+06
2.2E+06	4.32E+04	1.05	FALSE	124	118	124	9.6E+04	99%	2.11E+06
			TRUE	122	115	121	9.6E+04	99%	2.07E+06
2.8E+06	0.00E+00	0	FALSE	124	115	124	1.5E+05	98%	2.68E+06
	2.68E+06		TRUE	124	115	124	1.5E+05	98%	2.68E+06
3.4E+06	0.00E+00	0	FALSE	123	113	124	2.3E+05	97%	3.24E+06
			TRUE	123	113	124	2.3E+05	97%	3.24E+06
4.0E+06	0.00E+00	0	FALSE	123	111	124	3.2E+05	97%	3.80E+06
			TRUE	123	111	124	3.2E+05	97%	3.80E+06
4.6E+06	0.00E+00	0	FALSE	123	108	124	4.2E+05	96%	4.35E+06
			TRUE	123	108	124	4.2E+05	96%	4.35E+06
5.2E+06	0.00E+00	0	FALSE	123	106	124	5.4E+05	95%	4.90E+06
			TRUE	123	106	124	5.4E+05	95%	4.90E+06
5.8E+06	0.00E+00	0	FALSE	123	103	124	6.8E+05	94%	5.44E+06
			TRUE	123	103	124	6.8E+05	94%	5.44E+06
6.4E+06	0.00E+00	0	FALSE	123	101	124	8.4E+05	94%	5.98E+06
			TRUE	123	101	124	8.4E+05	94%	5.98E+06

For this feeder, we see that there are CVR possibilities for load levels at and below 2.2 MW. This then can be translated into expected savings, as we will address in the Costs and Benefits section.

The full code to perform this analysis is available on request. Running time is approximately one minute on a modern workstation.

Dynamic Powerflow Method

To provide a model that better captures the time-dependent CVR effects on load, we built a high-resolution dynamic time series model. This model is still in the process of verification and is included to indicate opportunities for future research.

In this dynamic model, feeder data come from Windmil, as before. Instead of static ZIP loads, we rely on GridLAB-D's ability to describe time-varying ZIP plug loads, along with HVAC, and its thermal interactions with weather and building architecture. (A full description of GridLAB-D's load modeling approach is beyond the scope of this report.) For sizing the loads, we replace the static load allocations from Windmil with house models, drawn randomly from a representative sample of residential houses and loads compiled by PNNL [2], then scaled according to the allocated load.

As in the static model, we compare baseline powerflow to a powerflow scenario in which CVR is active. We use GridLAB-D's CVR control scheme, which has been published in the IEEE Transactions on Power Systems and is openly available [12]. This scheme has two major goals: voltage optimization and reactive power control. To achieve reactive power control, shunt capacitors on the distribution feeder are operated to maximize the power factor at the substation. Voltage optimization is achieved through operation of the substation voltage regulator to minimize system voltage while keeping the measured End-of-Line (EOL) voltage within the

ANSI band We do not consider control of additional downstream voltage regulators. (See **Figures 4** and **5**.)

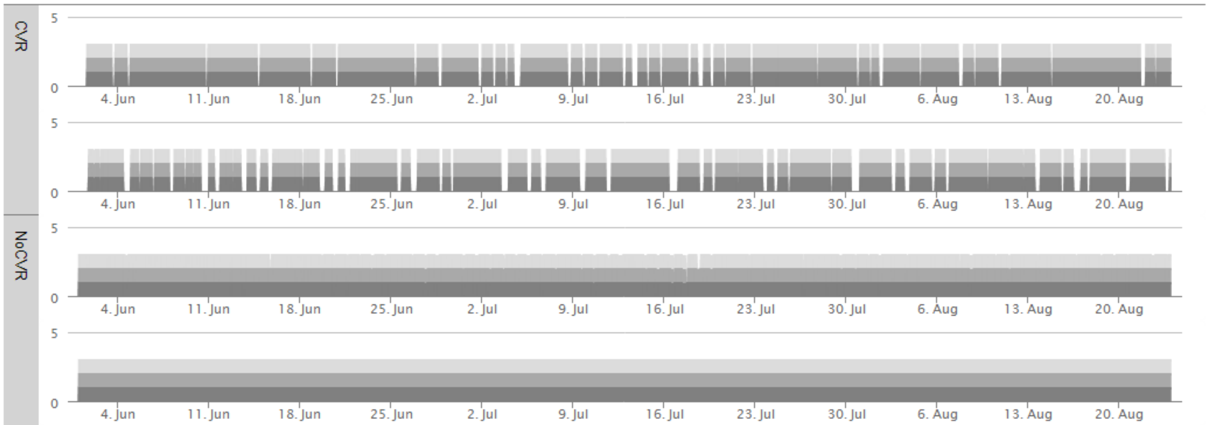

Figure 4. Dynamic Powerflow Simulation—Control of Capacitor Bank Switching

Figure 5. Three-Month Dynamic Powerflow Simulation—Powerflow across the Substation, and Loads and Losses Breakdown

Accuracy of Dynamic Powerflow Models

ZIP models are commonly used for modeling power system loads and estimating the benefits of VVO mechanisms. ZIP models provide excellent simulation results when looking at a single snapshot in time or the instantaneous power reduction provided. However, when studying the longer-term dynamics of voltage reduction, ZIP models are incapable of capturing the more complex behavior of loads, especially those driven by closed-loop control (e.g., thermostatic controls, such as HVAC or water heaters). Studying these effects requires more detailed load models that represent detailed behavior, particularly how voltage affects energy consumption and power demand in the presence of a control loop.

A single water heater provides a good example of a thermostatically controlled load that is poorly represented by a ZIP model. A water heater is modeled as a purely resistive element (100% impedance) in a ZIP model. GridLAB-D represents the behavior of the water heater as a physical process that determines the flow of heat energy; this is known as a physics-based or physical load model. The amount of heat energy within the water, or the temperature of the water, is affected by the amount of insulation around the water heater (also called the thermal jacket) and hot water usage in the home. GridLAB-D models the current temperature of the water, compares it to the thermostat set points, and determines when the device should be on or off. When the device is on, a voltage-dependent resistive element is applied to heat the water; i.e., if the voltage is lower, less power is demanded and therefore less heat is produced. This requires the device to run for a longer amount of time, as the same amount of energy is needed to heat the water to the desired temperature. In a ZIP model, a reduction of voltage results in reduced power demand and reduced energy consumption. However, in a physical model, a reduction in voltage results in a lower power demand but a longer run time for the device. **Figure 6** highlights this issue. Notice that the ZIP load (right-hand figure) shows the run time as constant at different voltage levels, reducing both energy and power, while the physical load model (left-hand figure) extends the run time at lower voltages, reducing power but not energy.

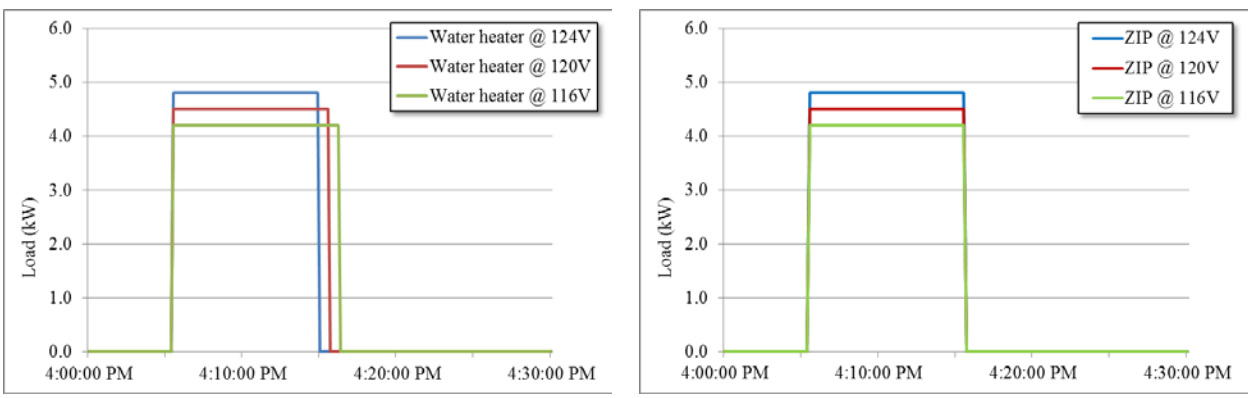

Figure 6. Comparison of Physical Water Heater Model versus Zip Model at Three Voltage Levels

We also can look at a collection of water heaters for two different volt/VAR services: peak reduction and energy reduction. Below is an example from GridLAB-D that simulates 1,000 water heaters as both physical and ZIP models. **Figure 7** shows a 2-hour peak reduction by lowering the voltage from 124 to 116 from 15:00 to 17:00; while this represents an extreme case, it highlights the effects. The dashed lines represent the ZIP model, while the solid line represents a physical model of the water heater (WH). At 15:00, both the ZIP and WH load are reduced by about 15%. However, by 16:00, the physical model reduction has significantly decreased as the water heaters return to their natural operational state (consuming the same amount of energy), while the ZIP model still shows a reduction of approximately 15%. In this 2-hour window, the ZIP model predicts that peak reduction will be far greater than it actually is.

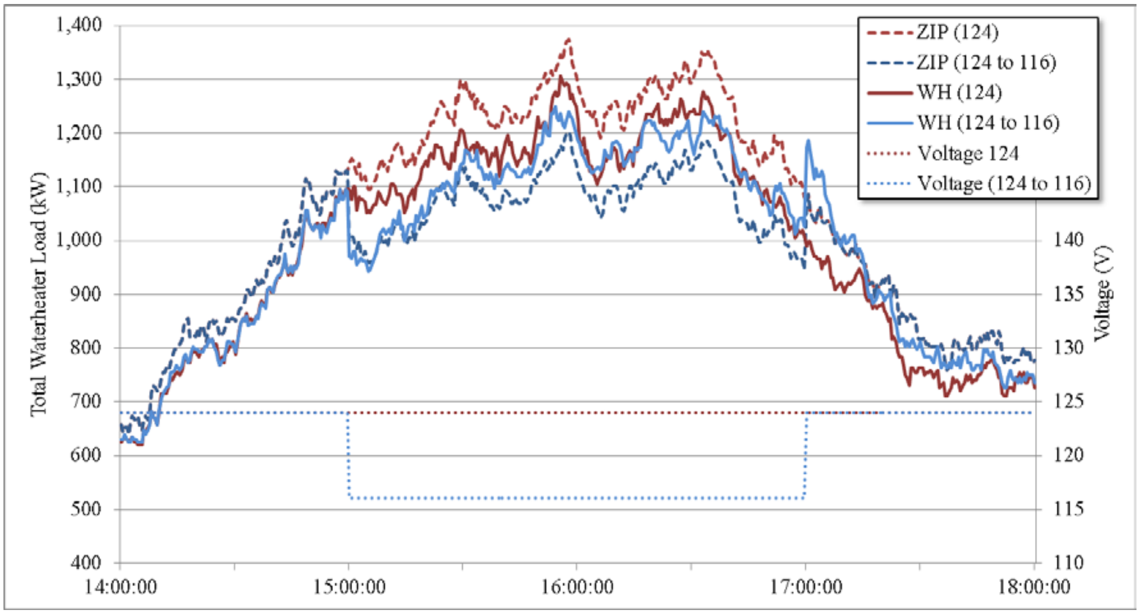

Figure 7. Peak Reduction Event-Shifting Voltage from 124 to 116 and Comparing Physical Water Heater Load vs. ZIP Load

VVO also can be used for energy reduction, operating the system at all times at lower voltages. Again, 1,000 water heaters are simulated as both physical and ZIP models for one day, operating the system at 124, 120, and 116 volts constantly throughout the day. The results are shown in **Table 2**—daily energy consumption and peak demand during the evening peak per water heater. Note that the physical model shows only a minimal change in the energy consumption, while the ZIP load indicates a 14% reduction, from 124 V to 116 V. Also note that the ZIP model predicts a greater peak reduction (14% reduction, from 124 V to 116 V) than the physical model (4% reduction).

Table 2. Comparison of Energy Consumption and Peak Demand

	Daily Energy Usage (kWh)	Evening Peak (kW)
ZIP, 124 V	14.94	1.374
ZIP, 120 V	13.99	1.287
ZIP, 116 V	13.07	1.203
WH, 124 V	14.01	1.307
WH, 120 V	13.99	1.287
WH, 116 V	13.96	1.262

Traditional ZIP models are appropriate for single instances in time, i.e., instantaneous reduction of load when lowering the voltage, but are inadequate for capturing the time-series effects of voltage reduction. Physical models that capture the dynamic behavior of the loads, including thermostatic control loops, are required to understand how load is affected by a change in voltage, either for energy or peak reduction. While this case has used water heaters as an example, the issues are equally valid for HVAC, albeit with different reduction numbers.

COSTS AND BENEFITS

Benefits of conservation voltage reduction accrue primarily to the utility and customers. We do not address the benefits of energy conservation to other groups as part of this study.

The CVR benefit with the largest and clearest payback, and hence of most interest to the cooperatives studied, was peak demand reduction. Loss reduction is another benefit. The principal cost of CVR programs is for hardware. Energy sales also are reduced as an effect of CVR.

Following the availability of data for validation, a summary of the realized costs and benefits of each project will be possible. At the time of writing, we considered expected costs and benefits from model results.

Static Load Model Cost-Benefit

In **Table 3**, we derive a cost-benefit analysis from the same model powerflows calculated in **Table 1**. For each historical month from a prior year's SCADA data, we use the historical peak and average loads to estimate peak/loss and energy consumption reductions, respectively. Each month's reduction watt values are the difference between the treated (CVR) model and the baseline, without re-regulation or capacitor bank additions. Results were interpolated linearly from nearest load matches among the 20 candidate powerflows to reduce the running time of the computations. A graph of these data is shown in **Figure 8**.

Table 3. Costs and Benefits for Re-Regulation of Test Feeder

Month	Season	Historical Loads (kW)		Peak Red.		Energy Red.		Loss Red.		Net
		Avg	Peak	kW	$	kWh	$	kW	$	$
January	Winter	2740	4236	0	0	19.45	-778	0.06	4	-774
February	Winter	2483	3312	0	0	10.20	-408	0.03	2	-406
March	Spring	2031	2964	0	0	22.59	-904	0.17	10	-893
April	Spring	2107	3025	0	0	26.58	-1063	0.20	12	-1051
May	Spring	2344	4076	0	0	5.19	-208	0.02	1	-206
June	Summer	2769	5811	0	0	20.50	-820	0.07	4	-816
July	Summer	3967	6746	0	0	0.00	0	0.00	0	0
August	Summer	3274	5204	0	0	0.00	0	0.00	0	0
September	Fall	2130	4904	0	0	27.78	-1111	0.21	13	-1099
October	Fall	1752	2337	4.94	29613	7.97	-319	0.06	4	29297
November	Fall	2208	3545	0	0	0.29	-12	0.00	0	-11
December	Winter	2482	3365	0	0	10.16	-406	0.03	2	-404

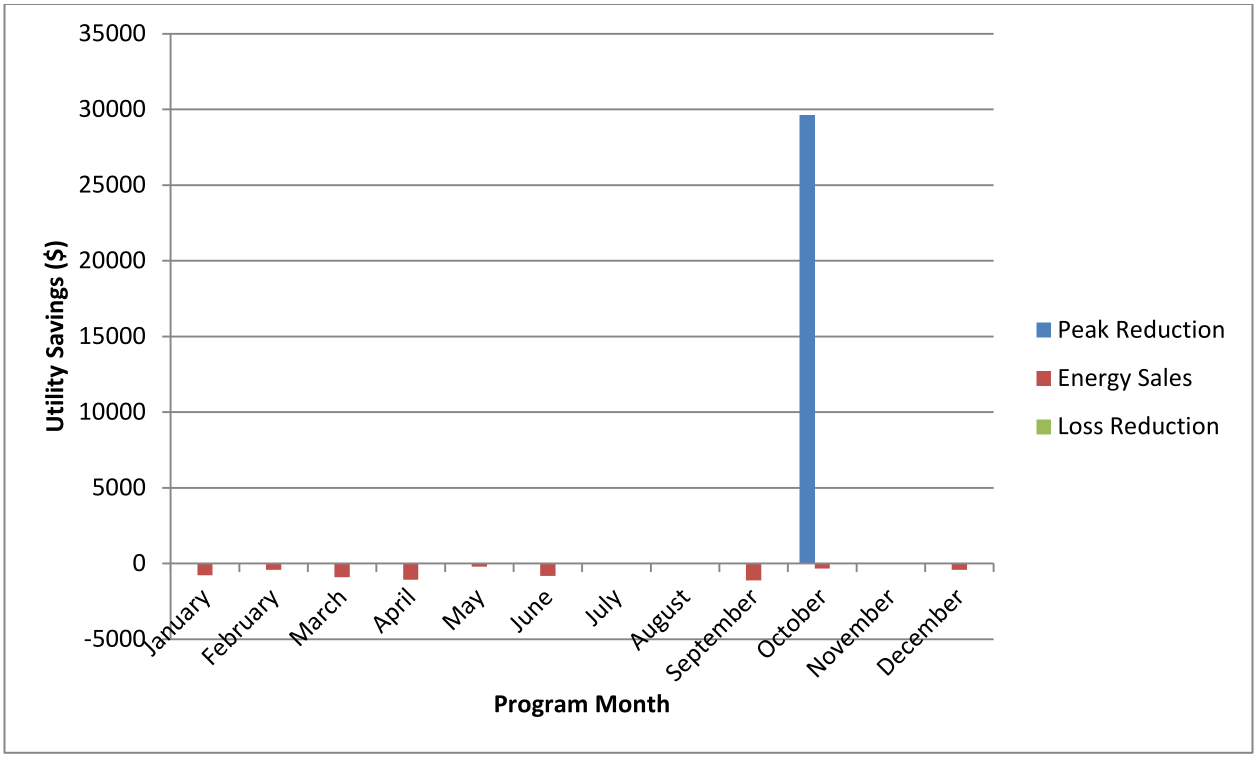

Figure 8. Utility Savings by Month and Cause

As **Figure 8** makes clear, the main benefit for the re-regulation of this feeder is a lucrative peak reduction in October. Loss reductions offer trivial savings. Lower energy sales are a significant cost but are far outweighed by the demand reduction savings. In some markets, energy savings can be recovered through conservation credits. The model assumes that CVR is run continuously to keep the system voltage as low as possible while still keeping all meters within the ANSI band. Were the system to be run only during peaks, the lost energy sales would be drastically reduced.

For customers, CVR paradoxically tends to lower each customer bill while also raising energy rates. The result is a net saving for customers.

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APPENDIX A: VERIFICATION CODE

The Mathematica code for the algorithms described in the verification section follows. Comments are included, and output is in line with the code that produced it. The source is available on request.

```
(*Import all SCADA data for [redacted] System*)
rawData = Import["C:\[redacted]", "*.txt"];
names = Import["C:\[redacted]", "Rules"][[2]];
Length[rawData]
```

97

```
tsvs = Map[ImportString[#, "TSV"] &, rawData];
```

```
(*An example TSV, first 10 rows*)
TableForm[tsvs[[2]][[1 ;; 10]]]
```

Meter ID	Date / Time	KW(ch: 1 set:0)	KVAR(ch: 2 set:0)	KVA(0(ch: 2 set:
[redacted]	1/1/12 01:00	53178.6	1376.28	53196.4
	1/1/12 02:00	50859.3	1298.28	50875.9
	1/1/12 03:00	49505.1	1284.24	49521.8
	1/1/12 04:00	48942.8	1330.8	48960.9
	1/1/12 05:00	49499.	1273.56	49515.3
	1/1/12 06:00	51046	1323.96	51063.2
	1/1/12 07:00	54255.3	1433.28	54274.3
	1/1/12 08:00	57461.8	1230.6	57475.

```
(*Function for cleaning data in each TSV.*)
subSet[tsv_] := Module[{droppedBlank, subset},
   droppedBlank = Select[tsv, Length[#] > 3 &];
   (* Pull out labels, KW and PF:*)
   subset = Map[#[[{1, 2, 3, -1}]] &, droppedBlank];
   subset
  ];
```

```
(*First ten lines from an example dataset:*)
cleanPreview[aTsv_] := TableForm[subSet[aTsv[[1 ;; 10]]]];
cleanPreview[tsvs[[1]]]
```

Meter ID	Date / Time	KW(ch: 1 set:0)	PF(0(ch: 3 set:0)
[redacted]	3/31/11 23:00	51368.6	1
	4/1/11 00:00	48710.1	1
	4/1/11 01:00	46935.7	1
	4/1/11 02:00	45749.7	1
	4/1/11 03:00	46057.5	1
	4/1/11 04:00	46995.4	1
	4/1/11 05:00	50116.4	1
	4/1/11 06:00	53410.8	1

```
(*Merge all the data.*)
merged = Map[subSet[#][[2 ;; -1]] &, tsvs];
flatMerge = Flatten[merged, 1];
```

```
(*Mapping between meter numbers and real names.*)nameRules =
 Table[tsvs[[i, 3, 1]] → StringReplace[names[[i]], {".txt" → "", " 2011" → "", " 2012" → "", "July 2012\\" → ""}],
   {i, 1, Length[tsvs]}] // Union
```

[redacted]

```
meterNames = DeleteDuplicates[Map[#[[1]] &, flatMerge]]
subMeters = meterNames[[2 ;; -1]];
```

```
{[redacted] , 7180863, 710462, 470538, 468706, 469573, 471135, 693716, 470508, 469664,
 638717, 470382, 664613, 664614, 664616, 468670, 470394, 470221, 7180864, 469653, 469661,
 470201, 664054, 470386, 470246, 469628, 470396, 471059, 469616, 470190, 558087, 470284, 470493}
```

```
dates = flatMerge[[All, 2]]; Sort[dates]; timeLimits = {DateList[dates[[1]]], DateList[dates[[-1]]]}
treatLimit = {{DateList["1 January 2012"]}, {}}
treatOffset = 5883; dates[[treatOffset]]
```

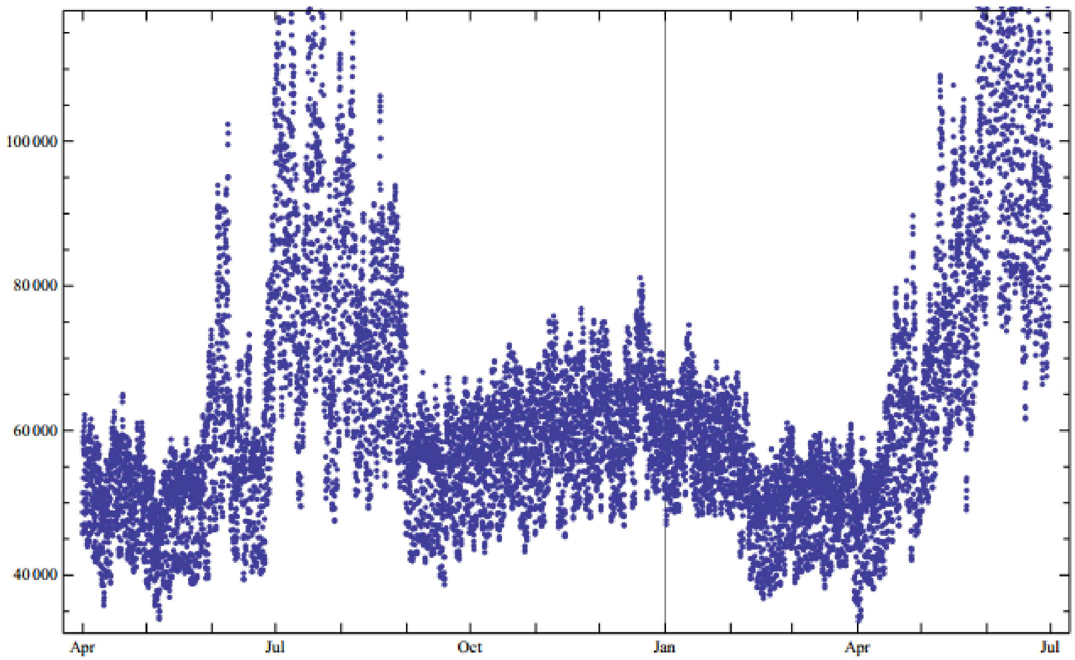
```
{{2011, 3, 31, 23, 0, 0.}, {2012, 6, 30, 22, 0, 0.}}
```

```
{{{2012, 1, 1, 0, 0, 0.}}, {}}
```

```
1/1/12 00:00
```

```
(* Helper function to query the dataset*)
getKilowatts[meterName_] := Select[flatMerge, #[[1]] == meterName &][[All, 3]]
```

```
(*System total KW timeseries:*)
DateListPlot[getKilowatts[meterNames[[1]]], timeLimits, ImageSize → Scaled[0.9], GridLines → treatLimit]
```




```
(*Small multiples graphing of all the substation KW readings, 2011+1/2(2012)*)
Table[DateListPlot[getKilowatts[x], timeLimits, ImageSize → Scaled[0.22], GridLines → treatLimit],
  {x, meterNames[[2 ;; -1]]}] // Partition[#, 4] &
```

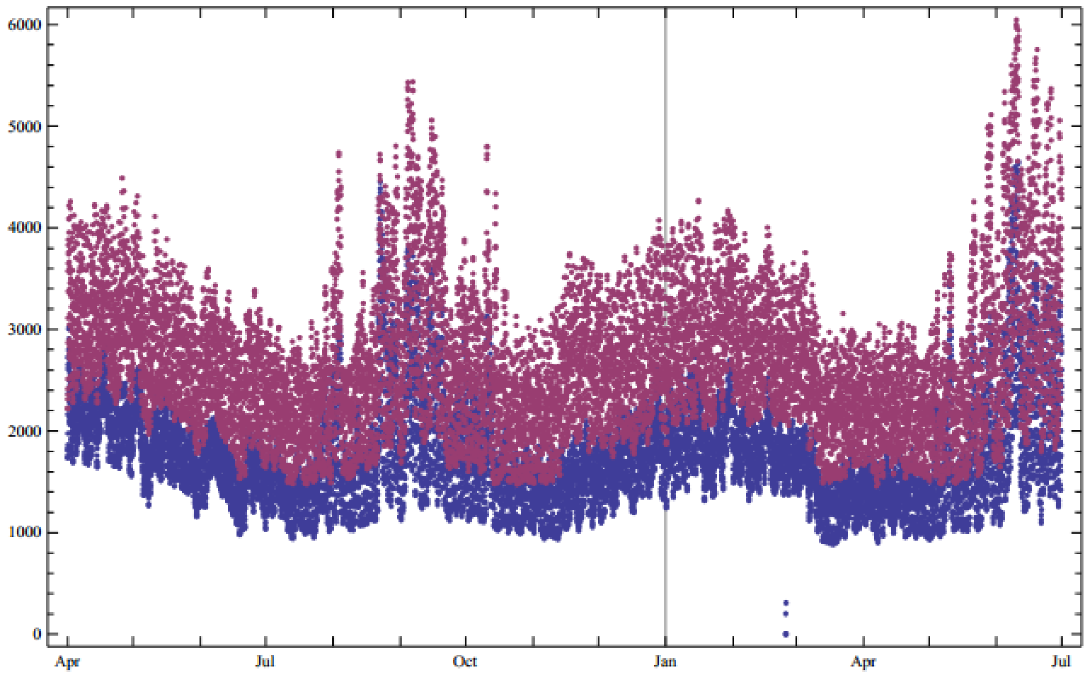
```
(*Correlation helper functions*)
subKilowatts[meterName_] := getKilowatts[meterName][[1 ;; treatOffset]];
safeCorr[x_, y_] :=
  If[Length[x] == Length[y] && Length[x] ≠ 0 && Length[y] ≠ 0, Round[Correlation[x, y], 0.01], -1];
```

```
(*Compute all correlations on treatment region. TAKES FOREVER*)
allCorrs = Table[safeCorr[subKilowatts[subMeters[[i]]], subKilowatts[subMeters[[j]]]],
   {i, 1, Length[subMeters]}, {j, 1, i}];
(*Ya know we could use the following to improve the performance by a factor or 2.
  stuff={a,b,c,d,e};
Table[stuff[[i]]*stuff[[j]],{i,1Length[stuff]},{j,1,i}]
*)

(*Nice display of all correlations.*)
colorize[x_] := Style[x, FontColor → ColorData["TemperatureMap"][x]];
TableForm[Map[colorize, allCorrs, {2}], TableHeadings → {subMeters, subMeters}]
```

	7 180 863	710 462	470 538	468 706	469 573	471 135	693 716	470 508	469 664	638 717
7 180 863	1.									
710 462	0.09	1.								
470 538	0.6	0.07	1.							
468 706	0.94	0.11	0.58	1.						
469 573	0.24	0.09	0.37	0.28	1.					
471 135	0.42	0.02	0.92	0.39	0.32	1.				
693 716	0.88	0.18	0.47	0.93	0.39	0.27	1.			
470 508	0.79	0.08	0.24	0.7	-0.06	0.07	0.67	1.		
469 664	0.91	0.18	0.48	0.96	0.25	0.28	0.97	0.72	1.	
638 717	0.88	0.15	0.66	0.89	0.45	0.5	0.89	0.54	0.89	1.
470 382	0.85	0.08	0.87	0.82	0.38	0.76	0.74	0.52	0.75	0.85
664 613	0.32	-0.02	0.56	0.33	0.41	0.55	0.3	-0.04	0.26	0.47
664 614	0.25	-0.17	0.38	0.27	0.25	0.4	0.18	-0.06	0.18	0.36
664 616	0.59	0.14	0.18	0.59	0.13	0.05	0.63	0.56	0.63	0.57
468 670	0.95	0.15	0.69	0.94	0.25	0.52	0.85	0.69	0.89	0.88
470 394	0.64	0.04	0.89	0.61	0.3	0.86	0.48	0.28	0.51	0.66
470 221	0.53	0.03	0.88	0.46	0.26	0.88	0.36	0.29	0.37	0.51
7 180 864	-0.04	-0.11	-0.09	-0.04	-0.01	-0.1	-0.03	0.	-0.04	-0.05
469 653	0.34	0.32	0.02	0.36	0.11	-0.11	0.45	0.51	0.42	0.25
469 661	0.39	-0.03	0.18	0.41	0.21	0.07	0.48	0.38	0.43	0.34
470 201	0.36	-0.09	0.24	0.3	0.14	0.17	0.34	0.42	0.32	0.29
664 054	0.4	0.06	0.23	0.39	0.21	0.11	0.46	0.42	0.43	0.36
470 386	0.44	0.03	0.19	0.43	0.22	0.08	0.51	0.49	0.48	0.39
470 246	0.42	-0.02	0.22	0.39	0.2	0.12	0.46	0.48	0.43	0.36
469 628	0.42	0.08	0.19	0.44	0.26	0.08	0.51	0.41	0.47	0.39
470 396	0.37	0.01	0.11	0.37	0.21	0.01	0.46	0.42	0.42	0.34
471 059	0.41	0.06	0.15	0.43	0.23	0.03	0.52	0.44	0.48	0.38
469 616	0.41	0.12	0.14	0.43	0.23	0.02	0.53	0.46	0.49	0.38
470 190	0.36	0.15	0.04	0.39	0.17	-0.09	0.49	0.47	0.45	0.3
558 087	-0.04	0.	-0.02	-0.02	-0.02	-0.02	-0.02	-0.01	-0.03	-0.05
470 284	0.45	-0.01	0.27	0.44	0.27	0.17	0.51	0.45	0.47	0.42
470 493	0.42	0.	0.15	0.38	0.16	0.05	0.46	0.52	0.43	0.34

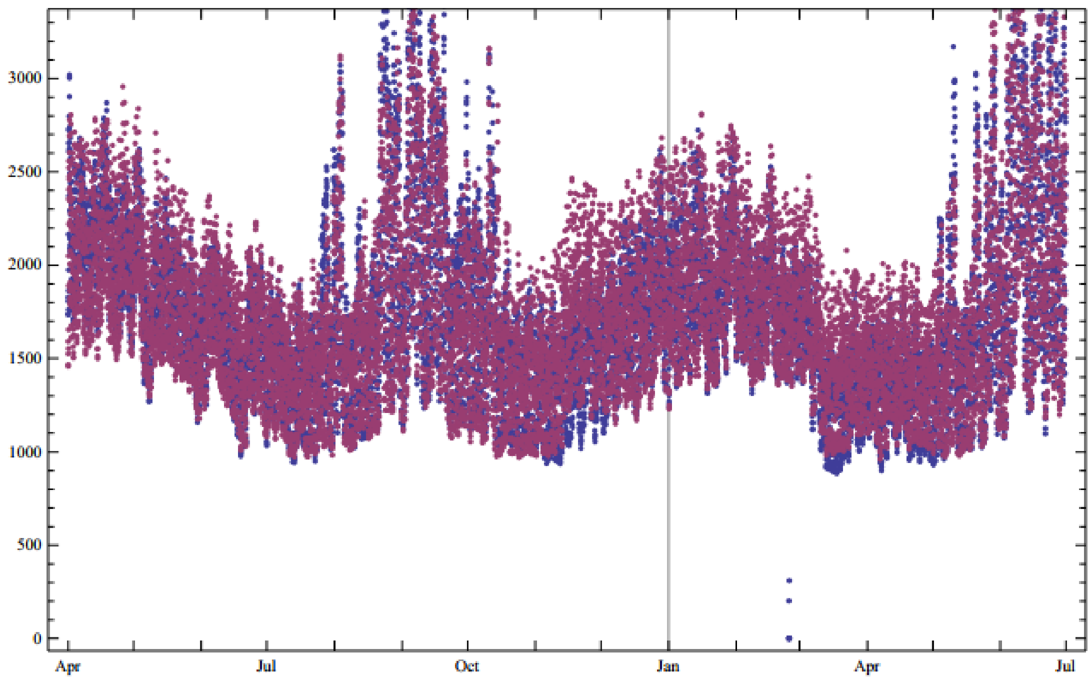
```
(*Highly correlated pair.*)
DateListPlot[{getKilowatts[7180863], getKilowatts[469664]},
 timeLimits, ImageSize → Scaled[0.9], GridLines → treatLimit]
```




```
(*Rescale the correlated feeder to remove mean differences. Label is the energy difference.*)
meanMult[x_, y_, size_: Scaled[0.9]] := Module[{xKw, yKw, yTimesMean},
  xKw = getKilowatts[x];
  yKw = getKilowatts[y];
  yTimesMean = yKw * Mean[xKw] / Mean[yKw];
  DateListPlot[{xKw, yTimesMean}, timeLimits, ImageSize → size,
   GridLines → treatLimit, PlotLabel -> Total[xKw - yTimesMean]]
 ]
```

```
meanMult[7180863, 469664]
```

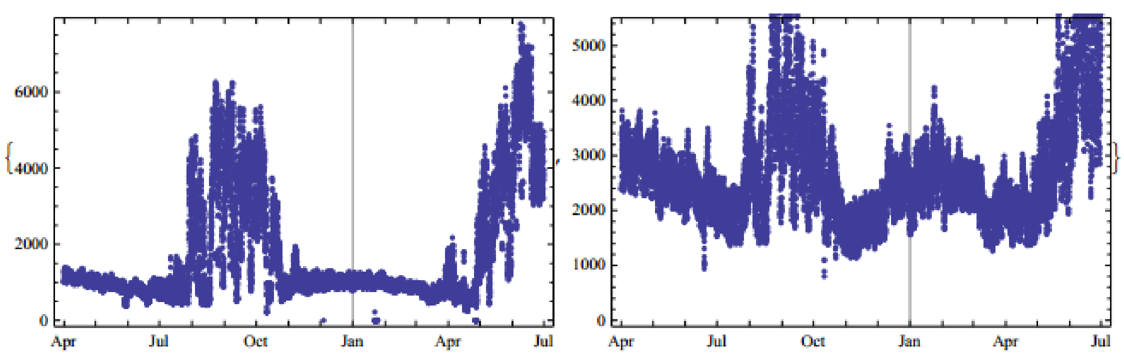
-3.75417×10^{-9}



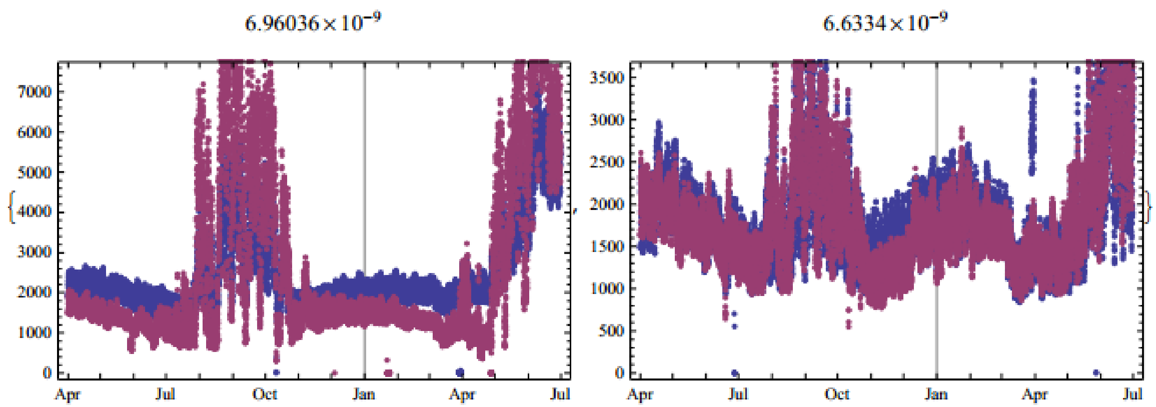

```
(*Target Feeders: 471135→"[redacted] and 470382→[redacted].*)

{DateListPlot[getKilowatts[471135], timeLimits, ImageSize→Scaled[0.45],
  PlotLabel→"[redacted], GridLines→treatLimit], DateListPlot[getKilowatts[470382],
  timeLimits, ImageSize→Scaled[0.45], PlotLabel→[redacted], GridLines→treatLimit]}
```

[redacted] [redacted]



```
(*With highly correlated feeders. Red are the CVR feeders.*)
{meanMult[470538, 471135, Scaled[0.45]], meanMult[468670, 470382, Scaled[0.45]]}
```




```
energyDiff[control_, test_] :=
 Total[getKilowatts[control][[treatOffset ;; -1]] - getKilowatts[test][[treatOffset ;; -1]]]

{energyDiff[470538, 471135], energyDiff[468670, 470382]}
```

$\{7.04823\times10^{6}, -6.31177\times10^{6}\}$

```
peakDiff[control_, test_] := Module[{controlKw, testKw},
  controlKw = getKilowatts[control][[treatOffset ;; -1]];
  testKw = getKilowatts[test][[treatOffset ;; -1]];
  Null
 ]
```