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2016 Smart Grid Report

Send the completed Cover Sheet and the Report in an email addressed to PUC.FilingCenter@state.or.us

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Print

Lisa D. Nordstrom
Lead Counsel
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September 30, 2016

Public Utility Commission of Oregon
Filing Center
201 High Street SE, Suite 100
P.O. Box 1088
Salem, Oregon 97301

RE: UM 1675 - Idaho Power Company's 2016 Smart Grid Report

Attention Filing Center:

Idaho Power Company submits for filing its *2016 Smart Grid Report* in compliance with Order No. 12-158 in Docket No. UM 1460 and Order No. 16-045 in UM 1675. In addition to the Smart Grid Report, the Company has included the following documents:

- Appendix A Stakeholder Input
- Appendix B Peak Reliability Project Plan
- Appendix C Conservation Voltage Reduction Report
- Appendix D ENGO Static VAr Device Pilot Project Report
- Appendix E Idaho Power whitepaper entitled "A Method for Determining the Relationship Between Solar Irradiance and Distribution Feeder Peak Loading"
- Appendix F Electric Vehicle Quick Facts Brochure
- Appendix G Electric Vehicle Charging Impacts Study
- Appendix H Smart Grid Metrics
- Appendix I Draft Observability Methodology Document
- Appendix J Quarterly Peak Reliability Synchrophasor Program Project Status Report
- Appendix K June 2016 Idaho Power *Connections* Newsletter
- Appendix L Accessible Data Tables

Please address all data requests and other communication to:

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Informal substantive questions concerning this filing may be directed to Regulatory Analyst Kristy Patteson at 208-388-2982 or kpatteson@idahopower.com.

Sincerely,

Lisa D. Nordstrom

Lisa D. Nordstrom

LDN:kkt

Enclosures

cc: Service List – UM 1675
Service List – UM 1460
Service List – LC 63
Service List – UE 233

SMARTgrid Report

September 30, 2016

IDAHO POWER
An IDACORP Company

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LIST OF ACRONYMS

A/C—Air Conditioning

ACC—Automated Capacitor Control

AMI—Advanced Metering Infrastructure

ANSI—American National Standards Institute

CGI—CGI Group Incorporated

CR&B—Customer Relationship and Billing

CRM—Customer Relationship Management

CSR—Customer Service Representative

CVR—Conservation Voltage Reduction

DR—Demand Response

DSM—Demand-Side Management

EDW—Enterprise Data Warehouse

ENGO—Edge of Network Grid Optimization

EPRI—Electric Power Research Institute

EV—Electric Vehicle

F—Fahrenheit

GHI—Global Horizontal Irradiance

IEEE—Institute of Electrical and Electronics Engineers

ILC—Irrigation Load Control

INL—Idaho National Lab

IRP—Integrated Resource Plan

kV—Kilovolt

kVA—Kilovolt Ampere

kW—Kilowatt

kWh—Kilowatt-hour

LSE—Linear State Estimator

LTC—Load Tap Changer

MDMS—Meter Data Management System

MW—Megawatt

NWEC—NW Energy Coalition

OAR—Oregon Administrative Rule

ODOE—Oregon Department of Energy

OMS—Outage Management System

OPUC—Public Utility Commission of Oregon

ORS—Oregon Revised Statute

POA—Point of Array

PLC—Power Line Carrier

PMU—Phasor Measurement Unit

PSERC—Power System Engineering Research Center

PV—Photovoltaic

QoS—Quality of Service

RC—Reliability Coordinator

RIT—Renewable Integration Tool

ROSE—Region of Stability Existence

SCADA—Supervisory Control and Data Acquisition

SE—State Estimator

SGIG—Smart Grid Investment Grant

SGM—Smart Grid Monitoring

SIWS—Solar Irradiance Weather Station

TE—Transportation Electrification

TES—Thermal Energy Storage

TOD—Time of Day

TVP—Time Variant Pricing

V—Volt

VAr—Volt Ampere Reactive

VVMS—Volt/VAr Management System

VVO—Volt/VAr Optimization

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EXECUTIVE SUMMARY

Idaho Power Company (Idaho Power or the company) is pleased to present its *2016 Smart Grid Report* in compliance with Order No. 12 158 issued by the Public Utility Commission of Oregon (OPUC) in Docket UM 1460. The OPUC's smart grid goal and objectives as set forth in this order are as follows:

> The Commission's goal is to benefit ratepayers of Oregon investor-owned utilities by fostering utility investments in real-time sensing, communication, control, and other smart-grid measures that are cost-effective to consumers and that achieve the following:
>
> - Enhance the reliability, safety, security, quality, and efficiency of the transmission and distribution network
> - Enhance the ability to save energy and reduce peak demand
> - Enhance customer service and lower cost of utility operations
> - Enhance the ability to develop renewable resources and distributed generation.

This document presents Idaho Power's fourth annual smart grid report and addresses the company's efforts toward accomplishing the OPUC's goals. This report explains the company's overall strategies, goals, and objectives as they pertain to its smart grid efforts. It provides a review of current smart grid projects, initiatives, and activities being performed by the company and describes additional projects the company plans to undertake in the next five years. Opportunities the company has identified, as well as potential constraints, are also discussed.

Idaho Power evaluates new smart grid technologies and opportunities in a systematic process to determine if they solve an existing problem, improve efficiency, increase reliability, improve safety or security, or enhance customer satisfaction. Opportunities for funding smart grid projects are evaluated using common criteria alongside other capital projects being considered by the company.

In addition to fulfilling or meeting OPUC reporting requirements, this document serves as a high-level strategic document for Idaho Power to plan and track its smart grid projects. It acts as a company-wide repository of all smart grid projects, reports, and studies underway or planned in the near-term future.

The OPUC's specific recommendations for this report included in Order No. 16-045, Docket UM 1675, will be reviewed in Section V. Targeted Evaluations.

SOLICITATION OF STAKEHOLDER INPUT

In preparation for filing this report, Idaho Power provides the public and other parties an opportunity to contribute information and ideas on smart grid investments and applications.

To solicit input from the general public, Idaho Power completed a draft report and made it available for review by the public and other stakeholders for a specific review period.
The company placed an advertisement—Share Your Ideas About Smart Grid—in the two newspapers with the best coverage in Idaho Power's Oregon service area, the Argus Observer (Ontario) and the Hells Canyon Journal (Halfway). Idaho Power included a web link in the newspaper ads that directed readers to a copy of the draft smart grid report.

Idaho Power also sent an email soliciting comments to all parties on the service lists of the initial smart grid docket, UM 1460; Idaho Power's last Oregon general rate case docket, UE 233; Idaho Power's last integrated resource planning docket, LC 63; and Idaho Power's 2015 smart grid report docket, UM 1675. Idaho Power requested comments be submitted by August 26, 2016.

Copies of the newspaper advertisements, the email solicitation, the informal comments received, and Idaho Power's responses are provided in Appendix A. Also included is a screenshot of the smart grid landing page from Idaho Power's website.

I. Smart Grid Goals, Objectives, Strategy, and Process

The smart grid is a concept whereby utilities deploy new technologies to reduce costs and improve the operation of the electrical power system. As an industry, utilities have been doing this for years; it is not new. What is new is the speed in which new technologies are becoming available and the abundance of data now available through advanced metering infrastructure (AMI) meters and monitoring devices.

This document represents a vision of what Idaho Power's future may look like in the near to mid-term future and presents various projects and programs Idaho Power is undertaking or may undertake to prepare for that future. Some of the projects are already underway, while others are for future implementation. The *2016 Smart Grid Report* is a vision paper supported with concrete studies and analysis created by a working group of Idaho Power senior managers and senior staff. The vision represented herein is forward looking and as such, may be adjusted in some areas as years progress.

A. Goals and Objectives

The Smart Grid is Customer Centered

The smart grid concept provides customers easier access to their energy use information and empowers them to act on that information. It provides information to customers, and in general, serves them in a manner that allows them to be more involved and proactive in managing their energy use. Idaho Power believes customers expect utilities to provide a different experience than the traditional paradigm of service provided in the past. In part, this paradigm change is driven by the increasing use of technology in our everyday lives. Customers will seek an interactive experience that includes information that enables them to make choices in their energy use.

Smart Grid is Data Rich

The smart grid is a data-rich environment with embedded sensing devices located throughout the electric system that allows for the automation of protection and control while providing the information needed to more efficiently operate the system. It provides two-way flows of information between devices and between Idaho Power and its customers. It gives the utility the ability to more efficiently integrate distributed resources. It provides resiliency in utility response to storm- or event-driven outages, speeding up restoration efforts.

Edge of Network

The smart grid is moving to the edge of the network—an area where utilities have traditionally not gone. This edge goes all the way to the secondary side of the service transformer and even into the homes and businesses served by Idaho Power. The ability to control power quality at the customer level enables the system to become more efficient and responsive to customer needs while maintaining customer privacy.

The smart grid represents an opportunity to enhance the value customers receive from the electric system. Idaho Power is committed to helping customers realize this value through good planning and making wise investments, considering both costs and benefits associated with any smart grid project. Idaho Power must maintain the safety and reliability expected of it by both customers and employees while implementing this vision. By optimizing and modernizing the power system, Idaho Power can enhance customer service, improve power reliability, promote energy efficiency, and more efficiently integrate renewable resources.

At Idaho Power, the smart grid vision consists of seven major characteristics:

1. Enhance customer participation and satisfaction
2. Accommodate generation/energy storage
3. Enable new products/services/markets
4. Improve power quality
5. Optimize asset efficiency
6. Anticipate and respond to disturbances
7. Provide resilient operation/robustness

B. Strategy

The company's strategy for realizing the smart grid vision consists of focusing investments in the following areas:

Operations

Idaho Power will continue to make considerable investments in real-time sensing, diagnostic, communications, and control equipment to increase the efficiency and reliability of the system and make the system more resilient. Simultaneous with these investments, Idaho Power must meld together planning activities, field work, and operations. Actions will be taken to integrate new operations tools with existing tools that are familiar to system operators.

Determining a strategy for communicating with the many devices to be installed on the electrical system is critical to the smart grid's long-term success. While Idaho Power has operated a number of different communication systems for many years, many of the systems are becoming outdated or have reached capacity. A distribution system communications strategy must provide speed, bandwidth, and high security while minimizing costs.

Idaho Power will undertake some specific operational projects that are described more fully in this report, including the following:

- Replace the Outage Management System (OMS)

- Refine the renewable energy (wind) integration tool
- Install a transmission line situational awareness tool
- Conduct a substation fiber-based protection and control pilot
- Enhance the existing conservation voltage reduction (CVR) program

Customer Systems

Idaho Power believes its customers' expectations are changing and they want more, timely information about their energy use. To provide customers easier access to information about their energy use and enable them to take actions based on that information, many background activities must occur.

One specific customer systems project that will be undertaken and is described more fully in this report is the development of the Customer Relationship Management (CRM) system.

Advanced Metering Infrastructure

With most Idaho Power meters now having AMI capabilities, Idaho Power seeks to more fully utilize the AMI system and the information received to improve the service offered to its customers. One specific project that is being undertaken is the implementation of automated service connects in Oregon.

C. Process

Idaho Power has a systematic process for evaluating smart grid projects. The Transmission and Distribution Strategy (formerly the Research Development and Deployment) department is the primary department responsible for the assessment of new grid technologies, including smart grid opportunities. This department is responsible for tracking and evaluating industry technologies, guiding technology pilots, and assessing pilot-project outcomes.

Plans for utility-wide deployment of successful technologies are submitted for capital funding and evaluated with all other capital-funding requests. The high-level process is shown in Figure 1.

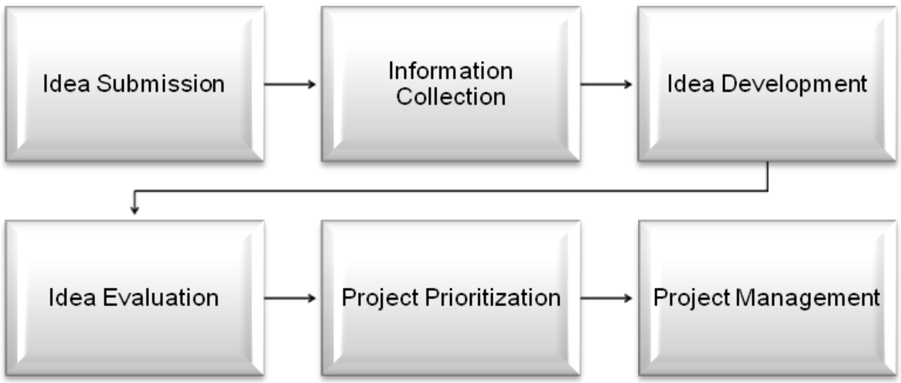

Figure 1. Idea processing

Smart grid ideas are analyzed to determine if they solve an existing problem, improve efficiency, increase reliability, improve safety or security, or enhance customer satisfaction. Smart grid ideas are developed into deployable pilot projects and evaluated based on the cost/benefit. The pilot project is submitted to a review team to ensure all aspects of the project have been included in the initial design and to evaluate external impacts of the project (e.g., communication infrastructure and operating capabilities). The project is then evaluated for funding against all other projects. After the pilot project is funded and deployed, it is evaluated against the projected costs and benefits determined in the initial evaluation stage. If the pilot project meets expectations, a project plan is developed for utility-wide deployment.

II. Status of Smart Grid Investments

The following sections describe the smart grid projects, initiatives, and activities currently underway and the results to date.

A. Transmission Network and Operations Enhancements

Transmission Situational Awareness Grid Operator's Voltage Stability Monitoring and Control Assistant

Idaho Power system operators rely on day-ahead power flow analysis and some real-time analysis tools to manage the grid.

The goal of this project is to develop an application that enhances grid reliability by improving the quality and use of the synchrophasor data received from more than 584 western interconnection phasor measurement units (PMU).

Idaho Power, Southern California Edison, Peak Reliability, California Independent System Operator, Bonneville Power Administration, San Diego Gas and Electric, and V&R Energy have received a U.S. Department of Energy research and demonstration grant for a new synchrophasor-based software application, named the Grid Operator's Monitoring & Control Assistant. See Appendix B for Peak Reliability's project plan. The funding matches dollars committed by the seven participants to extend and deploy synchrophasor technologies.

Peak Reliability will use the grant to improve the quality and use of the synchrophasor data it receives from the PMUs referenced above.

The proposed software application will consist of the following major components:

1. Use of a linear state estimator (LSE) for the following purposes:

    - Estimating the system state using a direct, non-iterative solution based on PMU measurements of voltage and current
    - Validating the results of conventional model-based state estimator (SE)
    - Potentially replacing the conventional SE solution if it becomes temporarily unavailable
    - Utilizing cases created by the LSE for voltage stability analysis

2. Voltage stability analysis software ROSE (Region of Stability Existence)—A real-time analysis tool that increases situational awareness of the operators that allows for the accurate and timely prediction of steady-state instability.
3. An off-line version of ROSE—This will be provided to allow planners to troubleshoot and develop scenarios to be used in the real-time version.
4. Automatic computation of advisory optimal corrective actions for voltage stability preservation.
5. Computation of phase angle difference limits in real-time using a new methodology for line/path stressing based on maximized loading of transmission lines/paths.
6. Easy-to-understand visualization of synchrophasor data, voltage stability analysis results, and optimal corrective actions on a custom-built situational awareness wall.

V&R Energy will perform a demonstration of the software tool. Idaho Power will prepare and provide data to V&R Energy, respond to the data-related questions, review and provide feedback on the functionalities of the tool, test the software tool, and receive training on the software application.

The software will validate the SE, compute corrective actions to maintain voltage stability, compute phase angle difference limits, and provide operator visualization of synchrophasor data. The software will provide visibility in between snapshots of the SE and also during critical times when the SE solution is not available. The overall goal of the project is to improve grid reliability.

The Beta version of the Grid Operator’s Monitoring & Control Assistant has been installed on Idaho Power’s System Planning computers for evaluation. This Beta version does not include the LSE at this point but does include a near real-time analysis program (ROSE), as well as an event analysis program (ROSE off-line) to allow planners to review past events. The near real-time

Beta version acquires an SE solution from the peak reliability coordinator (RC) every 5 minutes and computes selected path limits.

Dynamic Line Capacity Pilot

As originally described in the 2014 Smart Grid Report, Idaho Power and the Idaho National Lab (INL) continue to collaborate on a system that predicts wind speed and direction along the transmission line from an area-specific wind model using real-time weather station information located along the transmission line. The software program being developed by the INL calculates the actual line limits based on the measured ambient conditions and wind model results.
A pilot system with 15 weather stations was installed in a test area monitoring a portion of the 230 kilovolt (kV) and 138-kV transmission lines between Hagerman, Bliss, and Glenns Ferry, Idaho. The original pilot system is being expanded to include 46 weather stations covering the entire line corridor from Midpoint Substation north of Twin Falls to Boise Bench Substation in Boise, Idaho. The original pilot system weather stations have been upgraded, and the additional weather stations are to be installed during 2016.

The pilot project has progressed with the installation of several new weather stations. The INL has developed and continues to update the software to calculate operating line limits to be completed in 2016. It is anticipated that the remaining weather station installations will be complete during fall 2016. When installation is complete, all of the data will be available to the software developed by the INL. The company expects to have real-time line-limit capacity calculations for the lines in this project available via Idaho Power's PI database with historical values for review and demonstration by Idaho Power's planning and engineering and operations departments. Idaho Power and the INL continue to gather data to assess the potential to dynamically rate transmission line operating limits in the Hells Canyon area along the Oregon–Idaho border with six weather stations currently installed. Idaho Power is still working to install a seventh weather station at the Hells Canyon power plant. Data gathering is expected to continue through 2016 and will be assessed after the end of the year. Due to the extreme topology of the Hells Canyon area, this is a very challenging endeavor. Figure 2 shows dynamic line capacity equipment installed in Hells Canyon. Idaho Power and the INL continue to work closely together to further this technology and approach.

Figure 2. Dynamic line capacity equipment installed in Hells Canyon

Power System Engineering Research Center

Idaho Power currently participates in the Power System Engineering Research Center (PSERC)—an Industry-University Cooperative Research Center, drawing on university capabilities to creatively address the challenges facing the electric power industry. It conducts research for innovative solutions to these challenges using multidisciplinary research expertise in a multi-campus work environment and facilitates the interchange of ideas and collaboration among academia, industry, and government, which also helps educate the next generation of power system engineers.

Idaho Power is tracking the following projects:

- **Life-Cycle Management of Mission-Critical Systems through Certification, Commissioning, In-Service Maintenance, Remote Testing, and Risk Assessment.** This PSERC project addresses the criteria for robust and reliable operation and offers solutions in terms of both the methodology and practical tools to perform required testing and evaluation. The outcome of the project will be delivery of several testing and evaluation tools: testing and certification lab, testing and certification equipment and protocols, calibration and field-testing equipment for in-service maintenance, software tools to enable remote testing and detection of failures, and visualization tools that are able to track the quality of service (QoS) state of critical systems and inform operators about deterioration modes.

- **Leveraging Conservation Voltage Reduction for Energy Efficiency, Demand-Side Control, and Voltage Stability Enhancement in Integrated Transmission and Distribution Systems.** PSERC is developing a new algorithm based on load modeling to assess real-time real/reactive load-reduction effects of CVR. A co-simulation framework for transmission and distribution systems is proposed to investigate the impacts of CVR on voltage stability margins of transmission systems. The coordination between energy-oriented and stability-oriented CVR will be studied. The mutual impacts between voltage reduction and voltage control of distributed generation will also be investigated.

- **Monitoring and Maintaining Limits of Area Transfers with PMUs.** This PSERC project will develop practical methods based on PMUs to detect and act on conditions in which the transfer of power through areas of the power system should be curtailed to satisfy thermal line limits and small-signal stability limits. Closed-loop controls for robust stability will also be developed. The larger objective is to combine measurements with physical network models to turn PMU data into actionable advice for operators to improve the management of bulk power transfers and control instabilities. Implementation of this project is subject to additional funding to support this work.

- **Real-Time Synchrophasor Measurements-Based Voltage Stability Monitoring and Control.** This PSERC project will attempt to improve the situational awareness of the power grid by assessing the short-term and long-term voltage stability in real time using synchrophasor measurements. These methods have been validated on standard Institute of Electrical and Electronics Engineers (IEEE) test cases, and their performance on a real system (~10,000 buses) will be studied. The analysis will provide insights on the effective locations for short-term monitoring and efficient control strategies. The long-term voltage stability assessment using a reduced local network for a given, limited number of PMUs will be developed. These algorithms will be integrated and implemented in a real-time test environment for validation and to anticipate issues in actual implementation.

B. Substation and Distribution Network and Operations Enhancements

Solar End-of-Feeder Project

Idaho Power is implementing a small-scale proof-of-concept photovoltaic (PV) pilot project for feeders with low voltage near the end of the feeder. The purpose of the pilot project is to evaluate its operational performance and its cost-effectiveness. The system will be designed to maintain the feeder voltage within +/-5 percent of nominal voltage (American National Standards Institute [ANSI] C84.1) and be cost competitive with other options.

The original concept for the project included a battery system. The battery was included as a way to provide voltage support for nighttime loads. The company sought to find the optimal location for the project by studying 12 sites. The load shape of every site was analyzed and compared to a solar PV output shape. A close alignment between the load shape and the PV output was found, eliminating the need for a battery system.

The end-of-feeder project has been sized at 15 kilowatts (kW) of single-phase generation, which will be produced at 240 volts (V) and connected to a single phase of the MOON 042 feeder at 7.2 kV. The planned project site is in north-central Lincoln County near Shoshone, Idaho, at the end of a single-phase branch circuit that serves a pivot irrigation customer. The site and surrounding area are subject to low-voltage conditions during the irrigation season. Data analysis from previous years showed the peak time occurs during daylight hours, making PV an ideal candidate to reduce peak load.

A detailed model of the end of the feeder was constructed to simulate the impact on the voltage of adding generation at the end of the MOON 042 feeder. The model includes: voltage regulators, distributions lines, service transformers, and service lines. The simulation results using this model were compared with measured data to verify its accuracy.

The addition of 15 kW of solar PV generation is expected to increase the voltage of the customers with the lowest voltage by 2.3 V on a 120-V base. The average expected increase for all customers is 0.5 V on a 120-V base. The expected voltage increase will keep all the customers within range A of the ANSI C84.1 standard.

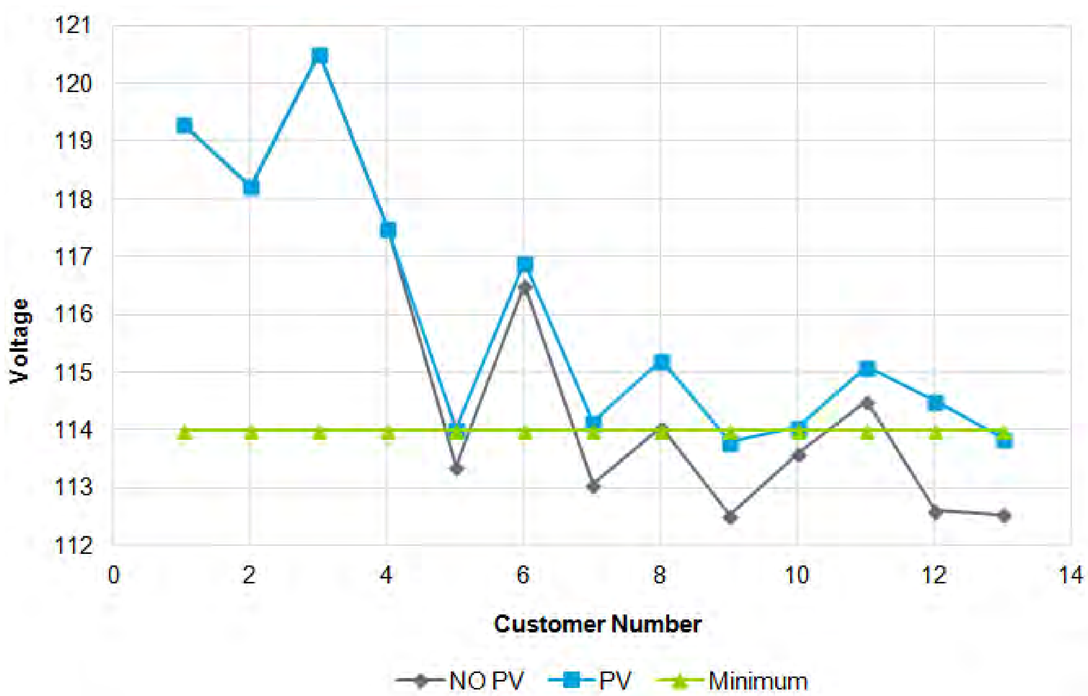

Figure 3. Expected voltage

Figure 3 shows the lowest voltage experienced by the 13 customers downstream of the voltage regulator, MOONRG322, during the months of June and July.

The results of the simulation show that adding 15 kW of PV would have reduced the low voltage read by 96%. It also shows that the minimum voltage for all the customers who experienced low voltage during the summer would have been higher.

Internal analysis indicates the 15-kW solar PV generation can be constructed at the project site at a lower cost than rebuilding the distribution feeder to create the same voltage improvement for the project area, making it economically viable. The project was put out for bid to design, procure, and construct in summer 2016. Construction is nearly complete, with the project expected to be on-line in fall 2016.

Electric Vehicle Charging Stations

Idaho Power is preparing for the accelerated adoption of electric vehicles (EV) through fleet use, customer incentives, and education. Within its own operations, Idaho Power is integrating EVs into its fleets. The company has seven electric passenger vehicles in its fleet and six plug-in or hybrid bucket trucks. Electric bucket trucks use electricity to power equipment when idling, reducing emissions and noise while working in neighborhoods and communities. More electric bucket trucks are on order for 2016.

Idaho Power has installed EV charging stations at 10 company facilities and has established a workplace charging pilot for employees who drive EVs. The company is collecting data on hours and times of use. In addition, the company has installed 5 types of charging stations at its corporate headquarters in Boise. Idaho Power invites businesses, civic groups, and others interested in EV charging to visit its headquarters to learn about the technologies available. On September 11, 2016, Idaho Power hosted a Drive Electric Week event at its Boise headquarters. The event was co-sponsored by the Idaho Sierra Club and Treasure Valley Clean Cities Coalition. This event was open to the public and featured different EV technologies that included 52 EVs, 15 electric bikes and a solar go-kart. Figure 4 shows how customers moved from car to car, talking to different EV owners about their cars.

Figure 4. EV car show

In May 2016, Idaho Power launched an EV Charging Incentive for business customers to encourage workplace, fleet vehicle and public charging. The initial offering was $1,000 for a single-port charger and $1,500 for a dual-port charger. Feedback was that installation costs tended to be higher than first estimated. To allow more flexibility, Idaho Power changed the incentive to 50% of the project costs for installing one or more chargers, up to $7,500 per site. Charging stations must be installed between April 18 and November 11, 2016, to be eligible for the incentive.

Idaho Power is also currently working on its Transportation Electrification (TE) Plan and TE programs to be filed with the OPUC by December 31, 2016. As directed by Senate Bill 1547, the OPUC opened Docket AR 599 to establish a rulemaking regarding TE. The goals of Senate Bill 1547 and Docket AR 599 are to accelerate TE to reduce petroleum use, achieve optimum levels of energy efficiency and carbon reduction, meet federal and state air-quality standards, meet Oregon's greenhouse gas emissions reduction goals described in Oregon Revised Statute (ORS) 468A.205, and improve public health and safety. As detailed in the AR 599 Rulemaking, Idaho Power is required to file a TE Plan and an Application for TE Programs by December 31, 2016. The TE Plan will be an overview document that outlines the company's long-term TE framework to accelerate TE. The TE programs will be company-proposed programs to accelerate TE.

CVR Enhancement Project

Idaho Power initially began the CVR project in 2009. The project focused on feeders where CVR could be implemented at minimal cost by simply changing the settings on distribution substation transformer load tap changers (LTC) (referred to here as "one control point"). The CVR Enhancement Project began with project design in early 2014 and equipment installation in late 2014/early 2015. To validate the energy savings associated with CVR, Idaho Power chose a method similar to that described in the Electric Power Research Institute (EPRI) *Green Circuits: Distribution Efficiency Case Studies* document. Idaho Power aggregated AMI data on separate treatment transformers and compared the data against a set of control transformers to produce CVR factors for each customer class and weather zone. The validation study determined the effects of CVR on commercial and residential customers in each of six company-identified weather zones. The six weather zones were identified as Boise, Twin Falls, Pocatello, McCall, Ontario, and Ketchum. One treatment transformer in each weather zone was studied for each rate class. Additionally, one transformer dedicated to irrigation loads was studied. Data collection was performed on all transformers for an entire year.

The scope of the CVR Enhancement Project includes the following:

- Validate energy savings associated with CVR using measured instead of modeled values
- Quantify the costs and benefits associated with implementing CVR
- Determine methods for expanding the CVR program to additional feeders
- Pilot methods for making Idaho Power's CVR program more dynamic

  Note: This item is partially addressed in the related project, Edge of Network Grid

Optimization (ENGO) Solid-State Reactive Power Compensation Device Use for Improving the Dynamic Performance of CVR, which is discussed later in this report.

- Determine methods for ongoing measurement and validation of CVR effectiveness

Idaho Power has completed data collection and analysis for the CVR Enhancement Project. As envisioned, Idaho Power would dynamically control the CVR program such that voltages on transformers are minimized while maintaining customers' voltage levels to meet the ANSI C84.1 and not overly burdening substation and line equipment with excessive operations. To view the analysis results, along with a complete report on the CVR Enhancement Project, see Appendix C. In summary:

- Residential and commercial CVR factors varied by season, and at times there was an increase in energy as opposed to the desired energy decrease. In general, energy savings were realized associated with load connected to each treatment transformer, through in some cases the energy saved was very small.

- CVR factors, and therefore energy-savings potential, varied greatly from one weather zone to another. This indicates that any extensive CVR program would require significant flexibility and customization in setting control parameters. Even within a particular weather zone, the CVR factors may vary between individual substations, though not as widely as between weather zones.

- Using CVR for demand reduction during peak loading conditions is generally beneficial for load reduction based on study results. However, it would be difficult to institute CVR for both energy and demand reduction concurrently since there would not be a visible reduction at peak if CVR is already on for energy-saving purposes.

ENGO Solid-State Reactive Power Compensation Device Use for Improving the Dynamic Performance of CVR

Idaho Power installed 65 ENGO solid-state reactive power compensation devices on TERY-012 and TERY-014 feeders in Pocatello, Idaho. A Supervisory Control and Data Acquisition (SCADA)-controlled LTC controller was installed on the TERY T131 transformer that supplies these feeders so day-on/day-off testing of CVR could be performed. This transformer was previously identified as a potential CVR transformer, but the voltage drop was too great on feeder TERY-012, therefore CVR was not deployed. If the ENGO units can successfully be used to raise the voltage on TERY-012, TERY T131 may qualify for CVR control.

The goal of the project is two-fold:

1. Provide voltage support at points along the feeder that are modeled as voltage low points so CVR can be applied. Note that CVR calculation in this project is not as complete as that calculated in the primary CVR Enhancements Project and is only indicative of the positive potential for CVR.

2. Determine if deploying such a large number of units on a single feeder can act to optimize the voltage on the feeder primary side (12.47 kV), therefore improving the voltage profile along the entire feeder.

Results of this project are inconclusive due to line capacitor misoperation in 2015, so the study has continued into 2016. The report will be finalized once the current testing is complete.

Metrics Used for Measuring Benefits

Table 1 shows the various metrics used for measuring benefits.

Table 1. Metrics used for measuring benefits

Substation Phase Balance Improvement—Maximum Average Phase Difference Reduction	Flatten Feeder Voltage—Maximum Decrease in Standard Deviation*	Voltage Increase End of Feeder (Max)	Low Voltage Mitigation when CVR ON—% Fewer Low-Voltage Readings at Monitored Locations	Technical Loss Reduction due to ENGO Units While in CVR Mode	Average CVR Factor for Energy	Reduction of Energy Consumption due to CVR**
0.1939 V	0.797 V	2.219 V	80.83%	3.33%	1.5	3.75%

*Decrease in standard deviation represents the difference between substation voltage and end of feeder voltage.

**Calculation of CVR factor performed using day-on/day-off testing and calculating the difference in energy used from metering at substation end of feeder. This CVR factor is a combined number for all customer types connected to this feeder and represents only 4 weeks of testing. No separation between customer classes was performed.

Project Description

TERY-12 is a 12,470-V feeder served out of the TERY substation in eastern Pocatello, Idaho. It is mostly an urban feeder, though one branch serves a transmitter site atop a mountain a few miles from the city of Pocatello (see map). ENGO units were installed on both TERY-012 and TERY-014 feeders, with their distribution determined by power flow modeling. Most of the units (57) were installed on TERY-012, with a handful of units (8) installed on TERY-014 to balance the phase voltages as seen from the substation. Data analysis mostly took place on TERY-012.

The ENGO units include voltage monitoring capability via cellular connection, but it was decided to also deploy other voltage monitoring devices to determine the effect such a large number of ENGO devices would have on the feeder's primary voltage. Single-phase smart grid monitors (SGM) were installed on TERY-012 and on TERY-014 to measure phase voltages. One SGM was already in place on TERY-012. Three-phase power-quality monitors were installed on a couple of three-phase service transformers to capture voltages. Additionally, voltages were collected twice daily from 70 AMI meters on TERY-012. Finally, numerous measured quantities were collected at the substation, including transformer and feeder voltages, power flows, volt ampere reactive (VAr) flows, and power factor.

The units began operation on May 8, 2015, cycling on and off with a 24-hour cycle (i.e., day on/day off). The SCADA-controlled substation LTC was installed September 17, 2015, and the project immediately reduced the LTC tap center position from the normal 123 V to

120 V to begin CVR testing. The LTC remained at 120 V until March 31, 2016, when data collection was finalized. Figure 5 shows ENGO and monitoring-device locations.

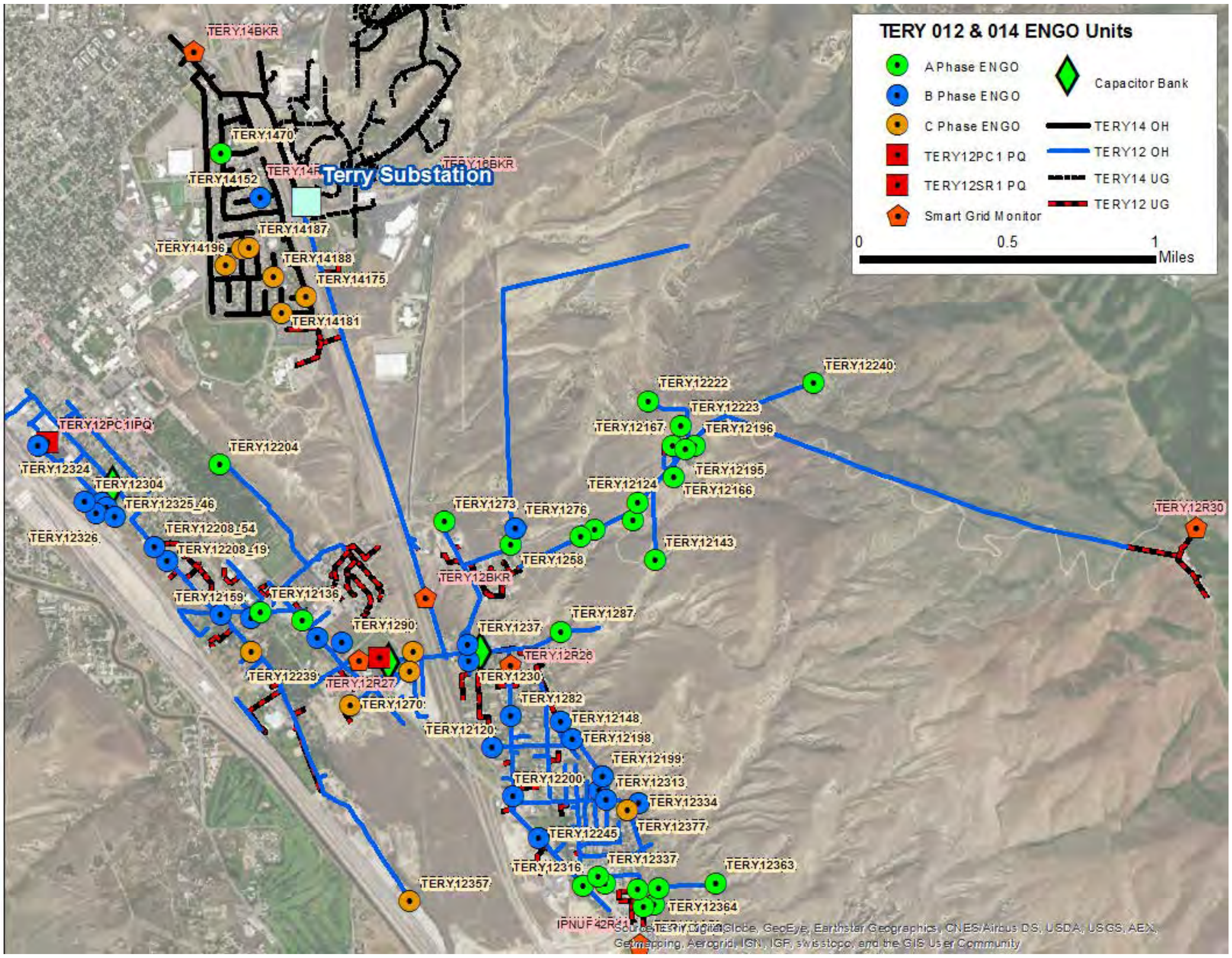

Figure 5. ENGO and monitoring-device locations

Project Results

Balance Substation Voltages

As determined using PI database historical values in the substation, the ENGO units improved the voltage balance between phases, but not dramatically so. B Phase voltages normally run lower than A and C phase voltages on the TERY-12 feeder, so more ENGO units were installed on phase B to try to balance the voltages. Figure 6 shows a comparison of phase voltages with ENGO units on and with ENGO units off and the feeder voltage reduced for CVR. On average, the difference between A and B phase decreased by 0.0557 V, and the difference between B and C phase decreased by 0.1939 V with the ENGO units on. These are probability curves calculated based on the measured substation values. A steeper and taller curve indicates a better voltage profile.

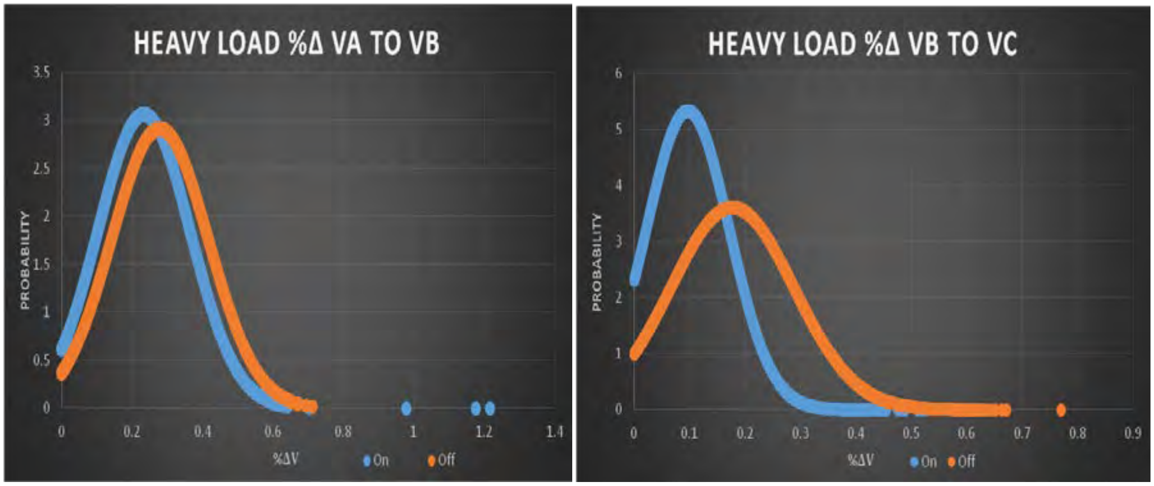

Figure 6. Change in voltage difference between Phase A and Phase B and between Phase B and Phase C

Flatten Feeder Voltages (CVR On)

Using the distributed voltage meters installed throughout the feeder, a normal distribution was created to determine if the voltage drop that occurs along a feeder could be decreased using ENGO units. Most of the ENGO units were installed on phases A and B with just a few on Phase C. As expected, the ENGO units had minimal effect on Phase C. However, the normal distribution of voltages on phases A and B were more dramatic, particularly on Phase A. Figure 7 shows the normal distribution of voltages for phases A and B. Note how much tighter the voltages became (steeper, more defined slope) with the ENGO units on.

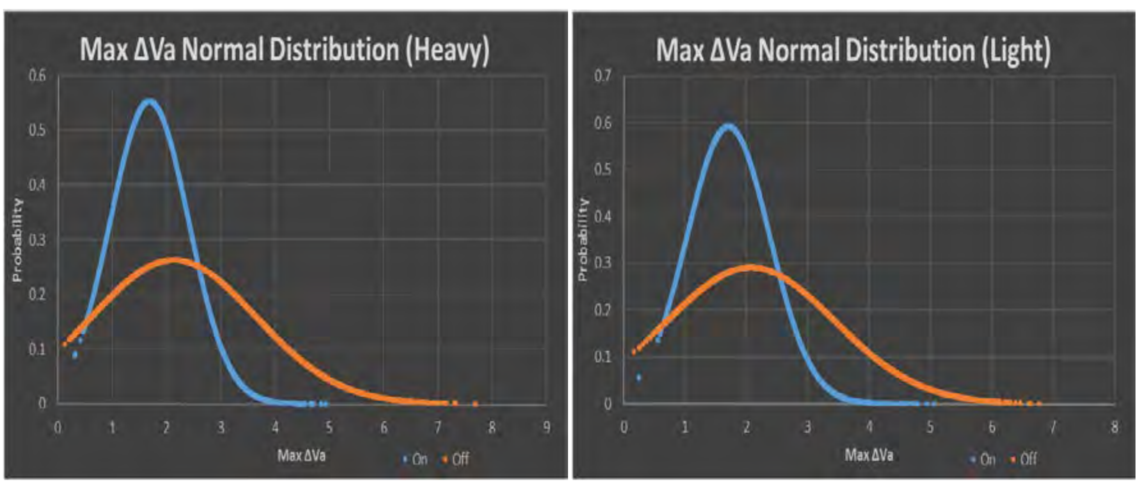

Figure 7. Normal distribution function with ENGO units on and off

Raise Feeder Voltage

Voltages were sampled using both three-phase power quality meters and AMI meters to determine if the feeder voltage was raised when the ENGO units were on. Figure 8 shows the results for phases A and B from a power quality monitor installed near the end of the feeder. The figure shows the ENGO units had a definite and positive effect on voltage.

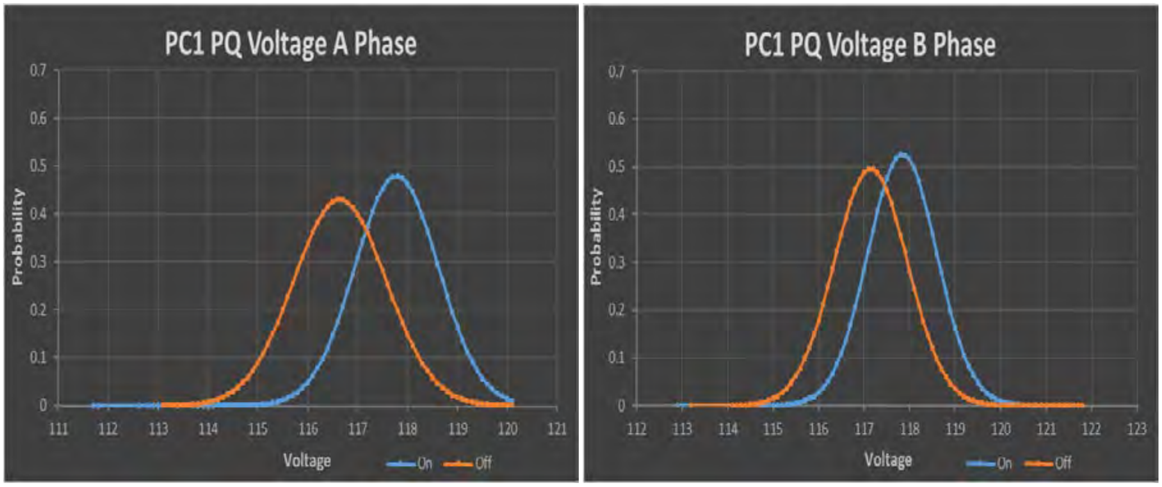

Figure 8. Voltage rise at end of feeder

Low Voltage Mitigation

Data collected from an SGM located at a transmitter station atop a mountain, a mile and a half from the nearest ENGO unit, shows the ability of the ENGO units to raise the primary voltage. Figure 9 shows voltages under normal feeder voltage conditions and with feeder voltages reduced for CVR.

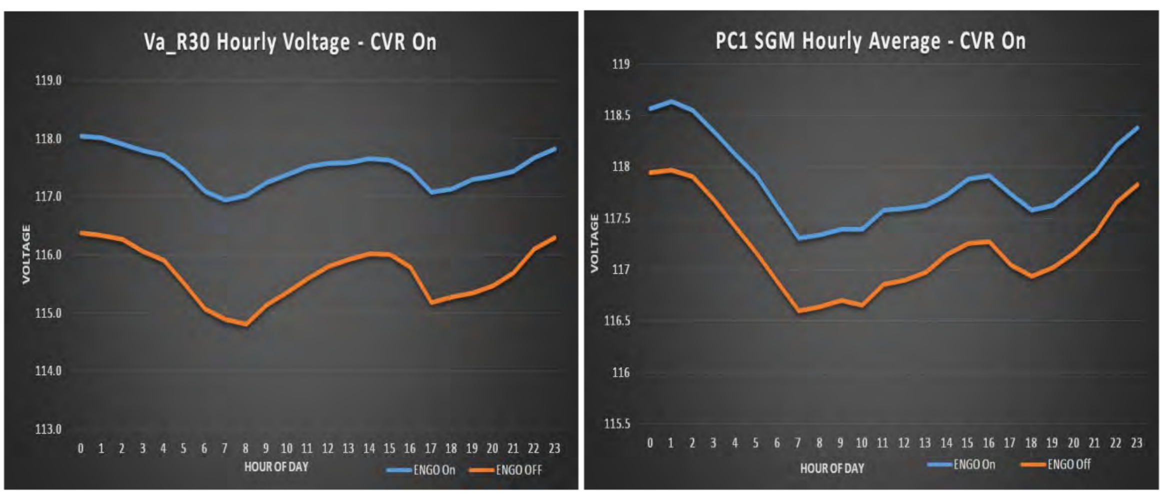

Figure 9. ENGO ability to mitigate low voltage

Summary

Using ENGO units in large numbers proved they have the ability to flatten a feeder's voltage profile, increase phase voltage balance, and address spot voltage problems. ENGO units can therefore be a viable means to allow the CVR program to expand to previously unqualified feeders and substations. However, ENGO units may not be the lowest-cost option available, so a cost/benefit analysis will be required for each feeder upgrade project.

ENGO Solid-State Reactive Power Compensation Device Pilot

The ENGO Static VAr Device Pilot Project consisted of installing 10 ENGO units on Portneuf Substation's feeder 42 (PNUF-042) near the far end of Arbon Valley, Idaho. The units were installed on the secondary side of nine 25 kilovolt-ampere (kVA) service transformers and one 50 kVA service transformer to determine if they could resolve voltage flicker issues that customers experience on this remote, single-phase feeder section.

The original scope of the project was to install, operate, and test ENGO units on various feeders, with the end result being a report providing recommendations concerning ENGO unit use on the Idaho Power system for voltage support. During the early stages of the project, it was suggested that units be placed on PNUF-042 to test their ability to mitigate voltage flicker occurring on this long rural feeder. While the units were not designed to mitigate for voltage flicker, it was hoped their high-speed operating characteristics would provide the ability to mitigate flicker.

In addition to the ten ENGO V-10 units installed on PNUF-042, one unit was installed at a greenhouse facility in Eagle, Idaho, in December 2013 to test for harmonics injection and to determine if the ENGO unit would interfere with the AMI signal.

While the results of this project show the ENGO units do not mitigate the particular voltage flicker occurring on PNUF-042, much operational experience was gained:

- The units are able to increase the voltage supplied from the secondary of a service transformer by as much as 3 V, depending on transformer loading.
- The units do not inject significant harmonics into the circuit.
- The units are compatible with Idaho Power's Two-Way Automatic Communication System (TWACS)-based AMI and actually improve the communications signal if they are located near the meter (not a long service drop).
- The metering within the ENGO units is able to capture events on the distribution system, such as significant voltage sags.
- The units are reliable, with the only significant failures occurring because of cellular communications loss. Even when communications are lost, the units retain the voltage data and will communicate the information upon return of communications. They also continue to regulate when communications are not present.

This pilot project is complete. To view the analysis results, along with a complete report on the ENGO Static VAr Device Pilot Project, see Appendix D.

Photovoltaic and Feeder Peak Demand Alignment Pilot

Idaho Power designed a pilot program to study the statistical relationship (correlation) between solar intensity and load, as well as relationships between load and meteorological parameters, such as wind speed and ambient temperature. The pilot was limited to a single distribution feeder containing three solar irradiance weather stations (SIWS). The methods for performing the study were divided into four chronological steps:

1. Choose a residential feeder.
2. Design and install the model weather/solar stations.
3. Gather solar, weather, and load data.
4. Analyze the data for possible correlations.

A residential feeder in west Boise was chosen for the study. Each of three SIWSs located along the feeder route were designed so they collected global horizontal irradiance (GHI), westerly and southerly point-of-array (POA) wind speed, wind direction, ambient temperature, and GPS time synchronization data. Each weather station is comprised of three solar-intensity monitors with the following orientation: south for maximum annual energy output (typical customer orientation), west for maximum output coincident with feeder peak demand, and horizontal for the global solar intensity reference.

Solar intensity data was gathered at the three weather stations during summer 2013. Analysis of the data indicates a relationship between solar intensity and electrical load under certain circumstances:

- Solar intensity analyzed at the southerly-configured sensors led load by approximately 4 hours with a correlation of 0.94 across all three locations (Figure 10).
- Solar intensity analyzed at the westerly-configured sensors led load by approximately 2 hours with a correlation of 0.9 across all three locations. The curves of the westerly configured irradiances tended to peak nearer the actual time of feeder peak loads, but with lower certainty than the southerly- and horizontally-configured irradiances (Figure 11).
- Solar intensity analyzed at the horizontally-configured sensors (also referred to as global) led load by approximately 4 hours with a correlation of 0.95 across all three locations (Figure 12).

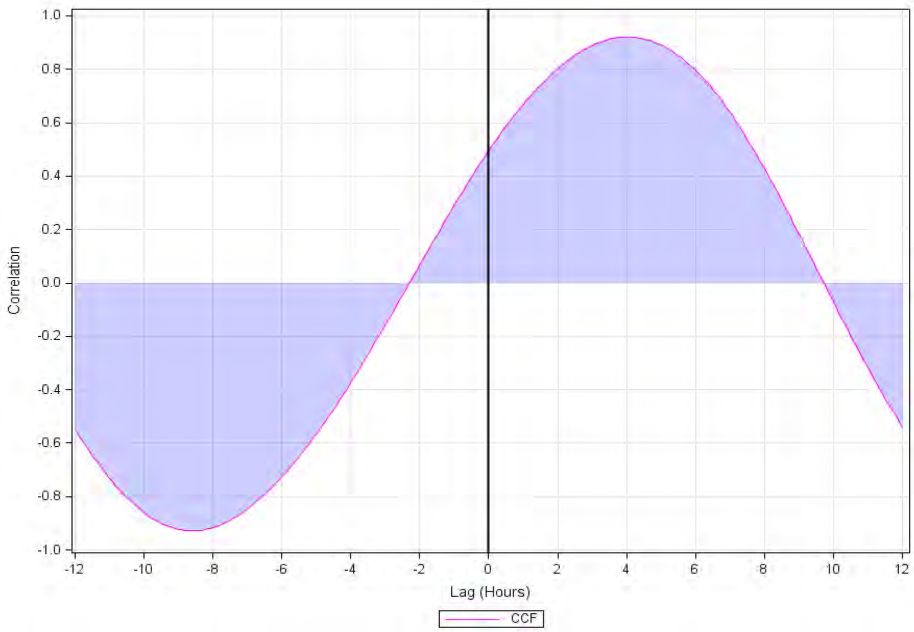

Figure 10. Southerly solar by load cross-correlation function for July 1, 2013

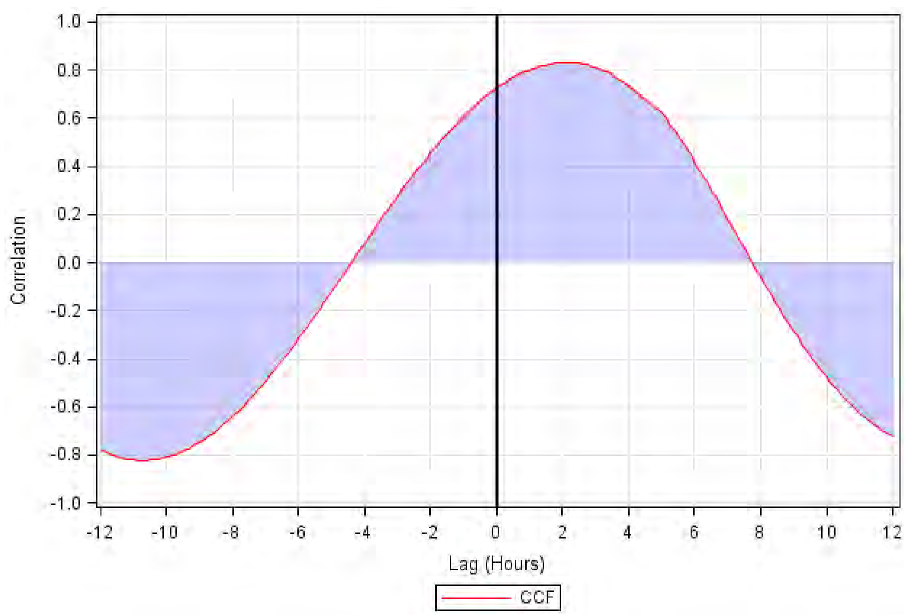

Figure 11. Westerly solar by load cross-correlation function for July 1, 2013

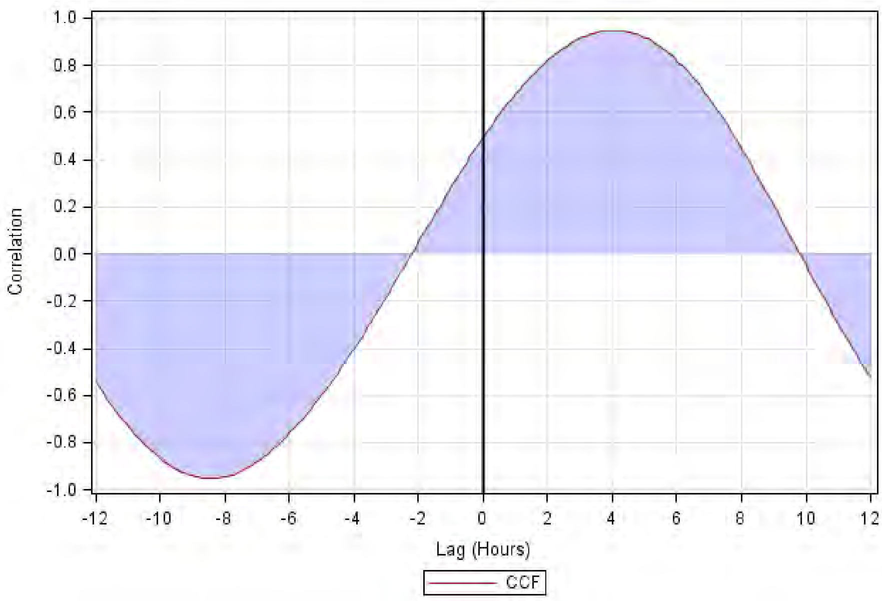

Figure 12. Global solar by load cross-correlation function for July 1, 2013

The data also indicates there is a strong correlation between ambient temperature data and load data, but at best a tepid correlation between wind speed data and load data.

- Ambient temperature measured at the three SIWSs tends to lead load from 0.70 to 0.86 hours, with a correlation ranging from 0.96 to 0.97 across all three locations.

- Wind speed measured at the three SIWSs tends to lead load from 1.80 to 2.38 hours, with a correlation ranging from 0.68 to 0.70 across all three locations. This tepid statistical relationship between wind speed and load also was not a surprising result, considering the low auto-correlation results applied to wind speeds.

This pilot program is now complete. The findings from the study indicate PV panel orientation can be aligned to more closely follow the peak demands on a summer afternoon. Idaho Power is using this data when performing generation interconnection studies of large PV systems, both at the feasibility level and at the system impact level.

Idaho Power published a white paper on the results of the pilot program titled, *A Method for Determining the Relationship between Solar Irradiance and Distribution Feeder Peak Loading*. The white paper provides more detail on the research performed during the pilot, as well as more detail regarding the correlation between solar intensity and load. To view the white paper, see Appendix E.

Substation Fiber-Based Protection and Control Pilot

Present technology and practices require numerous multi-conductor copper cables to connect pieces of substation yard equipment to the control building for protection and control. These copper control cables represent a significant percentage of the overall cost of a new substation.

Newly built Idaho Power substations could use fiber optics in lieu of copper wires to connect pieces of substation yard equipment to the control building for protection and control.

Idaho Power, Schweitzer Engineering Laboratories, and Alcatel–Lucent (now Nokia) are currently developing the digital equipment needed to implement a highly reliable substation fiber-optic network. The pilot project will install a system in 2016 that parallels an existing substation protection and control system to demonstrate the reliability and viability of this technology. The fiber optic-based protection and control demonstration project at Hemingway Substation is progressing. The conceptual design is complete and the various components have been selected. Schweitzer Engineering Laboratories is building the yard cabinets and control racks that will be used for this project. Construction is anticipated to be complete in the fourth quarter of 2016 with the fiber-optic cable, yard cabinets, and control rack installation. Data collection will occur for one year after construction is complete. This project will not only demonstrate the protection and control over fiber-optic concepts but will implement Precision Time Protocol for very accurate time keeping and time stamping over a highly reliable fiber-optic network—a necessary development for this standards-based approach to proceed.

Once demonstrated, not only will this technology potentially reduce costs for Idaho Power and its customers in future installations by decreasing the amount of copper wire installed, but it could prompt industry-wide adoption of this approach.

Replace the Existing Outage Management System

Idaho Power's existing OMS is aging and is no longer supported by the original vendor. In 2010, Idaho Power began the effort to select a vendor and implement a new OMS. The project was progressing until early 2012 when critical Idaho Power resources assigned to the OMS project were needed to support the higher priority Customer Relations and Billing (CR&B) project. In fall 2012, Idaho Power suspended the OMS project but reinitiated it in late 2014. The focus in 2015 was selecting and contracting with a vendor to provide the desired OMS capability. Idaho Power selected CGI's PragmaLine OMS system and initiated the design phase of the project in August 2015; the design phase was completed in December 2015. Development and implementation phases began in January 2016, and the new OMS platform is slated to be operational in the fourth quarter of 2016.

A new OMS platform will aid in customer service restoration after power system interruption events. The OMS system models the distribution, substations, and vital transmission elements used to serve energy to our customers. The system also ties the local transformers providing service to the customers being served. When a customer calls to report a power interruption, the OMS system analyzes the circuit, referencing other customer calls when available, to predict the most probable device causing the interruption. Crews are then dispatched to the predicted device to investigate the cause of the outage and restore service. In addition, by integrating the OMS system with Idaho Power's SCADA system, the OMS system will show customer interruptions automatically when a SCADA device is opened. These devices are typically inside substations, such as feeder breakers or power circuit breakers. It will allow more efficient use of restoration crews, thereby increasing customer satisfaction and decreasing costs.

Implementation of Automated Connect/Disconnect Capability

Idaho Power's AMI project that concluded in 2011 did not include the installation of remote-controlled connect/disconnect switches. At that time, Idaho Power was unable to justify the cost of installing these switches at all metering points on its distribution system. Company representatives have continued to physically visit customer service locations to manually connect and disconnect services as needed.

However, Idaho Power has recognized the capability of the AMI system to remotely control service connect/disconnect switches. After the initial AMI installation, the company analyzed the costs and benefits of installing AMI-controlled service connect/disconnect switches at a select number of locations. The company believes the capital costs are more than offset by eliminating the cost of manual connects/disconnects at locations that have multiple visits to manually connect or disconnect service each year.

Approximately 15,956 residential service locations in Idaho Power's total service area (approximately 811 in Oregon) have multiple manual connect/disconnect events each year. The company has replaced the current meters at these locations with new meters equipped with remotely controlled connect/disconnect switches via the AMI system. On September 15, 2015, Idaho Power implemented remote connect/disconnect functionality for approximately 14,000 customers in its Idaho service area. However, Idaho Power postponed implementation in Oregon because additional work was needed to comply with Oregon Administrative Rule (OAR) 860-021-0405(9)(b)(B). A project plan was developed in fourth quarter 2015 for implementing remote connect functionality in Oregon. Following the OPUC's approval of Idaho Power Tariff Advice 16-09, the company started remotely connecting services in eastern Oregon on August 16, 2016.

Table 2 lists project milestones:

Table 2. Project milestones and dates

Milestone	Date
1. Began installing remote connect/disconnect AMI meters	April 21, 2014
2. Completed installations of remote connect/disconnect AMI meters	December 31, 2014
3. Implemented the automated connect/disconnect process in Idaho	September 15, 2015
4. Developed a project plan to implement remote connect/disconnect functionality in Oregon	December 31, 2015
5. Conference call with OPUC Consumer Staff to explore options to OAR 860-021-0405(9)(b)(B)	April 21, 2016
6. Filed Tariff Advice 16-09 to establish a charge for remote service connection in Oregon	May 6, 2016
7. OPUC approved Tariff Advice 16-09	July 5, 2016
8. Implemented remote connect functionality in Oregon	August 16, 2016

By installing this technology as described, Idaho Power expects to realize the following benefits:

1. Reduce the annual cost of connecting and disconnecting services
2. Improve customer service by consistently completing the connect/disconnect function in a more timely manner
3. Reduce a potential safety risk for employees traveling to customer locations, accessing service locations, and removing and installing energized meters as is currently done for manual connect/disconnect activities
4. Reduce the environmental impact of driving hundreds of thousands of miles each year to perform this function manually

Implement Additional AMI Outage Scoping and Restoration Confirmation Functionality

Formerly known as the Sentry System, Idaho Power has implemented an SGM system that monitors system reliability. The SGM system has approximately 1,400 monitored sites that record momentary and sustained outage activity. Currently, sustained outage notification from the SGM system is fed directly into Idaho Power's OMS, which notifies operators when a sustained outage is detected. Once aware of the outage, the OMS operators can request a manual query of AMI meters in the affected area to more precisely identify the location of the outage.

In 2013, Idaho Power tested AMI integration with the SGM system and found that the systems can exchange sufficient data to provide the OMS with outage information related to event origination and tracking of outage restoration activity.

As part of Idaho Power's OMS replacement project, the company will integrate the OMS and AMI systems, allowing the OMS operators to manually query AMI meters in the area of a sustained SGM outage event. The SGM system used in conjunction with the OMS and AMI systems can assist OMS operators in quickly and accurately locating outages on the distribution system and initiating outage restoration efforts without depending on customer calls.

The objective described above will integrate the OMS and AMI systems. In the current environment, "pinging" meters (call to the meter to verify it is energized) is performed through a separate tool, requiring the operator to compare separate systems while evaluating the meter's response. Enabling the operators to view the SGM call and initiate the AMI meter ping process all from the OMS system will reduce operator intervention and data interpretation.

This work has been included within the scope, cost, and schedule of the OMS replacement project. The completion of the project is forecasted to be November 2016. The main benefit will be the initiation of outage restoration without depending on customer calls.

Volt/VAr InterTechnology Control Pilot

Idaho Power initiated a 2016 project titled the InterTechnology Control Pilot as a lead up to the Volt/VAr Optimization (VVO) project scheduled for later this decade. Through this project, Idaho Power hopes to enhance its experience in controlling feeder voltages using LTCs, line voltage regulators, and line capacitors in a coordinated fashion and assist in determining the scope of the VVO project, as well as the strategy and requirements associated with a VVO system. This project can act to validate or invalidate the feasibility of applying various control strategies. If chosen wisely, the location of this project can serve to test various Volt/VAr related strategies and technologies at future times.

The scope of the Volt/VAr InterTechnology Control Pilot is to accomplish the following:

1. Determine a strategy or set of strategies that can be used for optimizing the Volt/VAr characteristics on a distribution feeder (i.e., flatten feeder voltage profile, improve VAr support for the transmission system, or other strategies).

2. Determine a strategy for coordinating the actions of LTCs, voltage regulators, and capacitors on a distribution feeder or set of feeders fed from one distribution transformer.

3. Install a small pilot project to test the identified strategies.

4. Make recommendations concerning individual devices to be used in a Volt/VAr optimization system.

The outcome of this project will be a coordinated Volt/VAr management strategy involving two feeders that can be used as a basis for developing a system-wide Volt/VAr management strategy.

Idaho Power has installed line devices on two feeders served out of Aiken Substation near Blackfoot, Idaho. The new capacitor bank controllers and voltage regulator controllers with two-way communications installed can be used for monitoring various line quantities, as well as send out signals to the line devices to change control set points. The new line capacitor banks will more evenly distribute the feeder's VAr support. Additionally, the substation LTC controller has been connected to SCADA so control can be remotely performed.

The project is expected to be completed at the end of 2016, though more data collection may occur in 2017.

C. Customer Information and Demand-Side Management (DSM) Enhancements

Advanced Metering Infrastructure

In 2011, Idaho Power completed the installation of AMI hardware and software, a meter data management system, a metering data warehouse, and approximately 500,000 digital AMI meters (including 18,000 meters in Oregon) for a total investment of $73 million. The AMI system is currently collecting hourly energy consumption data and daily kilowatt-hour (kWh) and kW readings for all AMI meters deployed in Idaho and Oregon. The AMI system provides two-way communications to 99 percent of Idaho Power's metered retail service locations (93 percent in Oregon). The remaining metered retail service locations did not meet Idaho Power's business-case requirements at the time the implementation plan was initiated in 2009. Idaho Power continues to manually read meters at these locations and periodically re-evaluates the business case for installing AMI equipment in substations located in sparsely populated areas.

Idaho Power continues to leverage the AMI system for uses beyond billing data collection. These additional uses include the following:

- **Outage Detection**—If a meter stops communicating, a trouble order is issued.
- **Partial Power Detection**—The phase voltages on all three-phase services are measured three times a day. If one of the phase voltages shows as missing, a trouble order is initiated.
- **System Voltage Reads**—Voltage data is collected three times a day at all active three-phase services and other locations as requested by company planning or field engineers (currently 40,000 sites).
- **Select Load and Voltage Studies**—In place of installing additional field monitoring devices, voltage and load information can be collected for specific service locations on request.
- **Customer Load Control**—The AMI system communicates commands to both the A/C Cool Credit and Irrigation Peak Rewards demand response (DR) programs.
- **Reverse Power Flow Detection**—The AMI system detects unauthorized customer generation, attempted energy diversion activities, and metering installation errors.
- **Instrument Transformer Meter Installation Verification**—Meter technicians periodically validate the accuracy of instrument transformer metering installations.
- **Investigations of Non-Communication Issues**—These investigations have uncovered service issues, including unintended distribution circuit field ties, distribution capacitor issues, distribution line regulator issues, overloaded circuits, and power quality issues.
- **Remote Connect/Disconnect**—Beginning September 15, 2015, Idaho Power started using the AMI system capability of remotely connecting and disconnecting services in Idaho for customer move-ins and move-outs and customer nonpayment disconnects and reconnects. Idaho Power implemented remote connection capability in Oregon on August 16, 2016.

myAccount

myAccount continues to be an effective engagement platform for Idaho Power's customers. In the 12-month period from July 2015 to June 2016, on average 152,518 myAccount logins were registered each month. The myAccount landing page is the gateway for customers to access their specific account and energy usage information. Once logged in, customers can view their bill, make payments, and initiate online account transactions and inquiries. Additionally, customers can access very detailed account and energy usage information, including their hourly AMI data via idahopower.com, at their convenience, 24–7. myAccount enables customers to make informed choices about their energy use and provides information on how to use energy wisely.

In May 2016, Idaho Power updated the myAccount landing page as illustrated in Figure 13. The new landing page includes icon-driven navigation, helping customers access the account information that is most important to them, including detailed energy use. A central component of the landing page is the "next estimated bill" feature. A bar chart is displayed so customers can quickly compare their previous month's energy usage to their current month's estimated bill, and compare the same month from the prior year. This graph gives customers a very visual and insightful look at their current and historical energy use.

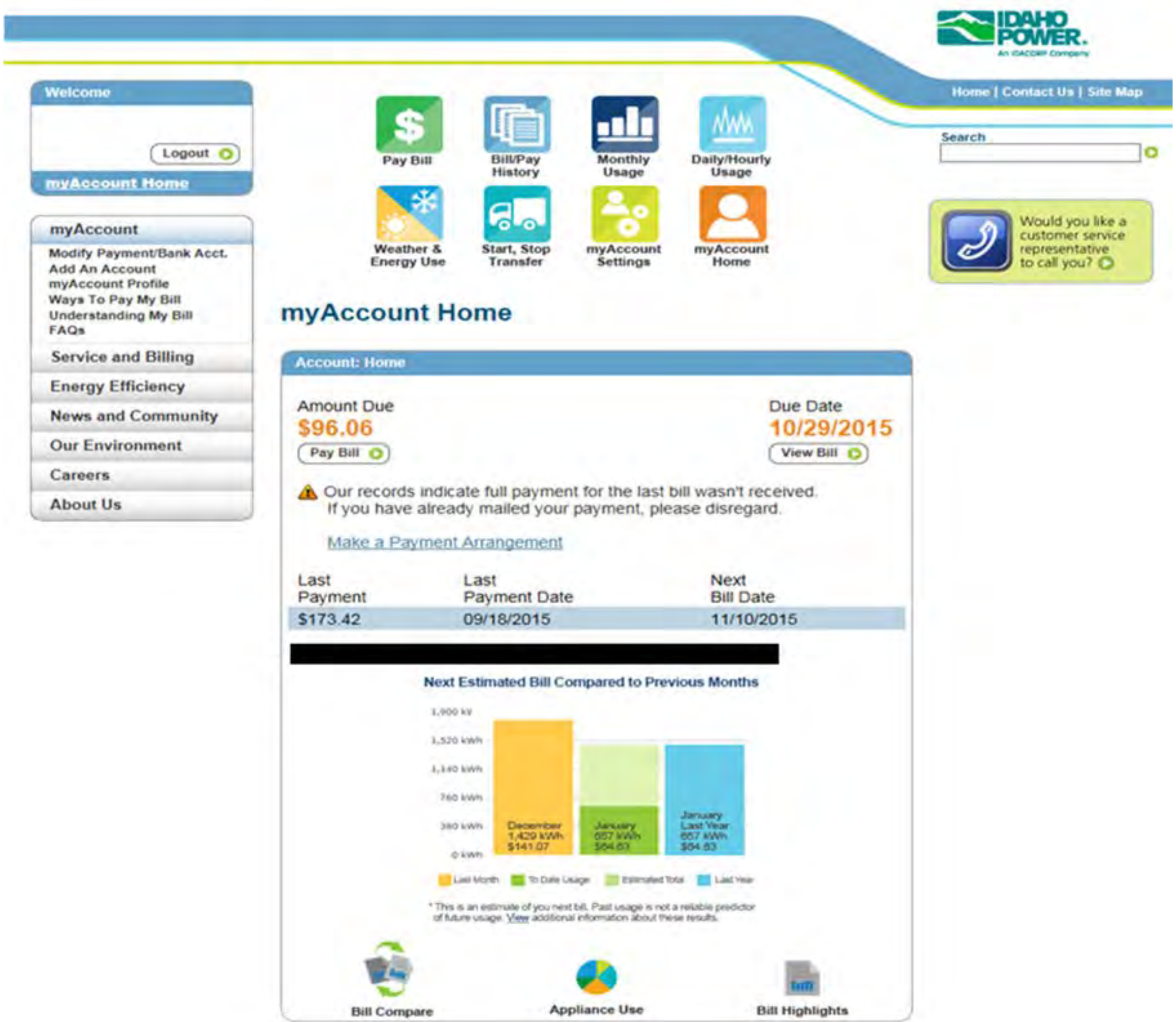

Figure 13. Updated myAccount landing page

Direct Load Control

Idaho Power has offered optional direct load control, or DR, programs since 2004 to residential and irrigation customers, and to all of its customer segments since 2009. The company has offered an air conditioning (A/C) cycling program, A/C Cool Credit; an irrigation direct load control program, Irrigation Peak Rewards; and a commercial/industrial DR program, the Flex Peak Program. The A/C Cool Credit and Irrigation Peak Rewards programs use smart grid technology—more specifically, the power line carrier (PLC) technology to activate load-control devices installed on customer equipment. All three programs use the hourly load data made possible by AMI to help determine the load reduction achieved during a DR event, and the company uses the hourly data to reconcile customer payments for some Irrigation Peak Rewards and Flex Peak Program participant payments.

Irrigation Peak Rewards

The Irrigation Peak Rewards program is a voluntary program (Oregon Schedule 23) available to agricultural irrigation customers. The purpose of the program is to serve as a peaking resource during times of extreme load on the Idaho Power system by turning off participants' irrigation pumps with the use of one or more load-control devices during the program season, June 15 through August 15. A control device attached to most of the participant's individual pump electrical panels allows Idaho Power to remotely control the pumps.

During 2016, approximately 2,288 customer sites were enrolled in the Irrigation Peak Rewards program, of which 44 are located in Oregon. Irrigation Peak Rewards was used three times during summer 2016. Preliminary results indicate the program's maximum peak reduction at generation level was approximately 275 MW.

Flex Peak

The Flex Peak Program (Oregon Schedule 76) is a voluntary program designed for Idaho Power's industrial and large commercial customers who are capable of reducing their electrical energy loads for short periods of time during summer peak days. Idaho Power took over management of this program from a third party aggregator in spring 2015. Participants are notified of a demand-reduction event two hours prior to the event, and in most cases reductions are achieved by the participants manually turning off equipment or otherwise changing their operations. The program objective is to reduce the demand on Idaho Power's system during periods of extreme peak electricity use.

For the 2016 season, 137 customer sites were enrolled in the Flex Peak Program, of which 9 are located in Oregon. The enrolled capacity is just over 31 MW for 2016. The Flex Peak Program was used three times during summer 2016. Preliminary results indicate the program's maximum peak reduction at generation level was approximately 41 MW.

A/C Cool Credit

The A/C Cool Credit program is a voluntary, dispatchable DR program (Oregon Schedule 74) designed for residential customers. Using communication hardware and software, Idaho Power cycles participants' central A/C or heat pumps off and on via a direct load-control device installed on the A/C or heat pump unit. Participants receive a monthly monetary incentive for participating in the program during the summer season.

Approximately 28,460 PLC-controlled switches are installed on customers' A/C or heat pump units in Idaho Power's service area. Of these, 373 are installed in Oregon. These switches allow Idaho Power to cycle customers' A/C or heat pumps during a cycling event. A/C Cool Credit was used three times during summer 2016. Preliminary results indicate the program's maximum peak reduction at generation level was approximately 34 MW.

Irrigation Load Control (ILC) Pilot

Idaho Power has predominantly used cell phone and web-based technology to enable the company's Irrigation Peak Rewards program. The objective of the ILC Pilot was to investigate using grid-enabled PLC communication to activate load-control devices on agricultural irrigation service locations to turn off irrigation pumps during program events. As part of the *American Reinvestment and Recovery Act* Smart Grid Investment Grant (SGIG), Idaho Power began conducting a pilot using grid-enabled PLC communication that would provide a reduced cost and more secure environment for program communication. The company currently has AMI-enabled load-control switches installed on approximately 25 percent of participants' service points.

Idaho Power has resolved a few installation issues and has used the AMI-enabled technology successfully at the sites on which it has been installed. Overall, Idaho Power has determined it is a viable method; the load-control devices will work on irrigation installations and can be used in the Irrigation Peak Rewards program. Idaho Power plans to continue to replace cell phone technology with grid-enabled PLC communication technology where it is available on the electrical distribution system.

Online Outage Map

Idaho Power's online outage map continues to be popular with customers and is recording heavy traffic. From July 1, 2015, through June 30, 2016, Idaho Power's outage map has been accessed 286,000 times. The map launched April 28, 2015, for both mobile and desktop platforms, and provides the following information: general vicinity of the outage, number of customers affected, crew status, and estimated time of restoration, if known.

The outage map experienced a record 8,745 views on July 19, 2016, when the Mile Marker 14 fire took out feeders from Lucky Peak to Idaho City and Placerville, causing an outage for 3,200 customers. Customers visited the map to get updates and information using both the desktop and mobile platforms.

The map is also pinned to the top of Idaho Power's Facebook and Twitter pages, so it is the first post users see upon loading the page. Idaho Power developed this map application in-house and will continue to upgrade the map with new features and information as they become available.

Figure 14 shows how the map looks on the application, and Figure 15 graphs monthly outage map visits from May 2015 to June 2016.

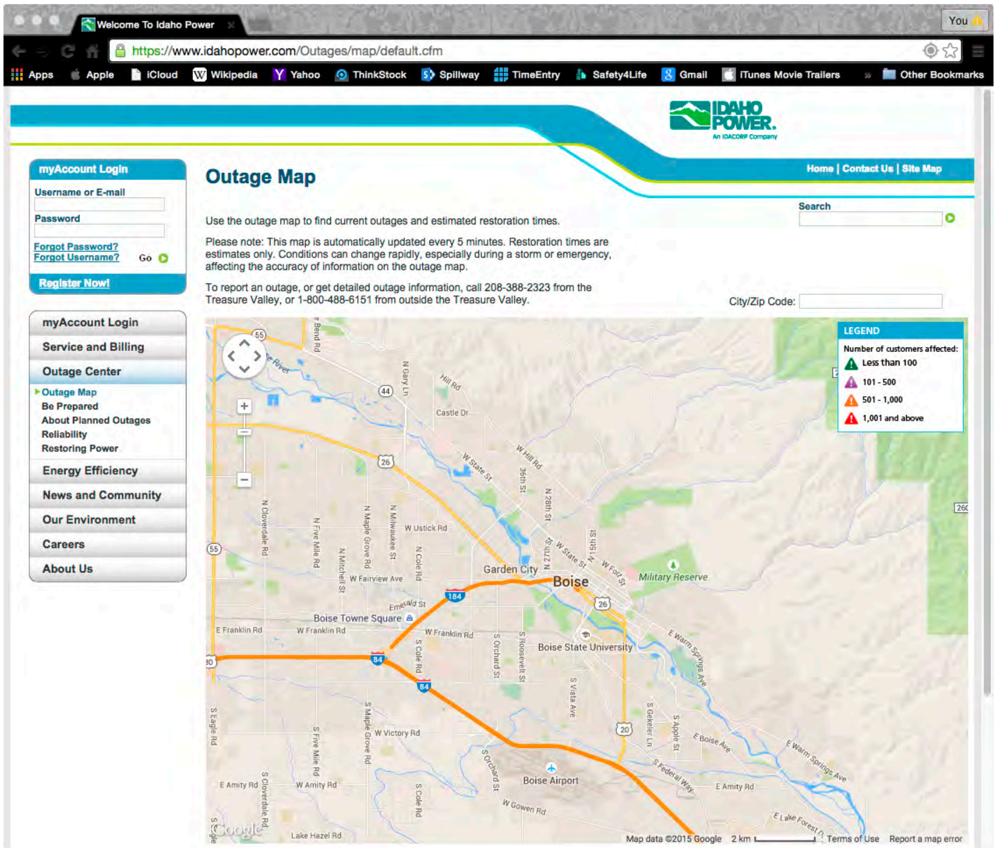

Figure 14. Screenshot of Idaho Power's online outage map

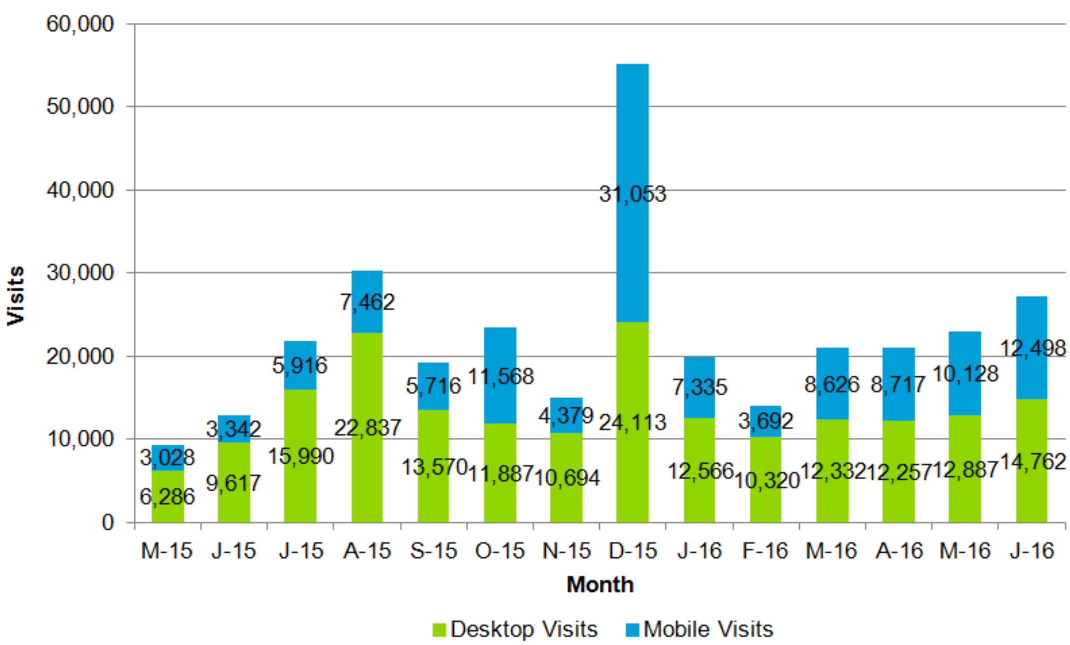

Figure 15. Monthly outage map visits, May 2015–June 2016

Integrated Demand Response Resource Control

Idaho Power manages three DR programs, as described in Section II.C of this report. Each program is unique and requires various steps by Idaho Power Generation Dispatch employees to dispatch events.

In 2015, Idaho Power began developing a DR integrated resource control tool. In 2016, this tool was used to dispatch each of the three programs, with the exception of a portion of the Irrigation Peak Rewards program. The project included electronically connecting each DR program's dispatch software to one software interface. It was determined that electronically connecting the systems into one software interface would increase operator visibility to programs and gain efficiencies when dispatching DR programs during events. The customized front-end screen was successfully used in 2016, and in 2017 Idaho Power will continue to improve this tool to include the rest of the Irrigation Peak Rewards program.

A single-interface dispatch solution makes it easier to train Generation Dispatch employees, and it creates a single source of knowledge rather than three. It also provides an environment in which it is less likely for incorrect program dispatch to take place, which can have a direct impact on customer satisfaction and the performance of these programs.

D. Distributed Resource and Renewable Resource Enhancements

Renewable Integration Tool—Current Project Developments

The Idaho Power SGIG helped fund the Renewable Integration Tool (RIT) project. The RIT project was intended to develop tools to allow grid operators to more efficiently and reliably integrate variable renewable resources with base load generation resources.

In 2014, the RIT was split into two tools: the Wind Forecast Tool and the Load Forecast Tool. Both of these are now operational and are providing benefits to the grid operators by allowing the system operators to more closely match supply and demand. A more balanced system in preschedule and in real time helps ensure there is sufficient supply to meet demand and less energy may need to be purchased or sold in the real-time market that may have a higher risk of adverse price volatility.

A project is currently in progress to develop similar forecasting capabilities that are offered by the Wind Forecast Tool for solar generation resources. The proliferation of distributed solar generation resources is expected to increase significantly over the next 5 to 10 years. The Solar Forecast Tool is expected to facilitate the reliable integration of these resources by grid operators. The first iteration of the Solar Forecast Tool was operational in early 2016. Ongoing data gathering and analysis will determine the maturity of the tool and identify future opportunities for visual enhancements, as well as improving the forecast accuracy.

A fully functional suite of RITs will allow grid operators to more efficiently and reliably integrate variable renewable resources with base load generation resources.

E. General Business Enhancements

The Mobile Workforce Management System Upgrade

Since 2007, Idaho Power has been using CGI's PragmaCad mobile workforce management system. This system is integrated with several other major systems necessary to provide automation for and support field service personnel. The version of PragmaCad in use at the company is several years old, and although still supported by CGI, it is multiple versions behind the latest release supplied by CGI. The latest release has increased functionality that will improve the efficiency of field personnel and allow the company to maintain vendor support.

Idaho Power's plans from 2015 to upgrade the existing version of PragmaCad have changed. Transitioning from the existing version to CGI's current release is more than a simple upgrade because new integrations are required. One of the major integrations is with the OMS system which, as stated earlier, is being replaced. Because both PragmaCad and PragmaLine (OMS) systems share common infrastructure, the decision was made to combine the OMS replacement and the PragmaCad upgrade projects. This work has been included within the scope, cost, and schedule of the OMS replacement project and is slated for completion in the fourth quarter of 2016.

III. Future Smart Grid Investments

This section describes smart grid investments Idaho Power is planning to undertake over the next five years (including pilots and testing). As stated previously, in addition to meeting reporting requirements, this section serves as a high-level strategic document for Idaho Power to plan its future smart grid projects. As such, the format of this section is different from the other sections in this report. The description for each of the following projects is laid out in the following format:

1. **Present**: What Idaho Power's present system looks like with regard to the individual project described.
2. **Objective**: What the objective is of the individual project described.
3. **Pilot or Project Description**: A description of the proposed or existing pilot or project.
4. **Benefit**: How the investment will reduce costs, improve customer service, improve reliability, facilitate demand-side and renewable resources, or provide other system benefits.

A. Transmission Network and Operations Enhancements

All of Idaho Power's transmission network or operations enhancements are currently underway and actively being worked on.

B. Substation and Distribution Network and Operations Enhancements

Automated Volt/VAr Management System (VVMS) Pilot

In the *2015 Smart Grid Report*, the company stated the VVMS pilot had been deferred to at least 2016 to give Idaho Power the opportunity to determine a general Volt/VAr management strategy. The Volt/VAr InterTechnology Control Pilot discussed in Section II.B is being used to help determine that strategy.

Present

Idaho Power currently operates an automated capacitor control (ACC) system that effectively controls reactive power flow (Volt-Ampere reactive power or VAr) at substation transformers by controlling distribution feeder capacitor banks. In place since the late 1990s, the ACC system is installed at 76 Idaho Power distribution substations. It uses one-way radio communications to command capacitor banks on and off with the goal to be near unity power factor at the substation transformer at all times with a slightly leading power factor at heavy load and a slightly lagging power factor at light load. Control is performed via computers at each substation; the system is not currently centrally controlled.

As effective as the system has been, the aging ACC system components are beginning to fail, leading to a system that is progressively less reliable. Direct replacement of the components is difficult because many are obsolete and no longer supported by vendors. Additionally, the present system is not suited to future growth.

Objective

Idaho Power's distribution system would have fully automated capacitor banks communicating two ways with a centralized control system. The capacitor banks would be controlled via a dedicated VVMS. The VVMS would monitor reactive power flow at the distribution substation level and would maintain near unity power factor (at the substation) to support the reactive power requirements of the bulk electrical system. Additionally, voltage would be monitored along distribution feeders, and capacitor banks would be switched on and off in a coordinated fashion to maintain an adequate voltage level to customers while maintaining adequate reactive power flow.

New solid-state reactive compensation devices may be installed on the customer side of service transformers to provide voltage support in areas where low voltage exists. Additionally, new solid-state voltage regulators could also be placed on the customer side of service transformers that would be able to both buck (decrease) and boost (increase) voltage levels in response to voltage variations caused by customer-owned distributed generation devices.

The VVMS would operate to smooth voltage variations along Idaho Power's distribution feeders, specifically in the case where the voltage variations are caused by variable and intermittent distributed generation sources at customer sites.

Pilot or Project Description

Beginning in the next few years, Idaho Power will pilot a new vendor-supported VVMS combined with bidirectional communications to replace the existing ACC system. The VVMS will control distribution substation transformer LTCs, line regulators, and distribution capacitor banks. Because of the speed at which VVMS systems are improving in the utility industry, Idaho Power decided to defer the pilot project to beyond 2017 to allow the vendor-supported VVMS platforms to mature and also give Idaho Power the opportunity to determine a general Volt-VAr management strategy that can be applied across the distribution system.

Benefit

To provide customers with adequate voltage to operate their devices, it is important to control reactive power flow and voltage on feeders. Utilities have traditionally done this by manually switching capacitor banks on and off seasonally and installing voltage regulators at strategic locations along distribution feeders. More recent technology allows utilities to automate and communicate with the capacitor bank switching and voltage regulator controls, therefore flattening the voltage profile along the feeders. This communication and automation will allow Idaho Power to smooth voltage variations along its distribution feeders and also provide Idaho Power the ability to more efficiently integrate small distribution system-based generating customers.

C. Customer Information and DSM Enhancements

Customer Relationship Management

Present

Idaho Power is seeking to enhance current internal marketing applications and processes to increase its ability to effectively provide analytics, reporting, and information for communication efforts both within the company and to external channels. Idaho Power is currently adopting a CR&B upgrade and plans to begin integrating the CRM in early 2017.

Objective

The objective of incorporating a single CRM system, integrated with the CR&B system, is to allow Idaho Power to manage and track customer interactions related to energy efficiency and other customer relations activities with the ultimate goal of increasing the effectiveness of Idaho Power's program and service offerings.

Pilot or Project Description

Using the CRM capabilities of the CR&B system, the CRM application will retrieve data from a variety of data sources (meter usage data, customer data, demographics, program data, etc.). The software will provide the ability to query and report both formally and on an ad-hoc basis. Customer preference management (opt-out, marketing frequency, topic choice, etc.) will also be a component of the system.

Benefit

The information will allow Idaho Power to better market its customer programs and service offerings. Systematically using various sources of data to reach customers should result in reduced printing and postage costs through more effective customer segmentation and targeted marketing. The information will aid the company in reaching customers more efficiently through the gradual shift to digital channels, such as email and text messages.

Ice-Based Thermal Energy Storage (TES)

Present

In its 2015 IRP, Idaho Power proposed a pilot project to investigate the costs and benefits of using ice-based TES.

Objective

The objective of this pilot is to investigate the costs and benefits of using TES.

Pilot or Project Description

Ice-based TES systems can shift peak-hour A/C load to off-peak periods. The load shifting occurs because the ice-based TES systems create ice during overnight off-peak hours, then use the stored ice in place of energy-intensive compressor units to provide cooling for A/C systems during peak-demand hours.

Idaho Power is currently working on finding a company-owned facility for the installation of an ice-based TES pilot system; designing the system; and preparing a detailed cost estimate. The focus is on an Idaho Power-owned facility rather than a customer-owned facility because the company was concerned about subjecting a customer to unknown challenges. The company thought it best to experiment with the technology on a company-owned facility since the company has no previous experience with this technology. Based on deployments elsewhere, the typical customer for an ice-based TES system is from the commercial sector into which many Idaho Power facilities fall. The pilot project's second phase will involve purchasing and installing the equipment, followed by data collection to determine the effectiveness of the concept in the Idaho Power service area.

Benefit

Load can be shifted from peak periods to off-peak periods because the TES system makes ice overnight during the off-peak period and can be used in place of A/C systems to operate during peak periods. Also, the TES system is reportedly a near-zero net energy process, meaning energy savings realized because of cooler overnight temperatures during the ice-making stage of the cycle are large enough to offset energy losses occurring as part of the energy storage process.

IV. Smart Grid Opportunities and Constraints

This section describes other smart grid opportunities Idaho Power is considering for investment over the next 5 to 10 years and any constraints that affect the company's investment considerations.

A. Transmission, Substation, Operations, and Customer Information Enhancements

Personalized Customer Interaction

Today, Idaho Power's customers using a desktop computer, tablet, or mobile phone can register and log in to myAccount and use the Energy Use Advising Tool to receive information regarding their energy use. Customers also have access to an outage map that displays current outages that affect more than 20 customers. As previously described in Section II.C., the map provides information on the location of the outage, the number of customers impacted, crew status, and if known, the estimated time of restoration. Idaho Power is preparing for continued growth in the multiple communication channels customers are using, and will use, to conduct business. Customers expect Idaho Power to proactively send them the information that is most important to them via the channel of their choice. Those channels will include the following: email, text messaging, phone applications, and social media platforms. Upon receiving this information, the customer will be empowered through the technology to adjust energy-using devices in their home or business to manage their energy usage or respond to outages. Examples of topics where Idaho Power believes customers want more interactive engagement include the following:

- Outage information
- Bill alerts
- Energy management tools
- Business transactions

Idaho Power does not currently have established systems to proactively engage customers to the level described above. Idaho Power is exploring opportunities and system improvements to more actively engage its customers using the technologies preferred by customers.

B. Evaluations and Assessments of Smart Grid Technologies

Electric Vehicle Charging Impacts Study

Idaho Power's EV Charging Impacts Study is optional for EV customers to participate in and is intended to evaluate the impact of residential EV charging on Idaho Power's distribution system. An AMI meter in the customer's garage-based charging station circuit allows Idaho Power to analyze how these customers are charging their cars. These meters are not used for billing purposes but for remote monitoring of charging patterns only.

The study began in July 2012 and finished at the end of 2015. At its peak, 15 EV charging stations were being monitored, including three at an Idaho Power facility. The participants received reports twice a year showing monthly energy use and when they were charging their vehicles. Figure 16 shows one participant's energy use by hour of the day summed over a six-month period, March through August. This customer owned a Chevrolet Volt.

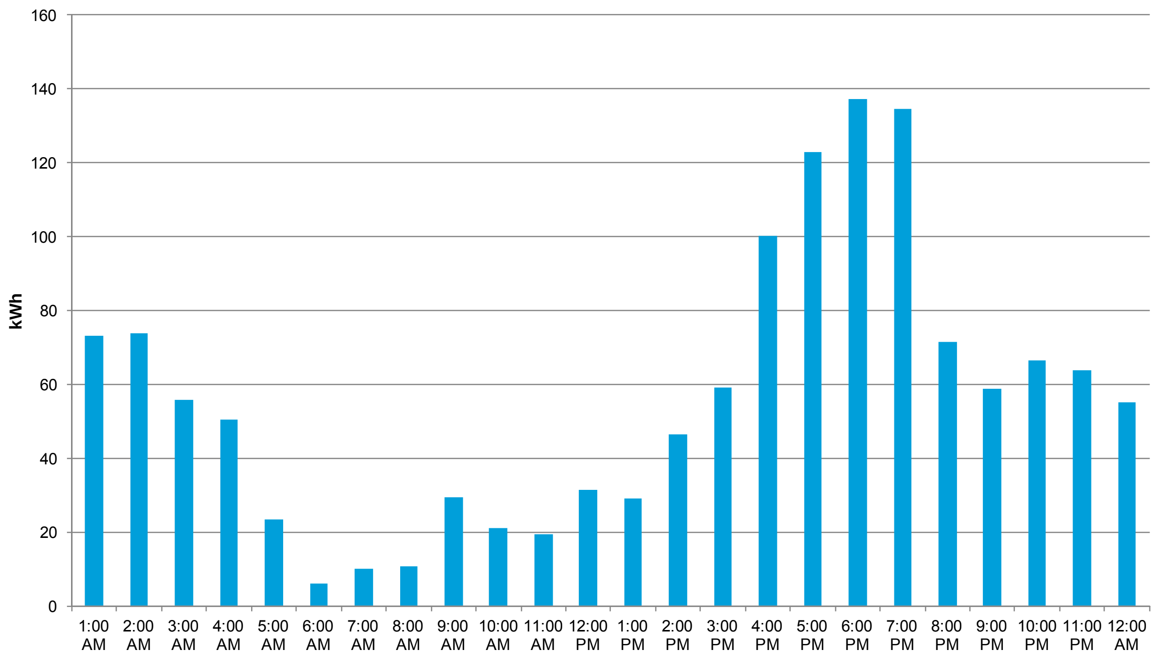

Figure 16. Charging times

This figure is fairly typical of the participants and shows that most energy use was coincident with Idaho Power's peak hours.

Data analysis indicates participating customers increase their monthly household energy use by an average 20 percent due to EV charging. While a significant consumption increase, EVs have great potential for shifting charging to off-peak if a utility offers appropriate incentives. In fact, a couple of the participants also participated in Idaho Power's time-of-day (TOD) pricing plan in Idaho and they shifted their energy use to off-peak. This indicates that with appropriate pricing signals, EVs may not detrimentally affect the distribution system and may even be beneficial to the system as a whole. The TOD plan has lower prices on weekdays after 9 p.m. and all day on weekends and holidays. To help educate customers, the company provides EV brochures with TOD information to various EV car dealerships across Idaho Power's service area. To view the Electric Vehicle Quick Facts brochure, see Appendix F.

This study is complete. To view the analysis results, along with a complete report on the Electric Vehicle Charging Impacts Study, see Appendix G.

C. Smart Grid Pilots and Programs

Although not organized or managed as a specific project, Idaho Power actively monitors smart grid related technology advancements, articles, research, reports, demonstration projects, and demonstration results as applicable. As energy generation, consumption, and management technologies continue to improve, additional opportunities for the deployment of smart grid enabled devices/appliances will become available. As these technologies continue to improve, it may be possible to create new products and services to help Idaho Power manage and optimize its system and help its customers manage their energy use, consumption, and distributed generation preferences. The areas being monitored include the management and integration of EVs, distributed resources, and microgrids.

D. State of Key Technologies

Idaho Power's customers are increasing their use of electrical technologies while at the same time some customers are desiring to generate their own power. They also want to know more about the energy they use and have the ability to more finely control their usage. The enabling technologies that allow Idaho Power's customers to do this are present today and only limited by cost and maturity. As costs come down, the company can expect the technologies will be used and may change interactions and relationships from what they are today.

Key technologies Idaho Power is tracking include the following:

- Cost and technical maturity of PV generating resources
- Cost, technical maturity, and availability of EVs
- Communications technology relating to smart grid components
- Smart inverters used for PV integration
- Technical maturity of tablet computing devices and available applications for energy tracking
- Energy storage technologies

V. Targeted Evaluations

This section responds to the nine smart grid-related recommendations adopted in OPUC Order No. 16-045, Docket UM 1675.

Recommendation No. 1

> *Idaho Power continue including stakeholder informal comments and the Company's respective responses as an appendix in future Smart Grid Reports.*

Idaho Power continues to include stakeholder informal comments and the company's respective responses as an appendix. This information is provided in Appendix A.

Recommendation No. 2

> *Idaho Power work with Staff to investigate, design and implement a TOD pilot that may include behavioral components that can be offered to Idaho Power residential customers if determined feasible.*

Idaho Power's primary goal in designing fair and appropriate rate structures is to reflect the cost to serve customers in each rate class. To reflect the appropriate cost structure in a TOD pricing plan for Oregon residential customers, Idaho Power has updated its analysis to determine the hourly variable power supply costs. The cost differentials between hourly time-blocks remain relatively small, with larger cost differentials reflected seasonally between summer and non-summer. Idaho Power is currently working on developing appropriate seasonally differentiated time blocks and the associated rates for a TOD offering. Once that is complete, Idaho Power plans to share the results and its recommendations with OPUC staff. The next phase of this project will be to work with OPUC staff to identify and develop behavioral components that could encourage customers on an optional TOD rate plan to shift their usage to off-peak times. Finally, Idaho Power will design a study intended to analyze the behavior of customers on the TOD rate plan so results can be evaluated and reported.

Recommendation No. 3

> *Idaho Power work with Staff and stakeholders to hold a workshop prior to the annual submission of the Company's smart grid report where Staff and stakeholders can review and offer suggestions to any quantifiable benefits the Company plans to provide.*

Idaho Power held a workshop with OPUC staff and stakeholders on June 1, 2016. The company invited OPUC staff, the NW Energy Coalition (NWEC), Oregon Department of Energy (ODOE) and Citizens' Utility Board of Oregon (CUB) via an e-mail sent on May 12, 2016. Attendees included OPUC staff and CUB. The workshop provided an opportunity for OPUC staff and stakeholders to review and discuss the metrics for each of the smart grid projects prior to submission of the 2016 Smart Grid Report. The group used WebEx to hold the discussion and review the metrics the company presented. The discussion during the workshop was productive and the company came away with useful suggestions. The company did not include costs or metrics for future projects because the costs and metrics for future projects have not been determined. Idaho Power will continue to report the cost-saving metrics for future smart grid reports. Resulting metrics discussed in the workshop are reflected in Appendix H.

Recommendation No. 4

> *Idaho Power provide the observability methodology document as an attachment to the ensuing smart grid report.*

The Draft Observability Report prepared by V&R Energy Systems Research, Inc., is provided in Appendix I.

Recommendation No. 5

> *Idaho Power provide updates on the LSE and the real-time voltage stability monitoring and control (RT-VSMAC) applications in future Smart Grid reports.*

The quarterly Peak Reliability Synchrophasor Program (PRSP) Project Status Report for quarter two, 2016, is provided in Appendix J.

Recommendation No. 6

> *Idaho Power work with Staff to determine possible AMI-related annual cost-saving metrics for future smart grid reports.*

Idaho Power's AMI system continues to provide the foundation for Idaho Power's smart grid. The company has identified the metrics used to quantify the benefits for all smart grid projects, including those projects that leverage the AMI system. The benefits and metrics can be found in Appendix H.

Recommendation No. 7

> *In the 2016 Smart Grid Report, Idaho Power identify possible opportunities for future DSM personalization features in myAccount and what capabilities are needed to deploy them.*

Idaho Power continues to enhance the online information, including more personalization, provided to registered myAccount users. A redesigned myAccount landing page was launched in May 2016. This new landing page includes icon-based navigation. Customers logging into their accounts can graphically see their current-month bill-to-date estimates and easily compare their estimated bills-to-date against the same month from the previous year. This is a quick way for customers to see if they are on track to use more, less, or the same amount of energy than they used the prior year. Additionally, the new, icon-based navigation provides customers easy access to robust energy advising tools. These energy advising tools allow customers to personalize information about the home, including appliances, giving customers more insight into their specific energy use.

Idaho Power will continue to explore future opportunities for DSM personalization for customers within myAccount. Opportunities may include account alerts ranging from past due dates to energy-use thresholds. Customers would manage the account alerts that are important to them, in their preferred communication channel.

Recommendation No. 8

> *In the 2016 Smart Grid Report, Idaho Power describe how solar end-of-feeder project benefits other than to infrastructure deferred upgrades can be captured.*

Idaho Power is exploring the use of solar PV as a method to mitigate low voltage at the end of a distribution feeder. This method, if successful, would provide Idaho Power with an alternative to often more-costly upgrades. There are other potential benefits to this end-of-feeder PV pilot project as well. One of the potential benefits is that by providing a small generator at the end of the feeder, feeder voltage may flatten over the length of the feeder. A flattened feeder voltage profile should help facilitate implementation of CVR. This pilot project may give Idaho Power the opportunity to learn not only about the implementation of PV but the possibilities of CVR in an application such as this. The size and placement of PV on a feeder will affect the feeder voltage profile along the feeder. Not all PV installations may be suitable for CVR. This pilot could demonstrate any potential limitations or potential benefits. For more information on the solar end-of-feeder project, see Section II.B.

Recommendation No. 9

> *In the 2016 Smart Grid Report, Idaho Power discuss how technologies like the CRM system can assist the Company in identifying customers who are prime for specific DSM programs.*

The company anticipates using the CRM to reach customers who may be included in a specific market for DSM programs. This will include using more effective customer segmentation to identify customers who have not yet participated in DSM programs but have similar characteristics to those who have. The information will aid the company in reaching customers more efficiently through the gradual shift to electronic channels, such as email and texting, which should reduce marketing costs. Additionally, the CRM will enable Idaho Power to integrate various data sources to more effectively combine customer information for marketing analysis. For more information on the CRM system, see Section III.B.

VI. Related Activities

This section discusses activities that relate to smart grid operations.

A. Cyber and Physical Security

All smart grid-related projects or plans conform to Idaho Power's Information Security Standards, which are in place to secure its cyber assets. Idaho Power's aim is to strengthen its long-standing tradition of electric reliability while fostering a culture of compliance and satisfying a broad set of reliability standards.

Smart grid projects also conform to the requirements of Idaho Power's Physical Security Program, preventing unauthorized access to personnel, equipment, material, and documents while safeguarding against espionage, sabotage, acts of terrorism, damage, and theft. Physical security is an integral part of all critical infrastructure protection, safety, fire, and crime-prevention programs.

B. Privacy

Idaho Power is committed to protecting the privacy of its customers and the data contained within company systems as stated in its Corporate Security Policy and evidenced by the company's Corporate Security Program. For confidential data, such as customer information and energy usage data, Idaho Power limits access using a need-to-know approach enforced by role-based access controls for employees and contractors and supported by periodic required training. The policies and controls undergo periodic reviews to ensure they support applicable mandates and guidance.

Idaho Power recognizes that new risks are emerging from smart grid technologies, both from the increase in data and the increasing interconnectivity of systems. To stay current on these, Idaho Power has joined collaborative public/private partnerships, such as the National Institute of Standards and Technology Smart Grid Interoperability Panel Cyber Security Working Group.

Idaho Power customers can access their energy usage data electronically via a registered and password-protected login (myAccount) on the Idaho Power website. Customers can also request that Idaho Power provide hard-copy usage information via fax, email, or mail.

Idaho Power provides protected customer information to entities other than the customer only under one of the following conditions:

- Receipt by Idaho Power of a court-ordered subpoena
- Presentation by a third-party of legal documentation substantiating the power of attorney for the customer of record
- Receipt by Idaho Power of written authorization from the customer of record identifying the third-party to whom information is to be released and specifying the information to be released
- Notification by a public utility commission that the customer of record has filed a complaint at which point information will be provided to PUC staff

In addition to the above conditions under which information for an individual customer may be provided, Idaho Power has several contractual business relationships with third parties for the procurement of services essential to the operation of the business (e.g., bill print services) that are subject to non-disclosure agreements and data security requirements.

C. General Customer Outreach and Education

Overview

As AMI installation has been completed, Idaho Power has provided residential, small commercial, and irrigation customers self-service options at idahopower.com. The self-service options help customers learn about energy, how they are using it, and how they can use it wisely. This technology gives customers the ability to view their hourly and monthly meter data with additional energy tools and analytics technology.

Using data collected from AMI meters, Idaho Power Customer Service representatives (CSR) have the ability to answer residential and small commercial customers' questions about their detailed energy usage. The CSR tool allows authorized, internal employees to see the same data as the internet-based self-serve customer. This helps CSRs more effectively consult with the customer about energy usage and high-bill inquiries.

Customer Outreach and Education Events

Idaho Power further increased its energy efficiency presence in the community in 2015 by providing energy efficiency and program information through 93 outreach activities, including events, presentations, trainings, and other outreach activities documented in the Outreach Tracking System. In addition to these activities, Idaho Power field staff throughout Idaho Power's service area delivered 204 presentations to local organizations addressing energy efficiency programs and wise energy use. In 2015, Idaho Power's Community Education team provided 124 presentations on The Power to Make a Difference to 3,359 students. The customer education representatives and other staff also completed 26 senior citizen presentations on energy efficiency programs and shared information about saving energy to a total of 944 seniors in the company's service area. Additionally, Idaho Power's energy efficiency program managers responded with detailed answers to 300 customer questions about energy efficiency and related topics received via Idaho Power's website.

As part of National Energy Awareness Month in October 2015, Idaho Power held its fifth annual student art contest in the Idaho Power service area, bringing energy education into the classroom and inspiring students and families to think more about energy. "Ways to Save Energy" was one of the categories, and both overall and regional winning students and their teachers were recognized.

At the outreach events, Idaho Power employees cover a wide range of information, answer customer questions, and assist customers in registering for the company online self-help services. The company also promotes idahopower.com, using myAccount to help customers learn more about using energy, tips and ideas to save energy, energy efficiency program information, AMI meter information, payment options, and general company information.

Communications

Idaho Power communicates frequently with customers through a variety of channels, including, but not limited to, billing statements, bill messages, bill inserts, *Connections* articles, customer letters, door hangers, postcards, brochures, web content at idahopower.com, hold messaging on the company's 1-800-488-6151 phone line, social media, public events, and customer visits.

As an example of how Idaho Power communicates with its customers, see Appendix K for a recent edition of the *Connections* newsletter that is distributed through customer bills for the benefit of Idaho Power customers.

Idaho Power has successfully leveraged the functionality of AMI and especially the hourly meter data to enable the majority of its customers to learn more about their energy usage and how to use energy wisely. The company has used events and other channels to provide customers relevant information on a frequent basis about energy efficiency, company and program information, and updates about AMI metering. Idaho Power also sends a new customer welcome letter inviting them to visit idahopower.com to learn more about their energy usage and to register on myAccount.

VII. CONCLUSION

Idaho Power continues to develop a vision and a strategy to anticipate what the future energy delivery system will look like and how it will meet customer needs and preferences, as well as improve company operations. The company continues to develop, test, and deploy the technologies needed to facilitate the transition to a smart grid future and integrate renewable generation into the power system.

The company strives to enable more proactive customer interaction, as with the use of the updated myAccount landing page, the mobile website, and the outage map, which informs and enables participation by customers.

Idaho Power is dedicated to continuing efforts toward a smart grid system to provide Idaho Power's customers with an efficient, reliable, and safe power system that fits with customer expectations of a more interactive experience.

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Appendix A. Stakeholder input

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IDAHO POWER®
An IDACORP Company

Share Your Ideas About **Smart Grid**

Idaho Power is preparing its annual smart grid investment report to the Public Utilities Commission of Oregon (OPUC). As part of this annual report we are seeking input, information and ideas from the public on smart grid investments and applications. The comment period is open August 8–26.

Please go to **idahopower.com/smartgrid** to review a draft version of the report. You'll also find more information about what the smart grid is, and how a smarter electrical grid can move the energy industry into a new era of reliability, availability and efficiency.

To share your input, please email **smartgrid@idahopower.com** or call Idaho Power Regulatory Analyst Kristy Patteson at (208) 388-2982. A summary of customer comments will be provided to the OPUC with Idaho Power's report.

The smart grid represents energy innovation, leveraging a combination of improvements that enhance customer service, power reliability, availability of renewable resources, and opportunities for time, energy and cost savings. The 2013, 2014 and 2015 reports can be found on our web site.

HYDRO

idahopower.com/smartgrid

Patteson, Kristy

From: Towell, Kimberly
Sent: Friday, August 05, 2016 11:21 AM
To: 'dockets@oregoncub.org'; 'oregondockets@pacificorp.com'; 'diane.broad@state.or.us'; 'john@grid-net.com'; 'renee.m.france@doj.state.or.us'; 'rfrisbee@si-two.com'; 'maury.galbraith@state.or.us'; 'richard.george@pgn.com'; 'wendy@nwenergy.org'; 'royhemmingway@aol.com'; 'bob@oregoncub.org'; 'pkeisling@gmail.com'; 'jess.kincaid@state.or.us'; 'keith@caporegon.org'; 'dockets@mrg-law.com'; 'adam@mrg-law.com'; 'douglas.marx@pacificorp.com'; 'michelle.mishoe@pacificorp.com'; 'sommer@oregoncub.org'; 'pge.opuc.filings@pgn.com'; 'john.volkman@energytrust.org'; 'michael.weirich@state.or.us'; 'dockets@renewablenw.org'; 'greg@richardsonadams.com'; 'stephanie.andrus@state.or.us'; 'erik.colville@state.or.us'; 'bryce.dalley@pacificorp.com'; 'jdj@racinelaw.net'; 'judy.johnson@state.or.us'; 'elo@racinelaw.net'; 'dreading@mindspring.com'; 'peter@richardsonadams.com'; 'irion@sanger-law.com'; 'dws@r-c-s-inc.com'; 'stephens@eslerstephens.com'; 'mec@eslerstephens.com'; 'doug.tingey@pgn.com'; 'sarah.wallace@pacificorp.com'; 'tony@yankel.net'; Michael Breish; 'esteb44@centurylink.net'; 'mike@oregoncub.org'; 'jravenesanmarcos@yahoo.com'; 'wendy.simons@state.or.us'; 'wendy@mrg-law.com'
Cc: Nordstrom, Lisa; White, Tami; Tatum, Tim; Larkin, Matt; Youngblood, Mike; Patteson, Kristy; Bearry, Christa
Subject: Idaho Power Company's 2016 Oregon Smart Grid Report - Comments Solicited
Attachments: DRAFT 2016 Smart Grid Report.pdf; IPC_AD_SmartGrid_ArgusObserver_07-16.pdf

Parties to Docket Nos. UM 1460, UE 233, LC 63, and UM 1675:

Idaho Power Company will be submitting its fourth annual Smart Grid Report to the Public Utility Commission of Oregon on October 1, 2016. As part of the annual report, Idaho Power is seeking public input and contributions from **August 8 through August 26, 2016**, on the attached Draft Smart Grid Report. To share your comments and ideas please email smartgrid@idahopower.com or call Kristy Patteson at (208) 388-2982.

Public input is being solicited through advertisements in the *Argus Observer* and *Hells Canyon Journal* newspapers. A copy of the advertisement is attached.

For more information about smart grid, and Idaho Power smart grid reports and projects, go to www.idahopower.com/smartgrid.

Thank you,

--
Kristy Patteson
REGULATORY ANALYST
Idaho Power | Regulatory Affairs

208-388-2982

Email kpatteson@idahopower.com

IDAHO POWER COMPANY'S RESPONSE TO INFORMAL COMMENTS FROM OPUC STAFF ON IDAHO POWER'S DRAFT 2016 SMART GRID REPORT

Submitted by Nadine Hanhan on August 26, 2016

General Comment

Staff appreciates the additional information provided in the appendices and clarity of the report. There were areas of the report where the Company provided a clearer picture of certain programs, why they evolved the way they did, and what the Company learned even though the original goal of the project was not met. Staff found this very helpful and encourages the Company to continue with this approach in future smart grid reports.

Additional Comments

<u>Substation and Distribution Network and Operations Enhancements</u>

Solar End-of-Feeder Project

The report states that the Company will plan on pursuing an end-of-feeder project to maintain feeder voltage using solar technology and a battery. However, the Company states in the next paragraph that it will not pursue the battery technology because it is not cost effective. This appears inconsistent. What was the original purpose of the battery and why was it deemed not cost-effective?

RESPONSE: In our original concept, the battery was included as a way to provide voltage support for nighttime loads. When we began the process, we sought to find the optimal location of the project by studying twelve different sites. The load-shape of every site was analyzed and compared to a solar PV output shape. We found that a close alignment between the load-shape and the PV output reduced the need for a battery. The chosen site tends to peak during the summer, thus there is a close alignment between the load-shape and the PV output. Therefore, there is no need for a battery. The body of the report has been updated to include this clarification.

Replace the Existing OMS

The Company states that a new OMS will "aid" in customer service restoration. Can the Company provide greater detail as to this benefit and any others?

RESPONSE: The statement that was made in the report is generally true of any OMS system. Specifically, it was said in the report that, "A new OMS platform will aid in customer service restoration after power system interruption events." The OMS system models the distribution, substations, and vital transmission elements used to serve energy to our customers. The system also ties the local transformers providing service to the customers being served. When a customer calls to report a power interruption, the OMS system analyzes the circuit, referencing other customer calls when available, to predict the most probable device causing the interruption. Crews are then dispatched to the predicted device to investigate the cause of the outage and restore service. In addition, by integrating the OMS system with Idaho Power's SCADA system, the OMS system will show customer interruptions automatically when a SCADA device is opened. These devices are typically inside substations, such as feeder breakers or power circuit breakers.

As indicated in the Implement Additional AMI Outage Scoping and Restoration Confirmation Functionality section of the 2016 Smart Grid Report, the OMS project will also integrate with Idaho Power's AMI and SGM systems. OMS operators will be able to "ping" meters via AMI in and around the area of an outage to determine the scope of the outage. SGM allows for autonomous reporting of power interruption. Upon power interruption, SGM devices will create a "call" in the OMS system. OMS operators can then use the AMI functionality to "ping" meters in the surrounding area to scope the outage. The AMI integration will also allow OMS operators to confirm restoration in large scale outages; which is useful for identifying embedded outages after initial restoration. Integrating with SCADA, AMI, and SGM can allow for more rapid prediction of the correct device, ensuring crews are dispatched to the most probable area in a timely manner.

Distributed Resource and Renewable Resource Enhancements

Renewable Integration Tool – Current Project Developments

The Company states that the Wind Forecast Tool and the Load Forecast Tool "are providing benefit to the grid operators." Can the Company provide greater detail as to what these benefits entail?

RESPONSE: Some of the biggest financial and operational challenges of integrating renewable generation on both day-ahead and real-time result from the lack of a consistent and accurate wind generation forecasting tool.

Without an accurate real-time wind forecasting tool, the grid operators are often required to carry additional operating reserves above and beyond what would normally be carried to ensure that there is always sufficient unloaded generation to cover the unplanned loss of large amounts of wind generation. The carrying of these additional operating reserves comes at a cost because this generation cannot be used to serve load or sold off-system to benefit customers. An accurate hour-ahead wind generation forecasting tool significantly lowers these costs by reducing the amount of energy that needs to be purchased or sold in order to account for unplanned increases/decreases in wind generation. A more accurate real-time wind generation forecast improves the reliable operation of the system by helping to ensure that sufficient operating reserves are maintained to cover any forecasted reductions of wind generation and ensure that there is sufficient generation on-line that can be reduced to cover forecasted increases in the wind generation.

An accurate day-ahead wind generation forecast tool has significant advantages as well for the reliable and efficient integration of renewable generation. An accurate forecast for day-ahead also allows the pre-schedulers to more closely match supply and demand prior to the real-time horizon. A more balanced system on preschedule helps ensure that there is sufficient supply to meet demand and less energy would need to be purchased or sold in the real-time market that typically has a higher risk of adverse price volatility.

Future Smart Grid Investments

The Company presents a format for describing future smart grid investments. The Company lists benefits as a descriptor but fails to mention costs. Is there a reason for this?

RESPONSE: Future smart grid investments are projects that are planned to be undertaken over the next five years. The format used for future projects addresses what Idaho Power's system looks like at present with regard to the future project, what the objective of the project is, a description of the project, and how the investment will provide system benefits. The company decided not to include costs for future projects because it would be mere speculation as to what the cost of the project would be given that the scope of the project may change and/or prices may change over the next five years. Idaho Power felt that it was best not to include a cost rather than to try to predict what the cost may be.

Ice-Based Thermal Energy Storage

Staff noticed that IPCO modified its initial phase of the TES pilot to focus on Idaho-Power owned facilities. Staff is interested to know what prompted the change. If there are significant customer hurdles, can the Company expect to implement this program after a successful "in-Company" pilot? More clarification on the hurdles would be helpful.

RESPONSE: Although the Thermal Ice Storage technology is not new, it is new to Idaho Power. The company was concerned about subjecting a customer to unknown challenges and thought it best to experiment with the technology on company-owned facilities since the company has no previous experience with this technology. The company had other concerns including: finding a willing customer, financial responsibility, operating concerns for the customer using an unknown cooling system, potential maintenance on the TES system, warranty issues with the customer's existing HVAC system, integration with the customer's existing HVAC system. The objective of this pilot is to use the experience to learn more about HVAC system integration and learn how the technology may be used to meet future needs identified in the IRP.

Smart Grid: Modern Ingenuity

Print

For Idaho Power, the Smart Grid represents energy innovation. It gives customers information they need to be wise energy consumers. It uses new technology to retrieve data and take actions that benefit electrical grid performance. And it leverages a combination of improvements that enhance customer service and power reliability, help integrate renewable resources, and create opportunities for time, energy and cost savings.

Smart Grid Benefits

- Enable customers to make more informed energy use decisions
- Reduce the time and impact of outages
- Limit effects of power line disturbances to strengthen the grid
- Support integration of renewable energy into our resource portfolio

Public Comment Period for Draft Report

Idaho Power is compiling its 2016 Oregon Smart Grid Report (PDF) and would like your comments on the draft document. Comments are being solicited through Aug. 26, 2016. Submit comments to: smartgrid@idahopower.com.

Company Reports

- 2015 Oregon Smart Grid Report (PDF)
- 2014 Oregon Smart Grid Report (PDF)
- 2013 Smart Grid Report (PDF)
- 2011 Smart Grid Plan (PDF)

Search

Additional Information

- FAQs
- 2016 Oregon Smart Grid Report (PDF)
- 2015 Oregon Smart Grid Report (PDF)
- Projects Information
- Supplier Center
- Electric Vehicles

Related Information

- The Smart Grid: An Introduction
- U.S. Department of Energy
- smartgrid.gov
- Smart Grid Information Clearinghouse

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Appendix B.
Peak Reliability Project Plan

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Project Plan

Part A: General

As more fully described below, PRSP Subrecipient will provide to Peak a licensed Linear State Estimator prototype and enhance Peak's currently licensed version of the Physical and Operational Margins ("POM") Region of Stability Existence ("ROSE"). PRSP Subrecipient will provide all of the requisite licenses to Peak for both the Linear State Estimator and POM ROSE.

POM, ROSE, and POM-State Estimator (POM-SE) are PRSP Subrecipient intellectual property.

Peak-ROSE software is a customization of ROSE software for Peak. Peak-ROSE software delivered during the project consists of the following programs:

- Physical and Operational Margins (POM);
- Optimal Mitigation Measures (OPM);
- Boundary of Operating Region (BOR);
- Potential Cascading Modes (PCM).

Two copies (one Real-Time and one Off-Line) of Peak-ROSE software will be delivered to Idaho Power Company ("IPC"), Southern California Edison ("SCE"), and San Diego Gas & Electric ("SDG&E"). One copy of real-time Peak-ROSE covers development, testing, training, and production environments.

POM-SE configuration for the project is POM- Linear State Estimator ("LSE") program. LSE prototype will be delivered to California Independent System Operator ("CAISO"), IPC, Peak, SCE, and SDG&E.

PRSP Subrecipient will build and make available the situational awareness wall. Based on cases created by LSE, measurement-based voltage stability analysis and corrective actions (previously known as remedial actions) are in scope.

Location of Project

The Services will be delivered primarily in the Peak offices at 7600 NE 41st Street, Suite 150 in Vancouver, Washington or 4850 Hahns Peak Drive, Suite 120 in Loveland, CO ("Facility"). Some work may be accomplished remotely if deemed appropriate by Peak.

PRSP Subrecipient Furnished Property or Services

PRSP Subrecipient is required to provide all computers, software, cell phones, and other supplies, materials or equipment reasonably needed to perform the required services.

Peak Furnished Property or Services

Peak will provide PRSP Subrecipient with limited access to desk space, meeting or conference room space at Peak's premises for PRSP Subrecipient to perform the services under this Contract at no charge to PRSP Subrecipient.

Part B: Technical Requirements and Work Activities

The Scope of Work for the software and support to be provided by the PRSP Subrecipient to support the PRSP is shown below.

PRSP Subrecipient shall provide to Peak an LSE that meets all of the following functional requirements:

The LSE shall perform the following functions as it relates to input data:

1. LSE shall be able to read a C37.118 data stream from any data source.
2. LSE shall be able to read a capture file as recorded and produced by Grid Protection Alliance's OpenPDC program.
3. LSE shall be able to read a CSV file format of future definition as determined by Peak Reliability and PRSP Subrecipients.

LSE shall be able to identify bad data, and to deliver a more correct value given the other measured quantities within close proximity to the bad quantity. LSE shall meet the following functional requirements associated with bad data detection and correction:

1. LSE shall detect and report topology errors or measurement errors.
2. LSE shall flag and report bad data in a manner that supports situational awareness of the bad data point.
3. LSE shall be capable of estimating and replacing a synchrophasor measured quantity given the appropriate measurement redundancy in the area.

4. LSE shall report to the user through a user interface and through automated reporting on a user configured periodicity (for example, once a day or once a week) synchrophasor data flagged as bad by LSE and/or replaced by LSE.

5. LSE will be able to create a "corrected" C37.118 data stream that includes the data that has been identified as bad and corrected by the LSE.

6. Bad Data Detection shall be able to run at a minimum of 30 times per second which will include a report identifying:

    a. Any topology issues identified.

    b. All suspected bad data will be replaced, and must be identified as being bad.

    c. Provide results that enable the user to identify potential problem PMUs to examine for trouble shooting.

LSE shall meet the following Linear State Estimation requirements:

1. LSE will only refer to Phasor Measurement Unit ("PMU") measurement-observable portions (islands) of the bulk electric system where a State Estimation will be executed.

    a. LSE shall solve for all measurement observable portions of the system, whose bounds will be determined by the observability (or as allowed by current visibility) resulting in individual "islands" that are able to be solved by LSE throughout the system.

    b. Non-measurement-observable portions of the system shall be equivalized through a method that will be reported to Peak and PRSP Subrecipients.

2. For non-observable parts of the system, where an iterative algorithm is needed, LSE shall provide a solution as fast as possible but not to exceed the "nominal" Westwide System Model ("WSM") traditional State Estimator ("SE") solution time of 10 seconds.

3. LSE shall enable the user to start and stop cycling of the LSE configurable through a user interface.

4. LSE must detect observability and provide information on observable islands in both text (i.e. delimited or tabular) and visual formats including:

a. Identifying changes in topology which may affect visible islands (increase or decrease).

b. Information for each measurement observable island shall include:

   i. Number of measurements.

   ii. Number/names of buses in observable islands.

   iii. Identification of critical measurements which will have major impacts on the observability boundary. (those which will make the system more or less observable by virtue of their own)

5. LSE shall enable the user to access input, output, and change settings to run LSE.

6. LSE shall enable the user to execute LSE on demand or by schedule mechanism.

7. LSE shall be able to export a solution for each identified observable island as well as for the combined observable/non-observable system to be used by current and future versions of ROSE.

8. LSE shall be able to run in a debug mode / study mode to get a re-run of a chosen measurement set as previously specified in the document for the LSE input data requirements.

9. LSE will display to the user, the following post run information and diagnostic capabilities:

   a. Start time of LSE execution;

   b. End time of LSE execution; and

   c. Measurement set identifiable for a given run (i.e. voltages, angles, flows, etc.).

   d. Comparison of input quantities with the estimated quantities.

   e. Presenting user with the severity of the bad data which was detected.

   f. Exporting the solution in a CSV file including the following items: measurement values, estimate values (voltage and phase angle) and identification of the measurement / estimate with area/zone/company name, station name, and bus name.

g. Number of observable network portions.

h. Availability of solution

PRSP Subrecipient shall provide Peak-ROSE that meets all of the following functional requirements:

1. Peak-ROSE shall be able to read and implement a full topology model as provided in the WSM export including:

   a. Allowing for changes in topology without having to go through Study Network Analysis (“STNET”) to export another case;

   b. Enabling topology processing;

   c. Visually navigating the one-line display of the substation;

   d. Using this for Remedial Action Scheme (“RAS”) modeling if equipment status is used.

2. Peak-ROSE shall be able to calculate self-sensitivities at each solved operating point (dV/dQ) with a positive sensitivity indicating a stable system, while a negative sensitivity would indicate an unstable system. (i.e. operating on the underside of the Power Voltage (“PV”) curve).

   a. This would give another needed indication of the true voltage stability, and help deal with some of the numerical instabilities that exist.

      1. Peak has witnessed ROSE solving on a low voltage solution and then reporting that interface value as the limit.

   b. Peak Subrecipient states that they can calculate the bus with the highest self-sensitivity at the point of collapse (nose). Please provide more detailed explanation of how Peak Subrecipient accomplishes this.

3. Peak-ROSE shall be able to enable multi-threading in order for each run of Peak-ROSE to be completed within the same time it takes Real Time Contingency Analysis (“RTCA”) to run (currently every 5 minutes).

4. Peak-ROSE will include the following Output File Enhancements:

a. Energy Management System ("EMS") alarm output file including:

1. Worst Contingency;
2. Violated Element;
3. Name and kV level of the weakest bus (for voltage stability);
4. Volts Amps Reactive ("VAR") margin at the weakest bus (for voltage stability);
5. Phase angle values of given buses corresponding to Basecase and Voltage Stability Limit for data mining and the ability to determine phase angle pairs at a later time.

5. Peak-ROSE shall perform PV-Curve analysis on the base-case (pre-contingency) and post-Contingency and stop the computation at an injection level (for both base-case and post-Contingency PV analysis) at which any one of the following occurs first:

a. Stability violation is encountered;

1. If for a contingency, stop computations for that contingencies but continue on with the other remaining contingencies

b. Source has reached its maximum capacity; or

c. Maximum transfer level as defined by scenario input file has been reached.

6. Peak-ROSE shall be able to add to the generator exciter capabilities/information Line Drop Compensation (LDC) /Reactive Current Compensation (RCC) consisting of adding or subtracting a reactance at the terminal to determine what and where the Automatic Voltage Regulator ("AVR") will regulate, and to enable the user to view Reactive Capability Curve.

7. Peak-ROSE shall allow users to rearrange/add/subtract/filter/search the columns in the "tables" section and include LABELS in all of the components for better visibility. The LABELS will follow the naming convention of long EMS ID (up to 32 char) proposed by Peak and Bonneville Power Administration ("BPA") for GE/PSLF and PowerWorld tools consistent with the Peak document detailing long EMS ID.

Objective	Activities
Agreement Execution	PRSP (PRSP Subrecipient and Peak) executed agreement
ROSE Software Integration at Idaho Power Company (IPC)	1. Deliver ROSE software 2. Integrate ROSE software, including configuration for use with Peak's real-time provided WSM 3. Successful end-to-end test that demonstrates full functionality. 4. Address and fix critical software defects
LSE Prototype at IPC - Observability Study	1. Observability study of Power Systems. Delivery is a report identifying existing measurement observability boundaries and desired PMU locations to provide improved observability for the LSE.
ROSE Software Integration at SDG&E	1. Deliver ROSE software 2. Integrate ROSE software, including configuration for use with Peak's real-time provided WSM 3. Successful end-to-end test that demonstrates full functionality. 4. Address and fix critical software defects
Peak-ROSE Enhancement #1: Peak-ROSE needs to read and implement a full topology model	1. Peak-ROSE shall have the capability to read and implement a full topology model 2. Peak Subrecipient to provide release notes and announce to all participants that enhancement is available on Peak Subrecipient provided SFTP site. (Exhibit E, Peak-ROSE #1)
LSE Prototype at IPC	1. LSE software will be installed and tested using IPC data, and critical variances addressed by

	the vendor. 2. Peak Subrecipient will successfully demonstrate end-to-end testing of the LSE using streaming C37.118 data as an input. 3. The LSE software installed will be tested and satisfactorily meet all functional requirements described in Exhibit E.
Peak-ROSE Enhancement #2: Calculate Self-sensitivities	1. Calculate self-sensitivities at each solved operating point 2. Peak Subrecipient to provide release notes and announce to all participants that enhancement is available on Peak Subrecipient provided SFTP site. (Exhibit E, V&R ROSE #2
Peak-ROSE Enhancement #3: Enable multi-threading	1. Enable multi-threading for ROSE 2. Peak Subrecipient to provide release notes and announce to all participants that enhancement is available on Peak Subrecipient provided SFTP site. (Exhibit E, Peak Subrecipient ROSE #3)
LSE at CAISO	1. LSE software will be installed and tested using CAISO data, and critical variances addressed by Peak Subrecipient. 2. Peak Subrecipient will successfully demonstrate end-to-end testing of the LSE using streaming C37.118 data as an input. 3. The LSE software installed will be tested and satisfactorily meet all functional requirements described in Exhibit E.

Peak-ROSE Enhancement #4: Output File Enhancements	1. Output file enhancements to improve alarming and overall situational awareness 2. Peak Subrecipient to provide release notes and announce to all participants that enhancement is available on Peak Subrecipient provided SFTP site. (Exhibit E, Peak Subrecipient ROSE #4)
LSE at SDG&E	1. Observability study of Power Systems. Delivery is a report identifying existing measurement observability boundaries and desired PMU locations to provide improved observability for the LSE. 2. LSE software will be installed and tested using SDG&E data, and critical variances addressed by Peak Subrecipient. 3. Peak Subrecipient will successfully demonstrate end-to-end testing of the LSE using streaming C37.118 data as an input. 4. The LSE software installed will be tested and satisfactorily meet all functional requirements described in Exhibit E.
Peak-ROSE Enhancement #5: Enhancements to PV-Curve Analysis	1. Stop PV analysis if either of the following occur: a. Stability violation is encountered. b. Source has reached maximum capacity. c. Maximum transfer level as defined in scenario has been reached. 2. Peak Subrecipient to provide release notes and announce to all participants that enhancement is available on Peak Subrecipient provided SFTP site. (Exhibit E, Peak Subrecipient ROSE #5)

LSE at SCE	1. Observability study of Power Systems. Delivery is a report identifying existing measurement observability boundaries and desired PMU locations to provide improved observability for the LSE. 2. LSE software will be installed and tested using SCE data and critical variances addressed by Peak Subrecipient. 3. Peak Subrecipient will successfully demonstrate end-to-end testing of the LSE using streaming C37.118 data as an input. 4. The LSE software installed will meet all functional requirements described in Exhibit E.
LSE at Peak	1. LSE software will be installed and tested using Peak data and critical variances addressed by Peak Subrecipient. 2. Peak Subrecipient will successfully demonstrate end-to-end testing of the LSE using streaming C37.118 data as an input. 3. The LSE software installed will be tested and satisfactorily meet all functional requirements described in Exhibit E.
Peak-ROSE Enhancement #6: Add to the generator exciter capabilities/information	1. Add line drop compensation and reactive current 2. Peak Subrecipient to provide release notes and announce to all participants that enhancement is available on Peak Subrecipient provided SFTP site. (Exhibit E, Peak Subrecipient ROSE #6)
Peak-ROSE Enhancement #7: Allow users to rearrange/add/subtract/filter/search the columns in the	1. Verify that users are allowed to rearrange/add/subtract/filter/search the columns in Tables 2. Peak Subrecipient to provide

Tables	release notes and announce to all participants that enhancement is available on Peak Subrecipient provided SFTP site. (Exhibit E, Peak Subrecipient ROSE #7)
Peak-ROSE Enhancement Completion	Upon successful completion of all stated ROSE enhancements stipulated by Peak within Exhibit E, (#1 - #7) the following will be performed for each enhancement and overall POM performance (not to exceed 6 weeks upon completion): 1. Successful end-to-end test that demonstrates full functionality 2. Address and fix critical software defects
ROSE Software Integration at SCE	1. Deliver ROSE software 2. Integrate ROSE software, including configuration for use with Peak's real-time provided WSM 3. Successful end-to-end test that demonstrates full functionality 4. Address and fix critical software defects
Measurement-based voltage stability analysis	1. Demonstrate that ROSE successfully performs voltage stability using LSE provided measurement-based cases as input. 2. Deliver measurement-based ROSE software to participants 3. Perform end-to-end testing for each participant to demonstrate that the measurement-based voltage stability works as expected. 4. Address and fix critical software defects as identified by CAISO, IPC, SDG&E, SCE and Peak.

Measurement-based corrective actions functionality in ROSE	1. ROSE shall identify corrective actions to mitigate the following conditions: a. Low voltage b. Voltage collapse c. Line and transformer thermal overload 2. Deliver correction action software to all participants 3. Address and fix critical software defects identified by CAISO, IPC, SDG&E, SCE and Peak
Building situational awareness wall	1. Provide display mockup of visualization wall 2. Review participant comments and update display mockup as necessary to meet participant needs 3. Develop visualization wall for implementation at participant sites.
Transferring the technology to project participants and training at Peak and TOs.	

Appendix C.
CVR Report

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Conservation Voltage Reduction Enhancements Project

Customer Operations
Planning Transmision &
Distribution Strategies

September 2016

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LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES

LIST OF ACRONYMS

AMI—Advanced Metering Infrastructure

ANSI—American National Standards Institute

CDD—Cooling Degree Days

CVR—Conservation Voltage Reduction

ENGO—Edge of Network Grid Optimization, static VAr compensating device

EPRI—Electric Power Research Institute

HDD—Heating Degree Day

kW—kilowatts

kWh—kilowatt-hour

LDC—Line Drop Compensation

LTC—Load Tap Changer

MVAr—megavolt amps (reactive)

MW—megawatt

NEEA—Northwest Energy Efficiency Alliance

PI—Process Intelligence software produced by OSIsoft used for data retrieval and storage

SCADA—Supervisory Control and Data Acquisition

SGM—Smart Grid Monitor

V—Volt

EXECUTIVE SUMMARY

This report culminates the first phase of a project to comply with the Public Utility Commission of Oregon's directive for Idaho Power to assess all of the available cost-effective conservation voltage reduction (CVR) potential in its Oregon service area. The notion of CVR is that energy will be conserved when the voltage supplied to customers is maintained in the lower portion (between 114 and 120 volts) of the American National Standards Institute (ANSI) standard. Idaho Power participated in a Northwest Energy Efficiency Alliance (NEEA) CVR study which reported energy saving of about 2% using mathematical models and sampling techniques. However, the three transformers and associated feeders analyzed in this study served an urban area and Idaho Power's Oregon service area is largely rural. Idaho Power developed the Conservation Voltage Reduction Enhancements Project ("Project") to specifically address both the uncertainty of modeling and the difference in service area demographics.k

The Project was established to validate energy reduction through direct load measurement; establish CVR factors (coefficients) for customer classes by weather zone; determine methods for extending CVR to additional circuits; quantify the implementation costs; pilot seasonal voltage settings; and establish methods for periodic validation. CVR was applied to a select group of transformers where minimal circuit modifications were required for proper operation. The extension of CVR to other transformers may require more extensive circuit modifications to realize energy reductions.

The application of CVR at the treatment locations resulted in variations in energy use across customer classes, weather zones, and seasons. In general, energy reductions were realized, though in some cases the reductions were minimal. The energy-reduction potential varied greatly from one weather zone to another. The study also demonstrated that CVR does reduce demand during peak loading conditions. However, it would be difficult to institute CVR for both energy and demand reduction concurrently since there would be no further reduction at peak if CVR is implement to reduce energy.

The Project implemented CVR on a select group of transformers where minimal modifications were necessary to enable CVR. Expanding CVR to other transformers will likely require more extensive circuit modifications to realize the maximum effect, which may not be cost beneficial in all cases. Therefore, any expansion of CVR to additional circuits will require significant analysis to determine the voltage control parameters and forecast of energy reductions.

INTRODUCTION

The presumption is that consumer lighting, home appliances and commercial equipment may use less energy when operated at a lower voltage. CVR is a term used to describe a method for decreasing energy use and/or demand by decreasing the voltage on a feeder. The CVR factor is a measure of load reduction as a function of voltage and is used to measure the effectiveness of a CVR program. A unit-less quantity, it is defined as the percentage reduction in demand or energy resulting from a reduction in voltage.

$$CVR\ Demand\ Factor\ = \frac{Demand\ Change\ (\%)}{Voltage\ Change\ (\%)}$$

$$CVR\ Energy\ Factor\ = \frac{Energy\ Change\ (\%)}{Voltage\ Change\ (\%)}$$

Depending on the load characteristics of a feeder, CVR Factors normally range from 0.5 to 1.0 and in some cases, exceed 1.0. A higher CVR factor indicates a greater potential for saving energy or reducing demand by reducing voltage.

The characteristics of demand on a feeder change as a function of time (seasonally and hourly) which means the CVR factor is not a static number. Additionally, CVR factors differ based on customer equipment (e.g. resistive heat, motors, and compressors) and geographic location (e.g. desert, mountain, urban, and rural).

Since 2007, Idaho Power has been studying the affects of CVR through various means. In 2007, Idaho Power participated in a Demonstration Pilot conducted by the NEEA. In 2009, Idaho Power implemented a CVR program that was a static, one control point program instituted at minimal cost. Finally, in 2014, Idaho Power implemented the CVR Enhancements Project in order to study the effects of CVR by customer rate class and by weather zone.

BACKGROUND OF CVR AT IDAHO POWER

In 2007, NEEA conducted a Pilot Demonstration Project with 12 Northwest Utilities, both public and private, to determine more efficient ways to design and operate distribution feeders. The goal of the Northwest Energy Efficiency Alliance Distribution Efficiency Initiative Project was to achieve energy reductions by limiting the primary distribution system voltage drop to 4 to 5 volts and operate the feeder voltage in the lower bandwidth of the ANSI voltage range, which is 126 V to 114 V at the customer meter. Line drop compensation[1] (LDC) settings in the substation voltage regulators helped reduce the average feeder voltage during off peak periods. The study found that the average system voltage over a utility's service territory can be reduced by 3–5 percent and the expected energy reductions are from 1–3 percent on average over the span of a year. The Pilot Demonstration Project determined the energy reductions on the utility side of the meter and the energy reductions for the customers.

NEEA Pilot Demonstration Project

As part of the NEEA Pilot Demonstattion Project, Idaho Power conducted a pilot at the Boise Substation on distribution transformers BOIS T-133, BOIS T-134 and BOIS T-135. At that time the transformers controlled approximately 66 MW of load at peak. The "day-on, day-off" method that was employed involved running the load tap changer (LTC) settings as Idaho Power normally would for one day and then reducing the base voltage for the next day. A timer provided a signal to the LTC controller to reduce the voltage level using a built-in contact on the Beckwith Controller that reduced the voltage set point by a fixed percentage.

The settings used for the voltage control are shown in Table 1.

[1] Line Drop Compensation is used to adjust the voltage at the substation bus such that it is regulated to a voltage point (load center) on a downstream line or feeder remote from the transformer or regulator bus. In Idaho Power's case, an estimate of the line resistance was made representing the load center of the load fed from the transformer. Line reactance was not considered due to Idaho Power's reactive power management through capacitor bank switching. This resistive compensation increases the substation bus voltage as increases in real power loading occur.

Table 1
LTC settings used in pilot

	BC	Rset	Xset	TD (sec)	BW
BOIS T-133					
CVR ON	118	4.5	0	30	3
CVR OFF	123	4.5	0	30	3
BOIS T-134					
CVR ON	118	8.0	0	30	0
CVR OFF	123	8.0	0	30	0
BOIS T-135					
CVR ON	118	5.5	0	30	0
CVR OFF	123	5.5	0	30	0

The control was performed over a 12 month period of time that spanned a portion of 2007 and 2008. The settings could not be changed remotely. If adjustments needed to be made, they were made at the substation. Certain points were monitored to capture the end of line (EOL) voltage. The data collected from these points was used to manually change the base voltage setting on the associated LTC if necessary.

Three phase MW and MVAr data was collected at the transformer level (15 minute average) throughout the pilot. The "normal setting" days were then used to create a load profile and compared to the load profile created by the "CVR setting" days. The actual voltage difference between the two profiles was assumed to be 5 V, which was the difference between the base voltage setting for normal setting days and CVR setting days. Combining this data yielded generic CVR factors to aid in calculating energy reductions and reduction in demand. Separate CVR factors were created for the individual seasons (Winter, Spring, Summer, and Fall).

The Idaho Power results from this study showed that a voltage reduction of approximately 3% resulted in an energy reduction of 1.5% to 2.5% and reduced demand by 1.8% to 2.6% . About 80% to 90% of these reductions occured on the customer side of the meter and the remaining reductions are attributed to an increase in power system efficiency. For a typical 1050 kWh/month residential customer, this would result in a reduction in the range of 180 to 300 kWh/year.

2009 CVR Project

Idaho Power implemented a CVR program in 2009. The 2009 CVR program was instituted at minimal cost by simply changing the tap settings on distribution substation transformer LTCs, referred to here as "one control point." No capital investments were made to associated feeders. Only a very small number of feeders qualify for CVR using this method because of low voltage issues that can occur at certain locations along the feeder. Also, controlling only at the transformer LTC, every feeder connected to an individual transformer must qualify for CVR status. So, even if only one feeder has low voltage issues, the entire group of feeders connected to a given transformer would not qualify.

A further complication that comes from operating a static, one control point program is that as an individual feeder's load characteristics change based on season, little can be done to adjust the voltage to compensate. Load growth also changes the voltage profile of a feeder. As a result, a feeder that may qualify for CVR may not be qualified soon after CVR is initiated without significant upgrades. Additionally, energy and demand reductions associated with CVR can vary tremendously from month to month.

Idaho Power has identified a number of additional feeders that could qualify for CVR operating in a static mode if upgrades to either the conductors or the voltage regulation equipment were made. However, Idaho Power had not fully quantified the existing system's benefits.

The project was broken into 3 phases, of which, only Phase I was implemented.

> Phase 1 focused on the most likely CVR candidates. These candidates were feeders where CVR could be implemented with LTC settings only, no feeder upgrades, no direct voltage feedback control and limited EOL voltage monitoring.
>
> Phase 2 was to focus on feeders that could be implemented with modest feeder upgrades.
>
> Phase 3 was to focus on feeders requiring more expensive capital upgrades such as reconductoring feeder sections and potentially adding remote voltage sensing with communications back to the substation.

The Northwest Power and Conservation Council's Regional Task Force identified minimum operation thresholds used to identify candidate circuits for operation in the lower ANSI voltage band. Among the thresholds is a maximum circuit voltage drop of 3.3 V from the substation to the lowest end-of-line voltage. Idaho Power has more than 600 distribution feeders in its service area. All of these feeders were reviewed for possible CVR implementation resulting in 264 potential candidates.

Phase 1

Two hundred sixty-four distribution feeder circuits in 81 substations were studied. This study focused on shorter and/or urban feeders that had the most promise of meeting Idaho Power's CVR goals. Phase 1 analyzed these feeders with extensive load flow analysis and eliminated feeders that did not meet the CVR maximum feeder voltage drop goals. Feeders were considered in groups by substation transformer. Of these 264 circuits, CVR was implemented on 30 feeder circuits in summer 2009. This was done by implementing new LTC settings. No capital additions were made to the associated feeders. There were no direct feedback control systems used, though there were a limited number of EOL voltage measuring devices used to monitor for low voltages. LDC settings were added to the LTC. As the loading on the transformer increases, the LDC setting increases the voltage, mitigating a potential low voltage situation for some customers. However, as the LDC settings kick in, the CVR benefit decreases.

Table 2 is a list of the transformers and feeders implemented in Phase 1. The initial implementation did not include BOIS T-133 or KRCH T-131 but after further analysis, they were added to the program. In the final Phase 1 program, MRDN T-132 was removed from the program due to customer sensitivity to the change in voltage. As of 2014, Idaho Power had employed CVR on 9 substation distribution transformers and 33 distribution feeders.

Table 2
Transformers and Feeders Implemented in Phase 1

ALMA T-51	BCRT T-131	HILL T-131	HDSP T-131	KRCH T-131
ALMA-11	BCRT-11	HILL-11	HDSP-11	KRCH-11
ALMA-12	BCRT-12	HILL-12	HDSP-12	KRCH-12
ALMA-13	BCRT-13	HILL-13		KRCH-13
ALMA-14	BCRT-14	HILL-14		
		HILL-15		
		HILL-16		
MRDN T-131	**WYEE T-131**	**WYEE T-133**	**BOIS T-133**	
MRDN-13	WYEE-11	WYEE-12	BOIS-11	
MRDN-14	WYEE-15	WYEE-16	BOIS-12	
MRDN-16	WYEE-17	WYEE-18	BOIS-22	
MRDN-17	WYEE-20			

Phase 2

Beginning in 2010, 69 additional feeder circuits out of the 264 were studied and/or re-examined. Of these 69 feeders, 9 more circuits were found to be candidates, requiring little capital expenditure to implement CVR. Later in 2011, an additional 22 feeder circuits were identified as good CVR candidates though some feeder upgrades were required to limit the circuit voltage drop to under 5 V (on a 120 V base).

Table 3 lists the feeders that were identified as good candidates. The cost estimate, in 2013 dollars, is included next to each transformer and includes replacing conductor and installing additional voltage regulators. Implementation of CVR on the 31 feeders identified in 2010/2011 did not take place.

Table 3
Feeders Identified as Good CVR Candidates

BOIS T-134 ($122k)	BOIS T-135 ($85k)	CDAL T-133 ($52k)	CDAL T-134 ($152k)
BOIS-19	BOIS-14	CDAL-11	CDAL-15
BOIS-21	BOIS-17	CDAL-12	CDAL-16
BOIS-23	BOIS-20	CDAL-13	CDAL-17
		CDAL-14	CDAL-18
USTK T-131 ($100k)	**USTK T-132 ($62k)**		
USTK-11	USTK-12		
USTK-13	USTK-15		
USTK-14	USTK-16		
USTK-17	USTK-18		

CVR Energy Reduction Calculations

The CVR energy reduction was calculated by using the CVR factor identified in the NEEA study (0.55) and applying it to the loads over the entire base year of 2009. This was done by assuming that the bus voltage at the substation is the same as the base voltage setting. In practice, this voltage goes over and under the base voltage within a set bandwidth, but since it spends approximately as much time over the base voltage as under it, the calculations were made on the base voltage. With these assumptions, the CVR program was estimated to reduce peak summer demand by about 1 MW for all the transformers in the program with a value of approximately $53,000. Energy reductions came in at around 6,000 MWh valued at $261,000. The total program benefit in 2009 was calculated at $314,000.

Low cost CVR implementation in accordance with the methods used in Phase 1 has largely been implemented. Additional CVR implementation in Phases 2 and 3 would require circuit upgrades or a change in the implementation method. CVR candidates requiring capital upgrades will need additional analysis and cost justification.

Given the limitations of the 2009 CVR project, Idaho Power decided that more analysis was needed to more fully understand the effects of CVR by customer class and the effects of CVR in different weather zones and intiated the CVR Enhancements Project as described in the following section of this report.

CVR ENHANCEMENTS PROJECT

In 2014, Idaho Power implemented the CVR Enhancements Project. The Project calculated CVR electrical loss reduction, validated energy reduction estimates, and evaluated methods to change set points seasonally, hourly or by temperature. It also evaluated using new technology to improve the voltage profile across feeders to effectively implement CVR.

Scope of the CVR Enhancements Project

The scope of the Project included the following:

- Validate energy savings associated with CVR using measured instead of modeled values.
- Quantify the costs and benefits associated with implementing CVR.
- Determine methods for expanding the CVR program to additional feeders.
- Pilot methods for making Idaho Power's CVR program more dynamic.

  Note: This is partially addressed in the related project, Edge of Network Grid Optimization (ENGO) Solid-State Reactive Power Compensation Device Use for Improving the Dynamic Performance of CVR, which is discussed in a separate report. Results of the ENGO study are inconclusive due to line capacitor mis-operation in 2015 so the study has continued into 2016. The report will be finalized once the present testing is complete.

- Determine methods for ongoing measurement and validation of CVR effectiveness.

Customer Energy Reductions Validation

Various methods were evaluated for validating the energy reduction associated with CVR. See Appendix A for a discussion of the various methods evaluated. Idaho Power chose a method similar to that described in the *EPRI Green Circuits: Distribution Efficiency Case Studies* document. Idaho Power aggregated advanced metering infrastructure (AMI) data on separate treatment transformers and compared the data against a set of control transformers to produce CVR factors for each customer class and weather zone.

Like the method described in the EPRI document, Idaho Power cycled between CVR and non-CVR voltage settings. Initial thoughts were to operate the treatment transformers such that they would alternate between CVR mode (voltage lowered) and normal (voltage) mode every 24 hours. Conversations with load research professionals from other utilities indicated there is evidence that *voltage* recovers from being controlled in a short time period but the *load* may not recover based on the heating/cooling envelope of the building and weather effects. Thus it was thought that a simple day-on/day-off cycling protocol wouldn't allow for the load to fully recover before switching into a different operating voltage. Idaho Power chose to use a 2-day-on/2-day-off protocol to allow for the load to recover from the voltage change.

The validation study determined the effects of CVR on commercial and residential customers in each of six company-identified weather zones. One transformer with irrigation load was selected for the purpose of evaluating impacts on irrigation customers.

The six weather zones were identified as Boise, Twin Falls, Pocatello, McCall, Ontario, and Ketchum. One treatment transformer in each weather zone was studied for each rate class. For this study, sufficient sample sizes of commercial and residential customers existed on a single transformer in each weather zone so it was not necessary to find different treatment transformers for each customer class. This was not the case for the control transformers; it was often necessary to choose different transformers for each customer class due to sample size limitations. Additionally, one transformer dedicated to irrigation loads was studied. Figure 1 shows the various weather zones as defined.

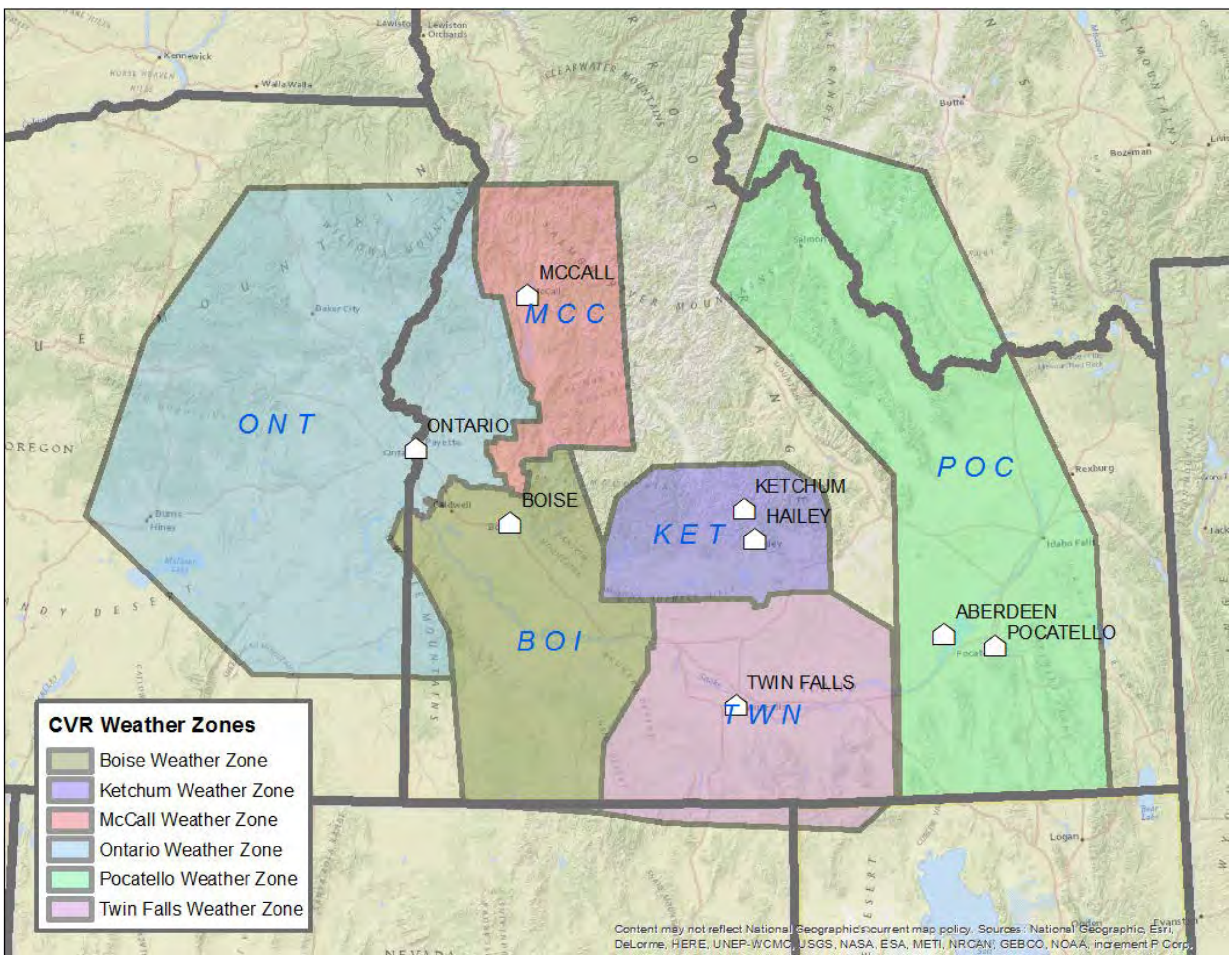


Figure 1
CVR Weather Zones

Design and Installation

Project design began in early 2014 with equipment installation taking place in late 2014 and into early 2015. Much of the early work consisted of determining testing procedures and protocols. The original intent was to begin gathering data January 1, 2015 and finish December 31, 2015. While the project plan called for data collection to begin on January 1, 2015, collection was delayed because of scheduling difficulties associated with LTC controller installation. Data collection started in February 2015 at four substations with the remaining transformers reporting data by May 1, 2015. Data collection was still performed on all transformers for an entire year.

The process used for setting up the study was:

1. *Select Treatment Transformers*—Transformers were identified on which CVR settings were applied in a two-day on and two-day off protocol. An initial screening of transformer loads from throughout Idaho Power's service area was performed to determine which ones could have their LTC settings lowered without violating ANSI C84.1 voltage standards anywhere along the feeder. Transformers were further screened so as to choose one from each weather zone plus one associated primarily with irrigation load. Table 4 lists the CVR treatment transformers selected for the study.

2. *Select Control Transformers*—A similar transformer was selected in the same weather zone having sufficient residential, commercial, or irrigation customers above the line regulators on each associated feeder to act as a control for the treatment transformer customers. Control and treatment transformer load shapes were matched as closely as possible for each customer class. Additionally, control transformers were chosen such that they were geographically close to each other to decrease variability due to weather. Table 4 lists the CVR control transformers selected for the study.

3. *Select Customer Samples*—After choosing appropriate transformers for both treatment and control, a statistically significant number of residential and commercial customers were chosen to represent each customer class. Customers were chosen based on an analysis that compared all the customers on the treatment transformer to those on the control transformer. Similar customer pairs were identified. The most influential determining factor was how many customers were located on the source-side of the first line regulator in the circuit. A single treatment transformer could have more than one control transformer, one to represent each customer class. Table 4 lists the sample size used for each transformer.

4. *Capture Data*—Hourly AMI data for each of the treatment and control customers and the hourly average transformer voltage to analyze along with the CVR on-off response was captured. An appropriate regression model was used to analyze the data based on the level of aggregation determined during analysis.

Table 4
CVR treatment and control transformers

		Sample Size	Treatment	Control
Boise	Commercial	261	MRDN T-131	CDAL T-133
	Residential	601	MRDN T-131	MRDN T-132
Twin Falls	Commercial	310	TFSN T-134	TFSN T-133
	Residential	1,423	TFSN T-134	TFSN T-133
Pocatello	Commercial	173	ALMA T-132	POCO T-054
	Residential	417	ALMA T-132	POCO T-054
Ketchum	Commercial	291	KCHM T-132	HALY T-131
	Residential	586	KCHM T-132	EKHN T-132
McCall	Commercial	132	MCAL T-131	MCAL T-133
	Residential	400	MCAL T-131	MCAL T-133
Ontario	Commercial	77	CARO T-061	VALE T-061
	Residential	431	CARO T-061	PAET T-132
Irrigation	Irrigation	49	PTVY T-131	PTVY T-132

Primary and Secondary Circuit Loss Reduction

Voltage reduction may result in reduced losses in the distribution circuit due to lower current flow through the wires and service transformers. Calculations were performed to determine the effect voltage reduction has on primary and secondary circuit losses associated with each transformer in the study. These losses include feeder line losses as well as losses through a customer's service transformer and service drop wiring. To calculate primary and secondary circuit losses, the hourly substation MWh values were used as recorded in the Process Intelligence software produced by OSIsoft used for data retrieval and storage (PI) and the hourly metered kWh data for each customer on the feeder. The losses were calculated using the following formula:

$$Loss\ (\%) = \frac{Substation\ Energy\ (MWh) - Customer\ Energy\ (MWh)}{Substation\ Energy\ (MWh)}$$

The losses were compared between days when voltage was reduced for CVR and days the voltage wasn't reduced.

Demand Reduction Calculations

CVR factors for demand used PI data for the individual treatment transformers at one-minute intervals for the three-month peak season only. The CVR factor is based on the 60 highest demands for each calendar date (i.e., the daily peak hour). This gives 60 data points for each day and 90 days for the entire peak season. The data used was from the substation which did not allow for determining CVR demand factors by customer class (residential and commercial).

Equipment Installation

Supervisory Control and Data Acquisition (SCADA)-controlled LTC controllers were installed on each treatment transformer so day-on/day-off commands could be performed remotely. This also allowed the CVR settings to be turned off remotely should voltages fall below ANSI standards. The LTC controllers were connected via fiber optic cables to their respective control houses where they connected to the local SCADA remote terminal unit.

Operating Mode Settings

Table 5 shows some of the operational parameters associated with each treatment transformer. See Appendix B for additional operational parameters. As was done in the 2009 study, LDC settings were used in this project and are referred to as R Compensation. The terms "ON" and "OFF" refer to days when CVR was on and days when CVR was off. The R value was calculated based on the estimated load center for the feeders served from the treatment transformer. For more information regarding LDC, see Appendix C.

Table 5
CVR Treatment Transformer Operational Parameters

Zone	Start Date	Transformer Rating (MVA)	Voltage Base* ON	Voltage Base* OFF	LDC R Compensation ON	LDC R Compensation OFF
Boise	3/1/2015	30.00	117.0	122.0	6	2
Twin Falls	2/5/2015	37.33	118.5	122.5	7	2
Pocatello	3/6/2015	30.00	119.0	123.0	4	0
Ketchum	2/12/2015	44.80	119.0	122.5	5	3
McCall	2/1/2015	22.40	118.0	122.0	18	0
Ontario	2/1/2015	20.00	119.0	123.0	5	0
Aberdeen	4/2/2015	40.00	118.5	123.0	8	0

*Bandwidth setting was 3 Volts for all transformers in all weather zones for both modes.

Data Gathering

While the Project Plan called for data collection to begin on January 1, 2015, collection was delayed because of scheduling difficulties associated with LTC controller installation. Data collection started in February 2015 at four substations with the remaining transformers reporting data by May 1, 2015. Data collection was still performed on all transformers for an entire year.

The following data was gathered for analysis:

- *Voltage*—Voltage data was collected at the substation on a 1 minute basis using PI.
- *Power*—Power was collected at the substation on a 1 minute basis using PI.

- *System Energy*—Energy was collected at the substation on a 1 minute and 1 hour basis using PI.
- *Customer Energy* – Energy was collected from AMI metering on a 1 hours basis.
- *Reactive Power*—Reactive power was collected at the substation on a 1 minute basis using PI.
- *Temperature*—Temperature was collected on a 1 minute basis using Smart Grid Monitors (SGM) near the substation. SGMs are devices that are placed on the secondary side of service transformers (240 Volt side) and can collect voltage and temperature readings.
- *LTC Operations*—Data was collected, where available, via PI with the intention of determining if CVR actions changed the number of LTC tap change operations. However, the PI data's resolution was on an hourly basis and lacked sufficient resolution to determine the actual number of tap changes occurring within an hour. Data might show that a tap change occurred between hour 1 and hour 2 but it would miss any tap changes that occurred within a given hour. That is, the LTC may have changed taps many times within an hour but the PI data would only have shown one tap change.

CVR was disabled or modified at a few substations for varying amounts of time due to operational issues. Following is a description of each scenario:

- *Cairo Substation (Ontario Weather Zone)*—for most hours in September, October and December, the treatment transformer in the Cairo Substation had an abnormal configuration so the CVR toggling was disabled. Days where CVR toggling was disabled are not included in the overall CVR factor calculations.
- *Aberdeen Substation (Irrigation Weather Zone)*—During pumping season, field crews began to notice feeder low voltages so the CVR voltage set point was increased.
- *McCall Substation (McCall Weather Zone)*—For maintenance purposes, the automated toggling in SCADA between CVR modes was disabled at McCall during a two-week period between December 27 and January 9. Unfortunately, peak loading for the year occurred during these weeks. The days where no toggling occurred were excluded from the analysis because they exaggerated the difference in energy and reduced the difference in voltage between modes. Additionally, for the McCall weather zone, the LDC settings applied within the LTC tended to produce higher band center voltages when in the reduced voltage mode as compared to the normal voltage mode. This is because during heavy loading, the system had some areas with low voltages using the original LTC settings. This resulted in the overall percentage difference in voltage between modes being minimal and sometimes positive, which tends to exaggerate the CVR benefits.

Data Analysis and Results

Treatment vs Control Group Correlation

Analysis was performed to determine how well the treatment groups of each customer class correlated with their corresponding control group. That is, were both groups' load shapes similar? A correlation coefficient greater than 0.70 is considered adequate for flagging and identifying abnormal behavior in the treatment group. A coefficient above 0.8 would be a strong relationship and above 0.9 would be a very strong (linear) relationship. The correlation was adequate in all cases analyzed and very strong in most. Figure 2 and Figure 3 show the correlation for the Boise commercial and residential classes respectively. Table 6 shows correlation coefficients for all weather zones.

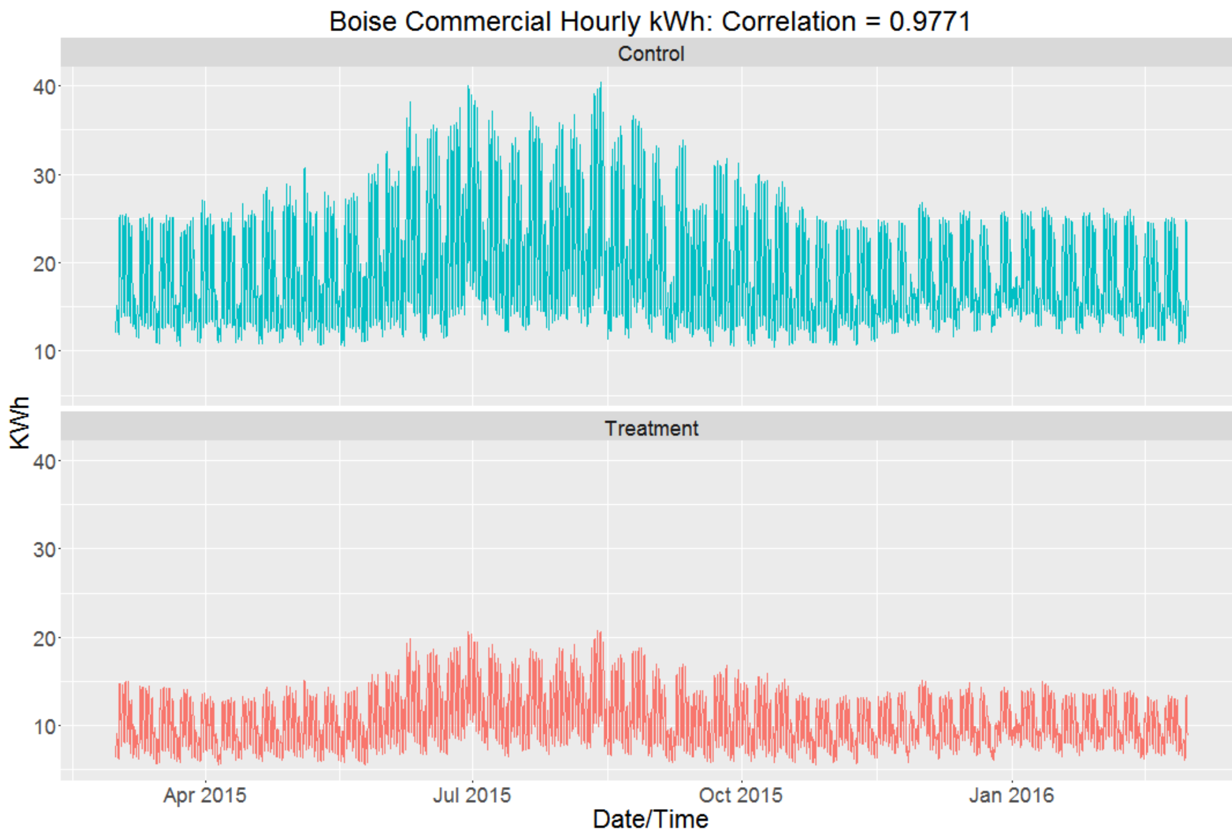


Figure 2
Boise Commercial kWh Correlation

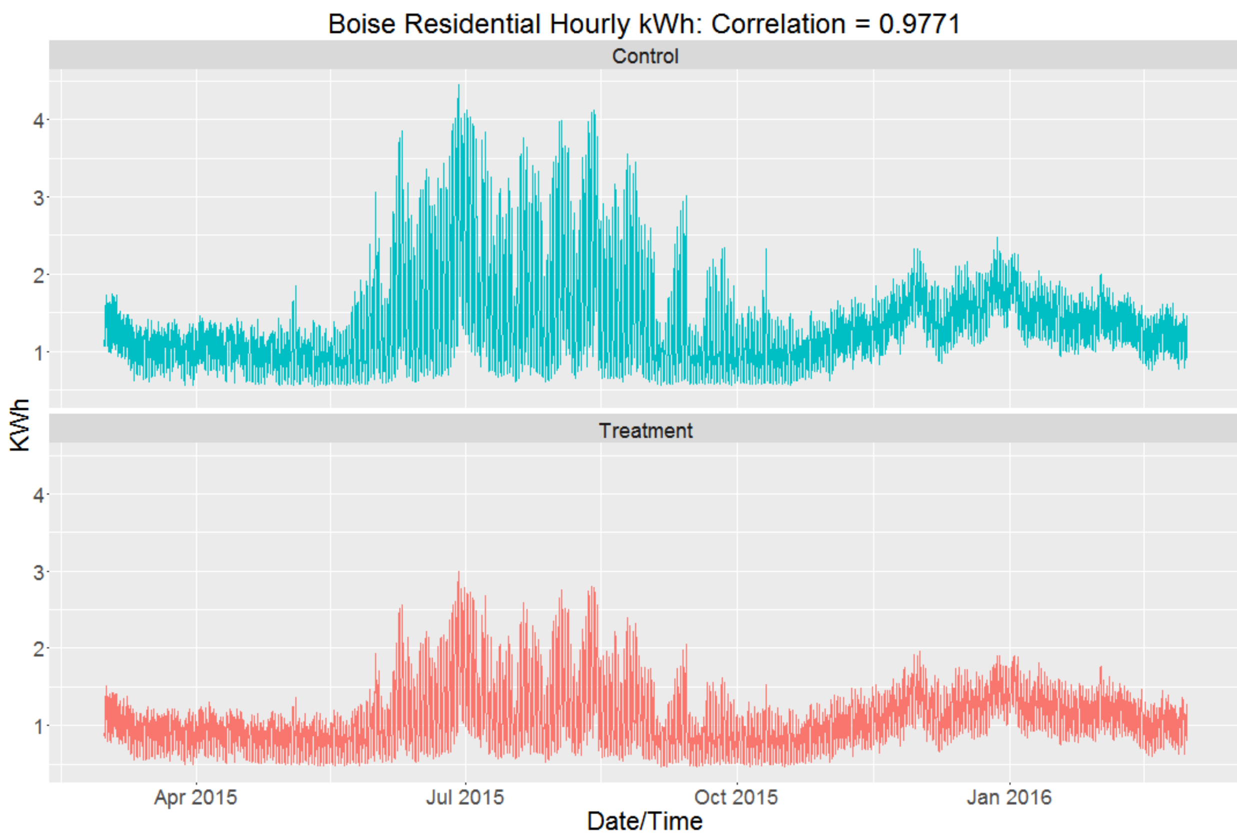


Figure 3
Boise Residential kWh Correlation

Table 6
Correlation Coefficients for all Weather Zones

Weather Zone	Boise	Twin Falls	Pocatello	Ketchum	McCall	Ontario	Irrigation
Commercial	0.9771	0.9295	0.8958	0.8946	0.8001	0.7362	0.9509
Residential	0.9745	0.9777	0.9403	0.9705	0.9711	0.9782	

CVR factors for both energy and demand at each treatment transformer were calculated based on the data gathered over the one year period. One CVR factor for demand was calculated for each transformer, representing both commercial and residential customers. Multiple CVR factors for energy were calculated, each based on either time period or temperature range. For more information on the method used to estimate the CVR factors, see Appendix D.

Primary and Secondary Circuit Loss Reduction Summary

A summary of primary and secondary circuit loss reduction associated with operating at a reduced voltage is provided in Table 7. Note that because of the abnormal circuit configuration at Cairo Substation (Ontario Weather Zone) occurring during three months of the study, the number of hours analyzed is reduced compared to the other weather zones. The same situation, though not as extensive, occurred at the McCall Substation.

Following is a description of the statistics reported in Table 7:

Transformer and Customer Metered MWh and MW—For each weather zone, the transformer MWh and customer metered kWh were gathered for the entire year then converted to average MW by dividing them by the number of hours in each sample. This was necessary because there weren't the same number of hours when comparing the normal voltage sample and the reduced voltage sample. The metered customer MWh values are aggregated AMI and primary metered customer hourly values while the transformer MWh values are 5 minute interval data as recorded in PI which were transformed into average hourly values.

Primary and Secondary Losses—This represents the total calculated primary and secondary circuit losses associated with operating under normal and reduced voltage. The circuit losses are represented first as a percentage of the transformer load then the total MW value of the losses. Finally, the MW value is converted to kWh for ease of understanding.

Primary and Secondary Loss Reduction—These rows represent the average hourly reduction in losses due to operating in a reduced voltage mode. Most important are the % losses and the kW_a value of the losses. The % losses represent loss reduction as a percentage of normal. Or said another way, it's the losses avoided by being in a reduced voltage mode.

Table 7.
Primary and Secondary Circuit Loss Reduction

	Mode	Hrs	Transformer MWh	Customer Metered MWh	Transformer MW_a	Customer Metered MW_a	Primary & Secondary Losses %	Primary & Secondary Losses MW_a	Primary & Secondary Losses kW_a
Boise	Normal Voltage	4,293	51,079.38	49,339.69	11.8983	11.4931	3.41%	0.4052	405.24
	Reduced Voltage	4,268	49,802.08	48,156.35	11.6687	11.2831	3.30%	0.3856	385.60
		Primary and Secondary Loss Reduction			0.2296	0.2099	**4.85%**	0.0196	**19.64**
Twin Falls	Normal Voltage	3,645	53,914.56	52,122.04	14.7914	14.2996	3.32%	0.4918	491.77
	Reduced Voltage	3,587	52,645.65	50,911.16	14.6768	14.1932	3.29%	0.4836	483.55
		Primary and Secondary Loss Reduction			0.1146	0.1064	**1.67%**	0.0082	**8.22**
Pocatello	Normal Voltage	4,144	46,815.87	44,915.40	11.2973	10.8387	4.06%	0.4586	458.61
	Reduced Voltage	4,188	46,604.90	44,741.06	11.1282	10.6832	4.00%	0.4450	445.04
		Primary and Secondary Loss Reduction			0.1691	0.1555	**2.96%**	0.0136	**13.57**
Ketchum	Normal Voltage	3,874	49,371.30	47,691.53	12.7443	12.3107	0.0340	0.4336	433.60
	Reduced Voltage	4,092	50,691.02	48,982.52	12.3878	11.9703	0.0337	0.4175	417.52
		Primary and Secondary Loss Reduction			0.3564	0.3404	**3.71%**	0.0161	**16.08**
McCall	Normal Voltage	4,085	17,906.56	17,149.55	4.3835	4.1982	0.0423	0.1853	185.31
	Reduced Voltage	4,031	17,482.77	16,748.90	4.3371	4.1550	0.0420	0.1821	182.05
					0.0464	0.0432	**1.76%**	0.0033	**3.26**
Ontario	Normal Voltage	2,423	19,095.10	18,312.76	7.88077	7.55789	0.04097	0.3229	322.88
	Reduced Voltage	2,481	19,324.81	18,552.22	7.78912	7.47772	0.03998	0.3114	311.40
					0.0916	0.0802	**3.56%**	0.0115	**11.48**
Irrigation	Normal Voltage	3,197	27,174.60	25,515.53	8.5000	7.9811	3.41%	0.5189	518.94
	Reduced Voltage	3,064	26,425.71	24,832.84	8.6246	8.1047	3.30%	0.5199	519.86
		Primary and Secondary Loss Reduction			-0.1245	-0.1236	**-0.18%**	-0.0009	**-0.92**

CVR Factor Summary

A summary of the analysis results for each weather zone are shown in Table 8. The results are categorized as follows:

Overall—Overall CVR factors for customer energy use over the entire year of data gathering.

Season—CVR factors and energy-use reduction by season, identified as winter (December through February), spring (March through May), summer (June through August), and fall (September through November).

Day of Week—CVR factors and energy use based on the day of week. This category has two subcategories: weekend/holiday and workday. Previous load research experience shows these two subcategories provide a reasonable representation of the seven day week.

Time of Day—Subdivided into four times of day represented as night (midnight to 6:00 a.m.), morning (6:00 a.m. to noon), afternoon (noon to 6:00 p.m.), and evening (6:00 p.m. to midnight).

Heating and Cooling Degree Days—CVR factors and energy use categorized by heating and cooling degree days (CDD). This is designed to measure the demand for energy needed to heat a building and is derived from measurements of outside air temperature. For example, if the average daily temp is less than 65, the absolute value of the difference between the average temp and 65 is measured as heating degree days (HDD). If the average daily temp is more than 65, then the absolute value of the difference between the average and 65 is measured as CDD. The colder it is below 65, the more HDD there are; the warmer it is above 65, the more CDD there are. Figure 4 shows a graphical representation of this concept.

For degree day reporting, the energy is shown on a per-degree day basis. That is, the energy is summed for the entire 24 hours instead of reporting on an hourly basis.

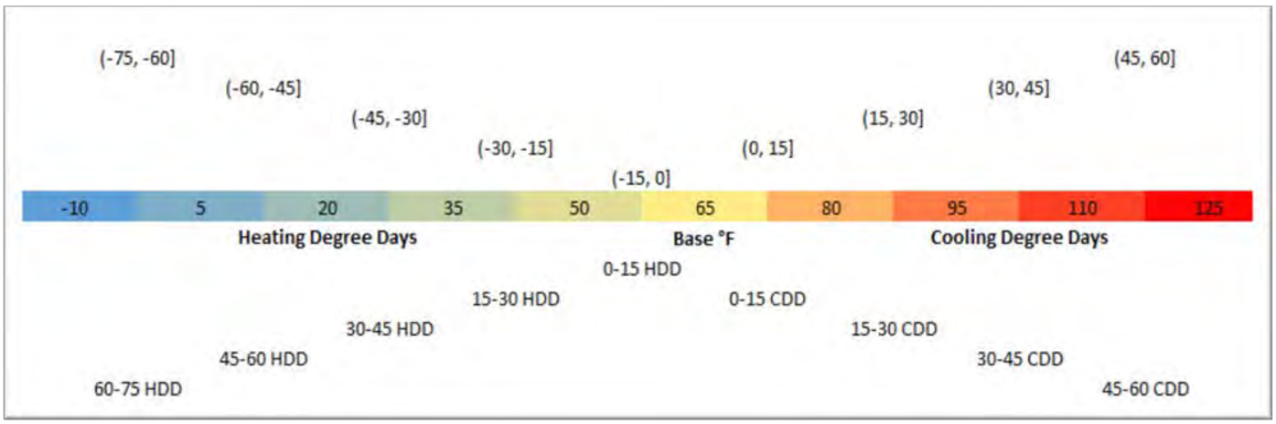


Figure 4
Heating and cooling degree days representation

To see additional statistics along with the overall CVR factors for each weather zone, see Appendix E.

Table 8
CVR factor summary—Boise, Pocatello, Twin Falls

LTC Settings	Boise				Pocatello				Twin Falls			
	Normal V—122, Reduced V—117				Normal V—123, Reduced V—119				Normal V—122.5, Reduced V—118.5			
Category	Commercial CVR Factor	Residential CVR Factor	Commercial Change in Energy	Residential Change in Energy	Commercial CVR Factor	Residential CVR Factor	Commercial Change in Energy	Residential Change in Energy	Commercial CVR Factor	Residential CVR Factor	Commercial Change in Energy	Residential Change in Energy
Overall												
Energy	0.78	0.86	-2.16%	-2.39%	0.87	0.63	-1.75%	-1.28%	0.65	0.41	-0.89%	-0.57%
Demand	1.38		-3.12%		2.46		-4.95%		-0.48		0.40%	
Season												
Dec/Jan/Feb	0.66	0.96	-1.84%	-2.65%	0.16	1.07	-0.30%	-2.02%	0.73	0.89	-0.87%	-1.06%
Mar/Apr/May	0.57	0.82	-1.58%	-2.30%	0.45	0.29	-0.99%	-0.63%	0.54	0.79	-0.87%	-1.27%
Jun/Jul/Aug	0.80	0.90	-2.11%	-2.38%	1.87	0.93	-3.63%	-1.80%	0.69	-0.04	-0.86%	0.04%
Sep/Oct/Nov	1.12	0.65	-3.23%	-1.88%	0.35	-0.39	-0.71%	0.78%	0.56	-0.65	-0.80%	0.94%
Day of Week												
Weekend/ Holiday	0.72	0.47	-2.05%	-1.32%	0.62	0.55	-1.27%	-1.13%	0.61	0.56	-0.86%	-0.78%
Workday	0.85	1.04	-2.33%	-2.86%	0.83	0.71	-1.66%	-1.42%	0.64	0.35	-0.88%	-0.48%
Time of Day												
Night (0000–0600)	0.7	0.84	-2.02%	-2.43%	0.85	0.59	-1.61%	-1.11%	0.67	0.31	-0.92%	-0.43%
Morning (0600–1200)	0.73	0.52	-2.09%	-1.51%	0.80	0.28	-1.71%	-0.60%	0.67	0.35	-1.03%	-0.54%
Afternoon (1200–1800)	0.80	1.06	-2.14%	-2.81%	0.93	0.57	-1.93%	-1.18%	0.47	0.24	-0.64%	-0.33%
Evening (1800–2400)	0.81	0.95	-2.16%	-2.52%	0.81	0.97	-1.59%	-1.91%	0.63	0.56	-0.76%	-0.68%
Heating/Cooling Degree Days												
Heating (-75,-60)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Heating (-60,-45)	6.41	-0.19	-18.91%	0.57%	0.28	-0.24	-0.50%	0.44%	-0.43	-5.76	0.40%	5.36%
Heating (-45,-30)	1.13	1.76	-3.10%	-4.83%	0.77	1.26	-1.45%	-2.37%	1.42	1.32	-1.64%	-1.52%
Heating (-30,-15)	0.08	0.60	-0.22%	-1.66%	-0.33	-0.02	0.69%	0.04%	-0.65	0.61	0.92%	-0.86%
Heating (-15,0)	0.45	-0.16	-1.28%	0.44%	0.79	0.57	-1.72%	-1.23%	1.24	-0.39	-2.03%	0.64%
Cooling (0,15)	-0.17	1.18	0.47%	-3.25%	1.75	0.91	-3.57%	-1.86%	-0.59	0.30	0.86%	-0.43%
Cooling (15,30)	2.72	0.59	-7.09%	-1.53%	1.05	0.29	-1.84%	-0.51%	1.66	-2.07	-1.78%	2.21%
Cooling (30,45)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Note: Red numbers indicate data points where there was an increase in energy from the reduced voltage as opposed to the desired energy decrease.

Table 8 (cont.)
CVR factor summary—Ketchum, McCall, Ontario, Irrigation

LTC Settings	Ketchum				McCall				Ontario				Irrigation	
	Normal V—122, Reduced V—117				Normal V—123, Reduced V—119				Normal V—122.5, Reduced V—118.5				Normal V—123, Reduced V—118.5	
Category	Commercial CVR Factor	Residential CVR Factor	Commercial Change in Energy	Residential Change in Energy	Commercial CVR Factor	Residential CVR Factor	Commercial Change in Energy	Residential Change in Energy	Commercial CVR Factor	Residential CVR Factor	Commercial Change in Energy	Residential Change in Energy	Irrigation CVR Factor	Irrigation Change in Energy
Overall														
Energy	1.11	1.16	-2.47%	-2.58%	2.89	5.75	-0.61%	-1.21%	0.19	0.91	-0.31%	-1.50%	0.22	-0.52%
Demand	0.78		-1.58%		-1.73		-3.39%		1.34		-1.85%		4.35	-2.98%
Season														
Dec/Jan/Feb	0.67	0.77	-1.39%	-1.60%	-1.15	-3.27	-1.10%	-3.14%	0.03	1.09	-0.05%	-1.78%	2.19	-6.36%
Mar/Apr/May	1.03	2.08	-2.21%	-4.48%	0.46	2.02	-0.17%	-0.77%	-0.11	0.68	0.21%	-1.30%	3.08	-10.56%
Jun/Jul/Aug	0.81	0.73	-1.91%	-1.74%	0.75	-0.50	-0.69%	0.46%	1.11	0.72	-1.65%	-1.07%	-0.67	0.83%
Sep/Oct/Nov	0.82	-0.17	-1.86%	0.38%	-0.5	-5.36	0.14%	1.50%	-0.79	0.39	1.21%	-0.60%	1.93	-5.32%
Day of Week														
Weekend/Holiday	1.02	1.78	-2.26%	-3.92%	6.35	9.86	-1.21%	-1.87%	0.80	1.38	-1.44%	-2.50%	-0.26	0.68%
Workday	1.08	0.90	-2.40%	-2.00%	1.45	3.53	-0.32%	-0.77%	-0.16	0.67	0.26%	-1.04%	0.26	-0.60%
Time of Day														
Night (0000–0600)	1.12	1.15	-2.34%	-2.40%	2.16	2.43	-1.29%	-1.45%	-0.46	0.83	0.72%	-1.30%	0.79	-1.77%
Morning (0600–1200)	0.98	1.11	-2.23%	-2.52%	-29.27	-51.76	-0.82%	-1.45%	-0.03	0.98	0.05%	-1.70%	1.17	-2.92%
Afternoon (1200–1800)	1.21	1.14	-2.74%	-2.59%	2.15	7.33	-0.25%	-0.85%	0.44	0.92	-0.73%	-1.54%	-0.75	1.81%
Evening (1800–2400)	0.88	1.05	-1.95%	-2.32%	1.03	6.32	-0.17%	-1.02%	0.72	0.94	-1.18%	-1.54%	-0.15	0.35%
Heating/Cooling Degree Days														
Heating (-75,-60)					0.99	-4.19	1.58%	-6.68%	N/A	N/A	N/A	N/A		
Heating (-60,-45)	0.67	0.53	-1.35%	-1.07%	0.24	0.30	0.30%	0.37%	N/A	N/A	N/A	N/A		
Heating (-45,-30)	0.57	0.19	-1.18%	-0.39%	3.66	7.81	2.08%	4.43%	0.74	-0.63	-1.11%	0.94%		
Heating (-30,-15)	0.70	0.16	-1.56%	-0.35%	-0.76	-4.82	0.31%	1.96%	-1.22	1.49	2.12%	-2.58%		
Heating (-15,0)	1.52	0.92	-3.27%	-1.99%	1.52	3.10	-1.64%	-3.35%	0.77	0.73	-1.43%	-1.36%		
Cooling (0,15)	0.72	0.53	-1.71%	-1.25%	-1.30	-5.55	1.12%	4.74%	1.35	0.18	-2.54%	-0.34%		
Cooling (15,30)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.42	-0.15	-1.53%	0.16%		
Cooling (30,45]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		

Note: Red numbers indicate data points where there was an increase in energy from the reduced voltage as opposed to the desired energy decrease.

Analysis Results Discussion

Reducing voltage produced annual energy reductions and positive annual CVR factors for energy in all of the weather zones analyzed ranging from a high of 5.75 for the residential customer class in McCall, Idaho, to a low of 0.19 for the commercial customer class in Ontario, Oregon. These extreme values may be questionable for reasons discussed in Appendix F. However, positive CVR factors were calculated in all weather zones. For demand, the CVR factors ranged from 4.35 in the Irrigation weather zone to -1.73 in the McCall weather zone. The high CVR factors at the extremes may not be reliable because CVR factors tend to be inflated when the voltage change is relatively small. Highlights from the analysis results for each weather zone can be found in Appendix F.

The analysis shows that, if using CVR to reduce energy use, it is best to operate at a reduced voltage most of the time or to change it infrequently to gain the greatest benefits. While CVR also results in demand reduction most of the time, it wouldn’t result in a measurable reduction at peak if CVR is already on for energy saving purposes. The goals may be mutually exclusive in that reducing voltage to reduce demand would require the voltage to be operating in the normal range before the demand reduction event, which it wouldn’t be if the voltage is at a reduced state for energy purposes.

Quantification of Costs and Benefits

As reported in the 2016 Smart Grid Report, the cost of the Enhanced CVR Project was $263,000. Going forward, the cost of implementing CVR on a per-transformer basis varies widely. The cost on a per-transformer basis depends on what capital investments are necessary to implement CVR on that transformer or feeder. In addition, the potential for energy reduction varies widely for future installations because the potential reduction in voltage will vary depending on the existing voltage profile on a given feeder. The energy-related benefits are listed in Table 8. The results are reported by customer class, weather zone, and by season. The potential energy reduction is directly related to the potential voltage reduction. Therefore, to quantify the cost and benefit of the expansion of CVR to additional circuits will require additional analysis to determine the voltage control parameters and forecast of energy reductions on a per case basis.

CVR PROGRAM STRUCTURE AND LAYOUT

Should Idaho Power decide to implement CVR across it's Oregon service area, the following is a draft program structure and layout. It also proposes procedures for program operation and maintenance and defines a method or methods to be used for ongoing measurement and validation of program effectiveness.

Program Structure

The proposed structure would be a matrixed team of personnel from various departments within Idaho Power's Customer Operations business unit. Overall management authority for the program would reside in the Transmission & Distribution Reliability department with the various regional operations personnel responsible for CVR implementation and operation within their region. A single senior level engineer would be responsible for ensuring program consistency in Idaho Power's Oregon service area.

CVR program operation could reside within a future Volt/VAr management system and would be automated once necessary equipment was installed and initial programming settings made. Authority for disabling CVR on any particular transformer would reside in the Distribution Grid Operations Department.

Program Maintenance

The CVR program would be designed to minimize any equipment or database maintenance requirements beyond those normally associated with substation and distribution line devices. On a periodic basis, regional engineering staff would be required to model distribution circuits to determine any changes to LTC settings necessitated by changing feeder load patterns. Caution must be used in changing LTC settings too often to make CVR more dynamic. Increased LTC operations can cause increased degradation of the LTC mechanical component, leading to early failure.

Coordination between Reliability, Distribution Grid Operations, Substation Apparatus and Geographic Information System departments would be required for transformer/feeder CVR operation annotation on drawings to ensure proper distribution system operation under abnormal conditions.

Method(s) for Ongoing Measurement and Validation of Program Effectiveness

Ongoing measurement and validation of program effectiveness is important to maintain the effectiveness of the CVR program. It is likely that all measurement would take place using existing substation PI values along with customer AMI data. Some additional line monitoring devices may be required where isolated and transitory low voltage locations are observed.

Method for qualifying new transformers for CVR

Similar to what has been done in the past, substation and feeder models would be used to determine if a given transformer could qualify for CVR and also to determine what system improvements could be made to allow a transformer's LTC set point to be lowered. No global voltage reduction goal has been identified at this point.

CONCLUSION

The application of CVR at treatment locations across Idaho Power's service area resulted in variations in energy use across customer classes, weather zones, and seasons. In general, energy reductions were realized associated with load connected to each treatment transformer, though in some cases the energy saved was very small. CVR factors may not be a reliable indicator of energy or demand reduction if the voltage change potential is relatively small.

Energy-reductions potential varied widely from one weather zone to another, as might be expected. This indicates that any extensive CVR program would require significant flexibility and customization in setting control parameters. Even within a particular weather zone, the CVR factors will likely vary between individual substations though not as widely as between weather zones.

CVR for demand reduction during peak loading conditions is generally positive based on study results. However, it would be difficult to institute CVR for both energy and demand reduction concurrently because there wouldn't be a visible reduction at peak if CVR is already on for energy saving purposes.

During the CVR Enhancements Project, CVR was applied to a select group of transformers where minimal modifications were necessary to enable CVR. Expanding CVR to other transformers will likely require more extensive circuit modifications to realize the maximum effect, which may not be cost beneficial in all cases. Therefore, any expansion of CVR to additional circuits will require additional analysis to determine the voltage control parameters and forecast of energy reductions on a case-by-case basis.

Appendix A
Potential Methods for Analyzing and Improving CVR

CUSTOMER OPERATIONS, PLANNING RESEARCH, DEVELOPMENT AND DEPLOYMENT

Conservation Voltage Reduction
Potential Methods for Analyzing and Improving CVR

REPORT

December, 2014

Introduction

There is currently no standard for measurement and verification of CVR benefits, though IEEE has a working group that is working towards that end. Through study of other utilities and vendors, validation of CVR reductions fell into a few categories, all with their own set of advantages and disadvantages. This document discusses the various techniques surveyed and describes the method chosen for validating CVR benefits at Idaho Power.

CVR Reductions Analysis Techniques

The CVR Factor is a measure of load reduction as a function of voltage and is used to measure the effectiveness of a CVR program. It is defined as the percentage reduction in load resulting from a 1% reduction in voltage.

CVR Factor = DE / DV

CVR Factors can range from 0.5 to 1.0 and in some cases, exceed 1.0. It is dependent on the load characteristics of a feeder.

The characteristics of demand on a feeder change as a function of time (seasonally and hourly) which means the CVR factor is not a static number but changes often. Additionally, the CVR factor varies by customer type and geographic location.

Model-Based

Measurement and verification can be performed using modeling software that estimates the CVR benefits to be gained on circuits.

Model Based Methodology description:

Advantages

- A model based system would result in better feeder models that the company can use going forward.

Disadvantages

- Communications must be installed to operate the system based on the output of the model.
- This cannot be done independently. In order to do model-based measurement and verification, a model-based implementation of CVR is required.
- LTC operations may increase for model based CVR systems.

Day-on/Day-off (Protocol #1)

Protocol #1 description:

Advantages

- Idaho Power has used this protocol in the past with some success. The methodology is familiar.
- The comparison circuits are identical to the control circuits.

Disadvantages

- There are many variables from day to day. Weather and customer usage patterns can be difficult to filter out with the accuracy required to capture CVR reductions.
- The LTC at the substation must have the ability to change settings on a daily basis.

Combination (EPRI Green Circuits)

EPRI Green Circuits description:

Advantages

- All of the advantages of Day-on/Day-off apply here.
- Variability due to weather and customer usage patterns can be somewhat filtered out by comparing the test transformer with a similar transformer.

Disadvantages

- More analysis is required and more data must be captured.
- The LTC at the substation must have the ability to change settings on a daily basis.

Historical Data Comparison (Edge)

Historic Data Comparison description:

Advantages

- LTC settings do not necessarily need to be changed throughout the year because the test year is compared to historical data.
- CVR reductions can be obtained throughout measurement period.

Disadvantages

- Results are acceptable at best. There are many variables that can skew the results from year to year, especially with certain customer groups (i.e. crop rotations can change customer usage significantly when all other variables are constant).

Heuristic Models

Heuristic Models description:

Advantages

- Heuristic models can be used to bridge gaps in data and are less extensive than other methods.

Disadvantages

- Few utilities employ this approach and it would require a good deal of research.
- Results are not guaranteed to be accurate or acceptable.

Appendix B
Treatment and Control Transformer Parameters

Boise Weather Zone

Parameter	Value
Start Date	03/01/15
End Date	02/29/16
Treatment Transformer	MRDNSUBT131
Control Transformer (Com)	CDALSUBT133
Control Transformer (Res)	MRDNSUBT132
Commercial Sample (Trt and Ctl each)	261
Residential Sample (Trt and Ctl each)	601
Treatment Transformer Rating (MVA)	30.0
Treatment Transformer $VSet_{Reduced}$	117.0
Treatment Transformer $R_{Reduced}$	6.0
Treatment Transformer $VSet_{Normal}$	122.0
Treatment Transformer R_{Normal}	2.0

Pocatello Weather Zone

Parameter	Value
Start Date	3/6/2015
End Date	3/5/2016
Treatment Transformer	ALMAT132
Control Transformer (Com)	POCOT054
Control Transformer (Res)	POCOT054
Commercial Sample (Trt and Ctl each)	173
Residential Sample (Trt and Ctl each)	417
Treatment Transformer Rating (MVA)	30.0
Treatment Transformer $VSet_{Reduced}$	119.0
Treatment Transformer $R_{Reduced}$	4.0
Treatment Transformer $VSet_{Normal}$	123.0
Treatment Transformer R_{Normal}	0.0

Twin Falls Weather Zone

Parameter	Value
Start Date	2/5/15
End Date	2/4/16
Treatment Transformer	TFSN T134
Control Transformer (Com)	TFSN T133
Control Transformer (Res)	TFSN T133
Commercial Sample (Trt and Ctl each)	310
Residential Sample (Trt and Ctl each)	1,423
Treatment Transformer Rating (MVA)	37.3
Treatment Transformer $VSet_{Reduced}$	118.5
Treatment Transformer $R_{Reduced}$	7.0
Treatment Transformer $VSet_{Normal}$	122.5
Treatment Transformer R_{Normal}	2.0

Ketchum Weather Zone

Parameter	Value
Start Date	3/1/2015
End Date	2/29/2016
Treatment Transformer	KCHM T132
Control Transformer (Com)	HALY T131
Control Transformer (Res)	EKHN T132
Commercial Sample (Trt and Ctl each)	291
Residential Sample (Trt and Ctl each)	586
Treatment Transformer Rating (MVA)	44.8
Treatment Transformer $VSet_{Reduced}$	119.0
Treatment Transformer $R_{Reduced}$	5.0
Treatment Transformer $VSet_{Normal}$	122.5
Treatment Transformer R_{Normal}	3.0

McCall Weather Zone

Parameter	Value
Start Date	3/1/2015
End Date	2/29/16
Treatment Transformer	MCAL T131
Control Transformer (Com)	MCAL T133
Control Transformer (Res)	MCAL T133
Commercial Sample (Trt and Ctl each)	132
Residential Sample (Trt and Ctl each)	400
Treatment Transformer Rating (MVA)	22.4
Treatment Transformer $VSet_{Reduced}$	118.0
Treatment Transformer $R_{Reduced}$	18.0
Treatment Transformer $VSet_{Normal}$	122.0
Treatment Transformer R_{Normal}	0.0

Ontario Weather Zone

Parameter	Value
Start Date	05/01/2015
End Date	04/30/2016
Treatment Transformer	CARO T061
Control Transformer (Com)	VALE T061
Control Transformer (Res)	PAET T132
Commercial Sample (Trt and Ctl each)	77
Residential Sample (Trt and Ctl each)	431
Treatment Transformer Rating (MVA)	20.0
Treatment Transformer $VSet_{Reduced}$	119.0
Treatment Transformer $R_{Reduced}$	5.0
Treatment Transformer $VSet_{Normal}$	123.0
Treatment Transformer R_{Normal}	0.0

Irrigation Weather Zone

Parameter	Value
Start Date	3/01/15
End Date	2/29/16
Treatment Transformer	PTVY T131
Control Transformer	PTVY T132
Sample (Trt and Ctl each)	49
Treatment Transformer Rating (MVA)	40.0
Treatment Transformer $VSet_{Reduced}$	118.5
Treatment Transformer $R_{Reduced}$	8.0
Treatment Transformer $VSet_{Normal}$	123.0
Treatment Transformer R_{Normal}	0.0

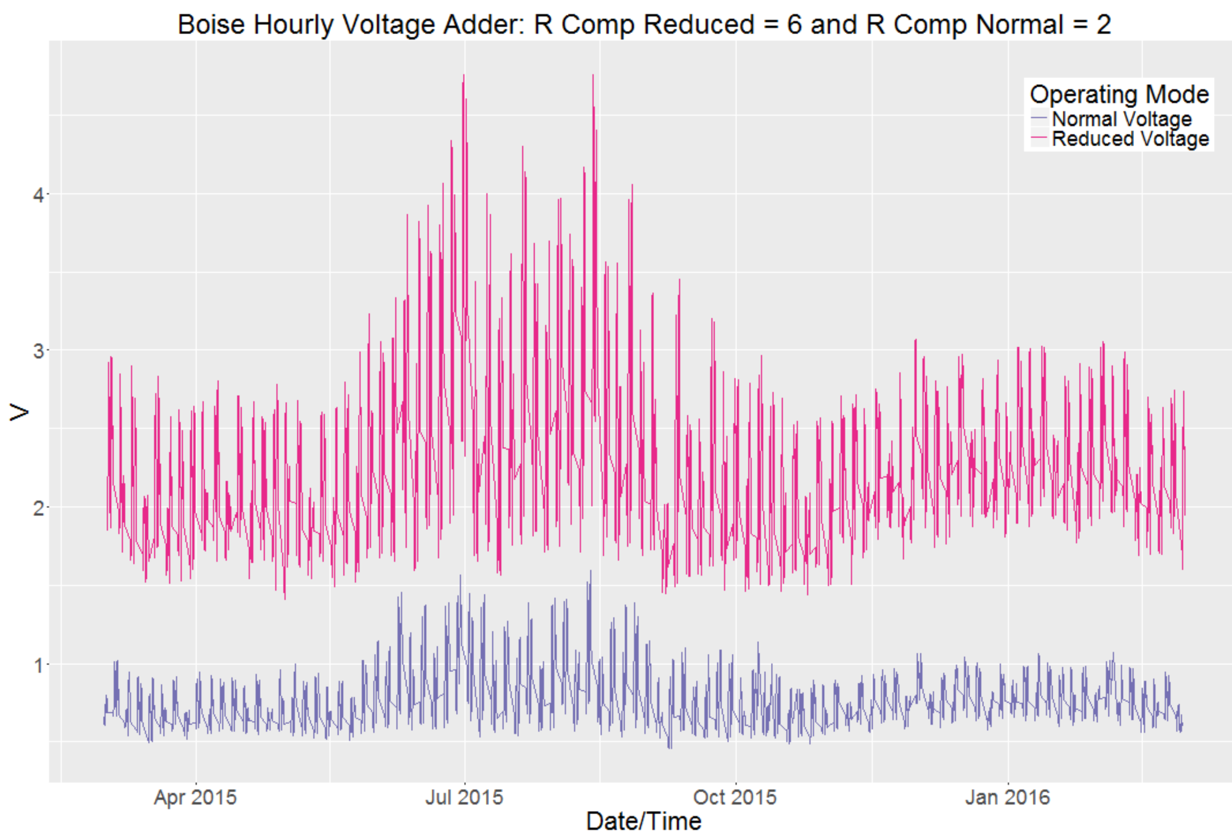
Appendix C
Line Drop Compensation Discussion

As discussed in the 2009 study, LDC is used to adjust the voltage at the substation bus such that it is regulated to a voltage point (load center) on a downstream line or feeder remote from the transformer or regulator bus. In Idaho Power's case, an estimate of the line resistance was made representing the load center of the load served from the transformer. Using LDC, bus voltage increases as transformer loading increases.

While the LDC voltage wasn't directly recorded via SCADA, it is calculated for the entire study period using the following formula,

$$V_{LDC_i} = R * \frac{MVA_i}{MVA_{Rating}}$$

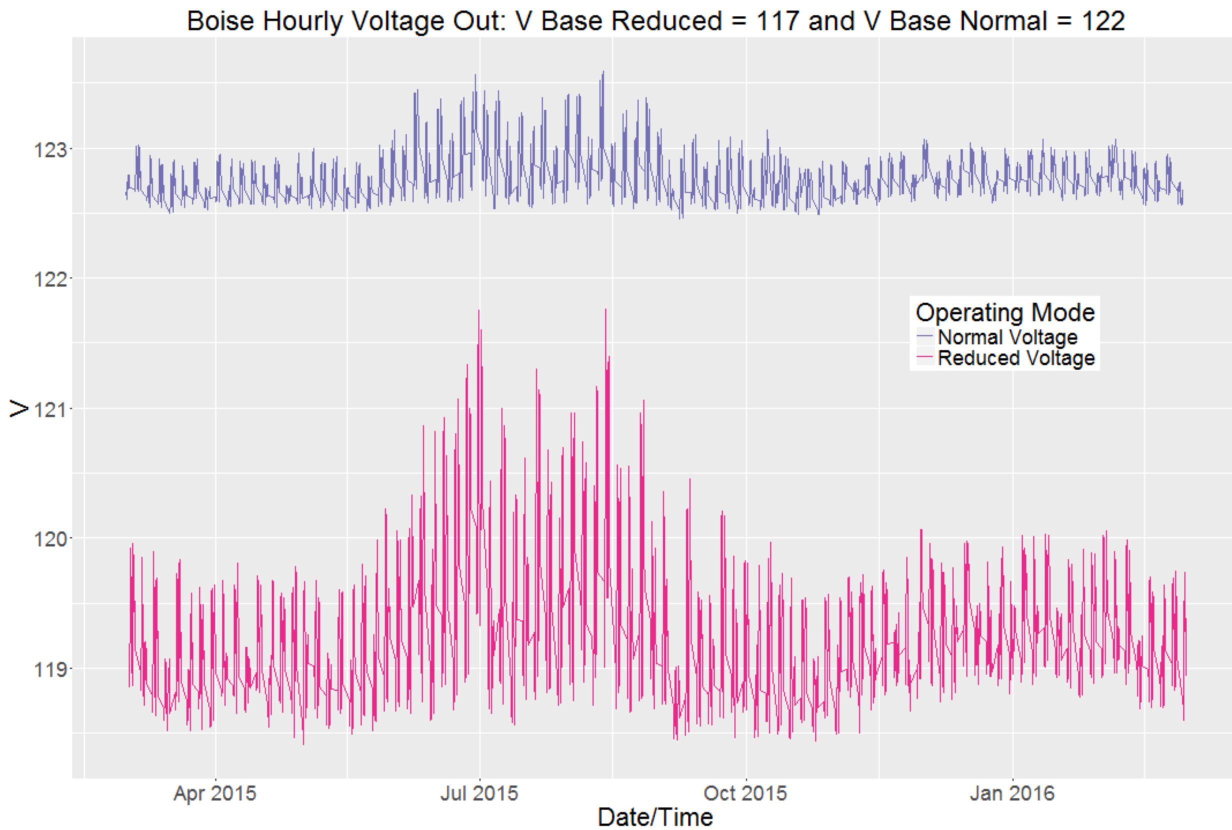
Where V_{LDCi} is the LDC offset voltage; MVA_i is the actual measured power flow from the transformer and MVA_{Rating} is the rated capacity of the transformer. The following figure shows graphically what the calculated LDC voltage offset was for the entire study period for the Boise treatment transformer. As can be seen from the graph, the voltage offset varied greatly when in the CVR (Reduced Voltage) mode as the LTC attempted to maintain voltages within acceptable values, particularly during heavy loading periods.



The following figure shows the calculated voltage commanded by the LTC during the same period. This includes the voltage offset using the formula,

$$V_{OUT_i} = V_{SET} + V_{LDC_i}$$

Where V_{OUTi} is the commanded transformer output voltage from the LTC; and V_{SET} is the band center voltage setpoint for the LTC. It is apparent from this graph that the voltage output from the transformer was relatively high during the summer when transformer loading was high meaning the voltage wasn't reduced for CVR purposes as much.



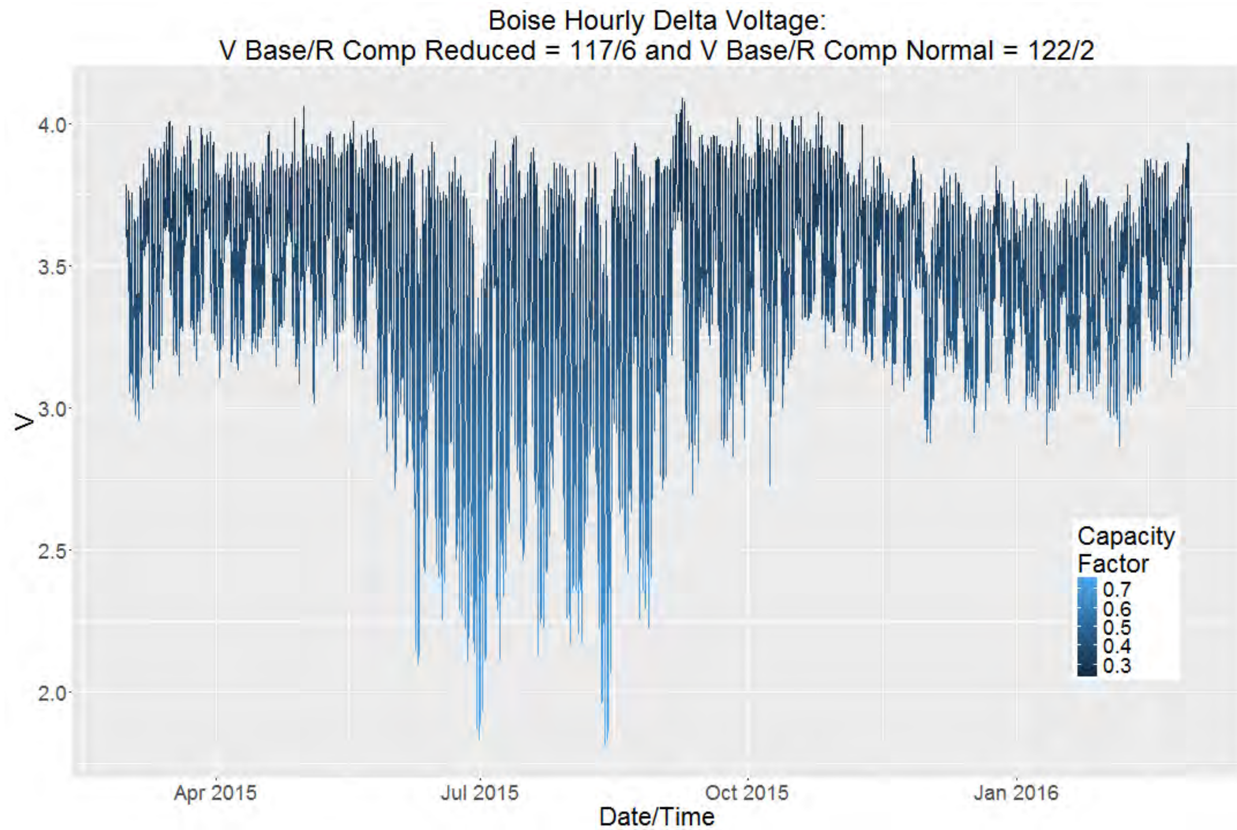
Finally, the following figure shows the theoretical difference in voltage output given the settings (voltage set point and r compensation) and actual measured hourly appearant power (MVA) for the year-long study period. It graphically highlights how much the voltage could be lowered using the "CVR" settings versus the "normal" settings, and how that varies during different loading conditions.

This was calculated using the formula,

$$Delta\ V = (V_{SET_{OFF}} - V_{SET_{ON}}) + \left[(R_{OFF} - R_{ON}) * \left(\frac{MVA_i}{MVA_{Rating}}\right)\right]$$

Where *Delta V* is the change in voltage due to LDC; V_{SETOFF} is the LTC band center voltage setpoint when CVR is off; V_{SETON} is the LTC band center voltage setpoint when CVR is on;

R_{OFF} is the LDC R compensation setting when CVR is off; and R_{ON} is the LDC R compensation setting when CVR is on. This is perhaps the most telling representation of how little voltage decrease could be commanded when loads were high in order to maintain end-of-line voltages within acceptable ranges.



Appendix D
Method to Estimate CVR Factors and Confidence Interval Estimation

Method to Estimate CVR Factors

All data processing and analysis was done in R version 3.2.2 (https://www.r-project.org/) on a Windows 7 64-bit operating system. The data that was used to estimate the CVR factors include an hourly (average of the) voltage measured at the treatment transformer (in volts), the hourly energy consumed on a per customer basis for each customer class of interest (i.e. commercial, residential, irrigation), and the status of the operational mode (i.e. reduced voltage or normal voltage). A single row of the data is shown below as an example.

Date/Time	Operating Mode Status	Voltage (Volts)	Commercial Per Customer Energy Consumption (KWh)	Residential Per Customer Energy Consumption (KWh)
2015-03-01 00:00:00	Normal Voltage	122.7977	7.115707	0.8953525

From this data, time series objects were created using the *zoo* function (see https://cran.r-project.org/web/packages/zoo/zoo.pdf for details). The arguments used for the *zoo* function were the numeric vector of interest (i.e. the column for voltage or energy consumption or the operating mode status) and the index that determines the order of the observations (i.e. the column for date/time). For a weather zone with both commercial and residential as the customer classes of interest, a total of four such time series objects were created: one each for voltage, commercial customer energy usage and residential customer energy usage, and the operating mode status coded as “Reduced Voltage” = 1 and “Normal Voltage” = 0. Then, a total of three regression models were estimated using the *dynlm* function (see https://cran.r-project.org/web/packages/dynlm/dynlm.pdf for details). Each model was of the form:

$$Y = \beta_0 + \beta_1 X$$

where Y is either voltage or energy consumption and X=1 when the operating mode is equal to “Reduced Voltage” and X=0 when the operating mode is equal to “Normal Voltage”. In this model, β_0 is the average of Y when X=0 (i.e. “Normal Voltage” operating mode) and β_1 is the additive effect that “Reduced Voltage” mode has on the average of Y (compared to the “Normal Voltage” mode). So, the estimated percent difference in the average voltage or energy consumption between the operating modes is:

$$\hat{\Delta} = \frac{\hat{\beta}_1}{\hat{\beta}_0}$$

Then, to calculate the CVR factor the percent difference was estimated for both the voltage and the energy consumption for all customer classes of interest, and the ratio of those percent differences was calculated as percent difference in energy (E) divided by percent difference in voltage (V):

$$\widehat{CVR_f} = \frac{\hat{\Delta}_E}{\hat{\Delta}_V}$$

An example of this calculation is shown below for the Boise, ID weather zone:

Parameter	Estimate
β_0 (Voltage)	122.58641
β_1 (Voltage)	-3.39240
β_0 (Commercial Energy Usage)	10.83546
β_1 (Commercial Energy Usage)	-0.23438
β_0 (Residential Energy Usage)	1.09639
β_1 (Residential Energy Usage)	-0.02620

$$\hat{\Delta}_V = \frac{-3.39240}{122.58641} = -0.02767 = -2.767\%$$

$$\hat{\Delta}_{ECom} = \frac{-0.23438}{10.83546} = -0.02163 = -2.163\%$$

$$\widehat{CVR_{fCom}} = \frac{-0.02163}{-0.02767} = 0.78164$$

$$\hat{\Delta}_{ERes} = \frac{-0.02620}{1.09639} = -0.02390 = -2.390\%$$

$$\widehat{CVR_{fRes}} = \frac{-0.02390}{-0.02767} = 0.86355$$

Method to Estimate Confidence Intervals for CVR Factors

The Bonferroni procedure was used to calculate the joint confidence intervals for each weather zone's results. This was done so that the confidence intervals within each weather zone's set of results could be interpreted simultaneously. Since the results for two separate models were needed to calculate the estimated CVR factor (see the previous section) for each customer class of interest, it was necessary to use an adjustment for the confidence intervals to ensure they could be stated simultaneously. For a weather zone with both residential and commercial customers of interest, three models were estimated each with two parameters (β_0 and β_1), for a total of six parameters estimated from the same data set. The following table is an example of the parameter estimates from all three models with standard errors for the Boise, ID weather zone.

Parameter	Estimate	Standard Error
β_0 (Voltage)	122.58641	0.01100
β_1 (Voltage)	-3.39240	0.01558
β_0 (Commercial Energy Usage)	10.83546	0.04313
β_1 (Commercial Energy Usage)	-0.23438	0.06108
β_0 (Residential Energy Usage)	1.09639	0.00598
β_1 (Residential Energy Usage)	-0.02620	0.00846

The Bonferroni procedure specifies a multiplier, B, that is calculated given the total number of observations in the data set and the number of confidence intervals in the family of tests. For each weather zone, these values are equivalent to the number of hours in the year of study (excluding the outlier hours) and the number of customer classes of interest. As an example, the Boise, ID weather zone had 4,397 hours in "Normal Voltage" mode and 4,372 hours in "Reduced Voltage" mode for a total of 8,769 hours in the year (note that the study period included an additional day accrued by a leap year). Since both commercial and residential customers were of interest in this weather zone, a total of six confidence intervals were included in the family of tests. The Bonferroni procedure specifies that the confidence limits for a parameter, β are:

$$\hat{\beta} \pm Bs\{\hat{\beta}\}$$

where $s\{\hat{\beta}\}$ is the standard error of the estimate of β. The Bonferroni procedure specifies that:

$$B = t\left(1 - \frac{\alpha}{2g}; n - 2\right)$$

For a family confidence coefficient of 0.95 (i.e. 95% confidence), α = 0.05. Thus, for the given n and g for the Boise, ID weather zone, the Bonferroni multiplier:

$$B = t\left(1 - \frac{0.05}{2 * 6}; 8769 - 2\right)$$

$$= t\left(1 - \frac{0.05}{12}; 8767\right)$$

$$= t(1 - 0.004167, 8767)$$

$$= t(0.995833, 8767)$$

$$= 2.638856$$

For the parameter estimates and the standard errors in the table above, the lower and upper 95% confidence limits shown in the table below can be calculated using the Bonferroni multiplier, B.

Parameter	Estimate	Standard Error	95% Lower	95% Upper
β_0 (Voltage)	122.58641	0.01100	122.55738	122.61544
β_1 (Voltage)	-3.39240	0.01558	-3.43351	-3.35129
β_0 (Commercial Energy Usage)	10.83546	0.04313	10.72165	10.94927
β_1 (Commercial Energy Usage)	-0.23438	0.06108	-0.39556	-0.07320
β_0 (Residential Energy Usage)	1.09639	0.00598	1.08062	1.11216
β_1 (Residential Energy Usage)	-0.02620	0.00846	-0.04853	-0.00387

To calculate the 95% confidence intervals for the CVR factors, the same calculations were used as in the previous section, however instead of the estimate, the lower and upper values were used, respectively. For example, the lower:

$$\hat{\Delta}_{VLower} = \frac{-3.43351}{122.55738} = -0.02802 = -2.802\%$$

$$\hat{\Delta}_{EComLower} = \frac{-0.39556}{10.72165} = -0.03689 = -3.689\%$$

$$\widehat{CVR_{fComLower}} = \frac{-0.03689}{-0.02802} = 1.31690$$

$$\hat{\Delta}_{EResLower} = \frac{-0.04853}{1.08062} = -0.04491 = -4.491\%$$

$$\widehat{CVR_{fResLower}} = \frac{-0.04491}{-0.02802} = 1.60296$$

and the upper:

$$\hat{\Delta}_{VUpper} = \frac{-3.35129}{122.61544} = -0.02733 = -2.733\%$$

$$\hat{\Delta}_{EComUpper} = \frac{-0.07320}{10.94927} = -0.00669 = -0.669\%$$

$$\widehat{CVR_{fComUpper}} = \frac{-0.00669}{-0.02733} = 0.24460$$

$$\hat{\Delta}_{EResUpper} = \frac{-0.00387}{1.11216} = -0.00348 = -0.348\%$$

$$\widehat{CVR_{fResUpper}} = \frac{-0.00348}{-0.02733} = 0.12743$$

Since the CVR factors are ratios of percent differences, the "lower" and "upper" confidence limits are switched. So, in the Boise, ID weather zone the estimate with 95% confidence limits for the CVR factor for commercial customers is 0.78164 (0.24460, 1.31690) and for residential customers is 0.86355 (0.12743, 1.60296).

Appendix E
Overall CVR Factors

Energy CVR Factors

α = 0.05 g = 6

Zone/Parameters				Estimate	Std Error	Lower	Upper		% Delta		CVR Factor			Reduced	Normal	Hours (Total)
Boise, ID	Normal*	V	Intercept	122.59	0.0110	122.56	122.62	-2.77%	-2.80%	-2.73%	Not Applicable			119.19	122.59	8,769
	4,397		Reduced	-3.39	0.0156	-3.43	-3.35									
	Reduced*	Com kWh	Intercept	10.84	0.0431	10.72	10.95	-2.16%	-3.69%	-0.67%	0.78	1.32	0.24	10.60	10.84	
	4,372		Reduced	-0.23	0.0611	-0.40	-0.07									
	B	Res kWh	Intercept	1.10	0.0060	1.08	1.11	-2.39%	-4.49%	-0.35%	0.86	1.60	0.13	1.07	1.10	
	2.6389		Reduced	-0.03	0.0085	-0.05	0.00									
Pocatello, ID	Normal*	V	Intercept	122.90	0.0090	122.87	122.92	-2.01%	-2.04%	-1.99%	Not Applicable			120.42	122.90	8,748
	4,394		Reduced	-2.47	0.0128	-2.51	-2.44									
	Reduced*	Com kWh	Intercept	10.46	0.0331	10.37	10.55	-1.75%	-2.96%	-0.56%	0.87	1.45	0.28	10.28	10.46	
	4,354		Reduced	-0.18	0.0469	-0.31	-0.06									
	B	Res kWh	Intercept	0.97	0.0038	0.96	0.98	-1.28%	-2.78%	0.20%	0.63	1.36	-0.10	0.96	0.97	
	2.6389		Reduced	-0.01	0.0054	-0.03	0.00									
Hailey, ID	Normal*	V	Intercept	123.29	0.0123	123.25	123.32	-2.21%	-2.25%	-2.18%	Not Applicable			120.56	123.29	8,243
	4,059		Reduced	-2.73	0.0173	-2.77	-2.68									
	Reduced*	Com kWh	Intercept	4.19	0.0123	4.16	4.22	-2.47%	-3.58%	-1.37%	1.11	1.59	0.63	4.09	4.19	
	4,184		Reduced	-0.10	0.0172	-0.15	-0.06									
	B	Res kWh	Intercept	1.48	0.0075	1.46	1.50	-2.58%	-4.52%	-0.69%	1.16	2.01	0.31	1.44	1.48	
	2.6389		Reduced	-0.04	0.0105	-0.07	-0.01									
Twin Falls, ID	Normal*	V	Intercept	122.80	0.0106	122.77	122.83	-1.37%	-1.41%	-1.34%	Not Applicable			121.11	122.80	8,749
	4,387		Reduced	-1.69	0.0150	-1.73	-1.65									
	Reduced*	Com kWh	Intercept	10.87	0.0332	10.78	10.96	-0.89%	-2.05%	0.25%	0.65	1.46	-0.19	10.77	10.87	
	4,362		Reduced	-0.10	0.0471	-0.22	0.03									
	B	Res kWh	Intercept	1.03	0.0046	1.02	1.04	-0.57%	-2.27%	1.09%	0.41	1.62	-0.81	1.03	1.03	
	2.6389		Reduced	-0.01	0.0066	-0.02	0.01									
McCall, ID	Normal*	V	Intercept	122.06	0.0151	122.02	122.10	-0.21%	-0.26%	-0.16%	Not Applicable			121.80	122.06	8,373
	4,212		Reduced	-0.26	0.0215	-0.31	-0.20									
	Reduced*	Com kWh	Intercept	10.51	0.0300	10.43	10.59	-0.61%	-1.69%	0.46%	2.89	6.57	-2.77	10.45	10.51	
	4,161		Reduced	-0.06	0.0426	-0.18	0.05									
	B	Res kWh	Intercept	1.41	0.0091	1.39	1.44	-1.21%	-3.69%	1.18%	5.75	14.34	-7.19	1.40	1.41	
	2.6389		Reduced	-0.02	0.0130	-0.05	0.02									
Ontario, OR	Normal*	V	Intercept	122.57	0.0124	122.54	122.60	-1.66%	-1.70%	-1.62%	Not Applicable			120.53	122.57	6,893
	3,448		Reduced	-2.03	0.0175	-2.08	-1.99									
	Reduced*	Com kWh	Intercept	8.76	0.0358	8.67	8.85	-0.31%	-1.86%	1.20%	0.19	1.09	-0.74	8.73	8.76	
	3,445		Reduced	-0.03	0.0506	-0.16	0.11									
	B	Res kWh	Intercept	1.54	0.0084	1.51	1.56	-1.50%	-3.60%	0.53%	0.91	2.12	-0.33	1.51	1.54	
	2.6390		Reduced	-0.02	0.0119	-0.05	0.01									
Aberdeen, ID	Normal*	V	Intercept	122.78	0.0186	122.73	122.83	-2.40%	-2.46%	-2.34%	Not Applicable			119.84	122.78	6,794
	3,485		Reduced	-2.94	0.0267	-3.01	-2.87									
	Reduced*	Irr kWh	Intercept	55.95	0.9415	53.47	58.44	-0.52%	-7.20%	5.59%	0.22	2.93	-2.39	55.66	55.95	
	3,309		Reduced	-0.29	1.3490	-3.85	3.27									
	B															
	2.6390															

*Hours in this mode of operation.

Demand CVR Factors

α = 0.05 g = 6

Zone/Parameters				Estimate	Std Error	Lower	Upper	% Delta			CVR Factor			Reduced	Normal	Hours (Total)
Boise, ID	Normal*	V	Intercept	122.98	0.0120	122.95	123.01	-2.26%	-2.30%	-2.22%	Not Applicable			120.20	122.98	5,514
	2,754		Reduced	-2.78	0.0170	-2.82	-2.73									
	Reduced*	MW	Intercept	18.83	0.0496	18.70	18.96	-3.12%	-4.13%	-2.13%	1.38	1.80	0.96	18.24	18.83	
	2,760		Reduced	-0.59	0.0701	-0.77	-0.40									
	B	MVAR	Intercept	-1.10	0.1197	-1.41	-0.78	-0.42%	2.83%	-6.31%	0.19	-1.23	2.84	-1.09	-1.10	
	2.6392		Reduced	0.00	0.0169	-0.04	0.05									
Pocatello, ID	Normal*	V	Intercept	123.18	0.0075	123.16	123.20	-2.01%	-2.04%	-1.99%	Not Applicable			120.70	123.18	5,447
	2,817		Reduced	-2.48	0.0108	-2.51	-2.45									
	Reduced*	MW	Intercept	15.52	0.0380	15.42	15.62	-4.95%	-5.92%	-3.99%	2.46	2.91	2.01	14.75	15.52	
	2,630		Reduced	-0.77	0.0547	-0.91	-0.62									
	B	MVAR	Intercept	0.10	0.0093	0.07	0.12	183.59%	196.81%	175.66%	-91.20	-96.65	-88.29	0.28	0.10	
	2.6392		Reduced	0.18	0.0134	0.15	0.22									
Hailey, ID	Normal*	V	Intercept	123.59	0.0123	123.56	123.62	-2.04%	-2.08%	-2.01%	Not Applicable			121.06	123.59	5,457
	2,743		Reduced	-2.53	0.0174	-2.57	-2.48									
	Reduced*	MW	Intercept	20.54	0.0462	20.42	20.66	-1.58%	-2.44%	-0.74%	0.78	1.17	0.37	20.22	20.54	
	2,714		Reduced	-0.33	0.0655	-0.50	-0.15									
	B	MVAR	Intercept	1.44	0.0069	1.42	1.45	-13.91%	-15.91%	-11.95%	6.81	7.65	5.96	1.24	1.44	
	2.6392		Reduced	-0.20	0.0098	-0.23	-0.17									
Twin Falls, ID	Normal*	V	Intercept	123.18	0.0095	123.15	123.20	-0.85%	-0.87%	-0.82%	Not Applicable			122.14	123.18	5,459
	2,696		Reduced	-1.04	0.0134	-1.08	-1.01									
	Reduced*	MW	Intercept	21.81	0.0588	21.66	21.97	0.40%	-0.60%	1.39%	-0.48	0.69	-1.71	21.90	21.81	
	2,763		Reduced	0.09	0.0827	-0.13	0.31									
	B	MVAR	Intercept	-1.70	0.0110	-1.73	-1.67	6.53%	8.78%	4.20%	-7.72	-10.04	-5.14	-1.81	-1.70	
	2.6392		Reduced	-0.11	0.0155	-0.15	-0.07									
McCall, ID	Normal*	V	Intercept	121.64	0.0129	121.61	121.68	1.96%	1.92%	2.00%	Not Applicable			124.03	121.64	4,362
	2,210		Reduced	2.39	0.0183	2.34	2.43									
	Reduced*	MW	Intercept	7.49	0.0185	7.44	7.54	-3.39%	-4.35%	-2.45%	-1.73	-2.26	-1.22	7.24	7.49	
	2,152		Reduced	-0.25	0.0264	-0.32	-0.18									
	B	MVAR	Intercept	0.85	0.0047	0.83	0.86	1.69%	-0.39%	3.71%	0.86	-0.21	1.85	0.86	0.85	
	2.6395		Reduced	0.01	0.0067	0.00	0.03									
Ontario, OR	Normal*	V	Intercept	122.89	0.0143	122.85	122.92	-1.38%	-1.42%	-1.34%	Not Applicable			121.19	122.89	5,334
	2,723		Reduced	-1.70	0.0205	-1.75	-1.64									
	Reduced*	MW	Intercept	11.15	0.0300	11.07	11.23	-1.85%	-2.88%	-0.82%	1.34	2.02	0.62	10.94	11.15	
	2,611		Reduced	-0.21	0.0429	-0.32	-0.09									
	B	MVAR	Intercept	-0.70	0.0077	-0.72	-0.68	-10.65%	-6.32%	-15.24%	7.72	4.44	11.41	-0.63	-0.70	
	2.6392		Reduced	0.07	0.0110	0.05	0.10									
Aberdeen, ID	Normal*	V	Intercept	122.86	0.0169	122.82	122.90	-0.69%	-0.74%	-0.63%	Not Applicable			122.02	122.86	5,460
	2,700		Reduced	-0.84	0.0238	-0.90	-0.78									
	Reduced*	MW	Intercept	24.08	0.1438	23.70	24.46	-2.98%	-5.28%	-0.75%	4.35	7.17	1.18	23.36	24.08	
	2,760		Reduced	-0.72	0.2022	-1.25	-0.18									
	B	MVAR	Intercept	0.46	0.0217	0.40	0.51	-8.03%	-29.28%	8.50%	11.72	39.76	-13.41	0.42	0.46	
	2.6392		Reduced	-0.04	0.0305	-0.12	0.04									

*Hours in this mode of operation.

Appendix F
Weather Zone Analysis Results

The following are highlights from each weather zone. In each weather zone, two tables (Overall CVR Factors and Demand CVR Factors) contain a few columns that warrant some description.

- **% Delta**—The change in voltage or energy on a per customer basis when in CVR mode.
- **Reduced**—These are the mean values when in reduced voltage mode. For kWh, MW, and MVAR, this is on a per customer basis.
- **Normal**—These are the mean values when in normal voltage mode. Again, for kWh, MW, and MVAR, this is on a per customer basis.

Additionally, the other tables in each section contain columns that warrant explanation.

- PDeltaV – The average change in voltage due to operating in CVR mode.
- PDelta Com KWH – The average change in energy use for commercial customers due to operating at a reduced voltage.
- PDelta Res KWH – The average change in energy use for residential customers due to operating at a reduced voltage.
- DD Type – Degree Day Type. This is applicable to the CVR Factors by Degree Day tables.
- DDCat – Degree Day Category. This is applicable to the CVR Factors by Degree Day tables.

Boise Weather Zone

Data collection for the Boise weather zone began March 1, 2015 and ended February 29, 2016. The treatment transformer was Meridian Substation, T131, located in Meridian, Idaho. The commercial class sample was 261 customers and the residential class sample size was 601 customers. Two separate control transformers were used:

- **Commercial Customers**—Caldwell Substation, T133 located in Caldwell, Idaho.
- **Residential Customers**—Meridian Substation, T132, located in Meridian, Idaho.

Overall CVR Factors for Boise Weather Zone

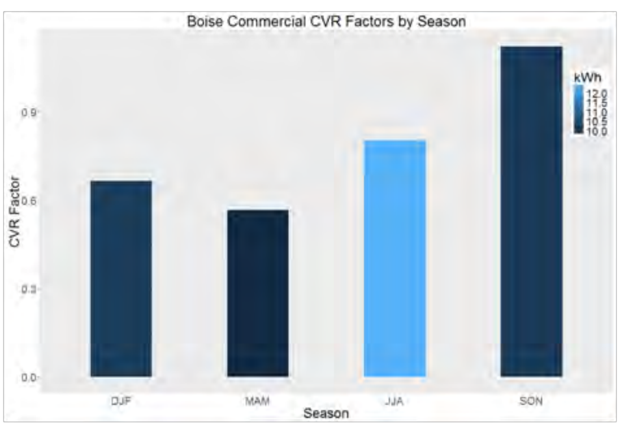
On average, the voltage in the Boise weather zone was reduced 2.8%. The calculated overall commercial CVR factor for energy was 0.78 and the residential CVR factor was 0.86. These numbers are in line with national averages and are shown in the following table.

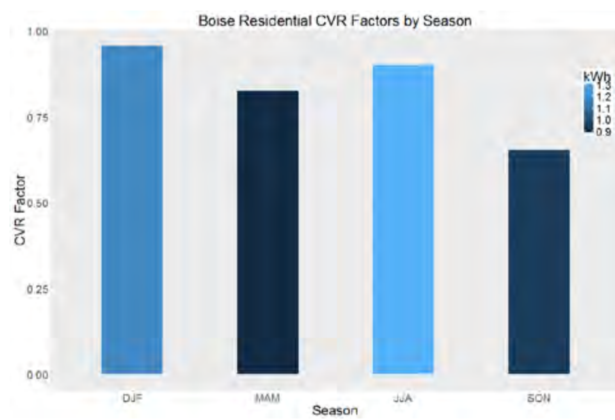
Zone/Parameters		% Delta (confidence interval)	CVR Factor (confidence interval)	Reduced	Normal	Hours n (TOTAL)
Boise, ID	V	**-2.77%** (-2.73%, -2.80%)	N/A	119.19	122.59	8,769
	Com kWh	**-2.16%** (-0.67%, -3.69%)	**0.78** (0.24, 1.32)	10.60	10.84	
	Res kWh	**-2.39%** (-0.35%, -4.49%)	**0.86** (0.13, 1.60)	1.07	1.10	

CVR Factors by Season for Boise Weather Zone

The best CVR factors for commercial loads occur in the fall while the best for residential occur in the winter. For both classes positive CVR factors are present year-round.

Season	Hours On	Hours Off	Avg Volt On	Avg Volt Off	Avg Com KWH On	Avg Com KWH Off	Avg Res KWH On	Avg Res KWH Off	PDeltaV	PDelta Com KWH	PDelta Res KWH	Com CVR Factor	Res CVR Factor
DJF(Winter)	1,076	1,103	119.27	122.66	10.18	10.37	1.18	1.21	-2.76%	-1.84%	-2.65%	0.66	0.96
MAM(Spring)	1,104	1,101	118.90	122.32	9.81	9.97	0.87	0.89	-2.79%	-1.58%	-2.30%	0.57	0.82
JJA(Summer)	1,104	1,103	119.48	122.71	12.34	12.60	1.29	1.33	-2.64%	-2.11%	-2.38%	0.80	0.90
SON(Fall)	1,088	1,090	119.13	122.66	10.05	10.39	0.94	0.95	-2.88%	-3.23%	-1.88%	1.12	0.65

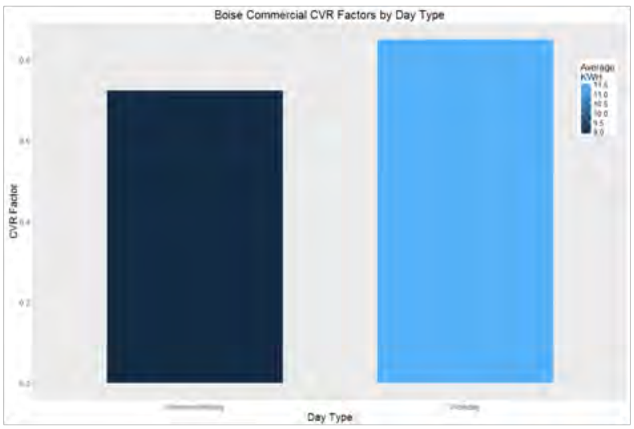


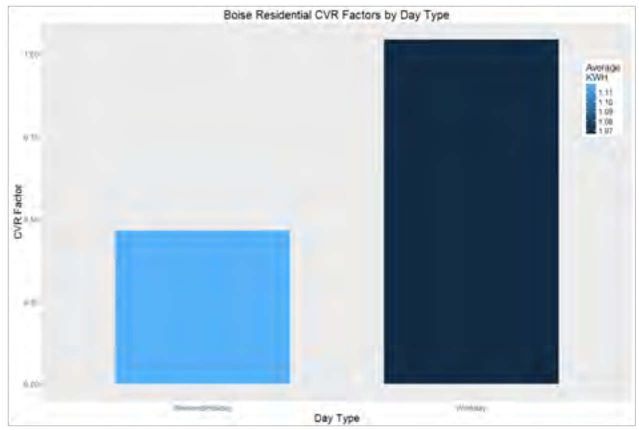


CVR Factors by Day Type for Boise Weather Zone

Residential CVR factors didn't show much change based on day of week, while commercial CVR factors were highest on workdays in the Boise Weather Zone. This is to be expected since many businesses are closed on weekends and their heating and cooling is set to moderate temperatures.

WedHol	Hours On	Hours Off	Avg Volt On	Avg Volt Off	Avg Com KWH On	Avg Com KWH Off	Avg Res KWH On	Avg Res KWH Off	PDelta V	PDelta Com KWH	PDelta Res KWH	Com CVR Factor	Res CVR Factor
Weekend/ Holiday	1,339	1,364	118.99	122.45	8.82	9.01	1.11	1.13	-2.83%	-2.05%	-1.32%	0.72	0.47
Workday	3,033	3,033	119.29	122.65	11.39	11.66	1.05	1.08	-2.74%	-2.33%	-2.86%	0.85	1.04

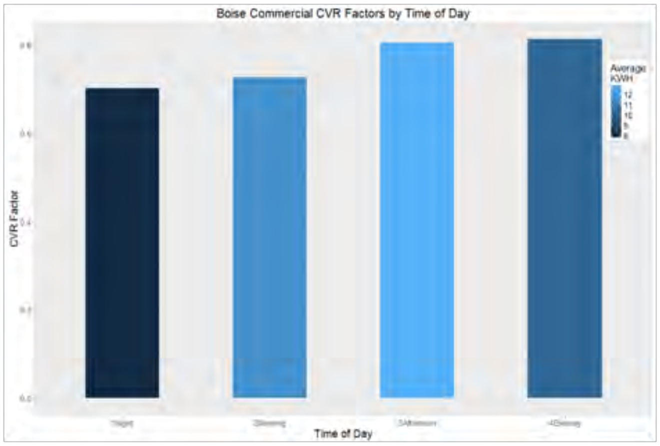


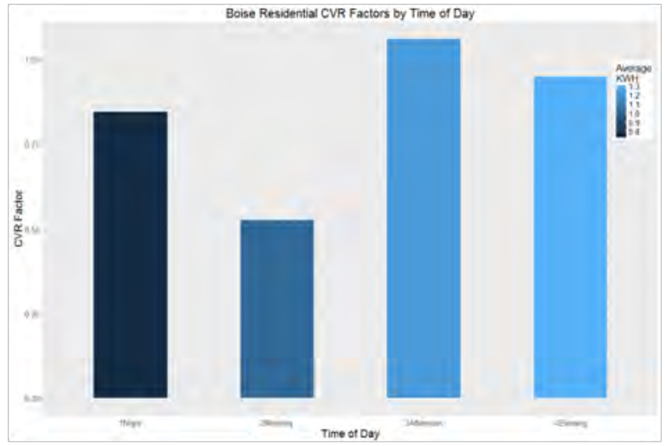


CVR Factors by Time of Day for Boise Weather Zone

Similar to Day of Week, commercial showed little change based on time of day. Residential CVR factors showed significant decrease in the morning hours of 06:00 and 12:00; it is not obvious why this is so.

TOD	Hours On	Hours Off	Avg Volt On	Avg Volt Off	Avg Com KWH On	Avg Com KWH Off	Avg Res KWH On	Avg Res KWH Off	PDelta V	PDelta Com KWH	PDelta Res KWH	Com CVR Factor	Res CVR Factor
Night	1,097	1,097	118.91	122.43	7.82	7.98	0.74	0.76	-2.88%	-2.02%	-2.43%	0.70	0.84
Morning	1,089	1,100	118.91	122.43	11.67	11.92	1.02	1.04	-2.88%	-2.09%	-1.51%	0.73	0.52
Afternoon	1,092	1,100	119.55	122.81	12.75	13.03	1.21	1.25	-2.65%	-2.14%	-2.81%	0.80	1.06
Evening	1,094	1,100	119.42	122.68	10.18	10.41	1.30	1.34	-2.66%	-2.16%	-2.52%	0.81	0.95

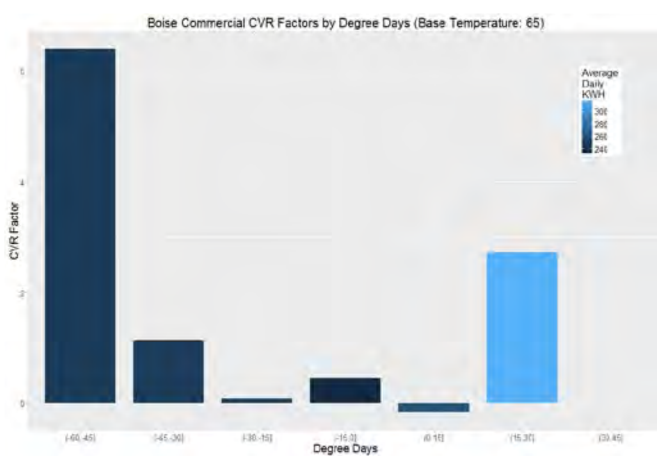


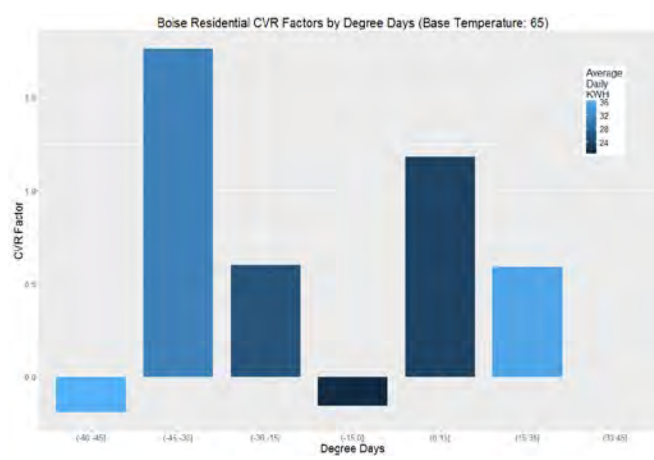


CVR Factors by Degree Day for Boise Weather Zone

There were a few temperatures at which the energy reduction was negative, but this only occurred for a few hours of the year. Note that at Heating,-60, -45 (corresponding to an outside temperature of 5°F to 20°F) the commercial decrease in energy was 18.91% as shown in the following table. This was an extremely cold-day reading, and very few data points were measured; therefore, this value is not considered valid.

DD Type	DDCat	Days On	Days Off	Avg Volt On	Avg Volt Off	Avg Com KWH On	Avg Com KWH Off	Avg Res KWH On	Avg Res KWH Off	PDeltaV	PDelta Com KWH	PDelta Res KWH	Com CVR Factor	Res CVR Factor
Heating	(-60,-45]	2	2	119.18	122.80	219.26	270.38	36.71	36.50	-2.95%	-18.91%	0.57%	6.41	-0.19
Heating	(-45,-30]	20	16	119.36	122.73	242.52	250.26	30.70	32.26	-2.74%	-3.10%	-4.83%	1.13	1.76
Heating	(-30,-15]	41	52	119.05	122.43	243.99	244.53	25.56	25.99	-2.75%	-0.22%	-1.66%	0.08	0.60
Heating	(-15,0]	46	39	118.97	122.46	232.22	235.24	20.52	20.43	-2.86%	-1.28%	0.44%	0.45	-0.16
Cooling	(0,15]	48	49	119.17	122.55	263.48	262.25	23.28	24.06	-2.75%	0.47%	-3.25%	-0.17	1.18
Cooling	(15,30]	25	24	119.65	122.86	308.17	331.69	34.97	35.51	-2.61%	-7.09%	-1.53%	2.72	0.59
Cooling	(30,45]	0	1	#N/A	122.56	#N/A	296.33	#N/A	47.28	#N/A	#N/A	#N/A	#N/A	#N/A

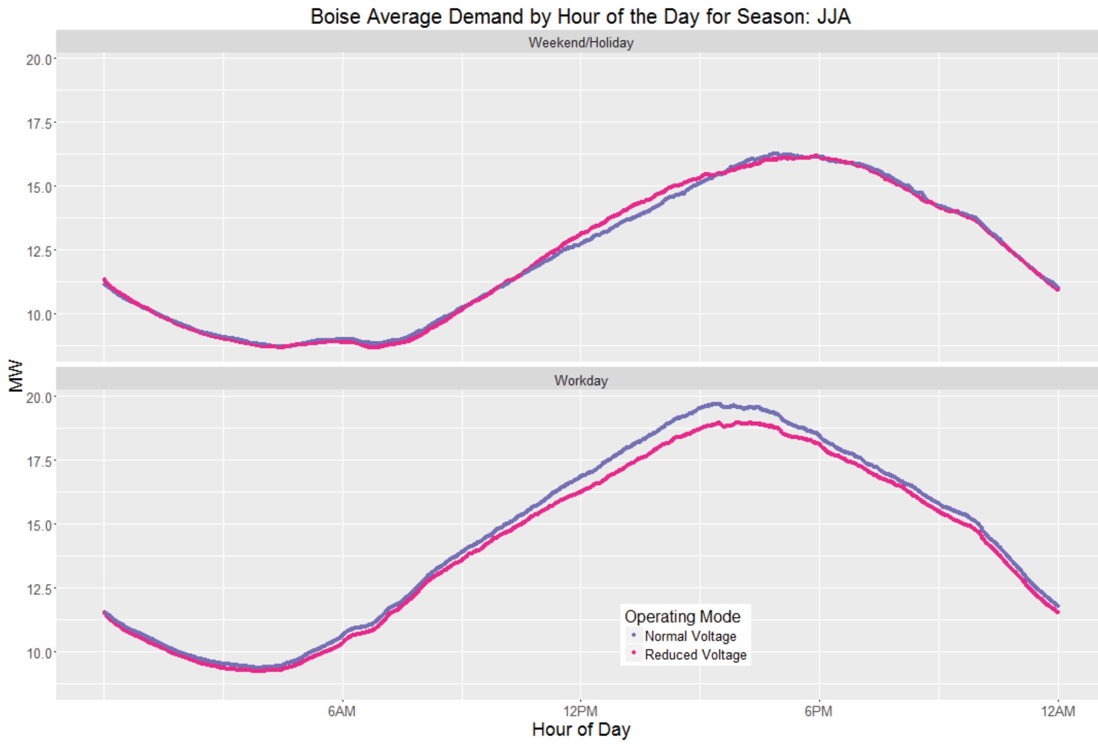


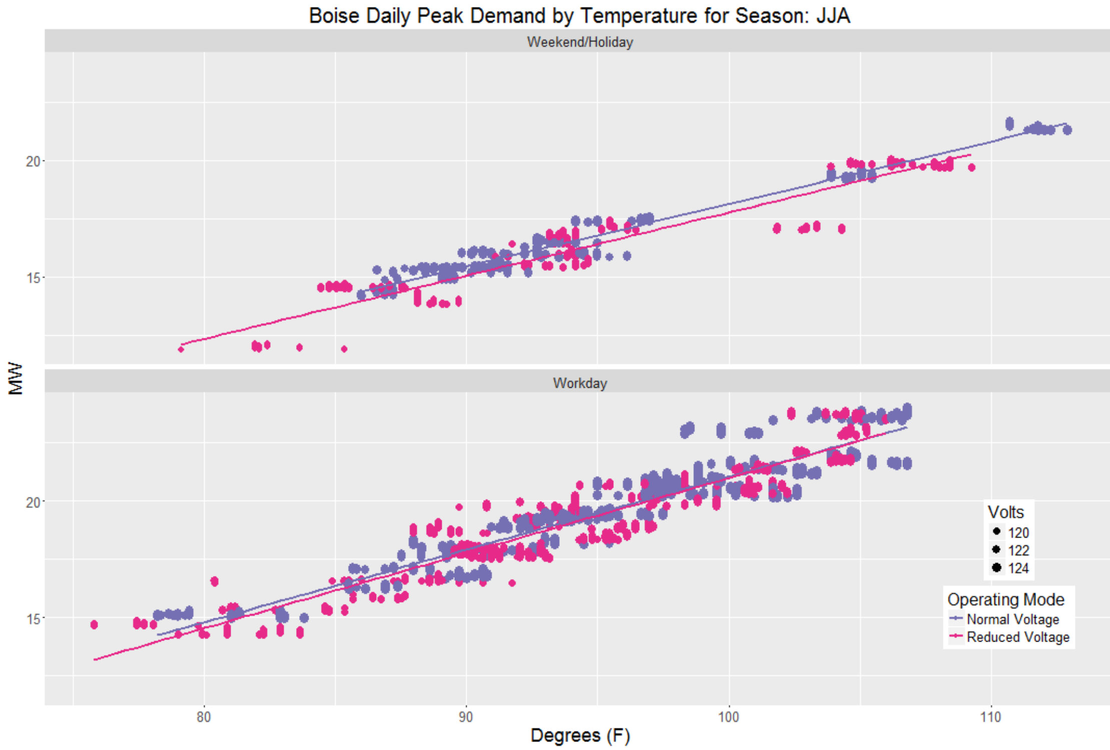


Demand CVR Factors for Boise Weather Zone

CVR can be used for peak demand-reduction purposes in the Boise Weather Zone with a CVR factor of 1.38.

Zone/Parameters		% Delta (confidence interval)	CVR Factor (confidence interval)	Reduced	Normal	Hours n (TOTAL)
Boise, ID	V	**-2.26%** (-2.22%, -2.30%)	Not Applicable	120.20	122.98	5,514
	MW	**-3.12%** (-2.13%, -4.13%)	**1.38** (0.96, 1.80)	18.24	18.83	
	MVAR	**-0.42%** (-6.31%, 2.83%)	**0.19** (2.84, -1.23)	-1.09	-1.10	





Pocatello Weather Zone

Data collection for the Pocatello weather zone began March 6, 2015 and ended March 5, 2016. The treatment transformer was Alameda Substation, T132, located in Pocatello, Idaho. The commercial class sample was 173 customers and the residential class sample size was 417 customers. Pocatello Substation transformer T54 was used as the control transformer for both customer classes.

Overall CVR Factors for Pocatello Weather Zone

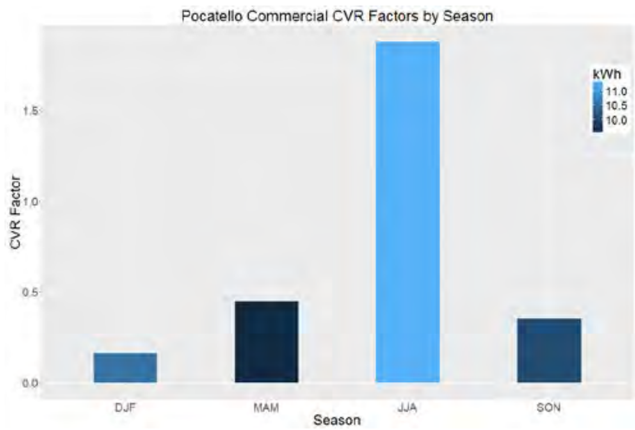
Similar to the Boise weather zone, the overall results for Pocatello show a commercial CVR factor of 0.87 and a residential CVR factor of 0.63 as shown in the following table. The voltage was reduced by an average 2.0%.

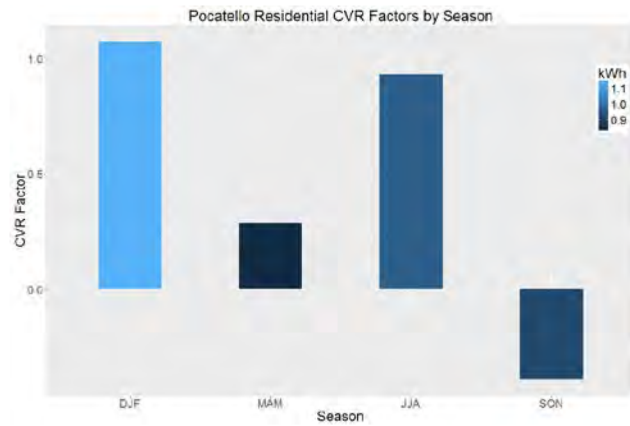
Zone/Parameters		% Delta (confidence interval)	CVR Factor (confidence interval)	Reduced	Normal	Hours n (TOTAL)
Pocatello, ID	V	**-2.01%** (-1.99%, -2.04%)		120.42	122.90	8,748
	Com kWh	**-1.75%** (-0.56%, -2.96%)	**0.87** (0.28, 1.45)	10.28	10.46	
	Res kWh	**-1.28%** (0.20%, -2.78%)	**0.63** (-0.10, 1.36)	0.96	0.97	

CVR Factors by Season for Pocatello Weather Zone

The best CVR factors for commercial loads occur in the summer, while the best for residential occur during the winter, though the residential CVR factor was also high during the summer. Commercial CVR factors were positive year-round while the residential CVR factor was negative during the fall.

Season	Hours On	Hours Off	Avg Volt On	Avg Volt Off	Avg Com KWH On	Avg Com KWH Off	Avg Res KWH On	Avg Res KWH Off	PDeltaV	PDelta Com KWH	PDelta Res KWH	Com CVR Factor	Res CVR Factor
DJF(Winter)	1,081	1,103	120.57	122.88	10.54	10.57	1.14	1.16	-1.89%	-0.30%	-2.02%	0.16	1.07
MAM(Spring)	1,124	1,078	120.18	122.89	9.51	9.60	0.82	0.83	-2.21%	-0.99%	-0.63%	0.45	0.29
JJA(Summer)	1,054	1,138	120.52	122.91	11.10	11.52	0.95	0.97	-1.94%	-3.63%	-1.80%	1.87	0.93
SON(Fall)	1,095	1,074	120.43	122.91	10.01	10.08	0.91	0.91	-2.01%	-0.71%	0.78%	0.35	-0.39

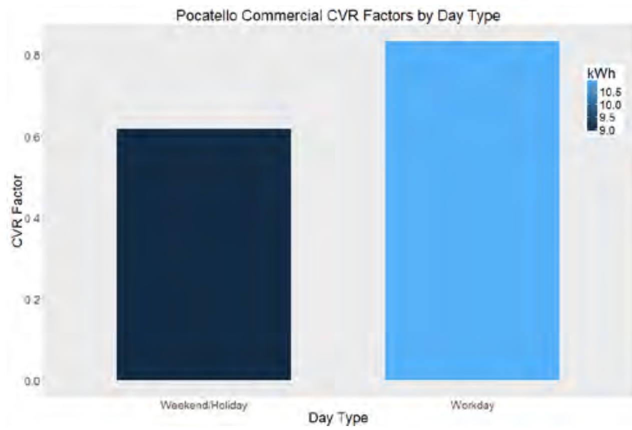


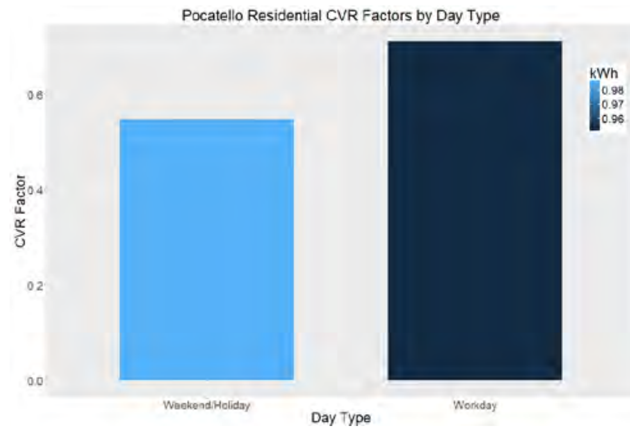


CVR Factors by Day Type for Pocatello Weather Zone

Both commercial and residential CVR factors were slightly higher on workdays than on weekends and holidays.

WedHol	Hours On	Hours Off	Avg Volt On	Avg Volt Off	Avg Com KWH On	Avg Com KWH Off	Avg Res KWH On	Avg Res KWH Off	PDelta V	PDelta Com KWH	PDelta Res KWH	Com CVR Factor	Res CVR Factor
Weekend/ Holiday	1,364	1,330	120.29	122.82	8.94	9.06	0.98	0.99	-2.06%	-1.27%	-1.13%	0.62	0.55
Workday	2,990	3,063	120.48	122.93	10.88	11.07	0.94	0.96	-1.99%	-1.66%	-1.42%	0.83	0.71

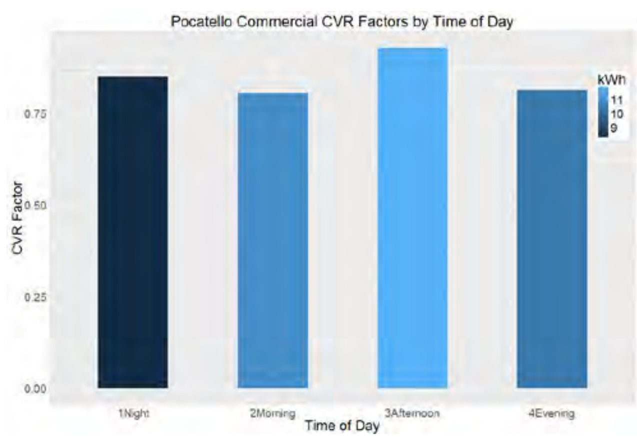


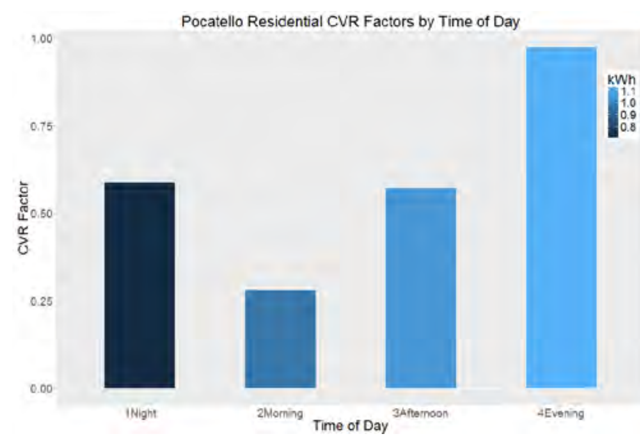


CVR Factors by Time of Day for Pocatello Weather Zone

Commercial CVR factors for the Pocatello Weather Zone were fairly consistent across all hours of the day while residential CVR factors varied significantly across the day with the highest occurring in the evening between 6:00 pm and 12:00 am.

TOD	Hours On	Hours Off	Avg Volt On	Avg Volt Off	Avg Com KWH On	Avg Com KWH Off	Avg Res KWH On	Avg Res KWH Off	PDelta V	PDelta Com KWH	PDelta Res KWH	Com CVR Factor	Res CVR Factor
Night	1,092	1,097	120.33	122.65	8.14	8.27	0.71	0.72	-1.89%	-1.61%	-1.11%	0.85	0.59
Morning	1,086	1,093	120.16	122.77	10.88	11.07	0.96	0.96	-2.13%	-1.71%	-0.60%	0.80	0.28
Afternoon	1,085	1,098	120.59	123.14	11.75	11.98	1.05	1.06	-2.07%	-1.93%	-1.18%	0.93	0.57
Evening	1,091	1,105	120.62	123.03	10.34	10.51	1.11	1.13	-1.96%	-1.59%	-1.91%	0.81	0.97

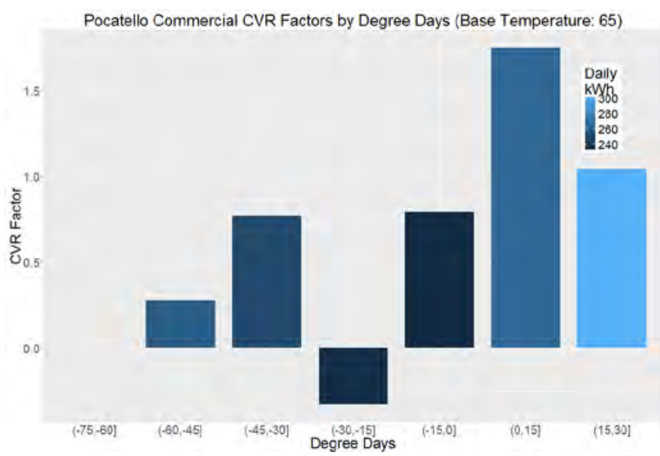


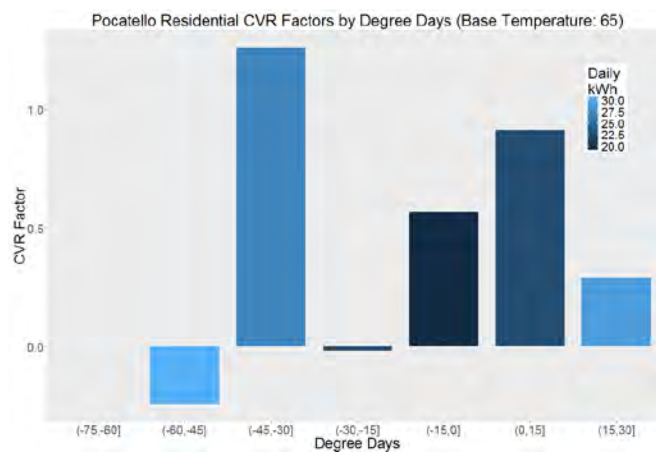


CVR Factors by Degree Day for Pocatello Weather Zone

Both customer classes generally displayed positive CVR factors regardless of temperature, though there were a few cold temperatures where each went slightly negative. On the other hand, for moderate cooling degree conditions (warmer temperatures), CVR factors were as high as 2.1 for commercial and 1.22 for residential.

DD Type	DDCat	Days On	Days Off	Avg Volt On	Avg Volt Off	Avg Com KWH On	Avg Com KWH Off	Avg Res KWH On	Avg Res KWH Off	PDeltaV	PDelta Com KWH	PDelta Res KWH	Com CVR Factor	Res CVR Factor
Heating	(-75,-60]	2	0	120.74	#N/A	253.87	#N/A	33.59	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Heating	(-60,-45]	6	9	120.69	122.91	260.27	261.58	30.81	30.68	-1.81%	-0.50%	0.44%	0.28	-0.24
Heating	(-45,-30]	36	35	120.56	122.86	249.29	252.96	26.86	27.51	-1.88%	-1.45%	-2.37%	0.77	1.26
Heating	(-30,-15]	43	43	120.31	122.91	235.44	233.83	22.12	22.11	-2.11%	0.69%	0.04%	-0.33	-0.02
Heating	(-15,0]	45	44	120.22	122.89	230.95	235.01	19.07	19.30	-2.18%	-1.72%	-1.23%	0.79	0.57
Cooling	(0,15]	44	45	120.42	122.92	262.44	272.17	22.21	22.63	-2.04%	-3.57%	-1.86%	1.75	0.91
Cooling	(15,30]	5	6	120.74	122.91	300.95	306.60	29.08	29.23	-1.76%	-1.84%	-0.51%	1.05	0.29

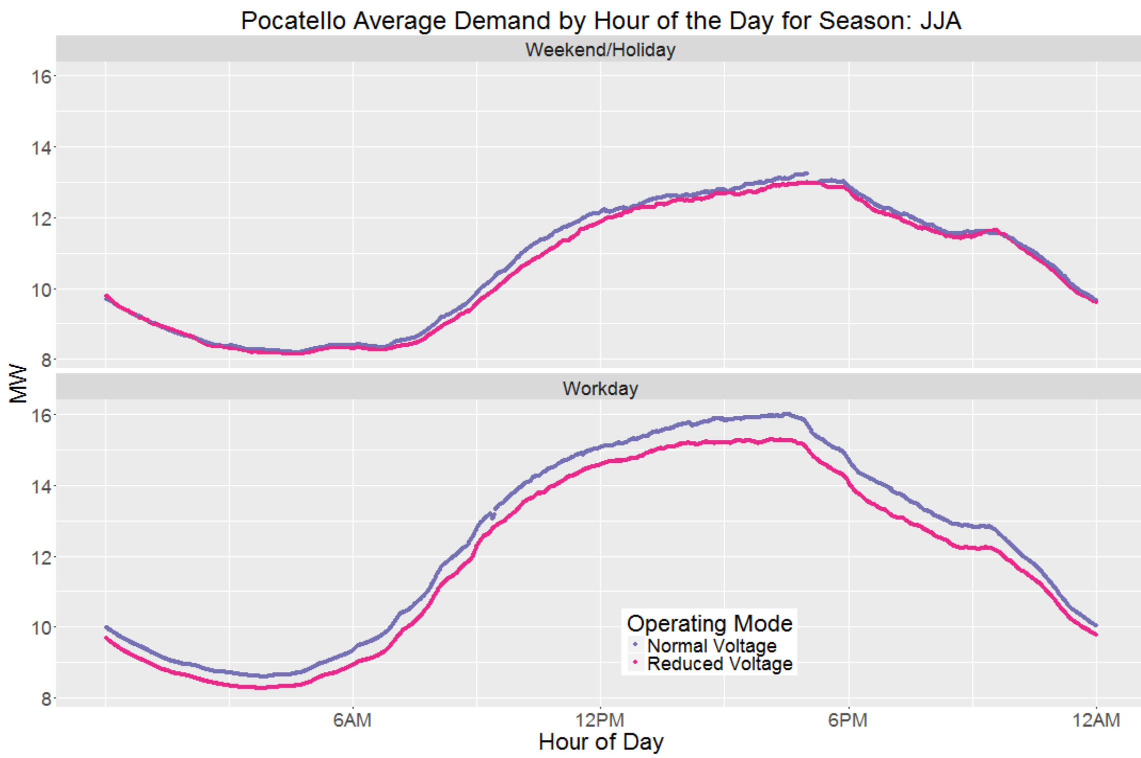


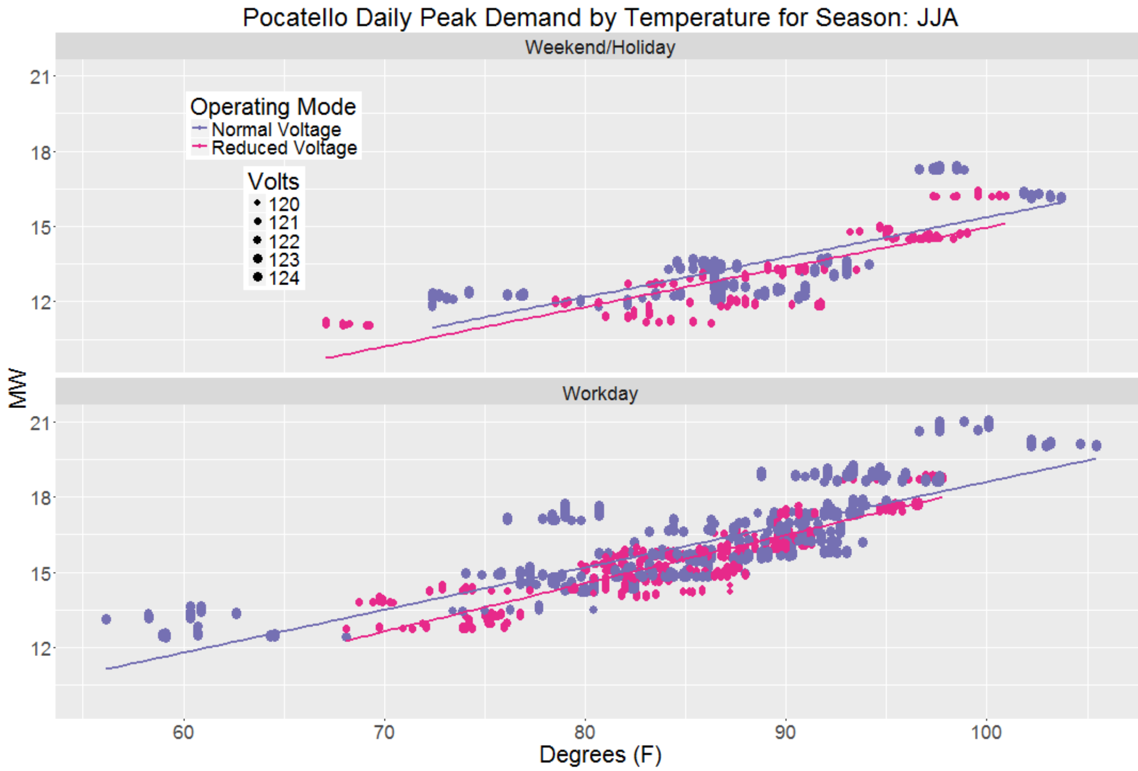


Demand CVR Factors for Pocatello Weather Zone

CVR can be used for peak demand-reduction purposes in the Pocatello Weather Zone with a CVR factor of 2.46 as shown in the following table. However, this CVR factor seems unrealistically high which Idaho Power attribute to the limited number of hours used in these calculations for demand CVR factors. This warrants further analysis prior to expanding these results to other substations in the Pocatello weather zone.

Zone/Parameters		% Delta (confidence interval)	CVR Factor (confidence interval)	Reduced	Normal	Hours n (TOTAL)
Pocatello, ID	V	**-2.01%** (-1.99%, -2.04%)	Not Applicable	120.70	123.18	5,447
	MW	**-4.95%** (-3.99%, -5.92%)	**2.46** (2.01, 2.91)	14.75	15.52	
	MVAR	**183.59%** (175.66%, 196.81%)	**-91.20** (-88.29, -96.65)	0.28	0.10	





Twin Falls Weather Zone

Data collection for the Twin Falls weather zone began February 5, 2015 and ended February 4, 2016. The treatment transformer was Twin Falls Substation, T134, located in Twin Falls, Idaho. The commercial class sample was 310 customers and the residential class sample size was 1,423 customers. Twin Falls Substation transformer T133 was used as the control transformer for both customer classes.

Overall CVR Factors for Twin Falls Weather Zone

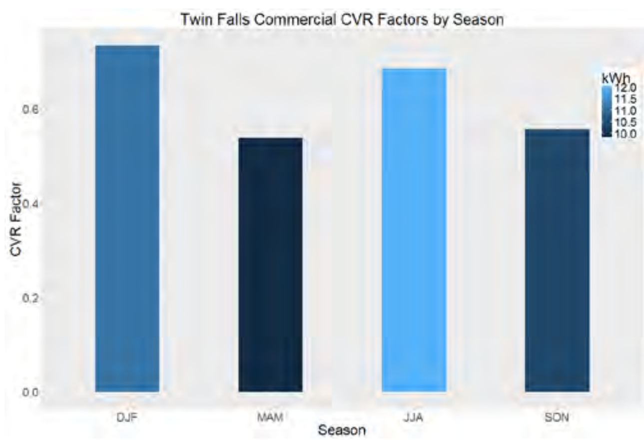
The overall results for the Twin Falls weather zone were slightly less positive when compared to the Boise and Pocatello weather zones. The calculated commercial CVR factor for energy was 0.65 and the residential CVR factor was 0.41 as shown in the following table. The average voltage change during the entire period was a relatively small -1.37%.

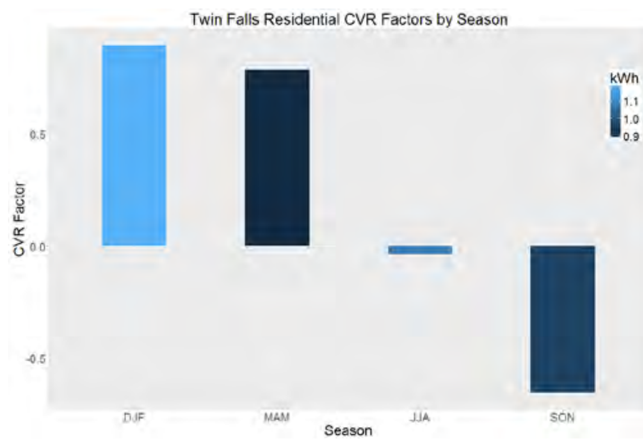
Zone/Parameters		% Delta (confidence interval)	CVR Factor (confidence interval)	Reduced	Normal	Hours n (TOTAL)
Twin Falls, ID	V	**-1.37%** (-1.34%, -1.41%)		121.11	122.80	8,749
	Com kWh	**-0.89%** (0.25%, -2.05%)	**0.65** (-0.19, 1.46)	10.77	10.87	
	Res kWh	**-0.57%** (1.09%, -2.27%)	**0.41** (-0.81, 1.62)	1.03	1.03	

CVR Factors by Season for Twin Falls Weather Zone

Interestingly, while commercial loads experienced positive CVR factors year-round, residential loads showed a slightly negative CVR factor in the summer and a significantly negative CVR factor in the fall months of September through November.

Season	Hours On	Hours Off	Avg Volt On	Avg Volt Off	Avg Com KWH On	Avg Com KWH Off	Avg Res KWH On	Avg Res KWH Off	PDeltaV	PDelta Com KWH	PDelta Res KWH	Com CVR Factor	Res CVR Factor
DJF(Winter)	1,055	1,105	121.37	122.82	11.08	11.17	1.19	1.20	-1.18%	-0.87%	-1.06%	0.73	0.89
MAM(Spring)	1,104	1,102	120.75	122.73	9.85	9.94	0.88	0.89	-1.61%	-0.87%	-1.27%	0.54	0.79
JJA(Summer)	1,104	1,098	121.34	122.87	11.97	12.07	1.09	1.09	-1.25%	-0.86%	0.04%	0.69	-0.04
SON(Fall)	1,099	1,082	121.00	122.77	10.36	10.44	0.95	0.94	-1.44%	-0.80%	0.94%	0.56	-0.65

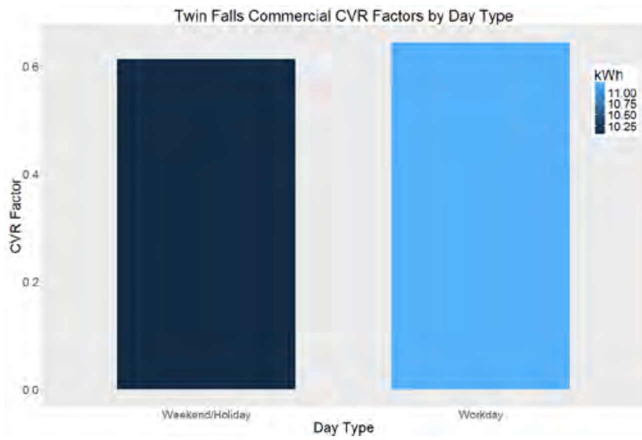


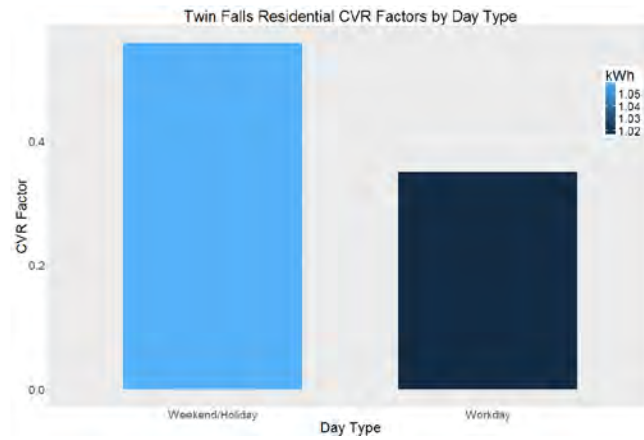


CVR Factors by Day Type for Twin Falls Weather Zone

Both commercial and residential customer classes displayed positive CVR factors regardless of whether it was a weekday or weekend. Residential customers showed a lower workday CVR factor which is opposite to that recorded in the Boise and Pocatello weather zones.

WedHol	Hours On	Hours Off	Avg Volt On	Avg Volt Off	Avg Com KWH On	Avg Com KWH Off	Avg Res KWH On	Avg Res KWH Off	PDelta V	PDelta Com KWH	PDelta Res KWH	Com CVR Factor	Res CVR Factor
Weekend/ Holiday	1,341	1,344	121.03	122.75	10.03	10.11	1.05	1.06	-1.40%	-0.86%	-0.78%	0.61	0.56
Workday	3,021	3,043	121.15	122.82	11.16	11.26	1.01	1.02	-1.36%	-0.88%	-0.48%	0.64	0.35

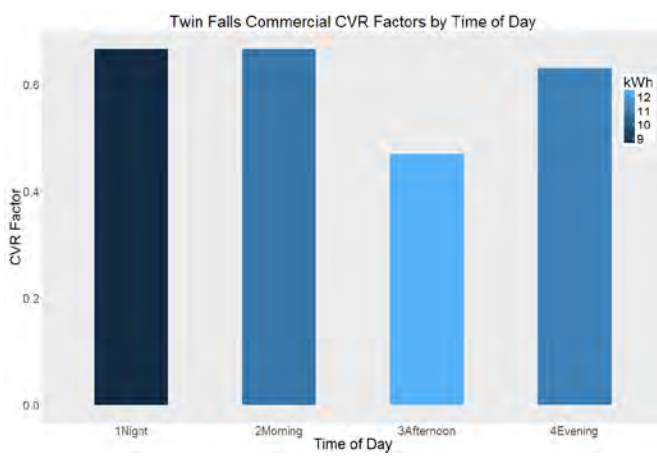


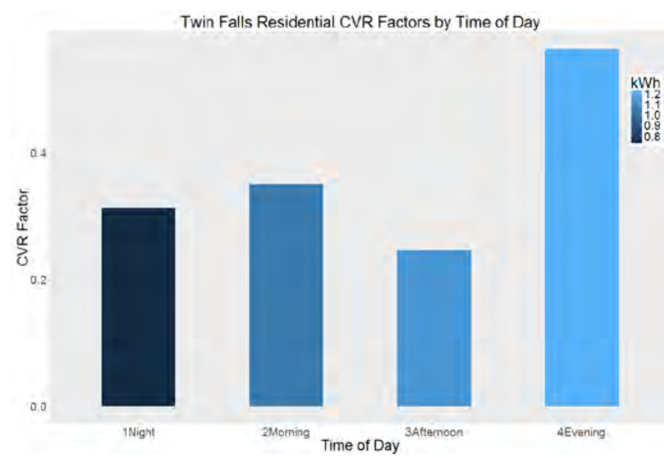


CVR Factor by Time of Day for Twin Falls Weather Zone

Both commercial and residential customer classes showed positive CVR factors across all hours of the day. While the commercial class showed fairly consistent CVR factors across the hours, residential CVR factors varied noticeably with the highest occurring in the evening hours of 6:00 pm to 12:00 am.

TOD	Hours On	Hours Off	Avg Volt On	Avg Volt Off	Avg Com KWH On	Avg Com KWH Off	Avg Res KWH On	Avg Res KWH Off	PDelta V	PDelta Com KWH	PDelta Res KWH	Com CVR Factor	Res CVR Factor
Night	1,092	1,091	120.68	122.36	8.64	8.72	0.72	0.73	-1.37%	-0.92%	-0.43%	0.67	0.31
Morning	1,090	1,097	120.68	122.58	10.91	11.03	1.03	1.04	-1.55%	-1.03%	-0.54%	0.67	0.35
Afternoon	1,088	1,101	121.45	123.12	12.48	12.56	1.13	1.14	-1.36%	-0.64%	-0.33%	0.47	0.24
Evening	1,092	1,098	121.64	123.12	11.22	11.30	1.22	1.23	-1.21%	-0.76%	-0.68%	0.63	0.56

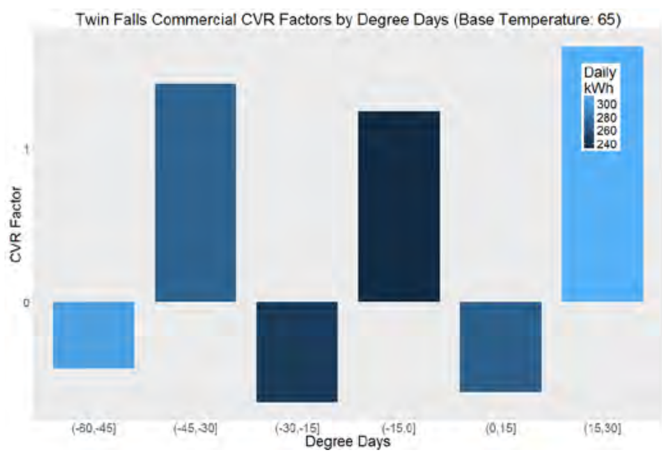


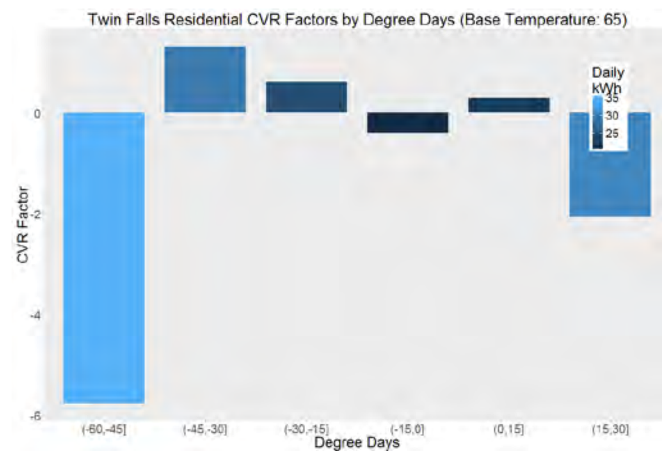


CVR Factors by Degree Day for Twin Falls Weather Zone

Commercial CVR factors were erratic over the measured temperature range; sometimes negative and sometimes positive with no obvious pattern discerned. Also of significance, residential loads experienced extremely negative CVR factors at both ends of the temperature spectrum. It is surmised this is because of the small sample size at these temperatures. That is, there were very few hours at these extreme temperatures so the results are not statistically significant.

DD Type	DDCat	Days On	Days Off	Avg Volt On	Avg Volt Off	Avg Com KWH On	Avg Com KWH Off	Avg Res KWH On	Avg Res KWH Off	PDeltaV	PDelta Com KWH	PDelta Res KWH	Com CVR Factor	Res CVR Factor
Heating	(-60,-45]	6	5	121.79	122.94	306.68	305.45	35.83	34.01	-0.93%	0.40%	5.36%	-0.43	-5.76
Heating	(-45,-30]	30	32	121.42	122.84	267.95	272.41	29.22	29.67	-1.15%	-1.64%	-1.52%	1.42	1.32
Heating	(-30,-15]	35	38	121.02	122.75	246.05	243.81	24.53	24.74	-1.41%	0.92%	-0.86%	-0.65	0.61
Heating	(-15,0]	48	42	120.75	122.75	231.88	236.68	20.49	20.36	-1.63%	-2.03%	0.64%	1.24	-0.39
Cooling	(0,15]	48	50	120.98	122.76	269.24	266.95	22.58	22.67	-1.46%	0.86%	-0.43%	-0.59	0.30
Cooling	(15,30]	15	15	121.70	123.02	312.15	317.79	31.11	30.44	-1.07%	-1.78%	2.21%	1.66	-2.07

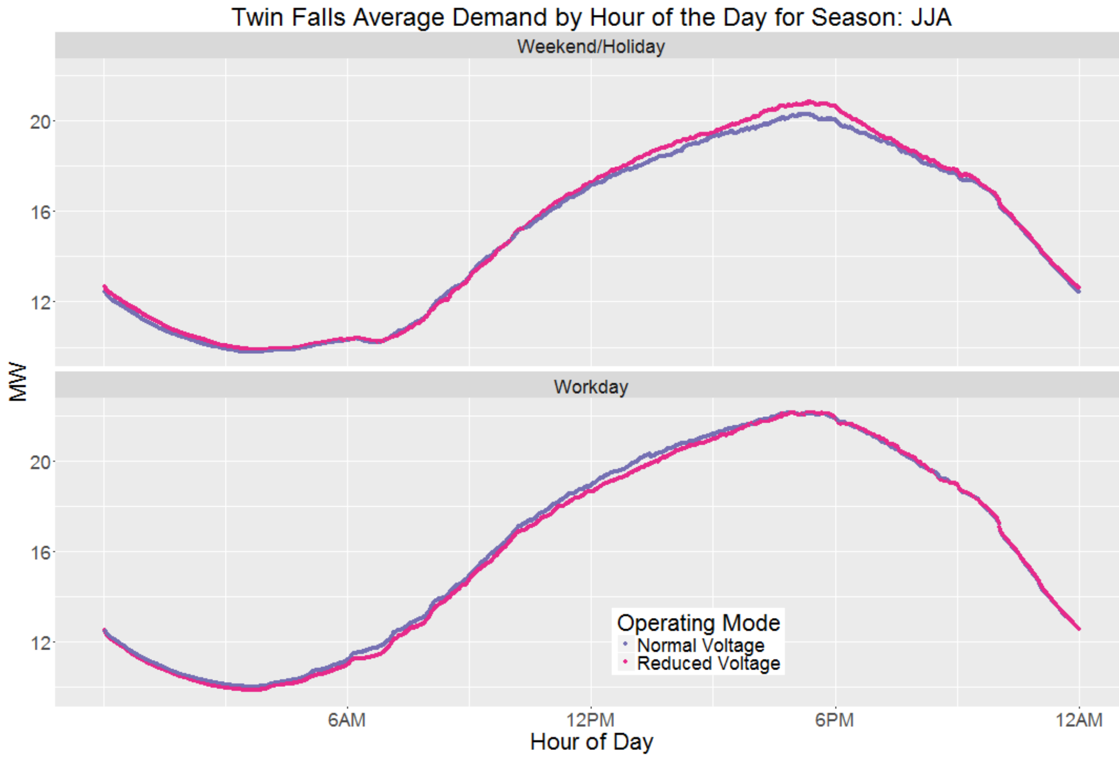




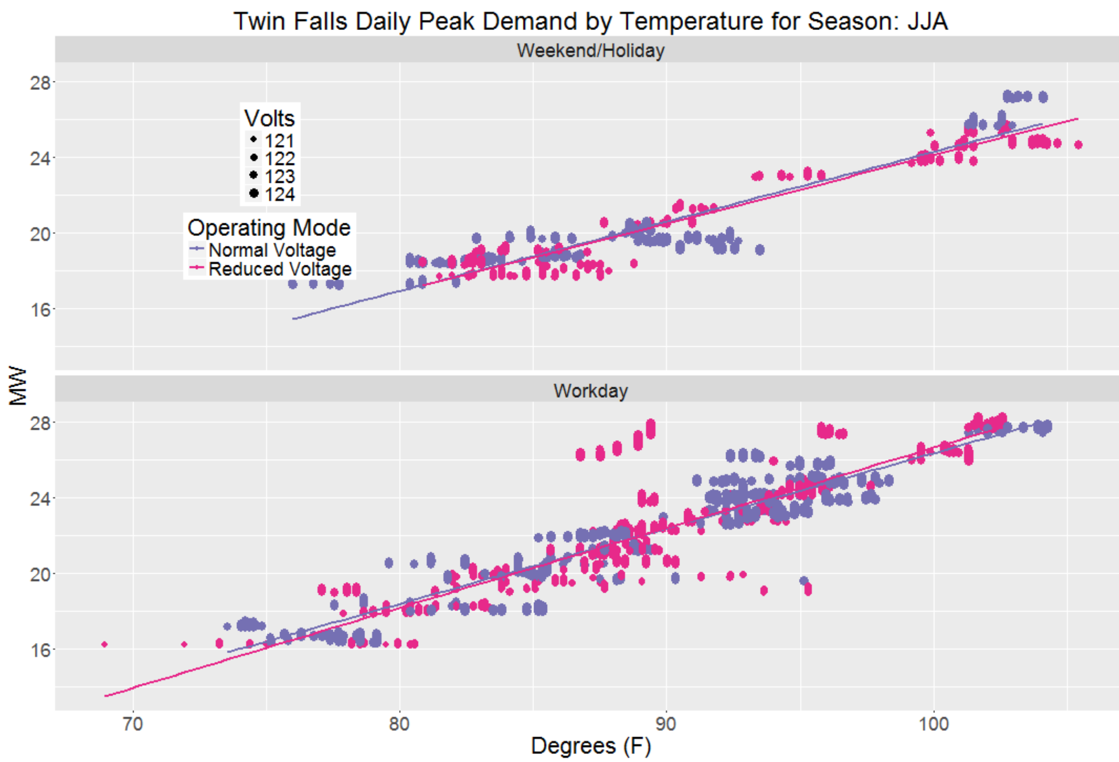
Demand CVR Factors for Twin Falls Weather Zone

The CVR factor for demand was -0.48 for the Twin Falls Weather Zone. This would indicate that using CVR during peak loading could increase load, so would not qualify for demand reduction. This corresponds with the negative CVR factor for energy results during summer.

Zone/Parameters		% Delta (confidence interval)	CVR Factor (confidence interval)	Reduced	Normal	Hours n (TOTAL)
Twin Falls, ID	V	**-0.85%** (-0.82%, -0.87%)	Not Applicable	122.14	123.18	5,459
	MW	**0.40%** (1.39%, -0.60%)	**-0.48** (-1.71, 0.69)	21.90	21.81	
	MVAR	**6.53%** (4.2%, 8.78%)	**-7.72** (-5.14, -10.04)	-1.81	-1.70	



Twin Falls Average Demand by Hour of the Day for Season: JJA
Weekend/Holiday
Workday
MW
20
16
12
Operating Mode
Normal Voltage
Reduced Voltage
6AM
12PM
6PM
12AM
Hour of Day



Twin Falls Daily Peak Demand by Temperature for Season: JJA
Weekend/Holiday
Workday
MW
28
24
20
16
Volts
121
122
123
124
Operating Mode
Normal Voltage
Reduced Voltage
70
80
90
100
Degrees (F)

Ketchum Weather Zone

Data collection for the Ketchum weather zone began March 1, 2015 and ended February 29, 2016. The treatment transformer was Ketchum Substation, T132, located in Ketchum, Idaho. The commercial class sample was 291 customers and the residential class sample size was 586 customers. Two separate control transformers were used:

- **Commercial Customers**—Haley Substation, T131 located in Hailey, Idaho.
- **Residential Customers**—Elkhorn Substation, T132, located in Sun Valley, Idaho.

Overall CVR Factors for Ketchum Weather Zone

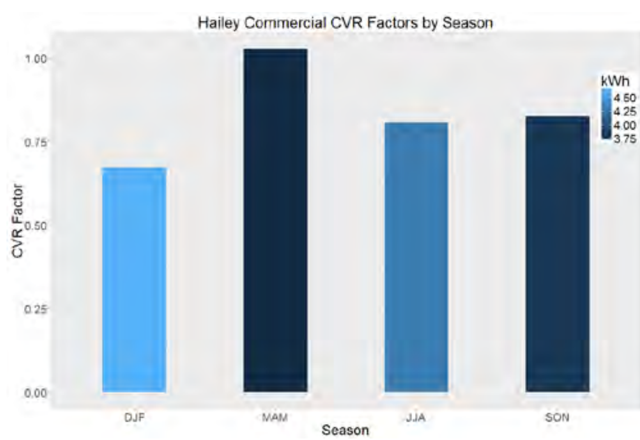
The calculated overall CVR factors were 1.11 for commercial loads and 1.16 for residential loads as shown in the following table. These are fairly high numbers, indicating both load types respond positively to voltage reductions. Voltage was reduced an average of 2.2%, a relatively large decrease.

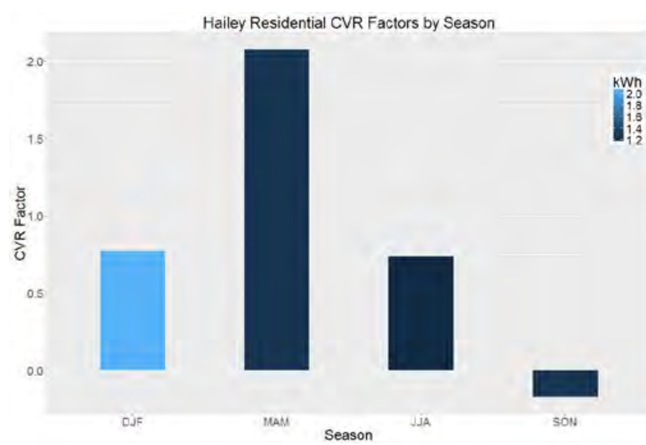
Zone/Parameters		% Delta (confidence interval)	CVR Factor (confidence interval)	Reduced	Normal	Hours n (TOTAL)
Ketchum, ID	V	**-2.21%** (-2.18%, -2.25%)	Not Applicable	120.56	123.29	8,243
	Com kWh	**-2.47%** (-1.37%, -3.58%,)	**1.11** (0.63, 1.59)	4.09	4.19	
	Res kWh	**-2.58%** (-0.69%, -4.52%)	**1.16** (0.31, 2.01)	1.44	1.48	

CVR Factors by Season for Ketchum Weather Zone

Commercial loads responded positively to CVR across all seasons with spring showing the best results. The residential CVR factor was slightly negative in the fall and was highest in the spring.

Season	Hours On	Hours Off	Avg Volt On	Avg Volt Off	Avg Com KWH On	Avg Com KWH Off	Avg Res KWH On	Avg Res KWH Off	PDeltaV	PDelta Com KWH	PDelta Res KWH	Com CVR Factor	Res CVR Factor
DJF(Winter)	1,081	1,103	121.14	123.71	4.62	4.69	2.07	2.10	-2.07%	-1.39%	-1.60%	0.67	0.77
MAM(Spring)	1,188	1,018	120.50	123.15	3.66	3.74	1.23	1.29	-2.15%	-2.21%	-4.48%	1.03	2.08
JJA(Summer)	1,068	1,138	120.22	123.13	4.26	4.35	1.18	1.20	-2.36%	-1.91%	-1.74%	0.81	0.73
SON(Fall)	847	800	120.33	123.10	3.77	3.84	1.27	1.26	-2.25%	-1.86%	0.38%	0.82	-0.17

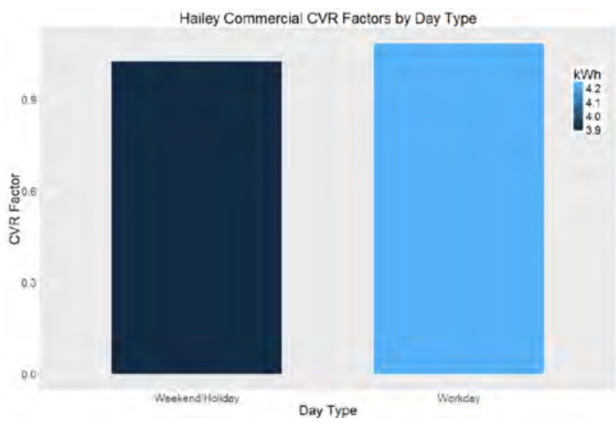


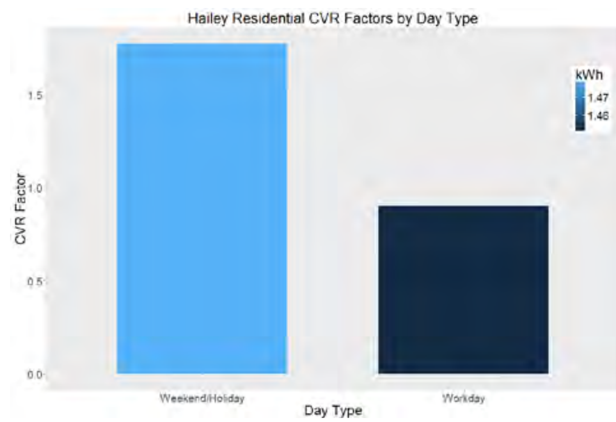


CVR Factors by Day Type for Ketchum Weather Zone

Commercial CVR factors were similar between weekdays and weekend/holidays. Similar to the Twin Falls weather zone, the residential CVR factor was smaller on workdays when compared to weekends and holidays though quite high in both day types.

WedHol	Hours On	Hours Off	Avg Volt On	Avg Volt Off	Avg Com KWH On	Avg Com KWH Off	Avg Res KWH On	Avg Res KWH Off	PDelta V	PDelta Com KWH	PDelta Res KWH	Com CVR Factor	Res CVR Factor
Weekend/ Holiday	1,317	1,223	120.54	123.26	3.85	3.94	1.45	1.51	-2.21%	-2.26%	-3.92%	1.02	1.78
Workday	2,867	2,836	120.57	123.30	4.19	4.30	1.44	1.47	-2.21%	-2.40%	-2.00%	1.08	0.90

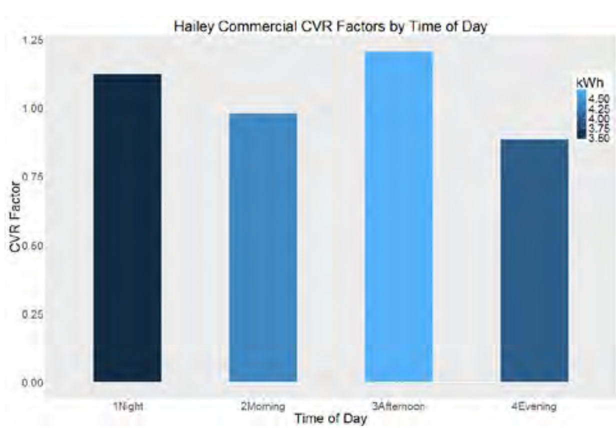


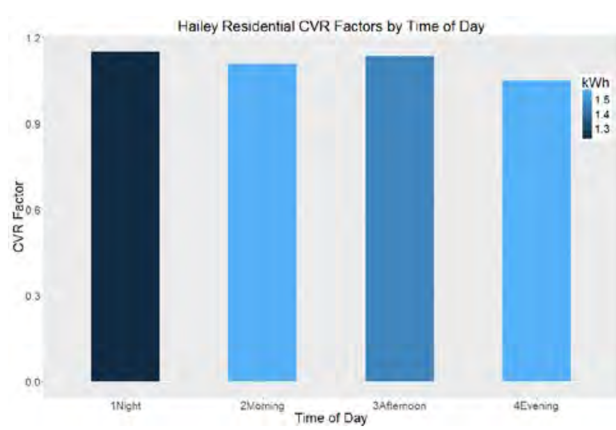


CVR Factor by Time of Day for Ketchum Weather Zone

CVR factors were positive over all hours of the day, with the smallest occurring for commercial customers between 6:00 p.m. and 12:00 am.

TOD	Hours On	Hours Off	Avg Volt On	Avg Volt Off	Avg Com KWH On	Avg Com KWH Off	Avg Res KWH On	Avg Res KWH Off	PDelta V	PDelta Com KWH	PDelta Res KWH	Com CVR Factor	Res CVR Factor
Night	1,056	998	120.76	123.33	3.43	3.52	1.21	1.24	-2.08%	-2.34%	-2.40%	1.12	1.15
Morning	1,054	1,010	120.09	122.89	4.33	4.42	1.55	1.59	-2.28%	-2.23%	-2.52%	0.98	1.11
Afternoon	1,037	1,026	120.59	123.39	4.65	4.78	1.45	1.49	-2.28%	-2.74%	-2.59%	1.21	1.14
Evening	1,037	1,025	120.80	123.53	3.95	4.02	1.56	1.59	-2.21%	-1.95%	-2.32%	0.88	1.05

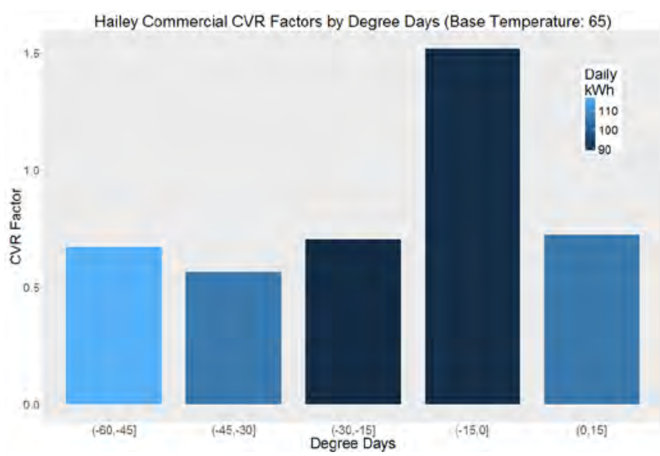


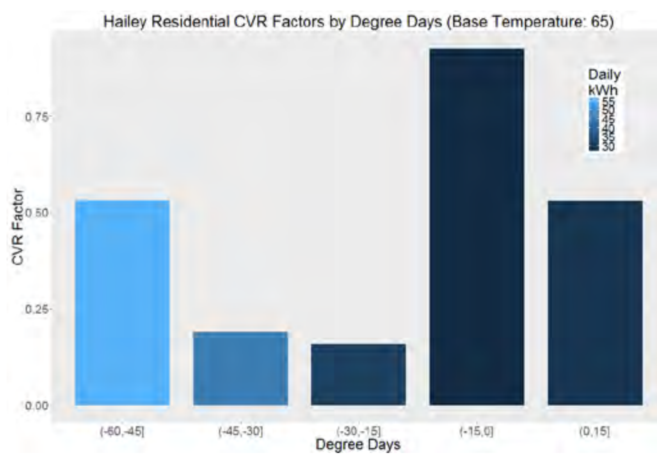


CVR Factors by Degree Day for Ketchum Weather Zone

Positive CVR factors existed over all temperature ranges though the residential CVR factor was relatively small in a couple HDD categories.

DD Type	DDCat	Days On	Days Off	Avg Volt On	Avg Volt Off	Avg Com KWH On	Avg Com KWH Off	Avg Res KWH On	Avg Res KWH Off	PDeltaV	PDelta Com KWH	PDelta Res KWH	Com CVR Factor	Res CVR Factor
Heating	(-60,-45]	12	15	121.32	123.81	116.88	118.48	55.86	56.46	-2.02%	-1.35%	-1.07%	0.67	0.53
Heating	(-45,-30]	46	42	121.00	123.58	105.98	107.25	45.39	45.57	-2.09%	-1.18%	-0.39%	0.57	0.19
Heating	(-30,-15]	28	33	120.44	123.18	87.67	89.05	31.36	31.47	-2.22%	-1.56%	-0.35%	0.70	0.16
Heating	(-15,0]	52	46	120.19	122.84	87.77	90.74	26.07	26.60	-2.15%	-3.27%	-1.99%	1.52	0.92
Cooling	(0,15]	35	34	120.20	123.12	105.29	107.12	28.57	28.93	-2.37%	-1.71%	-1.25%	0.72	0.53

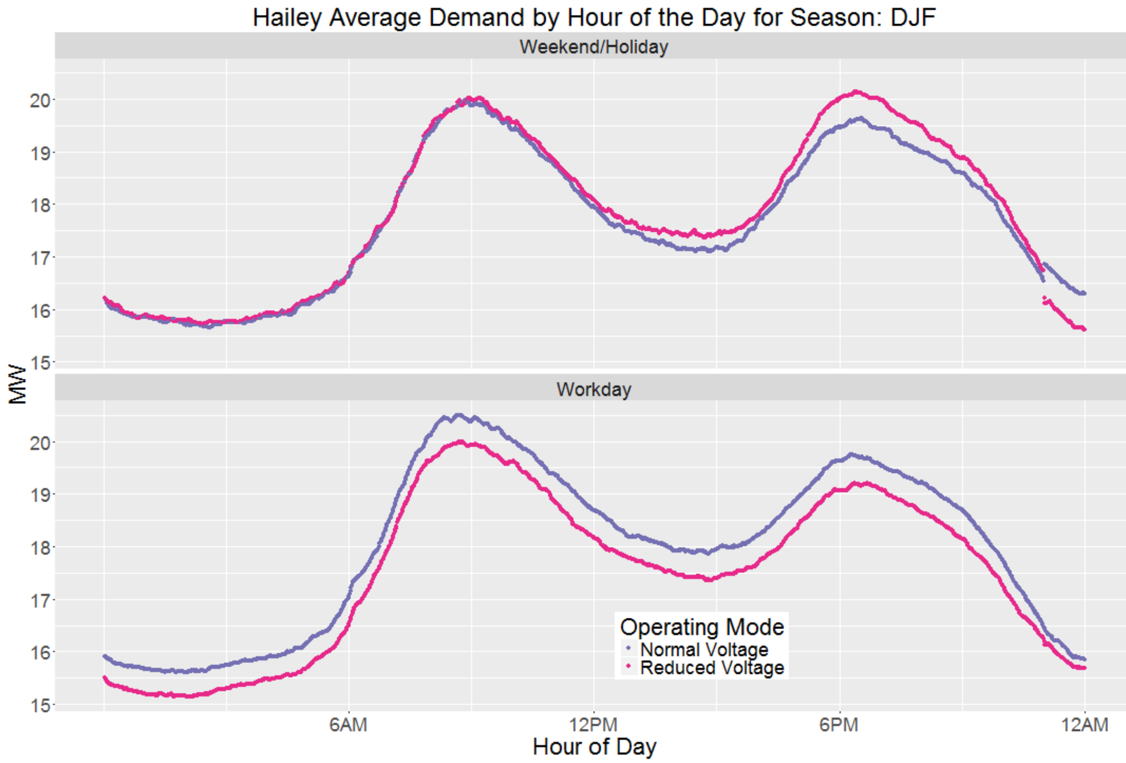


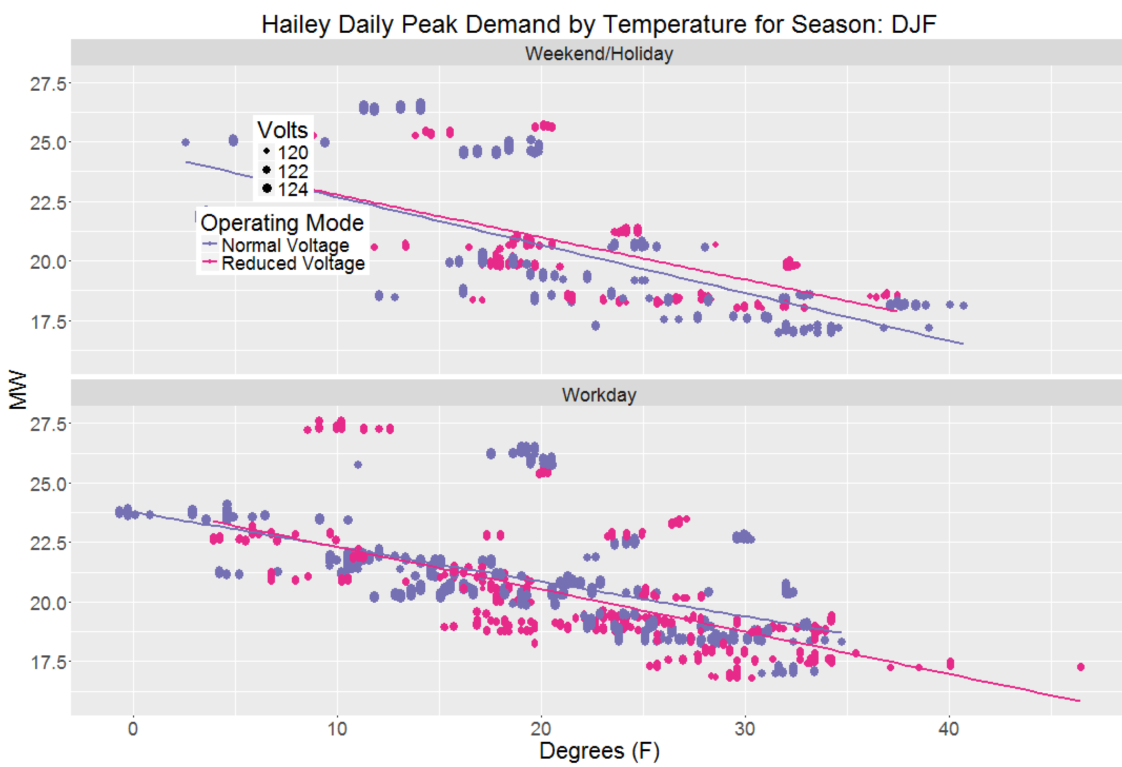


Demand CVR Factors for Ketchum Weather Zone

The CVR factor for demand in this winter peaking weather zone was 0.78, a relatively large number.

Zone/Parameters		% Delta (confidence interval)	CVR Factor (confidence interval)	Reduced	Normal	Hours n (TOTAL)
Ketchum, ID	V	**-2.04%** (-2.01%, -2.08%)	Not Applicable	121.06	123.59	5,457
	MW	**-1.58%** (-0.74%, -2.44%)	**0.78** (0.37, 1.17)	20.22	20.54	
	MVAR	**-13.91%** (-11.95%, -15.91%)	**6.81** (5.96, 7.65)	1.24	1.44	


Hailey Average Demand by Hour of the Day for Season: DJF
Weekend/Holiday
Workday
MW
20
19
18
17
16
15
Operating Mode
Normal Voltage
Reduced Voltage
6AM
12PM
6PM
12AM
Hour of Day


Hailey Daily Peak Demand by Temperature for Season: DJF
Weekend/Holiday
Workday
MW
27.5
25.0
22.5
20.0
17.5
Volts
120
122
124
Operating Mode
Normal Voltage
Reduced Voltage
0
10
20
30
40
Degrees (F)

McCall Weather Zone

Data collection for the McCall weather zone began March 1, 2015 and ended February 29, 2016. The treatment transformer was McCall Substation, T131, located in McCall, Idaho. The commercial class sample was 132 customers and the residential class sample size was 400 customers. McCall Substation transformer T133 was used as the control transformer for both customer classes.

For maintenance purposes, the automated toggling in SCADA between CVR modes was disabled on McCall T131 during a two-week period between December 27 and January 9. Unfortunately, peak loading for the year occurred during these weeks. The days where no toggling occurred were excluded from the analysis because they exaggerated the difference in energy and reduced the difference in voltage between modes. Additionally, for the McCall weather zone, the LDC settings applied within the LTC tended to produce higher band center voltages when in the reduced voltage mode as compared to the normal voltage mode. This is because during heavy loading, the system had some areas with low voltages using the original LTC settings. This resulted in the overall percentage difference in voltage between modes being minimal and sometimes positive, which makes it more difficult to obtain statistically relevant CVR factors.

Overall CVR Factors for McCall Weather Zone

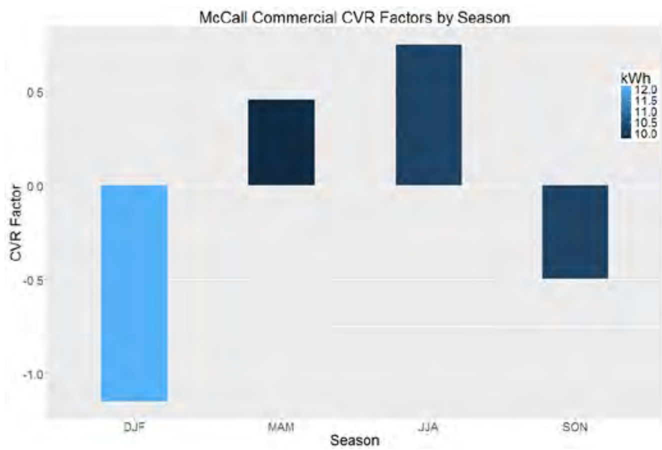
The overall results for the McCall weather zone show that reducing voltage by an average 0.2% provides for a commercial CVR factor of 2.89 and a residential CVR factor of 5.75 as shown in the following table. These extreme results were caused by the LDC settings and are considered suspect.

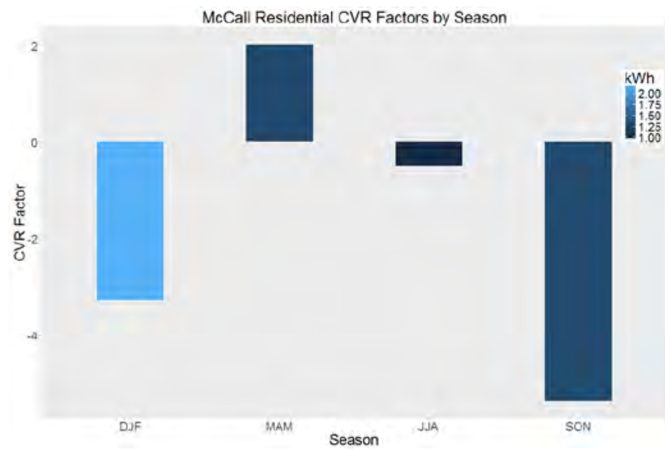
Zone/Parameters		% Delta (confidence interval)	CVR Factor (confidence interval)	Reduced	Normal	Hours n (TOTAL)
McCall, ID	V	**-0.21%** (-0.16%, -0.26%)		121.80	122.06	8,373
	Com kWh	**-0.61%** (0.46%, -1.69%)	**2.89** (-2.77, 6.57)	10.45	10.51	
	Res kWh	**-1.21%** (1.18%, -3.69%)	**5.75** (-7.19, 14.34)	1.40	1.41	

CVR Factors by Season for McCall Weather Zone

Because of the effects from the LDC settings, both commercial and residential CVR factors were negative during both winter and summer.

Season	Hours On	Hours Off	Avg Volt On	Avg Volt Off	Avg Com KWH On	Avg Com KWH Off	Avg Res KWH On	Avg Res KWH Off	PDeltaV	PDelta Com KWH	PDelta Res KWH	Com CVR Factor	Res CVR Factor
DJF(Winter)	880	923	123.33	122.16	12.05	12.19	2.15	2.22	0.96%	-1.10%	-3.14%	-1.15	-3.27
MAM(Spring)	1,102	1,103	121.67	122.13	9.71	9.72	1.28	1.29	-0.38%	-0.17%	-0.77%	0.46	2.02
JJA(Summer)	1,077	1,104	120.92	122.04	10.15	10.22	0.99	0.98	-0.92%	-0.69%	0.46%	0.75	-0.50
SON(Fall)	1,102	1,082	121.58	121.92	10.21	10.19	1.31	1.29	-0.28%	0.14%	1.50%	-0.50	-5.36

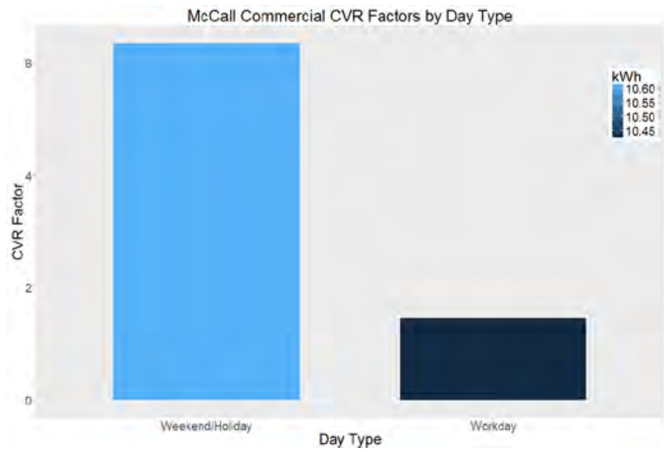


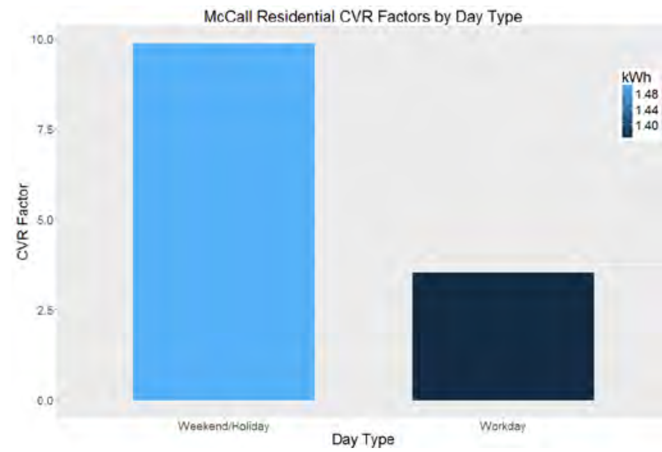


CVR Factors by Day Type for McCall Weather Zone

For both customer classes, CVR factors were better on weekends and holidays compared to workdays.

WedHol	Hours On	Hours Off	Avg Volt On	Avg Volt Off	Avg Com KWH On	Avg Com KWH Off	Avg Res KWH On	Avg Res KWH Off	PDelta V	PDelta Com KWH	PDelta Res KWH	Com CVR Factor	Res CVR Factor
Weekend/ Holiday	1,261	1,307	121.85	122.08	10.55	10.68	1.49	1.52	-0.19%	-1.21%	-1.87%	6.35	9.86
Workday	2,900	2,905	121.78	122.05	10.41	10.44	1.36	1.37	-0.22%	-0.32%	-0.77%	1.45	3.53

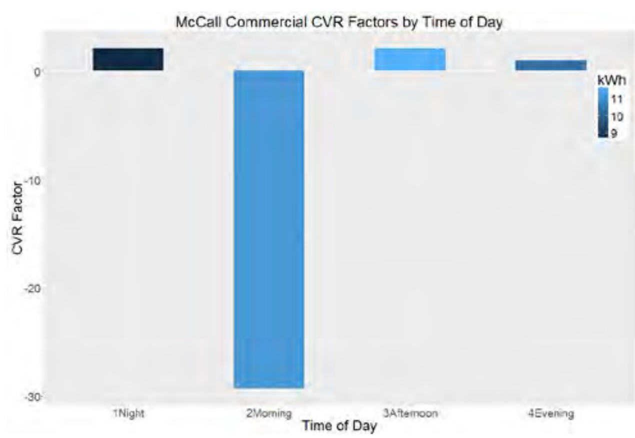


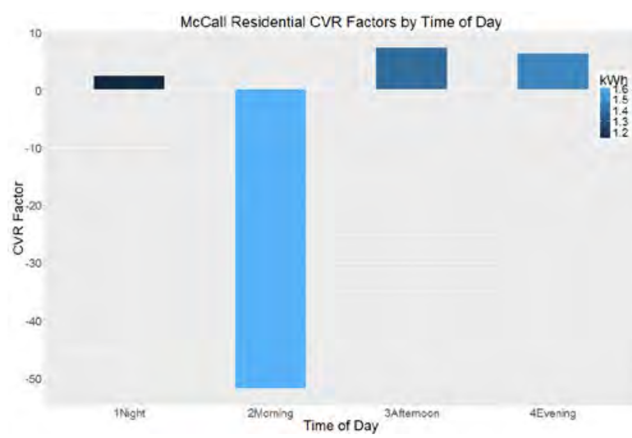


CVR Factors by Time of Day for McCall Weather Zone

CVR factors were extremely negative between the morning hours of 6:00 am and 12:00 pm for both customer classes.

TOD	Hours On	Hours Off	Avg Volt On	Avg Volt Off	Avg Com KWH On	Avg Com KWH Off	Avg Res KWH On	Avg Res KWH Off	PDelta V	PDelta Com KWH	PDelta Res KWH	Com CVR Factor	Res CVR Factor
Night	1,044	1,058	121.42	122.15	8.57	8.68	1.14	1.15	-0.60%	-1.29%	-1.45%	2.16	2.43
Morning	1,037	1,061	121.74	121.71	11.16	11.25	1.61	1.63	0.03%	-0.82%	-1.45%	-29.27	-51.76
Afternoon	1,035	1,046	121.96	122.10	11.73	11.76	1.38	1.39	-0.12%	-0.25%	-0.85%	2.15	7.33
Evening	1,045	1,047	122.09	122.28	10.35	10.37	1.47	1.48	-0.16%	-0.17%	-1.02%	1.03	6.32

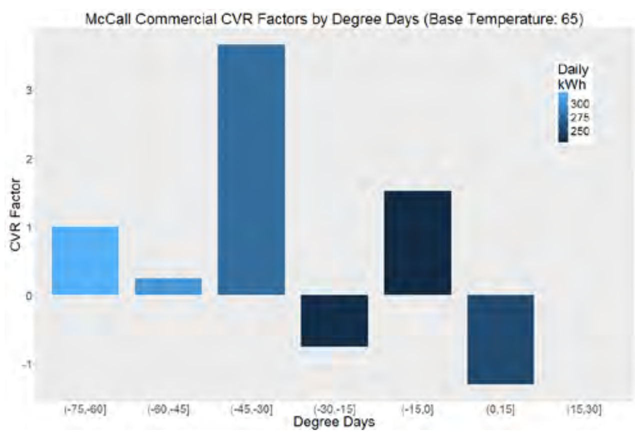


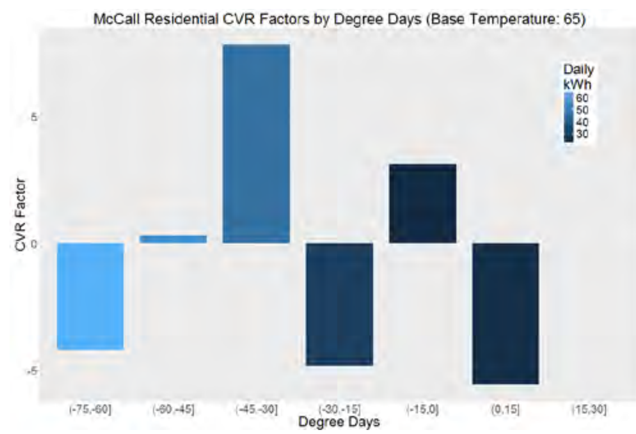


CVR Factors by Degree Day for McCall Weather Zone

Both customer classes show a very erratic pattern across all temperatures.

DD Type	DDCat	Days On	Days Off	Avg Volt On	Avg Volt Off	Avg Com KWH On	Avg Com KWH Off	Avg Res KWH On	Avg Res KWH Off	PDeltaV	PDelta Com KWH	PDelta Res KWH	Com CVR Factor	Res CVR Factor
Heating	(-75,-60]	2	6	124.07	122.12	324.58	319.52	61.93	66.36	1.59%	1.58%	-6.68%	0.99	-4.19
Heating	(-60,-45]	8	10	123.80	122.27	305.69	304.78	55.54	55.33	1.25%	0.30%	0.37%	0.24	0.30
Heating	(-45,-30]	47	44	122.95	122.25	279.83	274.14	47.04	45.04	0.57%	2.08%	4.43%	3.66	7.81
Heating	(-30,-15]	49	46	121.48	121.98	232.16	231.45	30.17	29.59	-0.41%	0.31%	1.96%	-0.76	-4.82
Heating	(-15,0]	45	45	120.58	121.89	226.71	230.50	22.39	23.16	-1.08%	-1.64%	-3.35%	1.52	3.10
Cooling	(0,15]	21	22	121.01	122.05	253.86	251.06	24.82	23.69	-0.86%	1.12%	4.74%	-1.30	-5.55
Cooling	(15,30]	0	1	#N/A	122.39	#N/A	278.81	#N/A	26.39	#N/A	#N/A	#N/A	#N/A	#N/A

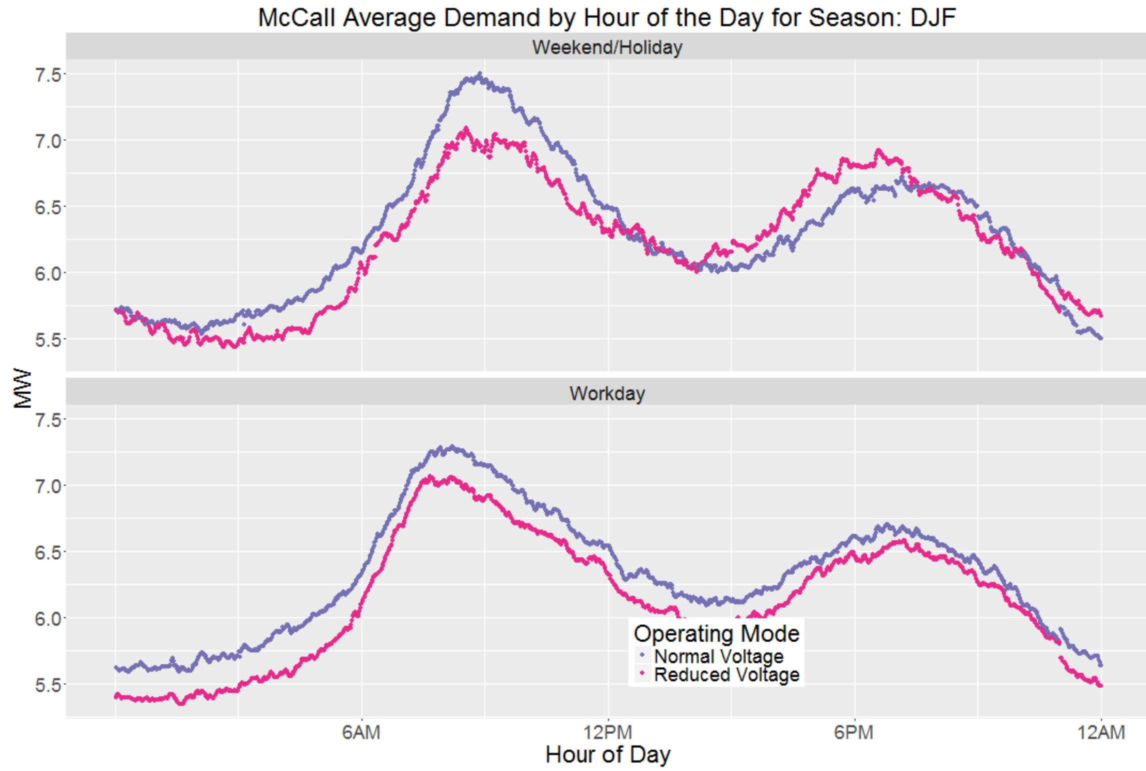


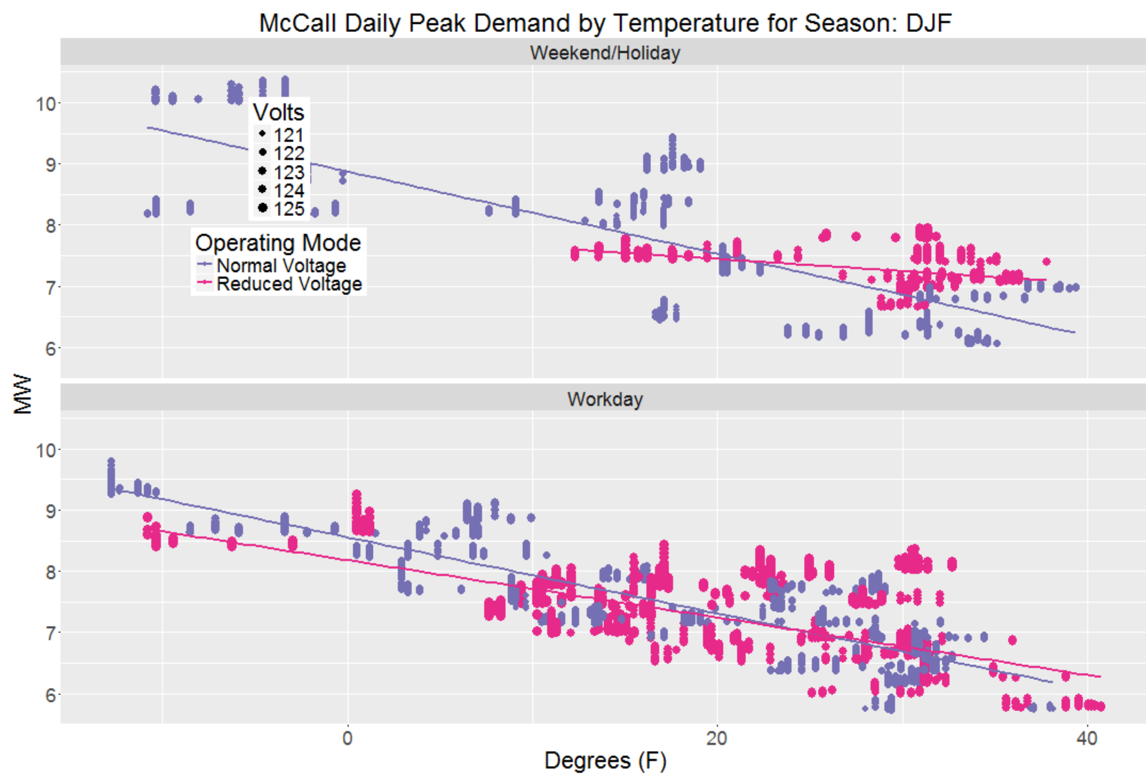


Demand CVR Factors for McCall Weather Zone

Over the peak operating season (winter for this zone), the average voltage actually increased due to LDC settings, and therefore the CVR factor for demand was -1.73. Like above, these results are considered suspect.

Zone/Parameters		% Delta (confidence interval)	CVR Factor (confidence interval)	Reduced	Normal	Hours n (TOTAL)
McCall, ID	V	**1.96%** (2.0%, 1.92%)	Not Applicable	124.03	121.64	4,362
	MW	**-3.39%** (-2.45%, -4.35%)	**-1.73** (-1.22, -2.26)	7.24	7.49	
	MVAR	**1.69%** (3.71%, -0.39%)	**0.86** (1.85, -0.21)	0.86	0.85	


McCall Average Demand by Hour of the Day for Season: DJF
Weekend/Holiday
Workday
MW
7.5
7.0
6.5
6.0
5.5
Operating Mode
Normal Voltage
Reduced Voltage
6AM
12PM
6PM
12AM
Hour of Day


McCall Daily Peak Demand by Temperature for Season: DJF
Weekend/Holiday
Workday
MW
Volts
121
122
123
124
125
Operating Mode
Normal Voltage
Reduced Voltage
10
9
8
7
6
0
20
40
Degrees (F)

Ontario Weather Zone

Data collection for the Ontario weather zone began May 1, 2015 and ended April 30, 2016. The treatment transformer was Cairo Substation, T61, located just to the east of Ontario, Oregon. The commercial class sample was 77 customers and the residential class sample size was 431 customers. Two separate control transformers were used:

- **Commercial Customers**—Vale Substation, T61 located in Vale, Oregon.
- **Residential Customers**—Payette Substation, T132, located in Payette, Idaho.

Over a one-week period in fall and again during a one-month period in winter, the treatment transformer in the Cairo Substation had an abnormal configuration and the CVR toggling was disabled. Days where CVR toggling was disabled are not included in the overall CVR factor calculations.

Overall CVR Factors for Ontario Weather Zone

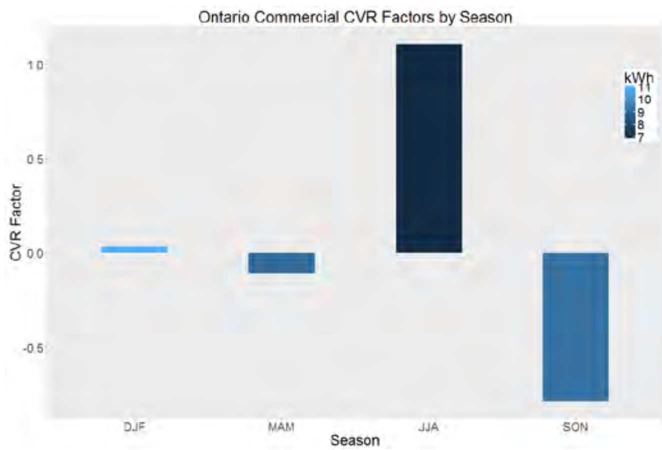
Overall CVR factors were determined to be 0.19 for commercial loads and 0.91 for residential loads as shown in the following table. The commercial CVR factor was relatively small though the sample size of commercial customers was also small compared to the residential sample (77 commercial customers, 431 residential customers). Average voltage change over the entire year was -1.7%.

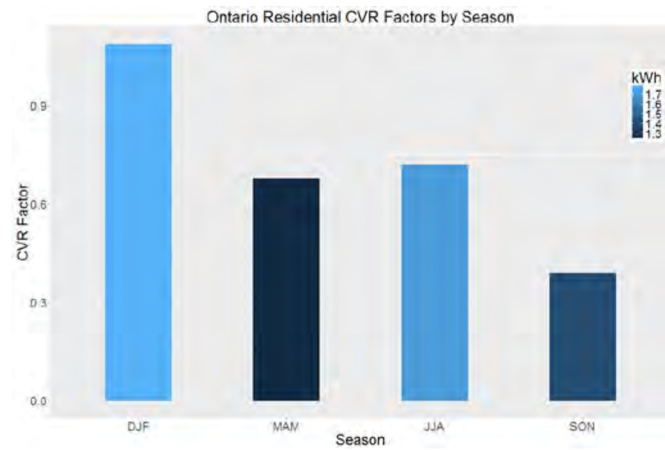
Zone/Parameters		% Delta (confidence interval)	CVR Factor (confidence interval)	Reduced	Normal	Hours n (TOTAL)
Ontario, OR	V	**-1.66%** (-1.62%, -1.70%)		120.53	122.57	6,893
	Com kWh	-**0.31%** (1.20%, -1.86%)	**0.19** (-0.74, 1.09)	8.73	8.76	
	Res kWh	**-1.50%** (0.53%, -3.60%)	**0.91** (-0.33, 2.12)	1.51	1.54	

CVR Factors by Season for Ontario Weather Zone

Commercial customers displayed negative CVR factors in spring and winter and a high CVR factor in the summer. Residential CVR factors remained positive across all temperatures and were relatively high in the winter.

Season	Hours On	Hours Off	Avg Volt On	Avg Volt Off	Avg Com KWH On	Avg Com KWH Off	Avg Res KWH On	Avg Res KWH Off	PDeltaV	PDelta Com KWH	PDelta Res KWH	Com CVR Factor	Res CVR Factor
DJF(Winter)	600.00	623.00	120.57	122.58	11.02	11.02	1.78	1.81	-1.63%	-0.05%	-1.78%	0.03	1.09
MAM(Spring)	1,122.00	1,074.00	120.30	122.64	9.04	9.02	1.25	1.27	-1.91%	0.21%	-1.30%	-0.11	0.68
JJA(Summer)	1,102.00	1,102.00	120.75	122.58	6.88	6.99	1.70	1.72	-1.49%	-1.65%	-1.07%	1.11	0.72
SON(Fall)	620.00	648.00	120.54	122.43	9.26	9.15	1.40	1.41	-1.54%	1.21%	-0.60%	-0.79	0.39

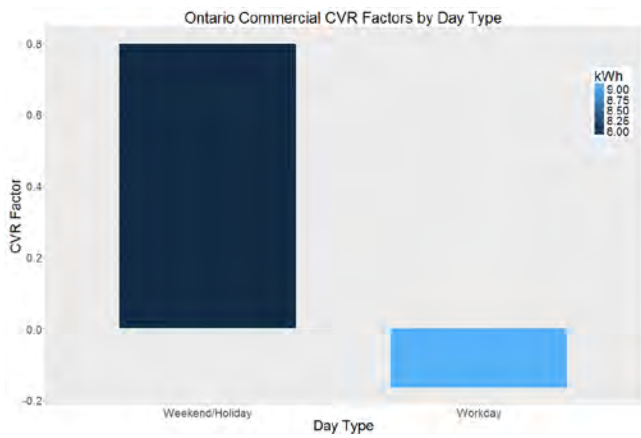


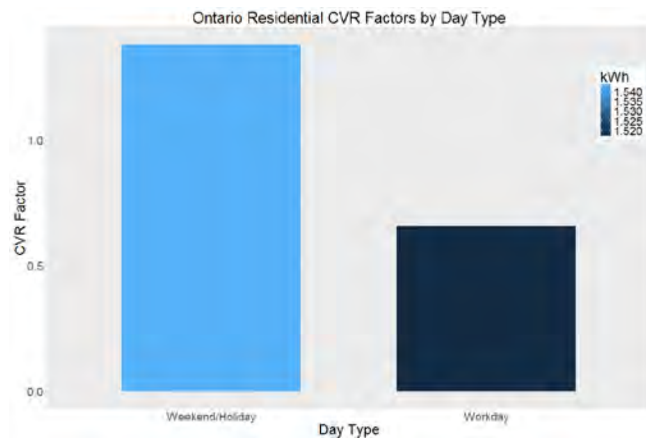


CVR Factors by Day Type for Ontario Weather Zone

The commercial CVR factor for the Ontario weather zone was 0.80 on weekends/holidays and negative on workdays. As mentioned previously, there were not many commercial customers in the sample so any one large customer could significantly influence the results. Residential CVR factors were positive over both day types and significantly so on weekends/holidays.

WedHol	Hours On	Hours Off	Avg Volt On	Avg Volt Off	Avg Com KWH On	Avg Com KWH Off	Avg Res KWH On	Avg Res KWH Off	PDelta V	PDelta Com KWH	PDelta Res KWH	Com CVR Factor	Res CVR Factor
Weekend/ Holiday	1,076	1,056	120.31	122.52	7.86	7.98	1.52	1.56	-1.81%	-1.44%	-2.50%	0.80	1.38
Workday	2,368	2,391	120.64	122.59	9.13	9.11	1.51	1.53	-1.59%	0.26%	-1.04%	-0.16	0.66

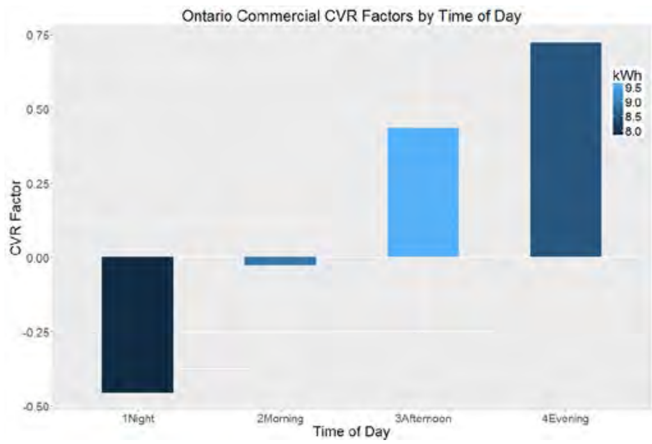


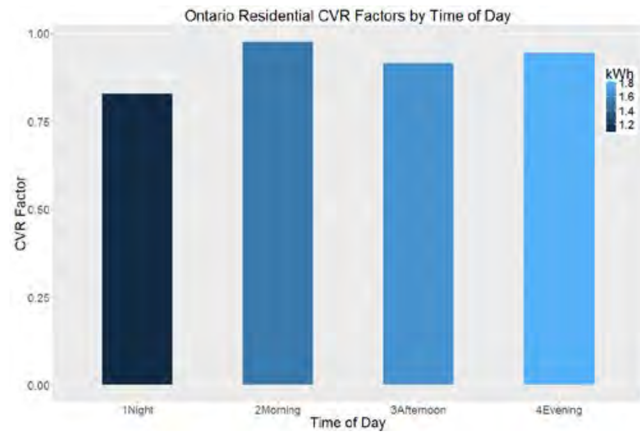


CVR Factors by Time of Day for Ontario Weather Zone

Residential class customers displayed positive CVR factors over all hours of the day while commercial customers were only positive after 12:00 pm. Nighttime CVR factors for commercial class customers were significantly negative.

TOD	Hours On	Hours Off	Avg Volt On	Avg Volt Off	Avg Com KWH On	Avg Com KWH Off	Avg Res KWH On	Avg Res KWH Off	PDelta V	PDelta Com KWH	PDelta Res KWH	Com CVR Factor	Res CVR Factor
Night	859	864	120.59	122.52	7.91	7.86	1.08	1.10	-1.58%	0.72%	-1.30%	-0.46	0.83
Morning	860	860	120.14	122.28	8.95	8.95	1.52	1.54	-1.74%	0.05%	-1.70%	-0.03	0.98
Afternoon	862	861	120.64	122.70	9.61	9.68	1.65	1.68	-1.68%	-0.73%	-1.54%	0.44	0.92
Evening	863	862	120.76	122.77	8.45	8.55	1.80	1.83	-1.64%	-1.18%	-1.54%	0.72	0.94

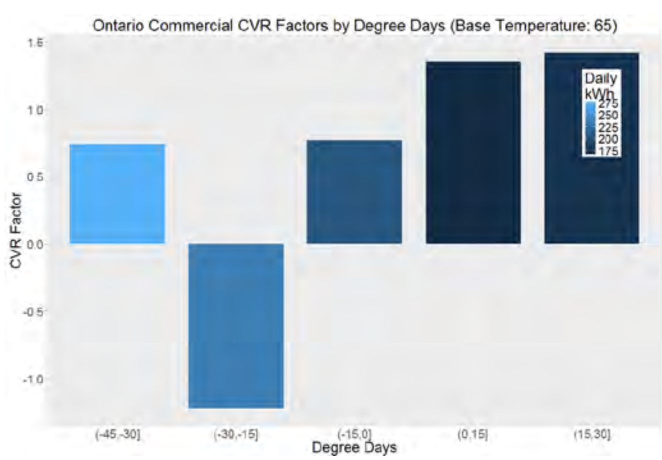


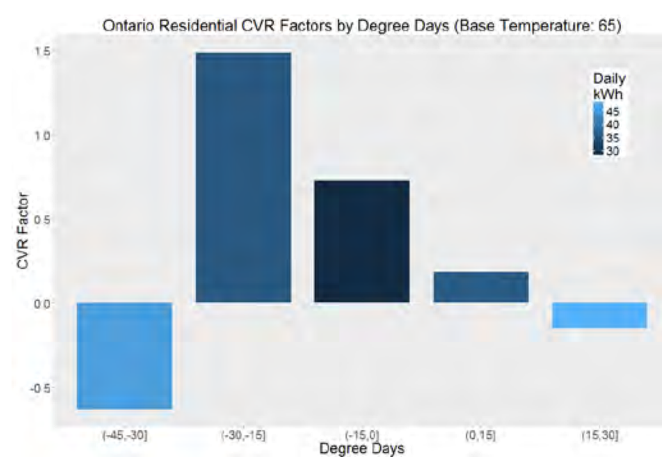


CVR Factors by Degree Day for Ontario Weather Zone

The commercial customer class increased energy use while CVR was active in the HDD category of -30, -15 resulting in a negative CVR factor. The same thing happened for the residential class in a couple degree day categories. However, generally the CVR factors for both classes were positive over most temperatures.

DD Type	DDCat	Days On	Days Off	Avg Volt On	Avg Volt Off	Avg Com KWH On	Avg Com KWH Off	Avg Res KWH On	Avg Res KWH Off	PDeltaV	PDelta Com KWH	PDelta Res KWH	Com CVR Factor	Res CVR Factor
Heating	(-45,-30]	16	19	120.71	122.55	274.34	277.43	46.14	45.71	-1.50%	-1.11%	0.94%	0.74	-0.63
Heating	(-30,-15]	39	32	120.46	122.59	240.56	235.57	35.28	36.21	-1.73%	2.12%	-2.58%	-1.22	1.49
Heating	(-15,0]	35	35	120.29	122.57	206.36	209.35	28.14	28.52	-1.86%	-1.43%	-1.36%	0.77	0.73
Cooling	(0,15]	40	42	120.23	122.52	167.68	172.05	36.13	36.26	-1.87%	-2.54%	-0.34%	1.35	0.18
Cooling	(15,30]	14	15	120.99	122.31	175.86	178.59	48.59	48.51	-1.07%	-1.53%	0.16%	1.42	-0.15

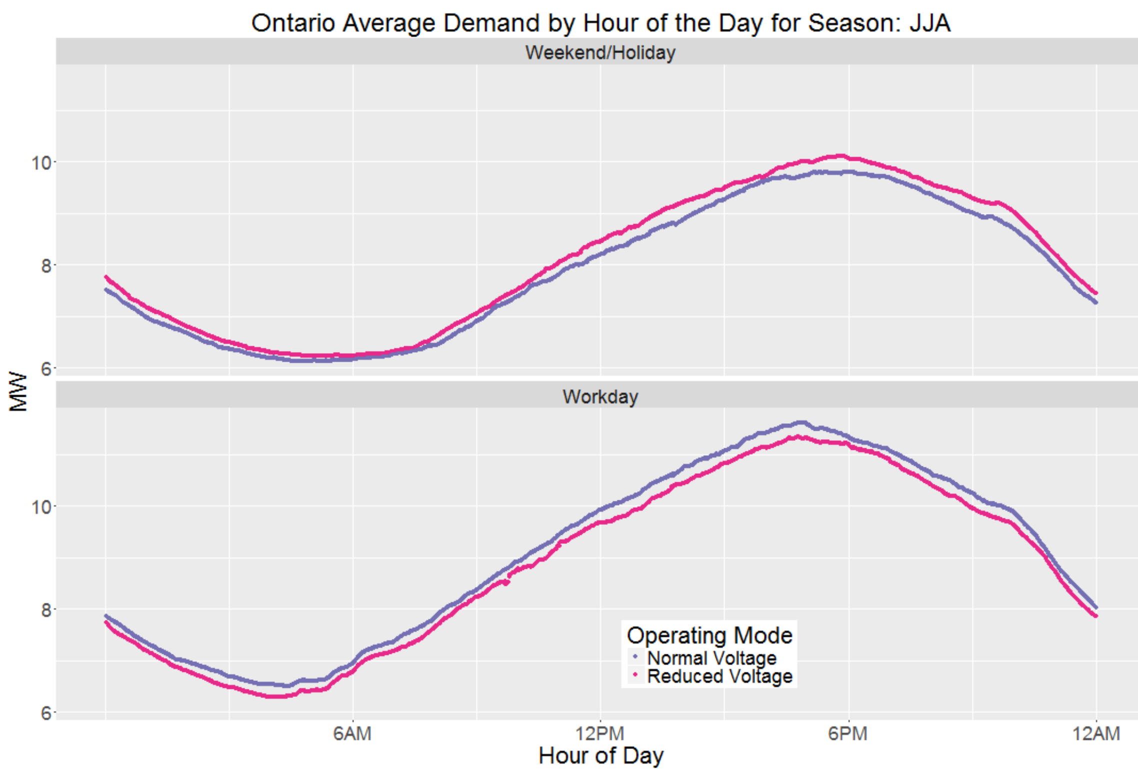


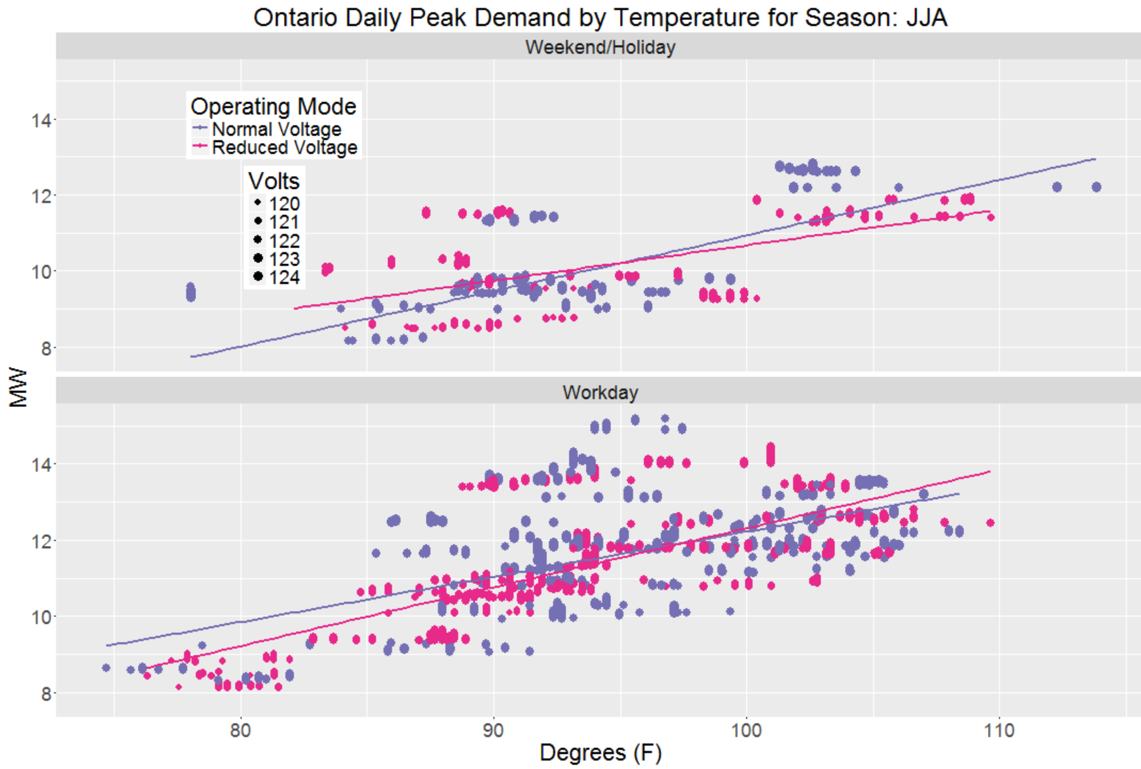


Demand CVR Factors for Ontario Weather Zone

The CVR factor for demand was 1.34 which is a favorable value.

Zone/Parameters		% Delta (confidence interval)	CVR Factor (confidence interval)	Reduced	Normal	Hours n (TOTAL)
Ontario, OR	V	**-1.38%** (-1.34%, -1.42%)	Not Applicable	121.19	122.89	5,334
	MW	**-1.85%** (-0.82%, -2.88%)	**1.34** (0.62, 2.02)	10.94	11.15	
	MVAR	**-10.65%** (-15.24%, -6.32%)	**7.72** (11.41, 4.44)	-0.63	-0.70	





Irrigation Weather Zone

Data collection for the Irrigation weather zone began March 1, 2015 and ended February 29, 2016. The treatment transformer was Pleasant Valley Substation, T131, near Aberdeen, Idaho. The sample size was 49 customers. Pleasant Valley Substation transformer T132 acted as the control transformer.

CVR was applied to one transformer to determine if CVR could be effective for reducing energy use where the load was primarily associated with irrigation. Pleasant Valley substation in Eastern Idaho was selected. During pumping season, this transformer could be loaded as high as 35 MW, while during winter, the daily maximum load might be as low as 1 MW.

Overall CVR Factor for Irrigation Weather Zone

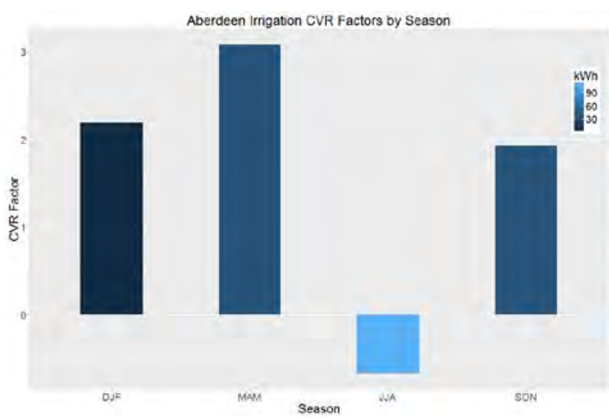
A rather small overall CVR factor for energy of 0.22 was achieved for the Irrigation weather zone as shown in the following table. Because irrigation pumps tend to be sensitive to low voltages, caution must be used when lowering the voltage for CVR. None-the-less, an average voltage decrease of 2.4% was achieved even with LDC active which is a relatively large decrease.

Zone/Parameters		% Delta (confidence interval)	CVR Factor (confidence interval)	Reduced	Normal	Hours n (TOTAL)
Irrigation	V	**-2.40%** (-2.34%, -2.46%)	Not Applicable	119.84	122.78	6,794
	Irr kWh	**-0.52%** (5.59%, -7.20%)	**0.22** (-2.39, 2.93)	55.66	55.95	

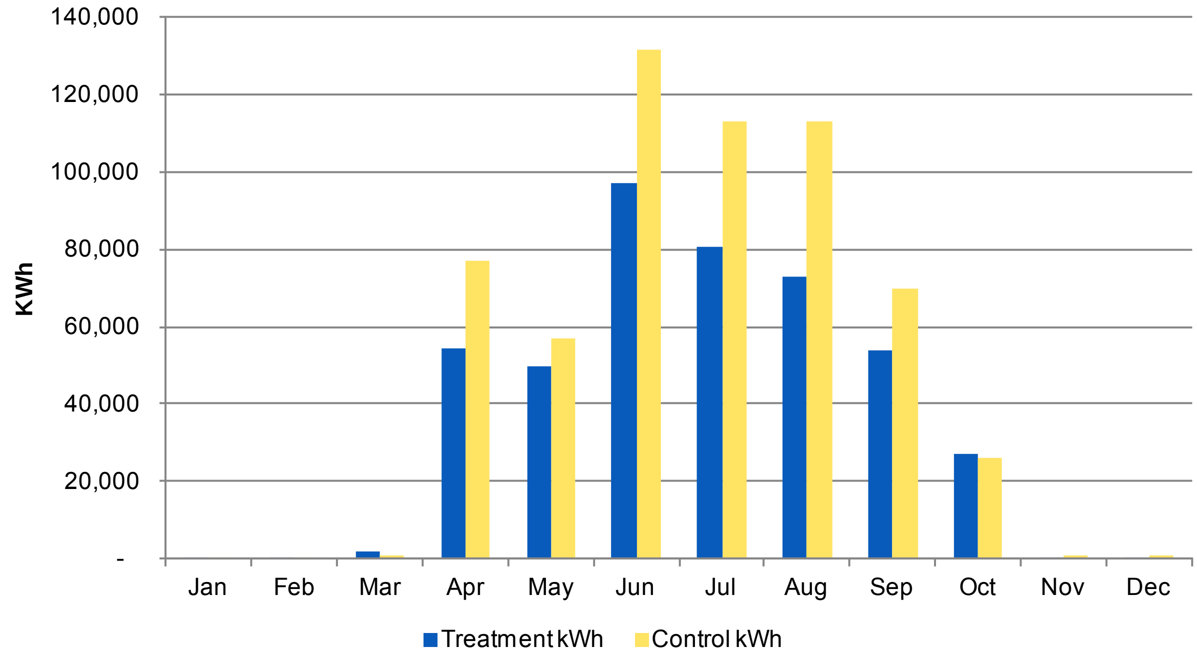
CVR Factors by Season for Irrigation Weather Zone

Analyses show that CVR resulted in increased energy use during the summer pumping season. CVR was much more effective during the non-summer months. All other months display very high CVR factors which seem unrealistic though may be accounted for by the fact irrigation loads are quite low or non-existent during these seasons.

Season	Hours On	Hours Off	Avg Volt On	Avg Volt Off	Avg Irr KWH On	Avg Irr KWH Off	PDeltaV	PDelta Irr KWH	Irr CVR Factor
DJF(Winter)	561	595	119.00	122.56	0.36	0.38	-2.90%	-6.36%	2.19
MAM(Spring)	582	720	118.59	122.80	34.61	38.69	-3.43%	-10.56%	3.08
JJA(Summer)	1,091	1,114	121.42	122.94	113.79	112.86	-1.23%	0.83%	-0.67
SON(Fall)	1,075	1,056	119.34	122.72	36.93	39.00	-2.76%	-5.32%	1.93



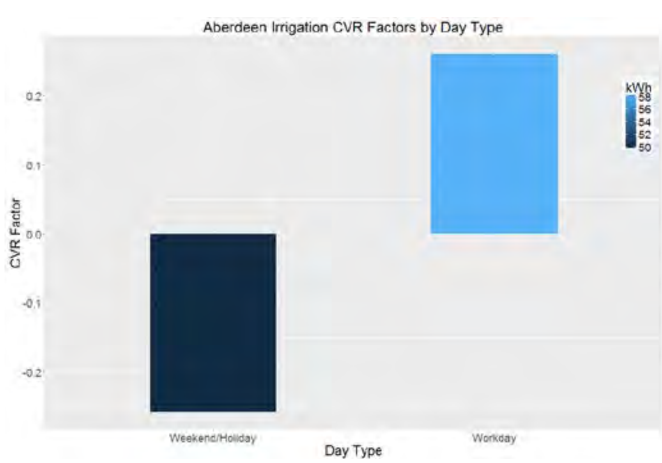
The following figure shows the monthly average load values for the treatment and control group customers. From this graph it can be seen that while summer is certainly the peak irrigation season, energy is also used in the late spring and early fall months. From November to April, there is nearly zero energy use for the irrigation customers. The CVR factors obtained for those time periods are not representative of irrigation loads. The seasonal values shown in the previous figure must be read with this in mind.



CVR Factors by Day Type for Irrigation Weather Zone

The difference in CVR factors between weekends/holidays and workdays are nearly diametrical opposites though very small in value. Because the energy reduction is small in absolute terms, the fact that the CVR factors seem opposite can be considered insignificant. During the summer pumping months, farmers in this region tend to irrigate significantly less on Sundays and Mondays than on other days. This would explain the lower average energy use for weekends.

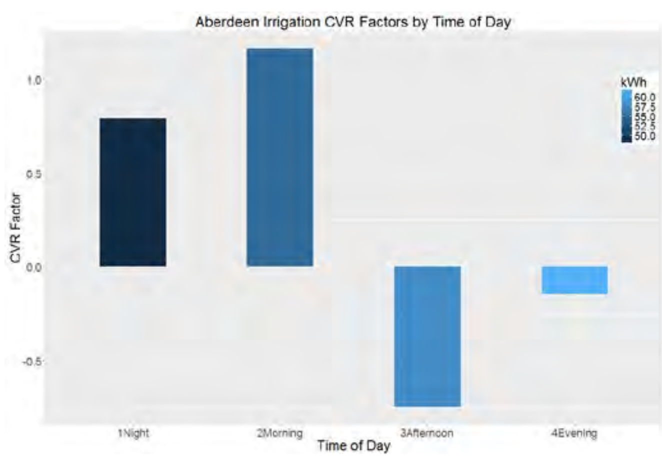
WedHol	Hours On	Hours Off	Avg Volt On	Avg Volt Off	Avg Irr KWH On	Avg Irr KWH Off	PDeltaV	PDelta Irr KWH	Irr CVR Factor
Weekend/ Holiday	1,056	1,050	119.57	122.79	50.03	49.69	-2.63%	0.68%	-0.26
Workday	2,253	2,435	119.97	122.78	58.30	58.65	-2.29%	-0.60%	0.26



CVR Factor by Time of Day for Irrigation Weather Zone

Afternoon and evening hours tend to have negative CVR factors while night and morning hours are positive. Irrigation patterns in this region tend to show more energy use in the afternoon and evenings with a nearly predictable lowest energy use in early morning hours. Because CVR factors are negative when energy use is highest, the conclusion can be drawn that pumping motors use more energy when voltage is reduced. Care must be taken when applying CVR to irrigation loads.

TOD	Hours On	Hours Off	Avg Volt On	Avg Volt Off	Avg Irr KWH On	Avg Irr KWH Off	PDeltaV	PDelta Irr KWH	Irr CVR Factor
Night	821	872	120.02	122.76	47.60	48.46	-2.23%	-1.77%	0.79
Morning	831	874	119.56	122.64	54.15	55.78	-2.51%	-2.92%	1.17
Afternoon	837	869	119.91	122.88	58.91	57.86	-2.42%	1.81%	-0.75
Evening	820	870	119.86	122.84	61.95	61.73	-2.42%	0.35%	-0.15



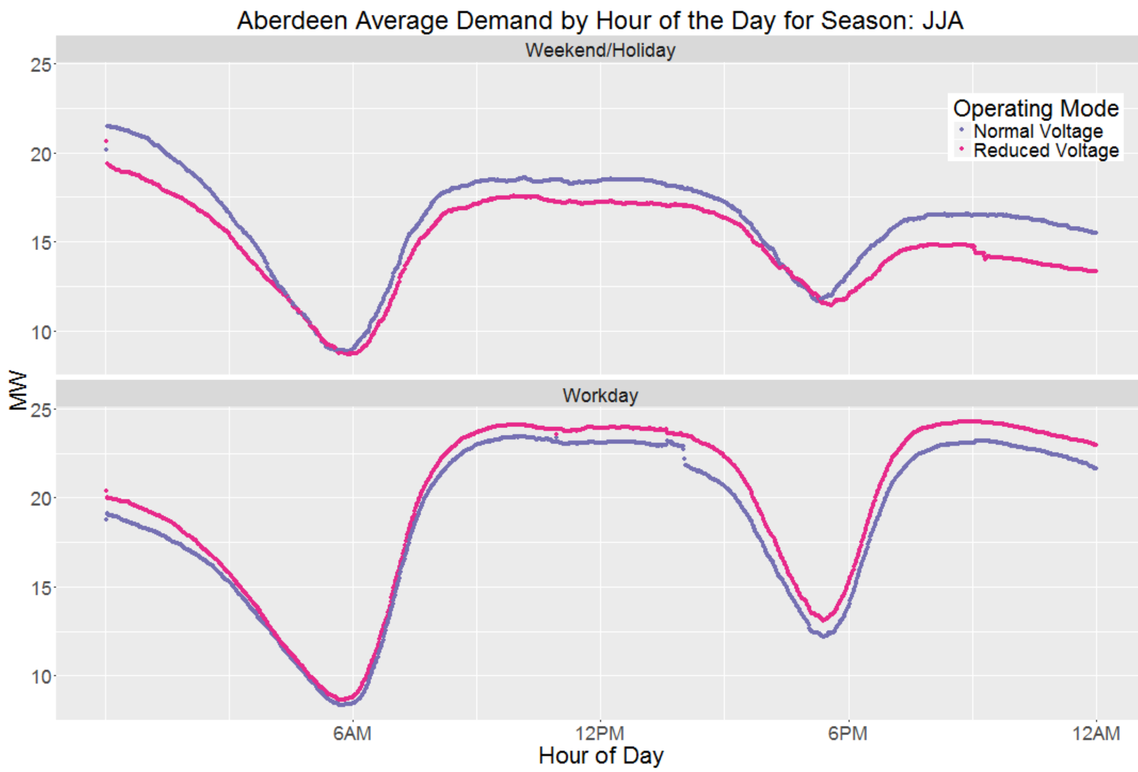
CVR Factors by Degree Days for Irrigation Weather Zone

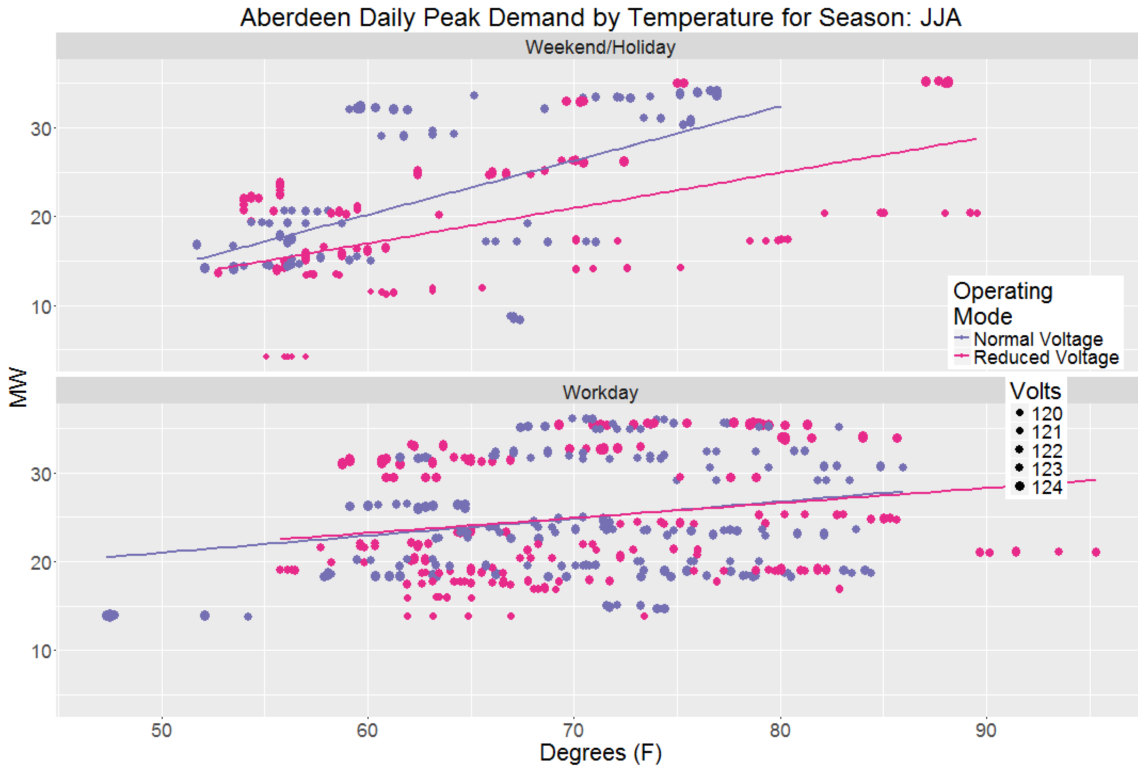
Nearly all significant load values for the irrigation zone occurred during the same degree day values, so no graph is provided.

Demand CVR Factor for Irrigation Weather Zone

A CVR factor for demand of 4.35 was calculated. The average voltage change during this period was only 0.69% which likely resulted in an inflated CVR factor for demand.

Zone/Parameters		% Delta (confidence interval)	CVR Factor (confidence interval)	Reduced	Normal	Hours n (TOTAL)
Irrigation OR	V	**-0.69%** (-0.63%, -0.74%)	Not Applicable	112.02	122.86	5,460
	MW	**-2.98%** (-0.75%, -5.28%)	**4.35** (1.18, 7.17)	23.36	24.08	
	MVAR	**-8.03** (8.50%, -29.28%)	**11.72** (-13.41, 39.76)	0.42	0.46	


Aberdeen Average Demand by Hour of the Day for Season: JJA
Weekend/Holiday
Workday
Operating Mode
Normal Voltage
Reduced Voltage
MW
25
20
15
10
6AM
12PM
6PM
12AM
Hour of Day


Aberdeen Daily Peak Demand by Temperature for Season: JJA
Weekend/Holiday
Workday
MW
Degrees (F)
30
20
10
50
60
70
80
90
Operating Mode
Normal Voltage
Reduced Voltage
Volts
120
121
122
123
124

Appendix D.
ENGO Static VAr Device Pilot Project

CUSTOMER OPERATIONS PLANNING
T&D STRATEGIES

ENGO STATIC VAR DEVICE PILOT PROJECT

Final Report

BUDGET ID #RDND140001
WO #27401454
BUDGET ID MAINTENANCE # 24297

June 2016

Table of Contents

Executive Summary

The ENGO Static VAr Device Pilot Project consisted of installing 10 Edge of Network Grid Optimization (ENGO) units on Portneuf Substation's feeder 42 (PNUF-042) near the far end of Arbon Valley, Idaho. The units were installed on the secondary side of nine 25 kVA service transformers and one 50 kVA service transformer to determine if they could resolve voltage flicker issues that customers experience on this remote, single phase feeder section.

The original scope of the project was to install, operate and test ENGO-V10 and ENGO-V30 solid state VAr compensating devices on various feeders on the Idaho Power system with the end result being a report providing recommendations concerning ENGO unit use on the Idaho Power system for voltage support. During the early stages of the project, management suggested that the units be placed on PNUF-042 to test their ability to mitigate voltage flicker occurring on this long rural feeder. While the units were not designed to mitigate for voltage flicker, it was hoped their high speed operating characteristics would provide the ability to mitigate flicker.

In addition to the ten ENGO V-10 units installed on PNUF-042, one unit was installed at H&H Tomato Green House in Eagle in December 2013 to test for harmonics injection and to determine if the ENGO unit would interfere with the AMI signal.

While the results of this project show that the ENGO units do not mitigate the particular voltage flicker occurring on PNUF-042, much operational experience was gained.

- The units are able to increase the voltage supplied from the secondary of a service transformer by as much as 3 Volts, depending on transformer loading.
- The units do not inject significant harmonics into the circuit.
- The units are compatible with Idaho Power's TWACS based AMI and actually improve the communications signal if they are located near to the meter (not a long service drop).
- The metering within the units is able to capture events on the distribution system such as significant voltage sags.
- The units are reliable with the only significant failures occurring because of cellular communications loss. Even when communications are lost, the units retain the voltage data and will communicate the information upon return of communications. They also continue to regulate when communications are not present.

Even though the ENGO units did not mitigate for voltage flicker on PNUF-042, it is recommended that the units be left in-place on PNUF-042 until they are needed for use on other feeders where they can be used for their designed function which is to improve the voltage on the secondary side of service transformers.

Introduction

Varentec's Edge of Network Grid Optimization (ENGO) unit is a solid state (static) VAr compensation device that provides dynamic or variable voltage control at the secondary side of distribution service transformers. The first ENGO unit, and the only available at this time, is the single phase ENGO-V10, which provides up to10 kVAr of reactive support in steps of 1 kVAr. Varentec developed the ENGO-V10 using U.S. Department of Energy, Advanced Research Projects Agency-Energy (ARPA-e) funding as well as significant venture capital funding. The ENGO-V10 units are now in full production and Varentec is selling them both domestically and overseas. Recently, Varentec moved manufacturing from India to a higher-quality manufacturing facility located in Mexico.

The ENGO-V10 provides dynamic voltage control to correct for low voltage conditions and provides fast variable voltage control on the low-voltage side of distribution transformers. The device includes voltage monitoring, advanced analytics, diagnostics and communications, providing visibility to the secondary side voltage profile. When low voltage levels are present, the unit detects and acts to help regulate the voltage by injecting up to 10 kVAr of capacitance in 1 kVAr increments into the circuit. Advanced algorithms assure that multiple units can be simultaneously deployed on a feeder, even in close proximity to each other, with no hunting or fighting between units. Testing at Idaho Power has shown that the unit can detect a low voltage event and inject reactive power into the circuit in just over ½ cycle (approximately 9 milliseconds).

The unit measures the raw voltage waveform, taking 32 samples per cycle. It report voltages every minute and provides measured minimum and maximum voltages along with an average voltage captured (Vrms) over the minute. The unit communicates this information using a cellular network (Sprint) and automatically downloads readings in batch approximately every two hours. The data can be retrieved via Varentec's web-hosted application software, ENGO Manager. A user can also command the ENGO unit to communicate its realtime data at any time using ENGO Manager.

This pilot project was to deploy up to 31 ENGO units; 25 ENGO-V10 units and six of the newer three phase ENGO-V30 units, to evaluate their viability for voltage support on feeders with spot voltage problems with the intent to use ENGO units in place of more expensive solutions such as reconductoring or small voltage regulators. The goal was also to potentially pilot the devices on feeders involved in the Conservation Voltage Reduction (CVR)[1] program where a more dynamic or aggressive voltage setting is desired. It was hoped that the ENGO units could be applied to localized low voltage spots along a feeder so that the overall feeder voltage level could be reduced thus maximizing the feeder's CVR potential. Additionally, evaluation was to be made to determine what, if any, affect the ENGO units have on Idaho Power's TWACS communications signal used by the AMI system.

On December 6, 2013, Idaho Power received a quote for 25 ENGO-V10 units from Varentec that included an additional 6 ENGO-V30 units free of charge as part of a DOE funded

[1] Conservation Voltage Reduction is a program whereby utilities can reduce energy consumption and demand by reducing feeder voltage levels.

initiative if the order was placed by December 27, 2013. The order was placed on December 17th and the ENGO-V10 units were received on December 30th. Note, the ENGO-V30 units were still in development at the time this report was written so have not been received. Correspondence with Varentec indicates they are still collecting information from various utilities (including Idaho Power) on the desired form for the ENGO-V30, pushing production into 2016. Since the ENGO pilot project is now complete, the ENGO-V30 units will be deployed on CVR test feeders once they are received.

Design and Installation

Table 1 shows the project timeline.

PO for 25 ENGO-V10 Units Issued	December 17, 2013
Received 25 ENGO units	December 30, 2013
Project Team formed	January 9, 2014
Received cost estimates for installation	January 17, 2014
Determined installation locations	April 10, 2014
Varentec recommends using fused disconnect	May 1, 2014
Received fused disconnect switches	June 2, 2014
Received design for M&M including disconnect	June 13, 2014
Installed ENGO units on PNUF-042	June 19, 2014
First control initiated	June 25, 2014
End of pumping season on PNUF-042	July 31, 2014

Table 1. Project Timeline

The original intent with the ENGO pilot project was to install a total of 25 ENGO-V10 units on one or more feeders to resolve spot voltage problems and also to test their ability to improve feeder voltage in support of conservation voltage reduction efforts. The project was redirected by management to install the units on PNUF-042, a feeder that had experienced voltage flicker problems and was thought to require expensive hardware upgrades. The ENGO-V10 has the capability to respond to voltage changes in just over ½ cycle so it was surmised that the flicker problem could be resolved by applying these units. Initial evaluation of the portion of PNUF-042 that experienced voltage flicker problems showed that all 25 ENGO-V10 units could be deployed on this feeder. The goal was to smooth out the voltage fluctuations experienced by customers on this feeder. It must be noted that the ENGO-V10 was not designed to resolve voltage flicker problems so it wasn't certain they could do so.

The project team was formed in mid-January and consisted of:
Kent McCarthy – Project Leader
Tyson Kent – T&D Reliability Engineering

Kelly Hulse – PQ Coordination
Jon Axtman – Customer Relations - Capital
Jim Burdick – T&D Planning

Other personnel involved in the project included:
Jun Golo – Methods and Materials
Jerald Rowan – Customer Relations - East
Mike Collins – T&D Reliability Engineering
Mark Bailey – T&D Reliability Engineering
Bret Beck – Regional Lineman (Trouble Work)
Tieg Radtke – Regional Lineman (Trouble Work)

Cost estimates were performed for installation of the ENGO-V10 units by Project Portfolio Management and the cost was estimated to be approximately $700 per unit, assuming a two-man crew with one bucket truck.

Installation design was initiated with Methods and Materials Department in February 2014. Final design was ready in April, but a technical change was recommended by Varentec on May 1st that required an installation design change. The ENGO-V10 units come equipped with external inline fuses to protect the electronics in case of internal failure. Varentec has experienced numerous failures of these external fuses and recommended that a separate fused disconnect switch be installed in-line with the ENGO-V10 unit to replace the inline fuses. This required a design change to the installation process. The ENGO-V10 units are pole mounted and it was necessary to mount the ENGO-V10 units and the fused disconnect switches outside the communications space in accordance with National Electrical Safety Code standards while providing climbing space so a lineman could navigate around the units if using climbing gear. Methods and Materials redesigned the installation and provided it to the project on June 13th. Because of the recommendation to install a separate fused disconnect and the resulting redesign and purchase of the switches, the project missed the beginning of the summer operating season.

At the beginning of the project, it was understood that the ENGO-V10 units were programmable such that the size of the service transformer to which the ENGO unit was attached could be programmed into the unit thus allowing a 10 kVAr unit to be attached to a small service transformer without fear of overloading the transformer. For example, a 10 kVAr ENGO unit can be safely connected to a 25 kVA transformer because even if the transformer was operating at full load and a full 10 kVAr was injected into the circuit, the transformer wouldn't be overloaded. However, if a full 10 kVAr is injected into a smaller transformer's circuit while the transformer is operated at a high loading, it could overload the transformer thus the necessity to limit VAr injection for smaller transformers. Discussions with Varentec indicated that this VAr limiting design feature was not yet implemented in the units Idaho Power received. Since many of the transformers on this circuit were less than 25 kVA, not all 25 ENGO-V10 units could be applied to the PNUF-042 feeder. Acceptable locations were found for a total of 10 ENGO-V10 units.

Installation of all 10 ENGO-V10 units was performed on June 18th using Line Operations Technicians and one-man line crews. No difficulties were experienced installing the devices.

See Appendix A for installation photos. The units began reporting voltage measurements on June 18 immediately after installation.

Figure 1 shows the ENGO-V10 installation locations. Appendix B contains descriptions of unit locations.

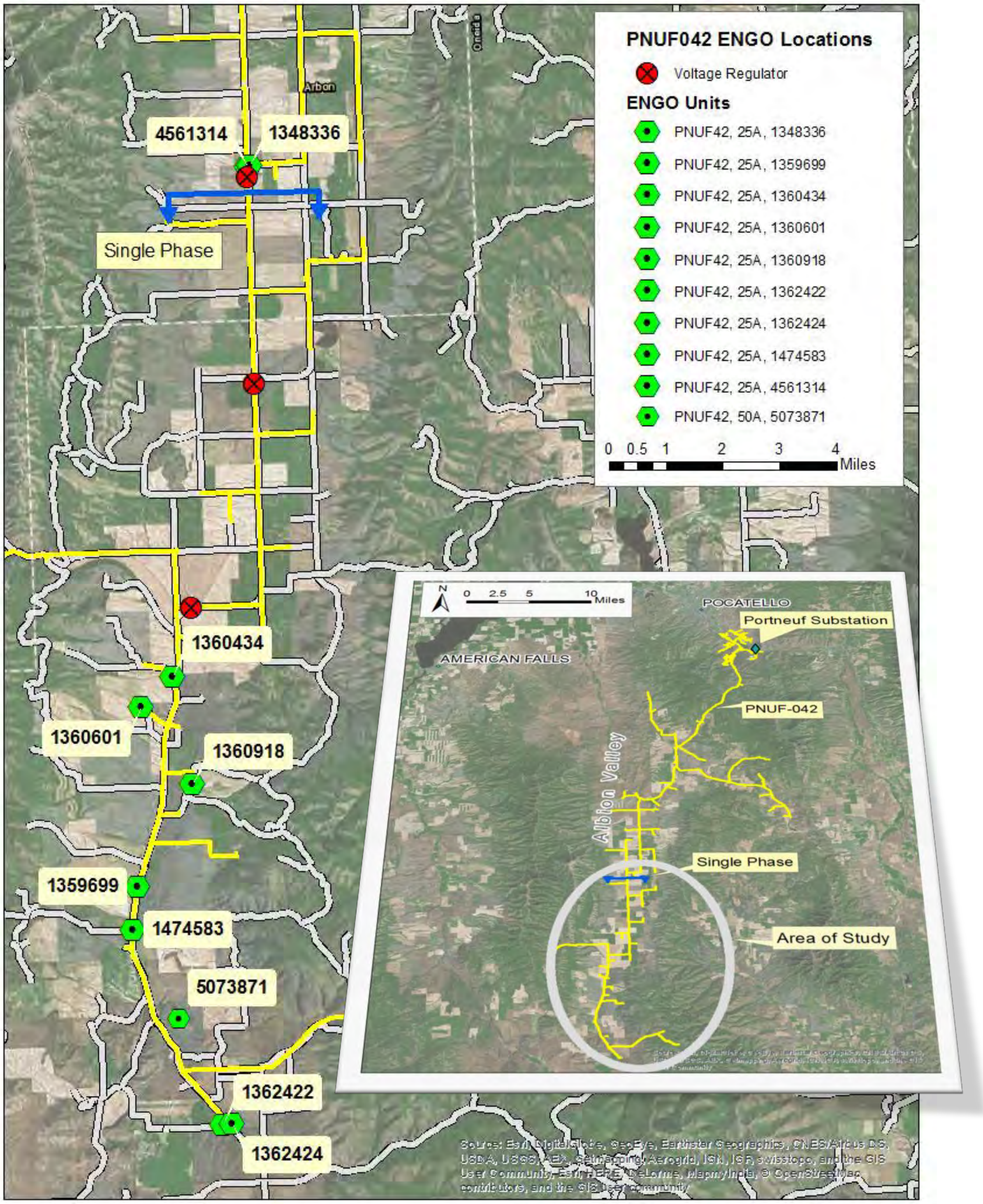


Figure 1. PNUF-042 ENGO-V10 Locations.

Testing Procedure and Results

Because installation was delayed by design changes and pumping season ends around July 31st, unit testing was limited. Table 2 shows the test schedule.

Baseline voltage with no control set points applied	June 19
Initiate control at 240 V on three geographically dispersed units	June 25
Initiate day-on/day-off control routine on all units	July 10
Initiate hour-on/hour-off control on all units for 1 day, 7am to 4pm	July 23, 7 am to 4 pm
Resume day-on/day-ff control routing on all units	July 23, 4 pm
End day-on/day-off all units	July 31
Set units for continuous 240 V operation	August 1

Table 2. Test Schedule

Baseline

The first week after the units were installed, voltage monitoring was performed with control turned off in the units to setup a baseline for the project and to monitor for voltage flicker events. Figure 2 is a screenshot of the Varentec ENGO Manager software showing these baseline voltages for two of the ENGO-V10 units installed. The first unit shown was installed just upstream from a voltage regulator on a two-phase section of line and the second unit shown was installed about 8 miles downstream from the voltage regulator on a single-phase section. Notice the increased voltage fluctuations measured by the downstream unit which is likely caused by the weak nature of the single phase line. The secondary sides of the transformers associated with this project appear to operate around 240 V on average. Note, the Unit numbers match the transformer GISO numbers to which the ENGO units were attached. This feature of the ENGO Manager software in which the end-use can customize unit numbers makes tracking unit operations and setpoints convenient.

Figure 2. Baseline Voltage Sample

Small Sample Testing

The following two weeks, three of the units were set for 240 volts and left to inject VArs to hold this voltage. Figure 3 shows the voltage profile for these three units with the gold colored line indicating the voltage set point.

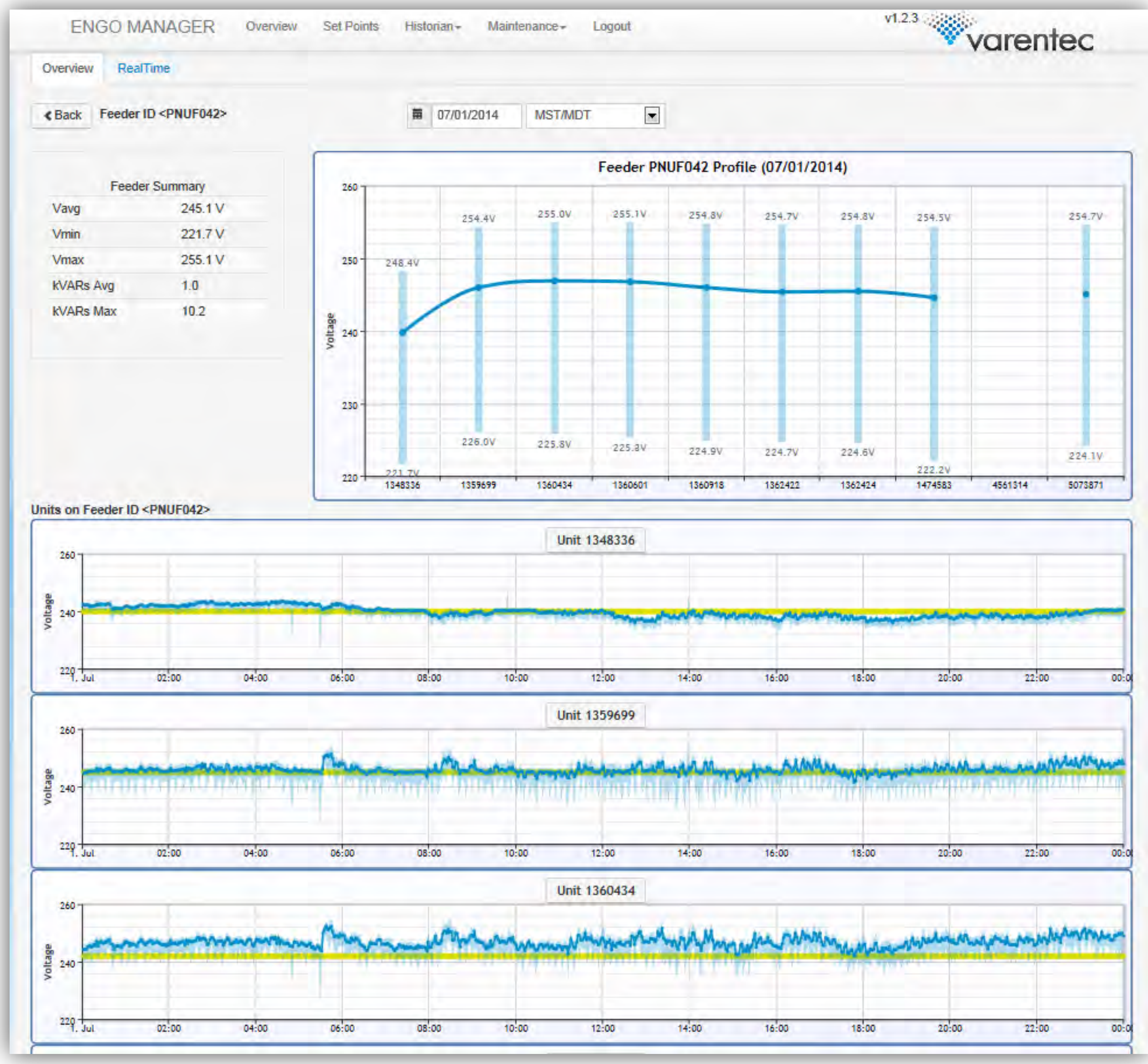


Figure 3. Three Units set at 240 Volts

Both Idaho Power and Varentec observed the unit operations and voltages during this time. Varentec noted that most of the units were experiencing excessive VAr injection changes with some units reporting up to 10,000 switching operations per day (a switching operation being defined as a change in state for any of the 10 capacitors in an ENGO-V10 unit). Figure 4 shows one of the controlled units initiating 10,232 operations in one day. The green lines on the chart indicate KVArs injected. Varentec pointed out the units were designed for hundreds of operations per day and operating in the thousands could shorten the 15 year design life. Therefore, the bandwidth around the voltage settings was widened from the default +/- 1 Volt to +/- 2 Volts on all units, resulting in fewer operations.

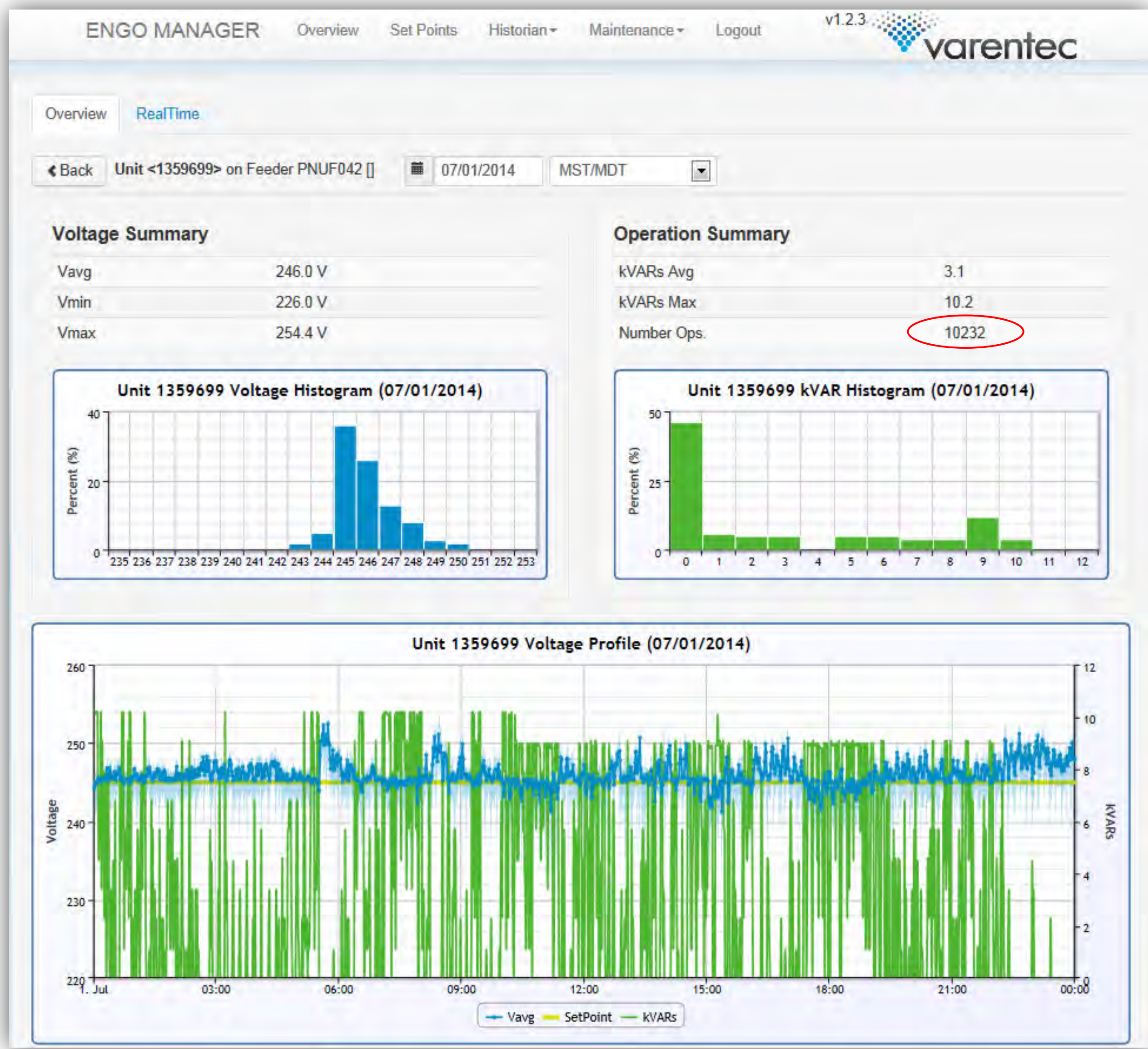


Figure 4. Unit 1359699 showing excessive number of operations

Day-On/Day-Off Testing

On July 10th, Idaho Power began cycling the units such that they were on (controlling) one day and off (not controlling) the next day. This day-on/day-off schedule is an automatic function embedded in the ENGO Manager software and continued until July 31st. See Appendix C for the full cycling schedule. Figure 5 shows Unit 1362424 cycling between two days. The top chart shows a day when control is off (a line is drawn at the 240 Volt point for reference) and the bottom chart is a day when control was set to 240 Volts. Notice that the ENGO unit maintained the average voltage above 240 Volts on the day it was controlling. On the non-control day, the average voltage frequently went below 240 Volts.

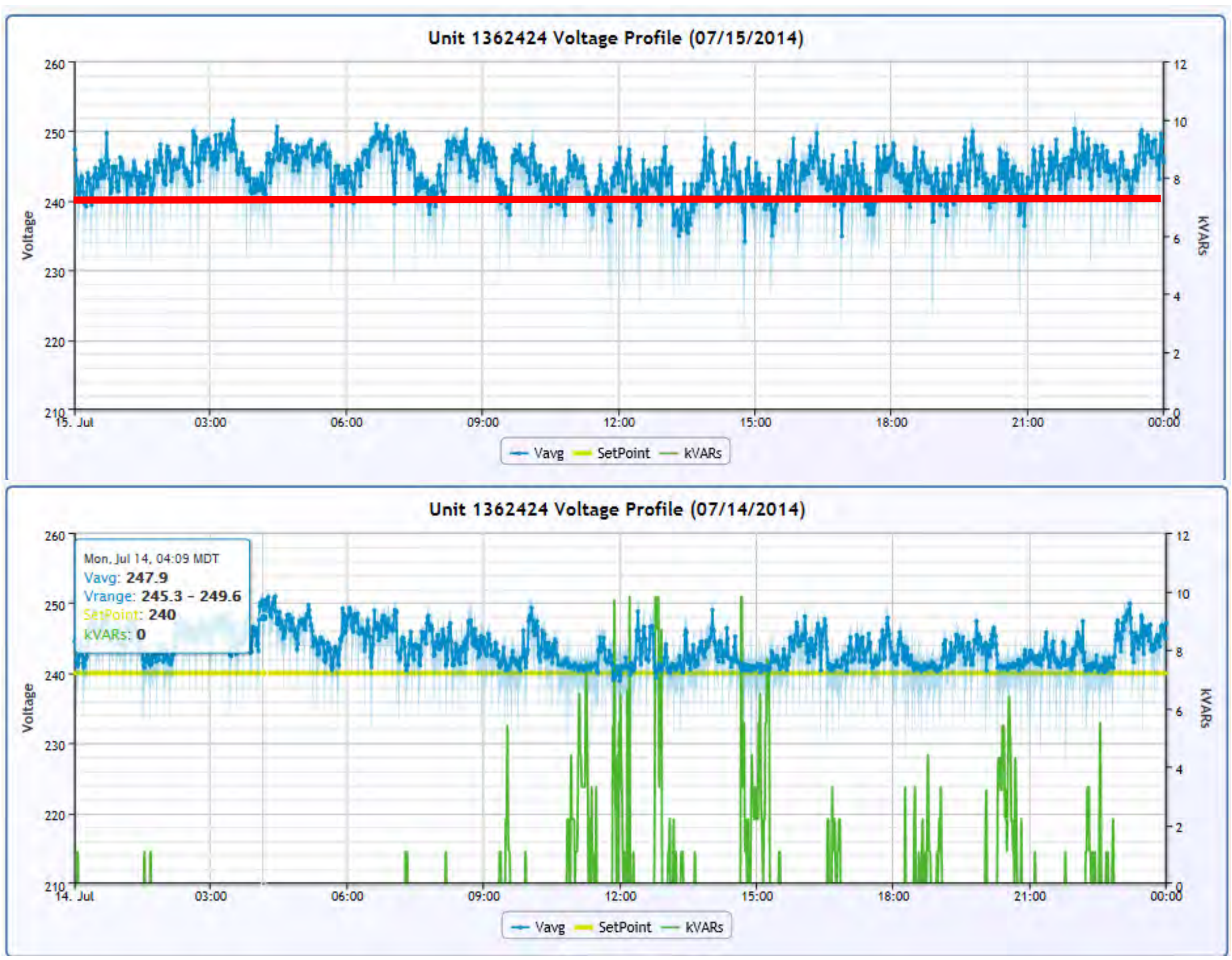


Figure 5. Unit 1362424 cycling

Hour-On/Hour-Off Testing

On July 23rd, all units operated in an hour-on/hour-off schedule from 7:00 am to 4:00 pm. See Appendix C for the full cycling schedule. Figure 6 shows Unit 1348336 during these hours. This unit is upstream of the voltage regulator. The ENGO-V10 unit appears to have increased the voltage when in control mode by as much as 3 Volts, a potentially important piece of information should the ENGO units be used in Idaho Power's Conservation Voltage Reduction program.

Figure 7 shows Unit 1474583 which is about 8 miles downstream of the voltage regulator. Close examination of the chart shows this unit also increased voltage by around 3 Volts immediately after it came on as long as the voltage was below 240 Volts when the unit was activated.

None of the other units had any effect on voltage during the hour-on/hour-off routine because the voltage never fell below 240 Volts at their individual locations during this time period.

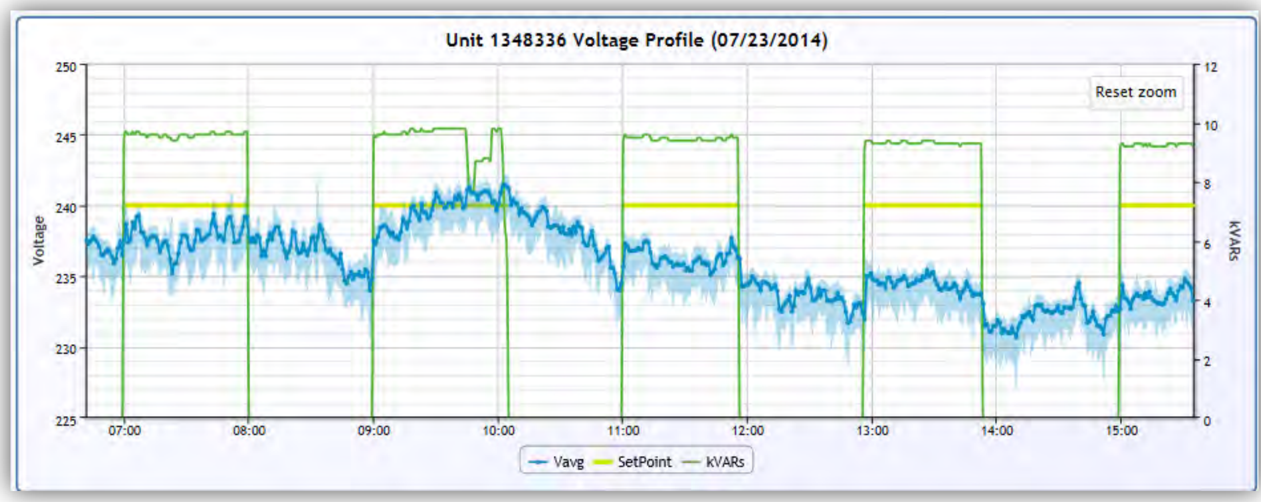


Figure 6. Unit 1348336 cycling; hour-on/hour-off

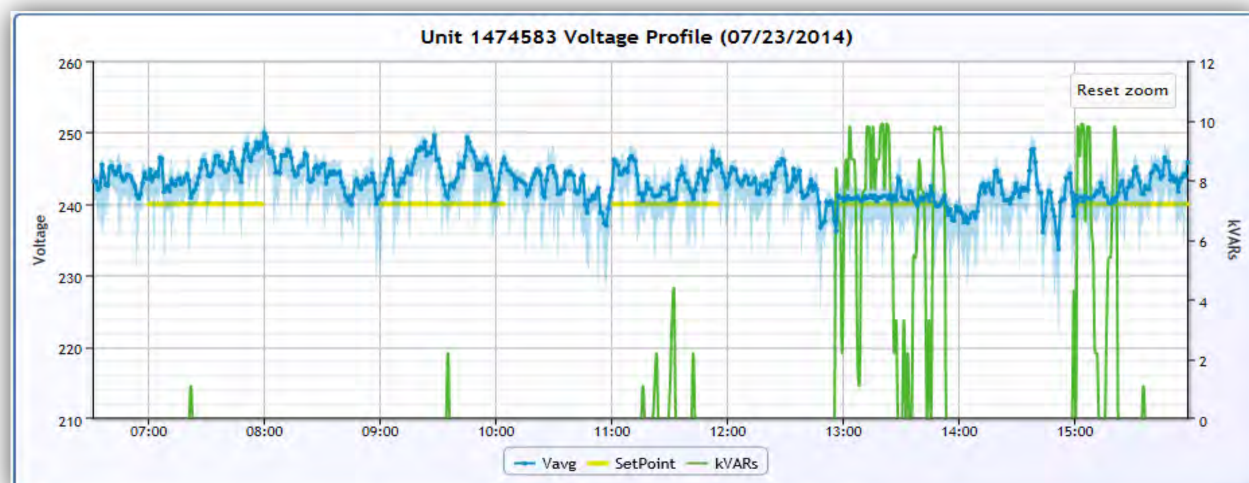


Figure 7. Unit 1474583 cycling; hour-on/hour-off

Voltage Sag Event

At 07:00 on July 21st, all ENGO units recorded a significant voltage sag event with voltages going as low as 159 Volts. This can be seen in Figure 8. This was a very short event on PNUF-042 and was caused by a 138 kV line downed into a distribution feeder fed from Portneuf Substation. This event unfortunately occurred on a day when the ENGO units were cycled off and were not controlling for voltage so it couldn't be determined if the units would have reacted to this event.

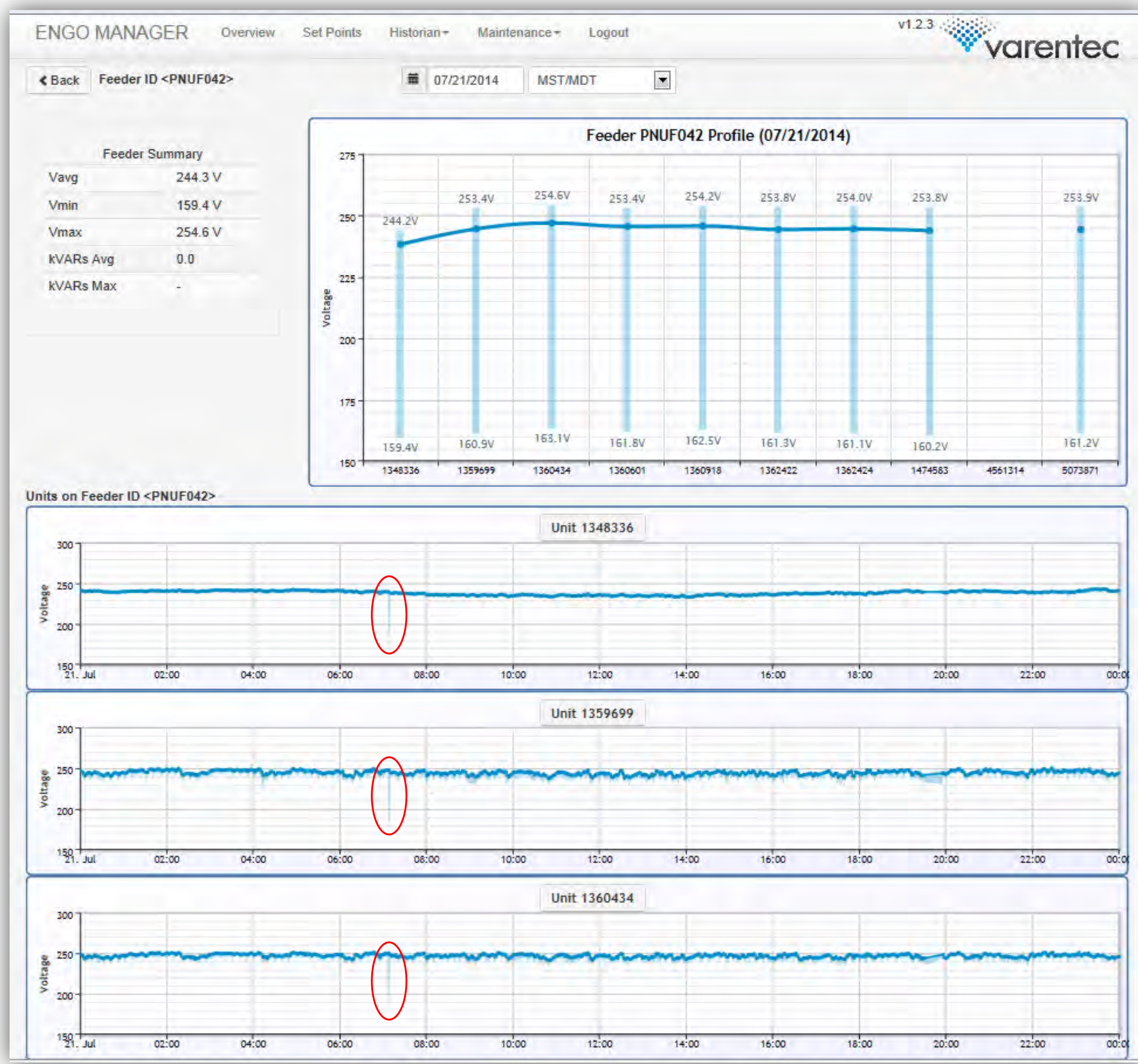


Figure 8. Voltage Sag Event

Voltage Flicker Measurement

An IEEE 1453 compliant flicker meter was connected at the service entrance of the customer attached to transformer GISO #1360918 and recorded voltage flicker events over the entire testing period between July 10 and July 31. This device records voltage fluctuations and objectively infers light flicker. The unit of measure is *Perception of Light Flicker in the Short Term*, or Pst, with short term being defined as a 10-minute interval. The results from the flicker measurements are shown in the following three figures. Figure 9 shows the actual Pst measured over the span July 17 through 19. Channel 1 and Channel 2 in this figure show the Pst measured from line to ground. In general, if Pst is greater than 1.0, the flicker can be perceived by the customer and is great enough to be an annoyance. The ENGO device connected to this transformer was in an on state July 18 and it appears it had no effect on the flicker compared to July 17 and 19. Note, Channel 3 is Pst measured line to neutral and is generally considered useless noise as far as flicker measurement is concerned.

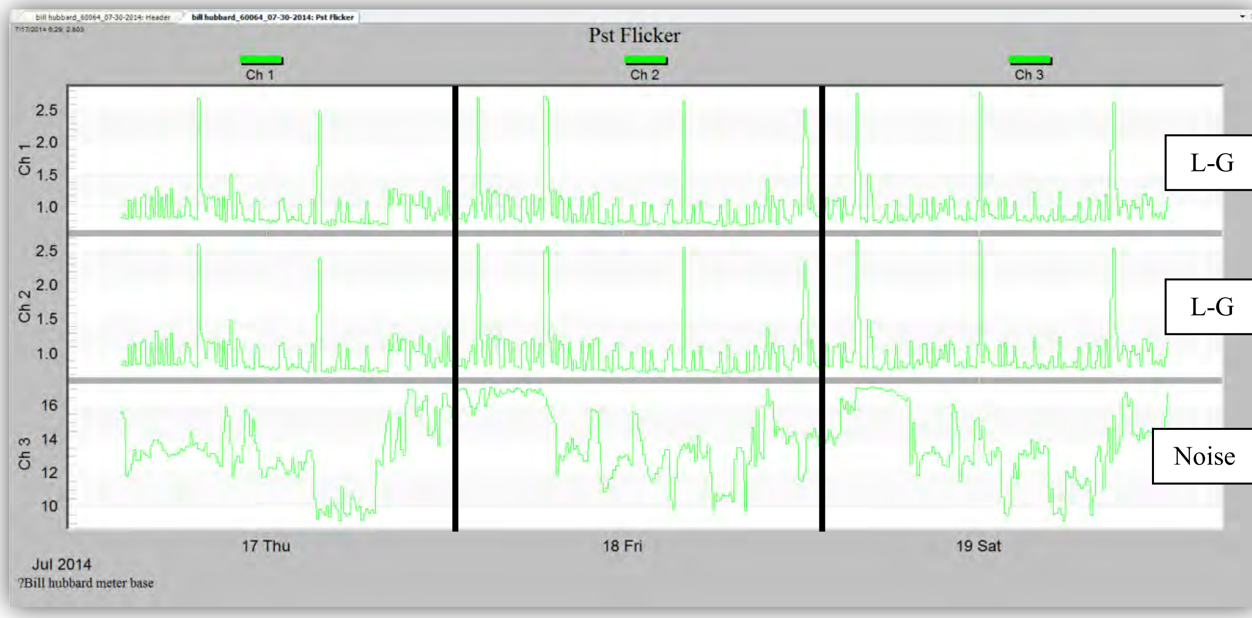


Figure 9. Pst Flicker Measurement

Figure 10 shows the ratio of the minutes that contained elevated Pst in a day against the total minutes for the day. This ratio is plotted in time with the state of the ENGO unit either "ON" or "OFF." Again, this figure shows the ENGO had no discernible influence on flicker. Figure 11 shows the Flicker vs ENGO status for July 23rd when the ENGO unit was cycling on/off every hour between 7:00 am and 4:00 pm. It can be seen on all three figures that this customer experiences a great amount of flicker on a daily basis due to the weak characteristics of this single-phase radial line. Any slight load addition or subtraction on the feeder is felt by every customer.

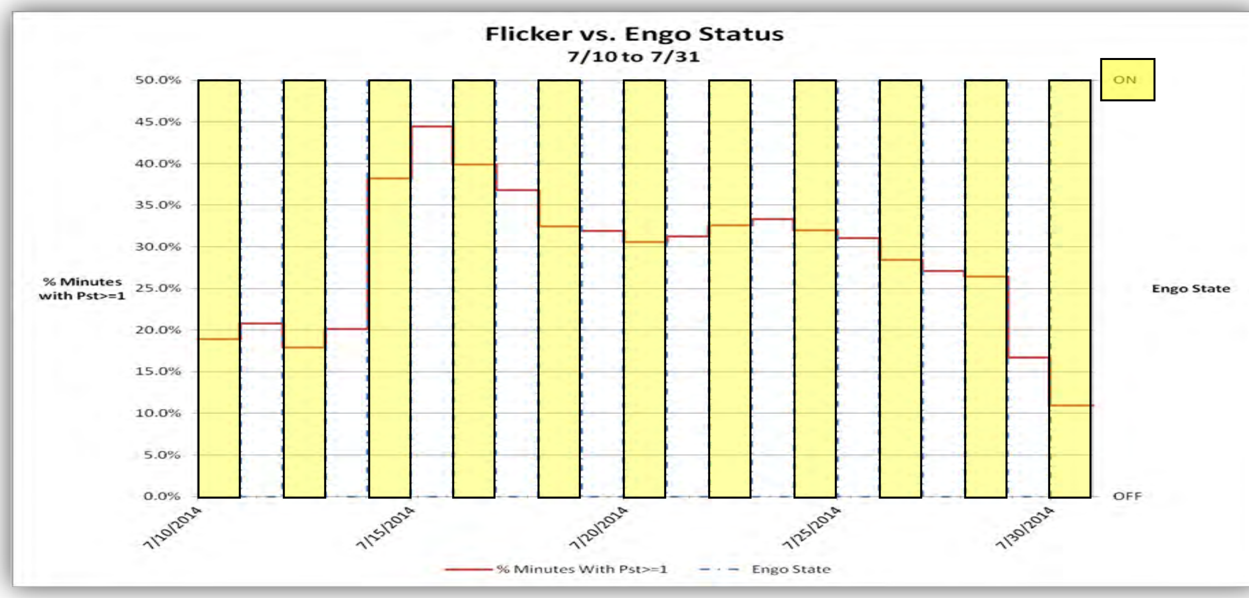


Figure 10. Flicker vs ENGO status during day-on/day-off cycling

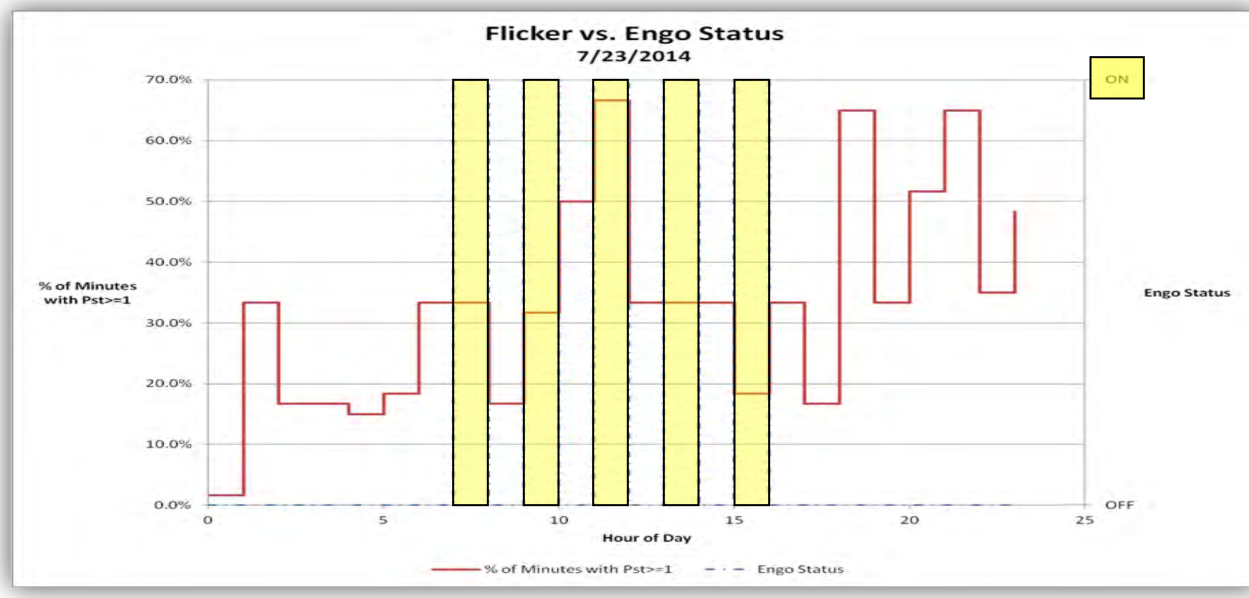


Figure 11. Flicker vs ENGO status during hour-on/hour-off cycling

The ENGO device does not appear able to mitigate for voltage flicker in its present form. The device has the ability to detect a single-cycle RMS voltage deviation so it is thought by the project team that with firmware modifications by Varentec, an ENGO unit might be able to make use of a flicker management algorithm that could aid in some flicker events. However, to fully mitigate flicker, the device would need to use some form of sub-cycle measurement and initiate a high speed response of the device, even faster than it presently can.

The ENGO units installed on PNUF-042 were left in-place through 2015 in order to further test their ability to mitigate flicker. An IEEE 1453 compliant flicker meter was connected at the service entrance of the customer attached to transformer GISO #1359699 which was considered to be the most likely location where flicker could be observed (based on previous customer complaints). Once again, no discernible difference in the measured flicker could be found between the days when the ENGO unit was actively injecting VArs and when the ENGO unit was in a non-active mode.

Power Quality Monitors vs ENGO-V10 Units

A power quality monitor was connected at the meter base connected to the secondary of transformer GISO #1360918 via the service drop and the resulting voltage waveforms were compared to those recorded by the ENGO unit also connected to this transformer. Figure 12 shows average voltages recorded during the time span July 17 through July 20. The top chart is the PQ monitor (green is voltage and blue is current) and the bottom chart is the ENGO unit. Times shown on the ENGO unit's X-axis are in universal time meaning the 6:01 time shown is 12:01 a.m. Mountain Standard Time.

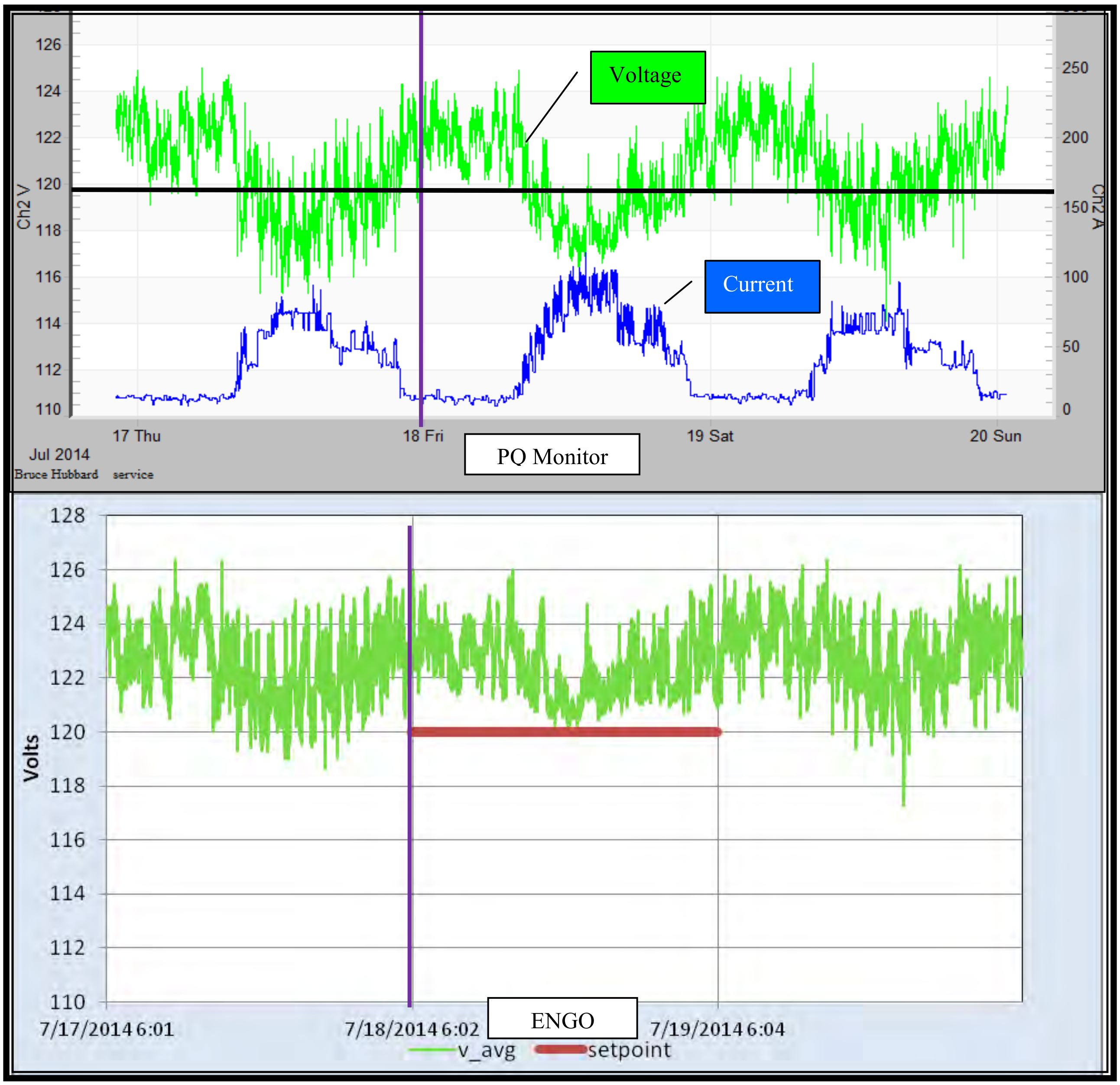


Figure 12. Average RMS Voltage at Unit #1360918

Figure 13 shows minimum voltages for the same time span (PQ monitor green line is voltage and pink line is current). The voltage difference observed between the PQ meter and the ENGO device is due to the voltage drop between the transformer and the meter base.

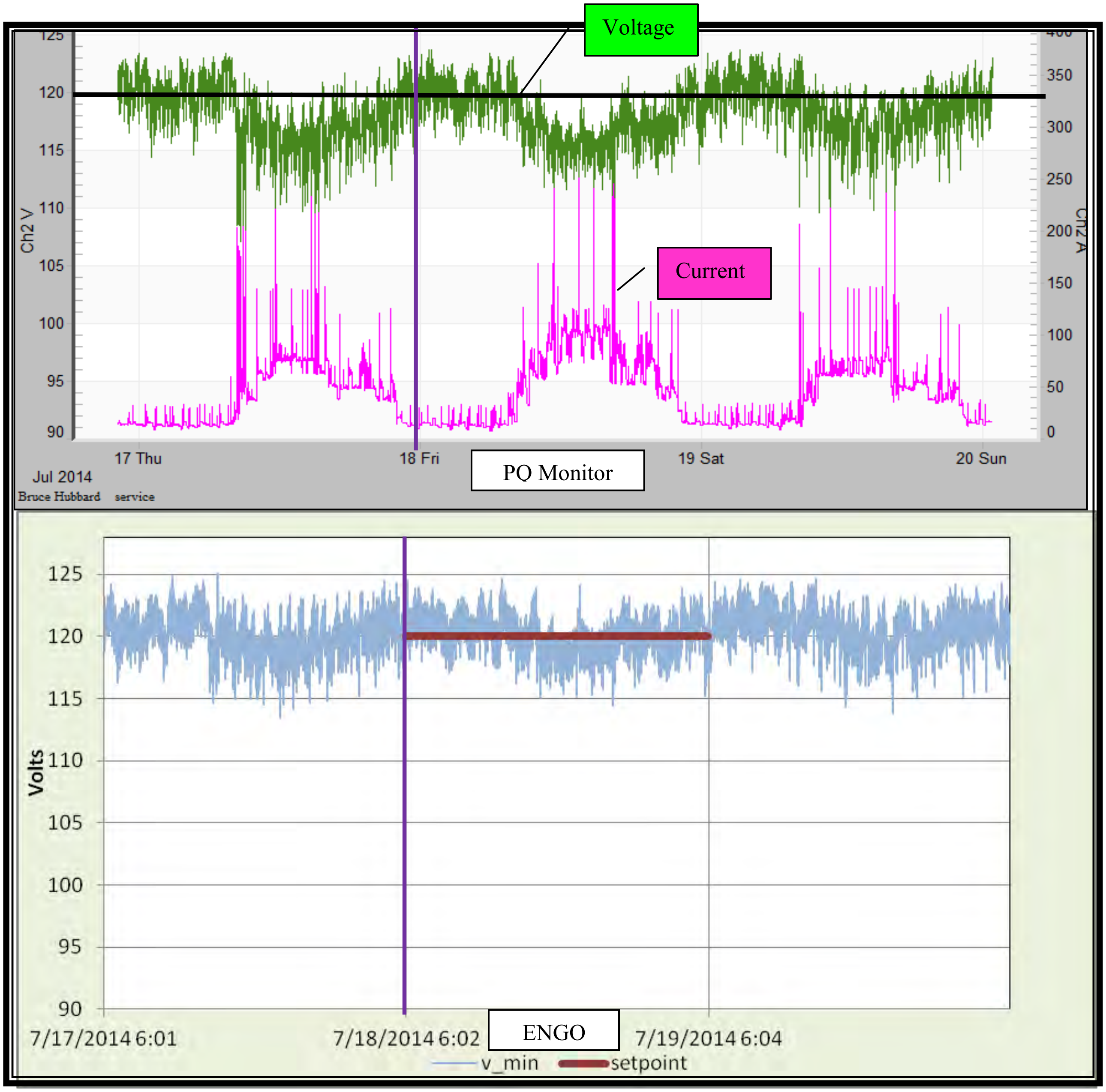


Figure 13. Minimum RMS Voltage at Unit #1360918

Voltage and Current Distortion Caused by ENGO Units

A power quality monitor was connected next to an ENGO-V10 unit installed at H&H Tomato Green House in Eagle in December 2013. Analysis of the voltage and current distortion caused by the ENGO unit showed they increased voltage distortion by around 1.5%. It should be noted this location has an extremely high non-linear load so this small increase in distortion should be expected and is acceptable. There was also some fairly significant current distortion increase but again, was deemed acceptable. Figure 14 shows the voltage and current waveforms with the ENGO unit turned off along with the voltage harmonics chart. Figure 15 shows the same charts with the ENGO unit injecting a full 10 kVAr.

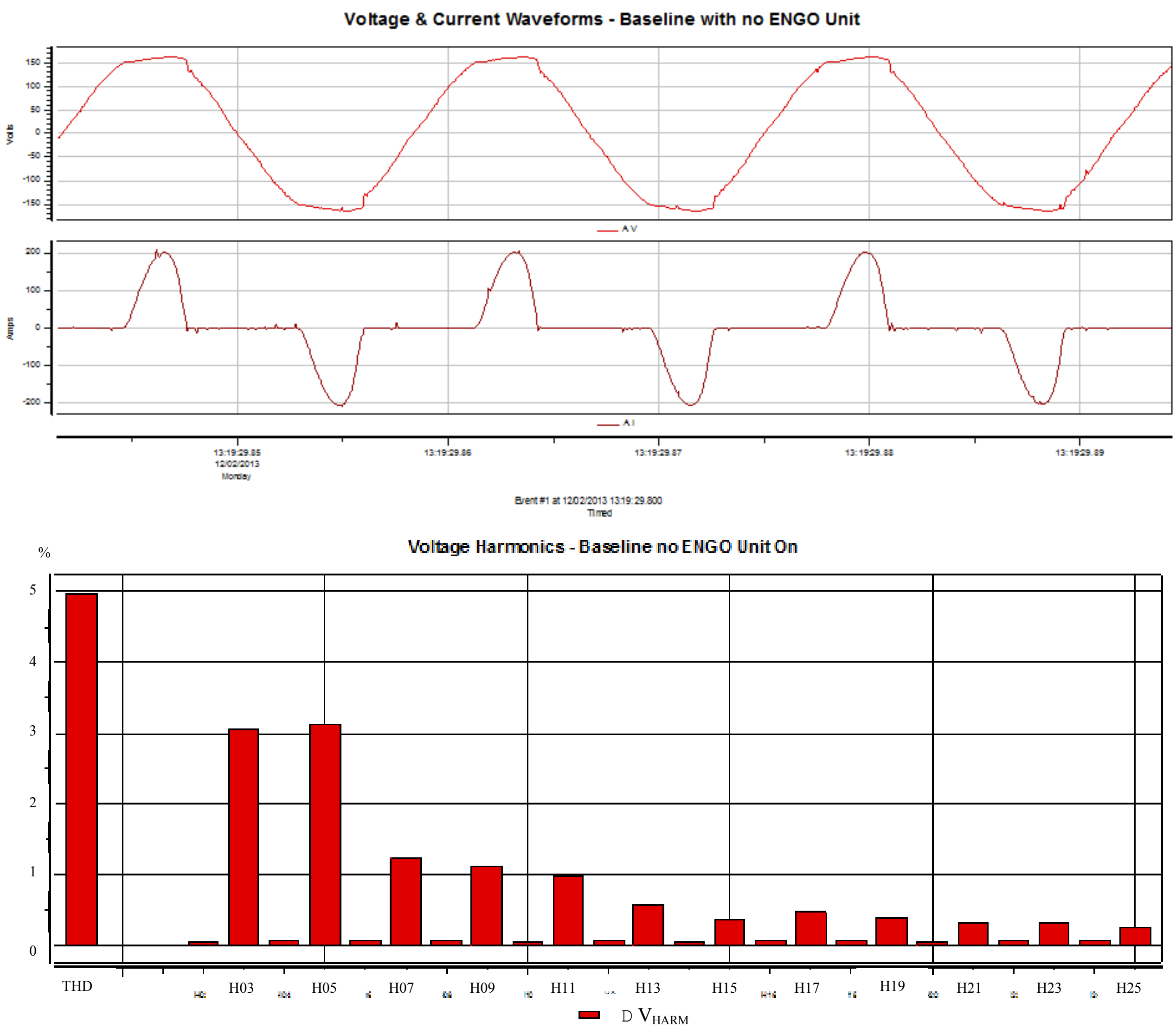


Figure 14. Voltage & current waveforms and voltage harmonics with ENGO unit off

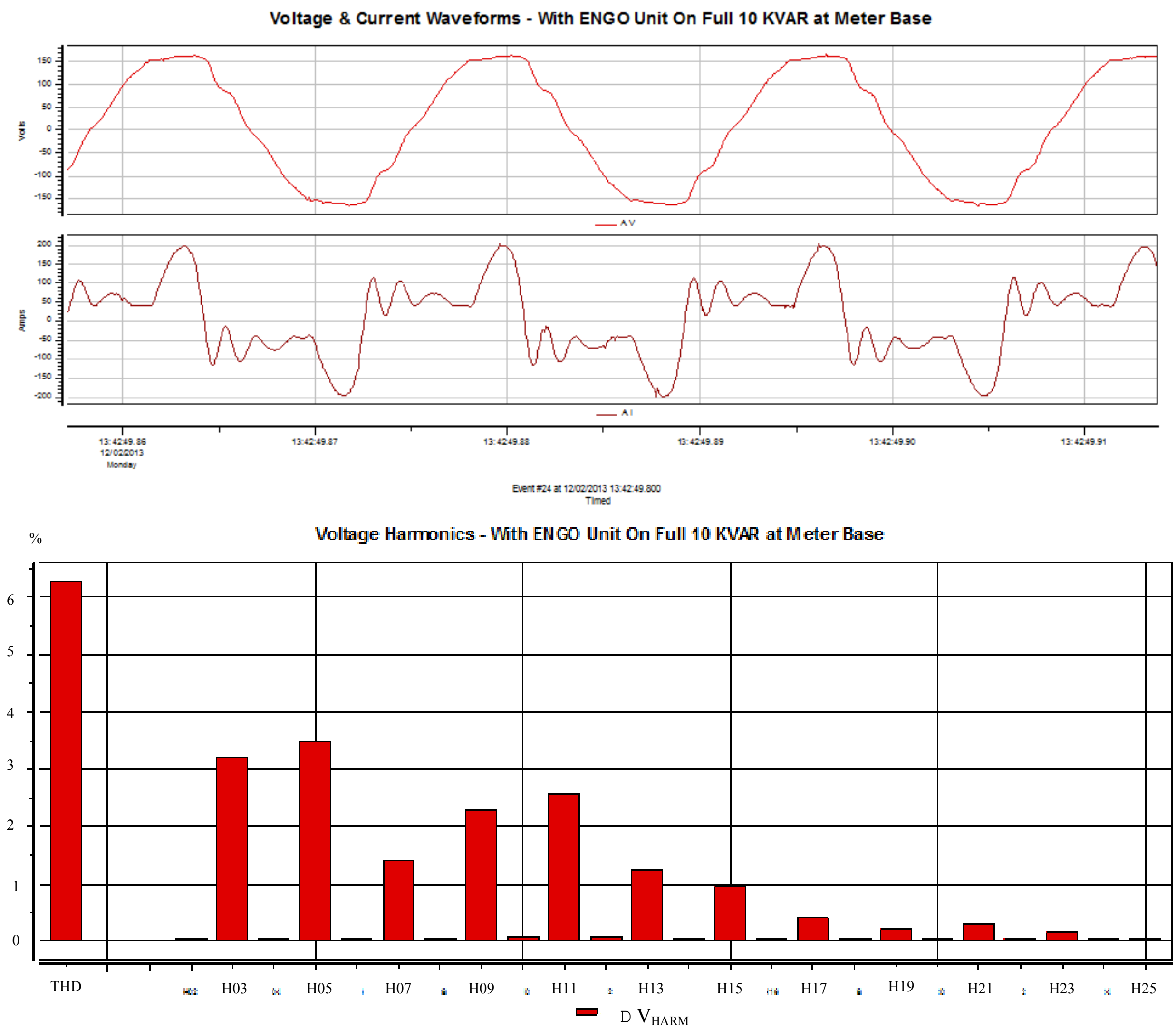


Figure 15. Voltage & current waveforms and voltage harmonics with ENGO unit injecting 10 kVAr

AMI Interference Testing

Testing was also performed on the unit installed at H&H Farms to determine if:

1) The ENGO unit could interfere with Idaho Power's TWACS powerline carrier based AMI system or
2) The TWACS powerline carrier signal could cause the ENGO unit to mis-operate. These two concerns are addressed separately below.

ENGO unit interfering with AMI signal – It was surmised by the Power Quality Department that the ENGO unit might interfere with the AMI system's powerline carrier signal. TWACS inserts a 50 to 80 amp current spike (something like a short circuit) near the voltage zero crossing of the waveform feeding through the customer's meter. This spike contains the packet of information that is communicated between the meter and the substation. It was feared that this "notch" in the waveform might be attenuated or even eliminated by having the voltage supported by the ENGO unit's VAr injection so near to the meter.

The same power quality monitor that was used to test for harmonic distortion was used to evaluate the ENGO unit's affect on the AMI signal. The monitor was set to sample at 256 samples/cycle which is just adequate for analyzing this notch that lasts only 1 millisecond. The monitor shows a definite decrease in the size of the voltage notch but very little, if any, decrease in the current notch. This result is actually very positive in that the data carrying current notch maintains its full information carrying capability while decreasing the size of the voltage notch which has been determined to be a source of customer equipment malfunction in the past. Figure 16 shows the TWACS communications signal without the ENGO unit installed followed by Figure 17 which shows the communications signal with the ENGO unit installed. Note the near elimination of the voltage notch in the signal. Further testing showed the voltage notch elimination was most pronounced if the ENGO unit was near the meter. The notch elimination was not nearly as pronounced for long service drops where the distance between the service transformer and the meter was large.

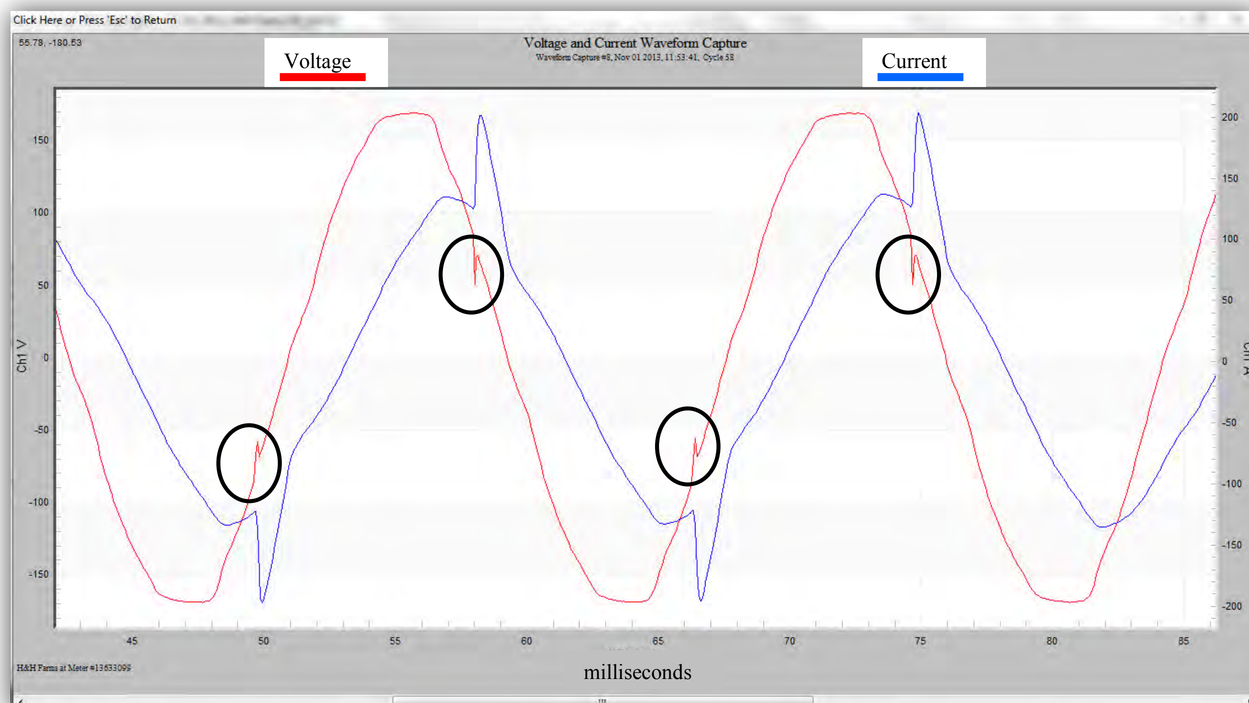


Figure 16. TWACS communication without ENGO unit installed. Measured at transformer.

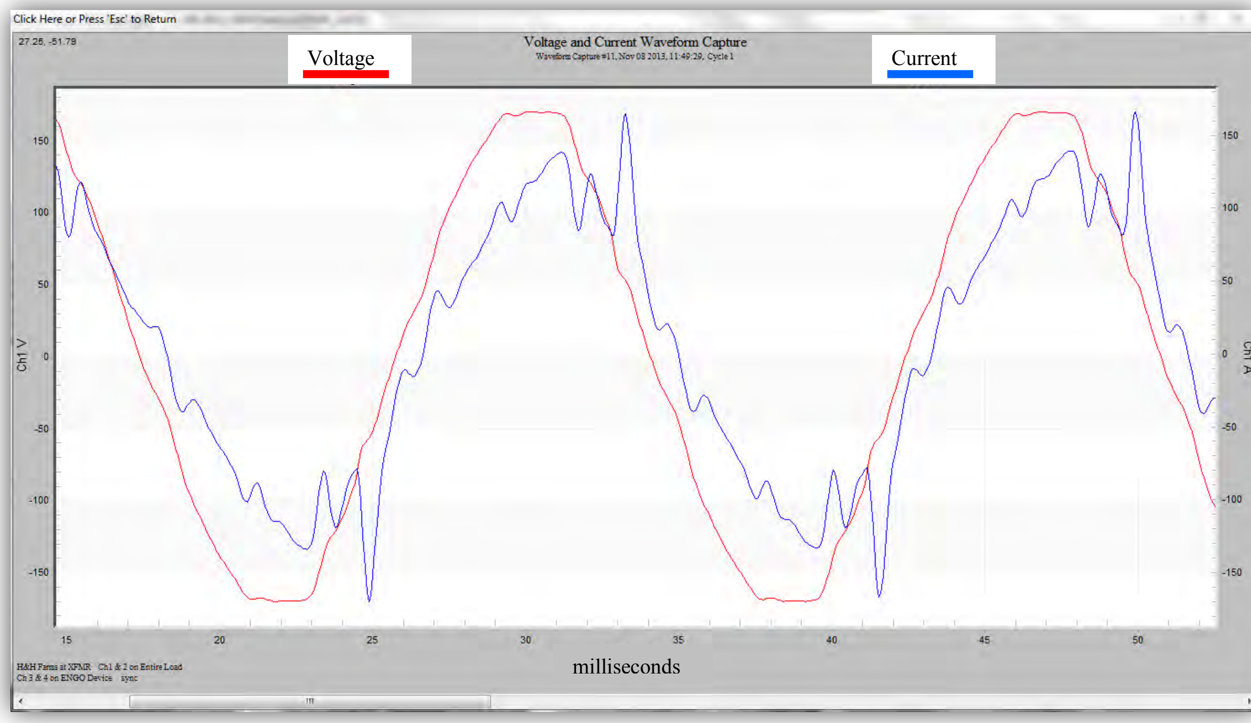


Figure 17. TWACS communication with ENGO unit installed. Measured at transformer.

In addition to the power quality monitor at the ENGO site, communications to and from the meter was monitored by the Metering Operations Department via the TWACS system itself. This monitoring indicated no interference with the AMI signal.

AMI signal affecting ENGO unit operation – There was some initial concern that the signal injected onto the power line could cause the ENGO unit to turn on or off. Because the ENGO unit can react so fast to voltage changes, it was thought that the voltage notch imposed on the 60 Hz signal by the TWACS might cause the ENGO unit to cycle off or at least decrease the VArs injected for the period of time the signal was present. Testing showed this to not be the case. Correspondence with Varentec indicates that the ENGO unit takes 32 samples per cycle to come up with an RMS voltage value. The ENGO unit continuously samples the voltage which gives it a rolling Vrms value to which the ENGO unit responds. TWACS doesn't tend to change the RMS voltage significantly so the ENGO units won't respond to the TWACS signal.

Observations

As a research project, noting observations is important. The following are notable observations from the project.

- The ENGO-V10 units have a green communications indicator LED attached externally to the bottom. These lights are bright enough that Idaho Power received a complaint from one customer who had a unit mounted to a pole near their bedroom. These lights could also provide an attractive target should someone wish to do some nighttime target shooting. Varentec should consider removing these LED lights. Note, as of 2016, Varentec has provided the capability to turn this light off remotely using cellular communications.

- Varentec is good to work with and have been very responsive to questions and device support.
- Cell carrier can be a problem. The ENGO-V10 units communicate via cell using Sprint as the carrier. Shortly after installation, Sprint experienced a system-wide problem that caused all the units to cease communicating. Nine of the units recovered quickly with no data loss but one unit has never recovered and needs to be replaced. Varentec has provided a replacement unit.Note, unit stopped communicating on June 24th, 9:00 am.
- It would be nice if the ENGO Manager software had two modes of operation. The first mode would be password protected so only a limited number of persons could operate the unit. The second mode would allow ENGO data to be seen but would not allow control of the unit.
- The ENGO Manager software allows only one day of information to be seen graphically. It would be nice to see more than one day at once. Note, as of 2016, ENGO Manager software (now referred to as Grid Edge Management System or GEMS) has the capability of viewing more than one day's worth of data at once.
- The Set Points screen always defaults to 240 V. Should default to the device's present setting.

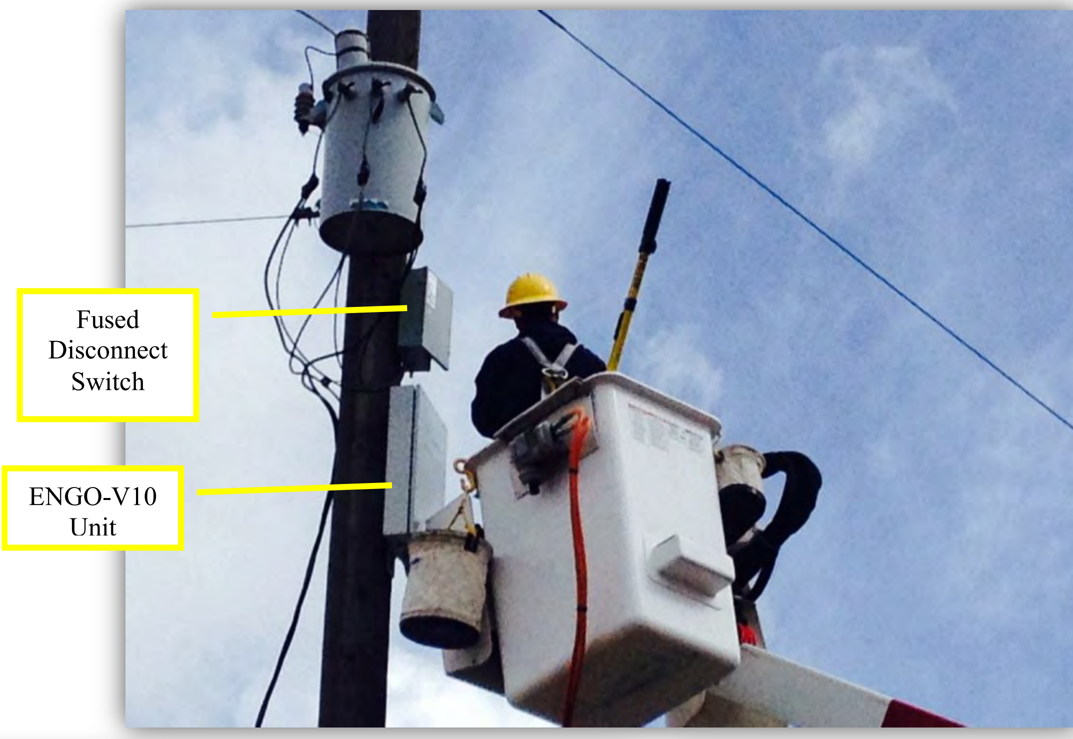
Conclusion/Recommendations

While the ENGO units failed to mitigate for voltage flicker problems, they did perform as designed.

- The units are able to increase the voltage supplied from the secondary of a service transformer by as much as 3 Volts, depending on transformer loading.
- The units do not inject significant harmonics into the circuit.
- The units are compatible with Idaho Power's TWACS based AMI and actually improve the communications signal if they are located near to the meter (not a long service drop).
- The metering within the units is able to capture events on the distribution system such as significant voltage sags.
- The units are reliable with the only significant failures occurring because of cellular communications loss. Even when communications are lost, the units retain the voltage data and will communicate the information upon return of communications. They also continue to regulate when communications are not present.

Even though the ENGO units did not mitigate for voltage flicker on PNUF-042, it is recommended that the units be left in-place on PNUF-042 until they are needed for use on other feeders where they can be used for their designed function which is to improve the voltage on the secondary side of service transformers.

Appendix A – ENGO Installation Photos




VERSALIFT

Appendix B – ENGO Device Location Descriptions

Transformer Giso #	Transformer KVA	Peak Demand KW	% Loading	Location	Device Serial #	Cell Reference	V Setpoint	On Day-Time
1348336	25	25	100	Just upstream from V Reg.	130826-58	10.192.128.145	245	6/25-0916
1359699	25	16	64	x	130826-60	10.192.49.146	245	6/25-0748
1360434	25	30	120	x	130911-60	10.192.129.79	245	6/30-
1360601	25	25	100	x	130705-55	10.192.49.130	245	7/9-1046
1360918	25	7	28	x	130826-25	10.192.72.97	245	7/9-1046
1362422	25	19	76	End of Line	130826-19	10.192.49.137	245	7/9-1047
1362424	25	2	8	End of Line	130911-04	10.192.128.149	245	7/9-1047
1474583	25	32	128	Near AT&T	130826-12	10.192.49.131	245	7/9-1046
4561314	25	11	44	Just upstream from V Reg.	130826-29	10.192.49.136		
5073871	50	9	18	x	130911-98	10.192.128.150	245	7/9-1047

Appendix C – ENGO Device Cycling Schedule

Daily																						
Transformer GISO #	*Thu, 07/10*	*Fri, 07/11*	*Sat, 07/12*	*Sun, 07/13*	*Mon, 07/14*	*Tue, 07/15*	*Wed, 07/16*	*Thu, 07/17*	*Fri, 07/18*	*Sat, 07/19*	*Sun, 07/20*	*Mon, 07/21*	*Tue, 07/22*	*Wed, 07/23*	*Thu, 07/24*	*Fri, 07/25*	*Sat, 07/26*	*Sun, 07/27*	*Mon, 07/28*	*Tue, 07/29*	*Wed, 07/30*	*Thu, 07/31*
1348336	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF
1359699	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF
1360434	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF
1360601	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF
1360918	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF
1362422	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF
1362424	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF
1474583	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF
4561314	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF
5073871	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF

Hourly	Wed 7/23									
Transformer GISO #	7:00 AM	8:00 AM	9:00 AM	10:00 AM	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM
1348336	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF
1359699	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF
1360434	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF
1360601	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF
1360918	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF
1362422	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF
1362424	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF
1474583	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF
4561314	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF
5073871	ON	OFF	ON	OFF	ON	OFF	ON	OFF	ON	OFF

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Appendix E.
A Method for Determining the Relationship Between Solar Irradiance and Distribution Feeder Peak Loading

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A Method for Determining the Relationship between Solar Irradiance and Distribution Feeder Peak Loading

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***Abstract*—A method for determining the relationship between solar irradiance and distribution feeder peak loading is presented. Two research questions were posed: (1) is there a statistical relationship between solar intensity and load and (2) what other relationships might there be between load and meteorological parameters. A distribution feeder was chosen where data from three equidistant solar irradiance weather stations (SIWSs) was collected between June 21, and September 21, 2013. The data was analyzed using a combination of cross-correlation and maximum cross-correlation / kernel density. The results of the study show that there seems to be a correlation between solar intensity and load, but that correlation is optimally significant when the variables are time-shifted.**

***Index Terms*—Autocorrelation, photovoltaic systems, power distribution, solar energy**

I. Introduction

As electrical power utility customers install their own roof-top photovoltaic (PV) systems, the question arises whether the utility itself could benefit from PV systems that it owns and operates. The effect of cloud cover on PV operability could be less than expected because cloud cover might also have an effect on distribution feeder loading; in other words, as the solar intensity decreases, so also might the loading on an accompanying distribution feeder decrease, or vice versa.

A benefit to a utility when its residential customers begin interconnecting PV systems onto its distribution system might be to balance increasing loads, thus allowing the utility to postpone future feeder upgrades necessitated by load growth. Because of that benefit, a research project designed to collect solar intensity and feeder loading data simultaneously during the summer of 2013 was initiated.

II. A Brief Overview of Existing Research

The existing research of PV system effects on the operations of their distribution feeders yielded three broad categories:

1. Research that addresses distribution feeder simulation that includes PV system interconnection.
2. Research that addresses PV system interconnection that mitigates on-going distribution feeder issues.
3. Research that determines how solar irradiance and cloud cover affects the operation of PV systems on distribution feeders.

Among the research that addresses distribution feeder simulation are Sandia National Laboratories [1] and EPRI [2] each of whom developed software for modeling distribution feeder operation with PV systems interconnected. Additional research in feeder modeling includes determining optimal PV locations and sizing [3]–[4] as well as researching the effects of high-penetration PV onto distribution feeders [5]–[6].

Among the research that addresses PV interconnection as mitigation to on-going feeder issues are using PV systems as non-traditional solutions to distribution feeder problems [7], using PV systems with energy storage for feeder load smoothing [8]–[9], and using PV systems with CVR to manage feeder voltages [10].

Among the research that determines how solar irradiance and cloud cover affects the operation of PV systems on feeders is research of a cloud shadow model to recreate the power generated by rooftop PV systems [11] as well as research of how PV system design can change the dispersion of PV energy across a feeder because of passing clouds [12].

Common to the referenced research is the focus on PV systems interconnected onto a distribution feeder. The research reported in this paper is different because it seeks to find the relationship between solar intensity / cloud cover and a distribution feeder's actual loading. In other words, this research is concerned with how sunshine or clouds may impact the amount of distribution feeder load created throughout the day.

III. Research Design

Two questions formed the basis of the research design:

1. Is there a statistical relationship between solar intensity and load?
2. What other relationships might there be between load and meteorological parameters?

In April 2013, a project was designed to answer the research questions. The scope of the project included the following tasks:

- Study a residential feeder to determine weather / solar monitoring locations.
- Install weather / solar stations and gather solar, weather, and load data.
- Analyze the data for possible correlations.

The research project included purchasing and installing solar intensity monitors, PV panels, and power metering and recording equipment. Studying the relationships between load and meteorological parameters other than solar intensity, wind speed, and ambient temperature were considered to be outside the scope of the project.

The research was limited to data obtained from a single residential feeder typical for the installation of roof-top PV systems; feeders that might host larger, utility-scale installations were considered to be outside the project's scope.

IV. SITE SELECTION CRITERIA

The study feeder is located in a city of approximately 215,000 population. The city's climate is semi-arid, with average monthly sunshine ranging from a peak of 400 hours in July to 105 hours in December [13]. The distribution feeder chosen to host the solar irradiance weather stations (SIWSs) and collect solar irradiance data met the following conditions:

- Covering a geographical distance greater than 3.2 kilometers in an east-to-west direction to be able to track the effects of cloud cover as the clouds move from one SIWS site to the next.
- Being comprised of mostly residential and light commercial customers.
- Being one where the installation of the SIWSs would be as accessible as possible, located near the operating office where the data would be analyzed.

The study feeder is summer-peaking rated 34.5kV and 20MVA. A 34.5kV feeder typically covers a greater geographical area than a 12.5kV feeder, thus being more likely to meet the condition set for geographical configuration. The feeder is configured such that the distance from its eastern-most location to its western-most location is approximately 5.6 kilometers.

Three SIWSs were installed on the feeder at locations that were (1) as geographically equidistant from one another as possible and (2) as free from impediments to irradiance data-gathering as possible.

Each station was initially designed to include global horizontal irradiance (GHI) monitoring, point-of-array (POA) monitoring in the westerly direction, wind speed monitoring, wind direction monitoring, ambient temperature monitoring, and GPS time synchronization. POA monitoring in the southerly direction and globally was added later. Westerly POA monitoring was chosen because of the sun's location at the time of the feeder's 2012 peak. Later, the southerly POA was added to emulate typical PV system installations.

V. DATA COLLECTION

Solar and weather data was captured onto an SD card — at a data capacity of 2G — located in the data logger. At a set time interval, the data was collected by removing the SD card from the data logger, copying the data from the SD card to a laptop's hard drive, deleting the data from the SD card, and replacing the SD card back into the data logger.

The following data was collected from each of the SIWS sites:

- UTC time
- Wind speed (the average over a ten-second interval) in meters / second (m/s)
- Wind gust (the peak over a ten-second interval) in m/s
- Wind direction in degrees (with 0^{o} being North)
- Local battery voltage (over a ten-second interval)
- Ambient temperature in ^{o}C
- Solar irradiance POA South in watts /meter^2 (watts/m^2)
- Solar irradiance POA West in watts/m^2
- Global Horizontal irradiance in watts/m^2

Initially, data was collected every two weeks because of the need to ensure that a minimum amount of data would be lost should an issue with the logger arise. Data was collected on May 24, June 4, July 1, July 15, August 1, August 8, September 12, and October 2. Load data for the feeder was also collected in ten-second intervals to match the times of the collected irradiance data.

VI. DATA ANALYSIS

A. Cross-correlation analysis

To find relationships between solar intensity and load / other meteorological parameters, the data was nominalized so that each variable ranged between 1 and 0. That allowed the two correlated time-series to be more easily relatable when graphed as well as to provide a common axis from which to compare results for different days. Figure 1 shows a typical nominalized load shape and irradiance shape for the westerly-configured sensor on SIWS01 on the system peak load day of July 1, 2013.

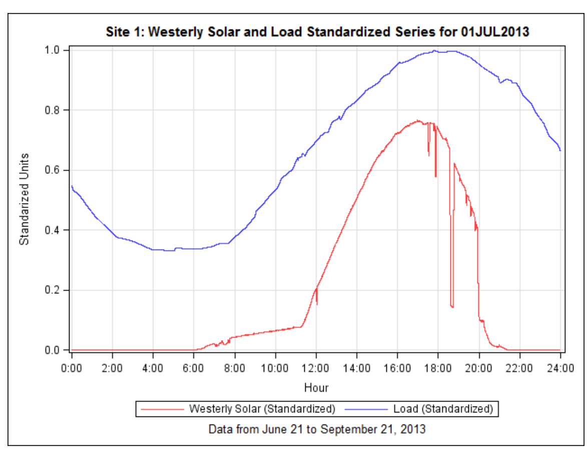

Figure 1. Southerly solar and load, 7-1-2013

Even though data was collected at 10 second intervals, cross-correlations were calculated at 5-minute intervals to allow for quicker computation. For each correlation, the load time-series was held constant while the other time-series — southerly, global, and westerly sensor configurations; temperature; and wind speed — were shifted across a ±12-hour range. Cross-correlations were graphed for each of the 93 days of the study at each of the three SIWSs. Fifteen cross-correlation computations were made for each day of the study at each of the three SIWSs, resulting in the production of 4915 cross-correlation graphs.

For the July 1, 2013, SIWS01, example Figures 2 through 4 show the graphs of the various cross-correlation calculations at ±12 hours:

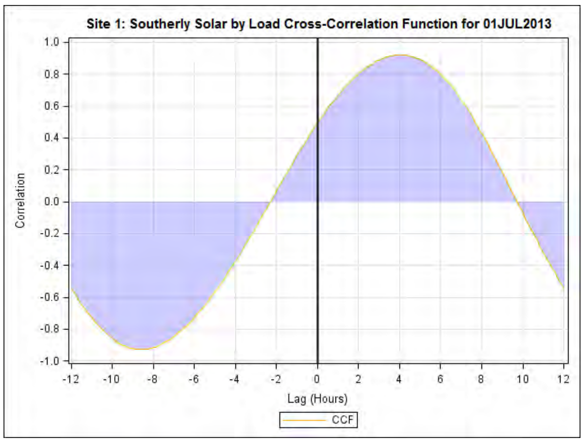

Figure 2. Cross-correlations for Southerly Solar and load at SIWS01 on 7-1-2013

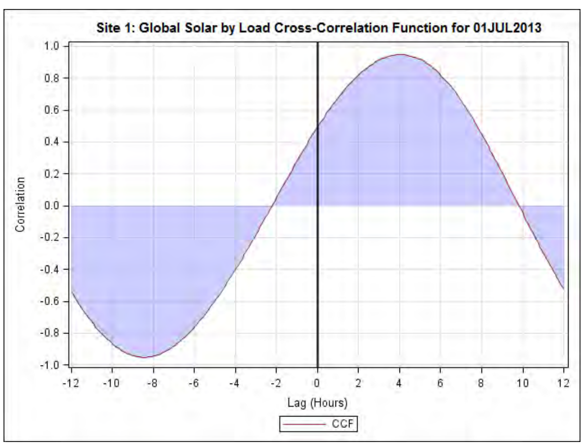

Figure 3. Cross-correlations for Global Solar and load at SIWS01 on 7-1-2013

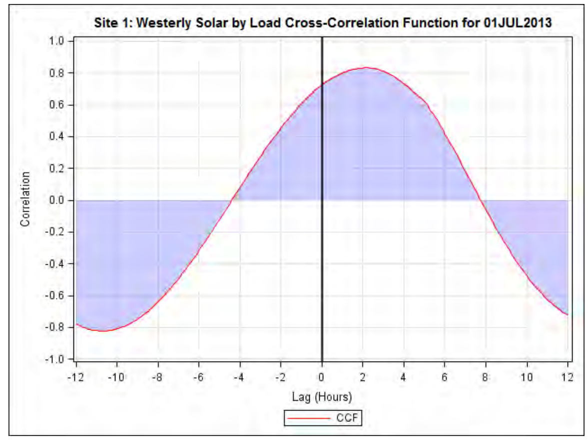

Figure 4. Cross-correlations for Westerly Solar and load at SIWS01 on 7-1-2013

For the clear and sunny July 1, 2013, the correlations between the sensor configuration's time series and the load's time series are fairly significant. For the worst case westerly configuration versus load, the maximum correlation of 0.81 occurred when the feeder's load data lagged the solar intensity data by two hours. On the same day and SIWS, the maximum correlation was 0.90 when the load data lagged the solar intensity data by four hours on the southerly-facing sensor, and the maximum correlation was 0.92 when the load data lagged the solar intensity data by four hours on the global sensor.

B. *Maximum cross-correlations / kernel densities*

While the cross-correlations provided information relating to the relationships between irradiances and loads for each of the individual days of the study period, the question remained regarding if any relationships over the entire 93-day study period could be identified. To answer that question, maximum cross-correlations were calculated to create kernel densities.

For each time series pair, the maximum cross-correlation and the time lag when the maximum cross-correlation occurred were identified for each day of the study period. Next, the results from each day were used to estimate a bivariate kernel density for each pair of time series. This bivariate density estimate yielded a point that represented the most common occurrence over the course of the study for the strength of the linear relationship and the amount of time the offset occurred. The ranges of both the linear relationship and the offset in time were also observed from the bivariate density estimates.

The density plots in Figure 5 show, for SIWS01, the estimates between the load and the southerly sensor configuration for solar intensity both 2-dimensionally and 3-dimensionally.

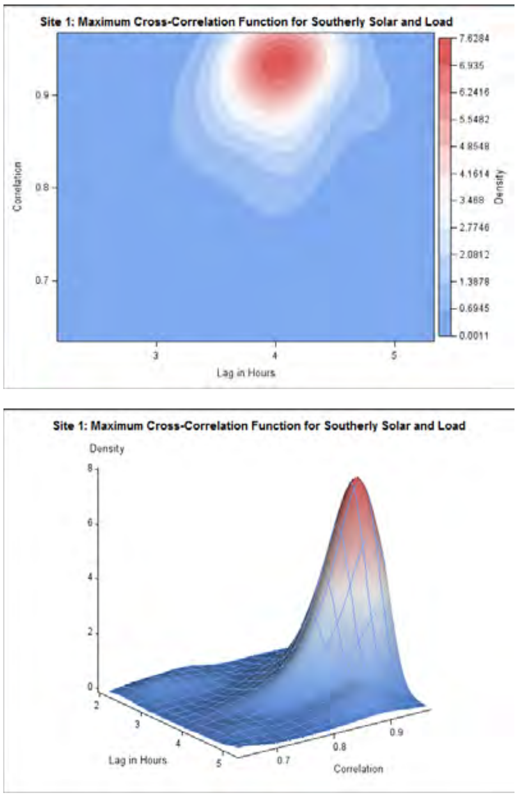

Figure 5. Example kernel density for SIWS01 southerly solar versus load over the study period

The most common daily occurrence was a strong linear relationship of 0.94 between the solar intensity and load lagged by approximately four hours. Over the course of the entire summer, the range of the strength of the relationship was generally greater than 0.80 with the lag generally between three and five hours.

For each of the three SIWSs, twelve kernel densities were calculated that showed irradiances versus load relationships, irradiances versus ambient temperature relationships, and irradiances versus wind speed relationships. It was from analyzing these thirty-six calculations that the results of the study, and answers to the research questions, were formed.

VII. Results

A. *Relationships to load*

First, there seems to be a statistical relationship between solar intensity and load, but with the understanding that correlation does not imply causation.

- Solar intensity analyzed at the southerly-configured sensors tends to lead load from 3.96 to 4.13 hours with a correlation of 0.94 across all three SIWS locations.
- Solar intensity analyzed at the global-configured sensors tends to lead load from 4.00 to 4.02 hours with a correlation ranging from 0.95 to 0.96.
- Solar intensity analyzed at the westerly-configured sensors tends to lead load from 1.76 to 1.94 hours with a correlation ranging from 0.88 to 0.91. The curves of the westerly-configured irradiances tend to peak closer to the time of feeder peak loads, but with lower certainty than the southerly- and global-configured irradiances.

Next, there seems to be a strong correlation between ambient temperature and load data, but a tepid correlation between wind speed and load data.

- Ambient temperature tends to lead load from 0.70 to 0.86 hours with a correlation ranging from 0.96 to 0.97 across all three SIWS locations. While not a surprising result, what was a little surprising was the range in lead time between the three SIWSs.
- Wind speed tends to lead load from 1.80 to 2.38 hours with a correlation ranging from 0.68 to 0.70 across all three locations. This tepid statistical relationship between wind speed and load also was not surprising considering the low auto-correlation of wind speeds.

B. *Disclaimers*

When drawing conclusions based upon the analysis of the data, a few disclaimers need to be considered.

- The conclusions are limited by the study time period. The conclusions would likely have been different if data had been analyzed for seasons other than summer.
- The conclusions are limited by the locations of the study's SIWSs. The conclusions would likely have been different if data had been collected (1) from a different type of feeder or (2) from a different geographical area.

These disclaimers, however, can also be considered opportunities to continue the research to test the statistical methods and analysis used in the study.

VIII. Discussion

A. *Lessons learned from the research design process*

As with most research, the most difficult part of the design was choosing and applying the most appropriate statistical tool. After the data was collected, an iterative process ensued, beginning with making a simple correlation between daily peak loads and daily peak irradiances, and realizing that using such a tool with two variables that were clearly unrelated yielded unsatisfactory results. Time-shifting the data, first though the auto-correlations and then cross-correlations, provided a means of accessing the daily relationships between the variables. Finally, applying maximum cross-correlations and plotting kernel densities allowed the statistical relationships — calculated over the entire 93-day study period — to emerge. Any similar research in the future will also need to implement a cross-correlational / maximum cross-correlational / kernel density approach to data analysis.

A couple decisions made early in the research design positively affected the ability to answer the research questions: the choice to collect the data from irradiance sensors rather than from solar panels, and the choice to add a southerlyexposed sensor to the global and westerly sensors at each of the three SIWSs. The decision to collect data from three somewhat equidistant locations along the feeder route, while not necessary for answering the research questions, did provide the opportunity to validate the data collected and will be a source of analysis of geographical relationships between the variables.

B. *Possible applications of the research results*

The analyzed data set has already been implemented. The data has been used with OpenDSS software to perform generation interconnection studies of utility-scale PV systems. Other applications of the data have been in assisting with resource planning as part of the utility's integrated resource plan and in collaboration with Sandia National Laboratories for their variability and GHI to POA conversion studies. Probably the most interesting possibilities for applying the research results would be for:

- Recommending preferred PV orientations to commercial customers for their rooftop applications that would best support reducing the effects of feeder summer peak loads.
- Designing a demonstration project of a PV system coupled with energy storage to extend peak load reduction at the end of a distribution feeder.

C. *Opportunities for further research*

Data continues to be collected from the three SIWSs beyond the initial study period, resulting in more than a year's worth of data having been collected. Opportunities have been identified regarding additional studies that could be made with the study data as well as with the additional data collected post-study.

1) *Using this research study's data.*

The SIWSs were geographically configured along the feeder route, spaced equidistant from one another. While that fact was not pertinent in answering the research questions, it could generate a follow-up research project to determine the geographical relationships between irradiance data collected from the three SIWS sites. The data collected could be also be used to calculate the solar energy density (Watt-hours/m^2) per time interval for each site at each solar intensity orientation. Another use of the research data could be to run irradiance statistics over a multiple-day time period to see if a relationship is evident as a predictor of the seasonal peak load.

Finally, the data could be used in combination to determine how PV installation for home- and business-owned systems could provide optimal benefit the utility.

2) *Branching out from this research study data.*

Other interesting areas for further research can be sorted according to (1) using the additional data that has been collected subsequent to the study period and (2) implementing additional types of research design protocols. Some ideas for using the additional data collected include:

- Analyzing data from other seasons of the year, such as the time of the feeder's winter peak load or the time of the feeder's minimum peak load.
- Analyzing cross-correlations of solar irradiance to wind to find any complimentary relationships.
- Analyzing data collected in summer 2014 compared to data collected in summer 2013.

Some ideas for implementing additional design protocols include:

- Determining what effects humidity might have on solar intensity and load.
- Including cross-correlations of the loads from adjacent feeders to follow the effects of cloud cover.
- Analyzing data from additional feeder types where solar might be of interest.
- Including volatility in irradiance statistical analyses.
- Correlating wind speed to solar volatility.
- Designing a study similar to this research design for a winter-peaking area.

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Appendix F.
Electric Vehicle Quick Facts Brochure

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Fluctuating gas prices, advancements in battery technology, environmental concerns and federal incentives have all led to an increased interest in electric vehicles (EVs). As your electricity provider, Idaho Power is preparing for accelerated consumer adoption of EVs and wants to help our customers better understand the technology.

What is an EV?

EVs run off an electric motor and a battery pack. They're powered entirely by electricity and have zero tailpipe emissions. Also referred to as Battery Electric Vehicles (BEVs) or Plug-in Electric Vehicles (PEVs), EVs are charged by plugging into a charging station. **Example: Nissan Leaf.**

Plug-In Hybrid Electric Vehicles (PHEVs) are hybrids with larger battery packs and an Internal Combustion Engine. PHEVs can be plugged into a charging station to recharge their battery pack(s) or run off gasoline. **Example: Chevy Volt.**

Nissan Leaf

Chevy Volt

IDAHO POWERED™

Idaho Power's leading the way:

To get familiar with the technology, Idaho Power has added several passenger EVs to our fleet, as well as hybrid-electric bucket trucks, electric utility vehicles and battery-assisted trucks. We also installed five charging stations of varying make and model at our Downtown Boise office, specifically for employee workplace charging. We will continue to monitor advancements in EV and charging station technology to make sure our customers have the information they need.

Email **ev@idahopower.com** for information.

Thinking about adding an
EV TO YOUR FLEET?
Come see ours in **ACTION!**

Learn more at
idahopower.com/ev

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IDAHO POWER
An IDACORP Company

Electric Vehicles 101

IDAHO POWERED™

What are the benefits of owning an EV?

Fuel savings: Electricity as a fuel is significantly cheaper than gasoline or diesel.

Better air quality: EVs are zero-emissions vehicles, which improves air quality.

Local fuel: More than half of Idaho Power's energy is generated in our service area, meaning your fuel dollars stay at home.

Less maintenance: EVs have far fewer moving parts to be maintained than traditional vehicles.

Performance: Unlike traditional engines, EVs are always "on," meaning instant acceleration.

What about Idaho Power's Time of Day plan?

We're encouraging EV owners to consider our Time of Day pricing plan instead of the Standard plan. The Time of Day plan has lower prices weekdays after 9 pm and all day on weekends and holidays. This option could save you money and, by charging during off hours, you'll help even out demand on the power grid. For more information, visit **idahopower.com/TOD**.

The first step to determining which plan is right for you is to register to use myAccount. Signing up is easy and you'll get access to detailed information about your account and energy use. To enroll, go to **idahopower.com/register**.

TAX CREDIT

The Alternative Fuel Infrastructure Tax Credit has been extended through 2016. For details visit **www.afdc.energy.gov/laws/10513**

I'm interested – how do I charge it?

EVs are powered all or in part by electricity. The time it takes for a full charge depends on the type of vehicle, temperature, driving habits and the type of charging station, among other factors.

There are three options for charging:

Level 1 – 120V, dedicated 15-20A circuit. Used both at home and work, Level 1 charging draws a lower electrical demand but takes longer to charge a car than the other options.

Level 2 – 240V, dedicated 30-40A circuit. Typically found at businesses and public sites, these units are also available for home use. This type of unit will recharge an EV much faster than Level 1, allowing multiple users throughout the day.

DC Fast Charging – 480V. These units are typically found at public facilities. Note that not all EVs are equipped for fast charging.

Visit **www.PlugShare.com** to find public charging locations in your area.

How much energy does it take to charge an EV?

It takes about 0.3 kilowatt hours (kWh) to go one mile in an EV. So for example, a 10-mile commute to work would require 3 kWh of electricity.

DOE's eGallon calculator provides up-to-date gasoline vs. electricity prices at: **www.energy.gov/maps/egallon**.

I'm Ready to Buy – What's Next?

1. Choose the vehicle that best suits your driving needs.
2. Decide which charging method is right for you.
3. Have a licensed electrician inspect your service panel to ensure your home is ready for EV charging.
4. Examine your energy use and how charging will affect it, and choose which pricing plan is right for you.

Idaho Power recommends using a licensed electrician for any home or workplace electrical work.

Appendix G.
Electric Vehicle Charging Impacts Study

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CUSTOMER OPERATIONS PLANNING
T&D STRATEGIES

ELECTRIC VEHICLE CHARGING IMPACTS PROJECT

Final Report

BUDGET ID # RDND110101
WO #27364609

August 2016

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Executive Summary

The Electric Vehicle Charging Impacts Project (CHIP) was an optional customer program intended to evaluate the impact of residential EV charging on Idaho Power's distribution system. An AMI meter in the customer's garage-based charging station circuit allowed Idaho Power to analyze how these customers charged their cars. These meters were not used for billing purposes but only for remote monitoring of charging patterns. Additionally, AMI meters were installed at the Boise Operations Center (BOC) to track energy usage of Idaho Power's fleet EVs based at the BOC.

Over a 3-1/2 year period, 17 EV charging stations were tracked and the data analyzed. Some observations from the study are:

- A well designed, data gathering research project requires enough participants that a statically significant sample can be obtained. Because of the slow uptake of EV ownership in Idaho, very few participants could be found thus this study does not provide defendable, data-backed conclusions. Originally the project planned to install metering in up to 60 participant's homes but in the end, only 14 customers were found to participate and two of those were Idaho Power employees who drove fleet vehicles. However, some trends are fairly obvious and others can be intuitively inferred.
- Participants who purposely shifted their charging to off-peak periods significantly reduced their impact on the distribution system. Conversely, participants who plugged their cars in upon coming home from work had a fairly significant impact on peak loading.
- Participants increased their home energy use by between 19% and 21%, a significant increase.
- EV charging appears to be a fairly diversified load that won't likely impact the distribution system as significantly as one might think. Users don't tend to charge all at the same time and the load should be easily shifted to off-peak if appropriate incentives are offered.

Introduction

Electric Vehicles, both battery electric (BEV) and plug-in hybrid (PHEV) are beginning to be purchased by Idaho Power customers and by Idaho Power to integrated into its fleet. The additional load these vehicles will present to the Idaho Power distribution system is not well understood and will be influenced by how the electric vehicles are used and charged.

Idaho Power's EV Charging Impacts Project (CHIP) was an optional customer program intended to evaluate the impact of residential EV charging on Idaho Power's distribution system. An AMI meter in the customer's garage-based charging station circuit allowed Idaho Power to analyze how these customers charged their cars. These meters were not used for billing purposes but only for remote monitoring of charging patterns. Additionally, AMI meters were installed at the Boise Operations Center (BOC) to track energy usage of Idaho Power's fleet EVs based at the BOC.

Over a 3-1/2 year period, 17 EV charging stations were tracked and the data analyzed.

Design and Installation

The project installed standard Idaho Power AMI meters in participants' EV charging station circuits, collected the data via TWACS, and then analyzed the data received to estimate the effect EVs have on Idaho Power's distribution system. Customers volunteered to participate for two years from the date the AMI meter began to record data (see Appendix A for Customer Agreement). In the beginning of the project, it was difficult to find participants because of the slow adoption of EVs in Idaho; therefore, the beginning date for each customer was different. The first recorded energy at the BOC was May 25, 2012 and at a customer site August 1, 2012 with data collection continuing through the end of December, 2015. At the end of the contract term for the early participants, they were asked if they were willing to keep the AMI meters installed until the end of 2015; all but one agreed though some dropped out due to other circumstances such as an inoperable charging station or because they sold their EV.

Idaho Power contracted with Total Electric to install the AMI meters in existing EV charging station circuits at no cost to the project participant. If the participant installed the AMI meter at the same time the EV charging station was installed and used the same contractor for both, Idaho Power provided a $100 incentive (see Appendix B for Customer Application for Payment) to offset the costs of installing the meter since in this case, the participant would likely not be using Total Electric for the installation. Participants were required to live in an owner-occupied dwelling unit and hardwire the EV charging station (as opposed to plug-connected). Further, the charging station had to be Level 2 (208/240 V).

At its peak, the project was monitoring 17 charging stations:

- 12 in customer homes
- 3 at the Boise Operations Center
- 2 in employee homes

Charging from these stations were 10 Chevrolet Volts and 5 Nissan Leafs. One of the Nissan Leaf owners traded his car for a Tesla Model S near the end of the project. Two of the customers were net-metered solar owners and one was on Idaho Power's Time Of Day rate plan. 16 of the charging stations were located in the Boise metropolitan area while one was located in Hailey. Even though the Oregon portion of Idaho Power's service area was included in the project, no participants joined in Oregon. Table 1 shows participants in the study by initial.

Table 1. CHIP Participants

Participant	City	Car	IPC Fleet?	Dates Active	Notes
BW1	Boise 83706	Volt	Yes	July 2012 - May 2015	Moved into new house May 2015. Did not install new meter.
JO1	Emmett 83617	Leaf	Yes	July 2012 - Dec 2014	Charging station stopped working Dec 2014. Not replaced.
ZR1	Nampa 83687	Volt	No	Aug 2012 - Dec 2015	
PM1	Hailey 83333	Volt	No	Nov 2012 - Dec 2015	
MD1	Boise 83712	Volt	No	Aug 2012 - Dec 2015	
EM1	Boise 83709	Volt	No	Nov 2012 - Dec 2015	
JL1	Meridian 83646	Leaf	No	Jan 2013 - Dec 2015	
LA1	Boise 83702	Volt	No	Feb 2013 - Mar 2015	Did not extend past 2 years project term.
MV1	Meridian 83646	Volt	No	Jun 2013 - Dec 2015	
SJ1	Boise	Leaf	No	Jul 2013 - Feb 2015	Sold vehicle, disconnected chargng station Feb 2015.
DB1	Boise 83716	Volt	No	Aug 2013 - Dec 2015	
MS1	Boise	Leaf/Tesla	No	Nov 2013 - Dec 2015	Participant replaced Leaf with Tesla Model S in October 2015.
KM1	Meridian 83642	Volt	No	Dec 2013 - Jul 2015	Charging station stopped working Jul 2015. Not replaced.
TM1	Boise, 83712	Volt	No	Dec 2013 - Dec 2015	

Data collection was smooth with little lost data. The exception was data collected at the BOC. For the project, it was important that each of the three charging stations at the BOC be assigned to and used by only one Idaho Power fleet EV. Originally, the BOC charging stations were Blink brand but these units failed numerous times, causing the fleet EV drivers to share whichever charging stations were operational. While the AMI meters accurately collected data, the charging stations themselves were so unreliable that data analysis was paused until the units could be replaced. By the time the units were replaced, it made little sense to continue collecting data for the project. Because of this, very little data from the BOC was available for analysis in this report.

The project team consisted of:

Kent McCarthy – Project Leader, Technical Lead
Joel Clark – Load Forecasting and Research

Data Analysis

Data from the AMI meters was gathered to determine,

1. Demand placed on distribution system
2. Energy used for charging car batteries

Data Limitations

There are some limitations identified in this project concerning the data and participants.

- Because of the slow EV adoption rate in Idaho, the project had very few participants. Originally the project planned to install metering in up to 60 participant's homes and in the end, only 14 customers were found to participate and two of those were Idaho Power employees who drove fleet vehicles.
- One of the vehicles in the study was driven very little so energy use for charging it was quite small.
- One of the participants in the project used a comparatively large amount of energy in the winter to heat their home. Because there were so few participants, this tended to skew the combined usage data during winter months. However, this participant didn't use significantly more energy to charge their EV.
- There were many periods where individual participants didn't charge their car:
    - Charging station inoperable
    - Vacation
    - Drove a different car for a while such as a company provided vehicle

Peak Day Demand

The AMI meters used in this study don't directly report hourly demand. Instead, they report hourly energy use. During a given hour, an EV may or may not draw a consistent amount of power (demand) over the entire hour. While the precise demand is not calculated, it is probably more important to determine energy use increase during peak hours to determine effects on distribution system equipment. For this reason, hourly energy use will be used as a surrogate for demand in the following discussion.

Looking at data for the system peak days in 2013, 2014 and 2015, the following graphs depict the demand increase due to EV charging. For simplicity, the system peak day for each year was chosen as opposed to using the individual feeder peak days.

Looking at Figure 1 it can be seen that EV charging had a significant peak which coincided with the household energy use on the 2013 system peak day. Were this to occur across a given feeder, the effects could be detrimental to the distribution system. However, not all participants were even charging at this time. There was significant diversity occurring during this peak period so the effects would not likely be so detrimental.

Figure 2 which shows the peak day for 2014 is interesting in that the average participant's household peak occurred very late in the day (11:00 pm) while the EV charging peak occurred at 6:00 pm. It is noted however, there was EV charging during the entire peak period from 4:00 pm to 9:00 pm.

Looking at Figure 3 which shows the 2015 peak day, EV charging appears to have occurred later in the evening than earlier years. Not much can be concluded from this because the small sample size makes individual actions influence the entire data set. If only a couple participants were on vacation this day or had changed their driving habits, it would skew the data. Once again though, the trend is for charging to occur during near peak periods.

Figures 4 through 17 show the individual participant energy use for peak day 2014. While these graphs might not show group trends, they are illustrative of charging patterns. As expected, most EV owners plug their vehicles in upon coming home from work and immediately begin charging. The exceptions are mainly those who purposely shift their charging to off-peak hours. Figure 16 shows the charging pattern for MV1 who, while not a TOD participant, purposely set the automated charging feature in her Volt to begin charging at 10:00 pm even though she would typically connect the vehicle to its charging station late in the afternoon. Note the red line in each graph shows the average household energy use for the group as a whole for each hour of the day.

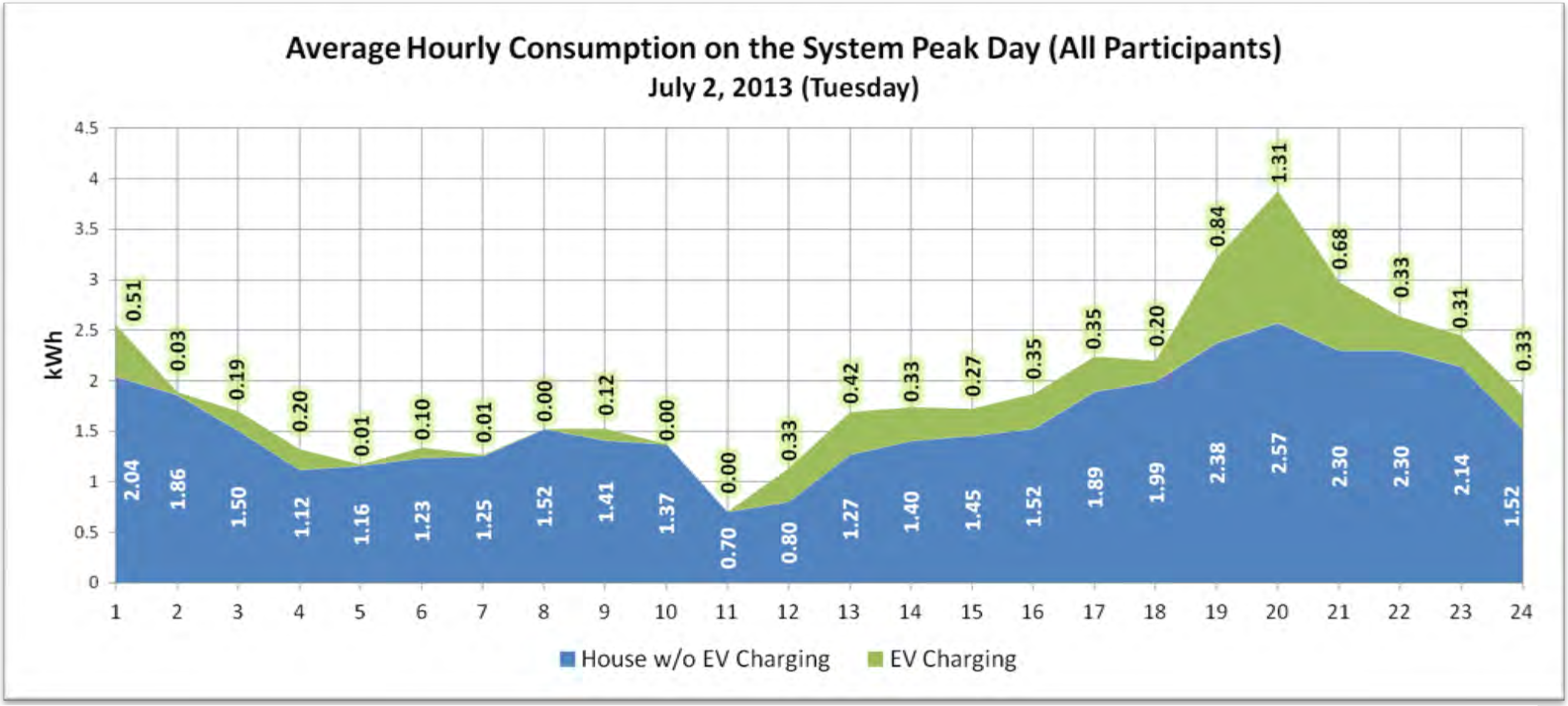


Figure 1. Average Hourly Consumption on the System Peak Day 2013

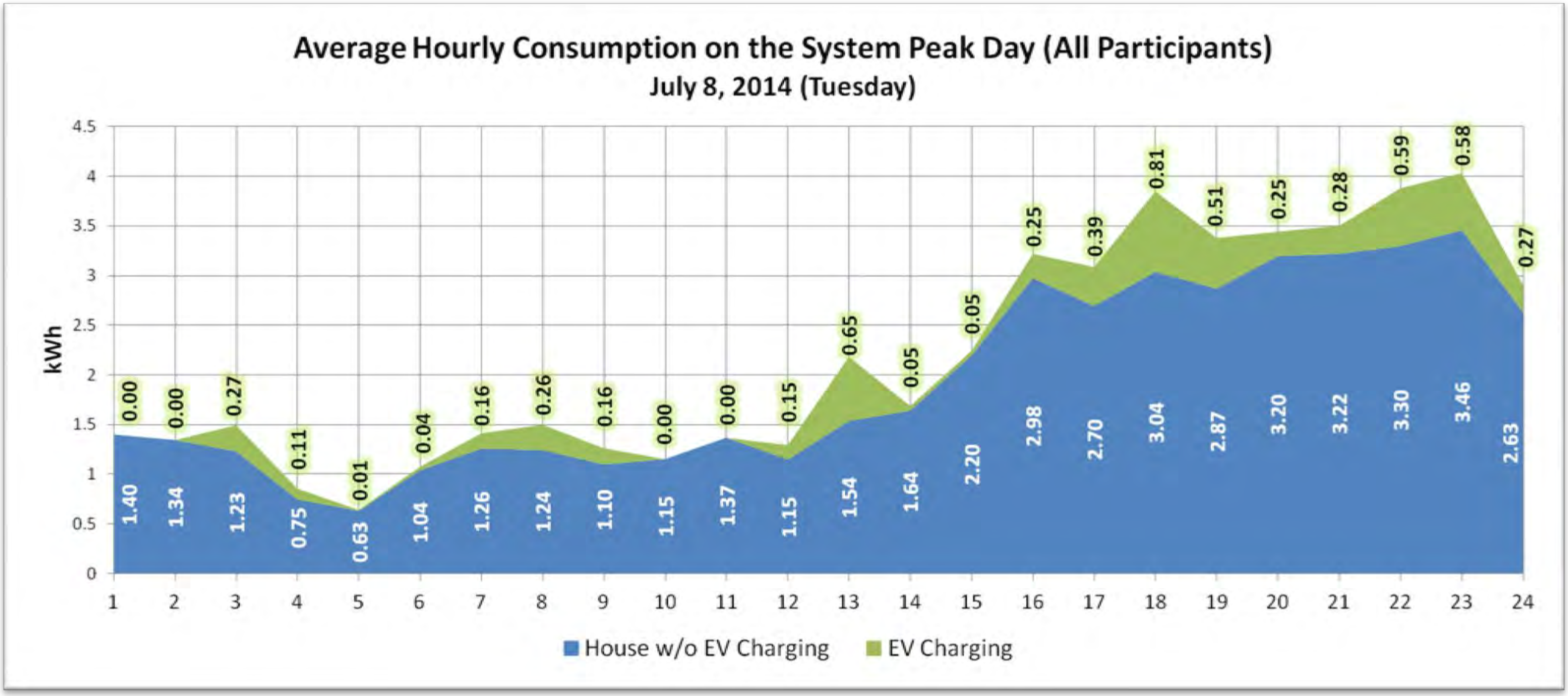


Figure 2. Average Hourly Consumption on the System Peak Day 2014

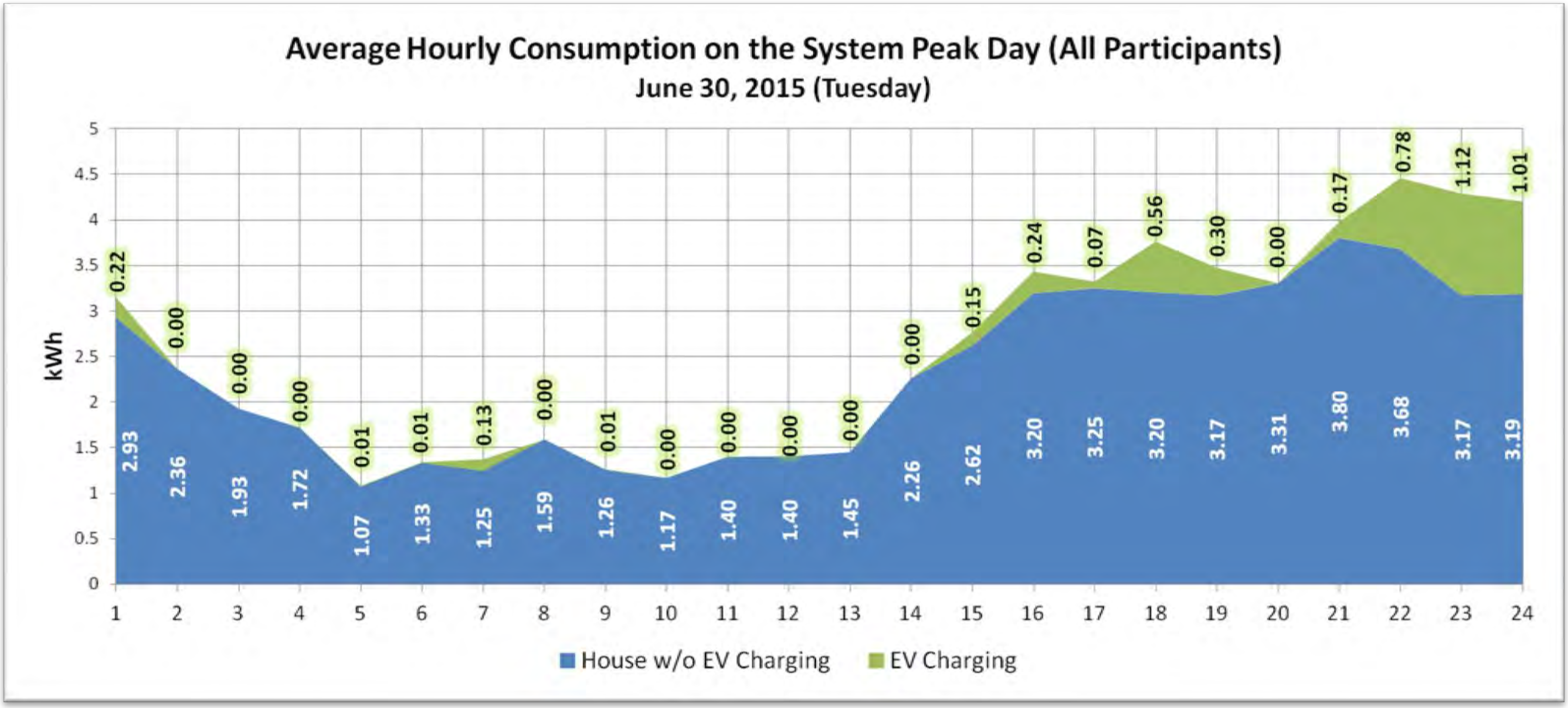


Figure 3. Average Hourly Consumption on the System Peak Day 2015

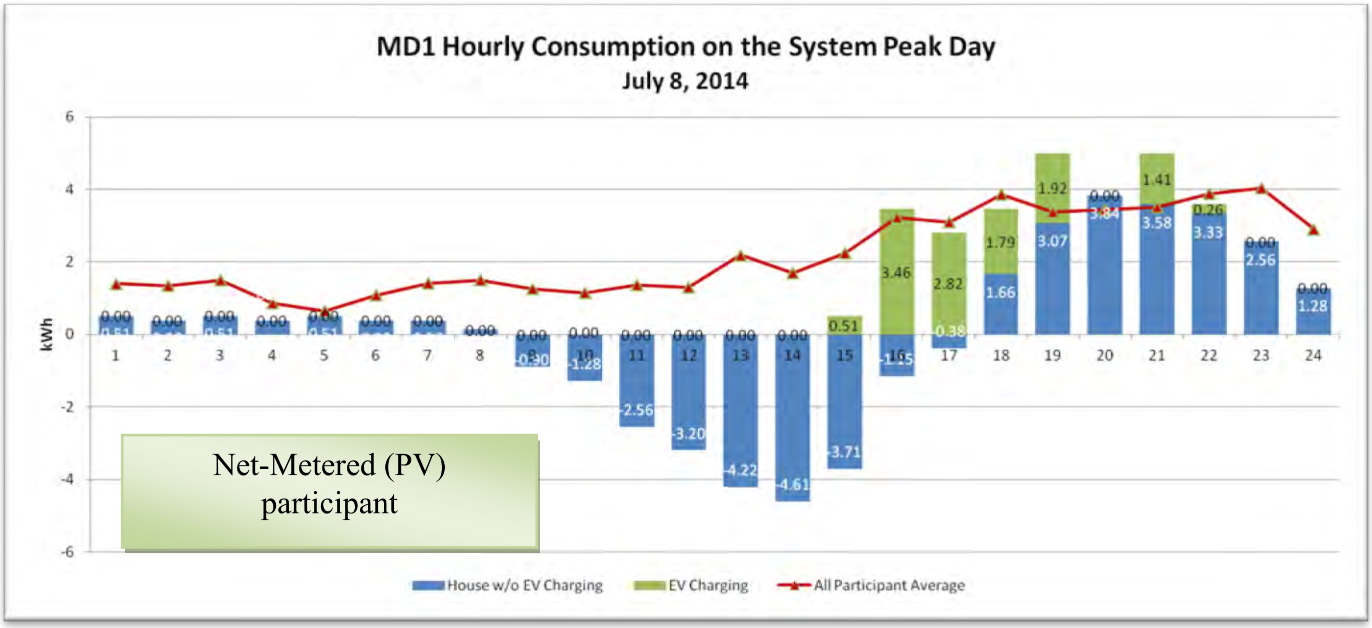


Figure 4. Participant MD1 Hourly Consumption on the System Peak Day 2014

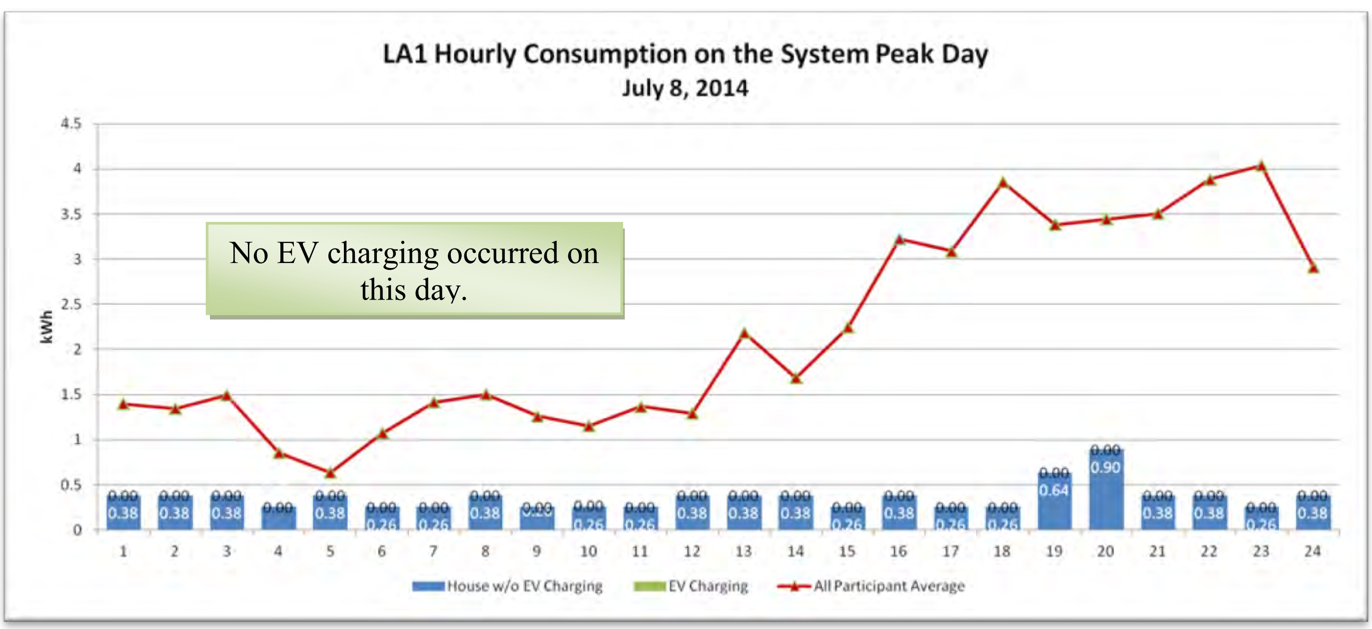


Figure 5. Participant LA1 Hourly Consumption on the System Peak Day 2014

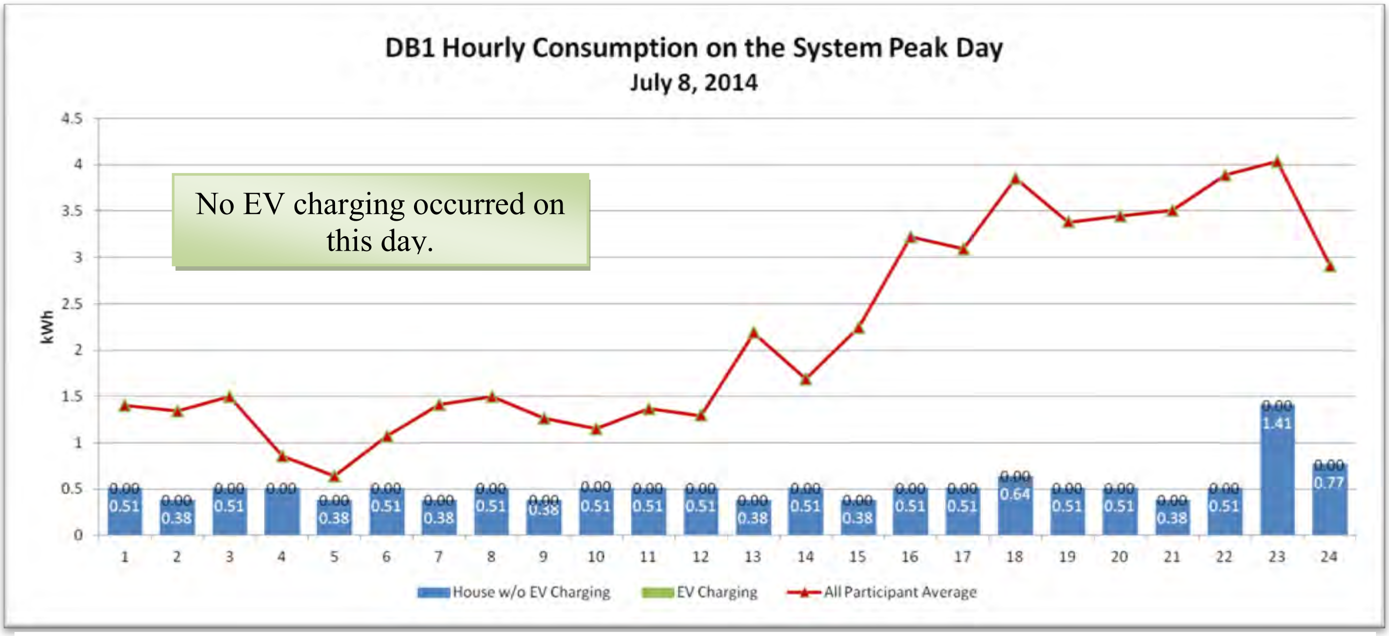


Figure 6. Participant DB1 Hourly Consumption on the System Peak Day 2014

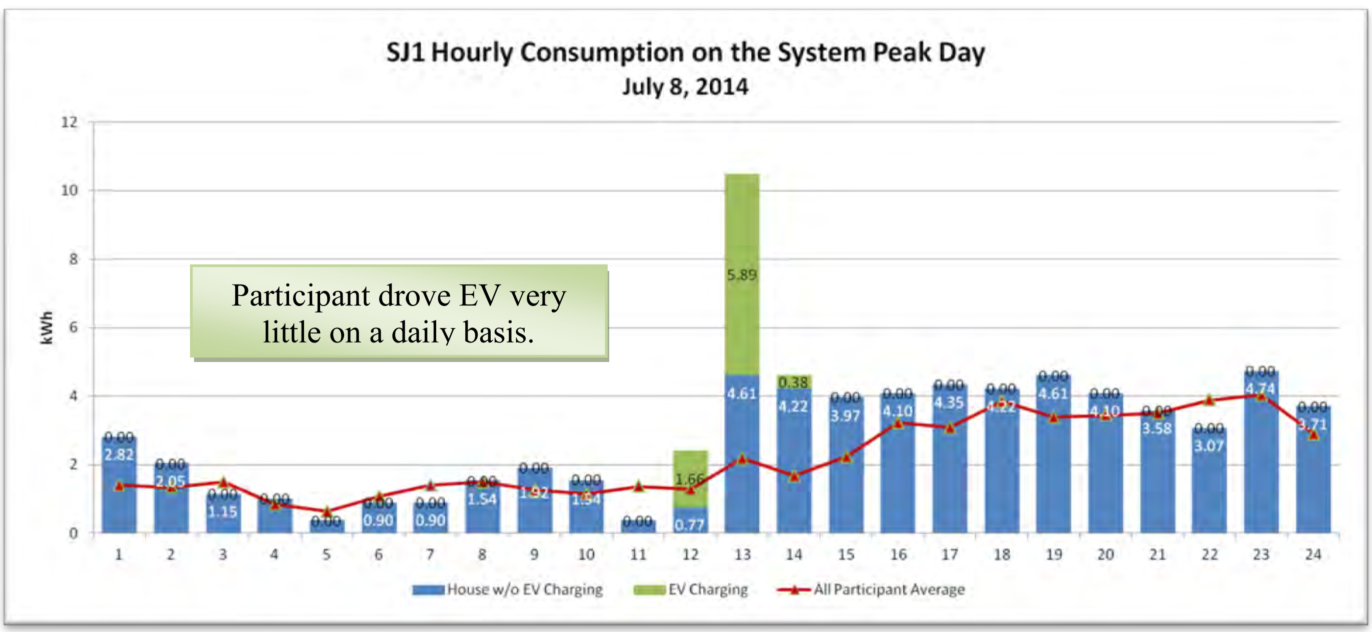


Figure 7. Participant SJ1 Hourly Consumption on the System Peak Day 2014

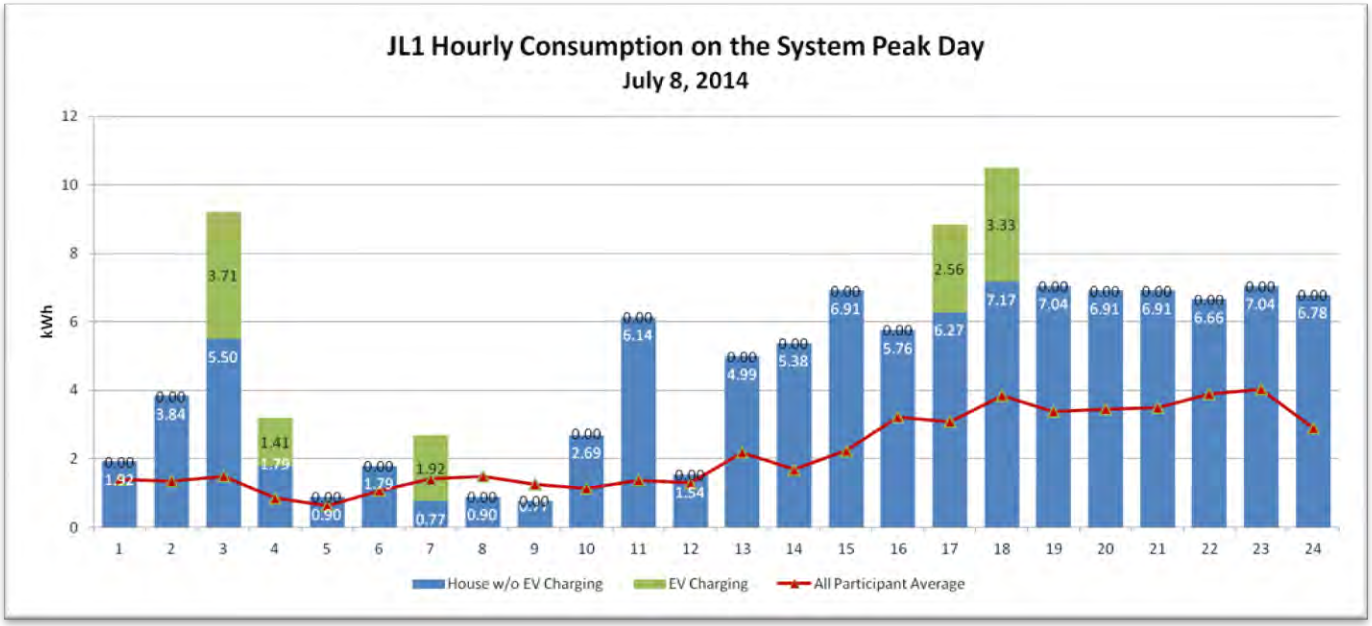


Figure 8. Participant JL1 Hourly Consumption on the System Peak Day 2014

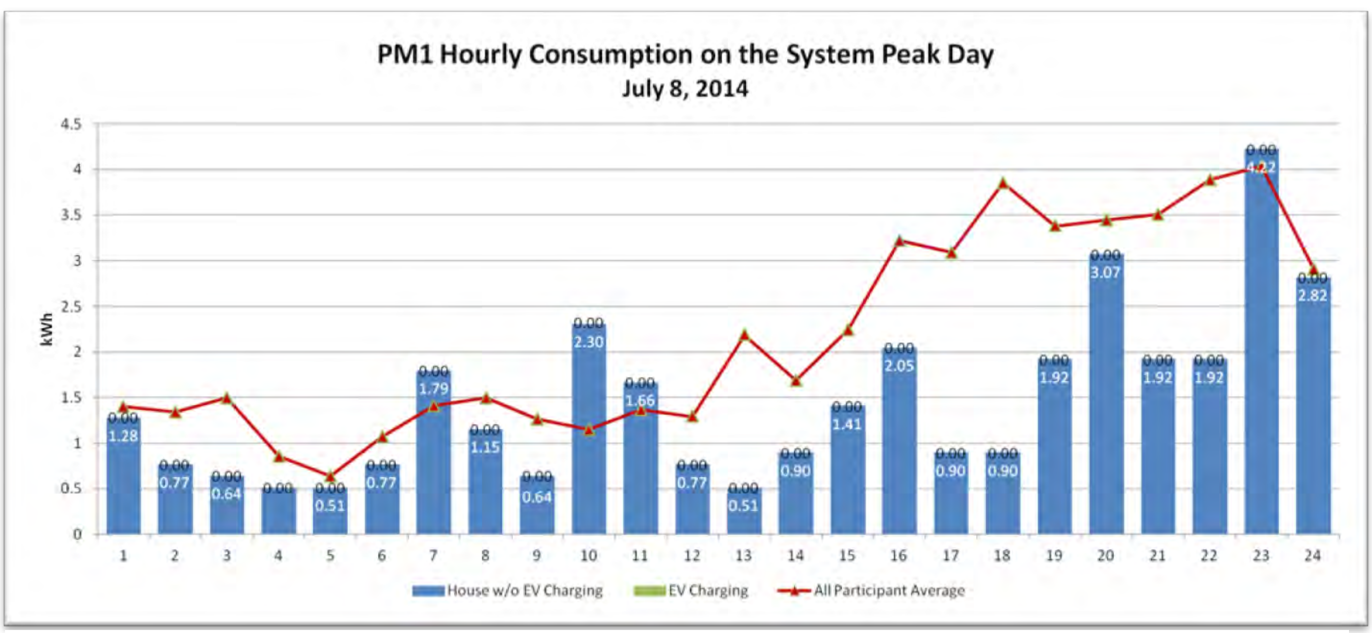


Figure 9. Participant PM1 Hourly Consumption on the System Peak Day 2014

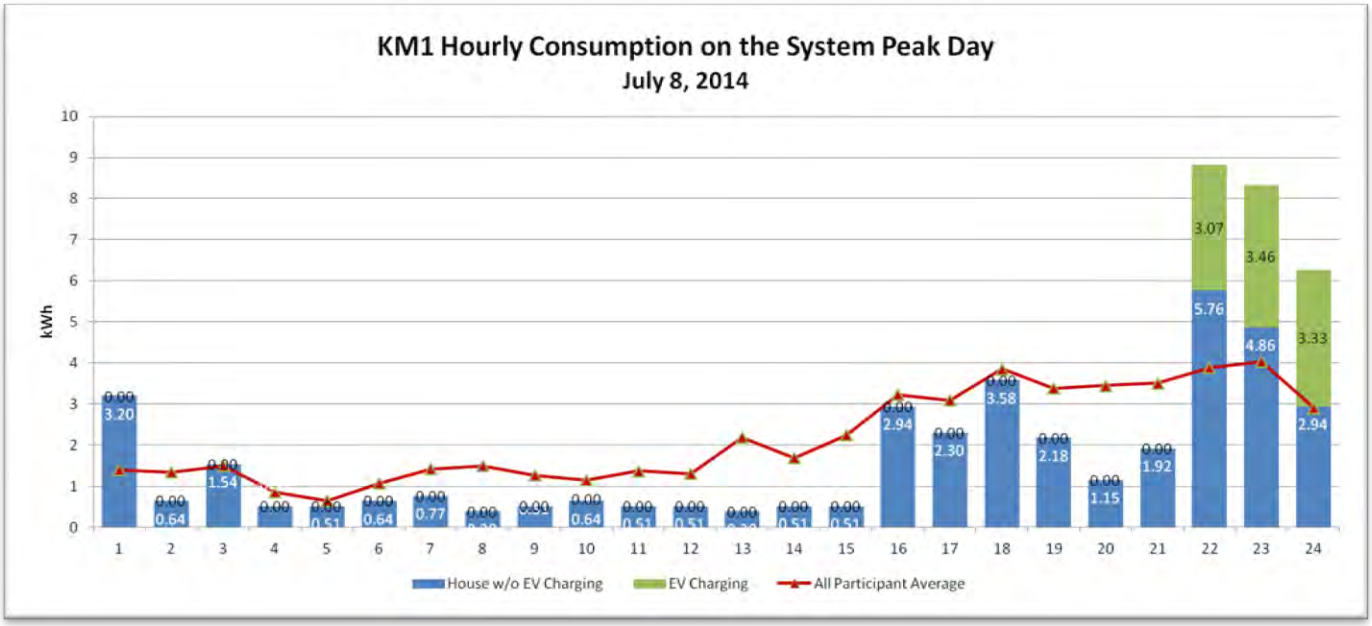


Figure 10. Participant KM1 Hourly Consumption on the System Peak Day 2014

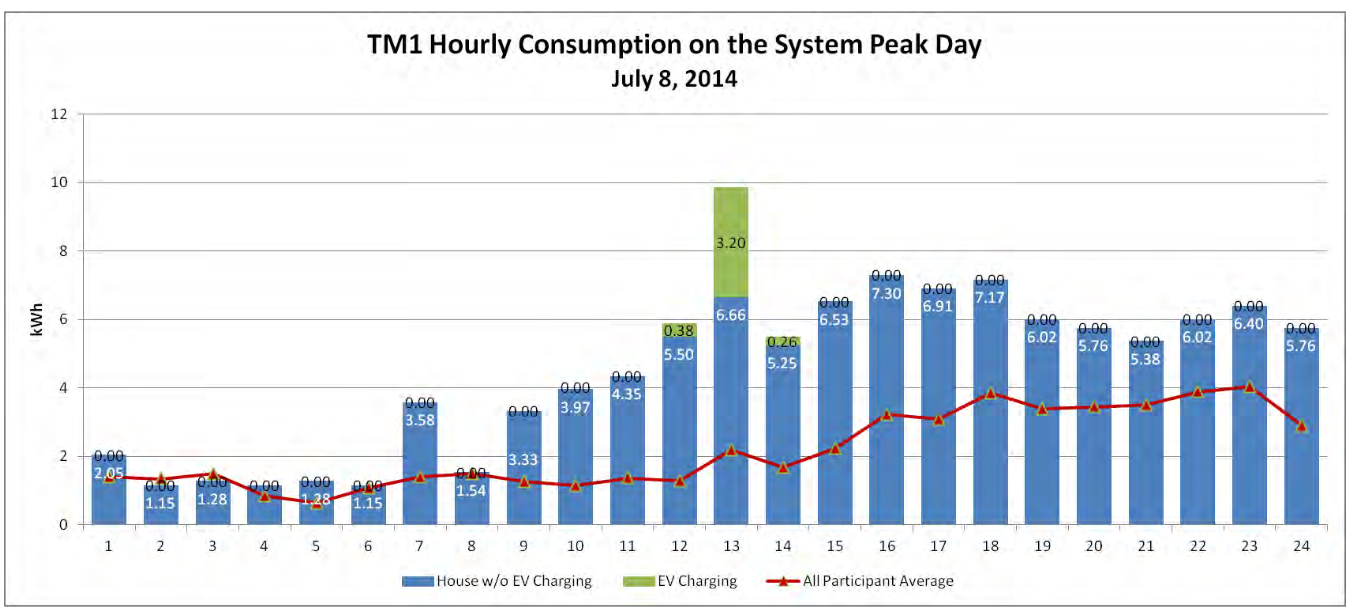


Figure 11. Participant TM1 Hourly Consumption on the System Peak Day 2014

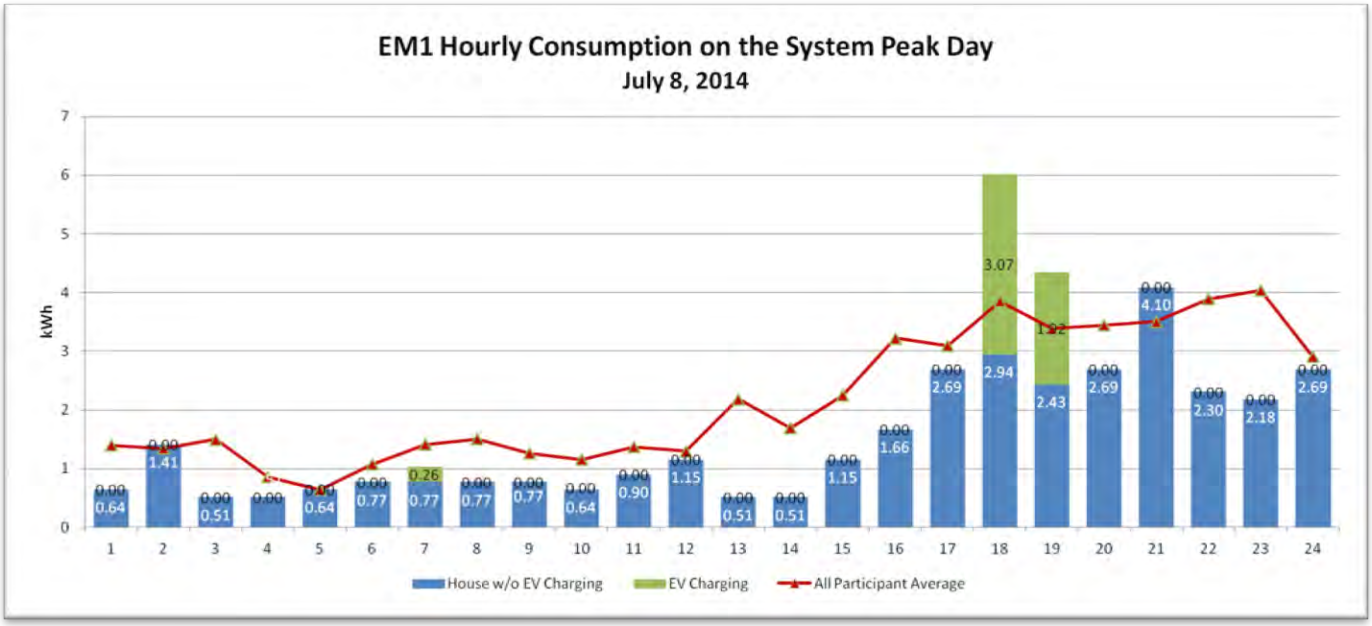


Figure 12. Participant EM1 Hourly Consumption on the System Peak Day 2014

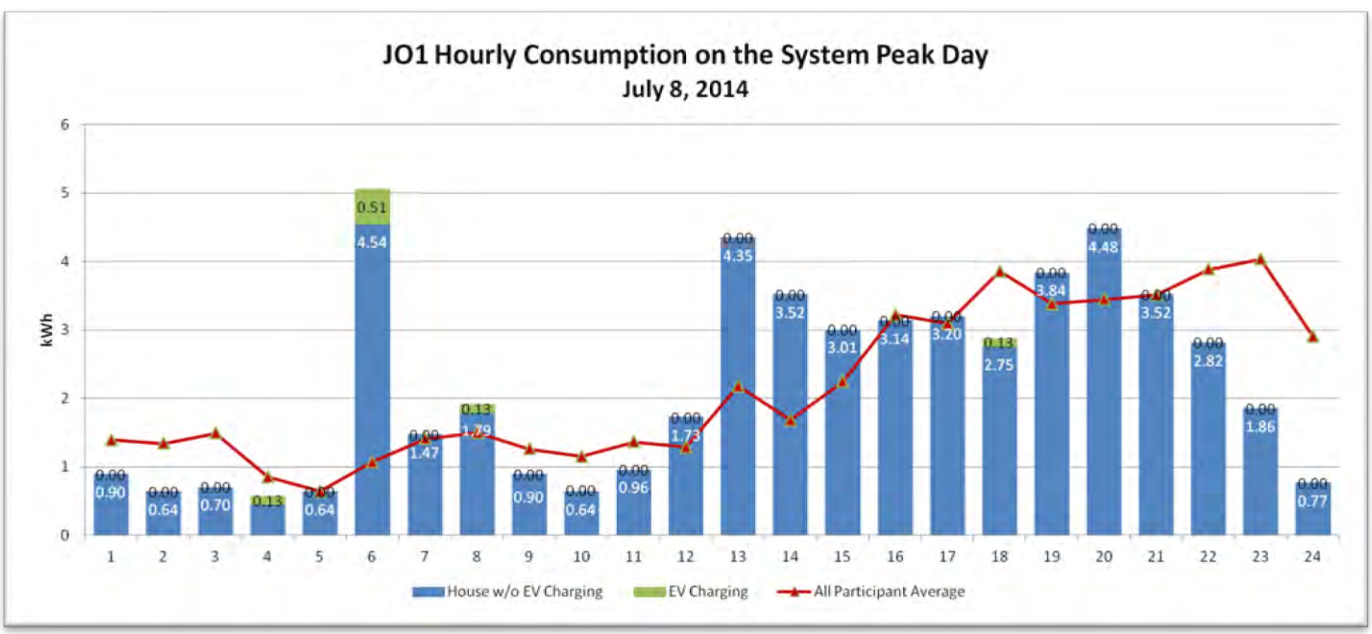


Figure 13. Participant JO1 Hourly Consumption on the System Peak Day 2014

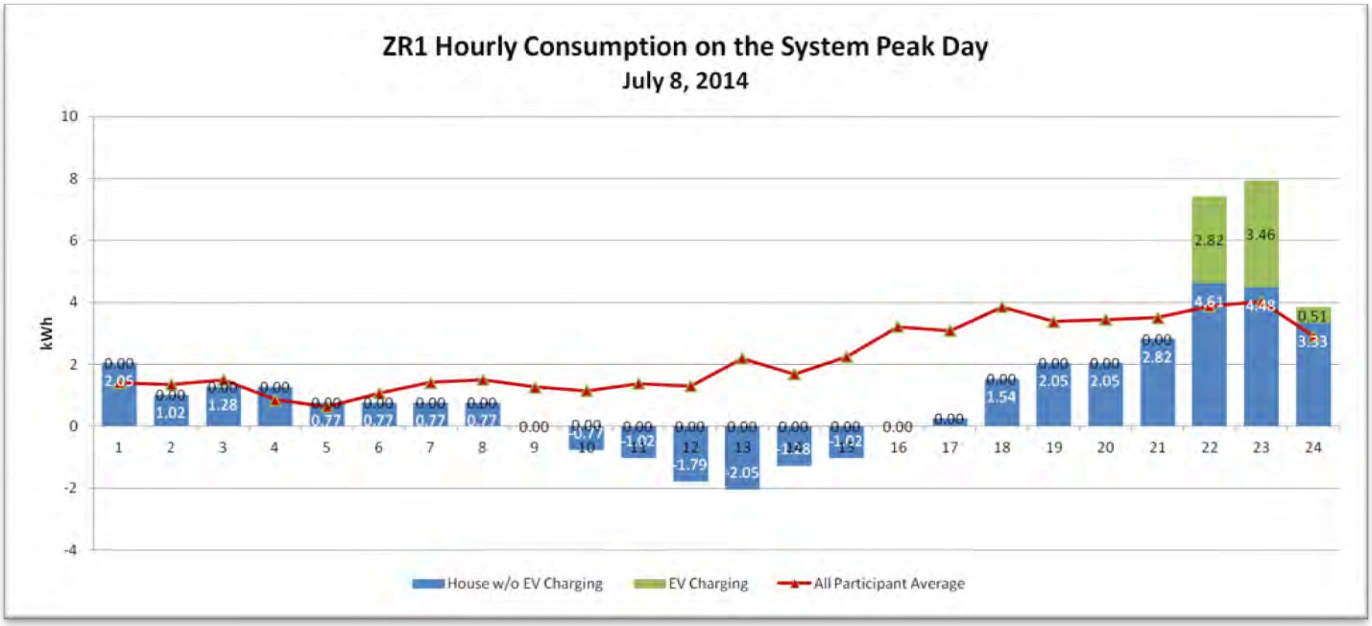


Figure 15. Participant ZR1 Hourly Consumption on the System Peak Day 2014

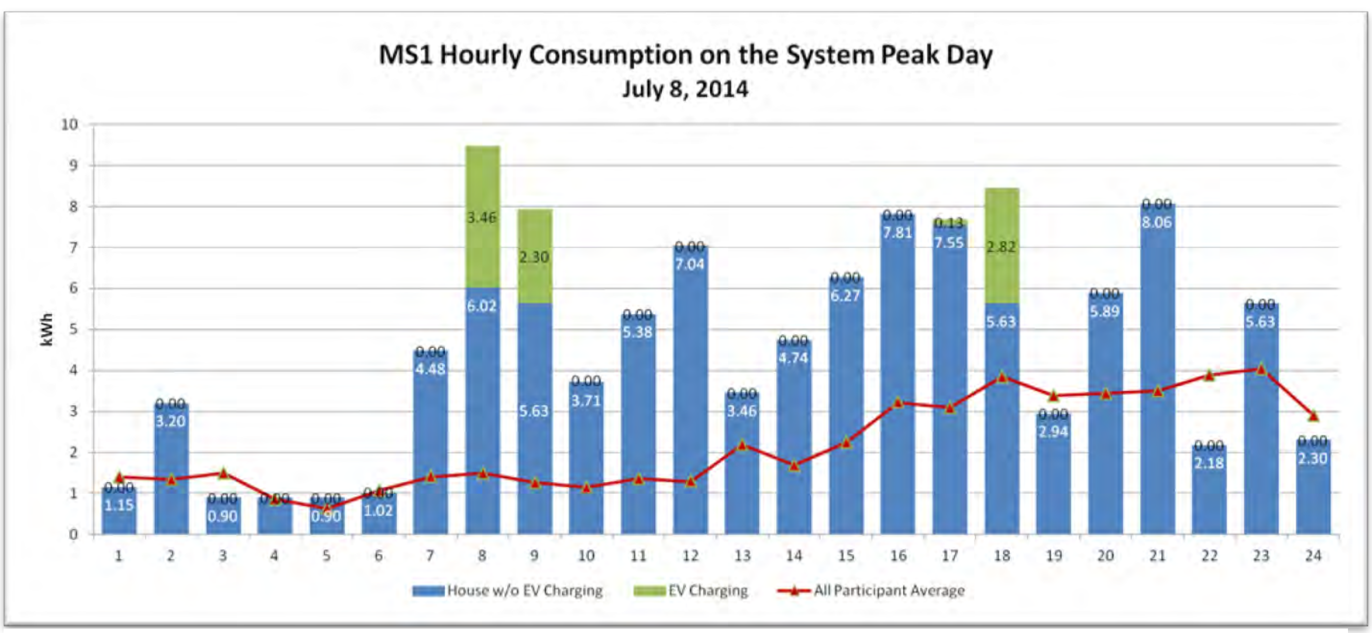


Figure 14. Participant MS1 Hourly Consumption on the System Peak Day 2014

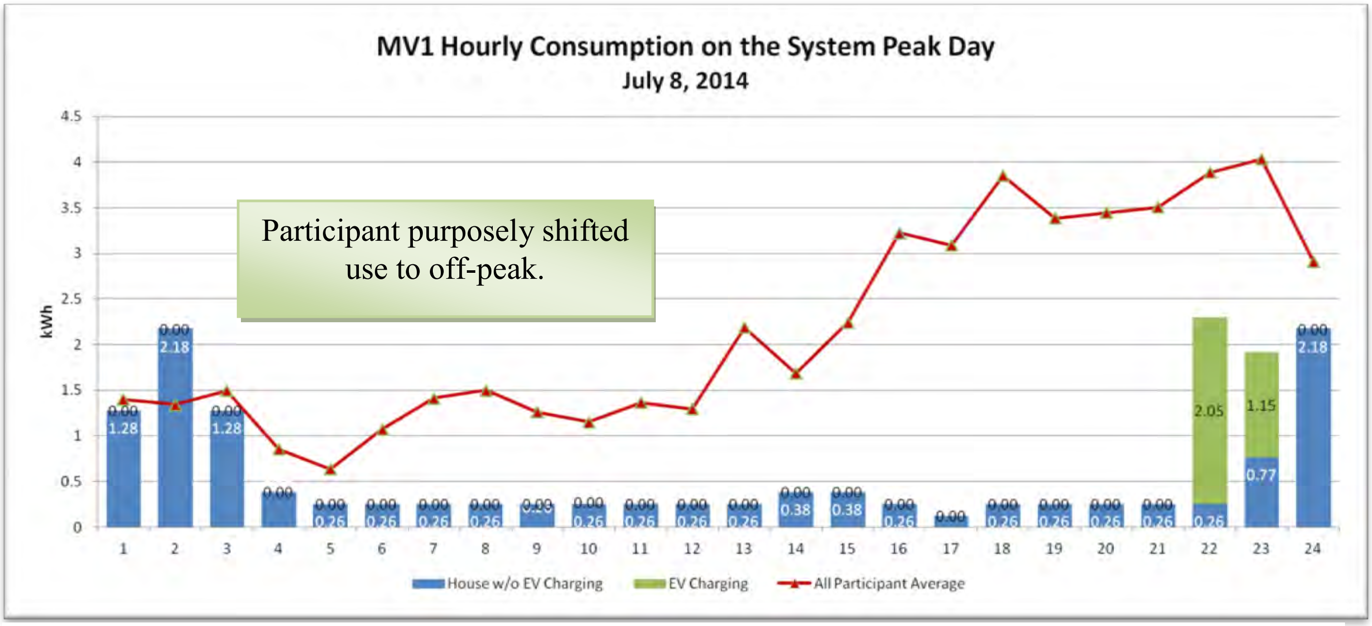


Figure 16. Participant MV1 Hourly Consumption on the System Peak Day 2014

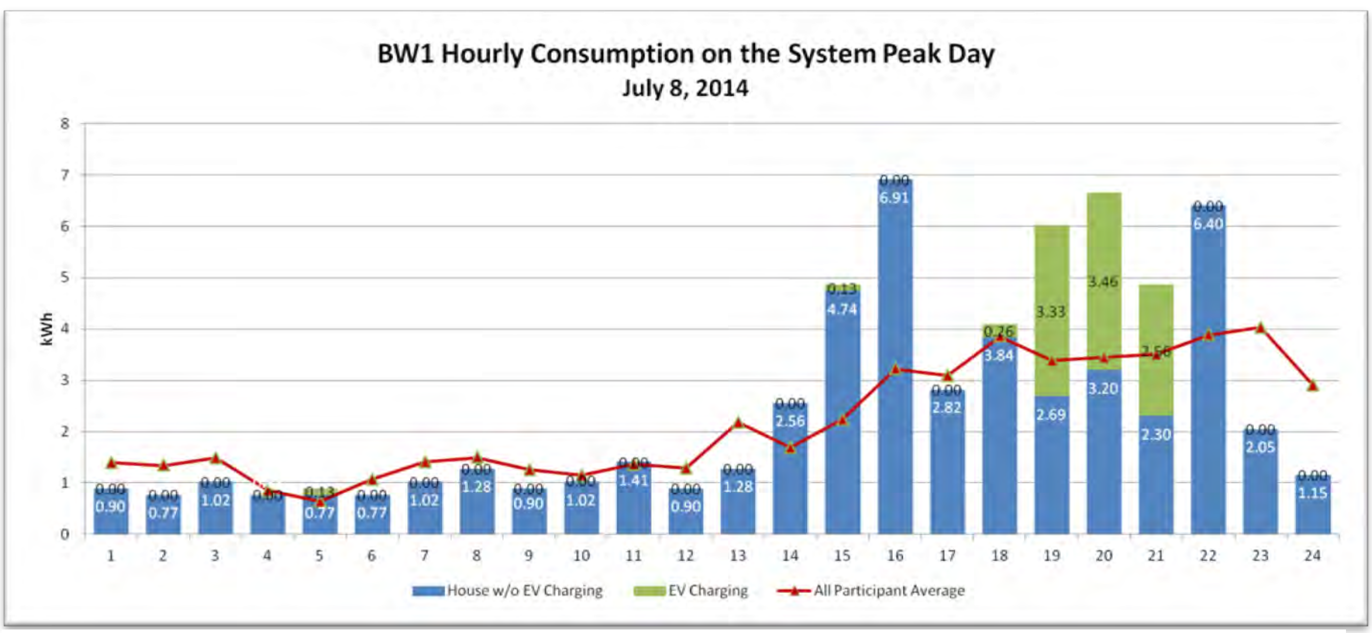


Figure 17. Participant BW1 Hourly Consumption on the System Peak Day 2014

Energy Use

Energy used for charging the EVs was tracked using the AMI meter. Analysis indicated on average, the participant group as a whole increased their whole house energy use by 21% during the months January 2014 through December 2014. This time span was chosen to coincide with the period that all participants were active. For the entire study period, August 2012 through December 2015, the participant group increased their energy use by an average 19%. This later number may be important because there was a noticeable trend for individuals to decrease their energy used for charging once the excitement of owning a new vehicle was over. That is, they drove less.

Looking at average monthly house consumption, four views were analyzed:

- Total Monthly House Consumption
- Average Monthly House Consumption (All Participants)
- Average Monthly House (Excluding Net-Metered Participants)
- Average Monthly House Consumption (Net-Metered Participants)

Total Monthly House Consumption

Figure 18 shows the total energy consumption by all participants on a monthly basis from August 2012 through the end of the project, December 2015. The blue bars indicate the total energy used by all homes in the study excluding the energy used for charging the EVs. To determine this value, the recorded energy use by the EVs was subtracted from whole-house meter data on an hourly basis. The green bar in Figure 18 shows the total energy consumption by all participants' EVs on a monthly basis. The yellow line indicates the how much more energy was used on a percentage basis each month by all participants as a whole. The earliest numbers should be discounted because there weren't very many participants thus any one home could skew the data. In fact, July 2012 is removed from the graph because there was only 1 participant during the first month.

Figure 19 shows essentially the same thing as Figure 18 but the total energy consumption is averaged on an individual basis. That is the total energy values are divided by the number of participants in the program during a particular month.

It can be seen from these graphs that energy consumption by all participants increased between 10% and 36% with the highest occurring during spring and fall. This is not because the EVs use more energy during these shoulder months but because the household energy use tends to be lower during low heating and cooling seasons thus on a percentage basis, the increase is exaggerated. An EV actually uses more energy during the summer and winter for the same reason a house uses more energy; heating and cooling loads. A resistive heating element is used to heat the cabin in an EV which tends to draw down the battery rather rapidly. Similarly, though not as dramatically, cooling the cabin also tends to draw down the battery.

Figure 20 shows the average monthly house consumption but excludes participants who owned solar panel and were net-metered to Idaho Power. This graph shows month over month increases in energy use of between 8% and 25%.

Figure 21 shows the average monthly house consumption of just the net-metered participants. This graph does not show the percent increase in energy use because during many months, Idaho Power was not supplying energy to these homes on a net basis so the energy increase would be meaningless. It can be seen however that EV charging in many cases caused these homes to consumer more energy than they provided back to the grid. Because there were only two net-metered participants in this study, no valid conclusions can be drawn from this data. However, the trend would indicate that EVs represent a significant load addition to a home and a PV installation designed to net-meter in the homeowner's favor may not do so if EV charging is added.

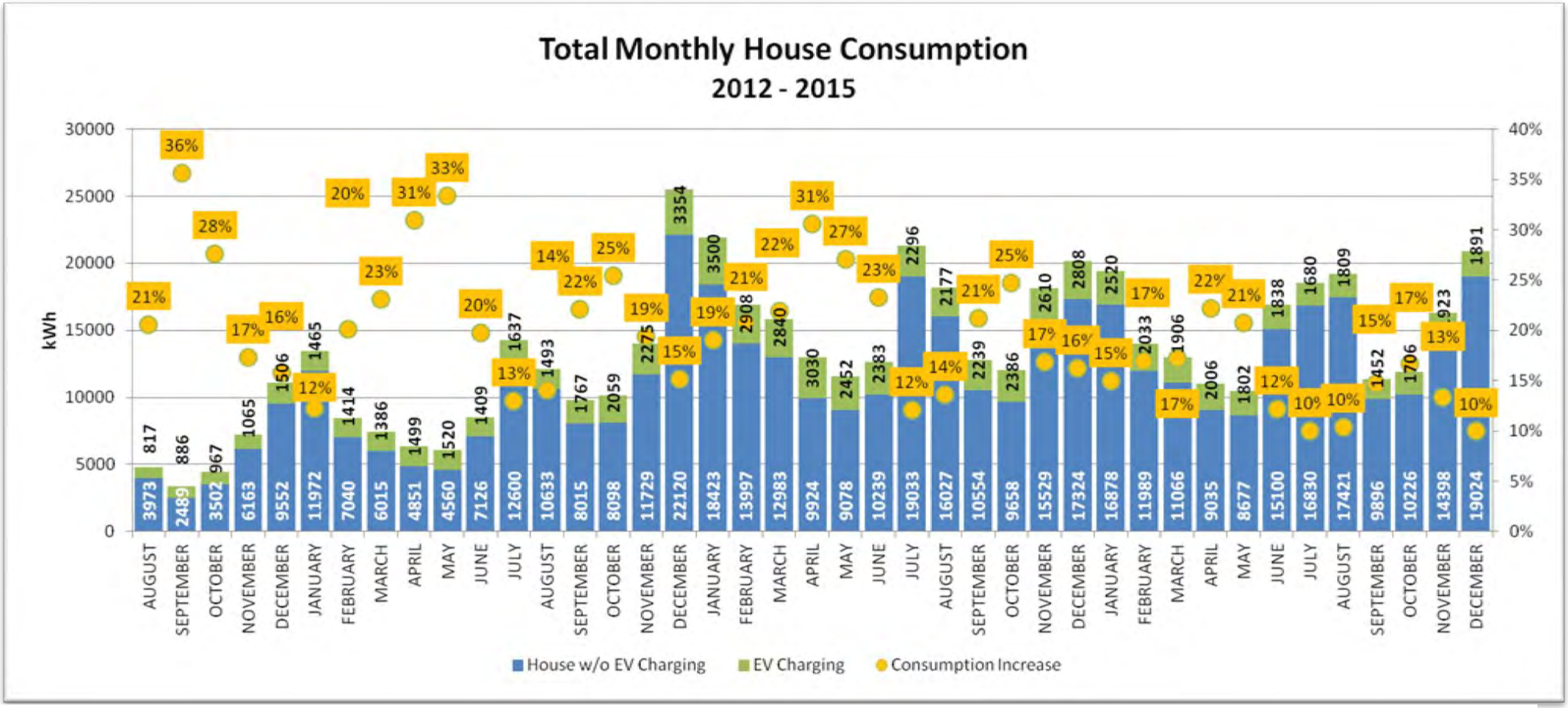


Figure 18. Total Monthly House Consumption 2012 - 2015

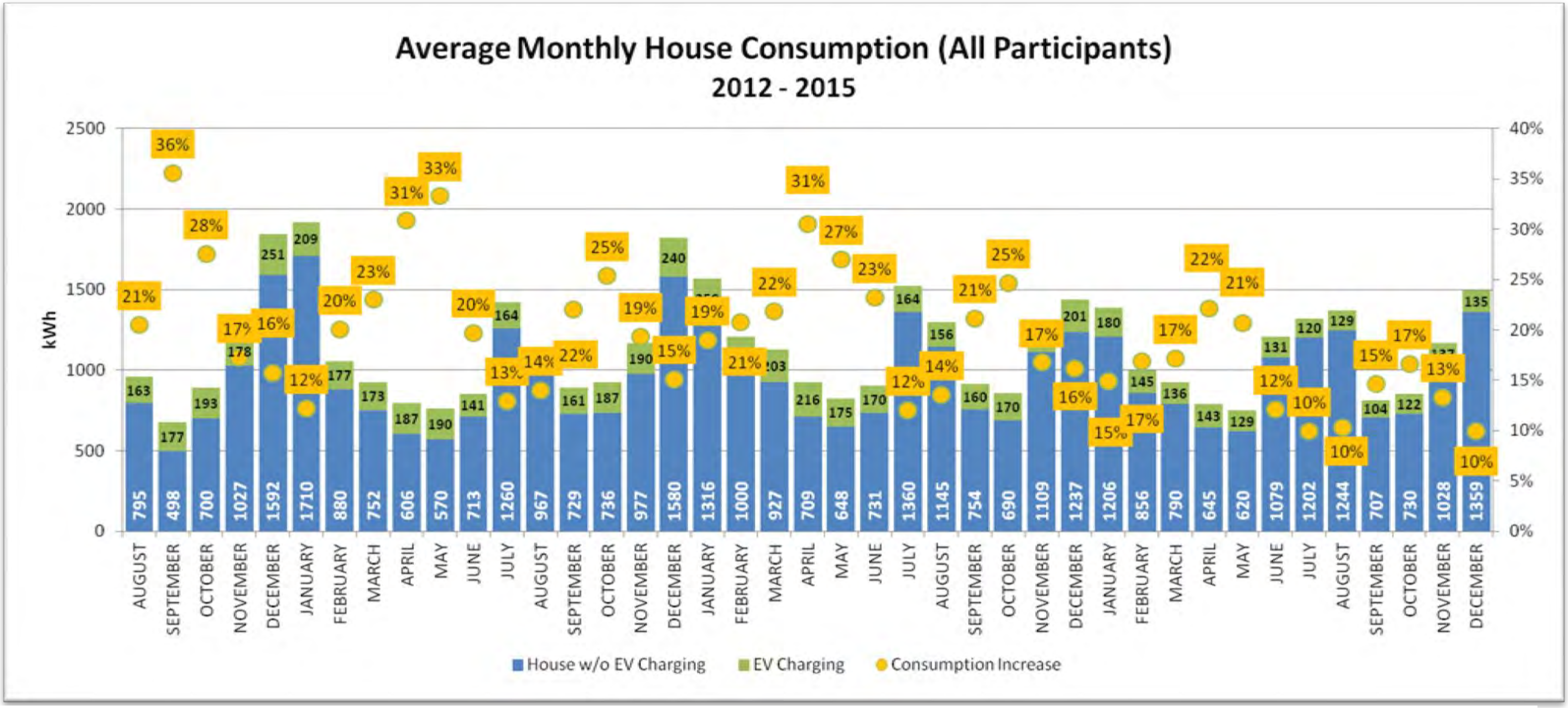


Figure 19. Average Monthly House Consumption (all participants) 2012 - 2015

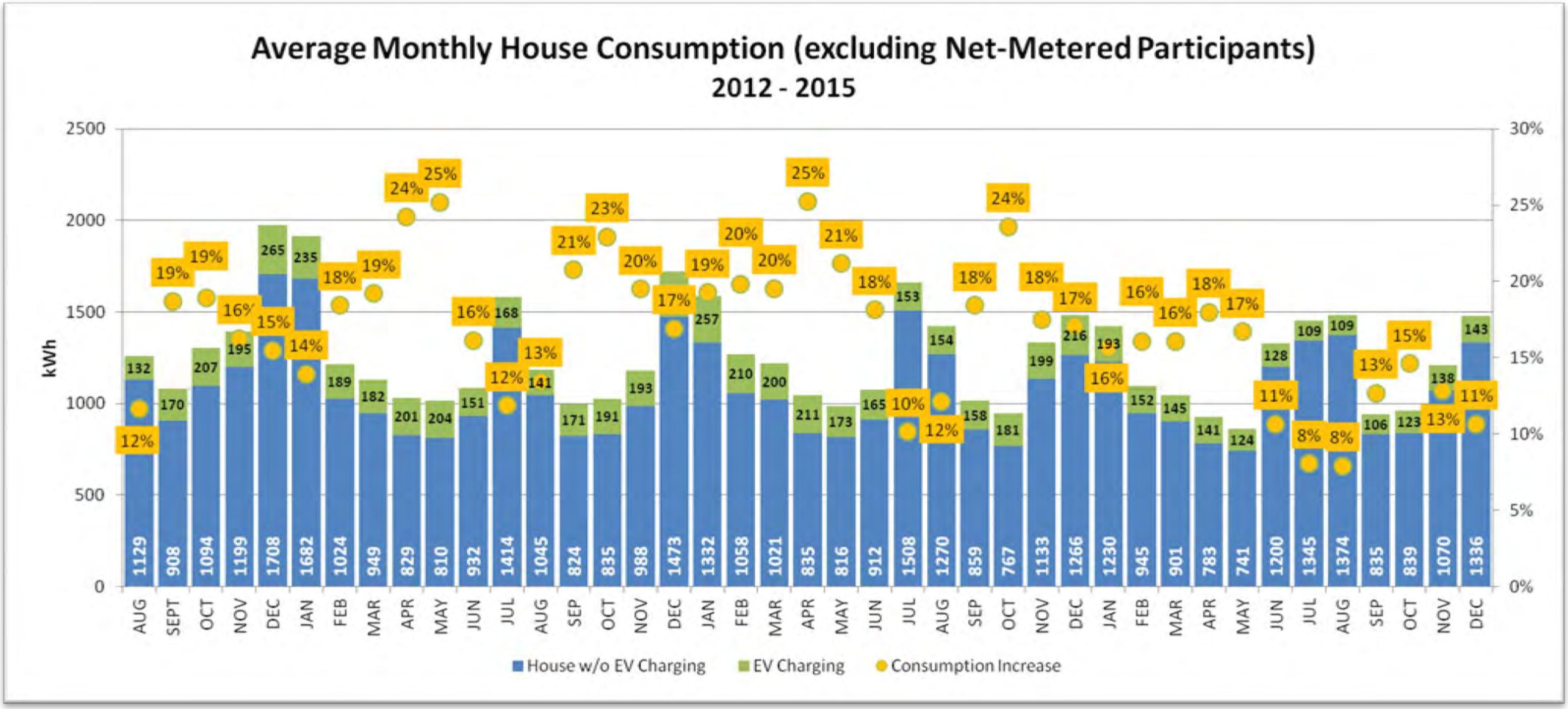


Figure 20. Average Monthly House Consumption (excluding net-metered participants) 2012 - 2015

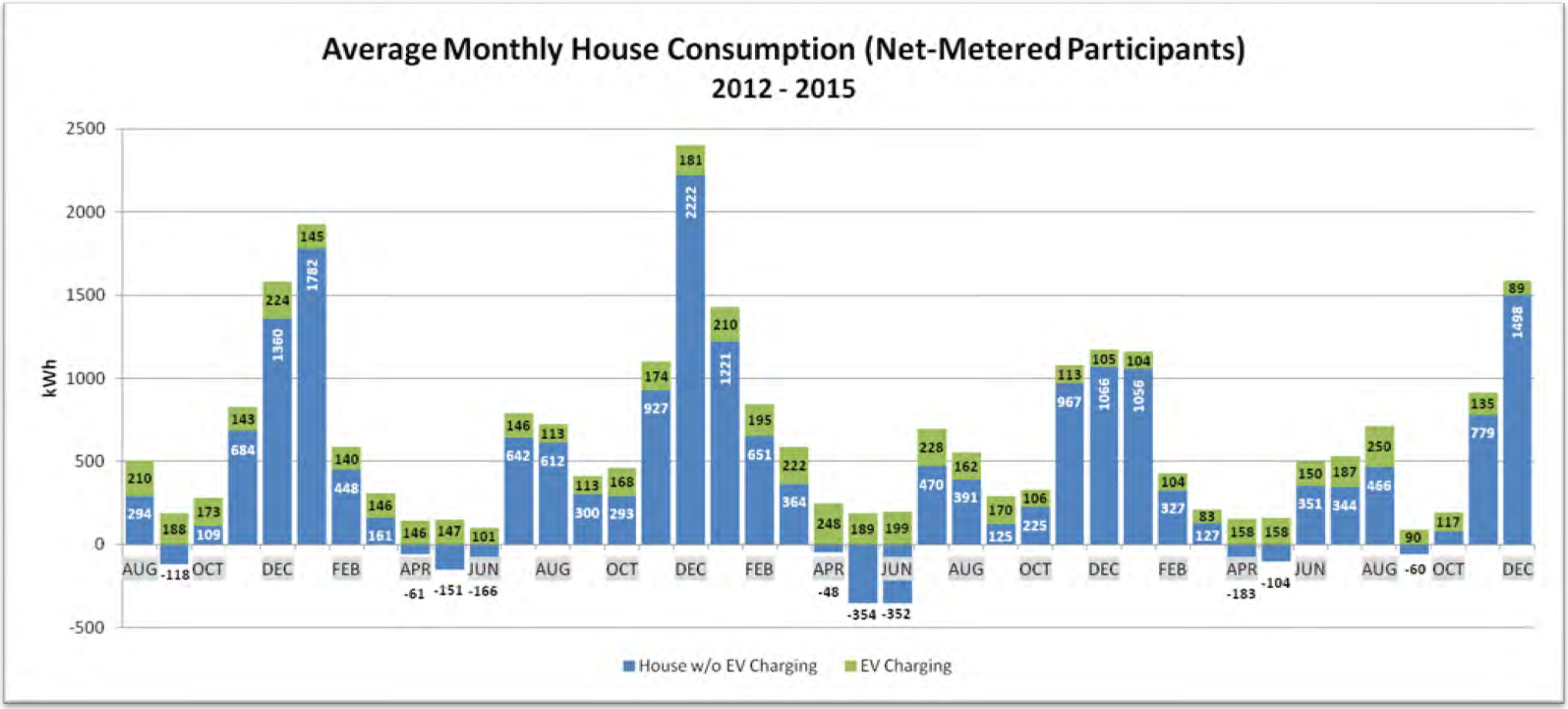


Figure 21. Average Monthly House Consumption (net-metered participants) 2012 - 2015

Average Seasonal House Consumption

Energy use by the various participants is graphed on a seasonal basis which provides a better view of energy use variations based on time of year. The following graphs show energy use for the four seasons of 2014, which is the only full year in which all participants were active. One of the participants did not charge their car the time between October and December 2014 because of an inoperable charging station which likely has some effect on the graph since this particular customer was a rather large winter-time energy user.

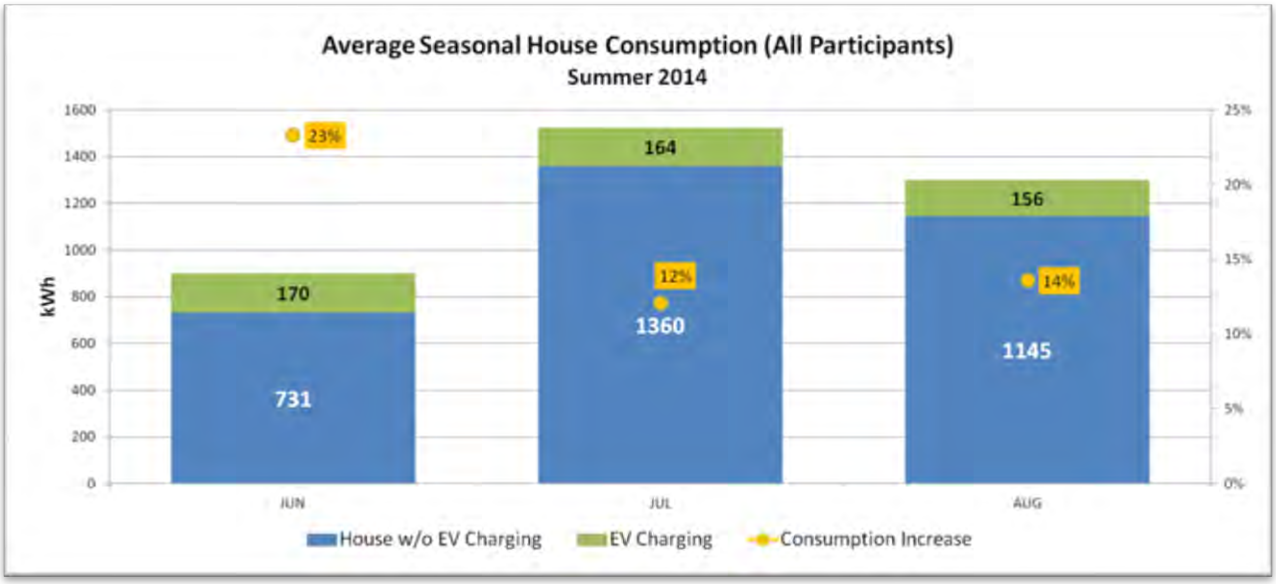


Figure 22. Average Seasonal House Consumption - summer 2014

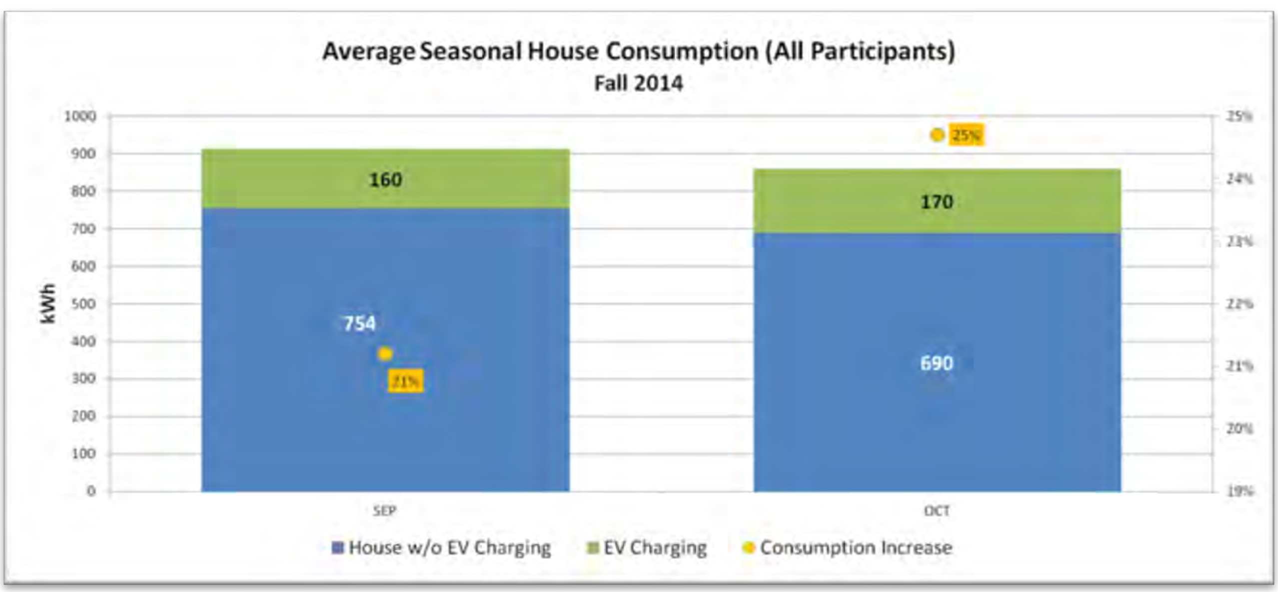


Figure 23. Average Seasonal House Consumption - fall 2014

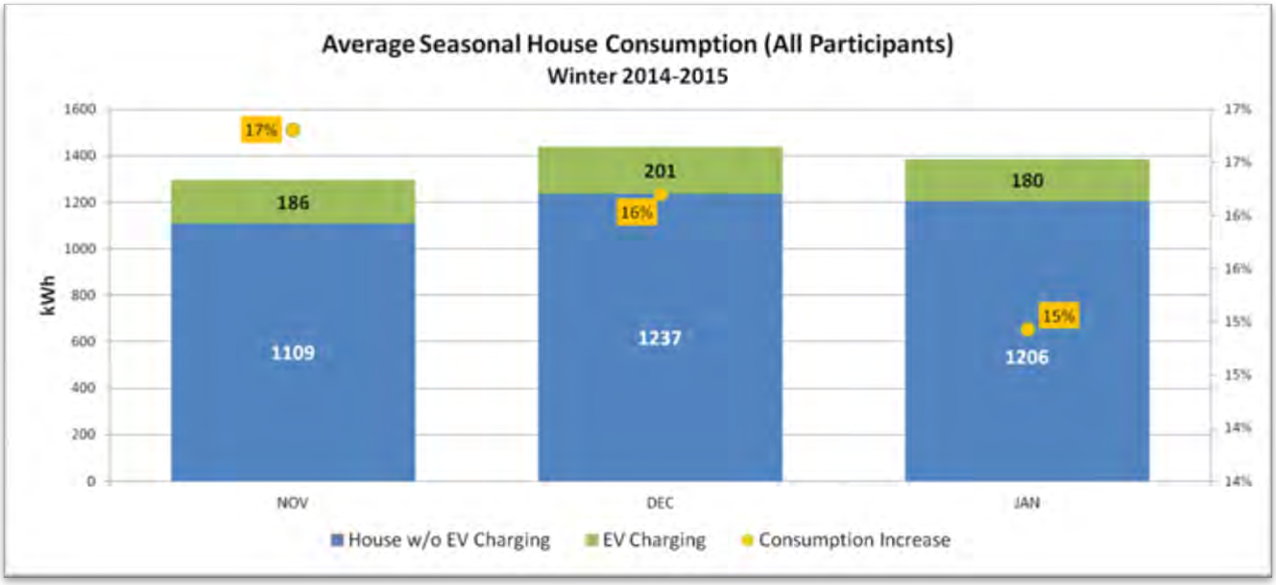


Figure 24. Average Seasonal House Consumption - winter 2014

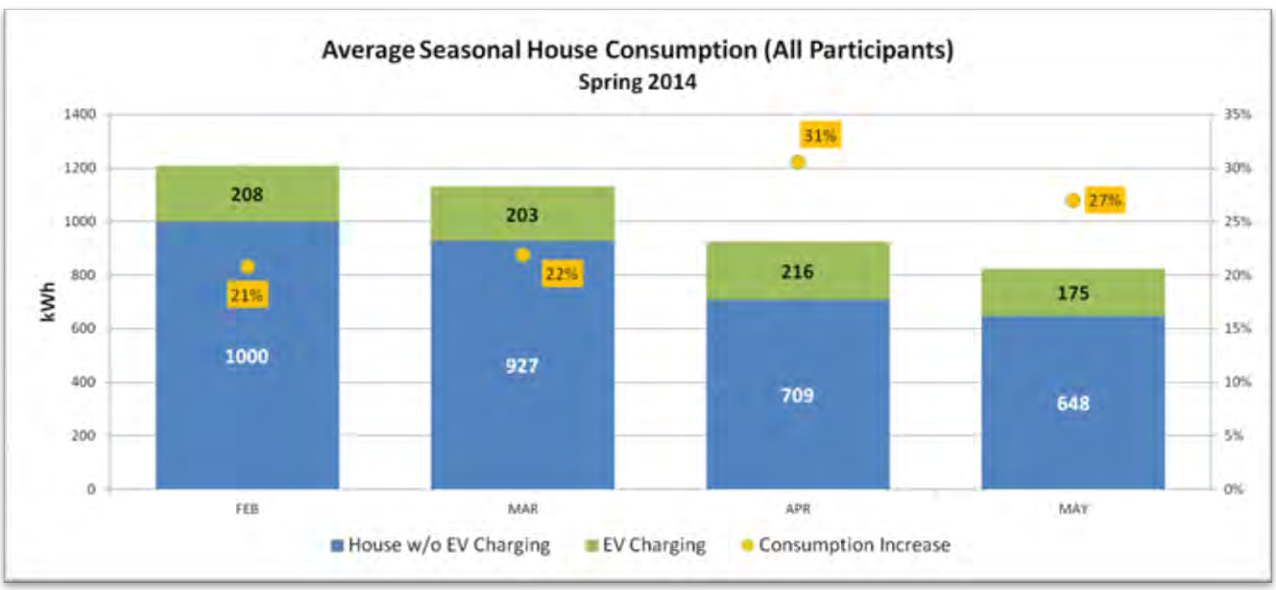


Figure 25. Average Seasonal House Consumption - spring 2014

Figure 26 shows the average monthly energy use by all the charging stations in the project. This graph shows the seasonal variations in energy use which, as pointed out before, is due to heating and cooling load in the vehicle. Winter-time energy use is the highest. The only year where all participants were active was 2014. The average monthly energy use over the entire year for 2014 was 188 kWh. It's interesting to note that energy use appears to go down after the first few months of EV ownership. This makes sense; people tend to drive new cars more because of the excitement of owning a new vehicle. Additionally, with EVs the owners learn to drive their cars more efficiently and thus use less energy as time goes on.

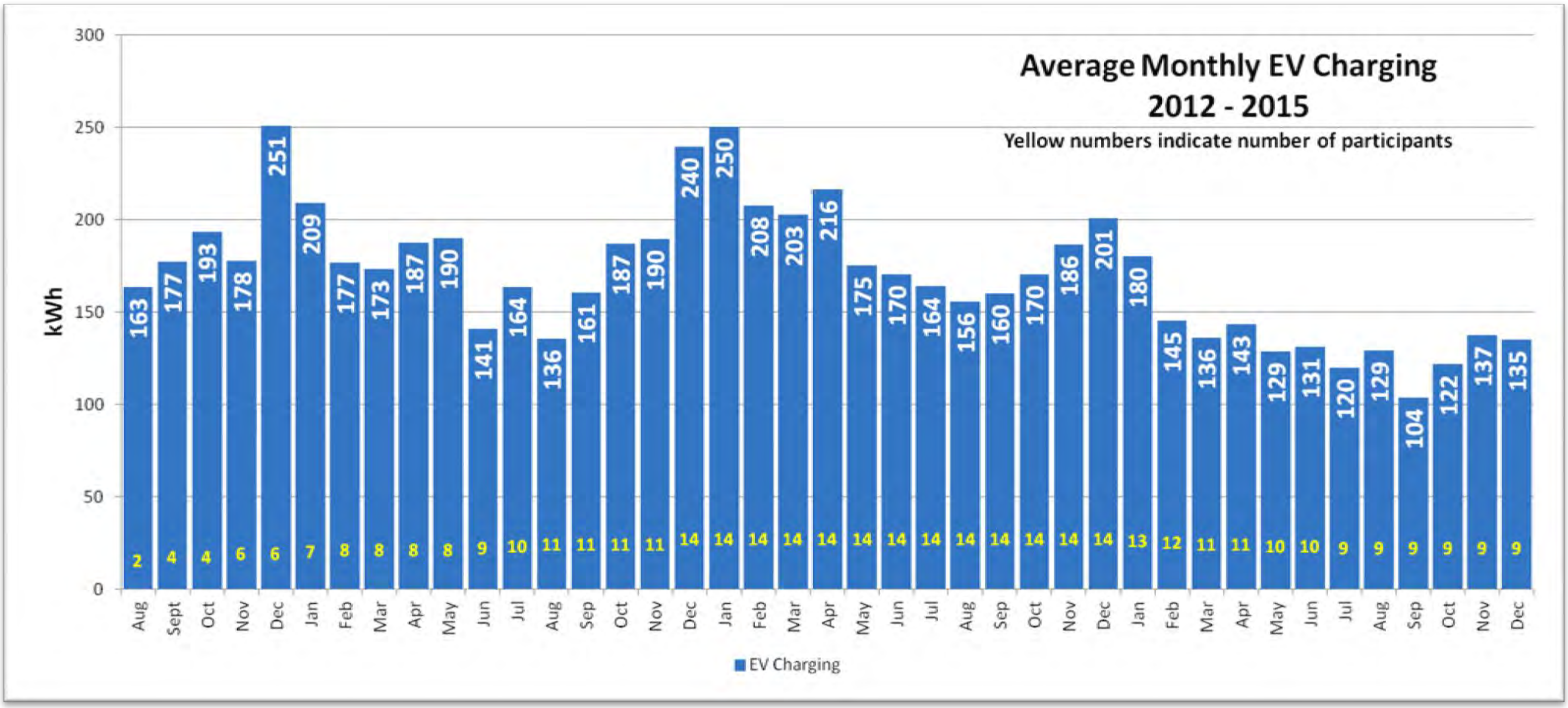


Figure 26. Average Monthly EV Charging 2012 - 2015

Combined consumption for Fleet Vehicles
As mentioned previously, the data for fleet vehicles based at the BOC was not very complete because of inoperable charging stations. There are some months available where good data was gathered. The charging characteristics for one fleet EV is discussed below, which is the only vehicle where contiguous months were recorded.

<u>Nissan Leaf, Idaho Power vehicle number 1903 assigned to Jerry Olson as a commuter vehicle.</u> This car was used for Jerry's commute between his home in Emmet and his work location at the BOC. Jerry was also provided a charging station for his home, the data for which was discussed in the previous section. The data evaluated is from the dates July 2012 through December 2013. The first chart (Figure 27) below shows the charging profile for the EV. As can be seen, Jerry plugged his vehicle in when he arrived at work in the morning and it charged throughout the day, peaking in the morning. Oftentimes he needed to use the vehicle to travel between Idaho Power facilities thus some charging took place into the early afternoon.

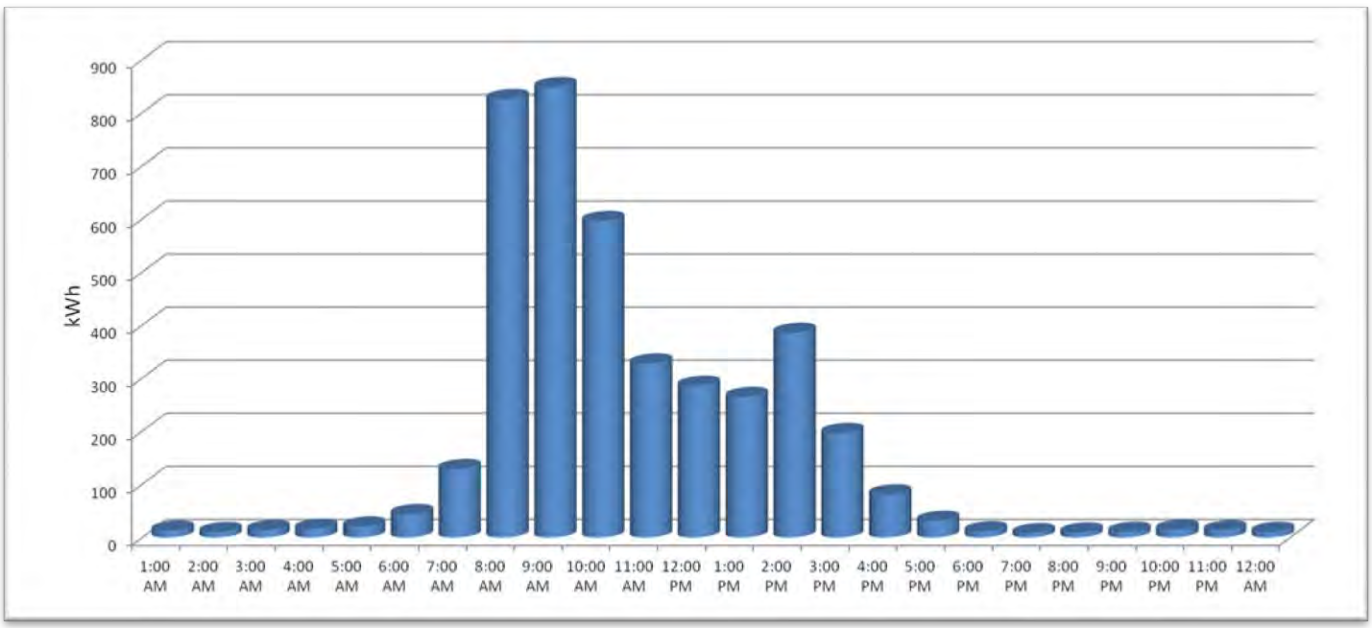


Figure 27. Charging Profile for IPC Vehicle 1903. July 2012 - December 2013

Figure 28 is an interesting look at how this vehicle was charged. The chart shows a fairly even split between workplace charging and at-home charging with slightly more energy being used at the BOC charging stations than at home. This makes sense because normally the vehicle travelled the same distance whether going from home to work or from work to home. If Jerry didn't travel some during the work day, energy use from home would likely be higher because of the hill that has to be driven from Boise to Emmet, requiring more energy. Energy use was most definitely higher in the winter months which would be due to the resistive electric heating used in the Leaf.

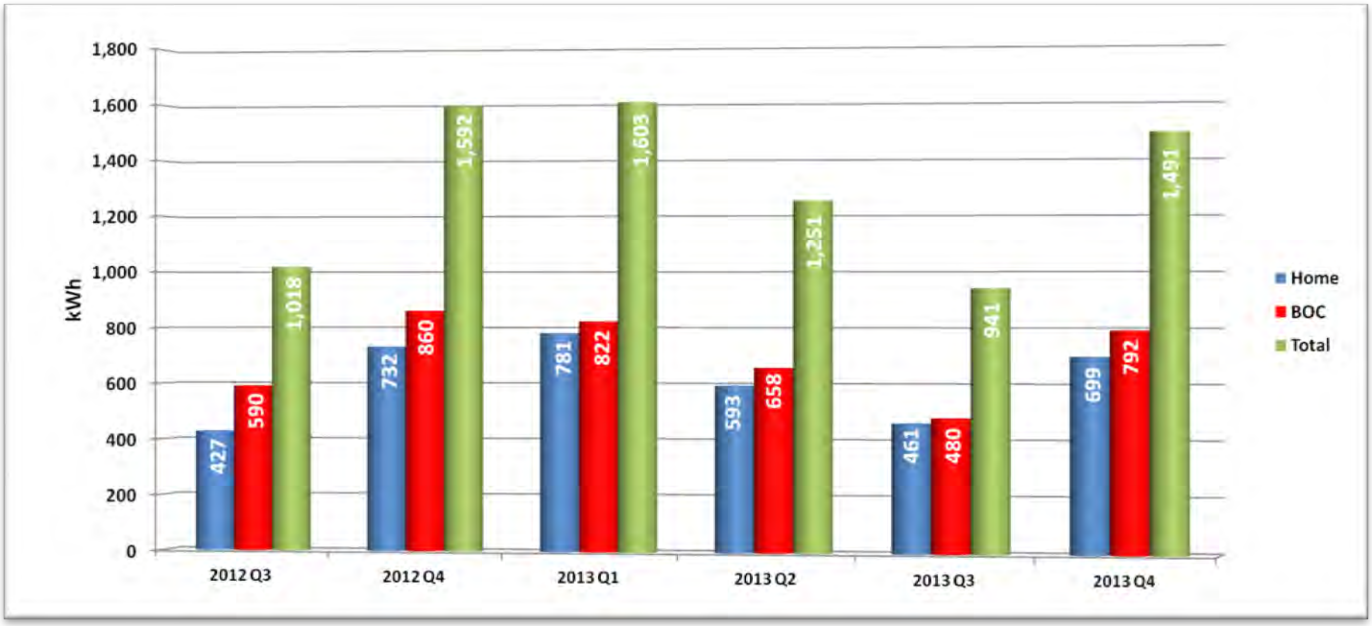


Figure 28. Energy Use for Charging IPC Vehicle 1903. July 2012 - December 2013

Data Provided to Participants

As promised in the customer agreement, Idaho Power provided each customer with a report every six months that showed their energy use, charging pattern and estimated cost of energy to charge their vehicles. Appendix C shows an example of one customer's bi-yearly report.

Observations

As a research project, noting observations is important. The following are notable observations from the project.

- A well designed, data gathering research project requires enough participants that a statically significant sample can be obtained. Because of the slow uptake of EV ownership in Idaho, very few participants could be found thus this study does not provide defendable, data-backed conclusions. However, some trends are fairly obvious and others can be intuitively inferred.
- Participants who purposely shifted their charging to off-peak periods significantly reduced their impact on the distribution system. Conversely, participants who plugged their cars in upon coming home from work had a fairly significant impact on peak loading.
- Participants increased their home energy use by between 19% and 21%, a significant increase.
- EV charging appears to be a fairly diversified load that won't likely impact the distribution system as significantly as one might think. Users don't tend to charge all at the same time and the load should be easily shifted to off-peak if appropriate incentives are offered.

Appendix A – Customer Agreement

Customer Agreement for Electric Vehicle Charging Impacts Project

THIS CUSTOMER AGREEMENT FOR ELECTRIC VEHICLE CHARGING IMPACTS PROJECT ("Agreement") is made this   day of   , 20   ("Effective Date"), by and between IDAHO POWER COMPANY ("Idaho Power" or the "Company") and   ("Customer"). In this Agreement, Idaho Power and Customer may be referred to individually as a "Party" or collectively as the "Parties."

RECITALS

WHEREAS, electric vehicles of both the battery electric type, and the plug-in hybrid type (together, "EV(s)"), are beginning to be purchased by certain Idaho Power customers throughout the Company's service territory located in Idaho and eastern Oregon ("Service Territory"); and

WHEREAS, the additional load these EVs will have on Idaho Power's electrical distribution system is not yet determined, but will be influenced by how the EVs are being used and charged; and

WHEREAS, Customer is the owner of an EV and, pursuant to the terms and conditions set forth in this Agreement, desires to participate in a certain electric vehicle charging impacts project (the "Project"), as further described in this Agreement, offered by Idaho Power at no cost to Customer; and

WHEREAS, Customer and Idaho Power enter into this Agreement pursuant to the terms and conditions set forth below, with the goal that the Project will provide mutual benefits both Parties.

NOW THEREFORE, for good and valuable consideration, the Parties hereto agree as follows:

1. **Recitals.** The Recitals set forth above are by this reference incorporated herein.

2. **The Project.** Idaho Power will install, through a licensed electrical contractor ("Contractor"), an Advanced Metering Infrastructure meter ("AMI Meter") at Customer's primary residence, in series with Customer's existing EV supply equipment (the "EV Charging Station"). The AMI Meter will monitor the energy/demand profile associated with Customer's EV during the Term of this Agreement ("Electric Charging Profile"). Idaho Power shall periodically during the Term of this Agreement, and in no event less than once during each six month period hereof, provide to Customer an Electric Charging Profile developed exclusively by Idaho Power for Customer's EV. Upon expiration of the Agreement, Idaho Power will remove the AMI Meter from Customer's residence and provide to Customer a final Electric Charging Profile that includes an aggregate summary of charging data for the entire Term of the Agreement.

3. **Project Eligibility.** To qualify to participate in the Project, Customer must be an Idaho Power customer and must live in an owner-occupied dwelling unit located within the Company's Service Territory. Further, Customer's EV Charging Station must be a Level 2 (208/240 volt) EV Charging station, must be permanently wired into Customer's electrical supply, and must be on a dedicated 208/240 volt circuit. Only one EV may be charged from an individual EV Charging Station. Therefore, if Customer owns more than one EV, each EV must have its own EV Charging Station.

4. **Customer Obligations.** In consideration of Idaho Power providing an EV charging profile to Customer upon expiration of the Project, and by agreeing to participate in the Project, Customer hereby authorizes and agrees to allow Idaho Power provide to Contractor, Customer's name, physical address and telephone number for the sole purpose of scheduling and performing all AMI Meter installation services.

   Customer agrees to allow Idaho Power to hire Contractor to perform the AMI Meter installation and authorizes and agrees to allow Contractor to enter Customer's premises to perform such AMI Meter installation alongside Customer's EV Charging Station. Customer agrees to allow Contractor to inspect Customer's electrical system to determine if any changes to the system are necessary to install the AMI Meter, and if so, authorizes Contractor to perform all such changes. In the event the AMI Meter requires repair or replacement at any time during the Term of this Agreement, Customer agrees to allow Contractor access to the AMI Meter to perform such repair or replacement services upon reasonable notice from Idaho Power to Customer. At the end of the Project, Customer authorizes and agrees to allow Contractor to enter upon Customer's premises to remove the AMI Meter from Customer's home.

5. **Idaho Power Obligations.** Idaho Power will provide and pay for all AMI Meter installation services performed by Contractor. The Company agrees to accommodate Customer's preference, at Idaho Power's reasonable discretion, to locate the AMI Meter in the specific location where Customer desires at Customer's residence. Upon expiration of this Agreement, Contractor will remove the AMI Meter from Customer's residence and remediate the installation site by placing a cover over the meter base. The meter base will be left in-place where it is mounted. Idaho Power will provide to Customer, an Electric Charging Profile developed by Idaho Power exclusively for Customer's EV not less than one time during each six month period during the Term of this Agreement and a final Electric Charging Profile that includes all electrical usage data for Customer's EV for the entire term of the Project.

   If the AMI Meter installation is performed at the same time as the installation of Customer's EV Charging Station, and the same electrical contractor performs both installations, Idaho Power agrees to pay Customer an amount totaling $100.00 to offset the costs incurred by Customer associated with installing Customer's EV Charging Station. Customer shall be responsible for any and all taxes levied or assessed upon this $100.00 payment from Idaho Power.

6. **Warranties and Disclaimers.** Customer acknowledges and agrees that Idaho Power assumes no responsibility or liability for the effectiveness or technical adequacy, and that the Company makes no warranties of any kind whatsoever, as to the accuracy of the Electric Charging Profile. Idaho Power expressly disclaims any and all implied warranties related to the Project or the Electric Charging Profile.

7. **Term and Termination.** This Agreement shall commence on the Effective Date and shall continue for a period of 24 months from the Effective Date ("Term"). Either Party may terminate this Agreement at its convenience with at least 60 days notice to the other Party.

8. **Waiver.** Waivers of any right, privilege, claim, obligation, condition, or default shall be in writing and signed by the waiving Party. No waiver of either Idaho Power or Customer of any breach of this Agreement shall be a waiver of any preceding or succeeding breach, and no waiver by either Idaho Power or Customer of any right under this Agreement shall be construed as a waiver of any other right.

9. **Miscellaneous.** This Agreement shall be binding upon the parties and their respective heirs, successors and assigns. Any obligation of this Agreement which may involve performance subsequent to termination of this Agreement, or which cannot be ascertained or fully performed until after termination of the Agreement, including without limitation, waiver and limitation of liability, shall survive. Neither Party shall be deemed an agent, partner, joint venturer, or employee of the other Party. Customer will comply with all applicable federal, state and local laws related to Customer's obligations under this Agreement. Enforcement and interpretation of this Agreement shall be in accordance with the laws of the state of Idaho, notwithstanding its choice of law provisions. Venue shall be in Ada County, Idaho.

AGREED AND ACCEPTED as of the Effective Date.

(CUSTOMER NAME)

By: ______________________________

Name: ______________________________

Title: ______________________________

Date: ______________________________

IDAHO POWER COMPANY

By: ______________________________

Name: ______________________________

Title: ______________________________

Date: ______________________________

Appendix B – Customer Application for Payment

Application for Payment—
Electric Vehicle Charging Impacts Project

If the AMI Meter installation is performed at the same time as the installation of Customer's EV Charging Station, and the same electrical contractor performs both installations, Idaho Power agrees to pay Customer an amount totaling $100.00 to offset the costs incurred by Customer associated with installing Customer's EV Charging Station.

Customer Information

Name:	
☐ Account Number or ☐ Meter Number (Provide one):	
Address:	
Phone:	
E-Mail:	

Contractor Information

Company:			
Date Installed:			
Location:	Street Address	City	State

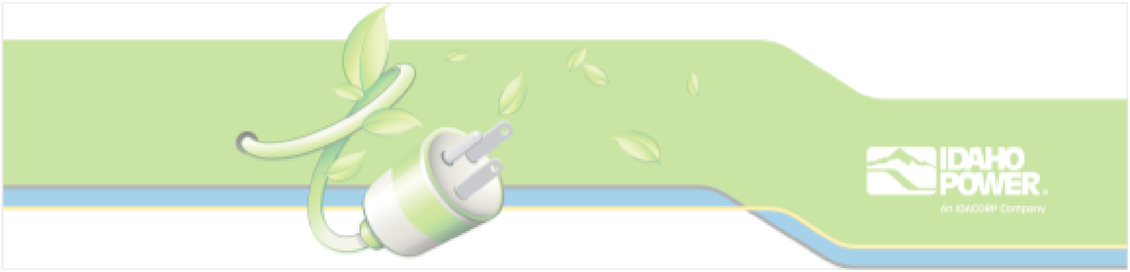
By signing below, I certify that I qualify to participate in the Project; am an Idaho Power customer, and I live in an owner-occupied dwelling unit located within the Company's Service Territory. Further, my EV Charging Station is a Level 2 (208/240 volt) EV Charging station, is permanently wired into my electrical supply, and is on a dedicated 208/240 volt circuit.

I understand that only one EV may be charged from an individual EV Charging Station and that for every EV that I own, each EV has its own EV Charging Station.

Customer Name *(please print)*	Customer Signature	Date

Please return completed form with an **attached invoice** to:
Idaho Power Company, Attn: Kent McCarthy, PO Box 70, Boise, ID 83702.

Appendix C – Sample Customer Bi-Yearly Report



Participant
Address
City, State, ZipCode

Vehicle	Chevrolet Volt
Charging Period	March 1, 2015 through August 31, 2015
Est. Energy Cost Summer[1]	10¢ per kilowatt-hour (kWh) when buying from Idaho Power
Est. Energy Cost non-Summer[1]	9¢ per kWh when buying from Idaho Power
Period	184 days
Energy Used	1348 kWh
Energy Used in March	166 kWh
Energy Used in April	252 kWh
Energy Used in May	202 kWh
Energy Used in June	142 kWh
Energy Used in July	227 kWh
Energy Used in August	359 kWh
Maximum Demand[2]	4.15 kilowatts (kW)
Highest Day and Energy Used	August 26, 22.53 kWh
Average Daily Energy Use	7.33 kWh (8.37 kWh if days where no energy was used are excluded)

[1] Energy costs are estimated using seasonal rates and reflect Tier 1 rates based on your home's monthly energy use.
[2] Demand is the rate at which your charging station draws energy from the circuit, which is measured in kilowatts (kW or thousands of watts). Demand multiplied by time equals energy, which is measured in kilowatt hours (kWh).

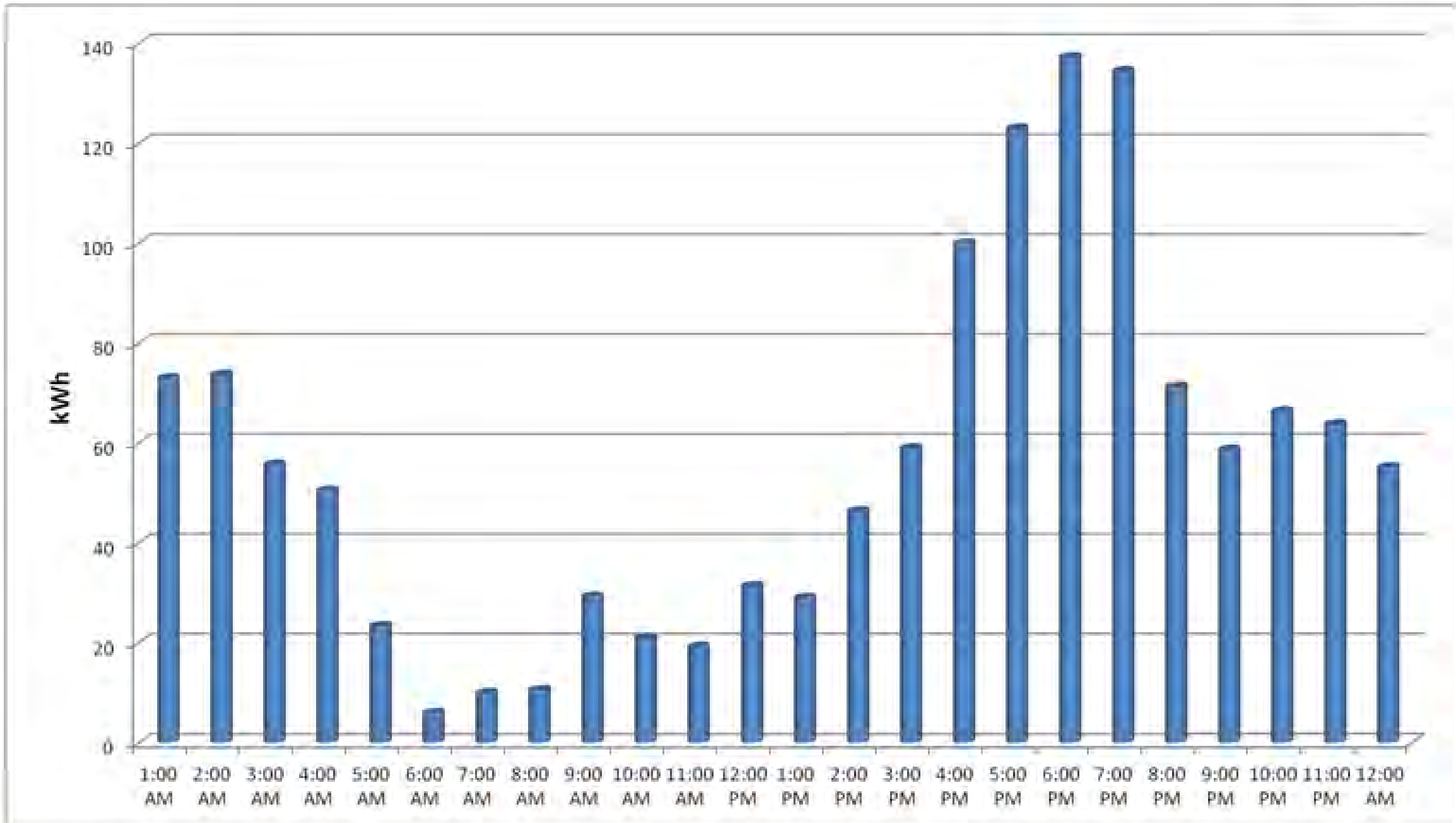


Figure 1. Charging times
This figure shows the entire range of charging times. Most of your vehicle charging took place between 4:00 p.m. and 8:00 p.m. so was mostly on-peak. Another way to look at this figure is it shows the amount of energy used each hour of the 24-hour day during the six month period of study. For example, if all the energy used during the 6:00 p.m. hour over all the days in the period is added together, you used 138 kWh.

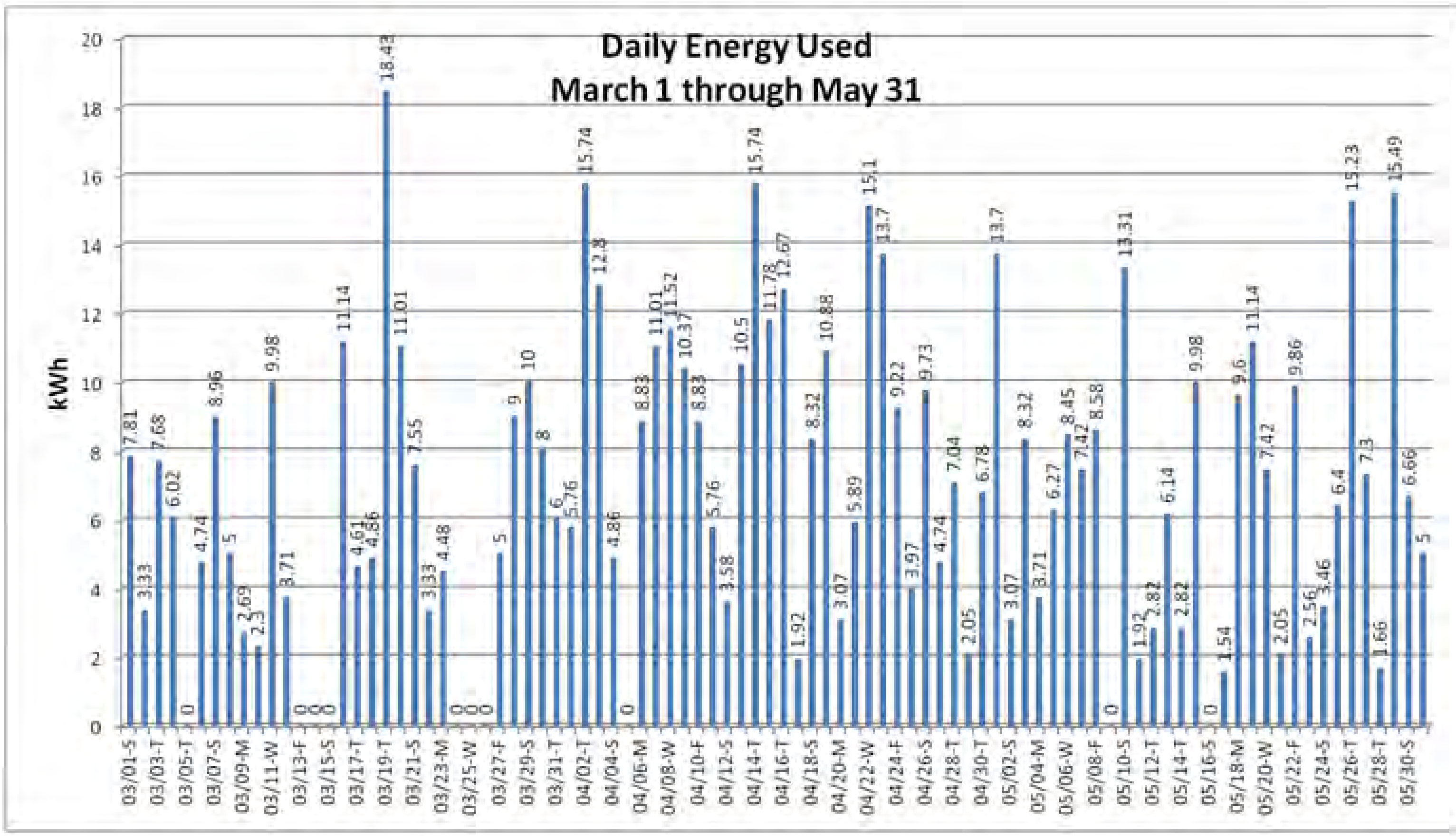


Figure 2. Daily energy use, March 1 through May 31
This figure shows your energy use by day over the period of March 1 through May 31 and the next figure shows June 1 through August 31. The average daily energy use over the entire period of study was 7.33 kWh. If the days that energy use was zero are excluded, the average daily energy use was 8.37 kWh.

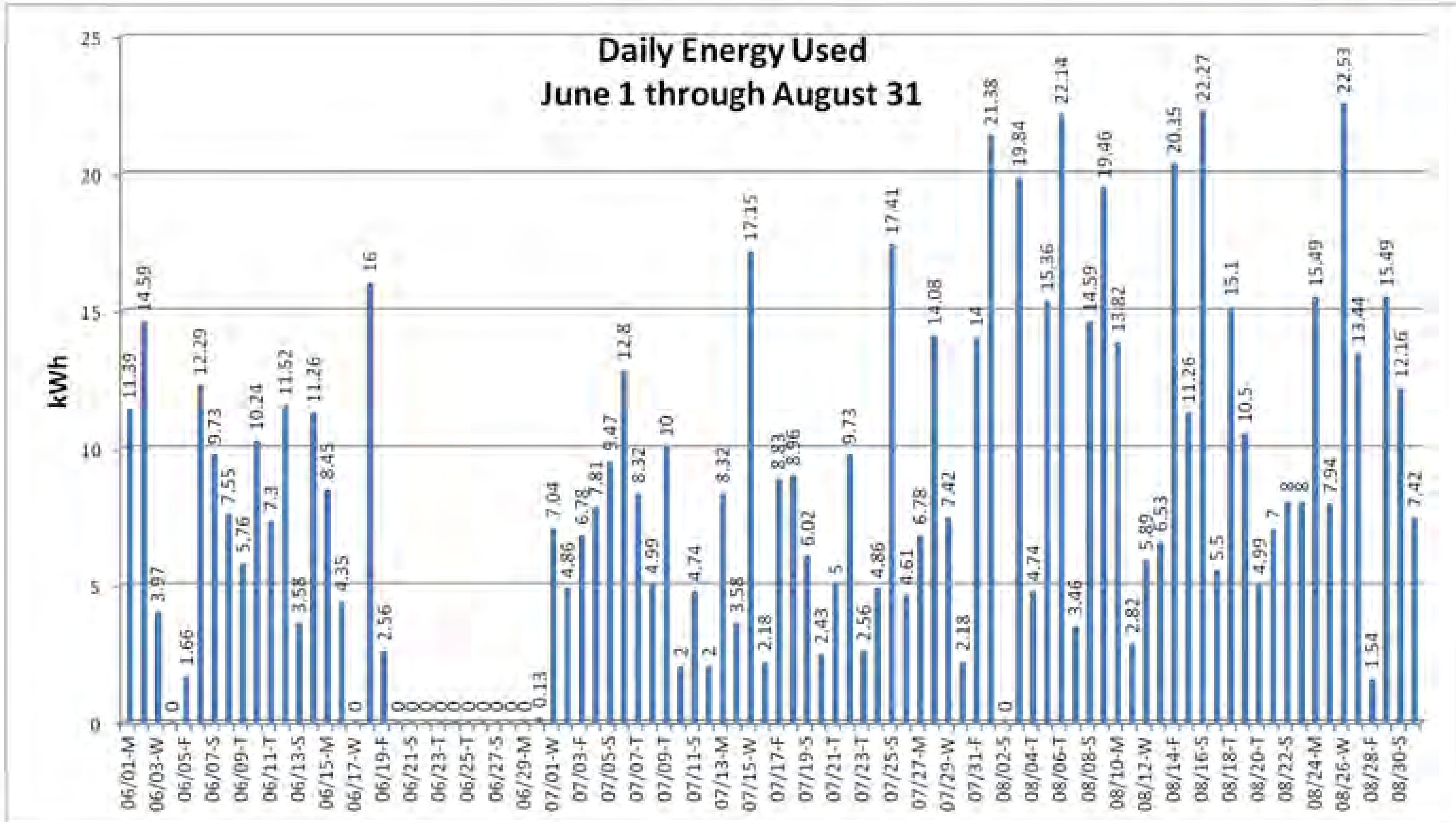


Figure 3. Daily energy use, June 1 through August 31

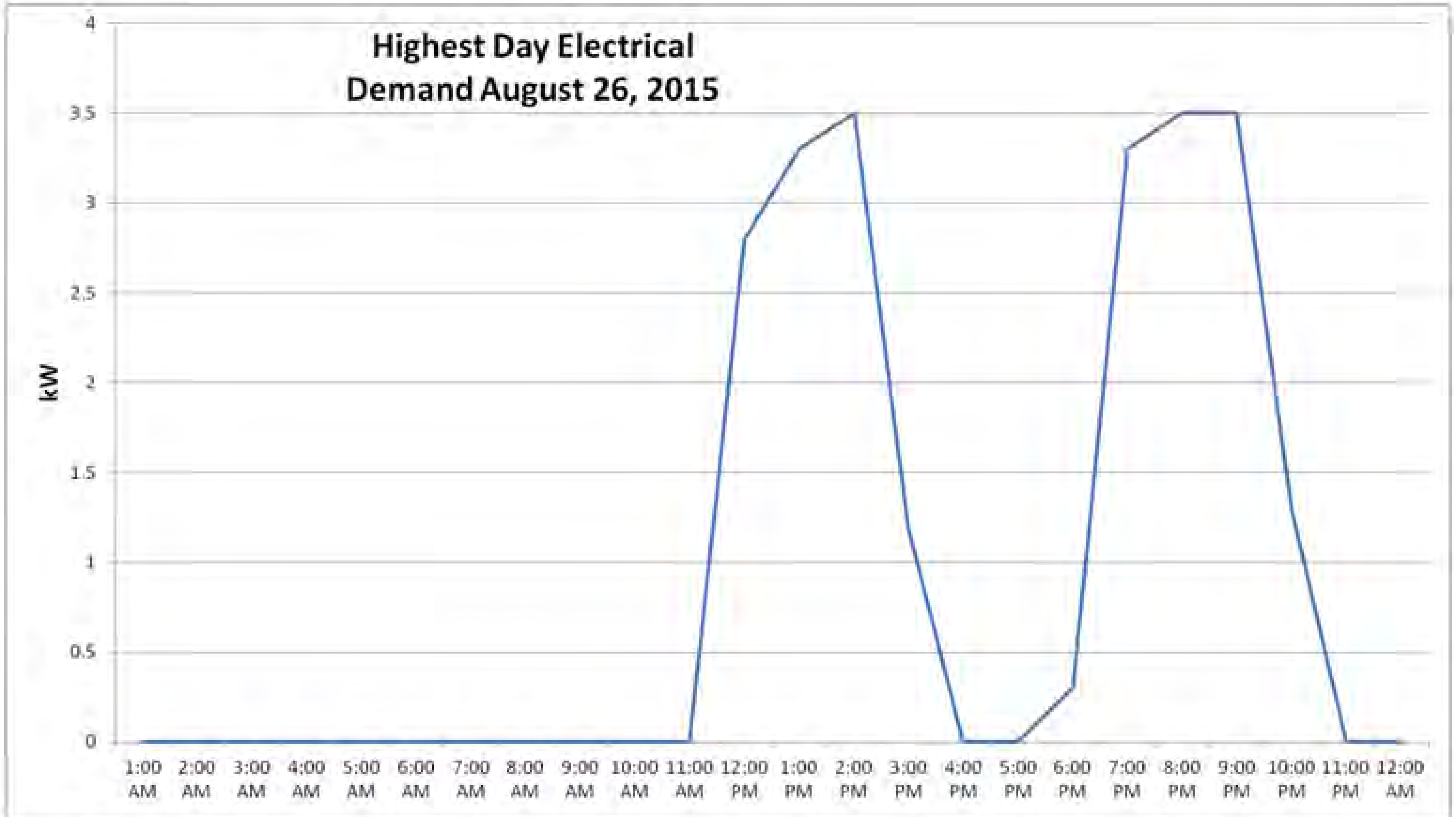


Figure 4. Highest day electrical demand
This figure shows the charging profile for the highest day of use recorded during this period which occurred on August 26th. Notice this graph is in kilowatts (kW) instead of kWh so it shows the demand or rate at which your charging station drew energy from the electrical system.

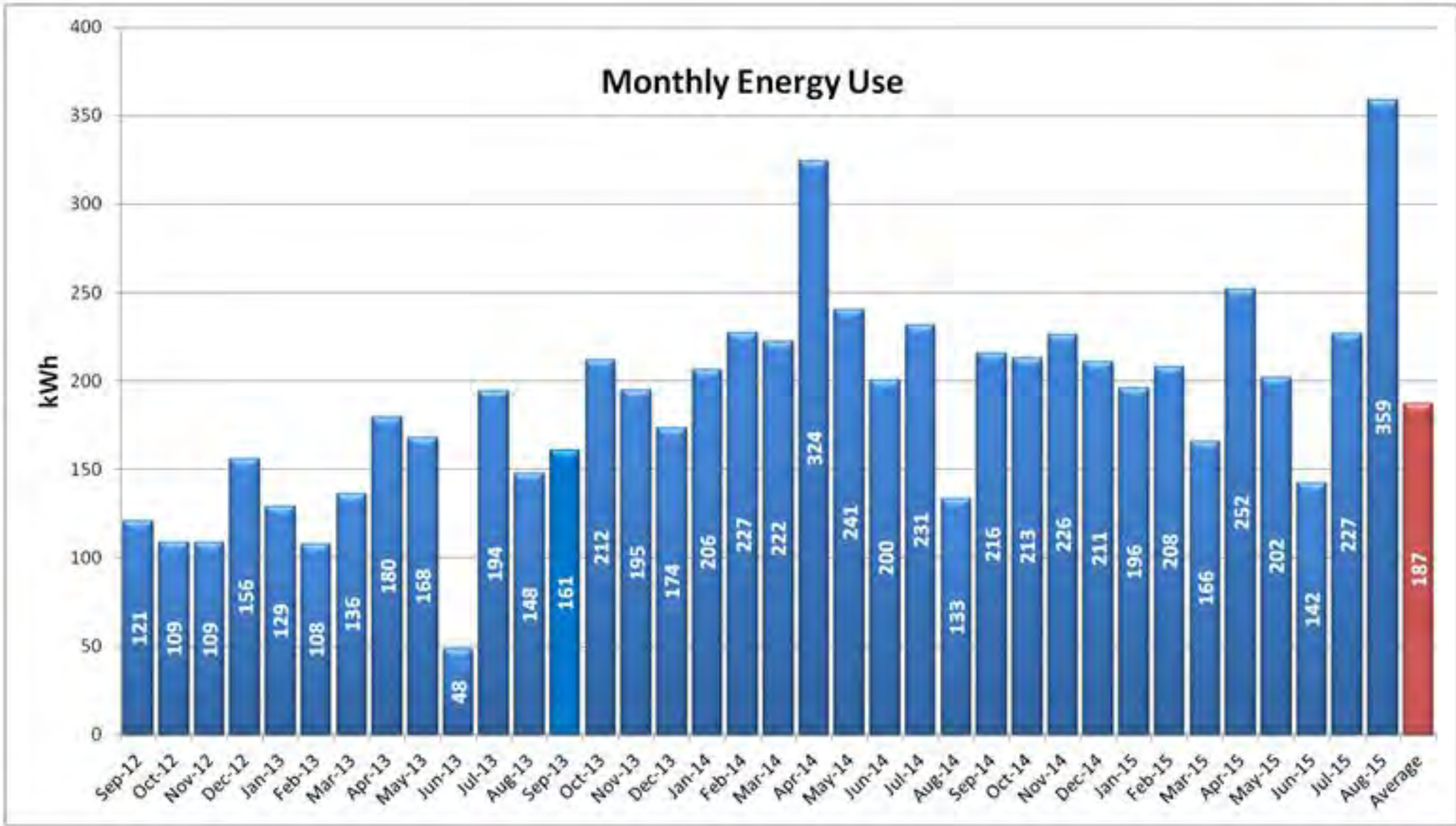


Figure 5. Monthly Energy Used
This graph shows the total energy used for charging your vehicle on a monthly basis.

Appendix H.
Smart Grid Metrics

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Smart Grid Metrics

II. STATUS OF CURRENT SMART GRID INVESTMENTS

A. Transmission Network and Operations Enhancements

Transmission Situational Awareness Peak Reliability Hosted Advanced Application

Description: This provides remote access to Peak Reliability Coordinator (RC) state estimator as well as a set of displays used by Peak RC to monitor the interconnection. Peak Reliability's Hosted Advanced Applications (HAA) provides enhanced situational awareness of pre- and post-contingency system conditions that help Transmission Operators (TOPs) to reliably monitor their systems. The Hosted Advanced Applications File Management tool provides a means for HAA users to manage their files in the HAA environment including file transfer (state estimator solutions) between a local machine and the HAA environment.

Status: Complete

Benefits: The ability for the operators to determine whether a planned outage and/or forced outage (e.g. line out of service) would result in a system operating limit exceedance.

Cost: $75,000 Annually

Metric: # of potential System Operating Limit (SOL) exceedances avoided

# of Potential SOL Exceedances Avoided
4

A. Transmission Network and Operations Enhancements (continued)

Transmission Situational Awareness Voltage Stability Monitoring Pilot

Description: The expectation for the VSMS software was to monitor real-time voltage stability, as well as have the capability to utilize archived PMU data to perform post-event voltage stability analysis. Pending additional installation of PMUs at key locations, this project may be revisited at that time. Further testing at a couple of stations will be required for benchmarking and calibrating the monitoring tool. Idaho Power is currently exploring engaging in another pilot project on the same area (different algorithm) of voltage stability that appears to have reached a more matured level of development.

Status: Ongoing

Benefits: Avoid drifting into voltage instability during unforeseen operating conditions

Cost: TBD

Metric: TBD

Dynamic Line Capacity Pilot

Description: Transmission line ratings are static and are based on conservative and often worst-case environmental factors. A dynamic transmission line rating system is based on real time or near real time measured environmental conditions, such as ambient temperature, wind speed and wind direction. This allows the line rating to be more accurate as it is based on actual conditions. An increase of at least 20% of the static line rating is often possible.

Status: Ongoing

Benefits: Transmission System increased operational flexibility and increased operating limits by replacing conservative assumptions with known measurements

Cost: $440,000 total cost of project over the past five years

Metric: Identify the times when we make use of the additional capacity. (TBD - project is still in the pilot construction phase. Testing indicates that we will see capacity gains, but none to claim yet.)

B. Substation and Distribution Network and Operations Enhancements

Conservation Voltage Reduction Enhancements

Description: Minimize voltages on transformers while maintaining customers' voltage levels to meet the National Service Voltage Standard (ANSI C84.1). CVR would also be able to reduce demand on transformers during peak load periods in response to capacity requirements. The scope of the project includes the following: validate energy savings associated with CVR using measured instead of modeled values; quantify the costs and benefits associated with implementing CVR; determine methods for expanding the CVR program to additional feeders; pilot methods for making Idaho Power's CVR program more dynamic; and determine methods for ongoing measurement and validation of CVR effectiveness.

Status: Complete

Benefits: Validation of customer and utility energy and demand savings from CVR

Cost: $263,000 total cost of project

Metric: kWh and kW reduction between typical and CVR operated feeders.

	Boise		Pocatello		Twin Falls		Ketchum		McCall		Ontario		Irrigation
	Commercial	Residential	Commercial	Residential	Commercial	Residential	Commercial	Residential	Commercial	Residential	Commercial	Residential	Irrigation
Energy	-2.16%	-2.39%	-1.75%	-1.28%	-0.89%	-0.57%	-2.47%	-2.58%	-0.61%	-1.21%	-0.31%	-1.50%	-0.52%
Demand	-3.12%		-4.95%		0.40%*		-1.58%		-3.39%		-1.85%		-2.98%

*Red numbers indicate data points where energy use increased under CVR. Examining this data may prove useful for making CVR more dynamic and informing Idaho Power which seasons, days of the week, times of the day and temperatures CVR works best in a particular weather zone.

B. Substation and Distribution Network and Operations Enhancements (*continued*)

ENGO use for improving performance of CVR

Description: Evaluate ENGO unit ability to mitigate voltage problems in place of more expensive solutions such as reconductoring or installing small voltage regulators.

Status: Ongoing

Benefits: Improve ability to apply CVR to feeders that currently have voltages too low to qualify for CVR.

Cost: Preliminary project cost estimate of $59,410

Metric: Customer voltage improvement

Customer voltage improvement	
Substation Phase Balance Improvement-Maximum Average Phase Difference Reduction	0.1939 V
Flatten Feeder Voltage - Maxium Decrease in Standard Deviation*	0.797 V
Voltage Increase End of feeder (max)	2.219 V
Low Voltage Mitigation when CVR ON - % Fewer Low Voltage Readings at monitored locations	80.83%
Technical Loss Reduction due to ENGO units while in CVR Mode	3.33%
Average CVR Factor for Energy**	1.5
Reduction of Energy Consumption due to CVR**	3.75%

* Decrease in standard deviation represents the difference between substation voltage and end of feeder voltage.

** Calculation of CVR factor performed using day on/day off testing and calculating the difference in energy used from metering at substation end of feeder. This CVR factor is a combined number for all customer types connected to this feeder and represents only 4 weeks testing. No separation between customer classes performed. This CVR factor cannot be directly compared to CVR factors calculated in CVR Enhancements project and is only indicative of the positive potential for CVR.

B. Substation and Distribution Network and Operations Enhancements (*continued*)

Power System Engineering Research Center (PSERC)

Description: This is a PSERC High Impact Project: Life-cycle management of critical systems through certification, commissioning, in-service maintenance, remote testing, and risk assessment. The life-cycle management of critical systems is particularly complex since it requires tools and methodologies that are not readily available, so some custom approaches are typically taken, which may be costly. Typical examples are the deployment of synchrophasor based Wide Area Protection, Monitoring and Control (WAMPAC) and Special Protection System (SPS) where no standard tools for certification, commissioning, in-service maintenance and risk assessment are available. This project will deliver such tools and make some of them readily available for the industry to use at the host universities.

Status: Ongoing

Benefits: Awareness and/or implementation of new projects, methods and technologies that can increase the operational and planning efficiencies.

Cost: $50,000 total cost of project

Metric: # of projects, methods and technologies that become adopted by the company.

# of Projects Adopted
0

B. Substation and Distribution Network and Operations Enhancements (*continued*)

Solar End-of-Feeder Project

Description: Explore and install a pilot project to determine the possible benefits of using energy storage, "smart" inverter technology and/or PV solar panels at the end of the feeder.

Status: Ongoing

Benefits: Multiple customer voltage improvement

Cost: 2016 budget of $225,000

Metric: Deviations outside of ANSI-A (TBD - there are none to date)

Renewable Integration Tool

Description: The Renewable Integration Tool (RIT) was developed to provide the Load Serving Operators a more accurate wind generation forecast to utilize when balancing supply and demand. A wind generation forecast is generated for both day ahead and real time balancing purposes and displays the trends for both actual generation and the forecast generation for determining forecast accuracy. The day ahead and real time operators utilize this forecast to determine what resources are available and needed to serve firm system demand for the next day(s) and hour(s). The RIT is being expanded to forecast the solar generation that is scheduled to come on-line over the next few years.

Status: Ongoing

Benefits: Improved optimization of dispatchable resources

Cost: $470,000 wind forecast project, $60,000 solar forecast project

Metric: # of curtailments of renewable generation, amount of energy curtailed, amount of generation acquired during the hour as a result of renewable generation deficit.

# of Curtailments	Amount of Energy Curtailed	Amount of Generation Acquired as a result of renewable generation deficit
0	0	0

B. Substation and Distribution Network and Operations Enhancements (*continued*)

Implementation of Automated Connect/Disconnect Capability at Selected Locations Through AMI

Description: Approximately 15,955 meters with remote controlled disconnect and reconnect capability have been installed at customer locations that historically required multiple visits annually.

Status: Complete

Benefits: Reduced connect/reconnect labor and expenses, collection labor and expenses, reduced reconnect fee in Idaho, reduced reconnect response time, improved employee safety.

Cost: $1.0 million total cost of project

Metric: Change in head count, # of remote meters installed, # of remote disconnects, # of remote reconnects, change in reconnect fee, and reconnect response time**.

Jurisdiction	Year	Positions Reduced	Total # of Remote Meters Installed	# of Remote Disconnects	# of Remote Reconnects	Change in Reconnect Fee
Idaho	2015	5	13,728	3,178	3,201	-$7
	2016*		1,417	4,999	4,889	
Oregon	2015	0	772	0	0	$0
	2016*	0	39	0	0	

*January 1 through June 30, 2016

**Remote reconnects occur every hour, at the top of the hour.

C. Customer Information and Demand-Side Management Enhancements

Advanced Metering Infrastructure

Description: Idaho Power has deployed the Aclara Two-way Automated Communications System (TWACS) on 99% of the retail customers served, 99% in Idaho and 93% in Oregon. The TWACS technology is installed in the distribution substation and communicates with meters through the distribution power line.

Status: Complete

Benefits: Reduced cycle billing and customer movement meter reading, reduced bill estimates, reduced cancel re-bills, reduced trouble call mileage (pinging), enhanced failure and voltage monitoring. Daily and hourly energy use information for 99% of customers.

Cost: $71,281,847 total cost of project

Metric: Operation and Maintenance Cost Reduction (Docket No. UE 233, DR No. 343)

Operation and Maintenance Cost Reduction (Idaho & Oregon)	
O&M Costs Reductions Related to Metering Activity	$3,353,192
O&M Costs Reductions Related to Connect/Disconnects	$4,045,913
Total O&M Benefits	**$7,399,104**

C. Customer Information and Demand-Side Management Enhancements *(continued)*

my Account (Energy Use Advising Tool)

Description: myAccount gives customers on-line access to Bill and Payment History, Usage History, Daily And Hourly Energy Use, Energy Use vs Degree Days, Pay My Bill, Ways To Pay My Bill, Add An Account, Electric Service Requests, myAccount Profile, Understanding My Bill, FAQs, How My Usage Compares, How I Use Energy, and When I Use Energy.

Status: Ongoing

Benefits: Provides customers with direct access to their account information including energy consumption patterns. Enhances customers' ability to be engaged and educated on ways to use energy more effectively and efficiently. Facilitated by the AMI system.

Cost: $207,000 total cost of project

Metric: # of Monthly log-ins, # of myAccount customers that logged in

Month	# of Log-ins	# of Customers that logged in	Avg Log-ins/Day
July 2015	144,740	71,252	4,669
August 2015	141,834	72,707	4,575
September 2015	143,950	73,082	4,798
October 2015	146,235	74,363	4,717
November 2015	148,200	74,217	4,940
December 2015	153,365	75,059	4,947
January 2016	165,519	79,127	5,339
February 2016	157,319	79,139	5,425
March 2016	162,339	81,182	5,237
April 2016	153,304	78,588	5,110
May 2016	154,122	79,145	4,972
June 2016	159,289	79,939	5,310

C. Customer Information and Demand-Side Management Enhancements *(continued)*

Customer Outage Map

Description: Idaho Power's Outage Map application provides customers with near-real-time information about outages that impact their home or business. Idaho Power launched the online Outage Map application on April 28, 2015. The Outage Map is located on the Idaho Power website in the Outage Center. Customers can view either the full version if using a desktop computer or they can use the mobile version if using a mobile device. The map is tied to the Outage Management System and will be automatically updated every five minutes.

Status: Ongoing

Benefits: Improved customer service during electricity outages. The Outage Map enables Idaho Power to improve customer communication and better meet customer expectations. The following information will be available for known outages, both planned and unplanned: time the outage started, number of customers affected, the status of the restoration crew (in-route or on site), and the estimated time of restoration (ETR).

Cost: No additional costs were incurred by Idaho Power for this activity. The work was performed as regular work duties.

Metric: # of visits to the Outage Map on the Idaho Power website

# of visits to Outage Map*	
Desktop Visits	183,832
Mobile Visits	120,432
Total Map Visits	**304,264**

*July 1, 2015 through June 30, 2016

C. Customer Information and Demand-Side Management Enhancements *(continued)*

Direct Load Control

Description: Idaho Power has offered optional direct load control, or DR, programs since 2004 and to all of its customer segments since 2009. The company has offered an air conditioning (A/C) cycling program, A/C Cool Credit; an irrigation direct load control program, Irrigation Peak Rewards; and a commercial/industrial DR program, FlexPeak Management. The A/C Cool Credit and Irrigation Peak Rewards programs use smart grid technology, more specifically the power line carrier (PLC) technology to activate load control devices installed on customer equipment. All three programs use the hourly load data made possible by AMI to help determine the load reduction.

Status: Ongoing

Benefits: Demand response programs serve as a peaking resource during times of peak load on the Idaho Power system. Minimize or delay the needs to build supply-side peaking resources. Facilitated by the AMI system.

Cost: $9,000,638 total 2015 annual expenses for demand response

Metric: Results from all three DR programs (MW and # of participants per program) and event reporting

Demand Response Program	# of Participants	Demand Reduction (MW)
2015 A/C Cool Credit	29,000	36
2015 Flex Peak Program	72	26
2015 Irrigation Peak Rewards	2,259	305

E. General Business Enhancements

Idaho Power Enterprise Data Warehouse

Description: The Enterprise Data Warehouse (EDW) is a database for storing customer and meter data.

Status: Ongoing

Benefits: The EDW supports the Company's analytical and reporting, customer data viewing and analytics (see myAccount), ensures that reporting activities do not adversely impact performance of the source systems.

Cost: Preliminary Cost Estimate of $1,584,648

Metric: # of types of data (meter data, customer data), # of fields within each type of data

Meter Data (# of fields)	Customer Data (# of fields)
217	2403

E. General Business Enhancements (*continued*)

Meter Data Management System Upgrade

Description: Upgrade the existing version of Itron Enterprise Edition (IEE) to the latest version.

Status: Complete

Benefits: Provided additional functionality - support of complex rate and billing options, enabled net metering rate option (validate and scale hourly data for net metered customers with negative #s). Moved IEE from the no longer supported Windows XP operating system to Windows 7 thereby eliminating certain security concerns. The upgrade also allowed Idaho Power to eliminate some customizations that are now part of the base product supported by Itron.

Cost: $351,738 total cost of project

Metric: # of net metered customers in both Idaho and Oregon

Jurisdiction	Customer Group	# of Customers*
Idaho	Residential	682
Idaho	Small Commercial	28
Idaho	Large Commercial	56
Idaho	Irrigation	3
Oregon	Residential	12
Oregon	Small Commercial	2
Oregon	Large Commercial	4
Oregon	Irrigation	7

* Customer count as of June 30, 2016

III. FUTURE SMART GRID INVESTMENTS

A. Transmission Network and Operations Enhancements

Transmission Situational Awareness Grid Operator's Monitoring and Control Assistant

Description: This project relates to the Linear State Estimator (LSE) and Region of Stability Existence (ROSE) tools. The LSE is a quasi-real-time state estimator solution based on PMU data. This provides for a non-iterative power flow solution of the (reduced) system. The ROSE tool will be fed by either the Peak RC state estimator or the LSE and will calculate real time a margin to voltage stability or to a Path SOL violation.

Status: Future

Benefits: Avoid drifting into voltage instability during unforeseen operating conditions

Cost: TBD

Metric: TBD

Available Transfer Capacity Calculation Tool

Description: This tool will allow for a more realistic determination of the available transfer capacity (ATC) based on actual utilization of the transmission facilities and statistical behavior of the renewable resources. The GUI was intended to facilitate the display of results obtained by the tool (mainly probabilistic ATC). Note that with a given total transfer capability (TTC) and the existing transmission commitments (ETC) statistics as determined from the tool, the ATC can be easily calculated. The latest version of the tool developed by NCSU can handle future system changes, but there is still a fair amount of work that needs to be performed externally to gather the necessary data (historical path flows, historical and forecasted wind and loads, etc) to perform the analysis. At this time Idaho Power is evaluating ways to streamline the data gathering process and include other renewable resources (i.e., solar) in the calculations.

Status: Future

Benefits: An increase in internal path ATC over conventional methods of determining available transfer capacity.

Cost: TBD

Metric: TBD

B. Substation and Distribution Network and Operations Enhancements

Substation Fiber-Based Protection and Control Pilot

Description: Idaho Power's Research, Development, and Deployment team has been working with a protective relay supplier and a network communications equipment supplier developing specifications and methodologies needed to design, build and maintain a new fiber communications digital substation concept. It is proposed that the new systems being developed be overlaid on the existing systems at the Hemingway Transmission Station. The Hemingway to Summer Lake 500 kV line sees frequent activity and would provide an ideal test environment for development of this technology.

Status: Future

Benefits: Lower substation construction cost

Cost: TBD

Metric: TBD

Automated Volt/VAr Management System Pilot

Description: Idaho Power will pilot a new vendor supported VVMS combined with bidirectional communications to replace the existing Automated Capacitor Control system.

Status: Future

Benefits: Flatten feeder voltage profile

Cost: TBD

Metric: TBD

B. Substation and Distribution Network and Operations Enhancements *(continued)*

Replace the Existing Outage Management System

Description: Replace the existing Outage Management System (OMS). The new OMS will integrate into existing control and operating software platforms, including: the Geographic Information System (GIS), Supervisory Control and Data Acquisition (SCADA), Advance Meter Information (AMI), Mobile Workforce Management (MWM), and Customer Relationship and Billing (CR&B) systems.

Status: Future

Benefits: Vendor Support of the application to accomplish faster identification of outage, more accurate count of customers impacted by the outage, enhanced outage communication with customers

Cost: TBD

Metric: TBD

Implement Additional AMI Outage Scoping and Restoration Confirmation Functionality

Description: Integrate the AMI system with the Sentry System.

Status: Future

Benefits: See "Replace the Existing Outage Management System"

Cost: TBD

Metric: TBD

C. Customer Information and Demand-Side Management Enhancements

Customer Relationship Management (CRM)

Description: Using the CRM capabilities of the CR&B system, the CRM application will retrieve data from a variety of data sources (meter usage data, customer data, demographics, program data, etc.). The software will provide the ability to query and report both formally and on an ad hoc basis. Customer preference management (opt-out, marketing frequency, topic choice, etc.) will also be a component of the system.

Status: Future

Benefits: Manage and track customer interactions related to energy efficiency and other customer relations activities to increase effectiveness of Idaho Power's program and service offerings.

Cost: TBD

Metric: TBD

Integrated Demand Response Resource Control

Description: Idaho Power manages three DR programs. The dispatch associated with each program is unique to the program and requires various steps by generation dispatch employees utilizing multiple systems. An opportunity exists to increase operator visibility to programs and gain efficiencies when dispatching DR programs during events.

Status: Future

Benefits: Efficiencies/accuracy of load dispatch.

Cost: TBD

Metric: TBD

III. FUTURE SMART GRID INVESTMENTS (*continued*)

E. General Business Enhancements

Upgrade the Mobile Workforce Management System

Description: Upgrade the existing version of PragmaCAD to the latest version to maintain vendor support and realize improvements in the functionality of the latest version.

Status: Future

Benefits: Vendor Support of application to optimize scheduling of customer appointments by location, employee skill, levelizing work load

Cost: TBD

Metric: TBD

IV. Smart Grid Opportunities and Constraints

A. Transmission, Substation, Operations, and Customer Information Enhancements

Personalized Customer Interaction

Description: Proactively provide information to customers that is most important to them using email, text messaging, phone applications, and social media platforms.

Status: Future

Benefits: Proactively communicates with customers in the channel of their choice on topics that are the most important to them. Improves customer satisfaction and reduces customer calls.

Cost: TBD

Metric: TBD

B. Evaluations and Assessments of Smart Grid Technologies

Electric Vehicle Charging Impacts Study

Description: Evaluate the impact of residential EV charging on Idaho Power's distribution system.

Status: Complete as of 2016

Benefits: Gain an understanding the likely impact to utility facilities of electric vehicle charging

Cost: $51,000 total cost of project

Metric: Increase in household demand at peak

Average Demand Increase (per participant)	
Peak Hours (13:00 – 21:00)	After Peak (22:00 – 24:00)
13.3%	21.9%

Maximum Demand Increase (per participant)	
Peak Hours (13:00 – 21:00)	After Peak (22:00 – 24:00)*
125%	800%

* Small home, energy efficient, likely only vampire (standby) loads

B. Evaluations and Assessments of Smart Grid Technologies (*continued*)

Photovoltaic and Feeder Peak Demand Alignment Pilot

Description: Conduct a study of a residential/small commercial feeder to determine the number of weather stations, including solar intensity monitors that need to be installed along the feeder to gather and characterize the solar/weather patterns. Gather feeder load data and correlate the feeder load to the solar generation potential along the feeder. Includes purchase and installation of (probably) permanent solar intensity monitors, PV panels, and power metering and recording equipment.

Status: Complete in 2016

Benefits: Gain an understanding of the potential for solar PV generation to contribute to feeder peak load demand reduction.

Cost: $25,000 total cost of project

Metric: The cross correlation and time offset of the feeder load data in MW and the solar irradiance in Watt/m^2.

	Solar Peak Leads Load Peak (# of hours)
Southerly	3.96 to 4.13
Global	4.00 to 4.02
Westerly	1.76 to 1.94

B. Evaluations and Assessments of Smart Grid Technologies (*continued*)

Solar-Powered Parking Lot Lighting

Description: High-pressure sodium lighting was replaced with high-efficiency LEDs in an employee parking lot. Solar panels were mounted on each light pole so that energy can be fed back onto Idaho Power's distribution system when the solar panels produce more energy than the LED lights consume.

Status: Complete

Benefits: Lighting for parking lot on a net-zero annual energy basis

Cost: This project was funded by shareholder dollars. No project costs were charged to customers.

Metric: Annual Net consumption/generation in kWh

Year 1

Month	Year	Net kWh Consumption	Running Total
September	2013	8	8
October	2013	(5)	3
November	2013	244	247
December	2013	383	630
January	2014	417	1047
February	2014	277	1324
March	2014	(0)	1323
April	2014	(157)	1167
May	2014	(359)	808
June	2014	(382)	426
July	2014	(359)	66
August	2014	(262)	(196)
Running Total		(196)	

Negative = net generation
Positive = net load

Year 2

Month	Year	Net kWh Consumption	Running Total
September	2014	(144)	(144)
October	2014	2	(142)
November	2014	217	75
December	2014	412	487
January	2015	307	794
February	2015	28	822
March	2015	(188)	634
April	2015	(344)	290
May	2015	(339)	(48)
June	2015	(438)	(487)
July	2015	(403)	(890)
August	2015	(329)	(1219)
Running Total		(1,219)	

Negative = net generation
Positive = net load

Year 3

Month	Year	Net kWh Consumption	Running Total
September	2015	(214)	(214)
October	2015	(9)	(222)
November	2015	189	(34)
December	2015	405	371
January	2016	291	662
February	2016	22	684
March	2016	(22)	662
April	2016	(304)	358
May	2016	(347)	11
June	2016	(391)	(381)
July	2016		
August	2016		
Running Total		(381)	

Negative = net generation
Positive = net load

Appendix I.
Draft Observability Methodology Document

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Optimal PMU Placement to Achieve Full Observability of Idaho Power Co. System

DRAFT

July 2016

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1. OPTIMAL PMU PLACEMENT FOR POWER SYSTEM OBSERVABILITY

The phasor measurement unit (PMU) placement problem refers to the minimum number of PMUs to be placed in the network while maintaining observability of the entire electric power system network, [1], [2].

There exist multiple definitions of power system network observability. A power system is considered to be observable for a given network topology if voltage vector at each node can be calculated based on the PMU measurements. The definition of observability may be extended such that in addition to computing voltage vector, values of load, generation and parameters of reactive sources (capacitors/reactors, VSC, FACTS devices, etc.) are calculated as well. In [3], a power system is defined as observable if "for a given topology and a set of available measurements, it is possible to determine the power flow across the system circuits".

Since voltages are state variables for the steady-state model of a power system network, for the purpose of this study, we will consider a power system network to be observable if voltage vector at each node can be calculated based on the PMU measurements. This formulation includes several modifications, for example, considering PMUs that have been already installed, limiting the number of PMU measurements [4], incorporating PMU cost, excluding pre-defined locations [5].

2.

APPROACHES TO ANALYSIS OF POWER SYSTEM OBSERVABILITY

Formulation of PMU placement problem depends on the definition of a criterion for complete system observability. There are two types of criteria to define system observability: numerical and topological, [6], [7].

2.1 Numerical Approaches to Power System Observability Analysis

Numerical definition assumes that there exists a system of linear equations

$$B(v) = m \tag{1}$$

such that equation

$$B^T B(v) = B^T m \tag{2}$$

has a unique solution,

where

v is vector of bus voltages;

m is the vector of measured voltages and currents.

The uniqueness of the solution is checked by transforming matrix $B^T B$ to LDL^T form,

where

L is a lower triangular matrix;

D is a diagonal matrix.

When a power system network is fully observable, matrix D is a non-zero matrix, [9].

2.2 Topological Approaches to Power System Observability Analysis

Topological definition is based on identifying nodes where voltage either is measured by PMU or may be computed based on a PMU measurement at another node.

Consider a power system network with N nodes. Let X_i be a binary variable associated with bus i. Variable X_i is set to 1 if a PMU is installed at node i, else it is set to zero. Let Y_j be a binary variable associated with node j voltage. Variable Y_j is set to 1 if voltage vector at node j is known, else it is set to zero. Then, the objective function of optimal PMU placement to achieve full network observability in terms of topological definition can be formulated as follows:

$$\sum_i X_i \rightarrow min,$$

$$\sum_i X_i + \sum_j Y_j = N. \tag{3}$$

There is no analytical expression to determine the value of variable Y_j (e.g., to check the statement that Y_j is set to 1 if voltage vector can be computed, and 0 – if it cannot be computed). Thus, whether voltage vectors can be computed based on the identified PMU placement can be only checked algorithmically. Thus, optimization approaches for optimal PMU placement are either based on search algorithms or some assumptions, and do not guarantee identification of minimum number of PMUs.

If voltage vector at a bus and current vector on a branch connected to the bus are measured by a PMU, then bus voltage at the other end of this branch may be computed. If there is only one circuit connected to a bus, or current on another circuit and all branches connected to this bus, except one branch, is known, current on this circuit may be computed using Kirchhoff's Law. If PMU measures voltage at one of a branch and another PMU measures current at the other end of this branch, then voltage at this bus (see Figure 2-1) is computed as follows:

$$V_j = \frac{V_i - ZI_j}{1 + Z\,Y_j}, \qquad Y_j = i\left(\frac{B}{2} + Y_{shunt}\right), \qquad I_i = I_j + Y_j V_j + Y_i V_i, \tag{4}$$

where

V = is complex vector of voltages,

I = is complex vector of current,

Y = is vector of admittance.

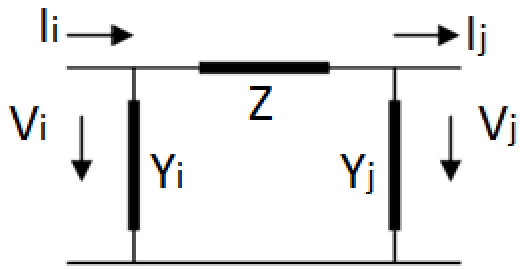


Figure 2-1
Power System Network

Note that the above computation is also useful for bad data detection.

These computations allow to decrease the number of PMU installations.

In [4], a spanning tree approach is used to check the system observability. The advantage of this approach is that it allows to limit the number of measurements coming from one PMU, for example there may be one or two currents measured by one PMU. However, in this approach, the number of PMU locations depends on which bus is selected as a root (e.g., starting) bus of the tree. Thus, to ensure the minimum number of PMU placements, it is necessary to repeat the search using each network bus as a root bus. Another difficulty in using this approach is that the number of possible trees becomes overwhelming as the dimensions of the power system model increase, [8]. Therefore, a certain depth of observability is introduced to reduce the number of searches, [9].

Another approach to optimal PMU placements is the use of search algorithms, for example Improved Tabu Search (ITS), [10] – [12]. One more search algorithm, Non-dominated Sorting genetic algorithm, is introduced in [13]. Based on these references, currently search approached are effective only for small power system models.

2.3 Use of Linear Programming for Optimal PMU Placement

Formulating optimal PMU placement as a binary linear programming problem is the most frequently used approach, [2]. It is based on the following assumptions:

1. PMU installed at a bus directly measures bus voltage phasors and branch current phasors on all branches connect to this bus.
2. Buses where voltage phasor may be computed based on PMU measurements are connected to the bus where PMU is installed.

Use of assumption (2) results in overestimation of the number of PMU locations. A realistic power system network has a large number of transition (e.g., zero injection) buses with no generators, loads, and switched shunts connected to this bus. Kirchhoff's law may be applied to compute voltage phasor at these buses, even if they are not directly connected with a bus where a PMU is installed.

The number of PMU installations may be significantly reduced by increasing the number of decision of variables and constraints in the linear programming formulation. An algorithm that considers zero injection buses in optimal PMU placement problem is descried in [14].

Use of nonlinear programming for optimal PMU placement problem is presented in [5]. To solve the optimal PMU placement problem, the approach uses convex quadratic function and non-convex quadratic constraints. The advantage of this approach is that it has the ability to provide multiple solutions with the same number of PMU locations. The approach uses the upper bounds for the binary decision variables, which makes it easier to obtain the solution.

3.
PURPOSE OF THE OBSERVABILITY STUDY FOR IPC

A system is considered to be observable if voltages at all system nodes are known. A number of PMUs have been already installed at Idaho Power Co. (IPC). The purpose of this study is to identify the optimal placement of additional PMUs such that IPC network becomes fully observable:

- PMUs should be placed such that voltage can be computed at all nodes at IPC.
- The optimal PMU placement is performed for a given system topology defined by the West-wide System Model (e.g., *WSMExport.csv* file):
  - The current study is performed for system topology described by file *WSMExport_PowerWorldAux_20151129.csv*.
  - The methodology is also tested for the system topology described by *WSMExport_PowerWorldAux_20160502.csv*.
- Locations of existing PMUs installed at IPC are incorporated during the optimal PMU placement analysis. These locations are defined in the file *WSM_PMU_OpenPDC_signal_mapping.csv*.
- It is assumed that two nodes connected by switchgear have equal voltage. Therefore, these nodes can be collapsed. Only collapsed nodes are used during computations.
- It is assumed that if a PMU is located at a collapsed node (e.g., **PMU node**), current vectors on all branches connected to this node are also known.

4.
INITIAL GRAPH OF THE IPC SYSTEM

Let us consider IPC footprint in the West-wide System Model, and collapse nodes at IPC footprint connected by switchgear. After consolidation is performed, the graph of IPC network consists of 361 collapsed nodes.

Detailed information about this graph is given in Attachment 1 *NodeInfoInitialGraph.xlsx*. The graph is defined by 361 collapsed nodes and nodes adjacent to them. A node is considered an adjacent node if it is connected with any node that comprises a collapsed node through an in-service line or transformer.

4.1 HasPmu Property

A collapsed node is a PMU node if a PMU is installed at one of the original nodes comprising the collapsed node, as defined in file *WSM_PMU_OpenPDC_signal_mapping.csv*. If a collapsed node is a PMU node, its **HasPmu** property is set to **True** in the *NodeInfoInitialGraph_20160516.xlsx*.

4.2 Zero Injection Property

A collapsed node is considered a **Zero Injection** node, if the following conditions are satisfied:

- There are no generators, loads, and switched shunts connected to this node. Only in-service devices are considered.
- It is not connected with nodes outside of IPC's footprint via tie-lines.

Therefore, Kirchhoff's law may be applied to **Zero Injection** nodes.

4.3 Initial Graph for IPC

Initial graph for IPC is shown in Figure 4-1.

It has the following characteristics:

```
IPC Nodes = 361
Pmu Nodes = 21
Zero Injection Nodes = 158
```

Figure 4-1
Initial graph for IPC

5.
EQUIVALENT GRAPH REDUCTION

Let us further reduce IPC model. Nodes are removed from the graph if voltage at these nodes may be calculated using the rest of the model as follows:

1. A radial **Zero Injection** node is removed if it is connected with the rest of the graph only with one line. Thus, it has only one adjacent node. The process is repeated in a loop since after removing a node, an adjacent node may become a radial **Zero Injection** node.
2. A chain of **Zero Injection** nodes is replaced with one edge. Vertices of these edges become adjacent nodes. This substitution is done in a loop.

Note that PMU nodes should not be removed.

Equivalent graph of IPC network is shown in Figure 5-1.

It has the following characteristics:

```
IPC Nodes = 299
Pmu Nodes = 21
Zero Injection Nodes = 96
```

Figure 5-1
Equivalent graph of IPC Network

Detailed information of this graph is given in Attachment 2 *NodeInfoReducedGraph.xlsx*.

6. OPTIMAL PMU PLACEMENT FOR FULL SYSTEM OBSERVABILITY

6.1 Optimal PMU Placement for Full System Observability Using Linear Programming

The optimal PMU placement problem for complete system observability is solved by the binary linear programming approach.

Let us introduce the following notation:

xNum is a binary variable which shows the state of PMU installation, where

$$\mathbf{xNum} = \begin{cases} 1, if\ a\ PMU\ is\ installed\ at\ node\ i \\ 0, if\ a\ PMU\ is\ not\ installed\ at\ node\ i \end{cases}$$

Thus, if a PMU is installed at a node, **xNum** = 1, otherwise it is equal to zero.

Current vectors on all branches connected to a **PMU node** are assumed to be known. Thus, voltage at this node can be computed if PMU is installed at either this node or an adjacent node.

<u>An example for IPC graph:</u>

Let us define the following variables: x32778, x32785, x32794, x32995, etc. and consider node 32778 which has four adjacent nodes 32785, 32794, 32879, and 32995. Then, observability constraint for node 32778 is:

$$\mathrm{x32778} + \mathrm{x32785} + \mathrm{x32794} + \mathrm{x32879} + \mathrm{x32995} \geq 1$$

Objective function is minimization of the number of PMU installations, e.g., minimization of the sum of **xNum**.

This is a standard integer linear programming problem, which can be solved by a standard solver. MATLAB solver was used for the simulation. As a result, <u>**111 PMU locations were identified, including 21 existing locations**</u>.

6.2 Optimal PMU Placement for Full System Observability Using Linear Programming while Considering Kirchhoff's Law

Algorithm described in Section 4.1 may be further enhanced. Let us consider a **Zero Injection** node and adjacent nodes. If voltage is known at all nodes but one, we can compute voltage at the latter node.

For example, node 32821 is a **Zero Injection** node with adjacent nodes 34003, 32827, 32828, and 33267 (see file *NodeInfoReducedGraph.txt*). According to Section 4.1, the following inequalities ensure observability of the corresponding node:

Node 32821: $x32821 + x34003 + x32827 + x32828 + x33267 \geq 1$

Node 34003: $x32821 + x32881 + x32829 + x33810 + x34003 + x33369 \geq 1$

Node 32827: $x32827 + x32821 \geq 1$

Node 32828: $x32828 + x32821 \geq 1$

Node 33267: $x33267 + x32821 \geq 1$

In order to define whether node voltage can be computed, let us introduce variables u32821, u34003, u32827, u32828, and u33267 such that the following inequalities hold:

Node 32821: $x32821 + x34003 + x32827 + x32828 + x33267 \geq u32821$

Node 34003: $x32821 + x32881 + x32829 + x33810 + x34003 + x33369 \geq u34003$

Node 32827: $x32827 + x32821 \geq u32827$

Node 32828: $x32828 + x32821 \geq u32828$

Node 33267: $x33267 + x32821 \geq u33267$

The observability constraint is changed as it is now not required that each **uNum** be equal to 1. Voltage being known at all nodes adjacent to **Zero Injection** node, except one, is a sufficient condition:

$u32821 + u34003 + u32827 + u32828 + u33267 \geq 4$

As a result, less number of PMUs are needed to be placed to ensure complete observability of the system.

MATLAB solver was used for the simulation. As a result, **88 PMU locations were identified, including 21 existing locations**.

6.3 Iterative Solution of Linear Programming Problem

Propagation of property "voltage is known" is an iterative process. Initially "voltage is known" at nodes where PMUs are installed. Based on voltage at these PMU nodes, voltage at adjacent nodes are computed at the next iteration. At the following iteration, we compute voltage at some other nodes using Kirchhoff's Law for **Zero Injection** nodes, etc.

During this study, we introduced an approach that allows us to define this iterative process in terms of linear programming. Please note that the concept of "iteration" is not present in linear programming formulation. In order to build this iterative process, let us define sets of binary variables (e.g., having values of 0 and 1) as shown in Table 6-1.

Table 6-1
Sets of Binary Variables

Property	Notation	Value
The state of PMU installation	$\boldsymbol{xNum}$	1 - a PMU is installed, 0 - a PMU is not installed
Voltage is computed at node **Num** on the i^{th} iteration	$\boldsymbol{uNum_i}$	1 - voltage is computed, 0 - voltage is not computed
Voltage is computed at a group of nodes adjacent to **Zero Injection** node **Num** on the i^{th} iteration	$\boldsymbol{gNum_i}$	1 - voltage is computed at all nodes in a group, 0 - voltage is not computed at all nodes in a group

Property "voltage is known" propagates as follows:

$$x \rightarrow u_1 \rightarrow g_1 \rightarrow u_2 \rightarrow g_2 \rightarrow \cdots \rightarrow u_i \rightarrow g_i \rightarrow \cdots \rightarrow u_{MaxIter},$$

subject to the following conditions:

$\boldsymbol{xNum}$ = 1, if a PMU is installed at a node;

$\boldsymbol{uNum_1}$= 1 if a PMU is installed (x = 1) either at this or one of adjacent nodes;

$\boldsymbol{gNum_1}$= 1, for the group consisting of a **Zero Injection** node and adjacent nodes: if the total number of nodes where voltage was computed on the 1st iteration (n_1 = 1) is greater or equal to the number of nodes in the group minus 1;

. . . ,

$\boldsymbol{uNum_i}$= 1 "voltage is known" at a node on the i^{th} iteration, if it was either known on the previous iteration i – 1, or the node is a part of the group in which we computed voltage on the previous iteration;

$\boldsymbol{gNum_i}$= 1, "voltage is known" at the group consisting of a **Zero Injection** node and adjacent nodes on the i^{th} iteration if the total number of nodes where "voltage is known" on this iteration (n_i = 1) is greater or equal to the number of nodes in the group minus 1;

. . . ,

$\boldsymbol{uNum_{MaxIter}}$= 1 "voltage is known" at all nodes on the last iteration.

The following inequalities ensure that the above conditions are satisfied:

$$xNum + \sum_{\substack{K=Node\ Numbers \\ conneected\ to\ node\ Num}} xK \geq uNum_1$$

$$uNum_i + \sum_{\substack{K=Node\ Numbers \\ conneected\ to\ node\ Num}} uK_i \geq (N_{Nodes} - 1) * \ gNum_i$$

$$uNum_{i-1} + \sum_{\substack{K=GroupNumbers \\ that\ contain\ node\ Num}} gK_{i-1} \geq \ uNum_i$$

MATLAB solver was used for the simulation. As a result, **80 PMU locations were identified, including 21 existing locations**.

6.4 Decreasing the Number of Variables

The number of variables is of essential importance in mixed integer linear programming problem. When the number of variables is large, the solver either takes very long time to run (can be hours or days), or it fails to solve.

We introduced two approaches to decrease the number of variables.

After the number of variables is decreased, MATLAB solver identifies **78 PMU locations including 21 exiting locations.**

6.4.1 Decreasing the Number of Variables: Approach 1

For nodes that are not adjacent to a **Zero Injection** node, we do not need to form variables at each iteration of the computational process.

Explanation: Property "voltage is known" propagates through the groups of nodes that are adjacent to a **Zero Injection** node.

6.4.2 Decreasing the Number of Variables: Approach 2

For 21 **PMU nodes** and adjacent nodes, voltage is computed on the 1st iteration. Thus, creating variables for them is not needed.

7. USING POM SUITE AND MATLAB FOR PERFORMING OBSERVABILITY ANALYSIS

A significant number of algorithms have been developed to solve integer linear programming problem. There is no one single most effective algorithm. For certain computations some algorithms have been found more effective. Each of the algorithms also has a large number of settings. There are no rules for selecting optimal values of these settings, and these settings are frequently selected based on try-and-cut approach.

There also exist a large number of standard software products with built-in functions to solve integer linear programming problem. We tested the following software products to identify optimal PMU locations for IPC:

- Microsoft Solver Foundation;
- LPSolve;
- Extreme Optimization Numerical Libraries;
- MATLAB.

7.1 Setting up Observability Study

Observability study is executed as follows:

1. Execute program *LpModelForOptimalPmuPlacement.vb* from POM/ROSE interface in order to prepare linear programming model by identifying decision variables, writing the expression of the objective function and defining constraints:
    - Microsoft Solver Foundation was selected as the most effective tool for preparing linear programming model.
    - Model is written to an .mps file supported by Microsoft Solver Foundation.
2. Solve integer linear programming problem in MATLAB using the following steps:
    - Read the .mps file using function mpsread.
    - Run program intlinprog with default settings.
    - Results of observability study which list optimal PMU locations are written to a comma-delimited (.csv) file.
    - Note that it is useful to impose a limit on the run time. For example, run time to identify 78 PMU locations is 800 sec on a standard desktop.

7.2 Identifying the Optimal Number of Iterations

Parameter **MaxIter** (maximum number of iterations) was added to the linear programming model (see Section 4.3). The larger the value of **MaxIter**, the more accurate linear programming model is, and thus, the smaller the number of PMU locations. However, increasing the value of this parameter makes linear programming model more complex, and thus, the number of variables and constraints increases.

Table 7-1 shows how the number of the decision variables decreases using the approaches describer in Section 4.4.

Table 7-1
Decreasing Number of Decision Variables

Value of MaxIter	Number of Decision Variables	Number of Constraints	Number of PMU Locations
0	298	319	111
1	629	650	82
2	960	981	78

* - run time is 800 sec.

7.3 Checking the Results of Optimal PMU Placement

The results of optimal PMU placement may be checked using POM/ROSE script *Test101_CheckPmuPlacement.vb*. The script checks that PMU locations as identified in Section 5.2 are sufficient to determine voltages at all nodes at IPC.

This check is performed as follows:

1. Graph of IPC system is defined by a list of node as well as the list of edges:
   - For each node: a list of edges coming from this node is created;
   - For each edge: a list of nodes connected by this edge.
   - Note that this approach allows us to compute node voltages, current on edges, as well as directly use Ohm's and Kirchhoff's Laws.
2. Initial graph reduction is not performed.
3. PMU mapping file is read and locations of existing PMUs are identified. It is assumed that voltages at these nodes and current on the edges coming from these nodes are known.
4. Propagation of property "voltage is known" as well as property "current is known" is performed. Propagation of these properties is an iterative process. At each iteration, propagation is computed using the following algorithm:
   - If voltage at a node and current on an edge coming from this node are known, then voltage at an opposite end node can be computed using Ohm's Law.
   - If voltage at two nodes connecting an edge is known, current on this edge can be computed using Ohm's Law.

- If current on all edges connected to a **Zero Injection** node, except one, is known, current on this edge is computed using Kirchhoff's Law.
- If voltages at all nodes adjacent to a **Zero Injection** node are known, voltage at a **Zero Injection** node can be computed.
  This is the most complex condition defined by a linear equation written for the unknown voltage:
  - Current on each edge is expressed in terms of this unknown voltage using Ohm's Law.
  - From Kirchhoff's Law it follows that the sum of these currents is equal to 0.

Results of the check performed for 78 PMU locations are shown in Figure 7-1.

```
Observable Nodes:  78, Edges: 233
Observable Nodes: 278, Edges: 321
Observable Nodes: 323, Edges: 383
Observable Nodes: 352, Edges: 400
Observable Nodes: 358, Edges: 407
Observable Nodes: 361, Edges: 407

Stage Check
IPC Nodes = 361
Zero Injection Nodes = 151
Pmu Nodes = 78
PMU Placement is good.
```

Figure 7-1
Checking Results of PMU Placement

8. STEPS TO RUN OBSERVABILITY STUDY

To run the observability study in POM/ROSE and MATLAB, please perform the following steps:

1. Open POM/ROSE software.

   1.1 Load a project.

   1.2 Run script *LpModelForOptimalPmuPlacement.vb*:

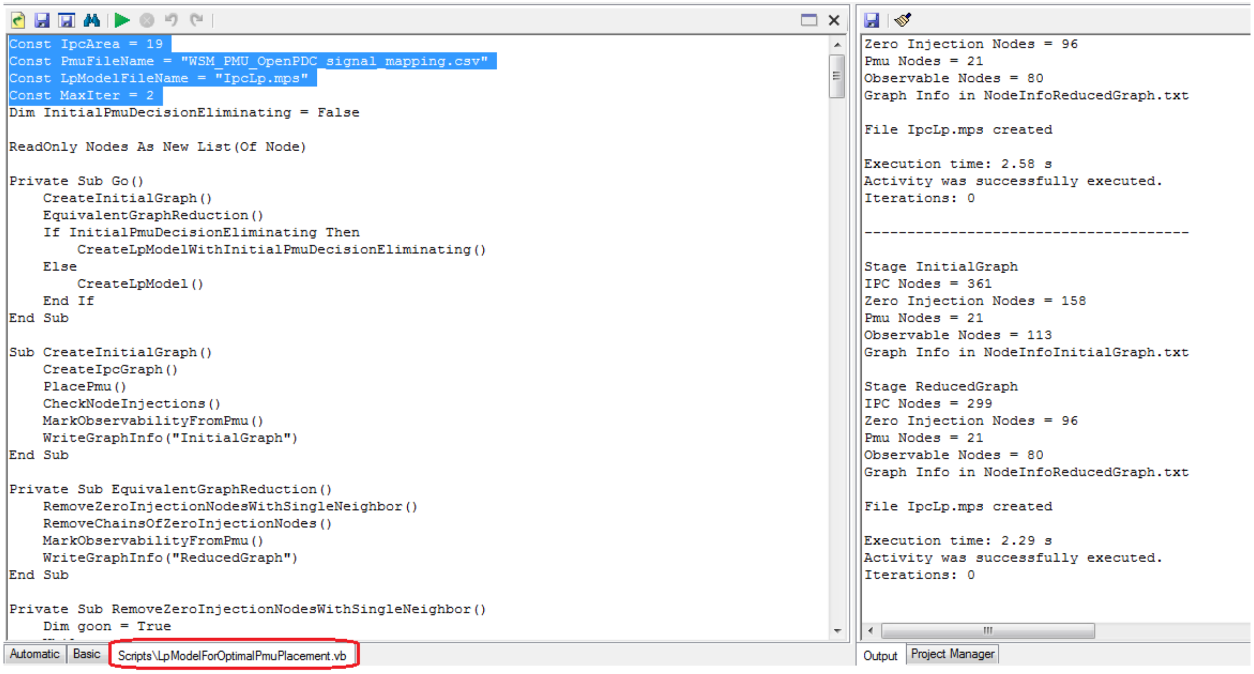
   a. Open the script

   b. Set the control area number for IPC:
   `Const IpcArea = 19`

   c. Enter the name of the mapping file for mapping PMU signals to nodes in the WSM file:
   `Const PmuFileName = WSM_PMU_OpenPDC_signal_mapping.csv"`

   d. Enter the name of the LP model file:
   `Const LpModelFileName = "IpcLp.mps"`

   e. Enter the maximum number of iterations
   `Const MaxIter = 2`



The script creates three output files:

- *IpcLp.mps*;
- *NodeInfoInitialGraph.txt*;
- *NodeInfoReducedGraph.txt*.

2. Open MATLAB.

2.1 Run function `mpsread` to read file *IpcLp.mps*:

```
p = mpsread('path\IpcLp.mps')
```

For example,

```
p = mpsread('C:\ROSE_IPC_Observability\VSA\Work\IpcLp.mps')
```

2.2 Run program `intlinprog` with default settings as follows:

```
options =
optimoptions(@intlinprog,'PlotFcn',@optimplotmilp)

p.options = options

[x,fval,exitflag,output] = intlinprog(p)
```

Note, you can set to `options.MaxTime` = 800 to decrease run time (e.g., to limit it to 800 sec).

2.3 Write the results of observability study (e.g., a list of optimal PMU locations) to a comma-delimited (.csv) file as follows:

```
p1 = readmps('ipclp.mps')
writetable(table(transpose(p1.columnnames), x), 'PMUs.csv')
```

Results are saved to file *PMUs.csv*.

3. Go back to POM/ROSE software.

3.1 Run script *CheckPmuPlacement.vb*:

a. It reads contents of file *PMUs.csv*

```
Const MatLabResultFileName = "PMUs.csv"
```

9. CONCLUSION

The results of using an effective approach developed by V&R Energy for identifying optimal locations of PMU installations is described in this report. The approach is based on automated iterative process of forming decision variables and constraints of a binary integer programming problem, and solving them with standard linear programming solvers.

The study identified 78 PMU locations, including 21 locations of existing PMUs for IPC model that consist of 361 buses. It is usually assumed that buses with PMU installations comprise about 30% of the total number of buses in the model, [9]. The proposed solution allows us to decrease the number of PMU installations approximately by 42 PMUs compared to convention techniques (361/3 – 78 = 42 PMUs).

A fast topological approach was also demonstrated to analyze the observability of the IPC network. It computes voltage and flows in the system based on the results of observability analysis. The results of observability analysis were checked to ensure that after 78 PMUs were installed, this was sufficient to compute voltages at all 361 buses at IPC.

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11. APPENDIX 1: FILE "*NodeInfoInitialGraph.csv*" FOR IPC SYSTEM

Node Number	Station	Name	HasPmu	Zero Injection	Neighbors
32778	ADELAIDE	300	FALSE	TRUE	(32785 32794 33879 32995)
32785	ADELAIDE	800	FALSE	TRUE	(32778 33531 34258 33958 33340)
32794	ADELAIDT	300	FALSE	TRUE	(32778 33879 32995)
32795	ALAMEDA	800	FALSE	FALSE	(33572 32799)
32799	ALAMEDAT	800	FALSE	TRUE	(32795 34413 33541)
32802	AM_FALLS	800	FALSE	FALSE	(32812 32815 33053 33736)
32812	AM_FALLS	810	FALSE	TRUE	(32802)
32815	AM_FALLS	813	FALSE	FALSE	(32802)
32821	ANDRSN_R	100	FALSE	TRUE	(34017 32827 32828 33267)
32827	ANDRSN_R	1300	FALSE	FALSE	(32821)
32828	ANDRSN_R	1301	FALSE	FALSE	(32821)
32829	BCWF	138	FALSE	TRUE	(34003 32836 34300)
32836	BCWF	1002	FALSE	TRUE	(32829 32837)
32837	BCWF	1003	FALSE	TRUE	(32836 32839)
32839	BCWF	1100	FALSE	FALSE	(32837)
32840	BETHELCT	800	FALSE	FALSE	(34517 33226)
32849	BLACKCAT	803	FALSE	FALSE	(34408 33843)
32852	BLACKFOT	1200	FALSE	FALSE	(32856)
32856	BLACKFOT	800	FALSE	TRUE	(32852 34184)
32858	BLISS	800	TRUE	TRUE	(34444 32868 32869)
32868	BLISS	1001	FALSE	FALSE	(32858)
32869	BLISS	1002	FALSE	FALSE	(32858)
32873	BLK_CNYN	600	FALSE	FALSE	(33382)
32881	BLK_MESA	800	FALSE	FALSE	(33562 34000)
32884	BL_GULCH	800	FALSE	TRUE	(34485 33012 32891)
32891	BL_GULCH	1004	FALSE	FALSE	(32884)
32893	BNET_MTN	200	FALSE	TRUE	(34272 33249)
32903	BOISE	804	FALSE	FALSE	(33450 34513)
32908	BOISEBCH	200	TRUE	TRUE	(32984 32986 32983 33907 32940 32948 32985 32941 32947 33899 33495 33769 33298)
32915	BOISEBCH	208	FALSE	TRUE	(32940 33122)

32922	BOISEBCH	214	FALSE	TRUE	(32948 33122)
32936	BOISEBCH	225	FALSE	TRUE	(32941 33122)
32938	BOISEBCH	227	FALSE	TRUE	(32947 33576)
32940	BOISEBCH	229	FALSE	TRUE	(32908 32915)
32941	BOISEBCH	230	FALSE	TRUE	(32908 32936)
32947	BOISEBCH	231	FALSE	TRUE	(32908 32938)
32948	BOISEBCH	232	FALSE	TRUE	(32908 32922)
32949	BOISEBCH	800	FALSE	FALSE	(33443 33850 33450 33355 33135 32983 32984 32985 32986)
32978	BOISEBCH	1001	FALSE	FALSE	(32984)
32981	BOISEBCH	1101	FALSE	FALSE	(32986)
32983	BOISEBCH	1	FALSE	TRUE	(32908 32949)
32984	BOISEBCH	2	FALSE	TRUE	(32908 32949 32978)
32985	BOISEBCH	3	FALSE	TRUE	(32908 32949)
32986	BOISEBCH	4	FALSE	TRUE	(32908 32949 32981)
32995	BORAH	3044	TRUE	TRUE	(33004 32794 33003 32778)
33003	BORAH	319	FALSE	FALSE	(32995)
33004	BORAH	320	FALSE	FALSE	(32995)
33006	BORAH	201	TRUE	TRUE	(33037 33592)
33010	BORDER	800	FALSE	FALSE	(33012)
33012	BORDERTP	800	FALSE	TRUE	(33010 32884 34593)
33021	BOWMONT	205	FALSE	FALSE	(33023)
33023	BOWMONT	800	FALSE	FALSE	(33585 33785 33729 33021 34392)
33037	BRADY	200	TRUE	FALSE	(33069 33070 33068 33713 33006)
33053	BRADY	802	FALSE	TRUE	(33070 33069 32802 33297 34235 33068)
33066	BRADY	1104	FALSE	FALSE	(33070 33069)
33067	BRADY	1105	FALSE	FALSE	(33068)
33068	BRADY	1	FALSE	TRUE	(33037 33053 33067)
33069	BRADY	2	FALSE	TRUE	(33037 33053 33066)
33070	BRADY	3	FALSE	TRUE	(33037 33053 33066)
33077	BRIDGE	806	FALSE	FALSE	(34514 33233 34597 33086)
33086	BRIDGE	1100	FALSE	FALSE	(33077)
33122	BROWNLEE	228	TRUE	TRUE	(33503 32915 33126 33127 34126 33576 32936 32922 33124 34211 34103)
33124	BROWNLEE	1002	FALSE	FALSE	(33122)
33126	BROWNLEE	1004	FALSE	FALSE	(33122)
33127	BROWNLEE	1005	FALSE	FALSE	(33122)
33128	BRUNO_BG	800	FALSE	FALSE	(33132)
33132	BRUNO_BG	804	FALSE	TRUE	(33128 33134 34380)
33134	BRUNO_BG	806	FALSE	TRUE	(33190 33132 34222)
33135	BUTLER	800	FALSE	FALSE	(34564 32949)

33140	BYPASS	805	FALSE	FALSE	(33919 33357)
33152	CALDWELL	207	TRUE	TRUE	(33769 34056 33744 33154)
33154	CALDWELL	800	FALSE	FALSE	(33152 34540 33762 34349)
33168	CANALIPC	831	FALSE	TRUE	(33186 33174)
33174	CANALIPC	1103	FALSE	FALSE	(34062 34322 33168)
33186	CANAL_TP	801	FALSE	TRUE	(33958 33168 33394)
33190	CANYN_CR	800	FALSE	FALSE	(33134 34350)
33200	CARTWRIT	806	FALSE	FALSE	(33355 33330)
33204	CAWP	141	FALSE	FALSE	(33821 33562)
33210	CHESTNUT	806	FALSE	FALSE	(33585 33213)
33213	CHESTNUT	809	FALSE	TRUE	(33210 33916)
33215	CLIFF	800	FALSE	FALSE	(34090 33392)
33226	CLOVERDL	808	FALSE	FALSE	(33783 34513 32840 34319 33843)
33230	COPPRFLD	202	FALSE	FALSE	(34126)
33233	CURLEW	800	FALSE	FALSE	(33077)
33240	DALE	800	FALSE	FALSE	(33688 34422)
33249	DANSKIN	200	FALSE	TRUE	(33254 33495 32893 33260)
33254	DANSKIN	800	FALSE	TRUE	(33996 33369 33249)
33260	DANSKIN	1800	FALSE	FALSE	(33249)
33267	DIXIE	500	FALSE	FALSE	(32821)
33292	DON	822	FALSE	FALSE	(33295 33293 34184 33572 33717 33297)
33293	DON	1000	FALSE	TRUE	(33292)
33295	DON	1004	FALSE	TRUE	(33292)
33297	DON_TAP	800	FALSE	TRUE	(33292 33427 33053)
33298	DRAM	200	FALSE	TRUE	(33850 32908 34272)
33329	DRAM	826	FALSE	TRUE	(33810 33850)
33330	DRY_CK_J	800	FALSE	TRUE	(33431 33200 33535)
33334	DUFFIN	820	FALSE	FALSE	(33340 33643)
33340	DUFIN_TP	800	FALSE	TRUE	(33334 32785)
33345	EAGLEIPC	804	FALSE	FALSE	(34368 33348)
33348	EAGLE_TP	800	FALSE	TRUE	(33435 33345 33654)
33352	ECKERT	800	FALSE	FALSE	(33355)
33355	ECKERT	804	FALSE	TRUE	(32949 33200 33352)
33357	EDEN	800	FALSE	FALSE	(33140 33598)
33363	ELKHRNIP	803	FALSE	FALSE	(33675 34561)
33369	ELMORE	808	FALSE	FALSE	(33254 34003)
33370	EMMETT	800	FALSE	FALSE	(33382 34365 34541)
33382	EMMETT	605	FALSE	FALSE	(33370 32873 34018)
33386	E_GATE	800	FALSE	FALSE	(34290 33676)
33392	E_GATE_T	800	FALSE	TRUE	(34461 33215 33676)
33394	E_HILLS	800	FALSE	TRUE	(34477 33186 33398)
33398	E_HILLS	1000	FALSE	FALSE	(33394)

33416	FOSSIL_G	804	FALSE	TRUE	(33418 33688 34444)
33418	FOSSIL_G	1001	FALSE	FALSE	(33416)
33427	FREMONT	804	FALSE	FALSE	(34196 33297)
33431	GARY	801	FALSE	TRUE	(33330 34513)
33435	GARY	805	FALSE	FALSE	(33348)
33438	GLENSFRY	800	FALSE	FALSE	(33440)
33440	GLFRY_TP	800	FALSE	TRUE	(33438 34300 34495)
33443	GOWEN	800	FALSE	FALSE	(33987 32949)
33450	GROVE	803	FALSE	FALSE	(32903 32949)
33455	HAILEY	800	FALSE	FALSE	(34561 34338)
33461	HAY_MILL	800	FALSE	FALSE	(33529 33473 34258)
33473	HAY_MILL	1007	FALSE	FALSE	(33461 34274)
33486	HAZELATP	804	FALSE	FALSE	(33944 33490)
33490	HAZELBTP	802	FALSE	FALSE	(33486 34548)
33495	HBRD	808	FALSE	TRUE	(33249 32908 34056)
33503	HELLSCYN	206	TRUE	FALSE	(33509 33122)
33509	HELLSCYN	1005	FALSE	FALSE	(33503)
33511	HEWLETT	800	FALSE	FALSE	(33783 33654)
33529	HEYBURN	816	FALSE	TRUE	(33946 34227 33461 34477)
33531	HEYBURNT	800	FALSE	TRUE	(32785 34389 34159)
33535	HIDNSPGS	800	FALSE	FALSE	(33330 34365)
33541	HIGHLDTP	803	FALSE	FALSE	(34358 32799)
33546	HILLSDAL	805	FALSE	FALSE	(33987 34320)
33547	HILL_IPC	800	FALSE	FALSE	(33728 33762)
33553	HINES	601	FALSE	FALSE	(33560 34552)
33560	HINES	126	FALSE	FALSE	(33553)
33562	HMWP	801	TRUE	TRUE	(32881 33566 33204)
33566	HMWP	1000	FALSE	TRUE	(33568 33562)
33568	HMWP	1002	FALSE	TRUE	(33566 33569)
33569	HMWP	1100	FALSE	FALSE	(33568)
33572	HOKU	140	FALSE	TRUE	(33292 32795)
33576	HORSEFLT	200	FALSE	TRUE	(33122 33580 32938)
33580	HORSEFLT	204	FALSE	TRUE	(33576 34375)
33585	HPY_VALY	803	FALSE	FALSE	(33023 33210)
33590	HSHECOGN	602	FALSE	TRUE	(34018)
33592	HUNT	200	FALSE	TRUE	(33888 33006 33598)
33598	HUNT	800	FALSE	TRUE	(33592 34422 34548 33357 34461)
33618	HYDRA	806	FALSE	FALSE	(34451 33650)
33621	IDAHOME	800	FALSE	FALSE	(33958 34514 33625)
33625	IDAHOME	1000	FALSE	FALSE	(33621)
33639	JACKSON	1102	FALSE	FALSE	(34062)
33643	JCLAWSON	800	FALSE	FALSE	(33334)
33649	JEROME	807	FALSE	FALSE	(33650)

33650	JEROM_TP	800	FALSE	TRUE	(34080 33618 33649)
33654	JOPLIN	800	FALSE	FALSE	(33511 33348)
33665	JUSTICE	204	FALSE	TRUE	(33888 34027 33688)
33668	KARCHER	800	FALSE	FALSE	(33670)
33670	KARCHERT	800	FALSE	TRUE	(34083 33668 34045 34604)
33675	KETCHUM	804	FALSE	FALSE	(33363)
33676	KIMBRLY	801	FALSE	FALSE	(33386 33392)
33688	KING_ST	807	FALSE	TRUE	(33789 34426 33240 34485 33416 33821 33665)
33696	KINPORT	301	FALSE	FALSE	(33701)
33701	KINPORT	305	TRUE	FALSE	(33696 33726 33879)
33713	KINPORT	203	TRUE	TRUE	(33037 33726 33717)
33717	KINPORT	800	FALSE	TRUE	(34358 33292 33713)
33724	KINPORT	1000	TRUE	FALSE	(33726)
33726	KINPORT	1	FALSE	TRUE	(33701 33713 33724)
33728	KRCHR_TP	801	FALSE	TRUE	(33547 34045)
33729	KUNA_TAP	800	FALSE	FALSE	(33987 33023)
33736	LAMBIPC	801	FALSE	FALSE	(32802 34181)
33744	LANGLEYG	205	TRUE	TRUE	(33750 33754 33152 34101 33756)
33747	LANGLEYG	800	FALSE	TRUE	(33756 34540)
33750	LANGLEYG	1111	FALSE	FALSE	(33744)
33754	LANGLEYG	1003	FALSE	FALSE	(33744)
33755	LANGLEYG	1004	FALSE	FALSE	(33756)
33756	LANGLEYG	1	FALSE	TRUE	(33744 33747 33755)
33757	LINCOLNI	800	FALSE	TRUE	(33761 33908 34338)
33761	LINCOLNI	804	FALSE	FALSE	(33757)
33762	LINDEN	800	FALSE	FALSE	(33547 33154)
33769	LOCUST	202	TRUE	TRUE	(33152 32908 33783)
33783	LOCUST	809	FALSE	FALSE	(34408 33226 33769 33511)
33785	LOWELL	800	FALSE	TRUE	(33023 34525)
33789	LSALMON	800	FALSE	TRUE	(33800 33801 33688)
33800	LSALMON	1001	FALSE	FALSE	(33789)
33801	LSALMON	1002	FALSE	FALSE	(33789)
33810	LUCKY_PK	803	FALSE	TRUE	(33814 33329 34003)
33814	LUCKY_PK	1001	FALSE	FALSE	(33810)
33821	L_MALAD	800	FALSE	TRUE	(33688 33825 33204)
33825	L_MALAD	1000	FALSE	FALSE	(33821)
33827	MAGIC_TP	800	FALSE	TRUE	(33829 33983 34433)
33829	MAGIC_TP	802	FALSE	FALSE	(33827)
33839	MCCALL	806	FALSE	FALSE	(34375 34071)
33843	MERDNIPC	803	FALSE	FALSE	(33226 32849)
33850	MICRON	809	FALSE	FALSE	(32949 33298 33329)
33856	MIDPOINT	901	TRUE	FALSE	(33858)

33858	MIDPOINT	903	FALSE	TRUE	(33914 33856 33865)
33865	MIDPOINT	910	FALSE	TRUE	(33858)
33879	MIDPOINT	3062	TRUE	FALSE	(32794 33888 33701 32778 33914)
33888	MIDPOINT	200	TRUE	TRUE	(33879 33902 33665 33592 33904 33908)
33899	MIDPOINT	209	FALSE	TRUE	(32908 33904)
33902	MIDPOINT	212	FALSE	TRUE	(33907 33888)
33904	MIDPOINT	214	FALSE	TRUE	(33888 33899)
33907	MIDPOINT	230	FALSE	TRUE	(32908 33902)
33908	MIDPOINT	800	FALSE	FALSE	(33888 34080 33757)
33911	MIDPOINT	1000	FALSE	TRUE	(33914)
33914	MIDPOINT	3	FALSE	TRUE	(33858 33879 33911)
33915	MIDROSE	800	FALSE	FALSE	(33916)
33916	MIDROSE	801	FALSE	TRUE	(33213 33915 34045)
33919	MILNER	800	FALSE	FALSE	(33140 33944 33939 33934)
33934	MILNER	1008	FALSE	FALSE	(33919)
33939	MILNERPP	805	FALSE	TRUE	(33919 33941)
33941	MILNERPP	1300	FALSE	FALSE	(33939)
33944	MILNER_T	138	FALSE	TRUE	(34159 33486 33919)
33946	MINICO	800	FALSE	FALSE	(33529 34389)
33958	MINIDOKA	807	FALSE	TRUE	(33186 34223 32785 33982 33621 33977)
33977	MINIDOKA	1000	FALSE	FALSE	(33958)
33982	MINIDOKA	1105	FALSE	FALSE	(33958)
33983	MOONSTON	800	FALSE	FALSE	(33827 34561)
33987	MORA	800	FALSE	FALSE	(33546 33729 33443)
33996	MTHMAFB	803	FALSE	TRUE	(34380 33999 33254)
33999	MTHMAFB	806	FALSE	FALSE	(33996)
34000	MTN_HOME	1000	FALSE	TRUE	(34003 32881)
34003	MTN_HOME	800	FALSE	TRUE	(33369 33810 32829 34000 34017)
34017	MTN_HOME	100	FALSE	TRUE	(32821 34003)
34018	MTUR	601	FALSE	TRUE	(33382 33590)
34027	MT_AIRWP	205	TRUE	TRUE	(34033 34032 34272 33665)
34032	MT_AIRWP	1003	FALSE	TRUE	(34034 34027)
34033	MT_AIRWP	1004	FALSE	TRUE	(34037 34027)
34034	MT_AIRWP	1005	FALSE	TRUE	(34032 34038)
34037	MT_AIRWP	1008	FALSE	TRUE	(34033 34039)
34038	MT_AIRWP	1100	FALSE	FALSE	(34034)
34039	MT_AIRWP	1101	FALSE	FALSE	(34037)
34040	NAMPA	200	FALSE	TRUE	(34045 34056)
34045	NAMPA	800	FALSE	FALSE	(33728 33916 33670 34040)
34056	NAMPA_TP	200	FALSE	TRUE	(33152 34040 33495)
34057	NELSONTP	800	FALSE	TRUE	(34060 34532 34204)

34060	NELSONTP	803	FALSE	FALSE	(34057)
34062	NEWCOMB	1100	FALSE	FALSE	(33174 33639)
34071	NEWMEADW	802	FALSE	FALSE	(34403 33839)
34074	NEW_BURL	800	FALSE	FALSE	(34227)
34080	NHBT_TAP	800	FALSE	TRUE	(33650 33908 34081)
34081	NHBT_TAP	801	FALSE	FALSE	(34080)
34083	NORCO1	801	FALSE	TRUE	(34084 33670)
34084	NORCO1	802	FALSE	FALSE	(34083)
34088	NTVW_TAP	802	FALSE	FALSE	(34090)
34090	NTVW_TAP	804	FALSE	TRUE	(34088 34491 33215)
34096	N_POWDER	203	FALSE	FALSE	(34211 34098)
34098	N_POWDER	1000	FALSE	FALSE	(34096)
34101	ONTARIO	201	FALSE	TRUE	(34107 33744 34123)
34103	ONTARIO	2011	FALSE	TRUE	(34107 33122)
34107	ONTARIO	205	FALSE	TRUE	(34101 34103)
34123	ONTARIO	812	FALSE	FALSE	(34160 34532 34101)
34126	OXBOW	200	FALSE	TRUE	(34138 34134 33230 33122 34141)
34134	OXBOW	800	FALSE	FALSE	(34126 34375)
34138	OXBOW	1000	FALSE	FALSE	(34126)
34141	OXBOW	2000	FALSE	FALSE	(34126)
34148	PACIFICI	807	FALSE	FALSE	(34573 34477)
34159	PAUL_IDP	810	FALSE	FALSE	(33944 33531)
34160	PAYETTE	800	FALSE	FALSE	(34123 34541)
34170	PINGREE	800	FALSE	FALSE	(34184)
34180	PLEAS_VL	806	FALSE	FALSE	(34181)
34181	PLVLY_TP	800	FALSE	TRUE	(34180 33736 34223)
34184	PNGRE_TP	800	FALSE	TRUE	(33292 32856 34170)
34188	POLELINE	800	FALSE	TRUE	(34422 34194 34451)
34194	POLELINE	808	FALSE	FALSE	(34188)
34196	PORTNEUF	800	FALSE	FALSE	(34413 33427)
34202	QUARTZ	201	FALSE	TRUE	(34204 34211)
34204	QUARTZ	800	FALSE	FALSE	(34202 34057 34552)
34211	QUARTZTP	200	FALSE	TRUE	(34202 33122 34096)
34218	RAFT	804	FALSE	FALSE	(34223)
34222	RAFT_RVR	802	FALSE	FALSE	(33134)
34223	RAFT_T	800	FALSE	TRUE	(34181 33958 34218)
34227	RIVERTON	800	FALSE	FALSE	(34074 33529)
34235	ROCKLAND	802	TRUE	FALSE	(33053)
34236	ROES_CRN	807	FALSE	TRUE	(34258 34253)
34253	ROES_CRN	1025	FALSE	FALSE	(34236)
34258	ROE_CR_T	804	FALSE	TRUE	(33461 32785 34236)
34272	RTLSNAKE	212	FALSE	TRUE	(33298 34027 32893)
34274	RUPERT	1101	FALSE	FALSE	(33473 34283)

34283	RUPERT	1002	FALSE	FALSE	(34274)
34290	RUSSET	800	FALSE	FALSE	(34451 33386)
34300	SAILORCR	807	FALSE	FALSE	(34302 32829 33440)
34302	SAWTOOTH	802	TRUE	TRUE	(34310 34300 34303)
34303	SAWTOOTH	803	FALSE	FALSE	(34302)
34307	SAWTOOTH	1000	FALSE	TRUE	(34310 34312)
34310	SAWTOOTH	1003	FALSE	TRUE	(34302 34307)
34312	SAWTOOTH	1101	FALSE	FALSE	(34307)
34313	SCOVILLE	1200	FALSE	FALSE	(34315)
34314	SCOVILLE	1201	FALSE	FALSE	(34315)
34315	SCOVILLE	800	FALSE	FALSE	(34313 34314)
34319	SD_TAP	800	FALSE	TRUE	(33226 34377 34320)
34320	SD_TAP	801	FALSE	TRUE	(33546 34319)
34322	SEC_LIFT	1100	FALSE	FALSE	(33174)
34338	SILVER	800	FALSE	FALSE	(33455 33757)
34348	SIMPLOT	807	FALSE	FALSE	(34349)
34349	SIMPLOT	808	FALSE	TRUE	(34348 33154 34525)
34350	SINKR_CR	800	FALSE	TRUE	(34353 33190 34392)
34353	SINKR_CR	803	FALSE	FALSE	(34350)
34358	SIPHON	803	FALSE	FALSE	(33541 33717)
34364	SPRINGVL	802	FALSE	FALSE	(34365)
34365	SPRINGVL	803	FALSE	TRUE	(33370 33535 34364)
34368	STAR	801	FALSE	TRUE	(33345 34370)
34370	STAR	803	FALSE	FALSE	(34368)
34375	STARKEY	805	FALSE	FALSE	(33580 34403 34134 33839)
34377	STODDARD	800	FALSE	FALSE	(34319)
34380	STRIKE	800	FALSE	TRUE	(34388 33132 33996)
34388	STRIKE	1003	FALSE	FALSE	(34380)
34389	SUGAR	800	FALSE	FALSE	(33946 33531)
34392	SWANFALL	800	FALSE	TRUE	(34395 34350 33023)
34395	SWANFALL	803	FALSE	TRUE	(34392 34399)
34399	SWANFALL	1000	FALSE	FALSE	(34395)
34403	TAMARACK	802	FALSE	FALSE	(34375 34071)
34408	TENMLE	802	FALSE	FALSE	(32849 33783)
34413	TERRYIPC	800	FALSE	FALSE	(32799 34196)
34422	TFAL_JCT	800	FALSE	TRUE	(34188 33598 33240)
34426	TOPON_TP	800	FALSE	TRUE	(34430 34433 33688)
34430	TOPON_TP	804	FALSE	FALSE	(34426 34438)
34433	TOPON_TP	807	FALSE	TRUE	(34426 33827)
34438	TOPON_TP	812	FALSE	FALSE	(34430)
34444	TUANA	805	TRUE	TRUE	(34446 33416 32858)
34446	TUANA	1001	FALSE	TRUE	(34444 34447)
34447	TUANA	1002	FALSE	TRUE	(34446 34449)

34449	TUANA	1100	FALSE	FALSE	(34447)
34451	TWINFALL	800	FALSE	FALSE	(33618 34188 34290)
34461	TWNFLSPP	800	FALSE	TRUE	(34466 33598 33392)
34466	TWNFLSPP	805	FALSE	TRUE	(34461 34470 34468)
34468	TWNFLSPP	1002	FALSE	FALSE	(34466)
34470	TWNFLSPP	1004	FALSE	FALSE	-34466)
34477	UNITY	806	FALSE	TRUE	(34483 34148 33529 33394)
34483	UNITY	1000	FALSE	FALSE	(34477)
34485	UPSALMON	800	FALSE	TRUE	(34491 33688 34507 32884 34506)
34491	UPSALMON	811	FALSE	TRUE	(34504 34505 34485 34090 34495)
34495	UPSALMON	819	FALSE	TRUE	(34491 33440)
34504	UPSALMON	1005	FALSE	FALSE	(34491)
34505	UPSALMON	1006	FALSE	FALSE	(34491)
34506	UPSALMON	1007	FALSE	FALSE	(34485)
34507	UPSALMON	1008	FALSE	FALSE	(34485)
34513	USTICK	805	FALSE	FALSE	(33226 33431 32903)
34514	VALLEYR	803	FALSE	FALSE	(33077 33621)
34517	VICTJCT	800	FALSE	TRUE	(32840 34564 34523)
34523	VICTORY	804	FALSE	FALSE	(34517)
34525	VLVU	800	FALSE	TRUE	(34529 34349 33785)
34529	VLVU	804	FALSE	FALSE	(34525)
34530	WEISER	803	FALSE	FALSE	(34532)
34532	WEISERTP	800	FALSE	TRUE	(34530 34123 34057)
34535	WELLS_IP	800	FALSE	FALSE	(34593)
34538	WILIS	801	FALSE	FALSE	(34540)
34540	WILIS	803	FALSE	TRUE	(33154 33747 34538)
34541	WILOW_CR	800	FALSE	FALSE	(33370 34160)
34548	WILSONLK	803	FALSE	FALSE	(33490 33598)
34552	WJOHND	802	FALSE	FALSE	(33553 34204)
34561	WOOD_RVR	805	FALSE	TRUE	(33363 33983 33455)
34564	WYEE	800	FALSE	FALSE	(34517 33135)
34573	W_BURLEY	800	FALSE	FALSE	(34582 34148)
34582	W_BURLEY	1003	FALSE	FALSE	(34573)
34593	W_WELLS	800	FALSE	FALSE	(34535 33012)
34597	W_WENDOV	801	FALSE	FALSE	(33077 34602)
34602	W_WENDOV	1000	FALSE	FALSE	(34597)
34604	ZILOG	801	FALSE	TRUE	(33670 34607)
34607	ZILOG	804	FALSE	FALSE	(34604)

12. APPENDIX 2: FILE "*NodeInfoReducedGraph.csv*" FOR IPC SYSTEM

Node Number	Station	Name	HasPmu	Zero Injection	Neighbors
32778	ADELAIDE	300	FALSE	TRUE	(32785 32794 33879 32995)
32785	ADELAIDE	800	FALSE	TRUE	(32778 33531 34258 33958 33334)
32794	ADELAIDT	300	FALSE	TRUE	(32778 33879 32995)
32795	ALAMEDA	800	FALSE	FALSE	(33292 32799)
32799	ALAMEDAT	800	FALSE	TRUE	(32795 34413 33541)
32802	AM_FALLS	800	FALSE	FALSE	(32815 33053 33736)
32815	AM_FALLS	813	FALSE	FALSE	(32802)
32821	ANDRSN_R	100	FALSE	TRUE	(34003 32827 32828 33267)
32827	ANDRSN_R	1300	FALSE	FALSE	(32821)
32828	ANDRSN_R	1301	FALSE	FALSE	(32821)
32829	BCWF	138	FALSE	TRUE	(34003 32839 34300)
32839	BCWF	1100	FALSE	FALSE	(32829)
32840	BETHELCT	800	FALSE	FALSE	(34517 33226)
32849	BLACKCAT	803	FALSE	FALSE	(34408 33843)
32852	BLACKFOT	1200	FALSE	FALSE	(34184)
32858	BLISS	800	TRUE	TRUE	(34444 32868 32869)
32868	BLISS	1001	FALSE	FALSE	(32858)
32869	BLISS	1002	FALSE	FALSE	(32858)
32873	BLK_CNYN	600	FALSE	FALSE	(33382)
32881	BLK_MESA	800	FALSE	FALSE	(33562 34003)
32884	BL_GULCH	800	FALSE	TRUE	(34485 33012 32891)
32891	BL_GULCH	1004	FALSE	FALSE	(32884)
32903	BOISE	804	FALSE	FALSE	(33450 34513)
32908	BOISEBCH	200	TRUE	TRUE	(32984 32986 32949 33122 33576 33888 33495 33769 33298)
32949	BOISEBCH	800	FALSE	FALSE	(33443 33850 33450 33355 33135 32908 32984 32986)
32978	BOISEBCH	1001	FALSE	FALSE	(32984)
32981	BOISEBCH	1101	FALSE	FALSE	(32986)
32984	BOISEBCH	2	FALSE	TRUE	(32908 32949 32978)
32986	BOISEBCH	4	FALSE	TRUE	(32908 32949 32981)
32995	BORAH	3044	TRUE	TRUE	(33004 32794 33003 32778)

33003	BORAH	319	FALSE	FALSE	(32995)
33004	BORAH	320	FALSE	FALSE	(32995)
33006	BORAH	201	TRUE	TRUE	(33037 33592)
33010	BORDER	800	FALSE	FALSE	(33012)
33012	BORDERTP	800	FALSE	TRUE	(33010 32884 34593)
33021	BOWMONT	205	FALSE	FALSE	(33023)
33023	BOWMONT	800	FALSE	FALSE	(33585 34525 33729 33021 34392)
33037	BRADY	200	TRUE	FALSE	(33069 33070 33068 33713 33006)
33053	BRADY	802	FALSE	TRUE	(33070 33069 32802 33297 34235 33068)
33066	BRADY	1104	FALSE	FALSE	(33070 33069)
33067	BRADY	1105	FALSE	FALSE	(33068)
33068	BRADY	1	FALSE	TRUE	(33037 33053 33067)
33069	BRADY	2	FALSE	TRUE	(33037 33053 33066)
33070	BRADY	3	FALSE	TRUE	(33037 33053 33066)
33077	BRIDGE	806	FALSE	FALSE	(34514 33233 34597 33086)
33086	BRIDGE	1100	FALSE	FALSE	(33077)
33122	BROWNLEE	228	TRUE	TRUE	(33503 32908 33126 33127 34126 33576 33124 34211 34101)
33124	BROWNLEE	1002	FALSE	FALSE	(33122)
33126	BROWNLEE	1004	FALSE	FALSE	(33122)
33127	BROWNLEE	1005	FALSE	FALSE	(33122)
33128	BRUNO_BG	800	FALSE	FALSE	(33132)
33132	BRUNO_BG	804	FALSE	TRUE	(33128 33134 34380)
33134	BRUNO_BG	806	FALSE	TRUE	(33190 33132 34222)
33135	BUTLER	800	FALSE	FALSE	(34564 32949)
33140	BYPASS	805	FALSE	FALSE	(33919 33357)
33152	CALDWELL	207	TRUE	TRUE	(33769 34056 33744 33154)
33154	CALDWELL	800	FALSE	FALSE	(33152 34540 33762 34349)
33174	CANALIPC	1103	FALSE	FALSE	(34062 34322 33186)
33186	CANAL_TP	801	FALSE	TRUE	(33958 33174 33394)
33190	CANYN_CR	800	FALSE	FALSE	(33134 34350)
33200	CARTWRIT	806	FALSE	FALSE	(33355 33330)
33204	CAWP	141	FALSE	FALSE	(33821 33562)
33210	CHESTNUT	806	FALSE	FALSE	(33585 33916)
33215	CLIFF	800	FALSE	FALSE	(34090 33392)
33226	CLOVERDL	808	FALSE	FALSE	(33783 34513 32840 34319 33843)
33230	COPPRFLD	202	FALSE	FALSE	(34126)
33233	CURLEW	800	FALSE	FALSE	(33077)
33240	DALE	800	FALSE	FALSE	(33688 34422)
33249	DANSKIN	200	FALSE	TRUE	(33254 33495 34272 33260)
33254	DANSKIN	800	FALSE	TRUE	(33996 33369 33249)
33260	DANSKIN	1800	FALSE	FALSE	(33249)
33267	DIXIE	500	FALSE	FALSE	(32821)

33292	DON	822	FALSE	FALSE	(34184 32795 33717 33297)
33297	DON_TAP	800	FALSE	TRUE	(33292 33427 33053)
33298	DRAM	200	FALSE	TRUE	(33850 32908 34272)
33330	DRY_CK_J	800	FALSE	TRUE	(34513 33200 33535)
33334	DUFFIN	820	FALSE	FALSE	(32785 33643)
33345	EAGLEIPC	804	FALSE	FALSE	(34370 33348)
33348	EAGLE_TP	800	FALSE	TRUE	(33435 33345 33654)
33352	ECKERT	800	FALSE	FALSE	(33355)
33355	ECKERT	804	FALSE	TRUE	(32949 33200 33352)
33357	EDEN	800	FALSE	FALSE	(33140 33598)
33363	ELKHRNIP	803	FALSE	FALSE	(33675 34561)
33369	ELMORE	808	FALSE	FALSE	(33254 34003)
33370	EMMETT	800	FALSE	FALSE	(33382 34365 34541)
33382	EMMETT	605	FALSE	FALSE	(33370 32873)
33386	E_GATE	800	FALSE	FALSE	(34290 33676)
33392	E_GATE_T	800	FALSE	TRUE	(34461 33215 33676)
33394	E_HILLS	800	FALSE	TRUE	(34477 33186 33398)
33398	E_HILLS	1000	FALSE	FALSE	(33394)
33416	FOSSIL_G	804	FALSE	TRUE	(33418 33688 34444)
33418	FOSSIL_G	1001	FALSE	FALSE	(33416)
33427	FREMONT	804	FALSE	FALSE	(34196 33297)
33435	GARY	805	FALSE	FALSE	(33348)
33438	GLENSFRY	800	FALSE	FALSE	(33440)
33440	GLFRY_TP	800	FALSE	TRUE	(33438 34300 34491)
33443	GOWEN	800	FALSE	FALSE	(33987 32949)
33450	GROVE	803	FALSE	FALSE	(32903 32949)
33455	HAILEY	800	FALSE	FALSE	(34561 34338)
33461	HAY_MILL	800	FALSE	FALSE	(33529 33473 34258)
33473	HAY_MILL	1007	FALSE	FALSE	(33461 34274)
33486	HAZELATP	804	FALSE	FALSE	(33944 33490)
33490	HAZELBTP	802	FALSE	FALSE	(33486 34548)
33495	HBRD	808	FALSE	TRUE	(33249 32908 34056)
33503	HELLSCYN	206	TRUE	FALSE	(33509 33122)
33509	HELLSCYN	1005	FALSE	FALSE	(33503)
33511	HEWLETT	800	FALSE	FALSE	(33783 33654)
33529	HEYBURN	816	FALSE	TRUE	(33946 34227 33461 34477)
33531	HEYBURNT	800	FALSE	TRUE	(32785 34389 34159)
33535	HIDNSPGS	800	FALSE	FALSE	(33330 34365)
33541	HIGHLDTP	803	FALSE	FALSE	(34358 32799)
33546	HILLSDAL	805	FALSE	FALSE	(33987 34319)
33547	HILL_IPC	800	FALSE	FALSE	(34045 33762)
33553	HINES	601	FALSE	FALSE	(33560 34552)
33560	HINES	126	FALSE	FALSE	(33553)

33562	HMWP	801	TRUE	TRUE	(32881 33569 33204)
33569	HMWP	1100	FALSE	FALSE	(33562)
33576	HORSEFLT	200	FALSE	TRUE	(33122 34375 32908)
33585	HPY_VALY	803	FALSE	FALSE	(33023 33210)
33592	HUNT	200	FALSE	TRUE	(33888 33006 33598)
33598	HUNT	800	FALSE	TRUE	(33592 34422 34548 33357 34461)
33618	HYDRA	806	FALSE	FALSE	(34451 33650)
33621	IDAHOME	800	FALSE	FALSE	(33958 34514 33625)
33625	IDAHOME	1000	FALSE	FALSE	(33621)
33639	JACKSON	1102	FALSE	FALSE	(34062)
33643	JCLAWSON	800	FALSE	FALSE	(33334)
33649	JEROME	807	FALSE	FALSE	(33650)
33650	JEROM_TP	800	FALSE	TRUE	(34080 33618 33649)
33654	JOPLIN	800	FALSE	FALSE	(33511 33348)
33665	JUSTICE	204	FALSE	TRUE	(33888 34027 33688)
33668	KARCHER	800	FALSE	FALSE	(33670)
33670	KARCHERT	800	FALSE	TRUE	(34084 33668 34045 34607)
33675	KETCHUM	804	FALSE	FALSE	(33363)
33676	KIMBRLY	801	FALSE	FALSE	(33386 33392)
33688	KING_ST	807	FALSE	TRUE	(33789 34426 33240 34485 33416 33821 33665)
33696	KINPORT	301	FALSE	FALSE	(33701)
33701	KINPORT	305	TRUE	FALSE	(33696 33726 33879)
33713	KINPORT	203	TRUE	TRUE	(33037 33726 33717)
33717	KINPORT	800	FALSE	TRUE	(34358 33292 33713)
33724	KINPORT	1000	TRUE	FALSE	(33726)
33726	KINPORT	1	FALSE	TRUE	(33701 33713 33724)
33729	KUNA_TAP	800	FALSE	FALSE	(33987 33023)
33736	LAMBIPC	801	FALSE	FALSE	(32802 34181)
33744	LANGLEYG	205	TRUE	TRUE	(33750 33754 33152 34101 33756)
33750	LANGLEYG	1111	FALSE	FALSE	(33744)
33754	LANGLEYG	1003	FALSE	FALSE	(33744)
33755	LANGLEYG	1004	FALSE	FALSE	(33756)
33756	LANGLEYG	1	FALSE	TRUE	(33744 34540 33755)
33757	LINCOLNI	800	FALSE	TRUE	(33761 33908 34338)
33761	LINCOLNI	804	FALSE	FALSE	(33757)
33762	LINDEN	800	FALSE	FALSE	(33547 33154)
33769	LOCUST	202	TRUE	TRUE	(33152 32908 33783)
33783	LOCUST	809	FALSE	FALSE	(34408 33226 33769 33511)
33789	LSALMON	800	FALSE	TRUE	(33800 33801 33688)
33800	LSALMON	1001	FALSE	FALSE	(33789)
33801	LSALMON	1002	FALSE	FALSE	(33789)
33810	LUCKY_PK	803	FALSE	TRUE	(33814 33850 34003)

33814	LUCKY_PK	1001	FALSE	FALSE	(33810)
33821	L_MALAD	800	FALSE	TRUE	(33688 33825 33204)
33825	L_MALAD	1000	FALSE	FALSE	(33821)
33827	MAGIC_TP	800	FALSE	TRUE	(33829 33983 34426)
33829	MAGIC_TP	802	FALSE	FALSE	(33827)
33839	MCCALL	806	FALSE	FALSE	(34375 34071)
33843	MERDNIPC	803	FALSE	FALSE	(33226 32849)
33850	MICRON	809	FALSE	FALSE	(32949 33298 33810)
33856	MIDPOINT	901	TRUE	FALSE	(33879)
33879	MIDPOINT	3062	TRUE	FALSE	(32794 33888 33701 32778 33856)
33888	MIDPOINT	200	TRUE	TRUE	(33879 33665 33592 32908 33908)
33908	MIDPOINT	800	FALSE	FALSE	(33888 34080 33757)
33915	MIDROSE	800	FALSE	FALSE	(33916)
33916	MIDROSE	801	FALSE	TRUE	(33210 33915 34045)
33919	MILNER	800	FALSE	FALSE	(33140 33944 33941 33934)
33934	MILNER	1008	FALSE	FALSE	(33919)
33941	MILNERPP	1300	FALSE	FALSE	(33919)
33944	MILNER_T	138	FALSE	TRUE	(34159 33486 33919)
33946	MINICO	800	FALSE	FALSE	(33529 34389)
33958	MINIDOKA	807	FALSE	TRUE	(33186 34223 32785 33982 33621 33977)
33977	MINIDOKA	1000	FALSE	FALSE	(33958)
33982	MINIDOKA	1105	FALSE	FALSE	(33958)
33983	MOONSTON	800	FALSE	FALSE	(33827 34561)
33987	MORA	800	FALSE	FALSE	(33546 33729 33443)
33996	MTHMAFB	803	FALSE	TRUE	(34380 33999 33254)
33999	MTHMAFB	806	FALSE	FALSE	(33996)
34003	MTN_HOME	800	FALSE	TRUE	(33369 33810 32829 32881 32821)
34027	MT_AIRWP	205	TRUE	TRUE	(34039 34038 34272 33665)
34038	MT_AIRWP	1100	FALSE	FALSE	(34027)
34039	MT_AIRWP	1101	FALSE	FALSE	(34027)
34045	NAMPA	800	FALSE	FALSE	(33547 33916 33670 34056)
34056	NAMPA_TP	200	FALSE	TRUE	(33152 34045 33495)
34057	NELSONTP	800	FALSE	TRUE	(34060 34532 34204)
34060	NELSONTP	803	FALSE	FALSE	(34057)
34062	NEWCOMB	1100	FALSE	FALSE	(33174 33639)
34071	NEWMEADW	802	FALSE	FALSE	(34403 33839)
34074	NEW_BURL	800	FALSE	FALSE	(34227)
34080	NHBT_TAP	800	FALSE	TRUE	(33650 33908 34081)
34081	NHBT_TAP	801	FALSE	FALSE	(34080)
34084	NORCO1	802	FALSE	FALSE	(33670)
34088	NTVW_TAP	802	FALSE	FALSE	(34090)
34090	NTVW_TAP	804	FALSE	TRUE	(34088 34491 33215)
34096	N_POWDER	203	FALSE	FALSE	(34211 34098)

34098	N_POWDER	1000	FALSE	FALSE	(34096)
34101	ONTARIO	201	FALSE	TRUE	(33122 33744 34123)
34123	ONTARIO	812	FALSE	FALSE	(34160 34532 34101)
34126	OXBOW	200	FALSE	TRUE	(34138 34134 33230 33122 34141)
34134	OXBOW	800	FALSE	FALSE	(34126 34375)
34138	OXBOW	1000	FALSE	FALSE	(34126)
34141	OXBOW	2000	FALSE	FALSE	(34126)
34148	PACIFICI	807	FALSE	FALSE	(34573 34477)
34159	PAUL_IDP	810	FALSE	FALSE	(33944 33531)
34160	PAYETTE	800	FALSE	FALSE	(34123 34541)
34170	PINGREE	800	FALSE	FALSE	(34184)
34180	PLEAS_VL	806	FALSE	FALSE	(34181)
34181	PLVLY_TP	800	FALSE	TRUE	(34180 33736 34223)
34184	PNGRE_TP	800	FALSE	TRUE	(33292 32852 34170)
34188	POLELINE	800	FALSE	TRUE	(34422 34194 34451)
34194	POLELINE	808	FALSE	FALSE	(34188)
34196	PORTNEUF	800	FALSE	FALSE	(34413 33427)
34204	QUARTZ	800	FALSE	FALSE	(34211 34057 34552)
34211	QUARTZTP	200	FALSE	TRUE	(34204 33122 34096)
34218	RAFT	804	FALSE	FALSE	(34223)
34222	RAFT_RVR	802	FALSE	FALSE	(33134)
34223	RAFT_T	800	FALSE	TRUE	(34181 33958 34218)
34227	RIVERTON	800	FALSE	FALSE	(34074 33529)
34235	ROCKLAND	802	TRUE	FALSE	(33053)
34253	ROES_CRN	1025	FALSE	FALSE	(34258)
34258	ROE_CR_T	804	FALSE	TRUE	(33461 32785 34253)
34272	RTLSNAKE	212	FALSE	TRUE	(33298 34027 33249)
34274	RUPERT	1101	FALSE	FALSE	(33473 34283)
34283	RUPERT	1002	FALSE	FALSE	(34274)
34290	RUSSET	800	FALSE	FALSE	(34451 33386)
34300	SAILORCR	807	FALSE	FALSE	(34302 32829 33440)
34302	SAWTOOTH	802	TRUE	TRUE	(34312 34300 34303)
34303	SAWTOOTH	803	FALSE	FALSE	(34302)
34312	SAWTOOTH	1101	FALSE	FALSE	(34302)
34313	SCOVILLE	1200	FALSE	FALSE	(34315)
34314	SCOVILLE	1201	FALSE	FALSE	(34315)
34315	SCOVILLE	800	FALSE	FALSE	(34313 34314)
34319	SD_TAP	800	FALSE	TRUE	(33226 34377 33546)
34322	SEC_LIFT	1100	FALSE	FALSE	(33174)
34338	SILVER	800	FALSE	FALSE	(33455 33757)
34348	SIMPLOT	807	FALSE	FALSE	(34349)
34349	SIMPLOT	808	FALSE	TRUE	(34348 33154 34525)
34350	SINKR_CR	800	FALSE	TRUE	(34353 33190 34392)

34353	SINKR_CR	803	FALSE	FALSE	(34350)
34358	SIPHON	803	FALSE	FALSE	(33541 33717)
34364	SPRINGVL	802	FALSE	FALSE	(34365)
34365	SPRINGVL	803	FALSE	TRUE	(33370 33535 34364)
34370	STAR	803	FALSE	FALSE	(33345)
34375	STARKEY	805	FALSE	FALSE	(33576 34403 34134 33839)
34377	STODDARD	800	FALSE	FALSE	(34319)
34380	STRIKE	800	FALSE	TRUE	(34388 33132 33996)
34388	STRIKE	1003	FALSE	FALSE	(34380)
34389	SUGAR	800	FALSE	FALSE	(33946 33531)
34392	SWANFALL	800	FALSE	TRUE	(34399 34350 33023)
34399	SWANFALL	1000	FALSE	FALSE	(34392)
34403	TAMARACK	802	FALSE	FALSE	(34375 34071)
34408	TENMLE	802	FALSE	FALSE	(32849 33783)
34413	TERRYIPC	800	FALSE	FALSE	(32799 34196)
34422	TFAL_JCT	800	FALSE	TRUE	(34188 33598 33240)
34426	TOPON_TP	800	FALSE	TRUE	(34430 33827 33688)
34430	TOPON_TP	804	FALSE	FALSE	(34426 34438)
34438	TOPON_TP	812	FALSE	FALSE	(34430)
34444	TUANA	805	TRUE	TRUE	(34449 33416 32858)
34449	TUANA	1100	FALSE	FALSE	(34444)
34451	TWINFALL	800	FALSE	FALSE	(33618 34188 34290)
34461	TWNFLSPP	800	FALSE	TRUE	(34466 33598 33392)
34466	TWNFLSPP	805	FALSE	TRUE	(34461 34470 34468)
34468	TWNFLSPP	1002	FALSE	FALSE	(34466)
34470	TWNFLSPP	1004	FALSE	FALSE	(34466)
34477	UNITY	806	FALSE	TRUE	(34483 34148 33529 33394)
34483	UNITY	1000	FALSE	FALSE	(34477)
34485	UPSALMON	800	FALSE	TRUE	(34491 33688 34507 32884 34506)
34491	UPSALMON	811	FALSE	TRUE	(34504 34505 34485 34090 33440)
34504	UPSALMON	1005	FALSE	FALSE	(34491)
34505	UPSALMON	1006	FALSE	FALSE	(34491)
34506	UPSALMON	1007	FALSE	FALSE	(34485)
34507	UPSALMON	1008	FALSE	FALSE	(34485)
34513	USTICK	805	FALSE	FALSE	(33226 33330 32903)
34514	VALLEYR	803	FALSE	FALSE	(33077 33621)
34517	VICTJCT	800	FALSE	TRUE	(32840 34564 34523)
34523	VICTORY	804	FALSE	FALSE	(34517)
34525	VLVU	800	FALSE	TRUE	(34529 34349 33023)
34529	VLVU	804	FALSE	FALSE	(34525)
34530	WEISER	803	FALSE	FALSE	(34532)
34532	WEISERTP	800	FALSE	TRUE	(34530 34123 34057)
34535	WELLS_IP	800	FALSE	FALSE	(34593)

34538	WILIS	801	FALSE	FALSE	(34540)
34540	WILIS	803	FALSE	TRUE	(33154 33756 34538)
34541	WILOW_CR	800	FALSE	FALSE	(33370 34160)
34548	WILSONLK	803	FALSE	FALSE	(33490 33598)
34552	WJOHND	802	FALSE	FALSE	(33553 34204)
34561	WOOD_RVR	805	FALSE	TRUE	(33363 33983 33455)
34564	WYEE	800	FALSE	FALSE	(34517 33135)
34573	W_BURLEY	800	FALSE	FALSE	(34582 34148)
34582	W_BURLEY	1003	FALSE	FALSE	(34573)
34593	W_WELLS	800	FALSE	FALSE	(34535 33012)
34597	W_WENDOV	801	FALSE	FALSE	(33077 34602)
34602	W_WENDOV	1000	FALSE	FALSE	(34597)
34607	ZILOG	804	FALSE	FALSE	(33670)

13. APPENDIX 3: FILE "*IPC_PMU_LOCATIONS_2016.CSV*"

Location	Initial
BORAH_345_3044	1
MIDPOINT_345_3062	1
DUFFIN_138_820	0
MINIDOKA_138_807	0
DON_138_822	0
TERRYIPC_138_800	0
AM_FALLS_138_800	0
MTN_HOME_138_800	0
ANDRSN_R_115_100	0
VICTJCT_138_800	0
BLACKCAT_138_803	0
PNGRE_TP_138_800	0
TUANA_138_805	1
BLISS_138_800	1
EMMETT_69_605	0
HMWP_138_801	1
UPSALMON_138_800	0
USTICK_138_805	0
LOCUST_230_202	1
MIDPOINT_230_200	1
BROWNLEE_230_228	1
BOISEBCH_138_800	0
BOISEBCH_230_200	1
BRADY_230_200	1
BORAH_230_201	1
W_WELLS_138_800	0
BOWMONT_138_800	0
HPY_VALY_138_803	0
KINPORT_230_203	1
ROCKLAND_138_802	1
BRIDGE_138_806	0

OXBOW_230_200	0
HELLSCYN_230_206	1
BRUNO_BG_138_804	0
CANYN_CR_138_800	0
MILNER_138_800	0
CALDWELL_138_800	0
LANGLEYG_230_205	1
CALDWELL_230_207	1
NEWCOMB_34.5_1100	0
CANALIPC_34.5_1103	0
MTHMAFB_138_803	0
EAGLEIPC_138_804	0
ELKHRNIP_138_803	0
E_GATE_138_800	0
UPSALMON_138_811	0
SILVER_138_800	0
HAY_MILL_138_800	0
RUPERT_12.5_1101	0
WILSONLK_138_803	0
HEWLETT_138_800	0
RIVERTON_138_800	0
SUGAR_138_800	0
HILLSDAL_138_805	0
NAMPA_138_800	0
HINES_138_601	0
JEROM_TP_138_800	0
IDAHOME_138_800	0
MT_AIRWP_230_205	1
KARCHERT_138_800	0
LSALMON_138_800	0
KINPORT_345_305	1
KINPORT_14.4_1000	1
NEWMEADW_138_802	0
MIDPOINT_500_901	1
RAFT_T_138_800	0
NELSONTP_138_800	0
N_POWDER_230_203	0
PAYETTE_138_800	0
W_BURLEY_138_800	0
POLELINE_138_800	0
SAWTOOTH_138_802	1

SCOVILLE_69_800	0
SPRINGVL_138_802	0
TOPON_TP_138_804	0
TWNFLSPP_138_805	0
W_WENDOV_69_1000	0

Appendix J.
Quarterly Peak Reliability Synchrophasor Program (PRSP) Project Status Report

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Quarterly PRSP Project Status

Due: 1st week after quarter-end

Participant Name:	*Idaho Power Co.*	**Report For:**	*Quarter 2, 2016*
Project Manager: **PM Phone Number:**	*Guy Colpron* *208-388-2784*	**Date Submitted:**	*July 8th,2016*
Budget Forecast to Date:	*$200,000*	**Actuals to Date:**	**$235,051.71**

Key Accomplishments or Milestones:	• *The new PI PMU server system specically purchased to store PMU data has been installed and is now string the PMU data.* • *The control design for the installation of (5) new PMUs and (1) PDC is complete. The new PDC will be installed within the next quarter.*
Upcoming Activities: (Include key future activities both technical and management related.)	1. The On-Line version of the ROSE program will need to be matched with the PMU data defined in the IPCo scenarios. 2. The (3) IPCo scenarios will need to be re-evaluated as to their appropriateness for the current IPCo power system. We expect that minor changes to the scenarios will be required. 3. The ROSE program output needs to be evaluated. 4. The installation of the Linear state Estimator. 5. Continue to correct PMU/PDC data errors.
Changes to Plan: (Include Scope, approach, and Resource changes)	• No changes to the plan are anticipated at this point.
Significant Problems/ Risks:	• As PMU, PDC, and database information is being reviewed additional errors are being discovered. This will impact the performance of the ROSE/LSE programs.
Miscellaneous:	• A significant effort is being made by IPCo to validate PMU data and place it in a reliable storage system.

PRSP Contacts:
Jeanne Bullion – PRSP Program Manager
360-213-2349
jbullion@peakrc.com

Kenneth Young – PRSP Grant Accountant
360-213-2323
kyoung@peakrc.com

Marianna Vaiman – V&R Energy
310-979-5966
marvaiman@vrenergy.com

Appendix K.
June 2016 Idaho Power *Connections* Newsletter

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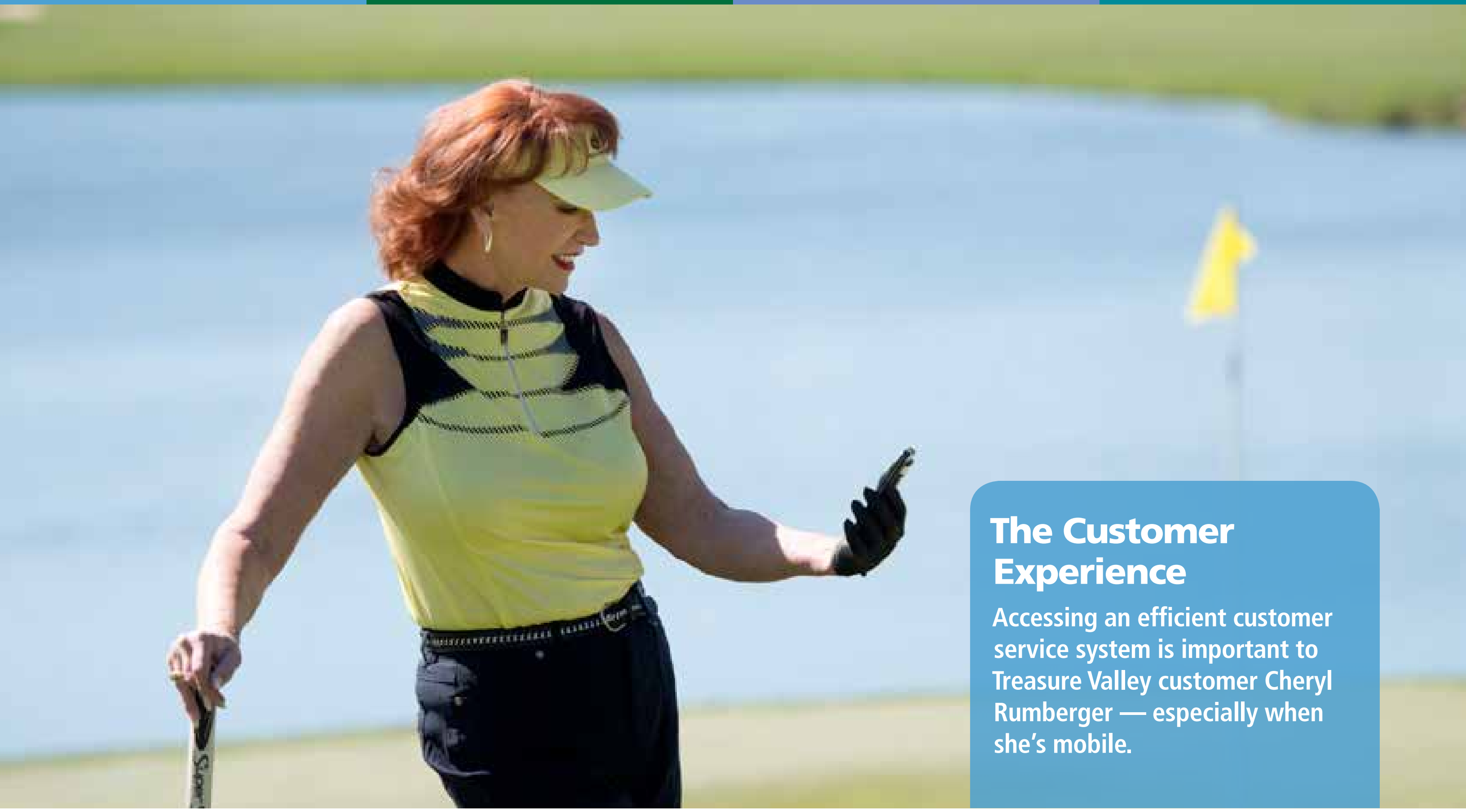
June 2016

Connections

IDAHO POWER
An IDACORP Company



The Customer Experience

Accessing an efficient customer service system is important to Treasure Valley customer Cheryl Rumberger — especially when she's mobile.

The "Voice of the Customer" Helps Improve Customer Service

Cheryl "Rusty" Rumberger was pleasantly surprised Idaho Power was interested in what she had to say about her customer experience with the company.

While requesting to relocate her electric service to a new residence recently, she used Idaho Power's automated phone system. Soon after, she accepted the company's invitation to test the phone system and provide input for improvements.

"Nobody looks forward to making a call to sign up for something you'll get a bill for," said Rusty. "You don't want to be intimidated or treated poorly; you want to have a nice experience, whether it's with a person or automated."

Usability Testing: Automated Phone System

In the one-on-one test environment, Rusty participated in mock phone calls for a variety of service needs, reacting as the system responded and different options were offered. The session documented how easy (or difficult) it was to navigate the system and recognize choices, such as going through each step necessary to start, cancel or move electric service.

"Everything worked properly, and it's one of the easiest automated systems I'd ever been through," Rusty concluded. "This is something you have to have; it says volumes about a company to be treated like a valued customer with efficiency and respect."

(continued on page 2)

News Feed

The Outage Map is One Year Old

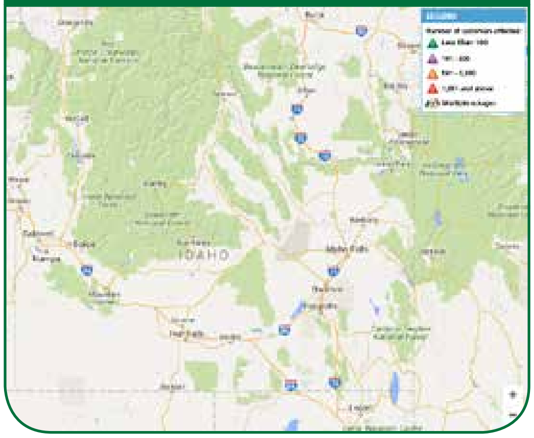
Our online outage map debuted a year ago on our Outage Center page. From April 28, 2015 to April 28, 2016, the outage map was viewed more than 260,000 times. On Dec. 21, the map had an all-time record, viewed more than 7,000 times in a single day (related to heavy snow in the McCall area).

The map provides outage details such as:

- Date and time the outage started
- Status (under investigation, assigned, crews en route or on-site)
- Number of customers affected
- Estimated time of restoration

You can easily connect to our outage phone system on your mobile device using a button on the map. The Outage Center web page provides other outage-related information, like frequently asked questions, safety information and tips on preparing an emergency kit.

View Outage Map



For large or prolonged outages, access our social media channels at facebook.com/idahopower or on Twitter @idahopower.

▶ idahopower.com/outage

Voice of the Customer *(continued from page 1)*

Focus Group: myAccount

Last November, Craig Whitted from Melba also provided feedback to Idaho Power, participating in a focus group for the online myAccount tool. Focus groups are small, in-person group discussions about specific topics or issues.

An agricultural and residential customer, Craig uses myAccount frequently — especially in the summer to monitor the electricity he uses to pump-irrigate 80 acres of crops. Although he was satisfied with myAccount's functionality, he welcomed the opportunity to provide input for improvements to the customer experience.

"Sometimes the people who build things know how to build them but don't always know how people use them," said Craig. "It's easy to get what I want on myAccount, but I also made some suggestions."

Customer Feedback

Idaho Power uses several methods, such as focus groups and usability testing, to gather input from customers like Rusty and Craig. In 2015, we conducted 16 different focus groups on a variety of topics. We also have customers help us with usability testing of our website.

Each year, we conduct our own customer relationship survey in which we contact more than 900 customers to get their opinions about our services. Participants are randomly selected and represent our four primary groups of customers: residential, small to medium business, large commercial and industrial, and irrigation.

We also subscribe to national studies that show how Idaho Power residential and business customers rank us compared to how other utility customers rank their electric utilities.

Last year, Idaho Power initiated its empowered community, a group of residential customers we send online surveys to every month. (See story on page 4.)

In the Works

We will continue to develop tools and systems to meet our customers' changing expectations and identify ways to improve their experience when interacting with us.

Our research will focus on what's most important to our customers. Whether it's how to view account information, find tips on how to use energy efficiently or request a service, we are taking steps to improve those interactions.

Banbury Golf Course, Eagle, Idaho

myAccount Has a New Look

In April, we unveiled a new design for myAccount — your online account information tool. Improvements were made throughout the application based on customer feedback. On your first visit since the change, a one-time pop-up message will tell you about the new design.

The home page now has icon-based navigation, similar to the mobile version. You'll notice a larger font size on all the myAccount pages and your primary account information displayed with "Amount Due" and "Due Date." There also are large "Pay Bill" and "View Bill" buttons. If you haven't already registered for myAccount, go to the Idaho Power website and discover how easy it is to manage your account online.

Here's what's in the works:

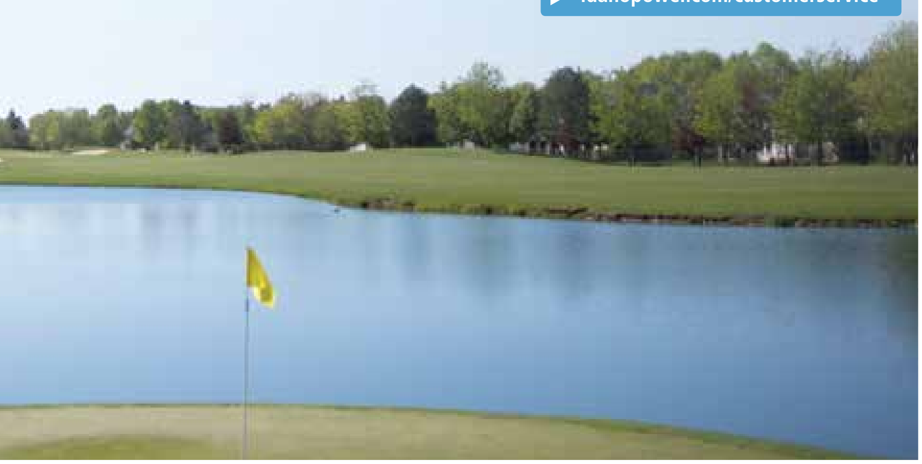
Automated Phone System
New menu options on the automated phone system will be available for calls to our Customer Service Center. The expanded menu will make it easier to navigate and respond to your needs.

Paperless Billing
We will be updating our online billing program, making it easier for customers to enroll in paperless billing and manage their account.

Idahopower.com
We are redesigning the Idaho Power website, from updating the look and feel to making it easier for you to find the information you need.

Communications
We want to provide options for how we communicate with you. This may include optional emails and text messages about upcoming outages and account information.

▶ idahopower.com/customerservice



Meeting Customer Expectations

Idaho Power customers are changing the way they want to interact with us. And we are changing with them!

In the not-too-distant past, our customers had limited access to their Idaho Power account information. If they wanted to conduct business, they needed to do so Monday through Friday during standard business hours. And the telephone, not the "smart" phone, was how customers got information about their account, requested new service or asked a billing question.

Today, customers have access to account information 24 hours a day, seven days a week through our automated phone system and website. Our mobile-friendly website makes it easy to view and pay your bill, monitor your energy use and check the outage map. It's also easy to speak with a Customer Service representative Monday through Friday from 7:30 a.m. to 6:30 p.m.

In 2015, our Customer Service representatives received nearly 850,000 calls and web interactions. Our automated phone system received another 400,000 customer requests for account information, and the website was accessed more than 3 million times. The majority of web visits were from customers viewing, paying and looking at their detailed energy use in myAccount.

How our customers prefer to do business with us will continue to change. So, we will continue to change as well — always with a focus to improve the customer experience.

In 2015...

850,000
calls & web interactions

24 hours a day

7 days a week

3 million
website hits

400,000
automated customer requests

▶ idahopower.com/myAccount

Online Community Provides Feedback

Your opinions and ideas are important to us.

That's why Idaho Power created an online community of customers to gather feedback through monthly surveys on a variety of topics. We wanted help tailoring programs and services to meet customer needs, and feedback on existing services to improve the customer experience.

Since its introduction in 2015, the online community has grown to nearly 1,200 customers who volunteered to participate, and the response has been great! Topics have ranged from outage communication to recreational opportunities to energy-saving programs and more.

Information on how to join the empowered community is available on Idaho Power's website.

Here's an example of feedback from community members who responded to specific online survey questions:

- Fifty-eight percent have visited one of Idaho Power's parks along the Snake River.
- Seventy-five percent said they would likely use an online outage map if Idaho Power had one. (We launched an outage map in April 2015.)
- Seventy-four percent say they are likely to make energy-saving improvements to their home in the next two to three years.
- Over 80 percent make contributions to non-profit organizations or other programs to help less fortunate members of their community.
- More than 82 percent have purchased LED light bulbs for their homes.
- Over 30 percent said they will consider buying an electric vehicle in the next five years.
- Twenty-three percent follow Idaho Power on Facebook.
- Forty-six percent always read this *Connections* newsletter in their monthly bill.

Join our empowered community

▶ idahopower.com/join

From The Electric Kitchen

June 2016

Dinner

Salmon Burgers

1 can (5 oz) pink salmon, drained
1 small shallot, minced (approx. 2 tsp)
2 eggs or ½ cup egg whites
¼ cup bread crumbs
2 tsp olive oil
2 tsp Dijon mustard
1 Tbsp each of minced fresh chives and dill weed
1 tsp grated lemon zest
¼ tsp salt
½ tsp lemon pepper

Dietary information per serving:

Calories: **270**
Protein: **20.6g**
Carbohydrates: **12g**
Fat: **15g**
Sodium: **988mg**
Fiber: **0.6g**

Place all ingredients in a bowl and thoroughly combine. If the mixture is too dry, add another teaspoon of mustard or a squeeze of lemon juice. Form into patties. Spray or wipe grill with oil and cook on medium-high heat until golden brown, approximately 6 minutes on each side. Makes two patties.

Connections is published monthly to inform our customers about services we provide, programs we offer and industry issues impacting our service area in southern Idaho and eastern Oregon. Our goal is to engage and inspire you to learn more about Idaho Power and how we are working together to meet your energy needs today and tomorrow.

Comments or questions are welcome at idahopower.com/contactus or at: Corporate Communications P.O. Box 70, Boise, ID 83707

Recipes are selected for nutritional value and low energy use in preparation. They are approved by Registered Dietitians Holly Hutchinson and Erin Green from the Central District Health Department in Boise, Idaho.

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Appendix L.
Accessible Data Tables

Data table for Figure 3 (no PV)

Customer	Service Point	Min Voltage	Counts of Low Voltage
1	403	119.31	0
2	748	118.22	0
3	382	120.53	0
4	971	117.50	0
5	476	113.38	3
6	152	116.50	0
7	270	113.07	5
8	764	114.05	0
9	495	112.53	1
10	183	113.60	12
11	528	114.50	0
12	703	112.60	12
13	343	112.54	24
Total		**112.53**	**57**

Data table for Figure 3 (PV)

Customer	Service Point	Min Voltage	Counts of Min Voltage
1	403	119.31	0
2	748	118.22	0
3	382	120.53	0
4	971	117.5	0
5	476	114.03	0
6	152	116.9	0
7	270	114.13	0
8	764	115.2	0
9	495	113.79	1
10	183	114.05	0
11	528	115.1	0
12	703	114.51	0
13	343	113.86	2
Total		**113.79**	**3**

Data table for Figure 15

Month	Desktop Visits	Mobile Visits
May 15	6,286	3,028
June 15	9,617	3,342
July 15	15,990	5,916
August 15	22,837	7,462
September 15	13,570	5,716
October 15	11,887	11,568
November 15	10,694	4,379
December 15	24,113	31,053
January 16	12,566	7,335
February 16	10,320	3,692
March 16	12,332	8,626
April 16	12,257	8,717
May 16	12,887	10,128
June 16	14,762	12,498

Data table for Figure 16

Time	kWh
1:00 a.m.	73.0
2:00 a.m.	73.7
3:00 a.m.	55.7
4:00 a.m.	50.5
5:00 a.m.	23.4
6:00 a.m.	6.0
7:00 a.m.	10.0
8:00 a.m.	10.6
9:00 a.m.	29.3
10:00 a.m.	21.1
11:00 a.m.	19.3
12:00 p.m.	31.4
1:00 p.m.	29.0
2:00 p.m.	46.4
3:00 p.m.	59.0
4:00 p.m.	100.0
5:00 p.m.	123.0
6:00 p.m.	137.3
7:00 p.m.	134.5
8:00 p.m.	71.3
9:00 p.m.	58.7
10:00 p.m.	66.4
11:00 p.m.	63.8
12:00 a.m.	55.2

CERTIFICATE OF SERVICE

I hereby certify that on September 30, 2016, I served a true and correct copy of Idaho Power Company's 2016 Smart Grid Report on the parties in Dockets UM 1460, LC 63, UE 233, and UM 1675 by e-mail to said person(s) as indicated below.

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