

Kentucky Power Company
KPSC Case No. 2020-00174
AG-KIUC First Set of Data Requests
Dated August 12, 2020
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DATA REQUEST

AG_KIUC_1_097 Since KPCo is relying so heavily on data pertaining to AMI systems deployed in the service territories of its affiliated utilities, provide:

- a. copies of all cost-benefit analyses performed by or on behalf of those affiliated companies;
- b. technical details of all metering systems, including manufacturer, make and model numbers of all meters and the price per meter, communications network, and computer backhaul equipment, including all relevant costs; and
- c. all operational expense savings achieved, broken down by type of operational expense, in each such territory resulting from the deployment of AMI technology.

RESPONSE

- a. The Company notes that the characterization upon which this request is premised is incorrect. The Company did not rely on the type of analysis described in this request. Kentucky Power's decision to propose its AMI deployment program, while informed by meter cost information other jurisdictions and the benefits of centralized processes in coordination with its affiliates, is based on the needs and requirements of Kentucky Power to provide electric service to its customers.
- b. Please refer to KPCO_R_KIUC_AG_1_97_ConfidentialAttachment1 for meter models and pricing. All AEP companies utilize a mesh-network based communications system that are returned via a cellular backhaul.
- c. Please refer to the Company's response to subsection a. Kentucky Power did not rely on the type of analysis described in this request.

September 10, 2020 Supplemental Response

- a. Please see KPCO_R_KIUC_AG_1_97_Attachment2 through KPCO_R_KIUC_AG_1_97_Attachment18 for the requested information. This information is being provided by Kentucky Power subject to the following objections. The request also seeks information that is outside of Kentucky Power's possession,

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custody, and control, and which was prepared by or on behalf of the Company's affiliates based upon the facts a circumstances unique to those affiliates at the time the information was prepared, and without Kentucky Power's involvement or knowledge. The Company further objects to the production of non-Kentucky Power documents about which no Company witness in this case has personal knowledge. The requested information is irrelevant and not likely to lead to the discovery of admissible evidence. Kentucky Power did not rely on analyses of the sort requested in AG-KIUC 1-97 (a) or AG-KIUC 1-97(c) in deciding to replace its existing AMR meters with AMI meters. As described in the testimony of Company Witness Blankenship at pages 3-6 and Company Witness West at pages 13-14 and 17-19, the maintenance of the status quo through substitution of the Company's existing AMR meters with replacement AMR meters would require Kentucky Power to invest in facilities and a technology that is becoming technologically and functionally obsolescent. AMR meters are being abandoned by industry and currently are manufactured by a single supplier. Additional investment in AMR technology also would require the Company replace its existing SCM platform, which is no longer being supported, with a SCM+ platform. In providing the information Kentucky Power reserves the right to object on grounds of lack of relevancy, confusion, misleading the trier of fact, and considerations of undue delay to the use of the information for any purpose.

c. See the Company's supplemental response and objections in subpart (a).

Witness: Stephen D. Blankenship
Brian K. West

Final Technical Report



gridSMART[®] Demonstration Project

A Community- Based Approach to Leading the Nation in Smart Energy Use
Department of Energy (DOE) Smart Grid Demonstration Project (SGDP)
Contract Award Number DE-OE0000193

June 2014



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Notifications

Acknowledgment

This material is based upon work supported by the Department of Energy under Award Number DE-OE0000193.

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Use of the Terms Partner and Partnership

The use of the words “partner” and “partnership” herein is intended to indicate a mutually beneficial collegial relationship, rather than a partnership as defined under state law.



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EXECUTIVE SUMMARY

Project Objectives

The AEP Ohio gridSMART[®] Demonstration Project (Project) achieved the following objectives:

- Built a secure, interoperable, and integrated smart grid infrastructure in northeast central Ohio that demonstrated the ability to maximize distribution system efficiency and reliability and consumer use of demand response programs that reduced energy consumption, peak demand, and fossil fuel emissions.
- Actively attracted, educated, enlisted, and retained consumers in innovative business models that provided tools and information reducing consumption and peak demand.
- Provided the U.S. Department of Energy (DOE) information to evaluate technologies and preferred smart grid business models to be extended nationally.

Project Description

Ohio Power Company (the surviving company of a merger with Columbus Southern Power Company), doing business as AEP Ohio (AEP Ohio), took a community-based approach and incorporated a full suite of advanced smart grid technologies for 110,000 consumers in an area selected for its concentration and diversity of distribution infrastructure and consumers. It was organized and aligned around:

- Technology, implementation, and operations
- Consumer and stakeholder acceptance
- Data management and benefit assessment

Combined, these functional areas served as the foundation of the Project to integrate commercially available products, innovative technologies, and new consumer products and services within a secure two-way communication network between the utility and consumers. The Project included Advanced Metering Infrastructure (AMI), Distribution Management System (DMS), Distribution Automation Circuit Reconfiguration (DACR), Volt VAR Optimization (VVO), and Consumer Programs (CP). These technologies were combined with two-way consumer communication and information sharing, demand response, dynamic pricing, and consumer products, such as plug-in electric vehicles and smart appliances. In addition, the Project incorporated comprehensive cyber security capabilities, interoperability, and a data assessment that, with grid simulation capabilities, made the demonstration results an adaptable, integrated solution for AEP Ohio and the nation.

Executive Summary



Project Impact

The Project accelerated smart grid deployments by improving grid reliability, increasing grid efficiency, lowering consumer energy consumption, reducing peak demand, and significantly reducing carbon emissions. AEP Ohio's gridSMART[®] initiative integrated a suite of advanced grid technologies into the existing electric network that improved service quality and reliability, lowered energy consumption, and saved money for consumers and AEP Ohio. The new technologies helped AEP Ohio improve efficiencies, identify and respond to outages more quickly, and better monitor and control the operation of the distribution grid.

Overall, the Project showed that implementing AMI technology provided significant cost, reliability, and environmental benefits for the utility and its consumers.

This report provides information about the deployment of gridSMART technologies and includes best practices and lessons learned that can be used to:

- Improve other smart grid deployments
- Drive industry standards development
- Lower the risk of implementing new technologies into existing electrical networks
- Allow for product improvement and commercialization
- Drive consumer behavioral changes through the introduction of new consumer tariffs and programs.

Based on the success of the Project, AEP Ohio has filed a gridSMART Phase 2 (Phase 2) project with the Public Utilities Commission of Ohio (PUCO). This proposed expansion is based on proven and accepted technology solutions. Phase 2 will extend the benefits demonstrated in the Project and deliver additional benefits to a broader set of consumers. Through Phase 2 AMI, AEP Ohio expects to drive significant financial benefits, positively impact customer service and customer satisfaction, improve meter field personnel safety, and reduce environmental impacts. It also will enable demand response (DR) and Competitive Retail Electric Service (CRES) providers to offer consumer programs. Phase 2 DACR is expected to improve Customer Minutes Interrupted (CMI), which will help AEP Ohio consumers annually avoid millions of dollars in lost productivity. Phase 2 VVO is expected to generate significant efficiencies that translate to customer savings.

The following table identifies the Project participants, collaborations, commercialization, and the AMI customer portal.

Executive Summary



Project Participants	
Prime award recipient	<ul style="list-style-type: none"> Ohio Power Company
Sub-recipients	<ul style="list-style-type: none"> Battelle Memorial Institute Electric Power Research Institute
Federally Funded Research and Development Center Partner	<ul style="list-style-type: none"> Pacific Northwest National Laboratory
Academic and Research Organizations	<ul style="list-style-type: none"> The Ohio State University The Ohio State University Fisher College of Business Technology and Entrepreneurship Center
Vendors	<ul style="list-style-type: none"> General Electric Lockheed Martin Opower PCS UtiliData S&C Electric Company Silver Spring Networks
Key Collaborators	<ul style="list-style-type: none"> AEP Ohio Energy Efficiency/Demand Response Collaborative American Electric Power Service Corporation National Institute of Standards and Technology Ohio Consumers Counsel PJM Interconnection LLC Public Utilities Commission of Ohio
Project Tools and Products	
Project-Developed Collaboration	<ul style="list-style-type: none"> Cyber security information sharing collaborative
Commercialization	<ul style="list-style-type: none"> GridCommand™ Active Demand Management GridCommand™ Distribution Smart Grid Dispatch (SGD) engine <ul style="list-style-type: none"> Home Energy Manager Enhanced Programmable Communicating Thermostat
AMI Customer Portal	<ul style="list-style-type: none"> Opower's Home Energy Reporting System and Insight Engine

Table 1. Project Participants, Tools, and Products

Executive Summary



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1 INTRODUCTION

In 2009, the United States Department of Energy (DOE) awarded a Smart Grid Demonstration Cooperative Agreement to Ohio Power Company (the surviving company of a merger with Columbus Southern Power Company), doing business as AEP Ohio. The AEP Ohio gridSMART® Demonstration Project (Project), award number DE-OE0000193, integrated and evaluated commercially available products, innovative technologies, and new consumer products to understand the economic, environmental, and reliability benefits that could be achieved with scaling such technology to the electrical grid.

This *Final Technical Report* provides insight into the implementation, operation and analytical progression of demonstrated technologies.

1.1 References

References used to prepare this report include:

Document	Date
AEP Ohio gridSMART Demonstration Project Metrics and Benefits Reporting Plan	October 13, 2010
Statement of Project Objectives (SOPO)	January 18, 2013
Instructions For Preparation of Deliverables for Cooperative Agreements Under the Smart Grid Demonstration Program	January 18, 2013
Smart Grid Demonstration Program Guidance for Technology Performance Reports	June 17, 2011
Guidebook for ARRA Smart Grid Program Metrics and Benefits—Smart Grid Demonstration Project	June 2010
AEP Ohio gridSMART Demonstration Project Management Plan (Revision 1)	June 25, 2010
AEP Ohio gridSMART Demonstration Project Quarterly Build Metrics Report	January 31, 2014
AEP 2009 Fact Book	September 30, 2009

Table 2. List of Document References



1.2 Contacts

Name	Role	Telephone
Karen Sloneker	Principal Investigator, AEP Ohio—Director, Customer Service and Marketing	614-883-6677
Scott Osterholt	AEP Ohio—Manager Advanced Distribution Infrastructure gridSMART Project Leader	614-883-6872
Paula Igo	AEP Ohio—gridSMART Project Manager	614-883-7895
Rick Gamp	AEP Ohio—gridSMART Project Comptroller	614-883-6771
Frank Jakob	Battelle Memorial Institute—Project Manager	614-424-4130

Table 3. List of Contacts

1.3 AEP Ohio Demonstration

Ohio Power Company is a unit of the American Electric Power System (AEP), one of the largest electric utilities in the country. Ohio Power Company is commonly referred to as AEP Ohio (AEP Ohio). AEP Ohio and AEP are collectively referred to as AEP in this report.

AEP Ohio was selected because its service area reflects the region and much of the nation in terms of demographic and economic strata, energy consumption patterns, distribution infrastructure, and climate characteristics.

The AEP Ohio territory allows for small-scale and controlled testing of various new technologies and consumer programs in such an environment. The Project integrated these technologies and programs, which included utility-operated distribution system improvements, consumer-managed technology, two-way communications technology, demand management and dispatch technology, and utility-to-consumer interfaces.

1.3.1 Area

Consumers	
Consumers	1.5 million
Communities	890
Counties	61
Distribution	
Distribution Lines	47,000 miles
Transmission	
Transmission Lines	9,200 miles
Generation	
Total Capacity	11,736 MW
Assets	
Total	\$8.3 billion



Figure 1. AEP Ohio Territory

Table 4. AEP Ohio Territory Attribute Estimates

Introduction



The Project was located within northeast central Ohio and in the territory formerly served by Columbus Southern Power Company (CSP). This area demonstrates ideal characteristics for implementation and evaluation of grid-enhancing technology. It included a significant number of 13 kV and 34.5 kV circuits; had distribution stations; included diverse consumer income levels; had a good blend of industrial, commercial, and residential accounts; and received a large number of customer service orders.

In this report, the term System area refers to former CSP's territory. The term Project area refers to the area where Project assets, functionality, or programs were implemented, as shown in Figure 2.



Figure 2. Project Area Scope

Introduction



The table below summarizes the high-level characteristics of both the System and Project areas discussed in this report.

Metric	System area (2009)	Project area
Total number of consumers:		
Residential	667,018	100,000
Commercial & Industrial	81, 866	10,000
Peak load:		
Summer	4,209 MW	800 MW
Winter	3,934 MW	650 MW
Total MWh sales:		
Residential	7,303,192 MWh	1,200,000 MWh
Commercial & Industrial	13,320,621MWh	1,000,000 MWh
Total number of substations	136	16
Total number of distribution circuits	673	80
Total miles of distribution line	18,876 miles	3,000 miles
Total miles of transmission line	2,274 miles	0 miles

Table 5. AEP Ohio’s gridSMART System and Project areas

1.3.2 Technologies

The Project introduced multiple technology enhancements to the infrastructure of the AEP Ohio Project area, including:

- Advanced Metering Infrastructure (AMI) – Two-way communication enabled meters
- Distribution Automation Circuit Reconfiguration (DACR) – Automation of distribution assets
- Volt VAR Optimization (VVO) – Voltage control and optimization
- Consumer Programs (CP) – Cost-saving opportunities through enhanced communication

The addition of the above technologies served as the foundation to enable two-way communication with consumers and allowed for consumer programs and products. The introduction of these technologies also required comprehensive cyber security and interoperability capabilities for both new and legacy systems.

Explanations of each technology and the extent of its functionality are outlined within the Demonstrated Technology sections of this report.

Introduction



1.3.3 Benefits

Each technology, or combination of technologies, produced a benefit to the utility and/or electricity consumers. The table below summarizes some of the benefits of these technologies.

Benefit Category	Benefit	Technologies
Economic	Reduced meter operations costs – meter reading routes	AMI
Economic	Reduced meter operations costs – avoided truck rolls	AMI, DACR
Economic	Reduced electricity costs to consumers	CP, DACR, VVO
Economic	Reduced peak load	CP, DACR, VVO
Reliability	Improved outage response time	AMI, DACR
Reliability	Increased number of meters reporting daily	AMI
Reliability	Increased distribution system reliability	DACR
Environmental	Reduced number of truck rolls	AMI, DACR
Environmental	Reduced meter operations vehicle miles	AMI, DACR
Environmental	Reduced CO ₂ emissions	AMI, CP, DACR, VVO
Environmental	Reduced pollutant emissions	AMI, CP, DACR, VVO

Table 6. Benefits of Technologies

The Project provided several positive outcomes for AEP Ohio and its consumers.

Consumer benefits:

- Enhanced customer service and satisfaction (for example, through faster, remote service connections, and elimination of estimated bills).
- Opportunity to participate in various consumer programs allowing consumers to:
 - Receive near real-time information about electricity usage.
 - Manage their electricity usage and lower their consumption.
 - Save money with the same level of comfort and service.
- Reduced outage times through the automation of circuit reconfiguration.

AEP Ohio benefits:

- Reduced costs through the elimination of meter reading routes and reduced field visits.
- Improved employee safety.
- Improved system reliability.
- Improved customer satisfaction.
- Reduced peak demand.
- Performed tasks remotely, such as reading meters and restoring service.
- Recognized potential equipment failures or outages, allowing proactive maintenance and repair.

Introduction



Overall, the Project showed that implementing AMI, DACR, and VVO technologies provided significant cost, reliability, and environmental benefits for the utility and its consumers. The success of this holistic approach to smart grid implementation enabled AEP Ohio to move forward with the gridSMART Phase 2 (Phase 2) filing.

Introduction



1.3.4 Impact Metric Reference

The table that follows provides a list of metrics by technology. Analysis for each metric is documented in this Final Technical Report.

Impact Metric Reference			
ID	Scope	Description	FTR ID
AMI			
M04	Project	Meter Operations Cost	M04-AMI
M05	Project	Truck Rolls Avoided	M05-AMI
M06	Project	Meter Operations Vehicle Miles	M06-AMI
M07	Project	CO ₂ Emissions	M07-AMI
M08	Project	Pollutant Emissions (SO _x , NO _x , PM _{2.5})	M08-AMI
M09	System	CO ₂ Emissions	M09-AMI
M10	System	Pollutant Emissions (SO _x , NO _x , PM _{2.5})	M10-AMI
M11	Project	Meter Data Completeness	M11-AMI
M12	Project	Meters Reporting Daily	M12-AMI
M29	Project	Outage Response Time	M29-AMI
Consumer Programs			
M01	Project	Hourly Consumer Electricity Usage	M01-CP
M02	Project	Monthly Consumer Electricity Usage	M02-CP
M03	Project	Peak Load and Mix	M03-CP
M07	Project	CO ₂ Emissions	M07-CP
M08	Project	Pollutant Emissions (SO _x , NO _x , PM _{2.5})	M08-CP
M09	System	CO ₂ Emissions	M09-CP
M10	System	Pollutant Emissions (SO _x , NO _x , PM _{2.5})	M10-CP
DACR			
M13	Project	Distribution Circuit Load	M13-CR
M14	Project	Distribution Circuit/Equipment Overload	M14-CR
M15	Project	Deferred Distribution Capacity Investments	M15-CR
M16	Project	Equipment Failure Incidents	M16-CR
M17	Project	Distribution Equipment Maintenance Cost	M17-CR
M18	Project	Distribution Operations Cost	M18-CR
M19	Project	Distribution Circuit Switching Operations	M19-CR
M21	Project	Distribution Restoration Cost	M21-CR
M25	Project	Truck Rolls Avoided	M25-CR
M26	Project	SAIFI	M26-CR
M27	Project	SAIDI/CAIDI	M27-CR
M28	Project	MAIFI	M28-CR
M29	Project	Outage Response Time	M29-CR
M30	Project	Major Event Information	M30-CR
M31	Project	Distribution Operations Vehicle Miles	M31-CR
M32	Project	CO ₂ Emissions	M32-CR

Introduction



Impact Metric Reference			
ID	Scope	Description	FTR ID
M33	Project	Pollutant Emissions (SO _x , NO _x , PM _{2.5})	M33-CR
M34	System	CO ₂ Emissions	M34-CR
M35	System	Pollutant Emissions (SO _x , NO _x , PM _{2.5})	M35-CR
VVO			
M03	Project	Peak Load and Mix	M03 - VVO
M13	Project	Distribution Circuit Load	M13 - VVO
M15	Project	Deferred Distribution Capacity Investments	M15 - VVO
M16	Project	Equipment Failure Incidents	M16 - VVO
M17	Project	Distribution Equipment Maintenance Cost	M17 - VVO
M20	Project	Distribution Capacitor Switching Operations	M20 - VVO
M22	Project	Distribution Losses (%)	M22 - VVO
M23	Project	Distribution Power Factor	M23 - VVO
M32	Project	CO ₂ Emissions	M32 - VVO
M33	Project	Pollutant Emissions (SO _x , NO _x , PM _{2.5})	M33 - VVO
M34	System	CO ₂ Emissions	M34 - VVO
M35	System	Pollutant Emissions (SO _x , NO _x , PM _{2.5})	M35 - VVO

Table 7. Impact Metric Reference



2 DEMONSTRATED TECHNOLOGY – ADVANCED METERING INFRASTRUCTURE

2.1 Purpose

Advanced Metering Infrastructure (AMI) technology incorporates meters that enable two-way communication between AEP Ohio and consumer premises. These meters use network capabilities to provide detailed, near real-time information and to interact with other external devices that the consumer controls.

Prior to the AEP Ohio gridSMART[®] Demonstration Project, AEP Ohio operated with analog meters that registered usage and readings at consumer premises. This approach required meter readers to physically observe the meter and collect meter data. Although a few other meter types existed in the Project area, there were no AMI meters.

AEP Ohio's demonstration of AMI meters intended to:

- Prove that the Silver Spring Networks (SSN) technology could function properly in urban, suburban, and rural applications.
- Show efficiencies associated with automated meter reading on a large-scale basis, including real-time meter reading and daily meter reads.
- Demonstrate the effect of AMI meters on meter operations costs.
- Demonstrate remote reconnect and disconnect capabilities, along with program advantages and disadvantages.
- Leverage the two-way communication with meters in the field, network, and back office.
- Study the demographic groups, including multi-unit, residential, commercial, and industrial, with a complete mixture of socioeconomic classes, and their response to different aspects of the AMI meters.
- Evaluate data generated by the AMI meters generate and the best way to use the information, including meter alarms and alerts, power quality information, energy usage, outage notification, and restoration notifications.
- Enable the use of two-way Home Area Networks (HAN) as part of the energy efficiency and demand response programs.
- Exhibit the benefits of receiving real-time information from different operational areas, such as billing, consumer service, engineering, dispatch, meter reading, and credit.
- Reduce or shift electricity demand and consumption through consumer programs.

Advanced Metering Infrastructure



2.2 Technology

AEP Ohio deployed 110,000 General Electric kV2c and I210+c model meters, including 4-channel recording capability, voltage detection, and ZigBee communication in the Project area. These meters include two-way communication abilities and use a Radio Frequency (RF) mesh network with wireless carrier backhaul communications.

AMI Asset Summary
<ul style="list-style-type: none"> 100,000 residential meters 10,000 non-residential meters 31 access points 133 relays

Table 8. AMI Asset Summary

In addition to the meters, the network included a network interface card for each meter, relay, access point, and eBridge. The single-phase residential meters also included a remote connect/disconnect switch. In addition to standard meter functions, AEP Ohio used the AMI system for remote connect/disconnect capabilities, outage reporting, interval data collection, calculation of bill determinants (kWh, kW, kVARh, on-peak, off-peak), power quality monitoring, and consumer programs facilitation. The figure below shows an AMI meter in Power On and Power Off modes.

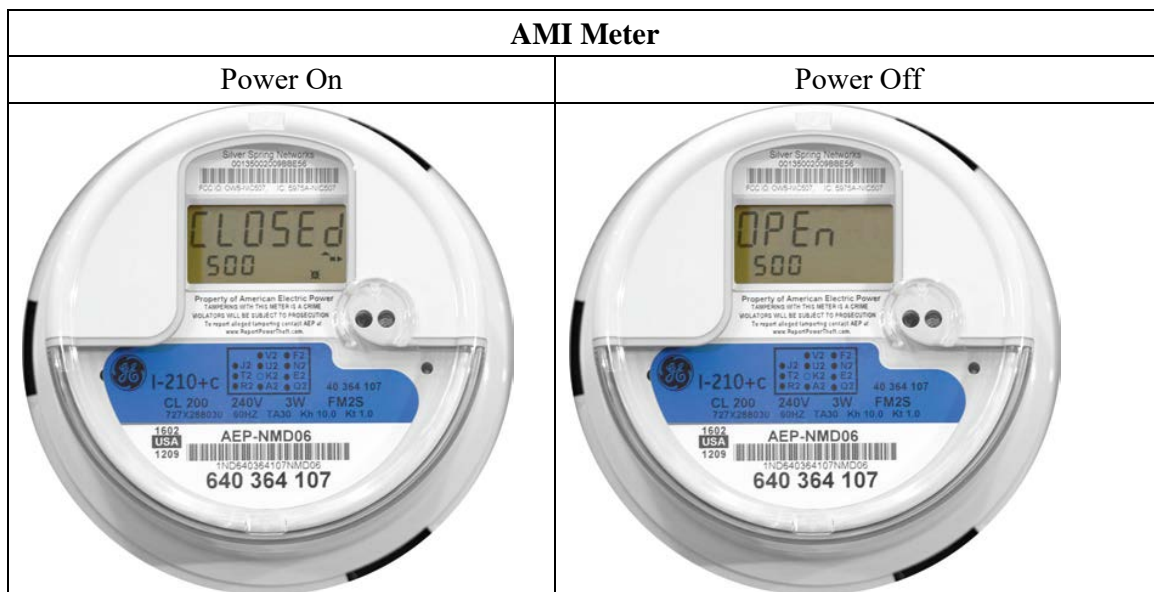


Figure 3. AMI Meters

Advanced Metering Infrastructure



The meter infrastructure interfaced with back-office systems to collect, measure, and manage meter, consumer, and utility activities. The meter infrastructure included the following integrations:

- UtilityIQ[®] software (UIQ)
- Marketing and Customer Service System (MACSS) for consumer-associated data management
- Meter Data Management (MDM)
- Distribution Management System (DMS)
- Demand Response Manager (DRM)

The following figure illustrates the AMI system implementation within AEP Ohio.

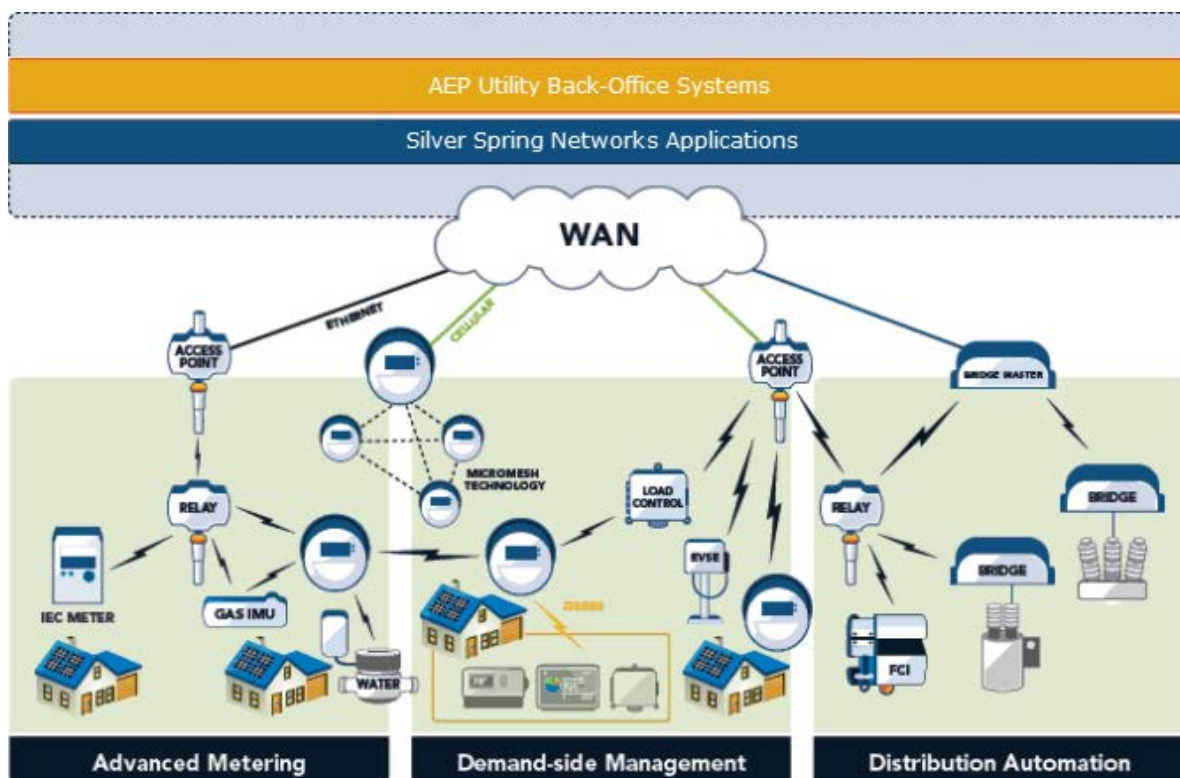


Figure 4. AMI System Illustration



2.3 Approach and Implementation

AEP Ohio installed the meters in an area of central Ohio that had one of the highest bill payment delinquency rates. The intention was to leverage this technology to reduce truck rolls required to perform disconnections for non-payment (DNP) and subsequent reconnections.

To install the meters as quickly as possible, AEP Ohio retained contract resources to install the wireless network and all single-phase meters. AEP Ohio employees installed all poly-phase and instrument-rated meters while contractors were completing the single-phase installations.

As installations were completed, a parallel reading period ensued. The manual reads were compared with the over-the-air reads to ensure that the meter was installed at the correct location and that the meter was reading with 100 percent accuracy. Meter installations were complete by April 1, 2010. AEP Ohio found these meters to be accurate in their out-of-box state, and major manual intervention was not required. As a result, the parallel reading process concluded in June 2010, earlier than planned.

2.4 Impact Metrics Required for AMI

The impact metrics shown in the table below are associated with the AMI technology suite; eight relate to the Project area and two relate to the System area.

Metric ID	Metric Scope	Metric Description	AMI
M04	Project	Meter Operations Cost	M04-AMI
M05	Project	Truck Rolls Avoided	M05-AMI
M06	Project	Meter Operations Vehicle Miles	M06-AMI
M07	Project	CO ₂ Emissions	M07-AMI
M08	Project	Pollutant Emissions (SO _x , NO _x , PM _{2.5})	M08-AMI
M09	System	CO ₂ Emissions	M09-AMI
M10	System	Pollutant Emissions (SO _x , NO _x , PM _{2.5})	M10-AMI
M11	Project	Meter Data Completeness	M11-AMI
M12	Project	Meters Reporting Daily	M12-AMI
M29	Project	Outage Response Time	M29-AMI

Table 9. Impact Metrics Addressing AMI Technology Performance

Refer to the *Metrics Analysis for AMI* section that follows for details.



2.5 Metrics Analysis for AMI

This section provides details for each AMI metric, and includes those requested by the DOE during the definitization of the Cooperative Agreement. Trends were not always observed, however data is presented for each metric.

2.5.1 Meter Operations Cost (M04-AMI)

This metric analyzes savings, incremental and ongoing, resulting from avoiding consumer service truck rolls, eliminating meter reading routes, and reducing meter theft. Also included are the increased costs associated with equipment failure, software licensing, and network maintenance in order to calculate a net savings value.

2.5.1.1 Objective

The purpose of this metric is to understand AMI's impact on the overall cost of AEP Ohio's meter operations.

2.5.1.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data:

- AEP Ohio meter readers typically read one route per day. For calculation purposes, it is assumed that eliminating a route equals eight hours of labor.
- Cost reduction was determined based on conversion factors for vehicle and labor rates.
- Cost reduction did not include potential of savings resulting from truck rolls avoided.

2.5.1.3 Calculation Approach

The following queries and methods were used to generate results:

- Certain types of consumer events, such as check read requests, can be processed remotely by using the AMI system, thereby avoiding a truck roll. A list was compiled of all consumer event order types that lead to an avoided truck roll. The number of truck rolls avoided due to AMI was then calculated based on the number of consumer events with matching order type codes.
- Average mileage per truck roll was calculated by month for each AEP Ohio service center in the Project and System areas. These average mileage values were applied to the count of truck rolls avoided to calculate mileage avoided due to AMI.
- Labor savings from AMI truck rolls avoided per service center, month, and meter funding source were calculated by multiplying the number of truck rolls avoided by an estimated \$20 per truck roll.
- Vehicle savings from AMI truck rolls avoided per service center, month, and meter funding source were calculated by multiplying the number of truck rolls avoided by the average vehicle cost per work order completed by each service center and month.
- Labor costs from AMI truck rolls required per service center, month, and meter funding source were calculated by multiplying the number of truck rolls required by \$50 per truck roll.

Advanced Metering Infrastructure



- Vehicle costs from AMI truck rolls required per service center, month, and meter funding source were calculated by multiplying the number of truck rolls required by the average vehicle cost per work order completed by each service center and month.

2.5.1.4 Organization of Results

This section describes the total net-meter operations dollar savings as a result of AMI from: service-related truck rolls avoided, meter reading routes eliminated, meter theft reductions, and meter tampering reductions.

- Service-related truck rolls avoided

Monthly graphs showing savings and additional costs incurred for vehicle and labor costs are provided in this section. Graphs are then presented for net-labor savings and net vehicle savings. Finally, a graph is presented showing the total dollar value of monthly savings due to truck rolls avoided.

- Elimination of meter reading routes

Savings analysis based on remote meter readings via the AMI network and the elimination of meter reading routes are provided in this section.

- Reduction in meter theft

Analysis of the difference in meter theft rates between AMI and non-AMI meters are provided in this section.

- Changes in meter failure rate

This section contains the analysis of the difference in meter failure rates between AMI and non-AMI meters.

- Software and Network maintenance costs

This section presents the results from analysis of the ongoing costs associated with the AMI network.

- Revenue Protection

Results from analysis of the reduction in meter theft achieved through meter tampering detection are described in this section.

2.5.1.5 Data Collection Results

This section shows savings results related to consumer service-related truck rolls, eliminated meter routes, and AEP Ohio's engineering analysis. In the graphs that follow, DOE represents the approximately 110,000 AMI meters that were deployed in the Project area. AEP represents the approximately 22,000 additional AMI meters deployed in the System area.

Advanced Metering Infrastructure

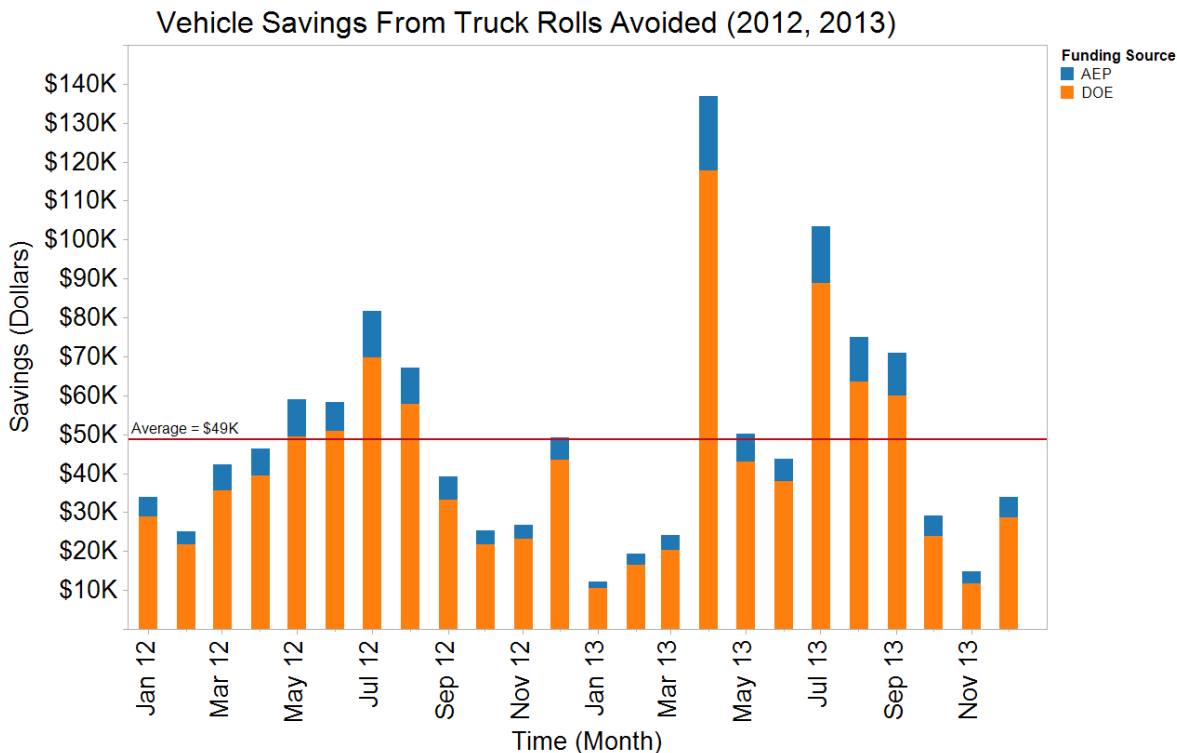


Figure 5. Savings from Reduced Vehicle Costs

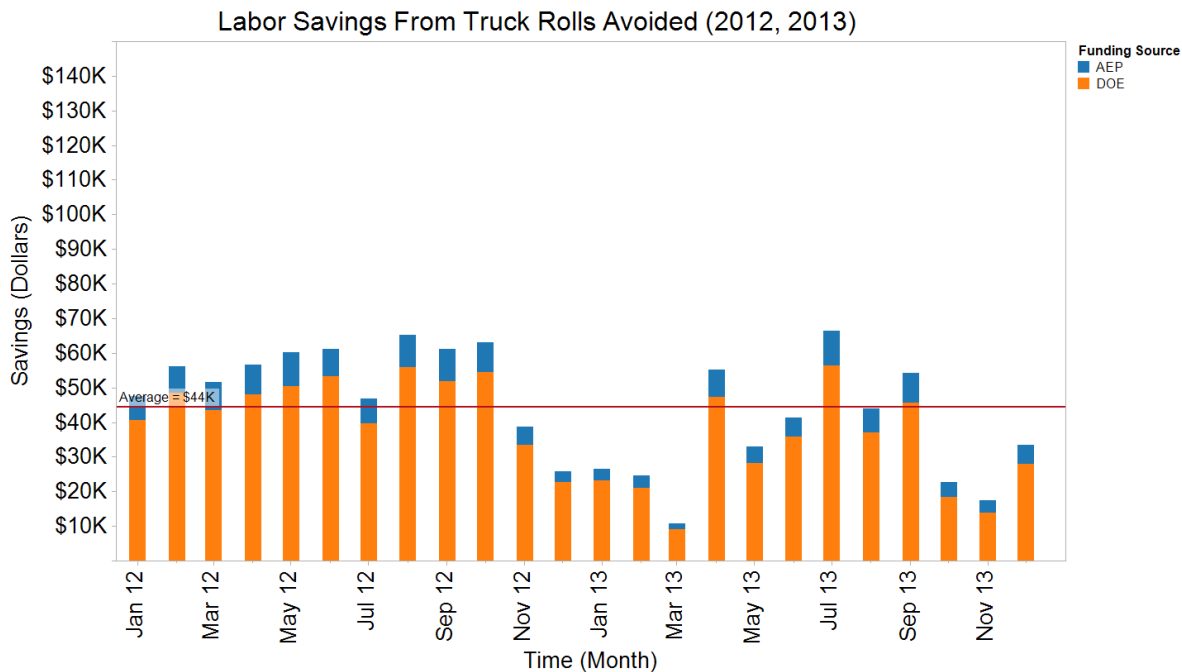


Figure 6. Savings from Reduced Labor Costs

Advanced Metering Infrastructure

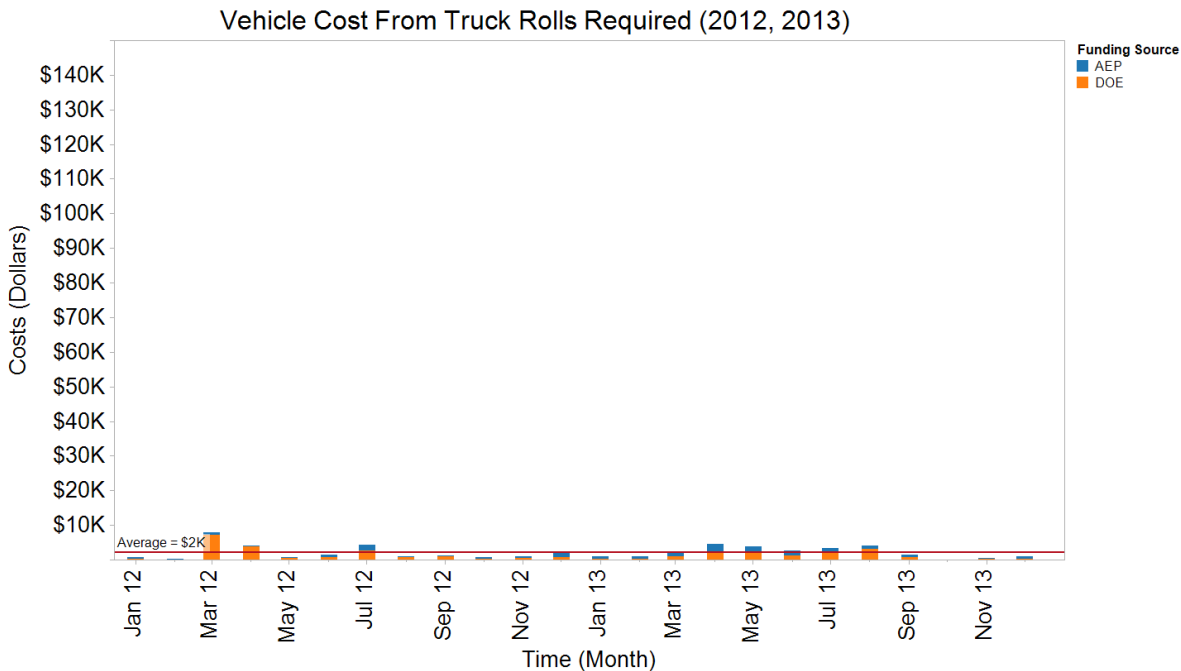


Figure 7. Additional Vehicle Costs from AMI

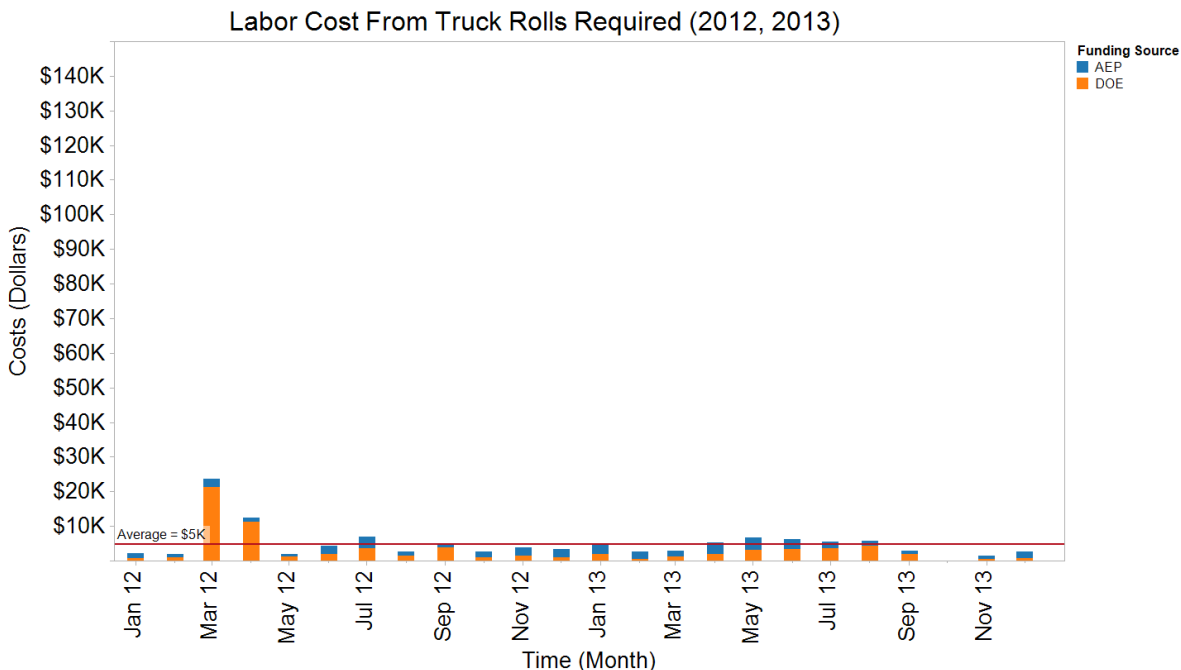


Figure 8. Additional Labor Costs from AMI

Advanced Metering Infrastructure

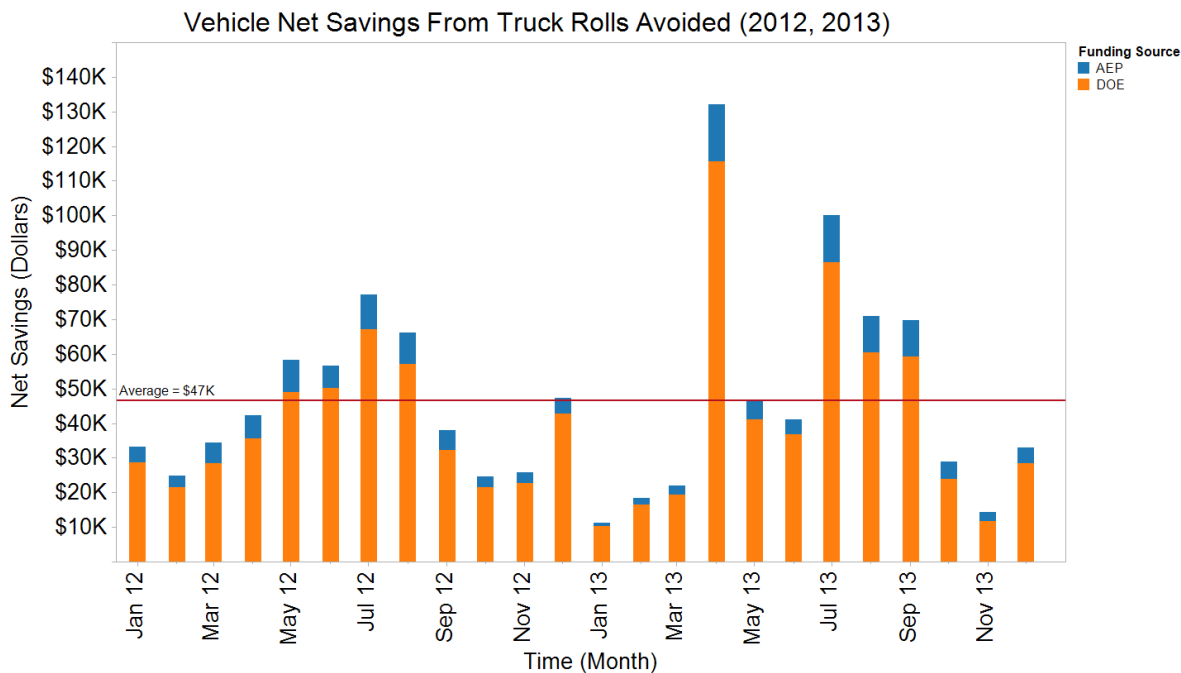


Figure 9. Net Vehicle Savings from Truck Rolls Avoided

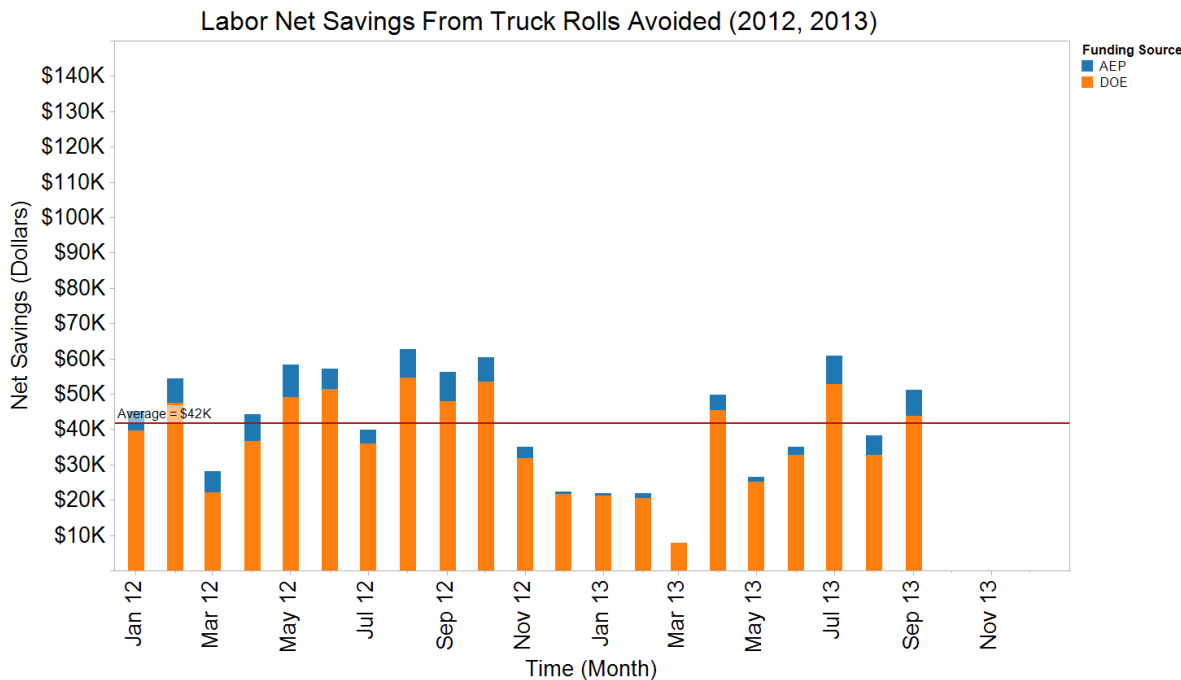


Figure 10. Net Labor Savings from Truck Rolls Avoided

Advanced Metering Infrastructure

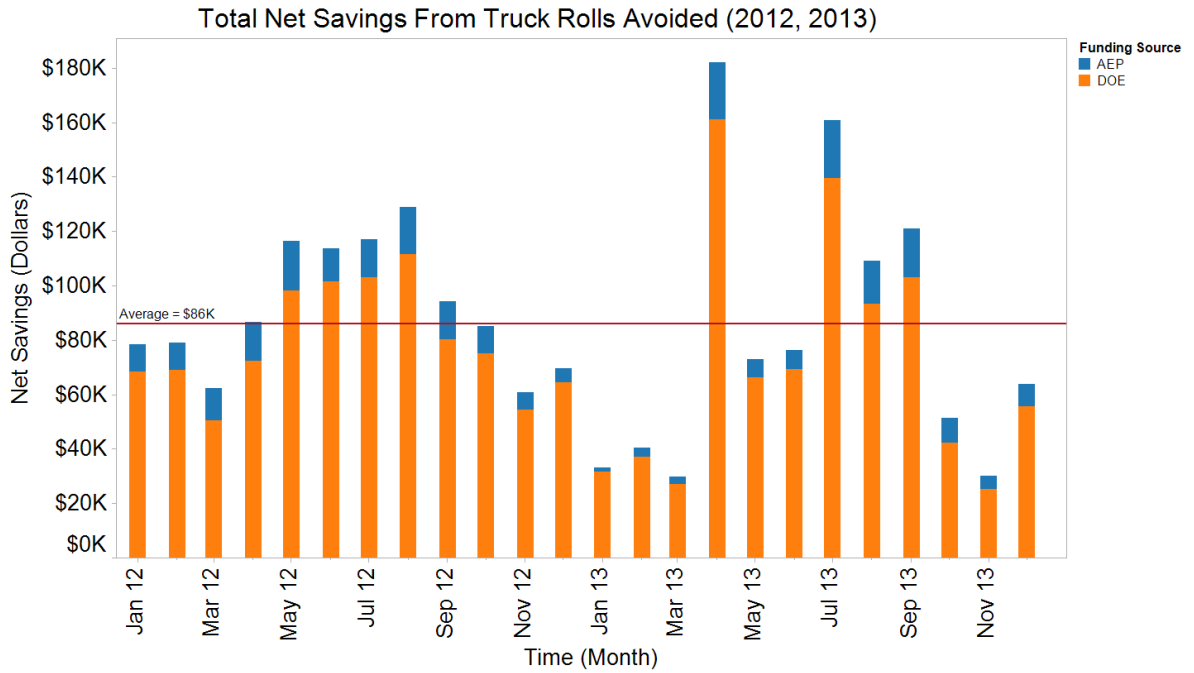


Figure 11. Total Net Savings Associated with AMI Service Truck Rolls Avoided

Advanced Metering Infrastructure



Results for Consumer Service Related Truck Rolls Avoided

The figure above shows the average monthly net savings due to truck rolls avoided from January 2012 through December 2013 was \$85,943, with a total savings of \$2,062,628. The population of meters was approximately 132,000 System area meters. The average per meter savings was therefore \$7.81 per meter per year.

Cost Savings from Eliminated Meter Reading Routes

Prior to the installation of AMI meters, AEP Ohio had 994 meter reading routes in the Columbus metropolitan area. Through the use of AMI, AEP Ohio was able to eliminate 187 meter reading routes, 100 percent of the meter reading routes in the Project area. AEP Ohio meter readers typically read one route per day. For calculation purposes, it is assumed that eliminating a route equals 8 hours of labor. As a result of installing AMI and eliminating 187 meter reading routes, AEP Ohio has saved 1,301.5 hours in labor and eliminated 10 meter reading positions. In addition, unread meter numbers have improved to 0.3 percent in the Columbus area each month.

The table below outlines the savings due to the elimination of meter reading routes.

Item	Hourly Cost	Total Hours	Total Savings
Meter Reader Salary (2012) - loaded	21.45	1,301.50	\$27,917
Vehicle Operations (2012)	7.50	1,301.50	\$9,761
Grand Total – Monthly			\$37,676
Grand Total – Yearly			\$452,112 (3.43 per meter per year)

Table 10. Meter Reading Route Elimination Savings

AEP Ohio has filed with the Public Utilities Commission of Ohio (PUCO) for expansion of the AMI project of an additional 894,000 meters. The meter reading efficiencies are projected to increase to approximately \$6-\$7 million in annual utility savings (adjusted for inflation).

Credit, collections and revenue enhancements through earlier theft detection, lower consumption on inactive meters and greater billing accuracy are projected to lead to an additional \$8-\$10 million in annual utility savings. Of that amount, \$1.5-\$2 million annually is operational savings from use of the remote service switch specifically for DNP. The benefits associated with automated DNP require a PUCO waiver for the current process that requires on-site customer interaction. The PUCO would need to consider whether and how the rules would be adjusted to allow for credit disconnects, considering all stakeholder options.

Results for Reductions in Meter Theft and Tampering

Meter Revenue Operations (MRO) is able to quickly identify and mitigate meter theft and tampering, which is a direct result of AMI technology.

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Meter Theft

Meter theft occurs when someone removes a meter from its authorized location and uses it elsewhere. Because of AMI technology, MRO is able to locate a stolen meter in near real-time. AEP Ohio uses UtilityIQ® (UIQ) back-office software for meter management. Within 15 minutes, this software sends notifications that an AMI meter is installed in a different location.

Meter Tampering

Meter tampering occurs when a meter or meter base is altered, causing inaccurate recording of that meter’s usage, affecting the consumer’s bill. With AMI, tampering was identified almost immediately and MRO identified physical tampering schemes, such as jumper placement behind a meter.

Overview

Tampering usually occurs with about 2 to 3 percent of AEP Ohio consumers. With AMI, the goal was to have AEP Ohio respond to tamper alerts within 24 to 48 hours of the first tampering notification. The AMI system sent tampering notifications immediately and enables MRO to respond to tampering orders quickly.

Details

In a 2013 sampling, 163 total tampering calls were identified through AMI and 147 confirmed instances of jumper placement behind the meter. AEP Ohio was able to bill a portion of these account holders for tampering and continued to investigate the remainder.

AEP Ohio’s meter tampering operating costs are billed to the tampering consumer. A breakdown of costs is provided below.

Tamper Operating Costs Per Meter	
Investigation Costs	\$49.00
Tampering lock installed	\$73.00
Meter charge for damages	\$125.00
Rebilling of Unmetered Revenue	Varies by account
Minimum Total charged to consumer	\$247.00

Table 11. Tamper Operating Costs per Meter

Changes in Meter Failure Rate

AEP Ohio had 3,780 meter failures associated with the AMI implementation, which equated to an approximate failure rate of 0.98 percent during the 3.5 years that the 110,000 AMI meters were installed in the Project area.

Note: This failure rate included the failed diode meters that skewed these numbers initially. However, the problem was diagnosed and corrected.

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Software and Network Maintenance Costs

This section contains the analysis of the ongoing maintenance costs associated with operating the AMI network.

Silver Spring Networks' (SSN) AMI fees for the northeast Columbus project are \$125,565 per year. This is the annual UIQ maintenance fee for 110,000 AMI meters (\$0.095 per meter per month). These recurring fees do not include individual Scope of Work agreements, Online Data Storage (ODS) agreements, and upgrades.

2.5.1.6 Summary

Elimination of truck rolls associated with consumer service calls and the elimination of manual meter reading routes were the major sources of meter operations cost reduction. Both sources included labor and vehicle savings, associated servicing, and reading meters manually. In addition, cost reductions may be realized as meter theft and tampering are identified and mitigated quickly.

The AMI system reduced truck rolls from meter reads and consumer service calls. Customer Service Representatives (CSRs) remotely connected to meters, disconnected meters, and diagnosed consumer issues. For example, AEP Ohio CSRs mitigated billing complaints by accessing and reviewing 15-minute AMI data. Representatives were able to remotely check a meter and review its status. This process often eliminated the need to send a service crew to physically check a meter.

There were more truck rolls as a result of increased consumers' concerns about the accuracy of their bills. These concerns were driven by the increase in information consumers had about their bills. However, this trend was sporadic and it surged on initial installation. Another source of additional truck rolls was AMI-specific maintenance issues (such as communications failures). These additional truck rolls were included in the total number of truck rolls avoided.

The savings from elimination of meter reading routes was fixed, and on a monthly basis, constant. The variability in monthly savings from avoided truck rolls was likely attributable to two major factors – weather events, which drove consumer service calls, and an initial adjustment period as consumers transitioned from traditional meters to AMI meters. There were also concurrent tariff changes with the AMI installation, and that likely drove a short-term increase in consumer service calls seen in February and March of 2012. There were also a number of issues for initial AMI installations that required subsequent truck rolls to correct any installation problems.



2.5.2 Truck Rolls Avoided (M05-AMI)

The AMI system has the potential to reduce the number of truck rolls required through the elimination of meter reading routes and the ability to remotely perform services such as check reads, connections, and disconnections.

2.5.2.1 Objective

This impact metric quantifies the number of truck rolls avoided because of AMI technology. This metric also takes into account the number of truck rolls added that are a result of new information this technology provides. For example, AMI can detect meter tampering and send alerts in near-real time.

2.5.2.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data:

- Disconnections for non-payment are excluded from this analysis because AEP Ohio was required to send a representative to consumer premises prior to service disconnection.
- A disconnect for non-payment did not equate to a truck roll avoided.
- One meter reader per truck. (Standard truck is a pick-up truck.)

2.5.2.3 Calculation Approach

Certain types of consumer events, such as check read requests, can be handled remotely via the AMI system, thereby avoiding a truck roll. A list was compiled of all consumer event order types that led to an avoided truck roll. Next, the number of truck rolls avoided because of AMI was calculated based on the number of consumer events with matching order type codes.

The following queries and methods were used to generate results:

- Truck rolls avoided per service center, month, and meter funding source were calculated by multiplying the ratio of miles for a circuit in a service center to total miles for a circuit times the number of consumer events for consumers with AMI meters where the order type that generated the consumer event was any order type except *Excess use on an inactive account*, the meter response to a meter request was not *Error*, and the consumer event type was one of the following:
 - Connect Request
 - Disconnect Request
 - Estimated Bill Complaint
 - High Bill Complaint
- Truck rolls required per service center, month, and meter funding source were calculated by adding the number of truck rolls required from AMI meter events, where the event type was *Tamper*, to the number of AMI meter requests, where the order request was *Read/Solve Access*.
- Net truck rolls per service center, month, and meter funding source were calculated subtracting the AMI truck rolls required from the AMI truck rolls avoided.

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2.5.2.4 Organization of Results

The following section describes the number of truck rolls avoided due to AMI from the following sources:

- Service-related truck rolls avoided

This section contains monthly graphs showing the number of truck rolls avoided, as well as the number of new truck rolls required because of AMI. A final graph is presented showing the net number of truck rolls avoided.

- Elimination of meter reading routes

This section contains a savings analysis that results from the elimination of meter reading routes because meters are read remotely through the AMI network.

2.5.2.5 Data Collection Results

This section shows savings results related to customer service-related truck rolls, eliminated meter reading routes, and AEP Ohio’s engineering analysis.

Results for Service Related Truck Rolls Avoided

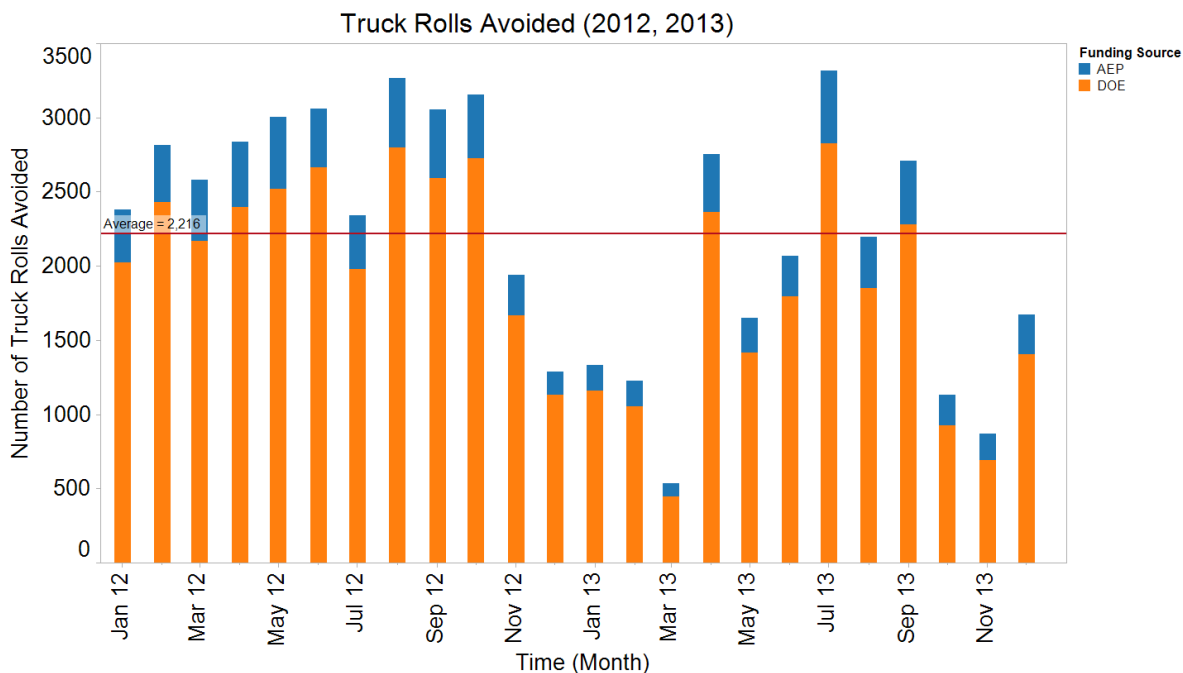


Figure 12. Truck Rolls Avoided Because of AMI

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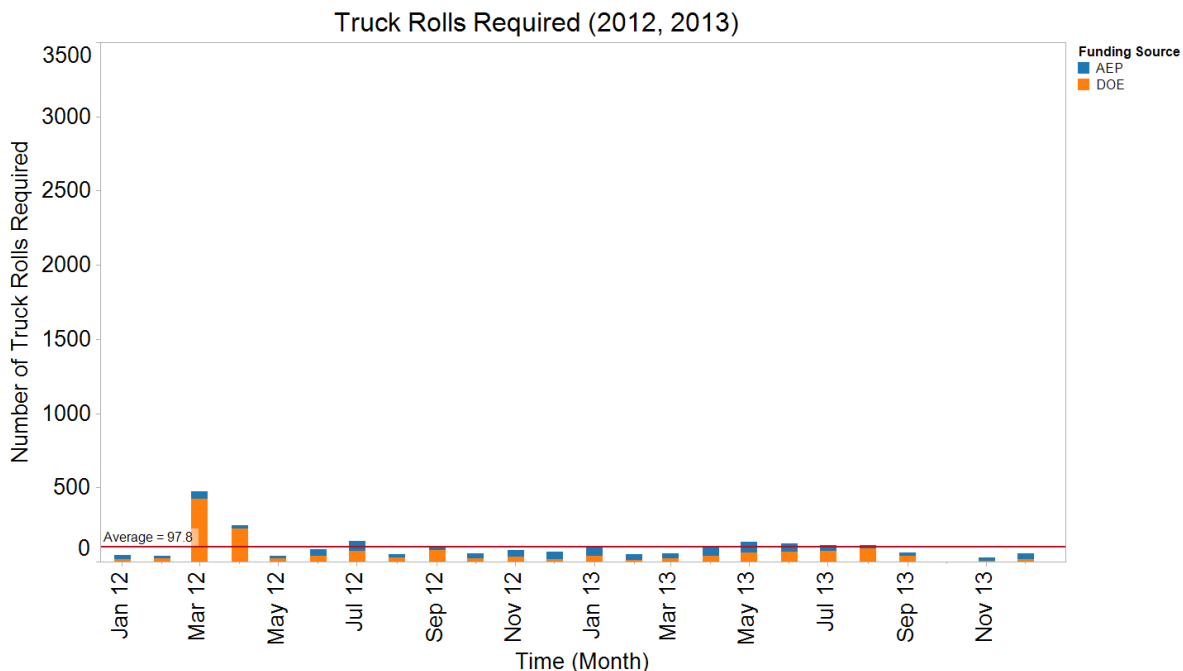


Figure 13. Additional Truck Rolls Required Because of AMI

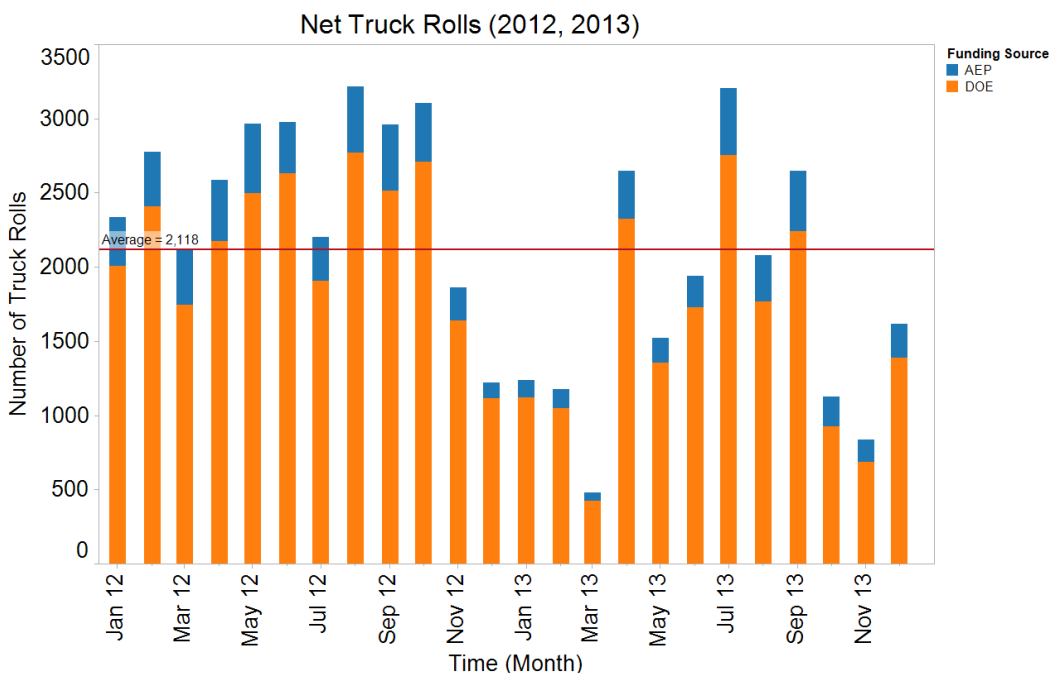


Figure 14. Net Truck Rolls Avoided Because of AMI

The average monthly net count of truck rolls avoided during January 2012 through December 2013 was 2,118 truck rolls per month. The total of number of net truck rolls avoided during January 2012 through December 2013 was 50,825. The 2012 average was 2,526 per month and the 2013 average was 1,709 per month.

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2.5.2.6 Results for Eliminated Meter Reading Routes

Prior to the installation of AMI meters, AEP Ohio had 994 meter reading routes in the Columbus metropolitan area. Through the use of AMI, AEP Ohio was able to eliminate 187 meter reading routes in the Project area. This resulted in 163 avoided truck rolls per month, or 1,952 truck rolls avoided per year.

Note that each meter reading route in this area normally required an average of eight hours per route for meter reading activities. Therefore, meter reading truck rolls represent a much larger mileage savings compared with meter service-related truck rolls.

2.5.2.7 Summary

The number of truck rolls avoided per month showed seasonal variation that can be attributed to several factors. For public safety reasons, fewer disconnect (and corresponding reconnect) events occurred during winter months. In April 2013 there was a noticeable increase due to the backlog of disconnects that were not performed during the winter.



2.5.3 Meter Operations Vehicle Miles (M06-AMI)

The AMI system has the potential to reduce the number of truck rolls that AEP Ohio meter operations staff perform through the elimination of meter reading routes and the ability to perform services remotely. These services include meter reading, meter connections, and meter disconnections.

2.5.3.1 Objective

This impact metric provides an estimate of the number of vehicle miles avoided and added because of changes from AMI technology.

2.5.3.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

The AMI system provides the capability to manage certain types of consumer events remotely, which results in mileage eliminated from truck rolls avoided.

2.5.3.3 Calculation Approach

A list was compiled of all consumer event order types that led to an avoided truck roll. The number of truck rolls avoided because of AMI was then calculated based on the number of consumer events with matching order type codes.

Average mileage per truck roll was calculated by month for each AEP Ohio service center in the Project and System areas. These average mileage values were applied to the count of truck rolls avoided to calculate mileage avoided because of AMI.

The following queries and methods were used to generate results:

- Vehicle distances per service center and month for the Meter Revenue Operations (MRO) and Field Revenue Operations (FRO) business units were calculated by summing the vehicle use mileage quantities.
- Average truck roll distances per service center and month for the MRO and FRO business units were calculated by taking the average of the vehicle distances by service center and month for the MRO and FRO business units divided by the number of completed work orders per service center and month.
- The meter operations vehicle miles avoided per service center, month, and meter funding source were calculated by multiplying the AMI truck rolls avoided per service center, month, and meter funding source by the average truck roll distances by service center and month for the MRO and FRO business units.

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2.5.3.4 Organization of Results

The following section describes the number of vehicle miles avoided from the following sources:

- Service-related truck rolls avoided
 This section contains monthly graphs showing the number of vehicle miles avoided as a result of the net number of truck rolls avoided.
- Elimination of meter reading routes
 This section contains analysis of vehicle miles avoided as a result of eliminated meter reading routes.

2.5.3.5 Data Collection Results

This section describes savings results related to service truck rolls, eliminated meter routes, and AEP Ohio's engineering analysis.

Results for Consumer Service-Related Truck Rolls Avoided

MRO and FRO Vehicle Distance (2012, 2013)

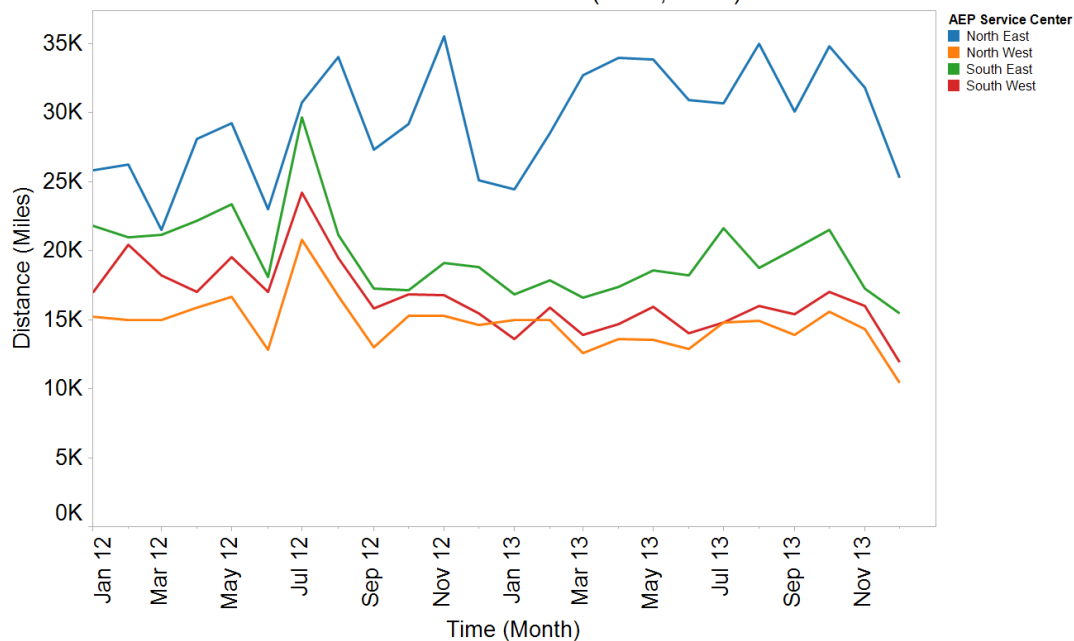


Figure 15. Total Vehicle Distance by Service Center

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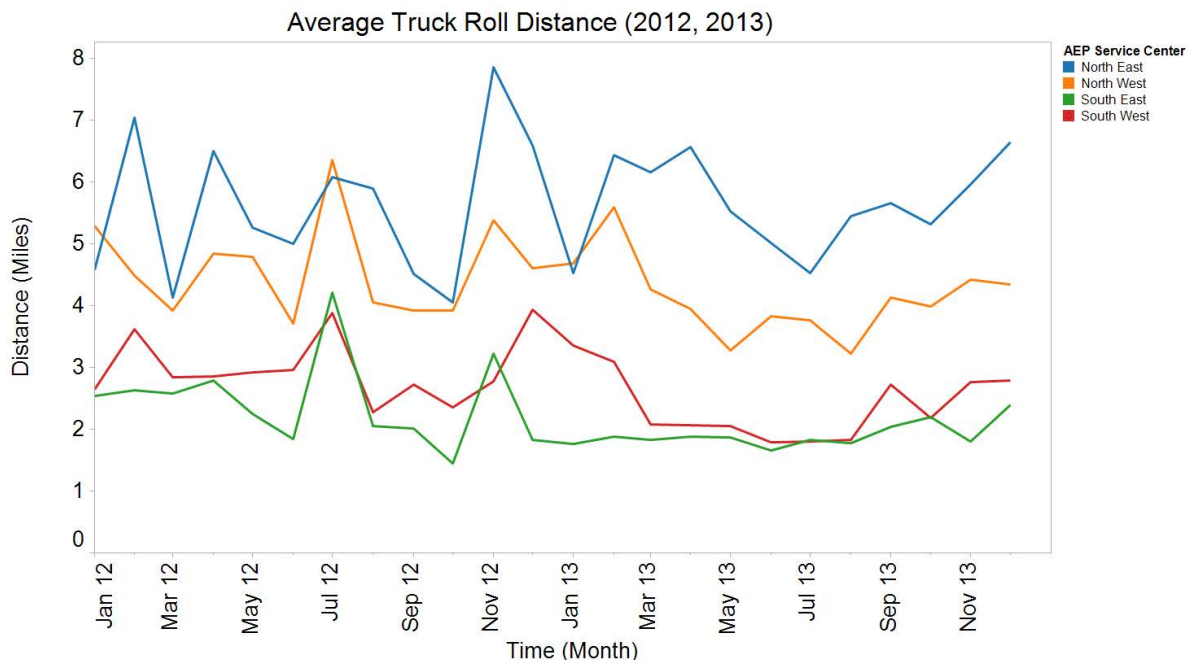


Figure 16. Average Truck Roll Distance by Service Center

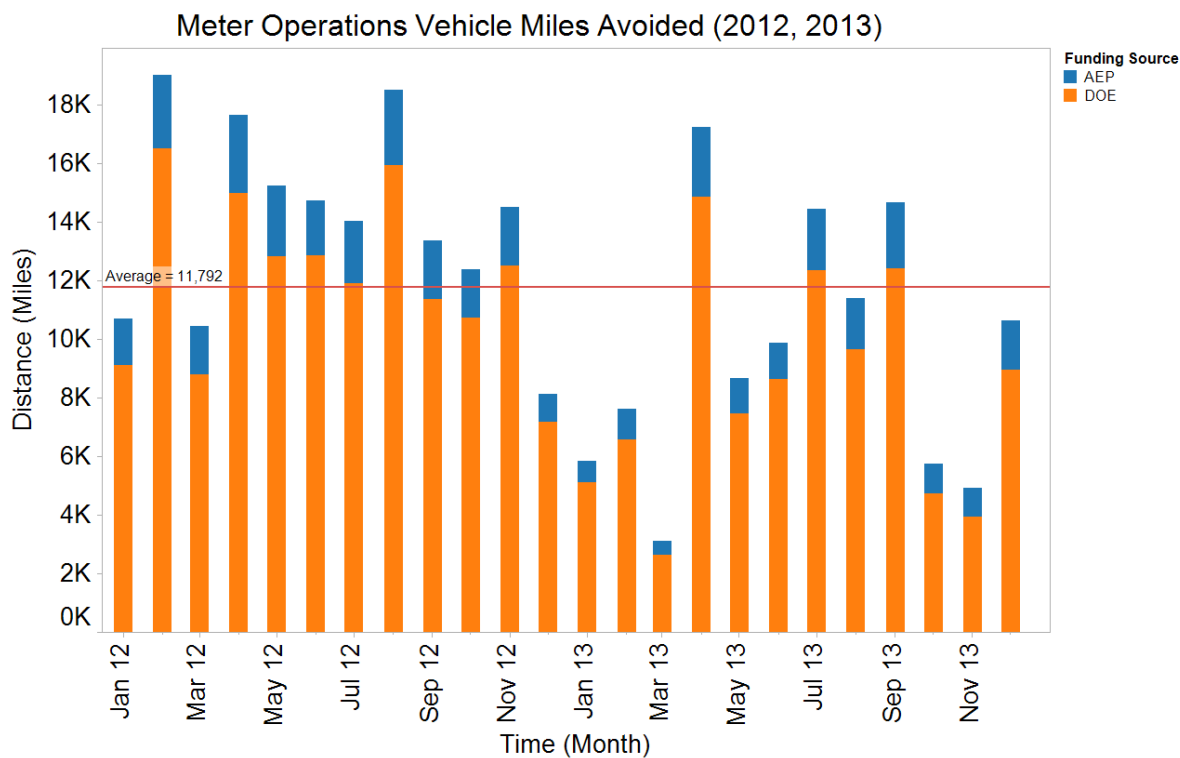


Figure 17. Net Mileage Avoided Due to AMI

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The average monthly net mileage avoided from January 2012 through December 2013 was 11,792 miles/month. The total miles avoided for the period of January 2012 through December 2013 was 282,996 miles.

Results for Eliminated Meter Reading Routes

Through the use of AMI, AEP Ohio was able to eliminate 187 meter reading routes in the Project area. This results in a vehicle mileage avoidance of 5,694 miles/month or 68,328 miles per year.

2.5.3.6 Summary

The meter operations vehicle miles avoided were a direct result of eliminating meter reading route vehicle use and eliminating on-site customer trips for connects and disconnects. There was no indication that there was a change in the number of truck rolls or the average mileage per truck roll due to different type of work being performed in the AMI area. The monthly total and average distance per truck roll were fairly consistent within each of the four Columbus service centers across the test period, but varied significantly by service center.

AEP Ohio's Northeast Service Center, which services the Project area, consistently had a higher total vehicle mileage and average truck roll distance than the other three service centers in Columbus. There was no evidence that this was a result of the AMI technology being deployed, but more a factor of the larger geographic layout of the Northeast Service Center coverage.



2.5.4 CO₂ Emissions - Project (M07-AMI)

The AMI system has the potential to reduce the number of truck rolls required through the elimination of meter reading routes and the ability to perform services remotely. Truck rolls avoided results in a reduction of fuel usage.

2.5.4.1 Objective

This impact metric provides an estimate of the CO₂ emissions saved by avoiding truck rolls resulting from AMI functionality.

2.5.4.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data:

- 8.8 kg CO₂ emissions/gallon for gas engines, 10.1 kg CO₂ emissions/gallon for diesel engines conversion factor.
Source: *United States EPA Office of Transportation and Air Quality Emissions Facts (EPA420-F-05-001)*
- The only significant impacts on CO₂ emissions due to AMI are achieved through truck rolls avoided because AMI has little direct impact on consumer usage patterns.

2.5.4.3 Calculation Approach

A list was compiled of all consumer event order types that lead to an avoided truck roll. The number of truck rolls avoided due to AMI was then calculated based on the number of consumer events with matching order type codes.

Average mileage per truck roll and average vehicle fuel efficiency were calculated by month for each AEP Ohio service center in the Project and System areas. CO₂ emission avoidance was calculated using fuel efficiency and mileage avoided.

The following queries and methods were used to generate results:

AEP Ohio provided an average fuel economy value for each vehicle. Corrected average monthly fuel efficiencies in miles per gallon per service center, month, and fuel type for vehicles the AEP Ohio Meter Revenue Operations (MRO) and Field Revenue Operations (FRO) business units used were determined as follows:

- Calculating the average of monthly vehicle mileage divided by monthly quantity of fuel for each vehicle.
- Because some suspect monthly vehicle mileage (703,281 miles, for example) was received, if the average of monthly vehicle mileage divided by monthly quantity of fuel divided by the average monthly average fuel economy value was not between 0.5 and 2.0, average monthly average fuel economies were substituted for the average of monthly vehicle mileage divided by monthly quantity of fuel. This calculation provides the corrected average monthly fuel efficiencies.

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Tons of CO₂ avoided per service center, month, meter funding source, and fuel type due to truck rolls avoided because of AMI technology were calculated as follows:

- Multiplying the number of truck rolls avoided by the average truck roll distance divided by the corrected average monthly fuel efficiency by (8.8 kg CO₂ emissions/gallon for gas engines, 10.1 kg CO₂ emissions/gallon for diesel engines) by 0.00110231131092 (kg to tons conversion factor).

2.5.4.4 Organization of Results

This section contains the results from analysis of CO₂ through the AMI network as follows.

- Customer service-related truck rolls avoided

This section contains monthly graphs showing the amount of CO₂ avoided due to the net number of truck rolls avoided.

- Elimination of meter reading routes

This section contains the results from analysis of CO₂ avoided due to the elimination of meter reading routes by reading meters remotely through the AMI network.

2.5.4.5 Data Collection Results

This section describes results for service-related truck rolls avoided, eliminated meter reading routes, and AEP Ohio's engineering analysis.

Results for Service-Related Truck Rolls Avoided

The average monthly net CO₂ avoided from January 2012 through December 2013 was 16.91 tons per month, with a total of 406 tons.

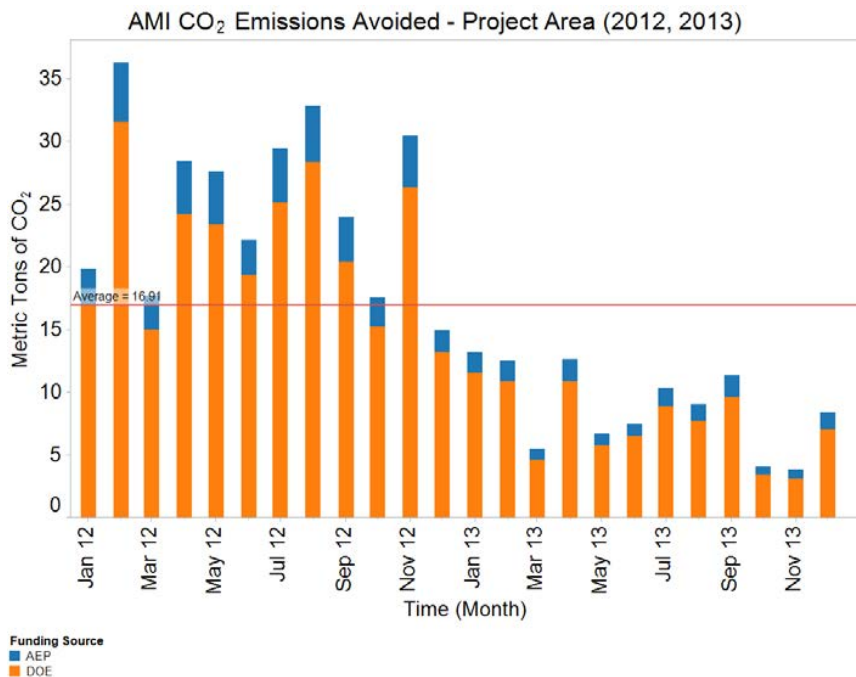


Figure 18. CO₂ Emissions Avoided as a Result of Reduced AMI Truck Rolls

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Results for Reduced CO₂ from Eliminated Meter Reading Routes

Through the use of AMI, AEP Ohio was able to eliminate 187 meter reading routes in the Project area. This results in a vehicle mileage avoidance of 5,694 miles/month or 68,328 miles per year. Using an Environmental Protection Agency (EPA) average value of 423 grams of CO₂ per mile (EPA-420-F-11-041) results in 2.408 metric tons of CO₂ avoided per month or 28.903 metric tons avoided per year.

2.5.4.6 Summary

The CO₂ emissions avoided were a direct multiple of truck roll miles avoided. As a result, the variations and differences in CO₂ emissions over time and service area were consistent with the variations in truck rolls avoided and average truck roll mileage.



2.5.5 Pollutant Emissions - Project area: SO_x, NO_x, and PM_{2.5} (M08-AMI)

The AMI system has the potential to reduce the number of truck rolls required through the elimination of meter reading routes and the ability to perform services remotely, such as meter reading, service connection, and disconnection. Truck rolls avoided can lead to reduced pollutant emissions from vehicles.

2.5.5.1 Objective

This impact metric provides an estimate of the amount of pollutant emissions saved by avoiding truck rolls due to the functionality of AMI technology.

2.5.5.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data:

- California Air Resources Board (CARB) limit value of 0.05 grams of Nitrogen Oxides (NO_x) per mile was used.

Source: *United States EPA 40 CFR part 86 Subpart S tier 2 Bin 5 Emissions limits at 50,000 mi*

- 0.01 g PM_{2.5} emissions/mi conversion factor

Source: *United States EPA 40 CFR part 86 Subpart S tier 2 Bin 5 Emissions limits at 100,000 mi*

- 0.165 g SO_x emissions/gallon for gas engines, 0.0963 g SO_x emissions/gallon for diesel engines conversion factor

Calculated from: sulfur content of gasoline = 30 ppm

Source: *U.S. EPA 40 CFR parts 80, 85, and 86 AMS-FRL-6516-2*

Sulfur content of ULSD diesel fuel = 15 ppm

Source: *U.S. EPA Office of Transportation and Air Quality Emissions Facts (EPA420-F-00-057)*

Molecular weight of SO₂ = 64 g/mole

Density of gasoline = 2.75 kg/gallon

Density of diesel fuel = 3.21 kg/gallon

2.5.5.3 Calculation Approach

Certain types of consumer events, such as check read requests, can be handled remotely using the AMI system, thereby avoiding a truck roll. A list was compiled of all consumer event order types that lead to an avoided truck roll. The number of truck rolls avoided due to AMI was then calculated based on the number of consumer events with matching order type codes.

Average mileage per truck roll and average vehicle fuel efficiency were calculated by month for each AEP Ohio Service Center. Pollutant emission avoidance was calculated using fuel efficiency and mileage avoided.

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The following queries and methods were used to generate results:

- Average monthly fuel efficiencies in miles per gallon per month and fuel type for vehicles the AEP Ohio MRO and FRO business units used were determined by calculating the average of monthly vehicle mileages divided by monthly quantity of fuel for each vehicle. If the average of monthly vehicle mileages divided by monthly quantity of fuel divided by the average monthly average fuel economy value was not between 0.5 and 2.0, average monthly average fuel economies were substituted for the average of monthly vehicle mileages divided by monthly quantity of fuel to calculate the corrected average monthly fuel efficiencies.
- Kilograms of SO_x avoided per service center, month, meter funding source, and fuel type due to truck rolls avoided attributable to AMI technology were calculated by multiplying the number of truck rolls avoided times the average truck roll distance divided by the corrected average monthly fuel efficiency times either 0.165 g SO₂ emissions/gallon for gasoline engines or 0.0963 g SO₂ emissions/gallon for diesel engines e times 0.001 (g to kg conversion factor).
- Kilograms of NO_x avoided per service center, month, meter funding source, and fuel type due to truck rolls avoided attributable to AMI technology were calculated by multiplying the number of truck rolls avoided times the average truck roll distance times 0.05 g NO_x emissions/mi times 0.001 (g to kg conversion factor).
- Kilograms of particulate matter (PM_{2.5}) avoided per service center, month, meter funding source, and fuel type due to truck rolls avoided attributable to AMI technology were calculated by multiplying the number or truck rolls avoided times the average truck roll distance times 0.01 g PM_{2.5} emissions/mi times 0.001 (g to kg conversion factor).

2.5.5.4 Organization of Results

The following section describes the amount of pollutants avoided due to AMI from the following sources:

- Consumer service-related truck rolls avoided
- This section contains monthly graphs showing the amount of pollutants avoided as a result of the net number of truck rolls avoided.
- Elimination of meter reading routes
This section contains the results from analysis of pollutants avoided due to the elimination of meter reading routes by reading meters remotely through the AMI network.

2.5.5.5 Data Collection Results

This section shows results for consumer service-related truck rolls, eliminated meter routes, and AEP Ohio's engineering analysis.

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Service-Related Truck Rolls Avoided

- The average monthly net NO_x avoided during January 2012 through December 2013 was 0.956 kg/month, with a total of 22.9 kg.
- The average monthly net SO_x avoided during January 2012 through December 2013 was 0.220 kg/month, with a total of 5.3 kg.
- The average monthly net particulate matter (PM_{2.5}) avoided during January 2012 through December 2013 was 0.191 kg/month, with an annual total of 4.6 kg.

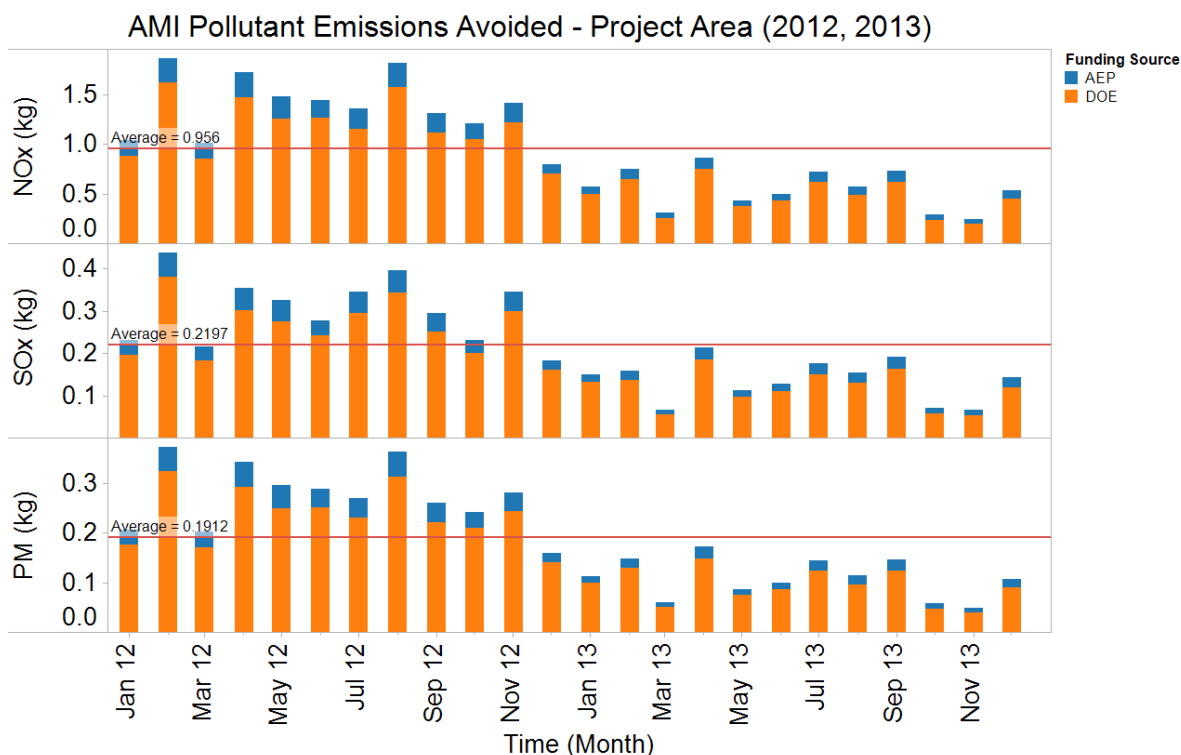


Figure 19. Pollutants Avoided Resulting from AMI Truck Rolls Avoided

Results for Eliminated Meter Reading Routes

Through the use of AMI, AEP Ohio was able to eliminate 187 meter reading routes in the Project area. This results in a vehicle mileage reduction of 5,694 miles/month or 68,328 miles per year.

Using a CARB limit value of 0.05 grams of NO_x per mile, results in 284.7 g of NO_x avoided per month or 3,416 g avoided per year.

SO_x and PM_{2.5} emissions from light-duty gasoline vehicles, which are typically used for meter reading routes, provided a small contribution to this impact metric.

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2.5.5.6 Summary

Pollutant emissions are a direct multiple of truck roll miles avoided. As a result, the variations and differences in pollutant emissions over time are consistent with the variations and differences in truck rolls avoided as well as average truck roll mileage.



2.5.6 CO₂ Emissions - System area (M09-AMI)

The AMI system has the potential to reduce the number of truck rolls required through the elimination of meter reading routes and the ability to perform some services remotely. These services include meter reading, meter connection, and disconnection. Truck rolls avoided can lead to reduced pollutant emissions from vehicles.

2.5.6.1 Objective

This impact metric provides an estimated amount of CO₂ that trucks would emit to perform services that could be performed remotely if AMI technology was extended to the entire System area.

2.5.6.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data:

- 8.8 kg CO₂ emissions/gallon for gas engines, 10.1 kg CO₂ emissions/gallon for diesel engines conversion factor was used.
- Meter reading truck tolls follow the same distance ratio as service truck rolls.

2.5.6.3 Calculation Approach

The AMI system provides remote service capabilities for certain types of consumer events. A list was compiled of all consumer event order types that lead to an avoided truck roll. The number of truck rolls avoided due to AMI was then calculated based on the number of consumer events with matching order type codes.

Average mileage per truck roll and average vehicle fuel efficiency were calculated by month for each AEP Ohio service center in the Project and System areas. Project area CO₂ emission avoidance was calculated using fuel efficiency and mileage avoided. This emission avoidance was then extrapolated to the System area based on number of consumers and average truck roll distances for each non-Project service center.

The following queries and methods were used to generate results:

The calculation that follows was used to determine avoided tons of CO₂ per service center and month if AMI technology were deployed throughout the AEP Ohio System area:

Truck rolls avoided per consumer in the Northeast Service Center were multiplied by the number of consumers without AMI technology per month times the average truck roll distance. This value was divided by the corrected average monthly fuel efficiency times (8.8 kg CO₂ emissions/gallon for gas engines, 10.1 kg CO₂ emissions/gallon for diesel engines) times 0.00110231131092 (kg to tons conversion factor).

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2.5.6.4 Organization of Results

The following section describes the amount of CO₂ that could be avoided if AMI was deployed to the entire System area from:

- Service-related truck rolls

This section contains monthly graphs showing the amount of potential CO₂ avoided as a result of a potential reduction in truck rolls.

- Elimination of meter reading routes

This section contains the analysis results from potential CO₂ avoided due to the elimination of meter reading routes. Meters are read remotely through the AMI network.

2.5.6.5 Data Collection Results

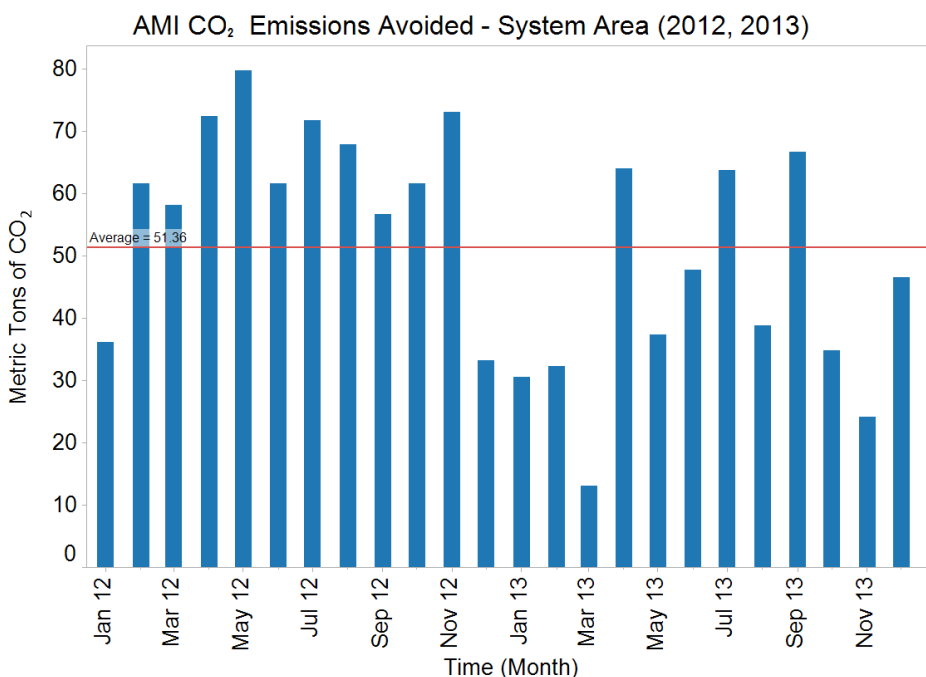


Figure 20. Potential CO₂ Avoided in System Area Due to AMI Truck Rolls Avoided

Results for Service-Related Truck Rolls Avoided

The average potential monthly CO₂ avoided for January 2012 through December 2013 was 51 tons per month, with a potential total of 1,232 tons if AMI were expanded to the entire System area.

2.5.6.6 Summary

CO₂ emissions are a direct multiple of truck roll miles avoided. As a result, the variations and differences in CO₂ emissions are consistent with truck rolls avoided and average truck roll mileage.



2.5.7 Pollutant Emissions - System area: SO_x, NO_x, and PM_{2.5} (M10-AMI)

The AMI system has the potential to reduce the number of truck rolls required through the elimination of meter reading routes and the ability to perform services remotely, such as meter reading, meter connection and disconnection.

2.5.7.1 Objective

This impact metric provides an estimate of the amount of pollutants that would have been emitted by trucks to perform services that could be avoided if AMI technology was extended to the entire System area.

2.5.7.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data:

- A CARB limit value of 0.05 grams of NO_x per mile was used.
Source: *United States EPA 40 CFR part 86 Subpart S tier 2 Bin 5 Emissions limits at 50,000 mi*
- 0.01g PM_{2.5} emissions/mi conversion factor
Source: *United States EPA 40 CFR part 86 Subpart S tier 2 Bin 5 Emissions limits at 100,000 mi*
- 0.165 g SO_x emissions/gallon for gas engines, .0963 g SO_x emissions/gallon for diesel engines conversion factor
Calculated from: sulfur content of gasoline = 30 ppm
Source: *U.S. EPA 40 CFR parts 80, 85, and 86 AMS-FRL-6516-2*
Sulfur content of ULSD diesel fuel = 15 ppm
Source: *U.S. EPA Office of Transportation and Air Quality Emissions Facts (EPA420-F-00-057)*
Molecular weight of SO₂ = 64 g/mole
Density of gasoline = 2.75 kg/gallon
Density of diesel fuel = 3.21 kg/gallon
- NO_x and SO_x emissions from light duty meter reading vehicles are considered negligible. All presented reductions in NO_x and SO_x are a result of service truck rolls.

2.5.7.3 Calculation Approach

Certain types of consumer events, such as check read requests, can be handled remotely by the use of the AMI system, thereby avoiding a truck roll. A list was compiled of all such consumer event order types. The number of truck rolls avoided due to AMI was then calculated based on the number of consumer events with matching order type codes.

Average mileage per truck roll and average vehicle fuel efficiency was calculated by month for each AEP Ohio service center in the Project and System areas. Project area pollutant emission avoidance was calculated using fuel efficiency and mileage avoided.

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This emission avoidance was then extrapolated to the System area based on number of consumers and average truck roll distances for each non-Project area service center.

The following queries and methods were used to generate results:

- Kilograms of SO_x per service center and month that would be avoided if AMI technology were deployed throughout the AEP Ohio System area due to truck rolls avoided were calculated by multiplying the truck rolls avoided per consumer in the Northeast Service Center times the number of consumers without AMI technology per month times the average truck roll distance times either 0.165 g SO₂ emissions/gallon for gasoline engines or 0.0963 g SO₂ emissions/gallon for diesel engines, times 0.001 (g to kg conversion factor)
- Kilograms of NO_x per service center and month that would be avoided if AMI technology were deployed throughout the AEP Ohio System area due to truck rolls avoided were calculated by multiplying the truck rolls avoided per consumer in the Northeast Service Center times the number of consumers without AMI technology per month times the average truck roll distance times 0.05 g NO_x emissions/mi times 0.001 (g to kg conversion factor).
- Kilograms of particulate matter (PM_{2.5}) per service center and month that would be avoided if AMI technology were deployed throughout the AEP Ohio System area due to truck rolls avoided were calculated by multiplying the truck rolls avoided per consumer in the Northeast Service Center times the number of consumers without AMI technology per month times the average truck roll distance times 0.01 g PM_{2.5} emissions/mi times 0.001 (g to kg conversion factor).

2.5.7.4 Organization of Results

The following section describes the amount of pollutants that could be avoided if AMI was deployed to the entire System area from the following sources:

- Service-related truck rolls avoided
This section contains monthly graphs showing the amount of potential pollutants avoided due to truck rolls avoided.
- Elimination of meter reading routes
This section contains the analysis of potential pollutants avoided due to the elimination of meter reading routes if AMI were extended to the entire System area.

2.5.7.5 Data Collection Results

As derived under Metric M09, System area meter reading potential mileage avoided is equal to 371,071 miles/year. Using a CARB limit value of 0.05 grams of NO_x per mile results in the potential for 18.6 kg NO_x avoided per year.

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SO_x and PM_{2.5} emissions from light-duty gasoline vehicles, which are typically used for meter reading routes, provided a small contribution to this impact metric.

- The average potential monthly net NO_x avoided was 3.50 kg/month, with a total of 84.0 kg.
- The average potential monthly net SO_x avoided was 0.858 kg/month, with a total of 20.6 kg.
- The average potential monthly net PM_{2.5} avoided was 0.700 kg/month, with a total of 16.8kg.

Service-Related Tuck Rolls Avoided

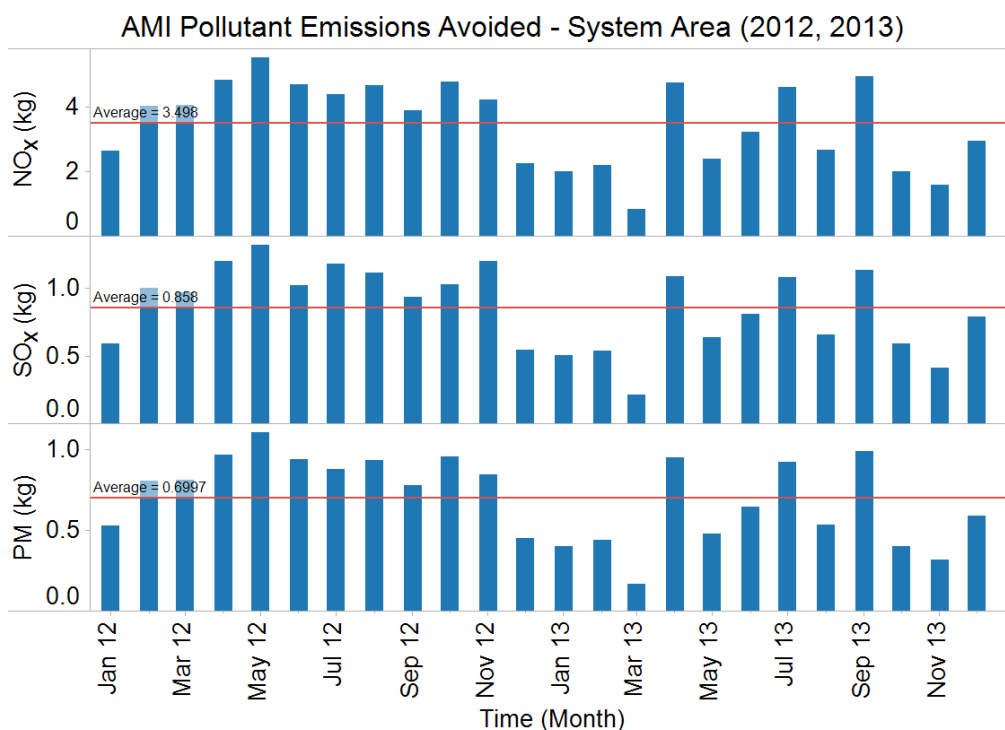


Figure 21. Potential Pollutants Avoided in System Area Due to AMI Truck Rolls Avoided

2.5.7.6 Summary

Pollutant emissions are a direct result of multiple truck roll miles avoided, and in this case are scaled to the System area. As a result, the variations and differences in pollutant emissions over time are consistent with the same in truck rolls avoided and average truck roll mileage.



2.5.8 Meter Data Completeness (M11-AMI)

2.5.8.1 Objective

AMI technology has the potential to provide near real-time meter data to the utility. This impact metric reports the percentage of successfully received meter readings through the AMI system.

2.5.8.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data:

- Any estimated readings are not counted as successful.
- Total expected readings are based on the number of active AMI consumers.

2.5.8.3 Calculation Approach

The following queries and methods are used to generate results:

- AMI readings received per meter and date were calculated by counting the number of non-estimated readings in the Input Data Category (IDC).
- AMI readings expected per meter, date, meter type, meter funding source, circuit, and substation were calculated by counting the number of intervals per day for normal and daylight savings on/off days times the number of AMI consumers.
- AMI readings missed per meter, date, meter type, meter funding source, circuit, and substation were calculated by subtracting the number of AMI readings received from the number of AMI readings expected.

2.5.8.4 Organization of Results

The following section describes the completeness of data reported through the AMI system as follows:

- Interval readings successfully reported through the AMI network
This section contains graphs showing the number of meter readings expected vs. the number received each day.
- Accuracy of reported meter data
This section contains AEP Ohio's results from analysis of meter data accuracy including their procedure for spot checking meters in the field.

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2.5.8.5 Data Collection Results

Interval Readings Reported Through the AMI Network

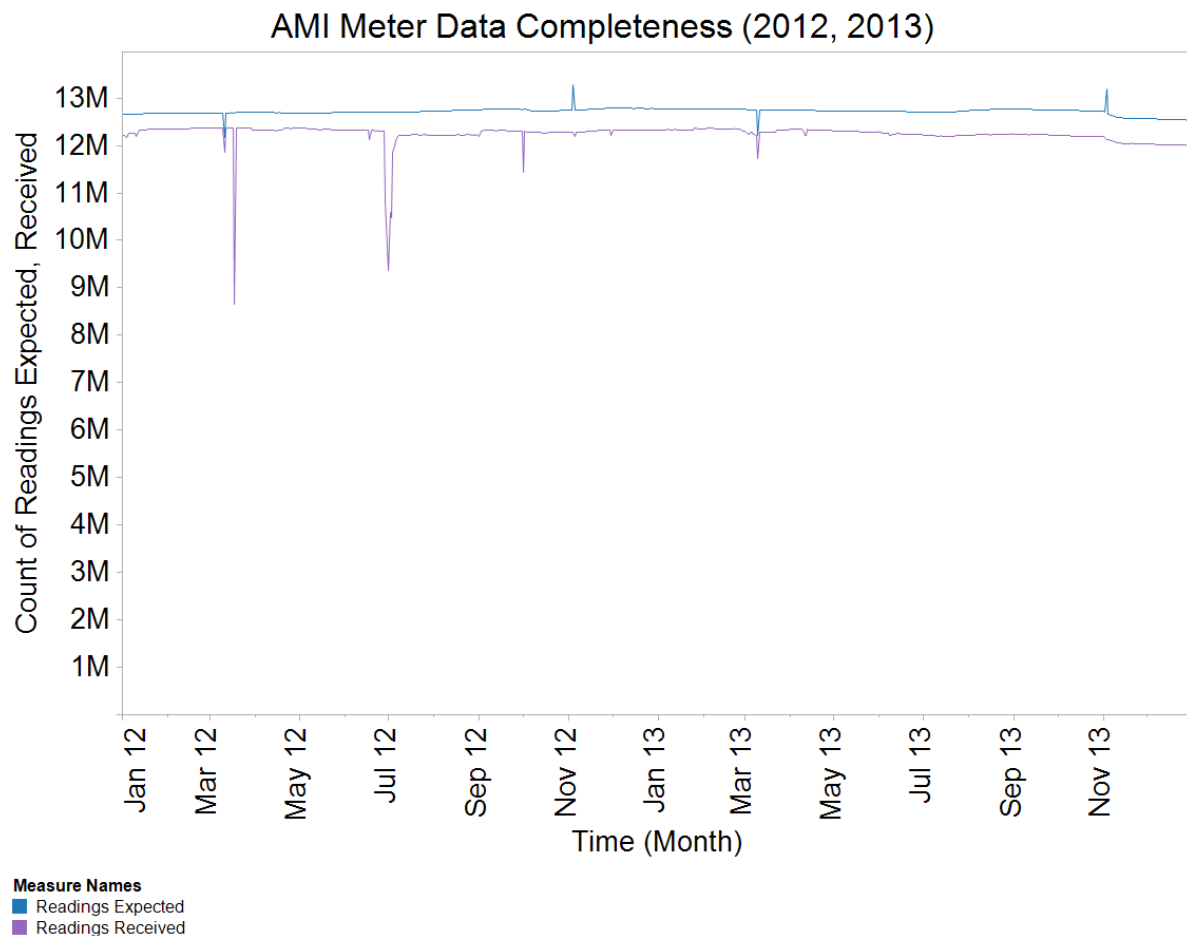


Figure 22. AMI Interval Readings Expected and Received Daily

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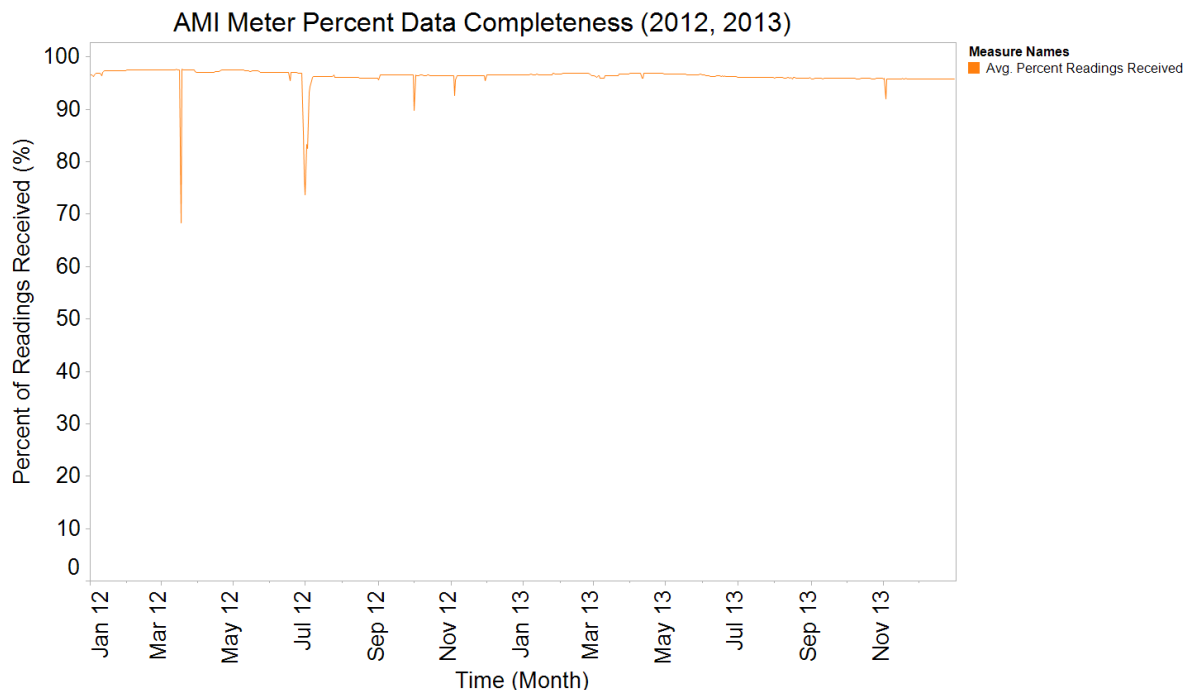


Figure 23. Percentage of Expected AMI Interval Readings Received Daily

2.5.8.6 Summary

More than 131,000 meters on 89 circuits are fully populated with AMI meters. On average, 95 percent of the expected readings have been received from these circuits. The highest average is 97.5 percent and the lowest average is 88 percent. More than 82 circuits exceeded 92.5 percent.

Meter data completeness is consistent throughout the Project period, with a few exceptions resulting from power outages, back-office system outages, or communications network outages. In such cases, the missed readings are for short durations, with the exception of prolonged recovery for some meters after the Derecho storm in late June 2012.



2.5.9 Meters Reporting Daily (M12-AMI)

AMI technology has the potential to provide near real-time meter data to the utility.

2.5.9.1 Objective

This impact metric reports the number of AMI meters that successfully receive meter data, at least once per day, through the AMI system.

2.5.9.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data:

- Estimated readings are not counted as successful.
- Total expected readings are based on the number of active AMI consumers.

2.5.9.3 Calculation Approach

This metric presents the number of AMI meters that successfully report at least one 15-minute interval reading per day.

The following queries and methods were used to generate results:

AMI readings missed per meter, date, meter type, meter funding source, circuit, and substation were calculated by subtracting the number of AMI readings received from the number of AMI readings expected.

2.5.9.4 Organization of Results

The following section describes the completeness of data reported through the AMI system. The specific aspect of data completeness analyzed under this metric is the number of meters successfully reporting at least once per day.

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2.5.9.5 Data Collection Results

Results for Interval Readings Reported Through the AMI Network

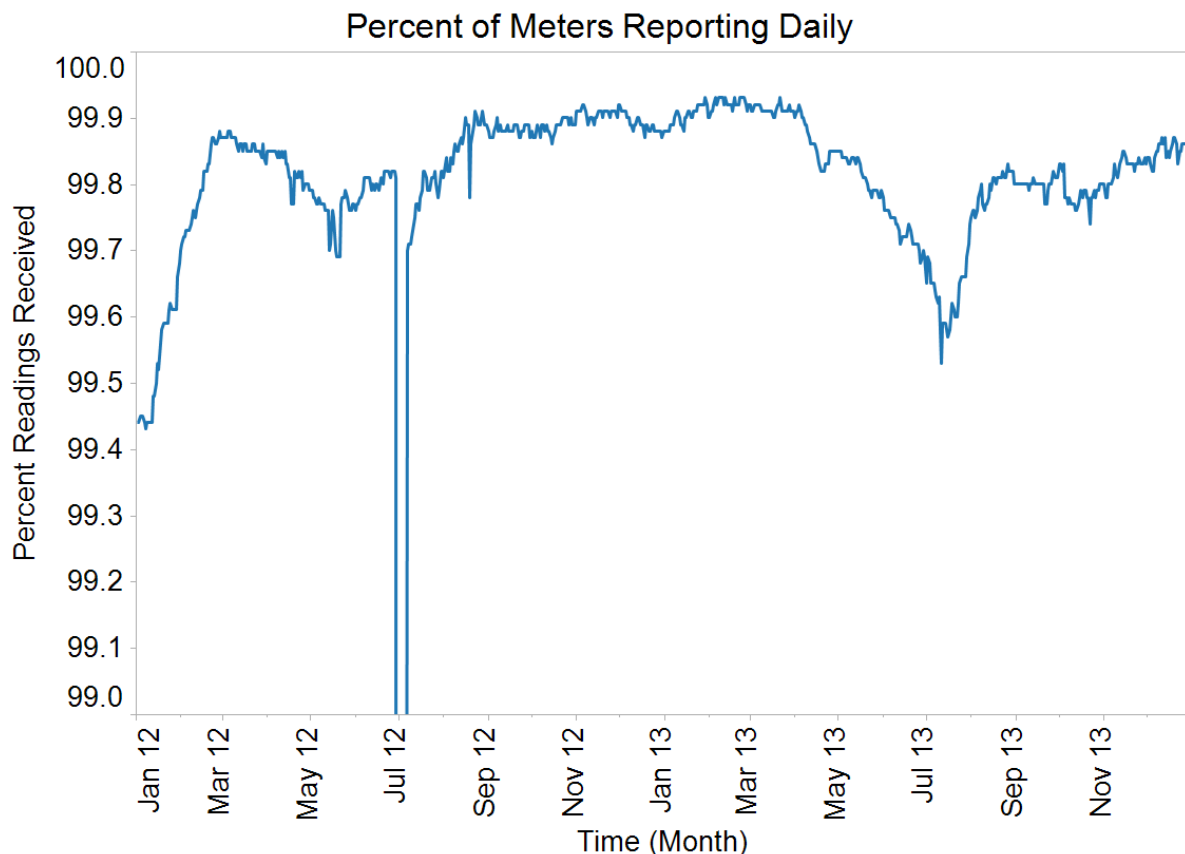


Figure 24. Percent of AMI Meters Reporting Each Day

2.5.9.6 Summary

Meters reporting daily remained relatively high and consistent over the Project time period. This metric does not include short-term communications outages or lost packets, since each meter is required to report a minimum of once per day, unlike the Meter Data Completeness (M11-AMI) metric. The exceptions were associated with major outages, including the late June 2012 through early July 2012 Derecho storm and the associated recovery.



2.5.10 Outage Response Time (M29-AMI)

2.5.10.1 Objective

The AMI system has the ability to notify AEP Ohio of consumer power outages in near real-time. This notification is expected to precede the first consumer-reported outage.

2.5.10.2 Assumptions

This section does not apply.

2.5.10.3 Calculation Approach

This section does not apply.

2.5.10.4 Organization of Results

This section does not apply.

2.5.10.5 Data Collection Results

Refer to the next section, *Outage Response Times and Last Gasp Study*.

2.5.10.6 Outage Response Times and Last Gasp Study

The AMI technology was evaluated to determine if meters automatically reporting outages were beneficial to the outage reporting and restoration process.

2.5.10.7 Evaluation of AMI Ping/Poll Functionality

A ping signal sends a query to a meter to determine if it is in service. A poll signal sends a query to a meter to determine the single phase line to line voltage (240v) on the source side of the meter. Poll capability is not yet available for multiphase meters. The ability to ping/poll meters was incorporated into AEP's PowerOn application. PowerOn is a web-based outage management application.

Studies were performed to track the daily number of dispatchers using ping/poll, and the number of results that returned within one minute. Results varied between a high of 79 percent to a low of 41 percent (technical problems existed skewing results for that month). The overall average for the period was 65 percent of ping/poll queries returning within one minute. Evaluation of the AMI ping/poll features in PowerOn yielded the following results, with associated benefits:

Everyday Use

- The poll feature was useful for consumer voltage complaints or voltage concerns on a given circuit.
- The ability to ping a single meter was useful for single-premises outages.

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Storms Use

- The ability to ping multiple meters was beneficial.
- AMI meters were queried to indicate that restoration was complete, which was beneficial for consumer communication.
- Evaluation during the June 29, 2012 Derecho demonstrated that the use of AMI ping/poll can be integrated into major storm restoration efforts to reduce time and effort and maximize employee efficiency.

Evaluation of AMI Meter Outage Processing System

The AMI Meter Outage Processing System was evaluated during daylight hours into late September 2012. Dispatch engineers noticed that recloser and breaker operations created spikes in meter traffic due to simultaneous, rapid powering down and up of multiple meters. This in turn increased the network delay and various communication problems. In the PowerOn system, this led to several false orders created that escaped the filters. In distribution automation (DA) the high volumes of meter messages (primarily power up) were sometimes conflicting with Distribution Automation (DA) signals to operate equipment and report status back to the control center. These conflicts caused communication losses for the DA operation.

The solution formulated was to implement a sleep timer for meter power up messages. That is, these messages would wait a predetermined time (set at five minutes) to send their messages. The five-minute delay would allow the DA commands and status indications to pass without competing with meter messages for communication resources.

The sleep timer was added on September 21, 2012. Following implementation, additional problems were discovered in that the power up message shows the power up time as the actual time plus five minutes (the time the message is sent, not actual power up time). This problem has not yet been resolved and for this reason AMI Meter Outage Processing was disabled until a solution could be found.

2.5.10.8 Evaluation of Meter Disconnects

AEP Ohio is also working through a business process issue associated with consumer disconnects. When a consumer is disconnected, either for nonpayment or a consumer request for home repairs/maintenance, an order is created in the Order Processing System (OPS) for the meter disconnect. At that time a reconnect order is also created by the system, as the consumer will be reconnected the vast majority of the time. When two OPS orders are created for the same consumer, the OPS filter does not properly filter the AMI meter from reporting an outage to Trouble Entry Reporting System (TERS) and consequently PowerOn. This condition requires correction before AMI Meter Outage Processing is fully implemented.

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2.5.10.9 Results

Some AMI meter features provided benefits for service restoration and were incorporated into the business culture in 2012. Outage Reporting remains a challenge.

- The ability to determine if a consumer's service is energized (ping) and remotely read the meter voltage (poll) provide good benefit for service restoration, particularly in storms. AMI's ping/poll functionality provides an important tool to better manage outages affecting AMI consumers, and is useful for managing the distribution system. Everyday use of ping/polls increases work crew efficiency and results in truck rolls avoided. The use of Ping/Poll during storms is helpful for verifying outage extent and provides valuable input for Outage Management System (OMS) modeling.
- AMI meter-generated outages predicted correctly according to operating company rules a majority of the time.
- Generally, AMI filters worked as designed.
- Many system integration issues were resolved.
- Test results reveal that using AMI meters to report outages has not yet proven beneficial to the business. Test periods in 2012 revealed multiple technical and business challenges that must be overcome before AMI outage reporting will prove successful.
- During major storms the use of the AMI Meter Outage Process would be a hindrance as it would increase traffic on the Outage Management System.

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2.5.11 Order Type Evaluation

In addition to the required metrics for AMI, Meter Revenue Operations managers analyzed order type patterns before and after AMI meters were installed. The statistics that follow show that several order types have decreased significantly in AMI territory. Data does not represent a one-for-one correlation of an order to a specific meter.

Meter Order Types				
Order Type	Description	Years	Totals	Observations
CL01	ELEC W/O FIELD READ	2007	45,249	Field order readings are now automated using UIQ, resulting in a 75 percent reduction in CL01s.
		2008	43,927	
		2009	42,645	
		2010	27,006	
		2011	8,905	
		2012	8,755	
		2013	4,756	
		Total	181,243	
CL20	ELEC WITH REMOTE READ	2010	8,904	<ul style="list-style-type: none"> • The CL20 Order type was not available prior to AMI. • This order type is related to order type CL01.
		2011	29,375	
		2012	27,511	
		2013	16,285	
		Total	82,075	
CL30	REMOTE READ AND DE-ENERGIZE	2010	2,395	<ul style="list-style-type: none"> • The CL30 order type was not available prior to AMI. • There were some dips in 2012 and 2013, but quantities stayed above the 2010 count of 2,395.
		2011	7,770	
		2012	6,876	
		2013	4,149	
		Total	21,190	
DN01	FLD READ & DISCONNECT	2007	6,450	This order type represents an unauthorized use of electricity and required a meter reading service call prior to AMI.
		2008	4,947	
		2009	5,194	
		2010	2,605	
		2011	521	
		2012	439	
		2013	247	
		Total	20,403	

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Meter Order Types				
Order Type	Description	Years	Totals	Observations
DN10	REMOTE READ & DE-ENERGIZE	2010	1,531	<ul style="list-style-type: none"> This order type was not available prior to AMI technology. DN10s are related to DN01 order types.
		2011	3,665	
		2012	2,390	
		2013	1,556	
		Total	9,142	
IO11	EXCESS USE INACT ACCT	2007	714	AEP Ohio back-office personnel were able to identify consumers who are using electricity on inactive accounts. This resulted in truck rolls avoided and loss reduction.
		2008	567	
		2009	360	
		2010	281	
		2011	100	
		2012	41	
		2013	12	
		Total	2,075	
IO12	ENERGY RECOVERY	2007	477	This order type represents recovery from meter tampering. With AMI, tampering was discovered in near real-time, which resulted in a decrease in tampering.
		2008	620	
		2009	598	
		2010	647	
		2011	241	
		2012	307	
		2013	324	
		Total	3,214	
IO40	CHECK READ/RE-READING	2007	6,697	Prior to AMI, this order type required a truck roll in most cases.
		2008	7,237	
		2009	5,948	
		2010	3,387	
		2011	3,235	
		2012	1,631	
		2013	832	
		Total	28,967	

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Meter Order Types				
Order Type	Description	Years	Totals	Observations
IO41	READ & SOLVE ACCESS	2007	474	Prior to AMI, this order type required a truck roll. Access issues and physical limitations were significantly reduced with AMI remote meter reading.
		2008	441	
		2009	754	
		2010	440	
		2011	41	
		2012	36	
		2013	55	
		Total	2,241	
OP20	ELEC WITH REMOTE READ	2010	689	This order type is associated with consumers moving into new premises. An OP20 was performed remotely with AMI, which resulted in truck rolls avoided.
		2011	2,584	
		2012	2,559	
		2013	1,674	
		Total	7,506	
OP30	REMOTE READ & ENERGIZE	2010	3,284	This order type is associated with a consumer move and service reconnection. An OP30 was performed remotely with AMI, which resulted in truck rolls avoided.
		2011	11,876	
		2012	11,368	
		2013	6,671	
		Total	33,199	
OP97	ELEC CONNECT AT SERVICE	2007	217	Prior to AMI, technicians had to travel to the service location and cut a pole to complete this operation. With AMI,
		2008	244	
		2009	241	
		2010	161	

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Meter Order Types				
Order Type	Description	Years	Totals	Observations
		2011	54	OP97 orders were performed remotely.
		2012	59	
		2013	27	
		Total	1,003	
RN01	FIELD READ AND CONNECT	2007	6,678	These orders have been reduced as a result of AMI technology. Prior to AMI, technicians had to travel to a site to read and connect a meter.
		2008	6,721	
		2009	7,062	
		2010	3,485	
		2011	1,365	
		2012	1,370	
		2013	827	
		Total	27,508	
RN10	REMOTE READ & ENERGIZE	2010	1,894	This order type is related to RN01. As RN01 orders are reduced, RN10 orders increased as a result of AMI remote read and energize (connect) capabilities. Note: Energize is a synonym for connect.
		2011	14,501	
		2012	14,296	
		2013	10,228	
		Total	40,919	
Data for 2013 represents January through July				

Table 12. AMI Order Type Evaluation



2.6 AMI Conclusions

AEP Ohio was able to eliminate 100 percent of the meter reading routes (187 routes) in the area where AMI was deployed. AMI also enabled AEP Ohio to reduce costs associated with meter operations activities. For example, through the use of remote service switch capabilities that enable secure connection and disconnection of electric service to consumer premises from the utility back office, AEP Ohio was able to reduce field visits associated with standard move in/move out orders.

AEP Ohio was able to leverage this technology to reduce truck rolls required to perform disconnections for DNP and subsequent reconnections.

The AMI deployment nearly eliminated the need for AEP Ohio to estimate monthly consumer electricity usage, resulting in a higher read rate in the Project area. The reduction of estimated bills led to greater billing accuracy and improved consumer satisfaction. When a consumer requested service termination, the AMI meter was read remotely and a final bill was sent without delays caused by manual reads. AMI meters equipped with a remote service switch enabled power to be turned on or off remotely. As a result, consumers could have service turned on in minutes, rather than waiting days.

From a reliability perspective, meters were queried to get an indication of whether a consumer had power. This indication was useful to troubleshoot consumer issues. In addition, there were some environmental benefits associated with reduced vehicle emissions as a result of reduced vehicle miles traveled.

Overall, the Project showed that implementing AMI technology provided significant cost, reliability, and environmental benefits for the utility and its consumers. Consumers in the System area were satisfied with the AMI technology and installation process. Less than 0.01 percent of consumers in the Project area requested to opt out of the technology, or experienced RF interference.



2.6.1 AMI Meter Outage Processing System

The AMI Meter Outage Processing System was evaluated during daylight hours into late September 2012. Dispatch engineers noticed that recloser and breaker operations created spikes in meter traffic due to simultaneous, rapid powering down and up of multiple meters. This increased the network delay and contributed to various communication problems. In the PowerOn system, this led to several false orders created that escaped the filters, which required modifications to the existing filters.

In Distribution Automation (DA) the high volumes of meter messages (primarily power up) were sometimes conflicting with DA signals to operate equipment and report status back to the control center. These conflicts caused communication losses for the DA operation. This issue has not been resolved. For this reason, AMI Meter Outage Processing System was disabled.

2.6.2 Meter Disconnects

AEP Ohio is also working through a business process issue associated with consumer disconnects. When a consumer is disconnected, either for nonpayment or a consumer request for home repairs/maintenance, an OPS order is created for the meter disconnect. At that time a reconnect order is also created by the system, as the consumer will be reconnected the vast majority of the time. When two OPS orders are created for the same consumer, the OPS filter, a subset of the Meter Outage Process filters, does not properly filter the AMI meter from reporting an outage to TERS and consequently PowerOn. This condition requires correction before AMI Meter Outage Processing is fully implemented.



2.7 Lessons Learned

This section describes lessons learned for AMI technology. Lessons learned are provided for Technology, Implementation, and Operations.

2.7.1 Technology

- Ensure network is designed and operational before meters are installed. Network optimization is essential as soon as all meter installations are completed.
- Recognize the importance of having temperature sensors on the meters' microprocessors. AEP developed a process to ensure that sensor data is monitored and actionable.
- Improve meter tracking process, including scrap meters for auditing purposes.
- Develop good test cases and ensure due diligence up front. Test cases apply to meters and systems, network software, and communication card (firmware).
- Monitor access points, relays, and components for performance and downtime.
- Perform a gap analysis on reporting tools and systems to identify what is needed for optimum performance. Develop or purchase new tools where in-house technology does not exist.
- Identify the best way to obtain and manage large quantities of AMI data for analytics and reporting, which requires expertise, tools, and planning.
- Use the beneficial AMI ping/poll functionality. AEP is working with multiple vendors to enhance this functionality.

2.7.2 Implementation

- Develop a strong project communication plan. It is a critical component to project success. All project team members, consumers, and stakeholders must be included.
- Install network equipment including access points and relays prior to meter installation
- Develop meter installation schedule considering meter blackout dates.
- Provide detailed instructions to the installation contractors. Quality control and oversight are important. This is critical for equipment installation and commissioning. For example, there were meter socket issues, but they were corrected midway through the implementation by having the installation contractor provide additional photos of meter sockets before and after installation. This is now an industry standard.
- Develop and improve stringent processes to gauge and mitigate interdependencies when new technologies are implemented.
- Perform a cost benefit analysis to determine best implementation model. Vendor-managed and vendor-hosted technology implementation is the most cost effective strategy for AEP Ohio.
- Collaborate with vendors to enhance products and implementation.

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- Provide necessary training and tools for expanded roles and responsibilities.
- Perform a root cause analysis as technological issues arise to gain understanding and make improvements.

2.7.3 Operations

- Consider changes in management needs when deploying the AMI Meter Outage Processing in dispatching centers. The following are some of the changes to consider:
 - Business processes within the Distribution Dispatch Center (DDC) need to be established for handling single meter AMI outages with no associated consumer calls before dispatching a service vehicle.
 - Unless benefit can be realized for using AMI Meter Outage Processing in major storms, processes must be in place to disable the functionality before the storm enters the service territory.
- Clarify and document roles and responsibilities in the project plan.
- Collaborate with vendor representatives. Emerging technology requires frequent management consultation to ensure the accuracy and depth of their product knowledge.
- Know the consumer. Keep messages simple, concise, and benefit-driven.
- Provide an education process for internal and contract resources to enable them to act as ambassadors of the technology that strengthens consumer acceptance.
- Integrate AMI ping/poll functionality into major storm restoration efforts to reduce time and effort and maximize employee efficiency.
- Implement a sleep timer for meter power up messages to reduce communication losses for distribution automation operations. These messages will transmit at a predetermined time (set at five minutes). The five-minute delay would allow the DA commands and status indications to pass without competing with meter messages for communication resources.

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3 DEMONSTRATED TECHNOLOGY – CONSUMER PROGRAMS

3.1 Purpose

The AEP Ohio gridSMART[®] Demonstration Project included the deployment of digital Advanced Metering Infrastructure (AMI) electric meters to the approximately 110,000 premises in the Project area to replace their existing analog electric meters. AMI meters feature 2-way communications between the consumer and the utility, the ability to measure and record usage in sub-hourly increments, and the ability to integrate supportive technologies such as programmable communicating thermostats, load control devices, and in-home displays into home area networks.

The analog meters produce usage data only on a billing cycle basis with no accessible time of usage information, hence residential rates are primarily based on average cost of service. AEP Ohio's standard tariff is a flat seasonal tariff with a declining block distribution rate in winter months and represents the average cost of electricity for generation and distribution.

The actual cost of service is variable based primarily on the generation mix required to meet demand. Residential energy usage varies by season, day of week, and time of day, with AEP Ohio residential load normally reaching maximum values during late afternoon periods on the hottest summer days. The incremental cost of supplying this peak load is much greater than the cost of serving normal load as high variable cost generation needs to be kept available and run to serve these high load hours.

With the deployment of AMI meters, tariffs were designed to more accurately reflect the underlying variability of the cost of service. Such variable price tariffs ranged from time-of-day rates, where the cost of electricity was lower during off-peak periods and higher during times of peak use, to real-time pricing programs, where rates most nearly aligned with actual wholesale market prices reflected in the locational marginal prices (LMP) of electricity.

AEP Ohio's deployment of AMI electric meters set the stage for a program to test several consumer programs that could impact utility generation and performance as well as consumer behavior. Using time-of-day tariffs and direct load control (DLC) riders, consumer programs were developed and implemented as an experimental part of the Project.

The introduction of these new consumer programs provided participating consumers with the opportunity for cost savings because of the technology's two-way communication functionality. Consumers were able to make choices based on the way electric rates varied throughout the course of a day. Depending on the program they were enrolled in, they had differing ways of interacting with the technology to make their choices. These consumer programs included time-of-use prices, critical peak price events, DLC events, and real-time pricing. Several experimental time-of-day tariffs and DLC riders were tested in order to determine at what level these tariffs and riders, either directly or indirectly, might reduce a consumer's electricity usage and reduce load for the utility.

Consumer Programs



Participants had the opportunity to more closely monitor their electric use and have greater control over their monthly electric costs by shifting usage from higher price periods to lower price periods or by reducing the demand on the electrical system during peak periods. From a utility perspective, a major goal of these consumer programs was to lower costs and peak demand during peak periods of high generation cost by altering the hourly loads for various residential consumer classes without negatively impacting customer satisfaction.

Because the rate structures and technologies being introduced were new to most of AEP Ohio's consumers, it was important that AEP Ohio provided consumer education and awareness programs to encourage participation in the programs.

Consumer Programs



3.2 Consumer Programs and Enabling Technologies

Consumer programs required program creation that integrated the supporting technologies including AMI, in-home devices, and enabling networking and software. Several programs emerged from that development effort that were installed and activated for consumer enrollment and participation. Upon consumer subscription, AEP Ohio equipped residences in the Project area with auxiliary devices designed to provide usage, pricing, and event information, as well as the technical capabilities to respond to that information. These devices were essential to the implementation of consumer programs.

Tariffs were approved for the various programs and branded for marketing purposes. The table below provides a brief comparison of the programs:

Market Name	Program Description
eVIEW	Consumer usage feedback device
SMART Shift	Two-tier time-of-day
SMART Shift Plus	Three-tier time-of-day with critical peak pricing events
SMART Cooling	Direct load control, thermostat only
SMART Cooling Plus	Direct load control with load control switch
SMART Choice	Real-time pricing with double auction
Standard Residential	Flat tariff with declining block rate, average cost

Table 13. Consumer Programs Descriptions

3.2.1 eViewSM

The eView program consisted of providing consumers with an in-home device that interacted with the smart meter to provide the consumer with current electrical usage and pricing information, enabling them to make decisions about their energy consumption. The device communicated with the smart meter through wireless technology. Consumers could see the average price of electricity and how much they were using and were encouraged to experiment by turning various household appliances on and off to see the difference in usage and costs. The device held usage and average cost data in memory for 30 days, which helped consumers who wanted to make comparisons and estimate upcoming bills.



Later in the Project, eView devices were offered to consumers who signed up for the other consumer programs.

3.2.2 SMART ShiftSM

The SMART Shift program was a two-tiered pricing option for the consumer that did not require any additional equipment. Participants were provided with information to actively monitor and

Consumer Programs



choose whether they would shift their electric usage to an off-peak time by being charged a lower rate for electricity consumed before 1 p.m. and after 7 p.m. weekdays and on weekends during the summer months (June to September). Electricity usage between 1 p.m. and 7 p.m. was charged at the higher rate, which could influence consumer behavior and impact utility peak electricity consumption curve. The program was designed to enable consumers to lower their bills by shifting usage from the higher priced time periods to the lower priced time periods.

3.2.3 SMART Shift PlusSM

The SMART Shift Plus program was a three-tiered pricing option that offered the consumer incentives to modify their electric usage patterns during peak load times on weekdays of the summer months (June to September). An in-home display (IHD) and optional Programmable Communicating Thermostat (PCT) were installed in the consumer’s home to accommodate participation in the program. The PCT gathered and displayed information about how much electricity was being consumed and how much it cost. The IHD displayed the current electricity use and rate and notified consumers when a critical price period was occurring. Consumers were then able to choose how and when to conserve electricity, or shift usage from one period to another, that would result in savings on their bills.



The tariff for this program permitted AEP Ohio to declare up to 15 critical peak pricing (CPP) events when AEP Ohio was experiencing unusually high demand. CPP events were not to exceed 5 hours per day during the calendar year. Energy consumed during these events was charged at a substantially higher rate, thus encouraging consumers to reduce their demand for power at times it cost AEP Ohio the most to produce.

Pricing for non-CPP times had three tiers with only a few cents difference between those tiers. All pricing tiers are depicted in the table below.

Rate Level	Hours
Low	Midnight – 7 a.m. 9 p.m. – midnight And Weekends
Medium	7 a.m. – 1 p.m. 7 p.m. – 9 p.m.
High	1 p.m. – 7 p.m.
CPP	As called – up to 5 hours each event and up to 15 events per year

Table 14. SMART Shift Plus Pricing Tiers

Consumer Programs



3.2.3.1 Smart Appliances

As part of the SMART Shift Plus program, the deployment of 33 Smart Appliances was included in the experiment. The General Electric (GE) smart appliances that were installed in 20 homes were:

- Washer
- Dryer
- Range
- Refrigerator
- Electric water heater

The appliances were equipped with circuitry that communicated with the SMART Shift Plus power display device and allowed the consumer to see in real time how much electricity was being used. When the SMART Shift Plus device detected a higher price for power, the appliances responded accordingly. During a price increase or a defined critical peak period when usage costs were higher, the appliances were programmed to respond as follows.

If...	Then...
The appliance was not running when a SMART Shift Plus unit signaled increased prices or a critical peak time began...	The appliance didn't run at all unless the consumer chose to override the programming using the appliance controls.
The appliance was already running when a SMART Shift Plus unit signaled increased prices or a critical peak time began...	The appliance went into energy-saver mode which curbed energy usage by slowing appliance power and lengthening the duration of the appliance cycles. If desired, the consumer was able to override this programming by using the appliance controls.

3.2.4 SMART CoolingSM

SMART Cooling was a direct load control (DLC) program, which enabled the utility to control electricity demand at the consumer's premises by remotely adjusting the PCT that was installed upon enrollment in the program. At times of peak energy demand from May through September between the hours of noon and 8 p.m., AEP Ohio was permitted to declare up to 15 non-emergency events. An additional 10 PJM Interconnection LLC (PJM) emergency events also could be declared during these months.

During these events, AEP Ohio remotely adjusted participating consumer PCTs up to four degrees higher than the consumer's programmed setting for a time period of up to five hours. Consumers could then elect to accept the increased setting and receive a bill credit, or they could override the setting and forfeit the credit.



3.2.5 SMART Cooling PlusSM

This program was an add-on to the SMART Cooling program by installing a load control switch (LCS) in addition to the IHD and PCT devices. The LCS was installed on electric water heaters, pool pumps, or hot tubs as additional power demand that could be managed remotely. These consumers were offered an incentive to reduce demand by allowing the utility to interrupt the devices during DLC events. Consumers with water heaters and hot tubs could experience 15 additional events during the months of October through April. Consumers had the ability to opt out during DLC events.

3.2.6 SMART ChoiceSM (Real-Time Pricing with Double Auction)

This program provided consumers the opportunity to participate in real-time pricing based on supply and demand for their particular power circuit. Pricing occurred every five minutes for each circuit included in the program. Consumers participated by using the home energy manager (HEM) and the enhanced programmable communicating thermostat (ePCT). For detailed information about this consumer program, see the *Demonstrated Technology – Real-Time Pricing with Double Auction* chapter of this document.

3.3 Approach and Implementation

Prior to development of the consumer programs, AEP Ohio determined that market research was required to understand which program features would appeal to consumers in the Project area. Consumer education requirements were also identified. Consumer demographic information was obtained and focus groups were conducted as the programs and technologies were developed. This approach provided a more effective rollout of the consumer programs, provided consumers with a better understanding of the various enabling technologies, and provided AEP-Ohio with information about which programs appealed to different types of consumers.

3.3.1 Market Research and Consumer Segmentation

One objective of the market research was to match consumer demographics with programs that would appeal to them and enable AEP Ohio to identify target markets for future programs and implement cost effective marketing strategies. The approach taken was to divide the Project area residential consumers into different marketing strata. Each stratum was created to be a proportional demographic representation of the Project area, containing all categories of residential consumers. A control group was also assigned as a baseline against which to measure the effectiveness of the various consumer programs. The control group consumers were not solicited for program participation so they received no marketing or educational materials. The resulting stratification model is illustrated in the following figure.

Consumer Programs



OH gridSMART CUSTOMER SEGMENTATION

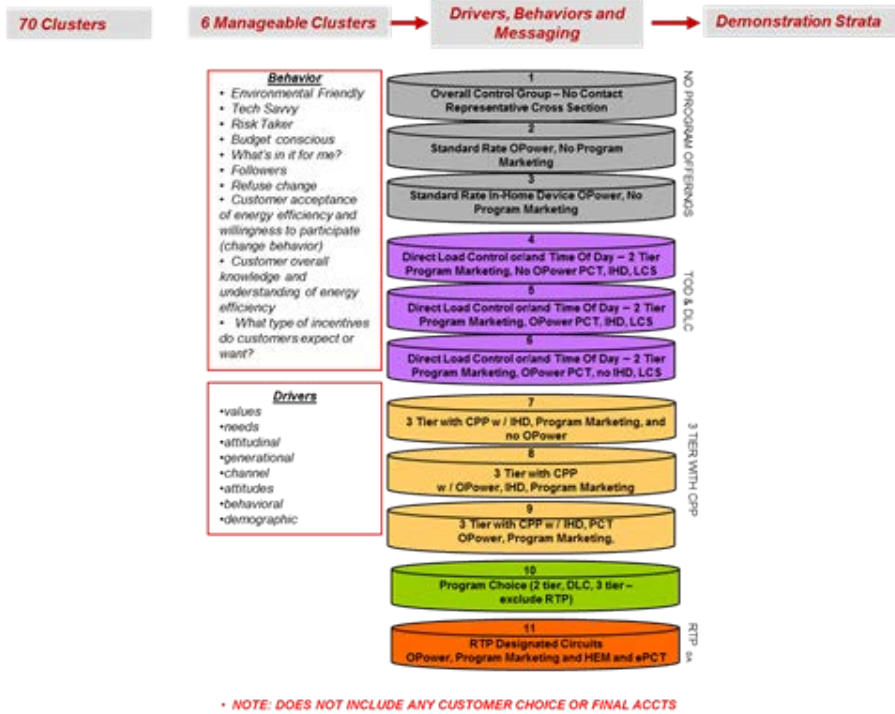


Figure 25. Consumer Segmentation

Consumer Programs



The residential consumers were divided into six different demographic groups for purposes of marketing and analysis. Following are the groups and their definitions:

Group Name / Number	Description
Optimizers (11 clusters)	Comprised of affluent, middle-aged homeowners, mix of married/single, mostly without children. This group represents approximately 17.3 percent of AEP Ohio's consumer base and 18.3 percent of budget billing consumers. Approximately 18.5 percent were high or extremely high users of electricity. This group was generally interested in energy efficiency programs, though none of the clusters were identified as being environmentally conscious.
Budget Stretchers (9 clusters)	This group consisted of low and middle income, mostly young renters, and single and without children. They represented approximately 12.7 percent of the consumer base and roughly 3.2 percent of budget billing consumers. This group was interested in energy efficiency programs with two of the nine clusters being identified as environmentally conscious.
Big Bills (8 clusters)	This group consisted of wealthy, middle-aged homeowners, married with some having children. Approximately 13.3 percent of the consumer base and around 19.1 percent of budget billing consumers are in this group. High or extremely high users of electricity represented 31.2 percent of the group. Many were interested in reducing their bills, but were busy with families, careers, etc., which limited the time they were willing to commit to reduced usage efforts. One of the eight clusters was identified as being environmentally conscious.
Remaining Budget Billed (16 clusters)	This group consisted of households with a mix of incomes, late middle-aged and senior, both married and single, and with or without children. They represented 21 percent of the consumer base and 38 percent of budget billing consumers. High or extremely high users of electricity represented 11.8 percent of the group. Since many were on fixed incomes, they were interested in ways to reduce their usage and save money. Two of the 16 clusters were identified as being environmentally conscious.
Remaining with Children (9 clusters)	This group consisted of mostly low to middle income families with children. They were both young and middle-aged and most owned their homes. They represented 17.5 percent of the consumer base and 10.7 percent of budget billing consumers. High to extremely high users of electricity represented 13.5 percent of this group. These households were generally busy with family and were not concerned with energy efficiency. None of the clusters were identified as environmentally conscious.
Remaining without Children (17 clusters)	This group was very diverse in their incomes, ages and home ownership status. It also contained both married and single homes without children. They represented 18.2 percent of the consumer base and 10.7 percent of budget billing consumers. Nine percent were high or extremely high users of electricity. These households were not generally concerned with energy efficiency. Two of the 17 clusters were identified as being environmentally conscious.

Table 15. Demographic Groups Identified for Marketing Purposes



3.3.2 Marketing Strategy

Residential consumers received smart meters as part of the Project, which was the enabling technology for development of the consumer programs. One of the main objectives that AEP Ohio established as part of the experimental design was to actively attract, educate, enlist, and retain consumers in consumer programs that provide tools and information to reduce cost, consumption, and peak demand. The primary marketing objective was to educate the consumer on the technology, the benefits to the consumer, and assist them in saving energy costs and being environmentally responsible. A complete marketing communications plan was necessary to provide that education, create awareness, and drive consumer program participation.

Using extensive market research and the resulting consumer segmentation, AEP Ohio was able to intelligently target specific demographics for each consumer program being implemented in the Project area. That market intelligence also helped ascertain the marketing channels and tactics that were used. For example, it was not feasible to use mass media – television, radio, and print – because those channels would advertise to people who were not part of the demonstration area or demographic. Thus, list management was used to direct specific marketing messages to the various consumer strata throughout the marketing effort.

Several different marketing channels were employed so that all eligible consumers were aware of their options:

- Web
- Direct mail
- Telemarketing
- Email
- Door-to-door
- Community events
- gridSMART Mobile

AEP Ohio experimented with different types of outreach to discover the best method or combination of methods to communicate with its consumers based on both the nature of the Project as well as the competition for electric service in the Project area. AEP Ohio focused on direct mail and was motivated to test different marketing channels

3.3.3 Consumer Outreach and Education

A key component to obtaining consumer interest and enrollments was to educate consumers about the programs and the potential opportunities for those consumers. AEP Ohio adopted a multi-channel approach to consumer education. Initial mailings were sent to each consumer informing them about the upcoming Project. Follow-up mailings with mostly educational information about smart meters were sent periodically for several months thereafter to entice and build interest for the upcoming technologies. AEP Ohio used a multi-channel approach to consumer outreach and education that included the gridSMART Website, gridSMART mobile, and a school teaching program within the Project area.

Consumer Programs



3.3.3.1 gridSMART Website

AEP Ohio expanded the Website content of www.aepohio.com to include information about gridSMART and consumer programs. The Website provided details about the Project as well as links to the different consumer programs available. The programs became open for online enrollment as they were rolled out to the Project area.

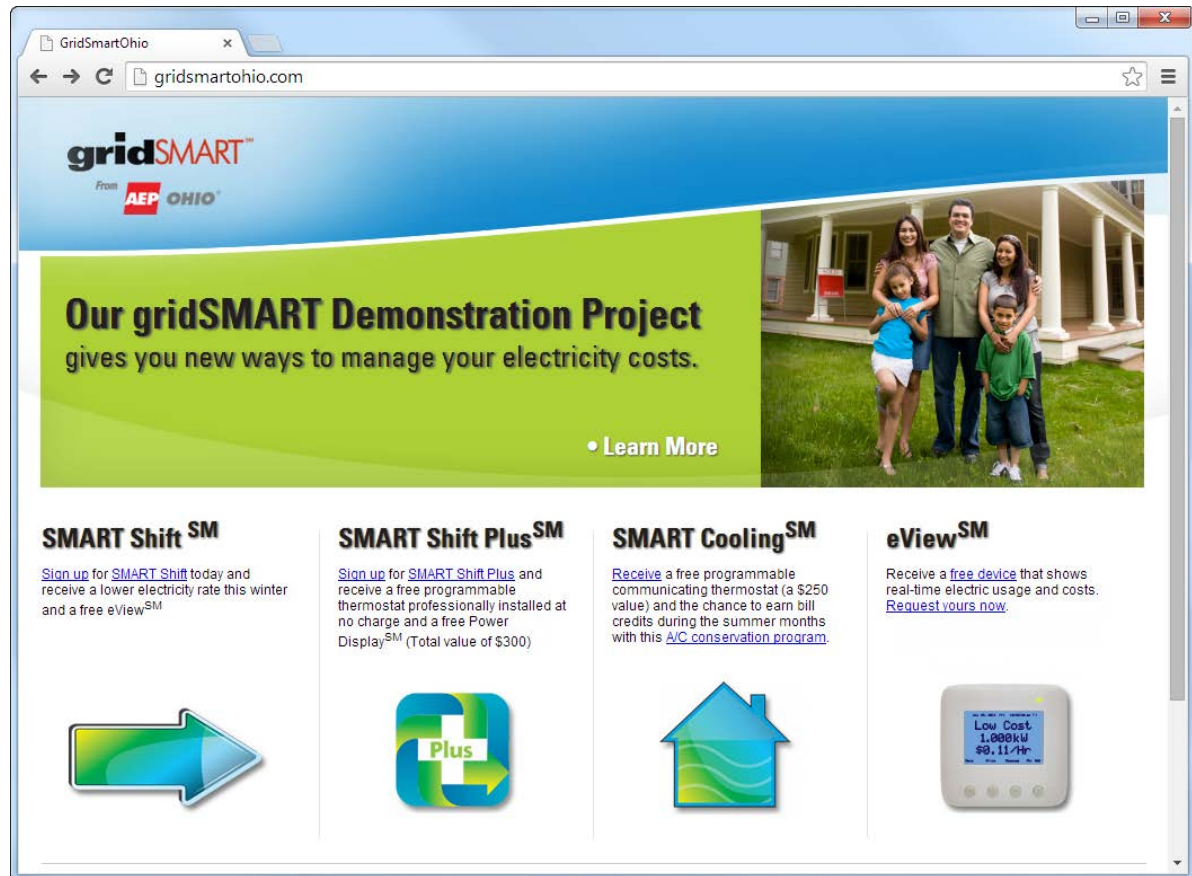


Figure 26. AEP Ohio gridSMART Demonstration Project Website

Consumer Programs



3.3.3.2 gridSMART Mobile

In addition to the Website and ongoing direct mail campaigns, AEP Ohio created the gridSMART Mobile unit as shown below.



Figure 27. gridSMART Mobile

This custom-built recreational vehicle (RV) contained six interactive exhibits designed to educate consumers about different aspects of the Project. Upon entering the vehicle, consumers were able to view a brief computer-driven, multi-media presentation. This presentation consisted of a video explaining the basics of the Project accompanied by a unique sound and light presentation that included a realistic display of thunder and lightning.

Following the presentation, participants received an introduction to smart meters, which was the impetus for consumer programs. This display provided a side-by-side comparison of the smart meter and the traditional meter and explained the benefits of using smart meters.

Other exhibits in the mobile unit included a unique seven-foot-long sliding computer monitor that allowed visitors to explore all components of AEP Ohio's holistic smart grid approach, including a variety of new technologies meant to help identify power outages, restore service faster, and make the distribution network more efficient. Visitors also could test their knowledge by competing in an interactive gridSMART trivia game.

When the Project's focus turned to enrolling consumers in the programs, the mobile unit was modified to be more of an enrollment site with more space designated for consumers to sign up for the programs in person.

Consumer Programs



3.3.3.3 Other Education

AEP Ohio worked with the Ohio Energy Project to develop and implement the gridSMART Education Program with 40 teachers and their students and families in 25 schools located throughout the Project area. Energy curriculum emphasized the new technologies and programs while correlating them to Ohio's Science Content Standards. This partnership supported learning objectives to help students with standardized assessments, and it raised awareness about the gridSMART technologies for potential participants within the Project area.

3.3.4 Enrollments

AEP Ohio chose to pilot the consumer programs first with selected employees that resided within the demonstration area. This type of live testing helped work out some of the potential issues that might have otherwise impacted consumer satisfaction. Once that testing was complete, the rollout of the programs to consumers began.

Upon completion of equipment testing and successful trials at AEP Ohio and in AEP employee homes in the Project area, programs were offered to consumers designated for program offerings under the stratification method described above in the Market Research and Consumer Segmentation subsection.

AEP Ohio used several methods to communicate to its consumers regarding enrollment in Consumer Programs. In considering the cost of using various methods and programs, AEP Ohio considered the following factors:

- Cost per enrollee
- Number of expected enrollees
- Return on investment

While implementing the Project, the utility market in Ohio moved from a regulated utility market to a competitive retail market. As of March 1, 2012, there were 14 competitive retail electric service (CRES) providers actively serving consumers in AEP Ohio's service territory, which meant they were potentially within the Project area as well. This shift to a competitive market had an impact on enrollments for consumer programs because consumers who enrolled with a CRES provider could no longer participate in the gridSMART Consumer Programs.

3.3.4.1 Consumer Acceptance

When consumers contacted AEP Ohio directly regarding potential program enrollment, each consumer was asked how they found out about the program and the primary motivation for pursuing program enrollment. Most consumers learned about the program from the program mailers, and most participated primarily to save money. The following illustrations provide the responses to those questions.

Consumer Programs

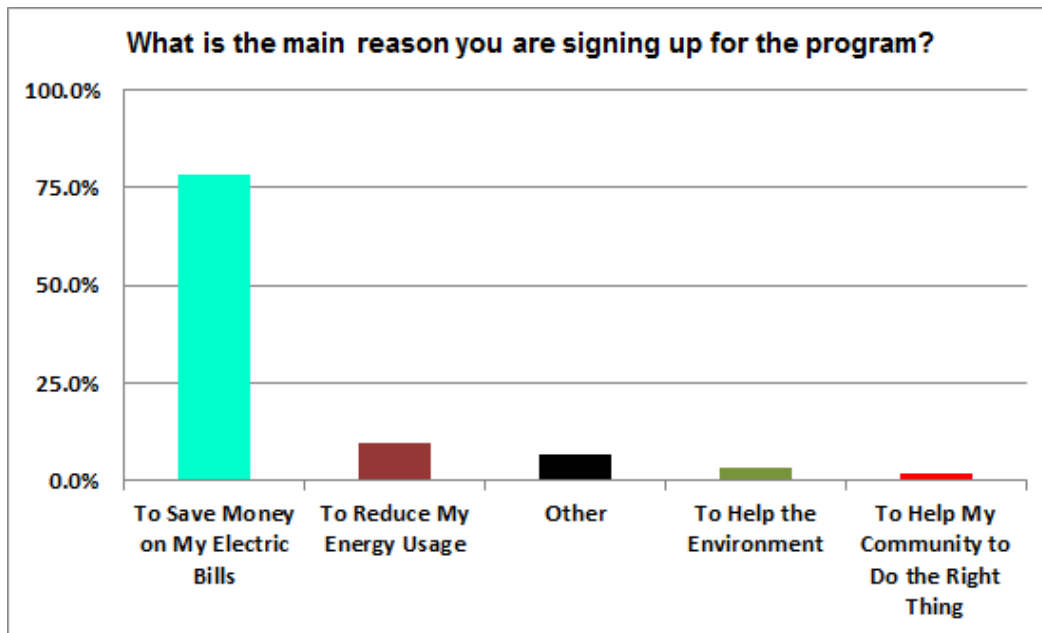


Figure 28. Consumer Enrollment Survey Results

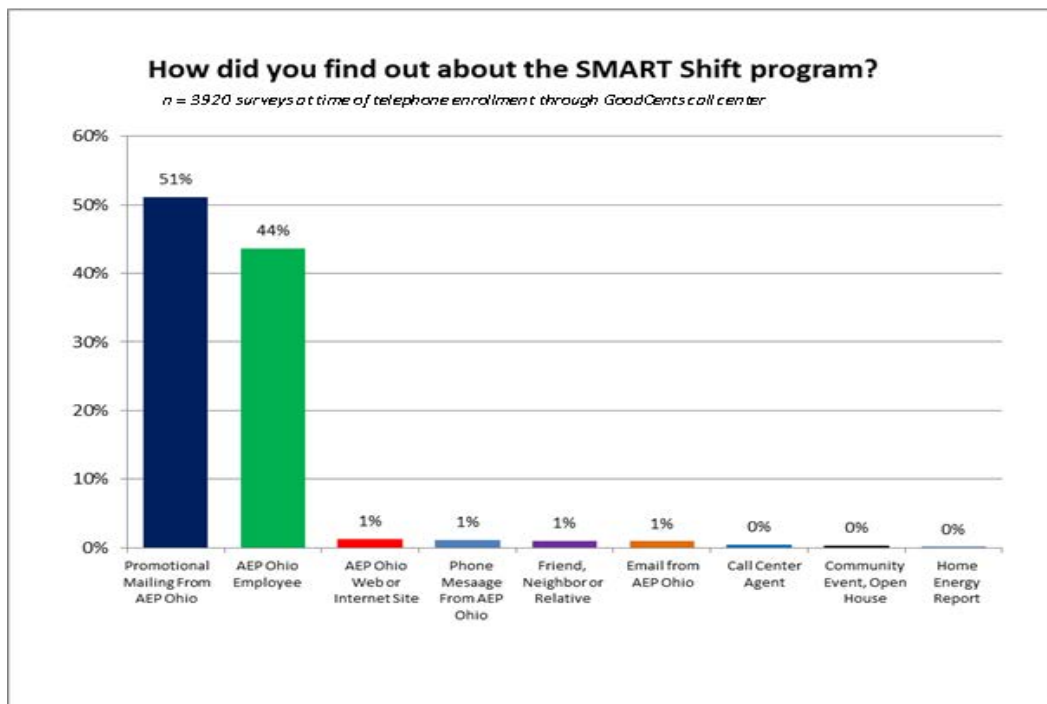


Figure 29. Consumer Awareness Survey Results

Consumer Programs



3.3.4.2 Customer Satisfaction

AEP Ohio conducted consumer satisfaction surveys throughout the course of the Project to better understand the consumers who were participating in the various programs. The survey results shown below indicated that the majority of participants wanted to reduce their electricity usage and realize the benefits of that reduction with lower monthly electric bills. When surveyed at the conclusion of the programs, the survey results showed that most participants perceived an impact on their monthly electric bills. Overall, these results are an indication that people like having the tools to reduce usage and costs and are likely to accept and participate in future consumer programs offered in the electric utility industry.

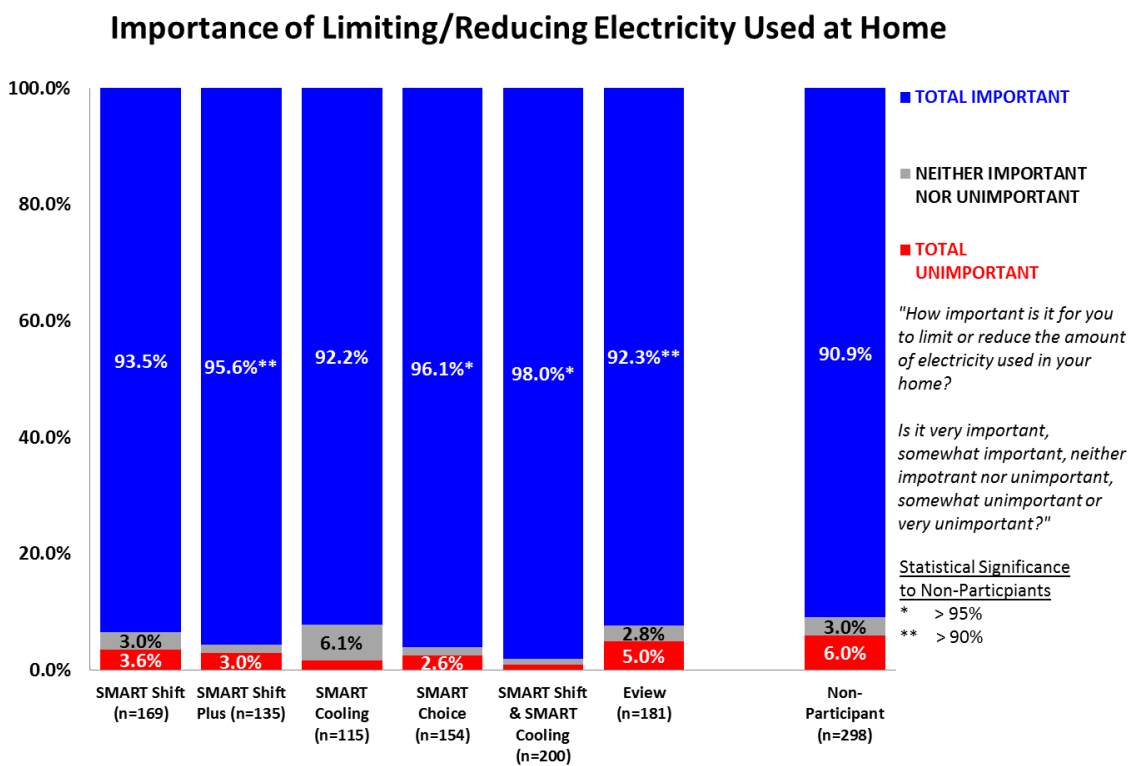


Figure 30. Survey Results - Importance of Limiting/Reducing Electricity Used at Home

Consumer Programs



Overall Satisfaction with gridSMART Consumer Programs

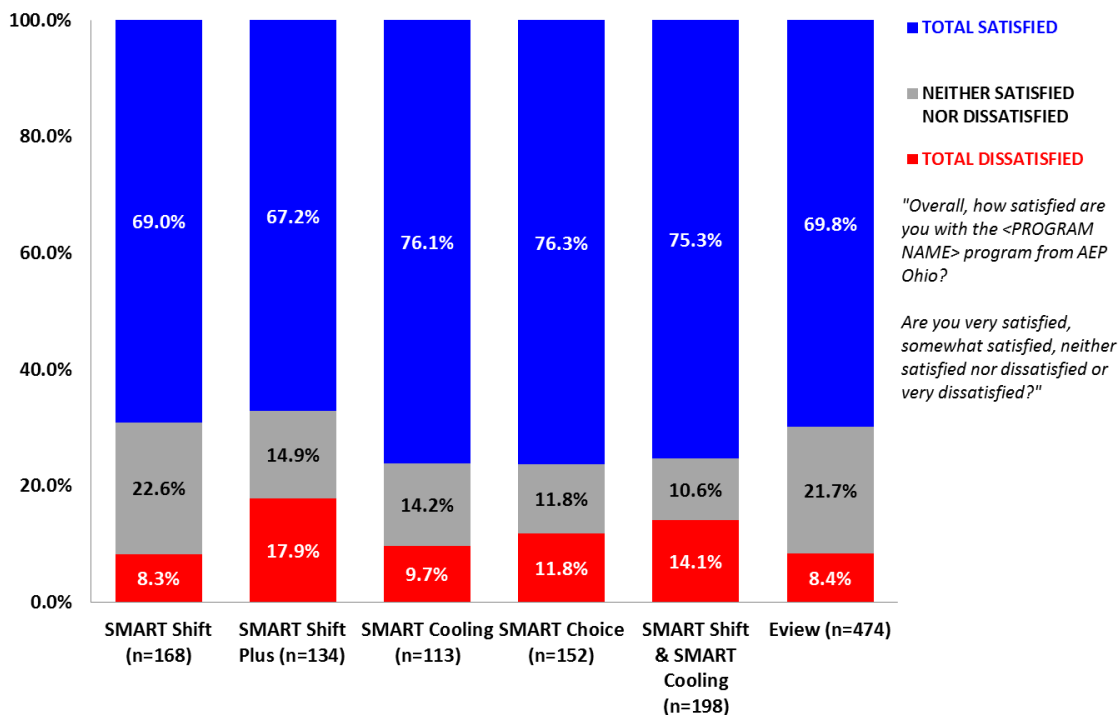


Figure 31. Survey Results - Overall Satisfaction with gridSMART Consumer Programs

Consumer Programs

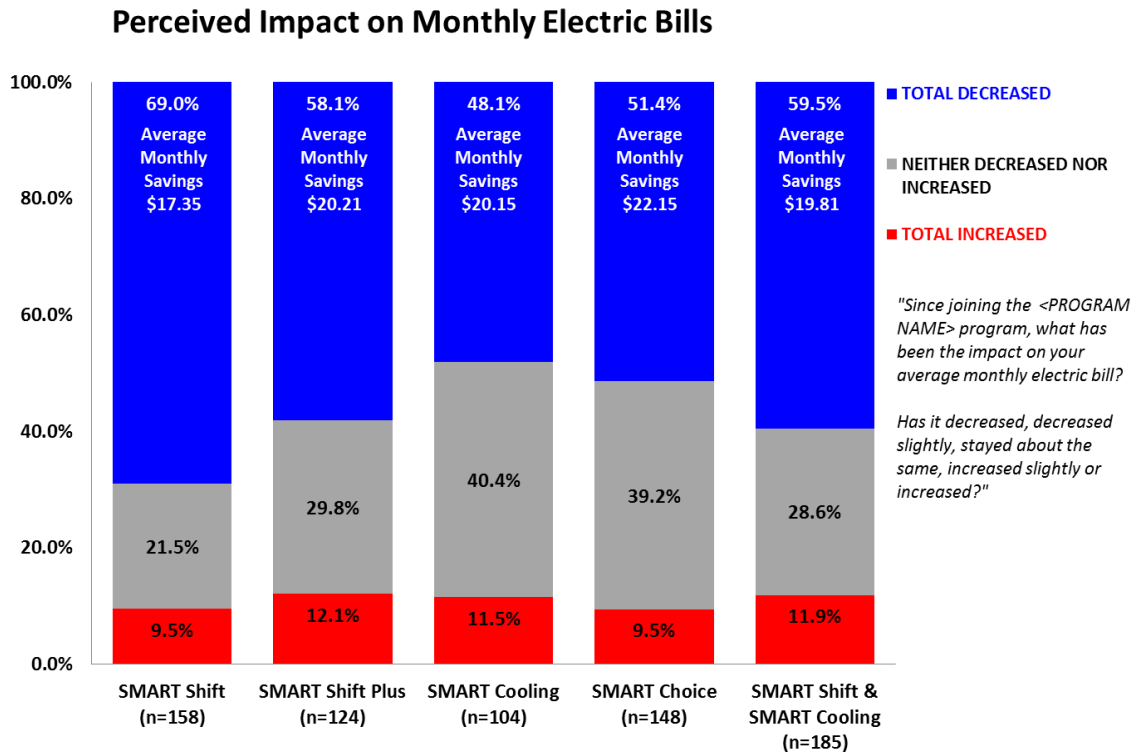


Figure 32. Survey Results - Perceived Impact on Monthly Electric Bills

3.4 Analysis

The primary objectives of the Consumer Programs technologies in this demonstration project were:

- To demonstrate consumer use of demand response programs to reduce energy consumption, peak demand, and fossil fuel emissions.
- To actively attract, educate, enlist, and retain consumers in innovative business models that provide tools and information to reduce cost, consumption, and peak demand.

To understand whether the demonstration project achieved those objectives, analysis was conducted using a control group against the consumer segments defined at the beginning of the Project. It is important to understand exactly what was measured and why. The following metrics provide an analysis and some comparison of the consumer programs experiment.

Consumer Programs



3.5 Impact Metrics Required for Consumer Programs

Consumer Programs and supporting devices had the potential to influence consumer usage patterns by enabling consumer control. Utilities could provide incentives for consumers to modify their usage and behavior to reduce peak loading and enable load shifting. Consumers in various account classes, demographic groups, and strata were expected to modify their behaviors and consumption patterns as a result of participating in any of the consumer programs offered.

The following impact metrics are associated with the consumer programs technology set. Five are related to the Project area, and two are related to the Systems area.

Metric ID	Metric Scope	Metric Description	Consumer Programs
M01	Project	Hourly Consumer Electricity Usage	M01-CP
M02	Project	Monthly Consumer Electricity Usage	M02-CP
M03	Project	Peak Load and Mix	M03-CP
M07	Project	CO ₂ Emissions	M07-CP
M08	Project	Pollutant Emissions (SO _x , NO _x , PM _{2.5})	M08-CP
M09	System	CO ₂ Emissions	M09-CP
M10	System	Pollutant Emissions (SO _x , NO _x , PM _{2.5})	M10-CP

Table 16. Impact Metrics Addressing Consumer Programs Technology Performance

Refer to the *Metrics Analysis for Consumer Programs* section that follows for details.



3.6 Metrics Analysis for Consumer Programs

This section provides details for each Consumer Programs metric, and includes those requested by the DOE during the definitization of the Cooperative Agreement. Trends were not always observed, however data is presented for each metric.

Please note that Project area and System area metrics related to emissions did not include the potential impact of shifting load over 24 hours.

3.6.1 Hourly Consumer Electricity Usage (M01-CP)

This impact metric illustrates the average consumer's usage profile based on demographics and the premises' location.

3.6.1.1 Organization of Results

All load profile data for this metric include information from 2012 and 2013.

Various views of data were selected to quantify and visualize this impact metric. The key parameters of interest include time, account class, and the account's applicable tariff. For residential accounts, applicable demographic data were used.

The time varying aspect of consumer behavior is addressed by:

- Aggregating data by three seasons- Summer, Winter and Autumn/Spring combined
- Aggregating data for different day types into three groupings
- Weekdays – Monday through Friday
- Saturday
- Sunday
- Graphing usage data as a function of each hour of the 24-hour day

The account class was set as the three traditional groupings of consumers: Industrial, Commercial and Residential. Residential consumers were categorized by account class, tariff, and demographic.

3.6.1.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data:

- Usage patterns were relatively consistent across spring and fall seasons.
- Usage patterns were relatively consistent across all weekdays.
- The Standard Residential tariff was a reasonable proxy for the baseline consumption patterns of consumers on program tariffs.

3.6.1.3 Calculation Approach

This impact metric provides an analysis of average daily usage patterns for consumers grouped by combinations of day of week, season, demographic, and tariff.

Consumer Programs



The following queries and methods were used to generate results:
 The hourly consumer electricity usage was calculated by averaging hourly consumer electricity usage into 24 hourly bins.

3.6.1.4 Data Collection Results

Hourly Load Profiles by Account Class: Summer/Winter, Industrial and Commercial

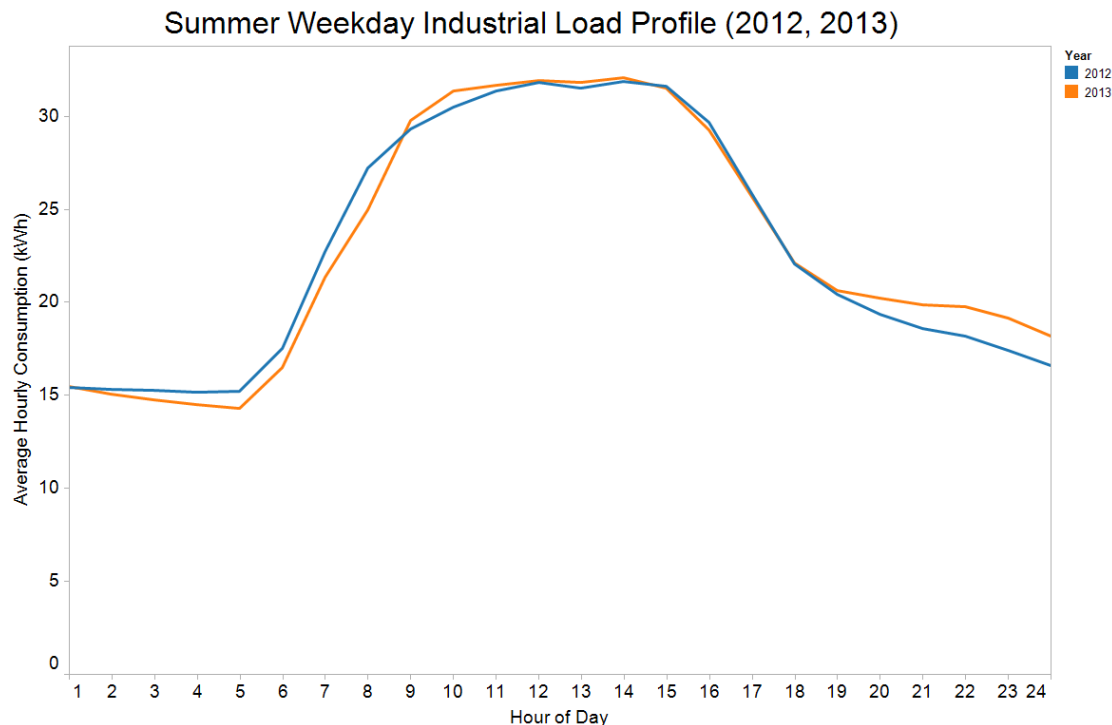


Figure 33. Summer Industrial Hourly Load Profile (Weekday)

Consumer Programs

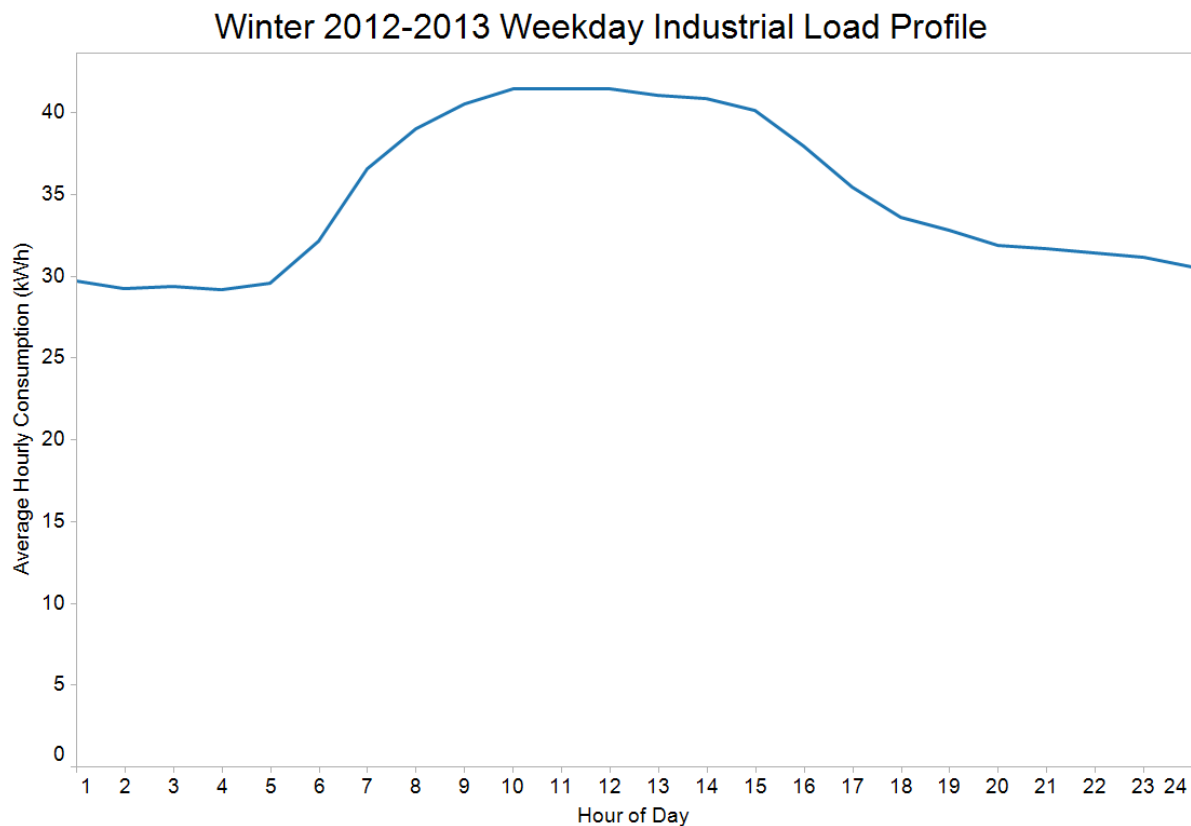


Figure 34. Winter Industrial Hourly Load Profile (Weekday)

Consumer Programs

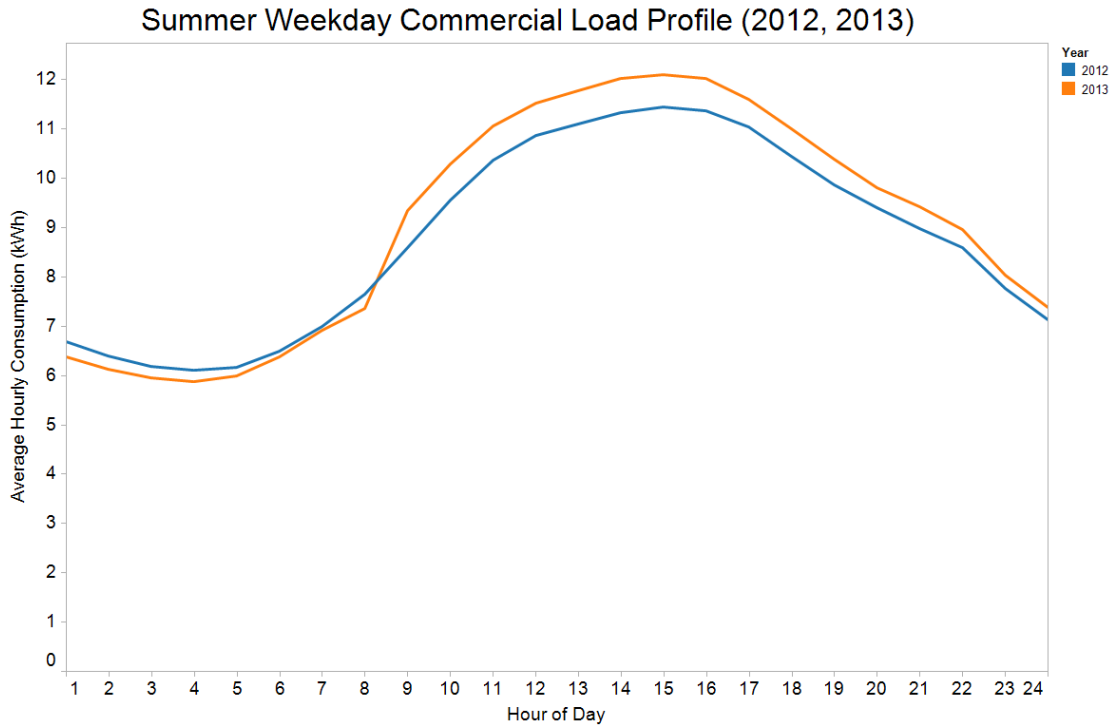


Figure 35. Summer Commercial Hourly Load Profile (Weekday)

Consumer Programs

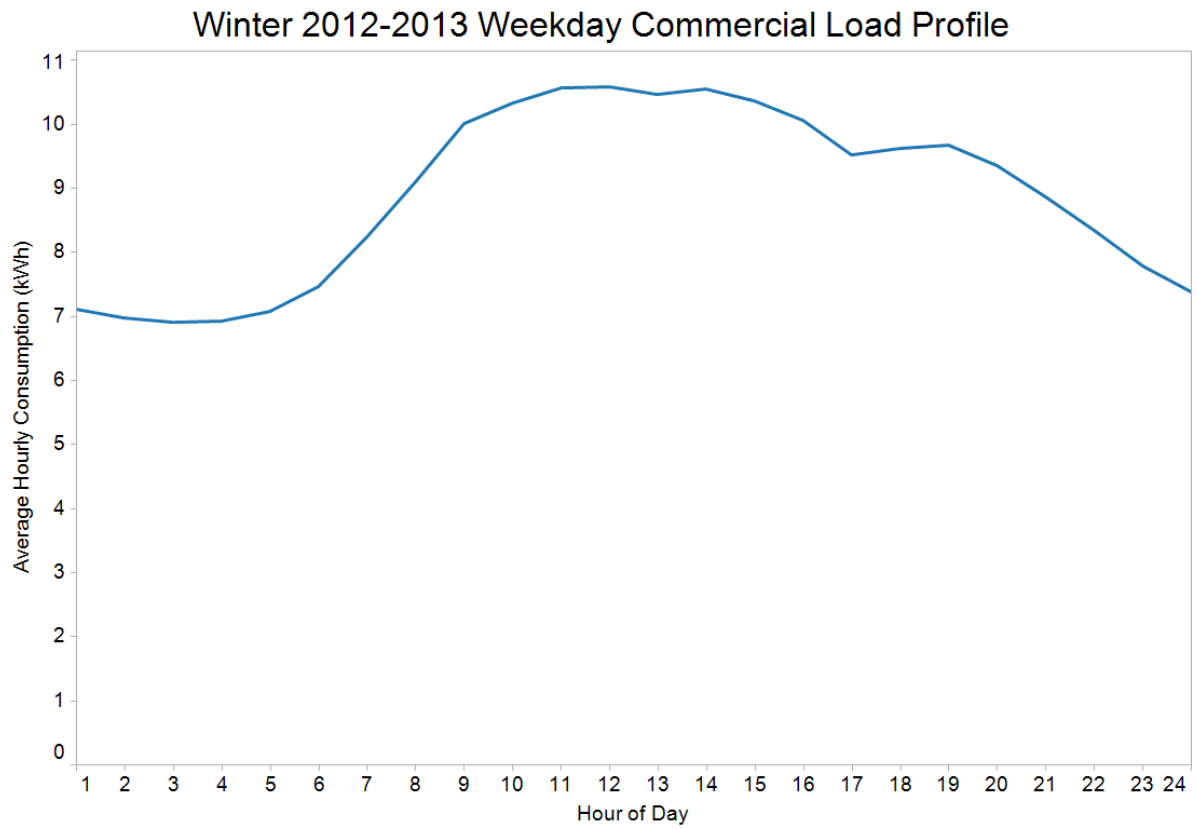


Figure 36. Winter Commercial Hourly Load Profile (Weekday)

Consumer Programs



Weekday Hourly Residential Load Profiles by Tariff for Each Season
Summer 2012 Weekday Residential Load Profile

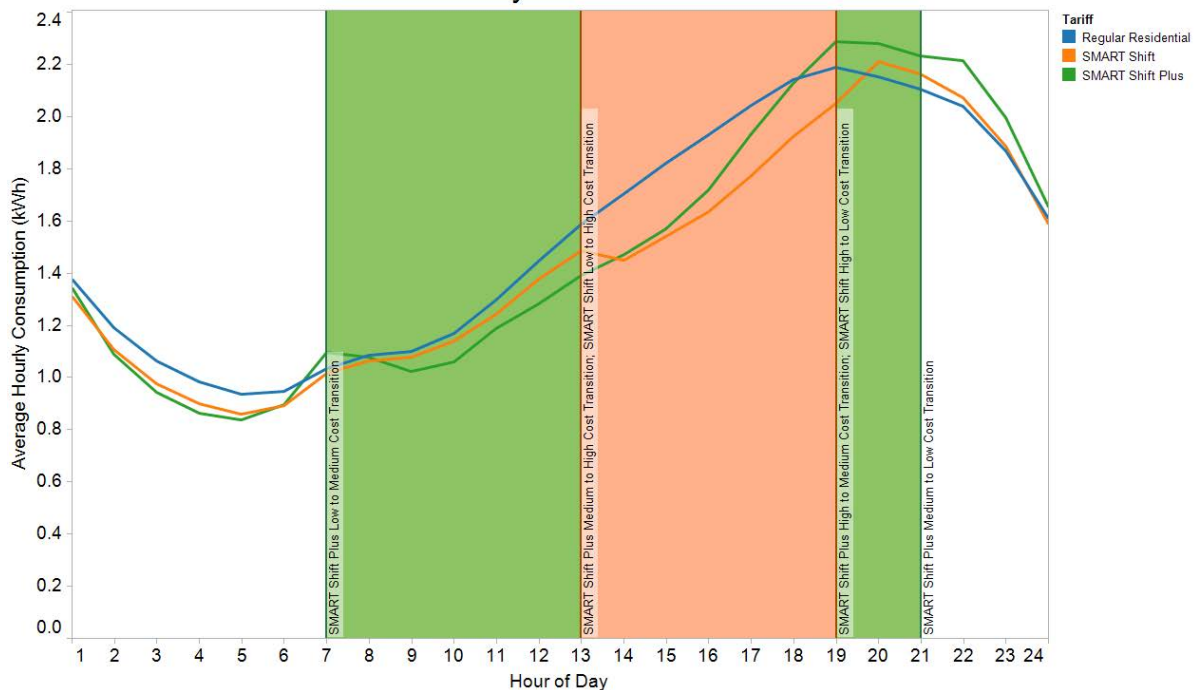


Figure 37. Summer Hourly Load Profile by Tariff (Weekday 2012)

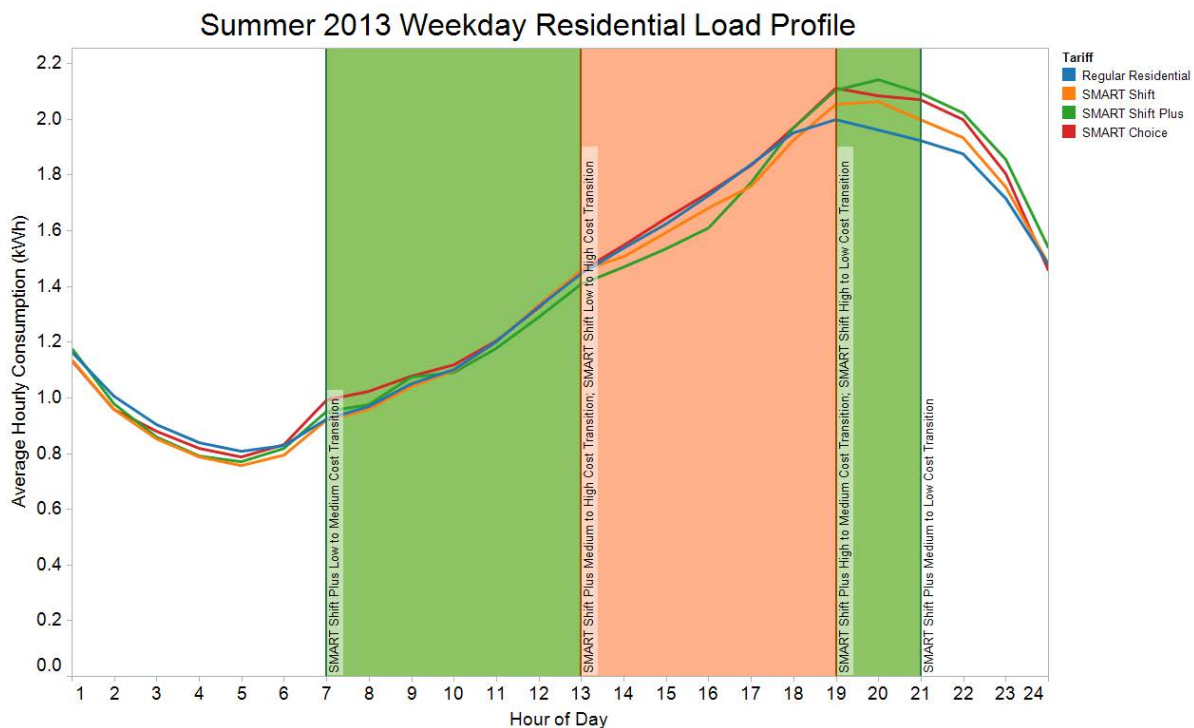


Figure 38. Summer Hourly Load Profile by Tariff (Weekday 2013)

Consumer Programs

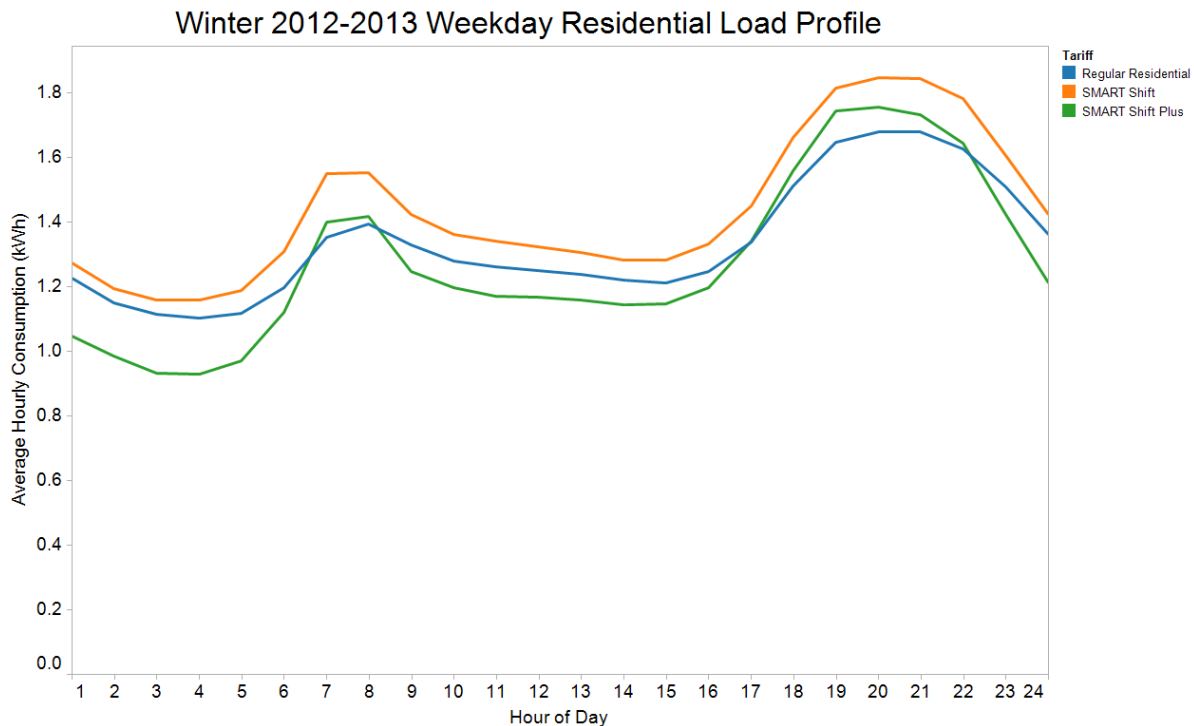


Figure 39. Winter Hourly Load Profile by Tariff (Weekday)

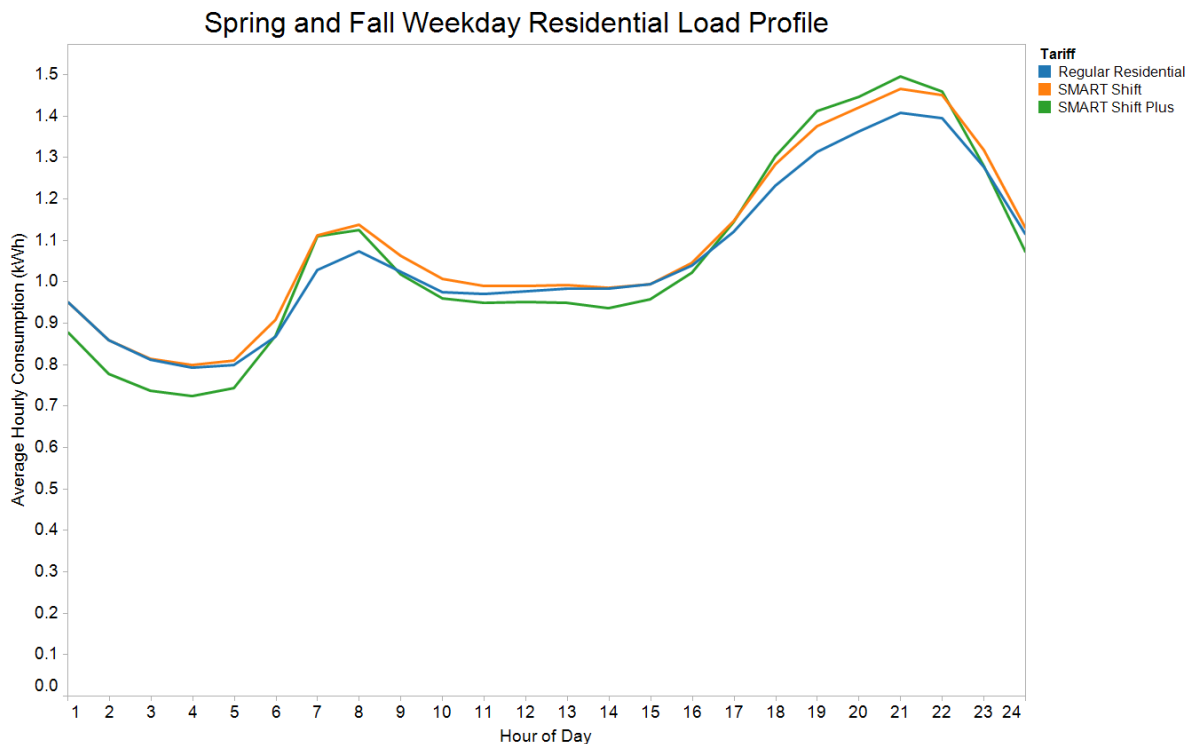


Figure 40. Autumn/Spring Hourly Load Profile by Tariff (Weekday)

Consumer Programs

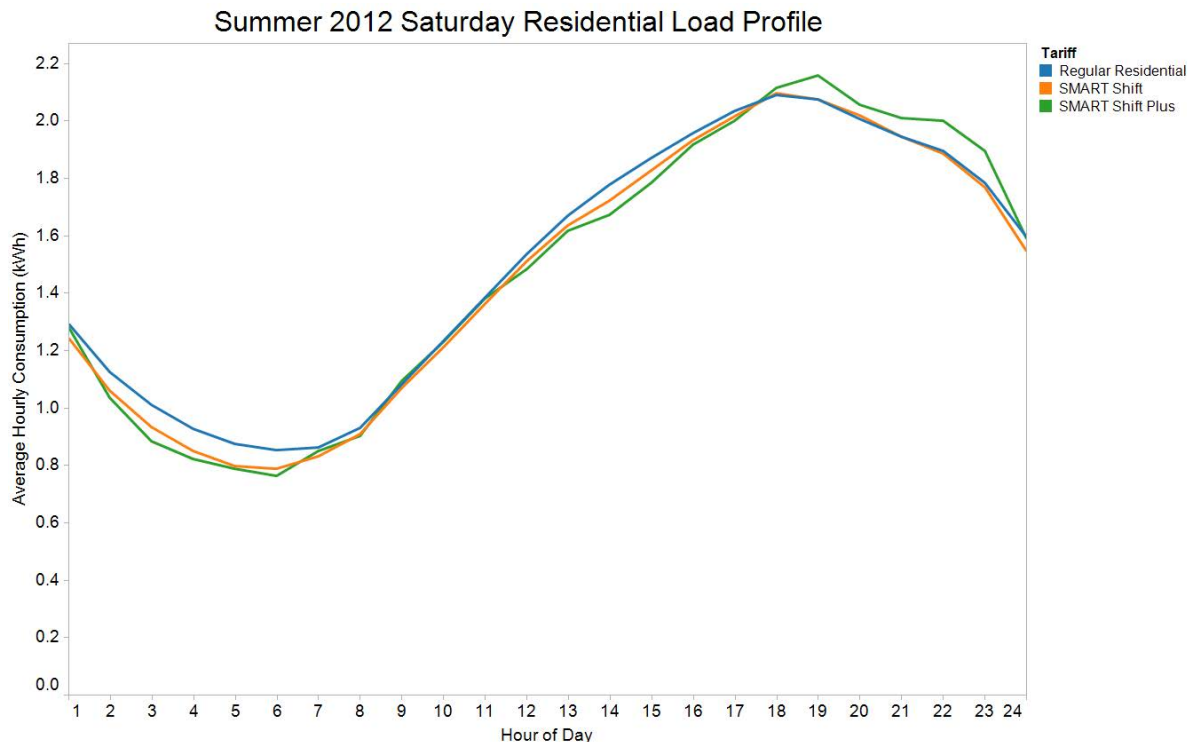


Figure 41. Summer Hourly Load Profiles (Saturday 2012)

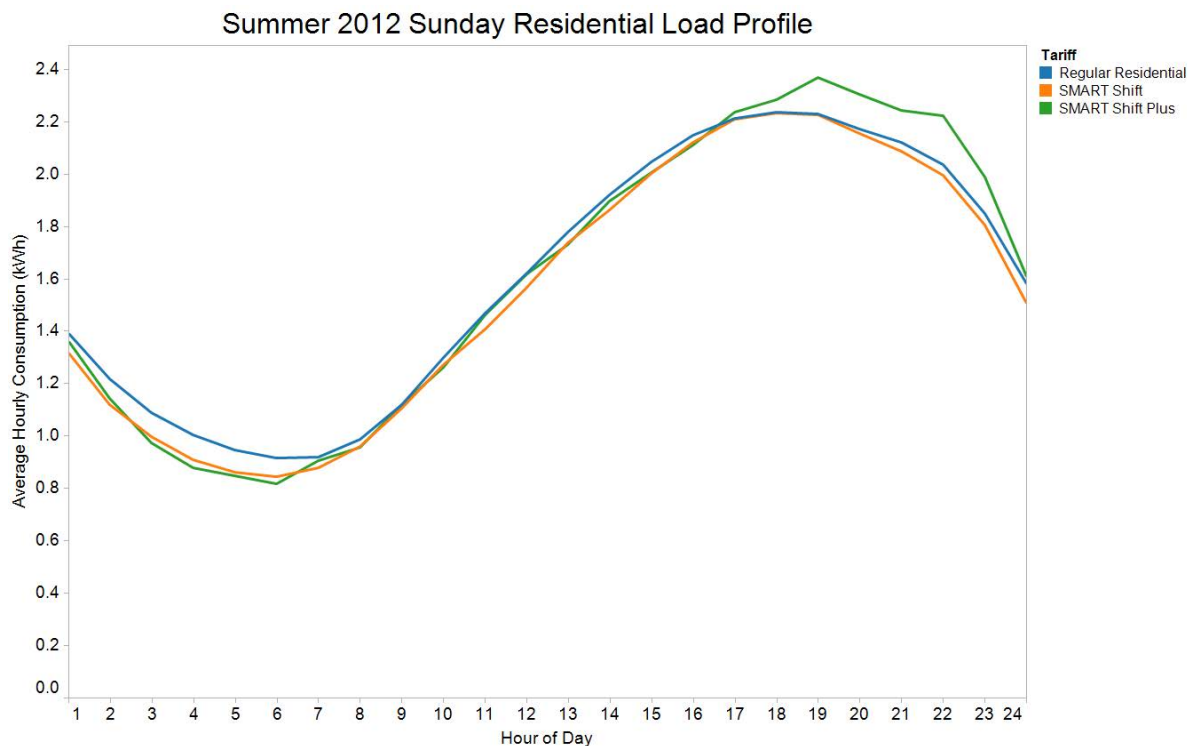


Figure 42. Summer Hourly Load Profiles (Sunday 2012)

Consumer Programs

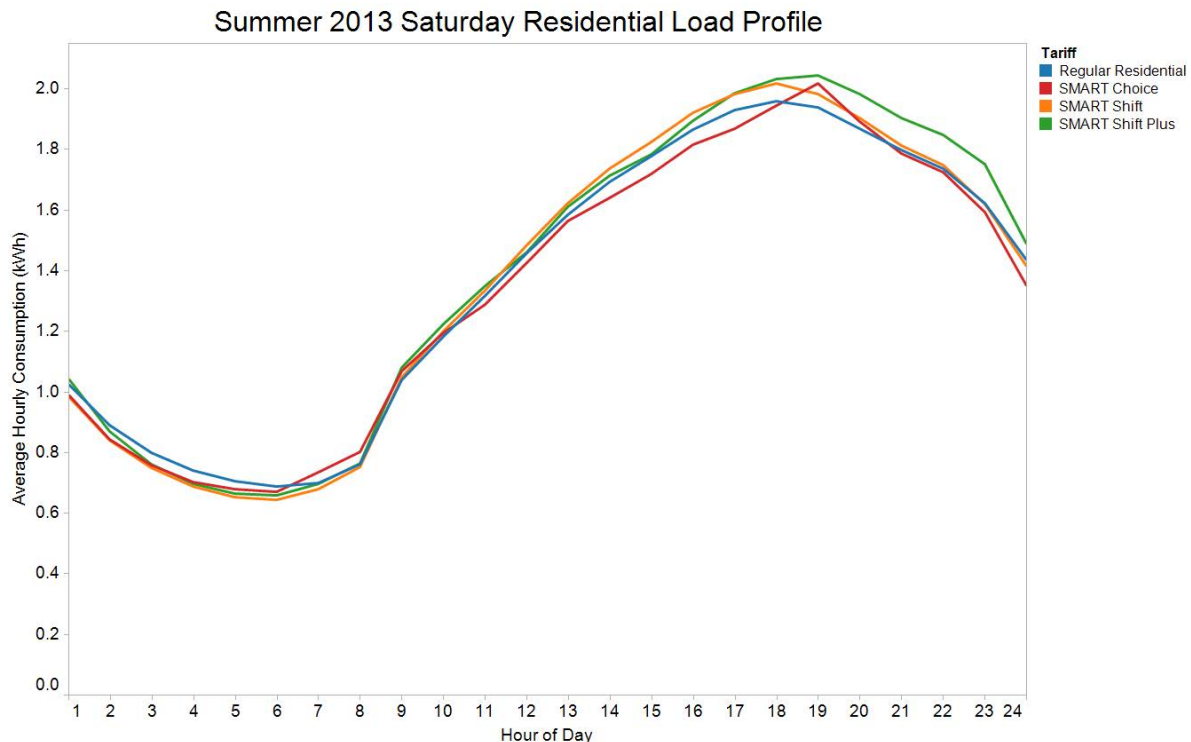


Figure 43. Summer Hourly Load Profiles (Saturday 2013)

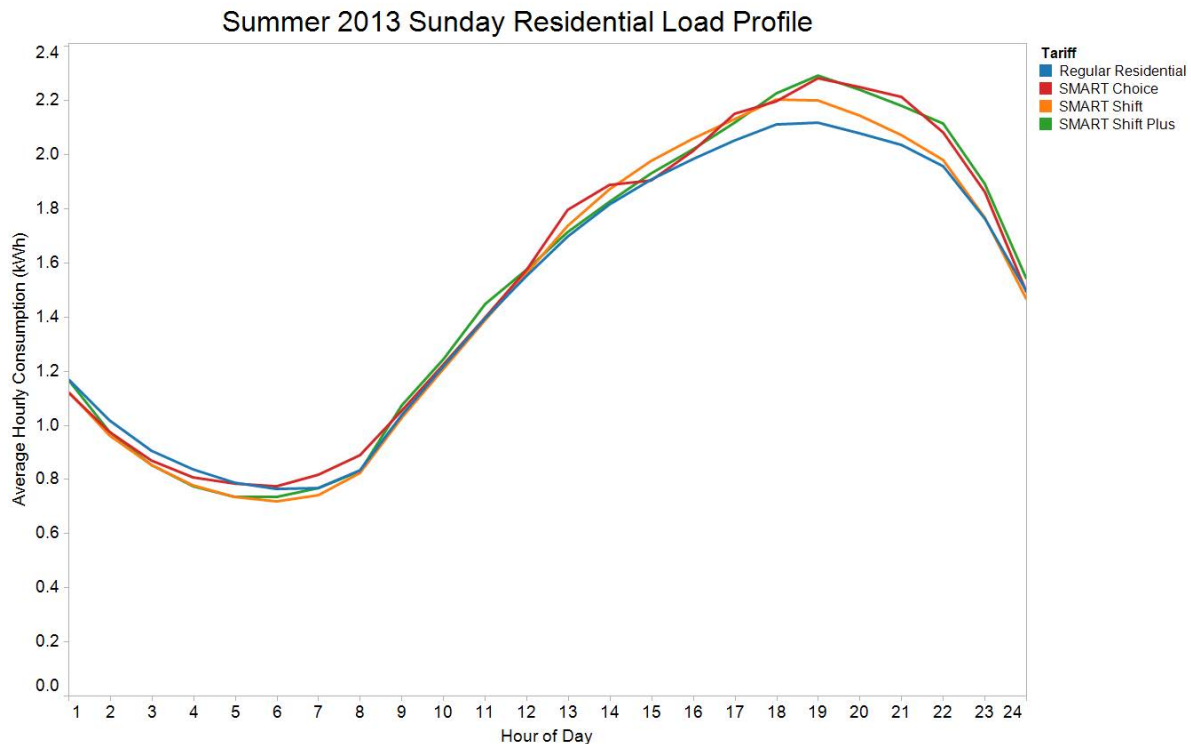


Figure 44. Summer Hourly Load Profiles by Tariff (Sunday 2013)

Consumer Programs

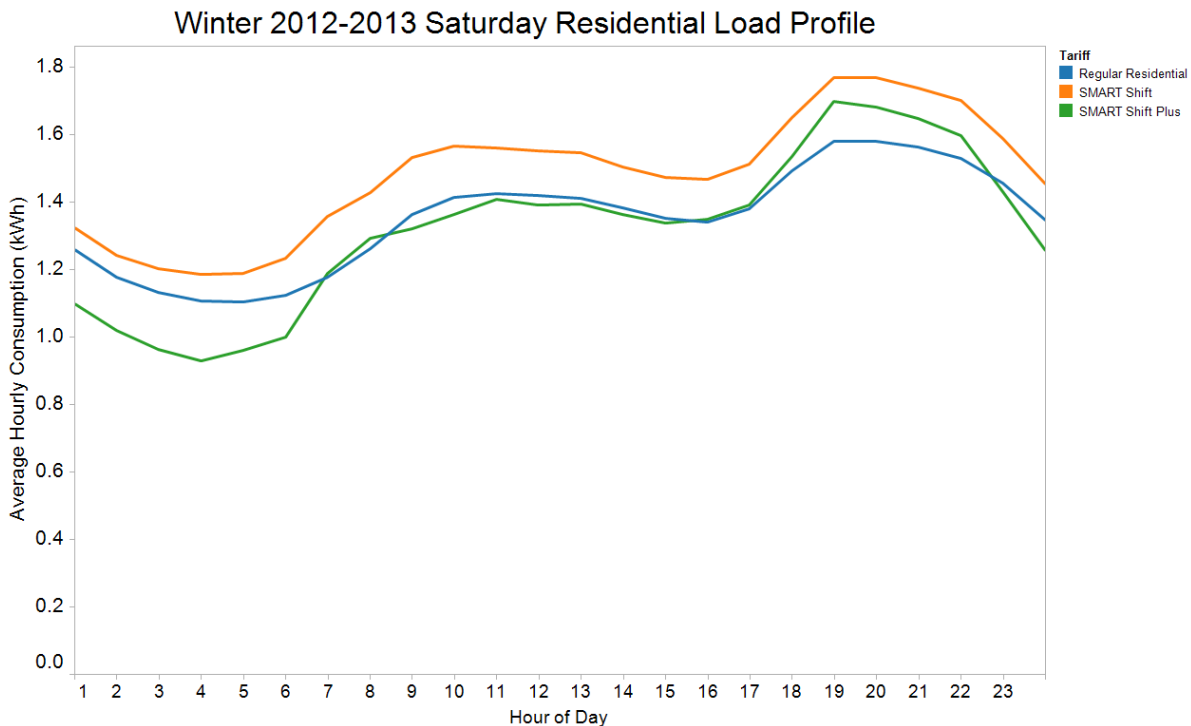


Figure 45. Winter Hourly Load Profiles by Tariff (Saturday)

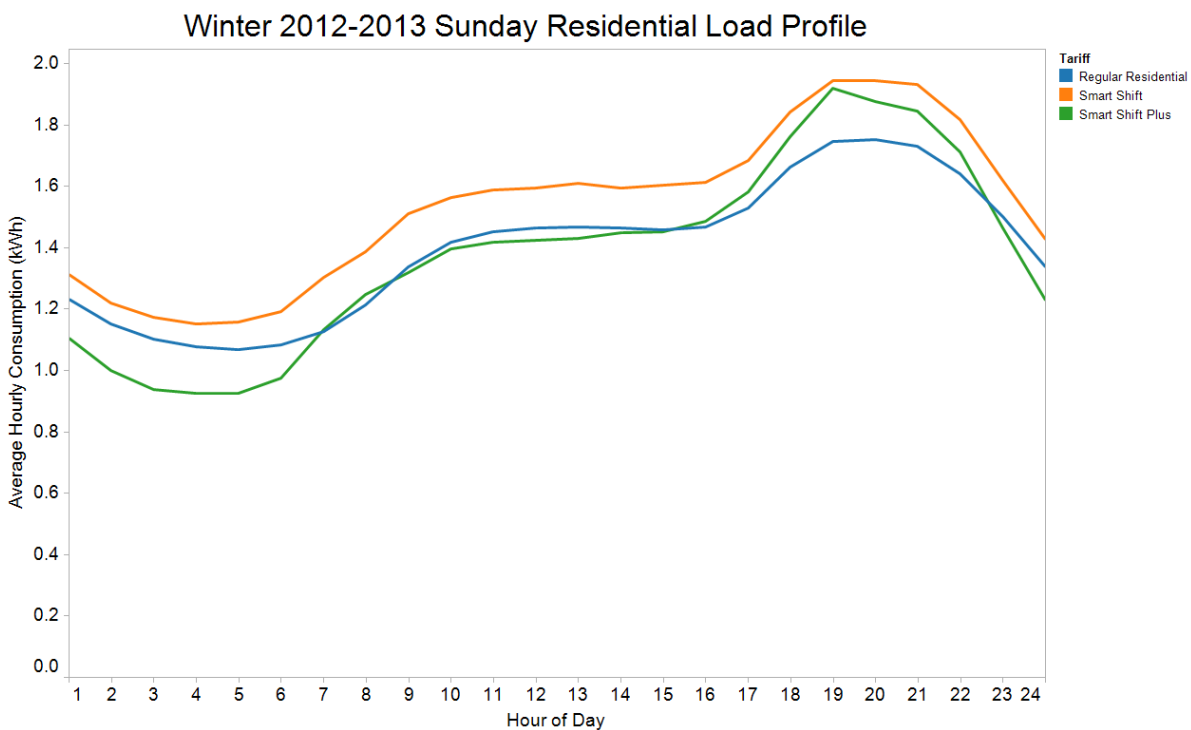


Figure 46. Winter Hourly Load Profiles by Tariff (Sunday)

Consumer Programs

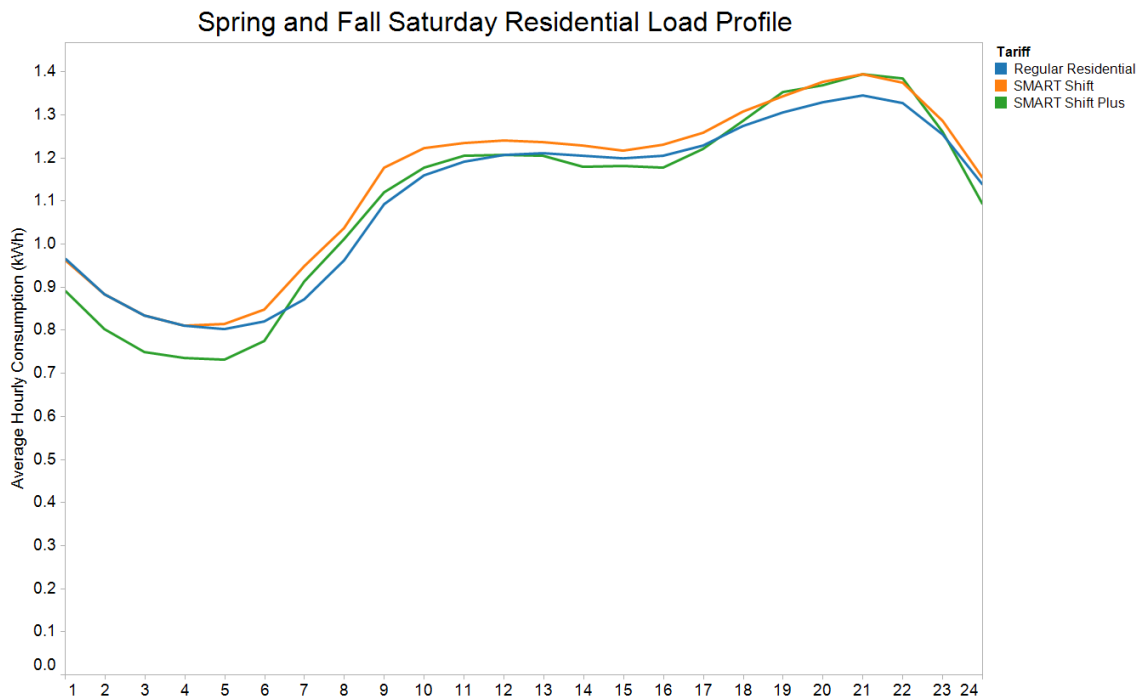


Figure 47. Autumn/Spring Hourly Load Profiles by Tariff (Saturday)

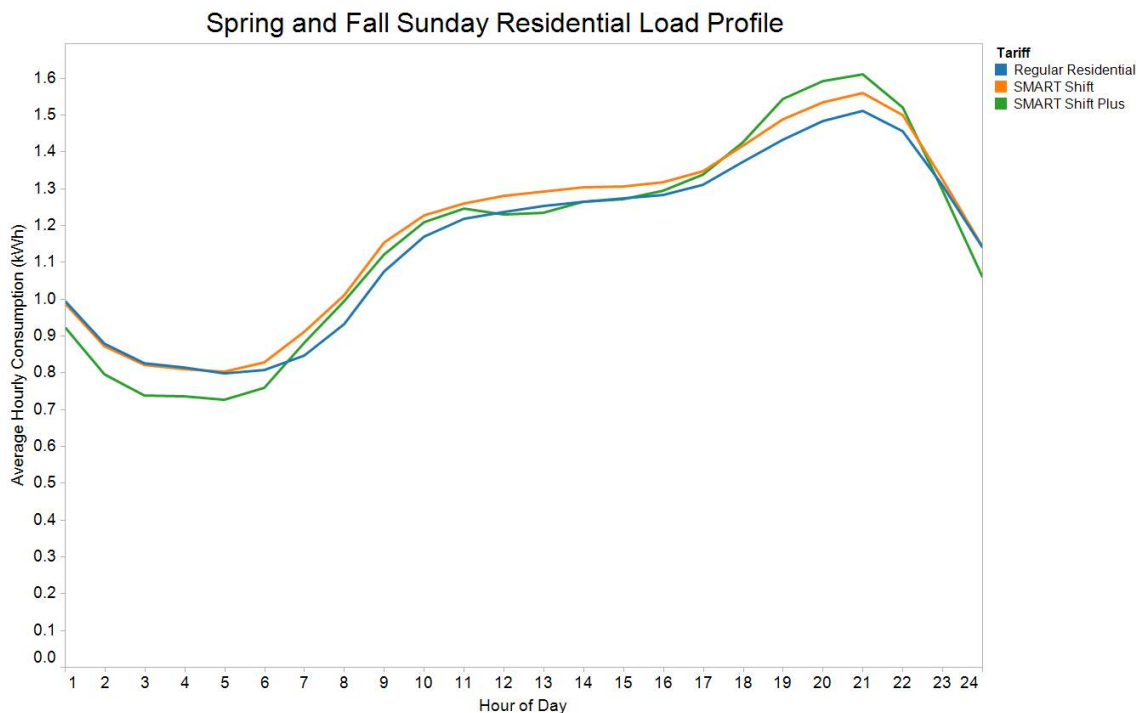


Figure 48. Autumn/Spring Hourly Load Profiles by Tariff (Sunday)



3.6.2 Conclusions

3.6.2.1 Load Shapes by Consumer Class and Season

Industrial loads had a large differential in peak and off-peak usage patterns, with a fast rise in loads between 6 a.m. and 9 a.m. and a subsequent drop in load around 5 p.m. They also had higher winter usage and a slightly less pronounced peak, with an approximate 20 percent higher peak in the winter compared to the summer. Commercial loads in the Project area had an afternoon peak around 3 p.m., with a much broader peak in the winter.

Residential loads had an evening peak, which changed from about 7 p.m. in the summer to 9 p.m. in the winter; this change was driven primarily by the switch from air conditioning (which moved peak consumption to earlier in the day), to heating (which pushed peak consumption to the evening hours). The spring and autumn residential load shapes exhibited a similar (although lower) evening peaking pattern as the winter season. The additional impacts of less daylight and more heating load contributed to a winter peak that was over 20 percent higher than in the spring/autumn. The summer peak was over 40 percent higher than the autumn/spring peak due to the large residential air conditioning load. This increase was despite the fact that there was a reduction in lighting loads due to additional daylight availability in the summer in the Project area.

3.6.2.2 Tariff Impacts

The time-of-day (TOD) tariffs (SMART Shift and SMART Shift Plus) each defined the peak period to be from 1 p.m. to 7 p.m. from June 1 to September 1. Both the SMART Shift and SMART Shift Plus consumers had lower consumption than the standard residential tariff (flat rate) consumers during the peak time periods in 2012. In 2013 however, the SMART Shift and SMART Shift Plus consumers had lower consumption during the first hours of the peak period and higher consumption during the last 2 hours and higher overall peak. After the peak period (approximately 7 p.m. to midnight) the time-of-day consumers' consumption was greater than the flat rate consumers in 2012 and 2013.

In the winter, the SMART Shift consumers had higher overall usage and a similar load shape compared to standard residential consumers. SMART Shift Plus consumers had a lower overnight and mid-day usage with sharper morning and evening peaks compared to standard residential consumers. During winter months, standard residential consumers were charged a declining block rate; SMART Shift and SMART Shift Plus consumers were charged a flat rate that was lower than the standard residential tariff.

The autumn/spring load profiles appeared similar across all three tariffs, with the TOD consumers exhibiting higher morning and evening peaks.

The TOD behavior may have been driven by PCTs, which allowed consumers to program different set points for specific time periods within a day. A typical PCT program had specific morning and evening time periods (representing the times consumers prepared for work/school and return home), which may have resulted in the higher consumption for the TOD/ CPP consumers during the morning and evening time periods.



3.6.3 Monthly Consumer Electricity Usage (M02-CP)

This impact metric measures the cost impact to electricity consumers as a result of various consumer programs.

3.6.3.1 Organization of Results

This metric presents average monthly bills for residential, commercial, and industrial consumer classes for the years 2011 through 2013. The residential graphs are distinguished by tariff and demographic and depict residential monthly average costs. The first residential graph shows the average monthly bill per consumer by tariff. The second graph shows the average monthly bill per consumer by demographic.

3.6.3.2 Assumptions

Please see the Calculation Approach for this metric.

3.6.3.3 Calculation Approach

This impact metric provides an analysis of average bill amount and average energy consumption for consumers grouped by demographic and marketing stratum.

The following queries and methods were used to generate results:

- Average monthly consumer electricity usage was calculated by averaging the billed usage for the ending month of the billing period for all residential consumers on the standard residential tariff.
- Average monthly consumer electricity usage per tariff was calculated by averaging the billed usage for the ending month of the billing period for all residential consumers on the standard residential, SMART Shift, and SMART Shift Plus tariffs.
- Average monthly consumer cost was calculated by averaging the billed amount for the ending month of the billing period for all residential consumers on the standard residential tariff. These data points were not normalized for rate changes occurring within the period.
- Average monthly consumer cost per tariff was calculated by averaging the billed amount for the ending month of the billing period for all residential consumers on the standard residential, two-tier TOD, and three-tier TOD with SMART Shift Plus tariffs.
- Hourly outdoor temperature in degrees Fahrenheit for Port Columbus International Airport was collected from the National Oceanic and Atmospheric Administration:
<http://hurricane.ncdc.noaa.gov/pls/plclimprod/poemain.accessrouter?datasetabbv=DS3505&countryabbv=&georegionabbv=>

Consumer Programs



3.6.3.4 Data Collection Results

Residential Monthly Cost Data

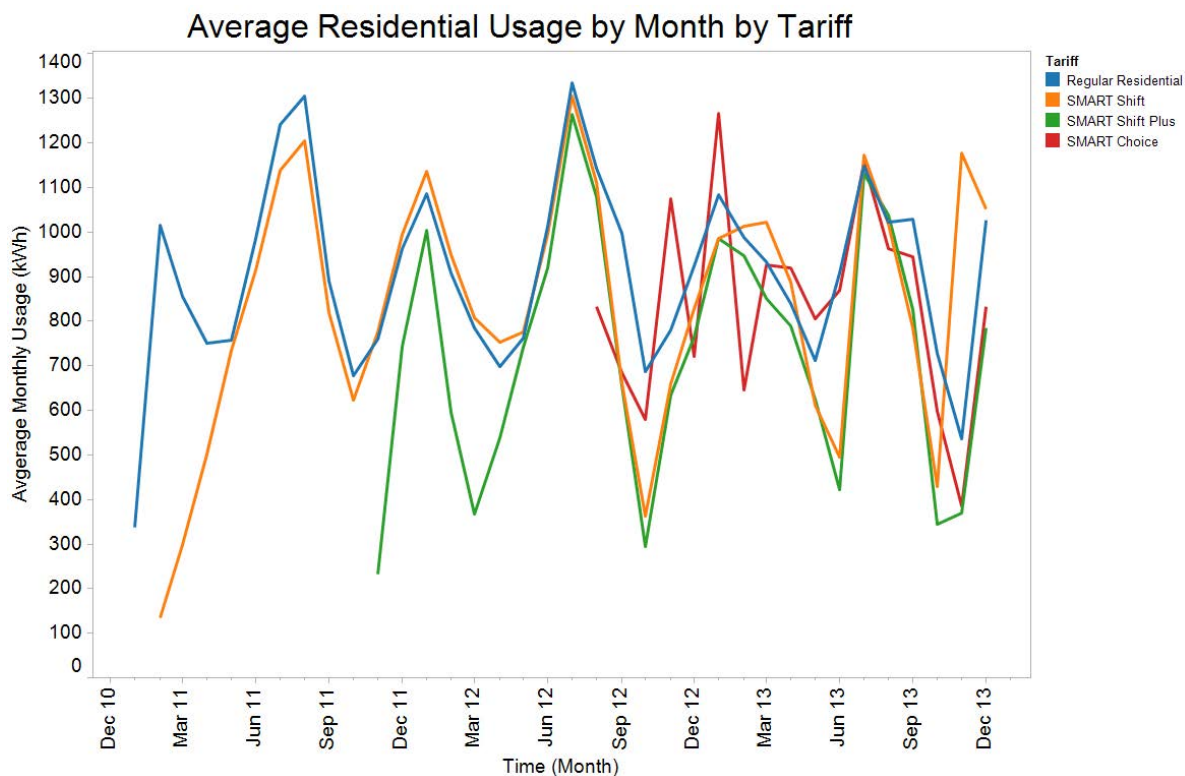


Figure 49. Average Residential Monthly Usage for Tariffs

Consumer Programs

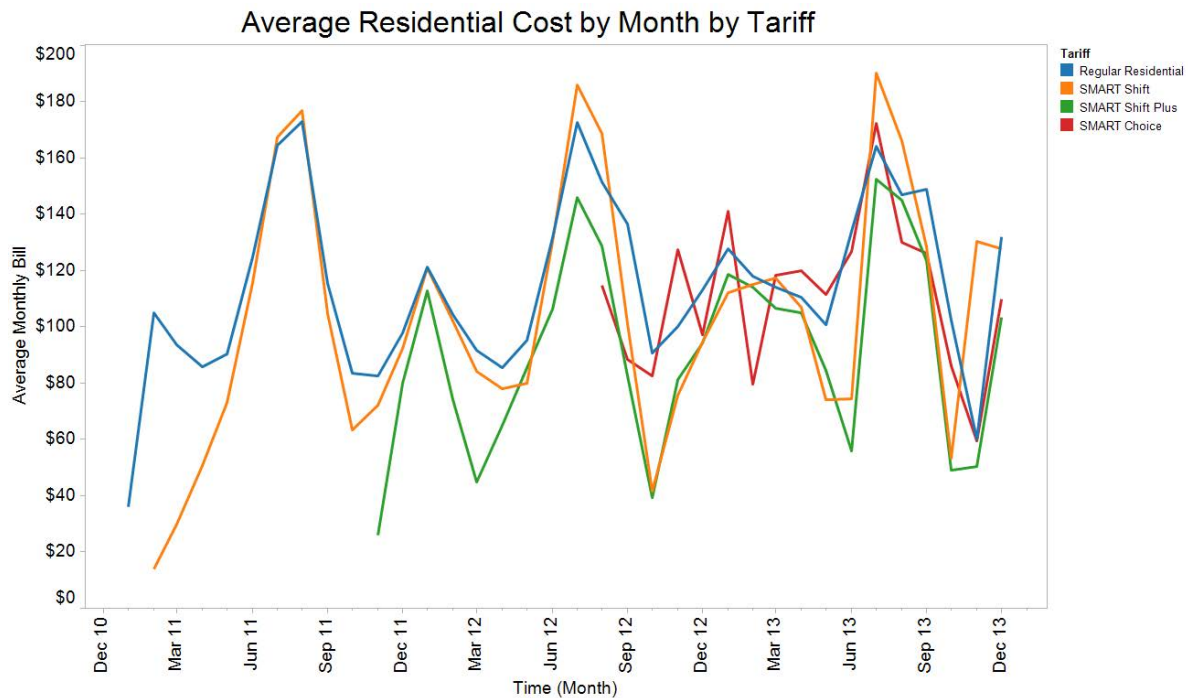


Figure 50. Average Residential Monthly Bill Amount for Tariffs

Consumer Programs

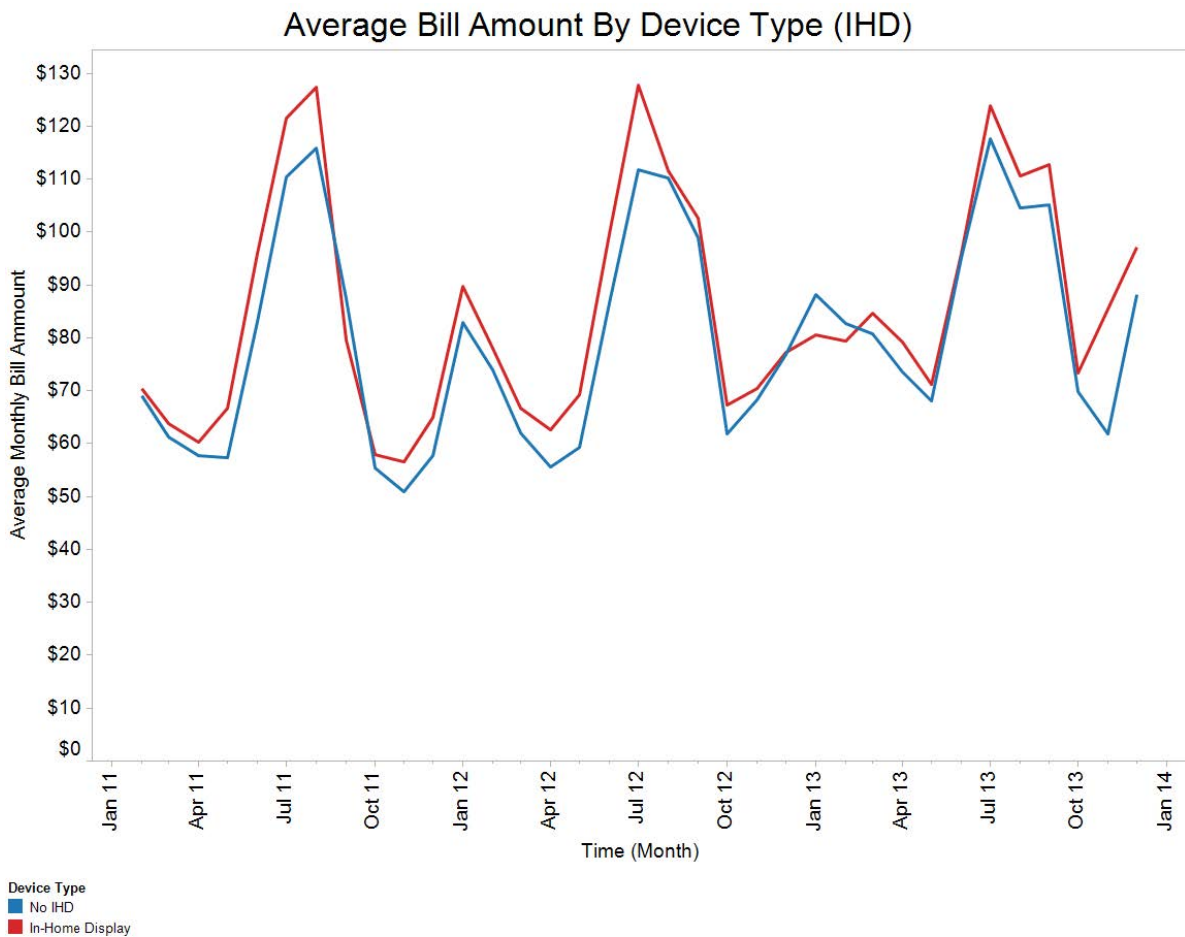


Figure 51. Average Residential Monthly Bill Amount for Consumers With vs. Without eVIEW

Consumer Programs



Average Residential, Commercial, Industrial Cost and Usage by Month

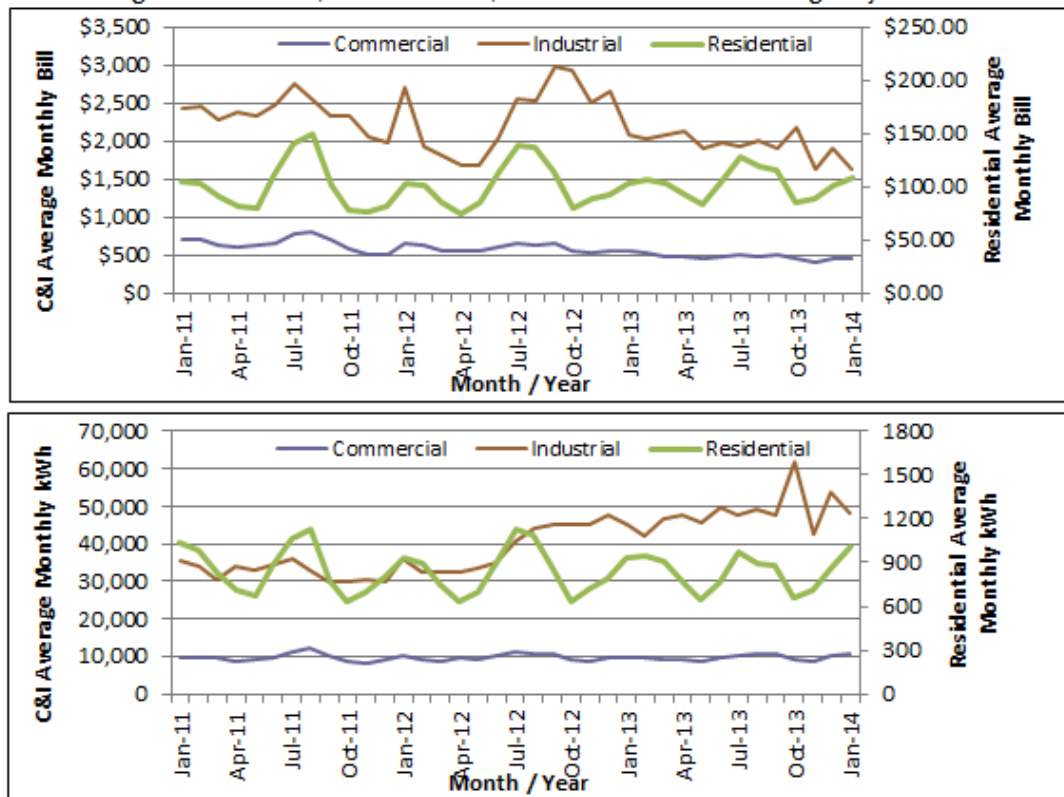


Figure 52. Comparison of Residential, Commercial, and Industrial Monthly Bill Amounts

Consumer Programs



Enrollments in eVIEW commenced in February 2012 and increased in 2013 due to canvassing efforts. The monthly enrollment and removal counts are presented in the figure below.

IHD Deployment by Month

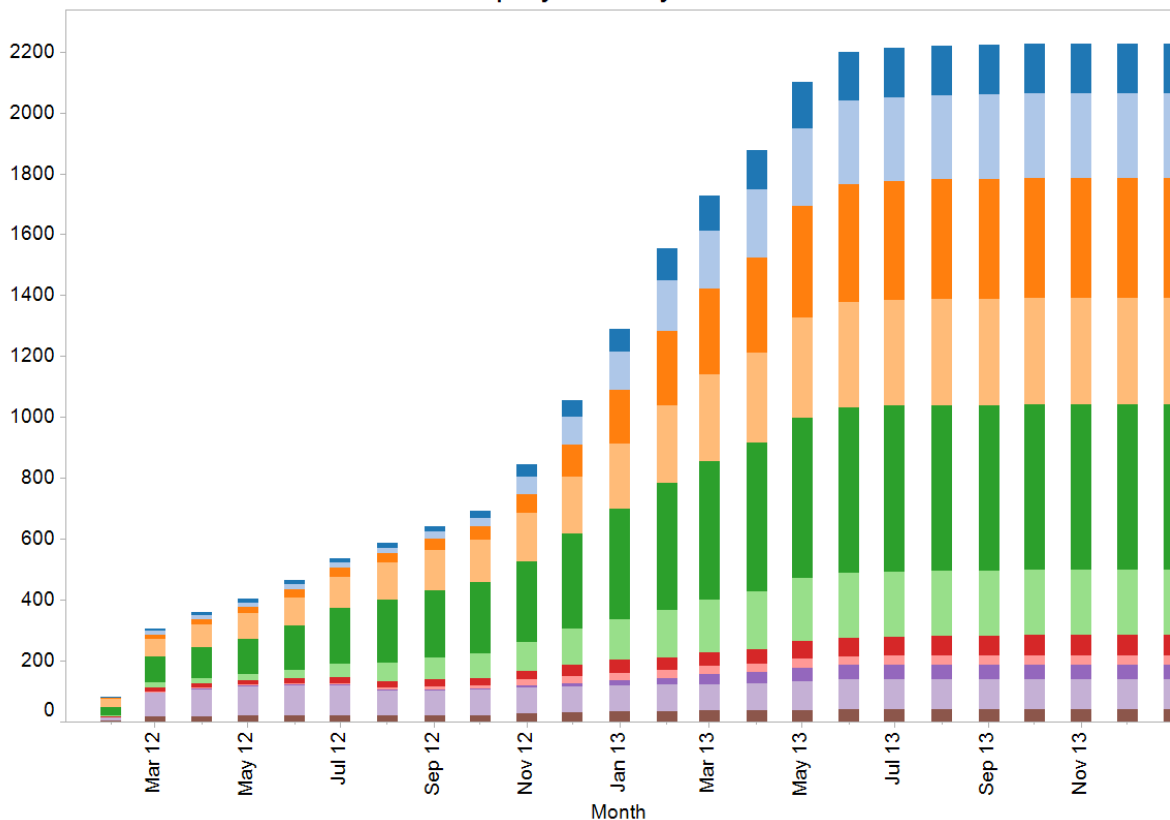
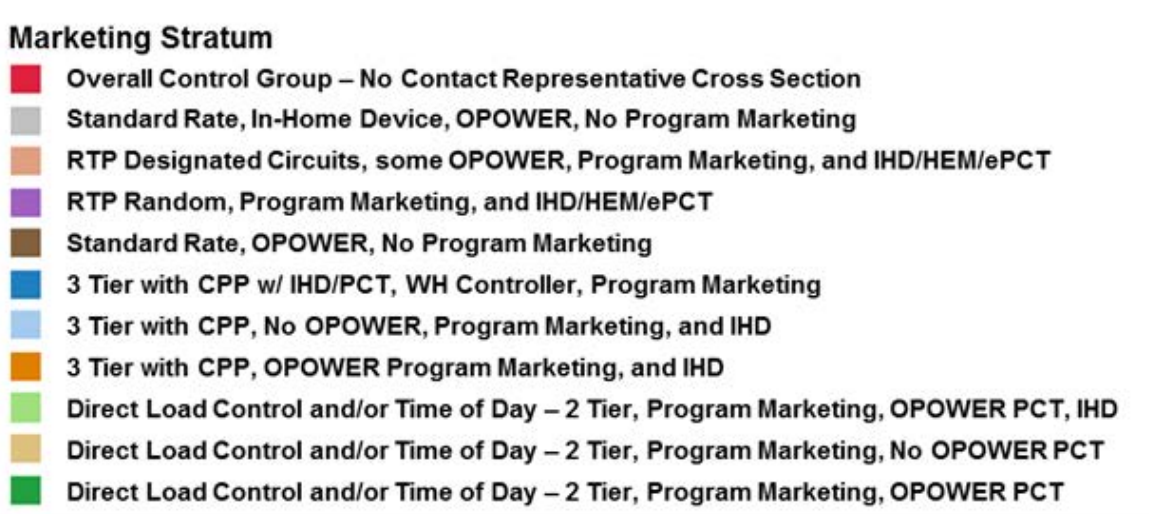


Figure 53. eVIEW In-Home Display Device Deployment by Month



Consumer Programs



Enrollments in SMART Shift commenced in February 2011 and increased in 2013 due to canvassing efforts. The monthly enrollment and removal counts are presented in the figure below.

Tariff Enrollment by Stratum - SMART Shift

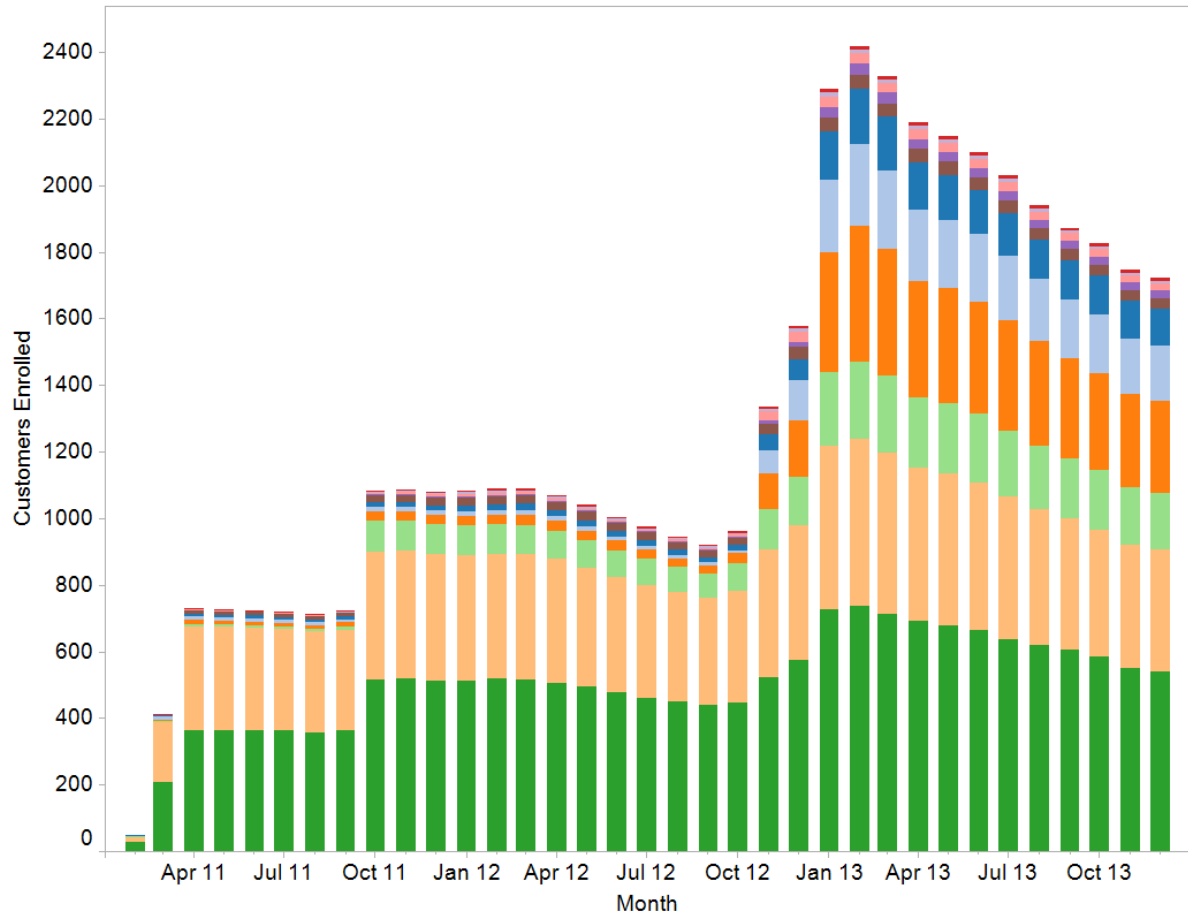


Figure 54. Consumer Enrollment by Month - SMART Shift

Marketing Stratum

- Overall Control Group – No Contact Representative Cross Section
- Standard Rate, In-Home Device, OPOWER, No Program Marketing
- RTP Designated Circuits, some OPOWER, Program Marketing, and IHD/HEM/ePCT
- RTP Random, Program Marketing, and IHD/HEM/ePCT
- Standard Rate, OPOWER, No Program Marketing
- 3 Tier with CPP w/ IHD/PCT, WH Controller, Program Marketing
- 3 Tier with CPP, No OPOWER, Program Marketing, and IHD
- 3 Tier with CPP, OPOWER Program Marketing, and IHD
- Direct Load Control and/or Time of Day – 2 Tier, Program Marketing, OPOWER PCT, IHD
- Direct Load Control and/or Time of Day – 2 Tier, Program Marketing, No OPOWER PCT
- Direct Load Control and/or Time of Day – 2 Tier, Program Marketing, OPOWER PCT

Consumer Programs



Enrollments in SMART Shift Plus commenced in November 2011 and increased in 2013 due to canvassing efforts. The monthly enrollment and removal counts are presented in the figure below.

Tariff Enrollment by Stratum - SMART Shift Plus

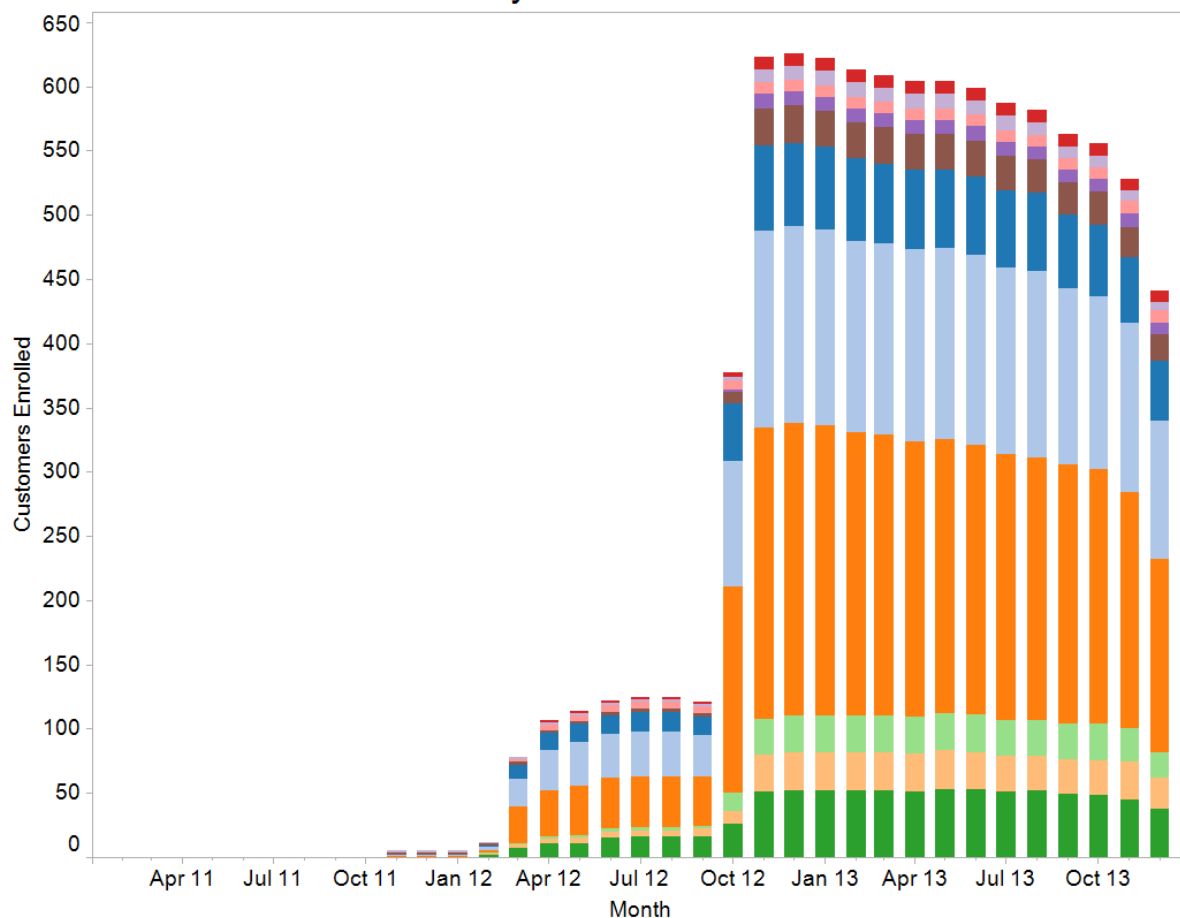


Figure 55. Consumer Enrollment by Month - SMART Shift Plus

- Marketing Stratum**
- Overall Control Group – No Contact Representative Cross Section
 - Standard Rate, In-Home Device, OPOWER, No Program Marketing
 - RTP Designated Circuits, some OPOWER, Program Marketing, and IHD/HEM/ePCT
 - RTP Random, Program Marketing, and IHD/HEM/ePCT
 - Standard Rate, OPOWER, No Program Marketing
 - 3 Tier with CPP w/ IHD/PCT, WH Controller, Program Marketing
 - 3 Tier with CPP, No OPOWER, Program Marketing, and IHD
 - 3 Tier with CPP, OPOWER Program Marketing, and IHD
 - Direct Load Control and/or Time of Day – 2 Tier, Program Marketing, OPOWER PCT, IHD
 - Direct Load Control and/or Time of Day – 2 Tier, Program Marketing, No OPOWER PCT
 - Direct Load Control and/or Time of Day – 2 Tier, Program Marketing, OPOWER PCT

Consumer Programs



Enrollments in SMART Cooling commenced in April 2011 and increased in 2013 due to canvassing efforts. The monthly enrollment and removal counts are presented in the figure below.

Program Enrollment by Stratum - Smart Cooling

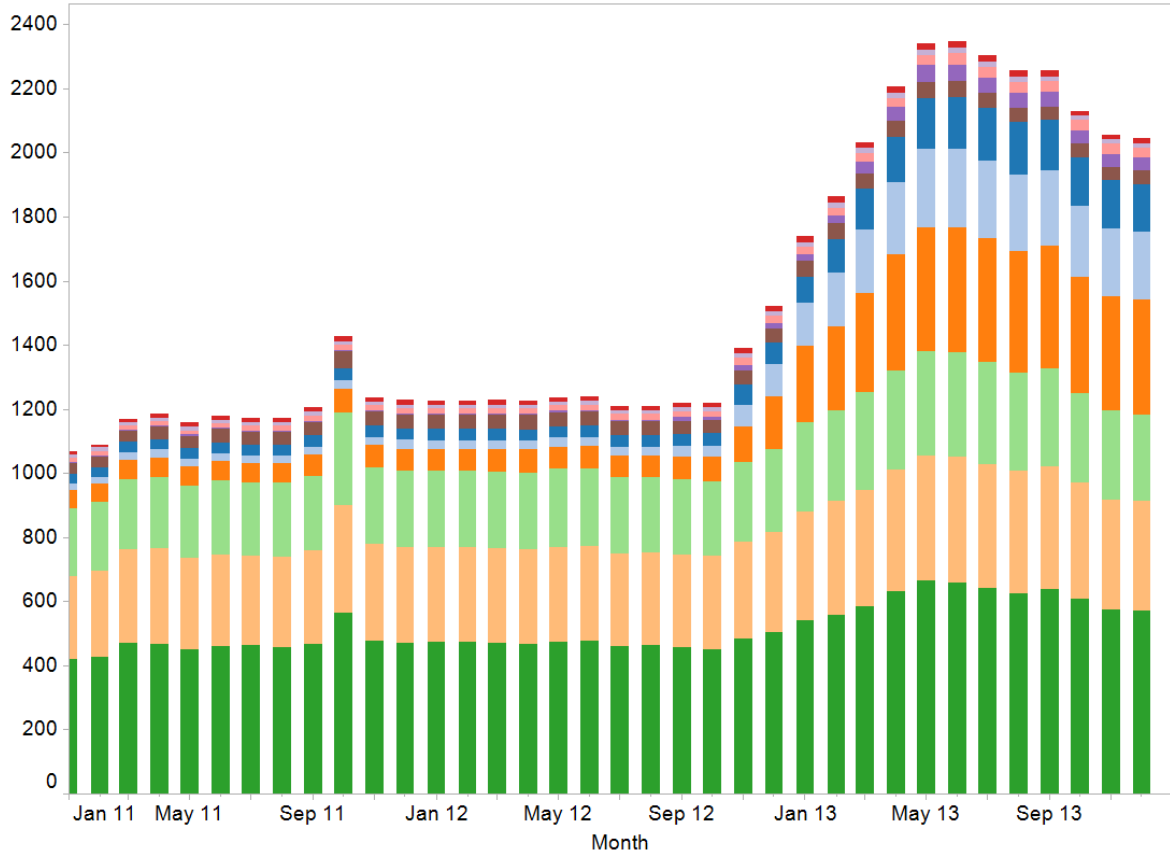
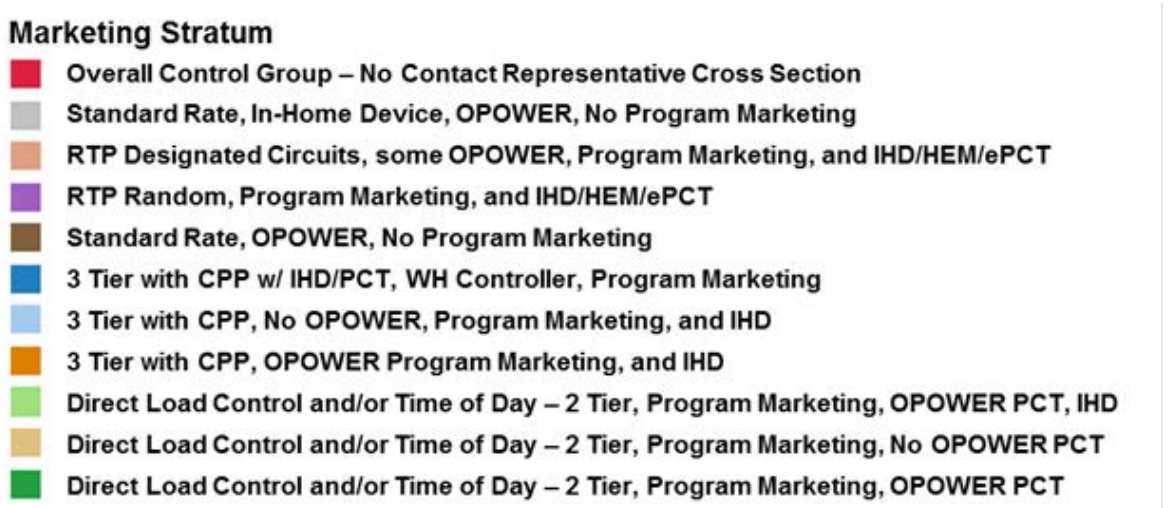


Figure 56. Consumer Enrollment by Month - SMART Cooling



Consumer Programs



Following a successful canvassing effort in 2013, enrollment efforts stopped after June 1, 2013 when the summer season began and data collection needed to be stabilized. The monthly enrollment and removal counts are presented in the figure below.

Tariff Enrollment by Stratum - SMART Choice

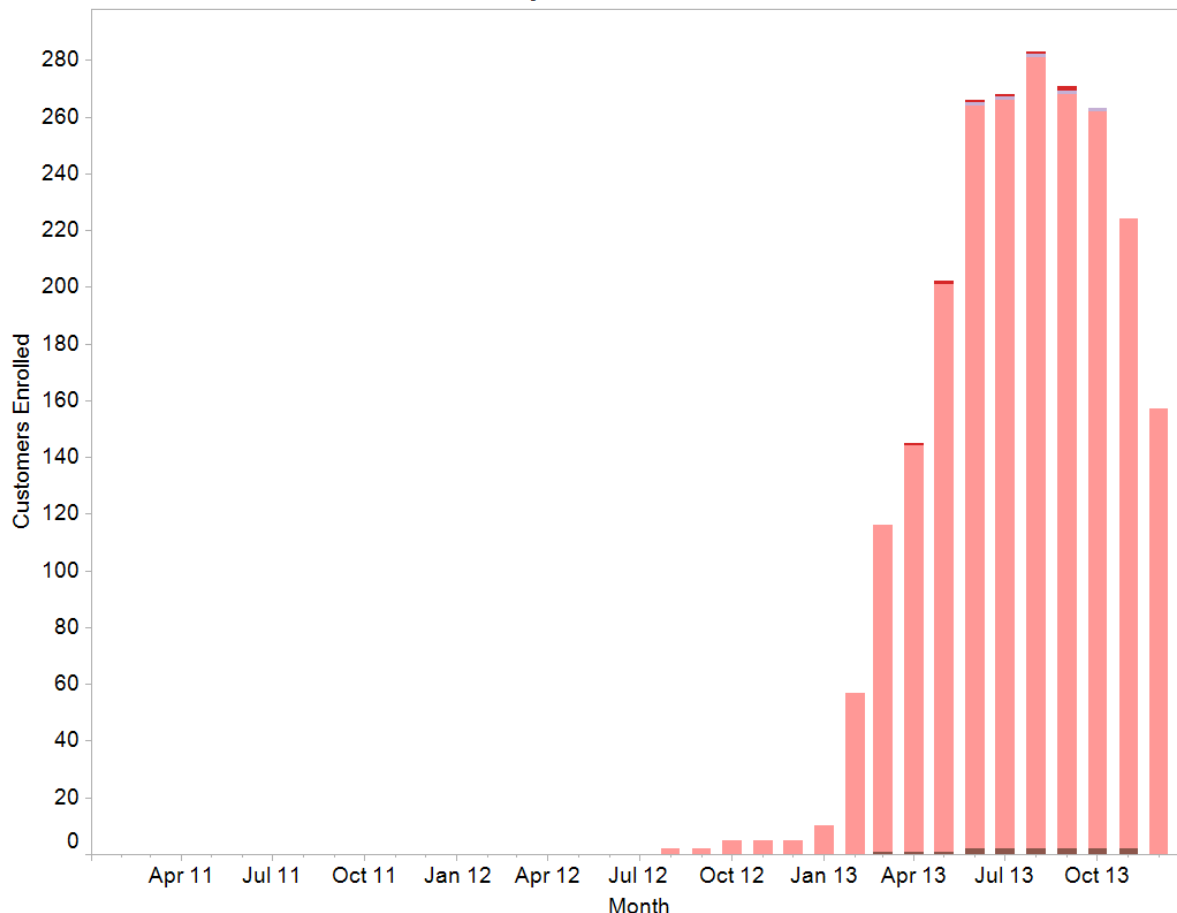
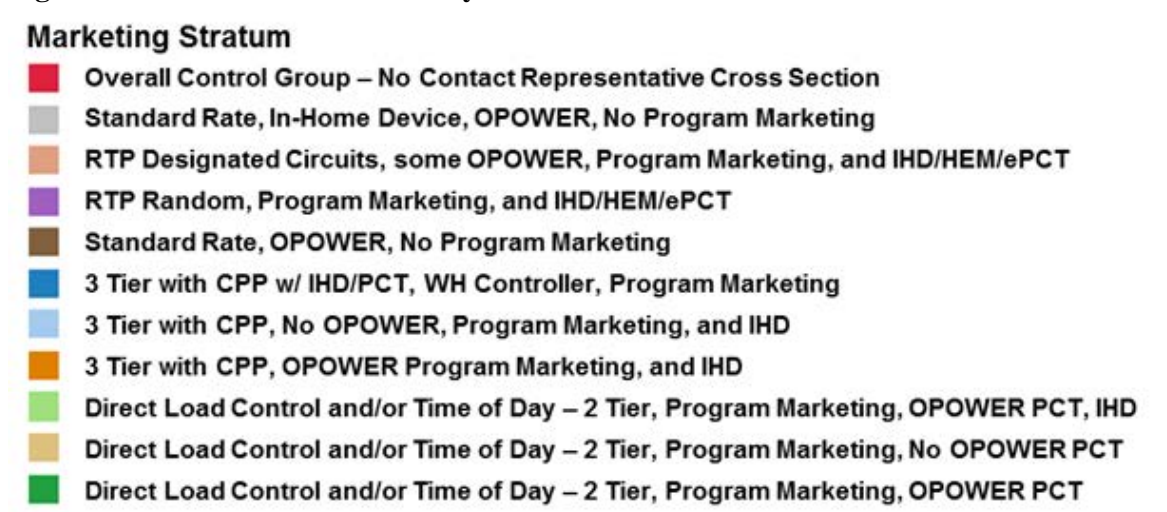


Figure 57. Consumer Enrollment by Month - SMART Choice





3.6.4 Peak Load and Mix (M03-CP)

This impact metric examines the impact of the various consumer programs on the daily usage peaks. This impact metric compares the impacts across account classes, such as residential, commercial, and industrial. Various consumer strata and demographic data were used to determine which programs had the most impact on peak load and mix.

3.6.4.1 Organization of Results

This impact metric assesses the ability of programs, tariffs, and technologies to influence consumers to shift their load away from traditionally typical peak periods.

The key parameters of interest included time, account class, the account's applicable tariff, and for residential accounts, applicable demographic data.

- The time variant aspect of the data was handled by graphing data as a function of each hour of the day.
- Account class was set as the three traditional groupings of consumers – industrial, commercial and residential.
- Residential consumers were categorized by account class, tariff, and demographic.
- Three key demographic groups were identified with the remainder of the consumers placed in one of three groups
- Consumers on a fixed billing program
- Consumers with and without children in the household
- Consumers without children in the household
- Commercial and Industrial Monthly Average

3.6.4.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data:

- For consumers on a program tariff, the most significant peak reductions occur on DLC and CPP event days.
- The Regular Residential tariff is a reasonable proxy for the baseline consumption patterns of consumers on program tariffs.

Consumer Programs



3.6.4.3 Calculation Approach

This impact metric provides an analysis of average daily usage patterns during selected peak days for consumers grouped by tariff.

The following queries and methods were used to generate analysis and graphs:

- Peak load and mix was calculated by averaging hourly consumer electricity usage into 24 hourly bins.
- Hourly outdoor temperature in degrees Fahrenheit for Port Columbus International Airport was collected from the National Oceanic and Atmospheric Administration here: <http://hurricane.ncdc.noaa.gov/pls/plclimprod/poemain.accessrouter?datasetabbv=DS3505&countryabbv=&georegionabbv=>
- Direct Load Control events per meter were selected based on the type of Direct Load Control device installed on a consumer’s premises.

3.6.4.4 Data Collection Results

Usage Data by Account Class and Hour of the Day for the Peak Week

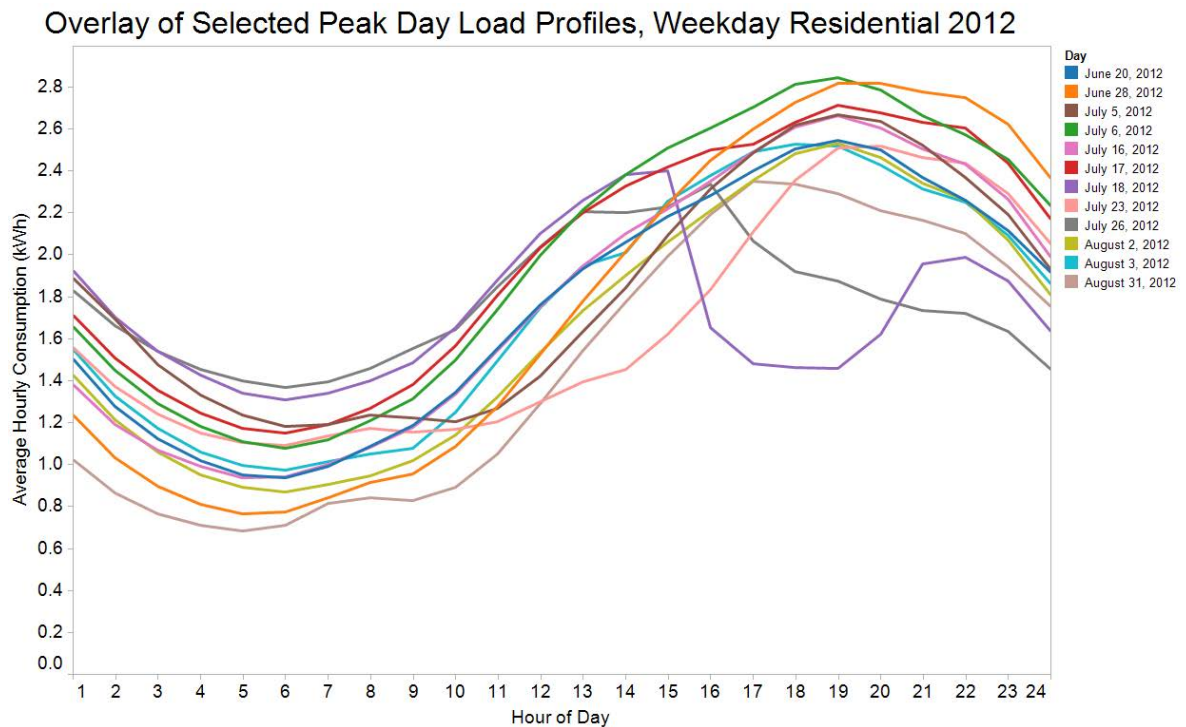


Figure 58. Overlay of Peak Load Days - Residential 2012

Consumer Programs

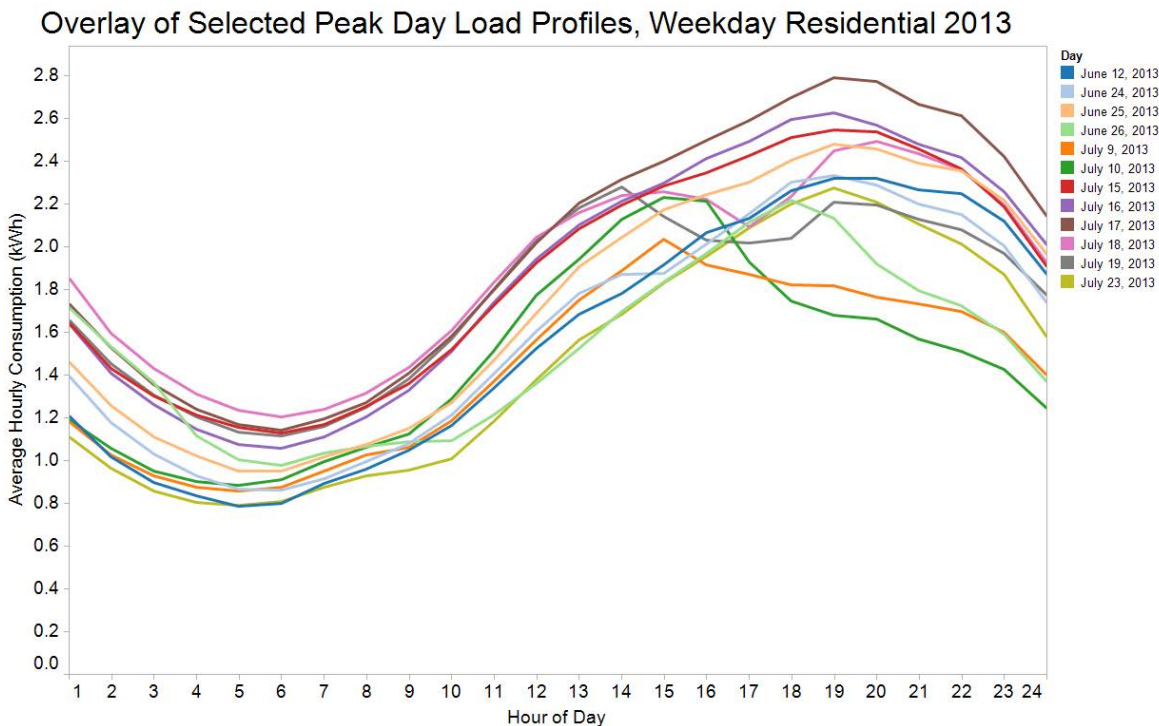


Figure 59. Overlay of Peak Load Days - Residential 2013

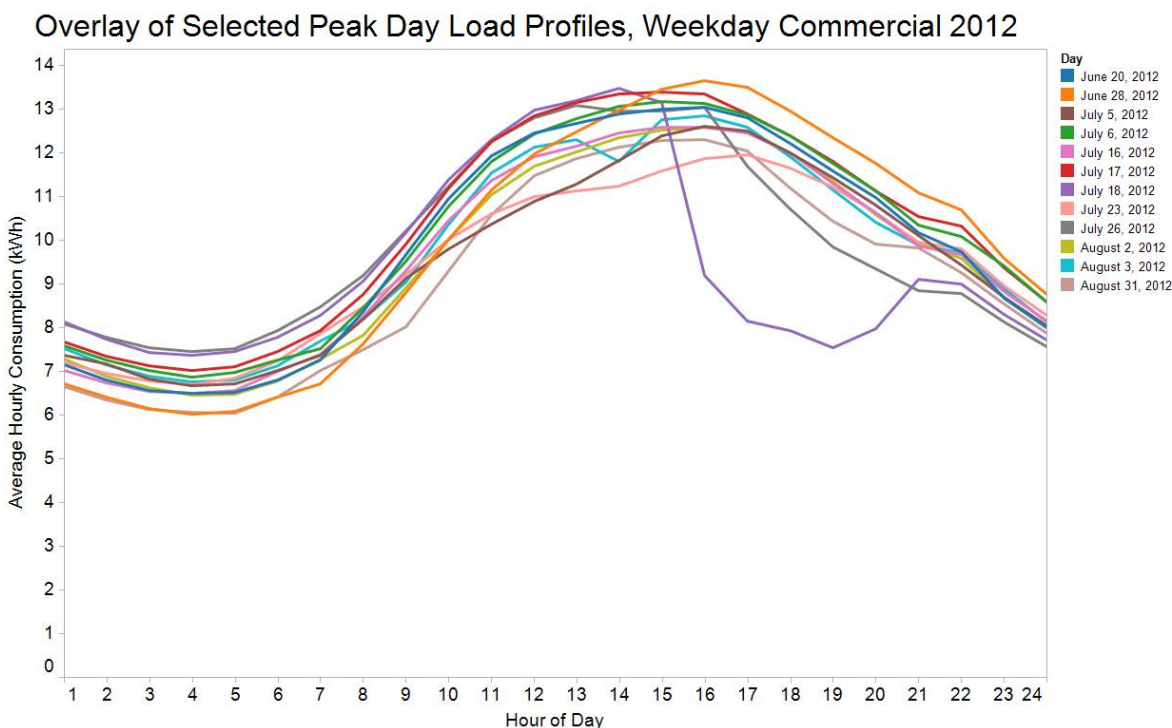


Figure 60. Overlay of Peak Load Days - Commercial 2012

Consumer Programs



Overlay of Selected Peak Day Load Profiles, Weekday Commercial 2013

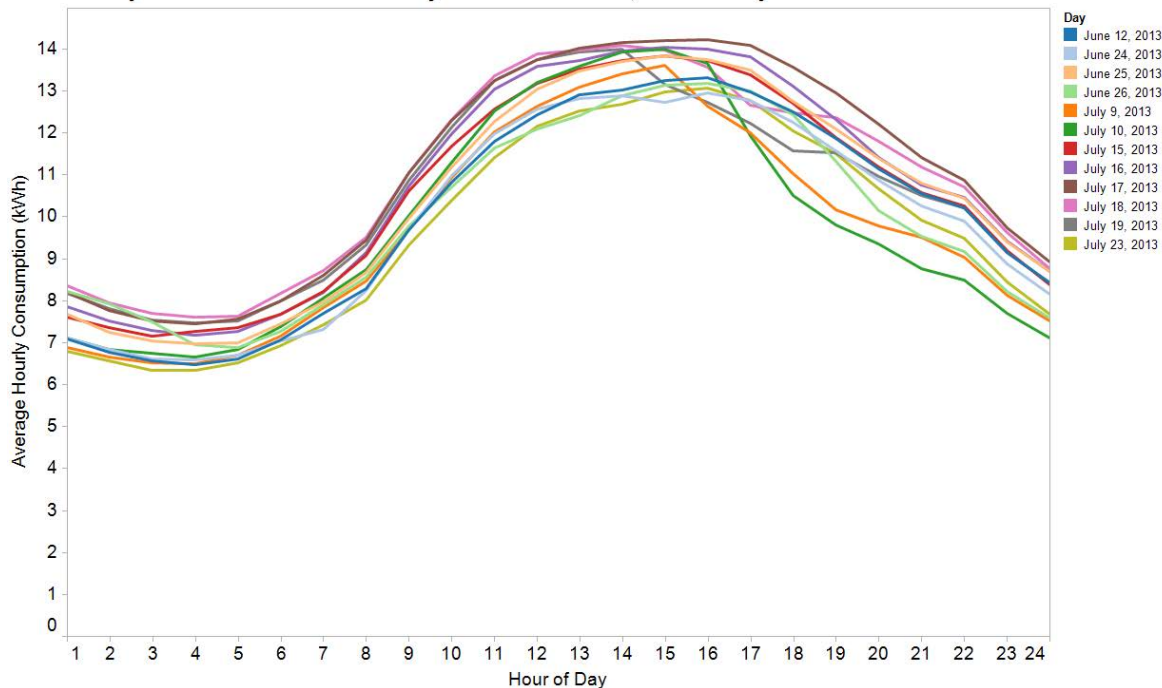


Figure 61. Overlay of Peak Load Days - Commercial 2013

Overlay of Selected Peak Day Load Profiles, Weekday Industrial 2012

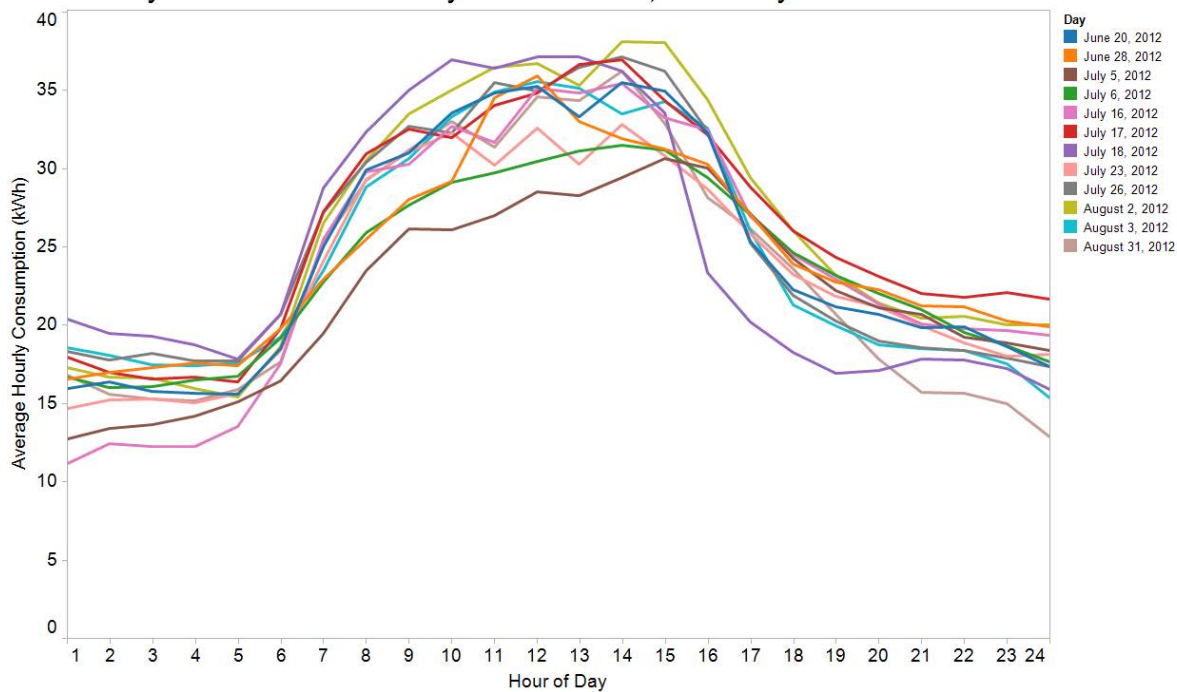


Figure 62. Overlay of Peak Load Days - Industrial 2012

Consumer Programs

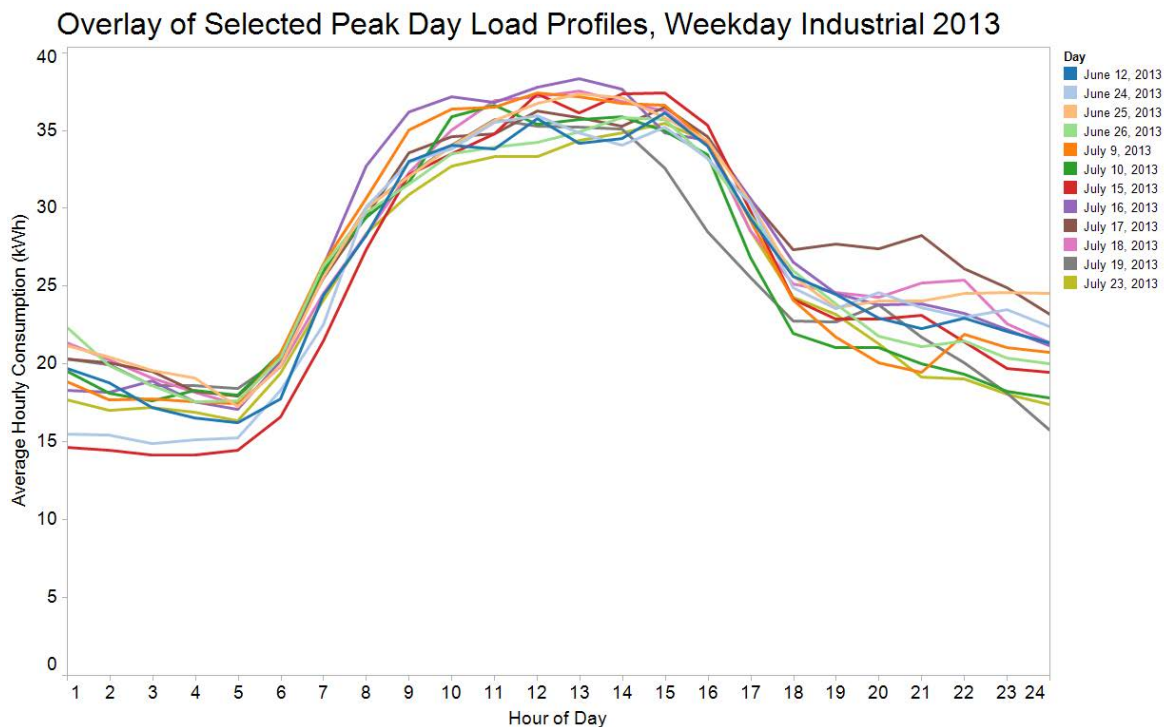


Figure 63. Overlay of Peak Load Days - Industrial 2013

Consumer Programs



Load Profile Data by Account Class for the Peak Day

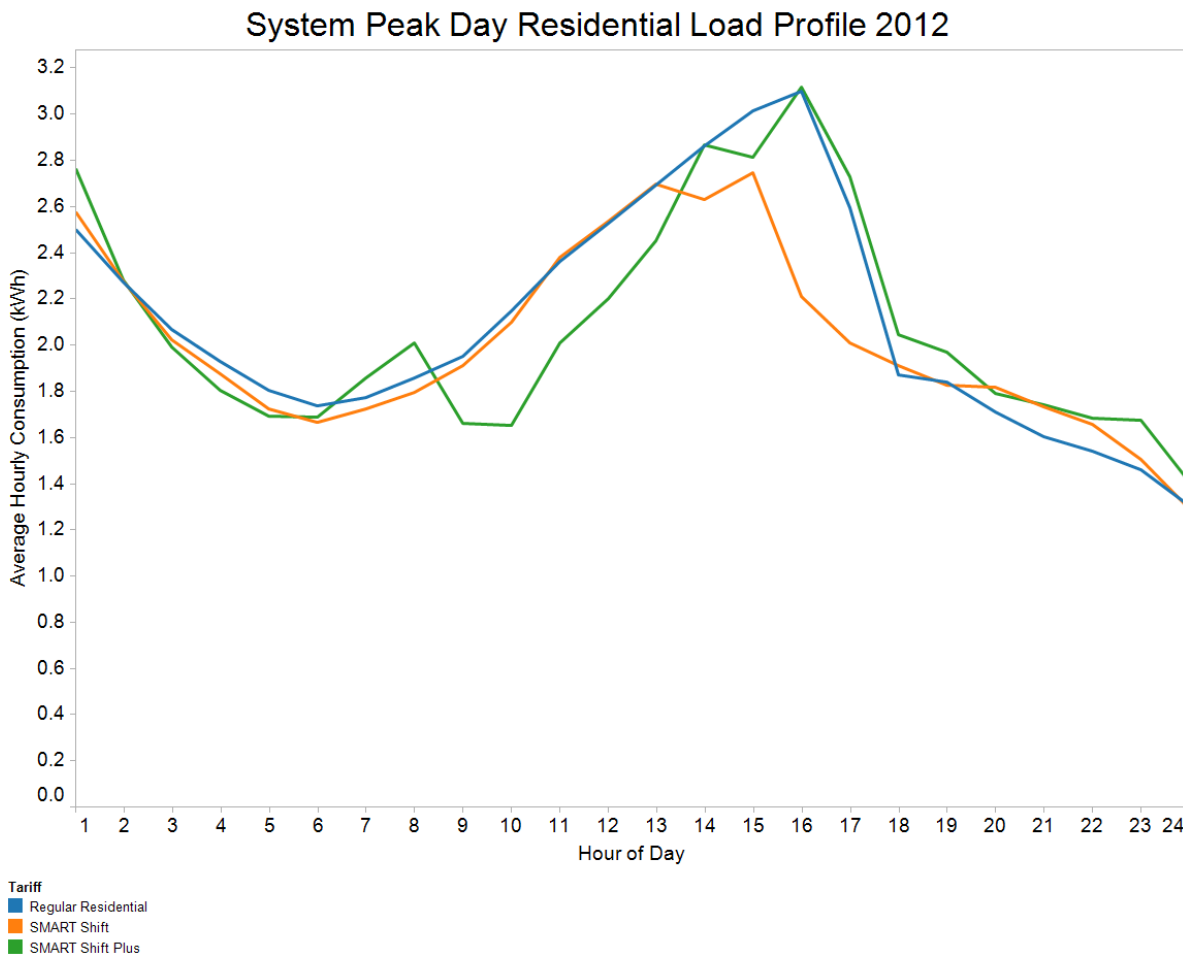


Figure 64. Residential Load Profile for System Peak Day - June 29, 2012

Consumer Programs

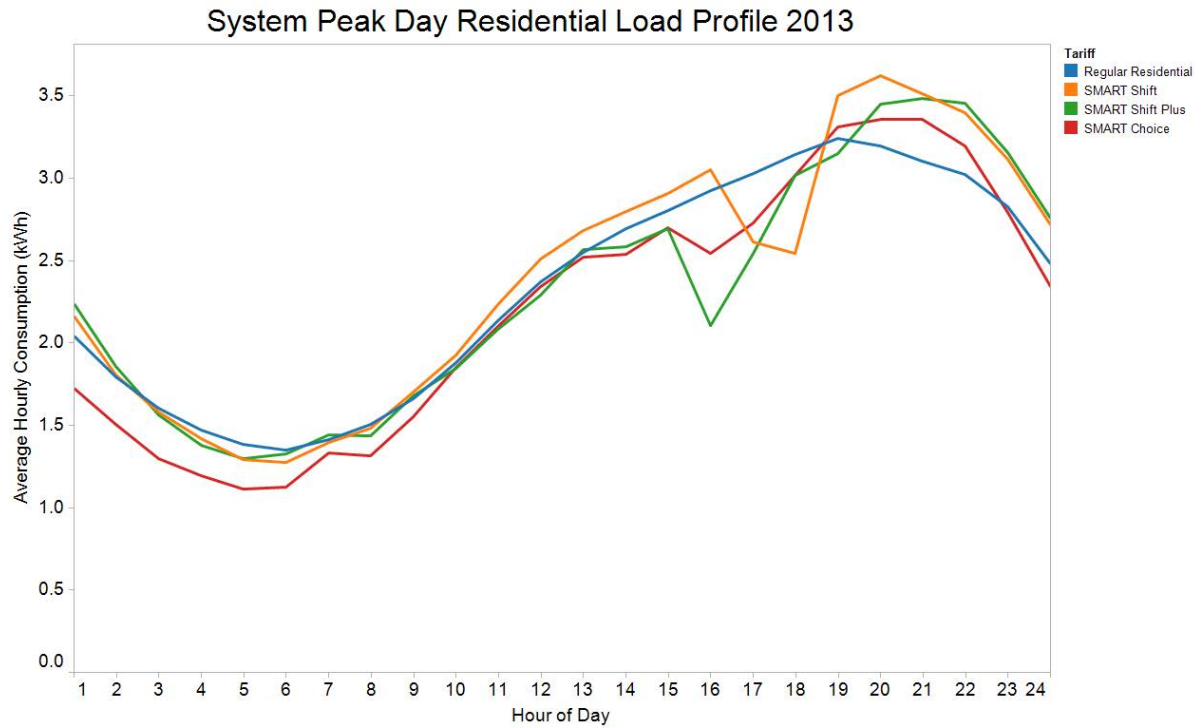


Figure 65. Residential Load Profile for System Peak Day - July 17, 2013

Consumer Programs

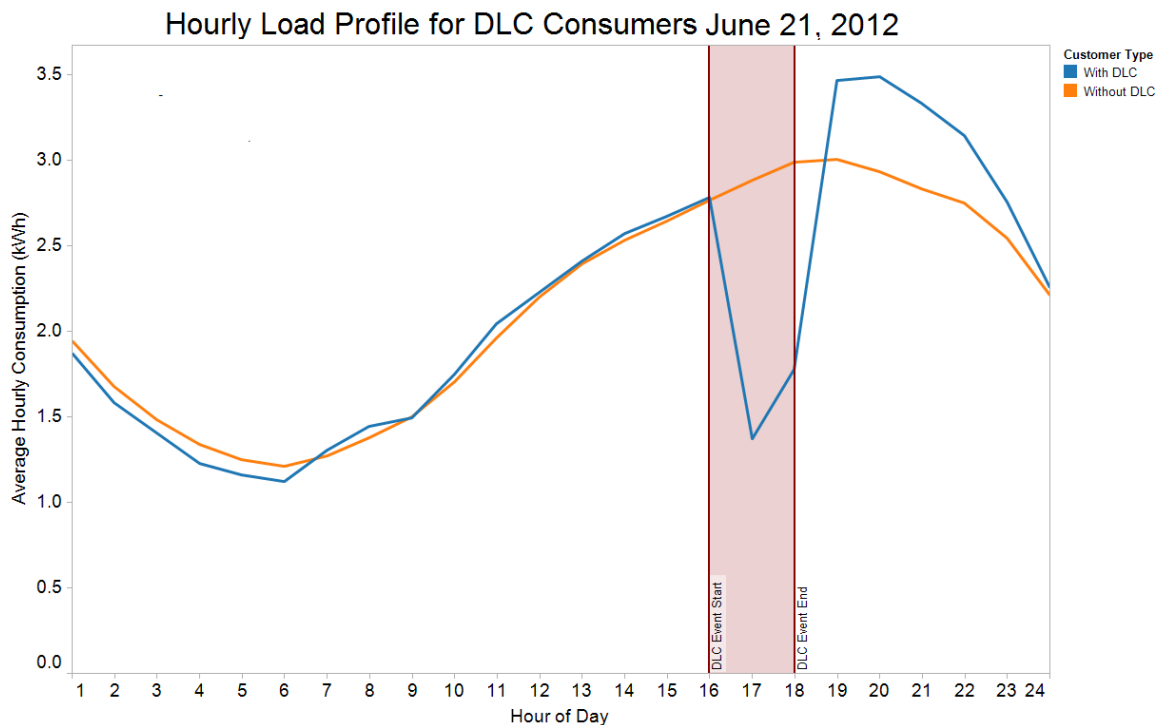


Figure 66. SMART Cooling DLC Event - June 21, 2012

6/21/2012 DLC Event Summary	
Average Event Load Reduction	1.338 kW / consumer
Peak Load Rebound	-0.605 kW / consumer
Event Energy	2.676 kWh / consumer
Rebound Energy	-2.422 kWh / consumer

Consumer Programs

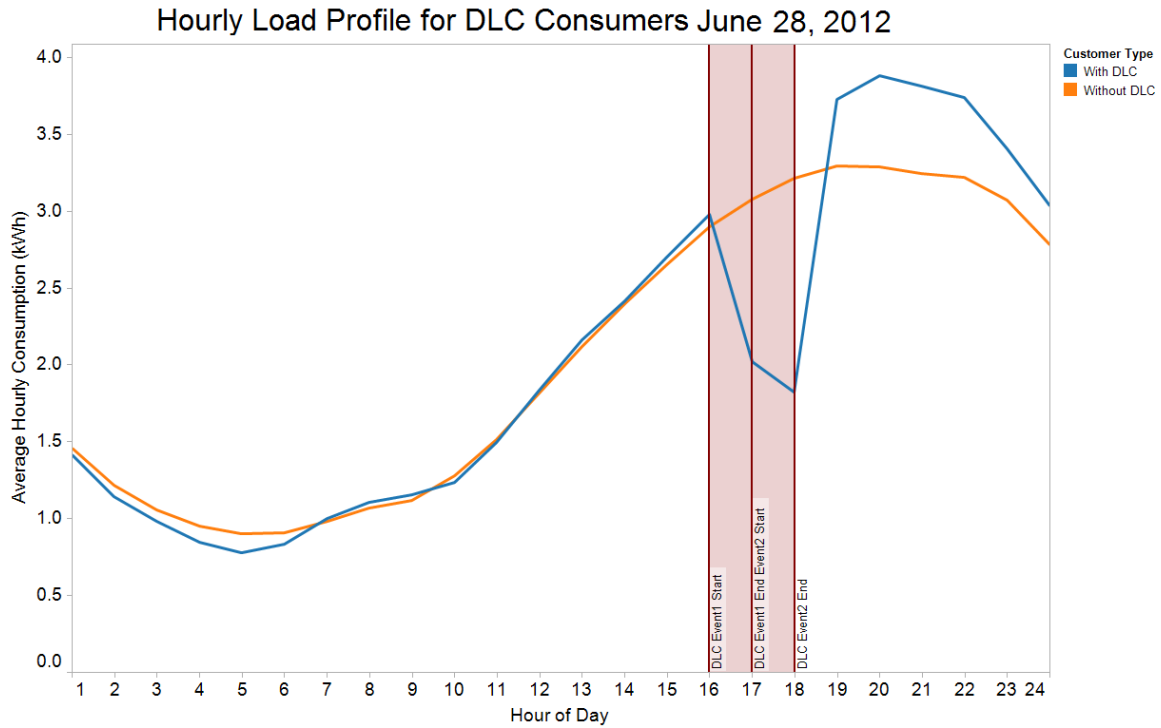


Figure 67. SMART Cooling DLC Event - June 28, 2012

6/28/2012 DLC Event Summary		
Average Event Load Reduction	1.173	kW / consumer
Peak Load Rebound	-0.696	kW / consumer
Event Energy	2.345	kWh / consumer
Rebound Energy	-3.283	kWh / consumer

Consumer Programs

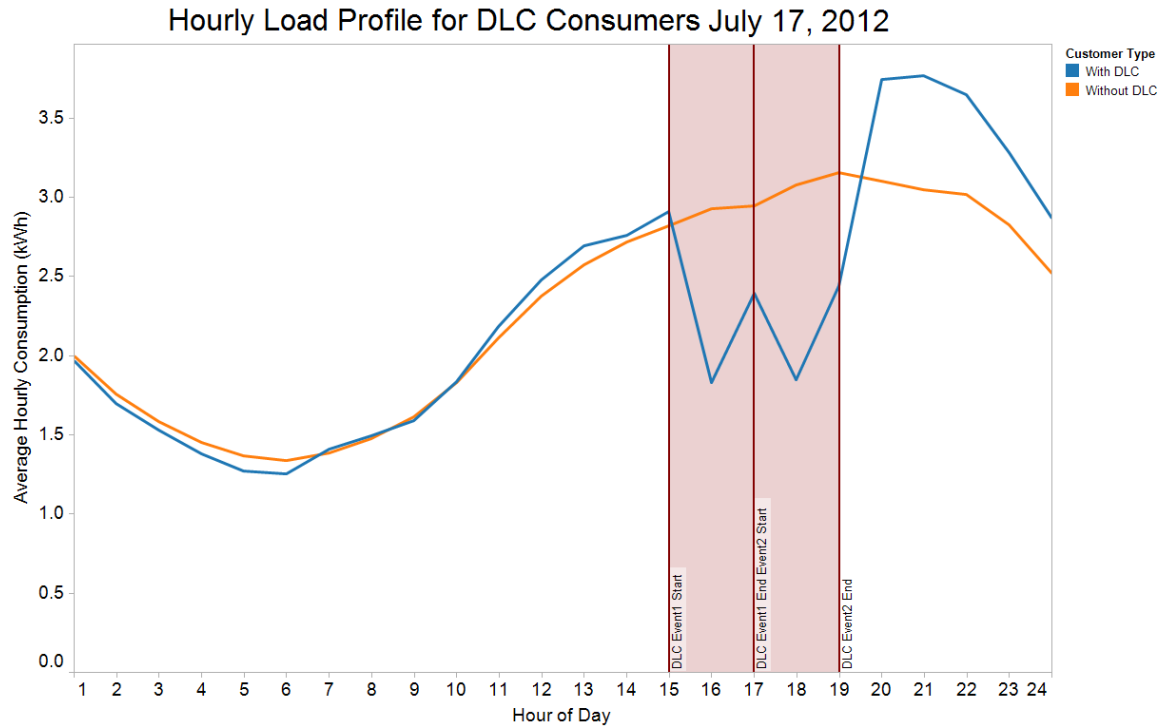


Figure 68. SMART Cooling DLC Event - July 17, 2012

7/17/2012 DLC Event Summary		
Average Event1 Load Reduction	0.814	kW / consumer
Average Event2 Load Reduction	0.956	kW / consumer
Peak Load Rebound	-0.748	kW / consumer
Event1 Energy	1.628	kWh / consumer
Event2 Energy	1.912	kWh / consumer
Rebound Energy	-2.916	kWh / consumer

Consumer Programs

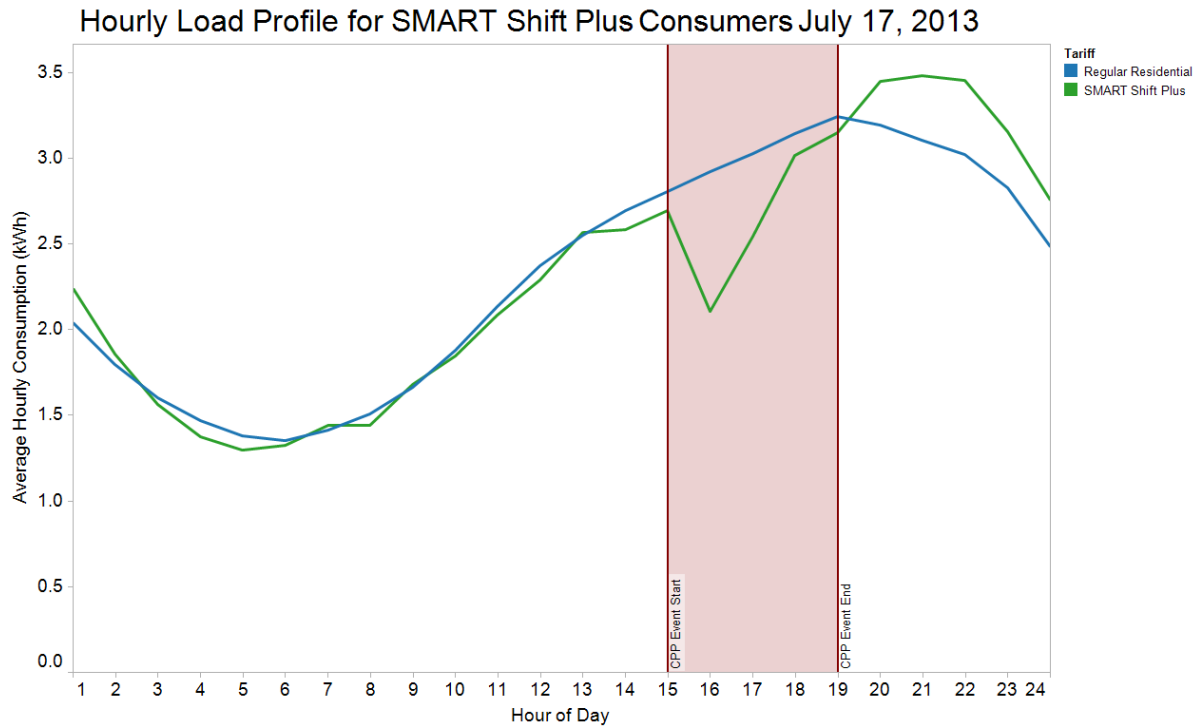


Figure 69. SMART Shift Plus CPP Event - July 17, 2013

7/17/2013 CPP Event Summary	
Average Event Load Reduction	0.338 kW / consumer
Peak Load Rebound	-0.484 kW / consumer
Event Energy	1.352 kWh / consumer
Rebound Energy	-1.919 kWh / consumer

3.6.4.5 Summary

The load and temperature curves for residential, commercial, and industrial consumers for the selected CPP and DLC event days demonstrate a fairly consistent response to the events. For both programs, the length of the events had a significant impact on the average reduction in KW over the event. For two hour events, consumers provided around 1.2-1.3 KW of average reduction across the duration of the event, while for four hour events, this number was reduced to ~0.6 to 0.8 KW. The variations can be attributed to temperature and other weather factors as well as variations in consumer behavior and the initial temperatures of the residences at the start of each event due to HVAC cycling randomness.

The post-event rebound behavior was also fairly consistent across both programs in terms of KW, and overall there was little or no net KWh savings. Some of this behavior can be attributed to the loss of diversity in the HVAC cycling across the population of participants, which was

Consumer Programs



evidenced by the lower overall consumption for these consumers during the early morning hours following an event. Once the events ended, the majority of the HVAC turned at nearly the same time, their natural hysteresis resulted in the overall average indoor temperature across the population being lower than normal once the post-event cycling had occurred. Thus, there was overall fewer overnight cycles occurring for the population.

The consistency of the behavior across the DLC and CPP consumers was attributed to the method of response for both. In both cases, the HVAC thermostat set point was set back in response to the event. The default CPP adjustment was equal to the typical DLC setback, and the consistency of the CPP response indicated that consumers were not reprogramming the setback settings but left them on the default setting.



3.6.5 Project CO₂ Emissions (M07-CP)

This impact metric examines the impact to CO₂ emissions resulting from changes in consumer usage behaviors in the Project area. In principle, the reduction of energy use or shifting of energy use to different times of day had an impact on the CO₂ emitted by the generation fleet. This impact metric compares the impacts against account classes, such as residential, commercial, and industrial. Various consumer strata and demographic data were used to determine which programs had the most impact to CO₂ emissions.

3.6.5.1 Organization of Results

This metric presents the impact of Consumer Programs on CO₂ emissions by quantifying the difference in energy consumption from new tariffs and technologies versus traditional residential flat-rate electric tariffs.

CO₂ Emissions Avoided by Month

This metric is displayed as a graph that shows the CO₂ emissions avoided by the consumers on the experimental for SMART Shift, SMART Shift Plus, and SMART Choice.

3.6.5.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data:

- Differences in CO₂ emissions per kWh due to shifting load from peak to off peak times are insignificant compared to the total CO₂ avoided through kWh reductions.

- CO₂: 0.00068956 tons/kWh

Source: *U.S. EPA eGRID2012 Version 1.0 Year 2009 Summary Tables for RFC West Region*

3.6.5.3 Calculation Approach

Load reduction was calculated as the difference between usage for consumers on an experimental tariff versus usage of similar consumers on the standard residential tariff. These results are reported for consumers grouped by demographic and by stratum.

Load reduction was translated into CO₂ reduction using typical generation emissions factors.

The following queries and methods were used to generate the analysis:

- Energy consumption reductions per month
- Consumer class
- Consumer stratum
- Consumer demographic
- Tariff

The calculation was done by subtracting the average billed hourly usage for residential consumers not on the standard residential tariff from average billed hourly usage for residential

Consumer Programs



consumers on the standard residential tariff for the same month, consumer class, consumer stratum, and consumer demographic.

Tons of CO₂ avoided per month, consumer stratum, consumer demographic, and tariff for consumer programs were calculated by multiplying the amount of CO₂ emissions avoided by the ratio of all consumers on a circuit to residential consumers not on the standard residential tariff.

3.6.5.4 Data Collection Results

CO₂ Avoided Per Month by Tariff

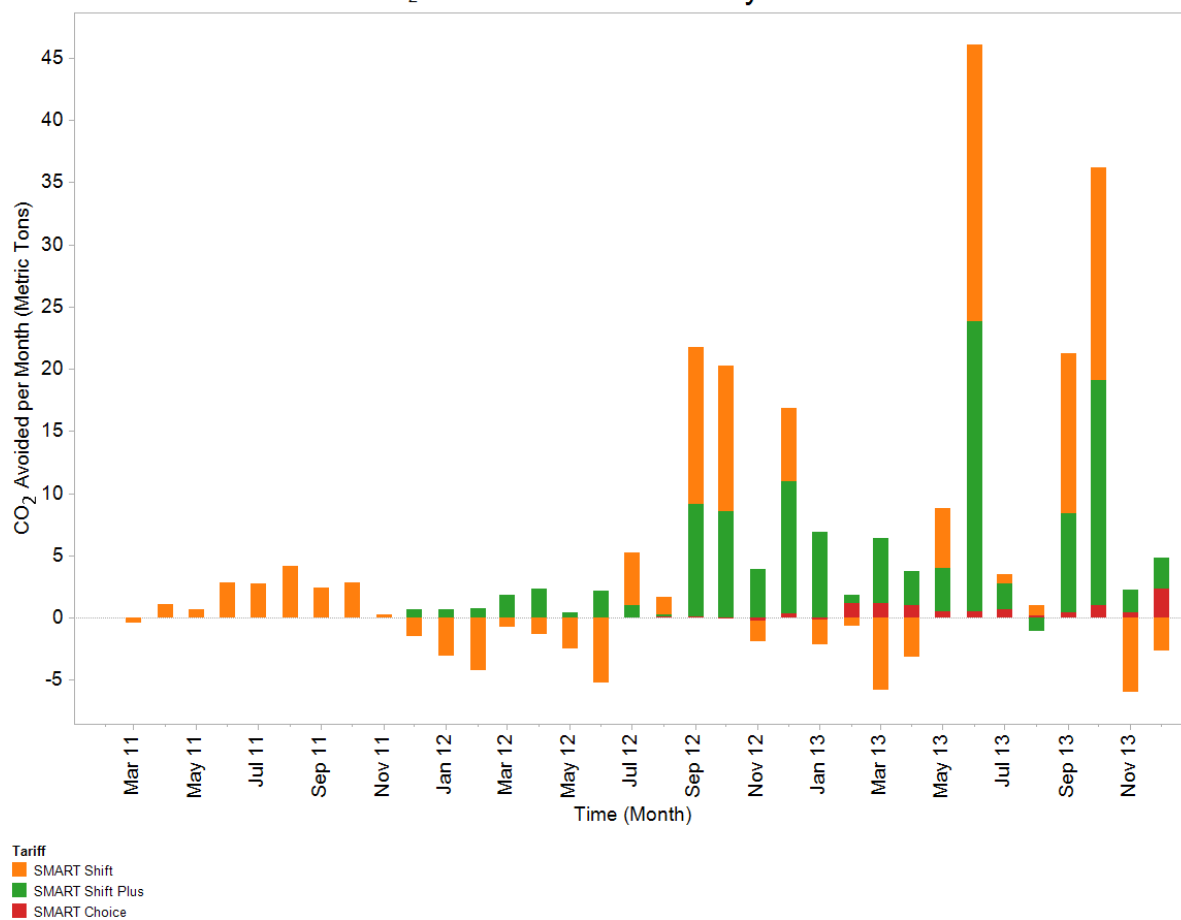


Figure 70. Monthly CO₂ Emissions Avoided or Contributed by Three Tariffs

3.6.5.5 Summary

Since the TOD and TOD/CPP consumers used less overall energy than the consumers on the standard residential tariff they contributed to lower CO₂ emissions. Based on this simple comparison, consumer programs resulted in nearly 196 metric tons of CO₂ reductions during the Project time period. Establishing pre-tariff baselines for the TOD/CPP and TOD consumers allowed for a more accurate accounting of these reductions.

Consumer Programs



From the data available, it appears that the TOD tariff encouraged conservation in the summer months yet may have led to slightly increased energy consumption (and thereby CO₂ emission) in the winter when the rates are lower than the standard tariff. Both TOD and CPP tariffs showed small values of CO₂ reduction when they were first introduced and larger values of reduction after they had been in place for several months. This was most likely due to a combination of an increase in the number of consumers participating in each tariff along with changes in behavior as consumers gained a better understanding of how to adjust their usage patterns for maximum savings.



3.6.6 Project Pollutant Emissions (M08-CP)

This impact metric examines the potential impact on pollutant emissions resulting from changes in consumer usage behaviors. In principle, the reduction of energy use or shifting of energy use to different times of day had an impact on the pollutants emitted by the generation fleet. This impact metric compares the impacts against account classes, such as residential, commercial, and industrial in the Project area. Various consumer strata and demographic data were used to determine which programs had the most impact to pollutant emissions.

3.6.6.1 Organization of Results

This metric presents the impact of consumer programs on pollutant emissions by quantifying the difference in energy consumption from new tariffs and technologies against traditional flat-rate electric tariffs.

Pollutant emissions avoided by month

This metric is displayed as a graph that shows the pollutant emissions avoided by the consumers in the Project area on the experimental tariffs SMART Shift, SMART Shift Plus, and SMART Choice.

3.6.6.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data:

- Differences in pollutant emissions per kWh due to shifting load from peak to off peak times are insignificant compared to the total pollutant emissions avoided through kWh reductions.
- SO_x: 0.00263084 kg/kWh
Source: *U.S. EPA eGRID2012 Version 1.0 Year 2009 Summary Tables for RFC West Region*
- NO_x: 0.00117934 kg/kWh
Source: *U.S. EPA eGRID2012 Version 1.0 Year 2009 Summary Tables for RFC West Region*
- PM_{2.5}: 0.001 kg/kWh
Source: *U.S. EPA eGRID2012 Version 1.0 Year 2009 Summary Tables for RFC West Region*

3.6.6.3 Calculation Approach

Load reduction due to consumer programs was calculated as the difference between usage for consumers on an experimental tariff versus usage of similar consumers on the standard residential tariff. These results are reported by tariff by month.

Load reduction was then translated into pollutant reduction using typical generation emissions factors.

The following queries and methods were used to generate the metric analysis:

- Energy consumption reductions per month, consumer class, consumer stratum, consumer demographic, and tariff based on consumer programs were calculated by subtracting the average billed hourly usage for residential consumers not on the standard residential tariff

Consumer Programs



from average billed hourly usage for residential consumers on the standard residential tariff for the same month, consumer class, consumer stratum, and consumer demographic.

- Kilograms of NO_x avoided per month, consumer stratum, consumer demographic, and tariff for consumer programs were calculated by multiplying the energy consumption reductions by 0.00117934 (kilograms per kWh).
- Kilograms of PM_{2.5} avoided per month, consumer stratum, consumer demographic, and tariff for consumer programs were calculated by multiplying the energy consumption reductions by 0.001 (kilograms per kWh).
- Kilograms of SO_x avoided per month, consumer stratum, consumer demographic, and tariff for consumer programs were calculated by multiplying the energy consumption reductions by 0.00263084 (kilograms per kWh).

3.6.6.4 Data Collection Results

Pollutants Avoided Per Month by Tariff

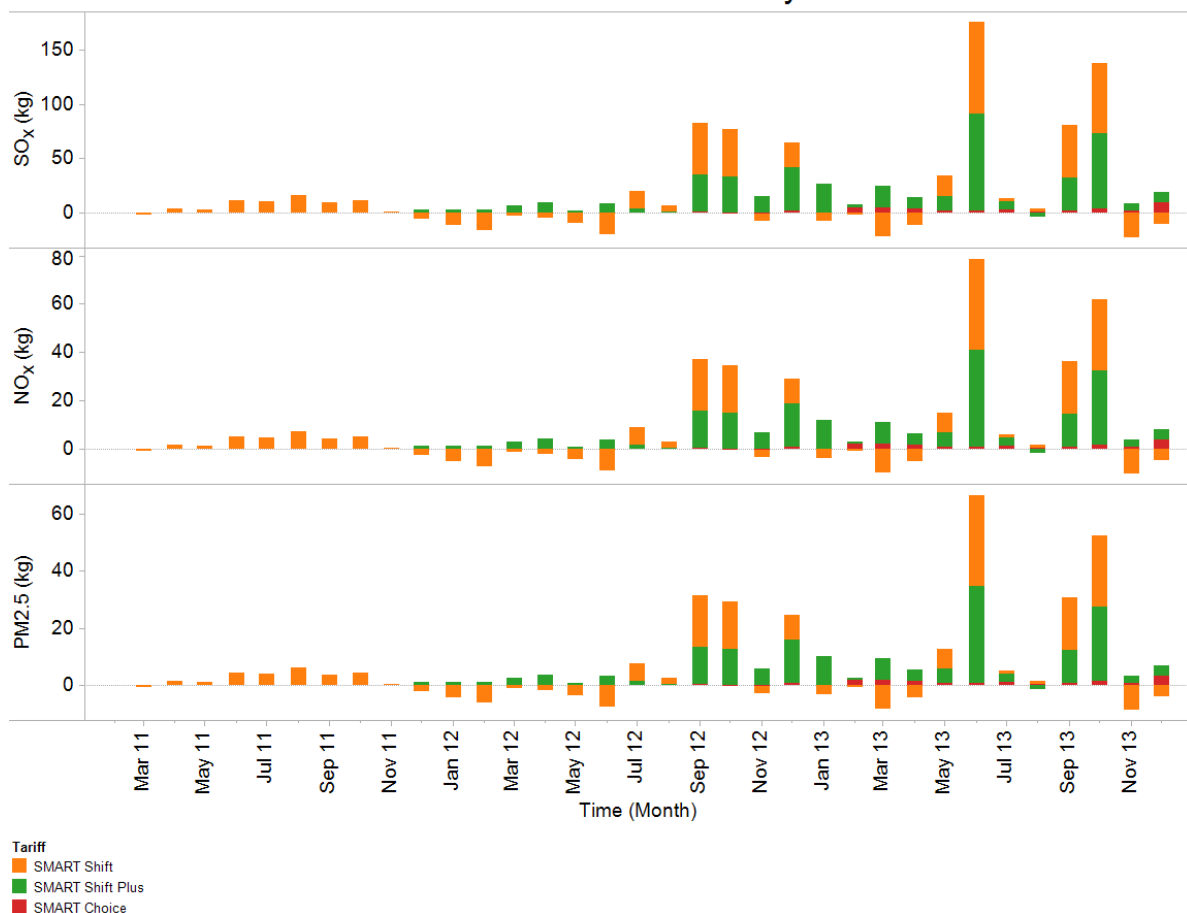


Figure 71. Monthly Pollutant Emissions Avoided or Contributed by Three Tariffs

Consumer Programs



3.6.6.5 Summary

NO_x and SO_x emissions reductions behaved the same as the CO₂ emissions reductions. Both the TOD and TOD/CPP consumers consumed less overall energy. Based on a comparison of these consumers' consumption to that of standard residential consumers, consumer programs resulted in approximately 749 kg of SO_x, 335 kg of NO_x, and 284 kg of PM_{2.5} reductions during the Project time period. The attribution of these reductions to the particular tariff was verified by baseline analysis for both consumer populations.

From the data available, the TOD tariff encouraged conservation in the summer months yet may have led to slightly increased energy consumption (and thereby pollutant emission) in the winter, when the rates were lower than the standard tariff. Both TOD and CPP tariffs showed small values of pollutant reduction when they were first introduced and larger values of reduction after they had been in place for several months. This reduction was most likely due to a combination of an increase in the number of consumers participating in each tariff along with changes in behavior as consumers gained a better understanding of how to adjust their usage patterns for maximum savings.



3.6.7 System CO₂ Emissions - System area (M09-CP)

This impact metric examines the potential impact to CO₂ emissions resulting from consumer usage behaviors in the System area. In principle, the reduction of energy use or shifting of energy use to different times of day should have an impact on the CO₂ emitted by the generation fleet. This impact metric compares the impacts against account classes, such as residential, commercial, and industrial. Various consumer strata and demographic data were used to determine which programs have the most impact to CO₂ emissions.

3.6.7.1 Organization of Results

This metric presents the impact of consumer programs on CO₂ emissions by quantifying the difference in energy consumption from new tariffs and technologies versus traditional flat-rate electric tariffs.

CO₂ Emissions Avoided by Month

This metric is displayed as a graph that shows the CO₂ emissions avoided by the consumers projected into the System area as if they were on the experimental tariffs SMART Shift, SMART Shift Plus, and SMART Choice.

3.6.7.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data:

- Consumer behavior changes due to program tariffs would be similar for consumers outside the Project area.
- CO₂: 0.00068956 tons/kWh

Source: *U.S. EPA eGRID2012 Version 1.0 Year 2009 Summary Tables for RFC West Region*

3.6.7.3 Calculation Approach

The following queries and methods were used to generate results:

Load reduction was calculated as the difference between usage for consumers on an experimental tariff versus usage of similar consumers on the standard residential tariff. These results are reported for consumers grouped by demographic and by stratum.

Load reduction was translated into CO₂ reduction using typical generation emissions factors. This reduction was then extrapolated onto the System area based on the ratio of total circuit load between the Project and System areas.

Tons of CO₂ avoided per month, consumer stratum, consumer demographic, and tariff for Consumer Programs were calculated by multiplying the energy consumption reductions by 0.00068956 (tons per kWh).

Consumer Programs



3.6.7.4 Data Collection Results

System Area Projection of CO₂ Avoidance per Month

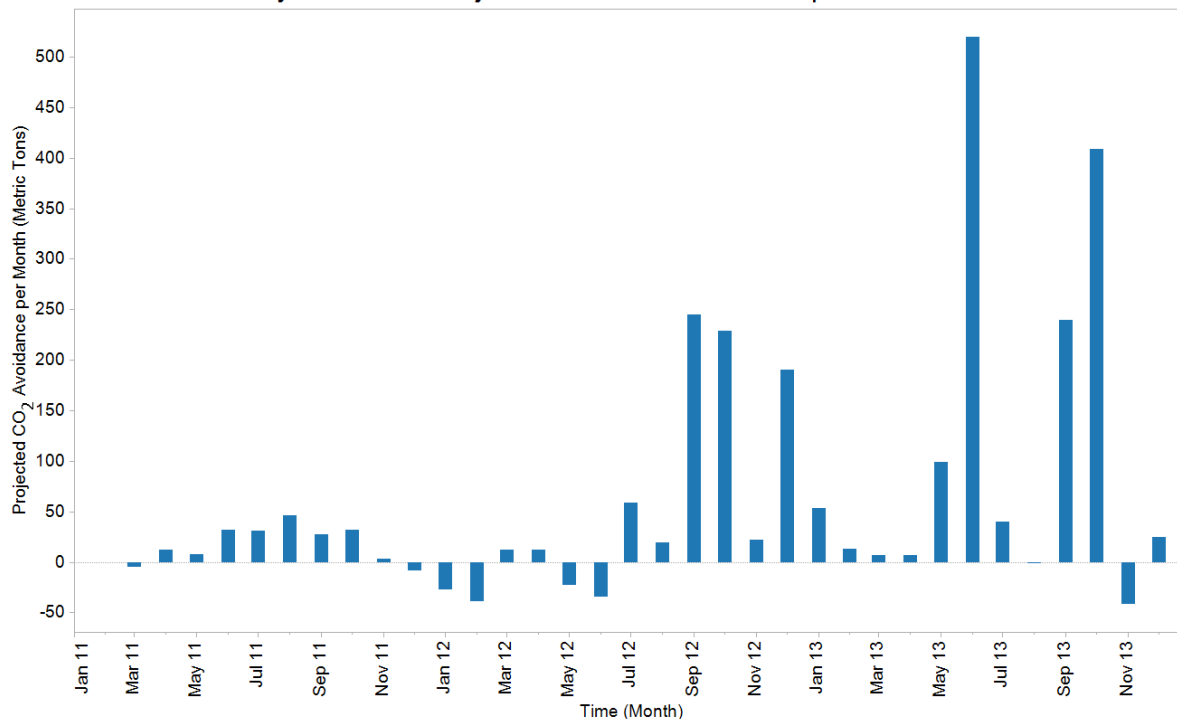


Figure 72. Monthly Projected Potential CO₂ Emissions Avoided or Contributed by Three Tariffs

3.6.7.5 Summary

The System area CO₂ reductions were an extrapolation of the Project area CO₂ reductions. This resulted in 2,212 metric tons of CO₂ avoided in the System area over this two year period. This extrapolation assumed that the current percentages of consumers on each tariff for the Project remained constant as they were extended to the entire System area. Additional reductions could be achieved by extending the tariffs to higher percentages of consumers although the result may not be linear.

From the data available, it appeared that the TOD tariff encouraged conservation in the summer months, yet may have led to slightly increased energy consumption (and thereby CO₂ emission) in the winter when the rates were lower than the standard tariff. Both TOD and CPP tariffs showed small values of CO₂ reduction when they were first introduced and larger values of reduction after they had been in place for several months. This was most likely due to a combination of an increase in the number of consumers participating in each tariff along with changes in behavior as consumers gained a better understanding of how to adjust their usage patterns for maximum savings.



3.6.8 System Pollutant Emissions (M10-CP)

This impact metric examines the potential impact on pollutant emissions if consumer programs were extended to the System area. In principle, the reduction of energy use or shifting of energy use to different times of day may have an impact on the pollutants emitted by the generation fleet. This impact metric compares the impacts against account classes, such as residential, commercial, and industrial in the system area. Various consumer strata and demographic data were used to determine which programs have the most impact to pollutant emissions.

3.6.8.1 Organization of Results

This metric presents the impact of consumer programs on pollutant emissions by quantifying the difference in energy consumption from new tariffs and technologies versus traditional flat-rate electric tariffs.

Pollutant emissions avoided by month

This metric is displayed as a graph that shows the pollutant emissions avoided by the consumers projected into the system area as if they were on the experimental tariffs SMART Shift, SMART Shift Plus, and SMART Choice.

3.6.8.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data:

- Consumer behavior changes due to program tariffs would be similar for consumers outside the Project area.
- SO_x: 0.00263084 kg/kWh
Source: *U.S. EPA eGRID2012 Version 1.0 Year 2009 Summary Tables for RFC West Region*
- NO_x: 0.00117934 kg/kWh
Source: *U.S. EPA eGRID2012 Version 1.0 Year 2009 Summary Tables for RFC West Region*
- PM_{2.5}: 0.001 kg/kWh
Source: *U.S. EPA eGRID2012 Version 1.0 Year 2009 Summary Tables for RFC West Region*

3.6.8.3 Calculation Approach

The following queries and methods were used to generate results:

Load reduction due to consumer programs was calculated as the difference between usage for consumers on an experimental tariff versus usage of similar consumers on the standard residential tariff.

Load reduction was translated into pollutant reduction using typical generation emissions factors, and was extrapolated to the System area based on the ratio of total circuit load.

The following queries and methods were used to generate the analysis and graphs:

- Kilograms of NO_x per month, circuit, and consumer demographic that would be avoided if Consumer Programs were deployed throughout the System area were calculated by multiplying the kilograms of NO_x emissions avoided by the ratio of all consumers on a circuit to residential consumers not on the standard residential tariff.

Consumer Programs



- Kilograms of PM_{2.5} per month, circuit, and consumer demographic that would be avoided if consumer programs were deployed throughout the System area. These were calculated by multiplying the kilograms of PM_{2.5} emissions avoided by the ratio of all consumers on a circuit to residential consumers not on the standard residential tariff.
- Kilograms of SO_x per month, circuit, and consumer demographic that would be avoided if consumer programs were deployed throughout the System area. These were calculated by multiplying the kilograms of SO_x emissions avoided by the ratio of all consumers on a circuit to residential consumers not on the standard residential tariff.

3.6.8.4 Data Collection Results

System Area Projection of Pollutant Avoidance per Month

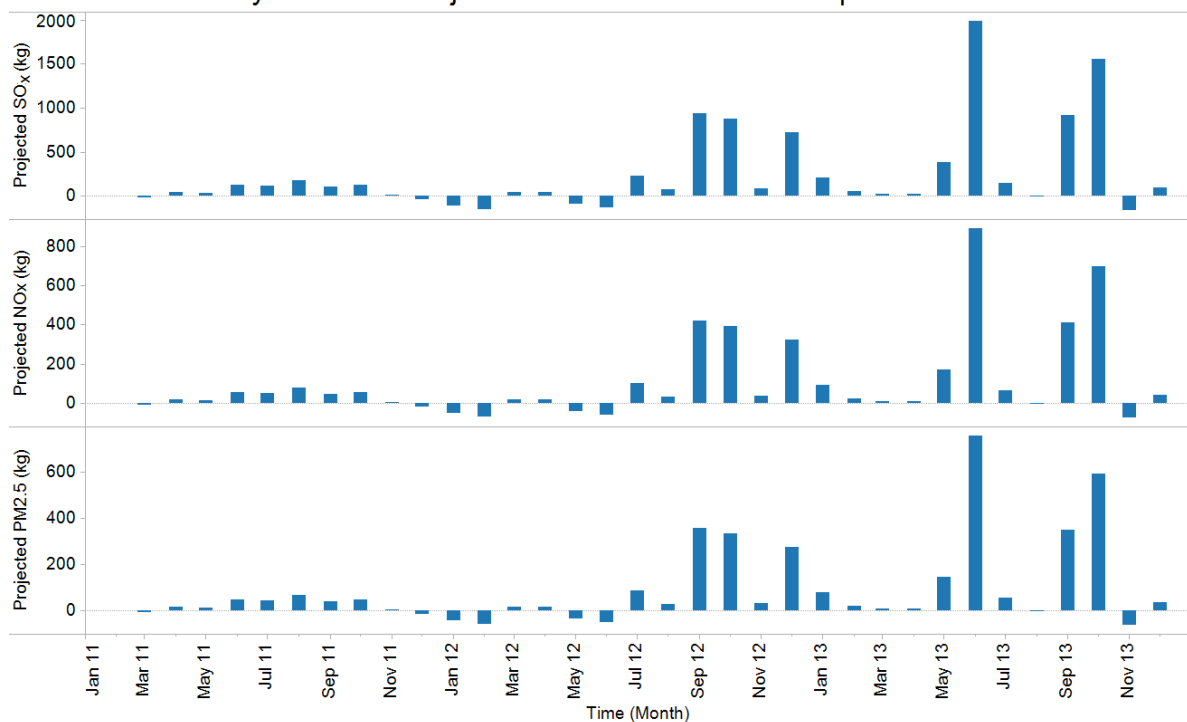


Figure 73. Monthly Projected Pollutant Emissions Avoided or Contributed by Three Experimental Tariffs

3.6.8.5 Summary

The system NO_x and SO_x reductions are an extrapolation of the Project area NO_x and SO_x reductions. This calculation resulted in approximately 8,442 kg of SO_x, 3,787 kg of NO_x, and 3,207 kg of PM_{2.5} reductions in the System area during this two year period. This extrapolation assumed that the current percentages of consumers on each tariff for the Project remain constant as they are extended to the entire System area. Additional reductions can be achieved by extending the tariffs to higher percentages of consumers although the result may not be linear.

SMART Shift resulted in conservation during the summer months with mixed results in the winter months when the rates were lower than the standard tariff. SMART Shift Plus resulted in greater conservation on a per customer basis and SMART Choice had minimal overall impact.

Consumer Programs



The increase in the year one to year two total avoidances were directly related to the significant increase in participation for all the tariffs in year two.

3.6.9 Comparison of Average Energy and Demand Impacts

Below is a comprehensive comparison of the results of the Consumer Programs impacts.

Summer 2012	Premises	Average Hourly Per Premises Energy (kWh) Impact	Average Per Premises Demand (kW) Impact
SMART Shift	877	-0.3	-0.3
SMART Shift Plus	108	-0.1	-0.2
SMART Cooling Events	898	-1.2	-1.5
eVIEW	318	-0.1	-0.2

Summer 2013	Premises	Average Hourly Per Premises Energy (kWh) Impact	Average Per Premises Demand (kW) Impact
SMART Shift	1848	-0.1	-0.2
SMART Shift Plus	619	-0.2	-0.3
SMART Shift Plus/CPP Events	619	-0.6	-0.7
SMART Cooling Events	1966	-1.1	-1.2
SMART Choice	217	-0.1	-0.2
eVIEW	1573	0.1	0.0

- Premises counts are for analysis purposes only and include those premises that were active in the tariff/program from June 1 to September 30 of the analysis year and are not representative of the total enrollment in these programs
- During high-cost hours for tariff-based consumer programs or event hours for event-based consumer programs
- Excludes SMART Cooling Event Dates
- Excludes SMART Shift impacts on those SMART Shift premises that also have SMART Cooling
- SMART Shift/Standard Tariff Consumers
- Excludes SMART Shift impacts on those SMART Shift premises that also have eVIEW
- Excludes SMART Shift Plus CPP Event Dates



3.7 Consumer Programs Conclusions

The Project provided useful information about consumer programs linked to AMI-driven technologies. It demonstrated that programs can be successfully implemented, but significant changes to back-office IT systems and business processes were required. The results indicated that consumers would participate in programs when given adequate information and enabling technologies. Dedicated customer service representatives were essential to handle significant call volume and address concerns as a high priority. Some consumers were motivated to modify their energy usage patterns when provided with appropriate tools and the potential for savings on their electric bills. However, overall energy usage impacts from these programs were minimal.

The SMART Shift and SMART Shift Plus programs exhibited lower energy and demand impacts in 2013 than they did in 2012. A milder weather season in 2013, an increased number of participants in 2013, less program communication in 2013, or a combination of those factors may have contributed to the difference in 2013 results.

Consumers participating in the SMART Cooling Program significantly reduced their demand during thermostat adjustment events. This reduction resulted in approximately twice the demand reductions achieved by those in SMART Shift Plus Program equivalent Critical Peak Pricing events. Thermostat adjustment provided the largest demand reduction for approximately the first hour. As temperatures in participants' homes began reaching the new thermostat set-points, HVAC operations resumed. This indicated that proper timing of the events and thermostat adjustment to coincide with AEP Ohio's peak load conditions was a critical component for program success.

Overall, program participants were satisfied with their experience. Customer satisfaction ratings ranged 67 to 76 percent, depending on the program. Program participants perceived an average savings of \$20 per month on their summer electricity costs.



3.8 Lessons Learned

3.8.1 Technology

- Perform thorough testing of all equipment and software in collaboration with vendor suppliers to ensure its readiness for implementation with consumers.
- Engage internal resources to assist with field testing of new technology and equipment to get meaningful feedback that further evolves the programs.

3.8.2 Implementation

- Form close working relationships with vendors and partners from the beginning to ensure strong knowledge transfer, thus creating internal subject matter experts.
- Allow sufficient time in the project plan to ensure the technology and processes are tested and ready for public implementation to save time and costs and preserve positive consumer perceptions.
- Provide in-depth training for participating consumers to help them better understand how to use the equipment and what to expect prior to or at the time of installation.
- When developing and implementing this kind of new technology, be sure to provide in-depth communication and training to regulators, so they better understand the full extent and impact of the tariffs and riders being requested. This Project required regulatory approval for various tariffs associated with the consumer programs. AEP Ohio met with regulators throughout the program onset to review tariff designs, potential participant impacts and overall program goals. Modifications to most of the programs resulted from these reviews.
- Carefully plan time-sensitive pieces of the proposed tariffs and riders to ensure coordinated timing with the actual rollout of technology and equipment to consumers.

3.8.3 Operations

- Consumer service groups and representatives must be fully trained and ready to support consumer inquiries immediately upon installation of new equipment and implementation of programs. An example of specialized training is ping/poll functionality.
- A focus on tight communication between the various impacted areas is necessary to ensure readiness for upcoming called events and pricing.
- The scope and depth of this new technology requires cooperation and communication across impacted functional teams.



4 DEMONSTRATED TECHNOLOGY – REAL-TIME PRICING WITH DOUBLE AUCTION

4.1 Purpose

The Real-Time Pricing with double auction (RTP_{da}) project was an experimental, collaborative research project between American Electric Power (AEP), AEP Ohio, Battelle, and Pacific Northwest National Laboratory (PNNL).

Branded as SMART ChoiceSM, the RTP_{da} program offered participating consumers an opportunity to take advantage of variable electric prices over the course of a billing cycle. The RTP_{da} consumer program gave the electricity consumer choices to effectively manage their own power usage in a more intelligent and informed manner. The program offered a complete demand response system that collected real-time market prices, so consumers could self-manage their power usage based on market price and comfort settings they controlled on their thermostats.

Throughout the operations phase of the project, RTP_{da} experiments were performed and analysis was conducted to assess the impacts and effectiveness of the research project based on the following objectives:

- Identify energy and demand changes.
- Determine benefits for both consumer and utility.
- Determine ability to manage distribution circuit load during congestion events.
- Determine technical and operational feasibility of a large scale deployment.
- Document lessons learned, technical and operational gaps, and overall consumer experience and satisfaction.

4.2 Technology

The RTP_{da} program was a complex combination of several internal and external systems and data sources, many of which were linked together for the first time. The interdependent data flow between devices and systems was critical for RTP_{da} to function properly.

RTP_{da} participation was predicated on the consumer having an AMI meter. In addition, consumers were given two pieces of hardware – a Home Energy Manager (HEM) and an enhanced Programmable Communicating Thermostat (ePCT). The HEM was the central premises controller that contained the integral logic that allowed RTP_{da} to function properly.

Real Time Pricing With Double Auction



4.2.1 Home Energy Manager (HEM)

The HEM was a customized piece of hardware that communicated with the following:

- AMI meter at the consumer's home
- ePCT
- Smart Grid Dispatch (SGD) system at AEP's operations center

The HEM monitored and controlled the ePCT within the home based on settings the consumer selected.



To ensure security, the HEM used Secure Sockets Layer (SSL) encrypted communications to send information to and from the SGD application via a cellular network. To further enhance security, a unique security certificate for each HEM was created. This security certificate was verified against the list of valid certificates and against the list of certificates that had been revoked before any communication took place.

4.2.2 Enhanced Programmable Communicating Thermostat (ePCT)

The customized ePCT was controlled by the HEM, provided real-time control of the HVAC temperature setting, and acted as the interface between the HEM and the consumer. The ePCT display provided the consumer with the estimated price for electricity, in \$/kWh, for the 5-minute interval.



Real Time Pricing With Double Auction



4.2.3 Real Time Pricing Integration Layer

The Real-Time Pricing Integration Layer (RTPi) was critical to all RTP_{da} functions (see figure below). The RTPi was a complex platform used to route data between back office applications, including Meter Data Management (MDM), AEP Cost Engine (ACE), and SGD.

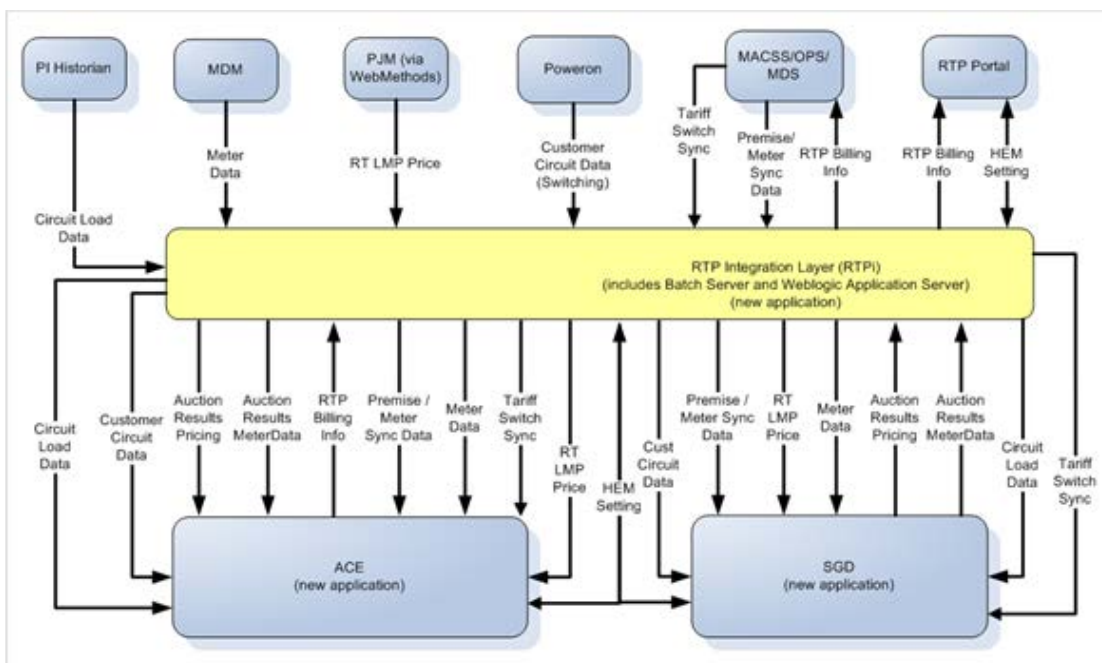


Figure 74. RTPi

4.2.4 Smart Grid Dispatch

The Smart Grid Dispatch (SGD) subsystem functioned as the primary interface between the HEM and AEP’s back office systems via the RTPi. The SGD managed the auction process for the markets within the RTP_{da} program.

For the RTP_{da} program, consumers who were served from one of four AEP Ohio distribution circuits within the Project area were eligible to participate. Each of the four distribution circuits was considered a separate market; the four individual markets ran simultaneously. The SGD managed the electricity market for each distribution circuit.

4.2.4.1 Performance Monitoring and Control User Interface

The Performance Monitoring and Control (PMC) application was the utility interface into the SGD. The PMC allowed the authorized utility operator to adjust system settings as well as view pertinent real-time data. The figure below illustrates the home page of the PMC and available features.

Real Time Pricing With Double Auction



Figure 75. PMC Home Page

PMC Functionality

The Market Data function provided a view of historical cleared price data for each distribution circuit presented in graphical form. The operator could click on any point on the graph and view the supply and demand curves for a particular 5-minute interval.

The HEM Status function allowed authorized operators to view the HEMs by status. Operators could also view HEM events for a particular date range. Examples of HEM events included loss of cellular communication and hardware events.

The Consumer Information function allowed the operator to view various pieces of information and data related to an RTP_{da} participant such as:

- Device history information including Occupancy Mode (home, away, or night), Comfort Setting (slider setting from 0 percent to 100 percent), thermostat set-point, whether or not the thermostat was in override mode, and the observed temperature in the home.
- Meter reading history information including meter register read, reading time stamp, and instantaneous demand reading in kW.
- HEM events and status history

Real Time Pricing With Double Auction



The following figures show two views of the Consumer Information screen.

ABOUT

SMART GRID DISPATCH

[Home](#) | [Market Data](#) | [HEM Status](#) | [Customer Data](#) | [Customer Messages](#) | [SGD Maintenance](#) | [Standard Messages](#)

Customer Information

Customer Descriptor: 108242300 Premise Descriptor: 108242300 [Return to Customer List](#)

Tarriff : 045 Firmware Version: 1.1.2.3340 Opt In Setting: Yes

Start Date: End Date:

Device History | Meter Reading History | HEM Events | HEM Status History

Reading Date	Occupancy Mode	Comfort Setting(%)	Customer Override	Set Point(°F)	Observed Temp(°F)	Temperature
12/21/2013 10:02 AM	home	40	Y	70	70.5	
12/21/2013 09:57 AM	night	60	Y	70	70.5	
12/21/2013 09:52 AM	night	60	Y	70	70.5	
12/21/2013 09:47 AM	night	60	Y	70	70	
12/21/2013 09:42 AM	night	60	Y	70	70	
12/21/2013 09:37 AM	night	60	Y	70	70	
12/21/2013 09:32 AM	night	60	Y	70	70	
12/21/2013 09:27 AM	night	60	Y	70	70	
12/21/2013 09:22 AM	night	60	Y	70	70	
12/21/2013 09:17 AM	night	60	Y	70	70	
12/21/2013 09:12 AM	night	60	Y	70	70	
12/21/2013 09:07 AM	night	60	Y	70	70	
12/21/2013 09:02 AM	night	60	Y	70	70	
12/21/2013 08:57 AM	night	60	Y	70	70	
12/21/2013 08:52 AM	night	60	Y	70	69.5	
12/21/2013 08:47 AM	night	60	Y	70	69.5	
12/21/2013 08:42 AM	night	60	Y	70	69.5	
12/21/2013 08:37 AM	night	60	Y	70	69.5	
12/21/2013 08:32 AM	night	60	Y	70	69.5	
12/21/2013 08:27 AM	night	60	Y	70	69.5	

1 2 3 4 5 6 7

Figure 76. Consumer Information - Device History Screen

Real Time Pricing With Double Auction

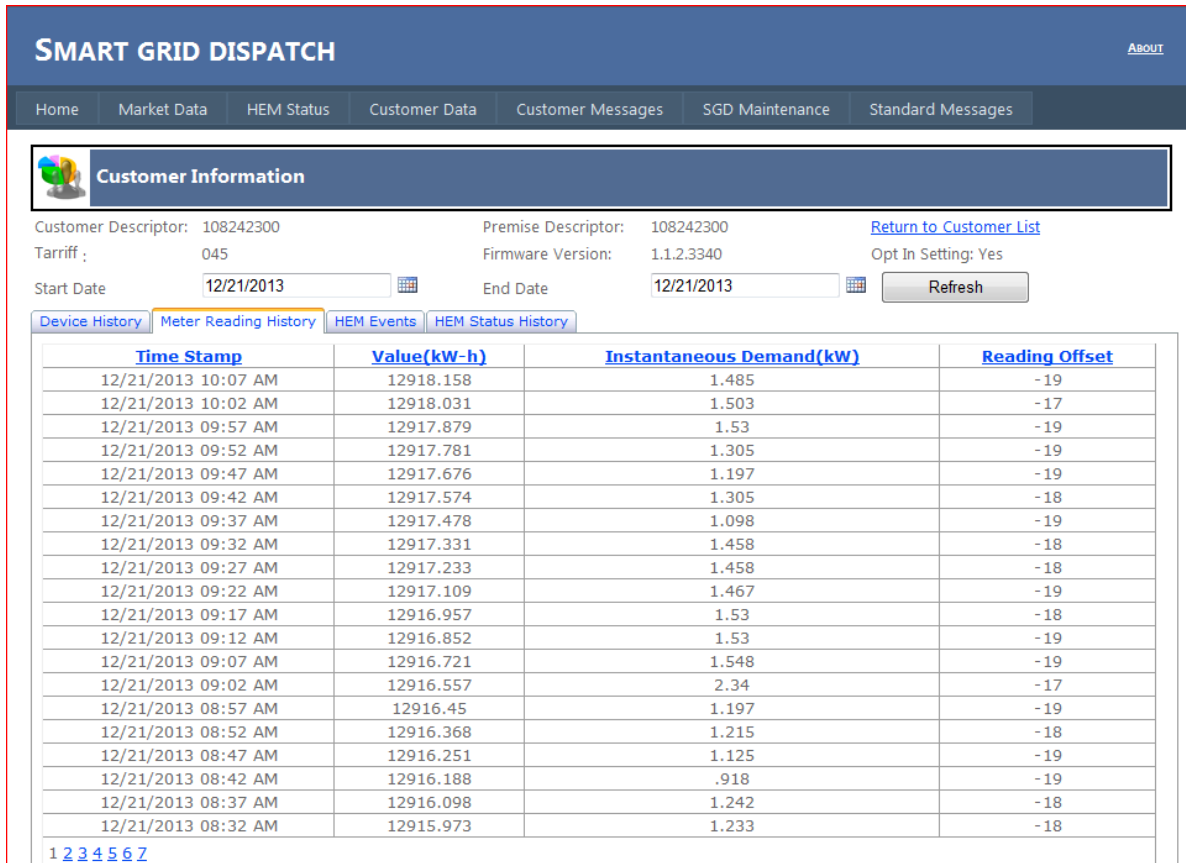


Figure 77. Consumer Information – Meter Reading History Screen

The Consumer Messages and Standard Messages function allowed the utility to initiate messages to consumers, such as program welcome messages or notifications of upcoming congestion test events. Messages could be sent to the ePCTs of the entire RTP_{da} consumer group or to a subset of consumers.

The SGD Maintenance function provided access to the following features:

- Circuit Parameters
- Tariff Parameters
- Global Parameters

The circuit parameters included the rated circuit capacity, the circuit capacity percent, and retail cost multiplier (RCM). The circuit capacity percent was lowered during the RTP_{da} experiments to artificially induce congestion on distribution circuits. If the product of rated circuit capacity and circuit percent capacity resulted in a value lower than current circuit load, the circuit would go into congestion.

The RCM price (\$44.25/MWH divided by the average PJM locational marginal price) was used to calculate the auction clearing price during non-congestion intervals (the locational marginal price multiplied by the RCM). The figure below shows an example of circuit parameters data.

Real Time Pricing With Double Auction



SMART GRID DISPATCH ABOUT

Home Market Data HEM Status Customer Data Customer Messages SGD Maintenance Standard Messages

Feeder Parameters

Feeder: 4210 Schedule Changes

Page 1 of 56

Effective Start Date & Time	12/01/2013 12:00:00 AM	11/08/2013 10:00:00 PM	11/08/2013 08:00:00 PM	11/07/2013 08:00:00 PM
Max Feeder Capacity (kW)	null	null	null	null
Feeder Capacity Percent (%)	95	95	13.5	95
Congestion Markdown (\$/MWh)	0	0	0	0
Retail Cost Multiplier	1.379061760778	1.424845736092	1.424845736092	1.424845736092
Rated Feeder Capacity (kW)	9426	9426	9426	9426
Auction Start Time Offset (Secs)	0	0	0	0
Retail Cost Adder (\$/MWh)	0	0	0	0
Reconcile Price Differential (\$/MWh)	0	0	0	0
Sell Bid QQuantity for RTP (kW)	null	null	null	null
	Delete	Delete	Delete	Delete

Figure 78. Circuit Parameters Screen

The Tariff Parameters function allowed the operator to define other riders and taxes that would apply to the consumer’s bill; these would be added to the cleared price to determine an estimated cost of electricity. Updated riders and taxes were provided each month during the program and input into the Rider Tax field in the Tariff Parameters screen. The total (cleared price + rider tax) displayed on the consumer’s thermostat every 5 minutes to give the consumer an estimate of the current cost of energy in \$/kWh.

Security

Access to the PMC interface was restricted to authorized users. Windows-based authentication verified access to the application and Active Directory credentials established on the Domain Controller authenticated each user and determined the level of access.

There were three major categories of access – SGD Admin, SGD Support and SGD Field Rep. The roles are defined below:

- SGD Admin – a limited number of users were designated with this access level since an SGD Admin could change, add, and delete parameters within the PMC as well as decommission HEMs.
- SGD Support – Information Technology (IT) personnel were designated with this access level. SGD Support users could view information and control firmware changes in the HEMs.
- SGD Field Rep – provided read-only access to authorized employees who needed to view information in the PMC.

Real Time Pricing With Double Auction



4.2.5 HEM Bids

The ePCT was configured by the consumer during installation to address their preference for comfort and economy. For each programmed period of operation, the homeowner specified their desired temperature (T_{Set}), their minimum and maximum temperature (T_{Min} , T_{Max}), and their preference for more comfort or more savings through the slider bar. Their slider selection was represented by the slope (k).

The HEM received the 5-minute market price of electricity from the SGD. The HEM kept track of an average price of electricity (P_{avg}). The average was calculated over the previous 24-hour period and was updated each interval to adjust for trends in pricing. The HEM then generated a bid for the associated location. The bid was based on complex algorithms that included but was not limited to the current market price and factors from the ePCT.

In the figure below, an elevated cleared price (P_{clear}) caused the ePCT to offset the set temperature in the house to $T_{Offset Set}$ from T_{Set} . Because the observed temperature in the house, $T_{Observed}$, was lower than the offset set temperature, the bid price (P_{bid}) from the HEM was lower than the cleared price. Because the bid price is less than the cleared price the HEM did not win the auction and the HVAC did not run during that interval.

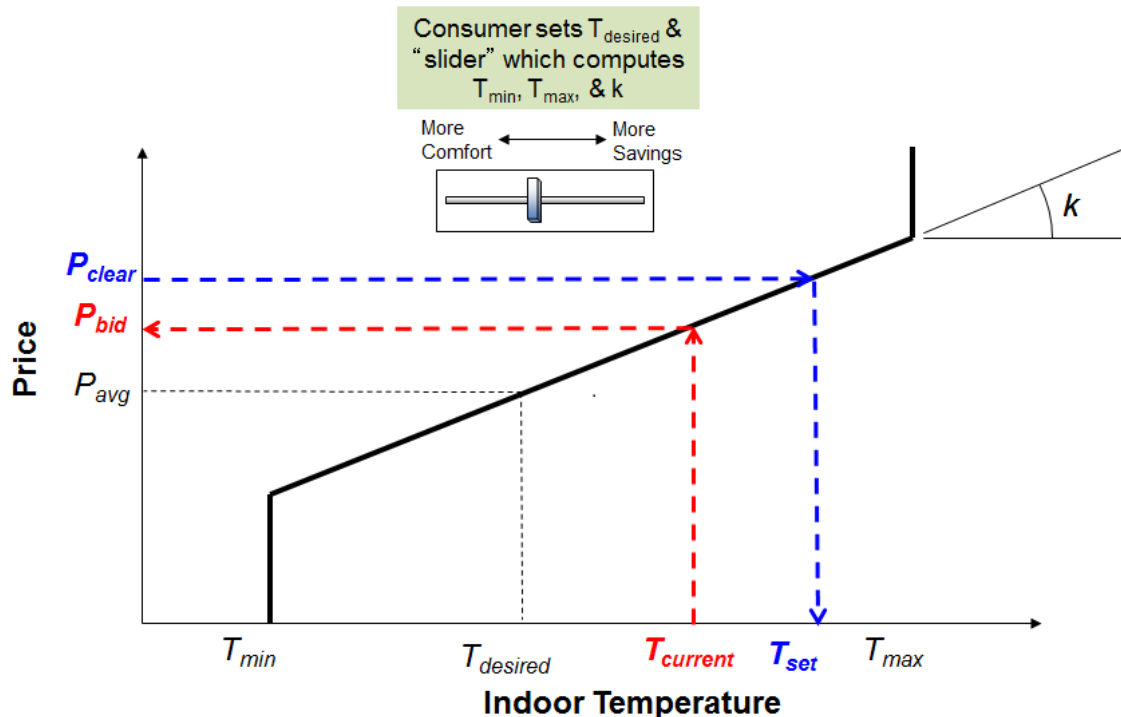


Figure 79. Bid Algorithm Calculation

4.2.6 Auction Process

The SGD aggregated the bids from all households on a given distribution circuit to develop the demand curve. The SGD also developed a supply curve which was a function of the real-time, 5-minute wholesale electricity price from PJM (the Regional Transmission Operator for this

Real Time Pricing With Double Auction



region), the RTP_{da} tariff, and other factors. A cleared price was established by the intersection of the two curves. This cleared price became the new prevailing retail real-time cost for electricity for the next 5-minute period. For illustrative purposes, the figure below shows the supply and demand curves which were generated by SGD using a complex set of algorithms.

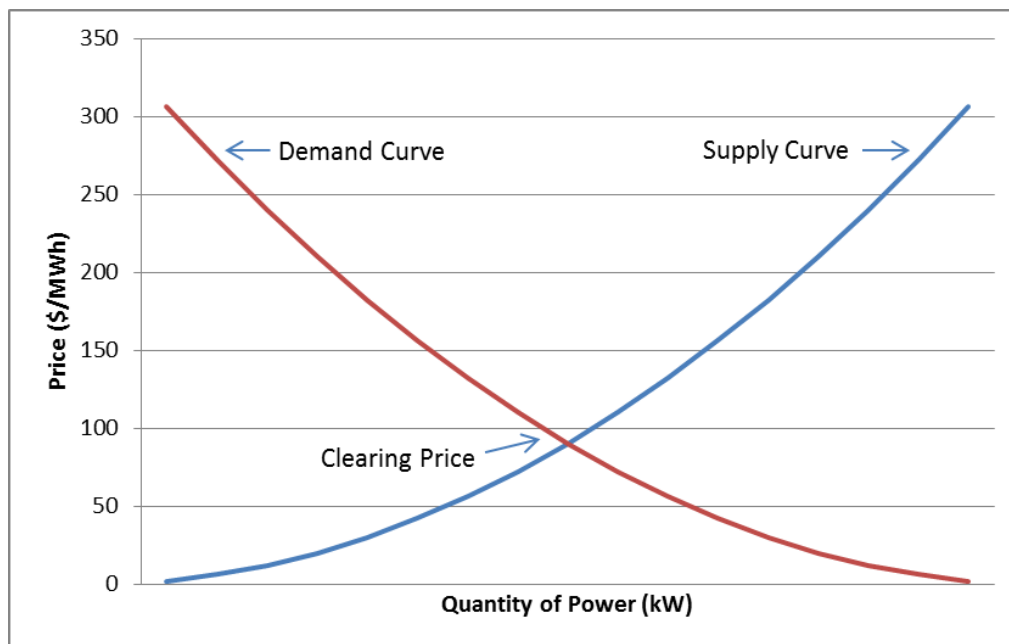


Figure 80. Illustrative Example of Supply Curve, Demand Curve and Cleared Price

The red curve represents the aggregated demand for power during the next increment of time (for example, 5 minutes) and the blue curve represents the supply side of power generation

Energy costs to the consumer increased under certain conditions:

- When demand on a circuit was high, causing it to exceed the circuit congestion limit.
- When the local market price of energy was high.

SGD managed 288 auctions each day for each circuit in the Project area; one for each 5-minute period during a 24-hour day.

Double-auction was a process where bids to buy power (from the HEM) and bids to sell power (from utility) were submitted independently.

Real Time Pricing With Double Auction



4.2.7 AEP Cost Engine

The AEP Cost Engine (ACE) determined the energy cost portion of the consumer's electric bill. ACE used the following types of data to determine the energy cost, including but not limited to:

- Consumer circuit ID
- The 5-minute interval usage
- The associated 5-minute cleared price
- Consumer's bid
- Congestion status

ACE aggregated the cost of energy for each of the 5-minute periods of the billing cycle. ACE then computed any credits the consumer may have earned. There were two possible credits available to the consumer:

- RTP incentive – available when the consumer voluntarily reduced their usage during a congestion event.
- RTP rebate – to ensure the consumer paid no more per KWh than other non RTP_{da} consumers on the same circuit. This provision ensured revenue neutrality.

This data was sent to the AEP billing engine for inclusion on the consumer's monthly electric bill.



4.3 Approach and Implementation

4.3.1 Development and Testing

The SGD and the PMC were developed by Battelle, and the interfaces into the back office systems were developed by AEP.

Due to the complex nature of this experimental program, AEP Ohio elected to perform extensive testing of the RTP_{da} technology before introducing it to the general population of consumers. A fully functioning internal production evaluation environment was installed and AEP employees were invited to participate. This phase of evaluation was called the Virtual Operations Test (VOT), which allowed AEP to exercise the software with real consumers to ensure the technology operated as expected. After the successful VOT, the RTP_{da} program was rolled out to AEP Ohio consumers in the RTP_{da} Project area.

4.3.2 Consumer Outreach – Education, Marketing and Enrollment

RTP_{da}, marketed as SMART ChoiceSM, was included in the overall outreach plan for consumer programs. See the Consumer Programs chapter for additional information.

4.3.3 Customer Service

Customer service was a high priority for AEP Ohio. In addition to AEP Ohio's normal customer service, the following steps were taken to ensure RTP_{da} consumers were satisfied with the experimental program.

- Due to the complex nature of the RTP_{da} program, all enrollments and equipment installations were closely monitored.
- The primary contact for the RTP_{da} consumers was an outside organization (call center) that was specifically trained on the RTP_{da} operation. A dedicated toll free number was provided to all RTP_{da} consumers.
- AEP Ohio internal resources were available 24 x7 to answer any questions the call center could not resolve or inquiries from consumers who contacted AEP Ohio directly.
- A service representative was dispatched immediately to resolve any issues with the installed equipment, up to and including replacement of a device.

Real Time Pricing With Double Auction



4.3.4 Consumer Survey Results

Consumers participating in the RTP_{da} offering were surveyed at selected points in time in order to quantify their overall satisfaction with the program. AEP contracted with an independent third party research firm for most of the consumer research reported here.

The final survey was administered to eligible RTP_{da} participants (HEM and ePCT installed and functional for a minimum of 30 days) as of 12/02/2013. Of the 256 eligible RTP_{da} consumers there were 154 completed surveys. The focus of this survey was to gauge participant final perceptions of the program.

Overall satisfaction with the RTP_{da} program was at 76.4 percent (total “satisfied” and “very satisfied” responses), the highest level measured over the three RTP_{da} participant surveys. This represents a slight gain from the 69.8 percent recorded in the SMART Choice Survey #2 and a return to the early satisfaction level of 73.8 percent noted in SMART Choice Survey #1.

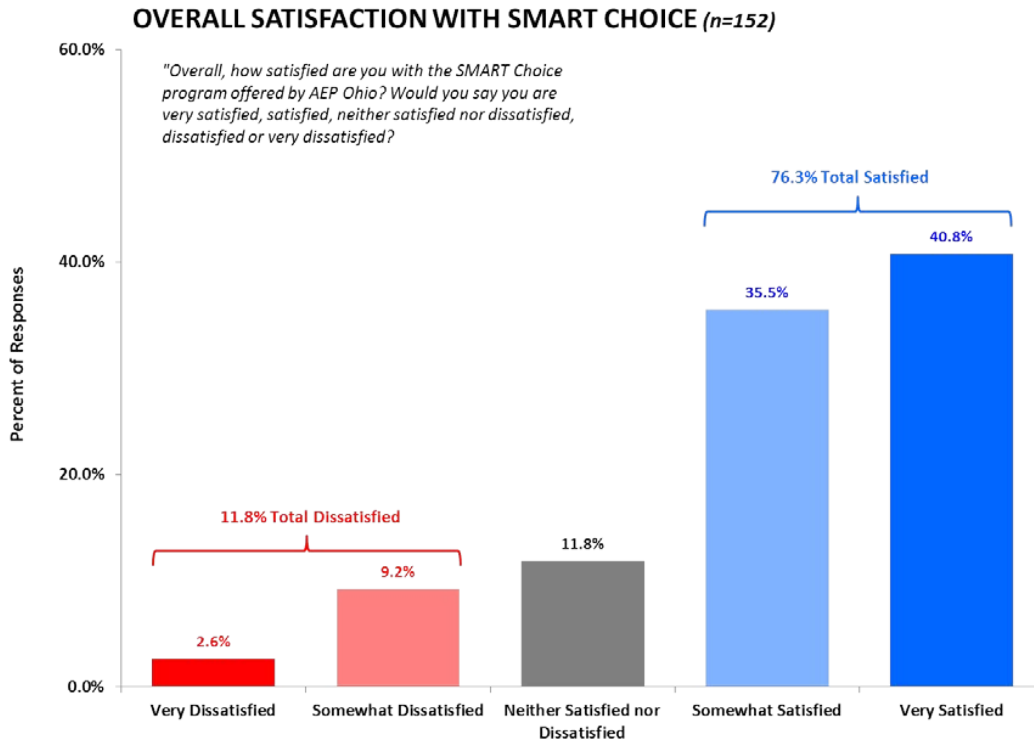


Figure 81. Overall Satisfaction with SMART Choice (RTP_{da})

Real Time Pricing With Double Auction

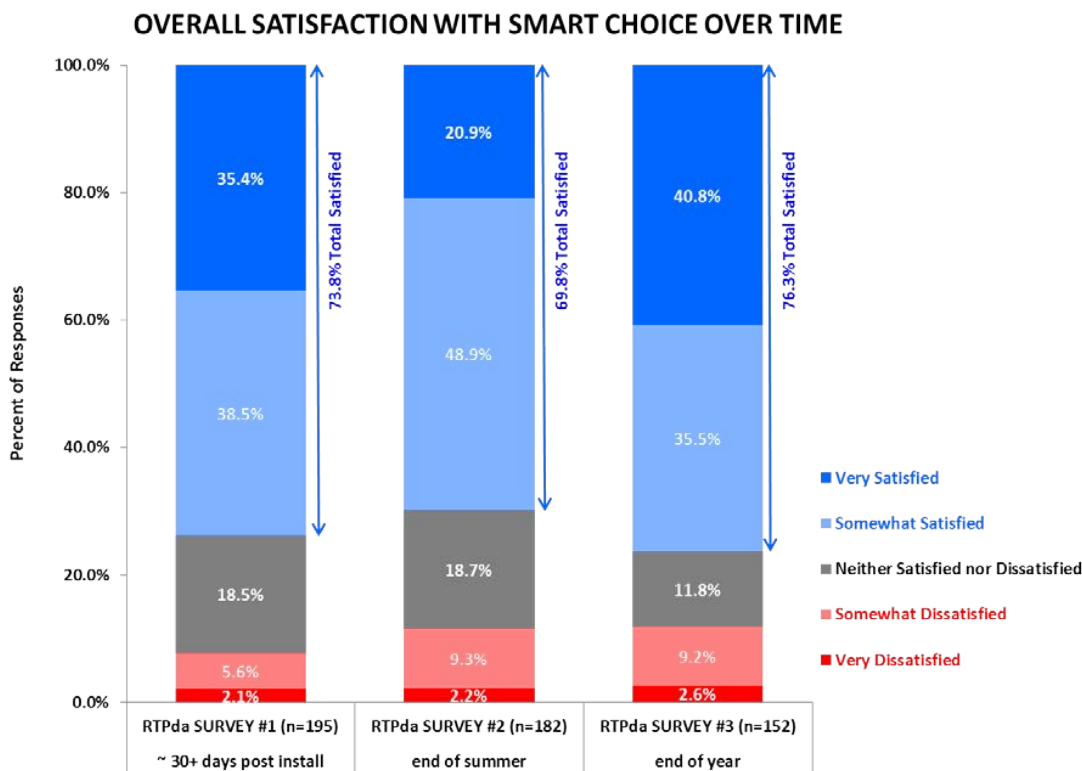


Figure 82. Overall Satisfaction with SMART Choice (RTP_{da}) Over Time

When participants were asked about the perceived impact of the RTP_{da} program on their monthly electric bills, about half (51.4 percent) indicated it either ‘decreased slightly’ (37.2 percent) or ‘decreased’ (14.2 percent). The average reduction in the monthly bills attributed to the RTP_{da} program for these individuals was \$22.15. Some respondents (9.5 percent) indicated that the program resulted in their monthly electric bills either “increased slightly” (6.1 percent) or “increased” (3.4 percent) with the average monthly increase at \$22.23.

Real Time Pricing With Double Auction

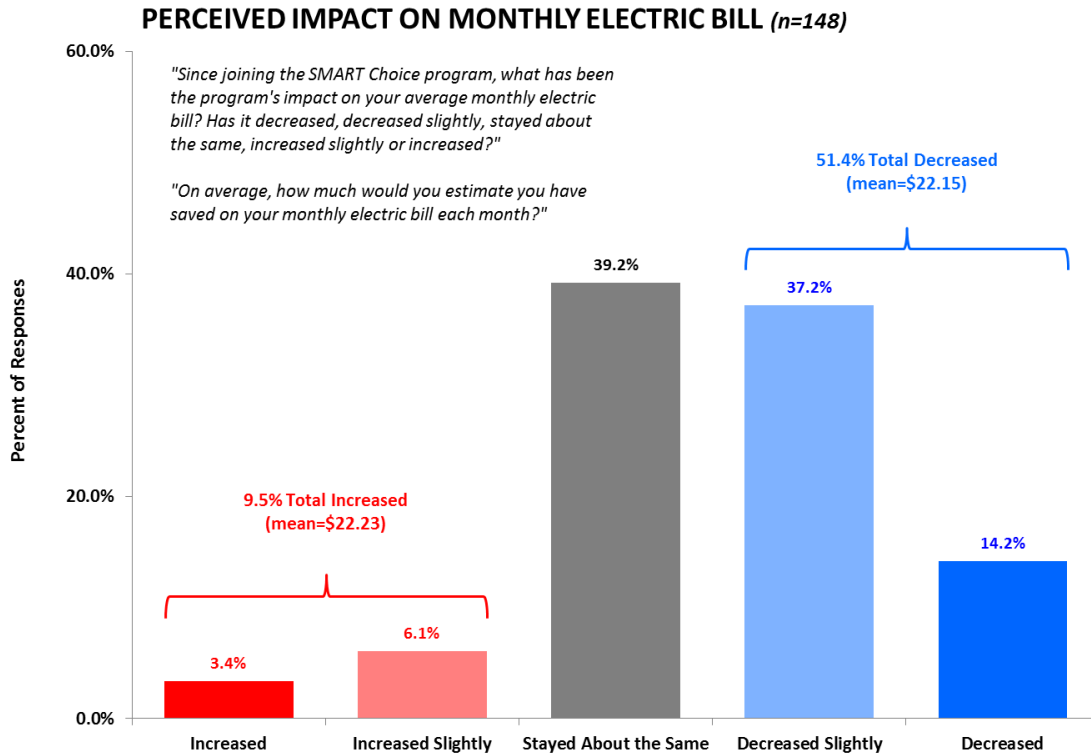


Figure 83. Perceived Impact on Monthly Electric Bill

4.4 Data Collection Results

This section is broken out into three levels to detail the impacts and performance and their propagation in the RTP_{da} project.

- The most basic level is the HEM at consumer premises. This is the primary building block of the entire RTP_{da} system. This level contains the consumer response to market fluctuations and circuit congestion.
- The next higher level is the aggregation of all HEMs on a circuit. At a circuit level the utility starts to see how the aggregated HEMs impact the distribution network. The utility can see the impact during peak load hours, congestion events and high price periods.
- The highest level is the circuits aggregated to a program level. At this level the utility can see the impacts across multiple circuits and can determine the overall average impact. This allows the utility to perform comparative analysis against the other consumer programs.

Real Time Pricing With Double Auction



4.4.1 Experiments

4.4.1.1 Non-Experiment

During normal operation of the RTP_{da} project, the HEM monitored the cost of power to the consumer at 5-minute intervals. At each interval the HEM adjusted the set temperature of the ePCT and the bid price based on the cleared price and the observed temperature in the house. If the price fluctuated significantly during an interval, the HEM offset the set temperature in the ePCT to reduce the power consumed during the higher price interval.

4.4.1.2 Experiments

For the RTP_{da} project, experiments were initiated to test the functionality of the system as well as to test consumer response to pricing events. During an experiment, artificial congestion was placed on the circuits using the PMC application. The simulation was accomplished by lowering the rated circuit capacity of each distribution circuit to a point that was lower than the current circuit load. This artificially induced congestion caused the pricing portion of the double auction algorithm to reach the price cap of \$1,000/MWh, which was a user-defined default setting in the PMC. The pricing spike caused the HEMs to offset the set temperature in the ePCT based on consumer-defined slider settings. To fully test system functionality, these experiments were performed over a broad span of days and times. In total, 96 experiments were run, providing a total of 293 hours of testing.

The table below presents a density chart of the experiments performed during the RTP_{da} program over various timeframes. As an example, of the 293 hours of testing performed, 12.35 percent of the total hours were performed on a Sunday with 4.53 percent of the total hours done on a Sunday between 3 p.m. and 5:55 p.m.

	12am - 5:55am	6am - 8:55am	9am - 11:55am	12pm - 2:55pm	3pm - 5:55pm	6pm - 11:55pm	Total
Sunday	0.00%	1.23%	1.23%	4.12%	4.53%	1.23%	12.35%
Monday	0.00%	0.00%	0.82%	1.99%	8.68%	3.74%	15.23%
Tuesday	0.00%	0.82%	0.38%	3.29%	11.90%	2.47%	18.87%
Wednesday	0.41%	2.88%	1.17%	3.53%	5.63%	0.69%	14.31%
Thursday	0.00%	0.82%	1.54%	2.13%	10.67%	3.70%	18.87%
Friday	0.00%	0.82%	0.34%	2.74%	1.65%	4.94%	10.50%
Saturday	0.00%	0.41%	3.70%	3.70%	1.23%	0.82%	9.88%
Total	0.41%	7.00%	9.19%	21.51%	44.29%	17.60%	

Table 17. RTP_{da} Experiments Density Chart

Real Time Pricing With Double Auction



The figure below is an expanded graphical representation of the table above. The majority of events (approximately half of the total experiment hours) were conducted between 3 p.m. and 5:55 p.m. This time frame was typically when AEP Ohio experienced a peak load hours event.

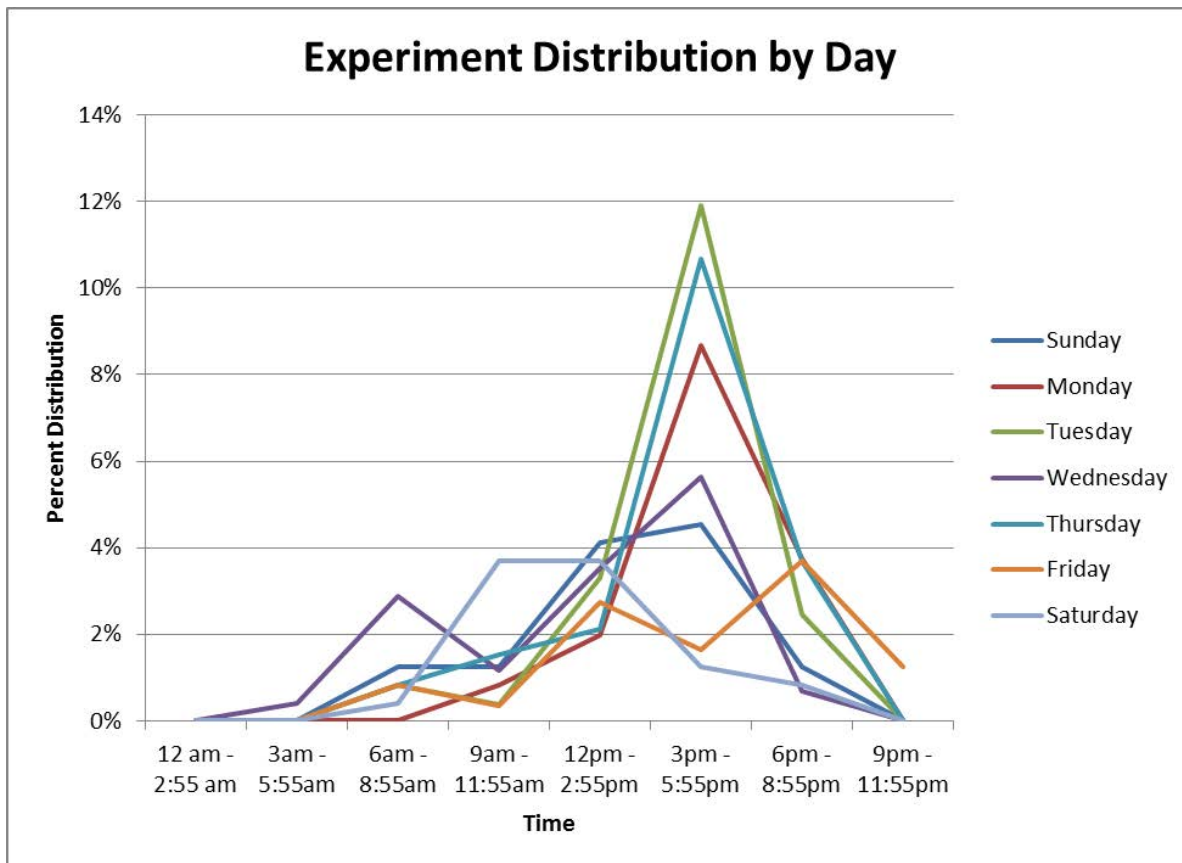


Figure 84. Hourly Distribution of RTP_{da} Experiments

Real Time Pricing With Double Auction



The figure below illustrates the hourly distribution of RTP_{da} experiments; some congestion events were induced to coincide with Critical Peak Price (CPP) events.

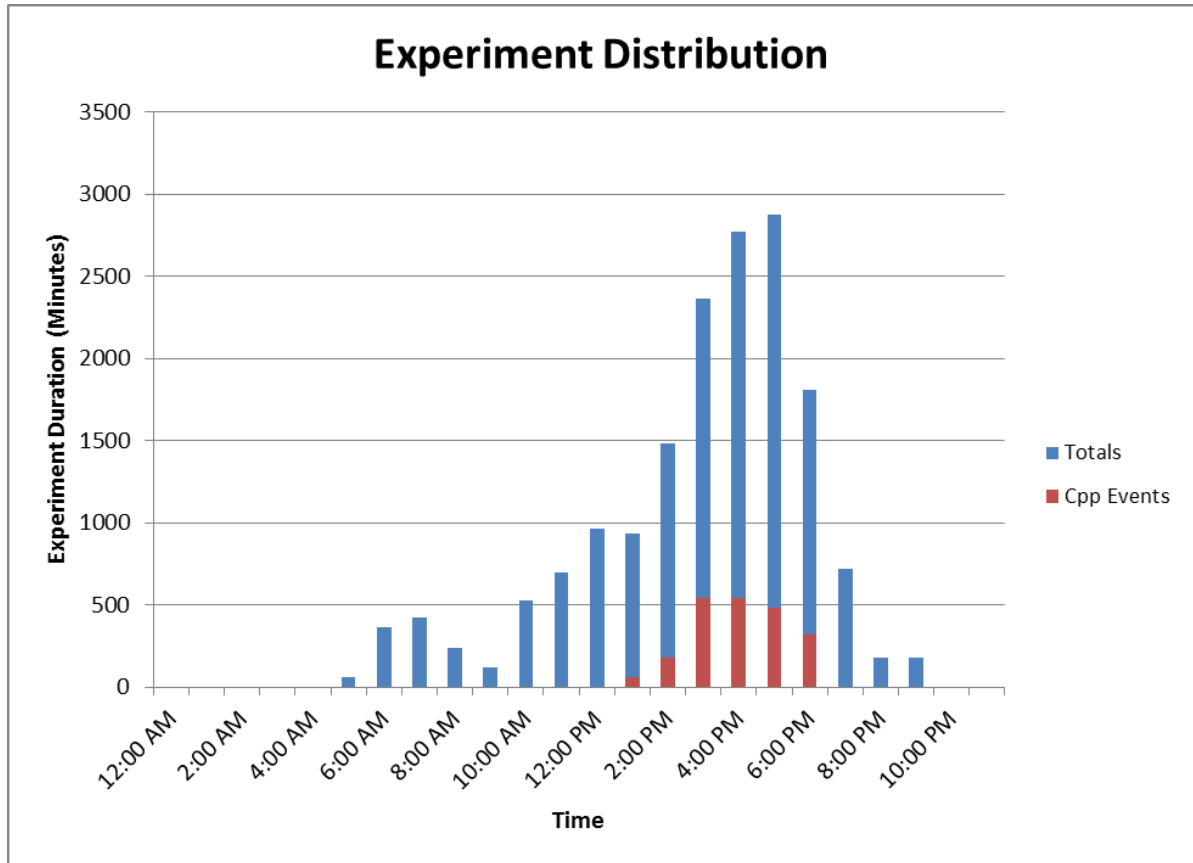


Figure 85. RTP_{da} Experiment Distribution by Day and Time

4.4.2 Consumer Level - HEMs

4.4.2.1 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data:

- The described behavior of a HEM was applicable during the summer season.
- During the summer season, there was no restriction on time of the experiments or the duration.
- The described behavior of a HEM applied to HEMs that had been commissioned and were fully operational.
- The described behavior of a HEM applied to HEMs that were not placed on hold via the ePCT by the consumer.

Real Time Pricing With Double Auction



4.4.2.2 Hot Day

On days with elevated temperatures, the HEM responded as anticipated and reacted to Locational Marginal Price (LMP) price spikes. On days when artificial congestion was induced these reactions were much more pronounced. When the HEM registered that the cleared price hit the price cap, it offset the set temperature of the ePCT to the maximum offset based on the consumer settings. As time progressed, the observed temperature inside the premises increased due to the elevated exterior temperature. In response, the HEM began to increase the bid price during each auction. The observed temperature in the premises continued to climb reaching the new set temperature. Once the observed temperature exceeded the offset set temperature, the HEM instantaneously increased the bid price to the maximum placing the HEM into a *must-run* state. During the *must-run* state, the HEM kept the bid price equal to or higher than the cleared price. In a *must-run* state the HEM will not issue any further temperature adjustments to the ePCT.

At the end of the experiment or when congestion was no longer an issue, the cleared price would begin to fall. This change caused the set temperature of the ePCT to return to its programmed value. The HEM stayed in a *must-run* state until the observed temperature was less than or equal to the set temperature, and the HEM lowered its bid price and returned to normal participation in the auctions.

The figure below illustrates a HEM-level view from a non-experiment hot day.

- When the observed temperature (red line) was less than the set temperature (dark blue line) the bid price (green line) was less than the cleared price (purple line). In these intervals the HEM had not won the auction.
- When the observed temperature was higher than the set temperature, the bid price was greater than or equal to the cleared price. In these intervals, the HEM won the auction. On this day there was no experiment scheduled, so the LMP was the major influencing factor on the oscillation in the set point.

This effect occurred at approximately 11 a.m. through 4 p.m. as the LMP (light blue line) fluctuated. This fluctuation caused the cleared price to fluctuate proportionately. As the cleared price rose and fell during this period, the set temperature mirrored the movement, shifting the temperature up during higher priced intervals and back down during lower priced intervals.

Real Time Pricing With Double Auction

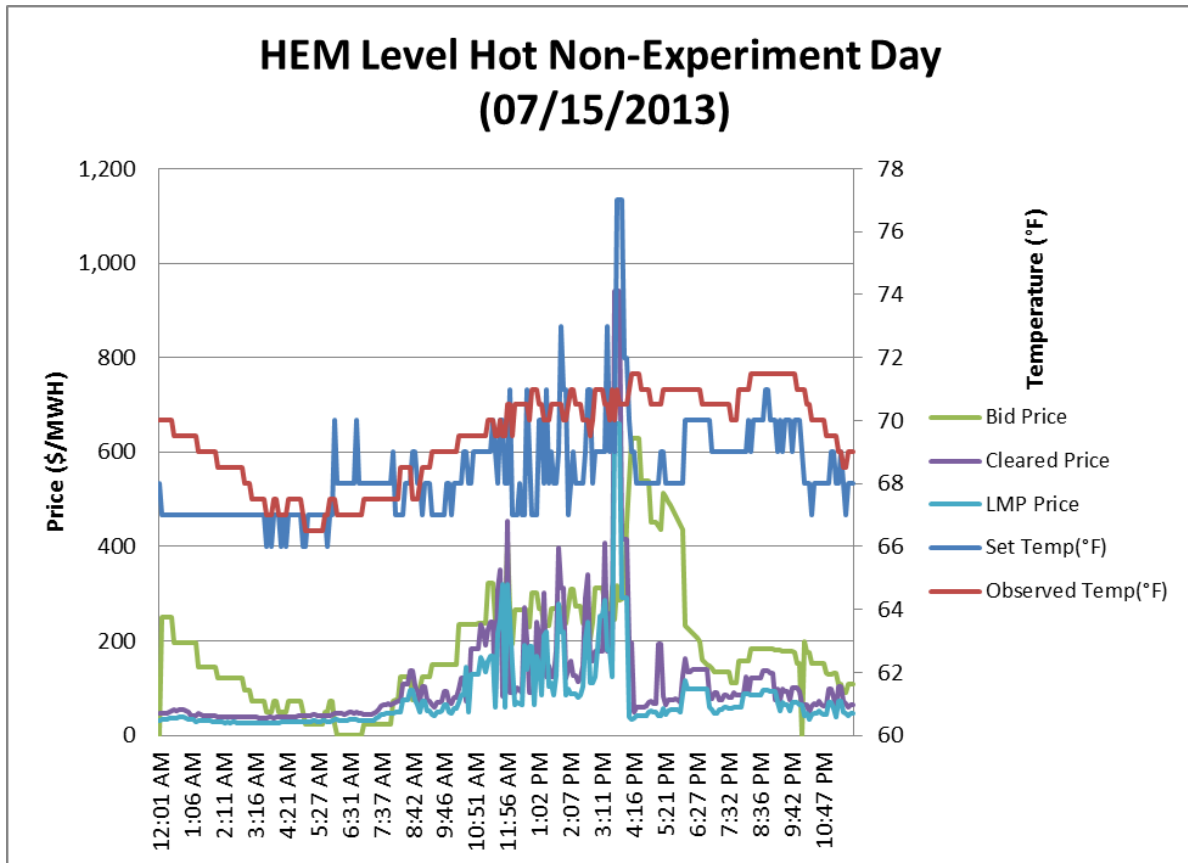


Figure 86. HEM Level Hot Non-Experiment Day

The figure below illustrates a HEM level view from an experiment on a hot day.

- When the observed temperature (red line) was less than the set temperature the bid price (green line) will be less than the cleared price, (purple line). In these intervals the HEM had not won the auction.
- When the observed temperature is higher than the set temperature the bid price will be greater than or equal to the cleared price. In these intervals the HEM won the auction. On this day the, prior to the experiment, the set temperature in the house (dark blue line) fluctuates slightly during the day based on the cleared price and the consumer’s slider settings. At 1 p.m. a congestion event started and the cleared price offset to the max bid price independent of the LMP price (light blue line).

During this event the set temperature offset from 68°F to 77°F. During the event the observed temperature climbed causing the bid price to rise. At approximately 4 p.m. there was a change in the consumer setting that caused the set temperature to drop to 73°F. The new set temperature was lower than the observed temperature causing the bid price to spike to the max bid price. With the cleared price equal to the bid price, the HEM won the auction and began to cool the house. The observed temperature was greater than the set temperature for the remainder of the day as the house rebounded from the experiment.

Real Time Pricing With Double Auction

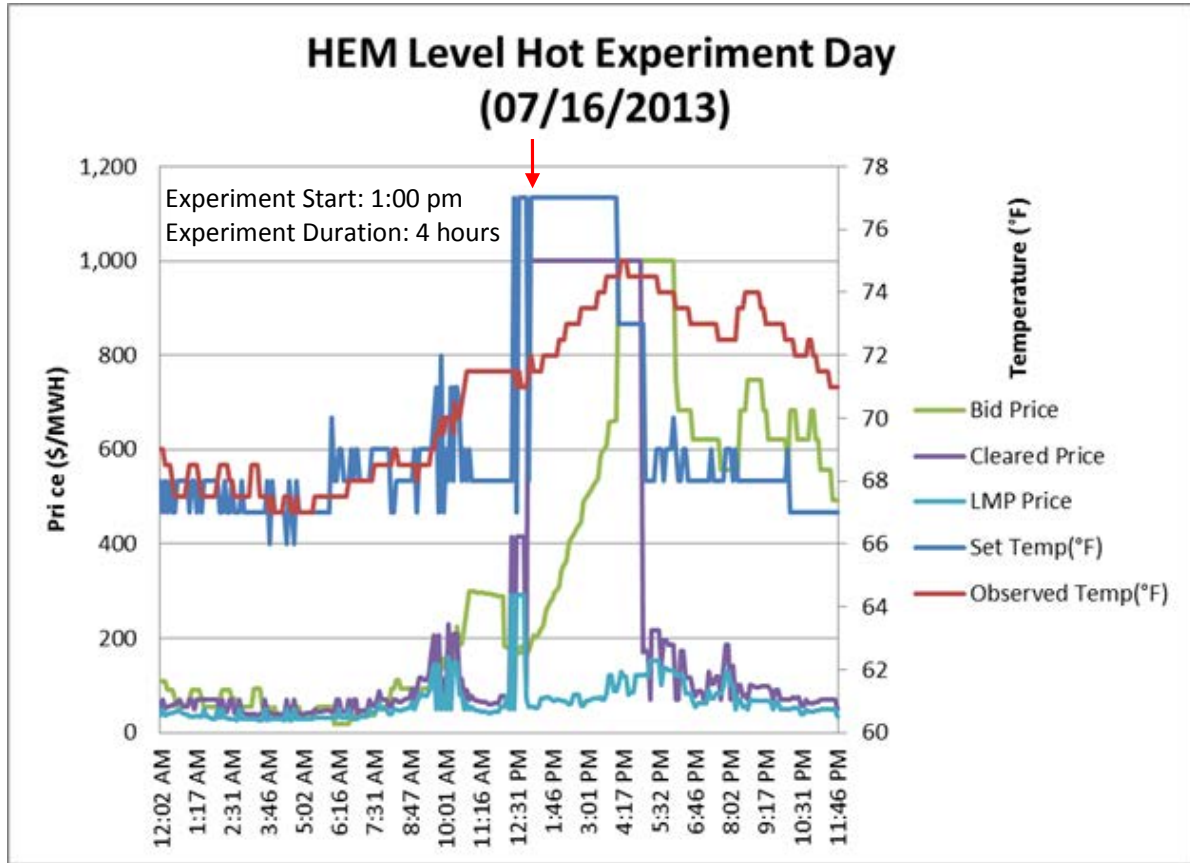


Figure 87. HEM Level Hot Experiment Day

4.4.2.3 Cold Day

On an experiment day with lower outside temperatures, the consumer level system reacted as expected. At the point where congestion was applied to the circuit, the cleared price responded by increasing to the price cap. The set temperature of the house offset to the maximum allowed temperature. However, the reduced exterior temperature caused the interior temperature of the premises to rise at a much slower pace. The HEM responded by keeping the bid price lower than what was observed during hot days. Consequently, the HEM never reached a must-run state leading to a reduced premises temperature recovery time after the congestion event.

The figure below illustrates a HEM-level view from a non-experiment cold day.

- When the observed temperature (red line) was less than the set temperature, the bid price (green line) was less than the cleared price (purple line). In these intervals, the HEM did not win the auction.
- When the observed temperature was higher than the set temperature, the bid price was greater than or equal to the cleared price. In these intervals, the HEM won the auction.

Real Time Pricing With Double Auction



On this day there was not an experiment scheduled, so the LMP was the major factor impacting the set temperature. On this day the LMP did not fluctuate through a wide range, which caused fewer set temperature changes than on the hot day. During this day there were only a few intervals in the morning when the observed temperature was higher than the set temperature causing the bid price to raise past the cleared price.

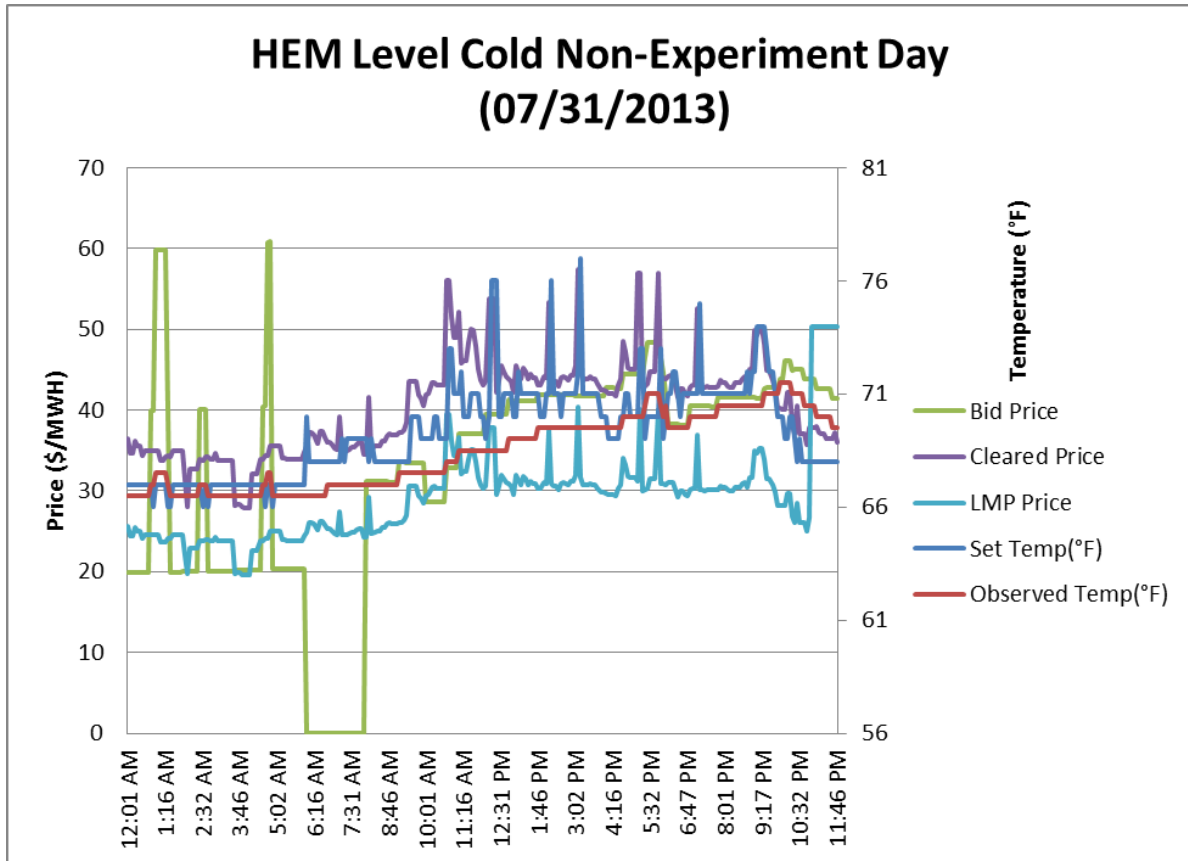


Figure 88. HEM Level Cold Non-Experiment Day

Real Time Pricing With Double Auction



The figure below illustrates a HEM level view from an experiment on a cold day.

- When the observed temperature (red line) was less than the set temperature (blue line), the bid price (green line) was less than the cleared price (purple line). In these intervals, the HEM did not win the auction.
- When the observed temperature was higher than the set temperature, the bid price was greater than or equal to the cleared price. In these intervals the HEM won the auction. At 5 a.m. a congestion event started causing the cleared price to rise to the max bid price thereby causing the set temperature to rise from 68°F to 75°F.

During this event there was not a significant climb to the observed temperature because of the colder outdoor temperature. Because there was not a significant climb to the observed temperature, the bid price remained much lower during the experiment. The experiment was released at 7 a.m. Because there was little deviation to the observed temperature, there was little to no rebound period after the event.

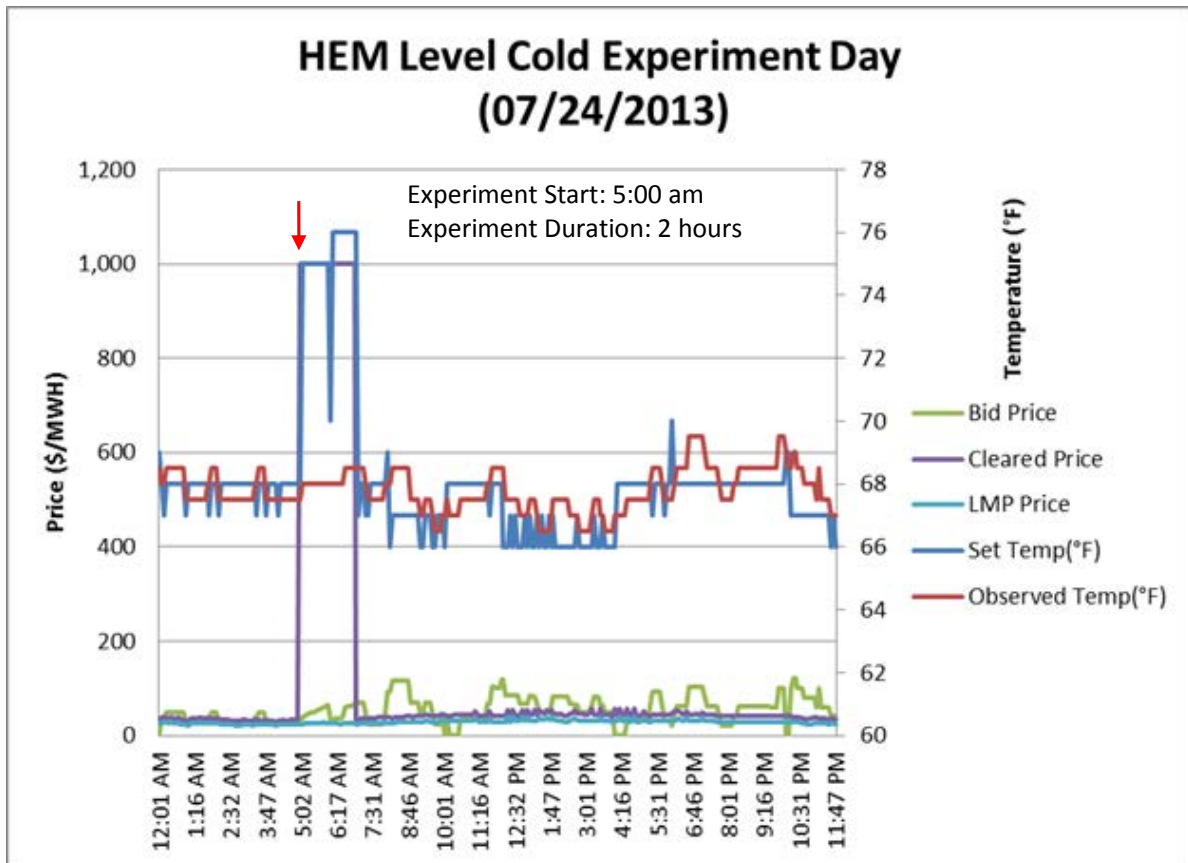


Figure 89. HEM Level Cold Experiment Day



4.4.3 Distribution Circuit Level

4.4.3.1 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data:

- The described behavior of a circuit applied during the summer season.
- During the summer season, there was no restriction on time of the experiments or restrictions on the duration of the experiments.
- During the experiments, no RTP load shifted from the experiment circuits.
- The described behavior of the circuit applied to intervals when there were no communication or back office data issues.

4.4.3.2 Calculation Approach

The RTP_{da} project had participants on four different distribution circuits. The system allowed for the tracking and recording of:

- Responsive load – the sum of all the RTP_{da} HVAC loads on the circuit.
- Active load – the amount of responsive load that cleared to run in the market period – participation in an auction.
- Inactive load – the amount of responsive load that did not clear to run in the market period – nonparticipation in an auction.
- Unresponsive load – the total circuit load minus the responsive load during the market period on the circuit.

The RTP_{da} circuit loads included the unresponsive load, which were those consumers not participating in the RTP_{da} program, and the responsive load or those consumers who were enrolled in the program. The active load and inactive load values were included in the responsive load portion of the circuit. These values represented the load on the circuit that contributed to the RTP_{da} load. At a circuit level, these values are the sum of all of the HEMs participating at each interval. During a congestion event these load values responded according to market prices and the user settings on each ePCT on that circuit.

The load response was based on several criteria. During a congestion experiment the resources were purposefully engaged. At the start of the experiment, the responsive load was reduced as the HEMs offset their set temperatures due to the price increase. As the experiment continued, the responsive load remained suppressed, reducing the total load on the circuit. On a hot day the observed temperatures in the premises climbed. Because of the individual HEM settings, the houses on the circuit reached their offset set temperature at different times. The load slowly ramped back up in the congestion period as the resources were exhausted. If the congestion were to remain in place on the circuit, all of the resources on the circuit would eventually become exhausted and the load reduction on the circuit would be minimal.

Real Time Pricing With Double Auction



These results were obtained by inducing congestion on days when peak demand reduction was needed. On days that peak demand reduction was required, the consumer was typically consuming power with their HVAC because of the high outside temperatures. The induced congestion released those power resources allowing maximum reduction. This method was used on several days during the experimental period. On a day with high forecasted loads, congestion events were scheduled to coincide with the critical peak pricing (CPP) program. A congestion event was also used during the PJM emergency demand response event to assist with overall load reduction.

The results on a cooler day are slightly different. As with the hot day, an initial responsive load reduction occurred at the start of the experiment. The cooler temperatures reduced the initial load reduction because of a smaller number of resources consuming power. The lower temperatures diminished the ramp up of the resources during the congestion event, allowing the congestion to hold longer on the circuit without the resources being exhausted.

The following figure illustrates a circuit level view from a hot non-experiment day. The blue line represents the total load on the circuit and the red line represents the total load minus the RTP load. On this day the load curve was a typical summer curve with low circuit load during the morning hours and the load peaking during mid to late afternoon. The green line represents the RTP load. During this day the RTP load was only responding to PJM prices. If there was a spike in the PJM price the circuit saw a reduction in RTP load. For example, the PJM price spiked from 3:40 to 3:50 p.m. from \$124 to \$660. This spike caused the RTP load reduction highlighted in the figure with the red circle. The RTP load fluctuated for the remainder of the day due to PJM prices.

Real Time Pricing With Double Auction

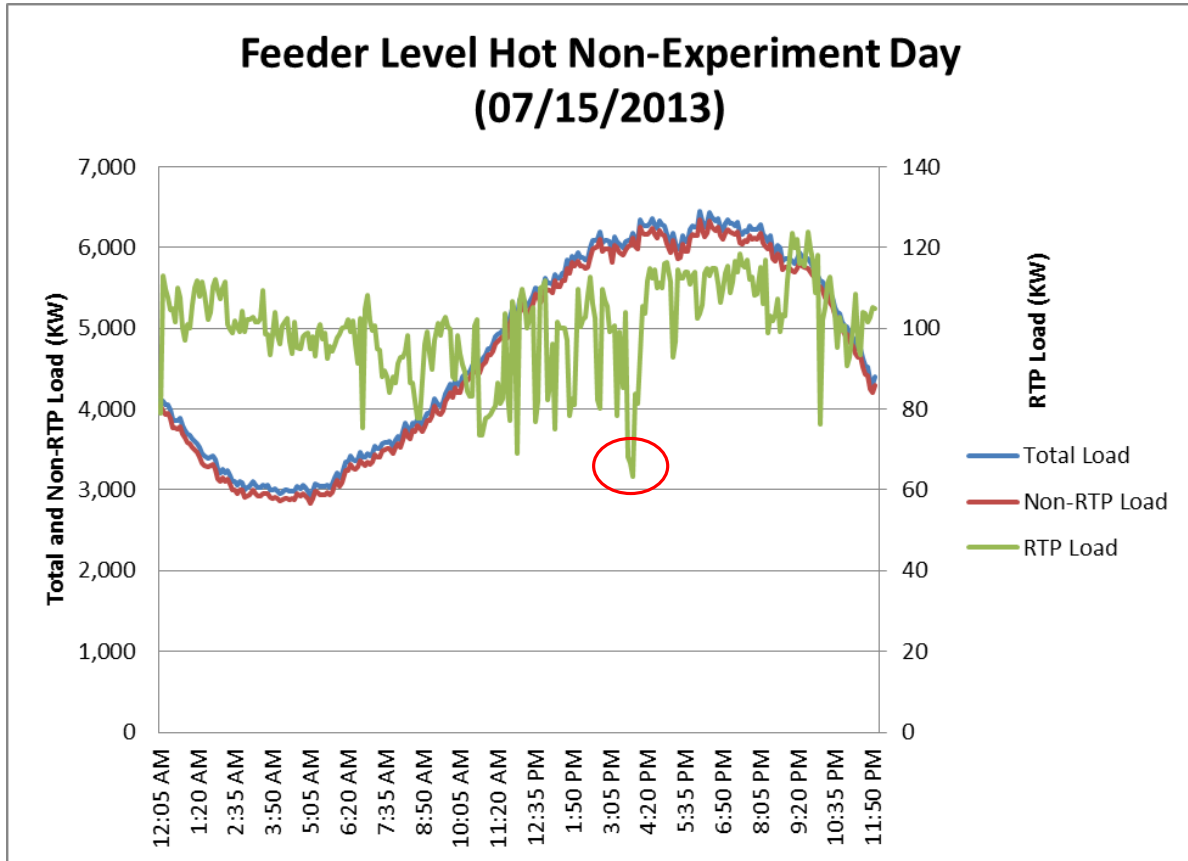


Figure 90. Circuit Level Hot Non-Experiment Day

Real Time Pricing With Double Auction



The figure below illustrates a circuit level view from a non-experiment cold day. The blue line represents the total load on the circuit and the red line represents the total load minus the RTP load. On this day the load curve was close to a typical summer curve with low circuit load during the morning hours and the load peaking during mid to late afternoon; however, it is slightly flatter than a typical summer curve because of the colder temperatures. The green line represents the RTP load. During this day there were no significant reductions and the overall RTP load was down because of the colder temperatures. The RTP load fluctuated for the remainder of the day due to PJM prices.

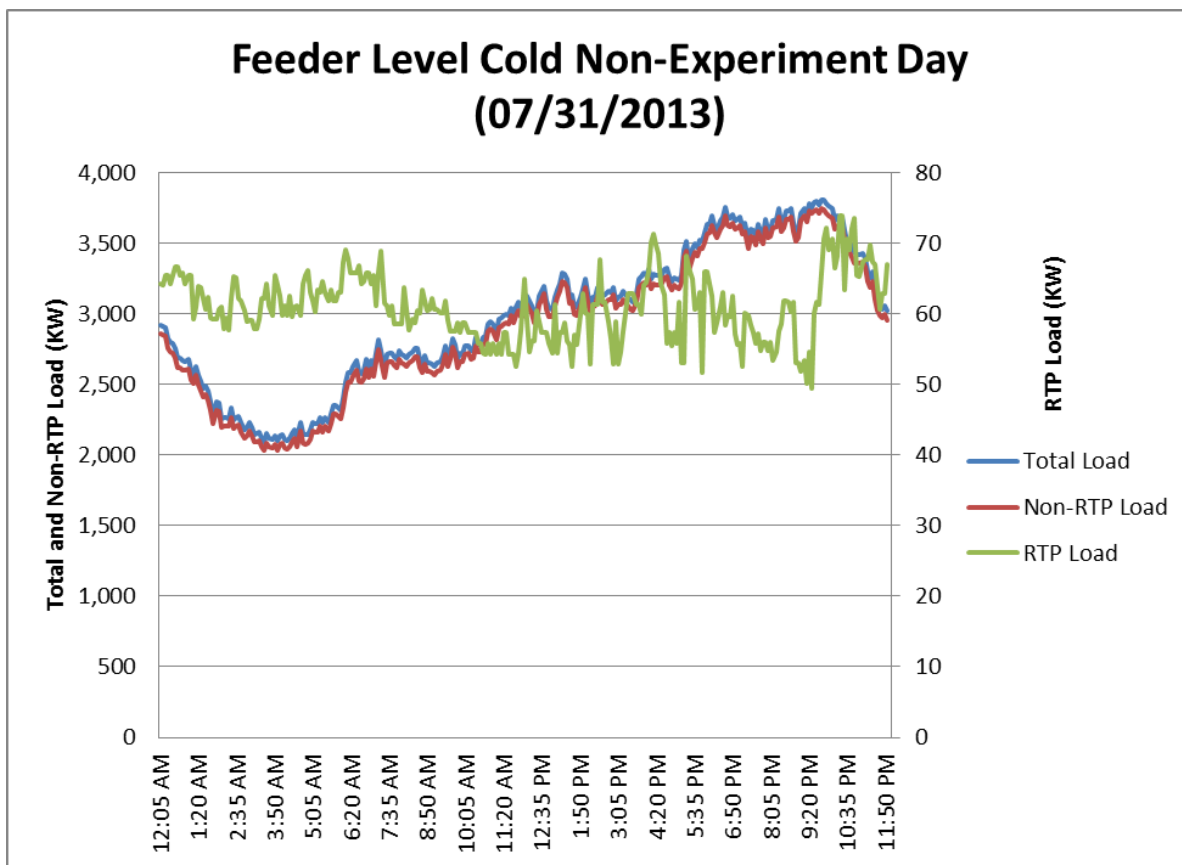


Figure 91. Circuit Level Cold Non-Experiment Day

Real Time Pricing With Double Auction



The figure below illustrates a circuit level view on a hot day. The blue line represents the total load on the circuit, and the red line represents the total load minus the RTP load. On this day the load curve was a typical summer curve with low circuit load during the morning hours and the load peaking during mid to late afternoon. The green line represents the RTP load. During non-experiment hours, the load fluctuation was minimal; however, there was a significant reduction of load shortly before the experiment due to a sharp increase in the PJM price. Once the experiment started at 1 p.m. there was another reduction in RTP load from approximately 100 kW to 60 kW. An overall reduction was sustained through the duration of the experiment; however in this experiment, at approximately 3 p.m., the RTP load started to slowly climb because the HEMs were reaching a must-run state. The RTP load reduction continued until the end of the experiment, and the load was released at 5 p.m. The RTP load fluctuated for the remainder of the day due to PJM prices.

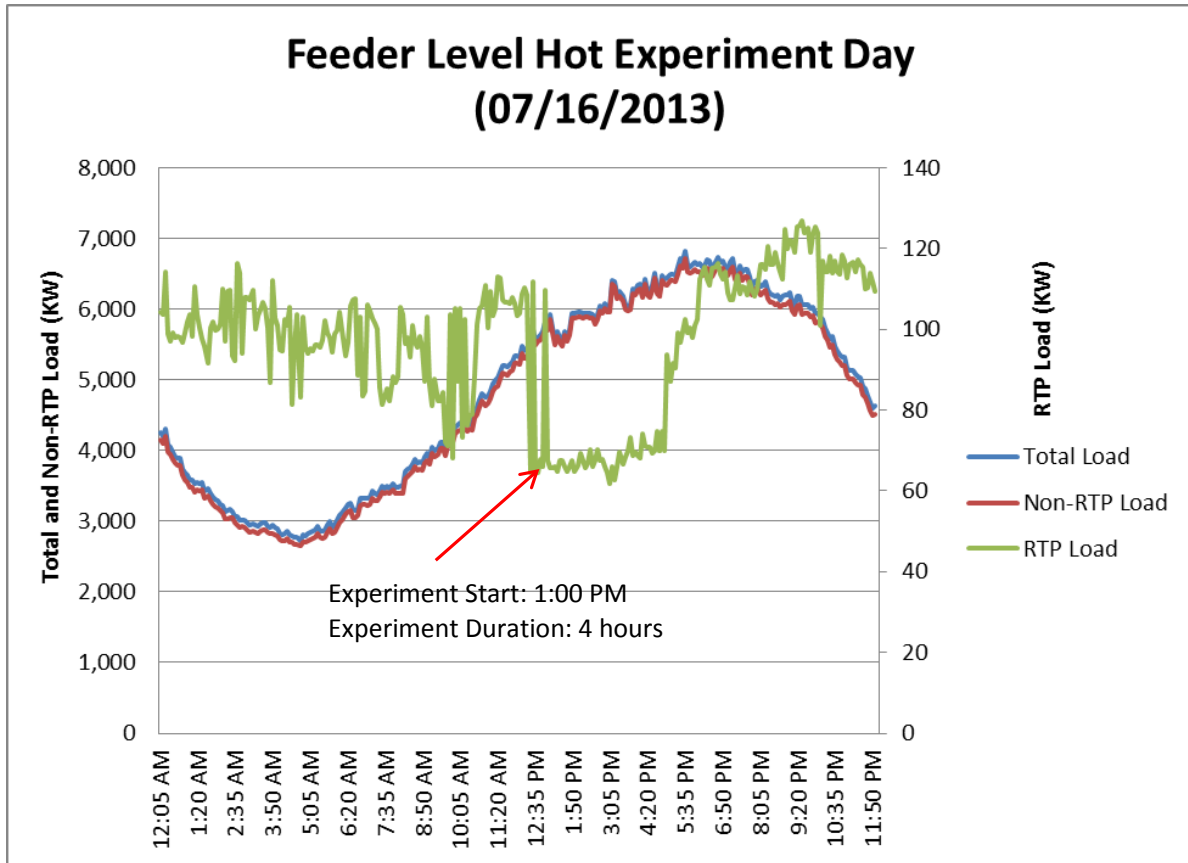


Figure 92. Circuit Level Hot Experiment Day

Real Time Pricing With Double Auction



The figure below illustrates a circuit level view on a cold day experiment. The blue line represents the total load on the circuit, and the red line represents the total load minus the RTP load. On this day the load curve was a typical summer curve with low circuit load during the morning hours and the load peaking during mid to late afternoon; however, the total load was reduced because of the cooler temperatures. The green line represents the RTP load. At 5 a.m. the experiment started, and the RTP load was reduced on the circuit from approximately 85 kW to 72 kW. This reduction was sustained through the experiment duration of 2 hours. At 7 a.m. the RTP load was released. The circuit saw a rebound from the RTP load for a short duration. The RTP load fluctuated for the remainder of the day due to PJM prices.

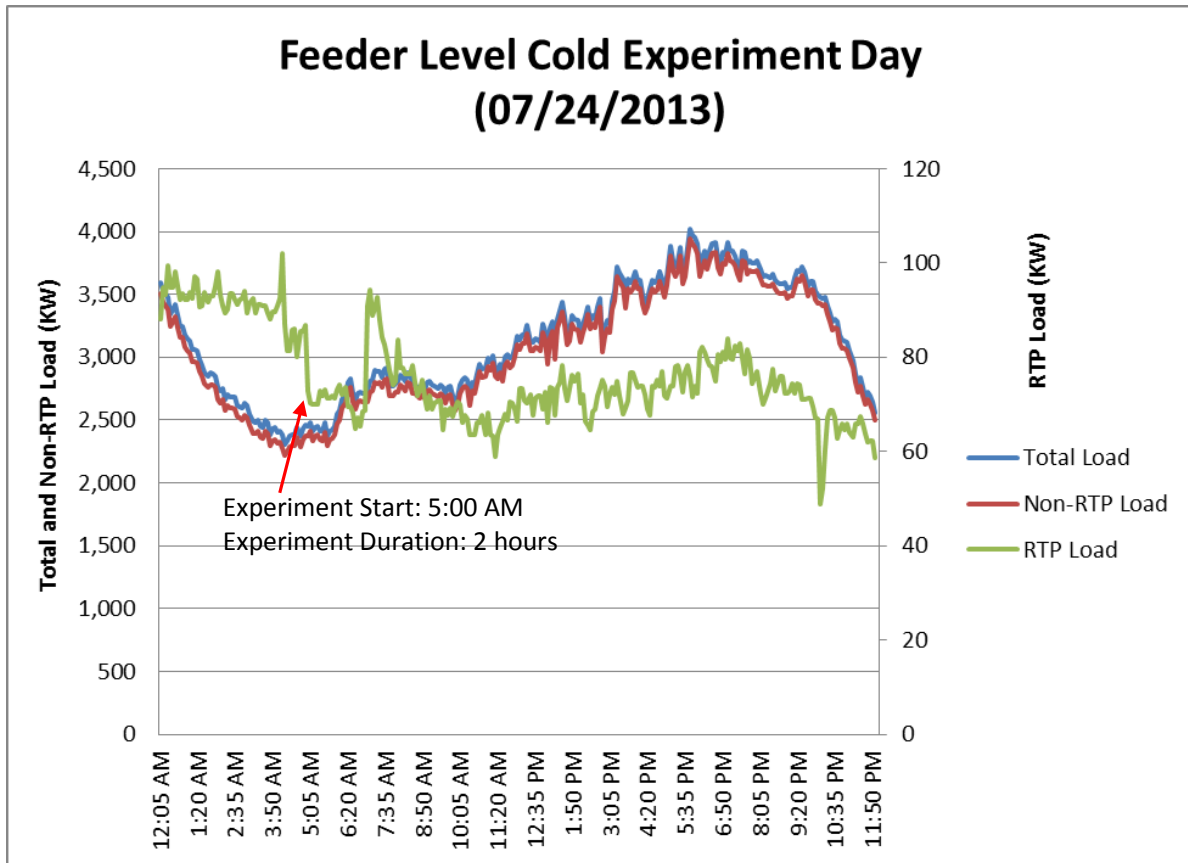


Figure 93. Circuit Level Cold Experiment Day

Real Time Pricing With Double Auction



The figure below illustrates a circuit level view of an experiment on a holiday. The blue line represents the total load on the circuit, and the red line represents the total load minus the RTP load. On this day the load curve was a typical summer curve with low circuit load during the morning hours and the load peaking during mid to late afternoon. The green line represents the RTP load. During non-experiment hours the load fluctuation was minimal. At 10:15 a.m. congestion was induced on the circuit. The RTP load responded, and there was a reduction in RTP load dropping from approximately 90 kW to 55 kW. As the experiment progressed, the load reduction was fairly constant for the duration of the experiment. At 12:10 pm the congestion was released, and the RTP load rebounded on the circuit. The RTP load fluctuated for the remainder of the day due to PJM prices.

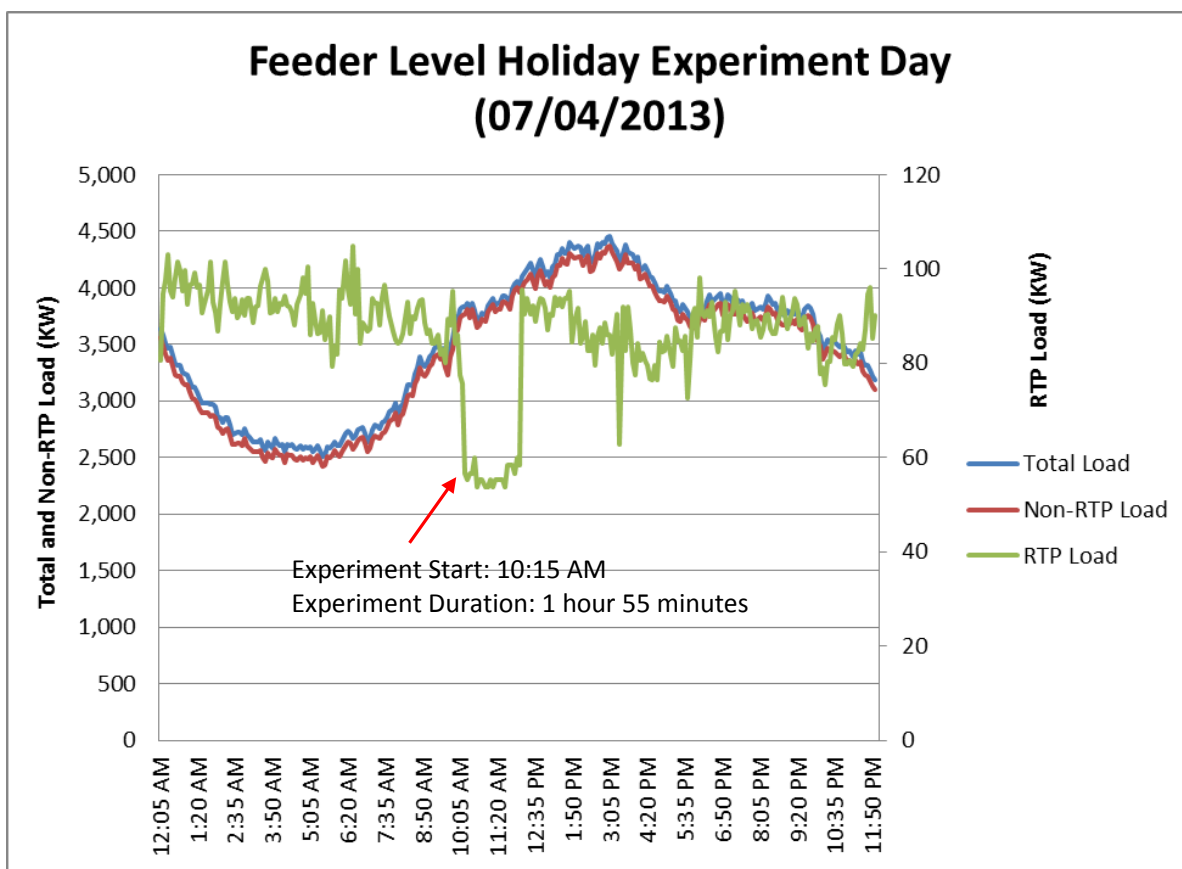


Figure 94. Circuit Level Holiday Experiment Day

Real Time Pricing With Double Auction



The figure below illustrates a circuit level view of an experiment on a PJM emergency day. The blue line represents the total load on the circuit, and the red line represents the total load minus the RTP load. On this day the load curve was a typical summer curve with low circuit load during the morning hours and the load peaking during mid to late afternoon. During this day PJM called an emergency event starting at 1:30 p.m. and lasting until 7:30 p.m. The green line represents the RTP load. During non-experiment hours, the load fluctuation was minimal with a slight price spike prior to the experiment causing a reduction for a short interval. At 3 p.m. the experiment started, and the RTP load reduced from approximately 115 kW to 85 kW. The reduction was sustained with a slight climb in RTP resources for the 4-hour duration of the experiment. At the completion of the experiment, the resources rebounded. The RTP load fluctuated for the remainder of the day due to PJM prices.

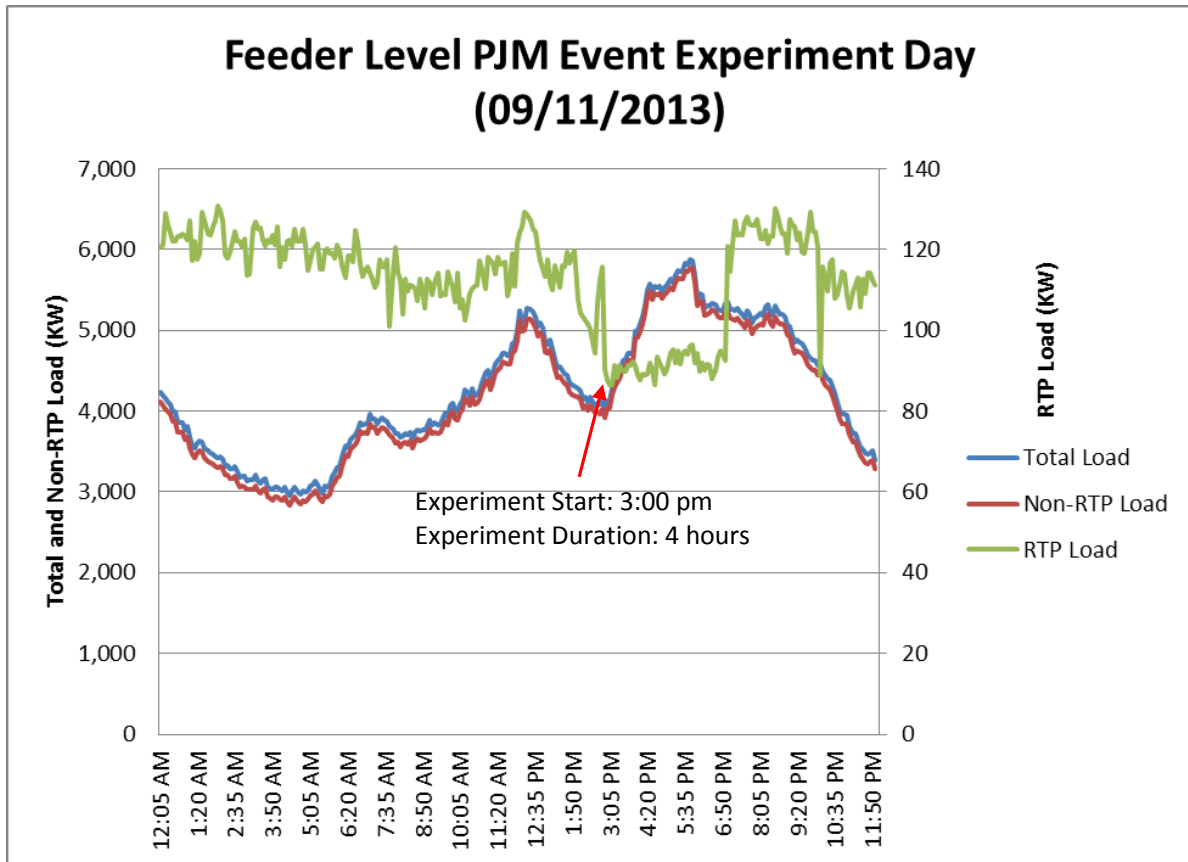


Figure 95. Circuit Level PJM Event Experiment Day



4.4.4 Consumer Program Level

The RTP_{da} data from all four distribution circuits was aggregated in order to calculate the overall average consumer energy and demand impacts at the consumer program level. The energy and demand impacts were calculated by comparing the average RTP_{da} premises hourly usage to the average hourly usage of a control group composed of comparable standard tariff consumers (see section 4.x for a full description of the calculation approach using control groups). The consumer program level of analysis provides insights into the impacts of RTP_{da} as a tariff rather than just a series of experiments.

4.4.4.1 RTP_{da} – Overall Impacts

This metric examines the overall impacts of the RTP_{da} program on consumers' energy usage and demand. This metric measured the average changes in consumer consumption during various periods of the day on experiment weekdays and weekends, and non-experiment weekdays and weekends. It also included two RTP_{da} experiment days – the summer 2013 peak day and a PJM emergency event day.

4.4.4.2 Organization of Results

This metric assessed the ability of RTP_{da} and associated technologies to influence consumers to decrease or shift their energy usage away from high-cost periods of the day.

For the analysis of the average experiment weekdays (Figure 96) and weekends (Figure 97) and non-experiment weekdays (Figure 98) and weekends (Figure 99), a high-cost period was defined as the hours from 1 p.m. to 7 p.m. For the summer 2013 peak day (Figure 100) and a PJM emergency event day (Figure 101), the analysis used the high-cost periods of the day as determined by the program experiments.

The key parameters of interest included experiment and non-experiment days (regardless of the time of day of the event), day types (weekdays and weekends), peak day and PJM emergency day, hour of the day and hourly kWh usage.

4.4.4.3 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

This impact metric provided an analysis of the average hourly RTP_{da} premises energy reduction between 1 p.m. and 7 p.m., the total average daily kWh reduction for RTP_{da} premises, and the maximum daily kW reduction for the average RTP_{da} premises for:

- Experiment weekdays and weekends
- Non-experiment weekdays and weekends
- The summer 2013 peak day
- A PJM emergency event day

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4.4.4.4 Calculation Approach

The following queries and methods were used for the analysis:

- Average hourly kWh reduction was calculated by averaging hourly usage by day type (event days, non-event days, weekdays, weekend days, summer peak day and PJM emergency day) for RTP_{da} premises and control group premises, and taking the hourly average of the differences between the groups of premises between 1 p.m. and 7 p.m.
- Total average daily kWh reduction energy was calculated by averaging hourly usage by day type for RTP_{da} premises and control group premises, and taking the hourly average of the differences between the groups of premises for the entire day.
- Maximum daily kW reduction was calculated by averaging hourly usage by day type for RTP_{da} premises and control group premises, and taking the maximum hourly difference between the groups of premises between 1 p.m. and 7 p.m.
- Only those RTP_{da} consumers participating in the program for the period of June 1, 2013 and September 30, 2013 were included in this analysis. To include those consumers that were enrolled for only part of the summer would have required recalculating the control group for each unique set of consumers.

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4.4.4.5 Energy and Demand Analysis – Summer 2013

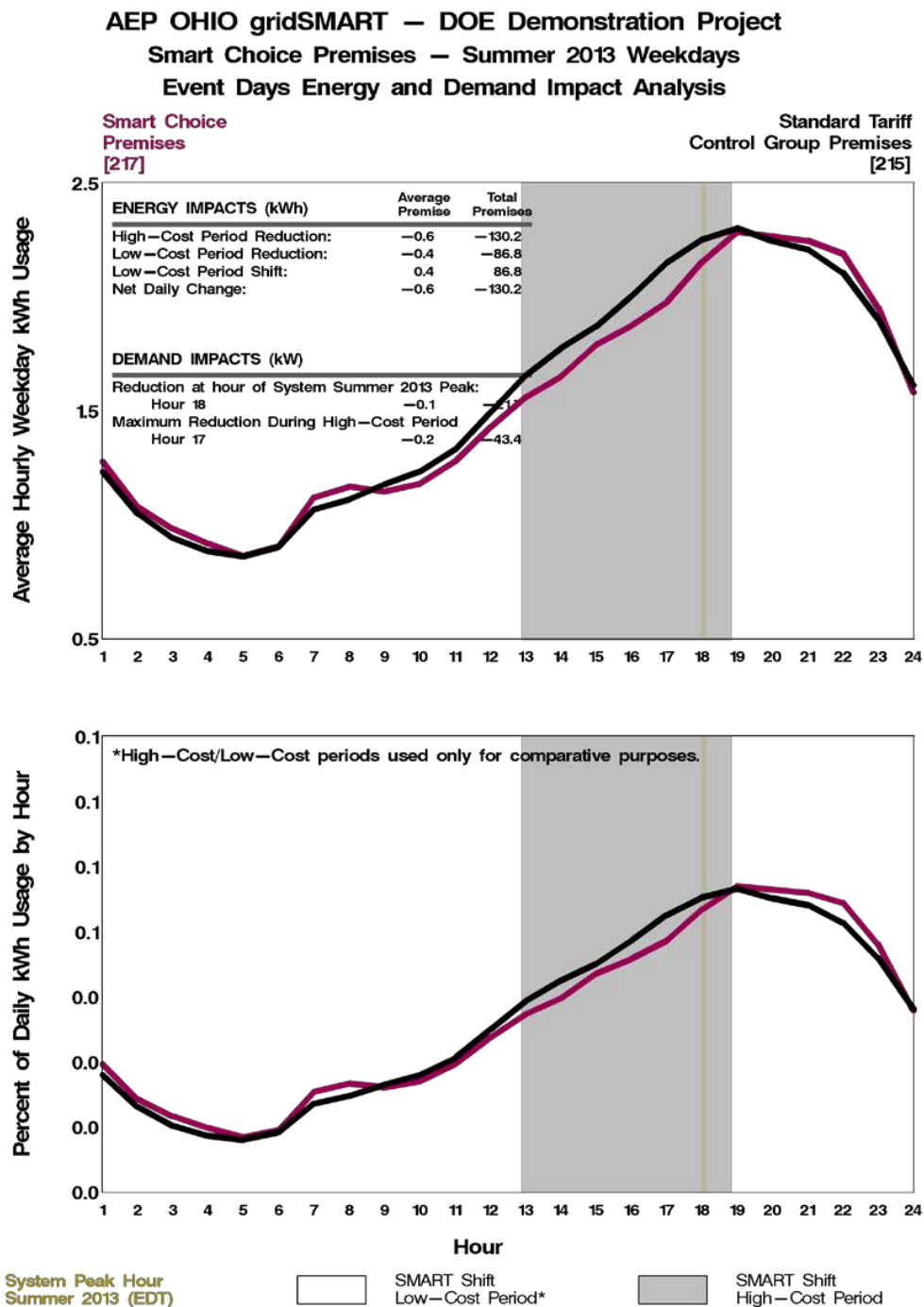


Figure 96. Event Days - Summer 2013 Weekdays

Real Time Pricing With Double Auction



AEP OHIO gridSMART — DOE Demonstration Project
Smart Choice Premises — Summer 2013 Weekends
Event Days Energy and Demand Impact Analysis

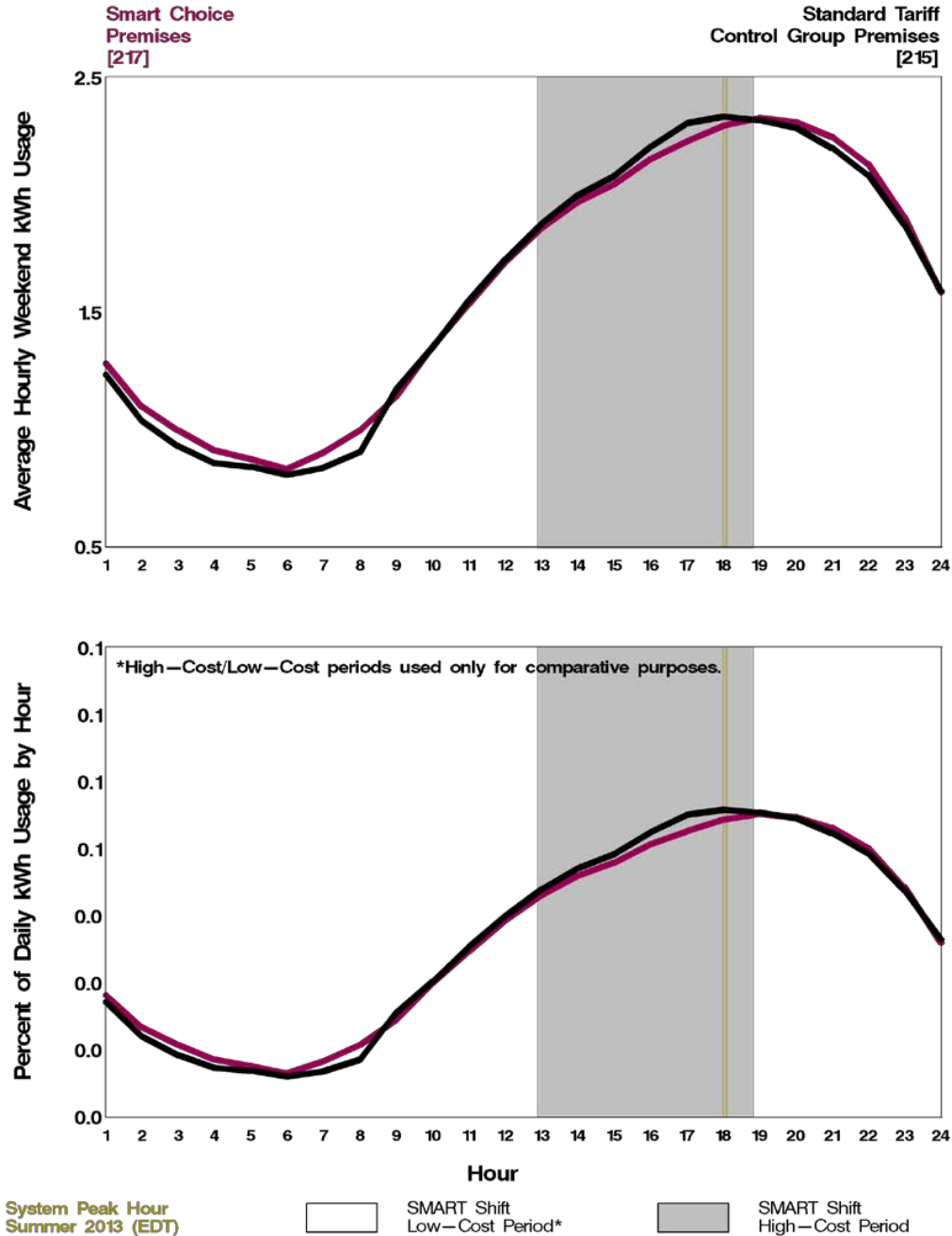


Figure 97. Event Days - Summer 2013 Weekends

Real Time Pricing With Double Auction



AEP OHIO gridSMART — DOE Demonstration Project
Smart Choice Premises — Summer 2013 Weekdays
Non—Event Days Energy and Demand Impact Analysis

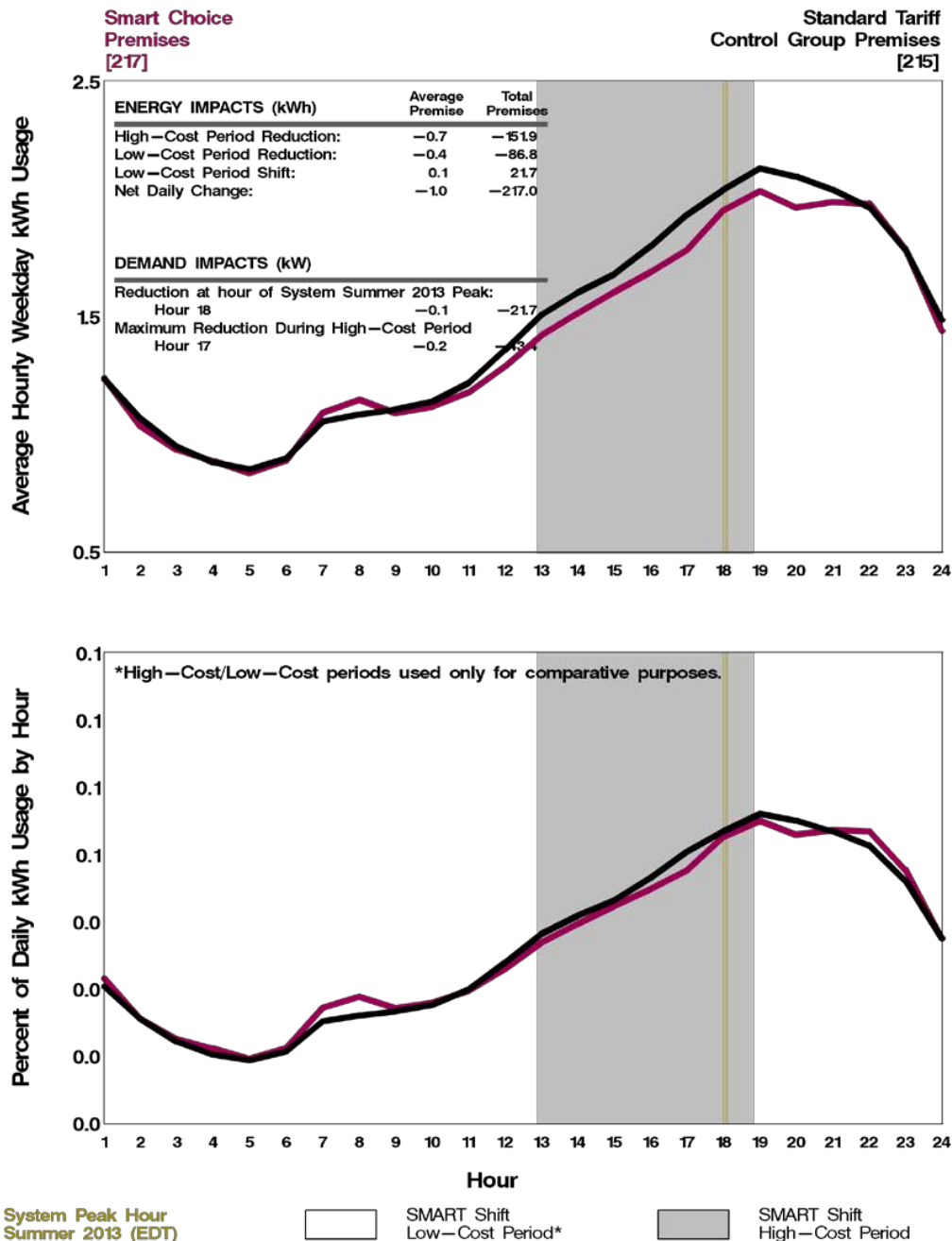


Figure 98. Non Event Days - Summer 2013 Weekdays

Real Time Pricing With Double Auction



AEP OHIO gridSMART — DOE Demonstration Project
Smart Choice Premises — Summer 2013 Weekends
Non—Event Days Energy and Demand Impact Analysis

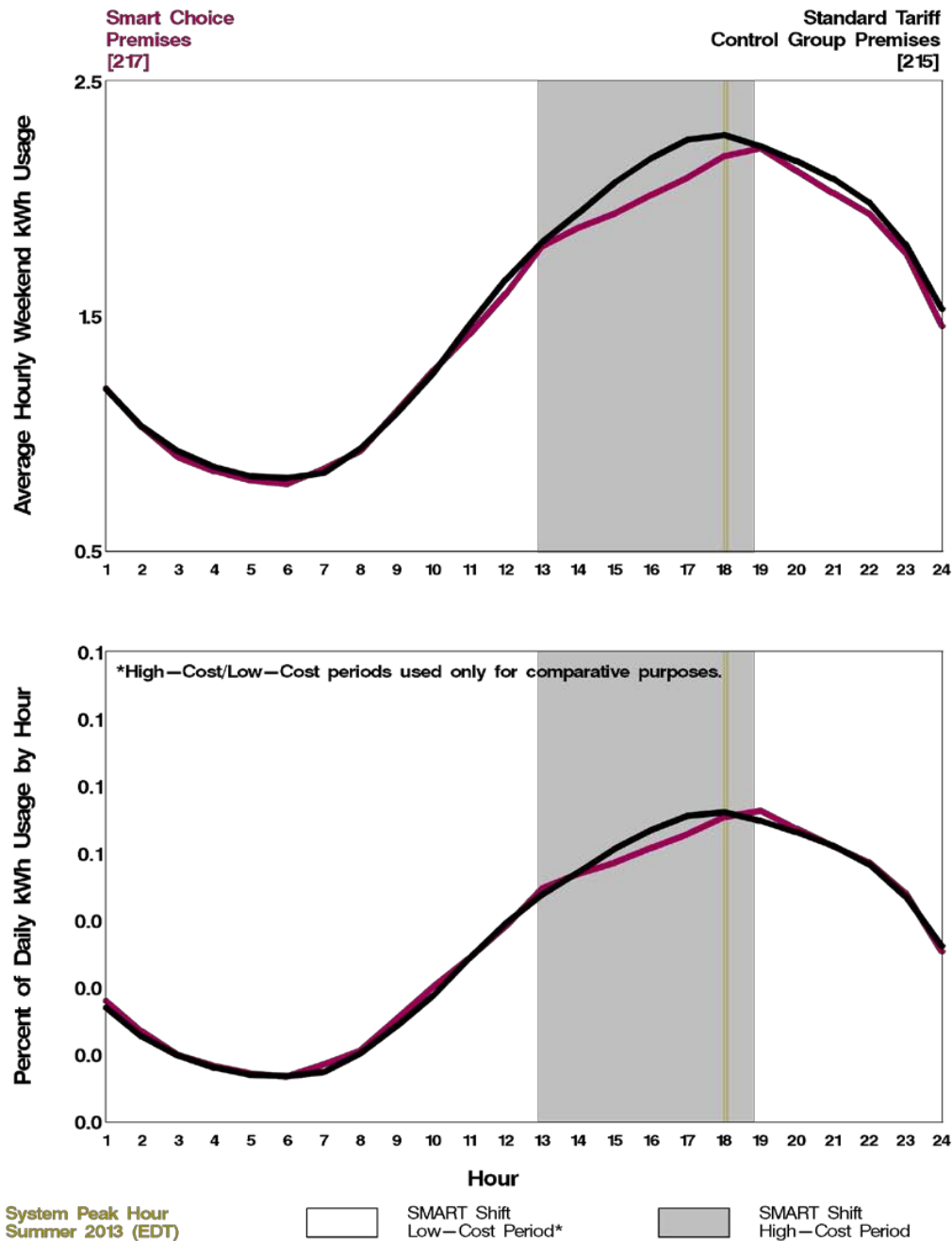


Figure 99. Non Event Days - Summer 2013 Weekends

Real Time Pricing With Double Auction



AEP OHIO gridSMART – DOE Demonstration Project
SMART Choice Experiment – 17 July 2013
Energy and Demand Impact Analysis

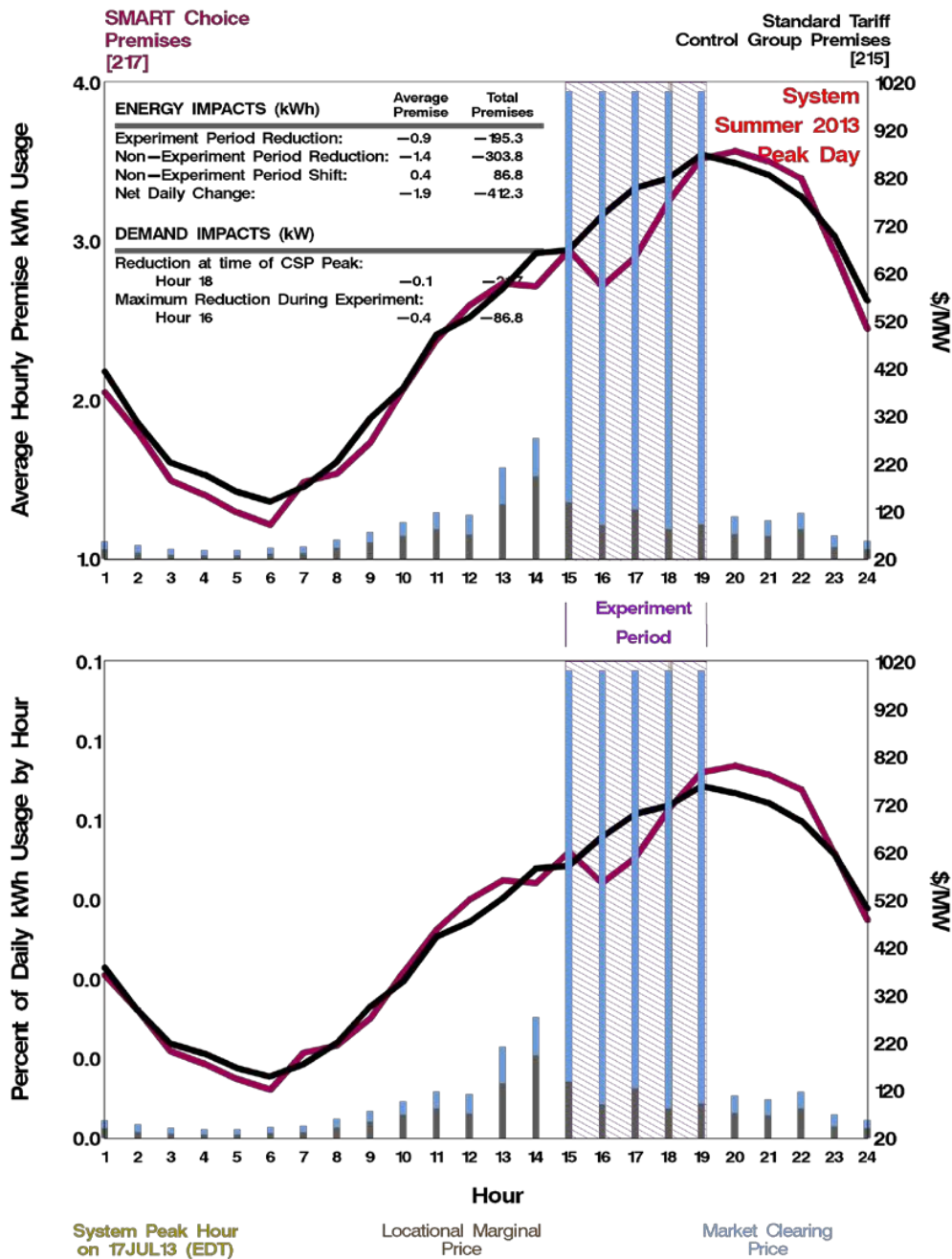


Figure 100. Peak Event Day - July 17, 2013

Real Time Pricing With Double Auction



AEP OHIO gridSMART – DOE Demonstration Project
SMART Choice Experiment – 11 September 2013
Energy and Demand Impact Analysis

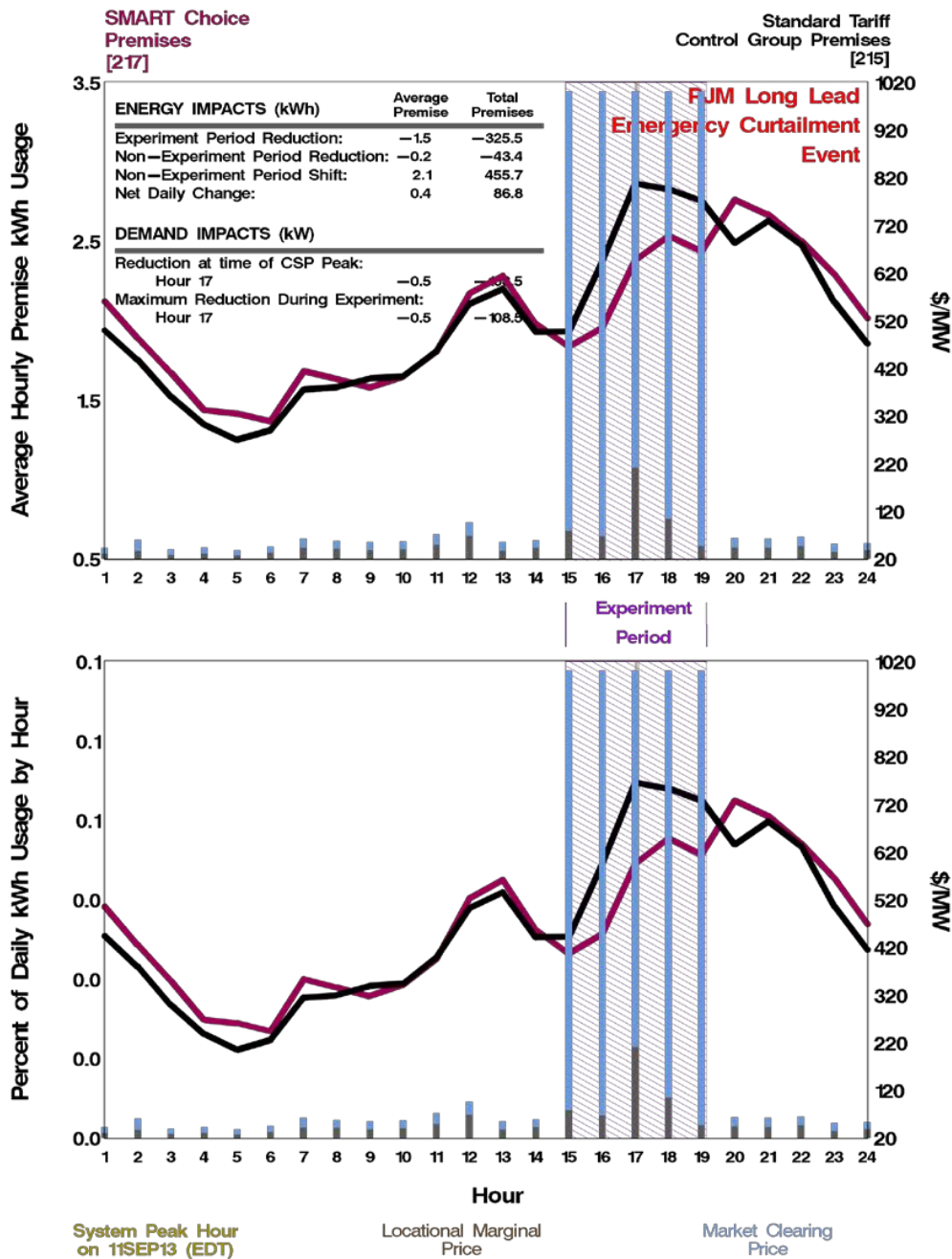


Figure 101. PJM Event Day - September 11, 2013

Real Time Pricing With Double Auction



4.4.4.6 Data Collection Results

RTP_{da} consumers reduced their average hourly consumption by 0.1 kWh between the hours of 1 p.m. and 7 p.m. on experiment weekdays and weekends. They reduced their average hourly consumption by the same amount on non-experiment weekdays. There were no observed changes in RTP_{da} average hourly kWh consumption on non-experiment weekends.

There were similar results regarding the maximum kW reduction between these hours as well. These observations are not inconsistent given the possible distribution of the RTP_{da} experiments across all hours of all days which tended to spread consumption impacts of the experiments over a wider range of hours. That there was an observed reduction in kWh consumption is perhaps indicative of the self-selection bias of these consumers that actively opted into this program.

When this analysis is applied to specific days when there were RTP_{da} experiments, the impacts of the program were more clearly observed.

RTP_{da} experiments were conducted on AEP's summer peak day of July 17, 2013 between 3 p.m. and 6 p.m. and on the PJM emergency curtailment event day of September 11, 2013 between 3 p.m. and 6 p.m.

The reduction in the observed average hourly kWh consumption of RTP_{da} consumers during the hours of the experiments on these days was 0.3 and 0.4 kWh respectively. The max kW reduction during the hours of the experiments on these days was 0.4 and 0.5 kW respectively.

Total daily kWh reduction measured the extent to which consumers shifted their kWh consumption from high-cost to low-cost periods of the day or reduced their kWh consumption altogether. For non-experiment weekdays and weekends, consumers decreased their total daily kWh consumption, but on experiment weekdays, consumers shifted their kWh consumption to the low-cost hours of the day. On the AEP summer peak day, consumers decreased their total daily kWh consumption more than on the average days. On the PJM emergency curtailment day, consumers tended to shift their kWh consumption to the lower-cost period of the day.

Real Time Pricing With Double Auction



Day Types		Average Hourly kWh Reduction ⁽¹⁾	Total Daily kWh Reduction	Max kW Reduction ⁽¹⁾
Experiment Days	Weekdays	0.1	0.6	0.2
	Weekends	0.0	0.3	0.1
Non- Experiment Days	Weekdays	0.1	1.0	0.2
	Weekends	0.1	1.0	0.2
Peak Day ⁽²⁾	n/a	0.3	1.9	0.4
PJM Emergency Day ⁽³⁾	n/a	0.4	0.4	0.5

Table 18. Energy and Demand Analysis - Summer 2013

Notes:

- Between 1 p.m. and 7 p.m., the SMART Shift Plus high-cost period used for comparison purposes only.
- Peak day was Wednesday, July 17.
- PJM emergency day was Wednesday, September 11.

4.5 RTP_{da} Conclusions

Real-Time Pricing with double auction was an experimental or beta project to understand what it would take to make this technology a viable program offering to the general public. There were several positive outcomes of the program:

- The theories behind the algorithms were proven correct. The HEMs generated bids, SGD accumulated the supply information and auctions took place. The price the consumer paid for energy varied with each 5-minute interval during the day.
- During a congestion event, load on the congested circuit was reduced by the participating RTP_{da} consumers. As the interval prices increased, the premises thermostat was adjusted to reduce demand. This is evident in the figures contained in the Distribution Circuit Level section of this chapter.
- Consumer response was observed by the consumer’s participation in the auctions through the ePCT settings.
- In general, the consumer comments were positive and satisfaction with the RTP_{da} program was high.

In addition to the positive outcomes, there were challenges to overcome before a full deployment could be considered.

- Some consumers who wanted to participate in the RTP_{da} program could not because of the lack of cellular service at their premises. This lack of cellular coverage impacted the number of participating consumers, thereby reducing the amount of potential RTP_{da} load on a circuit. Although cellular service was the most cost effective and easiest to implement for the Project, other technologies should be explored.

Real Time Pricing With Double Auction



- Often multiple trips to a consumer's premises were required in order to get the equipment installed, commissioned, and fully functional. After installation, continuous monitoring was required to ensure the equipment remained in a fully functional state.
- There were challenges in getting the real-time data processed through the legacy back office applications and back to the consumer premise in a timely manner. To account for this delay, a workaround was implemented that offset the 5-minute pricing by two intervals or ten minutes. In other words, the real-time 5-minute LMP for an interval ending at 12:05 was used for the auction with a timestamp of 12:15.
- The combined cost of the ePCT, HEM, and cellular communication for individual premises was too costly for the utility to absorb without some cost recovery mechanism such as in the tariff, through an additional rider, or by increasing the pricing in the tariff to recoup the cost of equipment and installation.
- Other consumer programs had greater financial value to the consumer and the utility than the RTP_{da} program. For detailed results, see the Consumer Programs chapter of this report.

4.6 Lessons Learned

4.6.1 Technology

- Software development needs to be done with the utility's perspective to ensure it is properly aligned with operational functions.
- Thorough testing of software and equipment is essential in preparation for rolling out a complex technology.

4.6.2 Implementation

- Collaboration and preparation is essential to manage an experimental, collaborative research project. With this type of project, allowing enough time for research and development is essential to meet objectives. The use of proven project management tools is effective to develop the technologies and ensure collaboration.
- Develop clear communications to provide expectations to vendors for user acceptance testing processes and feedback mechanisms.
- Select vendors and service providers that more closely align with program goals that accommodate effective collaboration and consistent outcomes and deliverables.
- When performing updates to a user interface, application, or device, the documentation must be updated accordingly. Documentation enhances consumer support as well as back office operations.

4.6.3 Operations

- Consistent communications between devices is dependent on a reliable cellular network. Although cellular service was the most cost effective and easiest to implement for the Project, other technologies should be explored.
- Align software development goals with ongoing operational systems.

Real Time Pricing With Double Auction



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5 DEMONSTRATED TECHNOLOGY – DISTRIBUTION AUTOMATION CIRCUIT RECONFIGURATION

5.1 Purpose

Distribution Automation and Circuit Reconfiguration (DACR) operating in conjunction with the Distribution Management System (DMS) leveraged two-way communication and infrastructure improvements to improve reliability. Automatic network reconfiguration quickly restored power to de-energized loads, even under complex circuit arrangements that were not suitable for simple loop schemes. DACR control systems could transfer loads automatically between circuits after an outage. This reduced outage times by allowing these networks to automatically respond to fault conditions and outages. It encompassed many system-wide control objectives in the distribution system, including:

- Improved circuit reliability and customer experience.
- Provided enhanced service restoration.
- Enabled data sharing with adjacent control areas.
- Enabled communications link failure detection.
- Demonstrated enhanced situational awareness.
- Demonstrated two-way communication among devices with DMS, central control center visibility, and automated outage recovery.
- Demonstrated equipment sensors that provided near real-time condition/status.
- Used integrated back office systems to provide remote and automated data collection, analysis, visualization, and action.
- Improved effectiveness of traditional protection practices.

5.2 Technology

DACR provided a system to remotely monitor, coordinate, and operate distribution circuit equipment, working behind the scenes to keep the power on. DACR automatically detected fault conditions and outages and strategically rerouted the paths of electricity within the electrical grid. For consumers, this resulted in improved reliability with fewer outages and quicker restoration times. DACR reduced the number of consumers impacted by an outage as well as decreased the amount of time consumers were without power by rerouting the flow of electricity. Any remaining outage areas were identified by the technology and crews were dispatched efficiently, which reduced restoration time.

Distribution substation breakers and line reclosers were designed to attempt to clear a fault by de-energizing the line for a few seconds to see if the fault cleared. If the fault persisted, the recloser de-energized the line and locked out until repairs were made and it was manually switched back in.

Distribution Automation Circuit Reconfiguration



Traditional circuit reconfiguration was based on distribution loop schemes that were effective for well-defined circuits. These schemes traditionally operated without communication by monitoring voltage at each switch to detect outages and restore loads. The drawback of using a loop scheme was that control decisions relied only on loss of voltage. DACR leveraged communications and coordinated control to improve reliability. DACR generally included Supervisory Control and Data Acquisition (SCADA), remote sensors, monitors, switches, digital relays, and controllers with embedded intelligence. The Distribution Automation Controller (DAC) was the intelligence behind DACR. All of the available circuit routes were programmed into each DAC. Together, these components gathered near real-time information to provide fault location, outage isolation, circuit reconfiguration, service restoration, and remote equipment monitoring. When a fault occurred, the DAC looked at data from all devices in its control. It then:

- Determined which line section was faulted.
- Identified devices that could be switched to isolate that section and restored power to the un-faulted sections.
- Checked to make sure no sections were overloaded.
- Commanded the devices to switch.

After performing these steps, the DAC sent a message to the Distribution Dispatch Center (DDC) to update the Distribution Management System (DMS) and the Outage Management System (OMS). This reconfiguration was designed to occur within two minutes.

During storms it was necessary to locate multiple fault locations, make repairs, and switch consumers back into service after repairs were made. DACR combined with DMS and OMS enabled the DDC operators to view outage locations and monitor how the DACR system isolated the problem areas. This visualization allowed the DDC operators to perform remote switching to restore service in addition to what the DACR logic was able to accomplish automatically. The remote switching was done without dispatching distribution line crews to the switch locations and expedited restoration of service to the consumer.

The following figure provides a schematic diagram for a typical DACR system.

Distribution Automation Circuit Reconfiguration

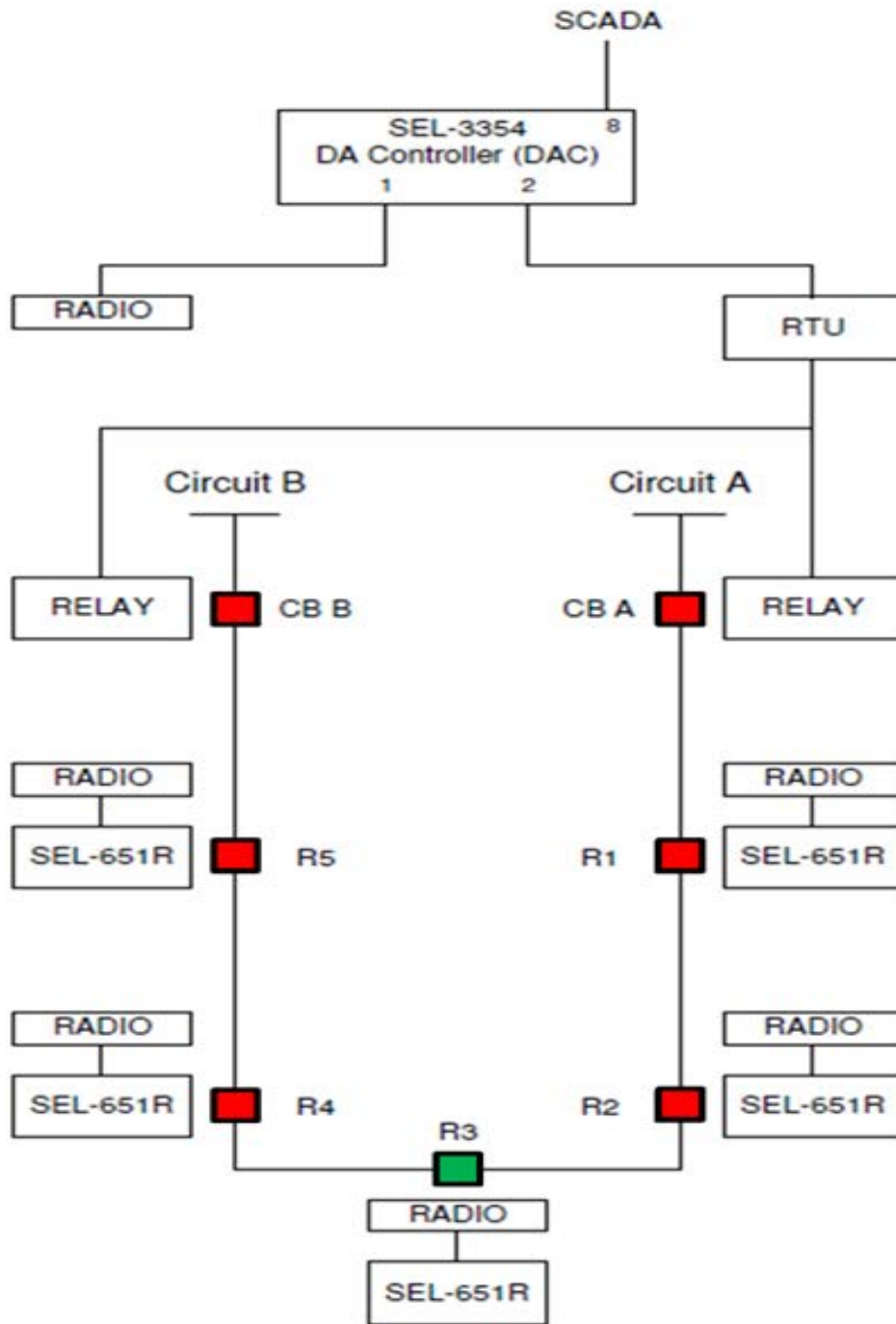


Figure 102. Example DACR System Architecture.¹

¹ A more detailed discussion of DACR than is practical here is available in: Greer, R., Allen, W., and Dulmage, A., "Distribution Automation Systems With Advanced Features," 55th Annual IEEE Rural Electric Power Conference, Chattanooga, TN, 2011.



5.3 Approach and Implementation

The AEP Ohio gridSMART Demonstration Project deployed DACR on 70 circuits in the Project area. As the DACR system was being designed, it was determined that line devices on the 70 circuits would be upgraded to allow for two-way communication, monitoring, and control via the DMS system. Monitoring and control capability was available on circuit breakers, reclosers, regulators, and capacitor banks. This allowed visualization of the distribution system conditions at all times and enabled proactive correction activities through remote switching of devices or crew dispatch.

The DACR system was monitored by the DMS, which provided alarms and visualization of the outage area to the DDC operators. This resulted in reduced outage times. Each DACR deployment included equipment from Schweitzer Engineering Laboratories (SEL) and G&W Electric (G&W). Replacement of existing station circuit breaker relays with SEL-351S relays enabled SEL DACs to function as controllers for circuits with circuit reconfiguration capability. On these circuits, DACs communicated with SEL-651R recloser controls, which were connected to G&W Viper reclosers. G&W Viper reclosers, SEL-651R recloser controllers, and SEL-3354 Distribution Automation Controller (DAC) automatically reconfigured circuits, isolated faulted line segments, and restored power to customers affected by an outage.

These systems used the DAC deployed in substations to communicate with recloser controllers on circuits associated with each station. When a recloser opened for a permanent fault, the recloser controller communicated with the substation DAC via a wireless mesh radio network, enabling the DAC to make decisions based on the state of the faulted circuit. The DAC then commanded the applicable normally closed recloser(s) on the other side of the faulted section of the line to open. When possible, it also instructed a normally open recloser at a tie point to an energized circuit to close and restore power to the open isolating recloser.

Distribution Automation Circuit Reconfiguration



5.4 Impact Metrics Required for DACR

The following 19 impact metrics are associated with the DACR suite of technologies; 17 relate to the Project area and 2 relate to the System area.

Metric ID	Metric Scope	Metric Description	DACR
M13	Project	Distribution Circuit Load	M13-CR
M14	Project	Distribution Circuit/Equipment Overload	M14-CR
M15	Project	Deferred Distribution Capacity Investments	M15-CR
M16	Project	Equipment Failure Incidents	M16-CR
M17	Project	Distribution Equipment Maintenance Cost	M17-CR
M18	Project	Distribution Operations Cost	M18-CR
M19	Project	Distribution Circuit Switching Operations	M19-CR
M21	Project	Distribution Restoration Cost	M21-CR
M25	Project	Truck Rolls Avoided	M25-CR
M26	Project	SAIFI	M26-CR
M27	Project	SAIDI/CAIDI	M27-CR
M28	Project	MAIFI	M28-CR
M29	Project	Outage Response Time	M29-CR
M30	Project	Major Event Information	M30-CR
M31	Project	Distribution Operations Vehicle Miles	M31-CR
M32	Project	CO ₂ Emissions	M32-CR
M33	Project	Pollutant Emissions (SO _x , NO _x , PM _{2.5})	M33-CR
M34	System	CO ₂ Emissions	M34-CR
M35	System	Pollutant Emissions (SO _x , NO _x , PM _{2.5})	M35-CR

Table 19. Impact Metrics Addressing DACR Technology Performance

Refer to the *Metrics Analysis for DACR* section that follows for details.



5.5 Metrics Analysis for DACR

This section provides details for each DACR metric, and includes those requested by the DOE during the definitization of the Cooperative Agreement. Trends were not always observed, however data is presented for each metric.

5.5.1 Distribution Circuit Load (M13-CR)

5.5.1.1 Objective

This impact metric examines circuit load for all circuits in the DACR Project area to historical data for the same circuits to identify the impact of DACR on circuit loads.

5.5.1.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

On an operational circuit, DACR will not influence circuit load. However, DACR improves reliability so the circuit will operate a higher percentage of the time.

5.5.1.3 Calculation Approach

The following queries and methods were used to generate results:

- Circuit load was measured as the instantaneous real power supplied to a circuit's voltage regulator, measured in kW. Power at the circuit regulator was recorded every 15 minutes for each of the three phases (A, B, C). Instantaneous real power was computed as the sum of real power over all three phases.
- Circuit load per circuit, substation, and time were collected.
- Substation load per substation and time were calculated by summing the load of circuits originating at substations.
- Hourly outdoor temperature in degrees Fahrenheit for Port Columbus International Airport was collected from the National Oceanic and Atmospheric Administration.

5.5.1.4 Organization of Results

This section provides circuit load graphs showing the total circuit load for each DACR Project area circuit. Each graph shows percentile results for real power, reactive power, and apparent power for all circuits in the Project area.

Distribution Automation Circuit Reconfiguration



5.5.1.5 Data Collection Results

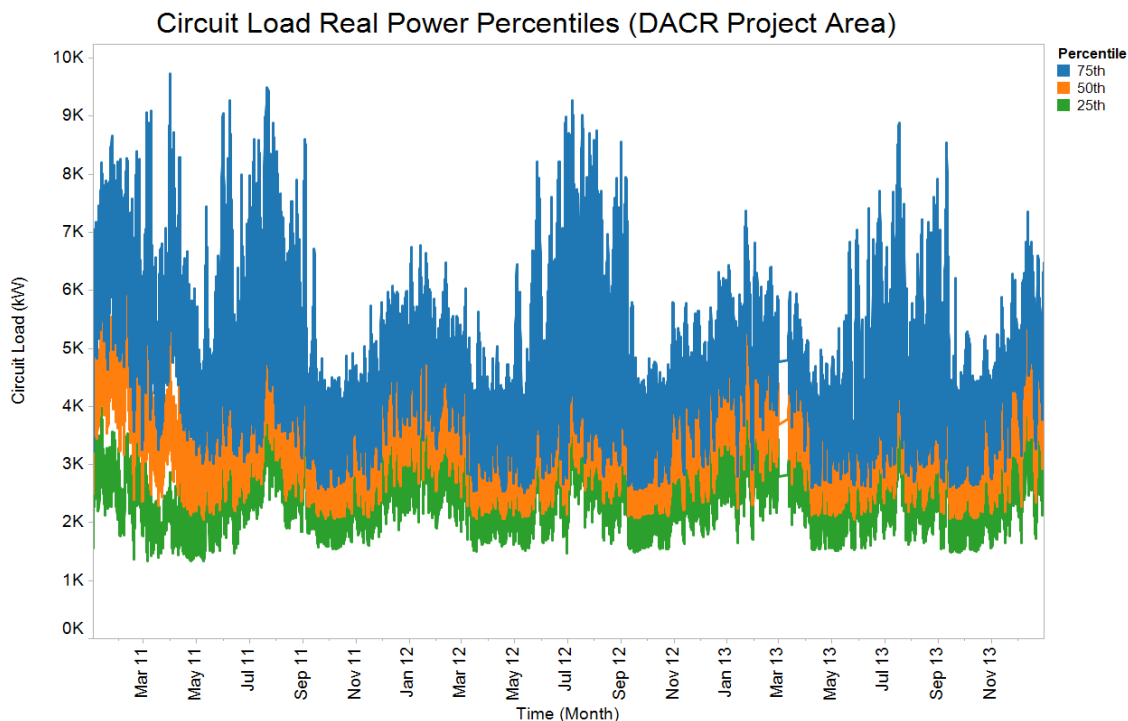


Figure 103. Circuit Load Real Power Percentiles (DACR Project)

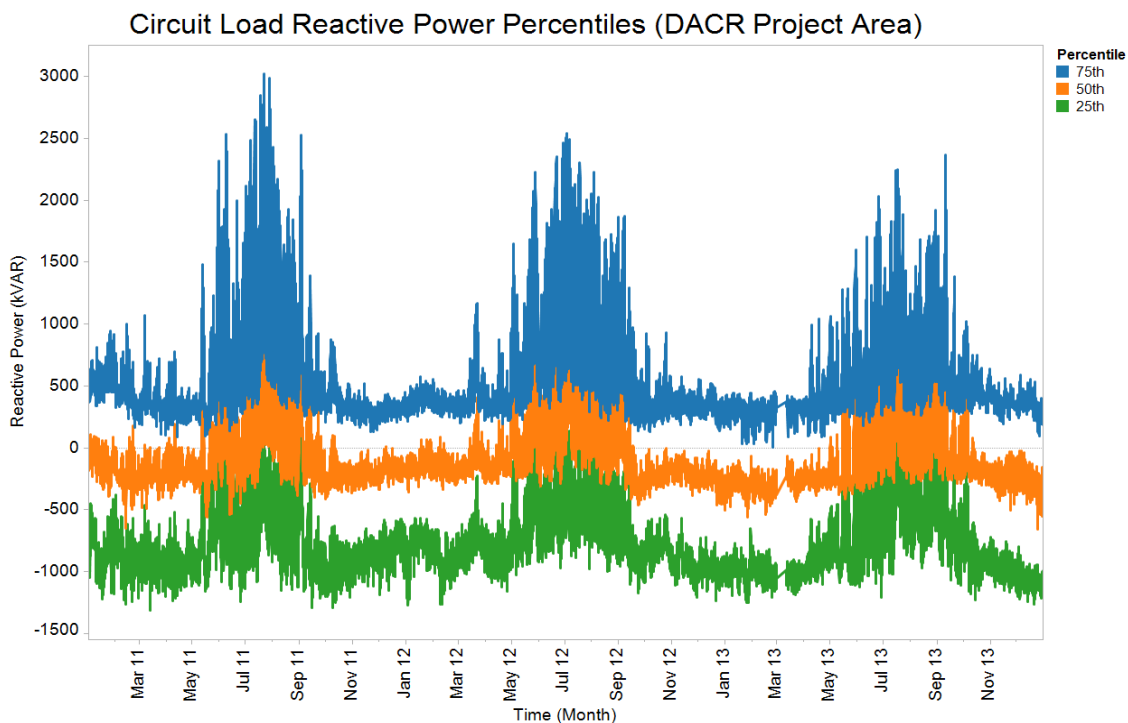


Figure 104. Circuit Load Reactive Power Percentiles (DACR Project)

Distribution Automation Circuit Reconfiguration

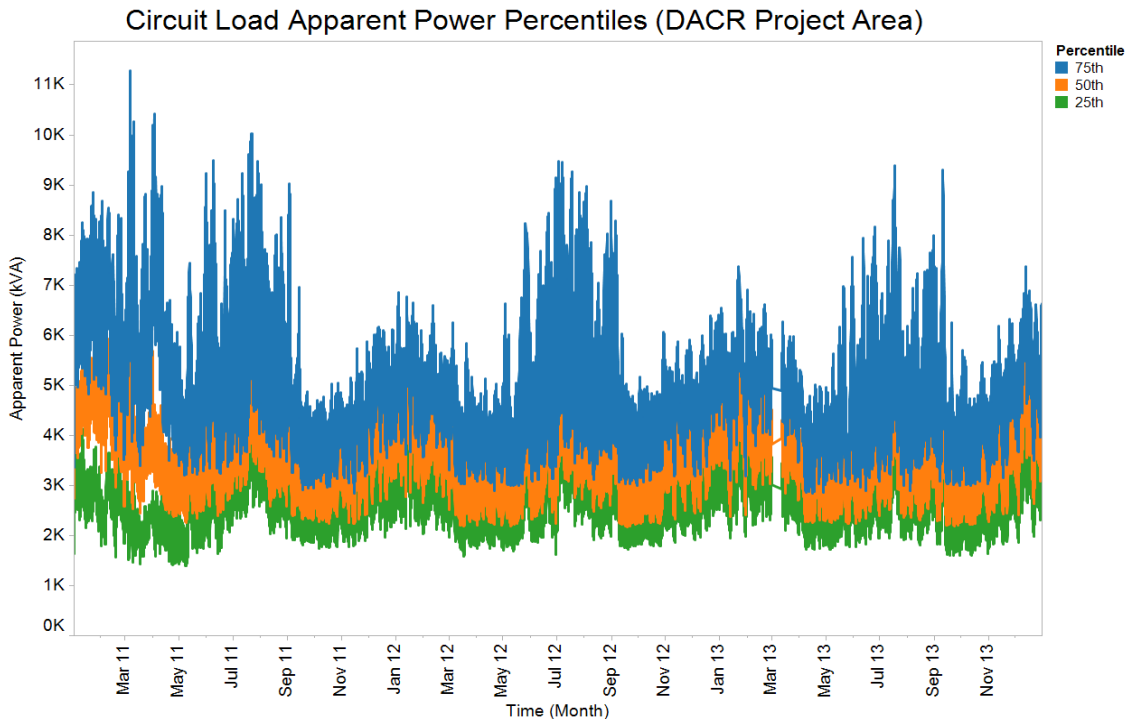


Figure 105. Circuit Load Apparent Power Percentiles (DACR Project)

5.5.1.6 Summary

As anticipated, there was no influence on normal Distribution Circuit Load due to DACR.



5.5.2 Distribution Circuit or Equipment Overload Incidents (M14-CR)

5.5.2.1 Objective

This impact metric reports equipment overload events within the Project area in order to quantify any reduction in the number of overload events on circuits with DACR capability.

5.5.2.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

Circuit and substation SCADA reports, event logs, and direct equipment notifications/alerts recorded switching operations performed to relieve equipment overloading. Any such events that resulted in equipment failure contributed to the cumulative count total.

5.5.2.3 Calculation Approach

The following queries and methods were used to generate results:

- Equipment overload events per equipment, equipment type, circuit, substation, and time were collected.
- Hourly outdoor temperature in degrees Fahrenheit for Port Columbus International Airport was collected from the National Oceanic and Atmospheric Administration.

5.5.2.4 Organization of Results

This metric was intended to present a table of circuit overload events reported within the DACR Project area. No such events occurred during the Project.

5.5.2.5 Data Collection Results

No overload events occurred during the Project. DACR did not influence the number of equipment overload events.

5.5.2.6 Summary

DACR did not influence the number of equipment overload events.

Distribution Automation Circuit Reconfiguration



5.5.3 Deferred Distribution Capacity Investments (M15-CR)

5.5.3.1 Objective

This impact metric provides a description of all distribution capacity investments that were deferred due to distribution automation.

5.5.3.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

Semi-annual variance analysis of distribution capital investment plan was performed.

5.5.3.3 Calculation Approach

No planned or deferred distribution capacity investments occurred within the DACR Project area; therefore, no calculation approach was necessary.

5.5.3.4 Organization of Results

This metric is a study of deferred distribution capacity investments due to circuit reconfiguration distribution automation.

5.5.3.5 Data Collection Results

AEP Ohio reviewed planned projects in Distribution Load Forecasting where DACR circuits would be involved. No projects were deferred as a result of DACR. DACR did not influence distribution capacity investments.

5.5.3.6 Summary

DACR did not influence distribution capacity investments.



5.5.4 Equipment Failure Incidents (M16-CR)

5.5.4.1 Objective

This impact metric provides counts of equipment failure events within the Project and System areas in order to quantify the effects DACR has on equipment failures.

5.5.4.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

Circuit and substation SCADA reports, event logs, and direct equipment notifications/alerts recorded switching operations performed to relieve equipment overloading. Any such events that resulted in equipment failure contributed to the cumulative count total. Failures for the following equipment types in this report included:

- Capacitor Banks
- Distribution Transformers
- Reclosers
- Switches
- Voltage Regulators

Other equipment types had no failures.

5.5.4.3 Calculation Approach

The following queries and methods were used to generate results:

- Equipment failure events per date, equipment type, circuit, and substation were collected by linking equipment compatible units to circuit equipment types.
- Equipment failure rate was calculated by the total number of failures divided by the total number of installations for each equipment type.

The part of the System area excluding the footprint of the Project area was referred to as the non-Project area.

5.5.4.4 Organization of Results

This metric shows equipment failure event information grouped by equipment type by month and equipment failures associated with substations in the Project area compared to the non-Project area. Each graph shows the quantity of equipment failures on the vertical axis and separates the columns by either type of equipment, month, or substation.

Distribution Automation Circuit Reconfiguration



5.5.4.5 Data Collection Results

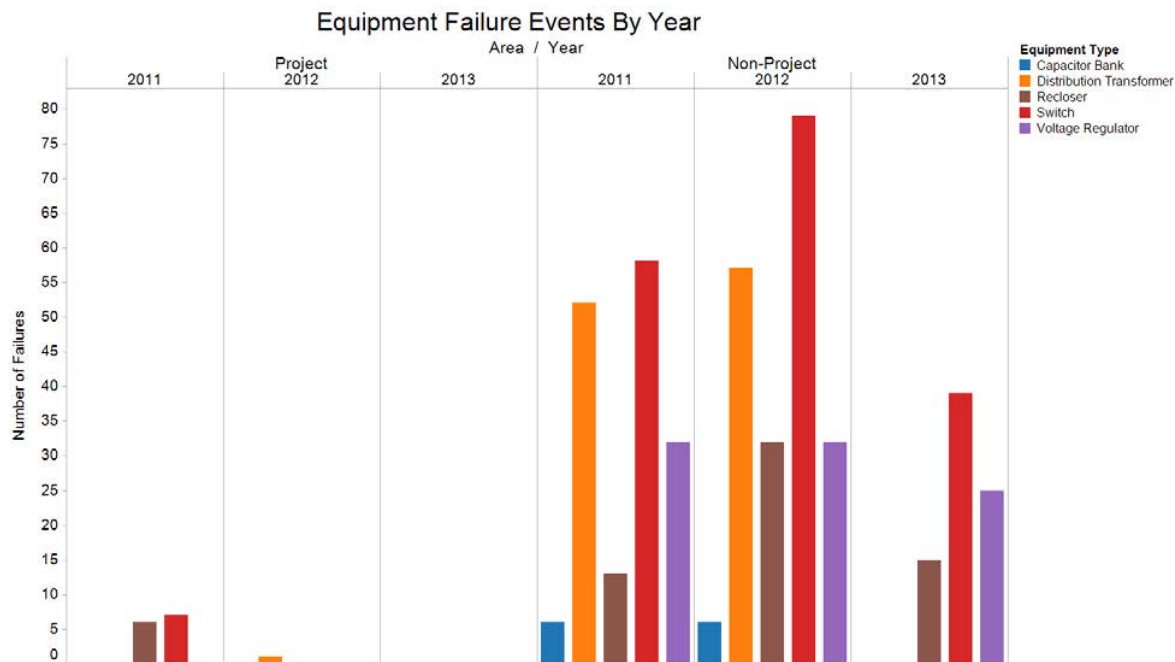


Figure 106. Equipment Failure Events by Year (Project vs. Non-Project Area)

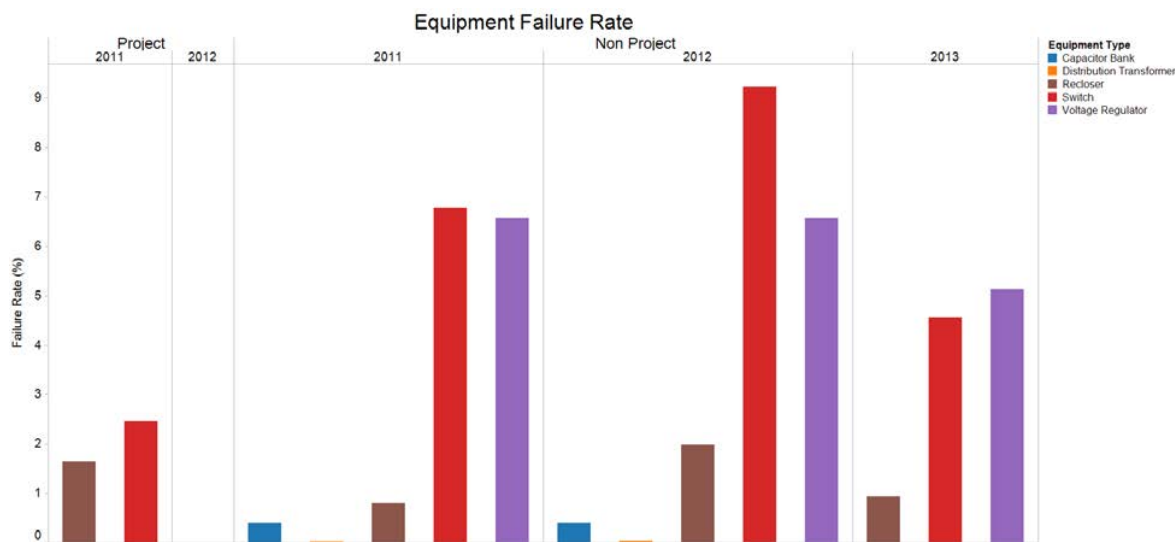


Figure 107. Equipment Failure Rate by Year (Project vs. Non-Project Area)

Distribution Automation Circuit Reconfiguration

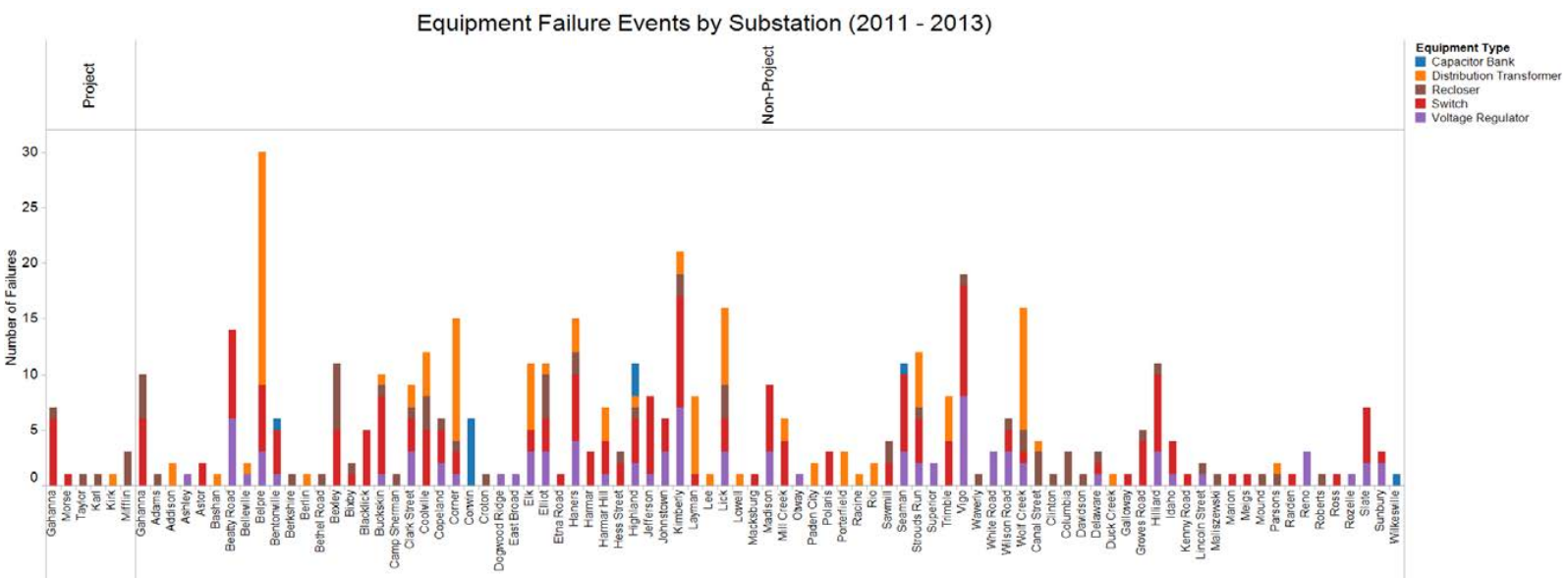


Figure 108. Equipment Failure Events by Substation (Project and Non-Project Area)

5.5.4.6 Summary

No increase in equipment failure events was evident from the data.



5.5.5 Distribution Equipment Maintenance Cost (M17-CR)

5.5.5.1 Objective

This impact metric provides monthly cost data for distribution maintenance activities throughout the Project and System areas.

5.5.5.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

Maintenance assumptions identified here are solely for the purpose of this reporting metric and do not follow traditional AEP Ohio accounting policies.

Maintenance costs in the Project area included:

- Non-warranty asset replacement of capacitors, regulators, reclosers, and associated controls or protective devices
- Estimated inspection
- Equipment failures
- IT infrastructure maintenance
- Telecommunications infrastructure

Maintenance costs in the non-Project area included:

- Total asset replacement costs on capacitors, regulators, reclosers, and associated controls or protective devices
- Inspection programs including repairs
- Equipment failures

The part of the System area excluding the footprint of the Project area was referred to as the non-Project area.

5.5.5.3 Calculation Approach

The following queries and methods were used to generate results:

Distribution equipment maintenance labor, material, vehicle fleet, and construction overhead costs per circuit, substation, and work order close date were calculated by summing labor, material, vehicle fleet, and construction overhead costs.

5.5.5.4 Organization of Results

This metric presents monthly average equipment maintenance costs per circuit for both the Project and non-Project areas. Each graph shows average maintenance costs per circuit by month separated by components of construction overhead, labor cost, fleet cost, material costs, and the sum of all four, components. Two graphs are presented; one for the Project area and one for non-Project area.

Distribution Automation Circuit Reconfiguration



5.5.5.5 Data Collection Results

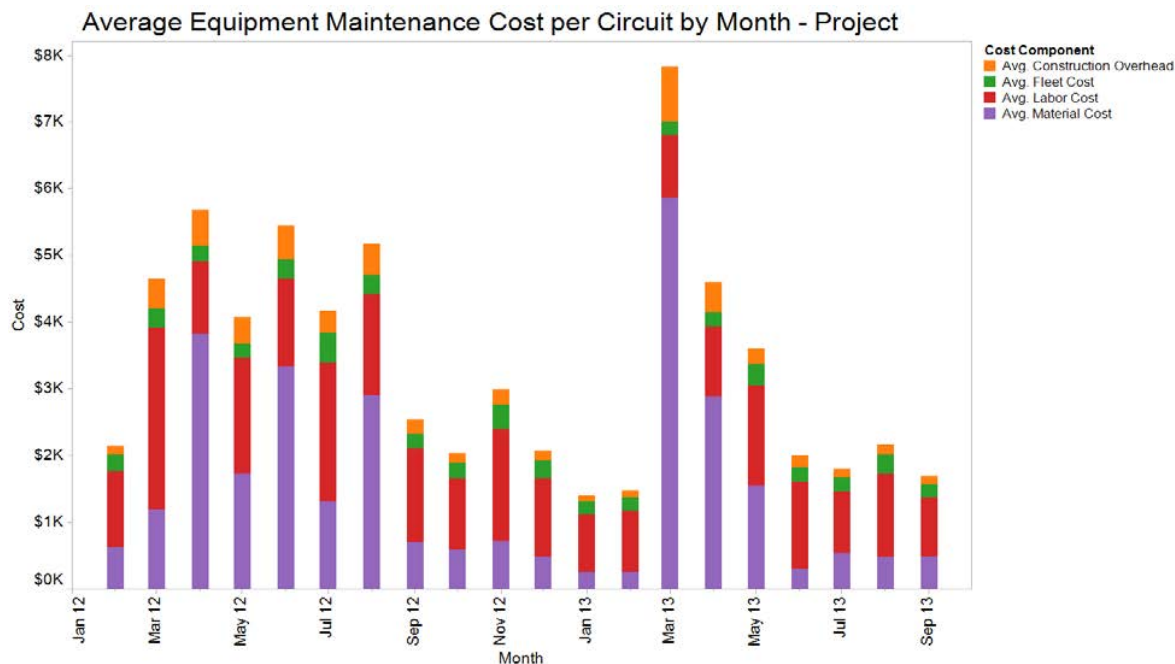


Figure 109. Average Equipment Maintenance Cost per Circuit by Month (Project Area)

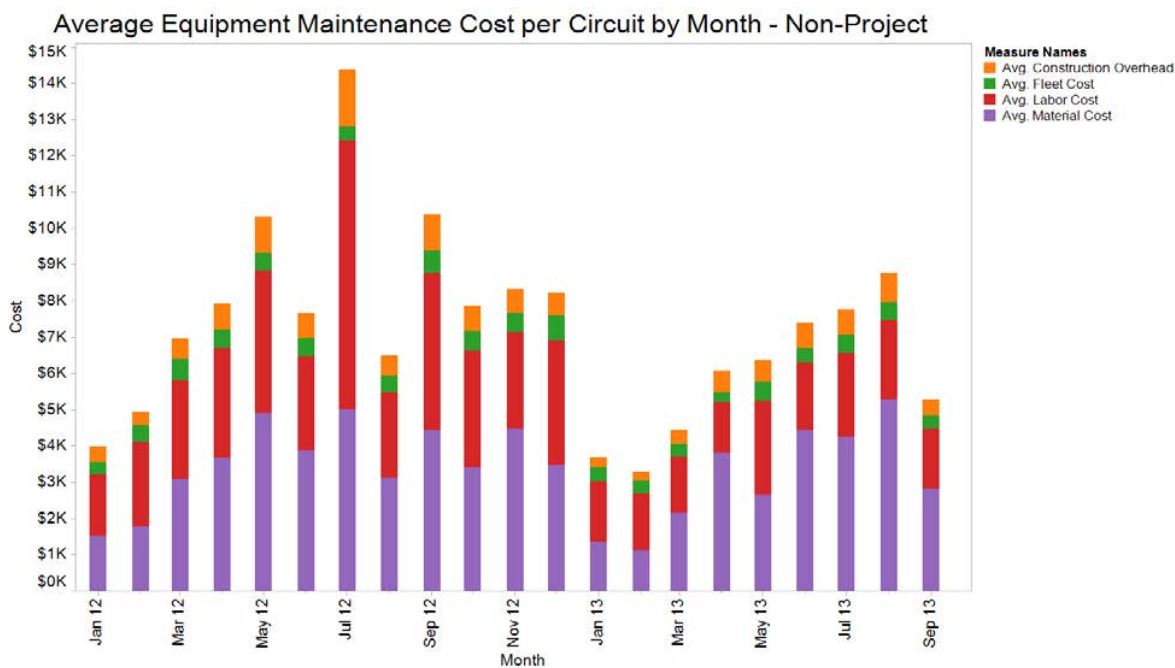


Figure 110. Average Equipment Maintenance Cost per Circuit by Month (Non-Project Area)

Distribution Automation Circuit Reconfiguration



5.5.5.6 Summary

The patterns and profiles of costs between the Project area and the non-Project area appear to be within normal month-to-month variation for the Project area. These are based on events in the Project area, and not indicative of impacts of DACR.

Distribution Automation Circuit Reconfiguration



5.5.6 Distribution Operations Cost (M18-CR)

5.5.6.1 Objective

This metric provides an estimate of the cost reduction and/or addition achieved by the elimination of inspection programs and reduction in truck rolls due to the installation of the DACR system.

5.5.6.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data:

- Inspection costs were not addressed here. Consequently operation cost reductions were estimated solely from truck rolls avoided.
- Truck roll assumptions:
 - Truck rolls avoided by DACR were due to multi-step outages and scheduled switching events.
 - A short truck roll was 15 minutes and a standard (long) truck roll was 90 minutes.
 - Operations were conducted by one service staff member in one service truck.

5.5.6.3 Calculation Approach

Analysis was conducted by counting the number of remote switching operations and assigning each as either a short or standard truck roll avoided. Standard truck rolls represented a crew traveling from the service center to a switching location. Short truck rolls represented a crew traveling from one switching device to another nearby switching device on the same circuit or on an adjacent circuit. Cost was determined based on conversion factors for vehicle and labor rates.

The following queries and methods were used to generate results:

- Short truck rolls avoided per equipment, equipment type, month, circuit, and substation due to DACR technology were calculated by selecting remote equipment switching events that occurred during multi-step restoration outages. These were combined with remote recloser switching events that occurred within five minutes of another remote recloser switching events on the same circuit.
- Standard truck rolls avoided per equipment, equipment type, month, circuit, and substation due to DACR technology were calculated by selecting remote recloser switching events which occurred more than five minutes after another remote recloser switching event on the same circuit that did not occur during an outage with a single restoration step.
- Vehicle savings from truck rolls avoided per equipment, equipment type, month, circuit, and substation due to DACR technology were calculated by summing short truck rolls avoided multiplied by \$7.50 per truck roll with standard truck rolls avoided multiplied by \$45.25 per truck roll.
- Labor savings from truck rolls avoided per equipment, equipment type, month, circuit, and substation due to DACR technology were calculated by summing short truck rolls avoided multiplied by \$15.75 per truck roll with standard truck rolls avoided multiplied by \$94.00 per truck roll.

Distribution Automation Circuit Reconfiguration



5.5.6.4 Organization of Results

This metric provides savings from avoided truck rolls per month associated with DACR.

5.5.6.5 Data Collection Results

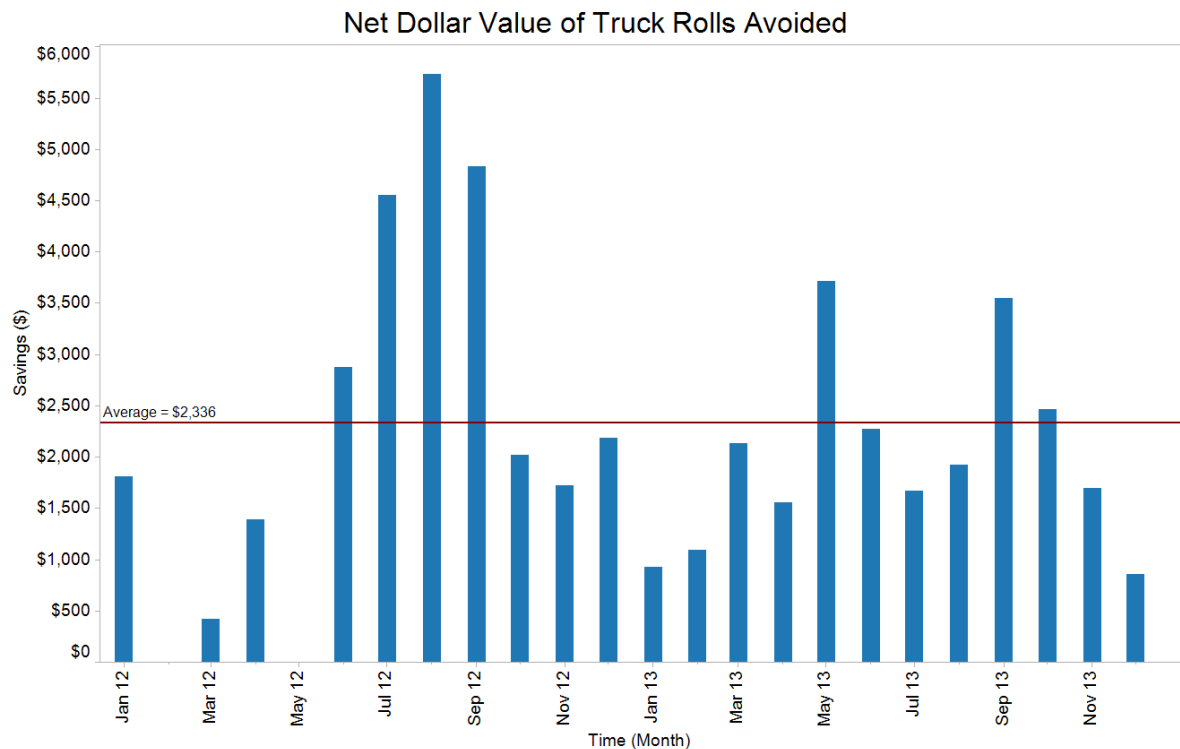


Figure 111. Net Dollar Value of Truck Rolls Avoided

5.5.6.6 Summary

The DACR technology had a greater savings due to avoided truck rolls during the summer months, driven by a combination of a larger number of maintenance operations, construction projects, and weather events occurring in the summer season.



5.5.7 Distribution Circuit Switching Operations (M19-CR)

5.5.7.1 Objective

This impact metric counts the number of switching actions performed by the DACR system and compares these numbers to historical manual switching data to estimate effects on operational costs.

5.5.7.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

Data collected prior to the implementation of the DMS system are artificially inflated due to the previous lack of a single system of record for tracking switching events.

5.5.7.3 Calculation Approach

The following queries and methods were used to generate results:

- Equipment switching events per equipment, equipment type, date, current state, circuit, substation, and event type were calculated by counting equipment switching events.
- Short truck rolls avoided attributable to DACR technology were calculated by selecting those remote switching events that occurred during outages that were combined with two recloser switching events within 5 minutes of one another on the same circuit. This analysis was segmented by equipment type, month, circuit, and substation, and excluded outages with a single restoration step.

5.5.7.4 Organization of Results

Switching events are presented as counts of device operations by device type over time.

Distribution Automation Circuit Reconfiguration



5.5.7.5 Data Collection Results

Automated Device Operations per Day

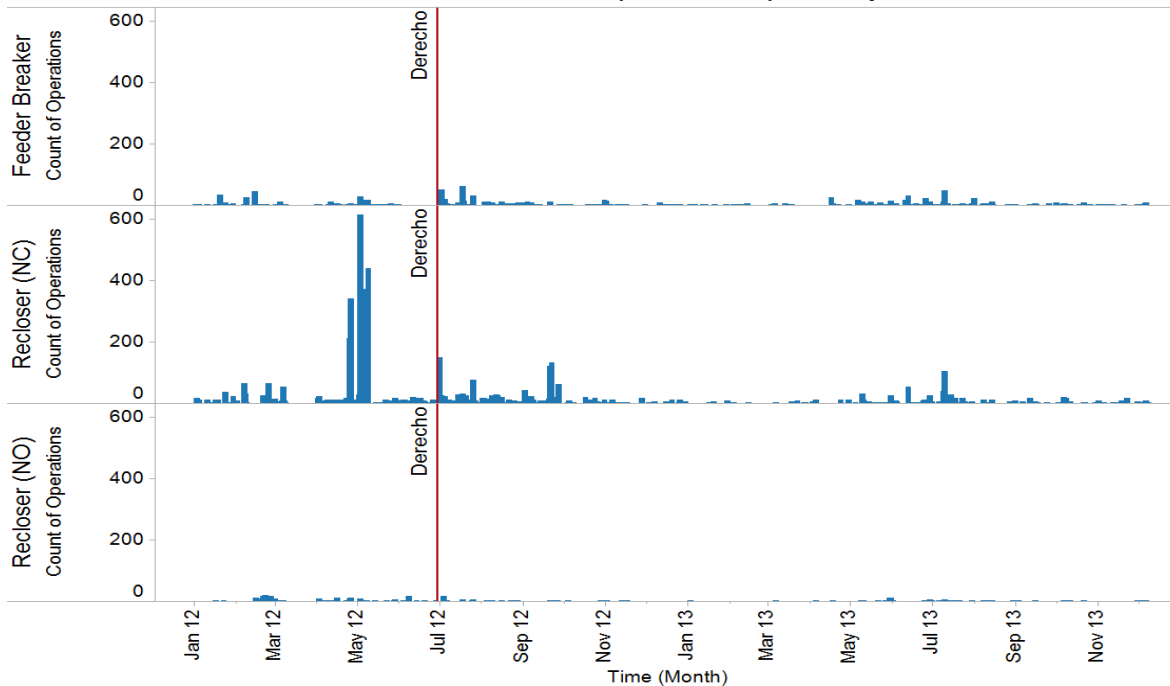


Figure 112. Automated Device Operations per Day

Remote Device Operations per Day

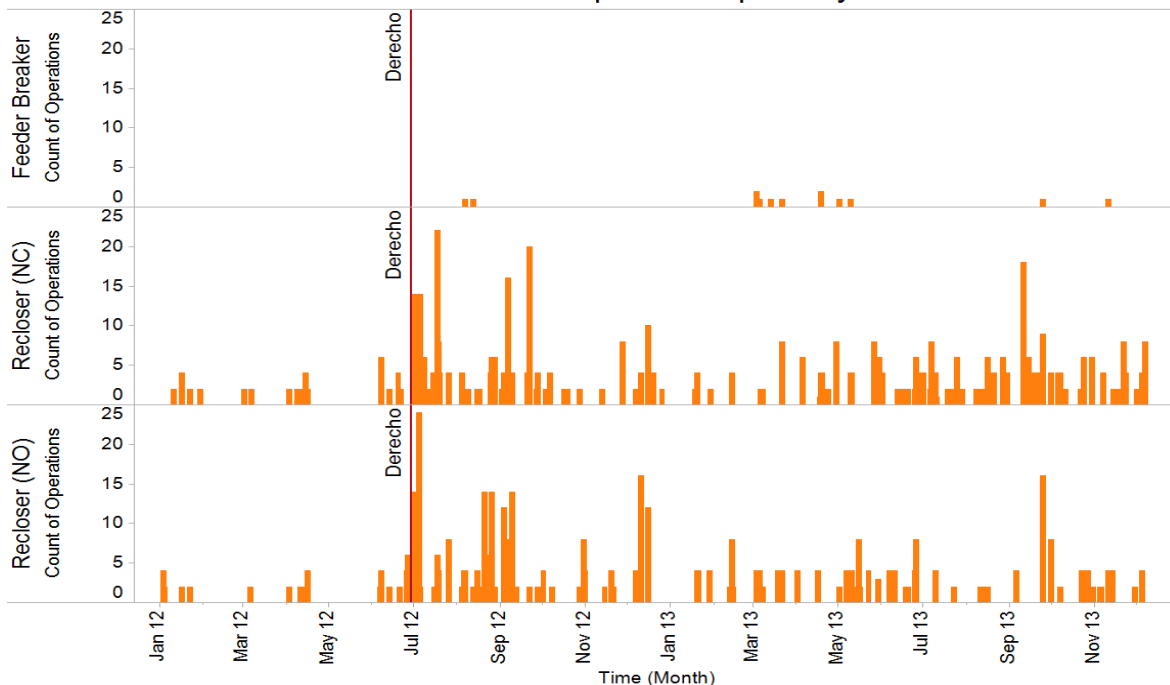


Figure 113. Remote Device Operations per Day

Distribution Automation Circuit Reconfiguration



5.5.7.6 Summary

There was insufficient data available to draw conclusions about the overall number of events and whether they were declining as the DACR technology was tuned and operational experience matures, or increasing, and the effect of weather events on the number of switching events.

Distribution Automation Circuit Reconfiguration



5.5.8 Distribution Restoration Cost (M21-CR)

5.5.8.1 Objective

This impact metric compares Customer Minutes of Interruption (CMI) avoided for manual switching activities to automated switching by DACR.

5.5.8.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

Cost savings for CMI avoided was attributed to achieving reduced labor and associated costs such as reduction in lodging expenses. Using both major and non-major event data from 2005 through 2009, a 5-year average was computed. This extended time period accounts for annual variation caused by weather events.

5.5.8.3 Calculation Approach

Using a charge code set up for restoration on DACR circuits, the following queries and methods were used to generate results:

- Distribution restoration CMI per circuit, substation, outage, and date were calculated by subtracting the time of the first customer call from the time of the outage in minutes multiplied by the number of customers affected by the outage.
- Distribution restoration CMI costs per circuit, substation, outage, and date were calculated by subtracting the time of the first customer call from the time of the outage in minutes multiplied by the number of customers affected by the outage multiplied by \$0.052 yields dollars per minute.
- CMI avoided per circuit, substation, and month for non-jurisdictional major event days were calculated by selecting the CMI avoided reported by AEP Ohio.
- CMI avoided costs per circuit, substation, and month for non-jurisdictional major event days were calculated by multiplying the CMI avoided reported by AEP Ohio by \$0.052 yields dollars per minute.

5.5.8.4 Organization of Results

This metric presents CMI avoided by DACR and the associated cost savings of reducing CMI. Each graph shows the total customer minutes or equivalent cost impact of avoided CMI by month due to DACR.

Distribution Automation Circuit Reconfiguration



5.5.8.5 Data Collection Results

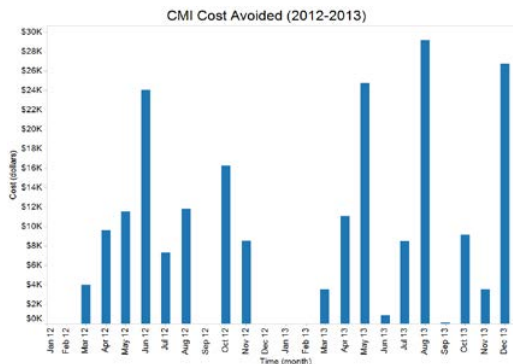
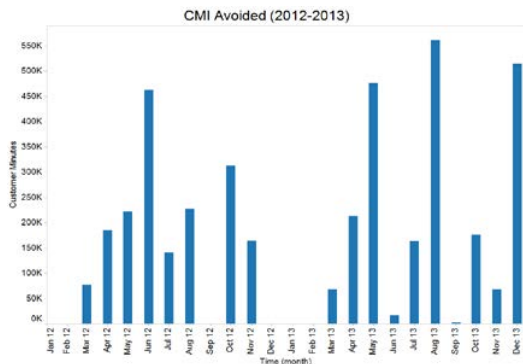


Figure 115. CMI Avoided Due to DACR

Figure 114. Dollar Value of CMI Avoided Due to DACR

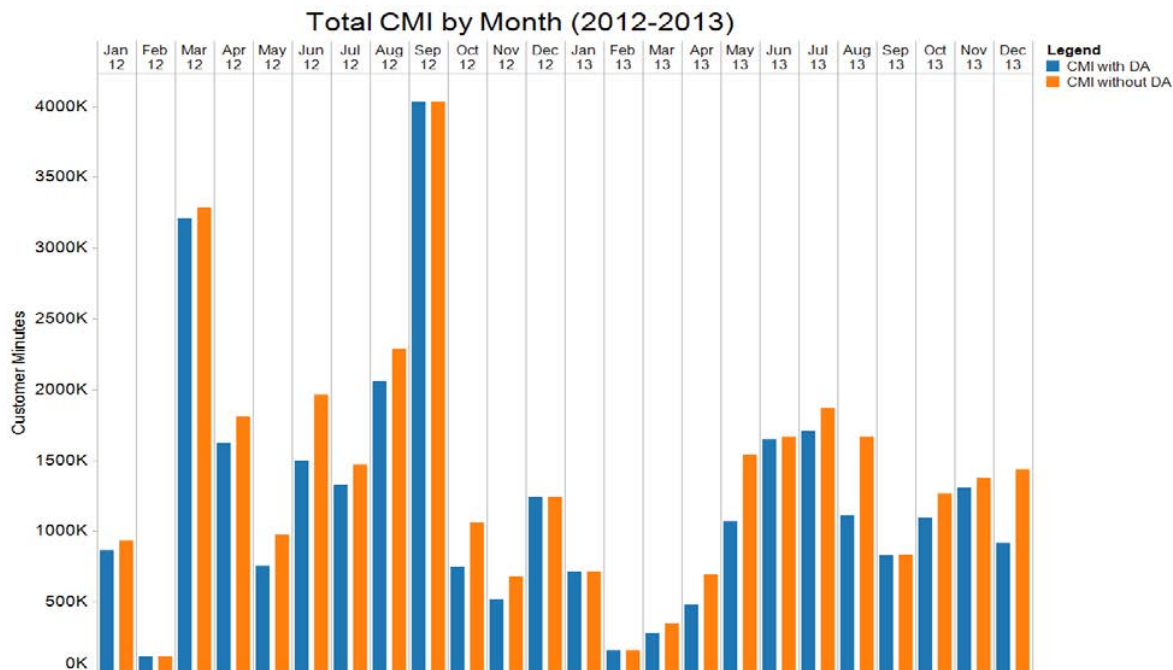


Figure 116. Total Project Area CMI With and Without DACR

Distribution Automation Circuit Reconfiguration



5.5.8.6 Summary

DACR was able to successfully reduce CMI when outages occurred in the Project area, which resulted in a corresponding dollar value savings. Some months showed greater savings than others, including some months with no savings. This may be due to the location of the outages on the circuit. Only the outages that were in an area where a circuit reconfiguration was possible were capable of resulting in a CMI reduction. CMI impacts varied in direct proportion to the number of outage events that occurred and were typically driven by weather patterns.

5.5.9 Truck Rolls Avoided (M25-CR)

5.5.9.1 Objective

This metric provides a count of the number of switching actions performed by the DACR system that would otherwise have required a truck roll for manual switching.

5.5.9.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

All circuit reconfiguration events would have been previously performed by a dispatched crew before the installation of DACR.

5.5.9.3 Calculation Approach

Analysis was conducted by counting the number of remote switching operations and assigning each as either a short or standard truck roll avoided. Standard truck rolls represented a crew traveling from the service center to a switching location. Short truck rolls represented a crew traveling from one switching device to another nearby switching device on the same circuit or on an adjacent circuit.

The following queries and methods were used to generate results:

- Short truck rolls avoided per equipment, equipment type, month, circuit, and substation due to DACR technology were calculated by selecting remote equipment switching events that occurred during multi-step restoration outages. These were combined with remote recloser switching events that occurred within five minutes of another remote recloser switching event on the same circuit.
- Standard truck rolls avoided per equipment, equipment type, month, circuit, and substation due to DACR technology were calculated by selecting remote recloser switching events which occurred more than 5 minutes after another remote recloser switching event on the same circuit that did not occur during an outage with a single restoration step.

5.5.9.4 Organization of Results

Truck rolls avoided by automated DACR switching may be one of two types: Standard truck rolls represented a crew traveling from the service center to a switching location. Short truck rolls represented a crew traveling from one switching device to another nearby switching device on the same circuit or on an adjacent circuit. These graphs show the total count of short and standard truck rolls avoided by month.

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5.5.9.5 Data Collection Results

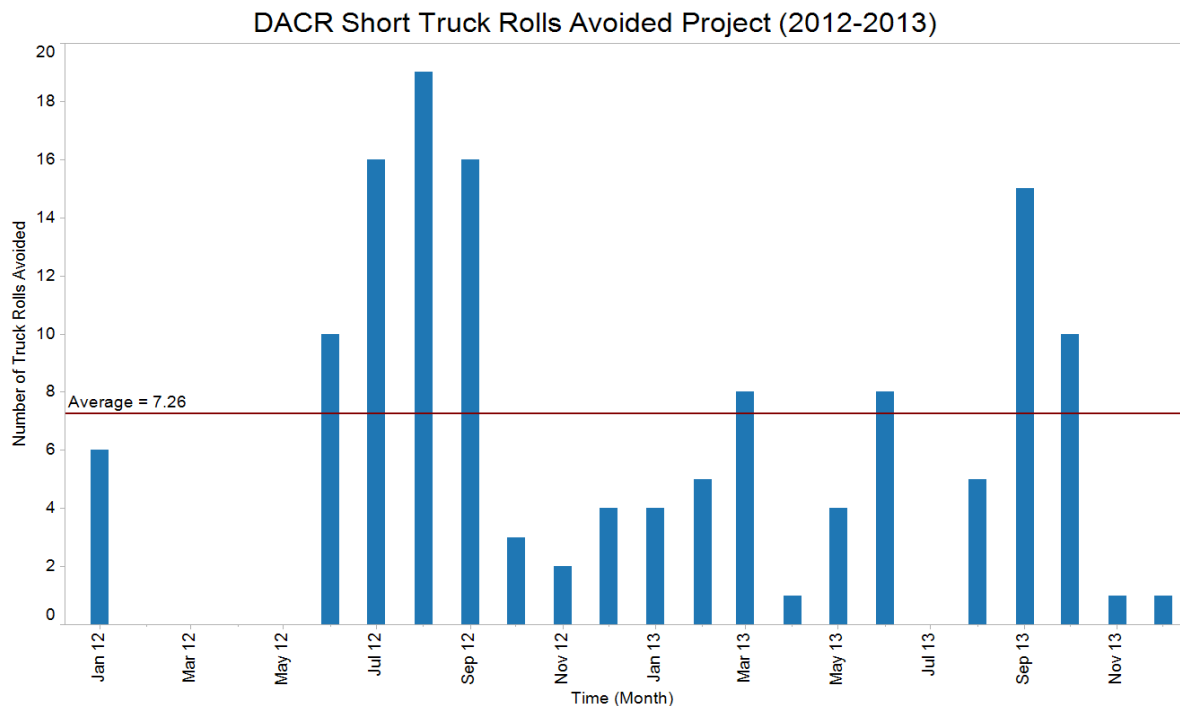


Figure 117. Short Truck Rolls Avoided due to DACR

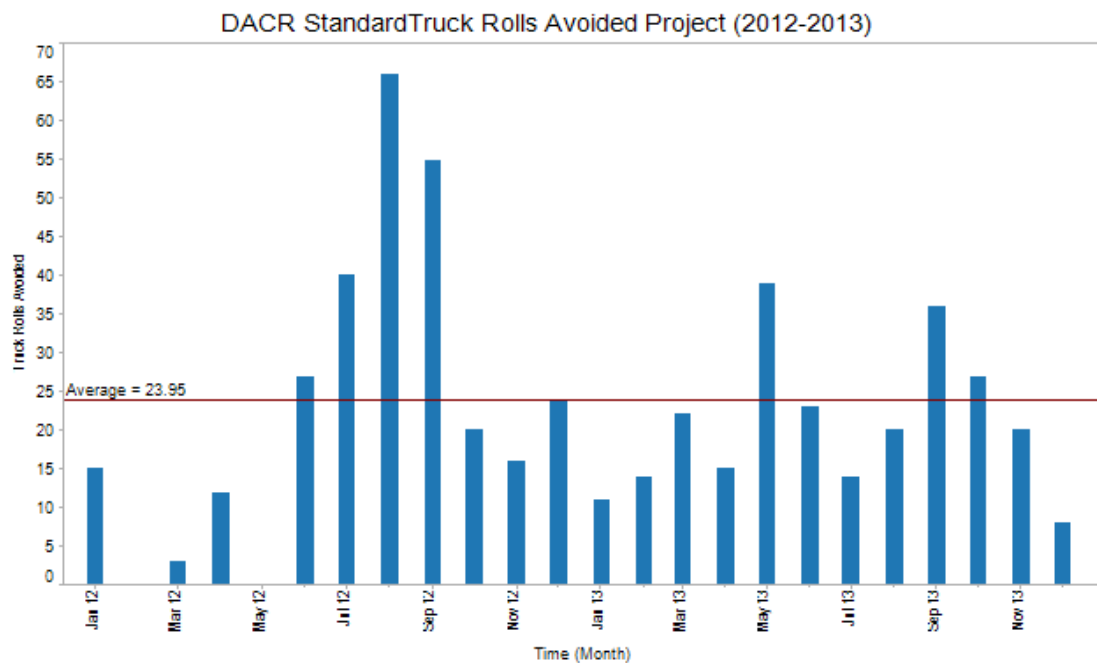


Figure 118. Standard Truck Rolls Avoided due to DACR

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5.5.9.6 Summary

Truck rolls were primarily avoided due to the reconfiguration that happened after outages. Therefore the number of truck rolls avoided per month varied greatly depending on weather events. Due to the short duration of the project, the average number of truck rolls avoided over time may not have been consistent with those experienced during the Project.

Distribution Automation Circuit Reconfiguration



5.5.10 SAIFI (M26-CR)

5.5.10.1 Objective

This metric provides a report of actual System Average Interruption Frequency Index (SAIFI) for DACR project circuits as well as calculations of what SAIFI would have been without DACR.

5.5.10.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

This analysis assumed that customers restored within five minutes using DACR did not experience a sustained outage, in accordance with IEEE 1366 definitions.

5.5.10.3 Calculation Approach

Actual SAIFI data was reported directly by AEP Ohio. SAIFI without DACR was calculated using customers interrupted (CI) avoided due to DACR.

The following queries and methods were used to generate results. Note that major event days were calculated as defined in IEEE 1366:

- SAIFI With DACR: SAIFI per month, circuit, and substation was calculated by dividing CI excluding major event days by the number of consumers served on the circuit:
$$\text{SAIFI} = \text{CI} / \text{customers served.}$$
- SAIFI Without DACR: SAIFI per month, circuit, and substation was calculated by adding the avoided CI excluding major event days to the CI with DACR excluding major event days and dividing that sum by the number of consumers served on the circuit.

5.5.10.4 Organization of Results

This metric presents a comparison of monthly SAIFI for System area circuits with and without DACR capabilities. The graph and tables show the total SAIFI per month for all Project area circuits.

Distribution Automation Circuit Reconfiguration



5.5.10.5 Data Collection Results

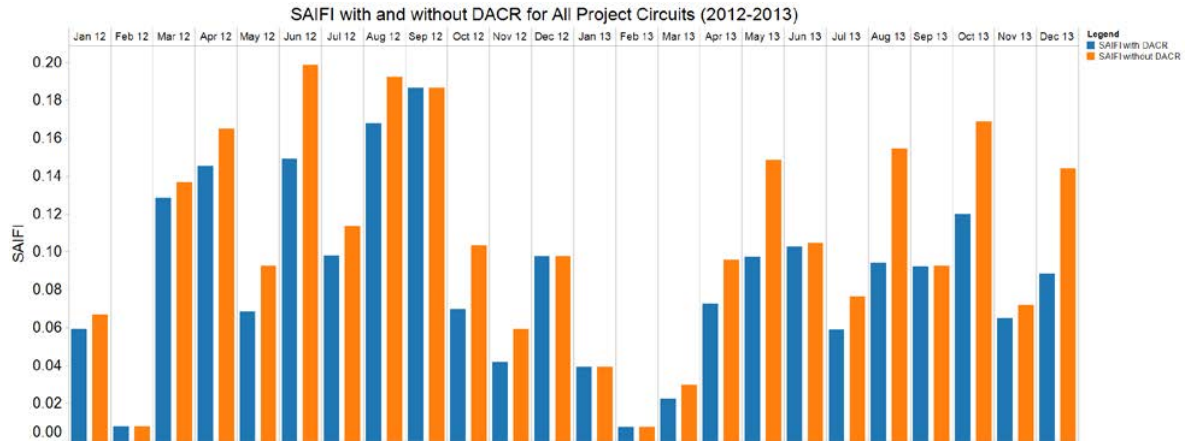


Figure 119. SAIFI with and without DACR for Project Area Circuits

Project Area (70 circuits)				
	Year	With DACR	Without DACR	% Improvement
SAIFI	2011	1.606	1.673	4.0%
	2012	1.226	1.400	12.4%
	2013	0.869	1.151	24.5%

Table 20. SAIFI Comparisons

5.5.10.6 Summary

Project area DACR circuits consistently demonstrated lower SAIFI values than those same circuits without DACR. The DACR impact on SAIFI will vary from circuit to circuit and from year to year depending on the number and location of outages.

Distribution Automation Circuit Reconfiguration



5.5.11 SAIDI/CAIDI (M27-CR)

5.5.11.1 Objective

This metric provides a report of actual System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI) for DACR project circuits as well as a calculation of what SAIDI and CAIDI would have been without DACR. Each graph shows the total SAIDI or CAIDI per month for circuits with and without DACR.

5.5.11.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

This analysis assumed that customers restored within five minutes using DACR did not experience a sustained outage, in accordance with IEEE 1366 definitions.

5.5.11.3 Calculation Approach

Actual SAIDI and CAIDI data were reported directly by AEP Ohio. SAIDI and CAIDI without DACR were calculated using customers interrupted (CI) and customer minutes interrupted (CMI) avoided due to DACR.

The following queries and methods were used to generate results. Note that major event days were calculated as defined in IEEE 1366:

- SAIDI with DACR: SAIDI per month, circuit, and substation was calculated by dividing CMI excluding major event days by the number of customers served on the circuit:
$$\text{SAIDI} = \text{CMI} / \text{customers served.}$$
- SAIDI without DACR: SAIDI per month, circuit, and substation was calculated by adding the avoided CMI for non-jurisdictional major event days to the CMI with DACR excluding major event days and dividing that sum by the number of customers served on the circuit.
- CAIDI with DACR: CAIDI per month, circuit, and substation was calculated by dividing SAIDI with DACR by SAIFI with DACR: $\text{CAIDI} = \text{SAIDI} / \text{SAIFI}$.
- CAIDI without DACR: CAIDI per month, circuit, and substation was calculated by dividing SAIDI without DACR by SAIFI without DACR.

5.5.11.4 Organization of Results

This metric presents a comparison of monthly SAIDI and CAIDI for Project area circuits with and without DACR capabilities.

Distribution Automation Circuit Reconfiguration



5.5.11.5 Data Collection Results

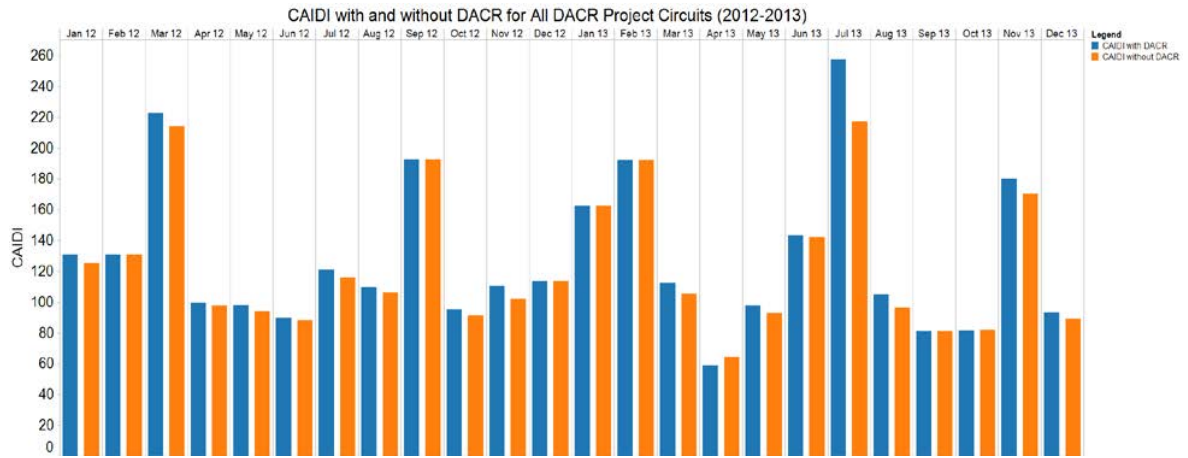


Figure 120. CAIDI with and without DACR for all Project Area Circuits

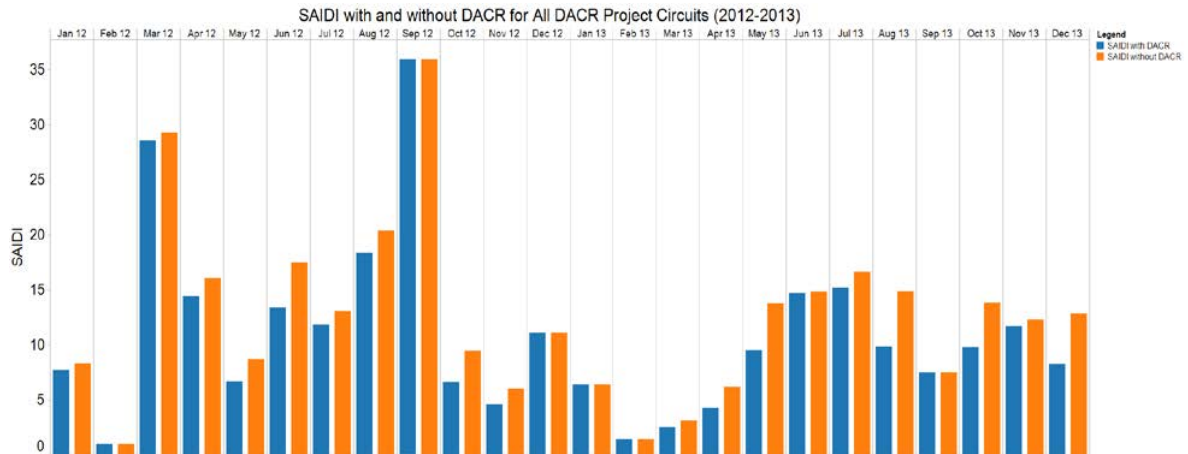


Figure 121. SAIDI with and without DA for All DACR Project Area Circuits

Project Area (70 circuits)				
	Year	With DACR	Without DACR	% Improvement
SAIDI	2011	180.9	186.5	3.0%
	2012	161.4	175.7	8.2%
	2013	99.7	123.1	19.0%
CAIDI	2011	112.6	111.4	-1.1%
	2012	131.6	125.6	-4.8%
	2013	114.7	107.0	-7.3%

Table 21. SAIDI/CAIDI Comparisons

Distribution Automation Circuit Reconfiguration



5.5.11.6 Summary

DACR technology had more impact on SAIDI than on CAIDI. DACR technology reduced the number of impacted consumers and resulted in a reduction in SAIDI, on individual outages. The impact of DACR on the SAIDI of the Project area will vary from year to year depending on the number and location of outages as well as annual weather events. CAIDI measured the average outage duration for only those consumers who experience a sustained outage.

Once DACR technology minimized the impact of an outage, consumers not able to be restored by DACR experienced similar outage duration as consumers on non-DACR circuits. Service that would have been restored quickly in the past could now be restored so quickly that a sustained interruption was not experienced. It appeared that consumers who experienced a sustained outage were interrupted for a longer duration because CAIDI increased. The reason for the increase was that short duration outages were removed from the average that CAIDI represented. The fundamental time to repair each fault/outage was not impacted directly by DACR technology.

Distribution Automation Circuit Reconfiguration



5.5.12 MAIFI (M28-CR)

5.5.12.1 Objective

This metric provides an estimation of monthly Momentary Average Interruption Frequency Index (MAIFI) in the Project area.

5.5.12.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

Only recloser and breaker operations that resulted in interruptions lasting less than 5 minutes in duration and did not result in a lockout contributed to the MAIFI.

5.5.12.3 Calculation Approach

The following queries and methods were used to generate results:

MAIFI is defined as the number of momentary customer interruptions occurring in a time period divided by the number of customers served.

$$MAIFI = \frac{CI_{mom}}{Customers_Served}$$

The number of momentary customer interruptions per month was computed in several steps.

1. All customers were assigned to a recloser or breaker zone.
2. The energy state was determined for each zone through time accounting for circuit reconfiguration.
3. Any time a zone was de-energized and then re-energized for a period of 5 minutes or less, momentary customer interruptions were counted for all customers in the zone. Note that momentary interruptions occurring less than 5 minutes before or after a sustained interruption or previously counted momentary interruption were not included in this count.

Once a count of momentary customer interruptions was determined, MAIFI was then computed for each month over the Project area.

5.5.12.4 Organization of Results

This metric presents the monthly MAIFI for Project area circuits.

Distribution Automation Circuit Reconfiguration



5.5.12.5 Data Collection Results

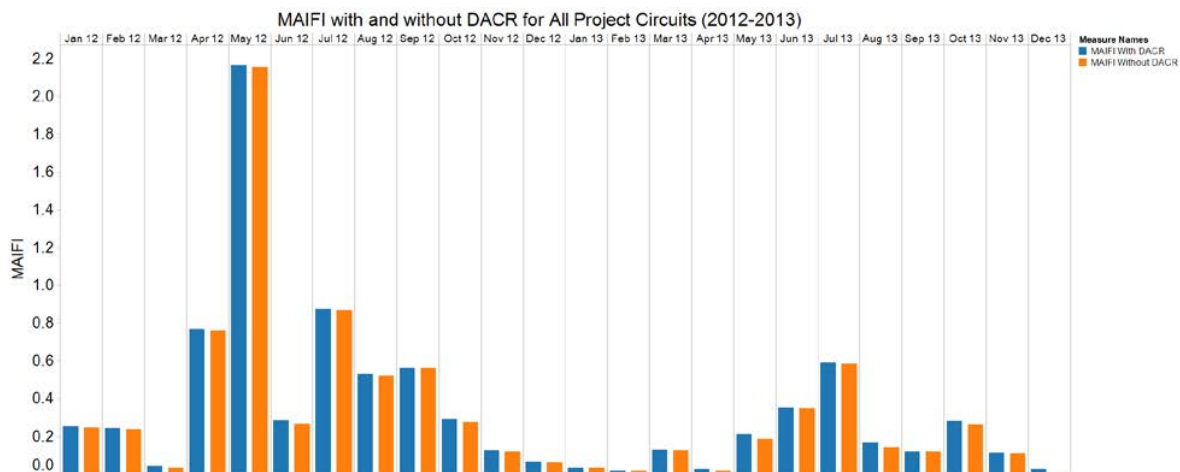


Figure 122. Monthly MAIFI With and Without DACR circuits

5.5.12.6 Summary

Historical data for comparison was not available prior to the Project because AEP did not have a mechanism for tracking MAIFI. This was an example of how distribution automation improved visibility of AEP's distribution system.

The value of MAIFI with and without DACR showed that circuit reconfiguration contributed a very small increase in the number of momentary interruptions. This was expected because circuit reconfiguration effectively converted sustained outages into momentary interruptions for consumers in zones that were reconfigured.

Distribution Automation Circuit Reconfiguration



5.5.13 Outage Response Time (M29-CR)

5.5.13.1 Objective

This metric is intended to gauge the improvement in the response time that occurs as a result of DACR notification.

5.5.13.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

This analysis assumed that outage response time was defined as the time it took for AEP Ohio to become aware that an outage had occurred. This metric did not include the time it took to correct the outage.

5.5.13.3 Calculation Approach

The following queries and methods were used to generate results:

For each outage reported on circuits with DACR installed, the time of the first associated lost-power customer event was compared to the DACR reported outage start time.

5.5.13.4 Organization of Results

Data required for this metric requires reliable matching of customer event calls with specific outages reported by DACR. This customer/DACR event matching was not achievable under the current record keeping system.

5.5.13.5 Data Collection Results

No results are available.

5.5.13.6 Summary

This consumer to DACR event matching was not achievable under the current record keeping system.

Distribution Automation Circuit Reconfiguration



5.5.14 Major Event Information (M30-CR)

5.5.14.1 Objective

This metric describes the DACR system's performance and usage during major events that occur during the demonstration period.

5.5.14.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

To demonstrate the impact of DACR on major event service, results achieved during the Derecho event are presented.

5.5.14.3 Calculation Approach

Not applicable

5.5.14.4 Organization of Results

This metric presents the findings of an AEP Ohio produced study of the Derecho event

5.5.14.5 Data Collection Results

The following major events were extracted from a special AEP Ohio study enumerating these events:

- DACR systems had limited ability to restore consumers within the first hour.
- 1,420 consumers on three circuits were restored to service automatically.
- DACR was disabled when the DDC determined the magnitude of damage.
- SCADA switching (53 remote recloser operations) of distribution line devices resulted in:
 - Restoration to service of approximately 10,000 consumers after repairs was completed.
 - Transfer and shedding load from limited circuits in abnormal and extreme loading conditions.
 - Estimated savings of 30-60 minutes per truck roll, resulting in approximately 40 hours of crew time saved where resources could be utilized elsewhere on the System.
 - Utilization of AMI meters to close over 300 outage tickets eliminating the use of field resources for verification.

5.5.14.6 Summary

DACR integration with the Distribution Management System (DMS) had positive impact on outage locating and restoration following major events.

Distribution Automation Circuit Reconfiguration



5.5.15 Distribution Operations Vehicle Miles (M31-CR)

5.5.15.1 Objective

This metric provides an estimate of the number of vehicle miles avoided due to DACR and compares it with mileage from a similar area without DACR.

5.5.15.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

All avoided truck rolls would have been dispatched from the normally assigned service center.

5.5.15.3 Calculation Approach

The following queries and methods were used to generate results:

Analysis was conducted by counting the number of remote switching operations and assigning each as either a short or standard truck roll avoided. Standard truck rolls represented a crew traveling from the service center to a switching location. Short truck rolls represented a crew traveling from one switching device to another nearby switching device on the same circuit or on an adjacent circuit.

The following queries and methods were used to generate results:

- Distribution operation vehicle miles per service center, month, vehicle, and vehicle characteristics for sections of circuits with DACR were calculated by multiplying vehicle mileage by the percentage of the circuit with DACR divided by 100. The distribution operation vehicle miles per service center, month, vehicle, and vehicle characteristics for sections of circuits without DACR were calculated by multiplying vehicle mileage by the percentage of the circuit without DACR divided by 100.
- Vehicle miles avoided due to DACR technology per service center, circuit, and month were calculated by summing the sum of urban (5 miles), rural (20 miles), and combination (10 miles) standard truck roll distances for standard truck rolls avoided with the sum of urban (2 miles), rural (4 miles), and combination (3 miles) short truck roll distances for short truck rolls avoided.

5.5.15.4 Organization of Results

This metric presents total vehicle miles avoided due to DACR by month. The graph shows the total miles avoided per month.

Distribution Automation Circuit Reconfiguration



5.5.15.5 Data Collection Results

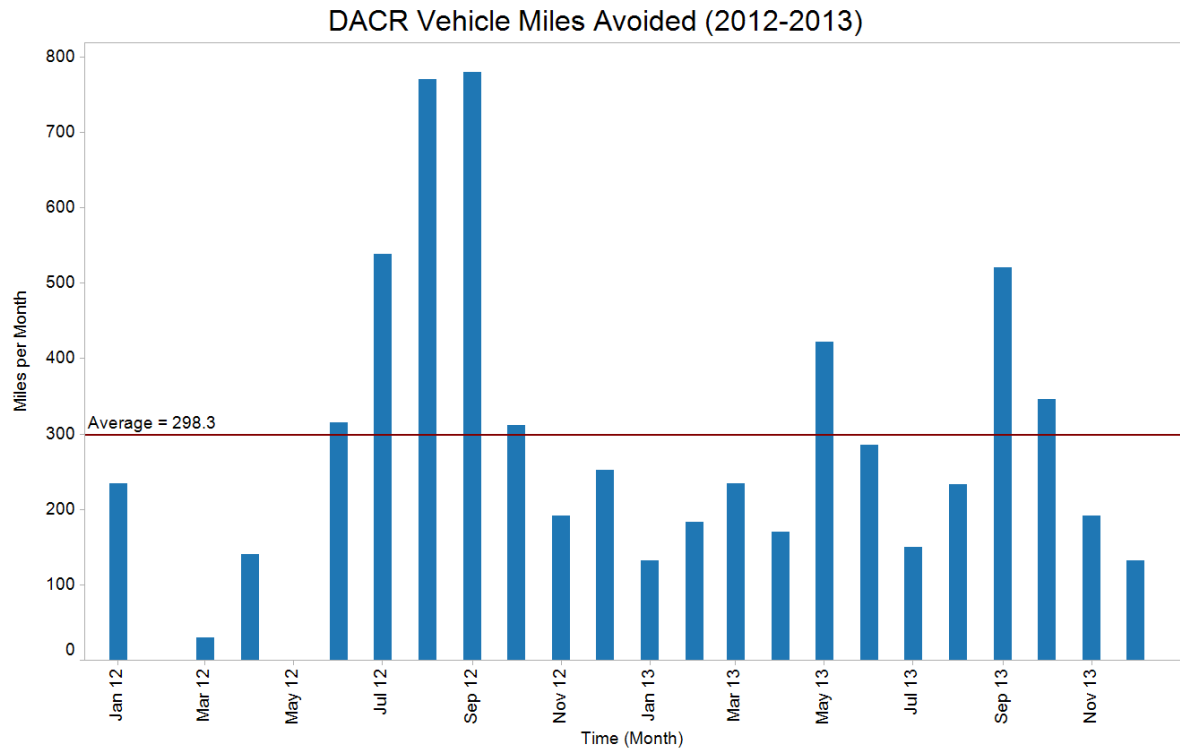


Figure 123. DACR Vehicle Miles Avoided

5.5.15.6 Summary

The DACR system and DMS reduced the number of miles driven to address operational activities. The average number of miles avoided is estimated at 298.3.

Distribution Automation Circuit Reconfiguration



5.5.16 CO₂ Emissions - Project area (M32-CR)

5.5.16.1 Objective

This impact metric provides an estimate of the amount of avoided and/or added CO₂ emitted due to reduced driving miles resulting from use of DACR technology.

5.5.16.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data:

- The only significant impacts on CO₂ emissions due to DACR are achieved through truck rolls avoided since DACR has little direct impact on consumer usage patterns.

- SO_x: 0.00263084 kg/kWh

Source: *U.S. EPA eGRID2012 Version 1.0 Year 2009 Summary Tables for RFC West Region*

- NO_x: 0.00117934 kg/kWh

Source: *U.S. EPA eGRID2012 Version 1.0 Year 2009 Summary Tables for RFC West Region*

- PM_{2.5}: 0.001 kg/kWh

Source: *U.S. EPA eGRID2012 Version 1.0 Year 2009 Summary Tables for RFC West Region*

5.5.16.3 Calculation Approach

CO₂ reduction was calculated as a function of vehicle miles avoided using emissions data specific to AEP Ohio's distribution service fleet vehicles.

The following queries and methods were used to generate results:

- Short truck rolls avoided per equipment, equipment type, month, circuit, and substation due to DACR technology were calculated by selecting remote equipment switching events that occurred during multi-step restoration outages. These were combined with remote recloser switching events that occurred within five minutes of another remote recloser switching events on the same circuit.
- Standard truck rolls avoided per equipment, equipment type, month, circuit, and substation due to DACR technology were calculated by selecting remote recloser switching events which occurred more than 5 minutes after another remote recloser switching event on the same circuit that did not occur during an outage with a single restoration step.
- AEP Ohio determined an average fuel economy value for each vehicle. Corrected average monthly fuel efficiencies in miles per gallon per service center, month, and fuel type for vehicles used by the AEP Ohio Distribution business unit were calculated by calculating the average of monthly vehicle mileages divided by monthly quantity of fuel for each vehicle. Because some suspect monthly vehicle mileages (i.e., 703,281 miles) were received, if the average of monthly vehicle mileages divided by monthly quantity of fuel divided by the average monthly average fuel economy value was not between .5 and 2, average monthly average fuel economies were substituted for the average of monthly vehicle mileages divided by monthly quantity of fuel to calculate the corrected average monthly fuel efficiencies.

Distribution Automation Circuit Reconfiguration



- Tons of CO₂ avoided per service center, circuit, and month due to truck rolls avoided due to DACR technology were calculated by dividing vehicle miles avoided by the corrected average monthly fuel efficiency times (8.8 kg CO₂ emissions/gallon for gas engines, 10.1 kg CO₂ emissions/gallon for diesel engines) times 0.00110231131092 (kg to tons conversion factor).

5.5.16.4 Organization of Results

The following section describes the amount of CO₂ avoided due to DACR as a result of truck rolls avoided. The graph shows the amount of CO₂ avoided due to the net number of truck rolls avoided in the Project area.

5.5.16.5 Data Collection Results

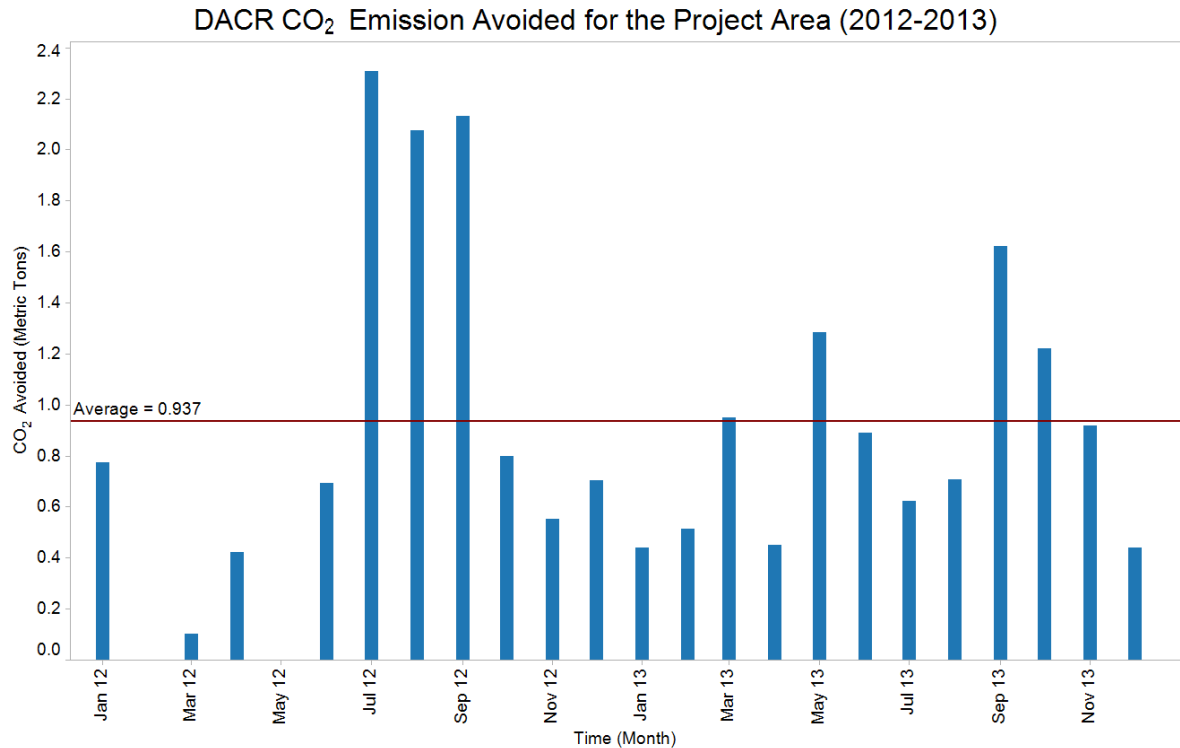


Figure 124. DACR CO₂ Emissions Avoided for the Project Area

5.5.16.6 Summary

Emissions reductions were a direct multiplier of avoided truck miles. CO₂ emissions were primarily reduced by the automated reconfiguration that happened after outages. Therefore the amount of CO₂ emissions reduced per month varied greatly depending on weather events.

Distribution Automation Circuit Reconfiguration



5.5.17 Pollutant Emissions - Project area: SO_x, NO_x, PM_{2.5} (M33-CR)

5.5.17.1 Objective

This impact metric provides an estimate of the amount of avoided and/or added pollutants emitted during driving miles due to use of DACR technology.

5.5.17.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

The significant impacts on pollutant emissions due to DACR were achieved through truck rolls avoided as DACR had little direct impact on consumer usage patterns.

- For the purposes of calculating SO_x for this metric, SO₂ emissions from vehicles was used as the measure for that metric.
- A CARB limit value of 0.05 grams of Nitrogen Oxides (NO_x) per mile

Source: *United States EPA 40 CFR part 86 Subpart S tier 2 Bin 5 Emissions limits at 50,000 mi*

- 0.01 g PM_{2.5} emissions/mi conversion factor

Source: *United States EPA 40 CFR part 86 Subpart S tier 2 Bin 5 Emissions limits at 100,000 mi*

- 0.165 g SO_x emissions/gallon for gas engines, .0963 g SO_x emissions/gallon for diesel engines conversion factor

Calculated from: sulfur content of gasoline = 30 ppm

Source: *U.S. EPA 40 CFR parts 80, 85, and 86 AMS-FRL-6516-2*

Sulfur content of ULSD diesel fuel = 15 ppm

Source: *U.S. EPA Office of Transportation and Air Quality Emissions Facts (EPA420-F-00-057)*

Molecular weight of SO₂ = 64 g/mole

Density of gasoline = 2.75 kg/gallon

Density of diesel fuel = 3.21 kg/gallon

Distribution Automation Circuit Reconfiguration



5.5.17.3 Calculation Approach

Pollutant reduction was calculated as a function of vehicle miles avoided using emissions data specific to AEP Ohio's distribution service fleet vehicles.

The following queries and methods were used to generate results:

- Short truck rolls avoided per equipment, equipment type, month, circuit, and substation due to DACR technology were calculated by selecting remote equipment switching events that occurred during multi-step restoration outages. These were combined with remote recloser switching events that occurred within five minutes of another remote recloser switching events on the same circuit.
- Standard truck rolls avoided per equipment, equipment type, month, circuit, and substation due to DACR technology were calculated by selecting remote recloser switching events which occurred more than 5 minutes after another remote recloser switching event on the same circuit that did not occur during an outage with a single restoration step.
- AEP Ohio determined average fuel economy value for each vehicle. Corrected average monthly fuel efficiencies in miles per gallon per service center, month, and fuel type for vehicles used by the AEP Ohio Distribution business unit were determined by calculating the average of monthly vehicle mileages divided by monthly quantity of fuel for each vehicle. Because some suspect monthly vehicle mileages (i.e., 703,281 miles) were received, if the average of monthly vehicle mileages divided by monthly quantity of fuel divided by the average monthly average fuel economy value was not between 0.5 and 2.0, average monthly average fuel economies were substituted for the average of monthly vehicle mileages divided by monthly quantity of fuel to calculate the corrected average monthly fuel efficiencies.
- Kilograms of NO_x avoided per service center, circuit, and month due to truck rolls avoided due to DACR technology were calculated by multiplying vehicle mileage avoided multiplied by 0.05 g NO_x emissions per mile multiplied by 0.001 (g to kg conversion factor).
- Kilograms of PM_{2.5} avoided per service center, circuit, and month due to truck rolls avoided due to DACR technology were calculated by multiplying vehicle mileage avoided multiplied by 0.01 g PM_{2.5} emissions per mile multiplied by 0.001 (g to kg conversion factor).
- Kilograms of SO₂ avoided per service center, circuit, and month due to truck rolls avoided due to DACR technology were calculated by dividing vehicle miles avoided by the corrected average monthly fuel efficiency multiplied by (.165 g SO₂ emissions/gallon for gas engines, .0963 g SO₂ emissions/gallon for diesel engines) multiplied by 0.001 (g to kg conversion factor).

5.5.17.4 Organization of Results

The following section describes the amount of pollutants avoided due to DACR as a result of truck rolls avoided. The graph shows the amount of pollutants avoided due to the net number of truck rolls avoided in the Project area.

Distribution Automation Circuit Reconfiguration



5.5.17.5 Data Collection Results

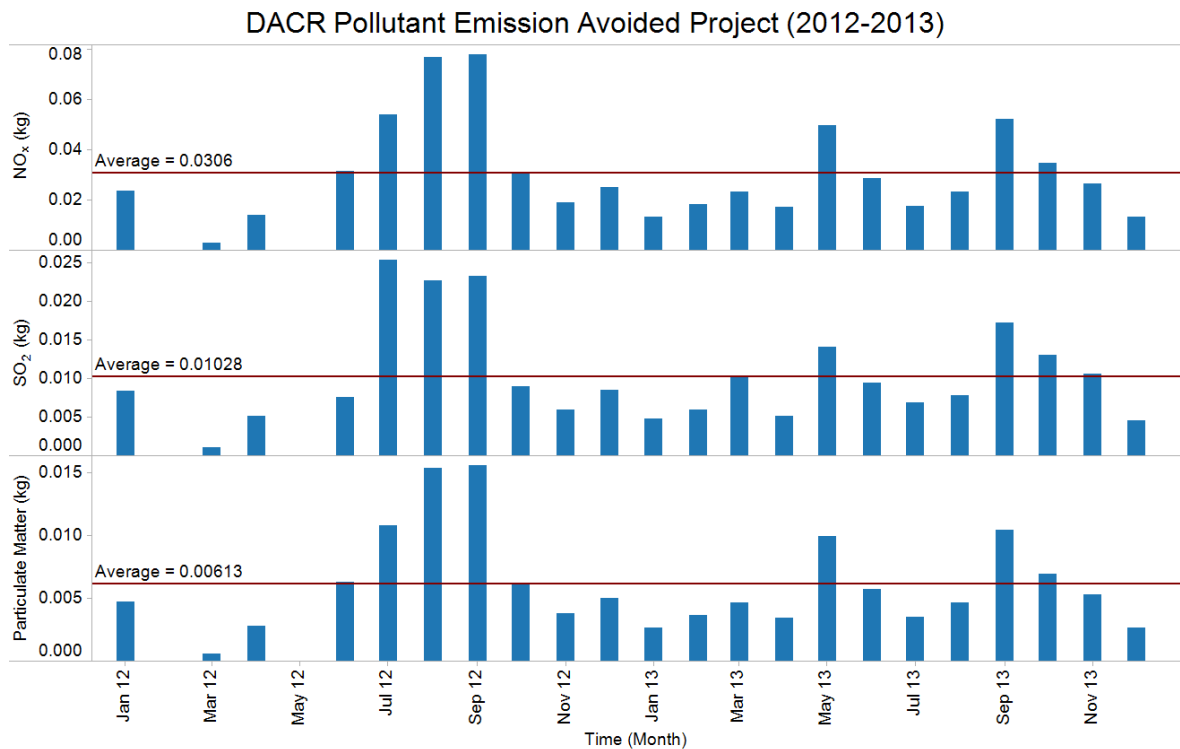


Figure 125. DACR Pollutant Emissions Avoided - Project Area

5.5.17.6 Summary

Emissions reductions were a direct multiplier of avoided truck miles. Pollutant emissions were primarily reduced by the automated reconfiguration that happened after outages. Therefore, the amount of pollutant emissions reduced per month varied greatly depending on weather events.

Distribution Automation Circuit Reconfiguration



5.5.18 CO₂ Emissions– System (M34-CR)

5.5.18.1 Objective

This metric provides an estimate of the CO₂ emissions that would be avoided by eliminating DACR related truck rolls throughout the entire System area.

5.5.18.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data:

- DACR impacts were consistent per circuit mile between the Project and non-Project areas.
- 8.8 kg CO₂ emissions/gallon for gas engines, 10.1 kg CO₂ emissions/gallon for diesel engines conversion factor.

Source: *United States EPA Office of Transportation and Air Quality Emissions Facts (EPA420-F-05-001)*

5.5.18.3 Calculation Approach

Project area CO₂ reduction was calculated as a function of vehicle miles avoided using emissions data specific to AEP Ohio's distribution service fleet vehicles. This reduction was then extrapolated to the System area based on the number of circuit miles in each area.

The following queries and methods were used to generate results:

Tons of CO₂ per service center and month that would be avoided if DACR technology were deployed throughout the System area estimated truck rolls avoided were calculated by multiplying the tons of CO₂ eliminated due to truck rolls avoided due to DACR technology multiplied by the ratio of circuit miles without DACR technology to circuit miles with DACR technology.

5.5.18.4 Organization of Results

The following section describes the amount of CO₂ avoided due to DACR as a result of truck rolls avoided. The graph shows the amount of CO₂ avoided due to the net number of truck rolls avoided in the System area.

Distribution Automation Circuit Reconfiguration



5.5.18.5 Data Collection Results

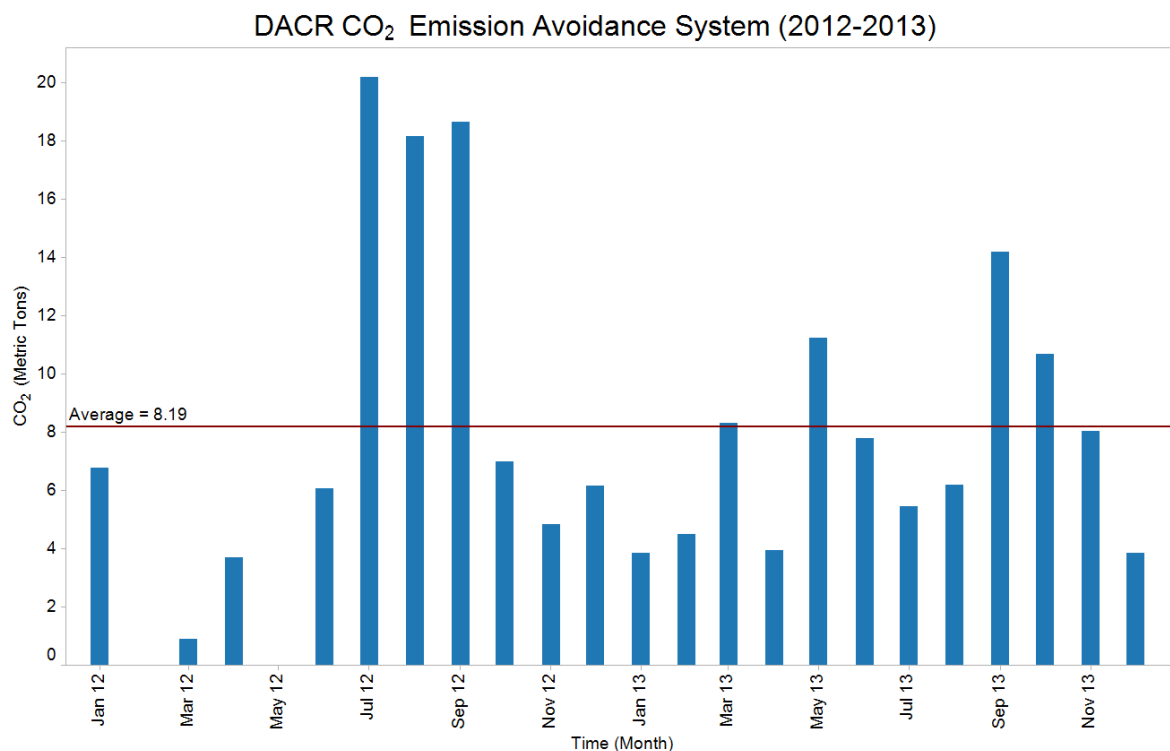


Figure 126. DACR CO₂ Emissions Avoided - System Area

5.5.18.6 Summary

Emissions reductions were a direct multiplier of avoided truck miles. CO₂ emissions were primarily reduced by the automated reconfiguration that happened after outages. Therefore the amount of CO₂ emissions reduced per month varied greatly depending on weather events.



5.5.19 Pollutant Emissions - System area: SO_x, NO_x, PM_{2.5} (M35-CR)

5.5.19.1 Objective

This metric provides an estimate of the pollutant emissions that would be avoided by eliminating DACR related truck rolls throughout the entire System area.

5.5.19.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data:

- DACR impacts were consistent per circuit mile between the Project and non-Project areas.
- A CARB limit value of 0.05 grams of Nitrogen Oxides (NO_x) per mile was used.

Source: *United States EPA 40 CFR part 86 Subpart S tier 2 Bin 5 Emissions limits at 50,000 mi*

- 0.01 g PM_{2.5} emissions/mi conversion factor

Source: *United States EPA 40 CFR part 86 Subpart S tier 2 Bin 5 Emissions limits at 100,000 mi*

- 0.165 g SO_x emissions/gallon for gas engines, 0.0963 g SO_x emissions/gallon for diesel engines conversion factor

Calculated from: sulfur content of gasoline = 30 ppm

Source: U.S. EPA 40 CFR parts 80, 85, and 86 AMS-FRL-6516-2

Sulfur content of ULSD diesel fuel = 15 ppm

Source: *U.S. EPA Office of Transportation and Air Quality Emissions Facts (EPA420-F-00-057)*

Molecular weight of SO₂ = 64 g/mole

Density of gasoline = 2.75 kg/gallon

Density of diesel fuel = 3.21 kg/gallon

5.5.19.3 Calculation Approach

Project area pollutant reduction was calculated as a function of vehicle miles avoided using emissions data specific to AEP Ohio's distribution service fleet vehicles. This reduction was then extrapolated to the System area based on number of circuit miles in each area.

The following queries and methods were used to generate results:

- Kilograms of SO₂ per service center and month that would be avoided if DACR technology were deployed throughout the AEP Ohio System area due to truck rolls avoided were calculated by multiplying the kilograms of SO₂ avoided due to truck rolls avoided due to DACR technology by the ratio of circuit miles without DACR technology to circuit miles with DACR technology.
- Kilograms of NO_x per service center and month that would be avoided if DACR technology were deployed throughout the AEP Ohio System area due to truck rolls avoided

Distribution Automation Circuit Reconfiguration



were calculated by multiplying the kilograms of NO_x avoided due to truck rolls avoided due to DACR technology by the ratio of circuit miles without DACR technology to circuit miles with DACR technology.

- Kilograms of PM_{2.5} per service center and month that would be avoided if DACR technology were deployed throughout the AEP Ohio System area due to truck rolls avoided were calculated by multiplying the kilograms of PM_{2.5} avoided due to truck rolls avoided due to DACR technology multiplied by the ratio of circuit miles without DACR technology to circuit miles with DACR technology.

5.5.19.4 Organization of Results

The following section describes the amount of pollutant avoided due to DACR as a result of truck rolls avoided. The graph shows the amount of pollutant avoided due to the net number of truck rolls avoided in the System area.

5.5.19.5 Data Collection Results

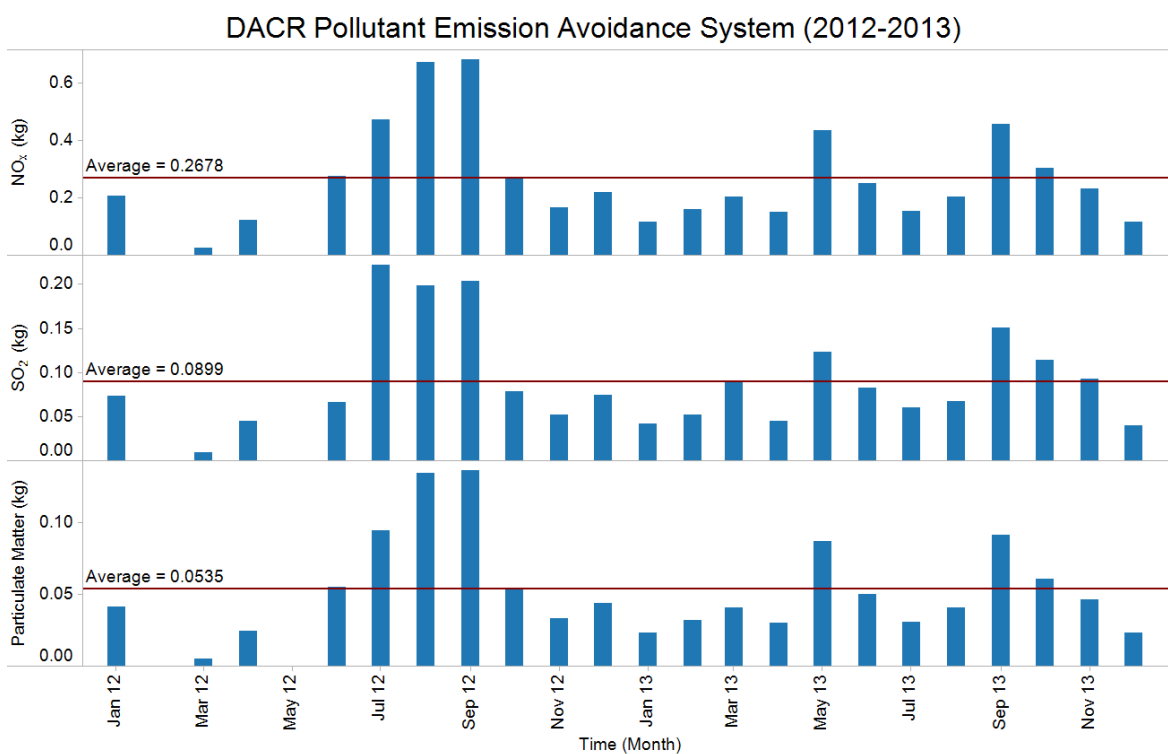


Figure 127. DACR Pollutant Emissions Avoided for System Area

5.5.19.6 Summary

Emissions reductions were a direct multiplier of avoided truck miles pollutant emissions were primarily reduced by the automated reconfiguration that happened after outages. Therefore the amount of pollutant emissions reduced per month varied greatly depending on weather events.

Distribution Automation Circuit Reconfiguration



5.6 DACR Conclusions

The most significant advantages of DACR were its impacts to reliability and its use during major events. Excluding major events, the Project, through the deployment of DACR on 70 circuits, was able to reduce Customer Minutes of Interruption (CMI) by 1,602,647 minutes, improving reliability for 19,309 consumers in 2012 and by 2,606,781 minutes, improving reliability for 31,407 consumers in 2013, as shown in the table below.

Project area (70 circuits)						
Year	Outages	Customers Interrupted	Customer Minutes Interrupted	# of Events (Automation Impacted CI)	Customers Restored via Automation	Customer Minutes Avoided
2010	2,244	163,380	17,940,145	n/a	n/a	n/a
2011	1,951	177,147	19,953,044	3	7,427	616,441
2012	1,838	136,741	17,989,775	16	19,309	1,602,647
2013	1,903	96,902	11,116,587	27	31,407	2,606,781

Table 22. DACR Outage Summary

Although weather conditions were the primary driver for changes in SAIFI and SAIDI, AEP Ohio could attribute some improvements of these indices from the DACR deployment. DACR technology had more impact on SAIFI than on SAIDI. DACR technology was typically able to reduce the number of consumers impacted by a specific outage resulting in a reduction in SAIFI. CAIDI represented the average outage duration for only those consumers who experienced a sustained outage and increased slightly.

Once DACR technology minimized the impact of an outage, consumers not able to be restored by DACR experienced similar outage duration as consumers on non-DACR circuits. Service that would have been restored quickly in the past could now be restored so quickly that a sustained interruption was not experienced. It appeared that consumers who experienced a sustained outage were interrupted for a longer duration because CAIDI increased. The reason for the increase was that short duration outages were removed from the average that CAIDI represented. The fundamental time to repair each fault/outage was not impacted directly by DACR technology.

During major events, DACR systems had limited ability to restore consumers within the first hour. DACR was initially disabled to ensure crew safety. When safety conditions were resolved, the system was enabled to aid restoration.

In addition to the reliability benefits described above, the systems also enabled crew labor savings, up to 2 hours per event, and in some instances avoided service calls entirely. This provided opportunities for AEP Ohio to perform additional proactive work on circuits in need of service, further enhancing reliability.



5.7 Lessons Learned

This section describes lessons learned for DACR technology. Lessons learned are provided for Technology, Implementation, and Operations.

5.7.1 Technology

- Implementation of a fully integrated vendor solution eliminates the need for multiple firmware upgrades and system enhancements.
- Provide training and process improvement to achieve the full benefit of the technology.
- Communications or control failures must return the field equipment to local control.
- Review and analysis of large amounts of data are essential to obtain the full benefits of DACR.
- Expand the design of circuit reconfiguration technologies to account for consumers with alternate feed sources, multiple station transformers and switching configurations.

5.7.2 Implementation

- Use compatible interface standards when integrating products to reduce failures and consumer service delays.
- Work closely with selected vendors to enhance existing products and facilitate integration with legacy equipment and systems.
- Develop standardized work processes for testing, configuring and commissioning devices and automation schemes.
- Plan and design the implementation of the voltage sensing equipment to enable installation on a one-pole structure.

5.7.3 Operations

- Standardize technology architecture and upgrades.
- Establish acceptance testing, customer support, and escalation procedures.
- Maintain a comprehensive inventory of spare components.
- Develop a formal process to integrate configuration control.
- Optimize the system to improve performance.
- Continue data collection and analysis to quantify long-term impacts to operations and maintenance costs.



6 DEMONSTRATED TECHNOLOGY – VOLT VAR OPTIMIZATION

6.1 Purpose

Volt VAR Optimization (VVO) is a demand-side management program that reduces energy consumption and demand without consumer interaction or participation. The primary focus of VVO is to reduce circuit demand and energy consumption by flattening and lowering voltage on the circuit while maintaining consumer service voltage standards. As a secondary goal VVO also attempts to provide reactive power support. Consumers realize lower consumption with the same level of comfort and service.

6.2 Technology

Traditionally voltage regulation on a circuit has been achieved by setting the voltage at the beginning of the circuit high enough so that voltages at the end of the circuit remained within acceptable limits. This approach provided acceptable service voltage even during peak load but did not result in the most efficient operation of the circuit. Voltage control devices, both regulators and shunt capacitors, traditionally have been operated using local set points. While the set points may be coordinated, capacitor and voltage regulator controls operate independently without communication to a master control that coordinates their operation. These independently operating, stand-alone devices may not optimize overall system efficiency.

VVO dynamically controls and coordinates multiple devices to manage both voltage and reactive power. System-wide efficiency is achieved by simultaneously coordinating operations using continuous measurements from multiple sensors distributed across the circuit.

The following figure shows a typical VVO implementation with components of the VVO system identified on a map showing the circuit layout.

Volt VAR Optimization

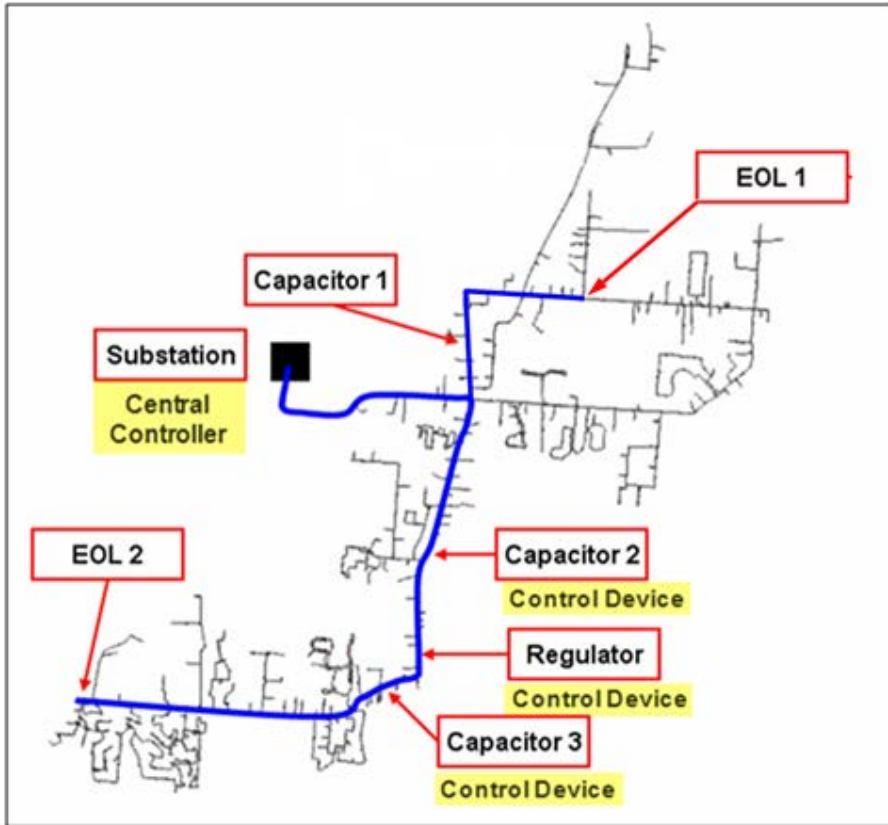


Figure 128. VVO Example

As shown in the VVO example, controls are placed on regulators and capacitors with a central controller installed at the substation. Distributed sensors, including end-of-line (EOL) monitors, supply the central controller with circuit, environmental, or other data. The central controller processes this data and instructs the control devices to adjust voltage and power factor on the line as needed. The controllers and monitors work together to maintain the voltage and power factor at a desirable level, thus reducing overall energy consumption.



6.3 Approach and Implementation

Similar to traditional voltage regulation methods, conceptual approaches to achieve VVO and the commercial systems to implement them vary widely. As part of the AEP Ohio gridSMART[®] Demonstration Project, two separate VVO systems were deployed.

Because VVO technology was evolving, commercial vendors had no ready-to-go system in place. AEP Ohio selected two vendors in order to gain experience installing the technology and to quantify the energy efficiency and demand reduction results.

One of the systems was General Electric Coordinated Volt VAR Control (CVVC). The CVVC provided command and control for S&C Electric Company's IntelliCAP[®] capacitor controllers and for Cooper CL6-B voltage regulator controllers while monitoring EOL voltages. Cooper CL6-B controllers operated both circuit voltage regulators and line voltage regulators. IntelliCAP controllers operated switched capacitor banks. The integrated system provided voltage and VAR support to flatten and lower a circuit's voltage profile while promoting unity power factor.

AEP Ohio also deployed the PCS Utilidata VVO system. The PCS system provided command and control for S&C Electric Company's IntelliCAP[®] capacitor controllers and for Cooper CL6-B voltage regulator controllers while monitoring EOL voltages. Cooper CL6-B controllers operated both circuit voltage regulators and line voltage regulators. IntelliCAP controllers operated switched capacitor banks. The integrated system provided voltage and VAR support to flatten and lower a circuit's voltage profile while promoting unity power factor.

Seventeen circuits, including 13kV and 34.5kV circuits, were selected for VVO installations. AEP Ohio installed the technology, including upgraded controls on existing regulators and capacitors, to determine the effectiveness on non-optimized circuits.

Volt VAR Optimization



6.4 Impact Metrics Required for VVO

The following impact metrics are associated with the VVO suite of technologies; 10 relate to the Project area and 2 relate to the System area.

Metric ID	Metric Scope	Metric Description	VVO
M03	Project	Peak Load and Mix	M03-VVO
M13	Project	Distribution Circuit Load	M13-VVO
M15	Project	Deferred Distribution Capacity Investments	M15-VVO
M16	Project	Equipment Failure Incidents	M16-VVO
M17	Project	Distribution Equipment Maintenance Cost	M17-VVO
M20	Project	Distribution Capacitor Switching Operations	M20-VVO
M22	Project	Distribution Losses (%)	M22-VVO
M23	Project	Distribution Power Factor	M23-VVO
M32	Project	CO ₂ Emissions	M32-VVO
M33	Project	Pollutant Emissions (SO _x , NO _x , PM _{2.5})	M33-VVO
M34	System	CO ₂ Emissions	M34-VVO
M35	System	Pollutant Emissions (SO _x , NO _x , PM _{2.5})	M35-VVO

Table 23. Impact Metrics Addressing VVO Technology Performance

Refer to the *Metrics Analysis for VVO* section that follows for details.



6.5 Metrics Analysis for VVO

This section provides details for each VVO metric, and includes those requested by the DOE during the definitization of the Cooperative Agreement. Trends were not always observed, however data is presented for each metric.

Please note that Project area and System area metrics related to emissions did not include the potential impact of shifting load over 24 hours.

6.5.1 Peak Load and Mix (M03-VVO)

6.5.1.1 Objective

The VVO dynamically flattens and lowers circuit voltage profiles to reduce energy consumption and demand while maintaining consumer service voltage standards. This impact metric provides an overview of residential electrical demand by circuit and the cumulative effects of VVO for selected circuits and months.

6.5.1.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

For circuits where Advance Metering Infrastructure (AMI) meters were available, peak load was measured as the sum of AMI real power readings. Where AMI was not available, the instantaneous real power supplied to a circuit's voltage regulator, measured in kW, was used. Power was recorded every 15 minutes for each of the three phases (A, B, and C). Instantaneous real power was computed as the sum of real power over all three phases.

- For this metric, peak load and mix includes only residential consumers.
- Hourly VVO On versus VVO Off load was temperature normalized using the approach described in the calculation subsection below. Additional weather factors and behavioral shifts across seasons/weeks were not considered.

6.5.1.3 Calculation Approach

The following queries and methods were used to generate results.

VVO peak load and mix were analyzed in three steps:

1. Determine temperature correction functions.
2. Apply temperature corrections.
3. Bin data into load profiles.

An extract of hourly data was created to select weekday load data from all residential consumers on the circuit being analyzed. Each data point in this extraction consists of a time stamp, average residential load aggregated over the entire circuit, and a temperature value. This data extract was then subdivided into two sets: one set for days during which the VVO system was operated in a day/on day/off sequence, and a second set for days in which the VVO system was operated in a steady on or off state.

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Temperature Normalization

Temperature normalizations were determined from the steady state data set. First, the data set was grouped by hour of the day. Then, for each hour, an average load was calculated. Next, each record was assigned a load ratio equal to load reading divided by average load as well as a temperature difference equal to the temperature reading minus 65 degrees F. For each hour, scatter plots were generated showing temperature difference versus load ratio and fitted using third order polynomial curves. The resulting polynomial functions were then used as temperature correction factors in subsequent stages of this analysis.

Temperature Correction

All raw temperature readings from the experimental day/on day/off data set were corrected using third order polynomials described above. Unique correction functions were used for each hour of the day as well as for VVO day/on versus VVO day/off times. All load readings were normalized to the monthly average temperature for each corresponding hour.

Load Profile

Load profile graphs were generated for each month by binning temperature corrected load values from the day/on day/off data set by hour of the day. Separate series were used to show readings when VVO was on versus readings taken when VVO was off.

6.5.1.4 Organization of Results

The following section presents load profile graphs for consumers on VVO circuits. These graphs each contain two lines, one line showing hours in which VVO was on and one line showing hours in which VVO was off. Graphs have been generated for residential consumers from a representative circuit for three months.

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6.5.1.5 Data Collection Results

Weekday Load Profile Circuit 1 May 2022 by Hour

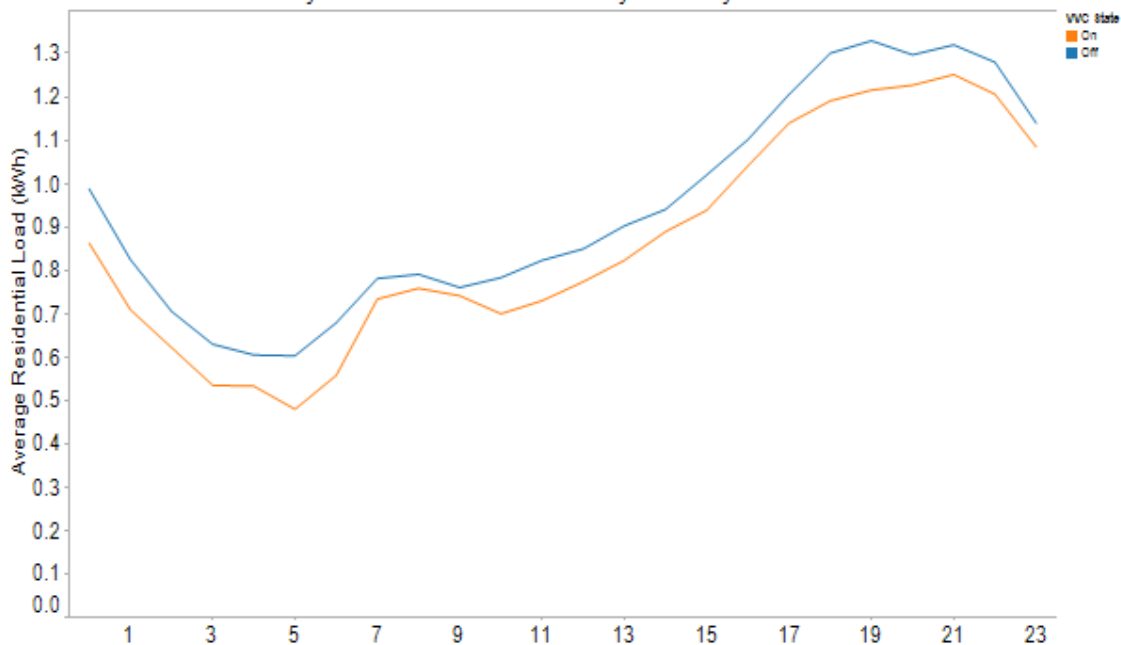


Figure 129. Temperature Normalized Hourly Load with VVO Day/On and Day/Off (May 2012)

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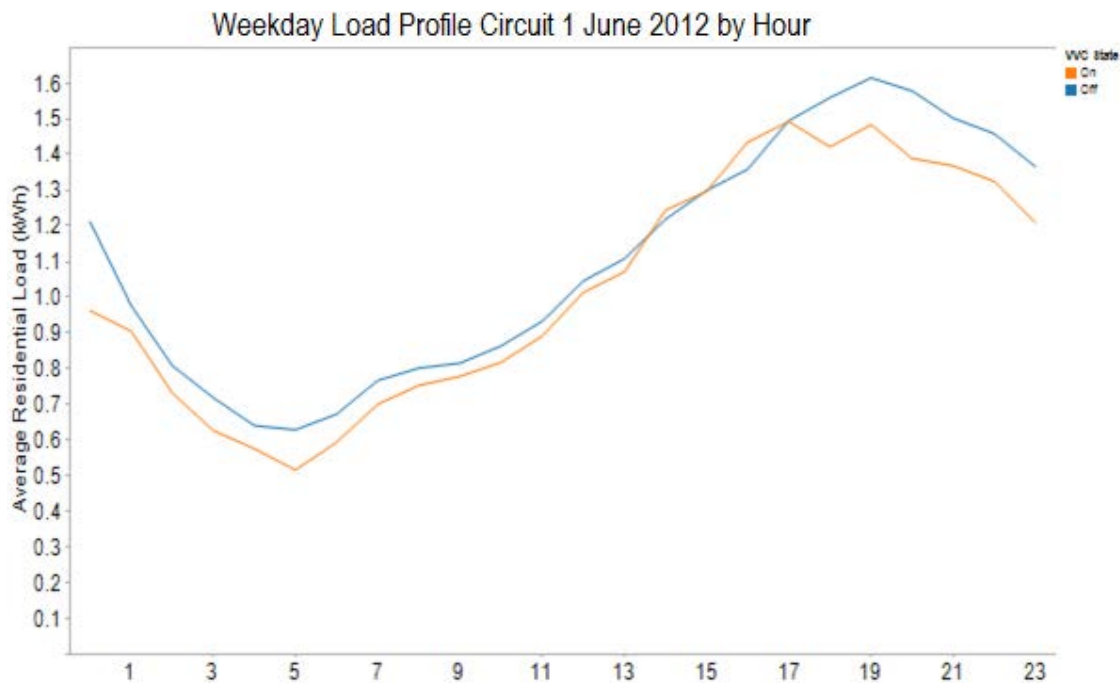


Figure 130. Temperature Normalized Hourly Load with VVO Day/On and Day/Off (June 2012)

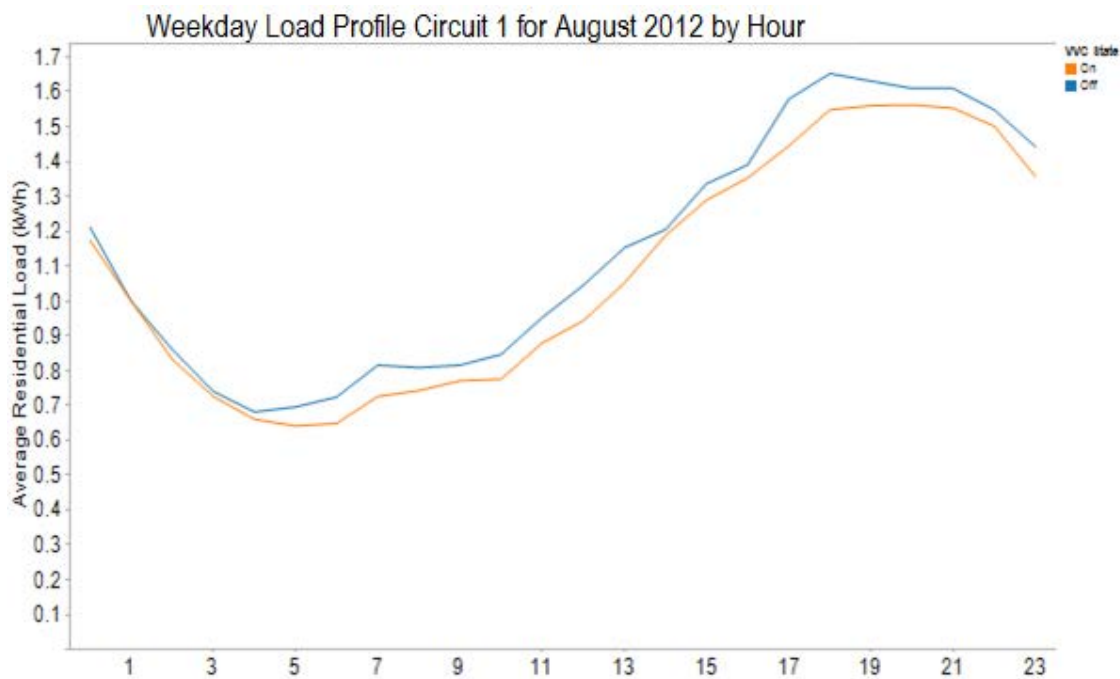


Figure 131. Temperature Normalized Hourly Load with VVO Day/On and Day/Off (Aug 2012)

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The preceding graphs represent the impacts of VVO on peak loading.

6.5.1.6 Summary

VVO provided an average of approximately 3 percent reduction in residential load for consumers with AMI meters during the test period.



6.5.2 Distribution Circuit Load (M13-VVO)

6.5.2.1 Objective

VVO is expected to reduce total circuit load by flattening and lowering voltage levels while maintaining consumer service standards. This metric examines the impact of VVO on circuit load.

6.5.2.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

VVO operated using the day/on day/off sequence for extended time periods during the Project. Circuit load was measured as the instantaneous real power measured in kW. Power was metered at the station regulator for each circuit every 15 minutes for each of the three phases (A, B, and C). Instantaneous real power was computed as the sum of real power over all three phases.

6.5.2.3 Calculation Approach

The following queries and methods were used to generate results.

Distribution feed load was analyzed in three steps:

1. Determine temperature correction functions.
2. Apply temperature corrections.
3. Bin data into load profiles.

An extract of hourly data was created to select weekday load data from all residential consumers on the circuit being analyzed. Each data point in this extraction consists of a time stamp, average residential load aggregated over the entire circuit, and a temperature value. This data extract was then subdivided into two sets: One set for days during which the VVO system was operated in a day/on day/off sequence, and a second set for days in which the VVO system was operated in a steady on or off state.

Temperature Normalization

Temperature normalizations were determined from the steady state data set. First, the data set was grouped by hour of the day. Then, for each hour, an average load was calculated. Next, each record was assigned a load ratio equal to load reading divided by average load as well as a temperature difference equal to the temperature reading minus 65 degrees F. For each hour, scatter plots were generated showing temperature difference versus load ratio and fitted using third order polynomial curves. The resulting polynomial functions were then used as temperature correction factors in subsequent stages of this analysis.

Temperature Correction

All raw temperature readings from the experimental day/on day/off data set were corrected using third order polynomials described above. Unique correction functions were used for each hour of the day as well as for VVO day/on versus VVO day/off times. All load readings were normalized to a temperature of 65 degrees F.

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Load Profile

Load profile graphs were generated for each month by binning temperature corrected load values from the day/on day/off data set by hour of the day. Separate series were used to show readings when VVO was on versus readings taken when VVO was off.

6.5.2.4 Organization of Results

The following section presents load profile graphs for VVO circuits based on circuit load data. Each graph contains two lines, one showing hours in which VVO was on and one showing hours in which VVO was off. Graphs have been generated separately for each month.

6.5.2.5 Data Collection Results

The figures on the following pages quantify the impact metric for this section.

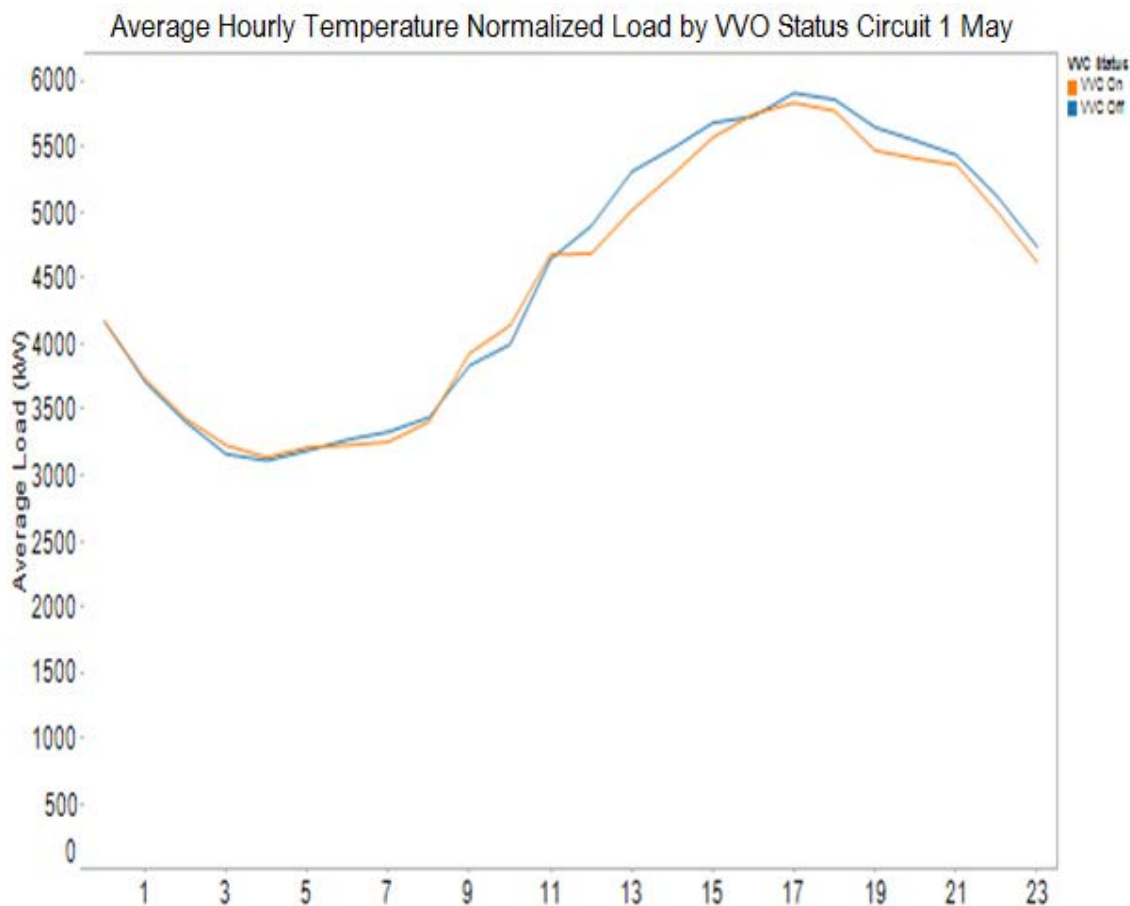


Figure 132. Circuit 1: Circuit Load

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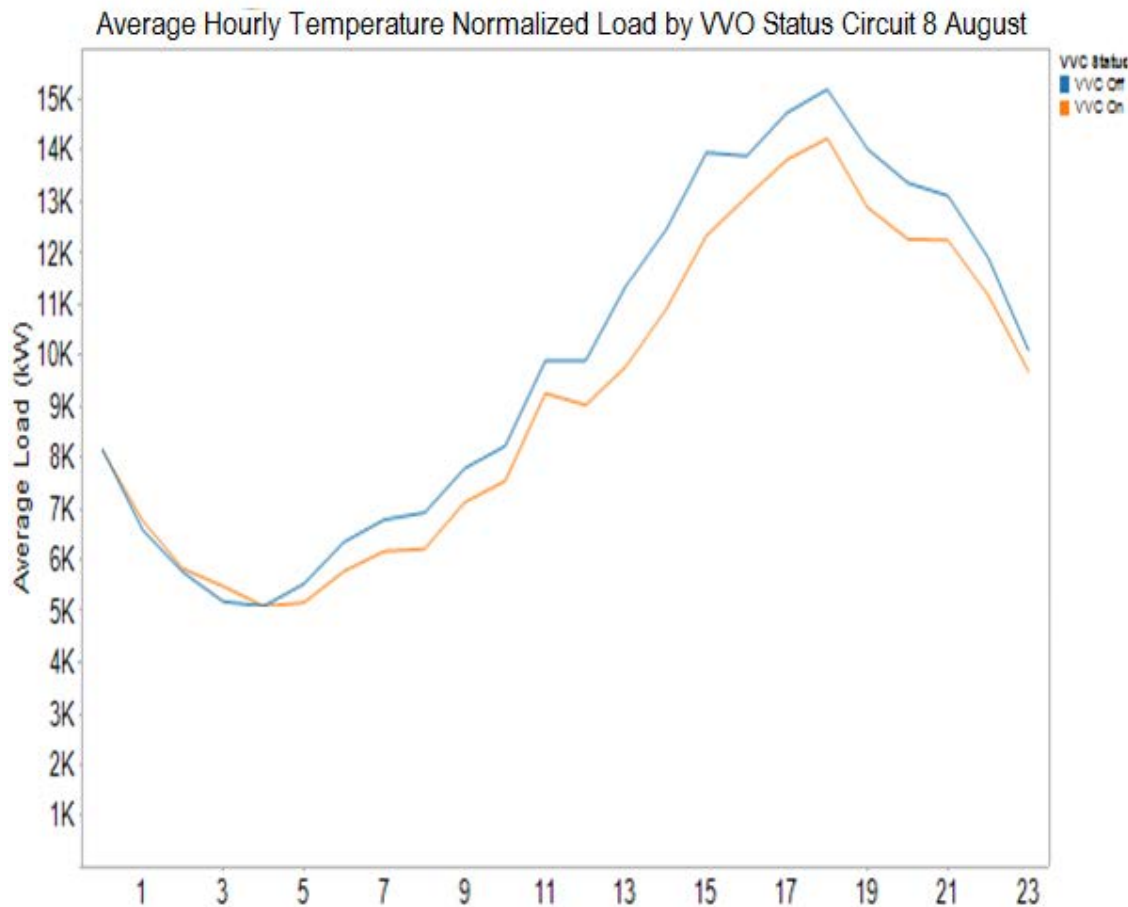


Figure 133. Circuit 8: Circuit Load

The graphs presented above represent the impacts of VVO on distribution circuit load.

6.5.2.6 Summary

VVO provided an average of approximately 3 percent reduction in circuit load.



6.5.3 Deferred Distribution Capacity Investments (M15-VVO)

6.5.3.1 Objective

Utility operators periodically upgrade distribution circuit equipment and systems to satisfy demand and take advantage of improved technology. Those upgrades require significant capital investment and impact the economics of operation. VVO has the potential to achieve benefits that reduce the need for such investments. This impact metric provides a description of all distribution capacity investments that were deferred due to VVO.

6.5.3.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

Semi-annual variance analysis of distribution capital investment plan was performed.

6.5.3.3 Calculation Approach

No planned or deferred distribution capacity investments occurred within the Project area. Therefore, a calculation approach was unnecessary.

6.5.3.4 Organization of Results

This metric is a study of deferred distribution capacity investments due to VVO.

6.5.3.5 Data Collection Results

AEP Ohio reviewed planned projects in Distribution Load Forecasting where VVO circuits would be involved.

6.5.3.6 Summary

Within the short duration of the Project, there were no planned distribution capacity investments within the Project area. Therefore, no projects were deferred as a result of VVO. VVO did not influence distribution capacity investments.



6.5.4 Equipment Failure Incidents (M16-VVO)

6.5.4.1 Objective

Frequent VVO equipment operations may result in increased equipment wear. This impact metric provides counts of equipment failure events within the Project and System areas in order to quantify these effects.

6.5.4.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

Circuit and substation Supervisory Control and Data Acquisition (SCADA) reports, event logs, and direct equipment notifications/alarms recorded switching operations performed. Any such events that resulted in equipment failure contributed to the cumulative count total. Failures for the following equipment types are included in this report:

- Capacitor Banks
- Distribution Transformers
- Reclosers
- Switches
- Voltage Regulators

6.5.4.3 Calculation Approach

The following queries and methods were used to generate results:

- Equipment failure events per date, equipment type, circuit, and substation were selected by linking equipment compatible units to circuit equipment types.
- Hourly outdoor temperature in degrees Fahrenheit for Port Columbus International Airport was collected from the National Oceanic and Atmospheric Administration.

6.5.4.4 Organization of Results

The following graphs report the number of equipment failure events that occurred on VVO and non-VVO circuits within the Project area.

- **Count of Equipment Failures by Year for VVO vs. non-VVO Circuits**
This graph shows the number of equipment failures per year for each type of equipment tracked. The graph is divided into two sections, one showing the 17 VVO circuits, and the other showing the rest of the Project area. This represents a population of approximately 80 circuits.
- **Equipment failure rates for VVO versus non-VVO circuits**
This graph shows the number percent failure rate per year for each type of equipment tracked. Failure rates were calculated as a percentage of the population of each device type within the VVO and non-VVO areas. The graph is divided into two sections, one showing the 17 VVO circuits, and the other showing the rest of the Project area. This represents a total population of approximately 80 circuits.

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6.5.4.5 Data Collection Results

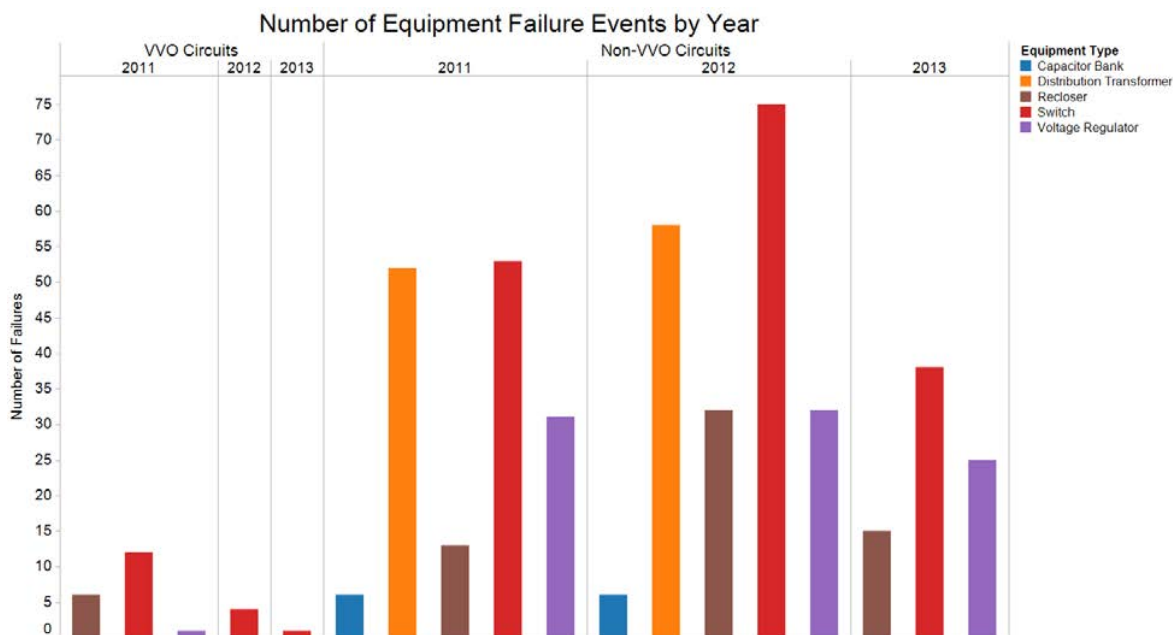


Figure 134. Count of Equipment Failures by Year for VVO vs. Non-VVO Circuits

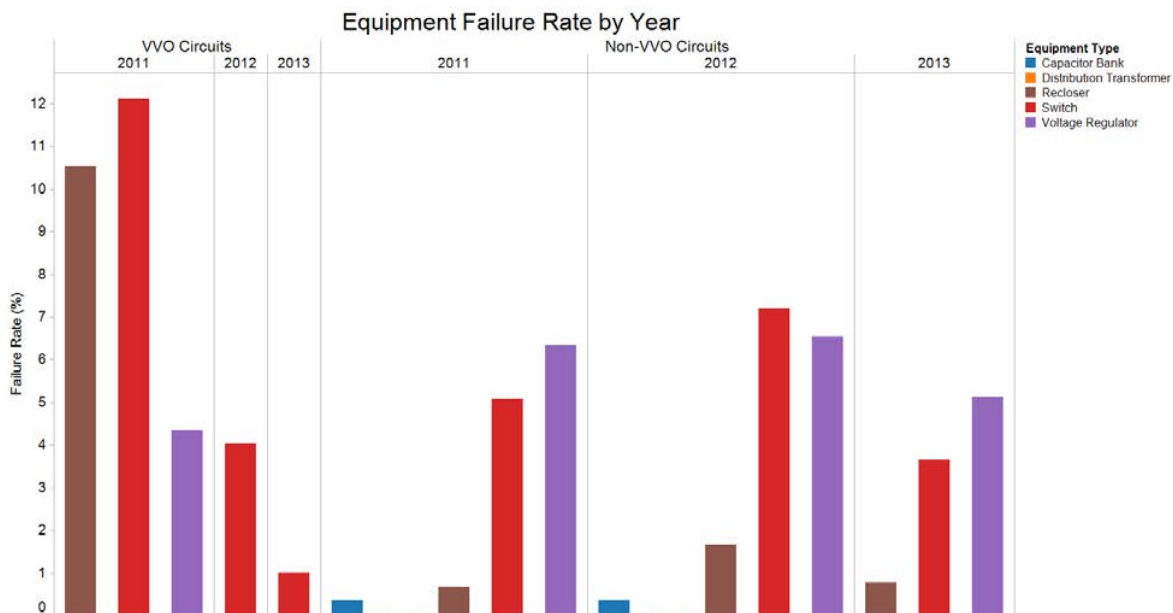


Figure 135. Equipment Failure Rate by Year for VVO vs. Non-VVO Circuits

6.5.4.6 Summary

There are no statistically significant trends in equipment failure rate due to VVO. There was no evidence of either an increase or decrease in failure events attributable to VVO.



6.5.5 Distribution Equipment Maintenance Cost (M17-VVO)

6.5.5.1 Objective

Reduced consumption can result in reduced costs, deferred capital investments, extended equipment life, and reduced fuel consumption. Because VVO reduces consumption, the addition of VVO equipment has the potential to affect maintenance costs. With the intent to capture expected maintenance costs and/or savings associated with maintaining a VVO system compared to traditional distribution operations, this impact metric provides monthly cost data for distribution maintenance activities throughout the Project and System areas.

6.5.5.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

Maintenance assumptions identified here are solely for the purpose of this reporting metric and do not follow Generally Accepted Accounting Principles (GAAP).

- Maintenance costs in the Project area include:
 - Non-warranty asset replacement costs on capacitors, regulators, reclosers, and associated controls or protective devices
 - Estimated inspection costs
 - Equipment failures
 - IT infrastructure maintenance costs
 - Telecommunications infrastructure costs
- Maintenance costs in the System area include:
 - Total asset replacement costs on capacitors, regulators, reclosers, and associated controls or protective devices
 - Inspection programs including repairs
 - Equipment failures

6.5.5.3 Calculation Approach

The following inputs were used to generate results:

Distribution equipment maintenance labor, material, vehicle fleet, and construction overhead costs per circuit, substation, and work order close date were calculated by summing labor, material, vehicle fleet, and construction overhead costs.

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6.5.5.4 Organization of Results

The following section reports the maintenance related costs incurred on VVO and non-VVO circuits within the System area.

- Equipment maintenance for VVO circuits
 This graph shows the cost in dollars per month within the VVO Project area for each maintenance cost component. This covers a population of 17 circuits.
- Equipment maintenance costs for non-VVO circuits
 This graph shows the cost in dollars per month outside the VVO Project area but within the System area for each maintenance cost component. This covers a population of approximately 700 circuits.

6.5.5.5 Data Collection Results

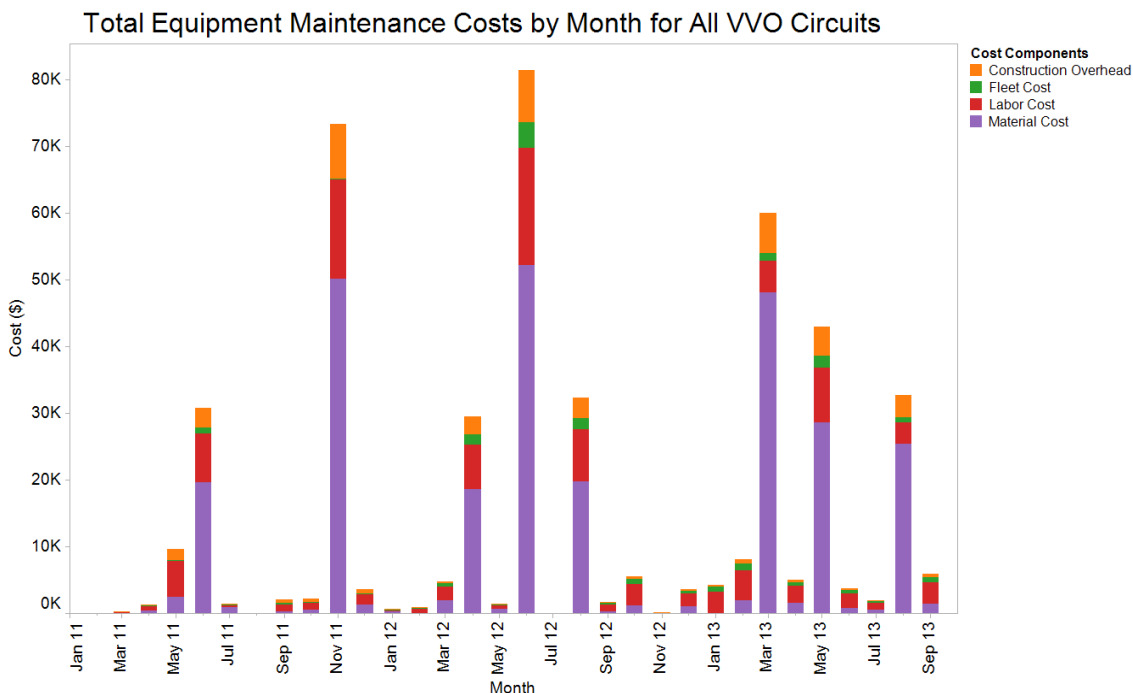


Figure 136. Breakdown of Monthly Maintenance Costs for All VVO Circuits

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Total Equipment Maintenance Costs by Month for All Non-VVO Project Circuits

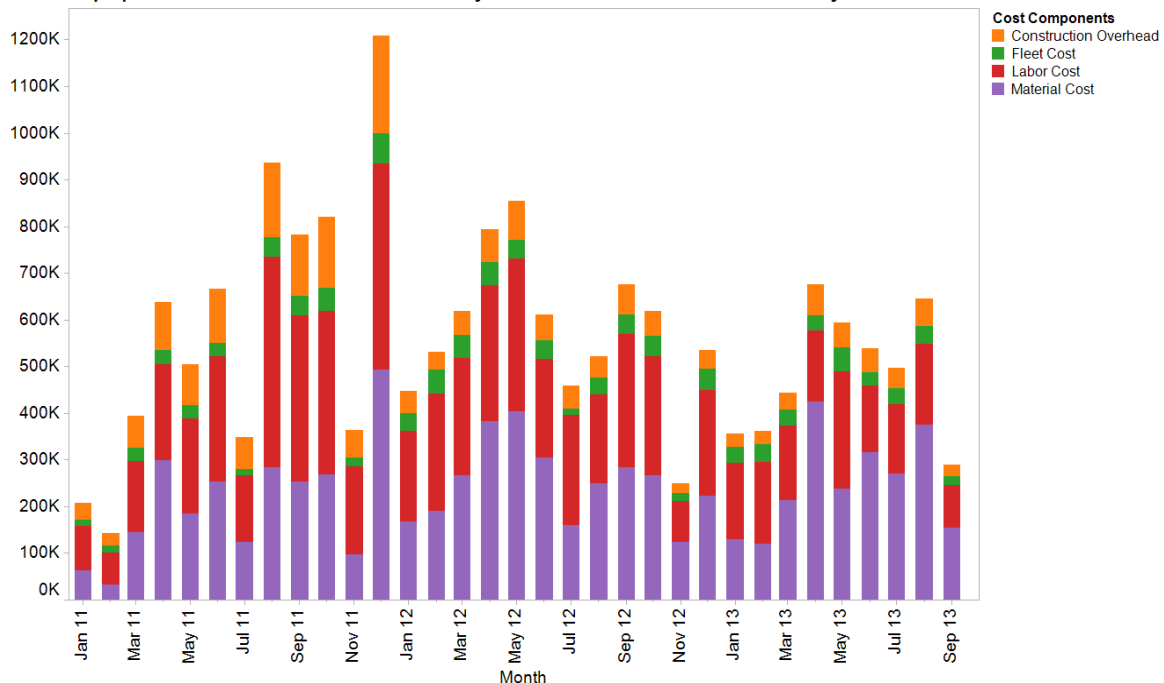


Figure 137. Breakdown of Monthly Maintenance Costs for All Non-VVO circuits

6.5.5.6 Summary

Maintenance costs are driven by factors such as periodic schedules, replacements, and failures. There is no evidence of impact on maintenance costs due to the installation and operation of VVO. A longer term of observation would be necessary to determine definitively if VVO has a measurable impact on maintenance.



6.5.6 Distribution Capacitor Switching Operations (M20-VVO)

6.5.6.1 Objective

VVO controls switched capacitors to achieve targeted power factor settings, switching the capacitors on or off to provide reactive power support. Excessive switching operations may lead to increased maintenance. This impact metric examines the behavior of switched capacitor banks in the Project area by counting how many non-VVO and VVO switching events occurred during the Project period.

6.5.6.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

Distribution capacitor switching events per circuit, substation, and day were selected by counting switching events on capacitors.

6.5.6.3 Calculation Approach

The following queries and methods were used to generate results:

- Distribution capacitor switching events per circuit, substation, and day were selected by counting switching events on capacitors.
- The average switching operations per capacitor bank were calculated by summing the total number of capacitor switching operations for a day then dividing by the number of capacitor banks that switched. If a capacitor bank did not switch, then it was not included as part of the average calculation for that particular day.

6.5.6.4 Organization of Results

The following section reports the number of capacitor switching events on VVO and non-VVO circuits within the Project area.

- Average Capacitor Switching Operations per Capacitor Bank

This graph shows per capacitor averages of switching events per day within the VVO Project area and also for the non-VVO portion of the Project area. The VVO plot covers a population of 17 circuits while the non-VVO plot covers a population of approximately 63 circuits.

- Total Count of Capacitor Switching Operations

This graph shows counts of switching events per day within the VVO portion of the Project and for the non-VVO portion of the Project.

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6.5.6.5 Data Collection Results

Average Switching Operations per Capacitor Bank

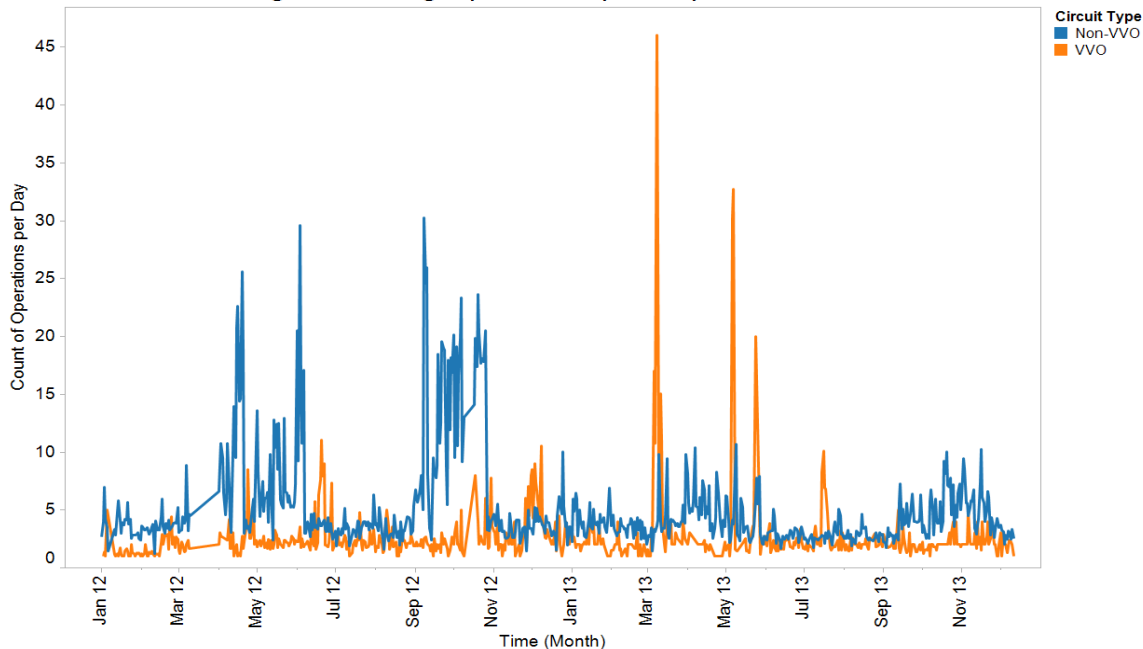


Figure 138. Average Number of Capacitor Switching Events per Capacitor Bank: VVO vs. non-VVO

Total Capacitor Switching Operations by Circuit Type

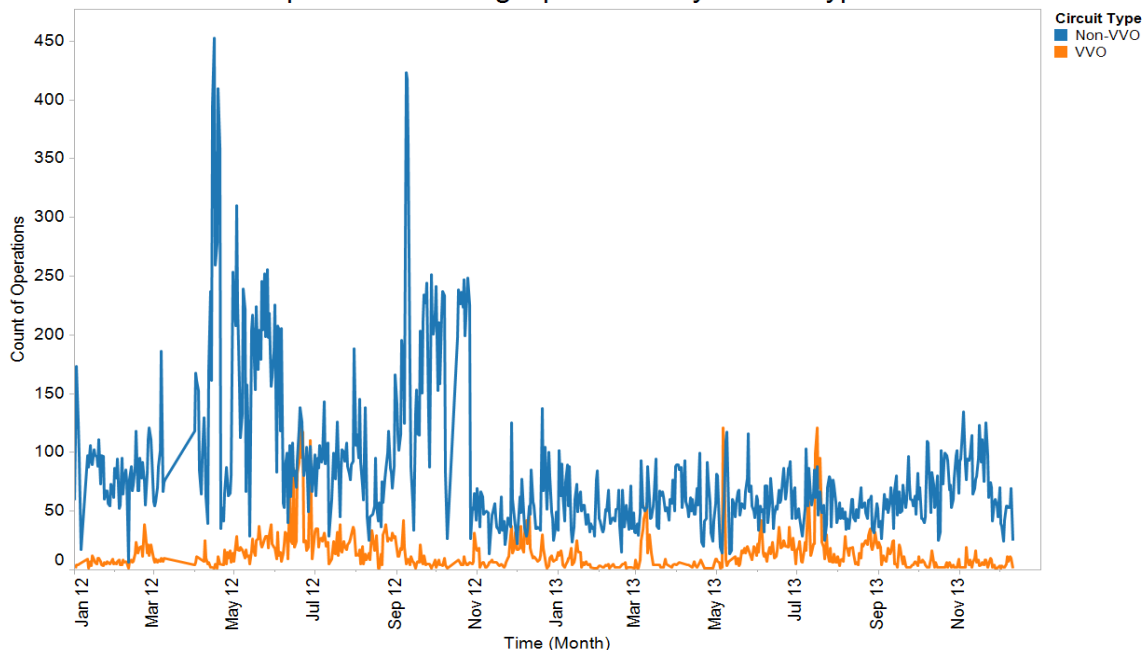


Figure 139. Total Count of Capacitor Switching Events for VVO: All Non-VVO Circuits

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6.5.6.6 Summary

On average, VVO circuits had fewer capacitor switching events than non-VVO circuits in the Project area. Several factors may have contributed to this result, including variations across circuit configurations. It was also possible that non-VVO circuits were more likely to experience oscillatory behavior due to the distributed nature of their local control, where individual set points may have triggered multiple events in a short period of time.

The figure labeled *Average Number of Capacitor Switching Events per Capacitor Bank: VVO vs. non-VVO* shows a small number of capacitors switching sufficient number of times to appear as spikes. Further explanations of the three days in which spikes occurred include:

- On March 8, 2013 a single capacitor bank opened 23 times and closed 23 times resulting in 46 operations. None of the other 48 capacitor banks on VVO circuits operated on March 8, 2013. The average switching operations for March 8, 2013 is shown as 46 and appears as a spike.
- On May 7, 2013 there were 3 capacitor banks that operated. Two of the capacitor banks had 32 operations each and the other capacitor bank had 34 operations. None of the other 46 capacitor banks on VVO circuits operated on May 7, 2013. The average switching operations for May 7, 2013 is shown as 32.67 and appears as a spike.
- On May 24, 2013 there was 1 capacitor that operated 20 times. None of the other 48 capacitor banks on VVO circuits operated on May 24, 2013. The average switching operations for May 24, 2013 is shown as 20 and appears as a spike.



6.5.7 Distribution Losses (M22-VVO)

6.5.7.1 Objective

VVO reduces circuit demand by flattening and lowering circuit voltages, primarily by using voltage regulators. At the same time, VVO actively controls capacitor banks to maintain circuit power factors near unity.

Electrical loss in the circuit can be investigated using the difference between power provided by the circuit regulator and the total power delivered to the consumer loads. This impact metric presents the difference between circuit load measured at the substation via the SCADA system and the metered load measured through AMI. The net result is the total non-AMI metered load on the circuit. Distribution losses are a component of total non-AMI metered load and are expected to be impacted by VVO.

6.5.7.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

There are many elements that contribute to differences between circuit load data and the summation of AMI metered data for each circuit. These factors include:

- Consumers without AMI meters (mechanical meters)
- Unmetered load, such as street lights
- Electricity theft
- Circuit line losses

Note: Factors that AMI does not measure are considered non-technical losses. AMI does not measure consumers without AMI meters, unmetered load, or electricity theft. Factors that AMI does measure are considered technical losses. AMI does measure circuit line losses.

6.5.7.3 Calculation Approach

The following queries and methods were used to generate results:
Using concurrent measurements available on 15-minute intervals, Distribution losses were calculated by subtracting total real AMI power from real circuit power. This represents both technical and non-technical losses. Next, a comparison was made showing changes in non-AMI metered load associated with VVO status (on versus off).

The following queries and methods were used to generate results:
Distribution unmetered load, energy theft, and losses were calculated by subtracting the 15-minute interval readings from AMI meters on a circuit from the circuit load measured at the circuit regulator. These calculations were repeated per circuit, by VVO controller status, and by time.

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6.5.7.4 Organization of Results

- AMI meter penetration by circuit
 This graph shows the percentage of meters that are AMI meters on each VVO circuit. Further analysis of non-AMI metered load is conducted only for circuits that have at least 90 percent AMI meter penetration.
- Calculation of non-AMI metered power
 This graph illustrates the calculation of non-AMI metered power by showing measured circuit load, a summation of the AMI interval data for that circuit, and the non-AMI metered power for a representative distribution circuit. Non-AMI metered power is calculated as circuit load minus AMI summation.
- Non-AMI metered load
 The following section shows the non-AMI metered load on selected VVO circuits. More detailed analysis is provided for times during which AEP Ohio implemented a day/on day/off sequence. This strategy consists of alternately enabling and disabling the VVO system for 24-hour periods in order to demonstrate differences in circuit load, consumer energy consumption, and losses.

A table of statistics is provided for circuits that exhibit day/on and day/off behavior.

6.5.7.5 Data Collection Results

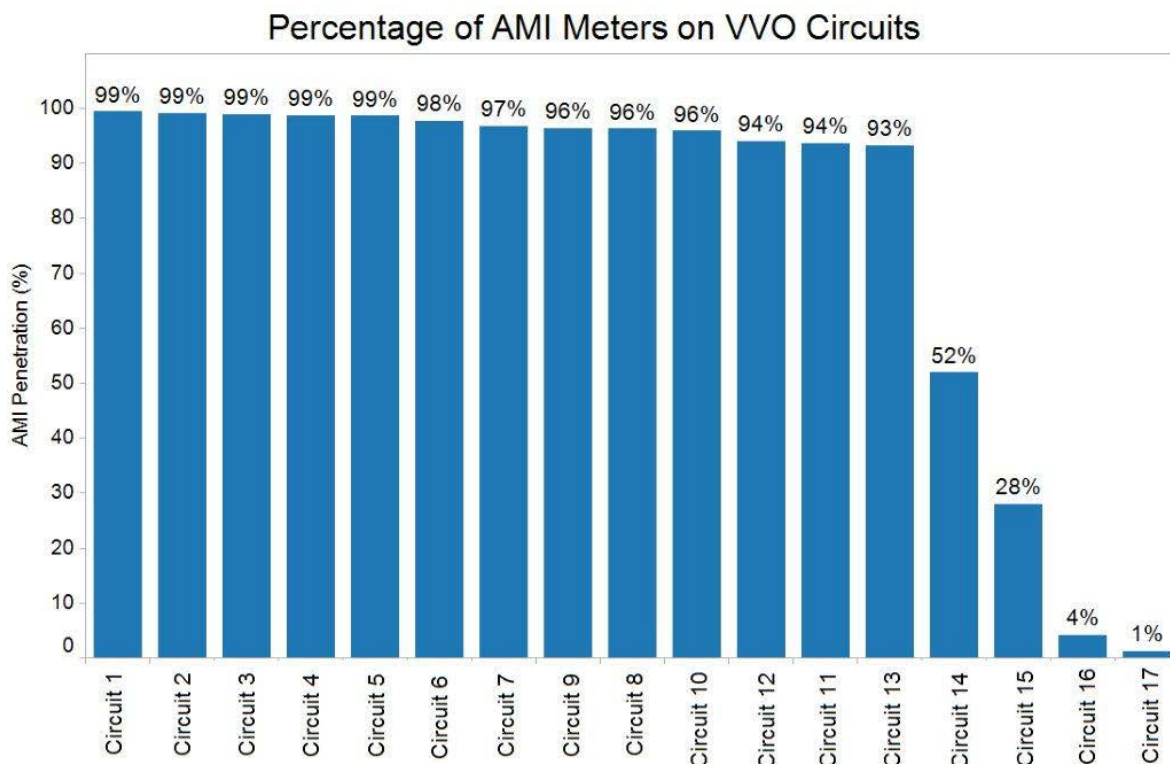


Figure 140. Percentage of AMI Meters for Each VVO Circuit

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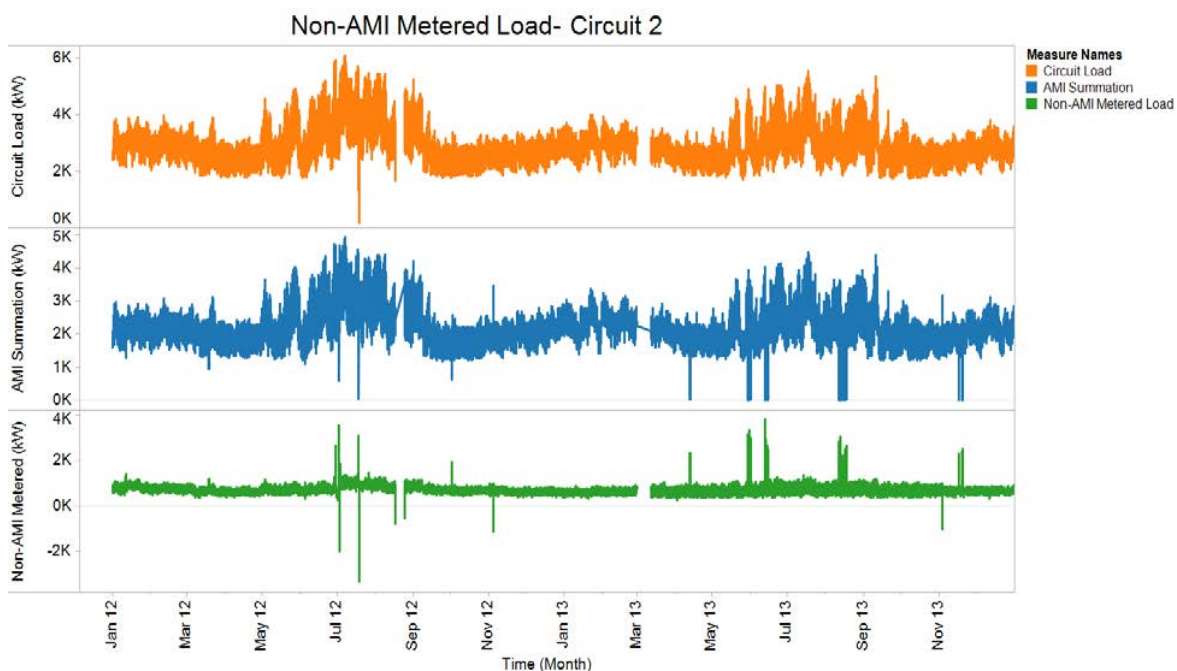


Figure 141. Circuit 1: Calculation of Non-AMI Metered Power

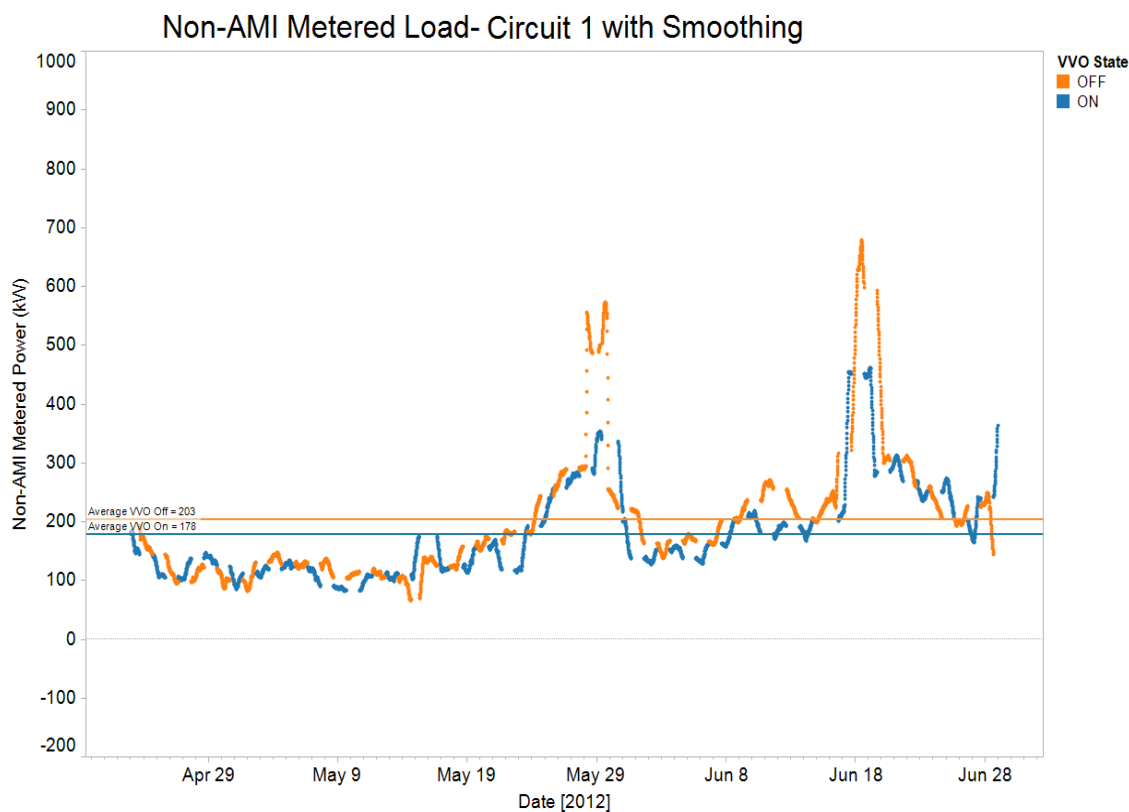


Figure 142. Circuit 1: Non-AMI Metered Power vs. Time

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The summary statistics for Circuit 1 are:

Circuit 1		
Volt-VAR Status	Avg Power	% Difference
On	171.0187	11.0%
Off	192.2625	
Outliers Removed		
On	171.0187	6.8%
Off	183.4525	

Table 24. Circuit 1 Statistics

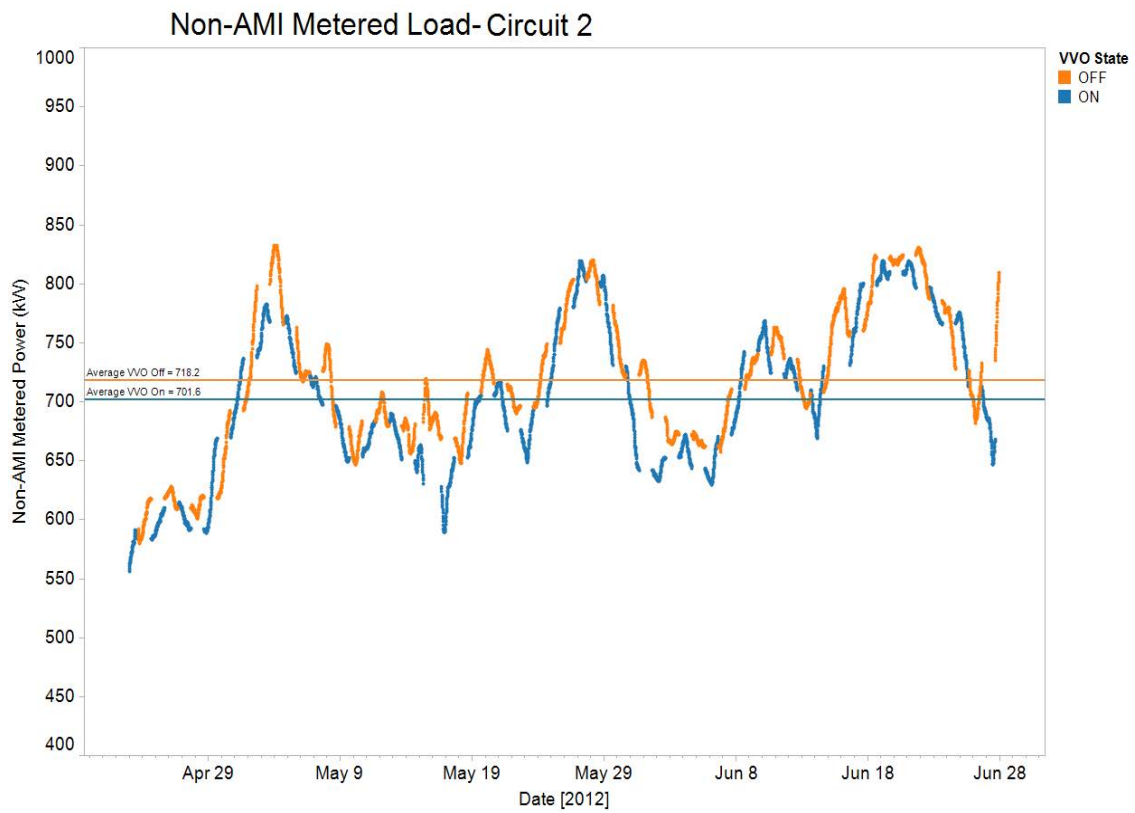


Figure 143. Circuit 2: Non-AMI Metered Power vs. Time (Apr-Aug)

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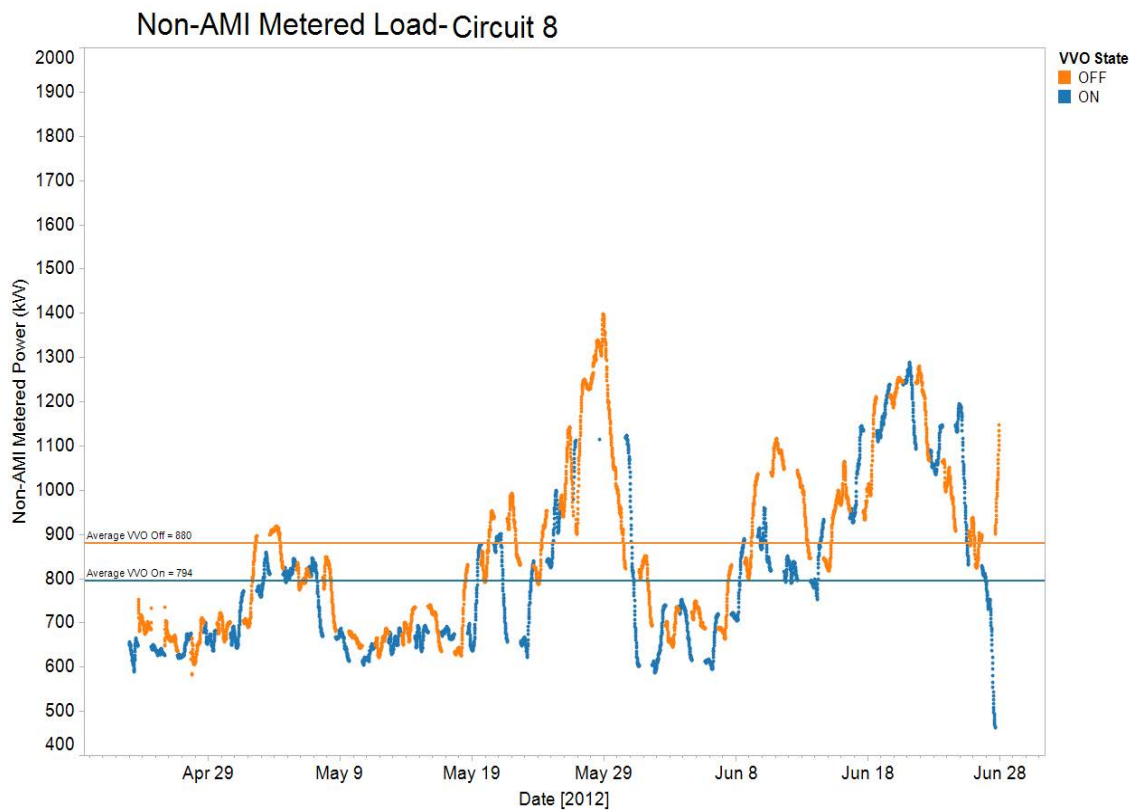


Figure 144. Circuit 8: Non-AMI Metered Power vs. Time

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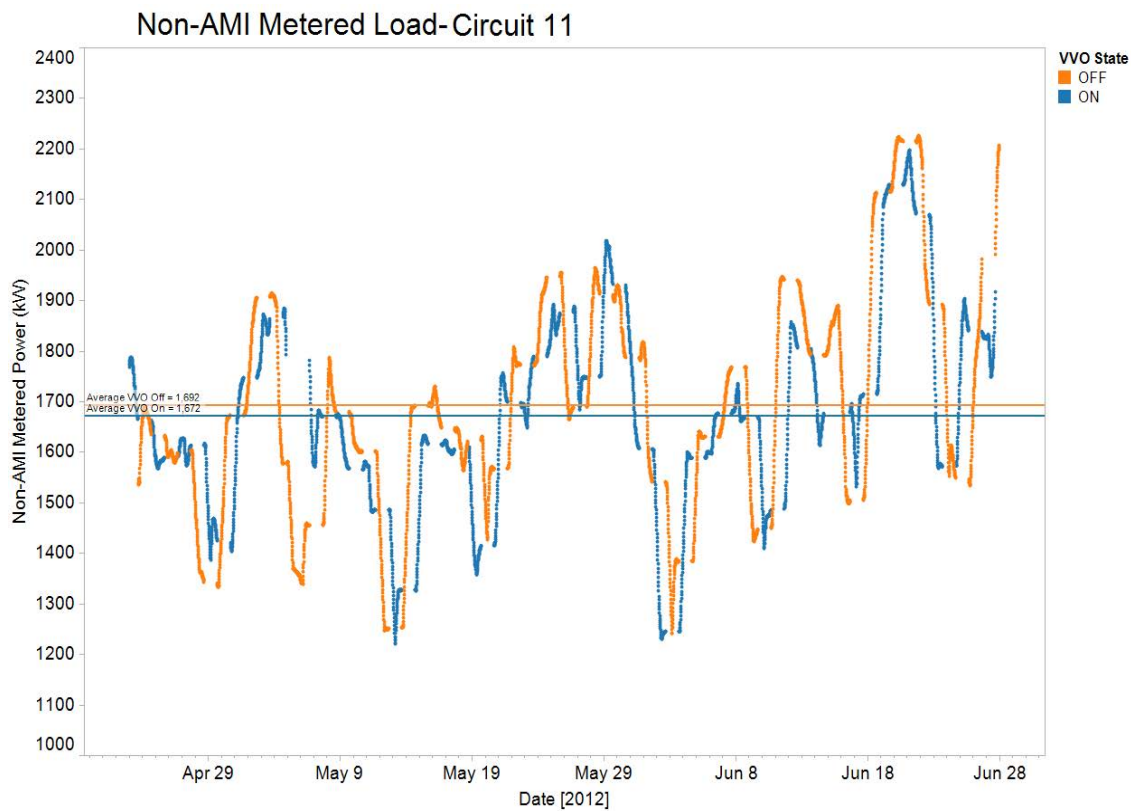


Figure 145. Circuit 11: Non-AMI Metered Power vs. Time

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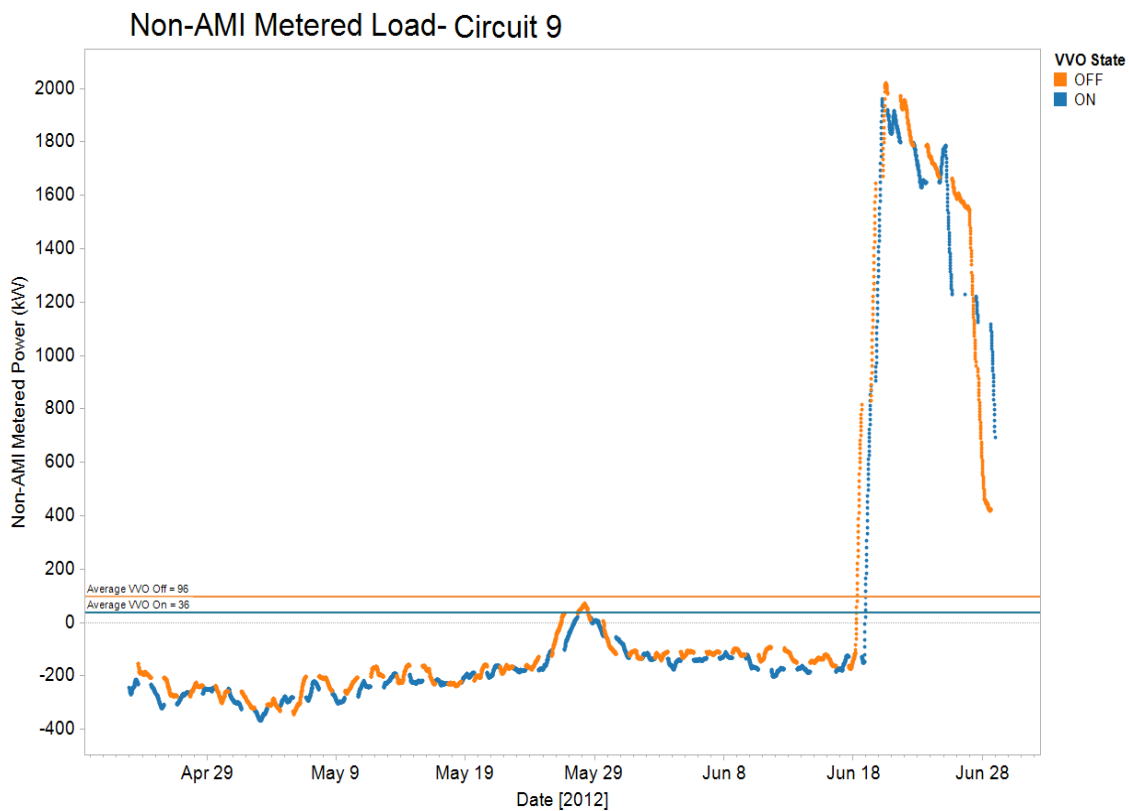


Figure 146. Circuit 9: Non-AMI Metered Power vs. Time

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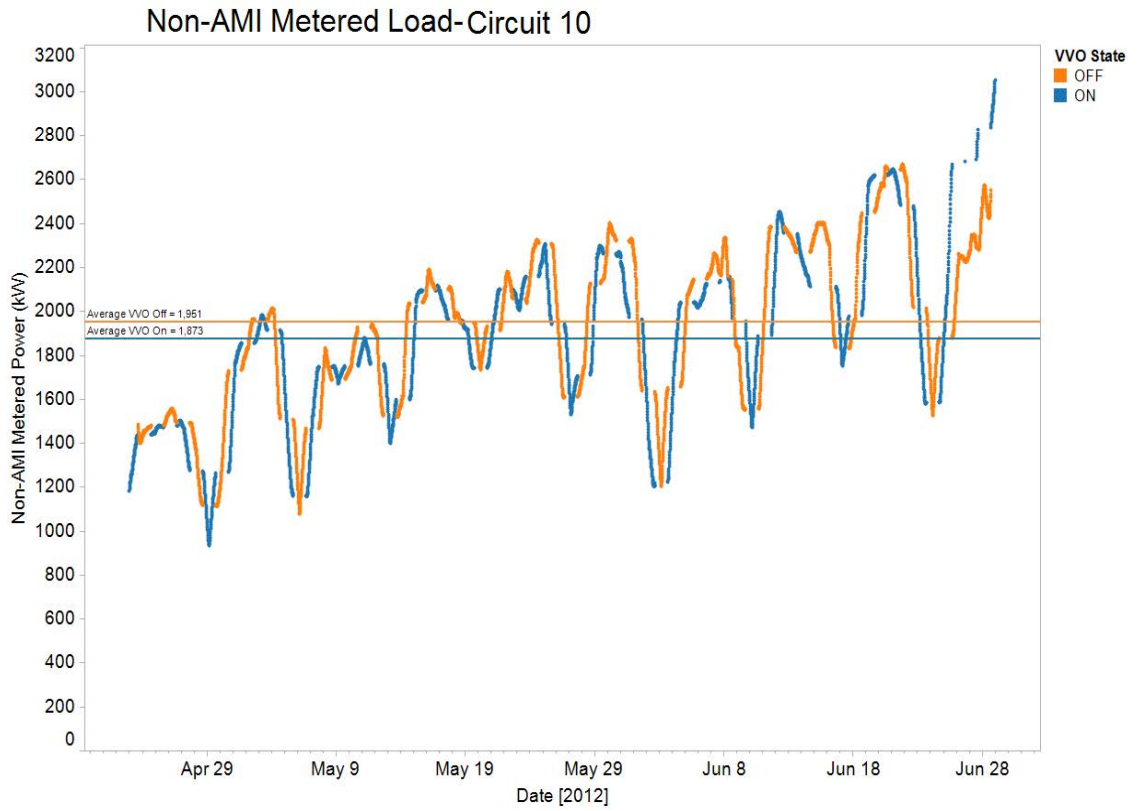


Figure 147. Circuit 10: Non-AMI Metered Power vs. Time

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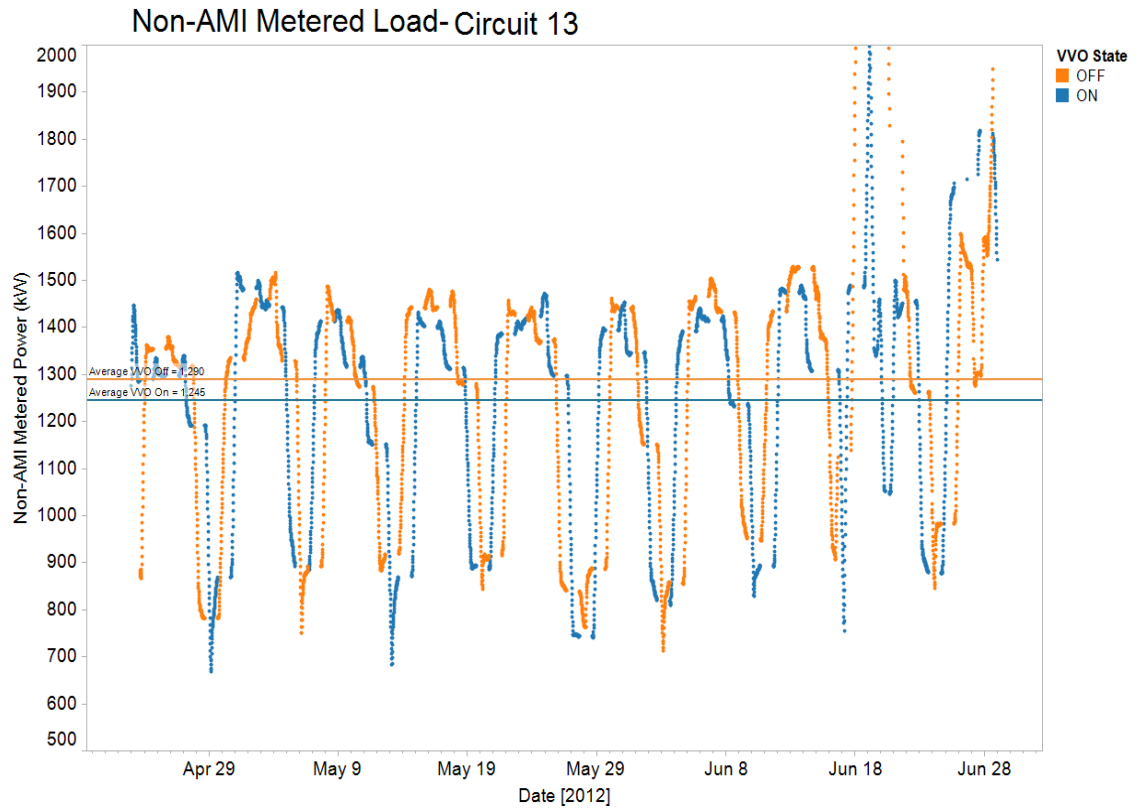


Figure 148. Circuit 13: Non-AMI Metered Power vs. Time

6.5.7.6 Summary

For the majority of circuits, non-AMI metered load was reduced during VVO On periods. This reduction was associated with both losses and reductions in other non-AMI metered loads, such as street lights). For Circuit 1, there was approximately a 4 percent reduction in non-metered load.

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6.5.8 Distribution Power Factor (M23-VVO)

6.5.8.1 Objective

VVO reduces circuit demand by flattening and lowering circuit voltages, primarily by using voltage regulators. Simultaneously, VVO actively controls capacitor banks to maintain circuit power factors near unity. Power factor is an indication of how efficiently the distribution system is delivering power. A system operating at unity power factor delivers power more efficiently than one operating at either a leading or lagging power factor. This impact metric presents the reported power factor for circuits across various time ranges.

6.5.8.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

This measure has not been adjusted for any load, weather, or seasonal factors.

6.5.8.3 Calculation Approach

The following queries and methods were used to generate results:

- Power factors per circuit, VVO controller status, and time were calculated by dividing the real power on the circuit by the apparent power on the circuit.
- Hourly outdoor temperature in degrees Fahrenheit for Port Columbus International Airport was collected from the National Oceanic and Atmospheric Administration.

6.5.8.4 Organization of Results

The following section reports power factors achieved for VVO circuits when VVO was on versus off. Each plot shows circuit load, power factor when lagging, and power factor when leading color coded by VVO status.

Volt VAR Optimization



6.5.8.5 Data Collection Results

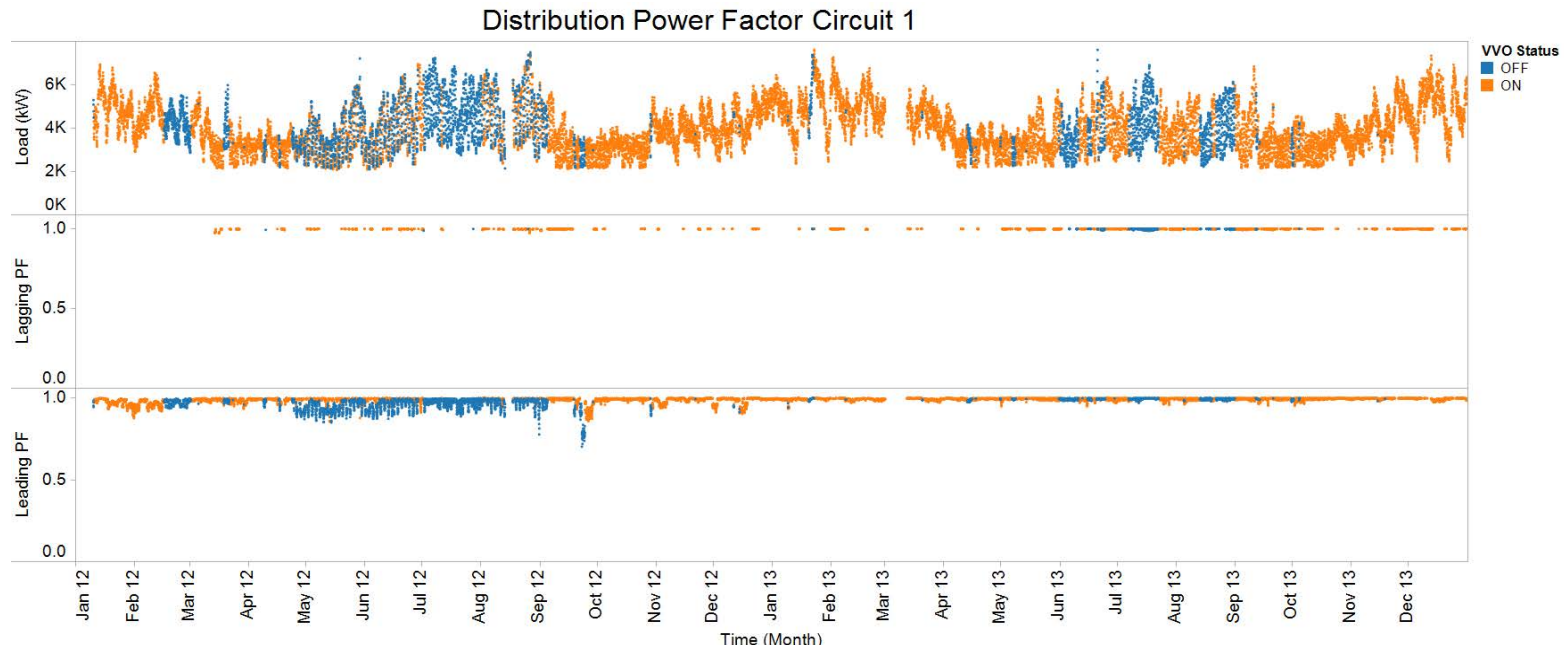


Figure 149. Circuit 1: Power Factor

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Circuit	VVO On Average Power Factor	VVO Off Average Power Factor
Circuit 9	0.95316	0.93325
Circuit 13	0.96541	0.9783
Circuit 14	0.98753	0.99159
Circuit 15	0.98468	0.98457
Circuit 17	0.98188	0.98431
Circuit 16	0.99479	0.98604
Circuit 3	0.99087	0.97011
Circuit 4	0.97623	0.98803
Circuit 6	0.96716	0.98603
Circuit 7	0.94318	0.95313
Circuit 12	0.98488	0.99303
Circuit 5	0.97937	0.97898
Circuit 11	0.98253	0.98361
Circuit 8	0.96501	0.97264
Circuit 1	0.99171	0.9721
Circuit 2	0.9929	0.99286
Circuit 10	0.98371	0.97398

Table 25. Average Power Factor by Circuit -2012

6.5.8.6 Summary

VVO On shifted power factors from leading toward lagging compared to VVO Off cases. The VAR flows were more stable with VVO On. The overall power factor across all circuits did not significantly deviate from unity.



6.5.9 CO₂ Emissions - Project area (M32-VVO)

6.5.9.1 Objective

VVO has the potential to dynamically control voltage and power factor on circuits to reduce consumer energy consumption and losses. This reduced demand can result in energy conservation, reduced costs, deferred capital investments, extended equipment life, and reduced fuel consumption. The reduction in energy consumption from VVO is expected to have a direct impact on reduced CO₂ emissions through a reduction in emissions from power generation plants. This impact metric presents the CO₂ emissions reduction as a function of conserved energy in the Project area.

6.5.9.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data:

- The day/on day/off sequence operated over a subset of the Project. Load reductions for the remainder of the Project were consistent with those measured during the testing period.
- CO₂: 0.00068956 tons/kWh
Source: *U.S. EPA eGRID2012 Version 1.0 Year 2009 Summary Tables for RFC West Region*

6.5.9.3 Calculation Approach

The following queries and methods were used to generate results:

Energy reduction due to VVO was estimated for each VVO circuit during times when the system was operated in a day/on day/off sequence.

Because VVO was operated in a day/on day/off sequence over a subset of the year, up to 11 percent of circuit load readings produced load reduction estimates. In order to accurately convey the potential energy savings associated with VVO, these load reduction values were then extrapolated to the full number readings in a year in order to calculate what the load reduction would have been if the VVO systems operated continuously during the year.

CO₂ avoided due to VVO was then calculated by multiplying load reduction by a typical generation emissions factor of 0.68956 metric tons per MWh.

6.5.9.4 Organization of Results

The following section provides an estimate of CO₂ reduction due to the reduction in energy use associated with the VVO system. Positive numbers indicate a reduction in CO₂ emissions.

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6.5.9.5 Data Collection Results

The results below quantify the impact metric for this section.

Presentation of CO₂ Avoided:

- Total energy usage avoided during VVO day/on day/off sequence: 3,912 MWh
- Total CO₂ emissions avoided during VVO day/on day/off sequence: 2,679 Metric Tons
- Energy avoided if VVO had been on continuously for all 17 Project area circuits throughout 2012 and 2013: 36,360 MWh
- CO₂ avoided if VVO had been on continuously for all 17 Project area circuits throughout 2012 and 2013: 25,072 metric tons

6.5.9.6 Summary

CO₂ emissions reduced due to VVO are a conversion of total energy conserved into equivalent CO₂ reductions. This assessment indicated that during the VVO day/on day/off sequence, 2,679 metric tons of CO₂ were avoided, and that if VVO had been on continuously throughout 2012 and 2013 for all 17 Project circuits, 25,072 metric tons of CO₂ would have been avoided.



6.5.10 Pollutant Emissions - Project area: SO_x, NO_x, and PM_{2.5} (M33-VVO)

6.5.10.1 Objective

VVO has the potential to dynamically control voltage and power factor on circuits to reduce consumer energy consumption and losses. This reduced demand can result in energy conservation, reduced costs, deferred capital investments, extended equipment life, and reduced fuel consumption. The reduction in energy consumption from VVO is expected to have an impact on reduced pollutant emissions through a reduction in emissions from power generation plants. This impact metric presents the pollutant emissions reduction as a function of conserved energy in the Project area.

6.5.10.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data:

- The day/on day/off sequence operated over a subset of the Project. Load reductions for the remainder of the Project were consistent with those measured during the testing period.

- SO_x: 0.00263084 kg/kWh

Source: *U.S. EPA eGRID2012 Version 1.0 Year 2009 Summary Tables for RFC West Region*

- NO_x: 0.00117934 kg/kWh

Source: *U.S. EPA eGRID2012 Version 1.0 Year 2009 Summary Tables for RFC West Region*

- PM_{2.5}: 0.001 kg/kWh

Source: *U.S. EPA eGRID2012 Version 1.0 Year 2009 Summary Tables for RFC West Region*

6.5.10.3 Calculation Approach

The following queries and methods were used to generate results:

Energy reduction due to VVO was estimated for each VVO circuit during times when the system was operated in a day/on day/off sequence.

Because VVO was operated in a day/on day/off sequence over a subset of the year, up to 11 percent of circuit load readings produced load reduction estimates. In order to accurately convey the potential energy savings associated with VVO, these load reduction values were then extrapolated to the full number readings in a year in order to calculate what the load reduction would have been if the VVO systems operated continuously during the year.

NO_x avoided due to VVO was calculated by multiplying load reduction by a typical generation emissions factor of 1.17934 kg per MWh.

PM_{2.5} avoided due to VVO was calculated by multiplying load reduction by a typical generation emissions factor of 1.0 kg per MWh.

SO_x avoided due to VVO was calculated by multiplying load reduction by a typical generation emissions factor of 2.63084 kg per MWh.

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6.5.10.4 Organization of Results

The following section provides an estimate of pollutant reductions due to the reduction in energy use associated with the VVO system. Positive numbers indicate a reduction in pollutant emissions.

6.5.10.5 Data Collection Results

The results below quantify the impact metric for this section:

- Total energy usage avoided during VVO day/on day/off sequence: 3,912 MWh
- Total NO_x emissions avoided during VVO day/on day/off sequence: 4,613 kg
- Total PM_{2.5} emissions avoided during VVO day/on day/off sequence: 3,912 kg
- Total SO_x emissions avoided during VVO day/on day/off sequence: 10,291 kg
- Energy avoided if VVO had been on continuously for all 17 Project area circuits throughout 2012 and 2013: 36,360 MWh
- NO_x avoided if VVO had been on continuously for all 17 Project area circuits throughout 2012 and 2013: 42,881 kg
- PM_{2.5} avoided if VVO had been on continuously for all 17 Project area circuits throughout 2012 and 2013: 36,360 kg
- SO_x avoided if VVO had been on continuously for all 17 Project area circuits throughout 2012 and 2013: 95,657 kg

6.5.10.6 Summary

Pollutant emissions are a direct multiplier of energy reductions. This analysis indicated that operating VVO full time for the Project circuits would have resulted in annual reductions of 42,881 kg of NO_x, 36,360 kg of PM_{2.5}, and 95,657 kg of SO_x during 2012 and 2013.



6.5.11 CO₂ Emissions - System area (M34-VVO)

6.5.11.1 Objective

The previous two subsections examined the influence of VVO on pollutant emissions in the Project area. This impact metric extends that work by estimating the potential for reducing CO₂ emissions if VVO were deployed across the System area.

6.5.11.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data:

- The day/on day/off sequence operated over a subset of the Project. Load reductions for the remainder of the Project were consistent with those measured during the testing period.
- VVO would have a similar impact on circuit load for circuits in the non-Project area.
- CO₂: 0.00068956 tons/kWh

Source: *U.S. EPA eGRID2012 Version 1.0 Year 2009 Summary Tables for RFC West Region*

6.5.11.3 Calculation Approach

The following queries and methods were used to generate results:

Energy reduction due to VVO was estimated for each VVO circuit during times when the system was operated in a day on/day off sequence. This estimation is explained under M13, Distribution Circuit Load.

Because VVO was operated in a day on/day off sequence over a subset of the year, roughly 10.9 percent of circuit load readings produced load reduction estimates. In order to accurately convey the potential energy savings associated with VVO, these load reduction values were then extrapolated to the full number readings in a year and to the full number of circuits in the System area.

CO₂ avoided due to VVO was then calculated by multiplying extrapolated energy reduction by a typical generation emissions factor of 0.68956 metric tons per MWh. To determine the CO₂ reductions that would have been obtained if the entire System area had deployed VVO for all of 2012, the Project area reductions are multiplied by a factor of 25.159, which is the ratio of total energy in the system to energy in the VVO circuits.

6.5.11.4 Organization of Results

The following section provides an estimate of potential CO₂ reduction due to the reduction in energy use associated with the VVO system. These results are an extrapolation to the AEP Ohio System area based on energy reductions observed in the Project area. Positive numbers indicate a reduction in CO₂ emissions.

6.5.11.5 Data Collection Results

Presentation of CO₂ Avoided:

System extrapolation of VVO energy reduction for 2012 and 2013: 882,504 MWh

System extrapolation of VVO CO₂ emissions avoided: for 2012 and 2013: 608,539 metric tons

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6.5.11.6 Summary

System CO₂ reductions projections indicated that 608,539 metric tons of CO₂ emissions would have been avoided if VVO operated continuously across the entire System area for all of 2012 and 2013.

Volt VAR Optimization



6.5.12 Pollutant Emissions - System area: SO_x, NO_x, and PM_{2.5} (M35-VVO)

6.5.12.1 Objective

The previous subsection estimated the potential for reducing CO₂ emissions if VVO were deployed across the System area. This impact metric provides similar estimates for additional pollutant emissions.

6.5.12.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data:

- The day/on day/off sequence operated over a subset of the Project. Load reductions for the remainder of the Project were consistent with those measured during the testing period.
- VVO would have a similar impact on circuit load for circuits in the non-Project area.
- SO_x: 0.00263084 kg/kWh
Source: U.S. EPA eGRID2012 Version 1.0 Year 2009 Summary Tables for RFC West Region
- NO_x: 0.00117934 kg/kWh
Source: U.S. EPA eGRID2012 Version 1.0 Year 2009 Summary Tables for RFC West Region
- PM_{2.5}: 0.001 kg/kWh
- Source: U.S. EPA eGRID2012 Version 1.0 Year 2009 Summary Tables for RFC West Region

6.5.12.3 Calculation Approach

The following queries and methods were used to generate results.

Energy reduction due to VVO was estimated for each VVO circuit during times when the system was operated in a day/on /day/off sequence. This estimation is explained under M13, Distribution Circuit Load.

Because the AEP Ohio day/on day/off sequence only operated over a subset of the year, roughly 10.9 percent of circuit load readings produced load reduction estimates. In order to accurately convey the potential energy savings associated with VVO, these load reduction values were extrapolated to the full number of readings in a year and to the full number of circuits in the System area in order to calculate what the potential load reduction would be if VVO systems were installed System-wide and operated continuously.

NO_x avoided due to VVO was calculated by multiplying load reduction by a typical generation emissions factor of 1.17934 kg per MWh.

PM_{2.5} avoided due to VVO was calculated by multiplying load reduction by a typical generation emissions factor of 1.0 kg per MWh.

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SO_x avoided due to VVO was calculated by multiplying load reduction by a typical generation emissions factor of 2.63084 kg per MWh.

To determine the pollutant reductions that would have been obtained if the System area had deployed VVO for all of 2012, the Project area reductions are multiplied by a factor of 25.159, which is the ratio of total load in the system to load in the VVO circuits.

6.5.12.4 Organization of Results

The following section provides an estimate of potential pollutant reduction due to the reduction in energy use associated with the VVO system. These results are an extrapolation to the System area based on energy reductions observed in the Project area. Positive numbers indicate a reduction in pollutant emissions.

6.5.12.5 Data Collection Results

The results below quantify the impact metric for this section:

- System extrapolation of VVO energy reduction for 2012 and 2013: 882,504 MWh
- System extrapolation of VVO NO_x emissions avoided for 2012 and 2013: 1,041,000 kg
- System extrapolation of VVO PM_{2.5} emissions avoided for 2012 and 2013: 883,000 kg
- System extrapolation of VVO SO_x emissions avoided for 2012 and 2013: 2,322,000 kg

6.5.12.6 Summary

System pollutant reductions projections indicated that using VVO continuously for all System circuits would have resulted in annual reductions of 2,322,000 kg of SO_x, 1,041,000 kg of NO_x, and 883,000 kg of PM_{2.5} and during 2012 and 2013.



6.6 VVO Conclusions

Voltage standards exist in the electric utility industry, such as ANSI C84.1, that mandate an acceptable voltage range at the secondary of the distribution transformer. VVO enables a reduction of the average voltage that each consumer on the circuit receives, thereby reducing the annual energy consumption of the circuit while maintaining the quality of service to the consumer.

Based on Project results, AEP Ohio estimates that a 3 percent reduction in energy consumption and a 2 to 3 percent reduction in peak demand can be obtained on those circuits on which VVO technology is deployed.

6.7 Lessons Learned

During the Project, implementing VVO technology was new to AEP Ohio and there were lessons learned regarding implementation, operations, and the technology itself. This section shows those lessons learned. AEP Ohio addressed these issues during the Project and continues to use this experience to develop processes and guidelines for future VVO deployments. Lessons learned are provided for Technology, Implementation, and Operations.

6.7.1 Technology

- Systems engineering for new technology requires planning.
- Smart grid technologies require a high level of team coordination during commissioning and engineering phases. This includes system planners, circuit engineers, telecommunications, security dispatch centers, distribution control engineers.
- Work with vendors to ensure equipment interoperability. It is important for utilities and vendors to work together to enhance smart equipment so multiple devices become interoperable. Continuous updates to vendor equipment and specifications create challenges. Therefore, it is critical to ensure proper integration with existing systems.
- The use of three-phase regulators is not recommended. Some technical issues were encountered working with three-phase regulators and other legacy components.
- Turn data into action. The introduction of new smart grid devices and the ability to communicate information has created large amounts of data and log files. This includes system operation and equipment performance data. IT reporting and data mining applications need to be developed to turn this data into actionable knowledge.

6.7.2 Implementation

- Include performance specifications in all Requests for Proposal (RFP) to gauge market readiness.
- Testing, configuring and commissioning devices and automation schemes is more time consuming and complicated than stand-alone devices.
- Validate vendor system claims including acceptance testing, consumer support, and escalation procedures

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- Establish compensation structures to better ensure that vendors achieve anticipated outcomes.
- Deploying DACR and VVO in the same area created unforeseen challenges:
 - VVO was designed and constructed first before circuit reconfiguration in sub-optimal footprint.
 - Initial VVO applications required stable topology.
 - Today interoperability between DACR/VVO means VVO is turned off prior to allowing DACR to change topology.

6.7.3 Operations

Establish interoperability between DACR and VVO to enable VVO to remain on even when DACR changes topology.

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7 DEMONSTRATED TECHNOLOGY – ELECTRIC VEHICLES

7.1 Purpose

The introduction of electric vehicles into the consumer market has raised questions around grid and load preparedness for mass market adoption. AEP Ohio set out to gain a better understanding of the charging behavior of drivers of plug-in electric vehicles (PEVs) and to explore how consumer programs, Electric Vehicle Supply Equipment (EVSE) locations, and supply level affect users' charging behavior. AEP Ohio also examined the impact that electric vehicles may have on the utility system.

7.2 Technology

AEP Ohio deployed PEVs - nine Chevrolet Volt plug-in hybrid electric vehicles (PHEVs), one CODA battery electric vehicle (BEV), two Mercedes Smart Electric Drive BEVs, and one Ford Escape modified to be a PHEV. The Ford Escape and Mercedes Smart Electric Drives were withdrawn from the program due to ongoing mechanical issues.

AEP Ohio deployed 36 charging stations. Level 1 (L1) EVSEs usually are provided by the vehicle manufacturer and use a standard 120V electrical outlet. L1 EVSEs typically charge at a rate of about 1.4 kW. Thirteen 120 V outlets were installed among four workplace locations for L1 charging. AEP Ohio selected Ecotality's Blink EVSE as the Level 2 (L2) charger. Level 2 chargers were available in both wall mount and pedestal models, required installation, and utilized a 240 volt AC input electrical outlet. The Blink EVSEs had communications built in and were able to collect charging data including event times and energy provided. Twenty-three L2 EVSEs were installed in a combination of residential, workplace, and public locations. L2 EVSEs typically charge at a rate of about 3.3 kW or 6.6 kW depending on the vehicle. On L2, the Volts charge at 3.3 kW while the CODA charges at 6.6 kW.

AEP Ohio collaborated with the Electric Power Research Institute (EPRI) to implement an on-board vehicle data acquisition system to gather vehicle performance information for both charging and driving events, which was used on the Chevrolet Volts.

7.3 Approach and Implementation

AEP Ohio reviewed various vehicle manufacturers to evaluate all technologies. However, due to market penetration and vehicle availability, vehicle options were limited. Ten vehicles were selected and deployed for the majority of the project, which included nine Chevrolet Volts and one CODA.

Participants were chosen from AEP employees who lived in the AEP Ohio gridSMART[®] Demonstration Project (Project) area. Each participant was assigned a vehicle to drive for at least one year. Some vehicles were then redistributed to a new set of participants. A total of sixteen employees were assigned vehicles during the Project.

Electric Vehicles



AEP Ohio also explored the installation process of EVSE infrastructure. Participants with a range of demographics were chosen for the residential installations, including a residential apartment complex. AEP Ohio provided an Advanced Metering Infrastructure (AMI) meter for all installations to gather energy consumption data for charging the PEVs. Most of the residential installations were non-billing meters, but two participants received actual EVSE billing meters. One of the two participants had a second meter installed in parallel to the residential meter, while the other had the meter installed in an apartment complex.

Each participant was provided with an L2 EVSE at their residence. Participants were required to be on a variable rate tariff to examine the effect pricing might have on their charging behavior. Three tariffs were available to the participants including:

TOD2 – Two Tier	
Peak	1 p.m. – 7 p.m., M-F June 1 – September 30
Off Peak	All other time
TOD3 – Three Tier with Critical Peak Price	
High	1 p.m. – 7 p.m., M-F, June 1 – September 30
Medium	7 a.m. – 1 p.m. & 7 p.m. – 9 p.m., M-F, June 1 – September 30
Low	Midnight – 7 a.m. & 9 p.m. to Midnight, M-F, June 1 – September 30
Critical Peak Pricing (CPP)	Up to 15 events/year, up to 5 hours/event
RTP_{da} – Price calculated at 5-minute intervals	

Table 26. Variable Rate Tariffs

A combination of L1 and L2 locations were provided at four AEP work locations in central Ohio as follows:

- One Riverside Plaza (1RP): 2 L2s and 5 L1s
- 850 Tech Center Dr., Gahanna (GAH): 2 L2s and 3 L1s
- Ohio Operations Center (OOC): 2 L2s and 3 L1s
- Dolan Technology Center (DTC): 1L2 and 2 L1s

The participants were given the option to use workplace charging for a fee of \$10 per month. If enrolled, they were assigned an L1 parking location with unlimited charging. The L2 EVSEs were not assigned but were available for use by any participant enrolled in workplace charging although they were requested to limit their L2 use to no more than 4 hours per day. A Blink Fleet card was required to use the L2 workplace EVSEs that enabled the project to track usage by participant.

Electric Vehicles



Finally, five L2 EVSEs were installed for public use as follows:

- 2 units at a Walmart/Sam’s Club location
- 2 units at Easton Town Center
- 1 unit at the GAH office

All participants were given a Blink Public card (an identification card designed to authenticate the user’s charging session) that allowed them to charge at these locations and to track their charging events. Blink cards were provided to the proprietors allowing non-Project participants to use the EVSEs. Any Blink member with a card could also use these EVSEs, making the chargers open to the public. These public chargers allowed charging at no cost to the consumer.

In all cases (residential, workplace, and public), metering and EVSE data was captured providing a data set of charging behavior.

7.4 Analysis

7.4.1 Cost of Installation

The figure below shows the average installation cost for residential, workplace, and public locations.

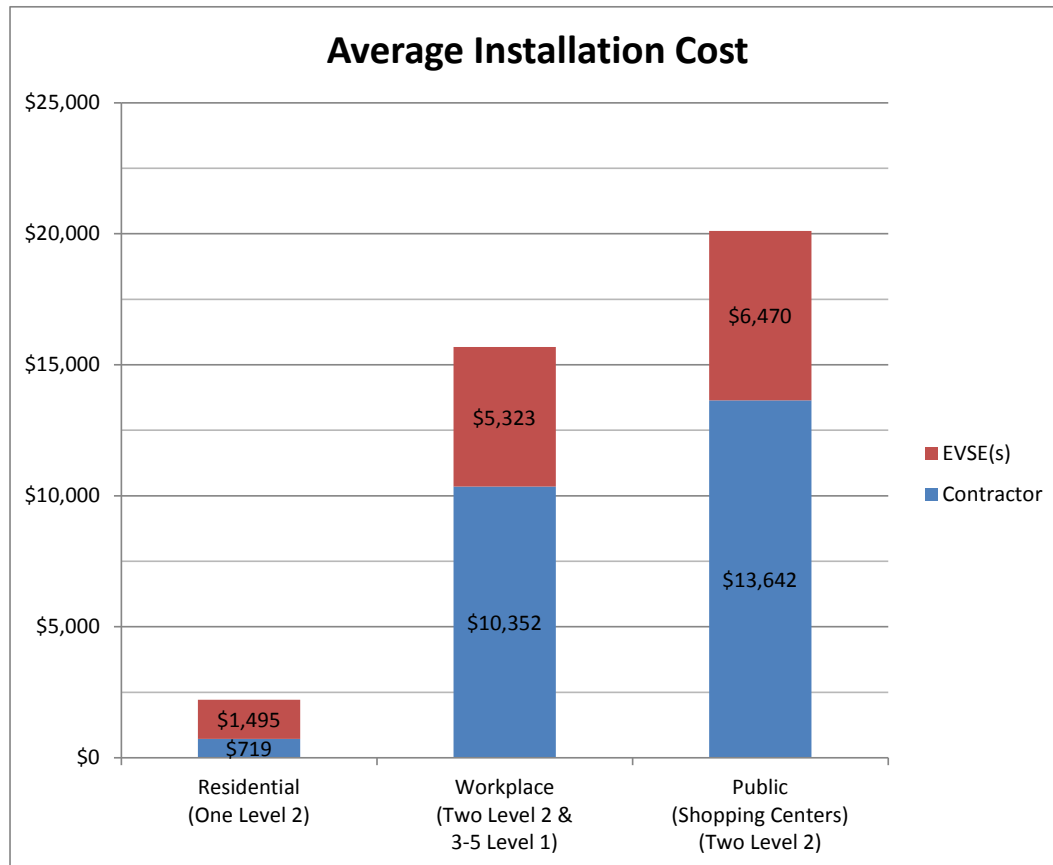


Figure 150. Average Installation Costs

Electric Vehicles



The apartment location was not included because it was significantly different from a residential installation. Its cost was \$3,675.00 (\$2,180.00 contractor cost and \$1,495.00 EVSE cost). The DTC workplace location was not included because the labor was performed by employees.

7.4.2 Grid Impact – Level 1 and Level 2 Charging

A concern an electric utility may have as PEVs are adopted is the effect charging will have on the distribution assets' ability to serve the increased demand.

7.4.2.1 Objective

AEP evaluated the impact that PEV charging may have on residential transformers. The participants were served from distribution transformers ranging in size from 25 kVA to 100 kVA.

7.4.2.2 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

Transformer load was modeled using actual 15-minute load profiles from two one-year periods:

- Period 1 was October 1, 2011 to September 30, 2012 that included a summer with multiple extremely hot days.
- Period 2 was October 1, 2012 to September 30 2013 and included a mild summer.

The summer temperatures were of interest because peak summer loading could be a limiting factor for an asset's ability to carry load and to achieve its desired life expectancy.

7.4.2.3 Calculation Approach

An average annual vehicle profile at 15-minute intervals was calculated based on the residential charging profiles from Project vehicles.

The method used to determine a calculated transformer life in years was to add the average annual vehicle load profile to a given transformer's load profile for the designated period. This calculation was performed for zero to ten PEVs, simulating the effect of no PEVs on the transformer up to ten to determine if the transformer life would fall below AEP's guideline of 30 years. This was done for both periods and for each of the 16 transformers considered.

7.4.2.4 Results

According to the simulation, 14 of the transformers could accommodate at least 10 PEVs for both periods. One 25 kVA transformer was limited to 9 PEVs for Period 1. Another 25 kVA transformer was limited to 4 PEVs during Period 1 and 8 PEVs during Period 2. The table below shows the impact of PEV charging on transformer life expectancy. The red cells indicate life expectancy less than AEP's guideline of 30 years.

Electric Vehicles



Xfmr #	kVA Rating	Period	Number of PEVs Simulated on the Transformer										
			0	1	2	3	4	5	6	7	8	9	10
1	50	Year 1 (10/1/11-9/30/12)											
		Year 2 (10/1/12-9/30/13)											
2	50	Year 1 (10/1/11-9/30/12)											
		Year 2 (10/1/12-9/30/13)											
3	25	Year 1 (10/1/11-9/30/12)											
		Year 2 (10/1/12-9/30/13)											
4	100	Year 1 (10/1/11-9/30/12)											
		Year 2 (10/1/12-9/30/13)											
5	37.5	Year 1 (10/1/11-9/30/12)											
		Year 2 (10/1/12-9/30/13)											
6	50	Year 1 (10/1/11-9/30/12)											
		Year 2 (10/1/12-9/30/13)											
7	25	Year 1 (10/1/11-9/30/12)											
		Year 2 (10/1/12-9/30/13)											
8	25	Year 1 (10/1/11-9/30/12)											
		Year 2 (10/1/12-9/30/13)											
9	37.5	Year 1 (10/1/11-9/30/12)											
		Year 2 (10/1/12-9/30/13)											
10	50	Year 1 (10/1/11-9/30/12)											
		Year 2 (10/1/12-9/30/13)											
11	75	Year 1 (10/1/11-9/30/12)											
		Year 2 (10/1/12-9/30/13)											
12	50	Year 1 (10/1/11-9/30/12)											
		Year 2 (10/1/12-9/30/13)											
13	25	Year 1 (10/1/11-9/30/12)											
		Year 2 (10/1/12-9/30/13)											
14	50	Year 1 (10/1/11-9/30/12)											
		Year 2 (10/1/12-9/30/13)											
15	50	Year 1 (10/1/11-9/30/12)											
		Year 2 (10/1/12-9/30/13)											
16	75	Year 1 (10/1/11-9/30/12)											
		Year 2 (10/1/12-9/30/13)											

Table 27. The Impact of PEV Charging on Transformer Life Expectancy

The participants had the option to enroll in workplace charging for a \$10 monthly fee. Nine participants enrolled in workplace charging for the entire time they had a vehicle while three participants did so for part of the time they had a vehicle. Four participants chose not to enroll in workplace charging. Average charging profiles were created based on a participant’s workplace charging enrollment status.

Figure 151 through Figure 156 represent average residential and workplace charging profiles for the groups of participants with and without workplace charging. The plots include bars showing the first standard deviation. The general shape of the demand profiles for both groups during weekday and weekend charging is similar. The group without workplace charging experienced an average peak demand of 1.0 kW at 8:00 p.m. while the group with workplace charging experienced an average peak demand of 0.7 kW at the same time.

A significant standard deviation during charging periods indicated a high variability of actual charging demand.

Electric Vehicles



Overall Average Weekday Profile with 1 SD Error without Workplace Charging

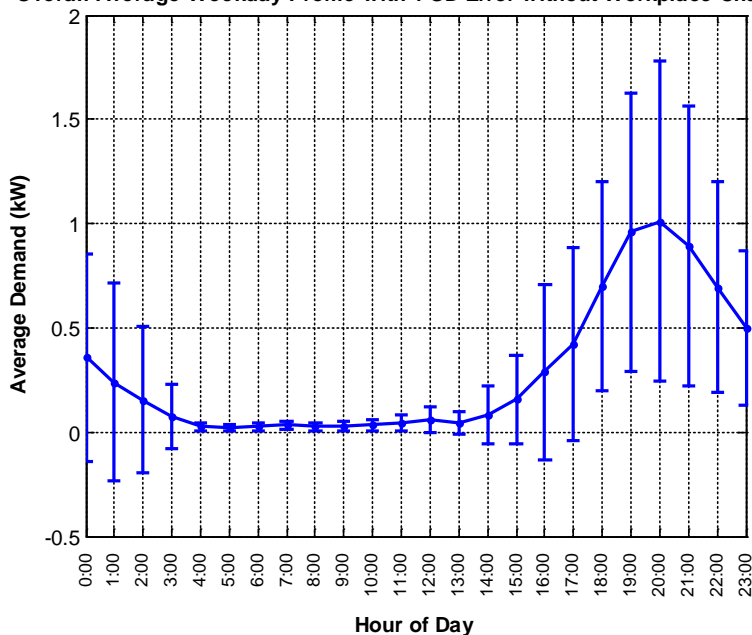


Figure 151. Average Residential Weekday Profile of Group without Workplace Charging

Overall Average Week Profile with 1 SD Error with Workplace Charging

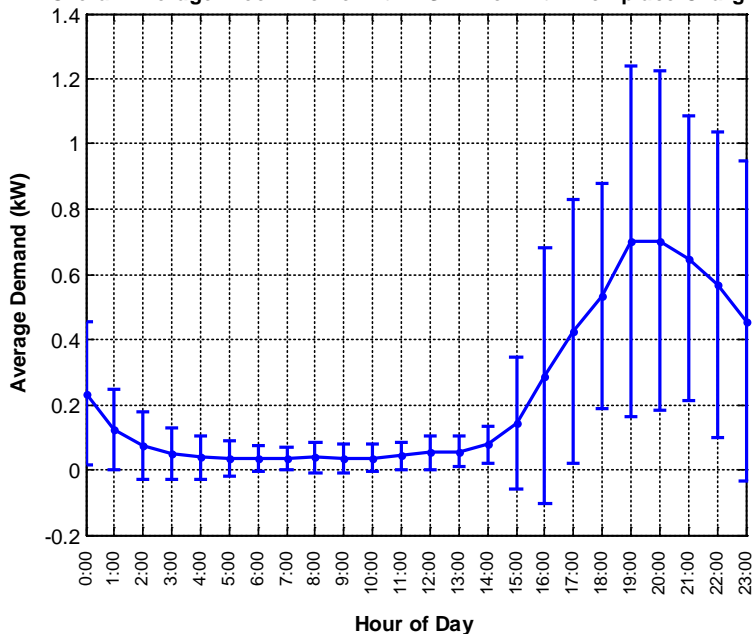


Figure 152. Average Residential Weekday Profile of Group with Workplace Charging

Electric Vehicles

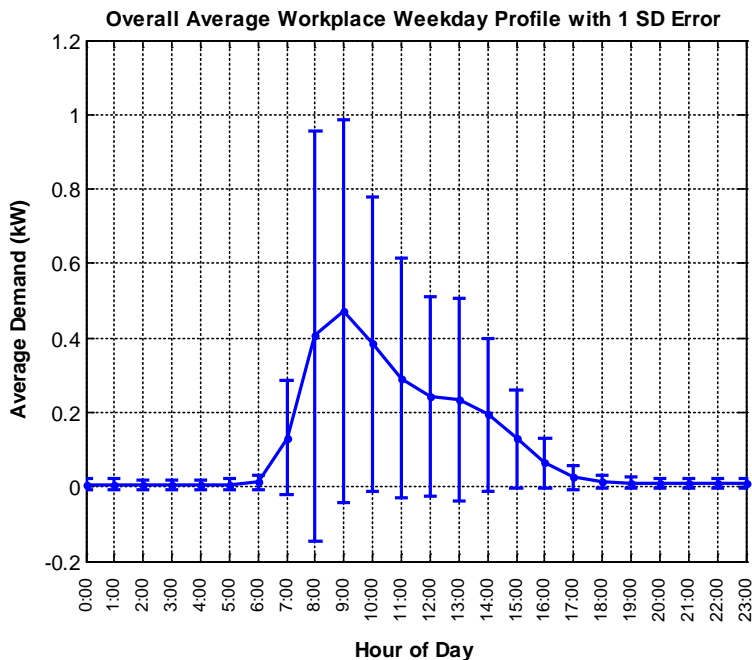


Figure 153. Average Workplace Weekday Profile of Group with Workplace Charging

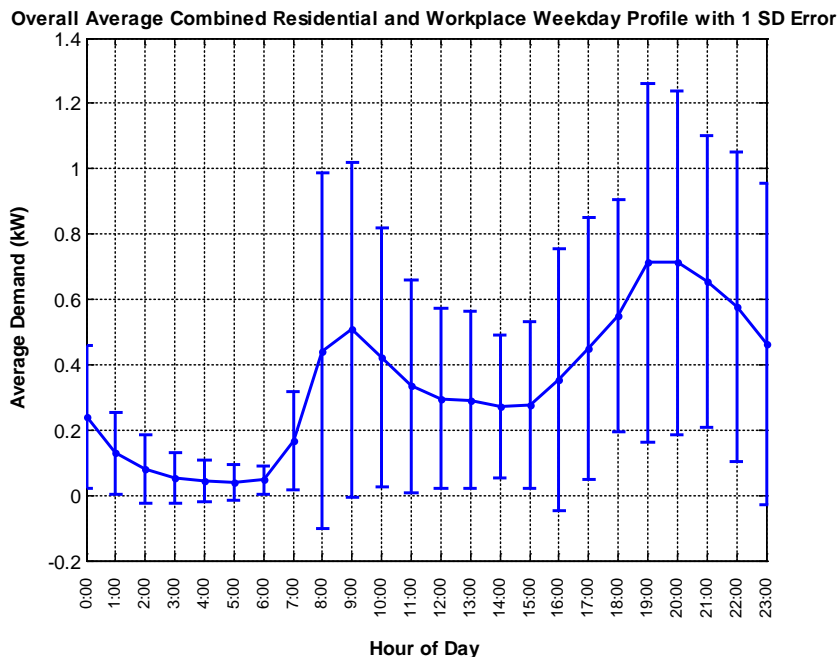


Figure 154. Average Combined Residential and Workplace Weekday Profile of Group with Workplace Charging

Electric Vehicles



Overall Average Weekend Profile with 1 SD Error without Workplace Charging

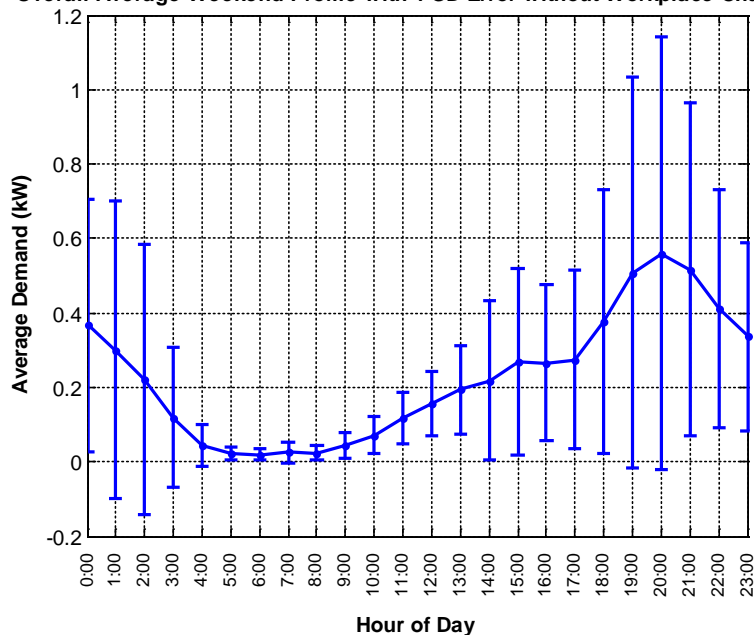


Figure 155. Average Residential Weekend Profile of Group without Workplace Charging

Overall Average Weekend Profile with 1 SD Error with Workplace Charging

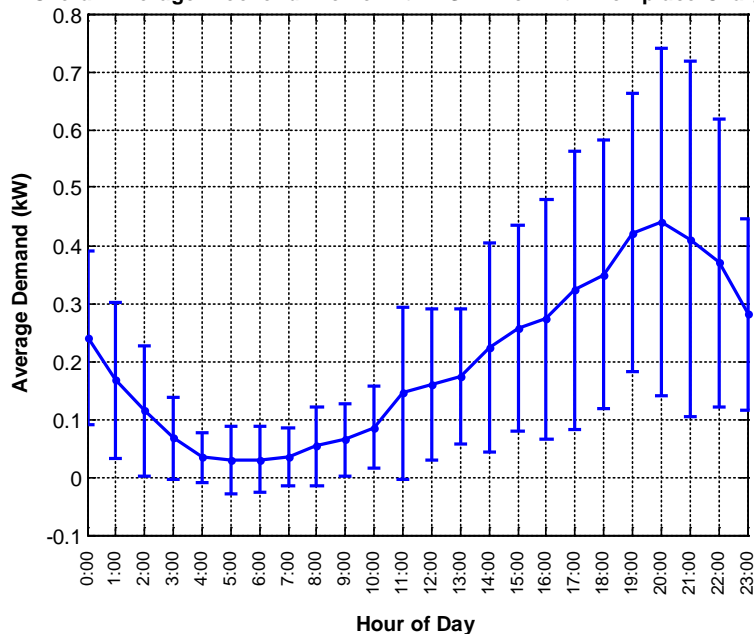


Figure 156. Average Residential Weekend Profile of Group with Workplace Charging

Electric Vehicles



The figure below represents the average annual energy consumption by location type. The residential locations were divided into two groups of those with and without workplace charging. The group without workplace charging received more energy at home than the group with workplace charging. The Level 2 workplace units were used to deliver an average of 1161 kWh annually compared to 325 kWh for the Level 1 locations. The public Level 2 units delivered an average of 1497 kWh.

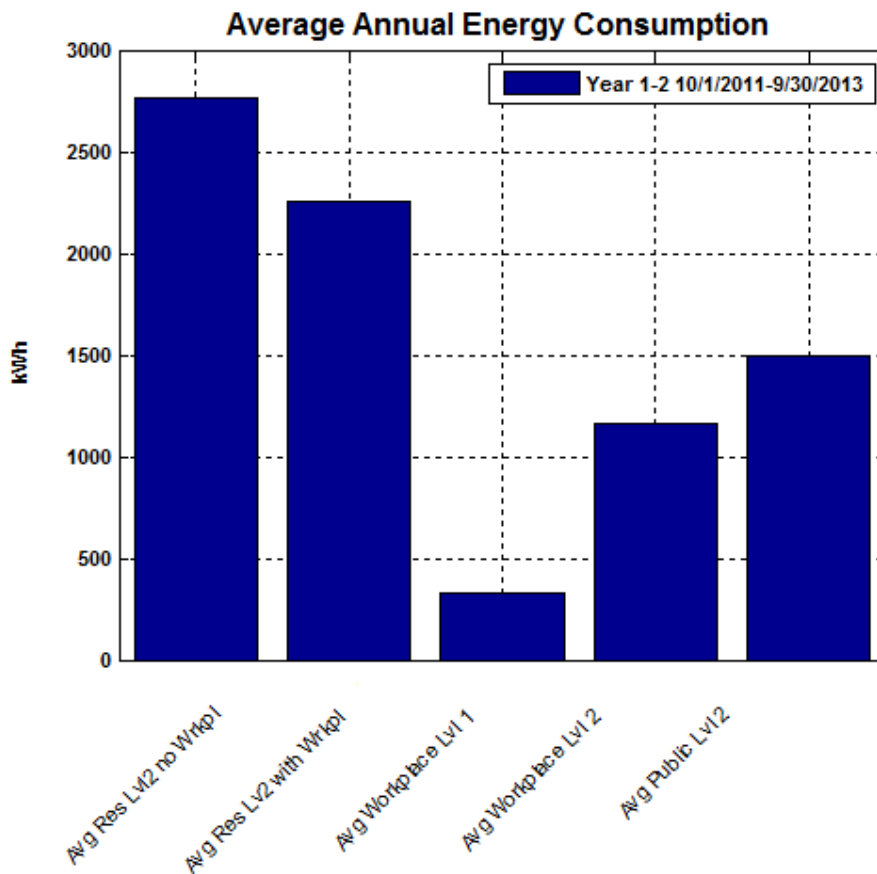


Figure 157. Average Annual Energy Consumption by Location

Electric Vehicles



7.4.3 Grid Impact – Level 1 Only Charging

7.4.3.1 Objective

AEP Ohio evaluated the effect of replacing Level 2 with Level 1 charging based on the amount of energy delivered during a charge event.

7.4.3.2 Calculation Approach

The following queries and methods were used to generate results. AEP Ohio determined how much energy was delivered for each Level 2 charging event and then how much energy would have been delivered during the same connection time using a Level 1 charging rate. The approximate Level 2 charge rate for the Volt is 3.3 kW and for the Coda was 6.6 kW, compared to an approximate Level 1 charge rate of 1.44 kW for the Volt and 1.47 kW for the Coda. This comparison was performed separately for the Coda and the Volt due to the different Level 2 charge rates. It was also performed separately for residential, workplace, and public charging since the typical connection times one might spend at each type of location may differ.

7.4.3.3 Results

The figures below represent the probability that a given percentage of a Level 2 charge could have been obtained using Level 1 charging at residential locations. For the Volt, 40 percent of an L2 charge would have been obtained about 18 percent of the time, while 100 percent of the L2 charge would have been obtained 70 percent of the time. For the Coda, 100 percent of the L2 charge would have been obtained 58 percent of the time.

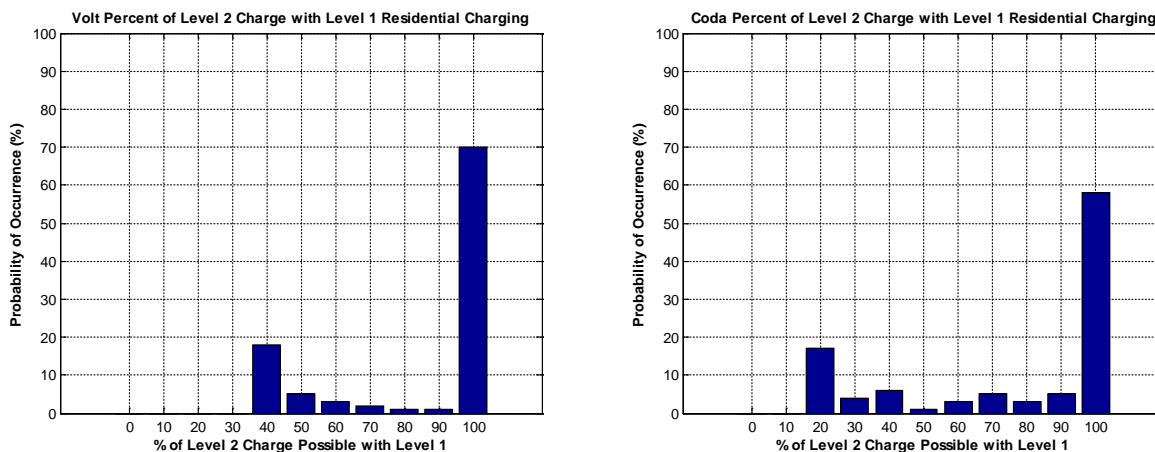


Figure 158. Residential Percent of Level 2 Charge Possible with Level 1 Charging on Two Vehicle Models

Electric Vehicles



The following figures represent the probability that a given percentage of a Level 2 charge could have been obtained using Level 1 charging at a workplace location. For the Volt, 100 percent of an L2 charge would have been obtained about 54 percent. For the Coda, 100 percent of the L2 charge would have been obtained 66 percent of the time.

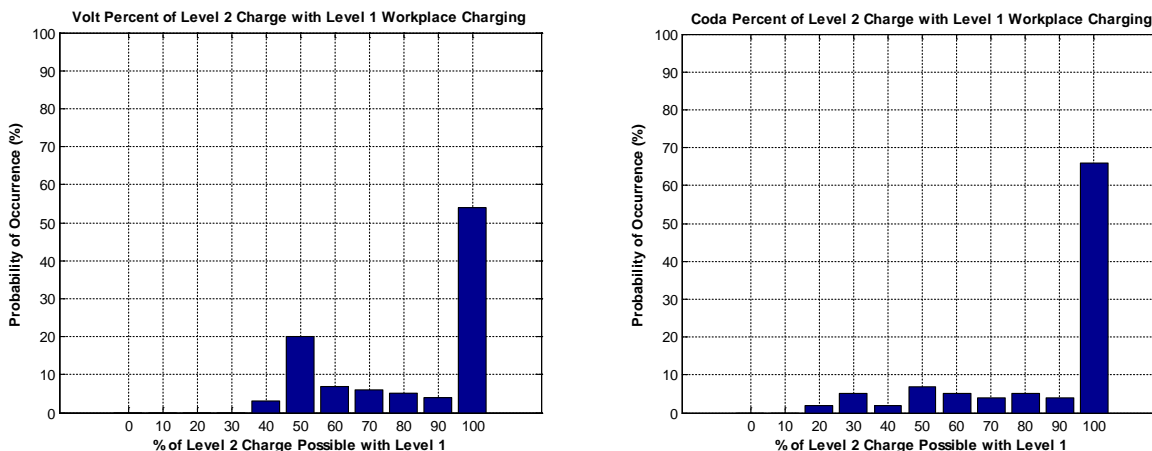


Figure 159. Workplace Percent of Level 2 Charge Possible with Level 1 Charging on Two Vehicle Models

The figures below represent the probability that a given percentage of a Level 2 charge could have been obtained using Level 1 charging at a public location. For the Volt, 50 percent of an L2 charge would have been obtained 60 percent of the time, while 100 percent of the L2 charge would have been obtained 23 percent of the time. For the Coda, 30 percent of the L2 charge would have been obtained 67 percent of the time.

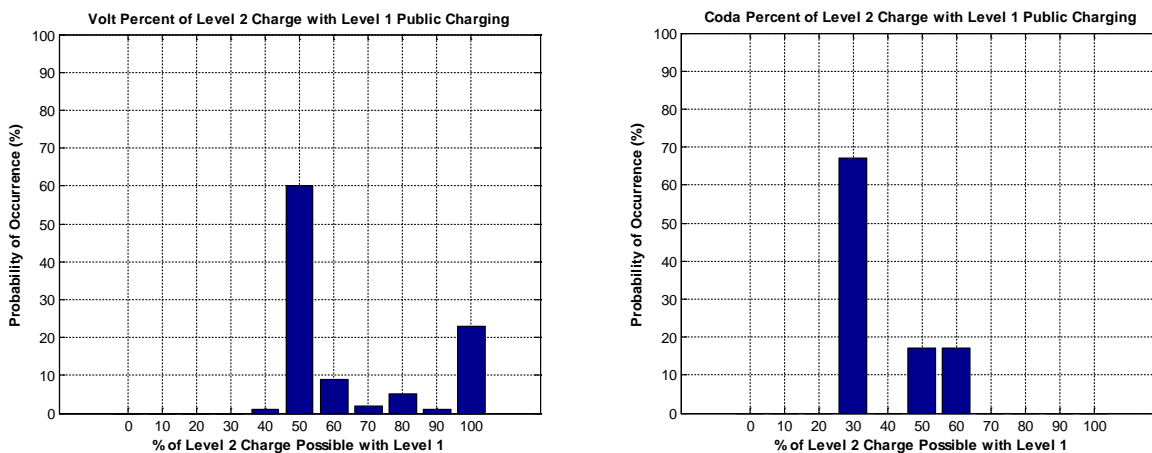


Figure 160. Public Percent of Level 2 Charge Possible with Level 1 Charging on Two Vehicle Models

Electric Vehicles



7.4.4 Grid Impact – Public Locations

7.4.4.1 Assumptions

This section contains assumptions made when collecting, analyzing, and presenting the data.

Level 1 charging is sufficient for the home and workplace locations since the time generally spent there is long enough to obtain a full charge while locations of shorter stays, like those at public locations, would benefit from Level 2 charging.

7.4.4.2 Objectives

AEP looked at what impact the charging of PEVs might have on public Level 2 charger locations.

7.4.4.3 Results

The figure below represents the total energy used to charge vehicles by public locations by month in kWh. There was a significant difference in the amount of energy used between these two locations even though they were located in close proximity to one another. The location could be a key to EVSE usage especially during the early adoption period of PEVs.

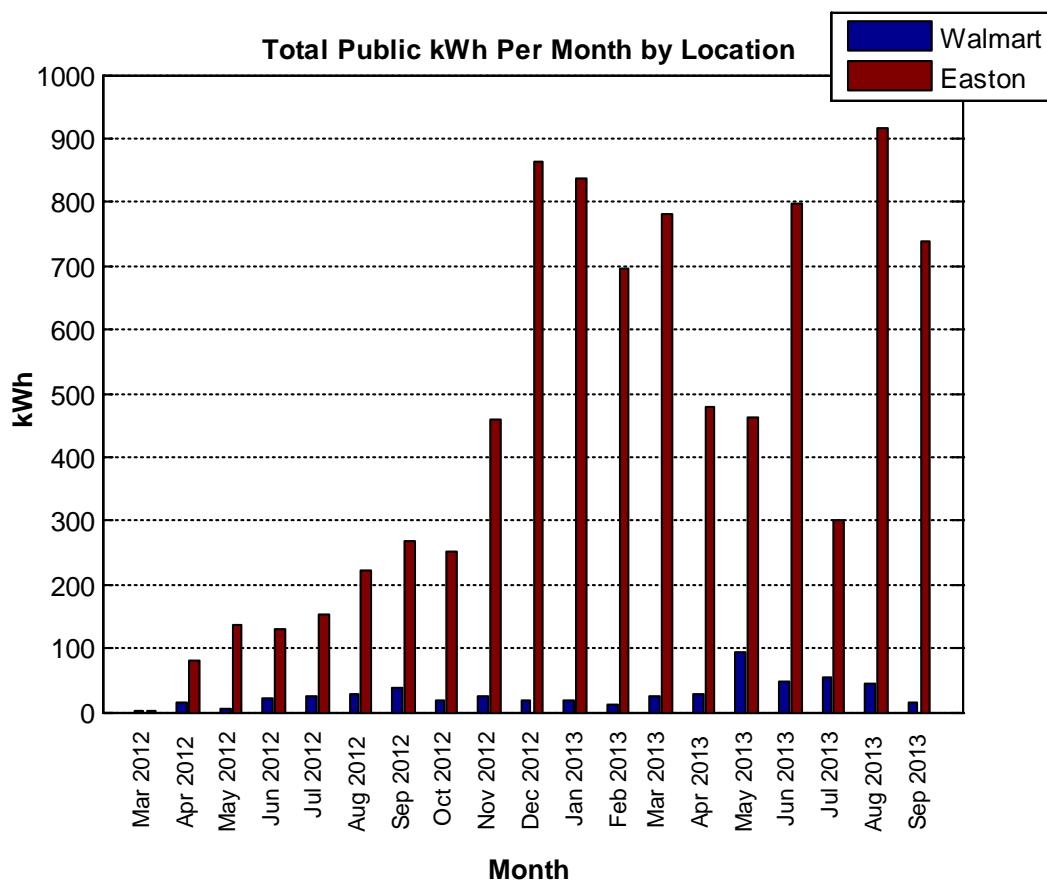


Figure 161. Energy Consumed by Month at Public EVSE Locations

Electric Vehicles



The following figure shows the number of charging events at each of the public locations by month. There was a significant increase in the number of charge events per month over the course of the Project at the Easton location, while the Walmart location experienced a lower utilization.

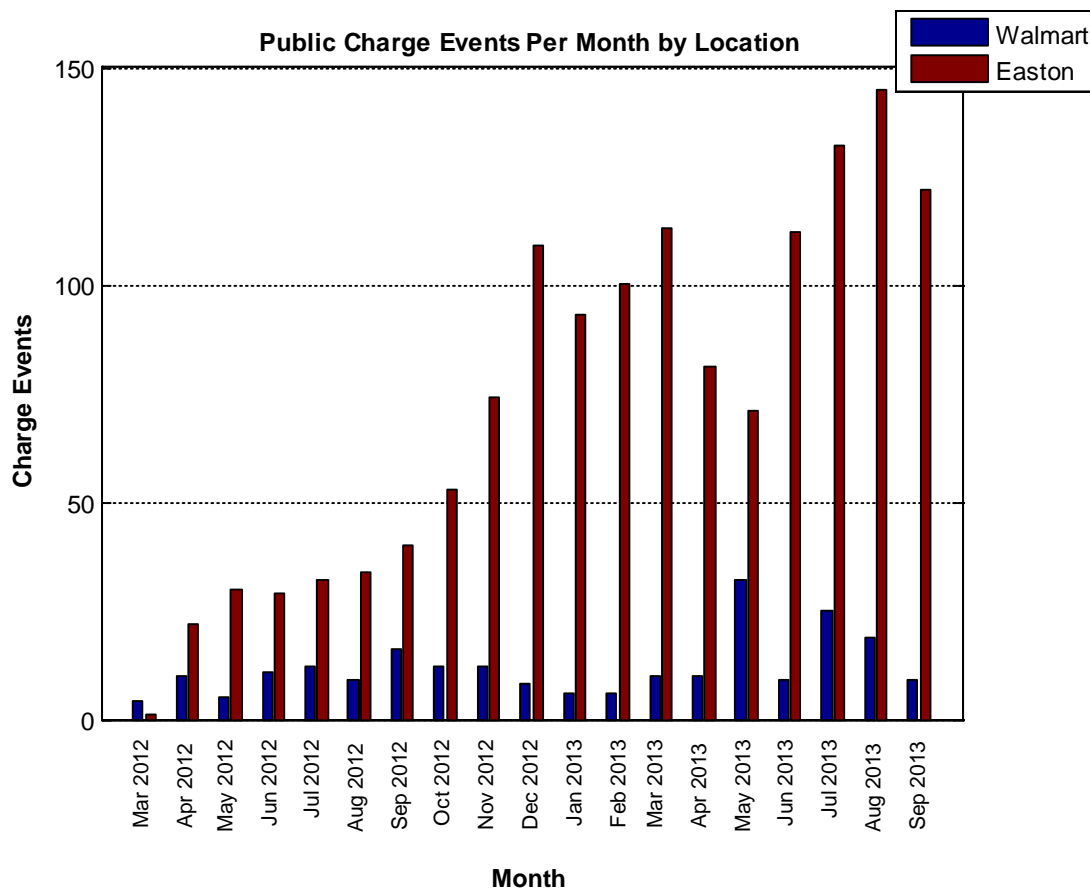


Figure 162. Number of Charging Events by Month at Public EVSE Locations

7.4.5 Consumer Behavior by Participant

7.4.5.1 Objective

To examine the effect pricing might have on charging behavior, each participant was required to be on one of three variable price tariffs: TOD2, TOD3, or RTP_{da} as described at the beginning of this section.

7.4.5.2 Calculation Approach

The peak demand during the elevated price time was compared to the peak demand of the entire profile to determine if the participant was predominantly charging the vehicle during the low cost

Electric Vehicles



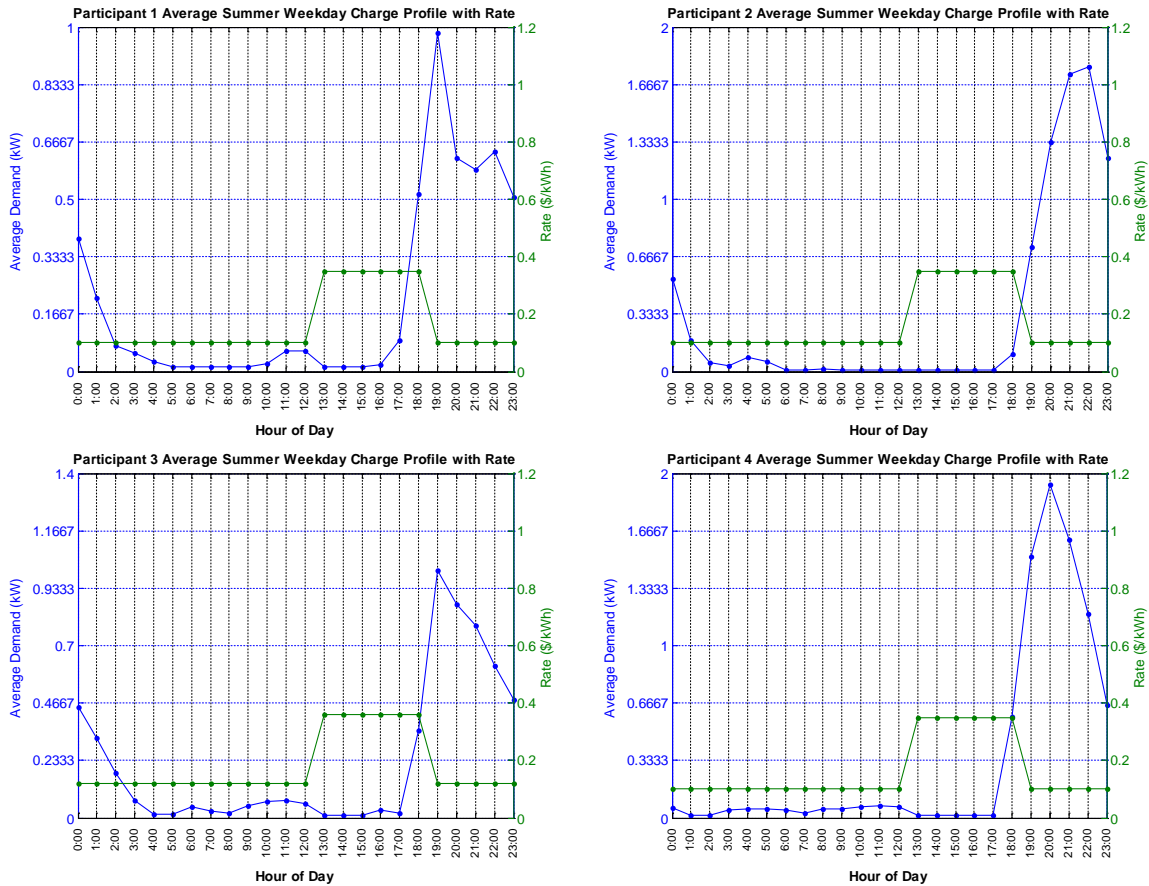
period. This ratio (R) was used to classify the participant’s tendency to charge during the low price times as follows:

- Strong: $R < 0.2$ - Participant predominantly charged during low price times.
- Moderate: $0.2 \leq R \leq 0.4$ - Participant generally charged during low price times.
- Mild: $R > 0.4$ - Participant would regularly charge during higher price times.
- None - If the peak demand occurred during a higher price time.

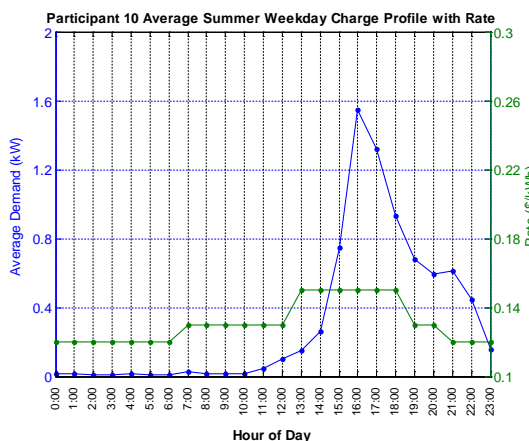
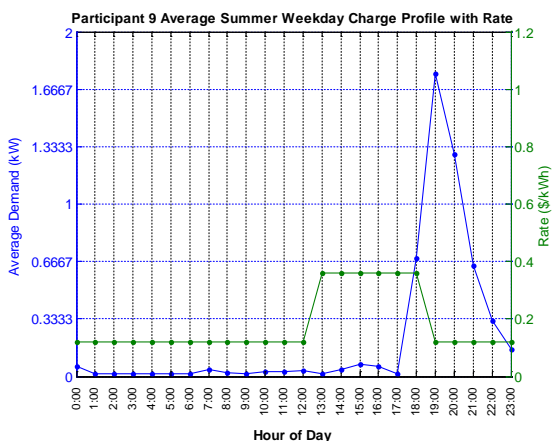
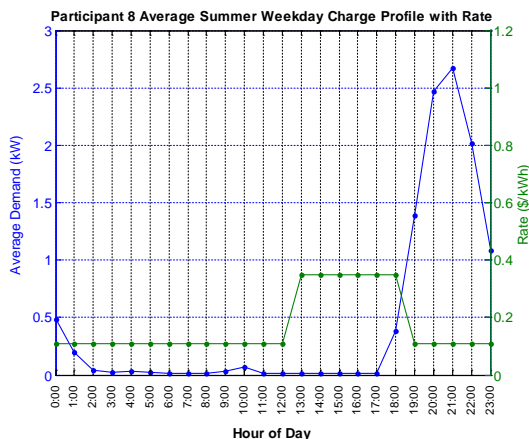
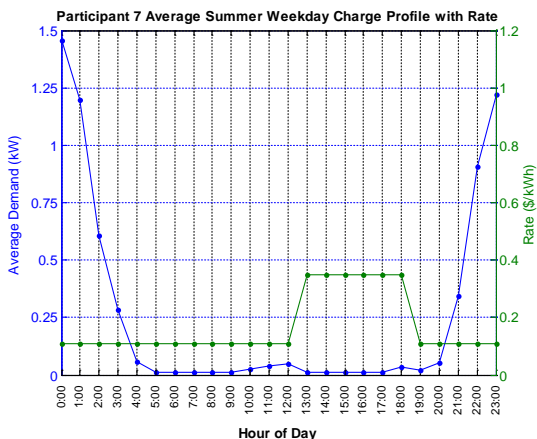
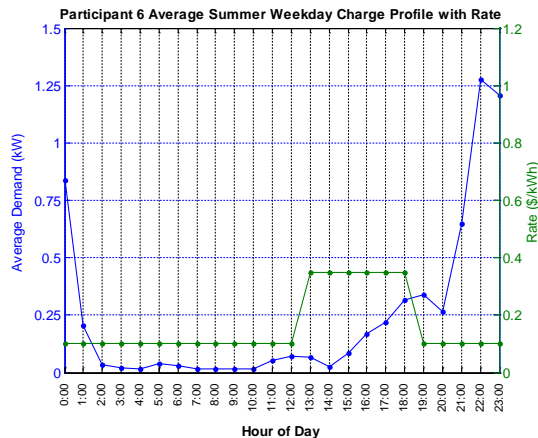
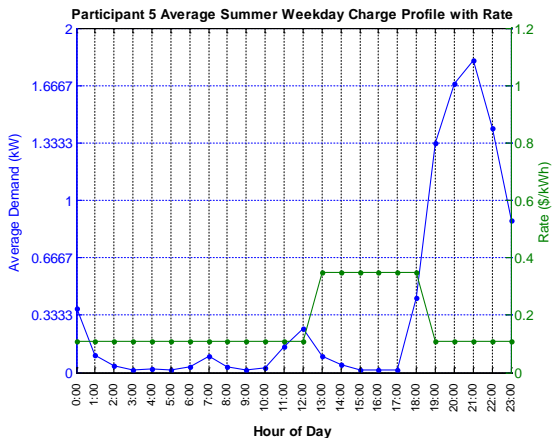
7.4.5.3 Results

The 14 graphs in the following figure represent the average weekday load profile for each participant during the June 1 through September 30 2012 and June 1 through September 30 2013 periods when they had a vehicle and were on one of the time-of-day tariffs. Also plotted is the average weekday tariff during that period. This makes it easy to see if a participant was predominantly charging their vehicle during the low cost period.

Of the 16 participants, one participated in the real time pricing tariff which wasn’t quantified in the terms described above. Another participant did not have the vehicle during the June through September period and was not quantified as well.



Electric Vehicles



Electric Vehicles

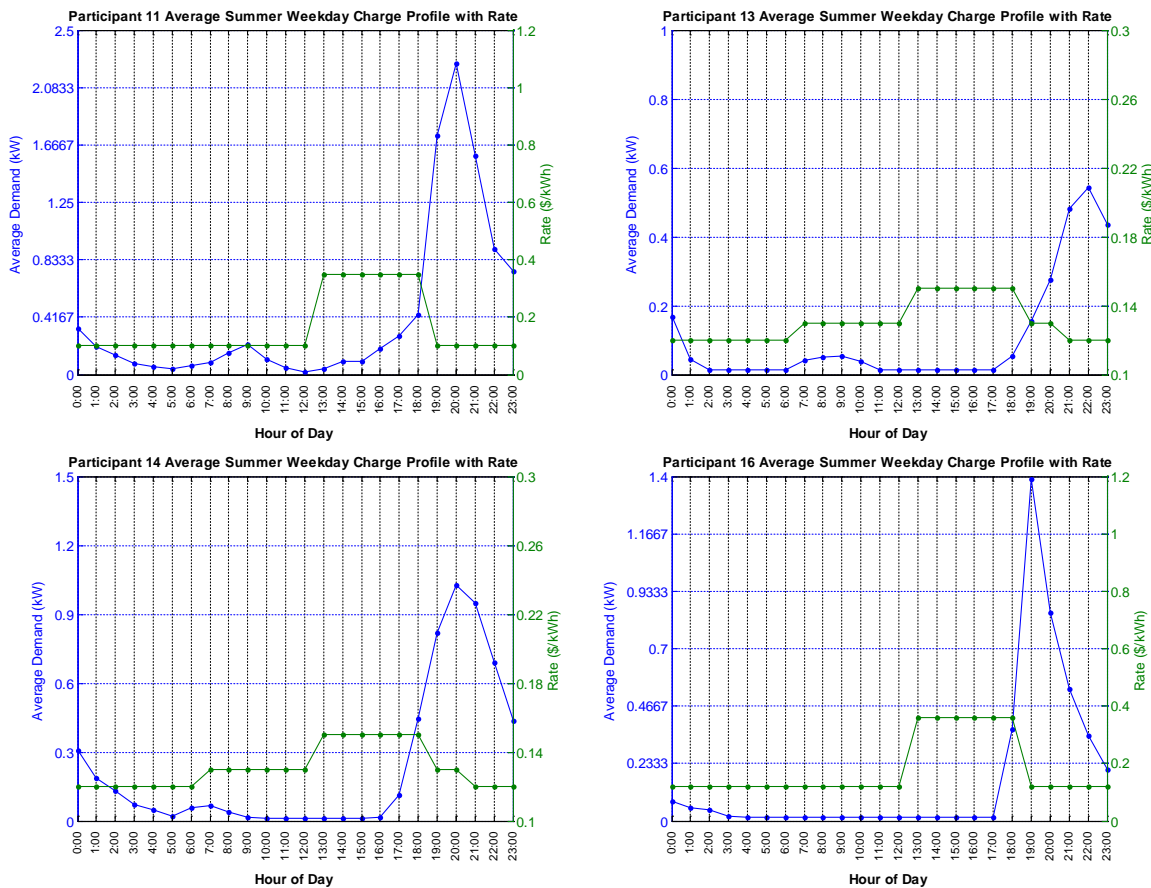


Figure 163. Participant Profiles During Time of Day Pricing

Electric Vehicles



The following table shows the tendency of the participants to charge during the low price period. Overall 72 percent of participants demonstrated a Strong or Moderate tendency to charge during the low price period. Of those on the Two Tier tariff, 91 percent showed a Strong or Moderate tendency to charge during the low price period. None of the participants on the Three Tier tariff showed a Strong or Moderate tendency to charge during the low price period. This may be due to the fact that the price difference between low and higher periods is greater for the two tier-tariff than for the three-tier tariff.

Tendency to Charge at Low Price	Overall		Two Tier Time of Day		Three Tier Time of Day	
	Number of Participants	Percentage	Number of Participants	Percentage	Number of Participants	Percentage
Strong	4	29%	4	36%	0	0%
Moderate	6	43%	6	55%	0	0%
Mild	2	14%	1	9%	1	33%
None	2	14%	0	0%	2	67%
Total	14		11		3	

Table 28. Participants Tendency to Charge during Low Price Periods

7.4.6 Consumer Behavior by Location

Participants were given the option to use workplace charging for a fee of \$10 per month. Participants' workplace charging was metered so that the total energy consumed by each participant is known.

7.4.6.1 Objective

AEP determined energy usage of each participant at home and at work.

7.4.6.2 Calculation Approach

The average cost of energy (\$/kWh) for workplace charging by participant was calculated. Twelve of the participants used workplace charging.

Electric Vehicles



7.4.6.3 Results

The following figure shows the average cost of energy for each participant to charge their vehicle at home and work. The average cost of all charging energy is also shown. Eight participants paid a higher effective rate for workplace charging than they did at home and seven of these were significantly higher. Four participants paid a lower effective rate to charge at work. Participant 15 was on the RTP_{da} tariff so their average rate was not calculated. In addition, they did not use workplace charging.

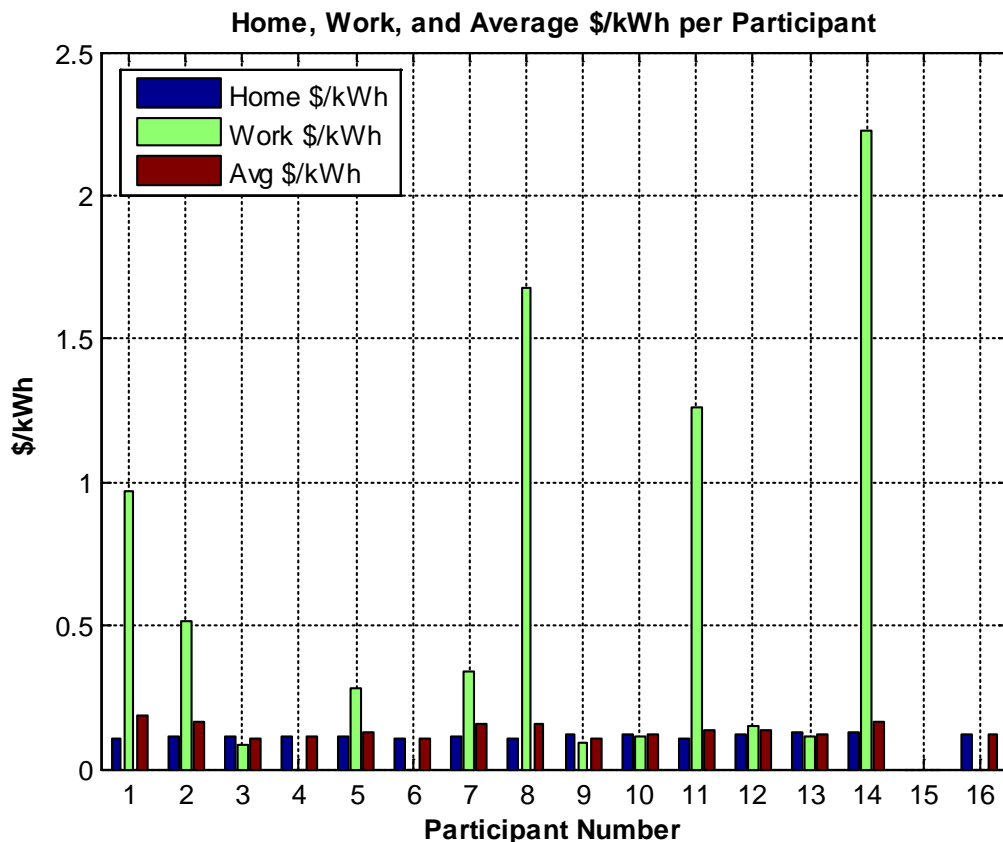


Figure 164. Average Cost of Energy to Charge PEVs at Home and Work by Participant

Electric Vehicles



The figure below shows the average cost of energy to charge PEVs at home, work, and the overall average for participants who used workplace charging. On average, the group paid about \$0.11/kWh to charge at home compared to \$0.21/kWh to charge at work. If the PEV gets about 2.8 miles/kWh and that a similar gasoline vehicle would get 26.3 mpg, then \$0.21/kWh works out to an equivalent \$1.97/gallon of gasoline. An employee would need to consume approximately 91 kWh per month at work to achieve the same rate of \$0.11/kWh at home. A driver would need to consume an average of 4.55 kWh/day at work, assuming 20 work days per month.

Overall Home, Work, and Average \$/kWh for Participants with Workplace Charging

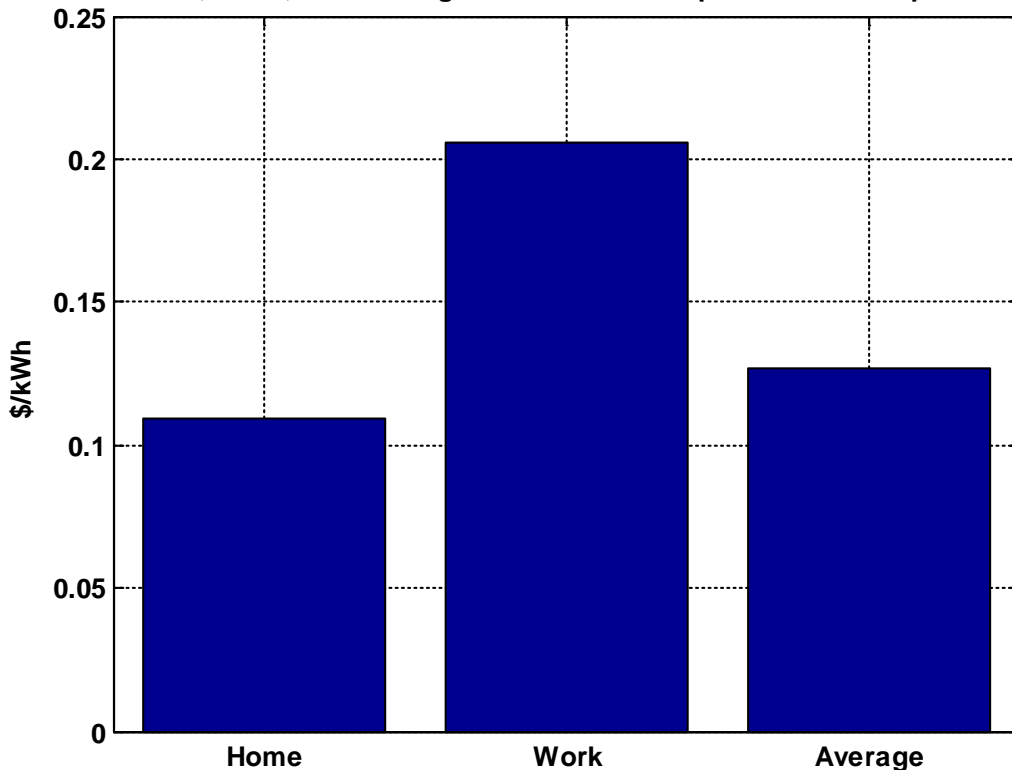


Figure 165. Average Cost of Energy to Charge PEVs at Home, Work, and Overall Average for Participants with Workplace Charging

Electric Vehicles



The figure below represents the number of charging events by location (Residential, Workplace, and Public) for each participant.

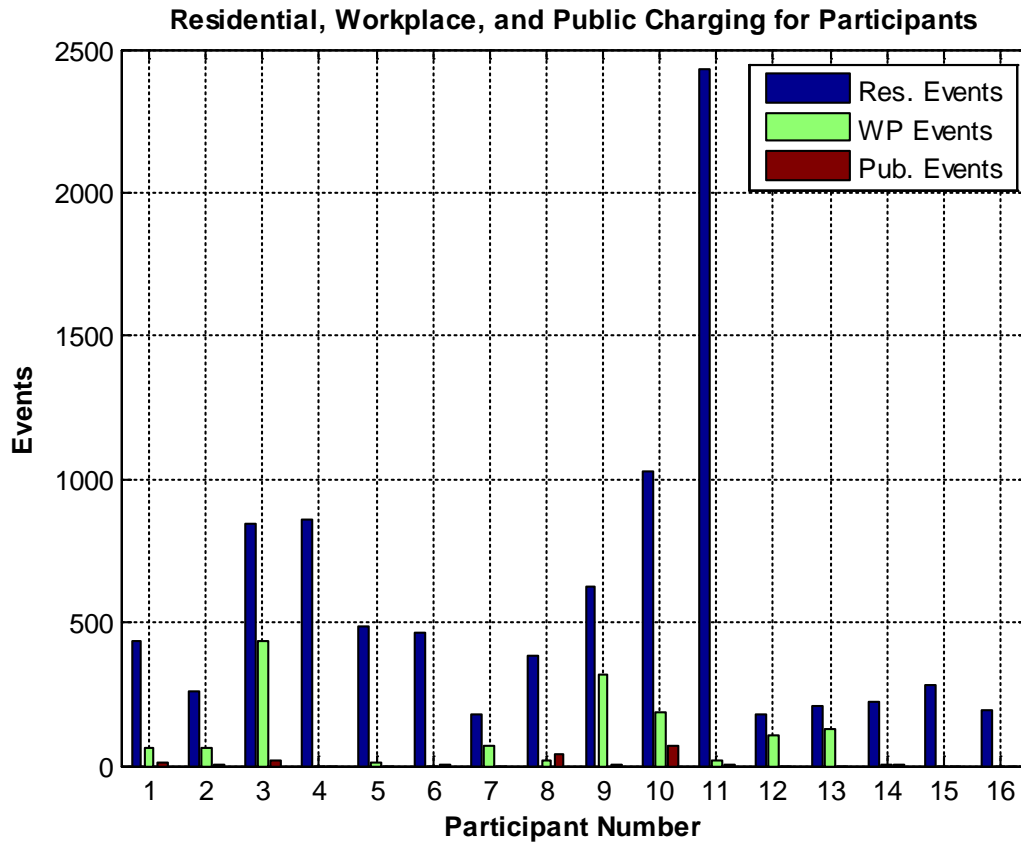


Figure 166. Number of Charging Events by Location for Each Participant

Electric Vehicles



The figure below represents the total kWh consumed by location for each participant. The majority of events and energy consumed for every participant occurred at their residence.

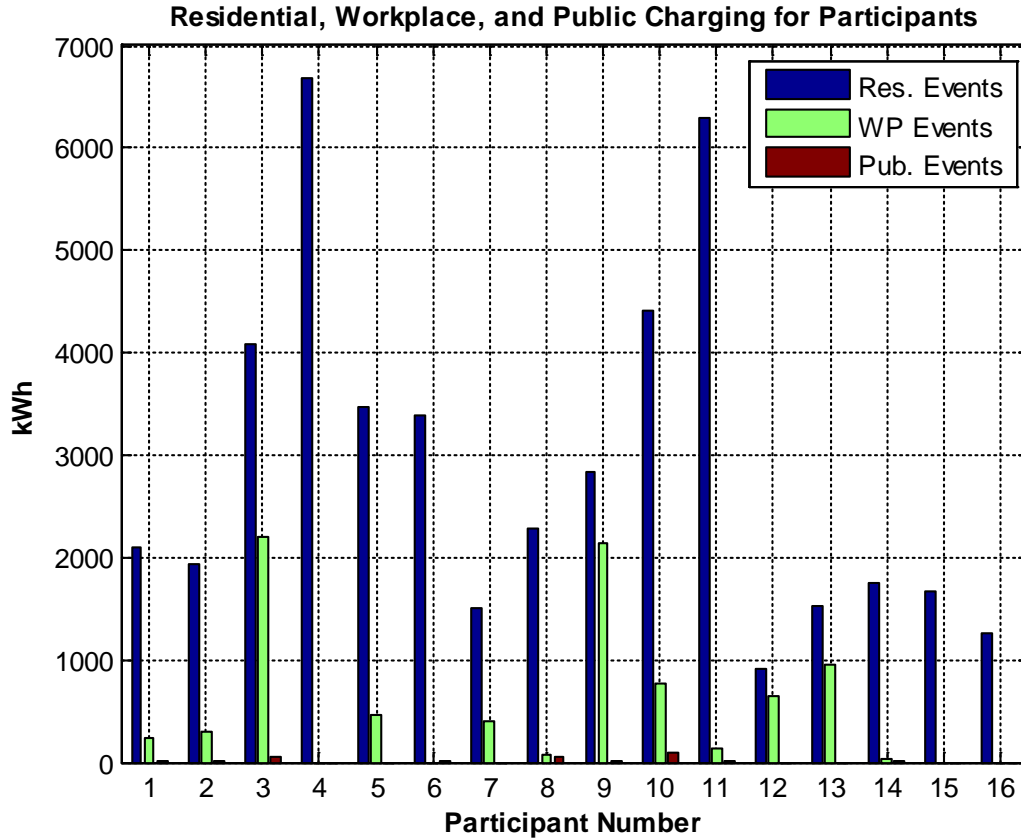


Figure 167. Amount of Energy Consumed by Location for Each Participant

Electric Vehicles



7.4.7 Vehicle Statistics

7.4.7.1 Objective

AEP Ohio analyzed ten of the PEVs used in this Project.

7.4.7.2 Results

Ten vehicles were driven for a total of 271,415 miles of which 67 percent or 182,286 were electric miles and 33 percent or 89,129 were gasoline miles. These vehicles averaged 112 mpg. Driving on battery saved 7,781 gallons of gasoline. The following table provides a summary.

Vehicle Information Summary	
Total Miles	271,415
Electric Miles	182,286
Gas Miles	89,129
MPG (Average)	112
Gallons of Gas Consumed	2,434
Gallons of Gas Saved	7,781

Table 29. Vehicle Statistics Summary

The following figure shows the number of total, electric, and gas miles driven for each vehicle. In all cases the number of electric miles exceeded the number of gas miles.

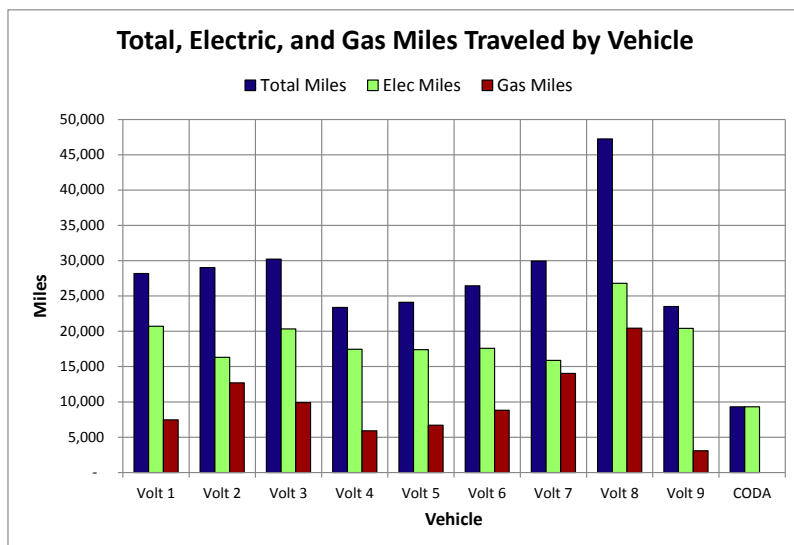


Figure 168. Total, Electric, and Gas Miles Traveled by Vehicle

Electric Vehicles



This figure shows the average mpg for each vehicle excluding the Coda since it was all-electric. The vehicles ranged from an average of 76 mpg to over 250 mpg with the overall average for these vehicles being 112 mpg.

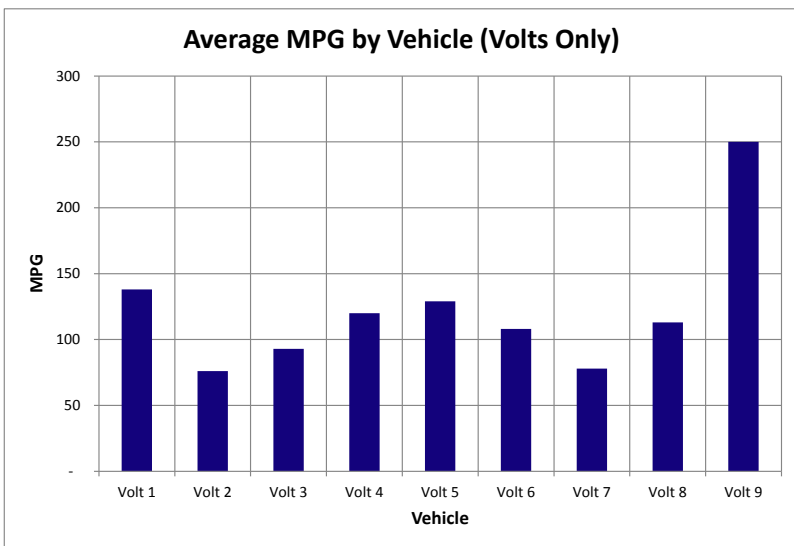


Figure 169. Average MPG by Vehicle

The figure below shows the number of gallons of gasoline consumed and saved by each vehicle. The number of gallons saved exceeded those consumed in all cases. The gasoline saved ranged from 352 gallons to 1379 gallons and averaged 778 gallons per vehicle.

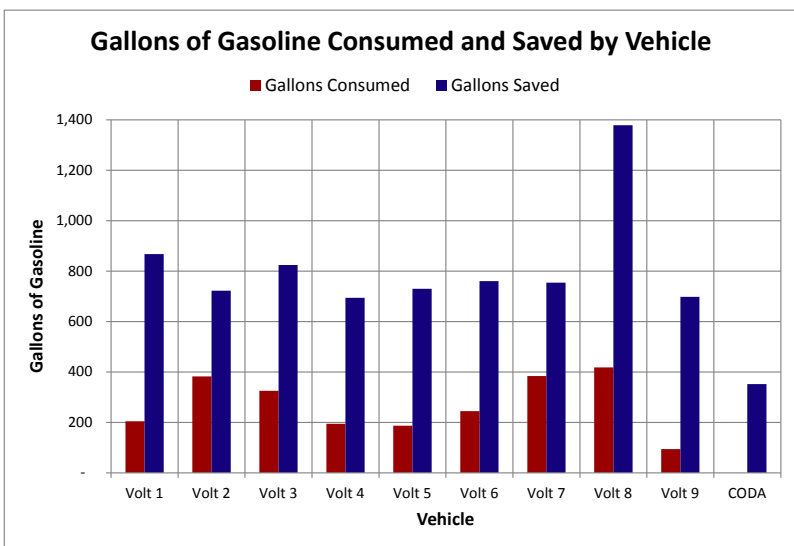


Figure 170. Gallons of Gasoline Consumed and Saved by Vehicle

Electric Vehicles



7.4.8 Vehicle Performance

One of the Volts participated in an EPRI project whereby certain vehicle performance data was collected and shared on an aggregate basis. This vehicle was assigned to a single participant for the duration of the Project. The following figure shows the average miles driven per kWh by month for this vehicle, which ranged from a low of about 2 miles/kWh in February 2013 to a high of 3.7 miles/kWh in August 2013. The miles per kWh for the vehicle were generally lower during the winter and higher during moderate and warmer months.

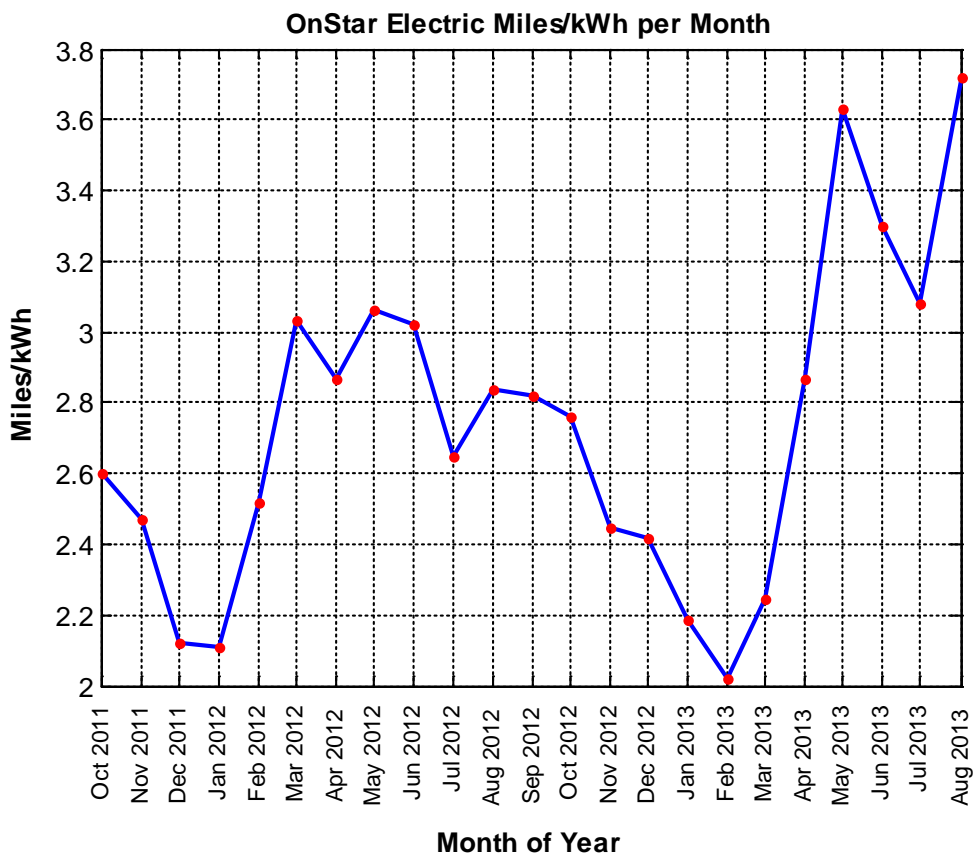


Figure 171. Average Miles Driven per kWh by Month

Electric Vehicles



7.4.9 Consumer Experience

Each participant was asked to fill out a survey related to their overall experience with the vehicles and the project. The overall experience was positive. Four of the questions related to electric vehicles could be quantified and are shown in the following figures.

The figure below shows the majority of participants were more interested in the range of the vehicle than its affordability or comfort. Participants generally tried to drive on electric as much as possible to minimize their fuel expense.

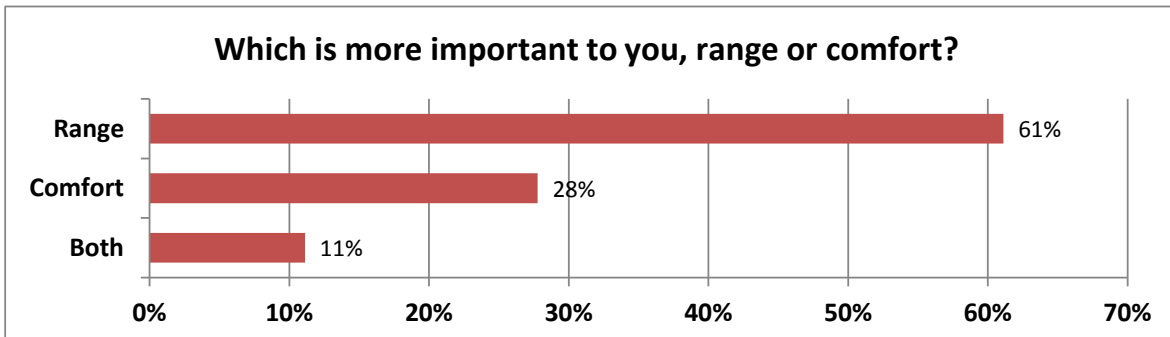


Figure 172. Range or Comfort Preference

The figure below shows the participants were willing to consider an electric vehicle for use as their personal vehicle. The majority of these participants cited the cost of electric vehicles as a barrier to their purchase.

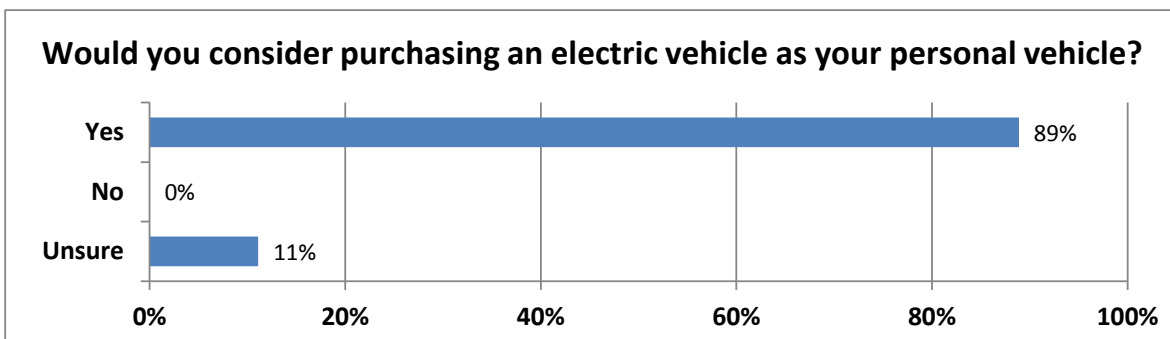


Figure 173. Consider Purchasing an EV

Electric Vehicles



The following figure indicates that for 39 percent of the participants, the availability of Level 3 charging would have some influence on their decision to purchase an electric vehicle

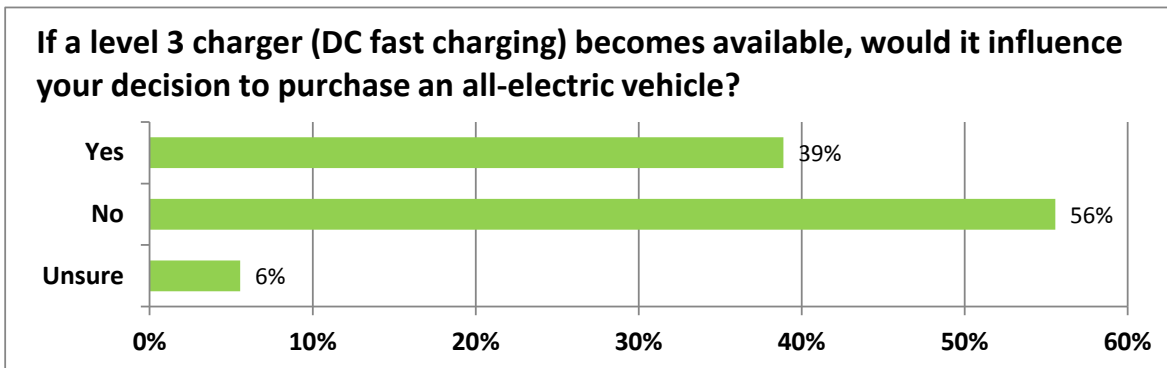


Figure 174. Level 3 Charging Effect on Purchasing an EV

The figure below indicates that the participants have a strong preference toward making their next vehicle purchase an electric vehicle of some sort. Sixty-four percent favor a PHEV and 14 percent a hybrid electric vehicle (HEV), resulting in 78 percent favoring an electric vehicle of some sort.

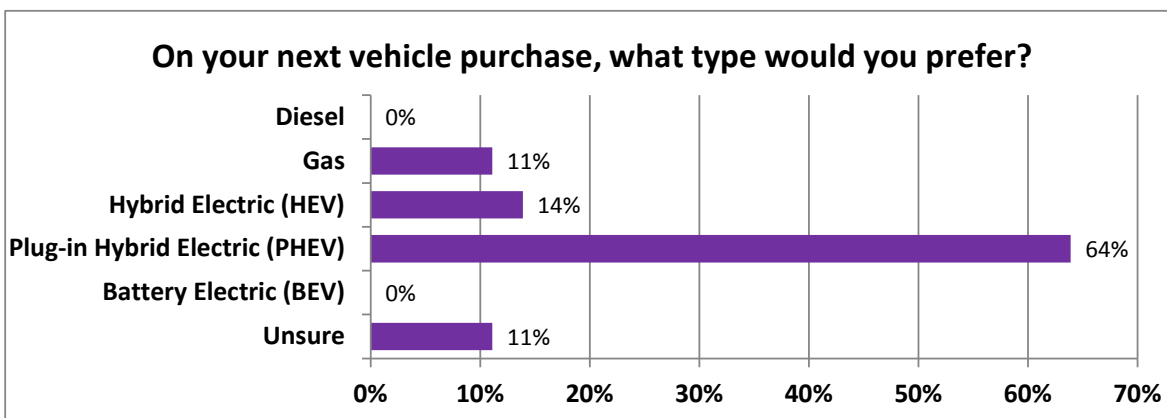


Figure 175. Next Vehicle Purchase Type Preference

Electric Vehicles



7.5 Electric Vehicles Conclusions

Initial adoption of PEVs did not appear to have a significant impact on transformer loading. As adoption rates increase, the rate (kW demand) at which PEVs charge increases. Increased adoption rates as well as increased PEV charge rates (kW demand) are ongoing considerations for the utility.

The analysis showed that Level 1 charging may be sufficient for most adopters at home and the workplace, especially if the vehicle was a PHEV instead of a BEV. Level 2 charging would be more beneficial at locations where shorter charge times would be experienced, but this would only be necessary in some cases for a BEV.

There was a correlation between electric rates and charging behavior when the price difference was significant as was the case with the two-tier tariff. In this case, 91 percent of the participants demonstrated a strong or moderate tendency to charge during the low price time periods. In the three-tier tariff where the price difference was less significant between the electric rates, the participants showed little to no tendency to charge during low price periods.

Workplace charging was used by 12 of the 16 participants. Eight of these participants paid a higher rate at work than they did at home. Five participants paid rates for workplace charging that were higher than what they would have paid to use gasoline instead of the electricity they received at work. It was unclear to what extent participants might have been aware of the effective cost (\$/kWh) they were paying for workplace charging, since they paid a flat monthly fee of \$10. At least one participant would have preferred an option to pay per charge at work.

Ten vehicles were driven for a total of 271,415 miles of which 67 percent or 182,286 were electric miles and 33 percent or 89,129 were gasoline miles. These vehicles averaged 112 mpg. Driving on battery saved 7,781 gallons of gasoline.

The majority of the participants indicated that they would prefer their next vehicle purchase be an electric vehicle of some type.

7.6 Lessons Learned

This section describes lessons learned for PEV technology.

- Initial adoption of PEVs *did not* appear to have significant impact on residential transformer loading.
- A thorough analysis should be completed before public chargers are sited, as PEV usage tends to be location-specific.
- Level 1 charging may be sufficient in most cases (residential and workplace) as parking duration is long enough for full charge.

Electric Vehicles



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8 DEMONSTRATED TECHNOLOGY – CYBER SECURITY

8.1 Purpose

AEP Ohio endeavored to build a secure, interoperable, and integrated smart grid infrastructure in northeast central Ohio. The deployed technologies required comprehensive cyber security capabilities for both new and legacy systems. The AEP Ohio gridSMART[®] Demonstration Project cyber security team integrated into all areas of the Project to ensure device and threat monitoring and sharing.

8.1.1 Device Security

The smart grid used various techniques and technologies to provide a more reliable and stable power grid. Many of the technologies used were new, redesigned, or re-provisioned from a previous purpose. Both types introduced new risks to critical infrastructure components. The role of the cyber security technology was to ensure the security of all new and existing devices and networks.

The Cyber Security plan, as approved by the U.S. Department of Energy (DOE), required each technology implementation to provide clear documentation demonstrating its proposed approach to cyber security. This approach would prevent broad-based systemic failures in the electric grid should a cyber security breach occur.

The cyber security team worked closely with the technology teams and vendor participants to meet the cyber security requirements by implementing security assessment processes, procedures, standards, and policies for all technology areas. Upon determining cyber security risk types and levels, AEP Ohio established acceptable risk levels for each technology area, and designed, tested, and implemented strategies and mitigations.

8.1.2 Cyber Threat Monitoring and Sharing

The interconnectedness of the smart grid opened opportunities for cyber security threats to utility networks, which could be difficult to pinpoint and address. Tools, processes, and concepts were used to deter and detect a variety of these threats, including:

- Location
- Investigation
- Minimization of impact
- Mitigation

Additionally the cyber security team was continually learning and adapting to attackers' techniques, tactics, and procedures.



8.2 Technology

8.2.1 Device Security

AEP is committed to ensuring a reduction of risk to the lowest acceptable level, not only for AEP, but also for its consumers and the grid. This required extensive testing of all technologies. The following commercially available technologies were subjected to intensive cyber security testing:

- **General Electric (GE) i210+c Meter** – Primary residential AMI meter deployed in the Project area.
- **GE KV2C** – Primary commercial AMI meter deployed in the Project area.
- **Silver Spring Networks (SSN) UtilityIQ®** – AMI head-end system for meter management and monitoring.
- **SSN Demand Response Manager (DRM)** – SSN’s head-end software application in the UIQ application suite. DRM’s web-based interface allowed utility operators to manage HAN devices, create, monitor and manage demand response events, and obtain analytics about load shed and customer participation.
- **Home Energy Manager (HEM)** – Provided an interface to consumers participating in the Real Time Pricing with Double Auction (RTP_{da}) program. This device served as the communication agent among the Enhanced Programmable Communicating Thermostat (ePCT), the AMI meter, and the Smart Grid Dispatch system.

8.2.2 Cyber Threat Monitoring and Sharing

The Project acquired a suite of cyber security capabilities and services that provided advanced network protection and a multi-pronged approach to advance threat detection and management.

8.3 Approach and Implementation

8.3.1 Device Security

The Project implemented a comprehensive cyber security plan that included a complete battery of vulnerability and penetration tests starting with the meter, through the network, to the head-end system. The comprehensive testing strategy for the Project involved a series of steps strategically placed throughout the development and deployment cycle of the Project. The steps were as follows:

- Step 1 – Technology Review
- Step 2 – Risk Assessment
- Step 3 – Vulnerability Assessment
- Step 4 – Penetration Testing

In Step 1, the review entailed researching all of the capabilities of the product and identifying the potential points of attack.

In Step 2, AEP conducted formal risk assessments on all technology components.

Cyber Security



In Step 3, AEP evaluated applications and hardware to determine if there were potential vulnerabilities in the product.

Step 4 consisted of penetration testing for all technology areas.

During Steps 3 and 4, AEP developed final reports that outlined the severity of the vulnerabilities identified and the recommended actions for remediation. If the determined risk was greater than the acceptable level, a remediation plan was developed and implemented.

AEP Ohio subjected all technology components of the Project to this complete battery of tests, including penetration testing.

8.3.2 Cyber Threat Monitoring and Sharing

Lockheed Martin collaborated with AEP Ohio to develop the Palisade™ suite of tools based on the intelligence management approach. Palisade enabled cyber security analysts to manage alerts, detections, mitigations, and courses of action in a single application. This centralization of investigative activities greatly reduced the amount of time analysts needed to filter through noise. These tools allowed analysts to focus their time on extracting actionable intelligence and using this intelligence to detect active threats on the network.

The threat and information sharing portal was launched to foster a secure environment allowing cyber threat intelligence to be shared among the utility industry, and included approximately 15 large utility adopters as of summer 2013. Building an extensive cyber security threat database was extremely important to utilities seeking advanced computer network defense capabilities. Other industries, including oil and gas and healthcare, have also adopted the collaboration and intelligence sharing benefits of the Threat and Information Sharing portal.

Advanced Persistent Threats (APT) Sensors integrated into existing corporate security environments to provide ongoing and focused network visibility. The sensors provided detection and alerts on covert malicious command and control challenges, network anomalies, and detection of advanced file exploits.

8.4 Cyber Security Conclusions

8.4.1 Device Security

Several vulnerabilities were discovered in Step 1 shown in paragraph 8.3.1. The first vulnerability was fixed with a change in physical production of a device while the second one required updated software

Step 2 issuers of data being transferred from AEP systems to third-party systems in an unsecure manner were resolved by changing to Secure File Transfer Protocol (FTP). Secure FTP has now been made the standard method of data transfer between AEP systems and third-party systems.

Step 4 penetration test issues were resolved through the reconfiguration of network security devices.

Cyber Security



Further issues were resolved with updated meter management software. The cyber security team determined that there was a need for a recurring assessment of network security due to the continually evolving environment with the addition of new devices, updated firmware, and updated software.

8.4.2 Cyber Threat Monitoring and Sharing

Through Palisade and in collaboration with sources including the Department of Homeland Security (DHC), the threat and information sharing portal, and the North American Electric Reliability Corporation (NERC), the cyber security team reviewed and discussed intelligence reports of known issues that affected the electric industry and those potentially aimed at AEP. The gridSMART cyber security team is now a member of several threat information sharing teams networks, products, and devices.

AEP developed the Cyber Security Operations Center (CSOC). It was designed to provide highly customizable threat management and response that was implemented on top of AEP's existing security framework. The CSOC included:

- The Palisade suite of tools that provided single-source threat detection management.
- Advanced Persistent Threat (APT) sensors that delivered a wide visibility of IT assets and critical network infrastructure.
- Threat and information sharing that included a secure portal to share vital threat information practices among participating utility partners.

Interoperability



9 DEMONSTRATED TECHNOLOGY – INTEROPERABILITY

9.1 Purpose

Interoperability (IOP) is the ability of systems and/or components to provide and receive services and information in a predictable way without significant user intervention. The exchange of information and interfaces was based on openly available standards and integrated, commercially available products, new technologies, and new consumer products and services within a single, secure, two-way communication network between the utility and consumers. The primary focus of IOP was to identify gaps in the current and proposed standards.

9.2 Technology

Interoperability is not a technology to be implemented, but rather a goal to be accomplished. The Interoperability Plan was outlined to accomplish two goals. The first goal was to develop a plan to use to ensure interoperability among all systems, devices, and data sources. The second goal was to document the extent to which the first goal was accomplished.

For the interoperability of the back office, the primary goal was to implement systems in such a way to protect against cascading failures. To accomplish this, the team implemented a communication standard and drove compliance to that standard. AEP Ohio engaged Electric Power Research Institute (EPRI) to assist in creating the Interoperability Plan. For this exercise, the team defined an interface as a pairing of systems or actors. This resulted in the creation of multiple use cases and multiple interfaces.

9.3 Approach and Implementation

The IOP test plan was organized by topic, such as Demand Response, Distribution Grid Management, and AMI. Each topic contained a set of use cases analyzed to discover the number and purpose of interfaces involved with each topic. Each interface was assessed to determine whether a relevant standard existed, with particular emphasis being placed on the standards enumerated in National Institute of Standards and Technology (NIST) Special Publication 1108, *NIST Framework and Roadmap for Smart Grid Interoperability Standards*. The interfaces were then assessed to determine if relevant standards were implemented by AEP Ohio and/or by its vendors in a manner that could be tested for standards compliance.

Interoperability's two-phase testing approach combined lab and field testing to obtain a complete Project evaluation. The first phase involved extensive lab testing of technologies by exercising their full range of functions. The second phase involved field tests with a limited base of consumers. This approach determined the functionality, reliability, security and overall system interoperability.

Because IOP affected several different technologies, there was not a single approach for the cumulative group. Each Project technology area had a unique approach for implementing interoperability. However, some common themes prevailed through most of the Project area, such as Common Information Model (CIM) messaging.

Interoperability



9.3.1 Common Information Model Compliant Messaging

Common Information Model compliant messages were implemented across several topic areas as a means of communication between systems. By implementing CIM-compliant messaging, a standard message format was created to exchange information between new and legacy systems, allowing for interoperability beyond AEP systems. This was part of the back-office strategy for interoperability.

9.3.2 IntelliGrid

EPRI's IntelliGrid methodology provided a conceptual architecture that was implemented within platform-independent solutions. This methodology promoted open, interoperable systems and standards; provided tracking and analysis of smart grid technologies; and captured best practices. The Project Interoperability Plan was derived from the IntelliGrid methodology with specific roadmaps for smart grid development and deployment.

The IOP test plan started with a conceptual architecture and then moved to development of a platform-independent architecture that provided a basis for integrating applications. The primary goal was to develop an architecture with vendor-specific aspects, but with the ability to plug in many different vendor applications as a result of industry interface standards. Legacy systems and technology were integrated using appropriate gateways and translators.

9.4 Use Cases

Twenty-seven use cases were developed, in cooperation with EPRI, to test the interoperability of the Project components. These components included: back-office systems, communication network, Home Area Network (HAN), and AMI. These use cases were grouped in five categories:

- Demand Response – nine use cases
- Distribution Grid Management – two use cases
- Electric Transport – one use case
- Advanced Metering Infrastructure – twelve use cases
- Work Management System – three use cases



Interoperability

9.5 Use Case Analysis

There were eight interface types:

- CIM or ANSI standards
- Future CIM or ANSI standards
- Vendor Proprietary
- AEP Proprietary
- Open – applying for CIM or ANSI standard
- None – no standard applies
- Proprietary LAN
- Custom

AEP identified these standards within the five categories of use cases:

Demand Response had nine use cases using twenty-eight interfaces

- Standard – seventeen
- Vendor Proprietary – two
- Open – five
- None – four

Distribution Grid Management had two use cases using thirteen interfaces

- Vendor Proprietary – three
- AEP Proprietary – three
- Proprietary LAN – seven

Electric Transport had one use cases using five interfaces

- Standard – one
- Vendor Proprietary – three
- None – one

AMI had twelve use cases using nineteen interfaces

- Standard – thirteen
- Vendor Proprietary – four
- None – two

Interoperability



Work Management System had three use cases using twenty-one interfaces

- Standard – seven
- Future Standard – five
- Vendor Proprietary – two
- Custom – seven

9.6 Interoperability Conclusions

The barriers to interoperable implementation of smart grid technologies consisted of the varying maturity of vendor products. The majority of Project interfaces were CIM and ANSI standards compliant. Application for CIM standardization for some interfaces was submitted.

Overall, the integration of devices into AEP Ohio systems proved to be interoperable. Although the integration processes were manual and required significant effort and end-to-end verification of every data point from the field to the back office, they were successfully implemented. AEP Ohio mitigated resource requirements by using a single communications protocol, limiting device types, and creating internal data exchange standards.



10 DEMONSTRATED TECHNOLOGY – MODELING AND SIMULATION

10.1 Purpose

In the AEP Ohio gridSMART[®] Demonstration Project (Project) area smart grid technologies were deployed to 80 distribution circuits. It was important to assess potential impact if the technology deployments were extended to the remaining 1,700 distribution circuits in AEP Ohio's service territory. The Modeling and Simulation (M&S) project developed a simulation engine and applied it to evaluate the effects of new technologies in a variety of circuit configurations. In addition to simulating the types of technologies that were field deployed as part of the Project, photovoltaic, sodium sulfur batteries, and community energy storage were also simulated. The technologies that were studied to determine their effects on circuit behavior included:

- 25kW Community Energy Storage (CES)
- 1MW Sodium Sulfur Battery (NaS)
- Photovoltaic (PV)
- Plug-in Hybrid Electric Vehicle (PHEV) and Plug-in Electric Vehicle (PEV) charger
- Volt VAR Optimization (VVO)
- Fixed Price Tariff
- Load Control Switch (LCS) used for Direct Load Control (DLC)
- Time of Day (TOD) Tariff
- TOD Critical Peak Pricing (TOD/CPP) Tariff
- Real Time Pricing Double Auction (RTPda) Tariff

M&S modeled a representative subset of the 1,700 distribution circuits in AEP Ohio. Modeling a representative subset of circuits could allow technology impacts to be scaled up to all circuits in AEP Ohio. Models were representative of AEP circuits and indicate what may happen in practice. There are multiple variables that may impact simulations as well as field deployment results.

All results provided in this section are from simulations incorporating the above technologies.

10.2 Technology

The M&S team used GridLAB-D[™], an open source code developed by Pacific Northwest National Laboratory (PNNL) to model the circuits. Additional proprietary modifications were made to GridLAB-D to simulate the new technologies for the Project. GridLAB-D simulated the distribution circuit from the substation to the individual premises along with their appliances, outlet and lighting loads, air conditioning, water heater, and the home insulation characteristics. Voltage, power, switch operations, and other dynamic variables at any location on the circuit

Modeling and Simulation



model were provided at discrete time intervals for conditions specified by a simulation. Performance metrics such as maximum peak power demand and energy consumption were estimated by analysis of the GridLAB-D outputs.

Building each circuit model required the following data:

- Graphical Information System (GIS) information describing the circuit configuration
- County Auditor information describing the premises' age, size, and location
- Premises and the associated distribution transformer
- Conductor information describing the house to distribution transformer connection
- Premises' characteristics
 - Number of occupants
 - Gas versus electric heat
 - AC versus no AC
 - Existing demand response model
 - Additional technologies
- Climate data
- Consumer electrical usage behavior based on their demand response

Information was gathered from existing AEP databases and other sources. The Project identified data sources and provided a centralized location to store the data.

A software tool was developed to facilitate the frequent building and modification of circuit models and assist in manipulating and analyzing GridLAB-D models. The new tool, GridCommand™ Distribution (GCD), is now commercially available. Highlighted features of GCD include the ability to:

- Create GridLAB-D model file from CymDist model files
- Import existing GridLAB-D files
- Export to GridLAB-D file format
- Display the circuit graphically based on latitude/longitude
- Add or delete new items from the circuit model using the console or graphical interfaces
- Support user scripts to modify the circuit model
- Display a tree view of every object in the model organized by type
- Support parametric analysis



10.3 Approach and Implementation

M&S was implemented using a sequence of four interrelated tasks:

- Stakeholder question analysis
- Baseline circuit model development
- Parametric analysis
- Reporting

Stakeholder question analysis defined project goals, identified questions that needed to be asked to achieve these goals, and developed metrics for the modeling process. As a result of this task, a set of goals, questions, and metrics (GQMs) was derived. A matrix of circuit simulations and experimental design was created using this set of GQMs.

Baseline circuit model development required identifying which circuits would be modeled and then developing accurate GridLAB-D models for each circuit. To select representative circuits, data regarding characteristics of all 1,700 circuits in the AEP Ohio distribution territory was collected. Circuits were then grouped into clusters based on these characteristics. This cluster analysis categorized the 1,700 circuits into 25 circuit types and identified 12 circuits that represented 94 percent of AEP Ohio distribution circuits. A total of 32 circuits were modeled that incorporated these 12 circuit types.

Baseline circuit models were developed and validated against Supervisory Control and Data Acquisition (SCADA) data for each circuit using GridLAB-D. A year-long GridLAB-D simulation was created for each of the circuits using a typical meteorological year (TMY) as the reference weather data. These models were validated against SCADA data from 2010 by comparing the simulated outputs against the SCADA records.

Parametric analysis included 1,247 year-long simulations, counting both baseline configurations and the technologies that were modeled. This task considered variations on technology penetration levels within a single circuit along with combinations of technologies within the same circuit.



10.4 Technology Model Descriptions

Modules for many of these technologies existed in GridLAB-D prior to starting the project, including PV, PHEV/PEV, DLC, ToD, ToD/ CPP, VVO, and RTP_{da}. However, the CES, and NaS modules did not exist and were added to GridLAB-D as part of this Project. Technology specification documents were generated for each of the technologies, and the existing modules were evaluated to determine if they were sufficient to support the proposed numerical analysis. Additionally, a proprietary VVO module was used for circuits that had at least one line regulator. A short description of each technology follows.

Community Energy Storage (CES) units were evaluated on a set of 12 baseline circuit models. CES was evaluated in three major modes of operation: islanding, peak shaving, and VAR support. In islanding mode, CES was examined to determine its ability to island customers during an outage. The effects of CES islanding support on System Average Interruption Duration Index (SAIDI) were reviewed. In peak shaving mode, CES was operated using both scheduled and load following charge/discharge methods. Finally, CES's ability to provide VAR support was also considered. The effects of CES were evaluated as a function of penetration density for each circuit, where penetration density was computed as the fraction of total connected kVA for a given circuit. CES units were then added to each circuit model for a range of densities, and with varied control parameters at each density. In each model, all of the CES units were operated as a fleet using a central control with all units operating identically.

Sodium Sulfur batteries (NaS) were evaluated on a set of 12 baseline circuit models. NaS was evaluated in three major modes of operation: islanding, peak shaving, and VAR support. In islanding mode, NaS was examined to determine its ability to island customers during an outage. The effects of NaS islanding support on SAIDI were reviewed. In peak shaving mode, NaS operated using scheduled and load following charge/discharge methods. Finally, NaS's ability to provide VAR support was also considered. The effects of NaS were evaluated as a function of penetration density (battery size) for each circuit, where penetration density was computed as the fraction of total connected kVA for a given circuit. A single NaS unit of the appropriate size was then added to each circuit model for a range of densities with varied control parameters at each density.

Photovoltaics (PV) were evaluated on a set of 12 baseline circuit models. The ability of PV arrays to reduce circuit demand and energy was evaluated. This included an examination of how well PV complements peak shaving when a CES fleet is added to the circuit. Circuit voltage profile with PV arrays was examined including the arrays' effect on voltage regulation when transient events occur (i.e., cloud cover). Circuit demand and energy were evaluated under several PV array configurations. Each PV array configuration specified both total PV generation capacity and PV array locations along the circuit. Total PV generation capacity was specified as a fraction of total circuit connected kVA, calculated as the sum over transformer nameplate ratings. Location of PV arrays along the circuits included both evenly distributed and intentionally clustered cases.

Plugin Hybrid Electric Vehicle/Plugin Electric Vehicle (PHEV/PEV) was evaluated on a set of 12 baseline circuit models. The impact of PHEV/PEV on circuit behavior was evaluated in three major areas: equipment, overloads, circuit demand, and energy usage. Additional models

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evaluated the interaction of PHEV/PEV with CES batteries. In the combined technology (CES and PHEV/PEV) simulations, CES was operated using load following peak shaving method. The effects of the combined technologies were examined for individual distribution transformers. The effect of the PHEV/PEV on circuit demand and energy usage was evaluated, along with the possibility of equipment overloads. This included an examination of how circuit demand could be affected by the combination of PHEV/PEV demand and CES peak shaving and charging demands. PHEV/PEV was added to each circuit using a range of densities.

Volt VAR Optimization (VVO) technology was evaluated on a set of 32 baseline circuit models. The impact of VVO on circuit behavior was evaluated in three major areas – real and reactive circuit demand, real and reactive energy, and voltage profile management. The ability of VVO to reduce circuit demand and energy consumption was evaluated as well as its influence on circuit voltage profiles. For VVO operating alone, different combinations of end-of-line voltage and circuit power factor target settings were used. Additionally, VVO combined with PV, and VVO combined with fleets of CES batteries were evaluated. The combination of these technologies was evaluated to determine whether or not they operated synergistically together. Density level of other circuit components such as capacitors and regulators was examined.

The five tariff programs were evaluated on three baseline circuit models. Simulating consumer response to tariffs required trying to predict human response to pricing changes. Unlike other technologies such as PV or EV, there was no simulation object that can predict exactly how humans will respond. Because of this consumer response uncertainty, the tariff results in this simulation were meant to show a range of potential responses. This is why the tariff analysis was limited to three circuits. The ability of tariffs to reduce peak circuit demand and energy consumption was evaluated. Circuit demand and energy were evaluated under each tariff at varying consumer response levels. When possible, consumer responses to tariffs were based on available data from existing tariff programs. If no data was available, high and low response levels were simulated to demonstrate a range of potential consumer responses.



10.5 Summary of Simulation Results

Results from the simulations for each of the technologies are summarized in the following paragraphs.

10.5.1 CES

Community Energy Storage was analyzed as a fleet of CES units across 12 different circuits. Each of these circuits represents a single cluster of circuit types. Each CES unit includes a battery with a 23.4 kilowatt (kW) rated power output, 23.4 kVAR reactive power support, and 23.4 kilowatt-hours (kWh) of energy available when fully charged. The CES control managed the activities of the individual CES units in the fleet. CES was evaluated for its islanding, peak shaving, and reactive power support capabilities. For each of these operating modes a Goals, Questions and Metrics (GQM) was identified to determine the effectiveness of that mode.

CES Islanding

The ability for CES to provide islanding support was evaluated by reviewing the average fleet state charge using both the load following and scheduled peak shaving methods. The 12 circuits modeled in this analysis experienced an average of approximately 1.7 outages per year, with an average outage duration of approximately 2.3 hours. The results showed that on average there was sufficient battery capacity to sustain consumers for the 2.3 hour outage average. Islanding provided by CES was found to improve SAIDI. The percent change in SAIDI from the baseline was shown to be directly proportional to the number of houses on the circuit connected to CES.

CES Peak Shaving

The CES was operated using two peak shaving control methods, load following and scheduled. For the load following control method, discharge and charge set-points were chosen based on circuit load to determine when CES should start discharging and start charging. In the scheduled control method, a set discharge and charge daily time schedule was determined for each circuit.

The first figure that follows shows CES peak shaving using scheduled discharge for one of the 12 circuits during a two-day period, The second figure that follows shows the same result using load following Peak Demand Reduction.

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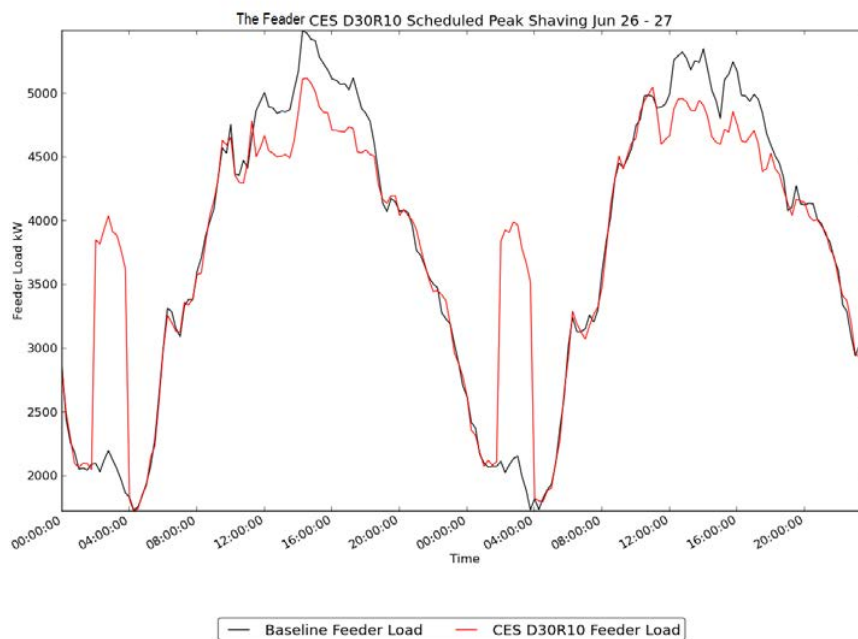


Figure 176. The Circuit Scheduled Peak Demand Reduction -- June 26 -27

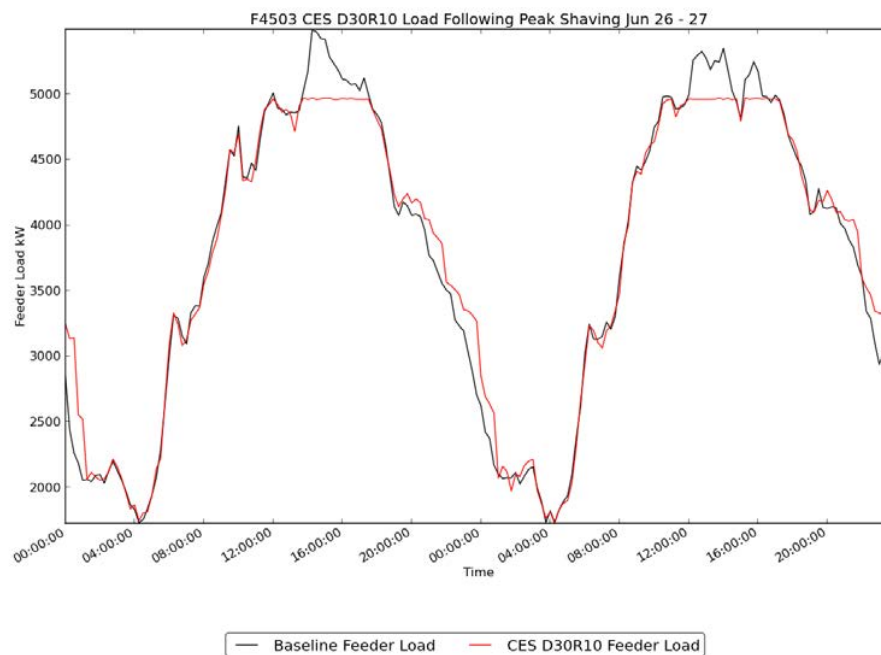


Figure 177. The Circuit Load Following Peak Demand Reduction -- June 26 - 27

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For each of these control methods, the amount of peak demand shaved, energy reduction, and the number of active versus successful peak shaving days were evaluated. The results showed, on average, scheduled shaved less peak demand than the load following control method. The average over all circuits and densities was 1.75 percent for scheduled and 3.27 percent for load following. Often the scheduled discharge missed the peak event and produced a much smaller difference between the circuit peak and the CES peak.

The load following analysis also showed that CES peak shaving worked best on circuits that had a high level of residential consumers, low commercial, and low levels of industrial consumers. These circuits had a large connected kVA, which resulted in more CES units being deployed on those circuits (simulation based on residential connected kVA). On average, the load following peak shaving events had both a larger peak reduction and larger percentage peak reduction compared to the scheduled events.

The ratio of successful to unsuccessful peak shaving days was higher in load following method compared to the scheduled method because the load following method had better set-points compared to the scheduled peak shaving method. Increasing CES density and reducing the reserve island capacity gives the greatest peak shaving and overall energy reduction. The results also show that for the load following case, it was extremely important to have load balanced among the phases on the circuit. Despite careful analysis to determine the best discharge and charge set-points, it could result in models that do not discharge/charge correctly. This implies that using static settings for the entire year may not work. These settings may need to be periodically reviewed and adjusted to better meet the objectives.

CES VAR Support

CES was evaluated in reactive power support mode. For the circuits modeled in this analysis, CES was effective at driving the average power factor to unity for most of the circuits. Those circuits that did not reach unity achieved an average power factor of 0.98. In general CES was able to reduce the yearly average in each circuit. There were a few exceptions to this in the load following peak shaving control method. Despite these exceptions, load following performed much better in general compared to scheduled discharge.

However, considering all circuits and all densities together, on average the kVARh reduction was 3.45×10^6 for scheduled and 3.26×10^6 for load following. This was due to several cases in the load following method where the kVARh savings were negative, compared to the scheduled results, which only had one instance. These negative values occur for the higher densities in one circuit and for lower densities in another. Negative values also occur for one circuit, but only at the highest density level for the load following control method. Load following, unlike scheduled, only discharged on a few days of the year for most circuits, and it only did so during a peak event.

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Thus, any reactive power support that occurred during these events was subject to available battery capacity not used for real power peak shaving. The scheduled results showed that on average, the amount of reactive power was always reduced. This was because scheduled discharges occurred every day, even on days when demand was small, so there was more power available for reactive power support. For some circuits, the power factor of the baseline model was very close to unity, which indicated that they had sufficient VAR support from capacitor banks. This meant that when CES was actively providing VAR support, an excess number of VARs was generated. Increasing the CES density was more effective at reducing kVARh. However, for most of the circuits, the kVARh reduction saturated because the power factor reached unity.

Overall, CES for both load following and scheduled methods provided significant reactive power support. No direct correlation was found between the CES reactive power support capability and the circuit characteristics.

CES Control Strategy

The simulated control strategy analysis indicated that load following control resulted in the best method to support peak shaving and reactive power support based on the circuits modeled. Load following also provided the most benefit to islanding because the low number of active peak shaving days resulted in an average annual battery state of charge that was close to 100 percent. Given the size of the CES deployed in the models, there was sufficient battery capacity to eliminate the average service interruptions for consumers connected to CES on the circuits that were studied.

10.5.2 NaS

A single NaS battery was deployed on each of the 12 baseline circuits. The NaS battery size varied based on the density being modeled for a given circuit. The battery could provide both real and reactive power support. Like CES, the NaS control managed the activities of the NaS battery. NaS was evaluated for its islanding, peak shaving, and reactive power support capabilities. For each of these operating modes, a GQM was identified to determine the effectiveness of that mode.

NaS Peak Shaving

The NaS battery was operated with two peak shaving methods – load following and scheduled. For the load following control method, discharge and charge set-points were chosen to determine when the battery should start discharging and start charging. In the scheduled control method, a set discharge and charge schedule was determined for each circuit.

The following figure shows NaS peak shaving using scheduled discharge for one of the 12 circuits during a two-day period. The next figure shows the same result using load following.

NaS Islanding

The simulated control strategy analysis indicated that load following control was the best method to support peak shaving and reactive power support based on the circuits modeled. Load following also provided the most benefit to islanding because the low number of active peak shaving days resulted in an average annual battery state of charge (SOC) that is close to 100 percent. The results also showed that in the types of outage events where NaS islanding would be

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effective (outages affecting the entire circuit), the NaS batteries were capable of providing islanding support to a limited number of consumers on the circuit, positively affecting the system reliability indices for these circuits. These gains were limited by the fact that NaS islanding applied to only a small subset of the outages experienced on a circuit, and that in most cases, only a fraction of the consumers on a circuit could be supported during an outage due to the location of high demand consumers. For this reason, circuit layout and battery placement should be considered in order to optimize islanding benefits.

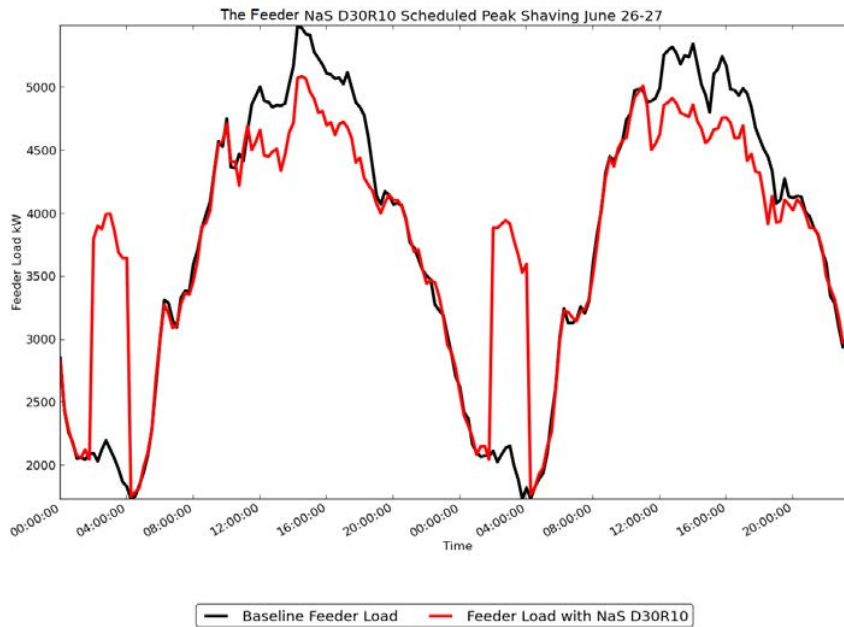


Figure 178. The Circuit Scheduled NAS Peak Demand Reduction -- June 26 -27

Modeling and Simulation

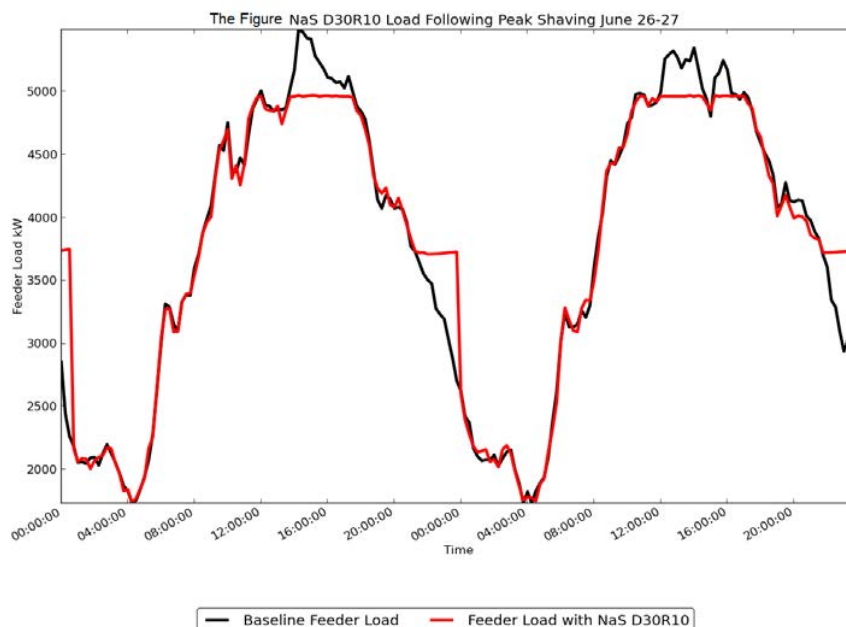


Figure 179. The Circuit Load Following NAS Peak Demand Reduction -- June 26 - 27

For each of these control methods, the amount of peak shaved, energy reduction, and the number of active versus successful peak shaving days were evaluated. The results showed the scheduled method shaved more peak energy than the load following control method. Scheduled was active every day of the year, and load following was active a fewer number of days. This was due to the fact that load following charges/discharges were based on set-points and was independent of the time of day when the peak occurred. Scheduled was directly dependent on the time of day when the peak occurred. Often the scheduled discharge missed the peak event and produced a much smaller difference between the circuit peak and the NaS peak. The load following analysis also showed that NaS peak shaving worked best on circuits that had a high level of residential consumers, low commercial, and low levels of industrial consumers. These circuits had a large connected kVA, which resulted in a larger NaS battery being deployed on those circuits.

On average, the load following peak shaving events had both a larger peak reduction and percentage peak reduction compared to the scheduled events. The ratio of successful to unsuccessful peak shaving days was higher in the load following method compared to the scheduled method. This was because the load following method had better set-points compared to the scheduled peak shaving method. This was due to the fact that load following charges/discharges based on set-points and thus was independent of the time of day when the peak occurred. The scheduled method was directly dependent on the time of day when the peak occurred. In many cases the annual peak was reduced with the addition of NaS. This showed how NaS peak shaving could be used as an alternative to traditional capacity improvement technologies to mitigate distribution system overloads.

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NaS VAR Support

NaS was evaluated in reactive power support mode as well. For the circuits modeled in this analysis, NaS was effective at driving the average power factor to unity for all of the circuits. In general, NaS was able to reduce the yearly average kVARh in each circuit. Increasing the NaS density was more effective at reducing kVARh; however, for most of the circuits, the kVARh reduction saturated because the power factor reached unity. Overall, the NaS battery using both load following and scheduled methods provided significant reactive power support. No direct correlation was found between the battery’s reactive power support capability and the circuit characteristics.

10.5.3 PV

PV was analyzed across the same 12 representative circuits used for CES and NaS. Each PV array had a 5 kilowatt (kW) rated power output. The impact of PV arrays on circuit behavior was evaluated in three major areas – circuit demand, energy usage, and the voltage profile of the circuit. Effects caused by sudden cloud cover were also studied. For each of these effects, a GQM was identified to determine the effectiveness of PV in each area.

PV Impact Evaluation

One of the potential benefits of PV was its ability to shave peak demand. PV output could provide energy during peak times to effectively offset circuit demand. Since PV output relied solely on the amount of sunlight, optimum peak shaving occurred when the solar irradiance level was high at the time of peak loading.

The following figure shows the demand reduction generated using PV for one of the 12 circuits.

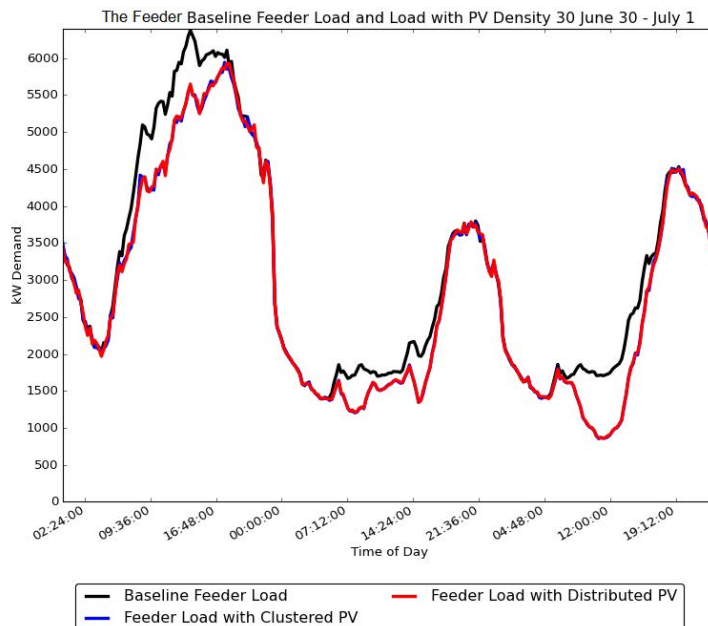


Figure 180. The Circuit PV Peak Demand Reduction -- June 30 - July 1

Modeling and Simulation



The examination of the effectiveness of PV peak shaving for the 12 circuits showed there was good synchronization between PV output and the annual maximum peak load. On nine of the twelve circuits, the annual maximum circuit peak load was effectively shaved. Higher PV penetration densities achieved larger amounts of peak shaving on the highest annual peaks. The amount of load shaved ranged from less than 1 percent to just below 12 percent of the maximum peaks. In only three simulation cases, the maximum annual peak circuit load was not shaved by the PV output. These three circuits were night peaking and did not benefit from PV during the highest peak times. The analysis showed that at least 40 percent of the time PV would shave some of the daily baseline peak. Based on annual averages, daily peak shaving was not strongly influenced by PV deployment density.

The amount of energy produced by the simulated PV deployments and its effect on circuit energy consumption was also examined. The annual energy produced by a single PV array was 7,887 kWh. The peak output in the winter months was approximately 50 percent of the peak output during the period from late spring through early fall. The highest power output of a single array during the year was 4.78 kW. PV deployed on a circuit provided substantial savings in annual circuit energy. For PV with penetration density of 30 percent, the reduction in average annual energy ranged from 1.14 percent to 8.65 percent. For PV with density of 10 percent, the average annual reduction ranged from 0.484 percent to 3.08 percent. Increasing the PV density increased the amount of peak shaved and energy reduction for the circuits modeled. The results showed that circuits with larger PV densities installed had the most peak reduction.

Reduced energy consumption resulting from PV was significant for all circuit types and the amount of energy saved was linearly dependent upon PV penetration density with higher densities providing increased energy savings. The largest energy savings occurred from late spring through early fall when the PV output was greatest. Distributed and clustered PV deployments had essentially the same amount of annual energy savings.

The impact of PV deployment on circuit voltage was examined. Deployment of PV could improve system voltage, but it also had the potential to create voltage problems. The impact on the voltage profile from clustering groups of PV arrays on the circuit and the impact from distributing PV arrays more uniformly along the circuit were compared.

The deployment of PV on the 12 circuits did not create voltage problems on the circuits even when PV arrays were clustered and the PV density was 30 percent. The PV deployment did not appreciably change the average voltage profile of the circuit. On some circuits there was a slight increase (0.1 to 0.2 volts) in average voltage with the PV deployed. Voltage regulators did not experience a substantial increase in the number of tap changes over the course of the year. The investigation into the impact of PV on the voltage profile revealed no significant issues from increased voltage excursions outside the prescribed limits of 117 to 126 volts at end-of-line (EOL) monitoring points or circuit regulators, and regulator tap changes were nearly unaffected.

The impact of a large and rapid change in PV output was examined. Rapid changes in the solar irradiance that may occur during cloud cover events translate into rapid changes in PV output, and hence, the circuit load, potentially affecting voltage on the circuit. An extreme cloud event was simulated on each of the 12 circuits. Large and rapid changes in the circuit load caused by

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PV output power swings from the simulated cloud cover event did not create issues with voltage-level excursions at the circuit regulator. At EOL locations, voltage could potentially swing up to 4 volts during cloud cover events on long circuits with large PV installations. In 11 out of 12 cases, the cloud event did not create any voltage issues at the EOL locations. The longest circuit modeled saw the largest voltage swing, but even its EOL voltage excursions remained within established flicker limits.

Combination of PV with CES

In addition to deploying PV arrays, simulations were conducted that combined PV and CES. The CES control managed the activities of the individual CES units in the fleet. The combination of CES and PV was examined to quantify the peak shaving benefits. Both technologies were deployed at a density of 20 percent for this analysis. A probability analysis previously mentioned above to quantify the effectiveness of PV peak shaving for daily demand was repeated for the CES and PV combination. This showed that at least 60 percent of the time CES and PV would have shaved some of the daily peak compared to baseline, an improvement over the 40 percent result found for PV alone. Results for individual circuits based on maximum annual peaks were varied depending on whether comparisons were done using synchronized or unsynchronized peaks. The discrete nature of the simulation results, with results recorded on 15-minute intervals, may indicate the need to average the annual maximum results, such as occurred in the probability analysis. Median synchronized annual peak reduction for the 12 circuits was 4.5 percent for CES and PV, and 2.5 percent for PV alone. Using unsynchronized annual peaks, the median reduction was 2.1 percent for CES and PV, and for PV alone. By adding CES to the circuits with PV both the maximum annual and daily peak shaves are likely to improve.

The simulation results show that PV provided benefits in all three major areas – circuit demand, energy, and the voltage profile of the circuit. Daily demand peaks were shaved at least 40 percent of the time, and the highest daily peak during the year was shaved on all daytime peaking circuits. PV also significantly reduced energy consumption for all circuit types with higher PV densities giving increased reductions. The deployment of PV did not create voltage problems on the circuits.

10.5.4 PHEV/PEV

The deployment of PHEV/PEV charging stations was analyzed across the same 12 representative circuits. The impact of PHEV/PEV charging stations on circuit behavior was evaluated in four major areas – circuit demand, voltage excursions, density effects and energy consumption. For each of these effects, a GQM was identified to determine the effects of PHEV/PEV charging stations in each area.

PHEV/PEV Charger Impact Evaluation

On a circuit level, PHEV/PEV chargers could shift the circuit peak demand if the additional load created was large enough relative to the overall circuit load, and the PHEV/PEV charging time frame occurred later than the peak time without PHEV/PEV installed. The following figure illustrates this shift for one of the 12 circuits.

Modeling and Simulation

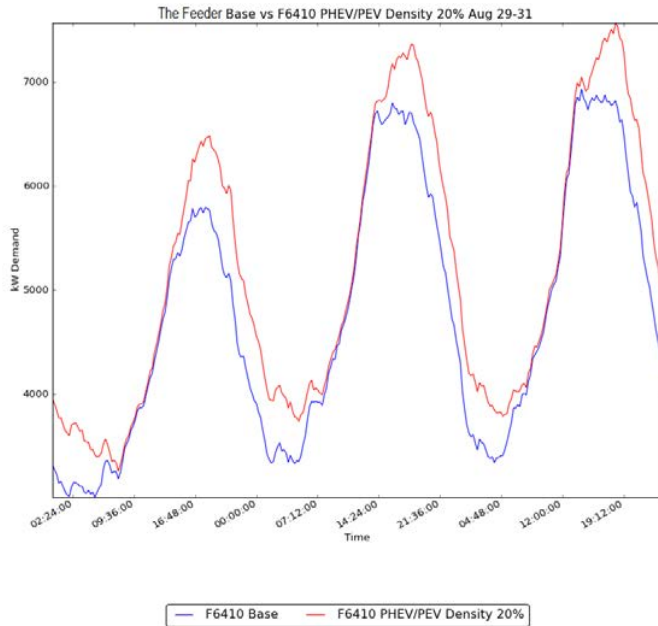


Figure 181. The Circuit Peak Demand Shift Due to PHEV/PEV -- August 29 - 31

This shift in peak demand was highly dependent on the circuit characteristics and loading profile.

The load from the PHEV/PEV chargers increased the daily circuit peak almost every day of the year on each circuit. The maximum daily circuit peak load increase due to the PHEV/PEV charger load as a percentage of the daily peak ranged from:

- 3.2 percent to 19.5 percent for PHEV density at 10 percent (average 10.3 percent)
- 5.1 percent to 29.8 percent for PHEV density at 20 percent (average 15.8 percent)
- 9.3 percent to 44.9 percent for PHEV density at 30 percent (average 23.0 percent)

The maximum increase in the daily circuit peak from the PHEV/PEV chargers did not occur on the same day that the maximum circuit peak for the year occurred. These were often shifted to completely different days of the year. The peak demand from PHEV/PEV chargers was not influenced by weather conditions like the annual peak day. With PHEV/PEV chargers, the daily peak often did not occur at the same time as the base case. The peak typically shifted to a later time in the day.

The PHEV charger load made up a larger portion of the daily peak load in the off peak seasons, such as the months of January and October, than in the peak season of June. For PHEV/PEV densities of 10 percent, 20 percent, and 30 percent, the average annual energy increase per circuit was 4.72 percent, 9.51 percent, and 14.7 percent respectively. Because consumption varied linearly with PHEV/PEV density, the data could be used to extrapolate the effects of a higher or lower density of PHEV/PEV chargers on the circuit.

Modeling and Simulation



Considering the total number of PHEV/PEV chargers installed on each circuit, very few line transformers over 25 kVA in size were overloaded with the addition of charger load even at the highest density. On some rural circuits with predominantly smaller (less than 25 kVA) transformers installed, the addition of one to two larger PHEV/PEV chargers could be enough to create overload conditions.

Regarding low voltage conditions, as more PHEV/PEV chargers were installed; more voltage drops below the acceptable 115v were observed. Because 114v must be maintained at the consumer's service entrance, 115v was chosen as the voltage excursion point to allow for a 1-volt drop on the secondary service equipment between the transformer and the consumer meter. Due to low service voltage, more line transformer, secondary conductor and service lateral upgrades will be required as additional PHEV/PEV chargers are added.

Based on results from the voltage excursion and transformer overload analysis, maintaining secondary service voltage within acceptable limits is more likely to be an issue than the overloading of line transformers.

Combination of PHEV/PEV with CES

In addition to deploying PHEV/PEV charging stations, simulations were conducted that combined PHEV/PEV charging stations and CES. The CES control managed the activities of the individual units in the CES fleet. For this analysis, the combination of CES and PHEV/PEV load profile was evaluated. CES was previously shown to be an effective technology for reducing daily peak load on circuits. The addition of PHEV/PEV chargers largely did not disrupt the ability of CES to shave loads. Generally, there was little evidence of synergy between the CES and PHEV/PEV charging schedules, and CES may temper the peak loads caused by PHEV/PEV chargers.

Simulation demonstrated that widespread deployment of PHEV/PEV charging stations can have substantial impacts on circuit behavior. These impacts could result in equipment upgrades of service transformers as well as secondary side service laterals. PHEV/PEV charging stations not only resulted in overload situations, they also affected the time of day when the peak demand occurred. This shift in peak is potentially harmful to service equipment because the power consumption remains high for longer periods during the day, which increases wear on equipment. This data shows that PHEV/PEV charging station effects scale linearly with density, which gives greater ability to assess the impact of these technologies on a circuit.

10.5.5 VVO

This section describes results from a parametric study of Volt VAR Optimization (VVO) on a set of 32 baseline circuit models. The impact of VVO on circuit behavior was evaluated in three major areas – circuit demand, energy usage, and the voltage profile of the circuit. The impact of VVO on circuit behavior was also evaluated for each of the 32 circuits with three modifications – added circuit components (voltage regulators and capacitors), added CES, and added PV. For each of these effects a GQM was identified to determine the effectiveness of VVO in each area.

Modeling and Simulation



In the original experimental design, 32 circuits were planned to be simulated with VVO. However, circuits with multiple regulators could not be simulated using the built-in GridLAB-D VVO module. A proprietary module was used for these circuits which had mixed results. There are 6 circuits out of the 32 that have multiple regulators. As a result for the VVO only sections, results are shown for 26 circuits.

VVO Technology Impact

VVO was effective in reducing synchronized and absolute annual demand peaks and in reducing energy consumption. With VVO targeted for 117V EOL voltage and 0.98 leading power factor (PF), the median annual peak kW demand reduction for the 26 circuits studied was 2.43 percent for synchronized peaks and absolute peaks. The median daily average peak demand reduction was 3.68 percent with VVO set for 117V EOL voltage and 0.98 leading PF. With the same VVO target settings, the annual energy savings averaged 4.05 percent (median = 4.24 percent) relative to the baseline cases.

On average EOL target voltage played a more significant role than did target PF in determining the amount of peak demand reduction and energy savings. Based on the median percentage annual energy reduction, the 117V target setting provided the best energy savings compared to 118V and 119V settings at a target PF of 0.98 leading. Four of the five circuits that benefited most from VVO for daily peak demand reduction also benefited most for reducing energy consumption. Defining circuit characteristics such as miles, line number of residential consumers, or primary circuit voltage were not common among these high performing circuits.

The VVO results were affected by the use of two different VVO modules. An open source VVO controller was used for simulations if the circuit did not have a line voltage regulator. A proprietary VVO controller was used for simulations of circuits that had line voltage regulators. The open source controller was unbiased and treated the voltage set point as its target allowing the EOL voltage to be below the target at times. The proprietary controller treated the voltage set point target as a minimum and biased the EOL voltage to be above this target most of the time. Because of the differences in the way each controller responded to the EOL voltage target, the results produced by these different controllers were significantly different.

These differences affected comparisons between the results for circuits with a line regulator and the results for circuits without a line regulator. Regardless of the target voltage and power factor, the median VVO annual peak demand reduction percentage was significantly lower than the median VVO daily average peak demand reduction percentage. This difference was indicative of the inability of the circuit voltage regulators and line voltage regulators to lower the voltage profile on most circuits as much during peak demand periods as they could during periods of lighter load. During peak periods, the higher load on the circuit caused increased voltage drop, and the voltage regulators had to maintain a higher voltage level in order to keep the EOL voltages within acceptable limits. The following two figures illustrate the voltage profiles for one of the modeled circuits during off peak and peak demand respectively.

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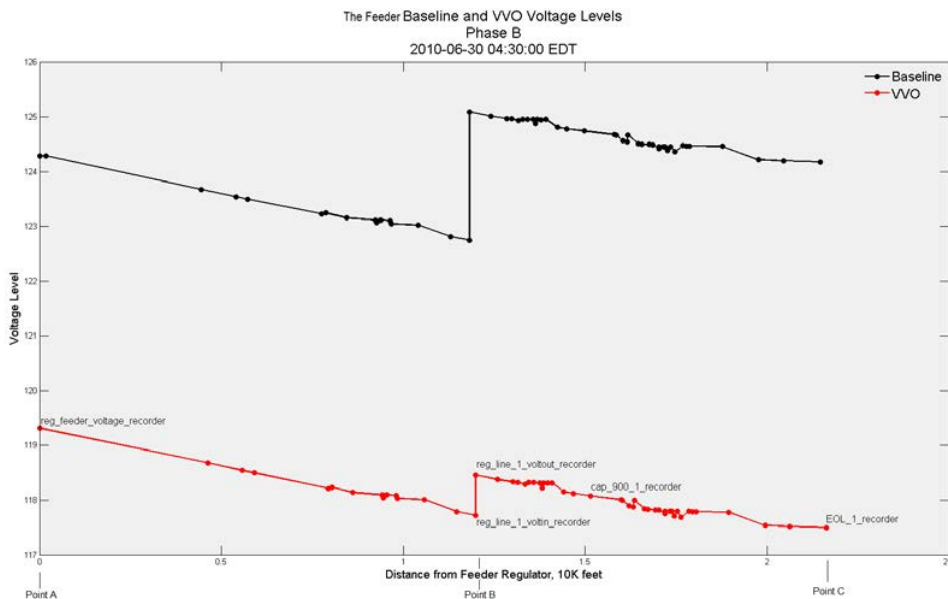


Figure 182. The Circuit Off Peak Voltage Profile Drop Due to VVO

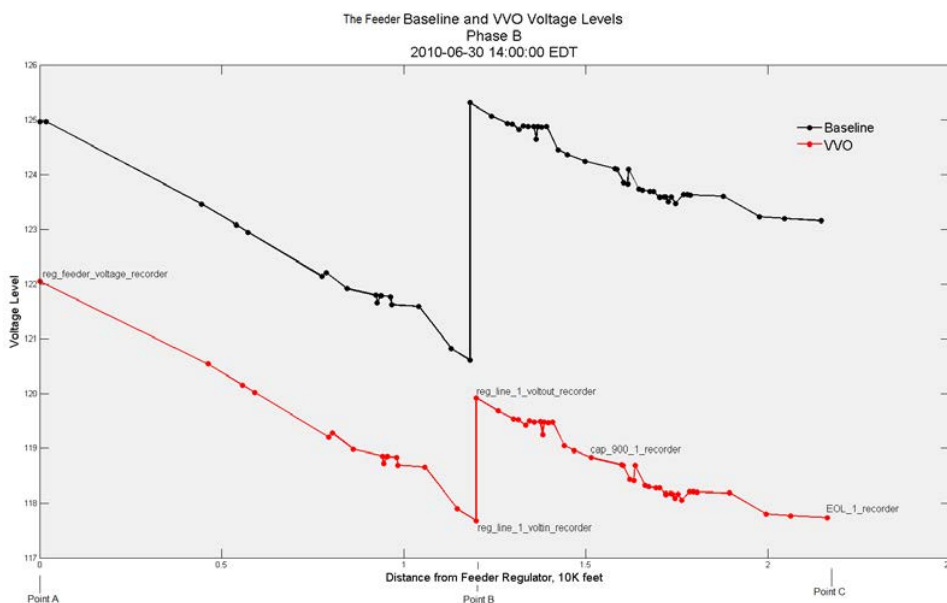


Figure 183. The Peak Voltage Profile Drop Due to VVO

VVO was less effective in reducing reactive demand peaks than it was in reducing kW demand peaks. Individual circuit results were highly variable, but median annual reactive demand reductions ranged from 0.92 percent to 1.79 percent for both synchronized and absolute peaks.

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For 117V, 118V and 119V target EOL voltage, VVO improved the annual average PF on 15, 15, and 16 of the 26 circuits respectively. For the remaining circuits the same target EOL and PF values produced a slight decrease in annual average PF. For target PF values of 0.98 leading, 0.98 lagging, and 0.96 leading with a 117V target EOL voltage, VVO improved the annual average PF on 14, 15, and 15 of 26 circuits, respectively. Changes in target power factor settings had more effect on reactive demand peak reduction than the changes in EOL target voltage.

For reactive energy consumption, VVO provided mixed results with large variations in reduction from circuit to circuit. With varying EOL voltage target and a constant target PF of 0.98 leading, the annual reactive energy savings ranged from a savings of 81.26 percent to an increase in consumption of 181.47 percent. Changes in target power factor settings had more effect on reactive energy reduction than did changes in EOL target voltage. The varying results in reduction may be due to:

- Constant power loads dominating peak conditions
- Different control logic, control points and control measures used to control the capacitors²

Adding a line regulator, a capacitor or both a line regulator and a capacitor on circuits with VVO did not consistently improve VVO peak demand reduction performance. This lack of consistent peak demand reduction was because added components were not able to flatten circuit voltage profiles much better than the flattening provided by the VVO before additional components were added. Additionally, the proprietary VVO object used in the simulations maintained higher voltage profiles compared to the open source GridLAB-D VVO object, which was also used.

The small improvement in annual and average daily energy savings and demand reduction from circuit components added to a circuit with VVO could be attributed primarily to the fact that the implementation of VVO without added circuit components harvests most of the potential energy savings and demand reduction from lowering the circuit voltage. Because the circuit demand was near its peak for only a small percentage of time during the year, the implementation of VVO allowed the existing regulators and capacitors on the circuit to lower the voltage profile significantly for most of the year.

The addition of a supplemental line voltage regulator or capacitor may allow the voltage on portions of the circuit to be lowered further, but the amount of further reduction would be very limited. The VVO had already greatly flattened the circuit voltage profile using the existing voltage regulators and capacitors on the circuit. Also, the voltage reduction from the added regulator or capacitor would have affected a small portion of the load on the circuit further limiting the amount of reduction. Because the circuit voltage profile was higher during times when the circuit load was high, an added voltage regulator or capacitor would be most effective

² In the baseline case, each capacitor was switched using kVAR on and kVAR off set-points to switch the capacitor on and off using kVAR measurements from only one of the three phases at the capacitor location. In the VVO case, the capacitors were switched based upon the total three phase kVAR measured at the circuit regulator.

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at reducing the voltage during those times. However, the amount of time the demand was high was relatively short, and the amount of further voltage reduction was still very limited. The addition of a capacitor provides less potential for an improvement in VVO demand reduction and energy.

Compared to the baseline, VVO set for 117V EOL target voltage and 0.98 leading PF decreased the median number of annual regulator tap operations by 0.2 percent. However, individual circuit results varied widely. For target voltage of 117V, 118V, and 119V simulated with a target power factor of 0.98 leading, 13, 13, and 12 of 26 circuits respectively showed a decrease in the annual number of regulator tap operations, and the remaining circuits showed an increase. Similarly for all three target power factors simulated with a target EOL voltage of 117V, 13 of 26 circuits showed a decrease in the annual number of regulator tap operations and the remaining circuits showed an increase.

Voltage excursions outside the 116.5V - 126.5V range were examined as indicators of potential voltage issues from VVO operation. With EOL target voltages of 117V, 118V and 119V and a target PF of 0.98 leading, the number of annual voltage excursions above 126.5V either stayed the same or decreased on 23 of the 26 circuits. However, the number of voltage excursions above 126.5V increased on 3 of the 26 circuits.

With VVO set for 117V and the three target PF (0.98 leading, 0.96 leading, and 0.98 lagging), the 0.96 leading PF setting produced the best results with only 5 of the 26 circuits experiencing an increase in the number of voltage excursions above 126.5V.

With VVO target settings of 117V and 0.98 leading PF, 23 of 26 circuits experienced an increase in the number of voltage excursions below 116.5V. With target voltage settings of 118V and 119V with 0.98 leading PF, fewer circuits experienced an increase in the number of voltage excursions below 116.5V and the amount of increase was generally smaller than the amount of increase with the 117V setting.

For voltage excursions below 116.5V, with VVO set for 117V and the three target PFs simulated, the 0.96 leading PF setting produced the best results with only 5 of the 26 circuits experiencing an increase in the number of voltage excursions. With VVO set for 117V the majority of circuits experienced a large increase in the number of voltage excursions below 116.5V at each of the three VVO PF settings.

If a VVO target voltage setting of 117V is selected, the circuit may need to be monitored to insure voltage levels remain above the lower limit. Improved voltage excursion results may be possible by modifying VVO control settings such as time delays and dead band settings.

Evaluate Combination of VVO with PV

In general the addition of PV did not have a significant impact on the number of voltage excursions experienced on the 26 circuits. Based on this result, the addition of PV should not create out-of-limits voltage conditions.

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For many circuits either clustered or distributed, PV combined with VVO improved the annual maximum kW peak shaving performance compared to the performance of VVO operating alone. On several circuits the maximum PV output on the day of the maximum annual peak demand did not coincide with the annual maximum peak demand. For these circuits, this difference in timing resulted in little or no peak shaving contribution from the PV.

Because most of the 25 circuits were summer peaking and the daily maximum PV output coincided more closely with the summer peak than at other times of the year, VVO combined with PV was more effective in reducing the annual maximum peak demand than reducing the daily average peak demand.

A comparison was made between the annual peak shaving results for VVO combined with PV to the sum of the annual peak shaving results for VVO operating alone and the annual peak shaving results for PV operating alone. The objective was to see if the interaction of VVO and PV operating together produced a greater sum than the sum of their individual effects when operating alone. The result of this comparison suggests that very little synergy existed between the two technologies.

At the circuit level the addition of PV to VVO universally improved the savings in annual energy usage over the savings provided by VVO operating alone. The energy consumption reduction results of VVO plus PV compared to the sum of PV and VVO reduction results revealed very little synergy between the technologies when VVO was combined with PV.

Based upon median results, VVO combined with PV did a better job of reducing synchronous reactive peak demand than VVO operating alone. This result reflects the reduced PF caused by the real power output of the PV and by the limitations placed upon the VVO by the number and size of switched capacitors on the circuit.

Some circuits were not affected by the PV because their reactive demand peak occurred while there was no PV output. For circuits that were affected by the PV output, the VVO did not fully compensate for the circuit reactive demand peak on some of them. For other circuits affected by the PV, the VVO overcompensated as it tried to maintain the target power factor. As a result, some circuits decreased peak reactive demand and some circuits increased peak reactive demand when VVO was combined with PV compared to VVO alone.

In addition, negative values in peak reactive demand reduction may be attributable to slight timing effects. The circuit load composition on some circuits being predominated by loads with ZIP fractions model increased reactive loading when the circuit voltage was lowered by the VVO. In addition, the average PF under baseline conditions was higher than the VVO target PF of 0.98. Under these conditions, the reactive demand with VVO or with VVO combined with PV would be expected to be somewhat greater at times than the baseline reactive demand.

Even though PV did not provide VAR support, VVO combined with PV produced additional reduction in annual reactive consumption for many circuits compared to the baseline case. The median improvement in annual reactive consumption reduction considering all 25 circuits was only 0.01 percent for all PV densities for both distributed and clustered configurations,

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comparing the annual reactive energy consumption reduction for VVO combined with PV compared to the annual reactive energy consumption reduction for VVO operating alone. The combination of VVO with PV significantly increased the number of voltage excursions above 126.5V on most of the 25 circuits as compared to the number of excursions on circuits with VVO only. Compared to the baseline case, VVO operating alone with target EOL voltage at 117V and target PF of 0.98 leading generally increased the number of voltage excursions below 116.5V. For nearly all of the circuits, PV deployment with the VVO operational increased the number of excursions below 116.5V. The number of voltage excursions was independent of the PV density for both clustered and distributed configurations.

Circuits with VVO and clustered PV had more voltage excursions below 116.5V than circuits with VVO and distributed PV. On some circuits, the power output from clustered PV and higher density PV appears to have raised the EOL voltage at some locations causing the VVO to lower voltage regulator output voltage too much at times. Customizing VVO control settings such as time delay and voltage bandwidth to reflect the unique conditions on a particular circuit may be advisable to reduce the number of voltage excursions.

When PV density or clustering of PV concentrates in one area on a circuit with VVO, relocation of an existing EOL monitoring point or the placement of a new EOL monitoring point may be necessary to maintain voltage within the acceptable voltage range. On circuits with higher concentrations of PV where VVO implementation is being planned, studies should be made that take PV into account when locating the VVO EOL voltage monitoring points.

Evaluate Combination of VVO and CES

VVO and CES produced poor results in terms of additional annual peak demand reduction compared to VVO operating alone. Just over half the circuits with data showed some additional annual demand reduction with CES added. However, the amount of reduction was less than 1 percent on most of the circuits which had additional demand reduction. Slightly better results were produced for additional daily peak demand reduction, but the VVO and CES improved the median average daily peak demand reduction by less than 1 percent considering both clustered and distributed CES configurations. Adjustment of the CES control set-point would have improved peak demand reduction performance.

With the addition of CES, the charging energy for the CES units decreased the annual and daily energy savings compared to VVO operating alone. However, the average daily energy savings for VVO and CES was positive for all circuits with available data.

The additional VAR support provided by CES resulted in an additional reduction in reactive demand on most circuits compared to VVO operating alone. VVO and CES clustered improved the annual reactive demand reduction on twenty-four of the twenty-four circuits and improved the daily average reactive demand reduction on twenty-four of the twenty-four circuits.

The VAR support from CES complemented the VAR support provided by the VVO by further reducing the reactive energy requirements on the circuits. The VVO and CES significantly reduced the annual reactive energy usage compared to the VVO operating alone. Compared to VVO operating alone, VVO and CES (distributed and clustered) reduced the annual reactive

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energy usage on all circuits with available data. The average daily reactive energy results did not reflect significant VAR contribution from CES.

All circuits with available data except four experienced an increased number of tap operations with VVO and CES compared to VVO acting alone. For several circuits, the increase was significant with the number of tap operations more than doubled by adding a large density of CES. Overall the combination of VVO and CES had a beneficial effect by reducing voltage excursions compared to VVO operating alone on most circuits, but VVO significantly increased the number of regulator tap operations. For 21 of the 24 circuits, the number of annual voltage excursions below 116.5V either stayed the same or decreased for VVO and CES clustered compared to VVO operating alone. The results for distributed CES showed the number of voltage excursions above 126.5V were similar to the results for clustered CES. However, distributed CES had fewer excursions.

For voltage excursions below 116.5V, the number of voltage excursions either stayed the same or decreased for 21 of the 24 circuits comparing VVO and CES clustered with VVO operating alone. For VVO and CES distributed, the annual number of excursions below 116.5V was slightly better than VVO with clustered CES.

CVRf_{Energy} is a metric used to measure the average responsiveness of a circuit's energy consumption to voltage reductions. CVRf_{Energy} factors for 25 circuits with VVO were calculated. The CVRf_{Energy} varied from circuit to circuit and ranged from a high of 2.52 to a low of 0.51. CVRf_{Energy} closely correlated to the Average CVRf_{Demand}. For a given circuit the CVRf_{Energy} varied over a very small range as the VVO voltage and PF settings were changed. The median of the CVRf_{Energy} factors for these circuits varied slightly from a low of 0.76 to a high of 0.77 for the five VVO settings simulated. The relationship between the circuit energy consumption and voltage level was nonlinear, that is a given percentage voltage change at a higher voltage level produced more energy consumption change than the same percentage voltage change at a lower voltage level. None of the defining circuit characteristics had significant correlation with CVRf_{Energy}.

The simulation results show that VVO provided benefits in all three major areas: circuit demand, energy usage, and the voltage profile of the circuit. Adding conventional circuit components such as voltage regulators or capacitor banks was compatible with VVO operation and marginally improved VVO performance. Adding more recently introduced technologies such as photovoltaic arrays or CES was compatible and complementary to VVO performance.

10.5.6 Project Tariffs and Riders

This section analyzes the deployment of multiple types of Project tariffs and riders (Tariff) on three circuits from AEP Ohio. Only three circuits were chosen because consumer response to Tariffs is not dependent on circuit characteristics. Each Tariff was deployed at 100 percent penetration for the simulations. The results of the simulation should therefore be scaled to expected penetration levels. Circuit demand and energy were evaluated under each Tariff at varying consumer response levels. When possible, the range of consumer responses to Tariffs

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were based on available data from existing Tariff programs. This data was used to set high and low response levels.

If no data was available, high and low response levels were estimated to demonstrate a range of potential consumer responses. For each of these effects, a GQM was identified to determine the effectiveness of Tariffs in each area.

Tariff Impact

One of the potential benefits of Tariffs is the ability to shave peak demand. Tariffs offer an incentive for consumers to reduce electricity usage during peak demand times. For DLC, some circuits showed peak reductions ranging from 0.2 percent to 0.3 percent for both high and low response cases. Sample circuit A showed a 33.9 percent peak reduction for the low response case, and 39.4 percent for the high response case. The success of the peak demand reduction depended largely on whether or not the maximum 4-hour load control event was timed correctly with the circuit peak. The load control event was timed correctly for sample circuit A, but missed the peak time on sample circuits B and C. The DLC event time periods were chosen by selecting the typical peak hours on the hottest days of the year. Given the 4-hour event time limit, initiating the event too early may result in an absolute peak that occurs after the event has ended. Initiating the event too late may mean that the opportunity to reduce the absolute peak has passed.

Simulation results show the ideal time period for a DLC event, but it is more difficult to set the ideal event time period without knowing exactly when the absolute peak will occur. In an actual DLC event, there obviously would not be a way to know exactly when the absolute peak will occur. The TOD tariff reduced peak demand in the range of 23.26 percent to 34.83 percent for the low-response cases across all three circuits. The peak was reduced in the range of 24.93 percent to 35.79 percent for the high-response circuits. TOD/CPP peak reduction ranged from 31.03 percent to 44.88 percent for low-response cases, and 37.61 percent to 69.06 percent for high-response cases, with critical peak events proving to be very effective at reducing demand. RTP_{da} peak demand reduction ranged from 2.51 percent to 10.17 percent for low-response cases and 1.53 percent to 9.89 percent for high-response cases. These results should be scaled to expected penetration levels. For each tariff, a common byproduct of the peak reduction was a sharp increase in demand immediately after the peak pricing period. This demand rebound often went higher than the original peak. Because the demand rebound is expected to scale linearly with penetration levels, this effect would be significantly lessened at penetration levels less than 100 percent.

Another potential benefit of Tariffs is a reduction in energy consumption. Each Tariff showed a net energy reduction despite the high demand rebound after peak periods. The DLC had average daily energy savings ranging from 0.39 percent to 0.67 percent for low-response cases, and 0.46 percent to 0.79 percent for high-response cases. The TOD tariff had an average daily energy reduction ranging from 4.79 percent to 9.17 percent for low-response cases, and 4.73 percent to 9.35 percent for high-response cases. The TOD/CPP tariff low-response cases ranged from 8.62 percent to 15.69 percent and 8.78 percent to 15.73 percent for high response cases. For the RTP_{da} tariff, average daily energy reduction ranged from 5.60 percent to 9.53 percent for low-response cases and 6.96 percent to 12.00 percent for high-response cases. Like the peak demand reduction results, these results should be scaled to expected Tariff penetration levels.

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Tariff simulations for DLC, TOD, TOD/CPP, and RTP_{da} showed that each Tariff can be effective at reducing peak demand and energy usage. Each Tariff also showed a demand rebound immediately after the peak pricing period. Because these simulations were run at 100 percent Tariff penetration, the peak demand reductions should be scaled to expected Tariff penetration levels. The demand rebound effect would also be significantly lessened at penetration levels less than 100 percent.

10.6 Modeling and Simulation Conclusions

The overarching conclusions of the Modeling and Simulation effort show the effects of adding smart technologies to the grid. A benefit of using modeling for this type of analysis is that it provides the ability to predict the effects of smart grid technologies before capital investments are incurred. Synergies among multiple smart technologies and potential negative combinations of others can be identified. Modeling and Simulation provides beneficial analysis to invest in a stronger, more robust electric grid for the future.

Details and conclusions regarding the simulation results of individual technologies as well as combinations of technologies are more fully described in the section labeled *Summary of Simulation Results*.

10.7 Lessons Learned

- Open source distribution circuit simulation tools allow sophisticated and detailed simulations for many aspects of the distribution circuit from the substation down to the individual houses and their appliances, outlet and lighting loads, air conditioning, water heater, and the home insulation characteristics.
- User interfaces and analysis tools such as GridCommand Distribution provide speed and efficiency for developing and evaluating GridLAB-D models and simulations.
- Smart Grid Technologies are developing, and due to the interplay between simulation and implementation, the technology simulation tools are also developing.
- Open source modules for several distributed generation technologies are currently full-featured and provide valuable tools for simulations of both individual and combined technologies.
- Open source simulation modules for VVO are adequate for many simulations, but their current versions have limited ability to deal with complex circuits containing multiple line regulators connected in series configurations.
- The section labeled *Summary of Simulation Results* provides information regarding how combinations of technologies might work together. These combinations include PV and CES, PEV and CES, VVO and CES, and VVO and PV.

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Commercialization



11 COMMERCIALIZATION

11.1 Background

AEP Ohio and Battelle partnered on the AEP Ohio gridSMART[®] Demonstration Project to build a secure, interoperable, and integrated smart grid that demonstrates the ability to improve grid reliability, efficiency, and cost through the effective evaluation, integration, and deployment of innovative energy technologies in central Ohio. Part of the overall project involved actively attracting, educating, enlisting, and retaining consumers using innovative business models that provide tools and information to reduce costs, consumption, and peak demand, as well as providing the Department of Energy (DOE) with optimal information to evaluate technology and preferred business models. In addition, the project assessed the commercialization opportunities for a number of technologies that were demonstrated in partnership with participating companies, including the market readiness of emerging technologies and the economic impact of these commercial activities.

As part of the Project, commercialization opportunities were assessed for a number of technologies demonstrated in partnership with participating companies, which included the market readiness of emerging technologies, the economic impact of such commercial activities, and lessons learned. A wide variety of commercial partners committed to collaborate and assist AEP Ohio in evaluating and advancing promising technologies. The Commercialization Working Group (CWG) included AEP Service Corporation, AEP Ohio, Battelle, and The Ohio State University's (OSU) Fisher College of Business. The CWG provided a forum for sharing information necessary to complete outcome-oriented business plans that create and evolve market-ready, smart grid products by considering existing markets, manufacturing capabilities, and distribution channels.

The CWG's goal was to track commercial progress of smart grid technologies, report to the DOE how the AEP Ohio gridSMART Demonstration Project accelerated commercialization of smart grid technologies, and develop a comprehensive collection of market intelligence, tactical guidance, and cost-benefit analyses for commercial partners.

During the course of the Project, the utility market in Ohio moved from a regulated utility market to a competitive retail electric service (CRES) market. As of March 1, 2012, there were 14 CRES providers actively serving consumers in AEP Ohio's service territory, which meant they were potentially within the project area as well.

The Project was designed to successfully accelerate the commercialization of smart grid technologies through multiple stages of testing and guidance from the commercial partners. A wide variety of commercial partners committed to help in evaluating and advancing promising technologies. The proposed process included three segments:

- Extensive equipment laboratory testing
- Equipment field deployments
- Assessment by the AEP Ohio gridSMART[®] Demonstration Project CWG

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The overall structure is shown in the figure below.

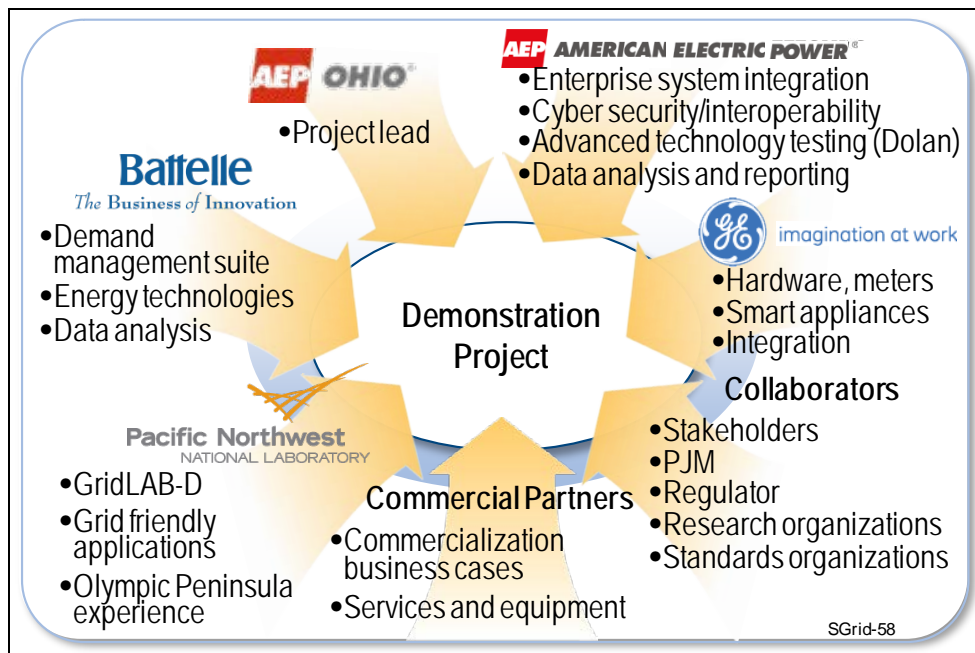


Figure 184. Integrated Project Team

Equipment testing was conducted by the commercial partners, Battelle, and AEP Ohio at AEP’s Dolan Technology Center (DTC). Equipment field deployments provided performance data for both the individual products as well as integrated, optimized solutions. AEP Ohio used GridLAB-D, a simulation software package, to appropriately identify the best scenarios for component integration without costly trial-and-error approaches. The CWG provided a forum for sharing information necessary to complete outcome-oriented business plans that evolve and create market-ready smart grid products.

Vendor risk was reduced through rigorous testing, and key commercialization insight was provided by the CWG’s processes. This strategy included field deployment experience through a commercialization process agreed upon by the CWG and the commercial partners. It considered existing markets, distribution channels, and manufacturing capabilities.

AEP Ohio and Battelle agreed to engage OSU’s Fisher College of Business Technology and Entrepreneurship Center (TEC) to provide an evaluation framework for use by the CWG.

11.2 Purpose

This document details AEP Ohio’s gridSMART® Commercialization Plan that contains a process and framework developed by TEC and the CWG. This plan enabled AEP Ohio and Battelle to track commercial progress of smart grid technologies and report to the DOE how the Project has accelerated commercialization of smart grid technologies.

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TEC and the CWG evaluated the commercial progress of selected technologies being developed within the Project and summarized key results and successes achieved by those commercial partners' technologies. In addition to technical and commercial progress, TEC and the CWG considered important societal benefits, including economic impact, job creation, and local benefits. TEC and the CWG provided an overview of the acceleration of commercialization achieved through the Project.

The CWG also created reports containing lessons learned, including best practices for commercialization, and elaborated on how lessons learned in the Project can benefit future technology development and energy product vendors. The aggregated evaluations from the various technologies developed a comprehensive set of market intelligence, tactical guidance, and a cost-benefit analysis for commercial partners based on a regulated utility market.

11.3 Roles and Responsibilities

This project was performed by three key groups: AEP Ohio, CWG, TEC, and the individual commercial partners.

The role of the CWG was to provide critical industry-wide insight into utility industry needs, trends, and other industry attributes to support the commercial evaluations and reporting. The CWG was ultimately responsible for gaining commercial partner approval to provide demonstration data to be delivered to the DOE as well as partner-specific insights into the technical and commercial opportunity for each commercial partner. They also shared market and technical data as well as conclusions based on laboratory and field testing to assess the commercialization progress. AEP provided resources to the CWG and made initial contacts to potential commercial partners to gain their support and involvement in the commercialization plan. Battelle provided data and resources to the CWG as required.

Technology Entrepreneurship and Commercialization Center (TEC) provided expertise in early-stage commercial evaluations as well as in evaluating a breadth of technologies and products in the context of a customized commercial framework. This evaluation was designed to fit the specific stage of product development or technologies of each commercial partner. Evaluations were used to assist in developing reports demonstrating progress of commercial partners related to the Project. TEC was responsible for gathering data from the CWG and commercial partners as well as performing secondary market research to support these efforts. TEC used multiple data sources to support preparation of reports describing the progress of the commercial partners and to communicate TEC's findings to the three key groups and the individual commercial partners.

The role of each commercial partner was to provide data necessary for the Project's reporting and the commercial progress evaluations. Individual commercial partners were responsible for providing data on the start-of-project, end-of-project, and periodic status updates describing technical and market development.

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11.4 Methodology

The broad objective underlying commercialization was to drive innovation and technology-based economic development through advanced grid technologies. TEC worked closely with the CWG to develop a customized commercialization framework to assess and accelerate the commercial advancement of each commercial partners' technologies and products. This framework was used in parallel with the commercialization framework supported by the CWG to provide valuable market intelligence to commercial partners and establish and measure the societal benefits of the Project.

11.5 Commercialization Framework

The State of Ohio adopted a comprehensive framework for assessing the stage of commercial development for new technologies. Because of its relevance to economic development in Ohio and the degree to which the broader economic development community was familiar with this framework, TEC and the CWG decided to use the Commercialization Framework (see figure below) for the following purposes:

- To assess the progress of the overall Project for moving energy technologies closer to commercialization.
- To understand the specific opportunities and challenges each commercial partner faced along the commercialization path.
- To identify the key transitional resources that have enabled the commercial partners to have an economic impact.

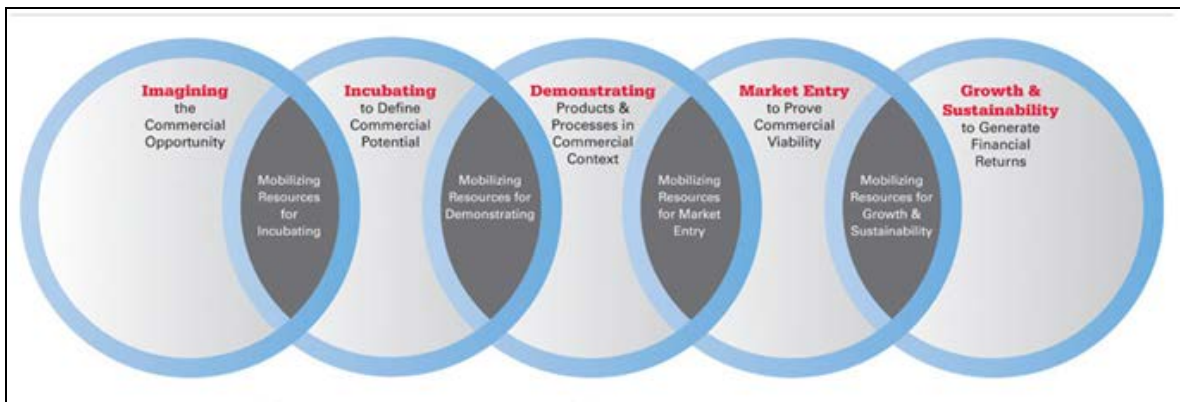


Figure 185. Commercialization Framework

An important benefit was the ability to track the progress of individual technologies and products as well as the overall evolution of the collection of technologies and products over time. The framework accommodated the layers of resources, activities, and engagements to capture the progression through various stages of commercialization.

The innovation process for the market introduction of new products and services involved a great deal of uncertainty. In order to understand how the participating companies progressed under these conditions, TEC and the CWG used the *Inside Innovation* framework to assess the unique

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factors, opportunities, and challenges each company managed during the Project. The Inside Innovation framework tracked progress on and iteration between three factors critical to innovation: Technology, Market, and Implementation³ as defined below.

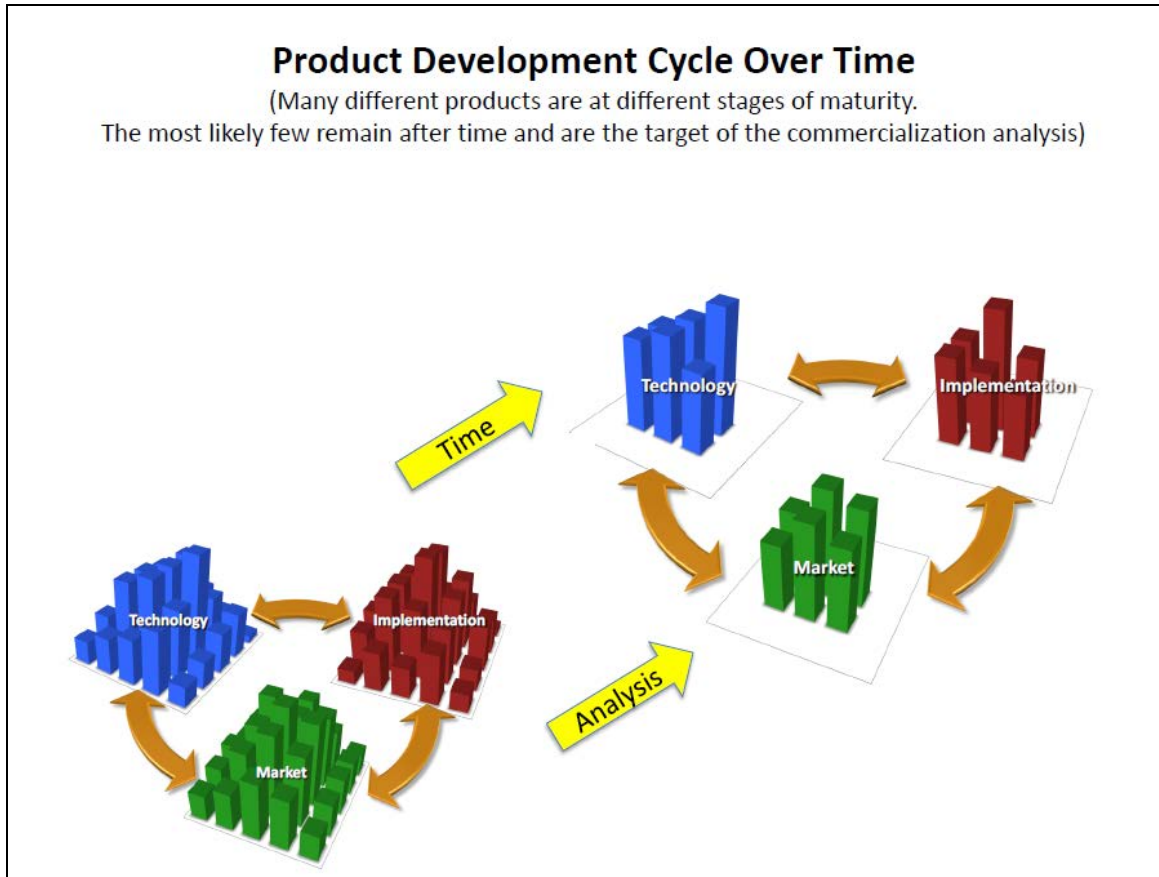


Figure 186. Inside Innovation Framework

- Technology:** Technical factors that are objectively verifiable by scientific methods.
- Market:** Individuals and organizations that actually use the proposed innovation, what value they perceive in the innovation, and what specific benefits they realize from its use.
- Implementation:** The processes and transactional experiences that must occur to make the innovation functional in the designated market.

³ Fitzgerald, E., Wankerl, A. and Schramm, C., Inside Real Innovation, World Scientific Publishing Co., Singapore, 2011.

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TEC integrated and modified these models so that:

- They were uniquely effective at assessing the degree of innovation traction and economic impact in the gridSMART[®] Demonstration Project.
- They were useful for communicating the position and progress of each commercial partner and for the Project as a whole to the DOE.

11.6 Segments

Technical validation was performed through a three-segment process supported by AEP Ohio, Battelle, and utility industry members. The three segments included the following.

- Extensive laboratory testing
- Equipment field deployments
- Assessment by the commercial partner and the CWG

Equipment testing was performed by the commercial partners as well as at AEP's DTC facility. Field deployments and software simulation and modeling provided critical data for integration. Finally, the CWG met with commercial partners to review testing and field evaluation, to review performance against expected metrics, and to develop / refine business cases.

11.7 Factors

The CWG developed business cases that included a review of the core intellectual property and its readiness for commercialization, the viability of the commercial partner, estimated utility and/or consumer adoption of each technology, and the estimated market potential for the technology. The overall business case included the following.

- Potential revenues
- Utility, consumer, and societal costs and benefits
- Full consideration of the regulatory framework for recovery of costs and sharing of benefits

11.8 Impact on Technology Commercialization

TEC and the CWG performed detailed characterization of the commercialization progress for technologies and products listed in the *Commercialization Opportunities* table in this section. When necessitated by the gridSMART products budget, the technologies and products were selected and prioritized based on factors such as business alignment, stage of commercialization, probability for success, magnitude of projected benefit, and the commercial partner's willingness to engage in the process.

- For selected technologies at the imagining and incubation stages, TEC evaluated each technology according to TEC's Capabilities, Methods, Outcomes (CMO) methodology. CMOs provide a structure by which competitors' complementary technologies can be identified and compared. In addition, TEC provided basic market information such as market size or trends predicted for each selected technology, as well as an estimated break-even price to achieve market entry success.

Commercialization



- For innovations at the incubation and demonstration stages, TEC made available its Structured Concept Testing process, by which key features were articulated, key market targets were identified, features were validated with relevant market players, and an estimated breakdown price to achieve market entry success was determined.
- For products in the demonstration and market entry stages, TEC developed and assessed innovative business models, including assessing the industry value system, supply chain, pricing strategy, decisions about partnering/outsourcing, a cost-benefit model, core assets, and infrastructure costs.

For the selected technologies, three common dimensions of benefit were considered:

- **Benefit to Utility** – For all technologies, TEC assessed the market impact or prospective market impact of the innovation. The core of this assessment is a cost-benefit analysis that may be used to address regulatory considerations. Together, these considerations were aggregated into overall industry value drivers. In addition, TEC assessed the impact innovations have on competition, competitive behavior, and how markets operate.
- **Benefit to Consumer** – In addition to directly quantifiable benefits related to energy savings as a result of controlling time of use or direct rate impacts, TEC considered non-utility consumer benefits such as the impact of improved efficiency or reliability as identified by commercial partners or the CWG.
- **Broader Societal Impacts** – Beyond direct benefits to the utilities and consumers, TEC also considered the broader societal impacts of AEP Ohio's gridSMART Project with a specific focus on the efforts of its technologies and commercial products, such as educational benefits, workforce development, economic development, and diversity.

Commercialization



Suite/Product	Technology/ Product	Start-of-Project Status	End-of-Project Status	
Distribution Automation	Distribution Management System and SSI Interface	Incubating	Market Entry	
	Volt VAR Optimization	Incubating	Market Entry	
	Volt VAR Optimization	Incubating	Market Entry	
	Circuit Reconfiguration	Demonstrating	Growth & Sustainability	
Cyber Security and Operations Center		Imagining	Demonstrating	
Smart Appliances		Demonstrating	Growth and Sustainability	
AMI Meters	Smart Meter	Demonstrating	Growth & Sustainability	
AMI Communications	Communication to meter	Demonstrating	Growth & Sustainability	
	Utility IQ	Demonstrating	Growth & Sustainability	
Automobile	Electric Vehicles	Demonstrating	Growth and Sustainability	
	Charging Stations	Incubating	Market Entry	
Demand Reduction and Management	Grid Router / Home Energy Manager (HEM)	Imagining	Demonstrating	
	enhanced Programmable Control Thermostat (ePCT) (COTS)	Market Entry	Market Entry	
	Centralized Distribution Management System Control	Imagining	Incubating	
	enhanced Programmable Control Thermostat (ePCT) (AEP Standard)	Imagining	Demonstrating	
	enhanced Programmable Control Thermostat (ePCT) (Real-time Pricing - Battelle)	Imagining	Demonstrating	
	SmartGrid Dispatch Engine	Imagining	Demonstrating	
	In-Home Energy Display (Standard)	Imagining	Demonstrating	
	In-Home Energy Display (real-time pricing)	Imagining	Incubating	
	Modeling, Analytical, and Simulation Tools	Grid Lab-D	Incubating	Demonstrating
		Integration of Grid Lab-D Open DSS and Near-real-time Power flow modeling	Imagining	Imagining
Consumer Programs	AEP Billing Engine (ABE)			
	Customer Engagement/ Characterization	N/A	Incubation	
	Consumer Web Portals	Incubating	Demonstrating	

Table 30. Commercialization Opportunities

Commercialization



11.9 Engaging Commercial Partners

Initially, AEP reached out to each commercial partner to introduce the technology Commercialization Plan and communicate the high-level benefits to the partners. The CWG then interviewed selected commercial partners in order to understand the specific inventions, products, business models, and other technical and commercial information.

TEC also worked closely with AEP Ohio to understand AEP Ohio's requirements and objectives. The CWG shared its perspective on market features, trends, and regulatory considerations. TEC performed primary and secondary market research and combined this data with the insights provided by the commercial partners and the internal gridSMART assessment team data. The value of TEC's evaluations depended directly on the engagement with the commercial partners and the quality of information shared. Participation by the commercial partners in the Project was voluntary, and TEC and the CWG appropriately safeguarded any confidential information.

11.10 Benefits to Commercial Partners

The selected commercial partners received valuable market intelligence, including opportunity size, industry trends, and value system analyses that augmented existing market intelligence. This information can be prohibitively expensive when purchased from traditional research organizations. In particular, commercial partners were able to improve product features and refine development plans based on customized assessments of competing technologies produced from public sources and insights into emerging technologies.

The market intelligence developed was tailored for the stage of development of each commercial partner. The independent economic and competitive analysis performed on behalf of the commercial partners could be used to confirm and validate internal business plans. However, the extent to which these analyses were performed was dependent on the amount of information obtained from public marketing materials.

The CWG also performed an economic assessment of the technology/product that was developed in the Project. In addition to topline market size, penetration estimates, and revenue potential, the CWG considered costs and benefits to the utility, consumer, and society as related to the subject innovation. These benefits were considered within a regulatory framework for recovery of costs and sharing of benefits.

Cooperation from each commercial partner ensured that the CWG and TEC were able to bring the highest quality data and analysis to bear on accelerating and guiding commercialization of each commercial partners' product or technology.

Commercialization



11.11 Commercial Partner Reports

Progress/status reports were provided to the Project team at regular intervals. These reports characterized the partner's stage of commercialization, their partners, resources, cost-benefit analysis, and other factors that governed the characterization and were the basis for commercial adoption. These reports also described the work performed and the results of that work to characterize the commercial partners as detailed in the Methodology section above.

Based on the interests of the commercial partners, alignment with Project goals, and budgets, commercial partner projects were selected and prioritized as necessary. Aggregating individual status reports helped to capture the path to commercialization taken by the commercial partner.

11.12 Project Report

The status reports and summary reports for commercial partners were used to prepare Project status reports that tracked the overall evolution of the portfolio of technologies and commercial products. The report highlighted commercialization trends, lessons learned, and best practices based on the evolution of the individual participants and a summary of overall Project effectiveness.

11.13 Commercialization Conclusions

Engaging vendor participants in the Commercialization effort allowed for assessment of commercialization opportunities including the market readiness of the emerging technologies and the economic impact of these commercial activities. While AEP provided the utility perspective, Battelle and TEC provided valuable analysis and insights regarding the product development. The Project successfully accelerated the commercialization of smart grid technologies through multiple stages of testing and guidance from the commercial partners.

11.13.1 Overarching Observations

The primary lesson learned from the Project was that external DOE funding was particularly effective at advancing technologies over regulatory or technical demonstration barriers. Products and technologies where DOE funding was especially meaningful include:

- Those that faced regulatory considerations, including rate structure limitations;
- Technologies that were in an early stage of technical development; and
- Products that addressed a need where the solution benefits from close collaboration among utilities.

Commercialization



In contrast, those technologies facing consumer adoption barriers benefited less substantially from DOE funding. Technologies which commercial advancement was more significantly supported by the DOE funding are Cyber Security, GridLAB-D, and Smart Grid Dispatch Engine (SGDE).

- Cyber Security was recognized by utilities as a priority prior to the Project. The Project adopted the Palisade suite of tools. More importantly, cyber security collaboration among utilities was a direct outcome of DOE funding. The collaboration between AEP Ohio and Lockheed Martin supported by the DOE funding has led to a more secure utility grid.
- Development of the Grid Command™ Distribution tool, used with GridLAB-D, accelerated development of the simulation environment up to the critical point of becoming practical to use by utility engineers and not solely by researchers. Enhanced simulation environments are enabling more rapid development and deployment of new grid capabilities. DOE funding was able to kick-start creation of this capability to a point where industry and academia is able to continue its refinement.
- For SGDE, the dearth of utility markets that allow demand-based residential pricing clearly discourages commercial enterprises from developing such a system. With DOE funding, the demonstration system was developed and possible. Policy makers can now use this information to evaluate if free-market pricing for residential electricity is desirable. Without DOE funding for this demonstration project, such decision would lack market pricing efficacy data in the electric utility domain.

End-user focused technologies that were not significantly impacted include the ePCT and GE Smart Appliances.

- In the case of ePCT, the initial product form was a thermostat with a programmable interface. While this feature was valuable for demonstration projects, the ePCT technology itself was already commercially viable, and so did not advance in the framework during the Project. The fact that the ePCT could be adapted to the real-time-pricing application was a strong endorsement of the flexibility of this device in the marketplace.
- The GE Smart Appliances also did not significantly advance in the framework. Because no national standard for communications between residences and utilities is imminent, this product was a weak fit for the Program. GE has since modified its approach with this technology toward a more appropriate business model focused on consumer connectivity and convenience.

The most significant impact of DOE funding can be seen in areas where DOE investment broadly impacted the industry, as opposed to a single utility or commercial partner. Cyber Security is the clearest example of such an impact as it is a pervasive concern throughout the utility industry. Cyber Security centers are now at each utility where DOE funding had a large impact.

Commercialization



Demonstration of the Home Energy Manager (HEM) had comparatively less impact given the level of investment. Each demonstration involved individual consumers, education, and buy-in. While long-term impact may be substantial, the impact-to-cost ratio for a technology like HEM was less than that for Cyber Security.

Another successful technology demonstration is Volt VAR Optimization (VVO). Because of the technical nature of the system and investment in engineering and sensors, the cost was significant. The potential improvement in grid performance and long term return clearly supported this demonstration.

11.13.2 Other Observations

11.13.2.1 Need for Technology-Stimulating Policy Considerations

Due to the dynamics of the regulatory environment, the Smart Grid Dispatch Engine (SGDE) faced a “chicken and egg” challenge. The current regulatory landscape does not widely support variable pricing and, therefore companies are unwilling to fund projects to develop technology that enables or streamlines variable (market-based) pricing. Potential vendors of technologies like SGDE seek clear signs from regulators that tariff structures might change.

The regulators are cautious in advancing variable pricing models absent clear demonstration that this type of system is viable. The developer of SGDE, Battelle, believes that the DOE funding helped move the technology ahead of the market. The Project demonstrated the viability of market-based pricing for residential utility consumers, and in a sense is “pushing the market” toward being able to consider such pricing schemes.

Recognizing a general societal preference for market choice, and a move toward choice in the electrical utility industry, it is reasonable to conclude that technology that enables true supply-demand market pricing fits with a broad underlying trend within the society.

11.13.2.2 Financing/Accounting/Investment Considerations

Traditionally, amortization periods for utility equipment are controlled in accordance with investments that must remain in place for many years. However, today’s smart grid technologies often have lifecycle dynamics more similar to computer and information technology than transmission infrastructure.

This resulted in recognition that even if a new technology proved to be effective in today’s environment, required amortization schedules would require carrying the asset on a utility’s books long beyond the end of its useful life. This accounting dynamic has direct implications on the adoption of emerging smart grid technologies.

The accounting practices of the utility industry were not a specific focus of the Project. The topic was recognized during discussions with commercial partners and utility professionals.

Commercialization



11.13.2.3 Results

DOE funding for the Project provided impetus and risk management for critical smart grid technologies. The complex nature of the smart grid is impacted by:

- Ratepayer preferences and preconceptions
- Current Electric utility practices and installed infrastructure
- Regulatory precedence and political considerations

DOE funding for the Project helped reduce hesitation in exploring new technologies and allowed participants to experiment with approaches and technologies that might have otherwise been considered too risky. This increased innovation accelerated learning and encouraged collaborations and, for some technologies, advanced their commercialization potential.

The technologies that advanced most with DOE funding were those that are more utility-centric, such as, Cyber Security, VVO, and GridLab-D. Those technologies that focused on ratepayers saw progress, but the greater number of individuals involved with ratepayer decision-making dampened the impact of DOE funding for those technologies.

A clear exception to this observation is SGDE, which bridges utility and ratepayer. For SGDE, DOE funding was essential, since a working model of a market-driven pricing for electric power is unlikely to be developed and implemented without external support. SGDE is important also because it provides early evidence supporting free-market based pricing for electricity, supporting general trends toward markets, and choice in the utility industry today.

Commercialization



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12 WORKFORCE PLANNING

12.1 Purpose

The purpose of the workforce plan is to provide a summary outlining the composition of the workforce required to support the AEP Ohio gridSMART[®] Demonstration Project implementation.

The workforce plan enables AEP Ohio to understand what workforce requirements are needed to successfully design, operate, and maintain the technologies and provides valuable information for future smart grid deployments.

12.2 Background

The emerging technologies of the Project required specialized skill sets to carry out their deployment. The legacy organizational structure and job descriptions did not easily accommodate the needed skill sets. As the Project progressed, the roles and responsibilities necessary to be effective were established. Resources were identified across the company, and those resources stepped up to contribute their talents to the Project. This staffing exercise further provided insight to workforce planning requirements for future smart grid implementations across the industry.

12.3 Challenges

It was critical to identify the resource requirements and existing gaps as part of the planning, implementation, and operation of gridSMART technologies. Challenges that affected the resource identification were:

- The traditional organizational structure is vertical in nature with the various functional areas established in silos. This structure posed a challenge for communication across impacted functional areas
- New technologies required skills from multiple resources across the organization.
- The project goals eliminated the need for certain positions, so it was necessary to identify ways to re-train and re-deploy existing resources.

12.4 Cross Functionality

The technologies implemented for the Project were more sophisticated than existing technologies and included multiple organizational disciplines. For example, Information Technology (IT) was a key resource for each of the technologies. IT's role included the need for such proficiencies as software support/ monitoring and data management/ analysis. These skills were needed to effectively implement and operate all facets of the Project technologies – engineering, equipment, operations, and consumer support. Existing job descriptions did not accommodate any single job that had a combination of the needed attributes.

Workforce Planning



Impacted functional areas identified as a result of the Project were:

- Information Technology (IT)
- Cyber Security
- Interoperability
- Information Privacy
- Telecommunications and Network Services
- Engineering
- Equipment Installation and Maintenance
- Operations
- Customer Service/ Call Center

Resources were identified for the purposes of the Project; however, future implementations of the technologies will require:

- Job descriptions/roles that blend proficiencies from multiple functional areas to achieve effective results.
- Re-training resources that are displaced due to the implementation of smart grid technologies. For example, meter readers that are displaced with AMI technology could be re-trained to support the technology in place of the previously required physical meter readings.
- Cross training of skill sets enables the transfer of knowledge and effective support across functional areas. This approach ensures day-to-day coverage and manages employee attrition more seamlessly.

12.5 Customer Service

A critical goal of the Project was managing customer satisfaction as they were introduced to new technologies and programs. More advanced skills in customer support were needed to be able to respond to inquiries and resolve issues because of the complexity of the technologies.

For future deployments of smart technologies, customer service representatives (CSR) will need to be trained in depth on all facets of a technology – the equipment, the technology system, the back office systems, and IT troubleshooting. This approach equips the CSRs with a comprehensive understanding of the technologies to be able to effectively troubleshoot and resolve issues.



12.6 Observations

The following information is the result of the experience and feedback from the different technology teams that participated in the Project as it pertains to workforce concerns.

- Provide additional employee resources to manage data as a result of the implementation of new software applications and the resulting data influx.
- Include sufficient time and resources to perform employee training. Identify key resources to train and cross train in specialized areas when implementing new and complex technology and processes. Keep up-to-date documentation and a knowledge database for specific roles to ensure continuity and ease of learning to mitigate employee turnover during the Project.
- Train customer service groups and representatives to support consumer inquiries immediately upon installation of new equipment and programs.
- Co-locate IT resources from both the utility/operations area and the research/development entity for better communication, more effective collaboration, and more efficient decision making.
- Leverage existing talent from within the company before bringing in external consultants. Provide specialized training to enhance the internal resources' value to the project.
- Build the technology team with key resources from both the utility and the R&D provider and co-locate them for better collaboration and a more efficient development process.
- Gain efficiencies with the expertise throughout the organization. Currently the expertise is within organizational silos.
- Provide the opportunity for employees to acquire new skill sets such as data analysis and network expertise. AEP's workforce developed knowledge of alarms and systems monitoring, which resulted in actionable work for field personnel.
- Ensure that experienced testers are available for system testing.
- Improve project manager continuity and technical support.
- Clarify and document essential roles and responsibilities.
- Implement a tiered technical support staff to install and maintain grid management systems.
- Create opportunities for existing engineers to add new competencies and expertise.

12.7 Industry Changes

As smart grid technologies become more prevalent across the industry and job descriptions change, it will be important to prepare the incoming work force:

- Redefine college curriculum to accommodate the new smart grid technologies associated with their power and telecommunications courses.
- Mentor and train incoming resources, so they are equipped to take on the new and blended roles as the currently aging work force retires.

Workforce Planning



- Utility companies will need to upgrade existing job descriptions and redefine new roles that include the blended skill sets.
- The organizational structure will need to adapt to support cross-cutting technologies.

12.8 Workforce Planning Conclusions

As a result of the Project, AEP Ohio recognized the inherent challenges associated with the existing workforce as effective resources for the Project and for smart grid technologies in general. As smart grid technologies emerge, one of the most critical concerns for effective implementation and ongoing operations will be newly defined job skills and the necessary training. Utilities must become more nimble to adjust workforce management policies and develop cross-functional work processes and training programs to facilitate the implementation of smart grid technology and ensure qualified personnel are retained.



13 LESSONS LEARNED

This section describes lessons learned for all demonstrated technologies. Others may find benefit from issues and solutions that AEP encountered, mitigated or resolved. Lessons Learned are provided for Technology, Implementation, and Operations.

13.1 Technology

- Smart grid technologies require a high level of interdepartmental coordination.
- Ensure communication network is designed and operational before field equipment is installed. Network optimization is essential to facilitate efficient operations.
- Develop robust test cases to ensure functionality of the systems.
- Monitor network equipment and components for performance and downtime.
- Perform a gap analysis on reporting tools and systems. Develop or purchase new tools where in-house technology does not exist.
- Align software development goals with ongoing operational systems.
- Identify project key personnel and conduct thorough training that includes hands-on access to the equipment they will be supporting.
- Allow sufficient time in the project plan to ensure the technology and processes are tested and ready for implementation to save time and costs and preserve positive consumer perceptions.
- Maintain a consumer-centric focus to help socialize new technologies and processes, grow positive consumer perception of the utility, and successfully participate in a competitive market.
- When developing and implementing smart grid technology, provide in-depth communication and training to regulators providing a better understanding of the tariffs and riders being requested.
- Perform thorough testing of all equipment and software in collaboration with vendor suppliers to ensure its readiness for implementation with consumers.
- Assess data management based on system and equipment potential for data volume. Estimate data storage requirements and plan/build data warehouse accordingly. Ensure all data is available for complete analysis and reporting.
- IT reporting and data mining applications need to be developed to turn the large amount of data into knowledge and identify which items the utility needs to take proactive action on.
- Work with vendors to ensure equipment interoperability. It is important for utilities and vendors to work together to enhance smart grid equipment resulting in interoperable devices, ensuring successful integration with existing systems.



13.2 Implementation

- When deploying multiple technologies, synchronize deployment to maximize efficiencies and reduce rework.
- Stringent processes are needed to gauge and mitigate interdependencies when new technologies are implemented.
- Vendor-managed and vendor-hosted technology implementation is the most cost effective strategy.
- Clarification and documentation of roles and responsibilities are essential in project planning.
- When technological issues arise, a root cause analysis must be performed to gain understanding and make improvements.
- Engage other utilities and industry experience to develop best practices in consumer outreach and education.
- A phased rollout approach allows for effective consumer communications. Consumers were engaged through letters, phone calls, door hangers, and mail communications pieces, emphasizing consumer benefits of the technology.
- Contract terms with vendors and service providers must address:
 - Documentation and key deliverables
 - Enumeration of roles and responsibilities
 - Service level expectations
 - User acceptance testing requirements
 - System acceptance testing requirements
 - Software/firmware licensing and support
- Customer service groups and representatives must be fully trained and ready to support consumer inquiries immediately upon installation of new equipment and implementation of programs.
- Allow sufficient implementation time to manage potential technology issues that may be identified following installation.
- Conduct focus groups and use surveys to gain a better understanding of the consumers' perceived benefits, enabling the team to better direct both the consumer education and the technology to the targeted consumers.
- Schedule time-sensitive pieces of the proposed tariffs and riders to ensure coordinated timing with the actual rollout of technology and equipment to consumers.
- Develop an integrated marketing and consumer outreach strategy for more effective coordination of schedules and operational controls to ensure cost and time savings.

Lessons Learned



- Testing, configuring and commissioning devices and automation schemes is more time consuming and complicated than stand-alone devices.

13.3 Operations

- Keep consumer messages simple, concise, and benefit-driven.
- Provide an education process for internal resources to enable them to act as ambassadors of the technology that strengthen consumer acceptance.
- Leverage internal resources and expertise whenever possible to ensure more control and involvement in decision making, development, and implementation.
- When selecting vendors, service providers, or partners, have more closely aligned goals that accommodate effective collaboration and consistent outcomes and deliverables.
- When a vendor performs updates to a user interface, application, or device, the documentation must also be updated accordingly. This documentation enhances consumer support as well as back office operations.
- Integrate AMI ping/poll functionality into major storm restoration efforts to reduce time and effort and maximize employee efficiency.
- Implement a sleep timer for meter power up messages to reduce communication losses for distribution automation operations. These messages will transmit at a predetermined time (set at five minutes). The five-minute delay would allow the DA commands and status indications to pass without competing with meter messages for communication resources.
- Align regulatory requirements to maximize impact of technology capabilities to operations. For example, eliminate connect/disconnect site visit requirements to efficiently use remote capabilities.

Lessons Learned



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14 PROJECT CONCLUSIONS

14.1 Introduction

The AEP Ohio gridSMART[®] Demonstration Project was designed to evaluate a broad scope of potential smart grid technologies in order to guide subsequent deployment plans. AEP Ohio has not only gained valuable experience in the performance of these technologies, but also in the operation of communication interfaces and how to optimize the processes to deliver the benefits envisioned. This experience prepares AEP Ohio for a more efficient and effective implementation as it deploys select technology and process improvements across the AEP Ohio service territory.

The following benefits have been achieved as a result of the Project:

- Improved safety for AEP Ohio employees
- Operational efficiencies through real-time information and remote operations
- Improved access to meter reading data
- Fewer number of consumer outage events
- Reduced number of consumers experiencing sustained (>5 minutes) outages
- Faster restoration times for sustained outages (>5 minutes)
- Demand reduction through new tariff offerings and the education of consumers regarding energy costs and use of technology
- Improved energy efficiency and demand reduction
- Improved customer satisfaction

The DOE funding was instrumental in advancing smart grid technologies and ensuring Project success. DOE funding was especially meaningful for the following areas:

- Regulatory considerations, including rate structure limitations
- Technologies that were in an early stage of commercial development
- Products that addressed a need where the solution benefits from close collaboration among utilities
- Best technologies for moving from an integrated utility to one functioning in a deregulated market
- Information sharing to promote a secure and interoperable system

14.2 AMI

The Project demonstrated several operational benefits. For instance, by installing AMI meters, AEP Ohio eliminated 100 percent of the meter reading routes (187 routes) in the area where AMI was deployed. AMI also enabled AEP Ohio to reduce costs associated with meter operations activities.

Project Conclusions



For example, through the use of remote service switch capabilities that enable secure connection and disconnection of electric service to customer premises from the utility back office, AEP Ohio reduced field visits associated with standard move in/move out orders. The combined meter reading and meter operations savings totaled approximately \$859,100 (\$7.81 per meter per year).

Category	Project area result
AMI Meters	110,000
Meter Reading and Meter Operations Savings (annual)	\$859,100 (\$7.81/meter)

Table 31. AMI Meter Benefits

Credit, collections and revenue enhancements through earlier theft detection, lowered consumption on inactive meters and greater billing accuracy led to additional savings and benefits.

AMI offered a host of important benefits, including:

- Improved data for billing
- Better customer service and satisfaction
- Reduced outages
- Improved crew and meter reader safety
- Reduced environmental impact

Note: The above benefits have not been monetarily quantified.

With automated meter reads, AMI nearly eliminated estimated bills, improving billing accuracy. AMI yielded a typical monthly read rate of 99.9 percent, leading to greater billing accuracy and improved customer satisfaction.

AMI led to better customer service. For instance, when a consumer wanted to terminate service, the AMI meter could be read remotely and a final bill sent without delays caused by manual reads. Similarly, AMI meters equipped with a remote service switch enable power to be turned on or off remotely. As a result, a consumer moving in could have service turned on in minutes, rather than waiting days.

AMI provided consumers with the ability to view their energy consumption on a more granular level; typically multiple data points per day were provided. This data provided consumers a better understanding of their consumption behavior. The availability of this data also enabled consumers to participate in consumer programs. These programs were designed to reduce peak demand, thereby allowing consumers to benefit through savings.

AMI also provided billing and customer service efficiencies that enabled AEP Ohio to quickly address inquiries. Consumers experienced fewer billing issues from continual meter reads and the elimination of estimated meter reads through AMI. Company representatives had near real-time access to meter data that helped them discuss actual usage information with consumers.

Project Conclusions



When a consumer called about power loss, the near real-time access also enabled the company to determine whether the power loss was due to an outage or to an issue on the consumer side of the meter, such as a blown house breaker fuse.

From a reliability perspective, when an AMI meter detected a loss of voltage, a message was sent indicating the consumer had lost power. Messages that successfully reached AEP Ohio's internal systems were used in conjunction with consumer telephone calls to predict the extent of the outage. Also, meters were queried (pinged/poll) to get an indication of whether a consumer had power. This indication was useful to troubleshoot consumer issues and to verify restoration following an outage.

From a safety perspective, because crews could remotely determine whether a meter had power, crew exposure and safety were improved. Also, due to AMI, fewer meter readers were required in the field, which reduced physical meter reading efforts and, thus, reduced safety issues.

With remote capabilities, the number of miles driven by metering and service personnel was reduced. In addition, there were environmental benefits associated with reduced vehicle emissions as a result of reduced vehicle miles traveled.

14.3 Consumer Programs

AEP Ohio offered consumer programs as part of the AEP Ohio gridSMART Demonstration Project. AMI provided consumers with the ability to view their energy consumption on a more granular level, which provided a better understanding of consumption behavior. Consumer programs were designed to reduce peak demand, thereby allowing consumers to benefit through savings.

Consumer programs provided significant net benefit to consumers. These programs were:

- SMART ShiftSM two-tier time-of-day tariff
- SMART Shift PlusSM three-tier Time-of-Day with Critical Peak Pricing
- SMART CoolingSM direct load control (DLC) program
- SMART Cooling PlusSM DLC program
- SMART ChoiceSM real time pricing with double auction
- eViewSM consumer usage feedback device

Additionally, Home Area Network (HAN) devices were used by consumers to better use data and pricing signals to control their consumption activity.

The consumer programs proved to be a technical success and were accepted by consumers. Consumers who participated in AMI-enabled consumer programs rated their overall satisfaction with AEP Ohio higher than did AEP Ohio consumers overall.

The Project engaged in a public outreach and education plan which played a key role in the successful implementation of consumer programs. A multi-pronged communications approach

Project Conclusions



engaged key community thought leaders, consumers, and other targeted audiences by providing timely and thorough information regarding the overall Project, timeline, rollout and benefits of the technologies. The plan clearly communicated with communities and consumers to ensure acceptance, which ultimately led to higher customer satisfaction and retention rates.

The proposed AEP Ohio gridSMART Phase 2 will deploy AMI meters with communication modules to enable in-home communication from the meter. This communication facilitates consumer program offerings. AEP Ohio views its role as a provider of the metering infrastructure that enables the offering of these programs by market participants. AEP Ohio envisions that Competitive Retail Electric Service (CRES) providers will take the lead role in these enhanced customer program offerings.

14.4 Real Time Pricing with Double Auction

AEP Ohio was able to successfully demonstrate an experimental tariff that allowed consumers to take advantage of fluctuating energy pricing. The Project demonstrated that the approximately 250 participating consumers were able to shift their energy consumption and paid less for energy by using RTP_{da} technology. The experimental program worked as designed resulting in net benefits to the consumers and the utility.

Challenges would need to be addressed before considering future deployments. AEP Ohio was often required to make multiple trips to consumers' homes to install, commission, and ensure functionality of RTP_{da} equipment. Once installed, there were reliability issues; some with the equipment itself as well as with the communications between the various devices and the back-office systems. Cellular service was not available in all parts of the Project area, which did not allow those consumers to participate in the program. The combined cost of equipment and communications was significant and, when compared to other consumer programs, the RTP_{da} program provided less financial value to consumer and utility.

14.5 DACR

The Project, through the deployment of DACR on 70 circuits, was able to reduce Customer Minutes of Interruption (CMI), improving reliability. While weather conditions are the primary driver for changes in SAIFI and CAIDI, AEP Ohio attributed some improvements of these indices from the DACR deployment. All consumers on the 70 DACR circuits experienced improved SAIFI and SAIDI.

In addition to the reliability benefits described above, the systems also enabled crew labor savings, up to 2 hours per event, and in some instances avoided service calls entirely. Both of these situations provided opportunities for AEP Ohio to perform additional proactive work on circuits in need of service, further enhancing reliability.

Improved system reliability has significant impact on economic output too. Based on the *Cost of Power Interruptions to Electricity Consumers in the United States*, Ernest Orlando Lawrence Berkeley National Laboratory (2006), AEP Ohio, if expanded to an additional 250 circuits, estimates that DACR could reduce societal costs by approximately \$71 million per year through the reduction of outages experienced by consumers.

Project Conclusions



14.6 VVO

The Project VVO demonstration was designed to realize a reduction in energy consumption and a reduction in peak demand on circuits where VVO was deployed.

Voltage standards exist in the electric utility industry, such as ANSI C84.1, that mandate an acceptable voltage range at the secondary of the distribution transformer. VVO enabled a reduction of the average voltage that each customer on the circuit received, thereby reducing the annual energy consumption of the circuit while maintaining the quality of service to the end-use consumer. Based on results obtained through field demonstrations, AEP Ohio estimates that a 3 percent reduction in energy consumption and a 2 to 3 percent reduction in peak demand can be obtained on those circuits on which the technology is deployed.

Along with the efficiency benefits, the technology associated with VVO also provided VAR support, offsetting the need for Generation and Transmission resources to provide VARs. The technology required for VVO augmented other technologies to improve visibility into system performance and circuit automation.

14.7 Security and Interoperability

The Project implemented innovative advancements in the cyber security and interoperability arena. The Project was able to validate secure two-way communications from AEP systems through consumer premises. The Project engaged in penetration and interface testing to facilitate this validation.

The Project developed and implemented a state of the art Cyber Security Operations Center (CSOC). The CSOC continuously provided advanced security checks, monitored the network, and identified vulnerabilities and threats to ensure grid security. The CSOC, with its industry threat sharing integration functionality, continuously gathered and shared threat information with peer utilities and government agencies.

AEP Ohio treated consumer consumption data collected through the smart grid with a high level of protection. Consumers were assured that the safety and security of their information were protected by extensive and dedicated resources.

The Project cyber security and interoperability efforts have led the development of industry standards. AEP Ohio will continue to strive to improve interoperability, security, and consumer protection. AEP Ohio will continue to use the CSOC and dedicated security and privacy experts to review smart grid technologies and equipment to ensure strict standards are met. AEP Ohio will continue to place emphasis on building interoperability, security, and privacy into future deployments.

Project Conclusions



14.8 Next Steps

The AEP Ohio gridSMART Demonstration Project successfully demonstrated the deployed technologies. AEP Ohio submits that a gridSMART expansion enables a fundamental change in the way the company operates, serving as the necessary foundation upon which AEP Ohio will provide more reliable service and greater efficiency opportunities for consumers. AEP Ohio has filed the AEP Ohio gridSMART Phase 2 (Phase 2) plan with the Public Utilities Commission of Ohio to extend elements of gridSMART throughout AEP Ohio's service territory.

Phase 2 builds upon the Project's success. It includes Advanced Metering Infrastructure (AMI) for approximately 894,000 customers across urban and suburban areas; Distribution Automation Circuit Reconfiguration (DACR) for approximately 250 circuits; and Volt VAR Optimization (VVO) for approximately 80 circuits. AEP Ohio is targeting a deployment timeline of approximately four years for all three technologies as proposed. In addition to extending the benefits of AMI, DACR, and VVO achieved by the Project to a larger base of consumers, it is envisioned that Phase 2 also will provide the following benefits:

- Support for a more robust consumer choice market by enabling consumer access to information, improved data for market settlement, and potential for time-differentiated rate design offerings.
- Reduced uncollectible revenue, theft and consumption on inactive meters through automated remote disconnect and continuous usage data availability.
- Enhanced customer service and satisfaction (for example, through faster, remote service connection).
- Better information to consumers concerning their electricity usage, enabling them to conserve energy, save money, and help to protect the environment.

Phase 2 is built upon proven technologies and solutions that have been implemented in the Project and broadly deployed in the market. Phase 2 will extend the benefits demonstrated in the Project and deliver additional benefits to a broader set of consumers. Through Phase 2, the company expects to:

- Drive significant financial benefits.
- Positively impact customer service and customer satisfaction.
- Improve safety performance.
- Improve regional economic output.
- Reduce environmental impacts.
- Enable CRES providers to offer valuable consumer programs.
- Improve CMI where DACR is deployed.
- Avoid millions of dollars of potential lost economic productivity annually.
- Generate significant efficiencies that translate to consumer savings.

Glossary



GLOSSARY OF TERMS

Word/Phrase	Definition
Access Points	Access Points – Devices that connect the radio frequency mesh network linking all intelligent endpoints to the utility’s backhaul or wide area network links.
Active Load	In the RTP _{da} program, the amount of responsive load that cleared to run in the market period – participation in an auction.
American Electric Power	American Electric Power is one of the largest electric utilities in the United States, delivering electricity to more than 5 million customers in 11 states. AEP ranks among the nation’s largest generators of electricity, owning nearly 38,000 megawatts of generating capacity in the U.S. AEP also owns the nation’s largest electricity transmission system, a nearly 39,000-mile network that includes more 765 kilovolt extra-high voltage transmission lines than all other U.S. transmission systems combined. AEP’s transmission system directly or indirectly serves about 10 percent of the electricity demand in the Eastern Interconnection, the interconnected transmission system that covers 38 eastern and central U.S. states and eastern Canada, and approximately 11 percent of the electricity demand in ERCOT, the transmission system that covers much of Texas. AEP’s utility units operate as AEP Ohio, AEP Texas, Appalachian Power (in Virginia and West Virginia), AEP Appalachian Power (in Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and east and north Texas). AEP’s headquarters are in Columbus, Ohio.
AEP Ohio	Ohio Power Company is a unit of the American Electric Power System and does business as AEP Ohio. It is the surviving entity of the merger with Columbus Southern Power Company. It is the electric utility distributing electricity to portions of Ohio and West Virginia and is the award recipient.
AEP Ohio gridSMART [®] Demonstration Project	One of the sixteen (16) ARRA- funded Smart Grid Demonstration Projects (SGDP) awarded by DOE to AEP Ohio.
Bridge	Device used to create a connection between two separate computer networks or to divide one network into two.

Glossary



Word/Phrase	Definition
Customer Average Interruption Duration Index (CAIDI)	The average outage duration that any given customer would experience in a sustained outage. This index is calculated by dividing the total consumer minutes of interruption by the number customers interrupted.
Circuit	The wired power grid infrastructure distributing electricity from an electric utility
Check Read	An on-demand meter reading
Columbus Southern Power (CSP)	Columbus Southern Power is the original award recipient, and was merged out of existence with Ohio Power Company.
Distribution Automation Circuit Reconfiguration (DACR)	Automatic circuit configuration for recovery from electric faults.
Direct Load Control (DLC) Event	To respond to a period of high energy demand, the utility sends signals to Home Area Network (HAN) devices in the consumer residence to reduce usage.
Direct Load Control (DLC) Rider	The mechanism by which participation in the DLC program is reimbursed for participation. A credit is applied to the monthly bill.
Double Auction	A process of buying and selling where competitive buyer bids (demand bids) are matched with competitive seller offers (supply bids). Potential consumers submit their bids for energy based on the smart appliances' needs and the electric utility simultaneously compiles an asking price related to the quantity of energy supplied. The system combines the received consumer bids for energy and compares this cumulative bid curve with the electric utility's cumulative generation and purchase cost curve to determine the market cost for energy to be consumed. The intersection of the cumulative demand bid curve with the energy supply cost curve is the resulting market value or the clearing price of energy for the present time increment. The clearing price is the actual price paid for energy by the consumer but limits and adjustments, such as cost correction factors, may be applied before the clearing price is determined.
Circuit	The wired power grid infrastructure distributing electricity from an electric utility.
Feeder	See Circuit.
Grid	The wired infrastructure, above and below ground, which distributes electricity from the electric utility to the consumer.
gridSMART [®]	The AEP registered trademark for implementation of smart grid technology.

Glossary



Word/Phrase	Definition
Inactive Load	In the RTP _{da} program, the amount of responsive load that did not clear to run in the market period – nonparticipation in an auction.
Last Gasp (outage) message	The alarm message sent by the AMI meter that power has gone out. A capacitor in the meter discharges to send a signal over the communications network prior to losing power.
Momentary Average Interruption Frequency Index (MAIFI)	The average number of momentary interruptions that a consumer would experience. This is calculated as the total number of consumer momentary (<=five minutes) interruptions divided by the total number of consumers served.
Must-Run State	During an RTP _{da} auction when the observed temperature exceeds the offset set temperature, the HEM increases the bid price to the maximum and no further temperature adjustments to the ePCT are made.
Ohio Power Company	The unit of the American Electric Power System that distributes and sells electricity in Ohio and West Virginia, the surviving company of the merger with Columbus Southern Power Company. It is also known as AEP Ohio, the name used throughout this report.
Outage Response Time	In this report, the time between notification of an outage and when AEP Ohio declares an outage and dispatches a crew.
Peak Load	The maximum amount of power that is used or produced by consumers over a defined period of time.
Peak Load and Mix	The analysis of peak load at a point in time and the different types of consumers contributing to that peak (residential, commercial, and industrial). Consumers are on different tariffs and in different demographics.
Ping/Poll	A process that determines the availability of a network devices or interfaces by using an echo request.
PJM Interconnection LLC (PJM)	A Regional Transmission Organization (RTO) in the United States.
Project	AEP Ohio gridSMART Demonstration Project, awarded to Ohio Power Company by U.S. DOE (award number DE-OE0000193).
Project area	The Project area is located in the northeast quadrant of Central Ohio.
Rate	The cost of electricity per unit of measure.
Residential Peak Day	The peak load consumed by residential consumers on a week day.
Rebate	A credit applied to consumers' electricity bill for their participation in certain types of programs.

Glossary



Word/Phrase	Definition
Relay	A device that extends the radio frequency signal in places where meters are not located and an Access Point is out of reach. A relay can be deployed on pole tops or building floors and can efficiently augment and retransmit the radio frequency signal.
Responsive Load	The sum of all the RTP _{da} HVAC loads on the circuit.
Rider	A rate mechanism that collects or refunds costs for specific projects or services.
System Average Interruption Duration Index (SAIDI)	The average outage duration that any given customer would experience in a sustained outage. This index is calculated by dividing the total customer minutes of interruption by the number of customers served.
System Average Interruption Frequency Index (SAIFI)	The average number of sustained interruptions that a customer would experience. This index is calculated as the total number of consumer sustained interruptions (>five minutes) divided by the total number of consumers served.
Smart Grid	A suite of existing and emerging concepts, technologies, tools, techniques, and system configurations that can be innovatively applied and integrated to improve technical, operational, efficiency, reliability, safety, and environmental impact of electricity consumption.
Smart Grid Demonstration Program (SGDP)	The 16 U.S. Department of Energy projects demonstrating new and more cost-effective smart grid technologies can be applied and integrated to significantly improve technical, operational, and business-model feasibility. See www.smartgrid.gov .
eView SM SMART Shift SM SMART Shift Plus SM SMART Cooling SM SMART Cooling Plus SM SMART Choice SM	The AEP Ohio branded Consumer Programs demonstrated by this Project.
Smart Meter	A utility meter capable of two-way communication with the utility company.
System area	The System area is the area served by Columbus Southern Power in 2009; approximately 750,000 electricity consumers. This was established at the beginning of the Project. CSP merged with Ohio Power Company and is known as AEP Ohio.
System Peak Day	The peak load of a combination of circuits that constitute the utility company footprint on a given day.
Tariff	A Public Utilities Commission of Ohio (PUCO) approved algorithm for the electricity utility to use in charging and billing consumers for the use of electricity.

Glossary



Word/Phrase	Definition
Unity	Refers to a power factor of 1.0 that is obtained when current and voltage are in phase.
Unresponsive Load	In the RTP _{da} program, the total circuit load minus the responsive load during the market period on the circuit.
VAR	Volt-ampere reactive, a component of electricity on the grid.
Volt VAR Optimization (VVO)	A demand-side management program that reduces energy consumption and demand without consumer interaction or participation

Glossary



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List of Acronyms/Abbreviations



LIST OF ACRONYMS/ABBREVIATIONS

Acronym	Definition
AC	Alternating Current
ACE	AEP Cost Engine
AMI	Advanced Metering Infrastructure
ANSI	American National Standards Institute
ARRA	American Recovery and Reinvestment Act of 2009
BEV	Battery Electric Vehicle
CARB	California Air Resources Board
CAIDI	Customer Average Interruption Duration Index
CES	Community Energy Storage
CIM	Common Information Model
CMI	Customer Minutes Interrupted
CO ₂	Carbon Dioxide
CP	Consumer Programs
CPP	Critical Peak Pricing/Price
CRES	Competitive Retail Electric Service
CSOC	Cyber Security Operations Center
CVVC	Coordinated Volt VAR Control
CWG	Commercialization Working Group
DA	Distribution Automation
DAC	Distribution Automation Controller
DACR	Distribution Automation Circuit Reconfiguration
DLC	Direct Load Control
DMS	Distribution Management System
DNP	Distributed Network Protocol/Disconnection for Nonpayment
DOE	U. S. Department of Energy
EOL	End-of-line
EPA	Environmental Protection Agency
ePCT	Enhanced Programmable Communicating Thermostat
EVSE	Electric Vehicle Supply Equipment
FRO	Field Revenue Operations
FTP	File Transfer Protocol
GQM	Goals, Questions, and Metrics
GridLAB-D	Smart Grid Simulator Utility
HAN	Home Area Network
HEM	Home Energy Manager
HVAC	Heating, Ventilation, and Air Conditioning
ID	Identifier
IEC	International Electrotechnical Commission
IHD	In-home Display
IMU	Interface Management Unit
IT	Information Technology

List of Acronyms/Abbreviations



Acronym	Definition
kVARh	kiloVolt-Amp-reactive-hour
LCS	Load Control Switch
LMP	Locational Marginal Price
MAIFI	Momentary Average Interruption Frequency Index
MDM	Meter Data Management
MFR	Multi-Feeder Reconnection
MRO	Meter Revenue Operations
NIST	National Institute of Standards and Technology
NO _x	Nitrogen Oxides
OMS	Outage Management System
PCT	Programmable Communicating Thermostat
PEV	Plug-in Electric Vehicle
PHEV	Plug-in Hybrid Electric Vehicle
PJM	PJM Interconnection LLC
PUCO	Public Utilities Commission of Ohio
PV	Photovoltaics
RF	Radio Frequency
RTP _{da}	Real Time Pricing with Double Auction
RTPi	Real Time Pricing Integration Layer
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SGD	Smart Grid Dispatch
SO ₂	Sulfur Dioxide
SO _x	Sulfur Oxides
TERS	Trouble Entry Reporting System
TOD	Time-of-Day
TOD/CP	Time-of-Day with Critical Peak Price
UIQ	UtilityIQ [®]
VAR	Volt-Ampere Reactive
VOT	Virtual Operations Test
VVO	Volt VAR Optimization



Appendix A

APPENDIX A – ENVIRONMENTAL REFERENCES

This Appendix contains a list of conversion constants used in the calculations associated with the Impact Metric analysis. These factors were either provided by AEP to Battelle when they were specific to utility operations or by Battelle for standardized engineering calculations.

AEP-Authored Conversion Factors

- [CF-AEP-01] Meter event labor cost for truck roll avoided\$20.00
 This factor provides a dollar value representing the amount of labor saved for each truck roll avoided due to AMI.

- [CF-AEP-02] Meter event labor cost truck roll added\$50.00
 This factor provides a dollar value representing the amount of additional labor required for each new truck roll required due to AMI.

- [CF-AEP-03] Short truck roll avoided vehicle cost - switching event.....\$7.50
 This factor provides a dollar value representing the vehicle related savings for each short truck roll avoided due to circuit reconfiguration DA.

- [CF-AEP-04] Standard truck roll avoided Vehicle Cost - switching event.....\$45.25
 This factor provides a dollar value representing the vehicle related savings for each standard truck roll avoided due to circuit reconfiguration DA.

- [CF-AEP-05] Short truck roll avoided Labor Cost - switching Event\$15.75
 This factor provides a dollar value representing the labor savings for each short truck roll avoided due to circuit reconfiguration Distribution Automation.

- [CF-AEP-06] Standard truck roll avoided Labor Cost - switching Event.....\$94.00
 This factor provides a dollar value representing the labor savings for each standard truck roll avoided due to circuit reconfiguration Distribution Automation.

- [CF-AEP-08] \$/CMI.....\$0.052
 This factor provides a dollar value representing the savings associated with avoiding one customer minute of interruption.



Appendix A

Battelle-Authored Conversion Factors

AMI

CO₂: 8.8kg/gal gasoline; 10.1 kg/gal diesel

Source: United States EPA Office of Transportation and Air Quality Emissions Facts (EPA420-F-05-001)

SO_x: 0.165 g/gal gasoline; 0.0963 g/gal diesel

Calculated from: sulfur content of gasoline = 30 ppm

Source: U.S. EPA 40 CFR parts 80, 85, and 86 AMS-FRL-6516-2

Sulfur content of ULSD diesel fuel = 15 ppm

Source: U.S. EPA Office of Transportation and Air Quality Emissions Facts (EPA420-F-00-057)

Molecular weight of SO₂ = 64 g/mole

Density of gasoline = 2.75 kg/gallon

Density of diesel fuel = 3.21 kg/gallon

NO_x: 0.05 g/mi

Source: United States EPA 40 CFR part 86 Subpart S Tier 2 Bin 5 Emissions limits at 50,000 mi

PM_{2.5}: 0.01 g/mi

Source: United States EPA 40 CFR part 86 Subpart S Tier 2 Bin 5 Emissions limits at 100,000 mi

Consumer Programs

CO₂: 0.00068956 tons/kWh

Source: U.S. EPA eGRID2012 Version 1.0 Year 2009 Summary Tables for RFC West Region

SO_x: 0.00263084 kg/kWh

Source: U.S. EPA eGRID2012 Version 1.0 Year 2009 Summary Tables for RFC West Region

NO_x: 0.00117934 kg/kWh

Source: U.S. EPA eGRID2012 Version 1.0 Year 2009 Summary Tables for RFC West Region

PM_{2.5}: 0.001 kg/kWh

Source: U.S. EPA eGRID2012 Version 1.0 Year 2009 Summary Tables for RFC West Region

DACR and VVO

Note that DACR conversion factors are the same as that for AMI and that VVO conversion factors are the same as that for CP.



Appendix B

APPENDIX B – PACIFIC NORTHWEST NATIONAL LABORATORY REPORT WITH REAL TIME PRICING

Appendix B





Prepared for the U.S. Department of Energy
under Contract DE-AC05-76RL01830

PNNL-23192

AEP Ohio gridSMART[®] Demonstration Project Real-Time Pricing Demonstration Analysis

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February 2014



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operated by
BATTELLE
for the
UNITED STATES DEPARTMENT OF ENERGY
under Contract DE-AC05-76RL01830

Printed in the United States of America

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PNNL-23192

AEP Ohio gridSMART[®] Demonstration Project Real-time Pricing Demonstration Analysis

SE Widergren	A Somani
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DP Chassin	

February 2014

Prepared for
the U.S. Department of Energy
under Contract DE-AC05-76RL01830

Pacific Northwest National Laboratory
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Summary

This report contributes initial findings from an analysis of significant aspects of the American Electric Power, Ohio (AEP Ohio) gridSMART[®] Real-Time Pricing – Double Auction (RTP_{da}) demonstration project (the Project). Over the course of four years, Pacific Northwest National Laboratory (PNNL) worked with Ohio Power Company (the surviving company of a merger with Columbus Southern Power Company), doing business as AEP Ohio, and Battelle Memorial Institute to design, build, and operate an innovative system to engage residential consumers and their end-use resources in a participatory approach to electric system operations, an incentive-based approach that has the promise of providing greater efficiency under normal operating conditions and greater flexibility to react under situations of system stress. The material contained in this report supplements the findings documented by AEP Ohio in the main body of the gridSMART report. It delves into three main areas: impacts on system operations, impacts on households, and observations about the sensitivity of load to price changes.

The RTP_{da} system operated from December 2011 through the fall of 2013. An adequate population of households for system experiments was achieved in the late spring of 2013. As air conditioning equipment was the only type of load under RTP_{da} control, and as the great majority of this equipment only operated in cooling mode, the period of analysis was set from June 1 to September 30, 2013. The system was designed to collect a large amount of operational data, including the status of the enhanced programmable communicating thermostat (ePCT) parameters, indoor temperature, household energy consumption, and the RTP_{da} market data (such as household and supply price and quantity bids, market cleared price, and total distribution feeder¹ load). This was supplemented by data from the meter data management system, the billing system, weather data, and demographic data about the households (such as square footage and type of construction).

As with any operating system, the data are incomplete and testing behavior can pose challenges. Gaps in data from communications errors, equipment failures, and the like offered challenges to the analysis and add a level of uncertainty to the findings. In addition, the investigation found that the Project's plans to frequently exercise the RTP_{da} system with congestion events imposed on the households to observe their response under different circumstances (for example, days of week, times of day, and temperature conditions). A congestion event occurs when the load level of a distribution circuit (otherwise known as a feeder) exceeds the capacity limit of the feeder. Operators can impose a congestion event by setting the capacity limit below the present load level. This causes the market clearing process to drive prices higher. The investigation found that by frequently imposing congestion events, the resulting high prices desensitized the response of the equipment to normal market fluctuations when not in a congestion event. Once problems such as these were uncovered, the analysis attempted to compensate for their impacts, and thus come closer to a more accurate picture for addressing the questions under investigation. Simulations of the RTP_{da} system were also performed to help address some of these challenges and to scale the household resources to a size that allows for the investigation of system impacts.

¹ The term "distribution feeder" refers to the electric line that feeds a community of houses and terminates in a distribution substation. This is also known as a distribution circuit, as used elsewhere in the AEP Ohio gridSMART Demonstration Project Report. For the sake of brevity it is referred to simply as a feeder in this document.

The findings confirm the basic premise correlating reduction of short-term energy use with price increases and conversely, increase in energy use with price decreases. From a system impact point of view, simulations show that with a 35% penetration of RTP_{da} households, a load reduction of about 5% can be obtained for a 3.5-hour system peak event. For a 2-hour local, feeder peak event, a nearly 8% load reduction can be obtained. Regarding the impact on 5-minute wholesale energy purchases, the field data analysis indicates that, if there were no congestion events, overall energy consumption by the average RTP_{da} household could be reduced by over 5% and wholesale costs could similarly be reduced by 5% compared with the average non-responsive control group household. Simulations of the same wholesale impacts report an average of 1.2% reduction in energy consumption per household and 2.5% reduction in wholesale energy costs.

Consumer impacts studied include household bills, their thermostat statistics, and the actual energy use of the air conditioning equipment. When the RTP_{da} households' bills are computed using the RTP_{da} tariff versus the standard tariff, the study shows that there is good dispersion of relatively minor increases and decreases across all household energy use levels. Average monthly bills decrease slightly using the RTP_{da} tariff, thanks largely to the incentive savings. When investigating the average RTP_{da} bill compared to a calculation of the average bill of the non-responsive control group on the standard tariff, the analysis indicates about 5% reduction in the average RTP_{da} household bill, with a slight increase in overall energy usage. The components that appear to contribute to the average bill reduction are the incentive payments from the frequent congestion events and the flexibility to alter energy use in response to market price fluctuations. The energy usage is not reduced as reported in the wholesale energy purchases above because the congestion events are not excluded in this analysis as they were for the wholesale purchases analysis. Simulations indicate a roughly 4% savings in RTP_{da} bills versus the same households on the standard tariff that are not responding to price signals and incentives.

A study of thermostat settings shows a wide variety of settings by consumers with some indications of clusters, such as those who prefer more comfort and those who balanced comfort and economy more. To study consumer learning patterns, their behavior would need to be monitored for a longer period of time that included multiple seasons. The congestion events indicate that only 4% of the consumers overrode their thermostat setting at some point during the 2-hour events, whereas 10% of the consumers overrode their thermostat setting at some point during the 4-hour events. This provides some verification of consumer fatigue that would need careful attention in operating such programs. Lastly, the amount of energy bid in the market for the air conditioning units appears to have been underestimated from the observed energy draw on these units. The amount of energy bid into the real-time market should be more accurate in a full-scale deployment.

To analyze the sensitivity of load to price changes, the energy data measured at 5-minute intervals for each household was correlated with the corresponding 5-minute wholesale market information. Though the distribution of individual household responses is quite scattered, a filtering of the information corroborates the expectation that energy use decreases when price increases. This is particularly pronounced during hot periods when there is a great deal of air conditioning load operating in the presence of high, but fluctuating, energy prices. In addition, an analysis of the RTP_{da} household response to congestion events (resulting in high market prices) shows a strong dependence on outside temperature and the timing of the events (for example, peak versus off-peak periods). These factors affect the amount of energy curtailment initially available from the population of RTP_{da} resources, as well as the subsequent response of these resources to maintain, degrade, or enhance curtailment levels over the duration of the event. The findings contained in this report are termed *initial* because they only begin to address some of

the questions about the operation of the RTP_{da} system. Due to the complex nature of interactions between consumers and the electricity system, and the complexity of electric system operations in general, many more questions arise about the performance and potential benefits of this approach. The data gathered as a result of this project will be of significant value for further research.

Acronyms and Abbreviations

AEP Ohio	American Electric Power, Ohio
CAISO	California Independent System Operator
CPP	critical peak pricing
DOE	U.S. Department of Energy
ePCT	enhanced programmable communicating thermostat
ERCOT	Electric Reliability Council of Texas
HEM	home energy manager
HVAC	heating, ventilation, and air conditioning
kW	kilowatt(s)
kWh	kilowatt-hour(s)
LMP	locational marginal price
MDM	meter data management
MSE	mean-squared error
MWH	megawatt-hours
P_{base}	base price of the supply curve
P_{cap}	price cap
P_{clear}	cleared price
PDF	probability distribution function
PJM	PJM Interconnection, LLC, AEP Ohio's Regional Transmission Organization
PNNL	Pacific Northwest National Laboratory
Q_{clear}	cleared load/quantity
RTP	real-time pricing, also used as a shortened version of RTP _{da}
RTP _{da}	real-time pricing, double auction
SMART Shift Plus SM	a form of critical peak pricing implemented in the GridSMART Project
SRMCP	synchronized reserve market cleared price
$T_{desired}$	desired temperature
T_{max}	maximum temperature
T_{min}	minimum temperature

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1.0 Introduction

The gridSMART® Real-Time Pricing– Double Auction (RTP_{da}) Demonstration Project (the Project) is a part of the consumer-oriented projects within the overall American Electric Power, Ohio (AEP Ohio) gridSMART program. This project engages residential households to adapt their electricity use in response to a fluctuating 5-minute price signal. In particular, heating, ventilation, and air conditioning (HVAC) units are managed by intelligent software in the home that interacts with a real-time electricity market. The electricity supply price is function of the PJM wholesale market price of electricity as described in the real-time tariff approved by the Public Utility Commission of Ohio (Schedule RS-RTP, 2012).

Significant effort went into the specification, design, development, and deployment of the RTP_{da} demonstration so that AEP Ohio, the U.S. Department of Energy (DOE), and the Project partners could learn from the experience of this innovative approach to engaging end-use systems to the benefit of the consumer and the service provider. The analysis of the RTP_{da} demonstration addresses the question, “What did we learn from the RTP_{da} experiment?” The topics for analysis were developed by the AEP Ohio and Pacific Northwest National Laboratory (PNNL) Project team and each organization was given responsibility for a portion of the topics. This report covers analysis topics assigned to PNNL. Other analysis topics related to the RTP_{da} demonstration, such as customer satisfaction, are covered elsewhere in the gridSMART Project report.

While this analysis report provides insights into the behavior of the RTP_{da} system and its implications for service providers and consumers, it represents only a step on a path to discovering the characteristics and capabilities of end-use systems to participate in system operations and how to best engage them for consumer, local, and regional system objectives. Where appropriate, the report provides perspective for the results and lists additional issues that still need to be addressed.

1.1 Analysis Objectives

The RTP_{da} demonstration represents the first time that a real-time electricity market with an approved regulatory tariff has operated in a realistic situation of approximately 200 households. These households are supplied by four distribution feeders and represent a small fraction of the roughly 2000 total number of households on these feeders. While the measurements on the HVAC systems in these households provide good data to help quantify their price-responsive behavior, the penetration level is too low to address other analysis questions that require significant penetration levels of RTP_{da} households. For this reason, simulations of a higher penetration of RTP_{da} households are needed. Once calibrated to behave similarly to actual household loads, simulations can be configured to provide insights into questions that would be difficult and costly to address in the demonstration.

This analysis report investigates the following areas:

- the potential benefits of RTP_{da} for system-capacity and feeder-capacity issues
- the potential benefits of improving wholesale purchases in the real-time (5-minute) market and participation in a spinning reserve market

- the impacts of RTP_{da} from the consumer's perspective, including consumer bills and consumer configuration of the thermostat set point and adjustments of it over time
- a characterization of the sensitivity of the RTP_{da} loads to price fluctuations and their behavior when called upon for system events.

This analysis report explains the approach taken for the investigation, the source of the information, and the results obtained. Other areas of analysis, such as the implications of RTP_{da} in overall energy consumption or customer satisfaction with the program offering, were done by AEP Ohio. This document supplements that other analysis.

The analysis also includes the results of simulations of RTP_{da} households. While the measurements on these HVAC systems in these households provide good data to help quantify their price-responsive behavior, the penetration level is too low to address other analysis questions that require significant penetration levels of RTP_{da} households. For this reason, simulations of a higher penetration of RTP_{da} households are needed. Once calibrated to behave similarly to actual household loads, simulations were used to provide insights into questions that would be difficult and costly to address in the demonstration.

1.2 RTP_{da} Theory of Operations

The following sections describe the way in which the RTP_{da} system operates. This provides a context for better understanding the analysis results described in this report. The theory of operations starts with a description of how the distribution feeder market works. This is followed by a high-level description of the RTP_{da} dispatch system and how the end-use devices interact with this system.

1.2.1 Market Operations

The RTP_{da} system follows a transactive-control approach to coordinate household equipment participation in system operations. The term "transactive control" refers to a distributed decision-making approach that allows suppliers and consumers of energy to arrive at a coordinated solution for how each participant will operate based upon a trade-off of the value they place on electricity for a specified time. In this case, an energy market is used to resolve which HVAC loads will run in the next operating interval. The design combines

- a 5-minute retail RTP_{da} reflecting PJM wholesale locational marginal price (LMP) and capacity values
- an RTP_{da} tariff designed to be revenue neutral for the average consumer prior to any load shifting induced by the rate, and with the intent to robustly protect the consumer and the utility from long-term fluctuations in market prices
- a retail double-auction market design that directly manages congestion (that is, limits that constrain the amount of load served) at the distribution feeder level
- a retail market design capable of managing a share of congestion occurring at levels in the grid above a distribution feeder (for example, transmission), allocated to responsive load served by that feeder

- an economically rational heating/cooling thermostat design that balances a consumer’s desire to save on their electric bill in exchange for their willingness to be flexible, and that bids the price at which the load it controls will operate (or not), plus the quantity of that load
- a price-normalization scheme that eliminates the need for a consumer to understand or specify price levels as (for example) high, medium, and low, and that adapts to both short-term (days) and long-term (years) changes in price.

The following sections present the operational objectives driving the Project and the design incorporating the elements listed above.

1.2.1.1 RTP_{da} Market – Uncongested Conditions

A double-auction market implements a mechanism to determine the price at which supply and demand match at a given time. Bids are collected for a specified period of time from market opening to market closing, after which the market is cleared. The market clears every 5 minutes, a period that approximately matches the typical air conditioning load cycle.

After the market clears, the cleared price (P_{clear}) becomes the new prevailing retail RTP_{da} and the cleared load (Q_{clear}) varies with the demand curve. When the cleared price is published, devices can respond appropriately based on internal price-response logic. The auction itself does not provide any bookkeeping or enforcement of the price-response logic. It simply provides a central facility for buyers and sellers to deliver their price and quantity response information and obtain the prevailing RTP. The following figure shows the feeder supply curve, the ordered demand curve of bids for energy from the RTP_{da} households, and the market clearing at the intersection of these two curves.

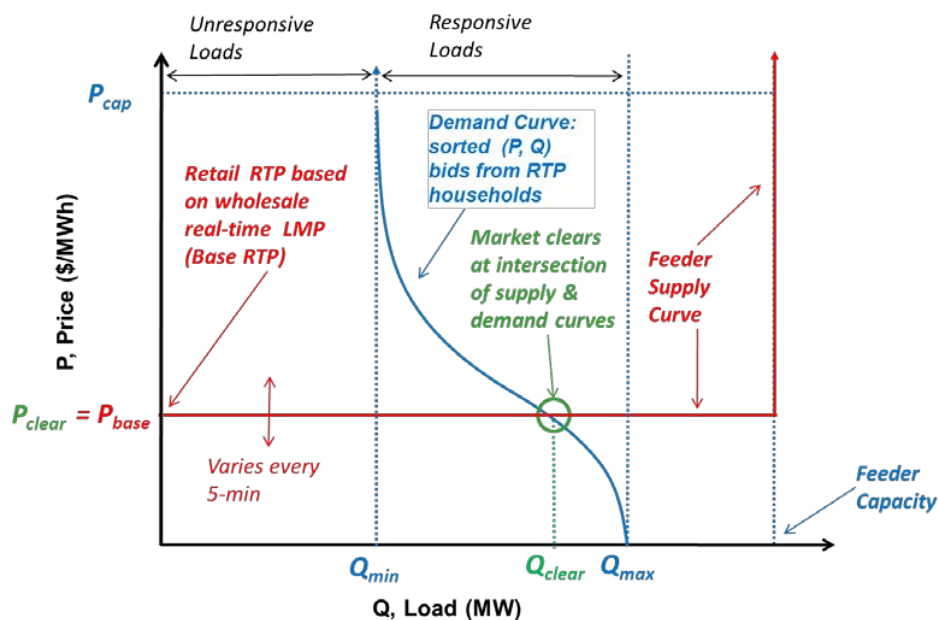


Figure 1.1. RTP_{da} Market Clearing – Uncongested Condition

1.2.1.2 RTP_{da} Market – Distribution Congestion

Congestion reflects feeder capacity limit constraints or system-wide operational constraints whose resolution could benefit from load reduction. Congestion can be addressed by allocating load reduction at the distribution feeder level in proportion to household bids on that feeder. By participating in a reoccurring market mechanism to negotiate energy need by willingness to pay, participants' actions can dynamically mitigate congestion limits.

During congestion, the cleared price (P_{clear}) is greater than the 5-minute, price of supply (P_{base}), and the cleared quantity (Q_{clear}) equals the feeder capacity, as shown in the Figure 1.2. Every time period (5 minutes), P_{clear} varies in order to try to keep load at the feeder capacity. The market auction proceeds as follows:

- The cleared price (P_{clear}) is set to clear the total load (Q_{clear}) at feeder capacity.
- When congested, $P_{clear} > P_{base}$.
- P_{clear} varies every 5 minutes to try to keep load at feeder capacity.
- If there is an inadequate amount of responsive load to hold the feeder capacity, the market will clear at its limit, that is, the price cap, P_{cap} .
- As shown in Figure 1.2, the total load on the feeder can theoretically vary between a minimum (Q_{min}) and maximum (Q_{max}).

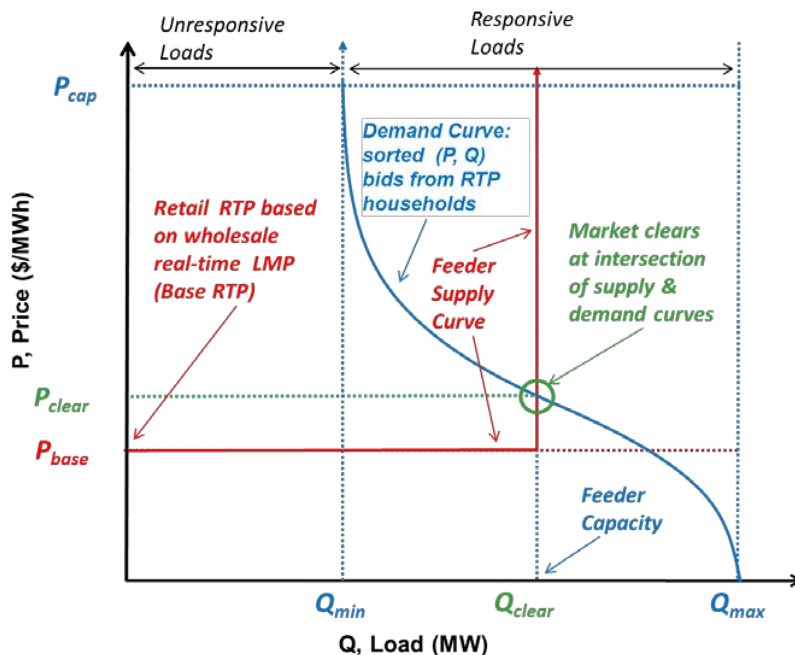


Figure 1.2. RTP_{da} Market Clearing – Congested Condition

The RTP_{da} mechanism can also be used to address system congestion issues, that is, issues that the service provider may have with system capacity constraints. In that case, an overall system load

reduction target is desired. To accomplish this, a share of the system-wide load reduction target can be allocated to each distribution feeder's households in proportion to their price and quantity bids. The number of RTP_{da} households per feeder and the feeder load itself play important roles in keeping Q_{clear} below the feeder capacity.

1.2.1.3 RTP_{da} Market – Rebate and Incentive Mechanisms

The market clearing at a higher price during congestion events encourages the bidding equipment to curtail operations. This allows consumers to avoid paying a high market price for energy; however, their exposure to higher prices was done to benefit the system, not to make the price-responsive consumer pay more for energy than a flat-rate consumer. The excess payment of the RTP_{da} consumers due to the higher cleared price than the base supply price (P_{base}) is indicated in Figure 1.3 as the congestion surplus (in the figure, only the households in the RTP_{da} program are represented). This surplus is either rebated back to the consumers at the end of the month, or equivalently, the consumers are only charged the P_{base} price even though the market cleared above this price. As the service provider did not experience added costs from associated wholesale price increases, and was able to avoid other, higher priced solutions (such as purchasing generation), the congestion surplus represents revenue for the service provider. Returning the congestion surplus back to the consumer removes the unfair burden of charging price-responsive consumers more, when in fact they are helping the service provider to avoid more costly alternatives.

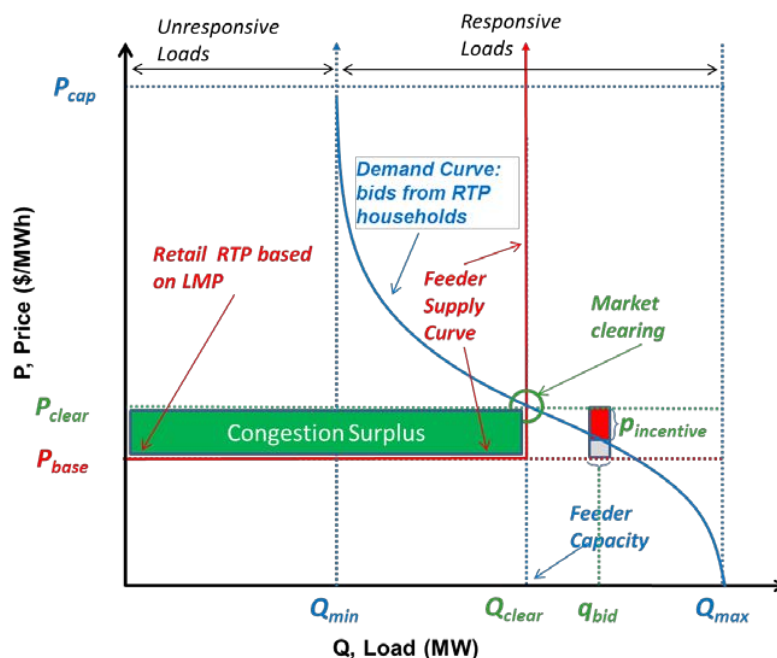


Figure 1.3. RTP_{da} Congested Condition – Congestion Surplus Rebate and Incentive

In fact, the rebate of the congestion surplus does not include any percentage of the added, long-term benefit that system operation achieves by reducing or moving a peak load condition (for example, deferring distribution system infrastructure upgrades). The value of this long-term benefit can be shared with the RTP_{da} households that actually reduced their load by using an incentive mechanism. Several

alternatives were reviewed by the Project team as to how an incentive could be calculated. The team chose an algorithm meant to reward consumers who are the most flexible to price changes. Figure 1.3 shows an example of the incentive provided to a consumer with the bid (p_{bid}, q_{bid}) . The incentive is computed as the quantity of energy consumed (that is, the product of the bid and the 5-minute time interval) times a function of the difference between cleared price and RTP_{da} base price.

$$\text{If } P_{base} \leq p_{bid} \leq P_{clear},$$

$$\text{then } p_{incentive} = q_{bid} \times F(P_{clear} - P_{base}).$$

If not, then no incentive is applied.

1.2.2 Dispatch System

The RTP_{da} system runs an electricity market on a distribution feeder-by-feeder basis. For the demonstration, four markets are running simultaneously, one for each of four feeders that supply the participating households. A simplified drawing of one of the markets is depicted in Figure 1.4.

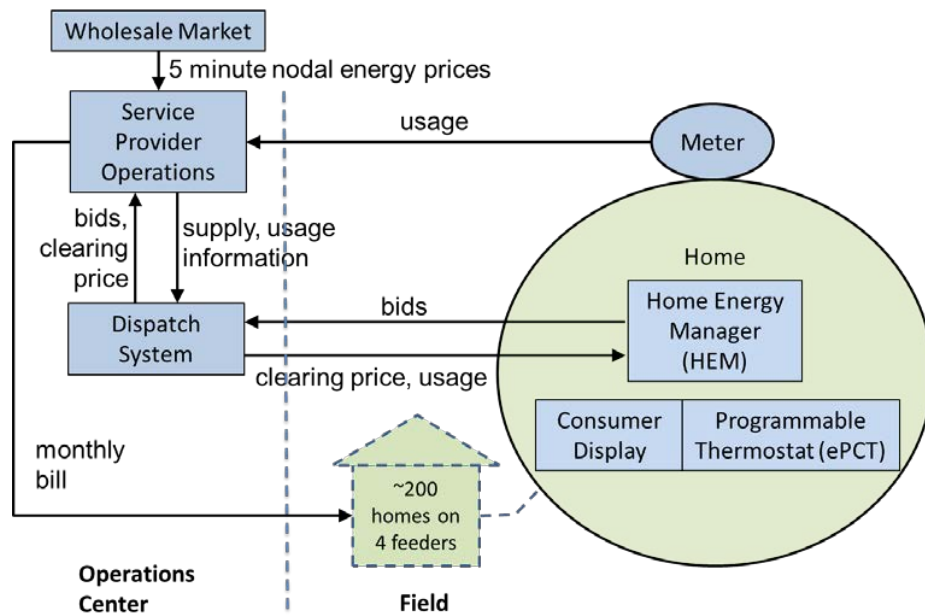


Figure 1.4. RTP_{da} System Overview

Within the home is an electronic program-controlled thermostat (ePCT) communicating with an HVAC unit and a home energy manager (HEM). The HEM hosts a software agent that monitors the market price of electricity and converts the residents' desired temperature set point, the current deviation from that set point, and their preference setting for relative comfort and savings into an amount it is willing to bid for the next 5 minutes of electricity. The HEM takes this price, along with the amount of electricity needed to run the HVAC unit, and assembles all bids in the home (in this case there is only

one, representing the HVAC ePCT) and communicates the bid information via a cellular connection to the dispatch system located in the operations center.

The dispatch system assembles the bids from all households on the feeder along with the market price for supplying electricity as determined by the RTP_{da} tariff and based on the LMP for electricity in the feeder's service area. The dispatch system clears the market of supply and demand bids where the two curves intersect, creating a cleared price (as shown in Figure 1.1). The cleared price is broadcast to all homes' HEMs and sent to the service provider's operations system for billing. The billing system exchanges information with the advanced metering infrastructure smart meter at the home to obtain the energy used during the 5-minute interval so the bill can be calculated. The HEM communicates the results of the auction to the ePCT, which sends the appropriate operating signal to HVAC unit. A consumer display is built into the ePCT; it displays the estimated billing price for energy so the consumer can participate with other energy saving actions, should they be monitoring the system.

This transactive-control approach results in very simple message exchange. In general, the approach is sensitive to data-exchange privacy concerns because the transacting parties only need to share what they are willing to pay for a quantity of electricity. What is returned to all participants on the feeder is the market cleared price. For experimental purposes, additional information is collected to understand the performance of the RTP_{da} system. For example, the observed temperature in the home is recorded, as is the deviation of the temperature from the desired set point. In addition, the configuration of the ePCT is monitored, including the residents' preference for savings or comfort and any system overrides, so that consumer behavior can be studied.

1.2.2.1 Thermostat Agent

The smart thermostat agent is configured by the consumer to address their preference for comfort versus economy. For each daily period of operation (for example, "Home," "Away," or "Night"), the homeowner specifies their desired temperature ($T_{desired}$), and influences their minimum and maximum temperatures (T_{min} , T_{max}), through a five-level setting for their preference for more comfort (tighter temperature control) or more savings (more flexible temperature control), as represented by the slope (k) in Figure 1.5. To simplify the discussion, only cooling mode is described below.

The thermostat agent's price-responsive controller is programmed to account for two market phenomena: price trends and price variability. In the case of price trends, the agent needs to determine whether a price is expensive or inexpensive. What may seem like a high price today may seem like a low price tomorrow, and vice versa. We see this in the fluctuation of the price of gasoline, where today's price may seem low compared with the price paid several months ago. In the case of price variability, we look at the volatility of short-term changes in price. Although the average price over a period may be relatively constant, the variability of the actual price above and below the average can change.

The volatility (standard deviation divided by mean) of wholesale and retail prices varies over time. Because the price-responsive controllers are designed to attenuate their response in the presence of more volatile prices, the determination of volatility is essential to the operation of the overall RTP_{da} system. In the case of this demonstration, the time window for the calculation of price volatility is the most recent 24 hours. The effect of this implementation is to attenuate the responses of the thermostat agents during the 24 hours that follow a period of significantly increased price volatility. The longer the duration of increased volatility, or the greater the volatility, the more the thermostat agents' responses

are attenuated. For this reason it is typical to see diminished response to LMP fluctuations during the 24 hours that follow a feeder constraint event.

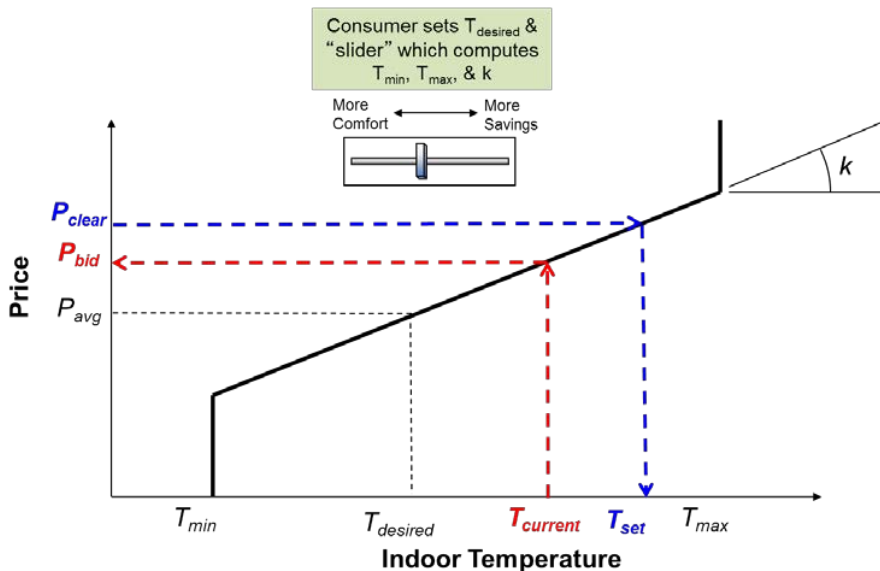


Figure 1.5. HVAC Thermostat Agent Price-Response Curve in Cooling Mode¹

Bids are submitted every 5 minutes up until 60 seconds before the market is cleared. The bid price P_{bid} in the figure above is computed by each thermostat agent as follows:

$$P_{bid} = P_{avg} + \frac{(T_{current} - T_{desired}) \times k \times P_{dev}}{T_{max} - T_{min}} \quad (1.1)$$

- where
- P_{avg} = the average price over the last 24 hours
 - P_{dev} = the standard deviation of the price over the last 24 hours
 - $T_{current}$ = the current indoor air temperature
 - $T_{desired}$ = the desired indoor air temperature
 - k = the responsiveness desired by the consumer
 - T_{max} = the maximum temperature limit
 - T_{min} = the minimum temperature limit.

P_{bid} and q_{bid} are sent by the HEM to the market system, where they are assembled with the other bids and the market is cleared. The cleared price (P_{clear}) is then published to all the RTP_{da} HEMs on the feeder, which pass it on to the thermostat agents where the price-response curve is used to define the temperature set point for the next 5 minutes of operation (T_{set} , see Figure 1.5). In the cooling mode case in Figure 1.5, the fact that $P_{clear} > P_{bid}$ results in T_{set} being set higher than $T_{current}$ and less than T_{max} so the HVAC unit will not run. A higher comfort setting would result in higher prices bid as the indoor temperature deviates from $T_{desired}$.

¹ Hammerstrom, D. J., et al, "Pacific Northwest GridWise® Testbed Demonstration Projects, Part I. Olympic Peninsula Project," Pacific Northwest National Laboratory, PNNL-17167, October 2007.

In cooling mode, if the current temperature is above the maximum temperature ($T_{current} > T_{max}$), then a bid at the price cap with zero quantity is submitted (that is, the consumer is fully unsatisfied). If the current temperature is below the minimum temperature ($T_{current} < T_{min}$) then a bid of zero price and zero quantity is submitted as a programming convention to represent that the consumer is fully satisfied.

The bid quantity is provided by the RTP_{da} equipment installer based on the estimated nominal power demand of the heating/air-conditioning unit. The bid state is determined by the operating mode of the heating/air-conditioning unit—for example, “Off,” “Cool,” or “Heat.”

If a previously submitted bid is invalidated by a change in ePCT state (for example, “Off” to “Cool”), or if there was a disruption of service, then a new bid is computed and submitted to replace the previous bid. All bids received are recorded in the system database, but only the last bid received is used to clear the market.

1.2.2.2 HVAC Operating States

To better understand the operating status of the HVAC equipment and its interplay with the market bidding system, the following states are considered in the summer cooling scenario of the analysis. A diagram of the HVAC states and their possible transitions over time is depicted in Figure 1.6. The flag, “Included in Market,” indicates that the HEM successfully communicated with the RTP_{da} dispatch system so that its bid can be included in the next auction.

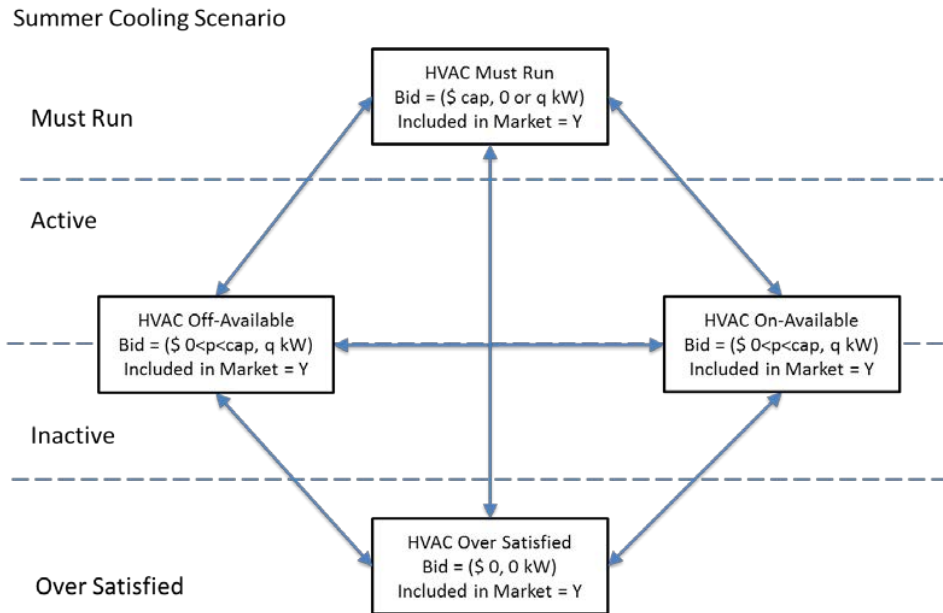


Figure 1.6. HVAC State Diagram

- **Must Run:** This state is reached in two situations. First, if the household temperature and comfort settings in the ePCT result in a bid at the highest price allowed in the market, P_{cap} , then the unit will automatically clear the market and will be expected to be in the “On” state during the next 5-minute

period. Second, in the case where $T_{current} > T_{max}$ (that is, the household temperature is over the maximum temperature set point), then the thermostat agent is programmed to bid price = \$0 and quantity = q_{bids} , and it is expected to be in the “On” state no matter what the cleared market price. This distinction is made so that the HVAC unit is counted as unresponsive load. This convention allows the dispatch system to more easily recognize it as unresponsive.

- **Over-Satisfied:** If $T_{current} < T_{min}$ (that is, the household temperature is below the minimum temperature set point), then the HVAC unit is in the Over-Satisfied state and will bid price = \$0 and quantity = 0.
- **Active:** Represents the state where the HVAC bid was cleared (p_{bid} higher than P_{clear}) to run in the market period. The HVAC unit can either be Off and available to remain Off or turn On, or On and available to remain On or turn Off.
- **Inactive:** Represents the state where the HVAC bid was not cleared (p_{bid} lower than P_{clear}) to run in the market period. As with the Active state, the HVAC unit can either be On or Off and available to switch states.

In moving from one auction to the next, it is possible that an HVAC unit may stay in the same state or move to any other state. As the internal temperature is increasing in conditions of steady market supply price, one would expect an HVAC unit to move from Inactive to Active, and possibly to Must Run, if it could not keep up with the temperature increases. However, under volatile market conditions and congestion events, state changes could be more dramatic.

Considering the entire RTP_{da} household load under control (RTP_{da} Load), a more detailed market clearing illustration is presented in Figure 1.7 to reflect the different states of the HVAC units in a

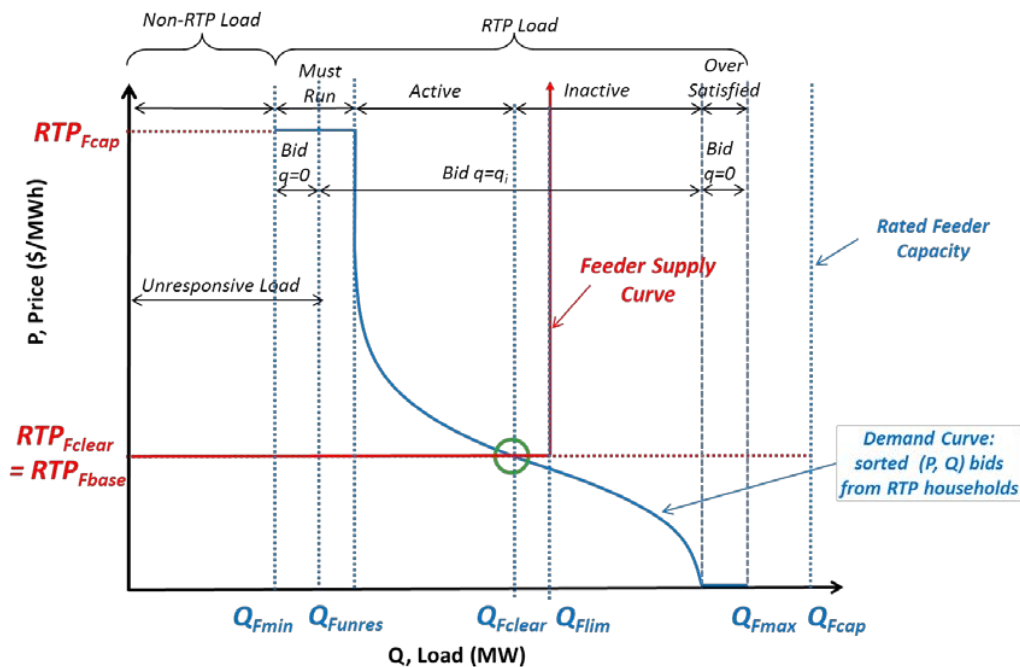


Figure 1.7. RTP_{da} Load Bidding Classifications – Non-Congested Case

particular 5-minute auction. The HVAC units to the left in the figure are in the Must Run state, followed by the Active units, then the Inactive units, and lastly the Over-Satisfied units. The remaining load on the feeder is referred to as Non-RTP_{da} Load. This is slightly different from the definition of the Unresponsive Load, which also includes the Must Run devices that submit a zero bid. The subscript F in the figure refers to feeder-based variables, with new variable $Q_{F\text{unres}}$ being the quantity of unresponsive load on the feeder, $Q_{F\text{lim}}$ being the congestion limit placed on the feeder, and $Q_{F\text{cap}}$ being the rated capacity of the feeder.

1.3 RTP_{da} Experiment Setup

To run the RTP_{da} demonstration, households were recruited to participate under the RTP_{da} tariff and they were outfitted with the ePCTs and HEMs. The RTP_{da} dispatch system was commissioned and communication was enabled between the various components of the system. An operations experiment plan was developed for testing the RTP_{da} system and performing congestion experiments.

1.3.1 RTP_{da} Households

The RTP_{da} households were selected from a pool that already had smart meters installed. These meters provided data to the meter data management (MDM) system and were also read by the HEMs, which returned metered data with their market bids, the status of the ePCT, and the indoor temperature. Based on consumer recruitment into the RTP_{da} program, changes that occurred with the households, and the eventual decommissioning, the number of participants grew over the spring and summer of 2013 and diminished in the fall months as their equipment was removed. The household equipment was configured at the time of installation, and the consumer was trained on how to enter their desired thermostat settings and change them to reflect their preferences over time. Any changes were recorded and sent back to the RTP_{da} dispatch system from the HEM.

The RTP_{da} dispatch system and the HEMs were designed to handle problems with communications. For example, default values were used for the PJM LMP price if there were delays in getting that from PJM. If a HEM's bid came in too late for the 5-minute market auction, then it did not participate in that auction, but it could participate in the next auction in which a successful bid was submitted and received. To properly analyze the behavior of the system, missing or bad data need to be detected and removed. An understanding of the default or backup settings is needed, as their appearance in the data collection can become regular, potentially skewing analysis results and observations.

The RTP_{da} system operated from December 2011 through the fall of 2013, but a sufficient population of households for conducting the experiments was not installed and operational until June, 2013. As most of the HVAC resources only operated in cooling mode, there was little heating HVAC market interaction after the beginning of October. For this reason, we limit the bulk of RTP_{da} analysis to the period from 1 June 2013 through 30 September 2013.

1.3.2 Operations Experiments and Data Collection

To identify and quantify various value streams, and to fully characterize the behavior of RTP_{da} resources, various operating scenarios were designed for the congestion experiments. The operating scenarios involved changing feeder congestion limits for varying durations to engage the RTP_{da} resources.

The RTP_{da} experiments were conducted to test the response of RTP_{da} resources based on parameters such as time of day (peak/off-peak), day of week, and weather conditions (temperature, wind, etc.). Operating scenarios were also designed to test the response of RTP_{da} resources during the critical peak pricing (CPP) events called by AEP Ohio. Finally, fatigue experiments were designed to test the extent to which the RTP_{da} households continued responding to high clearing prices, by letting the indoor temperature rise, before manually overriding the thermostat settings.

Feeder Limit Setting for RTP_{da} Congestion Experiments

First, the process of inducing feeder congestion to conduct an RTP_{da} experiment will be described. Figure 1.8 presents a conceptual view of how congestion limits were set to engage RTP_{da} resources during experiments. The dispatch system allows the operator to enter a percentage ($C_{\%}$) of the feeder's rated capacity (Q_{FCap}) to define the feeder congestion limit (Q_{Flim}). The initial plan was to conduct the congestion experiments by setting the feeder congestion limit in a manner that would engage 10–25% (α) of the total RTP_{da} responsive load on the feeder, using the following formula:

$$C_{\%} = Q_{Flim} / Q_{FCap} \times 100\% \quad (1.2)$$

$$C_{\%} = (Q_{Ftotal} - \alpha Q_{res}) / Q_{FCap} \times 100\% \quad (1.3)$$

where

- $\alpha < 1$ = portion of Q_{res} to engage
- Q_{Flim} = feeder congestion limit
- Q_{FCap} = feeder rated capacity
- Q_{Ftotal} = total feeder load
- Q_{res} = responsive feeder load
- $C_{\%}$ = percent of the feeder rated capacity.

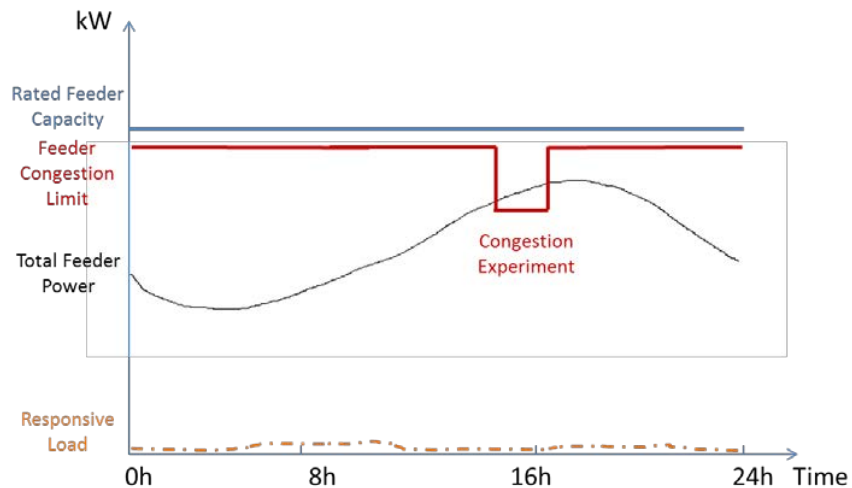


Figure 1.8. Engaging Responsive Load on a Feeder by Varying the Congestion Limit

However, the responsive loads were low compared to the total feeder load levels to the extent that the normal unresponsive load variations were greater than the total responsive load; thus, the reduction of the feeder capacity limit as a percentage of the responsive load did not always lead to congestion on the feeder. To be sure that the RTP_{da} resources would be engaged, the feeder congestion limit (Q_{Flim}) in the congestion experiments was set at 10% below the total (responsive plus unresponsive) prevailing feeder load, instead of the total responsive load. As an example of setting the feeder congestion limit, consider a total load level of 3 MW on a 10 MW feeder with only 100 kW of total responsive load. To impose congestion during an experiment, the feeder limit would be set at 10% below 3 MW, i.e., 2.7 MW (Q_{Flim}) or at 27% (C_0) of the rated feeder capacity of 10 MW (Q_{FCap}).

Period of Study

The initial two-week period in the beginning of June was deemed a practice period. Congestion experiments were scheduled during this period on a limited basis to help shed light on the systemic behavior of RTP_{da} resources under different operating conditions. The information gathered during this period was instructive in setting up more extensive experiments later.

Practice Period

RTP_{da} resources were initially engaged for 60 minutes by setting the feeder capacity limit at 10% below the prevailing feeder load. If the RTP_{da} resources were not exhausted during the test period, the length of time to impose congestion was increased by 30 minutes during the experiment, while keeping the same congestion limit. Congestion experiments during the practice period were conducted under constant supervision of staff members at both PNNL and AEP Ohio.

Normal Operation

After the initial practice period, congestion experiments were scheduled daily during the last two weeks of June. The experiments were initially conducted under constant supervision of PNNL and AEP Ohio staff members. However, the experiments were later scheduled to run without constant supervision, once it was determined that market conditions were not being violated and that the RTP_{da} resources were not being exhausted during the course of the experiment. Table 1.1 and Table 1.2 present a breakdown of congestion experiments scheduled over different hours of a day, as well as weekend versus weekday experiments. As can be seen in Table 1.1 and Table 1.2, respectively, majority of the congestion experiments were conducted during peak periods on weekdays. The feeder capacity limits were set at 10% below the prevailing feeder load at the start of the experiment to ensure that the RTP_{da} resources were engaged.

Table 1.1. Breakdown of Congestion Experiments by Hour of Day

5:00–10:00	10	10.42%
10:00–14:00	25	26.04%
14:00–22:00	61	63.54%
Total	96	100.00%

Table 1.2. Breakdown of Congestion Experiments by Day of Week

Weekend	25	26.04%
Weekday	71	73.96%
Total	96	100.00%

Table 1.3 presents the breakdown of congestion experiments based on the experiment durations. As mentioned earlier, 4-hour and 6-hour experiments were conducted to test consumer fatigue, as measured by the number of manual adjustments to thermostat controls.

Table 1.3. Breakdown of Congestion Experiments by Experiment Duration

2 Hours	70	72.94%
4 Hours	25	26.04%
6 Hours	1	1.04%
Total	96	100.00%

SMART Shift Plus Events and Feeder Constraints

To study the response of RTP_{da} resources during SMART Shift PlusSM events called by AEP Ohio, experiments were scheduled to coincide with and span the duration of the SMART Shift Plus events. SMART Shift Plus events were typically called for 4 hours; these also served as consumer fatigue tests. Table 1.4 below shows the experiments scheduled on the SMART Shift Plus event days, when congestion experiments were scheduled to coincide with the SMART Shift Plus events.

Table 1.4. Congestion Experiments Scheduled during SMART Shift Plus Events

SMART Shift Plus Day	SMART Shift Plus Date	Start Time (Eastern)	Duration (Hours)
Tue	7/16/2013	13:00	4
Wed	7/17/2013	15:00	4
Thu	7/18/2013	15:00	4
Thu	8/22/2013	15:00	4
Tue	8/27/2013	14:00	4
Thu	8/29/2013	14:00	4
Fri	8/30/2013	15:00	4
Tue	9/10/2013	15:00	4
Wed	9/11/2013	15:00	4

1.4 Control Groups

A number of control households were selected that were expected to have characteristics similar to the RTP_{da} households, but that remained under the standard residential tariff. Changes in behavior of the RTP_{da} group can be estimated by comparing RTP_{da} results against those of the control group. A pool of thousands of households who did not participate in the customer-oriented projects was established from which control group households could be chosen. From this pool, PNNL developed a control group of 272 households for comparison in several of the analyses in this report. Note that this RTP_{da} control group is different from other control groups used in other parts of the gridSMART report.

This section describes the way in which the control group was selected from 2010 metered data and how the control group data from 2013 were corrected for use in comparisons with RTP_{da}2013 metered data. A set of definitions for the groups of households used for the analyses follows.

1. RTP13: This group represents the 192 households who were technology-enabled and participated in the RTP_{da} market some or all the time in 2013. Often their energy use in an interval such as 5 minutes will also be referred to as RTP13.
2. RTP10: This is a group of 272 households who were recruited in 2013 as potential RTP_{da} participants and were in the RTP_{da} system database. The 15-minute energy use data for 2010 was obtained for these households. This group includes the 192 RTP13 households that participated in the RTP_{da} market during the demonstration period; however, the selection was done prior to the analysis of how many RTP_{da} households actually participated in the market.
3. Ctrl10: From the pool of households who did not participate in the gridSMART program, a set of 272 households were identified as close to RTP10 in their 15-minute energy use profiles. These are referred to as Ctrl10.
4. Ctrl13: The energy use by the same set of households as Ctrl10 in 2013 is referred to as Ctrl13.
5. RTPnr10: The average energy used by a household in Ctrl10 was then adjusted to improve the comparison with the RTP_{da} households in 2010 (RTP10). This adjusted control group is referred to as RTPnr10 (“nr” meaning non-responsive).
6. RTPnr13: The average energy used by a household in Ctrl13 was then adjusted to improve the comparison with the RTP_{da} households in 2013 (RTP13). This adjusted control group is referred to as RTPnr13.

1.4.1 Control Group Member Selection Process

The following describes how the control group was initially selected to create a set similar to RTP_{da} households, but not in the program. This involved acquiring data for candidate households to be in the control group, processing the data, (including handling bad or missing values in the acquired data), and employing data filtering mechanisms to help match load shapes to select control group members from the candidates that could represent non-responsive RTP_{da} households.

Data Acquisition: The 2010 15-minute MDM data for approximately 11,800 homes were used to identify the control group. The analysis interval was from June 1, 2010 through September 30, 2010.

Bad and Missing Values: 15-minute values that exceeded 40 kWh (an unusually high and suspect value) were treated as bad data and removed by setting the large value to zero so that they would be handled as missing data during subsequent processing. Missing values in the household meter data were replaced using a zero-order hold before any selection filter was applied. Note that the missing values were reset to zero after the filter (see below) was applied to avoid affecting the match with an RTP_{da} household itself.

Filtering: Load data collected at sub-hourly intervals can exhibit large fluctuations in the average energy (that is, power) measurement due to the cycling behavior of large loads. The quantity of interest is the duty cycle, but this quantity cannot be directly observed from interval energy data. However, for time intervals longer than the cycling time of the loads the average load, P_{avg} , is related to the duty cycle, D , as

$$D = \frac{P_{average}}{P_{on}} \quad (1.4)$$

where P_{on} is power measured when the equipment is On.

This property is used to estimate the total load at various time intervals by filtering the load data using a sliding-window filter based on the $1/p$ -state binomial probability distribution function (PDF). The binomial PDF is defined as

$$\text{Prob}\{t|n, p\} = \binom{n}{t} p^t (1-p)^{(n-t)} \quad (1.5)$$

where $p = 2$ and describes the probability that the true state (On or Off) at the time $t = n/2$ is described by the observed state at the time t . The choice of the window size n was based on the load cycling time relative to the sampling time Δt_{sample} ; for example,

$$n = \frac{\Delta t_{on} + \Delta t_{off}}{\Delta t_{sample}} \quad (1.6)$$

Note that the filtered data has zero lag (it is shifted back by a half window). In addition, the last sample is held for an additional half window to provide a smooth end to the filtered data. The result of applying such a filter with window size of 8 15-minute periods is shown in Figure 1.9.

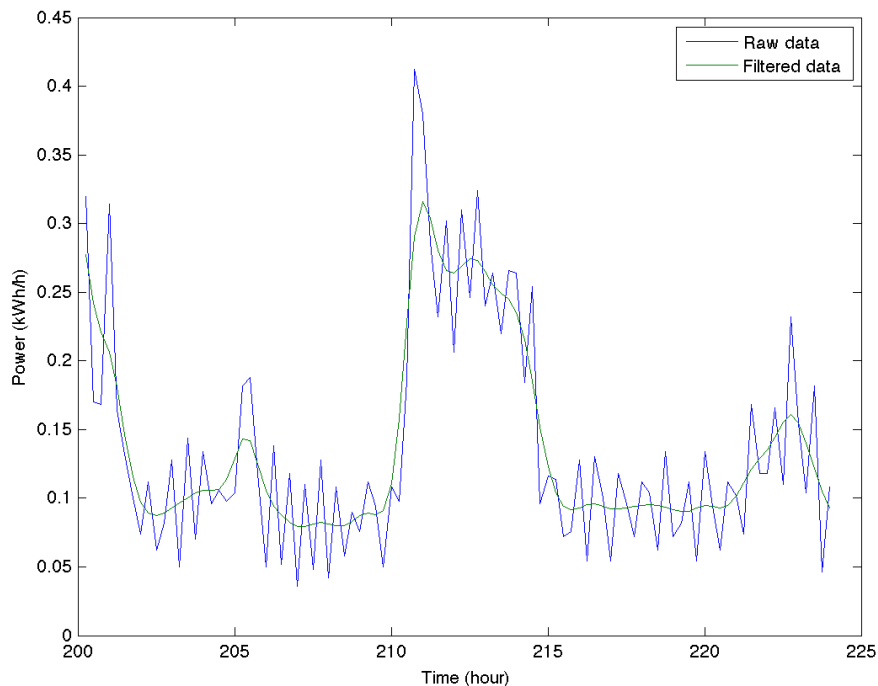


Figure 1.9. Raw and Filtered 15-Minute Electric Meter Data with a 2-Hour Binomial Window Size

Load Shape Matching: The simplest method for load shape matching is based on minimizing the total mean-squared error (MSE) between candidate load shapes

$$MSE = \sum_{t=1}^N (x_t^+ - y_t^+)^2 \quad (1.7)$$

where N is the number of samples in the time series, and x^+ and y^+ are the non-zero values from the load shape time-series vectors. An example of a match is shown in Figure 1.10. The corresponding figures, known as heat maps because they show the high (hot) and low (cold) areas, are shown in Figure 1.11. Each RTP_{da} home was assigned a single control home. However, some control home choices were matched to more than one RTP_{da} home. In such cases, the next-best match that was not already selected for the control group was chosen.

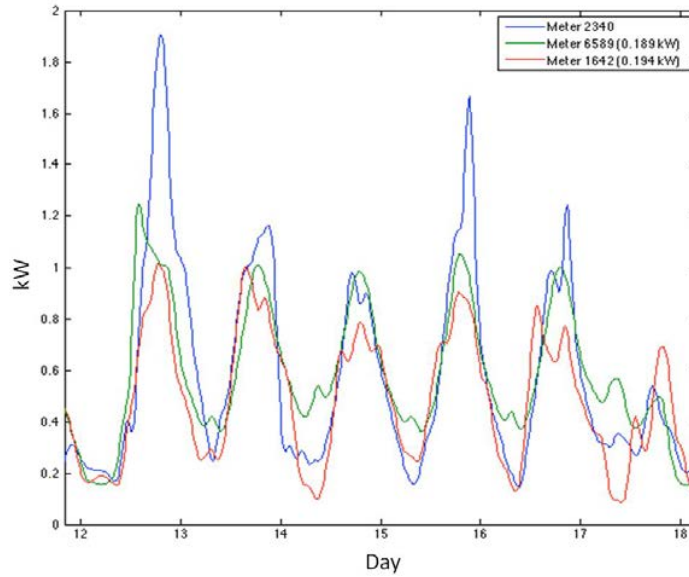


Figure 1.10. Illustration of Match of Reference Load (blue) to Best Fit (green) and Second-Best Fit (red)

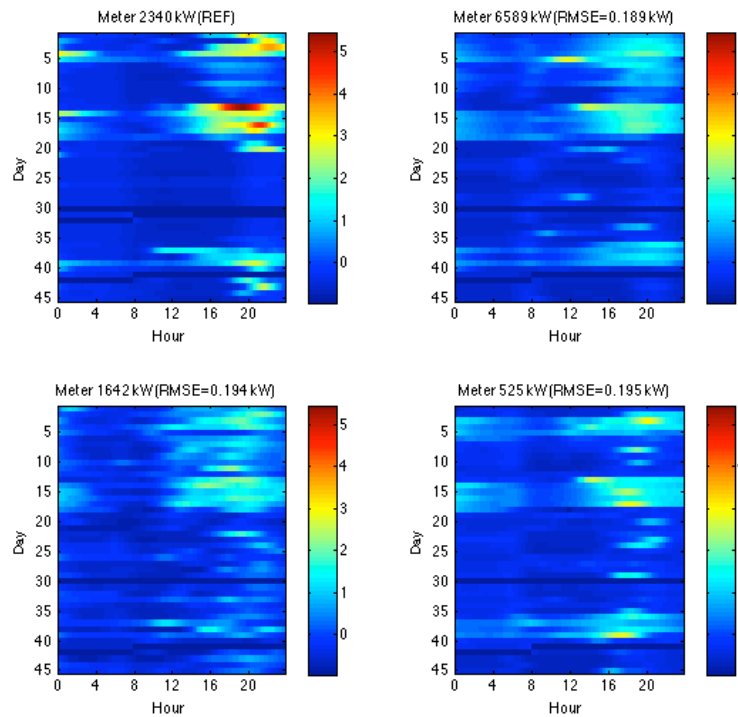


Figure 1.11. Load Shape Maps for Reference (upper left), Best Match (upper right), Second-Best Match (lower left), and Third-Best Match (lower right)

1.4.2 Control Group Adjustment for RTP_{da} Group Comparison

Recall that the RTP_{da} load data from the 2010 data are referred to as RTP10 and the RTP_{da} data measured during the course of the demonstration period in 2013 are referred to as RTP13. Similarly, the control group data for 2010 and 2013 are referred to as Ctrl10 and Ctrl13, respectively. If Ctrl13 accurately represents the behavior of RTP13 had they not been price responsive, then it is a simple matter to subtract the interval data for the average of the two groups to determine price response. Despite the optimal search for a best fit of Ctrl10 with RTP10, there were substantial differences. A typical 7-day profile of energy use by the two groups in 2010 is shown in Figure 1.12. The variations, especially of peak loads, are of concern. While the selection process emphasized load shape matching, it did not match peak energy use. An adjustment was made to make Ctrl10 closer to RTP10. The correction procedure is explained below, and the resulting group is RTP_{nr}10.

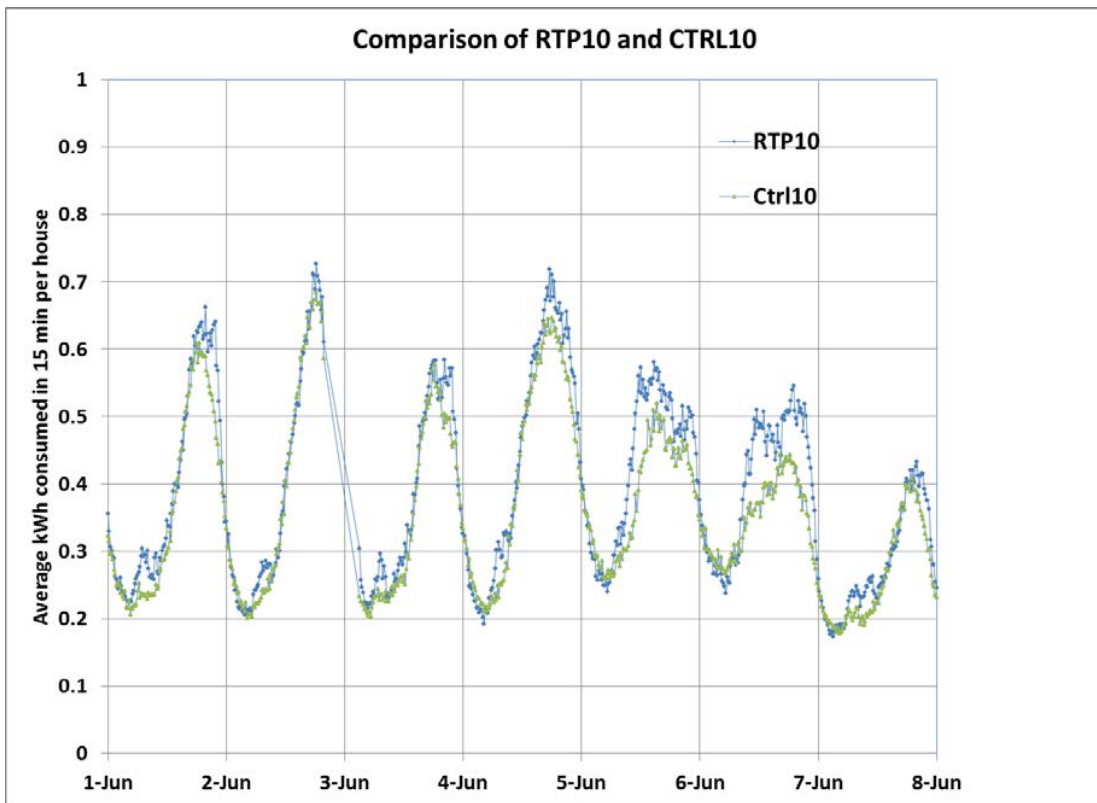


Figure 1.12. Comparison of RTP10 and Ctrl10 Profiles for a Typical 7-Day Period

Consider a relationship between RTP10(*t*) at time *t* and Ctrl10(*t*) of the form

$$RTP10(t) \sim f(Ctrl10(t), Time\ of\ day) \tag{1.8}$$

As RTP10 and Ctrl10 are experiencing the same outdoor temperature, the time of day (actual date is not relevant) turned out to be a good proxy for many of the un-modeled variables, including outdoor temperature. Another approach is to consider the difference between RTP10 and Ctrl10 as a function of Ctrl10 and time-of-day. A Ctrl10 value of 0.6 at 3 pm on a day in July (this would happen on a relatively

cool July day) gets the same correction as a Ctrl10 value of 0.6 at 3 pm on a day in September (this would happen on a relatively warm September day). Thus, the Ctrl10 value and time-of-day act as proxies for temperature. So $RTP10 - Ctrl10 \sim f(Ctrl10, \text{time-of-day})$ is our non-parametric model. And $RTP10 \sim Ctrl10 + f(Ctrl10, \text{time-of-day})$ is just another $f(Ctrl10, \text{time-of-day})$. If the function f is parameterized in some fashion, the parameters can be estimated by a method such as the least-squares method. However, because the functional form as well as the parameters and their interpretation are not of much interest, a non-parametric method was used. The method of choice was LOcal regrESSion (LOESS).² This was implemented in MATLAB[®].

The time series

$$RTPnr10(t) = f(Ctrl10(t), \text{Time of day}) \tag{1.9}$$

is a significantly better approximation of RTP10 than Ctrl10. Weekdays and weekends were treated separately. The resulting fit for the same 7-day period as in Figure 1.12 is shown in Figure 1.13.

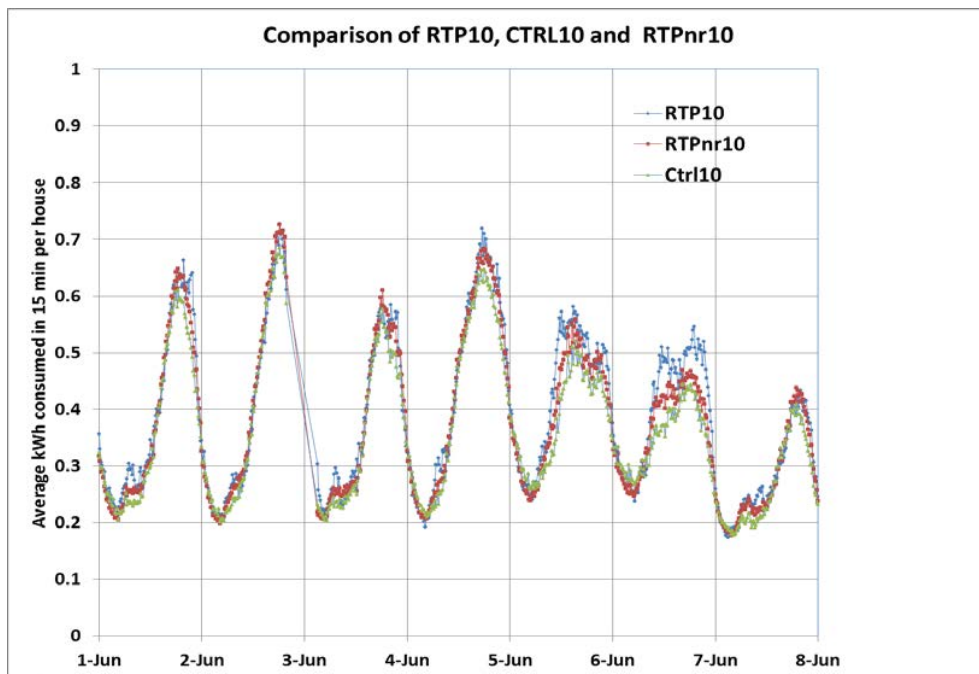


Figure 1.13. Comparison of RTP10, RTPnr10, and Ctrl10 Profiles for the Same 7-day Period as in Figure 1.12

The fit for the entire 122-day period is shown in Figure 1.14.

² <http://www.mathworks.com/products/datasheets/pdf/curve-fitting-toolbox.pdf>

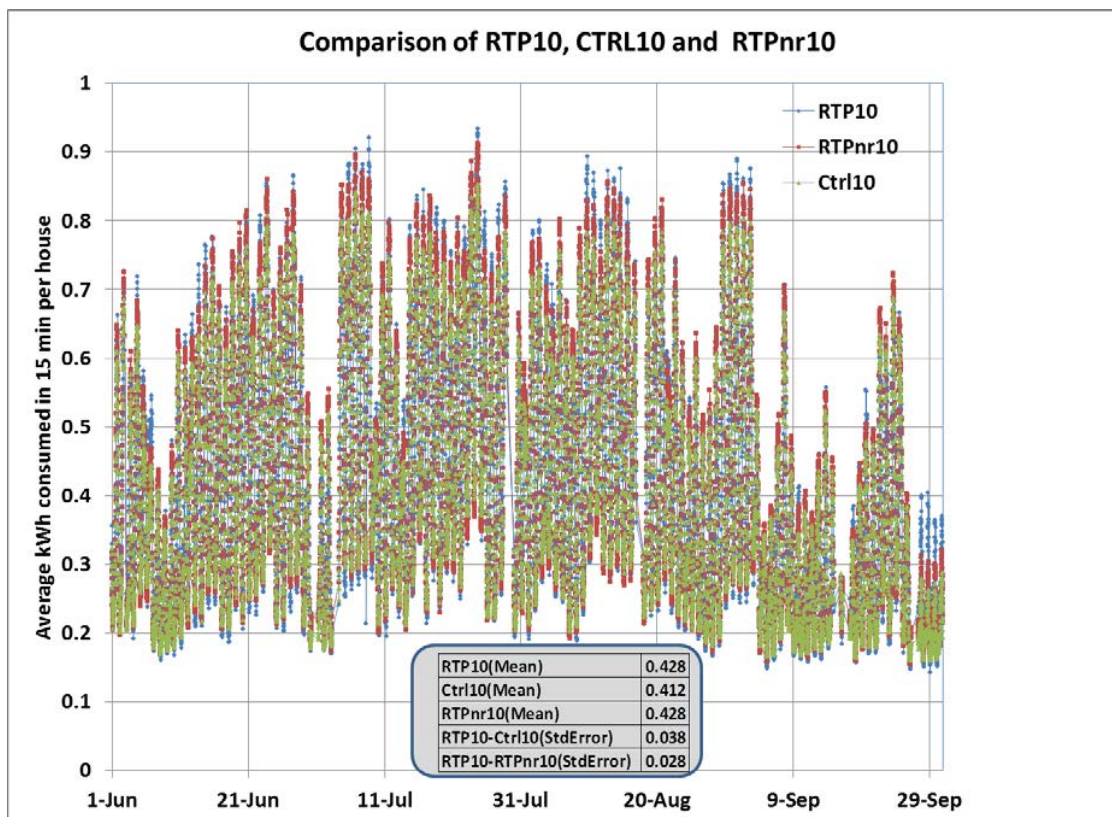


Figure 1.14. Comparison of RTP10, RTPnr10, and Ctrl10 Profiles for the Period June to September 2010

Although Figure 1.14 is crowded, one can discern that RTPnr10 is closer to RTP10 than Ctrl10 is. This is quantified by the comparison of means and standard errors in the inset in Figure 1.14. The performance of LOESS in matching peak loads can be assessed by comparing the top 5% of RTP10 loads with the coincident Ctrl10 and RTPnr loads. This is shown in Figure 1.15. It is clear that, for our purposes, RTPnr is a much more accurate representation of RTP_{da} than Ctrl.

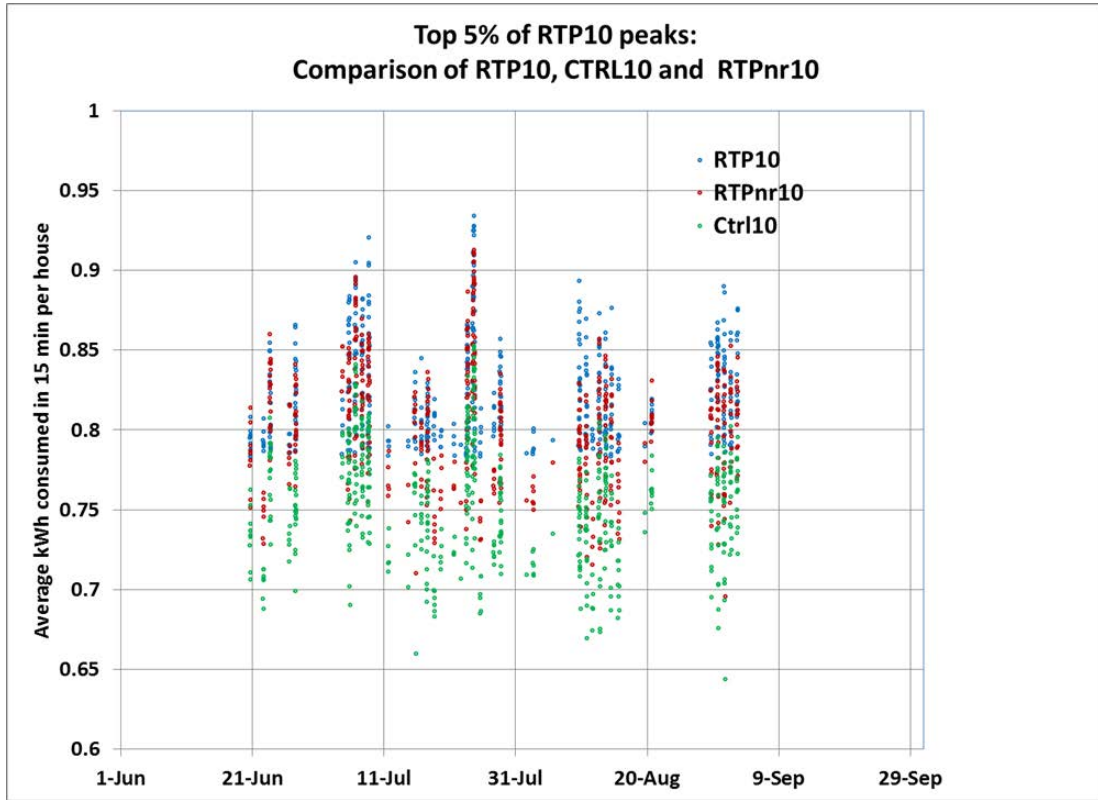


Figure 1.15. Comparison of the Top 5% of RTP10 Loads with the Coincident Ctrl10 and RTPnr Loads

We can now use the LOESS model to generate RTPnr13 from Ctrl13. From this point on, we will use RTPnr13 as the corrected control group with which RTP13 is to be compared. RTP13 is available in 5-minute intervals, whereas RTPnr13 (generated from 15-minute Ctrl13) is in 15-minute intervals. A linear interpolation method was used to generate 5-minute data from the 15-minute data. (This process is much cleaner than rolling up 5-minute RTP13 data into 15-minute data, for which missing data creates a number of special issues.)

Consistent handling of missing data is essential. Although Ctrl10 is an aggregate over a maximum of 272 households, there are many periods with fewer households. For obtaining statistically good aggregate data, only data to which >80% of the 272 contributed were retained. Similar processing was done for RTP10. The missing data time stamps for the two need not be the same. Only time stamps for which both RTP10 and Ctrl10 data are present are retained. Similar processing was done for RTP13 and RTPnr13.

1.5 Document Structure

This report supplements the RTP_{da} system analysis done by AEP Ohio in the main body of the gridSMART Project report. It covers three major areas:

- an analysis of the impacts of the RTP_{da} approach to engage end-use resources for system operations, including its application to address system capacity concerns, wholesale purchases, and spinning reserves,
- an analysis of impacts related to the consumer, including household bills, the consumers' interactions with the thermostats, and a comparison of the amount of energy bid into the market for running the HVAC units and the actual consumption of those units,
- and an analysis of the sensitivity of the of the RTP_{da} load to the fluctuating price of energy, including the observed response of the RTP_{da} resources to the congestion experiments.

2.0 System Impacts

The following sections describe the results of an analysis of impacts that affect system operations of the service provider. These include system- and feeder-capacity issues, wholesale power purchases, and the potential of applying RTP_{da} resources to spinning reserve markets.

2.1 Capacity

This analysis measures the reduction in capacity expansion requirements due to a price-induced shift in household peak load. The benefit of this analysis will be presented in terms of kW/household reduction in peak load.

Evaluating the capacity reduction is a complex problem that can be difficult to observe and characterize under real-world conditions, especially when the penetration level of RTP_{da} households is relatively low compared to other groups. A series of experiments were developed on the end-use resources to characterize their behavior and limitations. The results of these experiments were used to better calibrate the parameters of the simulation models. The simulation models were then used to quantify the potential for capacity reduction at various penetration levels.

2.1.1 Results of Analysis

The simulation models of the RTP_{da} system were evaluated on three peak days in July to determine the greatest sustainable capacity reduction that was achievable. On these days (July 16–18), the temperature was greater than 90° F on five successive days. The evaluation was performed by (1) lowering the capacity limit until the cleared price reached the price cap during peak system load hours and (2) lowering the capacity limit until the price cap was reached during the projected peak feeder hours. The simulations in (2) were also run over the four-month test period to verify that the capacity could be maintained at a lower level throughout the four-month period. The simulations were performed at 15%, 25%, 35%, and 50% RTP_{da} penetration levels. The models were “tuned” to be responsive only to peak conditions, and not wholesale price fluctuations; this is similar to a day following a high-price event, when the controllers are desensitized to small fluctuations in the wholesale price.

Figure 2.1 shows a representative simulation during a 3.5-hour peak system load event. Figure 2.2 shows a representative simulation on the same day, but focusing on feeder peak reduction. All measurements are 15-minute average demand and are translated into a kW/household basis. Notice that the feeder peak is near the end of the event, highlighting that system and feeder peak demands do not necessarily align; hence the need to look at the availability of the resource in different periods. In Figure 2.1, notice that after the event is triggered, the two lines approach each other after approximately 2.5 hours, indicating that the resource is no longer able to hold a load reduction and the households begin to become less responsive, while in Figure 2.2 the resource begins to reduce sooner (approximately 2 hours into the event). The time the reduction is called for this peak load event affects the overall availability of the resource.

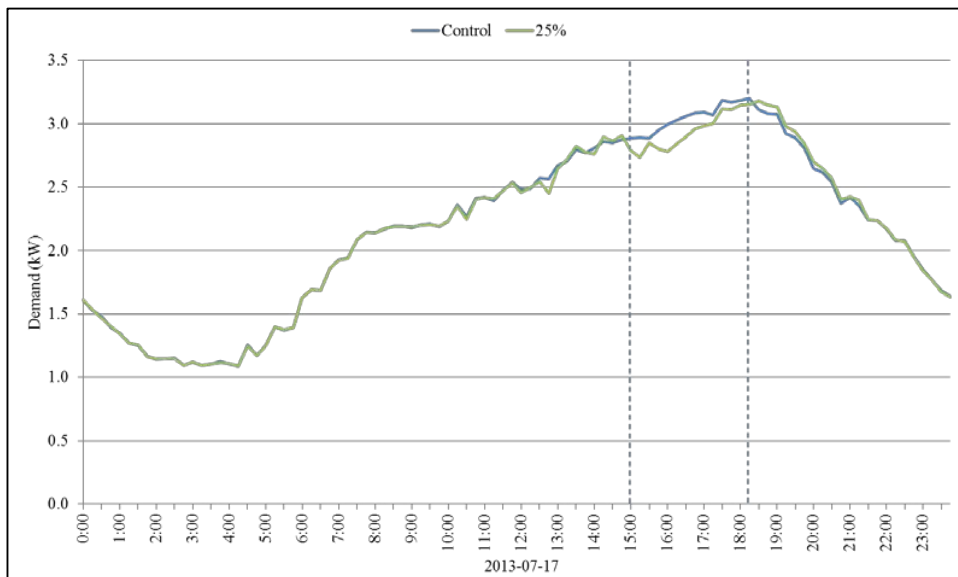


Figure 2.1. Time-Series Simulation during Peak System Load Event with 25% Penetration of RTP_{da} Households

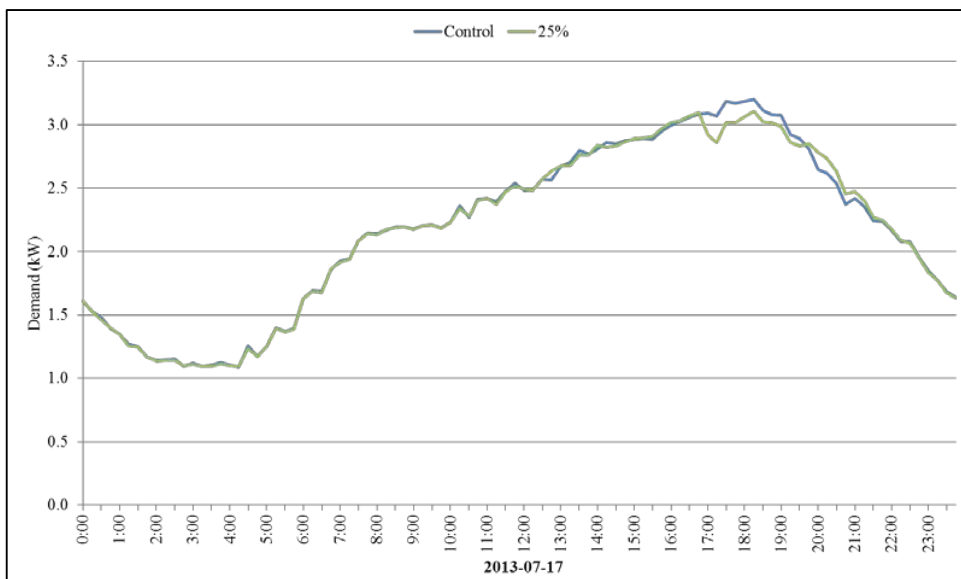


Figure 2.2. Time-Series Simulation of Feeder Peak Reduction with 25% Penetration of RTP_{da} Households

Figure 2.3 and Figure 2.4 show the peak demand reduction (i.e., the difference between the greatest demand before the capacity constraint was applied and the greatest demand after it was applied) as a function of RTP_{da} penetration levels for peak load events and feeder peak reduction, respectively. Additionally, a linear trend line has been added to the figures for clarification. Notice that the ability to reduce the peak during the feeder peak situation is much greater than during a peak system load event. This is for a number of reasons. The first is that the peak system load event lasted longer than the feeder

peak event, meaning the resources are spread out over a longer period. The second is that the availability of resources for reduction is lower in non-feeder peak periods. If the values are extrapolated to 100% penetration (or the average response of an RTP_{da} household), it is seen that the RTP_{da} households provide a 13% load reduction during a peak system load event and a 22% reduction during feeder peak events.

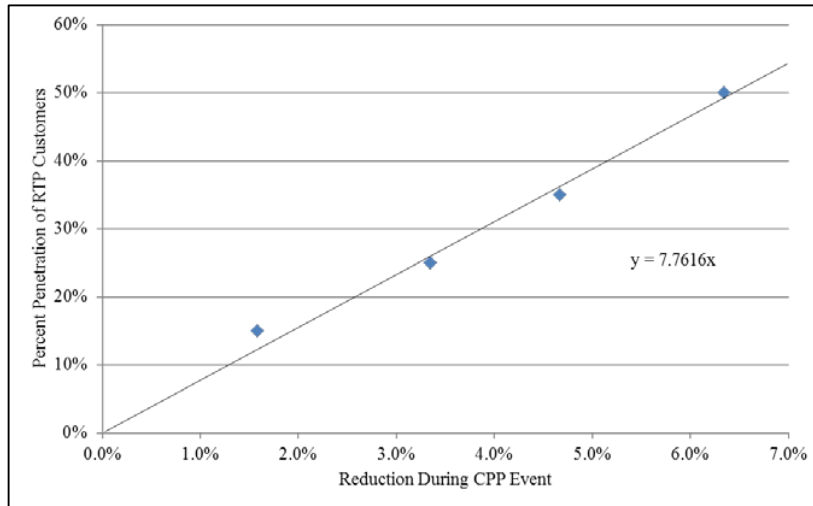


Figure 2.3. Comparison of Peak Reduction during a Peak System Load Event at Different RTP_{da} Penetration Levels

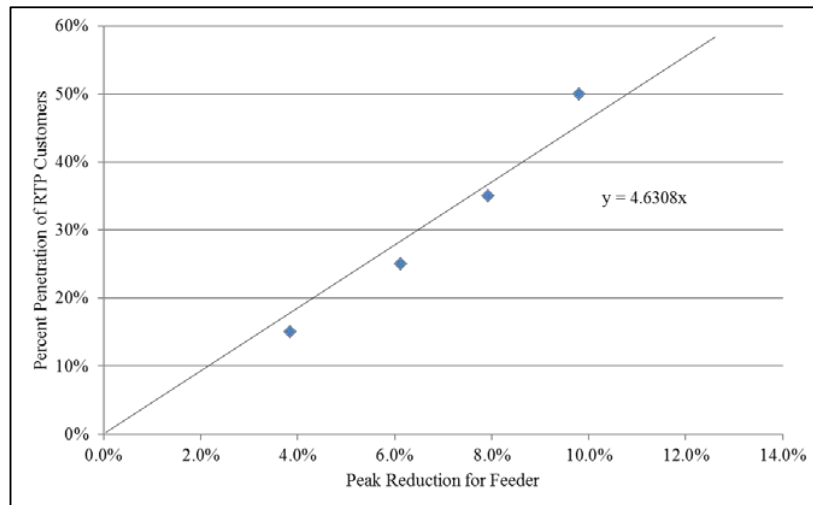


Figure 2.4. Comparison of Feeder Peak Reduction at Different RTP_{da} Penetration Levels

Note that these values represent a specific case for RTP_{da} household response, and in some ways, the “best case.” In all simulations, it was known ahead of time when system peak events would occur and for how long, and what the load would be during a peak system load event. In an actual system, this will not be well known and the determination of the capacity limit may overuse resources (leading to early decay of the response) or underuse resources (leaving unused capacity from this resource). Even in simulation, the reduction did not provide a perfectly flat load (see Figure 2.2), as the market lags

behind the changing load of the non-RTP_{da} households. Incorporation of short-term load prediction may improve this aspect of RTP_{da} system performance.

Additionally, the length of the time the resource is needed affects the amount of reduction available. For example, a 1-hour peak system load event is able to sustain deeper reductions than a 6-hour peak system load event. Figure 2.5 shows the reduction of demand as a function of the length of a peak system load event using the same simulation and day shown previously. This is shown with 100% penetration of RTP_{da} households. Notice that after 4 hours, the load has effectively returned to a new baseline state, with a minor reduction coming from the thermostat setback. Also, note the magnitude of the rebound after releasing the peak system load event. While significant rebounds occur in the peak periods, if the end of the event is timed correctly after the control peak, the rebound is relatively minor and much lower than during the peak period. The recovery period for all events is such that most devices do not return to normal operation until 22:00 hours, seven hours after the start of the event.

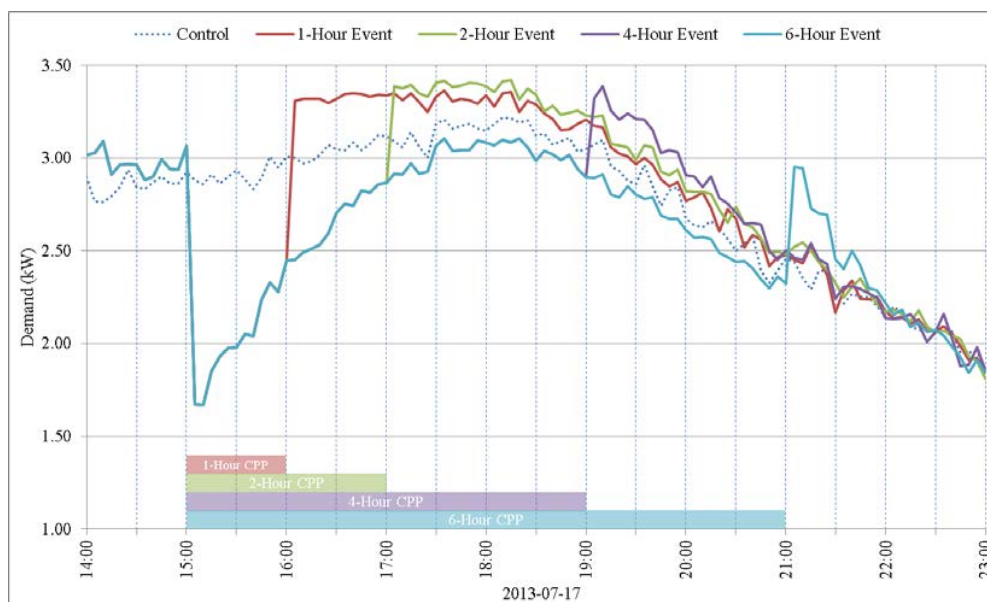


Figure 2.5. Comparison of Average Household Demand during a 1- to 6-Hour Peak System Load Event

2.2 Wholesale Purchases

Price-responsive loads alter their load shape in response to the retail energy prices. If the retail prices are determined in real time by wholesale market LMPs, then demand response to prices should result in decreased cost of wholesale energy purchases. The purpose of this analysis is to examine the impact on wholesale purchases using the data captured related to energy use by the HVAC systems in response to the market signal.

The approach is to compare the energy use in response to RTP_{da} every 5 minutes by the RTP_{da} households against the energy use by the control group. The difference is attributed to price response. Knowing the LMP, the difference in wholesale purchase costs can be calculated.

In this section, only the aggregate response by the participants is considered. That is, data from individual participants were aggregated. The way missing data were handled was considered in Section 1.4.2. The definitions of the household groups were listed in Section 1.4.

2.2.1 Response to Prices

It is instructive to examine RTP13 and RTPnr13 for typical periods. In addition, LMP data also were acquired. Figure 2.6 shows a comparison between RTP13 and RTPnr13 in the top panel and the difference between RTP13 and RTPnr13 and LMP in the bottom panel, which uses the same x-axis day intervals.

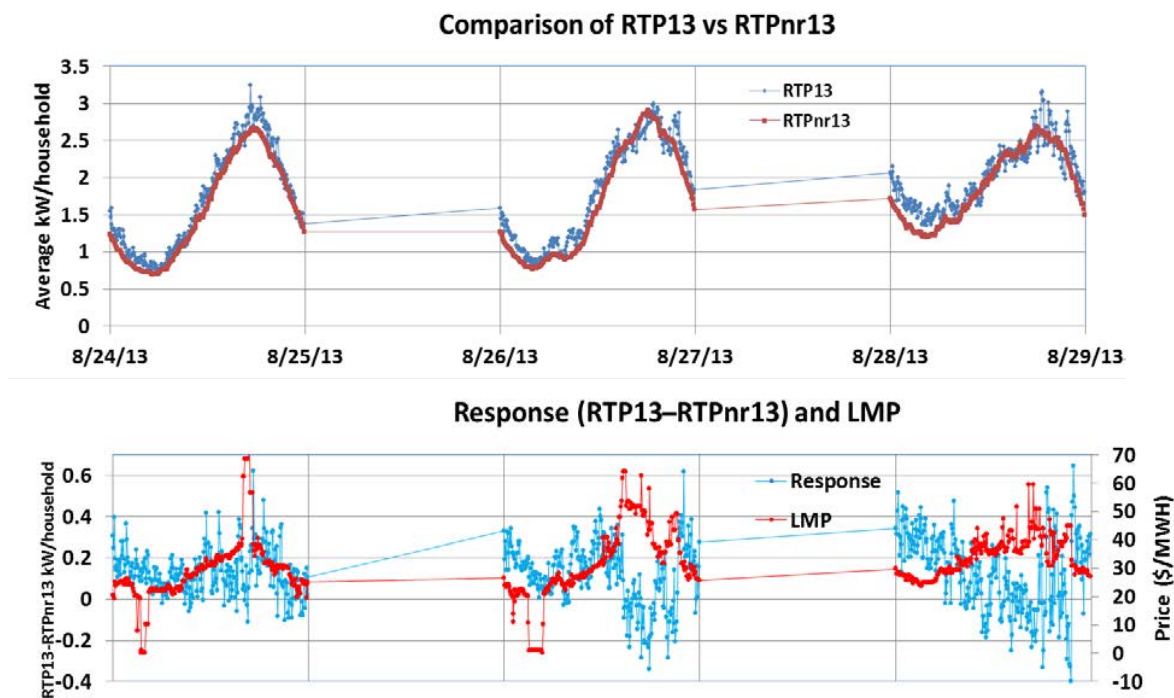


Figure 2.6. A Comparison between RTP13 and RTPnr13 (top), and between RTP13-RTPnr13 and LMP (bottom)

No data are plotted for August 25 and August 27. On those days, feeder congestion experiments were done, so on those days, the system is responding to real-time prices generated by simulated feeder congestion and not to wholesale LMP-generated prices. For this reason, feeder congestion experiment days were excluded from the wholesale purchase analysis. August 26 shows a very discernable load response to prices.

2.2.2 Totals for the 4-Month Period

The aggregation of RTP13 and RTPnr13 will now be examined to compare total loads with and without price response, and $\text{RTP13} \times \text{LMP}$ and $\text{RTPnr13} \times \text{LMP}$ will be examined to compare wholesale

purchase costs with and without price response. Out of the 122 days in June, July, August, and September, all days when congestion experiments were performed were excluded. Furthermore, only aggregate data that received contributions from >80% of the maximum number of contributors was included. This resulted in 50 days of usable data—31 weekdays and 19 weekend days. Not all 50 days had data for every one of the 288 5-minute periods. Because this affected both RTP13 and RTPnr13 similarly, this was not considered sufficient reason to exclude a day. Table 2.1 shows a summary for the 50 days.

Table 2.1. Summary of Energy and Wholesale Costs for July–September Before Adjustments

Energy			
RTP13 (kWh/day/house)	36.21		
RTPnr13 (kWh/day/house)	35.55		
RTP13 is	1.9%	higher	than RTPnr13
Wholesale cost			
RTP13 (\$/day/house)	\$1.432		
RTPnr13 (\$/day/house)	\$1.42		
RTP13 is	0.7%	higher	than RTPnr13

Feeder congestion days were excluded, but they affected the behavior of the HVAC units the following day. The high prices (~\$1000/MWH) experienced during the congestion period made the prices expected by HEMs high for 24 hours following the conclusion of the feeder congestion experiment. This resulted in the normal prices appearing low, and the HEMs responded by lowering the house temperatures. This can be seen in Figure 2.7, which shows that the daily average observed temperature for the non-congestion days was generally substantially lower than the desired set points. The moving average in the figure is computed over 5 points.

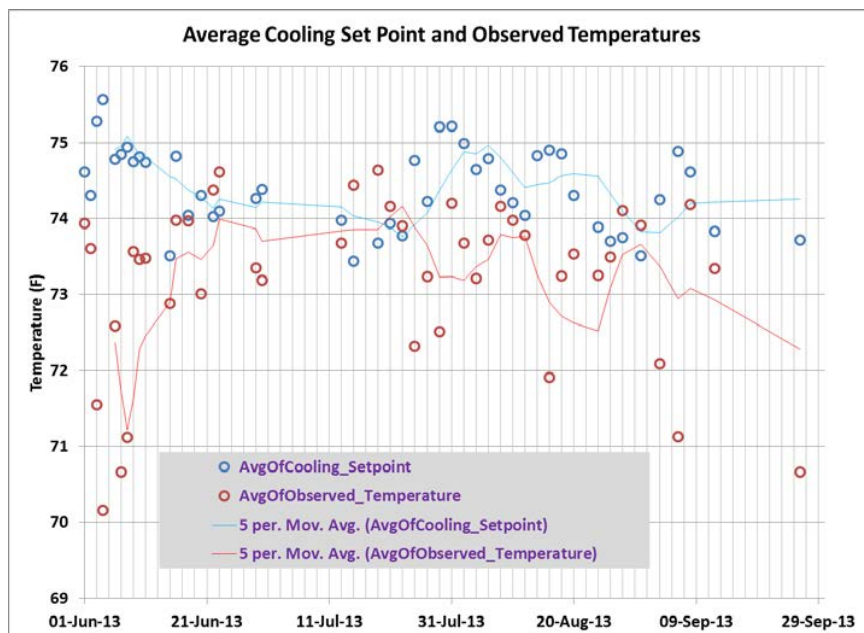


Figure 2.7. Daily Average Cooling Set Points and Observed Temperatures during Non-Congestion Days

The undesirable situation of temperatures below desired set points necessitated adjustments for the additional cooling energy use. This was done as follows. From a plot of daily average outside temperature obtained for the Columbus, Ohio, weather station, a regression of daily energy use versus daily average outside temperature was performed. Separate regressions were performed for weekdays and weekends. The results are shown in Figure 2.8 and Figure 2.9.

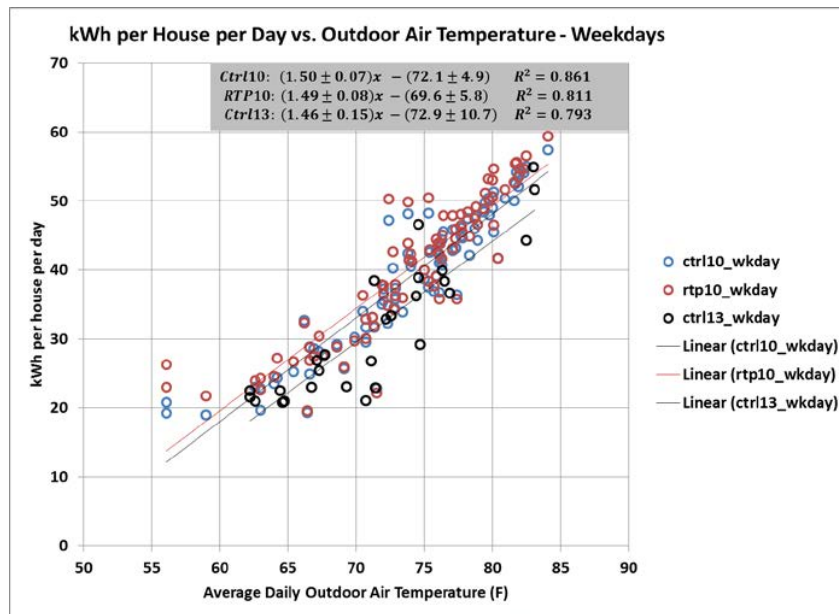


Figure 2.8. Plot of Daily Average Energy Use per House versus Average Outdoor Temperature for Weekdays

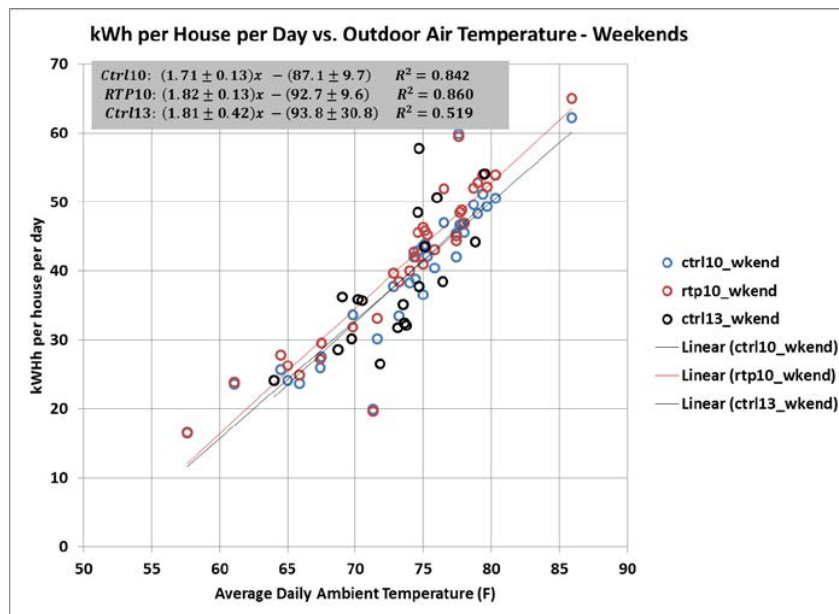


Figure 2.9. Plot of Daily Average Energy Use per House versus Average Outdoor Temperature for Weekend Days

From the above regressions, a value of 1.5 kWh/day/house/°F was derived for weekdays and 1.8 kWh/day/house/°F for weekend days. The behavior of Ctrl13 is statistically indistinguishable from that of Ctrl10. This means that on a weekday, if the average outdoor temperature increases by 1°F, the energy use for the day increases by 1.5 kWh/house. Similar considerations apply for the weekend days. Increasing the outside temperature by 1°F is, to a very good approximation for energy use, equivalent to decreasing the inside temperature by 1°F. If it is now assumed that, in the absence of feeder experiments, the average observed temperature would have been equal to the average desired temperature set point (rather than the observed temperature resulting from the RTP_{da}-driven set point), a compensation term for the daily energy use and the resulting impact to wholesale cost can be applied. The compensation term for the wholesale cost can be calculated as the average LMP for the day times the change in kWh per household for the day. The results of applying such compensation are shown in Table 2.2.

Table 2.2. Summary of Energy and Costs for July–September after Compensating for Congestion Experiments

After compensating for the impact of congestion experiments on non-congestion days		
Energy		
RTP13_Compensated (kWh/day/house)	33.66	
RTPnr13 (kWh/day/house)	35.55	
RTP13_Compensated is	5.3%	lower than RTPnr13
Wholesale cost		
RTP13_Compensated (\$/day/house)	\$1.351	
RTPnr13 (\$/day/house)	\$1.423	
RTP13_Compensated is	5.0%	lower than RTPnr13

The kWh usage is reduced by 5.3% and the wholesale costs by 5.0%. Comparing this table with Table 2.1, it can be seen that the effect of the temperature compensation on cost reduction was not commensurate with the effect of temperature compensation on kWh reduction. This is due to the fact that the compensation was effective largely during periods of low prices, as seen in Figure 2.10.

Some sources of error and their impacts follow. These include:

- There is a difference in the demographics of RTP_{da} households over the years 2010 to 2013, and similarly in the control group.
- The RTP10 group had 272 households, whereas RTP13 had 192 households. This is not necessarily a problem, but further review that the pool characteristics match would add confidence.
- The compensation method for the excessive cooling due to congestion experiments in the preceding day deserves further investigation.
- Good data representing only 50 days of operation survived the various filters.
- Even on these 50 days of good data, the number of houses contributing was variable.

No attempt was made to quantify the errors arising from these sources in this report; however, it remains a good topic for future investigation.

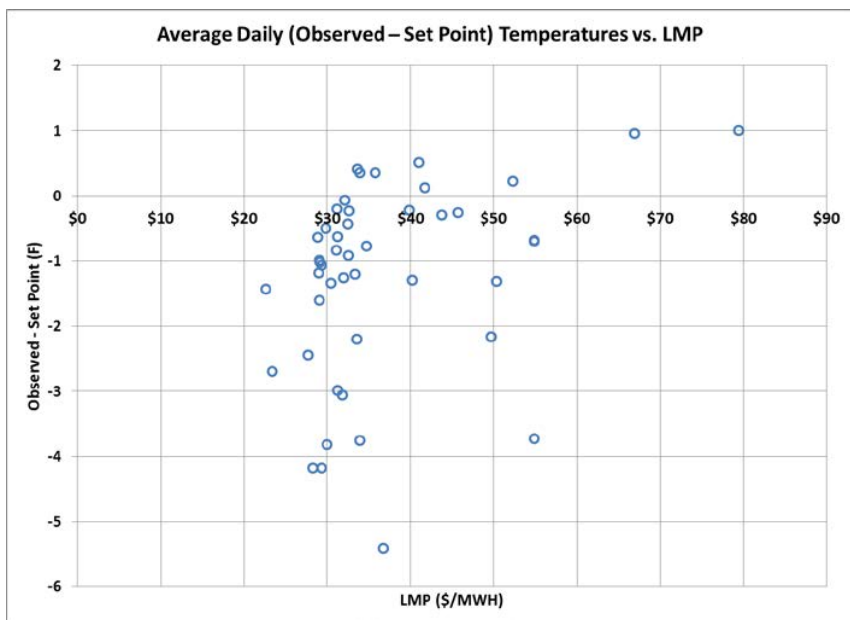


Figure 2.10. The Depression of Observed Temperature Below Set Point versus Average LMP for the Day

2.2.3 Simulated Results

The RTP_{da} household information was used to calibrate GridLAB-D¹ simulated models. These household models were used within GridLAB-D to represent 25% penetration of RTP_{da} households; 300 households were “experimental” while 900 were operated similarly in each simulation and did not respond to variations in price. The experimental households were modeled using three different scenarios:

1. Control – the households were simulated using the standard pricing tariff.
2. RTP_{da} – the households were simulated using the residential RTP_{da} service tariff and responded to wholesale price fluctuations in a manner similar to those observed in the pricing experiments (for example, thermostat slider and temperature settings, internal air temperature decay rates, etc.).
3. RTP_{da} Congested – the households were simulated using the residential RTP_{da} service tariff, responded to wholesale price fluctuations, and responded to capacity limits placed on the feeder aligned with the actual experiments (96 experiments in four months).

The simulations were run for four months, collecting energy consumed at 5-minute intervals by each of the 300 RTP_{da} households. An “average” RTP_{da} household was constructed from the resulting information by summing all 300 loads and dividing by 300 in each interval. The total wholesale energy cost for the average household is shown in Table 2.3. Table 2.4 shows these same values in terms of percent of total energy costs, showing an average RTP_{da} household savings of 2.5% for wholesale energy costs on a per RTP_{da} household basis. When accounting for the effects of the congestion experiments,

¹ www.gridlabd.org

this number is reduced to 1.5%. This is expected, as the effect of the congestion experiments is to reduce sensitivity to wholesale price fluctuations. Note that the energy costs per day match closely with the experiment results shown in Table 2.1 above.

Table 2.3. Comparison of Monthly Wholesale Energy Costs for an Average Household (\$)

	Monthly Wholesale Energy Cost Per Household (\$)					
	June	July	August	September	Average	Per Day
Control	\$43.93	\$57.57	\$42.58	\$37.92	\$45.50	\$1.492
RTP _{da}	\$42.80	\$55.68	\$41.69	\$37.17	\$44.34	\$1.454
RTP _{da} Congested	\$43.10	\$56.55	\$42.05	\$37.44	\$44.79	\$1.470

Table 2.4. Reduction of Wholesale Energy Costs for an Average Household (%)

	Change in Consumer Wholesale Energy Cost (% Savings)				
	June	July	August	September	Average
RTP _{da}	2.6%	3.3%	2.1%	2.0%	2.5%
RTP _{da} Congested	1.9%	1.8%	1.2%	1.3%	1.5%

Looking at the impact on energy consumption, Table 2.5 shows the average energy reduction for each of the cases (a positive number indicates reduced energy consumption). The average reduction in energy consumption is 1.2%, decreasing to 0.9% during the congestion experiments due to the effects of precooling.

Table 2.5. Reduction of Energy Consumption for an Average Household (%)

	Change in Consumer Energy (% Reduced)				
	June	July	August	September	Average
RTP _{da}	1.3%	1.3%	1.4%	0.7%	1.2%
RTP _{da} Congested	1.1%	0.9%	1.0%	0.7%	0.9%

While these values do not perfectly align with the estimated results in Table 2.2 above, they are very similar, and provide additional veracity to the method described in Section 2.2.2 for adjusting the load shapes.

2.3 Spinning Reserves

This analysis investigates the spinning reserve capacity that can be achieved at any given time due to the demand response capability of the loads in the demonstrations. “Spinning reserve” is the extra generating or demand response capacity that is available to the system operator within a short interval of time to meet demand in case a generator goes down or there is another disruption to the supply. Most system operators require the spinning reserve capacity to be available to compensate for the loss of the

largest power plant (plus a fraction of the peak load) within a preset amount of time (typically 10 minutes), and be available to respond continuously for a preset amount of time (typically 30 minutes). The spinning reserve capacity is a short-term capability and can therefore be measured in kW/household/hour or kWh/household/hour. It can also be measured in annual monetary terms as the \$/household earned in the spinning reserve market. This analysis evaluates the capability of RTP_{da} households to participate in spinning reserve markets. While this analysis is not comprehensive, it is used to determine a “best case” for RTP_{da} households participating in spinning reserve markets, using average market prices from various independent system operators.

2.3.1 Results of Analysis

Spinning reserve is an ancillary service that can be bid into the ancillary services market. Within PJM, the Synchronized Reserve and Regulation Market decides the Synchronized Reserve market cleared price (SRMCP). As load becomes price responsive, like the HVAC loads in the RTP_{da} demonstration, the load can be considered as a spinning reserve for specific durations in the day and can be bid into ancillary services markets. Knowing the amount of load that can be safely bid into the spinning reserve market is important not only to make a bid, but to also be assured that the required reserve requirement can be successfully satisfied if called upon to provide the service. The auction collects all RTP_{da} customer resource availability and the bid curve can be used to determine the amount of resource available at any given market period, as shown in Figure 2.11. The highlighted area represents the households that are willing to reduce their demand given the proper incentive (via the RTP). The service provider may engage only a fraction of the total available resource to participate in the spinning reserves market by setting the congestion limit, and hence the cleared price, appropriately. The utility would weigh the cost of acquiring the resource (incentive payment to displaced consumers) against the benefit from provision of spinning reserve capacity (revenue from spinning- reserve markets, or avoidance of self-scheduling cost).

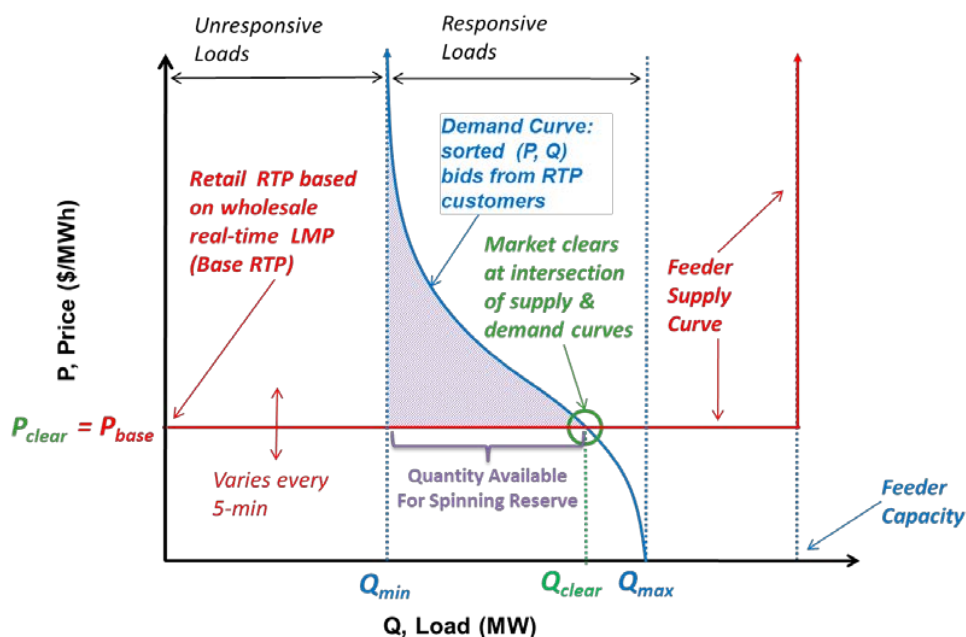


Figure 2.11. Resource Available for Spinning Reserve During Each Market Period

In each market period, the total quantity (kW) of responsive load less than the load at the cleared price is available for participation in the spinning reserve call. In this study, the quantity is calculated for each 5-minute interval, then averaged over the hour to determine the amount of load available for a one-hour spinning reserve call (although most spinning reserve calls last for periods much shorter than one hour).

The overall spinning reserve capabilities of the system during the study period are difficult to determine because the frequent congestion experiments held over the operational period distort a more natural behavior of the bidding system. To better estimate the benefits, PNNL instead used the simulated models to determine the average amount of resource available at every hour of the summer. By then comparing that value to the average PJM market price at each hour, the maximum amount of possible revenue generation in the spinning reserve market can be estimated. Note that this includes every hour in the summer and assumes that no spinning reserve calls were made to affect future household behavior. It also assumes that there is enough resource in the RTP_{da} system to participate in the market. These assumptions are used to determine the “best case” scenario for capturing spinning reserve revenue.

Table 2.6 shows the results of this study in the form of total revenue generated per RTP_{da} household per month. This is calculated by determining the total amount available (as shown in Figure 2.11), then dividing by the total number of RTP_{da} households. The spinning reserve prices were exceptionally low in the PJM market for the summer evaluated, averaging \$0.49/MWh between June and October of 2013. A number of additional historical spinning reserve markets were evaluated for comparison. While the potential in PJM’s market is extremely small, in other markets, where spinning reserve resources are in higher demand, differing amounts of revenue can be generated with relatively little impact on the consumer (assuming the resource is called relatively infrequently). The results of three other markets are shown for comparison. This analysis does not address the impact on the spinning reserve market itself or the reduction of overall prices as additional demand- response resources participate, but rather highlights the potential uses of this system.

Table 2.6. Spinning Reserve Markets and the Maximum Amount of Revenue Available to RTP_{da}

	PJM 2013 ^(a)	CAISO 2013 ^(b)	ERCOT 2013 ^(b)	ERCOT 2008 ^(a)
Total Revenue Per Household Per Month	\$0.08	\$1.78	\$5.79	\$13.64
(a) Based on average hourly prices				
(b) Based on average monthly prices				

3.0 Household Impacts

This chapter analyzes the impacts of the RTP_{da} approach on consumers and their residential equipment. These include household electricity bills, consumer interactions with their thermostats, and the quantity of HVAC energy bid into the market versus the amount observed from the metering data.

3.1 Household Bill Impacts

This section analyzes the impact on RTP_{da} household bills (per tariff Schedule RS-RTP, 2012) for the months of June through September 2013. The RTP_{da} bills are divided into the following components:

$$B_{RTPtot} = B_{RTPeng} - B_{RTPinc} + B_{RTPfixed} \quad (3.1)$$

where

B_{RTPtot}	=	RTP _{da} household total bill per period of interest
B_{RTPeng}	=	RTP _{da} household energy-sensitive component of the bill per period of interest
B_{RTPinc}	=	RTP _{da} household incentive savings component of the bill per period of interest
$B_{RTPfixed}$	=	RTP _{da} household fixed, non-energy-sensitive component of the bill per period of interest.

The incentive savings is calculated as explained in Section 1.2.1.3. In any one month, the incentive savings (B_{RTPinc}) is not allowed to exceed the RTP_{da} market-based energy component (a portion of B_{RTPeng}) of the RTP_{da} bill; however, it is possible that $B_{RTPinc} > B_{RTPeng}$ on a daily or hourly basis. As the monthly billing periods for the households are staggered throughout a month, and 5-minute energy usage information is available from the meters, the non-energy portion of the monthly bill is spread evenly over 5-minute intervals to obtain $B_{RTPfixed}$ and the 5-minute energy data are used with the RTP_{da} tariff to obtain 5-minute portions of B_{RTPeng} . The 5-minute household market bidding data are used to calculate a 5-minute B_{RTPinc} component, and Equation (3.1) is used to calculate B_{RTPtot} . This 5-minute data forms the basis for calculating average hourly bills. The average bill for any one hour is calculated based on the population of households that are participating during that hour. This is done for every hour (for which good data exist) over the four-month period. These hours are also analyzed in subsets of peak and off-peak, and hot and mild temperature periods.

Because the bills in this analysis are calculated based on the energy use data captured by the RTP_{da} system about and the RTP_{da} tariff, there will be discrepancies with the actual bills calculated by the AEP Ohio billing system. That system must handle various complicating situations with regard to metering and household changes, and make appropriate adjustments to the final bill that are not replicated here.

The average \$/hr billing information over the months of June through September for all households in the RTP_{da} group is presented in Table 3.1 below. The total bill and the contributions to it are represented according to averages of the totals as well as the averages for the top and bottom 25% of households by bill component area. In addition, the average \$/hr of the bills for households in off-peak (22:00–14:00) and peak (14:00–22:00) periods is also listed. Both off-peak and peak periods are further filtered for mild (outdoor temperature ≤ 80°F) and hot (outdoor temperature > 80°F) weather. These same quantities are repeated in Table 3.2, but reflect percentages based on the average total RTP13 bill.

One can see from the tables that the incentive savings were dispersed to households of all levels of energy usage by amounts on the order of 3–4%. When looking at all the households according to incentive savings component, the average of the top 25% bills of the households received a savings of 12% of the average total bill of all households. This counteracts a 2.5% increase in the energy-sensitive portion of the bill, for a total bill savings of about 5% from the average \$/hr over the entire population of households. Those in the bottom 25% have no incentive savings contribution and show a higher average total bill of about 10.5% compared with the average of all households.

Table 3.1. RTP_{da} Bill \$/hr Averages for All Households

Metric	RTP13				
	Total Bill	kWh	Energy	Incentive	Fixed
Average \$/hr Total Bill	0.1916	1.4812	0.1909	0.0081	0.0087
Top 25%	0.2563	1.9742	0.2539	0.0064	0.0087
Bottom 25%	0.1289	0.9987	0.1277	0.0076	0.0087
Average \$/hr Energy Bill					
Top 25%	0.2531	1.9706	0.2529	0.0084	0.0087
Bottom 25%	0.1290	0.9805	0.1253	0.0050	0.0087
Average \$/hr Incentives					
Top 25%	0.1820	1.5486	0.1963	0.0230	0.0087
Bottom 25%	0.2116	1.5643	0.2029	0.0000	0.0087
Average \$/hr Off-Peak	0.1506	1.2089	0.1457	0.0039	0.0087
Off-Peak Mild	0.1204	1.0101	0.1148	0.0031	0.0087
Off-Peak Hot	0.1754	1.3727	0.1712	0.0045	0.0087
Average \$/hr Peak	0.2736	2.0257	0.2812	0.0164	0.0087
Peak Mild	0.1891	1.5225	0.1884	0.0081	0.0087
Peak Hot	0.3405	2.4247	0.3547	0.0230	0.0087

Table 3.2. RTP_{da} Bill \$/hr Averages: Percent of Average Total Bill for All Households

Metric	RTP13				
	Total Bill	kWh	Energy	Incentive	Fixed
Average \$/hr Total Bill	100.0%	100.0%	99.7%	4.2%	4.6%
Top 25%	133.8%	133.3%	132.6%	3.3%	4.6%
Bottom 25%	67.3%	67.4%	66.7%	3.9%	4.6%
Average \$/hr Energy Bill					
Top 25%	132.1%	133.0%	132.0%	4.4%	4.6%
Bottom 25%	67.3%	66.2%	65.4%	2.6%	4.6%
Average \$/hr Incentives					
Top 25%	95.0%	104.6%	102.5%	12.0%	4.6%
Bottom 25%	110.5%	105.6%	105.9%	0.0%	4.6%
Average \$/hr Off-Peak	78.6%	81.6%	76.1%	2.0%	4.6%
Off-Peak Mild	62.8%	68.2%	59.9%	1.6%	4.6%
Off-Peak Hot	91.6%	92.7%	89.4%	2.4%	4.6%
Average \$/hr Peak	142.8%	136.8%	146.8%	8.5%	4.6%
Peak Mild	98.7%	102.8%	98.4%	4.2%	4.6%
Peak Hot	177.8%	163.7%	185.2%	12.0%	4.6%

The bill components can also be viewed across the peak and off-peak periods with hot and mild weather. This ranges from off-peak+mild incentive savings of 1.6% of the average \$/hr total bill to peak+hot incentive savings of 12%. The impact on the hourly rate of the bills over these periods is about 63% for off-peak+mild to about 180% for peak+hot periods when compared to the average \$/hr for all time periods. This range is more dramatic than for the kWh consumed in those periods because energy prices for the RTP_{da} households are generally greater during peak+hot periods than during off-peak+mild periods.

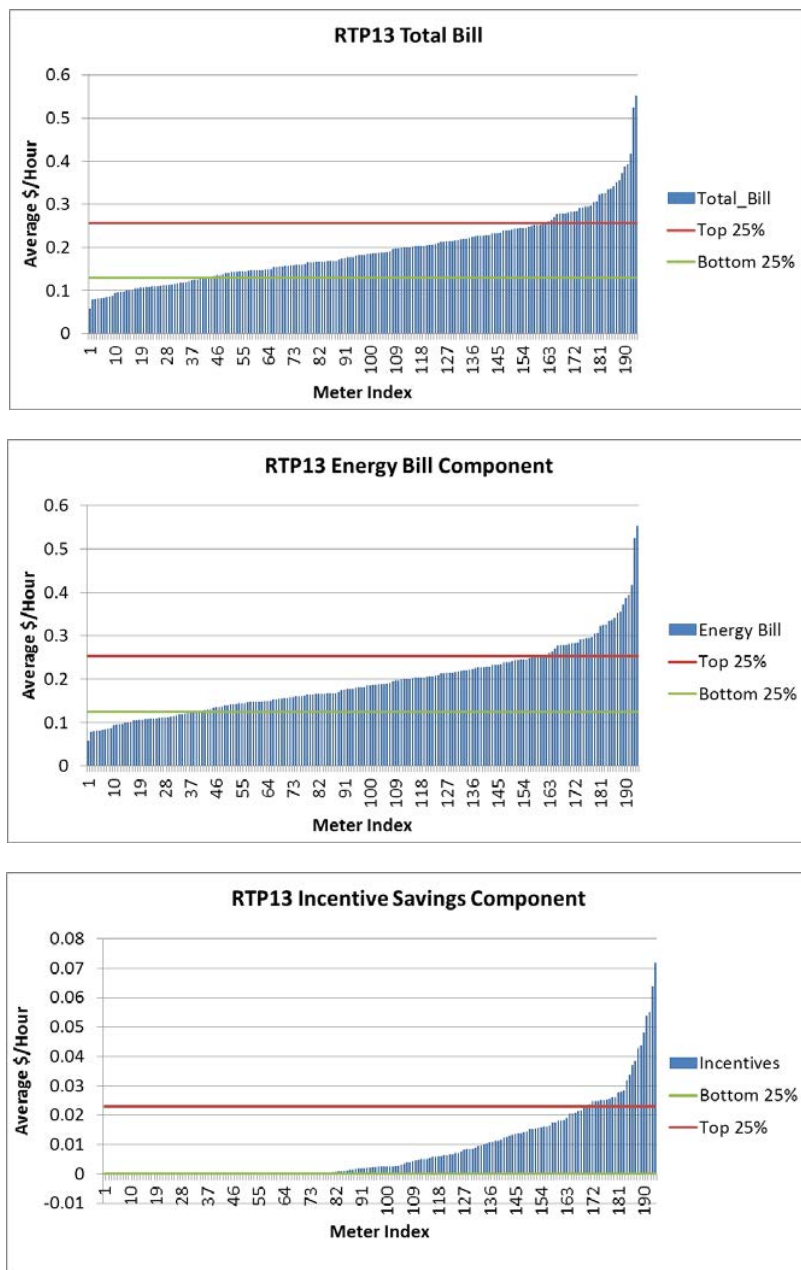


Figure 3.1. RTP_{da} Average Hourly Household Bills with Total, Energy, and Incentive Savings Components

The graphs in Figure 3.1 show the distribution of the hourly rates for the population of households as ordered from lowest to highest household for each bill component; the households (indicated by meter index in the graphs) are reordered in each graph from lowest to highest household contribution. Each figure includes the average of the top and bottom 25% for the population being displayed.

One can see from these figures that there are a few households with relatively high total average hourly energy bills, with the remainder distributed with a relatively flat slope. When one looks at the incentive savings component, about 40% of the households received little or no incentive savings, while about 10% of households had significant average \$/hr incentive savings. Note that the incentive saving is allowed to exceed the RTP_{da} market-based contribution to the energy portion of the bill on an hourly basis, but not on a monthly basis.

The graphs in Figure 3.2 depict the distribution of the average \$/hr energy-sensitive components of the bills for households in off-peak and peak periods. Both off-peak and peak periods are further filtered for mild and hot weather as defined above. For each graph, the households are reordered from lowest to highest contribution for the population displayed.

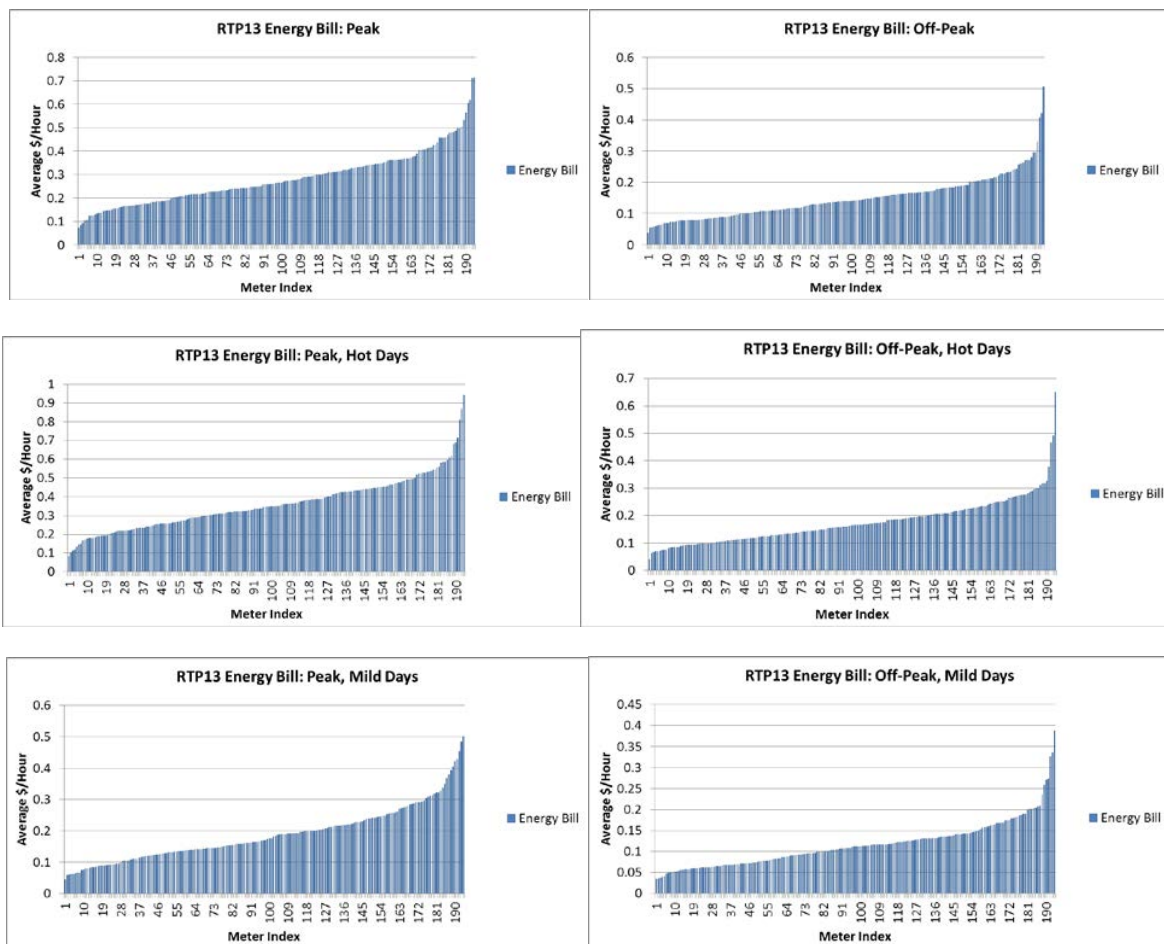


Figure 3.2. RTP_{da} Average Hourly Household Energy-Sensitive Bill Component for Peak and Off-Peak Periods

From these graphs one can see the relatively small number of households at the extremes of the billing range and the significant differences in peak+hot and peak+mild versus off-peak conditions. Similarly, the incentive savings contributions to the RTP_{da} bills are shown in Figure 3.3.

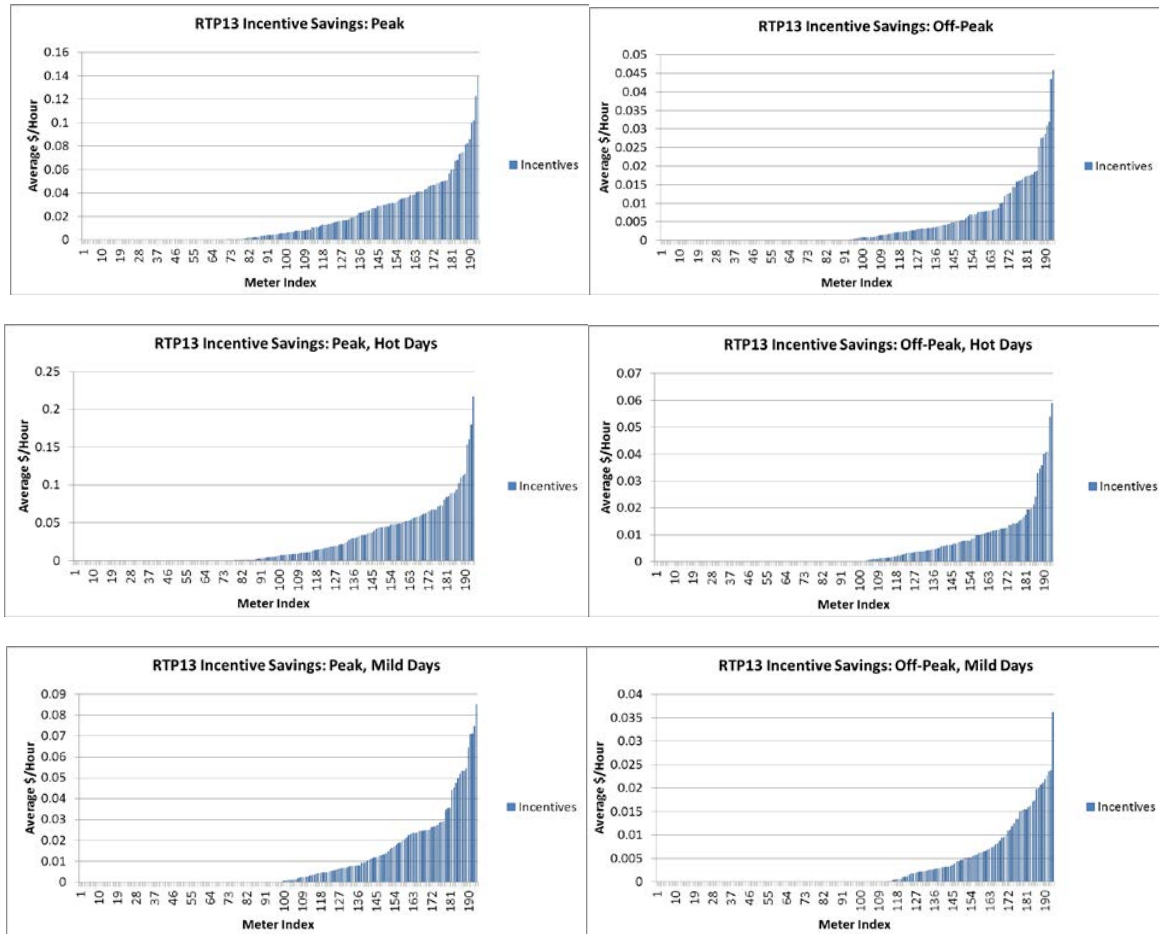


Figure 3.3. RTP_{da} Average Hourly Household Incentive Savings for Peak and Off-Peak Periods

A review of the incentive savings indicates that the peak periods have significantly more savings than the off-peak periods. This is to be expected, as there is more HVAC resource available for market-based curtailment in the peak periods. The difference is also likely increased because more congestion experiments were run during peak periods (see Section 1.3.2). The hot days also have significantly more incentive savings than the mild days, again likely because there is more HVAC resource available to participate in the market.

The following subsections describe comparisons of the RTP_{da} bill with bills for the same households subjected to the standard tariff (RTP_{std}). Since the RTP_{da} congestion experiments called upon the households more frequently than would be expected in typical operations, an additional section is provided that compares the bills of RTP_{da} to non-RTP_{da} households.

3.1.1 RTP_{da} Household Bills Compared with Standard Tariff

Figure 3.4 presents the total RTP_{da} bill with the total standard tariff bill. Each “index number” is one household in one month (which may be June, July, August, or September); some households will be listed four times (June-September), while others may only appear once. Household bills that had less than 80% data acquisition through the RTP_{da} dispatch system were removed from this analysis, due to large variability and errors in the bill calculation. Figure 3.4 orders the household bills by kWh consumed over the four-month period and compares the households’ RTP_{da} bills against the same households’ bills as if they had been charged the standard tariff. One can see that there is a wide spread of relatively small bill increases and decreases at all levels of consumption; this is more clearly shown in Figure 3.5.

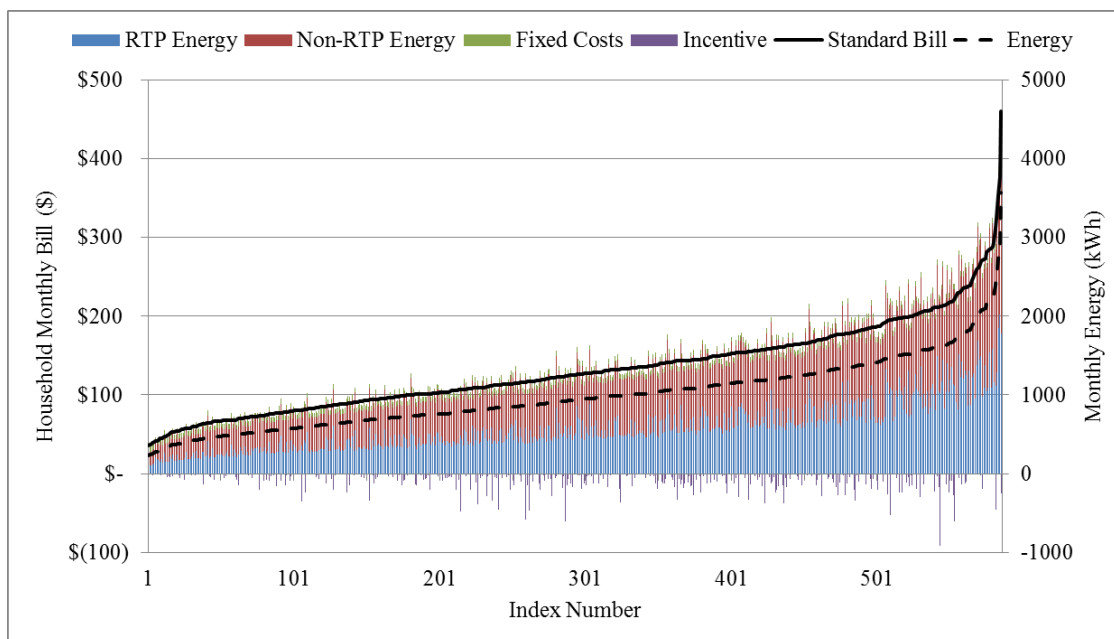


Figure 3.4. RTP_{da} Bill Comparisons with Standard Tariff Applied to the Same Households

The distribution of the difference between the RTP_{da} bills’ without incentive savings compared to the same energy consumption calculated with the standard tariff is plotted in Figure 3.5. Again, this is sorted by monthly energy consumption. Figure 3.6 re-sorts the data by the change in overall bill. The two figures indicate that slightly more than half of the households were paying less under the new tariff; however, the households paying more did so by a greater amount, and on average, household bills were increased by \$3.68, evenly spread across all household sizes. However, Figure 3.7 and Figure 3.8, in which the incentive is included in the bill calculation, show that many of the households were saving by switching to the new tariff; on average, household bills were decreased by \$1.99, again spread across the sizes of the households. This indicates that the large number of congestion experiments may have made the prices appear lower (causing precooling) and disrupted the revenue neutrality calculations. However, when including the incentive, a majority of households were saving, indicating that by responding to the congestion events households are able to see savings.

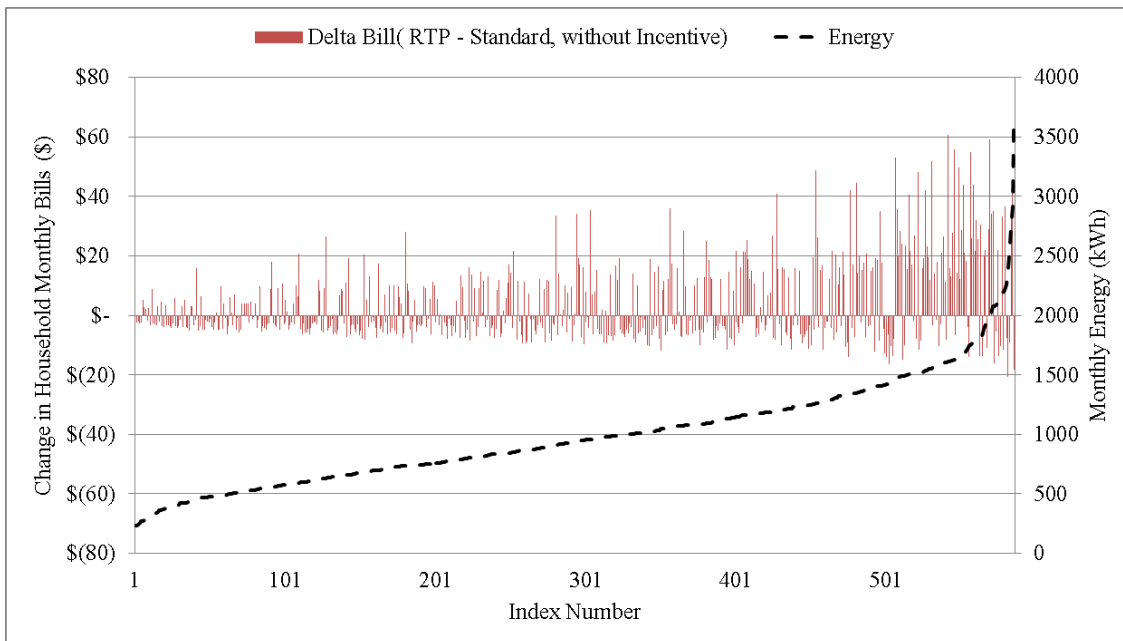


Figure 3.5. RTP_{da} Bill (Without Incentive Component) Minus Standard Tariff Bill

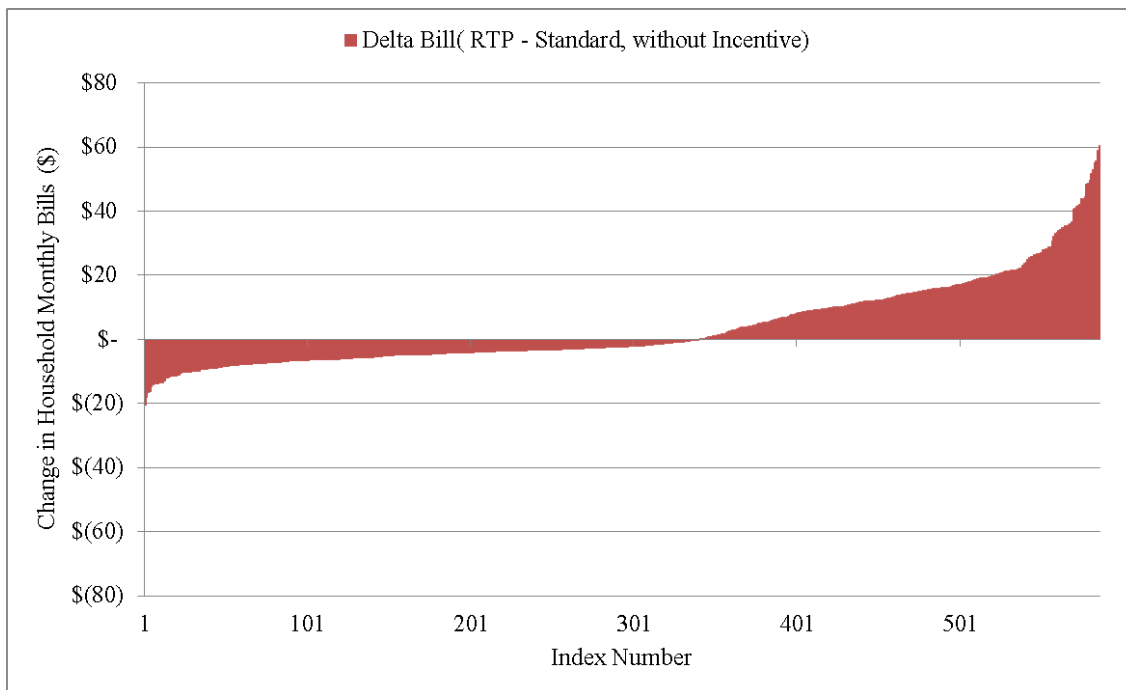


Figure 3.6. RTP_{da} Bill (Without Incentive Component) Minus Standard Tariff Bill, Sorted by Change in Bill

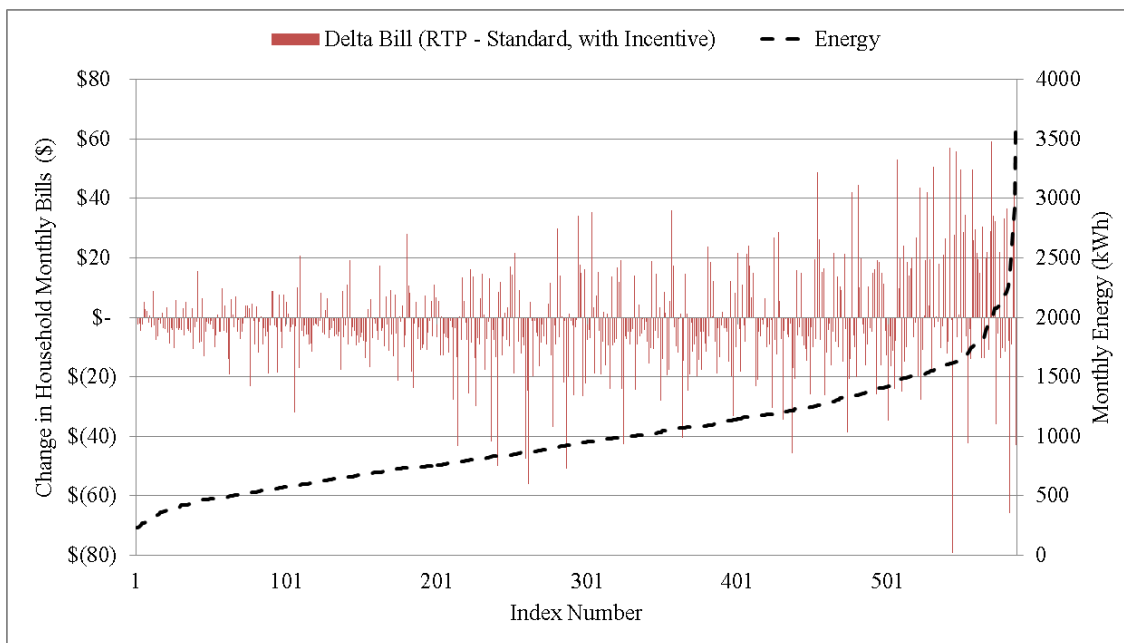


Figure 3.7. RTP_{da} Bill (With Incentive Component) Minus Standard Tariff Bill

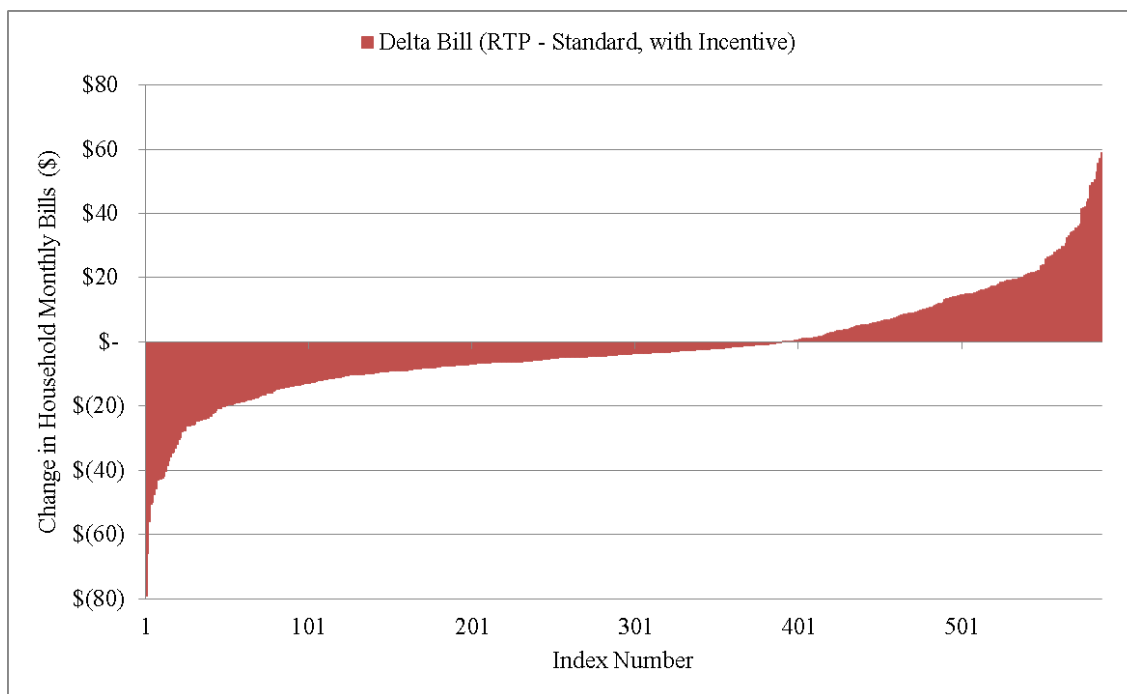


Figure 3.8. RTP_{da} Bill (With Incentive Component) Minus Standard Tariff Bill, Sorted by Change in Bill

3.1.2 RTP_{da} Bills Compared to Control Group

The average \$/hr billing information over the months of June through September for all households in the RTP_{da} group and the RTPnr control group, and their percentages with respect to the average of all households' RTP_{da} bills, are presented in Table 3.3 and Table 3.4. The fixed-cost portion of the bills is the same for both RTP_{da} and RTPnr bills; it is listed in Table 3.1 and not shown here, so the bill components will not sum precisely to the total bill. The difference represented in the Delta Energy column only shows the energy component and does not include the incentive savings component of the bills.

The RTP_{da} billing information is calculated as reported in Section 3.1. The RTPnr billing information is calculated from the 15-minute metered data obtained for the households in the control group, then averaged and adjusted as explained in Section 1.4.2 to create an average RTPnr household energy use for each hour. The standard tariff is then applied to this average energy use to calculate the total bill and the energy component. As with the RTP_{da} bill calculation, discrepancies may exist between the RTPnr average billing calculation and the actual bills for the control group.

Table 3.3. \$/hr Averages for RTP_{da} Bill Households Compared with Control Group (RTPnr)

Metric	RTP13				RTPnr13			Delta		
	Total Bill	kWh	Energy	Incentive	Total Bill	kWh	Energy	Total Bill	kWh	Energy
Average \$/hr Total	0.1916	1.4812	0.1909	0.0081	0.2016	1.4516	0.1928	-0.0101	0.0296	-0.0019
Average \$/hr Off-Peak	0.1506	1.2089	0.1457	0.0039	0.1666	1.1878	0.1578	-0.0160	0.0211	-0.0120
Off-Peak Mild	0.1204	1.0101	0.1148	0.0031	0.1381	0.9736	0.1293	-0.0178	0.0365	-0.0145
Off-Peak Hot	0.1754	1.3727	0.1712	0.0045	0.1939	1.3934	0.1851	-0.0185	-0.0207	-0.0139
Average \$/hr Peak	0.2736	2.0257	0.2812	0.0164	0.2717	1.9792	0.2629	0.0019	0.0465	0.0183
Peak Mild	0.1891	1.5225	0.1884	0.0081	0.2056	1.4817	0.1968	-0.0165	0.0408	-0.0084
Peak Hot	0.3405	2.4247	0.3547	0.0230	0.3283	2.4055	0.3195	0.0122	0.0192	0.0352

Table 3.4. \$/hr Average Percentages of Average Total RTP_{da} Household Bill Compared with Control Group (RTPnr)

Metric	RTP13				RTPnr13			Delta		
	Total Bill	kWh	Energy	Incentive	Total Bill	kWh	Energy	Total Bill	kWh	Energy
Average \$/hr Total	100.0%	100.0%	99.7%	4.2%	105.3%	98.0%	100.7%	-5.3%	2.0%	-1.0%
Average \$/hr Off-Peak	78.6%	81.6%	76.1%	2.0%	87.0%	80.2%	82.4%	-8.4%	1.4%	-6.3%
Off-Peak Mild	62.8%	68.2%	59.9%	1.6%	72.1%	65.7%	67.5%	-9.3%	2.5%	-7.6%
Off-Peak Hot	91.6%	92.7%	89.4%	2.4%	101.2%	94.1%	96.6%	-9.6%	-1.4%	-7.2%
Average \$/hr Peak	142.8%	136.8%	146.8%	8.5%	141.8%	133.6%	137.2%	1.0%	3.1%	9.6%
Peak Mild	98.7%	102.8%	98.4%	4.2%	107.3%	100.0%	102.7%	-8.6%	2.8%	-4.4%
Peak Hot	177.8%	163.7%	185.2%	12.0%	171.4%	162.4%	166.8%	6.4%	1.3%	18.4%

Overall, the average \$/hr savings in the bills of all households in this analysis is about 5% in RTP_{da} versus the RTPnr control group; however, the overall energy consumption is about 2% higher. When one looks at the sensitivity of the bills to the different types of operating periods, further insights can be gained. For the off-peak periods, the RTP_{da} bills show a slightly greater savings compared to the control group even though their energy usage is slightly higher.

A potential reason for this is the ability of the RTP_{da} households' HVAC units to respond to market price fluctuations in the off-peak periods. As explained in Section 2.2, the many congestion experiments performed had the effect of desensitizing the thermostat controllers to high prices. This had the effect of making prices that were not near the market cap appear to be bargains for a significant period of time after a congestion experiment. This could have resulted in overcooling. When market prices remained high after the congestion experiment, the effect was to use more energy during a normally high-price period. This phenomenon appeared to be emphasized when looking at the average \$/hr during the peak+hot period. In this case, the energy consumption was 1.3% higher for the RTP_{da} group than for the control group; however, the energy component of the bill was 18.4% higher and the total bill was 6.4% higher. This is likely because, on average, the additional energy was being purchased at high market prices relative to the standard tariff. The effect of the incentive savings during these periods was to significantly reduce the impact of the large energy component on the overall average total bills.

When looking at peak+mild days, a greater amount of energy was used by the RTP_{da} group on average; however, the total bills were reduced by 8.6% compared to the control group, likely because the mild weather suppressed the market prices. Similar savings were seen in all off-peak figures, likely due to the lower market prices during the off-peak periods.

To summarize, the bill comparison between the RTP_{da} households and the RTP_{nr} control group indicated bill savings in the summer months. More-detailed examination of the behavior of the RTP_{da} group in different periods of operation and the changes in the bill components revealed a variety of differences between the two bills. The low penetration of RTP_{da} households on each feeder and the frequent congestion experiments had a large impact on the behavior of the RTP_{da} resources and their interaction with the market. In addition, the accuracy of the representation of the control group as a “non-responsive” reflection of the RTP_{da} households deserves further scrutiny. More investigation is needed to fully understand these impacts.

One approach to isolate the impact of the congestion experiments as well as to compare results with a “perfect” control group is to model the RTP_{da} system using the GridLAB-D simulator. Section 3.1.3 reports the results of the use of simulation to both increase the penetration of RTP_{da} households and independently look at the performance of the RTP_{da} system with and without congestion experiments.

3.1.3 RTP_{da} versus Non-RTP_{da} Bill Comparison – Simulation

Simulations of the RTP_{da} group with controls and the same households without controls have been executed in GridLAB-D. The simulated households have been configured to represent the sizes and types of housing in the RTP_{da} group. The observed RTP_{da} household thermostat statistics and energy usage information have been used to calibrate the simulated households. This section reports the comparison of their bills. Bill comparisons include the summer months without congestion events and with congestion events to better understand the impacts.

Households were simulated within GridLAB-D to represent 25% penetration of RTP_{da} households; 300 households were “experimental” while 900 were operated similarly in each simulation and did not respond to variations in price. The experimental households were run using four different scenarios:

1. Control – The households were simulated using the standard pricing tariff (Schedule R-R, 2012).
2. RTP_{da} Without Response – The households were simulated using the experimental residential real-time pricing service tariff (Schedule RS-RTP, 2012), but did not respond to price fluctuations (these households could be considered to serve a purpose equivalent to the RTP_{nr} households described in the previous section, but with the advantage that in the simulator, they are precisely the same household models).
3. RTP_{da} – The households were simulated using the residential RTP_{da} service tariff and responded to wholesale price fluctuations in a manner similar to those observed in the pricing experiments (for example, thermostat slider and temperature settings, internal air temperature decay rates, etc.).
4. RTP_{da} Congested – The households were simulated using the residential RTP_{da} service tariff, responded to wholesale price fluctuations, and responded to capacity limits placed on the feeder aligned with the actual experiments.

The bills are calculated using all components of the tariffs, including all fixed, rider, and energy charges. The bills are presented as the average of all four months and the impact on that average monthly bill. Figure 3.9 shows the monthly billing impact when switching from the standard tariff to the RTP_{da} tariff, without changing load behavior. The left-hand axis (red bars) indicates the percentage by which the household’s bill changes when switching from the standard tariff to the RTP_{da} tariff, where a negative number indicates a savings when moving from the standard tariff to the RTP_{da} tariff. The right-hand axis (blue line) indicates the monthly energy consumption of the household, ranked from low to high (left to right). The percent differences are consistent across most household sizes with an average reduction of

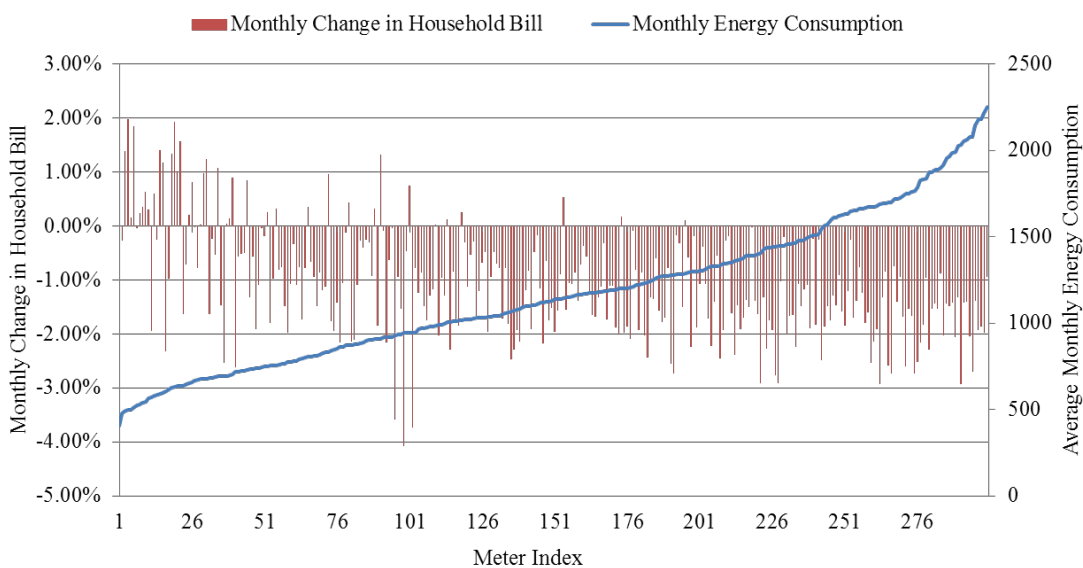


Figure 3.9. Change in Monthly Household Bills When Switching from Standard Tariffs to RTP_{da} (No Response), Without Responding to Price Fluctuations

1.1% in the bill. This indicates that during the four-month period, the RTP_{da} rate was nearly revenue neutral but slightly skewed toward decreasing the households' bills. The rate was designed to be revenue neutral over an entire year, but may show variance within any given period. The energy consumption is identical in these two cases.

Figure 3.10 shows a similar plot for households responding to wholesale price fluctuations. In this case, the difference in bills reflects moving from RTP_{da} Without Response to RTP_{da} (with response). The households are still stacked from left to right according to their energy consumption using the standard tariff (that is, Household 10 is the same Household 10 in each graph). This indicates the amount of savings seen by each household in responding to the price, with the effects of whether the rate is revenue neutral removed—in other words, the amount the household saves by allowing their thermostat to be adjusted in response to price fluctuations. The average reduction in the bill is 2.1%, with an average decrease in energy consumption of 1.2%.

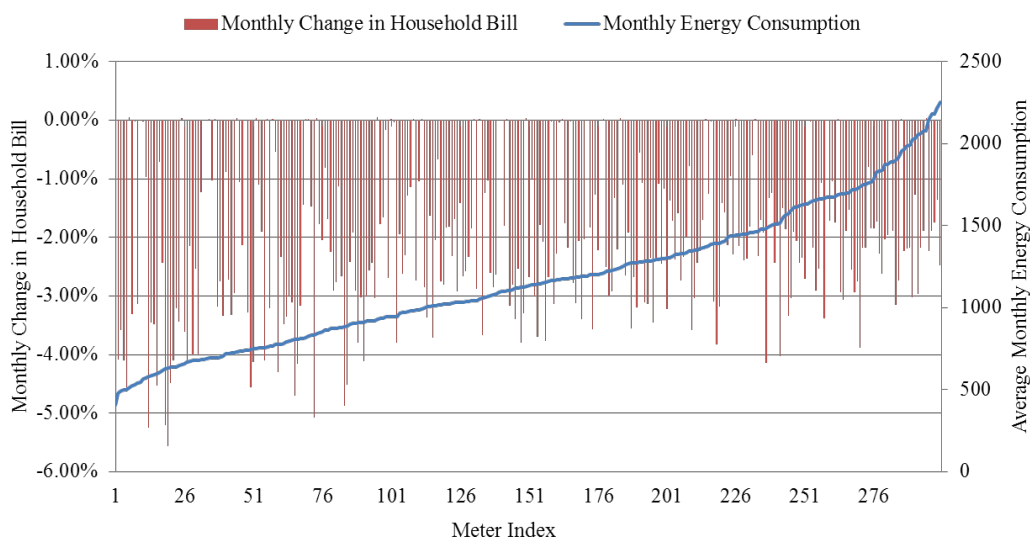


Figure 3.10. Change in Monthly Household Bills When Responding to Price Fluctuations (changing from RTP_{da} Without Response to RTP_{da} With Response)

Figure 3.11 is a combination of Figure 3.9 and Figure 3.10, moving from the standard tariff to RTP_{da} (with response). The average household reduces their bill by 3.2% and reduces energy consumption by 1.2%. Figure 3.12 shows the same information, but in terms of actual dollars saved (rather than percentage of bill). The average bill reduction is \$5.11 with a maximum (average) reduction of \$12.43 (one household was able to see a \$22.52 reduction for the month of July). The reduction of the bill is consistent across household sizes in terms of percent reduction, with larger energy users seeing a larger decrease in proportion to their energy use.

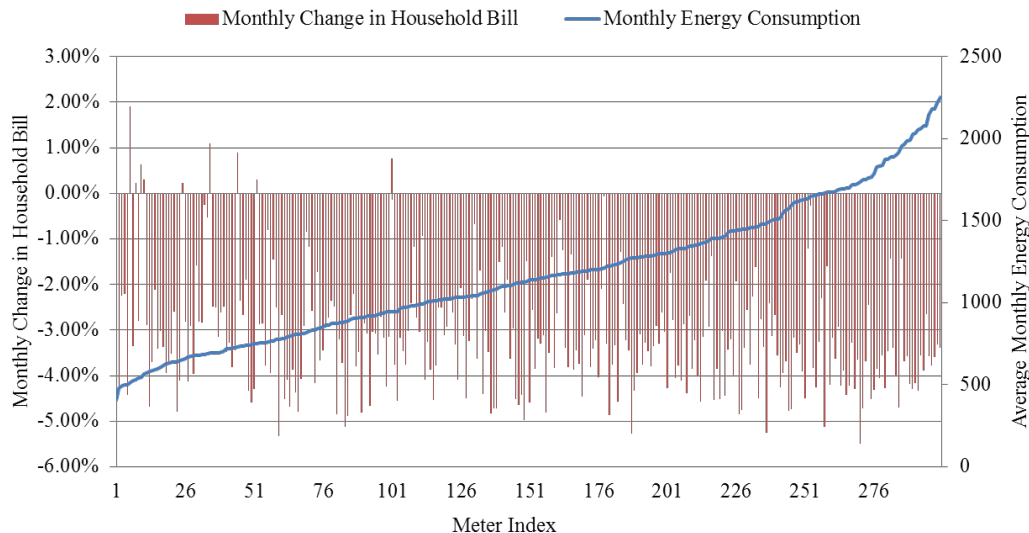


Figure 3.11. Percentage Change in Monthly Household Bills When Switching from Standard Pricing to RTP_{da} With Response

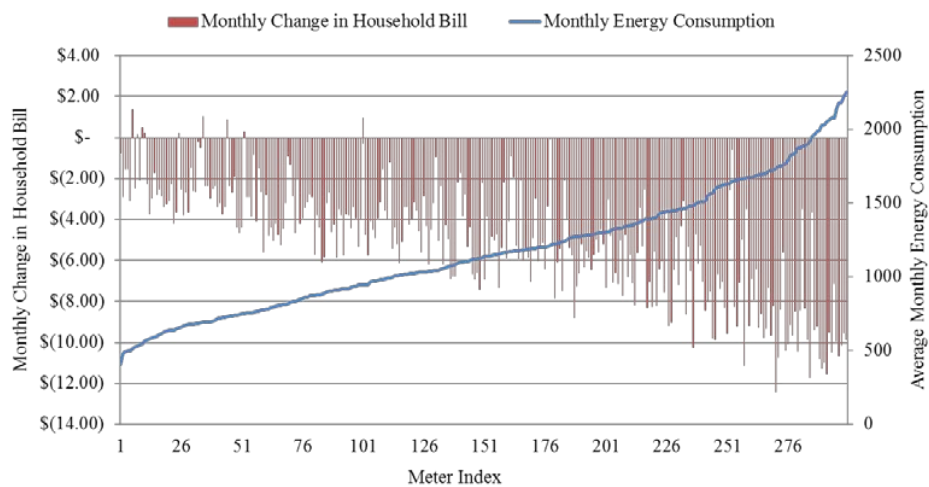


Figure 3.12. Change in Monthly Household Bills (\$) When Switching from Standard Pricing to RTP_{da} With Response to Price Fluctuations

Figure 3.13 shows the impacts on the household monthly bill when moving from RTP_{da} with response to RTP_{da} Without Response with the 66 congestion experiments during the June-to-September period (out of 96 total congestion experiments done in all of 2013). The experiments caused prices to rise very high for a few hours and reduce demand, then “appear” very low for the following 24 hours as the average price was increased. This caused a number of units to lower their thermostat cooling set points and increase energy consumption (by 0.27% on average over the four-month period). For households that frequently responded to the congestion event by decreasing demand during the period, significant savings were seen (the maximum reduction was \$31.16) driven by the incentive payment. Households that were not overly responsive saw a slight increase in their bills (between \$0 and \$3), driven by the increased

demand caused by precooling. Ideally, the system would not be operated that often, so it is assumed that the level of impact and savings would be decreased.

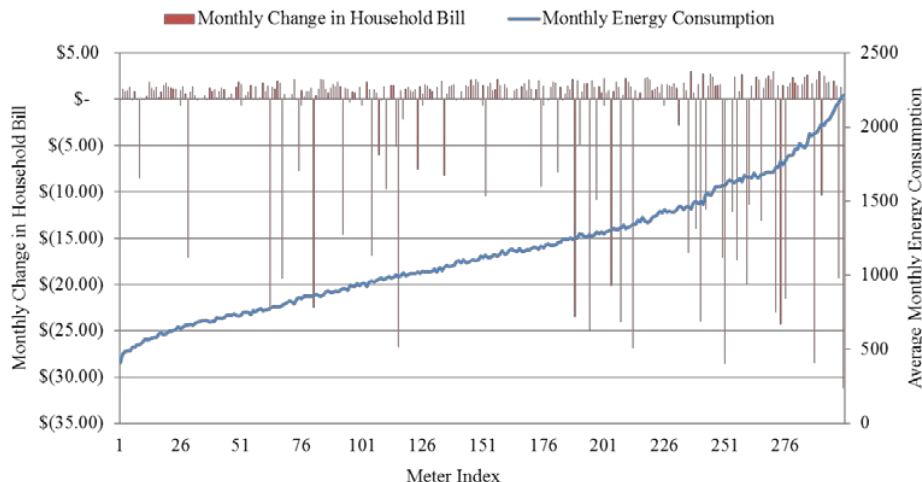


Figure 3.13. Change in Monthly Household Bills When Switching from RTP_{da} With Response to RTP_{da} Without Response, Taking into Account the Congestion Experiments Used in the Actual System

Table 3.5 through Table 3.8 show the average household bills by month for each of the cases discussed above. RTP_{da} cases include a breakdown into the base bill, rebate payments, and incentive payments. Note that the rebate payments approximately nullify the effects of increased prices due to the congestion experiments, but not quite (as indicated by the slight rise in most household bills during the experiments).

Table 3.5. Average Monthly Bill with Standard Tariff

	Average Household Bill Control Group (Standard Tariff)				
	June	July	August	September	Average
Total	\$153.14	\$164.96	\$161.19	\$139.92	\$154.80

Table 3.6. Average Monthly Bill with RTP_{da} Tariff and No Response

	Average Household Bill RTP _{da} Without Response				
	June	July	August	September	Average
Base Bill	\$148.25	\$178.30	\$152.40	\$132.42	\$152.84
Rebate	\$-	\$-	\$-	\$-	\$-
Incentive	\$-	\$-	\$-	\$-	\$-
Total	\$148.25	\$178.30	\$152.40	\$132.42	\$152.84

Table 3.7. Average Monthly Bill with RTP_{da} Tariff and Response

	Average Household Bill RTP _{da} Wholesale Response				
	June	July	August	September	Average
Base Bill	\$145.53	\$172.97	\$149.55	\$130.71	\$149.69
Rebate	\$-	\$-	\$-	\$-	\$-
Incentive	\$-	\$-	\$-	\$-	\$-
Total	\$145.53	\$172.97	\$149.55	\$130.71	\$149.69

Table 3.8. Average Monthly Bill with RTP_{da} Tariff and 66 Congestion Experiments

	Average Household Bill RTP _{da} with Congestion Experiments				
	June	July	August	September	Average
Base Bill	\$167.53	\$232.78	\$231.56	\$199.80	\$207.92
Rebate	\$(21.38)	\$(57.75)	\$(80.80)	\$(68.46)	\$(57.09)
Incentive	\$(1.08)	\$(3.05)	\$(3.35)	\$(2.63)	\$(2.53)
Total	\$145.08	\$171.97	\$147.42	\$128.72	\$148.30

Table 3.9 summarizes the changes in household bills by month from the standard tariff to each of the three RTP_{da} experiments. Negative values (in parentheses) indicate a reduction in the bill. Notice the increase in July bills, even in the RTP_{da} Without Response case, indicating that wholesale prices were higher than expected in July.

Table 3.9. Comparison of Bill Reductions from Standard to RTP_{da} Tariff

	Delta Average Household Bill Control to RTP _{da}				
	June	July	August	September	Average
RTP _{da} Without Response	\$(4.89)	\$13.34	\$(8.79)	\$(7.50)	\$(1.96)
RTP _{da} With Response	\$(7.61)	\$8.01	\$(11.64)	\$(9.21)	\$(5.11)
RTP _{da} With Congestion	\$(8.06)	\$7.01	\$(13.77)	\$(11.20)	\$(6.51)

3.2 Thermostat Statistics

This section explores the RTP_{da} consumers' interactions with their thermostat. A statistical characterization of the population of thermostat settings is presented, followed by an investigation of the thermostat override changes that occurred during congestion event periods.

3.2.1 Thermostat Settings

In the course of the Project, the consumers exercised their choice of setting the cooling and heating set points, as well as the comfort slider settings. In addition, they had the choice of overriding the system until the next scheduled period or indefinitely. A number of aspects of these choices can be studied, but the overall features will be considered first.

The period of analysis was the four-month period June 1–September 30, 2013. The occupancy status had four possibilities: “Home,” “Night,” “Away,” and “Vacation.” The day was divided into six parts of 4 hours each. Weekday and weekend differences are implicit in the occupancy status (that is, generally more hours of the day are in occupied status during the weekend), so no distinction was made for this study. The comfort setting has six possibilities: 0, 20, 40, 60, 80, and 100, with 0 being most comfort oriented and 100 being most economically oriented. The cooling set points covered a wide range: 55°F to 95°F. So the total number of bins will be (4 occupancy statuses) × (6 day periods) × (6 slider settings) × (41 cooling set points in 1°F increments), or 5904 bins. The amount of data available from a household was dependent on recruitment date, communication issues, and other matters. To normalize for this variability, each household was given one vote that could be distributed among the 5904 bins. Imagine each household receiving a sheet of paper of unit area. It can be torn into a maximum of 5904 pieces (often far fewer) in proportion to the fraction of time the house was in the state represented by a bin and placed in that bin. The areas of the pieces of paper in each bin were summed. These sums are shown in the graphs below, where a separate graph is drawn for each of the four occupancy statuses and six day periods, resulting in a possible 24 graphs. Each graph is further normalized so that the probabilities for each bin add up to 100%. “Away” status in the period midnight to 4 a.m. did not occur, so no graph is shown for that combination. The 23 graphs are shown in Figure 3.14, Figure 3.15, Figure 3.16, and Figure 3.17.

The trends seen in these graphs are generally self-explanatory. Additional studies exploring the changes during the course of the Project are possible but have not been performed. For example, a study of the default and initial comfort settings selected as part of the ePCT installation and training process could shed light on how these statistics evolved over time. As one demographic study, the impact of the size of the house on the settings was explored. Figure 3.18 shows the distribution of aggregated (overall occupancy modes and hours of day) overall occupancy statuses and day periods for the smallest 25% and the largest 25% of the houses as well as for all the households.

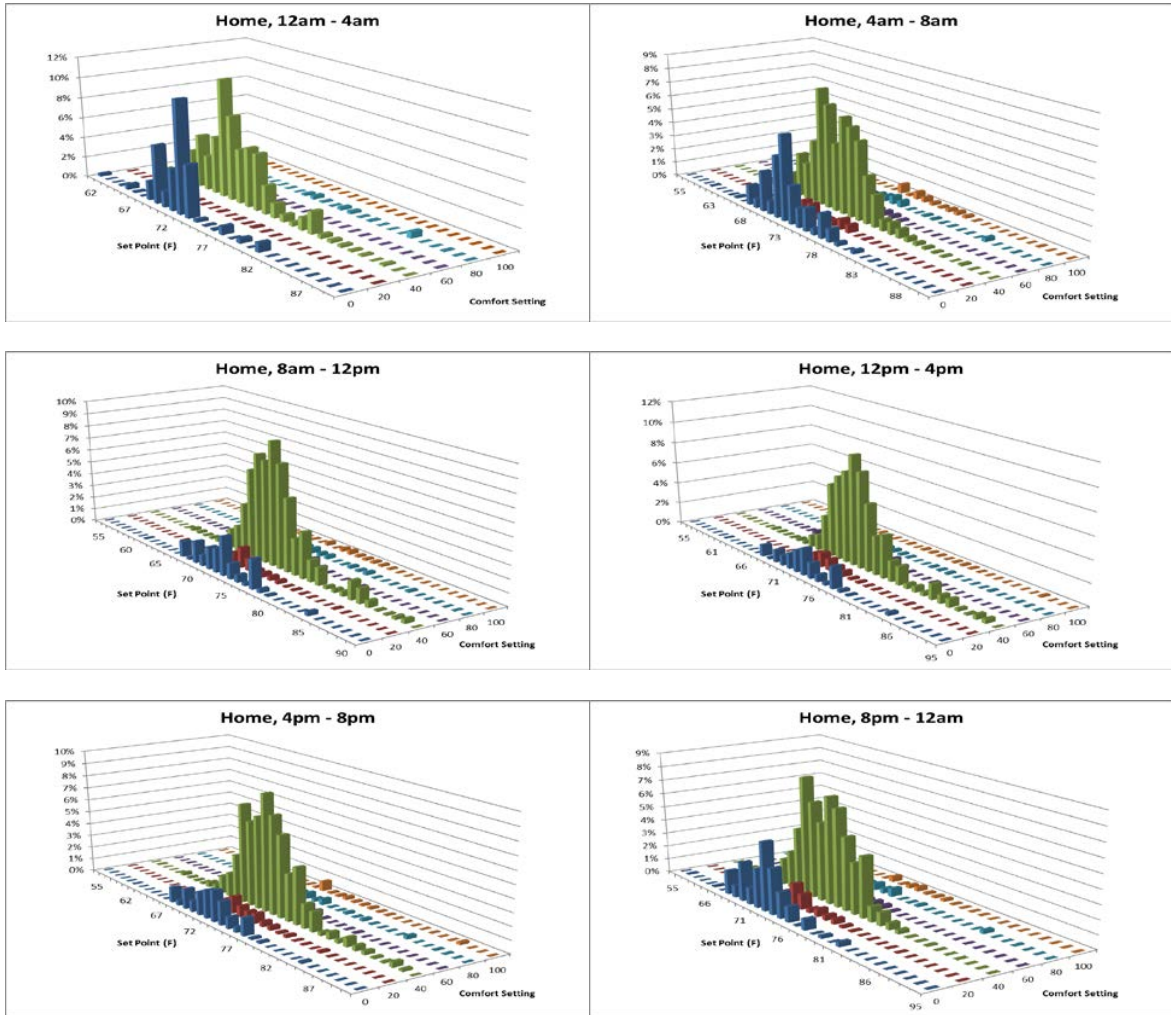


Figure 3.14. Cooling Set Point and Slider Distribution for Occupancy Status “Home”

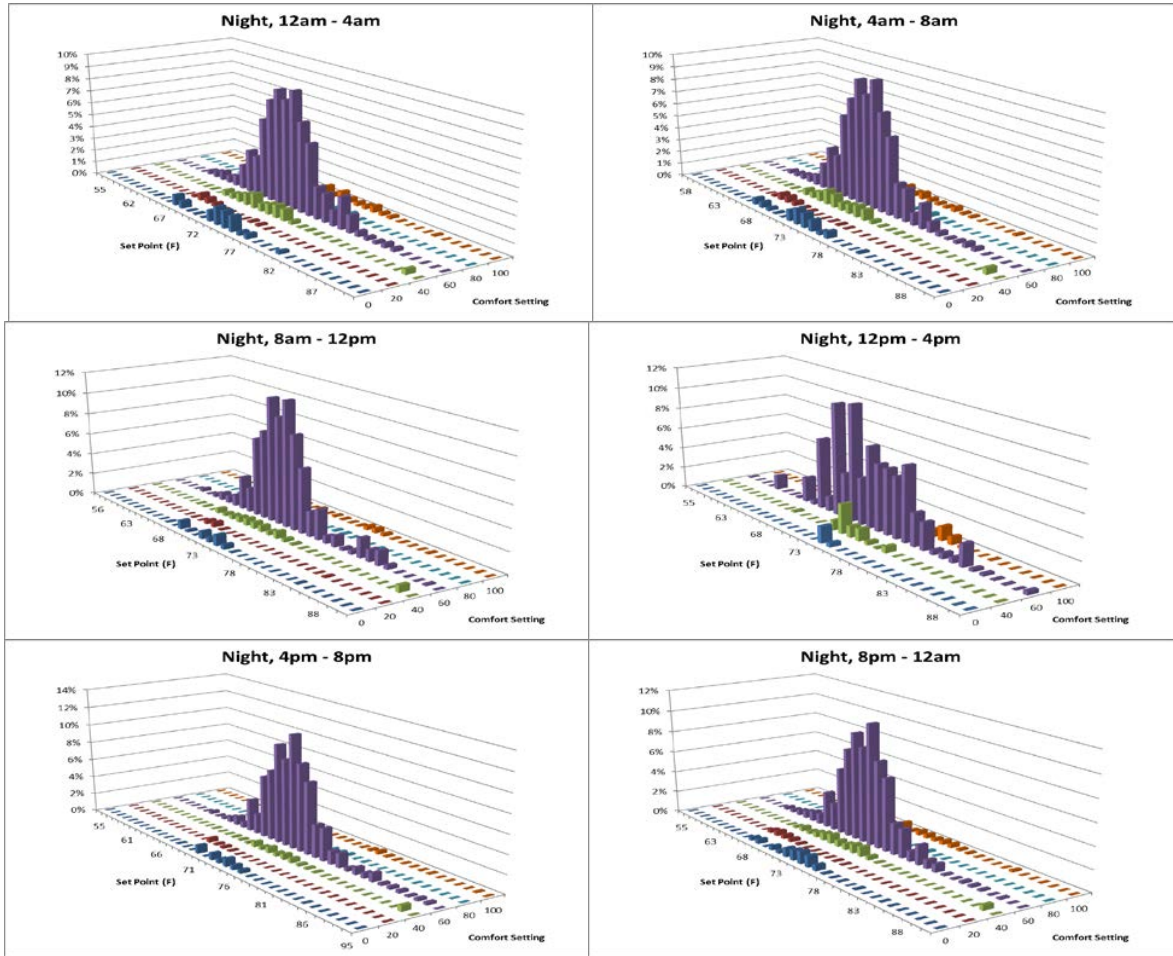


Figure 3.15. Cooling Set Point and Slider Distribution for Occupancy Status “Night”

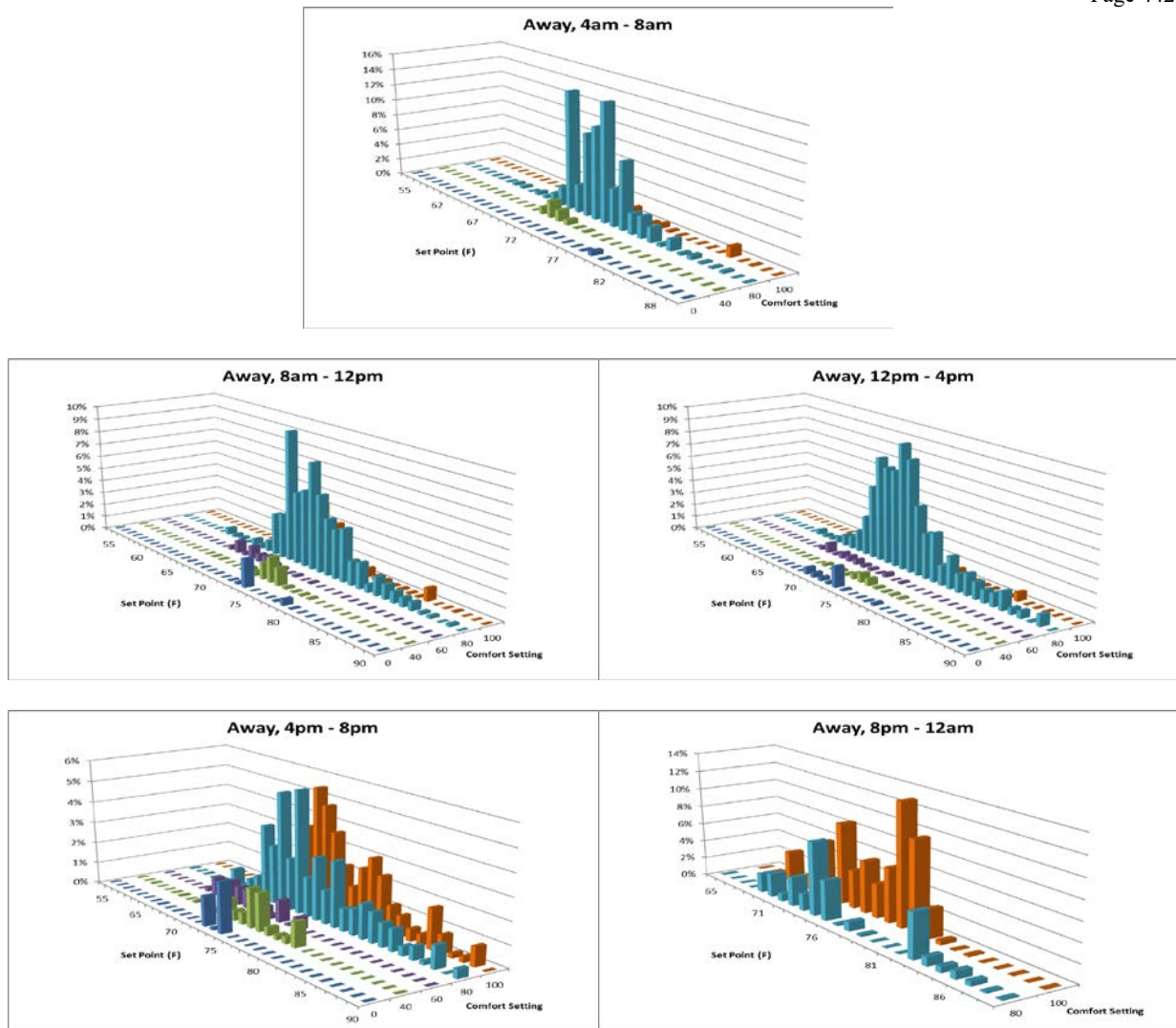


Figure 3.16. Cooling Set Point and Slider Distribution for Occupancy Status “Away”

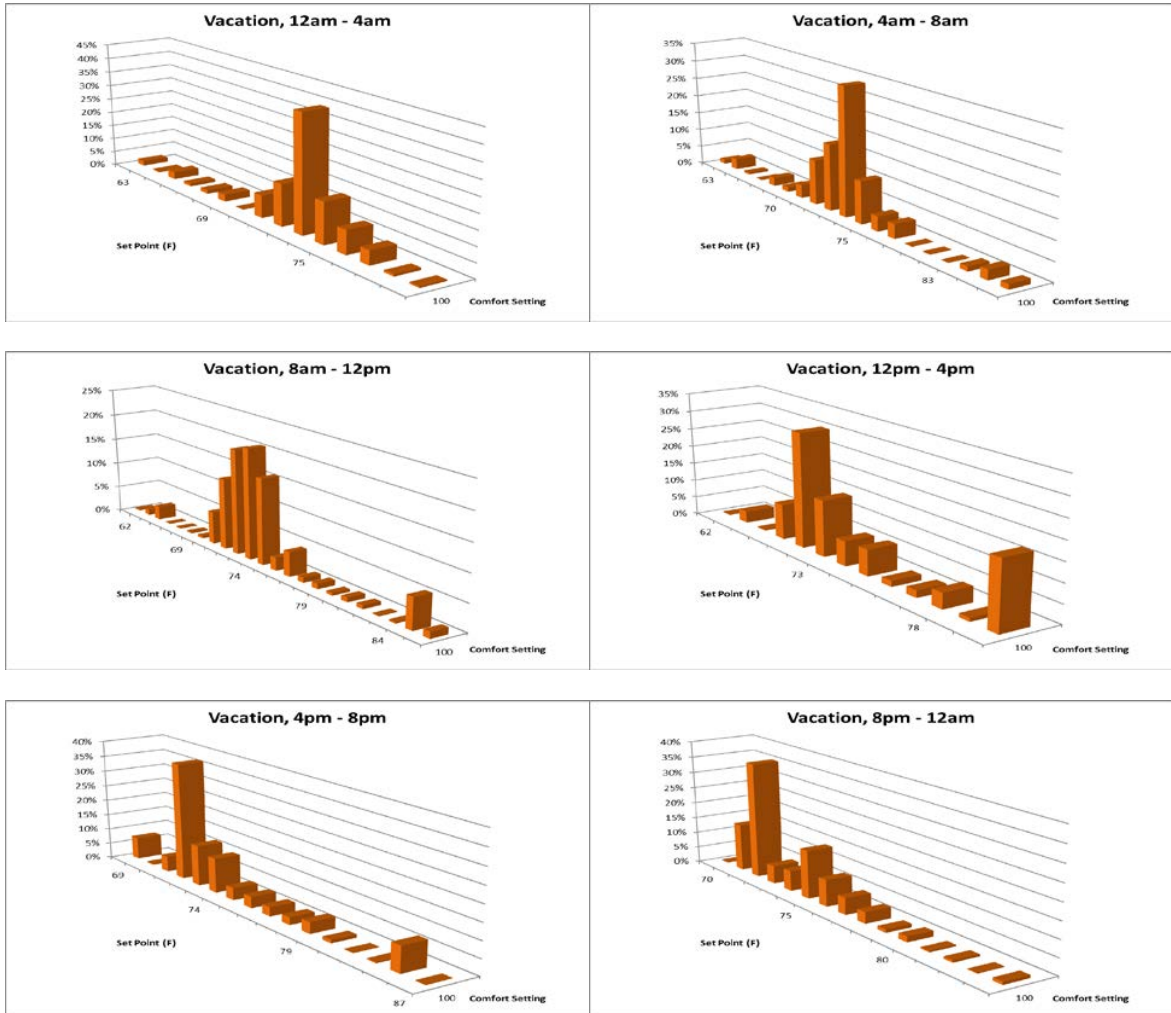


Figure 3.17. Cooling Set Point and Slider Distribution for Occupancy Status "Vacation"

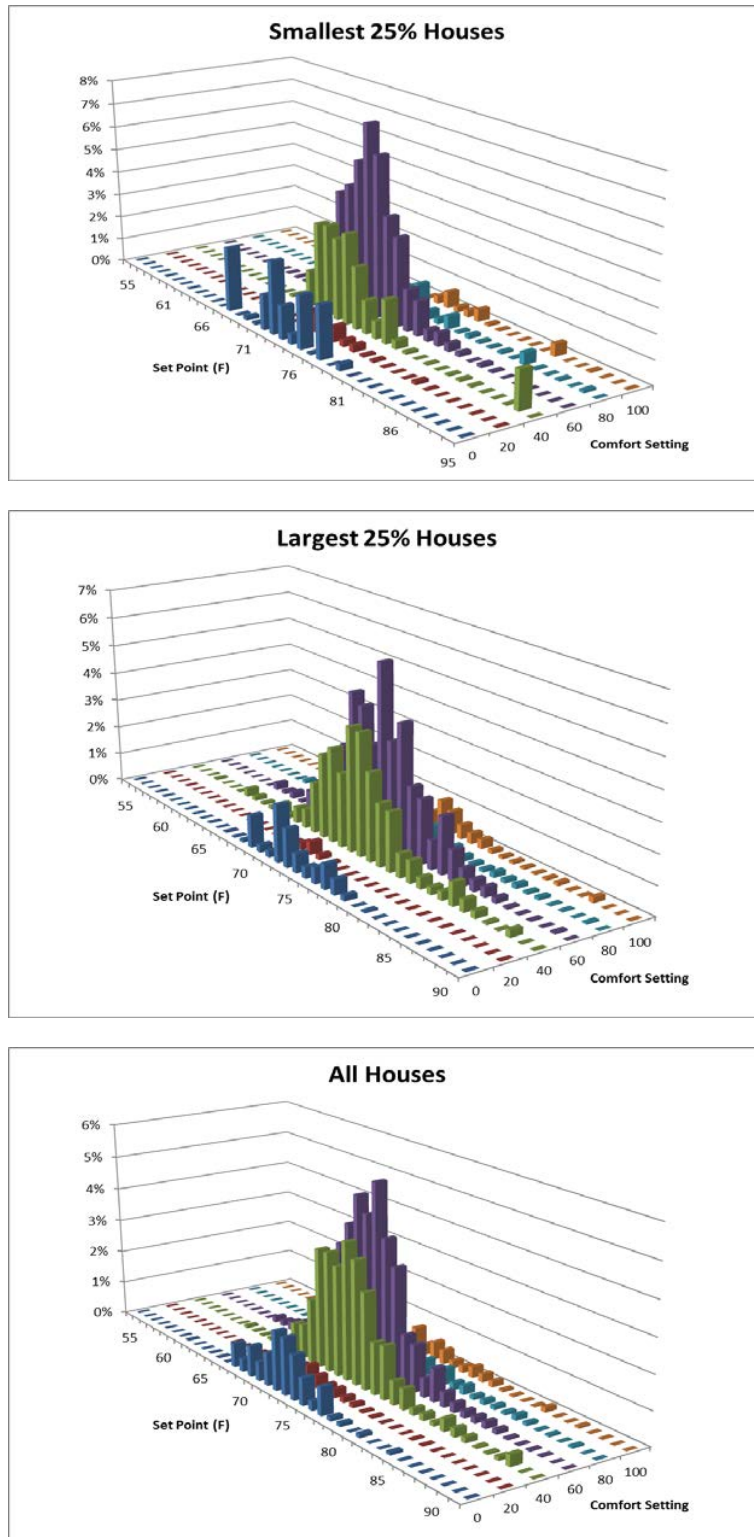


Figure 3.18. Effect of House Size on Cooling Set Points and Slider Settings Aggregated over All Occupancy Settings and Hours of Day

3.2.2 Thermostat Override Statistics

Table 3.10 shows the percentage of households that overrode their programmed thermostat settings during 2-hour and 4-hour congestion experiments. The override status was calculated as being positive for only those thermostats that were not in the override mode at the start of the experiment (that is, they were participating in the market), but at some point during the experiment were manually overridden. In 14 out of the total 69 2-hour experiments no thermostats were overridden, while only three 4-hour experiments recorded no overridden thermostats.

Table 3.10. Thermostat Override Statistics for 2-hour and 4-hour Congestion Experiments

2-Hour Experiments			4-Hour Experiments		
% Households that Overrode	Frequency	Probability	% Households that Overrode	Frequency	Probability
0%	14	20.00%	0%	3	11.54%
0–1%	13	18.57%	0–1%	3	11.54%
1–2%	25	35.71%	1–2%	4	15.38%
2–3%	10	14.29%	2–3%	3	11.54%
3–4%	5	7.14%	3–4%	2	7.69%
4–5%	3	4.29%	4–5%	3	11.54%
5–6%	0	0.00%	5–6%	3	11.54%
6–7%	0	0.00%	6–7%	3	11.54%
7–8%	0	0.00%	7–8%	0	0.00%
8–9%	0	0.00%	8–9%	1	3.85%
9–10%	0	0.00%	9–10%	1	3.85%
Total	70	100%		26	100%

Figure 3.19 compares the numbers of households that overrode their programmed thermostat settings during on-peak and off-peak 2-hour congestion experiments. It is evident that more households in override status were recorded during on-peak periods (14:00 – 22:00), as compared to off-peak period (22:00 – 14:00) experiments.

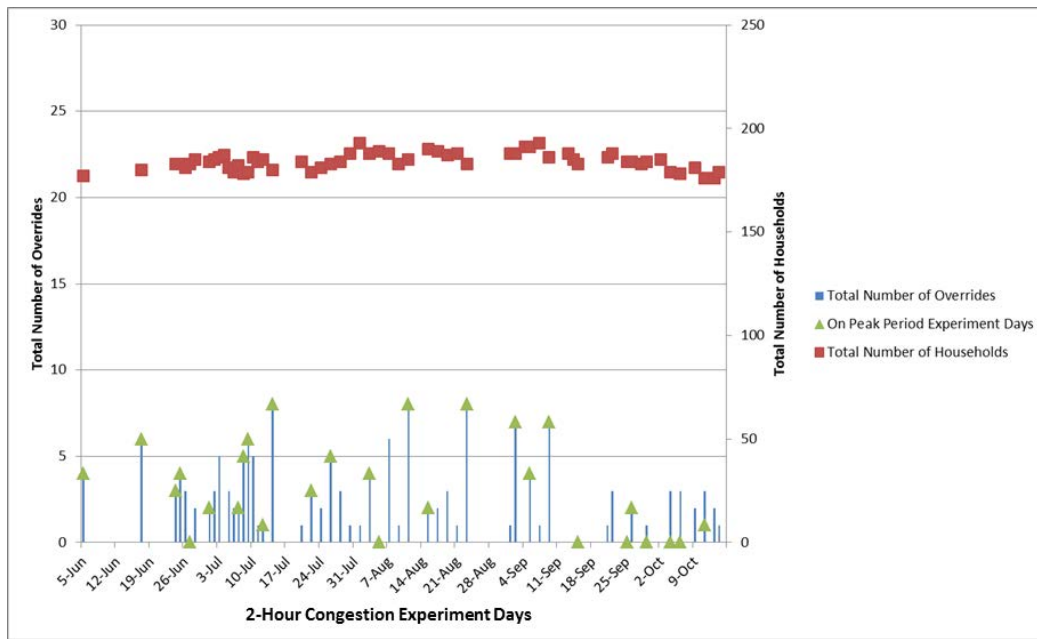


Figure 3.19. Thermostat Override Statistics during 2-hour Congestion Experiments

Figure 3.20 presents the override statistics recorded during 4-hour congestion experiments, which were conducted over the on-peak periods of the day. The figure also presents a comparison of the override statistics when the experiment was called during a SMART Shift Plus (critical peak pricing) event versus, along with the other 4-hour experiments. It is evident that a greater number of households override their programmed thermostat settings during SMART Shift Plus events.

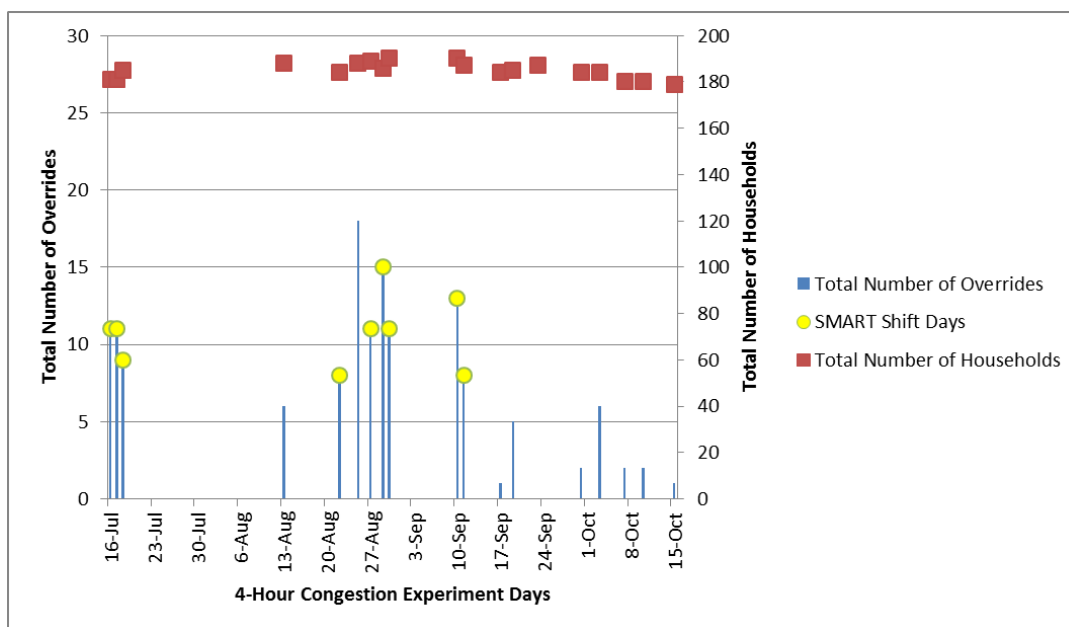


Figure 3.20. Thermostat Override Statistics during 4-hour Congestion Experiments

Figure 3.21 and Figure 3.22 present comparisons of the total numbers and the percentages of households that override their programmed thermostat settings during 2-hour versus 4-hour congestion experiments. The figures may be interpreted as override “duration” curves, presenting the numbers and percentages, respectively, of households in override status during 2-hour and 4-hour experiment periods. From both the figures, it is evident that a greater number of households override their programmed thermostat settings during 4-hour experiments than during 2-hour experiments. This may be attributed to greater discomfort due to the rising house temperatures during 4-hour experiments when HVACs stayed off for a considerably longer duration.

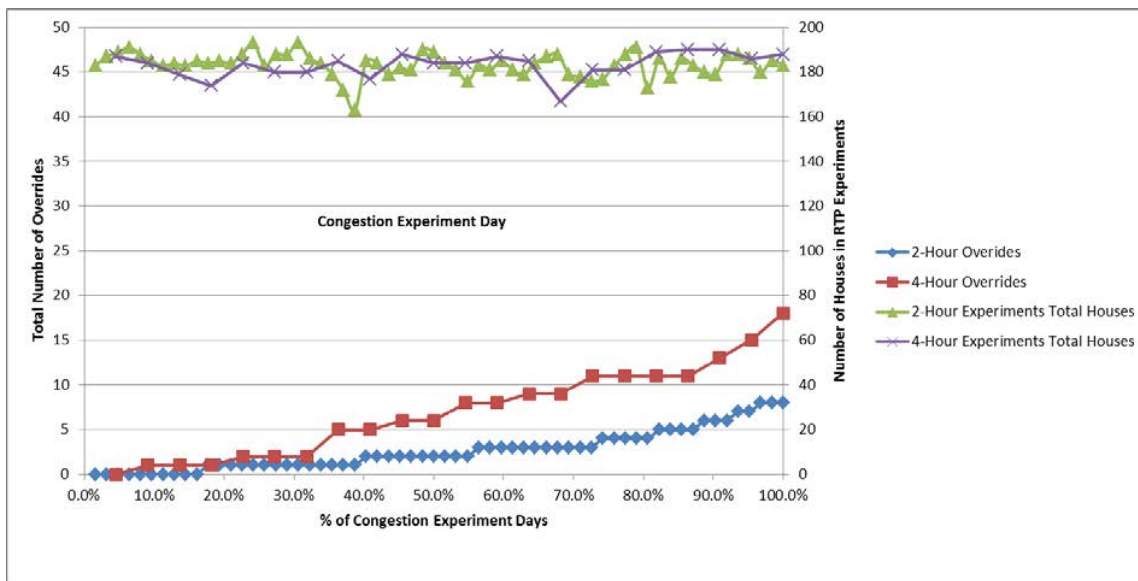


Figure 3.21. Override Duration Curves for 2-Hour and 4-Hour Congestion Experiments

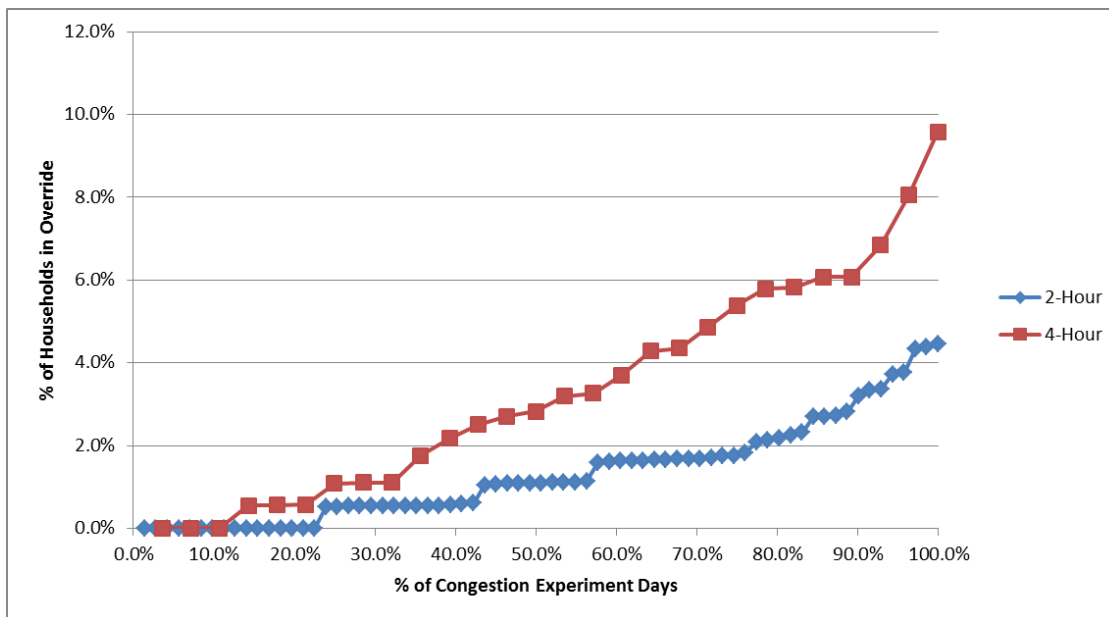


Figure 3.22. Override (% of total) Duration Curves for 2-Hour and 4-Hour Congestion Experiments

3.3 HVAC Bid Quantity versus Actual Load

When ePCT equipment was installed in a home, it was configured to store the estimate for the amount of power that the HVAC unit would draw when operating. The Project assumed that the compressors are fixed speed, which appears reasonable today, but will likely change in the future as HVAC units become more efficient. The installer estimated the power draw based on the nameplate rating and/or size of the compressor. A look-up table was provided to help convert HVAC heating/cooling size to the power draw. The estimated power draw was stored in the HEM equipment for use as the HVAC bid quantity (q_{bid}). The accuracy of this estimate when compared to the actual power draw could be important to the performance and stability of the RTP_{da} system under wide-scale deployment.

Analysis of the metered data for the RTP_{da} households was undertaken to determine the actual power drawn for each unit. The results of this analysis are presented below. Details of the methodology are left for a future publication.

3.3.1 Results of Analysis

Figure 3.23 plots the meter analysis value for each household as compared with the nominal value (q_{bid}) used in the RTP_{da} auction. If the values corresponded well, then the points in the graph would be expected to cluster closely around the dotted diagonal. Instead we see that, in general, the HVAC equipment is drawing more power than the household is bidding into the market. The distributions for 99 households of their bid power quantities and estimated power quantities are shown in Figure 3.24, indicating a significant deviation from the quantities bid.

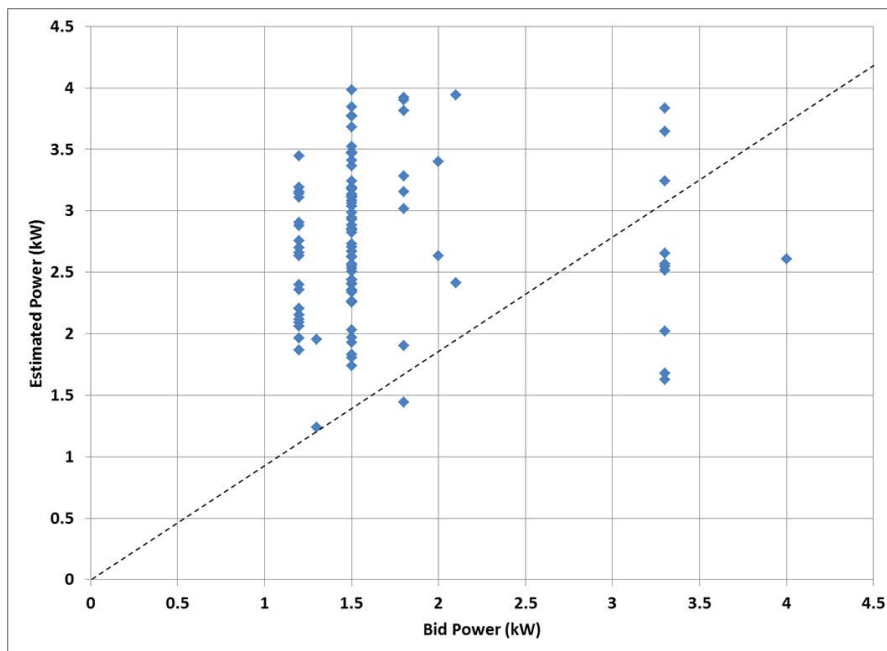


Figure 3.23. Estimated HVAC Power from Metered Data versus Bid Power for the Same Household

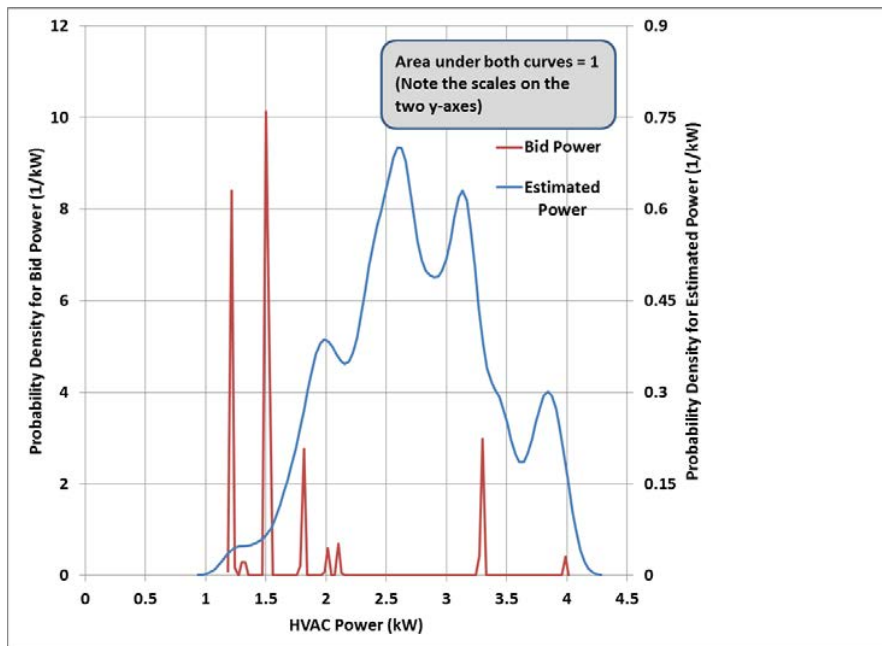


Figure 3.24. Distributions of HVAC Bid Power and Estimated Power

The linear vertical groupings of points in Figure 3.23 likely occurred because the look-up table listed a few key values: 1.2, 1.5, 1.8, 2.1, and 3.3. These values are also clearly apparent in the red line in Figure 3.24.

If the system becomes constrained either due to limited supply or due to congestion, the market cleared price is determined by price, energy bids. These bids should be accurate for proper operation. However, in this project, the responsive load was so small that the market either cleared at the feeder base price (non-congested situation) or at the feeder market cap (congested situation). In either case, the inaccuracy of the bid quantities did not affect the market clearing. As the energy-sensitive portion of the household bills were calculated from the metered quantity, this portion of the bill was not affected. However, the incentive saving calculation is dependent on the bid quantity, so inaccuracies can have an effect here.

Bid power inaccuracy would also have an impact on the analysis of load sensitivity to price when there is a high penetration of RTP_{da} resources on the feeder. In this case, a congestion situation can occur where the market clears between P_{base} and P_{cap} . The bid power inaccuracy may cause the market to clear at different energy quantity and price points (see Figure 3.25).

This situation is a topic for future analysis. A simulation of the RTP_{da} system could be set up to run two sets of scenarios using the PJM real-time market pricing information and the congestion event periods. One set of scenarios would run the households that bid q_{bid} , but size the HVAC models to match the distribution seen from the meter data analysis as in the demonstration. The other set of scenarios would adjust q_{bid} to accurately reflect the meter data analysis values. The scenarios would be scaled to show different penetrations of RTP_{da} households on the feeders. Comparisons of these runs would provide insight regarding the impact of bid power errors on the performance of the RTP_{da} system.

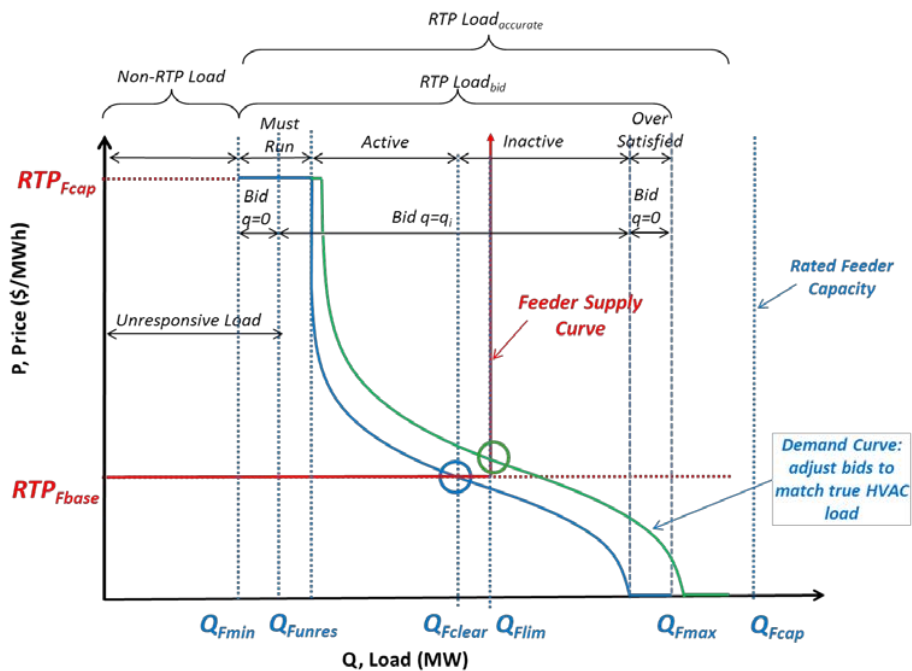


Figure 3.25. Conceptual Bid Curve Comparison of Bid versus Accurate HVAC Draw

4.0 RTP_{da} Load Sensitivity to Price

This chapter investigates the price-responsive nature of the RTP_{da} resources over the course of the summer. The first section analyzes data collected for each household to explore the population of RTP_{da} resources' sensitivity to the 5-minute, LMP-based market price fluctuations experienced during the experiment. It is followed by a similar investigation done using the GridLAB-D simulator. The final section investigates the response of the RTP_{da} resources to the imposed congestion events, where the market cleared at the price cap for the duration of the event.

4.1 Results from Measured Data

The responses of the thermostat agents are not really to energy prices but to variations in the prices around the “expected” price, the expected price being the average price experienced during the previous 24 hours. Consider the relationship between response defined as (RTP13 – RTPnr13) and LMP. The LMPs are used as proxies for the real-time prices that are used for the bids. An LMP of, for example, \$40/MWH may be perceived as high at some times and as low at other times. If perceived as high, the result is a tendency for reduction of energy use compared to the control houses. If it is perceived as a low price, the tendency is toward increased energy use. Therefore for a given LMP, the response at different times can vary over a range of values. This is seen in Figure 4.1. In this figure, the 5-minute average change in energy between RTP13 and RTPnr13 households for non-congestion experiment days is plotted against the corresponding time period's 5 minute LMP. A heavily smoothed response is shown as the blue points. Also shown is a histogram of the LMPs in the data points. The series of vertical streaks

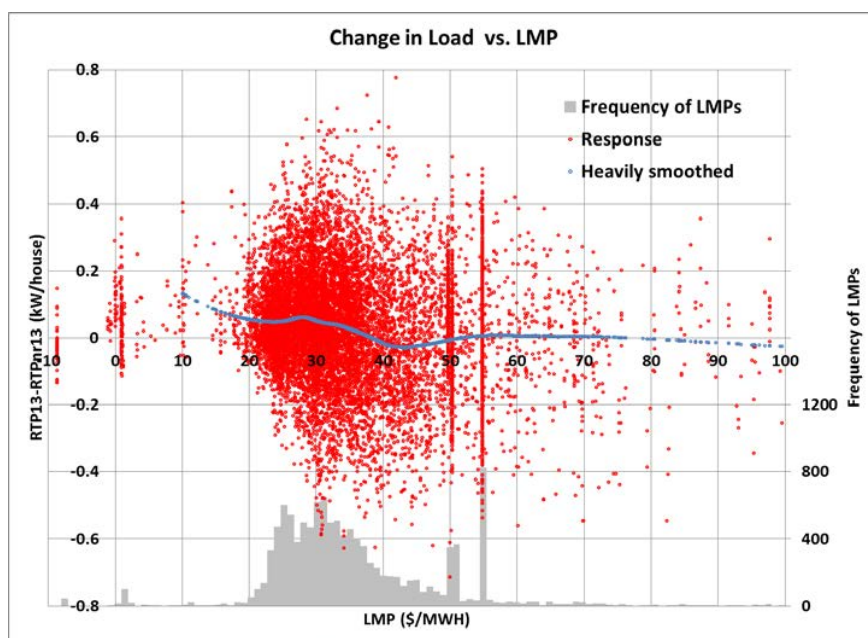


Figure 4.1. Response versus LMP for About 12,000 5-Minute Data Points Covering the Period June–September 2013

correspond to some default prices used when no LMP was transmitted. The LMPs are truncated at 100 \$/MWH because points beyond that are sparse. A histogram of the full range of LMPs from \$-8.67 to \$659.09 is shown in Figure 4.2.

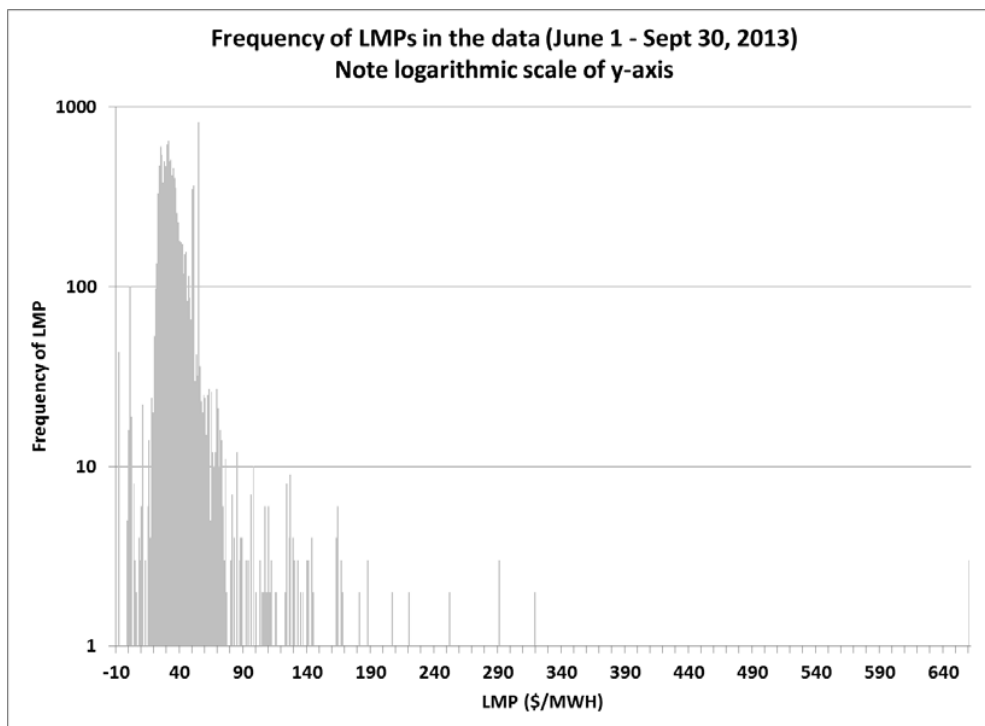


Figure 4.2. A Histogram of the Full Range of LMPs (from $-\$8.67$ to $\$659.09$) Seen During the Analysis Period

Even though the response is to variations in LMP and not to LMP itself, a heuristic expectation is that higher prices should generally result in a negative response. It is therefore of interest to determine the correlation coefficient between the response and LMP. This coefficient is -0.17 , confirming heuristic expectations of the design of the RTP_{da} system.

4.2 Simulated Results

Similar to previous sections, households were simulated within GridLAB-D to represent 25% penetration of RTP_{da} households; 300 households were “experimental” while 900 were operated similarly in each simulation and did not respond to variations in price. The experimental households were modeled using three different scenarios:

1. Control – the households were simulated using the standard pricing tariff.
2. RTP_{da} – the households were simulated using the residential RTP_{da} service tariff and responded to wholesale price fluctuations in a manner similar to those observed in the pricing experiments (for example, thermostat slider and temperature settings, internal air temperature decay rates, and such).

3. RTP_{da} Congested – the households were simulated using the residential RTP_{da} service tariff, responded to wholesale price fluctuations, and responded to capacity limits placed on the feeder aligned with the actual experiments (96 experiments in four months).

The simulation results offer an additional comparison against the actual data, without the necessity of using filtering and regression techniques, as simulation provides a “perfect” control group. The graph in Figure 4.3 is similar to Figure 4.1, but uses the simulated response data (RTP_{da} minus Control) and includes every day within the four-month period (rather than a subset in the field data case where congestion days were removed). The graph is truncated as before and does not show some periods of very high price and high load response. The figure is presented to show the similarities between the simulated and actual responsive loads; particularly the area around LMPs of 30 to 60 \$/MWh. A negative value on the y-axis indicates a reduction in demand when moving to the RTP_{da} group. It can be seen that when the LMP is relatively low (less than \$30/MWh), there is almost no change in demand when moving to the RTP_{da} rate. Further research is needed, though this may be indicative of having very little resource available for reduction during relatively low LMP periods (e.g., early morning periods). However, as LMP becomes higher, there is a significant trend toward reduced demand. It should be noted that data points higher than \$60/MWh are of much lower density and the trend line is less certain.

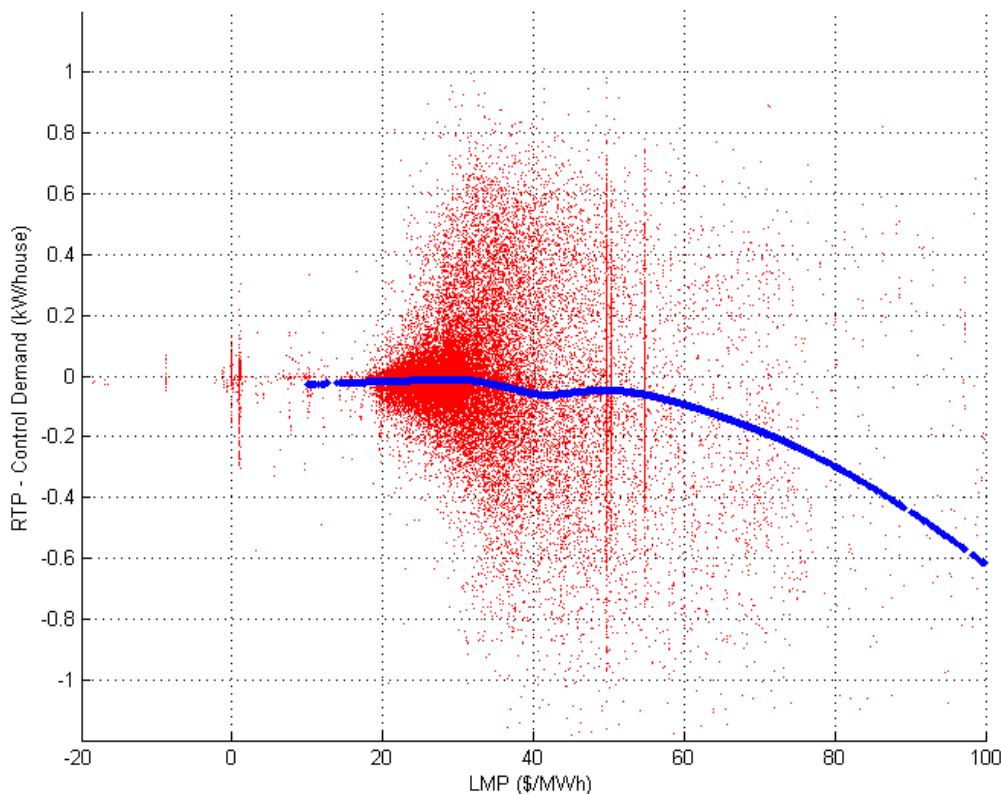


Figure 4.3. Change in Load versus LMP between the Control and RTP_{da} Groups (positive value indicates increased load)

To replicate what was seen in the deployed system, the 96 congestion events were applied to the population of devices. Figure 4.4 shows the relationship between LMP (that is, not the price directly seen by the consumer) and the change in load behavior. The application of the congestion events tended to increase demand during periods of high prices and negate some of the decreases seen during low to medium price periods. This is most likely driven by the congestion event raising the average price and making the LMP look like a better deal in the hours following the events. This may have a significant impact immediately after a congestion event, when units are trying to recover, especially if high LMPs are coincident with the congestion event. The absolute LMP is indifferent to whether the congestion event occurred; however, the thermostat agents will perceive this price as relatively lower following a congestion event, and will increase their consumption following the event. While this is greatly exaggerated by using 96 congestion events, it does suggest that for 24 hours after a high-price or congestion event, households will tend to “over consume” relative to high LMP values, as this price will appear to be a relatively low price. More investigation is warranted to better understand and quantify the simulation results and calibrate simulation models with further information that can be gleaned from the field data.

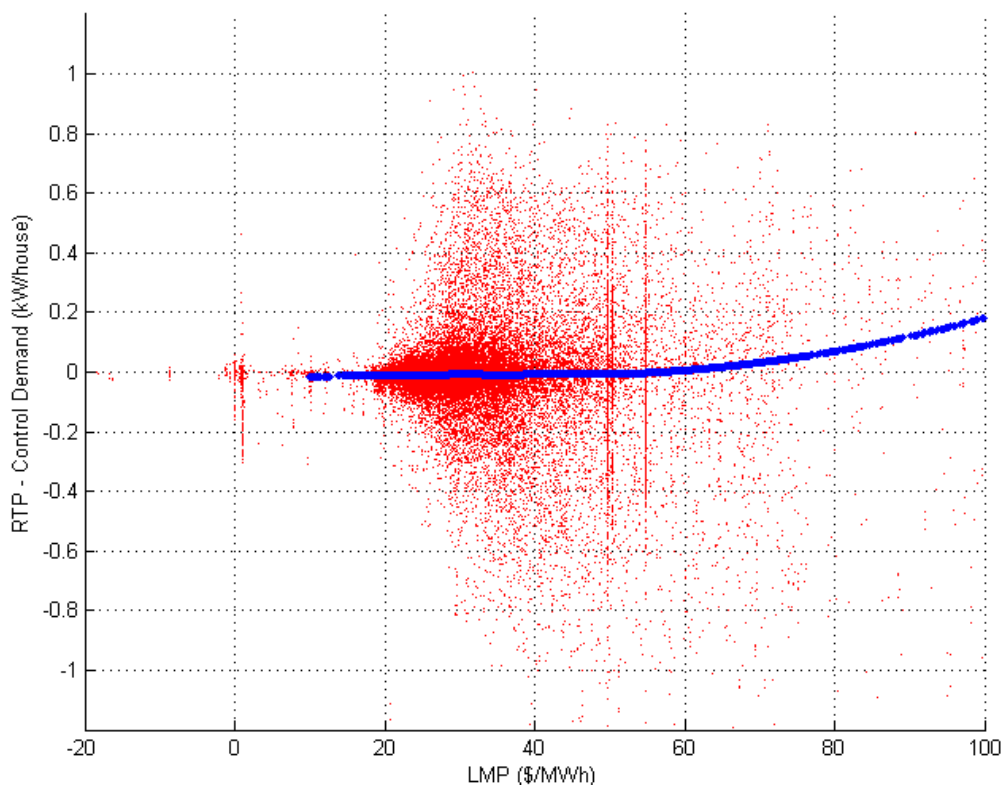


Figure 4.4. Change in Load versus LMP between the Control and RTP_{da} Groups Including Congestion Experiments

To look at this effect, Figure 4.3 and Figure 4.4 were adapted to look at the response to the supply price in terms of standard deviations from the average price. This effectively translates the price into how

the thermostat controller views it; the current price is always relative to the average price from the previous 24 hours. So, the price is calculated and displayed as

$$P_{\sigma} = \frac{P_{supply\ bid} - P_{average\ 24\ hours}}{P_{standard\ deviation\ 24\ hours}} \quad (4.1)$$

Figure 4.5 shows the same (non-congested) case as Figure 4.3, but with the price translated into relative prices. The patterns can be difficult to discern. In general, one would expect that as relative price increases, the amount of reduction in demand should increase. However, during any given market period, the response to price is dependent on what happened in previous markets. For example, after an extended period of +2.5 standard deviation prices, in which loads were continuously deferring, a price of +1.5 standard deviations might be a relatively attractive price due to the deferral of operation. So, at any given 5-minute period, the RTP_{da} load may increase with higher prices, but the overall trend should be strongly toward decreased demand during relatively high-price periods.

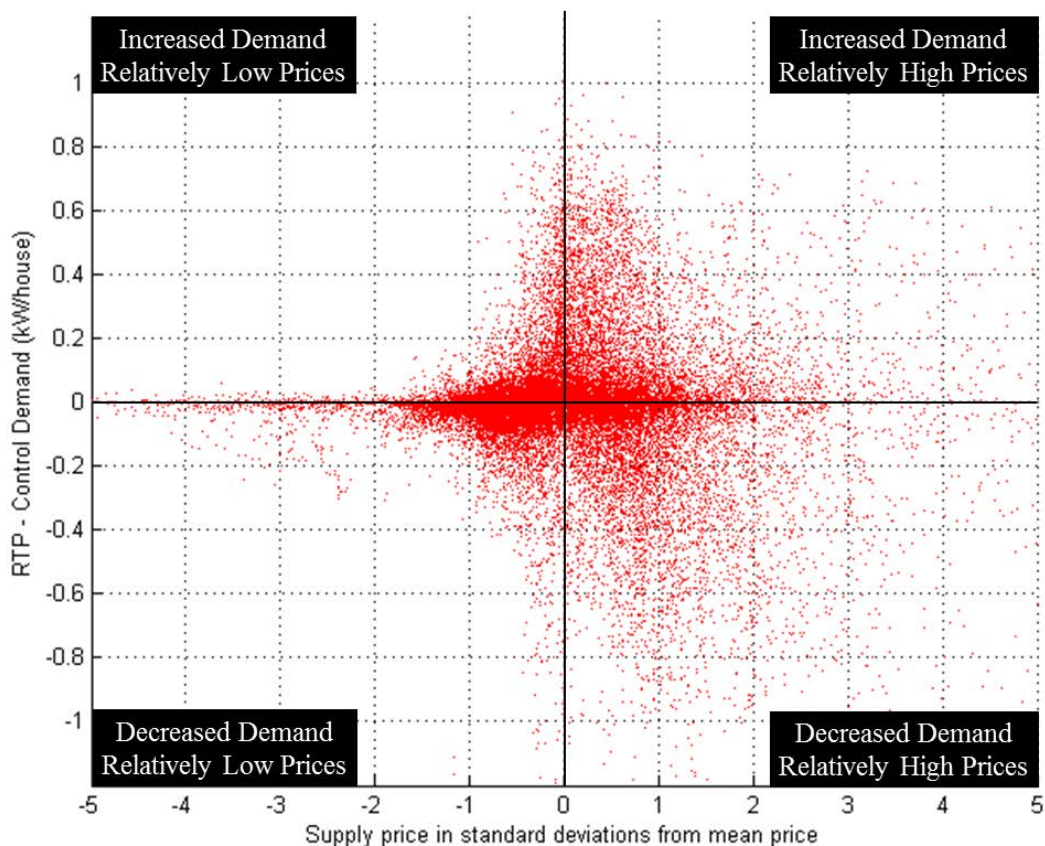


Figure 4.5. Change in Load versus Relative Price between Control and RTP_{da} Groups

Figure 4.6 breaks the same data into three temperature “bins,” where the temperature bin represents the current outdoor temperature during that 5-minute market interval. Blue represents temperatures less than 70°F, green between 70 and 80°F, and red over 80°F. The black lines are trend lines determined using the same technique as in Figure 4.1. When presented this way, a number of trends are quickly

identifiable. Again, the trends are important and not the individual points. In any given individual market clearing, depending on what occurred in previous market clearings, the RTP_{da} load may increase or decrease relative to the control group no matter the relative price. For example, if the RTP_{da} load has been deferred for 30 minutes, a relative price of +1 may appear quite reasonable (recovery from the deferral may cause an increase in load). However, if the price has been relatively low for the past 30 minutes, a price of +1 is too high for the current resource status (and decreases the load). Looking at the trend lines reduces this noise and determines whether the system in aggregate is behaving as designed, or in other words, decreasing demand during relatively high-price periods.

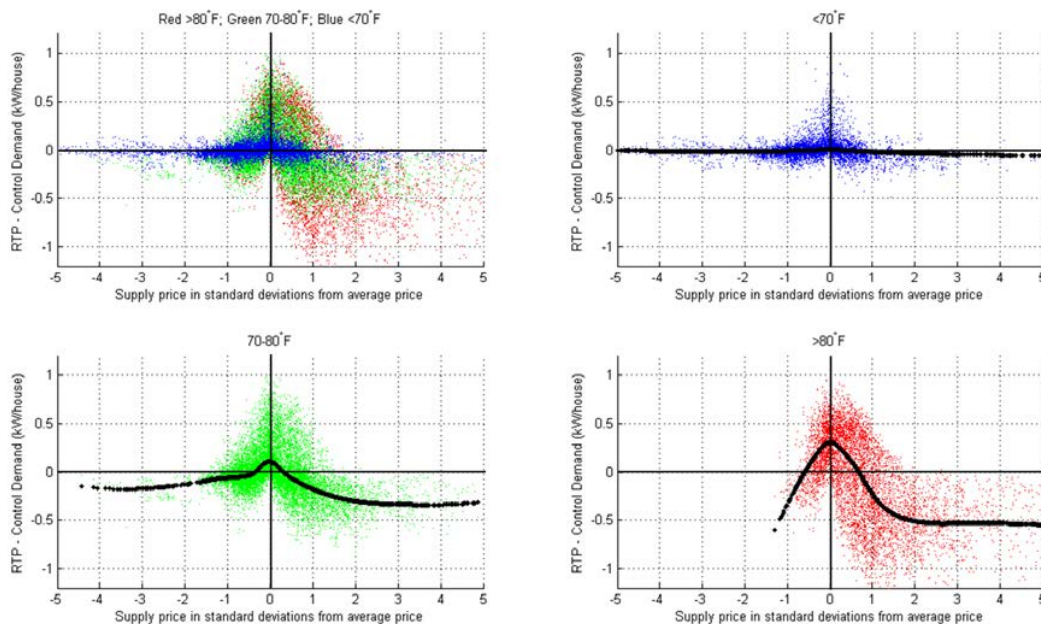


Figure 4.6. Change in Load versus Relative Price between Control and RTP_{da} Groups Broken into Outdoor Air Temperature Bins

In the “less than 70 degrees” bins (the simulations were for summer periods only), when there is minimal air conditioning, the trend is very flat with a very slight trend toward reducing demand as price increases. This is expected, as there is minimal resource during these periods (albeit some resources still available). Also, while there are some individual cases where demand increases or decreases, the overall trend is to minimally decrease load as a function of price. When temperatures are greater than 80 degrees (red), it is clear that as relative price increases, load decreases to a plateau value of approximately 0.5 kW/household. This is as expected (and desired). Of note, however, is that when price is between -0.5 and 0.5 standard deviations, the trend is actually to increase load. Most likely, this is caused by the devices “recovering” during slightly higher prices after very high-price periods that tend to occur more often during hot periods of the day. Data for the 70–80 degree time periods (green) are in between data for the other two graphs. Additionally, as temperature climbs, the relative price also climbs, indicating that a higher temperature day after a cooler temperature day tends to experience higher LMPs. In future applications, this observation could be used to better predict upcoming prices and better tune the controllers to respond to high and low price excursions, which would allow for a rough prediction of demand reduction available during any given market cycle as a function of outdoor air temperature.

In conclusion, this analysis of field and simulated data is but a start to understand and provide insight to the complex interactions at play in the RTP_{da} system. The basic trend observed of reducing load as LMPs rise is directional evidence of the desired behavior with the system; however, many more questions are raised about the strength of this correlation and its behavior under different market, weather, and temporal-related conditions. Further investigation is needed to address these questions and gain greater insight.

4.3 RTP_{da} Load Event Response

Due to the relatively low penetration of RTP_{da} households on each feeder, the impact of each congestion experiment was to engage all of the resources and drive the cleared market price to the price cap. A benefit of these experiments is that they demonstrated the maximum amount of response that could be obtained under various operating conditions. This section investigates the magnitude of the responses from the resources to the congestion events and how well the resources responded over the duration of the event.

4.3.1 Events Response Magnitude

The magnitude of the response is estimated by evaluating the difference between the fractional change in the control group load and the RTP_{da} group load relative to their averages for the 4 hours prior to the beginning of the event. The 4 hour period is chosen as it strikes a balance between prior conditions sample size and variance. The fractional response of response group x relative to control group y is defined as

$$r_t(x, y) = \frac{\sum_{n=1}^{N_x} x_{n,t}}{\sum_{n=1}^{N_y} y_{n,t}} - 1 \quad (4.2)$$

The mean response for the 4 hours prior to the start of the event at $t = 0$, where the time interval is 5 minutes and t is in hours, is evaluated as

$$\bar{r}(x, y) = \frac{1}{16} \sum_{-4 < t \leq 0} r_t(x, y) \quad (4.3)$$

and is used to normalize all the responses thereafter. The percent response is evaluated relative to this 4-hour mean prior to the event.

The magnitude of the response after the start of the event relative to the response prior to the event is thus

$$R(x, y) = r_t(x, y) - \bar{r}(x, y) \quad (4.4)$$

This result is shown for 2-hour and 4-hour duration events by the solid lines in Figure 4.7.

4.3.2 Event Response Uncertainty

The uncertainty of the response is estimated by first evaluating the variance of the control group and the RTP_{da} response group for various response types (for example, 2-hour event, 4-hour event, mild day,

hot day, off-peak period, on-peak period). All the responses for the selected response types were grouped after being normalized with respect to the conditions prior to the event. The variance of a group load x^N (N is the number of active meters) at the time t is given by

$$v_t(x) = \frac{1}{N^2} \sum_{n=1}^N (x_{n,t} - \bar{x}_t)^2 \quad (4.5)$$

To compute the uncertainty of the difference between response group x and the control group y , we must compute the covariance

$$c_t(x, y) = \frac{1}{N^2} \sum_{n=1}^N (x_{n,t} - \bar{x}_t)(y_{n,t} - \bar{y}_t) \quad (4.6)$$

The 63% confidence interval for the response of the response group x relative to the control group y is

$$\sigma_t = \sqrt{v_t(x) + v_t(y) - 2c_t(x, y)} \quad (4.7)$$

This result for 2- and 4-hour events is shown by the dotted lines in Figure 4.7.

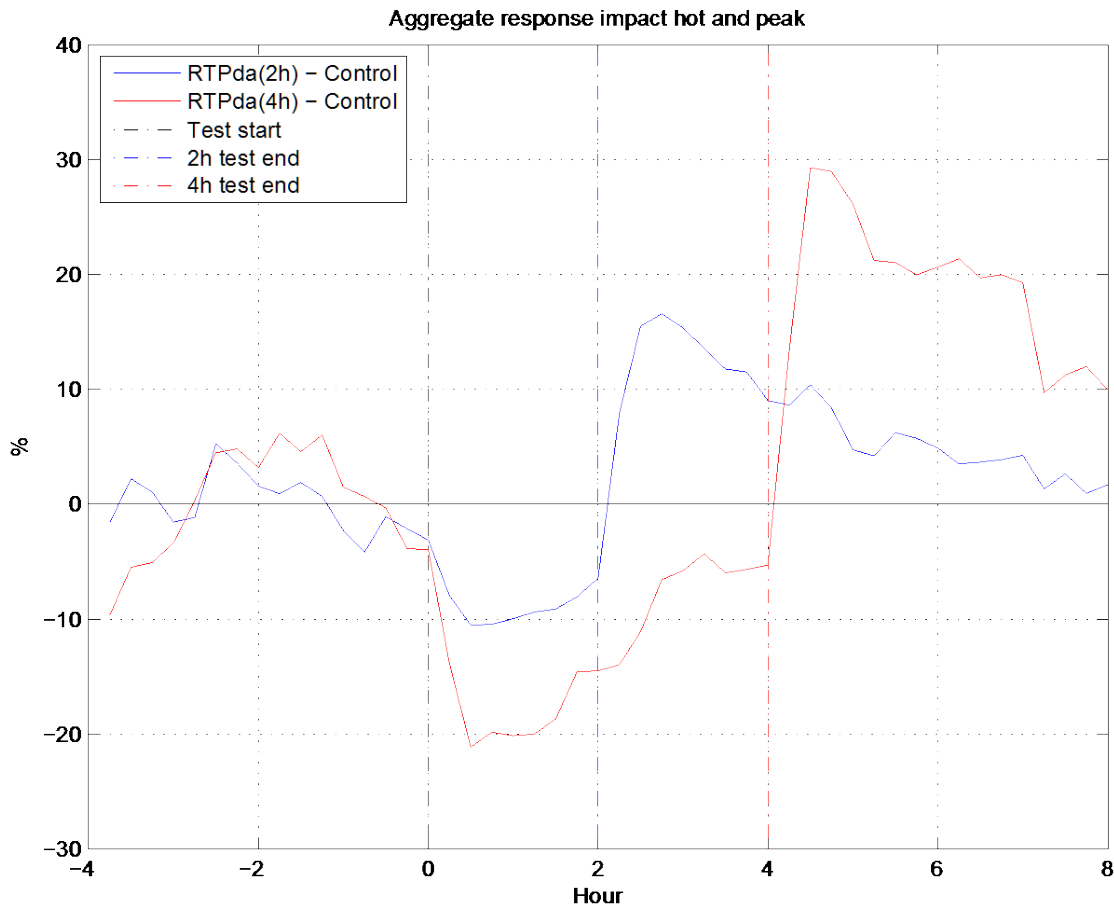


Figure 4.7. Aggregate Response to 2- and 4-hour Congestion Events

The results for the various event and day types are summarized in Table 4.1. The initial response is evaluated 15 minutes after the start the event. The response trend refers to the general trajectory of the response after the initial response to the event. It is evaluated for the duration of the event as a linear fit to the data in percent per hour with the same percent scale as initial response. The initial uncertainty is given for the 63% confidence interval on the same scale as the initial response. The uncertainty trend refers to the general trajectory of the uncertainty after the initial response to the event. It is evaluated in %/h on the same scale as the initial response for the duration of the event.

Table 4.1. Summary of Group Responses by Event and Day Type

Event Type	Initial Response (%)	Response Trend (%/h)	Initial Uncertainty (%)	Uncertainty Trend (%/h)
All events	-8.6	1.0	4.2	-0.2
All 2 h	-6.4	-0.3	5.9	-0.3
Hot+peak 2 h	-10.5	1.3	11.4	-0.6
Mild+peak 2 h	-1.4	-3.1	16.4	-0.8
All 4 h	-17.9	4.1	17.2	-0.6
Hot+peak 4 h	-22.5	4.7	23.1	-0.7
Mild+peak 4 h	-9.3	3.0	63.4	-2.0

The 2-hour events have a much shallower initial response than the 4-hour events (10.5% versus 22.5%). This is mostly driven by the timing of the events. Many of the 4-hour events occurred during high peak periods in the late afternoon on successive hot days, while the 2-hour events occurred over a greater variety of situations in both time of day and daily temperatures. Also, on mild days 4-hour events tended to start later in the day relative to 2-hour events. Thus the 2-hour events tended to start with very few RTP_{da} HVAC resources available and as more unconstrained HVAC resources began operating, the system became more responsive (hence the negative percent response trend). In contrast, 4-hour events started with more RTP_{da} resources already in operation and moved into times of the day where RTP_{da} resources became more constrained in their ability to respond. Therefore, the trend was for decreasing RTP_{da} resource response (positive response percent trend). On peak days, events usually began with more RTP_{da} resources available and the trend was generally toward fewer RTP_{da} resources as time passed. As the resources were depleted, it became harder to distinguish the experiment response from the control group.

Further analysis of the data, such as segmenting the graphs according to time of day, weekday versus weekend, and temperature can help in more fully characterizing the response of the RTP_{da} resources to these events.



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U.S. DEPARTMENT OF
ENERGY

gridSMART® Phase 2 Business Case

Introduction

American Electric Power (“AEP”) has been actively engaged in planning, deploying, and evaluating smart grid technologies and programs across the 11-state AEP System since 2007. AEP’s gridSMART® initiative integrates a suite of advanced grid technologies into the existing electric network that can improve service quality and reliability, lower energy consumption, and save money. The new technologies can help AEP improve efficiencies, identify and respond to outages more quickly, and better monitor and control the operation of the distribution grid.

AEP Ohio’s (“Ohio Power Company” or the “Company”) gridSMART® Phase 1 project was designed to evaluate a broad scope of potential smart grid technologies on a smaller scale in order to guide subsequent deployment plans. AEP Ohio has not only gained valuable experience in the performance of these technologies, but also in the operation of communication interfaces and how to optimize the processes to deliver on the benefits envisioned. This experience prepares AEP Ohio for a more efficient and effective implementation as it deploys select technology and process improvements to the broader scale and more diverse customer base proposed in Phase 2.

The following benefits have been achieved as a result of AEP Ohio’s Phase 1 in the deployment area:

1. Improved safety for AEP Ohio employees
2. Operational efficiencies through real-time information and remote operations
3. Fewer number of customer outage events
4. Reduced number of customers experiencing sustained (>5 minutes) outages
5. Faster restoration times for sustained outages (>5 minutes)
6. Demand reduction through new tariff offerings and the education of customers regarding energy costs and use of technology
7. Improved energy efficiency and demand reduction with Volt/VAR Optimization (“VVO”)
8. Improved customer satisfaction
9. Improved access to meter reading data

As we reflect on the successes of our gridSMART Demonstration Project, we have analyzed what others in our industry have already achieved with their Smart Grid deployments, recognizing that many others are extending these Smart Grid benefits to their customers at a much faster pace and have dramatically increased customer satisfaction. In numerous cases, large Electric Utility companies have deployed Smart Grid modernizations to their entire customer base. AEP Ohio believes that a gridSMART expansion enables a fundamental change in the way we operate, serving as the necessary foundation upon which we will provide more reliable service and greater efficiency opportunities for our customers in the future. Going forward, it is the intent of AEP Ohio

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to continue to extend elements of the gridSMART® program throughout the AEP Ohio service territory, starting with the proposed Phase 2 project as further defined through this submittal.

gridSMART® Phase 2 will build upon AEP Ohio's successful gridSMART® Phase 1 experience. The project will be comprised of Advanced Metering Infrastructure ("AMI") for approximately 894,000 customers across urban and suburban areas; Distribution Automation Circuit Reconfiguration ("DACR") for approximately 250 priority circuits; and Volt/VAR Optimization ("VVO") for approximately 80 circuits. AEP Ohio is targeting a deployment timeline of approximately four years for all three technologies as proposed. In addition to extending the benefits of AMI, DACR, and VVO achieved in Phase 1 to a larger base of customers, it is envisioned that Phase 2 also will provide the following benefits:

1. Support for a more robust customer choice market by enabling customer access to information, improved data for market settlement, and potential for time-differentiated rate design offerings.
2. Reduced uncollectible revenue, theft and consumption on inactive meters through automated remote disconnect and continuous usage data availability.
3. Enhanced customer service and satisfaction (e.g., through faster, remote service connection).
4. Better information to customers concerning their electricity usage, enabling them to conserve energy, save money, and help to protect the environment.

gridSMART® Phase 2 is built upon proven technologies and solutions that have been implemented in gridSMART® Phase 1 and broadly deployed in the market. This document describes the benefits, costs, and rate impacts for gridSMART® Phase 2 as well as examples of benefits achieved by other utilities who have deployed AMI, VVO, and Distribution Automation ("DA") reliability solutions similar to DACR, plus examples of customer acceptance of utility smart grid programs.

AEP Ohio gridSMART® Roadmap

As technology advances, the electric utility industry has the opportunity to enhance the way it does business to provide both customer and utility benefits. AEP Ohio's gridSMART® strategy takes advantage of these technology advancements. It is the Company's vision that these technology improvements will yield customer satisfaction layered upon a foundation of utility efficiencies.

The Company has approximately 1,533,000 meters installed throughout its service territory. Of this total, AEP Ohio has converted approximately 132,000 meters to AMI. The converted meters are providing the expected benefits. The current AMI technology is proven for urban deployment areas, typically with meters in relatively close proximity to one another.

This proposal for Phase 2 includes the next step for AMI deployment. In Phase 2, the Company expects to convert an additional 894,000 meters to AMI bringing the total to just over one million AMI meters. AEP Ohio has 200,000 customers with automated

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meter reading, not associated with this proposal, and an additional 302,000 customers for which an advanced metering plan is still under review. The Company will continue to carefully evaluate meter and networking technologies to determine how best to serve these customers in the most cost-effective manner possible while delivering maximum benefits. If the AMI technology continues to advance and a rural AMI solution becomes more cost effective, the Company may reevaluate the plan regarding rural meter technology. Overall, the Company envisions all meters to be replaced with an advanced meter technology over the next 4-6 years.

Of the approximate 1,600 total distribution circuits within AEP Ohio, the Company has deployed DACR on 70 circuits in Phase 1. These circuits are providing the expected benefits. When a fault occurs, DACR automatically reconfigures the associated circuits to restore power to customers in non-faulted zones on a circuit. Circuits that have a physical connection to other circuit(s) or are adjacent to other circuits are candidates for deployment where reliability could be enhanced through the installation of the DACR technology. Each DACR installation provides added reliability and operational enhancements. Currently, the Company has targeted approximately 450 circuits with these physical characteristics that should yield solid reliability benefits through the deployment of DACR. Phase 2 proposes installing this technology on approximately 250 distribution circuits that result in the greatest reliability or operational benefits. The remaining circuits could be proposed to be deployed under a gridSMART® Phase 3 at a later date or under the Distribution Investment Rider, if approved by the Commission.

The Company has also deployed VVO on 17 distribution feeders at five substation feeders as part of Phase 1. The formal evaluation of these circuits indicated the technology provided the expected results. The VVO technology the Company intends to deploy takes advantage of Conservation Voltage Reduction (“CVR”) in addition to Volt-Amp Reactive (“VAR”) or reactive power optimization. This combination improves the overall efficiency of the circuit as the majority of the electrical loads on a distribution system will consume less energy as the voltage is reduced. Currently, the Company has targeted approximately 80 circuits for VVO deployment as part of Phase 2. The targeted circuits are expected to yield significant benefits. Additional circuits that are considered good candidates for VVO could then be proposed for deployment under a Phase 3 plan at a later date or under the Distribution Investment Rider, if approved by the Commission or under the Energy Efficiency (“EE”) program if needed to meet required objectives.

Benefits

DACR Benefits

Reliability

AEP Ohio’s gridSMART® Phase 2 DACR is designed to improve outage identification and restoration times, and to enhance storm hardening with enhanced visibility in the areas where the systems are deployed.

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In Phase 1, through the deployment of DACR on 70 circuits, AEP Ohio was able to reduce Customer Minutes of Interruption (“CMI”) by 1,861,441 minutes, improving reliability for 22,427 customers in 2012. While weather conditions are the primary driver for changes in SAIFI and CAIDI, AEP Ohio can attribute some improvements of these indices from the DACR deployment. In 2012, all customers on the 70 DACR circuits experienced a SAIFI of 1.228 as compared to 1.429 without DACR deployed on the same 70 circuits – an improvement of 14.1 percent. Similarly, all customers on the 70 DACR circuits experienced a SAIDI of 161.5 as compared to 178.3 without DACR deployed on the same 70 circuits – an improvement of 9.4 percent. Importantly, these results were realized prior to more recent efforts to optimize the system with initial 2013 results significantly more favorable than those experienced in 2012.

Phase 2 will deploy DACR technology on approximately 250 circuits that have the characteristics of being best positioned to yield reliability improvements. This deployment is targeted to reduce CMI by up to 30 percent over the 3-year average for the deployed circuits, which is approximately the midpoint of the achieved CMI reductions reported by the US Department of Energy (“DOE”) in December 2012 for utilities that had prior experience with automated feeder switching. This could yield more than 21 million CMI per year on circuits serving more than 330,000 customers in the project areas.

In addition to the reliability benefits described above, the systems also enable crew labor savings, up to 2 hours per event, and in some instances avoid service calls entirely. Both of these situations provide opportunities for AEP Ohio to perform additional proactive work on circuits in need of service, further enhancing reliability.

Economic Output

Improved system reliability has significant impact on economic output too. Based on the “Cost of Power Interruptions to Electricity Consumers in the United States, Ernest Orlando Lawrence Berkeley National Laboratory” (2006), AEP Ohio estimates that DACR could reduce societal costs by approximately \$71 million per year through the reduction of outages experienced by customers.

AMI Benefits

AMI Financial Benefits

gridSMART® Phase 1 has demonstrated several operational benefits. For instance, by installing AMI meters, AEP Ohio was able to eliminate 100 percent of the meter reading routes (187 routes) in the area where AMI was deployed. AMI also enabled AEP Ohio to reduce costs associated with meter operations activities. For example, through the use of remote service switch capabilities that enable secure connection and disconnection of electric service to customer premises from the utility back office, AEP Ohio was able to reduce field visits associated with standard move in/move out orders. The combined

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meter reading and meter operations savings totaled approximately \$860,000 (\$6.50 per meter per year).

For Phase 2, the per-meter savings are projected to be higher because meters are less geographically concentrated in Phase 2 than in Phase 1, and Phase 2 projections include labor inflation. These efficiencies are projected to ramp to approximately \$6-\$7 million in annual utility benefits.

Category	Phase 1 result	Phase 2 projection
AMI Meters	132,000	894,000
Meter Reading and Meter Operations Savings (annual)	\$860,000 (\$6.50/meter)	\$6,000,000- \$7,000,000 (\$6.71-7.83/meter)

Credit, collections and revenue enhancements through earlier theft detection, lower consumption on inactive meters and greater billing accuracy are projected to lead to an additional \$8-\$10 million in annual utility benefits. Of that benefit, \$1.5-\$2 million annually is operational savings from use of the remote service switch specifically for credit disconnects. It is important to note that the benefits associated with automated credit disconnects require a PUCO waiver for the current process that requires on-site customer interaction. The PUCO would need to consider whether and how the rules would be adjusted to allow for credit disconnects, considering all stakeholder options.

AMI Additional Benefits

AMI offers a host of important benefits that have not been monetarily quantified in the business case, such as:

1. Improved data for billing
2. Better customer service and satisfaction
3. Reduced outages
4. Improved crew and meter reader safety
5. Reduced environmental impact

With automated meter reads, AMI nearly eliminates estimated bills, leading to greater billing accuracy. AMI has been proven to yield a typical monthly read rate of 99.9 percent as compared to the AEP Ohio average of 96.9 percent across its entire system. With automated meter reads and a higher read rate, AMI helps to nearly eliminate estimated monthly consumer electricity usage, leading to greater billing accuracy and improved customer satisfaction.

AMI leads to better service and customer satisfaction. For instance, when a customer wishes to terminate service, the AMI meter can be read remotely and a final bill sent without delays caused by manual reads. Similarly, AMI meters equipped with a remote service switch enable power to be turned on or off remotely. As a result, a customer moving in can have service turned on in minutes, rather than waiting days.

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AMI also provides the customer with the ability to view their energy consumption on a more granular level; typically multiple data points per day will be provided. This data can be useful for a customer providing better understanding of their consumption behavior. The availability of this data can also enable customers to participate in programs such as enhanced demand response (“DR”) or time-differentiated pricing tariffs that might be offered by DR or CRES providers. AEP Ohio envisions that DR or CRES providers will take the lead role in these enhanced customer program offerings. As the auction market develops, AEP Ohio will evaluate filing for a supplemental simple time-differential Standard Service Offering (SSO) rate option. Such programs are designed to reduce peak demand, thereby allowing customers to benefit through savings. Additionally, Home Area Network (“HAN”) devices can be used by the customer to better utilize the data and pricing signals to control their consumption activity. The proposed AEP Ohio gridSMART® Phase 2 will deploy AMI meters with communication modules to enable in-home communication from the meter. AEP Ohio views its role as a provider of the metering infrastructure that enables the offering of these programs by market participants.

Customer programs like the gridSMART® Phase 1 SMART Shift, two-tier time-of-day tariff could provide significant net benefit to customers. If DR or CRES providers offered similar programs to Phase 2 AMI customers, the estimated net customer benefits, assuming 5 percent penetration and 10 percent peak load reduction across all AEP Ohio customers, could be approximately \$4 to \$6 million in annual customer savings.

In addition to the benefits previously described, AMI provides billing and call center efficiencies that will enable staff to address more inquiries and to do so faster. Customers should experience fewer billing issues from continual meter reads and the elimination of estimated meter reads through AMI, and call center representatives will have real-time access to meter data which will help them discuss actual usage information with customers. When a customer calls about power loss, the real-time access also will enable call center representatives to determine whether the power loss is due to an outage or to an issue on the customer side of the meter, such as a blown house breaker fuse.

From a reliability perspective, when an AMI meter detects a loss of voltage, a message is sent indicating the customer has lost power. Messages that successfully reach AEP Ohio's internal systems can be used in conjunction with customer telephone calls to predict the extent of the outage. Also, meters can be queried (pinged/pollled) to get an indication of whether a customer has power. This indication can be useful to troubleshoot customer issues and to verify restoration following an outage.

From a safety perspective, because crews can remotely determine whether a meter has power, crew exposure and safety is improved. Also, due to AMI, fewer meter readers will be required in the field, which will reduce physical meter reading efforts and, thus, will reduce safety issues. AEP Ohio estimates that incidents and severity days associated with meter reading will be reduced by 72 percent relative to the past two years' performance.

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With remote capabilities, the number of miles driven by metering and service personnel will be reduced by an estimated 440,380 miles annually. In addition, there are some environmental benefits associated with reduced vehicle emissions as a result of reduced vehicle miles traveled with 186,556 metric tons of CO₂ avoided annually. These estimates are based on reductions experienced during AEP Ohio's gridSMART® Phase 1.

The above benefits from customer programs, billing and call center efficiencies, reduced personal injuries, and other operational savings together could represent an estimated \$39 million in incremental net present value.

VVO Benefits

Efficiency Benefits

AEP Ohio's gridSMART® Phase 2 VVO is designed to realize a reduction in energy consumption where deployed, and a reduction in peak demand on circuits where VVO is deployed.

Voltage standards exist in the electric utility industry, such as ANSI C84.1, that mandate an acceptable voltage range at the secondary of the distribution transformer. VVO enables a reduction of the average voltage that each customer on the circuit receives, thereby reducing the annual energy consumption of the feeder while maintaining the quality of service to the end-use customer. Based on results obtained through field demonstrations, AEP Ohio estimates that a 3 percent reduction in energy consumption and a 2 to 3 percent reduction in peak demand can be obtained on those circuits on which the technology is deployed.

Other Benefits

Along with the expected efficiency benefits, the technology associated with VVO also provides VAR support, offsetting the need for Generation and Transmission resources to provide VARs. VVO also promotes a "self-healing" grid by maintaining acceptable voltages after a "self-healing" event has occurred. The technology required for VVO will also augment other technologies to improve visibility into system performance and circuit automation.

Costs

DACR Costs

DACR costs are primarily capital costs from equipment and installation, and an O&M component associated with operating and maintaining this equipment. As for DACR, AEP Ohio requested its existing vendors to provide an estimate of updated costs to help in evaluating the cost effectiveness of potential future deployments. The costs included

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in this business case are current and will be updated annually as actuals are incurred. For Phase 2, AEP Ohio is estimating \$427,000 in total capital cost per deployed DACR circuit through the life of the technology. This cost represents an increase of approximately \$37,500 per circuit relative to Phase 1, due to adding functionality in order to improve load transferability. Operating and Maintenance expense is estimated at 3% of the total capital investment through the life of the technology.

AMI Costs

To generate an accurate estimate of AMI costs, AEP Ohio asked its existing vendors of key system elements to provide an estimate of updated costs to help in initially evaluating the cost effectiveness of potential future deployments. The costs included in this business case are current and will be updated annually as actuals are incurred.

AMI costs will be driven largely by capital expenditures for meters, meter communications equipment, and labor for meter installation. Ongoing operating costs, primarily consists of incremental back office staff to operate the systems. In direct dollar terms, the Phase 1 average cost per meter installed (a combined average for single phase and poly-phase including all related project expenses including associated communication infrastructure) for AMI was \$210. For Phase 2, AEP Ohio is estimating \$180 per installed meter, a reduction of approximately 17 percent.

In addition, the existing meters to be replaced will have a net book value (“NBV”) of approximately \$72 million. As part of this filing, AEP Ohio seeks to recover the NBV costs, as they are incurred, as a Phase 2 program expense over the term of the rider.

VVO Costs

VVO costs are primarily capital costs from equipment and installation, and an O&M component associated with operating and maintaining this equipment. For Phase 2, AEP Ohio is estimating approximately \$250,000 in total capital cost per deployed VVO circuit through the life of the technology. Operating and Maintenance expense is estimated at 3% of the total capital investment through the life of the technology.

Along with the capital and O&M cost associated with the VVO technology deployment, this type of energy efficiency technology also provides significant customer energy and bill savings benefits. Even though the technology is installed on the distribution system, VVO is an energy efficiency program that directly reduces demand and energy for AEP Ohio customers. Like more traditional energy efficiency programs, VVO should qualify for recovery of all distribution lost revenues and shared savings, and the VVO energy efficiency savings should count towards AEP Ohio’s energy efficiency targets. AEP Ohio anticipates the approval for recovery in AEP Ohio’s 2015-2017 Energy Efficiency filing. The lost distribution revenue should be recovered for all customer rate classes not currently covered in the pilot decoupling adjustment mechanism and shared savings should be approved in the same manner as other measurable programs in the current and future approved energy efficiency plans.

Attachment A

In Case No. 10-501-EL-FOR, the Commission denied the Company’s request to determine there is a need for the Turning Point Solar Project. As part of that order, the Commission reiterated that the Company had committed to spend \$20 million on that investment and ordered AEP Ohio to do so by the end of 2013. The Commission directed that the benefits of the \$20 million investment flow through to the Company’s rate payers. The Company is proposing to invest \$20 million in VVO which if approved for this investment, will allow the Company to optimize approximately 80 circuits. AEP Ohio is currently evaluating its future needs associated with meeting its Energy Efficiency (EE) legislative mandates and may request up to another 80 VVO circuits as a separate filing if needed to meet these EE targets.

In Case No. 11-346-EL-SSO, the Commission determined that VVO was not necessarily a part of gridSMART® as it could be installed without the presence of gridSMART® technologies but recognized that it enhances or is necessary for gridSMART® technology to operate properly and efficiently (Case No. 11-346-EL-RDR Opinion and Order at 62). The Company proposes to install \$20 million of VVO as part of the gridSMART® Phase 2 rider filing. VVO benefits the customers by reducing usage up to 3 percent as determined through the gridSMART® Phase 1 pilot. This benefit will be realized by customers by reducing usage and as such reducing the charges to be realized in the future.

Rate Impacts

The table below reflects the first five years of customer impact assuming the same mechanics of the Phase 1 rider with the exception of changing the recovery of investments from an “as spent” to an “in service” basis as the Commission directed in its August 8, 2012 Opinion and Order in Case No. 11-346-EL-SSO (page 63). The table also reflects, fully loaded costs, and 7-year depreciation for AMI and 30-year depreciation for DACR and VVO.

Average Monthly Rate Impact \$		
	Residential	Non-Residential
Year 1	0.42	1.74
Year 2	1.75	7.19
Year 3	2.34	9.64
Year 4	2.75	11.31
Year 5	2.90	11.93
Average	2.03	8.36
Average monthly bill in 2012	127.93	Varies
Average Increase	1.6%	Varies

Attachment A

Based on the average AEP Ohio Residential monthly customer bills for 2012, the average monthly bill increases represent 1.6 percent. Due to such wide varieties in usage and operational characteristics, the non-residential impact will vary for each customer class. Based on the cash flows of the proposed project plan and associated capital deployment, the average monthly Residential rate impacts will not exceed \$1.00 in year 1, \$2.25 in year 2, \$2.75 in year 3, \$3.00 in year 4 and \$3.25 in year 5. The average monthly non-Residential rate impacts will not exceed \$3.50 in year 1, \$9.00 in year 2, \$10.75 in year 3, \$11.50 in year 4 and \$13.25 in year 5.

Benefit/Cost Analysis

As described above, Phase 2 involves a variety of benefits and costs. Those have been evaluated over a 15-year period, and the delta between benefits and costs reflects the customer impact. Each metric is shown below with two different views: the Cash View (or nominal view) and the Net Present Value (“NPV”) View.

For the comprehensive benefits and costs for the three technologies, the Cash View shows a net of \$860 million benefit and benefit-cost ratio of 2.8. The NPV shows a net of \$346 million benefit and a benefit-cost ratio of 2.0.

	CASH VIEW	NET PRESENT VALUE VIEW**
15 Year Benefits	O&M: \$193 million Capital: \$ 1 million Energy / Capacity: \$115 million Reliability:* \$1.016 billion TOTAL: \$1.325 billion	O&M: \$100 million Capital: \$ 1 million Energy / Capacity: \$ 59 million Reliability:* \$519 million TOTAL: \$679 million
15 Year Costs	O&M: \$136 million Capital: \$329 million TOTAL: \$465 million	O&M: \$ 77 million Capital: \$256 million TOTAL: \$333 million
15 Year Customer Impact	Net Cash Flows: \$860 million Benefit/Cost Ratio: 2.8	Net Cash Flows: \$346 million Benefit / Cost Ratio: 2.0

* Based on the “Cost of Power Interruptions to Electricity Consumers in the United States, Ernest Orlando Lawrence Berkeley National Laboratory” (2006)

** The Cash View reflects the nominal estimated expenditures and benefits related to the Phase II implementation. The Net Present Value (NPV) is calculated using an After Tax Weighted Average Cost of Capital (WACC) of 7.69%.

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Proven Solutions and Technologies

gridSMART® Phase 2 represents a fundamental change in the way AEP Ohio operates and enables new technologies, and is based on proven solutions that have been deployed across the United States.

For example, the Edison Foundation estimates that 36 million Smart Meters already had been installed by May 2012, and several utilities have already completed large-scale AMI deployments such as Florida Power & Light, CenterPoint, Sacramento Municipal Utility District, and Southern Company. AEP's subsidiary AEP Texas is also deploying 1 million AMI meters, with 80 percent currently installed. Many of these and other utilities are achieving tangible benefits. The December 2012 U.S. DOE SGIG Program AMI report ("Operations and Maintenance Savings From Advanced Metering Infrastructure – Initial Results") shows reductions in meter operations costs of 13 to 77 percent and reductions in miles driven, fuel consumed and CO₂ emission of 12 to 59 percent.

AMI has also enabled numerous dynamic pricing programs. For example, Oklahoma Gas & Electric ("OGE") has enrolled approximately 76,000 customers in its AMI-based demand response program, which resulted in a 67 megawatt reduction in peak demand in 2012 and an average \$191 savings in energy costs per participating customer.

Reliability applications like DACR are widely deployed and generating benefits as well. For example, the U.S. DOE reported in December, 2012, that approximately 30 utilities that had deployed automated feeder switching. Among the approximately 300 feeders where operators had previous experience with automated feeder switching, CMI was reduced 11 to 56 percent.

VVO is a proven commercial technology with multiple suppliers providing solutions to accomplish similar goals. AEP Ohio proposes to implement a technology similar to the Phase 1 deployment. VVO technology is being deployed at three AEP Ohio affiliates in Indiana, Oklahoma, and Kentucky.

The above examples highlight how technologies like those in the gridSMART® initiative have been broadly proven in the field, reducing the technology risks associated with AEP Ohio achieving its target benefits.

Customer Acceptance

The gridSMART® technologies not only are proven to be technically a success, but also widely accepted by customers. Customers who participated in gridSMART® Phase 1 and participated in AMI-enabled consumer programs rated their overall satisfaction with AEP Ohio seven percent higher than did AEP Ohio customers overall.

A public outreach and education plan will play a key role in the successful implementation of Phase 2. Similar to the successful strategy used in Phase 1, a multi-

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pronged communications approach will engage key community thought leaders, customers and other targeted audiences by providing timely and thorough information regarding the overall project, timeline, rollout and benefits of the technologies. An outreach plan that clearly communicates transparency with communities and customers will be developed and used to ensure acceptance, which ultimately will lead to higher customer satisfaction.

Other utilities across the US have reported strong acceptance of Smart Grid technology, such as:

- Sacramento Municipal Utility District (“SMUD”) has deployed approximately 600,000 AMI meters and has reported high customer satisfaction. As SMUD reported, “Customer satisfaction drove the project. Throughout, SMUD maintained customer satisfaction levels in the mid-90th percentile. Ongoing surveys measure customer satisfaction with the meters, the installation process and the associated communications. The complaint rate was only 0.09 percent.”
- OGE has deployed approximately 780,000 AMI meters and has enrolled over 76,000 participants to its AMI-based dynamic pricing demand response program called SmartHours. 94 percent of customers said they were likely to recommend the program to friends and family.
- Memphis Light Gas and Water (“MLGW”) conducted a survey after its AMI pilot with “95 percent saying they would recommend the smart meter experience to a friend.”

At a macro level, JD Power and Associates reported higher customer satisfaction with AMI. They found that customer satisfaction among customers with smart meters “averages 667 (on a 1,000-point scale), 43 points higher than among customers whose homes are not equipped with smart meters.”

Another successful key to achieving customer acceptance is offering an alternative to the limited number of customers who have concerns with AMI meters. AEP Ohio supports providing the customer an opportunity to "opt-out" of receiving an AMI meter and retaining a standard meter. If a customer opts-out they would incur all expenses associated with manual meter reading so that these costs are not paid for by other customers. AEP Ohio appreciates the PUCO initiative for "opt-out" rulemaking and the Company has provided comments on the initial version of the rule. AEP Ohio will comply the future PUCO ruling related with AMI meter opt-outs.

Security and Privacy

Through the gridSMART Demonstration Project, AEP Ohio implemented innovative advancements in the cyber security arena including an enhanced state of the art Cyber Security Operations Center (CSOC) in partnership with the U.S. Department of Energy and vendors. Providing advanced security checks and balances, this CSOC monitors and identifies vulnerabilities 24/7 to ensure grid security.

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Customers can be assured that the safety and security of their information is protected by extensive and dedicated resources. Recognized as an innovator with its industry threat sharing integration functionality, this CSOC continuously gathers and shares threat information with peer utilities and government agencies.

Privacy issues have garnered customer attention, though the Company notes that the issue of customer privacy is not a new concept introduced by the deployment of the smart grid. The Company is supportive of the PUCO's continued efforts to ensure the protection of customer information and commented on consumer privacy in Case No. 11-277-GE-UNC.

The electric utility industry in Ohio has traditionally collected, used, and protected significant amounts of sensitive customer information. For example:

- The nature of information necessary to conduct utility business includes personally identifiable information (PII) such as social security numbers and related credit information.
- Utilities have routinely collected interval metering information for decades for larger commercial and industrial customers as part of administering and billing tariffs that rely on such information and for operating its business.
- Interval metering data on select residential and smaller commercial and industrial customers has been collected and utilized for decades in order to develop and monitor customer load profiles necessary for system resource planning and the proper allocation of costs. This data is not substantially different than that which is collected by newer smart meters.

Therefore the collection, use, and protection of proprietary and confidential data have occurred in some form almost since AEP Ohio's inception. The Company has always fulfilled the obligation to maintain the confidentiality of this information, as well as the trust of their customers, without notable exception.

The current legislative and regulatory rules provides for protection of customer data privacy, regardless of how that information is gathered by the utility. AEP Ohio treats customer consumption data collected through the smart grid with the same high level of protection required by these legislative and regulatory expectations.

The proposed Phase 2 deployment will continue these efforts and strive to improve security and privacy customer protection. We will utilize dedicated security and privacy experts to review the technology and equipment to ensure strict standards are met. We will place emphasis on building security and privacy into the deployment as well as creating a system to evaluate that these standards remain as the technologies go into service.

Conclusion

AEP Ohio's gridSMART® Phase 2 project, based on proven and accepted technology solutions, will extend the benefits demonstrated in Phase 1 and deliver additional benefits to a broader set of customers. Through Phase 2 AMI, the Company expects to drive

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significant financial benefits through AMI and enable a variety of additional benefits that positively impact customer service such as customer satisfaction; meter field personnel safety; regional economic output and reduced environmental impacts. It also will help enable DR and CRES providers to offer valuable customer programs. Phase 2 DACR is expected to improve CMI where the system is deployed, which will help avoid millions of dollars of potential lost economic productivity annually. Phase 2 VVO is expected to generate significant efficiencies that translate to customer savings. Overall, the rate impact on customers is expected to be low, just 1.6 percent on average.



AEP Ohio

Revised Phase 3 Full System Feasibility Study Final Report

Revised Phase 3 Full System Feasibility Study Final Report

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Revised Phase 3 Full System Feasibility Study Report

1 Executive Summary

Ohio Power Company (“AEP Ohio”) received approval to proceed with its Smart Grid Phase 2 plan from the Public Utilities Commission of Ohio (“Commission”) in February 2017. That plan describes how AEP Ohio proposes to deploy advanced metering infrastructure (“AMI”), distribution automation circuit reconfiguration (“DACR”), and Volt-VAR optimization (“VVO”) technology within specific locations of AEP Ohio’s service area.

In addition to approving AEP Ohio’s Smart Grid Phase 2 plan, the Commission’s order required that AEP Ohio prepare and submit two engineering and feasibility and selection studies. The “Phase 2 Feasibility and Selection Study” report (“Phase 2 report”) was submitted by AEP Ohio to the Commission in February 2018. That report describes how AEP Ohio will prioritize and select locations where AMI, DACR, and VVO will be deployed within the Smart Grid Phase 2 project area. Section 3 of the Phase 2 report describes feasibility and selection study objectives applicable for both AEP Ohio’s authorized Smart Grid Phase 2 and future anticipated Smart Grid Phase 3 deployments. A common theme among all the objectives identified in Table 1 of the Phase 2 report is to “maximize customer and company benefits for the technologies proposed.”¹ Section 4 of the Phase 2 report presents specific metrics and prioritization processes that fulfill all Table 1 objectives for AMI, DACR, and VVO. In addition, Section 4 describes how DACR and VVO metrics will be monetized to develop a prioritized business case portfolio analysis of all proposed DACR and VVO candidates, how the portfolios will be annually updated, and how DACR and VVO candidates will ultimately be selected for deployment.

This document, the “Revised Phase 3 Full System Feasibility Study” (“Phase 3 report”) presents the latest version of a benefit-cost analysis or business case for all future anticipated AMI, DACR, and VVO Phase 3 deployments within all remaining areas of AEP Ohio’s service area.² This latest version is an update of the original Phase 3 report submitted to the Commission in June 2018. Similar to the June 2018 report, Sections 2 and 3 of this Phase 3 report updates the prioritized business case portfolio analysis of all DACR and VVO distribution bus candidates as described in Section 4 of the Phase 2 report. For this reason, the Phase 2 report should be regarded as a companion reference document to this Phase 3 report (and the original June 2018 report) to avoid repetitive content describing the business case portfolio analysis development process.

In contrast to DACR and VVO, the Phase 2 report does not describe the business case development process for AMI. The Phase 2 report describes how AEP Ohio’s approved AMI deployment will be prioritized across 43 cities within the Phase 2 AMI deployment area, but does not discuss an AMI business case. Section 4

¹ Commission Order and Opinion dated February 1, 2017, Section IV (1) (B) (iii).

² AEP Ohio eliminated distribution circuits from the business case for a variety reasons. Circuits excluded from the Revised Phase 3 Full System Feasibility Study include, but are not necessarily limited to: 4 kV circuits, network circuits, circuits serving a few dedicated customers, circuits with insufficient capacity, or circuits have inadequate (or no) interconnections with adjoining circuits, etc.

of this updated Phase 3 report will present all relevant benefit and cost estimates, and business case results for a proposed Phase 3 AMI deployment within the remainder of AEP Ohio's service territory. Finally, Section 6 consists of an Appendix providing updated details of the prioritized DACR and VVO business case portfolio analysis for all candidate DACR schemes and VVO distribution buses and a description of all financial assumptions used throughout all DACR, VVO, and AMI business cases.

2 DACR Business Case and Portfolio Analysis

AEP Ohio has prepared a benefit-cost analysis or "business case portfolio analysis" for every DACR scheme candidate proposed for a Phase 3 deployment. All the benefit and cost data and associated assumptions used to prepare DACR business case portfolio analysis is presented in Sections 2.1. Results of the business case portfolio analysis for all Phase 3 DACR scheme candidates are summarized in Section 2.2.

2.1 DACR Benefit and Cost Data and Assumptions

AEP Ohio's 2013 application to the Commission seeking approval of its proposed Smart Grid Phase 2 plan included a business case justifying the proposed deployment of DACR on selected circuits throughout the AEP Ohio's service territory. The benefits component of this DACR business case was based on the societal economic benefits to customers associated with improved electric service reliability that is well documented through research sponsored by the U.S. Department of Energy's Lawrence Berkley National Laboratory ("LBNL").³ In addition to AEP Ohio, LBNL's sponsored research has been referenced in numerous studies and by other electric utilities to justify their proposed smart grid programs. AEP Ohio's application of the methodology described in LBNL sponsored research to estimate the value of improved distribution reliability achievable with DACR was recognized and approved by order of the Commission in February 2017.

The Phase 3 business case portfolio analysis prepared for every DACR scheme candidate is based on the same LBNL methodology and approach previously used by AEP Ohio and previously accepted by the Commission to monetize reliability improvements associated with DACR. However, the Phase 3 study relies on updated estimates on the value of improved electric service reliability published by LBNL and reliability data for the three year period ending calendar year 2017 on all candidate DACR schemes and circuits.^{4,5} Updated estimates on the value of improved electric service reliability for LBNL's methodology are reproduced in Table 1 on page 3.

A properly designed DACR business case portfolio analysis includes the capital costs and operations and maintenance ("O&M") costs required to purchase, deploy, own, and maintain DACR infrastructure to realize the anticipated reliability benefits. A description of these costs incurred by AEP Ohio over the 15

³ The economic benefits of improving electric service reliability is based on the LBNL sponsored research of Sullivan, M., Mercurio, M., Schellenberg, J., & Eto, J. in their (2010) paper "How to Estimate the Value of Service Reliability Improvements."

⁴ Sullivan, M., Schellenberg, J., & Blundell, M. (Jan 2015). *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States (LBNL-6941E)* (p. xii). Ernest Orlando Lawrence Berkeley National Laboratory.

⁵ All AEP Ohio reliability data excludes transmission outages and major event days.

year time horizon of the DACR business case portfolio analysis is provided in Table 2 on pages 3-4.

Table 1
Estimated Interruption Cost per Event by Duration and Customer Class

Duration (Min)	Residential	Small C&I	Med-Large C&I
Momentary	\$4.22	\$445	\$14,001
30	\$4.86	\$562	\$16,476
60	\$5.51	\$699	\$19,246
240	\$10.27	\$2,032	\$42,654
480	\$18.59	\$5,070	\$90,894
960	\$35.02	\$9,788	\$178,886

Table 1 Notes:

1. Interruption costs per event by duration and customer class represents the outage cost associated with an individual interruption for a typical or average sized customer within the meta-database used by the principal investigators who performed the LBNL sponsored research. Table durations represent customer average interruption duration index (“CAIDI”) values.
2. See Footnote 4 on page 2 of this report for the LBNL source where these estimated interruption costs are published. The interruption costs above published by LBNL are in 2013 dollars. These costs have been escalated to 2019 dollars within the DACR business case portfolio analysis using the Consumer Price Index published by the U.S. Bureau of Labor Statistics.
3. Example calculation:

Assume a distribution circuit serves 1000 residential customers, 100 small C&I customers, and 2 medium & large C&I customers. Also, assume the circuit has a circuit CAIDI of 60 minutes and a system average interruption frequency index (“SAIFI”) of 1.00. (The system average interruption duration index or “SAIDI” is 60 minutes.)

The annual societal economic cost of interruptions on this circuit is 1000 residential customers × \$5.51 per residential customer + 100 small C&I customers × \$699 per small C&I customer + 2 medium & large C&I customer × \$19,246 per medium & large C&I customer = \$113,902. If the annual outage frequency is reduced by 50 percent (SAIFI is 0.50 and CAIDI is unchanged) the annual economic cost of interruptions is reduced by half, i.e. \$113,902 × 0.50 = \$56,951.

Table 2
Description of Capital and O&M Costs for DACR Infrastructure

1. Substation infrastructure
 Includes estimated capital costs associated with breaker control upgrades, new or upgraded remote terminal units, control house panel upgrades, and station yard cable raceway upgrades including fiber optic or other control cabling replacements.
2. Distribution line infrastructure
 Includes initial capital costs, O&M costs for each candidate distribution circuit and DACR scheme

associated with:

- a) Reclosers/controls or recloser control upgrades
- b) Voltage regulator banks/controls or regulator bank control upgrades
- c) Switched capacitor bank/controls or capacitor bank control upgrades

3. Communication infrastructure

Includes initial and replacement capital costs and O&M costs for each candidate distribution circuit and DACR scheme associated with cellular LTE and/or mesh radios installed at (or near) each recloser, voltage regulator bank, and switched capacitor bank location.

4. Information technology infrastructure

Includes initial and replacement capital costs and O&M costs associated with all DACR controller hardware, software licensing, fees and maintenance support.

2.2 DACR Business Case and Portfolio Analysis Results

AEP Ohio has prepared a benefit-cost analysis or “business case” for 146 DACR schemes involving 711 distribution circuits identified as candidates for a possible Smart Grid Phase 3 deployment.⁶ As described within the Phase 2 report, a business case for each DACR scheme candidate is essential to ensure that AEP Ohio is delivering the greatest monetized benefits of improved electric service reliability minus the costs (i.e. net benefits) previously identified in Table 2 to procure, deploy, operate, and maintain the proposed DACR infrastructure.

The business case prepared for each DACR scheme candidate represents the net benefit “cash flows” that are discounted at AEP Ohio’s after-tax weighted cost of capital to estimate the 15 year net present value (“NPV”) of the proposed scheme.⁷ These net benefit cash flows include the monetized LBNL benefits associated with improved reliability, initial and replacement capital costs, and O&M costs associated with substation, distribution, communication, and information technology (“IT”) infrastructure.⁸ Also, these cash flows incorporate the combined tax effects associated with the depreciation of capitalized infrastructure assets and the tax effects associated with annual O&M expenses. The cash flow model for DACR scheme “CRA991” provided in Table 3 on page 6 illustrates all the annual cash flows that yields a 15 year NPV of \$7,034,782 in the bottom right corner of the table.

⁶ Each DACR circuit scheme candidate includes 2 or more interconnected distribution circuits served from one or more substations that can be automatically switched and reconfigured as necessary to isolate and limit an outage to the smallest area impacting the fewest number of customers that is practical.

⁷ The term “net benefit cash flows” or simply “cash flows” used hereinafter within this report include benefits from the perspective of customers such as the societal economic benefit of improved reliability and improved energy efficiency / reduced retail power costs associated with DACR and VVO respectively. Also, the term net benefit cash flows or simply cash flows also includes operational savings associated with AMI.

⁸ AEP Ohio operating savings associated with outage restoration and lost retail revenue were originally examined, but eventually discarded from the DACR business cases because their contributions were negligible.

This level of business case modeling detail illustrated in Table 3 was repeated for each of the other 145 DACR scheme candidates before assembling all business case results into AEP Ohio's DACR portfolio. This DACR portfolio of DACR scheme candidates was then prioritized and ranked by their individual 15 year NPV values in descending order from candidates with the highest NPV to candidates with the lowest (or most negative) to identify DACR scheme candidates delivering the greatest value to AEP Ohio customers. A graphical summary of the NPV results for all 146 Phase 3 DACR scheme candidates is provided in Figure 1.

The business case developed for all 146 DACR scheme candidates is based on a common set of financial assumptions and notes that are summarized within Section 6.3 (Appendix) of this Phase 3 report. Among the 146 DACR scheme candidates investigated, 80 schemes impacting 416 distribution circuits have business cases with positive 15 year NPV values. Collectively, these 80 DACR schemes deliver to AEP Ohio customers improved electric service reliability estimated to have a 15 year present value societal economic benefit of \$569,908,200 compared to the estimated 15 year present value cost of \$349,945,501 to deploy, own, operate, and maintain the needed DACR infrastructure. (The 15 year NPV for all 80 schemes is \$219,962,699.) In other words, AEP Ohio customers realize \$1.63 in DACR benefits for every dollar of DACR related capital and O&M costs incurred over 15 years on these 80 schemes. A tabular listing of all 146 DACR scheme candidates graphically illustrated in Figure 1 is provided in Table 10 of Section 6.1 (Appendix). The DACR scheme candidates with the 10 highest 15 year NPV values from Table 10 is reproduced in Table 4 on page 7.

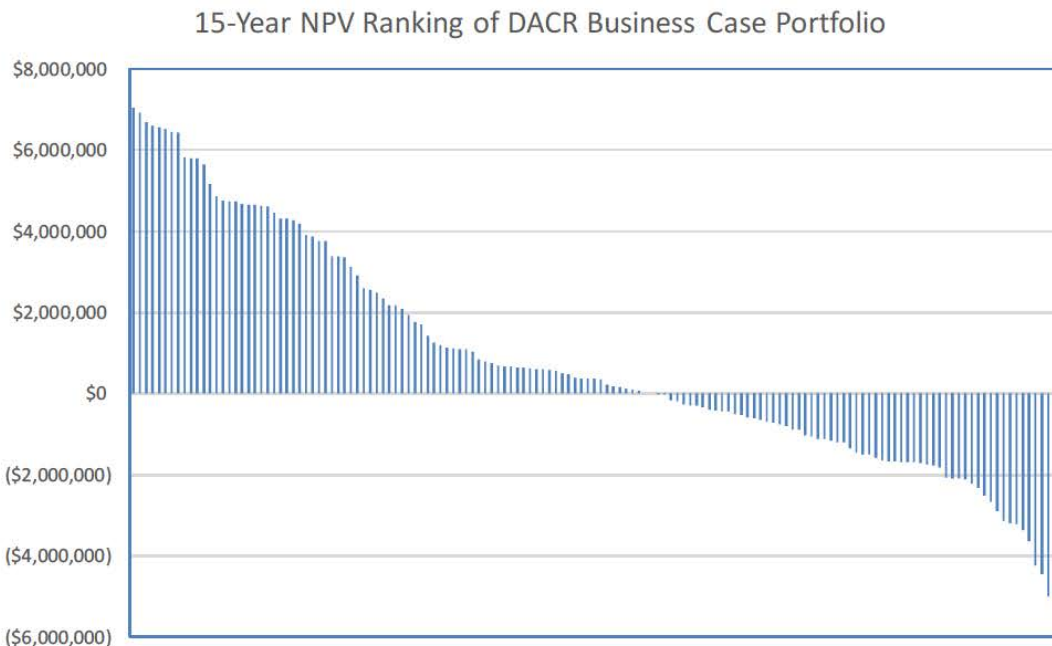


Figure 1: Prioritized Business Case Portfolio of DACR Schemes

Table 3
Cash Flow Model for Highest Ranked DACR Scheme "CRA991"

Exhibit SSO-3
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	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Related Costs	\$3,948,800	\$9,870	\$9,870	\$9,870	\$9,870	\$0	\$0	\$0	\$0	\$0	\$364,839	\$0	\$0	\$0	\$0
Capital Cost - Substation Infrastructure	\$1,145,510	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Capital Cost - Distribution Infrastructure	\$2,405,165	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Capital Cost - Communication Infrastructure	\$345,450	\$9,870	\$9,870	\$9,870	\$9,870	\$0	\$0	\$0	\$0	\$0	\$350,509	\$0	\$0	\$0	\$0
Capital Cost - Info Tech Infrastructure	\$52,675	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$14,330	\$0	\$0	\$0	\$0
Capital Cost - Customer Infrastructure	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Subtotal - Capital Costs	\$3,948,800	\$9,870	\$9,870	\$9,870	\$9,870	\$0	\$0	\$0	\$0	\$0	\$364,839	\$0	\$0	\$0	\$0
Depreciation Related Costs															
Dep Exp - Substation Infrastructure	\$25,456	\$25,456	\$25,456	\$25,456	\$25,456	\$25,456	\$25,456	\$25,456	\$25,456	\$25,456	\$25,456	\$25,456	\$25,456	\$25,456	\$25,456
Dep Exp - Distribution Infrastructure	\$75,161	\$75,161	\$75,161	\$75,161	\$75,161	\$75,161	\$75,161	\$75,161	\$75,161	\$75,161	\$75,161	\$75,161	\$75,161	\$75,161	\$75,161
Dep Exp - Communication Infrastructure	\$23,030	\$23,688	\$24,346	\$25,004	\$25,662	\$25,662	\$25,662	\$25,662	\$25,662	\$25,662	\$26,657	\$26,657	\$26,657	\$26,657	\$26,657
Dep Exp - Info Tech Infrastructure	\$10,535	\$10,535	\$10,535	\$10,535	\$10,535	\$0	\$0	\$0	\$0	\$0	\$2,866	\$2,866	\$2,866	\$2,866	\$2,866
Dep Exp - Customer Infrastructure	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Tax Benefit of Dep - Substation Infrastructure	\$5,570	\$5,570	\$5,570	\$5,570	\$5,570	\$5,570	\$5,570	\$5,570	\$5,570	\$5,570	\$5,570	\$5,570	\$5,570	\$5,570	\$5,570
Tax Benefit of Dep - Distribution Infrastructure	\$16,445	\$16,445	\$16,445	\$16,445	\$16,445	\$16,445	\$16,445	\$16,445	\$16,445	\$16,445	\$16,445	\$16,445	\$16,445	\$16,445	\$16,445
Tax Benefit of Dep - Com Infrastructure	\$5,039	\$5,183	\$5,327	\$5,471	\$5,615	\$5,615	\$5,615	\$5,615	\$5,615	\$5,615	\$5,833	\$5,833	\$5,833	\$5,833	\$5,833
Tax Benefit of Dep - Info Tech Infrastructure	\$2,305	\$2,305	\$2,305	\$2,305	\$2,305	\$0	\$0	\$0	\$0	\$0	\$627	\$627	\$627	\$627	\$627
Tax Benefit of Dep - Customer Infrastructure	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Subtotal - Tax Benefit of Depreciation	\$29,359	\$29,503	\$29,647	\$29,791	\$29,935	\$27,630	\$27,630	\$27,630	\$27,630	\$27,630	\$28,475	\$28,475	\$28,475	\$28,475	\$28,475
Net Book - Substation Infrastructure	\$1,120,054	\$1,094,598	\$1,069,143	\$1,043,687	\$1,018,231	\$992,775	\$967,320	\$941,864	\$916,408	\$890,952	\$865,496	\$840,041	\$814,585	\$789,129	\$763,673
Net Book - Distribution Infrastructure	\$2,330,004	\$2,254,842	\$2,179,681	\$2,104,519	\$2,029,358	\$1,954,197	\$1,879,035	\$1,803,874	\$1,728,712	\$1,653,551	\$1,578,390	\$1,503,228	\$1,428,067	\$1,352,905	\$1,277,744
Net Book - Communication Infrastructure	\$322,420	\$308,602	\$294,126	\$278,992	\$263,200	\$237,538	\$211,876	\$186,214	\$160,552	\$134,890	\$123,162	\$96,504	\$69,847	\$43,190	\$16,533
Net Book - Info Tech Infrastructure	\$42,140	\$31,605	\$21,070	\$10,535	\$0	\$0	\$0	\$0	\$0	\$0	\$11,464	\$8,598	\$5,732	\$2,866	\$0
Net Book - Customer Infrastructure	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Property Tax - Substation Infrastructure	\$34,162	\$33,385	\$32,609	\$31,832	\$31,056	\$30,280	\$29,503	\$28,727	\$27,950	\$27,174	\$26,398	\$25,621	\$24,845	\$24,068	\$23,292
Property Tax - Distribution Infrastructure	\$71,065	\$68,773	\$66,480	\$64,188	\$61,895	\$59,603	\$57,311	\$55,018	\$52,726	\$50,433	\$48,141	\$45,848	\$43,555	\$41,264	\$38,971
Property Tax - Communication Infrastructure	\$9,834	\$9,412	\$8,971	\$8,509	\$8,028	\$7,245	\$6,462	\$5,680	\$4,897	\$4,114	\$3,756	\$2,943	\$2,130	\$1,317	\$504
Property Tax - Info Tech Infrastructure	\$1,285	\$964	\$643	\$321	\$0	\$0	\$0	\$0	\$0	\$0	\$350	\$262	\$175	\$87	\$0
Property Tax - Customer Infrastructure	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Subtotal - Property Tax	\$116,346	\$112,534	\$108,703	\$104,851	\$100,979	\$97,128	\$93,276	\$89,425	\$85,573	\$81,721	\$78,645	\$74,675	\$70,706	\$66,737	\$62,767
Operations & Maintenance Expense	\$126,654	\$128,002	\$130,227	\$132,490	\$134,791	\$137,341	\$139,401	\$141,492	\$143,615	\$145,769	\$146,719	\$148,919	\$151,153	\$153,420	\$155,722
O&M - Substation Infrastructure	\$34,365	\$34,881	\$35,404	\$35,935	\$36,474	\$37,021	\$37,577	\$38,140	\$38,712	\$39,293	\$39,882	\$40,481	\$41,088	\$41,704	\$42,330
O&M - Distribution Infrastructure	\$72,155	\$73,237	\$74,336	\$75,451	\$76,583	\$77,731	\$78,897	\$80,081	\$81,282	\$82,501	\$83,739	\$84,995	\$86,270	\$87,564	\$88,877
O&M - Communication Infrastructure	\$16,034	\$16,575	\$17,128	\$17,695	\$18,274	\$19,076	\$19,363	\$19,653	\$19,948	\$20,247	\$19,352	\$19,643	\$19,937	\$20,236	\$20,540
O&M - Info Tech Infrastructure	\$4,100	\$3,309	\$3,359	\$3,409	\$3,460	\$3,512	\$3,565	\$3,618	\$3,673	\$3,728	\$3,745	\$3,801	\$3,858	\$3,916	\$3,975
O&M - Customer Infrastructure	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Subtotal - O&M Expenses	\$126,654	\$128,002	\$130,227	\$132,490	\$134,791	\$137,341	\$139,401	\$141,492	\$143,615	\$145,769	\$146,719	\$148,919	\$151,153	\$153,420	\$155,722
Customer Benefits	\$1,256,258	\$1,281,478	\$1,307,204	\$1,333,446	\$1,360,215	\$1,387,521	\$1,415,375	\$1,443,789	\$1,472,773	\$1,502,339	\$1,532,498	\$1,563,263	\$1,594,646	\$1,626,658	\$1,659,314
Operating Benefits	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Operating Benefits & Expenses Net of Taxes	(\$160,472)	(\$158,404)	(\$157,005)	(\$155,620)	(\$154,249)	(\$155,537)	(\$154,138)	(\$152,762)	(\$151,412)	(\$150,086)	(\$147,579)	(\$146,197)	(\$144,842)	(\$143,512)	(\$142,209)
Depreciation Tax Benefit	\$29,359	\$29,503	\$29,647	\$29,791	\$29,935	\$27,630	\$27,630	\$27,630	\$27,630	\$27,630	\$28,475	\$28,475	\$28,475	\$28,475	\$28,475
Property Tax Expense	\$90,889	\$87,912	\$84,918	\$81,909	\$78,885	\$75,876	\$72,867	\$69,858	\$66,850	\$63,841	\$61,437	\$58,336	\$55,236	\$52,135	\$49,034
O&M Expense	\$98,942	\$99,995	\$101,733	\$103,501	\$105,299	\$107,291	\$108,900	\$110,534	\$112,192	\$113,875	\$114,617	\$116,336	\$118,081	\$119,852	\$121,650
Operating Benefits	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Subtotal - Cash Flow Net of Taxes	(\$160,472)	(\$158,404)	(\$157,005)	(\$155,620)	(\$154,249)	(\$155,537)	(\$154,138)	(\$152,762)	(\$151,412)	(\$150,086)	(\$147,579)	(\$146,197)	(\$144,842)	(\$143,512)	(\$142,209)
Annual Customer & Utility Net Cash Flow	(\$2,853,014)	\$1,113,204	\$1,140,329	\$1,167,956	\$1,196,096	\$1,231,984	\$1,261,238	\$1,291,027	\$1,321,361	\$1,352,253	\$1,020,080	\$1,417,066	\$1,449,804	\$1,483,146	\$1,517,104
Cumulative Customer & Utility Net Cash Flow	(\$2,853,014)	(\$1,739,810)	(\$599,481)	\$568,475	\$1,764,571	\$2,996,554	\$4,257,792	\$5,548,819	\$6,870,180	\$8,222,433	\$9,242,514	\$10,659,579	\$12,109,384	\$13,592,530	\$15,109,634
Annual PV Customer & Utility Cash Flow	(\$2,646,581)	\$957,938	\$910,278	\$864,871	\$821,622	\$785,041	\$745,531	\$707,922	\$672,129	\$638,073	\$446,507	\$575,393	\$546,092	\$518,229	\$491,738
Cumulative NPV Customer & Utility Cash Flow	(\$2,646,581)	(\$1,688,643)	(\$778,365)	\$86,506	\$908,128	\$1,693,169	\$2,438,700	\$3,146,621	\$3,818,751	\$4,456,824	\$4,903,330	\$5,478,724	\$6,024,815	\$6,543,044	\$7,034,782

Table 4
Prioritized Business Case Portfolio of DACR Schemes (Top 10)

Candidate	Rank	NPV	PV Benefits	PV Costs	Circuits	Total	Rule 11	District	District Sub-Area
CRA991	1	\$7,034,782	\$12,465,319	\$5,430,537	7	7	0	Columbus	Columbus, SW - 65
CRC200	2	\$6,906,261	\$12,856,299	\$5,950,038	8	15	0	Columbus	Columbus, SE - 64
CRC517	3	\$6,684,020	\$12,009,602	\$5,325,581	7	22	0	Columbus	Columbus, SE - 64
CRC414	4	\$6,607,554	\$10,326,328	\$3,718,774	5	27	0	Columbus	Columbus, NW - 66
CRC013	5	\$6,549,871	\$15,097,977	\$8,548,106	10	37	0	Chillicothe	Portsmouth - 82
CRA999	6	\$6,516,946	\$12,011,153	\$5,494,208	7	44	0	Columbus	Columbus, SE - 64
CRC407	7	\$6,446,330	\$10,304,355	\$3,858,026	5	49	0	Columbus	Columbus, NW - 66
CRA109	8	\$6,437,162	\$15,818,159	\$9,380,997	11	60	0	Canton	North Canton - 20, South Canton - 21
CRA996	9	\$5,818,869	\$11,217,561	\$5,398,692	7	67	0	Columbus	Columbus, SW - 65
CRC518	10	\$5,801,212	\$9,614,601	\$3,813,388	5	72	0	Columbus	Columbus, SE - 64, Columbus, SW - 65

The DACR business case and portfolio analysis presented in this report assumes AEP Ohio will utilize the same DACR technology in previous and current deployments approved by the PUCO to achieve a reduction in outage frequency (SAIFI) of 15.8 percent. AEP Ohio continues to examine additional technologies to further enhance distribution reliability and deliver additional customer benefits. These technologies may be included as part of AEP Ohio's formal application to the PUCO seeking approval of a Phase 3 DACR deployment or may be proposed to the PUCO at a later date as part of a separate application and proceeding. In addition, AEP Ohio continues to examine business processes, evaluate the recent performance of existing DACR schemes, and review other external performance outcomes that may contribute to additional reductions in outage frequency and/or outage duration.

3 VVO Business Case and Portfolio Analysis

AEP Ohio has prepared a benefit-cost analysis or "business case portfolio analysis" for every VVO bus candidate proposed for a Phase 3 deployment. All the benefit and cost data and associated assumptions used to prepare VVO business case portfolio analysis is presented in Sections 3.1. Results of the business case portfolio analysis for all Phase 3 VVO bus candidates are summarized in Section 3.2.

3.1 VVO Benefit and Cost Data and Assumptions

The net change or reduction in demand and energy that may be realized by deploying VVO are measures associated with improving energy efficiency. Estimating AEP Ohio improvements in energy efficiency achievable with VVO required that calendar year 2017 data on peak loads, and retail sales and revenue data by customer rate class and distribution circuit be collected and totaled for each Phase 3 VVO bus candidate. The benefits of improved energy efficiency are monetized by estimating reductions in customers' retail power costs associated with a given average percent reduction in voltage and energy at each VVO bus.

A properly designed VVO business case portfolio analysis includes the capital costs and operations and maintenance ("O&M") costs required to purchase, deploy, own, and maintain VVO infrastructure to realize the anticipated reliability benefits. A description of these costs incurred by AEP Ohio over the 15 year time horizon of the VVO business case portfolio analysis is provided in Table 5.

Table 5
Description of Capital and O&M Costs for VVO Infrastructure

1. Substation infrastructure

Includes estimated capital costs associated with voltage regulator control upgrades, voltage regulator bank replacements, new or upgraded remote terminal units, control house panel upgrades, and station yard cable raceway upgrades including fiber optic or other control cabling replacements.

2. Distribution line infrastructure

Includes initial capital costs and O&M costs for each candidate distribution circuit and VVO distribution bus associated with:

- a) Voltage regulator banks/controls or regulator bank control upgrades
- b) Switched capacitor bank/controls or capacitor bank control upgrades
- c) New line voltage monitors

3. Communication infrastructure

Includes initial and replacement capital costs and O&M costs for each candidate distribution circuit and VVO distribution bus associated with cellular LTE and/or mesh radios installed at (or near) each voltage regulator bank, switched capacitor bank, and line voltage monitor locations.

4. Information technology infrastructure.

Includes initial and replacement capital costs and O&M costs associated with all VVO controller hardware, VVO and AMI module software licensing, fees and maintenance support.

3.2 VVO Business Case and Portfolio Analysis Results

AEP Ohio has prepared a benefit-cost analysis or "business case" for 445 VVO buses involving 973 distribution circuits identified as candidates for a possible Smart Grid Phase 3 deployment. As described within the Phase 2 report, a business case for each VVO bus candidate is essential to ensure that AEP Ohio is delivering the greatest monetized benefits of energy efficiency from the perspective customers, i.e. retail power cost savings minus the costs (i.e. net benefits) previously identified in Table 5 to procure, deploy, operate, and maintain the proposed VVO infrastructure.

The business case prepared for each VVO bus candidate represents the net benefit cash flows that are discounted at AEP Ohio's after-tax weighted cost of capital to estimate the 15 year net present value ("NPV") of the proposed scheme. These net benefit cash flows include retail customer power costs savings, initial and replacement capital costs, and O&M costs associated with substation, distribution,

communication, and information technology (“IT”) infrastructure.^{9, 10} Also, these cash flows incorporate the combined tax effects associated with the depreciation of capitalized infrastructure assets and the tax effects associated with annual O&M expenses. The cash flow model for VVO bus “E.WOOSTER 1X” provided in Table 7 on page 11 illustrates all the annual cash flows that yields a 15 year NPV of \$1,413,711 in the bottom right corner of the table.

This level of business case modeling detail illustrated in Table 7 was repeated for each of the other 445 VVO bus candidates before assembling all business case results into AEP Ohio’s VVO portfolio. This VVO portfolio of VVO bus candidates was then prioritized and ranked by their individual 15 year NPV values in descending order from candidates with the highest NPV to candidates with the lowest (or most negative) to identify VVO bus candidates delivering the greatest value to AEP Ohio customers. A graphical summary of the NPV results for all 445 Phase 3 VVO bus candidates is provided in Figure 2.

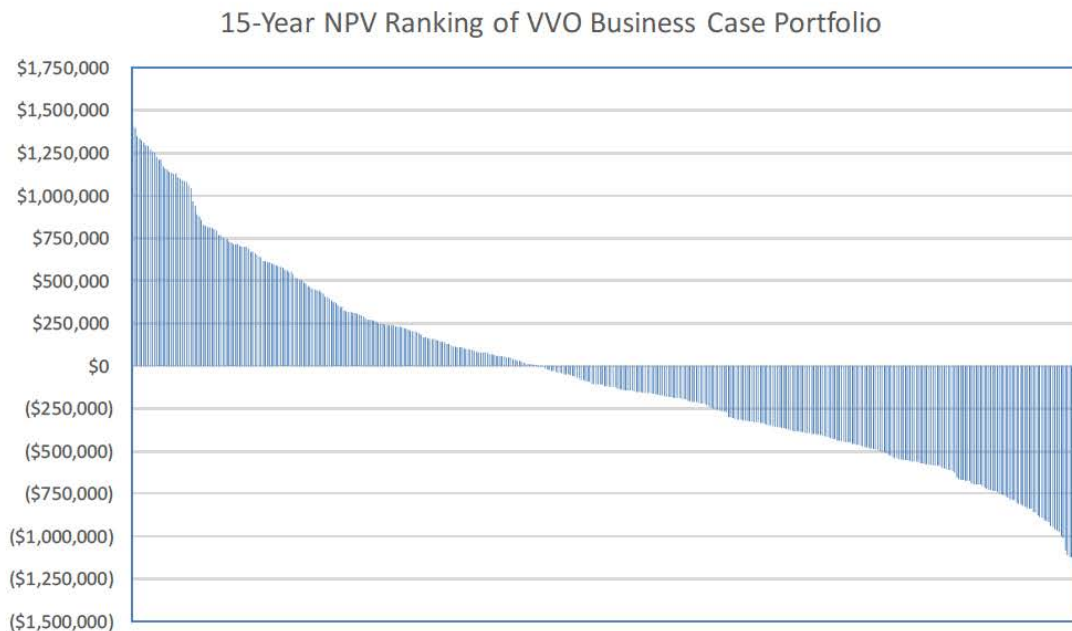


Figure 2: Prioritized Business Case Portfolio of VVO Distribution Buses With AMI

⁹ AEP Ohio operating savings associated with deferred plant investment was originally investigated, but eliminated from the VVO business case because no tangible benefits could be estimated or their contributions were negligible.

¹⁰ Reductions in CO₂ are identified in the business case, but not monetized pending establishment of an incentivized U.S. cap-and-trade, tax credit, or other program.

The business case developed for all 445 VVO bus candidates is based on a common set of financial assumptions and notes that are summarized within Section 6.3 (Appendix) of this Phase 3 report. Among the 445 VVO bus candidates investigated, 190 buses impacting 492 distribution circuits have business cases with positive 15 year NPV values. Collectively, these 190 VVO buses with positive business cases deliver greater energy efficiency (and reduced retail power costs) yielding an estimated 15 year present value benefit of \$414,035,474. In contrast, AEP Ohio incurs an estimated 15 year present value capital and O&M cost of \$322,788,749 to procure, deploy, operate, and maintain the needed VVO infrastructure. (The 15 year NPV for all 190 buses is \$91,246,725.) In other words, AEP Ohio retail customers realize \$1.28 in VVO benefits for every dollar of VVO related capital and O&M costs incurred over 15 years on these 190 buses. In addition, improved energy efficiency associated with VVO is estimated to reduce CO₂ emissions by 6,611,509 metric tons (“t”) over 15 years.¹¹ A tabular listing of all 445 VVO bus candidates graphically illustrated in Figure 2 is provided in Table 11 of Section 6.2 (Appendix). The VVO bus candidates with the 10 highest 15 Year NPV values from Table 11 is reproduced in Table 6.

Table 6
Prioritized Business Case Portfolio of VVO Buses (Top 10)

Candidate	Rank	NPV	PV Benefits	PV Costs	Reduced CO2	Circuits	Total	OHA
E.WOOSTER 1X	1	\$1,413,711	\$3,414,614	\$2,000,903	57,979	3	3	2
ZUBER 1X	2	\$1,400,035	\$3,400,938	\$2,000,903	57,373	3	6	1
CLINTON 2Y	3	\$1,347,376	\$3,543,115	\$2,195,739	48,668	4	10	0
DELAWARE 2Y	4	\$1,334,621	\$2,474,862	\$1,140,241	39,113	2	12	0
BROOKSIDE 1X	5	\$1,324,917	\$3,847,521	\$2,522,604	71,377	4	16	0
WEST CANTON 3X	6	\$1,307,386	\$1,901,720	\$594,334	33,704	1	17	0
CLINTON 2X	7	\$1,296,188	\$3,491,926	\$2,195,739	50,011	4	21	1
WHITE RD 1X	8	\$1,290,359	\$3,812,963	\$2,522,604	66,810	4	25	0
S.SIDELIM 3X	9	\$1,270,645	\$3,271,548	\$2,000,903	56,410	3	28	1
N.LIBERTY 3X	10	\$1,254,954	\$2,734,170	\$1,479,216	40,431	2	30	0

All the VVO business case portfolio analysis results heretofore presented within this Phase 3 report assumes AEP Ohio will utilize its VVO vendor’s proprietary software to achieve greater voltage reduction and energy efficiency by analyzing metering interval and voltage data wherever AMI is deployed. The VVO vendor asserts that AEP Ohio can achieve an average 4 percent reduction in energy usage (and retail power costs) if AEP Ohio integrates the vendor’s proprietary software with its other VVO hardware and software wherever AMI is deployed. However, the VVO vendor asserts only an average 3 percent voltage reduction can be achieved if AEP Ohio doesn’t have AMI interval and voltage data (i.e. no AMI has been deployed) and doesn’t procure and integrate the vendor’s software with its other VVO infrastructure.

AEP Ohio’s VVO business case portfolio analysis is significantly impacted if AMI isn’t deployed where VVO is proposed, the VVO vendor’s proprietary software isn’t purchased and integrated with the vendor’s other systems, and average voltage and energy reduction is limited to 3 percent. A graphical summary of these impacts on NPV results for all 445 Phase 3 VVO bus candidates is provided in Figure 3 on page 12.

¹¹ The official symbol for the metric ton in the International System of Units (“SI”) is “t”.

Table 7
Cash Flow Model for Highest Ranked VVO Bus "E.WOOSTER 1X"

Exhibit SSO-3
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	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Related Costs	\$1,268,940	\$2,925	\$2,925	\$2,925	\$2,925	\$0	\$0	\$0	\$88,786	\$0	\$106,365	\$0	\$0	\$0	\$0
Capital Cost - Substation Infrastructure	\$666,180	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Capital Cost - Distribution Infrastructure	\$363,690	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Capital Cost - Communication Infrastructure	\$104,760	\$2,925	\$2,925	\$2,925	\$2,925	\$0	\$0	\$0	\$0	\$0	\$106,365	\$0	\$0	\$0	\$0
Capital Cost - Info Tech Infrastructure	\$134,310	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$88,786	\$0	\$0	\$0	\$0	\$0	\$0
Capital Cost - Customer Infrastructure	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Subtotal - Capital Costs	\$1,268,940	\$2,925	\$2,925	\$2,925	\$2,925	\$0	\$0	\$0	\$88,786	\$0	\$106,365	\$0	\$0	\$0	\$0
Depreciation Related Costs															
Dep Exp - Substation Infrastructure	\$14,804	\$14,804	\$14,804	\$14,804	\$14,804	\$14,804	\$14,804	\$14,804	\$14,804	\$14,804	\$14,804	\$14,804	\$14,804	\$14,804	\$14,804
Dep Exp - Distribution Infrastructure	\$11,365	\$11,365	\$11,365	\$11,365	\$11,365	\$11,365	\$11,365	\$11,365	\$11,365	\$11,365	\$11,365	\$11,365	\$11,365	\$11,365	\$11,365
Dep Exp - Communication Infrastructure	\$6,984	\$7,179	\$7,374	\$7,569	\$7,764	\$7,764	\$7,764	\$7,764	\$7,764	\$7,764	\$8,066	\$8,066	\$8,066	\$8,066	\$8,066
Dep Exp - Info Tech Infrastructure	\$26,862	\$26,862	\$26,862	\$26,862	\$26,862	\$0	\$0	\$0	\$17,757	\$17,757	\$17,757	\$17,757	\$17,757	\$0	\$0
Dep Exp - Customer Infrastructure	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Tax Benefit of Dep - Substation Infrastructure	\$3,239	\$3,239	\$3,239	\$3,239	\$3,239	\$3,239	\$3,239	\$3,239	\$3,239	\$3,239	\$3,239	\$3,239	\$3,239	\$3,239	\$3,239
Tax Benefit of Dep - Distribution Infrastructure	\$2,487	\$2,487	\$2,487	\$2,487	\$2,487	\$2,487	\$2,487	\$2,487	\$2,487	\$2,487	\$2,487	\$2,487	\$2,487	\$2,487	\$2,487
Tax Benefit of Dep - Com Infrastructure	\$1,528	\$1,571	\$1,613	\$1,656	\$1,699	\$1,699	\$1,699	\$1,699	\$1,699	\$1,699	\$1,765	\$1,765	\$1,765	\$1,765	\$1,765
Tax Benefit of Dep - Info Tech Infrastructure	\$5,877	\$5,877	\$5,877	\$5,877	\$5,877	\$0	\$0	\$0	\$3,885	\$3,885	\$3,885	\$3,885	\$3,885	\$0	\$0
Tax Benefit of Dep - Customer Infrastructure	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Subtotal - Tax Benefit of Depreciation	\$13,131	\$13,174	\$13,217	\$13,259	\$13,302	\$7,425	\$7,425	\$7,425	\$11,310	\$11,310	\$11,376	\$11,376	\$11,376	\$7,491	\$7,491
Net Book - Substation Infrastructure	\$651,376	\$636,572	\$621,768	\$606,964	\$592,160	\$577,356	\$562,552	\$547,748	\$532,944	\$518,140	\$503,336	\$488,532	\$473,728	\$458,924	\$444,120
Net Book - Distribution Infrastructure	\$352,325	\$340,959	\$329,594	\$318,229	\$306,863	\$295,498	\$284,133	\$272,768	\$261,402	\$250,037	\$238,672	\$227,306	\$215,941	\$204,576	\$193,210
Net Book - Communication Infrastructure	\$97,776	\$93,522	\$89,073	\$84,429	\$79,590	\$74,751	\$69,912	\$65,073	\$60,234	\$55,395	\$50,556	\$45,717	\$40,878	\$36,039	\$31,200
Net Book - Info Tech Infrastructure	\$107,448	\$80,586	\$53,724	\$26,862	\$0	\$0	\$0	\$0	\$71,029	\$53,271	\$35,514	\$17,757	\$0	\$0	\$0
Net Book - Customer Infrastructure	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Property Tax - Substation Infrastructure	\$19,867	\$19,415	\$18,964	\$18,512	\$18,061	\$17,609	\$17,158	\$16,706	\$16,255	\$15,803	\$15,352	\$14,900	\$14,449	\$13,997	\$13,546
Property Tax - Distribution Infrastructure	\$10,746	\$10,399	\$10,053	\$9,706	\$9,359	\$9,013	\$8,666	\$8,319	\$7,973	\$7,626	\$7,279	\$6,933	\$6,586	\$6,240	\$5,893
Property Tax - Communication Infrastructure	\$2,982	\$2,852	\$2,717	\$2,575	\$2,427	\$2,191	\$1,954	\$1,717	\$1,480	\$1,243	\$1,136	\$890	\$644	\$398	\$152
Property Tax - Info Tech Infrastructure	\$3,277	\$2,458	\$1,639	\$819	\$0	\$0	\$0	\$0	\$2,166	\$1,625	\$1,083	\$542	\$0	\$0	\$0
Property Tax - Customer Infrastructure	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Subtotal - Property Tax	\$36,872	\$35,125	\$33,372	\$31,613	\$29,848	\$28,813	\$27,778	\$26,743	\$25,708	\$24,673	\$23,638	\$22,603	\$21,568	\$20,533	\$19,498
Operations & Maintenance Expense	\$71,068	\$72,208	\$73,382	\$74,574	\$75,786	\$77,084	\$78,240	\$79,414	\$80,276	\$81,480	\$82,351	\$83,586	\$84,840	\$86,113	\$87,405
O&M - Substation Infrastructure	\$19,985	\$20,285	\$20,589	\$20,898	\$21,212	\$21,530	\$21,853	\$22,181	\$22,513	\$22,851	\$23,194	\$23,542	\$23,895	\$24,253	\$24,617
O&M - Distribution Infrastructure	\$10,911	\$11,074	\$11,240	\$11,409	\$11,580	\$11,754	\$11,930	\$12,109	\$12,291	\$12,475	\$12,662	\$12,852	\$13,045	\$13,241	\$13,439
O&M - Communication Infrastructure	\$4,838	\$4,999	\$5,165	\$5,334	\$5,507	\$5,751	\$5,838	\$5,925	\$6,014	\$6,104	\$6,194	\$6,284	\$6,374	\$6,464	\$6,554
O&M - Info Tech Infrastructure	\$35,334	\$35,849	\$36,387	\$36,933	\$37,487	\$38,049	\$38,620	\$39,199	\$39,788	\$40,377	\$40,966	\$41,555	\$42,144	\$42,733	\$43,322
O&M - Customer Infrastructure	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Subtotal - O&M Expenses	\$71,068	\$72,208	\$73,382	\$74,574	\$75,786	\$77,084	\$78,240	\$79,414	\$80,276	\$81,480	\$82,351	\$83,586	\$84,840	\$86,113	\$87,405
Customer Benefits	\$331,191	\$339,521	\$348,060	\$356,813	\$365,787	\$374,987	\$384,418	\$394,086	\$403,997	\$414,157	\$424,573	\$435,252	\$446,198	\$457,420	\$468,924
Operating Benefits	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Operating Benefits & Expenses Net of Taxes	(\$71,192)	(\$70,675)	(\$70,179)	(\$69,694)	(\$69,219)	(\$75,302)	(\$75,397)	(\$75,505)	(\$73,177)	(\$72,886)	(\$72,370)	(\$72,096)	(\$71,837)	(\$75,900)	(\$76,094)
Depreciation Tax Benefit	\$13,131	\$13,174	\$13,217	\$13,259	\$13,302	\$7,425	\$7,425	\$7,425	\$11,310	\$11,310	\$11,376	\$11,376	\$11,376	\$7,491	\$7,491
Property Tax Expense	\$28,805	\$27,440	\$26,070	\$24,696	\$23,317	\$22,509	\$21,700	\$20,891	\$21,775	\$20,544	\$19,413	\$18,174	\$16,935	\$16,120	\$15,304
O&M Expense	\$55,518	\$56,409	\$57,326	\$58,257	\$59,204	\$60,218	\$61,121	\$62,038	\$62,712	\$63,563	\$64,333	\$65,298	\$66,277	\$67,271	\$68,280
Operating Benefits	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Subtotal - Cash Flow Net of Taxes	(\$71,192)	(\$70,675)	(\$70,179)	(\$69,694)	(\$69,219)	(\$75,302)	(\$75,397)	(\$75,505)	(\$73,177)	(\$72,886)	(\$72,370)	(\$72,096)	(\$71,837)	(\$75,900)	(\$76,094)
Annual Customer & Utility Net Cash Flow	(\$1,008,941)	\$265,921	\$274,955	\$284,194	\$293,643	\$299,685	\$309,021	\$318,581	\$324,034	\$341,271	\$245,839	\$363,156	\$374,362	\$381,520	\$392,830
Cumulative Customer & Utility Net Cash Flow	(\$1,008,941)	(\$743,020)	(\$468,064)	(\$183,870)	\$109,774	\$409,458	\$718,479	\$1,037,059	\$1,279,093	\$1,620,364	\$1,866,203	\$2,229,359	\$2,603,720	\$2,985,240	\$3,378,070
Annual PV Customer & Utility Cash Flow	(\$935,937)	\$228,831	\$219,486	\$210,446	\$201,709	\$190,964	\$182,665	\$174,690	\$173,114	\$161,032	\$107,608	\$147,458	\$141,009	\$133,307	\$127,328
Cumulative NPV Customer & Utility Cash Flow	(\$935,937)	(\$707,106)	(\$487,621)	(\$277,175)	(\$75,465)	\$115,499	\$298,164	\$472,855	\$595,969	\$757,000	\$864,608	\$1,012,066	\$1,153,075	\$1,286,383	\$1,413,711

Assuming AMI is not deployed and only an average 3 percent voltage and energy reduction can be achieved, the number of VVO bus candidates with positive business cases falls from 190 buses and 492 distribution circuits to 69 buses and 197 distribution circuits. Collectively, these 69 VVO buses with positive business cases deliver an average 3 percent reduction in energy usage (and retail power costs) with an estimated 15 year present value benefit of \$135,669,131 compared to \$414,035,474 if AMI is deployed and an average 4 percent voltage can be achieved. AEP Ohio's 15 year present value capital and O&M cost to procure, deploy, operate and maintain less VVO infrastructure falls from \$322,788,749 to \$122,931,982 if AMI is not deployed. However, the overall impact is that AEP Ohio retail customers realize \$1.10 in VVO benefits for every dollar of VVO related capital and O&M costs incurred over 15 years if AMI isn't deployed versus \$1.28 in VVO benefits for every dollar VVO costs if AMI is deployed. In addition, less energy efficiency associated with a less ambitious VVO deployment is estimated to reduce CO₂ emissions by 2,177,893 t versus 6,611,509 t over 15 years.

15-Year NPV Ranking of VVO Business Case Portfolio

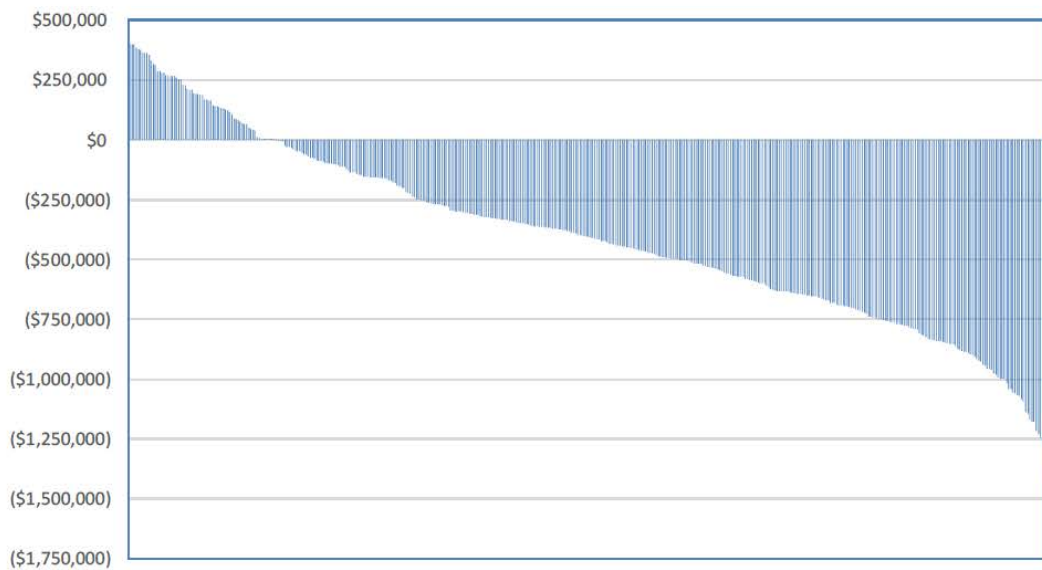


Figure 3: Revised Prioritized Business Case Portfolio of VVO Distribution Buses Without AMI

The VVO business case and portfolio analysis presented in this report assumes AEP Ohio will utilize the same VVO technology in previous and current deployments approved by the PUCO. However, AEP Ohio intends to monitor rapidly emerging technologies such as photovoltaics, electric vehicle charging loads and infrastructure requirements, micro grids, and demand response that can all potentially impact future proposed VVO deployments. These technologies (and perhaps others) have potential to alter load shapes and energy usage patterns that may influence how AEP Ohio reliably serves customers' future power requirements.

4 AMI Business Case

The remainder of AEP Ohio's service territory where AMI may be deployed as part of a proposed Smart Grid Phase 3 project is already equipped with a legacy drive-by automated meter reading ("AMR") system employing one-way radio communication technology. Preparing an AMI business case for a proposed Phase 3 AMI deployment typically begins with identifying and estimating relevant benefits and costs associated with one or more AMI vendors and communication technologies.¹² However, AEP Ohio is presently deploying as part of its Smart Grid Phase 2 project a Silver Spring Networks™ ("SSN") AMI solution. (SSN has recently been acquired by Itron™.) The AMI business case assumes this Itron-SSN solution will be expanded as part of a future Smart Grid Phase 3 deployment because the costs associated with expansion are relatively well known.¹³ Also, the cost of expanding the existing Itron-SSN solution doesn't depend on legacy systems or processes; in other words, the cost to expand the existing Itron-SSN solution is the same regardless of if AMI replaces traditional manual meter reading or the existing AMR system. (The choice of communication technology will be revisited later in this section.)

In contrast to costs, many of the benefits associated with AMI are impacted by the legacy systems or processes that AMI is intended to replace or augment. For example, AMR has displaced traditional meter reading and the added benefit of migrating from a legacy AMR system to AMI represents an incremental impact on the AMI business case; benefits originally realized with AMR cannot be recaptured. Aside from incremental metering reading benefits, additional benefits identified by AEP Ohio is based on the ability to remotely connect and disconnect meters, reduce bad debt expenses on past due accounts, and provide the meter interval data needed to expand and promote energy efficiency.

AEP Ohio's AMI business case results is similar to the experience of other utilities replacing legacy AMR system with AMI; the cost of migrating from AMR to AMI is not impacted and fewer tangible benefits result in negative business cases. Similar to DACR and VVO, the AMI business case represents the net benefit cash flows discounted at AEP Ohio's after-tax weighted cost of capital to estimate the 15 year net present value ("NPV") of the proposed Phase 3 AMI deployment. These net benefit cash flows include the aforementioned benefits, initial and replacement capital costs, and O&M costs associated with smart meters, communication, and information technology ("IT") infrastructure. Also, these cash flows incorporate the combined tax effects associated with the depreciation of capitalized infrastructure assets and the tax effects associated with annual O&M expenses. The cash flow model for the AMI business case provided in Table 8 on page 15 illustrates all the annual cash flows that yields a negative 15 year NPV of \$77,876,330 in the bottom right corner of the table. Not illustrated in the cash flow model is the 15 year reduction in CO₂ emissions from vehicles, which is estimated to be 159,916 t.¹⁴

¹² AMI may include a variety of communication technologies such as licensed radio frequency ("RF"), unlicensed RF mesh, or power line carrier that enables two-way communications.

¹³ AEP Ohio's Itron-SSN solution features unlicensed RF mesh communication technology and public LTE carriers.

¹⁴ Reductions in CO₂ are identified in the business case, but not monetized pending establishment of an incentivized U.S. cap-and-trade, tax credit, or other program.

A major factor contributing to a negative AMI business case is the estimated cost of deploying RF mesh communication infrastructure in the remaining portion AEP Ohio's service area that is predominantly rural. AEP Ohio has reexamined its communication options and concludes RF mesh remains today the preferred technology that provides the desired communication flexibility.^{15, 16} For example, RF mesh leverages today's existing public cellular LTE network. However, the flexibility of RF mesh doesn't preclude AEP Ohio from deploying hybrid communication infrastructure in the future such as private cellular LTE, licensed RF, and fiber optic cable, etc.¹⁷ AEP Ohio asserts that AMI is a desirable and necessary technology as part of a future Smart Grid Phase 3 deployment for a variety of reasons including, but not necessarily limited to:

1. The ability of VVO to "maximize customer and company benefits" is dependent on AMI to provide meter interval and voltage data.¹⁸
2. AMI is required to fulfil a Phase 2 report Table 1 objective to ". . . provide customers and CRES providers with customer interval data . . . [and] develop such systems and processes using a phase-in approach, and transfer as much data as possible to customers and CRES providers through the implementation stages."¹⁹ Existing and future customers would not have the opportunity to participate in existing or future energy efficiency programs if AMI is not deployed.
3. AMI will be leveraged to enable the deployment of additional smart grid technologies such as smart street lighting, demand management, etc. and,
4. AMI will augment AEP Ohio's outage management system and service restoration processes.

¹⁵ A goal of AEP Ohio when reexamining its communication options was to leverage existing AMI IT technology and communication infrastructure and avoid the added expense of operating and maintaining AMI systems from multiple vendors. Similarly, power line carrier as an alternative communication path has limited bandwidth and flexibility.

¹⁶ Power line carrier ("PLC") was an alternative considered by AEP Ohio for rural portions of the utility's service area, but PLC has limited bandwidth and flexibility for applications beyond AMI.

¹⁷ These other communication technologies can also be leveraged for DACR, VVO, and other future applications.

¹⁸ Commission Order and Opinion dated February 1, 2017, Section IV (1) (B) (iii).

¹⁹ Commission Opinion and Order dated February 1, 2017, Section IV (B), Par. (21).

Exhibit SSO-3
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Table 8
Cash Flow Model for AMI Business Case

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Related Costs	\$10,494,544	\$27,048,799	\$27,588,475	\$11,055,676	\$290,503	\$1,268,811	\$294,166	\$306,526	\$314,898	\$318,444	\$1,372,524	\$332,371	\$336,126	\$344,481	\$351,547
Capital Cost - Substation Infrastructure	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Capital Cost - Distribution Infrastructure	\$2,797,720	\$22,830,917	\$23,289,240	\$9,306,721	\$181,285	\$184,845	\$188,547	\$192,319	\$196,242	\$200,158	\$204,147	\$208,295	\$212,436	\$216,655	\$221,127
Capital Cost - Communication Infrastructure	\$511,552	\$4,167,132	\$4,247,724	\$1,696,671	\$56,149	\$56,992	\$50,947	\$5,8714	\$62,331	\$61,117	\$62,034	\$65,179	\$63,908	\$67,149	\$68,832
Capital Cost - Info Tech Infrastructure	\$7,185,272	\$5,075	\$5,151	\$5,284	\$5,308	\$1,026,975	\$5,472	\$5,492	\$5,6325	\$5,7169	\$1,106,344	\$58,897	\$59,781	\$60,678	\$61,588
Capital Cost - Customer Infrastructure	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Subtotal - Capital Costs	\$10,494,544	\$27,048,799	\$27,588,475	\$11,055,676	\$290,503	\$1,268,811	\$294,166	\$306,526	\$314,898	\$318,444	\$1,372,524	\$332,371	\$336,126	\$344,481	\$351,547
Depreciation Related Costs															
Dep Exp - Substation Infrastructure	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Dep Exp - Distribution Infrastructure	\$186,515	\$1,708,576	\$3,261,192	\$3,881,640	\$3,893,726	\$3,906,048	\$3,918,618	\$3,931,440	\$3,944,522	\$3,957,866	\$3,971,476	\$3,985,362	\$3,999,525	\$4,013,968	\$4,028,710
Dep Exp - Communication Infrastructure	\$34,103	\$311,912	\$595,094	\$708,205	\$711,949	\$715,748	\$719,144	\$723,059	\$727,214	\$731,289	\$735,424	\$739,769	\$744,030	\$748,507	\$753,095
Dep Exp - Info Tech Infrastructure	\$1,437,054	\$1,447,204	\$1,457,507	\$1,467,963	\$1,478,577	\$246,918	\$247,702	\$248,498	\$249,306	\$250,127	\$260,000	\$266,845	\$267,703	\$268,574	\$269,457
Dep Exp - Customer Infrastructure	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Tax Benefit of Dep - Substation Infrastructure	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Tax Benefit of Dep - Distribution Infrastructure	\$40,809	\$373,836	\$713,549	\$849,303	\$851,947	\$854,643	\$857,394	\$860,199	\$863,061	\$865,981	\$868,959	\$871,997	\$875,096	\$878,256	\$881,482
Tax Benefit of Dep - Com Infrastructure	\$7,462	\$68,246	\$130,207	\$154,955	\$155,774	\$156,606	\$157,439	\$158,205	\$159,114	\$160,006	\$160,911	\$161,862	\$162,794	\$163,773	\$164,777
Tax Benefit of Dep - Info Tech Infrastructure	\$314,428	\$316,648	\$318,902	\$321,190	\$323,513	\$54,026	\$54,197	\$54,371	\$54,548	\$54,728	\$54,821	\$58,386	\$58,573	\$58,764	\$58,957
Tax Benefit of Dep - Customer Infrastructure	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Subtotal - Tax Benefit of Depreciation	\$362,699	\$758,731	\$1,162,658	\$1,325,449	\$1,331,234	\$1,065,275	\$1,068,940	\$1,072,776	\$1,076,724	\$1,080,715	\$1,088,071	\$1,092,245	\$1,096,463	\$1,100,793	\$1,105,216
Net Book - Substation Infrastructure	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Net Book - Distribution Infrastructure	\$2,611,205	\$23,733,546	\$43,761,594	\$49,186,676	\$45,474,235	\$41,753,031	\$38,022,960	\$34,283,840	\$30,535,559	\$26,777,851	\$23,010,522	\$19,233,455	\$15,446,366	\$11,649,053	\$7,841,469
Net Book - Communication Infrastructure	\$477,449	\$4,332,668	\$7,985,298	\$8,973,764	\$8,317,955	\$7,659,208	\$6,991,011	\$6,326,666	\$5,661,784	\$4,991,612	\$4,318,221	\$3,643,630	\$2,963,509	\$2,282,151	\$1,597,888
Net Book - Info Tech Infrastructure	\$5,748,218	\$4,351,763	\$2,945,768	\$1,530,088	\$104,579	\$884,637	\$691,607	\$498,601	\$305,619	\$112,662	\$95,005	\$745,057	\$537,135	\$329,238	\$121,269
Net Book - Customer Infrastructure	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Property Tax - Substation Infrastructure	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Property Tax - Distribution Infrastructure	\$79,642	\$723,873	\$1,334,729	\$1,500,194	\$1,386,964	\$1,273,467	\$1,159,700	\$1,045,657	\$931,835	\$816,724	\$701,821	\$586,620	\$471,114	\$355,296	\$239,165
Property Tax - Communication Infrastructure	\$14,562	\$132,146	\$243,552	\$273,700	\$253,698	\$233,606	\$213,226	\$192,963	\$172,684	\$152,244	\$131,706	\$111,131	\$90,387	\$69,606	\$48,736
Property Tax - Info Tech Infrastructure	\$175,321	\$132,729	\$89,846	\$46,668	\$3,190	\$2,691	\$2,1094	\$15,207	\$9,321	\$3,436	\$29,067	\$22,724	\$16,383	\$10,042	\$3,702
Property Tax - Customer Infrastructure	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Subtotal - Property Tax	\$269,525	\$988,748	\$1,668,126	\$1,820,561	\$1,643,852	\$1,534,055	\$1,394,020	\$1,253,828	\$1,113,340	\$972,405	\$862,593	\$720,475	\$577,884	\$434,943	\$291,602
Operations & Maintenance Expense	\$2,333,232	\$4,238,961	\$6,224,601	\$7,086,544	\$7,094,841	\$7,206,319	\$7,337,442	\$7,471,389	\$7,608,318	\$7,747,800	\$7,894,382	\$8,039,479	\$8,187,377	\$8,338,164	\$8,492,413
O&M - Substation Infrastructure	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
O&M - Distribution Infrastructure	\$417,760	\$1,233,375	\$2,088,137	\$2,457,886	\$2,381,233	\$2,423,842	\$2,467,314	\$2,511,750	\$2,557,016	\$2,603,210	\$2,650,435	\$2,698,554	\$2,747,753	\$2,797,890	\$2,849,164
O&M - Communication Infrastructure	\$91,314	\$842,524	\$1,621,573	\$1,950,108	\$1,989,100	\$2,029,135	\$2,069,436	\$2,110,748	\$2,153,345	\$2,196,686	\$2,242,578	\$2,287,753	\$2,333,715	\$2,380,677	\$2,428,992
O&M - Info Tech Infrastructure	\$1,824,158	\$2,163,062	\$2,514,891	\$2,678,550	\$2,724,508	\$2,753,342	\$2,800,692	\$2,848,891	\$2,897,956	\$2,947,904	\$3,001,369	\$3,053,172	\$3,105,909	\$3,159,598	\$3,214,257
O&M - Customer Infrastructure	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Subtotal - O&M Expenses	\$2,333,232	\$4,238,961	\$6,224,601	\$7,086,544	\$7,094,841	\$7,206,319	\$7,337,442	\$7,471,389	\$7,608,318	\$7,747,800	\$7,894,382	\$8,039,479	\$8,187,377	\$8,338,164	\$8,492,413
Customer Benefits	\$60,848	\$558,627	\$1,076,637	\$1,291,736	\$1,317,667	\$1,344,120	\$1,371,103	\$1,398,628	\$1,426,705	\$1,455,346	\$1,484,562	\$1,514,365	\$1,544,766	\$1,575,777	\$1,607,411
Operating Benefits	\$164,519	\$1,510,397	\$2,910,246	\$3,492,552	\$3,562,665	\$3,634,186	\$3,707,142	\$3,781,653	\$3,857,748	\$3,934,917	\$4,013,910	\$4,094,490	\$4,176,686	\$4,260,533	\$4,346,064
Operating Benefits & Expenses Net of Taxes	(\$1,542,053)	(\$2,145,233)	(\$2,729,656)	(\$2,904,400)	(\$2,712,278)	(\$2,923,679)	(\$2,856,059)	(\$2,789,207)	(\$2,723,173)	(\$2,657,552)	(\$2,617,212)	(\$2,552,416)	(\$2,488,131)	(\$2,424,430)	(\$2,361,711)
Depreciation Tax Benefit	\$362,699	\$758,731	\$1,162,658	\$1,325,449	\$1,331,234	\$1,065,275	\$1,068,940	\$1,072,776	\$1,076,724	\$1,080,715	\$1,088,071	\$1,092,245	\$1,096,463	\$1,100,793	\$1,105,216
Property Tax Expense	\$210,553	\$772,410	\$1,303,140	\$1,422,222	\$1,284,177	\$1,198,404	\$1,089,009	\$979,490	\$869,741	\$759,643	\$673,858	\$562,835	\$451,443	\$339,778	\$227,800
O&M Expense	\$1,822,221	\$3,311,476	\$4,662,658	\$5,336,008	\$5,542,490	\$5,629,576	\$5,732,010	\$5,836,649	\$5,943,618	\$6,052,581	\$6,167,092	\$6,280,441	\$6,395,979	\$6,513,774	\$6,634,273
Operating Benefits	\$128,522	\$1,179,922	\$2,273,484	\$2,783,382	\$2,783,154	\$2,839,026	\$2,896,019	\$2,954,157	\$3,013,462	\$3,073,957	\$3,135,667	\$3,198,615	\$3,262,827	\$3,328,329	\$3,395,145
Subtotal - Cash Flow Net of Taxes	(\$1,542,053)	(\$2,145,233)	(\$2,729,656)	(\$2,904,400)	(\$2,712,278)	(\$2,923,679)	(\$2,856,059)	(\$2,789,207)	(\$2,723,173)	(\$2,657,552)	(\$2,617,212)	(\$2,552,416)	(\$2,488,131)	(\$2,424,430)	(\$2,361,711)
Annual Customer & Utility Net Cash Flow	(\$11,975,748)	(\$28,635,405)	(\$29,241,763)	(\$12,668,340)	(\$1,685,114)	(\$2,848,371)	(\$1,779,123)	(\$1,697,105)	(\$1,611,366)	(\$1,520,650)	(\$2,505,174)	(\$1,370,423)	(\$1,279,491)	(\$1,193,134)	(\$1,105,848)
Cumulative Customer & Utility Net Cash Flow	(\$11,975,748)	(\$40,611,153)	(\$69,852,917)	(\$82,521,257)	(\$84,206,371)	(\$87,054,741)	(\$88,833,664)	(\$90,530,968)	(\$92,142,335)	(\$93,662,985)	(\$96,168,159)	(\$97,538,582)	(\$98,818,073)	(\$100,011,206)	(\$101,117,054)
Annual PV Customer & Utility Cash Flow	(\$11,109,229)	(\$24,641,424)	(\$23,342,495)	(\$9,380,904)	(\$1,157,538)	(\$1,815,030)	(\$1,051,658)	(\$930,590)	(\$819,644)	(\$717,533)	(\$1,096,558)	(\$556,454)	(\$481,940)	(\$416,895)	(\$358,438)
Cumulative NPV Customer & Utility Cash Flow	(\$11,109,229)	(\$35,750,653)	(\$59,093,148)	(\$68,474,051)	(\$69,631,590)	(\$71,446,620)	(\$72,498,278)	(\$73,428,669)	(\$74,248,513)	(\$74,966,046)	(\$76,062,604)	(\$76,619,058)	(\$77,100,998)	(\$77,517,893)	(\$77,876,330)

5 Revised Phase 3 Full System Feasibility Study Summary

Results of the DACR, VVO, and AMI business cases previously presented within this Phase 3 report can now be aggregated to provide a summary of the Revised Phase 3 Full System Feasibility Study. Viewed holistically, AEP Ohio asserts these business cases support a proposed Smart Grid Phase 3 deployment of DACR, VVO, and AMI within AEP Ohio's remaining service territory. This holistic view of the DACR, VVO, and AMI business cases provided in Table 9 includes a total column that assumes these projects are independent of each other. In reality, the VVO business case illustrated in Table 9 is dependent on the assumption that AMI will also be deployed to deliver an average 4 percent reduction in energy consumption and retail power costs savings to AEP Ohio customers.

Table 9
15 Year Business Case Summary for DACR, VVO and AMI

Description	DACR	VVO	AMI	Total
Present Value Benefits	\$569,908,200	\$414,035,474	\$40,037,595	\$1,023,981,269
Present Value Costs	\$349,945,501	\$322,788,749	\$117,913,925	\$790,648,175
Net Present Value	\$219,962,699	\$91,246,725	(\$77,876,330)	\$233,333,094
Benefit-Cost Ratio	1.63	1.28	0.34	1.30
Reduced CO ₂ Emissions	Not Applicable	6,611,509 t	159,916 t	6,771,425 t

Table 9 Notes:

1. The DACR column represents totals for the 80 schemes impacting 416 distribution circuits that have positive 15 year NPV business case outcomes.
2. The VVO column represents totals for the 190 buses impacting 492 distribution circuits that have positive 15 year NPV values business case outcomes.
3. VVO business case results assumes AMI is deployed and AMI interval and voltage data is available to achieve an average 4 percent voltage and energy reduction.
4. The total column assumes the proposed DACR, VVO, and AMI projects are independent of each other and any project with a positive business case may be selected for deployment. In other words, the proposed DACR, VVO, and AMI projects do not represent mutually exclusive projects where the acceptance of one or more projects implies that other projects must be rejected. Mutually exclusive projects arise for a variety of reasons including, but not necessarily limited to: dependencies that exist among projects, funding or budgeting constraints, or the existence of projects that differ in scale, size, or timing of cash flows where projects should be selected on the basis of NPV.
5. Present value benefits and present value costs include the effects of combined federal/state income taxes and property taxes where appropriate. Present value benefits is the sum of the annual benefit cash flows that are discounted at AEP Ohio's after-tax weighted average cost of

capital. Similarly, present value costs is the sum of the annual cost cash flows that are discounted at AEP Ohio's after-tax weighted average cost of capital.

6. The benefit-cost ratio is defined as ratio of the present value benefits to the present value costs.
7. Other items of interest.

All business case results presented within this Phase 3 report including annual benefits, costs, and net benefits (i.e. benefits minus costs) are discounted by AEP Ohio's after-tax cost of capital, which is subject to change. A comparison of the non-discounted benefits and costs in the table below is useful to illustrate the overall scale of the net benefits delivered to AEP Ohio retail customers assuming that DACR, VVO, and AMI are all part of a future Smart Grid Phase 3 deployment. All DACR and VVO totals within the table only include DACR schemes and VVO buses with positive business cases.

Description	DACR	VVO	AMI	Total
Non-discounted benefits	\$1,013,158,954	\$739,795,573	\$75,006,685	\$1,827,961,212
Non-discounted costs	\$453,930,875	\$440,478,348	\$176,123,738	\$1,070,532,961
Non-discounted net benefit	\$559,228,079	\$299,317,225	(\$101,117,053)	\$757,428,251
Ratio of benefits-to-costs	2.23	1.68	0.43	1.71

6 Appendix

Section 6.1 provides a tabular summary of business case results for all 146 DACR scheme candidates and 711 distribution circuits included within the Revised Phase 3 Full System Feasibility Study.

Section 6.2 provides a tabular summary of business case results for all 445 VVO bus candidates and 973 distribution circuits included within the Revised Phase 3 Full System Feasibility Study.

Section 6.3 provides a compilation of all financial evaluation and other assumptions used to develop the DACR business case and portfolio analysis, the VVO business case and portfolio analysis, and the AMI business case.

6.1 Prioritized Portfolio Analysis of DACR Scheme Candidates

Table 10
Prioritized Business Case Portfolio of DACR Schemes

Candidate	Rank	NPV	PV Benefits	PV Costs	Circuits	Total	Rule 11	District	District Sub-Area
CRA991	1	\$7,034,782	\$12,465,319	\$5,430,537	7	7	0	Columbus	Columbus, SW - 65
CRC200	2	\$6,906,261	\$12,856,299	\$5,950,038	8	15	0	Columbus	Columbus, SE - 64
CRC517	3	\$6,684,020	\$12,009,602	\$5,325,581	7	22	0	Columbus	Columbus, SE - 64
CRC414	4	\$6,607,554	\$10,326,328	\$3,718,774	5	27	0	Columbus	Columbus, NW - 66
CRC013	5	\$6,549,871	\$15,097,977	\$8,548,106	10	37	0	Chillicothe	Portsmouth - 82
CRA999	6	\$6,516,946	\$12,011,153	\$5,494,208	7	44	0	Columbus	Columbus, SE - 64
CRC407	7	\$6,446,330	\$10,304,355	\$3,858,026	5	49	0	Columbus	Columbus, NW - 66
CRA109	8	\$6,437,162	\$15,818,159	\$9,380,997	11	60	0	Canton	North Canton - 20, South Canton - 21
CRA996	9	\$5,818,869	\$11,217,561	\$5,398,692	7	67	0	Columbus	Columbus, SW - 65
CRC518	10	\$5,801,212	\$9,614,601	\$3,813,388	5	72	0	Columbus	Columbus, SE - 64, Columbus, SW - 65
CRC211	11	\$5,796,865	\$9,059,815	\$3,262,950	4	76	1	Columbus	Columbus, SW - 65
CRC433	12	\$5,643,259	\$10,246,377	\$4,603,118	5	81	2	Newark	Mt Vernon - 51
CRA987	13	\$5,150,980	\$9,918,629	\$4,767,650	5	86	0	Newark	Belmont - 61
CRC210	14	\$4,854,330	\$10,169,299	\$5,314,969	7	93	0	Columbus	Columbus, SE - 64
CRA111	15	\$4,753,632	\$9,082,538	\$4,328,906	5	98	1	Canton	North Canton - 20, South Canton - 21
CRC002	16	\$4,736,549	\$8,838,253	\$4,101,704	5	103	0	Chillicothe	Chillicothe - 20
CRA104	17	\$4,732,845	\$9,839,789	\$5,106,944	6	109	0	Canton	North Canton - 20
CRC508	18	\$4,665,132	\$9,333,319	\$4,668,187	6	115	0	Columbus	Columbus, NE - 63, Columbus, SE - 64
CRA113	19	\$4,644,907	\$6,255,809	\$1,610,902	2	117	0	Canton	North Canton - 20
CRC019	20	\$4,640,757	\$11,550,548	\$6,909,791	8	125	2	Chillicothe	Ironton - 81
CRC021	21	\$4,623,144	\$7,341,148	\$2,718,004	3	128	0	Chillicothe	Chesapeake - 22
CRA120	22	\$4,598,691	\$14,199,086	\$9,600,395	11	139	1	Newark	Coshocton - 82
CRA397	23	\$4,450,131	\$17,207,274	\$12,757,143	14	153	0	Canton	Wooster - 70
CRC028	24	\$4,318,799	\$8,400,907	\$4,082,108	5	158	1	Athens	Gallipolis - 14
CRC994	25	\$4,310,009	\$8,150,307	\$3,840,298	5	163	0	Columbus	Columbus, SE - 64
CRC416	26	\$4,256,207	\$6,515,513	\$2,259,307	3	166	2	Columbus	Columbus, NE - 63, Columbus, NW - 66
CRC434	27	\$4,190,811	\$10,569,362	\$6,378,552	7	173	2	Athens	McConnelsville - 13
CRC507	28	\$3,907,411	\$7,797,567	\$3,890,156	5	178	0	Columbus	Columbus, NE - 63, Columbus, SE - 64
CRC993	29	\$3,854,860	\$6,353,492	\$2,498,632	3	181	0	Western Ohio	Kenton - 34
CRC201	30	\$3,765,261	\$8,353,931	\$4,588,670	6	187	0	Columbus	Columbus, SW - 65
CRC411	31	\$3,759,182	\$9,784,629	\$6,025,447	8	195	0	Columbus	Columbus, NW - 66
CRA119	32	\$3,383,181	\$5,158,615	\$1,775,434	2	197	0	Canton	New Philadelphia - 71
CRA118	33	\$3,382,220	\$6,209,904	\$2,827,683	3	200	0	Canton	New Philadelphia - 71
CRA998	34	\$3,346,352	\$5,577,616	\$2,231,264	3	203	1	Columbus	Columbus, SE - 64
CRC205	35	\$3,117,419	\$8,563,644	\$5,446,225	7	210	0	Columbus	Columbus, SW - 65

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Candidate	Rank	NPV	PV Benefits	PV Costs	Circuits	Total	Rule 11	District	District Sub-Area
CRC036	36	\$2,909,945	\$6,625,345	\$3,715,400	4	214	0	Athens	Marietta - 260
CRC998	37	\$2,598,281	\$9,418,394	\$6,820,113	9	223	0	Columbus	Columbus, NW - 66
CRC988	38	\$2,557,782	\$7,160,900	\$4,603,118	5	228	1	Canton	East Liverpool - 51
CRC014	39	\$2,485,467	\$6,365,400	\$3,879,933	4	232	0	Chillicothe	Portsmouth - 82
CRC223N	40	\$2,327,337	\$6,207,270	\$3,879,933	4	236	0	Newark	Newark - 50
CRC982	41	\$2,177,399	\$4,705,935	\$2,528,536	3	239	0	Columbus	Columbus, NE - 63, Delaware - 62
CRC430	42	\$2,176,268	\$9,836,684	\$7,660,416	9	248	0	Newark	Mt Vernon - 51
CRA110	43	\$2,086,887	\$11,522,737	\$9,435,850	11	259	0	Canton	South Canton - 21
CRC521	44	\$1,936,325	\$3,711,759	\$1,775,434	2	261	0	Athens	Crooksville - 11
CRC402	45	\$1,774,763	\$4,777,824	\$3,003,061	4	265	0	Columbus	Columbus, NW - 66
CRA333	46	\$1,711,384	\$3,815,882	\$2,104,499	2	267	0	Canton	New Philadelphia - 71, Wooster - 70
CRC204	47	\$1,429,941	\$4,454,328	\$3,024,386	4	271	0	Columbus	Columbus, SW - 65
CRC519	48	\$1,248,383	\$5,851,514	\$4,603,131	5	276	0	Athens	Crooksville - 11
CRC025	49	\$1,189,960	\$3,688,592	\$2,498,632	3	279	0	Chillicothe	Wellston - 16
CRA115	50	\$1,122,069	\$5,725,200	\$4,603,131	5	284	0	Canton	South Canton - 21
CRC020	51	\$1,099,340	\$2,737,668	\$1,638,328	2	286	0	Chillicothe	Ironton - 81
CRC011	52	\$1,084,027	\$3,023,994	\$1,939,966	2	288	1	Chillicothe	Seaman - 23
CRC005	53	\$1,078,763	\$5,746,950	\$4,668,187	6	294	0	Chillicothe	Chillicothe - 20
CRC004	54	\$1,018,301	\$3,845,985	\$2,827,683	3	297	1	Chillicothe	Chillicothe - 20
CRA600	55	\$833,574	\$14,827,925	\$13,994,351	17	314	0	Western Ohio	Findlay - 33
CRC509	56	\$780,968	\$5,109,880	\$4,328,913	5	319	0	Columbus	Columbus, SE - 64
CRA993	57	\$749,025	\$3,943,416	\$3,194,391	4	323	0	Columbus	Columbus, SW - 65
CRA368	58	\$689,697	\$5,741,802	\$5,052,104	6	329	0	Canton	Steubenville - 50
CRC410	59	\$659,085	\$2,910,919	\$2,251,834	3	332	0	Columbus	Columbus, NW - 66
CRA101	60	\$653,407	\$4,845,207	\$4,191,800	5	337	0	Canton	North Canton - 20, South Canton - 21
CRC419	61	\$650,102	\$2,315,857	\$1,665,755	2	339	0	Columbus	Columbus, NE - 63
CRC983	62	\$636,250	\$3,858,054	\$3,221,804	4	343	0	Athens	Lancaster - 22
CRC513	63	\$613,099	\$2,388,533	\$1,775,434	2	345	1	Columbus	Columbus, SE - 64
CRA117	64	\$609,232	\$2,713,730	\$2,104,499	2	347	0	Canton	New Philadelphia - 71
CRC418	65	\$604,037	\$2,544,003	\$1,939,966	2	349	1	Columbus	Delaware - 62
CRA100	66	\$588,079	\$7,782,318	\$7,194,239	9	358	0	Canton	North Canton - 20
CRA367	67	\$562,122	\$7,773,551	\$7,211,429	8	366	1	Canton	Steubenville - 50
CRC001	68	\$492,595	\$6,967,564	\$6,474,969	8	374	0	Chillicothe	Chillicothe - 20
CRA989	69	\$480,087	\$6,858,639	\$6,378,552	7	381	0	Newark	Cambridge - 81
CRC207	70	\$388,798	\$1,966,802	\$1,578,003	2	383	0	Columbus	Columbus, SW - 65
CRC018	71	\$375,771	\$5,088,581	\$4,712,810	5	388	1	Chillicothe	Ironton - 81
CRA125	72	\$375,464	\$2,479,963	\$2,104,499	2	390	0	Western Ohio	Bucyrus - 11
CRC427	73	\$367,148	\$1,868,371	\$1,501,223	2	392	0	Columbus	Columbus, NE - 63
CRC437	74	\$353,419	\$6,622,291	\$6,268,872	7	399	1	Newark	Zanesville - 80
CRA985	75	\$208,265	\$3,035,949	\$2,827,683	3	402	0	Newark	Belmont - 61
CRA102	76	\$166,855	\$2,632,576	\$2,465,721	3	405	0	Canton	North Canton - 20
CRC026	77	\$160,431	\$2,264,930	\$2,104,499	2	407	0	Chillicothe	Portsmouth - 82

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Candidate	Rank	NPV	PV Benefits	PV Costs	Circuits	Total	Rule 11	District	District Sub-Area
CRC520	78	\$105,808	\$3,985,741	\$3,879,933	4	411	0	Athens	Crooksville - 11
CRC425	79	\$87,422	\$2,346,729	\$2,259,307	3	414	1	Columbus	Delaware - 62
CRC417	80	\$73,395	\$1,613,783	\$1,540,388	2	416	0	Columbus	Columbus, NW - 66
CRC422	81	\$0	\$0	\$0	0	416	0	Columbus	Columbus, NE - 63, Delaware - 62
CRC027	82	\$0	\$0	\$0	0	416	0	Chillicothe	Wellston - 16
CRC023	83	(\$10,809)	\$2,093,690	\$2,104,499	2	418	0	Chillicothe	Portsmouth - 82, Wellston - 16
CRC016	84	(\$11,685)	\$2,815,998	\$2,827,683	3	421	1	Chillicothe	Portsmouth - 82
CRC010	85	(\$160,988)	\$3,225,361	\$3,386,349	4	425	0	Chillicothe	Seaman - 23
CRA133	86	(\$179,782)	\$3,425,939	\$3,605,721	4	429	0	Western Ohio	Fremont - 12
CRC436	87	(\$274,403)	\$4,328,715	\$4,603,118	5	434	0	Newark	Zanesville - 80
CRC405	88	(\$288,689)	\$3,628,899	\$3,917,589	5	439	0	Columbus	Columbus, NE - 63, Columbus, NW - 66
CRC042	89	(\$299,174)	\$2,693,041	\$2,992,216	3	442	1	Athens	Marietta - 260
CRC214	90	(\$331,200)	\$1,444,234	\$1,775,434	2	444	0	Western Ohio	Paulding - 31
CRA400	91	(\$392,799)	\$4,539,383	\$4,932,182	5	449	0	Newark	Cambridge - 81
CRA114	92	(\$427,022)	\$1,677,477	\$2,104,499	2	451	0	Canton	South Canton - 21
CRA108	93	(\$447,540)	\$4,769,083	\$5,216,623	6	457	0	Canton	North Canton - 20, South Canton - 21
CRA988	94	(\$447,607)	\$2,160,704	\$2,608,312	3	460	0	Newark	Cambridge - 81
CRA990	95	(\$509,100)	\$3,370,833	\$3,879,933	4	464	0	Newark	Belmont - 61
CRC432	96	(\$518,710)	\$1,256,724	\$1,775,434	2	466	0	Newark	Mt Vernon - 51
CRA994	97	(\$591,181)	\$1,717,315	\$2,308,495	3	469	0	Columbus	Columbus, SW - 65
CRC421	98	(\$608,517)	\$3,281,632	\$3,890,149	5	474	0	Columbus	Columbus, NW - 66
CRC008	99	(\$648,813)	\$3,954,305	\$4,603,118	5	479	2	Chillicothe	Seaman - 23
CRA373	100	(\$687,392)	\$2,304,823	\$2,992,216	3	482	2	Canton	Steubenville - 50
CRA112	101	(\$723,021)	\$942,734	\$1,665,755	2	484	0	Canton	South Canton - 21
CRA107	102	(\$764,258)	\$2,008,586	\$2,772,844	3	487	0	Canton	North Canton - 20
CRC992	103	(\$801,348)	\$2,026,335	\$2,827,683	3	490	0	Western Ohio	Kenton - 34, Lima - 30
CRC409	104	(\$883,456)	\$645,180	\$1,528,636	2	492	0	Columbus	Columbus, NW - 66
CRA105	105	(\$895,043)	\$699,409	\$1,594,453	2	494	0	Canton	North Canton - 20
CRA334	106	(\$1,024,324)	\$1,803,360	\$2,827,683	3	497	0	Canton	Wooster - 70
CRC017	107	(\$1,061,511)	\$3,541,620	\$4,603,131	5	502	0	Chillicothe	Portsmouth - 82
CRC986	108	(\$1,107,389)	\$1,720,294	\$2,827,683	3	505	0	Canton	Steubenville - 50
CRA984	109	(\$1,107,932)	\$3,166,134	\$4,274,066	5	510	0	Newark	Belmont - 61
CRA103	110	(\$1,153,812)	\$3,142,189	\$4,296,001	5	515	0	Canton	North Canton - 20
CRC209	111	(\$1,200,270)	\$5,149,333	\$6,349,603	8	523	0	Columbus	Columbus, SW - 65
CRC997	112	(\$1,212,850)	\$4,931,074	\$6,143,924	8	531	0	Columbus	Columbus, NW - 66
CRA106	113	(\$1,357,165)	\$336,003	\$1,693,168	2	533	0	Canton	North Canton - 20
CRC987	114	(\$1,466,666)	\$1,361,018	\$2,827,683	3	536	0	Canton	East Liverpool - 51
CRA124	115	(\$1,500,218)	\$275,216	\$1,775,434	2	538	0	Western Ohio	Bucyrus - 11
CRC423	116	(\$1,508,973)	\$1,154,178	\$2,663,151	3	541	0	Columbus	Delaware - 62
CRC213	117	(\$1,584,644)	\$1,966,224	\$3,550,868	4	545	0	Western Ohio	Paulding - 31
CRA611	118	(\$1,638,411)	\$137,023	\$1,775,434	2	547	0	Western Ohio	Ottawa - 35
CRC223W	119	(\$1,661,745)	\$1,165,938	\$2,827,683	3	550	0	Western Ohio	Paulding - 31

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Candidate	Rank	NPV	PV Benefits	PV Costs	Circuits	Total	Rule 11	District	District Sub-Area
CRA335	120	(\$1,669,330)	\$435,169	\$2,104,499	2	552	0	Canton	Wooster - 70
CRA134	121	(\$1,686,143)	\$1,086,701	\$2,772,844	3	555	0	Western Ohio	Fremont - 12
CRC516	122	(\$1,697,167)	\$78,268	\$1,775,434	2	557	0	Columbus	Columbus, SW - 65
CRC428	123	(\$1,697,203)	\$3,629,099	\$5,326,302	6	563	0	Columbus	Delaware - 62
CRA128	124	(\$1,717,414)	\$387,085	\$2,104,499	2	565	0	Western Ohio	Upper Sandusky - 13
CRC400	125	(\$1,761,908)	\$510,483	\$2,272,391	3	568	0	Columbus	Columbus, NW - 66
CRC408	126	(\$1,767,772)	\$2,083,199	\$3,850,970	5	573	0	Columbus	Columbus, NW - 66, Columbus, SW - 65
CRA126	127	(\$1,816,181)	\$4,562,384	\$6,378,565	7	580	0	Western Ohio	Willard - 14
CRA601	128	(\$2,066,593)	\$4,651,259	\$6,717,852	8	588	0	Western Ohio	Findlay - 33
CRC216	129	(\$2,093,295)	\$5,008,455	\$7,101,750	8	596	0	Western Ohio	Van Wert - 32
CRA621	130	(\$2,098,070)	\$4,674,629	\$6,772,699	8	604	0	Western Ohio	Lima - 30
CRC989	131	(\$2,124,623)	\$538,528	\$2,663,151	3	607	0	Western Ohio	Ottawa - 35
CRC991	132	(\$2,217,882)	\$2,385,236	\$4,603,118	5	612	0	Western Ohio	Findlay - 33, Lima - 30
CRA986	133	(\$2,326,104)	\$2,835,679	\$5,161,783	6	618	0	Newark	Belmont - 61
CRA131	134	(\$2,515,788)	\$1,035,080	\$3,550,868	4	622	0	Western Ohio	Tiffin - 10
CRA123	135	(\$2,670,424)	\$1,044,977	\$3,715,400	4	626	0	Western Ohio	Bucyrus - 11
CRC984	136	(\$2,889,473)	\$1,778,714	\$4,668,187	6	632	0	Columbus	Columbus, SE - 64
CRA121	137	(\$3,128,861)	\$1,474,256	\$4,603,118	5	637	0	Newark	Coshocton - 82
CRA130	138	(\$3,199,836)	\$2,061,410	\$5,261,246	5	642	0	Western Ohio	Fremont - 12, Tiffin - 10
CRC412	139	(\$3,226,409)	\$2,321,665	\$5,548,073	7	649	0	Columbus	Columbus, NW - 66
CRC401	140	(\$3,354,561)	\$1,164,052	\$4,518,613	6	655	0	Columbus	Columbus, NW - 66
CRA622	141	(\$3,632,233)	\$9,254,996	\$12,887,229	16	671	0	Western Ohio	Lima - 30
CRA135	142	(\$4,244,064)	\$1,082,252	\$5,326,316	6	677	0	Western Ohio	Fremont - 12
CRA127	143	(\$4,438,022)	\$2,170,131	\$6,608,153	8	685	0	Western Ohio	Upper Sandusky - 13
CRC219	144	(\$4,993,374)	\$2,831,547	\$7,824,921	9	694	0	Western Ohio	Paulding - 31
CRC215	145	(\$5,035,644)	\$3,841,527	\$8,877,171	10	704	0	Western Ohio	Lima - 30, Van Wert - 32
CRA610	146	(\$5,166,654)	\$1,047,378	\$6,214,033	7	711	0	Western Ohio	Ottawa - 35

6.2 Prioritized Portfolio Analysis of VVO Bus Candidates

Table 11
Prioritized Business Case Portfolio of VVO Distribution Buses

Candidate	Rank	NPV	PV Benefits	PV Costs	Reduced CO2	Circuits	Total	OHA
E.WOOSTER 1X	1	\$1,413,711	\$3,414,614	\$2,000,903	57,979	3	3	2
ZUBER 1X	2	\$1,400,035	\$3,400,938	\$2,000,903	57,373	3	6	1
CLINTON 2Y	3	\$1,347,376	\$3,543,115	\$2,195,739	48,668	4	10	0
DELAWARE 2Y	4	\$1,334,621	\$2,474,862	\$1,140,241	39,113	2	12	0
BROOKSIDE 1X	5	\$1,324,917	\$3,847,521	\$2,522,604	71,377	4	16	0
WEST CANTON 3X	6	\$1,307,386	\$1,901,720	\$594,334	33,704	1	17	0
CLINTON 2X	7	\$1,296,188	\$3,491,926	\$2,195,739	50,011	4	21	1
WHITE RD 1X	8	\$1,290,359	\$3,812,963	\$2,522,604	66,810	4	25	0
S.SIDELIM 3X	9	\$1,270,645	\$3,271,548	\$2,000,903	56,410	3	28	1
N.LIBERTY 3X	10	\$1,254,954	\$2,734,170	\$1,479,216	40,431	2	30	0
NEW LEXINGTON 3X	11	\$1,252,510	\$3,253,413	\$2,000,903	44,225	3	33	0
ROCKHILL 4X	12	\$1,223,402	\$3,115,355	\$1,891,953	46,868	3	36	0
LAZELLE (#0098) 1X 2X	13	\$1,211,775	\$4,256,086	\$3,044,311	67,234	5	41	0
MARION ROAD 25E3-4Y	14	\$1,211,357	\$3,157,341	\$1,945,984	41,374	3	44	1
ASTOR (#0046) 1Y 2Y	15	\$1,172,381	\$4,503,710	\$3,331,329	75,625	6	50	0
NORTH ZANESVILLE 1X	16	\$1,156,724	\$2,418,025	\$1,261,302	33,641	2	52	0
MORSE ROAD (#0058) 1Y 2Y	17	\$1,151,588	\$5,020,224	\$3,868,636	81,535	6	58	0
WEST CANTON 4X	18	\$1,137,523	\$1,731,857	\$594,334	30,808	1	59	1
BRIGGS DALE (#0073) 1X 2X	19	\$1,133,449	\$3,134,352	\$2,000,903	44,637	3	62	0
W.MELROSE 1X	20	\$1,128,670	\$3,651,274	\$2,522,604	66,044	4	66	0
WILSON ROAD 3X	21	\$1,127,021	\$2,785,491	\$1,658,470	59,848	3	69	0
WESTERVILLE (#0055) 1X 2X	22	\$1,106,661	\$3,107,564	\$2,000,903	46,032	3	72	0
KENTON 1X	23	\$1,097,247	\$1,764,215	\$666,968	27,429	1	73	1
VANWERT 1X	24	\$1,086,344	\$3,087,247	\$2,000,903	48,172	3	76	0
ADA 1X	25	\$1,084,730	\$3,085,634	\$2,000,903	47,242	3	79	1
NORTH NEWARK 5X	26	\$1,080,323	\$3,081,227	\$2,000,903	41,217	3	82	0
SHANNON 1X	27	\$1,062,368	\$3,439,705	\$2,377,336	51,981	4	86	0
ST. CLAIR 2X	28	\$1,043,898	\$3,305,010	\$2,261,112	66,695	4	90	1
ROBERTS 3X	29	\$965,404	\$3,270,106	\$2,304,702	60,244	4	94	0
ROCKHILL 1X	30	\$940,420	\$1,571,071	\$630,651	23,858	1	95	0
BIXBY 4X	31	\$892,479	\$3,484,696	\$2,592,216	71,018	4	99	0
HILLIARD 4X	32	\$874,909	\$2,626,769	\$1,751,859	38,352	3	102	0
UPSANDUSK 4X	33	\$856,958	\$2,857,861	\$2,000,903	43,288	3	105	1
MARION ROAD 15E1-5Y	34	\$825,927	\$1,931,574	\$1,105,647	34,403	2	107	0
KARL ROAD 3X	35	\$820,667	\$3,004,296	\$2,183,629	44,896	4	111	0
DUBLIN (#0023) 2X 3X	36	\$811,417	\$5,275,501	\$4,464,085	104,433	8	119	2
HESS STREET (#0054) 1X 2X	37	\$811,265	\$4,159,329	\$3,348,063	94,110	6	125	0
BERKSHIRE 1X	38	\$805,941	\$2,285,157	\$1,479,216	38,474	2	127	0

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Candidate	Rank	NPV	PV Benefits	PV Costs	Reduced CO2	Circuits	Total	OHA
CALCUTTA 1X	39	\$803,640	\$2,282,856	\$1,479,216	32,998	2	129	0
N.COSHOCT 3X	40	\$791,146	\$2,792,050	\$2,000,903	39,538	3	132	1
N.MCCONNE 1X	41	\$768,275	\$1,725,797	\$957,523	25,154	1	133	0
WILSON ROAD 1Y	42	\$765,737	\$2,977,031	\$2,211,294	44,000	4	137	0
JUG STREET 1X	43	\$751,862	\$2,231,078	\$1,479,216	65,730	2	139	0
SAWMILL 4X	44	\$745,366	\$2,497,226	\$1,751,859	35,055	3	142	0
SOUTH COSHOCTON 4X	45	\$742,461	\$2,743,364	\$2,000,903	40,816	3	145	0
PLEASANTS 1X	46	\$729,318	\$2,621,271	\$1,891,953	38,380	3	148	0
W.LOGAN 1X	47	\$725,174	\$2,204,391	\$1,479,216	31,134	2	150	1
KARL ROAD (#0009) 1X 2X	48	\$713,257	\$4,534,607	\$3,821,350	67,038	7	157	0
SOUTH NEWARK 2X	49	\$711,980	\$1,973,282	\$1,261,302	26,746	2	159	0
ASTOR (#0046) 1X 2X	50	\$711,260	\$4,885,325	\$4,174,065	82,599	7	166	0
MILL CREEK 4X	51	\$706,073	\$2,457,933	\$1,751,859	45,396	3	169	1
KENNY ROAD (#0003) 1X 2X	52	\$700,490	\$3,490,543	\$2,790,053	78,238	5	174	2
GREELY 2X	53	\$697,305	\$2,176,521	\$1,479,216	33,226	2	176	0
W.WOOSTER 1X	54	\$697,153	\$2,176,369	\$1,479,216	37,457	2	178	0
BEXLEY 3Y	55	\$688,015	\$3,236,641	\$2,548,626	51,553	4	182	0
MORSE ROAD 3X	56	\$668,728	\$1,766,598	\$1,097,869	29,485	2	184	0
GLENMOOR 1X	57	\$667,930	\$2,147,146	\$1,479,216	28,018	2	186	0
DUBLIN 1X	58	\$660,108	\$2,892,150	\$2,232,042	54,895	4	190	1
EAST WILLARD 1X	59	\$647,739	\$1,387,347	\$739,608	20,738	1	191	0
HILLIARD (#0021) 1X 2X	60	\$638,021	\$3,836,375	\$3,198,354	57,153	4	195	0
WILSON ROAD 2Y	61	\$634,571	\$2,580,555	\$1,945,984	52,272	3	198	1
LEIPSIC 2X	62	\$615,898	\$1,282,866	\$666,968	24,036	1	199	0
SUGRCRTRM 1X	63	\$613,725	\$2,092,941	\$1,479,216	43,826	2	201	0
BRIDGEVILLE 1X	64	\$609,932	\$2,610,836	\$2,000,903	53,591	3	204	0
ADDISON 1X	65	\$605,662	\$2,606,565	\$2,000,903	44,768	3	207	0
LANCASTER JUNCTION 2X	66	\$600,567	\$1,861,868	\$1,261,302	27,949	2	209	1
LANCASTER JUNCTION 1X	67	\$595,583	\$1,856,885	\$1,261,302	27,118	2	211	1
SHARON VALLEY 1X	68	\$592,790	\$2,593,693	\$2,000,903	36,920	3	214	0
NEWPHILA 4X	69	\$584,787	\$1,251,755	\$666,968	17,031	1	215	0
DELPHOS 1X	70	\$581,498	\$1,321,106	\$739,608	21,466	1	216	0
HYATT 2X	71	\$573,799	\$3,096,403	\$2,522,604	47,090	4	220	0
AVONDALE 2X	72	\$560,074	\$1,299,682	\$739,608	18,724	1	221	0
LIVINGSTON AVE (#0025) 1X 2X	73	\$559,623	\$2,560,527	\$2,000,903	42,303	3	224	0
MARION ROAD W2	74	\$551,102	\$2,497,086	\$1,945,984	34,822	3	227	0
KIRK 1X	75	\$548,864	\$2,028,080	\$1,479,216	31,208	2	229	1
MAPLE GROVE 1X	76	\$536,023	\$2,015,239	\$1,479,216	30,198	2	231	0
BOLIVAR 1X	77	\$517,656	\$1,996,872	\$1,479,216	32,483	2	233	0
CORWIN 1X	78	\$510,537	\$1,844,472	\$1,333,936	26,093	2	235	0
ROSEMOUNT 2X	79	\$500,661	\$1,240,269	\$739,608	19,137	1	236	0
MOUND (#0030) 1X 2Y	80	\$499,788	\$4,353,306	\$3,853,518	88,665	6	242	3
MARTINSBURG ROAD 1X	81	\$485,732	\$2,486,635	\$2,000,903	51,450	3	245	0

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Candidate	Rank	NPV	PV Benefits	PV Costs	Reduced CO2	Circuits	Total	OHA
LINCOLN STREET (#0218) 1X 2X	82	\$482,339	\$2,483,242	\$2,000,903	39,600	3	248	0
EAST NEWARK 1X	83	\$469,542	\$2,470,445	\$2,000,903	32,402	3	251	0
NORTH ZANESVILLE 2X	84	\$464,895	\$1,726,197	\$1,261,302	24,636	2	253	1
TWORIDGES 1X	85	\$453,802	\$1,933,018	\$1,479,216	28,187	2	255	0
FRAZEYSBURG 1X	86	\$448,081	\$1,405,603	\$957,523	18,780	1	256	0
CLINTON 3X	87	\$443,169	\$2,926,422	\$2,483,253	41,832	4	260	0
SOUTH POINT 7X	88	\$442,906	\$1,073,557	\$630,651	13,849	1	261	0
CANAL STREET (#0013) 1X 2X	89	\$430,831	\$5,615,264	\$5,184,433	91,714	8	269	3
BIXBY 3X	90	\$422,733	\$3,302,463	\$2,879,730	54,906	4	273	0
W.NEWPHIL 4X	91	\$404,280	\$1,738,216	\$1,333,936	22,238	2	275	0
BANNOCKRD 1X	92	\$401,686	\$1,880,903	\$1,479,216	25,539	2	277	0
EASTOWNRD 1X	93	\$391,639	\$2,174,641	\$1,783,002	34,323	3	280	0
ETNA 2X	94	\$383,902	\$1,050,870	\$666,968	15,139	1	281	0
GRANVILLE 1X	95	\$374,189	\$2,375,092	\$2,000,903	29,597	3	284	0
EASTONSTR 2X	96	\$366,864	\$1,584,589	\$1,217,724	28,713	2	286	0
DELAWARE 3X	97	\$352,697	\$1,492,938	\$1,140,241	26,362	2	288	1
CIRCLEVILLE 1X	98	\$346,879	\$2,129,881	\$1,783,002	34,092	3	291	1
S.VANWERT 2X	99	\$343,465	\$2,344,369	\$2,000,903	41,475	3	294	1
CLARK STREET 2X	100	\$323,208	\$2,106,210	\$1,783,002	34,913	3	297	0
HESS STREET (#0054) 3X 4X	101	\$319,664	\$4,242,756	\$3,923,091	68,759	6	303	1
WOOSTER 3X	102	\$314,777	\$1,793,993	\$1,479,216	30,987	2	305	0
BILLIAR 2X	103	\$312,941	\$1,052,549	\$739,608	15,613	1	306	0
ELK 2X	104	\$311,749	\$1,573,051	\$1,261,302	21,985	2	308	0
GROVES ROAD (#0038) 7X 8X	105	\$307,898	\$3,349,161	\$3,041,263	45,841	5	313	0
BEALLAVEN 3X	106	\$305,824	\$2,306,727	\$2,000,903	38,955	3	316	0
ACADEMIA 1Y	107	\$298,290	\$1,777,506	\$1,479,216	26,882	2	318	1
MARION ROAD 15W1-4Y	108	\$295,234	\$1,953,704	\$1,658,470	39,970	3	321	0
SHANNON 2X	109	\$292,018	\$1,480,686	\$1,188,668	20,887	2	323	0
MEIGS 1X	110	\$277,974	\$1,017,582	\$739,608	13,929	1	324	0
CARROLLTON 2X	111	\$271,148	\$1,532,450	\$1,261,302	22,462	2	326	1
RIO 1X	112	\$269,122	\$1,603,057	\$1,333,936	22,187	2	328	0
SUGARHILL 1X	113	\$265,247	\$1,744,464	\$1,479,216	22,046	2	330	0
WILSON ROAD 3Y	114	\$263,608	\$2,762,416	\$2,498,808	39,997	4	334	0
STEUBENVI 1X	115	\$261,618	\$2,262,522	\$2,000,903	37,582	3	337	1
S.CAMBRID 3X	116	\$252,356	\$1,209,878	\$957,523	20,212	1	338	0
CLINTON 3Y	117	\$248,207	\$2,731,460	\$2,483,253	36,731	4	342	0
MILLBROPA 6X	118	\$245,262	\$1,724,478	\$1,479,216	24,339	2	344	0
HAVILAND 2X	119	\$240,572	\$1,198,095	\$957,523	14,326	1	345	0
ETNA ROAD 2X	120	\$239,415	\$1,715,597	\$1,476,182	24,022	2	347	0
UTICA 1X	121	\$238,360	\$1,717,577	\$1,479,216	23,903	2	349	0
SCIOTO TRAIL 2X	122	\$236,344	\$1,715,560	\$1,479,216	31,665	2	351	0
GALLOWAY 1X	123	\$234,265	\$1,710,447	\$1,476,182	26,411	2	353	0
DOGWOOD RIDGE 1X	124	\$233,742	\$2,234,645	\$2,000,903	28,385	3	356	0

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Candidate	Rank	NPV	PV Benefits	PV Costs	Reduced CO2	Circuits	Total	OHA
E.DOVER 1X	125	\$233,173	\$1,190,695	\$957,523	16,385	1	357	0
BEXLEY 2Y	126	\$226,292	\$791,570	\$565,278	16,268	1	358	0
RARDEN 2X	127	\$224,884	\$964,492	\$739,608	14,207	1	359	0
GROVES ROAD 7Y	128	\$223,736	\$1,325,236	\$1,101,500	19,135	2	361	0
COOLVILLE 1X	129	\$218,496	\$958,104	\$739,608	14,827	1	362	0
S.E.LOGAN 1X	130	\$213,254	\$1,170,776	\$957,523	17,830	1	363	0
BELLVILLE 1X	131	\$205,791	\$1,163,314	\$957,523	17,673	1	364	0
EAST PROCTORVILLE 1X	132	\$201,925	\$868,893	\$666,968	10,426	1	365	0
SHAWNEERD 1X	133	\$200,394	\$2,201,298	\$2,000,903	36,027	3	368	0
EASTONSTR 1X	134	\$194,941	\$2,021,528	\$1,826,586	29,747	3	371	0
FINDLAY 2X	135	\$193,911	\$860,879	\$666,968	13,706	1	372	0
CRESTWOOD 1X	136	\$182,673	\$2,183,577	\$2,000,903	43,509	3	375	0
CORNERSTONE 2X	137	\$168,312	\$1,429,613	\$1,261,302	23,967	2	377	0
ASHAVENUE 1X	138	\$165,475	\$2,166,379	\$2,000,903	33,404	3	380	0
SMITHFIEL 1X	139	\$161,310	\$1,118,832	\$957,523	13,458	1	381	0
WILLISTON 1X	140	\$157,866	\$2,158,770	\$2,000,903	28,464	3	384	0
SUNNYSIDE 6X	141	\$157,275	\$2,158,178	\$2,000,903	33,100	3	387	0
W.GALION 1X	142	\$157,169	\$1,636,386	\$1,479,216	23,352	2	389	0
MARION ROAD E2	143	\$153,079	\$1,811,549	\$1,658,470	38,200	3	392	0
NEWPHILA 3X	144	\$146,877	\$1,480,813	\$1,333,936	20,385	2	394	0
W.MILLERB 1X	145	\$142,767	\$1,100,290	\$957,523	18,866	1	395	0
LINDEN AVENUE 2X	146	\$140,359	\$2,141,262	\$2,000,903	30,265	3	398	1
LOUISVILL 1X	147	\$136,667	\$2,137,571	\$2,000,903	29,096	3	401	0
GENOA 1Y	148	\$130,361	\$1,048,525	\$918,165	16,597	1	402	0
BARNESVIL 1X	149	\$129,827	\$2,130,731	\$2,000,903	29,066	3	405	1
PARSONS (#0057) 2X 3X	150	\$118,199	\$2,640,803	\$2,522,604	45,777	4	409	0
THORNVILLE 1X	151	\$115,126	\$1,594,342	\$1,479,216	19,941	2	411	0
RIVERVIEW 2X	152	\$113,617	\$2,114,520	\$2,000,903	35,207	3	414	2
CENTER STREET 1X	153	\$110,208	\$2,111,111	\$2,000,903	29,676	3	417	0
PLEASANTS 2X	154	\$108,110	\$738,761	\$630,651	8,538	1	418	0
BYESVILLE 1X	155	\$106,601	\$2,107,504	\$2,000,903	31,288	3	421	0
COOLVILLE 2X	156	\$105,376	\$844,984	\$739,608	10,992	1	422	0
VIGO 1X	157	\$96,267	\$1,575,483	\$1,479,216	19,484	2	424	0
N.WILLARD 1X	158	\$96,237	\$2,097,140	\$2,000,903	32,071	3	427	0
SEAMAN 1X	159	\$92,974	\$2,093,877	\$2,000,903	27,902	3	430	1
CLIFTMONT AVE 1X	160	\$91,068	\$1,048,590	\$957,523	16,173	1	431	0
DELPHOS 2X	161	\$87,179	\$826,787	\$739,608	12,587	1	432	0
SUNSETBOU 1X	162	\$84,315	\$2,085,218	\$2,000,903	29,450	3	435	1
N.W.LIMA 1X	163	\$80,137	\$2,602,740	\$2,522,604	38,177	4	439	0
HEBRON 1X	164	\$78,959	\$1,036,481	\$957,523	14,042	1	440	0
MEMORIALD 1X	165	\$78,598	\$2,601,201	\$2,522,604	38,651	4	444	1
LANCASTER 4X	166	\$78,516	\$1,557,733	\$1,479,216	23,573	2	446	0
BLUFFTON 1X	167	\$77,294	\$1,556,510	\$1,479,216	26,866	2	448	1

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Candidate	Rank	NPV	PV Benefits	PV Costs	Reduced CO2	Circuits	Total	OHA
WEST GRANVILLE 1X	168	\$69,557	\$1,027,080	\$957,523	17,066	1	449	0
MCCOMB 1X	169	\$67,056	\$632,334	\$565,278	8,515	1	450	0
W.NEUPHIL 3X	170	\$62,826	\$729,794	\$666,968	11,832	1	451	0
18 ST.HTS 2X	171	\$60,418	\$800,026	\$739,608	10,306	1	452	0
SMITHVILL 1X	172	\$59,548	\$1,017,070	\$957,523	15,582	1	453	0
E.LOGAN 1X	173	\$53,883	\$2,054,786	\$2,000,903	29,186	3	456	0
SOUTH NEWARK 1X	174	\$52,766	\$1,314,068	\$1,261,302	19,537	2	458	0
WHEELERSB 1X	175	\$52,071	\$1,009,594	\$957,523	13,816	1	459	0
GROVES ROAD 3X	176	\$51,534	\$3,643,547	\$3,592,013	50,518	6	465	0
SLATE 1X	177	\$48,172	\$1,527,389	\$1,479,216	21,183	2	467	0
NORTH HEBRON 1X	178	\$47,289	\$1,526,505	\$1,479,216	23,364	2	469	0
ETNA ROAD (#0070) 1X 3X	179	\$38,682	\$2,703,532	\$2,664,850	53,154	4	473	1
STRASBURG 1X	180	\$35,845	\$1,515,061	\$1,479,216	23,208	2	475	0
EAST UNION 1X	181	\$30,486	\$1,509,703	\$1,479,216	22,502	2	477	0
MILL ST 1X	182	\$27,513	\$985,035	\$957,523	17,834	1	478	0
ELK 1X	183	\$22,270	\$1,283,572	\$1,261,302	19,992	2	480	0
DUCK CREEK 1X	184	\$18,780	\$2,019,683	\$2,000,903	36,703	3	483	0
FOREST 3X	185	\$15,506	\$755,114	\$739,608	8,877	1	484	0
RIO 2X	186	\$11,688	\$678,655	\$666,968	11,527	1	485	0
GROVES ROAD 8Y	187	\$11,071	\$1,400,085	\$1,389,014	21,227	2	487	0
BILLIAR 1X	188	\$7,711	\$747,320	\$739,608	11,588	1	488	0
S.DELPHOS 1X	189	\$7,219	\$1,486,436	\$1,479,216	23,834	2	490	0
S.FINDLAY 2X	190	\$3,025	\$1,220,749	\$1,217,724	23,374	2	492	1
MILES AVE 1X	191	(\$1,782)	\$1,999,121	\$2,000,903	29,751	3	495	1
BEAVER 1X	192	(\$5,081)	\$1,474,135	\$1,479,216	17,030	2	497	0
E.SPARTA 2X	193	(\$5,496)	\$661,472	\$666,968	9,391	1	498	0
JEFFERSON (#0145) 1X 2X	194	(\$14,600)	\$1,986,303	\$2,000,903	26,286	3	501	0
WAKEFIELD 1X	195	(\$19,177)	\$1,460,039	\$1,479,216	17,690	2	503	0
DENNISON 4X	196	(\$23,414)	\$934,108	\$957,523	14,519	1	504	1
NORTH END FOSTORIA 2X	197	(\$28,534)	\$1,305,402	\$1,333,936	17,350	2	506	0
MCCOMB 2X	198	(\$28,831)	\$536,447	\$565,278	16,307	1	507	0
BLENDON 1Y	199	(\$33,611)	\$1,184,113	\$1,217,724	15,136	2	509	0
NORTH BALTIMORE 1X	200	(\$38,490)	\$1,440,727	\$1,479,216	19,946	2	511	0
SCIOTOVIL 1X	201	(\$41,263)	\$1,437,953	\$1,479,216	16,925	2	513	0
ROSEMOUNT 1X	202	(\$43,589)	\$696,020	\$739,608	9,624	1	514	0
PACKARD 1X	203	(\$46,819)	\$1,954,084	\$2,000,903	28,980	3	517	0
CORNERSTONE 1X	204	(\$47,625)	\$1,213,677	\$1,261,302	15,688	2	519	2
TORONTO 1X	205	(\$51,007)	\$1,428,209	\$1,479,216	20,379	2	521	0
BELPRE 1X	206	(\$51,825)	\$1,209,476	\$1,261,302	18,706	2	523	0
CIRCLEVILLE 2X	207	(\$59,378)	\$1,723,624	\$1,783,002	27,588	3	526	0
W.ALIKANN 1X	208	(\$63,816)	\$893,706	\$957,523	13,328	1	527	0
COLERAIN 1X	209	(\$70,884)	\$886,639	\$957,523	11,274	1	528	0
OERTELS 1X	210	(\$73,130)	\$1,406,086	\$1,479,216	16,042	2	530	0

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Candidate	Rank	NPV	PV Benefits	PV Costs	Reduced CO2	Circuits	Total	OHA
ROCKBRIDG 1X	211	(\$83,113)	\$1,396,103	\$1,479,216	17,391	2	532	0
SOUTH GRANVILLE 1X	212	(\$86,027)	\$1,393,189	\$1,479,216	28,490	2	534	0
HIGHLAND AVENUE 1X	213	(\$87,690)	\$1,913,214	\$2,000,903	27,969	3	537	0
E.FREMONT 1X	214	(\$92,653)	\$1,386,563	\$1,479,216	24,303	2	539	0
MINFORD 1X	215	(\$94,895)	\$1,384,322	\$1,479,216	17,699	2	541	0
SMYRNA 1X	216	(\$102,440)	\$855,083	\$957,523	10,351	1	542	0
E.LANCAST 1X	217	(\$107,999)	\$631,609	\$739,608	8,436	1	543	0
COLUMBIA 1X	218	(\$108,388)	\$1,658,342	\$1,766,730	24,814	2	545	0
N.CANTON 1X	219	(\$108,408)	\$2,414,196	\$2,522,604	40,059	4	549	0
MILLWOOD 1X	220	(\$108,873)	\$1,892,031	\$2,000,903	24,512	3	552	0
WALNUT CR 1X	221	(\$110,498)	\$847,024	\$957,523	16,173	1	553	0
TILTONSVI 2X	222	(\$116,479)	\$1,362,737	\$1,479,216	20,812	2	555	0
PARK 1X	223	(\$116,619)	\$1,362,597	\$1,479,216	25,450	2	557	0
ADAMS 2X	224	(\$117,056)	\$1,362,160	\$1,479,216	18,023	2	559	0
DILLONVAL 1X	225	(\$121,892)	\$835,630	\$957,523	10,652	1	560	0
STONESTREET 3X	226	(\$124,666)	\$1,876,238	\$2,000,903	30,819	3	563	1
ST. CLAIR 3X	227	(\$124,780)	\$1,571,054	\$1,695,834	29,697	3	566	0
MARTINSFE 1X	228	(\$134,817)	\$1,344,399	\$1,479,216	19,467	2	568	1
LEESVILLE 2X	229	(\$135,720)	\$603,888	\$739,608	6,788	1	569	0
SUPERIOR 1X	230	(\$136,602)	\$820,920	\$957,523	10,826	1	570	0
WEST PHILO 1X	231	(\$140,642)	\$816,881	\$957,523	10,455	1	571	0
ROZELLE 1X	232	(\$141,385)	\$1,337,832	\$1,479,216	17,350	2	573	0
CROOKSVILLE 3X	233	(\$142,438)	\$815,085	\$957,523	10,860	1	574	0
NEGLEY 1X	234	(\$143,014)	\$1,857,889	\$2,000,903	41,486	3	577	0
BERLIN 1X	235	(\$143,629)	\$1,335,587	\$1,479,216	23,649	2	579	0
NEFFS 1X	236	(\$147,116)	\$810,407	\$957,523	10,067	1	580	0
RENO 1X	237	(\$150,424)	\$1,328,792	\$1,479,216	27,363	2	582	0
PLY.HGTS. 1X	238	(\$152,889)	\$804,634	\$957,523	12,625	1	583	0
BLISSPARK 1X	239	(\$154,782)	\$1,846,121	\$2,000,903	27,889	3	586	2
SHAWNEE 1X	240	(\$157,051)	\$1,322,165	\$1,479,216	14,958	2	588	0
BLOOM ROAD 1X	241	(\$157,837)	\$799,685	\$957,523	11,953	1	589	0
BUCYRUS 1X	242	(\$158,268)	\$1,842,636	\$2,000,903	30,945	3	592	0
CENTERBURG 1Y	243	(\$158,279)	\$508,689	\$666,968	6,634	1	593	0
BATEVILL 1X	244	(\$161,412)	\$796,111	\$957,523	9,312	1	594	0
LEXINGTON 1X	245	(\$162,566)	\$1,316,650	\$1,479,216	19,432	2	596	0
N.WOOSTER 1X	246	(\$166,737)	\$790,786	\$957,523	10,391	1	597	1
HIGHLAND TERRACE 1X	247	(\$168,631)	\$788,891	\$957,523	9,144	1	598	0
EAST OTTAWA 1X	248	(\$172,001)	\$1,307,215	\$1,479,216	22,428	2	600	0
EAST WILLARD 2X	249	(\$173,599)	\$566,009	\$739,608	13,748	1	601	0
MADISON 1X	250	(\$174,913)	\$1,304,304	\$1,479,216	27,917	2	603	0
S.CANTON 2X	251	(\$181,219)	\$776,303	\$957,523	11,391	1	604	0
EASTOWNRD 2X	252	(\$181,771)	\$1,601,232	\$1,783,002	24,225	3	607	1
AUGLAIZE 1X	253	(\$184,532)	\$555,076	\$739,608	5,970	1	608	0

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Candidate	Rank	NPV	PV Benefits	PV Costs	Reduced CO2	Circuits	Total	OHA
N.IRONTON 1X	254	(\$185,688)	\$771,835	\$957,523	9,905	1	609	0
N.SPENCVI 1X	255	(\$186,049)	\$1,293,167	\$1,479,216	20,028	2	611	0
RUHLMAN 1X	256	(\$188,027)	\$2,334,577	\$2,522,604	33,560	4	615	2
BUCYRUSCT 2X	257	(\$188,232)	\$1,812,671	\$2,000,903	31,185	3	618	1
S.GREENWI 1X	258	(\$191,683)	\$765,839	\$957,523	10,275	1	619	0
BELPRE 2X	259	(\$197,221)	\$1,064,080	\$1,261,302	15,687	2	621	0
COL.GROVE 1X	260	(\$199,285)	\$758,238	\$957,523	9,596	1	622	0
CAIRO 1X	261	(\$205,626)	\$751,896	\$957,523	10,560	1	623	0
MOUNT STERLING 1X	262	(\$207,992)	\$749,531	\$957,523	8,425	1	624	0
MEIGS 2X	263	(\$209,407)	\$530,201	\$739,608	6,155	1	625	0
SUMMERHIL 1X	264	(\$211,922)	\$1,267,295	\$1,479,216	21,454	2	627	0
GINGER 1X	265	(\$213,210)	\$1,266,006	\$1,479,216	15,878	2	629	0
W.LAFAYET 1X	266	(\$214,243)	\$1,264,973	\$1,479,216	16,213	2	631	0
PITTSBURGH AVENUE (#4204) 1X 2X	267	(\$219,937)	\$1,780,966	\$2,000,903	23,335	3	634	0
FREMONTCT 2X	268	(\$221,633)	\$735,889	\$957,523	11,190	1	635	0
E.TIFFIN 1X	269	(\$223,148)	\$1,256,068	\$1,479,216	19,222	2	637	0
IDAHO 1X	270	(\$233,574)	\$1,245,643	\$1,479,216	16,580	2	639	0
S.VANLUE 1X	271	(\$241,274)	\$716,248	\$957,523	8,558	1	640	0
CORNER 1X	272	(\$245,385)	\$1,755,519	\$2,000,903	22,691	3	643	0
COOPERMILL 2X	273	(\$251,224)	\$706,298	\$957,523	8,524	1	644	0
ROBERTSVI 1X	274	(\$254,343)	\$703,179	\$957,523	9,257	1	645	0
AUGLAIZE 2X	275	(\$258,204)	\$481,404	\$739,608	6,715	1	646	0
CAMBRIDGE 1X	276	(\$262,003)	\$1,217,213	\$1,479,216	18,310	2	648	0
CADIZ 1X	277	(\$263,776)	\$1,215,441	\$1,479,216	17,028	2	650	1
CORWIN 2X	278	(\$265,762)	\$401,205	\$666,968	5,539	1	651	0
ST.CLAIRA 1X	279	(\$271,122)	\$1,729,781	\$2,000,903	22,031	3	654	1
MOUNT VERNON 1X	280	(\$298,203)	\$1,181,014	\$1,479,216	18,829	2	656	1
FINDLAY CENTER 2X	281	(\$301,863)	\$655,660	\$957,523	8,729	1	657	0
ANCHOR-HOCKING 2X	282	(\$302,817)	\$654,705	\$957,523	8,250	1	658	0
GAMBIER 1X	283	(\$312,375)	\$1,166,841	\$1,479,216	17,405	2	660	0
CARROLLTON 1X	284	(\$312,701)	\$948,601	\$1,261,302	13,535	2	662	0
KALIDA 3X	285	(\$315,522)	\$1,163,694	\$1,479,216	23,008	2	664	0
CLARK STREET 1X	286	(\$316,604)	\$1,466,398	\$1,783,002	29,764	3	667	1
MADISONBURG 2X	287	(\$320,512)	\$1,680,392	\$2,000,903	27,758	3	670	1
BEXLEY 3X	288	(\$322,271)	\$243,006	\$565,278	7,036	1	671	0
BREMEN 1X	289	(\$323,751)	\$633,771	\$957,523	7,648	1	672	0
MONROESTR 1X	290	(\$326,676)	\$1,674,227	\$2,000,903	22,422	3	675	1
MAHONINGR 1X	291	(\$326,942)	\$1,673,961	\$2,000,903	26,794	3	678	0
TIFFINTAP 2X	292	(\$328,085)	\$1,151,131	\$1,479,216	21,327	2	680	0
OAKWOOD 1X	293	(\$331,676)	\$2,190,927	\$2,522,604	33,007	4	684	0
18 ST.HTS 1X	294	(\$332,242)	\$407,366	\$739,608	8,409	1	685	0
LOCK 1X	295	(\$333,473)	\$1,145,743	\$1,479,216	15,407	2	687	0
SOUTH SOMERSET 1X	296	(\$336,229)	\$621,294	\$957,523	8,174	1	688	0

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Candidate	Rank	NPV	PV Benefits	PV Costs	Reduced CO2	Circuits	Total	OHA
S.FINDLAY 1X	297	(\$338,567)	\$1,488,020	\$1,826,586	24,495	3	691	0
W.HICKSVI 1X	298	(\$344,426)	\$613,096	\$957,523	8,317	1	692	0
SAVANNAH AVENUE 4X	299	(\$348,627)	\$1,130,589	\$1,479,216	15,871	2	694	0
HOWARD 3X	300	(\$350,548)	\$1,128,668	\$1,479,216	13,508	2	696	0
RARDEN 3X	301	(\$355,634)	\$383,974	\$739,608	4,540	1	697	0
HOPEDAILE 1X	302	(\$358,093)	\$599,429	\$957,523	7,474	1	698	0
COSHOCTON 1X	303	(\$359,646)	\$1,641,257	\$2,000,903	20,777	3	701	1
CENTERBURG 1X	304	(\$361,050)	\$972,885	\$1,333,936	23,461	2	703	0
CALIFORNIA 1X	305	(\$362,964)	\$2,159,639	\$2,522,604	32,110	4	707	0
E.N.CONC. 1X	306	(\$363,810)	\$1,115,406	\$1,479,216	18,835	2	709	0
BIGPRAIRI 1X	307	(\$369,341)	\$588,181	\$957,523	7,214	1	710	0
DERWENT 1X	308	(\$373,443)	\$584,080	\$957,523	7,559	1	711	0
ROSEFARM 1X	309	(\$378,904)	\$578,618	\$957,523	6,588	1	712	0
MILL CREEK 2X	310	(\$380,433)	\$203,520	\$583,953	8,946	1	713	1
REEDURBAN 1X	311	(\$381,589)	\$2,141,015	\$2,522,604	33,767	4	717	0
REYNOLDS 1X	312	(\$385,806)	\$1,093,410	\$1,479,216	16,215	2	719	0
POSTON 3X	313	(\$386,192)	\$571,331	\$957,523	10,054	1	720	0
HEMLOCK 1X	314	(\$387,788)	\$1,091,428	\$1,479,216	14,612	2	722	0
LEESVILLE 1X	315	(\$388,332)	\$351,276	\$739,608	4,312	1	723	0
W.TORONTO 1X	316	(\$392,809)	\$1,086,407	\$1,479,216	14,090	2	725	0
OTWAY 1X	317	(\$394,901)	\$562,622	\$957,523	6,866	1	726	0
ASHLEY 1X	318	(\$395,430)	\$1,083,786	\$1,479,216	13,105	2	728	0
APPLECREE 1X	319	(\$396,892)	\$560,631	\$957,523	9,461	1	729	0
DRESDEN 1X	320	(\$397,078)	\$1,082,139	\$1,479,216	14,398	2	731	0
MINERVA 1X	321	(\$399,154)	\$1,601,749	\$2,000,903	26,164	3	734	0
OAKLAND 1X	322	(\$403,695)	\$1,597,208	\$2,000,903	22,978	3	737	0
N.WELSVIL 1X	323	(\$404,864)	\$1,074,352	\$1,479,216	13,837	2	739	0
LANSING 1X	324	(\$410,408)	\$547,114	\$957,523	6,261	1	740	0
SOUTH BELMONT 1X	325	(\$413,326)	\$1,065,890	\$1,479,216	13,674	2	742	0
ST. CLAIR 2Y	326	(\$414,875)	\$1,280,958	\$1,695,834	25,078	3	745	0
CRIDERSVI 1X	327	(\$419,669)	\$1,059,548	\$1,479,216	14,359	2	747	1
PEKIN 2X	328	(\$424,493)	\$533,030	\$957,523	8,524	1	748	0
WILKESVILLE 1X	329	(\$426,054)	\$531,469	\$957,523	6,228	1	749	0
PAYNE 1X	330	(\$428,899)	\$1,050,317	\$1,479,216	13,491	2	751	0
E.MT.CORY 1X	331	(\$436,409)	\$521,114	\$957,523	6,144	1	752	0
SHADYSIDE 1X	332	(\$439,279)	\$1,039,938	\$1,479,216	13,330	2	754	0
E BUCYRUS 1X	333	(\$442,371)	\$1,036,845	\$1,479,216	14,322	2	756	0
BLOOMVILL 1X	334	(\$444,343)	\$513,179	\$957,523	5,790	1	757	0
FRIENSHIP 1X	335	(\$446,951)	\$1,032,265	\$1,479,216	12,771	2	759	0
TORREY 5X	336	(\$448,647)	\$1,030,569	\$1,479,216	16,094	2	761	0
AVONDALE 1X	337	(\$449,158)	\$290,450	\$739,608	3,296	1	762	0
FINDLAY 1X	338	(\$459,424)	\$874,512	\$1,333,936	13,595	2	764	0
PLEASANTV 1X	339	(\$459,503)	\$1,019,713	\$1,479,216	13,394	2	766	0

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Candidate	Rank	NPV	PV Benefits	PV Costs	Reduced CO2	Circuits	Total	OHA
NORTH END FOSTORIA 1X	340	(\$460,495)	\$206,472	\$666,968	4,755	1	767	0
HILLVIEW 1X	341	(\$461,151)	\$1,018,065	\$1,479,216	14,811	2	769	0
SALINEVIL 1X	342	(\$468,462)	\$489,061	\$957,523	5,533	1	770	0
PENNSVILL 1X	343	(\$472,660)	\$1,006,556	\$1,479,216	10,879	2	772	0
E.LANCAST 2X	344	(\$475,460)	\$264,148	\$739,608	3,427	1	773	1
SULPH.SPR 1X	345	(\$476,030)	\$1,003,187	\$1,479,216	12,059	2	775	0
RACINE 1X	346	(\$484,095)	\$473,428	\$957,523	5,929	1	776	0
PLEASANGR 1X	347	(\$485,798)	\$471,724	\$957,523	5,987	1	777	0
PROCTORVL 3X	348	(\$487,834)	\$991,382	\$1,479,216	12,524	2	779	0
DELANO 1Y	349	(\$491,099)	\$1,509,805	\$2,000,903	37,267	3	782	2
N. CROWN CITY 1X	350	(\$492,018)	\$465,505	\$957,523	4,873	1	783	0
STANTONST 2X	351	(\$500,818)	\$978,398	\$1,479,216	13,626	2	785	0
N.CAMBRID 1X	352	(\$505,666)	\$451,857	\$957,523	8,559	1	786	1
NORTH WALDO 2X	353	(\$506,507)	\$972,709	\$1,479,216	13,037	2	788	0
CARROTHER 1X	354	(\$511,757)	\$445,766	\$957,523	5,032	1	789	0
WEST CANTON 1X	355	(\$523,040)	\$1,854,296	\$2,377,336	29,520	4	793	0
N.FREMONT 1X	356	(\$527,871)	\$1,473,032	\$2,000,903	24,600	3	796	0
COPELAND 1X	357	(\$534,473)	\$1,466,430	\$2,000,903	20,042	3	799	1
KENNY ROAD (#0003) 1Y 2Y	358	(\$541,095)	\$3,940,007	\$4,481,102	68,281	7	806	3
E.SPARTA 1X	359	(\$543,082)	\$790,853	\$1,333,936	11,439	2	808	0
SARDINIA 1X	360	(\$544,074)	\$935,142	\$1,479,216	12,463	2	810	0
SCIO 1X	361	(\$547,648)	\$931,568	\$1,479,216	11,986	2	812	0
MUNGEN 1X	362	(\$550,612)	\$406,911	\$957,523	4,554	1	813	0
RAVEN 1X	363	(\$550,659)	\$928,557	\$1,479,216	12,363	2	815	0
W.OAKWOOD 1X	364	(\$552,192)	\$405,330	\$957,523	4,730	1	816	0
NORTH HICKSVILLE 2X	365	(\$556,047)	\$705,255	\$1,261,302	9,904	2	818	1
LAFAYETTE 1X	366	(\$560,984)	\$918,232	\$1,479,216	12,398	2	820	0
ARBOR ST 1X	367	(\$561,680)	\$917,537	\$1,479,216	13,182	2	822	1
OLDWASHIN 1X	368	(\$561,875)	\$395,647	\$957,523	4,733	1	823	0
KILLBUCK 1X	369	(\$562,713)	\$394,810	\$957,523	5,306	1	824	0
GEORGESRU 1X	370	(\$570,948)	\$908,269	\$1,479,216	12,259	2	826	0
PADEN CITY 2X	371	(\$571,762)	\$385,761	\$957,523	5,513	1	827	0
SHREVE 1X	372	(\$577,200)	\$902,017	\$1,479,216	12,491	2	829	0
SO.MORRAL 1X	373	(\$577,369)	\$380,153	\$957,523	4,408	1	830	0
FULTON 1X	374	(\$579,020)	\$900,196	\$1,479,216	10,053	2	832	0
JONES CITY 1X	375	(\$579,053)	\$378,469	\$957,523	4,295	1	833	0
S.MAR.FER 1X	376	(\$582,391)	\$1,418,513	\$2,000,903	19,300	3	836	0
AMSTERDAM 1X	377	(\$585,742)	\$893,475	\$1,479,216	10,502	2	838	0
BROADACRE 1X	378	(\$587,827)	\$891,389	\$1,479,216	12,438	2	840	0
POMEROY 3X	379	(\$587,839)	\$891,377	\$1,479,216	11,134	2	842	0
W.MALTA 1X	380	(\$596,055)	\$883,162	\$1,479,216	10,317	2	844	0
BROKEN SWORD 1X	381	(\$601,692)	\$877,524	\$1,479,216	10,116	2	846	0
ZOARVILLE 1X	382	(\$605,595)	\$873,621	\$1,479,216	10,360	2	848	0

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Candidate	Rank	NPV	PV Benefits	PV Costs	Reduced CO2	Circuits	Total	OHA
LEIPSIC 1X	383	(\$612,433)	\$721,502	\$1,333,936	9,302	2	850	0
BENTONVILLE 1X	384	(\$612,436)	\$866,780	\$1,479,216	13,242	2	852	0
ISLETA 1X	385	(\$615,003)	\$342,519	\$957,523	3,907	1	853	0
FOREST 2X	386	(\$623,451)	\$116,158	\$739,608	2,499	1	854	0
ARLINGTON 1X	387	(\$652,643)	\$826,573	\$1,479,216	10,498	2	856	0
E.DELPHOS 1X	388	(\$663,486)	\$815,730	\$1,479,216	13,245	2	858	0
CONESVILLE 1X	389	(\$667,789)	\$289,733	\$957,523	3,603	1	859	0
BEAVERDAM 1X	390	(\$668,405)	\$810,811	\$1,479,216	11,020	2	861	0
STCLAIRSV 1X	391	(\$674,055)	\$283,468	\$957,523	3,359	1	862	0
BUCKSKIN 1X	392	(\$676,598)	\$1,324,306	\$2,000,903	16,451	3	865	0
DECLIFF 1X	393	(\$676,676)	\$802,540	\$1,479,216	9,796	2	867	0
SENECAVILLE 1X	394	(\$691,336)	\$266,186	\$957,523	2,767	1	868	0
CROTON 1X	395	(\$691,700)	\$265,823	\$957,523	2,964	1	869	0
CONTINEL 1X	396	(\$692,949)	\$786,268	\$1,479,216	9,715	2	871	0
OTTOVILLE 1X	397	(\$693,406)	\$785,810	\$1,479,216	10,720	2	873	0
KIMBOLTON 1X	398	(\$693,723)	\$263,800	\$957,523	2,702	1	874	0
HILLNDALE 1X	399	(\$703,208)	\$776,008	\$1,479,216	11,141	2	876	0
BELLAIRE 1X	400	(\$714,093)	\$765,124	\$1,479,216	12,043	2	878	1
E.HAVERHI 1X	401	(\$725,190)	\$754,027	\$1,479,216	10,315	2	880	0
S.CONVOY 1X	402	(\$729,740)	\$749,477	\$1,479,216	10,631	2	882	0
WINTERSVI 1X	403	(\$729,937)	\$1,270,966	\$2,000,903	18,776	3	885	0
NORTH HICKSVILLE 1X	404	(\$732,756)	\$528,546	\$1,261,302	7,366	2	887	1
WILDCAT 1X	405	(\$733,486)	\$745,730	\$1,479,216	9,268	2	889	0
MACKSBURG 2X	406	(\$736,489)	\$221,033	\$957,523	2,660	1	890	0
HIGHSTREE 1X	407	(\$747,528)	\$731,688	\$1,479,216	15,492	2	892	1
GLENWOOD 1X	408	(\$751,456)	\$727,760	\$1,479,216	8,076	2	894	0
S.CADIZ 1X	409	(\$759,531)	\$197,991	\$957,523	3,168	1	895	1
DUNKIRK 3X	410	(\$762,452)	\$716,764	\$1,479,216	8,195	2	897	0
BEARTOWN 1X	411	(\$772,461)	\$706,755	\$1,479,216	8,099	2	899	0
W.MOULTAN 1X	412	(\$781,240)	\$176,282	\$957,523	2,114	1	900	0
NEWCOMERS 1X	413	(\$786,912)	\$692,305	\$1,479,216	10,419	2	902	0
BROOM ROAD 1X	414	(\$789,292)	\$1,211,611	\$2,000,903	16,252	3	905	0
BRIDGEPORT 1X	415	(\$804,809)	\$674,407	\$1,479,216	8,901	2	907	0
MILL CREEK 3X	416	(\$810,668)	\$941,191	\$1,751,859	16,615	3	910	2
PANDORA 1X	417	(\$812,428)	\$666,788	\$1,479,216	10,059	2	912	0
STONYHOLL 1X	418	(\$824,085)	\$1,176,819	\$2,000,903	17,430	3	915	0
RUTLAND 1X	419	(\$827,477)	\$130,046	\$957,523	1,374	1	916	0
WARSAW 1X	420	(\$830,123)	\$649,093	\$1,479,216	6,988	2	918	0
WILLARD 1X	421	(\$834,521)	\$644,695	\$1,479,216	7,472	2	920	0
OHIOCITY 1X	422	(\$834,736)	\$122,787	\$957,523	1,418	1	921	0
N.MIDLPT 1X	423	(\$854,454)	\$624,762	\$1,479,216	8,776	2	923	0
ANTWERP 1X	424	(\$859,566)	\$619,650	\$1,479,216	7,247	2	925	1
N.FREDERI 1X	425	(\$874,955)	\$604,261	\$1,479,216	8,474	2	927	0

Candidate	Rank	NPV	PV Benefits	PV Costs	Reduced CO2	Circuits	Total	OHA
ROBYVILLE (#5007) 1X 2X	426	(\$884,372)	\$594,844	\$1,479,216	6,476	2	929	0
KOSSUTH 1X	427	(\$889,654)	\$67,869	\$957,523	328	1	930	0
FLUSHING 1X	428	(\$908,193)	\$571,024	\$1,479,216	6,358	2	932	0
FLAG CITY 1X	429	(\$910,491)	\$1,612,112	\$2,522,604	22,377	4	936	0
NEELYSVIL 1X	430	(\$914,499)	\$1,086,405	\$2,000,903	13,286	3	939	0
HARMAR HILL 1X	431	(\$941,254)	\$1,581,349	\$2,522,604	23,477	4	943	0
SHERWOOD 1X	432	(\$944,180)	\$535,036	\$1,479,216	6,070	2	945	0
LOWELL 1X	433	(\$960,473)	\$518,743	\$1,479,216	6,011	2	947	0
COALGROVE 1X	434	(\$964,210)	\$515,006	\$1,479,216	5,343	2	949	0
N.UPSANDU 1X	435	(\$974,359)	\$504,857	\$1,479,216	6,797	2	951	0
E.FINDLAY 1X	436	(\$998,211)	\$481,005	\$1,479,216	6,397	2	953	0
LATTY 1X	437	(\$1,011,026)	\$468,190	\$1,479,216	5,308	2	955	1
RAY 1X	438	(\$1,081,092)	\$398,124	\$1,479,216	5,253	2	957	0
MCDERMOTT 1X	439	(\$1,112,867)	\$366,350	\$1,479,216	3,862	2	959	0
COMMERCE 1X	440	(\$1,122,201)	\$357,015	\$1,479,216	6,818	2	961	0
NEW MATAMORAS 1X	441	(\$1,124,712)	\$354,505	\$1,479,216	3,979	2	963	0
OTTAWA 1X	442	(\$1,125,638)	\$875,265	\$2,000,903	12,328	3	966	0
E.SPRING 1X	443	(\$1,176,051)	\$303,165	\$1,479,216	2,958	2	968	0
WEST TRINWAY 1X	444	(\$1,191,742)	\$287,474	\$1,479,216	5,241	2	970	0
BLOOM 1X	445	(\$1,310,629)	\$690,274	\$2,000,903	8,318	3	973	0

6.3 Financial and Other Assumptions

Table 12
Financial Assumptions

Financial Evaluation Criteria	Value	
After-Tax Weighted Average Cost of Capital	7.80%	
Combined Federal & State Income Tax Rate	21.88%	
Local Property Tax Rate	3.05%	
Basis for Determining Property Tax	Net Book	
<hr/>		
Depreciation of Capitalized Infrastructure	Tax Dep	SL Dep
Substation (DACR and VVO) ^{20, 21}	SLD 45	SLD 45
Distribution (DACR and VVO) ^{20, 21}	SLD 32	SLD 32
Smart Meters (AMI) ²¹	SLD 15	SLD 15
Communication ²¹	SLD 15	SLD 15
Information Technology	SLD 5	SLD 5
<hr/>		
Operations & Maintenance Category	Value	
T&D Infrastructure O&M - % of Plant:	3.0%	
Com Infrastructure O&M - % of Plant:	3.0%	
Info Tech Infrastructure O&M - % of Plant:	3.0%	
<hr/>		
Annual Escalation Variables	Value	
Substation & Distribution Costs	1.5%	
Communication Costs	1.5%	
Information Technology Costs	1.5%	
Annual O&M Expenses	1.5%	
System Load Growth	1.0%	
Meter Population Growth	0.5%	
Retail Power Costs	1.5%	
LBNL cost of interruptions	1.5%	

²⁰ Digital controls and related appurtenances have a much shorter service life than their associated substation and distribution devices such as breakers, reclosers, voltage regulators, switched capacitor banks, or other equipment. Because of their shorter service life, these controls and appurtenances may eventually be segregated into separate plant accounts and depreciated sooner than their associated substation or distribution devices.

²¹ Any digital equipment such as substation and distribution device controls, their related appurtenances, smart meters, or digital radios, etc. that are anticipated or planned to be replaced prior to being fully depreciated is assumed in this Phase 3 report to be sold or disposed of at book value or exchanged with a similar asset that results in no accounting gains or losses.

Other Assumptions and Notes:

1. Cisco™ field radios required for DACR and VVO installed is anticipated to be replaced every 10 years. Scheduled capital replacement of all Cisco™ field radios is included within all the DACR and VVO business cases.
2. All DACR and VVO business cases include capital costs and O&M costs associated Cisco's field network directory ("FND"). These costs may decrease if other AEP business units or operating companies choose to deploy Cisco's FND.
3. Itron-SSN field radio access points and relays required for AMI is assumed to be operated until they fail in-service. The cost to replace failed SSN access points and relays is included within the AMI business case.
4. DACR controller hardware and software is anticipated to be replaced every 10 years. Scheduled capital replacement of this IT infrastructure is included within all the business cases for each DACR scheme candidate.
5. VVO controller hardware and software is anticipated to be replaced every 8 years. Scheduled capital replacement of this IT infrastructure is included within all the business cases for each VVO bus candidate.
6. The business case for each VVO bus candidate assumes that AMI is deployed and software licenses are purchased for the VVO vendor's AMI module, which enables voltage reduction be increased from 3 percent to 4 percent to achieve greater energy savings.
7. The business case for each DACR scheme candidate assumes that outage frequency (SAIFI) is reduced 15.8 percent and CAIDI is unchanged.
8. Reduced CO₂ emissions over 15 years assume AEP Ohio's electricity CO₂ emission factor of 0.88 metric tons per MWh remains unchanged over the 15 year business case for each VVO bus candidate.
9. Reduced CO₂ emissions over 15 years associated with vehicles is based on the gasoline CO₂ emission factor of 19.60 lbs. of CO₂ per gallon.
10. The topology and baseline reliability of all distribution circuits and DACR scheme candidates remains unchanged over the 15 year study period.
11. The topology of distribution circuits and VVO bus candidates remains unchanged over the 15 year study period.

BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE COMPANY)
OF OKLAHOMA TO BE IN COMPLIANCE WITH)
ORDER NO. 591185 ISSUED IN CAUSE NO. PUD)
201100106 WHICH REQUIRES A BASE RATE)
CASE TO BE FILED BY PSO AND THE)
RESULTING ADJUSTMENT IN ITS RATES AND)
CHARGES AND TERMS AND CONDITIONS OF)
SERVICE FOR ELECTRIC SERVICE IN THE)
STATE OF OKLAHOMA)

CAUSE NO. PUD 201300217

FILED
JAN 17 2014

DIRECT TESTIMONY OF

DEREK S. LEWELLEN

ON BEHALF OF

PUBLIC SERVICE COMPANY OF OKLAHOMA

COURT CLERK'S OFFICE - OKC
CORPORATION COMMISSION
OF OKLAHOMA

JANUARY 2014

TESTIMONY INDEX

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I. INTRODUCTION

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Q. WOULD YOU PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS?

A. My name is Derek S. Lewellen, and I am the Manager of gridSMART® and Meter Revenue Operations for Public Service Company of Oklahoma (PSO or Company). My business address is 212 E. Sixth Street, Tulsa, OK 74119.

Q. WOULD YOU PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. I earned a bachelor's degree in Electrical Engineering from Oklahoma State University in 1989 and a Master's degree in Business Administration from Oklahoma City University in 1994. I have 24 years of electric utility operations experience. I began my career in 1989 with the Company as a substation engineer. In 1992, I was named as a substation superintendent. In 1994, I was named Manager, Distribution for the Lawton District. From 2000 until 2004, I worked in various management positions with the American Electric Power Service Corporation (AEPSC) in Columbus, Ohio, evaluating distribution systems and leading special projects. In 2004, I was named Manager, Distribution for the McAlester District. I held that position until I was named to my current position with the Company in 2010.

Q. WOULD YOU PLEASE DESCRIBE YOUR RESPONSIBILITIES AS MANAGER OF gridSMART® AND METER REVENUE OPERATIONS?

A. I am responsible for gridSMART® deployment and leading the existing Meter Revenue Operations group for the Company. My duties include providing overall

1 planning and coordination of technical project activities for gridSMART®
2 implementation. My responsibilities also include directing, supervising, and
3 coordinating the duties of field personnel in the safe installation, operation,
4 maintenance, reading, connecting and disconnecting of meters and metering
5 equipment for all end-use customers as well as distribution, transmission, and
6 station facilities.

7 Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY BEFORE ANY
8 REGULATORY AGENCY?

9 A. Yes. I testified before the Oklahoma Corporation Commission (OCC or
10 Commission) in Cause No. PUD 200700397, which was an application on behalf
11 of the Company to defer, amortize, and recover storm costs associated with the
12 January 2007 ice storm that impacted the Company's service territory. Also, I
13 submitted testimony in Cause No. PUD 201100083, which was an application
14 asking for approval of a waiver from Commission rule OAC 165:35-21-21(3) and
15 approval of changes to PSO's electric service rules and terms and conditions of
16 service. Most recently, I submitted testimony in Cause No. PUD 201100168,
17 which was an application asking for approval of three new tariffs associated with
18 PSO's gridSMART® program.

19 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

20 A. My testimony gives an update on PSO's gridSMART® projects, discusses the
21 Company's proposal to deploy advanced metering infrastructure (AMI)
22 throughout its service territory and associated consumer programs, and provides
23 information regarding the Company's future plans for gridSMART® deployment.

1 II. PSO's gridSMART® PROGRAM

2 Q. PLEASE PROVIDE AN OVERVIEW OF PSO'S gridSMART® PROGRAM
3 COMPONENTS.

4 A. As an introduction, gridSMART® is American Electric Power Company, Inc.'s
5 (AEP) name for its smart grid program. PSO's gridSMART® program is an
6 initiative that started in 2010 and includes advanced metering (metering capable
7 of two-way communication) at our customers' residential and business locations,
8 and advanced grid management technology equipment on PSO's distribution
9 system. The main components of PSO's smart grid program include AMI,
10 distribution automation (DA), volt/var optimization (VVO), in-home devices, and
11 a customer web portal.

12 AMI refers to systems that measure, collect, and analyze energy usage
13 from meters through a communications network. This infrastructure includes
14 hardware, such as meters that enable two-way communications (AMI meter), the
15 communications network, customer information systems, and meter data
16 management systems.

17 The DA component includes automated circuit reconfiguration on
18 distribution circuits and substations, and involves the installation of automated
19 reclosures to reduce the number of customers impacted by an outage.

20 The VVO component includes the coordinated control of capacitor banks,
21 voltage regulators, and transformer load tap changers on distribution circuits and
22 substations to optimize voltage and power factors.

1 The in-home device component assists customers in managing electric
2 usage in conjunction with tariffs, such as time of day (TOD) and direct load
3 control (DLC) tariffs.

4 PSO's customer web portal includes: single account sign-on via existing
5 customer account log-in, bill-to-date and forecasted bill; daily, weekly, and
6 monthly use; existing rate plan information and rate comparison; tips to reduce
7 energy use; and carbon impact.

8 Q. HAS PSO IMPLEMENTED gridSMART[®] ON ANY PART OF ITS
9 DISTRIBUTION SYSTEM?

10 A. Yes, PSO implemented a comprehensive gridSMART[®] project in its Owasso
11 area, and expanded AMI and consumer tariffs in three additional locations.

12

13 III. PSO gridSMART[®] PROJECT UPDATE

14 Q. PLEASE SUMMARIZE THE COMPANY'S DEPLOYMENT OF AMI
15 TECHNOLOGIES.

16 A. PSO has deployed AMI meters to approximately 14,500 customers in the original
17 Owasso project area in 2011. Based upon the customer response and benefits of
18 AMI stemming from this deployment, an additional 17,000 AMI meters were
19 deployed in 2012 (1,000 University of Tulsa Campus, 6,500 Okmulgee, and 9,500
20 Sand Springs). Also, all customers with an AMI meter have access to the
21 customer web portal. The approximately \$13.2 million capital investment
22 associated with these AMI deployments and in-home technology were in service
23 and were being used by customers during the test year.

1 Q. PLEASE SUMMARIZE THE COMPANY'S DEPLOYMENT OF GRID
2 MANAGEMENT TECHNOLOGIES AND RESULTS.

3 A. The grid management technologies, DA and VVO, were only installed in Owasso
4 between 2011 and 2012 on 11 circuits. Subsequently, DA and VVO were
5 expanded to two additional circuits in 2013. Due to technological and scheme
6 complexities, and a general lack of outage events, DA results are still under
7 review. After evaluating the 2012 VVO performance, it was determined that
8 improvements could be made and a subsequent study of the technology was
9 needed. PSO has conducted an evaluation of 2013 VVO performance, the results
10 of which will be available in mid-2014. Additional evaluations, including the
11 impacts of the technology on customers, are being performed by an independent
12 and nationally recognized third party, Pacific Northwest National Labs, which is
13 part of Battelle National Labs. It is anticipated that these results will be available
14 in mid-2014. Once the VVO and DA studies are completed and the results have
15 been reviewed, grid management technologies will be evaluated for possible
16 inclusion in a future phase of gridSMART[®] deployment, since operational
17 efficiencies are achieved by deploying DA and VVO on circuits simultaneously.

18 Q. WHAT OBJECTIVES WERE ACCOMPLISHED WITH THE SMART GRID
19 DEPLOYMENT PROJECTS?

20 A. PSO accomplished several objectives after implementing smart grid technologies
21 as a part of these projects. PSO gained operational experience with a variety of
22 smart grid technologies including AMI, DA, VVO, consumer engagement, two-

1 way communications, and back office system implementations. The Company
2 gained a greater understanding of customer response on three fronts:

- 3 • customer benefits of deploying AMI technology;
- 4
- 5 • the potential impact of advanced consumer tariffs on customer energy
- 6 consumption, peak demand and energy cost and how customers
- 7 respond to pricing and enabling technology; and
- 8
- 9 • the potential impact of providing customer access to interval energy
- 10 usage through an interactive customer web portal.
- 11

12 Q. PLEASE SUMMARIZE WHAT RESULTS THE COMPANY HAS
13 EXPERIENCED FROM AMI AND ASSOCIATED CUSTOMER TARIFF
14 DEPLOYMENTS AND HOW THESE LESSONS WILL BE UTILIZED IN
15 FUTURE DEPLOYMENTS.

16 A. Overall, PSO learned from the original Owasso project and subsequent AMI
17 deployments that an integrated set of smart grid technologies and tariffs allows
18 customers to reduce their energy and peak demand consumption, and save money
19 on their monthly electric bills. This result was accomplished through a
20 combination of technology and tariffs, which provided customers with the
21 information necessary to manage their electric usage. Customers served with
22 smart grid technologies experienced service improvements in terms of faster order
23 fulfillment and improved service reliability, which led to improved customer
24 satisfaction. For example, Customer Service Representatives in the Customer
25 Solutions Center (CSC) are able to initiate connect orders, which can result in the
26 customer's electric service being turned on in real-time via an automated
27 electronic switch. Overall, gridSMART[®] provides PSO with operational benefits

1 that help streamline operations and improve our understanding of system
2 conditions and operations.

3 Q. CAN YOU PLEASE GIVE MORE DETAILS ON THE CUSTOMER SERVICE
4 BENEFITS THAT RESULTED FROM THE AMI DEPLOYMENTS?

5 A. Customers experienced improved customer service resulting from the AMI
6 deployments. This result was driven by PSO's customer web portal, AMI meters,
7 in-home technology, as well as the programs that PSO implemented that helped
8 educate customers and achieve energy savings by taking advantage of TOD rates
9 and air conditioner control programs.

10 A summary of the 2012 and 2013 results is shown in Figure 1 through
11 Figure 4 for the on-peak summer months. The energy and demand impacts of the
12 tariffs were evaluated by comparing AMI customers' usage versus the usage of a
13 comparable group of customers on the standard tariff. Differences between 2012
14 and 2013 can be attributed to temperature differences: 2012 was an abnormally
15 hot year, whereas 2013 displayed more typical weather patterns.

16 Figure 1 summarizes PSO's SMART Shift Program, which is a two-tier
17 TOD tariff. For the two-tier TOD tariff, the high cost period is non-holiday
18 weekdays from 2 p.m. to 7 p.m., while the low-cost periods were all other hours
19 in the billing months of June through October (on-peak months). The billing
20 months of November through May have a low cost declining block rate schedule
21 for all hours of all days, and the price paid in this period is the same as the
22 standard tariff.

1

Figure 1

SMART Shift Program Summary			
Year	Number of Participants	Average Bill Savings Per Participant	Percent of Participants that Experienced Savings
2012	222	6.5%	89%
2013	768	3.8%	84%

2

Figure 1 shows that not only were there a large number of participants in the SMART Shift Program, but 84% to 89% of these participants were able to reduce their electric usage and save money on their monthly bills (3.8%-6.5% average savings).

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Figure 2 summarizes PSO's SMART Shift Plus Program, which is a three-tier TOD tariff with critical peak pricing (CPP). For the three-tier TOD tariff, during the billing months of June through October, the low-cost periods were all hours on weekends and holidays plus non-holiday weekdays from 11 p.m. to 10 a.m. The medium-cost hours were from 10 a.m. to 2 p.m. and 7 p.m. to 11 p.m. on non-holiday weekdays, and the high-cost hours are from 2 p.m. to 7 p.m. on the same non-holiday weekdays. CPP periods could only be called on the same non-holiday weekdays.

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Figure 2

SMART Shift Plus Program Summary					
Year	Number of Participants	Average Monthly Energy Reduction During High Cost Hours	Average Demand Reduction During High Cost Hours	Average Bill Savings Per Participant	Percent of Participants that Experienced Savings
2012	51	18	0.8	N/A*	N/A*
2013	76	6	0.8	0.8%	49%

*2012 number of participants was not a large enough sample size.

15

Figure 2 shows that only a small portion of customers participated in the SMART Shift Plus Program. It also shows that of these participants, only about half experienced a small savings on their monthly bills.

16

17

1 Figures 3 and 4 summarize the SMART Cooling (DLC) and Air
 2 Conditioner Cycling Programs. These programs allowed PSO to control enrolled
 3 customers' thermostats during certain hours during the peak months. The
 4 customers had the option of not participating in an event, and therefore not
 5 receiving a credit. For 2012, 10 SMART Cooling events were called, while in
 6 2013, five SMART Cooling events were called. These events were opportunities
 7 for customers to save on their electric bills by using their air conditioning less
 8 during specific time periods. An eligible event day is where the forecasted
 9 demand for the day is within 93 percent of PSO's forecasted peak demand.

Figure 3

SMART Cooling Program Summary – Temperature Offset					
Year	Number of Participants	Average Energy Reduction per Event per customer (kwh)	Average Demand Reduction per Event per customer (kw)	Average Percentage Demand Reduction per Event	Percent of Participants per Event
2012	130	3.8	2.5	45.5%	82%
2013	391	2.8	2	38.5%	91%

Figure 4

SMART Cooling Program Summary - Air Conditioner Cycling					
Year	Number of Participants	Average Energy Reduction per Event per customer (kwh)	Average Demand Reduction per Event per customer (kw)	Average Percentage Demand Reduction per Event per customer	Percent of Participants per Event
2012	55	7.5	2.2	32.8%	93%
2013	224	4.8	0.8	15.4%	91%

12 Figures 3 and 4 show that the SMART Cooling Programs both had a high
 13 percentage of participants per event (82%-93% participation rate). They also

1 show that the participants experienced significant demand reductions for each
 2 event (15.4%-45.5% average demand reduction per event).

3 Q. HOW DID PSO MEASURE THE CUSTOMER SATISFACTION SUCCESS OF
 4 THESE PROGRAMS?

5 A. To gauge the improved customer service, PSO conducted a survey in 2012 as part
 6 of the Owasso project. Overall satisfaction across the gridSMART[®] programs
 7 averaged a 77 percent positive response, with 79 percent of survey participants
 8 indicating that the programs had met or exceeded their expectations. In fact, 92
 9 percent of survey participants indicated a preference to continue in the programs
 10 in 2013. This survey was administered by a third-party research firm that
 11 conducted the interviews via telephone for calendar year 2012. Of the 350
 12 program participants, approximately one-third (91) answered the survey. These
 13 program participants were enrolled in one or more of the SMART Shift, SMART
 14 Shift Plus, or SMART Cooling Programs for a minimum of 60 days. Figure 5
 15 summarizes the 2012 survey results.

16 **Figure 5**

2012 Participant Survey Results				
	SMART Shift	SMART Cooling	SMART Shift & SMART Cooling	SMART Shift Plus
Overall Satisfaction with Program	79%	79%	75%	78%
Met or Exceeded Expectations	68%	93%	77%	83%
Likelihood to Continue Program in 2013	95%	100%	93%	83%

17 In addition, a group of non-participants (i.e. PSO customers with AMI
 18 meters that were not enrolled in a program) were surveyed to help learn more
 19 about why customers did not participate in the programs. When asked what PSO
 20 could do to make these programs more appealing, greater promotion and customer

1 education were frequently mentioned as well as showing how program
2 participation could reduce individual monthly electric bills. These findings
3 indicate a substantial opportunity exists to better promote these consumer
4 programs and ultimately increase enrollment levels.

5 Q. CAN YOU PLEASE GIVE MORE DETAILS ON THE OPERATIONAL
6 BENEFITS THAT RESULTED IN THE AMI DEPLOYMENT AREAS?

7 A. The four AMI deployment areas helped PSO achieve operational benefits through
8 AMI's functionality. For example, AMI has remote connect/disconnect
9 capability. PSO found that the ability to remotely connect and disconnect led to
10 improved operational capabilities, as well as improved customer service as
11 referenced earlier in my testimony. The three metrics highlighted below
12 summarize some of the operational achievements for remote operations in 2013
13 for 31,500 meters.

- 14 ○ Average Number of Monthly Credit Disconnect Orders Completed – 320
- 15 ○ Average Number of Monthly Credit Reconnects Completed – 310
- 16 ○ Average Number of Monthly Connect/Disconnects Completed – 1,300

17 The operational benefits derived from the ability to connect or disconnect a
18 customer remotely at the customer's property include the significant reduction in
19 the time required to complete connection/disconnection orders, and establishing
20 service to new customers quicker. The ability to remotely read meters helped
21 improve billing accuracy and led to decreased meter estimations. Also, there is
22 no longer a need to send meter readers to a customer yard on a monthly basis.
23 However, PSO will still need occasional access for meter testing and

1 maintenance. The following metrics highlight some of the operational benefits
2 achieved through this ability in 2013:

- 3 ○ Average Number of Monthly Remote Reads – 31,500
- 4 ○ Average Number of Monthly Saved Truck Rolls – 1,900
- 5 ○ Average Number of Monthly Hazards Avoided – 1,100

6 Without the need to drive to customers' premises for meter reads, PSO was
7 able to avoid dangerous conditions, such as vicious dogs, or inaccessible
8 locations. PSO tracks customer premises that have these types of conditions. In
9 PSO's service territory, there are approximately 24,000 premises that have
10 customer-related hazard codes of bad dog, vicious dog, or pit bull. In addition,
11 PSO estimates approximately 5,300 customer bills each month due to inaccessible
12 locations. There are an additional 130,000 PSO premises that have dogs that are
13 not coded as hazardous.

14 Q. CAN YOU PLEASE GIVE MORE DETAILS ON THE RELIABILITY
15 BENEFITS THAT RESULTED FROM THE AMI DEPLOYMENTS?

16 A. The two-way communications capabilities of AMI allowed PSO to achieve
17 improved customer reliability by alerting PSO to potential reliability issues. For
18 example, temperature alerts are sent when the AMI device detects large variances
19 in temperature due to rare instances of excessive heat in the meter. In 2013, 37
20 temperature alarms were investigated, which led to 21 proactive repairs of meter
21 blocks in various stages of failure before the customer was even aware of any
22 problem.

1 Similarly, the AMI meters can help detect power outages. PSO has the
2 ability to quickly determine if service is available to a customer with a disconnect
3 switch and to verify that service has been restored following an interruption. PSO
4 is working on integrating AMI with outage management systems to be better
5 equipped to detect power outage locations.

6 Finally, AMI provides voltage interval reading capability. This
7 functionality helps to support voltage optimization and to identify problems
8 before they occur. PSO is continuing to develop and refine this functionality.

9 Q. DOES PSO EXPECT TO SEE SIMILAR RESULTS AND BENEFITS FROM
10 ITS PROPOSED AMI DEPLOYMENT PROGRAM?

11 A. Yes, PSO expects to achieve similar results throughout its entire service territory,
12 as well as additional benefits that I discuss later in my testimony, with its
13 proposed AMI deployment program.

14 Q. CAN YOU PLEASE PROVIDE MORE DETAILS ON THE CUSTOMER WEB
15 PORTAL?

16 A. Yes. The customer web portal gives customers timely consumption and pricing
17 information, along with tips on how to save energy. The customer web portal is
18 seamlessly integrated into the existing customer account log-in process, which
19 means customers log in to their existing account on PSOklahoma.com. If they
20 have an AMI meter and log in to their existing account, they are automatically
21 presented with their usage information. Some of the functionality in the customer
22 web portal includes a rate comparison (using historical usage data as a basis,
23 customers could compare costs of various rates), near real-time access to usage

1 information, historical usage information with temperature overlay, forecasted bill
2 calculation based upon current usage, energy efficiency tips, and how their usage
3 compares to others in their community. Customers also have the ability to link
4 directly to existing PSO energy efficiency programs currently being offered to
5 help manage their energy usage.

6 At the end of 2013, PSO upgraded its customer web portal to include
7 Green Button functionality. Green Button is an industry-led effort to provide
8 customers with secure and easy access to their energy usage information from
9 their AMI meters in both a consumer-friendly and computer-friendly format via a
10 "Green Button" on PSO's customer web portal. Stated another way, the Green
11 Button functionality allows customers to download their energy usage
12 information onto their own computers so they can perform their own analyses.
13 Through October of 2013, over 2,200 active customers have used the customer
14 web portal. PSO has found that customer web portal usage increases after
15 customers receive education material.

16

17 IV. PROPOSED AMI DEPLOYMENT PROGRAM

18 Q. PLEASE GIVE AN OVERVIEW OF PSO'S PROPOSED AMI DEPLOYMENT
19 PROGRAM.

20 A. PSO plans to deploy approximately 522,000 AMI meters throughout its entire
21 service territory over a three-year time period. This number of AMI meters is in
22 addition to the approximately 31,500 already in-service. This deployment will
23 allow PSO to implement consumer programs, as well as a Pre-Pay Billing

1 Program, which PSO anticipates will be part of a future formal application with
2 the Commission in 2014, as discussed later.

3 Q. HOW DOES THIS PROPOSAL DIFFER FROM PSO'S PREVIOUS SMART
4 GRID TECHNOLOGY DEPLOYMENTS?

5 A. PSO's proposed AMI Deployment Program is only for AMI, consumer tariffs,
6 and the customer web portal to take advantage of usage information.

7 Q. WHY IS PSO PLANNING ON IMPLEMENTING ONLY AMI IN ITS
8 CURRENT PROPOSAL?

9 A. PSO's proposed AMI deployment is a prudent investment, as it provides our
10 customers access to the benefits of AMI currently experienced by most other
11 electric consumers in Oklahoma. Customers are requesting more information and
12 choices that can be supplied by AMI. This is a phased-in approach in deploying
13 gridSMART[®] technology: PSO will first provide AMI technology and voluntary
14 consumer programs that can benefit customers in the near term, while the grid
15 management technology, DA and VVO are to be deployed in future phases once
16 the technology is fully evaluated, as mentioned earlier.

17 This AMI deployment will also serve as the platform for voluntary
18 consumer programs designed to engage customers to reduce energy usage and
19 demand, the customer web portal, pre-pay billing functionality, and future
20 gridSMART[®] deployments.

21 Q. WHY IS PSO CHOOSING NOW FOR THE TIMING OF THIS
22 DEPLOYMENT?

1 A. As previously mentioned, PSO wants to extend the benefits of AMI to customers
 2 in its service territory; benefits that customers served by other utilities in
 3 Oklahoma are already receiving and that PSO customers are now expecting.
 4 Electric utilities continue upgrading their customers' analog electric meters with
 5 digital 'smart' meters, according to the latest report from IEE, an Institute of the
 6 Edison Foundation. As of July 2013, nearly 40 percent of U.S. households have a
 7 smart meter. In May 2012, only 33 percent of households had smart meters.¹ Now
 8 is the perfect time for PSO's proposed deployment, as the costs of AMI meters
 9 have decreased approximately 25 percent in the last three years.

10 Q. PLEASE GIVE AN OVERVIEW OF PSO'S AMI IMPLEMENTATION PLAN.

11 A. As part of this deployment, all components of the project, including contractors
 12 and meter and network suppliers, will be competitively bid to ensure the lowest
 13 cost is achieved. PSO will also provide customer enhanced communications to
 14 help educate customers on the usage and benefits of AMI. Figure 6 provides an
 15 overview of the planned AMI deployment.

Figure 6

Deployment Time Frame	PSO Deployment Area	AMI Meters Deployed
4 th quarter 2014	SE Oklahoma	60,000
2015	Metro Tulsa	285,000
1 st quarter 2016	NE Oklahoma - Remaining locations	60,000
2 nd and 3 rd quarter 2016	SW Oklahoma	117,000
4 th quarter 2016	All areas	Any Remaining Meters

17 Prior to deploying AMI meters in the different PSO communities, PSO plans to
 18 communicate with our customers through community meetings, customer letters,
 19 call dialer messaging, door hangers, and post card mailings. PSO's key messages

¹ IEE, an Institute of the Edison Foundation, *Utility-Scale Smart Meter Deployments: A Foundation For Expanded Grid Benefits*, August 2013 report, page 1.

1 will create awareness of the AMI meter deployment plan for city and community
 2 leaders, notify PSO customers of their AMI meter installation, inform them of its
 3 benefits, and provide educational information to customers on their individual
 4 usage via the customer web portal to help them make informed energy choices.

5 Q. WHY WILL THE IMPLEMENTATION PERIOD TAKE THREE YEARS?

6 A. Three years is needed to allow PSO to efficiently and cost-effectively obtain the
 7 necessary resources for the project, deploy AMI, and implement the associated
 8 programs and functionality. A period of less than three years is not sufficient to
 9 accomplish the full scope of PSO's proposal.

10 Q. WHAT IS THE ESTIMATED TOTAL CAPITAL COST FOR THE PROPOSED
 11 PROJECT?

12 A. The estimated total project capital cost is approximately \$132.9 million. In
 13 addition to capital cost, over the first three years an estimated \$15.5 million in
 14 incremental O&M is also needed. The \$132.9 million amount includes \$13.2
 15 million in capital investment included in the test year (as previously mentioned in
 16 my testimony). Figure 7 summarizes the cost of the project.

17 **Figure 7**

Total Project Cost		
Project Component	Capital	O&M*
AMI	\$119,700,000	\$14,500,000
Consumer Programs	\$0	\$5,950,000
Test Year Capital Investment	\$13,200,000	\$0
Anticipated Savings	\$0	(\$5,000,000)
Totals	\$132,900,000	\$15,450,000

18 * For the first three years.

1 Q. HOW WERE THESE PROJECTED COSTS DEVELOPED?

2 A. The project costs, as detailed in Company witness Andrew Williams' testimony,
 3 were developed based upon the planned deployment schedule, costs identified
 4 during the earlier deployments of AMI technology, and initial vendor pricing
 5 information. As mentioned earlier, all aspects of the project will be competitively
 6 bid.

7 The average capital cost in the original AMI areas (i.e., Owasso,
 8 University of Tulsa, Okmulgee, and Sand Springs) was approximately \$428 per
 9 customer. The average capital cost per customer developed as part of the AMI
 10 deployment plan in this proceeding is approximately \$230, which is almost 47
 11 percent less than the original cost. This reduction in cost is reflective of such
 12 factors as having a comprehensive deployment plan that installs the meters over a
 13 three-year time period, and AMI price reductions due to the maturing of the
 14 technology.

15 Q. WHAT IS THE AMI PORTION OF THE PROJECT COST?

16 A. The AMI portion of the project cost is approximately \$119.7 million in capital
 17 and \$14.5 million in incremental O&M over the three-year deployment period.

18 Figure 8 summarizes the AMI portion of the project cost.

19 **Figure 8**

AMI Deployment Cost		
Component	Capital	O&M
gridMGMT	\$600,000	\$3,300,000
AMI Meter	\$87,000,000	\$6,300,000
AMI Network	\$24,900,000	\$1,600,000
AMI IT	\$7,200,000	\$3,300,000
Totals	\$119,700,000	\$14,500,000

20

1 Q. PLEASE PROVIDE DETAILS FOR EACH COST COMPONENT OF THE
2 AMI DEPLOYMENT.

3 A. The gridMGMT component, or grid management, is the project management and
4 consumer education portion of the project. The AMI Meter component includes
5 the 522,000 meters and the cost of installation and associated expenses. The AMI
6 Network component is the communications network, associated equipment, the
7 cost of installation, and associated expenses. The AMI IT component is the
8 information technology associated with the project, including the meter system
9 interface, customer web portal, programs, tariffs, data analytics, outage orders,
10 pre-pay billing functionality, and security.

11 Company witness Williamson discusses the revenue requirements
12 associated with the proposed AMI deployment program. Company witness Sartin
13 proposes cost recovery via a tracker, and Company witness Aaron provides the
14 tariff for recovery of the AMI costs.

15 Q. WHAT BENEFITS SHOULD CUSTOMERS EXPERIENCE ONCE THEY
16 HAVE AMI?

17 A. PSO customers receiving AMI as part of this program should experience benefits
18 similar to those experienced by PSO's customers that were part of the prior AMI
19 deployments. The following list is a summary of those benefits, which I
20 described earlier in my testimony.

- 21 • Customer web portal for consumer education
- 22 • Consumer energy savings
- 23 • Remote connect/disconnect capability
- 24 • Power outage detection
- 25 • Remotely read meters on demand

- 1 • Voltage interval reading
- 2 • Alarms, such as temperature

3 Q. WHAT OTHER BENEFITS SHOULD BE ACHIEVED THROUGH THE
4 IMPLEMENTATION OF AMI IN PSO'S SERVICE TERRITORY?

5 A. AMI provides both quantitative and qualitative benefits. From a quantitative
6 perspective, during the deployment, the expected O&M savings associated with
7 labor, vehicles, and associated overheads will be approximately \$5.0 million.
8 Beginning in 2017, PSO anticipates that the O&M savings for the annual labor,
9 vehicle, and overheads will be offset by an increase in O&M expenses associated
10 with AMI network and IT on an annual basis. These components were explained
11 earlier in my testimony.

12 Additionally, AMI offers a host of benefits that have not been monetarily
13 quantified, and should be realized in the future, such as:

- 14 • Improved data for billing
- 15 • Better customer service and satisfaction
- 16 • Quicker processing of some meter orders
- 17 • Improved credit/collections
- 18 • Lower consumption on inactive meters
- 19 • Identification and reduction in theft
- 20 • Reduction in call center volume
- 21 • Improved crew and meter reader safety
- 22 • Obsolete meter avoidance
- 23 • Reduced environmental impact

24 With automated meter reads, AMI nearly eliminates estimated bills,
25 leading to greater billing accuracy, which also leads to improved customer
26 satisfaction. For instance, when a customer wishes to terminate service, the AMI
27 meter can be read remotely and a final bill sent without delays caused by manual
28 reads. Similarly, AMI meters equipped with a remote service switch enable

1 power to be turned on or off remotely. As a result, a customer moving in can
2 have service turned on in minutes, rather than waiting until the next business day.

3 AMI also provides customers with the ability to view their energy
4 consumption on a more granular level; typically multiple data points per day will
5 be provided. This data can be useful for customers, as it can help provide a better
6 understanding of their energy usage and consumption behavior. The availability
7 of this data can also enable customers to participate in consumer programs. Such
8 programs are designed to reduce peak demand and energy usage, thereby allowing
9 customers to benefit through potential savings on energy costs.

10 In addition, AMI provides billing and call center efficiencies that will
11 enable employees to address more inquiries in a more expeditious manner.
12 Customers should experience fewer billing issues due to the elimination of
13 estimated meter reads. Call center representatives will have real-time access to
14 meter data, which will help them discuss actual usage information with
15 customers. When a customer calls about a power outage, the real-time access also
16 will enable call center representatives to determine whether the outage is due to a
17 PSO-outage or to an issue on the customer side of the meter.

18 From a reliability perspective, when an AMI meter detects a loss of
19 voltage, a message is sent indicating the customer has lost power. PSO can use
20 this information in conjunction with customer telephone calls to help determine
21 the extent of the outage. Also, meters can be queried (pinged/pollled) to get an
22 indication of whether a customer has power. This indication is useful to
23 troubleshoot customer issues and to verify restoration following an outage.

1 From a safety perspective, fewer meter readers will be required in the field
2 through the use of AMI, which will reduce physical meter reading efforts and
3 thereby reduce potential safety issues. Although PSO will have cost savings
4 related to a decrease in meter operations activities, these savings will offset other
5 costs of the program, such as costs for customer communications and education,
6 communication network, and IT systems.

7 With remote capabilities, the number of miles driven by metering and
8 service personnel will be reduced on an annual basis. Not only does this reduce a
9 number of safety issues, there are also benefits associated with reduced vehicle
10 emissions as a result of reduced vehicle miles.

11 Q. CAN YOU PLEASE GIVE MORE DETAILS ON THE TARIFFS AND
12 ASSOCIATED CONSUMER PROGRAMS PSO WILL IMPLEMENT?

13 A. Yes. As I previously mentioned, PSO will implement tariffs and voluntary
14 consumer programs, which will help PSO customers realize additional benefits of
15 AMI. PSO will request OCC authorization in 2014 for any changes or additions
16 to the existing tariffs in an application similar to PSO's filing in Cause No. PUD
17 201100168, which was an application asking for approval of three tariffs
18 associated with the Owasso project.

19 In fact, PSO envisions the revised tariffs and programs will be similar to
20 the existing tariffs approved in the aforementioned case. This would include a
21 TOD tariff and pilot either a DLC or Residential Peak Time Rebate (RPTR) tariff
22 associated with peak demand reduction.

1 The TOD (SMART Shift) tariff will send price signals about the costs of
2 providing power in the on-and off-peak seasons and at different times of day
3 during the peak season. The general premise of this tariff is the recognition that it
4 is more expensive to provide electric energy during certain hours of certain days.
5 This tariff provides an incentive for customers to shift electric use from peak
6 periods to non-peak hours, which permits customers to save on energy costs.
7 PSO's plan is to keep the existing two-tier residential TOD tariff and discontinue
8 the CPP (SMART Shift Plus) tariff based upon the lack of customer participation
9 and benefits experienced during the last two summers (see Figure 2).

10 Under the pilot DLC (SMART Cooling) or RPTR tariff, PSO would
11 provide enrolled customers incentives to control their electric usage during certain
12 hours during the peak months. Based upon the lessons learned in the pilot, an
13 easy to understand and market-driven in-home technology must be utilized.
14 Alternatives are currently being evaluated. This includes providing a rebate
15 towards the purchase of an approved programmable communicating thermostat
16 for customers enrolled in either the TOD or DLC/RPTR tariff. Once the pilot
17 phase of the new DLS/RPTR tariff has been completed in 2015, PSO anticipates
18 that the TOD, and either the DLC or RPTR tariff would be filed in 2015 and
19 rolled out to customers in 2016.

20 Q. WHAT ARE THE ANTICIPATED COSTS OF OFFERING CONSUMER
21 PROGRAMS?

22 A. The anticipated costs for the program are based upon the premise that PSO will
23 not own, maintain, or install in-home devices, but instead provide customer

1 rebates towards the purchase of an approved programmable communicating
 2 thermostat that will aid customers in managing their energy usage if they sign up
 3 for one of the tariffs. Figure 9 summarizes the consumer program costs.

4 **Figure 9**

Consumer Program Costs*				
Program Component	2014	2015	2016	Totals
Customer Education	\$300,000	\$500,000	\$1,250,000	\$2,050,000
Program Management	\$250,000	\$500,000	\$750,000	\$1,500,000
Thermostat Rebate	0	\$400,000	\$2,000,000	\$2,400,000
Totals	\$550,000	\$1,400,000	\$4,000,000	\$5,950,000

5 *Program costs are based on estimated customer enrollments during the three-
 6 year deployment period of 0 in 2014, 2,000 in 2015, and 10,000 in 2016.

7 Q. WHAT ARE THE ANTICIPATED BENEFITS THAT CUSTOMERS WILL
 8 RECEIVE FROM PARTICIPATING IN THE CONSUMER PROGRAMS?

9 A. Based on the pilot results for the SMART Shift Program (see Figure 1), PSO saw
 10 that the participants in this program saved an average of approximately \$8 per
 11 month during the five-month summer season. PSO anticipates similar savings for
 12 customers that participate in this program following the AMI deployment.
 13 Similarly, PSO saw that participants in the SMART Cooling Programs (Figures 3
 14 and 4) save \$2.50 per air conditioning unit controlled per event. As I mentioned
 15 earlier, for 2012 there were 10 SMART Cooling events and five in 2013.

16 Q. WILL THERE BE ANY OTHER PROGRAMS PSO PLANS TO OFFER?

17 A. PSO plans to request implementation of a Pre-Pay Billing Program in a
 18 subsequent proceeding. The Pre-Pay Billing Program allows customers to pay for
 19 their electricity service in advance, and track their usage along with their account
 20 balance. Benefits to customers from this program include a reduction in fees and
 21 deposits, easier budgeting, convenience, and increased awareness of usage.

1 V. FUTURE DEPLOYMENTS

2 Q. WHAT IS PSO'S LONG-TERM OBJECTIVE ONCE AMI IS FULLY
3 DEPLOYED?

4 A. PSO envisions an AMI deployment as a platform for the implementation of
5 other consumer programs and gridSMART[®] technologies. As technology
6 advances, the electric utility industry has the opportunity to enhance the way it
7 does business to provide additional customer benefits. PSO's AMI deployment
8 strategy provides a foundation for these future technology advancements. It is
9 the Company's vision that its gridSMART[®] program will yield improved
10 customer satisfaction layered upon a foundation of utility efficiencies. For
11 example, building upon the successful deployment of AMI, it is PSO's intent to
12 implement new consumer programs in an effort to help our customers reduce
13 energy usage and save on energy costs. Full AMI deployment will also provide
14 the opportunity for more proactive data analysis, which will help improve
15 reliability, reduce outage times, and improve capacity planning. As mentioned
16 earlier, once DA and VVO technology is fully evaluated, it is anticipated a plan
17 for this technology will be provided as a future phase of gridSMART[®].

18
19 VI. CONCLUSION

20 Q. DO YOU HAVE ANY FINAL THOUGHTS?

21 A. Yes. PSO has proven that AMI offers a number of benefits through the successful
22 implementation of this technology in four different areas. PSO plans to continue
23 this effort with the deployment of AMI throughout the rest of its service territory.
24 The AMI deployment, which includes approximately \$132.9 million investment

1 and \$15.5 million in incremental O&M, will take three years to complete, and will
2 provide benefits to both PSO and our customers.

3 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

4 A. Yes, it does.

BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

FILED
MAY 29 2014

APPLICATION OF PUBLIC SERVICE COMPANY)
OF OKLAHOMA TO BE IN COMPLIANCE WITH)
ORDER NO. 591185 ISSUED IN CAUSE NO. PUD)
201100106 WHICH REQUIRES A BASE RATE)
CASE TO BE FILED BY PSO AND THE)
RESULTING ADJUSTMENT IN ITS RATES AND)
CHARGES AND TERMS AND CONDITIONS OF)
SERVICE FOR ELECTRIC SERVICE IN THE)
STATE OF OKLAHOMA)

**COURT CLERK'S OFFICE - OKC
CORPORATION COMMISSION
OF OKLAHOMA**

CAUSE NO. PUD 201300217

REBUTTAL TESTIMONY OF

DEREK S. LEWELLEN

ON BEHALF OF

PUBLIC SERVICE COMPANY OF OKLAHOMA

MAY 2014

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EXHIBITS

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EXHIBIT DSL 2R	Analyses of The Tariff Programs

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Derek S. Lewellen, and I am the Manager of gridSMART[®] and Meter Revenue Operations for Public Service Company of Oklahoma (PSO or Company). My business address is 212 E. Sixth Street, Tulsa, OK 74119.

Q. ARE YOU THE SAME DEREK S. LEWELLEN WHO PREVIOUSLY FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to various statements and recommendations in the Responsive Testimonies of Tonya Hinex-Ford representing the Public Utility Division (PUD) of the Oklahoma Corporation Commission (OCC or Commission), and Barbara R. Alexander representing the American Association of Retired Persons (AARP).

Specific to Ms. Hinex-Ford's testimony, I will describe how PSO's plan fully addresses the three criteria she requires of AMI deployments by: guaranteeing \$11 million of savings; providing customer tariff offerings and complimentary technology that allow customers to better manage their electric usage with the ability to generate bill savings; and offering free home energy reports for customers without internet access.

In responding to Ms. Alexander, I will focus primarily on her general assertion that PSO's proposal does not provide enough benefits for customers to warrant full deployment at this time. More precisely, I will show how PSO's

1 program is cost effective in terms of the quantifiable benefits alone, because it yields
2 a positive net present value of more than \$7 million over a 15-year period. I will also
3 discuss other significant benefits, such as more immediate outage restorations, and
4 explain that while these benefits are more qualitative in nature, they undoubtedly
5 provide important benefits and enhanced customer service. Regarding Ms.
6 Alexander's issues with our proposed tariff offerings, I will thoroughly explain why
7 each offering was chosen and how they stand to benefit customers. I will also show
8 how the results from our pilot offerings are statistically sound and why her arguments
9 to the contrary are without merit. Additionally, I will rebut Ms. Alexander's claim
10 that the installation of AMI meters will result in a degradation of consumer
11 protections by showing that we are in compliance with both the Commission's rules
12 for Disconnection of Service (OAC 165:35-21) and Final Order 589969 issued in
13 Cause No. PUD 201100083. Lastly to Ms. Alexander's testimony, I will explain why
14 her recommended disallowance of the costs associated with our distribution
15 automation (DA) and Volt/Var Optimization (VVO) programs should be wholly
16 rejected by describing how both programs are showing favorable operating results,
17 thus benefiting customers.

18

19 II. PSO'S PLAN CONFORMS WITH THE REQUIREMENTS SET FORTH BY
20 PUD WITNESS TONYA HINEX-FORD

21 Q. CAN YOU PLEASE PROVIDE AN OVERVIEW OF MS. HINEX-FORD'S
22 TESTIMONY?

1 A. Yes. Overall, Ms. Hinex-Ford recognized the customer benefits of a full AMI
2 deployment, including a customer web portal for consumer education, consumer
3 energy savings, remote connect/disconnect capability, power outage detection,
4 remotely read meters on demand, voltage interval reading, and temperature alarms;
5 and notably she testifies that “the smart grid is believed to increase both the reliability
6 and efficiency of the grid.” (at 8-9, 12). And although Ms. Hinex-Ford recognizes the
7 benefits of AMI throughout her testimony, she concludes that PUD does not
8 recommend approval of the project and instead emphasizes three items that should be
9 contained within future proposals. Specifically, she recommends that the following
10 elements be included in subsequent proposals: “guaranteed savings on O&M
11 expected savings associated with labor, vehicles, and overheads; effective
12 pricing/technology combination for customers; and for those customers that do not
13 have internet access and have an AMI meter, a Home Energy Report be made
14 available free of charge specifically to LIHEAP and Senior Citizens.”

15 Q. DOES YOUR PROPOSAL ADDRESS THE REQUIREMENTS OF MS.
16 HINEX-FORD ?

17 A. Yes. Our proposal satisfies each element set forth by Ms. Hinex-Ford as I will detail
18 below.

19 A. GUARANTEED SAVINGS

20 Q. DO YOU SUPPORT MS. HINEX-FORD’S RECOMMENDATION TO
21 GUARANTEE ANY COST SAVINGS RESULTING FROM PSO’S PROPOSED
22 AMI DEPLOYMENT?

1 A. Yes. Ms. Hinex-Ford highlighted the \$5.0 million in operations and maintenance
2 (O&M) savings that I described in my direct testimony that will result from labor,
3 vehicles, and overheads during the deployment period. PSO will guarantee this
4 \$5.0 million in O&M savings during the three-year deployment period and an
5 additional \$6 million in O&M savings in the first year after deployment, which totals
6 \$11 million in guaranteed savings over four years. Pursuant to Company witness
7 David P. Sartin's direct testimony, PSO would recover the costs of the AMI
8 deployment net of the guaranteed savings through a rider, which would remain in
9 effect until the first base rate case after full deployment. At that time, the costs as
10 well as these savings would be included in base rates.

11 Q. PLEASE PROVIDE ADDITIONAL DETAILS ON THESE GUARANTEED
12 SAVINGS.

13 A. PSO's Meter Revenue Operations (MRO) organization currently has 111 field
14 employees and contractors (59 meter reader and 52 field specialists) that perform
15 meter reading and field orders (i.e. meter connect/disconnect orders, replace
16 single-phase meters, and move in/out orders). Once PSO has completed its AMI
17 deployment, PSO's MRO organization would be reduced by approximately 83 field
18 employees. This reduction of 83 field MRO employees equates to a 75 percent
19 reduction in existing staffing, and would be accompanied by a similar reduction in
20 vehicles and overheads. This is approximately \$47.6 million of loaded labor and
21 vehicle savings on a net present value (NPV) basis over a 15-year period.

1 Q. HOW DOES PSO'S GUARANTEED SAVINGS LEVEL COMPARE TO THE
2 SAVINGS GUARANTEED BY OKLAHOMA GAS AND ELECTRIC COMPANY
3 (OGE) IN CAUSE NO. PUD 201000029?

4 A. From a savings perspective, OGE guaranteed \$22.3 million in operational benefits
5 during their four-year deployment period.¹ As I have stated, PSO is guaranteeing
6 \$11.0 million in savings over the same timeframe. Differences in the amount of
7 savings between OGE and PSO are primarily due to the number of meters at each
8 company, where OGE reportedly replaced 792,000 meters with an AMI meter, and
9 PSO has approximately 554,000 meters. Since OGE has more meters, it would have
10 needed more meter reading and associated staff than PSO, which created a greater
11 savings opportunity for OGE. In addition, there are differences in the number of
12 meter readers per customer of each company, which are based on the unique
13 characteristics of each company's customer group and each company's practices of
14 reading meters. For these reasons, the number of meter reader employee reductions
15 OGE reported was 120, while PSO has 59 meter reader reductions. OGE estimated a
16 reduction of approximately 200 full-time positions within the company by the end of
17 its deployment period.² As I stated above, PSO anticipates a reduction of
18 approximately 83 full-time positions, or 75 percent of the field staff. Based upon a
19 high-level comparison of staffing and associated reductions, the amount of
20 guaranteed O&M reductions by both companies is comparable.

¹ Direct Testimony of Howard Motley, March 15, 2010, at 8. Cause No. PUD 201000029.

² Direct Testimony of Jesse Langston, March 15, 2010, at 9. Cause No. PUD 201000029.

1 B. EFFECTIVE PRICING AND TECHNOLOGY COMBINATIONS

2 Q. DOES PSO'S PLAN ADDRESS MS. HINEX-FORD'S REQUIREMENT OF
3 EFFECTIVE PRICING AND TECHNOLOGY COMBINATIONS?

4 A. Yes. As discussed in my Direct Testimony, PSO proposes to carry forward from the
5 pilot projects both the Time of Day (TOD) and Direct Load Control (DLC) pricing
6 offerings because they resulted in the highest participation and savings for customers
7 during the pilot phases. These two voluntary programs also allow customers the
8 greatest flexibility to participate in either one or both of the programs. In terms of
9 technology, PSO proposes to offer a thermostat rebate program to assist customers in
10 purchasing a qualifying programmable thermostat, compatible with the programs.
11 Ms. Hinex-Ford's recommendation aligns with PSO's goal of implementing tariffs
12 and voluntary consumer programs, which will help PSO's customers realize the
13 benefits of AMI. This recommendation also aligns with PSO's thermostat rebate
14 program pilot, which will provide enrolled customers incentives to control their
15 electric usage through the use of an easy-to-understand and market-driven in-home
16 device.

17 Q. WILL YOU PLEASE EXPLAIN THE TOD PROGRAM?

18 A. Yes. The TOD (SMART Shift) tariff will send price signals about the costs of
19 providing power at different times of day during the peak season. The general
20 premise of this tariff is the recognition that it is more expensive to provide electric
21 energy during certain hours of certain days. This tariff provides an incentive for
22 customers to shift electric use from peak periods to non-peak hours, which permits
23 customers to save on energy costs, and it is easy for customers to understand.

1 Q. WILL YOU PLEASE ALSO EXPLAIN THE DLC OFFERING?

2 A. Under the DLC offering, PSO will provide enrolled customers with incentives to
3 allow PSO to control their Air Conditioning (A/C) during peak periods. The DLC
4 tariff provides a customer with a \$2.50 bill credit per A/C unit that is controlled per
5 event. The customer can opt out of the event at any time via their thermostat without
6 penalty. PSO can call up to 16 events Monday through Friday during the months of
7 June through September and each event can last no longer than 5 hours. The
8 customer has the opportunity to receive up to \$40 per A/C unit controlled per on peak
9 season.

10 Q. PLEASE DESCRIBE THE THERMOSTAT REBATE PROGRAM.

11 A. PSO proposes to offer a thermostat rebate program to assist customers who choose to
12 enroll in the TOD and/or DLC program. The rebate will apply to a qualifying
13 programmable thermostat.

14 For 2015, PSO will offer rebates totaling \$400,000 and \$2,000,000 in 2016,
15 based upon the forecasted customer enrollments. The rebate will be \$150 per
16 thermostat with a maximum of two rebates per household. Once the pilot phase is
17 completed, PSO will continue the rebate program in some form.

18 Q. WHILE MS. HINEX-FORD DID NOT MAKE A SPECIFIC RECOMMENDATION
19 WITH REGARD TO TECHNOLOGY, SHE REFERENCED PROVIDING FREE
20 IN-HOME DEVICES (I.E., COMPANY-OWNED DEVICES). WHY IS PSO
21 PROPOSING THE REBATE PROGRAM RATHER THAN PROVIDING FREE,
22 COMPANY-OWNED DEVICES?

1 A. Offering rebates versus company-owned devices is based on the pilot experience of
2 PSO owning, installing, and maintaining in-home technology, and market research
3 that indicates this is the prevailing approach in the market. As discussed in the
4 discovery response to AARP 4-2, the following is just a sampling of utilities
5 employing the rebate approach: ComEd, National Grid, San Diego Gas & Electric,
6 Pacific Gas and Electric Company, Southern California Edison, Florida Power &
7 Light Company, Xcel Energy, and Austin Energy.

8 In providing rebates for commercially available thermostats, PSO is not
9 directly competing with HVAC companies on the installation and maintenance of
10 thermostats. This approach also reduces the ongoing costs that would otherwise be
11 associated with PSO installing, owning, and maintaining thermostats. Further,
12 customers owning and maintaining the in-home technology should be more engaged
13 in the program.

14 Q. MS. HINEX-FORD'S TESTIMONY, AS WELL AS PUD WITNESS LUIS SAENZ,
15 REFERS TO PSO'S VARIABLE PEAK PRICING RESIDENTIAL SERVICE
16 (VPPRS) PILOT TARIFF. WHY DID PSO DECIDE NOT TO CARRY
17 FORWARD THIS TARIFF?

18 A. As I described in multiple discovery responses, PSO customers participating in the
19 VPPRS did not experience a similar level of savings as the participants of the TOD
20 and DLC offerings did. Based on that experience, PSO's proposal is to focus on the
21 two tariffs that have proven to produce the most savings and choices for customers.
22 With that said, if Ms. Hinex-Ford provides an explanation of why the tariff is
23 necessary—despite the less than favorable results experienced during the pilot—

1 beyond what appears to be OGE's experience in 2011 with a similarly named tariff,
2 then PSO will consider additional tariffs going forward.

3 Q. WHEN WILL THE ABOVE-DESCRIBED TARIFF OFFERINGS AND THE
4 THERMOSTAT REBATE PROGRAM BE AVAILABLE TO CUSTOMERS?

5 A. All of the programs will be available during the implementation of AMI meters. By
6 that I mean that once an AMI meter is installed on a customer's premises, beginning
7 in January, 2015, the customer will be able to enroll in one or both of the programs
8 for the 2015 on-peak season.

9 C. HOME ENERGY REPORTS

10 Q. WHAT IS MS. HINEX-FORD'S RECOMMENDATION CONCERNING FREE
11 HOME ENERGY REPORTS?

12 A. Ms. Hinex-Ford recommends making a Home Energy Report available free of charge
13 to those customers without internet access, namely LIHEAP eligible customers and
14 Senior Citizens. She notes that OGE agreed to make available Home Energy Reports
15 to customers without internet access, and that the report is free to customers
16 qualifying for LIHEAP or those qualifying for OGE's Senior Citizen Program.

17 Q. DOES PSO PLAN TO OFFER HOME ENERGY REPORTS?

18 A. Yes, PSO fully supports this recommendation and will provide a home energy report
19 to customers who make a request and who otherwise do not have access to PSO's
20 customer web portal. Importantly, the reports will be made available free of charge to
21 LIHEAP qualifying and senior citizen customers, as well as any other customers
22 without internet access that request a home energy report.

1 III. CONTRARY TO THE ASSERTIONS OF MS. ALEXANDER, PSO'S
2 PROPOSAL YIELDS SIGNIFICANT BENEFITS FOR CUSTOMERS

3 Q. WHAT IS YOUR RESPONSE TO MS. ALEXANDER ON THE SUBJECT OF
4 COST SAVINGS? IS PSO'S PROPOSED AMI DEPLOYMENT
5 COST-EFFECTIVE AND LIKELY TO GENERATE SAVINGS THAT WILL
6 BENEFIT PSO'S CUSTOMERS?

7 A. Yes. PSO's program will generate savings that include, in part, reductions in bad
8 debt, theft, and consumption on inactive meters, billing and call center reductions,
9 energy reductions associated with a Pre-Pay program, and energy and peak load
10 reductions stemming from tariffs and consumer programs. Together, the quantifiable
11 savings result in a positive net present value (NPV) of over \$7 million. Further, there
12 are numerous customer quality of service benefits that are not easily quantifiable but
13 undoubtedly beneficial to customers.

14 Q. WILL YOU PLEASE EXPLAIN HOW ONE CAN ENSURE THAT PSO'S
15 PROGRAM IS COST-EFFECTIVE?

16 A. Yes. As discussed in my direct testimony, the estimated total project capital cost is
17 approximately \$132.9 million. In addition to the capital cost, an estimated \$15.5
18 million in incremental O&M is also needed over the three-year deployment period.
19 The \$132.9 million amount includes \$13.2 million in capital investment included in
20 the test year associated with the pilot program, which included the deployment of
21 approximately 31,500 AMI meters. Figure 1 summarizes the cost of the project.

1

Figure 1

Total Project 3 year Costs		
Project Component	Capital	O&M
AMI	\$119,700,000	\$15,500,000
Consumer Programs	\$0	\$5,950,000
Test Year Capital Investment	\$13,200,000	\$0
Guaranteed Savings*	\$0	(\$11,000,000)

2

* For the first four years.

3

Figure 2 summarizes the 15-year (life of assets) net present value for the revenue requirement and quantifiable benefits, which shows AMI produces net benefits to customers of \$7.4 million. This analysis does not include the qualitative benefits that I will more fully discuss later in my testimony.

4

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Figure 2

AMI Program	15-year Net Present Value
Revenue Requirement	(\$176.5 million)
Consumer Programs	(\$16.2 million)
Avoided Capacity Additions	\$113.6 million
Field Labor/Fleet	\$47.6 million
Bad Debt, Theft, Consumption on Inactive Meters, and Obsolete Meter Avoidance	\$35.3 million
Billing/Call Center	\$0.7 million
Other	\$2.9 million
Total	\$7.4 million

8

Q. CAN YOU PLEASE ELABORATE ON THE QUANTIFIABLE BENEFITS FROM FIGURE 2, BEGINNING WITH THE \$113.6 MILLION OF SAVINGS ASSOCIATED WITH AVOIDED CAPACITY REDUCTIONS?

9

10

11

A. Yes. The overall expected benefit associated with demand and energy reductions associated with Pre-Pay and consumer programs is avoided capacity costs. PSO projects that due to the demand and energy reductions associated with the Pre-Pay

12

13

1 and consumer programs, PSO would be able to effectively eliminate the need for
2 approximately 82 MW of capacity additions. These avoided capacity costs include
3 the avoided cost of the generation investment, lower fuel costs, and lower fixed O&M
4 expenses with the avoided generation plants. If Pre-Pay and consumer programs
5 were not implemented, these capacity additions would be projected to cost customers
6 approximately \$113.6 million on an NPV basis over a 15-year period.

7 As I described in my direct testimony, PSO plans to implement a voluntary
8 Pre-Pay Billing Program and will be seeking approval later this year. This is contrary
9 to the testimony of Ms. Alexander who incorrectly interpreted our decision not to
10 deploy Pre-Pay in 2011 in a pilot area as a decision to never go forward with the
11 program.

12 The Pre-Pay Billing Program allows customers to pay for their electric service
13 in advance, and track their usage along with their account balance. Benefits from the
14 Pre-Pay program include having additional choices for customers in establishing a
15 pre-pay account and energy reductions, similar to other industries such as cellular
16 phones. These benefits are based upon experiences other utilities have with Pre-Pay
17 programs, such as Salt River Project, Arizona Public Service, and Oklahoma Electric
18 Cooperative. These utilities have reported that customers have reduced energy usage
19 over 10 percent due to energy awareness and have reported an increase in overall
20 customer satisfaction by customers being in more control and providing additional
21 billing choices instead of post-usage.³ Based upon the programs at other utilities,

³ A review of Pre-Pay Programs for Electricity Service, California Public Utilities Commission, Policy and Planning Division Policy Paper, July 26, 2012.

1 PSO assumes that 10 percent of eligible residential customers will participate in a
2 Pre-Pay program in the first 5 years.

3 Based upon the pilot results and the ability to market to additional customers,
4 PSO estimates that 8 percent of the eligible customers will participate in voluntary
5 AMI-enabled tariffs and customer programs (Time-of-Day and Direct Load Control
6 Programs) that provide the customer the opportunity to save money by shifting usage
7 from high-cost periods to low-cost periods or by reducing demand at times of PSO
8 company peaks in the first five years of the program. The focus of these programs is
9 to reduce energy consumption during peak periods. Based upon the pilot results, an
10 average of 1.8 kW reduction during the peak period was realized for each residential
11 customer participating in the DLC program and 0.3 kW for the TOD program.

12 Q. PLEASE DESCRIBE THE \$47.6 MILLION OF SAVINGS RELATED TO THE
13 FIELD LABOR AND FLEET REDUCTIONS.

14 A. As previously described, these savings are from the reduction in labor, vehicles, and
15 overheads that will occur because of the installation of AMI meters. Today, PSO's
16 field staff of 59 meter readers reads over 6.4 million meters annually. Once AMI is
17 fully implemented, it will no longer be necessary for meter readers to enter a
18 customer's property to read the meter on a monthly basis. There will also be
19 reductions associated with the 52 specialists PSO currently employs, who perform
20 field orders (i.e. meter connect/disconnect orders, replace single-phase meters, and
21 move in/out orders). In 2013, there were approximately 360,000 orders that involved
22 these specialists. Each of these orders requires a visit to the customer's property, but
23 the majority of these visits will not be needed with the installation of AMI.

1 Also, PSO's field staff and specialists drove over two million miles in 2013.
2 Reducing this amount of staff will result in fewer vehicles and less mileage being
3 driven.

4 Q. WILL YOU PLEASE ADDRESS THE \$35.3 MILLION OF SAVINGS RELATED
5 TO BAD DEBT, THEFT, AND CONSUMPTION?

6 A, The implementation of AMI will allow for a reduction in costs related to bad debt,
7 theft, and consumption on inactive meters through its remote disconnection
8 capability.

9 PSO investigated over 3,800 theft cases in 2013 and anticipates additional
10 cases will be identified through the use of AMI. Based on industry benchmarking,
11 PSO believes that energy losses resulting from theft could be as much as three percent
12 of the company's annual gross revenue. However, taking a more conservative
13 approach, PSO has assumed that its electric energy theft losses are approximately 0.5
14 percent of gross revenue,⁴ which is \$19.8 million.

15 PSO also believes that it can reduce bad debt by approximately 50 percent,
16 amounting to \$13.8 million of savings. Through the implementation of a Pre-Pay
17 program, PSO anticipates additional reductions in bad debt based upon experiences at
18 other electric utilities.

19 Obsolete meter avoidance yields savings of \$1.2 million by avoiding the cost
20 of replacing meters during the deployment period that had reached the end of their

⁴ Deciding on "Smart" Meters: The Technology Implications of Section 1252 of the Energy Policy Act of 2005; Edison Electric Institute, September 2006 p 13,14.
Revenue Metering Loss Assessment, EPRI, Palo Alto, CA, Arizona Public Service Co., Phoenix, AZ, National Grid USA, Worcester, MA, South Carolina Electric & Gas., Columbia, SC, and Baltimore Gas & Electric., Baltimore, MD 2001.1000365.

1 useful lives. That is, some of the meters that are part of PSO's system are in need of
2 repairs. By replacing these meters with an AMI meter during deployment, the repair
3 costs associated with these meters are avoided.

4 Also, having the ability to remotely disconnect meters allows for the reduction
5 in consumption on inactive meters, producing savings of \$0.4 million.

6 Combined, the reduction in theft, bad debt, consumption on inactive meters,
7 and obsolete meter avoidance will result in approximately \$35.3 million of benefits
8 on an NPV basis over a 15-year period.

9 Q. PLEASE ALSO DESCRIBE THE BILLING AND CALL CENTER EFFICIENCIES
10 AS WELL AS THE SAVINGS THAT COMPRISE THE "OTHER" CATEGORY.

11 A. AMI provides billing and call center efficiencies that will enable employees to
12 address more inquiries in a more expeditious manner. Call center representatives will
13 have real-time access to meter data, which will help them discuss actual usage
14 information with customers. When a customer calls about a power outage, the real-
15 time access also will enable call center representatives to determine whether the
16 outage is due to a PSO outage or to an issue on the customer side of the meter.
17 Billing and call center efficiencies would result in approximately \$0.7 million of
18 benefits on an NPV basis over a 15-year period.

19 "Other" benefits include a reduction in injuries and motor vehicle accidents by
20 having 75 percent fewer field employees. Also, AMI provides a benefit to the utility
21 in providing a more automated, lower-cost means of obtaining and managing
22 customer interval usage data needed for ratemaking, planning, special billing, and
23 demand response program implementation and evaluation. This in turn could lead to

1 a reduction in capacity and reliability planning resources. The 15-year NPV
2 associated with these is approximately \$2.9 million.

3 Q. NOW THAT YOU HAVE DESCRIBED THE QUANTIFIABLE BENEFITS, CAN
4 YOU PLEASE COVER THOSE BENEFITS MORE QUALITATIVE IN NATURE?

5 A. Yes. As I have previously described in my direct testimony, there are a number of
6 qualitative benefits for customers once AMI has been deployed. The following list
7 provides additional information pertaining to the customer benefits resulting from
8 AMI.

- 9 • Increased customer education and satisfaction due to Customer Web Portal and
10 related tools – The customer web portal contains customer education information, as
11 well as decision-making features to help customers save on their electric bills:
 - 12 ○ Customers have the information, such as near real-time data and usage
13 information, and tools to proactively reduce and manage energy usage;
 - 14 ○ Forecasted bill feature to help make informed energy decisions by granting
15 customers the ability to see energy usage, bill-to-date information, and
16 forecasted bill information. This allows customers to proactively make
17 energy consumption changes instead of responding reactively to an
18 after-the-fact bill;
 - 19 ○ Customers have the ability to make rate comparisons by viewing prior usage
20 patterns and comparing this information with different tariffs, such as a
21 voluntary TOD tariff to determine if they would have saved money on a TOD
22 tariff based upon prior usage patterns and potential savings if usage patterns
23 change;
 - 24 ○ Customers have the ability to track and compare usage against prior periods
25 with a temperature overlay by having access to historical usage and near
26 real-time usage information; and
 - 27 ○ Ability to request a home energy report for customers who do not have
28 internet access.
 - 29

- 1 • Power outage detection through real-time access:
 - 2 ○ Outage order creation will be implemented as meters are deployed, which will
 - 3 quicken the dispatch of outage restoration resources and provide better
 - 4 communications about the restoration efforts; and
 - 5 ○ The ability to poll meters after an outage helps to ensure power is restored or
 - 6 identifying nested/pocket outages in large outage events, such as a feeder
 - 7 outage.
- 8 • Additional and improved metering activities:
 - 9 ○ The ability to remotely read meters on demand for move-in/outs, and billing
 - 10 inquiries, which is more timely and convenient for customers;
 - 11 ○ The ability to perform credit reconnects automatically with AMI meters. In
 - 12 2013 PSO had performed over 40,000 credit reconnects and with the
 - 13 implementation of AMI over 90% of these orders would have been processed
 - 14 automatically, typically within minutes from when a payment is made versus
 - 15 up to 24 hours for non-AMI meters;
 - 16 ○ Ability to perform residential service connections remotely, which helps to
 - 17 accommodate customer moves. In 2013, PSO performed over 88,000 connect
 - 18 orders and with the implementation of AMI almost 90% of these orders would
 - 19 have been processed automatically within minutes versus up to 24 hours for
 - 20 non-AMI meters;
 - 21 ○ Virtual elimination of estimated meter readings due to access issues,
 - 22 inclement weather, or hazardous conditions. In 2013, PSO had over 200,000
 - 23 skipped readings, which resulted in 190,000 estimated bills to customers.
 - 24 Once AMI is fully implemented, it will no longer be necessary for meter
 - 25 readers to enter a customer's property to read the meter on a monthly basis.
 - 26 Since weather, access, and staffing schedule issues will be avoided, skipped
 - 27 reads and associated estimated bills will be significantly reduced;
 - 28 ○ A reduction in billing complaints over time as estimated meter readings are
 - 29 replaced by actual readings, which improves the accuracy of customers' bills;
 - 30 ○ PSO resources generally no longer need to access customer yards on a
 - 31 monthly basis to read the meter or perform service orders, which can cause
 - 32 inconveniences for customers. As mentioned earlier, PSO meter readers and
 - 33 field specialist made over 6.75 million visits to individual customer yards in
 - 34 2013; and
 - 35 ○ Deploying AMI reduces the number of customer premises visits annually, and
 - 36 subsequently reduces the number of hazards PSO personnel are exposed to

- 1 each year. PSO estimates that AMI will help to avoid a number of safety
2 hazards that include over 24,000 accounts coded bad dog, vicious dog, or pit
3 bull, which accounts for 288,000 opportunities avoided annually, and an
4 additional 130,000 accounts coded having a dog, which is an additional 1.5
5 million avoided hazards.
- 6 • Quality of Service improvements as a result of AMI's functionality:
 - 7 ○ Temperature alarms that identify high temperatures in the meter, which
8 confers the ability to investigate and proactively correct issues, resulting in
9 avoiding potential customer outages;
 - 10 ○ Equipment loading can be recognized and proactively corrected prior to an
11 outage occurring or a customer is even aware of an issue. For example, the
12 AMI meter will capture 15-minute average voltage data, and with analytics,
13 can identify trends where voltage increased over time, which may be
14 indicative of a transformer on the verge of failing or other service quality
15 issues. These locations can be proactively identified, and equipment can be
16 replaced prior to the transformer failing and causing an outage; and
 - 17 ○ Power quality investigations are aided through interval kWh, kVAh, voltage
18 information, and meter events provided by AMI, which can help protect
19 customers.
 - 20 • Environmental impacts can be mitigated:
 - 21 ○ Through customer participation in PSO's consumer programs and tariffs, peak
22 and ongoing energy reductions can be achieved, which decreases carbon
23 emissions from power plants as less power is needed; and
 - 24 ○ By being able to remotely connect and disconnect service, PSO will reduce
25 the amount of truck rolls associated with these activities, which leads to a
26 decrease in vehicle emissions. In 2013, PSO field employees drove over two
27 million miles, which is anticipated to be reduced by 75 percent.
 - 28 • As a platform for the future, additional AMI functionality that has yet to be developed
29 will lead to additional benefits:
 - 30 ○ Having AMI helps facilitate the necessary infrastructure to support electric
31 vehicle charging;
 - 32 ○ Similarly, AMI helps facilitate distributed generation and net metering;
 - 33 ○ AMI will facilitate access of future customer-deployed technologies that will
34 help manage energy usage by giving customers ready access to information
35

1 provided directly from the meter. However, such technologies are still in their
2 infancy; and

3 o Ability to test new applications for other customers, such as commercial
4 demand and energy reduction programs.

5 Q. MS. ALEXANDER CONTENDS THAT PSO HAS NOT ADEQUATELY
6 DOCUMENTED THE BENEFITS FROM ITS CUSTOMER PROGRAMS, NOR
7 HAS PSO GIVEN ANY “FACTUAL ANALYSIS OF COSTS AND BENEFITS.”
8 HAS PSO PROVIDED DETAILED INFORMATION ABOUT THE BENEFITS
9 ASSOCIATED WITH AMI?

10 A. Yes. PSO has provided detailed benefit information stemming from AMI’s usage in
11 PSO’s pilot, as well as the anticipated benefits of PSO’s proposed AMI deployment
12 in my direct testimony, discovery responses, as well as other documentation. The
13 only information included in my Rebuttal Testimony not previously provided is
14 PSO’s commitment to the \$11 million of guaranteed savings, the addition of the
15 avoided capacity costs into the NPV analysis, and providing additional details for
16 customer program enrollments provided in direct testimony or discovery response.

17 The following list highlights information provided in regard to AMI benefits:

- 18 • Benefits of AMI – Company witness Lewellen’ s direct testimony, pages 8-9, 13-15,
19 and 21-24;
- 20 • Cost/benefit analysis – Discovery responses AG 5-7, AARP 1-1, AARP 1-2, and
21 AARP 2-10;
- 22 • Analysis of pilot results – Company witness Lewellen’ s direct testimony, pages 9-12,
23 discovery responses AARP 1-5, AARP 2-4, AARP 2-12, and AARP 4-9;
- 24 • Additional AMI deployment cost information:
 - 25 o Customer engagement costs – discovery responses AARP 1-20, and AARP
26 1-4;

1 their monthly electric costs by potentially shifting usage from higher-price periods to
2 lower-price periods or by reducing the demand on the electrical system during peak
3 periods. From a utility perspective, a major goal of these consumer programs is to
4 lower costs and the peak demand during peak periods of high generation cost.

5 Q. WHAT WERE THE BENEFITS TO CUSTOMERS OF THE PILOT PROGRAM?

6 A. Participating customers saved money on their electric bills by reducing electric usage
7 when tariff prices were highest during peak periods when PSO's cost to serve
8 customers is at its peak, and shifted their usage to lower tariff price periods when
9 PSO's costs to serve customers is lower. These customer benefits will be extended to
10 all PSO customers with the successful implementation of AMI throughout PSO's
11 service territory. In addition to these savings, all PSO customers save from the
12 reduced cost of PSO avoiding the costly addition of new power plants.

13 Q. WHAT ISSUES DID MS. ALEXANDER HAVE WITH THE ANALYSIS AND
14 RESULTS OF THE PILOT PROGRAMS?

15 A. Ms. Alexander contends that PSO's analysis of its Smart Shift program, which
16 utilized averages, does not provide enough important information to truly evaluate the
17 results of the program (at 14). For example, Ms. Alexander states that it would be
18 important to determine whether summer bills were higher for what percentage of
19 customers and whether there are any demographic characteristics among the
20 participants that may affect the results of the program.

21 Q. PLEASE RESPOND TO THOSE ISSUES.

22 A. Analysis of demographic characteristics of participants provides little value in a load
23 impact analysis, since the programs are voluntary opt-in programs. Analysis of

1 impacts of the average of the participants opting into the program is a standard
2 industry analysis method for determining impacts achieved from a program and, as
3 the graphs in EXHIBIT DSL-2R show, the analysis provided clearly comparable and
4 meaningful results. Although detailed bill savings analysis was not presented in
5 original testimony, bill savings over the summer period for each participant were
6 analyzed and the distribution of participant bill savings was examined. As discussed
7 in my direct testimony, approximately 84% to 89% of the participants in the SMART
8 Shift Program experienced overall bill savings, while about 49% of the participants in
9 the SMART Shift Plus Program experienced bill savings. Figure 5.1 and 5.2, which
10 are part of EXHIBIT DSL-2R, provide a graphical view of those analyses for the
11 SMART Shift and SMART Shift Plus Programs, respectively, where each vertical bar
12 represents one participant.

13 Q. WHAT IS YOUR RESPONSE TO MS. ALEXANDER'S ASSERTION THAT
14 THERE IS NO EVIDENCE THAT CUSTOMERS PARTICIPATING IN THE
15 TARIFF PROGRAMS LOWERED THEIR ANNUAL USAGE?

16 A. I agree with that assertion. The SMART Shift and SMART Shift Plus Programs are
17 not intended to be energy reduction programs, but are intended to provide customers
18 an additional pricing program option under which participants have the opportunity to
19 lower their electric bill by shifting usage from higher-priced time periods to
20 lower-priced time periods. Therefore, it is not surprising that there is no indication
21 that participating customers lowered their overall usage, even in the summer
22 timeframe. As for the non-summer months, these programs did not contain any
23 provision for different prices during different price periods in the non-summer

1 months, so there was no expectation of usage reductions or usage shifts in those
2 months.

3 Q. WHAT WAS MS. ALEXANDER'S STATEMENT CONCERNING THE USE OF
4 CONTROL GROUPS AND THE PEAK LOAD REDUCTIONS REPORTED FOR
5 2012?

6 A. Ms. Alexander contends that PSO's analysis of peak load reductions associated with
7 the pilot programs for 2012 was based on a "simple" comparison to a control group of
8 customers. She then builds upon this statement and erroneously states that this data
9 lacks statistical validity because PSO did not calculate the statistical validity (at 15).
10 She then concludes that based on the lack of statistical validity and that PSO had only
11 fully utilized one year of program results, PSO cannot rely on this analysis to make
12 future projections (at 15-16).

13 Q. ARE THESE CONCERNS ABOUT STATISTICAL VALIDITY AND FUTURE
14 PROJECTIONS VALID?

15 A. No. Each control group was selected using standard experimental analysis
16 procedures. Care was exercised to ensure that the control group was a valid
17 representation of the participant group. The validity of the control group to represent
18 the participant group was verified by examining the hourly usage levels and patterns
19 in a summer period prior to the participants' enrollment in the program. Figure 6.1 of
20 EXHIBIT DSL-2R shows that comparison for the SMART Shift program. As per
21 Figure 6.1, the usage pattern is so close that it is difficult to tell there are actually two
22 separate profiles graphed. The aforementioned graphical figures provided in
23 EXHIBIT DSL-2R clearly show the methodology used provided meaningful results.

1 V. MS. ALEXANDER'S CONCERNS WITH PSO'S PROPOSED CONSUMER
2 OFFERINGS ARE WITHOUT MERIT

3 Q. PLEASE ADDRESS MS. ALEXANDER'S COMMENTS ABOUT PSO NOT
4 PROVIDING HOME ENERGY MANAGEMENT DEVICES (ALEXANDER AT
5 17-18).

6 A. For the reasons previously discussed in Section II, PSO proposes to offer significant
7 rebates to cover the majority, if not all, the cost of an in-home thermostat, rather than
8 supplying a company-owned device. Given that this is the predominant approach
9 used in the industry, Ms. Alexander's claims that not providing a "free" device will
10 result in lessened participation (from that in the pilot) are unfounded.

11 Q. WHAT CONCERNS DOES MS. ALEXANDER MAKE CONCERNING THE DLC
12 PROGRAM AND IN-HOME TECHNOLOGY?

13 A. Ms. Alexander has indicated she has concerns with PSO's DLC pilot. Specifically,
14 since PSO's DLC pilot hasn't been fully developed yet (at the time of direct
15 testimony), she is concerned about costs, benefits, and the timing of the
16 implementation (at 18). However, she is generally in favor of a DLC program that
17 relies on customer credits and rewards, but does not believe that AMI is necessary in
18 order to implement such a program (at 25). She is also concerned with what she
19 believes is a shift in responsibility for customers to pay for in-home devices and the
20 potential adverse impact this has on low-income and elderly customers' ability to
21 participate in tariffs and consumer programs (at page 23). Finally, Ms. Alexander
22 believes that an effective DLC program can be implemented that does not utilize

1 AMI. Pursuant to PSO's response to discovery request AARP 1-16, PSO agreed that
2 conceptually, it is plausible to implement a DLC program without AMI by relying on
3 smart thermostats and communication directly with those thermostats or other devices
4 via the customers' Wi-Fi network.

5 Q. PLEASE ADDRESS MS. ALEXANDER'S CONCERNS REGARDING THE DLC
6 PILOT IN CONJUNCTION WITH PSO NOT PROVIDING A FREE
7 THERMOSTAT.

8 A. Although implementation of DLC programs without AMI is being piloted at a
9 number of utilities, in its present form, customers would not be able to participate in
10 any of the other AMI-enabled customer programs or receive any of the benefits
11 associated with AMI that I have discussed in detail. Without AMI meter data, it is
12 more difficult to measure the demand response of the program, and customers are not
13 provided the near real-time feedback on changes made to reduce or shift energy usage
14 during peak periods

15 For example, through use of an AMI meter, customers have access to both
16 current and historical interval data, and the ability to participate in TOD tariffs. This
17 interval data allows customers the ability to make more informed decisions about
18 their electricity usage and the resulting impact on their electricity bill.

19 In respect to shifting the costs to customers, with the rebate covering the
20 majority, if not all, the cost of the thermostat, costs are not shifted to customers and
21 there should not be a barrier for any customer class to participate in the programs.
22 For customers to participate in the TOD tariff, in-home technology is not required. In
23 addition, customers have full control of their thermostats, even during a DLC event.

1 Customers can override the controls and opt not to participate in the event without
2 penalty.

3

4 VI. PSO'S CUSTOMER EDUCATION PLAN IS BOTH
5 COMPREHENSIVE AND EFFECTIVE

6 Q. WHAT DOES MS. ALEXANDER STATE CONCERNING AN OUTREACH AND
7 EDUCATION PLAN FOR PSO'S PROPOSED AMI DEPLOYMENT?

8 A. Ms. Alexander states that PSO has not provided any outreach and education plan as
9 part of its filing that would suggest that PSO would have a higher participation rate
10 (at 19) than what it has projected. Furthermore, Ms. Alexander recommends that
11 PSO improves its education and outreach program based upon the pilot survey
12 responses and program evaluation (at 23).

13 Q. HAS PSO DEVELOPED A COMPREHENSIVE EDUCATION AND
14 COMMUNICATION PLAN TO REACH CUSTOMERS REGARDING PSO'S
15 PROPOSED AMI DEPLOYMENT BASED ON CUSTOMER FEEDBACK AND
16 OTHER FACTORS?

17 A. Yes. When this case was originally filed, PSO's customer education and
18 communication plan was still in development. As stated in the Application, PSO was
19 mandated by the Commission to file this base rate case no later than January 18,
20 2014. However, since the filing was made, PSO has completed its initial customer
21 education and communication plan, which I have included as EXHIBIT DSL-1R.
22 Based on PSO's experience and lessons learned from the pilot, as well as information
23 gleaned from PSO's sister companies and other utilities that have deployed AMI, we

1 are confident that our plans to reach customers will be effective, proactive, and
2 engaging. During the pilot program, the opportunity to provide customer education
3 on programs was limited. For example, mass media such as newspaper, radio and
4 television, or public events such as home and garden shows, could not be used since
5 the message would be shared with a much larger group of ineligible customers, which
6 could have potentially created confusion. The customer education program will help
7 our customers understand our proposed AMI deployment, what they can expect once
8 they have AMI, how they can participate in AMI-enabled tariffs and programs,
9 processes available if they have questions or concerns, and the expected benefits of
10 AMI.

11 Q. PLEASE PROVIDE MORE DETAILS ABOUT PSO'S CUSTOMER EDUCATION
12 AND COMMUNICATION PLAN.

13 A. Prior to receiving an AMI meter, PSO's customers will receive messages through
14 numerous communication channels as part of PSO's communication plan. These
15 communications will include clear and concise information, and are designed to
16 manage customer expectations and ensure that customers understand the installation
17 process. These communications will take the form of customer letters, phone
18 messages, door hangers, customer web portal communications, and other external
19 communications (bill boards, community newspapers, and magazines). Examples of
20 these communications and their content are included in EXHIBIT DSL-1R.

21 The education plan will communicate the benefits of AMI to customers as
22 well as the AMI deployment schedule. The overall objective of the education plan is
23 to help customers reap the benefits of AMI, improve the customer experience, and

1 provide easy to understand information about the tariffs and customer programs to
2 facilitate enrollment. The education plan will utilize consumer group meetings and
3 community events, a Mobile Exhibit Trailer, as well as internal communications to
4 train and educate PSO employees so that they may better serve our customers. PSO
5 is especially excited about its Mobile Exhibit Trailer, which will provide interactive
6 opportunities for our customers to learn about AMI, the customer web portal and the
7 associated tariffs and customer programs. The Mobile Exhibit Trailer will be
8 traveling across our service territory to fairs, schools, home and garden shows, and
9 festivals allowing an invaluable chance to provide face-to-face and hands-on
10 education to our customers.

11

12 VII. PSO'S DISCONNECTION PROCESS

13 Q. WHAT ARE MS. ALEXANDER'S CONCERNS REGARDING THE
14 DISCONNECTION PROCESS FOR CUSTOMERS WITH AMI?

15 A. Ms. Alexander is concerned that the installation of AMI may result in the degradation
16 of consumer protections associated with disconnections for nonpayment (at 30). For
17 example, Ms. Alexander believes that the installation of AMI would eliminate any
18 required premises visit, or in-person contact attempts (at 28), which she feels is one
19 such consumer protection.

20 Q. WILL PSO'S PROPOSED AMI DEPLOYMENT REDUCE OR DEGRADE
21 CONSUMER PROTECTION POLICIES ASSOCIATED WITH DISCONNECTION
22 FOR NONPAYMENT?

1 A. No. First and foremost, as PSO discussed in discovery response AARP 1-21, PSO's
2 procedures regarding disconnection for nonpayment strictly follow the requirements
3 set forth in OAC 165:35-21-Disconnection of Service and for those customers with
4 AMI meters, Order No. 589969 of Cause No. PUD 201100083. For residential
5 customers, regardless of the type of meter they have, if a bill is not paid by the due
6 date, the first disconnect notice is mailed to customers with their next month's bill.
7 This notice satisfies the minimum ten-day requirement found in OAC
8 165:35-21-20(b). To satisfy the minimum 48-hour notice required by OAC 165:35-
9 21-20(c), a second disconnection notice is scheduled to be mailed 12 business days
10 after the first notice. Additionally, though not required by the Commission's Electric
11 Rules, PSO contacts customers by telephone 48 hours prior to disconnect to notify
12 them that they need to contact PSO regarding their service. When the customer
13 contacts PSO, they are then informed that their service is subject to disconnect.

14 The only premises visit that PSO is required to make is to leave a disconnect
15 notice at the premises at the time of disconnection for those customers without an
16 AMI meter. As per PSO's response to discovery request AARP 1-22, PSO generally
17 does not attempt contact with the residential customer at the time of the disconnection
18 of service. As can be seen from PSO's disconnection policies, customers are given
19 ample communications and time to avoid the disconnection. Furthermore, if a
20 customer with an AMI meter is disconnected for nonpayment, having an AMI meter
21 allows them to have their service restored within minutes instead of up to 24 hours
22 once payment has been made at an authorized pay station.

1 A. Ms. Alexander recommends that the Commission should reject PSO's attempts to
2 recover the costs of DA and VVO because of what she perceives to be a failure on the
3 part of PSO to provide performance results that show that these technologies will
4 provide benefits to PSO's customers (at 8).

5 Q. HAVE DA AND VVO PROVIDED THE BENEFITS TO CUSTOMERS THAT
6 PSO ANTICIPATED?

7 A. Yes. The Owasso pilot did create the results and benefits originally anticipated by
8 PSO. The Owasso pilot results, along with the south Tulsa DA project and
9 information from other utility experiences, will be used by PSO to develop an overall
10 grid management strategy later this year.

11 For DA, PSO originally installed a first generation distribution automation
12 scheme in South Tulsa that has been operating very successfully for over five years,
13 allowing PSO to avoid approximately 1.3 million customer outage minutes. DA has
14 been successfully used for a number of years across the electric utility industry in
15 various forms, with many industry studies on its benefits. For the Owasso pilot, the
16 purpose of installing DA was to evaluate the next generation of DA equipment and
17 how to integrate this independent technology on the same circuits with VVO
18 technology.

19 Concerning VVO, the purpose of the Owasso pilot was to develop VVO
20 technology with an industry leading company and evaluate their solution versus other
21 solutions being developed across the electric utility industry. The VVO system in
22 Owasso has only been operational since June of 2012, less than two years, including
23 multiple enhancements and two independent evaluations. The method for evaluating

1 the technology is to perform alternating day on/off measures for over 90 days, then
2 model the data and evaluate the day-on versus day-off performance. The evaluation
3 was performed by Pacific Northwest Nation Labs (PNNL), which took several
4 months and was provided in early 2013. The first year test results were less than
5 expected, but not uncommon in developing new technology.

6 A number of improvements were identified with the anticipation of improving
7 the 2013 summer performance. Enhancements to the VVO system were made in the
8 spring of 2013 and another day on/off evaluation was done in the summer of 2013,
9 which included modeling over 150 million data points by PNNL. The final report for
10 the 2013 evaluation was delivered in March 2014 and showed significant
11 performance improvements between the 2012 evaluation and the 2013 evaluation.
12 These results highlight the potential benefits of a well-functioning VVO system.
13 These improvements include an energy reduction on a per-feeder-basis of
14 approximately 2% to 7%. Also, the analysis showed that the VVO successfully
15 controlled power factor at the feeder level to within 0.02 of unity power factor. This
16 evaluation was provided in discovery to all parties as part of PSO's response to
17 AARP 4-12, yet recognition of it was noticeably absent from the testimony of Ms.
18 Alexander. There are two additional studies that PNNL is performing (see my direct
19 testimony at 7) that will be available in the summer of 2014.

IX. CONCLUSION

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Q. DO YOU HAVE ANY FINAL REMARKS BEFORE CONCLUDING YOUR TESTIMONY?

A. Yes. No party has provided any valid, unrebutted reason as to why PSO's AMI deployment should be delayed. For the last three years, PSO has successfully installed, operated, and evaluated multiple AMI pilot areas through a methodical, phased-in approach. Because of this, we have benefitted from lessons learned and added experience with the new technologies, resulting in tremendous benefits for our customers. PSO's approach has also allowed us to realize a significant drop in meter prices (over 25 percent) in the last three years. As I already discussed, the all-in cost per customer of our AMI program is 21% less than that approved for OGE's AMI program. With the penetration rate of AMI meters across the country exceeding 50%, now is the time for PSO to move forward with AMI for the benefit of our customers.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.



PSO
Advanced Metering Infrastructure System (AMI)
Customer Communication and
Education Plan

May 23, 2014

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Purpose and Mission

The purpose of this document is to provide a communication plan for the deployment of the Advanced Metering Infrastructure System (AMI) in Public Service Company of Oklahoma's (PSO) service territory. This communication plan will help raise awareness and increase education to customers on the benefits of AMI.

AMI Background Overview

PSO's gridSMART AMI project was part of the initiative originally launched by its parent company, AEP, in 2007 to modernize PSO's electric system and prepare PSO for the growth of customer opportunities. The initial gridSMART initiative featured:

- Advanced Metering Infrastructure System (AMI),
- Customer programs designed to promote energy efficiency and conservation,
- Distribution grid management including:
 - Distribution automation, and
 - Voltage Optimization

The AMI project is an extension of the 2010 gridSMARTSM Owasso pilot program and since that time, PSO has been able to evaluate the AMI grid technologies in Owasso and realize the technology benefits. Based upon the favorable customer response of the Owasso pilot program, additional AMI meters were deployed in 2012 for the University of Tulsa Campus, City of Okmulgee, and the City of Sand Springs.

Digital meters capture more detailed usage information that can be used to develop programs to inform customers about their usage patterns and offer new pricing programs, both of which are intended to help consumers manage their electricity use. Other benefits to replacing the existing mechanical meters to a two-way communication system include reducing operational costs, such as costs associated with reading meters and connecting/disconnecting meters. The new digital meters will also allow for enhancements in outage detection.

Scope of the Project

PSO has proposed extending the deployment of AMI to cover its entire 30,000 square mile service territory for approximately 520,000 customers over a three-year period, beginning in September 2014 and continuing through July 2016. This will bring PSO to a full deployment of approximately 550,000 AMI meters. The deployment timing for the completion of this \$130 million project could change pending regulatory approval.

PSO's objectives are to:

- Educate PSO customers on AMI and its benefits,
- Educate PSO employees,
- Educate public officials, the media, and others who are likely to interact with customers during the deployment process,
- Provide a timeline of the AMI meter installation schedule and the impact to customers, and
- Begin to communicate and market customer programs January 2015.

We anticipate and remain committed to a cohesive and consistent strategic approach to the region overall, but remain open to the need for occasional adjustments and customization based on the needs and response in each community where PSO enjoys a relationship with our customers.

Implementation Plan

Deployment Schedule

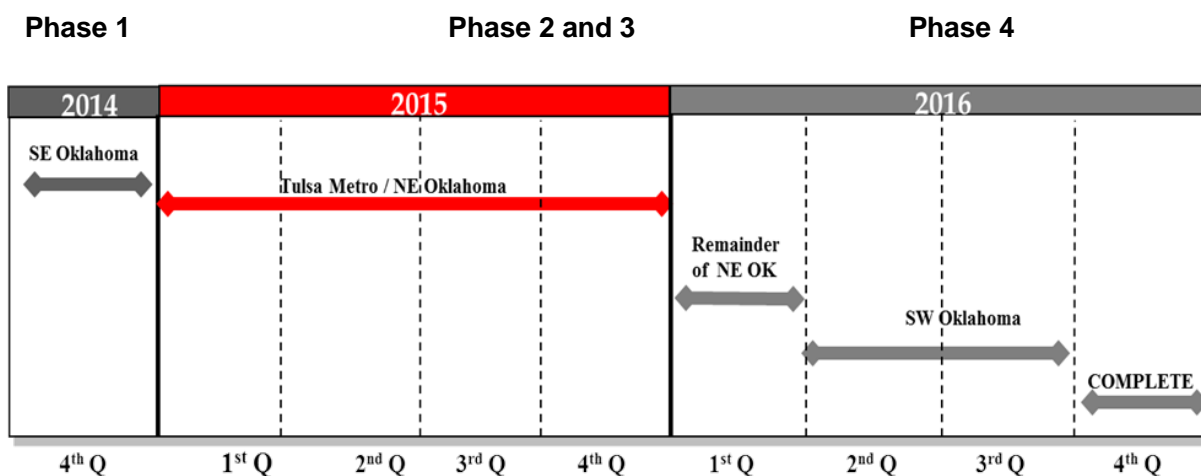
PSO's AMI deployment schedule will encompass four phases:

AMI Deployment Schedule

Phase 1	Phase 2	Phase 3	Phase 4
<ul style="list-style-type: none"> • McAlester Oklahoma Area • Installation of approximately 60,000 meters 4th Qtr. 2014 	<ul style="list-style-type: none"> • Tulsa Oklahoma Area • Installation of approximately 260,000 meters 1st Qtr. 2015 	<ul style="list-style-type: none"> • Northern Division • Installation of approximately 20,000 meters 4th Qtr. 2015 	<ul style="list-style-type: none"> • Northern/Lawton Oklahoma Area • Complete Northern Division of approximately 30,000 meters 1st Qtr. 2016 • Lawton installation of approximately 182,000 meters 2nd Qtr. 2016

Timeline

This timeline details the tactical areas and rollout sequence of Phases 1 through 4 of the AMI deployment plan. The timing of customer education and communications activities will remain flexible to respond to the shifting of AMI implementation schedules, including community-sequenced installations, pre-installation activities, and education based on differences and distinctions of each community.



AMI Customer Communication Plan

Leading up to the customer meter installations, PSO customers will be exposed to messages about digital meters through numerous communication channels. Still, once actual installations of meters begin, we cannot assume any customer level of knowledge about digital meters. Clear and concise information sent to customers in the weeks prior to installation will be designed to manage their expectations and ensure that the customers understand the installation process.

AMI Customer Communication Plan

Form of Communication	What	Why	When
Customer Letter	Initial letter informing customers of projected meter installation date.	The letter will introduce installation vendor, installation process, and benefits.	4 to 8 weeks prior to meter installation.
Phone Blast Message	A phone message to notify customers prior to meter installation that their traditional meter will be replaced with a digital meter.	Inform customers of what to expect. Educate customers on digital meter benefits.	3 to 4 weeks prior to meter installation.
Door Hanger	Door hanger will be left, informing customers they now have a new digital meter.	Reminding them about the benefits of the digital meter and access to the Customer Web Portal (PSOklahoma.com).	Once the meter is installed at each premise.

AMI Customer Communication Plan

Form of Communication	What	Why	When
Customer Web Portal Communication (PSOklahoma.com)	Website is a resource of information and education about digital meters and customer programs available.	Will have FAQs and messaging, including PSO AMI meter implementation plan, and schedule.	In the development stage.
Other External Communications	Bill Boards, Community newspapers, and magazines.	PSO Customer Communication plan will engage customers regarding digital meters where they live, work, and play throughout the PSO service territory.	July 1, 2014
PSO Mobile Exhibit Trailer	A 53-foot trailer with sides that expand to provide approximately 900 square feet of space.	Provide engaging displays and exhibit concepts that will effectively engage and educate customers about AMI and program offerings.	1 st Qtr. 2015

See Examples of the Customer Letter, Phone Blast message, and Door Hangers provided below.

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Residential Letter Example

DATE

Dear PSO Customer,

In mid-XXX, PSO will begin work to install new digital meters in your area as part of our project to upgrade the electric distribution system to new digital technology.

What You Need To Know

- A PSO contractor – VENDOR NAME -- will perform the meter replacement work at residences. VENDOR' employees will be clearly identified with photo ID badges as working for PSO. If you have any doubts about someone claiming to be a contractor working for PSO, please contact PSO's Customer Solutions Center –1-888-216-3523 for verification.
- PSO will call you up to 8-4 weeks before we plan to install the new digital meter at your address.
- After we have installed the new meter we will leave a door hanger to confirm that the work was performed and to provide you some additional information about the device.
- You do not need to be at your home for the installation. All of the necessary work will be performed outside. We will need access to the electric meter, but there will be no need for the worker performing the meter replacement to gain access to the inside of your home or business.
- Typically, it'll take only about 30 seconds to remove the existing meter and plug in the new meter. During the few moments while the new meter is being installed, your home or business will be without power. The worker will spend another minute or two to make sure the new meter is communicating properly with PSO's secure radio system before moving on to the next address.
- While PSO does not anticipate any problems during the meter replacement, we recommend that you take whatever measures you feel are necessary to protect important computer files and sensitive electronics and appliances from brief electric interruption.
- We also recommend that you secure all pets in your yard (if in same fenced area where electric meter is located) by keeping them indoors or another secure location on the meter replacement date.
- If you keep your fence gate locked, please be sure to unlock it on the appointed date.
- There is no out-of-pocket cost to you.
- If you have any questions, please contact PSO's Customer Solutions Center:
1-888-216-3523

Regards,

Public Service Company of Oklahoma

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Commercial Letter Example

DATE

Dear PSO Customer,

In mid-XXXX, PSO will begin work to install new digital meters in your area as part of our project to upgrade the electric distribution system to new digital meter technology.

What You Need To Know

- PSO employees will perform the meter replacement at all industrial locations. [Note: PSO will use a contractor to replace meters on most residential and commercial accounts.]
- After we have installed the digital meter we will leave a door hanger to confirm that the work was performed and to provide you some additional information about the device.
- You do not need to be at your business for the installation. All of the necessary work will be performed outside. We will need access to the electric meter, but there will be no need for the worker performing the meter replacement to gain access to the inside of your home or business.
- Typically, it'll take only about 30 seconds to remove the existing meter and plug in the new meter. Most businesses have bypass levers inside their meter cans, so there should be no disruption of electric service while the meter is being replaced. The worker will spend another minute or two to make sure the new meter is communicating properly with PSO's secure radio system before moving on to the next address.
- While PSO does not anticipate any problems during the meter replacement, we recommend that you take whatever measures you feel are necessary to protect important computer files and sensitive electronics and appliances from a brief electric interruption.
- We also recommend that you secure all pets in your yard (if in same fenced area where electric meter is located) by keeping them indoors or another secure location on the meter replacement date.
- If you keep your fence gate locked, please be sure to unlock it on the appointed date.
- There is no out-of-pocket cost to you.
- If you have any questions, please contact PSO at 918-XXX-XXXX.

Regards,

Public Service Company of Oklahoma

Example of Phone Blast

This is an important message from Public Service Company of Oklahoma about the installation of your new digital meter.

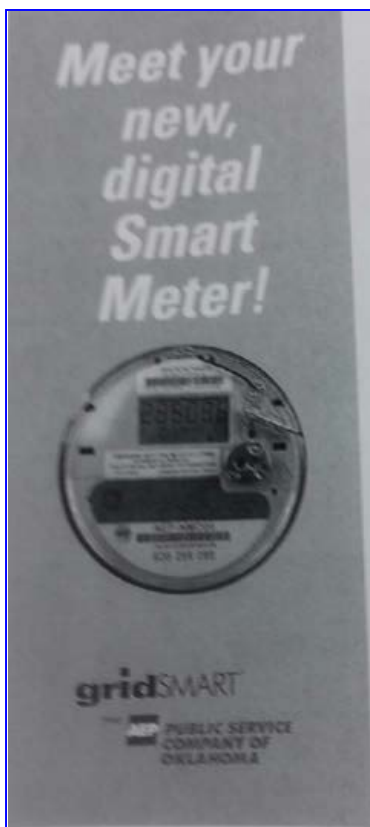
Your home or business is in the PSO AMI Project area. You should have received a letter from us in mid XXXXXX notifying you of this exciting new endeavor.

Over the next several weeks, contracts crews from PSO will install new advanced digital meters in your neighborhood. During the installation process your home or business may experience a brief power interruption as our crew safely completes their work.

Once installed, PSO will leave a printed door hanger describing the benefits of your new meter. There is no additional cost to you for the new meter.

For more information about PSO AMI Project, please visit our website PSOklahoma.com or call our 24 hour customer solution center at 1-888-216-3523. Thank You.

Example of a Door Hanger



Your electric meter just got smarter. PSO has installed your new, digital meter. It works with PSO's secure, two-way communications network to provide near real-time collection and transfer of information about your electricity usage.

- Improved power outage diagnosis – PSO can communicate with meters, which assists in troubleshooting customer power issues.
- Better customer service – PSO can respond faster to most residential service requests because these operations often can be performed remotely.
- Greater privacy – Meter readers will no longer need to enter your property every month.
- Consumer Programs – benefits from a number of energy-saving programs that will help manage electricity use.

Note: By XXXXXXXX, you may view your energy usage in greater detail, including 15-minute intervals, via PSO's website: psoklahoma.com. If you have questions, please contact PSO's Customer Solutions Center: 1-888-216-3523

WWW.PSOklahoma.com Facebook Twitter

AMI Education Plan

The outreach and education plan will communicate to customers the benefits of the digital meters and our AMI deployment schedule process. PSO's objective of the education and outreach effort is to help customers capture value from the investment, to enhance the customer experience with easy access to information, and simplify the enrollment process for customer programs.

AMI Education Plan

Form of Education	What	Why	When
Consumer Group Meetings and sponsor and/or participate in community events.	<ul style="list-style-type: none"> • Chamber of Commerce Meetings • Town Hall Meetings • City Hall Meetings • Events & Trade shows 	<p>Reach as many customers as possible where they live to educate them about AMI meters.</p> <p>Don't wait for customers to connect, rather take AMI deployment information to them.</p>	On Request
Mobile Exhibit Trailer	<ul style="list-style-type: none"> • The exhibit will be a 53-foot trailer with sides that expand to provide approximately 900 square feet of space. • PSO will target community events in their service territory. • During and after AMI deployment 	<p>Provide engaging displays and exhibit concepts that will effectively engage and educate customers on program offerings, and Customer Web Portal, giving them the ability to enroll in a program of choice.</p> <p>Offering an interactive opportunity that will educate and engage visitors with features designed to fully display AMI technology,</p>	Rolling out 1 st Qtr. 2015

		including pricing programs and customer program offerings.	
Form of Education	What	Why	When
Internal Communications	Train, equip, and empower employees to be PSO AMI meter advocates.	Providing the resources they need to communicate with customers.	Communication with employees will be ongoing throughout the AMI deployment.
Consumer Programs	Alternative Pricing and Customer Programs such as Time of Day (TOD), Direct Load Control (DLC), Bring Your Own Thermostat (BYOT), and Pre-Pay program.	Reach as many customers as possible where they live to educate them about AMI meters and about the consumer program offerings.	Communication with our customers will be ongoing throughout the AMI deployment.

PSO Mobile Exhibit Plan

As part of a comprehensive communications strategy, PSO intends to develop and execute plans to create a mobile exhibit which will highlight AMI technologies and associated programs, as well as provide additional information on the company and its various initiatives and activities.

The exhibit will be inside of a 53-foot trailer with sides that expand to provide approximately 900 square feet of space.

While targeting different audiences, the mobile exhibit will utilize interactive displays, exhibits, and other appropriate technology to educate visitors about, among other things, the benefits that advancing technologies can bring to the way we deliver electricity and serve customers.

PSO intends to educate customers by:

- Providing engaging displays and exhibit concepts that will effectively engage the audience.
- Offering an interactive opportunity that will educate and engage visitors with features designed to fully display AMI technology, Customer Web Portal, and consumer program offerings.
- Ensure that the exhibit’s displays are interactive, appealing, inviting and informative, and will educate the customer on program offerings, giving them the ability to enroll

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in the program of their choice, such as two tiered pricing options, BYOT program, Customer Web Portal, and

- Education information will be directed for:
 - 1.) Customers who will have the opportunity to modify behaviors that will enable them to receive the full array of customer benefits, and
 - 2.) Youth ages 11 to 18 with an emphasis on educating them on the importance of energy conservation.

PSO will target community events in their service territory such as; state fairs, Home and Garden shows, and community festivals to display the mobile unit throughout the year.

The timeline to begin showcasing the mobile trailer will be first quarter 2015.

AMI Customer Programs and Benefits

A number of qualitative benefits for customers, as well as future benefits, are anticipated to be realized once AMI is fully deployed. Some of these benefits stem from AMI's ability to measure granular data and communicate in near real-time. The following list provides additional information pertaining to customer programs and benefits:

Customer Web Portal - The customer web portal contains customer education information, as well as decision-making features to help customers save on their electric bills:

- Customers have the information, such as near real-time data and usage information, and tools to proactively reduce and manage energy usage;
- Forecasted bill feature to help make informed energy decisions by granting customers the ability to see energy usage, bill-to-date information, and forecasted bill information. This allows customers to proactively make energy consumption changes instead of responding reactively to an after-the-fact bill;
- Customers have the ability to make rate comparisons by viewing prior usage patterns and comparing this information with different tariffs, such as a voluntary time-of-day (TOD) tariff to determine if they would have saved money on a TOD tariff based upon prior usage patterns and potential savings if usage patterns change;
- Customers have the ability to track and compare usage against prior periods with a temperature overlay by having access to historical usage and near real-time usage information;
- Ability to request a Home Energy Report for customers who do not have internet access.

Alternative rates and programs - for customers to manage their energy usage, and reduce or shift energy usage outside of peak periods:

- Opportunities to enroll in optional pricing options to save money if customers are willing to shift or reduce electric usage;
- Voluntary Pre-Pay billing program to be implemented during the AMI deployment that would provide customers additional choices on how to pay for electric services. PSO is working on a Pre-Pay program associated with the full AMI deployment;
- Rebate program to either pay the full cost or pay a significant amount of the cost of a programmable wireless (WI-FI) enabled thermostat for customers to manage their air-conditioning usage, which is the largest residential energy usage device during the on-peak months.

Power outage detection through real-time access:

- Outage order creation will be implemented as meters are deployed, which will quicken the dispatch of outage restoration resources, and provide better communications about the restoration efforts;
- The ability to poll meters after an outage helps to ensure power is restored or identify nested/pocket outages in large outage events, such as a feeder outage.

Additional and improved metering activities:

- The ability to remotely read meters on-demand for move-in/outs, and billing inquiries, which is more timely and convenient for customers;
- The ability to perform credit reconnects automatically, typically within 15 minutes versus from when a payment is made, versus up to 24 hours for non-AMI meters;
- Residential service connections can be made within minutes versus up to 24 hours, which helps to accommodate customer moves;
- Virtual elimination of estimated meter readings due to access issues, inclement weather, or hazardous conditions;
- A reduction in billing complaints over time as estimated meter readings are replaced by actual readings, which improves the accuracy of customers' bills;
- PSO resources generally no longer need to access customer yards on a monthly basis to read the meter or perform service orders, which can cause inconveniences for customers.

Environmental impacts can be mitigated:

- Through customer participation in PSO's consumer programs and pricing options, peak and ongoing energy reductions can be achieved, which decreases carbon emissions from power plants as less power is needed;
- By being able to remotely connect and disconnect service, PSO will reduce the amount of truck rolls associated with these activities, which leads to a decrease in vehicle emissions.

As a platform for the future, additional AMI functionality that has yet to be developed will lead to additional benefits:

- Having AMI helps facilitate the necessary infrastructure to support electric vehicle charging;
- Similarly, AMI helps facilitate distributed generation and net metering;
- AMI will help facilitate access of future customer-deployed technologies that will help manage energy usage by giving customers ready access to information provided directly from the meter. However, such technologies are still in their infancy;
- Ability to test new applications for other customers, such as commercial demand and energy reduction programs.

AMI Risk Communication Plan

PSO's communication, customer contact, and AMI teams will be fully prepared to anticipate, respond rapidly, and manage potential risk situations that could arise among customers and communities during the deployment period. This risk management communications plan represents a comprehensive and sustained program for how we will anticipate customer issues and concerns, and work to address and mitigate problems quickly and thoroughly.

Our approach to managing issues surrounding the AMI deployment is guided by the following principles:

- Customer education – We will ensure that we communicate our digital meter installation plan and all related policies and procedures to customers using multiple channels, to proactively answer questions and address concerns.

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- Anticipation of concerns – We will proactively address potential concerns to prevent problems and complaints before they occur.
- Empathy for customers – We will increase our dialogue with customers to ensure that we listen and understand them, and as has been our practice in the past, we will approach each customer's concern with courtesy and respect.

Communication Process

A team has worked to proactively identify potential customer questions and concerns. The team has developed a comprehensive risk management procedure to determine how various types of issues will be routed, and to conduct a targeted and responsible process to address and resolve them. It will begin with pre-deployment communications to help customers anticipate what is ahead, and clarify for them the technology and logistics in advance of installations. This plan is a working document and will be revised and updated as needed to ensure issues are being handled in the most efficient and effective manner, and to address additional situations that may emerge.

- Using existing processes/procedures for addressing escalated issues,
- Encouraging cross-functional teams to report any AMI issues that emerge – ensuring all are documented and resolved,
- Responding to customers within an appropriate timeframe,
- Recommending potential solutions to all issues, especially recurring issues,
- Assisting with the compilation of the escalated issues to help quantify and understand causes, and prevent recurrences, and
- Ensuring closure with customers.

Customer Concerns and Complaints

Customer concerns and complaints will be routed appropriately based on their origin and the expedient resolution process. In many or most cases, these concerns or complaints will be routed to the PSO Customer Solution Center, where representatives will be equipped and trained to address and resolve them.

Vendor installers and field technicians will adhere to a clear protocol for receiving customer inquiries and complaints courteously and empathetically, and will report appropriate issues to PSO expediently for resolution. Vendor installers will handle complaints regarding meter installation as well as Vendor installers' personnel and damages.

Customers will be notified to provide information on any specific needs prior to the start of installations. PSO will identify the special needs customers for meter install vendor. In addition

to a letter regarding the new meter installation, all customers will receive an automatic reminder call before installation.

Risk Communications Team

Key departments and teams will be engaged in the customer concern/complaint resolution process, including the following:

- Meter Revenue Operations (MRO)
- Customer Services and Marketing
- Customer Solutions Center (Call Center)
- Meter Installation Vendor
- PSO Billing Personnel
- Customer Account Managers (CAM's)

Risk Scenarios

PSO has identified the following risk scenarios and issues concerning AMI deployment and the installation of digital meters. In order to provide a framework for a proactive and efficient response, we have developed specific messages to address each scenario.

• Customer wants to opt out of meter installation

Key Messages:

- ✓ PSO wants to make sure that every meter is compatible with system-wide enhancements and to provide every customer with the advantages of these new technologies, PSO is replacing all meters in its service area over the next 3 years.
- ✓ Even if you are not interested in utilizing the enhanced energy management and money-saving tools digital meters will provide, new technologies included with the digital meters will ultimately improve the service and reliability for every PSO customer. Here are just a few of the features:
 - Two-way communication between digital meters and PSO that significantly reduces the need for estimated bills and provides PSO with the information needed for more accurate billing,
 - Energy budgeting and tracking and personalized energy-efficiency tips,

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- The automatic connects and disconnects to meters performed within 15 minutes versus up to 24 hours for non-AMI meters, and
- PSO resources generally no longer need to access customers yards on a monthly basis to read the meter or to perform service orders, which can cause inconveniences for customers.

- **Customer questions purpose of the digital meter**

- **Assertion: Customers reject the need for the digital meter and the change that's occurring.**

Key Messages:

- ✓ After the initial installation, this digital meter will serve much like the old meter. It will be read and will provide monthly billing information like the old meter. Ultimately, this meter will support the utility of the future, serving as a conduit for enhanced two-way communication between the customer's meter and the company.
- ✓ These are the kinds of enhancements to PSO's energy delivery system that will help to enhance energy efficiency and conservation across the nation. This is intended to help customers reduce energy consumption and help protect the environment.
- ✓ PSO wants to make sure that every meter is compatible with system-wide enhancements and provide every customer with the advantages of these new technologies, PSO is replacing all meters in its service area over the next 3 years.

Customer questions cost or value of AMI meter program

- **Assertion: Customers will be paying for digital meter installation, meter not worth the cost**

Key Messages:

- ✓ There will be no immediate cost to customers for the new meters. PSO will seek to recover its costs for the meter modernization system in a rate case before the Oklahoma Corporation Commission.
- ✓ No charges will be made to the customer without first the review and approval of the Oklahoma Corporation Commission.
- ✓ Under our forecasts, the long-term benefits to the customer from the technology, and the programs it can support, will outweigh the costs. This technology has the capability to give customers meaningful information on energy prices and usage so they can make informed decisions.

- ✓ This also will enhance reliability by helping the company to more quickly identify the cause of outages so we can move quickly to restore power. And it will provide greater convenience to the customer by providing the ability to start and end service without having to dispatch service personnel.
- ✓ When a customer calls about a power outage the real-time access also will enable call center representatives to determine whether the outage is due to a PSO outage or to an issue on the customer side of the meter.

Customer notes increase in bill following installation

Estimated billing customer adjusts to actual billing

Assertion: customer claims their bill is wrong and the new digital meter system is to blame.

Key Messages:

- ✓ PSO is reviewing your complaint. If we identify any inaccuracies we will correct them right away, find out the cause, and take steps to ensure it doesn't happen again.
- ✓ There may be other factors contributing to your higher-than-usual bill and we will also review those possibilities with you.
- ✓ Similar to your old meter, digital meters measure the energy that is used by residents of your home. The meter itself cannot and will not increase your bills.
- ✓ It should be noted that in rare instances, old analog meters can stick or run 'slow,' resulting in inaccurate bills. In cases like this, the digital meter will now measure your energy usage at the actual rate.

Customer inconvenienced by scheduling and/or post-installation inspections

Assertion: Customer could not work out schedule with Vendor installers

Key Messages:

- ✓ Vendor installer has committed to being flexible and makes multiple attempts, if necessary, in scheduling installation times with customers.
- ✓ If that doesn't work, a PSO installer will have the responsibility to make the installation.

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- ✓ This is an important and unprecedented initiative and we're going to go the extra mile to be flexible and accommodate our customers.
- ✓ PSO may also be conducting post-installation audits to review the work of the installers. No appointment is necessary and inspections will take place only where PSO can gain access on their own.

Customer concerned that PSO is controlling their energy usage

- ✓ The digital meter takes frequent readings of your energy usage, but it only measures the electricity used in your household, it does not control it.
- ✓ PSO will offer an optional rate program that will allow PSO to adjust a customer's thermostat during peak event days.

Customer concerned about health risks

Key Messages:

- ✓ While concerns have been raised about the potential impact of the RF generated by AMI meters, numerous studies have shown that AMI meters using RF technologies do not pose any known adverse health risks. As with any electric device that utilizes RF, AMI meters have been monitored, tested, and certified to ensure they meet certain safety standards. The RF exposure levels from AMI meters are far below the levels permitted by the Federal Communications Commission (FCC), which sets health standards for RF exposure, based on extensive reviews of biological and health literature.
- ✓ According to the Electric Power Research Institute, the "relatively weak" strength of the RF signals generated by AMI meters means that any impact of RF exposure would be minimal—similar to the levels of the exposure from televisions and radios.¹ In fact, AMI meters produce significantly less RF exposure than other common electric devices, such as cell phones, baby monitors, wireless routers, laptop computers, and microwave ovens.
- ✓ RF exposure from an AMI meter is far below—and more infrequent—than other common electric devices. In fact, AMI meters typically broadcast their signal typically less than 2 minutes each day. The communication is usually from outside the customer's home, so exposure to radio waves is minimal. In addition, the electric panel and wall behind the meter actually block much of the radio signal from entering the home.

¹ "An Investigation of Radiofrequency Fields Associated with the Itron Smart Meter," Electric Power Research Institute, December 2010.

- ✓ RF is measured in units of microwatts per square centimeter. A microwatt is very small— it's one-millionth of a watt.
 - Held at your ear, a cell phone's RF signal would be 1,000 to 5,000 microwatts per square centimeter.
 - Standing two feet from a microwave oven, the RF signal would be 50 to 200 microwatts per square centimeter.
 - Standing 10 feet from an AMI meter, the RF signal would be 4 microwatts per square centimeter.

- ✓ RF exposure of AMI meters is regulated. The FCC sets the standards for RF permissible exposure limits and approves the frequencies that AMI meters use. All AMI meter radio devices must be certified in compliance with the FCC's rules and guidelines before being installed. The manufacturer tests the devices to FCC specifications and then presents the test results to an independent certification laboratory or to the FCC directly. Only after the FCC reviews the detailed report and certifies the AMI meter radio device can the manufacturer market and sell the devices. The same procedures are used for Wi-Fi network equipment in personal computers and wireless routers located nearly everywhere in our homes and offices.²

Customer concerned about accuracy of the new meter

Assertion: Customers argue that this new equipment will, whether fairly or unfairly, increase customers' bills and result in a windfall to the company.

Key Messages:

- ✓ The technology systems that support AMI systems have extensive data validation processes to protect the accuracy of your billing records. In addition, AMI meters must meet rigorous requirements for accuracy, which were developed by the American National Standards Institute (ANSI). National Institute of Standards and Technology (NIST)-certified test equipment also is required to verify initial and continuing AMI meter accuracy.

- ✓ A recent study by an independent testing group found that 99.91 percent of AMI meters were accurate within 0.5 percent.³ In fact, the study found that AMI meters were more accurate than the mechanical meters they replaced. In addition, AMI meter groups are continuously tested and monitored by your electric company to ensure they are operating correctly.

² "A Discussion of Smart Meters and RF Exposure Issues: An EEI-AEIC-UTC White Paper," Edison Electric Institute; Association of Edison Illuminating Companies; and Utilities Telecom Council, February 2011.

³ Edison Electric Institute, "Smart Meters and Smart Meter Systems: A Metering Industry Perspective," March 2011.

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- ✓ Electric companies constantly monitor the data transmitted from AMI meters to verify that electricity usage is within expected ranges. If readings show a significant difference from normal levels of use, technicians will inspect the meter. PSO takes these steps to ensure that your electric bill is accurate.

Customer concerned about the privacy of their information

Assertion: AMI is just another incursion into people's privacy; that "Big Brother" is watching

Key Messages:

- ✓ As the advanced grid allows PSO to collect real-time customer usage data, customers want to ensure that their data are secure. PSO works hard to protect the privacy of their customers' data—and continues to make data privacy a key priority as the smart grid develops.
- ✓ PSO is making the security and privacy of customer data key components of their grid modernization efforts. PSO uses advanced encryption technologies to protect all data transmitted by AMI meters. PSO also complies with the data privacy guidelines and by state laws set by Oklahoma legislature and regulation at OCC.
- ✓ Since protecting customer data is a top priority in modernizing the grid, PSO is working with federal agencies, such as the Department of Homeland Security, the Department of Energy, and the National Institute of Standards and Technology (NIST), to adapt existing privacy and security standards to meet the new data requirements that accompany smart grid technology. NIST guidelines are being applied to remote access, authentication, encryption, and the privacy of metered data and customer information.
- ✓ PSO is highly regulated at the state level. In 2011, Oklahoma passed the Electric Usage Data Protection Act. The purpose of the law is to establish standards to govern the access to and use of usage data, as defined in Section 3 of the act by electric utilities, customers of electric utilities, and third parties. State regulators closely monitor the privacy safeguards that are being developed for the new AMI grid technology systems.

Customer concerned about security risks and vulnerability of the grid.

Assertion: A customer is concerned about the AMI grid system and that the data that's collected in this system can be obtained by hackers and used against customers

Key Messages:

- ✓ Cybersecurity threats can cause disruptions in the flow of power and other problems if cyber intruders send computer signals to the electronic controls used in some electric generation and transmission infrastructure. PSO takes cybersecurity threats very seriously. In fact, electric companies must meet mandatory cybersecurity standards that

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require companies to implement training, physical security, and asset recovery plans to protect against the threat of cyber-attacks.

- ✓ As the advanced grid is built, electric companies are incorporating cybersecurity protections into both the grid architecture and the new AMI grid technologies. The electric power industry is working closely with vendors, manufacturers, and government agencies to ensure that the AMI grid is secure. These measures also help to ensure that customer data remains protected from cybersecurity threats.

Customer concerned that meter reader jobs are being eliminated

Key Messages:

- ✓ Traditional meter readers, who will no longer be required to “make their rounds” to personally read meters, will have the opportunity to be re-trained for other jobs within PSO.
- ✓ PSO’s goal is to handle all staffing reductions through attrition or job transfers.

Customer confused by new AMI meter technology

Key Messages:

An AMI meter is a digital meter that allows two-way communication between customers’ homes and PSO via a wireless network.

- ✓ Shortly after the installation of the first AMI meter, features such as energy budgeting and tracking, and personalized energy-efficiency tips will be available to customers via a Customer Web Portal available beginning approximately second Qtr. 2015. Some of these will include:
 - Monthly/Daily/Hourly usage data
 - Customer bill analysis
 - Rate Comparison and energy pricing program information
 - Customer’s Carbon impact
 - Green Button Energy customer reports

Customer concerned that PSO will benefit more than customers

Key Messages:

- ✓ AMI grid is an updated energy system that gives customers the power to manage and save energy more efficiently. It will allow PSO to improve the way it serves its customers. Here are some examples:
 - Two-way communication between digital meters and PSO significantly reduces the need for estimated bills and provides PSO with the information needed for more accurate billing.
 - In the future, digital meters will also provide automatic alerts about power outages that will help PSO locate and repair problems (though PSO will still want to hear from customers about outages).

Customer does not experience expected benefits anticipated on basis of education and promotion

Assertion: Your ad/letter/representative/other said that when the digital meters are fully functional, I can better manage my electricity and reduce my bills. I don't see that happening.

Key Messages:

- ✓ PSO expects the AMI technology to provide many benefits, and PSO believes the new meters and associated features have the capacity to change customer use of energy.
- ✓ The features of digital meters will roll out over time, and full benefits will not be available until the whole system is set up, including all meters installed, the two-way communications system operating, and new pricing and load control opportunities rolled out to customers. We expect all benefits will be available after customers receive an AMI meter.

Customer concerned that seniors, limited income and other vulnerable customer groups will pay more than their fair share

Key Messages:

Many digital meter features and technologies are especially beneficial to seniors and limited-income customers:

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- ✓ Seniors and other customers who may be on fixed or limited budgets can take advantage of personal energy usage information that allows them to better manage their energy costs.
- ✓ In the future, digital meter technology will also enable PSO to offer energy rebate programs such as BYOT, and pricing options such as Time of Day (TOD), and Direct Load Control (DLC), that can help lower customer bills.
- ✓ Digital meters will provide automatic alerts about power outages that will help PSO locate and repair problems (though PSO will still want to hear from customers about outages).
- ✓ Ability to request home energy reports for customers that do not have internet access.

Vendor identification badge used inappropriately or by an imposter

Assertion: PSO didn't tell customers how to protect themselves from imposters and didn't do enough to prevent people from impersonating Vendor or PSO personnel.

Key Messages:

- ✓ We notified customers in advance when Vendor installers would be in the neighborhood and how to identify them in the advance letters that we mailed. We encourage customers on an ongoing basis to challenge our employees and contractors for identification and encourage them to contact our Customer Solutions Call Center to confirm utility work at their location.
- ✓ We periodically advise the public to beware of individuals claiming to be utility personnel, who may request access to their homes, encouraging them to check for ID.
- ✓ Both PSO and Vendor notify local authorities when they are working in a community.
- ✓ In this case, we're working with local authorities to assist in any way possible.

Customer experiences extended service interruption during and after installation

Assertion: Interruption of service causes inconvenience to the customer

Key Messages:

- ✓ Installation of the digital meter requires a brief interruption of service. PSO and Vendor anticipated the potential for the inconvenience that can be caused by such an interruption, even if only brief and temporary.

- ✓ As a result, we're taking steps to minimize this inconvenience.
- ✓ In our advanced mailing to the customer, which is being sent to customers one to four weeks before the installer visits, we explained the potential for an interruption to the customer.
- ✓ When an installer arrives, he/she makes an attempt to notify the customer, facility representative, or multi-residential management office to advise them of their presence and the impending brief service interruption.
- ✓ If necessary, Vendor can schedule an appointment to accommodate customers on life-support equipment or issues that would be experienced if service was interrupted to business customers.

Meter box is inaccessible or obstructed

Assertion: We cannot safely gain access to our meter due to obstructions located on the customer premises.

Key Messages:

PSO's tariff clearly states that the company, at all reasonable times, has access to meters, service connections, and other property owned by it on a consumer's premises. Refusal on the part of the consumer to provide reasonable access for the above purposes shall be deemed to be sufficient cause for discontinuance of service on the part of the utility, after at least ten (10) days written notice. In the event the customer is a tenant, the utility should attempt to notify the property owner of the access violation and pending disconnection of service. Service will be reconnected after a method of permanent access on the meter reading date is agreed upon by the customer and utility. If the consumer and/or property owner does not correct unsafe conditions or obstructions, including dangerous animals, the utility may relocate the meter to a safe and accessible location at the expense of the consumer and/or property owner. The utility shall provide its employees with a means of identification in order to claim the right of access.

Meter box was damaged during installation

Assertion: During the meter exchange, Vendor/PSO identified a meter box that is/was damaged during the process. The customer, who typically is responsible for the meter box attached to their respective location, believes they are now responsible for repairs.

Key Messages:

- ✓ PSO apologizes for this inconvenience with the meter box. Although these occurrences are rare, they can and do happen when equipment like this is exposed to the outdoors or

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may have been in place for an extended period of time. Know that we will work as safely and quickly as possible to restore your service.

- ✓ In some cases we do find there may be excessive corrosion, damage from the elements, or existing conditions that were found to be unsafe during this process.
- ✓ We will take the time to complete repairs as quickly and safely as possible, at the company's expense, in order to restore your service.
- ✓ Although this may involve customer-owned equipment, this is a one-time expense the company will incur to facilitate the installation of digital meters.
- ✓ We will only make repairs to the meter box. However, there may be other issues regarding your service that may need to be addressed by a contractor.
- ✓ Our goal is to return service to you as soon as possible and minimize any inconvenience to customers. We hope you will be patient as we make these repairs to help ensure the safety of our employees/contractors and your equipment.

Customer damage claim denied by Vendor and PSO

Assertion: A customer claims they suffered damage by a PSO or Vendor installer and both deny the claim.

Key Messages:

- ✓ PSO will review claims on a case-by-case basis, and if we believe it is a valid claim, then PSO will make the customer whole.
- ✓ We are monitoring claims to Vendor on a monthly basis to monitor the volume and to ensure that there is not a bigger issue that we need to address.
- ✓ PSO will make sure our Vendor upholds its obligations under the contract.

Random isolated issues

Assertion: I have a problem with the new meter (or the exchange process) and I believe it is indicative of a systemic problem with this deployment.

Key Messages:

- ✓ PSO is aware of the situation.
- ✓ We apologize for any inconvenience this has caused and we appreciate your patience as we work through this issue.

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- ✓ We've checked and we don't have any indication of this being a systemic problem or a larger issue. Apparently, it is an isolated incident.
- ✓ We will work to resolve your issues as quickly and safely as possible.

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Additional Details Pertaining to The Analyses of The Tariff Programs

Figure 3.1: Two-Tier TOD Without Thermostat PSO Peak Day

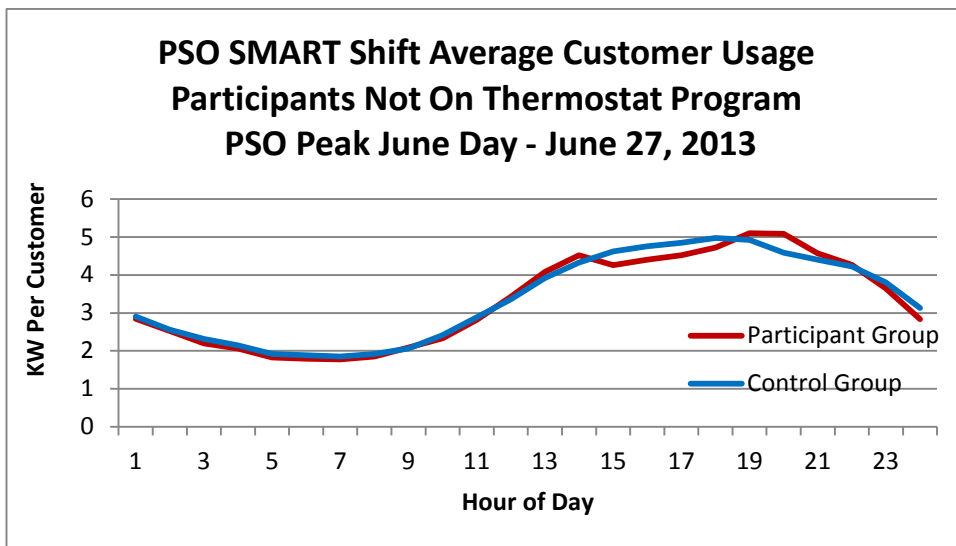
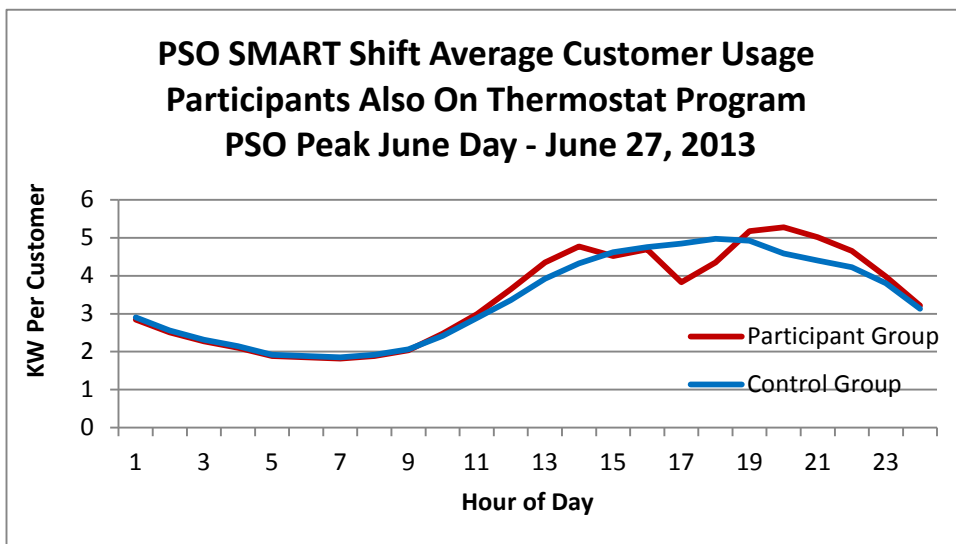


Figure 3.2: Two-Tier TOD With Thermostat PSO Peak Day



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Figure 3.3: SMART Shift Participant Large Load Shifter

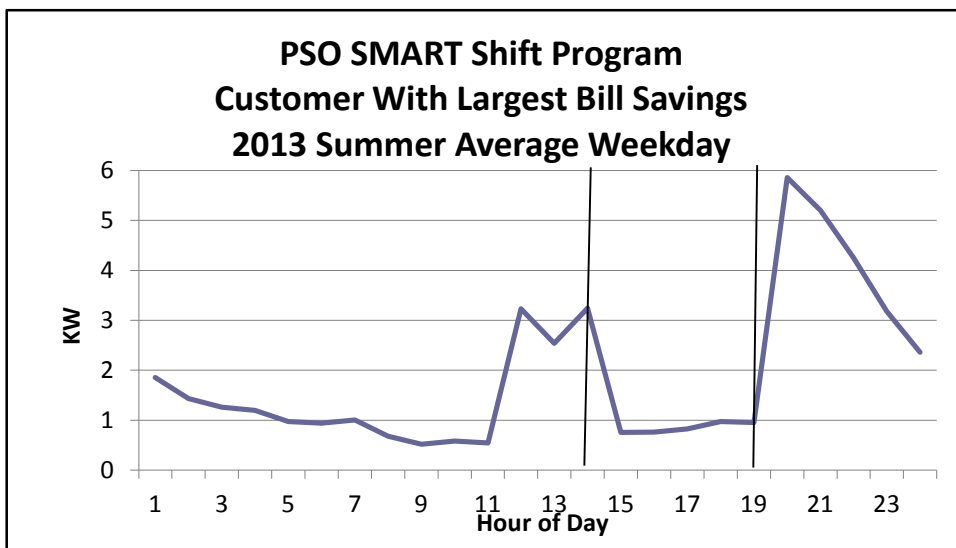
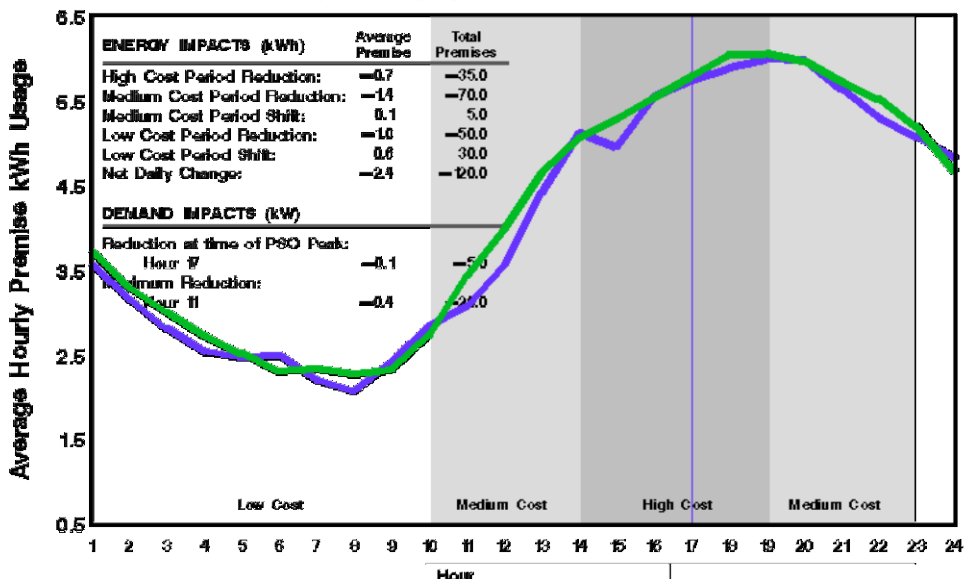


Figure 4.1: VPPRS Event, August 1, 2012

Public Service of Oklahoma
 Energy and Demand Impact Analysis – Summer 2012
 SMART Shift Plus (Tariff 36) Premises Summer Peak Day (August 01)

SMART Shift Tariff Premises [80]
 Standard Tariff Control Group Premises [300]



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→ SMART Shift Plus Periods

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Figure 4.2: SMART Shift Plus Participants 2013 Event Days

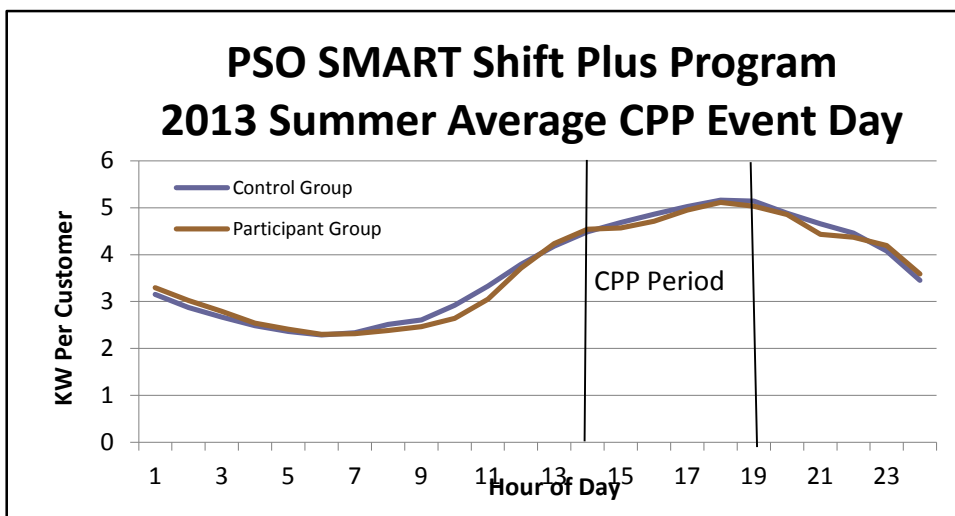
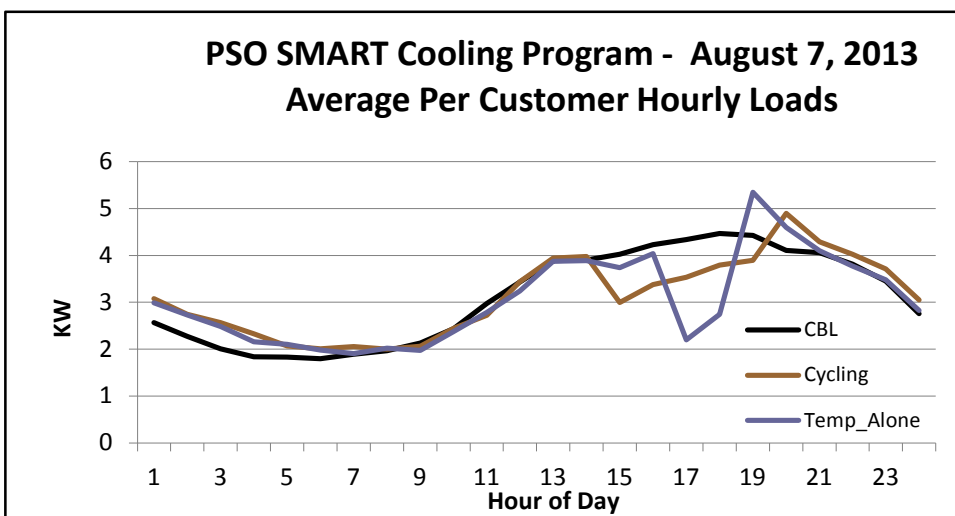


Figure 4.3: August 7, 2013 SMART Cooling Event Day



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Figure 5.1: Distribution of Bill Savings For SMART Shift Participants

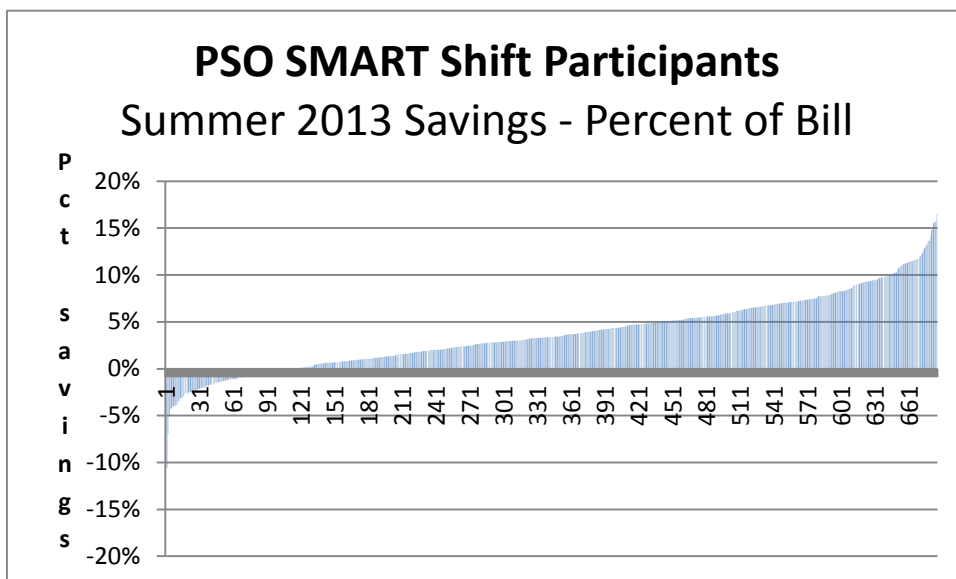
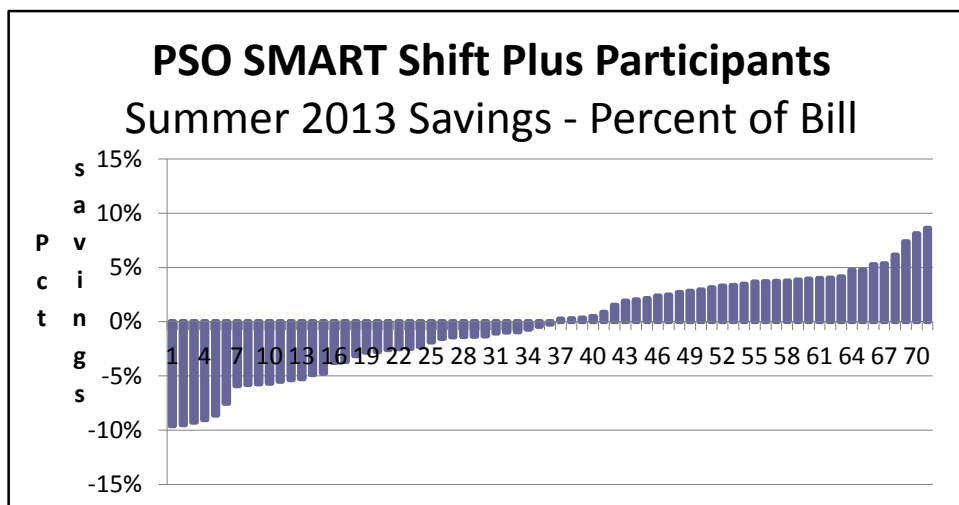
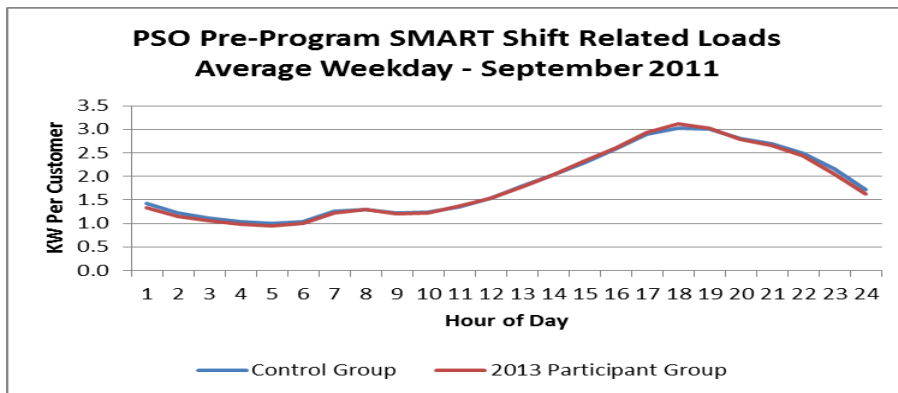


Figure 5.2: Distribution of Bill Savings For SMART Shift Plus Participants



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Figure 6.1: SMART Shift Program Control Group Validation



BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE COMPANY)
OF OKLAHOMA TO BE IN COMPLIANCE WITH)
ORDER NO. 591185 ISSUED IN CAUSE NO.)
PUD 201100106 WHICH REQUIRES A BASE RATE) CAUSE NO. PUD 201300217
CASE TO BE FILED BY PSO AND THE)
RESULTING ADJUSTMENT IN ITS RATES AND)
CHARGES AND TERMS AND CONDITIONS OF)
SERVICE FOR ELECTRIC SERVICE IN THE)
STATE OF OKLAHOMA)

FILED
JUL 15 2014

COURT CLERK'S OFFICE - OKC
CORPORATION COMMISSION
OF OKLAHOMA

SUPPLEMENTAL REBUTTAL TESTIMONY

DEREK S. LEWELLEN

ON BEHALF OF

PUBLIC SERVICE COMPANY OF OKLAHOMA

JULY 15, 2014

TESTIMONY INDEX

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EXHIBIT DSL-SR2	Company’s Response to AARP 5-3

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I. INTRODUCTION

Q. Would you please state your name and position in the Company?

A. My name is Derek S. Lewellen, and I am the Manager of gridSMART[®] and Meter Revenue Operations for Public Service Company of Oklahoma (PSO or Company).

Q. Did you file Direct and Rebuttal Testimony in this Cause?

A. Yes.

II. TESTIMONY PURPOSE

Q. What is the purpose of your Supplemental Rebuttal Testimony?

A. My Supplemental Rebuttal Testimony responds to the Supplemental Responsive Testimony of Barbara R. Alexander representing the AARP. In responding to Ms. Alexander, I will focus primarily on her unfounded assertions that PSO's costs, benefits, and projected program participation rates are not defensible and are based on unrealistic assumptions. More precisely, I will show that the basis for PSO's AMI deployment costs, benefits, and participation rates are based on reasonable assumptions that yield a positive net present value (NPV). Furthermore, I will address Ms. Alexander's failure to acknowledge the host of benefits that will significantly improve the quality of service for customers.

Q. Before addressing Ms. Alexander's specific assertions, will you please discuss what is generally lacking from her testimony?

A. Yes. What is mostly lacking from her testimony is that she offers no credible evidence to support her conclusions, which result from her purely speculative worst-case scenarios. Her arguments are based on faulty assumptions that are not factually-

1 based or credible. While Ms. Alexander is critical of PSO's analysis, she does not
2 offer alternatives as to how PSO could or should have structured its cost/benefit
3 analysis or projected program participation rates; she simply states that PSO's
4 analysis cannot be relied upon. Ms. Alexander continues to ignore or outright reject
5 the customer service benefits that will result from PSO's proposed AMI deployment,
6 such as near real-time remote connect/disconnect capability, power outage detection,
7 remotely read meters on demand, a customer web portal for consumer education,
8 consumer energy savings, voltage interval reading, and temperature alarms. These
9 customer service benefits are recognized throughout the industry with AMI
10 deployments.

11 Ms. Alexander also seems to ignore the fact that AMI is a proven technology
12 that is available to approximately 50 percent of the nation and is already approved for
13 the majority of the regulated utility customers in Oklahoma. Further, PSO has over
14 three years of experience with its AMI equipment, programs, and back office systems
15 associated with a systematic pilot roll-out within portions of its service territory
16 encompassing all customer types, with the exception of a very few large industrial
17 customers.

18 As I discuss below, PSO's costs, benefits, and participation rates are based on
19 reasonable assumptions stemming from PSO's pilot experience, the experience of
20 PSO's sister companies, and industry experience and benchmarking. These
21 assumptions are based upon the most probable outcomes, and the program is cost-
22 effective in terms of the quantifiable benefits alone, as it yields a positive net present

1 value over a 15-year period, including \$11 million in guaranteed savings over the first
2 four years.

3

4 **III. PSO'S COST ESTIMATES FOR AMI DEPLOYMENT AND**
5 **CONSUMER PROGRAMS ARE EVIDENCE-BASED**

6 **Q. Are Ms. Alexander's assertions concerning PSO's estimated costs to deploy AMI**
7 **correct?**

8 A. No. Ms. Alexander asserts that since PSO has not updated its estimated costs to
9 deploy AMI using vendor quotes or similar information, "...there is little evidence to
10 support the Company's estimated costs." As I related in my direct testimony, the
11 estimates for PSO's proposed AMI deployment are based on the costs identified from
12 PSO's earlier AMI deployments and initial vendor pricing information, based upon
13 leveraging the buying power of AEP, i.e. actual historical cost data. PSO also used
14 the experience of its sister companies, AEP Texas and AEP Ohio, in validating its
15 cost estimates. As I also mentioned in my direct testimony, all components of the
16 project will be competitively bid to ensure the lowest cost is achieved. Since the
17 filing of my direct testimony, the competitive bidding process has commenced, and
18 while still ongoing, the information gleaned through the process has confirmed PSO's
19 cost estimates.

20 **Q. Are Ms. Alexander's concerns regarding the estimated costs for PSO's Pre-Pay**
21 **Program valid?**

22 A. No. Ms. Alexander asserts that PSO has not identified or described any O&M or
23 capital costs for customer education or for its future Pre-Pay Program during the

1 three-year deployment period other than \$2.1 million in capital costs included in
2 Company witness Williamson's workpaper. Based on these perceptions, she believes
3 that PSO has not provided any justification for its Pre-Pay Program. (at 8-9)

4 First, let me clarify that PSO does not consider the Pre-Pay Program as a
5 consumer program, but rather another billing and payment channel for customers,
6 such as PSO's current automatic bill-payment option and average monthly payment
7 plan. PSO has identified all costs related to its Pre-Pay Program, the aforementioned
8 \$2.1 million in capital, which will be used to develop the necessary IT infrastructure
9 that will allow the Company to implement its Pre-Pay Program. Regarding Ms.
10 Alexander's criticism about lacking a description of what the \$2.1 million in capital
11 includes, at no time during this proceeding was this information requested. To her
12 criticism that no O&M costs were estimated as part of this program, the Company
13 does not foresee any O&M expenses associated with the development of this
14 program; therefore, they were not included. The Company reiterated the costs of its
15 future Pre-Pay Program in multiple data requests, such as the Company's responses to
16 AARP 5-23 and AARP 5-25.

17 The customer education costs for PSO's Pre-Pay Program are included in the
18 gridMGMT component in Figure 8 of my direct testimony. These customer
19 education costs are associated with PSO's overall AMI customer education efforts
20 (e.g. letters, newspaper ads, door hangers) that the Company has included as part of
21 its proposed AMI deployment and are separate from customer education costs related
22 to the tariffs (consumer programs) that are also part of PSO's proposed AMI
23 deployment. These costs were also included in the gridMGMT component included

1 in Mr. Williamson's workpaper. At no time during this proceeding were the specific
2 costs for customer education related to PSO's Pre-Pay Program requested.

3 **Q. Please address Ms. Alexander's concerns about other cost estimates included in**
4 **the Company's NPV analysis.**

5 A. Ms. Alexander's assertion that the Company did not include any rebate costs
6 associated with its Direct Load Control (DLC) Program beyond the first two years of
7 the program (at 9-10) is incorrect, as the costs of the rebate program were included
8 beyond 2016. Figure 9 of my direct testimony only shows the costs of the thermostat
9 rebate included as part of the consumer program costs for 2015 and 2016 (the
10 deployment period). The workpaper that was part of my rebuttal testimony ("AMI
11 Benefits Workpaper_Lewellen") includes 15 years of forecasted consumer program
12 costs, which include the rebate costs, on the tab labeled "NPV Consumer Prog."

13 Concerning bill credits, Ms. Alexander is correct that PSO did not include the
14 costs of the event credits in its NPV analysis. This exclusion is arguably appropriate
15 since cost recovery of the credits is not sought in this case and the bill credits are a
16 direct benefit that customers receive. However, to remove any potential controversy
17 about this issue the Company has revised "AMI Benefits Workpaper_Lewellen" and
18 has supplemented the Company's response to AARP 8-8.¹ On the "NPV Consumer
19 Prog" tab of this workpaper, I have broken out the costs of the event credits for a 15-
20 year time period. As can be seen from this updated analysis, the NPV over a 15-year
21 period associated with the cost of the event credits would be approximately \$3.9

¹ "AMI Benefits Workpaper_Lewellen" has been revised to include the credits and has been included in the Company's supplemental response to AARP 8-8 as AARP Supplemental 8-8 Attachment 1.

1 million. Since the NPV calculated in rebuttal testimony for the total AMI plan was
2 \$7.4 million, the impact of this adjustment would reduce the net benefits to \$3.5
3 million. Nevertheless, even with this adjustment, the benefits continue to exceed the
4 costs resulting in an analysis that continues to support the cost effectiveness of the
5 AMI technology.

6 In response to Ms. Alexander's claim that PSO is not including costs to
7 customers who participate in PSO's consumer programs, it is important to note that
8 the only consumer program where customers may potentially incur costs is the DLC
9 program. Although an in-home device will be necessary for the DLC program, no
10 device is necessary for the Time of Day (TOD) and Variable Peak Pricing Residential
11 Service (VPPRS) programs. Moreover, PSO has repeatedly stated that it anticipates
12 that its rebate will cover the cost of the in-home device, which will be readily
13 available through retail stores, such as home improvement stores. As far as
14 installation costs are concerned, these off-the-shelf in-home devices are relatively
15 simple to install using nothing more than a screwdriver. Most retail in-home device
16 companies provide simple and easy-to-understand instructions, videos, and customer
17 support to help with installation.

18 In regards to the Pre-Pay Program, as per the Company's responses to AARP
19 5-13, AARP 5-23, and AARP 5-25, there are no incremental customer costs
20 associated with its Pre-Pay Program. Ms. Alexander's references to the Company's
21 response to AARP 8-15 is taken out of context. AARP 8-15 asked PSO to describe
22 the *current* payment methodologies available to make a payment that results in a
23 credit to their account the same day. The Company responded with the requested

1 information and reiterated that these are the payment methods for all customers today.
2 Ms. Alexander took this information out of context to conclude that these same
3 charges will apply to PSO's Pre-Pay Program, ignoring PSO's statement that the Pre-
4 Pay Program may have additional payment methodologies available. Ms. Alexander
5 also misquotes the fees related to the current payment methods. The Company's
6 response to AARP 8-15 sets forth \$2.95 for a credit card payment and \$1.50 for a
7 walk-in payment, not \$3.95 and \$1.95 as stated in her Supplemental Responsive
8 Testimony. (at 11)

9 **Q. What about Ms. Alexander's assertions that PSO customers will bear the risk if**
10 **PSO's costs to deploy AMI exceed its estimates?**

11 A. As I previously stated, Company witness Sartin provides additional details in his
12 Supplemental Rebuttal Testimony on this matter. Although Mr. Sartin addresses this
13 issue, I will take this opportunity to correct a statement Ms. Alexander included as
14 part of this concern. Specifically, Ms. Alexander states that "...guaranteed savings of
15 \$5 million for three years and \$11 million in the fourth year." (at 11) She also makes
16 a similar statement earlier in her testimony regarding the guaranteed savings (at 6),
17 which is also incorrect. As I stated in my rebuttal testimony, PSO is guaranteeing
18 \$11 million over four years, not \$11 million in the fourth year. The \$11 million
19 includes the \$5.0 million in O&M savings that will occur during the deployment
20 period and \$6.0 million in the fourth year.

21 **Q. Does Ms. Alexander provide or cite any support for her assertions or concerns**
22 **on these issues?**

23 A. No, she does not.

1 **IV. PSO'S ESTIMATED BENEFITS ASSOCIATED WITH OPERATIONAL**
2 **COST SAVINGS ARE RELIABLE**
3 **AND EVIDENCE-BASED**

4 **Q. What are Ms. Alexander's concerns regarding bad debt, theft, consumption on**
5 **inactive meters, and obsolete meter avoidance benefits?**

6 A. Overall, Ms. Alexander asserts that these benefits are "new" benefits and were not
7 included as part of Mr. Lewellen's original testimony. She also states that the basis
8 for PSO's cost/benefit calculations related to these categories is "questionable and not
9 based on any Company specific analysis or any results from the pilot program." (at
10 12)

11 **Q. Are these benefits "new" as Ms. Alexander contends?**

12 A. No. As the Company has repeatedly stated, most of the data PSO relied upon for the
13 benefits related to bad debt, theft, consumption on inactive meters, and obsolete meter
14 avoidance was provided as part of the Company's response to AG 5-7. This data
15 formed the foundation for Company witness Lewellen's rebuttal workpaper, "AMI
16 Benefits Workpaper_Lewellen." Other than a couple of items detailed in the
17 Company' response to AARP 5-3, the values presented in the "Refined Cash Flows"
18 tab of AG 5-7 Attachment 2² directly tie with the values given in the "NPV Benefits"
19 tab in the rebuttal workpaper.

² Ms. Alexander included AG 5-7 Attachment 1 as part of her Responsive Testimony in this proceeding, but did not include AG 5-7 Attachment 2. As such, the Company has included AG 5-7 Attachment 2 as Exhibit DSL-SR1.

1 As per the Company's response to AARP 5-3³, there were only two
2 differences between debt, theft, obsolete meter avoidance, and consumption on
3 inactive meters. First, the theft reduction calculation in rebuttal testimony was
4 revised and used a revenue reduction of 0.50% instead of 0.25%. Second, the benefit
5 amounts for these items were combined in the Company's response to data request
6 AG 5-7, whereas they were separated for clarity in rebuttal testimony. For additional
7 details, please see line 29, "Credit / Collections, Theft, and CIM Benefits," of the
8 "Refined Cash Flows" tab of AG 5-7 Attachment 2 (Exhibit DSL-SR1). The
9 equivalent lines are 29, 30, and 31, of the "NPV Benefits" tab of Company witness
10 Lewellen's rebuttal workpaper, "AMI Benefits Workpaper_Lewellen."

11 **Q. Are Ms. Alexander's assertions that PSO's basis regarding theft of service is**
12 **"bereft of support" and that no documentation was provided to support a**
13 **change in the assumption valid?**

14 A. No. The benefit level changing from 0.25% to 0.50% of gross revenue was
15 documented in my rebuttal testimony. To this end, I explained that although industry
16 benchmarking showed that energy losses from theft could be as high as 3% of the
17 Company's annual gross revenue, yet PSO took a conservative approach and assumed
18 that its electric energy theft losses are approximately 0.50% of gross revenue.

19 Although PSO is able to currently track its losses due to identified theft, PSO
20 is not able to track all of the funds repaid by the customers responsible for the theft.

21 There are a myriad of reasons for this. For example, the account may have been

³ The Company is including the Company's response to AARP 5-3 as Exhibit DSL-SR2 as it is correlated with both AG 5-7 Attachment 2 and "AMI Benefits Workpaper_Lewellen."

1 closed, the Company may be unable to locate the customer, or the customer may pay
2 a portion of the bill at a later time. One of the issues with theft is that once the
3 Company is aware it has occurred, PSO does not know the extent of the theft until
4 subsequent to investigating and confirming the amount of theft. Secondly, once theft
5 is detected, PSO must have definitive proof of the responsible party in order to bill
6 them, which is another reason repaid funds are difficult to track. It is for this reason
7 that PSO has used benchmarking data in determining a reasonable approximation of
8 the extent of energy theft that is occurring on the Company's system. This is yet
9 another benefit that AMI has over PSO's current meters, i.e. the ability to detect theft
10 when it occurs, and investigate immediately to mitigate the issue.

11 PSO used two benchmarking studies as a basis for its theft reduction
12 assumptions in the cost/benefit analysis I provided as part of my rebuttal. The first
13 study was conducted by the Edison Electric Institute (EEI), an internationally
14 recognized organization that represents all U.S. investor-owned electric companies,
15 has 70 international electric companies as affiliate members, and 250 industry
16 suppliers and related organizations as associate members. EEI provides public policy
17 leadership, as well as strategic business intelligence. The second was a study
18 conducted by the Electric Power Research Institute (EPRI), which is an independent,
19 nonprofit organization that conducts research, development and demonstration
20 relating to the generation, delivery, and use of electricity. EPRI is considered a
21 leading organization within the electric industry and is comprised of over 1,000
22 members worldwide.

1 Benchmarking is a widely used and accepted business practice that allows
2 companies to obtain information from outside organizations and apply this to its own
3 organization to form a comparative analysis. This practice is very useful to help a
4 company gauge itself against others within its industry, as well as to help provide
5 guidance and reasonableness of the comparative metric. The EEI and EPRI studies
6 found that losses due to theft can range from 1% to as high as 3%. These findings
7 show that PSO's choice of 0.50% is reasonable, albeit conservative. This was also
8 the same assumption that Oklahoma Gas and Electric Company used as the low-end
9 for this benefit as part of their cost/benefit analysis for AMI.⁴

10 **Q. Are any of Ms. Alexander's views concerning PSO's estimate of the reduction of**
11 **bad debt correct?**

12 A. No. Ms. Alexander's belief that PSO's estimate of benefits related to the reduction of
13 bad debt based primarily on PSO's future Pre-Pay Program is completely erroneous.
14 Of the \$13.8 million in present value benefits stemming from the reduction in bad
15 debt, approximately \$0.5 million, or less than 4% of the total benefit for this category,
16 is attributable to PSO's Pre-Pay Program. The other 96% of this benefit is
17 attributable to AMI's remote disconnect functionality. This information was
18 provided in the tab "NPV Benefits" of my rebuttal workpaper, "AMI Benefits
19 Workpaper_Lewellen." Line 29 of this tab is clearly labeled "Reduction in Bad Debt
20 – Remote Disconnect," and shows the 15-year NPV benefit associated with this item

⁴ Direct Testimony of Jesse Langston, March 15, 2010, at 7. Cause No. PUD 201000029.

1 is \$13.3 million. Line 32 of this same tab, which is also clearly labeled, shows the
2 reduction in bad debt related to prepaid metering of approximately \$0.5 million.

3 As far as her allegation that PSO did not cite any published reports and failed
4 to identify the utilities it benchmarked for this benefit, the citation is included on page
5 14 of my rebuttal testimony. This cites a report titled “A review of Pre-Pay Programs
6 for Electricity Service,” which is a recently (2012) published report that is publicly
7 available. Not only does this report name utilities that have implemented pre-pay
8 programs, and what their experience has been, but also three of these utilities were
9 named in both rebuttal testimony and the Company’s response to AARP 6-7.
10 Examples include Salt River Project, Arizona Public Service (a pilot), and Oklahoma
11 Electric Cooperative.

12 **Q. Please address Ms. Alexander’s concerns regarding the savings attributed to the**
13 **billing and call center and “other” categories as used in PSO’s cost/benefit**
14 **analysis.**

15 A. Once again, Ms. Alexander is incorrect in her unsupported assumptions. As stated in
16 my rebuttal testimony, the savings related to billing and call center stem from the
17 efficiencies that AMI will enable. Ms. Alexander believes that having more
18 information will increase the length of customer calls, but the exact opposite is true.
19 After the AMI deployment, call volume and call length will decrease. For example,
20 customers will have better and more accurate data concerning their electricity usage
21 and bill, which decreases the number of calls to the call centers since customers no
22 longer need to contact PSO to obtain this information. As for her belief that outage
23 detection on the part of customer service representatives is not immediately available

1 with AMI, this is also incorrect as it will be an immediate benefit that will also reduce
2 call volume associated with outage calls. As previously stated and reiterated in
3 direct and rebuttal testimony, the benefits of AMI are available to our customers once
4 they receive an AMI meter, not after full deployment as Ms. Alexander contends.

5 Ms. Alexander also has the erroneous belief that a reduction in capacity and
6 reliability planning resources equates to a promise to avoid new investments. In my
7 rebuttal testimony, I explained that AMI provides a more automated, lower-cost
8 means of obtaining and managing customer interval usage data needed for
9 ratemaking, planning, special billing, and demand response program implementation
10 and evaluation. These functions are typically performed by capacity and reliability
11 planning resources. With access to the interval usage data, the capacity and reliability
12 planning resources become more efficient in their analyses, thus reducing costs
13 associated with this activity, including eliminating dedicated load research meters. In
14 no way was a promise made on the part of PSO that equates to avoiding new
15 investment due to being able to obtain and manage customer interval data enabled by
16 AMI.

17

18 **V. PSO USED REASONABLE AND CREDIBLE ESTIMATES OF**
19 **PARTICIPATION RATES AND IMPACTS ASSOCIATED WITH ITS**
20 **CUSTOMER PROGRAMS**

21 **Q. Please address Ms. Alexander's unsupported beliefs about PSO's participation**
22 **rates being defective and lacking credibility.**

23 A. Regarding her implication that PSO cannot base future participation rates on PSO's
24 pilot program results because the design of the consumer programs has changed (at

1 20), the design of PSO's DLC program has not changed, rendering this argument
2 groundless. As per the Company's response to data request AARP 5-19, the design
3 of the program has not changed, only the ownership of the thermostat. Changing the
4 ownership of the thermostat does not constitute a design change to the program, as
5 the program will function the same as it did during the pilot. The purpose of a pilot is
6 to deploy an initial design to learn from and improve upon before full
7 implementation. The Company defined the DLC program, as well as the specific
8 tariff that it applies to, in its response to data request AARP 8-10. I also point out that
9 PSO has not proposed any design changes to any of its other consumer programs. As
10 I stated earlier, an in-home device is not required to participate in either the TOD or
11 VPPRS programs.

12 Ms. Alexander's belief that customers will not enroll in the DLC program
13 because they will not receive a "free" in-home device, is also without merit. As PSO
14 has repeatedly stated, such as in the Company's response to AARP 8-11, the
15 Company does not anticipate that providing its customers with a rebate will change
16 customer participation. Also as per this response, PSO anticipates that the \$150
17 rebate will likely cover the cost of an in-home device. Further, Ms. Alexander's
18 assumption that PSO's rebate will be a post-purchase rebate is premature as PSO has
19 not determined whether or not its rebate will be pre- or post-purchase. Therefore with
20 the rebate, the cost of the in-home device should not be a barrier for any customers to
21 participate in the program.

22 As to the other portion of this allegation, that customers will not participate at
23 the same levels as the pilot because they are required to "take affirmative" action, she

1 has no basis or underlying data for this argument. Rather, it has been PSO's
2 experience with energy efficiency and demand response programs that customers are
3 much more likely to fully utilize energy efficiency programs when they are engaged
4 in the programs by taking some action on their own behalf and/or having invested
5 some of their own funds. This is the same approach PSO proposes with thermostats,
6 which is requiring interested customers to affirmatively select the program, obtain
7 and install the thermostat, and take actions consistent with the pricing terms of the
8 tariffs to achieve benefits.

9 As previously stated, PSO does not anticipate any change in the participation
10 rate for the DLC program due to a change in the ownership of the in-home device.
11 Furthermore, as discussed in my rebuttal testimony, PSO's approach is the
12 predominate approach used by utilities across the country.

13 Finally, as previously discussed, Ms. Alexander also makes another false
14 assumption that PSO is only planning to offer rebates for two years, as she
15 erroneously believes that PSO has only included two years of costs related to the
16 rebate program in its cost/benefit analysis. As I clearly stated in my rebuttal
17 testimony, once the pilot phase of the rebate program is complete, "PSO will continue
18 the rebate program in some form." (at 9) In the workpaper that was part of my
19 rebuttal testimony ("AMI Benefits Workpaper_Lewellen"), I included 15 years of
20 consumer program costs, which include the rebate costs, on the tab labeled "NPV
21 Consumer Prog."

22 **Q. Please respond to Ms. Alexander's concerns about PSO's future Pre-Pay**
23 **Program.**

1 A. Ms. Alexander doesn't appear to understand what a Pre-Pay Program entails. As per
2 my direct testimony (at 26), the Pre-Pay Program is simply a voluntary billing option
3 for customers. This type of billing option is an established method of billing that has
4 been utilized by other utilities for years. Ms. Alexander's argument that PSO's Pre-
5 Pay Program must be "defined, proposed, tested, or reviewed" before PSO is able to
6 utilize industry benchmark data to project benefits in a cost/benefit analysis is
7 unfounded. Again, as I have previously discussed, the use of benchmark data is a
8 widely used and accepted business practice that allows companies to obtain
9 information from outside organizations and apply it to its own organization to form a
10 comparative analysis. Based on the benchmarking data that PSO has used, the
11 participation rates and benefit levels that a Pre-Pay Program affords are reasonable
12 assumptions.

13 Regarding her other assertion that PSO has not provided any cost information
14 regarding the Pre-Pay Program, I addressed this earlier in my Supplemental Rebuttal
15 Testimony. PSO has identified all costs related to its Pre-Pay Program.

16 In response to Ms. Alexander's criticism of including its Pre-Pay Program
17 prior to approval, PSO will soon file a formal application with the Commission with a
18 detailed plan for the implementation of its Pre-Pay Program. In that proceeding, there
19 will be ample opportunity for others to weigh-in on this program and shape its final
20 form. Any other issues that parties may have about this program can be addressed in
21 this future proceeding. PSO does not envision a scenario of the program not being
22 approved, as it will be a completely voluntary bill payment option that also affords
23 customers additional choices that help manage energy usage and costs.

1 **VI. PSO WILL TRACK AND REPORT BENEFITS PER SETTLEMENTS**
2 **EXECUTED IN THIS PROCEEDING**

3 **Q. Please address Ms. Alexander’s assertion that PSO has failed to set forth any**
4 **methodology to track and report benefits.**

5 A. In this proceeding, PSO filed a Joint Stipulation and Settlement Agreement on June
6 17, 2014, which was subsequently supplemented on July 9, 2014 by a Second Joint
7 Stipulation and Settlement Agreement (Second Stipulation). The Second Stipulation,
8 if approved, will require PSO to submit the following AMI-related information on an
9 annual basis:

- 10 • The number of meters installed;
- 11 • A summary of communication plans executed;
- 12 • Participation rates of new tariffs;
- 13 • The number of automated connects and disconnects;
- 14 • Cost information (investment, O&M, guaranteed savings, etc.);
- 15 • AMI-related customer complaints;
- 16 • Percentage of AMI meters read; and
- 17 • Demand reduction and energy savings by program.

18 **VII. PSO’S AMI BENEFITS EXCEED THE**
19 **COSTS OF THE DEPLOYMENT**

20 **Q. Is Ms. Alexander correct in her assertion that the qualitative benefits**
21 **attributable to AMI are only theoretical in nature?**

22 A. No. The customer service benefits of AMI are proven benefits, not theoretical in
23 nature as Ms. Alexander contends. Ms. Alexander outright rejects these important

1 customer service benefits suggesting that they should be ignored since they are not
2 quantifiable in a cost/benefit analysis. As I have stated, customer service benefits are
3 real benefits to our customers and must be taken into consideration when making the
4 decision to deploy AMI. These benefits include:

- 5 • Increased customer education and satisfaction due to customer web portal and related
6 tools:
 - 7 ○ The customer web portal contains customer education information, as well as
8 decision-making features to help customers save on their electric bills;
 - 9 ○ Customers have the information, such as near real-time data and usage
10 information, and tools to proactively reduce and manage energy usage;
 - 11 ○ The forecasted bill feature helps inform energy decisions by granting
12 customers the ability to see energy usage, bill-to-date information, and
13 forecasted bill information. This allows customers to proactively make
14 energy consumption changes instead of responding reactively to an
15 after-the-fact bill;
 - 16 ○ Customers have the ability to make rate comparisons by viewing prior usage
17 patterns and comparing this information with different tariffs, such as a
18 voluntary TOD tariff to determine if they would have saved money on a TOD
19 tariff based upon prior usage patterns and potential savings if usage patterns
20 change;
 - 21 ○ Customers have the ability to track and compare usage against prior periods
22 with a temperature overlay by having access to historical usage and near
23 real-time usage information; and
 - 24 ○ Customers who do not have internet access have the ability to receive a free
25 home energy report.
- 26 • Power outage detection through real-time access:
 - 27 ○ Outage order creation will be implemented as meters are deployed, which will
28 quicken the dispatch of outage restoration resources and provide better
29 communications about the restoration efforts; and
 - 30 ○ Meters can be polled after an outage helps to ensure power is restored or
31 identifying nested/pocket outages in large outage events, such as a feeder
32 outage.

- 1 • Additional and improved metering activities:
- 2 ○ Meters can be remotely read on demand for move-in/outs, and billing
3 inquiries, which is more timely and convenient for customers;
- 4 ○ Credit reconnects can be performed automatically with AMI meters. In 2013
5 PSO had performed over 40,000 credit reconnects and with the
6 implementation of AMI over 90% of these orders (36,000) would have been
7 processed automatically, typically within minutes from when a payment is
8 made versus up to 24 hours for non-AMI meters;
- 9 ○ Residential service connections can be performed remotely, which helps to
10 accommodate customer moves. In 2013, PSO performed over 88,000 connect
11 orders and with the implementation of AMI almost 90% of these orders
12 (79,000) would have been processed automatically within minutes versus up
13 to 24 hours for non-AMI meters;
- 14 ○ Estimated meter readings are virtually eliminated due to access issues,
15 inclement weather, or hazardous conditions. In 2013, PSO had over 200,000
16 skipped readings, which resulted in 190,000 estimated bills to customers.
17 Once AMI is fully implemented, it will no longer be necessary for meter
18 readers to enter a customer's property to read the meter on a monthly basis.
19 Since weather, access, and staffing schedule issues will be avoided, skipped
20 reads and associated estimated bills will be significantly reduced;
- 21 ○ Billing complaints are reduced as estimated meter readings are replaced by
22 actual readings, which improves the accuracy of customers' bills;
- 23 ○ PSO resources generally no longer need to access customer yards on a
24 monthly basis to read the meter or perform service orders, which can cause
25 inconveniences for customers. As mentioned earlier, PSO meter readers and
26 field specialist made over 6.75 million visits to individual customer yards in
27 2013; and
- 28 ○ Deploying AMI reduces the number of customer premises visits annually, and
29 subsequently reduces the number of hazards PSO personnel are exposed to
30 each year. PSO estimates that AMI will help to avoid a number of safety
31 hazards that include over 24,000 accounts coded bad dog, vicious dog, or pit
32 bull, which accounts for 288,000 opportunities avoided annually, and an
33 additional 130,000 accounts coded having a dog, which is an additional 1.5
34 million avoided hazards.

- 1 • Quality of service improvements as a result of AMI's functionality:
- 2 ○ Temperature alarms can identify high temperatures in the meter, which
- 3 confers the ability to investigate and proactively correct issues, resulting in
- 4 avoiding potential customer outages;
- 5 ○ Equipment loading can be recognized and proactively corrected prior to an
- 6 outage occurring or a customer is even aware of an issue. For example, the
- 7 AMI meter will capture 15-minute average voltage data, and with analytics,
- 8 can identify trends where voltage increased over time, which may be
- 9 indicative of a transformer on the verge of failing or other service quality
- 10 issues. These locations can be proactively identified, and equipment can be
- 11 replaced prior to the transformer failing and causing an outage; and
- 12 ○ Power quality investigations are aided through interval kWh, kVAh, voltage
- 13 information, and meter events provided by AMI, which can help protect
- 14 customers.
- 15 • Environmental impact mitigation:
- 16 ○ Customer participation in PSO's consumer programs and tariffs enables peak
- 17 and ongoing energy reductions, which decreases carbon emissions from power
- 18 plants as less power is needed; and
- 19 ○ By being able to remotely connect and disconnect service, PSO will reduce
- 20 the amount of truck rolls associated with these activities, which leads to a
- 21 decrease in vehicle emissions. In 2013, PSO field employees drove over two
- 22 million miles, which is anticipated to be reduced by 75 percent.
- 23 • Future functionality for developing technologies:
- 24 ○ AMI helps facilitate distributed generation and net metering and the necessary
- 25 infrastructure to support electric vehicle charging; and
- 26 ○ AMI will facilitate access of future customer-deployed technologies that will
- 27 help manage energy usage by giving customers ready access to information
- 28 provided directly from the meter; and it will facilitate new applications for
- 29 other customers, such as commercial demand and energy reduction programs.
- 30

31 **Q. Does Ms. Alexander provide or cite any support for her assertions or concerns**

32 **on these issues?**

33 A. No, she does not.

VIII. CONCLUSION

1
2 **Q. Please summarize your Supplemental Rebuttal Testimony.**

3 A. PSO's proposed AMI deployment costs, benefits, and participation rates are based on
4 logical and reasonable assumptions that show the benefits of AMI exceed the costs.
5 AMI is a proven technology already available to approximately 50 percent of the
6 United States and is already offered to many customers within Oklahoma. PSO's
7 proposed AMI deployment will provide a host of quantitative and customer service
8 benefits, as well as consumer programs which will be immediately available to PSO's
9 customers once they receive an AMI meter. The deployment should not be delayed
10 due to the unfounded criticisms of Ms. Alexander.

11 **Q. Does this conclude your Supplemental Rebuttal Testimony?**

12 A. Yes.

Three Year Deployment Cash Flows - PSO AMI / Consumer Program Deployment

Cost / Benefit Component	AMI Costs															Total
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	
O&M																
Project / MRO Staffing Requirements	0	(2,200,000)	(2,400,000)	(2,450,076)	(2,523,579)	(2,599,286)	(2,677,265)	(2,757,583)	(2,840,310)	(2,925,519)	(3,013,285)	(3,103,684)	(3,196,794)	(3,292,698)	(3,391,479)	(39,371,557)
Severance Costs	0	(1,000,000)	(2,000,000)	0	0	0	0	0	0	0	0	0	0	0	0	(3,000,000)
Consumer Education / Communication	(400,000)	(1,000,000)	(1,000,000)	(750,000)	(750,000)	(750,000)	(750,000)	(750,000)	(750,000)	(750,000)	(350,000)	(350,000)	(350,000)	(350,000)	(350,000)	(9,400,000)
Head End Software SAAS vs. Hosted	(400,000)	(600,000)	(700,000)	0	0	0	0	0	0	0	0	0	0	0	0	(1,700,000)
Backoffice IT	(75,000)	(150,000)	(300,000)	(317,000)	(324,000)	(330,000)	(337,000)	(344,000)	(351,000)	(358,000)	(365,000)	(372,000)	(380,000)	(387,000)	(395,000)	(4,785,000)
Network	(120,000)	(650,000)	(840,000)	(1,312,000)	(2,690,000)	(2,355,000)	(3,594,000)	(1,499,000)	(1,499,000)	(3,616,000)	(3,353,000)	(5,155,000)	(1,499,000)	(1,567,000)	(3,094,000)	(32,843,000)
Security	(200,000)	0	0	(75,000)	0	0	(75,000)	0	0	(75,000)	0	0	0	0	0	(425,000)
Other	(150,000)	(150,000)	(150,000)	(1,210)	(1,238)	(1,267)	(1,297)	(1,328)	(1,359)	(1,391)	(1,424)	(1,458)	(1,492)	(1,527)	(1,563)	(466,557)
Total	(1,345,000)	(5,750,000)	(7,390,000)	(4,905,286)	(6,288,817)	(6,035,554)	(7,434,562)	(5,351,911)	(5,441,669)	(7,725,911)	(7,082,709)	(8,982,141)	(5,427,286)	(5,598,225)	(7,232,042)	(91,991,114)

Capital																
Meters / Installation	(23,435,280)	(23,988,177)	(25,290,797)	(377,014)	(385,909)	(395,013)	(404,332)	(413,872)	(423,636)	(433,631)	(443,861)	(454,333)	(465,052)	(476,023)	(487,254)	(77,874,183)
Inventory Holding Costs	(4,357,863)	(4,445,527)	(4,671,250)	0	0	0	0	0	0	0	0	0	0	0	0	(13,474,641)
Meter Replacement	0	0	0	(212,532)	(427,308)	(650,917)	(654,480)	(658,127)	(661,859)	(665,680)	(669,591)	(673,595)	(677,692)	(681,887)	(686,180)	(7,319,848)
Backoffice IT	(2,625,400)	(3,950,000)	(1,500,000)	0	0	0	0	0	0	0	0	0	0	0	0	(8,075,400)
Network	(5,350,000)	(5,252,000)	(10,557,000)	0	0	0	0	0	0	0	0	0	0	0	0	(21,159,000)
Security	(300,000)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(300,000)
Other IT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	(36,068,543)	(37,635,704)	(42,019,047)	(589,546)	(813,217)	(1,045,930)	(1,058,812)	(1,071,998)	(1,085,495)	(1,099,311)	(1,113,452)	(1,127,927)	(1,142,744)	(1,157,910)	(1,173,434)	(128,203,071)

Cost / Benefit Component	AMI Benefits															Total
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	
O&M																
Field Labor / Labor - Related Reductions	0	1,000,000	4,000,000	6,317,243	6,434,112	6,553,143	6,674,377	6,797,853	6,923,613	7,051,700	7,182,156	7,315,026	7,450,354	7,588,186	7,728,567	89,016,329
Billing / Call Center Reductions	0	30,243	61,606	95,069	96,828	98,619	100,443	102,302	104,194	106,122	108,085	110,085	112,121	114,195	116,308	1,356,219
Credit / Collections, Theft, and CIM Benefits	0	1,007,810	2,015,620	3,053,970	3,145,589	3,239,956	3,337,155	3,437,270	3,540,388	3,646,599	3,755,997	3,868,677	3,984,738	4,104,280	4,227,408	46,365,456
Reduction in Bad Debt - Prepaid Metering	0	12,785	25,569	38,354	51,139	76,708	89,493	102,278	102,278	102,278	102,278	102,278	102,278	102,278	102,278	1,112,272
Other Benefits	0	75,125	153,029	236,152	240,520	244,970	249,502	254,118	258,819	263,607	268,484	273,451	278,510	283,662	288,910	3,368,859
Total	0	2,125,963	6,255,824	9,740,788	9,968,188	10,213,397	10,450,970	10,693,819	10,929,292	11,170,306	11,417,000	11,669,517	11,928,000	12,192,601	12,463,471	141,219,135

Capital																
Obsolete Meter Avoidance Costs	239,475	487,810	752,780	0	0	0	0	0	0	0	0	0	0	0	0	1,480,065
Field Labor / Labor - Related Reductions	0	93,930	187,860	281,790	290,244	298,951	307,920	317,157	326,672	336,472	346,566	356,963	367,672	378,702	390,063	4,280,962
Other Benefits	0	51,214	104,324	160,991	163,969	167,002	170,092	173,239	176,444	179,708	183,032	186,418	189,867	193,380	196,957	2,296,638
Total	239,475	632,955	1,044,964	442,781	454,213	465,953	478,012	490,396	503,115	516,180	529,599	543,382	557,539	572,082	587,021	8,057,665

Cost / Benefit Component	Other Benefits															Total
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	
Energy / Capacity																
Energy Reduction - Prepaid Metering	0	332,966	735,733	1,154,752	1,574,523	2,404,439	2,792,303	3,309,155	3,762,943	3,835,129	3,980,602	4,090,606	4,143,325	4,273,312	4,365,851	40,755,640
Total	0	332,966	735,733	1,154,752	1,574,523	2,404,439	2,792,303	3,309,155	3,762,943	3,835,129	3,980,602	4,090,606	4,143,325	4,273,312	4,365,851	40,755,640

Net AMI Cash Flows																
O&M	(2,362,849)	(1,018,048)	868,103	4,835,501	3,679,371	4,177,844	3,016,408	5,341,909	5,487,622	3,444,395	4,334,291	2,687,375	6,500,714	6,594,375	5,231,428	52,818,440
Capital	(35,829,068)	(37,002,750)	(40,974,083)	(146,765)	(359,004)	(579,977)	(580,801)	(581,602)	(582,380)	(583,131)	(583,854)	(584,546)	(585,205)	(585,828)	(586,414)	(120,145,407)
Other	0	345,751	761,302	1,193,106	1,625,662	2,481,147	2,881,796	3,411,433	3,865,221	3,937,407	4,082,879	4,192,884	4,245,603	4,375,590	4,468,129	41,867,911
Total	(38,191,917)	(37,675,047)	(39,344,678)	5,881,843	4,946,029	6,079,014	5,317,403	8,171,740	8,770,463	6,798,671	7,833,317	6,295,714	10,161,112	10,384,137	9,113,144	(25,459,056)

Cost / Benefit Component	Consumer Programs Costs															Total
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	
O&M																
Consumer Program Costs	0	(2,900,000)	(2,900,000)	(2,900,000)	(2,900,000)	(2,900,000)	(1,000,000)	(1,000,000)	(1,000,000)	(1,000,000)	(1,000,000)	(1,000,000)	(1,000,000)	(1,000,000)	(1,000,000)	(23,500,000)
Incremental FTE	(62,000)	(63,860)	(65,776)	(67,749)	(69,782)	(71,875)	(74,031)	(76,252)	(78,540)	(80,896)	(83,323)	(85,822)	(88,397)	(91,049)	(93,781)	(1,153,133)
Total	(62,000)	(2,963,860)	(2,965,776)	(2,967,749)	(2,969,782)	(2,971,875)	(1,074,031)	(1,076,252)	(1,078,540)	(1,080,896)	(1,083,323)	(1,085,822)	(1,088,397)	(1,091,049)	(1,093,781)	(24,653,133)
Capital																
MACSS Investment	(1,500,000)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(1,500,000)
Total	(1,500,000)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(1,500,000)

Cost / Benefit Component	Consumer Programs Benefits															Total
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	
Energy / Capacity																
Peak Load Reduction - DLC, TOU (both), Web Portal	0	244,275	766,937	2,147,147	4,366,924	5,327,136	5,525,153	5,754,935	6,018,042	6,316,086	6,650,737	7,023,724	7,436,833	7,891,912	8,390,874	73,860,715
Total	0	244,275	766,937	2,147,147	4,366,924	5,327,136	5,525,153	5,754,935	6,018,042	6,316,086	6,650,737	7,023,724	7,436,833	7,891,912	8,390,874	73,860,715

Net Consumer Program Cash Flows

O&M	(62,000)	(2,963,860)	(2,965,776)	(2,967,749)	(2,969,782)	(2,971,875)	(1,074,031)	(1,076,252)	(1,078,540)	(1,080,896)	(1,083,323)	(1,085,822)	(1,088,397)	(1,091,049)	(1,093,781)	(24,653,133)
Capital	(1,500,000)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(1,500,000)
Peak Load Reduction Savings	0	244,275	766,937	2,147,147	4,366,924	5,327,136	5,525,153	5,754,935	6,018,042	6,316,086	6,650,737	7,023,724	7,436,833	7,891,912	8,390,874	73,860,715
Total	(1,562,000)	(2,719,585)	(2,198,839)	(820,602)	1,397,142	2,355,261	4,451,122	4,678,683	4,939,502	5,235,190	5,567,415	5,937,901	6,348,436	6,800,863	7,297,094	47,707,582

Total GridSmart Cash Flows

O&M	(2,424,849)	(3,981,908)	(2,097,673)	1,867,752	709,589	1,205,969	1,942,377	4,265,657	4,409,082	2,363,499	3,250,968	1,601,553	5,412,317	5,503,326	4,137,648	28,165,307
Capital	(37,329,068)	(37,002,750)	(40,974,083)	(146,765)	(359,004)	(579,977)	(580,801)	(581,602)	(582,380)	(583,131)	(583,854)	(584,546)	(585,205)	(585,828)	(586,414)	(121,645,407)
Other	0	590,026	1,528,239	3,340,253	5,992,586	7,808,283	8,406,949	9,166,369	9,883,263	10,253,493	10,733,617	11,216,608	11,682,436	12,267,503	12,859,003	115,728,626
Total	(39,753,917)	(40,394,632)	(41,543,517)	5,061,240	6,343,171	8,434,275	9,768,525	12,850,423	13,709,965	12,033,861	13,400,731	12,233,615	16,509,548	17,185,001	16,410,237	22,248,526

Total GridSmart Costs

O&M	(2,424,849)	(7,117,516)	(8,447,145)	(7,873,035)	(9,258,599)	(9,007,429)	(8,508,593)	(6,428,163)	(6,520,209)	(8,806,807)	(8,166,032)	(10,067,964)	(6,515,683)	(6,689,274)	(8,325,823)	(114,157,121)
Capital	(37,568,543)	(37,635,704)	(42,019,047)	(589,546)	(813,217)	(1,045,930)	(1,058,812)	(1,071,998)	(1,085,495)	(1,099,311)	(1,113,452)	(1,127,927)	(1,142,744)	(1,157,910)	(1,173,434)	(129,703,071)
Total	(39,993,392)	(44,753,221)	(50,466,192)	(8,462,581)	(10,071,815)	(10,053,359)	(9,567,406)	(7,500,161)	(7,605,704)	(9,906,118)	(9,279,484)	(11,195,891)	(7,658,427)	(7,847,185)	(9,499,257)	(243,860,193)

PSO gridSMART Summary Business Cases

AMI - All Costs and Benefits After Tax WACC: **7.38%**

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
Benefits	239,475	3,091,883	8,036,521	11,338,321	11,996,924	13,083,789	13,721,285	14,493,371	15,195,350	15,521,615	15,927,200	16,303,505	16,628,865	17,037,995	17,416,342
Costs	(37,413,543)	(43,385,704)	(49,409,047)	(5,494,832)	(7,102,034)	(7,081,484)	(8,493,374)	(6,423,909)	(6,527,165)	(8,825,222)	(8,196,162)	(10,110,069)	(6,570,030)	(6,756,135)	(8,405,476)
Total Cash Flows	(37,174,068)	(40,293,821)	(41,372,526)	5,843,489	4,894,890	6,002,305	5,227,910	8,069,462	8,668,185	6,696,393	7,731,039	6,193,436	10,058,834	10,281,860	9,010,866

NPV:	(\$58,601,798)
NPV B/C Ratio:	0.63
Total Cash Flows:	(\$30,161,746)
Cash B/C Ratio:	0.86

Consumer Programs - All Costs and Benefits

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
Benefits	0	244,275	766,937	2,147,147	4,366,924	5,327,136	5,525,153	5,754,935	6,018,042	6,316,086	6,650,737	7,023,724	7,436,833	7,891,912	8,390,874
Costs	(1,562,000)	(2,963,860)	(2,965,776)	(2,967,749)	(2,969,782)	(2,971,875)	(1,074,031)	(1,076,252)	(1,078,540)	(1,080,896)	(1,083,323)	(1,085,822)	(1,088,397)	(1,091,049)	(1,093,781)
Total Cash Flows	(1,562,000)	(2,719,585)	(2,198,839)	(820,602)	1,397,142	2,355,261	4,451,122	4,678,683	4,939,502	5,235,190	5,567,415	5,937,901	6,348,436	6,800,863	7,297,094

NPV:	\$19,434,427
B/C Ratio:	2.13
Total Cash Flows:	\$47,707,582
Cash B/C Ratio:	2.82

AMI and Consumer Programs - All Costs and Benefits

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
Benefits	239,475	3,336,158	8,803,457	13,485,467	16,363,848	18,410,925	19,246,438	20,248,306	21,213,392	21,837,701	22,577,938	23,327,228	24,065,697	24,929,907	25,807,217
Costs	(38,975,543)	(46,349,564)	(52,374,823)	(8,462,581)	(10,071,815)	(10,053,359)	(9,567,406)	(7,500,161)	(7,605,704)	(9,906,118)	(9,279,484)	(11,195,891)	(7,658,427)	(7,847,185)	(9,499,257)
Total Cash Flows	(38,736,068)	(43,013,406)	(43,571,365)	5,022,886	6,292,033	8,357,566	9,679,032	12,748,145	13,607,687	11,931,583	13,298,453	12,131,337	16,407,270	17,082,723	16,307,960

NPV:	(\$39,167,371)
B/C Ratio:	0.78
Total Cash Flows:	\$17,545,836
Cash B/C Ratio:	1.07

EXHIBIT DSL-SR2

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

**APPLICATION OF PUBLIC SERVICE)
 COMPANY OF OKLAHOMA TO BE IN)
 COMPLIANCE WITH ORDER NO. 591185)
 ISSUED IN CAUSE NO. PUD 201100106 WHICH)
 REQUIRES A BASE RATE CASE TO BE FILED) CAUSE NO. PUD 201300217
 BY PSO AND THE RESULTING ADJUSTMENT)
 IN ITS RATES AND CHARGES AND TERMS)
 AND CONDITIONS OF SERVICE FOR)
 ELECTRIC SERVICE IN THE STATE OF)
 OKLAHOMA)**

**PUBLIC SERVICE COMPANY OF OKLAHOMA’S RESPONSE TO
 AARP’S FIFTH SET OF DATA REQUESTS**

Question No. 5-3:

With regard to the costs and benefits included in the “AMI Benefit Workpaper_Lewellen” attached to your testimony, identify how each cost and benefit assumption in your Rebuttal Testimony differs from that included in the cost benefit analysis provided in response to AG 5-7 and support the basis for this change.

Response No. 5-3:

The only revisions from the preliminary cash flow model provided in AG5-7 are the forecasted benefits associated with theft reduction, development of the avoided generation costs, the performance of the NPV calculations, and the separation of some of the benefits into individual categories to provide clarity. The NPV calculations were performed on a cash flow model provided in AG 5-7. The following table compares the differences between rebuttal and AG 5-7 for these items:

Category	AG 5-7	Rebuttal Testimony
Theft Reduction	Assumed a theft % of revenue reduction rate of 0.25%	Assumed a theft % of revenue reduction rate of 0.50%
Avoided Generation Costs	Not originally calculated	Calculated for Rebuttal in response to the testimony of AARP witness Alexander (at 16)
NPV Calculations	Calculated for AMI and for consumer programs separately	Calculated individually for each benefit associated with PSO’s proposed AMI deployment and associated consumer programs. However, this relied on the same cash flow model used for the presentation given as part of AG 5-7
Benefit Aggregation	The benefit amount associated with the reduction in theft, CIM, and bad debt were combined into one figure	The benefit amounts associated with the reduction in theft, CIM, and bad debt were separated into separate figures

Prepared By: Derek S. Lewellen

Title: Mgr gridSMART & MRO

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE COMPANY)
OF OKLAHOMA, AN OKLAHOMA)
CORPORATION, FOR AN ADJUSTMENT IN ITS)
RATES AND CHARGES AND THE ELECTRIC)
SERVICE RULES, REGULATIONS AND)
CONDITIONS OF SERVICE FOR ELECTRIC)
SERVICE IN THE STATE OF OKLAHOMA)

CAUSE NO. PUD 201700151

DIRECT TESTIMONY OF

DEREK S. LEWELLEN

ON BEHALF OF

PUBLIC SERVICE COMPANY OF OKLAHOMA

FILED
JUN 30 2017

COURT CLERK'S OFFICE - OKC
CORPORATION COMMISSION
OF OKLAHOMA

JUNE 2017

TESTIMONY INDEX

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I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS?

A. My name is Derek S. Lewellen, and I am the Meter Infrastructure & Program Development Manager for Public Service Company of Oklahoma (PSO or Company). My business address is 212 E. Sixth Street, Tulsa, OK 74119.

Q. WOULD YOU PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. I earned a bachelor's degree in Electrical Engineering from Oklahoma State University in 1989 and a Master's degree in Business Administration from Oklahoma City University in 1994. I have over 27 years of electric utility operations experience. I began my career in 1989 with the Company as a substation engineer. In 1992, I was named as a Substation Superintendent. In 1994, I was named Manager, Distribution for the Lawton District. From 2000 until 2004, I worked in various management positions with the American Electric Power Service Corporation (AEPSC) in Columbus, Ohio, evaluating distribution systems and leading special projects. In 2004, I was named Manager, Distribution for the McAlester District. In 2010, I was named the Manager of gridSMART and also assumed the responsibility for Meter Revenue Operations for PSO in 2013 until I was named to my current position with the Company in 2016.

Q. WOULD YOU PLEASE DESCRIBE YOUR RESPONSIBILITIES AS METER INFRASTRUCTURE AND PROGRAM DEVELOPMENT MANAGER?

1 A. I am responsible for the organization that deployed and now operates and
2 maintains PSO's Advanced Meter Infrastructure (AMI) system. My duties
3 include providing overall planning and coordination of technical project activities
4 for the AMI implementation, and developing and managing customer benefit
5 programs. My responsibilities also include directing, supervising, and
6 coordinating the duties of field personnel in the safe installation, operation, and
7 maintenance of the AMI system including meters and communications network.

8 Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY BEFORE ANY
9 REGULATORY AGENCY?

10 A. Yes. I testified before the Oklahoma Corporation Commission (OCC or
11 Commission) in Cause No. PUD 200700397, which was an application on behalf
12 of the Company to defer, amortize, and recover storm costs associated with the
13 January 2007 ice storm that impacted the Company's service territory. Also, I
14 submitted testimony in Cause No. PUD 201100083, which was an application
15 asking for approval of a waiver from Commission rule OAC 165:35-21-21(3) and
16 approval of changes to PSO's electric service rules and terms and conditions of
17 service. I also submitted testimony in Cause No. PUD 201100168, which was an
18 application asking for approval of three new tariffs associated with PSO's AMI
19 deployment. I also submitted testimony in Cause No. PUD 201300217, which
20 was an application on behalf of the Company to adjust its rates. Most recently, I
21 submitted testimony in Cause No. PUD 201500109 to provide a nonstandard
22 metering option to customers.

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II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to discuss PSO’s system-wide implementation of AMI, explain the technology, support the associated costs and describe the operational benefits already being achieved less than one year following full deployment.

III. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. After successfully testing AMI in three pilot areas, PSO developed a plan to fully implement the technology throughout its entire service area to gain the many operational, reliability and customer experience benefits made possible by AMI.

PSO completed deployment in July of 2016, ahead of schedule and under budget despite installing more meters and more functionality than originally planned. The capital expenditures were over seven percent lower than original projections, while the operations and maintenance (O&M) expenses were 33 percent less. Although AMI has been fully deployed for less than one year, operational, reliability, and customer experience benefits are already being realized at significant levels, many beyond original projections.

Specific to the operational savings, PSO achieved significant labor, overhead and vehicle savings, and is on track to realize even more in 2017. Additional operational benefits and savings include a reduction in bad debt with further reductions expected from PSO’s prepay program; the improved ability to

1 identify theft and consumption on inactive meters; a substantial one-time avoided
2 investment from replacing obsolete meters; and billing and call center
3 efficiencies. Finally, since PSO personnel no longer need to access customers'
4 premises to reach meters and their miles driven is significantly reduced, the safety
5 of employees is dramatically improved.

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IV. AMI DEPLOYMENT

8 Q. WHAT IS AMI?

9 A. At a high level, AMI refers to systems that measure, collect, and analyze energy
10 usage from meters through a communications network. This infrastructure
11 includes hardware, such as meters, that enable two-way communications, and a
12 communications network that provides the communication path between the
13 meters and PSO's Information Technology (IT) systems. PSO's IT systems
14 include the customer information systems, meter data management system,
15 analytics hub, and the customer webportal. These IT systems utilize the AMI data
16 to provide useful information to customers. I more fully describe PSO's AMI
17 system later in my testimony.

18 Q. WHY DID PSO DEPLOY AMI THROUGHOUT ITS SERVICE TERRITORY?

19 A. PSO began testing AMI in 2011. Through three pilots, PSO gained valuable
20 experience with the technology and associated customer offerings, achieving
21 operational efficiencies and customer benefits almost immediately.

1 Based on the pilot results, as well as the maturation of the AMI technology
2 and stabilization of pricing, PSO decided to move forward with full deployment
3 to deliver operational, reliability and customer service benefits system-wide.

4 Q. PLEASE DESCRIBE PSO'S DEPLOYMENT PLAN.

5 A. In 2013, PSO developed an initial project plan to install AMI meters, network
6 equipment, and supporting IT systems. The plan and projected costs were based
7 upon the experience gained with PSO's pilots, lessons learned from other utilities
8 like AEP Texas and Oklahoma Gas and Electric (OG&E), PSO's procurement
9 experience, and available pricing.

10 PSO determined deployment would take three years to efficiently and
11 cost-effectively obtain the necessary resources for the project, install the
12 technology and IT systems, and implement the associated consumer programs and
13 functionality. As discussed below, meter installations were scheduled by district
14 beginning in September 2014, with expected completion approximately 24
15 months later in the fourth quarter of 2016.

16 In early 2014, PSO refined the project plan to incorporate details such as
17 the bidding processes for material and various contract resources, material
18 delivery schedules, supporting IT projects, network design, meter and network
19 installation schedules, customer communication plans, and consumer program
20 development. All of these steps were layered into the project plan to ensure
21 timely completion of the three-year project.

22 Part of the plan involved significant amounts of IT work necessary to
23 effectively manage, store, and utilize over a quarter of a billion pieces of data

1 received daily. This included scaling a meter data management system, creating a
2 central storage location for meter data to be used in analytics and expansion of
3 meter network software from the pilot to handle the volume of data, making
4 Customer Information System (CIS) changes, developing a prepay option that
5 integrates into multiple existing systems, configuring webportal integrations, and
6 developing and implementing Consumer Programs (or Power HoursSM).

7 Q. WAS THE PILOT EXPERIENCE USED TO HELP CREATE THE
8 DEPLOYMENT PLAN?

9 A. Yes, the pilot experience shaped the deployment plan in many ways. PSO
10 utilized lessons learned from the pilot to enhance the reliability of the
11 communication network. This involved developing a plan to use multiple
12 communication paths with two different cellular providers and devices connected
13 to internal PSO communication networks for redundancy and diminished risk
14 from a single network carrier failure.

15 PSO also refined and enhanced its customer communication plan for the
16 full AMI deployment, based in part on lessons learned from the pilot. This
17 enhanced communication plan helped educate customers on how to utilize AMI,
18 as well as the benefits enabled by AMI.

19 Finally, PSO was able to leverage IT solutions developed for the pilot, and
20 scaled existing systems such as network systems and meter data management
21 systems, for full deployment of AMI.

1 Q. DID PSO USE COMPETITIVE BIDDING DURING DEPLOYMENT?

2 Yes, PSO competitively bid all aspects of the project to ensure requirements were
 3 met at the best available pricing. For example, PSO sought bids from multiple
 4 AMI communication providers for components such as network equipment and
 5 associated IT systems, meter vendors, meter installation contractors, network
 6 equipment installation contractors, and customer webportal providers.

7 Q. PLEASE DESCRIBE THE METER AND NETWORK INSTALLATION
 8 SCHEDULE.

9 A. PSO installed meters and network equipment by district, beginning in the
 10 McAlester District in 2014. The network equipment was typically installed a
 11 minimum of 60 days prior to meter installation to ensure the meters could
 12 communicate when installed.

13 Figure 1 summarizes the deployment time frame, the PSO deployment
 14 area that received the AMI meters, the approximate number of network
 15 communication devices installed, and the approximate number of AMI meters
 16 installed in each deployment area.

17 **Figure 1**

Deployment Time Frame	PSO Deployment Area	Network Equipment Deployed	AMI Meters Deployed
2011-2012	Pilot Areas	70	33,000
4Q 2014 -1Q 2015	SE Oklahoma	1,300	60,000
2015	Metro Tulsa	750	298,000
1Q 2016	NE Oklahoma	1,500	58,000
2Q 2016	SW Oklahoma	1,400	115,000
3Q-4Q 2016	Cleanup All Areas		2,000
Total		5,020	566,000

18

1 Q. HOW DID PSO COMMUNICATE WITH CUSTOMERS DURING THE
2 DEPLOYMENT?

3 A. Prior to and during AMI meter installation, PSO provided customers information
4 about AMI, the customer webportal and associated Consumer Programs. This
5 communication took place through multiple communications channels. For
6 communications related specifically to the meter exchange, the following direct
7 customer contact channels were used:

- 8 • Customer Letter: This was the initial contact in the form of a letter
9 informing customers of their projected meter installation date. The letter
10 was sent out approximately four to eight weeks prior to the new meter
11 installation. Approximately 533,000 letters were sent to homes or
12 businesses.
- 13 • Phone Blast Message: As a reminder of impending installations, customers
14 were notified via phone message one to four weeks prior to the new meter
15 installation.
- 16 • Door Hanger: At the time meters were exchanged, door hangers were left
17 to inform customers that their existing meters had been exchanged for an
18 AMI meter and how to contact PSO if they had any questions or concerns.
19 The door hanger also included information about the meter, including
20 benefits of AMI and how to access the customer webportal.

21 Q. WHEN DID PSO COMPLETE DEPLOYMENT?

22 A. Aside from minor cleanup, PSO completed deployment ahead of schedule in July
23 2016. In addition to deploying ahead of schedule, more meters were installed
24 than originally projected,¹ additional functionality such as an enhanced webportal
25 was made available, and the project came in under budget as discussed in more
26 detail below.

¹ Since the deployment of AMI entailed fewer PSO employees visiting locations throughout the service territory to read meters, the additional meters installed were associated with temporary vacant accounts. Installing meters on these accounts allows for near-real time connections when a customer moves in, and the ability to deter and identify theft at these locations.

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V. PROJECT COSTS

Q. WHAT ARE THE FINAL PROJECT COSTS?

A. The final project costs are \$110,811,458 in capital expenditures, and \$13,757,961 of O&M expenses for the AMI deployment period of 2014 through 2016. These totals are approximately \$8.9 million and \$6.7 million under the original cost estimates respectively, as shown in Figure 2.

Figure 2

AMI Program	2014-2016 Projected	2014-2016 Actual	Amount Under Budget
Capital Spend – project	(\$119.7 million)	(\$110.8 million)	\$8.9 million
O&M Spend - project	(\$20.5 million)	(\$13.8 million)	\$6.7 million

Q. HOW DID PSO COMPLETE THE PROJECT AHEAD OF SCHEDULE AND UNDER BUDGET DESPITE INSTALLING MORE METERS THAN ORIGINALLY PLANNED?

A. PSO competitively bid all components of the project, including contractors, meter, and network suppliers. In addition, PSO was able to leverage its purchasing power to obtain a lower cost for AMI meters and network equipment. This was the largest contributor to the decrease in capital costs because the projected capital cost per customer dropped significantly from the pre-deployment projection of \$230 to \$208 actual.²

In terms of the reduced O&M costs, employee severance costs were approximately \$2.0 million less than projected, staffing and salaries for new

² During the pilot, the total capital cost was approximately \$428 per customer.

1 positions were \$2.5 million less than the projected expense, and costs associated
 2 with the network and IT components were approximately \$2.0 million less than
 3 originally projected. The staffing for new positions associated with AMI was also
 4 less than projected, which is an ongoing savings greater than originally projected.

5 Q. PLEASE PROVIDE ADDITIONAL DETAILS PERTAINING TO THE AMI
 6 DEPLOYMENT COSTS.

7 A. The project costs are comprised of five major cost components: Grid
 8 Management, AMI Meter, Network, AMI IT, and Consumer Programs. The cost
 9 of each component is shown below in Figure 3.

Figure 3

AMI Deployment Cost		
Component	Capital	O&M
Grid Management	\$3.1 million	\$4.0 million
AMI Meter	\$77.3 million	\$.7 million
AMI Network	\$11.7 million	\$0 million
AMI IT	\$18.7 million	\$3.4 million
Consumer Programs		\$5.7 million
Totals	\$110.8 million	\$13.8 million

11
 12 The Grid Management component includes project management,
 13 consumer education, and the employee severance costs. The project management
 14 for the deployment incorporated labor, scheduling resources, and expenses to
 15 manage all aspects of the project. Consumer education covered the creation and
 16 distribution of information to customers, including the meter change-out
 17 communication previously discussed. Also included is the one-time employee
 18 severance costs associated with reducing 85 positions.

19 The AMI Meter component includes the AMI meters, installation costs,
 20 and associated meter expenses. More specifically, this includes the purchasing,

1 shipping, testing, and handling of the AMI meters, along with the removal,
2 testing, and disposal of existing meters.

3 The AMI Network component includes the communications network,
4 supporting equipment, installation, and associated expenses, as well as the design,
5 purchase, and installation of approximately 5,000 network communication
6 devices along with any dedicated distribution transformers needed to power the
7 equipment.

8 The AMI IT component includes the information technology associated
9 with the project, including but not limited to the meter system interface, meter
10 data management system, CIS changes and enhancements, customer webportal,
11 integration of customer programs, IT enhancements to implement and support
12 customer tariffs, data analytics, automated outage order process, prepay billing
13 functionality,³ and security.

14 The Consumer Programs component included Honeywell costs associated
15 with program management, call center costs for customer enrollment and
16 inquiries, software for both enrollment and the customer online store used to
17 purchase thermostats, customer education and processing thermostat rebates.
18 Company witness Scott Ritz provides additional details related to PSO's
19 PowerHoursSM programs, including the thermostat program.

20 Q. WHAT HAS BEEN THE OVERALL IMPACT OF THE AMI DEPLOYMENT
21 ON PSO'S METER EXPENSES?

³ Actual spend at the end of 2016 for prepay IT was slightly less than the pre-deployment projection of \$2.1 million in capital.

1 A. As shown in Figure 5 of Company witness Steven F. Baker's direct testimony,
2 O&M expenses in this category have increased since the last PSO base case. The
3 increase in meter expense is primarily attributable to: (1) Consumer Programs
4 (\$3.3 million), (2) customer education (\$0.6 million), and (3) additional IT items
5 necessary to support AMI (\$0.5 million). These are reasonable, ongoing expenses
6 necessary to maximize the benefits of AMI to customers, and consistent with pre-
7 deployment projections.

8 VI. OPERATIONAL SAVINGS AND BENEFITS

9 Q. DID PSO ACHIEVE THE LEVEL OF O&M SAVINGS FROM THE
10 REDUCTION IN LABOR, VEHICLES AND OVERHEADS PROJECTED IN
11 CAUSE NO. PUD 201300217?

12 A. Yes. In Cause No. PUD 201300217, PSO projected a \$5.0 million savings during
13 the three-year deployment period and an additional \$6 million in the first full year
14 after deployment. In 2014 through 2016, PSO realized over \$8.85 million in
15 associated labor, overhead and vehicle savings, which is \$3.35 million greater
16 than the projected \$5 million. PSO is also on target to achieve over \$6 million in
17 annualized labor, overhead and vehicle savings in 2017.

18 This savings represents the elimination of all 59 meter reader positions,
19 the reduction of the field meter services staff from 52 employees to 28,⁴ and the
20 elimination of two clerical positions. This is a total of 85 positions, as well as the

⁴ Field employees include those that perform meter connect/disconnect, replace single-phase meters, customer move in/out, etc.

1 associated vehicles, which equals the number of employee and vehicle reductions
2 projected in Cause No. PUD 201300217. Current headcount and payroll are not
3 expected to reduce further beyond the test year end.

4 Associated with the staffing and vehicle reductions, PSO avoided over
5 525,000 truck rolls and 1.3 million miles during 2016. This is approximately 60
6 percent less than the amount of miles driven prior to the deployment of AMI.
7 PSO anticipates further mileage reductions in 2017 and is projected to meet or
8 exceed the original projection of reducing miles driven by 75 percent or
9 approximately 1.5 million miles.

10 Q. HAVE THE GUARANTEED SAVINGS BEEN RETURNED TO
11 CUSTOMERS?

12 A. The \$11 million of guaranteed savings will be passed through to customers by the
13 end of 2017. At the end of May 2017, \$7,587,256 had passed through the AMI
14 Rider to customers. The remaining balance of savings is projected to go to
15 customers through the AMI Rider by year end. The AMI Rider is discussed in
16 more detail in the testimonies of PSO witnesses Randall Hamlett and Jennifer
17 Jackson.

18 Q. WHAT BENEFITS ARE ACHIEVED RELATED TO BAD DEBT?

19 A. With the ability to automate the disconnect and reconnect process of customer
20 delinquent accounts, PSO is able to reduce the annual amount of charge-offs.
21 Prior to the deployment of AMI, the three-year average for charge-offs was
22 almost \$6 million annually. In 2016, even though AMI was not yet fully
23 deployed, the charge-off amount was slightly over \$5 million, which represents an

1 approximately \$1 million reduction in bad debt. This reduction benefits all
2 customers because it reduces the amount of uncollected billings that is passed
3 through to all customers.

4 The charge-off reduction was accomplished through a combination of
5 factors, mainly the ability to process almost 100 percent of the credit disconnects,
6 and the ability to process credit disconnects after a moratorium. Prior to AMI,
7 this was a manual process constrained due to the number of available resources,
8 which allowed some customers to increase the delinquency period another 30
9 days. Also, having the ability to remotely connect/disconnect at the meter has
10 eliminated the reconnect fee and reduced the number of services disconnected at
11 the pole due to an inaccessible meter.

12 Now that AMI is fully deployed and PSO is offering Power PaySM
13 (prepaid billing), PSO is expecting charge-offs to be further reduced in 2017,
14 beyond the \$1.6 million achieved over the deployment period (this is slightly less
15 than the original projection of \$1.7 million reduction during the same period).
16 This expectation is based upon the experiences of other electric utilities with
17 prepay programs that have created a positive impact on charge-offs. This is
18 attributed to Power PaySM customers being able to defer up to \$500 of past-due
19 amounts coupled with the ability to pay the deferred amount over time.

20 Q. HOW DOES AMI AFFECT THE AMOUNT OF THEFT AND
21 CONSUMPTION ON INACTIVE METERS?

22 A. AMI enables a reduction in both theft and consumption on inactive meters
23 through the use of analytics and the installation of a remote disconnect switch in

1 meters. Identifying and stopping theft faster has a positive impact on reducing the
2 unknown amount of stolen or unaccounted-for energy.⁵ Prior to AMI (2012
3 through 2014), PSO investigated on average over 3,900 cases of theft annually.
4 In 2016, AMI enabled PSO to investigate over 6,100 cases, which is a 60 percent
5 increase in theft investigations.

6 For usage on inactive accounts, during the same three-year period prior to
7 AMI, PSO identified over 4,600 inactive accounts that showed usage. Prior to
8 AMI, these were found by field personnel during monthly meter reading in
9 instances where the meter had been energized. Since the completion of AMI, this
10 has declined to approximately ten inactive accounts having usage per month.

11 Q. ARE THERE SAVINGS ASSOCIATED WITH PSO'S IMPROVED ABILITY
12 TO IDENTIFY THEFT AND CONSUMPTION ON INACTIVE METERS?

13 A. Yes. However, since PSO can only measure the amount of theft that is actually
14 found—in other words, PSO cannot measure theft that is either deterred by just
15 the presence of AMI or theft that is not yet identified via analytics—the savings
16 are difficult to precisely quantify. Taking these factors into consideration, it
17 makes sense to look at a range of possible savings. At the most conservative end,
18 using only the cases of theft that PSO identified in 2015 and 2016, PSO realized
19 approximately \$565,000 of savings in theft and usage on inactive meters. This
20 estimation method seems to fall short because it does not take into consideration
21 the amounts of theft yet to be identified or theft deterred by AMI. Citing an EPRI

⁵ Note also that for the remainder of this discussion, that theft and consumption on inactive meters benefits are interrelated; therefore it is difficult to fully discern individual impacts. If PSO finds usage on an inactive meter, this could eventually transition into a theft situation.

1 study,⁶ it is reasonable to assume a range of one to four percent of a utility's
2 revenue can be attributed to theft, with a most likely range of between one to two
3 percent. The most likely range identified by EPRI equates to \$5.2 million to
4 \$10.4 million for PSO. PSO originally projected a conservative annual potential
5 savings using 0.5 percent of revenue as a basis for theft reduction, which equates
6 to \$2.6 million in savings due to a reduction of theft during the deployment.
7 While we cannot say which approach is the most accurate, we know with
8 certainty that AMI is creating real and significant savings for customers by both
9 detecting and deterring theft and usage on inactive meters.

10 Q. ARE THERE OTHER BENEFITS FROM THE FASTER IDENTIFICATION OF
11 THEFT?

12 A. Yes. AMI improves public safety by identifying and reducing the number of
13 hazardous situations associated with theft. Specifically, public safety is improved
14 by more quickly correcting situations where theft is occurring and a hazardous
15 condition exists that could cause significant injury, death, or property damage.
16 Before AMI, on average, PSO was locating and correcting approximately 380
17 locations a year. In 2016, over 900 hazard locations were found, which is an
18 approximately 140 percent increase.

19 Q. PLEASE DISCUSS THE BENEFITS DERIVED FROM OBSOLETE METER
20 AVOIDANCE.

⁶ Advanced Metering Infrastructure Technology, "Limiting Non-Technical Distribution Losses in the Future; Electric Power Research Institute, December 2008, pages 1-14 to 1-18 A.

1 A. Obsolete meter avoidance creates a one-time avoided investment by replacing
2 meters during the deployment period at the end of their useful lives and scheduled
3 to be replaced due to manufacturer bulletins, testing, and field observations. PSO
4 conservatively projected \$1.2 million in avoided investment during the
5 deployment period; however, the actual avoided investment was approximately
6 \$9.1 million. On average, PSO replaced over 16,000 meters annually due to
7 obsolescence prior to the AMI deployment. This equates to over 48,000 meters
8 during the three-year deployment. By replacing these meters with an AMI meter,
9 the replacement costs associated with these meters are avoided.

10 Q. WILL YOU PLEASE DESCRIBE THE BILLING AND CALL CENTER
11 EFFICIENCIES?

12 A. AMI provides billing and call center efficiencies by reducing call volume and
13 enabling employees to address inquiries in a more expeditious manner. Calls
14 associated with billing, credit and investigation orders, which are approximately
15 40 percent of the annual call volume, have been reduced approximately 14
16 percent in 2016 alone. In comparing the annual call volume prior to AMI
17 deployment (2012 through 2014) to the deployment timeframe (2015 and 2016),
18 PSO received over 190,000 fewer phone calls. Based on an estimated cost per
19 transaction, this reduction in phone calls represents a productivity savings of
20 approximately \$395,000 versus the original projection of \$91,000. This amount
21 will likely increase now that AMI is fully deployed.

1 Q. WILL YOU PLEASE DISCUSS HOW AMI AFFECTS EMPLOYEE SAFETY?

2 A. Because of AMI, PSO personnel no longer need to access customers' yards to
3 read meters. Prior to AMI, PSO meter readers and field specialists made over
4 6.75 million visits to customer premises and drove over 2.1 million miles each
5 year. During these visits, PSO employees were subjected to vehicle accidents, as
6 well as hazardous situations on customers' premises. For example, PSO has over
7 24,000 accounts that are identified as bad dog, vicious dog or pit bull, which
8 accounted for over 288,000 opportunities for harm per year. Post deployment,
9 over 99 percent of these visits to customer premises are eliminated and annual
10 vehicle mileage decreased 60 percent as of the end of 2016.⁷

11 While it is difficult to place a dollar value on avoided accidents and
12 employee injuries, there is certainly inherent value. In the last two years, the
13 Meter Services (MS) group has not experienced an injury or vehicle accident.
14 PSO attributes this mostly to AMI because our risk greatly diminished with the
15 implementation, and the safety statistics show it. Had AMI been installed three
16 years earlier, we can assume the avoidance of more than five employee injuries
17 and over 35 vehicle accidents.

18 MS employee injury severity varied between minor injuries such as cuts,
19 sprains, and minor dog bites, to significant dog bites that caused several surgeries,
20 several months of missed work, and even significant emotional trauma. MS-
21 related motor vehicle accidents varied as well, with most involving minor damage

⁷ PSO is on track to reduce mileage by 75 percent in 2017. Note also that the reduction in premises visits and mileage is not a one-for-one correlation because the remaining MS personnel still require travel for other, albeit limited, reasons.

1 or injuries. Nonetheless, every incident has the potential for significant injury and
2 even the loss of life. There is usually a very fine line between a minor accident
3 and one with significant consequences, and for PSO's MS group, AMI is
4 significantly minimizing the possibility of safety-related events—an invaluable
5 benefit to both employees and customers.

6 Q. BEYOND THE UTMOST BENEFIT OF KEEPING EMPLOYEES OUT OF
7 HARM'S WAY, ARE THERE QUANTIFIABLE SAVINGS THAT RESULT
8 FROM THE AVOIDANCE OF ACCIDENTS?

9 A. It is impossible to precisely quantify savings associated with the avoidance of
10 injury and vehicle accidents, but there are certain statistics and experiences that
11 are informative. For example, according to the Center for Disease Control and
12 Prevention (CDC), the average emergency room visit for a car accident injury is
13 around \$3,300 per injury. If that person is hospitalized, then the average cost is
14 around \$57,000 per injury. There are many other avoided costs like lost days
15 worked, property/vehicle damage and safety investigations, which can cost
16 anywhere from \$10,000 to \$15,000 for minor accidents and/or events, and
17 \$50,000 for major accidents, that in total can become very material even for
18 minor accidents.

19 Q. HAS PSO EXPERIENCED OTHER SAVINGS DUE TO THE
20 IMPLEMENTATION OF AMI?

21 A. Yes. There are other savings due to the elimination of the handheld meter reading
22 technology, employee safety clothing, employee training, and travel expenses
23 previously needed by the field employees to complete their daily duties. The

1 elimination of these items equates to approximately \$389,000 versus the original
2 projection of \$288,000.

3 Q. HOW DO THE ACTUAL COST SAVINGS FOR OPERATIONAL SAVINGS
4 AND EFFICIENCIES FOR THE FIRST THREE YEARS COMPARE TO THE
5 PROJECTED SAVINGS?

6 A. The operational savings realized in the first three years are greater overall than
7 original projections. With more time and experience with AMI, more operational
8 savings and efficiencies are expected to be realized.

9

10

VII. CONCLUSION

11

Q. DID PSO SUCCESSFULLY DEPLOY AMI TO THE BENEFIT OF
12 CUSTOMERS?

13

A. Yes. PSO completed the installation of approximately 533,000 AMI meters
14 ahead of schedule and under budget by over seven percent in capital expenditures
15 and 33 percent in O&M expenditures. Further, despite being fully deployed for
16 less than one year, operational, reliability, and customer experience benefits are
17 already being realized at significant levels, many beyond original projections.

18

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

19

A. Yes, it does.

AFFIDAVIT OF DEREK S. LEWELLEN

STATE OF OKLAHOMA)

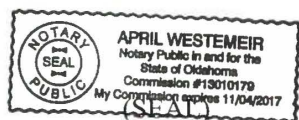
COUNTY OF TULSA)

On the 15 day of June, 2017, before me appeared Derek S. Lewellen, to me personally known, who, being by me first duly sworn, states that he is the Manager, Meter Infrastructure and Program Development for Public Service Company of Oklahoma and acknowledges that he has read the above and foregoing document and believes that the statements therein are true and correct to the best of his information, knowledge and belief.



Derek S. Lewellen

Subscribed and sworn to before me this 15th day of June, 2017.



Notary Public

My commission expires: 11/04/17