Smart Grid Demonstration Project

Final Report

MARCH 11, 2015

NRECA
A Touchstone Energy® Cooperative

CRN
Cooperative Research Network

Smart Grid Demonstration Project

Final Report

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Prepared by

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The National Rural Electric Cooperative Association

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

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

About CRN

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

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

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

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

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EXECUTIVE SUMMARY

The National Rural Electric Cooperative Association (NRECA) organized the NRECA-U.S. Department of Energy (DOE) Smart Grid Demonstration Project (DE-OE0000222) to install and study a broad range of advanced smart grid technologies in a demonstration that spanned 23 electric cooperatives in 12 states. More than 205,444 pieces of electronic equipment and more than 100,000 minor items (bracket, labels, mounting hardware, fiber optic cable, etc.) were installed to upgrade and enhance the efficiency, reliability, and resiliency of the power networks at the participating co-ops.

The objective of this project was to build a path for other electric utilities, and particularly electrical cooperatives, to adopt emerging smart grid technology when it can improve utility operations, thus advancing the co-ops' familiarity and comfort with such technology. Specifically, the project executed multiple subprojects employing a range of emerging smart grid technologies to test their cost-effectiveness and, where the technology demonstrated value, provided case studies that will enable other electric utilities—particularly electric cooperatives—to use these technologies.

NRECA structured the project according to the following three areas:

1. Demonstration of smart grid technology
2. Advancement of standards to enable the interoperability of components
3. Improvement of grid cyber security

We termed these three areas **Technology Deployment Study**, **Interoperability**, and **Cyber Security**. Although the deployment of technology and studying the demonstration projects at co-ops accounted for the largest portion of the project budget by far, we see our accomplishments in each of the areas as critical to advancing the smart grid. All project deliverables have been published.

Technology Deployment Study: The deliverable was a set of 11 single-topic technical reports in areas related to the listed technologies. Each of these reports has already been submitted to DOE, distributed to co-ops, and posted for universal access at www.nreca.coop/smartgrid. This research is available for widespread distribution to both cooperative members and non-members. These reports are listed in **Table 1.2**.

Interoperability: The deliverable in this area was the advancement of the MultiSpeak™ interoperability standard from version 4.0 to version 5.0, and improvement in the MultiSpeak™ documentation to include more than 100 use cases. This deliverable substantially expanded the scope and usability of MultiSpeak, ™ the most widely deployed utility interoperability standard, now in use by more than 900 utilities. MultiSpeak™ documentation can be accessed only at www.multispeak.org.

Cyber Security: NRECA's starting point was to develop cyber security tools that incorporated succinct guidance on best practices. The deliverables were: cyber security extensions to MultiSpeak,™ which allow more security message exchanges; a Guide to Developing a Cyber Security and Risk Mitigation Plan; a Cyber Security Risk Mitigation Checklist; a Cyber Security Plan Template that co-ops can use to create their own cyber security plans; and Security Questions for Smart Grid Vendors.

Chapter 1:

Introduction and Goals of the Project

The objective of this project was to build a path for other electric utilities, and particularly electrical cooperatives, to adopt emerging smart grid technology when it can improve utility operations. At the start of the project, co-ops were interested in a range of smart grid technologies and applications but did not have the experience to be certain of their value or the particulars of deployment, integration, and operation. The purpose of this project was to advance the co-ops' familiarity and comfort with such technology.

Specifically, the project executed multiple subprojects employing a range of emerging smart grid technologies to test their cost-effectiveness and, where the technology demonstrated value, provided case studies that will enable other electric utilities—particularly electric cooperatives to use these technologies.

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For purposes of evaluation, the technologies deployed have been classified into three major categories, each with four specific technologies, as listed in **Table 1.1**.

Table 1.1: Technical Scope of the Project

Technical Scope of the Project		
Technology Category	**Specific Technologies in Each Category**	
Enabling Technologies	Advanced Metering Infrastructure Telecommunications	Meter Data Management Systems Supervisory Control and Data Acquisition
Demand Response	In-Home Displays and Web Portals Prepaid Metering	Demand Response Over Advanced Metering Infrastructure Interactive Thermal Storage
Distribution Automation	Renewables Integration Advanced Volt/VAR Control	Smart Feeder Switching Conservation Voltage Reduction

In the original Funding Opportunity Announcement, DOE emphasized the need to advance the smart grid through both demonstration and improvement in two specific areas: interoperability and cyber security. Accordingly, NRECA structured the project according to the following three areas:

1. Demonstration of smart grid technology
2. Advancement of standards to enable the interoperability of components
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We termed the three areas **Technology Deployment Study**, **Interoperability**, and **Cyber Security**. Although the deployment of technology and studying the demonstration projects at co-ops accounted for the largest portion of the project budget by far, we see our accomplishments in each of the areas as critical to advancing the smart grid. All project deliverables have been published.

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Table 1.2: Technology Deployment Technical Reports

AMI-Based Load Research – KIUC Demonstration
Building Consumer Acceptance to Maximize the Value of Grid Modernization
Communications – The Smart Grid's Enabling Technology
Conservation Impact of Prepaid Metering – Motivation and Incentives for Pre-Pay Systems
Costs and Benefits of Conservation Voltage Reduction – CVR Warrants Careful Examination
Costs and Benefits of Smart Feeder Switching – Quantifying the Operating Value of SFS
Delaware County Electric Cooperative – DR Capability and Predictability
Demand Response – Testing the Theoretical Basis for DR
Energy Storage – The Benefits of "Behind-the-Meter" Storage: Adding Value with Ancillary Services
Multi-Tenant Meter Data Management – A Systems Approach to Hierarchical Value
Washington-St. Tammany Case Study – Stress-Testing Designs Before Deployment

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Cyber Security: The deliverables are listed in **Table 1.3**.

Table 1.3: Cyber Security Deliverables

Cyber security extensions to MultiSpeak,™ which allow more security message exchanges
Guide to Developing a Cyber Security and Risk Mitigation Plan
Cyber Security Risk Mitigation Checklist, a list of activities/security controls needed to implement a cyber security plan, with rationales
Cyber Security Plan Template, a form that co-ops can use to create their own cyber security plans
Security Questions for Smart Grid Vendors

In this final report, we summarize the accomplishments of the Technology Deployment Study and Cyber Security components of the project. The MultiSpeak™ standards and use cases are available only to MultiSpeak™ members and are not amenable to presentation in document form.

As of 6/30/2014, the following major equipment has been installed:

Table 1.4: List of Installed Equipment

Act.	Equipment Description	Installed
Adams		
AMI & DR	AMI meters, Form 2S, w/remote disconnect	200
	Load control relays	200
	Load control software, Aclara	1
	AMI Test board	1
SCADA & D/A System Master Station Computers and Software	Master Station Software (Enterprise)	0.5
D/A Equipment	Distribution Switches Controllers	2
	Distribution Fault Detectors (Overhead)	12
	Distribution Fault Detectors (Underground)	6
	Radio Communication Equipment	1
	Overhead Switches	2
Adams-Columbia		
SCADA & D/A System Master Station Computers and Software	Enterprise SCADA Hardware (Communications, Servers, and Switches)	1
	100-kVar Capacitors w/Switching Controls	41
	100-kVar Capacitors, Fixed Bank	1
	Volt/VAR Regulator Unit w/Active Comms	40
	OH Distribution Switches w/Controls	4
	Distribution Switches Controllers	5
	Distribution Reclosers w/Controls	4
	Radio Communication Equipment	52
	Distribution Capacitor Banks w/Controllers	31
	RTU	1
	Underground Switches	7
Calhoun		
Master Station Computers and Software	Master Station Software, Servers, etc.	1
Substations/Tower/Repeater Equipment PLC	Substation Equipment	
	Signal Coupling Unit Type SCU-810	10
	H-Field Coupler to Enhance Reception for 2-way	20
	Carrier Control Unit Type CCU-711 Single Bus	5
	Primary Coupling Type PCC Rated 125KV BIL, 50 KVAR	15
	Ethernet Module for CCU	5
	Repeater, Type 902	7
	Repeater, Type 850	3
	Repeater, Type 801	3
	Capaciformer Single-Phase Coupler	5
AMI Meters & Modules	1S	15
	2S (CL200)	1160
	3S (CL410)	840
	4S (CL410)	15
	8S/9S (MCT430)	25
DR Load Control	LCR-3102: Two-Way LCR – Dual-Relay, One 5 AMP and One 30 AMP	450
Clarke		
Master Station Computers and Software	Master Station Software	1
	Hardware (Servers, Switches)	1

Act.	Equipment Description	Installed
	MDM Software	1
Substations/Tower/Repeater Equipment	PLC Substation Equipment	11
	Radio Backhaul Equipment	18
	Radio Backbone Communications Equipment (Microwave Links)	6
	Communications Towers and Poles	45
	Repeater 902 Assembly for Single/Three-Phase Coupling at 7.2/7.62 kV	21
	Repeater 801 Assembly	15
	H-Field Couplers	10
	Repeater 850 Assembly	34
AMI – Solid State Meters and Modules	Focus Retrofit Kits, 1S	1080
	2S (CL200)	4350
	3S (CL30)	2300
	5S/6S	5
	4S	7
	12S (CL200)	2
	Poly Phase (Multiphase) 9S	59
	Poly Phase (Multiphase) 15S/16S	9
	Focus AL-EA140000-OZ83, Solid State Meter	8
SCADA & D/A System Master Station Computers and Software	Master Station Software (Enterprise)	1
	Enterprise SCADA Hardware (Communications, Servers, and Switches)	1
D/A Equipment	Distribution Switches	20
	Distribution Switches Controllers	20
	Distribution Reclosers	32
	Distribution Regulator Panels	30
	Radio Communication Equipment	23
	Capaciformer	14
	Capacitor Bank, 50 KVAr	69
DR Load Control Equipment	LCR-3102: Two-Way PLC LCR – Dual-Relay, One 5 AMP and One 30 AMP	250
Corn Belt		
Substations/Tower/Repeater Equipment	Radio Backhaul Communications Equipment	53
SCADA and D/A System Master Station Software and Computers	Yukon Load Management Controller (Small SCADA)	2
Delaware County		
Substations/Tower/Repeater Equipment	Backhaul Communications Equipment	1
	PLC Substation Equipment	5
	PLC Injection Transformers	5
	Substation AMI/Equipment/Backhaul Communication Network Interface (ER) (Router and Firewall)	5
AMI – Modules for the Quantities Indicated	2S (CL20)	5150
	Poly Phase module	20
Solid State Meters for the Quantities Indicated	2S (CL20)	5150
	3S Meter w/Module	80
	4S Meter	8
	5S Meter	5
	8S/9S Meter	9
	15/16S Meter	4

Act.	Equipment Description	Installed
IHD/Web Portal Pilot (Activity 54)	IHD /Ecometer	59
	Zigbee/WiFi/Other Module	150
	Remote Service Switch Adaptor	20
	Focus AX-SD Meter w/Service Disconnect Module	131
DR Over AMI (Activity 55)	LM Switches	800
Delta-Montrose		
MDM (Activity 99)	MDM Software	1
Prepaid Metering (Activity 94)	Y72190-311B, Remote Service Disconnect Collar	200
	Master Station Software (Enterprise)	1
IHD Pilot (Activity 3)	Aclara TWACS IHD Unit	200
	Power Usage Software	1
EnergyUnited		
D/A Equipment	Pole-Mounted Load Break Disconnect Switch	3
	Preconfigured Automation Controllers w/Voltage Sensors	6
	Control Communications Equipment	3
MDM (Activity 112)	MDM Software	1
Prepaid Metering (Activity 96)	Single-Phase Disconnect Collar	4150
	Locking Ring	4150
	Disconnect Compatible Meters, Landis+Gyr	846
Flint		
Master Station Computers and Software	Enterprise Utilisales MS Software	1
Substations/Tower/Repeater Equipment	Item Number Y86700-627, Control and Receiving Unit	1
	Item Number Y83760-1, Inbound Pick-Up Unit	1
	Item Number Y88300-301-Set, Outbound Modulation Unit	1
	Item Number Y86914-309, Mira Boards	36
	Item Number ACLARA SCPA-G2, Upgrade Boards	45
AMI – Modules	Item Number 1S-CL100, 120 V Meter Modules	105
	Item Number 2S-CL200, 240 V, Meter Modules	41268
	Item Number 3S-CL20, 240 V, Meter Modules	41
	Item Number 4S-CL20, 240 V, Meter Modules	1172
	Item Number 8S/9S-CL20, 277 V, Meter Modules	632
	Item Number 12S-CL200, 120 V, Meter Modules	100
	Item Number 16S-CL200, 277 V, Meter Module	151
Solid State Meters	Item Number 1S, CL100, 120V, kWh only, Basic Function Meter	105
	Item Number 2S-CL200, 240V, kWh and kW Basic Function Meter	41268
	Item Number 3S-CL20, 240V, kWh and kW Basic Function Meter	41
	Item Number 4S-CL20, 240V, kWh and kW, Basic Function Switch	1172
	Item Number 8S/9S CL20, 277V, kWh and kW advanced Function Meter	632
	Item Number 12S-CL200, 120V, kWh and kW Basic Function Meter	100
	Item Number 16S, CL200, 277V, Advanced Function Meter	151
	Item Number 2S, CL200, Y72990-1, UMT-R-G+, RD – for I2100+Meter Modules	6000
	GE Item Number I-210+, Form 2S, 240V, Class 200 Meter, Including S-2 Demand Soft Switch Installed and Enabled	6000
	Item Number 727X230091, 2S, CL200, 240V, kWh and kW	2070

Act.	Equipment Description	Installed
	Basic Function Meter w/S2, V2 and O Switches	
	Item Number 2S-CL200, 240 V, UMT, Meter Modules	2070
LM – IHD – Other	Item Number Y92500-1, IHDs	150
Great River Energy		
MDM/DRM (Activity 107)	MDM Software	1
	Demand Reduction Management (DRM) Software	1
Interactive Thermal Storage (Activity 113)	Energy Market Management Control Software	1
	Steffes Water Heater Controls	10
Humboldt		
Master Station Computers and Software	Master Station Software	1
Substations/Tower/Repeater Equipment	PLC Substation Ancillary Equipment	1
	Carrier Control Unit Type CCU-711 Single Bus	8
	Signal Coupling Unit Type SCU-810	13
	Primary Coupling Capacitors Type PCC Rated 125 kV BIL, 50 kVA	39
	H-Field Coupler to Enhance Reception for 2-Way	29
	Repeater Type RPT-902	9
	Repeater Type RPT-850	4
	Repeater Type RPT-801	4
	Capaciformer Single-Phase Coupler (Specify Primary Voltage = 7,620V)	7
Solid State Meters W/Integrated AMI Modules	2S (CL200)	1556
	3S	500
	5S, 6S, 8S, 12S, 15S	143
LM/IHD	LM Switches	500
Iowa Lakes		
LM/IHD	Peak Alert Monitors	2952
	LM Switches	2952
Kaua'i		
Substations/Tower/Repeater Equipment	Wireless Collectors	2
	Substation AMI/Equipment/Backhaul Communication Network interface (ER) (Router and Firewall)	78
Solid State Meters W/AMI – Modules for the Quantities Indicated	DGA1001X-2902, FM2S, 240V, 3W, CL200, 4-Jaw Meter	30008
	DGBH001V-2902, FM125, 120V, 3W,CL200, 5-Jaw Meter	2404
	EM0J001V-2902, FM4S, 240V, 3W, CL20, 6-Jaw-Change to S4 Meter	32
	GM2B001V-2902, FM16S, 120V, 4WY, CL200, 7-Jaw Meter	1200
	EG04001V-2902, FM2S, 240V, 3W, CL320, 4-Jaw Meter	20
	5N0210X0-0Z99-AH00, FM6S, 120-480v, 4WY, CL20, 13-Jaw, 1-KYZ Outputs, REF (U)	12
	GM9A001V-2902 FM8S, 240V, 4WD, CL20, 13-JAW, REF (V), Meter	24
	5N0010X0-0Z99-AH00, FM9S, 120-480V, 4WY, CL20, 13-Jaw, 1-KYZ Outputs, REF (Y)	20
	GM9A001V-0Z99, FM9S, 120-277V, 4WY, CL20, 13-Jaw, REF (Z), Meter	160
	GM2B001V-0Z99, FM166, 277V, 4WY, CL200, 7-Jaw, Meter	160
	GM2B001V-0AA0, FM15S, 240V, 4WD, CL200, 7-Jaw, Meter	72
	5N9C00X0-0Z99-AH00, FM12S, 480V, 3W, CL200, 5-Jaw Meter	72

Act.	Equipment Description	Installed
	5N0100X0-OZ99-AH00, FM5S 120-480V, 3W, CL20, 8-Jaw, Meter	240
	5N0120X0-0Z99-AH00, FM5S, 120-480V, 3W, CL20, 8-Jaw, 2-KYZ Outputs	4
	GM6A001V-2902, FM6S 120-277V, 4WY, CL20, 13-Jaw, REF (T) Meter	560
LM – IHD – Other for the Quantities Indicated	IHD units	525
Kotzebue		
AMI Equipment	L&G 2S (CL200) AMI Meter Focus AXSD	1110
	Item Number 4R00020A0-000-H031	27
	L&G Gridstream PLC Module for Focus AX SD	1110
	L&G Gridstream PLC Module for S4E Poly Phase	40
D/A Equipment	15KV-2SD-RVAC3-OIL-MS-200/200-3PH, Switch	1
	25KV-2SD-RVAC3-OIL-MS-200/200-3PH, Switch	1
	ABB Dynamic VAR Compensator	1
Lake Region		
MDM/DRM (Activity 108)	MDM/DRM Software (in cooperation with GRE)	1
IHD Pilot (Activity 109)	Utilisales Software	1
	IHDs	50
Menard		
MDM Equipment	NISC MDMS system	1
Advanced Volt/VAR Control (Activity 29)	Distribution Capacitor Banks w/Controllers	10
	Distribution Capacitor Banks w/Controllers, Pole Mount	40
MVE		
Renewable/DG Integration (Activity 104)	Silent Power OnDemand Battery System 9.2kW	5
	Silent Power OnDemand Battery System 5kW	12
DR Over AMI (Activity 110)	DR Software (shared project with GRE and LRE)	1
LM – IHD – Other	LM Switches	9432
Owen		
LM – IHD – Other for the Quantities Indicated	HAN installation and Tendril Transport	211
	HAN installation w/Thermo and Hot Water	211
	Tendril Transport Hardware	311
	Tendril Translate (ERT to Zigbee)	311
	LM Switches – Water Heater	211
	Smart Plugs – Controllable Wall Plugs	10
	Smart Thermostats	211
D/A Equipment	Nove 3-Phase OCR Switches w/F6 Controls	4
	Distribution Switches Control Software	4
	Automation Software	1
	Distribution Regulator Panels	54
	Fiber Buildout Equipment	1
	DEMICO Weather Station	10
	Three-Phase Monitors	4
	CG Automation STN-9150	18
	Fiber/Microwave Communication Equipment	1
Prairie		
Master Station Computers and Software	Master Station Software	1
	Hardware Server Switches	1
Substations/Tower/Repeater	PLC Substation Equipment	4

Act.	Equipment Description	Installed
Equipment	Repeater, Type 801	10
	Repeater, Type 902	19
	Repeater, Type 850	8
	Capaciformer	12
	Signal Coupler	27
	Carrier Control Unit	17
	Ethernet Switching Gear	17
	Coupling Capacitors	81
	H-Field Couplers	56
AMI Modules	2S (CL20)	4000
	(CL320), 3S, 4S	900
	Poly Phase (Multiphase)	140
Solid State Meters	2S (CL20)	4000
	(CL320), 3S, 4S	900
	Poly Phase (Multiphase)	140
LM/IHD	LM Switches	800
Salt River		
D/A Equipment	Distribution Switches w/Controllers and Radio Comms	29
Snapping Shoals		
Installation of Smart Feeder Switching System (Activity 78)	Enterprise SCADA Hardware (Communications, Servers, and Switches)	3
	SCADA Hardware (Switches)	22
D/A Equipment	Intelliruptor Pulse Closer	3
	Distribution Reclosers	97
Washington-St. Tammany		
D/A Equipment	Control House, Box Structure, 30' X 30' Steel	9
	Relays for Autonomous Control For 69kv Sub-Transmission In Closed Loop Fashion	30
	DT1-72.50 F1 FR Circuit Breakers	24
	Substation Communications Control Equipment	9
	69KV POF-350, CATALOQ J710600TEAAAA w/600/350:1:1,0.15%Z,0.3%ZZ Transformers	36
	69KVA Outdoor Airbreak Switch, Type V2-C, Vertical Break, 3 POLE, 1,200 AMP	6
	Outdoor Disconnect Switch, Rated 69kVA, 1,200 AMP	120
	Control Panels for 69Kv Breakers and Transmission Lines	13
	Fiber Optic Communications Control Equipment for Substation to SCADA	1

Chapter 2:

Succinct Summary of the Topical Reports

Reports in the following areas were prepared to guide utilities in developing their own smart grid projects.

Costs and Benefits of Smart Feeder Switching – *Quantifying the Operating Value of SFS*
Nine rural electrical cooperatives deployed distribution automation (D/A) technologies in Smart Feeder Switching (SFS) applications. The research defined an analytical methodology for quantifying the value of two SFS operational benefits—rapid restoration following a fault and reduced losses through feeder load balancing. The report compared projected values with field study results from the participants. From this comparison, it defined a logical modeling framework for assessing SFS costs and benefits.

Costs and Benefits of Conservation Voltage Reduction – *CVR Warrants Careful Examination*
Four rural electrical cooperative utilities deployed conservation voltage reduction (CVR) technology. The report used data from the field studies of the technology for the development and calibration of a hybrid power flow-economic model. It then derived a methodology for cost-benefit analysis of CVR, with the largest and clearest payback coming from peak demand reduction—the benefit of most interest to the cooperatives studied. Additional benefits included reductions in losses and energy requirements.

Communications – *The Smart Grid's Enabling Technology*
This report confirmed communications as an indispensable enabling technology for any fully implemented smart grid and one of the four enabling technologies deployed in the demonstration; it also found the other three to be dependent on telecommunications to some degree. Each required the movement of great volumes of data from one point to another. This study gleaned insights from the co-ops that took part in the demonstration—particularly the decision-making processes—providing a backdrop for defining the communication requirements of current and future smart grid applications and the additional research needed on decision processes.

Demand Response and Critical Peak Pricing – *Testing the Theoretical Basis for DR*
Demand response (DR) programs were deployed at several cooperatives for the demonstration project. Consumer- or cooperative-initiated actions to affect end-use activity can provide several benefits to the electric system. For this demonstration, we prepared a guiding econometric analysis and modeling approach. Initial findings relate to implementation issues; results from the demonstration will help test the validity of previously hypothesized DR models. Enhancements from the research can provide for estimation of distribution system losses and the interrelationship of D/A with DR.

Conservation Impact of Prepaid Metering – *Motivation and Incentives for Pre-Pay Systems*
The motivation for prepayment programs varies among cooperatives. Prepaid generally serves lower-income members. It helps them with management of their expenses and eliminates the need for dauntingly large deposits. It is also useful for short-term accounts, such as for events, temporary occupancy, vacant properties, and construction projects. Programs with diverse objectives were tested in this project, focusing on value to the member/customer. In general, the investigation corroborated the basic tenants of prepayment as stated in previous work, including high degrees of member satisfaction, appreciation of alternatives, greater implementation options through vendor support, and better energy awareness. The issue of conservation was somewhat difficult to validate based on the data available, but the participants surveyed believed they were saving energy.

Energy Storage – *The Benefits of "Behind-the-Meter" Storage*
Behind-the-meter energy storage refers to devices and services that allow for storage internal to homes or commercial buildings. Energy storage can be valuable in addressing frequency regulation, DR, "valley filling" of off-peak loads, and other services, and is poised to become an important element of the electricity infrastructure. Deployment of energy data management, coupled with energy storage systems, enables smart devices to provide both traditional and non-traditional storage services, including emergency power and grid support. In this study, two related behind-the-meter projects involved distribution co-ops and a generation and transmission (G&T) cooperative in validating the technologies and determining their value for demand reduction and provision of key ancillary services, such as frequency regulation.

Multi-Tenant Meter Data Management – *A Systems Approach to Hierarchical Value*
For this demonstration, Great River Energy (GRE) and the National Information Solutions Cooperative (NISC) created a secure information-sharing framework. The multi-tenant data management system allows a G&T's member systems to collaborate and coordinate their DR resources with greater agility. Through the deployment of this system, GRE has enabled its distribution cooperatives to achieve the benefits and economies of scale while maintaining local control.

Washington-St. Tammany Case Study – *Stress-Testing Designs Before Deployment*
This case study of one cooperative's communications installation illustrates success in the face of unexpected developments. Lessons learned from this demonstration project include the win-win from re-evaluating and reconsidering the original proposed communication design. WSTE required substantial improvements to its communications system to support its extensive new smart feeder switching. The quick design, using standard tools to design a radio system, indicated the need for only a modest number of mid-sized towers. Field tests, however, showed that the unique and dense vegetation of southern Louisiana attenuated the signal to a much greater degree than the standard planning tools had indicated. The system was redesigned as a result. This is an excellent case study of the value of serious testing before deployment.

Delaware County Electric Cooperative – *DR Capability and Predictability*
One of the demonstration participants instituted a DR program to shed load when requested by an independent system operator. This case study describes implementation of advanced metering infrastructure (AMI) and load control switches to accomplish the intended beneficial result.

AMI-Based Load Research – *KIUC Demonstration*
The implementation of an advanced metering infrastructure provided the vehicle for a first-ever system-specific load research program. The case study of the load research demonstration examined the expectations of a robust evaluation of system load characteristics for both rate studies and system engineering.

Building Consumer Acceptance to Maximize the Value of Grid Modernization
Much of the policy analysis surrounding the smart grid has focused on the transformation of the nation's electric system from an electro-mechanical system to a digital system; less discussed, but equally important, is not only how the smart grid is transforming the relationship between the utility and its customers, but also the need for changing this relationship. This NRECA demonstration project illustrated the difficulties and benefits of communicating and engaging with consumers in a new way.

Chapter 3:

Technology Deployment Summary and Performance

3.1 Technology Installed

As part of this project, the following types of technology were deployed:

Advance Metering Infrastructure (AMI) differs from traditional automatic meter reading (AMR) in that it enables two-way communications with the meter. This equipment consists of the smart meters and their connection to a means of communicating back to the electric utility. A smart meter is usually a digital electrical meter that records consumption of electric energy in intervals of an hour or less and communicates that information at least daily, but frequently hourly or even at 15-minute intervals, back to the utility for monitoring and billing purposes.

Meter Data Management (MDM) systems refer to an emerging component in the smart grid infrastructure that performs long-term data storage and management for the vast quantities of data delivered by smart metering systems. These data consist primarily of usage data and events read from the meters. The MDM system typically will import the data, then validate, cleanse, and process them before making the data available for billing and analysis. The MDM system usually also provides the data interface to the customer billing system and outage management systems, and may also control the remote connect/disconnect of service, depending on the meter types installed. Furthermore, an MDM system may provide reporting capabilities for load and demand forecasting, management reports, and customer service metrics.

Telecommunications are the backbone of the modern smart grid system. This is the main area in which modern systems differ significantly from previous systems. Not only do two-way communications occur between the devices in the field and the utility offices, but the quantities of information are orders of magnitude higher than they were previously. Thus, most utilities face the need to upgrade their communications infrastructure. The equipment installed to do this upgrade ranges from radio links and towers to fiber optic cable and routers to power line carrier head-end systems and supporting equipment. In addition, post-substation aggregated data may also be carried under a service agreement by commercial data carriers using fiber optic or microwave high-speed data links.

Supervisory Control and Data Acquisition (SCADA) systems are computer control systems that provide exactly what this name implies. Most utilities already have some form of SCADA system in place at their command centers to monitor the state of their distribution system and control reclosers, voltage regulators, and other equipment at substations; frequently, however, the newer smart grid equipment requires either upgrades or replacement of existing systems.

In-Home Displays (IHDs) and Web Portals refer to two different technologies that provide consumer-facing displays of electric power usage and event notifications from the electric utility. IHDs typically are dedicated LCD display units that can be set on a counter or shelf and provide up-to-date electricity usage information to the consumer. For utilities implementing Time-of-Use (TOU) or other tiered pricing strategies, the IHDs also can display the current rates that consumers are paying for their power. Several studies have shown that such information can affect consumer behaviors and reduce power consumption. Web portals provide much the same information through access to a secure web page, but have the advantage of being able to display a richer range of information and graphical representations. They also have the advantage of being more easily modified as the needs of the utility change. The downside is that they require consumers to log in and display the information, though some systems now being developed allow consumers to enable push notifications to mobile devices.

Demand Response over AMI utilizes the two-way communications implicit in AMI to turn large load devices on and off at the consumer premises. Typically, these consist of HVAC and water heater loads. Participation in these DR activities is a voluntary enrollment by the consumer, wherein they receive some benefit or discount on their electric bill. While earlier AMR-based systems could also control switches in a consumer's house, no feedback mechanism existed to let the utility know if the switch was operating correctly. The ability to shed load during peak times is a critical cost reduction strategy for many electric distribution utilities.

Prepaid Metering is another new capability made possible by the computer control of the new smart meters and their supporting systems. Consumers pre-purchase their electricity for the month, and the system has the ability to turn off the electricity to the house when that amount has been consumed. Several studies have shown a change in consumer behavior involving reduced electricity usage based on their prepaying for electricity. This technology also reduces the costs for utilities associated with activating and deactivating accounts, and is particularly useful in transient and multi-tenant dwellings, where frequent account changes are common. Many options and variations are being tested with this technology, from split power systems in which essential electrical services would not be disconnected (i.e., for furnace control in northern Alaska) to kiosks for prepayment in local convenience stores to notification of low balance and payment authorization via a mobile device.

Interactive Thermal Storage via the bi-directional communications potential provided by the smart grid allows for innovative developments in moving load from peak times to non-peak hours. In one demonstration, two residential hot water heater systems were deployed and tested. One used a heat pump system to capture local ambient heat; the other heated water to very high temperatures (185F+) during times when grid electricity usage was low and therefore cheaper, and then mixed the hot water with cold water from the supply to achieve the desired usage temperature. In this manner, the energy was stored during the time it was available cheaply and used during the time it was needed, which otherwise would typically be a peak usage time. Shifting loads from peak times is another critical element in reducing the costs of electric distribution utilities.

Renewables Integration refers to a number of technologies that make it easier for utilities to integrate solar and wind electricity generation sources reliably into the distribution system. The active flow of information between the utility command center and the distributed renewable energy generation source allows these devices to be monitored and controlled, and for energy storage devices in the form of large battery arrays to be switched in and out to help level the supply as the sun and wind varies.

Smart Feeder Switching is a critical component of many distribution utilities' outage management systems. This capability is extremely significant, allowing utilities to monitor the state of their distribution grid and determine outages caused by damage or equipment failure, isolate the damaged section, and then switch power supply around the damaged sections to restore power quickly to the majority of their consumers. The equipment utilized for this activity includes large computer-controlled recloser switches, typically installed in substations or smaller, pole-mounted units for neighborhood distribution control. Control schemes for switch management may be centralized at the command center for the utility or be distributed so that each switch "talks" to its neighbors, acts locally, and reports back to the command center.

Advanced Volt/VAR control refers to the process of managing voltage levels and reactive power (VAR) throughout the power distribution system by the utilization of computer-controlled voltage regulators and capacitor banks. Volt/VAR control can help to reduce both the over-voltage and under-voltage violations that can occur when large inductive and capacitive loads are switched on and off. Increasingly, Volt/VAR control also is being used to manage distribution system voltages to reduce demand and energy consumption, and achieve significant energy savings.

Conservation Voltage Reduction (CVR) is similar to Advanced Volt/VAR control, in that it uses the computer-controlled voltage regulators to achieve energy savings. The idea behind CVR is an old one; if the voltage to an induction motor is reduced from 120VAC to 114VAC, it can save some energy. The problem always has been that the voltage on an electric distribution system naturally decreases with distance from the substation. If too little voltage is provided, the potential energy saving is lost and damage may occur to the motors and other consumer devices. The smart grid offers the ability to monitor the voltage precisely all the way to the meter and provides the ability to set substation and neighborhood voltage regulators to achieve optimal energy savings—up to 3% in some cases.

Table 3.1 shows which technologies were demonstrated at the various cooperatives.

Table 3.1:Technology Deployments, by Cooperative

NRECA Smart Grid Demo Project – Summary Chart

		Activity Types											
		Demand Response				Distribution Automation (DA)				Enabling Technologies			
	Participants	IHD/Web Portal Pilots	DR over AMI	Prepaid Metering	Interac-tive Thermal Storage	Renew-ables	Smart Feeder Switching	Advanced Volt/VAR Control	CVR	AMI	MDM	Comm	SCADA
Cooperative	Adams Electric Co-op, IL	●	●								●	●	
	Adams-Columbia Electric Co-op, WI							●	●				
	Blue Ridge Electric, NC										●		
	Calhoun Co. ECA, IA												
	Clarke Electric Co-op, Inc., IA						●						●
	Corn Belt Power Co-op, IA												
	Delaware County Electric Co-op, NY		●		●					●			
	Delta Montrose EA, CO												
	EnergyUnited, NC						●						
	Flint EMC, GA	●								●			
	Great River Energy, MN				●						●		
	Humboldt Co. REC, IA [1]									●			
	Iowa Lakes EC, IA							●	●				
	Kaua'i Island Utility Co-op, HI									●			
	Kotzebue Electric Assn., AK			●		●	●						
	Lake Region Electric Co-op., MN										●		
	Menard Electric Co-op, IL							●					
	Minnesota Valley EC, MN					●					●		
	Owen Electric Co-op, Inc., KY						●	●				●	●
	Prairie Energy Co-op, IA									●			
	Salt River Electric Co-op Corp., KY												
	Snapping Shoals EMC, GA												
	Washington-St. Tammany EC, LA											●	●

1. During the course of this project Humboldt Co. REC merged with, and is now part of, Midland Power Cooperative.

3.2 Technology Evaluation

This section provides a brief summary of the work at each co-op in each of the technology categories listed above. Per discussions with DOE, NRECA has prepared a standalone report in each category. The reports do not match one on one with the 12 technology categories, but rather are arranged around topics of interest to utilities—a project orientation rather than a technology orientation. These reports are intended to be accessed individually, as it is unlikely that any utility will want to undertake all of the projects—particularly not as a single effort. Publishing the reports separately makes them more accessible and easier to understand. For completeness, however, they are furnished later in this document.

3.2.1 Advanced Metering Infrastructure (AMI)

Calhoun Co. REC, IA – Cooper Power Systems (Cooper) was Calhoun's vendor for this project. Procurement of materials and scheduled deliveries were prompt and without difficulty, but integration of the Cooper software was challenging for Calhoun's small IT staff, which had limited experience in this area. We expect other, comparable utilities would struggle similarly.

Nonetheless, the system is now completed and fully functional. The data collected from the AMI system have been largely beneficial in communicating with members about their electric usage. In addition, having the AMI technology available has made the cooperative more efficient during outages and reduced the number of truck rolls.

The meter readings can now be collected within an 18-hour reading period versus a two-to-three day conventional meter read allowance. The AMI system also measures kW load at targeted accounts or locations to enable more accurate transformer sizing. Stored meter data have allowed Calhoun to follow up on several concerns regarding high bill complaints. As a side benefit, the installation of the new meters resulted in the discovery of some faulty meter sockets that may have led to outage situations.

Clarke Electric Co-op, Inc., IA – The AMI system selected at Clarke was the Power Line Carrier model AMI system, as developed by Cooper/Cannon. Clarke experienced significant issues with the installation of this equipment. Initially it had problems because large numbers of the meter modules were shipped with the incorrect communications and address settings, and then had more problems in getting the meters to actually communicate back to the collectors and getting the data back to the co-op offices. Cooper sent field engineers out to Clarke to diagnose the issues and found that the problem was the signal-to-noise ratio on the lines; the solution was to include significantly more signal repeaters in the system. While significantly increasing the cost of the system (more than $100K), it has been mostly successful, but it still has not been possible to get the read rate up to more than 98%, and the delays caused by these problems significantly delayed full adoption of the new system. Clarke has said that, knowing what it knows now, it probably would not have chosen the AMI equipment it did.

The co-op reports that issues with the AMI system continue to use up significant co-op resources. By the end of the project, it has been able to achieve a frozen monthly read rate as high as 98.5%, but this level requires significant ongoing efforts in the field. Most of the efforts have been in troubleshooting areas with poor read rates, internal radio frequency (RF) interference issues, troubleshooting failed modules, or other failed or poor performing components of the AMI system. A firmware update may resolve some of the issues, but the effort required to update each meter on the system is significant.

Delaware County Electric Co-op (DCEC), NY – DCEC selected Landis+Gyr meters for their compatibility with the rest of the co-op's meter system. The installations of the meters went smoothly, as did that of the substation equipment. Minor issues, such as refinement, were discovered during the process, all of which were resolved for successful operation. Processes improved as the work advanced and DCEC personnel became more familiar with the equipment.

Landis+Gyr provided support to resolve any issues. The integration between DCEC's legacy SCADA system and the Landis+Gyr hosted server required more developmental work than planned, as some of the desired functionality was unique, and the co-op judged the functionality for meter reading, outage management system applications, and voltage monitoring as very good. However, extracting data from the AMI system to use in other ways may be accomplished only with manual intervention, which is less than desirable.

EnergyUnited (EU), NC – EU did not deploy its AMI system under the terms of this project, but since the AMI deployment was ongoing simultaneously with the prepaid metering activity in the smart grid project, the co-op's experience is directly relevant and appropriate to report here. EU deployed a very large hybrid AMI solution—both power line carrier (PLC) and RF metering—using the Cooper Technologies AMI system. The RF technology has proven to be a more reliable means of communications, providing the bandwidth to obtain hourly readings at a very high percentage rate. In contrast, the noise over the power lines and bandwidth limitations make power line carrier a much less desirable solution, but one necessary in the more remote and geographically rugged sections of the service territory. Given the bandwidth constraints and noise and substation signal cross-talk issues, EU does not anticipate that it will be able to use the PLC AMI system for hourly data for all customers. This limits the use of the analytics possible when reviewing transformer loading and other engineering applications. However, the PLC and RF meters both provide the ability to communicate with the meter disconnect collar used as part of the prepaid metering study.

Flint EMC, GA – Flint selected the Aclara TWACS system to complete its AMI system. TWACS was chosen because the co-op already had several thousand meters of this type installed. Under this activity, it installed more than 51,000 additional meters (GE meters with Aclara communications modules). Although the meters and modules had to be sourced from separate distributors, the distributors coordinated at the factory level to ship fully assembled meters ready to install to Flint. The new meters have provided a significant cost savings in metering operations, as all meters can now be read remotely. In addition, the new AMI meters' "ping" feature has been incorporated into the co-op's outage management processes to roll trucks more accurately to the correct area. Additional co-op costs savings have been achieved through analysis of the AMI data to uncover cases of suspected power theft.

As a part of the AMI deployment, Flint also installed 6,000 meters with the remote disconnect feature. These units have proven to be particularly valuable in reducing costs to the co-op and its members in buildings that see high turnover in occupancy. The units save the trip cost to disconnect and later reconnect, and the customer saves the trip charge normally added to the bill to partially reimburse those costs.

As an added benefit of AMI deployment using remote disconnect meters, Flint has been able to deploy a residential prepay meter rate. This has been a highly successful program, with an adoption rate of 14% of total membership, consistent with the target adoption. Eliminating the deposit for prepay customers assists many low-income members. When an existing member accepts the prepay plan, part of the payments are applied to the member's account arrears, making the member "whole" after some amount of time. This has mitigated a substantial portion of bad debt write-off, since many of these members otherwise would have defaulted on the account and left the co-op with unpaid arrears.

Humboldt Co. REC, IA – Humboldt purchased power line carrier AMI equipment from Cooper Industries. This system was chosen for its two-way communications with the meters and ability to support a load management system. In practice, the co-op has been able to get meter readings once a day but has fallen short of its goal of gathering load profile information on an hourly basis. Humboldt chose to install the equipment on its own. However, given the challenges the co-op faced, its officials suggest that Cooper could better serve the industry by providing an installation team to install all of the software, server hardware, and even the meters for the first substation, including all integration to the billing and customer information (CIS) systems.

Kaua'i Island Utility Co-op (KIUC), HI – KIUC's experience with the Landis+Gyr AMI metering system has been very positive. Although the project did encounter typical "bumps in the road," the co-op reports that throughout the installation process, Landis+Gyr was very prompt and competent in addressing the issues. The equipment is working as expected, and KIUC is excited to be Hawaii's leader in smart meter deployment. In addition, although KIUC chose not to pursue an MDM system (MDMS) during the smart grid project, its use of the system during these years convinced KIUC of the importance of an MDM for leveraging AMI data. The cooperative will be installing a Landis+Gyr MDMS by the end of 2015.

Prairie Energy Co-op, IA – In general, the procurement and installation of the PLC-based AMI meters went smoothly at Prairie, in that meters arrived ready to install. However, the supporting electronic files for integration into the existing back-office billing systems were problematic. One vendor sent a complete file, and the other sent two files; combining these files manually was time consuming and tedious.

The primary goal of the new meters was to enable ad hoc, immediate meter reads at any time. Due to interference on the power line, however, Prairie was unable to read many of the meters reliably. It attempted to resolve the problem by installing repeaters to boost the meter signals. Nearly doubling the number of signal repeaters on the system still did not solve all of the issues. The co-op tried to perform hourly reads on every meter, but this did not work reliably enough to make it worthwhile. The system provides sufficient capability for month-end billing purposes; however, if Prairie were to do it again, it likely would not use a PLC-based system. PLC problems were a common theme in our project—at Prairie, EU, Blue Ridge, and Clarke. PLC does not preclude AMI but limits its effectiveness for applications that demand high-frequency reads.

Being a mostly rural utility limits Prairie's communications options but, as technology advances, the co-op will strongly consider something other than a PLC- based system.

3.2.2 Meter Data Management (MDM)

Adams Electric Co-op, IL – Adams selected an MDMS provided by NISC. The integration of this software into its system took significantly longer than anticipated, which held up both the web portal activity and TOU pricing pilot. Although the integration effort has been time consuming, the end results met the original objectives in most cases; in some cases, they exceeded expectations. The cooperative can use the program for a number of processes, including better engineering analysis, sizing transformers, and helping with high bills.

Blue Ridge EMC, NC – Blue Ridge selected the Aclara MDMS based on its need to integrate with its existing Aclara TWACS AMI equipment. Part of the purchase agreement was that Aclara would perform the integration effort with Blue Ridge's back-office systems. Aclara originally planned to begin work on the project in March 2012 but was unable to put staff on it until December, somewhat delaying deployment. Going into the project, Aclara did not have existing MultiSpeak® interfaces for its system. The effort of developing, testing, and implementing these interfaces at Blue Ridge took longer than Aclara had anticipated. Once completed, Blue Ridge has found the product to be beneficial in analyzing meter consumption and interval data. Blue Ridge also purchased an additional revenue assurance module to assist with loss and theft detection. According to the co-op, the MDM project will continue to increase in scope and functionality over time, which will yield benefits to Blue Ridge members for the foreseeable future.

Delta-Montrose EA (DMEA), CO – DMEA selected the NISC MDM software system for the mix of functionality that fit its budget. The software has been installed and tested, and is now working correctly. Integrating the software with the existing billing and back-office systems went smoothly. The co-op reported that NISC offered it superior support and service. DMEA integrated the MDM with the NISC SmartHub web presentment system in June 2013, and now has approximately one-third of its membership (~11K meters) utilizing the NISC SmartHub web portal to access their electrical usage information and pay their bills. Additional integration with Master Station and power usage software also enabled a pilot of prepaid metering that began in the first quarter of 2013.

EnergyUnited (EU), NC – EU selected the MeterSense product by Harris Corporation. MeterSense is a highly configurable system that analyzes meter reads and data coming from the AMI system; however, a year's worth of historical meter readings were required to use and test MeterSense's reading validation processes effectively. This delayed the implementation process due to the quantity of data requiring full validation prior to go-live.

Once implemented, the integration of MeterSense with other EU systems, such as Cayenta and OMS, has allowed EU to automate many of its business processes and analyze data that can be useful for such things as ensuring the accurate billing of members, identifying lost revenue, and evaluating the efficiency of the co-op's electric system.

In the first six months the system was operational, MeterSense accomplished the following:

- Resolved more than 10,000 service orders that otherwise would have required a visit to the member's location and a billing representative to close the orders in Cayenta manually
- Identified 36 meter tampering occurrences, thus protecting the cooperative from lost revenue
- Estimated more than 1,500 meter reads for billing, thus eliminating the necessity of reading the meters at the location manually

EU looks forward to utilizing more features of the MDMS, such as utilizing functionality that will streamline outage detection and restoration verification. In addition, MeterSense will soon interface with the co-op's ESRI mapping system to monitor performance and promote operational efficiency.

Great River Energy (GRE), MN – After carefully specifying requirements and determining a make vs. buy decision for this novel multi-tenant MDM and DR management system, GRE selected NISC as the vendor to provide both systems. GRE and NISC worked together extensively, reviewing requirements and gaps at the beginning of the pilot demonstration. They made progress with the MDMS by the end of the demonstration period so the majority of GRE's requirements were met. The MDMS demonstration was successful, and the organizations are working on extending their relationship. The NISC DR management system (DRMS) failed two of the system acceptance milestone checks that related to high frequency readings. This led to the termination of the DR component of the project, but GRE still views a multi-tenant DRMS as a vital part of the software platforms it will need to achieve DR objectives successfully in the future; GRE currently is in the process of acquiring another DRMS solution.

Lake Region Electric Co-op (LRE), MN – LRE is one of the distribution co-ops associated with the GRE multi-tenant MDM system. This system is foundational to providing consumers real-time insight into their energy usage and is reviewed further in the IHD/Web portal section.

Minnesota Valley EC (MVE), MN – MVE is the third member of the GRE multi-tenant MDMS. MVE currently uses the MDMS to store and cleanse approximately 1,000,000 meter values a day, and perform analyses to determine the value of existing and new load management programs. The multi-tenant capabilities have enabled MVE to monitor distribution line loss by substation. Monthly, daily, or hourly analysis can be performed. Absent the multi-tenant capabilities, it would have been difficult and time-consuming to compare GRE's substation meter data to MVE's 36,000 meters.

3.2.3 Telecommunications

Adams Electric Co-op, IL – Adams installed new S&C microwave data systems (MDS) radios as part of its D/A upgrades. The radios were straightforward to install and have worked well.

Clarke Electric Co-op, Inc., IA – Clarke installed 450-MHz radio backhaul equipment and associated communications equipment to link Clarke's control center with 21 field switch locations and 11 substations. The vendor selected for this was RFIP. The vendor initially experienced coordination issues and did not meet the deployment schedule. Clarke was able to work with RFIP on installation issues, and the equipment was brought online in a timely fashion. Clarke currently is experiencing some communications breakdowns between multiple remote terminal units (RTUs) at various substations and at a significant number of D/A switches. Clarke currently is working to determine if the problem is radio related or if the SCADA system is not correctly processing the information it is receiving.

Corn Belt Power Co-op, IA – Corn Belt acts as an intermediary between generation and supply and a group of local rural electric cooperatives. The wireless communications system installed, purchased through Larson Digital Communications, consists of 53 radio transmitter/receivers and relays, and was installed by Corn Belt employees and contractors. The system provides a wide area network (WAN) between Corn Belt headquarters and its member cooperatives and the distribution substations, thus enabling load management control. The equipment installation went smoothly. The system allows Corn Belt to initiate a load control condition, pass this information to the distribution cooperatives and then, through their PLC networks, down to load control devices at the member level. It is estimated that the demand reduction savings to Corn Belt's members were $460,000 in 2012, $1,139,000 in 2013, and $678,000 (to the end of July) for 2014. These savings are expected to continue into the future.

Delaware County Electric Co-op (DCEC), NY – DCEC was limited by its geographical (topographical) constraints to using PLC communications for the project. DCEC installed a Landis+Gyr primary data collection system and five substation data aggregation RTUs. DCEC reports that it is experiencing reasonable throughput from its PLC system—sufficient for gathering accurate billing information. The co-op reports that it sees broadband communications as the key for the future of the smart grid and that the PLC system has significant data limitations. A PLC's limitations generally relate to limited bandwidth. Part of this is an inherent limitation in the technology, but bandwidth can be degraded further by noise on the line. Noise can come from exogenous radio frequency signals being picked up by the conductor or, more commonly, from arcing on the line. Although arcing is addressed in regular line maintenance, the tolerable level of arcing for PLC operations is much lower than for the delivery of electricity. Although PLC may be adequate for communication with a single device or meter, it is not suitable for broadcast messages. DCEC could not, for example, send a "conserve" message to everyone at once.

Owen Electric Co-op, Inc., KY – Owen has added significantly to its telecommunications network over the course of this project. A new tower building and microwave dish were added at an existing tower. MobilComm installed the equipment, which was integrated into Owen's WAN with the assistance of the co-op's staff and PTS, another vendor. In addition to the microwave equipment, Owen has added a significant amount of fiber lines to its network. All of the fiber has been installed, and the system is functioning as designed on the Ethernet portion. The project also incorporated new switches and routers that were compatible with the existing routers and switches in Owen's WAN. The new equipment allowed for a loop design of the WAN to utilize an open shortest path first (OSPF) routing protocol. Although there were some fiber optic partition issues on the T1 connection to Eastern Kentucky Power Cooperative, they were resolved successfully. Owen reports that it is fully satisfied with the fiber deployment and is planning additional fiber extensions to expand communication opportunities.

Washington-St. Tammany EC (WSTE), LA – WSTE originally planned to use microwave communications relays mounted on concrete poles to link its system of smart feeder switches. It was fairly sure that this system would work but it was discovered that microwave frequency attenuation from vegetation and other factors drove a need for towers twice the height originally planned. This change would have increased the cost of the system unacceptably, and the system had to be re-engineered. WSTE eventually determined that fiber optics provided the best combination of speed, cost, and durability; the equipment and supplies were ordered and this system has been installed. WSTE installed 109 miles of fiber, completed in December 2013.

3.2.4 Supervisory Control and Data Acquisition (SCADA)

Adams Electric Co-op, IL – Adams selected Open Systems International (OSI) for its SCADA system upgrade and has found OSI support to be excellent. It reports that the SCADA software is excellent and consistently exceeds expectations. The cooperative also has found that the new system provides it with more and better ways to monitor its distribution system. Furthermore, the active load control functionality of the software allows Adams to control air conditioner (AC) and water heater control relays from its legacy radio-based load management system. The cooperative can now control 10–15% of its peak load.

Adams-Columbia Electric Co-op (ACEC), WI – ACEC had an existing Survalent SCADA system, but the addition of the smart feeder switching activity necessitated some feature upgrades in its system. Procurement installation and configuration worked without a hitch.

Clarke Electric Co-op, Inc., IA – Clarke selected the OSI SCADA system for its SCADA and smart feeder control systems. This system is installed, functional, and operating correctly at several data points but the cooperative is still programming some of the equipment in the field and adjusting the SCADA software. Substantial software work was required to integrate the new SCADA with the rest of Clarke's systems but the work ultimately was accomplished satisfactorily. Currently, the SCADA system is functioning properly regarding real-time controls and data. The co-op reports that the OSI historical server, used to provide archived substation transformer and circuit load data, is still not working correctly. Clarke, in contrast to other users, has found it a challenge to get support from OSI despite being enrolled in its “gold support package.”

Owen Electric Co-op, Inc., KY – Very few technical issues arose during this project; the most significant issue was a firmware upgrade required to resolve an intermittent communication problem to Owen’s RTUs. The firmware upgrade was completed and resolved the problem successfully. The technical benefits have been realized through increased situational awareness of events in the field as a result of the increased data being retrieved from the field devices. For example, fault current magnitudes and fault targets have been used to identify fault locations and dispatch crews to the source of the problem, thus reducing outage durations for Owen’s membership. Additional cost savings were realized in 2014 through eliminated trips to substations, as the co-op now is able to reprogram the RTUs remotely.

Washington-St. Tammany EC (WSTE), LA – Due to issues related to its communications backbone, WSTT was delayed significantly in upgrading its SCADA system. It installed the Cooper Yukon in fall 2013; Cooper sent a team out to assist in the configuration and setup. The equipment all worked well, with the exception of the Schweitzer relays (SEL 221C) in one substation. As it turned out, those relays cannot send and receive the appropriate SCADA permissive signals. After analysis, those relays were replaced by compliant Cooper relays.

3.2.5 In-Home Displays (IHD)/Web Portal Pilots

Adams Electric Co-op, IL – Adams is providing a web portal pilot program to its members. To accomplish this, the co-op needed to integrate between its CIS (from Daffron) and the MDM software (from NISC). The interfaces between these two pieces of software took significantly more work than anticipated and were barely completed within the timeframe of this project. Some of Adams’s auxiliary meters are causing extra problems for the e-business and MDM software. Specifically, the mapping of meters to accounts assumed in the MDM software did not support Adams’s association of auxiliary with primary meters.

Customer acceptance of the web-based e-billing system has been very positive.

Approximately 10% of the members are using the e-business site on a monthly basis. With the new systems, members can visit a website to view their metering data down to the hour and review their usage patterns. The program has a planning tool that allows members to add markers to track different changes to their usage. For example, if a member adds a new electric heating system, hot tub, etc., the member can mark the date and hour it was installed and see how it changes the usage pattern. Members can also overlay their usage with the high, average, and low temperature, including humidity, to see how this affects usage. Members can make comparisons between different days and months and can see historically if certain days of the week are higher usage. The program provides a tremendous amount of data for members to use in understanding their usage patterns.

Delaware County Electric Co-op (DCEC), NY – All of DCEC’s deployed IHDs link to its respective endpoint/metering device via the Zigbee wireless radio link. Fifty of the IHDs are included in the study portion of this project. The Zigbee link allows the IHD to display selected energy measurements derived from the endpoint metering instruments. The study group of 50 is complete and operational. With the exception of three locations, all IHDs were deployed successfully using Landis+Gyr's hosted Command Center control system. Three devices required remedial addressing in the field to provision the Zigbee wireless radio link correctly; these now are working properly.

Delta-Montrose EA (DMEA), CO – DMEA integrated the MDM with the NISC SmartHub in June 2013; approximately one-third of its membership (~11K meters) is utilizing the NISC SmartHub web portal to access their electrical usage information and pay their bills.

Flint EMC, GA – One aspect of the project at Flint was to deploy a web portal for customer use in viewing and analyzing usage. This task was accomplished fairly easily by deploying a pre-built module on the co-op's CIS (Southeastern Data Corporation). This deployment allowed it to make the portal available to its entire customer base and provides near real-time usage data. Numerous improvements to the portal have been made since its inception, including a custom interactive tool for assisting members in troubleshooting high bill scenarios online.

The other aspect of this project was to pilot an IHD to provide peak demand notification and general usage information to a limited sample of members.

When the project was conceived, it was with the intent of using one of the commercially available IHDs that utilize the Zigbee communications protocol to gather information directly from the meter. At the time, Aclara was advertising its modules as available with the Zigbee chip. After Flint began the project and tried to procure them, Aclara informed the cooperative that they had no Zigbee-equipped modules ready to ship. Aclara eventually discontinued development of the Zigbee chip, citing range and wall penetration issues. Flint improvised and bought and repurposed Aclara's IHD designed for prepay metering, and purchased the Utilsales prepay software to send messages to the IHDs even though it is not using Aclara's prepay system. This device communicates to the system head-end server through the TWACS protocol, not directly with the co-located meter, as originally had been intended. The workaround allows Flint to send peak notifications but provides no real-time meter data reporting to the customer.

Kaua'i Island Utility Co-op (KUIC), HI – From the KIUC members' standpoint, the IHDs have been the most exciting aspect of the smart grid project. The co-op estimates that it has raised the level of awareness on individual consumer usage to a whole new level. In fact, its Board of Directors approved an additional 500 IHDs above the original procurement of 500. Once KIUC's MDMS is fully implemented, the co-op will have better access to a voluminous amount of data to determine if the IHDs actually had an impact on members' energy savings. It definitely raised the level of awareness of energy consumption to those co-op members able to participate. However, actual measured savings are yet to be determined.

Kotzebue Electric Assn. (KEA), AK – The KEA IHD program has been successful in making cooperative members more aware of their electrical energy consumption. The co-op received a great many positive comments. Members noted that their children were learning how to control appliances and were excited about turning them off when they were not in use. They currently do not have a good way to measure the monetary effect; however, the Landis+Gyr Ecometer IHD units were deployed in more than 850 member homes, with each receiving a tutorial on the use of the meter. KEA is planning to provide periodic refresher training on the units through the Ruralite magazine and the KEA website.

Lake Region Electric Co-op. (LRE), MN – LRE intended to provide a web portal interface for its consumers to get real-time data on their energy usage through the multi-tenant MDMS being developed with GRE. However, due to the large amount of administrative work to edit, estimate, validate, and/or recover the meter data for each account in the pilot program—such that the interval data presentment would also tally up to the month-end register balance—the pilot was deemed too expensive. Instead, the co-op decided to continue an existing program—the MyMeter application that was in place before this project began. That system is offered to all 26,000 members in the cooperative and used by approximately 4,000 accounts.

Menard Electric Co-op, IL – Menard implemented a web portal to provide customer-facing information from the MDMS on members' electric consumption. NISC provided the MDMS and, although the project timeline for development and deployment was not met, the web portal is now completely tested and in working order.

Minnesota Valley EC (MVE), MN – MVE is providing a web portal interface for its consumers to get real-time data on their energy usage through the multi-tenant MDMS being developed with GRE. Customers can also access this information via their smartphones.

Owen Electric Co-op, Inc., KY – Owen combined its web portal pilot program with a demand reduction effort in its Smart Home project. For this effort, Tendril was selected as the vendor, based on all-around capability, product, marketing, experience, and software. Owen officials feel that this decision was correct at the time, but given new knowledge and developments in the industry, they now acknowledge they would not choose Tendril. The project implementation was much more difficult than anticipated. All areas—hardware, software, marketing, and products—involved significant learning issues. Other unanticipated challenges included difficulties with the communications system and in addressing 400-amp meters. However, tackling these sorts of challenges on a small scale is the reason Owen initially chose to approach this effort in a small pilot.

The software deployed is software as a service (SaaS) from Tendril via the member's Internet; it provides members with control of their thermostats and hot water heaters via their PCs or smart phones. It also provides them with historic usage and billing data.

Members are asked to fill out a home profile online so their energy usage can be compared with other similar homes. The software also provided a place to set energy-saving goals, receive energy-savings idea, and share ideas with other pilot participants. From the co-op perspective, the major concern with the software was that it was geared toward energy savings and not peak demand savings, which is the driving savings value for the co-op.

3.2.6 Demand Reduction over AMI

Adams Electric Co-op, IL – The Aclara software has been installed, Aclara support has been excellent, and the active control of the load control switches is being integrated into Adams existing load control schemes. As part of the project, 200 new AMI-based load control relays (LCRs) were added to the existing radio-based demand reduction LCRs on water heaters and ACs. Using the Aclara software, the cooperative can control 10–15% of its peak load.

Calhoun Co. REC, IA – Calhoun currently is controlling the load control switches installed as part of this project (more than 317). Installations of the DR units have been positive, and the cooperative has seen a benefit to the overall system demand component, though no dollar figure has been calculated yet to assess the program's return on investment (ROI).

Clarke Electric Co-op, Inc., IA – DR has been implemented through a three-year demonstration project involving AC and/or water heater load controls at 80 homes. It has been reported from the field that the technology involved—load control relays for AC and water heaters—has worked well. The peak energy demand avoided seems to be minimal but evidence exists of both a load rebound subsequent to the control period and higher loads in the hour preceding control periods. The co-op suspects that this may be due to precooling of the participants' homes to a cooler than normal setting before the load control event.

Delaware County Electric Co-op (DCEC), NY – DCEC's demand reduction program centers on the control of member/customer electric water heating equipment. The deployed load management switches or load control switches (LCS),operate as a controlled endpoint of the Landis+Gyr PLC-based AMI system. Normally, the newly installed LCS devices control electric water heating equipment on a time-based schedule controlled by the AMI system. However, DCEC worked with its SCADA system provider (Survalent) and AMI system provider (Landis+Gyr) to integrate their respective systems using MultiSpeak. This integration allows the command sequence programs in SCADA, which measure and predict the DCEC system load, to control LCS devices in an optimal manner that minimizes purchased energy costs with respect to DCEC's power supplier's rate structure. DCEC's power supplier is the New York Power Authority (NYPA). The critical component of the project was to investigate the qualification of the controlled water heating system as a DR resource in the New York Independent System Operator's (NYISO) DR program. Unfortunately, after careful post-installation analysis, it does not appear that DCEC's demand reduction would be sufficient to qualify for inclusion in the NYISO payment program.

Nonetheless, the demand reduction system does assist in shaving the peak power demand of the system. The new LCS devices installed with this project replace a set of LCRs that were no longer supported. The "legacy" LCR system required the use of a separate PLC system that also was no longer supported. DCEC now has more than 675 controlled electric water heaters connected to the integrated AMI/SCADA system. Operation of the integrated system controlling these electric water heaters effectively helps DCEC manage its power purchases through the NYPA and has been judged very successful. DCEC believes that the integrated AMI/SCADA system will serve it well for many years to come, as support from both business partners—Landis+Gyr and Survalent—has been outstanding.

Humboldt Co. REC, IA –The co-op found the hot water and AC demand reduction equipment easy to install and has had very few issues with this system. Humboldt recently merged with, and is now part of, Midland Power Cooperative, so the installation rate of the DR equipment slowed down to some extent due to the added work load of the merger. However, the remaining load control switches were operational by the end of the second quarter in 2014. One of the largest obstacles to overcome for the DR installations was making arrangements with the membership to get the load control receiver installed, especially during normal business hours. An estimated 20% of the installations were completed after normal business hours or on weekends, which naturally drove up the cost of implementing the program. As of July 2014, the co-op has seen a one-time peak reduction of more than 2,100 KW to its peak demand.

Iowa Lakes EC, IA – Iowa Lakes struggled a bit in the beginning of its demand reduction program. The co-op reports that the design and programming of the IHD and demand reduction system provided by the vendor would in time have compromised the functionality of the system. In the end, the decision was made to discard the vendor's programming, and Corn Belt & Iowa Lakes developed their own program, which meets their present needs and expectations for the future. From a hardware perspective, to Cooper's credit, failures were under the expected 1%. The actual failure rate in a one-year period was 0.45% for the direct load management device and 0.31% for the IHD device. The program has been beneficial, however, and DR efforts have resulted in a savings of approximately $700K annually.

Kaua'i Island Utility Co-op (KIUC), HI – Demand reduction through the action of individual consumers is important on a truly "islanded" power system and can save members significant amounts. This is important, as Hawaii has some of the highest energy prices in the U.S. However, due to the extended amount of time it took to implement the AMI system, KIUC chose to defer the installation of DR switches at the time of this project.

Minnesota Valley EC (MVE), MN – The load control management switches the co-op selected are those from Aclara and are deemed to be of excellent quality. The installations have been straightforward, with no significant technical issues. The co-op already is seeing the benefits of having two-way communications to the load management switches. The co-op's best estimate is that it was unable to control about 15–20% of the previous receivers for a variety of reasons. The two-way communications of the Aclara device ensure that the load is controlled by allowing the utility to confirm the switch status and address any issues. MVE has used the resulting meter data in the MDM to estimate an increase in sheddable load of .25 kW per load control device. This has helped create a business case to exchange the remaining one-way load management receivers with two-way receivers.

Owen Electric Co-op, Inc., KY – Owen EC has combined its web portal pilot program with a demand reduction effort in what it calls its Smart Home project. See the listing under IHD/Web-portals.

Prairie Energy Co-op, IA – At this time, the co-op has installed more than 750 load control devices on numerous residential water heaters. The primary difficulty it has faced is adequate communications reliability. The LCRs seem to work fine when they actually receive a signal. Getting information to or back from them is dependent on the signal strength available from the device over the power line, distance back to the substation, amount of interference on the power lines, and electromagnetic interference inside the customer's site. Even with these difficulties, Prairie manages to control a significant number of the load control devices; the current system already has resulted in more than $230K in savings in the months since installation.

3.2.7 Prepaid Metering

Delta-Montrose EA (DMEA), CO – DMEA launched a limited pilot of prepaid metering in January 2013. That pilot not only leveraged the use of DMEA's new NISC MDM to enable prepaid services and disconnect/reconnect collars, but also utilized Aclara's IHD for customer presentment. Typical users of DMEA's prepaid services could have the ability to access DMEA's web portal though some technological means (web browser, smart phone, tablet, etc.). If they do not, an IHD is essential so members can find the status of their prepaid accounts. In the testing accomplished to date, all of the aforementioned systems (including the disconnect collar and IHD) have come together nicely, creating an easy-to-administer and easy-to-utilize prepaid program. DMEA planned to start a much more aggressive rollout of prepaid metering in the fourth quarter of 2014.

EnergyUnited (EU), NC – EU's prepaid metering system was developed as an integrated solution along with existing core systems—the Cayenta CIS and Cooper AMI systems. The use of the MultiSpeak® protocol made this a quick development turnaround, which worked out well; it has been a solid interface since implementation.

EU encountered some challenges with deployment when Cooper Technologies recalled the disconnect collars were recalled. The firmware in the collars required an update to ensure that they would validate all incoming signals and not disarm unless they received and verified a signal directly from the utility.

Once the technology bugs were resolved, the prepaid metering program became a widely accepted offering for EU's membership. Members could use this upon initial service connection in lieu of deposits. It also has proven useful in high turnover locations. The co-op has found that prepaid metering has made its members more aware of their daily usage; they also are gaining a better understanding of what drives electric use.

Dedicated IHDs are not supported by EU's prepaid system; instead, all communications with the customer are done via email, text messaging, phone calls, and member logins to a web portal. It has been noted that during warmer or colder weather periods, the volume of outbound communications to prepaid customers increases significantly. On average, 74% of EU's prepaid customers make more than two payments per month on their accounts.

Kotzebue Electric Assn. (KEA), AK – KEA experienced significant problems in finding any vendor to bid on a prepaid metering solution to fit its needs. The primary issue seemed to be that the co-op was simply too small and remote (it is north of the Arctic Circle), and the procurement process too cumbersome to make it attractive to the vendors.

Eventually KEA was able to get its existing meter management software supplier to agree to build out the prepaid metering capabilities. The significant delays in finding a vendor meant that this effort is just now beginning to bear fruit. KEA has asked its long-term CIS provider, Professional Computer Systems, Inc., to customize a prepay system that works with the existing PCS software suite it uses. PCS staff were onsite in Kotzebue in July 2014 to finalize the software interface and processing systems to get the system up and running for active use beginning in fall 2014.

3.2.8 Interactive Thermal Storage

Delaware County Electric Co-op (DCEC), NY – The heat pump water heating component of the project is a technology demonstration funded through matching funding by the New York State Energy Research and Development Authority (NYSERDA). This portion of the project called for the installation of 45 heat pump water heating devices at member/customer locations. The objective was to demonstrate the operation of these devices in the cooler northeastern U.S. The instrumentation packages, data gathering and analyses services, and technical guidance were provided by EPRI under a NYSERDA grant. Although there is no significant thermal storage of energy associated with these devices, a heat pump can provide electrically efficient heating of water by capturing the ambient heat in the basement or utility space. This avoids the use of the electrical heating elements and allows effective control of the water heating devices using energy in off-peak hours without inconveniencing members/customers.

Great River Energy (GRE), MN – GRE procured and installed Steffes grid interactive thermal storage water heaters. These units heat water to very high temperatures (185F+) during times when grid electricity usage is low, and thus cheaper, and then mix the hot water with cold water to the desired usage temperature. As the units are addressable over an IP address, they can be used to provide fast frequency regulation services to wholesale ancillary service markets. The revenue received by modulating the charge rate of these devices based on a signal received from the overseeing independent system operator can entirely offset the cost of energy to provide hot water for a home or business. The units have worked exceptionally well, and the initial results are promising.

3.2.9 Renewables Integration

Kotzebue Electric Assn. (KEA), AK – KEA's project got off to a slow start, due to a lack of resources at this small co-op. The project was re-scoped to enable completion within the timeframe of the NRECA Smart Grid Demonstration Project (SGDP) cooperative agreement. For the renewables integration component of the project, KEA was attempting to integrate its new large-scale wind turbines seamlessly with its existing diesel-fired generators. Determining what form of VAR compensation device would best integrate with their existing large diesel and the new large-scale wind generation systems took significantly longer than anticipated. Further difficulties were encountered in the simple logistics of heavy equipment delivery and installation to a town that is one of the farthest north in the entire country (30 miles north of the Arctic Circle and with free water ports open only four to five months of the year). The equipment for this part of the project was installed only recently. KEA selected the 1 MVAR ABB Statcom unit after significant study and review. The unit was received in Kotzebue in late fall 2013 and is in the final commissioning phase. The Statcom unit will allow a transition from the large diesel generator to the large wind turbines, along with the use of only a small diesel genset, during periods of high wind power penetration.

Minnesota Valley EC (MVEC), MN – MVEC has installed five Silent Power OnDemand 9.2-kWh battery storage devices and 12 5-kWh battery storage devices during the course of this project. The equipment experienced minor difficulties in the beginning, which were solved with a firmware update from the vendor. In addition, there were some problems regarding integration with the metering. At locations with only a general service meter, the installations were straightforward and relatively simple. Other installations were more complex, with sub-metered off-peak load and integrated solar panels. It took a while to figure out how best to configure the devices, but the co-op is now able to control them so as to reduce wholesale power costs. February 2014 was the first live test, in which they are actively trying to discharge the batteries to offset a billing peak while still limiting them to only five discharge events per month. The good news is that co-op members are very interested in the technology and have been supportive. Silent Power ceased operations on February 11, 2014, but has since reopened.

3.2.10 Smart Feeder Switching

Adams Electric Co-op, IL – The co-op reports that the S&C SCADA Mate overhead switches proved to be a good choice for its installation, and that S&C makes a good switch, designed for easy installation, which seems to be more robust than competing switches. After overcoming initial difficulties in programming the controllers due to incorrect firmware installed in the controllers, the switches now are working properly. The controllers have been fitted with Speed Net radios for peer-to-peer communication; these are faster and reported as having fewer errors than S&C's Utili-Net Radios. To date, the switches have not been called on to backfeed due to outages.

Also, as part of the smart feeder switching project, Adams has installed a number of overhead and underground fault indicators that report back to the SCADA system. The co-op has reported that HD Supply is a great vendor with which it was easy to work. The fault indicators are a great product, easy to install, met their needs, and definitely help with troubleshooting distribution system faults.

Adams-Columbia Electric Co-op (ACEC), WI – ACEC installed four overhead and six underground distribution switches, as well as four substation reclosers. The equipment was procured through Cooper Power Systems; delivery and installation were completed without incident. Since installation, ACEC has experienced one event that should have made the system operate. However, it was not a normal distribution line event. A squirrel caused a fault on the substation bus that in turn caused the substation transformer high-side fuses to blow. When the substation power was lost, communications at the substation were lost, and the automatic restoration could not take place. The co-op subsequently installed uninterruptable power supply systems at all of the substations to harden the substation communications against similar outages.

Clarke Electric Co-op, Inc., IA – Twenty-one S&C SCADA-Mate switches and 36 Form 6 controlled Cooper NOVA TS reclosers were installed and are functioning.

The automatic self-healing scheme involving the Lacona substation for restoring power during a transmission or substation outage is directed through SCADA. The scheme is functional; however, to date the co-op has chosen to initiate the scheme manually before working automated switching protocols into its operation procedures.

The S&C SCADA-Mate switches have been relatively reliable for remote switching operations. During testing, the co-op identified an increase in dropped information packets, which caused a degradation in switching reliability. The co-op is working to remedy the issue; it suspects that this is a communications or SCADA issue and is unrelated to the switches themselves. If the problem is persistent, it could be problematic for both the Lacona self-healing scheme and any remote switching that would be needed during a period of poor performance. That said, the switches are frequently switched remotely for line personnel, which has saved significant drive time in the field.

The co-op has experienced numerous problems with the Cooper Nova-TS reclosers, including water penetrating control cabling connections, power supply failures, and recloser actuator board failures. It is believed that the water issues can cause a short circuit that has the potential to damage the power supply and actuator board. There is a serious concern regarding this issue because a short between the open or close circuit pins could cause an unintended operation of the recloser. The recloser division of Cooper has provided excellent support, and the utility has received numerous replacement cables, junction boxes, and boards at no cost. Although Cooper has provided replacements for the cables and junction boxes to combat moisture issues, Clarke is not confident that the newer cable style will rectify the issue fully. The co-op is continuing to explore engineering solutions, including factors such as line maintenance, defective capacitors in meters, software upgrades, additional repeaters, and additional metering methods of operation. Until the problems are fully resolved, the co-op cannot definitively verify that energy use was read accurately.

EnergyUnited (EU), NC – EU partnered with Siemens to install a smart feeder switching system at its Boomer delivery point, a 12-kV delivery point with a poor reliability record. The new system initiates an automated transfer to an alternate source upon loss of the normal power supply. Because of the very rugged and hilly terrain, communications were a major concern from the outset of the project and the main challenge during implementation. Field testing made it apparent that wireless communications for some of the devices being installed were unacceptable. The overall configuration was modified to run on fiber optic cable; this proved successful. Siemens was able to adapt rapidly to this change and integrate all elements seamlessly. Because this particular system is customized due to its unique nature, the troubleshooting period has been lengthier than expected; however, the co-op reports that Siemens has been very helpful in making the necessary changes. Although test simulations have been successful, only a real-world disaster will prove the system's operation completely. Due to the success of this project, EU currently is in the planning stages with Siemens on additional D/A elsewhere on the system.

Kotzebue Electric Assn. (KEA), AK – KEA installed a 15-kV and a 25-kV switch in its substations. The switches are designed to actuate based on radio signals from the SCADA system; however, the radio communications to the switches have experienced some difficulties. KEA has plans to improve signal line-of-site to the switches in the near future. However, the new switches already have proven useful in isolating the KEA wind power site and USAF radar site during recent construction work at the airport, when the 25-kV switch was operated locally (not remotely, due to radio system problems). KEA linemen then were able to restore power to the sites quickly after work had been completed, using the 25-kV switch.

Owen Electric Co-op, Inc., KY – Owen installed four Cooper Nova Reclosers (with F6 Controls) as part of this project: two at the Western Regional Waste Water Treatment Plant and two the Narrows Waste Water Treatment Plant.

The utility reported that working with Cooper Power Systems was quite easy because of some previous work the co-op had done with Cooper. A previous state-funded self-healing project had proven successful after a great deal of work and collaboration between the two organizations, following a series of failures. That expertise and experience was brought forward into this project.

The four installations for this project were relatively routine, as Owen's crew had previous experience with this type of installation during the state project.

Owen reports that it generally has been pleased with the Cooper system because it can support a very complex self-healing network. However, Owen does not regard the system as perfect; the co-op would like to see Cooper make modifications in the YFA software that will allow AND/OR logic and some other basic changes. Currently, the Cooper system has minimal options for user-based modifications to the standard software. Owen has a strong need for this capability. If Cooper does not enable user-based modifications in the near future, Owen will look to implementing the desired logic using its own SCADA system and communications network to enable additional self-healing projects.

The first set of reclosers were tested and commissioned on March 15, 2012. There had been no interruptions in normal power at the time of this report. The second set of reclosers has failed pre-commissioning tests twice. Based on the review of the failed test data logs and some real-time analysis, the probable cause of failure pointed to excessive harmonic distortion inside the treatment plant. Owen performed harmonic analyses during the week of February 11, 2013. The focus of the investigation shifted to a potential customer-induced power quality issue. This definitely was not expected, but proved to be a "learning point" for both the vendor and Owen and a factor to check when deploying this type of technology. After significant analysis, Owen discovered that the root cause was not harmonic distortion, but a damaged oil controlled recloser control cable, and successful commissioning then took place. No further healing opportunities have occurred since the commissioning.

Salt River Electric Co-op Corp., KY – The co-op purchased 29 Intellirupters from S&C Electric. The switches were delivered, and the installation went as scheduled in the project plan. There was a minor problem due to incorrect radios installed in the switches that were delivered; the frequency range was not compatible with Salt River's existing system.

Although it is unclear how the incorrect model radios came to be installed, S&C was prompt in responding to the problem and correcting it. Thus far, the co-op reports it is pleased with the installation and that the switches have much greater capabilities than in previous systems. To date, the switches have been called upon to respond 22 times, affecting 10,404 total customers and reducing outage times by 75 minutes, on average.

Snapping Shoals EMC, GA – Snapping Shoals purchased recloser equipment from Cooper and S&C, and communication equipment from RuggedCom and Microhard. The co-op chose these vendors in part because of familiarity with the performance of the products and a comfort level with the vendors' technical expertise. Of course, there are always challenges with any technical project. For example, establishing effective radio communication to support the automated switching was difficult. It took more than a year, multiple trials, and multiple vendors before finding Microhard radios, which work reliably on this system and in this environment. It also has been challenging to develop procedures and train employees to take advantage of the new technology. However, in the end, the smart feeder switching solution has proven to be very reliable and effective in creating significantly more reliable service and a much more resilient power delivery system.

Since its inception in 2011, the system has experienced 37 automated switching events, preventing more than 20,000 customers from experiencing an outage. Those customers otherwise would have endured an outage lasting an average of 1.5 hours.

In addition, the ability to isolate damaged distribution lines by taking remote control of the devices has contributed toward saving an additional 33,000 consumer hours during this period. In response to one particular substation transformer outage, the utility restored service to all four feeders remotely within 15 minutes. Without remote control of field devices, restoration would have taken well over an hour.

An additional benefit has been found in substation maintenance. Because of the number of remotely controlled switches on the co-op's system, most substations can be switched out of service remotely. Without remote control, this work would require a truck with one or two employees at each switch to be operated; this means four to five trucks and crews tied up for about half a day, frequently running into overtime hours—all of this an average of six times a year. Although not a huge cost savings to the co-op, the convenience factor for the crews has been greatly appreciated.

Washington-St. Tammany EC (WSTE), LA – WSTT has installed 24 69-kV air break switches with Cooper ITP relays. These relays are programmed to monitor the switches upstream and downstream of their locations to isolate faults from storm damage or hardware failure, and then notify the SCADA system of state changes. The entire 69-kV distribution system is set up in a loop configuration so it can be fed from either direction.

3.2.11 Advanced Volt/VAR Control

Adams-Columbia Electric Co-op (ACEC), WI – ACEC had planned to install conventional distribution capacitor banks with controls and, to this end, went through the entire RFQ process. However, the opportunity arose for ACEC to procure new solid-state devices from Varentec that provide distributed voltage control on a neighborhood level. The units were installed on branches of a single substation and initial findings are hopeful. The units do cycle in and out rapidly and perform well. Unfortunately, the units experienced a 10% failure rate in the first month. These units have been replaced under warranty; Varentec has cited a known component issue and believes there will be no further issues. As it turned out, the problems with the Varentec units were not so much an equipment failure as a firmware problem that caused difficulty with the cellular communications hardware. That problem now has been remedied. The co-op reports that the Varentec devices themselves appear to be excellent for localized voltage support (especially end of feeder). ACEC is currently investigating an application using Varentec units to help reduce flicker on distribution circuits during irrigation well start-up. The primary benefit to date has been in improved power quality to co-op members.

Iowa Lakes EC (ILEC), IA – ILEC installed cap banks and controls at two substations that had large commercial loads. The substation's power factors were running at 55–69% for most of the year, causing voltage issues when these substations were taken down for maintenance. One set of capacitor banks was installed on the substation bus and the other out on the feeder adjacent to the commercial load (using a time clock). The power factors on both substations were corrected up to the 80% mark using SCADA control of the capacitor banks. The cooperative has had no issues with the capacitor bank units or voltage levels. To date, no dollar savings have been calculated; however, the primary goal of voltage consistency has been achieved.

Menard Electric Co-op, IL – All of the major material for the Volt/VAR project was sourced from Cooper Power Systems. Menard has used other Cooper equipment in the past, with satisfactory results. However, within the first few months of taking delivery of the equipment, Menard had several problems, ranging from programming the controller to a high percentage of failures in the field. Cooper since has released a new controller that corrects many of the programming difficulties. The multiple field failures experienced by Menard were found to be due to moisture accumulation inside the control. Cooper representatives inspected several controls that had been damaged due to moisture. Due to these issues, Cooper has offered to supply 50 replacement controls. Cooper plans to replace these with the modern CBC-8000 and will bill Menard for the difference between the new costs of the old CBC-7000 and the new CBC-8000—approximately $300/control. Menard also will have to spend an estimated $200/control in labor to exchange the controls, for a total estimated cost of $25,000. Menard believes Cooper is making a fair offer but the co-op will be spending approximately $25,000 more on this project than anticipated. When operating, the capacitor banks seem to perform well, with the features working as expected. Menard was pleased to have many of these banks installed before summer 2012 because at that time it hit the highest peak load it had ever seen.

Recently Menard's G&T announced that it is expecting all of its member cooperatives to meet a higher power factor going forward; this project allowed Menard to reach this level before it was mandatory.

Owen Electric Co-op, Inc., KY – Owen has taken a very detailed and methodical approach to developing its Volt/VAR program; Phase 1, the only phase that could be completed in the timeframe of this cooperative agreement, involved the GPS collection and field inventory of two substation distribution service areas and the installation of six three-phase ABB grid monitors. Davey Resource Group (DRG) was selected for the GPS/field inventory of six distribution feeders on two substations.

The field work that DRG provided was satisfactory. However, there were issues with the data integration between DRG and Owen's GIS database. Owen's data were developed from an older set of standards that conflicted with the DRG third-party software used for the GPS collection. The issues since have been resolved and Owen has developed a better grasp on disconnected editing of an ESRI database. The final feeder inventory was completed in January 2013, seven months behind schedule due to the integration issues.

This GPS pilot proved valuable not only in helping to develop a very accurate distribution analysis model for the upcoming Volt/VAR optimization (VVO) portion of the project; it also shed light on the complex details and unforeseen issues of a system-wide GPS collection project. Owen plans to GPS the remainder of its system beginning in 2015, and the experience gained under the SGDP cooperative agreement will allow the co-op to write a substantially better RFP.

As for the equipment deployed as part of this project, the grid monitor units did not perform as advertised. The units did not measure accurate voltage levels consistently. In addition, a significant safety concern arose due to a catastrophic failure of a monitor in the field. The units were returned to the vendor and, since an adequate explanation for the issue could not be found, the order was cancelled. The timeline of the cooperative agreement did not support re-sourcing monitoring units, and the remainder of this project was cancelled.

While the Volt/VAR project did not move out of Phase 1, Owen is continuing onward with its own VVO pilot project, though this is outside the scope of the agreement. Owen plans to share the results of its VVO project with NRECA by the third quarter 2015, and NRECA will publish the results.

3.2.12 Conservation Voltage Reduction (CVR)

Adams-Columbia Electric Co-op (ACEC), WI – The new Varentec units that ACEC has installed allow the operator to dial in a CVR target voltage and maintain that value. (See Section 3.2.11 on Volt/VAR for details on ACEC's Varentec installation issues.) ACEC examined the load data and has been unable to prove that the CVR is producing a measurable kW demand reduction. Its opinion is that the natural variability of the load in this area simply overwhelms the ability to see the effect of CVR, similar to trying to hear a whisper in a windstorm. The co-op has given the data to Varentec to see if it can do a better analysis. Nevertheless, ACEC maintains that other benefits of the Varentec units, primarily power quality, recommend their use even if the CVR cost savings are minimal or non-existent.

Iowa Lakes EC (ILEC), IA – ILEC worked with its partner co-op, Corn Belt, on this activity. Corn Belt did all of the hardware installation and programming in the substations. No problems have been reported as to low voltage or any other issues. To date, the savings from this technology implementation are calculated to be $18K in 2012, $41K in 2013, and $25K to date in 2014.

Chapter 4:

Interoperability and Cyber Security

The SGDP cooperative agreement provided the funding for NRECA to engage in developing approaches to interoperability and cyber security (CS) that are applicable to smaller utilities in general, including but not limited to co-ops. NRECA has been at the forefront of CS discussions for many years. Early on, NRECA was engaged in efforts to develop regulatory approaches to CS, but its work escalated with the growing interest in and concern about grid CS, as well as the support of the NRECA SGDP project. This section describes the work funded by the SGDP cooperative agreement, which accomplished much and laid the foundation for NRECA's ongoing program.

First, consider the challenge of making the cooperatives secure. NRECA's membership network includes about 900 co-ops, ranging from large, very sophisticated utilities that are among the most modern in the country to small co-ops with limited IT (and CS) capabilities. Co-ops engaged in bulk power transmission have been meeting North American Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) regulations for years, have capable teams in place, and are audited rigorously. Others are just beginning to think about CS. The challenge is how to support such a disparate community. NRECA's conclusion was that the solution did not rely on prescription—precise specification of the correct steps, methods, and controls required would risk pushing beyond the possible for some co-ops, while not challenging others.

Further, a compliance-based approach to CS idles the most important asset of the co-op community—the intellect, integrity, and commitment of its people. Building and operating an electric utility is an inherently dangerous job, requiring work with high voltages under challenging conditions. The industry, and particularly the co-ops, has made tremendous improvements over the last two decades. The approach taken was to make safety a part of every job and every business decision. Although there was extensive investment in training, equipment, and the development and sharing of best practices, the root changes were establishing safety as a top priority and making it a central part of the culture.

4.1 NRECA'S Approach to the Cyber Security Challenge

NRECA's conclusion when it started to move forward was that its approach should be based on five principles:

1. CS is and will remain a continuing, evolving problem
2. Given this fact, the utilities' approach to security likewise must evolve
3. The specific circumstances of different utilities require different paths
4. Making CS a basic part of utility culture is essential to engage the full capabilities of the organizations and the community
5. As always, the co-op community must work collaboratively

Following the successful model of utility safety programs, the approach developed was as follows:

- Engaging
- Dynamic
- Comprehensive
- Locally specific
- Collaborative

These are not platitudes; they are specific attributes of NRECA's work to date and its expanding, improving program. Any program lacking in these attributes will fail. NRECA has validated the quality of its work through feedback from numerous classes conducted using our guidance materials and one-on-one discussions with cooperatives. Wrapping around the specifics is a basic commitment to the principle of continuous improvement. A compliance-based program can intimidate organizations that are just starting and can trick accomplished organizations into thinking they have fixed a problem once they have put a check in every box. In contrast, a commitment to continuous improvement makes it easy for beginners to get started while driving the best to greater levels of achievement. Put simply, an organization assesses where it is and then asks itself about the next steps. How can it be more secure in a month, a quarter, or a year? NRECA has been promoting this approach for several years in many forums and believes that it has contributed to a positive and practical change in the CS dialogue. It has supported other efforts centered on continuous improvement, including the ES-C2M2.

4.2 NRECA Cooperative Research Network (CRN) Products and Services to Assist Members

NRECA's starting point was to develop tools for this assessment that incorporated succinct guidance on best practices. CRN's first product was a guidance document that summarized several thousand pages of guidance from NERC, the National Institute of Standards and Technology (NIST), and others in a single document. Although this was very well received, the community asked for more, demanding something on the order of a step-by-step, "how-to" document. In response NRECA developed a template. This template is an automated Word document that prompts a utility to answer a series of questions and, based on the answers, asks the user to enter documentation or commitments to actions and dates. For example, the first question is whether there is a senior executive assigned the responsibility for CS. If the answer is "yes," the user enters the name and contact information. If the answer is "no," the user sees text that explains why executive involvement is critical and suggests what to look for in a good leader. It then asks for a date when this leader will be in place. After working through all of the questions, the user has a plan for improvement, including documentation of the current state and specific actions with dates for improvement. NRECA envisions utilities working through this document on a recurring basis. The link below will provide access to our current documents. An update is in process, and NRECA is actively supporting NIST's development of a guidance document along the same lines. More than 34,000 copies of such NRECA documents have been downloaded.
https://groups.cooperative.com/smartgriddemo/public/CyberSecurity/Pages/default.aspx.

Beyond that initial work, NRECA has conducted classes to train co-ops in the implementation of its approach. Two excellent security consulting firms (Cigital and Enernex) are trained in this approach and offer user training.

4.3 Another View – The Security Pyramid

Another way to look at NRECA's approach is our "security pyramid," shown in **Figure 4.1**. For real security, it must exist at each level in the pyramid, reading the pyramid from the bottom. NRECA believes that security begins with secure components. That is, the software for each electrical and control component should be as secure as practical: devices should do the following:

- Be resistant to attack in installation, configuration, operations, and maintenance
- Be resilient when compromised
- Support relevant security protocols and enhancement

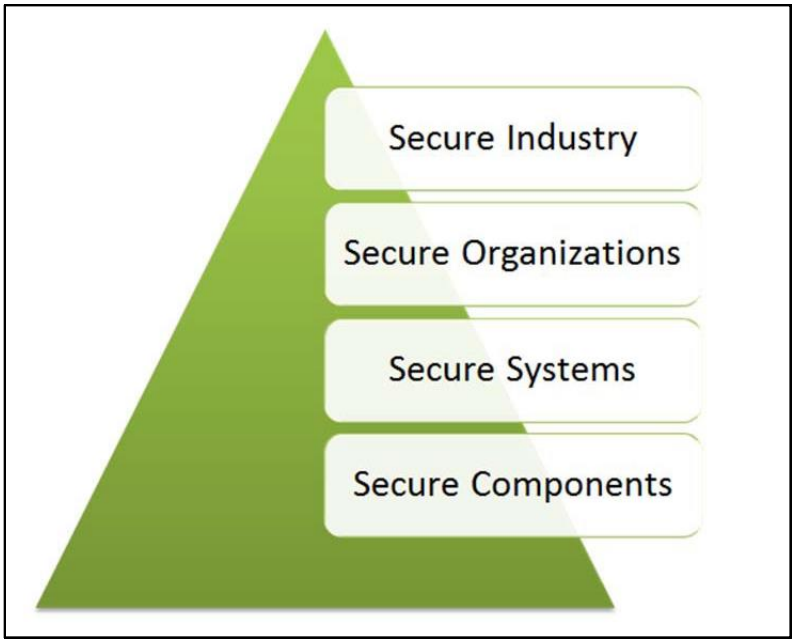

Figure 4.1: The Security Pyramid

4.4 Secure Components and Systems

The secure components should be built into secure systems at the utilities. Most of the focus of electric sector CS work to date has focused on this aspect and, in particular, on network security, but secure systems require more. The sector must pay greater attention to architectural security, particularly as utilities incorporate more managed services and cloud computing. At this point, the interoperability standards for utility software are not sufficiently developed or adopted to provide seamless integration. Every utility NRECA has examined is developing "glue code," but none is trained in secure software development. To address these gaps, NRECA CRN has a study underway in next-generation utility IT architecture and is developing a secure coding class for utilities.

4.5 Secure Organizations

Moving up the pyramid, secure systems must operate in secure organizations. The majority of CS failures show some element of organizational or human failure—either an active, malicious act or a failure to maintain security systems. It is essential to build a culture in which security is key priority, provide specific technical training, and build systems to monitor and improve performance. Again, continuous improvement is the guiding paradigm. Failures should be as visible as lapses in safety, and as much of a motivator.

4.6 Secure Industry

Finally, utilities must be able to work with each other and with service providers with confidence. Regulators have an essential role at this level.

While NRECA's focus to date largely has been on the middle layers of the pyramid—secure systems and secure organizations—we have begun to address the device and industry layers through MultiSpeak.® MultiSpeak® is the most widely deployed utility system interoperability standard, with more than 700 utility users. It provides unambiguous specifications for the exchange of information between different utility IT systems. NRECA believes that security and interoperability are inextricably entwined. Tight standards for interoperability support the following:

- Development of more secure devices by reducing the number of acceptable inputs and outputs
- Better testing
- More options for securing information interchange
- Reduction in the need for custom, expensive, and insecure glue code

Device developers that support only one or two specific message formats can harden their devices to reject anything other than those messages. By extension, testers have specific guidance to use in their validations. The testers can prove that the device accepts only validly formatted and authenticated inputs, and responds in a valid way. Finally, if all traffic between systems fits a standard, it is possible to incorporate special monitoring and filtering capabilities. It is much more difficult for an attacker to generate genuinely damaging injections when every packet has to meet very strict specifications at all layers.

NRECA has two efforts underway in this area. First, it has recently released extensions to MultiSpeak® to provide message-level security. This is the first in the utility space, and can be readily extended to other standards, such as those from the International Electrotechnical Commission (IEC). These extensions have been done through the MultiSpeak® review and vetting process, and are freely available to all MultiSpeak® members, a group including most major utility vendors. A free copy has been provided to Pacific Northwest National Laboratories for review and consideration by the IEC. Beyond the security standards, NRECA is continuing to develop MultiSpeak® to provide additional interfaces. NRECA currently is working on a secure version of GreenButton®.

SUMMARY

The experiences gained on the DOE SGDP have served to highlight the fact that the smart grid is truly an emerging technology field. Even at the end of this four-year project, the vendors frequently supplied equipment that was often the first of its type offered. The best example is the Mark II model. Of course bugs often must be worked out, integration issues with other equipment are common, and real-world field conditions often prove to be significantly different than anticipated by either the distribution utilities or the equipment vendors. As is common for emerging technology fields, system costs frequently wind up being as much as 30% higher than vendor quotes, and installation and integration timelines are two to three times longer than pre-project planning estimates.

These circumstances place a large burden on the utility to pick its equipment and vendors carefully. As the CEO of one of the cooperatives involved in the study said, “I have learned that the most critical component of any future projects going forward will be a vendor’s reputation for continued support. Feedback from utility project managers and technicians involved in deploying and maintaining like systems for similarly situated utilities is invaluable.”

There also seems to be a significant difference in the technology readiness levels of the D/A equipment and consumer-focused equipment such as AMI meters and IHDs. Most of the pain and development headaches have occurred on the meter level, either with the AMI meters and communications modules and individual IHD units, or with the broader communications and data collection systems of these units.

The D/A equipment generally involves a relatively straightforward upgrade of the controllers used to monitor and control large switches, reclosers, line capacitors, and voltage regulators. These large pieces of equipment are all mature power distribution technologies, both well understood and proven, and it is simply the control computers that are new. Even here, there is an apparent division between the large SCADA and control computers, and smaller, field-deployed controllers. The larger and more expensive devices would appear to have benefitted from the experience and development efforts of other like industries' control modernization efforts. The field units are more likely one-off designs and also must face the challenges of adverse environmental factors, and thus are more prone to failure.

That said, there have been significant strides forward even during the few years of this project. The equipment being delivered toward the end of this project more often has arrived correctly configured for immediate deployment. Interoperability standards are coalescing, and more products are being offered with MultiSpeak® to allow simplified data communication between disparate control and back-office systems. Vendors have significantly improved their understanding of the issues around CS, and many have improved their product offerings to make them much more resistant to cyber attack.

The Technology Deployment technical reports constitute Chapters 5–15.

Chapter 5:

AMI-Based Load Research – KIUC Demonstration

1. INTRODUCTION

The Kauai Island Utility Cooperative (KIUC) has begun a first-ever formal Load Research Study for the cooperative's electric system, using the newly installed Advanced Metering Infrastructure (AMI) system developed in association with the National Rural Electric Cooperative Association (NRECA) under the Smart Grid Demonstration Project. The Load Research Study is being undertaken for engineering and regulatory purposes, and will form the basis for certain rate studies expected to be filed with the Hawaii Public Utilities Commission in the near future. The value of an AMI system in providing robust statistical information on electric loads with a high degree of confidence is being demonstrated through this formal load research program, now underway. This report describes the development of the AMI system, the background for load research activities, the sense of accomplishment from the use of the system, and the expectations for accomplishing a robust evaluation of system load characteristics.

2. THE AMI-BASED LOAD RESEARCH PROGRAM

2.1 Research Objectives

The advent of AMI has been expected to provide a vastly improved foundation for electric utility system load research. The NRECA Smart Grid Demonstration Project included installation of advanced metering at the vast majority of the traditionally metered locations throughout the KIUC service territory. This installation was especially timely from the standpoint of providing an advantageous platform for demonstrating the value of AMI in completing a load research study.[1]

Until such time as the AMI system was installed, for rates and tariff development, KIUC had relied on sample data from comparable utilities or limited information from uniquely placed monitoring equipment. The Hawaii Public Utilities Commission (HPUC), particularly at the urging of the Hawaii Division of Consumer Advocacy[2] (Consumer Advocate) during the last KIUC rate case, has recommended that KIUC undertake a utility system-specific load research study. That study was intended to provide detailed information on electric usage characteristics among and within KIUC's consumer classes of service—Residential, Small and Large Commercial, and Industrial. Estimates at the time indicated that such a load research study, using traditional sampling and individually installed meters, would require hundreds of thousands of dollars to complete. In addition, updating research results would require similar levels of effort.

The AMI system installed at KIUC was identified as an efficient and effective means, among the many other potential uses of AMI information, of accomplishing a load research program in a cost-effective manner. Using AMI-installed equipment for data gathering and analysis provides for ready availability of requisite sample information, data accumulation, and analysis using already installed equipment, and load research statistics that can be updated easily. The information provided can be of such detail as to fully satisfy regulatory requirements and plan for and monitor the impacts of alternative rate structures on consumer behavior response.

[1] Over the study period, approximately 10% of KIUC's residential customers had opted not to accept installation of a smart meter. The level of "opt-out," however, was not considered significant in relation to the sample size, nor in limiting the usefulness of smart meters for conducting load research. Additionally, certain large power customers retained traditional meters as a result of totalizing metering applications.

[2] The Division of Consumer Advocacy is a division within the State Department of Commerce and Consumer Affairs.

2.2 Project Characteristics

The AMI installation was undertaken at KIUC for a variety of reasons. These included providing the following: (1) remote monitoring for reduced meter reading expenses; (2) engineering data for feeder load analysis; (3) consumer energy use characteristics associated with on-site solar hot water heating and photovoltaic (PV) installations; (4) limiting cycle billing adjustments from staggered meter reads; (5) remote cutoff and reconnection; (6) monitoring of load control impacts; and (7) routinely detailed demand and energy use statistics of individual load centers and aggregate loads. The AMI installation project included a radio transmission system for communications between the utility and the metering equipment, and installation of data collection software that would adequately provide for initiation of signals out from the cooperative and data transmission back from the individual metering points.

Once the installation was nearly complete, KIUC began the specific load research study using the AMI system. A contract was prepared for Leidos Engineering (Leidos was then a part of SAIC) to help set up the study, provide expertise in sample design and selection, and perform the necessary data analysis. NRECA was involved early in the contracting process, supporting the use of the AMI system in that fashion and coordinating with Leidos on the information gathered and application of the results.

2.3 Development and Implementation

Leidos designed the KIUC load research program, which included consideration of sharing information on the undertaking with NRECA by supplying periodic information during the year-long research. Leidos' efforts have included collecting preliminary load data from KIUC from which to evaluate the level of detail required within existing consumer classes to form statistically relevant programmatic data collection.

The load research program directed by Leidos was initiated in early summer 2013 with the anticipation of data collection through a complete one-year cycle. As the study progressed, it was determined that load research results would be developed across rate classes for calendar year 2013. As of late May 2014, the data collection was complete, and work was underway to finalize the analysis and prepare a final report.

2.4 Evaluation Criteria – Effectiveness

KIUC has demonstrated the effectiveness of using AMI for the load research program, in that the vast reach of a broad-based installation across a significant portion of the entire consumer base provides for essentially unlimited data sources. The primary limitation to use of the aggregate data is the sheer volume of information available, such that slightly different sampling techniques are required compared to traditional methods. The advantages are clear, in that all meters are available and random tests can be performed to validate the sample selection by identifying variances and deviations. A comparison to the difficulties experienced through load research using traditional sampling and metering approaches shows, in stark relief, the advantages of AMI. Information on unique sites that reflects implementation of distributed generation sources and load management programs from readily accessible AMI data provides additional benefits in rate setting for special incentive programs, as well as traditional cost-of-service studies.

2.5 Regulatory Acceptance and Justification

KIUC is now able to provide evidence of the load characteristics of a variety of consumers throughout the system, fully responding to the regulatory request for utility-specific load research. No longer will proxy data be required, nor will significantly disruptive and expensive research programs be required for rate structure updates or revisions to cost-of-service allocations. Questions as to the efficacy of incentive programs can be accomplished routinely by aggregating data from those locations at which programs were applied and via continuous monitoring of consumer response.

As the load research program at KIUC was initiated in 2013 and is continuing, the final results will not be available until mid-2014. As a result, the regulatory acceptance of the load research findings may be addressed in more detail following Consumer Advocate and HPUC staff review of the load research program and results at KIUC.

3. THEORETICAL BASIS OF LOAD RESEARCH

3.1 Value and Applications of Load Research

"Load Research" has been defined as "(a)n activity embracing the measurement and study of the characteristics of electric loads to provide a thorough and reliable knowledge of trends, and general behavior of the load characteristics of the customers serviced by the electrical industry. Simply put, Load Research allows utilities to study the ways their customers use electricity, either in total or by individual end uses."[3] The information obtained through load research provides the knowledge of electric use patterns and characteristics that the electric utility requires to effectively meet the service requirements that provide consumer and utility value.

A number of functional areas of the electric utility operation depend on this knowledge and load research results to perform effectively. These include the following:

- Generation – Net system output analysis, production cost and system model development, capacity planning, and load duration curves;
- Electric Choice – Load profiling, forecasting, settlement accounting, program and project evaluation;
- Distribution – Substation load analysis, transformer sizing, circuit load studies, load management, and loss studies;
- Marketing – Individual customer analysis, customer class analysis, on-peak demand, load studies, demographic studies, and major account demand analysis;
- Rates and Pricing – 8,760 class demand studies, billing determinants, allocation schedules, sample design and management, class and system peak analysis, and major account demand analysis; and
- Other – Demand-side management, weather normalization, and product development.

The Load Research Committee of the Association of Electric Illuminating Companies (AEIC) identifies the value proposition of AMI in the categories and activities shown in **Table 5.1**.[4]

[3] AEIC. "*Why Electric Utilities Need Load Research,"* a Load Research Primer for Electric Utility Leaders.
[4] AEIC. *Load Research Value Calculation*. January 9, 2007.

Table 5.1: Value of AMI

Category	Activity
System Analysis and Rates – Electric	◆ Main rate case ◆ Real-time pricing (design and implementation)
System Analysis and Rates – Gas	◆ Main rate case
Electric Choice/Deregulation	◆ Load profiles ◆ Energy procurement for basic service ◆ Hourly energy market price calculations
Load Management	◆ Transformer study ◆ Load response programs
Data Warehousing/Data Access	◆ Meter data management ◆ Interval data distribution (for fee)
Forecasting	◆ Air conditioning ◆ Residential and Commercial
New Technology	◆ New meter testing and support
Intellectual Capital	◆ Subject matter expertise ◆ Consulting
Settlement	◆ Shadow settlements ◆ Estimate peak contributions for ISO-installed capacity markets ◆ Estimate hourly loads for ISO energy markets
Market Research Support	◆ End-use analysis ◆ Conditional demand analysis ◆ Rate evaluation ◆ Sales analysis (unbilled revenue) ◆ Ad hoc data request
Customer Service Support	◆ Billing determinants ◆ Reporting and analysis of customers' interval data ◆ Revenue protection investigations
Asset Management/Optimization/Acquisition	◆ Generation ◆ Transmission ◆ Distribution

Through its various categories, activities, and applications of the knowledge obtained, load research contributes value to the utility, both strategically and financially. This value can be identified by the contribution of load research information to the financial parameters associated with system operations and revenue collection. The value is the portion of a measurable event that either increases revenue or produces real savings. This being the case, the continuity of the load research information is important, and gaps in knowledge, or failure to recognize changes in usage characteristics, can lead to failures in recognizing impending or actual losses of the savings or revenues.

3.2 Load Research Approach

A wide range of source data is available on the fundamentals of load research using "Smart Grid" technologies. This is now well known throughout the industry, and includes extensive work by the Electric Power Research Institute (EPRI) and others, such as AEIC's National Load Research Committee. For example, AEIC has provided a primer on why load research is important for electric utilities, and EPRI conducted a workshop in October 2010 for its members to identify how "…broad application of Smart Grid or AMI could both increase the need for and reduce the cost of acquiring high-quality load research data."[5] The concern at that time was that much of the load shapes that the industry had developed in years past and remained in use were perhaps no longer accurate representations of system characteristics. The cost of collecting data at the end-use level was considered quite expensive, due to special metering requirements.

The abstract of the EPRI workshop proceedings described a situation in which utilities and operating organizations sought better load shape information, and the deployment of smart meters presented both opportunities and challenges—the opportunity being the ability to capture system-wide load shape information without the need for the special metering. However, the widespread coverage of smart metering and the immense amount of data available required "rigorous" data collection and sampling procedures to obtain the requisite and relevant information at the "required levels of precision." Also, while smart meters provided premises-level data, additional research was needed to clarify whether the metering could be used to identify the impact on load shapes of new technologies, response to dynamic pricing, information feedback, and demand response programs.

3.3 Historical Methods of Load Research

Electric utilities have been conducting load research almost since the inception of the electric system through monitoring or recording of metered delivery by using strip chart recordings of voltage and current for motor loads and other devices. The so-called "modern era" of load research began with the introduction of demand recorders that used magnetic tape cartridges to record data pulses from a special meter that replaced the normal billing meter. The cartridges were collected and downloaded to mini-computers that translated the pulse data into time-series interval measurements of power. Similar systems were used for demand recording of Large Commercial and Industrial loads. Later evolution of the systems provided for devices that delivered load data via telephonic systems, hand-held recorders (the "automated meter reading" or AMR), radio, and power line carrier signals over the distribution network. These later systems provided greater capability than demand and energy recorders, and subsequent systems have expanded upon those capabilities, ultimately to provide "two-way" communications for delivery and receipt of information.

4. ENABLING TECHNOLOGY OF AMI-BASED LOAD RESEARCH

4.1 The KIUC AMI System

KIUC initially started looking at an AMI system in 2008 and, with the assistance of Power Systems Engineering, developed a business case for the implementation of an AMI. Once the business case was presented and accepted, KIUC enlisted the assistance of Katama Technologies to develop a Request for Proposal (RFP) to determine the requirements and selection criteria for an AMI system. In 2009, KIUC selected the Landis+Gyr (L&G) Gridstream® system, based on a radio frequency (RF) mesh network, and was ready to proceed with implementation when federal stimulus funding became available. An RFP meeting the requirements for stimulus funding was prepared in 2011 with the assistance of the NRECA National Consulting Group and was supplied to vendors.

[5] *End-Use Load Research in a Smart Grid World*. EPRI Abstract. September 23, 2010.

4.2 AMI Selection Criteria of KIUC

KIUC and its consultants conducted a very rigorous proposal evaluation of the vendor offerings. **Table 5.2** reflects the range of considerations used in evaluating the offerings; this resulted in the selection of an L&G system.

Table 5.2: KIUC Vendor Evaluation – Technical Specifications

Section	Technical Specification Requirement	Weight
6	General System Requirements	40
7	AMI Server Hardware and Software	40
8	Load Control Hardware and Software Requirements	10
9	WAN/Backhaul Communications	5
10	Fixed Network LAN Communications	20
11	Residential Electric Meters	20
12	Commercial and Industrial (C/I) Electric Meters	20
13	Load Management Hardware	10
14	Electric Grid Management Applications	15
15	System Administration and Security	20
16	Documentation	5
17	Quality Assurance, Testing, and System Acceptance	10
18	Vendor Support and Training	15
19	Implementation Roles and Requirements	5

The initial system implementation plan included seven collectors, 106 standard routers, and 29,630 electric meters; equipment installations were chosen strategically per design, so that the system implementation would not disrupt KIUC’s normal operating procedures. The functionality included capability for in-home displays, home area networks, dynamic pricing, and selective load control.

4.3 Installation and Operation Issues and Actions

Overall, KIUC has been very pleased with the decision to go with L&G for its AMI metering system (**Figure 5.1**). While it did encounter “bumps in the road” throughout the installation process, L&G and its deployment contractor were very prompt and competent in addressing the issues. The equipment is working as expected, and KIUC is excited to be the leader in the state of Hawaii in smart meter deployment. KIUC also is working on the rollout of a web portal to provide members with detailed usage from their smart meters.

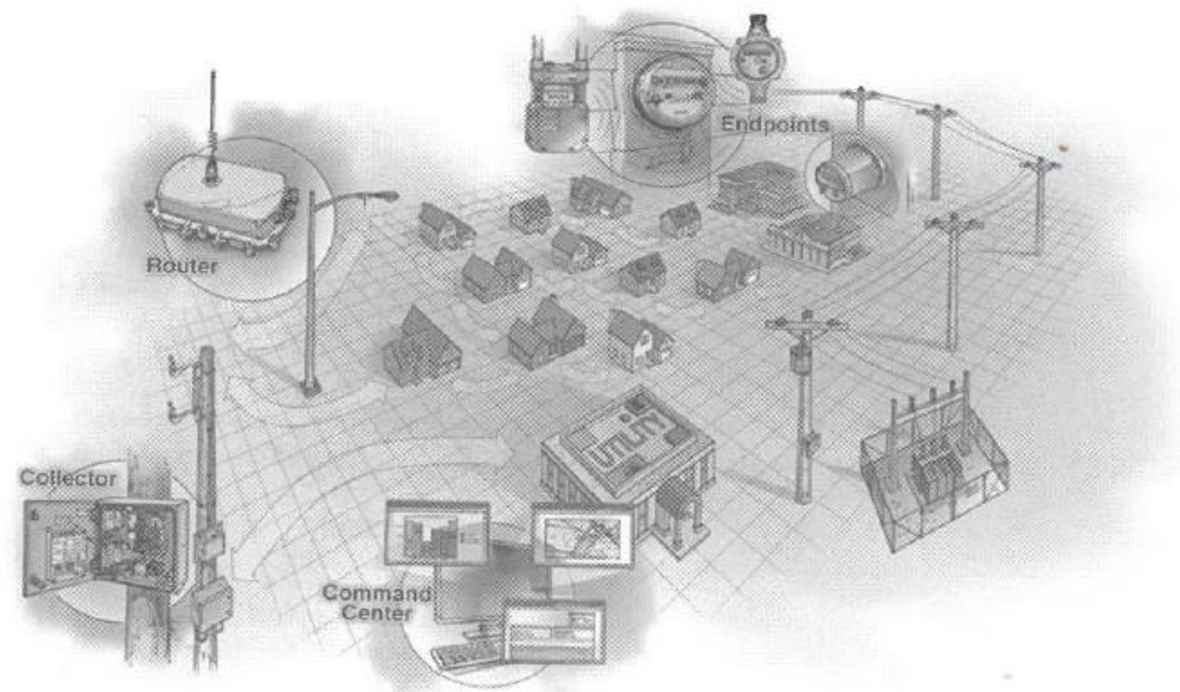

Figure 5.1: Landis+Gyr RF Mesh Network

5. AMI-BASED LOAD RESEARCH PROGRAM NOW UNDERWAY AT KIUC

The sequence of events for development of the load research study by Leidos is straightforward:

Sample Design and Selection → Meter Data Acquisition → Data Analysis → Reporting

Implementation of the AMI and the prevalence of the pre-existing interval metering simplified the process of sample selection, but only somewhat, in that a representative sample was still necessary for class load estimates. The ability to increase sample sizes cost effectively, both to achieve greater precision and allow for sub-sampling, was a key benefit of the AMI metering. For example, given the large variability of loads in the Large Commercial and Large Power classes, and their size relative to the other classes, the team decided simply to sample all customers in these classes (i.e., achieving what is commonly referred to as a "census" for these classes).

The load research is proceeding in steps, which include the following:

- Selecting sample consumers that are sufficiently representative to ensure precision of class load estimates;
- Capturing hourly or sub-hourly sample loads;
- Validation of the data collected;
- Reporting the class loads and load detail; and
- Supporting downstream analysis with the load information.

A sample design was prepared with the goal of maximizing precision with the sample size constraints that made use of data from a specified time period of metered data. Stratified sampling segmented the consumers into homogenous groups to improve precision, using one of the more common stratification variables—billed energy. The strata boundaries then were determined by statistical methods and samples allocated across the strata, followed by simple random sampling within the strata to capture sufficiently large sub-samples. The sample selection was determined using load data from January 2012. AMI-based load data from March 2013 then were received and processed.

The validation step is fundamentally a review of the recorded data for erroneous and/or missing values, which may be replaced with estimates in some instances. If certain samples are suspicious or unexplained, they may be replaced by samples of higher confidence.

Class load estimation is derived from the weighted mean across the strata of the hourly loads, followed by determination of class peak loads and identification of class loads during the system peak hour. Sample billing data obtained through July 2013 proved useful for "expansion" to full class representation, and system peak information was made available to Leidos for determination of system peak timing and benchmarking to ensure the representativeness of the load estimates.

The load research plan initially contemplated a November 1, 2012 to October 31, 2013 test-year period. However, the test-year period subsequently was moved to the 2013 calendar year. The data gathered in the study will be used to produce estimated class loads, including coincident and non-coincident class peak loads and load profiles. In addition, a series of benchmarking analyses are being performed to ascertain the reasonableness of the resulting class loads as compared to known system-level load data and class billing determinants.

A complete year of load research data has been collected, and Leidos will be revising the data sets and calculations developed over the course of the year and making necessary adjustments based on subsequent decisions with respect to stratification, sampling, or other issues.

5.1 Initial Findings of the Load Research Study, as Reported in November 2013

The initial findings, based on the March 2013 load data, reflected some typical load behaviors, including volatile intra-day loads, a high variance across the months, and numerous meters with zero usage in early March. Some examples of residential meter profiles are shown in **Figures 5.2-5.4**.[6]

[6] In the examples, the Y-axis is marked as kWh; however, as the data are given on an hourly basis, the data are kWh/hr, or simply kilowatts.

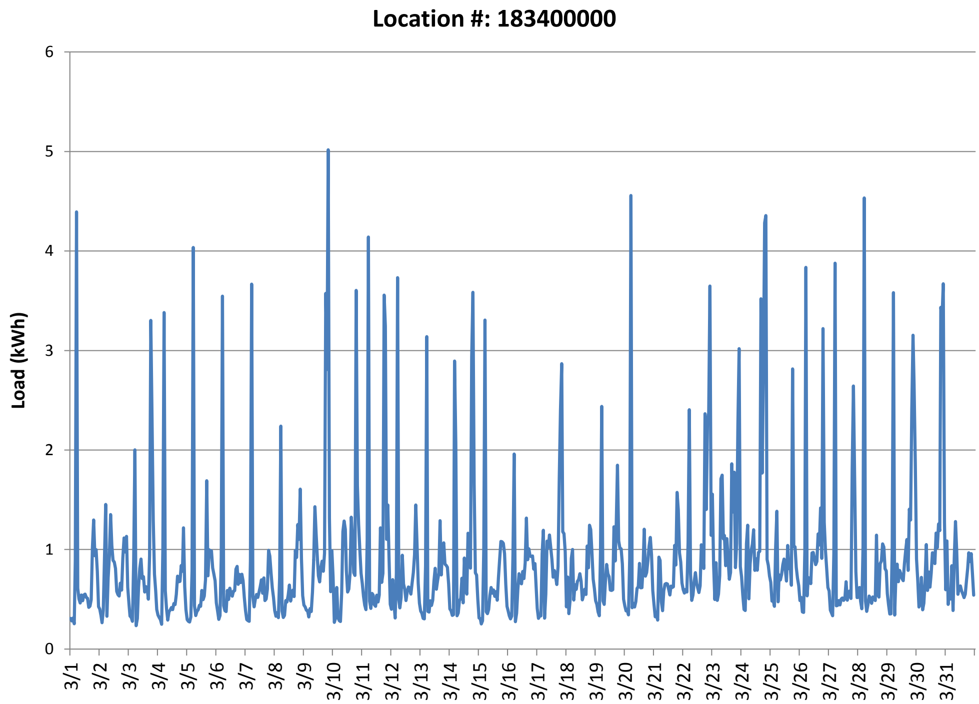

Figure 5.2: Residential Meter Profile – Example 1

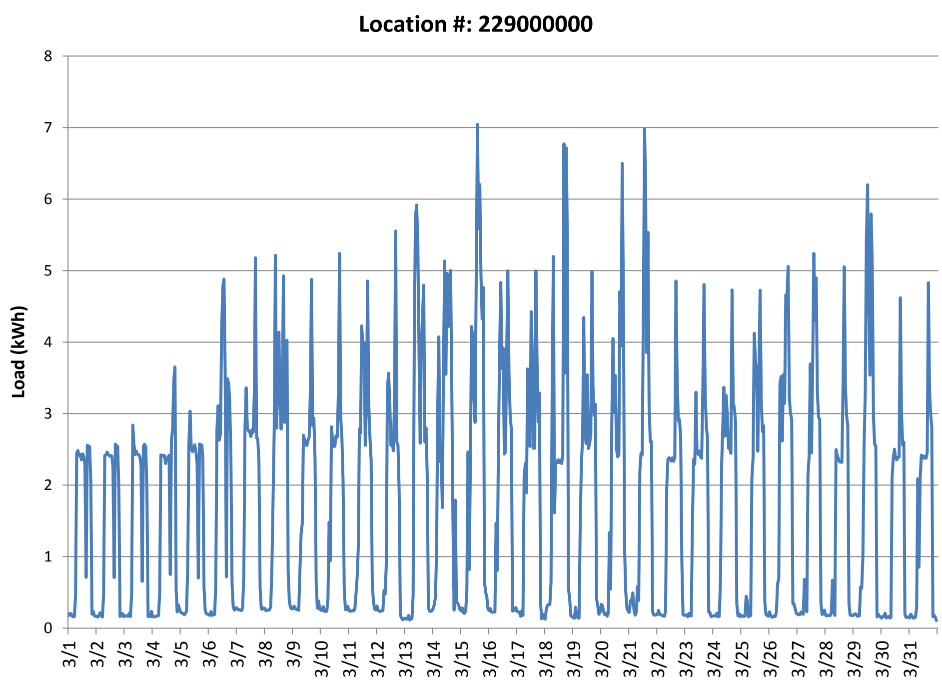

Figure 5.3: Residential Meter Profile – Example 2

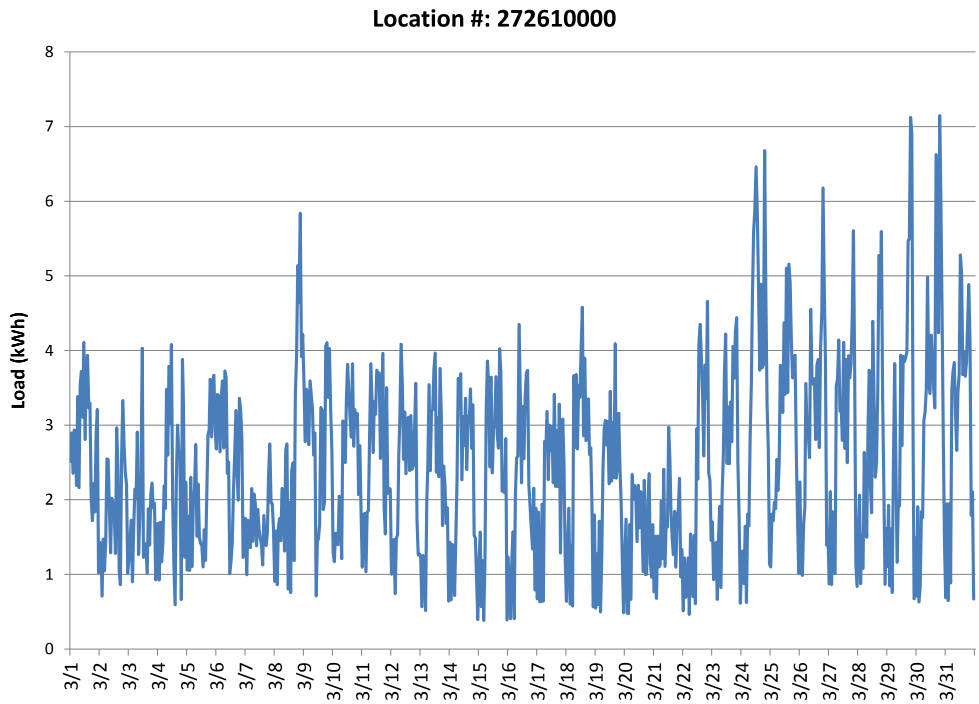

Figure 5.4: Residential Meter Profile – Example 3

In a few cases, unusual residential load patterns were observed, such as periodic low loads, periodic spikes, and periodic zero loads. However, these were largely observed to be functions of typical vacation home occupancy patterns, responses to weather conditions, and other explainable events and conditions (**Figures 5.5–5.7**).

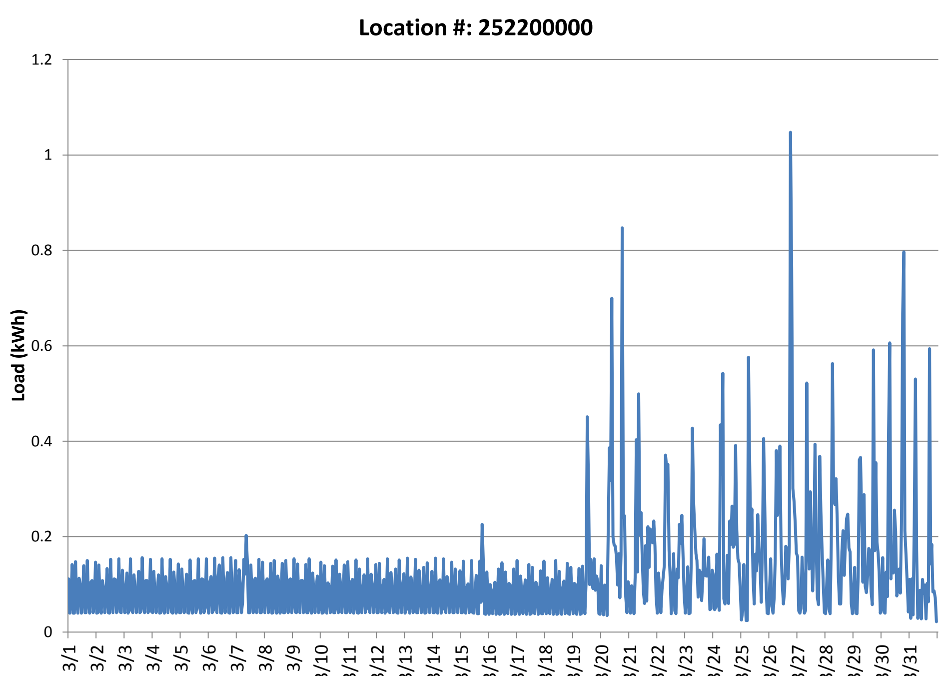

Figure 5.5: Residential Meter Profile – Example 4 (Periodic Low Loads)

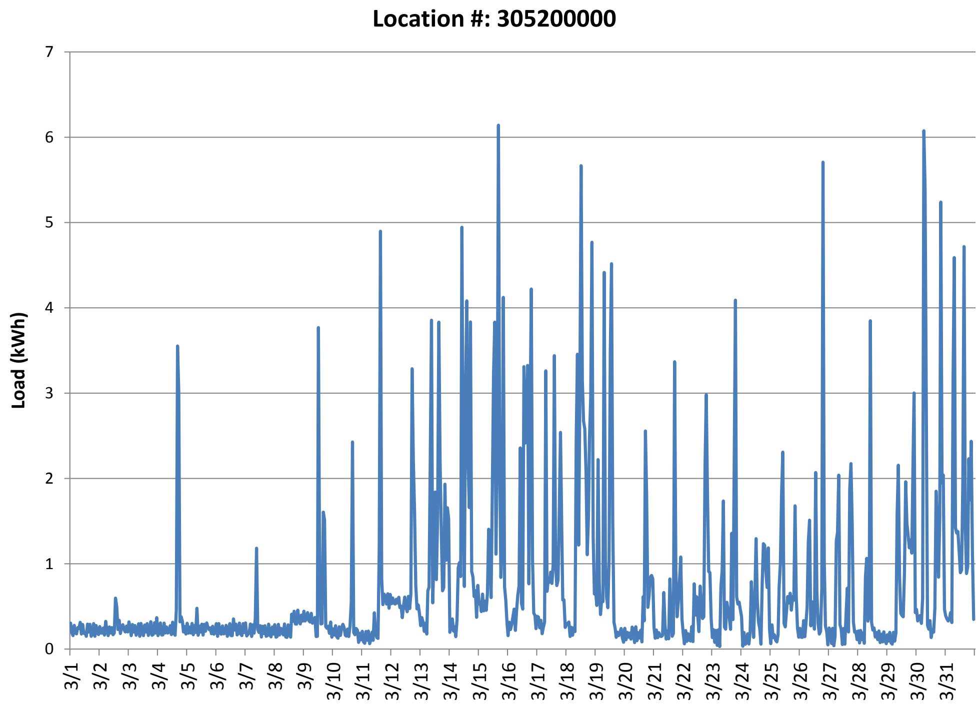

Figure 5.6: Residential Meter Profile – Example 5 (Periodic Low Loads)

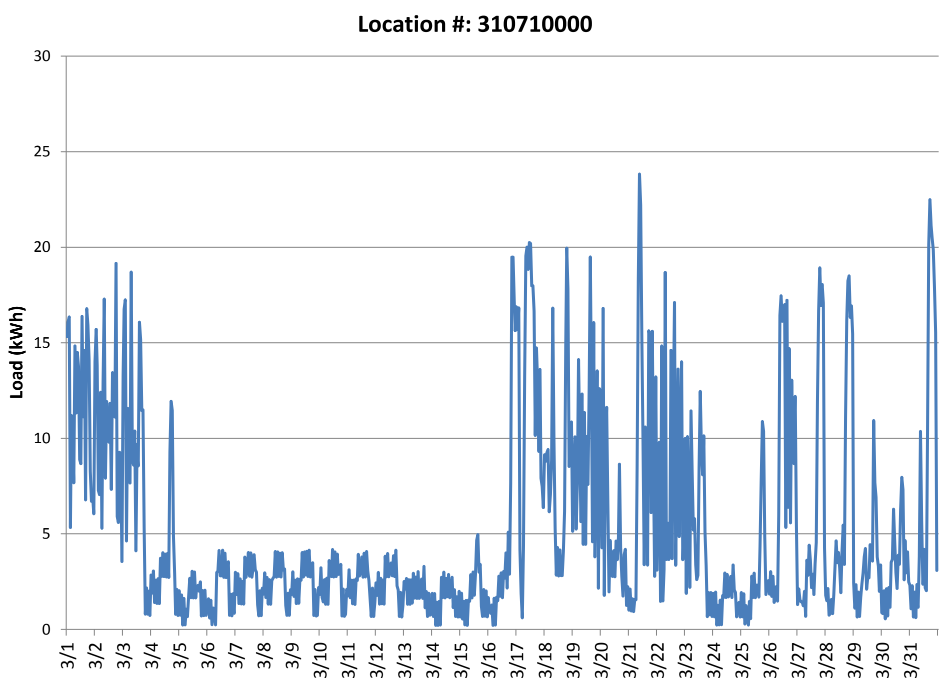

Figure 5.7: Residential Meter Profile – Example 6 (Periodic Low Loads)

Similar patterns emerged from the Small Commercial data set, with typical profiles and occasional periodic low loads (**Figures 5.8** and **5.9**).

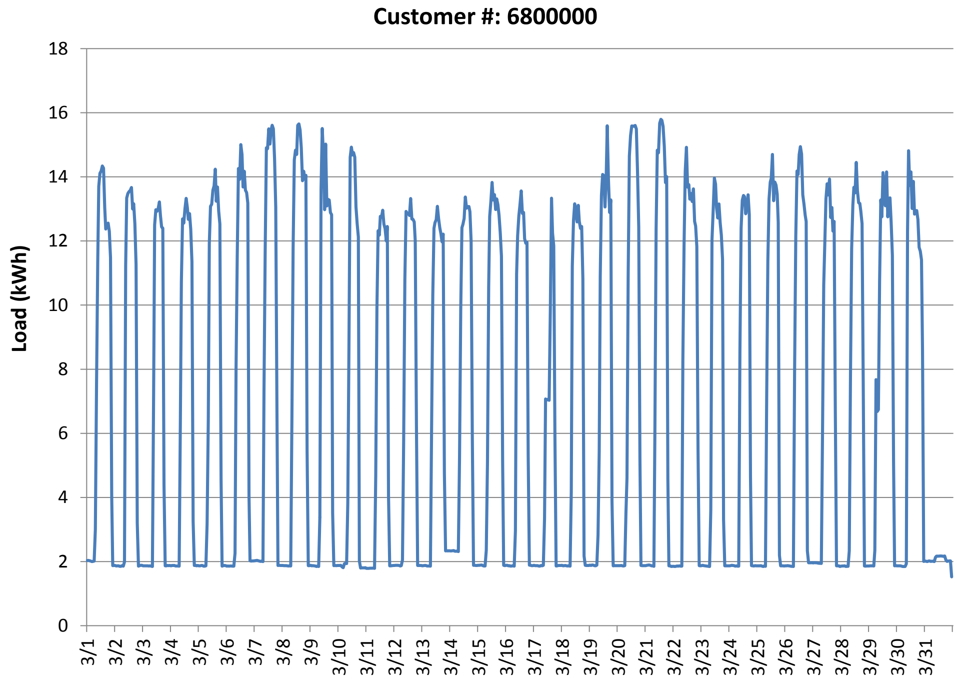

Figure 5.8: Small Commercial Meter Profile – Example 1

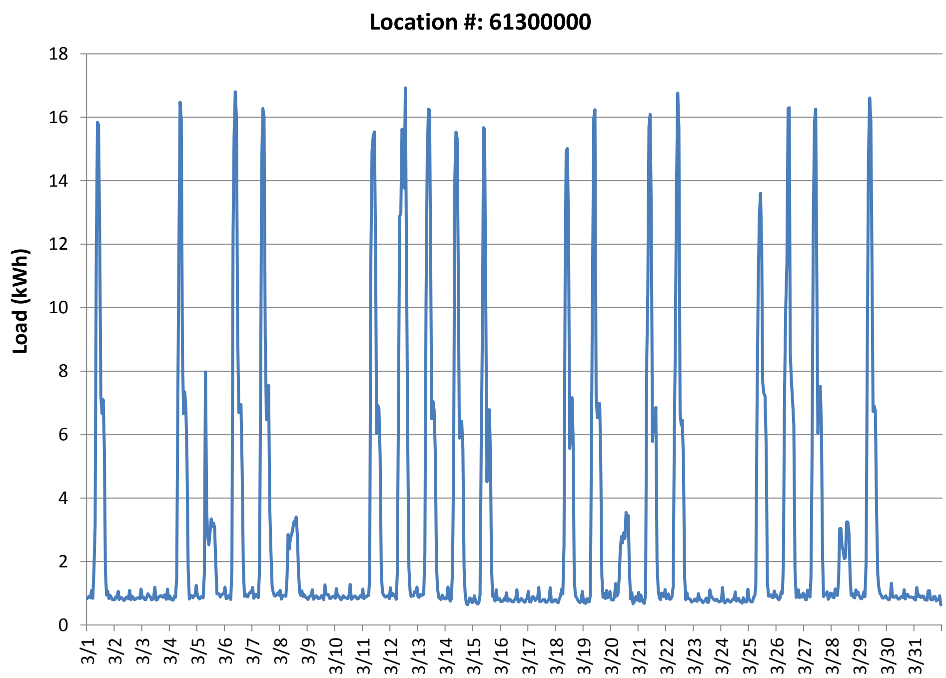

Figure 5.9: Small Commercial Meter Profile – Example 2

With Large Power, for which all metered consumers were expected to be included in the data set, an example of a periodic zero load reading was identified, calling for further investigation (**Figure 5.10**).

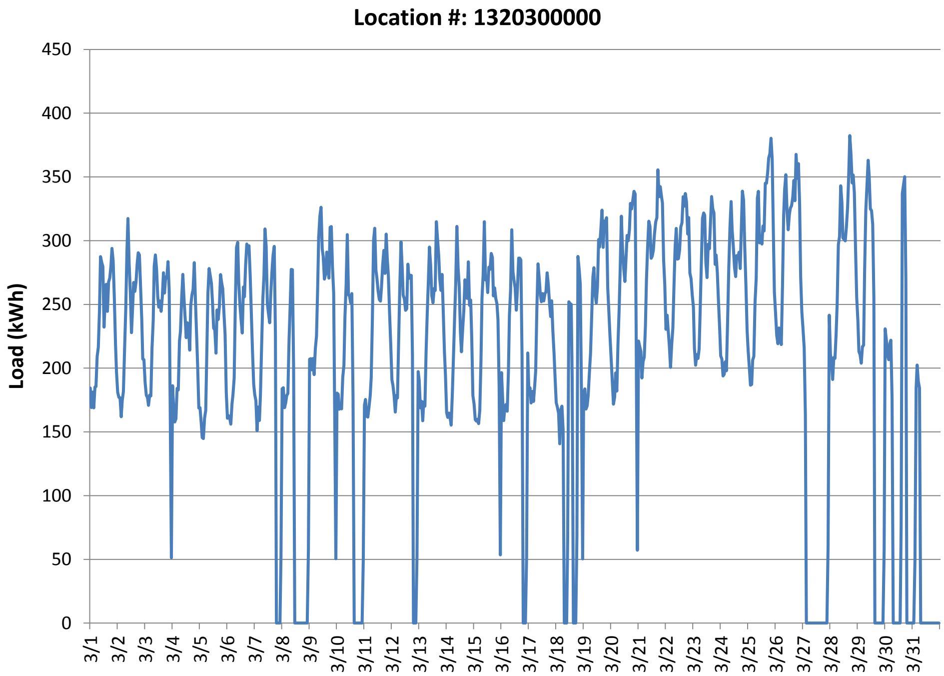

Figure 5.10: Large Power Meter Profile Example

5.2 Conclusions Drawn from the Initial Sampling and Selection

The conclusions drawn from the initial AMI-based data set are that the data appear remarkably clean and generally error free. Most locations follow sensible patterns, with typical weather variability and day-type patterns (especially the non-residential classes). Some locations reflect unusual operations, such as periodically unoccupied rental or condominium housing, intermittently higher-demand appliances or other end uses, and commercial facilities with odd hours.

The availability of data from the AMI system across nearly all consumers provides the opportunity to sample and identify anomalies—patterns that may not be recognized easily by traditional sampling and recording systems. Deriving sample data from an AMI system has allowed for larger samples than otherwise could be achieved cost-effectively and the ability to more easily identify and exclude samples containing invalid data without sacrificing precision.

Aside from a few minor clean-up issues, the estimated class loads are expected to be representative and reasonable. From the information available to date, the system load profiles for March 2013 are shown in **Figures 5.11–5.15** (excluding, in the case of the System Load Profile, certain non-metered loads and losses).

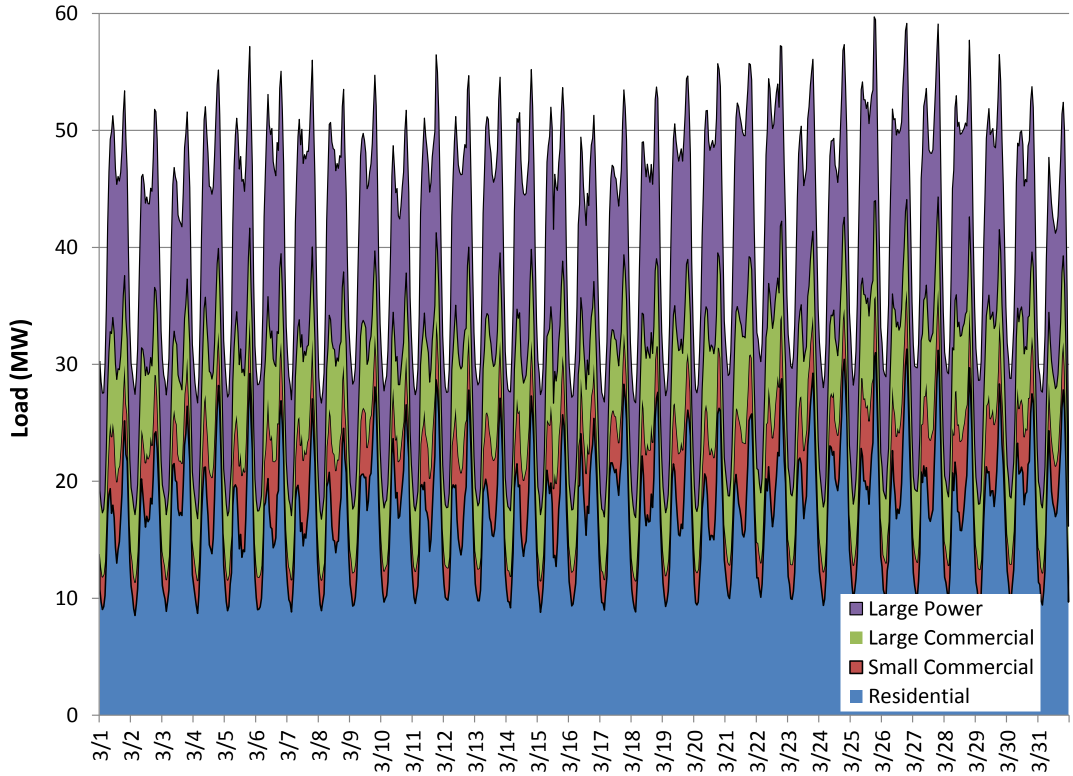

Figure 5.11: Partial System Load Profile – March 2013

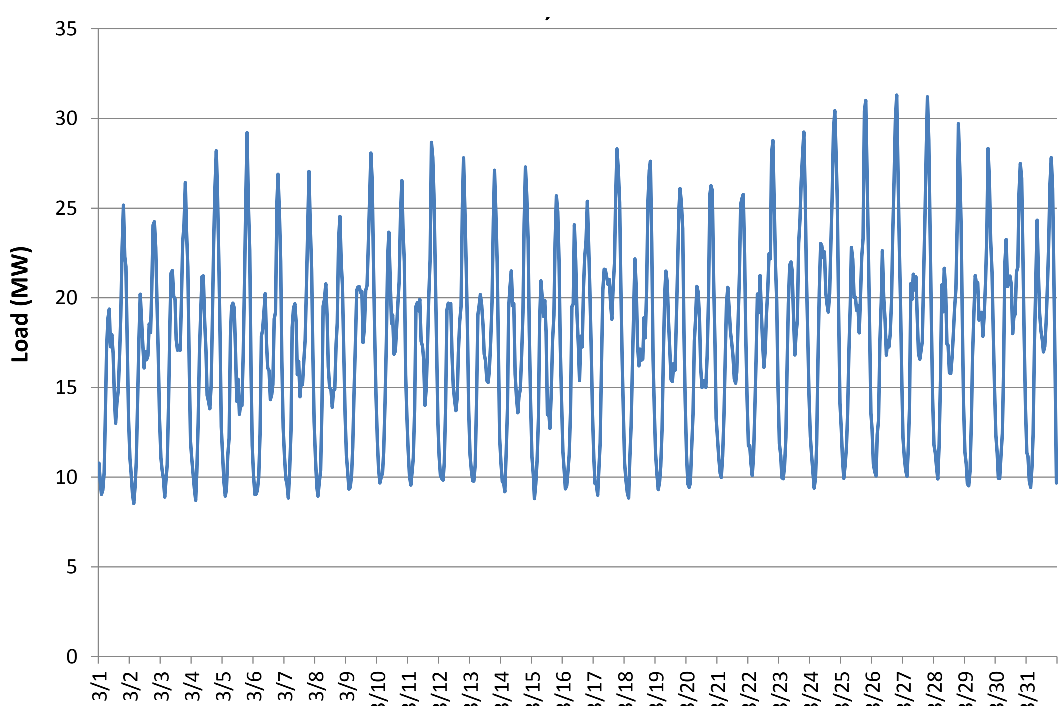

Figure 5.12: Residential Load Profile – March 2013

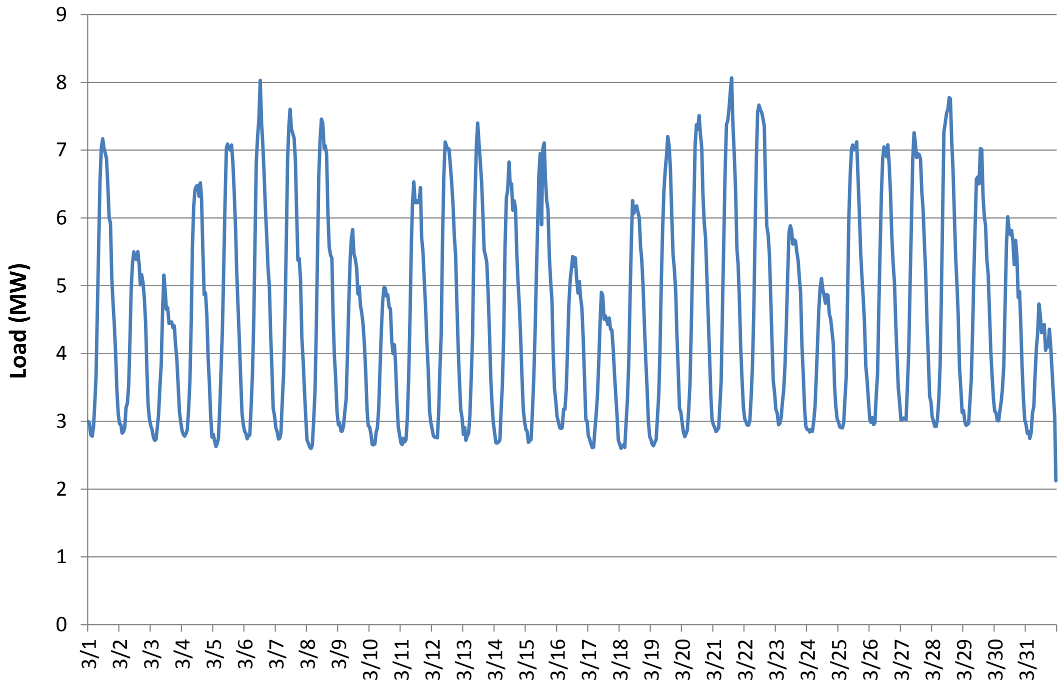

Figure 5.13: Small Commercial Load Profile – March 2013

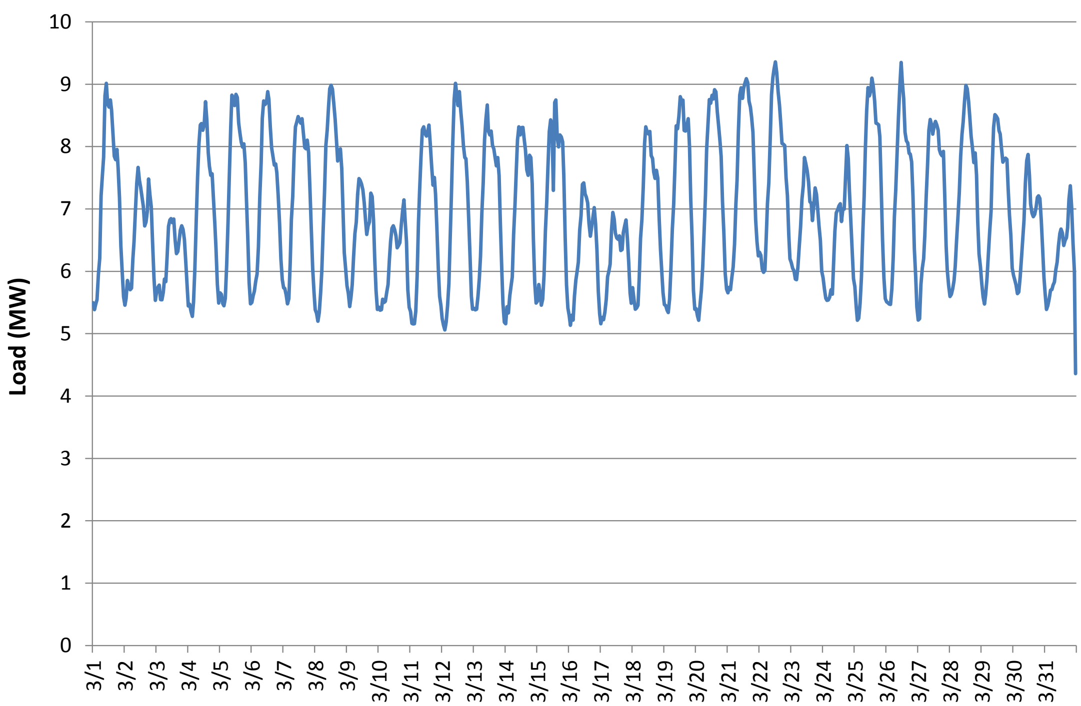

Figure 5.14: Large Commercial Load Profile – March 2013

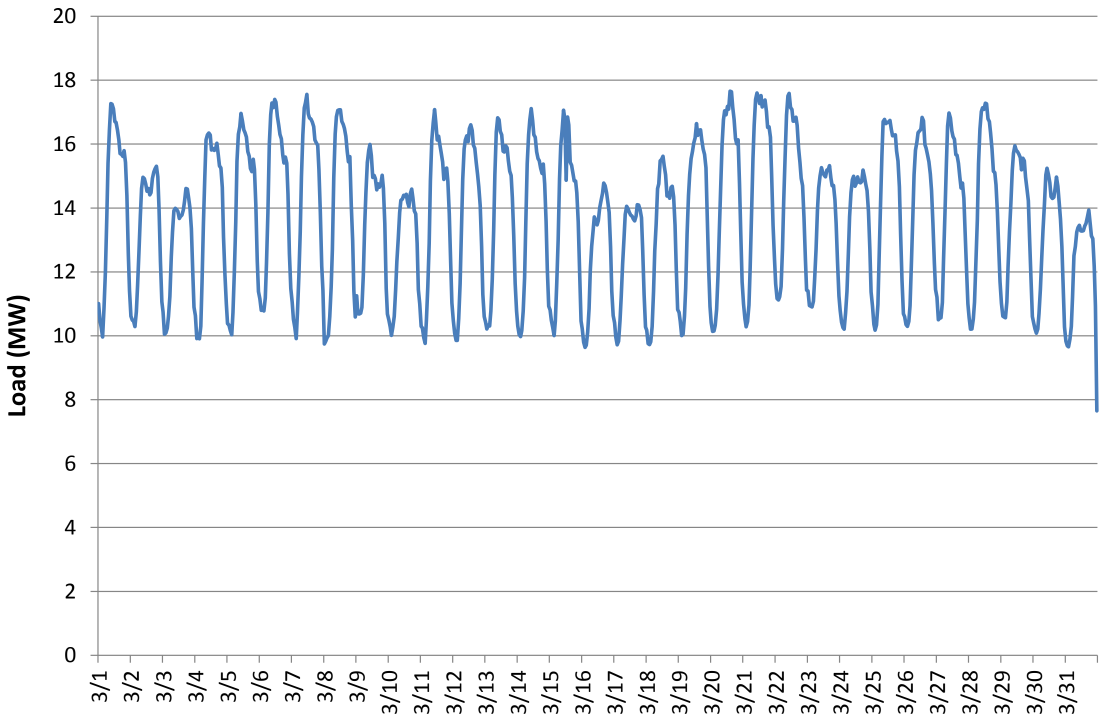

Figure 5.15: Large Power Load Profile – March 2013

Figures 5.16–5.19 depict the estimated load profiles of the Residential, Small Commercial, Large Commercial, and Large Power classes on the system peak day, illustrating the differences in contribution to the system peak relative to the class loads in question, which is of significant interest in cost-of-service calculations.

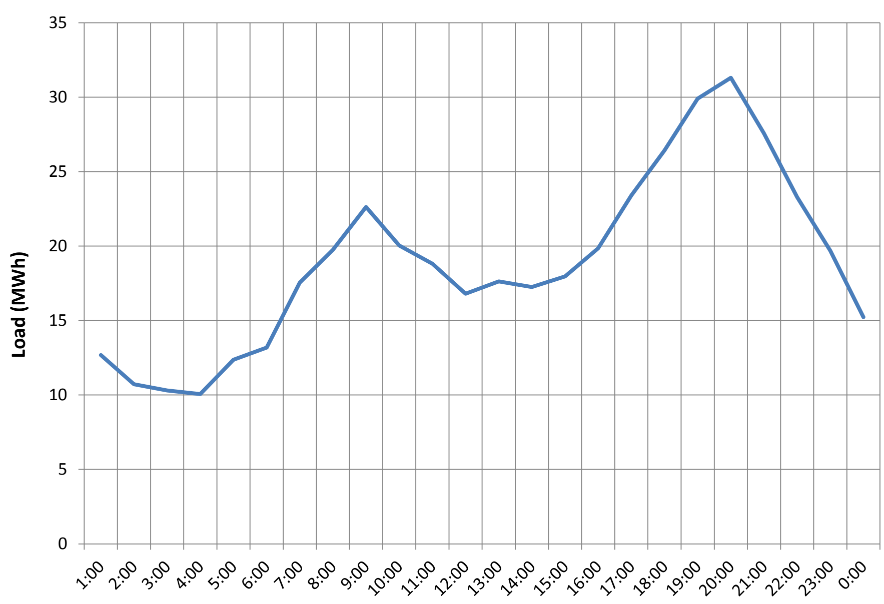

Figure 5.16: System Peak Day Load Profile – Residential (March 2013)

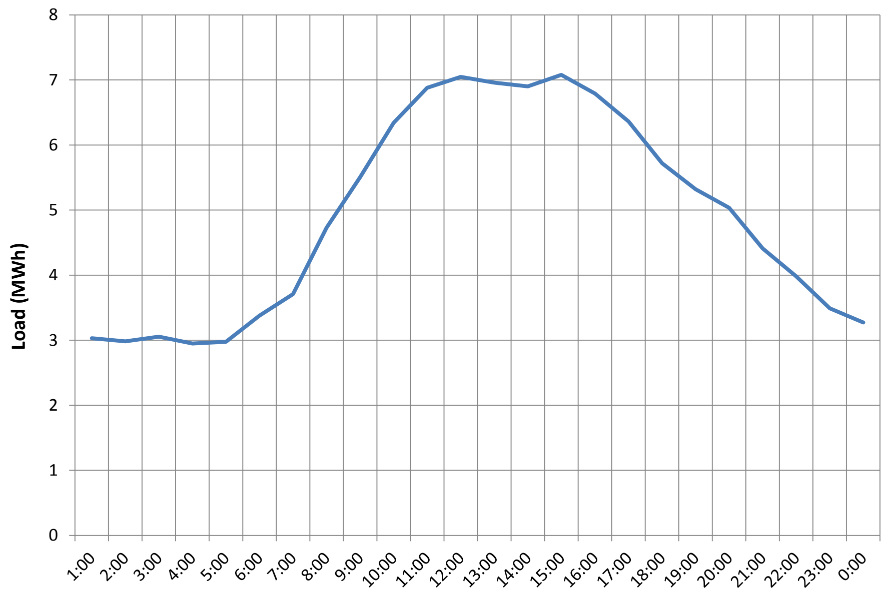

Figure 5.17: Peak Day Load Profile – Small Commercial (March 2013)

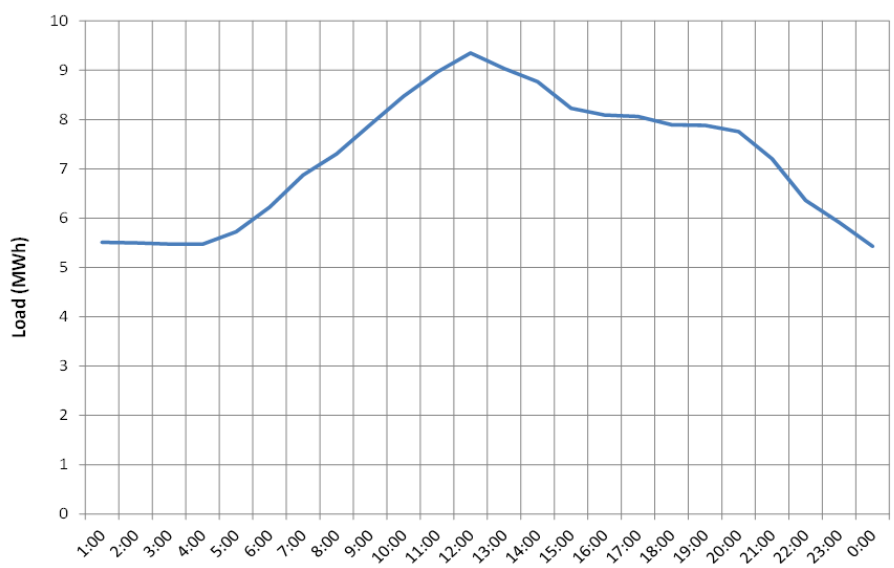

Figure 5.18: Peak Day Load Profile – Large Commercial (March 2013)

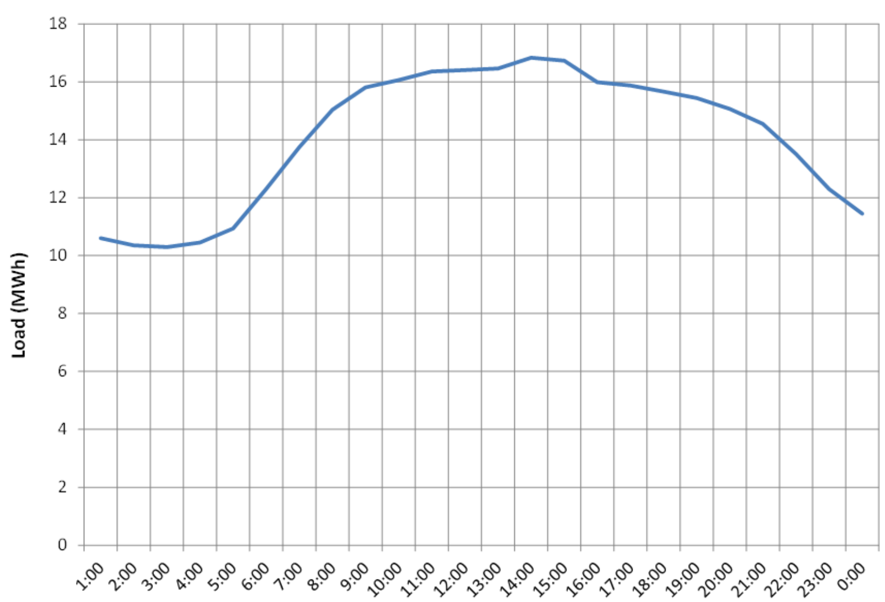

Figure 5.19: Peak Day Load Profile – Large Power (March 2013)

The initial AMI-based load research results also identified the opportunity to examine additional categories of load behaviors, such as net metered consumers providing a portion of their own generation requirements. By virtue of the AMI, information has become available to monitor those loads effectively.

For example, some average net load and generation profiles of net metering consumers on the KIUC system were available in March 2013 (**Figures 5.20–5.23**). The data represent net delivered and net received energy, rather than the full load requirements and total generation of the net metering customers.

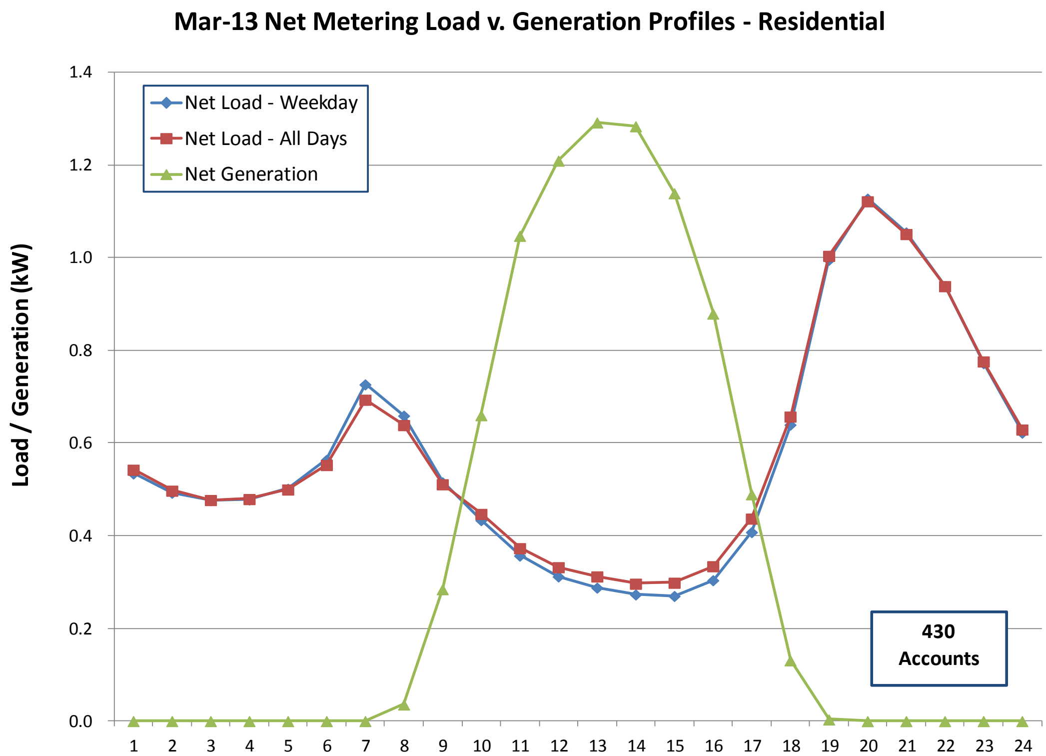

Figure 5.20: Net Metering Load vs. Generation Profiles – Residential

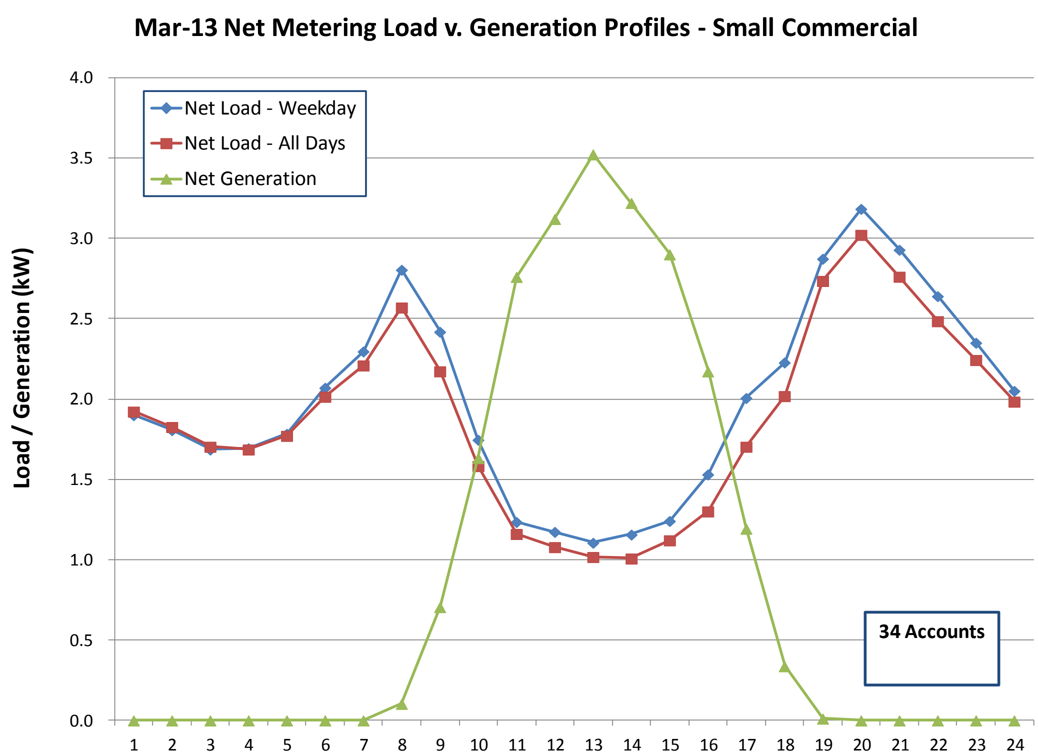

Figure 5.21: Net Metering Load vs. Generation Profiles – Small Commercial

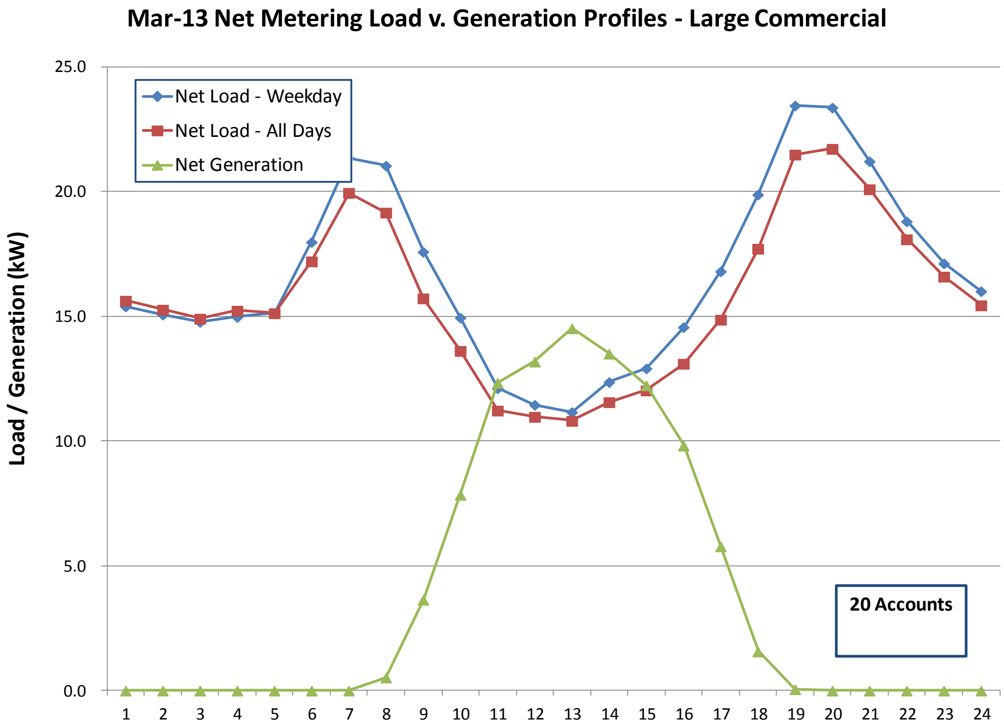

Figure 5.22: Net Metering Load vs. Generation Profiles – Large Commercial

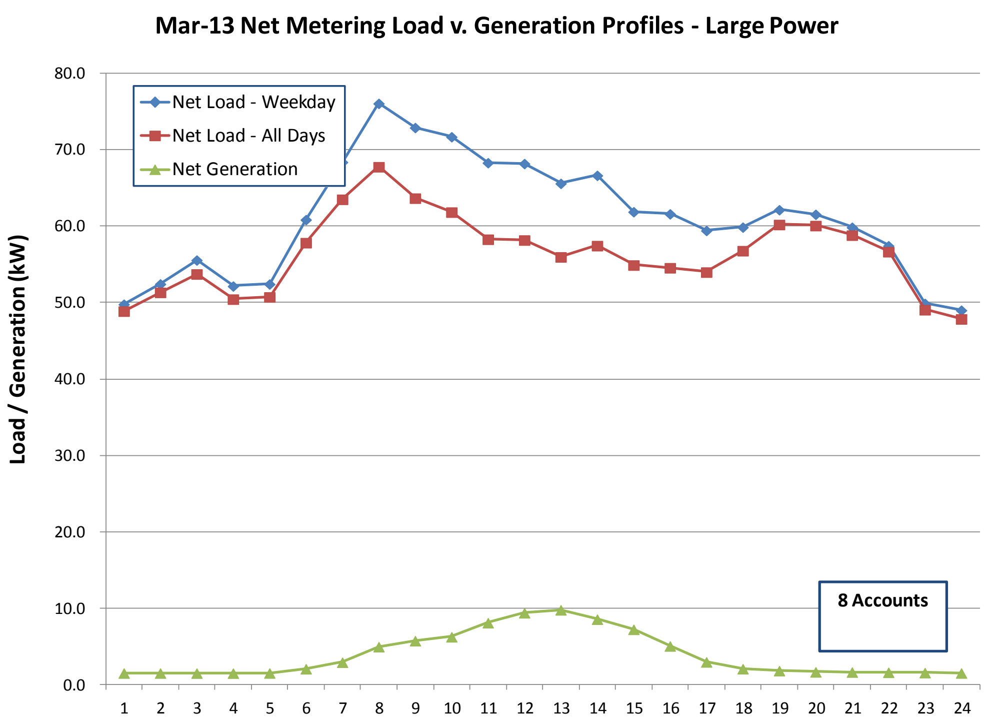

Figure 5.23: Net Metering Load vs. Generation Profiles – Large Power[7]

[7] With a limited sample size, however, generalized results may not be fully representative of the rate class.

5.3 Intermediate Results of the Load Research Study – May 2014

By late April 2014, data had been collected and load research results developed across the rate classes for the 12-month test year of calendar 2013. This included rate class loads and load profiles, as well as the data for the net energy metered loads, and those contributors of energy to the system from power in excess of on-site generation requirements. Continued success in the data collection was achieved through the use of the AMI system, which provided the level of detail appropriate for the load research study.

By that time, however, information became available that warranted further investigation. The items to investigate are related to the capability of the AMI system to provide a significant means for understanding the KIUC load situation. The availability of the AMI system information is relevant for evaluating differing information available to the cooperative.

One such issue is the measurement of the impact of on-site generation on the customer's load and the utility's system, a condition becoming more prevalent across the industry. The intermediate load research study results determined that the test-year peak load for the KIUC system occurred in July 2013.[8] The class contribution to the peak day load and the net metered load for generation by the system utility generation is shown in **Figure 5.24**. The item of particular interest to the demonstration study is the relationship and impact of the net metered loads and on-site facilities providing generation to the system.

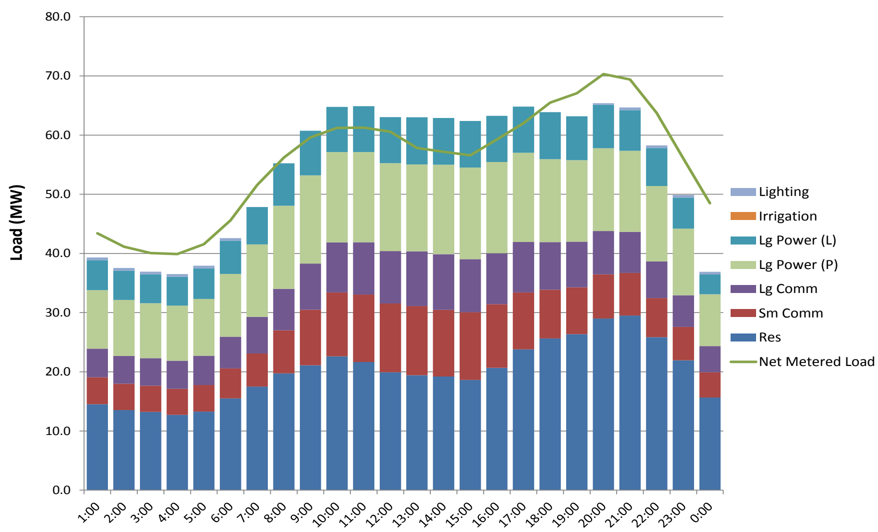

Figure 5.24: Sum of Class Loads vs. Metered System Peak Load – Peak Day July 2013

The net metered load in **Figure 5.24** is the load level reported by the KIUC SCADA system and is the sum of the feeder loads at the substation delivery points. In the absence of net metering and on-site distributed generation feeding into the grid, that load level typically would be above the sum of the individual class loads by a more or less constant percentage, representing distribution

[8] The actual system peak occurred, however, in December 2013, based on a later examination by KIUC of system losses. Confirmation of this will be incorporated in the final documentation of the study.

losses on the system and the level of power supply required to be supplied by the KIUC generation facilities. Thus, the load level reported by SCADA is the system load, net of the on-site generation.

The differential between the sum of the metered loads and the substation feeder load profile is the "backfeed," or level of exported on-site distributed generation, contributing to meet the total load of the system and distribution losses. A hypothetical adjustment to the substation feeder loads to account for the backfeed is included in **Figure 5.25**. The gross load of **Figure 5.25** is a hypothetical estimate of the amount of energy exported by the on-site generation facilities that has been added to the metered feeder loads to obtain a representation of the level of gross generation requirement.

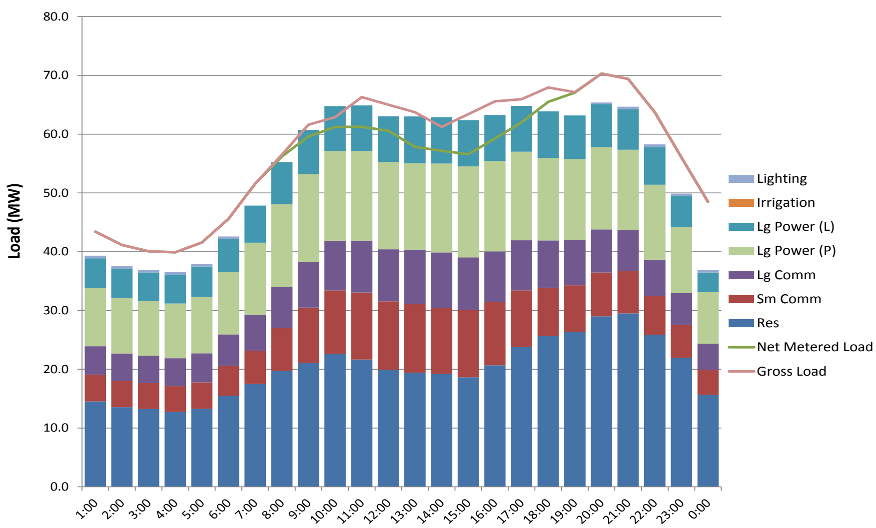

Figure 5.25: Sum of Class Loads vs. Metered System Load w/Adjustment – Peak Day July 2013

The level of exported on-site generation by an individual customer differentiates one customer from another within any of the customer classes and is an important consideration in rate design efforts. This information is particularly important for consideration of time-of-use rates or other pricing incentives to help optimize the power supply of the cooperative. **Figures 5.26** and **5.27** provide a comparison of load profiles within two rate classes (Residential and Small Commercial) differentiated by facilities that self-generate and/or export energy, identified as "NEM/Q" customers.[9] Additionally, observation of the start and end loads suggests that larger energy users may have greater generating capability than the typical customer.

[9] "NEM/Q" refers to participants in the KIUC Net Energy Metering programs, or those that export power from on-site generation to the KIUC system under the Schedule Q tariff.

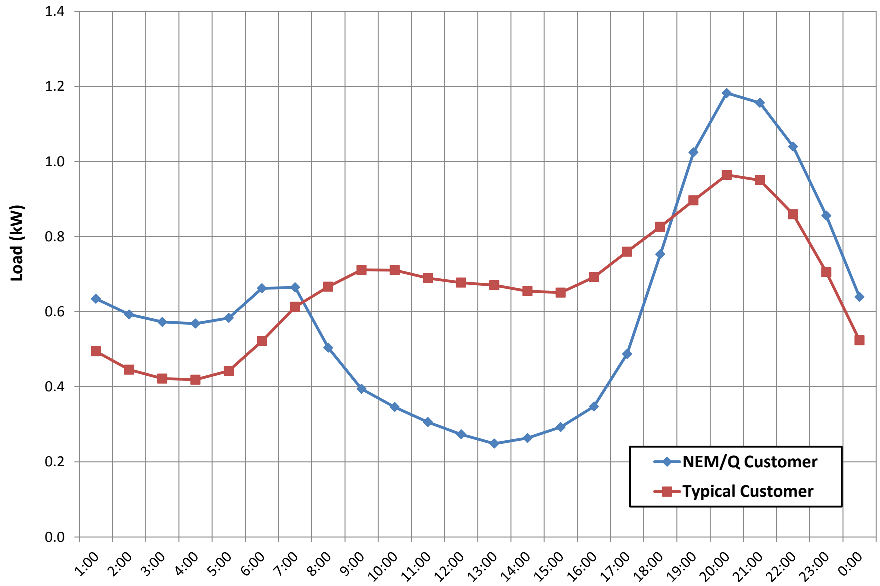

Figure 5.26: Residential Load Profile – Typical vs. NEM/Q – Peak Day July 2013

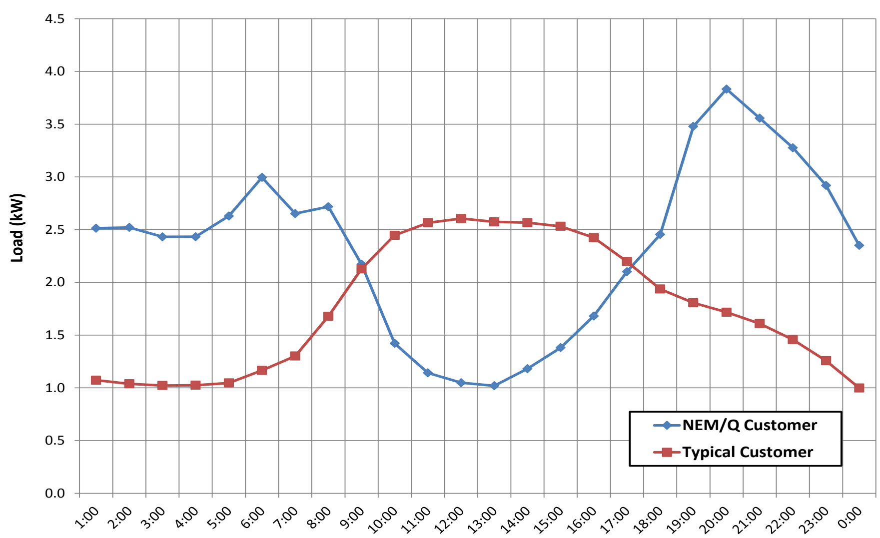

Figure 5.27: Small Commercial Load Profile – Typical vs. NEM/Q – Peak Day July 2013

The amount of energy contributed to the KIUC system by the NEM/Q customers varies over time as a result of external conditions and the amount of the internal load of the self-generating facility. For example, the average backfeed profile for residential customers is shown in **Figure 5.28**, indicating the differences by month in the amount of net generation provided to the system by on-site generation facilities. Adjustments to the generation profiles to develop "normal" on-site generation expectations may be required to ensure proper representation of loads for planning and evaluation purposes.

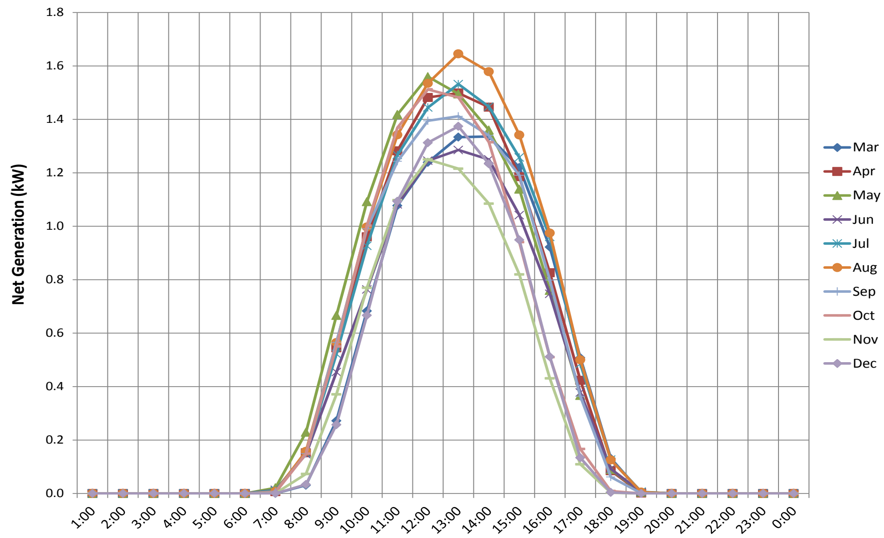

Figure 5.28: Average Residential NEM/Q Export, Calendar 2013

Another issue identified in the data collected over the test-year period was the impact of shifts in the status of the customers selected for the sampling of load data. The sample identified in the initial phases of the study was maintained throughout the data collection. However, changes within and between the classes were evident when reviewing the samples across the month. In addition to adding NEM/Q customers and the non-AMI metered accounts, a contributing factor was the gradual roll-out of AMI metering across the classes, leading to lower numbers in the earlier months of the year (e.g., January through March). The most significant shift can be seen in the Residential and Small Commercial NEM/Q participants, as shown in **Table 5.3**.

Table 5.3: KIUC Load Research Samples, by Month, Calendar 2013

Month	Residential (Sched D)	Small Comm (Sched G)	Large Comm (Sched J)	Large Power (Sched L)	Large Power (Sched P)	Res NEM/Q	Small Comm NEM/Q
Jan	343	274	197	8	97	N/A	N/A
Feb	375	289	215	8	98	N/A	N/A
Mar	399	304	226	8	99	430	34
Apr	434	324	251	8	99	478	37
May	437	334	271	8	99	483	38
Jun	317	293	216	7	74	230	13
Jul	440	342	269	8	95	486	42
Aug	446	347	286	8	96	495	41
Sep	447	354	294	9	97	500	42
Oct	448	361	296	8	96	503	41
Nov	446	360	297	9	95	504	41
Dec	445	358	298	9	96	504	43
Accounts	28,300	4,300	310	13	103	1,694	*

In 2013, for example, it was reported that there were approximately 800 new applications for NEM/Q interconnections among residential energy users. When using annual data, timing is an issue for establishing the sample; in addition, capturing the transfers between classes of customers or among specific customer characteristics is important to fully reflect the conditions of the system. The data from the AMI are available and accommodate the adjustment of the sample strata. Such adjustment is required to capture the following: (1) the growth in on-site generation; (2) the size of the systems installed; (3) the shift between customer classes; (4) the changes in customer class usage profiles due to that growth; and (5) the changed contribution to system energy through export.

Other issues related to the load research study not directly applicable to the demonstration include adjusting for certain large loads for which AMI meters may not have been installed due to unique operating or connection requirements, the correlation of system load and estimated loads, and other benchmarking refinements.

5.4 Next Steps in KIUC AMI-Based Load Research

Over the remainder of the load research study, Leidos and KIUC will be working together to address the issues identified relative to on-site generation characteristics and some remaining issues related to the data analysis, including the following:

- Resolving benchmarking issues
  - Differences identified between sampled and billed energy;
  - Differentials between hourly estimated and actual system load;
  - Late morning and early afternoon hours;
  - Late evening hours;
- Ensuring the correct capture of gross system load;
- Refinement of the solar generation profile; and
- Verifying the sample stratification (based on the 2013 system peak month rather than the January 2012 data, and re-stratifying if appropriate).

Once complete, the analysis and accompanying report will form the basis for rate design studies and supporting documentation that can be supplied to the HPUC and the Hawaii Consumer Advocate for a utility system-specific load research study by and for KIUC.

6. CONCLUSIONS FROM THE AMI-BASED LOAD RESEARCH DEMONSTRATION

The KIUC AMI-Based Load Research Demonstration has shown that the AMI system has provided remarkably clean and generally error-free data, reflecting the integrity of its system and data collection protocols and communications network. In addition, data collection was much more efficient than it would have been had traditional manually read meters been employed for the study. The comprehensive set of profiles for the initial month suggested that the full-year data set would be reasonable and fully representative of load class contributions to serve as a basis for rate studies and other purposes. The intermediate results provide even more compelling evidence for the use of the AMI for load research, particularly regarding the identification of differences in recorded information, and in providing the ability to revise a sample or include alternative data sets. Such capability avoids the onerous process of meter changeouts as strata change, as would be the case when using traditional load research metering.

With the full test-year calendar period results having been obtained and currently being refined, in part by additional and alternative data from the AMI system, it is apparent that an AMI-based system provides a better design for obtaining the requisite data than traditional equipment. The research objective of demonstrating the use of the AMI system for load research has been met through the initial and intermediate work. The benefit of the AMI system in support of ratemaking and other studies will derive from the integrity and availability of the comprehensive data. The load research results to date and analysis of the data supply evidence that AMI provides an effective and efficient means to collect the necessary data, and that the research objective of demonstrating the value of AMI in completing a load research study has been met.

The AMI system has allowed KIUC to avoid incremental costs in acquiring the load data, and the system has shown overall integrity and provides data uniquely associated with the KIUC consumer base on which it may rely. The ability to create a sample from a relatively unlimited database of recorded metering information has been useful for the sampling design and will assist in developing adjustments to reflect changes throughout the test period. Further work on the data collected and resolution of anomalous results will help to clarify unique features of the KIUC load requirements, including such factors as net metering circumstances and other non-utility generation. Furthermore, the AMI provides the opportunity to selectively identify unusual and anomalous loads; investigation of causes and impacts will provide for improved operating efficiencies.

7. RECOMMENDATIONS FOR FURTHER STUDY

Pending the final analysis and the results of regulatory acceptance of the research findings, several factors in the application of the AMI system for load research may be worthwhile candidates for further study. These include the following:

- The impact and effect of metering "opt-outs" and the impact on derived load characteristics for the system;
- Comparison with more traditional systems, such as PLC-based data collection, for data integrity and data continuity; and
- The value of periodic repetition of the sampling and the appropriate time frame for re-examination.

Chapter 6:

Building Consumer Acceptance to Maximize the Value of Grid Modernization

INTRODUCTION

Cooperatives that deployed consumer-facing technologies, including Advanced Metering Infrastructure (AMI) meters, as part of the Cooperative Research Network's Smart Grid Demonstration Project (SGDP) have discovered that these technologies not only can change the relationship between the utility and the end-use consumer, but also that this relationship must be changed to extract the full value of the smart grid. While much of the research on the smart grid has focused on the transformation of the nation's electric system from an electro-mechanical to a digital system, the co-op experience in the SGDP has revealed the importance of the human side of the equation. Maximizing the benefit of these smart grid technologies—demand response, time-of-use rates, peak pricing, and prepay and energy management tools—for both the utility and the consumer requires new kinds of engagement and communication with the latter. This report examines the difficulties and benefits of forging a new relationship with consumers to ensure the full value available from smart grid innovations.

Traditionally, electric utilities have operated solely as commodity suppliers to their consumers. Smart grid technologies, with some assistance from deregulation, are forcing utilities to re-evaluate that model. In some regions, new organizations—an energy efficiency cooperative in Vermont, for example—are aggregating demand response to sell into the market. Renewable energy providers are marketing solar and wind energy directly to members. By shunning smart grid technologies, utilities risk losing out to other businesses that can offer smart grid-enabled services—demand response rebates, customer data portals, renewable energy options—thus stepping in between the utility and the customer.

As daunting as such changes in the utility landscape appear, the cooperative business model—member-owned, not-for-profit—is well suited to this new environment. For cooperatives participating in the SGDP, new technologies have allowed them to offer their member-owners a whole new array of services, including customer data portals, prepay metering, residential thermal storage, residential energy storage, new pricing options, and automated outage notifications, among others. The experience of the participating co-ops can be viewed, at least in part, as a tale of transforming the utility from commodity supplier to service provider. In other words, the consumer services enabled by the smart grid will also be valuable in building the consumer trust needed to maximize its potential benefits.

The experiences of cooperatives that participated in the SGDP provide a preview of the risks and challenges ahead—and some of the solutions. The public and often toxic debates over smart meters that have bedeviled utilities since the PG&E controversy illustrate the risks. While cooperatives start out with the advantage of providing higher satisfaction to their consumer-members, they have not been exempt from these controversies. The collective experience of the SGDP co-ops offers a path forward, helping them shape a strategy and tools for building the customer trust needed in a more competitive environment.

THE RISKS

"Your meter is giving me nosebleeds"

Nearly all of the communications professionals who have gone through the experience of deploying a new AMI system agree on the importance of a proactive communications plan in educating customers and stakeholders in advance about the meter changeout and the new system.

Following the controversy over PG&E's smart meters, a cautionary tale for the entire industry, NRECA set out to assist co-ops ward off similar battles by producing a "Communicators' Toolkit for a Smart Meter Rollout" (Appendix 6A). Based on information from focus groups and a survey, the toolkit provides a guide to developing a communications plan and sample materials, including press releases, letters to member-consumers, presentations for public meetings, and even leave-behind door hangers.

Yet this brand of proactive communication about a basic utility function is new to many utilities, including co-ops. Many managers simply never considered communicating to their members about a meter changeout: their view was that the meter is utility property and the utility is free to make whatever change it deems necessary. Many co-ops installed smart meters without telling members and encountered no problems. (A PG&E employee noted, for example, that he had received no communication about the installation of a digital meter at a cabin he owned that was on co-op lines.) But in this brave, smart new world, the relationship between the utility and the customer is changing—the boundary between the utility and the customer is being altered. Customers aren't the only ones concerned—at a staff meeting to discuss a potential AMI deployment, a long-time operations manager raised concerns that the utility's domain would be extended beyond the meter. The smart grid alters the boundary line, and communication with consumers will be key in making this transition.

Kauai Island Utility Cooperative (KIUC) experienced by far the most intense and sustained controversy over smart meters. By all accounts, the cause was rooted in the island's unique culture. A fairly young cooperative, KIUC is moving aggressively to increase efficiency and renewable energy capacity to reduce its reliance on the expensive diesel that must be shipped to the island. In 2013, KIUC won top honors from the Solar Electric Power Association for its solar development. The deployment of AMI is critical to the co-op's resource management plan. To this end, the co-op purchased the Landis+Gyr Gridstream system and planned to install two-way meters for its 26,000 residential customers. As part of the demonstration project, KIUC also planned to install 1,000 in-home displays. Early on in the project, however, strong pushback from members created a significant obstacle.

As in many other jurisdictions, KIUC members raised concerns about the health impacts of smart meters and the adequacy of privacy protections. For utilities across the country, these debates have proved singularly frustrating to counter. What happened at KIUC is typical: a small but extremely vocal group of activists mounted a campaign against the new meters, sending letters to the editor, creating a website (stopkiuc.com), posting YouTube videos, attending community meetings, and even going door to door raising the alarm about "powerful radiation." KIUC's Jim Kelly has recounted members reeling off a list of ailments and attributing them to the meters—including nausea, fatigue, sleeplessness, chest pains, nosebleeds, and ringing in the ears.

Staff interviewed at KIUC and other co-ops for this report all shared the experience of trying to combat misinformation with data from Federal Communications Commission, peer-reviewed articles in professional journals, and other public and private agencies—usually to no avail. With the exception of KIUC, the number of other co-ops' members who could not be persuaded to accept a smart meter was no more than a handful. As KIUC's experience shows, however, a handful may be all it takes to derail a smart meter deployment.

It is interesting to note that some long-time staff remembered similar fears being raised about electromagnetic fields (EMF) more than 20 years ago. At that time, NRECA published a brochure to help co-ops educate and reassure their members about EMF.

Co-ops took different approaches to addressing members' concerns. In some states, the public utility commission chose to require utilities to offer an opt-out for customers. Many utilities followed that path voluntarily, preferring to accommodate these customers rather than engage in a public battle. While co-ops calculated the cost of reading analog meters differently, because they are member-owned, they uniformly required anyone opting out to pay the difference. To do otherwise would result in one set of members subsidizing special treatment for a minority. Anecdotally, adding a charge for in-person meter reading depressed the number of opt-outs.

Jim Kelly, the communicator for KIUC who was brought on board during the controversy, has sage advice for fellow cooperatives: keep the message simple and educate stakeholders in advance. The co-op communicated with members about the smart meter plans; however, in retrospect, the communications should have focused less on the technology and more on the issues that mattered to members. Kelly noted the co-op conducted surveys ahead of the project, which showed that 75 percent of respondents supported the move to smart meters, thus giving the co-op a false sense of security.

The experience of KIUC offers a central lesson for co-ops as they transition to a model that includes more services for members: communications should be framed from the consumer's point of view, not that of the utility.

"Smart meters are really surveillance devices"

Member concerns about privacy are far more difficult to address than health concerns because smart grid technology in fact will provide more data about the system and customers' usage. The new data are immensely valuable but also present a new risk.

Fewer KIUC members raised privacy concerns, but one customer did seek an injunction in federal court, arguing that the meters constituted an invasion of his privacy. He found a sympathetic judge, who did not issue an injunction but did express her own concerns in court, based on a flawed understanding of how smart meters work. In the end, KIUC settled with the customer, agreeing not to install a meter on his house.

It is common to hear utility staff scoff at the notion that they would use meter data—for example, a load profile that shows when a consumer is using a hot tub—to "spy" on members. "We're too busy keeping the power on," they say. These comments reveal a disconnect between the utility's and consumer's views of the data, however. Consumers are concerned because new meters make available a new pool of data about them and their habits. This concern is valid, and a utility would be well advised to commit publicly to a privacy policy regarding such new data.

Notably, the survey conducted by NRECA revealed that consumers who spend a greater portion of their take-home income on energy are more concerned about privacy. The good news is that these are the same customers who stand to benefit most from new applications enabled by this data that can lower their bills.

THE BENEFITS OF COMMUNICATING WITH MEMBERS ABOUT SMART GRID IMPROVEMENTS

Anecdotally, two co-ops that used the "Communicators' Toolkit" to guide their AMI deployment found their customer satisfaction scores actually rose over the course of the project. Simply communicating with consumer-members about efforts to modernize the system and improve reliability and efficiency will improve the co-op's relationship with its consumers.

It is also true that extracting the full benefit of smart grid technologies requires customer engagement, which is possible only with more active communications. To cite the most obvious example, residential load control using AMI or smart appliances requires the participation of members—a whole lot of them. While many co-ops have longstanding demand response programs based on one-way communication, Flint Energies' Senior Vice President for Member Relations Jimmy Autry warns that times have changed, and gaining the necessary trust of consumers has become more difficult. A recent study by the Lawrence Berkeley National Laboratory found demand response participation rates for 19 programs that were part of the DOE investment grant project ranged from 5% to 28%. Many utilities have little experience in soliciting consumers to join in a partnership, however.

Tresa Hussong with Iowa Lakes Electric Cooperative shared a telling anecdote in an interview about the co-op's smart grid projects. The co-op found that consumers who had signed up to participate in a demand response program when purchasing water heaters then did not agree to have their water heaters connected to the system once the infrastructure was in place. When the co-ops' linemen asked them, however, people were much more likely to answer "Yes." According to Hussong, people trust the linemen—they are the face of the cooperative. This anecdote underscores the essential element of trust in effective communications with consumers.

When NRECA first began working on developing its "Communicators' Toolkit," it convened a group of communicators to discuss what content and messages would be helpful. Two themes emerged from that initial meeting: (1) executive leadership at many co-ops viewed communication with members about the meters as an afterthought to the meter deployment process, and (2) utility staff have difficulty in putting themselves in the consumers' shoes when thinking about how messages from the utility will be received.

Another key to successful communications, according to Autry, is focusing on the benefits to members. While this principle sounds simple, following it can prove more difficult in reality. First, most of the benefits of smart grid applications are operational and will not be noticed by the customer. Second, while many utilities stressed the benefits of giving customers access to usage data and "greater control" over their bills, NRECA's research found members less interested in the benefits of seeing their own usage data than in improved reliability and efficiency.

Communications should address the key questions customers want answered (how will this new meter affect my bill?) and how the smart metering system will benefit them directly. While smart meters and other smart technologies will provide enormous benefits to co-ops and their members down the road, when deploying the meters, only communicate what you can deliver on day one. In public opinion research conducted by NRECA, the following benefits resonated with a strong majority of co-op consumer-members.

Improved efficiency

Co-op consumer-members like to know that the co-op is working to keep costs down by investing in efficiency. An NRECA survey found that consumers could readily understand that new meters allow the co-op to read meters remotely, reconnect remotely, and locate outages more quickly and precisely. They also understand that meter reading and improved outage management can save the co-op money— a savings that will benefit members.

Improved reliability

Consumers understand and like the fact that new technologies can make the system more reliable. It is easy to explain the difference between having a lineman in a truck try to find an outage and finding it using data sent by smart meters.

No more estimated bills or self-reads

A high percentage of co-ops transitioned from self-reading to AMI. For these co-ops, an end to the hassle of self-reading was a benefit to their members.

Improved customer service

The additional data from smart meters can help co-ops work with members to diagnose why they have high bills. There are many stories about co-ops using the data from smart meters as a tool to help their members analyze what is happening in their homes or businesses—and to help them find solutions.

CONCLUSION

The growing recognition that consumer distrust can be a formidable barrier to the smart grid is driving research efforts that look at consumer opinion and behavior. The unique relationship between co-ops and their consumer-members offers a new perspective on the role of trust in ensuring consumer acceptance. NRECA believes that communication without trust will not be effective. A utility can send out a stream of glossy attractive communications about sexy new devices and rebates, but if the consumer does not trust the utility, attracting consumer participation will be difficult.

Appendices

Appendix 6A: Communicators' Tools

1. Communicators' Toolkit for a Smart Meter Roll-Out table of contents
2. Communicating about Smart Meters and the Smarter Grid
3. Responding to Health and Privacy Concerns: Sample Recommendations and Talking Points
4. Deploying New Meters: Messages for Consumer Members

Appendix 6B: 2011 Smart Meter Messaging Survey Results, April 2011

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  - The Case for Communications
  - Communication Planning Toolkit
  - Rate Increases
  - Capital Credits Communications
  - Crisis and Severe Weather Communication
  - Resources for Website Managers
  - **Communicators' Toolkit for a Smart Meter Roll-Out**
- Social Media Guide
- Professional Development and Awards
- Communicator Groups
- Regional Meetings Press Kit
- Glossary of Terms (Use or Usage) and Sample Style Guide
- NRECA Graphic Standards Manual
- NRECA Map Data Project
- NRECA Communications Department Staff Directory

Cooperative.com > Interest Areas > Communications > Best Practices and Samples > Communicators' Toolkit for a Smart Meter Roll-Out

Communicators' Toolkit for a Smart Meter Roll-Out

This toolkit was funded by and coordinated with the Cooperative Research Network's Regional Smart Grid Demonstration Project (SGDP). In preparing the consumer materials, NRECA conducted focus groups in Colorado and Iowa and a telephone survey of 500 consumer members. The results of this consumer research are incorporated into the messaging as well as "the look and feel" of these materials.

All of the consumer materials are customizable – every co-op approaches the challenge of installing new meters a little differently. Some of the text on the consumer materials may not apply to your co-op. You can make edits based on your circumstances. We hope this toolkit makes your job easier.

Responding to Member Concerns About Privacy and Health Impacts

Please start with the recommendations document (linked first), which includes high-level recommendations on how to respond to member concerns.

- Smart Meter Health and Privacy Concerns: Sample Recommendations and Talking Points
- Sample Co-op Response to Member RF Concerns (Tideland EMC)
- RF Exposure Comparison Graphic
- Background on Smart Meters and RF from the Utilities Telecom Council
- EPRI: A Perspective on RF Exposure Associated With Residential Automatic Reading Technology

Developing a Communications Plan for Deploying Smart Meters

Use the documents below to develop a communications plan and effective messages.

- Sample Communications Plan & Timeline
- A Guide to Communicating About Smart Meters
- Message Triangle for a Smart Meter Roll-Out
- Sample press release
- Sample newsletter article
- Digital Meter FAQ

Consumer Materials

Note: **Before you download any image, please review the legal requirements (PDF).**

A proof PDF and packaged InDesign files are provided for the customizable items.

- Door hanger (PDF (low-res), PDF (high-res), InDesign (ZIP)
  Note: For production of the door hanger, contact The Summit Group for pricing or to print the customized door hangers.
  Contact information:
  Terry O'Neal
  240-491-5229
  Terry.Oneal@summitmg.com
- Brochure (PDF (low-res), PDF (high-res), InDesign (ZIP)
- "The Smarter Grid" Illustration (PDF, JPG)
- Radio-Frequency Exposure Levels from Smart Meters: A Case Study of One Model
  A whitepaper from the Electric Power Research Institute

Questions?

Questions, comments or problems with the communications kit materials?
Contact Tracy Warren, Sr. Media & Communications Manager, tracy.warren@nreca.coop.

COMMUNICATING ABOUT SMART METERS AND THE SMARTER GRID

Communicating to customers about advanced meter deployment—and eventually smart grid—is a challenge that many cooperatives are facing or will face in the next few years. The good news for co-ops that haven't begun installing smart meters is that we can benefit from new public opinion research and from lessons learned by utilities that have already gone through the process.

Messaging around smart meters is changing.

Messaging around smart meters has changed as utilities have learned to avoid over-promising. In communicating about new automated meters, the messages should be focused on the value that smart meters deliver to customers. Use the smart meter "message triangle" to help your co-op develop consistent, effective messages throughout the deployment.

NRECA conducted focus groups and a telephone survey to find out which benefits are important to consumer members and what concerns they may have. In general, while long-time co-op members trust their co-ops to make sound investments in new technology, newer members and members whose electric bills have a big impact on the household budget have more concerns about the new meters. Members with high bills are also more interested in how the new meters can benefit them.

Using the smart meter message triangle

Public research has shown what you probably already know: consumers know very little about automated meters. Some utilities have encountered backlash from advocacy groups, consumer skepticism and lawsuits in the process of deploying new meters. Co-ops can reduce the risk of opposition by going out early with the triangle's positive messages – and returning to the central theme: "new technology to help us serve you better."

The message triangle is a tool for all co-op employees to help the co-op as a whole communicate effectively with members and the public. When communicating about a new technology it's easy to get lost in the weeds. The triangle boils everything down to three basic messages: the new meters will improve efficiency, improve reliability and help the co-op keep costs down. Details shown under the main points are suggestions.

Adjust them according to your local or regional power supply situation, using facts about your co-op.

These benefits reinforce the central point: "new technology to help us serve you better." By consistently repeating these messages the co-op can break through all the other noise and static – including negative messages being spread on the Internet and word of mouth.
The messages about the benefits should be repeated over and over in any public communication, including media interviews, stakeholder meetings and conversations with neighbors.

In conversations and presentations, stick to three or four main points — no more. That will be enough to show the big picture but not so much that people will tune out. While all sides of the message triangle reinforce the main point in the center, don't assume that people will make the connection on their own. Whenever it seems natural, remind people, "the meters are a new technology that will help us serve our members better."

Cooperatives must continue to work to build trust within the community. Communicators can build trust by providing the media, employees, and other stakeholders with a straightforward and transparent explanation of the smart meter project plan, scope, and timeline early in the process.

Be sure to emphasize that co-ops, as member-owned not-for-profits, are looking out for the consumer.

It's All in the Details

In research conducted by NRECA, consumer said they want to know how the meter installation will directly affect them: When will the meter be installed? Are they going to lose power during the installation? Are their rates going to change as a result of the new meter?

Communicate early, using a variety of media, with these key details:

- when members can expect to have the new meter installed
- what will happen during installation
- what they will see on their bill following installation

Consumers' top concern about the new meters is whether or not they are going to result in higher costs. The reality is that for some members – those who read their own meters and those with older, less accurate meters – the answer may be yes. In addition, experience shows that installing new meters when the weather is changing can also lead to suspicions that higher bills are the result of the meter.

Customer service representatives should be prepared to explain the first bill following installation, which will have either two readings (one from the old meter and one from the new) or a combined total. They should also be prepared for some high bill complaints for those members whose old meters were inaccurate.

It's About the Member!

Communicating the Benefits

Communication pieces should address the key questions customers want answered and how the smart metering system will benefit them directly. While smart meters and other smart technologies will provide enormous benefits to co-ops and their members down the road, when deploying the meters only communicate what you can deliver on day one. In public opinion research conducted by NRECA, the following benefits resonated with a strong majority of co-op consumer members:

Improved efficiency

Co-op consumer members like to know that the co-op is working to keep costs down by investing in efficiency. Explain that with new meters the co-op can read meters remotely, reconnect remotely and locate outages more quickly and precisely. Make the point that remote meter reading and improved outage management can save the co-op money, a savings that will benefit members.

Improved reliability

Smart meters help the co-op identify the location of outages and respond more rapidly to restore power and give customers more information. Note that many utilities are recommending that customers continue to call in to report outages, to ensure that the systems are working properly.

Improved power quality

With more information coming from the meters and other new applications, the co-op can monitor the system better and improve power quality by reducing the number of spikes, blinks and surges.

No more estimated bills or self-reads

New meters improve the accuracy of meter reading. Smart meters eliminate the need for estimated reads or "self-reads," which may be prone to human error.

Access to data about power use.

In Touchstone Energy's 2010 Cooperative Difference survey, more than 60 percent of the respondents said they would definitely or probably use a web portal with information about their energy use. Consumers also like being able to choose whether to see hourly, daily or monthly data. Co-ops that have provided this feature to their members have received a very positive response from members.

Improved customer service

The additional data from the smart meters can help co-ops work with members to diagnose why a member has high bills. There are lots of stories about co-ops using the data from smart meters as a tool to help their members analyze what is happening in their home or business – and to help them find solutions.

CONSUMER CONCERNS ABOUT SMART METERS

Recent controversies over the deployment of smart meters in some areas of the country illustrate the importance of being prepared to allay consumer concerns. These controversies also underscore the value of communicating about the new meters early in the process. If your consumer members hear about the new meters from someone else first, the task of building their trust will be much harder.

Cost

Consumers are concerned that the new meters will increase their electric bills. In some cases, if the existing meters are old and inaccurate, the new accurate meters *will* in fact increase their bills. Customer service representatives should be prepared to take calls coming from members whose bills have gone up. Be careful not to suggest that the efficiency of the new system will result in lower electric bills.

Privacy

Public opinion research conducted by NRECA showed that consumers are susceptible to messages from the media or advocacy groups claiming that the new meters are a privacy threat. Be prepared to explain the steps taken to protect the data from the new meters.

Health concerns

Some utilities have faced backlash from customers concerned about new meters and radio waves. The level of RF waves emitted by smart meters, which are outside the home, is hundreds of times less than that of cell phones. Communicators and customer service representatives should be prepared to address health concerns. Consider posting information on the website. The Electric Power Research Institute has published reports on this topic.

REACHING THE CONSUMER MEMBERS

Research conducted by NRECA illustrates the importance of using multiple communications methods for reaching the members. 53 percent of those polled said they prefer to get their information via a letter in the mail; 22 percent prefer a phone call; 18 percent, especially younger members, prefer email.

The ideal communications plan will combine newsletter articles, letters, phone calls, emails and door hangers to provide members with information about the meter installation project.

Preparing the customer service representatives to answer members' questions and concerns during and after the installation is critical. Co-ops score high in customer satisfaction – new meters should increase satisfaction if the deployment is successful.

More Information

For more information, sample communications and tools, see the communicators section on Cooperative.com. or contact Tracy Warren (703) 907-5746.

NRECA
A Touchstone Energy® Cooperative

Responding to member concerns about privacy and health impacts related to smart meters

Editor's note: We have highlighted information that will need to be customized; however, please be sure to read this language carefully before using it to make sure that it applies to your system.

A few suggestions for responding to consumer concerns:

- Respond swiftly. Do not let allegations go unanswered (even the wacky ones).
- If you have members who have concerns about smart meter radio frequency fields (RF), privacy, or security (or all three), a personal response from a co-op representative is almost always the best option.
- Community listservs often serve as hub for this type of controversy: if possible, monitor the discussion on these listservs and respond to allegations swiftly. (You might consider a Facebook page dedicated to your smart meter rollout.)
- Make sure to get out into the community—ask to speak to any and all civic group meetings about the smart meter deployment and its benefits to members.

ON PRIVACY

The data from new digital meters helps us serve our members better. Our goals in installing new meters are to deliver better service, control rising operating expenses, improve system reliability through improved outage management and preventive maintenance, and provide our members with information they can use to make informed decisions about energy use.

[ABC cooperative] does not sell its members' data to any third party. [ABC Cooperative] abides by stringent policies that protect the privacy and security of your electric usage data. These policies can be found [insert information on where to find the policies, e.g., in the by-laws, in the service rules and regulations, posted on the co-op website, etc.].

[ABC cooperative] is committed to protecting the privacy and security of our members' personal information.

ON RF WAVES – Power line carriers

The data from the new meters will be sent back to the co-op office over power lines. Using the power lines for data transmission means that the meters will not emit any radio frequency fields (RF).

You should know that we are all continuously exposed to very low levels of both natural and man-made RF fields. Even the earth's surface and the human body are constant sources of RF fields. Inside your own home, you likely will find numerous items that emit RF fields, including microwave ovens, cell phones, cordless phones, televisions, Wi-Fi signals, antennas, and receivers, as well as lighting fixtures.

Your cooperative is a not-for-profit private business that is solely owned and operated by the members who receive electric service from us. When our board of directors approves a policy or procedure for the use of new equipment and technologies, they do so knowing that it also will apply to their own homes. In using this type of metering system, we have not only deemed it to be a wise and safe choice for all co-op members and their families, but our own families as well.

ON RF WAVES – Wireless meters

Research conducted by the Federal Communications Commission (FCC), the Electric Power Research Institute, the Utilities Telecom Council, and others has found no negative health impacts from digital meters that send information via a wireless communications network. The radio frequency fields (RF) emitted by digital meters fall well below the maximum recommended in federal guidelines.

People are continuously exposed to very low levels of natural and man-made RF. Even the earth's surface and the human body are constant sources of RF. Digital meters send information about home electricity use to [ABC Cooperative] by RF signals. [ABC Cooperative's] meters emit RF similar to that of many common household devices, such as baby monitors, cordless phones, remote-controlled toys, and medical monitors.

The exposure from new meters is much lower than other common sources for two reasons: (1) infrequent signal transmission, and (2) distance. On a daily basis, the cooperative's meters emit power for less than [one minute/five minutes] per day. In addition, these meters typically are placed outdoors, with a wall separating the meter from the living space. This combination of placement and infrequent operation means that you would need to be within one foot of **7,000** digital meters all communicating at the same time to reach the FCC exposure limit. You can rest assured that our new metering equipment is safe for you and your family. The metering products we selected have undergone testing by an accredited lab to verify that they meet all FCC requirements. [Make sure to verify with the meter manufacturer that this is the case!]

Your cooperative is a not-for-profit private business that is solely owned and operated by the members who receive electric service from us. When our board of directors approves a policy or procedure for the use of new equipment and technologies, they do so knowing that it also will apply to their own homes. In using this metering system, we have not only deemed it to be a wise and safe choice for all co-op members and their families, but our own families as well.

ON CYBER SECURITY

It's extremely unlikely but not impossible that someone could access information from the cooperative's metering system. Meter manufacturers are incorporating security features and encryption technology into their meters, as recommended by national security experts. New meters allow us to determine if someone tampers with your meter.

NOTE: Some co-ops have put in place cyber security and risk mitigation plans using the Cooperative Research Network's "Guide to Developing a Risk Mitigation and Cyber Security Plan," which is based on best practices compiled by the National Institute of Standards and Technology. If you would like more information on these materials, you can find them on the CRN page on NRECA.coop.

DEPLOYING NEW METERS: MESSAGES FOR CONSUMER MEMBERS

In 2011 NRECA, as part of the Cooperative Research Network's Smart Grid Demonstration Project, conducted public opinion research to test effective messages for communicating with members about smart grid technology.

EFFICIENCY

- With remote meter reading and reconnection, we can save time and money (and reduce air pollution).
- With more detailed data about demand and usage we can distribute power more efficiently.

RELIABILITY

- New meters help us locate—and respond to—outages faster and more safely.
- New meters can help us improve power quality, reducing surges and blinking.
- New meters mean consistent billing periods.

AFFORDABILITY

- Operating more efficiently can help minimize cost increases.
- We can use the new data to help our members address high bills.

New technology to help us serve you better

NRECA
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NRECA
MARKET RESEARCH SERVICES

2011 Smart Meter Messaging Survey Results

April, 2011

NRECA
A Touchstone Energy® Cooperative

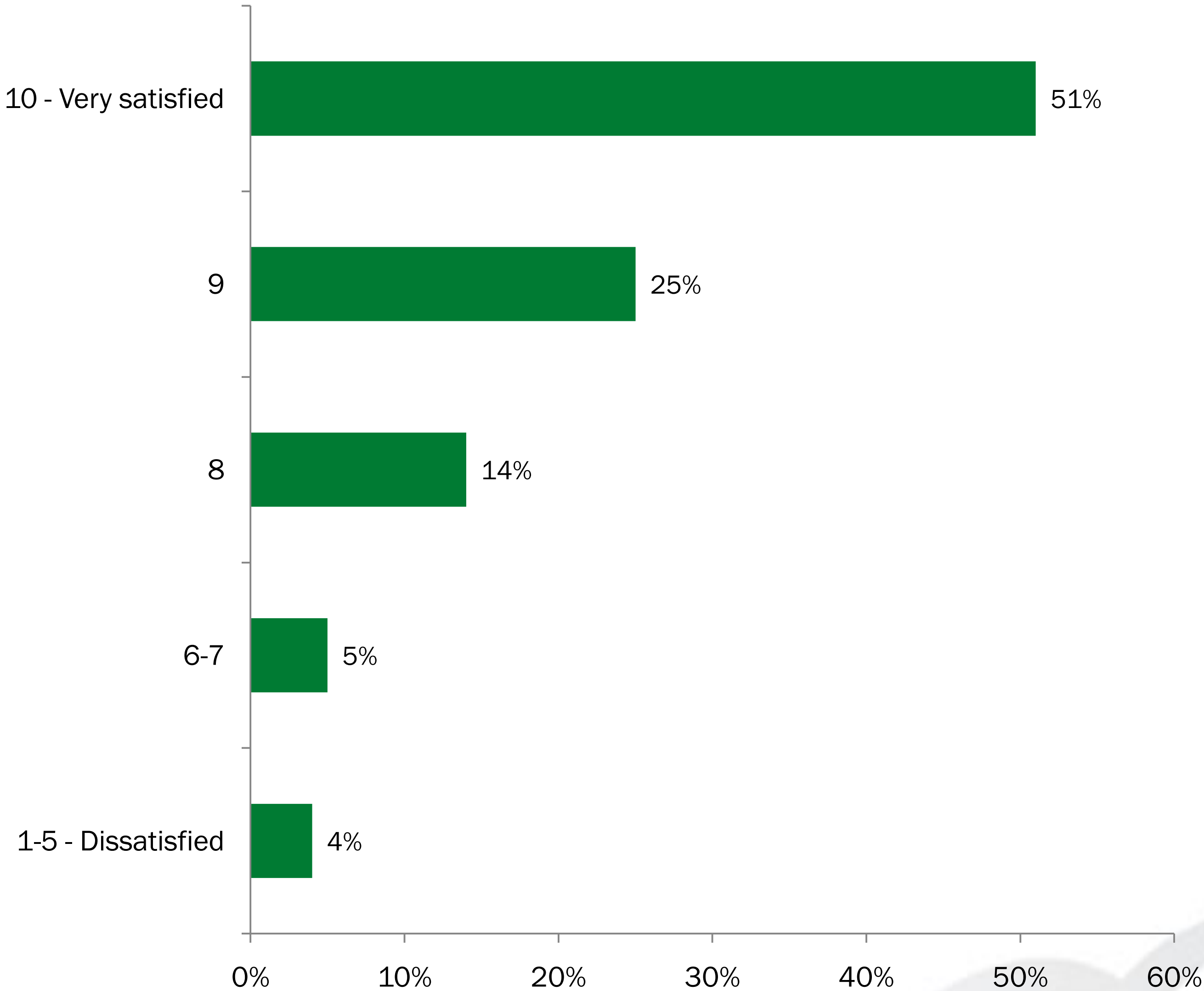
Study Methodology

- Five hundred interviews were completed April 7th – 13th -- 125 surveys with residential members of four co-ops:
  - ✓ Delaware County Electric Cooperative (New York)
  - ✓ Dixie Electric (Mississippi)
  - ✓ Federated REA (Minnesota)
  - ✓ Victoria Electric Cooperative (Texas)
- For two of the co-ops where connect date information was available, sample was drawn proportionate to tenure.
- This study was completed among the memberships of four different cooperatives, three of which are planning to install smart meters in the next 12 months and a fourth, Delaware County Electric, has had AMR in place for several years.
- Average interview length was 19 minutes.

Cooperative Performance Ratings

Overall Satisfaction With Electric Co-op

Mean = 9.03



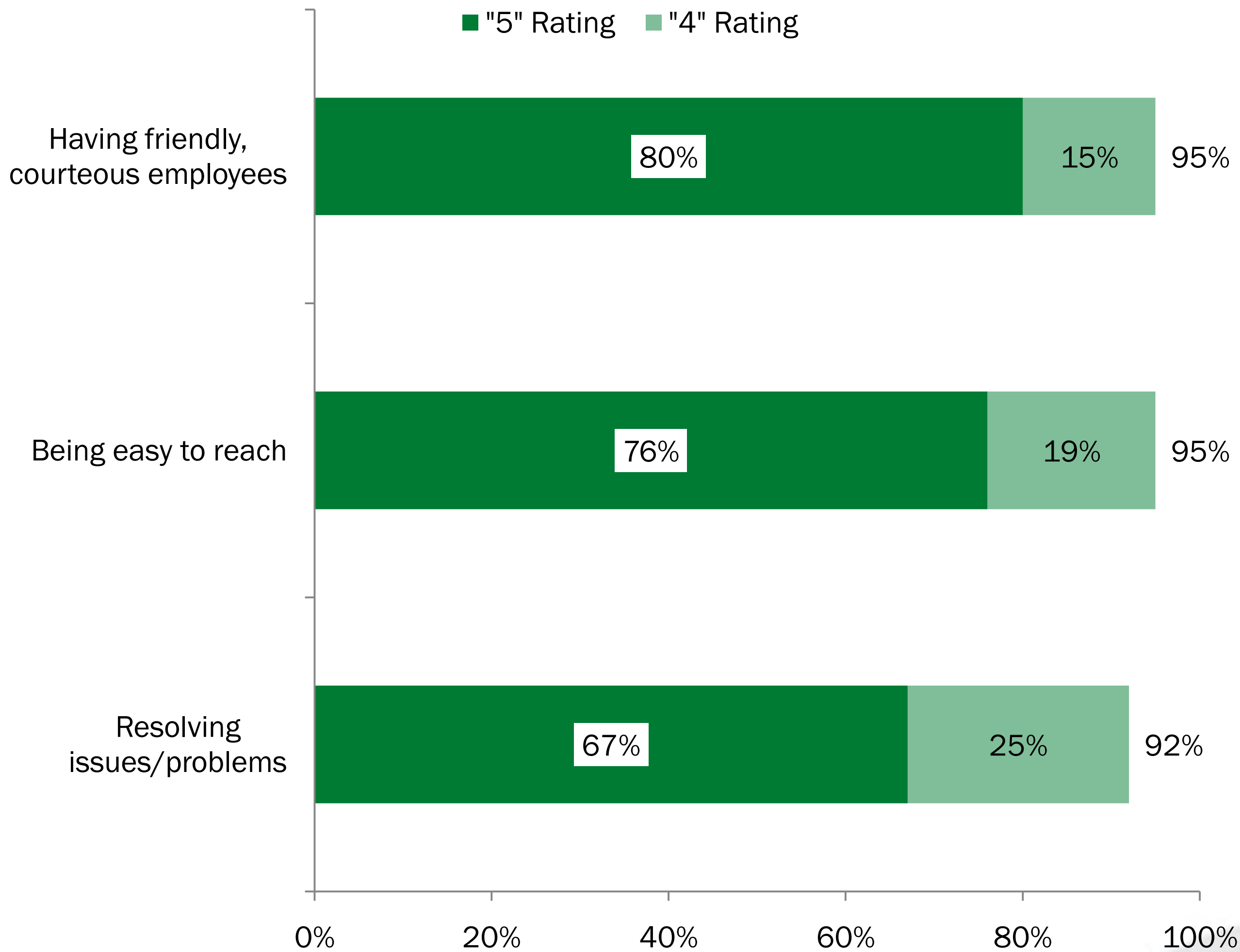
Using a 10-point scale where 1 is “very dissatisfied” and 10 is “very satisfied,” how satisfied overall would you say you are with your electric co-op?

- Overall, respondents express a strong level of satisfaction with their electric cooperative, with three-quarters indicating they are satisfied (25%) or very satisfied (51%). Satisfaction is high for all four cooperatives, with mean ratings ranging from 8.56 to 9.30.

- As is typical in other residential studies, members who are older, longer-tenured, and those with a sense of member identity give much higher satisfaction ratings than do their counterparts.

Member Service Performance Ratings

1-5 Scale: 1 = Very Poor; 5 = Excellent
Top 2 Box – "4" and "5" Graphed



On a 5-point scale where 1 means "very poor" and 5 means "excellent," how would you rate electric cooperative on the following?

- Respondents are very satisfied with the member service provided by their cooperative with more than nine in ten giving top two-box ratings.

Image, Communication and Trust Ratings

1-5 Scale: 1 = Very Poor; 5 = Excellent

Top 2 Box – "4" and "5" Graphed

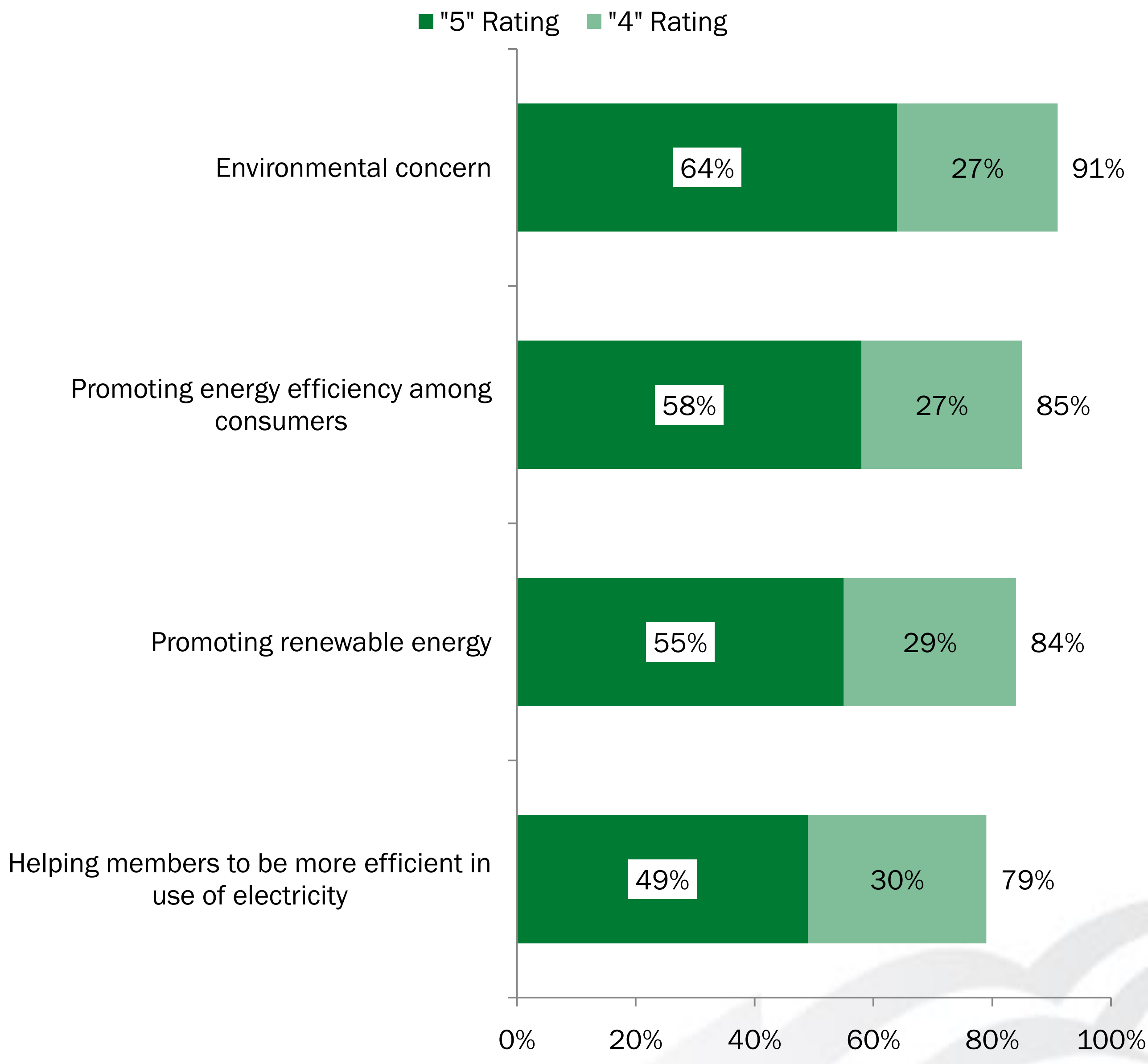
On a 5-point scale where 1 means "very poor" and 5 means "excellent," how would you rate electric cooperative on the following?

- High ratings are also given for the communication and trust attributes – especially for the co-op effectively managing the members' money and support of local communities.

Energy Efficiency/Renewable Energy Ratings

1-5 Scale: 1 = Very Poor; 5 = Excellent

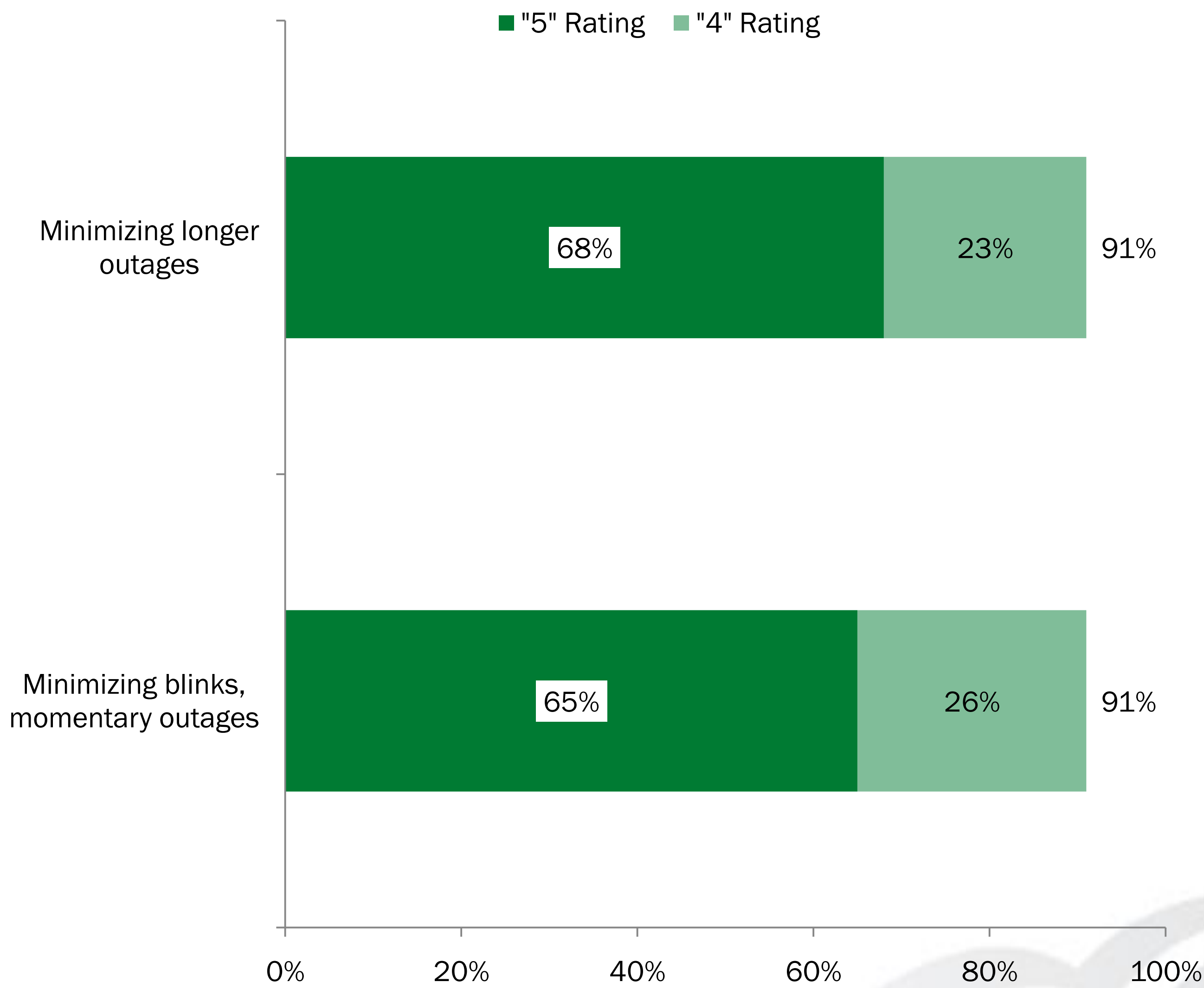
Top 2 Box – “4” and “5” Graphed



On a 5-point scale where 1 means “very poor” and 5 means “excellent,” how would you rate electric cooperative on the following?

Electric Service Performance Ratings

1-5 Scale: 1 = Very Poor; 5 = Excellent
Top 2 Box – "4" and "5" Graphed

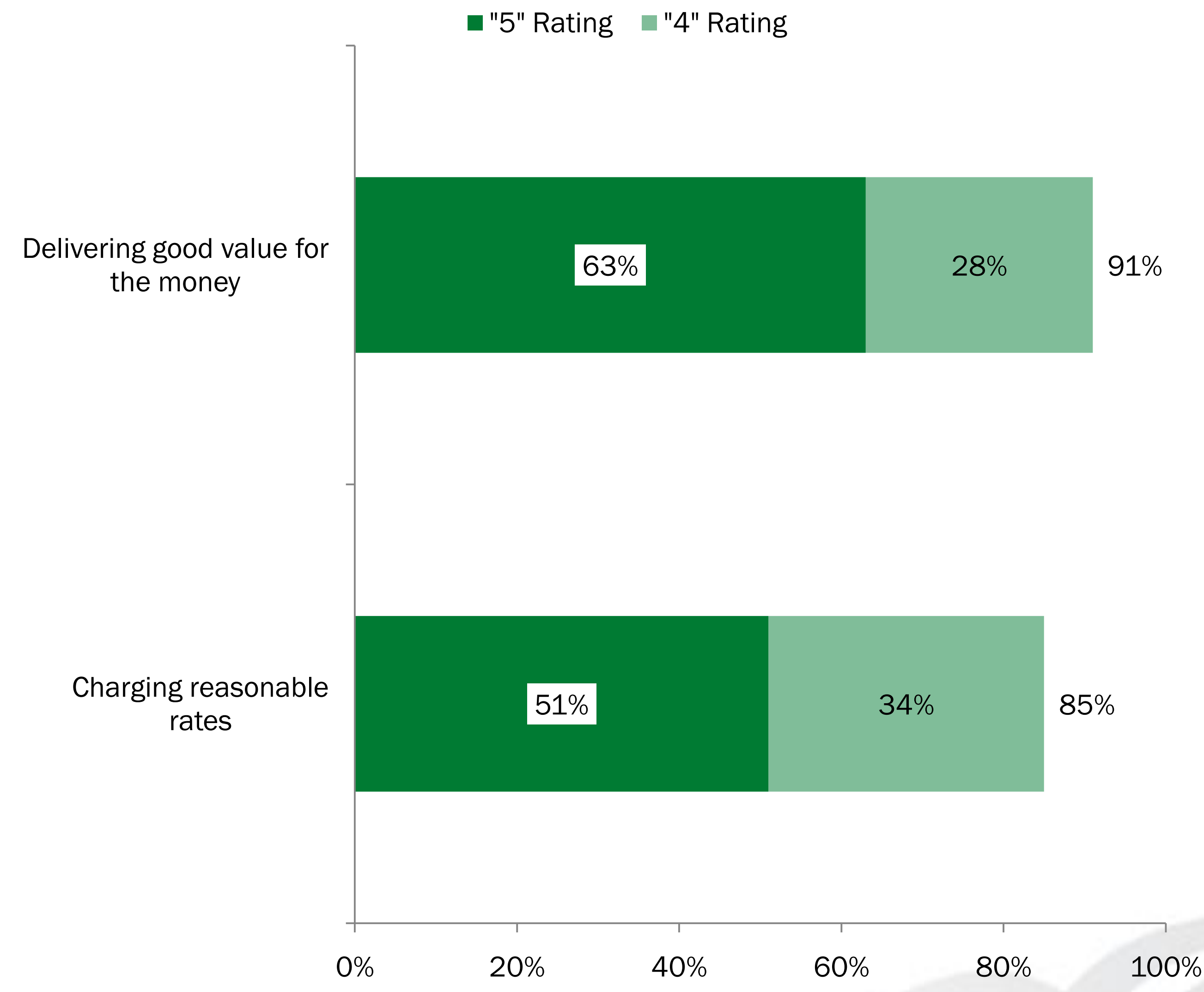


On a 5-point scale where 1 means "very poor" and 5 means "excellent," how would you rate electric cooperative on the following?

- The cooperatives receive high marks for both reliability and power quality.

Billing and Cost Ratings

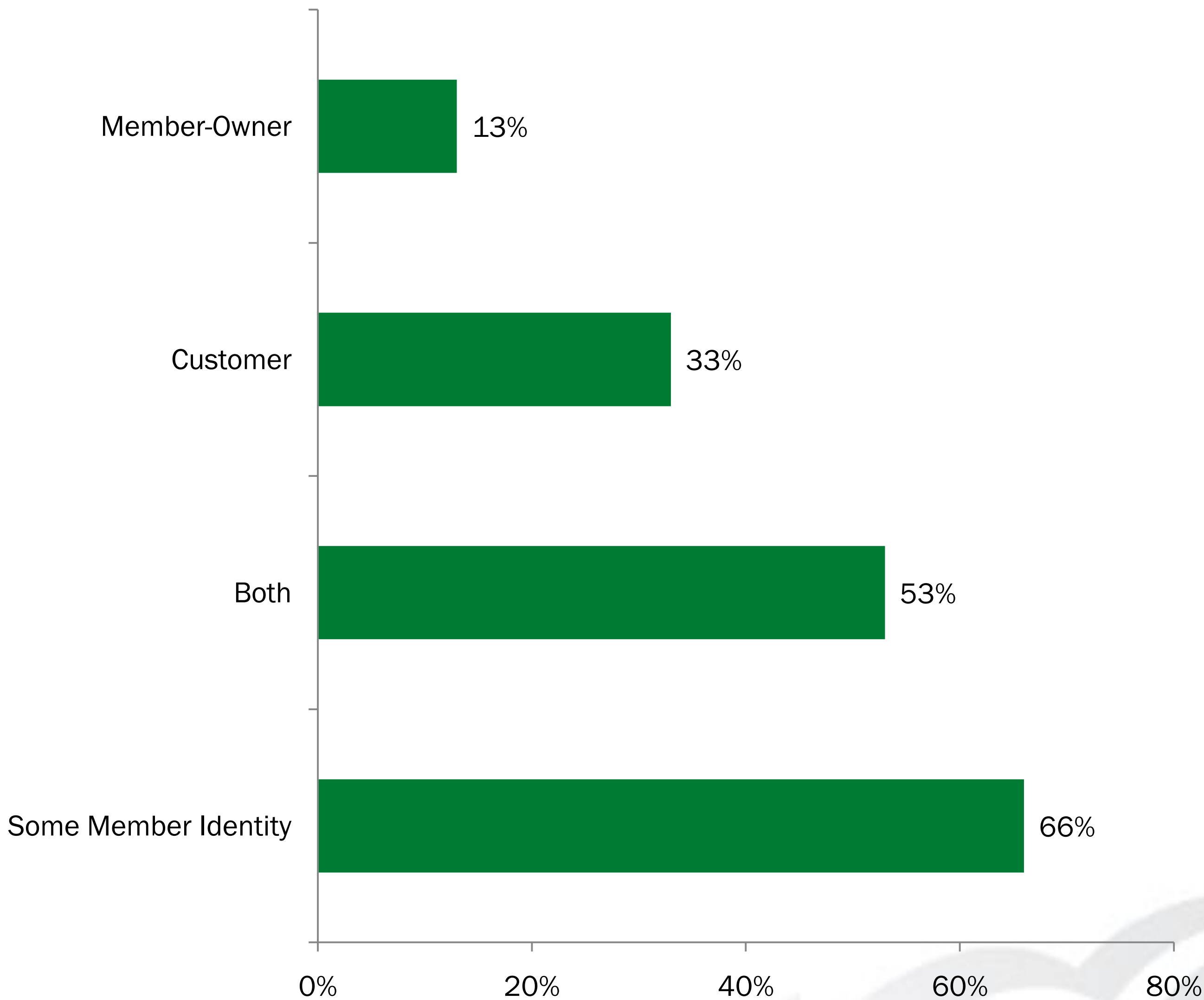
1-5 Scale: 1 = Very Poor; 5 = Excellent
Top 2 Box – “4” and “5” Graphed



On a 5-point scale where 1 means “very poor” and 5 means “excellent,” how would you rate electric cooperative on the following?

- A strong majority feel the co-op delivers good value and charges reasonable rates.

View Self as Member-Owner or Customer of Electric Cooperative



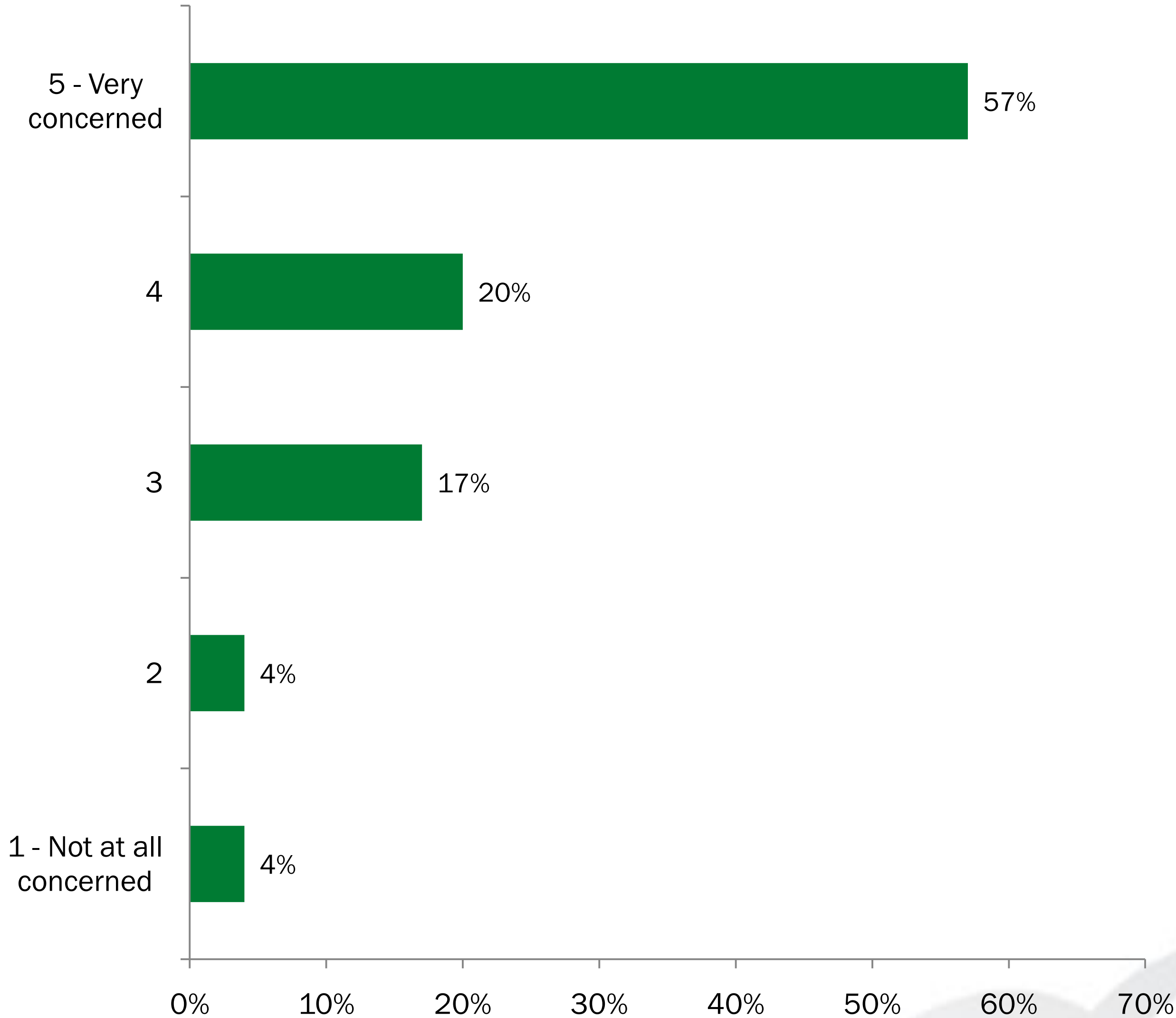
Do you view yourself as a member-owner or as a customer of your electric co-op, or both?

- Member identity is high with two-thirds having some member identity.
- While there are no significant differences based on age or tenure, those with member identity are much more likely than "customers" to have lower monthly electric bills.

Energy Situation

Level of Concern About Energy Situation

Mean = 4.22



How concerned are you about the energy situation? Please use a 1 to 5 scale where 1 is "not at all concerned" and 5 is "very concerned."

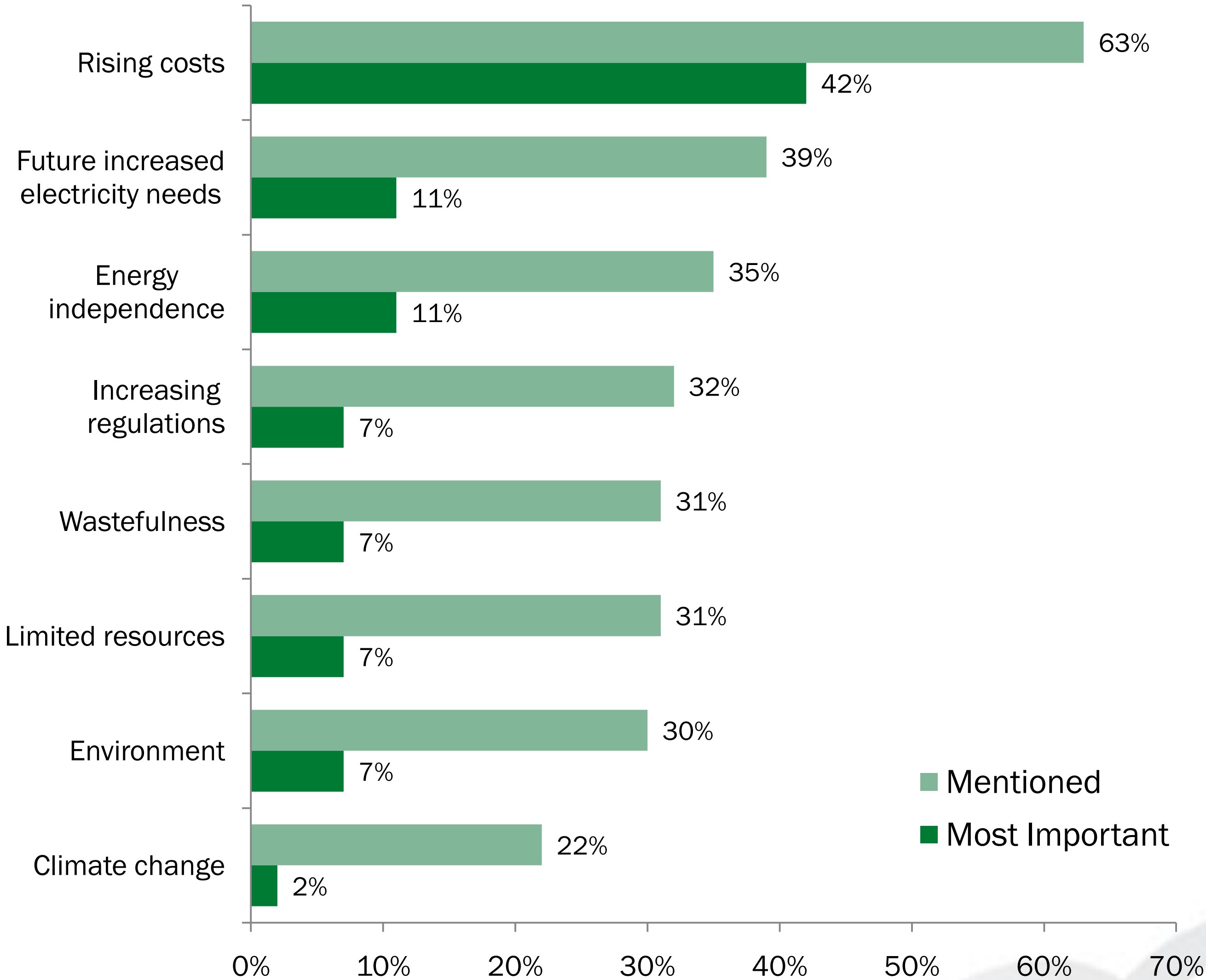
- Fully 77% are concerned or very concerned about the current energy situation. Fewer than one in ten are not concerned (giving "1" or "2" ratings).

- Those who are more concerned about the energy situation also report that their monthly electric bill has a big impact on their family budget, minimizing the amount of electricity used in their household is important, and they actively work to keep electricity bills low.

- In addition, older members (45 or older) and less affluent members are more concerned than are younger or more affluent members.

If Concerned About Energy Situation, What Is Driving Concern

Asked of Those Giving a "3" or Higher Rating, n = 459



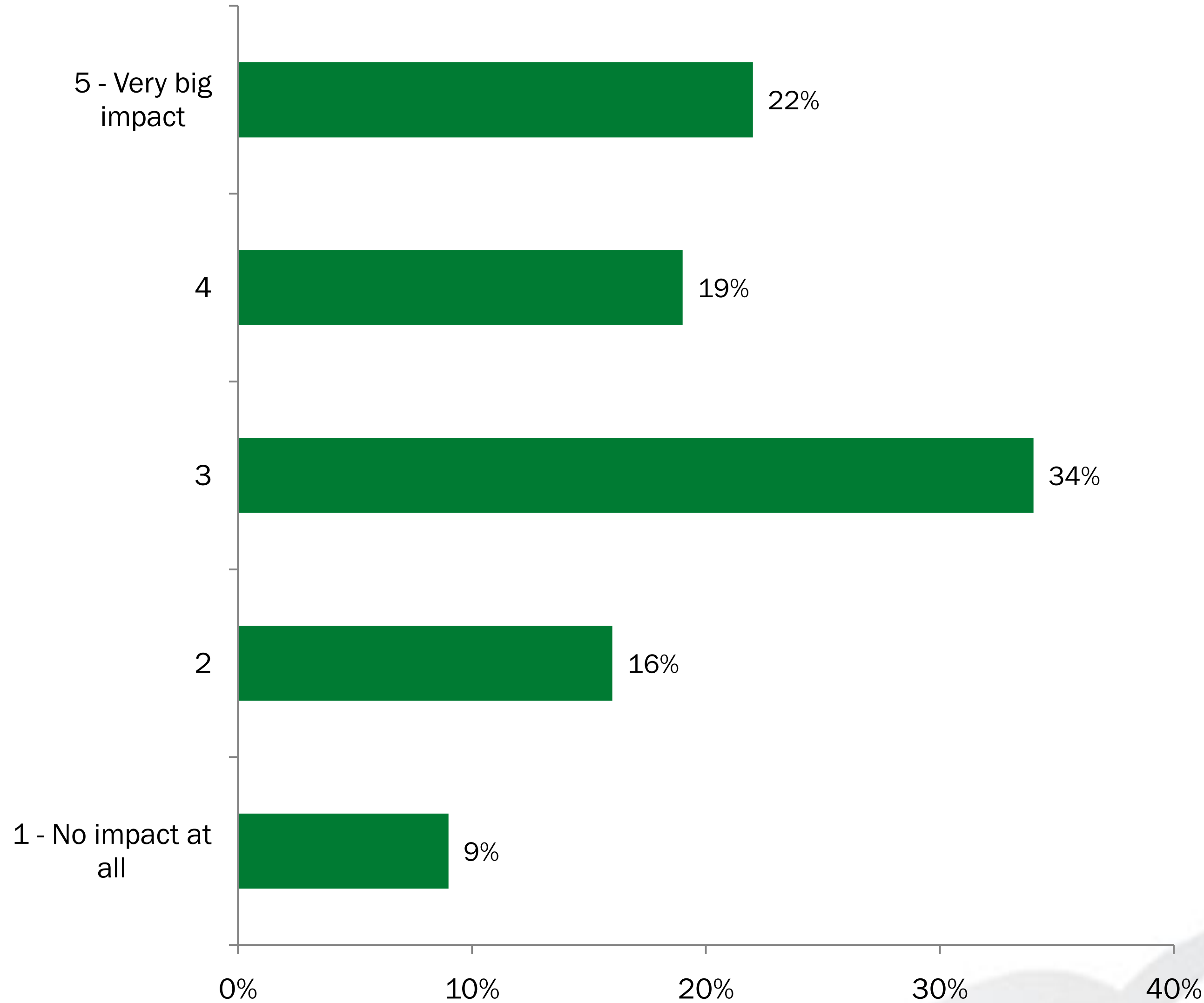
Which of the following is driving this level of concern? (If more than one selected) Which one is the most important?

- Respondents are almost four times more likely to indicate rising costs as the most important key driver of their concern than they are to identify future energy demand or energy independence.

- Among those concerned about the energy situation, the most frequently mentioned issues driving their concern are rising costs, future increase in the demand for electricity, and energy independence.

Impact of Monthly Electric Bill on Family Budget

Mean = 3.29

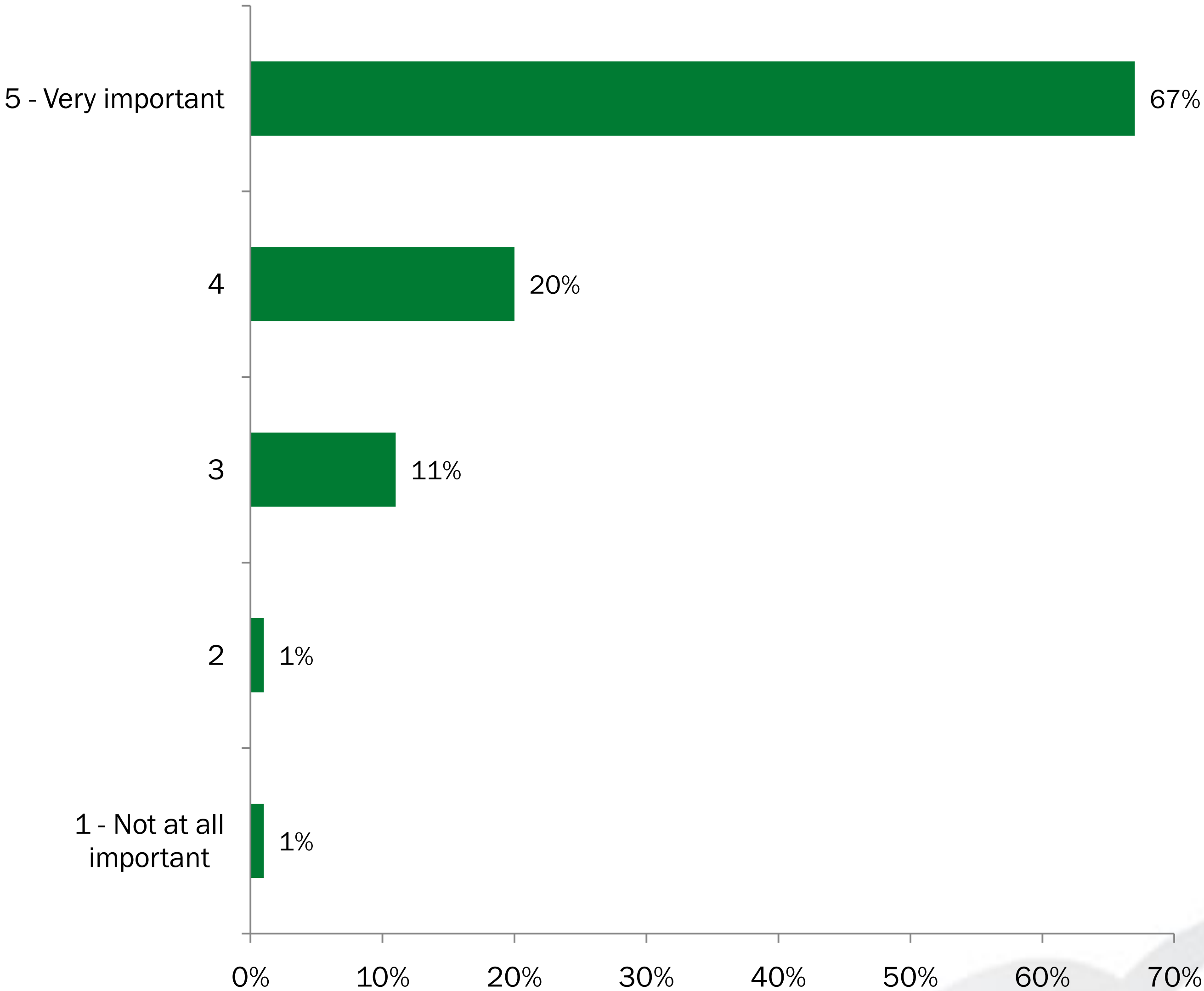


How big an impact does your monthly electric bill have on your family budget? Use a scale of 1 to 5 where 1 is no impact at all and 5 is a very big impact.

- Fifty-nine percent do not feel their electric bill has a big impact on their family budget. As would be expected, those with higher monthly electric bills and/or less affluent members are more likely to feel their electric bill has a big impact on their family budget.

Importance of Minimizing Electricity Use in Household

Mean = 4.51

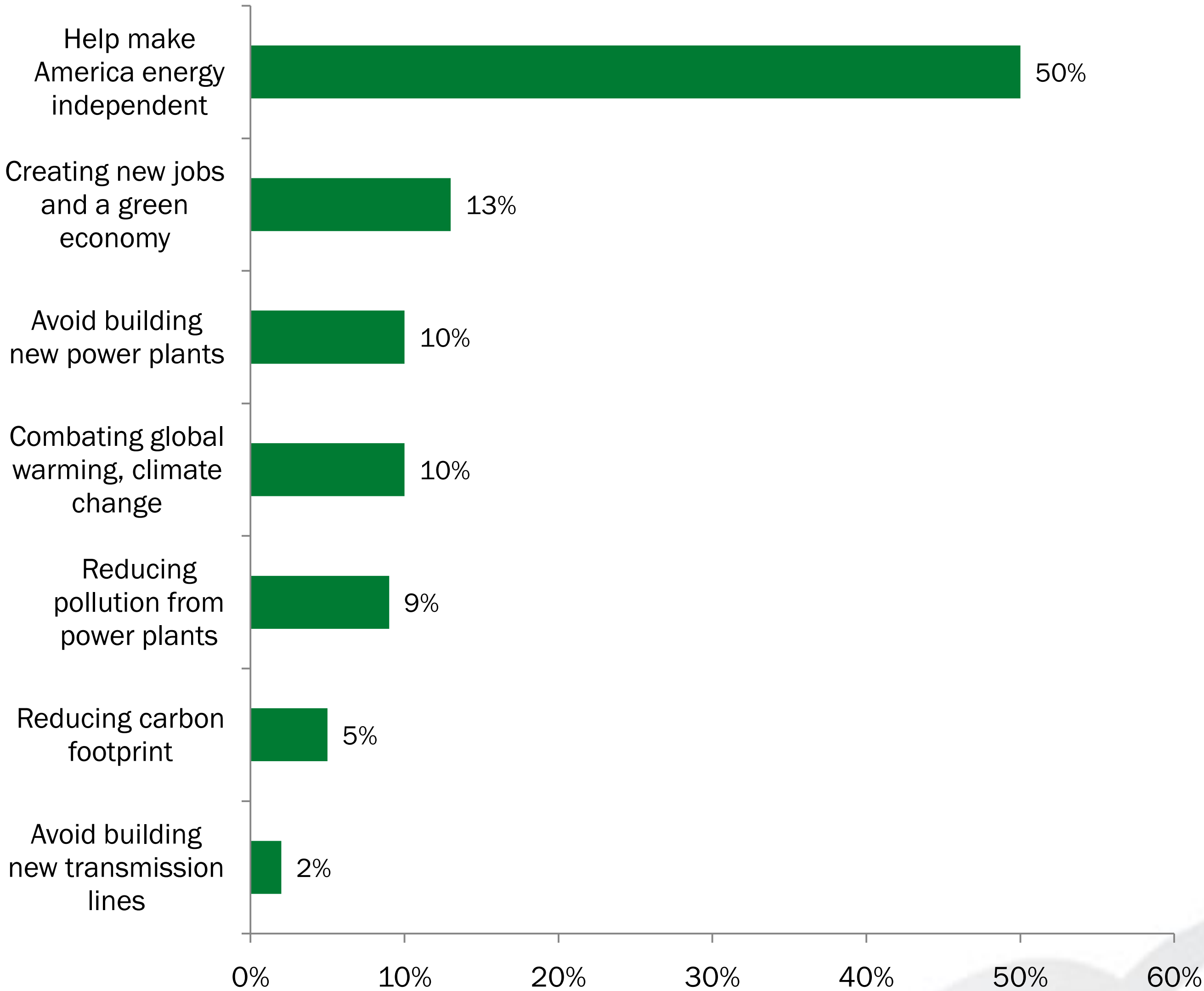


Looking at your own personal situation, how important is it to you to minimize the amount of electricity you use in your household?

- Almost nine in ten (87%) feel it important or very important to minimize electric use in their household.

- Older members, less affluent members, retired members, and females are more likely to feel it important to minimize household electric use.

Aside From Saving Money, Most Important Reason to Save Energy

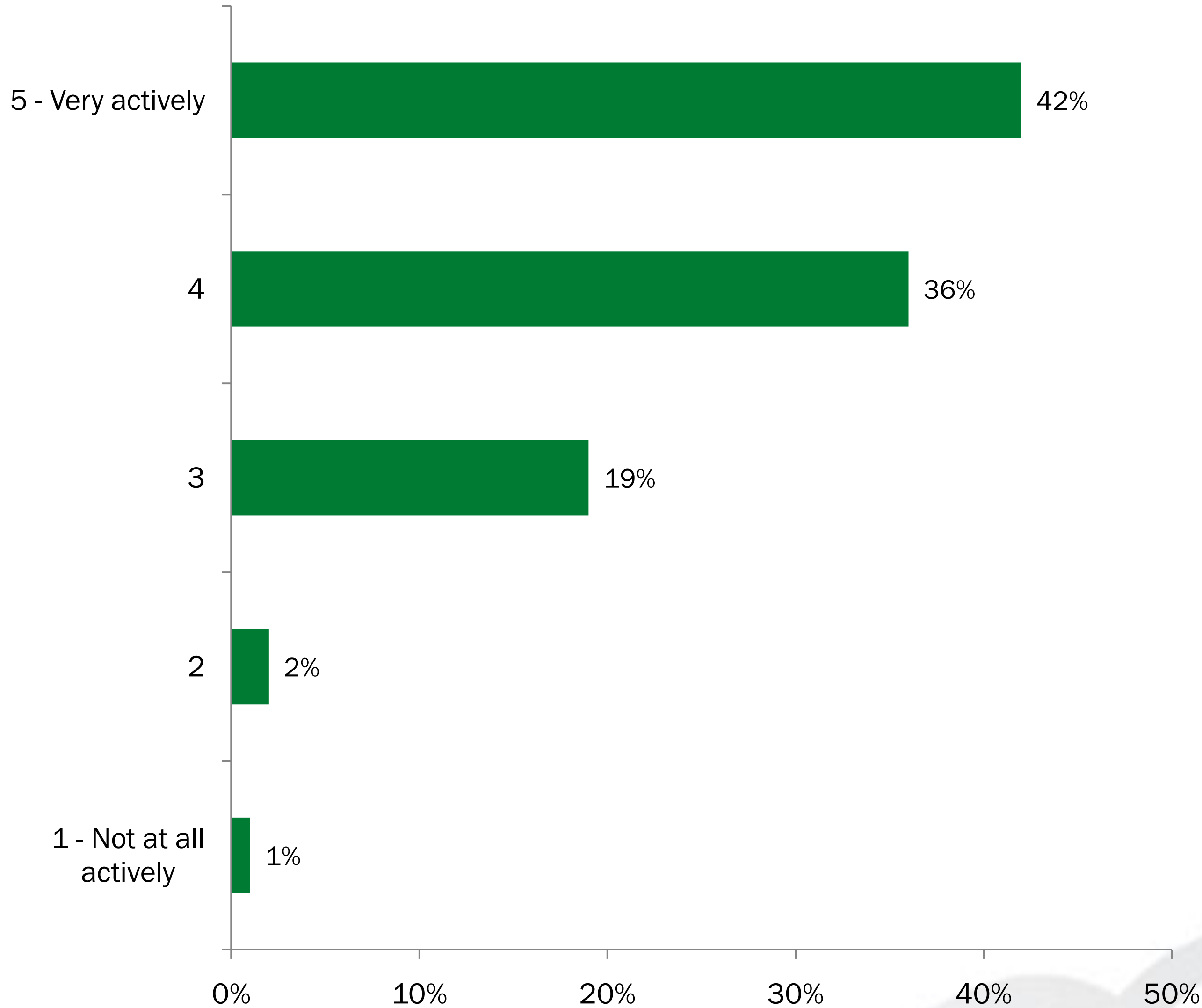


The main reason people are interested in saving energy is to save money, but there are other reasons as well. Which one is most important to you personally?

- Aside from monetary reasons, energy independence is by far the most frequently identified reason for saving energy.
- Younger members are much more likely to mention reducing pollution from power plants as an important reason than are older members.

How Actively Household Works to Keep Electricity Bill Low

Mean = 4.15



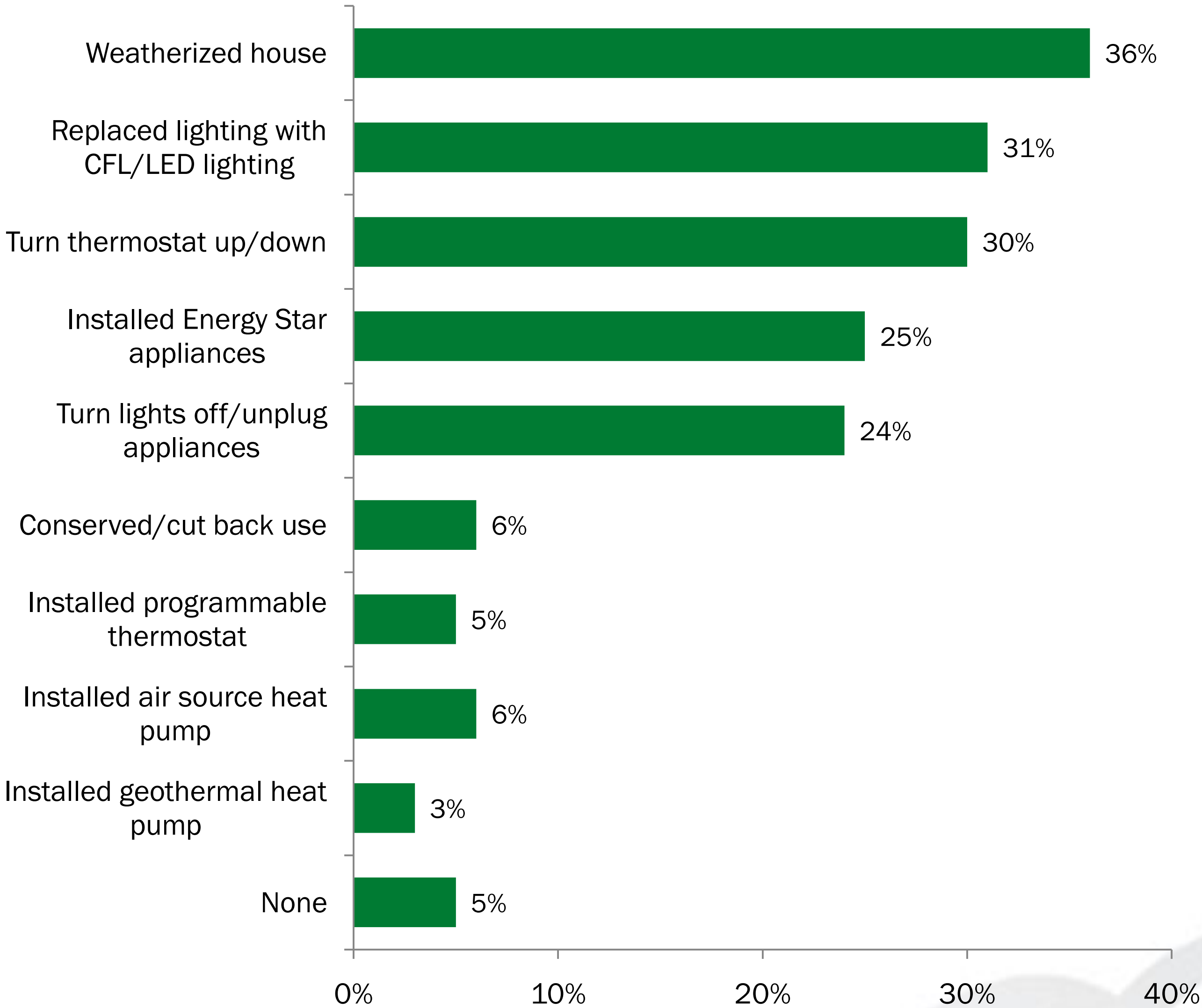
Generally speaking, how actively would you say your household works to keep your electricity bill low?

- More than three-quarters report working hard to keep their household electricity bills low.

- Those working more actively to minimize their electric use, those whose electric bill has a bigger impact on their budget, those paying lower monthly electric bills, older members, less affluent members, retired members, those living alone or with one other person, and those expressing a higher level of concern about the energy situation are much more actively working to reduce their electric bill than are their counterparts.

Energy Efficiency Step(s) Have Taken

Asked of Those Giving "3" Rating or Higher, n = 480



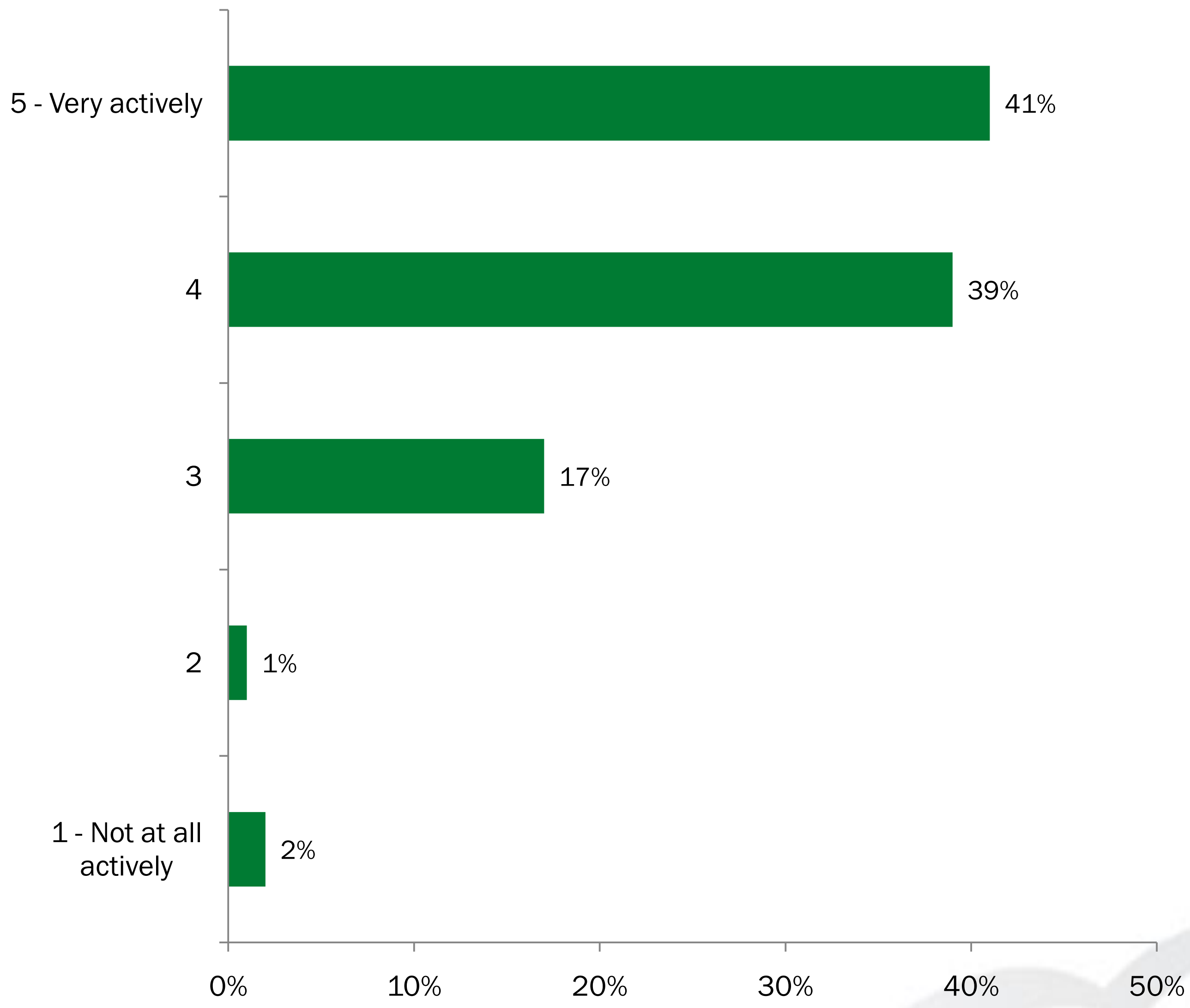
What type(s) of energy efficiency steps have you taken?

- Almost all (95%) have taken at least one energy efficiency measure in their home, with weatherizing, installing CFL/LED lighting, and adjusting thermostats most frequently mentioned.

- Affluent members are much more likely to have installed a programmable thermostat. Younger members are more likely to have purchased Energy Star appliances and/or adjusted their thermostat.

How Actively Co-op is Working to Address Energy Efficiency and Conservation

Mean = 4.14



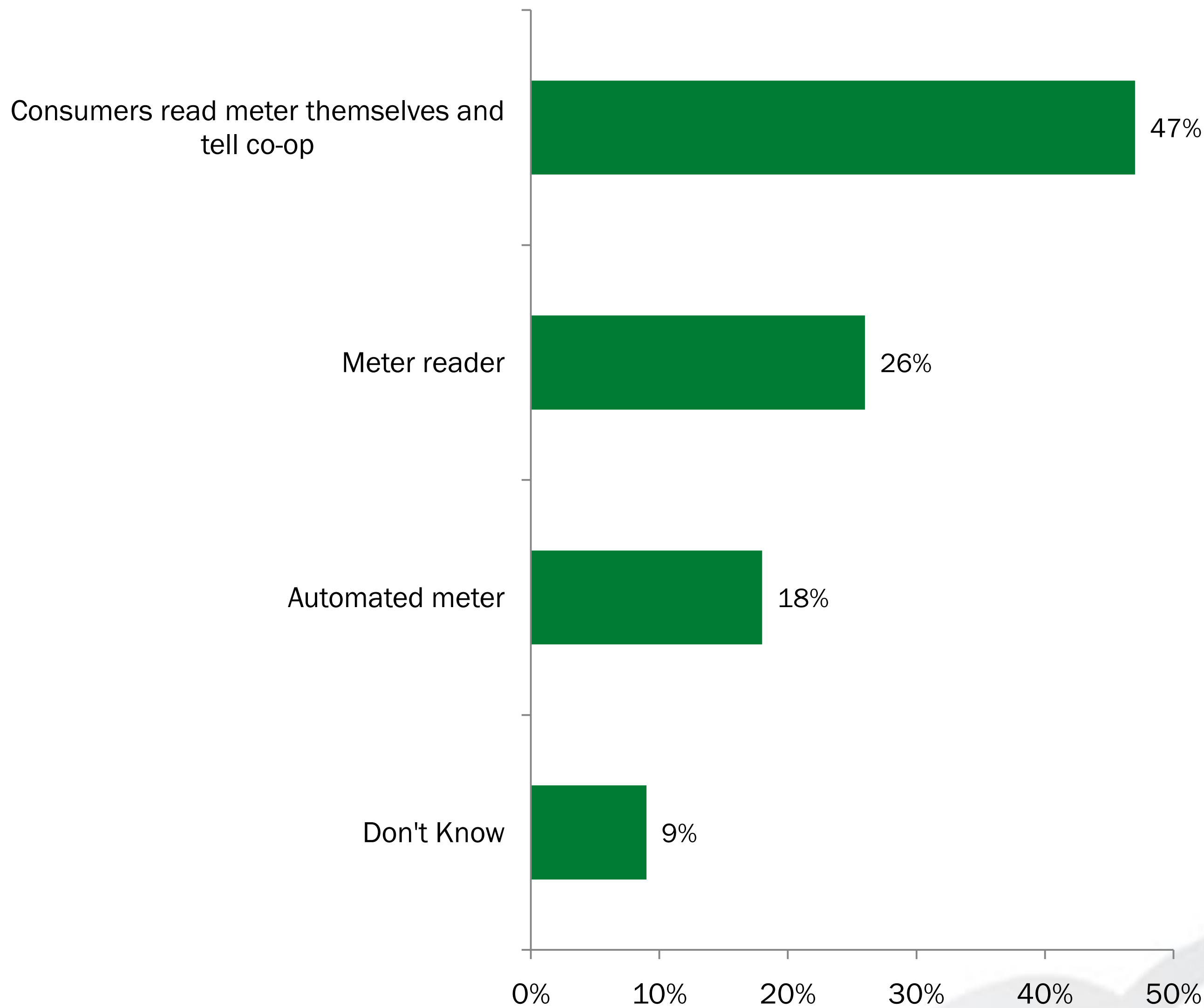
How actively do you feel your cooperative is working to address energy efficiency and conservation?

- Eighty percent feel their co-op is actively or very actively addressing energy efficiency and conservation.

- Those with member identity, those with lower electricity bills, older members, less affluent members, those in smaller households, and retired members give higher ratings for their co-op's conservation efforts than do their counterparts.

Perceptions of New Meters

Current Method Used To Read Electric Meters



Do you know how your electric company reads your meters?

- Almost half (47%) read their own meters, while one in four have a meter reader and one in five have an automated meter.

- Methods vary greatly by cooperative – one has automated meters, one relies primarily on meter readers, and ask their consumers to read their own meter.

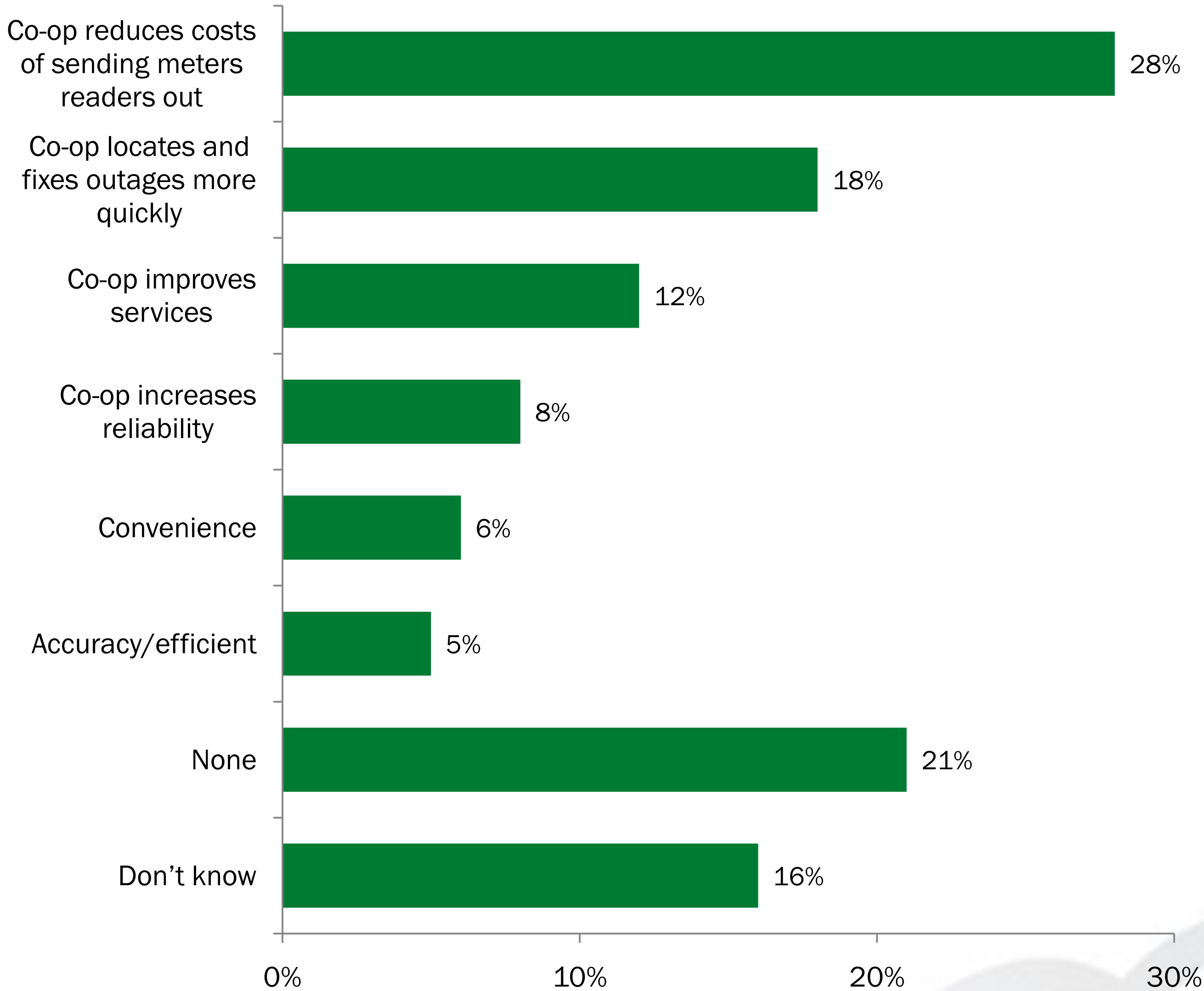
New Meter Explanation Read to Participants

Across the nation, electric utilities are using communication and automation technologies to improve service, increase reliability and help to control electricity costs. Installing new meters that can digitally transmit usage information back to the utility can help the utility locate outages faster and more precisely – sometimes before the consumer knows his power is out – and restore power more quickly. Also, because the meters can be read remotely, the utility will not need to send an employee out to each home to read the meter.

Respondents were then asked to identify what, if any, benefits they ascribed to the new meters.

Unaided Assessment of Benefits of New Meters

Multiple Responses Possible



What benefits, if any, do you see with changing to these new meters?

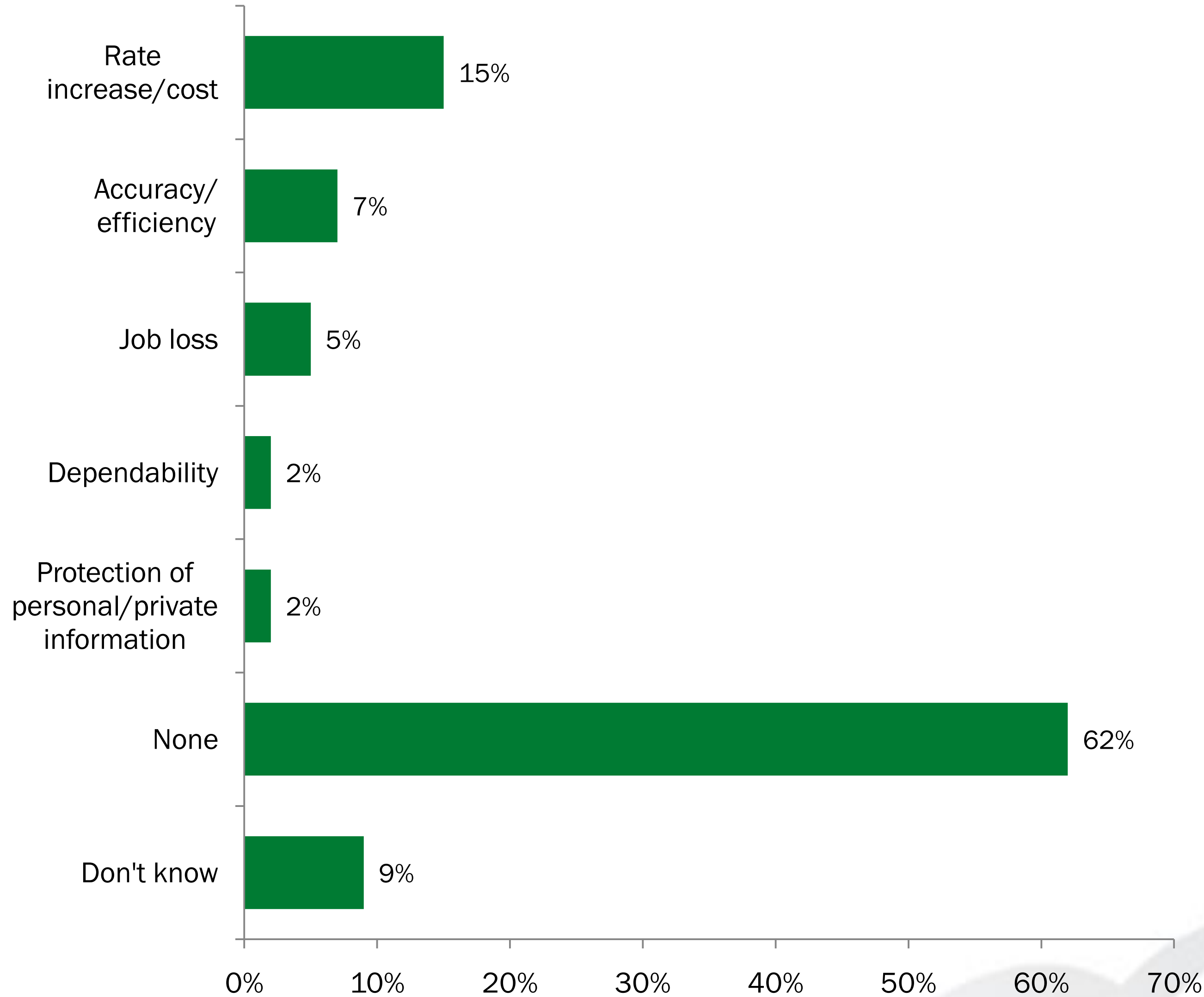
- Benefits of the new meters identified most frequently on an unaided basis are the co-op reducing costs by not sending out meter readers (28%) and the meters enabling the co-op to locate and fix power outages more quickly (18%). Still, 37% did not volunteer a benefit of the new meters when asked.

- Younger members are much more likely to have identified a benefit than older members.

- As would be expected, those who mention having concerns about the new meters are the least likely to mention a benefit of having them.

Concerns Expressed About Change to New Meters

Multiple Responses Possible

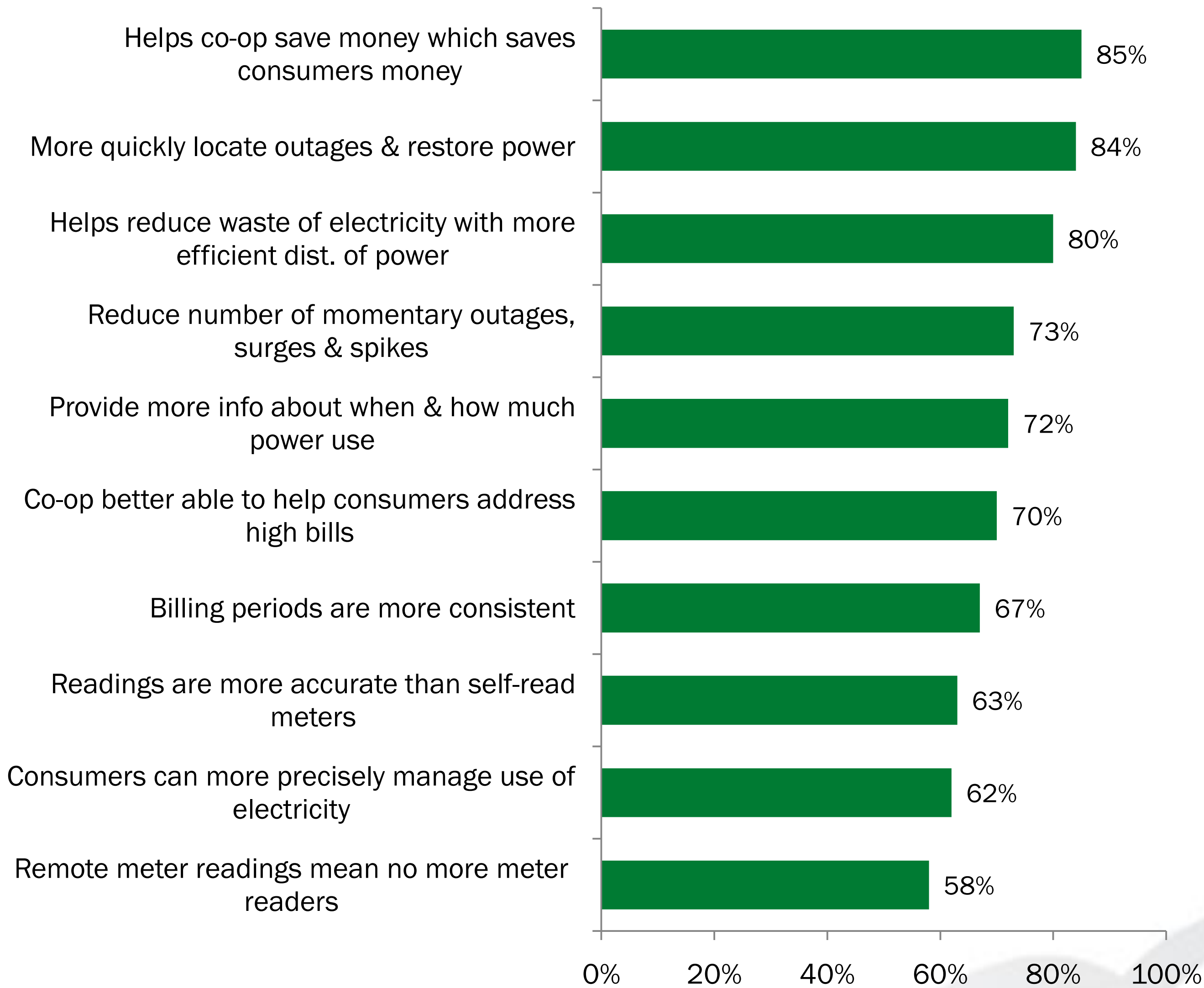


What concerns, if any, do you have about changing to new meters?

- Seventy-one percent did not mention any concerns about the new meters.
- Fifteen percent mentioned the cost/rate increase – twice as many as any other concern.
- Younger members, those working full- or part-time, those paying lower electric bills, newer members, and those living in larger households are much more likely to have mentioned a concern.

Consumer Assessment of New Meter Benefits

"4" and "5" Ratings Graphed



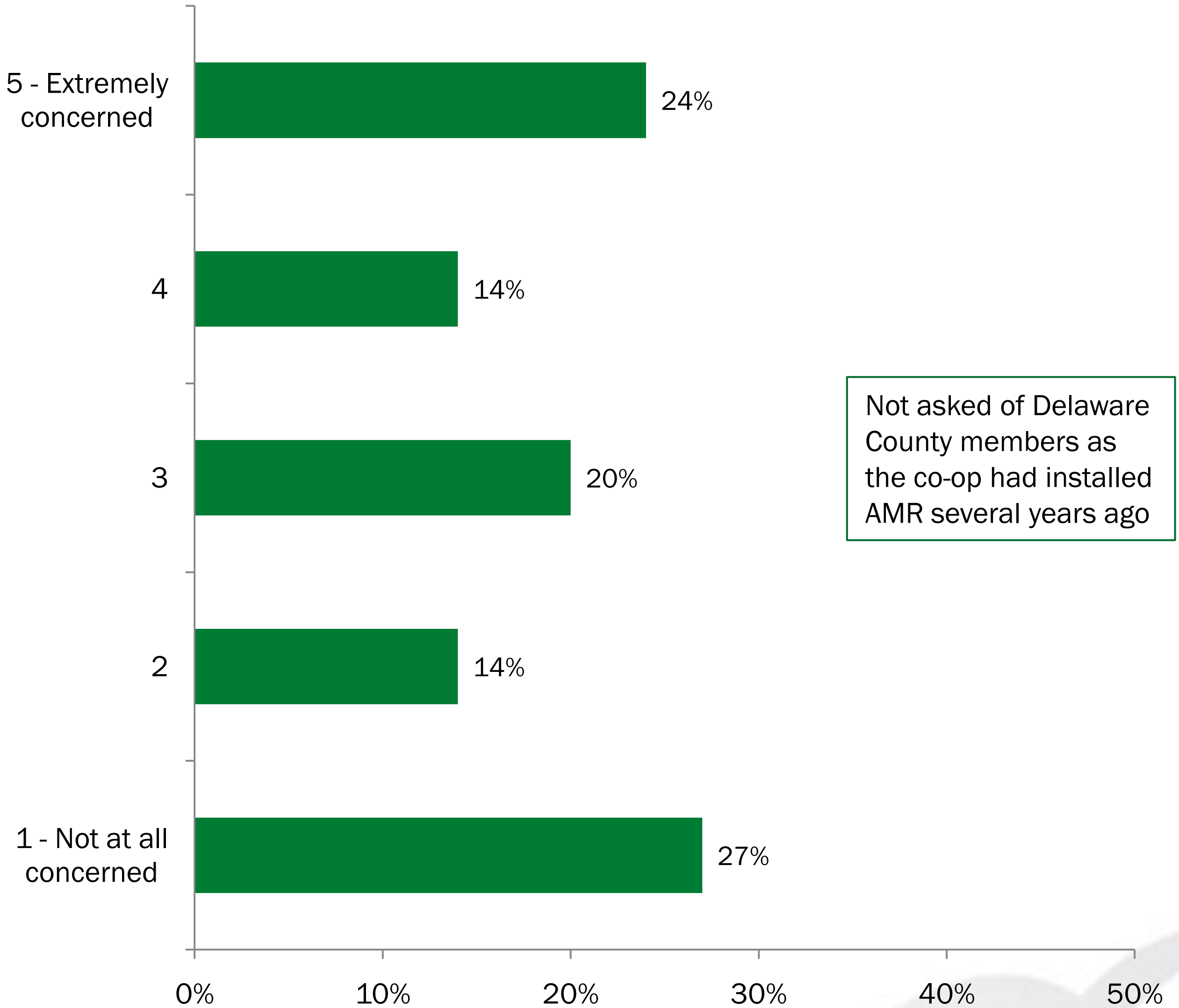
How important is the following statement to you using a five-point scale where one is "not at all important" and five is "very important"?

- The primary benefits identified by consumers are helping the co-op and the consumers save money, more quickly locating outages, and reducing waste of electricity. Secondary benefits are improved power quality, providing more information on energy use, helping members address their high bills, and having more consistent billing periods.

- Generally, females, less affluent members, and retired members place higher importance on the new meter benefits than do males, those working, or more affluent members.

Level of Concern About Security of Use Data Transmitted from New Meter To Co-op

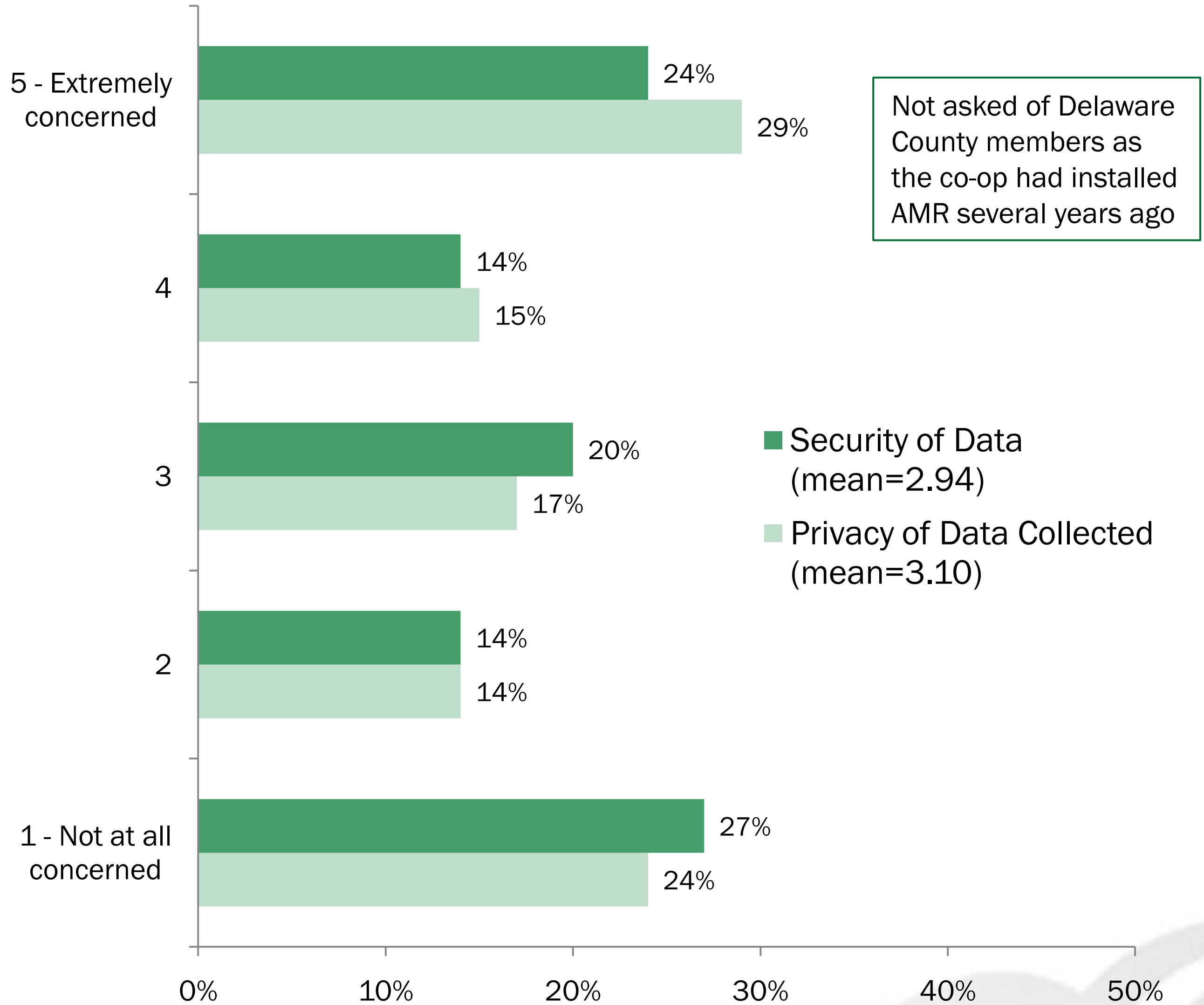
Mean = 2.94



New electric meter technologies can collect more detailed information about your electricity use patterns that could help you identify savings on your bill. How concerned would you say you are about the privacy of the data collected and stored by the co-op?

- Thirty-eight percent are concerned or very concerned about the security of their data being transmitted from the new meter to their cooperative while 41% have little or no concern.
- Those dissatisfied with their co-op and those concerned about the energy situation are much more concerned than are their counterparts about the security of their data.
- There are no significant differences based on age, income, or gender.

Level of Concern About Security of Electric Use Data and Privacy Data Collected/Stored by Co-op



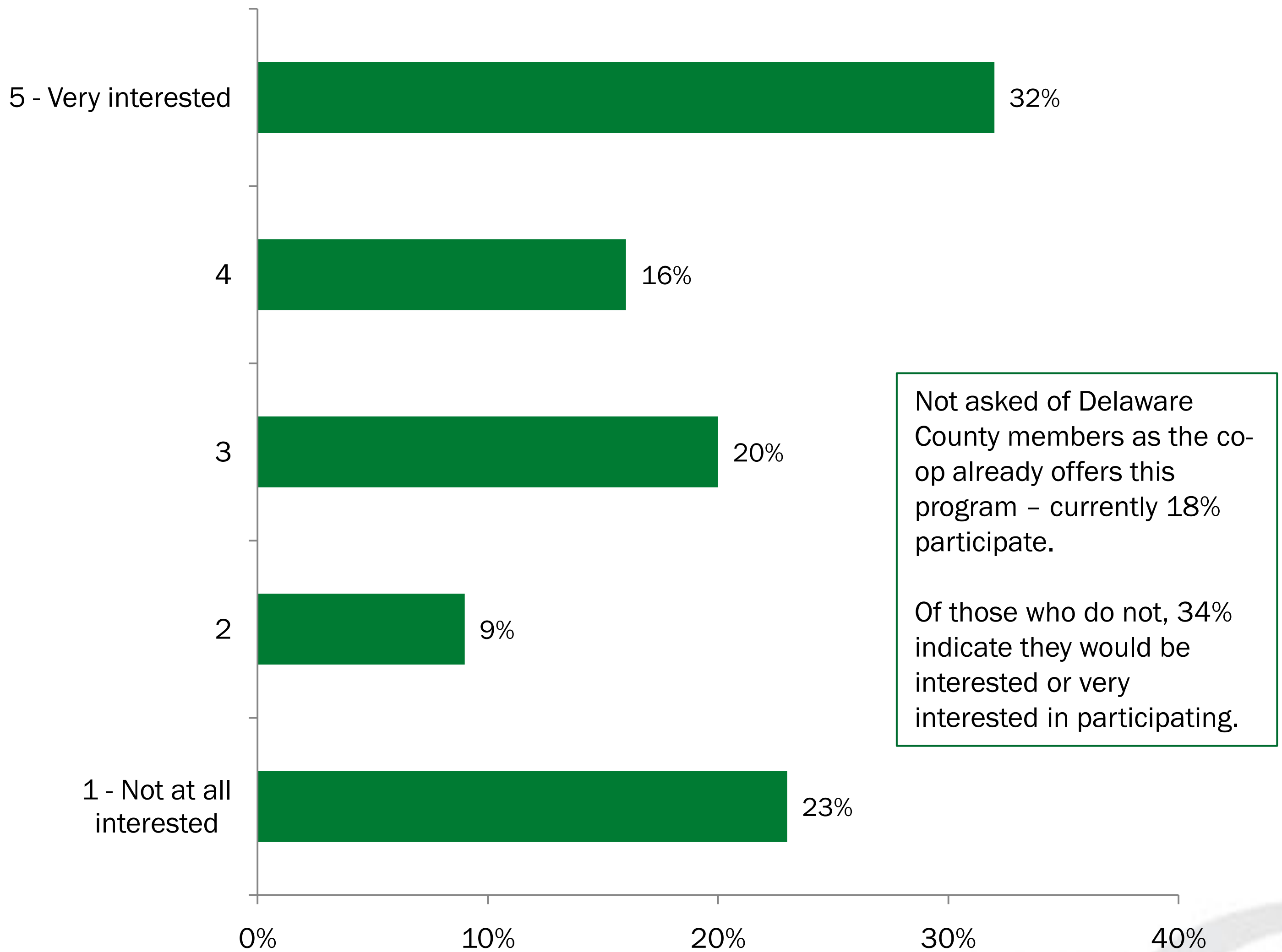
New electric meter technologies digitally transmit data from your home to the electric utility. Some people are concerned that the new technologies might put their privacy at risk. Your co-op believes strongly in protecting information about your electricity usage. How concerned would you say you are about the security of your electricity use data as it is transmitted from the new meter to the co-op? **New electric meter technologies can collect more detailed information about your electricity use patterns that could help you identify savings on your bill. How concerned would you say you are about the privacy of the data collected and stored by the co-op?**

- Fully 44% are concerned about the privacy of the data collected and stored by the co-op, while 38% express little or no concern.

- Concern is highest among less affluent members, those paying higher electric bills, those with a higher level of concern about the energy situation, and those whose electric bills have the biggest impact on their budget.

Level of Interest in Demand Response Program

Mean = 3.24

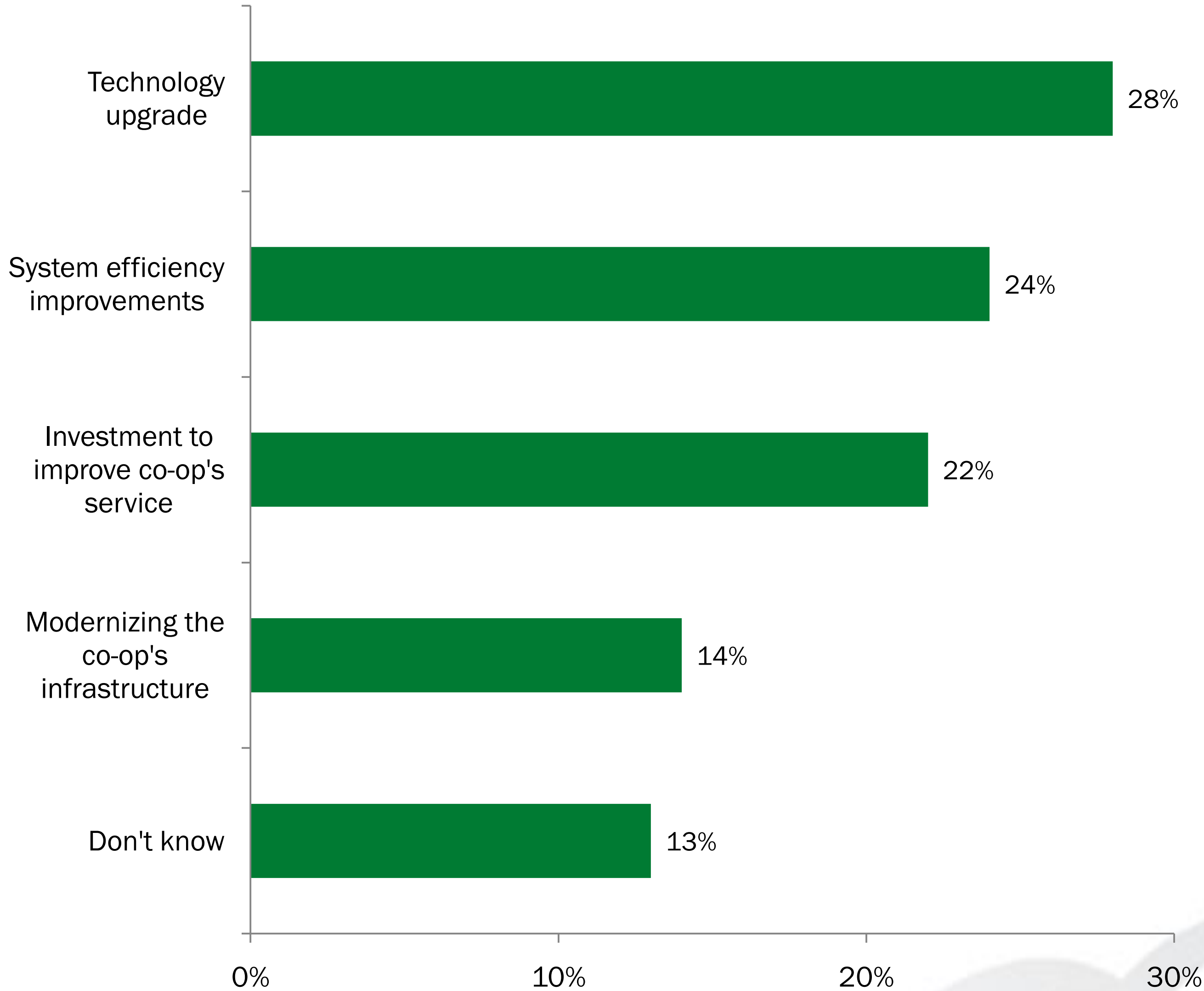


Many electric cooperatives are saving their consumer members money by using new technology to control their electric load during peak periods when the costs of electricity are highest for the utility and its consumers. Power costs during a peak period can be as much as ten times higher than off-peak times. These programs are voluntary, and consumers usually receive an incentive in exchange for allowing the co-op to shut off certain appliances for short periods when there is very high demand for power. If the co-op can reduce the demand for electricity during these periods, this usually leads to significant operational savings. How interested would you be in participating in a program like this?

- Almost half indicate they are interested or very interested in participating in a demand response program through their co-op. One-third indicate they are not interested or not at all interested.
- Interest is highest among those most concerned about the current energy situation.
- There are no differences based on the impact their bill has on their family budget.

Preferred Messages/Terms

Consumer Reactions to Different Process Descriptions

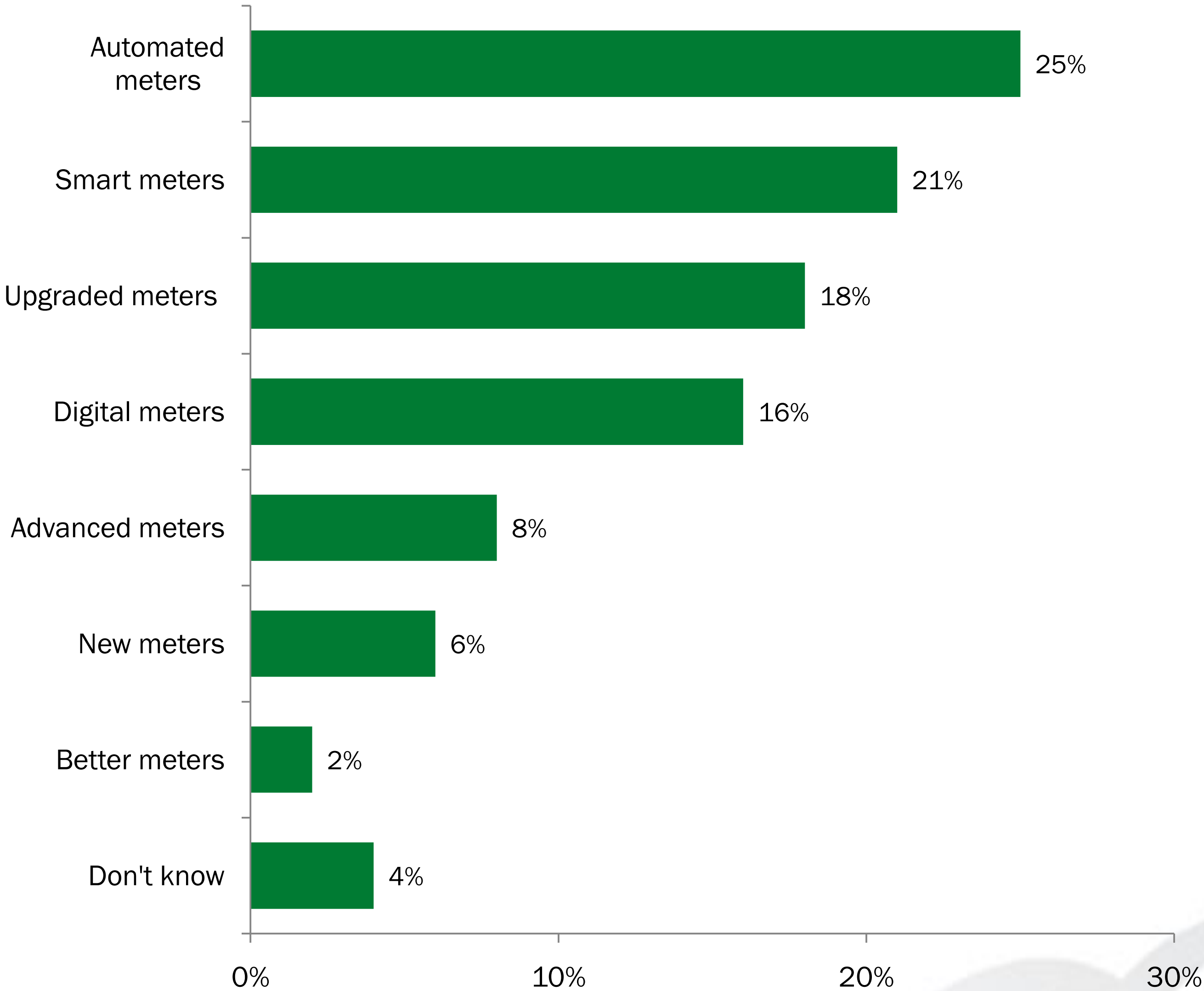


Which of the following would you think would be the best way to refer to the process of replacing these meters if the co-op was installing them?

- Respondents prefer “technology upgrade”, “system efficiency improvements”, or “investment to improve the co-op’s service” to describe the installation of the new meters. Only 14% mention “modernizing the co-op’s infrastructure”.

- Interestingly, there are no significant differences in preferences based on age, gender, income, or tenure.

Consumer Preference for Describing Meters



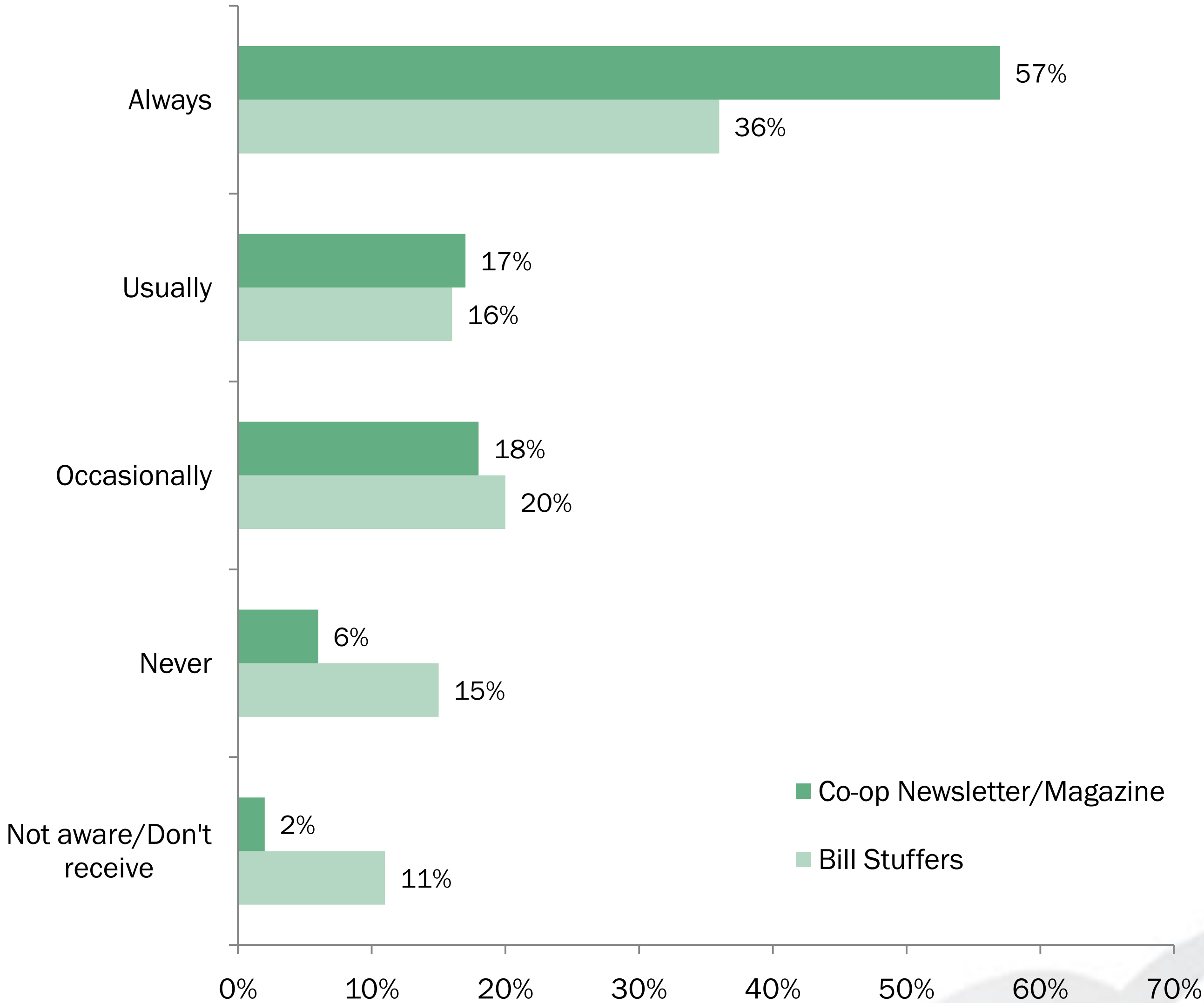
These meters have been called many different things. Which of the following do you think would be best when talking about these meters to the average consumer?

- Members like the term "automated meters" best, followed by "smart meters", "upgraded meters", or "digital meters". "Advanced meters", "new meters", and "better meters" are not as appealing as the other choices.

- "Smart meters" has more appeal among younger members than among older members.

Communications

Readership of Co-op Communications

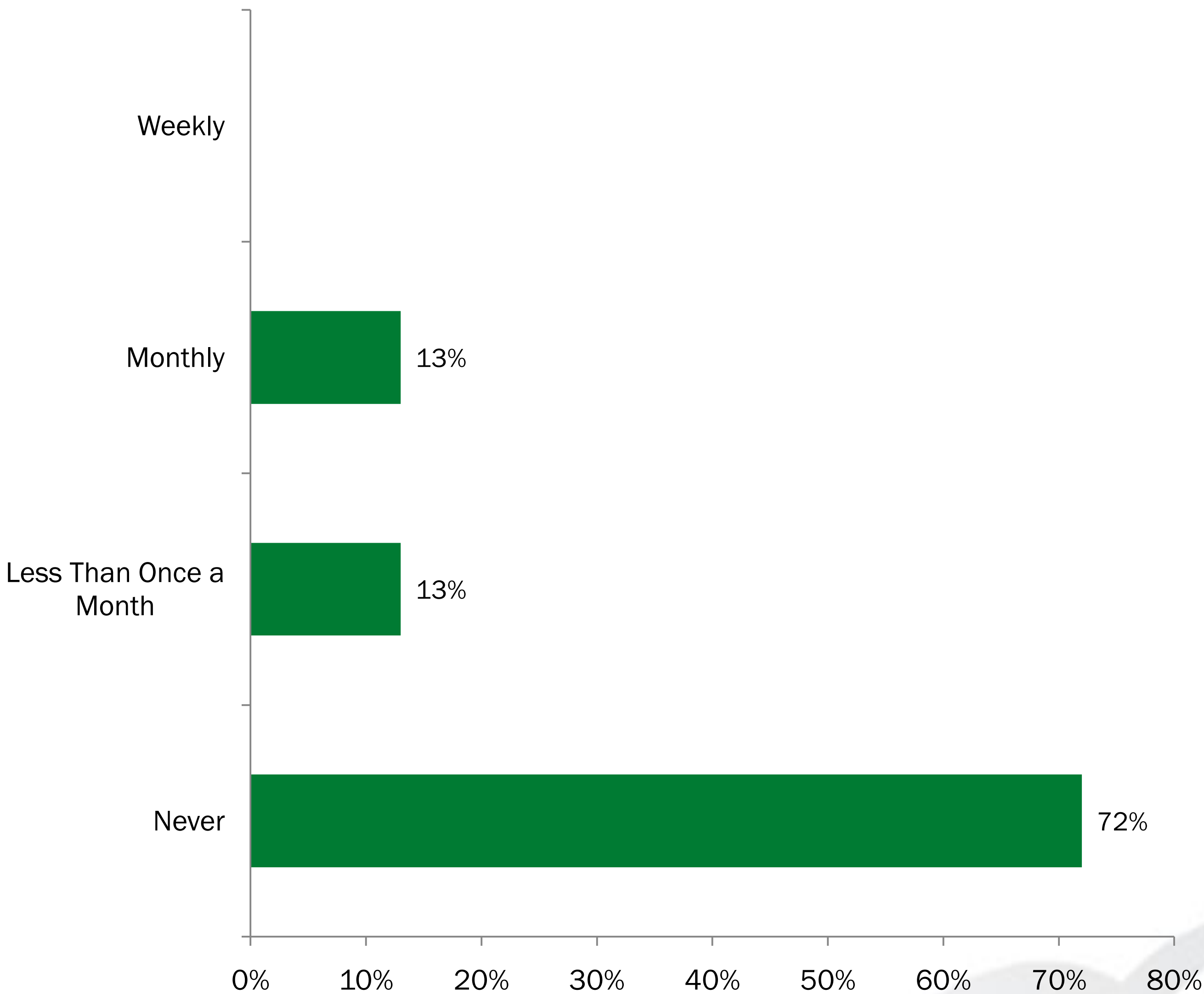


How often do you read the co-op newsletter/magazine? How often do you read stuffers that come with your monthly electric bill?

- Three-quarters indicate they usually or always read the cooperative newsletter or magazine. Half report they regularly read bill stuffers.

- Readership is higher among older members and those with lower monthly electric bills.

Frequency of Visiting Co-op Website

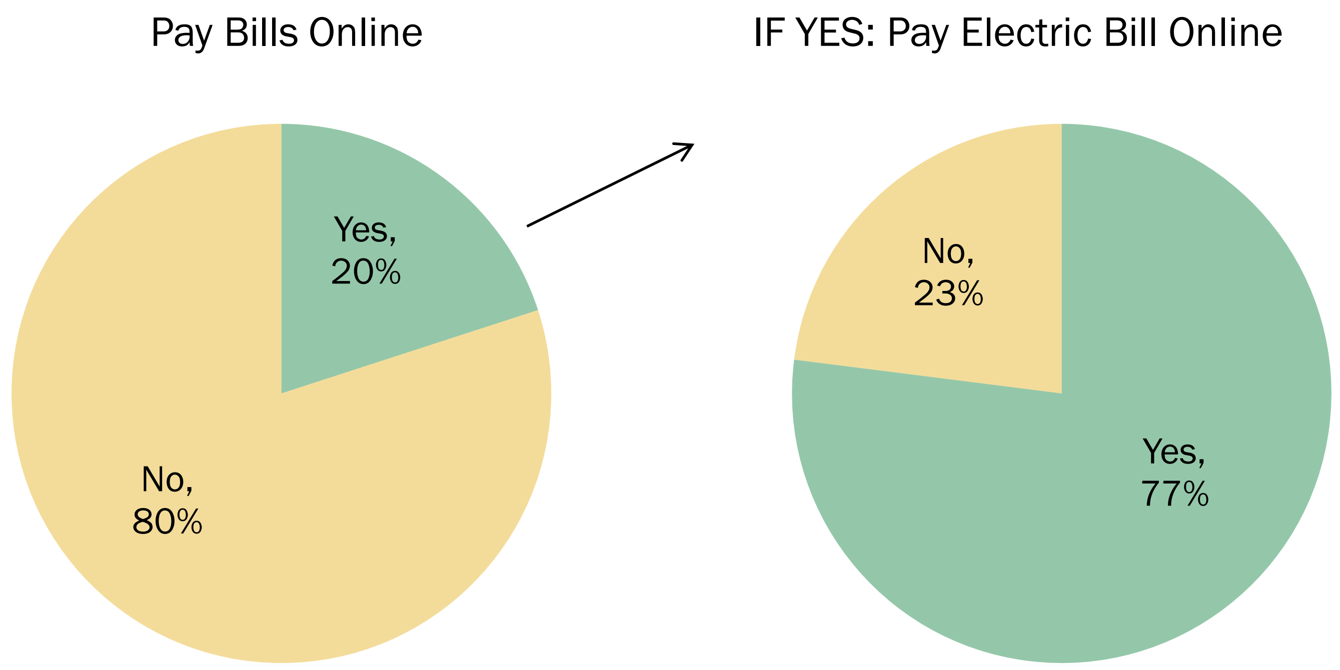


How frequently do you visit the co-op website?

- Just over one-quarter indicate they occasionally visit their cooperative's website. Responses vary by cooperative and range from 15% up to 35%.

- As one would expect, the frequency of visiting the co-op websites is higher among younger and more affluent members.

Online Bill Payment

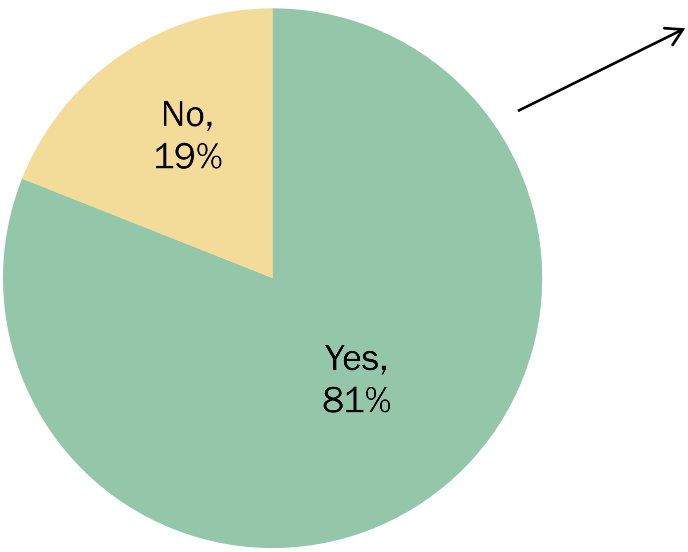


Do you pay bills online? If yes, do you pay your electric bill online?

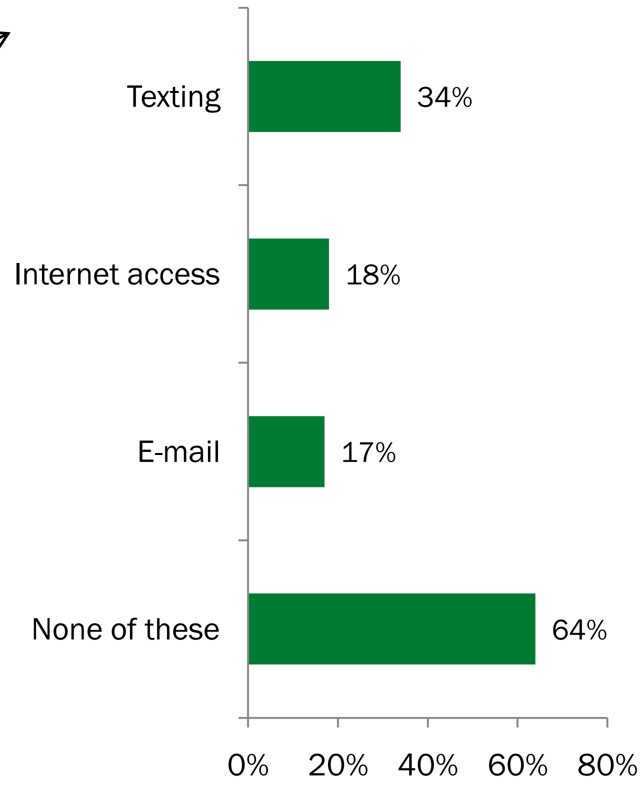
- Just one in five pay bills online, but of those that do, 77% pay their electric bill online.
- Younger members and more affluent members are significantly more likely than are their counterparts to pay bills online.

Mobile Phone

Has Mobile Phone



IF YES: Use of Mobile Phone



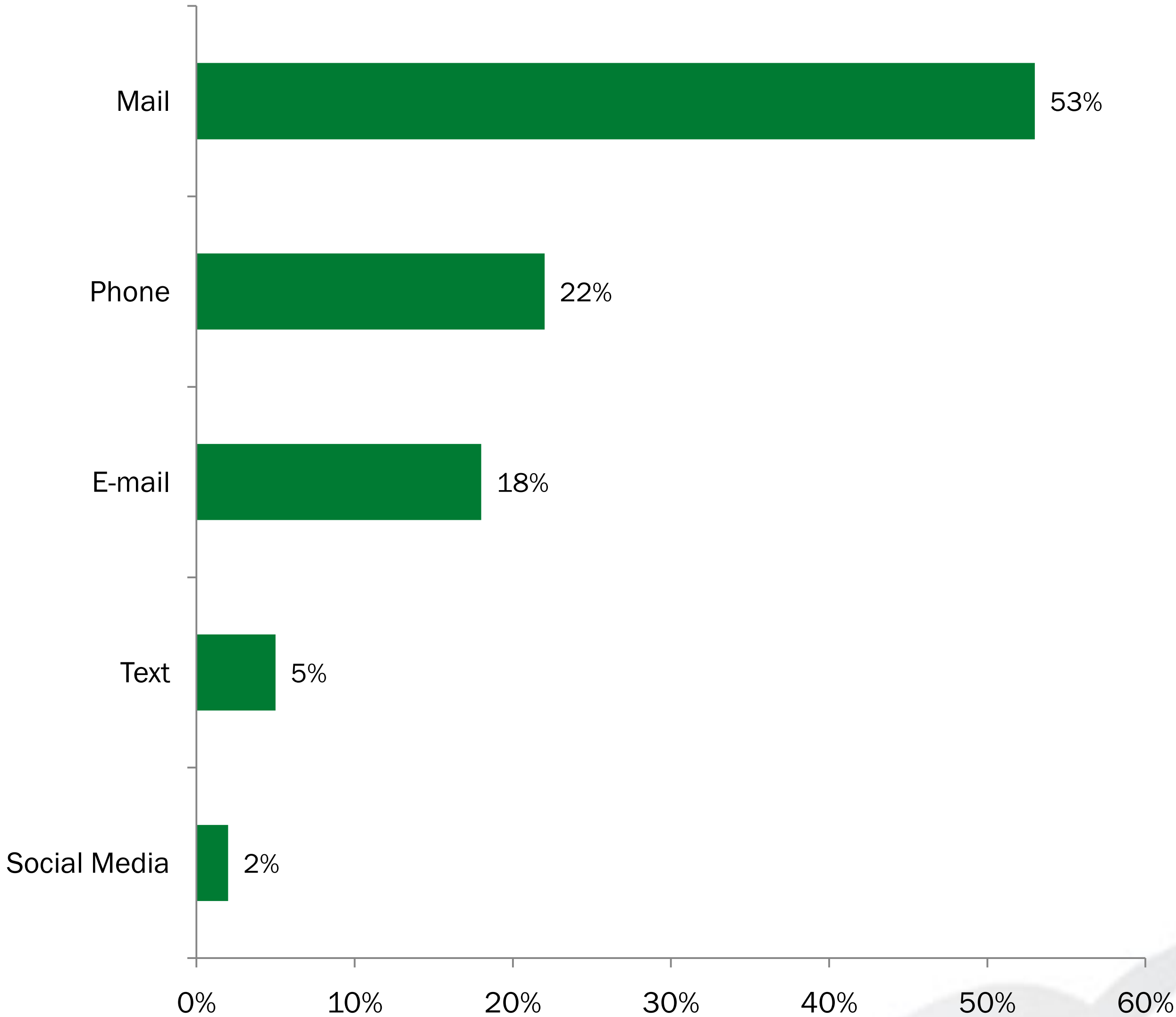
Do you have a mobile phone? If yes, do you use it for:

- Fully eight in ten (81%) have a mobile phone.

- Almost one in five use their mobile phone for Internet access and e-mail and one-third send/receive text messages on their mobile phone.

- Not surprisingly, the likelihood of both having a mobile phone and using it for more than voice are much higher among those who are younger or more affluent.

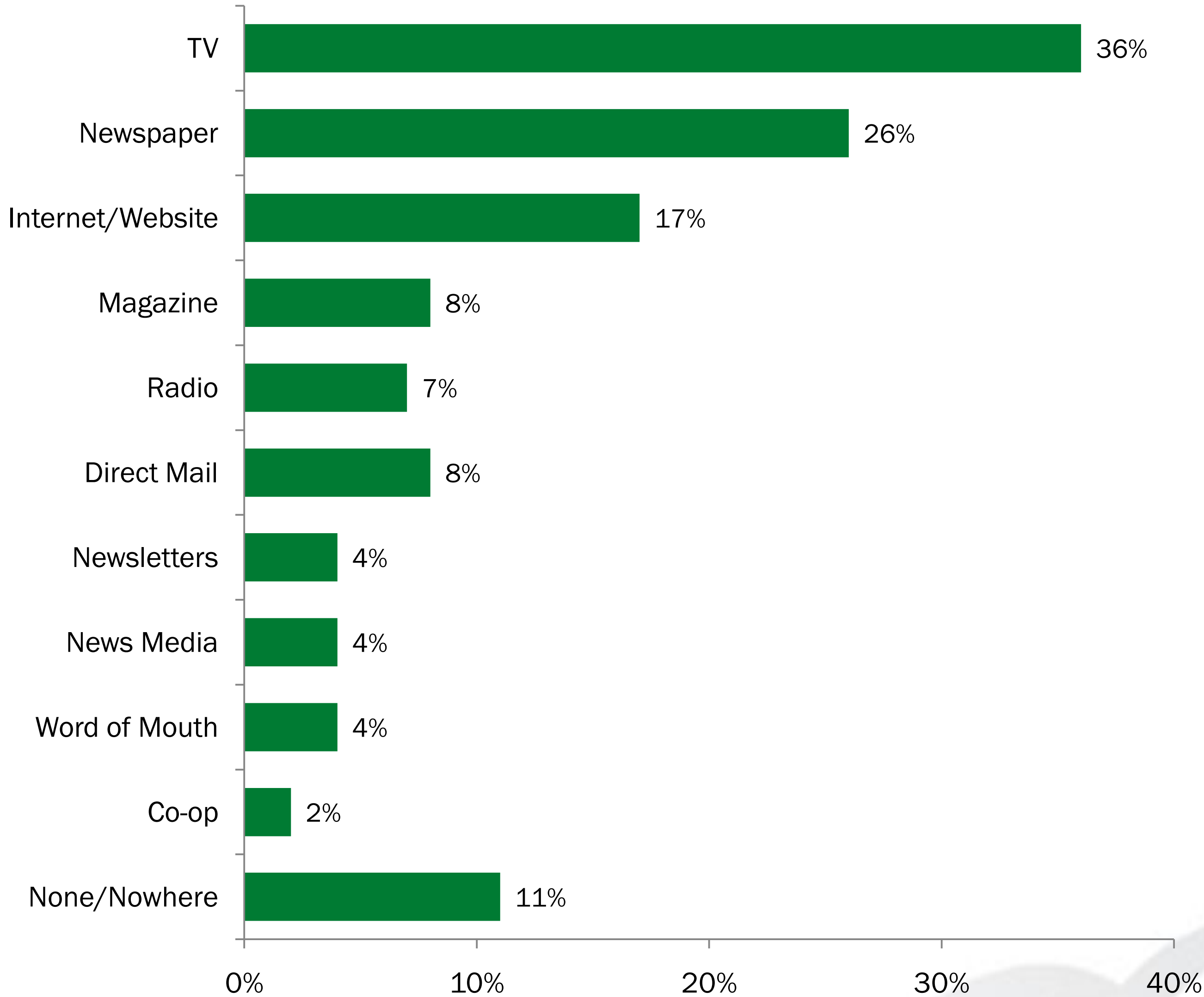
Preferred Method of Receiving Critical Information From Co-op



How would you prefer to receive critical information from your co-op?

- Over half (53%) would prefer to receive information from their cooperative by mail.
- One-fifth prefer phone or e-mail.
- Less affluent, longer-tenured members and/or those with lower bills are much more likely to prefer mail or phone.
- Younger members are the most likely to prefer e-mail, texting, or social media.

Other Sources of Information for News On Energy Issues



Where else do you get news related to energy issues?

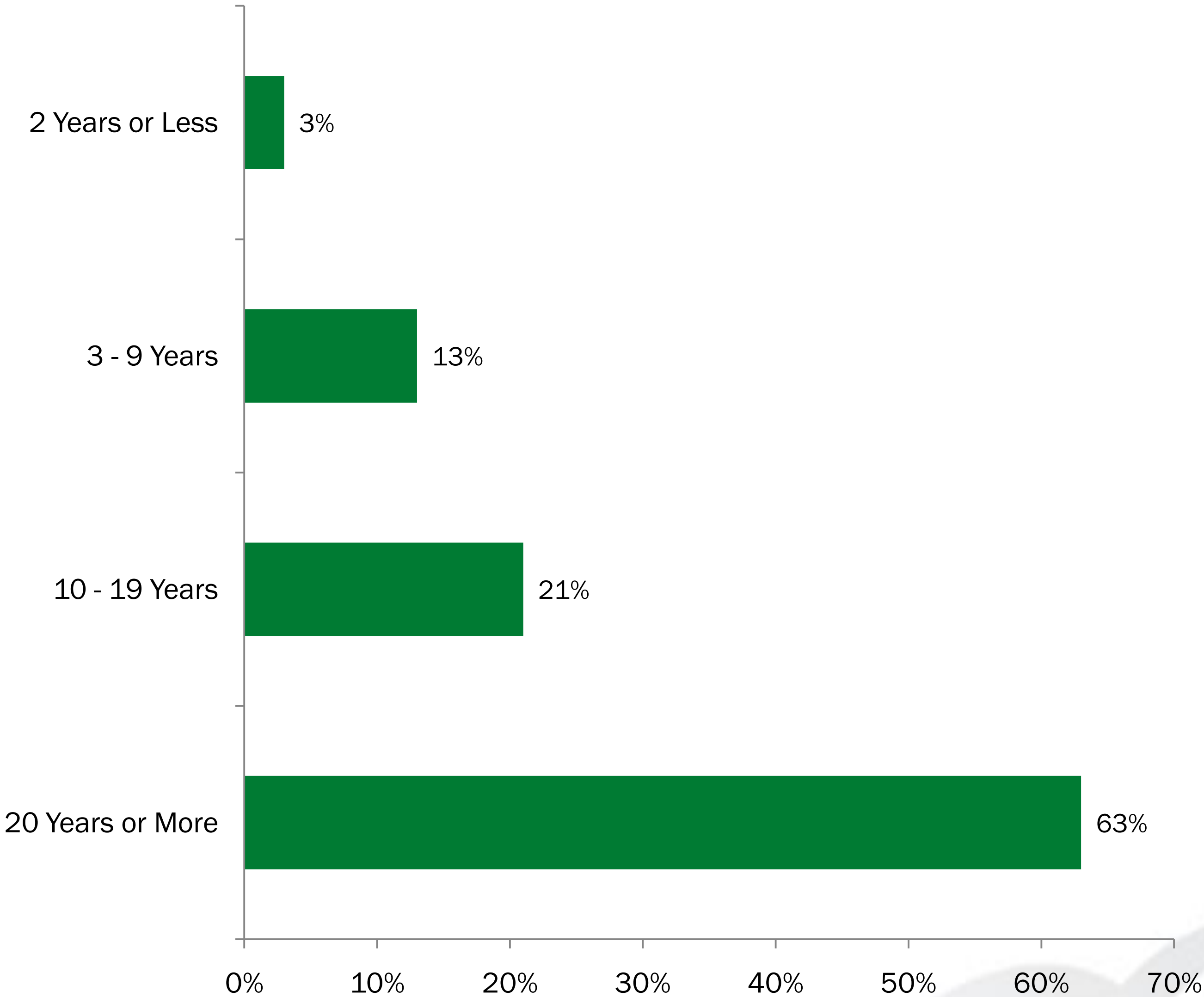
- The primary media sources members use for news on energy issues other than information received from their co-op are TV, newspaper, and the Internet.

- The Internet/websites are significantly more popular among newer members, younger members, more affluent members, those working full- or part-time, and males.

- Direct mail is the most used news source for less affluent members, while those with higher household incomes are the most likely to mention magazines.

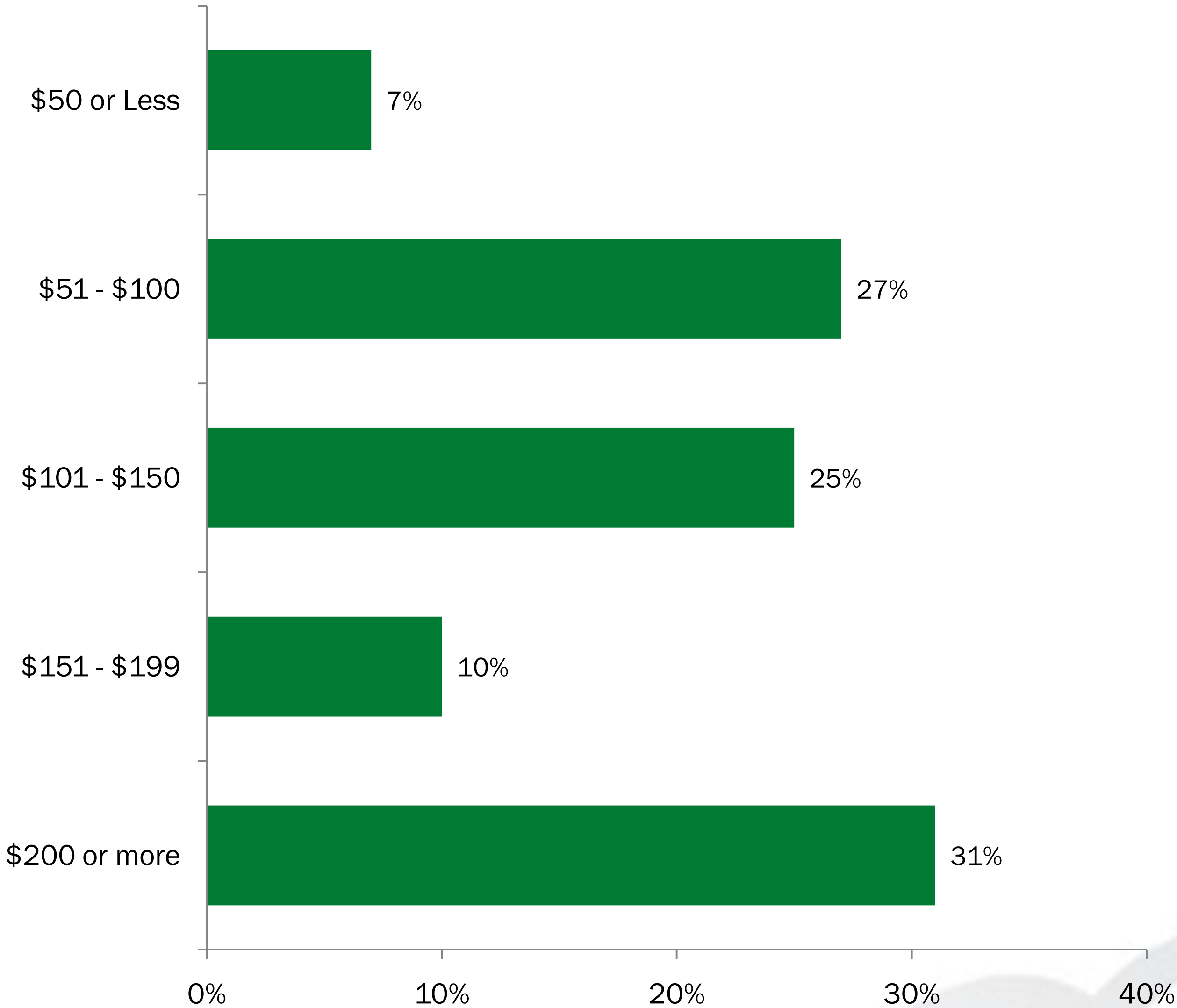
Demographics

Tenure



How long have you received your electric service from your cooperative?

Average Monthly Electric Bill

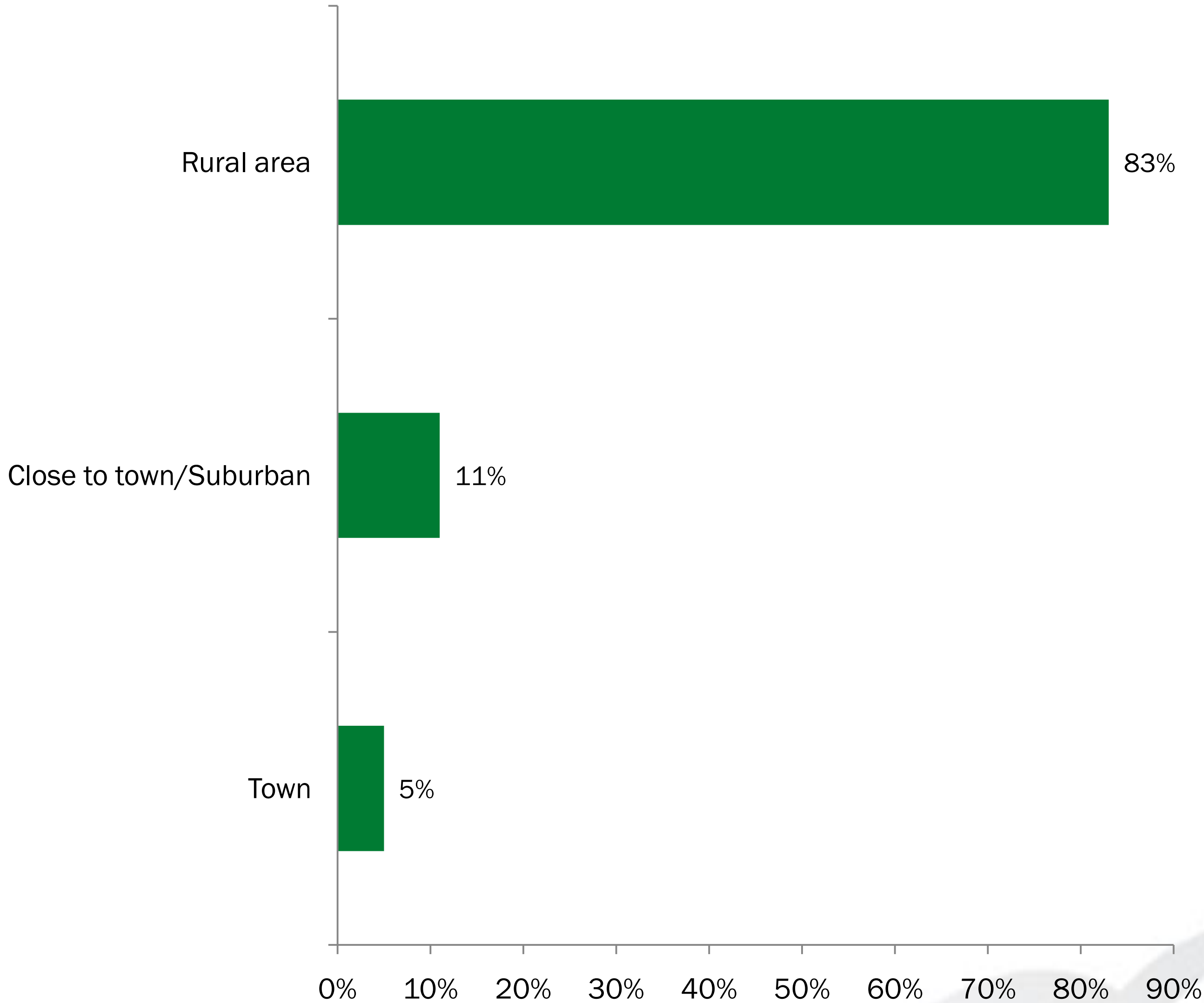


About how much is your average monthly electric bill?

- Respondents include a good cross-section of electricity bill amounts – fully one-third have monthly amounts of $100 or less, while almost one-third have bills of $200 or more.

- The size of the electric bills varies greatly by cooperative – both in the proportion having electric bills of $100 or less (16% to 60%) and those having the highest ($200 or more) monthly bills (15% to 42%).

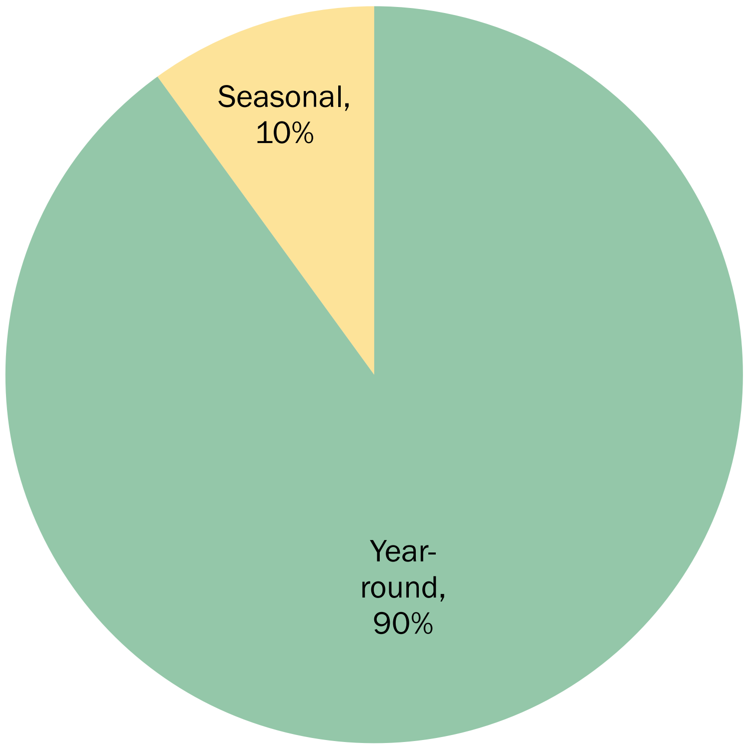
Type of Area



How would you describe the place you live?

- Fewer than one in five interviewed for this study live in a non-rural area.
- This is not unexpected as two of the cooperatives in the study are almost all rural, while two serve some non-rural areas.

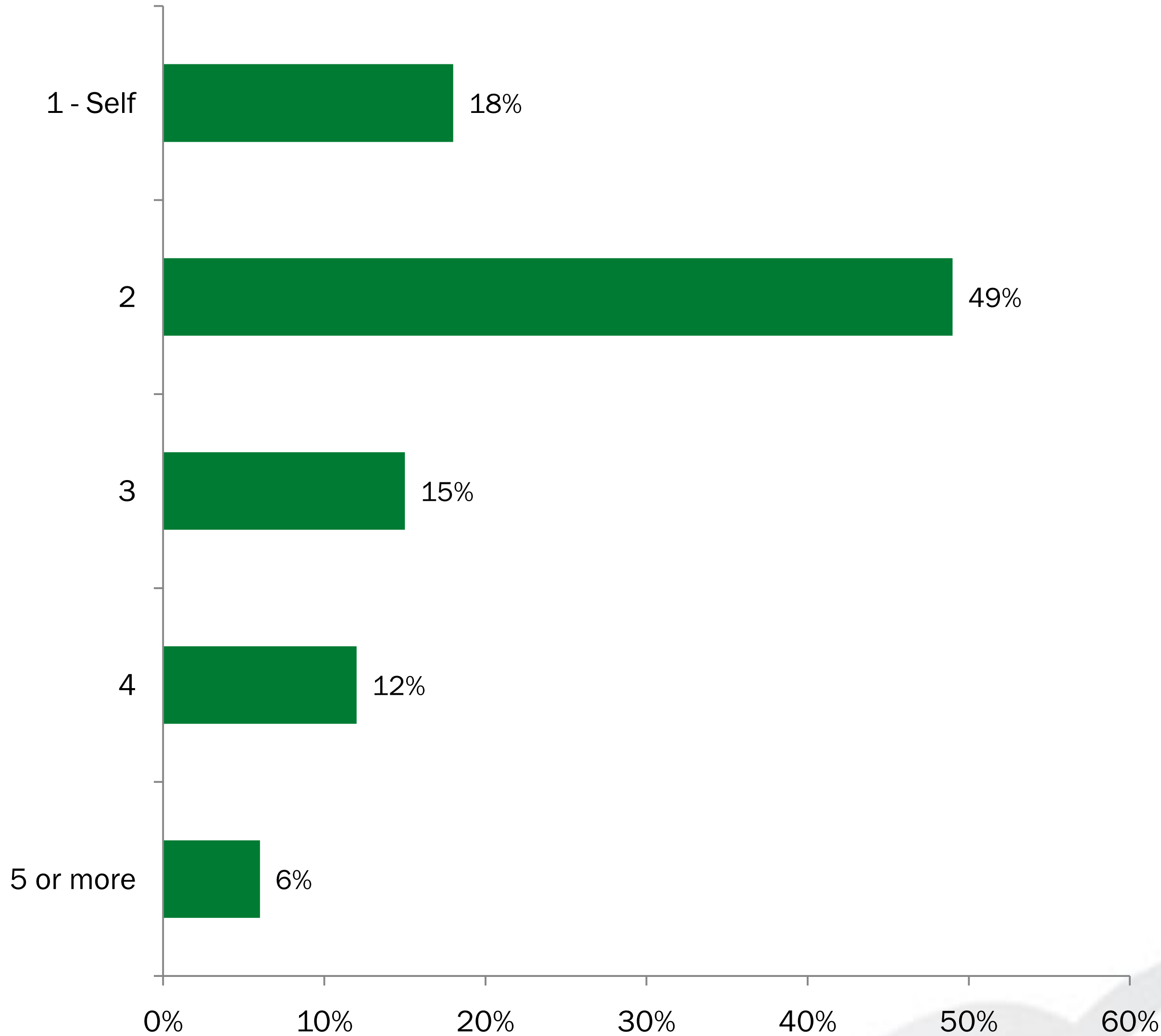
Primary or Seasonal Resident



Do you live in the home served by the co-op year-round or on a seasonal or recreation basis?

- Most (90%) of those interviewed live in their homes year-round.

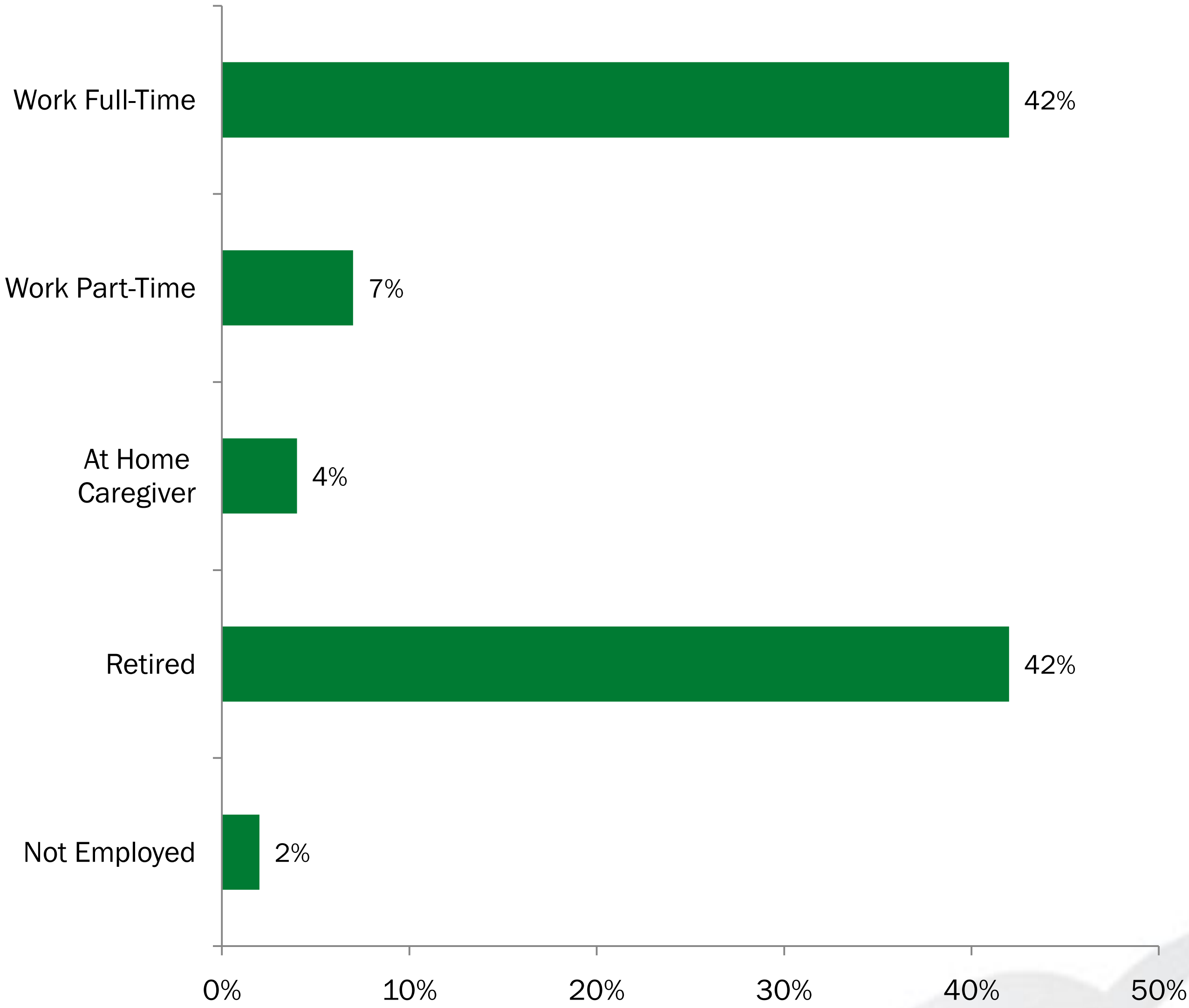
Number in Household



How many people are living in your home?

- Half live in households with two people.
- One-third live in households with three or more individuals.
- Almost one-fifth of the respondents live alone.

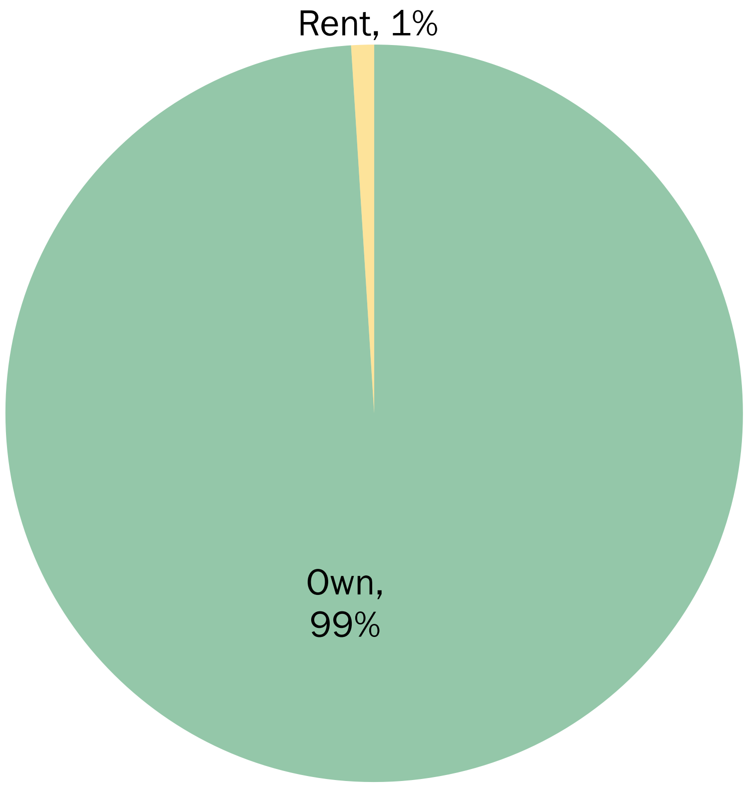
Employment Status



What is your current employment status?

- Almost half indicate they currently work full- or part-time while 42% are retired.

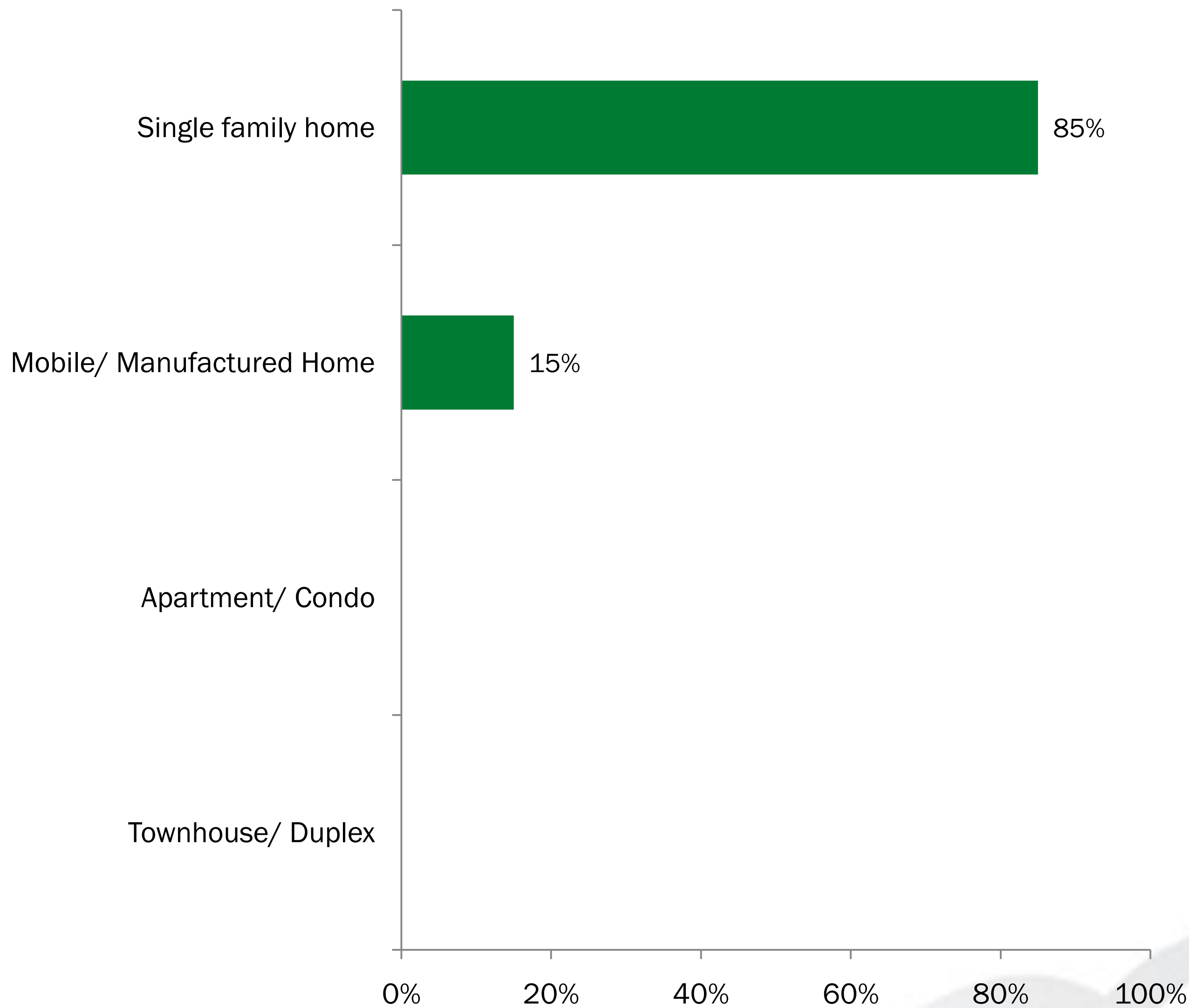
Own/Rent Home



Do you own or rent your home that is served by the co-op?

- Almost none of the respondents currently rent their home.

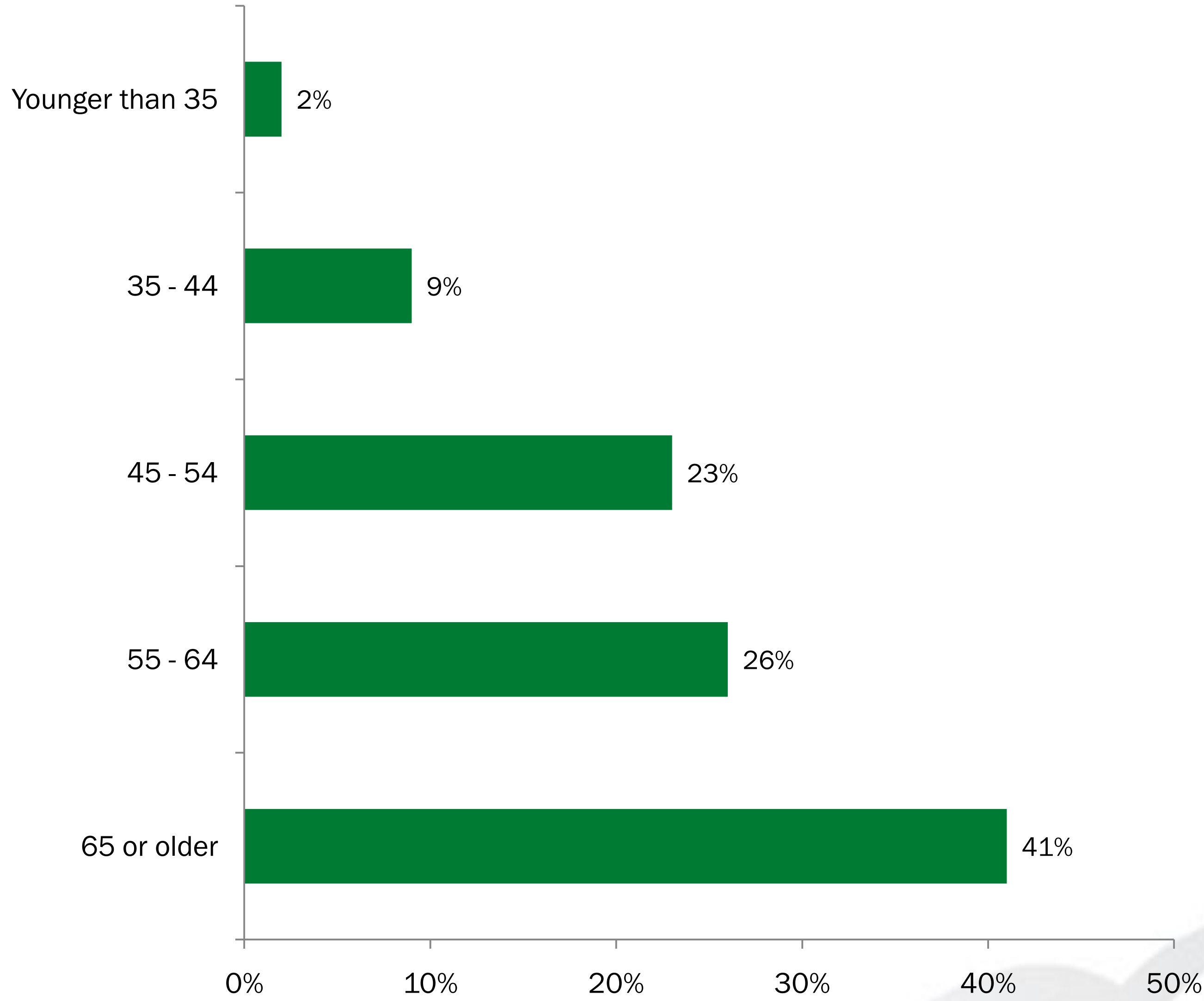
Dwelling Type



What type of dwelling is your home?

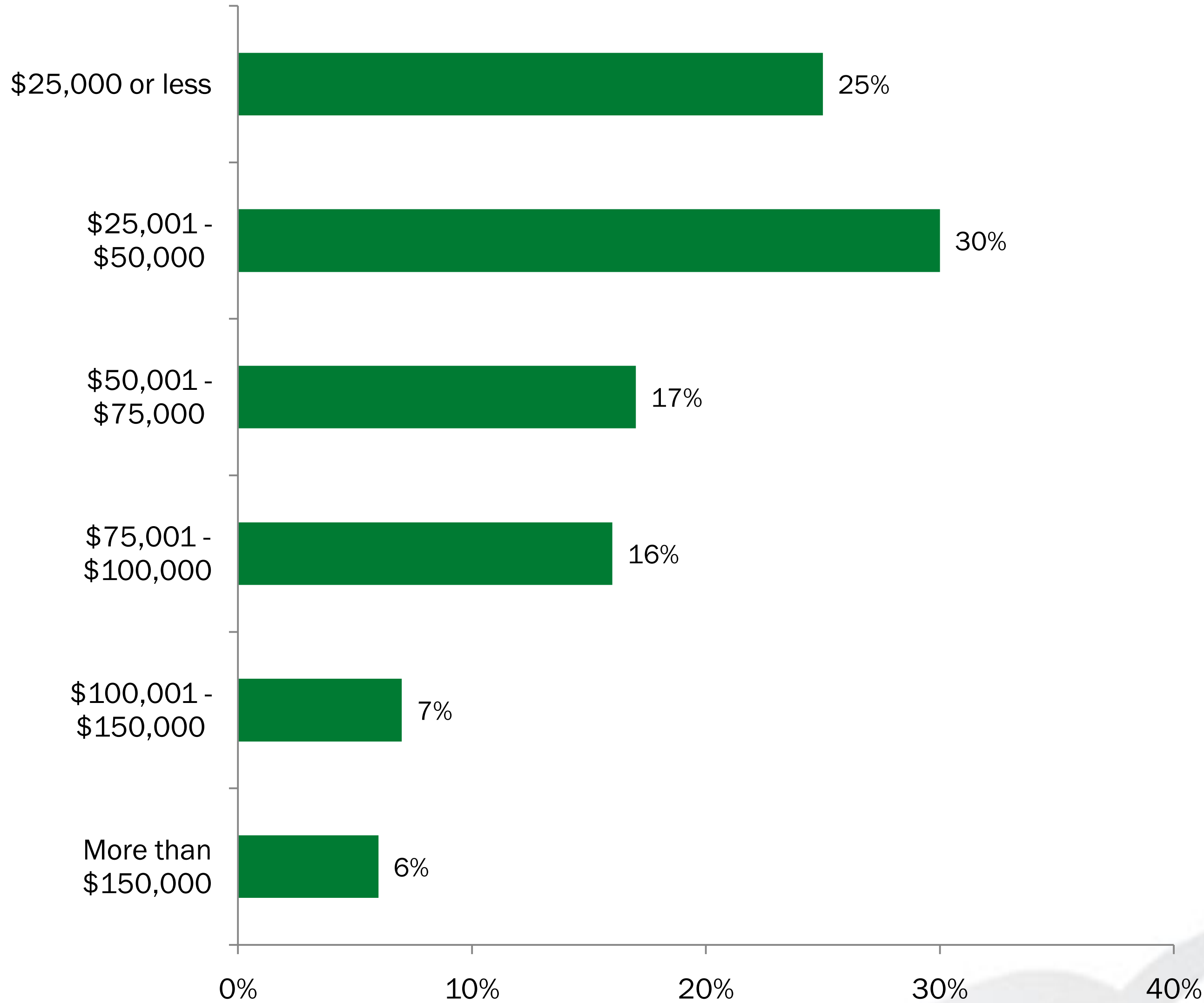
- Fifteen percent of those interviewed live in a mobile or manufactured home.

Age of Respondent



Which of the following age groups do you fall into?

Annual Household Income

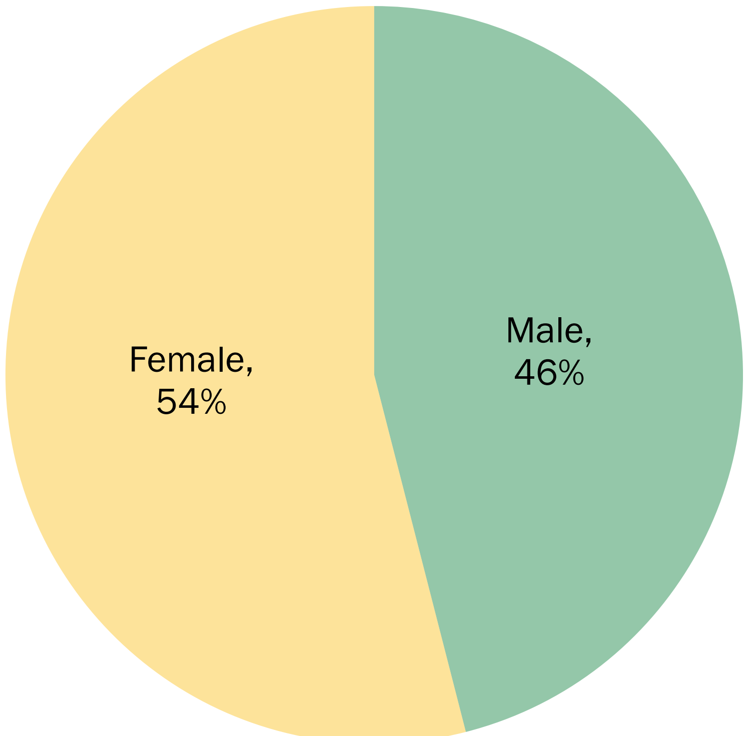


What was your approximate total household income before taxes?

- There is also a good representation of household incomes – one-quarter have incomes under $25,000 while 29% have annual incomes over $75,000.

- Twenty-seven percent chose not to respond to this question. Income questions typically have relatively high refusal rates.

Gender



Gender

- The study includes a good representation of both males and females – much closer to a 50-50 split than is typically seen in cooperative residential studies, which like the vast majority of surveys tend to skew more female.

Chapter 7:

Communications – The Smart Grid's Enabling Technology

SECTION 1: INTRODUCTION

By Maurice Martin, NRECA

Studies conducted as part of the Smart Grid Demonstration Project have reaffirmed one truism: Communications are an indispensable enabling technology for any fully implemented Smart Grid. This becomes apparent when looking at a range of Smart Grid functions:

- *In-Home Displays/Web portals.* Communications are needed to bring most recent meter data back to the database that drives the Web portal.
- *Demand Response over Advanced Metering Infrastructure (AMI).* Communications are needed to send demand response signals to meters and return measurements and verification of load reduction.
- *Prepaid Metering.* Communications are needed to collect usage data from meters and send connect/disconnect signals to meters and/or disconnect collars.
- *Interactive Thermal Storage.* Communications are needed to send control signals to water heaters and verify storage.
- *Smart Feeder Switching.* Switches need to communicate with each other and the head office to operate in a coordinated, effective manner.
- *Advanced Volt/VAR control.* Voltage regulators and VAR compensators need to communicate with each other and/or a control center to function in a coordinated, effective manner.
- *Conservation Voltage Reduction (CVR).* Measurements of end-of-line voltages need to be communicated back to a control center.

Communication was identified as one of four enabling technologies for the demonstration, but it can easily be shown that the other three enabling technologies all are dependent on communications to some degree:

- *AMI.* More frequent meter reads require more bandwidth for transmittal to the meter data management (MDM) system.
- *MDM.* Requires more frequent meters reads (see above).
- *Supervisory Control and Data Acquisition (SCADA).* Requires communication links between controlled devices (switches, etc.) and the control center, as well as between devices.

Communication thus plays a unique role in the Smart Grid—it is the enabling technology for other enabling technologies. Driving this demand for communications is the project that a fully implemented Smart Grid is likely to need, at an amount 10,000 to 100,000 times the data used by today's current grid; also, much of these data will need to be moved from one point on the grid to another.

At the same time, it must be acknowledged that communication, in and of itself, does not directly provide value either to the utility, the end user, or society in general. The value provided by communication is indirect—it resides in the value of the Smart Grid functions that it enables, and only there.

This indirect value represents the first challenge to anyone wishing to estimate the value of a potential communication upgrade. The second challenge arises from the fact that a single communication system can support multiple Smart Grid functions. For instance, a single radio network may support both prepaid metering and demand response. Calculating the return on investment (ROI) of a communication upgrade requires knowing the value of each supported Smart Grid function, any of which may be uncertain.

In some cases, the communication upgrade may end up supporting functions that are implemented only later. Perhaps these functions would not even be considered until after the new communications are in place—the available bandwidth inspires system planners to consider functions that previously were unfeasible. For example, a utility that installs fiber to support smart feeder switching may find itself with excess bandwidth and later elect to use that bandwidth to support volt/VAR control. A utility with excess bandwidth is likely to look for ways to derive value from it.

The third challenge to estimating the value of a potential communication upgrade arises from the fact that communication technology itself is a moving target. This problem is familiar to everyone who buys consumer electronics. Is it better to upgrade a laptop today and immediately begin enjoying the latest technology? Or is it better to get another year of use out of an older laptop and upgrade in 12 months, when the new models will be cheaper, faster, and have more features? Utilities face a similar conundrum when considering a communication upgrade.

Finally, a fourth challenge arises from the fact that the Smart Grid functions supported by communications are also moving targets. Innovation in the utility sector is gaining speed—every day brings new ideas for reducing system losses, better integration of renewables, and improving reliability. Most of these new functions require bandwidth. But which of these emerging applications will survive the rigors of the marketplace, and how much bandwidth will they require?

Co-ops spend approximately $38 million on demonstration activities, of which about $2.5 million (about 6.6%) is spent on communication. This low number says almost nothing about the cost of communication needed to support Smart Grid functions, however—many co-ops did not upgrade their communications for the demonstration because they already had communications adequate for their planned demonstration study.

This spending amount says even less about how much communications would cost for a fully implemented smart grid—most co-ops that upgraded their communications for the Smart Grid Demonstration Project sized their new communications systems according to the immediate needs of their individual research projects. They did not ask "How do I begin building a communication system that will support all of my current and future Smart Grid needs?" Yet, this is the most important question that can be asked about communications at this time.

The answer will vary from utility to utility, depending on topography, grid configuration, environment, meter densities, and a number of other factors. What is needed is a guide to take utilities through the process of accessing their current and future communication needs and making sense of the myriad options available.

While such a guide is beyond the scope of the Smart Grid Demonstration Project, important insights can be gleaned from the co-ops that took part in the demonstration. Section 2 looks at the experiences of demonstration co-ops, with an emphasis on their decision-making processes and how these affected results.

Section 3 is a first attempt to define communication requirements for current and future smart grid applications. This attempt is presented with the caveat that more work is required in this area; this section does not provide a guide to decision making.

Section 4 identifies future work needed in the area of communications, including a guide to decision making.

SECTION 2: CO-OP CASE STUDIES

By Maurice Martin, NRECA

Co-ops that upgraded their communication systems as part of the Smart Grid Demonstration Project had a myriad of options to choose from, including microwave, spread spectrum radio, fiber optics, cellular, and leased telephone lines.

The processes they used to navigate through the many options and select a solution show how chaotic the communication landscape is at this time. Cost was obviously a major consideration, but other decision drivers included recommendations from other co-ops, desire to own (rather than lease) a communication system, familiarity with the manufacturer or system, compatibility with legacy equipment, and compatibility of the communication system with local topography.

Co-op experiences during the demonstration reinforce the need for extensive testing of communication equipment prior to final installation. In-place testing provides the most value, as some challenges only manifest themselves in the environment in which they will operate.

2.1 Adams Electric Cooperative (AEC)

Headquarters: Camp Point, Illinois
Number of meters: more than 8,500

Demonstration project requiring communications upgrade:
AEC's goal was to improve reliability and restoration time for one of its key accounts: a Walmart complex. To this end, the co-op installed distribution automation (DA) switches (made by S&C Electric Company), which need to communicate with each other and the co-op control center.

Communications in place before the upgrade:
Adams already had MDS 9710 remote radios, which it used for AMI; SCADA data for its 13 substations; two DA switches; and a wind turbine. All locations have a line-of-sight antenna, with heights of 40–90 feet. There are two master radios at AEC's main office—one for SCADA and the other for AMI. The other two radios are connected to their respective servers via fiber to serial converters with fiber links from the radio hut.

Communications upgrade(s):

- An additional MDS 9710 was installed to connect the new DA switches with the co-op control center.
- A new SpeedNet 900-MHz spread spectrum radio was installed to provide peer-to-peer communication between switches.

Criteria used in selection of equipment for communications upgrade:

- Cost
- Staff familiarity with the same or similar equipment
  - MDS 9710 was already in play; no staff training was required
- Compatibility
  - S&C made the switches being installed as well as the new SpeedNet Radio chosen to support them

Pre-installation testing:

- For MDS 9710, RSSI study
- For SpeedNet, line-of-sight study

Difficulties encountered during installation:
- For MDS 9710, units had beta version of firmware (intended for the factory only).
- For SpeedNet, a nearby Holiday Inn was emitting radio frequency interference (RFI), requiring the co-op to relocate the antenna designed to serve the Walmart complex. The relocation added 300 feet of coaxial cable and 12 hours of labor to the project.

Does the new communications technology meet the needs of the project for which it was purchased?
Yes.

Integration issues:
None reported.

Did the communications upgrade leave the co-op with excess capacity?
No.

Does the co-op anticipate further communications upgrades in the near future?
The MDS 9710 radios are no longer available; some of the older units are failing. AEC is replacing these with new MDS SD9 units.

2.2 Clarke Electric Cooperative

Headquarters: Osceola, Iowa
Number of meters: 5,000

Demonstration project requiring communications upgrade:
Clarke's goal was to upgrade its automated meter reading (AMR) to AMI, add SCADA, add remote switching devices, and add load tracking capabilities through the regulators at the substation.

Communications in place before the upgrade:
Clarke used phone lines from the substations to the office. The cooperative had four different carriers, each of which had different pricing.

Communications upgrade(s):
- CalAmp Viper-SC 406.1-470MHz
- CalAmp Viper-SC Single Port Non-Redundant Base Station 406.1-470 MHz
- FreeWave HTP900-RE
- Cambium Networks Canopy Wireless PTP-300 5.8GHz

Criteria used in selection of equipment for communications upgrade:
- Cost
- Ownership
  - Desire to own communications infrastructure rather than depend on vendor (phone carrier)
- Recommendations from other utilities

Pre-installation testing:
RFIP performed field testing to determine communication type and height of poles and towers.

Difficulties encountered during installation:
Minimal.

Does the new communications technology meet the needs of the project for which it was purchased?
Yes.

Integration issues:
None.

Did the communications upgrade leave the co-op with excess capacity?
Yes. Clarke is considering uses for the excess, including additional automated switching and video monitoring at substations.

Does the co-op anticipate further communications upgrades in the near future?
No. However, this may change if Clarke decides to change AMI systems.

2.3 Corn Belt Power Cooperative

Headquarters: Humboldt, Iowa
A Generation & Transmission Cooperative

Demonstration project requiring communications upgrade:
Corn Belt's goal in upgrading its communications system was to provide another channel to each distribution substation to support power line carrier communications on the distribution lines. This was for load management control as well as customer meter reading and monitoring.

Communications in place before the upgrade:
Corn Belt's communications system consisted of a microwave backbone. Towers served as master sites for Multiple Address (MAS) radios, communicating with remote terminal units (RTUs) in the distribution substations.

Communications upgrade(s):
Corn Belt selected an MDS INET-II unlicensed radio from Larson Communications.

Criteria used in selection of equipment for communications upgrade:
Corn Belt had decided in advance that it would use Internet protocol (IP) communications to allow for other functions besides those that were part of the Smart Grid Demonstration Project. The co-op already had MDS I-NET equipment in place and wanted a seamless integration.

Pre-installation testing:
Several sites were checked using a basket truck to determine antenna height.

Difficulties encountered during installation:
Signal strength was an issue in places, requiring the installation of additional support structures to increase antenna heights.

Does the new communications technology meet the needs of the project for which it was purchased?
Yes.

Integration issues:
Minimal. Corn Belt had already updated its microwave backbone to include IP communications.

Did the communications upgrade leave the co-op with excess capacity?
The upgrade left Corn Belt with a small amount of excess capacity, which it uses to read substation meters. Corn Belt also lets its member distribution co-ops use this excess capacity to read customer meters.

Does the co-op anticipate further communications upgrades in the near future?
Corn Belt continuously upgrades its communication system.

2.4 Delaware County Electric Cooperative (DCEC)

Headquarters: Delhi, New York
Number of meters: 5,100

Demonstration project requiring communications upgrade:
Delaware County was upgrading to a new AMI system, which required IP communication circuits to all substations and purchase points to allow for full functionality.

Communications in place before the upgrade:
The AMR system at DCEC utilized dial-up (telephone line) circuits for communication receivers at the substations and purchase points. The SCADA system used for direct load control of customer water heating equipment used leased, analog, two-wire telephone circuits. Both systems used separate and distinct power line carrier technology from the substation or purchase points to the customer meter points or load control switch devices.

Communications upgrade(s):
For the upgraded AMI system, DCEC selected Landis+Gyr's TS2 system (a power line carrier-based system).

For the upgraded SCADA system, DCEC upgraded its RTUs to the Survalent "Scout" model. (The SCADA master server, also provided by Survalent, had been upgraded during a previous project.)

For each substation or purchase point, IP circuits for backhaul were selected based on the availability specific to each. For instance, at one purchase point, DSL was installed by Margaretville Telephone Company. Verizon Wireless provisioned cellular telephone-based IP at two substations. Fiber optic-based IP service was provided by Delhi Telephone Company at another substation, and satellite-based IP was provided by Hughes Net at the remaining substation location.

Criteria used in selection of equipment for communications upgrade:
Data rate requirements were specified for the AMI and SCADA systems for their backhaul circuits. Based on these specifications, DCEC determined that the available IP circuits would be sufficient to implement the Smart Grid Demonstration Project upgrades.

Other factors:
- Topography—service area is mountainous.
- Low customer density.
- Staff familiarity with Power Line Carrier (PLC)-type equipment. DCEC has had a long-standing relationship with its AMR vendor.

Pre-installation testing:
DCEC conducted IP speed tests at one of two substation locations designated for cellular-based IP service to determine if the data rate performance and connectivity would be acceptable.

Difficulties encountered during installation:
Minimal.

Does the new communications technology meet the needs of the project for which it was purchased?
Project needs mostly have been met, aside from the occasional loss of connectivity of an IP circuit. DCEC has noticed that the AMI power line courier-based system has data rate limitations in certain selected modes of operation, such as the gathering and reporting of interval energy data and issuance of the load control commands. Also, DCEC has had issues with periodic drop-outs, due to low signal-to-noise ratios from certain areas of the PLC system. However, no critical factors were missed in the co-op's original planning.

Integration issues:
For the AMI integration with the customer information system, few problems were noted. DCEC required significant assistance from both Landis+Gyr and Survalent to integrate the load management system with its AMI system. This assistance was in the form of software updates, setting changes, and command timing assistance.

The periodic drop-outs due to received low signal-to-noise ratios in certain areas of the PLC system have created problems for operation of the integrated outage management system (OMS). For conditions of low signal-to-noise ratio, the integrated OMS system will report outages on the system erroneously. The causes of the low signal-to-noise ratios appear to be related to the location of capacitive reactive compensation equipment, coupled with certain lengths of overhead line.

Did the communications upgrade leave the co-op with excess capacity?
The communications upgrade allows DCEC access to the Internet at all purchase points or substations, which may prove beneficial in the future.

Does the co-op anticipate further communications upgrades in the near future?
No other upgrades are planned in the near future.

2.5 Owen Electric Cooperative (OEC)

Headquarters: Owenton, Kentucky
Number of meters: 58,000

Demonstration project requiring communications upgrade:
OEC's goal was to create a redundant loop for its backbone to have multiple routes for the wide area network (WAN) and be able to use the co-op's Walton Service Center as an emergency relocation facility.

Communications in place before the upgrade:
OEC had a radial microwave backbone system combined with Telco Metro Ethernet to communicate between its headquarters and four other offices. It also used spread spectrum radios to communicate with substations.

Communications upgrade(s):
Fiber multiplexing (MUX) equipment was used for the optical ground wire (OPGW) fiber route because the fibers were being shared with East Kentucky Power Cooperative (EKPC), OEC's G&T.

Criteria used in selection of equipment for communications upgrade:

- Future co-op needs. Existing bandwidth requirements were set as the base, with the communication needs of the other Smart Grid applications factored in.
- OEC also evaluated future needs in conjunction with its strategic plan and possible technologies that could be implemented to arrive at the final bandwidth requirements.

Pre-installation testing:
As part of the request for proposal (RFP), the microwave hop was required to meet both physical and software path study requirements before it was accepted. The MUX equipment was tested at EKPC on a test bench and required to be tested and installed on site by the vendor before being accepted.

Difficulties encountered during installation:
The microwave hop was a hot stand-by and there were some issues in properly setting up and connecting the backup units. The MUX equipment had issues on the T1 side with timing bits.

Does the new communications technology meet the needs of the project for which it was purchased?
Yes.

Integration issues:
Going from a radial WAN to a looped redundant environment created some complexities, and there were some temporary problems with the integration of Open Shortest Path First (OSPF) protocol.

Did the communications upgrade leave the co-op with excess capacity?
OEC anticipated having excess capacity after the upgrade, and this was indeed the case. OEC will evaluate bringing its Internet connection from another office to increase reliability and bandwidth while reducing cost. The co-op will also evaluate additional monitoring at its substations along the fiber route.

Does the co-op anticipate further communications upgrades in the near future?
OEC is considering increasing bandwidth at a number of other substations and looking at its future bandwidth needs for both distribution automation and AMI.

2.6 Washington-St. Tammany Electric Cooperative

Headquarters: Franklinton, Louisiana
Number of meters: 50,000

Demonstration project requiring communications upgrade:
Washington-St. Tammany's goal was to make its transmission grid self-healing. To this end, the cooperative connected 24 transmission breakers to its SCADA system.

Communications in place before the upgrade:
Washington-St. Tammany had no communication to its substation prior to this project.

Communications upgrade(s):
The co-op is building out a 100+ mile fiber optic network to 18 of its substations, as well as a number of metering points. Prysmian 48F ADSS cable was selected, with Cooper Power Systems as the vendor. (Note: The co-op originally selected a microwave-based communications system. The reason for the switch to fiber is explained in the supplemental report "Washington-St. Tammany Case Study: Stress-Testing Designs Before Deployment.")

Criteria used in selection of equipment for communications upgrade:

- Cost
- Industry standards
- Extra bandwidth (beyond what was needed for the SCADA system) for possible future applications

Pre-installation testing:
Washington-St. Tammany tested a single pair of fibers within the blue sleeve on the reels before installation. (Note: Testing done on the original microwave-based communications system directly resulted in a switch to a fiber-based system. For details, see the supplemental report "Washington-St. Tammany Case Study: Stress-Testing Designs Before Deployment.")

Difficulties encountered during installation:
During the late 1960s and the early 1970s (the time during which the transmission lines were built), the designer did not foresee adding fiber. Most of the problems are occurring where the transmission line crosses the roadway and Washington-St. Tammany has distribution along the road. The fiber is installed below the intersecting distribution, yet must maintain 21 feet above the roadway. In many instances, Washington-St. Tammany has had to increase the transmission pole height by as much as 10 feet.

Does the new communication technology meet the needs of the project for which it was purchased?
Cannot be answered, as the fiber installation is still underway.

Integration issues:
Cannot be answered, as the fiber installation is still underway.

Did the communication upgrade leave the co-op with excess capacity?
The fiber installation, when completed, will leave Washington-St. Tammany with considerable excess capacity. The co-op is looking at different options to monetize this excess capacity. Options include leasing "dark fiber" and selling broadband to communities and consumers.

Does the co-op anticipate further communications upgrades in the near future?
No.

SECTION 3: DEFINING COMMUNICATIONS REQUIREMENTS FOR PRESENT AND FUTURE APPLICATIONS

By Rick A. Schmidt, Power Systems Engineering

Note: The Cooperative Research Network (CRN) is the national technology research organization managed by NRECA on behalf of its 900+ co-op members. When the Smart Grid Demonstration Project made it clear that defining communications requirements in this new era had grown far more complex, CRN commissioned Power Systems Engineering (PSE) to create the following guidance to support its efforts. Communications is undoubtedly a challenge throughout the industry. As a result, the following guidance may be of value to utilities outside of the co-op family. For this reason, CRN offers Section 3 of this report.

Of course, defining requirements is only a first step in addressing the communications challenge. Once the requirements are known, a guide will be needed to navigate the many options available. A plan for creating such a guide is discussed in Section 4.

Selecting the most appropriate communications architecture, technologies, and vendors starts with a roadmap that defines present and future communications requirements. Without clearly defined requirements, decisions could be made that are not the best choice in the long term. These short-sighted choices may be costly to rectify in the future.

This article presents a proven process for defining requirements and identifies typical requirements for the various segments of the communications architecture. The following topics are covered:

1. Detailed cooperative-wide automation and communications planning;
2. Key communications infrastructure requirements, such as latency, jitter, bytes per file/session, frequency of data being sent, interfaces, redundancy, level of mission criticality, security, and others; and
3. A review of the existing and emerging automation applications and common communications requirements for various applications, such as SCADA, Voice over Internet Protocol (VoIP), DA, mobile workforce, AMI, direct transfer trip schemes, and others.

3.1 Cooperative-Wide Automation and Communications Planning

In the past, adding a new application such as SCADA or AMI would drive the need to invest in new communications infrastructure; as new applications were added, co-ops would deploy a unique communications technology for each application. Because the technologies were less sophisticated and used primarily for single applications, the ramifications of a poor communications deployment choice, while disruptive to utility operations, would not usually spread beyond the realm of that one application.

Today, however, many co-ops are building more robust communications networks that can incrementally scale to the addition of new applications and enhanced capabilities of existing applications. Because most new communications infrastructure now supports multiple applications, and because that infrastructure is now more expensive, the risk of making the wrong choice is greater. To mitigate this risk, gaps in communications infrastructure should be identified prior to procurement by strategically planning for automation and communications across the utility over the next 10 years.

Figure 7.1 reviews the major steps involved in migrating from 10-year automation and communications plans through requirements definition.

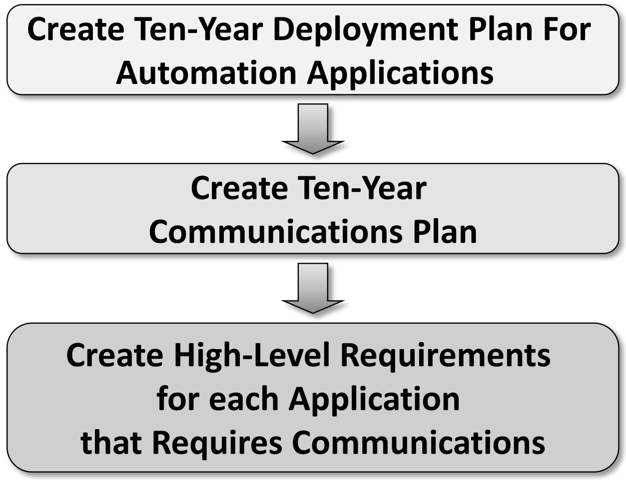


Figure 7.1: Creating a 10-Year Deployment Plan for Automation and Metering Applications

The 10-year deployment plan for automation applications is the key driver or influencer for communications. Although it is generally easier to forecast new automation programs with a three-year planning window, communications infrastructure has a life of 10 years or longer, so it is important that the cooperative extend its plan accordingly.

Listed below are factors that co-ops may want to consider when creating a 10-year deployment plan for automation applications:

1. **Existing Reliability Situation:** How much improvement is desired for electric reliability? Knowing where the co-op stands regarding Customer Average Interruption Duration Index (CAIDI), System Average Interruption Duration Index (SAIDI), etc. compared with its peers is a good start in identifying areas that may need improvement. Applications such as DA, new forms of SCADA, and even new types of outage restoration processes may all require new communications infrastructure. Therefore, a co-op could forecast the timing of programs such as DA or SCADA over a 10-year planning window.
2. **SCADA Changes at the Substations:** If a co-op does not have SCADA now, or if changes possibly could be made to the SCADA master (such as migrating from a proprietary protocol to Distributed Network Protocol/Internet Protocol (DNP/IP) within the 10-year planning window, new communications at the substations could be required.
3. **Office Communications Links:** Many co-ops have district offices, but those offices are often connected via data links to the main office, where systems such as the Customer Information System (CIS), AMI, OMS, and the phone system are housed. These data links often are undersized. This situation can be further exacerbated by the implementation of self-run cloud technologies (or "private clouds," as they sometimes are called). Therefore, forecasting the bandwidth requirements for various offices needs to be part of the 10-year plan.
4. **Impact of Cloud Computing:** A growing number of software applications are now available through vendors that offer cloud-based software solutions. "Cloud-based" generally refers to "Public Cloud" software run in a central data center off site from the co-op and accessed via the public Internet. Now that we are seeing cloud-based versions of software such as Meter Data Management Systems (MDMS) and other Software-as-a-

Service (SaaS) applications, the Internet is becoming much more mission-critical than in the past. Given these developments, we are now seeing co-ops increasing the bandwidth for the links that connect to the Internet, and often adding a redundant communications link to enable a second connection. A cooperative should forecast the impact of cloud computing on its automation programs over the next 10 years.

5. **Existing Automated Metering Situation:** If no AMI is in place now, or the co-op has at least a 10-year old PLC-based AMR system, there is a strong probability that within 10 years a new type of AMI system could be needed. This requirement may trigger the need for new backhaul communications.
6. **Possible Changes from Demand Side Management (DSM) Programs:** One-way 150 MHz paging and PLC technology historically has been used for load control. However, co-ops are now looking at a variety of technologies for transporting DSM. Therefore, a long-range forecast for DSM could impact long-range communications needs.
7. **Changes in the availability of the current service:** In some cases, a provider will decide to discontinue a service. For example, AT&T recently discontinued offering its frame relay service, leaving Georgia Transmission Corporation to hunt for alternatives. It is important to talk with service providers to find out their future plans for services.
8. **Increased role of telecommunication companies in providing communications services to utilities:** Co-ops are advised to engage telephone companies and wireless commercial providers to find out what services they offer now and what services they plan to offer in coming years. Recently, Prairie Power from Jacksonville, Illinois worked out an agreement with a cooperative-based telephone company to provide fiber optics for the backbone and members' electric substations.
9. **Mobile Radio Plans:** Co-ops should consider what changes may be required for mobile radio communications in the future, as in some cases their needs are shifting to IP base backhaul versus circuit switched. Digital trunking Land Mobile Radio (LMR) product lines are now generally affordable for co-ops needing to address mobile voice needs.
10. **Mobile Data and Automated Vehicle Location (AVL):** Co-ops should consider what communications requirements may be needed for mobile data or AVL in the next 10 years. The software for mobile service orders, mobile outages orders, and service order scheduling has greatly improved, and devices such as iPads and smart phones also have improved.
11. **Security requirements of future communications infrastructure:** With the sophistication of cyber-attacks increasing, and technology advances working against existing security mechanisms, attention must be paid to communications security (data-in-transit security). Even if the communications device does not have built-in security mechanisms, various encryption mechanisms, such as SSL, certificates, and virtual private networks (VPNs), can be leveraged to secure the data on these links. Periodic risk assessment, vulnerability assessment, and security planning need to be included in the overall planning with regard to communications.

3.1.1 Create a 10-Year Communications Plan

A 10-year communications plan can include communications for existing programs, such as those described above, and any other existing applications that require communications infrastructure. The more challenging programs to forecast, however, are new programs not currently in place at a co-op.

It is important to make decisions on the following:

1. **What current and new Smart Grid applications will be supported over the decade.** New programs may hard to predict, but it is worth the effort to engage all stakeholders and get their perspectives on what will be in place at different points over the next 10 years.
2. **The schedule of program deployment as well as the associated number of sites and costs for those deployments on an annual basis.** Many co-ops create annual budgets based on planning for that 12-month period only, but a 10-year plan ensures that utilities are budgeting with an eye toward the future.
3. **Internal consensus on the level of mission criticality for each new program from a reliability standpoint.** For example, a program may be defined as (a) mission critical and having a high impact on members, (b) operation critical, or (c) neither mission nor operation critical. These decisions could influence the subsequent decisions regarding what type of assets require either redundancy or some type of ring topology to protect against communications failures.
4. **Defined preference between private and commercial communications technologies per application.** Most utilities prefer the use of private communications technologies over commercial technologies for mission-critical applications. However, the often higher costs of private communications, the occasional lack of spectrum or higher cost of spectrum and, in some cases, a shortage of in-house communications expertise, can result in some use of commercial technologies.
5. **Shared LMR system and public safety.** There are a few states in which G&T and distribution co-ops have partnered with public safety organizations and received Federal Communications Commission (FCC) waivers to share an LMR system with public safety. First Responder Network Authority (FirstNet), an independent authority within the National Telecommunications and Information Administration (NTIA) intended to provide emergency responders (including utilities) with the first high-speed, nationwide network dedicated to public safety, is a new opportunity that is in its initial stages; it shows the potential for sharing a fixed data technology with public safety organizations. State-level meetings are just beginning on this topic; the rules and structure are in the early stages of development. For information on the progress of FirstNet, visit: www.ntia.doc.gov/category/firstnet.
6. **Defined preference between outsourcing to fill any existing staff gaps versus using existing or future internal staff.**
7. **Identification of any existing communication assets that can be leveraged over the long term, such as tower sites, fiber or microwave, relationships with local communications providers, and the communications experience of existing staff.**
8. **Defined internal willingness to share a communications link with a variety of applications, such as mixing AMI and SCADA over the same link.**

Once the applications that require communications are identified, the deployment time frame is identified, and decisions are made for the types of questions listed above, the 10-year communications plan can be documented. The next step is to define requirements.

3.1.2 Create High-Level Requirements for each Application Requiring Communications

The remaining sub-sections discuss some of the areas for which requirements must be defined, such as bandwidth and reliability, that apply to most applications and corresponding communications media. Individual vendor products are not discussed—rather, the focus is on defining requirements during the communications planning stage, with the goal of influencing the design of the communications architecture. Defining requirements during the planning stage enables cooperatives to make technology-level decisions before procurement so that their procurement will be smoother and more focused, saving them (and vendors) time and money.

For example, to determine a technology connecting substations to the main office, a co-op should begin by defining the high-level requirements for throughput, latency, interfaces, etc. Then the co-op determines what technology best meets those requirements. It might evaluate fiber optics, point-to-point microwave (licensed or unlicensed), point-to-multipoint spread spectrum, VSAT satellite, telco data leases, cable TV leases, WiMax point-to-multipoint, or private mesh-based products. Once a technology is selected, the cooperative can identify the appropriate vendors. When the co-op has refined its requirements and detailed specifications for procurement, it can issue an RFP only to those vendors.

3.2 Key Communications Infrastructure Requirements

There may be any number of requirements associated with a particular application, but the importance of those requirements will vary, depending on the utility's needs. In developing communications requirements, the utility should consider what is most important in each of the following areas:

1. **Operational Rules by Application:** Identify any "operational rules" associated with future applications that will be relying on the communications infrastructure. For example, if the utility is planning to migrate Ethernet connectivity to the substations, will the SCADA data acquisition thus change from polling to an unsolicited report by exception? Will AMI data be acquired at the master more often, such as going from once a week to once a day, four times a day, 24 times a day, or every 15 minutes? How many seconds of latency are acceptable from when the data are sent to when they are delivered? Will district office Internet traffic be routed over a link to the main office and then connected to the Internet from the main office, or will it connect to the Internet directly from each district office? All of these types of operational decisions will impact the requirements developed for the RFP.
2. **Deployment Timeline by Application:** We have already discussed the importance of a 10-year plan on an annual basis. Incorporating all applications planned for the lifetime of the backhaul network (about 10 years) helps a utility to understand the impact of its technology selection further into the future. For example, the co-op might weigh the option of deploying a more robust backhaul technology now than what actually is required for the initial technology deployment (such as AMI, for example) to accommodate future scalability for DA or other planned applications.
3. **Data Throughput and Latency:** Throughput is defined as the amount of data that must be transmitted, and at what rate, to meet a latency requirement. Throughput is measured in bits per second, such as: "kbps," which is kilobits per second, or "Mbps," which is megabits per second. Latency is defined as how much time it takes for a packet of data to get from one designated point to another. It sometimes is measured as the time required for a packet to be returned to its sender. It must be determined how much delay can be tolerated in the transmission to meet a defined user or system need. Sometimes the term "round-trip latency" is used to define the time it takes in seconds or milliseconds (ms) for data to travel from the master to a device and back to the master—such as how long it takes to travel from the SCADA master to a voltage regulator to retrieve a voltage read and return that information to the SCADA master. Various applications and programs have different latency expectations.

4. **Frequency of Data Transfers:** This refers to how often the communications facility is planned to be used. For example, a Wi-Fi access point located at a substation might not be used every day, or it might be used as often as several times per day. Depending on need, a video camera located at a substation that is currently programed to send a network health check once every half hour could be reprogrammed to send a video feed only when an "event" occurs or when requested by a dispatch employee. Therefore, that asset could sit idle most of the time. By contrast, SCADA might be programmed to send a data file once every five seconds around the clock.
5. **Interface – Serial or Ethernet:** Most new applications are interfaced with Ethernet to provide wider availability to communication products, more flexibility for maintenance of the communications site, and greater bandwidth. It is expected that many applications will remain serial for several years to come, but the clear trend is to migrate to Ethernet in the future.
6. **Reliability or Availability – 99.9%, 99.99%, or 99.999%:** Reliability or "availability" is defined as the probability that a system will perform without a failure for a stated period of time. Often these percentages are used fairly loosely and mean different things to different people. However, there are standard software programs and testing procedures available to determine the level of reliability achieved at, for example, a given microwave link. The distance of the link, the size or gain of the dishes, coax type and length used, throughput delivered, precipitation, and other factors all contribute to reliability. Sometimes these reliability percentages are used as targets, such as backbone at 99.999% (about 5 minutes per year of downtime), substations at 99.99% (a little less than an hour per year of downtime), or feeder devices such as cap banks or fault indicators at 99.9% (about 9 hours per year of downtime).
7. **Battery and/or Generator Backup:** Does the cooperative's communications system require generator backup? Does the application need to be available during a power outage? Generally, for SCADA and DA applications, the co-op probably wants to have the ability to monitor and control during power outages. AMI systems, on the other hand, do not need to have generator or battery backup, as meter readings do not change if there is no power flowing to them. The co-op also may want some systems to have battery backup, so that it knows if an outage is caused by a communications network failure or some other failure.
8. **Licensed vs. Unlicensed for Wireless Communications:** With the use of licensed technology, the designer must understand frequency border rules and avoid self-interference. Gathering information from co-users and other licensed spectrum users in the area is often completed in the requirements and pre-design phase of the project. With the use of unlicensed technology, part of the requirements-gathering process involves understanding the number of other unlicensed users that possibly share the same tower or are using the same unlicensed spectrum within the same path planned for the use of the application to be deployed.
9. **Ring Topology vs. Network Diversity or Secondary Link:** Backbone networks are often built with a ring topology, such that if a given communications link breaks between two points, a second route exists between them, thus avoiding an outage. Often this second route is a different type of back-up media, usually inferior to and lower in cost than the primary link, but adequate enough to be used for a short period of time until the primary communications link is repaired. Sometimes a manual change is needed to unplug the primary port and replace it with the diverse or back-up media choice.

10. **Coverage Requirements:** In prior years, coverage requirements were more tied to mobile radio voice system deployments. Now, requirements are tied to programs and used to define, for example, the number of homes reached with an AMI system or for a load control program, or the number of feeder devices reached with a given technology. Usually a coverage requirement is used as part of a formal RFP bidding process, with the co-op providing the latitude and longitude coordinates of the sites that need to be reached and other attributes, such as antenna height.
11. **Monitoring or Control Applications:** A monitoring application is a site such as a voltage regulator or fault indicator, where analog or status messages are gathered. A control application is a site, such as a feeder switch, that can be remotely opened or closed over the communications link. A site that provides monitoring functions only can most often get by with a slightly less reliable or less robust communications link compared to a site that provides control functions, which require the communications system to be available at any time it is needed.
12. **Who (or What) Is Waiting for the Data:** There are various applications from which a human located in a dispatch center or service center is waiting to get a response on a given data interrogation of a meter, RTU, modem, or other devices to which the communications link is routed. For some applications, such as AMI, a human generally is not waiting for hourly meter reads to be delivered; rather, those data simply feed into a database. However, when a message is sent to a particular meter to identify a possible outage, a human generally is waiting. This concern relates back to the latency requirement discussed earlier. Therefore, a program like AMI would have several requirements tied to latency, with different requirements for different types of functionality (i.e., longer latency allowable for hourly meter reads versus shorter latency allowable for user-operated meter inquiries).
13. **Direction—One-Way, Two-Way, Peer-to-Peer:** Most new communications media selections provide two-way communications. Some of the older paging and PLC technologies sent information only one way, but two-way technologies can both send and receive data. Peer-to-peer communications link two devices that are typically on feeders, such as relays. Some peer-to-peer applications will have extremely stringent latency requirements, such as 2 ms, and some as relaxed as 3 seconds.
14. **Circuit-Switched Packet-Switched TDM:** Time Division Multiplexing (TDM) is a process of transferring signals over a single communications channel in such a way that, although they appear to be traveling at the same time, they actually are taking turns on time-slot-based sub-channels. TDM typically delivers latency of less than 4 ms and is extremely consistent in its transmission. TDM has been used heavily for the transport of analog phone systems, analog LMR, and relay protection in a peer-to-peer mode. It is used when a latency requirement is very stringent. More recently, most of the microwave products now provide several radio ports that can be configured in TDM mode, along with an Ethernet port that can transport packed data.
15. **Jitter:** With many co-ops now routing VoIP traffic between their offices over an Ethernet link, as well as the increasing use of video transport, the impact of jitter has become important to understand. "Jitter" can be used to describe undesired timing fluctuations in a transmitted signal and an IP network. Jitter can result in incorrect decoding; dropping of packets, which may cause poor voice quality; pixelated video; and other errors. Jitter can occur for a number of reasons, including the way routers and switches queue packets, networks that have multiple routes from one node to another, non-uniform implementation of Quality of Service (QoS) rules, and just plain congestion. Jitter buffers can compensate

for jitter of up to about 100 ms, but excessive jitter (generally more than 100 ms) can result in dropped packets and will often increase end-to-end total latency. Many communication products include such jitter buffers, which can help. Depending on the codec and the compression standard used, 100 ms of delay mitigate jitter about the maximum target before it will begin impacting the audio quality.

Jitter is not very easy to test. Various standards establish protocols to allow VoIP to operate. Q931 protocols control call setup. H-225 defined protocols (RTCP) exchange information about lost packets end to end. ITU G113 includes specifications for transmission and processing impairments due to IP transport. VoIP and TDM over IP and video over IP are evolving over time. The standards controlling them and the test equipment designed to test them also are evolving.

In summary, the key aspects to consider when selecting the communications media for VoIP and video include the amount of latency expected between the two points and the associated hardware, software, and protocols, as described above, being used to mitigate the impact of jitter.

3.3 Typical Communications Infrastructure Requirements

The typical communications requirements shown in **Table 7.1** all depend on the application, but some generalities do apply across applications and cooperative sizes. These requirements are presented as an overview and are not all-inclusive. Because these requirements are generalized, caution is advised when adopting those listed in this article for the purposes of procurement. Terrain, operational preferences, budget, master system software capabilities, density of devices, and various other factors will always influence the unique set of requirements a utility develops for each application. Each of the applications is discussed in more detail following **Table 7.1**.

Table 7.1: Typical Communications Infrastructure Requirements

#	Application	Typical File Size per Session – Bits	Typical Latency Required or Desired	Reliability Target	Preference for Private versus Commercial	How Frequently Are Data Typically Sent?
1	Backhaul of PLC-Based AMI from Substations	1,000 meters / substation 1,000,000 bits	60 seconds	99.9%	Private	Once per day to 4 times per day, depending on vendor
2	Backhaul of Fixed Wireless-Based AMI from Collector Locations	1,000 meters / collector 1,000,000 bits	15 to 30 seconds	99.9%	Private	Every 15 minutes to hourly
3	Modern Distribution SCADA	4,080 bits for DNP3 over IP	150 ms	99.99%	Private	Every 2 to 5 seconds
4	Feeder Distribution Automation: Control Applications	4,080 bits for DNP3 over IP	1 second	99.9%	Private	Every 5 to 10 seconds
	Feeder Distribution Automation: Monitoring Applications	4,080 bits for DNP3 over IP	5 seconds	99.9%	Commercial	Every 10 to 60 seconds
5	Direct Transfer Trip Distribution Relay Protection	800 to 2,400 bits	Must be < 2 seconds to as fast as 3 ms	99.99%	Private	By exception
6	Mobile Workforce Management (MWM)	1,000 to 10,000	10 seconds	99.9%	Commercial	Once every 5 to 15 minutes
7	VoIP across a Private Network	Assume about 80 kbps of TCP/IP bandwidth for each simultaneous call.				

1. **Backhaul of PLC-Based AMI from Substations:** How often the data are sent from the substation PLC injector over the communications link to the co-op must be identified. This could range from every 5 minutes to once per day to once per week. A general rule of thumb is that a single meter read represents about 50 to 100 bytes of data (varying by vendor) when adding together the raw data and TCP/IP overheads. Therefore, the number of meters is a key variable in determining the size of the data file. Also, the AMI system will be used for a variety of ad-hoc requests, such as individual meter re-reads, outage detection and restoration reads, load control events, pre-pay meter reads, and voltage reads. As mentioned earlier, the expectation for the time it takes to retrieve the information is generally quicker for an ad-hoc read than for the daily meter read poll.
2. **Backhaul of Fixed Wireless-Based AMI from Collector Locations:** One of the main benefits of fixed wireless AMI is the capability to bring fresh metering data from the meter to the AMI master more quickly over the AMI network and the ability of the system to sense meter outages and send a response to the master without having to poll the meter location. Most utilities are bringing fixed wireless AMI data from the collectors to the master each hour, but they bring metering data back more frequently for some customer groups, such as time-of-use customers, pre-pay customers, and Distributed Generation (DG) metering locations.
3. **Modern Distribution SCADA:** Sometimes referred to as substation automation or modernization, this broad term refers to the often gradually upgraded electronic equipment in the substation, which primarily includes intelligent devices that are remotely accessible, provide two-way data flow with reliable communications, and are highly redundant. They also provide control of circuit breakers as well as alarming functionality, and act as a data historian and enable programs such as an integrated volt/VAR.

   As an example, communications architecture within the substation is depicted in **Figure 7.2**. Also shown is the way in which downline DA is routed to a substation over a wireless facility to reach the Ethernet switch located in the substation, and the way in which AMI PLC data are routed through the same Ethernet switch to reach a higher speed communications link at the substation.

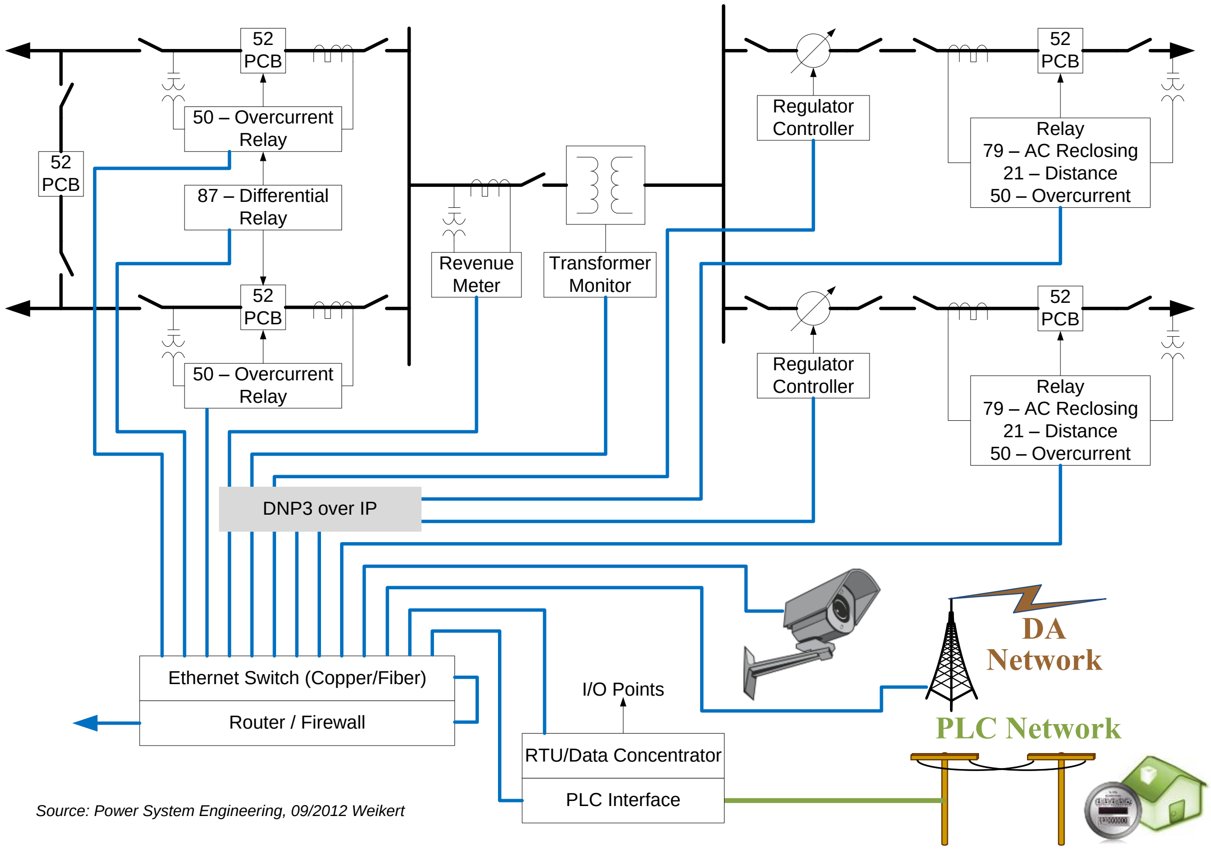


Figure 7.2: Communications Architecture within a Substation

4. **Feeder Distribution Automation Control and Monitoring Applications:** This generic term refers to a variety of distribution feeder programs. Nearly all DA programs include two-way communications between the feeder device and the SCADA master. For a few DA programs, such as a Direct Transfer Trip (DTT) scheme, the communications flow in a peer-to-peer mode between two feeder relays, with at least one of the connections routed to the feeder's substation to update the RTU for any change in state.

   The biggest challenge for any type of DA program generally is related to obtaining coverage to the antennas, usually located below the power lines, often 18–23 feet off the ground. Achieving the bandwidth requirement is not as significant a challenge. Most co-ops deploying DA have longer-term plans to communicate with several dozen DA points, often within the same area, so this is where the 10-year communications plan is particularly important in ensuring that the selected communications technologies are properly scalable.

   Several *Tech Surveillance* articles recently focused on some of the most common DA programs: smart feeder switching, CVR, and Volt/VAR. **Table 7.2** indicates benefits for common DA programs.

Table 7.2: Benefits for Common Distribution Automation Programs

DA Program Types	Improved Reliability	Improved Performance Indices	Increased Profit & Reduced Costs	Reduce Losses	Improved Asset Life
Smart Switching	✓	✓	✓		✓
Conservation Voltage Reduction (CVR)			✓		
Power Factor Improvement (VAr)	✓	✓	✓	✓	✓
Fault Indicators	✓	✓	✓	✓	✓

5. **Direct Transfer Trip Distribution Relay Protection DA:** DTT schemes are starting to be deployed, as many co-ops are now deploying some type of DG program. A DTT scheme typically involves communications between three points: the DG source, a relay located at the point of interface, and a second relay located upstream close to the serving substation. Communications between the relays is peer to peer. The SCADA system at the serving substation can update the SCADA master with any state change of the relay.
6. **Mobile Workforce Management (MWM):** In prior years, MWM was defined primarily as the process in which service orders and work orders were routed from a special software program interfacing with a CIS, skinnying down the data size to about 1,000 bytes, and then routing those data from the MWM server to a laptop located in a vehicle. With the introduction of tablet computers, smart phones, iPads, and the ease of video over smart phones and iPads, the applications for mobile computing are changing rapidly. Just a few years ago, a 4,800 bps mobile data network was adequate for most MWM programs, but now more robust mobile data communications are needed. There are only a few mobile data technologies that can deliver mobile broadband: 802.16e WiMax, some of the mesh technologies, white-space frequency, and cellular. Co-ops also can build hotspots with Wi-Fi and develop practices in which trucks visit hotspots for the transport of larger data files.
7. **VoIP across a Private Network:** VoIP comes into play for co-ops that have multiple offices sharing the same VoIP phone system. This means that the offices are connected with data lines and the branch offices are actually connected to the main office where the phone system server resides. In past years, co-ops used TDM to transport voice traffic, especially those using circuit-switched PBX phone systems, data lines ordered through a telephone company, or microwave or fiber links provided by the co-op through private communications. Now, with a VoIP phone system, the backhaul links used to connect the district office phone system to the primary office can use the same types of data lines used to transport Internet traffic or data from the CIS, SCADA, OMS, and other systems with native TCP/IP.

3.4 How Much Throughput Is Needed?

While the need for speed is obvious, determining data throughput and latency requirements can seem complicated. Determining the bandwidth requirements for a given application is often a two-step process. First, define the bandwidth and latency expectations to a given application device or location. For example, if the requirement is that the SCADA program deliver data in 1 second from a substation RTU to the SCADA master, then this is the defined latency that would be required of the system and measured during the system acceptance testing. After the bandwidth and latency requirements are defined, consider the planned network topology to assess the impact of network collisions.

For example, will several applications be routed to a common tower site that could act as a network node, or to another common network node? What applications may be selected for the use of commercial technologies versus private technologies owned by the co-op? **Figure 7.3** depicts a tower site being used as a major communications node.

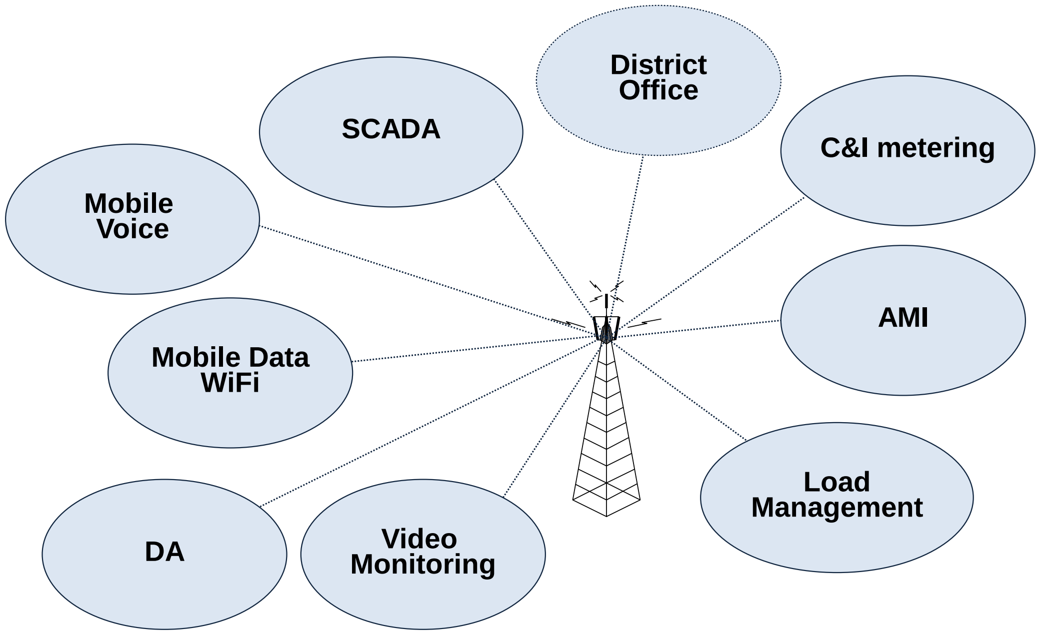


Figure 7.3: Tower Site as Communications Mode

The network topology illustrated in **Figure 7.3** requires that assumptions be made regarding each of the applications that flow into the common tower site. For example, how many meters are consolidated at a given collector or substation location? How many load control customers exist, and how often will the data be sent? What is the data acquisition means for SCADA or DA—polling, unsolicited report by exception, or shotgun polling? How many bytes are consumed by each application, and how frequently will those data come back from each application? This is why it is so important to plan the deployment timeline by application, including the number of devices and, if possible, their locations, over a period of 10 years to ensure the scalability of the selected communications technology.

Once a utility has compiled a list of the applications it will be including in the analysis, the next step is to determine the throughput requirements for each application. To determine the requirement for DA, for example, the amount of data per message (ranging from less than 100 bytes to multiple kilobytes), scan rates, requirements for round-trip latency, and device density all must be measured.

Note that devices such as RTUs, switches, capacitor bank controllers, and voltage regulators may be polled cyclically, with polling cycles (scan rates) that vary depending on the type of message and its priority. When DA device polling is unsolicited report-by-exception (RBX), throughput requirements during normal operations are significantly reduced versus throughput requirements during cyclic polling. In this case, bandwidth sizing is instead accomplished by determining the probable number of devices that will communicate through backhaul nodes during an outage, demand response, or other event. As the devices on an affected feeder may report exceptions in rapid succession, the ability to handle message collisions is important, particularly for slower communications technologies. Also, the number of DA points that feed into a common DA master will impact the bandwidth requirements.

Figure 7.4 depicts a scenario in which field DA points feed into tower sites and substation DA collection nodes.

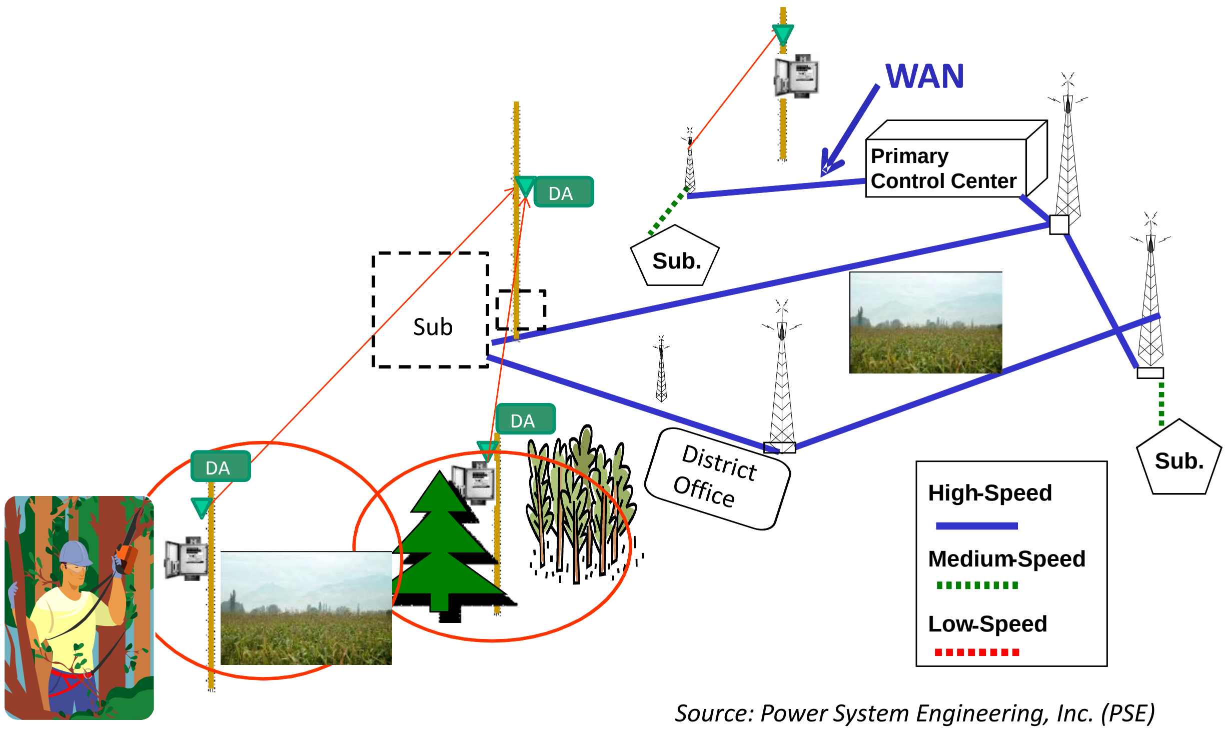


Figure 7.4: DA Points Feeding into Tower Sites and Substation DA Collection Nodes

Similar throughput analysis should be completed for AMI, SCADA, mobile workforce, video security, and any other applications on a co-op's list. The throughput for each application then is aggregated to determine the overall throughput and latency requirements for each backhaul node. The results may be verified by field and lab testing for existing and future applications.

Table 7.3 presents some of the typical requirements for common applications.

Table 7.3: Throughput Requirements for Common Applications

#	Applications	Bytes Per Remote Device Per Transaction (network overheads included)	Frequency of Transaction	Quantity of Devices Routing to Master Collection Site	Quantity of Bits Per Transaction	Typical Latency Required	Throughput Required at a Node Location
1	AMI: Single Meter Read	75	Every 15 minutes	1,000, varies by density	1,020,000	10 seconds	102 kbps
2	AMI: Single Meter Read	75	Once per hour	1,000	2,400,000	15 seconds	68 kbps
3	AMI: Single Meter Read	75	Once per hour	1,000	2,400,000	30 seconds	34 kbps
4	AMI: Outage Read	75	Sporadic	200	15,000	5 seconds	40 kbps
5	SCADA: Poll	300	Every 5 seconds	6 substations	248,480	1 second	24 kbps

#	Applications	Bytes Per Remote Device Per Transaction (network overheads included)	Frequency of Transaction	Quantity of Devices Routing to Master Collection Site	Quantity of Bits Per Transaction	Typical Latency Required	Throughput Required at a Node Location
6	DA (Collector Location)	100	Every 10 seconds	20 DA points to a single master	27,200	4 seconds	7 kbps
7	DA (Collection Location)	500	Every 10 seconds	20 DA points to a single master	136,000	4 seconds	34 kbps
8	Mobile Service Order	2,000	4 orders per transaction	NA	108,800	5 seconds	12.8 kbps
9	Video Monitoring	100,000	Per event	1	1,360,000	5 seconds	272 kbps

In summary, bandwidth requirements vary greatly based on the operational procedures established, the data acquisition interval, the architecture, and, in some cases, the vendor. Several variables can occur, for example, if any type of communication interruption occurs, such as if a given AMI or SCADA vendor's master system errors out, thus causing reads to be missed. The challenge for substations where AMI, SCADA, direct connect to IEDs, and even DA is routed from downline locations to a substation, lies in estimating how often and how much data will be sent at the same time.

For locations where multiple applications are routed over the same communications link, it is common to create routing priorities and guidelines for an Ethernet switch to follow. For example, if multiple applications can be routed over the same link, a co-op might prioritize at least 50 kbps of the available pipe to SCADA. The next 100 kbps might be prioritized for AMI, and the lowest priority could be all the other applications, such as downline DA, MWM, video, etc.

3.4.1 Radio Frequency Bandwidth Data Rates: Vendor Quoted vs. Actual Installed

For wireless technologies, understanding the difference between the vendor-quoted radio frequency (RF) data rate (the vendor's "marketing" specifications) and actual data throughput is crucial in determining whether a wireless technology will meet a co-op's throughput and latency requirements. For example, a product with a stated data rate of 100 kbps may yield only 20 or 50 kbps of actual installed data throughput, due to such factors as hardware and software delays, RF packet overhead, communications protocol overhead, half-duplex data transmission, network contention, retries, and many other factors.

It is recommended to test the throughput of the technologies being considered, both in a controlled lab environment and in the field, using planned antennas, antenna height, etc. Front-end processors (FEPs) may be used to help lower-capacity technologies manage rapid polling or numerous unsolicited messages during events.

3.5 Summary

Cooperatives understand that the ramifications are too significant simply to take a guess at communications requirements. It all starts with creating a 10-year plan for the applications that require communications and that the co-op expects to add or enhance. The following then should be undertaken:

- Create an application-level roadmap by year. Ask questions such as: When will SCADA be upgraded? When and how will advanced DA be deployed? When will a new LMR system be added? When will the existing one-way load control program be retired? When will the existing AMI system be retired and replaced with a new technology? When will mobile service orders be added?
- Define the actual requirements for each application. Defining the number of bytes to be sent, the frequency with which data are to be sent, and the requirements for bandwidth and latency is a great start toward narrowing down communications infrastructure alternatives.
- Create a communications architecture plan that defines throughput at remotes and any network concentration points, and determine if the architecture will have multiple tiers with different technology at different tiers, as well as the degree of commercial versus private technology.
- Create a communications deployment build-out schedule.
- Develop a plan for staffing and support during and after deployment, and develop a project management plan for the deployment.
- Seek funding approvals from a management team, board, and other funding sources such as the Rural Utilities Service (RUS).
- Begin detailed design tasks and procurement.

SECTION 4: FUTURE WORK NEEDED ON TELECOMMUNICATIONS

By Maurice Martin, NRECA

Defining communications requirements is an important step, but only takes us so far. The communications problem still needs to be addressed on three levels: support from both federal and state regulators, technical innovation, and decision-making guidance.

4.1 Support from Regulators

The regulatory landscape is varied for co-ops. In some states, electric co-ops are barred from providing broadband services to customers. This prohibition may be a function of cable and telecommunications providers desiring to limit the field of those who offer service. There also may be other historical reasons for the prohibition. For example, there may be concerns about cross-subsidization of broadband services by electric customers. Nevertheless, the prohibition can be a problem if no other service provider is willing to fill the gap. In many rural areas, customers are limited to telecommunications technology that is not capable of handling the large amounts of data available today. The large incumbent telecommunications providers are not willing to serve areas where the economics of sparse population do not drive sufficient return on capital invested. Thus, very rural areas lack access to broadband. Increasingly, lack of broadband is a major disincentive to economic growth and investment—and businesses of all types and sizes only will grow more dependent on high-speed connections in the future.

In general, electric cooperatives are not trying to get into the telecommunication business. However, some electric cooperatives are exploring offering broadband services to their member customers in light of lack of service from any other provider. This exploration is consistent with Cooperative Principle #7—Concern for Community. That principle states, "While focusing on member needs, cooperatives work for the sustainable development of their communities (emphasis added) through policies accepted by their members." In addition, if electric cooperatives had the option to sell their excess bandwidth (as Washington-St. Tammany is considering), they would have a funding mechanism for deploying the kind of high-speed telecommunication infrastructure needed to support their Smart Grid functions. Regulations that prohibit electric co-ops from offering broadband can thus have the unintended consequence of stopping grid modernization and stifling economic growth—a bleak scenario for rural America.

To offer broadband service to members, electric cooperatives must apply to the FCC to become Eligible Telecommunications Carriers (ETC). The designation as an ETC carries with it build-out milestones and deadlines as well as administrative reporting. While some electric cooperatives are electing to apply to become ETCs, others have chosen not to pursue that path.

Finally, many in the industry have articulated a need to dedicate a specific swath of spectrum to electric utilities as critical infrastructure providers. NRECA participates with other CII industry groups in exploring the possibility of dedicated spectrum for co-op needs. Spectrum is a scarce good with a high value, and many groups and industries are competing to buy it.

4.2 Technical Innovation

As stated, utilities have a number of technologies to choose from when upgrading their telecommunications, but each technology has its strengths and weaknesses; none by itself is a "one size fits all" solution. Co-ops must contend with varying topographies, customer densities, grid topographies, and other variables—in some cases, none of the existent technologies offers an affordable solution.

There are fascinating new technologies under development that may close the gap. Virginia Tech is working on cognitive radio networks—a communication system that is aware of its environment and adapts its performance accordingly. The "cognitive engine" is able to adjust operating frequency, protocol, and waveform, and monitors its own performance continuously. Cognitive radio holds out the promise of more efficient use of the spectrum, as well as more automation in deploying and maintaining a wireless infrastructure. The latter has particular value for rural cooperatives, many of which have limited staff expertise in communications. (Note in the case studies those co-ops that chose their systems based on staff familiarity with the equipment or manufacturer. A more automated system of deployment and maintenance would make new technology more accessible.)

The communications field is rich with ideas and innovation. While this gives co-ops more choices, it also increases the complexity of decision making when it becomes time for a communications upgrade. As seen from the case studies of co-ops that upgraded their communications, when faced with an overwhelmingly complex choice, staff sometimes will simplify by choosing technology with which they are already familiar.

4.3 Decision-Making Guidance

A guide for analyzing options for a communications upgrade would be a tremendous boon for both short- and long-term decision making. Such a guide would take into account communications systems currently deployed, the current and future needs of the utility, topology and customer density, and other important factors. It would identify logical phases for building out a communications infrastructure and take into account anticipated advances in communications.

The creation of such a guide is an ambitious project, but NRECA has found a partner to help with this effort: power and automation technology maker ABB. The company is currently in an information-gathering mode, meeting with co-ops and discussing their communication needs, goals, and challenges. The guide produced will be "vendor agnostic"—that is, it will not favor any one manufacturer. ABB's interest is in seeing more deployment of high-speed communications, which will open up new markets for its equipment sales.

NRECA and ABB expect the guide to be completed in 2014 and they will publish it for the entire co-op community. This effort will build on lessons learned from the Smart Grid Demonstration Project and point the way to a more advanced, fully functional Smart Grid of the future.

Chapter 8:

Conservation Impact of Prepaid Metering – Motivation and Incentives for Pre-Pay Systems

INTRODUCTION

This document is a review of prepayment programs under development at three distribution cooperatives as a part of the National Rural Electric Cooperative Association-U.S. Department of Energy (NRECA-DOE) Smart Grid Demonstration Project (SGDP). The intent of the document is to provide an overall status for each program, as well as compare and contrast the results of each. The three cooperatives are EnergyUnited (EU), Delta-Montrose Electric Association (DMEA), and Kotzebue Electric Association (KEA).

In June 2012, NRECA published a Prepaid Metering Analytical Report. The intent of the June 2012 report was to give utilities necessary information about defining and running a prepayment program. Considering further the opportunities for cooperatives in prepay programs associated with Smart Grid development, NRECA commissioned an update to the 2012 study, entitled "Electricity Prepayment Program Update for the Cooperative Market," to focus more specifically on the growth and status of prepayment. Among other things, the findings of this update are that (1) the presence of an AMI solution is a core enabler of prepayment; (2) many if not most of the customer information systems (CIS) now support the offering of prepayment as a payment method; and (3) prepayment in general is growing at a significant pace, perhaps as much as 55% over the past 2 years, and possibly even higher. In concert with the intent of the SGDP research, the Program Update is provided in and appendix to this report as supplemental information to assist cooperatives that are investigating prepayment programs.

EnergyUnited (EU)

EU is the second largest provider of residential electricity in North Carolina and among the 20 largest electric cooperatives in the United States. With more than a quarter-million consumers in parts of 19 North Carolina counties, EU is in the fast-growing Piedmont section of North Carolina—including parts of Charlotte, Greensboro, and Winston-Salem. Headquartered in Statesville, NC, with offices in seven cities and towns, EU's service area stretches the entire breadth of the state, from the Virginia border to Mecklenburg County.

EU was formed in 1998, when electrical cooperative members overwhelmingly voted to consolidate Crescent and Davidson Electric Membership Corporations. These two established cooperatives had served members for almost 75 years.

Delta-Montrose Electric Association (DMEA)

Delta-Montrose Rural Power Lines Association was organized in Colorado in August, 1938. Three years earlier, the Rural Electrification Administration (REA) was established by Executive Order 7037, signed by Franklin D. Roosevelt, for the purpose of promoting rural electrification. At that time, only a small percentage of American farms had electricity because power companies located in the city had not found it economically feasible to construct lines to sparsely populated areas. The REA was established to act as a banker, providing low-interest loans and technical assistance to cooperatives.

Electricity first flowed through Delta-Montrose Rural Power Lines Association's distribution system in May 1939 to serve 250 customers in the Pea Green area of Colorado, near Delta. Customers in the Delta, Hotchkiss, and Paonia areas were added in the following years.

Western Colorado Power Company (WCPC), an investor-owned utility, also provided electricity to the same territory as Delta-Montrose Rural Power Lines Association. Frequently, its secondary and primary lines and those of WCPC ran parallel to one another.

In 1971, the Public Utilities Commission of Colorado ordered an exchange of customers to correct this situation and consolidate certain areas. Two thousand customers were affected in this consolidation.

In May 1975, Delta-Montrose Rural Power Lines Association purchased a portion of the territory being served by WCPC, adding approximately 10,000 customers and 730 miles of line to its system. Because it no longer served only rural areas, the “Rural Power Lines” portion of its name was dropped and the cooperative became Delta-Montrose Electric Association (DMEA).

Kotzebue Electric Association (KEA)

Kotzebue Electric Association in Alaska has been around only since the 1950s. During its time in business, KEA has helped bring electric power to all of Kotzebue. Electric power was first was made available via small generators owned and operated by Kotzebue businesses. Arctic Literage, Alaska Communications Systems (now Alascom), Rotman Stores, the hospital, and Archie Ferguson were among those who supplied and sold excess power from their business generators to homes that were located within throwing distance.

Around 1949, a group of Kotzebue individuals began sending out feelers to find out how to start a local electric power cooperative. This group began the process of obtaining a loan from REA.

At around the same time plans were being made to launch KEA, Havenstrike Mining Company of Candle brought generators to Kotzebue. These generators had been used by the company in its gold mining operations. Two generators—75 and 100 kva—were set up. A few distribution lines also were set up by Havenstrike to deliver electricity to several homes that had been without power.

KEA also was beginning to set up its operations. Its first generator—50 kva—was set up near the present Alascom site. In the mid-1950s, KEA started setting its own distribution lines; the first was built to serve members along Front Street.

In late February 1956, KEA signed and executed a loan contract and mortgage with REA. By the end of that year, test runs on generators in KEA’s new plant were completed and 65 consumer/members were on line. Red Mullally became the first General Manager.

At around the same time, KEA bought Havenstrike’s electric business and consolidated the two operations.

Since then, KEA has grown along with its members’ needs. Along the way, an addition was made to the original plant, and new generators have served a growing demand for electricity. In 1987, an office building was added near the plant, and KEA’s main office moved into new quarters.

In recent years, KEA has spent much time and energy on developing new sources of energy. Because of the high costs of fuel and declining support from the state legislature to keep energy costs in rural Alaska at reasonable levels, KEA has worked to become a pioneer in the use of wind energy in an Arctic environment; the wind energy program provides an alternative source of energy, with the potential to keep electric costs at affordable levels.

Today, KEA has 840 members, and generates more than 22 million kWh per year. Getting electricity into the rural areas of Alaska has been a triumph not only of technology, but also of the people involved, both then and now.

PROGRAM OVERVIEWS

The following sections describe the technical, policy, and marketing aspects of the Prepayment Programs at each utility.

EnergyUnited

EU has an active prepayment program, with more than 1,400 current participants. With more EU

Technical Architecture

The systems involved in offering prepayment to EU members are the Customer Information System (CIS) from Cayenta, a division of N. Harris Computer Corporation, and the advanced metering infrastructure (AMI) solution from Cooper Power Systems. EU is also implementing MeterSense, a meter data management solution (MDMS) from North|Star Utilities Solutions, but it is not yet fully implemented and does not play any material role in the prepayment program.

Cayenta was specifically contracted by EU to develop the capability to support prepayment as part of its core CIS offering. EU specifically wanted to avoid implementing a third-party system for prepayment that would need to be integrated with and run alongside the Cayenta CIS. The high-level architecture of the system is shown in **Figure 8.1**.

The figure shows a non-typical approach to disconnects, as most programs are integrated to the point that these operations can be handled automatically, without the need for human intervention. However, EU is not comfortable with the reliability of the AMI communications at this time and has elected to process them manually to ensure that the operations are completed correctly.

All prepayment customers have remote disconnect devices installed at their residences. EU has a hybrid advanced metering system that includes a combination of power line communication (PLC) and radio frequency (RF) meters. At all PLC meter locations, a remote disconnect collar is installed. These collars are devices installed under the actual service meter and house the disconnect switch. Collars were the first embodiment of remote disconnect before meter manufacturers integrated the disconnect switch into the meter. EU will eventually move to these meters with the disconnects under glass. At RF advanced metering locations, EU already uses the remote disconnect under glass.

All communications with the customer are done via email, text messaging, phone calls, and members logging into a portal. Dedicated in-home display devices are not supported.

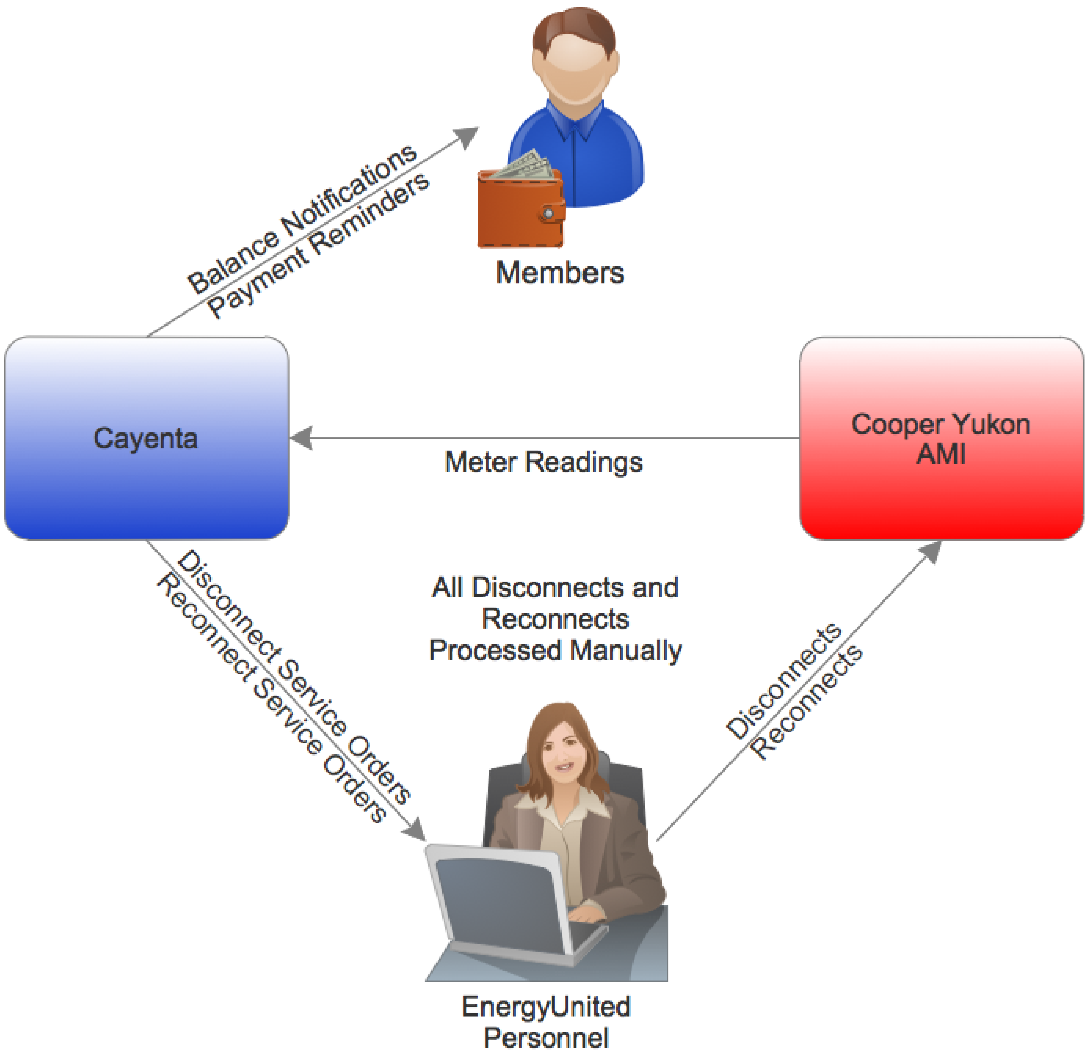


Figure 8.1: Cayenta/EU CIS High-Level Architecture

Policies

EU has taken a unique approach to defining the parameters under which its program operates. Traditionally, prepayment is a program of interest to new members who want to avoid large deposits and those whose accounts are in arrears. When members in arrears move to prepayment, a percentage of each amount tendered is taken and applied to the debt. Members are allowed to pay off their debt in this manner without falling further behind.

EU has structured its program to cater to new members virtually exclusively. Existing members with any amounts in arrears must satisfy their debt obligations before being allowed onto prepayment. The incentive for existing members to enroll in the Prepayment Program thus is not present.

EU does waive the deposit for new members enrolling in the Prepayment Program. This is a decided advantage over having to pay as much as several hundred dollars to get service. The costs of signing up for prepayment are as follows:

Table 8.1: Costs of EU Prepayment Sign-Up

Description	Cost
Service must have a minimum balance of $50 to start	$50.00
Service fee for disconnect collar installation is waived if member is paying a connection fee. The connection fee is:	$30.00
Cooperative membership fee	$5.00
Total Signup Cost	**$85.00**

Once service has been established, members receive daily updates on their balances via the update methodologies they choose. When an account gets to within five days or less of depletion based on daily usage, a daily notification is sent via phone call, text message, email, or any combination of these, based on the member's preferences.

If the account is disconnected due to lack of funds, the member must make the following payment amount to be reconnected:

Table 8.2: EU Reconnection Costs

Description	Cost
Minimum balance of $50 for reconnect	$50.00
Reconnect fee	$25.00
Payment of any amount below zero balance	$?
Total Minimum Reconnect Cost	$75.00

The concept of a reconnect fee associated with prepayment is unusual but not unheard of. The reconnect fee for the Prepayment Program is significantly less than the regular reconnect fee. The reconnect fee and the minimum balance criteria serve to act as a deterrent to disconnects. This is especially important to EU, since the disconnect/reconnect processes involve significant manual support. Without these fees, the program might become too labor intensive, given the current support requirements.

Other policies associated with the program are summarized as follows:

1. Prepayment is offered only to residential and small business members.
2. Prepayment enrollees are on the same rate as regular bill payment customers.
3. Prepayment is not offered to any service location where there is a demand charge component to the bill.
4. Disconnects are performed once daily, with the following stipulations:
   a. On Monday after all drop-box payments are processed.
   b. No disconnects on weekends or holidays (because of manual processing of disconnects).
5. Reconnects are performed 24/7 via the utility dispatch center.
6. No disconnects are performed when the temperature is below freezing or above 105 degrees.

Marketing

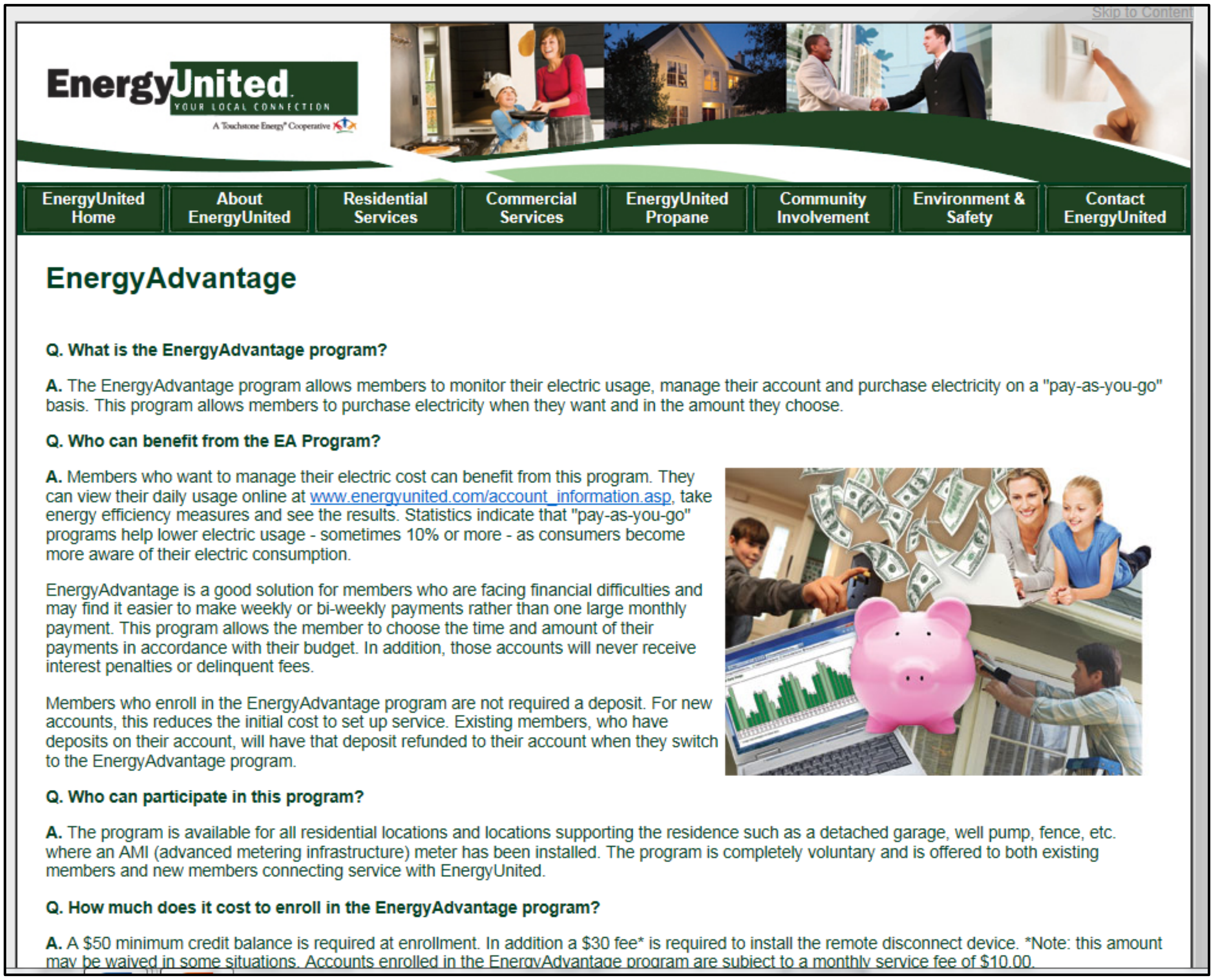
EU has done extensive work in promoting the program. EU has branded the Prepayment Program as the EnergyAdvantage (EA) program. Many utilities have seen this branding as an effective way to reference and market such a program. However, it should be noted that this in no way serves to disguise or hide that it is prepayment. According to member service personnel at EU, members readily understand this fact.

The following are the various ways in which the program has been promoted.

Website

Figure 8.2 shows the promotion of the Prepayment Program web page on the EU website.

Figure 8.2: EU Prepayment Program Web Page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EnergyAdvantage

Q. What is the EnergyAdvantage program?

A. The EnergyAdvantage program allows members to monitor their electric usage, manage their account and purchase electricity on a "pay-as-you-go" basis. This program allows members to purchase electricity when they want and in the amount they choose.

Q. Who can benefit from the EA Program?

A. Members who want to manage their electric cost can benefit from this program. They can view their daily usage online at www.energyunited.com/account_information.asp, take energy efficiency measures and see the results. Statistics indicate that "pay-as-you-go" programs help lower electric usage - sometimes 10% or more - as consumers become more aware of their electric consumption.

EnergyAdvantage is a good solution for members who are facing financial difficulties and may find it easier to make weekly or bi-weekly payments rather than one large monthly payment. This program allows the member to choose the time and amount of their payments in accordance with their budget. In addition, those accounts will never receive interest penalties or delinquent fees.

Members who enroll in the EnergyAdvantage program are not required a deposit. For new accounts, this reduces the initial cost to set up service. Existing members, who have deposits on their account, will have that deposit refunded to their account when they switch to the EnergyAdvantage program.

Q. Who can participate in this program?

A. The program is available for all residential locations and locations supporting the residence such as a detached garage, well pump, fence, etc. where an AMI (advanced metering infrastructure) meter has been installed. The program is completely voluntary and is offered to both existing members and new members connecting service with EnergyUnited.

Q. How much does it cost to enroll in the EnergyAdvantage program?

A. A $50 minimum credit balance is required at enrollment. In addition a $30 fee* is required to install the remote disconnect device. *Note: this amount may be waived in some situations. Accounts enrolled in the EnergyAdvantage program are subject to a monthly service fee of $10.00.

Figure 8.2: EU Prepayment Program Web Page (continued)

The web page can be accessed at:

https://www.energyunited.com/energy_advantage.asp.

Member Newsletter

Figure 8.3 shows a news item contained in the April 2012 EU newsletter.

CONNECT

VOLUME 14, Nº 4 | Published for Member/Owners of EnergyUnited | APRIL 2012

Plant Responsibly — 30

Cost of Electricity is Rising — 31

Bright Ideas Program Kicks Off — 32

You Get the Credit — 32

Introducing EnergyAdvantage: Pay-As-You-Go Billing Program

Food. Gasoline. Even cell phone minutes. We pay for these and other goods and services before we actually use them. EnergyUnited is now offering members the option to pre-pay for electricity through EnergyAdvantage, a new pay-as-you-go program. Pay-as-you-go programs have been around for a long time; however, due in part to the economy, these programs are growing in popularity especially at electric cooperatives. For those who want to take control over their electric costs, a pay-as-you-go program may be of benefit to you. Surveys indicate that 90 percent of those enrolled in similar programs believe they use energy more wisely as a result. In addition, statistics indicate that pay-as-you go programs, such as EnergyAdvantage, help lower electric usage resulting in real savings, sometimes by more than 10 percent, as consumers become more aware of their electric consumption.

The EnergyAdvantage program makes it easy for members to monitor their electric usage through the recently introduced daily energy usage graphs available online. Their energy usage is then used to calculate their daily cost allowing members to better manage and monitor their finances. Under this program, members can purchase electricity in smaller, incremental amounts on an as-needed basis. Purchasing electricity is quick and easy, even on holidays and weekends. Purchases can be made using any of EnergyUnited's convenient payment options, including bank draft, phone, mail, after-hours deposit facility, in person at any EnergyUnited office or authorized payment agent location, via online banking or through the EnergyUnited website, *www.energyunited.com*.

Members who elect to participate in the EnergyAdvantage program will be enrolled in our e-billing program and will receive a monthly statement of account by email. With EnergyAdvantage, members can check daily their account credit balance online at *www.energyunited.com* or by calling our automated account information system at 1-800-636-2371. To ensure easy, efficient account management, members can sign up to receive phone calls, text messages, and/or email alerts concerning their account credit balance and a need for payment to avoid disconnection of electric service.

"Members are empowered to effectively manage their energy use in a way that best suits their individual situation," said Kathleen Hart, vice president of customer care at EnergyUnited. "Most importantly, when they use less energy, it lowers demand on our entire system, which could save everyone money in the long run."

Enrollment in EnergyAdvantage is voluntary and available to all residential members. This is just one more way that EnergyUnited is looking out for you – making it easier than ever for you to view your daily usage online, take energy efficiency measures and see the results. To learn more about EnergyAdvantage or to enroll, visit *www.energyunited.com* or call (800)522-3793.

Holiday Closing: All co-op offices will be closed on Friday, April 6 in observance of Good Friday. Crews will be on call.

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Figure 8.3: News Story About the Prepayment Program in the EU Newsletter

Bill Insert

Figure 8.4 shows a bill insert created to promote the EU Prepayment Program.

Figure 8.4: Bill Insert Promoting the EU Prepayment Program

Delta-Montrose Electric Association

DMEA is not very far along in the rollout of its Prepayment Program. Currently, it has three DMEA employees working on prepayment in a test phase.

Technical Architecture

The systems involved in offering prepayment to DMEA members are the CIS from the National Information Solutions Cooperative (NISC) and the AMI solution from Aclara. DMEA is in the midst of transitioning from Aclara's MDMS solution to the package offered by NISC. However, this system does not play an active role in the prepayment service.

NISC and Aclara are vendors experienced in prepayment and played important roles in the definition of the interface requirements as part of the MultiSpeak specification. Their integrations appear to be solid, with DMEA personnel having a high degree of confidence in the solution. Therefore DMEA expects to allow the technology to automatically process disconnects and reconnects without human intervention or oversight. **Figure 8.5** shows a simplified high-level diagram of the architecture.

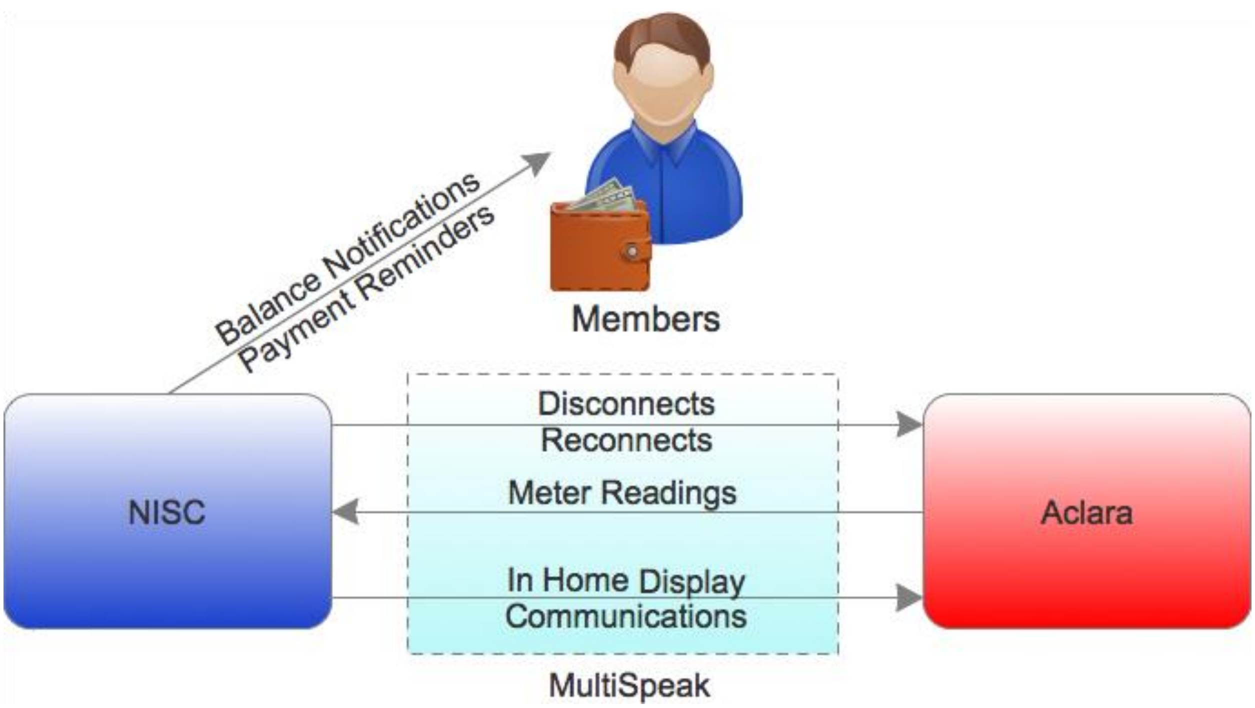

Figure 8.5: DMEA Prepayment System High-Level Architecture

As can be seen from the figure, DMEA will be utilizing in-home displays (IHD) as an optional communications channel to members. While many programs have eliminated this option in favor of email and text messaging, DMEA has chosen to include it due to the significantly rural aspect of its territory.

In addition to the email, text messaging, and IHD options, NISC offers an app that can be downloaded by iPhone and Android users. For more information, see the following:
http://www.smarthubapp.com/index.htm.

This app is in use by the DMEA personnel working on prepayment, with very positive results.

All prepayment customers will have disconnect collars installed at their residences. DMEA would like to eventually move to meters with integrated disconnects, which are currently available.

Policies

Because DMEA is not ready to roll out its program, many of its policies are not yet well formed. However, its positioning of the program would appear to be on the other end of the spectrum from that of EU.

DMEA will encourage those members who are in arrears to join the Prepayment Program and allow their debts to be paid off over time by taking a percentage of each amount tendered and applying it to the debt. Conversely, DMEA does not currently have a required deposit to get service. Therefore, it is unclear as to whether new members will elect to sign up for prepayment initially.

Other proposed policies associated with the program are summarized as follows:

1. Prepayment is offered only to residential and small business members.
2. Prepayment enrollees are on the same rate as regular bill payment customers.
3. Prepayment if not offered to any service location where there is a demand charge component to the bill.
4. Disconnects are to be performed once daily, including weekends. It is as yet unclear if disconnects will be processed on holidays.
5. Reconnects are performed 24/7.
6. No disconnect moratoriums are expected due to weather/temperature extremes. This is consistent with existing disconnect policies.
7. DMEA is considering some incentives for members to increase their level of sign-up to the program.
8. There is not expected to be any additional monthly or reconnect fee associated with the program.

Marketing

Marketing efforts for the program have been the subject of many discussions but the actual plans have not yet been formulated.

Kotzebue Electric Association

KEA is not very far along in the rollout of its Prepayment Program. While the program was anticipated to be rolled out in summer 2013, it likely will not be rolled out until spring 2014.

Technical Architecture

The systems involved in offering prepayment to KEA members are the CIS from PCS and AMI solution from Landis+Gyr. PCS and Landis+Gyr both are vendors experienced in the various aspects of prepayment. KEA expects to allow the technology to automatically process disconnects and reconnects without human intervention or oversight. A simplified high-level diagram of the architecture is shown in **Figure 8.6**.

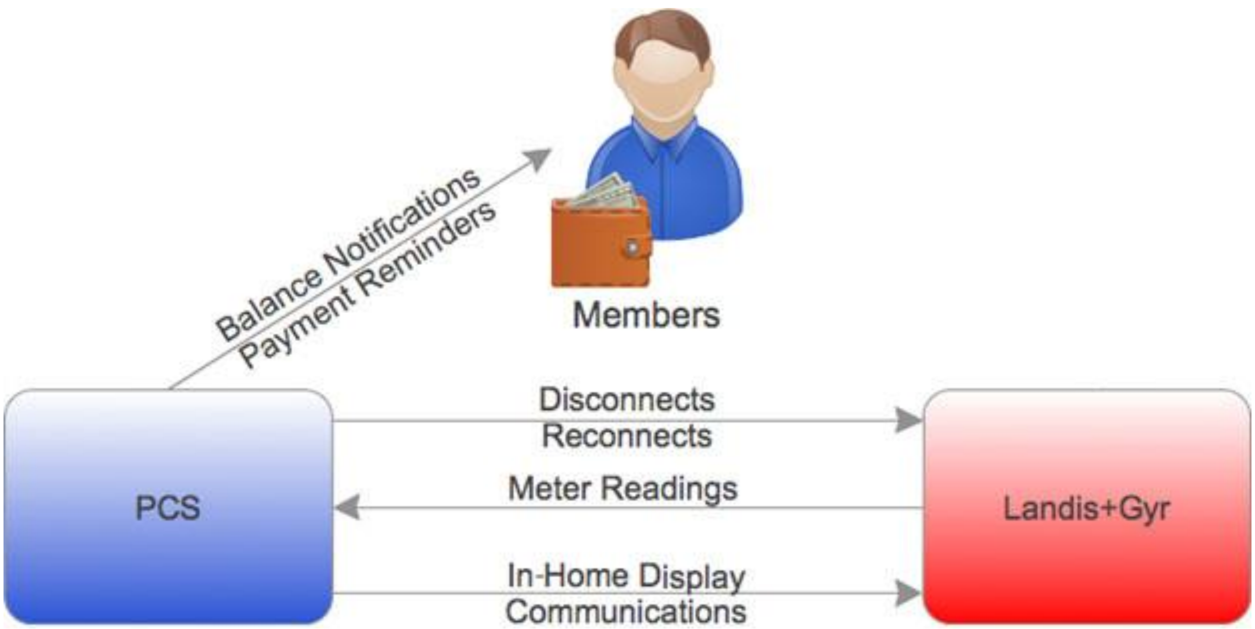

Figure 8.6: KEA Prepayment System High-Level Architecture

As can be seen from the figure, KEA will be utilizing IHDs as an optional communications channel to members. KEA has chosen to include this option in large part to assist its members in making decisions about their power consumption.

Policies

Because KEA is not ready to roll out its program, many of its policies are not yet well formulated. KEA will encourage those members who are in arrears to join the prepayment program and allow that debt to be paid off over time by taking a percentage of each amount tendered and applying it to the debt. In addition, KEA will encourage temporary residents to utilize the service as an alternative to regular bill payment and thus avoid a deposit.

Due to the weather extremes in the KEA territory, a service limiter feature will be utilized in the winter months in lieu of a hard disconnect. Service limiter functionality works in the following manner:

- A wattage limit is set for the premise based on historical usage, with the expectation that it will allow basic lifeline service but not unlimited usage.

- When the wattage level is exceeded, the service is temporarily disconnected.
- After the prescribed time period, typically a few minutes, the service is reconnected.
- After reconnection, there is a period of stabilization, typically also a few minutes, to allow the load to level out before the system starts monitoring the wattage level and the process begins all over again.

Other proposed policies associated with the program are summarized as follows:

1. Prepayment is offered only to residential and small business members.
2. Prepayment enrollees are on the same rate as regular bill payment customers.
3. Prepayment if not offered to any service location where there is a demand charge component to the bill.
4. Disconnects are to be performed once daily, and only during open-office hours.
5. Reconnects are performed during open-office hours.
6. Balance updates likely will be sent to members only on a weekly basis, unless the balance falls within the parameters requiring more frequent notification.
7. No additional monthly or reconnect fee is expected to be associated with the program.

Marketing

Marketing efforts for the program have been the subject of many discussions but the actual plans have not yet been formulated.

STATISTICS – ENERGYUNITED

Because the programs at DMEA and KEA are not yet in operation, we present here some of the statistics gathered on the EA program from EU.

Program Size

As of early September 2013, EU has implemented 2,554 prepayment contracts. At the same time, there are 1,442 active accounts. As expected, based on the program policies, only five of the 2,554 total contracts were obtained from existing members. All other prepayment contracts are with new members.

The purchase frequency of the accounts is shown in **Figure 8.7**.

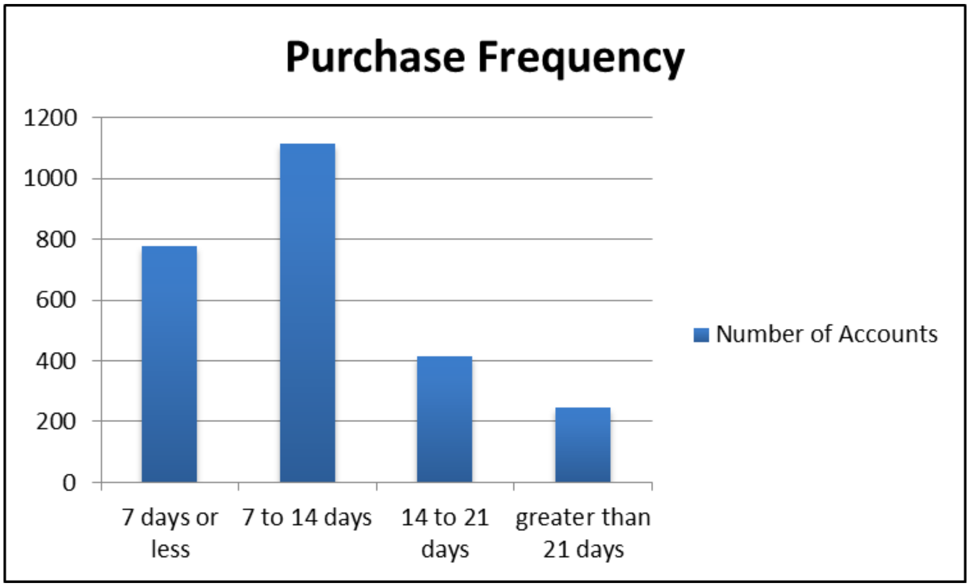

Figure 8.7: Purchase Frequency of EU Prepayment Program Accounts

As expected in the service of prepayment, and as shown in **Table 8.3**, very few members make purchases on a monthly basis. Virtually all of the accounts have taken advantage of the ability to make purchases more frequently.

Table 8.3: Purchase Frequency of EU Prepayment Accounts, Percentage by Time Period

Time Period	Percentage
7 days or less	30%
14 days or less	74%
21 days or less	90%

Disconnects

Because of the implementation of the reconnect fee, EU thought that the members on prepayment might be avoiding disconnects better than those in other programs. However, EU is processing, on average, about 141 disconnects per month, with an average of 17 being disconnected more than once per month and no more than three times per month. Members were disconnected more frequently during the hot summer months.

Outbound Communications

With balance updates and low balance reminders being sent to members on a daily basis, EU has a very high volume of daily outbound communications. On some days, as many as 700 phone calls are made.

Payment Types

One of the long-held beliefs regarding prepayment is that a program must have a way to accept cash payments on a 24/7 basis. The reasons are twofold. The 24/7 requirement is based on the fact that a member must have the ability to reconnect at any time. Even in cases when disconnects occur only during regular business hours, EU cannot predict when the member might discover the outage. Therefore, a means of reconnection on demand is deemed essential to a prepayment program.

The issue around being able to accept cash is based on the fact that many members might not have any type of banking relationship and operate strictly on a cash basis. The advent of prepaid credit cards has created opportunities for members to make payments online and via other outlets without a banking affiliation. While the information available for this report does not allow us to draw any conclusions on this issue, it is interesting to note how members are making their purchases in the program.

EU supports four different payment mechanisms:

- Office locations taking cash, checks, and credit cards
- Third-party providers (convenience stores) taking cash and checks
- Interactive Voice Response (IVR) taking checks and credit cards
- Online systems taking checks and credit cards

Note that debit cards are supported everywhere that credit cards are accepted.

The data set used for the following analysis consisted of daily transaction totals for each type of transaction from May 1, 2012 to August 23, 2013. In the case of office transactions, credit card transactions are broken out separately.

Total Transactions

Figure 8.8 shows the total amount of transactions for the period by payment mechanism.

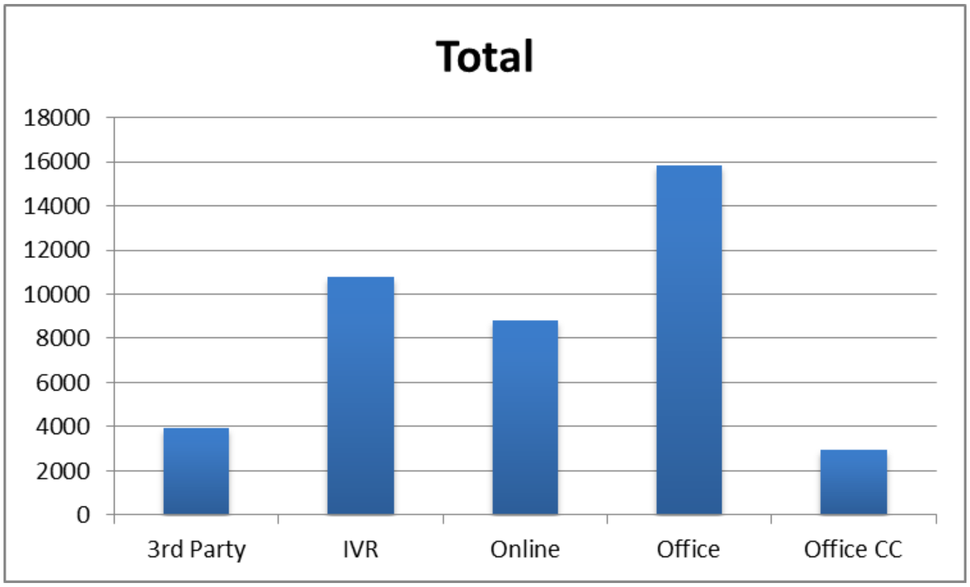

Figure 8.8: Number of EU Prepayment Program Transactions, by Payment Mechanism

From this figure, we can see that cash and check transactions at office locations exceeded all other transaction types. Also, all of the third-party transactions consisted of either cash or checks. Unfortunately, the data available do not indicate the percentage of these transactions that are cash or checks. However, it is reasonable to assume that prepayment transactions are heavily cash based.

Transaction Trends

Figure 8.9 shows how transactions have trended in the entire data set.

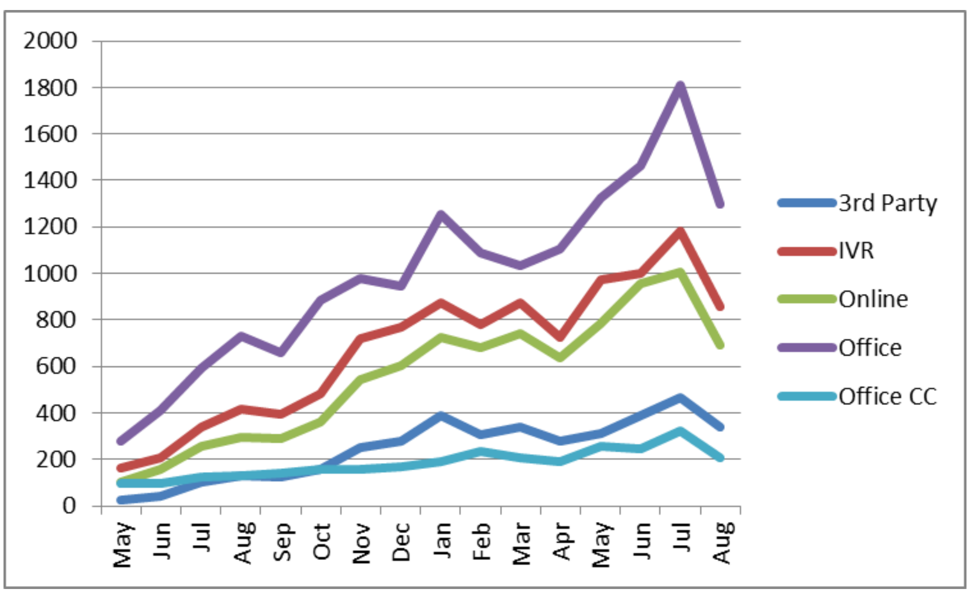

Figure 8.9: EU Prepayment Program Transaction Trends

It is interesting to note how all of the payment methods trended rather consistently over this time period, with the growth of office credit card payments being somewhat flatter than the others.

Holiday Transactions

The transaction analysis also examined the total transactions for all universally recognized holidays for the period, as shown in **Figure 8.10**.

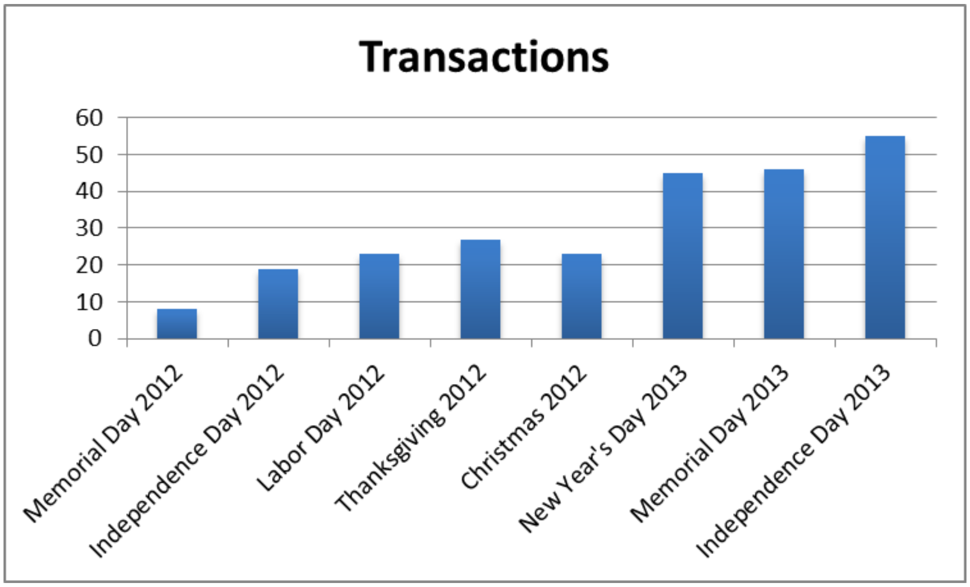

Figure 8.10: Transaction Trends for the EU Prepayment Program, by Holiday

It is difficult to draw any specific conclusions from these data, other than to say that members will initiate transactions at any time. Holiday transactions must be supported in ways that prevent members from being disconnected. EU's menu of transaction options supports the 24/7 need. As to cash transactions, third-party outlets (convenience stores) handled cash transactions on most of these holidays; some transactions of that type are included in the figure.

Energy Efficiency

The statistical and anecdotal expectations of prepayment have been that the program produces a natural energy conservation effect. The savings typically are somewhere in the 5% to 10% range. The hope was that this program would add to the statistical data showing that prepayment does indeed result in energy efficiency and conservation. However, because of the policies associated with the program, only five existing EU members have converted to prepayment. Therefore, there can be no really meaningful conclusions from the data. The lone account that had a reasonable amount of usage both before and after going on prepayment is shown in **Figure 8.11**.

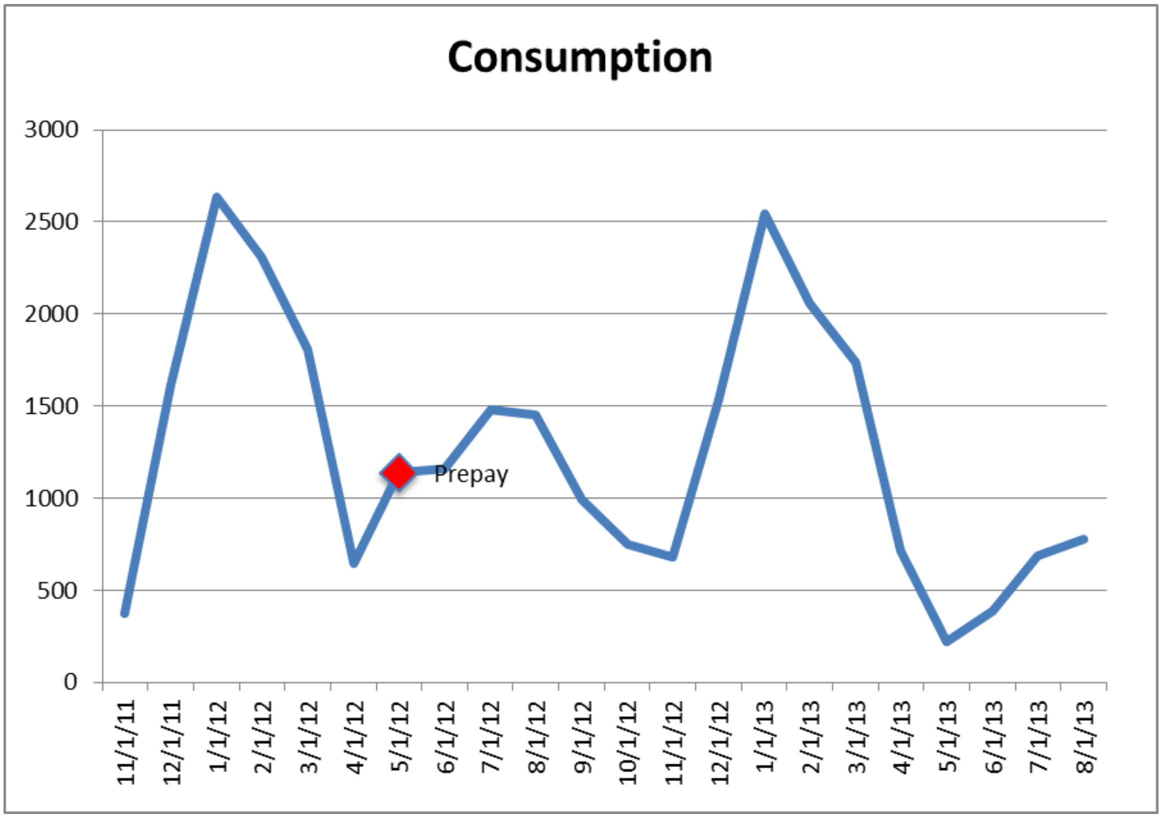

Figure 8.11: Electricity Consumption of One Account Before and After Joining Prepayment Program

As can be seen, no realistic conclusions can be made other than the usage appears remarkably similar both before and after enrolling in the Prepayment Program.

Customer Survey Results

To investigate the impact of prepayment on customers, a survey was conducted. Customers who were in the EU EnergyAdvantage program were asked to participate. The survey explored areas of satisfaction, as well as likes and dislikes regarding the program. The framework of the survey included the following:

- Customers making purchases at utility offices that were in the Prepayment Program were asked to complete a survey.
- No compensation was provided for completion of the survey.
- No names or account numbers were recorded during the survey, so the results are anonymous.
- Because of the framework of the survey, there is high certainty that all respondents indeed were EU customers participating in the Prepayment Program.
- A copy of the survey is included in Appendix 8A.

Length of Service

The first question on the survey asked how long the customer had been on prepayment. The results are shown in **Figure 8.12**.

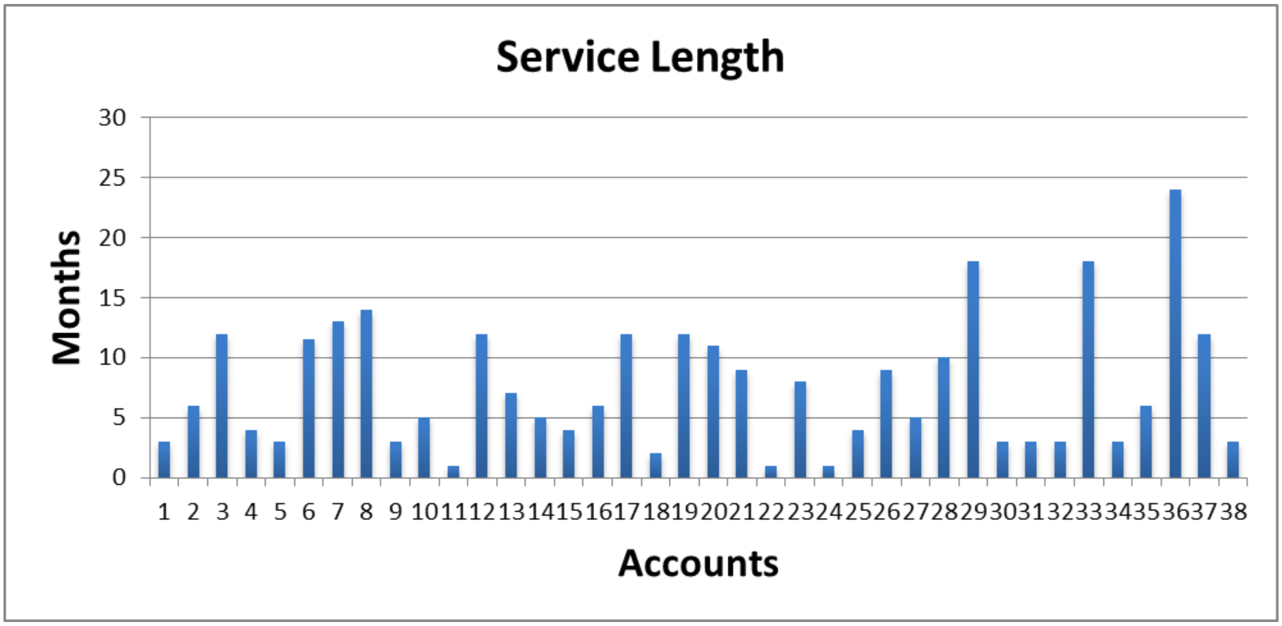

Figure 8.12: Customer Survey: Time in Prepayment Program

Respondents ranged in service duration from 1 month to 2 years, with the average service period over all the accounts being 7.5 months. Because of the random nature of the sampling and the relatively short time that the program has been offered, this spread of service times was not unexpected.

Overall Satisfaction

The most important question of the survey was to gauge the customer's overall satisfaction with the program. Respondents were asked to rate their satisfaction from 1 to 5, with 5 being the highest satisfaction and 1 being the lowest. The results from that question are shown in **Figure 8.13.**

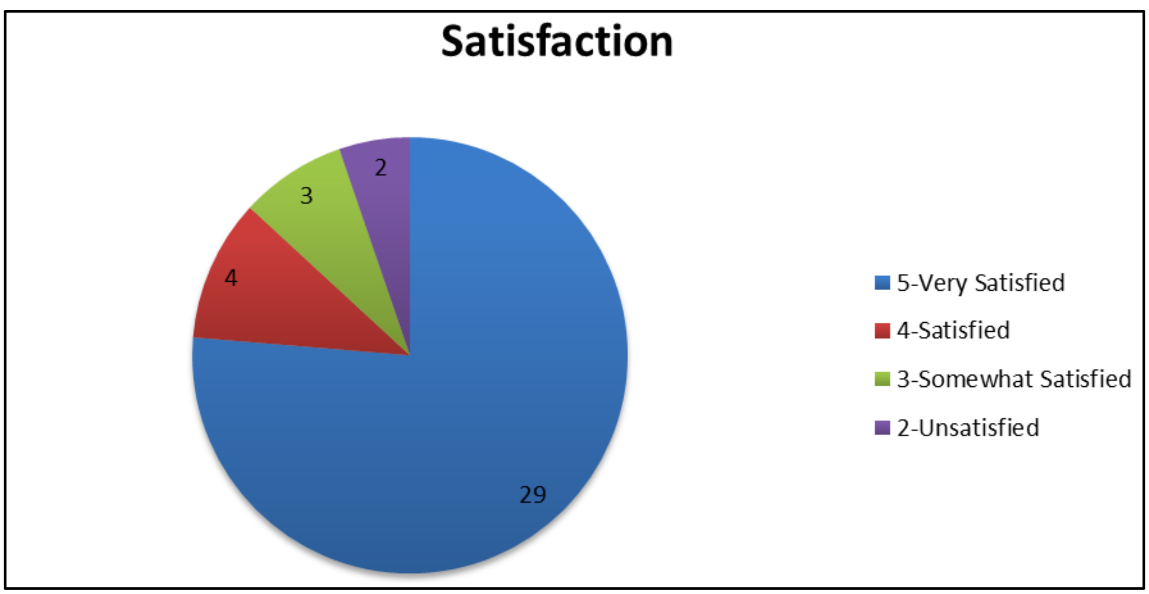

Figure 8.13: Customer Survey: Overall Satisfaction with Prepayment Program

As shown in the figure, 29 of the 38 respondents were highly satisfied with the program (76%). By combining the Satisfied and Very Satisfied groups, the overall approval numbers go to 33 of 38 (87%). This is in keeping with surveys done by other utilities—overall satisfaction rarely drops below 85%.

Reasons for Choosing Prepayment

The next question attempted to identify the main reason for selecting prepayment as the customer's billing method. This was an open-ended question, to allow respondents as much leeway as possible to articulate their reasons. The results of the question are shown in **Figure 8.14**.

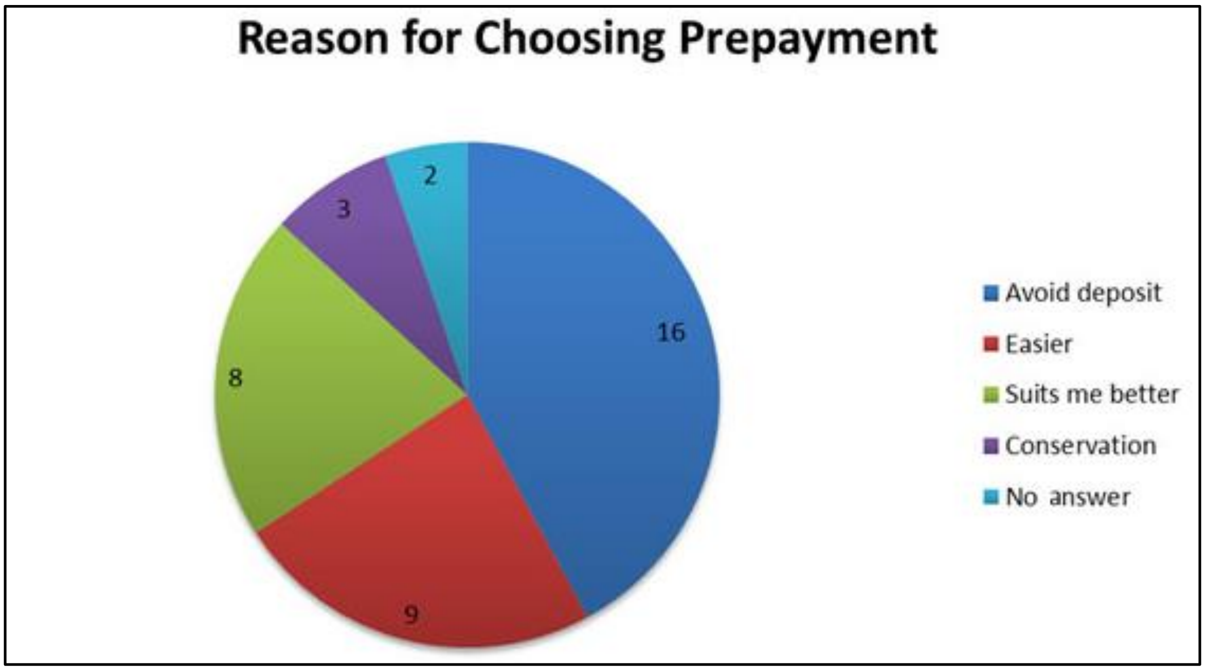

Figure 8.14: Customer Survey: Reason for Choosing Prepayment Program

Because of the way that EU has positioned its program, it is not surprising that the largest number of respondents mentioned the ability to avoid paying a deposit as their main reason for selecting prepayment. It also should be noted that there is likely some overlap with the "Easier" category, in that some respondents considered avoiding a deposit to be easier than having to pay one.

Included in the mix were other noteworthy responses, such as "Conservation" and "Suits me better." These are important categories; they show that prepayment does allow customers to feel more empowered, and that the utility is providing services that better fit their needs.

Saving Money

The question that is always crops up with prepayment is whether or not customers feel they are saving money. The distinction here is the word feel. Because these responses were anonymous, and the fact that many—if not most—of the customers in the Prepayment Program at EU are new customers, there is no real way to determine whether they are paying less for their electric service or not. Therefore, the survey sought an understanding of how customers feel about the service. The results of the survey are shown in **Figure 8.15**.

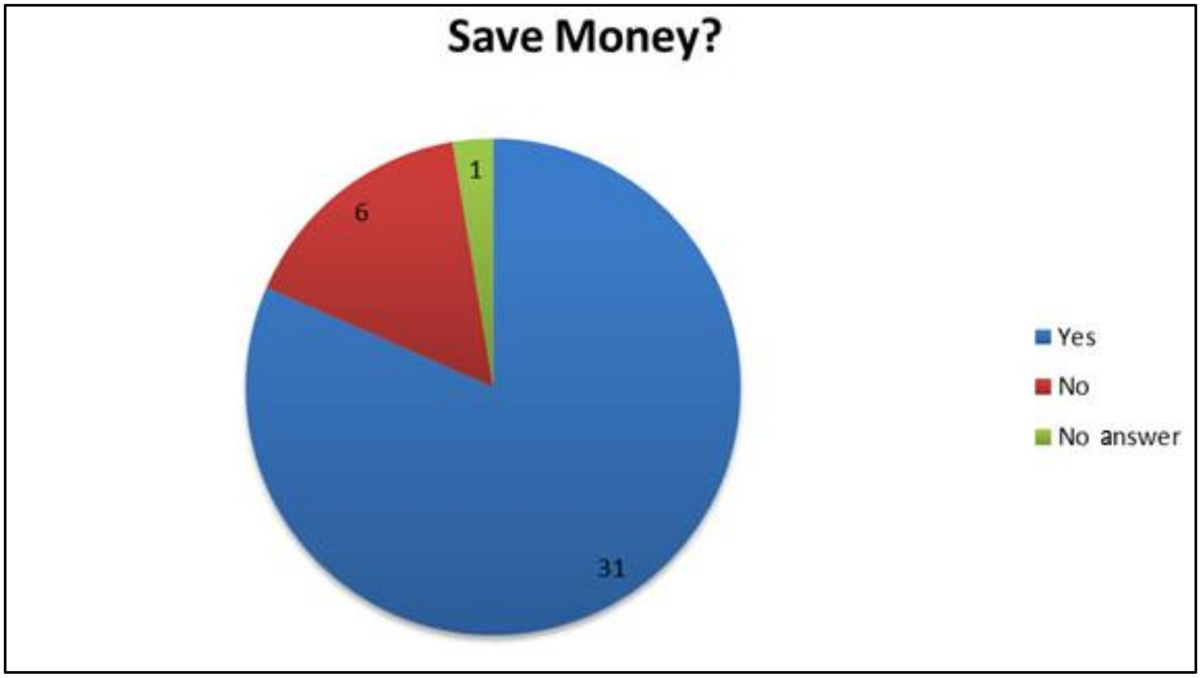

Figure 8.15: Customer Survey: Perceived Savings Through the Prepayment Program

A total of 31 out of 37 (84%) of respondents said they believed they had saved money through the Prepayment Program. This is a significant response, since EU has a reconnect fee of $25 to resume service after disconnect. It was not expected that the response to this question would be so positive. What is not known is if or how many times any of the respondents have been disconnected and have had to pay the $25 reconnect fee. However, this perception of saving money is obviously strong.

Easier to Pay

Because one of the benefits of prepayment is seen to be its much more flexible payment schedule, the survey also asked whether the respondents felt that it was easier for them to pay their bills. The results are shown in **Figure 8.16**.

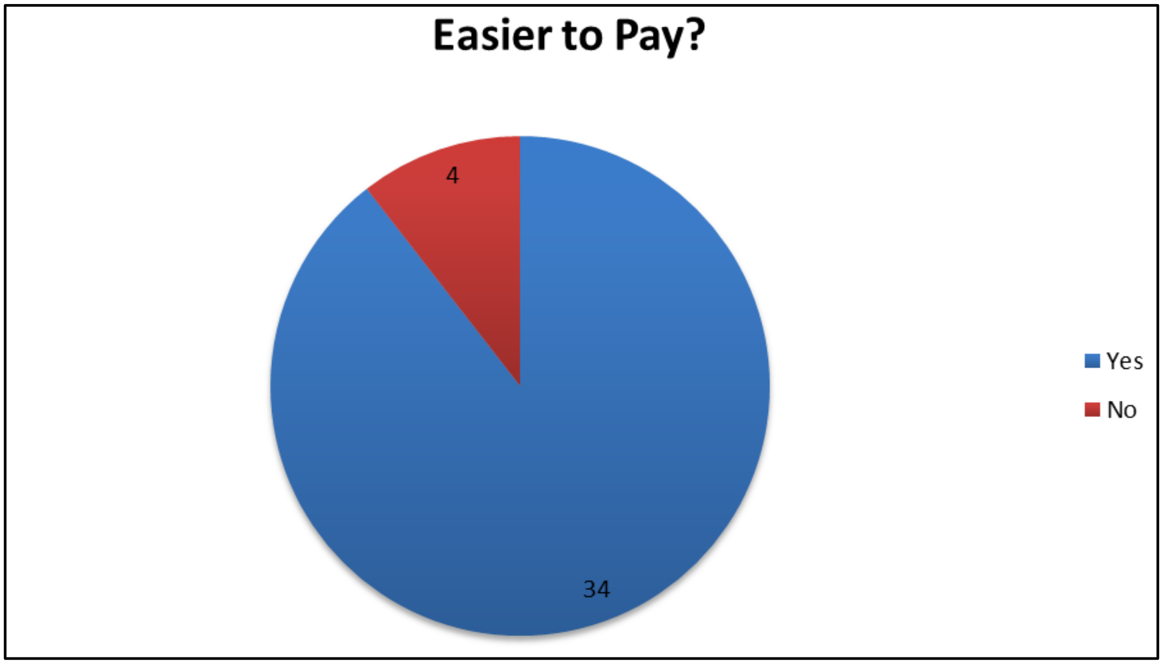

Figure 8.16: Customer Survey: Ease of Payment Through the Prepayment Program

A total of 34 out of 38 (89%) respondents said that it was easier for them to make payments through the Prepayment Program. This would seem to indicate that even the one respondent who was only "Somewhat Satisfied" with the program in response to the earlier survey question did believe that it was easier to make payments (34 out of 38 thought it to be easier, versus 33 out of 38 who were "Satisfied" or "Very Satisfied"). However, a closer look at the survey results shows that there is actually no correlation between these questions. Of the four respondents who said that it was NOT easier to make payments through the Prepayment Program, their corresponding satisfaction ratings are shown in **Table 8.4**.

Table 8.4: Customer Survey: It Was Not Easier to Make Payments Through the Prepayment Program

Respondents Saying it Was NOT Easier to Make Payments
5 – Very Satisfied
4 – Satisfied
4 – Somewhat Satisfied
2 – Unsatisfied

What this means is that three of the respondents to this question did not think it was easier to make payments in the program but still were "Satisfied" or better. It also means that three of the 34 positive respondents to this question still were not "Satisfied" or better in their overall appraisal of the program.

Purchase Frequency

The following data show the purchase frequency of the surveyed accounts. As can be seen from the chart, the survey results very closely mimic the data provided by EU. As shown in **Figure 8.17**, the bulk of the surveyed members purchase either weekly or biweekly.

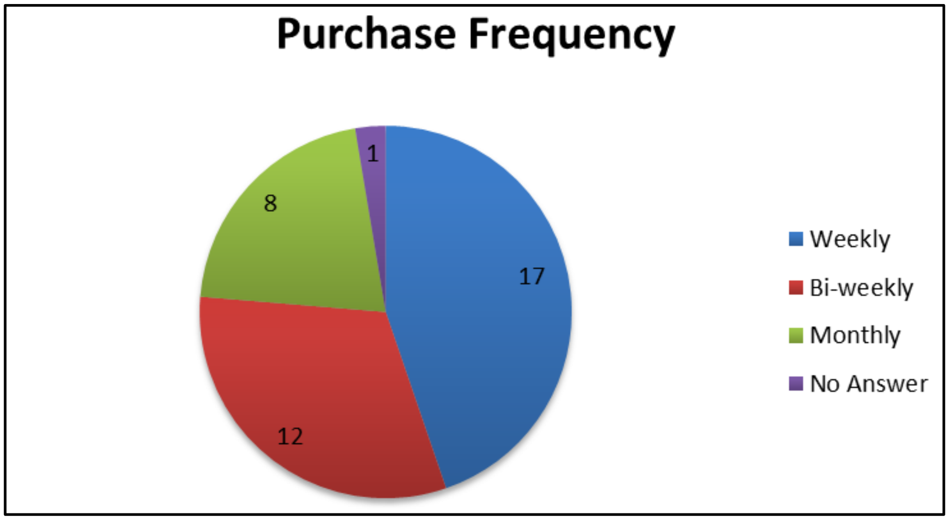

Figure 8.17: Customer Survey: Purchase Frequency in Prepayment Program

Biggest "Like"

The data in **Figure 8.18** show the results for the survey question asking about the biggest "like" about the program.

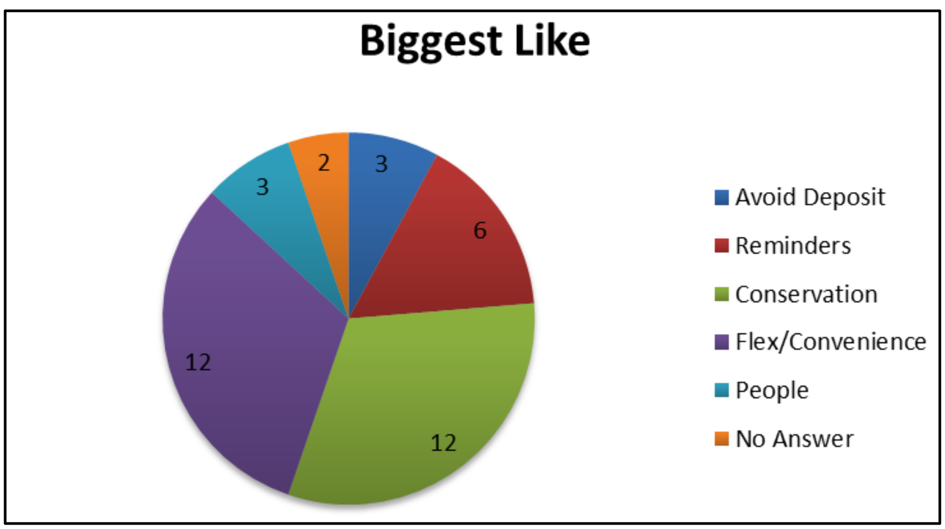

Figure 8.18: Customer Survey: Biggest "Like" About the Prepayment Program

The interesting thing about the results of this question is that it seems to suggest that, while many people chose prepayment to avoid the deposit, other benefits become apparent that surpass mere deposit avoidance.

Biggest "Dislike"

Figure 8.19 shows the results of the question asking members to specify their biggest dislike about the program.

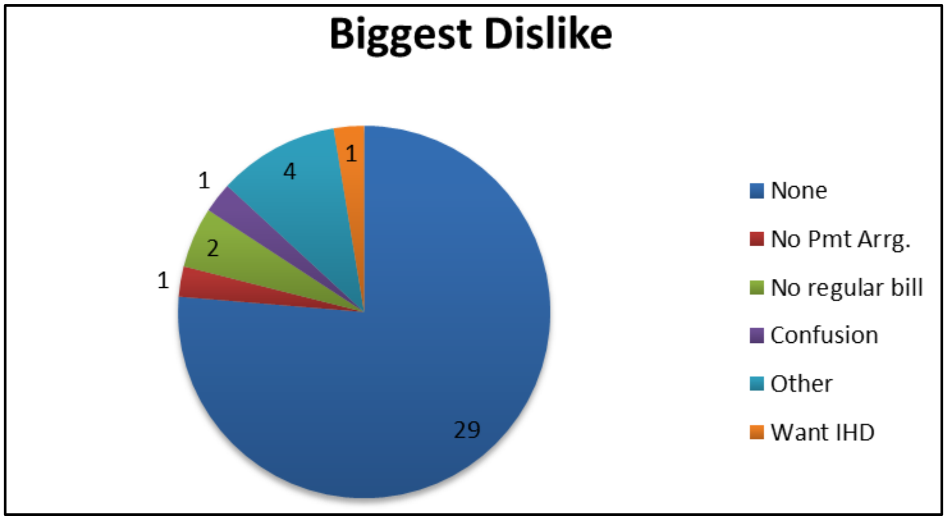

Figure 8.19: Customer Survey: Biggest "Dislike" About the Prepayment Program

The most significant thing about this result is that, overwhelmingly, members have virtually no complaints about the Prepayment Program. This is especially interesting, given the rules around reconnects, such as fees and minimum balances.

Additional Comments

The last question on the survey simply asked the participants if they had any other comments. The results of this question are as shown in **Figure 8.20**.

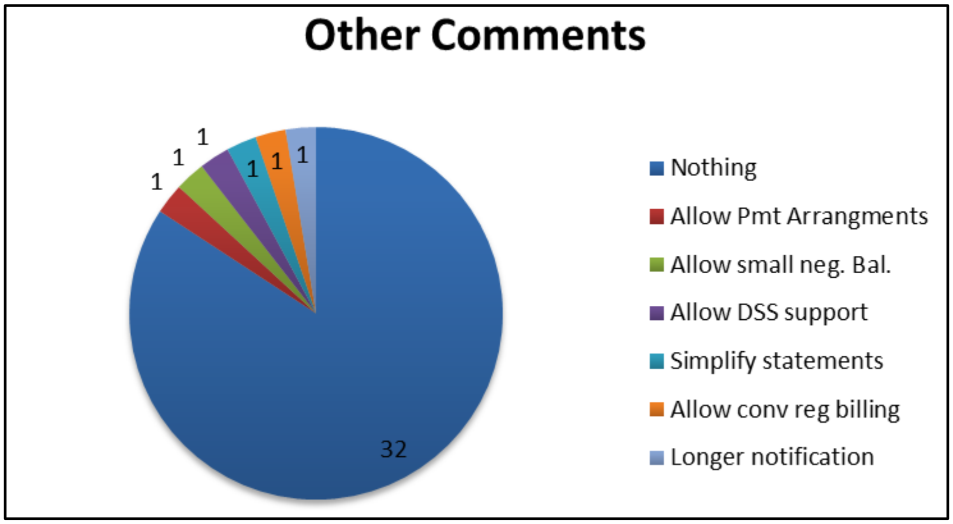

Figure 8.20: Customer Survey: Additional Comments

Once again, only some of the individual suggestions are noted. Most people surveyed did not make any additional comments.

CONCLUSION

EU has created a very effective Prepayment Program that is serving its new members in a way that seems to have generated high levels of satisfaction. While the policies of the program do not necessarily provide a means of debt retirement for existing customers, they do stem the tide of new debt being incurred.

By working with Cayenta, its CIS vendor, to develop prepayment functionality, EU chose an implementation methodology that is sustainable, scalable, and avoids additional systems and integrations. For the program to grow much beyond its current size, however, the overhead of manual processing of disconnects and reconnects must be addressed. Most other programs do not have this issue. It is a testament to the diligence of EU personnel that they have been able to keep up with the operations of the program at its current size.

DMEA and KEA are on the cusp of beginning their programs. The proposed policies for these programs are typical when compared to other, more mature prepayment programs at other utilities. The fact that DMEA does not currently have a deposit does cloud the process by which new members would sign up for service.

Conservation Impacts

It is reasonably clear that some customers perceive that they conserve energy AND also save money. However, the data gathered in this study do not prove that premise statistically. Other studies have pointed to energy savings in the range of 8% to 15%. One of the original goals of this study was to show energy savings and efficiency based on customer usage for at least a year before and after switching to prepayment. This timeframe was expected to answer the following questions:

- Is energy conservation a temporary benefit or does it last beyond the first few months?
- Is energy conservation seasonal, in that conservation occurs only when customers' bills tend to be higher?
- What are the energy conservation results with respect to weather variations?

To answer these questions, we will need to take a more controlled approach to the data gathering to make sure that we identify customer accounts that:

- Have a suitable amount of meter data history prior to switching to prepayment.
- Do not and have not moved for the duration of the study.
- Have not materially changed their power usage due to additions or changes in residence infrastructure.
- Have not significantly changed their lifestyle during the study.

It would be very useful to revisit both the DMEA and KEA programs in 2014 to engage in such a study.

Summary

In general, the results of this investigation further corroborate the basic tenants of prepayment as stated in the Prepaid Metering Analytical Report of June, 2012, including the following:

- Members have a high degree of satisfaction with the service.
- Members appreciate the alternative to the typical deposit requirement for new service.

- Prepayment has become a more implementable option, as existing AMI and CIS vendors now more readily support the service.
- Prepayment does promote better energy awareness.
- Prepayment can be effective and successful based on a variety of policy decisions.

What cannot yet be proven or disproven with this set of utilities and this report are the following:

- Prepayment is an effective tool in the area of energy efficiency and conservation.
- Prepayment can be effectively implemented regardless of the local weather climate (although prepayment has been present in Alaska and Canada for years).

In summary, the evolution of prepayment has reached the point at which most utilities should at least be considering developing a program. The evidence suggests that utilities can tailor the program to meet their specific needs without compromising its overall success and the satisfaction of the membership.

APPENDIX 8A – CUSTOMER SURVEY

EnergyAdvantage Program Member Survey

The following is a survey for EnergyAdvantage customers. Information gathered will be used to publish a report on the effectiveness of the program.

1. How long have you been using EnergyAdvantage? ___________________________
2. How would you rate your overall satisfaction with EnergyAdvantage? (1-low, 5-High) 1 2 3 4 5
3. What is the reason that you are on the EnergyAdvantage program?

   ____

   ____

4. Has EnergyAdvantage allowed you to save money on your bill? (Circle One) Yes No
5. Has EnergyAdvantage made it easier for you to pay for your electric usage? (Circle One) Yes No
6. How often do you make purchases on Energy Advantage? Daily Weekly Two Weeks Monthly
7. What is the biggest thing you like about EnergyAdvantage?

   ____

   ____

8. What is the biggest thing you dislike about EnergyAdvantage?

   ____

   ____

9. If possible, what would you change about EnergyAdvantage?

   ____

   ____

10. Please add any other comments you have about the EnergyAdvantage Program.

    ____

    ____

APPENDIX 8B – SUPPLEMENTAL INFORMATION: ELECTRICITY PREPAYMENT PROGRAM UPDATE

22 Molas Dr., Durango, CO 81301
(704) 430-7697

Electricity Prepayment Program Update for the Cooperative Market

Prepayment Status Update for the
Cooperative Research Network

June 12, 2014

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1. Introduction

The intent of this report is to provide an update on the status and penetration of the service of prepayment in the cooperative utility space. The Cooperative Research Network (CRN) published "Prepaid Metering Analytical Report" in June 2012 to offer assistance in the understanding, planning, and implementation of prepayment. This report focuses more specifically on the growth and status of prepayment today.

This report contains the following sections:

- **Vendor Update –** a review of those vendors and their systems that are enabling the service of prepayment
- **Prepayment Trends –** an overview of some of the emerging trends associated with prepayment
- **Utility Survey –** a survey of cooperatives to better quantify the impact and experiences with prepayment
- **Member Survey –** a survey of cooperative members to understand and quantify their experiences with prepayment and, in some cases, contrast them with non-prepayment members

The general conclusions of this report are as follows:

- The presence of an Advanced Metering Infrastructure (AMI) solution is a core enabler of prepayment.
- Many if not most customer information systems (CIS) now support the offering of prepayment as a payment method.
- Prepayment in general is growing at a significant pace. Evidence indicates that the number of prepayment programs has grown by 55% over the past 2 years. Because the surveys conducted as part of this report are not all encompassing, it is likely that this growth rate is even higher.
- Regulatory restrictions continue to be an impediment to prepayment growth in some states.
- Cooperatives offering prepayment recognize the value of the program and would offer it again if given the option.
- Members recognize the value of prepayment, as evidenced by the high satisfaction ratings.

The surveys referenced in this report likely represent some of the more extensive and more exhaustive work done with respect to prepayment. The results, in many aspects, are very revealing with respect to overall member satisfaction.

2. Vendor Update

For today's prepayment market, there are basically two systems enabling it—AMI vendors and billing engine vendors. Both types of vendors play an important role in offering prepayment.

1.1. AMI Vendors

The AMI vendor provides remote metering and disconnect capabilities. Virtually all of today's AMI vendors are capable of enabling prepayment because the current state of prepayment does not demand anything more from these vendors than what they would normally offer as part of their standard system.

1.1.1. Remote Meter Reading

In today's environment, the AMI system simply needs to provide periodic meter readings back to the billing engine. The only limiting factor in such systems may be the frequency with which these readings are retrieved. Basically, today's systems calculate account balance updates with every meter reading that becomes available. If readings are retrieved once per day, which is the absolute minimum frequency with which to retrieve readings in today's systems, then account balances will be updated once per day. Evidence from a number of existing prepayment programs has shown that this is a suitable update period.

If a utility desires updates more frequent than once per day, this requirement would need to be measured against the existing or proposed AMI infrastructure to determine if the communications needs can be met. This is where some AMI technologies might be stronger than others in their ability to support prepayment.

1.1.2. Remote Disconnect/Reconnect

Since most of the available solid-state meters on the market today support an optional integrated disconnect switch, virtually all AMI vendors can support the need to remotely connect and disconnect prepayment customers. The ways in which some vendors may differentiate themselves are as follows:

- Incremental cost of a meter that includes a disconnect
- Any limitations on frequency of switch operation due to the switch itself or the communications method
- Ability to have positive and reliable feedback as to the successful completion of a switch operation

This last point is extremely important because the reliability of switch operations must be enough so that the process can be automated. Otherwise, additional manual overhead may need to be employed to verify switch operations. From a customer perspective, it is vital to be able to restore power quickly to someone who has made a payment on his or her prepayment account, thus achieving a positive balance or reaching a level deemed acceptable for reconnect.

1.2. Billing Engine Vendors

Billing engine vendors are either the incumbent CIS providers or a third-party system that implements stand-alone prepayment functionality alongside an existing CIS. There are various factors that go into making the billing engine vendor selection. Most of the established CIS that serve the bulk of the cooperative market now offer prepayment. Stand-alone solutions may offer additional flexibility or other features perhaps not found in the legacy CIS prepayment offerings.

Whether the prepayment solution is implemented using the incumbent CIS or utilizes a third-party solution, the development of the MultiSpeak specification has been a huge contributor to making system integrations simpler and more reliable. In most cases, vendors can readily configure their systems to support the necessary interfaces without significant time or expense.

It is beyond the scope of this report to explore the various criteria that might go into a selection solution. This report instead simply will provide vendor information as a resource through which more information can be researched.

1.2.1. Cayenta

Cayenta is a division of N. Harris Computer Corporation. It offers a full-featured CIS that includes prepayment services. Cayenta serves a broad range of utilities, including cooperatives. For more information, go to www.cayenta.com.

1.2.2. Daffron

Daffron is a software company that offers a broad range of software solutions, catering mainly to the cooperative market. It supports a built-in prepayment service capability in its CIS. For more information, go to www.daffron.com.

1.2.3. Exceleron

Exceleron is a company offering a stand-alone prepayment solution that integrates with and operates alongside an existing CIS. Exceleron was one of the early pioneers of a stand-alone prepayment solution. For more information, go to www.exceleron.com.

1.2.4. NISC

NISC is a software company offering a broad range of software solutions, catering mainly to the cooperative market. It supports a built-in prepayment service capability in its CIS. For more information, go to www.nisc.coop.

1.2.5. Nighthawk

Nighthawk essentially is a hardware-based solution offering both meters and disconnect collars that enable the offering of prepayment. By utilizing cellular or other communications, Nighthawk enables surgical deployment of prepayment without having a completely deployed AMI solution. For more information, go to www.nighthawkcontrol.com.

1.2.6. PayGo

PayGo is a stand-alone software company offering a range of payment and billing solutions for utilities. It has had more success in the investor-owned utilities (IOU) market than cooperatives. One of the unique aspects of its system is that it offers the ability to download some firmware to a select group of AMI vendors' meters to perform some level of prepayment functionality at the meter. For more information, go to www.paygoelectric.com.

1.2.7. SEDC

SEDC is a software company offering a broad range of software solutions, catering mainly to the cooperative market. It supports a built-in prepayment service capability in its CIS. For more information, go to www.sedata.coop.

1.2.8. SmartGridCIS

SmartGridCIS is stand-alone software company offering a stand-alone prepayment solution. For more information, go to www.smartgridcis.com.

1.2.9. Others

As mentioned earlier, prepayment has been gaining momentum across the utility landscape. For this reason, most CIS vendors are supporting prepayment in some way. Thus, it is recommended always to check with the incumbent CIS vendor to learn of its capabilities and plans as part of any procurement process. Of course, being able to implement prepayment without needing to support an additional system has its advantages. However, these advantages may be overshadowed by a lack of maturity in the incumbent vendor as to the features, options, and configurability that may be necessary to provide the type of program desired.

Prepayment Trends

The way that prepayment is offered has changed significantly over the past 25 years. Systems have evolved from custom metering hardware solutions to those that leverage standard AMI systems and centralized billing engine solutions. As the demand for prepayment has increased, more innovation has occurred, as well as the evolution and utilization of the service itself. This section will describe some of the more recent trends.

1.3. In-Home Display

Prepayment solutions originally included some form of in-home display to support the provision of balance information to the customer. In today’s environment, the trend is away from in-home displays. There are several practical and technological reasons, as follows.

- In-home displays are another piece of equipment that utilities need to manage and support. Eliminating such devices makes the business case for prepayment simpler to prove and the program easier to manage.
- The proliferation of smart phones provides an alternative to a dedicated in-home display that is portable and supported by a third party.
- The ready access to the Internet provides a viable alternative to in-home displays.

1.4. Notification Options

Most prepayment billing engine solutions allow participants to configure notifications to suit their own needs. This configurability relates both to the means of communications and their frequency and thresholds. Today, a program participant potentially can configure the means of notification, including phone calls, emails, text messaging, or any combination of these. The user also can determine the balance levels or other levels and frequencies at which notifications can occur.

These advances in notification configuration provide great flexibility to the member. At the same time, they relieve the utility of trying to manage these notifications for individual members.

1.5. Service Fees

In many prepayment programs, the participant is charged an additional fee for this service. This fee has been shown to be not a significant deterrent to program participation, as the participants perceive that their savings and convenience more than offset the fee. However, as the actual costs to implement and support prepayment have dropped, the trend seems to be toward lowering or even eliminating additional periodic or transaction fees.

1.6. Apps

In addition to the various notification options described above, several vendors now have Apple and Android apps available for download. These apps support prepayment balance monitoring in an easy and convenient manner. Many of these apps provide a range of communications options beyond that of prepayment, and thus have greater appeal to members.

1.7. Energy Conservation

There is a growing trend to recognize prepayment as an energy conservation tool. Several studies have indicated that prepayment can result in 8%–15% energy conservation. However, these results must be tempered by understanding the type of member to which prepayment appeals. Some of the incentive for energy conservation is that the program participants are budget conscious. An attempt to market prepayment as an energy conservation tool to other member demographics may not yield the same results, as these participants may not be budget motivated.

1.8. Balance Calculations

While not necessarily a current trend, something expected to occur in the coming years for all CIS and third-party vendors is their development of solutions that move away from batch-based operations and provide more responsive information. In today's environment, most consumers are able to track their cell phone usage to the minute. Likewise, bank customers are able to see transactions made with a debit card virtually instantaneously after making them, via an online portal or app. The wealth of data produced by today's AMI solutions, along with prepayment solutions, would seem to be pushing vendors to move away from batch-based operations in favor of more responsive solutions. This is a major change for most established vendors; it will take time to achieve, but the drivers do seem to be there.

Utility Survey

The utility survey conducted as part of this report was intended to identify as many prepayment programs as possible, as well as their current status. Because many vendors are reluctant either to provide information about their clients or even possibly do not know which clients have active prepayment programs, this report took a more direct approach to identify those cooperatives with prepayment programs. The methodology utilized for this process was as follows:

- A questionnaire was emailed to a high-ranking member services or communications employee at each distribution system to discover if their co-op offers a prepaid meter program, and details on their program if they do offer one.
- A total of 837 invitations were sent out on April 29, 2014. Two reminders were sent to increase participation. A total of 353 invitees completed the survey and are included in these results—a response rate of 42%.
- It is important to note that in some cases the respondents did not answer all questions; this accounts for some variability of "n" in the data presented.

1.9. Prepayment Programs Offered

Of the 353 responses, the breakdown of the information collected, shown in Figure 1, is as follows:

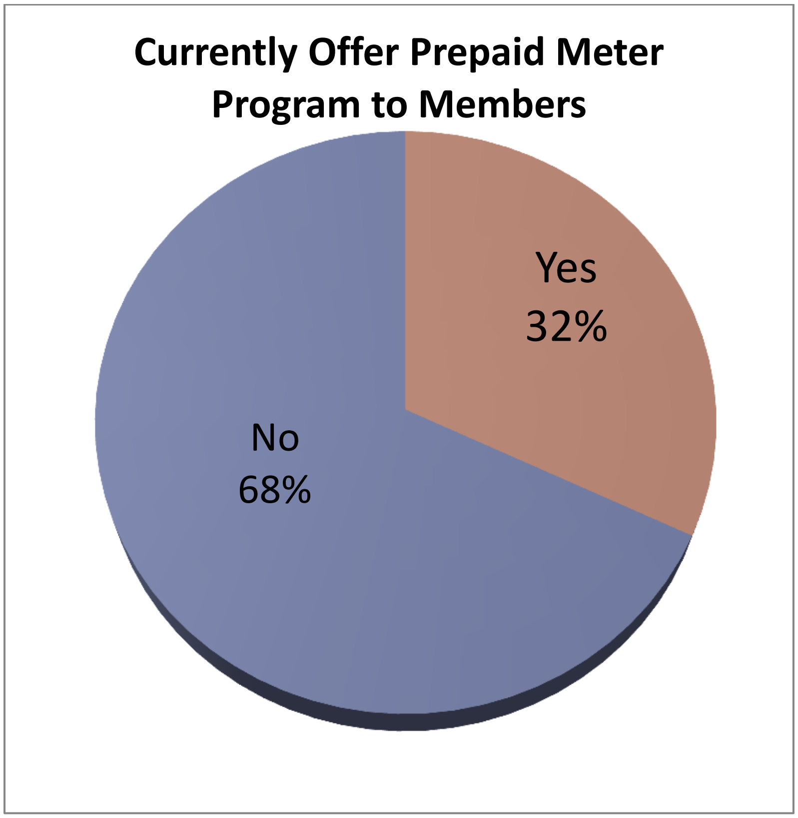


Figure 1. Co-Ops Currently Offering a Prepaid Metering Program to their Members

The data above represents 114 prepayment programs out of 353 cooperative responses. The Prepaid Metering Analytical Report published by CRN in June 2012 reported 95 active prepayment programs. This indicates a growth of 20% in prepayment programs over a 2-year span if we assume that all 95 of the programs identified in that report are included in this survey. A question as to how long a co-op's prepayment program had been in place, which had 104 respondents, indicates that this cannot be true (see Figure 2).

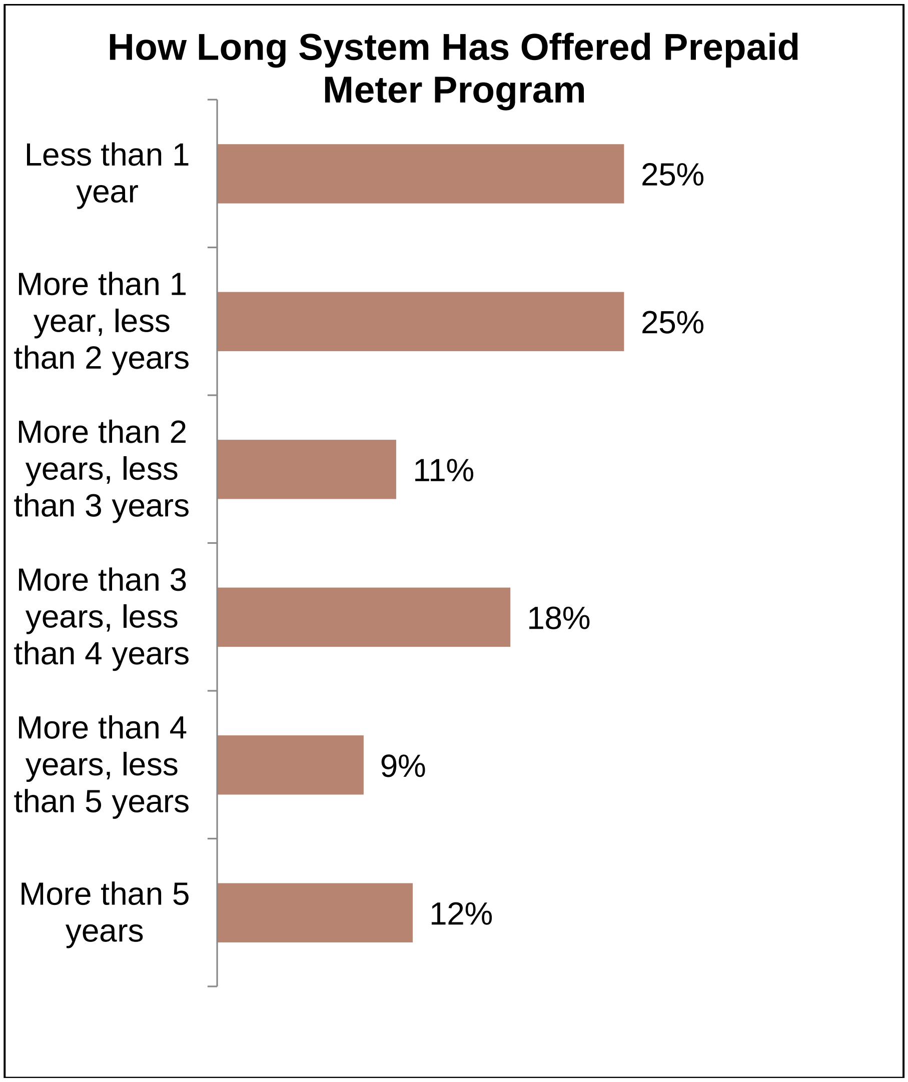


Figure 2. How Long Has the Utility Offered a Prepayment Program?

Since 50% of these 104 respondents said they had prepayment programs that were less than 2 years old, those 52 programs could not have been included in the 2012 report. This information indicates that prepayment programs have increased by at least 55% since 2014.

1.10. Likelihood of Offering Prepayment

For those cooperatives not currently offering prepayment (239), the survey asked a question as to the likelihood of introducing prepayment in the next 24 months. The results, shown in Figure 3, are as follows:

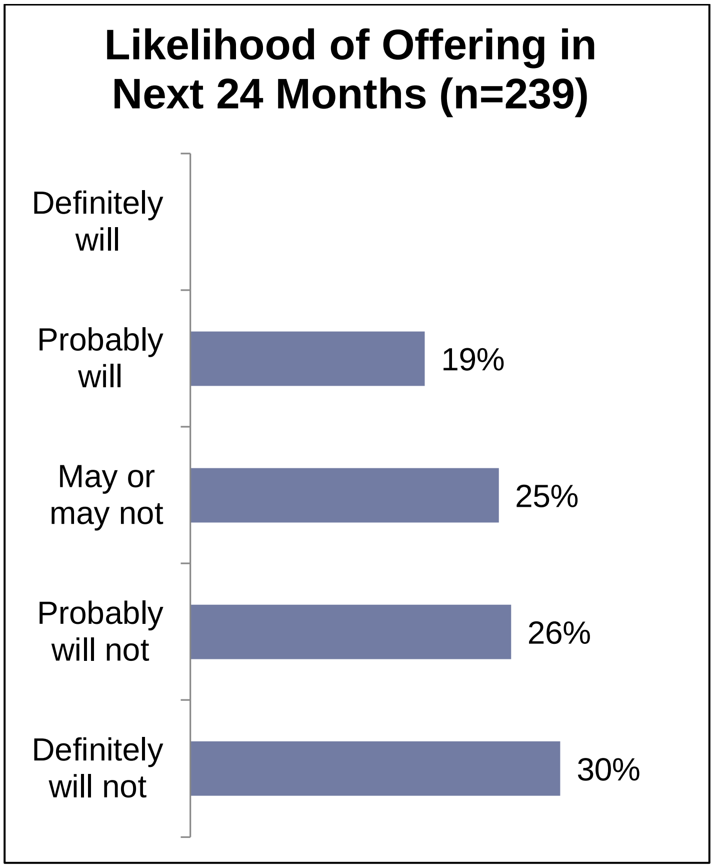


Figure 3. Likelihood of Offering a Prepayment Program in the Next 24 Months

There are several interesting aspects of these data. First of all, none of the 239 cooperatives is definitely committed to offering prepayment in the next 24 months. This is somewhat surprising, given the growth rate of prepayment cited earlier. However, it likely also indicates that the planning and decision-making process for prepayment is still a very slow and deliberate one.

At the same time, 19% of the cooperatives responding (representing 45 co-ops) indicated that they probably will offer prepayment. If these cooperatives follow through, this would represent a growth rate in prepayment over the next 2 years that would match the measured growth over the past 2 years.

1.11. Proportion of Residential Membership

Of the existing prepayment programs, utilities were asked to identify the percentage of residential members the program supported. The results, shown in Figure 4, are as follows.

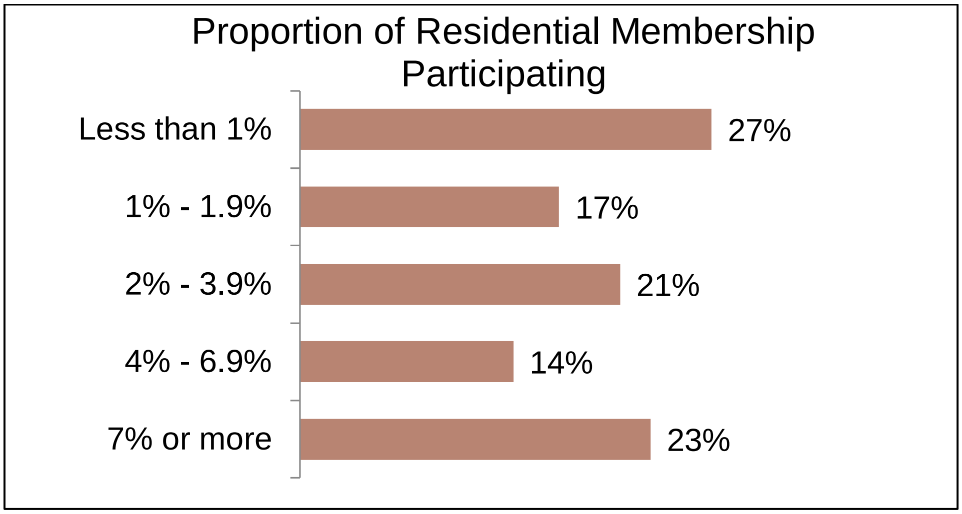


Figure 4. Proportion of Residential Members Participating in a Prepayment Program

Given that 50% of the respondents had programs that had been in place for 2 years or less, the smaller percentages of participation are not surprising. Many factors go into how large a program will become or how fast it will grow. The participation typically expected of residential members in a mature prepayment program is 10%.

1.12. Regulatory Limitations

Of the cooperatives surveyed, 49 indicated that regulatory restrictions play some role in their decision to offer prepayment or not. For those utilities, the responses to whether they would offer prepayment if these restrictions were changed are shown below in Figure 5.

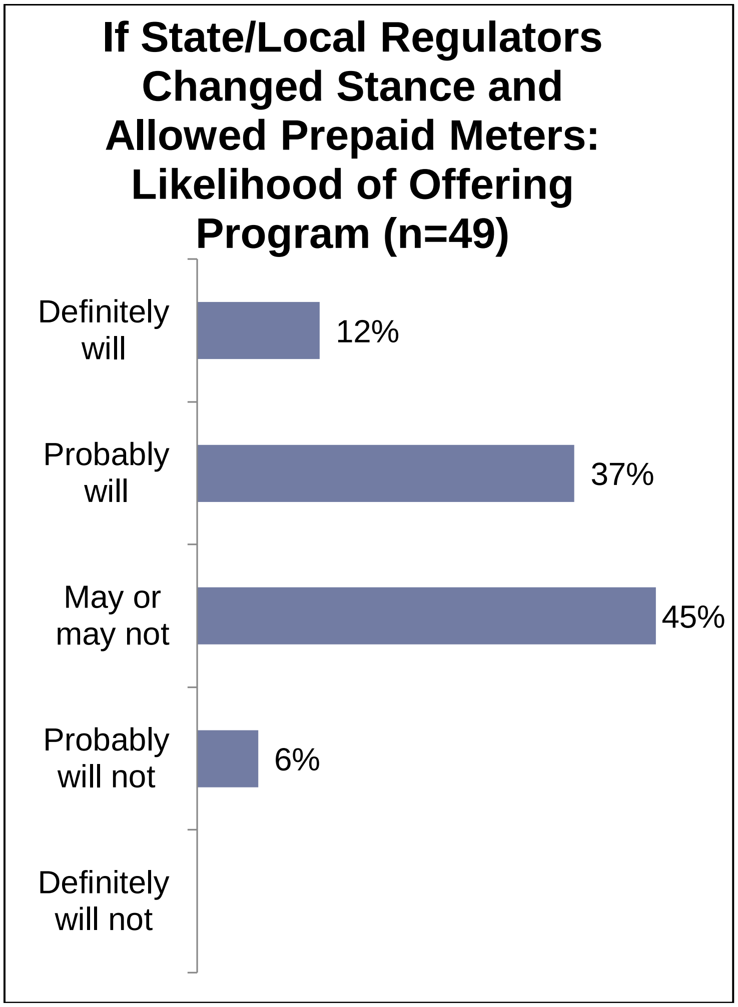


Figure 5. Likelihood of a Co-Op Adopting a Prepayment Program if Regulatory Restrictions Change

These responses indicate that, with regulatory changes, an additional 24 cooperatives either definitely or probably would offer prepayment. In other words, with regulatory changes, the growth of prepayment could potentially double.

1.13. Factors in Prepayment Decision

The survey asked respondents currently not offering prepayment and stating they were not likely to offer it (123 cooperatives) the biggest reasons for their position. The answers are summarized in Figure 6.

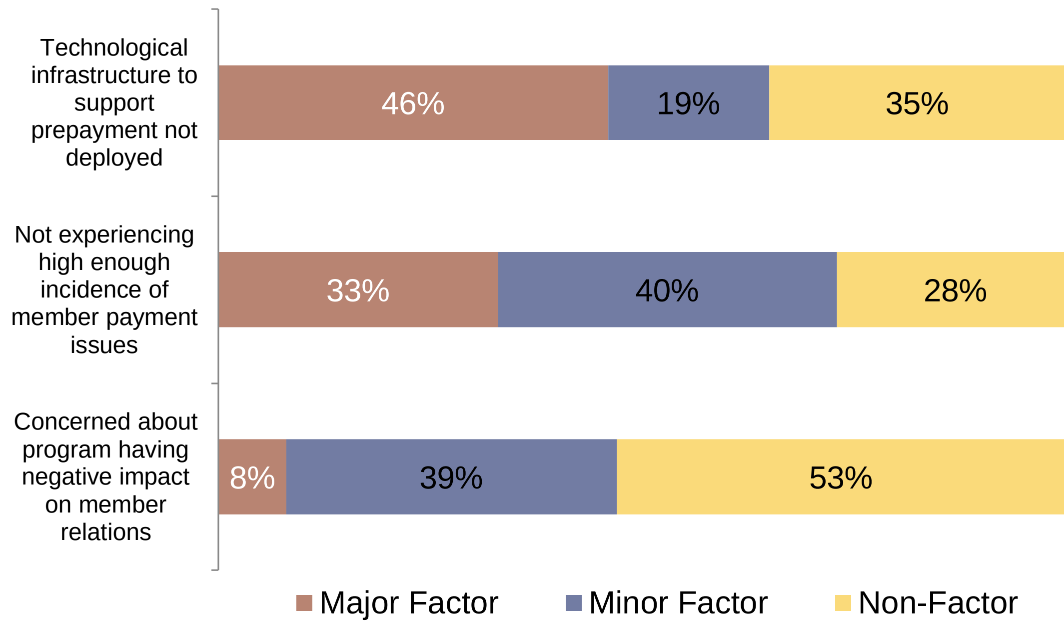


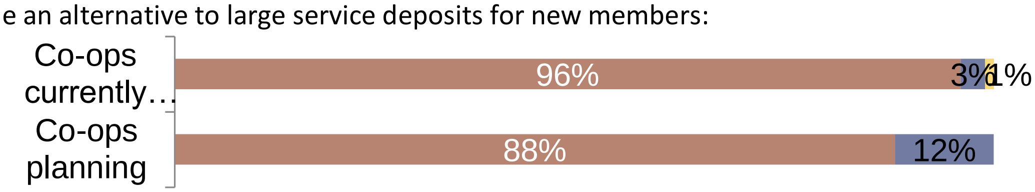
Figure 6. Reasons Co-Ops Do Not Offer Prepayment Programs

The breakdown of the answers regarding the first 2 of the 3 reasons listed above indicate that the technical infrastructure to support prepayment is still a significant impediment to many cooperatives, and the impression is lessening that prepayment will have a negative impact on member relations.

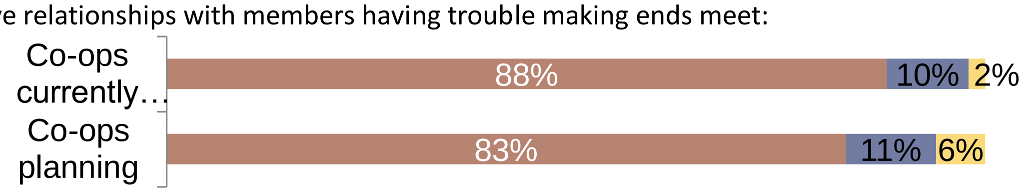
1.14. Factors in Decision to Offer Prepayment

This survey question asked the cooperatives that currently have prepayment programs (114) and cooperatives planning prepayment programs (108) the reasons why. The responses are shown in Figure 7.

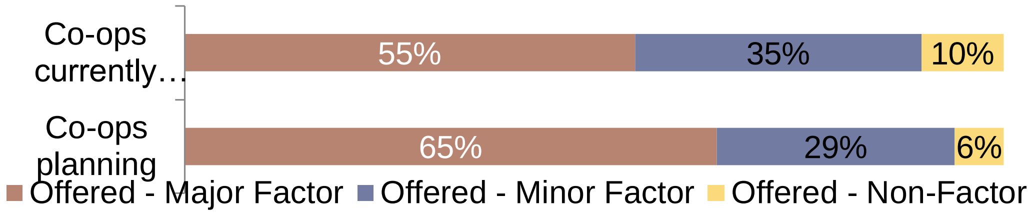
To provide an alternative to large service deposits for new members:



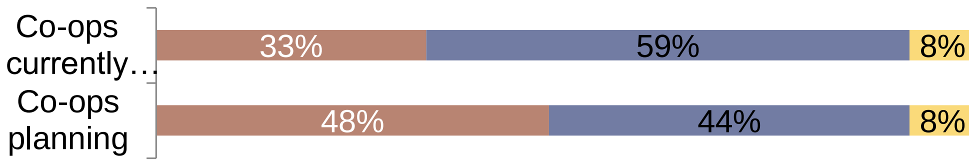
To improve relationships with members having trouble making ends meet:



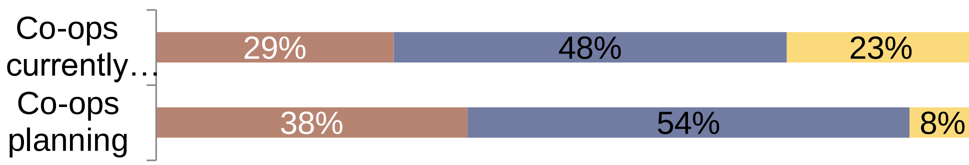
To reduce administrative costs/staff time pursuing delinquent accounts:



As a means to help consumers save energy:



As an option to address high bill complaints:



As a convenient option for transient/seasonal owners:

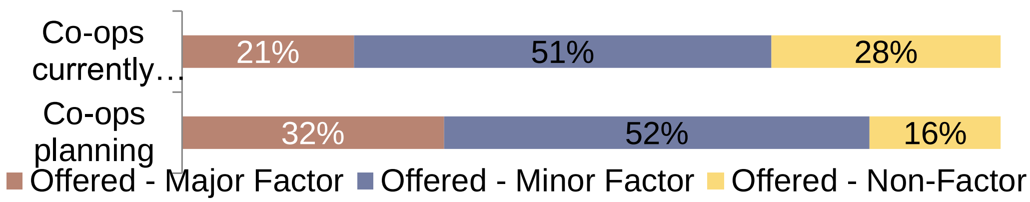


Figure 7. Reasons for Co-Ops to Have or Plan for a Prepayment Program

1.15. Overall Prepayment Program Experience

The following figures indicate responses from cooperatives indicating their overall experience with prepayment.

1.15.1. Level of Benefit

The results shown above are typical of other survey results. The ability of a utility to offer an alternative to high deposits has emerged as by far one of the main motivations for offering prepayment, as shown in Figure 8.

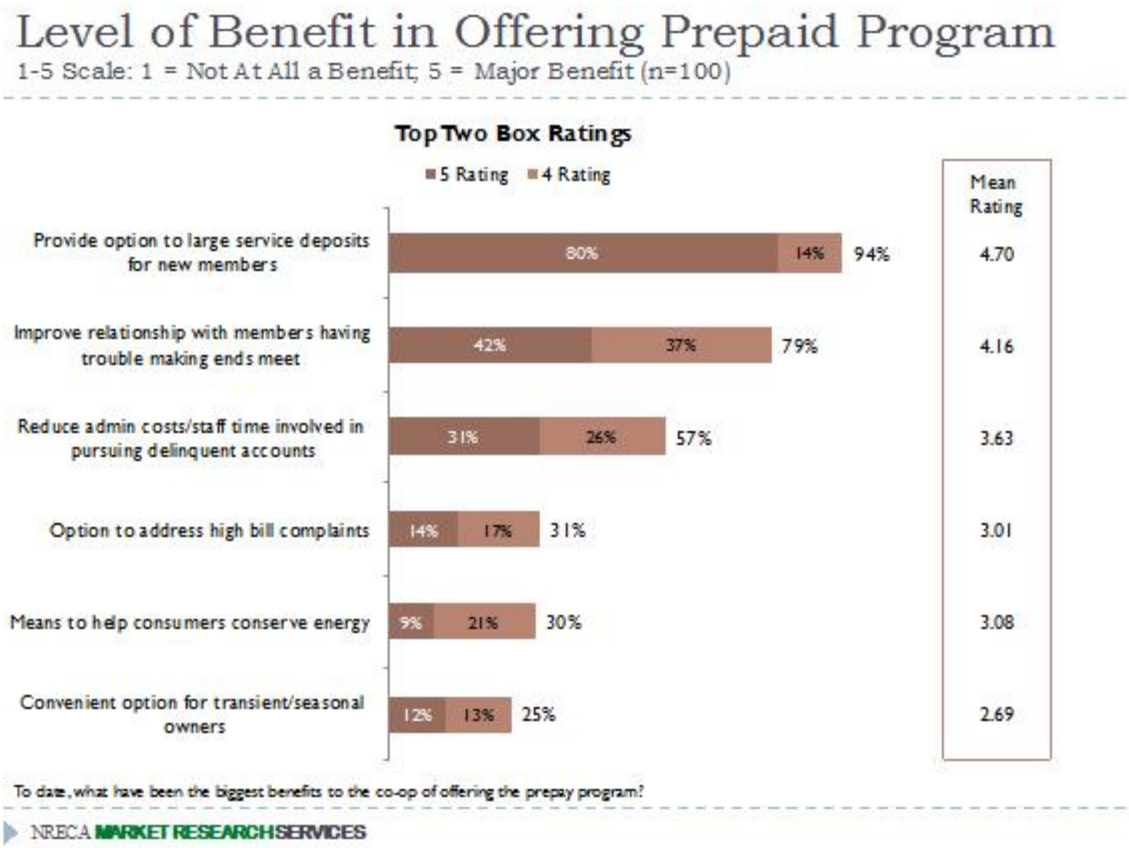


Figure 8. Level of Benefit in Offering a Prepayment Program

1.15.2. Unexpected Benefits

The unexpected benefits of prepayment are shown in Figure 9. The top answer to this question is an important consideration. Many people, both in the utility and regulatory areas, are skeptical regarding the ability of prepayment to help members better manage their bills. Evidence and other surveys have shown that creating an alternative to regular monthly billing allows for a new dynamic with respect to keeping current on energy costs.

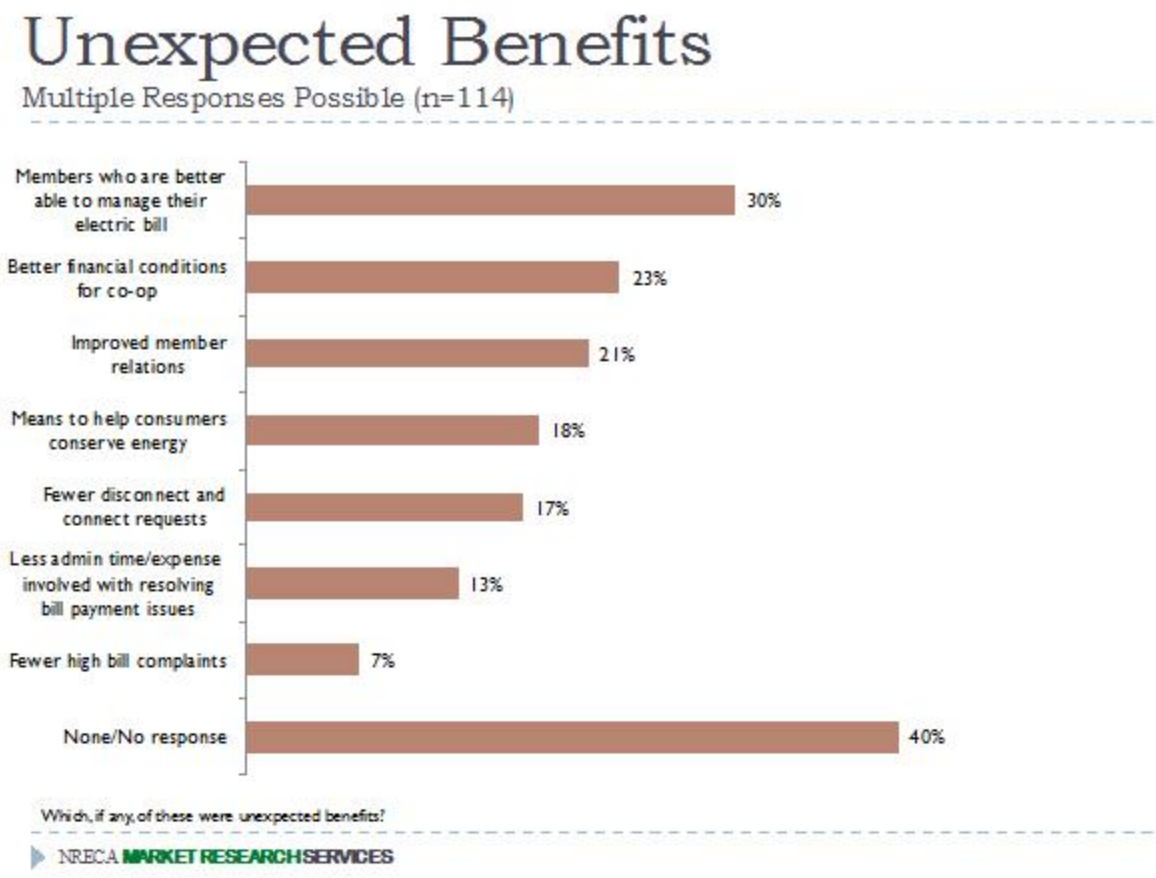


Figure 9. Unexpected Benefits from Offering a Prepayment Program

1.15.3. Biggest Challenges

The challenges in starting a prepayment program are shown in Figure 10. The top challenge identified by this question is very typical for most utilities. Most traditional utility payment solutions operate in a batched mode that is incompatible with prepayment because payments must be processed when they are received so that members can get credit for the purchase. Any purchase could be responsible for initiating a reconnection, which the member would expect to occur as soon as possible.

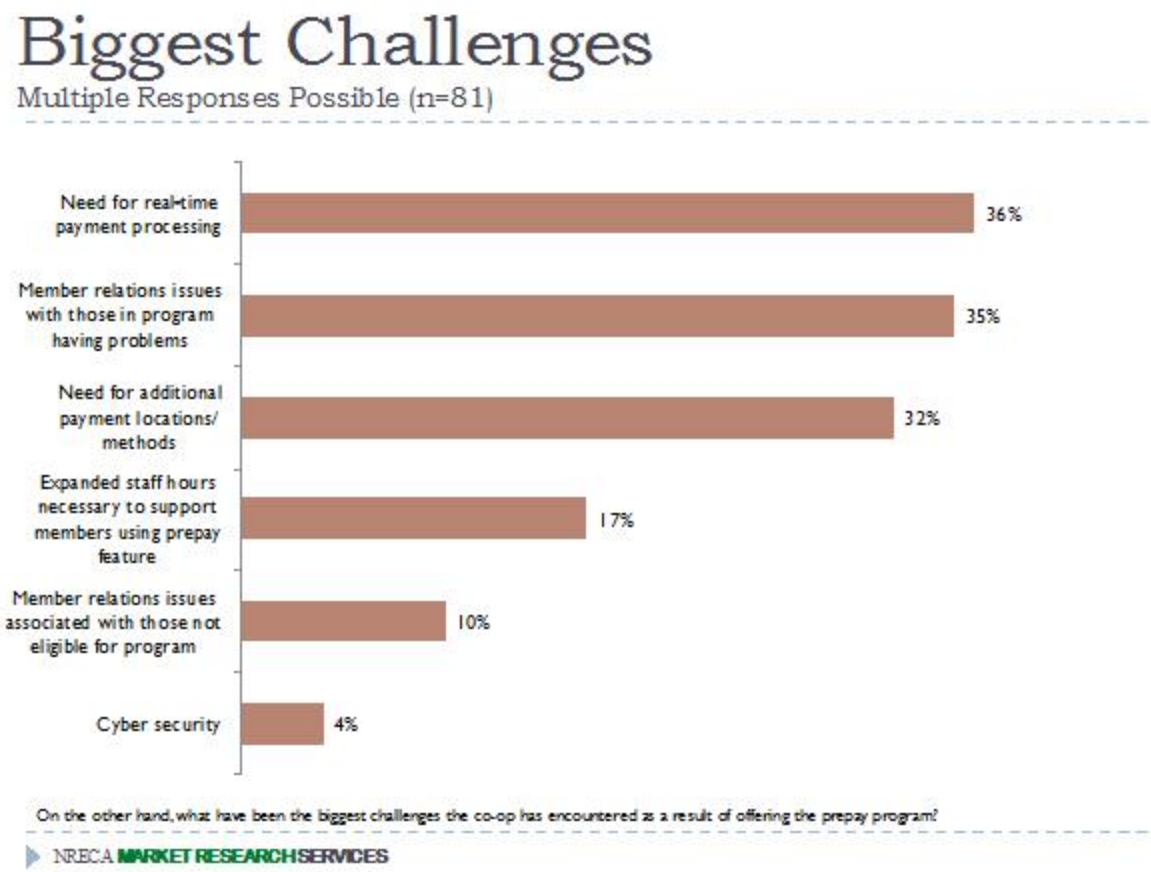


Figure 10. Biggest Challenges in Starting a Prepayment Program

1.15.4. Changes Noticed by Co-Ops

The degree to which co-ops have noticed changes due to a prepayment program are shown in Figure 11. The reduction of collection of various types of penalty or reconnection fees is a typical result of prepayment. From a business case standpoint, this loss of fee revenue needs to be considered, as well as whether there are corresponding savings to offset this loss.

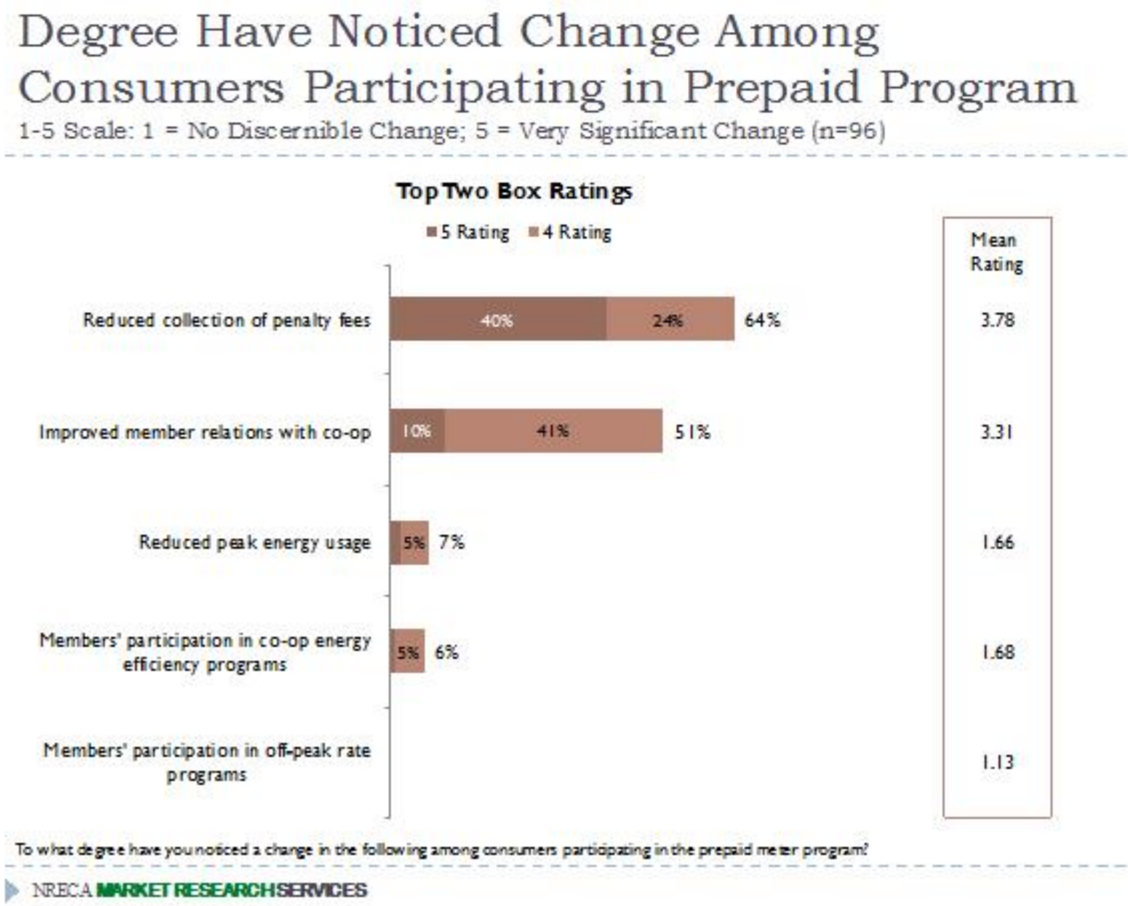


Figure 11. Consumer Notice of Changes due to a Prepayment Program

1.15.5. Participation Eligibility

Prepayment typically is offered to the entire residential population or to those businesses served by a 200-amp service because most systems support only a single-phase 200-amp disconnect switch. Certainly, as indicated below in Figure 12, locations involving life support or other medical considerations are not viable candidates for traditional prepayment. However, cooperatives could consider offering prepayment without the automatic disconnection to provide the convenience of payments based on the member's schedule.

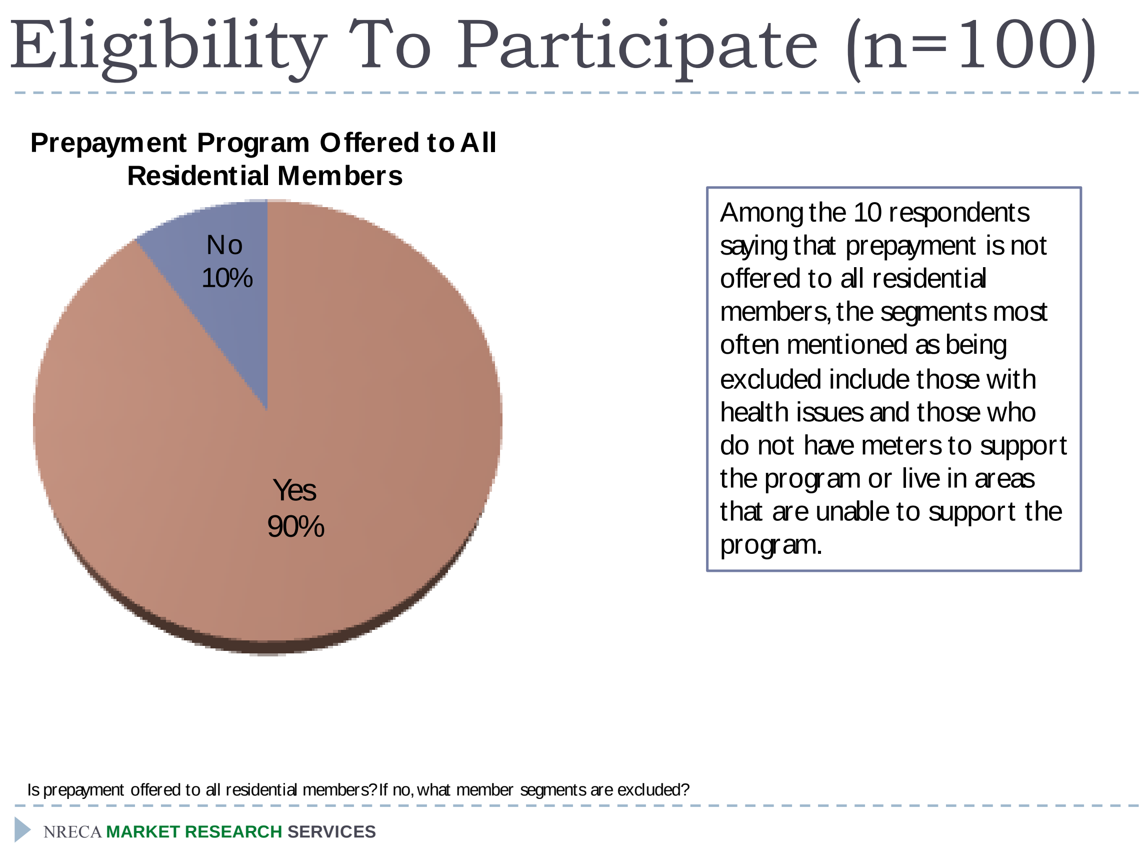


Figure 12. Eligibility to Participate in a Prepayment Program

1.15.6. Member Segment Marketing

Historically, prepayment requires minimal marketing activity**,** although some utilities do elect to brand and market the service in some way. Bill payment issues and avoidance of deposit fees are typically the two main motivators for enrolling in prepayment. Thus, the most effective marketing tool is a well-trained staff of service representatives and call center personnel that can readily recognize the best fit for members and make recommendations to them regarding prepayment. Market segments to which co-ops can market prepayment are shown in Figure 13.

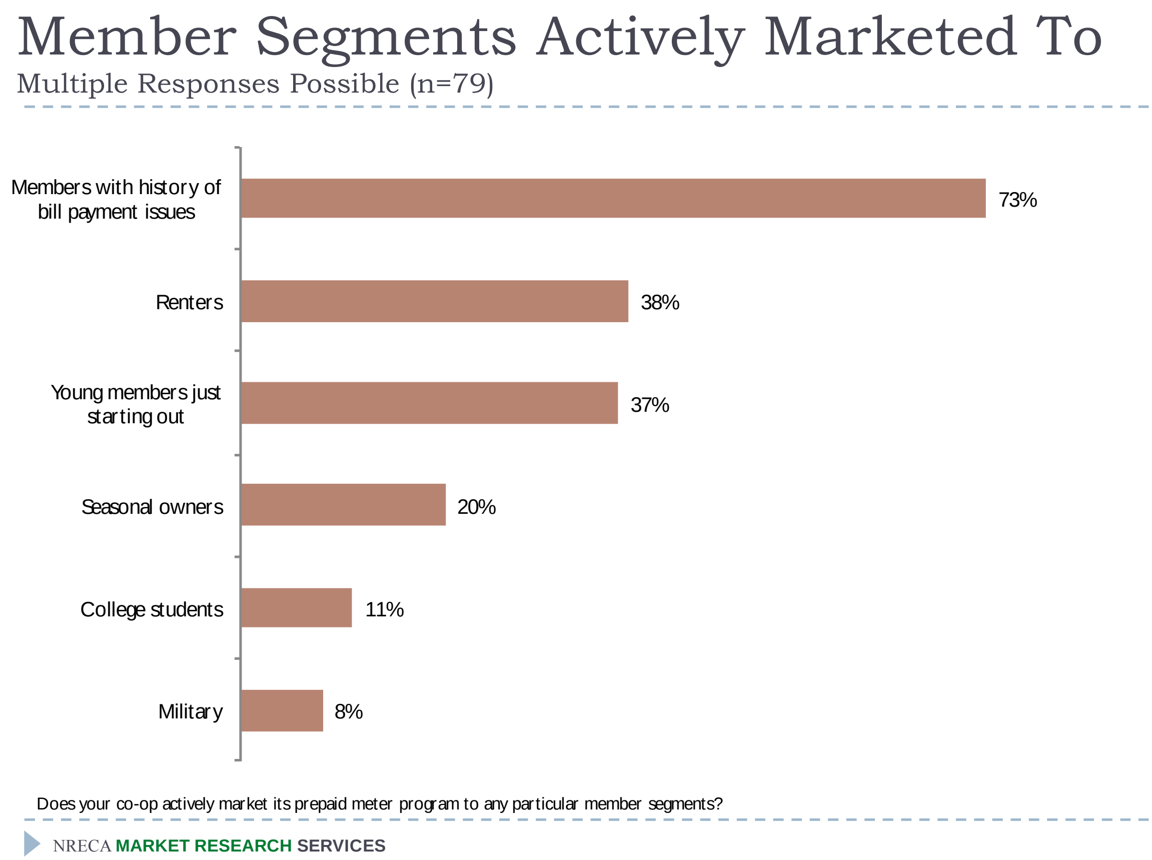


Figure 13. Market Segments to Which Co-Ops Can Market Prepayment

1.15.7. Prepayment Operation Restrictions

Restrictions on participation in a prepayment program are shown in Figure 14. The bottom 4 items in the graph below are very surprising. While it is not uncommon to perform disconnects only during specific days or hours, the generally accepted premise is that reconnects should be able to occur on all days and at all hours. It would be interesting to investigate the reasoning behind these policies. The likely reasoning is that these utilities do not yet have the level of automation in their systems to support this function.

The other interesting item in these 4 restrictions is that members with debt are not eligible. Prepayment typically is designed and offered so that debt can be paid off gradually as part of the service. However, cooperatives that either have a low incidence of debt or prefer a more direct approach to debt recovery have chosen to disallow these members from participating in prepayment. In these cases, the program typically is focused on new rather than existing members.

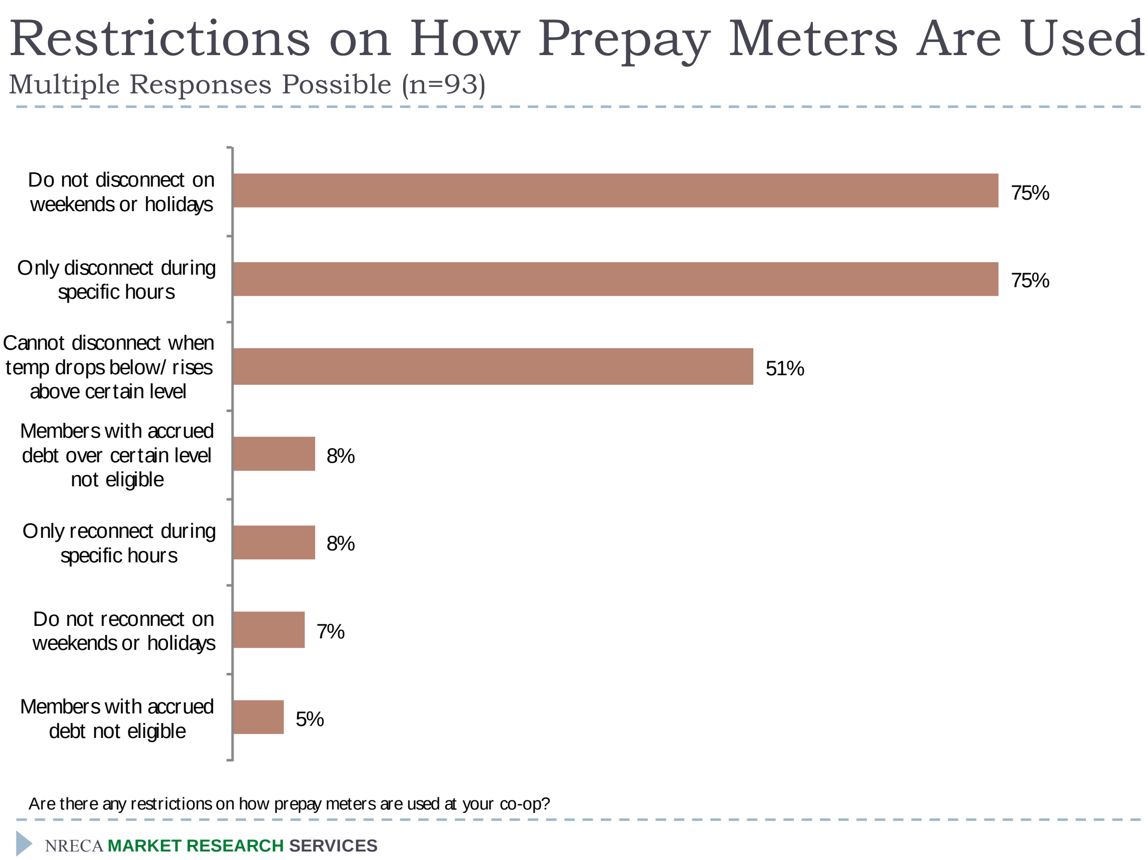


Figure 14. Restrictions on Participation in a Prepayment Program

1.15.8. Prepayment Program Fees

Flexibility in offering a prepayment program is significant. The fees and rates structures are shown in Figure 15. The policies at one cooperative versus another can be significantly different while both attain high member satisfaction.

One of the interesting things in these data is that 66% of the respondents say that the service reconnect fee has been eliminated. This means that 34% of the respondents still charge a reconnect fee of some kind. To understand why cooperatives continue to charge a reconnect fee requires some additional investigation. Many utilities still do this to cover the deployment costs of disconnect switches or as an attempt to minimize disconnect/reconnect transactions overall. The latter reason may be due to the additional manual processes necessary to verify switch operation.

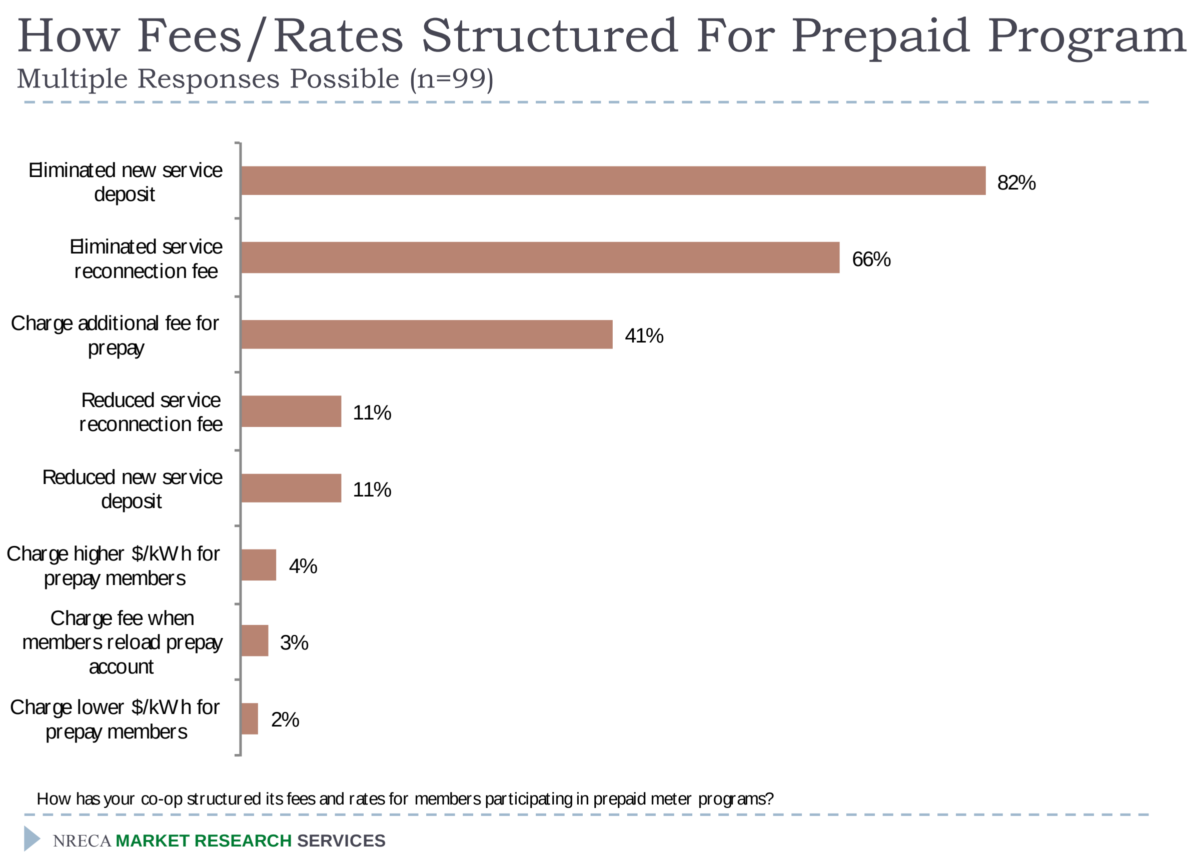


Figure 15. How Fees/Rates Are Structured for Prepaid Program

1.15.9. Likelihood of Offering Again or Recommending

The likelihood of either re-offering or recommending a prepayment program is shown in Figure 16. These results are very compelling for the validation of prepayment as a service. It is unlikely that a utility could get such a consensus on many other issues.

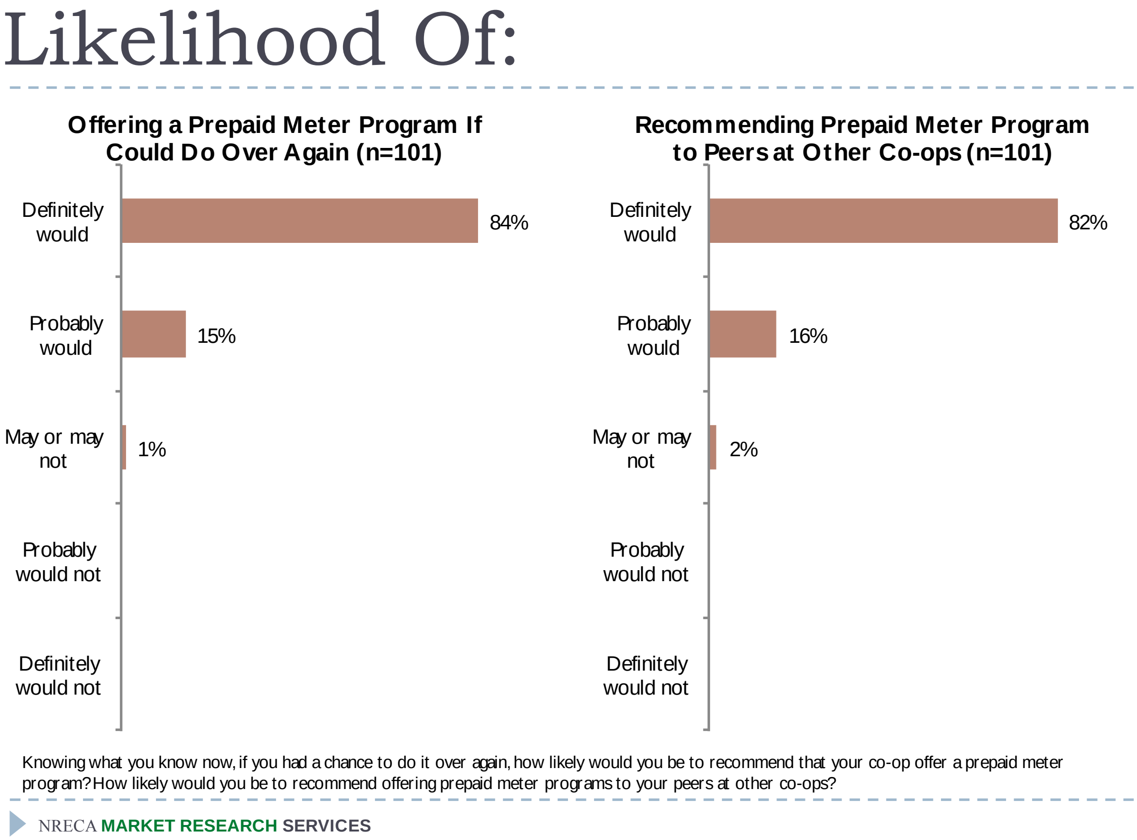


Figure 16. Likelihood of Re-Offering or Recommending a Prepayment Program

Member Survey

To understand the issues and impacts of prepayment from the member perspective, surveys of members from several different cooperatives were conducted. These surveys included groups of members that were and were not participating in prepayment programs. The results of these surveys are summarized in the following sections.

The specifics of the survey data are as follows:

- The member survey data was collected across 4 cooperatives:
  - Wood County Electric Cooperative in Texas
  - Minnesota Valley Electric Cooperative in Minnesota
  - Jefferson Energy Cooperative in Georgia
  - Jackson Energy Cooperative in Kentucky

- A total of 361 surveys were collected from prepayment program participants:
  - 279 by phone

    - 82 online

- A total of 316 surveys were collected from non-prepayment program participants:
    - 271 by phone
    - 45 online

It is interesting to note that, of the 4 cooperatives surveyed, Wood County is still using a smart card-based solution that relies on custom hardware rather than AMI communications. It is one of the last cooperatives that still utilizes this technology in its program. One of the larger cooperative prepayment programs, at Brunswick EMC in North Carolina, converted from custom hardware to an AMI-based solution a couple of years ago without any significant member complaints. (Note that the biggest issue in conversion is that balance updates go from real time, in the case of custom hardware, to periodic updates as seldom as once daily. For cooperatives that have never offered repayment using custom hardware, this balance update frequency is not a problem. Programs that have utilized custom hardware solutions can convert, and the benefits of an AMI-based system typically outweigh the loss of the real-time updates for the members.)

Another issue is that all 4 of the cooperatives surveyed apparently offer an in-home display as an option for balance and alert notifications. As mentioned earlier in this report, most programs today do not offer in-home displays as an option.

1.16. Overall Satisfaction

The data below, shown in Figure 17, indicate that prepayment participants are slightly less satisfied with their co-op than non-participants. However, what cannot be surveyed, although it would clarify this finding, is what the satisfaction score would have been prior to the enrollment in prepayment. The expectation is that it would have been much lower. Some of the other satisfaction metrics later in this report support that conclusion.

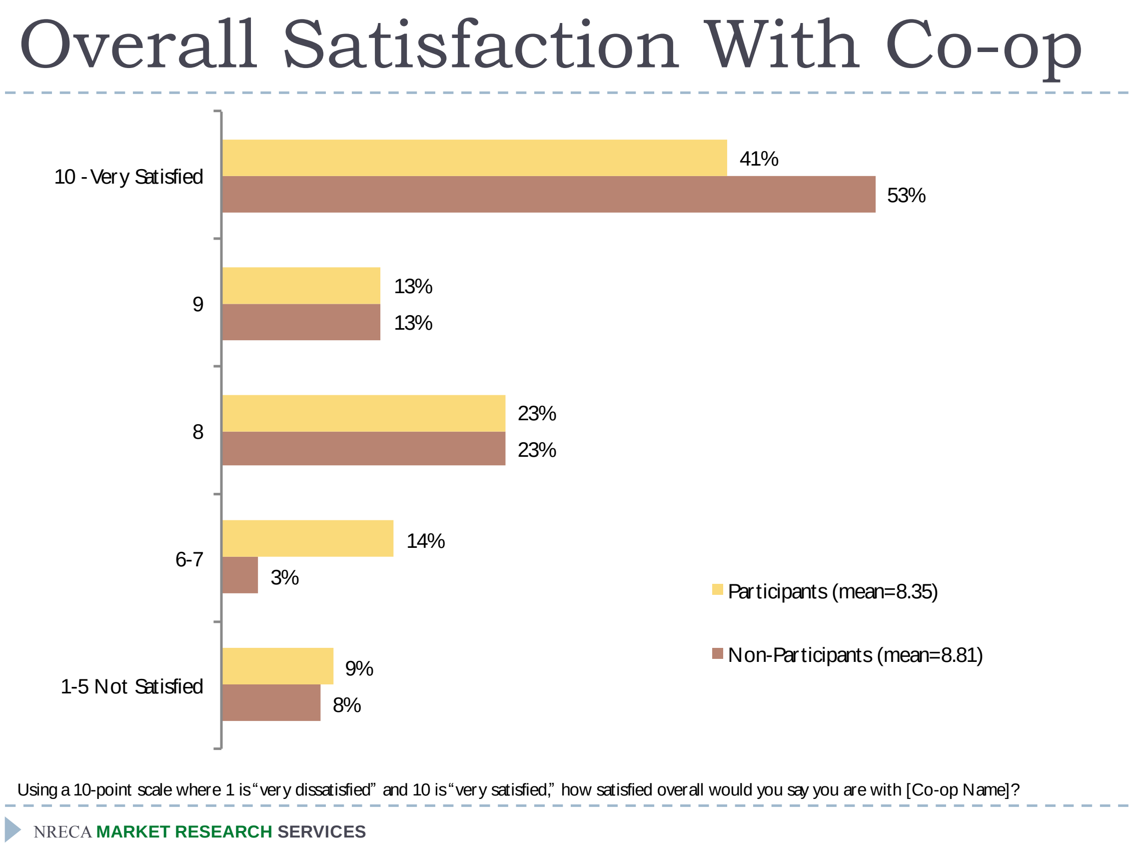


Figure 17. Overall Satisfaction with Co-Op

1.17. Performance Attributes

Figure 18 shows 12 aspects of cooperative performance. It is not surprising to see that cooperatives perform well in these areas. The conclusion is that prepayment does not adversely impact these perceptions. In fact, because prepayment might tend to serve a segment of the membership that may be less satisfied with cooperative performance, these data are encouraging because they show that these members have opinions on a par with others. It would be interesting to determine the overall impact of prepayment on the aggregate score of member satisfaction. However, the variables associated with such a study would make this difficult to prove.

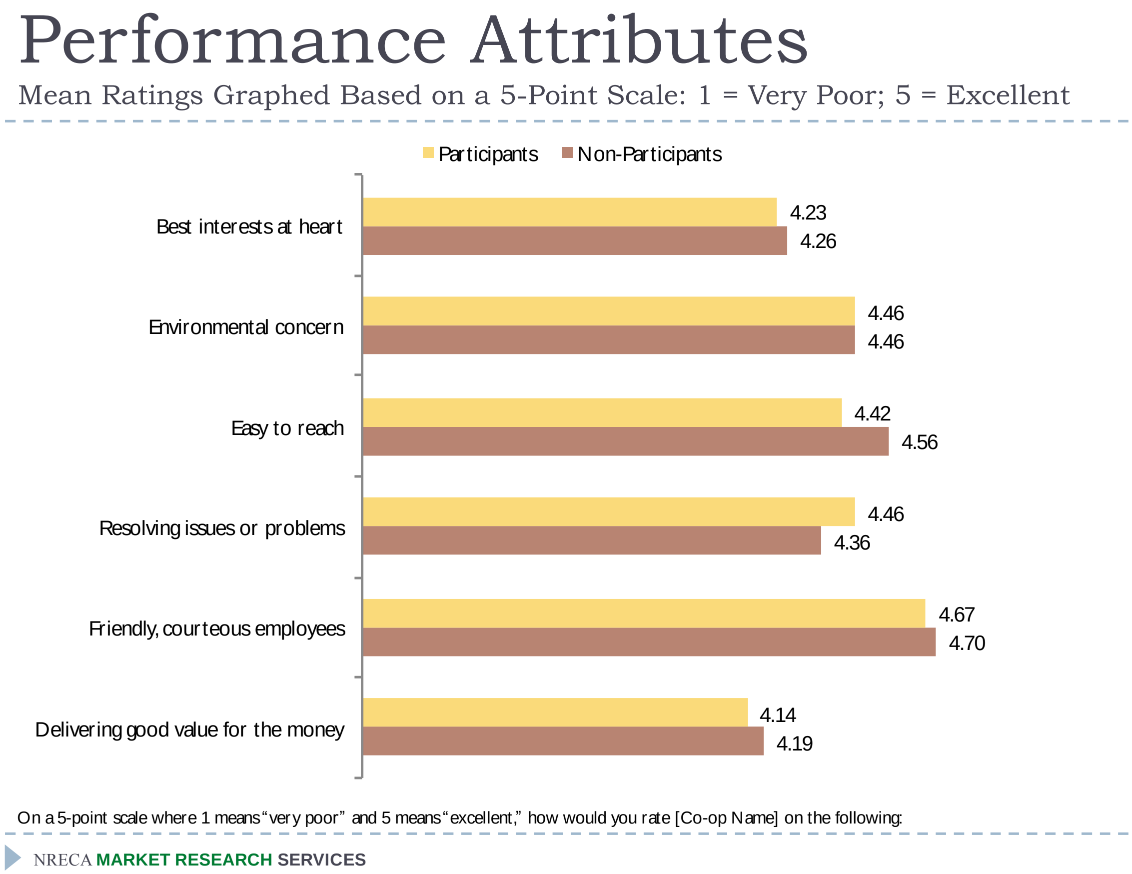


Figure 18. Co-op Performance Attributes

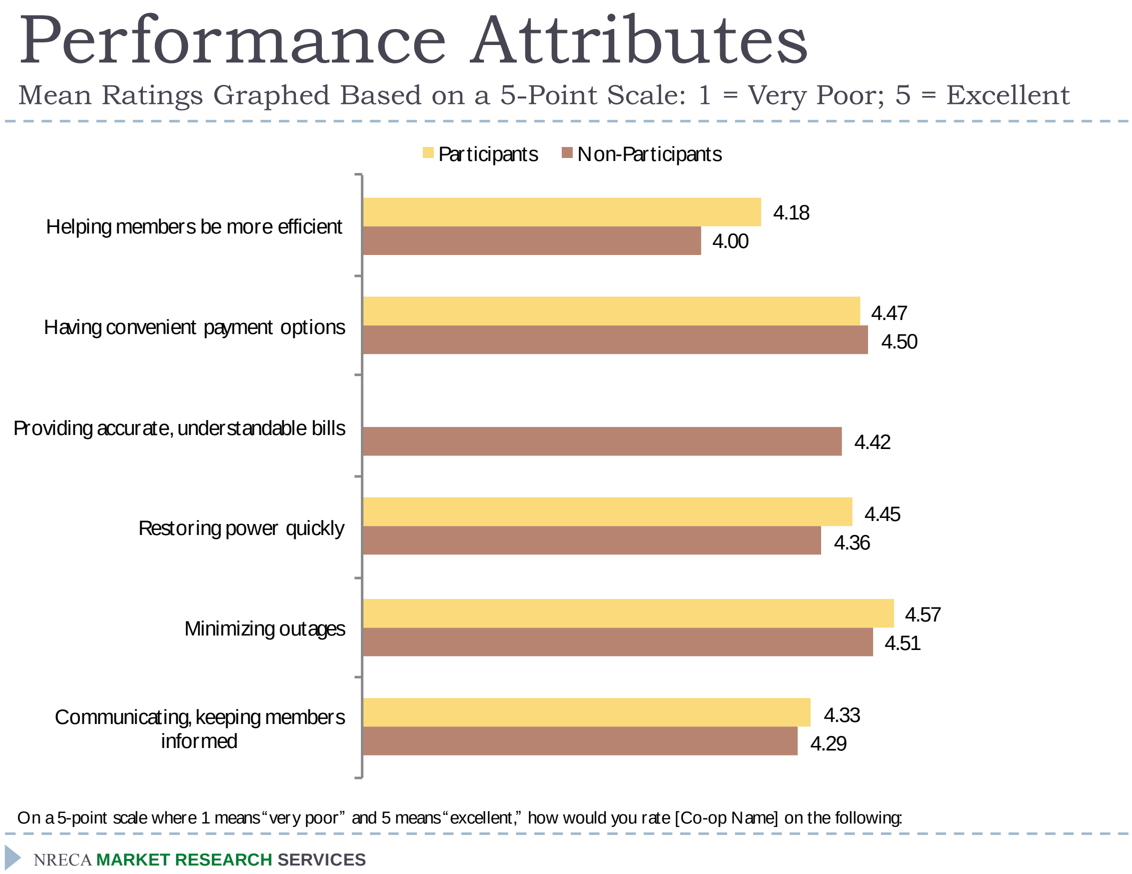


Figure 18. Co-op Performance Attributes (continued)

1.18. Prepayment Evaluation

Figure 19 shows member satisfaction with prepayment programs. These results are very consistent with other satisfaction ratings from other surveys. In general, most programs have an 85% or better score, with members rating the program as "good" or "excellent."

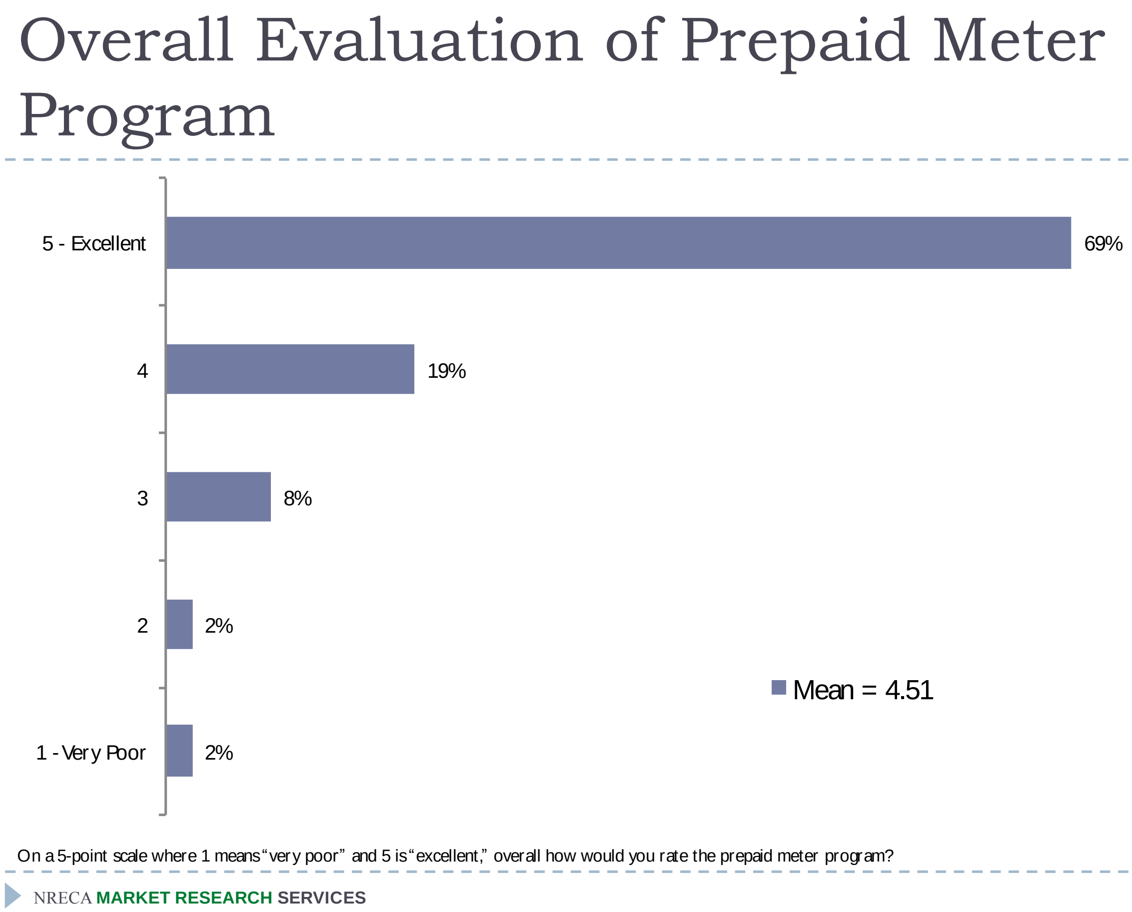


Figure 19. Member Satisfaction with Prepayment Programs

1.19. Length of Participation

Figure 20 shows the length of participation in a prepayment program. The data below are relatively indicative of the cooperatives surveyed and the length of time their programs have been offered. It is not uncommon for members of cooperatives that have been offering prepayment for longer periods of time to have been participants for 5 or 10 years. One of the interesting things to survey in the future would be to ascertain how frequently members move from prepayment back to regular billing.

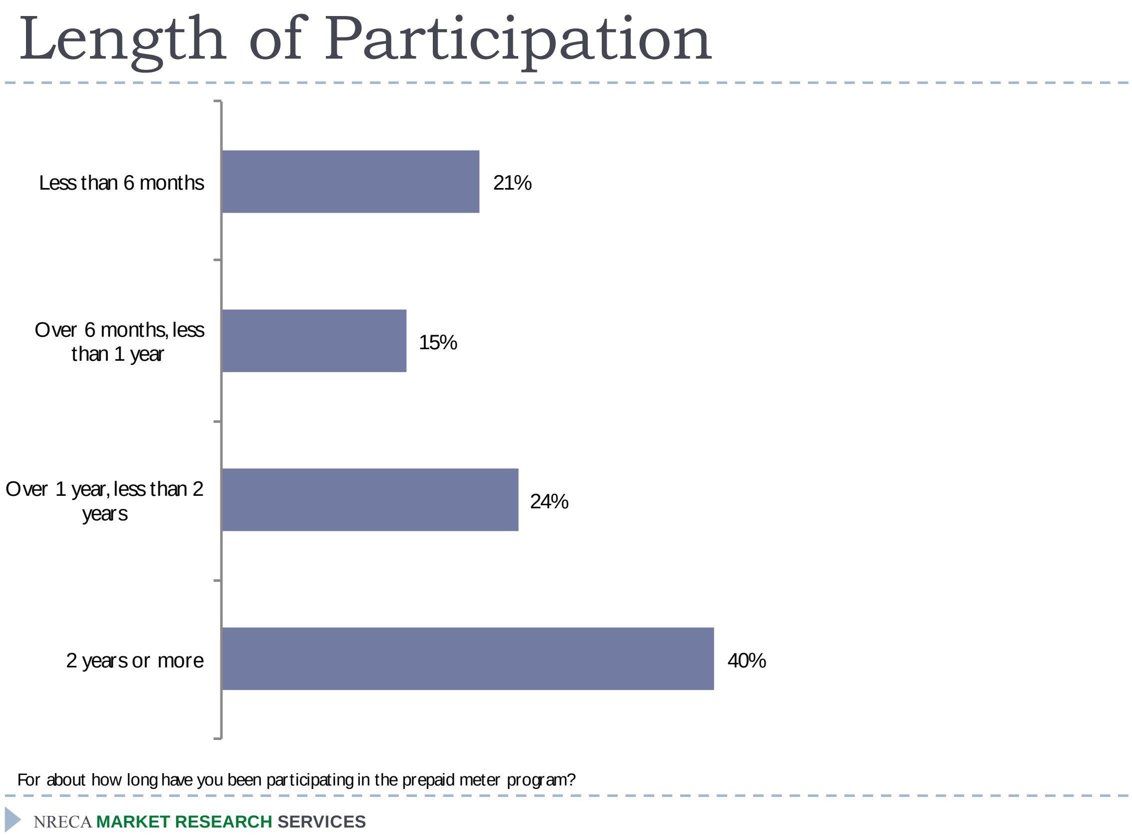


Figure 20. Length of Participation in a Prepayment Program

1.20. Reasons for Participation

The reasons for participation shown below in Figure 21 cover a broad spectrum of issues. Two surprises in these data are that “Be better able to track, manage electric bill” was the highest-rated reason and “Seasonal/weekend home” was a significant contributor. In many programs, the ability to avoid a high deposit seems to be the prime motivation.

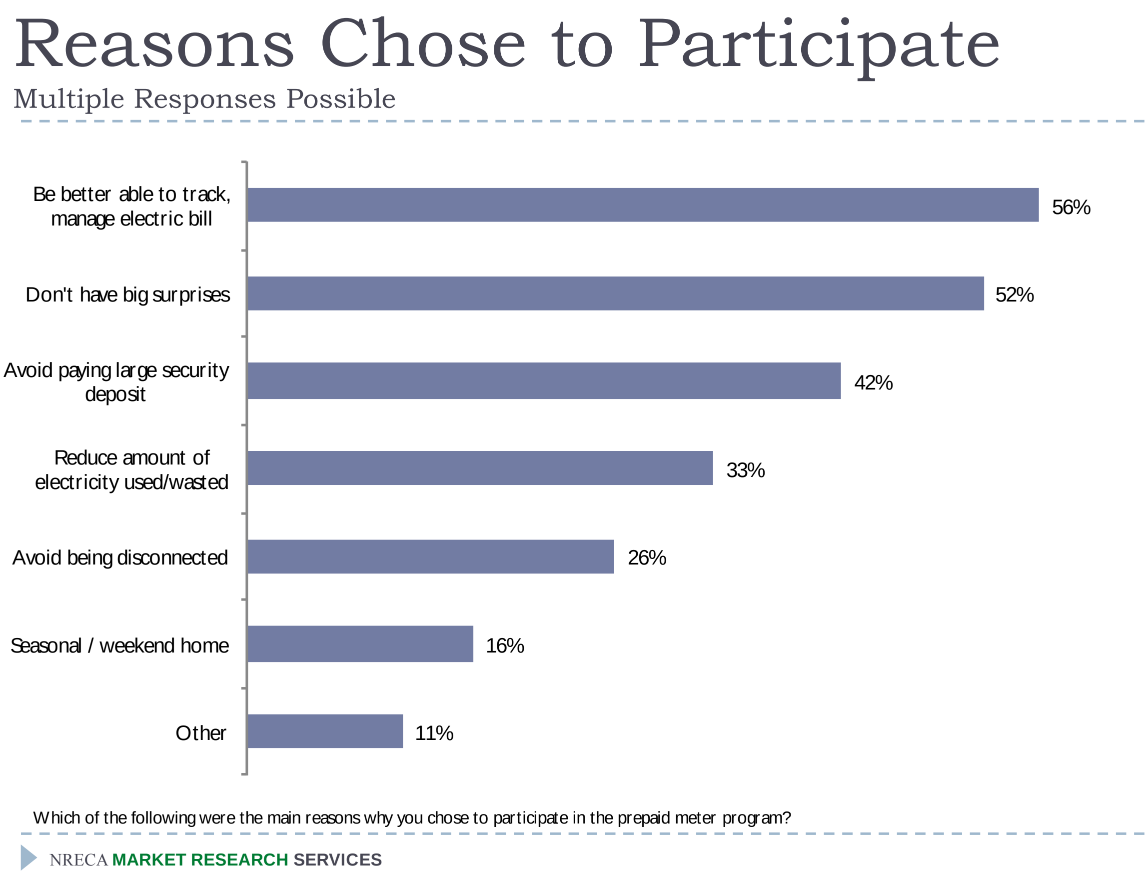


Figure 21. Reasons for Participating in a Prepayment Program

1.21. Experiences with Prepayment

Figure 22 represents ratings of 8 different aspects of the prepayment experience. Six of them have a rating higher than 4 on a 5-point scale. One of the aspects has a rating slightly lower than 4 (3.96). The final aspect has a rating of 2.75. However, the rating for “It is convenient to have to continually monitor my account” may be related to the way the question was phrased.

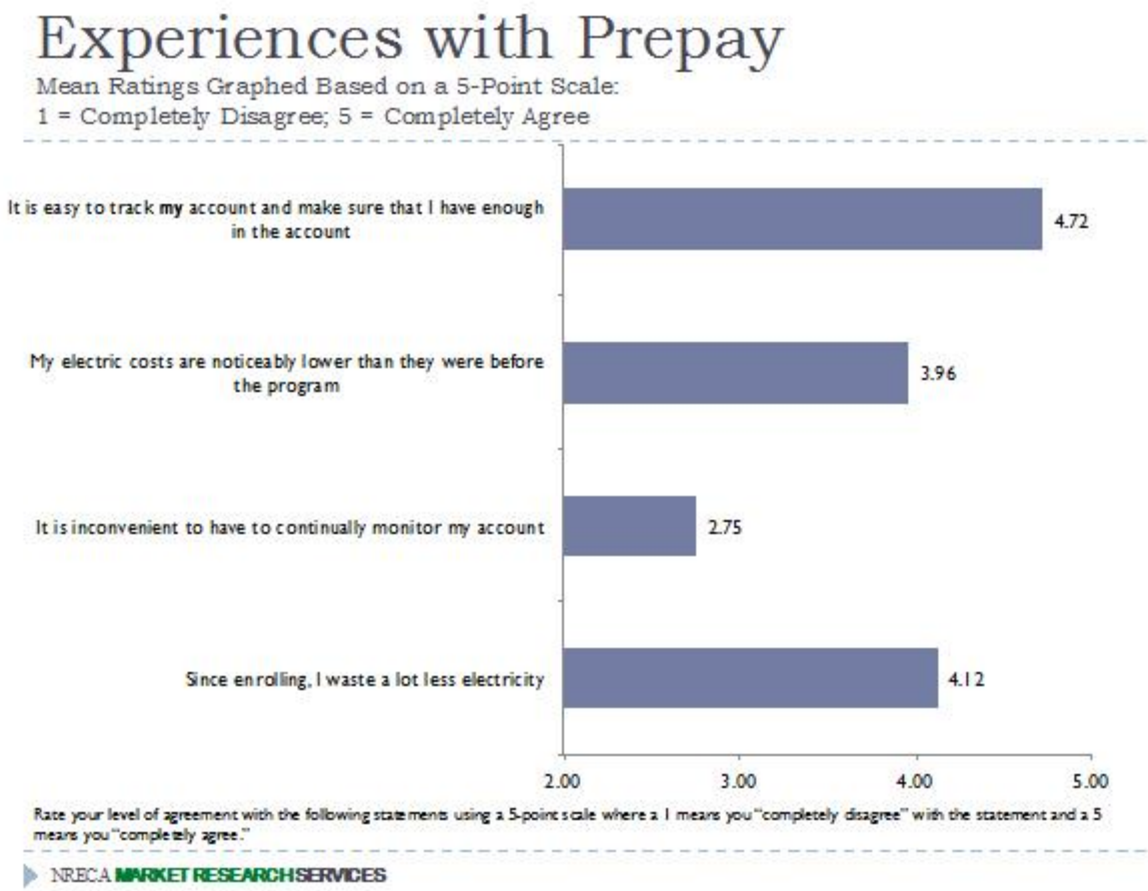


Figure 22. Experiences with Prepayment Programs

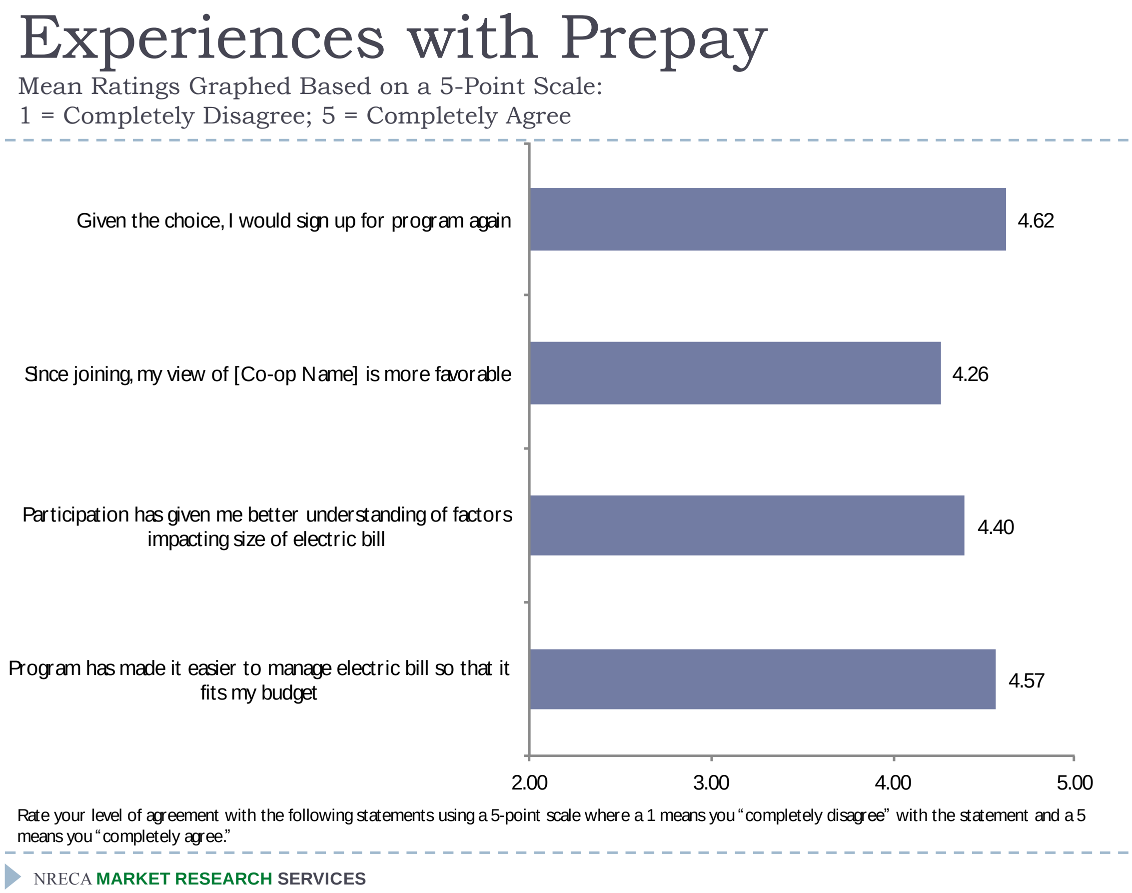


Figure 22. Experiences with Prepayment Programs (continued)

1.22. Balance Monitoring

Methods used to monitor balances are shown in Figure 23. Although it was reported in the Prepayment Trends section of this report that in-home displays were waning in both need and popularity, the data above show significant usage. This is because one of the cooperatives at which members were surveyed automatically provides an in-home display as part of the service.

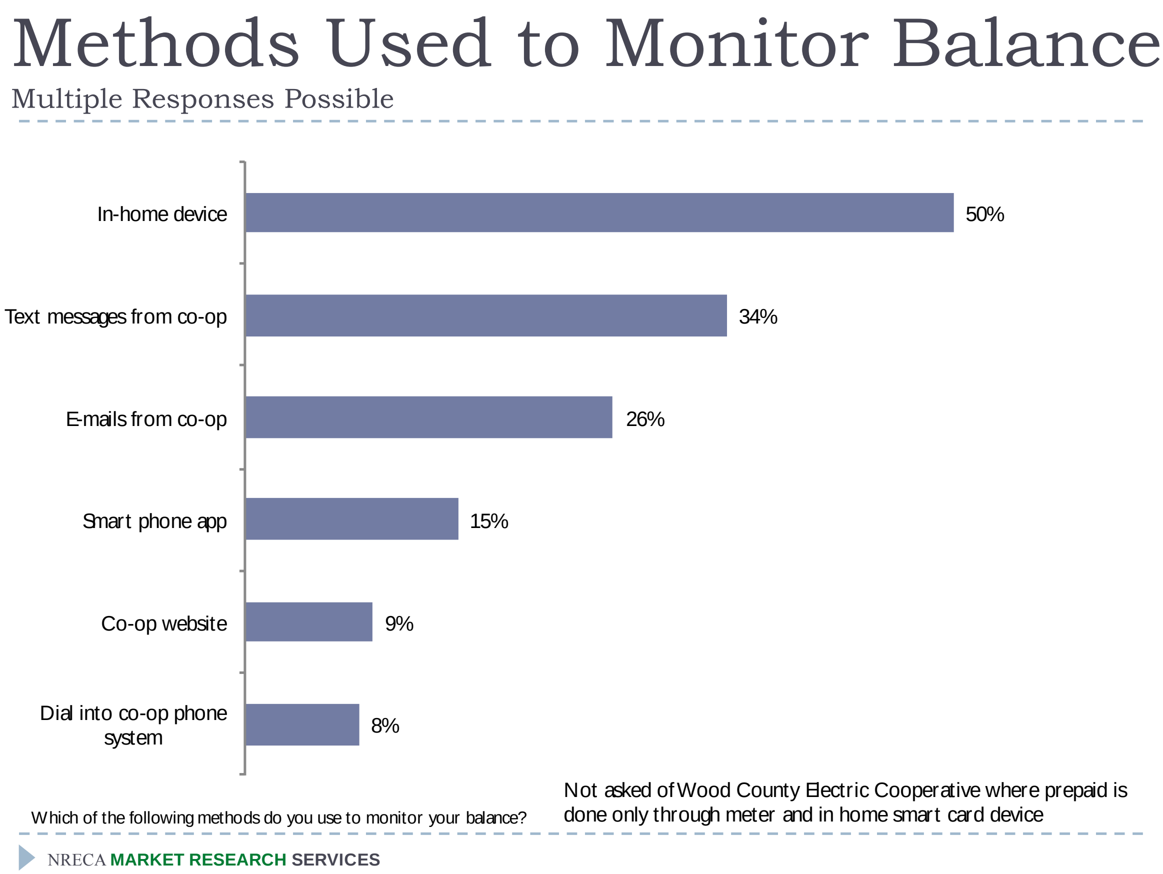


Figure 23. Methods Used to Monitor Balances

1.23. Purchase Frequency

Purchase frequency is an important aspect from both the member and cooperative perspectives. The data shown in Figure 24 regarding how often members put money into their accounts indicate that most (68%) will make purchases more frequently than once per month. This creates a significant change in the number of financial transactions the utility must make. It is important for the utility to ensure that this volume of transactions can be handled. While it is not shown in these data, the typical transaction window for many program participants is Friday afternoon, as that coincides with their getting paid. Thus, being able to handle a large volume of transactions over a relatively short period of time is critical to program success.

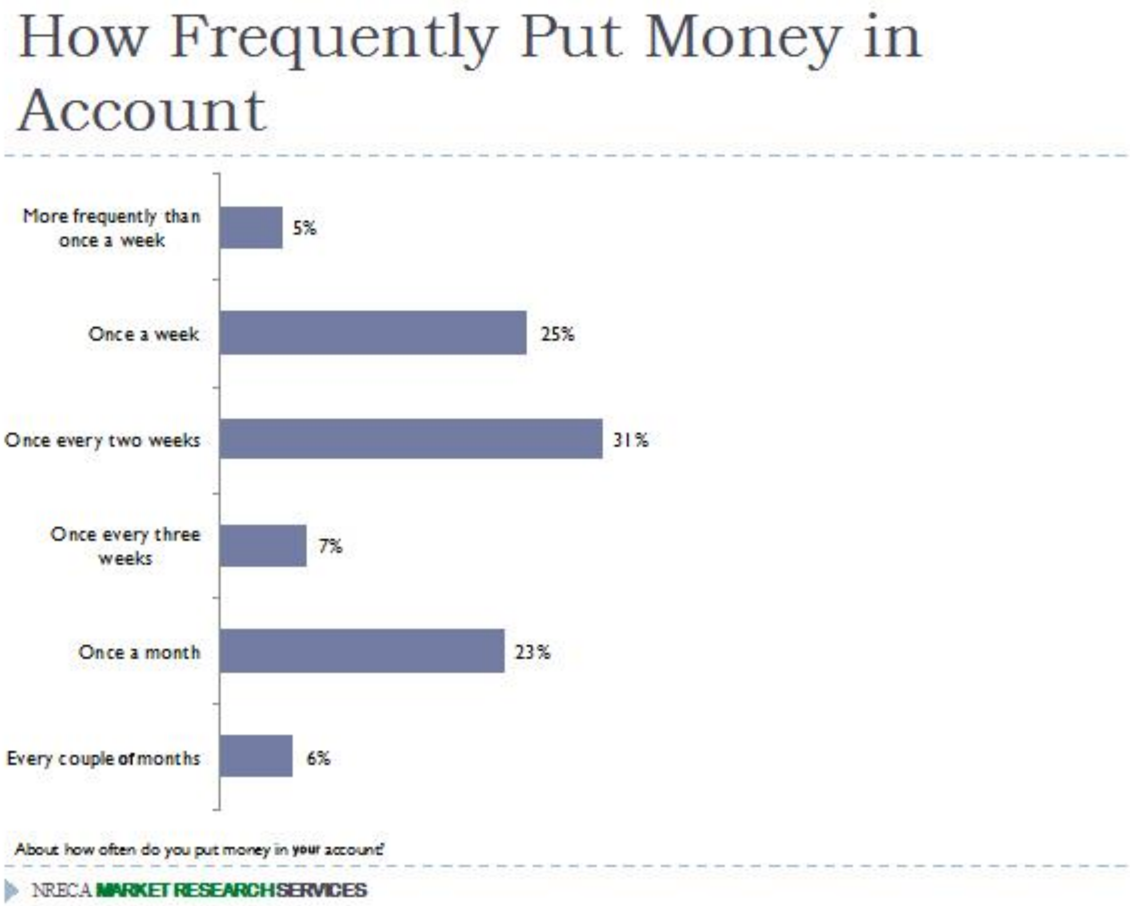


Figure 24. Members' Purchase Frequency

1.24. Energy Efficiency Impacts

Figure 25 shows activities taken by prepayment program participants with respect to energy efficiency. In general, these activities indicate that members whose usage is visible on a more granular basis (at least daily balance updates) do seem to be induced to increase conservation efforts. At the same time, it should be recognized that a significant portion of participants (40%) took no action at all.

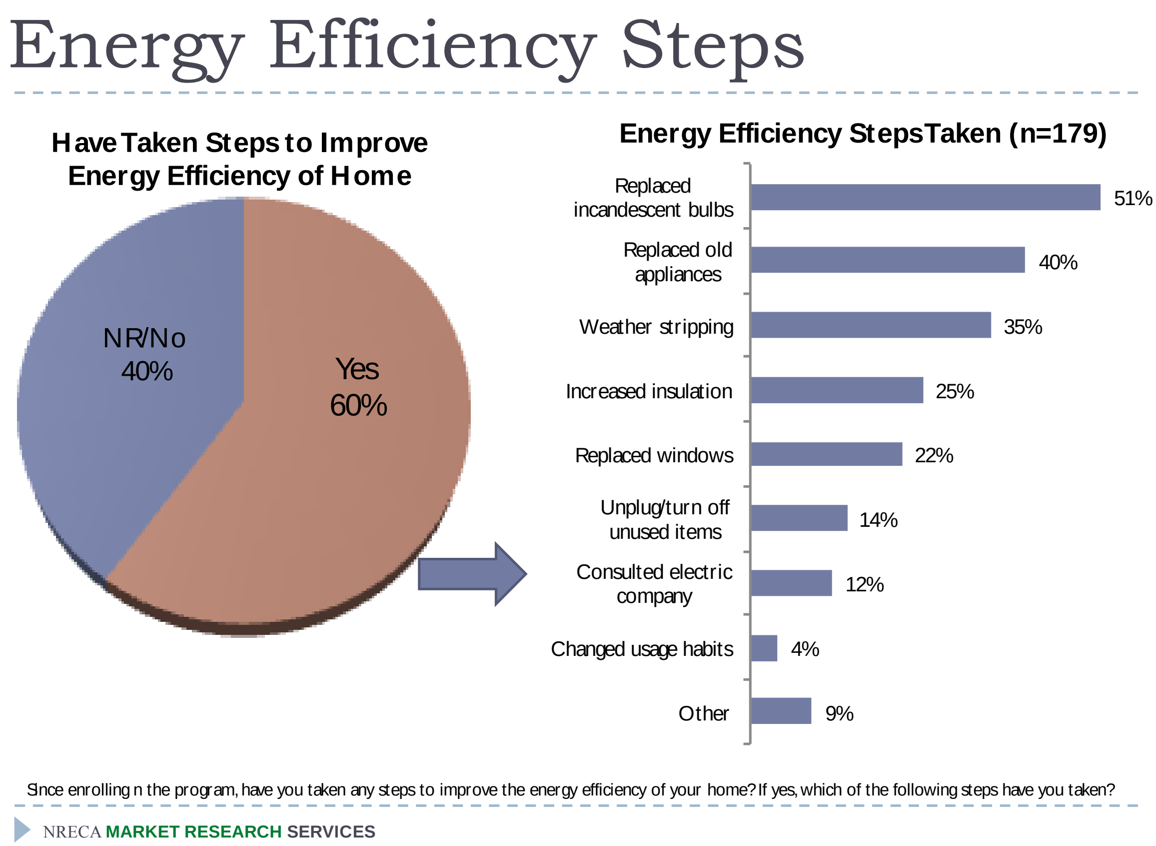


Figure 25. Activities Taken by Prepayment Program Participants with Respect to Energy Efficiency

1.25. Program Evaluation

The data in Figure 26 show very high satisfaction with cooperatives' ability to address issues and support members on prepayment. Cooperatives, more so than other types of utilities, are very customer (member) focused. The takeaway from these survey data is that, although prepayment tends to allow members to operate more autonomously, it does not diminish the need or ability of the cooperative to provide excellent customer service.

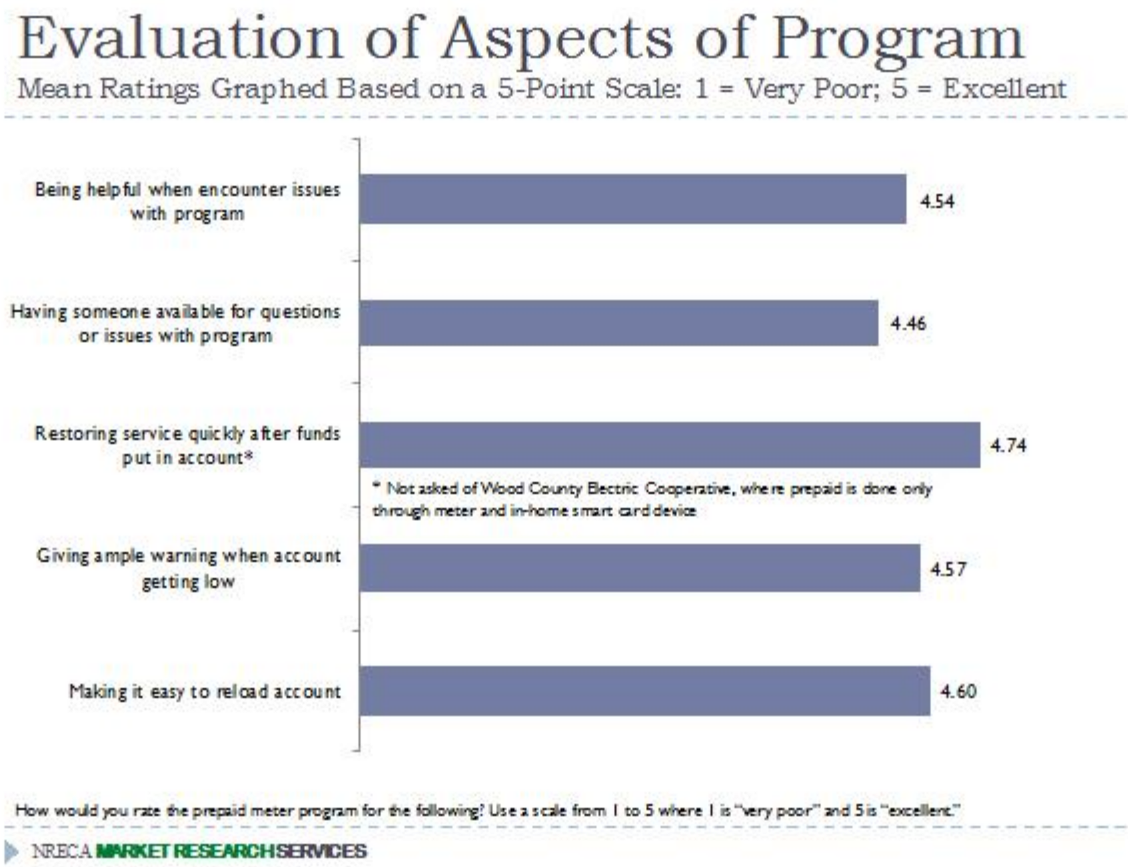


Figure 26. Evaluation of Prepayment Programs

1.26. Respondent Demographics

This section provides demographic information on the survey group.

1.26.1. Housing

The type of housing utilized by the survey group is shown in Figure 27. As can be seen, prepayment program participants tend to lean more toward mobile homes and rental locations than single-family homes. Because prepayment typically appeals to those for whom budgets are a concern, these results are not surprising.

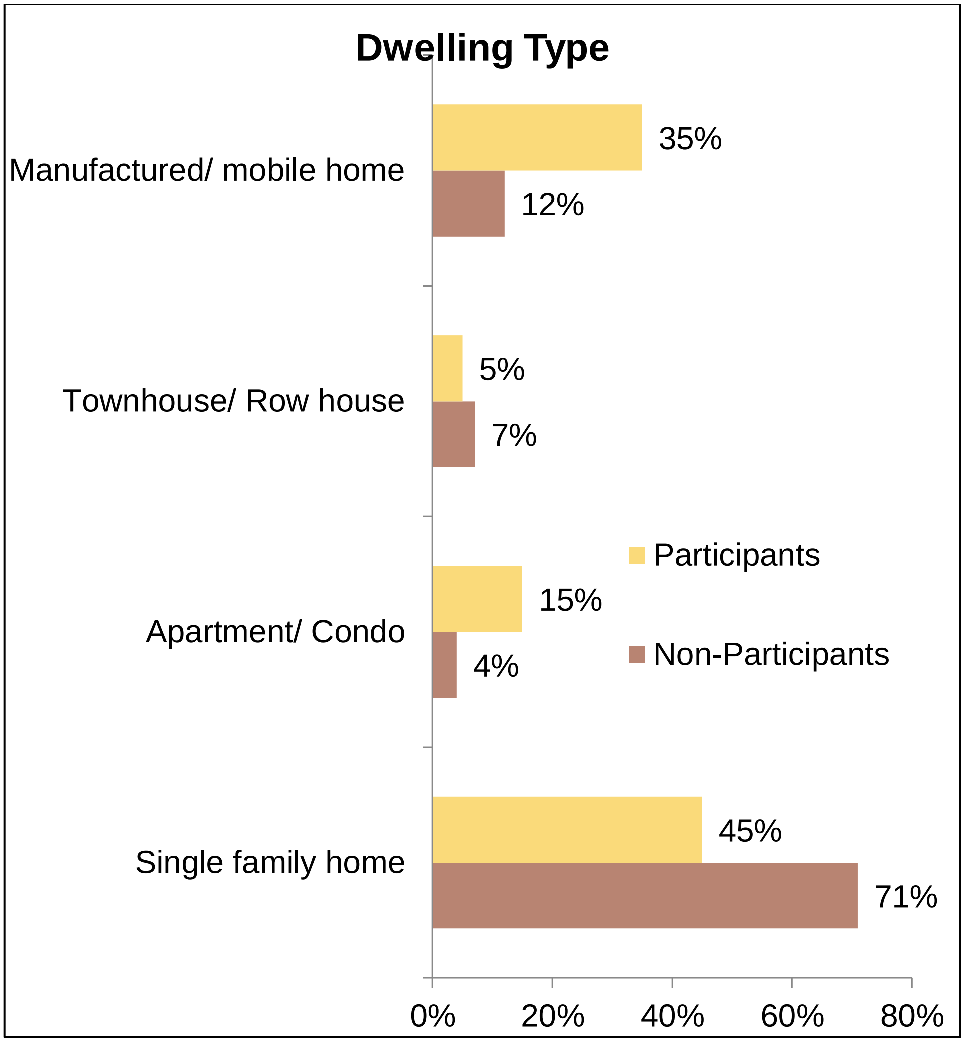


Figure 27. Types of Housing Utilized by the Survey Group

Figure 28 shows the types of housing for which the prepayment account is being used. The biggest surprise in these data is that 7% of those surveyed on prepayment used it for a dwelling that is a secondary or vacation home. The preference for prepayment in this context may be two-fold. The "secondary home" may be one that does not really require continuous power, so having the power disconnected can be a cost savings or even a safety solution. On the other end of the spectrum, some people prefer to make lump-sum payments and utilize the notification methods in the prepayment program to trigger additional purchases rather than receiving a monthly bill.

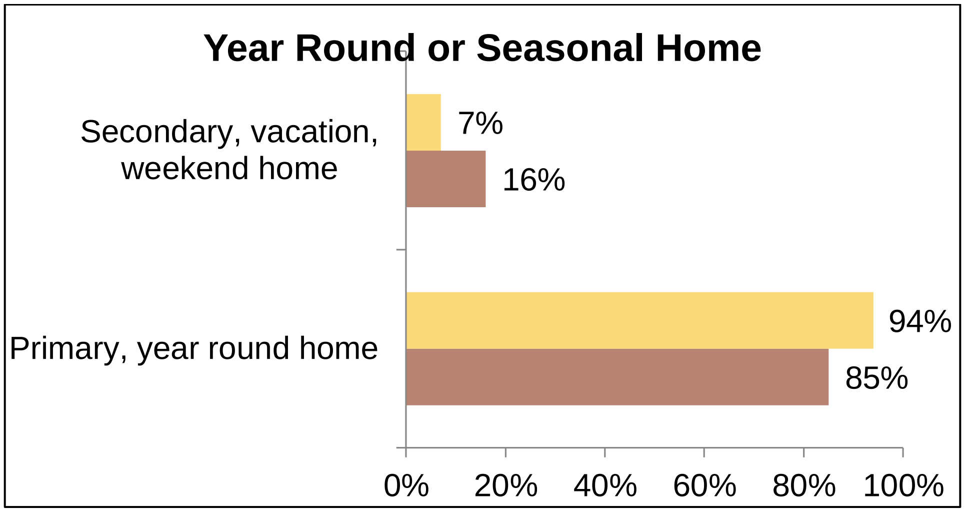


Figure 28. Types of Housing for which the Prepayment Account Is Being Used by the Survey Group

The last aspect of the demographic data is whether the members own or rent their residences, as shown in Figure 29. Although it would be reasonable to expect a large percentage of prepayment participants to be renters, it is still surprising to learn that more than half (54%) own their residences.

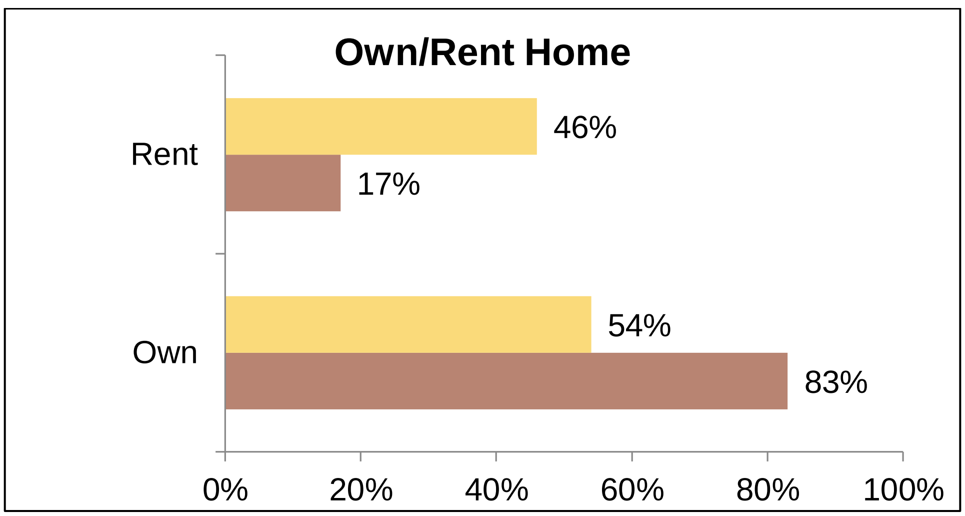


Figure 29. Survey Members' Home Ownership vs. Renting

1.26.2. Member Information

Figure 30 represents the ages of prepayment versus non-prepayment participants in the survey. These data bear out that prepayment typically appeals to younger members. This may be partly that one of the advantages of prepayment is avoiding the deposit. Younger members who are just starting out often are those who typically are subject to these deposits.

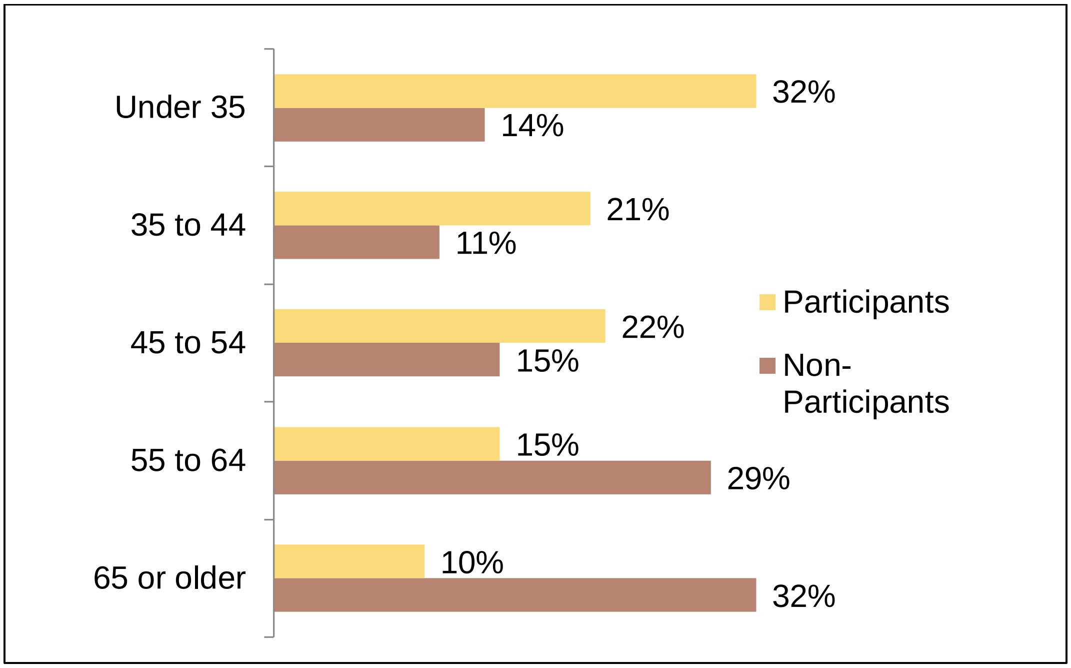


Figure 30. Ages of Participants vs. Non-Participants in Prepayment Programs

Figure 31 shows the employment statistics of the survey group. Most of these data align well with expectations. A slight oddity is that there were no active military personnel on regular bill payment. This could be for a number of reasons. Active members of the military tend to be more transient; for this reason, the utility serving military housing may encourage or provide incentives for choosing prepayment.

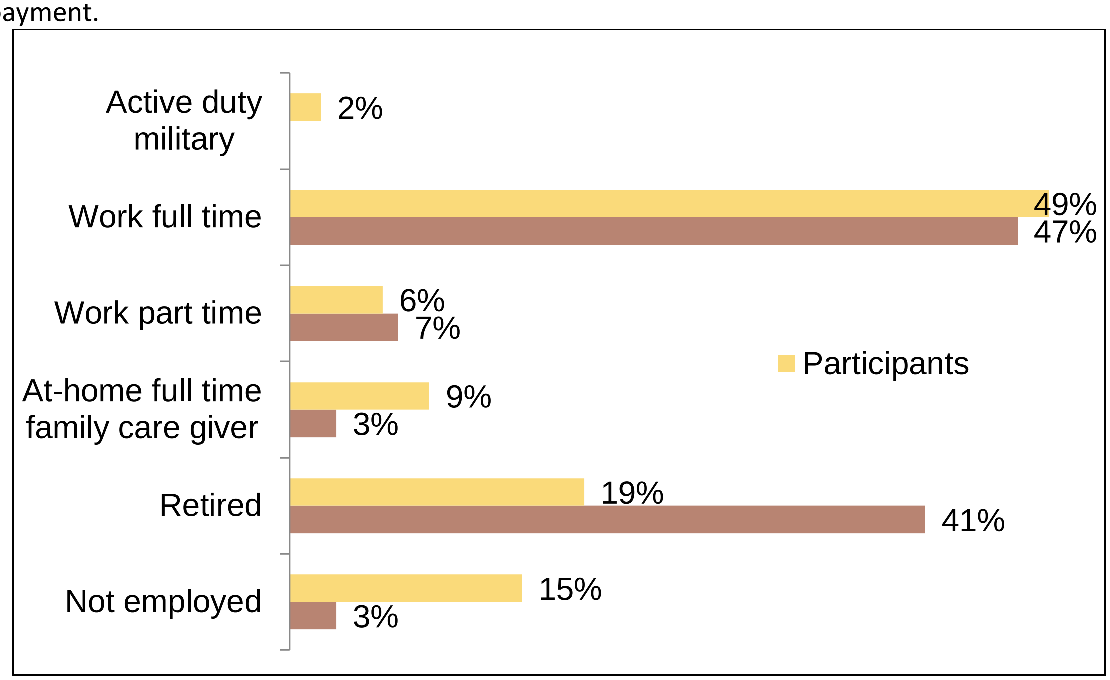


Figure 31. Employment Statistics for the Survey Group Members

The last aspect of member demographics has to do with household income, as shown in Figure 32.

These data fall in line with expectations. Lower-income households tend to choose prepayment more often than higher-income households. However, it should be noted that some higher-income households also choose prepayment.

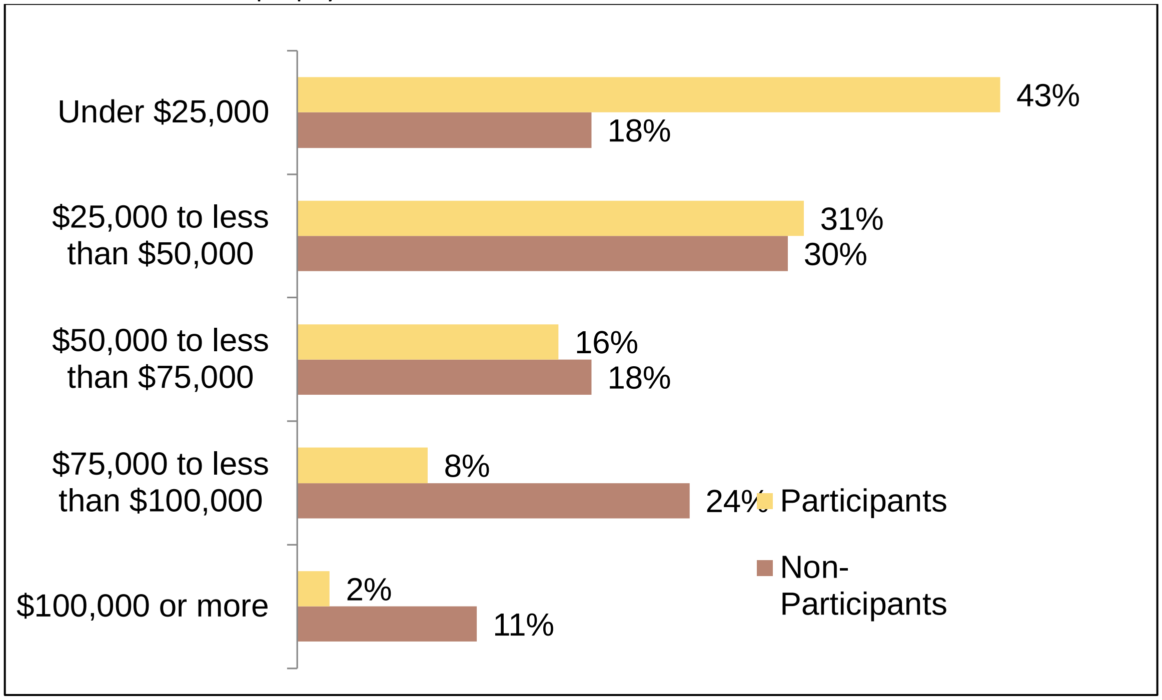


Figure 32. Income of Survey Group Members

Elected Outages

One concern of regulatory or other advocacy groups regarding prepayment is that members will be disconnected and not able to be reconnected in a reasonable timeframe. Figure 33 shows the number of times that the survey group has been disconnected.

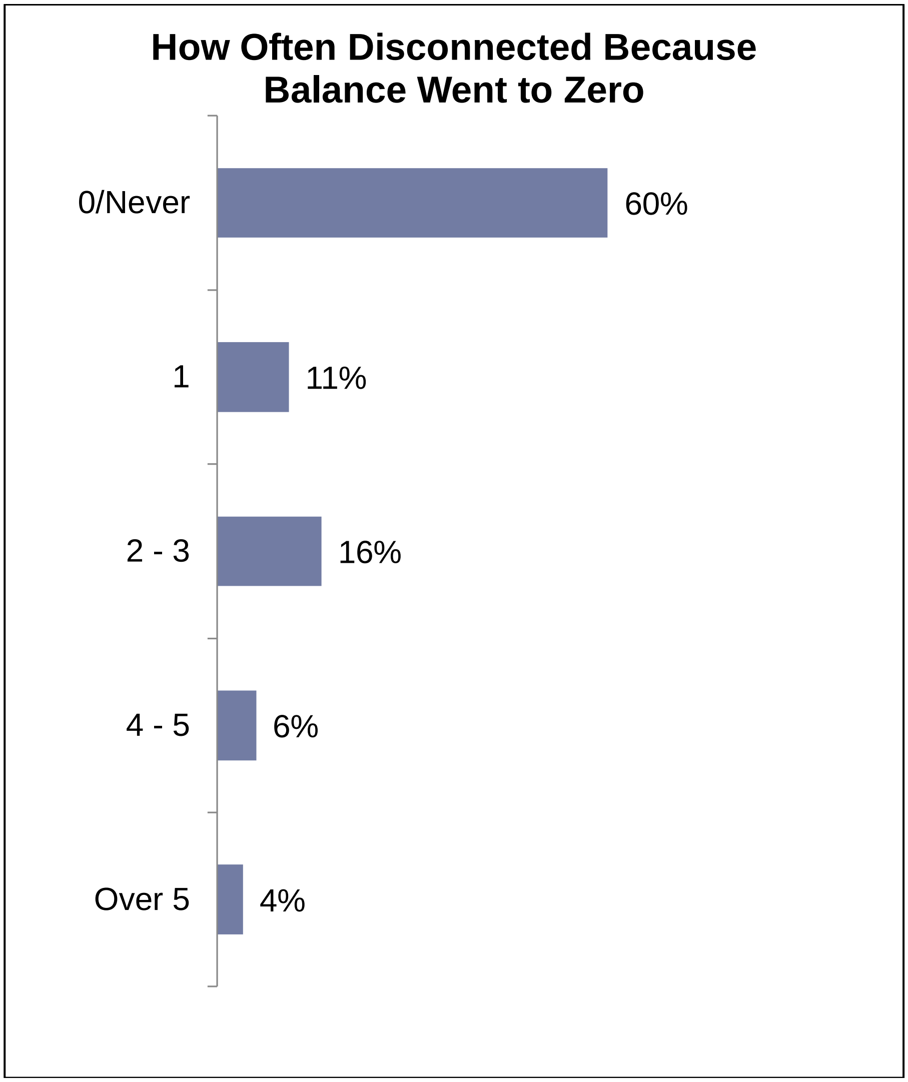


Figure 33. Number of Times Survey Group Members Were Disconnected

These data support the premise that having the convenience of being able to make purchases on members' schedules rather than receiving monthly bills is enough to help them avoid difficult payment situations. Well more than half of the members surveyed (60%) have never been disconnected. At the same time, less than 4% appear to have experienced recurring disconnections. This in and of itself should not necessarily be considered as a problem, as some members use the disconnect as the "final notification" that a purchase needs to be made. Since most programs do not have a reconnection fee (some prepayment programs still do have one), there is no real penalty, other than inconvenience, for a disconnection.

Summary

As with any exercise involving surveys, there are likely various aspects of the overall question list suggesting that additional questions might have been advisable, or that possibly a question may have been misunderstood. However, the overall results of these surveys and the general state of the market suggest the following:

- Prepayment has become a desirable and effective service to offer to co-ops' membership.
- Vendors have responded to the need by developing repayment solutions.
- The overhead for offering prepayment has been greatly diminished through the utilization of AMI.
- Member satisfaction is very high, regardless of the various nuances of the prepayment program offering.
- The only cooperatives that have no motivation for offering prepayment are those that:
    - Have a low incidence of unrecoverable debt
    - Do not charge a deposit
    - Have not yet implemented AMI
    - Are restricted from offering prepayment due to regulatory rules

It has taken approximately 25 years for prepayment to go from a curiosity to a recognized and beneficial program. In that time, advances in technology and utility systems have addressed the negatives of a prepayment solution, so the business case has become much easier to prove.

Chapter 9:

Costs and Benefits of Conservation Voltage Reduction – CVR Warrants Careful Examination

ACKNOWLEDGMENTS

We are grateful for the input from the following, without which this report would not have been possible:

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

ABSTRACT

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

EXECUTIVE SUMMARY OF RESULTS

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

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

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

RESEARCH QUESTIONS

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

TECHNOLOGY DESCRIPTION

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

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

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

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

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

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

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

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

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

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

FIELD DEPLOYMENTS

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

Adams-Columbia Electric Cooperative

Motivation

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

Installation Description

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

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

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

Planning Experience

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

Deployment Status

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

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

Deployment Lessons Learned

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

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

Realized Benefits

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

Owen Electric Cooperative

Motivation

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

Installation Description

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

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

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

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

Deployment Status

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

Iowa Lakes Electric Cooperative

Motivation

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

Installation Description

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

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

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

Planning Experience

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

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

Deployment Status

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

Verification and Realized Benefits

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

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

Voltage reduction has been verified via a SCADA display upgrade, and a matching load reduction is observable. In **Figure 9.1**, Gar substation voltage reduction, note the voltage and load reductions. The top graph shows voltage level, with scheduled reduction at 2 p.m. The bottom graph shows KW demand. The load spikes are from a demand response program operated by the power producer, not a product of the CVR regulation.

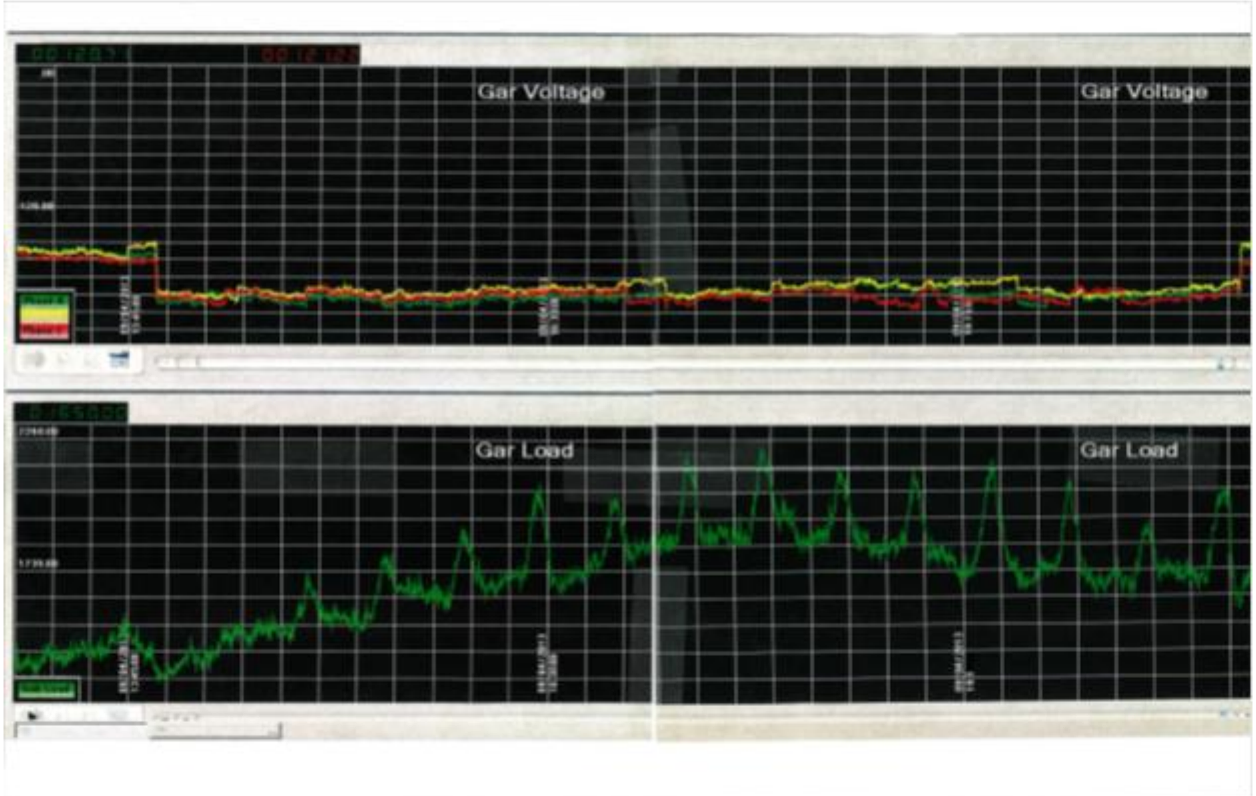


Figure 9.1: Gar Substation Voltage Reduction

VERIFICATION

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

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

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

The full source code for our verification scheme is available in Appendix 9A, along with interspersed example data from ACEC. As of November 15, 2013, the CVR installations were all complete, but data collection had just begun. To accurately evaluate CVR, a year's worth of

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

A dataflow diagram for the verification procedure is shown in **Figure 9.2**. From a set of SCADA data for the target feeder substations (typically provided as tab-separated value flat files), we derive a standard form (meter ID, timestamp, power, voltage, power factor); produce a correlation matrix for each pair of feeders based on a subset of the data as a control; select the most strongly correlated feeder for each treated CVR feeder; and then measure the relevant quantities ($\Delta E, \Delta Demand, F_{CVR}$) from these pairs.

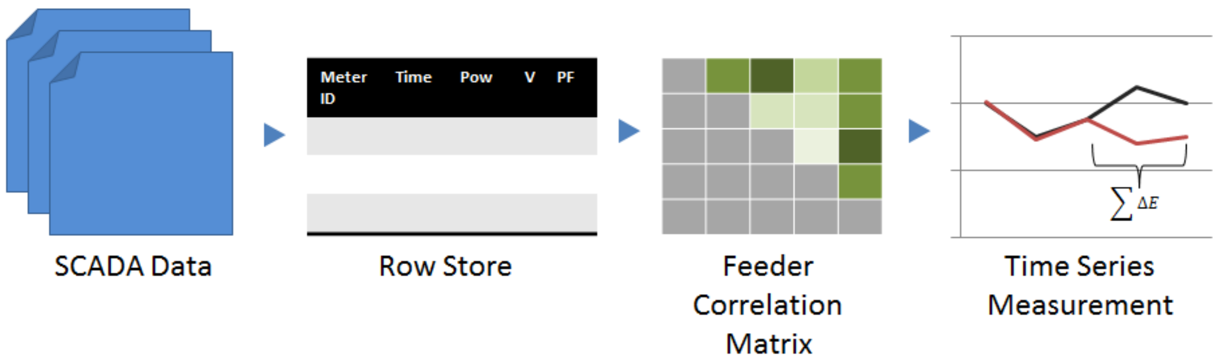


Figure 9.2: Verification Procedure Dataflow

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

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

MODELING CVR POWER SYSTEM BEHAVIOR

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

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

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

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

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

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

Static Peak and Mean Powerflow Method

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

As described above, we bring study feeder distribution hardware descriptions into the OMF from Windmil. Each base feeder then is duplicated, and the duplicate is modified using the OMF GUI to include any capacitor banks, line drop compensators, or other circuit elements installed as part of the project that would impact system losses or loads. An example of this editing process is shown in **Figure 9.3**.

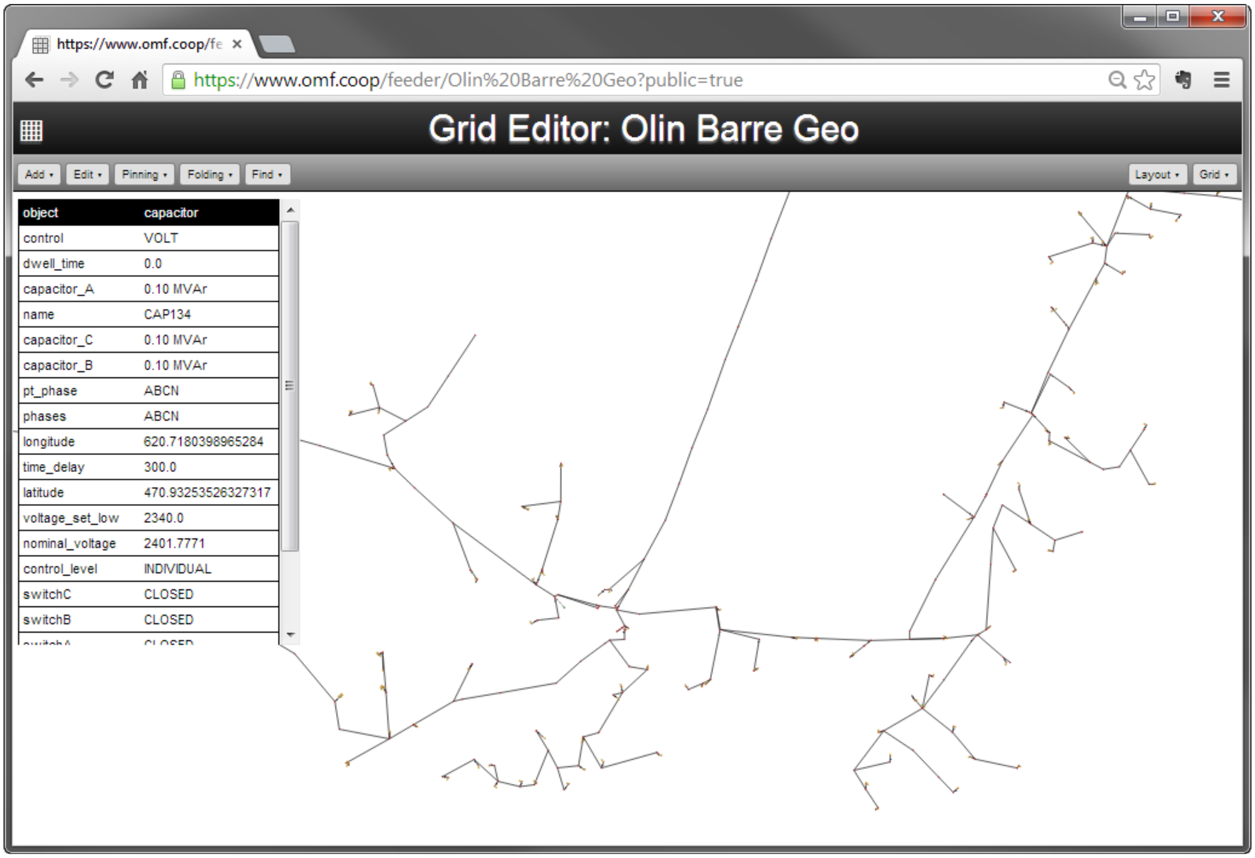


Figure 9.3: Specifying Capacitor Bank Properties in the OMF

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

A year's worth of historical SCADA data for the test feeder is used to determine peak and mean load levels for each month. The ZIP models then are scaled to 10 different load levels that can be used to linearly approximate all of the historical levels. Powerflow is run twice at each level: once at the current substation voltage and once at a substation voltage that is as low as possible with no meters outside of the ANSI voltage band (116–124 volts). The difference in consumption between the two voltage levels then gives the maximum possible savings that could be achieved via CVR. Model output for one example feeder is shown in **Table 9.1**.

Table 9.1: Powerflow Results for Test Co-Op Feeder

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

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

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

Dynamic Powerflow Method

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

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

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

ANSI band We do not consider control of additional downstream voltage regulators. (See **Figures 9.4** and **9.5**.)

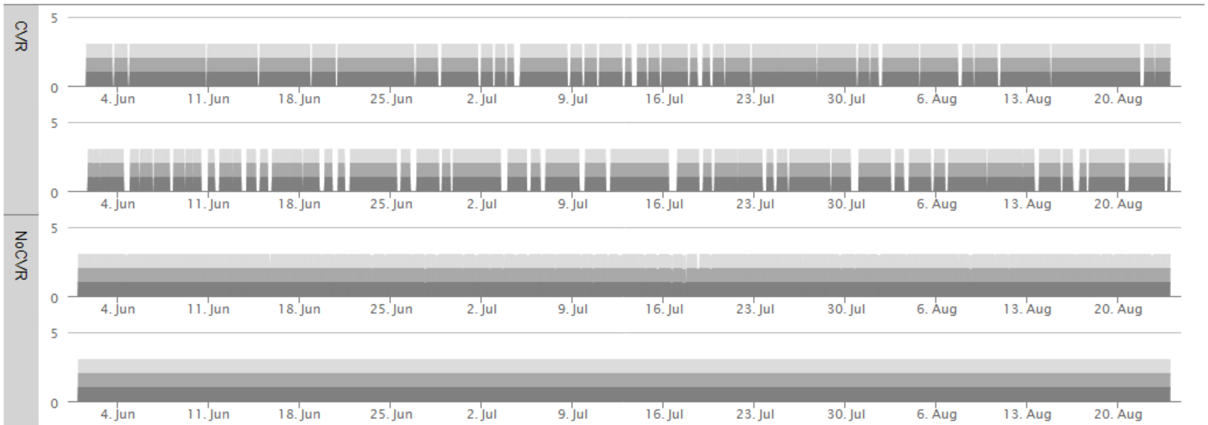


Figure 9.4: Dynamic Powerflow Simulation—Control of Capacitor Bank Switching

Figure 9.5: Three-Month Dynamic Powerflow Simulation—Powerflow across the Substation, and Loads and Losses Breakdown

Accuracy of Dynamic Powerflow Models

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

A single water heater provides a good example of a thermostatically controlled load that is poorly represented by a ZIP model. A water heater is modeled as a purely resistive element (100% impedance) in a ZIP model. GridLAB-D represents the behavior of the water heater as a physical process that determines the flow of heat energy; this is known as a physics-based or physical load model. The amount of heat energy within the water, or the temperature of the water, is affected by the amount of insulation around the water heater (also called the thermal jacket) and hot water usage in the home. GridLAB-D models the current temperature of the water, compares it to the thermostat set points, and determines when the device should be on or off. When the device is on, a voltage-dependent resistive element is applied to heat the water; i.e., if the voltage is lower, less power is demanded and therefore less heat is produced. This requires the device to run for a longer amount of time, as the same amount of energy is needed to heat the water to the desired temperature. In a ZIP model, a reduction of voltage results in reduced power demand and reduced energy consumption. However, in a physical model, a reduction in voltage results in a lower power demand but a longer run time for the device. **Figure 9.6** highlights this issue. Notice that the ZIP load (right-hand figure) shows the run time as constant at different voltage levels, reducing both energy and power, while the physical load model (left-hand figure) extends the run time at lower voltages, reducing power but not energy.

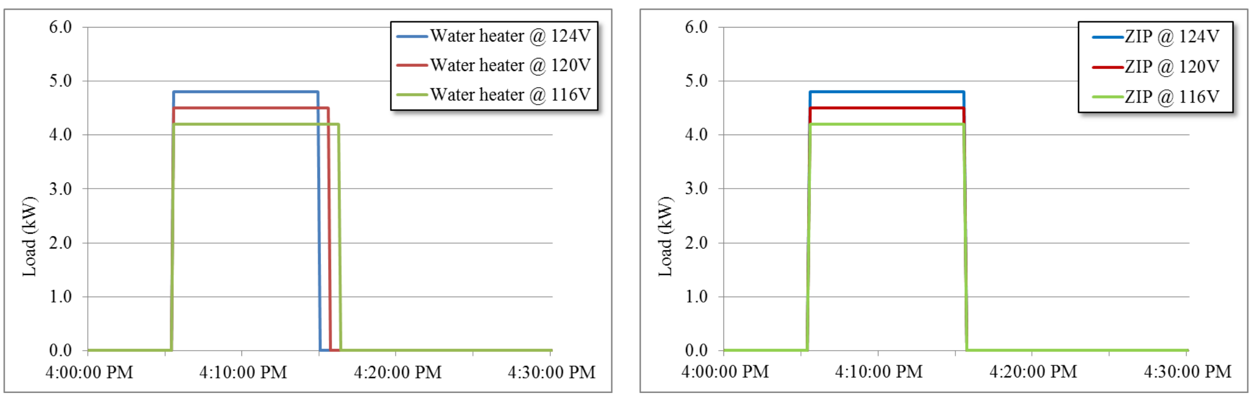


Figure 9.6: Comparison of Physical Water Heater Model versus Zip Model at Three Voltage Levels

We also can look at a collection of water heaters for two different volt/VAR services: peak reduction and energy reduction. Below is an example from GridLAB-D that simulates 1,000 water heaters as both physical and ZIP models. **Figure 9.7** shows a 2-hour peak reduction by lowering the voltage from 124 to 116 from 15:00 to 17:00; while this represents an extreme case, it highlights the effects. The dashed lines represent the ZIP model, while the solid line represents a physical model of the water heater (WH). At 15:00, both the ZIP and WH load are reduced by about 15%. However, by 16:00, the physical model reduction has significantly decreased as the water heaters return to their natural operational state (consuming the same amount of energy), while the ZIP model still shows a reduction of approximately 15%. In this 2-hour window, the ZIP model predicts that peak reduction will be far greater than it actually is.

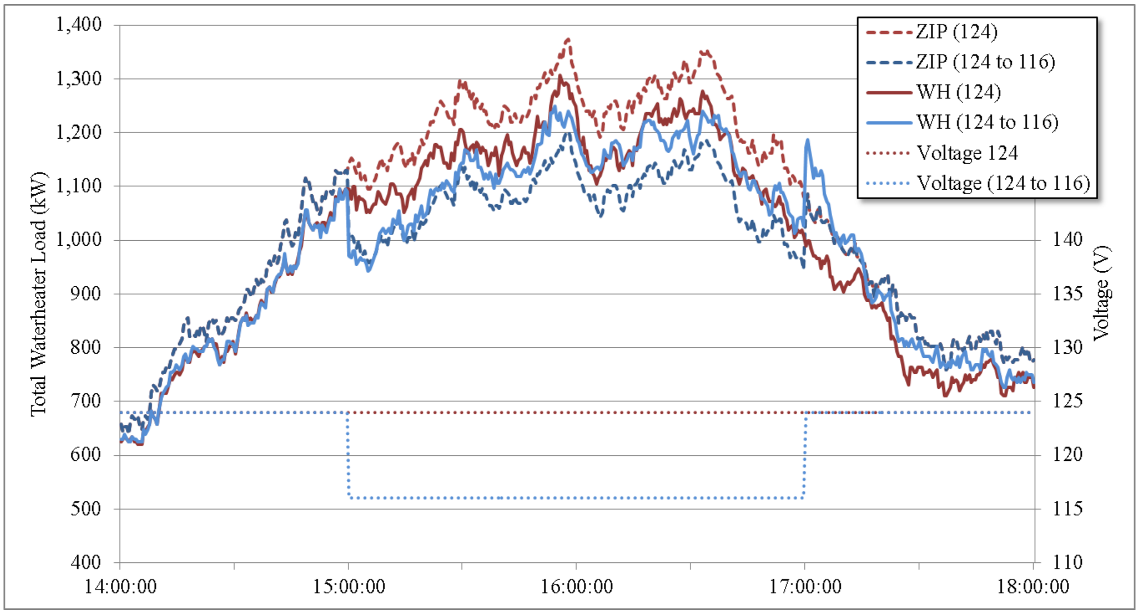


Figure 9.7: Peak Reduction Event-Shifting Voltage from 124 to 116 and Comparing Physical Water Heater Load vs. ZIP Load

VVO also can be used for energy reduction, operating the system at all times at lower voltages. Again, 1,000 water heaters are simulated as both physical and ZIP models for one day, operating the system at 124, 120, and 116 volts constantly throughout the day. The results are shown in **Table 9.2**—daily energy consumption and peak demand during the evening peak per water heater. Note that the physical model shows only a minimal change in the energy consumption, while the ZIP load indicates a 14% reduction, from 124 V to 116 V. Also note that the ZIP model predicts a greater peak reduction (14% reduction, from 124 V to 116 V) than the physical model (4% reduction).

Table 9.2: Comparison of Energy Consumption and Peak Demand

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

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

COSTS AND BENEFITS

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

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

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

Static Load Model Cost-Benefit

In **Table 9.3**, we derive a cost-benefit analysis from the same model powerflows calculated in **Table 9.1**. For each historical month from a prior year's SCADA data, we use the historical peak and average loads to estimate peak/loss and energy consumption reductions, respectively. Each month's reduction watt values are the difference between the treated (CVR) model and the baseline, without re-regulation or capacitor bank additions. Results were interpolated linearly from nearest load matches among the 20 candidate powerflows to reduce the running time of the computations. A graph of these data is shown in **Figure 9.8**.

Table 9.3: Costs and Benefits for Re-Regulation of Test Feeder

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

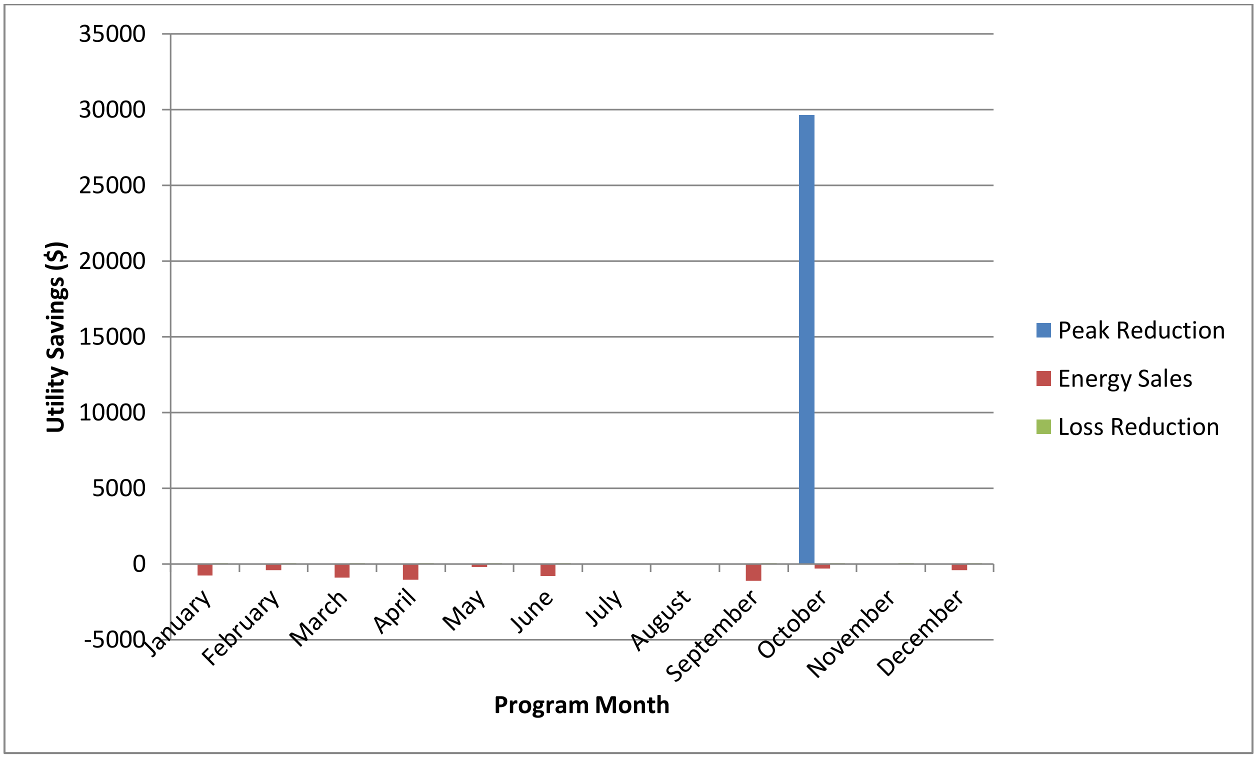


Figure 9.8: Utility Savings by Month and Cause

As **Figure 9.8** makes clear, the main benefit for the re-regulation of this feeder is a lucrative peak reduction in October. Loss reductions offer trivial savings. Lower energy sales are a significant cost but are far outweighed by the demand reduction savings. In some markets, energy savings can be recovered through conservation credits. The model assumes that CVR is run continuously to keep the system voltage as low as possible while still keeping all meters within the ANSI band. Were the system to be run only during peaks, the lost energy sales would be drastically reduced.

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

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APPENDIX 9A: VERIFICATION CODE

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

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

97

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

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

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

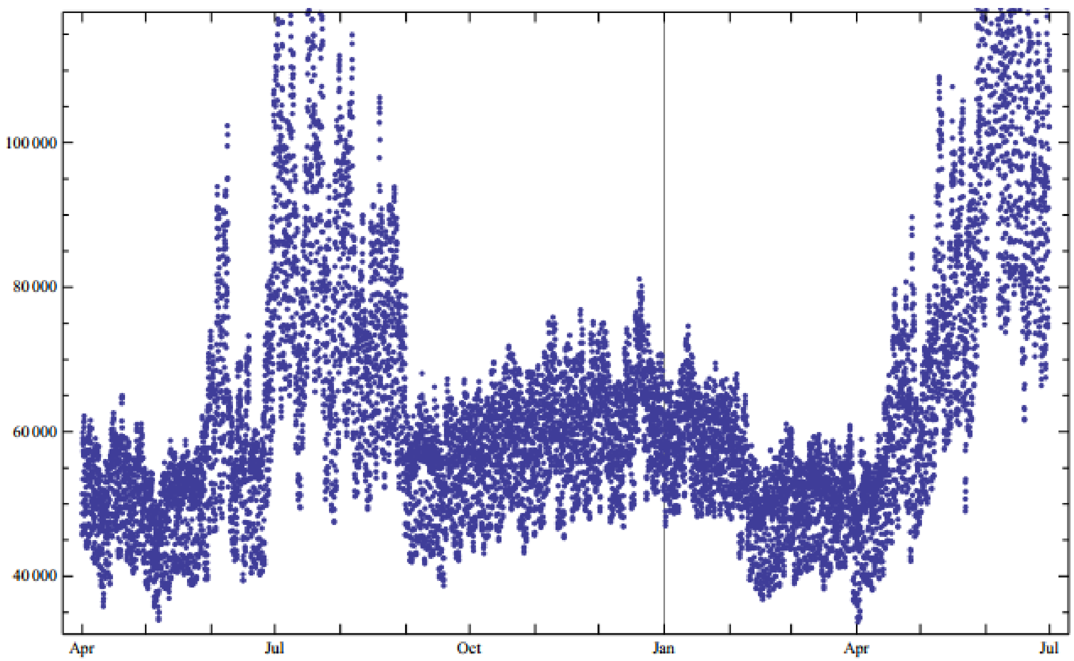
```
(*Function for cleaning data in each TSV.*)
subSet[tsv_] := Module[{droppedBlank, subset},
   droppedBlank = Select[tsv, Length[#] > 3 &];
   (* Pull out labels, KW and PF:*)
   subset = Map[#⟦{1, 2, 3, -1}⟧ &, droppedBlank];
   subset
  ];

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

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

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

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

[redacted]

```
meterNames = DeleteDuplicates[Map[#[[1]] &, flatMerge]]
subMeters = meterNames[[2 ;; -1]];
{[redacted] , 7180863, 710462, 470538, 468706, 469573, 471135, 693716, 470508, 469664,
 638717, 470382, 664613, 664614, 664616, 468670, 470394, 470221, 7180864, 469653, 469661,
 470201, 664054, 470386, 470246, 469628, 470396, 471059, 469616, 470190, 558087, 470284, 470493}

dates = flatMerge[[All, 2]]; Sort[dates]; timeLimits = {DateList[dates[[1]]], DateList[dates[[-1]]]}
treatLimit = {{DateList["1 January 2012"]}, {}}
treatOffset = 5883; dates[[treatOffset]]
{{2011, 3, 31, 23, 0, 0.}, {2012, 6, 30, 22, 0, 0.}}

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

1/1/12 00:00

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

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

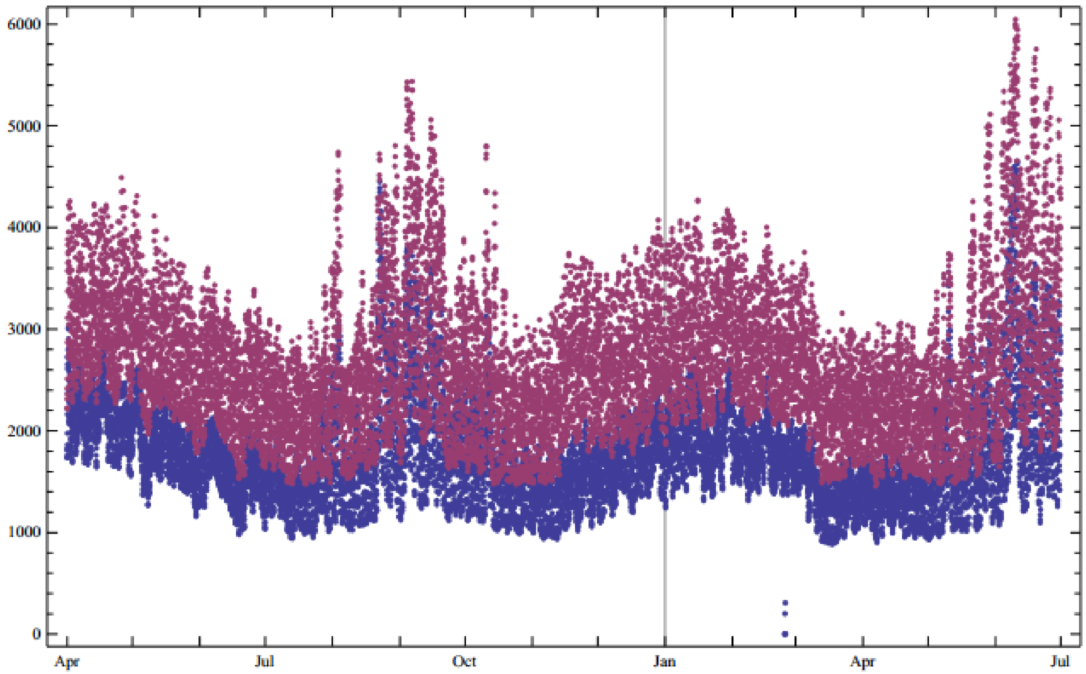



```
(*Small multiples graphing of all the substation KW readings, 2011+1/2(2012)*)
Table[DateListPlot[getKilowatts[x], timeLimits, ImageSize → Scaled[0.22], GridLines → treatLimit],
  {x, meterNames[[2 ;; -1]]}] // Partition[#, 4] &


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

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

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

	7180863	710462	470538	468706	469573	471135	693716	470508	469664	638717
7180863	1.									
710462	0.09	1.								
470538	0.6	0.07	1.							
468706	0.94	0.11	0.58	1.						
469573	0.24	0.09	0.37	0.28	1.					
471135	0.42	0.02	0.92	0.39	0.32	1.				
693716	0.88	0.18	0.47	0.93	0.39	0.27	1.			
470508	0.79	0.08	0.24	0.7	-0.06	0.07	0.67	1.		
469664	0.91	0.18	0.48	0.96	0.25	0.28	0.97	0.72	1.	
638717	0.88	0.15	0.66	0.89	0.45	0.5	0.89	0.54	0.89	1.
470382	0.85	0.08	0.87	0.82	0.38	0.76	0.74	0.52	0.75	0.85
664613	0.32	-0.02	0.56	0.33	0.41	0.55	0.3	-0.04	0.26	0.47
664614	0.25	-0.17	0.38	0.27	0.25	0.4	0.18	-0.06	0.18	0.36
664616	0.59	0.14	0.18	0.59	0.13	0.05	0.63	0.56	0.63	0.57
468670	0.95	0.15	0.69	0.94	0.25	0.52	0.85	0.69	0.89	0.88
470394	0.64	0.04	0.89	0.61	0.3	0.86	0.48	0.28	0.51	0.66
470221	0.53	0.03	0.88	0.46	0.26	0.88	0.36	0.29	0.37	0.51
7180864	-0.04	-0.11	-0.09	-0.04	-0.01	-0.1	-0.03	0.	-0.04	-0.05
469653	0.34	0.32	0.02	0.36	0.11	-0.11	0.45	0.51	0.42	0.25
469661	0.39	-0.03	0.18	0.41	0.21	0.07	0.48	0.38	0.43	0.34
470201	0.36	-0.09	0.24	0.3	0.14	0.17	0.34	0.42	0.32	0.29
664054	0.4	0.06	0.23	0.39	0.21	0.11	0.46	0.42	0.43	0.36
470386	0.44	0.03	0.19	0.43	0.22	0.08	0.51	0.49	0.48	0.39
470246	0.42	-0.02	0.22	0.39	0.2	0.12	0.46	0.48	0.43	0.36
469628	0.42	0.08	0.19	0.44	0.26	0.08	0.51	0.41	0.47	0.39
470396	0.37	0.01	0.11	0.37	0.21	0.01	0.46	0.42	0.42	0.34
471059	0.41	0.06	0.15	0.43	0.23	0.03	0.52	0.44	0.48	0.38
469616	0.41	0.12	0.14	0.43	0.23	0.02	0.53	0.46	0.49	0.38
470190	0.36	0.15	0.04	0.39	0.17	-0.09	0.49	0.47	0.45	0.3
558087	-0.04	0.	-0.02	-0.02	-0.02	-0.02	-0.02	-0.01	-0.03	-0.05
470284	0.45	-0.01	0.27	0.44	0.27	0.17	0.51	0.45	0.47	0.42
470493	0.42	0.	0.15	0.38	0.16	0.05	0.46	0.52	0.43	0.34

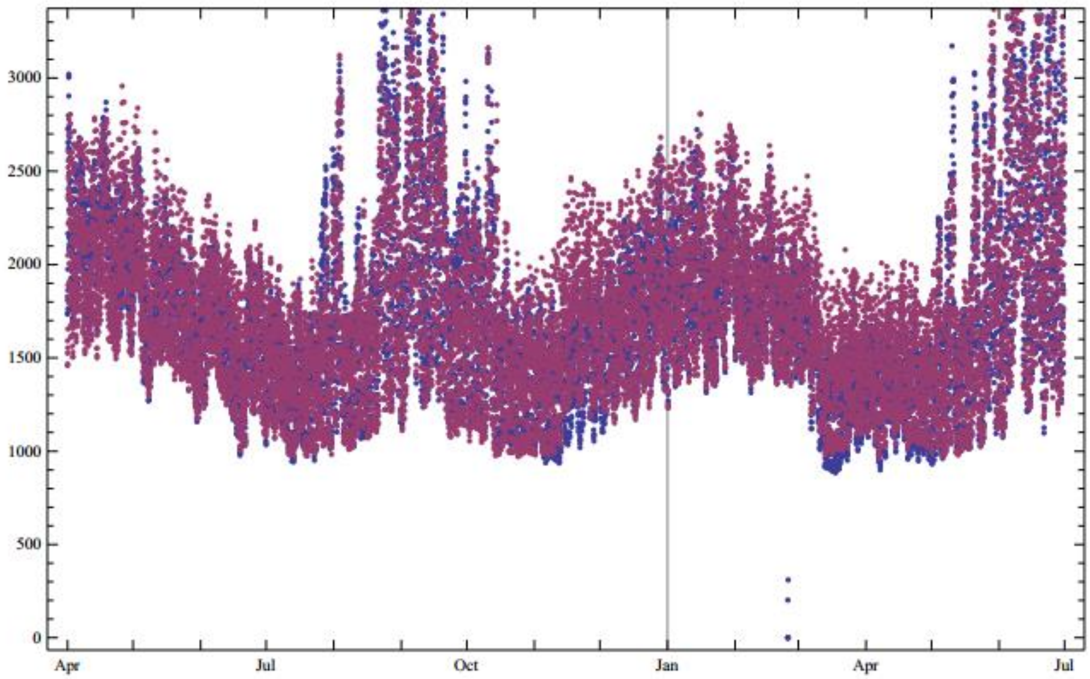
```
(*Highly correlated pair.*)
DateListPlot[{getKilowatts[7180863], getKilowatts[469664]},
 timeLimits, ImageSize → Scaled[0.9], GridLines → treatLimit]
```




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

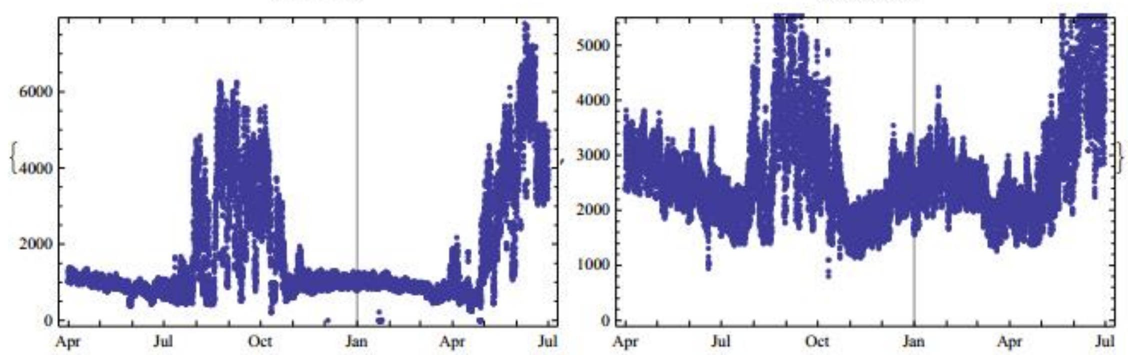
```
meanMult[7180863, 469664]
```

-3.75417×10^{-9}

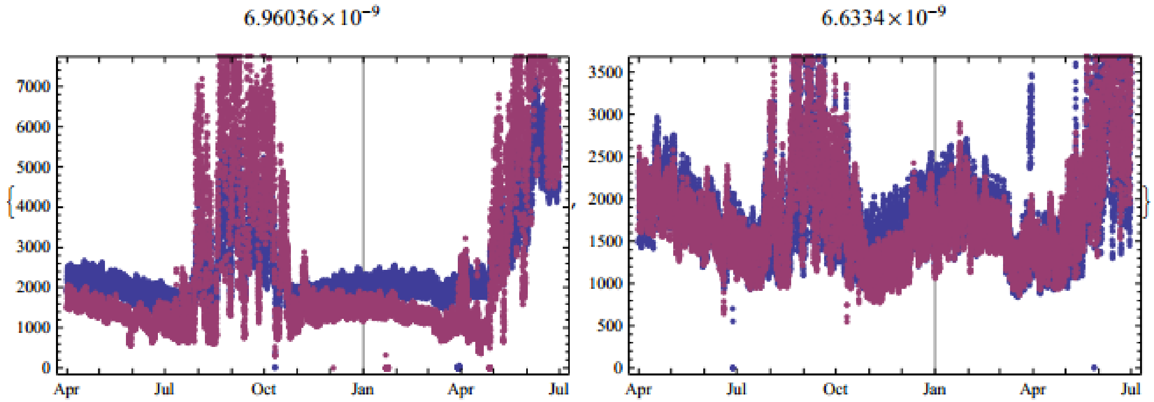



```
(*Target Feeders: 471135→[redacted] and 470382→[redacted].*)

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

[redacted] [redacted]



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




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

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

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

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

Chapter 10:

Costs and Benefits of Smart Feeder Switching – Quantifying the Operating Value of SFS

ACKNOWLEDGMENTS

We are grateful for the input from the following, without which this report would not have been possible:

- James Bridges, VP of Engineering, Owen Electric Cooperative
- Steve Estes, System Engineer, EnergyUnited
- Bryan Jones, Distribution Engineer, Washington-St. Tammany Electric Cooperative
- Gerald Schmitz, Electrical Engineer, Adams-Columbia Electric Cooperative
- Michael Milligan, Manager of Engineering, Snapping Shoals Electric Membership Corporation
- Timothy Sharp, COO, Salt River Electric Cooperative
- Craig Thompson, Partner, Thompson Engineering
- James Thompson, General Manager, Adams Electric Cooperative
- Brad Wilson, Manager of Engineering, Clarke Electric Cooperative

ABSTRACT

This report discusses the deployment experience at nine rural electrical cooperative utilities of distribution automation technologies applied to Smart Feeder Switching (SFS) applications. We investigate the suitability of models to represent and predict the benefits of these technologies, with extensions to automating screening and engineering analysis for future deployments. This study defines an analytical methodology for quantifying the value of two SFS operational benefits: (1) more rapid restoration following a fault and (2) reduced I^2R losses through feeder load balancing. It also conveys a listing of SFS benefits and costs, identifying those deemed to have first order impacts, and compares projected values with field study results from National Rural Electric Cooperative Association (NRECA) Smart Grid Demonstration Project participants. In addition, it defines a logical modeling framework and analytics process for evaluating costs and benefits.

EXECUTIVE SUMMARY OF RESULTS

1. Gaining experience with increasingly prevalent distribution automation technology was an important driver behind cooperative participation in these demonstrations.
2. Non-labor costs were consistent per automated switch, but costs per customer average interruption duration index (CAIDI) minute of improvement, when calculable, were variable due to the diverse system types under study.
3. Multiple cooperatives were able to bring large percentages (30%–50%) of their feeders into configurations that enabled self-healing through back-feeds and automatic source transfers.

RESEARCH QUESTIONS

- **Field Trials:**
  - In the co-ops that installed hardware, what were the expected and realized benefits for reliability and feeder balance?
  - What are best practices and common "gotchas" across all deployments?
  - How do the benefits accrue to the cooperative, co-op members, and upstream power providers?
  - What are the impacts of these technologies on maintenance efforts?
- **Model Extensions:**
  - Can we accurately represent reliability impacts of smart feeder switching technologies via powerflow models?
  - What feeder characteristics are correlated with what benefits, and can this information lead to a system screener to locate candidates for technology installation?

TECHNOLOGY DESCRIPTION

Smart Feeder Switching (SFS) employs hardware, software, and procedural components to perform automated switching actions on distribution feeder systems. It creates (1) a "self-healing" system that can locate and isolate faults and automatically restore service, and (2) a more efficient network that reduces distribution system losses through load balancing across feeders.

Distribution feeders can be designed in a loop or radial configuration. Loop configurations have more than one power source, whereas radial configurations have a single power source. Radial feeder design typically is used for feeders covering large geographic areas in remote locations.

Utilities usually design feeders in loop configurations, when economically feasible. A loop configuration allows utilities to restore power from another source in the event of a system fault.

Automated Fault Location, Isolation, and Restoration (FLIR)

In general, utilities have not implemented SFS systems at distribution-level voltages; therefore, system operators usually do not monitor the distribution system. When customers lose power due to a fault on a distribution line, utility operators usually are not aware of the service interruption until they receive a customer call. It can take several hours for utility crews to determine the fault location once they are dispatched. SFS enables remote monitoring of distribution system equipment and automates the fault location, isolation, and restoration processes so that electric service usually can be restored in minutes.

Feeder Switching for Load Balancing

Feeder switching for load balancing is the process of transferring loads from one feeder to another to balance the total load across multiple feeders and transformers, thus reducing line losses, calculated as the square of line current.

FIELD DEPLOYMENTS

Nine cooperatives completed SFS projects. Descriptions of the deployments follow.

Adams Electric Cooperative

Motivation

Adams Electric Cooperative (AEC) is a utility serving 8,500 members around Camp Point, Illinois (see **Figure 10.1**). The cooperative undertook this grant-funded project to better serve its members and leverage existing technology. A key goal was to improve restoration times when members are faced with an outage by automatically switching members to an alternate feed without any human intervention. This technology improves members' ability to keep their businesses operating.

Installation Description

As part of its SFS activity, AEC installed 2 distribution switch controllers, 2 distribution reclosers with panels, 18 distribution fault detectors, and 2 overhead switches. The two automatic switches were deployed in a heavily loaded area on the east side of Quincy, Illinois.

Total project hardware and software cost for communications, supervisory control and data acquisition (SCADA), and switching hardware was $190,000.

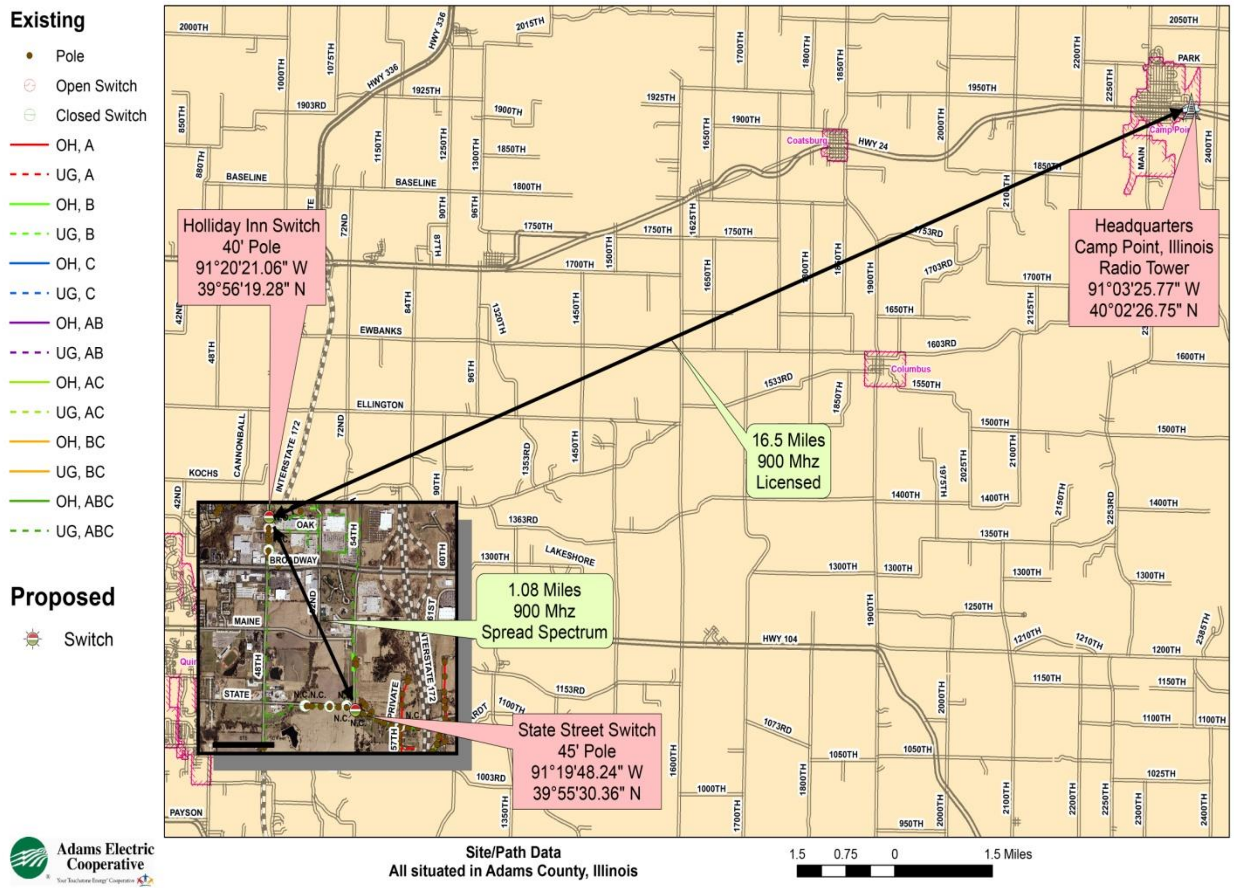


Figure 10.1: AEC Communications System Design and Switch Sites

Planning Experience

Engineering planning began with D/A switch site selection. Due to its St. Anthony West feeder's heavy commercial loads, the cooperative considers it an area of critical importance. The project was designed such that, if the St. Anthony West's normal feed was lost, the St. Anthony North feeder would pick up this area as an alternate feed. AEC prefers overhead D/A switches over underground D/A switches due to ease of install, cost, and configuration safety. With this in mind, AEC determined physical D/A switch placement using geographic information system (GIS) maps and a site visit, taking pole placement and normal opens into consideration.

A fault magnitude (coordination study) was performed to determine the settings necessary in the D/A controls for proper operation of the D/A switches. AEC had to determine the time-current curves, pick-up, and number of operations in all of the over-current devices up- and down-line of the D/A switches. This was achieved via a Milsoft Windmil model, device TCC specifications, and a coordination work sheet.

The cooperative also performed a coordination study to determine proper programming for the D/A switches, given system conditions and programming of existing 6801 control fields. Engineering and operations personnel reviewed all of the 6801 control fields, considering, for example, using the D/A switch to act as an over-current device that would open before the substation Nova reclosers would go to lock-out, and not allowing the alternate feed to close into a fault if a fault was present in between the D/A switches. AEC took into account programming that would minimize the outage time and assist in troubleshooting the outage.

A communication propagation study also was required. A line-of-sight study via GIS maps was conducted to determine the height of the AEC master radio antenna and the distance to the north D/A switch. This also provided the distance and height of the north and south D/A switches. On-site RSS tests were conducted using a 30' test MDS 9710 SCADA radio and antenna located at the proposed north D/A switch site. A received signal strength indicator (RSSI) reading of 80Db from AEC's master SCADA radio was considered more than adequate for reliable SCADA communication. No in-house equipment was available to test the peer-to-peer RSS, so AEC used the following method to determine whether a reliable peer-to-peer communication could be established: two bucket trucks were raised to a height of 30' to establish that a clear line of sight between the two peer-to-peer locations was available and the span did not exceed the distance limits of the two radios per S&C specifications.

Deployment Status

The installation of the distribution automation switches was completed in May 2012, and the system has been active since then.

Deployment Lessons Learned

AEC had no problems with installing and bringing the SCADA communication on line. However, with peer-to-peer communication, there was an issue with radio frequency (RF) interference from the Holiday Inn building in proximity to the north D/A switch. This required moving the peer-to-peer antenna one pole span to the south. It was not foreseen that RF interference would be a problem in the original location.

The S&C automatic controllers are functioning correctly but, in the start-up process, AEC had some difficulty in programming the controllers due to manufacturing problems: the wrong firmware was installed in the controllers.

Schweitzer underground and overhead fault indicators were easy to install and met the cooperative's needs. It is foreseen that these indicators will help with trouble shooting faults.

Realized Benefits

The cooperative has not experienced any faults, loss of voltage, single phasing, etc. on the distribution system where the distribution automation switches have been installed. Even though the switches have not yet operated, installing them and learning about their capabilities has improved the resiliency of the distribution system and provided experience to AEC engineers for future distribution automation projects.

Adams-Columbia Cooperative

Motivation

Adams-Columbia Cooperative (ACEC) is a cooperatively owned utility serving 36,000 members around Friendship, Wisconsin. ACEC's service territory was hit by severe storms in 2001, which led to making system resiliency a priority.

Installation Description

ACEC installed 10 distribution reclosers—4 overhead and 6 underground. All reclosers were outfitted with automatic controls and communications capabilities. The SCADA system also installed as part of the Smart Grid Demonstration is the point of control for these smart switches.

Although the reclosers can be human operated remotely, their role in the smart switching scheme is to report back system conditions to SCADA and then take orders to reconfigure the system from the smart grid software (Yukon Feeder Automation).

The utility's feeders are all in radial configurations. Currently, a limited amount of back-feeding is possible through switches normally open. This project increases the number of interconnection points and hence opportunities for power restoration in fault conditions.

Total hardware and software costs for this project were $414,000, which breaks down as follows (**Table 10.1**):

Table 10.1: ACEC Hardware and Software Costs

Hardware Description	Quantity	Unit Cost	Extd Cost
OH distribution switches with controls	4	$22,792	$91,168
Underground switches with controls	6	$39,970	$239,820
Radio communication equipment, 5.8 Ghz	2	$2,245	$4,491
Radio communication equipment, 900 MHz	13	$2,245	$29,191
Radio communication equipment, 200 MHz	9	$2,245	$20,209
		Eqpt Cost	$384,878
		Shipping (2%)	$7,698
		Sales Tax (5.5%)	$21,592
		TOTAL HW/SW	**$414,168**

New switch locations relative to substations are shown in **Figure 10.2**.

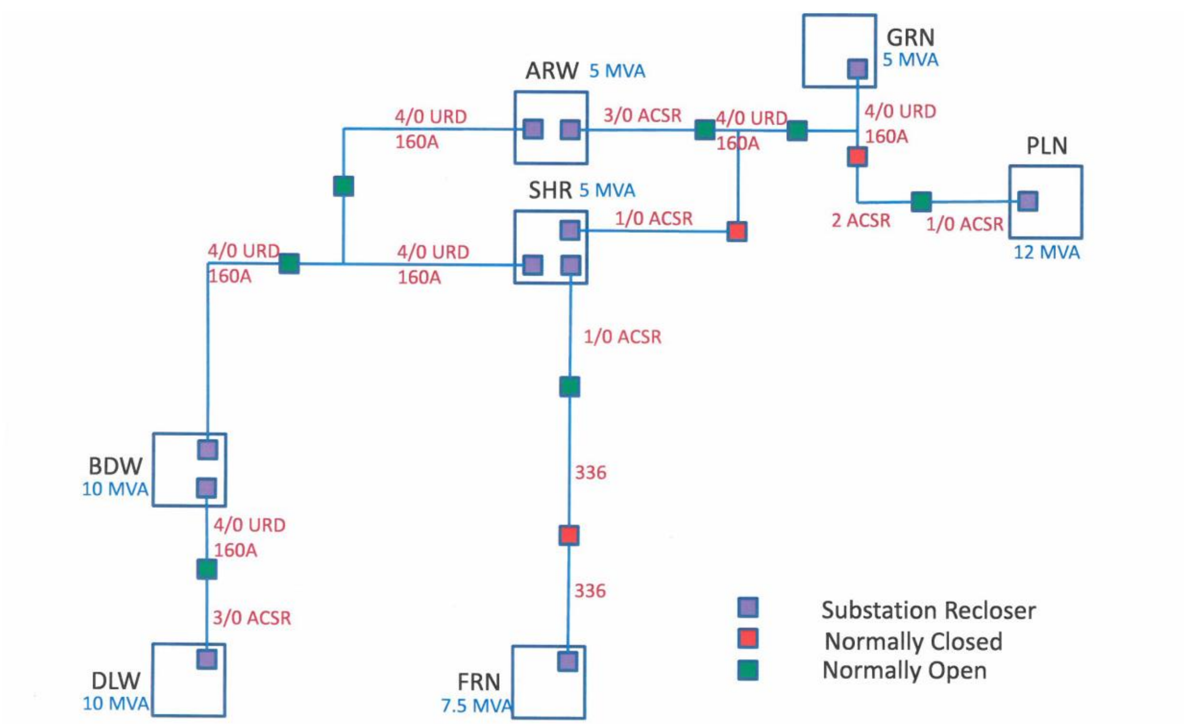


Figure 10.2: ACEC Substation Map with New Connectivity and Switch Settings

Deployment Status

All hardware has been deployed as of November 1, 2013. The system passed a brief outage test—when the test recloser was opened, feeders reconfigured as designed.

The system is expected to operate once a year when it is ready, so data volume for verification and resiliency benefit estimation is expected only after many years of system operation. There is a possibility of field testing with additional induced faults.

Clarke Electric Cooperative

Motivation

Clarke Electric Cooperative is a utility serving 5,200 customers in portions of eight counties in South Central Iowa. The primary motivation for this project was to improve operational efficiency for the cooperative and increase reliability for the members.

Installation Description

The SFS activity includes distribution switches/controllers at 21 field switch locations, distribution reclosers and automation equipment at 33 locations, and monitoring and control software.

The communications activity involved design and installation of radio backhaul equipment and associated communications equipment to link Clarke’s control center with DA at the 54 remote locations.

An additional SCADA activity was intended for the installation of both hardware and software for a small-scale SCADA system, which supports the smart feeder activity. In addition, Distribution Fault Anticipator monitors will be installed on all three feeders at one substation. This equipment and software will help determine potential distribution hardware that needs to be addressed. This will improve power delivery reliability and information transfer accuracy.

Deployment Status

Installation is complete and the hardware is functioning correctly in the field.

Lessons Learned

Brad Wilson, engineering manager at Clarke EC, shared his lessons learned: “Understand zoning and ordinances for the placement of towers. We had to relocate a tower that was installed too close to a roadway, assure that the engineering consultant is intimately familiar with the specific technology being implemented, and plan for extensive training for internal personnel. In fact, the internal personnel need to be involved in the installation and setup of the system if they will be assuming ownership after the project is completed.”

Realized Benefits

Clarke has implemented a self-healing scheme with the project switches that performs within minutes what were previously 4 hours of manual switching procedures. Both DA switches and electronically controlled reclosers operate in a sequence to restore service to feeders served from one substation, which had a history of transmission reliability issues.

The cooperative also has received some benefit from having switches that can be remotely operated instead of requiring a truck roll. Utilization of these capabilities, as well as the self-healing scheme, will increase as operational experience increases and engineering analysis continues. Clarke looks forward to adding more “brains” into the control software of these smart devices in the future.

EnergyUnited

Motivation

EnergyUnited (EU) is a cooperatively owned utility serving 121,000 customers around Statesville, North Carolina.

One of EU's top corporate goals is service reliability. Its current reliability rating is 99.98, but it is focusing on smart grid technologies with the intent of improving reliability for members as well as increasing overall efficiency.

Since EU's electric service area spans 19 counties throughout North Carolina, travel time sometimes increases the time required to complete restoration. For this reason, EU piloted an SFS project to test and demonstrate how this smart grid technology can increase reliability for members.

Installation Description

Currently EU has a 12.5 kV delivery, known as the Boomer Delivery. From this delivery, it has one circuit coming out, known as the Boomer Circuit. This circuit goes for several miles and is located at the far end of its service territory. When power is lost from its service provider, it can take a considerable amount of time for a crew to reach the site. Once service crews are at the site and have determined that the outage is caused by a loss of the source, EU may back-feed this circuit from another substation and circuit located approximately 8.5 miles away. Because the back-feed is a fairly good distance from the Boomer Delivery, there is a limit as to how much of the circuit can be back-fed. During lightly loaded periods, the entire circuit can be back-fed. During more heavily loaded periods, EU can back-feed only a portion of the circuit. It can take between an hour to 3 hours for crews to complete this back-feed and restore power to our members. The Boomer Delivery is located at the end of a fairly long circuit owned by Duke Energy. Because there is such a long distribution feeder serving this delivery, outages of the source are not uncommon.

To provide greater reliability to members, EU proposed automating this back-feed using distribution automation and the existing SCADA system. The automated system monitors the loading on the circuit at all times. A monitoring system is placed at the source of the delivery to sense a loss of source. In that event, the automated system determines the loading at the time just before the outage occurred. Based on this information, the automated system determines if the entire circuit, or only a portion, can be back-fed. Depending on the outcome of this decision, the automated system operates a series of 2 reclosers and 3 switches out on the circuit and completes the appropriate back-feed. Once power is restored to the source and EU has confirmed with the delivery provider that the outage is over, EU personnel trigger the system to undo the back-feed and return the circuit to normal operation.

Automating the back-feed system takes what typically would have been a 1- to 3-hour outage and reduces it to less than 5 minutes in most cases.

Total smart feeder switching project cost was $214,000, of which $138,000 was hardware and software purchased for the activity. **Figure 10.3** shows EU's one-line diagram.

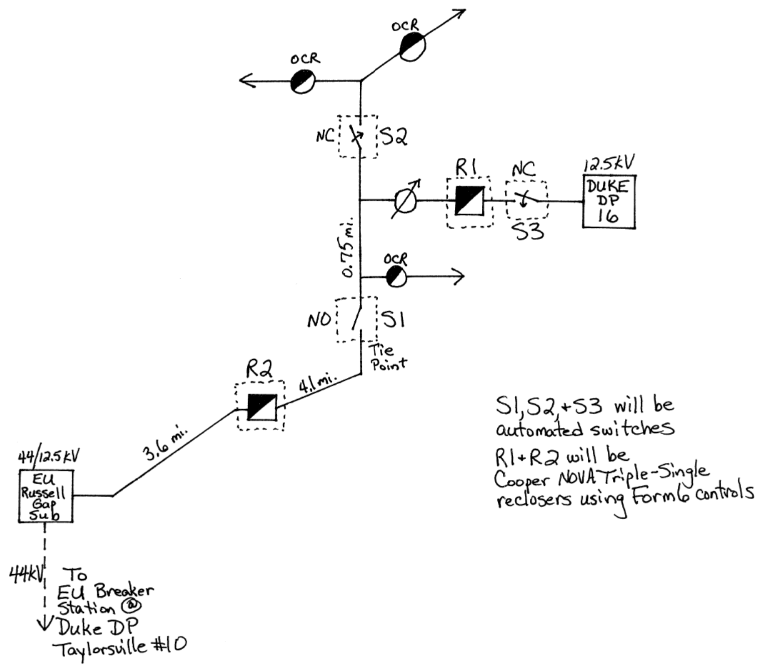


Figure 10.3: EU Project One-Line Diagram

Planning Experience

EU requires a business case for all projects outside the scope of routine business operations and with costs greater than $1,000.

There were two key drivers for the project in the business plan. One was the recognition that distribution automation systems are increasingly commonplace and that there is a need to test and build expertise in operating these systems. The second driver was the frequent source outages on the remote Boomer feeder:

> …automated switching system would eliminate the need for crews to travel to Boomer and would reduce the outage time to almost nothing. In the last 5 years, this delivery point has been out a total of almost 45 hours. Through the existing back-feed process, EU crews have been able to cut that to less than half. The proposed distribution automation system would have reduced that to a little over 3 hours. CMI (Customer Minutes Interrupted) would be reduced by 90%... Based on an outage history over the last 5 years, we estimate that this project will save approximately 0.75 CAIDI minutes per year. At a total project cost of $250,000, this equates to a cost per CAIDI minute of $333,000. [9]

Communications were seen as a particular challenge: hills and rugged terrain make line-of-sight communications difficult and existing communications infrastructure is sparse.

Deployment Status

EU is finishing the installation, with an expected completion date in mid-November 2013. All hardware has been delivered, and EU is in the process of changing some poles out and installing switches and other equipment. Once that is complete, Siemens will complete installation of the controllers and commission the system.

Deployment Lessons Learned

“Communications paths are the most critical element. The switching schemes and logic is actually a fairly simple thing. The real key is making sure all the devices can communicate well.” [10]

Kotzebue Electric Association

Motivation

Kotzebue Electric Association (KEA) is a cooperatively owned utility serving 1,264 customers around Kotzebue, Alaska. Its distribution system is not connected to the North American grid, and it operates all of its own generation assets. Because of this, it faces black-start situations atypical of those found at most distribution cooperatives.

Kotzebue frequently experiences temperatures below 40 degrees Fahrenheit and winds in excess of 50 MPH. Due to these conditions, even routine distribution system maintenance is difficult and places linemen at risk.

As rural residents in northwestern Alaska, KEA consumer-members face some of the highest costs anywhere in the nation. In 2008, residential power rates in the region were $.48/kWh in Kotzebue (up from $.39/kWh in 2007). KEA is working to implement long-term energy options, which currently include battery storage and 3 MW of wind generation, to assist its members in reducing their energy requirements.

Installation Description

KEA extended its use of automatic feeder switching capabilities with two pad mount, SCADA-controlled switches. This project doubled the number of automated switches at the utility, bringing all four feeders in the system under remote control.

The additional switches allow for sectionalizing in response to construction and maintenance needs. They also provide load shedding capabilities that do not require manual intervention by work crews. In the case of a black-start of the system, remote control of all four feeders allows easier service restoration and better power quality for consumers (due to reduced inrush currents), as each half of the load in the system can now be brought up individually.

Total smart feeder switching project cost was $333,000, of which $308,000 was hardware and software purchased for the activity.

The additional switches (numbers 3 and 4) are indicated in **Figures 10.4** and **10.5**, the system’s one-line diagrams.

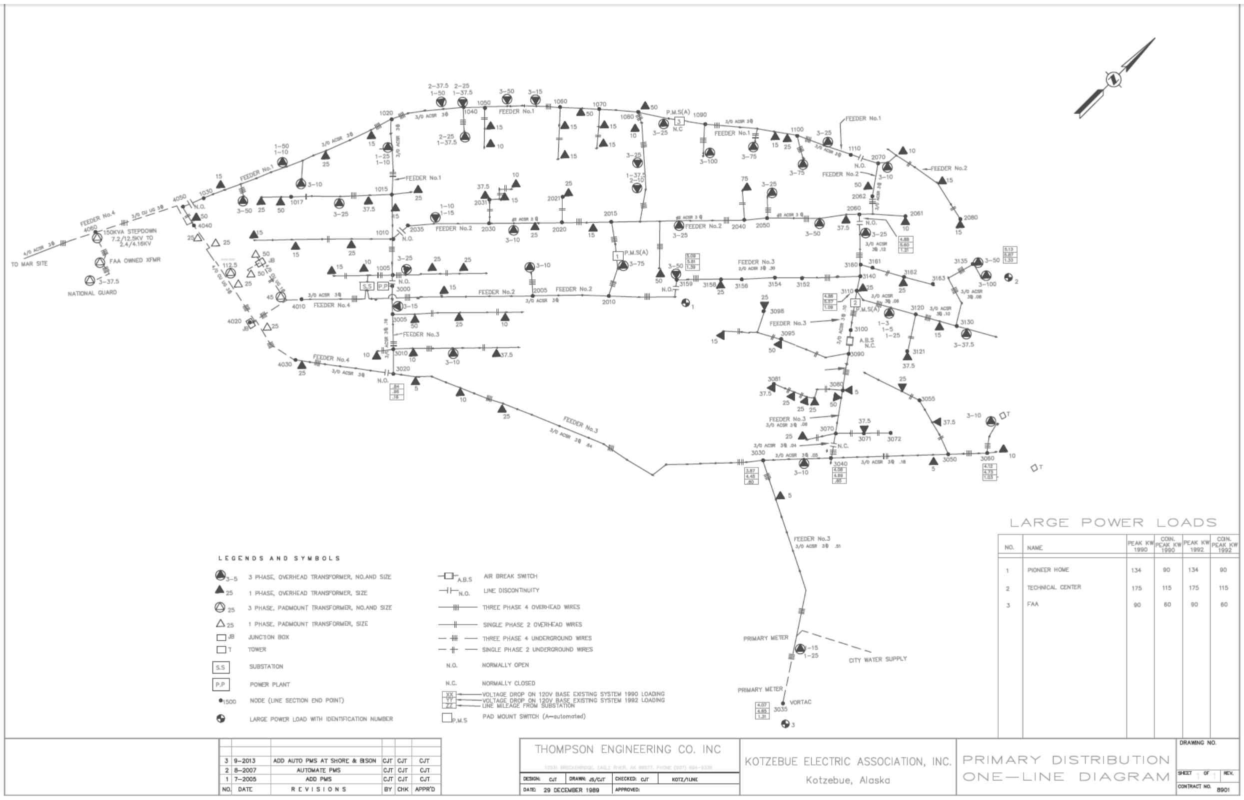


Figure 10.4: KEA Primary Distribution One-Line Diagram

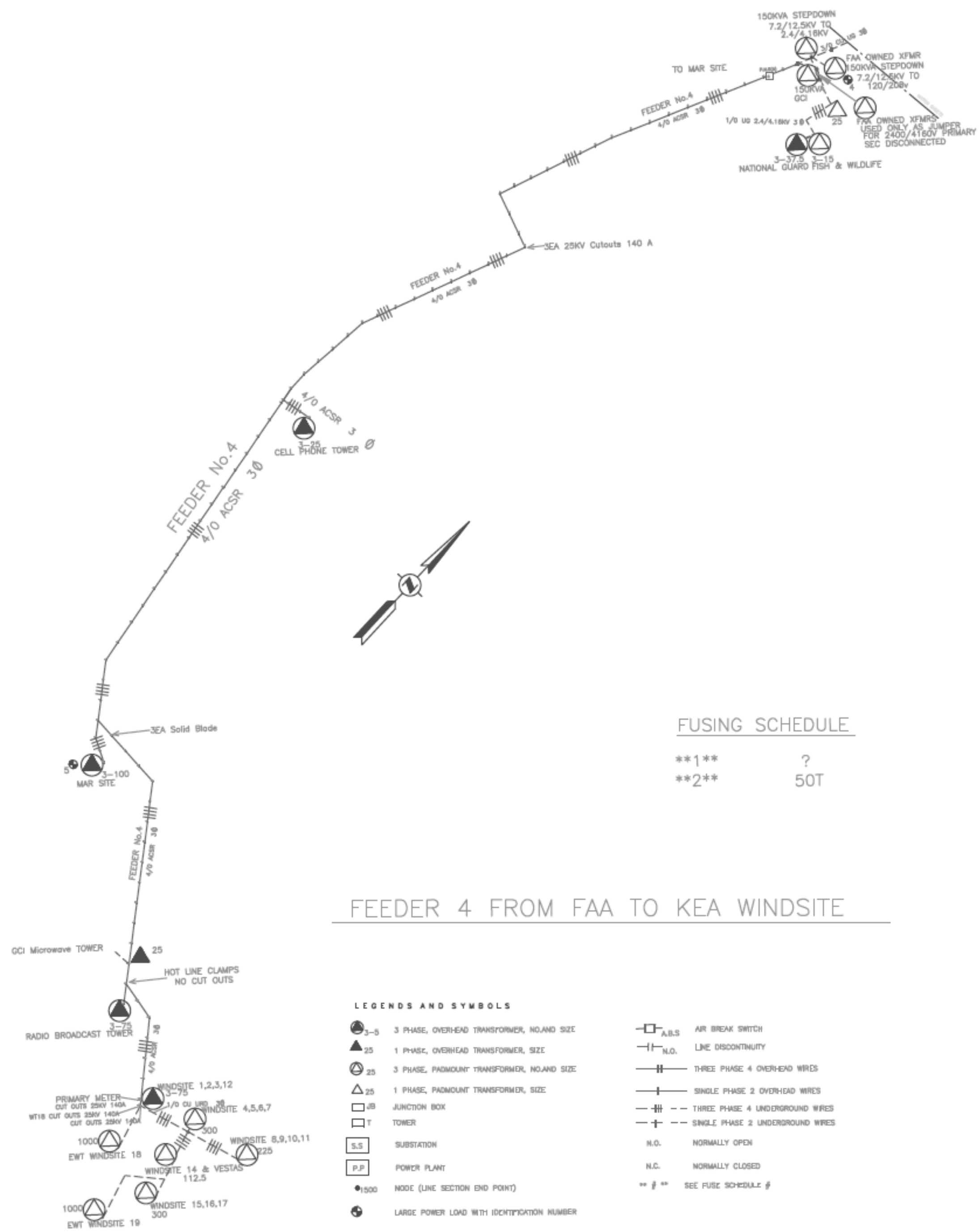


Figure 10.5: KEA Feeder 4 One-Line Diagram

Planning Experience

The original engineering design for this project was done in 2003 for a Rural Utilities Service (RUS)-funded installation of the original two pad mount switches.

Deployment Status

All hardware is deployed, tested, and operating correctly.

Owen Electric Cooperative

Owen Electric Cooperative is a utility serving 57,462 consumer-members around Owenton, Kentucky.

This smart feeder switching project aimed to provide redundant power to a municipal sewage treatment plan. Due to EPA regulations, the plant requires a highly reliable power supply to avoid negative environmental impacts that could result from plant shutdown. Owen could offer this capability more cheaply than backup generation by providing access to a second feeder source activated instantly via smart feeder switching.

Installation Description

Owen's SFS activity was targeted at two sites that will be able to automatically switch load using communication, switches, fault indicators and controls. In support, communications infrastructure was upgraded, including licensed fiber/microwave communications links between the Fulsom and Walton substations, and radio equipment was installed at 42 sites as support for this and other activities.

Total project costs for hardware and software were $107,000.

Planning Experience

Previous experience with automatic source transfer on a remote feeder serving a large residential subdivision provided the inspiration for this project. Multiple automatic service restoration events were achieved on this previous project, and telemetry capabilities have also been used to assist in other restoration events.

Deployment Status

The project hardware has been installed and in operation for over one year.

One source loss occurred during a period of high load. The switching system was not able to automatically restore service. When hardware was returned to the manufacturer for service, mechanical switch problems and a damaged control circuit board were discovered. The sewage treatment plant did lose power, but the outage was such that no regulatory fines were incurred.

Salt River Electric

Motivation

Salt River Electric is a utility serving 47,411 consumer-members around Bardstown, Kentucky. Salt River found that a majority of its outages in 2009 and 2010 were due to source losses at substations, due to transmission problems. Lacking direct control at the transmission level, the cooperative sought a method to improve reliability for its customers through smart feeder switching and redundant transmission sources.

Installation Description

The Smart Feeder activity includes the installation of 29 S&C IntelliRupter distribution switches with controllers. Also included in this activity is communications equipment required to make this equipment work.

A total of 25 switches were installed at normal opens between pairs of feeders in Salt River's system. Out of 100 circuits, 50 are now connected via this project hardware. In these 50 linked circuits, should an outage occur on either feeder or substation, the switches are configured to automatically back-feed from unaffected circuits, if feasible. This involves an automatic testing protocol, including voltage-based load testing and test reclosing operations. Delays of 2.5 minutes have been added to these automated switching operations to keep the switches from fighting other equipment, notably control systems at the transmission level. Switches also are able to be operator controlled remotely via SCADA.

Four additional switches were installed to create a looped circuit. These switches are intended for fault isolation.

Circuits for this project were selected based on historical load from all seasons. Pairs were selected for smart feeder switching in cases where the engineers were confident that each circuit could back-feed the other regardless of load level. Additional pairs of circuits could have been joined, but during times of high load, back-feed could not be guaranteed.

The total project cost is $1.32 million, of which $817,000 is hardware and software purchased for the activity.

Deployment Status

The system has been installed and operational since mid-2012.

Lessons Learned

Out of 29 switches installed, four had hardware or software problems that required vendor intervention. It was also found that the automation potential of the switches was excellent, but this also led to a lengthy and complicated configuration process. The software interface for this process is a potential area of improvement.

Realized Benefits

These switches also are useful for maintenance and sectionalizing. Co-op engineers estimated that they are used for these purposes once every 3 days. The co-op staff also appreciates automatic restoration events that occur in the middle of the night, which previously would have required manual intervention.

Typical outage times before the system was active amounted to multiple hours. In instances in which the smart feeder switches operate, this time has been reduced to minutes. The System Average Interruption Duration Index (SAIDI) scores have been trending downward for the past couple of years at Salt River. A survey of recent outages and outage time saved due to the smart feeder switching follows.

Table 10.2: Salt River Post-Project Outages and Customer-Minutes Saved

Outage ID	Customers	Minutes Saved	Customer-Minutes Saved
1	671	33	22,143
2	450	45	20,250
3	800	43	34,400
4	498	60	29,880
5	222	150	33,300
6	18	90	1,620
7	358	180	64,440
8	1795	50	89,750
9	481	21	10,101
10	412	21	8,652
11	344	45	15,480
12	261	124	32,364
13	137	125	17,125

Outage ID	Customers	Minutes Saved	Customer-Minutes Saved
14	300	206	61,800
15	450	90	40,500
TOTAL			**481,805**

Snapping Shoals Electric Membership Corporation

Motivation

Snapping Shoals Electric Membership Corporation (SSEMC) is a utility serving 91,000 customers around Covington, Georgia. This project was undertaken to improve system reliability, maintenance, and operational capabilities.

Installation Description

SSEMC's SFS activity significantly upgraded feeder switching capabilities. Following the upgrade, which encompasses 100 new SCADA-controlled reclosers, SSEMC has approximately 31% (28,000+ meters) of its customers within a zone capable of automatic restoration, and all but a few substations can be switched out of service remotely. As part of the project, some work was done on upgrading the SCADA system to handle these automation-capable reclosers and adding some fiber optic communications runs and Ethernet radios to the required field reclosers as necessary.

Project hardware comprised 97 Cooper NOVA reclosers and 3 S&C IntelliRupter PulseClosers. A majority of the switches were deployed as pairs, protecting customers in an automatic source transfer (AST) scheme, while the rest are independently deployed at normally open points. The independent devices are not automated but serve two critical roles by (1) facilitating outage restorations for pairs of feeders and (2) potentially being used for preplanned switching. The communications backbone is mostly single-mode fiber. Some of the more remote devices are served with Ethernet radios. (See **Figure 10.6** for a map of SSEMC's AST regions.)

Total project cost is $4.11 million, of which $2.11 million is hardware and software purchased for the activity.

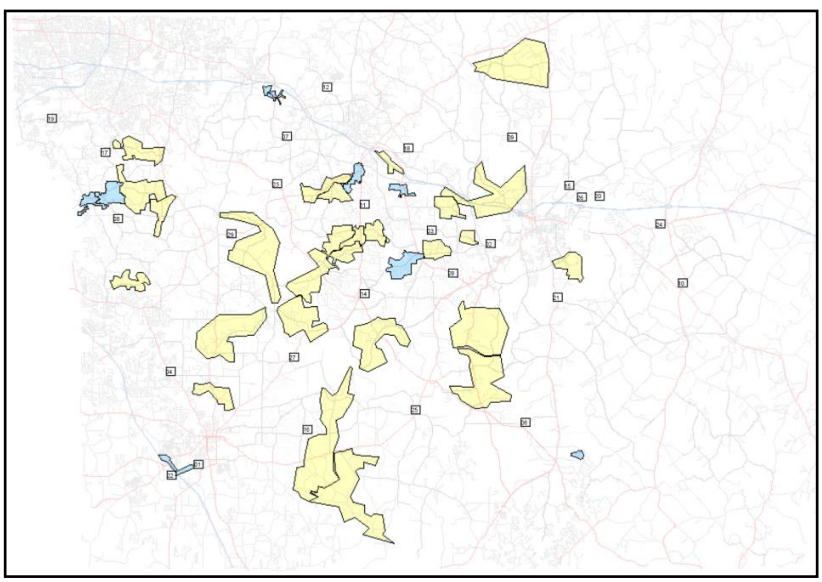


Figure 10.6: SSEMC AST Regions: Existing in Yellow, Project Additions in Blue

Planning Experience

SSEMC's first experience with smart feeder switching came in 2001. Following some outages to a large commercial customer, the cooperative decided to install an S&C Electric IntelliTeam AST system. This system detects outage on a primary feeder, switches load to a back-up feeder with no human intervention, and returns service to the primary feeder after power restoration. This technology has been a success, preventing 10 outages while serving up to 3 MW of load for approximately 60 customers over its past 12 years in service. However, the IntelliTeam system was not able to communicate with the SCADA system, limiting its operational potential.

In the years following this initial AST experience, SSEMC deployed several more schemes serving dense commercial zones, using controls that also were selected for the Smart Grid Demonstration Project. The new schemes were designed using a decentralized approach, with SCADA playing a supervisory role. The switching schemes restored power in much the same way as the original IntelliTeam, but they also updated SCADA after events happened and allowed the SCADA to take manual control when necessary.

Deployment Status

The hardware is deployed and the system was put into operation this year. Outage records and switching operations are being retained to quantify the value of the system.

Deployment Lessons Learned

From a distribution system employee's perspective, SFS can be scary. Most employees are not accustomed to working with technology that can automatically re-route power. Extensive training is required by some departments, but SSEMC encourages employees from all departments to attend. The results from the training have been fascinating, especially regarding employees who attend only because they are curious. Linemen initially had many questions about the safety aspects of automation. After training and experience with the system, they see how quickly narrowing down the scope of an outage reduces the pressure on line crews. The temptation to rush is reduced once most of the lights are on, thus enhancing safety. With participation comes better understanding, new ideas, acceptance, and results. What SSEMC has learned is that SFS is much more than technology. There is much more to learn, and the cooperative appreciates the opportunity that this grant has afforded.

SSEMC's system also is creating a great deal of outside interest, including an article in a recent issue of the trade journal Transmission and Distribution World [8]. Outside parties are most interested in how the cooperative has created a solution that goes beyond the individual components and demonstrates a comprehensive technology plan.

Realized Benefits

SCADA and switch automation used to assist with outage restorations has worked very well. Power can be restored safely, faster, and with fewer employees than before. In 2012, SSEMC experienced 16 events for which AST was used to address outages, thus preventing more than 11,000 consumer-hours of outage time. In five of those events, AST schemes automatically switched, preventing some customers from experiencing any service interruption. In that same year, more than 200 faults were automatically located. Most of those faults did not result in an outage, but the root cause was found about 75% of the time.

System maintenance also was improved, with savings realized through SFS. In spring 2013, several substations underwent routine testing, during which station unloading was accomplished quickly via remote switching. Normally, if everything goes as planned, testing is done during normal business hours with time to spare but, if there is a problem, restoring load can be delayed until after hours or even into the following day. In separate incidents, problems were discovered at two substations; it was after 10 p.m. before repairs were done on one of the stations, but dispatch was able to switch all 6 feeders back to normal from the office. Traditionally, this would have tied up a truck and one or two people at each open point on overtime, or the system would have been left as abnormal until the following day.

When problems were found on substations and the repairs pushed return switching past normal working hours, the new equipment saved man hours in switching the substation out of service via SCADA. However, the bulk of the benefit is the savings in crews and equipment on overtime, not just actively working, but also waiting on the repairs to be done for follow-up work.

The new equipment also has improved preplanned substation switching. Before the new equipment was installed, dispatch had to come to work at 6 a.m. to have a substation manually switched out of service by 8 a.m. for testing. With SCADA-enabled devices in place, the same switching can be done in about 30 minutes from the office.

Washington-St. Tammany Electric Cooperative

Motivation

Washington-St. Tammany Electric Cooperative (WSTE) is a utility serving 51,000 members north of New Orleans, Louisiana. The objective of this project was to improve the reliability of the system's transmission component, moving toward a self-healing capability. Hurricanes are a frequent hazard in the utility's service area, thus increasing the risk of large outages.

Installation Description

WSTE owns and operates 30 distribution substations served by 69 kV transmission lines. Unlike most cooperatives, WSTE owns transmission assets, including 180 miles of transmission lines. These, in turn, serve more than 5,000 miles of distribution line.

There are three components to the project—the SFS components, the SCADA system for control, and the supporting communications infrastructure. The communications infrastructure project includes fiber optic equipment at 14 substations. The SCADA system includes software and hardware requirements to implement advanced transmission and distribution automation projects. The SFS component involves installation of 24 transmission breaker relays and 27 transmission voltage monitoring systems in distribution substations.

Breaker relays are designed to operate in pairs to isolate faults, reclose in cases of momentary faults, and operate under SCADA control remotely. In concert with these capabilities, WSTE is closing the normal opens in its transmission network (see **Figure 10.7**). As a result, all substations will be served by 2 to 4 sources, and the long-term plan is to connect all substations in a heavily meshed network.

The total project cost is $6.36 million, of which $3.31 million comprises hardware and software purchased for the activity.

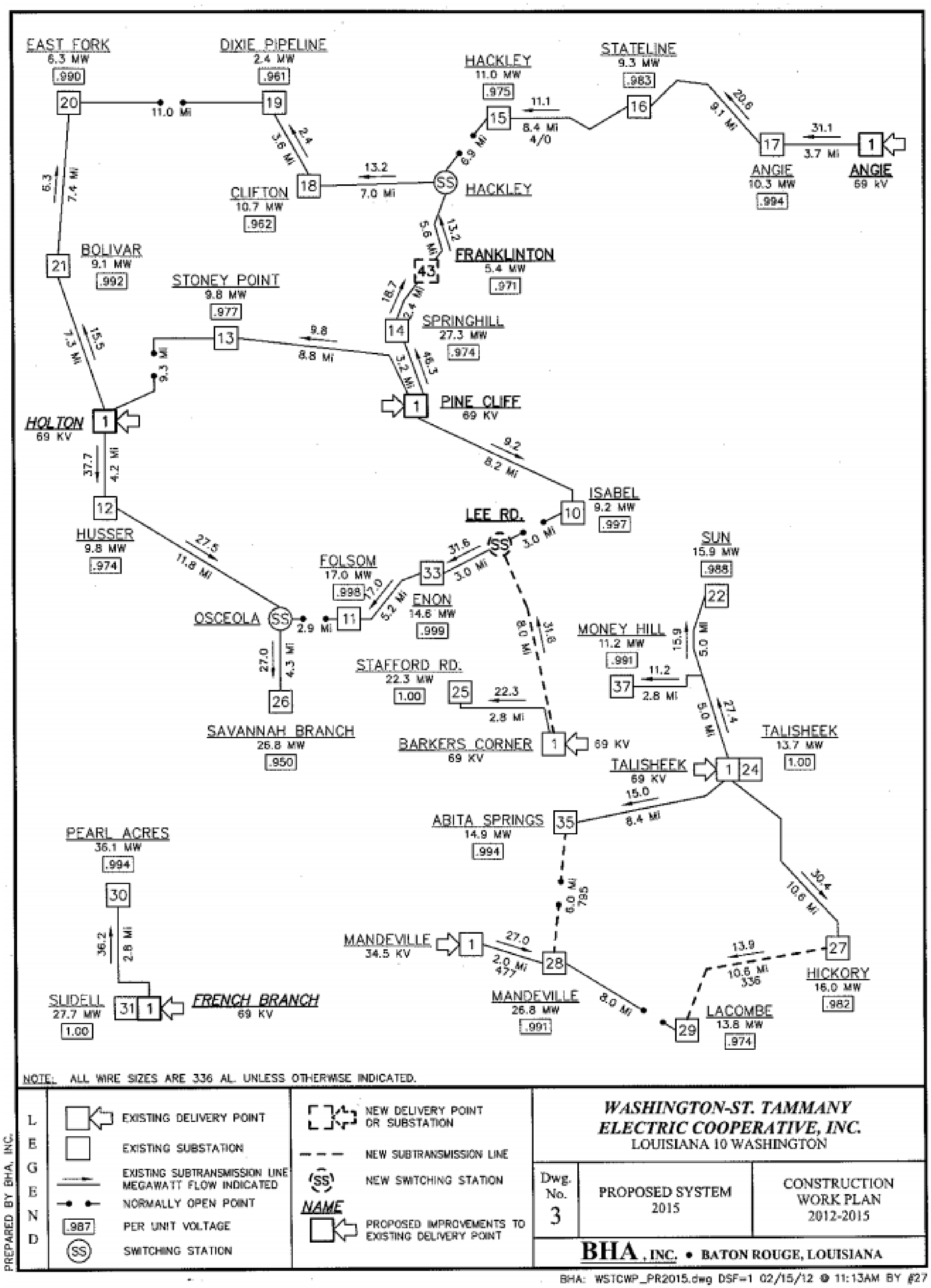


Figure 10.7: Washington-St. Tammany Transmission Network

Planning Experience

WSTE's transmission reliability strategy has been part of its engineering work plans for many years. In choosing to pursue upgrades of the transmission system instead of the distribution system, WSTE emphasized cutting down on transmission outages which, while rarer than distribution outages, affected more customers, since they cut off power to multiple substations. Furthermore, transmission faults on this rural system typically take line crews multiple hours to isolate and clear. When fully operational, the new automated switching scheme and multi-source transmission network will take the length of these outages from hours to less than a minute. SCADA and communications assets installed as part of this project will serve as a template for extending similar SFS capabilities to the distribution system.

Deployment Status

Deployment of the communications components of this project is ongoing and is expected to be completed by the end of 2013. During communications planning, a fiber optic option was found to be more economical than the original microwave/radio system, requiring schedule changes.

COST-BENEFIT METHODOLOGY

The following sections provide details about the SFS benefits and the cost methodology developed as part of this study.

SFS Benefits

SFS benefits were defined within three different domains. First, they were identified as deriving from either (1) Fault Location, Isolation, and Restoration; or (2) Feeder Switching for Load Balancing. Although these two functional areas both utilize switching, their control algorithms and grid impacts are quite different. Thus, this breakdown helped to determine the costs and benefits of each area.

Second, they were assigned to either a stakeholder category or, for benefits independent of a particular stakeholder group, to the "operational benefit" category. Each of these operational benefits can be baselined and measured easily. The first two domains are depicted in **Figure 10.8**.

Finally, benefits were categorized as having either first or second order impacts. First order impacts are considered to be the main drivers of SFS systems. **Tables 10.3** and **10.4** depict first and second order benefits, respectively, and also include parameters needed to calculate the benefit. Some benefit areas, such as reduced O&M costs, represent more than one sub-benefit group and need to be calculated separately and summed up at the end. Therefore, parameters needed to calculate each sub-benefit area also are listed in these tables.

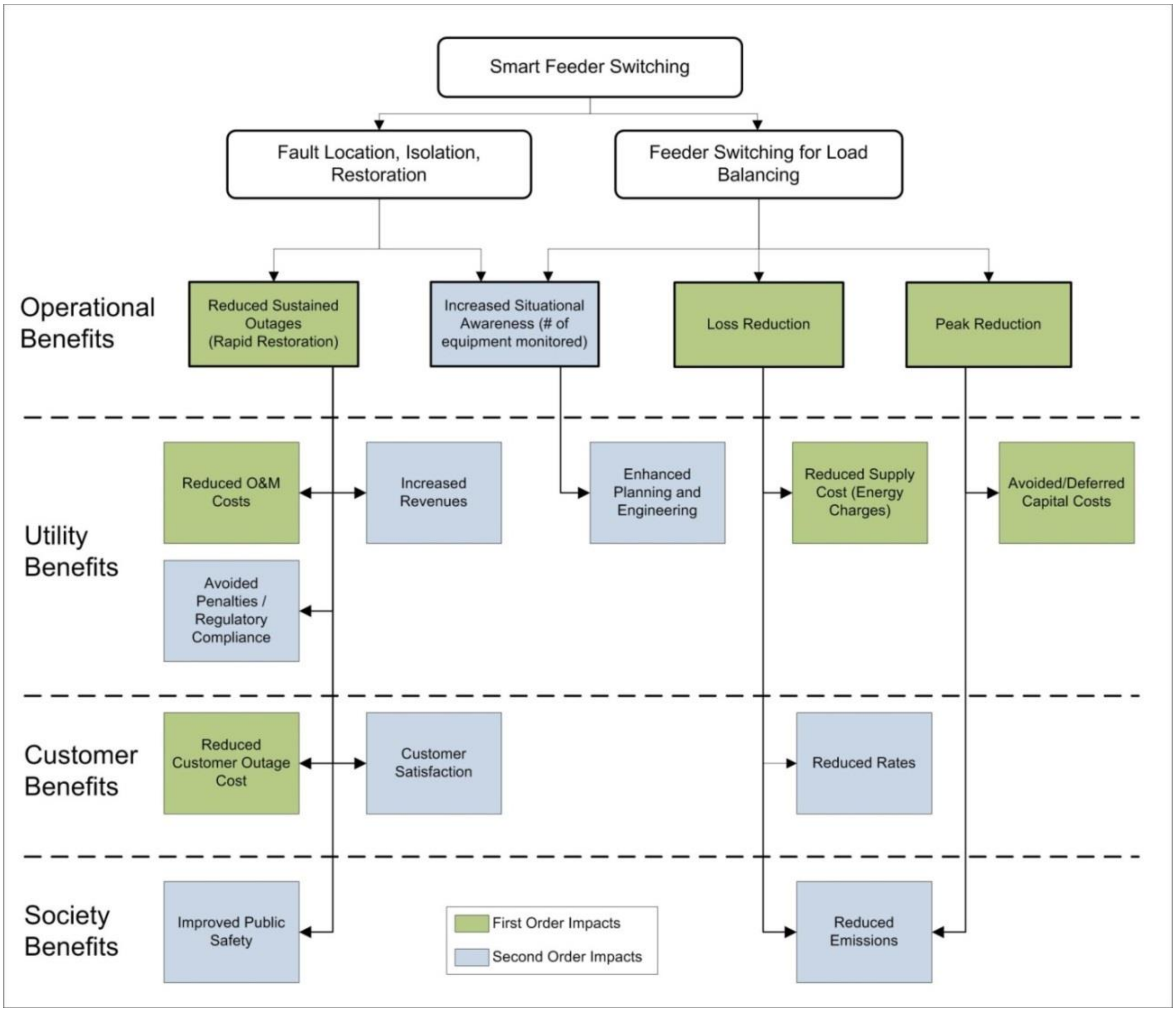


Figure 10.8: Smart Feeder Switching Benefits

Table 10.3: First Order Benefits

First Order Benefits	
Benefits	**Parameters**
Reduced O&M Costs	Annual FTE-hours avoided – Field Operations
	Annual FTE-hours avoided – Dispatch Center & Call Center
	Avoided vehicle costs
Reduced Customer Outage Cost	Avoided residential customer outage cost
	Avoided commercial customer outage cost
	Avoided industrial customer outage cost
Reduced Supply Cost (Energy Charges)	Avoided power supply cost
Deferred Capital Costs	Distribution capital investments deferred due to peak reduction

Table 10.4: Second Order Benefits

Second Order Benefits	
Benefits	**Parameters**
Increased Revenues	Utility additional energy sales as a result of reliability improvements
Avoided Penalties/Regulatory Compliance	Avoided penalties imposed by regulatory authorities due to SAIDI/CAIDI/SAIFI improvements
Customer Satisfaction	Improved customer satisfaction
Improved Public Safety	Improved public safety
Enhanced Planning and Engineering	Enhanced planning and engineering due to increased access to the field data
Reduced Rates	Reduced rates as a result of increased utility revenues
Reduced Emissions	Cap & trade cost
	Emissions reduced due to loss reduction
	Emissions reduced due to peak reduction

SFS Costs

Table 10.5 presents the capital and O&M costs typically incurred when implementing smart feeder switching. Exact costs depend on the size of the service territory or distribution infrastructure, level of existing automation, and state of existing IT and control systems.

Table 10.5: SFS Cost Categories

Cost Item	Cost Description
Distribution Infrastructure	Switchgear: reclosers, circuit breakers, load break switches, disconnect switches
	Sensors, current/potential transformers
IT and Control Systems	Supervisory control software
	IT infrastructure
	Automation hardware (IEDs, RTUs, PLCs)
Communications Equipment	Communications equipment
Engineering, Integration, and Testing	Engineering, integration, and testing
Annual Operations and Maintenance	Annual software maintenance cost
	Annual IT maintenance cost
	Annual automation maintenance cost

MODELING EXTENSION

The modeling framework to evaluate SFS systems is illustrated in **Figure 10.9** and includes four main functional components: (1) User Input/Feeder Import, (2) SFS Model, (3) Solvers, and (4) Output Module. The proposed functionality of each block is described below.

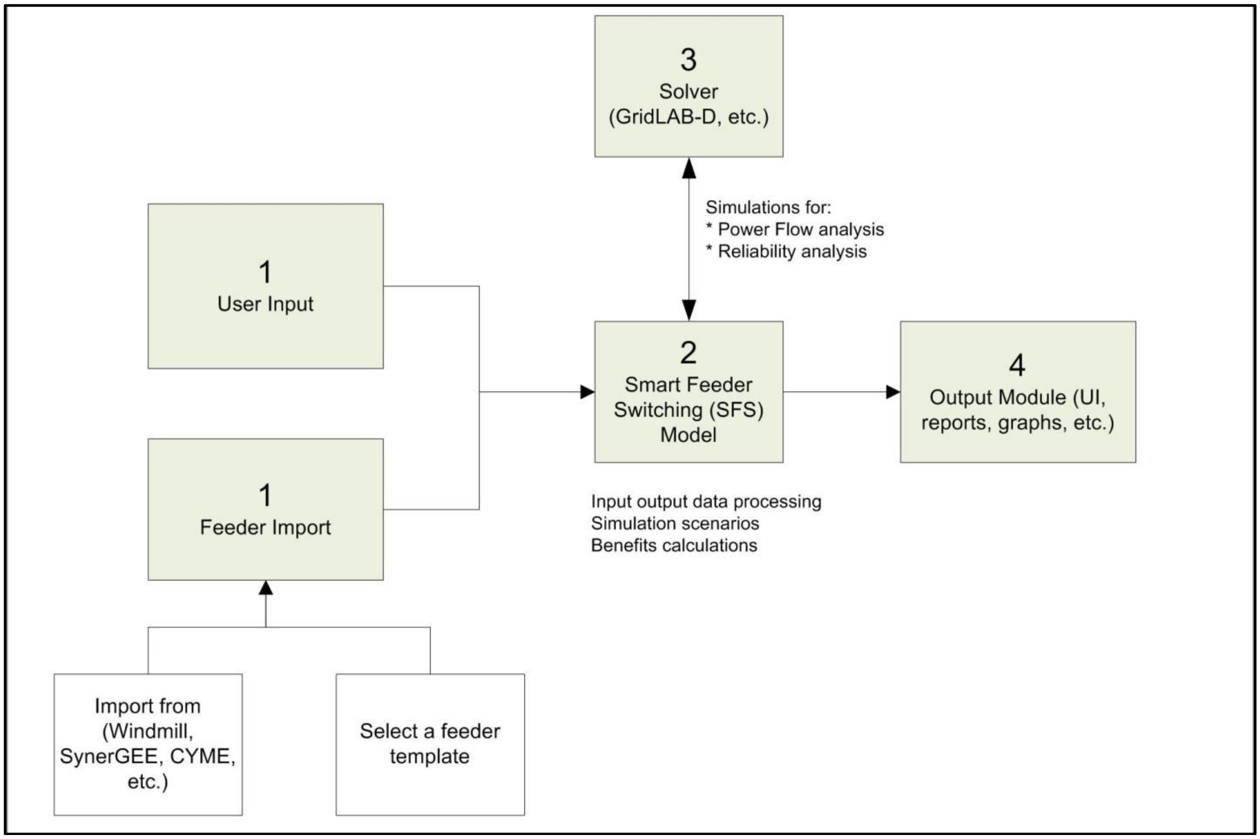


Figure 10.9: SFS Analysis Modeling Framework

User Input/Feeder Import: There are two types of inputs in this framework: user inputs and model import. User inputs include unit cost data, design parameters or preferences, financial parameters, feeder load data, and model configuration parameters, which are needed to perform cost and benefit calculations.

Feeder import is a specific feature that can be used to import distribution system models from commercially available software, such as Windmill, CYME, or SynerGEE. Utilizing these models will improve the accuracy of benefit estimations. It is also recommended to keep a library of typical distribution feeders in this model so that users may select a feeder that represents their system in case the distribution model is not available. Pacific Northwest National Laboratory (PNNL) has completed a Feeder Taxonomy project and has identified typical distribution feeders in the U.S. that can be leveraged in this effort.

- **SFS Model:** SFS Model is located at the core of this framework, where three main functions will be accomplished:
  - *Input/Output Data Processing:* Input data are converted to a format that solvers such as GridLAB-D can utilize. Output data are formatted for analysis reporting.
  - *Simulation scenarios:* User-defined scenarios will be simulated.
  - *Costs Calculations:* SFS Model will calculate costs based on user-provided data and default data available in its library. Cost calculation methodology is described in detail in the following sections.
  - **Benefits calculations:** Simulation results processed to calculate the monetary benefits listed in **Tables 10.2** and **10.3**.

- **Solvers:** Solvers include power system analysis software such as GridLAB-D, optimization engines such as CPLEX, and market simulation software such as PROMOD. It is expected that the majority of analysis can be done using GridLAB-D.
  - GridLAB-D is a power analysis software application with capabilities for modeling and simulating new smart grid technologies. The software has diverse functionality for running analyses on transmission, distribution, and market systems. We propose use of the Distribution Analysis module to perform time-series distribution load flow analysis and estimate the power loss and peak reduction, and the Reliability module to determine the improvements in reliability indices.
- **Output Module:** This module would generate tabular and graphical results, including inputs (design, financial, simulation parameters, etc.); derived inputs (customer outage costs, reduced losses, reliability indices, annual capital and O&M costs, etc.); annual costs/benefits in dollar amounts ($) and cost/benefit ratios (%); annual trend lines of reliability improvements/loss reductions/peak reductions; pie chart of cost/benefits; and bar chart of annual cost/benefits.

Cost Calculation Approach

The SFS analysis process will leverage the SFS deployment cost data that will be obtained from cooperatives, as they tend to be more accurate than generic integration and O&M cost estimates.

A proposed methodology for a cooperative to calculate SFS cost items is illustrated in **Figure 10.10**.

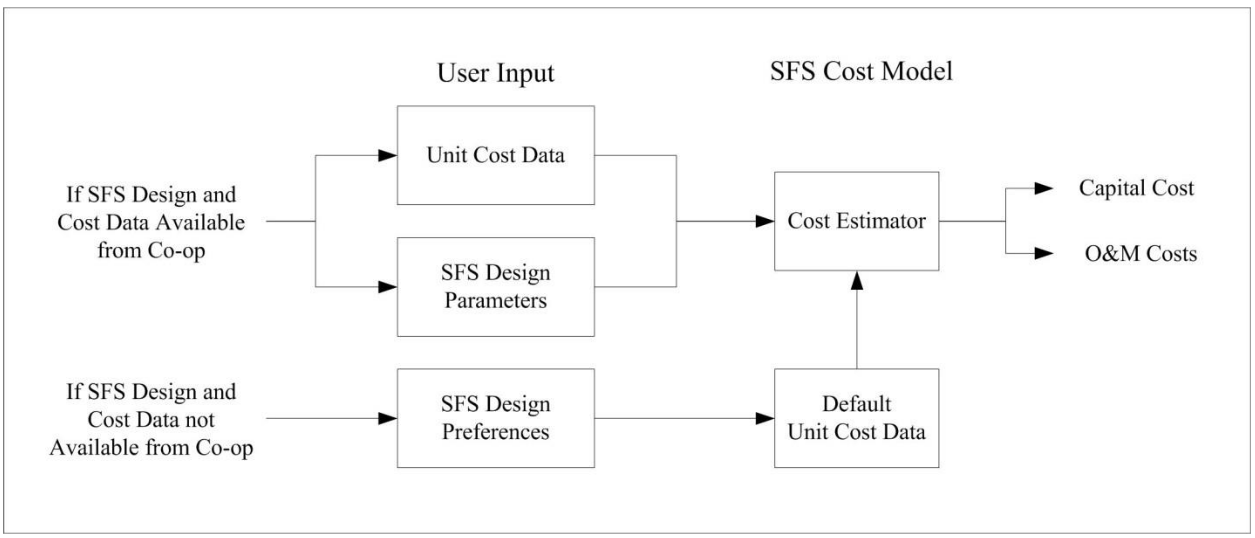


Figure 10.10: SFS Cost Calculation Methodology

In the case that unit cost data and proposed SFS design parameters are available, the user will be prompted to enter unit cost data, such as installed cost of reclosers, load break switch, etc. Necessary SFS system cost line items will be defined in the cost calculation tool. If a preliminary design already has been completed, the user will be able to enter design parameters, such as number of switches, type of switches, and type of communication system.

If the user does not have the unit cost data or preliminary design available, then a high-level cost estimate will be provided by the tool. To achieve this, the user will be asked to provide high-level design preferences. The cost model would include default unit cost data derived from cooperative-supplied cost data. The user will be able to select from this cost library to define the cost of specific devices.

User input cost and design data and default cost items will be used by the cost estimator to determine SFS solution capital and O&M costs.

Benefits Calculation Approach

The benefit analysis will entail both data calculations based on acquired performance data (in the case of peak load reduction) and more complex model simulation (as needed for loss reduction). The SFS analysis process will allow users to import industry-standard distribution system models from vendor products such as Windmill, CYME, and SynerGEE. This will enable the user to establish custom-tailored models that will closely resemble their distribution system parameters and obtain results relevant to their desired scenarios.

DATA REQUIREMENTS AND SOURCES

SFS Model Library

As described in previous sections, the SFS analysis process requires models that can be used to evaluate various deployment scenarios. **Table 10.6** outlines various data sets in the model library with the sources identified.

Table 10.6: Data Sets in the Model Library

Data Set	Source	Data Elements	Methodology
Distribution system feeder models	Co-ops	◆ Feeder models	Co-ops can upload their feeder models with feeder-type information (geographic, climatic, and feeder characteristics (length and capacity).
	PNNL	◆ Taxonomy feeder models	PNNL has developed 24 different sets of taxonomy feeders to represent a diversity of distribution feeder models comprising the U.S. distribution system.
Reliability improvements as a function of SFS design	Co-ops	◆ Co-op SFS design data for number, type, and location of SFS hardware components	Based on the co-op’s prior SFS deployment design and performance/reliability data, reliability improvements can be estimated as a function of SFS design.
	Co-op’s ARRA reporting	◆ Baseline and post-deployment reliability indices (SAIDI, SAIFI, CAIDI, and MAIFI) ◆ Baseline and post-deployment outage data	
	External surveys/ literature	◆ Similar to above	External surveys and literature may be used.

Data Set	Source	Data Elements	Methodology
Loss and peak reduction as a function of amount of transferred load	Co-op's ARRA reporting	◆ SFS event information (such as amount of load transfer, duration, etc.) ◆ Baseline and post-deployment 8760 feeder- loading data (kW, kVAR, kVA) ◆ Baseline and post-deployment equipment overload data ◆ Baseline and post-deployment distribution losses and power factor	Based on the co-op's prior SFS deployment design and operational data, loss reduction/peak reduction can be estimated as a function of amount of transferred loads for various feeder types.
	External surveys/literature	◆ Similar to above	External surveys and literature will be used.
Customer outage costs as a function of reliability indices	Co-ops	◆ Residential customer outage cost ◆ Commercial customer outage cost ◆ Industrial customer outage cost	Calculate customer outage costs for various customer classifications.
	External surveys/literature	◆ Similar to above	External surveys and literature will be used.
	ICE Calculator	◆ Outage cost	DOE's Interruption Cost Estimate (ICE) calculator is an extensive tool for estimating the customer outage costs of various customer classifications. Estimation is based on several realistic assumptions and can be customizable for various geographic areas and different customer characteristics.
O&M cost reduction as a function of reliability indices	Co-op's ARRA reporting	◆ Baseline and post-deployment O&M costs	Calculate the reduction in O&M costs due to the SFS deployments.
	External surveys/literature	◆ Baseline and post-deployment O&M costs	External surveys and literatures will be used.
Financial Data	Co-ops	◆ Average annual retail energy rate ($/kWh); average annual purchase power rate ($/kWh); inflation rate; tax rate; GDP; average field, dispatch center, and call center operations labor rate ($/hour); and expected life time of SFS project (years)	Calculate various financial factors listed.
	External surveys/literature	◆ Similar to above	External surveys and literature will be used.
Cost Data	Co-op's ARRA reporting	◆ T&D infrastructure costs, IT and control systems, communication hardware costs, and annual O&M costs	Calculate financial factors.
	External surveys/literature	◆ Similar to above	External surveys and literature will be used.

SFS Cost/Benefit Calculations

Once SFS models are built, users will need to provide certain input data to evaluate a given scenario. The users may also use the default data available in the model library. The complete set of data required to run the model is listed in **Table 10.7**.

Data Set Classifications:

- **Distribution System Characteristics:** This data set describes the state of a co-op's existing distribution system prior to SFS system deployment. If unknown, or if desired by the user, an appropriate predefined taxonomy feeder model from the model library can be used for analysis.
- **SFS Design Data:** Data related to the SFS project design, such as number, type, and physical location of SFS hardware components.
- **Financial Data:** Data describing co-op tariff and other financial information, such as wholesale/retail energy prices, average labor rates for various O&M activities, and average vehicle costs. The data set also includes other economic factors needed for net present value (NPV) of benefit calculations, such as inflation rate, tax rate, gross domestic product (GDP), and useful project life. If unknown, default values will be supplied by the model library.
- **Cost Data:** This data set consists of cost data for the elements specified in the above SFS costs section. If the cost details are unknown, the user can use the cost details available in the model library.
- **Future Capital Investments:** This data set captures future capacity expansion plans, such as substation transformer upgrades, distribution line reconductoring, and switchgear equipment upgrades.
- **GridLAB-D Simulation Scenario Inputs:** This data set consists of data required to run GridLAB-D simulations that produce expected SFS project results, including improvements in reliability indices, loss reduction, and peak reduction.
- **SFS project outcomes:** This data set is produced from GridLAB-D simulations and will be used in the cost-benefit model for monetizing benefits.

Table 10.7: Data Requirements of SFS Cost-Benefit Model

Data Classification	Data	Source	Usage
Distribution System Characteristics	◆ Study feeder models ◆ Performance and reliability data ◆ Operating and outage data ◆ Study feeders load profiles ◆ Study feeders load growth ◆ Customer classification (residential, commercial, and industrial)	Co-op (or) model library	Benefits monetization
SFS Design Data	◆ Number of project feeders ◆ Number, type, and location of SFS hardware components ◆ Type of communication ◆ Number, type, and location of communications hardware components	Co-op (or) model library	Cost estimation and benefits monetization

Data Classification	Data	Source	Usage
Financial Data	◆ Average annual retail energy rate ($/kWh) ◆ Average annual purchase power rate ($/kWh) ◆ Inflation rate ◆ Tax rate ◆ GDP ◆ Average field operations labor rate ($/hour) ◆ Average dispatch center and call center operations labor rate ($/hour) ◆ Average vehicle costs per fault location, isolation, and restoration event ◆ Expected life time of SFS project (years)	Co-op (or) model library	Cost estimation and benefits monetization
Cost Data	◆ T&D Infrastructure costs ◆ IT and control systems ◆ Communication hardware costs ◆ Annual O&M costs	Co-op (or) model library	Cost estimation
GridLAB-D Simulation Scenarios Inputs	◆ Updated feeder models with SFS design components ◆ Feeder switching sequence for load balancing event (switch positions) ◆ Feeder switching sequence for fault location, isolation, and restoration event (Switch positions) ◆ Event duration ◆ Event frequency (/yr) ◆ Device settings (substation transformer LTC, capacitor bank, etc.)	Co-op	Benefits monetization
SFS project outcomes	◆ Reliability indices improvements (SAIDI, CAIDI, and SAIFI) ◆ Loss reduction (kWh) ◆ Peak reduction (kW)	GridLAB-D simulations	Benefits monetization

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Chapter 11:

Delaware County Electric Cooperative – DR Capability and Predictability

1. INTRODUCTION

Delaware County Electric Cooperative (DCEC) is testing a Demand Response (DR) program designed to be able to shed demand when requested by the New York Independent System Operator (NYISO). This activity has been supported by the NRECA DOE Smart Grid Demonstration Project through the implementation of advanced metering infrastructure (AMI) and load control switches. Demand response programs for bidding into an ISO market typically have relied on larger industrial-scale customers. However, with the advent of widespread AMI adoption and load control switches for residential devices, it may be possible for distributed residential loads to bid into the market as a cohesive system. DCEC selected water heaters as the best option for its DR program because water heaters have several advantages. They draw a significant amount of load, can store energy thermally, and are commonplace in many homes.

2. RESEARCH OBJECTIVES

a. Demonstrate how much load—and how quickly—DCEC can reliably shed through a DR program with water heaters.
b. Determine the best way to apply this technology to decrease costs without compromising member satisfaction.

3. BACKGROUND: THE NRECA/CRN SMART GRID DEMONSTRATION PROJECT

a. *NRECA Overview*
NRECA received a $34 million Smart Grid Demonstration research grant from DOE in 2010. The resultant project, coordinated by NRECA’s Cooperative Research Network (CRN), purchased the necessary equipment on behalf of NRECA’s participating member cooperatives. Ancillary services related to the equipment are contracted directly between the supplier and NRECA’s member cooperatives. Electric distribution cooperatives have been evaluating the potential benefits of new technologies that could help increase operational efficiencies and improve service. Twenty-three of NRECA’s member electric cooperatives have deployed more than 250,000 smart grid components across the country to test the value of the new technologies for cooperative consumer-members.

b. *DCEC Overview*
DCEC of Delhi, New York, is a non-profit rural electric cooperative serving more than 5,300 member locations in 21 towns across four counties—Delaware, Schoharie, Otsego, and Chenango. Formed in 1941 as a corporation and converted in 1942 to a cooperative, DCEC has been a staple of its community for more than 70 years. Its employees now manage more than 800 miles of line, compared to just 8.2 miles in 1944. Its primary mission is to provide a safe, reliable, and cost-effective electric power supply to its members.

4. EXECUTIVE SUMMARY OF RESULTS

a. *Principal Findings*

Two series of tests were performed for this study, one in summer 2013, and one during the following winter. For both tests, control data also were collected during the same time period. During the summer tests, the demand curve for both the control and test data followed a similar trend of a decline followed by a rebound for the period of time sampled. However, during the period that the DR program was active, the demand reduced at 2.5 kW/minute, compared to the 1.2-kW/minute reduction tested in a control group without the DR program. On average, the inflection point of the test data was 55 kW lower and 80 minutes earlier than the control data. However, following the trough, the test loads rebounded faster and at the end of the period measured 112 kW higher than the control loads. Each additional water heater in the study lowered demand by an average of 0.6 kW during the test. This is in line with the findings of other studies of DR programs.

The winter tests were less conclusive—demand dropped 5.5 kW/min in the control studies and 6.3 kW/min during the tests. This is an increase of only 0.8 kW/min in the demand reduction rate. During the time period sampled, demand first increased and then decreased steadily. There was no indication that the DR program had a noticeable impact on when demand began to drop.

b. *Recommendations*

Based on the results of the test and the baseline provided by the control data, this DR program seems best suited for peak-shifting or bidding into the ISO market as a short-term DR program. The rebound effect that follows the DR program makes it unlikely that total load will be reduced.

c. *Further Research*

Further research is needed to test the reliability of this program in different situations. This research should focus on running the program at different times of the day and during different seasons. This is needed for two reasons. First, this program relies on the use of water heaters, which are subject to daily patterns of use; most hot water is used in the evening or mornings. Second, temperature affects hot water use, although this variable will be primarily seasonal.

5. LITERATURE/TECHNOLOGY REVIEW

a. *Previous Approaches to Residential Direct Load Control*

Using water heaters to shed load at a specific time is an example of Demand-Side Management (DSM), which encompasses a host of techniques and technologies to optimize energy use on the consumer side. DSM includes Energy Efficiency (EE) measures, Time-of-Use pricing, Demand Response, and Spinning Reserve.[10] These measures are intended to change the demand curve to benefit the utility by either reducing or shifting load. Energy must be produced in a quantity great enough to satisfy the single highest point of demand safely; in meeting this requirement, significant amounts of energy are wasted, however. By bringing the peak lower and the "troughs" higher, less energy production is needed to meet high peaks.[11] In addition to being more efficient, the ability to reduce load reliably when

[10] (Palensky and Dietrich, 2011, p. 381)
[11] (Saffre and Gedge, 2010, p. 300)

necessary can help lower the incidence of rolling blackouts. In California a rolling blackout occurred in June 2000 because a 50,000-MW system was short 300 MW, an amount that represented 0.006% of the total load.[12] Had an effective DSM program been in place to reduce demand by the necessary amount, the blackout could have been avoided. Events like this cost utilities more than just money—consumer satisfaction and trust also are lost when the grid does not perform reliably.

b. *DLC Approach to DR*

The application of DSM studied in this paper is most accurately classified as a DR program using a Direct Load Control (DLC) approach, in which the utility operator has control over the customers' water heaters and can determine the most optimal time to shed their load. In contrast, other DR programs require direct member participation and often offer incentives to encourage energy-saving behavior at specific times. For example, to get consumers to adjust their thermostats at peak demand times, a utility may offer a rebate on their electricity bills, but the utility cannot mandate conservation or remotely turn off an appliance under these conditions. DSM, whether consumer or utility controlled, is different from energy efficiency measures, which lower demand by a specific amount across the load levels. As opposed to EE measures, DSM (and specifically DLC in this study) does not lower energy consumption, just the demand at a given time. This leads to a rebound, or payback effect, of increased demand following the period of load shed. **Figure 11.1**—inserted only for demonstrative purposes—illustrates this impact on demand over time as well as the difference between DSM and EE measures:

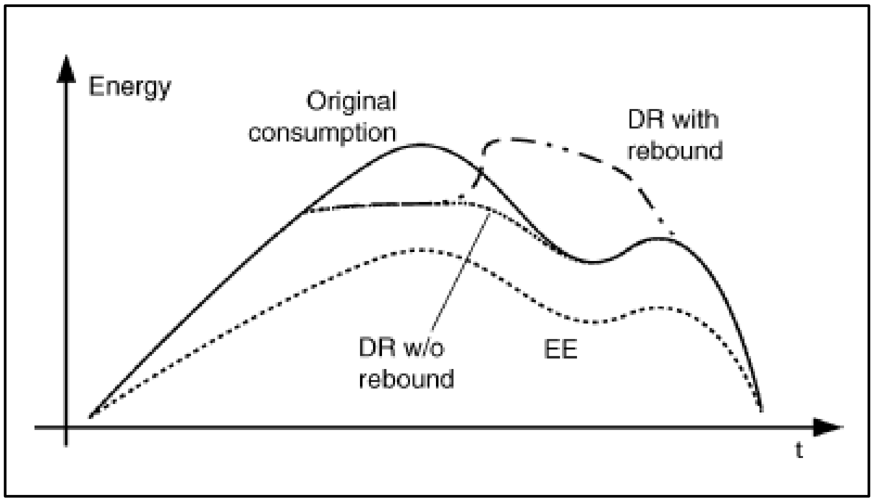

Figure 11.1[13]: Impact on Demand over Time and Difference between DSM and EE Measures

c. *Previous DLC Water Heater Studies*

A study in Norway estimated the payback effect for the hour following the DR program to be 0.2 kW per household or water heater (typically, there is only one water heater per household).[14] This means that utility operators need to be careful when instituting a DR program to avoid creating a new peak in demand as they shift load.

[12] (Saele, 2011 p. 102)
[13] (Palensky and Dietrich, 2011, p. 382)
[14] (Torgeir, 2009, p. 1)

The other primary issue is shedding load for such a period of time that it inconveniences consumers; only certain appliances lend themselves to this task. For example, a refrigerator DR program to directly control the temperature of the appliance might leave consumers' food too warm if the system is left to idle for too long. Many appliances do not make good targets for DLC, despite being used widely and having a substantial power factor, because they have no way to store energy (e.g., TVs) or the consumer is concerned that the program might negatively impact them (e.g., A/C units). However, electric resistance water heaters make a good target for DR programs because they consume a significant amount of energy (up to 30% of household loads in some areas); the heating element of a water heater typically is a resistor, making it simple and flexible to turn on and off; and water's high heat capacity allows it to act as a thermal energy storage device, meaning that it can be turned off for longer periods of time without any consumer dissatisfaction.[15] An ideally operated DR program would average out energy consumption in such a way that consumers' actions would be unaffected but still provide ample peak reduction or shifting for the utility.

Another area of interest for DR is the amount of load that can be shifted. This is essentially a function of how many consumers are participating, the power rating of the water heater, and the load factor of the appliances. Previous testing done in Norway found average demand reductions from 0.5 kW to 1 kW for each standard electrical water heater and 2.5 kW for hot water space heating systems.[16, 17]

American water heaters tend to have a slightly higher power rating than their European counterparts, by about 1 kW, meaning that the per water heater reduction would be even higher. However, efficiency policies often advocated in the U.S., which seek to ban the manufacturing or installation of electric resistance water heaters may, if successful, threaten the viability of using these residential water heaters for DR programs. Another factor is the increasing ubiquity of smart meters and appliances, which will make deploying DR programs easier and more cost-effective.

[15] (Diao, 2012 p. 1)
[16] (Torgeir, 2009, p. 20)
[17] (Saele, 2011, p. 107)

6. METHODOLOGY

Under the Smart Grid Demonstration Project, DCEC performed DR tests using residential water heaters. A total of 20 tests were performed for this study. Ten tests were run throughout summer 2013, starting on June 25 and ending on August 8; another 10 tests were run during the winter of 2013−2014, starting on November 24, 2013 and ending on February 10, 2014. The study group included 573 water heaters of varying sizes (30 gallon, 50 gallon, 80 gallon, and a farm class), but with similar heating element power ratings (3–3.8 kW for the non-farm classes and up to 4.5 kW for the farm classes). Each class of water heaters was divided into seven subgroups (except for the farm class, which is divided into two) for organizational purposes during the DR program. These subgroups then were recombined to form 16 “blocks” of roughly equal size that were used throughout the test to ramp the water heaters on and off the program. During the DR program, commands to shed were sent out to an entire block at one time and then unshed together after a specified amount of time had passed.

System load data were collected every 5 minutes for 6.5 hours during each test day and included the demand of each of the four feeders, the aggregate demand, the percentage of each type of water heater in “shed mode,” and the step of the test (each step corresponded to the number of blocks of water heaters in shed mode according to a defined matrix). The DR program itself functioned by shedding water heaters on and off (shedding a water heater means turning off its load control switch so that it cannot be turned on). However, the data collected do not show whether or not a water heater entering shed mode was off or on, or whether it would have turned on during shed mode or not. This means that shedding a water heater does not guarantee a reduction in demand, but only that it cannot be turned on. The key takeaway here is that areas with a more frequent water heating load will be able to shed more load at any given time.

Data collection began an hour before an initial command was sent out to water heaters to begin entering shed mode. In most tests, data collection began at 11:00, and the initial command was at 12:00 (a few tests started as late as 11:15, pushing all events back by a corresponding amount). The initial command was always to go to step 8 (out of the 16 total steps), which shed eight blocks of water heaters—roughly 50% of the water heaters. After beginning, another block was shed every 5 minutes, as the steps increased, until step 16, when 100% of the water heaters were shed. All water heaters remained in shed mode for 1 hour—marginally longer in some tests. After the full shed, the water heaters gradually were “unshed,” or allowed to turn back on. The return to service of the water heater loads was staggered by using the step matrix and set-time delays in the defined blocks to minimize the establishment of a subsequent peak loading condition. Similar to the stepping up process, the system stepped down once every 5 minutes. The goal was to avoid a condition in which all of the water heating equipment returned to service at the same time, which could have amounted to a coincident loading peak. However, unlike the shedding process, which is determined by signals sent to the different water heater blocks, the unshedding process occurred after a specified time frame. If the utility wanted to keep a water heater block in shed mode, another shed command had to be sent.

The stepping down process took 80 minutes, until there were no water heaters left in shed mode. Data were collected for another 2.5 hours after all of the water heaters were unshed to assess the amount of “load payback” or increase in demand due to the DSM program. Data collection ended for most tests at 17:30, although tests that started later also ran later.

The winter tests were conducted in the same manner, but began collecting data around 17:00 and started the DR program an hour later. Data were collected continuously until midnight. The program used the same stepping up and stepping down system but increased the length of the full shed for some tests.

Along with the test data, 14 days of load-level data without the DR program were provided—seven from the summer and seven from the winter. These data, collected from the same feeders and at the same intervals (every 5 minutes), were the control data for the experiment. This allowed for a baseline comparison of how the demand curve would have looked without the DR program.

In addition to the process outlined above, there are several important points about the study.

First, the blocks used to control which water heaters were shed were created because DCEC uses a Power Line Carrier (PLC) communications system that cannot accommodate requests to all of the blocks if they were to be initiated simultaneously. This limited how quickly demand could be reduced through this program because not all of the water heaters could be shed at once. Second, the shedding schedule operated in a “round robin” mode, also known as “first-in, first-out.” In this system, the first block of water heaters shed at step 1 would be the first block unshed at a later time. For example, at Step 14, the command sequence would shed 86% of the 30/40-gallon units, 86% of the 50-gallon units, 100% of the 80-gallon units, and 100% of the farm units. If the system stayed at step 14, unshed 30-, 40-, and 50-gallon units would be commanded to be shed to maintain the 86% value, whereas those that had been in shed mode the longest would time out and be allowed to return to normal operation. The 80-gallon and farm units would remain in shed mode, as allowed by the set-time delays. The command sequence would have knowledge of the subgroups in shed and would move to the unshed subgroup as needed according to the system strategy matrix, following set time delays. All of this was done to avoid inconveniencing one group of members with longer shed times.

Finally, an error source exists in each of our samples, originating with the sampling process in DCEC’s data acquisition system. DCEC’s feeder measurements do not register changes in demand smaller than 48 kW, 24 kW, 21 kW, or 19.2 kW, depending on which feeder it measures. While this quantization noise is relatively small, it could cause sampling error because the signal from this program also is small; each block should reduce demand by only 20 kW when shed, while the error is 17.5 kW RMSE. The error is largely ignored for this analysis because it is normally distributed around zero and, with a sufficient sample of tests, averages out to a negligible factor.

7. ANALYSIS

The primary goal was to find out how much load could be reduced, and in what time frame. Thus, the first analysis was conducted to show how demand changes as water heaters are shed. **Table 11.1** shows the slope of the relationship between demand and percentage of water heaters in shed mode.

Table 11.1: Slope of Relationship between Demand and Percentage of Water Heaters in Shed Mode

Date	Test No.	Weekday	Total kW Reduction at 100% Shed	Hours to Inflection Point
6/25/2013	1	Tuesday	21.84	1.82
7/5/2013	2	Friday	498.53	41.54416667
7/15/2013	3	Monday	345.45	28.7875
7/16/2013	4	Tuesday	307.96	25.66333333
7/17/2013	5	Wednesday	401.92	33.49333333
7/18/2013	6	Thursday	266.11	22.17583333
7/30/2013	7	Tuesday	324.36	27.03
7/31/2013	8	Wednesday	420.84	35.07
8/2/2013	9	Friday	384.1	32.00833333
8/8/2013	10	Thursday	640.71	53.3925
Test Averages:			**356.814**	**29.7345**

This shows that, for each additional 1% of water heaters shed, demand dropped by 3.56 kW. Given that there were 573 water heaters in the study, this averages out to 0.6 kW per water heater—a number similar to the reduction found in previous studies. This shows that for almost every test, demand drops during the implementation of the DR program, but we need to know the time frame of this effect as well.

Figure 11.2 provides an overview of all of the summer demand curves; the curves showing averages are bold. Time is shown in 5-minute intervals to correspond with the frequency of data collection (labeled "Time Step").

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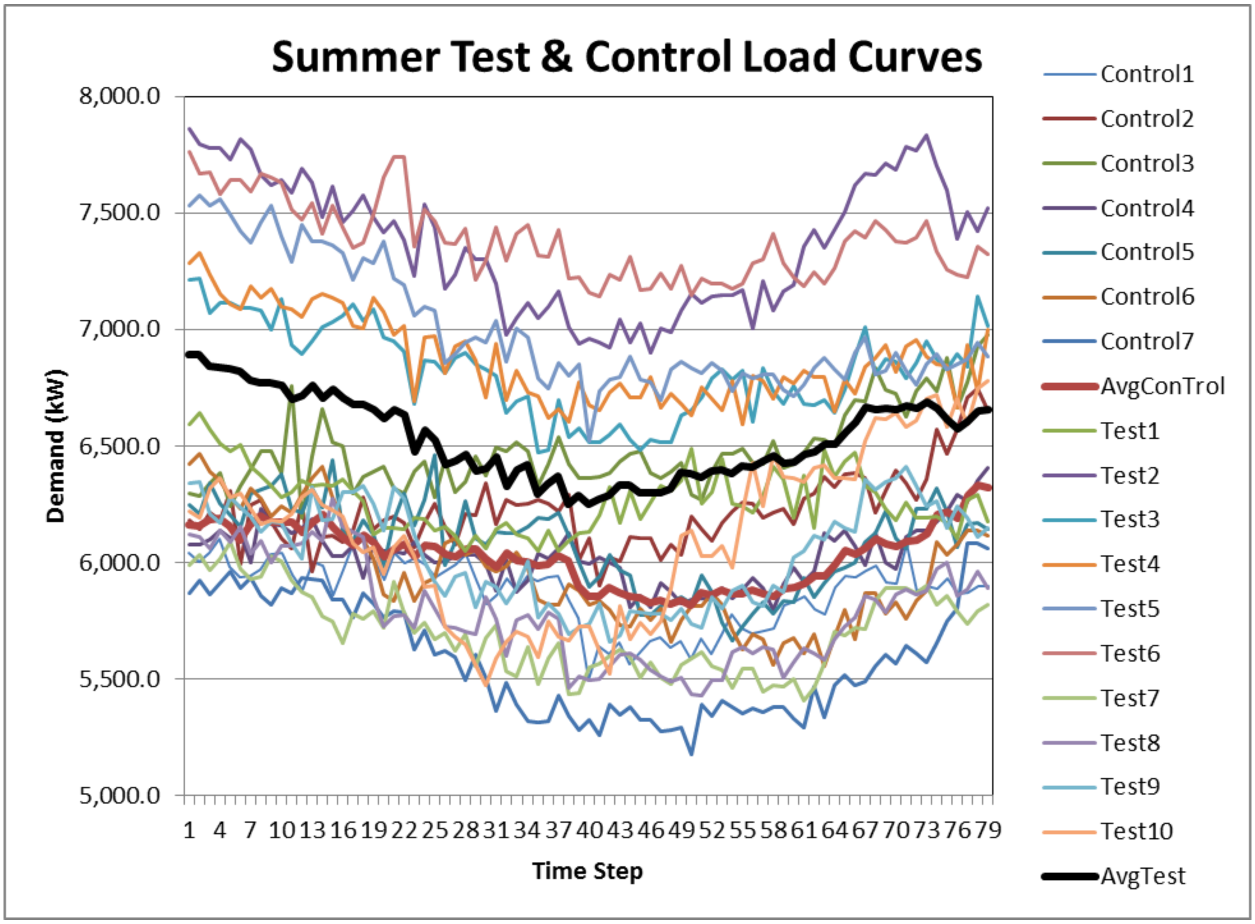

Figure 11.2: Overview of All Demand Curves

From these data, it is difficult to see trends or patterns amidst the noise. However, for both sets of data, the averages of the test and control data over the period the test was conducted and normalized by their starting value (**Figure 11.3**) display a U-shaped pattern. While both lines have a similar trend, the test data drop further and more sharply than the control data.

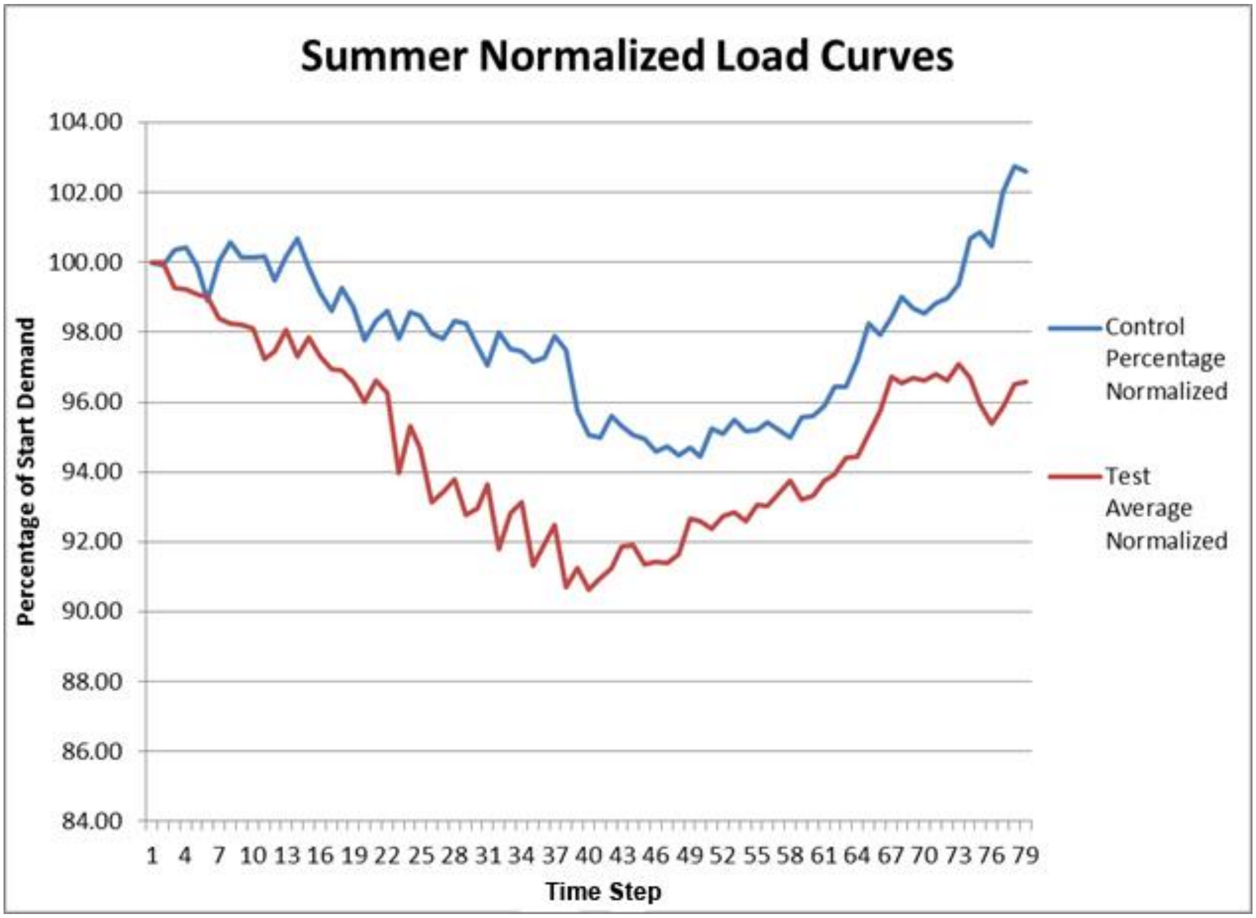

Figure 11.3: Averages of Test and Control Data over Test Period, Summer

In contrast, the winter data shown in **Figure 11.4** have a very different load shape, which starts lower, rises, and then steadily decreases (only the averages of the control and test data are shown).

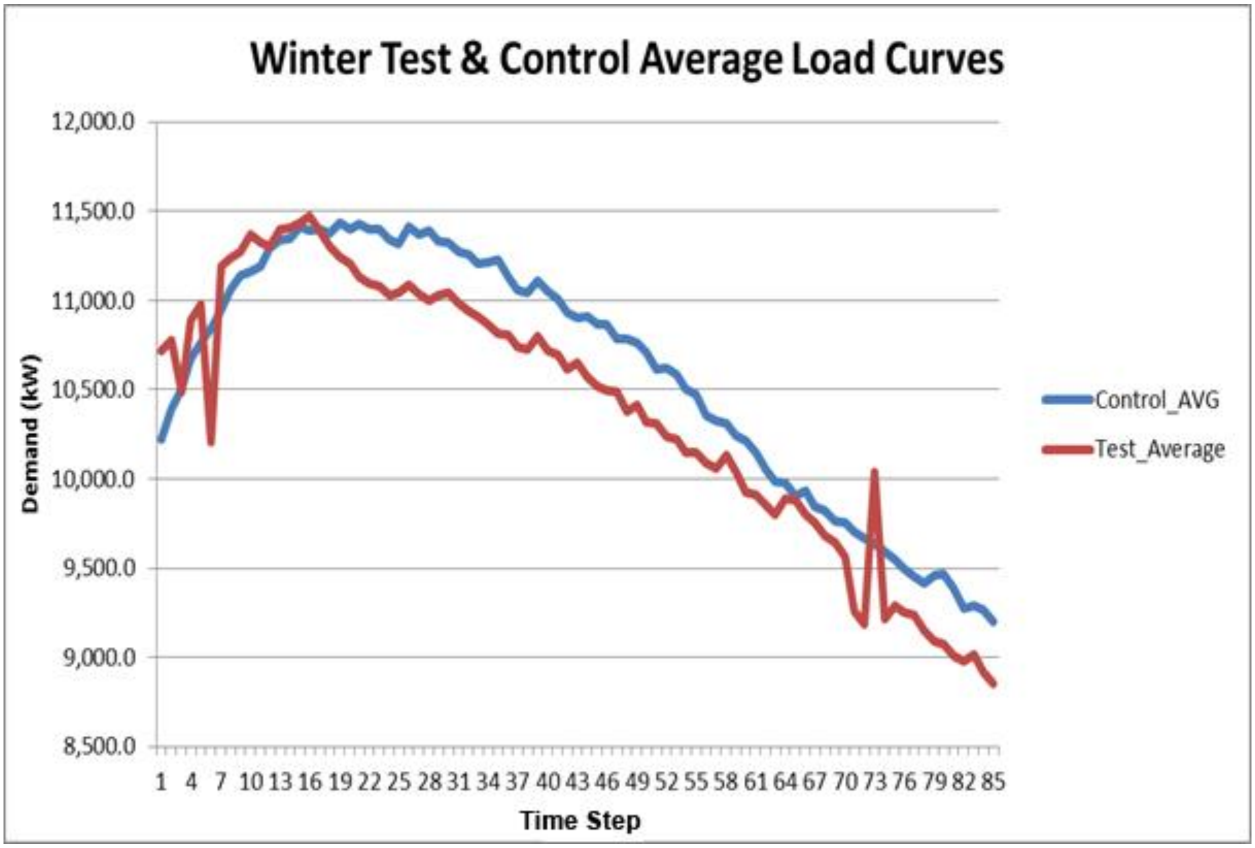

Figure 11.4: Winter Test and Control Average Load Curves

The next challenge was to find the inflection point of the DR program—when does demand start trending upward again? In an ideal world, this point would be at the end of step 16, right before water heaters start cycling out of shed mode. However, for various reasons, including system lag and other demand factors, the bottom of the curve does not exactly match the end of the DR full shed mode. To find the inflection point between where the demand is decreasing and increasing, the moving R-squared product was calculated. This means that every data point inside the middle 50% was assumed to be the potential inflection point; the linear regressions on either side then were calculated, and the R-squared values of each side were multiplied together. The point associated with the greatest of these products was selected as the true inflection point. This method ensured that each side had the greatest optimal linear fit, but not at the expense of making the other side a poor fit. The moving-R method then was applied to the control data to see how the breakpoints and rates of change compared to baseline data. See Appendix 11A for more information on the moving R-squared technique.

In **Figure 11.5**, the graphs of each test result show how demand changed over time during the test. The left vertical axis is demand in kW, the right vertical axis is the R-squared product of that point (corresponding to the gray line), and the horizontal axis is the time stamp in 5-minute intervals (for example, "40" corresponds to 3 hours and 20 minutes after the start of data collection, or 14:20 in most tests). The first vertical red line marks the start of the load shedding, the second red line is the start of the "full-shed" (all water heaters are in shed mode), and the third red line marks the end of the full-shed as the water heaters begin coming back online. The red squares are demand readings during the downward reduction, and blue squares are demand readings as demand begins to rise again. The point between the red and blue squares is the inflection point, based on the product of their R-squared values.

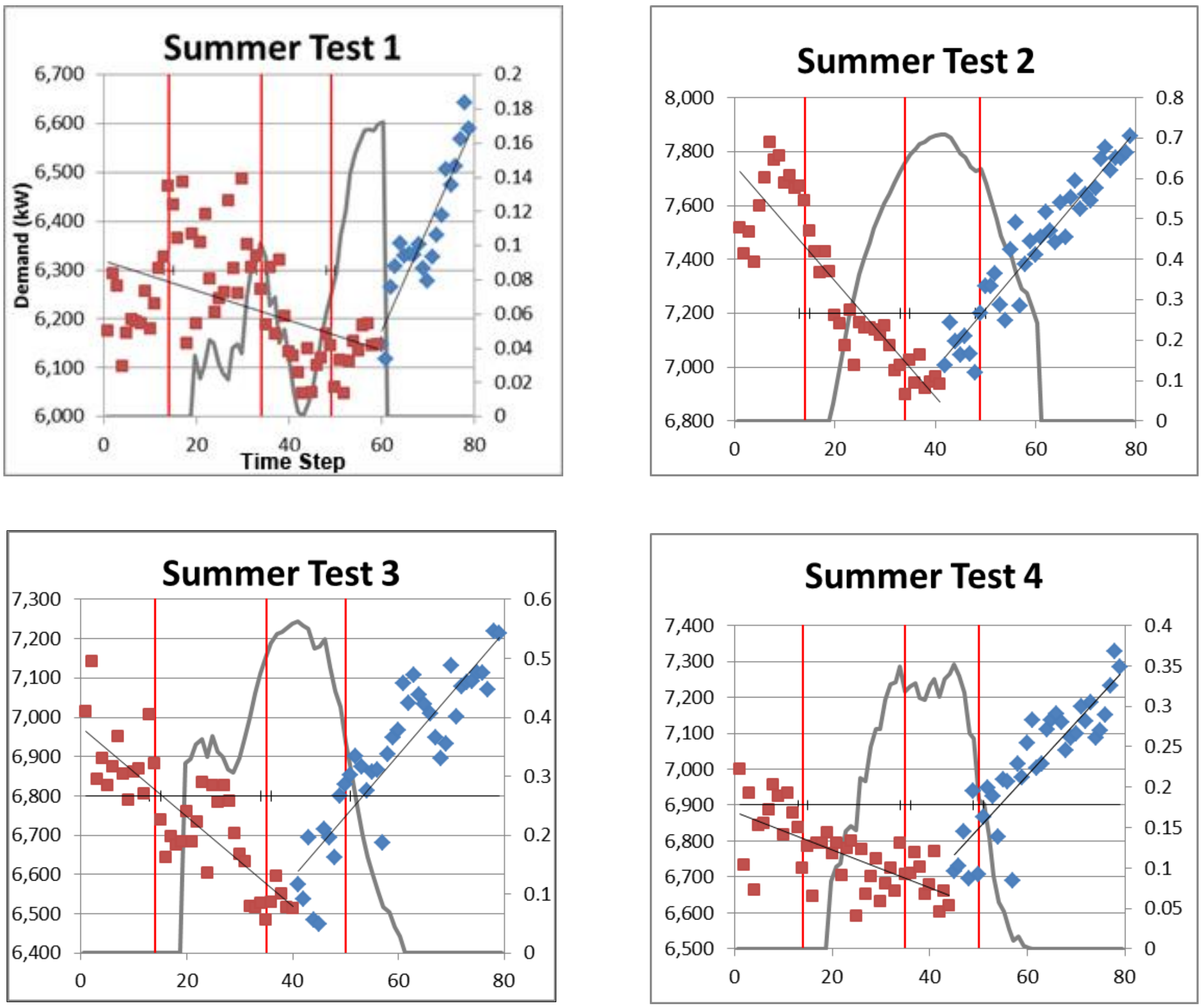

Figure 11.5: Demand Changes over Time during Each Test

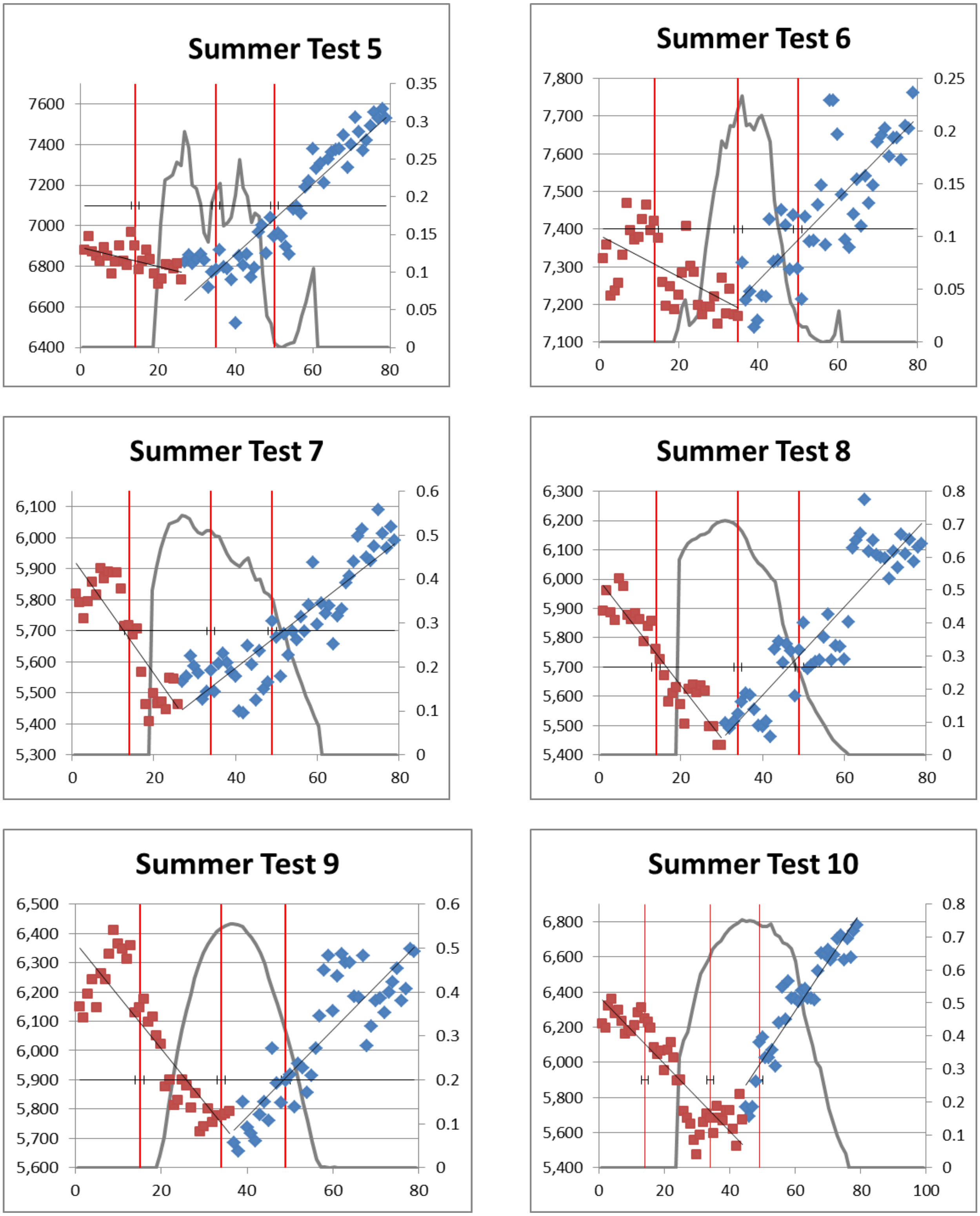

Figure 11.5: Demand Changes over Time during Each Test (continued)

The important characteristics of the data displayed above are how quickly demand falls and rises, and the location of the inflection point (or breakpoint). **Table 11.2** lists these numbers for all of the test and control data for summer.

Table 11.2: Rise and Fall of Demand, and Inflection Points, Summer Data

Date	Test No	Weekday	Inflection Point	Rate of Decrease kW/min	Rate of Increase kW/min	Total kW Demand Reduction	Total kW Demand Increase
Summer Test Data:							
6/25/2013	1	Tuesday	60	-0.61	4.22	-139.95	400.79
7/5/2013	2	Friday	42	-4.28	4.41	-599.06	815.96
7/15/2013	3	Monday	41	-2.29	3.12	-308.48	591.96
7/16/2013	4	Tuesday	45	-1.05	2.96	-162.96	503.95
7/17/2013	5	Wednesday	27	-0.96	3.46	-62.26	898.98
7/18/2013	6	Thursday	36	-1.10	2.16	-121.37	465.09
7/30/2013	7	Tuesday	27	-3.74	2.06	-243.24	534.46
7/31/2013	8	Wednesday	31	-3.58	3.01	-304.20	721.92
8/2/2013	9	Friday	37	-3.62	2.98	-398.22	625.00
8/8/2013	10	Thursday	45	-3.84	5.59	-595.26	950.47
Test Averages:			39.1	-2.51	3.40	-313.33	650.86
Summer Control Data							
6/26/2013	1	Wednesday	48	-1.66	2.14	-281.39	331.42
6/27/2013	2	Thursday	38	0.46	2.74	55.22	562.56
7/2/2013	3	Tuesday	70	0.53	5.26	148.68	236.82
7/11/2013	4	Thursday	54	-1.07	3.74	-213.90	466.98
7/12/2013	5	Friday	54	-1.84	4.31	-367.12	538.58
7/29/2013	6	Monday	60	-2.53	5.75	-581.21	546.71
8/5/2013	7	Monday	56	-2.92	5.91	-613.28	679.93
Control Averages:			54.28571429	-1.29	4.27	-259.46	527.06

This information confirms that there is a distinct difference in the rates of change. The DR program reduced demand at almost twice the rate of the control group (2.5 kW/minute and 1.28 kW/minute, respectively) and reached the local minimum in a much shorter time frame (80 minutes, on average). As shown in **Figure 11.6**, visualizing these data using the averages of the summer data clearly shows the impact of the load-shedding program:

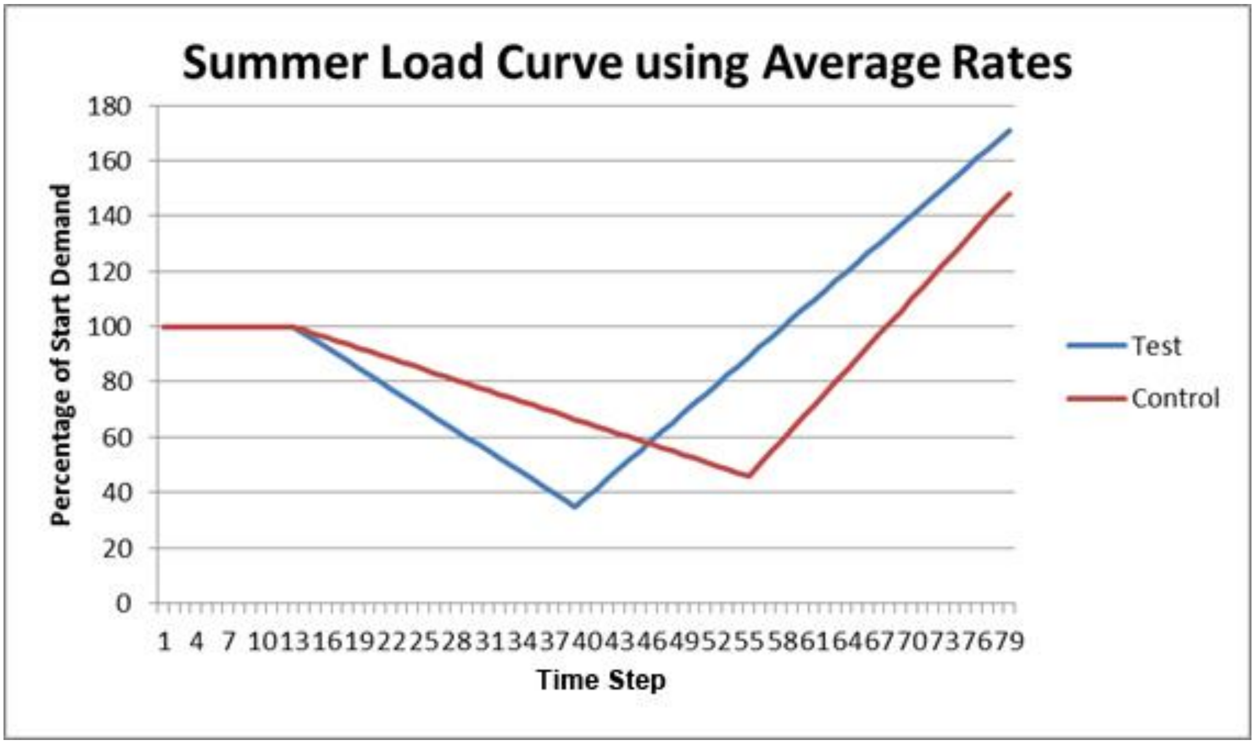

Figure 11.6: Rates of Change for DR Program and Control Group, Data Averages, Summer

The winter data have a very different load profile, and the impact of the program was neither as pronounced nor coincident on the inflection point. For these tests, the important characteristics were the rate of change during the test period and after the test, as compared to control data over the same time frame. **Table 11.3** lists these numbers for all of the test and control data for winter.

Table 11.3: Rise and Fall of Demand, and Inflection Points, Winter Data

Date	Test No	Weekday	Inflection Point	Rate of Decrease during Test Period kW/min	Rate of Decrease after Test Period kW/min
Winter Test Data:					
11/24/2013	1	Sunday	7	-7.68	-11.37
11/30/2013	2	Saturday	8	-6.50	-12.32
12/12/2013	3	Thursday	16	-3.96	-10.30
12/27/2013	4	Friday	16	-7.04	-9.73
12/31/2013	5	Tuesday	17	-4.91	-3.93
1/30/2014	6	Thursday	n/a	-3.01	-2.60
2/5/2014	7	Wednesday	n/a	-4.30	-9.38
2/9/2014	9	Sunday	n/a	-4.74	-12.03
2/10/2014	10	Monday	n/a	-3.20	-8.39
Test Average of Test 1-5			16	-6.30	-9.47
Winter Control Data					
1/17/2014	1	Wednesday	19	-3.14	-5.94
1/19/2014	2	Thursday	9	-8.60	-10.22
1/20/2014	3	Tuesday	17	-6.52	-5.64
1/21/2014	4	Thursday	10	-5.13	-5.27
1/24/2014	5	Friday	15	-3.94	-7.52
1/26/2014	6	Monday	9	-7.59	-7.09
1/27/2014	7	Monday	19	-3.87	-8.13
Control Average			13	-5.54	-7.12

The winter data are less complete than the summer data due to sampling difficulties. Test 8 was conducted during a different time frame, and tests 6–10 started at various times before the control and other tests. For these reasons, they are discounted from the winter average but still included in the table to show how their rates of change compare.

The winter data show that on average, demand dropped 0.75 kW/min faster during the test than it did for the control (6.3 compared to 5.54), but this is a smaller change than seen earlier. The average inflection points are much closer, and the control inflection average is actually before the test inflection point. This means that running the DR program in the winter is very unlikely to make demand drop sooner. The reasons for the DR program's lesser impact in the winter are discussed in the next section.

8. DISCUSSION OF RESULTS OF THE DEMONSTRATION

This study did not find any surprises in the amount of demand reduction by shedding water heaters. Similar to the studies conducted in Norway, demand dropped roughly one-half a kilowatt for each water heater shed. The study also showed the impact of the payback effect. Close consideration needs to be given to this phenomenon to avoid accidentally creating a new peak.

During the summer, the data show that the DCEC DR program is capable of reducing load in a timely and predictable fashion. In total, using the load-shedding technology at full shed reduced load by 356 kW from the start, on average. However, this number needs to be put in the context of the control data. The average local inflection point of the test data was 55 kW lower and 80 minutes earlier than the control data's average inflection point.

The winter test results were not as encouraging. Demand dropped less than it did during the summer, and more slowly. Demand only dropped 0.75 kW/minute faster during the tests than the control and did not occur sooner. Possible explanations include the following: fewer water heaters were used during the time of the test, or not as many people were living in the DCEC service territory during that time of the year (many homes there are vacation homes). It should be noted that the findings of this report are specific to the area studied and should not be taken as a general finding that DR programs are less effective in the winter. Further investigation is needed to determine why the program was less effective in the winter than the summer.

Potential uses for this program include peak-shifting and possible bidding into the NYISO market. For peak-shifting, DCEC could affect its own load curve and associated peaks. This could help the co-op smooth and lower demand, thus resulting in lower demand charges from the New York Power Authority (NYPA) and an improved load factor. An improved load factor helps to limit expensive incremental energy purchases during the winter months, at the time when DCEC exceeds its contractual limit for the purchase of low-cost hydro power provided by NYPA. Both of these methods result in financial savings for the cooperative and its consumer-members. Failure of the DR system results in higher demand charges to DCEC and increased purchases of expensive incremental energy for the cooperative in the NYISO market.

A markedly different strategy would be to bid into the NYISO market, either for uniform, contracted reductions or non-uniform sporadic reductions. This study and analysis will assist the co-op in judging whether to approach the NYISO to request the ability to participate or bid as a DR resource through the aggregation of controlled electric domestic water heating, which to our knowledge has not been done historically. Depending on the findings of this study, DR programs similar to DCEC's controlled electric water heating program could be implemented by other distribution cooperatives or municipal electric systems in New York State. Uniform contracted reductions would require DCEC to hard shed demand for the contracted kW level when requested by the NYISO. This is a more consistent and valuable contract. If DCEC was unable to meet the contracted level with the DSM program, other loads would have to be shed. For this application, DCEC would be paid for its reductions as a resource, but if DCEC was unable to meet the level required, there would be monetary penalties or forfeiture of payments. The second option is to participate in the non-binding Emergency Demand Response Program (EDRP) to provide non-uniform sporadic reductions as issued by NYISO. However, DCEC is first and foremost concerned with not compromising consumer satisfaction. While the tests clearly demonstrate the feasibility of its DR program, it has not yet been tested in all temporal or climatic conditions. Based on this fact, the best course of action is to use the DR program to shift load for its own benefit and participate in the EDRP when convenient. It is important for DCEC to fully characterize the ability of its DR load control program to meet the "step function" expectation that is assumed by the NYISO for any DR participant and, if it is unable to do so, then instead it might judge its value as some sort of "modified" participant.

9. CONCLUSIONS

The DCEC DR program successfully reduced demand in a reliable and predictable manner, but it is of limited capability regarding how much demand it can reduce, given the small differential between the inflection point in demand of the test and control data. Further research is needed to strengthen the reliability aspect of these results by testing the program at different times of the day, weekends, and seasonally. In addition, collecting more control data to create a "typical load curve" for each season would aid in the analysis. If more water heaters were given load control switches and added to the study, the capability of the program should increase as well. As long as large-capacity resistance water heaters continue to be used by consumer-members, cooperatives can make use of DR programs for a variety of purposes. The idea of cooperatives bidding into ISO markets using dispersed residential load controls is an innovative use of Smart Grid technology that is likely to proliferate in the future as DR programs gain more participants and devices.

10. RECOMMENDATIONS FOR FURTHER STUDY

Further avenues for future research and project development are numerous. The test should be conducted again at different times of the day, on weekends, and in different types of weather throughout the year. Conducting the test during the winter showed markedly different results than the summer. As future tests are conducted, regular control data for the same times should be collected on the day following or preceding the test. By running tests throughout the year and comparing the results, DCEC will have a better understanding of its program at different times and be able to leverage it more effectively. Additionally, the program should be expanded to include more residences if possible. A similar study could be undertaken in different locations and using different appliances. For example, tying air conditioning into the program in this location is not likely to be practical as there is little market penetration of residential air conditioning load in the DCEC service area; this could be viable in the warmer southwestern U.S. Future studies will help to strengthen the predictability and capability of these DR programs, however.

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Chapter 12:

Demand Response – Testing the Theoretical Basis of DR

1. INTRODUCTION

The National Rural Electric Cooperative Association (NRECA), through its research arm, the Cooperative Research Network (CRN), supports co-ops in the adoption of new technology and technology applications meant to control costs and improve reliability and service levels. The NRECA Smart Grid Demonstration Project (SGDP), as awarded by DOE, has directly benefited co-op utilities by furthering their understanding of the impacts and risks associated with smart grid technology deployments. It has further benefited utility customers through education on the potential benefits of modern technologies.

This Final Report includes information on several of the demand response (DR) programs deployed under NRECA's SGDP. It provides an overview of DR study objectives, co-ops participating in the DR study, and the programs implemented. It also provides a general overview of relevant DR technologies, program benefits, and solution costs. Data collected and reviewed to date are summarized, along with a discussion of data issues and anomalies specific to each co-op. Finally, the research objectives, approach, and results of our detailed econometric analysis—which was focused on testing the theoretical basis for DR—are presented, along with a discussion of the nexus of our study boundaries and the proposed Demand Response Screening Tool, which is detailed in Appendix 12A. Lessons learned from the entire research and analysis effort also are provided to inform future analyses.

Our desired analysis approach was to test various dimensions of the diverse co-op programs and validate the theoretical basis of these programs across a wide spectrum of variables. Gaining an understanding about demand response performance versus pricing program mechanisms and varying customer attributes enables co-ops to make educated decisions on the type of program that would serve their needs effectively, not only from a program structure design approach but also considering the customer type that would be ideal to recruit. Based on the limited number of co-ops that had valid and useful data and their current DR programs, our initial objectives were tailored to align with this less diverse field of analysis. Given that each of the co-ops had implemented demand response only with direct load control (water heating and air conditioning), the findings presented in this report are reflective of these types of programs only.

2. OVERVIEW OF NRECA SGDP DEMAND RESPONSE PROJECTS

2.1 Description of Co-op Projects

The SGDP included installation and demonstration of equipment designed to affect consumer behavior and alter the time pattern of electric energy usage by certain installed appliances. Systems deployed included in-home displays (IHDs) and load control switchgear. The technology of an IHD provides an avenue for the presentment of pertinent electric energy information, such as the current or cumulative level of consumption, the current effective price for time of use (TOU) and other dynamic pricing programs, and notice of incipient demand charges to the consumer. This enables consumers to make appliance use choices based on economic criteria. Load control devices on appliances provide an avenue for cooperatives to manage load by direct action. AMI systems with two-way communications are considered enabling technologies for direct load control (DLC). The SGDP included advanced metering infrastructure (AMI) as an enabling technology for the DR programs, along with previous or newly installed communications networks. **Table 12.1** depicts the equipment deployed by the participating cooperatives that considered demand response programs.

Table 12.1: Summary of Co-op DR Equipment Acquired

Participants	Demand Response			
	IHD/Web Portal Pilots	DR over AMI	Prepaid Metering	Interactive Thermal Storage
Adams Electric Co-op, IL	X	X		
Calhoun Co. ECA, IA		X		
Clarke Electric Co-op, Inc., IA		X		
Delaware County Electric Co-op, NY	X	X		
Delta Montrose EA, CO	X		X	
EnergyUnited, NC			X	
Flint EMC, GA	X			
Great River Energy, MN				X
Humboldt REC (Midland), IA		X		
Iowa Lakes EC, IA	X	X		
Kaua'i Island Utility Co-op, HI	X	X		
Kotzebue Electric Assn., AK	X		X	
Lake Region Electric Co-op., MN	X			
Menard Electric Co-op, IL	X			
Minnesota Valley EC, MN	X	X		
Owen Electric Co-op, Inc., KY	X	X		
Prairie Energy Co-op, IA		X		

These methods of managing consumer demand are intended to operate in such a way as to minimize environmental discomfort and increase consumer satisfaction. The benefits that accrue over time are expected to include reduced costs of power supply to the utility and related electric energy cost savings for retail consumers.

2.2 Research Objectives – Economic Value and Consumer Presentment

Consumer- or cooperative-initiated actions to affect end-use activity can provide several benefits to the electric system. NRECA/CRN's primary research objective was to examine the validity of previously hypothesized and tested demand response models, thus enabling revisions of and enhancements to these models. The models would then be available to be included in the Open Modeling Framework (OMF) to provide a means to more thoroughly estimate such factors as distribution system losses and the interrelationship of distribution automation with demand response. The OMF thus could be used to evaluate the economic impacts of both utility and end-user actions, such as response through in-home displays, within a single computational framework.

2.3 Role of Demand Response in the 21st Century Co-op

Co-ops increasingly are looking to demand response as a means of shifting and reducing peak demand, deferring capital upgrades to distribution infrastructure, and minimizing wholesale energy demand charges. As co-ops and the utility industry evolve into the 21st century, the utility will continue to be the primary beneficiary of most direct benefits; however, these cost savings in theory should be reflected as future energy and demand charge reductions for co-op customers.

Demand response likely will continue to grow in its influence on customer energy awareness and usage. IHDs and smart thermostats can help customers manage their load profiles and total consumption, leading to further dollar savings.

Another form of demand response is likely to continue growing in popularity and grid impact—the use of distributed generation (DG) and energy storage to shift and reduce peaks. Among many other grid, environmental, and financial benefits, the benefits of DG and storage to peak load management will be significant to co-ops and associated G&Ts, given the dispatch flexibility and ramp times characteristic of some of these assets.

3. OVERVIEW OF DEMAND RESPONSE PROGRAMS

Cooperatives and other utilities have used demand response since the mid-1900s to ensure that demand does not exceed supply and to manage the cost of supply. Early programs employed utility direct load control of customer-owned loads in the residential sector and interruptible programs in the commercial and industrial (C&I) sectors. Particularly prominent for cooperatives, management of irrigation pumps has been a productive demand resource for many years. As technology has enabled greater customer participation, some DR programs have migrated from direct utility control to customer control in response to a signal from the utility. This section summarizes the major parameters, applications, and technologies of demand response for cooperative utilities.

3.1 Applications

3.1.1 Peak Demand Reduction

The principal focus of demand response is generally to reduce peak demand. Other goals—such as energy conservation—typically are secondary and/or separately addressed. Depending on the cost structure of a co-op's power supply, reducing peak demand reduces generation, transmission demand charges, or operating costs, thus reducing overall cost of service for all members.

Reducing peak demand also can delay the need to expand transmission and distribution (T&D) capacity. Over the life of a distribution system, using demand response routinely to delay capacity upgrades by, for example, one year, can save a significant sum, roughly equal to the interest charge at prevailing rates on the utility's annual capacity expansion budget.

In addition, though often not financially quantifiable, reducing demand may reduce the co-op members' carbon footprint if peaking supplies are more carbon intensive than base load supplies. This will be the case, for example, if base load is supplied by nuclear or hydro sources and peak is served by fossil-fueled generation.

3.1.2 System Reliability

In the form of direct load control, demand response has always served an important role in system reliability by mitigating peak demand during challenging operating periods. These periods may arise due to unexpectedly high demand (e.g., due to unseasonably hot weather) or diminished supply (e.g., due to unscheduled supply shutdown or maintenance).

In some electric markets, demand response is now treated on a par with conventional generation as a non-spinning reserve that the system operator can invoke to balance supply and demand.

3.1.3 Other DR Applications

In the same way that local demand response can defer the need for distribution capacity expansion, coordinated regional DR programs can mitigate transmission congestion and delay the cost of transmission expansions. The value of this extends well past its financial impacts into environmental and social domains, where transmission expansion often encounters major obstacles.

Perhaps the most important role of demand response, just now emerging, is to dynamically manage demand to follow the variation in intermittent renewable supplies, such as wind and solar energy. While the technology for this appears to be available now, policy and practice are just beginning to apply it as renewable sources become economically attractive. Over time, by enabling reliable and renewable electric supply, success in this effort will very substantially mitigate greenhouse gas emissions, supporting regional economies that are concurrently robust and environmentally more benign.

3.2 DR Program Benefits

3.2.1 Avoided Capital Costs

As mentioned in the previous section, judicious use of demand response can delay the need to expand T&D capacity. Similarly, it can defer the need to acquire new generation resources. In both cases, the direct financial value to the co-op is equal to the interest on capital that would have been applied to secure the new T&D or generation. For example, deferring a $100,000 distribution upgrade for 3 years garners a $15,000 benefit if the utility's cost of capital is 5% ($5,000 per year on $100,000).

Some may debate whether the result is an avoided capital cost, or simply a delayed one. As demand response becomes integral to electric infrastructure operation, we may reasonably expect that (for example) deferring that $100,000 upgrade for 3 years will, for the same reasons, defer all subsequent upgrades for that system segment for generations to come. In effect, it achieves a permanent reduction in the capital cost of the electric assets needed to serve that load—an avoided capital cost.

Secondary benefits are more uncertain but may be much larger because things that change during the delay period can significantly alter the investment results. For example: the price of natural gas (or another major factor) may change a generation decision substantially; demand response or generation investments by others in the region may reduce some of the local need for new capacity; changes in DR technology or public participation/response may further delay the investment.

3.2.2 Avoided Energy Costs

Energy cost per kWh during peak periods is typically higher—sometimes much higher—than during off-peak periods. Therefore, demand response can reduce energy cost to the co-op, even though it does not always reduce total energy consumption. For example, shifting water heating load from peak to off-peak periods will have no direct effect on members' use of hot water. Thus, the kWh consumed to heat the water will not change materially. If the water heaters are controlled off for a long period, making the water less hot, members are likely to use more of it, with the result that the energy use will be about the same. In all cases, the "rebound" or "catch-up" consumption that occurs after the control to bring the water heaters back up to full temperature will offset the kWh reduction during the peak period.

Controlling air conditioners often results in some kWh reduction because members receive less space cooling. Therefore, the co-op and its members benefit from the reduced kWh incurred at peak period prices and from a small reduction in overall kWh consumption for the day. By the time the control program ends in early evening, the day is cooler and the catch-up consumption is less than the kWh avoided during the peak period.

Energy avoided can be significant in a DR program in which the utility sends a signal (a price signal or simply an event signal) to members and allows them to control the loads. In such cases, members will often do things the utility cannot do to reduce their consumption. They may turn off lights, decide to cook on a gas grill instead of an electric range, go to the movies and limit air conditioning (AC) of the house, reduce ventilation power to the barn if the day is windy, etc. DR programs that let the consumers decide what loads to shed consistently produce greater kWh reductions than utility direct control programs because the consumers have greater access to more of their loads and are commonly willing to respond to the financial incentives of the program.

3.2.3 Other DR Benefits

DR produces many other benefits that, though not large individually, are important in aggregate.

Electric line losses are proportional to the square of the current in the line. Therefore, when line current is high, losses are disproportionately higher. Demand response reduces the current when it is highest. For example, a 17-amp current in a distribution line may be reduced to 15 amps—a 12% reduction.[18] The losses in that line will be reduced by 22%, however.[19] Therefore, demand response reduces line losses at the time when they are the highest, reducing the co-op's operating costs by improving the overall efficiency of distribution.

The life of current-carrying assets in electric distribution is a function of time, temperature, and electric load. Partly because load affects asset temperature, high loads disproportionately shorten asset life. DR programs that reduce peak distribution loads extend the life of the distribution assets by reducing the time incurred at high load and high temperature. Expressed as a percentage, the potential for life extension is small, less than 10%. Because the total capital cost of the assets is large, however, this benefit is significant in the long run.

In parallel with the longer equipment life, demand response reduces maintenance costs for that equipment. Transformer overloads are reduced in frequency and severity, stress on connections is reduced, and switches last longer. The saving is small but cumulatively important over time.

Demand response lowers co-op members' electric bills directly in two ways, as mentioned above. It reduces the cost of energy by avoiding kWh during peak periods (or by minimizing demand charges to the co-op), and it reduces members' kWh consumption, especially if they have responded individually to DR events by shedding significant loads. The "other DR benefits" mentioned in this section also translate into bill savings for members. That is, reduced losses, extended asset life, and reduced maintenance costs all contribute to better service at lower cost. This enduring member benefit is the "bottom line" of demand response and is where the overall value of demand response shows the most.

18 $100\% \times [1 - (15 \div 17)]$.

19 $100\% \times [1 - (152 \div 172)]$.

3.3 Enabling Technologies

Demand response and load management (LM) systems are composed of the following:

- Devices at customer sites to communicate with customers and display information to them (optional in pure "direct" load control programs)
- Devices at customer sites to control customer loads
- IT resources at the utility to manage the program and data, and conduct communication with customer equipment

It is productive, and therefore usual, to guide and enhance the load management process by using Supervisory Control and Data Acquisition (SCADA) resources. This section describes these elements individually. Communication equipment and networks interconnect the system elements to transfer messages and data. These networks are diverse and may be public (e.g., a cellular phone network, broadcast FM radio, or the Internet) or private (e.g., a utility-owned meter communication network).

3.3.1 In-home Displays – Types and Information

IHDs make available real-time cost, usage, and related information to the customer. They range from simple to full featured and, correspondingly, from lower to higher cost. Some displays are able to receive signals from ZigBee-equipped smart meters, while others that do not are suitable for homes that have more traditional or advanced meters without ZigBee.

Simple devices only receive and display energy information. More capable versions allow the user to tailor the way the information is displayed, such as altering units (e.g., Fahrenheit or Celsius) or time dependence (e.g., hourly average kWh, daily average kWh, etc.). Even more capable devices can control the home's energy consumption in response to user programming. Some combine energy information and management with other convenience features.

The information residents receive from an IHD principally comprises energy (kWh) consumption and demand (kW) from any of a wide range of intervals the resident chooses. For example:

- Current kW demand
- kWh consumed so far today
- Maximum demand today
- kWh consumed and maximum demand to date this month
- kWh consumed and demand yesterday (or last week or month) or any individual day (or week or month)

Most devices also display the current time, day, and date. Those that can receive utility signals display DR event alerts. More capable (and expensive) devices provide more information, including inside and outside temperature, electricity price, graphs of any of these parameters over various periods, and projections of total kWh (and sometimes even the cost in dollars) at the end of the current month. Some also display environmental impact information, such as the estimated carbon footprint associated with the recorded kWh consumption.

Appendix 12A lists additional examples and their features. Note that the devices shown in Appendix 12A rely on a ZigBee-equipped smart meter to send meter data to the IHD or thermostat. However, DR programs can still be practical when the utility has not deployed ZigBee-equipped smart meters. Various providers offer devices that receive signals and data from the utility via paging, the Internet, a cellular phone network, or the electric power line.

3.3.2 Load Control Devices

"Load control" is control *by the utility* of customer-owned loads. Control commands are generated either at the utility or in a customer-programmed device (as described above) and are executed by the actual control device: a switch controlling the power to the load or a relay that controls the load, such as the relay in a thermostat. Switches are available to control loads in two categories: plug-in loads and wired-in loads.

Plug-In Loads

Typical large plug-in loads, as mentioned earlier, include dehumidifiers, window air conditioners, and chest freezers (to be controlled for short periods only). Though smaller plug-in loads, such as table lamps and fans, are too small to be of direct interest to a utility, they collectively constitute a significant control opportunity for the resident and the utility. These loads typically are equipped for control by the resident as part of an overall response to utility DR events.

Control devices for plug-in loads are widely available from many sources, including hardware and building supply stores, and from online suppliers of automation and control equipment. Typical costs are $20 to $80 per controlled load, plus $50 to $300 for a "hub" or central control and communication box.

Wired-In Loads

Wired-in loads routinely found in load control and DR programs include electric water heaters, air conditioners, pool and spa pumps, and electric strip and thermal storage heaters. These loads typically are served through a circuit breaker and are hard-wired to the supply line. The load control switch must be installed by a qualified electrician between the circuit breaker and the load. Control switches for wired-in loads are usually in plastic weatherproof NEMA-compliant boxes and can be provided with any of various communication technologies, from public cellular to private utility automation network radio.

3.3.3 Ancillary In-Home Devices

It is useful to be aware that, in some cases, the in-home devices described above will not operate reliably without additional equipment, which must be acquired and installed at additional expense. Primary examples are home network range extenders and protocol translators (sometimes called gateways). In residential applications, these devices typically cost less than $200 and can be installed by the resident, but a minority of residential situations may require more intensive effort to achieve reliable communication, incurring on-site technical support for program success.

3.4 Demand Response Program Parameters

3.4.1 Financial

Utilities arrive at the financial incentives embedded in DR programs through a variety of approaches, based on their power supply situations, customer base, and level of sophistication. The following provides a description of the typical incentive structure of DR programs and the typical approach to parameterizing those incentives and price differentials.

Dynamic Pricing and Other Price-Driven Programs

Dynamic pricing programs offer differential rates or a rebate on consumption during prescribed hours during on- and off-peak periods. In particular, dynamic pricing programs under this umbrella involve differing rates or rebates during event periods that are typically prescribed during, and must be triggered by, a particular time prior to the event. The pricing differential typically incorporates some combination of the following:

- Differentials in the cost of energy between on- and off-peak periods and during "super-peak" periods and otherwise. This information can be estimated from utility records regarding generating unit operations and cost characteristics, and power market transactions information or market indices and intelligence.
- Generation costs based on either of the following:
  - Cost of new generating capacity on an amortized basis, allocated across an assumed number of event hours in any year;
  - Wholesale demand rates allocated as above to an assumed number of event hours in a period.
- Transmission costs based on assumed costs of facilities or wholesale transmission billing rates allocated to assumed event hours, as above.
- Distribution costs, determined in a similar fashion as transmission costs.

Direct Load Control (DLC) programs

DLC programs typically are incentivized through either (1) specific dollar amount credits to the monthly bills of participating customers—across the entire year or during months for which events are allowed or expected to occur, and/or (2) rebates on new devices (typically of a particular efficiency threshold) installed with a DLC device. However, there are numerous programs for which no incentive is offered but that achieve some penetration.

The incentive level typically is derived through either an estimate of the benefit of avoided capacity, determined as described above for price differentials, or a survey of the practices of surrounding utilities.

3.4.2 Temporal

DR programs typically have prescribed timing, duration limits, and frequency limits, though not all do. The temporal parameters typically are developed so as to ensure a high probability of avoiding load at the most opportune time—during a system peak, the billing peak (for utilities served at wholesale), or a regional peak. Many programs are limited to a particular season, corresponding with the typical system peak conditions. Dynamic pricing programs that could be characterized as demand response, such as critical peak pricing (CPP), typically are limited to prescribed times of the day or potential event periods (as short as 2−3 hours up to 7 hours). Most DR programs have prescribed limits with respect to the number of events that can be called within a particular month or season. For example, many utilities limit DR events to some maximum number of events per summer season. DLC programs are less likely to have such limits and often are managed by utilities to minimize customer inconvenience and attrition.

3.4.3 Operational Conditions

As mentioned above, DR programs typically have certain prescribed timing characteristics designed to maximize the likelihood that they will be triggered during peak periods that correspond to demand cost incidence. Some DR programs also have prescribed triggers for events, corresponding to system load levels, load levels within the region (e.g., as reported or forecasted by an Independent System Operator, or ISO), or temperature conditions. Most DR programs, however, instead merely have such triggers incorporated into the DR program operator's practice on triggering events. In that case, it is the other prescribed characteristics that the participants solely rely on to anticipate the timing, length, and frequency of events.

3.4.4 Target Loads and Customer Groups

In 2012, the Federal Energy Regulatory Commission (FERC) reported[20] that DR programs in the U.S. had the potential to reduce demand by 66,300 MW. Of that, about 12% was in the residential sector, and nearly all of the rest was in the commercial and industrial sectors.[21]

In the residential sector, DR programs address large and small loads. The large loads are primarily AC, electric space heating (including heat pumps, storage heat, and baseboard or "strip" heat), and pool and spa pumps. These often are controlled directly by the utility when the resident has enrolled in a control program.

Small loads include essentially all other loads in residential service. Any that are discretionary to the resident can be controlled by the resident. DR programs that convey a price or other financial incentive to participants allow each to select what loads to control. Section 3.3.2 describes available devices residents can use to implement such control. Common choices are large loads (if not controlled by the utility), area lighting, dehumidifiers (a relatively large and deferrable load not readily controlled by the utility because it is a plug-in load), and food freezers (which stay cold for just a few hours but cannot be deferred longer).

Significant residential loads that generally are not controlled are well pumps, sump pumps, and electronic loads, such as entertainment and computing. Due to the only marginally deferrable character of food refrigeration and freezing loads, most residents choose not to control them.

Loads in the C&I sector can be divided similarly into those controlled by the utility and those controlled by the user. The diversity of loads is large, making it difficult to list them comprehensively. In general, they include, but are not limited to the following:

- Lighting (both interior and exterior)
- Process machinery (conveyors, mixers, grinders, machining operations, assembly operations, etc.)
- Process heating
- Large-scale space conditioning
- Service operations (escalators, elevators, information and displays, etc.)
- Irrigation and other pumping

3.5 Success Metrics

DR programs can be evaluated based on a combination of estimates regarding the abatement of peak demand and, in some cases, avoided energy, coupled with a valuation analysis regarding the cost to otherwise serve that demand or energy from either traditional supply-side generating resources or via wholesale purchases. Cooperatives can leverage a relatively standardized framework for conducting an analysis of success metrics. This section provides an overview of the central tenets of such a framework, namely (1) the manner in which avoided energy or demand is valued, and (2) financial metrics that compare the cost of the DR program to the value of the avoided energy or demand. Note that this section assumes that the engineering

[20] Federal Energy Regulatory Commission. "Assessment of Demand Response & Advanced Metering." Staff Report. December 2012, p. 22.
[21] The FERC report separated C&I programs from "wholesale" programs by ISOs, regional transmission organizations (RTOs), and other wholesale entities. Since the great majority of load participation in such wholesale programs is composed of C&I users, we combine the wholesale demand reduction with the C&I figure. FERC included agricultural consumption in the C&I sector.

estimates associated with individual DR responses (i.e., kW ratings and technical estimates of abatement) can be readily obtained.

Valuation of Avoided Peak Load/Energy

The key components of avoided cost (or benefits) of a given DR program over a pre-specified time horizon, some of which may not necessarily apply to every program, include the following:

- Avoided or delayed generation or purchased power capacity additions (demand savings)
- Avoided wholesale costs of energy production
- Avoided transmission/distribution cost (including avoided capital expenditures)
- System loss savings
- Avoided ongoing operation and maintenance (O&M) costs associated with transmission and T&D system improvements (if any)
- The value of potential power market sales of resources that are free to serve the external market in place of the energy generation that has been avoided as a result of the program

From an avoided cost perspective, the bulk of benefits associated with DR programs will arise from avoided demand and energy costs, potentially including avoided or delayed capacity additions costs if the DR program is of sufficient size and scope in participation. Capacity savings represent value in either deferred or avoided investment costs by the utility as well as a reduction in the cost of running expensive peak generation, which may be reflected in a demand tariff. Energy savings represent both immediate and ongoing cumulative benefits associated with the reduction in generation fuel and operating costs as well as losses. Depending on the utility in question, there are typically two key marginal capacity and energy situations that are likely to be encountered for targeted members—specifically, (1) the utility has avoided costly operation of native/existing peaking units; or (2) the utility buys marginal capacity and energy from the market or is a participating member of a G&T, whereby avoided costs can be mapped to an existing demand or energy rate.

In the former case, it is critical to identify the avoided marginal generating resource, either by selecting from a list of pre-defined generic marginal units (e.g., large natural gas combined cycle unit, small gas peaking unit, etc.) with performance characteristics representative of the regional market, or defining the operating characteristics of a specific marginal unit (which could also represent a contract, tariff rate, or market purchase).

To capture avoided demand costs, it is necessary to collect information on marginal generating unit capital and fixed O&M costs to estimate potential capacity savings. To the extent that there is an intermittency in the ability of the DR program to align peak shaving with the utility's system peak, such issues typically are examined to develop reasonable assumptions for dependable capacity (or the amount of capacity that realistically can be avoided at the time of the utility peak), which then are applied to the requested capacity cost information to determine capacity benefits.

To develop projections of avoided and incurred marginal energy costs, the heat rates of the assumed marginal generating resources (generic or member-defined) are typically multiplied by a (member-defined) forecast of fuel prices plus variable O&M and emission allowance costs (again, either pre- or member-defined) for the marginal unit to derive a total per-unit ($/MWh) marginal average energy cost for these resources. These average per-unit costs then would be multiplied by the projected avoided energy of the DR program (adjusted for marginal losses) to derive total energy cost impacts.

In the absence of such detailed information, a given co-op can review its existing contracts and tariffs to determine the most appropriate energy and demand rates to input into the evaluation model.

To the extent that the other aforementioned elements of avoided cost are present and relevant to a specific utility, most notably the potential for market sales, such estimates can be included as secondary benefits in an economic evaluation framework so as to provide a fair and objective evaluation of potential program benefits. Other examples of secondary benefits include, but are not limited to:

- The monetized value of avoided carbon emissions associated with abatement, using externally derived projections of potential future carbon costs or internal shadow values associated with carbon avoidance;
- The monetized value of jobs created that are associated with DR program implementation; and;
- The downstream economic benefits associated with energy and demand savings that represent an additional amount of disposable consumer income in the general economy.

Program Costs and Key Metrics

From a cost perspective, details regarding DR program cost elements can be developed using detailed information on grant funding and other internal utility costs. A more detailed cost itemization can help to better communicate the overall cost-benefit picture for a given deployment. The main categories of DR program costs can be defined as follows:

- Generic procurement costs associated with the communication network
- Capital cost of communications devices
- Capital and staffing costs associated with enhanced IT
- Installation and program management costs
- Marketing collateral associated with participant recruitment
- Lost electric revenues resulting from the avoided peak demand
- Customer education and public relations costs
- Marginal program participation incentive levels (i.e., discounts or rebates for participation) and other ancillary costs, as appropriate

Understanding success for a given DR program is a function of ensuring that the best available estimate of costs is combined with the best available estimate of avoided costs. While there are numerous approaches to an economic analysis of benefits, there are several industry-standard cost-benefit ratios, which can be defined as follows:

- *Utility Cost Test (UCT)* – A measure of whether the benefits of avoided utility costs are greater than the costs incurred by a utility to implement the DR program.
- *Rate Impact Measure (RIM) Test* – A measure of whether utility consumers that do not participate in a DR program would see an increase in retail rates as a result of other customers participating in a utility-sponsored DR program.
- *Total Resource Cost (TRC) Test* – A measure of whether the combined benefits of the utility and customers participating in the DR program are greater than the combined costs to implement the DR program.

The components of each of these ratios are summarized below. Note that such descriptions are generic in nature, and the exact applicability to a specific DR program will differ, depending on the nature of the measure(s) deployed. Some costs may be equal to zero for a significant number of DR programs.

Utility Cost Test (UCT):

Benefits	=	Avoided Energy Supply Costs (net generation level decreases × marginal energy costs)
	+	Avoided Capital Supply Costs (net generation level decreases × incremental capital costs)
	+	Avoided O&M Supply Costs (net gen. or distrib. level decreases × marginal O&M costs)
	+	Participation Charges
Costs	=	Increased Energy Supply Costs (net generation level increases × marginal energy costs)
	+	Increased Capital Supply Costs (net generation level increases × incremental capital costs)
	+	Increased O&M Supply Costs (net gen. or distrib. level increases × marginal O&M costs)
	+	Utility program costs (administrative costs)
	+	Incentives (utility incentives, rebates, etc.)

Rate Impact Measure (RIM) Test:

Benefits	=	Avoided Energy Supply Costs (net generation level decreases × marginal energy costs)
	+	Avoided Capital Supply Costs (net generation level decreases × incremental capital costs)
	+	Avoided O&M Supply Costs (net gen. or distrib. level decreases × marginal O&M costs)
	+	Revenue Gains (net meter level increases × retail rates)
	+	Participation Charges
Costs	=	Increased Energy Supply Costs (net generation level increases × marginal energy costs)
	+	Increased Capital Supply Costs (net generation level increases × incremental capital costs)
	+	Increased O&M Supply Costs (net gen. or distrib. level increases × marginal O&M costs)
	+	Revenue Losses (net meter level decreases × retail rates)
	+	Utility program costs (administrative costs)
	+	Incentives (utility incentives, rebates, etc.)

Total Resource Cost (TRC) Test:

Benefits	=	Avoided Energy Supply Costs (net generation level decreases × marginal energy costs)
	+	Avoided Capital Supply Costs (net generation level decreases × incremental capital costs)
	+	Avoided O&M Supply Costs (net gen. or distrib. level decreases × marginal O&M costs)
	+	Avoided Participant Costs (avoided capital, O&M, etc.)
	+	Tax Credits
Costs	=	Increased Energy Supply Costs (net generation level increases × marginal energy costs)
	+	Increased Capital Supply Costs (net generation level increases × incremental capital costs)
	+	Increased O&M Supply Costs (net gen. or distrib. level increases × marginal O&M costs)
	+	Incremental Participant Costs (capital costs, O&M, etc.)
	+	Utility DR Program Administrative and General (A&G) Costs

The computations of such ratios should reflect all of the incurred incremental costs and avoided incremental costs (benefits) applicable to the measure in question.

From the perspective of a given co-op, metrics that may be easier to communicate to stakeholders, such as the Net Present Value of Net System Benefits, or the internal rate of return of a given investment, may be used to complement the above cost-benefit analyses. In most cases, the TRC can be made equivalent to the cost-benefit ratio that reflects Net System Benefits, as long as the costs and benefits have been parameterized appropriately to capture the correct utility perspective.

Interpretation of success metrics by members and other stakeholders should be fairly simple by design. All of the relevant avoided costs of the DR program typically are subtracted from the total DR program intrinsic costs in each year. All of these Net System Benefits then are discounted back to today's dollars and added to compute the Net Present Value (NPV) of Net

System Benefits. In a year in which costs outweigh benefits, the benefit-cost ratio will be less than 1.0. This ratio hopefully should be above or equal to 1.0 as the study horizon extends. In general, a DR program that has a positive NPV of Net System Benefits should be implemented because the benefits outweigh the costs in the long run. If a Program has a negative NPV of Net System Benefits, program parameters may need to be re-examined, sensitivities may be necessary, or it may be that the program is simply too expensive relative to the expected demand/energy reductions. Devising a consistent framework for evaluating success in advance of deployment can help a utility ascertain the reasonableness of the level of investment required to achieve a certain amount of DR capability.

Finally, in certain instances, it may also be desirable to determine the number of participating customers required for the system to be cost-effective, given that a broader range of participants can absorb certain fixed and administrative costs of a given deployment more effectively, and that a larger pool of participants will result in a larger amount of abatement. Goal-seek techniques that leverage the above cost-benefit framework or sensitivity analysis can be utilized to determine the point at which the NPV of net program benefits turns positive (i.e., when the program becomes cost-effective, assuming a specific time horizon for the evaluation).

4. REVIEW OF PREVIOUS EMPIRICAL STUDIES OF DEMAND RESPONSE

Numerous studies have analyzed the results of dynamic pricing programs—primarily utility-sponsored pilot programs—over the last 10−15 years. The methodologies used to ascertain the significance of and quantify differences in load levels and load profiles, and the results of these studies, are discussed below.

4.1 Study Methodology

Demand savings and price elasticity estimates that are reported as part of many studies of DLC, DP, and other DR programs typically are estimated using regression techniques. The usual approach is to assemble load profile data for both program participants and non-participants (the latter group commonly being referred to as a "control group") and develop regression equations that seek to explain variations in load levels or characteristics (e.g., ratio of on- to off-peak load) as a function of DR event data; variables capturing enabling technologies; and other variables, including weather conditions, home and appliance characteristics, household characteristics, and day type and seasonal indicators, among others.

While demand savings estimates stand on their own and can be directly useful in gauging the value of some DR programs, elasticity estimates, in the form of both substitution and own-price elasticity, must be combined with pricing information to derive load profile changes resulting from dynamic pricing programs.

For dynamic pricing program evaluations, it is also fairly common for the price ratio to be embedded with additional covariates that capture the influence of other drivers—such as weather conditions, the installation of certain appliances, or the presence of IHDs or other enabling technologies—on the amount by which customers respond to changes in the dynamic pricing.

The elasticity of substitution can be derived from the empirical equation parameter estimates, either directly as the parameter on the price ratio, or the parameter on the price ratio combined with other daily conditions (e.g., weather) multiplied by the respective parameter. This elasticity of substitution is often reported directly as part of pilot program evaluation studies.

4.2 Results

4.2.1 Dynamic Pricing

Figure 12.1 illustrates the peak demand reductions observed for 80 such programs, grouped by the type of rate and the use of enabling technologies.[22] In general, critical peak pricing (CPP) and peak time rebate (PTR) rates resulted in greater demand reductions than time-of-use (TOU) rates. Enabling technologies generally increased the demand reductions.

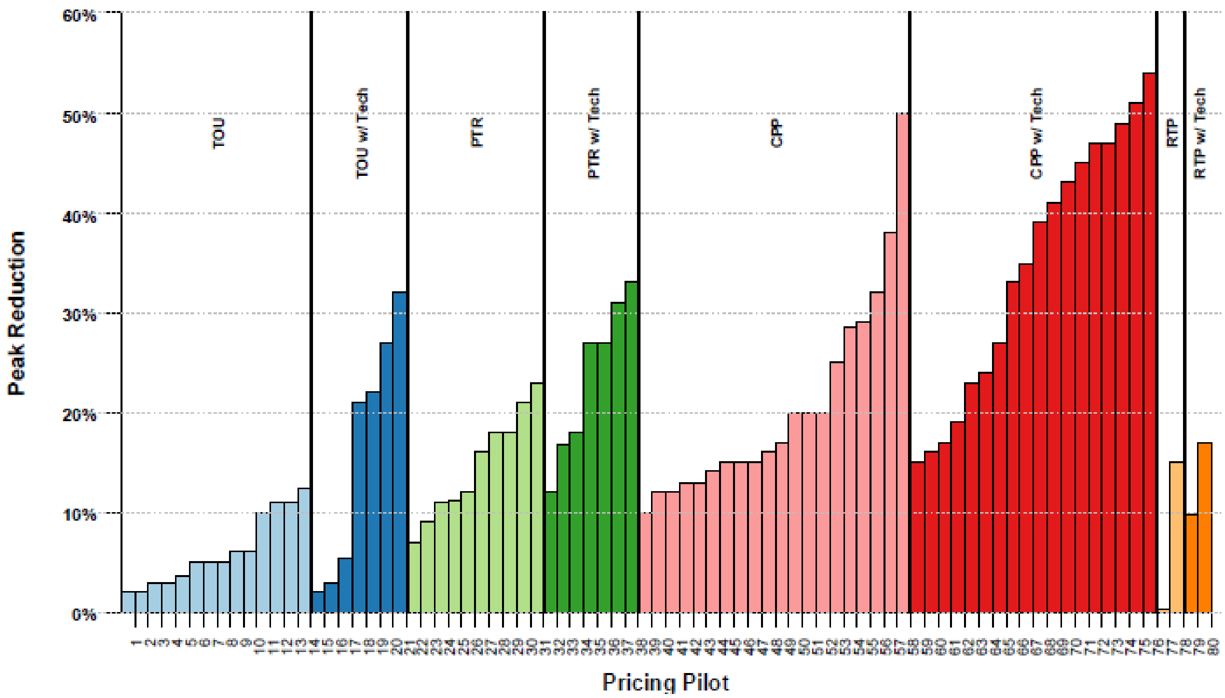

Figure 12.1: Peak Reduction by Rate Type and Technology for Dynamic Pricing Pilots[23]

A 2011 paper on the subject of dynamic pricing showed that, of 109 pricing programs from 24 different utilities, the median peak demand reduction was 12%. For those programs that used enabling technologies, the median peak demand reduction was 23%. While most of these were pilot programs and used various implementation approaches (e.g., different experimental structures, varying rates, on-/off-peak time periods, participant enrollment approaches, use of control groups, etc.), they generally showed similar price responsiveness from consumers. **Figure 12.2** depicts the peak reduction for a subset of the pilot programs, including the differences between programs that included enabling technologies (Technology Curve) and those that did not (Price-Only Curve). In both cases, the trend is for increasing reductions in demand as the difference between on-peak and off-peak prices increases (Peak to Off-Peak Price Ratio). The rate of greater reduction decreases at higher levels of peak to off-peak ratio.[24]

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[22] L. Wood. Institute for Electric Efficiency. "Dynamic Rates and Smart Meter Benefits." Presented to MACRUC, July 26, 2011.
[23] Ibid.
[24] Faruqui, A., and J. Palmer. "Dynamic Pricing of Electricity and Its Discontents." August 3, 2011, p. 4.

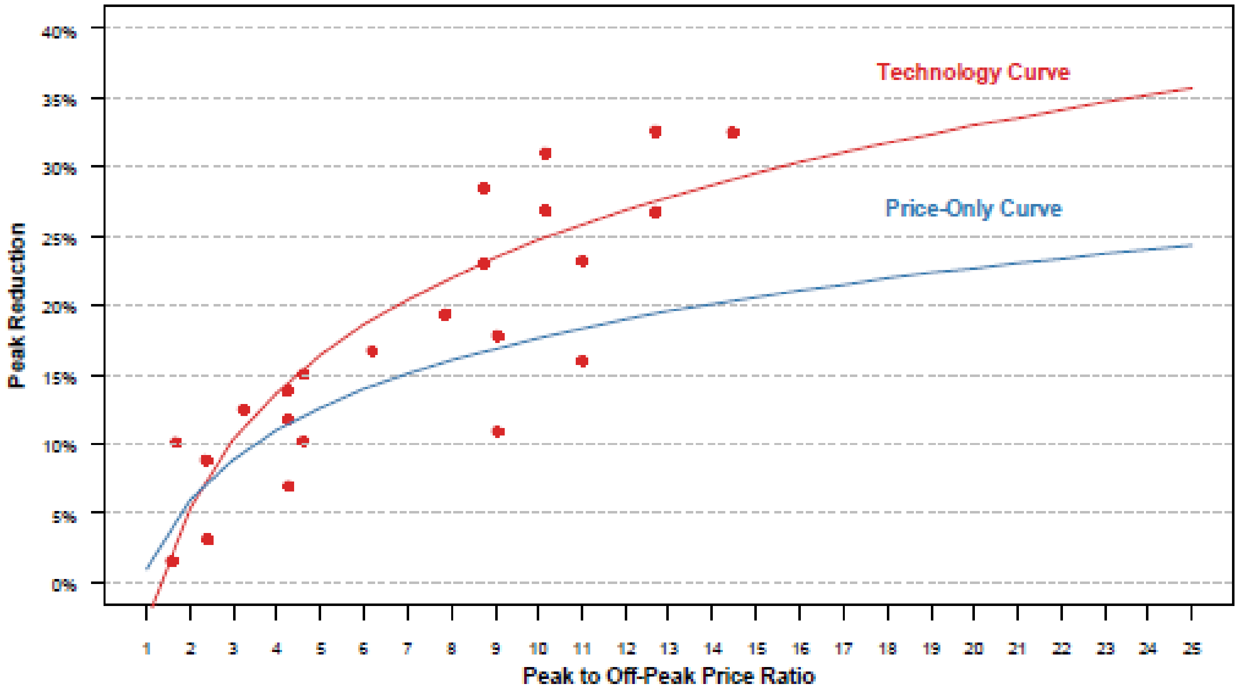


Figure 12.2: Peak Reduction by Rate Type and Technology for Dynamic Pricing Pilots[25]

Another measure of the responsiveness of consumers to dynamic prices is referred to as price elasticity. The extent to which customers shift electricity demand from on-peak to off-peak time periods can be quantified by the substitution elasticity, while the reduction in demand relative to the relevant price can be quantified by the own-price elasticity. Substitution elasticity is defined as the percentage change in the peak to off-peak demand ratio resulting from a 1% change in the peak to off-peak price ratio. Own-price elasticity is defined as the percentage change in peak demand resulting from a 1% change in price. The most prevalent measure of response to dynamic pricing is the substitution elasticity, presumably due to its more complete characterization of demand response to varying on-peak length and price differential, which are not addressed via own-price elasticity and would result in greater variations of estimated elasticity across programs with varying characteristics.

Based on the variety of studies and programs reviewed, estimates regarding elasticity of substitution varied from as low as essentially zero, or no response, to a high of approximately 0.35 (in absolute terms). There seemed to be no definitive variation across program types, which included TOU, CPP, and PTR programs.

Figure 12.3 illustrates the variation in demand reductions as a function of peak to off-peak price ratios for various elasticities based on CPP rate programs (demand reductions typically would be somewhat less for TOU programs that involve much longer on-peak periods). As discussed previously, the inclusion of enabling technologies like IHDs and programmable communicating thermostats (PCTs) typically was demonstrated to increase elasticity, or measured response, by 10−50%.

[25] Ibid.

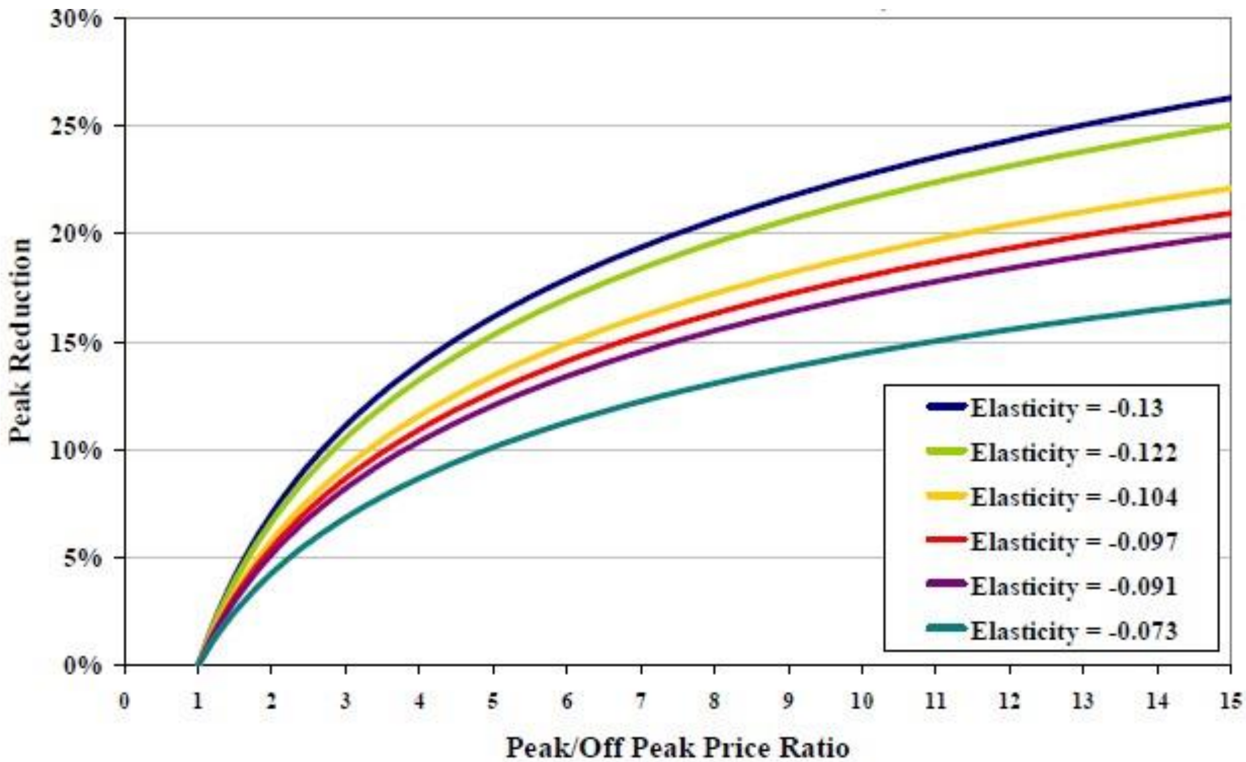


Figure 12.3: Peak Reduction, by Rate Type and Technology for Dynamic Pricing Pilots[26]

While the focus of the various pilot programs has been on demand reduction or load shifting, the pricing programs have had varying effects on energy use. Most studies of residential dynamic pricing pilots reflect that TOU, CPP, and similar pricing programs result in a reduction in energy consumption, although some studies have demonstrated a positive impact on energy consumption. However, the estimated changes in consumption were typically less than 5%.[27, 28]

4.2.2 Direct Load Control

The Lawrence Berkeley National Laboratory (LBNL) conducted a 2007 study to determine a widely applicable set of savings estimates for AC and water heater DLC programs within the footprint of PJM. Duty cycle models were constructed to examine a wide range of potential switch cycling strategies (27%, 43%, 50%, 67%, 75%, 87%, and 100%). Demand savings estimates were developed using a regression approach, capturing temperature humidity indices (THI) from nearby weather stations across the various cycling strategies, and tabularized for use by the participating utilities. The results of this analysis suggest the following for AC and water heater programs:

- At a THI of 84°F, the estimated demand reduction on air conditioning DLC for the 15-minute time period that ends at 5 p.m. ranged from a low of 0.37 kW for the 27% cycling strategy to a high of 2.06 kW at 100% cycling. The 50% cycling strategy was estimated to yield savings of 0.80 kW.

[26] Faruqui, A., and J. Palmer. "Dynamic Pricing of Electricity and Its Discontents." August 3, 2011 p. 4.
[27] Newsham, G.R., and B.G. Bowker. "The Effect of Utility Time-Varying Pricing and Load Control Strategies on Residential Summer Peak Electricity Use: A Review." NRC-CNRC Institute for Research in Construction. 2010, p. 15.
[28] Goldman, C. et al. "Coordination of Energy Efficiency and Demand Response." *LBNL*, January 2010, pp. 2–12.

- For customers with a seasonal AC of less than 1,600 kWh, the estimated demand savings for air conditioning DLC at a THI of 84°F ranged from a low of 0.21 kW for the 27% cycling strategy to 1.34 kW for the 100% cycling strategy. For large users (i.e., those with a seasonal use greater than or equal to 1,600 kWh), the demand savings ranged from a low of 0.48 kW for the 27% cycling strategy to 2.61 kW for the 100% cycling strategy.
- For DLC of water heaters, analysis was focused on the 100% cycling strategy, with an average estimated load reduction for summer weekday periods at hour ending 4 p.m. of 0.24 kW and for winter weekdays at hour ending 7 a.m. of 0.64 kW.

The Minnesota Department of Commerce, Division of Energy Resources conducted a 2013 Demand Response and Snapback Impact Study. The study was focused on the "snapback" impact of demand response, which can be defined as the increase in energy and demand in the hours immediately following a DR event, as well as research on estimated impacts of various DR programs.

The study utilized three methods of investigation: research on previous studies related to demand response, gathering and analyzing aggregate system load and DR data from two large Minnesota utilities during demand control days, and using energy modeling to analyze various DR controls as applied to typical residential and small commercial buildings. The analysis in this study focused entirely on facilities and utilities located in Minnesota and used weather data from three Minnesota climates.

The technologies used for demand response that exhibit snapback were found to be air conditioner cycling, water heater curtailment, and electric heating cycling. Other often-used technologies do not have snapback effects due to the nature of their operations. These include ice storage, electric heating thermal storage, and on-site generation.

The results of this analysis produced deemed energy and demand savings values for demand response and snapback for entire utilities, residential air conditioner cycling, water heater curtailment (in both winter and summer peaks), electric heat cycling, and electric heating thermal storage, as well as commercial packaged rooftop unit ice storage. These deemed savings values were intended to be used as estimates for utilities to determine the energy and demand impacts of DR technologies.

The results of this study show that, although most DR events produce significant snapback, there is still a net energy savings. **Table 12.2** has been extracted from the study report and summarizes the residential energy modeling results for a typical Minnesota home.

Table 12.2: Summary of Estimated Savings and Snapback – Residential[29]

Measure Description	Net kWh Savings	kW Savings	Snapback kWh	Snapback Peak kW
AC Cycling	0.71	0.30	0.72	0.34
Elec. Heat Cycling	3.11	1.42	5.49	1.97
Water Heater – Summer	0.40	0.60	2.71	2.71
Water Heater – Winter	0.09	0.84	2.03	2.03
Electric Thermal Storage	0.0	25.8	0.0	0.0

[29] "Minnesota Department of Commerce Final Report – Demand Response and Snapback Impact Study." August 2013.

4.2.3 Smart Appliances

The use of major appliances with enabling technologies provides an opportunity to further reduce peak demands. As noted previously, consumers have shown a willingness to modify the usage of appliances; however, this response generally has required active participation. Under an automated DR scenario involving smart appliances, it is anticipated that the response could be enhanced. For example, the Northwest GridWise Test Demonstration Projects used automated control of selected equipment (e.g., heating equipment, water heaters, clothes dryers) to respond either to pricing or other signals (e.g., electric power system frequency). The results generally showed the effectiveness of the approach for automated load shedding/shifting and acceptance by the participants.[30] A study by the Pacific Northwest National Laboratory estimated the benefits of smart appliances, including their potential as a "spinning reserve" resource in addition to load shifting and related energy savings impacts.[31] General Electric (GE) tested a number of "demand responsive enabled appliances" and a home energy management system in advance of the roll-out of its smart appliance product line. In a test on smart DR-enabled refrigerators in four homes, GE reported demand reductions of 27%.[32] The impact of smart appliances on home energy use and overall demand profiles depends on the load shedding/load reducing strategies elected. For example, run times/duty cycles can be modified, temperature settings can be adjusted, and water usage can be modified—all of which can have different effects. However, due to the relatively recent roll-out of smart appliances, there has been little experience on the actual DR impacts of these appliances.

5. OVERVIEW OF SELECT CO-OP DR PROGRAMS

The following discussion summarizes the nature and nuances associated with the DR programs deployed by those co-ops interviewed for this study. The discussion is organized into the following main categories, on a "by co-op" basis:

- *Program Structure and Application Protocols* – High-level program information and intelligence regarding the manner in which customers were recruited. Program longevity; customer presentment and program development approach; and parameters that constitute a DR event.
- *Enabling Technologies and Devices* – Types of enabling technologies used to enhance customer and load response to DR events.
- *Implementation and Operating Issues* – Feedback from our interviews regarding logistics and operating issues, as applicable.
- *Data Compilation and Reporting* – Preliminary synopsis of the data compilation and reporting that has been undertaken by a given co-op. Further follow-up and interaction with co-ops currently is underway that will shed further light on the nature and extent of the data made available through the Study Data and Asset Tracking System (SDATS) that directly maps to a given co-op's programs. Refer to Section 7 of this report for a detailed review of available data by co-op.

[30] D.J. Hammerstrom. "Pacific Northwest GridWise Demonstration Projects. Part I. Olympic Peninsula Project." October 2007. PNNL-17167.

[31] Sastry, C., V. Srivastava, R. Pratt, and S. Li. "Use of Residential Smart Appliances for Load Shifting and Spinning Reserves, Cost/Benefit Analysis." December 2010.

[32] The pilot program was operated in cooperation with Louisville Gas & Electric (LG&E) and involved 42 DR-enabled appliances in 15 GE employee homes (see Najewicz, D., "Demand Response Enabled Appliances/Home Energy Management Systems." Presentation to NREL, Golden, CO, October 1, 2009.)

- *Choice of Performance/Impact Metrics* – Nature and extent of program performance tracking, metrics collected on abated demand and associated savings, or any other approach to gathering feedback on program performance, up to and including the solicitation of feedback from program participants.

It is important to note that we have not independently verified the information or accounts associated with each description below, the content for which was derived exclusively from our interviews with key co-op representatives. Furthermore, in some cases, it is evident that SGDP funding was used to enhance capabilities or bolster investment in programs that may already have been in place for a given organization. In such instances, we have taken care to focus as much as possible on the exact programs within the SGDP umbrella to minimize overlap. However, given the opportunity to interface with participating co-ops, we have gathered some ancillary intelligence on DR programs that has been infused into this section with due consideration of both the confidential nature of certain information and the need to focus primarily on SGDP-related investments/outcomes.

5.1 Clarke Electric Cooperative

Program Structure and Application Protocols

Clarke Electric Cooperative (Clarke) in Iowa has roughly 5,000 customers and an approximate system peak demand of 20 MW (alternating between summer and winter peaking). Annual energy sales are 90,000 kWh. Clarke is served by the Central Iowa Power Cooperative (CIPCO), a 12-member G&T.

Clarke's program consists of a direct load control pilot with 80 participants. During the summer months of June, July, and August, Clarke controls water heaters and central air units between the hours of 4−7 p.m. on weekdays *every other time* the outside temperature exceeds 92˚F. Water heaters are cycled every 30 minutes, and central air units are cycled every 15 minutes. The rationale for program choice was predicated on the fact that AC and water heating end-uses are more prevalent and thus the largest sources of electricity usage during peak periods. The CIPCO summer peak typically occurs between 4–6 p.m., and is the primary demand billing determinant for Clarke. The winter period (see below) was chosen for simplicity/consistency with the control period for the summer, although Clarke recognized that the peak demand savings would be negligible or nonexistent during that period.

During the winter months of December, January, and February, Clarke controls water heaters between the hours of 4−7 p.m. on weekdays *every other time* the outside temperature is below 15˚F. Water heaters are cycled every 30 minutes. There are no limits to the number of events that can be called.

Clarke sent out a detailed letter soliciting participation from members. Clarke targeted 90 participants initially but retained 80 for the pilot program. Member-consumers received communications, including email, regular mail, post cards, and recruitment of walk-ins. The Clarke newsletter also mentioned the program. CIPCO assisted Clarke with the development of a random sample of potential participants to target. The pool of potential participants was strategically catalogued to focus on potential participants that currently had an electric water heater and who were most likely to have higher AC usage in the summer period. Customer presentment focused on the potential to help the co-op save money and incentives for participation, as well as a detailed letter that included contact information for Clarke representatives and a full description of the main enabling technology (further described below).

The participants were provided with incentives. Clarke committed to reward the members for allowing Clarke to control their AC units and water heaters for the summer months by crediting the account being controlled. The amount credited was set at $40, credited to the account in June of each of the two years. Clarke also planned to reward the members for allowing Clarke to control their water heaters for the winter months by crediting the account being controlled. The amount was set at $20, credited to the account in December of each of the two years. Incentives were derived based on benchmarking of nearby utility practices, most notably Alliant. Clarke reported that it provided enhanced incentives to obtain sufficient pilot participation quickly, given the compressed overall deployment schedule.

Enabling Technologies and Devices

Clarke deployed a power line communication (PLC) over an AMI system. The DLC system was the last component of the system added. A given event is programmed and kicked off before the Clarke office closes. Clarke also installed the technology on some devices within the Clarke office for testing purposes.

Clarke's main enabling technology from the customer perspective was a Load Control Receiver (LCR). When Clarke was not controlling load, participants would see only a green light lit up on their LCRs. When the above-cited outside temperature conditions were met, and Clarke was engaging in DLC, customers saw a red indicator light lit up on their LCRs.

Implementation and Operating Issues

Installation of the equipment began immediately after Clarke obtained participants. The Clarke operations department led the installation of the load control devices. Clarke made an effort to use one device to control both AC and water heater load whenever possible. The Clarke team created procedures and processes to run the Yukon system for testing individual and groups of LCRs, in addition to remote testing. Cooper Industries was retained to provide training, programming, and support of the Yukon system, working the load control devices in the field.

Clarke did not report any significant operating issues. There were some early issues related to the AMI system that were solved. The system is reportedly working very smoothly.

Data Compilation and Reporting

Clarke provided all necessary account information, such as the following:

- Current and past usage data
- Current and past temperature data
- Control dates
- Control times
- Interval data from the meters in the group

The Clarke Operations Assistant compiles the data and submits the information as scheduled.

Choice of Performance/Impact Metrics

Clarke has not yet completed detailed analysis of performance or developed specific impact metrics. Clarke's expectation is that, given its relatively small size and the small scale of the pilot, it is not reasonable to go to great lengths to determine such program parameters or develop an economic evaluation framework. As noted above, incentives were designed at a level that would ensure sufficient participation, given the compressed overall pilot schedule. Clarke anticipates that analyses conducted by others (e.g., Leidos, NRECA/CRN) will provide good information on its program.

With respect to feedback on program performance, Clarke provided detailed contact information for Clarke staff to all participants, including a direct cell phone number for participants to call in case they had significant issues. Clarke reports that there were several minor complaints that were entirely related to customer equipment failure, as opposed to the nature and extent of the DR program itself. Clarke reports that there has been virtually no attrition.

Clarke does not have any significant plans to adopt additional DR programs at this time. Any additional DR program implementation would need to be reviewed and endorsed by CIPCO prior to deployment.

5.2 Flint

Program Structure and Application Protocols

Flint has approximately 83,000 total customers. The Flint DR program consists of demand reduction via an IHD, which was deployed to 150 customers. There were also 150 customers that did not have an IHD but were informed of events via email and text message. The reasoning behind this dichotomy was to test for differences in efficacy of the program directly attributable to the presence of an IHD. There are also 150 customers that served as a control group. All participants in the IHD-based program were solicited on an opt-in basis.

Flint already has an existing DLC program, with nearly 20,000 DLC devices installed on various end-uses, such as ACs, water heaters, and irrigation systems. All of Flint's customers are on an AMI system. To select participants for the IHD program, accounts/meters were stratified into different groups to ensure a statistically representative sample of participants.

Flint's program was active through 2013, but the current status of the program is being evaluated. From June 1−September 30, based on Flint's review of its load forecast over the period 3–7 p.m., events would be called, with no limit on the number of events. Flint reports that, given the mild winter weather experienced recently, there has been a need for only two prescribed events over the past year—specifically, a 3-hour event and a 4-hour event, when both IHD and DLC program participants were activated.

Customers were recruited for the program via a contest that provided free appliances as a giveaway. Flint received 1,200 responses to the contest, and a winning customer was selected. Customers were presented with the event signals through IHDs or regular communication channels, as noted above. In addition, a dinner was held to discuss the benefits of the program and answer any questions that participants may have had about the program. This was done in parallel with hand delivery of IHDs to homes. Flint leverages various marketing materials to manage its existing DLC programs, such as direct mail, an initial signup incentive, and a credit on the participant bill. For the IHD program, customers were provided with a credit rate of $0.87/kWh, reduced during a given event. However, the rate was applied to an estimate of the difference between usage during the event and the estimated usage that otherwise would have occurred. This estimate was derived using a "past-look" algorithm that estimates what usage would have been otherwise and then credits the customer for that amount of abated energy.

Enabling Technologies and Devices

Flint deployed 150 IHDs as part of the SGDP study exercise. This was the main enabling technology regarding the customer. The participant was the main catalyst for reducing energy consumption during the events in question.

Implementation and Operating Issues

Flint does not report any operational or implementation issues with the IHDs. The IHD program was implemented predominantly as a study exercise. The core idea was to examine how voluntary, incentive-based programs compared to its existing DLC customer base and determine whether significant behavioral differences existed between an opt-in and an opt-out program structure.

Data Compilation and Reporting

Flint reports that all interval data have been posted within SDATS.

Choice of Performance/Impact Metrics

Flint reports that it is experiencing very little attrition, estimated to be less than or equal to five participants in the IHD program to date. There have been no direct follow-up efforts by Flint to obtain feedback from participants on the program. However, pending executive review, it is Flint's intention to continue with its existing DLC program and strive to sign up additional customers.

5.3 Corn Belt Cooperatives

The Corn Belt Cooperatives in Iowa include Corn Belt Power G&T and its members, Calhoun, Iowa Lakes, Midland/Humboldt, and Prairie Energy.

Program Structure and Application Protocols

The Corn Belt cooperatives are defined as Corn Belt Power Cooperative (Corn Belt), a G&T that comprises the member co-ops of Iowa Lakes Electric Cooperative, Midland Power Cooperative (now merged with the Humboldt Regional Electric Cooperative [REC]), Boone Valley Electric Cooperative, Prairie Energy Cooperative, Franklin Rural Electric Cooperative, Butler County Rural Electric Cooperative, Raccoon Valley Electric Cooperative, Calhoun County Rural Electric Cooperative, and Grundy County Rural Electric Cooperative. Corn Belt also serves the North Iowa Municipal Electric Cooperative Association (NIMECA). The summaries presented herein are based on interviews conducted with representatives from Corn Belt, Calhoun, Prairie Energy, and Midland, as well as follow-up information from Iowa Lakes.

Corn Belt administers a DLC program for water heaters, irrigation pumps, and storage heat. Corn Belt's water heater program is nearly 2 years old and is active all year long. Based on co-op interviews, there are currently 200 load control switches installed at Midland and 700 switches installed at Prairie Energy. The program is ongoing, and the NRECA grant, as a follow-on to a pilot program that was in place in 2008 with Iowa Lakes, provided for installation of additional switches and the deployment of newer and better technology than the neighboring G&Ts that have mature LM programs. Member co-ops cannot ignore the specific demand response signals/events. However, customers can call ahead during the holidays or other times when they do not wish to be controlled. The members can also work with individual customers to deactivate individual switches. The member co-ops report that they do not typically initiate independent control events above and beyond those administered by Corn Belt. There were no IHDs purchased as part of this program.

Water heaters are subjected to either full (100%) or partial (duty-cycle) control (e.g., 80%), as deemed appropriate. Corn Belt is responsible for projecting when control will begin so as to abate peak demand, and control occurs based on that subjective determination. Each month, Corn Belt analyzes the previous month and the same month from a year earlier to decide what the control threshold will be for that month. Typically, after the first control event in a given month, the system automatically steps in and implements control when demand reaches that level for the remainder of the month. However, there are exceptions, constituting manual overrides initiated by Corn Belt in the event of long control duration with expected higher loads later in the month. There are no limits on the number of events that can be called in a given month. However, the strategy taken by Corn Belt has been to cycle units to increase the amount of time that control can take place with minimal disruption or customer inconvenience.

Development of rebate levels was based on neighboring utility practices, some of which have been deploying similar programs for more than 20 years. Corn Belt did not want to engage in "reinvention" of program parameters that have been deployed successfully elsewhere.

Given that the program is opt-in, there is diversity in customer presentment and incentive levels across the member co-ops. Based on the interviews conducted, the following is a high-level summary of customer interaction:

- For Midland, customers are opt-in and either are part of the water heater discount program or, if they have older water heaters, are approached separately (with no discount offered) to participate in the program for purely altruistic reasons
- For Calhoun, marketing was conducted to members to volunteer to sign up; this process resulted in minimal interest
- For Prairie Energy, its marketing program mirrored Midland, and Prairie reports that the program typically is not refused when marketed properly

Customers are provided with a discount on the cost of a more expensive water heater in exchange for signing up for the program and allowing switches to be installed. The member co-ops are tasked with minimizing customer inconvenience.

Enabling Technologies and Devices

The Corn Belt program is predicated on a Yukon communication system. A two-way Express Com system sends a signal from Corn Belt to the member systems, and the individual member co-op Yukon system then sends the downstream signal to member customers. The Cooper/Cannon Demand response system serves as the connection between the G&T Yukon head end to the distribution co-op Yukon head-end system, and then sends a downstream signal to the individual customer switch. The control signal is a power line carrier modulation, sent on the power lines to all loads by equipment installed in the co-ops' substations. The aforementioned switches were installed subsequent to the Iowa Lakes pilot as a direct result of the NRECA grant.

Implementation and Operating Issues

The program's implementation was driven by the need to abate the Corn Belt peak demand as billed by Basin Electric. The demand rate for Corn Belt does not vary seasonally, and the member co-ops are billed based on their coincident peak with Corn Belt. Water heating is the main end-use that can contribute to peak reduction in all 12 months. Corn Belt did not report any specific implementation or operating issues. There were some data compilation/reporting challenges, as noted below.

Data Compilation and Reporting

Corn Belt's existing SCADA system provides full load intelligence. Corn Belt can manually intervene in the automatic system calls on events, as described above. Corn Belt reports that interval and event data are in the SDATS system. That data currently are being subjected to review. Corn Belt will provide its Load Management Operating Manual for review. In addition, Corn Belt will provide a tabular history of estimated DLC impacts on monthly peak for the duration of the program. Based on interviews conducted, there were some reports of data compilation and reporting challenges, as follows:

- Midland reports that there were some communication issues in getting kWh consumption reads in for billing. Midland believes that this problem was related to the operation of the PLC. There were also some challenges related to the merger of Humboldt REC and Midland, both of which had legacy Yukon systems.
- Iowa Lakes had similar challenges relating to data quality/transmission issues. Iowa Lakes will be compiling an abbreviated data set for analysis that reflects a sample of load over a 2-year period.
- Calhoun has had some difficulty with its meter communications and is in the process of making improvements to line data repeaters. Calhoun also will be providing a condensed data set for analysis.

Based on the interviews conducted, follow-up is being undertaken to ensure that event data are provided in concert with the interval data in SDATS.

Choice of Performance/Impact Metrics

Corn Belt reports that there has been no formal tracking of metrics or cost-benefit analysis conducted. Corn Belt receives a monthly report from the distribution co-ops on the number of switches installed, and estimates monthly impacts based on the control percentage, an assumed diversity percentage, and an assumed average kW rating. Because switches can only store data for approximately 36 hours, a more manual and continuous process would be necessary to fully extract actual event data from the switches.

Corn Belt does note that, based on customer pushback, the 100% control for the water heater program motivated it to adjust the cycle to 80% during control periods. Calhoun notes that there are challenges related to program participation when homes are sold to new owners.

There has been no formal communication plan to solicit feedback on the program or any customer surveys conducted. Corn Belt reports virtually no attrition. However, based on the interviews conducted, the following is an overview of performance-related feedback from the customer perspective:

- In Midland, a few people have called to express concerns (two calls out of all switches installed); one was related to the water heater itself and was unrelated to load control performance, and the other was related to a control event; Midland anticipates conducting a survey at some point soon, but there is no strict survey timeline.
- Prairie Energy has 700 switches installed, and only a handful of people complained about running out of hot water—some 50-gallon water heaters were moved to a lower-duration cycle to conserve hot water.
- For Calhoun, there were some concerns with the program but they have been very limited. Since the switches were deployed recently, in the spring 2014, the program is still in its early stages. To the extent that the program is extended to irrigation and storage heat, it will be done outside of the current NRECA grant.

In the medium term, Corn Belt is prepared to focus on AC and storage heater control. However, the individual member co-ops have not taken on these additions at this time. Iowa Lakes already has IHDs in place, and other co-ops are considering similar additions. The IHDs display a colored signal (green to yellow to red) to signify closeness to a potential peak, which in theory entices participants to avoid/delay hot water end-use. Currently, there is no peak pricing program. However, a handful of C&I customers do receive a price signal and are on a coincident peak rate. It remains to be seen whether such a program would be more widely marketed/introduced in the future.

5.4 Minnesota Valley Electric Cooperative

Program Structure and Application Protocols

Minnesota Valley Electric Cooperative (MVEC) has 43,000 customer meters, comprising 36,000 members spanning very rural to suburban areas. MVEC recently replaced 11,000 one-way LM devices with two-way receivers. This investment was helpful in alleviating the non-functional receivers, which MVEC estimates represented between 15% and 25% of the older receivers. MVEC notes that reliance on hourly data was an unreliable approach for determining which receivers were not functioning (as the interval was too long). With the new equipment, MVEC can obtain feedback from the load control receivers, making it relatively easy to detect failures.

MVEC also worked with Great River Energy and Basin Electric on a DR management system comprising new head-end software. The intent of the investment was to help abate peak demand in the summer, much like a standalone commercial customer.

The investments made were all a function of buttressing the existing MVEC DR program. This program is a DLC structure for AC, water heater control, and battery peak shaving. Water heating control occurs at night for peak shaving. AC cycling occurs in the summertime for the same reason, generally over the hours of 1–5 p.m. Heating control occurs in the winter, with batteries discharged to abate peak on an as-needed basis (typically several times a day). The program is permanent and has been in place for 20 years. There are currently 8,500 participants, with 8,000 of those having AC control, and the remainder having water heater and space heating control. The program is administered on an opt-in basis. There are certain limits to the number of events that can be called, as reported by MVEC.

Participants are provided with a discounted rate on the sub-metered portion of their bills (e.g., AC/heat pump). Customers are charged their basic rate for general service. Additionally, metered AC customers receive a 10% discount on their overall monthly energy bill. Regarding customer presentment and recruitment, MVEC did not engage in any additional recruitment or communication of program benefits to existing participants, given that the program has been in place for well over 20 years. However, one customer presentment technique that has been in place for quite some time relates to an energy savings line item on customer bills that shows "zero savings" for non-participants. MVEC also mails out a yearly energy report to bolster participation.

Enabling Technologies and Devices

The main enabling technology invested in is the aforementioned two-way receivers. The MVEC demand response program is operated via a power line communications system (which differs from a power line carrier system). The prior radio frequency system signal was intermittent and would not work consistently. In addition, MVEC also invested in support software, as described above.

Implementation and Operating Issues

MVEC does not report any significant operational or implementation issues. The program was implemented 20 years ago to provide rate relief and avoid costly demand charges. MVEC's bill is in part derived from its transmission peak with Great River Energy. The Basin Energy peak typically occurs between 1 p.m. and 9 p.m., and is also a billing determinant.

Data Compilation and Reporting

MVEC data as compiled in SDATS are currently being subjected to review (as available). MVEC reports that data initially uploaded to SDATS were less than optimal, as certain system challenges were being addressed. MVEC will be creating a smaller, concise data set for analysis. The data will provide identification of program types and include data for non-participants.

Choice of Performance/Impact Metrics

As a result of these new investments, MVEC estimates that there has been a 1-MW increase in water heater control capacity, and a 10–15% improvement on AC control devices. However, MVEC does note that 500 participants quit the program when the initial change out of load control receivers was attempted. In addition, between 50 and 100 customers per year are estimated to be irritated by AC cycling (out of all participants).

MVEC currently has plans for increasing its saturation rate, which stands at 46% across all current DR programs. MVEC is introducing three new programs—specifically, (1) a Wi-Fi-enabled EnergyHub device to set back thermostats for up to 4° for 3 hours, up to 7 days per month; a (2) a behavioral "beat the energy peak challenge" over the period 5–9 p.m., with cash prizes awarded to the winning participant; and (3) a pre-pay option of $5 if the customer reduces consumption during the peak, which MVEC reports was received favorably by half of all existing participants.

MVEC reports that it conducts periodic studies of its existing DR portfolio, which helps drive the rates associated with the program. The most recent study conducted was in 2011, which guarantees program rates through the year 2014. A new study of the program to lock in rates for the next cycle may be done at a later point.

5.5 Delaware County Electric Cooperative

Program Structure and Application Protocols

Delaware County Electric Cooperative (DCEC) in New York State has 5,300 meters and 840 miles of distribution lines. DCEC has a large number of seasonal accounts representing vacationers from urban areas of New York, which account for approximately 40% of its membership.

DCEC made a significant investment to buttress its existing DR program, which has been in place for 20 years. The program is predominantly focused on water heater control, and DCEC reports that AC load is not significant enough to warrant deployment of a DR program. DCEC monitors load from its main purchase points in 5-minute periods and projects system demand. Dispatch of demand response is controlled via a matrix. Load response/reduction is assessed and dispatched based on how much load control is deemed necessary (utilizing the existing Survalent SCADA system). The new technology for DLC uses a very low ultra-narrow band form of power line carrier, and block timing as a dispatch solution. DCEC merged or integrated the old and new systems to maintain the old matrix functionality resident in the SCADA programming. DCEC also installed new IHD devices (described further below).

Currently, there are 600 participants on a water heater DLC program. Additionally, there are 50 participants who have an IHD but not directly controlled water heaters. DCEC reports that it has very little AC load or other controllable load. There are also 100 participants with no DLC or an IHD (this serves as a control group). The DR program is active year round and is intended to improve system load factor. The program is administered on an opt-in basis. The program is active at any time of the day. Time-supervised demand shedding thresholds are set by the Assistant Manager (operator), based on his experience with the operation of DLC with respect to historical system demand levels. Typically, shedding is enabled during the historical morning and evening peak hours. The operator may also place the DLC system in the shedding mode, if needed. Typically, the shedding function is limited to twice per day; however, depending on system conditions, no shedding may take place on a daily basis. Durations are generally limited to approximately 4 hours in length, depending on the level of shedding needed to meet threshold limits.

Customers are provided with an incentive of $4 per month all year round for participating in the DLC program. There is no additional incentive associated with the IHD. Customers were recruited for the program via direct mail and newsletter advertisements, in addition to mention of the program at the DCEC annual meeting.

Enabling Technologies and Devices

In addition to the installation of the new DLC service, DCEC also installed IHDs as enabling devices. The IHDs use a ZigBee wireless connection that shows kWh consumption. The customer has the ability to select different display parameters in the IHD related to energy consumption, including color coding of the display background.

DCEC engaged in testing the DR system (10 separate tests were run) during the summer of 2013, and 10 additional tests in the winter of 2013−2014.

Implementation and Operating Issues

DCEC implemented the program to help control the cost of its New York Power Authority (NYPA) demand charge for hydro capacity and energy through load factor improvements. Furthermore, NYPA goes into the market to purchase energy for DCEC’s load in excess of its hydro allocation. This excess or incremental energy is more costly than the hydro-based energy, and the need for incremental energy is greatest during the winter period. Managing its load factor reduces incremental energy purchases while simultaneously increasing hydro-based energy purchases from NYPA to the greatest extent possible.

DCEC reports that the time it takes to transmit all load shed commands on the new power line carrier system, due to its very low transmission data rate, is 45 minutes. The TS 2 system was designed primarily for an AMI application, with very limited capabilities for real-time applications.

Data Compilation and Reporting

DCEC has been reporting hourly load data to NRECA’s Study Data and Asset Tracking System (SDATS) based on (1) 100 customers with DLC; (2) 50 customers with an IHD (no overlap with DLC); and (3) 100 participants with no DLC or IHD, serving as the control group for approximately 1 year. The DCEC SCADA system contains event data related to the percentage of load shed in a spreadsheet format. These data are not in SDATs and will be critical to analysis of the DCEC data. Other DCEC data currently are under review. DCEC reports that it used one feeder (representing approximately 384 customers) and dumped 6 months of hourly data into the SDATS system prior to the inception of the DLC and the IHD installations as a trial operation of the newly installed AMI system.

Choice of Performance/Impact Metrics

DCEC reports that it has saved approximately $50,000–$60,000 over a 10-month period as a result of the investment. To track program performance, a formal questionnaire was sent out to IHD customers. DCEC received 34 survey responses. Feedback on ease and usefulness of the IHD was generally favorable.

While there has been no formal follow-up to obtain feedback on the new investments within the program, DCEC reports that there has been some very limited attrition as a result of certain customers needing to ensure proper water temperature for downstream end-uses. Some dairy farms reportedly dropped out of the program due to water temperature problems in their production process. It should be noted that there are not a significant number of farm accounts, and this distinction is not captured in the data reported to SDATS (as this is not anticipated to have a significant impact from an analytical perspective).

DCEC does not conduct any formal cost-benefit analysis on the program or tracking of benefit-cost ratios. Deployment of the program was based on the perception that water heating as an end-use would result in the biggest DR capability. DCEC does estimate its demand savings and load factor improvements on a monthly basis.

6. REVIEW OF AVAILABLE PROGRAM DATA

6.1 Study Data and Asset Tracking System (SDATS)

SDATS is a web-based central data repository system developed to collect both asset and study data and reports in a timely fashion, enabling efficient DOE reporting and program analysis.

Project data collected in SDATS consist of the procurement, receipt, installation, and experiential information ("Asset Data") for all assets with a value greater than $5,000 procured through the NRECA SGDP. It also includes the build, impact, and baseline data ("Study Data") that are used for cost-benefit analyses by the NRECA study team and DOE. Study data are broken down further into "low-frequency" and "high-frequency" data. Low-frequency data are entered through a web interface called the SDATS. High-frequency data, such as meter interval and SCADA data, are uploaded by co-ops to a secure file upload site.

6.2 SDATS Data

We have carefully reviewed the following required groups of data within SDATS to be used for the proposed statistical and econometric analyses.

- Customer Systems Build Metric Data
- AMI and Customer Systems Impact Metric Data
- Meter Location Data
- Meter Interval Data
- DR Event Data

6.2.1 Customer Systems Build Metric Data

These metrics represent the number of installations of various customer system devices, such as in-home displays, web portals, DLC devices, smart appliances, programmable controllable thermostats, home area networks, and energy management devices, both at project and system levels. We extracted these data from a recent build metric report (Q2-2013) from SDATS. Data have been thoroughly reviewed and found to be in good condition, with no major data anomalies.

6.2.2 AMI and Customer Systems Impact Metric Data

These metrics reflect system impacts and benefits due to the installation of AMI and customer systems. A number of these metrics and associated data are relevant to the proposed statistical and econometric analyses, such as co-op coincident/system peaks. Some of the required data have been collected from recent semiannual reports (H1-2013) from each co-op and reviewed for data completeness. However, some co-ops missed reporting certain fields of required information in their reports. Supplemental data was requested by the co-ops for analytical purposes and is detailed further below.

6.2.3 Meter Location Data

These data contain various attributes of individual meters (meter locations), such as meter identification number; customer identification number; installation date; in-service date; feeder identification number; customer class; data acquiring frequency; data polling frequency; flags to indicate different features of meters, such as power quality monitoring, tamper detection, remote disconnect, etc.; and flags to indicate the participation in specific DR programs, such as IHDs, DLC for water heaters, DLC for ACs, web portal access, programmable controllable thermostats. Available meter location data for each co-op were collected and reviewed. There are some data anomalies, explained in detail in the next sub-section.

6.2.4 Meter Interval Data

These data contain different intervals of meter reading (kWh) data with date and time stamp. An exhaustive review of data available from SDATS revealed several data anomalies, explained in detail in the next sub-section. **Table 12.3** lists high-level stats of meter interval data extraction from SDATS for those co-ops reporting.

Table 12.3: Statistics of Meter Location and Interval Data Extraction from SDATS

	Meter Location Data	Meter Interval Data		
	Number of Meters	Number of Records	Interval	Duration
Calhoun Co. ECA, IA	1,844	Approx. 5000	Monthly	May-12 to Jun-12
Clarke EC, Inc., IA	12,394	Approx. 2.5 Million	5 min, 15 min, and Hourly	Mar-12 to Dec-12
Delaware County EC, NY	617	Approx. 2.7 Million	Hourly	Jan-12 to Mar-13
Delta Montrose EA, CO	No Data	No Data	No Data	No Data
Flint EMC, GA	59,690	Approx. 8.7 Million	Daily	Aug-11 to Mar-12
Humboldt REC (Midland), IA	2,037	Approx. 8.0 Million	Hourly	Jan-12 to Sep-12
Iowa Lakes EC, IA	9,655	Approx. 133 Thousand	Daily	Jan-12 to Jun-12
Owen EC, Inc., KY	No Data	No Data	No Data	No Data
Prairie Energy Co-op, IA	4,993	Approx. 17.7 Million	Hourly	Jan-12 to Sep-12
MVEC, MN	42,541	Approx. 24.1 Million	Hourly	Mar-12 to Aug-12

6.2.5 DR Event Data

These data contain DR event information, such as start of the event date/time stamp, end of the event date/time stamp, anticipated kW demand reduction, and actual kW demand reduction. Most co-ops have not reported these data in SDATS, and we are working directly with them and in some cases, their G&T, to request the data.

6.3 Data Quality Issues

As shown in **Table 12.3**, the extent and amount of data received across the co-ops varies and, importantly, the apparent quality or reasonableness of the data also varies.

6.3.1 Meter Location Data

The meter location data generally were understandable and useful. However, there were limited instances of apparent confusion regarding the fields that were intended to capture participation in DR programs. In a couple of instances, data were incorrectly entered and either reflected no participation in programs or the use of additional equipment (e.g., IHDs, PCT) not actually installed.

6.3.2 Customer Load Data

The following are the primary data quality issues impacting usefulness of the load data:

- A few co-ops uploaded data of only a daily or monthly frequency, which is not very useful for analysis of impacts on load profiles or energy consumption due to DR events.
- One co-op uploaded data that appear to represent daily cumulative meter readings rather than interval reads. While it seems likely that these values could simply be subtracted to yield the daily interval kWh, it was never resolved what the data actually represented, and there were a considerable number of missing data points. However, as discussed below, the co-op in question agreed to work on providing a new data set.
- Due to the limitations of the AMI system, some hourly load data were in whole numbers, which yield insufficient variation across many hours for the typical residential and small commercial customers, the loads of which are frequently less than 1 kW.
- For most of the co-ops that did provide hourly customer profile data, the data include numerous instances of potentially erroneous zero load intervals and anomalous spikes, as well as missing values.

It appears that many co-ops experienced data transmission issues over PLC communication systems, particularly early in the deployment of AMI equipment, which tends to cause missing and anomalous readings to be captured in the downstream systems. Issues such as line noise are also likely culprits in these cases. One of the co-ops reported that bandwidth was insufficient to transmit the load profile data, and that it was difficult at times simply to capture the consumption readings used for billing purposes. One of the co-ops reported that its communication issues were improved by the installation of additional repeaters along the distribution lines, although for many co-ops, it appears that data transmission from the substations back to the master station was also a problem.

In our experience, these sorts of communication issues are common to PLC systems and require the ongoing attention of an experienced operator of the equipment to monitor data feeds, ensure complete coverage on an ongoing basis, and engage in frequent re-uploading of anomalous data points. It is likely that co-op staff was stretched to afford this kind of attention and would require ongoing feedback on data review to engage in a secondary uploading process.

It also was noted that some co-ops, in consultation with NRECA, suspended uploading data to SDATS because of these data issues.

6.3.3 Conclusions

Calls were made to each co-op for which data quality issues or missing data were evident. Participating co-ops compiled additional data deemed useful in the study of the success of their DR programs. We received additional event data across the co-ops, as well as samples of customer load profile data from which to ascertain the tractability of formats and engage in a larger-scale compilation of customer load profile data. For at least one of the co-ops, the load profile collection capability of meters was disabled at some point, so no profile data can be captured from historical periods up to this point. The remaining sections of this report summarize the objectives, approach, and results of our detailed econometric analysis of all available co-op data.

Appendix 12A contains a detailed description of our proposed DR Planning Model, including an overview of types of programs covered, inputs, and outputs. This model and associated analysis process represent a simple yet complete method for estimating the value of deploying various DR program types at cooperative utilities. Only a portion of the data needed to fully populate the model was available from co-op DR deployments. Therefore, our goal is to leverage the data available to the greatest extent possible and subsequently identify additional data needed to fully build out a complete DR Planning Model that supports analyses of all relevant DR types and is empirically driven.

7. STATISTICAL AND ECONOMETRIC ANALYSES OF COOPERATIVE DR PROGRAM DATA – TESTING THE THEORETICAL BASIS FOR DEMAND RESPONSE

7.1 Testing the Theoretical Basis for Demand Response—Overview of Analysis Objectives

The theoretical basis for DR programs is a function of several commonly accepted assumptions. (1) It is assumed that a utility can engage in load control events over a period of time that aligns with its system or wholesale billing peak, thereby saving the utility and its customers money on costly wholesale peaking purchases. (2) The impact of a given load control event in kW reductions represents a significant reduction, typically based on general rules of thumb regarding appliance peak load and diversity, and the extent of control cycling. (3) A DR program can be administered in a cost-effective manner, in that the cost of abatement (infrastructure capital cost, participant incentives, and ongoing administrative costs) is less than the cost of otherwise having to meet that demand with traditional generating resources. The effectiveness of the program also rests on the premise that any "rebound" in load in periods succeeding or preceding the load control event do not cancel out savings gained during the period of control, and that targeting larger customers leads to larger returns (i.e., the best "bang for the buck" for demand response is generally achieved by targeting large customers).

This study utilized econometric analysis (described further in Section 7.2) to test a subset of these premises. By gathering empirical data in the form of hourly loads from participating co-ops and conducting analytical tests, the theories above are allowed to "confront" the data, so that it can be determined whether they are supported either fully or partially in real-world deployments. Although certain of the above premises may be obvious in a theoretical context, they are anything but obvious in practice. Obtaining objective estimates of abatement and evaluating theories provides significant value in terms of future investment decisions related to demand response. Such decisions can be made based on empirical evidence instead of theoretical assumptions that may or may not be supported by the data.

Table 12.4 provides a summary of the key research questions underpinning the theoretical basis for demand response, giving a high-level overview of which analysis objectives were covered in the study and the approach to achieving each research objective.

Table 12.4: Summary of Research Objectives

Research Question	Within Scope of Analysis?	Analytical Approach
Are load control events called during appropriate peak period times?	Yes	Compare duration of load control event data to peak timing data (where available).
Are load control kW reductions statistically significant?	Yes	Perform econometric analysis on hourly meter data from participating co-ops, controlling for hourly and weather variation.
Are there any significant load rebound effects either before or after the period of load control?	Yes	Examine leading or trailing edge hours in the econometric analysis for statistically significant and positive parameters.
Are full cycling and/or a focus on larger customers warranted as a function of larger abatement gains?	Yes	Conduct econometric analysis on isolated meters that are larger than average; conduct tests of variables that measure the percentage of load cycled (where data are available).
Are demand response programs cost-effective?	No	Refer to Section 10 below and Appendix 12A for a full description of a proposed DR screening tool that would address this question.

7.2 Analytical Approach and Data Sources

As mentioned above, econometric models were developed to estimate the parameters of interest. The primary functional form of the theoretical equation for these types of analyses is typically as follows:

$$\ln Yi,t = \alpha + \beta 1 \ln X1i,t + \beta 2 \ln X2i,t + \ldots + Bn \ln Xni,t + \epsilon i.t$$

Where,

Yi,t – The load characteristic of interest for customer i and day t

Xni,t – Explanatory variables for customer i and day t (discussed below)

α , βn – Parameters to be estimated via regression

Єi,t – The amount of error in the equation's estimate of Yt

As the data analyzed generally comprised customer loads and characteristics by customer and by day, they conform to what commonly are referred to as "panel data." Fixed effects panel estimation was the primary form of analysis conducted on each co-op's data set.

The econometric analyses attempted to explain variations in customer loads during DR events relative to loads for other hours/days, and as a function of a series of explanatory, or independent variables.

The dependent variable, or variable explained in these analyses, was the customer load during the DR event. This approach leveraged as many attributes of the programs and technologies as possible.

Explanatory variables typically include those regarding the relevant electric rates (for dynamic pricing programs), customer attributes, event conditions, and weather conditions. The set of available explanatory variables initially contemplated was the following:

- Ratio of on- to off-peak electric rates (for dynamic pricing programs)
- Installation of "enabling technologies," or devices to assist the customer in awareness of DR events or reacting to events (e.g., IHD, programmable communicating thermostat, text alerts, etc.)
- Installation of AC and/or electric heat
- Installation of other appliances (e.g., electric water heating)
- Daily weather conditions (maximum temperature, temperature-humidity index, and/or preceding day maximum temperature)
- Seasonal variables (e.g., month of year)
- Day-type variables (e.g., day of week)

In practice, the set of possible explanatory variables initially contemplated as control variables was larger than what actually was available from the co-op data. As these were all direct control programs, there were no pricing-related parameters, and as no data were available regarding customer characteristics outside of program participation, the equations tended to be relatively sparse as to explanatory variables. The primary parameter of interest was a simple binary variable defining the control event, typically controlling for participation in the applicable program by combining the control event and participation binaries into a single binary variable. These equations sometimes were supplemented by equations specific to participant groups and even individual meters, for testing purposes.

Leidos compiled meter and event data from the subset of co-ops. Data were available for highly disparate periods and stretches of time across the co-ops. Generally, we were able to capture sufficient overlap between the meter data and the event data to test for event impacts, but there were significant periods of meter and/or event data for which overlap between the two was not available.

We supplemented these data with weather data from a nearby weather station, both to control for weather variation—where the appliance subject to control was not significantly weather sensitive (e.g., water heating), and to capture the impact of weather variation on the controlled load—where the appliance was highly weather sensitive (e.g., air conditioning). Data collected included daily high and low temperature, humidity, and precipitation. High and low temperature data were used to derive daily heating and cooling degree days,[33] which was the primary weather variable utilized in the analysis.

The analysis process was inherently iterative, with varying combinations of explanatory factors being posed, estimated, and reviewed for explanatory power and statistical validity as compared to other combinations. Once the best combination of explanatory variables and their estimated parameters was ascertained, the econometric model for a given co-op was finalized. As necessary and

[33] Heating and cooling degree days are standardized measures of weather deviations in daily average temperature from a base, typically 65°F, summed over any period of interest. Heating degree days represent cool weather, and cooling degree days represent warm weather.

in alignment with the objectives listed in Section 7.1 above, alternative models were created to address differing research objectives, which are summarized in Section 8 below.

8. STATISTICAL AND ECONOMETRIC ANALYSIS RESULTS

The methodology described above was applied to the subset of participating co-ops that we were able to engage and that provided complementary and/or supplemental data relative to data contained in SDATS.

8.1 Summary of Findings

The tables below capture estimated parameters, which represent the average kW savings that can be expected on a per-participant basis during a load management event, for hours during which LM events tended to occur across the co-ops, as well as hours viewed as being in the critical period of likely significant impacts due to higher coincidence of consumption for the end-uses in question. The tables are organized by the type of control program, with **Table 12.5** providing an overview of estimated impacts of water heater control programs and **Table 12.6** providing impacts of AC control programs. To the extent that a given hour was not within the control period of the co-op in that row or was otherwise not captured in the analysis, that cell is grayed out. To the extent that a co-op did not engage in a particular load control program, that entity is not shown in the table. **Table 12.7** shows the combined impacts for AC and water heating programs—for some co-ops, all participants were in both programs, so the impacts of water heater and AC programs could not be determined separately. To the extent that no significant impact associated with load control was estimated for a particular hour or overall, "N/S" is shown in that particular table element.

Table 12.5: DLC Event Estimated kW Impacts—Water Heater Programs

Cooperative	# of Meters	# of Events	Overall	Hour Ending						
				7 a.m.	8 a.m.	9 a.m.	4 p.m.	5 p.m.	6 p.m.	7 p.m.
Clarke	80	7	-0.1					N/S	-0.2	N/S
DCEC	254	27	N/S	0.2[34]	-0.2	-0.1				-0.4
ILEC	317	97	-0.2	N/S	-0.3	N/S			-0.4	-0.6
PEC	530	372	N/S	N/S	0.4	N/S	-0.1	N/S	N/S	0.2

Table 12.6: DLC Event Estimated kW Impacts—AC Programs

Cooperative	# of Meters	# of Events	Overall	Hour Ending					
				3 p.m.	4 p.m.	5 p.m.	6 p.m.	7 p.m.	8 p.m.
Clarke	80	7	-0.2			-0.3	-0.3	-0.1	

Table 12.7: DLC Event Estimated kW Impacts—Combined AC & Water Heater Programs

Cooperative	# of Meters	# of Events	Overall	Hour Ending					
				2 p.m.	3 p.m.	4 p.m.	5 p.m.	6 p.m.	7 p.m.
FEMC	500	2	0.117		-0.2	-0.1	N/S	0.1	0.5
MVEC	190	15	-0.2		-0.3	-0.2	-0.2	-0.3	

34 Parameter is positive and significant. It is reported herein for completeness and likely is due either to higher overall load levels during that period that tend to crowd out the impact of the LM event, a load "rebound" effect (as described above), or to bias due to an omitted variable that cannot be measured.

It is important to note that some of the parameters in **Tables 12.5**, **12.6**, and **12.7** may be positive. These parameters are reported for completeness and generally are driven from (1) higher overall load levels during that period that tend to crowd out the impact of the LM event (control periods and groups notwithstanding); (2) omitted variable bias that may impact the precision of the parameter estimates; or (3) to the extent that the hour falls along the edge of a load control event in an adjacent hour, some amount of load "rebound" due to the adjustment of load, resulting from control/cycling in surrounding hours.

It is also important to note that in most cases, control groups (or meters that were not participants in a given DR program) were available. In addition, every day of meter data for a control group that was not a load control event day was effectively used to estimate a load "baseline," or the amount of kW that could be expected (which would vary based on hourly variables inserted into the model to control for per-hour variation). If the variable or variables that isolated load control events or other thresholds were statistically significant, they were found to be so over and above baseline control variables. As mentioned above, these baseline control variables included hour-of-the-day and weather variables designed to control for weather-induced variation that is separate from variation due to load control.

To aid in the interpretation of the data above and the data upon which they are based, **Figure 12.4** below provides a comparison of hourly loads for control and non-control days averaged across all participating customers for Clarke Electric Cooperative. Average load data shown reflect approximately 60 meters over 7 control days and 21 non-control days with similar climate conditions.[35] As shown below, the control days exhibit lower load levels in the key load control hours to some degree, most notably the hours ending 17, 18, and 19, with some load rebound evident in the hours ending 20 through 24. In addition, higher loads are also evident in the hours preceding the event, presumably illustrating customers being familiar with the control parameters and perhaps pre-cooling the home heading into a control event. For the purposes of this figure, the non-control days are isolated to similar temperature days and participating customers to produce a useful baseline reflecting similar cooling requirements and customers with air conditioning (non-participating customers may not have air conditioning).

[35] As mentioned previously, the summer portion of Clarke's load management pilot reflected control events on every *other* day meeting certain temperature thresholds (on a forecasted basis) during summer months and a requirement for participants to have central air conditioning.

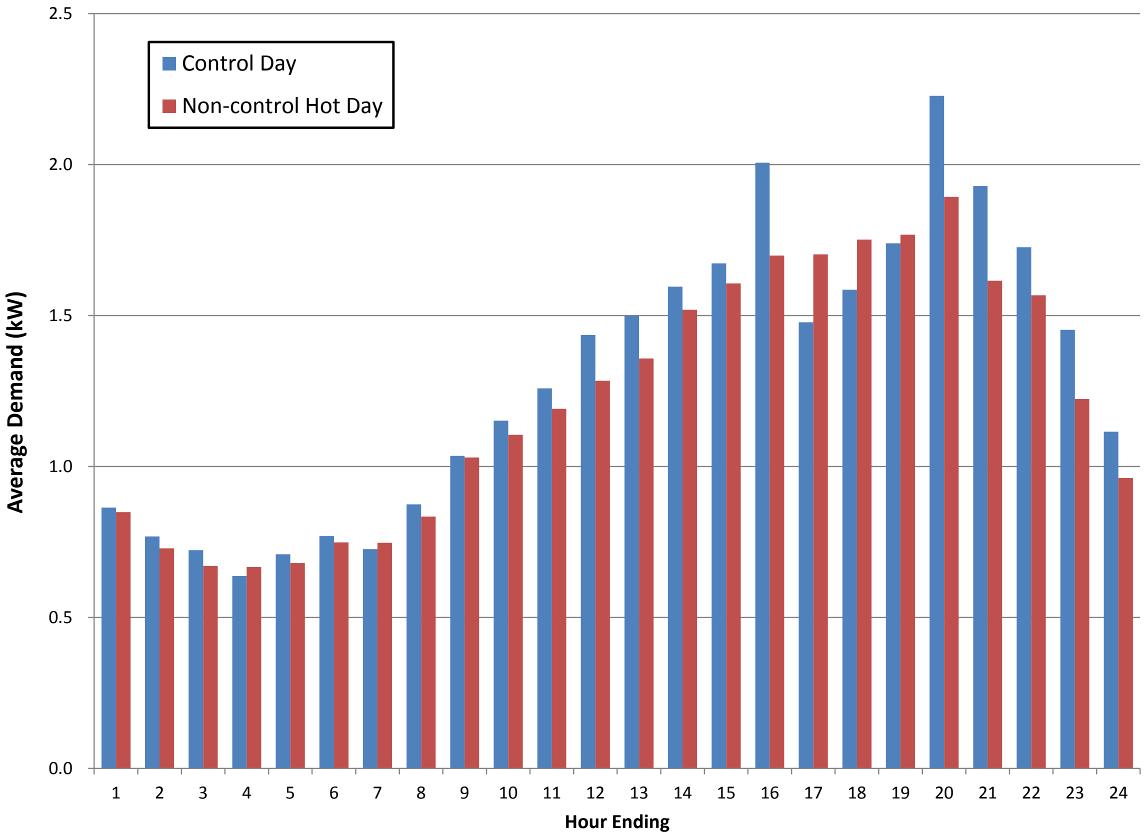


Figure 12.4: Comparison of Control vs. Non-Control Days with Similar Weather Conditions

The subsections below capture cooperative-specific program details and associated findings to provide more information regarding the numerical results and highlight key challenges associated with the analysis of each co-op's data, including thresholds required to generate significant findings (either through isolation of particular groups or compartmentalization of certain tiers of kW readings, as applicable).

8.1.1 Clarke Electric Cooperative

The Clarke data included 80 meters: 43 were participants in the AC control program only, 22 were in the water heater control program only, and 15 were in both programs. Accordingly, there were no non-participating customers. Control events during 2013, the only year for which data were provided, totaled seven events. As the control events were triggered by particular weather events on every other instance of such weather events, there were the same number of non-control days with similar weather conditions, which were included in the analysis as a baseline. There were numerous duplicate meter data observations, which were removed from the data set prior to analysis. Clarke meter data exhibited anomalous spikes in the loads of several meters, which were excluded from certain equation specifications to ensure that these potentially erroneous observations were not impacting the results.

Overall, impacts of load management were statistically significant, particularly for hours the ending 5 p.m. and 6 p.m. LM impacts were more significant upon isolating the data set for customers that were participating in either the water heater or AC program (i.e., using the non-control days as the only baseline rather than non-participating customers). It is possible that the perfect correlation between the coincident water heater and AC control events made it impossible for the statistics software to separate out the impacts of these programs. It is also possible that the effective baseline of non-control days for participating customers was more effective at isolating the control impact than the cross-sectional differences across non-participating customers (both those not participating in the particular program or in either program). In addition, there was evidence of both a statistically significant load rebound subsequent to the control period (as much as three hours after the control period) and higher loads in the hour preceding control periods, presumably due to pre-cooling of the home based on participant experience with the control program on preceding control days. These positive impacts in the hours surrounding the control period are readily visible in Figure 4 above.

8.1.2 Flint

FEMC meter data included more than 500 accounts; approximately 130 were in each of the following groups:

- Standard water heater and AC load control program
- Water heater and AC control program with notification of events via an IHD
- Water heater and AC control program with e-mail and text notification of events
- Baseline group with no load control

In August 2013, there were two load control events, spanning 3–7 p.m.

The hourly data available for Flint was reviewed and generally found to be reasonable. To ensure that empty cells or zero meter reads did not have an undue influence on our analysis, we generated an adjusted hourly meter read data set that excluded missing or “0” fields. This nuance did not appear to have a significant impact on the findings.

The data available for analysis for Flint was limited to the afternoon and evening hours, which makes it more difficult to find sufficient variation across the various groups and presents some econometric challenges when attempting to isolate hours and certain groupings. These challenges notwithstanding, the analysis reflects the following:

- During certain key hours and for certain key ranges of kW reads, most notably the customers that are larger than 13 kW, LM events were found to have a statistically significant impact on load.
- We have experimented with various combinations of isolated hours to determine how the threshold constraint changes the results; in general, the impacts of LM events are less significant for the smaller domain of kW readings, but become increasingly significant as the hour approaches 19 (7 p.m.) and the kW ratings are above 13.
- The above analysis suggests that, during evening peak periods, the program is having a statistically significant impact on the range of possible peak hours. The results shown in **Table 12.7** reflect that generally, there was a statistically significant and perceptible abatement impact in the early hours of combined control when all kW reads for all meters were analyzed in one model.

8.1.3 Iowa Lakes

ILEC meter load and control event data spanned October–December 2013. Meter load data included approximately 300 meters, all of which were participants in the water heater control program.

Load control events totaled nearly 100, although days during which there was control included as many as 4–5 events, many of them in nearby time intervals. The periods of control were across many hours but were most heavily focused in the early morning (hours ending 7 a.m. and 8 a.m.) and early evening hours (hours ending 6 p.m. and 7 p.m.). There were multiple control events for various groupings of water heaters, specified as "primary," "secondary," and "tertiary." For purposes of this analysis, only the primary water heater control events were analyzed.

The meter data included many meters with highly volatile and potentially anomalous load patterns. For purposes of the results provided in the tables above, 12 accounts were excluded from the analysis due to potentially erroneous data.

As evidenced by the results tables, statistically significant impacts of load control events were found in several daytime and evening hours, as well as overall, across all hours.

8.1.4 Prairie

The Prairie data set was generally reasonable. Initial econometric analysis was halted to investigate bracketed meter reads subsequently found to be separately metered heating load. After this investigation, those observations were excluded from the data set, and the econometric analysis was refreshed. Exclusion of the separate meters resulted in parameters for abatement that generally were larger and more in alignment with expectations. Based on the revised analysis, the following represent some overarching findings relative to the data set:

- The impact of load control over the aggregated hourly period was not statistically significant.
- Water heater participants, in certain isolated hours, did not have statistically significant amounts of abatement.
- The hours found to be statistically significant as to control periods were not necessarily bounded within the domain of hours that would be considered typical peak or control periods. (A possible exception is 8 p.m., which reflects hour 21, given the manner in which the time stamps for the data set were structured.)
- As evidenced by **Table 12.5**, some amount of statistically significant rebound impacts were also found in certain hours.
- The data were spliced in an effort to understand whether generally larger kW readings were subject to larger incremental abatement estimates. For the hours in question, load control events that align with meter reads of 10 kW or less generally were found to have a lower abatement impact than the estimated impact over the entire data set.

8.1.5 Minnesota Valley Electric Cooperative

For MVEC, the econometric data translation process that converts the data set into a dated panel for analysis initially identified some duplicated meter stamps and time stamps, which was believed to indicate that there were duplicates in the data set (same meter ID and same time stamp more than once). This prevented the software from doing a full panel translation and, as an alternative, "cell IDs" were created to ensure that each cross-sectional element was unique. The focus of our analysis was on the cycling of AC units; the "dual-fuel" meter reads were excluded from the analysis. Data were available for both the participation of a given meter and the percentage associated with the cycling of the end-use.

Leidos engaged in a more thorough data review and uncovered that the duplicate records were caused by a lack of precision in certain isolated time stamps, wherein the hour in question was not being read properly by our statistics software. We adjusted the format of the raw data and replicated our earlier analysis with a full panel data set to ensure the consistency of the findings.

The key findings associated with the MVEC data set are as follows:

- When kW readings were in the smaller range (less than 2 kW in a given hour) and during key hours in which LM events took place, there was a small and statistically significant impact associated with abatement.
- Weather data, including maximum and minimum temperatures and heating and cooling degree days, were included in the analysis, and cooling degree days in particular worked to control some of the weather-related variation in the data, after which LM participation was found to be statistically significant. In models that capture either temperature or degree day measures, the omitted variable bias associated with estimates that may not reflect control for sources of weather variation was considerably lower.
- The level of participation appears to matter—and generally in the expected direction (i.e., only load management percentages greater than 0.5 were statistically significant).

8.1.6 Delaware County Electric Cooperative

DCEC meter data spanned approximately January through July 2013, excluding March 2013, while the event data were available only for March through mid-April 2013. Another 10 tests were run during the winter of 2013−2014, starting on November 24, 2013 and ending on February 10, 2014. The meter data reflected consumption readings in whole kW, with the majority of readings of either 0 or 1 kW, reflecting rounding of readings to the nearest kW and an overall lack of precision (i.e., no difference between 0.1 kW and 0.4 kW or between 0.5 kW and 0.99 kW). The 27 control events were concentrated in the morning, from the hour ending 7 a.m. to noon and the evening, from the hour ending 7 p.m. to as late as 11 p.m., frequently occurring in both morning and evening hours on the same day. The data set was populated with "LM_XX" variables that captured specific events, as well as "LM_YY" variables that captured participation across various retail groups (e.g., farms). While this additional information was tested to determine the possibility of discerning differences in participation across groupings, there was no significant difference between the central variable that controlled for LM events and the other variables. This is likely to be driven in part by the lack of precision in the underlying kW reads.

Statistically significant impacts of LM events were sparse and typically not significant across the hours of control. Hours that were statistically significant tended to be focused around the typical periods of hot water usage in households, in the mid-morning and early evening hours, as shown in **Table 12.4** above. It is likely that the lack of precision of the meter data, along with the more typical data vagaries across the co-op data sets, limited the ability of the statistics software to detect load differences.

8.1.7 Overall Findings – Insights on the Theoretical Basis for DR

Based on the overall set of analyses completed by co-op, the following are some overarching themes regarding the findings, which represent high-level insights on certain theoretical bases for demand response as detailed in Section 7:

1. Load control events, when initiated, do result in statistically significant impacts for hours in which it is reasonable to anticipate a utility will peak. These impacts generally are in the same range for per-device, per-event kW savings across the entities in the analysis.
2. When the data for meters that had larger average kW readings were analyzed separately, there were larger statistically significant amounts of abatement. This is in general alignment with theoretical expectations, in that larger meters and larger customers are more

likely to achieve tangible reductions in load (i.e., reductions that can be teased out of the data) from load control programs.

3. Full control or cycling, or event criteria that generally cycle to a greater degree were found to be statistically significant in terms of abatement of kW. This suggests that partial cycling may be less effective at obtaining significant levels of abatement, and is in alignment with theoretical expectations.
4. There was a statistically significant rebound effect identified in certain co-op's models.
5. Weather data were extremely useful for controlling for variation when developing estimates of abatement and controlling for the impact of weather variation and the reduced parameter bias that results from models carefully infusing weather data into the analysis.

Demand Response Program Success in Abating Peaks

The value of a load control program lies in the utility's ability to control load during peak load hours—either the utility itself or its wholesale provider, if its demand charges are based on a coincident peak. This is due to the fact that capacity costs are driven from the utility's peak demand value, whether directly through a wholesale power supply contract or indirectly through generation assets built to meet a previously forecasted peak demand. In addition, capacity costs are driven by electricity demand during relatively few hours. Consequently, abatement that does not align with the utility peak or coincident peak provides only avoided energy cost, but no avoided demand cost.

Load control needs to occur in a sufficient number of hours to provide assurance of actually abating the utility's peak demand or the wholesale demand billing hour. However, the number of load control events cannot be unbounded, as frequent disruption of end-user comfort likely will lead to program participant attrition. Control cycling of less than 100% during control hours reduces this disruption considerably but also reduces the overall abatement.

To properly evaluate the economics of a load control program, this imperfection in the alignment of control events and peak load events should be taken into account. The reality is that peak periods cannot be forecasted with perfect accuracy, and the success of load control event timing typically is not known until well after the fact. In cases of wholesale power supply contracts for which monthly demand costs are driven by a single coincident peak hour (or annual demand costs, over a few summer months), capturing the full demand abatement benefits typically requires fewer hours of control. This proposition can be complicated by cases in which a host of the supplying utility's other wholesale customers also are "chasing" the peak.

In an effort to determine the co-ops' success at controlling loads during peak load periods, Leidos requested peak timing data from our contacts for the period overlapping the deployment of the load control program in question, at a minimum, or additional data, if available. Data regarding the timing of peak load events were available for three co-ops, DCEC, MVEC, and PEC. Data also were available on peak timing for Basin Electric Cooperative during 2012 and most of 2013, which were provided by Corn Belt Power Cooperative, and represent the basis for wholesale demand billing for the Corn Belt co-ops, including PEC. Of the 26 total peak events taken from these data, load control was called during 19, or 73%, of them. While Flint provided data regarding its top 10 load hours for 2013, they were not exactly comparable to data from the other co-ops, and it appeared likely that load control event data were not sufficiently available for this purpose. As PEC provided the longest time series of both monthly peak demand and control events, these data are most representative of that co-op and, in essence, of the Corn Belt

Power Cooperative—Corn Belt Power Cooperative initiates load control events. The data show that control events were successful at hitting the majority of peak events. However, as noted in the discussion of the econometric analysis of customer loads, statistically significant impacts on customer loads were found during only a subset of control event hours.

It is important to note that, while on the surface, comparing the recorded peak to the domain of load control events is one indicator of the possible success of a load control program, it is entirely possible that engaging in load control for a given hour actually reduced demand in an hour *that otherwise would have been the actual peak*. To more fully test whether a given program's control events matched the hypothetical peak that would have occurred absent the load control, it would be necessary to "gross-up" the relevant hourly load profile based on hourly estimated impacts. These hourly load data were not requested from the participating co-ops and, for the Corn Belt co-ops, could not be obtained from the wholesale provider in question, whose loads also would have been impacted by other wholesale customers engaging in load management. Such an analysis was beyond the scope of this project.

The results of our review suggest that the majority of the peak events analyzed were covered by load control. However, a key consideration, because only a subset of the control event hours was found to contain a statistically significant impact, is this: *the analysis suggests that utilities should take care to include conservative estimates of abatement in any future cost-benefit analyses*. Such estimates should capture discounting factors to account for the peak demand coincidence of the abatement and other net-to-gross factors that result in lower actual estimates of abatement, compared to theoretical rules of thumb or engineering-based estimates of end-use loads.

9. OBSERVED DATA CHALLENGES AND ISSUES—ECONOMETRIC ANALYSIS

In prior sections of the report, we summarized challenges regarding the collection, manipulation, and amalgamation of data for purposes of rendering those data suitable for econometric analysis. In addition to these, we uncovered other data challenges and issues after the onset of the econometric analysis. Given the large volume of data and the somewhat disparate nature of the control event data available, Leidos went through a secondary quality control process as the data were being subjected to initial specifications within Eviews and as part of the development of panel data sets (described in prior sections of this report) within Eviews.

The following is a list of the additional challenges encountered during the econometric analysis:

- Event data for several co-ops were not in the desired format required by the analysis. We had to simplify the data to bring them to the desired format and subsequently created other threshold variables within Eviews as deemed appropriate.
- In one co-op's data set, a few of the MeterIDs had a special character (bracket "[]") along with a numeric meter number that was discovered when attempting to create the panel data set within Eviews. After discussion with the co-op member, we realized that the brackets represent separate metering for heating. These separate meters were excluded from the analysis.
- Some co-ops' data sets had duplicate meter reading entries with different kW values for a similar MeterID and DateTime stamp. We had to remove these entries to create a consistent data set for the analysis.

- Some co-ops' meter reading data had zero values for the kW field. It was difficult to find out whether the zero values are actual kW or rounded-off values because some co-ops' meter data management systems round off the kWh readings to the nearest integer values or simply are not capable of capturing double precision values. To address the potential impact of this nuance on the analysis, we generated adjusted kW time series that excluded zero values, and ran the analysis using both data sets. As noted above, this nuance does not appear to have any impact on our findings, which is mostly due to the volume of observations in any given equation.

10. NEXUS BETWEEN ANALYSIS RESULTS AND DR SCREENING TOOL

The econometric analysis conducted in this project is a critical element of the Leidos vision for a Demand Response Planning Model, which is described in extensive detail in Appendix 12A. **Figure 12.5** provides a more high-level overview of the key components of the screening tool architecture.

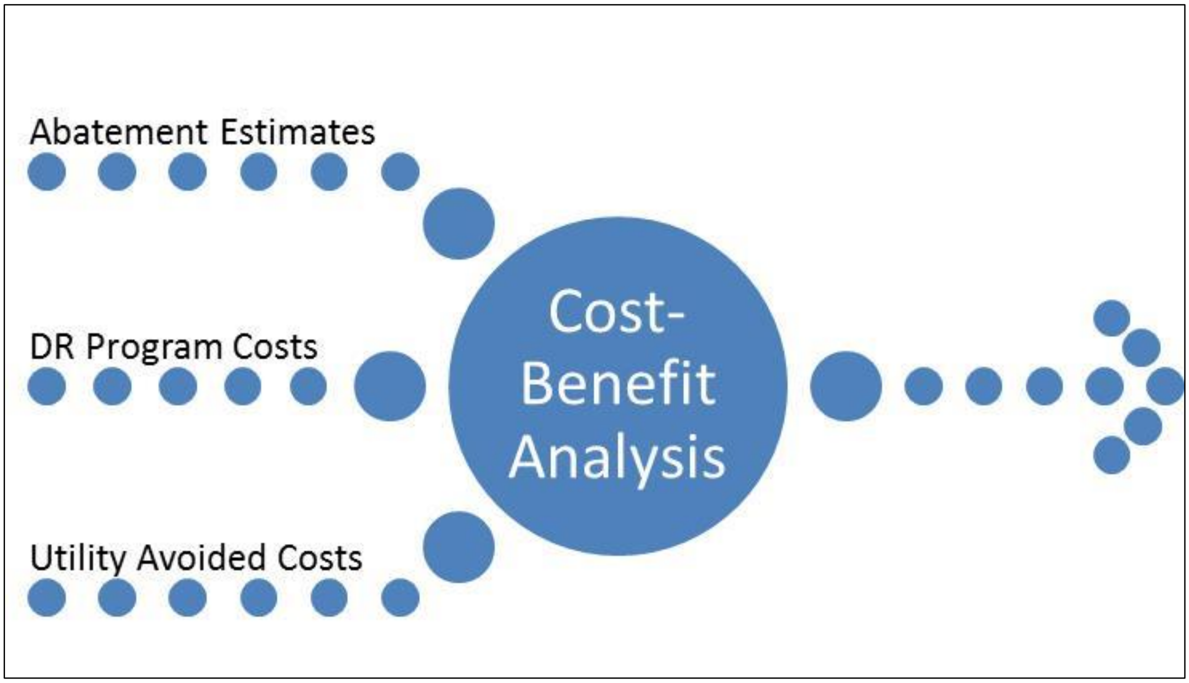


Figure 12.5: Top-Level Demand Response Planning Model Architecture

The econometric analysis conducted in this project provides (or can be manipulated to provide) the following critical assumptions to the planning model:

- If all else is equal, the per-unit, per-event, hourly kW abatement for a variety of load control programs, either in aggregate (for all hours), or for specific hours
- Details on which hours can be assumed to be statistically significant, in general, or based on the specific portfolio involved, which can inform assumptions that vary based on the type of program assessed and the range of hours over which load control events are anticipated to be initiated by the utility involved

- The likelihood that load control events resulting in statistically significant impacts align with utility peaks, which can inform discounting factors associated with peak coincidence for cost-benefit analyses

As evidenced in **Figure 12.5**, this domain of intelligence/information can be considered one-third of the triumvirate of assumptions required to objectively evaluate a DR program (or the universe of "abatement estimates"). The other two key components can be defined as (1) information on avoided costs, which typically are based on wholesale demand charges or more detailed estimated costs of power supply; and (2) detailed cost estimates associated with the all-in cost to deploy the demand response program, including core equipment, information technology/architecture, marketing and incentives, maintenance and repairs, and the long-term administrative and general costs associated with maintaining customer relationships and procuring new participants.

The construction of a robust DR planning model is the logical extension of the work summarized in this project. Refer to Appendix 12A for further details on other sources of data and more detailed discussions of suggested model architecture, inputs, and outputs.

11. LESSONS LEARNED

Based on the direct contact with participating co-ops, the review and manipulation of data as based on SDATS and follow-up information provided by individual co-ops, the results of the econometric analysis described above, and the Leidos vision for a downstream screening tool, the following are some lessons learned from our research endeavor.

1. ***Cooperatives would benefit from further education and tools to assess the costs and benefits of programs prior to deployment***. Leidos did not encounter any participating co-op that had engaged in cost-benefit analysis prior to deployment of the programs, which suggests that each entity based its deployment decisions either on prior experience with existing DR programs already in place or through more high-level judgment techniques. In an incentivized (or demonstration-based) context, this approach provides sufficient coverage of options, and indeed, co-ops were successful in obtaining statistically significant hourly impacts associated with their load control programs, as detailed above. However, were the utility to finance such an endeavor on its own, further analysis should be conducted to estimate the total resource costs of a given program compared to the utility's avoided power supply costs (or wholesale demand charges) and to examine the impact of the deployment on non-participants. The screening tool Leidos proposes to construct is predicated upon designing a user-friendly framework to engage in these types of analyses.
2. ***A common standard or rubric for data management, scrubbing, and reporting capabilities, which leverages the power of SDATS, would allow for more efficient long-term tracking of DR program performance***. Leidos engaged in a greater-than-anticipated effort in extracting data from the SDATS system and working with individual co-ops to understand, catalogue, and scrub meter data. Additionally, the nature and extent of reporting into the SDATS system appears to have been executed in different ways across the various entities. A common set of guidelines for how to review and scrub the information would greatly expedite future investigations into the efficacy of DR programs over a much longer period of time. Such guidelines are critical precursors to the econometric analysis, which itself can be refreshed as time progresses and the program

matures as to both the command that utilities have over anticipating the timing of load control events and the customer relationship management required to maintain a successful program.

3. ***Utilities should embed conservative estimates of load control impacts on a per-unit basis into their evaluations***. As evidenced by our modeling results, the efforts to generate load control events that are commensurate with the system peak are generally aligned with expectations. However, the process is not perfect, and additionally, the ability of a given event to achieve a statistically significant impact in a given hour varies based on the type of program and the individual utilities involved. These results reinforce the notion of incorporating discount factors for peak coincidence, persistence, and net-to-gross issues, and applying them to engineering-based estimates of the technical abatement potential of load control devices.
4. ***Utilities may be able to attract participants without significant monetary incentives*****.** In some instances, entities provided similar feedback on the methods and incentives used to attract program participants. A commonly heard element of this approach was to hold town hall meetings or "get the word out" in informal ways, with the core message being that participating in the program is helping the member's co-op, and consequently the community served by that co-op, to save money. The consumer reaction when presented with the program opportunity indicates that messaging strategies targeted toward the intrinsic benefits of load control may be a complementary tactic that can offset or reduce the need for direct financial incentives or credits. While compensatory incentives are unlikely to be phased out, the costs associated with attracting and maintaining program participants may be able to be reduced with the right communications platform.

APPENDIX 12A: DEMAND RESPONSE PLANNING MODEL

A.1 Purpose

Numerous demand response (DR) studies have been conducted over the past few decades in various regions of the United States. The outcomes and lessons learned from many of these pilots and theoretical research studies have published a wide spectrum of results. It is the NRECA's desire not to repeat or restudy this arena but to glean from it, the best of the existing research findings to frame an approach to develop an easily accessible yet robust DR cost-benefit evaluation model that will enable co-ops to evaluate the relative effectiveness of competing demand response programs.

Specifically, this meta-analysis and accompanying model will enable electric co-ops to understand the demand response potential that their specific class of customers will be able to provide, gauge the benefits of the DR, and quantify the costs of implementing such a plan. DR implementation results and data from the NRECA Smart Grid Demonstration Project will be leveraged for this analysis and tool development.

The overarching purpose of the DR model as based on the collective vision of NRECA and Leidos is to devise a tool that will accomplish the following:

- Provide a warehouse of cost estimates for a portfolio of potential DR programs (which are defined below)
- Provide algorithms and assumptions from which the load impacts of the portfolio of DR programs can be estimated, taking into account customer attributes, environmental conditions (e.g., weather conditions, seasons, day of the week, etc.), and the technical or engineering realities associated with a given program
- In the absence of user-provided data specific to the co-op, leverage representative assumptions regarding the cost of abated marginal energy or peak demand to monetize the overall load impacts
- Combine the cost of the program, the estimated avoided costs (benefits) of the program, and assumptions or analysis regarding potential participation rates for the program to compute benefit-cost ratios, discounted payback periods, and return on investment estimates that consider the most significant model factors ("first order effects"), with appropriate data proxies where necessary

The model will carefully balance inputs and assumptions formulated into outputs within the model itself with, as appropriate, exogenous estimates of certain key assumptions (such as adoption rates). Preliminarily, it is anticipated that research into existing empirical studies will drive the majority of model logic, with boundary constraints limited to estimates of program participation, which will be an exogenous user input that will allow model users to devise scenarios of their choosing. At a very basic level, the model will internally develop the unitary benefit-cost ratio, net present value of system benefits, and internal rate of return for a single instance implementation of every DR program within the pre-defined portfolio.

The remainder of this document details (i) a model overview that defines the DR programs we contemplate the tool will cover, provides the perspective from which the evaluation will be conducted, and delineates preliminarily contemplated inputs and outputs; (ii) the approach to be taken to devise model inputs; (iii) a high-level overview of the proposed model's processes, sequencing, and architecture, including details on how the ultimate benefits, costs, and return on investment calculations will be summarized; and (iv) the data that is anticipated to be required to execute the model. Finally, a discussion of next steps, given the information contained in this paper is also provided.

A.2 Model Overview

The core elements of the model development process that will define the model boundary are the types of DR programs the model will cover, the perspective of the cost-benefit evaluation, and the main model inputs and outputs. Each issue is summarized below, with the global understanding that the model boundary will be reviewed and refined during analysis and modeling activities, and that the items summarized herein are intended to provide us with sufficient specificity from which to finalize the model architecture.

Types of DR Programs Covered

The model will be able to provide coverage of the following DR programs:

- Direct Load Control, which in the residential sector will be constrained to the most top-of-mind programs, specifically, water heater, HVAC, pool pumps, and irrigation pumps, and for which up to 7 additional programs will be considered in the commercial and industrial sector
- Seasonal Time of Use
- Critical Peak Pricing (or time of use with a price differential during critical peak periods)
- Peak Time Rebates

The model will be parsimonious, in the sense that users will be able to model one program at a time, and will be able to generate multiple iterations of the model to compare various scenarios or alternative programs against one another using a set of consistently derived outputs (defined preliminarily below).

Perspective of the Evaluation

There are differing perspectives that can be taken when evaluating a given DR program from an economic standpoint. The seminal literature on DR programs generally categorizes these perspectives into one of the following categories:

- The utility administering the program
- The participant in the program
- The ratepayer who is not a participant in the program
- Society in general and/or the external environment as it pertains to the public good resulting from abatement of demand and energy through participation in the program

Based on feedback from NRECA and research and discussions within the Leidos team, the model as proposed will focus on the perspective of the utility administering the program. However, it should be noted that this perspective does not imply that the model will ignore the impact of specific rate differentials and incentive payments on participation and ultimate response. These issues will be of paramount importance, as they will serve as key inputs for specific programs that will allow for an objective evaluation of costs and benefits.

Preliminary Model Inputs

The following is a list of preliminarily contemplated model inputs. Some inputs will be directly derived and entered by the model user ("exogenous inputs"), whereas other inputs will require extensive research in order to parameterize the model and afford the user the requisite intelligence to render the model meaningful under a variety of contexts ("endogenous inputs"). The list below covers exogenous inputs, and the Approach section that follows details the proposed thought process, research, and analysis required to derive the endogenous inputs. In some cases, flexibility will be provided to the user to select default values derived endogenously in lieu of direct input intervention, and those redundancies are listed in parentheticals in the list.

- General information regarding the utility, case number/title
- Retail class in question that DR program is being applied to and the number of customers in that retail class
- Estimated baseline energy use and peak demand contribution of a given customer within the retail class in question (to be buttressed by default values derived from within the model)
- Type of DR program desired to be evaluated
- Estimated costs of the DR program for inception and ongoing maintenance (but only to the extent the user wishes to override endogenous model inputs)
- Study period desired for the analysis (to be bounded based on a reasonable "upper bound" for the DR portfolio based on research and analysis and in partnership with NRECA)
- Tolerances for discounted payback period (if applicable)
- Rate differentials for the specific program (as applicable)
- Estimated demand rate (at peak) and marginal energy cost for the utility in question (to be supplemented by a template in the model that will guide the user through derivation of such rates, if desired)
- Estimated participation rates in the given program (to be supplemented by default values based on research and analysis underpinning the program in question)
- Specific nuances of a given program or selections to narrow down the specific retail customer base ("attributes") that serve as levers for both estimated demand and energy savings and participation rates, that will be active and available for user interaction if the program is selected and inactive otherwise (refer to the Approach section for a listing of such attributes)
- Intelligence/assumptions about weather or seasonal elements of a given program (time of day, seasonal details, weather assumptions, etc.) that have a direct impact on participation and demand/energy savings (to be supplemented with "typical" conditions associated with deployment of a given DR program based on legacy implementations in the literature)

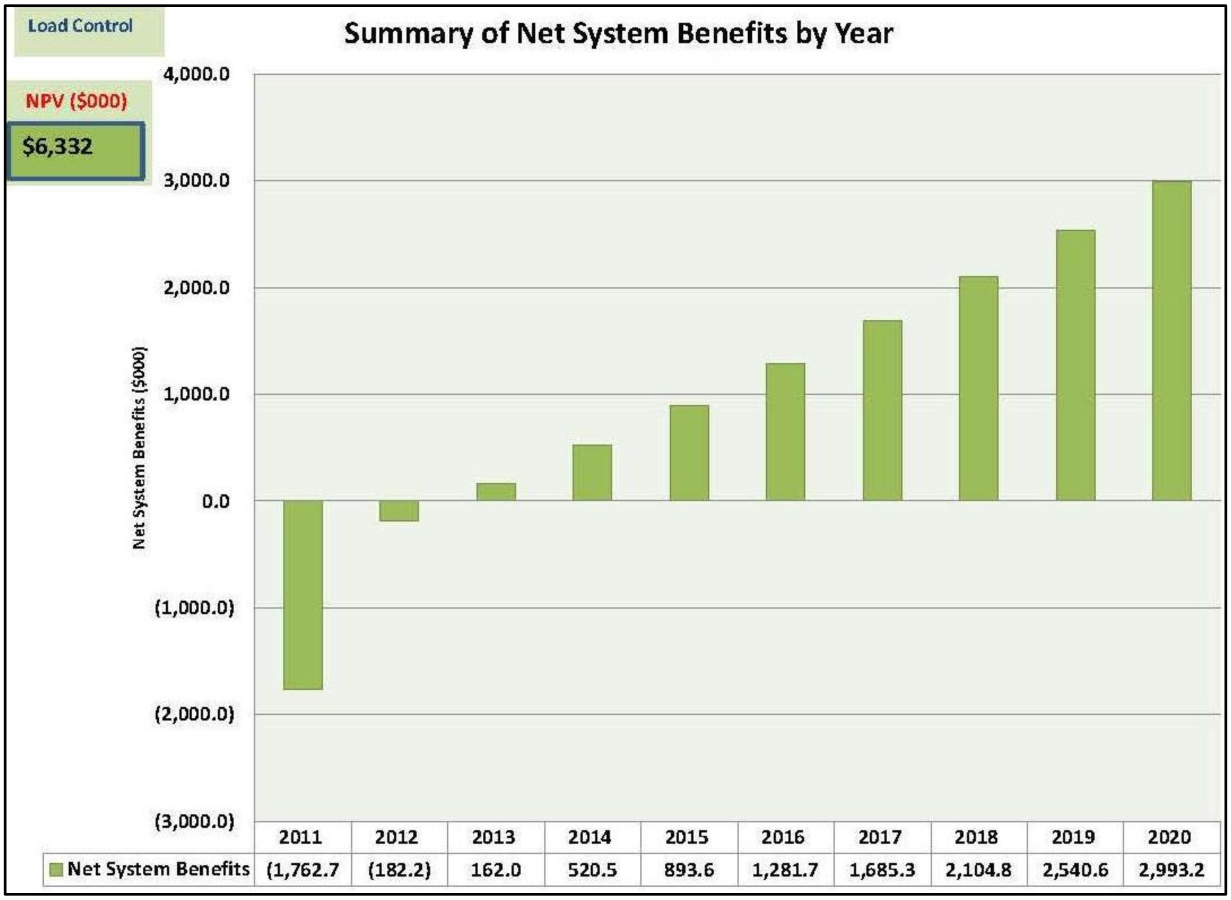
Preliminary Model Outputs

Given the exogenous user inputs and the endogenous model inputs (the approach for which is detailed below), the model will produce the following key outputs:

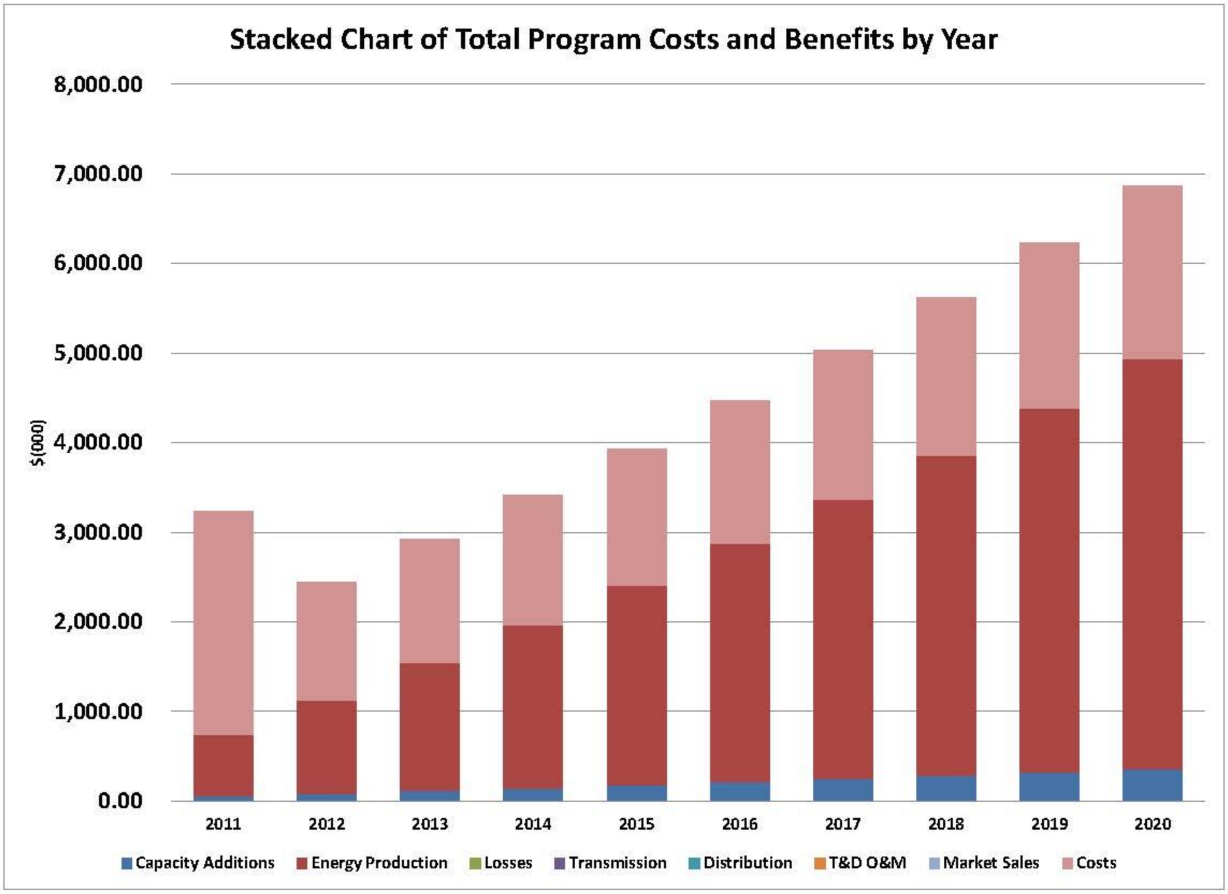
- Annual and overall energy/demand saved and/or energy shifted to shoulder hours (during study period)
- Net system benefits on a by-year and Net Present Value (NPV) basis, defined as the difference between total benefits and total costs of the DR program
- Benefit-cost ratios (e.g., Total Resource Cost Test), which can be used to determine estimated program payback periods and/or serve as a litmus test for whether a program is implemented
- Additional financial return metrics, most notably internal rate of return (IRR), which can be compared to the utility's IRR if it were to invest in programs other than DR
- Graphical outputs summarizing net system benefits on a by-year and NPV basis

The figures below represent example mock-up of outputs that will be derived from the model.

The first figure summarizes the net system benefits and NPV of a mock program by year over an example study period. Up-front net benefits are negative as a result of the investment, but over time, as the marginal cost of energy abated increases and the up-front investment amortization period ends, there is a significant upside.



The second figure compartmentalizes the elements of cost and avoided cost in a stacked bar chart. Consistent with the above example, the cost bar is larger at project onset in this mock example, and the benefits from the elements of avoided cost considered (which are preliminarily defined further below) increase over time.



It is important to stress that the model outputs will be informed by feedback from NRECA stakeholders to refine these preliminary outputs in terms of both aesthetics and priorities related to financial metrics, and that, given a robust cataloguing of the appropriate costs and benefits of a given program, calculation of various industry standard benefit-cost ratios can be accomplished by combining the appropriate cost and avoided cost (benefit) elements together.

A.3 Approach to Gathering Endogenous Model Inputs

Overall, several important aspects must be considered when establishing a methodology to quantify the costs and benefits of demand response which have direct consequences in terms of the key endogenous model inputs for each DR measure, which are as follows:

- The elasticity of substitution for a given retail class that results in energy savings/shifted to off-peak periods and peak demand savings
- Energy and demand baselines by retail class
- Typical weather or seasonal conditions for deployment of a given DR program
- Program costs (direct and ongoing)
- Participation rates (which allow for the allocation of certain fixed costs over a greater contingent of program participants)
- The relationship between up-front investment/incentive levels or price differentials and participation

Some obvious questions that must be addressed in order to parameterize the model with these endogenous inputs are:

- What customer attributes are important?
- What are the customer response sensitivities?
- What environmental conditions are relevant?
- Which DR treatments are the most effective?
- What drives the cost of the programs and implementation details?

With these questions in mind, and with the intent to develop a relatively simple initial model, we intend to focus our research on the population of co-op customers in each retail class (residential and commercial/industrial/agricultural) that is likely to provide load curtailment and participate in the DR programs, and quantify the impact of participation of those customers in the aforementioned portfolio of DR programs. We will establish a set of assumptions and perform analysis as needed that we will apply to the aforementioned specific customer attributes and then derive expected customer responses. Given reasonable assumptions regarding the nexus of these factors with actual customer activity and the savings to be achieved when deploying DR, DR program costs will be estimated as well as the DR benefits to the co-op, and these will determine the overall return on investment.

To define the appropriate customer population that will be the focus of our research, numerous attributes will be considered. Some of these attributes are fully relevant and others may not be germane enough to a parsimonious treatment of costs and benefits to warrant inclusion. Some key characteristics that have been identified in various studies are discussed below. We propose to bifurcate the retail space into residential customers and the collective commercial/industrial/ agricultural customer base when examining key attributes that will be used to derive the endogenous assumptions for each class by DR program. In addition, other key attributes outside of the retail distinctions will also be considered in the development of our endogenous inputs, most notably the elasticity of substitution. These factors, as well as the mathematical construct proposed to derive elasticity of substitution, are both detailed in the Model Architecture section below.

Residential Customer Attributes

This class of customer is likely the largest and most significant demand response group for many co-ops. As such, determining the simplest model will depend on what information is available about these customers. It all comes down to the ability to model their electric demand and predict that use over various conditions. Certain attributes that are drivers for consumption and, more importantly, curtailment will be considered and proxy attributes that may be substituted, if any, will be conceptualized. The majority of the specific customer data is expected to be obtained from the co-ops and augmented with a few proxy sources if necessary. The following attributes will be considered for residential customers as they pertain to measurement or estimation of DR impacts, and also for participation potential.

Attribute	Description
Energy Awareness	How energy conscious are the residents? Are they familiar with the impacts of energy production and the degree to which this affects price and the environment? Would this level of awareness drive the customers to step up their level of participation if it will lower costs or preserve the environment?
Income level	Is the income level a predictor of their consumption? Does income play a part in how motivated the customer is with respect to demand response signals? Can a home value estimate be an accurate proxy? Alternatively, can the proportion of electricity cost relative to income in a region (ZIP code or census tract) be used to determine how much abatement of consumption matters?
Owner or renter	Does ownership have a positive effect on DR?
Single or multi-family	How do the different densities of homes affect DR?
Number of occupants	Certainly, a greater electric demand is expected as the number of occupants increases, but does this inversely affect DR participation? Will they adjust their lifestyle to save a few dollars?
Urban or rural	Does the location play a part? Can ZIP code be an accurate proxy?
Electric price	Does the price per kWh that the customer routinely pays make a difference? Existing retail rates can be used for this purpose as well as for valuation of avoided energy.
Electric energy consumption (per home)	Does the amount of electricity consumed affect a customer's reaction to pricing signals? Research suggests that low-consumption customers do indeed respond to DR programs. Their responses tend to be about the same percentage reductions in demand and energy as larger consumption accounts

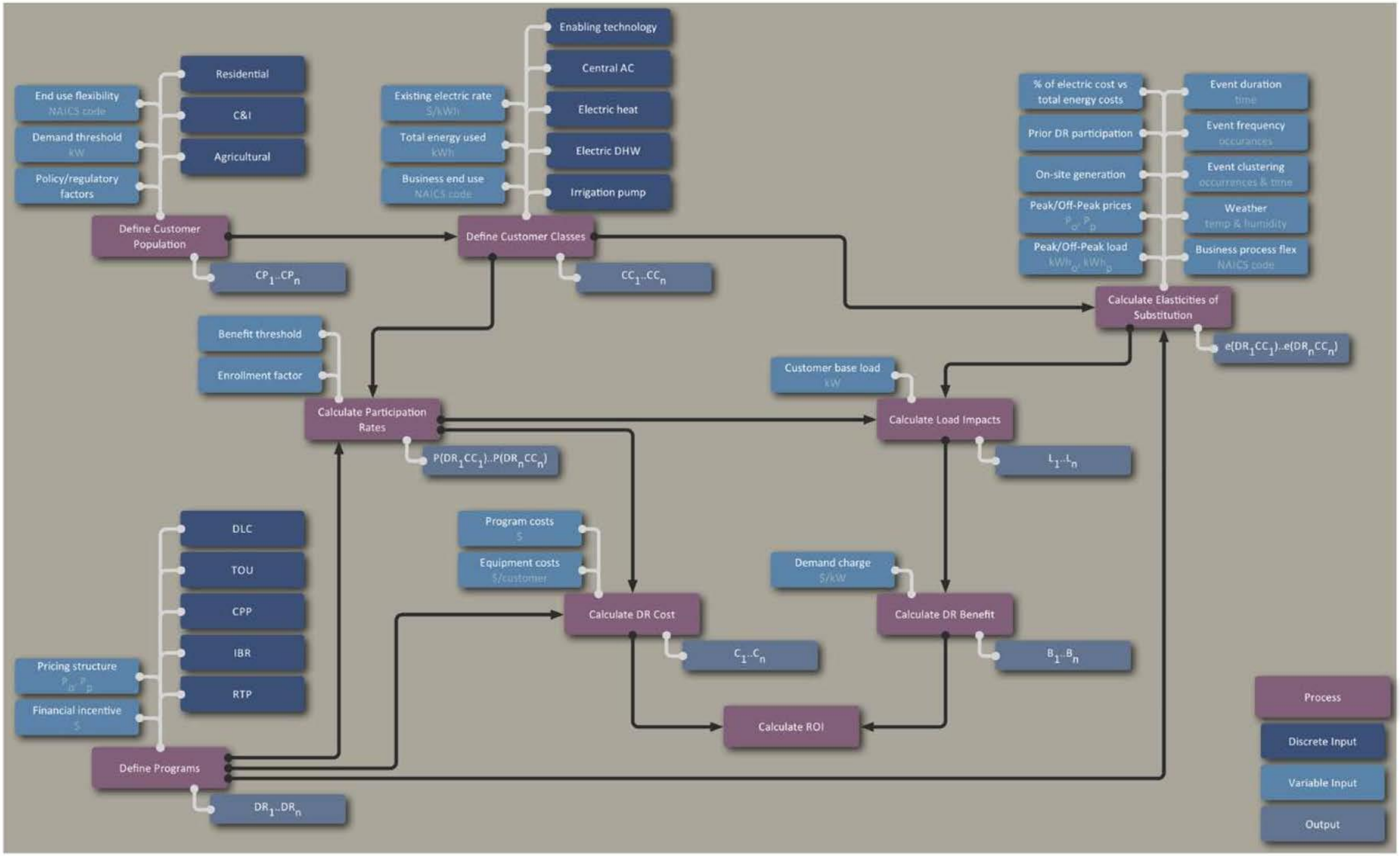
Commercial, Industrial, & Agricultural Customer Attributes

This class of customer, although typically fewer in number compared to the residential class, can individually have significant demand. They behave much differently and more diversely than residential customers and can be more difficult to model. The following attributes will be considered for commercial and industrial customers as they pertain to measurement or estimation of DR impacts, and also for participation potential.

Attribute	Description
Size of business	This will drive the overall consumption and, to some degree, the amount of curtailment possible.
Electric price	Does the price per kWh that the customer routinely pays make a difference? Are there specific commercial tariffs that may be counterintuitive with respect to DR?
Electric energy consumption (per sq. ft.)	Does the amount of electricity consumed affect a customer's reaction to pricing signals? Does a low consumption customer even have the ability to lower consumption any further?
End use	This perhaps is the primary factor in determining the potential DR. Does the business operate 24/7? Is electricity the fundamental energy source in the production of the end product? Does the business operate with multiple production shifts and have the ability to be flexible with its manufacturing process?

A.4 Model Architecture

The conceptual model addresses the above questions, and is depicted in the figure below.



The foundation of the model is driven by the baseline energy consumption of DR program participants. This provides the basis for determining the potential demand response from those participants. The discussion that follows provides a chronology of how the model will go about leveraging exogenous and endogenous inputs to derive the ultimate model outputs.

Define Customer Population and Classes for Analysis

The process begins by identifying the customer population for the DR program to be evaluated, as based on user entry. We propose to bifurcate the customer base into residential and commercial/industrial/commercial classes.

The model's endogenous assumptions will take care not to lump in customers that either cannot or will not participate in any demand response program. Customers that rely on electricity for critical operations are an example of a specific group (hospitals, data centers, restaurants, etc.) that may not be demand response eligible.

The purpose of this first step is to reduce the overall customer base into a smaller, demand response eligible subset that will be considered in the cost/benefit analysis. We believe that the bifurcation suggested will allow us to compute a representative elasticity of substitution that characterizes how a particular customer class will respond to a given DR program while keeping the model relatively simple in terms of structure.

Define Programs

Next, the model will consider the possible demand response pricing programs that are to be included in the analysis, as based on user selection and the aforementioned portfolio of DR programs. Various demand response treatments coupled with the desired pricing structures define the set of programs that drive the set of calculated elasticities. This element of the process will also define the costs of each program (either direct incentive costs, equipment subsidies, or ongoing administrative costs, as applicable) as a function of the specific program and the retail class selected by the user. Refer to the Data Requirements section of this paper for suggested sources of cost data.

Calculate Participation Rates

Based on the user input defining the targeted customer classes and the desired DR programs, the estimated participation rates will be calculated. As participation in utility DR programs can be fluid and vary from year to year, we intend to calculate these for each customer class/DR program pair based on a meta-analysis of existing literature for benchmark programs of like structure and customer base. Furthermore, as mentioned above, the user will have the full flexibility to revise or adjust our default model values based on their particular insights and estimates of penetration potential.

Calculate Elasticities of Substitution

Given the user-defined customer class and DR program, the response characteristics must be estimated. How will the targeted customer class respond to a price signal, given the relevant attributes and environmental and event conditions? How much of their on-peak energy will be moved to the off-peak period, and how much peak reduction can be expected? This will be a fundamental calculation within the model and will require significant research to (i) establish the attributes and environmental and event conditions that should be reflected in the model, and (ii) parameterize these factors as a part of the estimation of the by-participant impact of a given DR program.

Several demand response studies have documented the customer attribute, environmental, and event conditions that are dominant in determining the load response, in terms of elasticity of substitution, to DR events. As we anticipate estimating the DR impacts on an elasticity basis, the list below does not include price differentials between on- and off-peak, but the price differential is a significant driver. The key attributes denoted below are preliminarily proposed to comprise the "nuances" of a specific program, and the user will be able to use these nuances as levers in the model to utilize differing elasticity of substitution assumptions to the extent the model's endogenous calculation of the elasticity of substitution is informed by a given attribute. Note herein that retail class distinctions will also inform the elasticity of substitution calculation.

Key Attributes of DR Programs

Attribute	Description
Event duration	The duration of the demand response event drives the response rate; short events are more effective than longer events
Event frequency	Initially, demand response participation may be good, but as the frequency of events increases, the participation level decreases
Event clustering	As with the previous two event types, clustering is a combination of the two. Numerous events over a span of several days can be exhausting to the customer. As the clustering intensifies, customers begin to opt out of the DR program
Weather	As expected, both temperature and humidity play a significant role in demand response participation and the duration of these weather conditions is also significantly correlated with response.
Electric cost ratio	This attribute is the magnitude of the electric energy cost divided by the total energy cost for a customer. Some customers may have a mix of electric and oil or natural gas energy consumption, and the percentage of electric consumption to service their energy needs affects how they view their ability to lower their overall energy costs. Energy costs as a proportion of total income (residential) or revenue potential during requested times of DR deployment (commercial/industrial) may also factor into the propensity of the participant to curtail load.
Prior DR participation	Studies have also concluded that those customers that have either participated in a previous demand response program or are "energy cost" conscious are more active DR participants.
On-site generation	The presence of generation at a customer site is a strong indicator of positive participation. It allows the customer to continue their consumption, most likely a business operation, and reduce demand from the distribution system.
Business process flexibility/end use	There is evidence that from a business process perspective, if the operation has the flexibility to move end uses to different times of the day, then demand response participation is feasible. This can be accomplished with processes that may be able to run on an alternate shift, after hours, or deferred to the next day.
Automation of response	Response rates tend to be significantly better if there is equipment that can automatically manage the response for the participant, such as automated thermostats for residential customers.

Methodology for Computing Elasticity of Substitution

The model will deploy an econometric approach to compute elasticity of substitution. This approach will leverage as many of the above attributes as possible. However, it is likely that additional discrete adjustments to elasticity to capture certain attributes will be made based on the prevailing literature and/or expert judgment when sufficient data does not exist to infuse that attribute into the analysis.

The typical econometric analysis seeks to explain variations in customer loads during DR events, relative to loads in other hours, as a function of a series of explanatory, or independent variables. The dependent variable, or variable explained in these analyses, is typically the ratio of the average load during the DR event to the average load during other hours, or the "Peak Load Ratio." Explanatory variables typically include variables regarding the relevant electric rates, customer attributes, event conditions, and weather conditions, as detailed above. The primary analytical method is typically a multivariate econometric analysis, which quantifies the isolated impacts of a large number of a priori specified variables on the ratio of load during event hours to load during non-event hours.

The primary functional form of the theoretical equation is typically as follows:

$$\ln Yi,t = \alpha + \beta 1 \ln X1i,t + \beta 2 \ln X2i,t + \ldots + Bn \ln Xni,t + \epsilon i.t$$

Where,

Yi,t – The load characteristic of interest for customer i and day t

Xni,t – Explanatory variables for customer i and day t (discussed below)

α , βn – Parameters to be estimated via regression

Єi,t – The amount of error in the equation's estimate of Yt

As the data set to be analyzed will generally comprise customer loads and characteristics by customer and by day, it conforms to what is commonly referred to as "panel data."

The potential explanatory variables are typically tested for their ability to explain variations in the ratio of on- to off-peak average loads include the following (which are generally aligned with the attributes listed above):

- Ratio of on- to off-peak electric rates
- Installation of "enabling technologies," or devices to assist the customer in awareness of DR events or in reacting to events (e.g., in-home display, programmable communicating thermostat, text alerts, etc.)
- Installation of air conditioning or electric heat
- Installation of other appliances (e.g., electric water heating)
- Daily weather conditions (maximum temperature, temperature-humidity index, and/or preceding day maximum temperature)
- Seasonal variables (e.g., month of year)
- Day type variables (e.g., day of week)
- Housing type (e.g., single- vs. multi-family)
- Type of occupancy (full- vs. part-time)
- Extent of daytime home occupancy
- Household income
- Household education attainment
- Household size and composition (e.g., number of persons, number of children, percent of household between 13 and 18 years of age)
- Technological proclivity of household decision makers (e.g., early adapters vs. laggards on the product adoption curve)

The analysis process is inherently iterative, with varying combinations of explanatory factors being posed, estimated, and reviewed for explanatory power and statistical validity as compared to other combinations. The modern standard of practice for multivariate statistical modeling involves the notion that "theory must confront the data." It is a critical part of the process to delineate what theories, intuition, or engineering expectations exist relative to particular socioeconomic or demographic conditions, that can then be cross referenced with the empirical model to put those theories to the test. In some cases, adequate data regarding a variable of interest will not be available, which will require inference from other related variables or the use of a proxy of some kind.

Once the best combination of explanatory variables and their estimated parameters are arrived at, the resulting equation can be combined with assumed values for the explanatory variables to produce estimates of load impacts (i.e., the percentage of load shifted from on- to off-peak). For purposes of reporting a single elasticity value, it is typically necessary to populate certain explanatory variables (e.g., weather conditions) and solve for the resulting combined parameter on the price ratio. For example, weather conditions are likely to be related to the extent of the impact of dynamic prices on load characteristics. In order to report a single elasticity value, an assumption must be made for the weather conditions that are representative of the typical conditions that are relevant—for example, an average summer day or summer peak day might be utilized.

The empirical research on the impacts of DR programs typically indicates price elasticities that are in a reasonable range and statistically significant. The range of price elasticity estimated from the load data of participating customers has ranged from approximately -0.05 to -0.30. Most of these studies have shown greater elasticities in the presence of in-home displays and other enabling devices.

Calculate Monetized Benefits of Substitution

Based on the estimated elasticity of substitution for a given stratum of participating customer, the estimated peak demand abated and energy saved or shifted to off-peak hours will be monetized. As noted above, certain assumptions involved in the calculation will either be a function of default values endogenous to the model, user overrides, or templates designed to aid the user in determining the appropriate basis for valuation. Valuation of benefits will be achieved using the following avoided cost protocol:

- Abated peak demand will be valued at either the demand rate of the prevailing utility for the given customer class (if applicable) or the capacity cost of the marginal resource that would otherwise serve that load; as some customer classes are billed based on demand rates, benefits will be greater for those customer classes
- Energy saved will be valued at the marginal energy cost, either based on rate ratchets for on-peak energy or, if not applicable, the general energy charge (e.g., residential)
- Energy estimated to be shifted to shoulder hours will be valued only to the extent the specific customer class is subject to price discrimination based on peak/off-peak consumption; otherwise, there are no monetized savings, as the consumption is merely shifted and not saved
- The key components of avoided cost (or benefits) that are preliminarily contemplated for evaluation over a pre-specified time horizon, some of which may not necessarily apply to every DR option contemplated, include:

- Avoided or Delayed Generation or Purchased Power Capacity Additions (demand savings)
- Avoided Costs of Energy Production (including avoided emissions costs)
- Avoided Transmission/Distribution cost (including avoided capital expenditures)
- System Loss savings
- Avoided ongoing O&M costs associated with Transmission and Distribution system improvements (if any)
- The value of potential power market sales of resources that are free to serve the external market in place of the energy generation that has been avoided as a result of the DR Program

To the extent that adjustments need to be made to the list above to capture specific nuances of a given DR measure, such changes will be made, while balancing the need to develop conclusions about the costs and benefits of the program using a standardized method that reflects the current standard of practice in the electric utility industry, and that can easily be compared across different options.

From an avoided cost perspective, it is anticipated that the bulk of benefits will arise from avoided demand and energy costs, potentially including avoided or delayed capacity additions if the program is of sufficient size and scope in terms of participation. Capacity savings represent value in terms of either deferred or avoided investment costs by the utility as well as a reduction in the cost of running high-cost peaking generation. Energy savings represent both immediate and ongoing cumulative benefits associated with the reduction in generation fuel and operating costs of supply-side resources as well as losses. As most co-ops purchase their power, the users will be able to enter their own estimate of power supply costs for both demand and energy. However, we propose to make the modeling framework flexible enough to capture both key marginal capacity and energy situations that are likely to be encountered, specifically, (i) the utility has avoided operation of native/existing generation or abated the need for additional generating capacity, or (ii) the utility buys marginal capacity and energy from the market, whereby avoided costs can be mapped to an existing demand or energy rate.

Default values endogenous to the model for avoided demand and energy costs will be developed as supplemental and supportive of user-defined costs. As it is highly likely that almost all model users will have a good handle on their specific power supply costs, the analysis of default values will be sufficiently high level as to not divert excessive resources to the estimation process in lieu of focusing on higher priority model elements.

To capture endogenous avoided demand costs, the model will contain information from third party sources on the representative alternative supply side generating unit's capital and fixed O&M costs to estimate potential capacity savings. To the extent there is an intermittency in the ability of the measure to align peak shaving with the utility's system peak, such issues will be examined at a high level, and it is anticipated that NRECA will be able to assist Leidos with developing reasonable assumptions for dependable capacity (or the amount of capacity that can realistically be avoided at the time of the utility peak).

To develop projections of avoided and incurred marginal energy costs, the heat rate of the assumed alternative marginal generating resource (defined based on research of existing third-party databases) will be multiplied by a forecast of fuel prices plus variable operating and maintenance and emission allowance costs to derive a total per-unit ($/MWh) energy cost for the alternative supply-side resource. These average per-unit costs would then be multiplied by the projected avoided energy of the measure (adjusted for marginal losses) to derive total energy cost impact. In each case (demand and energy), a template will be provided as an option to the user to populate these more detailed statistics in lieu of direct entry of demand and energy rates, such that the user controls the inputs, but the model still computes the ultimate costs endogenously. The user will essentially have three choices in terms of validation (direct input of costs, use of defaults, or provision of needed information to recompute assumptions endogenously).

To the extent other elements of avoided cost are present and relevant, most notably the potential for market sales, the model will provide an input range for utilities to enter estimates of market sales potential into the model, so as to provide a fair and objective evaluation of potential DR program benefits. Default market prices at a high level by region of the country also will also be provided as an option.

Calculate Benefit-Cost Ratios, Internal Rate of Return, Net Present Value, and Discounted Payback Period

The model's internal logic will carefully review model inputs as gathered and delineated above and examine the resulting DR program evaluation model findings for reasonableness. Results for each measure will include the following (which are identical to the aforementioned model outputs from above):

- Annual and overall energy and demand saved and/or energy shifted to shoulder hours (during the study period)
- Net system benefits on a by-year and Net Present Value (NPV) basis, defined as the difference between total benefits and total costs of the DR program
- Benefit-cost ratios (e.g., Total Resource Cost Test), which can be used to determine estimated program payback periods and/or serve as a litmus test for whether a program is implemented
- Additional financial return metrics, most notably internal rate of return (IRR), which can be compared to the utility's IRR if it were to invest in programs other than DR
- Graphical outputs summarizing net system benefits on a by-year and NPV basis

Interpretation of model results by NRECA and other stakeholders will be fairly simple by design. The model will sum all of the avoided costs of the measure that are relevant and subtract the total measure's intrinsic costs in each year to arrive at Net System Benefits each year. These Benefits then all will be discounted back to today's dollars and added to compute the Net Present Value (NPV) of Net System Benefits. In a year in which costs outweigh benefits, the Benefit-Cost ratio will be negative. This will generally be the case in the first year of a program, when implementation costs are incurred but benefits have not had time to accumulate. For productive programs, this ratio will be above or equal to 1.0 as the study horizon extends. A measure that has a positive NPV of Net System Benefits is a program where benefits outweigh the costs in the long run. If a measure has a negative NPV of Net System Benefits, program parameters may need to be reexamined, sensitivities may be necessary, or it may be that the program is simply too expensive relative to the value of expected demand/energy reductions.

It will be critical to devise model calculations with an emphasis on the benefits and cost for the utility in question. There are industry-standard benefit-cost ratios that can be brought to bear, such as the Total Resource Cost Test, the Rate Impact Measure Test, etc. to evaluate impacts. As the model will calculate and summarize all relevant first-order costs and benefits, calculating alternative benefit-cost ratios from various perspectives (utility, utility and G&T, the participant, society, etc.) will be a natural consequence of the model structure. Based on NRECA feedback, the impact on the utility will be the priority perspective captured in the model. Alternative benefit-cost ratios, if deemed valuable, will be summarized as part of the results interface/tables of the model.

A.5 Approach to Gathering Endogenous Model Inputs

The model requires accurate data to drive the results, defining both the cost of the demand response program(s) and the benefits of such programs. It is clear that some required data may not exist or, if it does exist, the accuracy may come into question. For the areas where data do not exist or are not available for model consumption, substitutes and/or proxy data will be considered as a best fit for the specific inputs to the model.

Customer Population

To screen out the customer accounts that are not likely candidates for a demand response program, data about these customers is required. From a residential perspective, it is reasonable to assume that the majority of customers would be eligible and there is nothing compelling about their electric use that would immediately indicate that they could not contribute to demand response. It might however, be an option to eliminate the very low consumption customers from the mix, as the investment required to provide the hardware and in-home devices might be greater than the load reduction savings over several years. From that perspective, the payback period could be considerable. In this case, given the account demand data, a minimum threshold can be established that considers only those residential customers above a certain demand to be included in the customer population. Customers that may be on energy-assistance or other types of levelized billing programs or lower-income customers may also be able to be filtered out. With that said, in an effort to provide a holistic and inclusive set of assumptions when evaluating a given program, the model will give the utility the key economic metrics inclusive of such customers to the extent desired by the user utility.

Commercial and industrial customers should be viewed with a slightly different approach. There will be groups of customers that will not be likely candidates for a demand response program. Here, we would want to screen out the likes of hospitals, restaurants, and other end use customers that are clearly not capable of reducing their loads.

Given that many co-ops are located in rural regions of the country, the agricultural customer base could be a significant contributor to demand response.

The table below defines the data needed for each customer category:

Attribute	Residential	Commercial & Industrial	Agricultural
Business end use		NAICS code	NAICS code
Demand threshold	Average demand (co-op supplied)	Average demand (co-op supplied)	Average demand (co-op supplied)

Programs

The data input requirements for the aforementioned list of DR programs the model will cover will be derived from various studies conducted across the nation. Data will need to be gathered for these specific demand response programs and the intelligence gathered must provide the necessary pricing structure for the desired programs in the model.

The table below defines the program data needed for each customer category:

Attribute	Residential	Commercial & Industrial	Agricultural
Pricing structure	On/off peak price (study/user based)	On/off peak price (study/user based)	On/off peak price (study/user based)
Financial incentive	$ (study/user based)	$ (study/user based)	$ (study/user based)

Customer Class

The customer class process segments the customer population (as delineated above) into classes that have similar response characteristics. These are primarily based on how the customer uses electricity, how load reduction is implemented (via informational channels or direct control), and by particular sensitivities of customers. Generally, the energy use indicates the number and size of electric loads in the home and this can also align with the magnitude of household energy costs that are electric based rather than other fuel-based (like natural gas heating and cooking). Particular customer data will be required to support the classification and the model will categorize these with some knowledge of what *Elasticities of Substitution* are available.

The business activity of large customers is strongly correlated to their willingness to participate and thus, to how they might respond. Information on these customers' lines of business is available in the form of North American Industry Classification System (NAICS) codes. These codes distinguish groups of customers with similar energy usage characteristics, and we will use them to target likely customer groups for the commercial, industrial, and agricultural segment.

The table below defines the data needed for each customer category:

Attribute	Residential	Commercial & Industrial	Agricultural
Electric loads by end use	Major electric load devices (co-op supplied)	Major electric load devices (co-op supplied)	Major electric load devices (co-op supplied)
Existing electric tariff rate	$/kWh (co-op supplied)	$/kWh & $/kW (co-op supplied)	$/kWh & $/kW (co-op supplied)
On-peak energy	On-peak kWh (co-op supplied)	On-peak kWh (co-op supplied)	On-peak kWh (co-op supplied)
Off-peak energy	Off-peak kWh (co-op supplied)	Off-peak kWh (co-op supplied)	Off-peak kWh (co-op supplied)
Total energy cost	$ (co-op supplied)	$ (co-op supplied)	$ (co-op supplied)
On-site generation		Capacity (co-op supplied)	Capacity (co-op supplied)
Business type		NAICS code	NAICS code
Enabling technology	Device type (study/user based)	Device type (study/user based)	Device type (study/user based)

Participation Rates

The customer penetration rate is inherently very fluid and tends to change from year to year. Existing customers may drop out after a couple of years and others will join in any given year. Some may rejoin if the program changes and/or implements new incentives. Based on these factors, it will be more practical to estimate the participation rate based on the typical year of a single mature program, given there is data for such a program. Given data from previous demand response deployments, the enrollment factor can be one method to establish the appropriate value for the model.

Several methods in estimating participation rates have been documented from various studies, such as Expert judgment (or Delphi), Translated experience, Benefit threshold, and Choice model. Each one has advantages and disadvantages and can take considerable effort and experience to gain useful results. We will choose the method that is suitable for the model and reinforce a simple approach, allowing user input in the assumptions ultimately used.

The Benefit threshold approach might appear to be the best choice, as it strives to base the participation rate largely on the customer's expectation of benefits. It doesn't rely on data from previous program implementations and therefore, makes this an attractive option. It does, however, require assumptions on the benefit level that will encourage participation. A prudent approach will be to develop a high/med/low benefit level that will define a high/med/low participation rate for the model to apply.

The table below defines the participation-related data needed for each customer category:

Attribute	Residential	Commercial & Industrial	Agricultural
Benefit threshold	$ Savings/month (study/user based)	$ Savings/month (study/user based)	$ Savings/month (study/user based)
Enrollment factor	Typical rate from published studies (study/user based)	Typical rate from published studies (study/user based)	Typical rate from published studies (study/user based)

Elasticities of Substitution

The data required to develop the elasticity of substitution for each customer class is dependent on customer response from programs that have been implemented and studied. Without this type of data, it is difficult to estimate how customers may respond to demand response programs. Within the NRECA community, more than a dozen demand response demonstration programs slated for implementation and we will draw on those results to perform the estimation of elasticity for the model. If the data is insufficient to provide the essential input then other relevant published demand response pilots – of which there are numerous – will be explored.

Layered upon those base sensitivities, several other response factors will be estimated and used to adjust the base elasticities. Our approach will be to determine a high/med/low effect that will help illustrate the range of DR potential rather than target a single point. To the extent elasticity of substitution methods are not tractable for a given measure, load impacts will have to be estimated in a more discrete fashion as discussed above.

The table below defines the preliminarily contemplated data needed for each customer category. Refer to the discussion above regarding the analytical approach to determining elasticity of substitution, as there may be additional data needs uncovered as the execution of that approach moves forward.

Attribute	Residential	Commercial & Industrial	Agricultural
% Electric cost/total cost	Electric & Gas bill (co-op supplied)	Electric & Gas bill (co-op supplied)	Electric & Gas bill (co-op supplied)
Prior DR participation	Prior DR program details (co-op supplied)	Prior DR program details (co-op supplied)	Prior DR program details (co-op supplied)
On-site generation		Capacity (co-op supplied)	Capacity (co-op supplied)
Ratio on-peak to off-peak price	Prior DR program details (co-op supplied)	Prior DR program details (co-op supplied)	Prior DR program details (co-op supplied)
Ratio on-peak to off-peak load	Customer demand history (co-op supplied)	Customer demand history (co-op supplied)	Customer demand history (co-op supplied)
Event duration	Prior DR program results (co-op supplied)	Prior DR program results (co-op supplied)	Prior DR program results (co-op supplied)
Event frequency	Prior DR program results (co-op supplied)	Prior DR program results (co-op supplied)	Prior DR program results (co-op supplied)
Event clustering	Prior DR program results (co-op supplied)	Prior DR program results (co-op supplied)	Prior DR program results (co-op supplied)
Weather	Historical records (external data)	Historical records (external data)	Historical records (external data)

Baseline Customer Loads

The load impact calculation relies on the customer base load during planned demand response events. This will require access to customer demand history broken down into on-peak and off-peak consumption.

The table below defines the data needed for each customer category. The model will invite the user to input these values and, if the user does not have them, will substitute default values based on U.S. regional averages.

Attribute	Residential	Commercial & Industrial	Agricultural
Customer base load	Customer demand history (co-op supplied)	Customer demand history (co-op supplied)	Customer demand history (co-op supplied)

DR Cost

To calculate the demand response program cost, the model will leverage existing NRECA DR demonstration costs and nationwide studies of demand response implementations. As with other key inputs, the user will have the ability to override default values.

The table below defines the data needed for each customer category:

Attribute	Residential	Commercial & Industrial	Agricultural
Program costs	Prior DR program details (co-op supplied)	Prior DR program details (co-op supplied)	Prior DR program details (co-op supplied)
Equipment costs	Prior DR program details (co-op supplied)	Prior DR program details (co-op supplied)	Prior DR program details (co-op supplied)

DR Benefit

Refer to the above discussion for how benefits will be valued, and the three choices given the user related to marginal energy and demand rates used to value abatements.

The table below defines the data needed for each customer category:

Attribute	Residential	Commercial & Industrial	Agricultural
Demand charge	Co-op $/kW charge (co-op/study supplied)	Co-op $/kW charge (co-op/study supplied)	Co-op $/kW charge (co-op/study supplied)
Energy charge	Co-op $/kW charge (co-op/study supplied)	Co-op $/kW charge (co-op/study supplied)	Co-op $/kW charge (co-op/study supplied)

A.6 Summary

Our approach to DR cost-benefit evaluation will allow the NRECA's co-ops to simulate the effectiveness of defined DR programs and drive the model to quantify the cost and benefit results. It will leverage input data, from the individual co-ops, that will establish the specific attributes of customer base and energy supply costs that are critical to the analysis. Within the model, elasticities of substitution will be modeled through various existing demonstration programs, both within the NRECA membership and out in the industry (as needed). The user will have the capability to enter and adjust several parameters in the model that will enable a comprehensive analysis of what programs will be effective at differing levels of customer participation.

This initial conceptual model approach is based on the congruence of a number of methods and studies performed in various jurisdictions throughout the country. It is prudent that the next steps in vetting our model approach is to conduct a review with the NRECA and determine if we meet the expectations of method, functionality, and data access assumptions. We would also prefer to expose the defined user interaction with a few of the co-ops and solicit their feedback in how we envision the model to be used by them. We anticipate that with that feedback in hand we will then finalize the approach, architecture, and methodology.

Chapter 13:

Energy Storage – The Benefits of "Behind-the-Meter" Storage: Adding Value with Ancillary Services

ACKNOWLEDGMENTS

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

1. INTRODUCTION

1.1 Background: The NRECA Smart Grid Demonstration Project

The benefits of behind-the-meter energy storage were evaluated through two closely related technology demonstration projects involving storage at several electric distribution cooperatives (co-ops) and Great River Energy (GRE), a generation and transmission (G&T) electric cooperative in Minnesota. The overall goals were to validate the technologies and determine their value in demand reduction and for providing such ancillary services as frequency regulation and synchronous reserves to the Midcontinent Independent System Operator[36] (MISO) electricity market.

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

1.2 Battery Energy Storage Project

The first project involved battery energy storage systems at MVEC, WHCEA, and two nearby distribution co-ops—Federated and Meeker. The specific technology used was a Silent Power (SP) "OnDemand™ Energy Appliance"—an integrated utility-controlled edge-of-grid battery energy storage system.[37]

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

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

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

The first project accomplished the following goals:

1. Eighteen SP battery storage appliances have been installed in the field to learn about and solve issues related to installation at members' homes and businesses.
2. The stated features of the SP battery storage appliances were tested and evaluated in the field, using sealed lead acid batteries. Feedback was provided to the vendor on product deficiencies and suggestions for improvements.
3. When aggregated, the SP battery storage appliances provided controllable demand reduction that could reduce the need for future natural gas peaking units. The immediate benefit is cost savings on wholesale power demand charges for the participating distribution co-ops. The benefit for the G&T co-ops is achieved not only through reduced need for new capacity in the future, but also reduced congestion costs on the transmission networks. It is important to understand that the value of "dispatchable battery storage" is greater than more traditional options, such as electric water heater thermal storage, dual fuel electric heating, or cycled air conditioner control.
4. Simultaneous control of battery storage units in multiple distribution co-ops was simulated/tested for the purpose of providing aggregated ancillary services—in this case, for MISO.
5. Battery storage for small residential and commercial consumers was used for instantaneous and dispatchable load management.
6. The whole-house load management tool was tested in a natural gas market.
7. WHCEA is prepared to use battery storage as the "dual fuel" for air conditioning. Dual fuel uses electric heat as the primary source, and a back-up heating source, such as liquefied petroleum (LP) gas or fuel oil, during peak load conditions. In this case, the battery storage energy would be injected into the grid to offset the A/C unit load during peak load conditions. The A/C unit would function as normal during the peak load condition. This provides demand reduction savings over the peak while eliminating "rebound" peaks when control ends. The SP units for these locations were not installed during summer 2013, but data should be available by the end of summer 2014.
8. MVEC and WHCEA SP units successfully provided back-up power for critical circuits.
9. A battery storage unit allowed continued solar energy production during a power outage at one location with a 2,000-watt solar photo voltaic array, while remaining isolated from the grid.[38]
10. The SP battery storage inverter (@ 48 volts DC) was integrated with a 2,000-watt residential solar photovoltaic (PV) (@48 volts DC), thus reducing cost for the solar PV/storage solution because the two units shared an inverter.
11. The ability to measure the amount and impact of battery storage load before and after load control was tested.

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

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

1.3 Thermal Energy Storage Project

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

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

The overall project goals were accomplished:

1. Ten Steffes Water Heater Controls[39] with remotely configurable charge rates were deployed in the service territories of the participating member distribution cooperatives.
2. Two-way communication of the water heater controls was tested and evaluated.
3. The use of power-line carrier, 700-MHz wireless, and Wi-Fi were tested as possible communication technologies.
4. An economic model was developed for evaluating use of hot water heaters for frequency regulations.

2. PROJECT IMPLEMENTATION AND RESULTS – BATTERY ENERGY STORAGE

2.1 Enabling Technology

The battery storage project used equipment from SP. The OnDemand™ system used advanced lead acid battery energy storage for this study; a dedicated grid battery charger; an inverter that can serve in either grid-connected or isolated, off-grid modes; and a monitoring and control system. Lithium-ion batteries were available but not included in this study. It was felt that lead acid batteries might work, based on the anticipated few hours of control (about 150) a year. The system includes an option for connection of a PV array through either a maximum-power, point-tracking controller provided by SP or an external controller. OnDemand™ Energy Appliance specifications are shown in **Table 13.1**.

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

Table 13.1: OnDemand™ Energy Appliance Specifications

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

As shown in the table, the battery inverter is rated at 4.6 kW or 9.2 kW. The batteries installed during this demonstration by SP are GS-Yuasa 246 Amp-hour (AH) batteries that can produce 11.8 kWh or 23.6 kWh over a 20-hour discharge time. In discussions with WHCEA and MVEC, when the system is discharged over a quick 2 hours (WHCEA) and a 1-hour discharge time (MVEC), the peak output from the battery rated at 4.6 kW will be limited to less than 4.6 kW while also limiting the Depth of Discharge[40] (DOD) to <60% (WHCEA) or <80% (MVEC). This is because of Peukert's law, developed by the German scientist W. Peukert in 1897. He expressed the energy capacity of a lead acid battery as the rate at which it is discharged. As the rate increases, the battery's available energy capacity decreases (primarily from I^2R losses due to the series resistance in the batteries). With a limitation on the percentage of depth of discharge, as

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

the energy capacity of the battery decreases due to rate of discharge, its maximum kW output during the rapid discharge times also decreases.

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

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

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

2.2 Installation

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

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

Figure 13.1 shows a simplified installation wiring diagram.

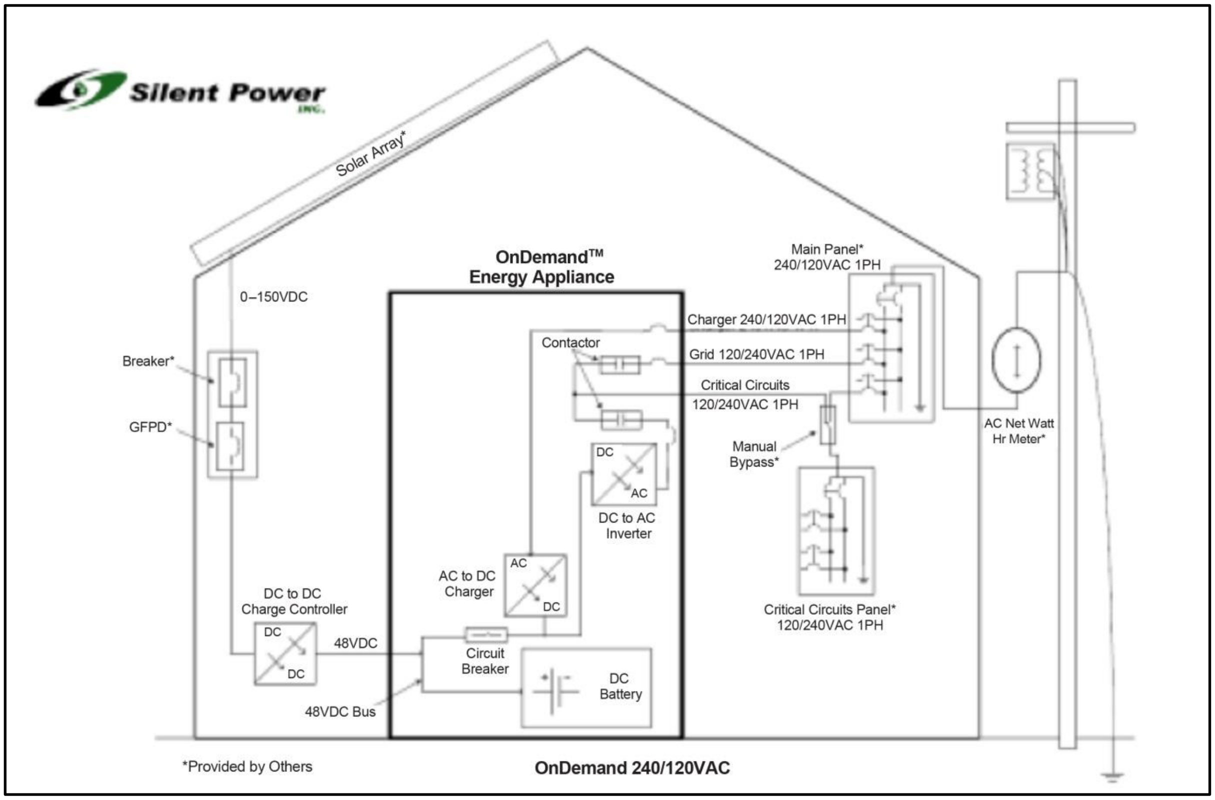


Figure 13.1: Simplified SP Installation Wiring Diagram

Project-Specific Installations

Table 13.2 shows the installation details for the units purchased for this project.

Table 13.2: Installation Details for the Units Purchased

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

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

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

Experience

Installation of the SP units began in July 2012 and was completed by August 2013 (see **Figures 13.2 and 13.3**). The co-ops experienced delays in installation, due primarily to control software issues and communications problems with the SP systems. These eventually were resolved.

Figure 13.2: 9-kW SP Unit with Cover Removed

WHCEA noted some specific issues with the installations:

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

Figure 13.3: Display on SP Appliance

2.3 Operation

General Operation

In normal operation, the battery charge circuit is turned off; the majority of power flows directly "across" the SP inverter bus to the critical load panel. The only losses in this state are the self-discharge of the battery and the "tare losses" (parasitic losses)[41] required to run the control system. Periodically, the software is instructed to charge the battery. There are two stages to this charge—a bulk charge and an "absorption" charge. The MVEC nominally rated 4.6-kW units were recharged on a daily basis and drew an average of about 40 watts per hour during periods for the tare load, even if the unit was not dispatched. This would put the tare loss and battery maintenance at about 29 kWh per month, or a little more than $3 for the 4.6-kW unit and $6 for the 9.2-kW unit at retail rates. If a power outage occurs, the unit will disconnect from the grid and supply power directly to the Critical Circuits Panel, forming an intentional "island" that operates separately from the main power grid. This continues either until the battery is fully discharged (at which point the battery is disconnected) or grid power is restored and stable for five minutes, at which point the system will reconnect to the grid. If a PV array is used, the array can recharge the battery during sunlight hours during this "islanded" period.

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

Project-Specific Operation

MVEC discharges its units at full nominal rated power (4.6/9.2 kW) until the battery is discharged to 80% battery DOD in the 1 hour it predicts will be the peak for the month. On average, it discharges the units about four or five times a month while attempting to hit the monthly peak demand. The battery is predicted to have a cycle life of about 450 cycles when operated at 80% DOD, as shown in **Figure 13.6**. Thus, if the units are discharged five times a month, the life of the battery will be about 90 months, or about 7.5 years. WHCEA discharges its units over a 2- to 3-hour period and usually discharges the batteries only down to 60% DOD, hoping to extend their life. The life of the battery when discharged down to 60% DOD is expected to be about 700 cycles, or about 12 years, if used five times a month. Federated discharges its unit at a 2.3-kW rate for one or two separate 1-hour periods, depending on the season. (Some winters may have two peaks; one in the morning and one in the afternoon or early evening; summers have afternoon peaks only.)

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

[41] Loss caused by a charge controller.

Maintenance Requirements

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

2.4 Data Collection

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

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

2.5 Economic Evaluation

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

A detailed analysis that calculates payback for future commercial units based on using detailed assumptions regarding the components is shown in **Table 13.3** for WHCEA and **Table 13.4** for MVEC. The assumptions used include the following:

- Electricity is valued at 11.7 cents per kilowatt hour (kWh) when discharged into the grid; when recharging, the battery is charged 4.9 cents per kWh.
- The datasheet rating of the battery in the small system is 246 amp-hours at 48 volts, or 11.8 kWh at the 20-hour rate. As mentioned previously, however, the nominal ratings are assumed to be 4.6 kW and 9.2 kW; if discharged quickly over a 2-hour period, the ratings are assumed to be 2.7 kW and 5.5 kW, respectively. If discharged at the fast rate of 1 hour, the ratings are assumed to be 3.2 kW and 6.5 kW, respectively.
- As mentioned previously, the actual useful storage of the battery is diminished because of reduction in capacity due to high rate of discharge, conversion of energy from DC to AC, and reserving some capacity to prevent damage to the battery during excessive discharge.
- System round-trip efficiency is 60%, based on 85% efficiency for the electronics in each direction and 83% DC round-trip efficiency quoted for the GS Yuasa 260 amp-hr. battery. However, while both the inverter efficiency and DC efficiency of the battery decrease as the battery discharges faster, that effect has not been included in this analysis.
- For the nominally 4.6 kW rating of the GS Yuasa 260 amp-hr. battery, there is a 40-watt continuous tare load (a parasitic load), including maintenance charges on batteries when not in use.
- It is assumed that eight cycles per month currently are required to meet the two demand peaks; each cycle lasts for ≈1.2 hours, resulting in an 80% discharge. It is assumed that about five cycles per month are required to meet a single demand peak.

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

Table 13.3: Battery Energy Storage Project Detailed Payback Analysis for WHCEA, Assuming 2-Hour Discharge, 5 Cycles per Month, 60% DOD

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

Table 13.4: Battery Energy Storage Project Detailed Payback Analysis for MVEC, Assuming 1-Hour Discharge, 8 Cycles per Month, 80% DOD

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

(The complete spreadsheets for the analysis of **Tables 13.3** and **13.4** are available upon request and posted on the NRECA CRN SharePoint.)

Some important observations and conclusions follow:

1. Battery storage has very limited (if any) payback when installed for peak load management or energy arbitrage (buying low-cost energy at night and redeploying it into the grid on peak). The only case that showed a small positive payback was the assumption of a lower-cost 10-kW SP battery system at $13,015 plus $1,000 for installation, compared to today's $18,800 for the SP battery system plus $1,200 for installation. All other cases had a negative net lifetime benefit, primarily because of the following factors:
   a. The demand charge savings alone are not enough to offset the capital cost of the equipment and installation.
   b. Lead acid batteries have a short life cycle if operated to a less than 60% DOD on a regular basis. Lithium-ion batteries were not tested in this study.
   c. The cost of equipment needs to come down. We feel this will happen for battery storage, as it did for solar panels. These dropped from $8/watt to under $1/watt once mass production and a competitive market developed. Companies like Tesla Motors and Solar City are working on bringing mass marketing of Lithium-ion batteries and solar PV to the U.S., and legislators and regulators are starting to provide incentives for solar. When lower costs and longer cycle life for batteries (probably Lithium-ion) are achieved, battery storage may have a return on investment for demand charge savings.
2. The case for battery storage is better if there is not only a peak load management application, but also usage in "premium power" applications, in which the customer is looking for better reliability and is willing to pay a monthly fee for the service—for example, $25−$30 per month.
3. The case for battery storage is best when combined with solar. In fact, solar should be combined with battery storage if the utility system peak is late in the day—after 6:00 PM, for example. Solar alone will cause cost-shifting to other members because it reduces kWh energy purchases but does not significantly reduce the kW demand. The effect is to reduce the utility's load factor, which could drive up the cost/kWh. **Figures 13.4** and **13.5** illustrate this issue.
4. Note that there is no assumption of any annual operation and maintenance costs. If the electric cooperatives have to send a technician out to each of the batteries once a year at a cost of $100 per visit, all cases will have a negative payback—even the one case that showed a positive payback here.

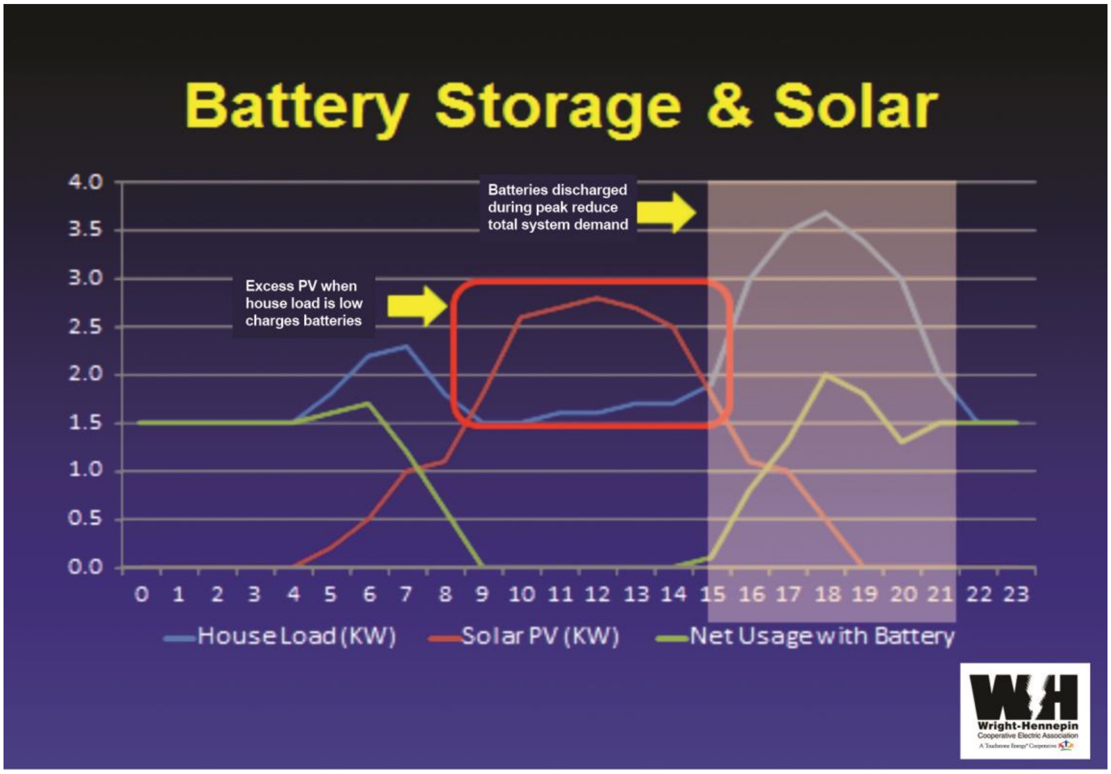


Figure 13.4: Battery Storage and Solar

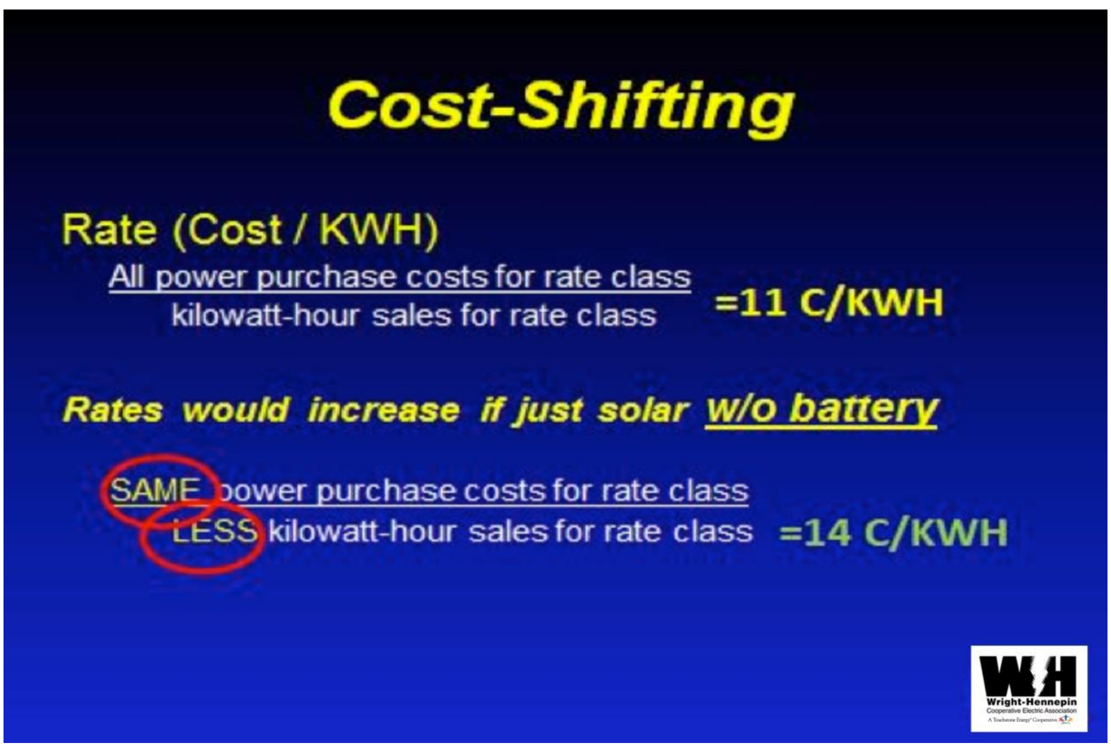


Figure 13.5: Cost-Shifting from Solar without Storage

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

1. As noted in **Figure 13.6**, the capacity of a VRLA battery goes down as the discharge rate increases. Different lead acid batteries are designed to be optimum at differing discharge rates. It is important to understand the full performance characteristics of a particular battery when attempting to determine whether these batteries overall will be viable in any given application. Obviously, if the cost for technology such as Lithium-ion batteries can be reduced to $500/kWh or (about $14,000 total installed cost), these batteries will be the preferred option, as they have cycle lives of 3,000 cycles or more at 80% DOD and 125,000 cycles at 10–20% DOD. The electric cooperative then could have the option to bid Lithium-ion batteries into the frequency regulation market as well as for demand charge reduction; this would open up a second value stream, further strengthening the financial return of battery energy storage systems.

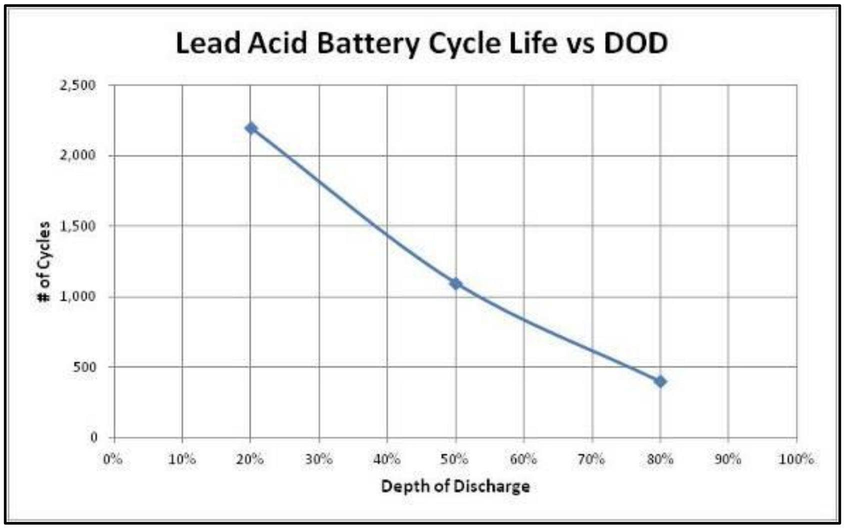


Figure 13.6: Lead Acid Battery Cycle vs. DOD

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

3. PROJECT IMPLEMENTATION AND RESULTS − THERMAL ENERGY STORAGE

3.1 Enabling Technology

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

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

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

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

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

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

The advantages of this technology include the following:

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

3.2 Installation

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

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

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

3.3 Operation

Project-Specific Operation

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

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

Figure 13.7: Typical Example of a GETS System Integrated with a 105-Gallon Marathon Hot Water Heater, on display at the PJM RTO (courtesy of Steffes Corporation)

A typical example of a GETS system is on display at the PJM headquarters, as shown in **Figure 13.7**.

3.4 Data Collection

Data are collected via a system developed by Steffes (**Figure 13.8**).

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

Figure 13.8: Steffes Data on Temperature, Power, and Energy for an Individual Water Heater

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

Initially, the plan by GRE and Steffes Corporation was to charge the hot water heaters at a 1.5-kW average heat-up during off-peak periods and swing up to 3 kW or down to 0 kW to respond to an ACE signal. However, as shown in **Figure 13.8** (the blue line) and **Figure 13.9**, the Steffes Corporation strategy is to charge using a valley-filling input strategy.

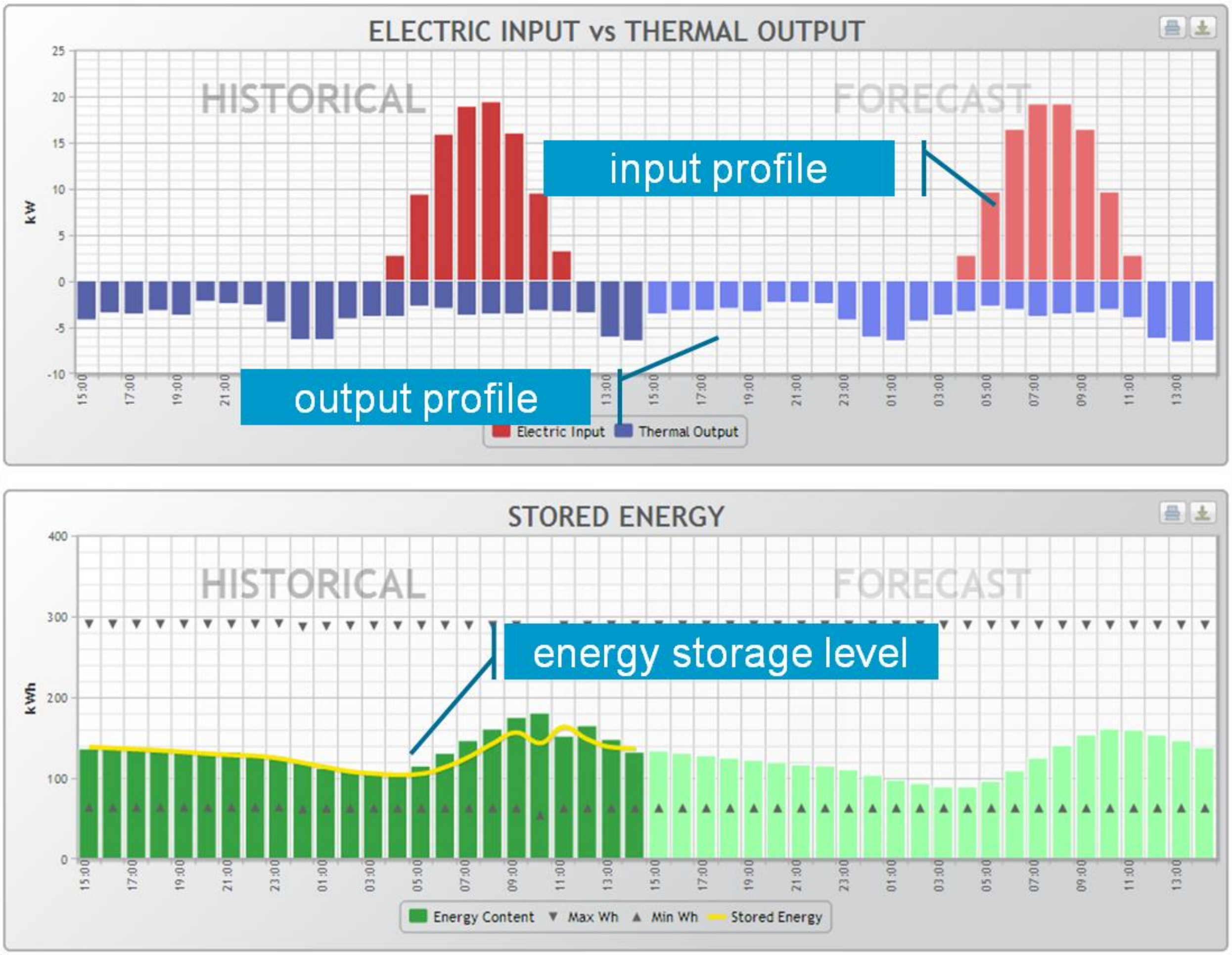


Figure 13.9: Steffes Corporation Valley-Filling Input Strategy

Steffes uses a valley-filling input strategy while simultaneously doing up and down fast regulation as needed for the aggregated 10 hot water heaters in the demonstration (as shown in **Figure 10**). Basically, the strategy is to begin slowly charging the hot water heater at 11 PM when the loads and the MISO LMP are still high (see **Figure 13.12** on LMP for MISO—$25/MWh at 11 PM) and then increase the average charge rate to 2 kW or more per hot water heater at 3 AM, when the loads and the LMP are lowest ($20/MWh) (shown as the red bars in Figure 9). This demonstrates valley filling of the off-peak loads and LMP. The average energy output profile is represented by the blue bars in **Figure 13.9**; the cumulative energy stored as thermal energy is shown in green and by the yellow line in the lower graph.

In **Figure 13.10**, the response to the simulated ACE signal from GRE is shown over a 2.5-hour time interval for the aggregated group.

In **Figure 13.10**, the load response from the GETS system is requested by the simulated ACE signal from GRE and plotted with the reported load. The plot occurs over a 2.5-hour time interval and shows near coincidence of the reported load relative to the requested load for frequency regulation.

Figure 13.10: Near Coincidence of Requested vs. Reported Load from GETS System Aggregated Group in Response to Simulated ACE Signals for Frequency Regulation

A more detailed evaluation of the fast response of the GETS to a simulated ACE signal in the current demonstration is shown in **Figure 13.11**. The load response in the left-hand graph is a function of the current 90-second latency in reporting the results. However, the Steffes Corporation is developing a controller and monitoring system that will reduce the latency to less than 10 seconds, as shown in the right-hand graph in this figure. The latency includes the communications latency back to the Steffes controller and monitoring system, computer analysis, and web site, referred to as the head-end system.

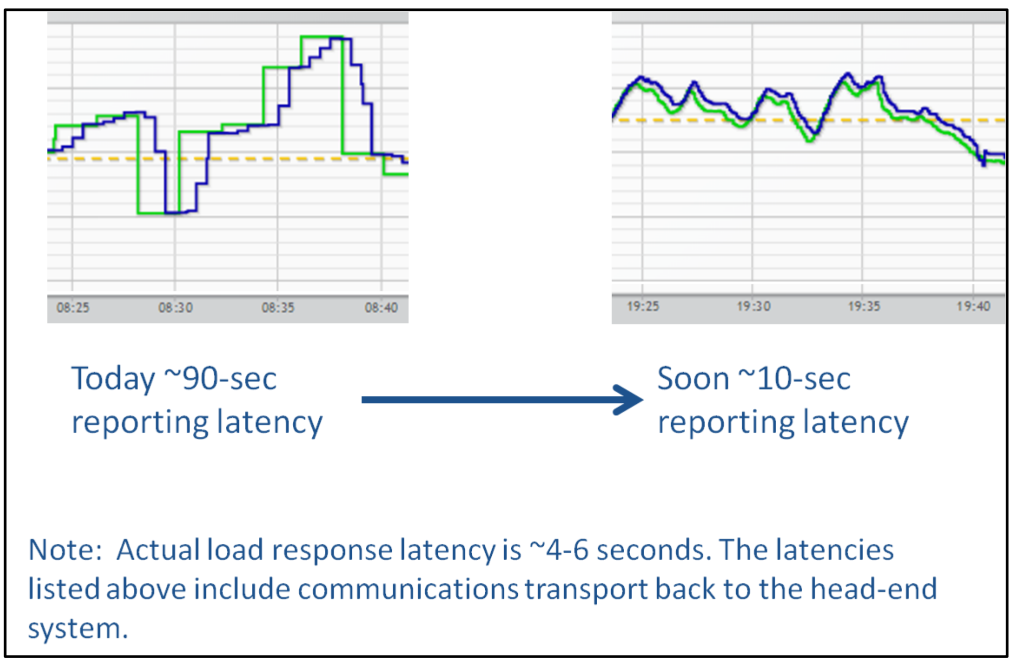


Figure 13.11: Detailed Steffes GETS System Load Response

3.5 Economic Evaluation

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

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

Over time, the MISO RMCP may increase to pay for additional fast-response frequency regulation. Conversely, for performance, the PJM RTO is paying a much higher price for fast regulation by paying a Regulation Market Capability Clearing Price (RMCCP) *and* a Regulation Market Performance Clearing Price (RMPCP). In 2013, the MISO RMCP averaged about $8.55/MWh for the year for all of the hours in a day, as noted in **Figure 13.12**. The line LMP minus RMCP is the effective cost for heating hot water and averages only $10/MWh if the hot water heater utilizes the Steffes Corporation GETS system for providing frequency regulation.

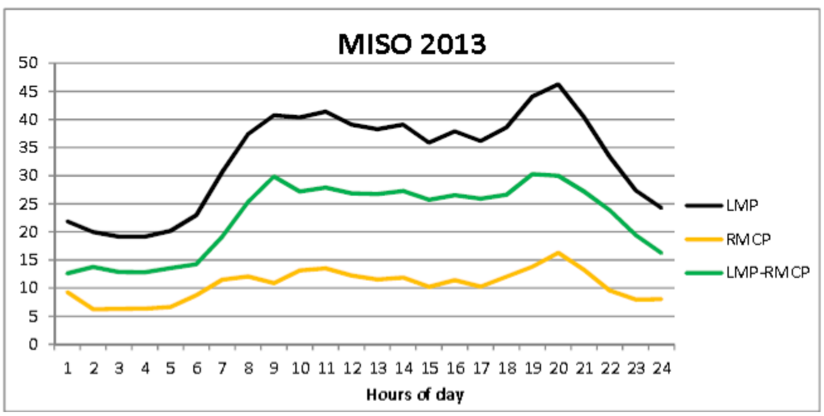


Figure 13.12: Average Hourly Prices in MISO in 2013 for LMP, RMCP, and LMP minus RMCP

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

Based on the MISO off-peak average price of $7/MWh, the equipment cost of $700 for the Steffes controller for this demonstration,[42] $75 for the mixing valve, $10 for shipping, and approximately $250 for installation (assuming no learning curve), the initial investment is not economical, given the current prices for MISO RMCP and the cost of acquisition and installation of the GETS system. **This assumes that the costs will be avoided for the current DSM**

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

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

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

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

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

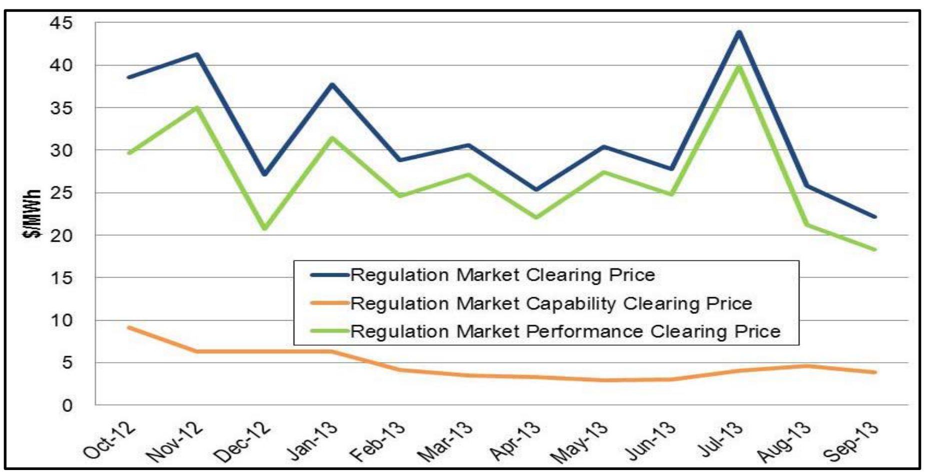


Figure 13.13: PJM Regulation Market Clearing Price, Oct 2012–September 2013. (Source: Oct 14, 2013 PJM RTO report to FERC on analysis of performance-based regulation for frequency regulation)

In **Figure 13.13**, the PJM RTO RMCP from October 2012 through September 2013 was about $31.64/MWh for all hours. This was significantly higher than the MISO RMCP of $8.55/MWh. Even the PJM RTO RMCCP of about $30/MWh was significantly higher than the MISO RMCP.

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

Figure 13.14 provides more detail on the PJM RTO RMCP, RMCCP, and RMPCP as a function of the time-of-day average for the entire year.

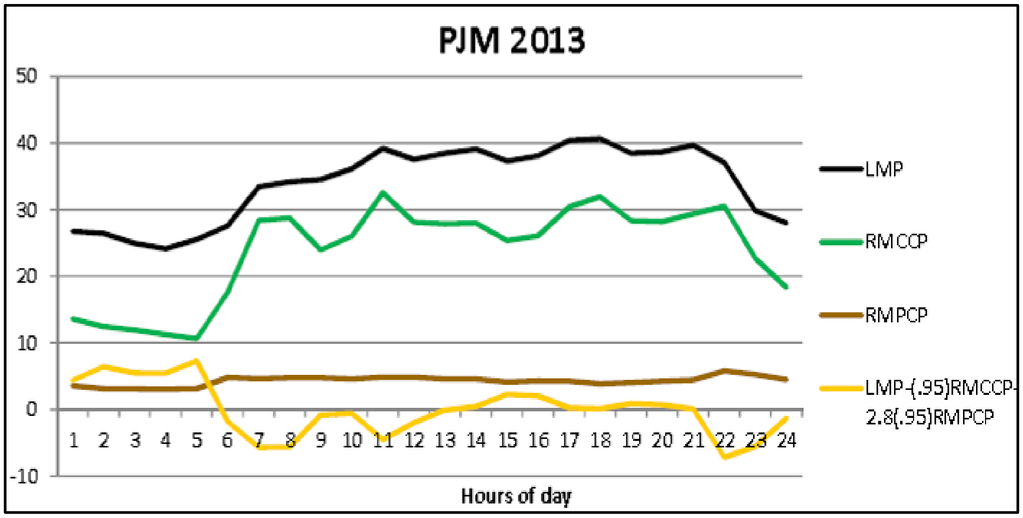


Figure 13.14: PJM RTO LMP, RMCCP, and RMPCP as a Function of the Time-of-Day Average for FY 2013

The equation and data for Locational Marginal Price developed by Steffes Corporation is LMP = (0.95*RMCCP) - (2.8*0.95*RMPCP), which represents an estimate of the average cost to heat a hot water heater providing frequency regulation. The "mileage factor" of 2.8 is calculated by the Steffes Corporation, which the PJM RTO calculates as a "marginal benefits factor" (discussed in more detail below). Of course, since the Steffes Corporation GETS system was set to operate only during the off-peak hours (11 PM to 7 AM), the average cost to heat the hot water was nearly zero (the yellow line). What is interesting and counterintuitive for the PJM RTO is that, with dynamic dispatch and an algorithm that would predict day-ahead LMP, RMCCP, and RMPCP (with mileage or marginal benefits factors), the lowest-cost time for charging the hot water heaters in the PJM RTO area would be the 3 hours between 6 AM and 9 AM, the 2 hours between 11 AM and 1 PM, and the 3 hours from 9 PM until midnight (for a total of 8 hours of charging throughout the day). Of course, in the case of MISO, the current optimum time for charging the hot water heaters is the 8 hours from 11 PM until 7 AM, as indicated in **Figure 13.12**. A great benefit of the Steffes GETS system is that it can be set to optimize the economics by weighing the compensation for frequency control against LMP prices and then selecting the combination that provides the best return.

3.6 More Detailed Discussion of Frequency Regulation Markets

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

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

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

3.7 Summary of the Economic Evaluation

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

4. CONCLUSIONS

4.1 Effectiveness of Battery Energy Storage in Meeting Utility Needs

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

4.2 Effectiveness and Benefits of Thermal Storage in Meeting Utility Needs

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

4.3 Overall Assessment of the Storage Demonstration

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

5. RECOMMENDATION FOR FURTHER STUDY

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

Chapter 14:

Multi-Tenant Meter Data Management – A Systems Approach to Hierarchical Value

INTRODUCTION

Cooperatives cooperate, and sometimes this means innovating to enable such cooperation. As part of the Smart Grid Demonstration Project (SGDP), Great River Energy (GRE), Lake Region Electric Cooperative (LREC), Minnesota Valley Electric Cooperative (MVEC), and National Information Solutions Cooperative (NISC) have come together to create a secure information-sharing framework that allows cooperatives within GRE's service area to cooperate, collaborate, and coordinate with more agility than previously possible. Leveraging this system, the cooperatives achieve many of the benefits and economies of scale, while also maintaining local control.

Research Questions

1. What needs does a multi-tenant meter data management system (MT-MDMS) meet for each of its tenants?
2. What are the functional and technical requirements necessary to meet those needs?
3. What is the potential value of an MT-MDMS to the broader industry (utilities, ISOs, research consortiums, owner-members)?
4. What are the barriers to the creation and adoption of this technology?
5. What role did the SGDP play in accelerating the development of this technology?

Important Findings

1. A defining feature of an MT-MDMS is the ability to aggregate data programmatically into "virtual meters" and share those data across organizations.
2. Information security—specifically, flexible, role-based access controls—is the most critical enabling feature for making an MT-MDMS viable.
3. The role-based information security framework opens the door to offering appropriate meter data access to other industry stakeholders.
4. The necessity of writing custom interfaces to other utility data systems is a significant cost and delay driver for an MT-MDMS, and it contributes to implementation delay.
5. This technology was enhanced by the DOE NRECA Smart Grid Demonstration.

NRECA OVERVIEW

NRECA received a $34 million Smart Grid Demonstration research grant from the U.S. Department of Energy (DOE). The resultant project, coordinated by NRECA's Cooperative Research Network (CRN), purchased the necessary equipment on behalf of NRECA's participating member cooperatives. Twenty-three of NRECA's member electric cooperatives embarked on a unique, nationwide demonstration project, deploying more than 250,000 smart grid components across the country to test the value of the new technologies for cooperative consumer members.

CRN and the participating electric cooperatives are evaluating the potential benefits of new technologies that could help increase operational efficiencies and improve electric service.

COOPERATIVE BACKGROUND

Great River Energy (GRE) is a not-for-profit electric cooperative owned by its 28 member cooperatives. GRE generates and transmits electricity for members located in the outer-ring suburbs of Minneapolis-St. Paul, Minnesota, up to the Arrowhead region of Minnesota and down to the farmland region in the southwestern portion of the state. Collectively, GRE's member cooperatives serve nearly 645,000 member-consumers.

The RFP discussed in this study concerns a procurement of an MDMS for GRE and two of its distribution member cooperatives: Lake Region Electric Cooperative (LREC) and Minnesota Valley Electric Cooperative (MVEC) (circled in **Figure 14.1**).

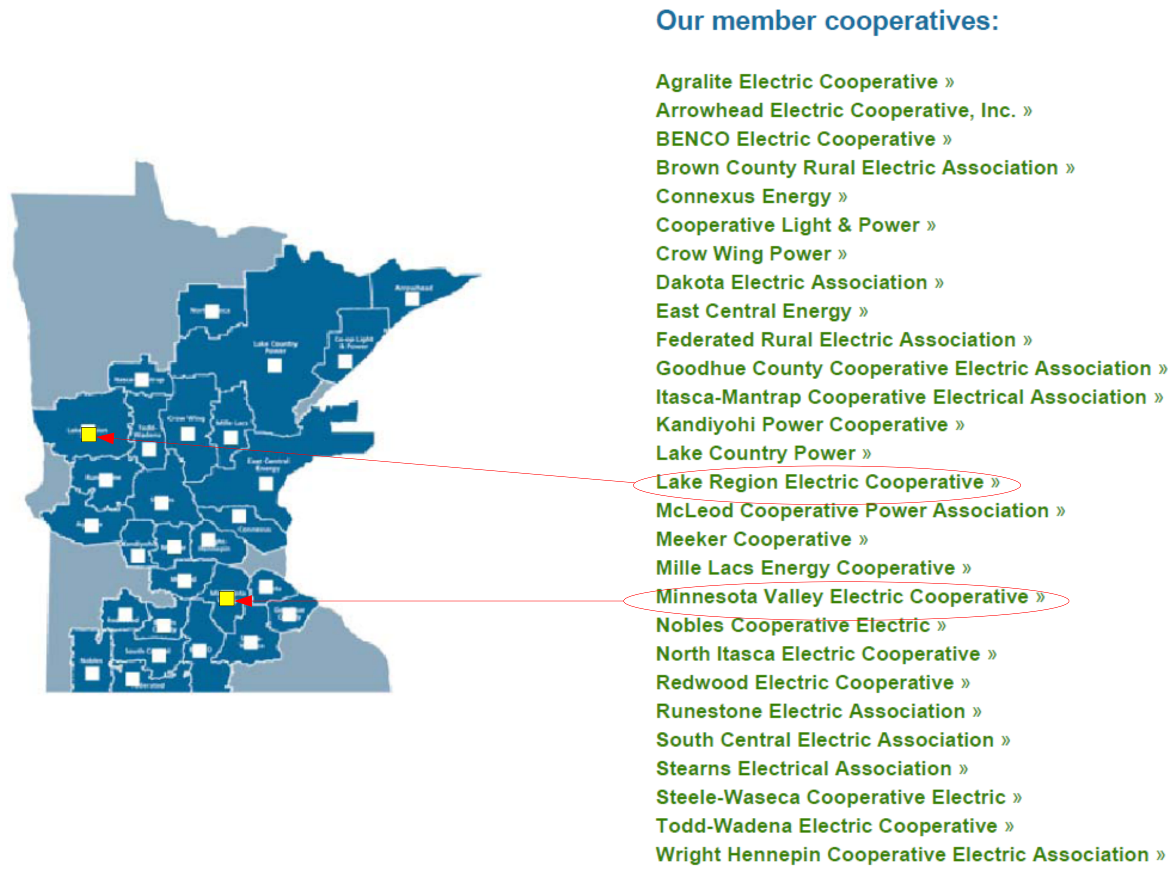


Figure 14.1: GRE Member Cooperatives

LREC provides retail electricity to more than 26,000 member-consumers. It has more than 31,300 advanced meter infrastructure (AMI) meters over a 3,200 square-mile service territory. Located in the west-central portion of Minnesota, LREC is a non-profit electric cooperative dedicated to providing power and opportunity to the areas it serves.

MVEC is an electric power distributor headquartered in Jordan, Minnesota. MVEC distributes electricity to 34,000 member-owners across nine counties in Minnesota: Blue Earth, Carver, Dakota, Hennepin, Le Sueur, Rice, Scott, Sibley, and Waseca.

METHODOLOGY

This study was conducted by examining the MT-MDMS specification and the correspondence between GRE and NISC during the procurement process to determine the system requirements and identify barriers to development and adoption. This was augmented with interviews with expert staff at NISC and GRE, so as to better understand the challenges, as well as the value, of an MT-MDMS.

DETAILED RESULTS

What needs does an MT-MDMS meet for each of its tenants?

In the procurement documents for the MT-MDMS, Great River Energy described its needs for the system.

Table 14.1: Great River Energy's MT-MDMS project goals as described in the RFP.

Project Goals

The purpose of this project is to demonstrate if a multi-tenant demand response and meter data management architecture will provide an economical solution for creating a comprehensive next-generation demand response environment in which cooperative members and renewable resources may interact with wholesale market prices.

This project represents the collaborative effort of three companies: Minnesota Valley Electric Cooperative (distribution cooperative), Lake Region Electric Cooperative (distribution cooperative), and Great River Energy (generation and transmission [G&T] cooperative).

GRE and its member systems currently operate an industry-leading load management program. The program is managed centrally by GRE and generally utilizes one- and two-way communications to load management receivers controlling air conditioning, space heating, water heating, irrigation, commercial/industrial, and electric-thermal storage. Changes in technologies and regulations are providing an impetus to develop the next-generation load management environment. Supporting the next-generation load management environment will require gathering data at several levels across the organizations and throughout each organization. GRE desires to evaluate a meter data management system's capability to efficiently gather and represent these data in a meaningful way.

To accomplish this goal, Great River Energy will implement the following technologies:

- Multi-tenant Meter Data Management (MDM) system
- Multi-tenant Demand Response Management (DRM) system

This next-generation demand response environment will enable the following objectives to be achieved:

1. Prove a functional and economic framework for a multi-tenant DRM and MDM environment in which multiple AMI systems will be integrated into the selected MDM.
2. Prove a security framework for multi-tenant DRM and MDM environment.

The system shall:

- Support approximately 80,000 physical metering endpoints across three individual organizations and 5,000 virtual meters
- Integrate metering data from multiple AMI systems
- Perform Validation, Editing, and Estimation (VEE) on metering data
- Support Complex Billing determinants utilizing interval data
- Aggregate meter data and apply logic to adjust meter data
- Sum meter data to a common interval (totalization)
- Create event markers on end-user meters, substations, distribution cooperatives, G&Ts, or wholesale market point
- Perform Data Analytics on input data for various operational, business, and billing purposes
- Present energy consumption information to end consumers
- An objective of this deployment is to demonstrate a multi-tenant system that will provide the following capabilities:
  - Logically partition metering data for G&T and member distribution cooperatives
  - Maintain data privacy and security
  - Grant full and/or limited access to meters and their related attributes to other organization(s) utilizing role-based permissions
  - Exist as an off-premise (hosted by vendor) or on-premise (utility-hosted) solution

Of these requirements for the system, the last four are the defining characteristics of an MT-MDMS.

What are the functional and technical requirements necessary to meet those needs?

GRE developed a detailed specification for the functional and technical requirements for the Multi-Tenant Meter Data Management and Demand Response Systems, found in Appendix 14A of this report, along with NISC's comments on those requirements. However, now that the system has been delivered and is starting to be used, two features stand out as being particularly important in making this multi-tenant environment work: virtual metering and secure data warehousing.

Virtual Metering

The MT-MDMS allows for the definition of "virtual meters." A virtual meter is a selective aggregation or "roll up" of a subset of the meters in the system, which then may be viewed, shared, and analyzed as if they were a single physical meter. This selection need not be a static list: the virtual meter is defined programmatically, according to meter attributes in the system. Those attributes include the distribution utility, rate class, substation, and participation in a particular program (e.g., demand response).

Virtual meters can be used for vertical aggregation, to sum up the usage for a distribution cooperative.

Vertical Aggregation

Figure 14.2 depicts vertical aggregation needs to sum meters with logical hierarchy. The example uses a cooperative and the substations serving that cooperative's load as the logical hierarchy. Summing the substation meters serving a cooperative's load creates a virtual meter point for the cooperative.

See functional and technical requirements 17 through 25 and 43 through 44 in Appendix 14A.

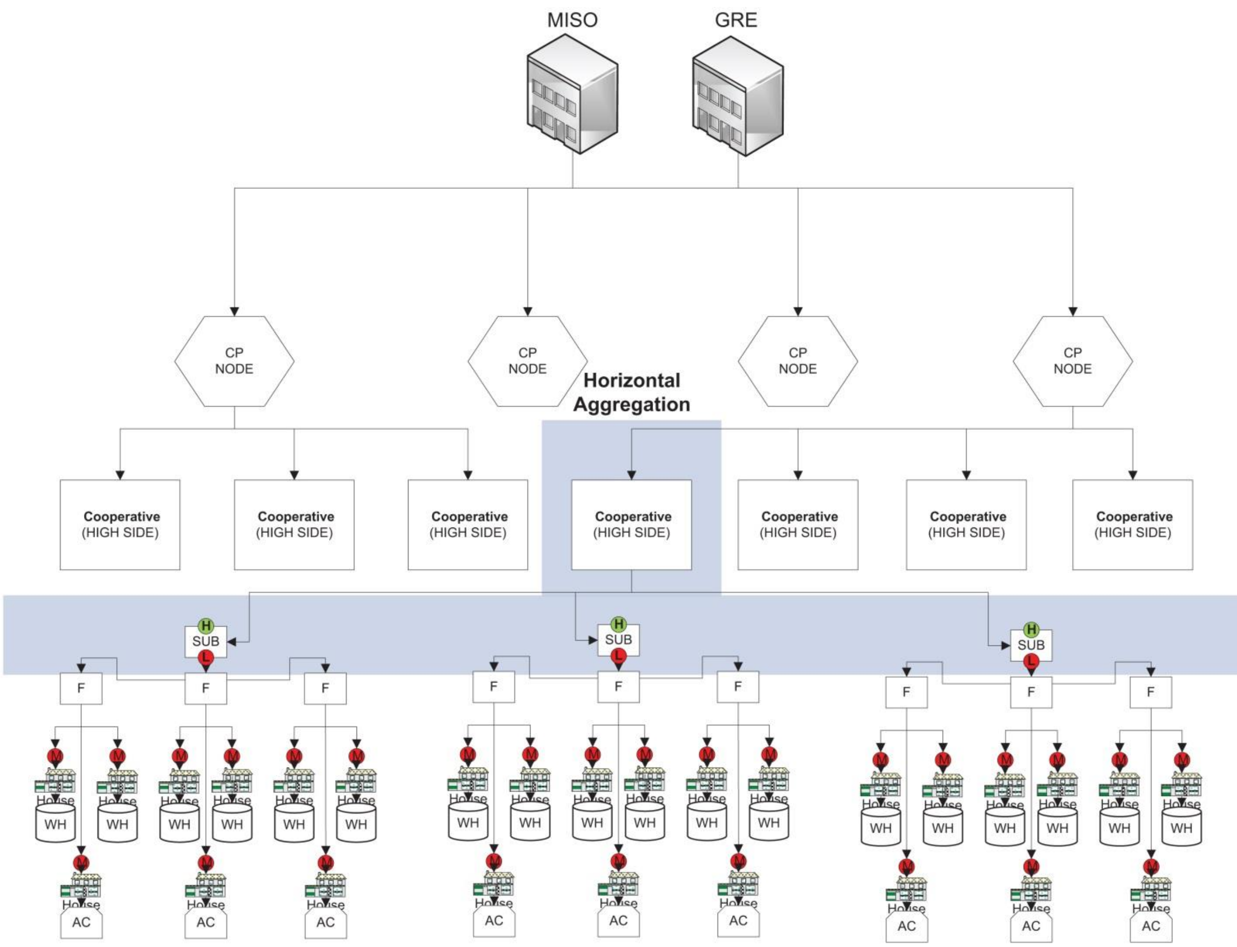


Figure 14.2. Vertical Aggregation Sums Meters with Logical Hierarchy

Virtual meters also can be used for horizontal aggregation, summing meters with certain attributes across utilities.

Horizontal Aggregation

Figure 14.3 depicts horizontal aggregation needs to sum meters with similar attributes. The example uses demand response programs as the key attribute by which to aggregate. All accounts with a controlled water heater are aggregated to a single virtual meter.

See functional and technical requirements 17 through 25 and 43 through 44 in Appendix 14A.

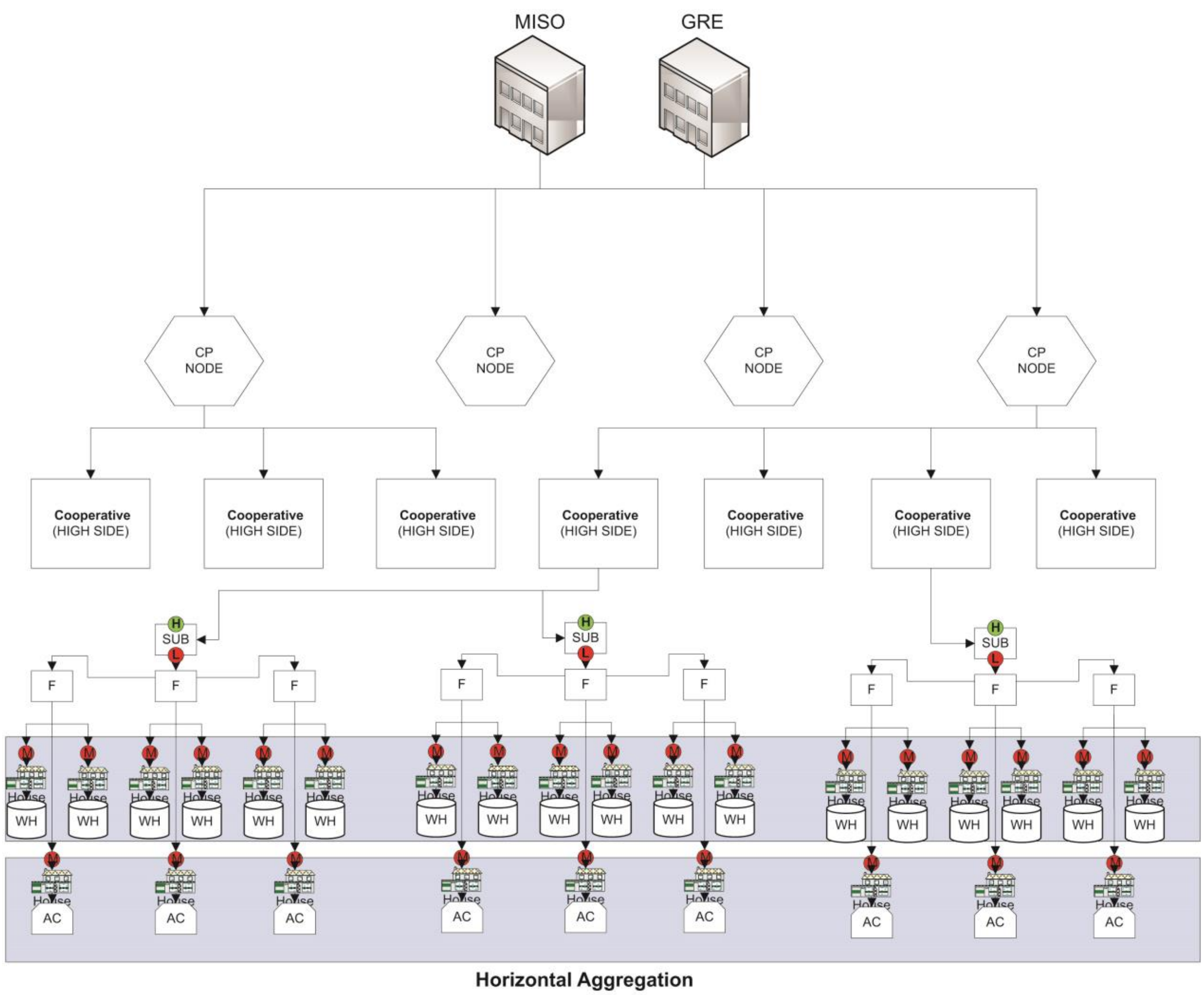


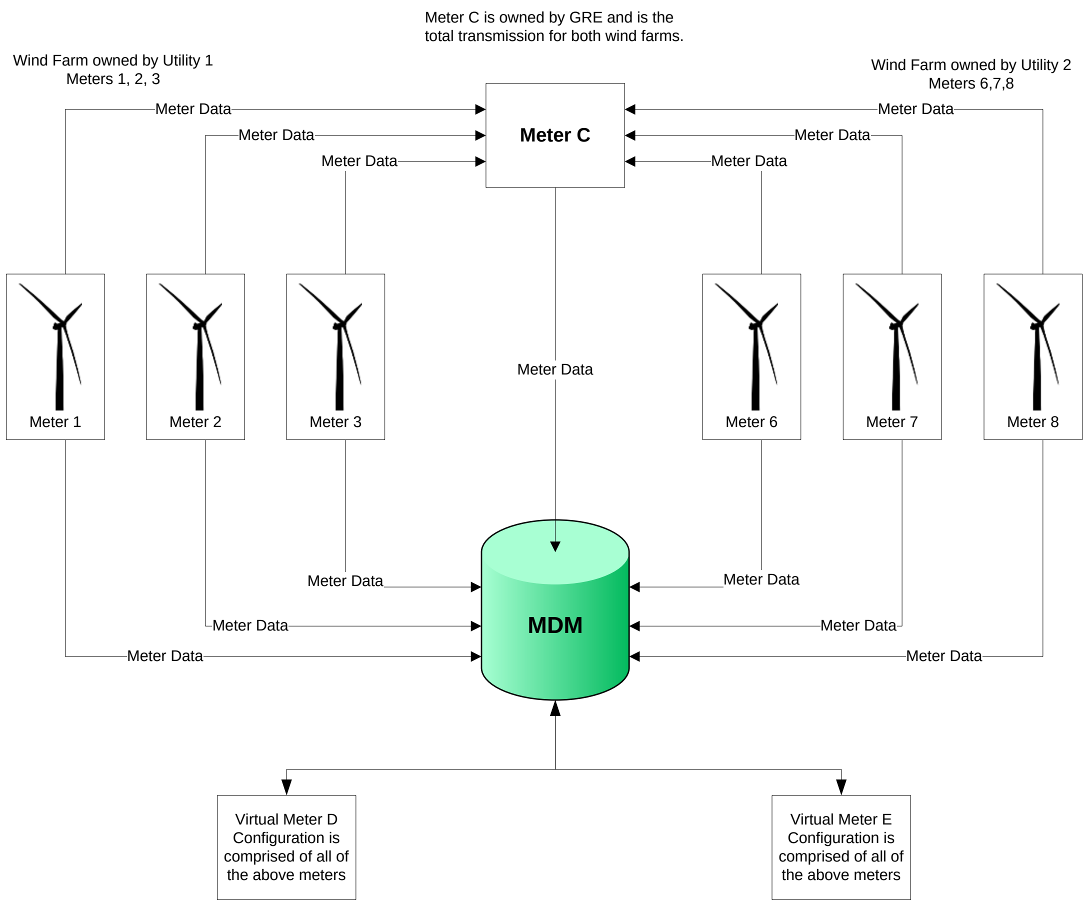
Figure 14.3: Horizontal Aggregation Sums Meters with Similar Attributes

These virtual meter definitions also can be used to conduct calculations on both real and virtual meters with math functions.

If-Then Aggregation Logic

Figure 14.4 provides an example of one of the types of aggregation the MT-MDMS provides.

See functional and technical requirement 23 in Appendix 14A.



<u>**Aggregation Logic Needed**</u>

If sum(meters(1+2+3+6+7+8)) + Meter C = 0 then
  Virtual Meter D = 0
  Virtual Meter E = 0

Else If sum(meters(1+2+3+6+7+8)) = 0 AND Meter C > 0 then
  Virtual Meter D = Meter C * .5
  Virtual Meter E = Meter C * .5

Else
  Virtual Meter D = Meter C / sum(meters (1+2+3+6+7+8)) * sum(meters (1+2+3))
  Virtual Meter E = Meter C / sum(meters (1+2+3+6+7+8)0 * sum(meters (6+7+8))

Figure 14.4: If-Then Aggregation Logic

Central Data Warehousing

NISC hosts the data for the MT-MDMS in a single database. The system logically separates the data by utility. Each utility owns its data and establishes the permissions pertaining to them. For instance, authorized personnel at a distribution co-op may choose to make one of their meters available for read-only access by GRE, the G&T. Within an organization, access is granted to personnel inhabiting a given role pertaining to the granularity of a meter.

This system is a flexible framework for applying the principle of "least privilege" to meter data. This means that it is oriented toward granting each user of the system the smallest amount of access necessary to conduct the duties assigned to his or her "role" in the system (i.e., his or her job). Colloquially speaking, meter data are shared on a "need-to-know" basis.

The security of a role-based access control system can only be as good as the security of its host. The security of NISC's hosted database was verified by GRE's information security specialists, who were permitted to run penetration tests against NISC's cloud-based hosting solution.

What is the potential value of an MT-MDMS to the electric power industry?

Secure, Real-Time Information Sharing

GRE staff emphasize the synergy between centralized data hosting and virtual metering in allowing them to share information effectively without jeopardizing the privacy of their members: virtual meters provide a way to share complicated aggregates of meter data in real time without divulging the underlying data from which the virtual meter was derived, while the shared hosting environment allows data to be shared without duplication.

Before this system was available, staff at GRE and its distribution cooperatives were aware of ways in which it would be useful to share meter data but in many cases they did not do so because of the time intensity of the processes to exchange data. Centralized hosting of the database reduces the time needed to share data. Previously, this entailed each cooperative tabulating meter data manually as a batch process and sharing the results via email. With virtual metering, intricate tabulations for a given cooperative's data can be defined as a virtual meter, which is always up to date and available to those personnel who need the sums—but not the addends—of those tabulations.

Bidding Demand Response and Other Storage Resources into MISO

The MT-MDMS was conceived to support dispatch, accounting, and measurement and verification of demand response resources spread across different distribution utilities. Previously, all of these tasks were performed manually. Dispatch was conducted via day-ahead emails. Accounting was conducted through time-consuming monthly batch submissions. Under the new system, dispatch is conducted via the multi-tenant demand response system, and data are collected automatically via virtual meters at every participating distribution cooperative. These virtual meters pertaining to the various demand response and storage assets on its system allow GRE to verify the efficacy of these resources in reducing demand and demonstrate it to the Midcontinent Independent System Operator (MISO).

Monitoring Line Losses and Power Theft

This system makes it easy to track system losses all of the time by defining a "losses" virtual meter as the hourly aggregate of load meters subtracted from the substation meters serving those loads. A "losses" meter then can be monitored for fluctuations that would strongly imply power theft.

Load Forecasting

The MT-MDMS can be used to better forecast future loads by allowing more nuanced and intuitive analysis of the differing consumption patterns among ratepayers or groups of ratepayers.

What are the barriers to the creation and adoption of this technology?

A few key barriers existed to the development and adoption of this technology. First and foremost, MT-MDM and DRM systems did not exist before GRE and NISC created them. There were also financial impediments to the acquisition or development of such a system even at a time when the need for such a system was known. Industry education was a third factor—at the beginning of this project, NISC had limited experience with the G&T side of the utility business. According to GRE, this education process was very successful, and the finished product not only met its specifications but exceeded its own vision as to the power and usability of the graphical user interface. DOE solved these three problems by reducing the financial risks involved in the development effort and contributing to the urgency needed to get the project from ideation to fruition by providing funds through the SGDP.

The other impediment to the development of this technology was the insufficiency of existing interoperability standards to support the effort. MultiSpeak was deemed to be the most applicable standard available and was a part of the system specification. However, MultiSpeak currently is missing some of the features that were found to be vital to this effort. GRE engineers asserted that the MultiSpeak methods for demand response programs lacked the features necessary to support GRE's need to start and stop whole programs.

What role did the SGDP play in accelerating the development of this technology?

As stated previously, DOE removed three out of the four impediments to the development of this technology by providing grant funds through the Smart Grid Demonstration grant.

CONCLUSIONS

Multi-tenant systems are those that serve many constituents with a common resource. Multi-tenancy is currently a busy area of research in computer security because of the ascendency of the cloud computing model, in which a given physical server might well be asked to host virtual machines from private entities with orthogonal or competing interests. This is a challenging problem because a multi-tenant system typically is asked to provide a high quality of service to all constituents while also maintaining a high degree of isolation between entities sharing that common, finite resource. These are somewhat competing goals, as has been demonstrated by the use of timing attacks on cloud services to infer what other services are running on the same physical server: such attacks present subtle quality-of-service issues (specifically, latency in acquiring computing resources) that originate from the shared and finite nature of the resource. However, whereas a given cloud-based server might have dozens of individual constituents in need of high-quality service and isolation, electric feeders may have thousands.

Electric grids are the ultimate multi-tenant systems because they provide uniform service and a high degree of isolation to nearly every member of society. The primary method for accomplishing this is the low-source impedance of the electric supply: Ohm's law shows that, all else being equal, the voltage in a home must drop when a neighbor turns on his or her television. Yet it is unusual for this change in a neighbor's load impedance to cause a noticeable change in the quality of our electric service. The voltage change originating from a neighbor's decreased load impedance is insignificant to our appliances, and even to our eyes: voltage "flicker"—variations in voltage that affect the brightness of electric lighting—is rare. The electric supply is a very low-impedance voltage source, and any load impedance sufficiently low to threaten the quality of service of other tenants of an appropriately maintained electric system is termed a "fault" and isolated from the rest of the system by fault protection devices (e.g., reclosers, circuit breakers, fuses, etc.). The low-impedance voltage source that provides a uniform voltage to owner-members regardless of their load is possible because our electric grids historically have been designed for projected future worst-case peak load conditions. In the transmission and distribution areas, this has meant sizing conductors, transformers, and other current-carrying assets much larger than necessary to meet typical loads. This implies that the capacity factor on typical distribution and transmission assets is low.

This peak-driven capacity planning has made the American electric grid a miraculous multi-tenant system-of-systems that has served nearly every member of society with a high quality of service, effective isolation from other tenants, and a century of declining energy costs. However, given the rapidly increasing price of conductors, the development of affordable distributed generation technologies, and the lack of market incentives around operating transmission and distribution assets since deregulation, building and maintaining electric systems in this way is becoming more expensive. Thus, there is considerable incentive to use and manage existing generation, distribution, and transmission assets more efficiently to hold down costs. Using and managing assets more efficiently requires knowledge of where inefficiencies in the system lie and an understanding of which techniques can be used to mitigate them. This pressing market need for advanced analytics and agile grid management is giving rise to a more agile, more data-driven grid.

Meter data management systems increasingly are becoming the "corpus callosum" of the data-driven grid—the nerve center that provides information services to many of the data systems in a utility. This is because the bulk of the data-enabling innovation in asset management, system planning, operations, and consumer programs in many systems originates with meters at the substations and the loads. While load meters historically have been used exclusively for monthly energy metering, electric meters increasingly are becoming powerful sensor packages that can report voltage, power factor, connection status, and complex load impedance in near-real-time. The MDMS is tasked with verification, validation, and analysis of meter data, and interfacing with other systems that rely on the data. Typically, these other systems are owned or leased by a single utility. However, the data and information contained in an MDMS have uses across organizational boundaries.

As part of the Smart Grid Demonstration grant, GRE specified an MDMS that reflected the multi-tenant nature of the electric grid—an MT-MDMS—that would provide a high level of service to and appropriate isolation between GRE and its constituent distribution utilities. This specification was issued as an RFP (per the rules of the DOE contract) to five vendors of meter data management systems. In the bidding process, GRE discovered that there was no such MT-MDMS on the market. NISC was selected as the vendor to provide the MT-MDMS. As is common with novel technology, there have been unforeseen implementation challenges. In this report, we have examined the system requirements for an MT-MDMS and the benefits this system is bringing to GRE and its constituent members, and discussed some of the challenges encountered while endeavoring to meet those requirements.

APPENDIX 14A: DETAILED FUNCTIONAL AND TECHNICAL REQUIREMENTS

MDMS Functional and Technical Requirements
Great River Energy

This document contains a list of your co-op's functional and technical specifications or requirements. Please respond "yes" or "no" in the appropriate space below, depending on whether your system is in compliance with the specification. In all cases, provide a brief commentary describing how your system complies or does not comply. If your system is in partial compliance, please provide an explanation and, if appropriate, offer an alternative.

		Supplier Response	
#	Requirement Description	Yes/No/ Partial/Exception	Comments
	Physical Meter Configuration		
1	The system may integrate with the provisioning to head-end system(s), DRM, and CIS, etc. for the addition/modification of meter configuration attributes.	Yes	MultiSpeak is used for meter asset modifications. There is also an interface for exchanging large amounts of usage data with the demand response management systems (DRMS).
2	The system shall provide the ability to disable and enable a meter and/or meter data from coming into the MDMS and its related processing	Partial	The meters can be moved to groups that have VEE processing turned off. There is not currently a way to keep the data from coming into the MDMS completely. NISC is willing to explore this business need with GRE and add something to the roadmap if necessary.
3	The system shall provide version history and audit trail for meter configuration attributes as modifications occur.	Yes	There is an audit trail for changes to the meter records. There are some of these configuration items that must be considered point-in-time change. For example, if the meter is receiving hourly data for a few weeks and then is changed back to receive only a daily reading, the MDMS will track when these interval changes occurred.
4	The system shall provide the ability to accept meter interval changes.	Yes	The system is designed to accept changes in the length of intervals. For example, if a meter collects 60-minute intervals and then changes to 15-minute intervals in the middle of the month, MDMS will accept this without any changes being made in MDMS.
5	The system shall provide the ability to handle meter data across meter changes occurring during the billing period, including meter changes reported to MDMS after meter readings are reported to MDMS.	Yes	Meter changes are accepted via MultiSpeak.
6	The system shall provide the ability to manually create or import meter configurations.	Exception	NISC is working through the design/development for manually maintaining meter asset information for certain groupings of meters.
7	The system shall provide the following meter attributes: meter ID, description, physical/electrical locations, totalization interval, active/inactive dates, etc.	Yes	These data are retrieved and stored in MDMS. In most cases, these data are provided by the CIS or Meter Asset system to MDMS via MultiSpeak.

#	Requirement Description	Supplier Response Yes/No/ Partial/Exception	Supplier Response Comments
8	The system may provide the ability to customize meter attributes.	Partial	NISC needs to know more specifics about what kind of customization would be needed. As mentioned, there are design/development projects in place to create and maintain meter asset information for certain groupings of meters within MDMS.
9	The system shall provide the ability to prime the MDM prior to go-live by receiving and loading all the pertinent core data from the designated master utility system(s), including data for meters and other devices, such as end-use consumer, premise, account, billing cycle, connectivity, module, etc.	Yes	NISC's MDMS uses a sync process (via MultiSpeak) to receive all of the meter asset, necessary customer, and location information.
10	The system shall provide the ability to synchronize with the designated master utility system(s) to keep data aligned for meter and devices, such as end-use consumer, premise, account, billing cycle, connectivity, module, etc.	Yes	The system uses MultiSpeak to keep the meter and necessary customer and location information in sync.
11	The system shall provide the ability to detect any inconsistencies that may occur in data being synchronized with other systems as a result of the synchronization processes.	Partial	There are logs in the MDMS that will track if data were sent via MultiSpeak but were not successfully accepted. There are still business challenges that NISC continues to address around this topic. We use MultiSpeak to sync the data, but there are times that the MultiSpeak does not get sent from the master system or areas where MultiSpeak does not accommodate certain data elements. In the case of sites using NISC's iVUE, we have started a process that would do a direct database compare behind the scenes to verify that the MultiSpeak methods are keeping the data in sync. We are still exploring what kind of options may be available for non-iVUE sites. The MDMS can re-synchronize data in the event that they become out of sync. This feature also depends on the capabilities of the integrating system in question.
	VEE Rule Configuration		
12	The system shall support the creation and modification of custom VEE rules and the ability to group rules into rule sets.	Yes	The VEE rules can be modified and applied to groups of meters differently. There is some limited ability to use Java scripting for customer logic. The VEE set-up screen supports the standard VEE rules defined by Edison Electric Institute.
13	The system shall provide the ability to apply different VEE rules and rule sets based on meter attributes.	Yes	VEE Groups within MDMS allow the utility to configure VEE rules differently by groups of meters. These groups can be defined by characteristics like meter type, rate, revenue class, service use type, etc.

#	Requirement Description	Supplier Response: Yes/No/ Partial/Exception	Supplier Response: Comments
14	The system shall provide the ability for VEE rules to be configurable with the ability to define the actions for each validation failure and have parameters that allow thresholds to be configured.	Yes	These are configured by VEE group and each rule can be turned on/off, action taken, and thresholds changed. For example, there are rations for when a Spike check may occur or, by VEE group, how many consecutive zeros are considered a failure.
15	The system shall provide industry standard validation checks for interval and register data.	Yes	NISC's MDMS uses standard VEE rules for both Interval and Register (cumulative) data. These can be configured by VEE group.
16	The system shall provide version history and audit trail for VEE rules as modifications occur.	Yes	The raw data, estimated data, and edited data are all stored in MDMS to provide a full audit of what happened to each interval.
Virtual Meter Configuration			
17	The system shall have the ability to group multiple meter points into a virtual meter and have the capability to apply logic to adjust meter data. A virtual meter is the sum of 1 to many physical and/or virtual meters with or without adjustment logic applied. See Figures 6, 7, and 8 in the RFP.	Yes	Roadmap item spanning 4th Quarter 2011 & 1st Quarter 2012.
18	The system shall provide version and audit history of virtual meter configuration as modifications occur.	Yes	Roadmap item spanning 4th Quarter 2011 & 1st Quarter 2012.
19	The system shall have the ability to enable/disable a physical or virtual meter comprised within a virtual meter.	Yes	Roadmap item spanning 4th Quarter 2011 & 1st Quarter 2012.
20	The system shall store adjustment factors for each meter (physical or virtual) within the virtual meter. Adjustment factors are used when aggregating meter data.	Yes	Roadmap item spanning 4th Quarter 2011 & 1st Quarter 2012.
21	The system shall provide the ability to disable and enable a virtual meter configuration and its related processing.	Yes	Roadmap item spanning 4th Quarter 2011 & 1st Quarter 2012.
22	The system shall store totalization intervals for a virtual meter. A virtual meter can have multiple intervals and must be stored separately.	Yes	Roadmap item spanning 4th Quarter 2011 & 1st Quarter 2012.
23	The system shall provide the ability to set up "if/then logic" for aggregating virtual meters. See Figure 8 in the RFP.	Partial	Roadmap item for the 1st half of 2012. Our plan is to build in some "if/ then logic," but NISC cannot commit to the standard "if/then logic" being able to support every scenario possible. Custom logic may be necessary for some situations.
24	The system may provide drill-through capabilities to view virtual meter composition.	Yes	Roadmap item spanning 4th Quarter 2011 & 1st Quarter 2012.
25	The system shall provide the ability to dynamically add physical meters to virtual meters based on attributes. As a	Partial	Roadmap item spanning 4th Quarter 2011 & 1st Quarter 2012. We need to work with GRE to clarify its objectives and requirements on what

		Supplier Response	
#	Requirement Description	Yes/No/ Partial/Exception	Comments
	meter is added/updated/removed to/from the MDMS, it is automatically modified in the virtual meters in which it resides.		would be automatically updated as opposed to items needing manual updates.
Meter Data			
26	The system shall provide the ability to support integration from multiple metering data sources, such as Aclara, MV-90, etc.	Yes	Currently supports integration with seven AMI vendors and also supports one of the MV-90 formats. The roadmap includes support for additional MV-90 formats.
27	The system shall ensure that data arriving to be stored in the MDMS does not come from a disabled meter; e.g., if a meter is deactivated in the MDM, the system should not process meter data from the AMI system.	Exception	The MDMS does receive data from the AMI system even if the meter is supposed to be inactive. This is done so we can report possible energy theft.
28	The system shall provide the ability to manually import data files when integrations are not available.	No	Historically, if the AMI integration is not currently supported by NISC but the AMI vendor is one that other utilities will also be using, then NISC will write an interface to receive the usage data from this vendor. However, we are willing to discuss this item further to learn more about what the business need is and what situation would occur when a standard integration could not be built.
29	The system shall provide the ability to prime the MDMS prior to go-live by receiving and loading all the pertinent core data from the designated master utility system(s), including data for meters and other devices, such as end-use consumer, premise, account, billing cycle, connectivity, module, etc.	Yes	The MDMS instance is synched to both the AMI system, CIS, etc. systems prior to going live. This allows the implementation team to analyze the data, make recommendations, and also use them for training and exploring by the utility.
30	The system shall provide the ability to synchronize with the designated master utility system(s) to keep data aligned for meter and devices, such as end-use consumer, premise, account, billing cycle, connectivity, module, etc.	Yes	The data are kept in sync with the various systems via MultiSpeak.
31	The system shall provide the ability to detect any inconsistencies that may occur in data being synchronized with other systems as a result of the synchronization processes.	Partial	There are logs in the MDMS that will track if data were sent via MultiSpeak but were not successfully accepted. There are still business challenges that NISC continues to address around this topic. We use MultiSpeak to sync the data but there are times that the MultiSpeak does not get sent from the master system or areas where MultiSpeak does not accommodate certain data elements. In the case of sites using NISC's iVUE, we have started a process that would do a direct database compare behind the scenes to verify that the MultiSpeak methods are keeping the data in sync. We are still exploring what kind of options

		Supplier Response	
#	Requirement Description	Yes/No/ Partial/Exception	Comments
			may be available for non-iVUE sites. The MDMS can re-synchronize data in the event they become out of sync. This feature also depends on the capabilities of the integrating system in question.
32	The system shall provide the ability to collect data from non-meter sources, including end-use consumer premise equipment and Home Area Networks.	Partial	We can support the collection of the interval data using any of the NISC-supported formats, including CMEP, MultiSpeak, etc. Given that some of these devices may not be managed by the utility, other interfaces will be required to manage the life cycle of the assets.
Validation, Editing, Estimation Process			
33	The system shall provide a real time or batch process for VEE.	Yes	The VEE is a real-time process. As soon as data are loaded to MDMS, the VEE process will automatically start.
34	The system shall provide versioning of data as it initially passes through VEE and as data is recollected and passed through VEE.	Yes	The usage data are stored and available for display in their raw, estimated, and manually edited forms.
35	The system shall provide the ability to override data exceptions.	Yes	Manual editing is available if the user has the appropriate security settings.
Validation			
36	The system shall validate all received meter data. The frequency shall be configurable based on the source of the data.	Yes	The NISC MDMS is designed to accept meter data as many times throughout the day as needed. The validation process occurs as soon as data are imported into the database.
Estimation			
37	The system should be able to re-interrogate the meter if data is not initially collected.	Yes	The system can accept and replace missing/estimated data if the AMI system is able to retrieve and resend the data. There are exceptions that are taken into account (has the account already billed, are the data being resent the same as the original data received).
38	The system shall be able to estimate any missing or invalid data minimally, on a daily basis for all meters, to ensure complete data sets.	Yes	The VEE process will automatically estimate missing data based on how the VEE rules are configured by the utility.
39	The system shall be able to estimate missing and invalid data using historical, linear interpolation, or class load profile data.	Yes	Historical and linear estimation are currently available, and there are settings in the VEE configuration that allow the utility to control when these methods are used. Class Load Profile has been designed and is on the Roadmap for 1st quarter 2012.
Editing			
40	The system shall provide a user interface and tool set for editing interval and register reads	Yes	The VEE editing screens allow the user the ability to manually edit data. There are user security settings to control who is able to edit the data.
Totalization Process			
41	The system shall support the ability to sum meter data to a common interval	Yes	The usage graph currently totalizes all intervals to the hourly level for display to the customers. The

		Supplier Response	
#	Requirement Description	Yes/No/ Partial/Exception	Comments
	using the Totalization Interval (e.g., hourly).		actual interval can still be seen in the VEE portal. There is also a dashboard chart that totalizes the usage for reporting purposes. NISC plans to do other things with totalization as it relates to virtual metering and other complex billing determinants.
42	Totalization shall happen as soon as data has passed the VEE process.	Yes	Currently, the totalization of the intervals is done on the fly and the "totalized" usage is not actually stored in the database. Some of this will change as the virtual meter project is completed. This totalization does and will occur after the VEE process.
Virtual Meter Aggregation Process			
43	The system shall provide the ability to aggregate meter data and apply logic to adjust meter data as the VEE process is completed. See Figures 6, 7, and 8 in the RFP.	Yes	The virtual metering calculations, processes, and reports are in various stages of design/development but are being added to the product and will be available for GRE (see comments in questions 33−40).
44	Virtual meter aggregation shall happen as soon as data has passed the VEE or totalization process if applicable.	Yes	Once the virtual metering project is completed, this will be calculated after the VEE and totalization process and will actually be stored in the database. (Currently, all "virtual" metering data are calculated on the fly.)
Events			
45	The system shall provide the ability to create event markers on end-user meters, substations, distribution cooperatives, G&T, or wholesale market points.	Partial	Energy Markers (Event Markers) can be created by the utility or the end customer, or imported from other systems. Currently, the Event markers are at the individual meter level. The roadmap includes virtual metering and data aggregation, which would open the event marker up to additional levels. It is also possible for Lockheed Martin's DRMS system to create Event Markers for the start and stop times of a DR event.
46	Events may or may not be repeatable.	Partial	Need additional clarification.
47	Events must have a type and time dimension.	Yes	The Event Markers can be for a specific date/time or a date/time range. Currently, the markers are not divided into "types" or groups, but NISC will build this "type" classification into the product.
48	Events may need to be applied retroactively or for the future.	Yes	Energy Markers can be applied to prior, current, or future dates.
49	Some may come from external source (e.g., DRM, Billing System).	Yes	Event Markers can be imported. For example, the DRMS module for NISC's MDMS has the ability to create Energy Markers and send them to MDMS.
50	The system shall provide the ability for a user to define which organizations, roles, and users events are visible (e.g., end-user consumer can see a DR event invoked by a G&T or distribution cooperative, G&T and distribution	Yes	The Event Markers created by the utility can be configured as visible for the end customer or visible only by the utility. Currently, events created by a customer are viewable to the individual utility of which they are a member. We do have an existing enhancement request to

#	Requirement Description	Supplier Response: Yes/No/ Partial/Exception	Supplier Response: Comments
	cooperative cannot see a consumer-defined event like a vacation).		allow end customers to indicate if they want the utility to see the Event Marker.
51	The system shall provide the ability to see events at the physical or virtual meter level and track through delivery system whether it is relational.	Partial	The Event Markers can be seen at the physical meter level; once the virtual meter development is completed, they could also be stored at the virtual level. There is not currently a relational track throughout the delivery system, but NISC is willing to work through this requirement with GRE and get it on the product roadmap.
52	The system may provide the ability for end-use consumers to create events.	Yes	Consumers can create their own Energy Markers.
Presentment – Web Interface/Portal			
53	The system may provide the ability for secure end-use consumer login to view their accounts.	Yes	The MDMS comes with a customer presentment tool called Usage & Billing Analysis. With NISC's new SmartHub system, these data can also be available to a customer via a Smartphone app.
54	The system may provide a secure end-use consumer login for bill presentment and payment and integrate to 3rd party payment provider.	Exception	The MDMS does provide a web presentment tool, integrated with NISC's Customer Self-Service tools, which support payments and bill presentment. Both Minnesota Valley and Lake Region use NISC Customer Self-Service. The Usage & Billing Analysis can also be integrated with other e-bill and payment vendors using single-sign-on standards.
55	The system may provide the ability for the end-use consumer to view Bill-to-Date information available from the CIS.	Yes	The Usage & Billing Analysis does allow the user to see historical usage and some high-level billing information, along with unbilled usage. NISC continues to build out this tool to include more and more cost-related features.
56	The system may provide the ability for the end-use consumer to graphically view power consumption.	Yes	The Usage & Bill Analysis allows the utility to see monthly, daily, and hourly usage. The temperature information is also displayed on this graph.
57	The system may provide energy efficiency and conservation educational tools.	Partial	The Usage & Bill Analysis allows the consumer to create energy markers. NISC is currently working on baseline and weather normalization calculations to allow the consumer to conduct analysis on these events. NISC is also exploring linking various software platforms that present efficiency and conservation education into the web presentment.
58	The system may provide the ability for the end-use consumer to create "What if" scenarios for selecting an alternative rate plan.	Yes	NISC is currently developing a Billing Comparison tool, which is planned for release in late 2011 or early 2012.

		Supplier Response	
#	Requirement Description	Yes/No/ Partial/Exception	Comments
59	The system may provide the ability for the end-use consumer to request a change in service.	Yes	NISC's E-Bill/Customer Self-Service (CSS) tool allows the user to request a change of service. The MDMS presentment tool integrates with NISC E-Bill/CSS. For sites not using NISC E-Bill/CSS, this feature would be dependent on their vendors' E-Bill/CSS. Both Minnesota Valley and Lake Region already use NISC's E-Bill/CSS tool.
60	The system may provide the ability for password recovery/self-service.	Yes	This is part of the E-Bill/CSS system that both Minnesota Valley and Lake Region use.
Complex Billing			
61	The system shall support the following billing methodologies:		
62	Time-of-Use Billing (TOU)	Yes	The MDMS supports framing/binning of interval data into TOU buckets. These can then be passed to CIS for billing.
63	Critical Peak Pricing (CPP)	Yes	The MDMS supports framing/binning for interval data for CPP rates. The utility is able to identify at any time which days and hours will be CPP, and there are also admin settings to limit the number of CPP events allowed in a year, and the months that a CPP event can occur.
64	Peak Time Rebate (PTR)	No	NISC's current focus on Dynamic Rates is Day-Ahead Real-Time Pricing, which is scheduled for release in the Spring of 2012. The next dynamic rate on the Roadmap would be Peak Time Rebate, currently scheduled sometime in late 2012.
65	The system shall include a calendar interface for configuring and scheduling complex billing methodologies.	Yes	The Dynamic Pricing options in MDMS have a calendar to allow the utility to easily define time frames.
66	The system may provide the capability to calculate meter-specific baselines for peak time rebates and demand response measurement and verification.	Partial	The DRMS module that integrates with NISC's MDMS performs baseline calculations used in M&V for demand response. NISC is also currently working on the development of baseline calculations and weather normalizations to be used in energy comparisons on MDMS. This will also be used for PTRs once we start that development for PTR sometime next year.
Reports/Data Analytics			
67	The system shall provide the ability to schedule reports for delivery.	Yes	Reporting functions can be scheduled in the dashboard module. Typically, utilities will activate this feature when their AMI import files are known to import at a specific time.
68	The system shall provide the ability to deliver and export report data in multiple formats, such as MS Excel, CSV, HTML, PDF, etc.	Yes	The data from MDMS can be exported to Excel or in a CSV format. There are also APIs, which allow a utility to extract data from MDMS.
69	The system shall provide the ability to create and save ad hoc reports.	No	The MDMS system has standard charts/reports that can be processed. These reports can have filters applied to them to narrow or alter the

		Supplier Response	
#	Requirement Description	Yes/No/ Partial/Exception	Comments
			results. The data are also available via APIs if they need to be exported. NISC is exploring a community library of "custom" reports, as well as some basic query-building-type reports. Our preferred approach is to work with the utilities on their reporting needs and build as many reports as possible into the standard product.
70	The system shall provide the ability to support reporting functions without adverse impact on the transactional processing of the MDMS.	Yes	Data that are exported from the primary storage cluster can be used to feed all reports, so performance issues are rarely encountered.
71	The system shall provide the ability to generate point-in-time and trend performance reports for each meter-read collection system.	Yes	The MDMS dashboard allows for filtering based on a variety of attributes that allow the utility to filter by collection system as well as meter type. Abilities in this area depend on the integration implementation into the asset management system.
72	The system shall provide the ability to create and maintain algorithms used for data analytics.	Yes	Scripting functionality exists in the MDMS, which allows custom reports to be written against the reporting engine.
73	Line Losses	Yes	Roadmap item for the 1st half of 2012.
74	Transformer loading analysis	Yes	Roadmap item for the 1st half of 2012.
75	Measurement and verification of DR events	Exception	NISC's MDMS has an optional DRMS module that will use the usage data stored in MDMS compared to the customer baseline usages for calculating M&V on DR events. The DRMS system can also update MDMS with markers for when an event started and stopped. NISC is currently working on some baseline and weather regression models that will allow consumers to do basic M&V for their accounts. This could be used for various types of Event Markers on the customer's account.
76	Revenue Protection (e.g., a premise that does not have an active end-use consumer is consuming any energy, or some energy above a threshold. Identify that the reverse energy flow is allowed for those meters which are in net metering mode, however, to avoid false indicators).	Yes	The MDMS Dashboard has a report called Unauthorized Usage.
77	The system shall provide the capability to profile end-use consumer meter data over a period of time and compare to other end-use consumers with like attributes.	No	This is being evaluated for a Roadmap item for several different purposes. The most common is for customer presentment, so customers can compare themselves to other like customers.
78	The MDMS database model shall be open, allowing organizations to create and save their own reports.	Exception	Above and beyond the standard reports, NISC's MDMS has APIs available for extracting any level of data from the MDMS.
79	The system shall provide reports that integrate with weather station system to use sky/temperature information.	Partial	NISC's MDMS pulls weather data for every weather station in the US. These data are then linked to the usage graphs for each individual

#	Requirement Description	Supplier Response: Yes/No/ Partial/Exception	Supplier Response: Comments
			location/meter in MDMS. Currently these data are not included in any other reports, but NISC is willing to have additional discussions about this to determine what the business need may be.
80	The system may provide reports to calculate Wet Bulb Temperature.	No	NISC is willing to work with GRE on defining this business need and determining the requirements and impact.
	Interoperability		
81	**Standards:** Supplier shall indicate which standards the proposed products and systems conform with, and how the system implements recommended best practices. A criterion for evaluation of the proposals will be a demonstrated knowledge of evolving open standards that will affect the MDM system and how those ongoing developments will impact the current project. The response to this section should demonstrate an understanding on the part of the Supplier that a key goal of the project is to demonstrate the ability of MultiSpeak® to provide a significant portion of the interoperability required by the MDM system.		The MDMS supports both MultiSpeak and International Electrotechnical Commission (IEC)-based message formats, depending on the nature of the data being moved. In some cases, due to IO constraints, SOAP messages are avoided while instead using streamable REST-based services. This significantly decreases node IO requirements, decreases bandwidth requirements, and increases performance. These factors help keep costing down while using a consistent data model across specifications. NISC's MDMS currently uses MultiSpeak for pulling data such as customer information and meter asset and location information. We also support both MultiSpeak and CMEP for receiving interval data from AMI vendors. We currently use a version of 3.X and are evaluating 4.1. As MultiSpeak continues to change and grow, the MDMS will adapt to meet these new available options. NISC maintains very close contact with MultiSpeak and participates in all of the meetings. We have a long history in our other applications, such as CIS, OMS, GIS, etc. for using many different MultiSpeak methods with various vendors.
82	**Required Hardware or Software:** In addition to identifying the hardware and software that will be supplied by Supplier, the Supplier shall describe any additional required hardware or software that will be needed for the fully integrated operation of the AMI system but that it does not intend to supply. For example, if middleware or an integration server to provide enhanced messaging or application functionality is required in order to achieve full functionality, these should be specifically identified.		The MDMS is a hosted cloud environment, so all hardware is purchased and maintained by NISC Operational Staff. There are no direct charges to the utility for hardware. There are no underlying software licenses for the utilities to purchase; the entire Cooperative Cloud is open source based. These two attributes were specifically designed to ensure the long-term visibility and cost effectiveness of the MDMS. During Implementation, an MDM proxy may need to be installed on the utilities' networks. This will help facilitate the communication between the enterprise systems and the cloud. This can be installed on an existing Windows-based machine at the utility.
83	**Interoperability with Different MultiSpeak Versions:** The AMI system provided by Supplier shall		Although this questions references "the AMI system provided by the Supplier"….we believe it means to indicate how the MDMS provided

		Supplier Response	
#	Requirement Description	Yes/No/ Partial/Exception	Comments
	interface with a number of enterprise application systems; each may have a different version of MultiSpeak-compatible interfaces. Please explain how Supplier will implement interfaces that support a number of different versions of MultiSpeak and specifically how the AMI application will interface simultaneously with a number of other applications that support several different versions of MultiSpeak.		by the supplier will support multiple versions on MultiSpeak. Currently, our MultiSpeak configuration allows us to indicate which version of MultiSpeak is being used. This is not just set at the utility level, but at the integration level at a utility, so an OMS integration may be on a different version than the CIS integration.
84	**Interfaces with Current Enterprise Software Applications:** As a minimum, the MDM system must integrate with all indicated "current" enterprise software applications (as listed in the RFP) via MultiSpeak Version 3.0 or later. Preference will be given to vendors that provide integration which is in compliance with the requirements of MultiSpeak Version 4.1 or later. See Appendices A and B for resources on the requirements of MultiSpeak Version 4.1.		NISC currently supports the following MultiSpeak methods for integration with CIS. "CancelDisconnectedStatus," "CancelUsageMonitoring," "InitiateUsageMonitoring," "InitiateDisconnectedStatus," "MeterChangedNotification," "MeterAddNotification," "MeterExchangeNotification," "MeterInstalledNotification," "MeterRemoveNotification," "MeterRetireNotification," "ServiceLocationChangedNotification," "CustomerChangedNotification," "PingURL," "GetMethods" getAllCustomers getAllMeters – assumed to be electric meters only getAllServiceLocations – assumed to be electric service locations only getDomainMembers "meter.utilityInfo.substationCode" "serviceLocation.revenueClass" "meter.extensions.rateSchedule" "meter.extensions.electricUseCd" "meter.meterType" "serviceLocation.district" "serviceLocation.boardDist" "serviceLocation.franchiseDist" "serviceLocation.schoolDist" "serviceLocation.taxDist" "serviceLocation.linemanServiceArea" "serviceLocation.servStatus" "serviceLocation.cityCode" "serviceLocation.county" NISC has not interfaced with Daffron directly but we are dedicated to working with it on interoperability testing for the above MultiSpeak methods. The location information could be coming from a CIS or GIS system. Other GIS integration being explored by NISC is the ability

#	Requirement Description	Supplier Response: Yes/No/ Partial/Exception	Supplier Response: Comments
			to export metering events to the GIS maps. The GIS integration may not be available at the projected live date of July 1, 2012; further discussions would be needed about what AEC would like to accomplish with an integration to GIS.
85	**MultiSpeak Interoperability Testing:** Supplier shall provide a MultiSpeak-certified interoperability test report on all interfaces with other applications that are supplied with the system provided in response to this request for proposals. Supplier shall prepare an interoperability test assertions document in the format adopted by the MultiSpeak Initiative, describing the business processes being supported, and showing all web service methods supported by the systems under test. When tested and certified by an approved MultiSpeak testing laboratory, this interoperability assertion shall become the certified test report.		Many of the integration items in focus for Minnesota Valley and Lake Region are between NISC's MDMS and NISC iVUE systems. We do not currently have an interoperability testing document for the integration back into our own applications. NISC does have testing documents for the integration between our CIS and OMS systems and some of the other vendors mentioned in this RFP. These are available for review on MultiSpeak's website (www.MultiSpeak.org). There are some vendors on the list for which NISC does not currently have a testing document for this integration. However, we are committed to working with each of these vendors to implement and test the MultiSpeak interfaces that are available and applicable to GRE's project. Listed below are the current MultiSpeak methods being used with MDMS: "CancelDisconnectedStatus," "CancelUsageMonitoring," "InitiateUsageMonitoring," "InitiateDisconnectedStatus," "MeterChangedNotification," "MeterAddNotification," "MeterExchangeNotification," "MeterInstalledNotification," "MeterRemoveNotification," "MeterRetireNotification," "ServiceLocationChangedNotification," "CustomerChangedNotification," "PingURL," "GetMethods" getAllCustomers getAllMeters – assumed to be electric meters only getAllServiceLocations – assumed to be electric service locations only (not as important) getDomainMembers "meter.utilityInfo.substationCode" "serviceLocation.revenueClass" "meter.extensions.rateSchedule" "meter.extensions.electricUseCd" "meter.meterType" "serviceLocation.district" "serviceLocation.boardDist" "serviceLocation.franchiseDist"

#	Requirement Description	Supplier Response: Yes/No/ Partial/Exception	Supplier Response: Comments
			“serviceLocation.schoolDist” “serviceLocation.taxDist” “serviceLocation.linemanServiceArea” “serviceLocation.servStatus” “serviceLocation.cityCode” “serviceLocation.county”
86	Required Exhibits. Supplier shall provide Exhibits I–V as described in the RFP document.		See Attached documents labeled Exhibits I– V.
	Integrations		
87	The system may provide the ability to interface with back-office systems like CIS, OMS, AMS, WFMS, and others using the International Electrotechnical Commission’s (IEC) Standard 61968 Part 9.	Partial	NISC’s MDMS does provide interfaces to various back-office systems such as CIS and OMS. The asset information is also available via MultiSpeak and, for most distribution utilities, comes from the CIS system. These interfaces are built using MultiSpeak. There is also pre-built integration with NISC’s Service Order system for creating service order requests for things such as meter exchanges, check meter read, etc. For other interfaces, NISC is willing to discuss the business need and create interfaces using MultiSpeak standards as necessary.
88	The system shall provide a standard integration for meter configuration and meter data from the following sources:		
89	Aclara Power Line TWACS	Yes	NISC’s MDMS has been installed at 15 Aclara sites already.
90	Itron MV-90	Yes	NISC supports some of the MV-90 interfaces but has plans to build out more.
91	OSI Monarch	Exception	NISC’s MDMS does not currently integrate with the OSI Monarch SCADA system. However, there are plans in place to build interfaces and specific reporting options into MDMS for SCADA. NISC would like to work with GRE on the detailed requirements for this and get the item on our 2012 roadmap.
92	DRM System (TBD)	Yes	NISC’s MDMS is integrated with Lockheed Martin’s DRMS (SEELoad).
93	The system shall provide a standard integration to send and receive events from the following sources		
94	DRM System (TBD)	Yes	NISC MDM’s is integrated with the Lockheed Martin DRMS (SEELoad).
95	NISC CIS	Yes	There are many different integration points between MDMS and NISC’s iVUE CIS application. Most of these are via MultiSpeak, but there are also some APIs for service order information, as well as billing history information.
96	Milsoft DisSPatch	Exception	The MDMS has not been integrated with Milsoft DisSPatch yet, but NISC will pursue a

#	Requirement Description	Supplier Response: Yes/No/ Partial/Exception	Supplier Response: Comments
			MultiSpeak interface for receiving OMS events.
97	The system shall provide the ability to integrate with external systems to send and/or receive any of the following data:		
98	Physical meter configuration	Yes	MultiSpeak is currently used to meter asset information.
99	Virtual meter configuration	Exception	Virtual metering is a current development project.
100	Physical meter data	Yes	The meter data are imported from the AMI systems and are available for export to CIS and other systems.
101	Virtual meter data	Exception	Virtual metering is currently being developed but once completed, it will be available for exporting.
102	Totalized physical meter data	Yes	Totalized meter data will be available for export. Currently, we use some totalize logic for TOU and CPP accounts. This usage is being exported to CIS currently. We also have a Meter Totalization report, which will have an Export to Excel button. More functionality will be available as we complete the virtual metering project.
103	Totalized virtual meter data	Yes	Totalized meter data will be available for export. Currently, we use some totalize logic for TOU and CPP accounts. This usage is being exported to CIS currently. We also have a Meter Totalization report, which will have an Export to Excel button. More functionality will be available as we complete the virtual metering project.
104	Events	Yes	The MDMS currently can receive event data from DRMS or CIS systems.
105	Demand response	Yes	MDMS is integrated with SEELoad DRMS for usage data to be used for M&V during a DR event. MDMS will also receive DR events from SEEload to indicate when a DR event started and stopped.
106	Outage	Partial	The MDMS will integrate with OMS to receive outage events but does not currently send information to the OMS system.
107	End-use consumer defined (e.g., consumer creates a vacation event to monitor usage while on vacation).	Yes	There are usage notifications in the Usage & Billing Analysis tool that an end consumer can turn on.
108	Financial (CPP, TOU, Dynamic Pricing)	Yes	TOU and CPP information is exported to CIS.
109	VEE (e.g. integrate with an external system to notify an estimation occurred for a meter)	No	NISC would like to talk to GRE about this item and learn more about the business need and requirements.
110	The system shall provide an interface to manage integrations.	Yes	Security controls can activate and deactivate integration points by user/vendor on the fly.
111	The system shall provide the ability for reports to integrate with weather	Yes	NISC's MDMS is already integrated with NOAA for pulling in weather data; however,

		Supplier Response	
#	Requirement Description	Yes/No/ Partial/Exception	Comments
	services, to incorporate weather data from sources such as: WSI EnergyCast PowerTrader.		NISC will provide the ability to receive weather data from other sources.
113	The system parsing the data arriving in the MDMS should make use of all the appropriate data validation and exception handling techniques.	Yes	Several functions are in place allowing the MDMS to pre-process files looking for common AMI-Export mistakes to make sure the data are ready for actual VEE. Administrators can configure this pre-processor to suit their needs, by AMI vendor. When pre-processor exceptions are encountered, an email is generated to the administrator(s) and a UI is in place to help the user resolve the issue without having to rely on intervention by NISC.
114	Data arriving to be stored in the MDMS is syntactically and semantically valid.	Yes	Several functions are in place allowing the MDMS to pre-process files looking for common AMI-Export mistakes to make sure the data are ready for actual VEE. Administrators can configure this pre-processor to suit their needs, by AMI vendor. When pre-processor exceptions are encountered, an email is generated to the administrator(s) and a UI is in place to help the user resolve the issue without having to rely on intervention by NISC.
115	Cleanse data stored in the MDMS from all private information.	Exception	To answer this fully, we will need a more detailed definition of "private information." The MDMS does not store phone numbers, social security numbers, etc., but we do store name, service address, and detailed usage information.
116	The system shall gracefully handle denial of service attempts from integration sources.	Yes	NISC has not had any issues with Denial of Service attacks due to the large amount of computing power available in the cloud environment. External integration sources are constantly monitored; should they generate an unexpected attack and NISC deems the load a threat to the system, we can activate firewall measures to circumvent the issue.
117	The system may provide the ability to communicate with, obtain data from, and control meters and Home Area Network (HAN) devices using International Electrotechnical Commission's (IEC) Common Information Model (CIM) 61968 Part 9 messaging standards.	Yes	If the devices are already contained in the asset management system, the MDMS can support most 61958 Part 9 measurements. Control functions are not currently supported. There is an enhancement in the MDMS roadmap that will not allow asset management controlled devices also to be accepted, maintained, and controlled natively in the MDMS.
Exception Handling			
118	The system shall provide the ability to generate meaningful error codes and error messages that can be used to help facilitate debugging system and end-user problems.	Yes	All application-level exceptions are logged and categorized in real time to alert engineering staff of potential runtime issues in the MDMS. This allows our staff to be proactive with bug fixes and support. Due to the fully distributed/cloud nature of the MDMS, most issues can be

		Supplier Response	
#	Requirement Description	Yes/No/ Partial/Exception	Comments
			resolved on the fly, with no application downtime.
119	The system shall provide the ability to monitor, report, and issue alarms for individual processes, group processes, and work or data flows within the system to ensure reliable operation.	Yes	Back-end processes have inherent failover support in the event a process aborts due to hardware or application failure.
	Multi-Tenant		
120	The system shall be able to logically partition the metering data for a G&T and member distribution cooperatives and maintain data privacy and security.	Yes	Because of the nature of the NISC Private Cloud, all data are stored only once and can be shared across the entire application platform. This assumes that the distribution utility has given explicit permission to the G&T to use its data.
121	The system shall provide the ability to prohibit G&T operational personnel from accessing detailed end-use consumer information.	Partial	This is an existing enhancement. Features in the MDMS, whether through the UI or web services, are locked down by function, not by interface. This method ensures that personnel have specific views and restricted edit capabilities only, depending on security settings.
122	The system shall provide the ability to delegate application administration tasks to each organization.	Yes	Each distribution utility and the G&T individually, have firm control of the sharing of information across the system. The MDMS employs Active Directory-style permissions models for users, roles, groups, and domains.
123	The system shall provide the ability for an individual organization to grant full and/or limited access to meters and their related attributes to other organization(s), utilizing roles-based permissions.	Yes	Because of the function-oriented security model, the NISC MDMS can consistently limit the viewing and editing of data throughout the system.
124	The system shall provide the ability to define access to the application modules and data to users of the system in a role-based manner within and across organizations.	Yes	
	Security		
125	The MDMS shall be designed and implemented using security-aware SDLC.	Yes	
126	The MDMS has passed a security penetration test by a qualified third party	Exception	We perform the PenTest on the MDM environment.
127	The system shall allow a System Administrator to perform database management and maintenance for the entire system.	Yes	
128	The on-premise system shall integrate with 3rd party authentication authorization and accounting systems	No	NISC iVUE admin is utilized across NISC Private Cloud apps.

#	Requirement Description	Supplier Response: Yes/No/ Partial/Exception	Supplier Response: Comments
	like Active Directory, RSA, Safeword, etc.		
129	The off-premise solution shall integrate with multiple federated authentication services.	Partial	The MDMS is currently switching over to an OpenID 2.0-based implementation that allows better compatibility with multiple back-end security providers, as well as allowing additional applications to have capabilities for Single Sign On between applications. Currently, Active Directory and iVUE Admin security directories are supported.
130	The system shall support password-based authentication with strong password security policies, such as: configurable password history field, minimum password length, minimum password complexity, account lockout, and password expiration. (If federated authentication, this is not required.)	Yes	NISC iVUE admin is utilized across NISC Private Cloud apps.
131	The system shall provide the ability to require entry of the old password when attempting to change a password.	Yes	
132	The system shall provide the ability to encrypt or hash passwords at rest in a database or directory.	Yes	
133	The system shall provide the ability to log and audit all application and database accesses throughout the system, capturing user names, timestamps, success/failure of transactions, source IP addresses, and transaction descriptions, as appropriate.	Yes	
134	The system shall provide the ability to perform an automatic log-off of a user after a configurable time frame of inactivity.	Yes	Session timeouts exist.
135	The system shall provide the ability to support a session kill on a browse away or browser close (for browser-based interfaces).	No	
	Architecture		
136	**Physical Environments**		
137	The system shall support the ability to logically and/or physically isolate non-production environments from production environments to ensure that activity or problems in non-production environments will not adversely affect the production environment.	Yes	Development and test environments are completely separate from production. The production environment exists only at our hosting facilities.
138	**Development:** To be used if actual development of applications used to enhance the MDMS solution are	Exception	Development happens on NISC development servers on NISC's corporate LAN, separate from the production environment.

#	Requirement Description	Supplier Response: Yes/No/ Partial/Exception	Supplier Response: Comments
	needed.		
139	**Test/Stage:** System used for testing purposes. It allows new releases of the MDMS software and integrations to be fully tested in the utility environment before being put into production.	Exception	Initial testing of a new release of MDMS is done in NISC's test/QA environment. Once the software is ready for beta, it is installed in our production MDMS cloud, where it can be beta tested with a small number of customers. The cloud environment very easily allows a quick upgrade of all customers or beta testing for a small group, as it can support multiple versions at once.
140	**Production:** System that is online and used for all operational activities.	Yes	The production MDMS cloud exists only at our hosting facilities, away from NISC's test/QA environments. The MDMS cloud environment allows for multiple versions of the MDMS software to be deployed at one time.
141	**Disaster Recovery:** This environment is the backup of the production environment. It is used to take the place of the production system should a failure occur.	Yes	The MDMS is designed on a distributed and redundant cloud architecture. Any single node failure is handled automatically and does not affect application availability. Three copies of the MDMS data are maintained across datastore nodes in the local cluster for redundancy. The distributed nature of this architecture can be extended to cover more than one location for location redundancy. NISC is planning on extending the cloud to another location in the future, which will add extra capacity and act as a disaster recovery site. Currently, data are exported from the database on a nightly basis to a SAN, where they are replicated to an off-site location over a dedicated fiber link.
142	The system may have the ability to migrate changes across environments.	Yes	The MSMS software changes will migrate from development, test, beta, and then production, based on defined release schedules.
	Database		
143	The system may provide a data warehouse or data mart.	Exception	NISC's MDMS is in a cloud architecture, which allows multiple utilities to have data stored on the same system. These data are stored in a way that keeps them separate for each utility but still allows a utility to share data with other entities. The resources of the hardware are then shared across all entities within the cloud.
144	The system may provide ETL tools to support for loading data into a separate data warehouse.	Partial	There are APIs and exports available for exporting the data. The concept of data marts is not built into MDMS.
	Resources and Management Issues		
145	The system shall provide the ability to be backed up on a scheduled basis.	Yes	Three copies of the MDMS data are maintained across datastore nodes in the local cluster for redundancy. Data are exported from the datastore on a nightly basis to a SAN, where they are replicated to an off-site location over a dedicated fiber link.

#	Requirement Description	Supplier Response: Yes/No/ Partial/Exception	Supplier Response: Comments
146	The technical infrastructure shall be designed to support hot backups, with no loss of system availability or unacceptable degradation of performance.	Yes	Three copies of the MDMS data are maintained across datastore nodes in the local cluster for redundancy. Data are exported from the datastore on a nightly basis to a SAN, where they are replicated to an off-site location over a dedicated fiber link. The MDMS system is available during these processes.
147	The system shall provide an administrative console for performing system maintenance.	Exception	The system is a hosted cloud application; all system monitoring and maintenance is done by the service provider.
148	The system shall provide disaster recovery abilities.	Yes	The MDMS is designed on a distributed and redundant cloud architecture. Three copies of the MDMS data are maintained across datastore nodes in the local cluster for redundancy. This distributed nature of this architecture can be extended to cover more than one location for location redundancy. NISC is planning on extending the cloud to another location soon. Currently data are exported from the database on a nightly basis to a SAN where they are replicated to an off-site location over a dedicated fiber link.
149	The technical infrastructure shall be designed to support failover to a disaster recovery environment with no loss of data and with a maximum downtime of 2 hours.	Partial	The MDMS is designed on a distributed and redundant cloud architecture. Any single node failure is handled automatically and does not affect application availability. Three copies of the MDMS data are maintained across datastore nodes in the local cluster for redundancy. This distributed nature of this architecture can be extended to cover more than one location for location redundancy. NISC is planning on extending the cloud to another location in the future, which will add extra capacity and act as a disaster recovery site. Currently, data are exported from the database on a nightly basis to a SAN where they are replicated to an off-site location over a dedicated fiber link.
150	The system shall provide the ability for horizontal or vertical scalability to improve performance and/or process additional load.	Yes	The MDMS is designed on a distributed and redundant cloud architecture. This architecture allows for near linear scalability as cloud nodes are added. The cloud architecture even allows scalability across data centers at multiple locations.
151	The system shall be fault tolerant and withstand a single failure of either hardware or software.	Yes	The MDMS is designed on a distributed and redundant cloud architecture. Any single node failure is handled automatically and does not affect application availability. Three copies of the MDMS data are maintained across datastore nodes in the local cluster for redundancy. This distributed nature of this architecture can be extended to cover more than one location for location redundancy.

		Supplier Response	
#	Requirement Description	Yes/No/ Partial/Exception	Comments
152	The system shall provide the ability to apply patches and upgrades with little or no system downtime required.	Yes	Once the software is ready for beta, it is installed in our production MDMS cloud, where it can be beta tested with a small number of customers. The cloud environment very easily allows for a quick upgrade of all customers or beta testing for a small group, as it can support multiple versions at once. These upgrades are done with very little or no downtime for the MDMS.
Performance			
153	The MDMS shall not be the limiting capability in the display or distribution of data. Consequently, the time to complete validation of all meter data (intervals and registers) and estimation of missing data (assume 5% missing) should be consistent with the overall AMI requirements to collect and process meter data.	Yes	The distributed computing nature of the NISC MDMS allows it to process data very efficiently at all levels of the system. This system was designed to yield industry-leading performance, while a variety of processes are running concurrently, such as imports, VEE, reporting, consumer presentation, web services, and employee-facing UI tools.
154	Interval data supplied to the system shall be processed through a Validation, Editing, and Estimation (VEE) engine when received from the head-end metering system.	Yes	The VEE process will automatically start as soon as the data are received from the AMI system.
155	The system shall be able to support 5-/10-/15-/60-minute interval metering data.	Yes	The NISC MDMS supports all IEC meter measurements down to the millisecond.
156	The technical infrastructure shall be designed and built to achieve an availability of 99.5% or greater.	Yes	Every component in our cloud environment has on-the-fly failure and restoration capabilities. Most upgrades and updates can be done on the fly with no downtime.
157	All processes shall be made available after unplanned system downtime within 1 working day.	Yes	To date the NISC MDMS has not been down for more than one working day.
158	The system shall be able to support approximately 80,000 physical metering endpoints across 3 individual organizations and 5,000 virtual meters.	Yes	There are existing sites using NISC MDMS that are importing hourly intervals for more than 160,000 meters per day.
159	The technical infrastructure shall be designed to ensure sufficient performance and scalability to meet the demonstration project requirements with an additional margin of 25%.	Yes	Due to the current size of the NISC Private Cloud and its elastic nature, we have the ability to reconfigure and add resources on the fly to ensure performance. The NISC Private Cloud and the MDMS both have a series of valves and controls in place in the event resources become scarce and we need to prioritize.
160	The system shall be capable of supporting 1,000,000 endpoints across 29 (GRE plus 28 members) organizations for a full deployment.	Yes	We currently support more than 1 million meters at nearly 4 billion readings. The system has been designed from the beginning to scale well outside of our entire customer base of more than 450 utilities. We have no known limits at this point in time.

#	Requirement Description	Supplier Response: Yes/No/ Partial/Exception	Supplier Response: Comments
Implementation Support and Training			
161	The vendor shall provide project management, solution architecture, and integration development to implement the system at the utility.	Yes	NISC's MDMS Implementation team will assign a project manager to facilitate the implementation, solution architecture, and necessary integration development.
162	The vendor shall provide up-front and ongoing classroom and hands-on training for both System Administrators and End Users	Yes	The standard proposal for NISC MDMS includes training via WebEx sessions during the implementation process. However, on-site training can be included at additional cost (time and material). NISC continues to provide training via WebEx session as new releases of the MDMS are made available. These releases occur about every 8 to 10 weeks.
163	The vendor shall provide a pre-defined method for the installation, configuration, and validation of the MDMS.	Yes	NISC's MDMS Implementation team uses a SILC to define the steps of the implementation process from beginning to end. This includes configuration, validation, and training.
164	The vendor shall provide 24x7 support for critical issues.	Yes	NISC's normal business hours are 7:30 AM to 5:30 PM Central Time. There are support staff that carry cell phones from 5:30 PM to 7:30 AM every day for any critical issues.

Chapter 15:

Washington-St. Tammany Case Study – Stress-Testing Designs Before Deployment

INTRODUCTION

All Smart Grid installations require design review prior to installation. However, several factors make early and rigorous review of communications designs especially critical:

- Communications is an enabling technology for all other Smart Grid functions and devices.
- Radio, wireless, and cellular communications are subject to environmental conditions that vary with geography.
- Radio, wireless, and cellular communications are subject to environmental conditions that vary over time. (Examples of this include weather, solar activity, and interference from industrial operations.)

It helps to have many sets of eyes on a communication design, and utilities must be open to feedback at each step. Sometimes they must make the difficult decision to change designs after implementation has begun. This was demonstrated when Washington-St. Tammany Electric Cooperative ran into a particularly difficult—and surprising—problem when deploying a communications system intended to connect transmission breakers to its supervisory control and data acquisition (SCADA) system.

The problem was unique to the area Washington-St. Tammany serves. However, the need to thoroughly stress-test communication designs is universal. This case study is meant to illustrate that need and highlight the success of that co-op's deployment in the face of unexpected developments.

ABOUT WASHINGTON-ST. TAMMANY (WST)

Washington-St. Tammany Electric Cooperative (WST) serves the southeastern Louisiana parishes of Washington, St. Tammany, and Tangipahoa, as well as the southern part of Marion County in Mississippi. WST operates 183 miles of transmission lines and more than 4,905 miles of distribution lines, seven transmission substations, two transmission switching stations, and 30 distribution substations.

WST serves more than 50,000 accounts. Its average line density is approximately 9 meters per mile. WST buys its powers from Louisiana Generation (a division of NRG Energy).

ABOUT WST'S SMART GRID DEMONSTRATION PROJECT

WST's goal for the Smart Grid Demonstration Project was to install 24 transmission breakers and connect these to its SCADA system. These breakers then could be controlled from WST's control center. Each breaker could also act autonomously, based on sensor data from its own distribution feeder and information communicated from other breakers. Using these data, breakers could pinpoint and isolate problems, making the feeder "self-healing."

A communication link thus would be required to connect each breaker with the control center. Communications would also be required between breakers, so that they could work in concert.

First Communications Plan: Microwave

WST commissioned a communication study, which was done from topographic maps. That study indicated that the communications needs could be met through a microwave system consisting of seven master sites (hubs) and 27 remote sites. Most towers in the system would need to be approximately 60–80 feet high. A couple of them would need additional height—approximately 100–120 feet. Connections from the hub towers to the control center or monitoring points would be achieved using T-1 lines.

Estimates for the per-tower price were approximately $8,000 for each 60- to 80-foot tower and approximately $12,000 for each 100- to 120-foot tower. Based on this estimate, WST decided to proceed with the microwave option.

Unexpected Difficulty

WST issued a Request for Proposal (RFP) for the construction. However, one of the vendors that responded indicated that the design the co-op had in mind would not work. This concern was based on assumptions about tree height in the areas between service towers.

The longleaf pines native to the area block microwave transmission. Consequently, any microwave communication system would need to have line-of-site, making tree height an important consideration. Tree height was assumed to be 90–100 feet.

However, this did not take into account that the trees in the area had not yet reached their maximum height. Large areas had been cleared at some point in the past (many by Hurricane Katrina). The trees standing there now are the result of replanting. Once it was realized that the trees would continue getting higher, estimates for tower height had to be recalculated.

WST worked with a new contractor on the re-estimate. Line-of-site was determined by positioning two bucket trucks some distance apart. The bucket trucks (owned by WST) could be extended to 60 feet. A mirror was mounted on one truck, and a light source on the other. By shining light from one toward the other, it was determined that line-of-sight did not exist at that height.

With the new data, the tower heights were recalculated. It was determined that, for many towers, the new required height would be 250 feet. This necessitated a switch from a monopole design to a self-supporting tower design. Not only were the structures themselves more expensive, but the larger footprints (relative to monopole structures) meant that real estate became a sizeable expense. Some 250-foot towers would cost approximately $250,000.

Simply by factoring in a better approximation of the average tree height, the cost estimate for the communication network had jumped substantially, making microwave unacceptably expensive.

Second Communications Plan: Fiber Optic

WST then examined other options. This time, the co-op sent out an RFP for a fiber optic system. It was determined that fiber could be strung from existing transmission towers at a cost of about $1,000,000. Under this plan, WST would run 48-count fiber—12 strands would serve the co-op's needs and the remaining 36 strands of "dark fiber" would be leased out, thus helping recoup some of the cost of deployment. In all, WST will deploy more than 100 miles of fiber throughout its system. The co-op expects this deployment to be completed by the end of 2013.

CONCLUSION

WST could have invested hundreds of thousands of dollars in a microwave system, only to find that it did not function as intended and did not meet the needs of its transmission breaker project. Only by being open to feedback about its design at all stages was the co-op able to avoid a misstep.

WST's fiber system will serve its Smart Grid communication needs for the foreseeable future, while also enabling the co-op to lease dark fiber. These leases will provide income to the co-op. In addition, the availability of this broadband resource will be an important resource for WST's service area, enabling economic development in the form of businesses that require broadband connectivity. This win-win scenario is a direct result of re-evaluating and reconsidering the original proposed communication design.