DISSERTATION

VOLTAGE REDUCTION AND AUTOMATION ON THE RESIDENTIAL DISTRIBUTION GRID

Submitted by

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ABSTRACT

VOLTAGE REDUCTION AND AUTOMATION ON THE

RESIDENTIAL DISTRIBUTION GRID

This paper represents the culmination of my research on the effects of voltage reduction and automation on the residential distribution grid. Although voltage reduction has been in use for many years, the strategies identified and tested through my research increase savings for utilities by reducing demand during peak periods. In addition, by automating switching to transfer load on the system, utilities will benefit not only during outage events, but in alleviating load on substations and equipment nearing capacity during load control events.

The energy grid has benefited from a number of efficiencies in the past several years; however, system peaks continue to be problematic for electric utilities from both a cost and infrastructure perspective. The following presentation sets forth automated voltage reduction techniques, as well as automated switching approaches on distribution line sections, in an effort to appropriately address these concerns.

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LIST OF ACRONYMS

AMR - Automated Meter Reading

ANSI - American National Standards Institute

DRU - Demand Response Unit

ETS –Electric Thermal Storage

FDIR - Fault Detection Isolation and Restoration

NRECA –National Rural Electric Cooperative Association

NWREC – Northwestern Rural Electric Cooperative

PJM - Pennsylvania-New Jersey-Maryland Interconnection Regional Transmission Organization

RTU - Remote Terminal Unit

SCADA – Supervisory Control and Data Acquisition

Chapter 1 - Introduction

Generally, utility companies can enhance the efficiency of the electrical power grid by reducing load or upgrading systems to improve the reliability and longevity of equipment. However, upgrades to the system, especially those that provide increased capacity, are often cost prohibitive because a significant portion of the infrastructure is decades old. Rather, power grid improvements are often accomplished through efficiency enhancements, supported by renewable generation (solar, wind, etc.). While public opinion is most always in favor of such “green” alternatives, they often provide less output per facility than traditional plants using natural resources (coal, natural gas and oil) or nuclear plants. Essentially, while generating capacity has remained relatively static[1], utilities’ rapid response to control load during peak periods is a cost-effective strategy to enhance the efficiency of the grid.

1.1 - The Pennsylvania Model

The utility that my research is based upon, Northwestern Rural Electric Cooperative (NWREC), is a member-owned, not-for-profit electric distribution cooperative that provides electricity and other energy-related services to approximately 20,000 member/owners in northwestern Pennsylvania. NWREC was the first electric distribution cooperative in Pennsylvania, established in 1936.

[1] https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_1_01

The cooperatives in Pennsylvania, in general, service more rural areas of the state, while investor-owned utilities serve more densely populated areas. The cooperatives do not generate power, rather, they purchase it through the Allegheny Electric Cooperative. Allegheny is member-owned, with board chairs from each of the 13 cooperatives in Pennsylvania and 1 from New Jersey. Power is purchased from First Energy, a large generation, transmission and distribution corporation in the northeast, which is part of the PJM (Pennsylvania-New Jersey-Maryland) Interconnection Regional Transmission Organization. PJM operates the wholesale electricity market and manages the transmission grid. For NWREC in particular, power is supplied to its 17 substations from 15 metering points through Penelec[2] transmission lines.

For utility companies in general, the benefits of updating aging infrastructure may be outweighed by the costs of replacing components on a system that is continuously in service. My research is affected as a result, since many of our delivery points have loading constraints. Moreover, the outside utility infrastructure through which we receive our power is less reliable than our system. As such, we have virtually no control over interruptions in electric service delivered to us that result from infrastructure failures beyond our system. Nevertheless, our customers expect and are entitled to reliable power. To the extent possible, we address such external utility failures with automation software that identifies the loss of delivered power and determines whether switching can be done to backfeed line sections from an alternate source in a few seconds, minimizing service disruption to our customers. In 2017, NWREC's system prevented 3,252,956 customer outage minutes[3] through automated switching.

[2]Penelec (Pennsylvania Electric Company) is a subsidiary of First Energy and provides electric service through its distribution system to customers in territory adjacent to our service area.
[3]customer outage minutes = customers affected by an outage * length of the outage in minutes

1.2 - Load Control

Allegheny and NWREC work together to maintain reliable systems and provide affordable power to the membership. Allegheny also works with the cooperatives to establish suitable control periods based on its monitoring of load curves received from First Energy systems. When loading nears a monthly peak, the cooperatives' systems are placed in "load control", where the load attributable to water heaters and heating systems are reduced. Power line carrier systems built for meter reading equipment are used to switch off Demand Response Units (DRU) for heavy resistive loads from water heaters and heating systems.

Demand response during peak periods is not a new concept. Utilities began pilot projects in the 1980's using power line carrier systems to reduce load during peaks. NWREC initiated a demand response program in the 1980's, which consists of water heater load control units that can be remotely accessed to reduce load during peak periods.

At NWREC, customers may opt into the load control program, which provides an electric water heater, at no cost for the unit or installation, a lifetime warranty and 24/7 service by our technicians. In exchange for the water heater and service, our technicians install a DRU (Demand Response Unit) on these water heaters. The DRU is a relay that operates through our automated meter reading system, which we can access remotely during peak periods. In addition, NWREC provides a discounted electric rate for customers with a second meter for electric heat systems that can be controlled during peak events. These heat systems utilize a secondary heat source or thermal storage unit to provide heat while the primary system is not energized. Both the water heaters and heat systems provide the cooperative additional revenue during non-peak periods while reducing these loads when demand charges are higher.

Efficiencies have made it difficult to plan for the one peak hour due to flatter load curves, so longer control times have been employed to ensure a peak isn't missed. This is problematic, since water heaters and heat systems cannot be controlled or shut off for periods in excess of 6-8 hours without inconveniencing customers. Water heater and thermal storage heat systems store the radiant energy much like a battery, to be used during peak times when they are not energized. However, if the heated water or thermal storage is depleted as a result of a prolonged control period, customers would be without warm water or residential heat. This is where voltage reduction can be utilized to reduce demand as loads are not shut off but rather the entirety of resistive loads are lowered within parameters that do not compromise customer safety or comfort.

1.3 - Cost of Purchased Power

In Pennsylvania demand costs continue to rise resulting in more incentive to reduce load on the Cooperative's system. Demand costs vary based on grid loading, generation capacity and the market. Each month there is a 1-hour demand charge based on the peak for that month on the First Energy bill. This 1-hour demand can be any hour except those on weekends or national holidays. The monthly demand charge in 2017 averaged nearly $6.50 per kwh during peak periods versus $0.11 per kwh during non-peak times. In addition to the monthly peaks, there are 5 PJM peaks for the entire region referred to as Hi5's. These are the highest 5 peak hours during the summer months that occur on the entire PJM system rather than just on the Penelec system. The 5 peaks are averaged and charged at a demand rate for the summer period. The demand charge for the summer of 2017 was approximately $57 per kwh during these peaks.

Chapter 2 – Voltage Reduction Background

Voltage reduction has been utilized since demand response was initiated in the 1980s as a method to reduce load to decrease power supplier peaks or distribution system loading. Most loads, other than inductive loads, will reduce when supply voltage is dropped. The reduction of supply voltage can be achieved through the use of load tap changers or voltage regulators. American National Standards Institute (ANSI) standards require meter side voltages to be between 126 and 114 volts. However, in practice, utilities typically maintain voltages between 126 and 120V to operate efficiently by keeping the current lower on conductors, which reduces heat loss. As such, throughout this paper, voltage and the percent of voltage reduction are in reference to 120 volts as the base.

Electrical distribution feeders have dissimilar loading characteristics; therefore, load reduced through voltage reduction is difficult to quantify. Also, load dropped as a result of voltage reduction is inherently different on each line section. Because the system is dynamic, loads that change significantly over a small time span make modeling difficult. For example, commercial/industrial operations (such as a saw mill) which are on feeders with a substantial number of residential customers distorts load modeling for that line section.

Joule's law and Ohm's law are employed to demonstrate how lowering voltage reduces power when the load is resistive (water heater, incandescent lighting, heating systems).

$$P=V^2/R \quad \text{(where P-Power, V-Voltage, R-Resistance)}$$

However, for constant power loads, such as motor loads for air conditioning systems, saw mills and refrigerators, reducing voltage increases current, which results in higher line loss. Historically, constant power loads, which increase current during demand periods, limits the success of voltage reduction efforts. VAR, a measurement of reactance, can be addressed by adding capacitors, if the power factor becomes enough of a concern to warrant the additional expense for this equipment. Power factor is a measurement of losses on a system, where a 100% resistive system would have a unity power factor of 1. Each measurement of power factor is a percentage off unity taking into account the losses versus real load, kW. Below is a diagram depicting the power triangle, which illustrates that real power, or the power consumers are using, is one leg of the triangle while the other leg is the reactive power attributable to equipment losses, usually from inductive motors. As the reactive power, or losses increase, the apparent power on the hypotenuse is increased. This apparent power is the load that transformers and equipment must be designed to accommodate. Therefore, if the reactive load is large enough, it will require utilities to install capacitor banks to address this deficiency, or size transformers much larger than necessary to address the real load for those consumers.

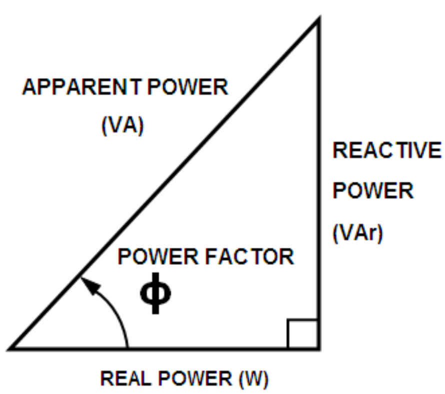


Figure 1 - Power Triangle

Capacitor controls can be added with switched banks to alleviate losses during control periods. Fortunately, in Northwestern Pennsylvania, load periods are not extensive, and the losses I encountered during my research did not affect the overall power factor billing for the month. Switched capacitor banks have been employed at large inductive loading sites to alleviate power factor issues on a routine basis. Below is a graph which illustrates the load and power factor on a feeder whose primary load is a pallet shop, which has a large inductive load due to its equipment power demands. The blue line is the load in kW on the feeder, the red is the kVAR. As can be seen, the kVAR spike at the beginning and end of the load changes when the capacitors are switched in or out of service.

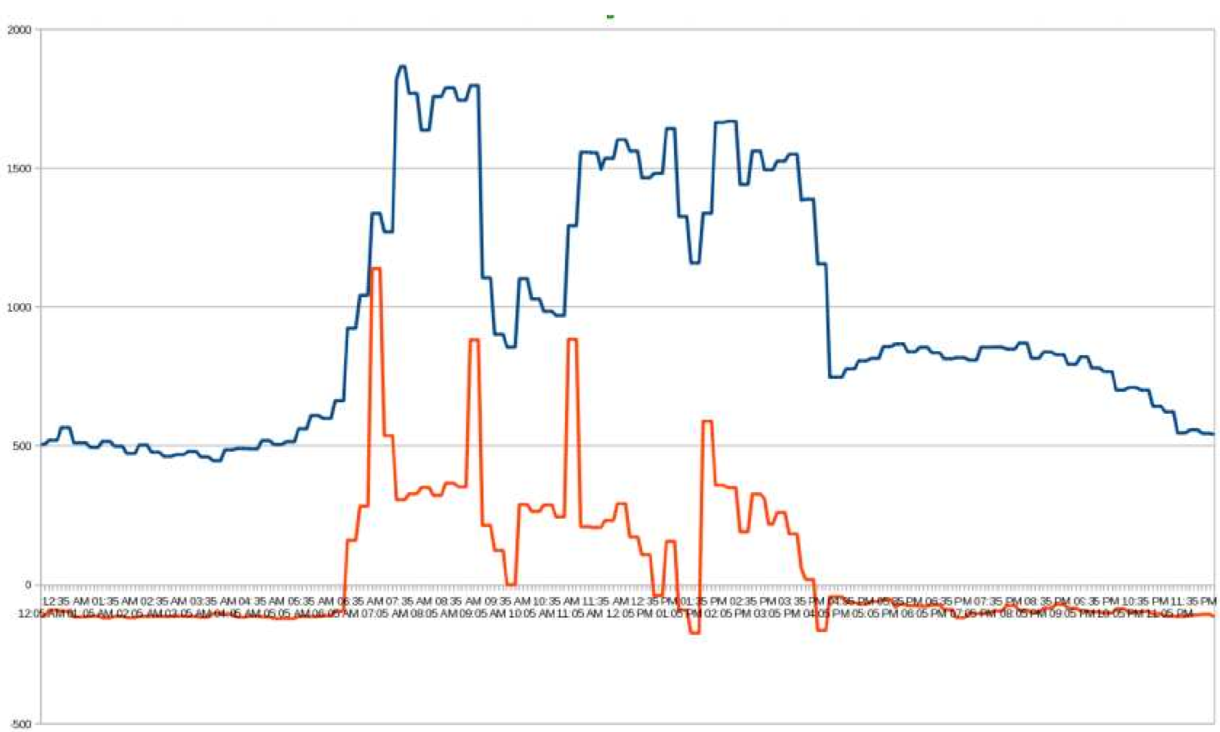


Figure 2 - Switched Capacitor

In the past, voltage reduction was implemented by utilities as a static system, which relied in part on approximations to set voltage levels. DRU's were used to trigger relays when load control periods were initiated and put voltage regulators into “voltage reduction” which, in essence, dropped their threshold to one set level until the control period ended. Voltage regulators are set with a percentage voltage reduction drop, which cannot be altered without re-programming the controls on site. Utilities may have been slow to adopt other voltage reduction strategies due to limited staff, lack of Supervisory Control and Data Acquisition (SCADA) systems, and lack of research and knowledge of the benefits and engineering behind such programs.

Without a SCADA system, load curves cannot be captured and savings are unproven. Also, settings would likely be at a very conservative level because end-of-line voltages cannot be easily monitored and changes cannot be initiated without field visits. Moreover, while DRU’s can be switched on or off remotely, without a feedback loop available through SCADA, it is difficult to verify whether the control has been initiated or terminated as expected.

It is also important to note that DRU’s for voltage regulator equipment require weatherproof cabinets as well as modifications to existing regulator cabinets. Not only is this an added expense, but there are risks of damage to existing equipment when performing necessary modifications.

Initially, voltage reduction was used to reduce peaks established by power suppliers where demand charges were substantially greater than standard costs. Voltage reduction, employing the methods discussed in this paper, is also utilized to curtail peaks on distribution systems to reduce the chance of nearing design capacity of existing equipment. As a result, large capital expenditures for additional capacity are either deferred or eliminated. This is similar to generation and transmission firms deferring capital outlays by increasing demand prices, which incentivizes distribution companies to reduce load. This reduces or eliminates the need to add capacity to address peak loads that are well beyond average system load. At NWREC both rationale support voltage reduction efforts - system load is reduced during power supply peak periods to decrease demand charges as well as reducing peaks while coming out of load control, to maintain flatter load curves and diminish the need for larger substation transformers and other ancillary equipment.

Over the past 5 years voltage reduction has been used as a means of load control at NWREC. It began as a pilot project to measure and evaluate the savings and effects and has subsequently grown to include the entirety of the system to maximize its benefits. Any reduction during peak periods results in significant cost savings. However, another substantial benefit is the resulting relief on the generation and transmission system. While the focus is typically directed toward billing cost reduction, the rationale behind the increased costs during peak periods is to not only recover costs associated with maximizing energy production, but also to incentivize distribution companies to reduce their load. This in turn, reduces the risk of blackouts caused by grid instability and loading that has reached or exceeded generation or transmission capacity. Simply put - distribution companies invest in reducing load, so the power generators and suppliers need not invest more than necessary to increase system capacity.

There are many approximations used to measure load dropped during a voltage control event. Factors that are considered in most modeling are line equipment that creates additional loading, conductor size changes, line splices which add resistance, and the types of load on the system, as opposed to the load as measured in kilowatts alone. My research approach is based on real time loading data of the system, substation and feeders, as well as line devices, eliminating the need for modeling and approximations.

Standard voltages are specified by the American National Standards Institute in standard ANSI C84.1 shown below. The table includes nominal system voltages on the low voltage points and the metering endpoints, based on nominal system voltages. There are two ranges, A and B, that include a maximum and minimum voltage. The range A service voltage values were used in my approach because this is the minimum permissible voltage at the service level, where the meters are reading their values. Range B are permissible only for short durations provided there are practical design means and corrective measures that can be implemented within a reasonable timeframe to improve these voltages to meet range A requirements. These would typically be voltage dips due to line protective devices operating or power supply voltage changes that would be corrected with voltage regulators to achieve range A levels.

VOLTAGE CLASS	Nominal System Voltage (Note a)			Nominal Utilization Voltage (Note h)	Voltage Range A (Note b)			Voltage Range B (Note b)		
					Maximum	Minimum		Maximum	Minimum	
	2-wire	3-wire	4-wire	2-wire 3-wire 4-wire	Utilization and Service Voltage (Note c)	Service Voltage	Utilization Voltage	Utilization and Service Voltage	Service Voltage	Utilization Voltage
Low Voltage	**Single-Phase Systems**									
	120			**115**	**126**	**114**	**108**	**127**	**110**	**104**
		120/240		**115/230**	**126/252**	**114/228**	**108/216**	**127/254**	**110/220**	**104/208**
	Three-Phase Systems									
			208Y/120	**200**	**218Y/126**	**197Y/114**	**187Y/108**	**220Y/127**	**191Y/110**	**180Y/104**
			(Note d)						(Note 1)	(Note 1)
			240/120	**230/115**	**252/126**	**228/114**	**216/108**	**254/127**	**220/110**	**208/104**
		240		**230**	**252**	228	216	254	220	208
			480Y/277	**460Y/266**	**504Y/291**	**456Y/263**	**432Y/249**	**508Y/293**	**440Y/254**	**416Y/240**
		480		**460**	**504**	**456**	**432**	**508**	**440**	**416**
		600		575	630	570	540	635	550	520
		(Note e)			(Note e)			(Note e)		

Figure 3 – ANSI Voltage Standards

Essentially, the voltage range of 126-114 V is used since the meters read on the 120 V base. The operation of the system is designed to comply with this voltage range through the use of voltage regulators.

The voltage on the distribution system changes with load current. When the current is low, the voltage drop from the voltage regulator to the customer at the end of the line is small. As current increases, the voltage drop to the customer at the end of the line increases.

Voltage regulators are used to raise and lower voltage to maintain permissible voltage levels at service points and are sized based on substation loading. The voltage regulator has multiple windings like a transformer, with contact points that are referred to as taps. Changing tap positions, without power interruptions to customers, is accomplished by an internal motor, activated by a control. Each voltage regulator has 16 tap positions above and below neutral, resulting in 32 potential settings. Each tap position for the regulators on our 7.2 kV system results in 5/8 of a volt change on a 120 V scale. The regulators are controlled by and send data to the SCADA system. The controls are set to run automatically but they can be overridden remotely.

Regulators are installed in the substations to correct power supply voltages on the entire distribution network. It is common to utilize the maximum permissible voltage of 126 V from the substation regulators to maintain the end of line voltage above 114 V. However, where long line lengths are a factor, another set of regulators is often required at a midpoint on the line to increase the voltage from their installed point to the end of the line. Based upon my testing and analysis, I was able to remove all but 6 sets of line regulators previously installed on our system. This had the further benefit of reducing the need to communicate with the additional regulators as well as any losses attributable to such equipment. These regulators had been installed in the past to address end-of-line voltage concerns or issues with voltage levels during backfeed events. In most cases, through line conductor upgrades, these concerns were adequately mitigated.

Modeling is only as good as the data on which it is based. In the past many assumptions were relied upon to set regulators. Today, data is available in real time through the SCADA system. Having the ability to analyze data in 5 minute intervals, operators can review every telemetry point on every communicating control for voltages, loading and operational data as well as equipment alarms or malfunctions.

Unlike load control for demand reduction, voltage reduction requires no customer interaction and, if done correctly, should not have any impact on, or be noticeable by, the customer. By working from the upper limits of the ANSI standards to the lower limits to reduce load, the voltage can be dropped without any negative impact. Through the use of our metering system, my goal was to monitor end of line voltages to ensure safe levels while maintaining voltage/load as low as possible. Since the primary focus was to maximize savings, I accepted the marginally increased losses that resulted during the voltage reduction periods. I determined that the savings far outweighed the short time period where equipment and heat losses were observed.

Chapter 4 – Voltage Reduction as a means of Demand Reduction

The voltage reduction method that I developed and researched at NWREC utilizes a communications backbone and SCADA system as well as an automated meter reading (AMR) system to capture end of line voltage readings. In 2013 I initiated a large project at the Cooperative to automate substation equipment and many line devices. Since then, every substation transformer, regulator and recloser has been linked to SCADA, as well as 62 electronic line reclosers and 6 sets of line regulators. Each of these points provides necessary feedback and data to allow the voltage reduction system to operate as efficiently as possible. The SCADA system provides power load data from across the distribution network and obtains real time alarms for recloser operations or equipment malfunctions. It also operates reclosers and regulators which save switching time and provides hot line tags for linemen safety during everyday maintenance and outage events.

In 2015 my project reached the point where communications channels to the devices were established and appropriate data was acquired so that a SCADA system could automate many processes. As data was captured and analyzed, I noted that older switching schemes were malfunctioning and were unsafe. As a result, Fault Detection Isolation and Restoration (FDIR) software was added to perform switching during outage events. Custom scripting was employed to provide much more interactive switching. When I connected substation DRU's to SCADA, their status could now be monitored in real time to notify dispatchers when load control was commenced by Allegheny and used to initiate voltage reduction. Through the use of additional custom scripting, DRU status changes now automatically initiate voltage reduction. When we go in and out of load control, relays trigger voltage control scripts to be run which have custom set points for each regulator control.

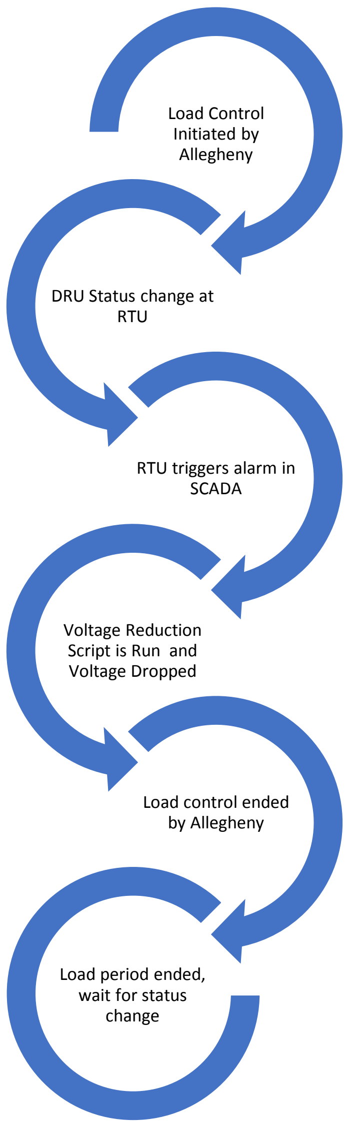


Figure 4 - Load Control Process

My voltage control script can be altered at any time to adjust voltage setpoint values. In this case the regulators are not placed into voltage reduction, rather the voltage setpoint is changed. This allows for any value to be written from the SCADA system to the setpoint on the regulator control. The script is run from the SCADA system and operators can raise or lower values to maintain end of line voltages compliant with ANSI standards that are monitored by the AMR system. It is my understanding that utilities with SCADA systems continue to use binary control points to put the regulators into voltage reduction rather than chosen set points. The amount of load dropped by NWREC now is considerably more than at other utilities where binary reduction methods are utilized, as my values can now be changed based on loading and weather[4] changes. Reduction was traditionally set and remained static at 2-3%. Now all feeders are dynamic in that the setpoints can be modified to result in reductions as high as 5-6%. If loading is changed or voltage levels are found to be too low at the end of the line these setpoint values can be altered to a more conservative level.

The AMR system now monitors voltages twice daily at every system endpoint. The jobs are scheduled to read all meters at the two most likely times that load control is initiated on the average day. Values are constantly monitored to determine if voltages can be lowered or must be raised in the voltage reduction script. Once these low settings are established, the end of line voltages are monitored less frequently, mainly during season changes to determine if voltages can be altered in the scripts. Based upon their distance from regulation, a small sample of meters was selected and voltage readings were recorded every 15 minutes to monitor the effect on these endpoints.

[4] Primarily, heating and air conditioning loads are affected by seasonal weather changes.

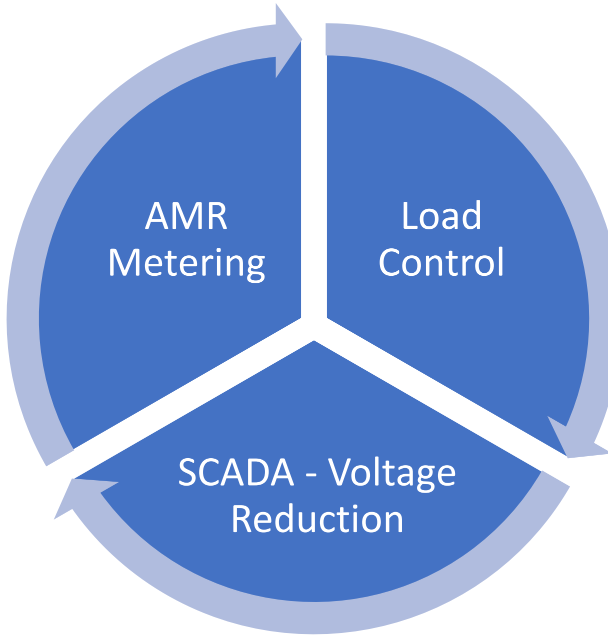
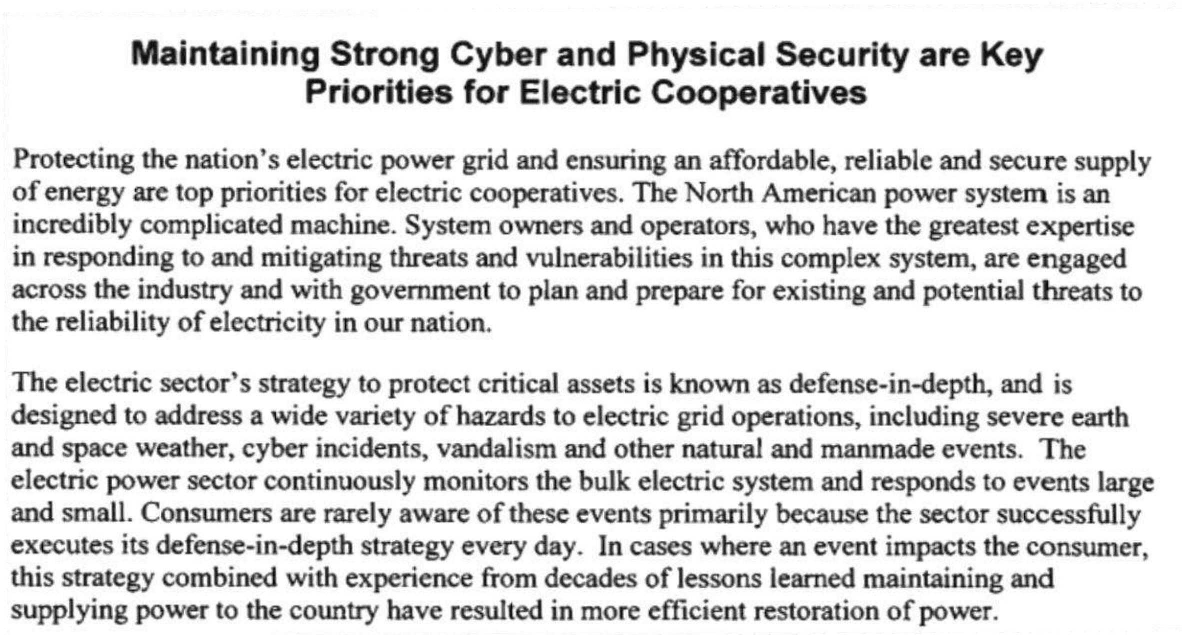


Figure 5 - System Cycle

Chapter 5 – System Security

Since the voltage reduction process is automated and relies on communications between the SCADA system and each control, ensuring that the entire system is secure from internal and external threats is of utmost importance. In fact, cybersecurity for the entire power grid is a national concern due to the potential threats to safety as well as the necessity for a reliable system. The biggest concern in a SCADA system is the protection of the public and line personnel, as well as controlled access to any portion of the system. This system allows staff to open and close switches and place safety tags on line sections or switches to help prevent line personnel injury. The system is also protected internally by limiting the number of personnel having credentials to log into the main system and issue controls.

A congressional delegates meeting in Washington D.C. in April 2018 raised concerns to government officials of the risks related to cybersecurity for the power grid, as noted in the following statement:



Maintaining Strong Cyber and Physical Security are Key Priorities for Electric Cooperatives

Protecting the nation's electric power grid and ensuring an affordable, reliable and secure supply of energy are top priorities for electric cooperatives. The North American power system is an incredibly complicated machine. System owners and operators, who have the greatest expertise in responding to and mitigating threats and vulnerabilities in this complex system, are engaged across the industry and with government to plan and prepare for existing and potential threats to the reliability of electricity in our nation.

The electric sector's strategy to protect critical assets is known as defense-in-depth, and is designed to address a wide variety of hazards to electric grid operations, including severe earth and space weather, cyber incidents, vandalism and other natural and manmade events. The electric power sector continuously monitors the bulk electric system and responds to events large and small. Consumers are rarely aware of these events primarily because the sector successfully executes its defense-in-depth strategy every day. In cases where an event impacts the consumer, this strategy combined with experience from decades of lessons learned maintaining and supplying power to the country have resulted in more efficient restoration of power.

Figure 6 – Cybersecurity briefing

SCADA controlled devices are divided into two groups– line devices and substations - each having different levels of security based on the equipment being communicated with, and risk level. Line devices are communicated with directly and have one control connected to a cellular modem. Substations have multiple connections to the modem for SCADA, AMR and substation cameras. The most vital components are enclosed in locked cabinets to help prevent unauthorized access.

The SCADA system utilizes DNP3 as its main communication protocol, which was developed mainly for electric and water utilities to bridge communications between master stations at a control center and remote terminal units or single intelligent electronic devices. The protocol was mainly developed as a reliable means to quickly pass information between devices and was not designed with added security. Most security applications utilize third party software that requires them to have access to the system to update and maintain their software. As such, this software is not appropriate for this use, where secure access must remain solely with the utility. Since only simple encryption and communication layers for read/write access was included with our initial installation, further hardening of our system was performed and customized in house.

Line devices are fitted with Verizon modems that have internal firewalls along with port and IP filtering. The modem only allows traffic on the IP's assigned to the control as well as the port that is used for that connection. The controls are in one locked cabinet that is pole mounted. Controls are also programmed through Eaton/Cooper proprietary software to allow traffic only from the modem IP address.

Substations utilize Remote Terminal Units (RTU's) to collect data from each control. The RTU uses fiber serial cabling to loop each of the recloser controls as well as the regulator controls for a communication path and are programmed with IP and port filtering. The Verizon modems employ IP filtering to allow the traffic through to the firewall. These firewalls function as security devices as well as switches to allow our communications through to the SCADA system, AMR system and substation cameras. The SCADA system is on its own port, which keeps it separated from all other networks back to the office server. In addition, intrusion protection is utilized with IP and port filtering.

Substation physical security is accomplished with 8 foot tall fences topped by 1 foot of barbed wire and locked gates. Video cameras, which are monitored by an offsite company 24/7, prevent and detect physical threats to the equipment.

Each SCADA endpoint is passed through an internal firewall in the NWREC network that is completely isolated from the rest of the network, as well as all other outside networks. Intrusion protection, antivirus and encryption are also utilized on the internal network to safeguard the SCADA system. The vendor for the SCADA system provides monthly patch updates as well as intrusion testing to ensure the system maintains the highest level of security.

Following is the Defense-in-Depth layered approach architecture for the system:

Layer 1 – Data Security

- Public Key Cryptosystem – ensures data that is passed is encrypted. This assures that content is encrypted using an individual's public key and can only be decrypted with the individual's private key.
- Data Loss Prevention –a job runs nightly to backup the database and drives to alternate drives, as well as to the cloud. Having backups in multiple locations allows for quick system recovery from attacks, natural disasters or hardware failures.

Layer 2 – Application Security

- Database Monitoring and Scanning – log and database activity monitoring is employed to analyze activity and protect sensitive databases from external attacks.

- Open Source Component Testing – evaluating known exploits versus proprietary software. This has been used in the past to identify Heartbleed and other exploits and allow them to be tested against in different environments.
- Sanitizing Data Fields – to meet the format for database requirements, preventing SQL injection. This process is used to remove sensitive information from a document or message so they may be distributed to a broader audience. This approach can also be used on documents which are erased, with some of the data remaining in storage.

Layer 3 – Endpoint Security

- Antivirus – to protect endpoints from being compromised by known malware. Also, assists in protection from browser hijacker, ransomware, key loggers, backdoors, rootkits, Trojan horses, worms, adware and other malware that poses a threat to the endpoint.
- Application Firewall – to protect endpoints from connections by unknown sources. The application firewall controls input, output and access to an application or service. It monitors and blocks inputs, outputs or system services that do not satisfy the policies established for the application firewall system.
- Patch Management – optimize the operating system environment through security updates. This creates a consistently configured environment secure against known vulnerabilities of operating systems and application software.

Layer 4 – Network Security

- Wireless Security – prevent unwanted access to the wireless network. WPA2 AES is used for encryption with a 256-bit key.
- Web-Content Filtering – prevent downloads of untrusted software. Barracuda software is employed to screen and exclude from access or availability web pages or e-mails that are deemed objectionable. Rules are established to determine what content and sites will be blocked on the internal network to detect and prevent outside threats.
- VLANs – segregate secure areas of the local network. Equipment can be partitioned on physical ports where each VLAN is connected to a dedicated network cable. This filters broadcast traffic, enhances security and mitigates network congestion.
- IP Filtering – only allow communications between specific IPs. Provides a mechanism for the network administrator to define what IP traffic is received and sent by the router. Filters can be set for incoming and outgoing traffic.
- Port Filtering – only allow communications between specific ports. Selectively enabling or disabling ports on network devices to allow traffic only on specified ports.
- Access Control – used in conjunction with remote access authentication over VPN's to the network to limit network access to specific users which enhances security and minimizes unauthorized access.

Layer 5 – Perimeter Security

- Firewall – system that monitors and controls the incoming and outgoing network traffic based on predetermined security rules. This establishes a barrier between the internal trusted network and the outside network.
- Intrusion Protection – prevent attacks from outside sources through a preemptive approach to monitor network traffic. This layer is directly behind the firewall to monitor for dangerous content and initiate countermeasures to prevent network attacks.
- Unified Threat Management – a complete perimeter security; including intrusion protection, gateway antivirus, antispyware and endpoint security enforcement. The all-encompassing system performs multiple layers of security functions such as network firewall, intrusion protection, gateway antivirus, VPN, content filtering and data loss prevention.
- Secure DMZs – zones in the network that allow access to internal resources securely.

Following is the network model for this cyber security system:

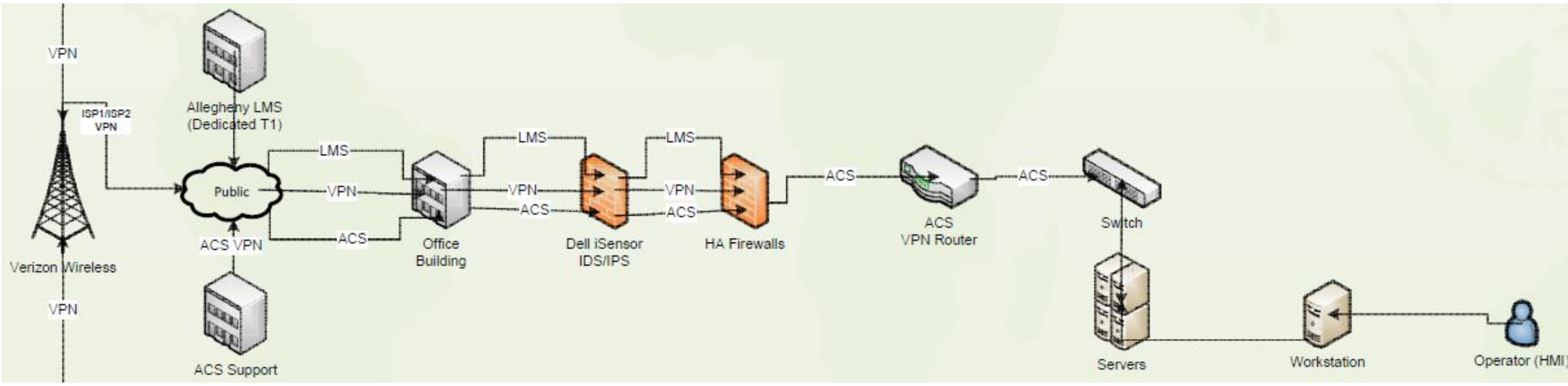


Figure 7 - SCADA System Security

Chapter 6 – Impacts and Benefits of Automating Voltage Reduction

6.1 - Voltage Reduction as Sole Method of Load Reduction

I began my research by performing a number of tests and analyzing the data from numerous dates at various times of day. The first set of tests was conducted with voltage reduction alone. There are times when the AMR system is down and load control cannot run; however, voltage reduction can be initiated manually through SCADA. Also, there are times when voltage reduction can be used to reduce load on the system to alleviate capacity concerns.

The tests confirmed that load is indeed being dropped by reducing line voltage. During load control periods, water heaters with DRU's are automatically switched off, so no load reduction is attributable to those devices by voltage reduction. With voltage reduction running alone, the water heaters and ETS (Electric Thermal Storage) accounts are still active on the system and the drop in voltage will reduce their respective loads as well.

During voltage reduction, since current rises due to constant power loads on the system, losses would typically be incurred. However, fixed capacitor banks were installed throughout the Cooperative's history to address losses from saw mills and other large constant power loads. These capacitor banks have effectively minimized the impact on the power factor during voltage reduction to the point where its effect on our monthly billing for purchased power is negligible. This effect is evidenced in the following graph, depicting the power factor and KVAR on the heaviest loaded substation while in voltage reduction. The power factor remains at or near +/- 100% while the KVAR actually decreases, indicating that losses have been effectively mitigated. The observed decrease is due to the fixed capacitor banks overcompensating by adding too much KVAR to the system for the amount of load actually present.

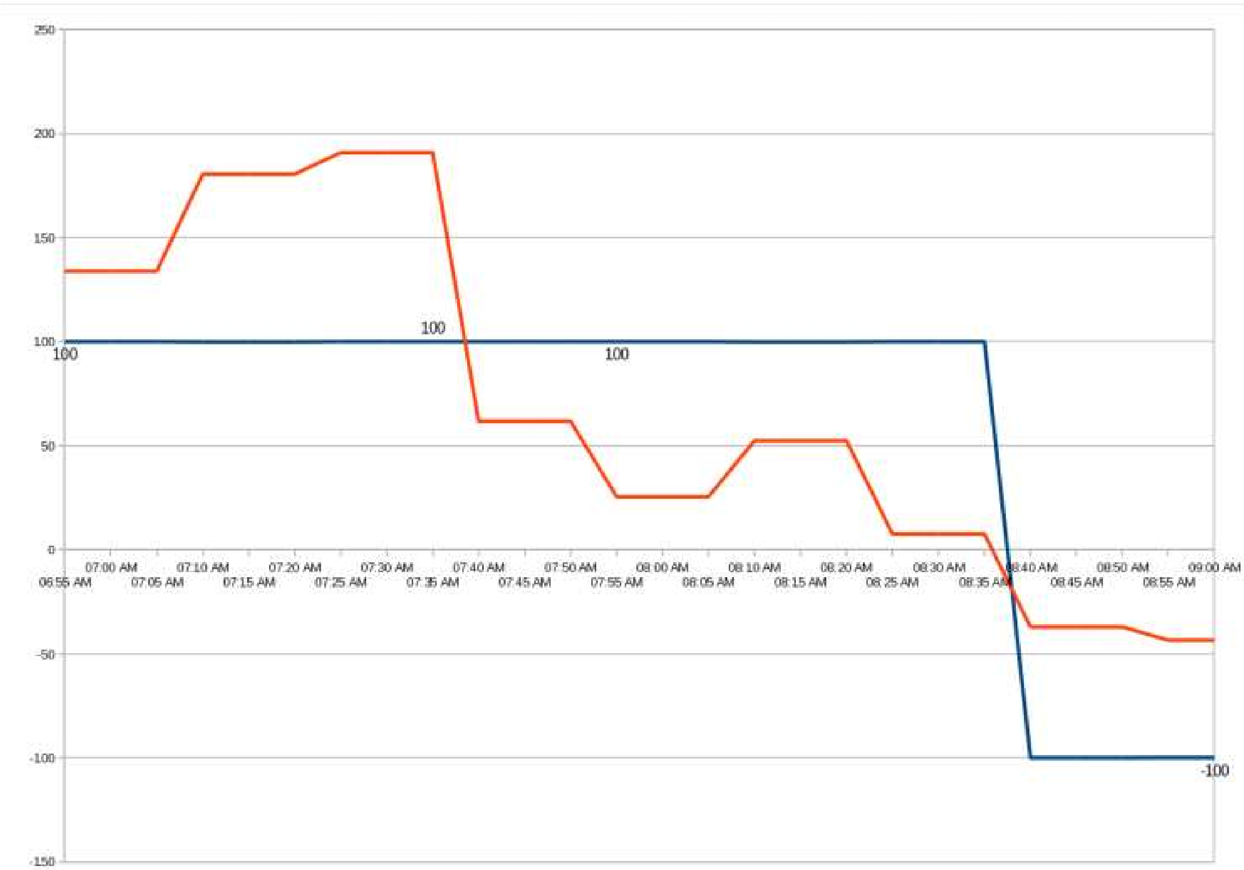


Figure 8 - Power Factor and KVAR

A National Rural Electric Cooperative Association (NRECA) report from 2014 states - “Decades of file 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%”.[5]

[5] https://www.smartgrid.gov/files/NRECA_DOE_Costs_Benefits_of_CVR_0.pdf

Therefore, the typical 3% voltage reduction should result in a 2.4% load reduction. However, using my automated method, voltages were reduced to the lowest safe levels possible in compliance with ANSI standards and achieve nearly a 5% load reduction, which is more than the reported NRECA average and utility standard. This is likely attributable to the fact that the NWREC system is primarily residential load, which is mainly resistive, versus the “average” system load with a greater commercial/residential mix, including more inductive loads. Further, I reduced voltages at different rates for each regulator bank, based upon my analysis of data for each bank. This was done in an effort to maximize savings, rather than setting one fixed level for all regulator banks in the system.

The following graph depicts the current when entering a voltage reduction period on the most heavily loaded substation in the system. The test was run for an hour to sample the change in current. As previously noted, a large rise in current could increase line losses due to heat loss. In these tests, I found that the current increase is small, and therefore results in little line loss. Therefore, most loads on these feeders are resistive rather than constant power inductive loads. My review and analysis of the customer base for these feeders confirmed that they are primarily residential.

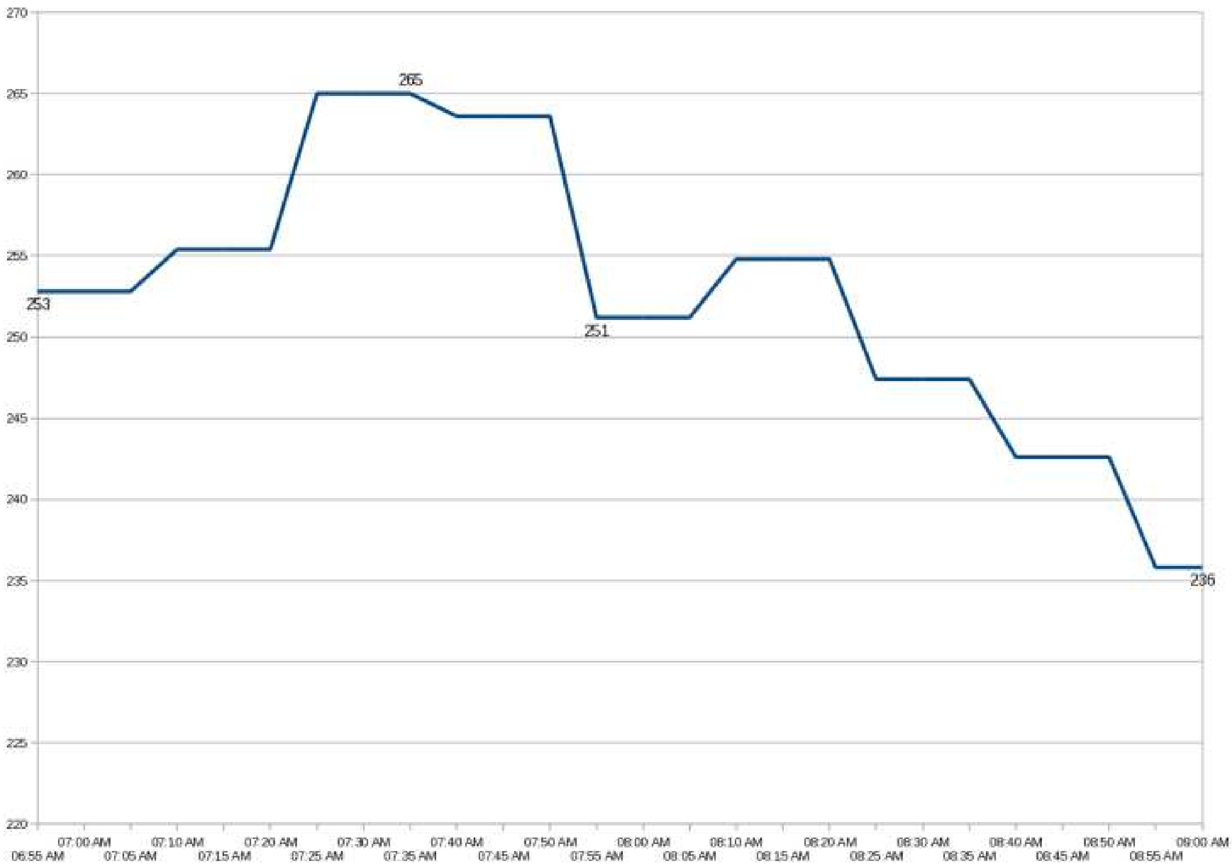


Figure 9 - Substation Current

Below, the most heavily loaded substation is shown depicting the load dropped during voltage reduction. We entered voltage reduction at 5,720 kW and dropped the load to 5,455kW. This results in a $1,723 savings on this substation alone during the peak on this day. Also, the 5% voltage reduction tested, resulted in 5% load reduction, which feeds primarily residential customers.

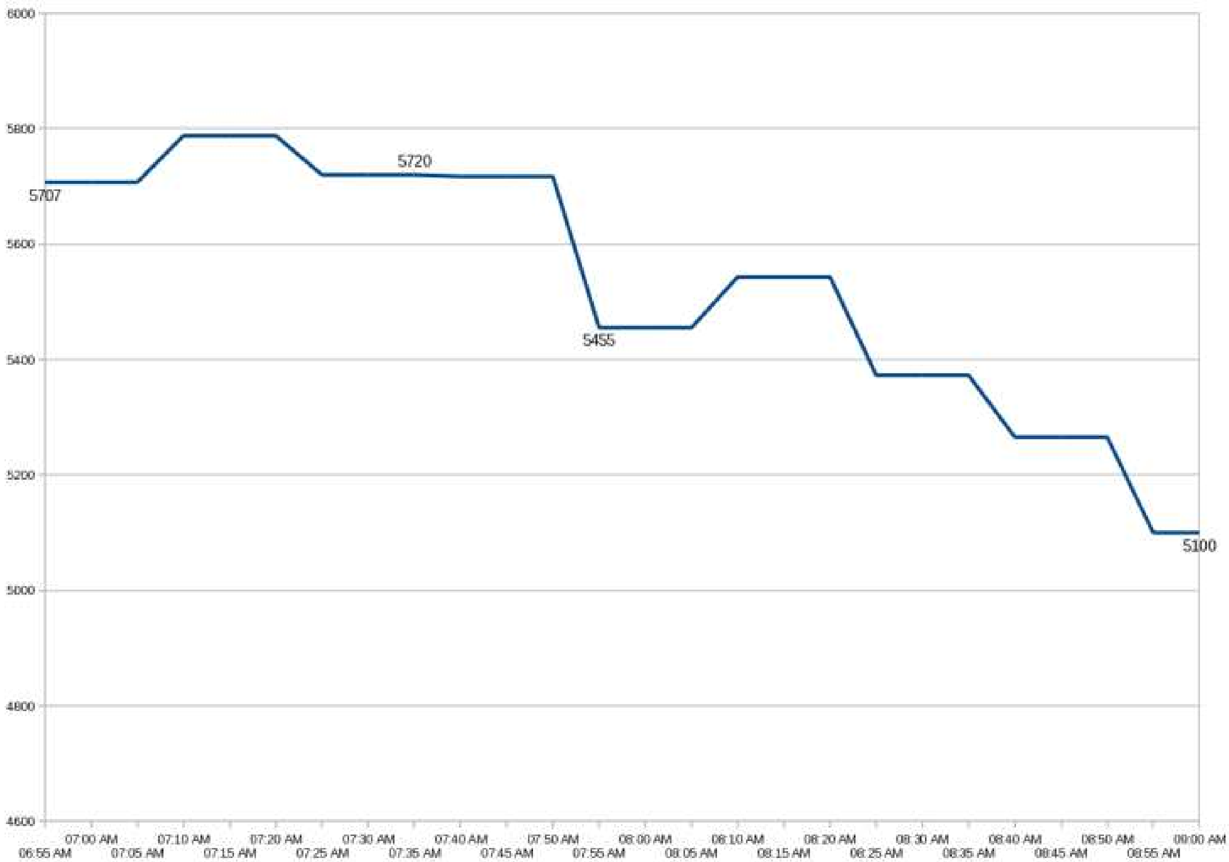


Figure 10 - Substation Load in kW

Below is a graph depicting the loading of the entire NWREC system when voltage reduction is initiated at 7:35. As can be seen, the loading rises until reduction is commenced, which is typical loading for an average winter day, when heating systems are turned on in the morning. Through my research and testing it is evident that the decrease in load during heating months due to voltage reduction has a larger impact than typical loading on a summer day.

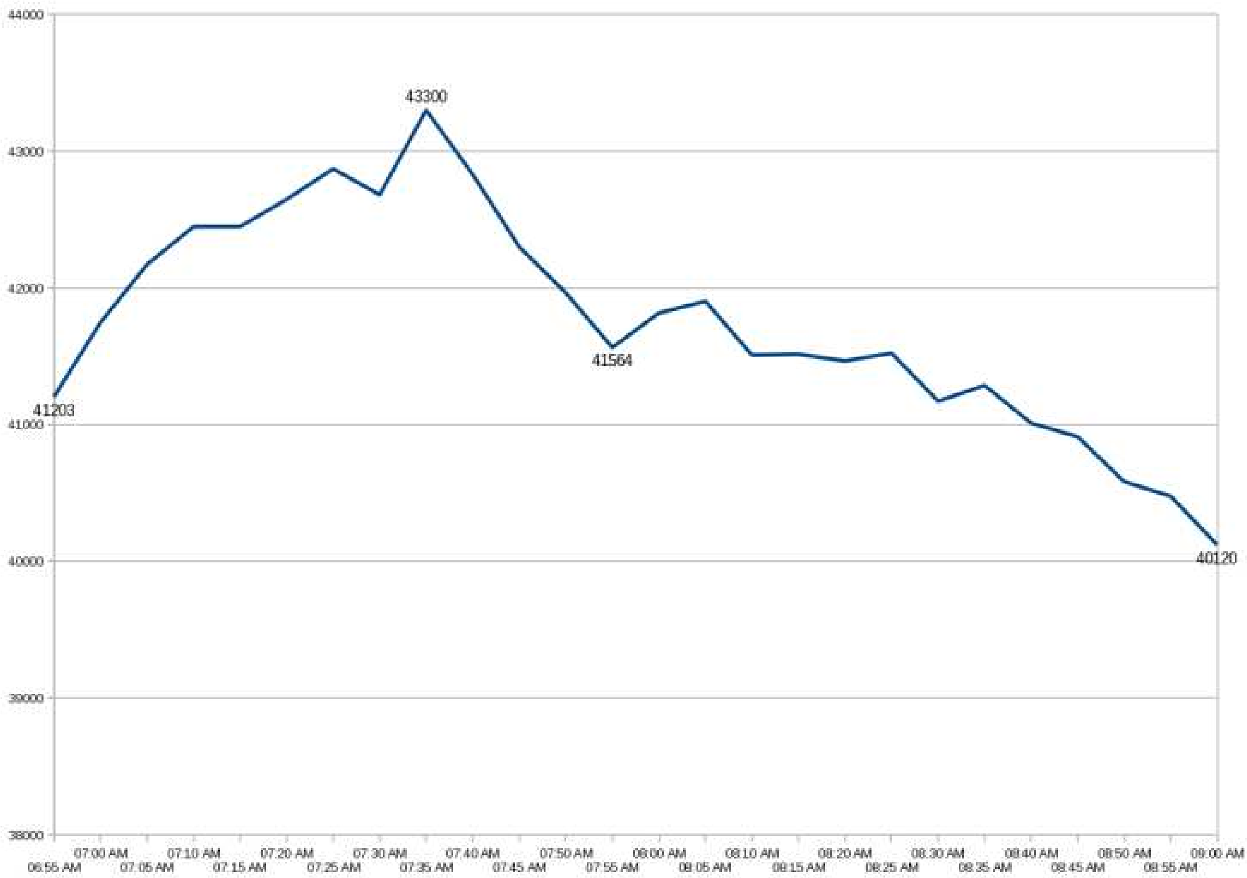


Figure 11 - System Load in kW

6.2 - Load Control as Sole Method of Load Reduction

For analysis purposes, it was necessary to establish the load reduced by load control alone. To accomplish this, approximately 8,000 water heaters and 550 heat accounts were removed from the Cooperative system. The tests confirmed that the current did not rise during the load control event as it had during voltage reduction, since the only control was removing these resistive loads. Of primary importance was noting the large system peak created at the end of the control period, when the controlled devices are all switched back on at the same time. Without the SCADA system to capture the relevant data, this load curve has never been fully appreciated and the recovery was estimated inaccurately. The recovery almost doubles the natural load curves on our system. As a result of my research and the ability to capture the relevant data through SCADA, we have made Allegheny aware of how large an impact load control has on NWREC's distribution system.

Financially, load control reduces load on the system and successfully saves NWREC money. The following graph depicts load control being initiated at 7:25 AM with the heat meters being removed from control at 12:45 PM and the water heaters being removed from control at 1 PM. This is often a strategy that Allegheny utilizes to energize the heat meters more quickly for customer comfort, as well as, attempting to reduce the peak on the First Energy system. Occasionally, load control was ended too soon, and the Pennsylvania cooperatives' recovery load established a new peak. When load control began for the event noted in the graph, the system was near 48,000 kW and dropped to around 42,000 kW. If the peak occurred during this control period, the savings would amount to approximately $39,120.

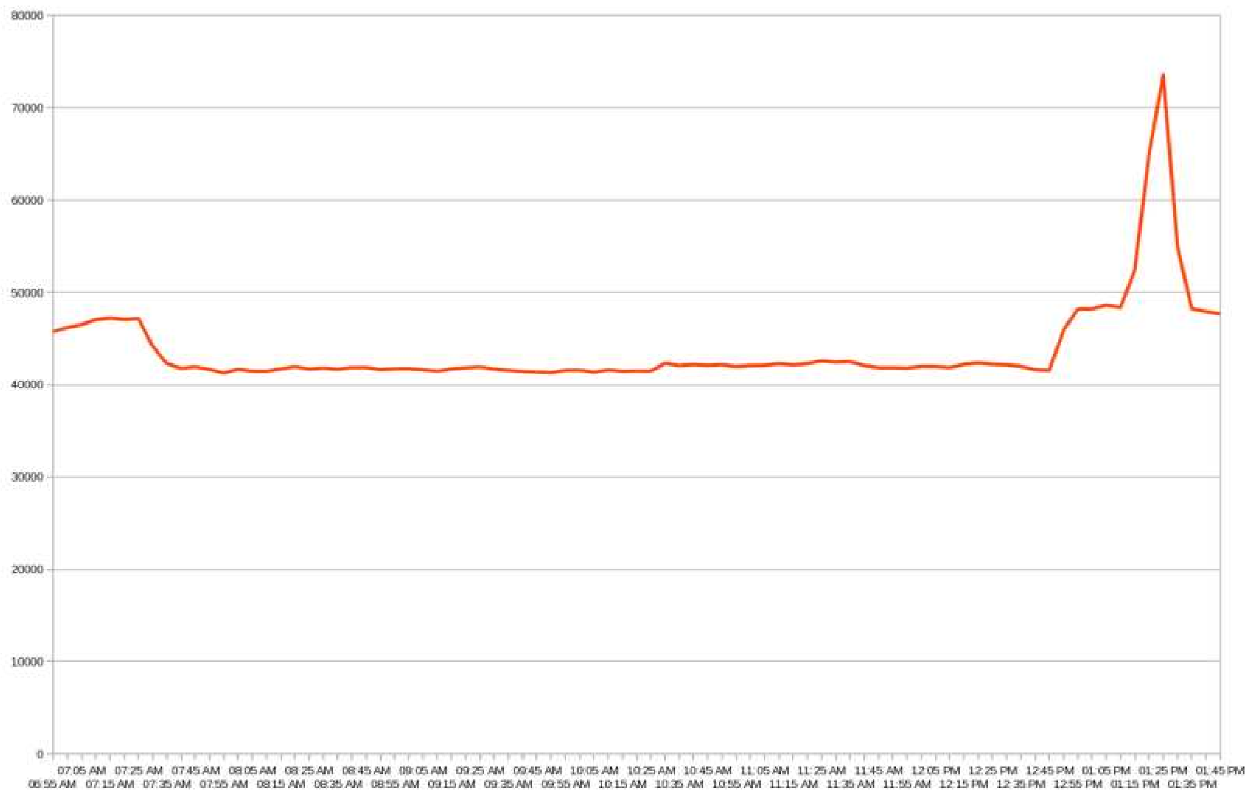


Figure 12 - System Load with Load Control Alone

The system load is a good representation of the loading that is occurring at each of the 17 substations without showing the varying industrial loads on individual feeders. The graph below depicts the same control period for only the most heavily loaded substation. It clearly demonstrates a pattern very similar to the system load graph above. The savings for this substation alone amount to $7,150 if the peak occurred during this control period. Most of my testing was performed on this substation because the loading is nearing capacity of the substation transformer. The substation capacity is 10 MVA with an emergency limit of 12 MVA with fan cooling. It is evident throughout the research that the 10 MVA limit is being surpassed.

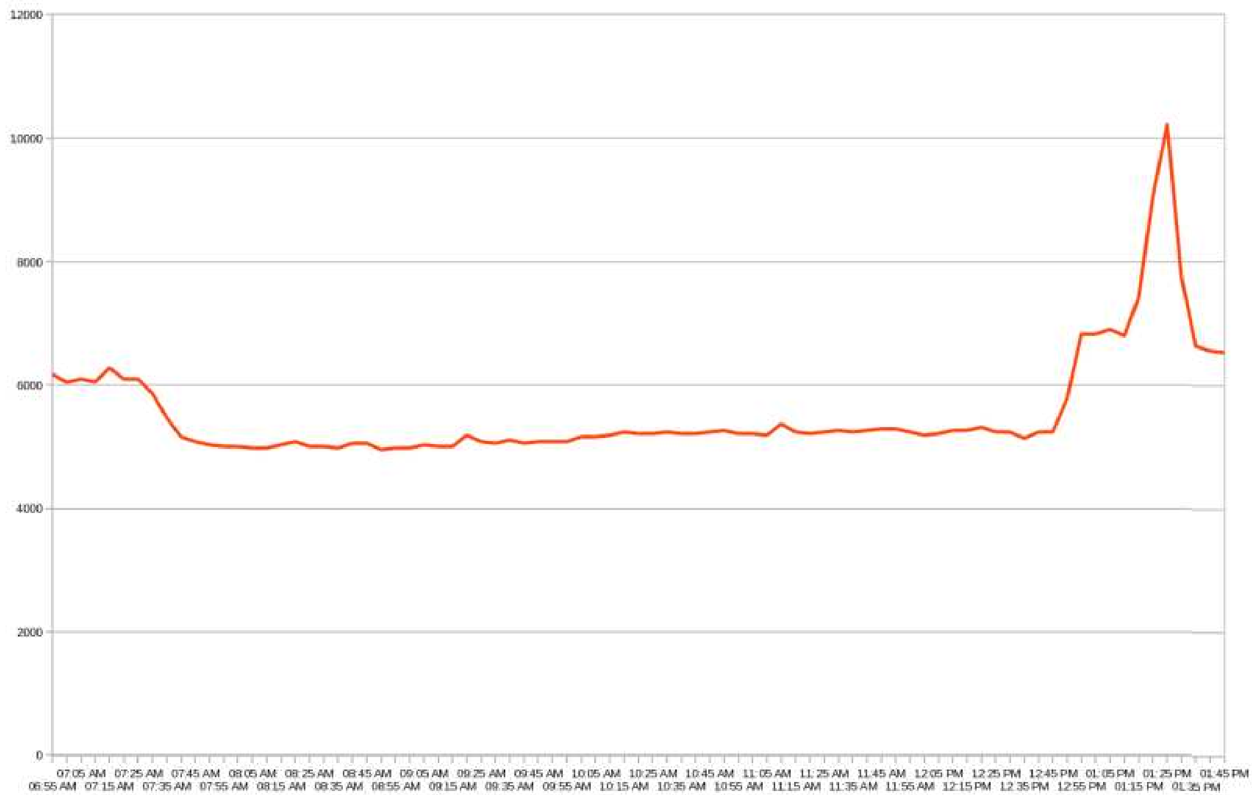


Figure 13 - Substation Load with Load Control Alone

6.3 - Voltage Reduction as a Method of Load Reduction with Load Control

With the two systems having been analyzed separately to establish their impacts on the NWREC system, I tested them together as they typically operate. I reduced voltage at the same moment load control was initiated and restored voltage when load control ended. Since, I automated the system, voltage reduction and load control are initiated and ended simultaneously, without user interaction.

Running the systems together creates a brief but very large observed peak when coming out of control. Currently, load control devices cannot be automated to come out in steps rather than all at once. Most utilities in Pennsylvania have configured their load control devices to control for only 50-75% of the hour to reduce the inrush recovery load and allow for longer control periods without customer disruption. This means the DRU will open and close its relay throughout the hour to only control the load on it for 50-75% of the time. Therefore, a substantial amount of load control benefit is lost. As such, I have not employed this strategy because of the lost savings that result. Instead, I chose to address the post load control peak through other approaches, discussed in Chapters 7 and 8.

It should be noted that, if nothing is done to address the peaks that results at the end of control period, utilities will incur large capital costs to increase capacity sufficiently to account for a 15-30 minute peak that is driven entirely by load control and not based on actual recurring load.

The following graph depicts the heat meters being removed at 1 PM and the water heaters with voltage reduction removed at 1:20 PM, showing that additional load is dropped when voltage reduction is applied during the load control event. This is for the most heavily loaded substation where the load at initiation was 6,700 kW and was dropped to 5,050 kW, saving approximately $10,750 or an additional $3,600 versus load control alone.

Figure 14 - Substation Load with Load Control and Voltage Reduction

It is important to note that due to the varying loads on the system attributable to seasonal changes there are different impacts on voltage reduction. A typical load control period during the summer months is shown below. The impact of voltage reduction is less due to the fact that most resistive devices used for heating are not online and the majority of residential load is fixed motor loads for air conditioning and refrigeration. I found, on average, that a typical load control period will have 16% of the shed load attributable to voltage reduction. Therefore, if 2,900 kW is dropped system-wide when we enter load control, 464kW of the decrease is attributable to voltage reduction. The following graph depicts loading for an "average" summer peak control period where it is apparent when load control is initiated, and the second decrease is due to voltage reduction.

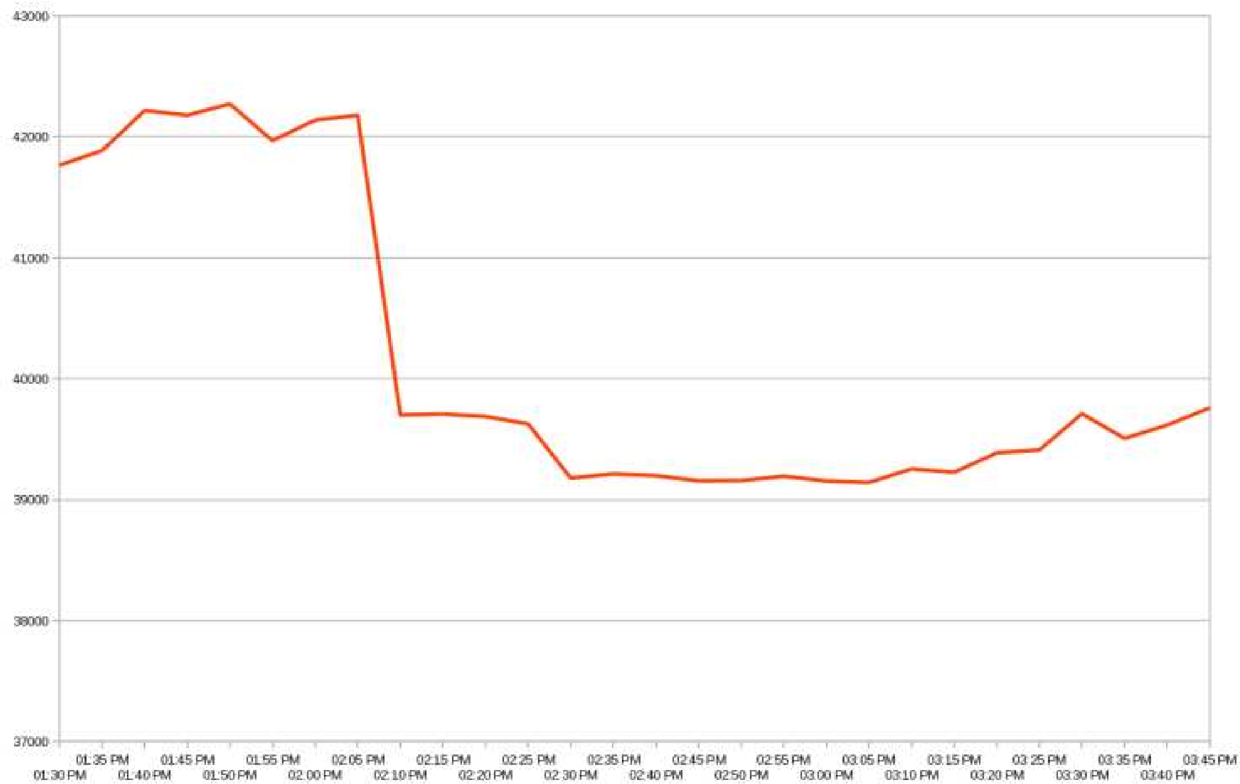


Figure 15 - System Load on Summer Peak

Conversely, our system typically has a higher resistive load, as expected, in winter, spring and fall since more heat devices are on, as well as, hot water heaters. I found the average reduction due to voltage reduction on our system during load control periods in those seasons was around 23%. Again, this means that if 5,600 kW is dropped system wide when we enter load control, 896 kW of the decrease is attributable to voltage reduction. Below is a graph depicting the average of our winter peak control periods. Again, it is apparent when load control is initiated, and the second drop is due to voltage reduction.

Figure 16 - System Load on Winter Peak

6.4 - Additional Benefits Identified during testing and research

During the voltage monitoring aspect of this research, I found abnormally high voltages on 16 meters in the system. When I had line crews investigate this further, we found that the residential transformers for these meters were likely struck by lightning at some point in the past, which burned windings open on the high side of the transformer but never faulted the transformer. Instead of the 60:1 ratio the transformers are built for, to reduce 7200 V to 120 V, they were in the 50's:1 range, creating high voltage on the customer side. In the past this was something the Cooperative was unaware of until a customer called with a complaint that their electronic equipment was either malfunctioning or not functional or they had filters that monitored the voltage themselves. In those cases, we would dispatch line crews to verify readings and change the transformers out. As a result of my research, we modified our practices, where we now sort meter voltages on the system from high to low to identify potential problem transformers. Line crews are dispatched to test these transformers and replace them as needed to avoid any potential negative effects on customer electronic equipment.

Another identified benefit from the research was the recognition that meters could be used to read blink counts, which are disruptions in service. With a simple meter reading job programmed to run daily, I was able to identify what meters had blinked the previous day. With this data, overlaid on the system map, we can identify the specific devices that were in operation when the blinks occurred. Line crews are then dispatched to investigate specific line sections to field confirm and repair faulty equipment.

Chapter 7 - Equipment Loading, Various Methods of Voltage Reduction

Utility long range plans must consider system loading. Due to the peak loads seen at the end of control periods, utilities in some cases must reduce the amount of load controlled to address this peak or build system capacity to meet the peak.

When factoring in the addition of voltage reduction, the peak is enhanced after load control ends. These peaks also affect Allegheny, which purchases power on behalf of all the cooperative utilities in Pennsylvania and has an impact on the control periods it initiates.

- Peak periods may end at 10 AM but due to the amount of load being controlled throughout the state, Allegheny cannot end a control period until 12 PM when the recovery peak will not create a peak on the First Energy or PJM system
- This is a large amount of load when considering the fact that, at normal load the 14 electric cooperatives in Pennsylvania and New Jersey have a relatively small impact on the transmission system

In some cases, where our substations have large amounts of controlled customers, there are substation transformers that are reporting overload conditions on the NWREC system. These peaks compel the cooperative to consider construction of new substations to split the load or increase transformer capacities, which typically would also require reconductoring and enlargement of ancillary equipment.

7.1 - Method of Curtailment – Reduce Voltage an Additional Hour Beyond Control Period

As load control periods lengthen we cannot delay recovery, which would leave water heaters and heat accounts in control for a prolonged period and deplete their storage. The first method I tested to reduce these recovery peaks was to continue the control recovery as planned by Allegheny but leave voltage reduction in place for an additional hour. This allows the water heaters and heat accounts a one hour period to recover before the voltage is increased to normal levels. When load control and voltage reduction are removed at the same time, the voltage is raised on those resistive loads that are switched back on, increasing the recovery load. During this hour the load control devices have time to recover some of their storage heat before the voltage is raised, adding the load from the resistive loads controlled, as well as those that were not under load control.

The following graph shows two similarly loaded days when load control was initiated by Allegheny. The red line denotes when load and voltage reduction were removed at the same time. The yellow line denotes when load control was removed by Allegheny and voltage reduction was removed with a 1 hour delay. As a result, the peak dropped considerably. It should be noted that this delay would not be possible without automating the system.

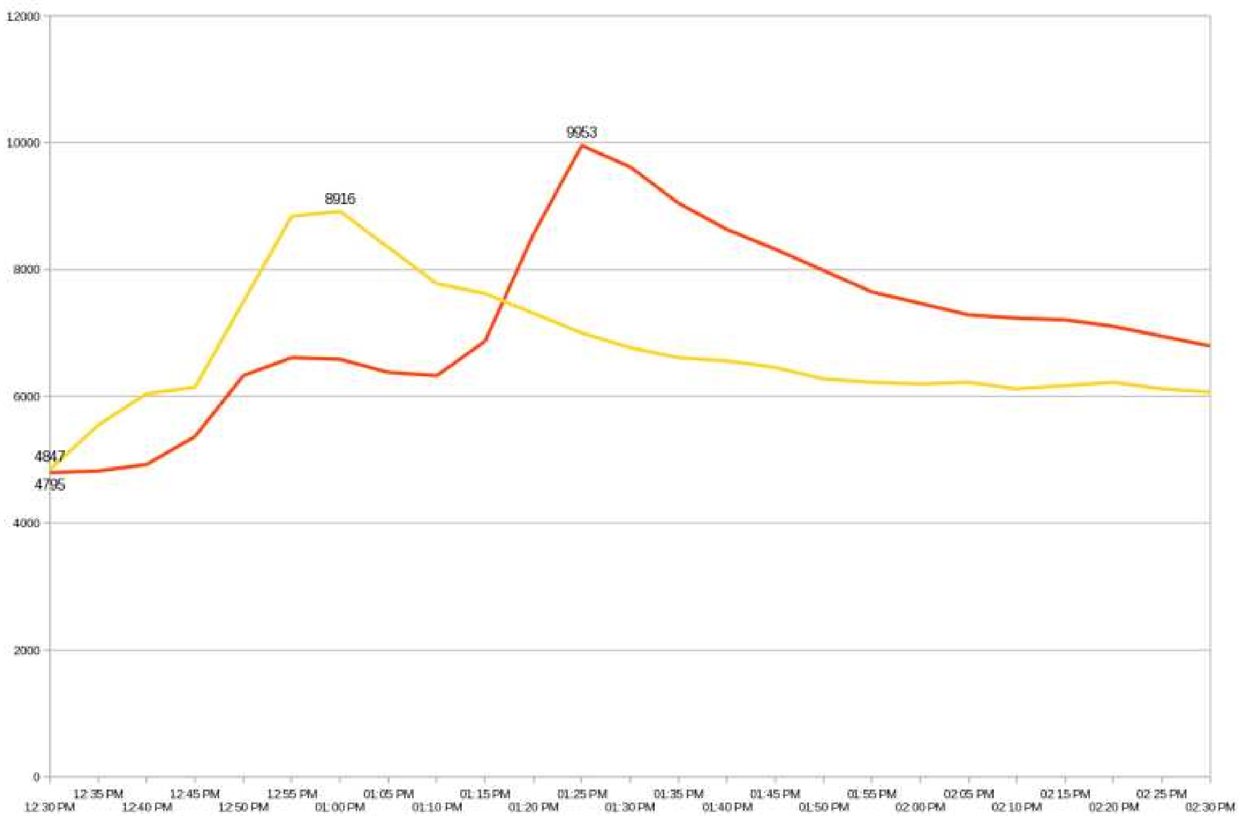


Figure 17 - Voltage Reduction Delay in Recovery

7.2 - Method of Curtailment – Reduce Voltage Only for One Hour After Control Ends

In extreme situations where the method shown above (leaving voltage reduction in control for an additional hour) doesn't completely alleviate the recovery peak, another method was tested and proven to reduce equipment loading further. Traditionally, voltage reduction was only used to reduce load during peak periods. However, it can also be employed to reduce recovery peaks for only certain line sections, which reduces the necessity for capital spending on unnecessary system upgrades to increase capacity for these line sections. With automated voltage reduction, different strategies can be employed for each substation and line section. If only one substation has a loading concern due to load control, then the other 16 on the NWREC system can continue to reduce load heavily through voltage reduction and load control.

For the NWREC system there is only one heavily loaded substation where recovery peaks consistently approach or exceed substation capacity. I performed tests where voltage reduction was not initiated for this substation, in conjunction with a load control event. For example, the added benefit of voltage reduction is not initiated on winter peak days where this particular substation's capacity will be met. As such, the peaks in December through February are not reduced through voltage reduction, all other months for this substation utilize both voltage reduction and load control.

The graph below depicts two similarly loaded days, the difference is realized by voltage reduction being initiated when coming out of load control rather than at the initiation of load control. By dropping the voltage at the moment load control has ended the peak was drastically lowered. End of line voltages in this test were nearing levels of concern but quickly recover as the load drops. This helped with the peak but the additional ampacity on the line from the water heaters and heat accounts being turned on, in conjunction with the voltage being lowered, created a large amount of voltage drop toward the end of the line.

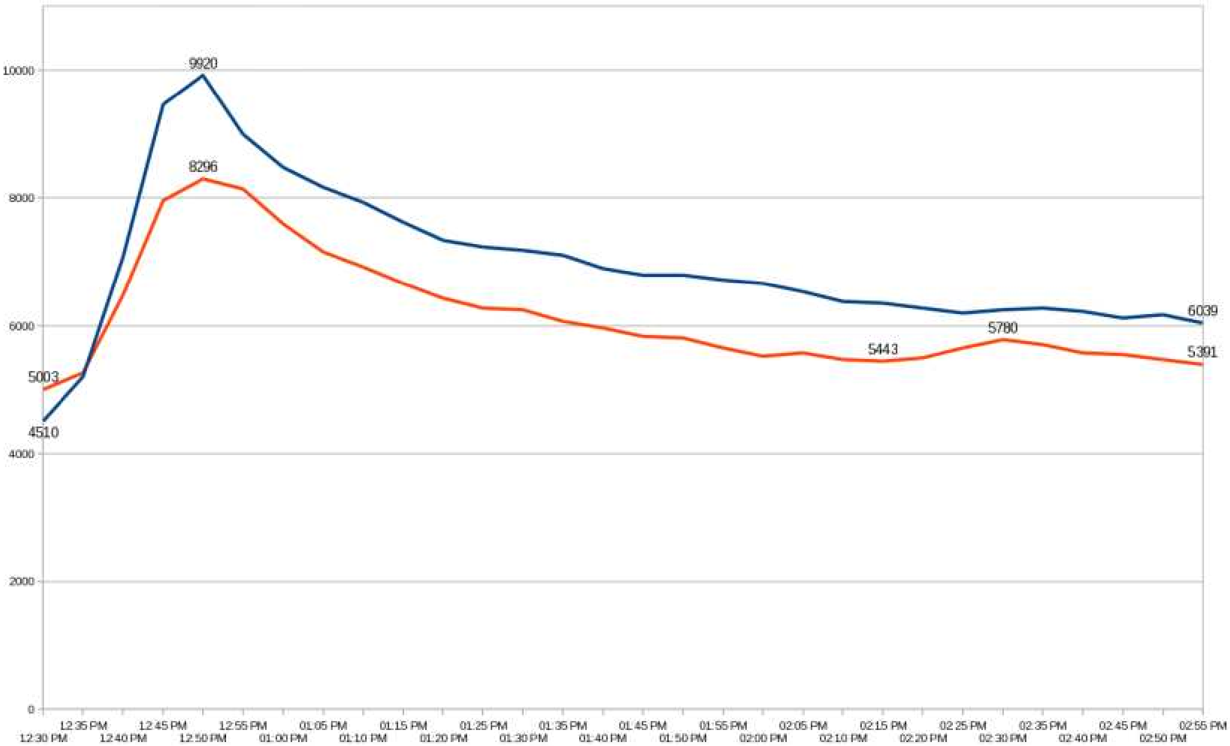


Figure 18 - Reducing Voltage at Recovery

Chapter 8 – The Future of Demand Reduction and Automation

8.1 - Automated Switching

The final phase of my research focused on automated switching between substations. Over the past 80 years NWREC has constructed and/or rebuilt substation tie lines with larger conductors and sufficient capacity to transfer load from one substation to another in an effort to provide more reliable power to customers and minimize the disruption caused by outages. Traditionally load transfers were performed manually by linemen opening and closing substation switches and tie switches.

In the early 2010's NWREC began efforts to automate switching with tie switches which utilize voltage sensing devices on either side of the open points to determine if one of the sources is disrupted. With a loss of source power, the line recloser opens and tie switches close. However, the sensing devices were mis-reading voltage drops caused by equipment failures as actual line faults, which were false alarms that triggered switching to begin. There were also safety concerns where the sensing device might recognize a loss of voltage as a fault on the line where an upline switch opened that it then automatically closed back into. This was of major concern to me since conductors could be laying on the ground and would be re-energized automatically by the switching scheme.

Over the past few years I worked with our SCADA vendor to customize our automated switching approach. Manual tie switches were replaced with "smart" switching FDIRs and many line switches that were single setting hydraulic models were replaced with electronic switches.

When load is shifted and feeds reversed, settings needed to be changed for proper coordination, which was accomplished with electronic switch controls. Now, the system is fully automated and every substation tie has been incorporated into the FDIR system. Every device is being monitored 24/7 for changes in the system. When a fault occurs, the system looks for the next downline switch and determines if its load can be fed from another source. If so, the downline switch will open and the best alternate source will close in to that device. Through the visualization of all devices in the system, the fault is isolated to a certain section and will not be re-energized.

The graphic below illustrates one of our substation ties, connecting three of our substations. The red squares are normally closed switches and the green are normally open switches. The load from these three sources is being monitored in real time so the best alternate source can be determined when an outage occurs. If the source voltage is lost at the substation and our Penelec transmission feed is down, the feeder switch at the substation is opened and FDIR will run to determine if the entire substation can be backfed. In our case, almost every substation's load can be transferred completely to one or more alternate substations.

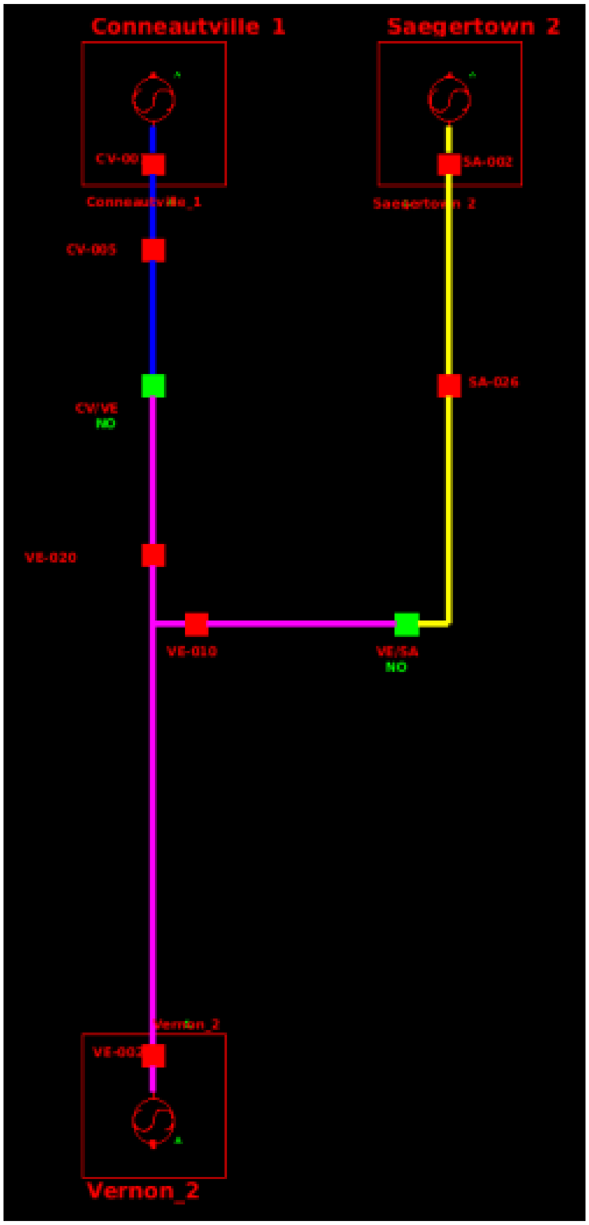


Figure 19 - Substation Tie

8.2 - Automated Switching with Voltage Reduction

Regulator control upgrades over the past 5 years have created opportunities unavailable in the past. Regulator tap changers determine the number of windings necessary to increase the supply voltage to within the bandwidth of the load settings. Newer regulator controls allow for tap capacity settings to be utilized, which defines the amount of load that can be placed on the regulator for each tap. In performing this function, the control will block tap changes from occurring that would overload the regulator. If the load increased during backfeed events, the taps will change to accommodate the capacities of the regulator. The graphic below shows the "Adaptive ADD-AMP" settings for a regulator. The values shown indicate that if the control requires the regulator to raise or lower voltage by 5% then the regulator can handle 160% of its rated load current. As can be seen, when the percentage change in voltage from source to load is raised, the limit of load current on the regulator is decreased. This decrease is due to the fact that for each tap change the regulator is introducing more windings into the circuit.

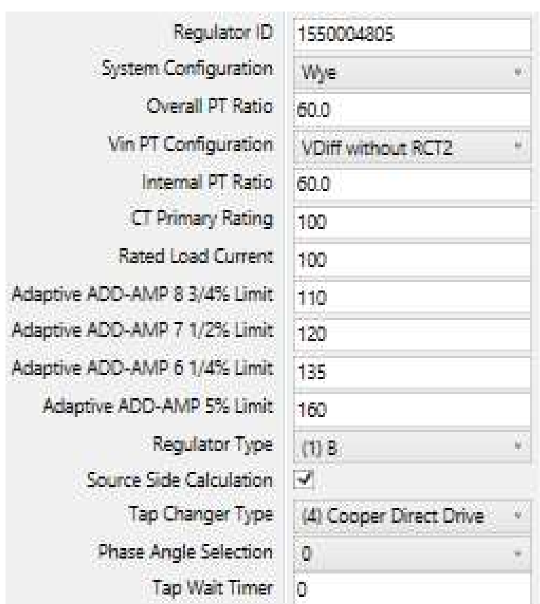


Figure 20 - Regulator ADD-AMP Settings

In addition, these bandwidth settings can be altered based on the direction of powerflow. If the regulator is in the normal forward direction it can have entirely different settings when powerflow is reversed for backfeeding, to ensure end of line voltages are within ANSI standards.

The settings with new regulator controls has allowed me to locate regulators near tie points for backfeeding only. I have programmed these tie regulators to sit at neutral until load is applied during a backfeed event. By remaining in the neutral position, the regulator windings are not in the circuit adding losses to the line during normal operations. When the regulator sees the load rise above 1% of its rating it will begin its function and change taps. In normal operation it is located at or near the tie switch so there is little to no load on it.

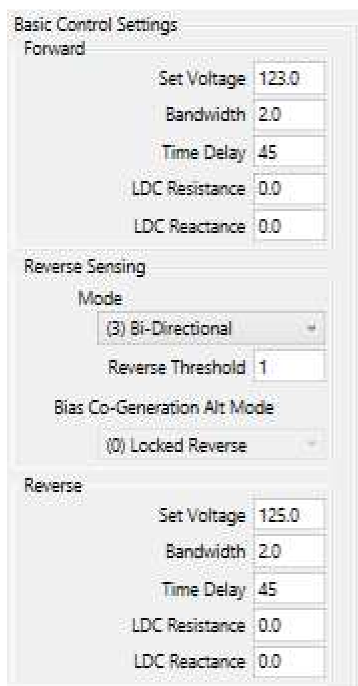


Figure 21 - Regulator Forward and Reverse Settings

The automation and SCADA upgrades ultimately allowed me to transfer load to alternate sources when coming out of load control, thereby reducing the need for additional substation capacity. Also, I was able to maximize savings for NWREC using this approach, rather than the method used by other utilities, where DRU's are reducing load for only 50 to 75% of an hour, as was discussed in Chapter 6.

The culmination of my voltage reduction and automation projects, as well as my research, has resulted in a system that can be adapted to transfer loads to the best sources and maximize savings.

Voltage reduction can be maximized, in addition to load control, because the substations that are near capacity when the control periods end, have alternate sources that can sufficiently accommodate the additional load of a few line switches. Over the past 3 winters I have been switching line devices to alternate substations when control periods end so I can continue to maximize savings by voltage reduction on top of load control. Below is a chart depicting the load of an over loaded substation in yellow from which I switched a large line section to an alternate substation, which is in red, alleviating all loading concerns.

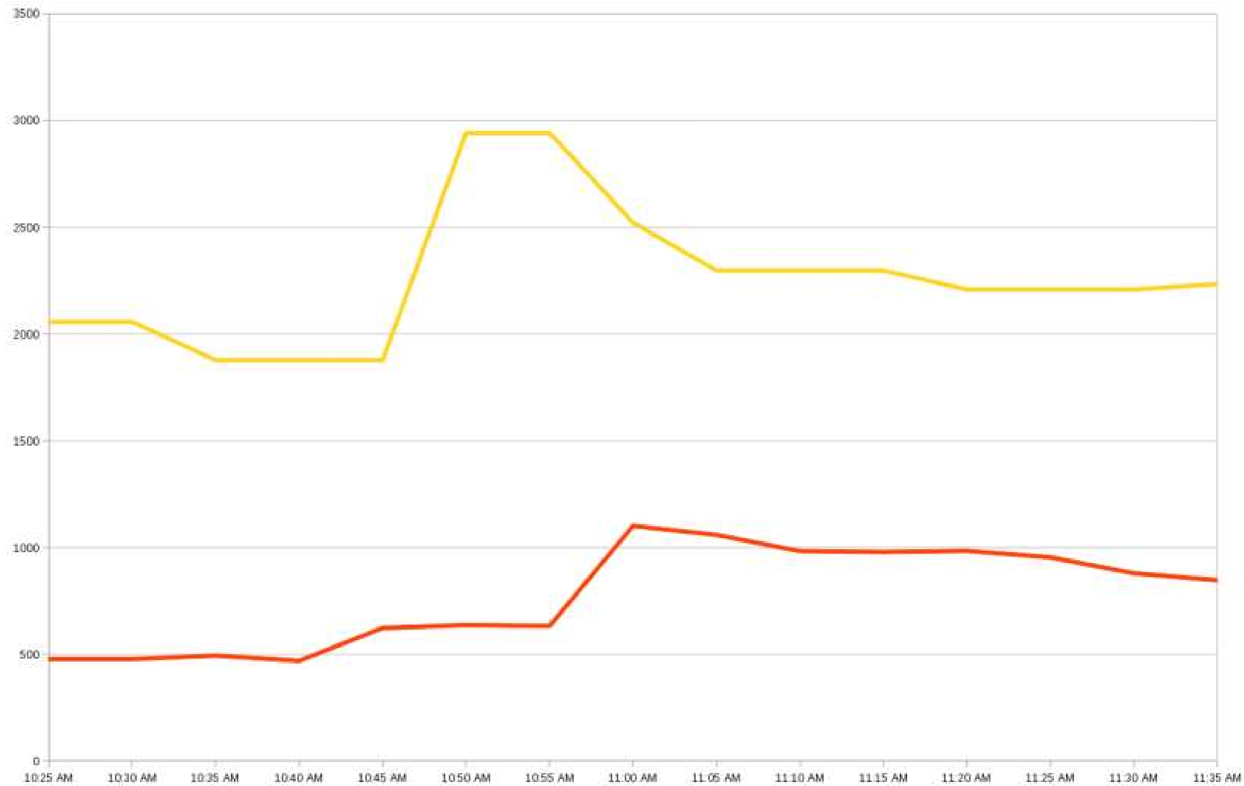


Figure 22 - Load Switched Between Sources

8.3 - Future Work

8.3.1 - Automating Feedback from AMR

Presently, the AMR and SCADA system do not communicate with one another because SCADA is on its own network. Through the use of newly released software, this bridge will be made with encryption to provide SCADA with access to meter voltage readings. Then the voltage reduction process can be fully automated to utilize the feedback from end-of-line meters to change the setpoints during the control period, to maximize savings. I will identify 20-30 end-of-line meters per feeder and read 5-6 of them every 15 minutes in cycles so the meters do not overheat. On the 15 minute intervals the readings will be posted in the SCADA system and an algorithm will determine if the voltage can be changed on each regulator bank.

8.3.2 - Automated Switching using Real Time Load Flow

Another aspect that I plan to investigate based upon this research is to utilize automation to switch line sections, based on real time load flow analysis, to the best available source. This process will only be activated when load control events are ending as it essentially means there will no longer be a normal feed for the system. This complicates line construction and maintenance as crews will need to be privy to the direction of flow for the line they're working on.

My goal is to utilize the existing FDIR software to trigger line analysis when a load control event occurs. The existing software analyzes real time load flows for every source and line section in the system, so the background work is completed. To build upon this, a new script will be written and run to determine which line sections or equipment are nearing capacity and evaluate whether a better source is available. Presently, FDIR is only triggered to run when a switch is opened under a fault condition or there is a loss of voltage on the transmission system. The new script will activate FDIR to read the loading constraints along with the SCADA real time loading values to alleviate any overloading conditions on the system. I have been manually doing the switching when overloading occurs, but this will automate the process between all substation ties. In essence, this will allow me to control as much load through load control and voltage reduction as possible without worrying about the recovery peak at the end of the control period that has been a concern for years.

Chapter 9 - Summary and Conclusion

9.1 - Savings on Purchased Power

Automating voltage reduction, in conjunction with the other strategies employed, substantially decreased system load and significantly increased savings to NWREC. Voltage reduction was successfully utilized to reduce system peaks, as well as equipment peaks, which has the substantial added benefit of deferring and/or eliminating capital expenses to increase equipment/system capacity.

Automated voltage reduction over the past 3.5 years of research and testing various methodologies resulted in an average of 23% of total load dropped during fall, winter and spring months and 16% in summer months. Therefore, nearly a quarter of the load shed during most peaks resulted from voltage reduction requiring little to no equipment maintenance and is automated. As a result, in 2017 NWREC benefitted by nearly $78,000 in savings for Penelec peaks and $26,000 for PJM Hi5 peaks using automated voltage reduction.

Table 1 – Monthly Peak Savings from Voltage Reduction

Monthly Peak	Load dropped in kW	Voltage Reduction Contribution in kW	Voltage Reduction Cost Savings
January	6568	1510.64	$9,849.37
February	6471	1488.33	$9,703.91
March	8267	1901.41	$12,397.19
April	5317	1222.91	$7,973.37
May	5465	874.4	$5,701.09
June	3680	588.8	$3,838.98
July	3520	563.2	$3,672.06
August	1999	319.84	$2,085.36
September	2528	404.48	$2,637.21
October	3311	761.53	$4,965.18
November	3295	757.85	$4,941.18
December	6396	1471.08	$9,591.44
	Total	11864.47	$77,356.34

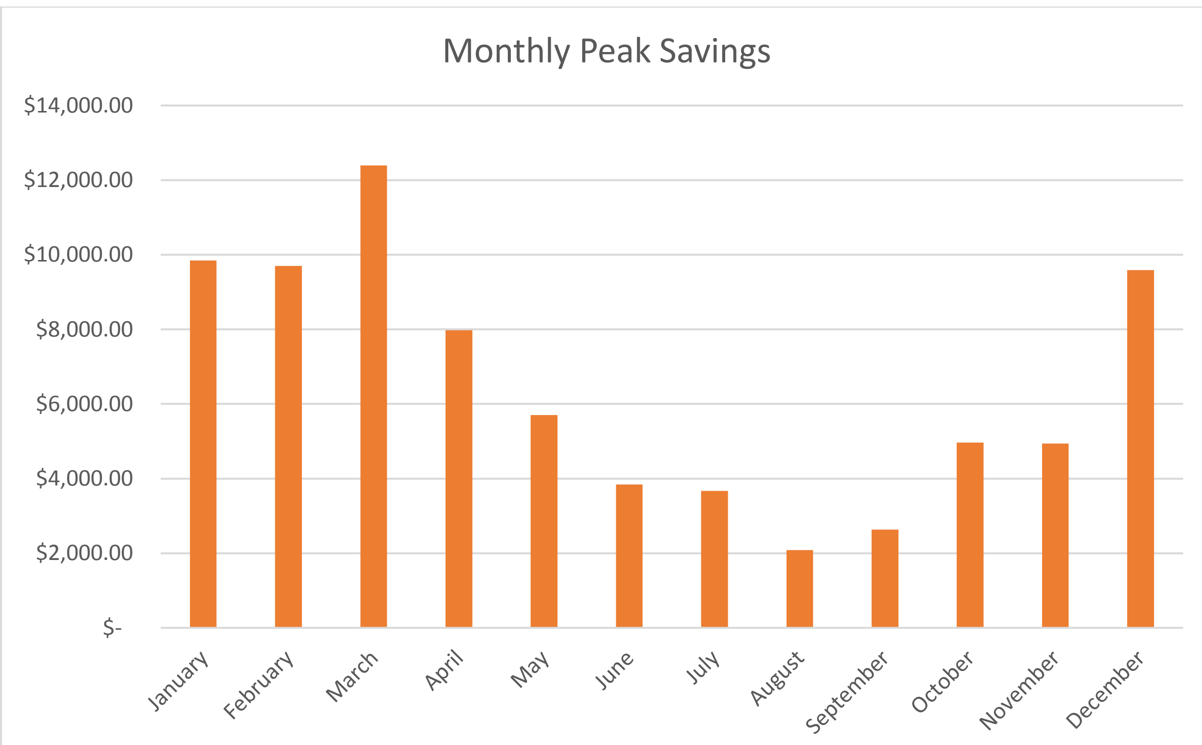


Figure 23 - Peak Demand Savings by Month

Table 2 - Hi5 Voltage Reduction Savings

Hi5	Load dropped in kW	Voltage Reduction Contribution in kW	Voltage Reduction Cost Savings
1	1968	314.88	
2	3519	563.04	
3	3395	543.2	
4	3564	570.24	
5	2090	334.4	
	Average	465.152	Total - $26,402.03

9.2 - Lost Revenue – Actual Savings

For 2017, the most recent complete year in my research, load control periods, which are initiated by Allegheny in an effort to incorporate the actual peak, totaled 504 hours, with only 17 being actual peak hours.[6] The missed hours resulted in approximately $18,000 of lost billed revenue for our utility. This value is calculated by multiplying regular power bill charges by the drop in load through voltage reduction during non-peak hours. Subtracting lost revenue from total savings of $104,000, results in a net annual savings of $86,000 due to automated voltage reduction strategies.

[6] The control periods are noted in the Appendix.

Table 3 - Lost Revenue from Voltage Reduction

Load drop on peak	Hours	Lost Revenue
6568	23	$1,357.82
6471	27	$1,570.43
8267	28	$2,080.60
5317	18	$860.24
5465	49	$1,674.41
3680	26	$598.27
3520	53	$1,166.52
1999	23	$287.48
2528	62	$980.04
3311	37	$1,101.14
3295	70	$2,073.17
6396	71	$4,081.78
		$17,831.91

9.3 - SCADA Return on Investment

To further refine the financial benefits achieved through voltage reduction also required a review of the costs associated with the installation of the SCADA system as well as the other equipment necessary to make this project successful. Shown below, the total cost of the SCADA system with the regulator upgrades was $150,000.

- RTU's - $1,881 * 19 = $36,000 (17 substations, 2 regulator banks)
- SCADA System - $43,000
- Upgraded Regulators and Controls - $40,000
- Installation time and materials - $31,000

However, it should be noted that the SCADA system would have been purchased and installed regardless of my research, since it provides a significant number of benefits to the NWREC beyond those utilized for my research and testing. Regardless, the costs are identified here for the benefit of other utilities that may otherwise not be considering the installation of SCADA for its benefits not related to this research.

My testing and analysis thus far have substantiated annual savings resulting from automated voltage reduction. These additional savings cost justify the purchase and installation of the SCADA system, with a payback period for NWREC of approximately 1-3/4 years. The SCADA installation project began in 2014 and was system wide at the beginning of 2015. Therefore, by the end of 2017, the SCADA system had already paid for itself through the benefits derived from automated voltage reduction alone. Since then the savings should continue to average approximately $90,000 per year from reduced demand charges, dependent upon changes in rates for future purchased power. In addition, the significantly enhanced monitoring and control functions provided by the SCADA system, as well as its use in automated switching, will substantially enhance the efficiency of the power grid in the future.

9.4 - Recovery Curtailment

There were two strategies I developed for reducing peaks at the end of load control periods using voltage reduction. The first was to leave voltage reduction active for an additional hour past the load control event. This strategy was proven successful and reduced transformer loading at the completion of load control periods. I would use this is in any case where capacity is an issue as it doesn't have any negative effects beyond an additional hour of lost revenue.

The second strategy was to not utilize voltage reduction in conjunction with load control but rather reduce the voltage only when the load control period ends. This strategy was proven very successful in reducing the peak but was pushing the limits of end-of-line voltages. I would use this in emergency situations only when automation cannot be used. It will certainly reduce the peak to save NWREC equipment but may result in low voltages which may affect members' electronic equipment near the end of the line.

In summary, the most effective strategy for reducing peaks on load control recovery is utilizing automation to transfer loads to alternate sources. This is also the most beneficial as load control and voltage reduction can be used together to reduce the most possible load during demand peaks while keeping the distribution equipment safely loaded. I believe this will be the strategy of the future and will be used throughout the power industry for financial benefits and to extend equipment longevity.

9.5 - Conclusion

As has been demonstrated through this research, automated voltage reduction results in substantial financial savings to a residential distribution cooperative utility. The energy market is evolving due in large part to the aging infrastructure of the grid, as well as the continued depletion of fossil fuel resources for energy production and the shift towards green alternatives. As such, the grid must increase its reliance on load reduction or energy storage strategies such as load control devices. Attempting to maximize savings during peak periods is not a new concept; however, the enhancement provided by automating voltage reduction is simply another approach to achieve additional benefits.

Employing load drop strategies often result in new peaks on the transmission grid or surpass load capacities of distribution equipment in the recovery period. Again, the future of the grid will depend on automation to transfer load between substations to alleviate capacity concerns. With a fully automated system, switching will be performed based on real time load calculations and predictive analysis to protect our vital electric power systems.

APPENDIX

Table 2 - 2017 Load Control Periods with Peaks

	7	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	
1/5/2017		1	1	1	1	1	1	1	1			1	1	1	1			
1/6/2017		1	1	1	1	1												
1/9/2017	1	1	**P**	1	1	1	1											24
2/2/2017		1	1	1	1	1	1	1					1	1	1			
2/3/2017		1	1	1	1	1												
2/9/2017													1	**P**	1	1		
2/10/2017		1	1	1														
2/17/2017		1	1	1	1													
2/23/2017									1	1								28
3/2/2017			1	1	1	1	1	1					1	1	1	1		
3/3/2017		1	1	1	1	1								1	1			
3/10/2017						1												
3/13/2017	1	1	1	1	1													
3/15/2017													1	1	**P**	1		
3/16/2017		1	1															29
4/3/2017		1	1	1	1	1												
4/4/2017															1	1		
4/5/2017					1													
4/6/2017					1	1	1								1	1		
4/7/2017		1	**P**	1	1	1	1											19
5/1/2017					1	1	1	1	1									
5/3/2017				1	1	1	1			1								
5/4/2017			1	1	1	1	1	1	1									
5/5/2017				1	1	1	1											
5/8/2017		1	1	1	1	1	1											
5/9/2017		1	1	1	1	1	1											
5/17/2017							1	1	1	1	1	1	1	1				
5/18/2017					1	1	1	1	1	1	**P**	1	1					50
6/9/2017				1	1													
6/12/2017						1	1	1	1	1	1	1	1					

6/13/2017						1	1	P	1	1	1	1						
6/14/2017										1	1							
6/22/2017										1	1	1	1					
6/30/2017									1	1	1	1	1					28
7/7/2017								1	1	1								
7/10/2017								1	1	1	1	1	1					
7/11/2017							1	1	1	1	1	1	1					
7/12/2017							1	1	1	1	1	1						
7/14/2017							1	1	1	1	1							
7/17/2017						1	1	1	1	1	1	1	1					
7/18/2017							1	1	1	1	1	1	1					
7/19/2017							1	1	1	1	1	1	1					
7/20/2017								P	1	1	1	1						
7/21/2017									1	1	1	1						58
8/1/2017							1	1	1	1	1	1						
8/2/2017							1	1	1	1								
8/17/2017									1	1	1	1						
8/21/2017								1	1	1								
8/22/2017								1	1	1	1	1						
8/23/2017							P	1										24
9/5/2017						1	1	1	1	1	1							
9/6/2017							1	1	1	1								
9/12/2017								1	1									
9/13/2017					1	1	1	1	1	1				1	1			
9/14/2018					1	1	1	1	1	1								
9/15/2017						1	1	1	1	1								
9/18/2017				1	1	1	1	1	1	1								
9/19/2017								1	1									
9/20/2017							1	1	1	1								
9/21/2017						1	1	1	1	1	1							
9/25/2017						1	1	1	1	1	1	1						
9/26/2017							1	P	1	1	1	1						63
10/3/2017														1	1			
10/4/2017				1	1	1	1	1	1	1				1	1			
10/5/2017					1	1	1	1	1									
10/6/2017						1	1	1										
10/9/2017			1	1	1	1	1	P	1	1								

10/10/2017								1	1	1								
10/30/2017					1	1	1											
10/31/2017		1	1	1	1	1												38
11/1/2017	1	1	1	1	1	1	1	1	1				1	1	1			
11/7/2017			1	1	1	1	1	1	1			1	1	1	1			
11/8/2017	1	1	1	1	1													
11/9/2017			1	1	1	1	1											
11/10/2017		1	1	1	1	1	1					1	1	1				
11/13/2017		1	1	1	1	1	1						1	1	1			
11/14/2017			1	1	1	1						1	1	1	1			
11/15/2017	1	**P**	1	1	1	1												
11/20/2017													1	1	1			
11/21/2017		1	1	1														71
12/4/2017	1	1	1	1	1	1						1	1	1	1			
12/6/2017		1	1	1	1	1	1					1	1	1	1			
12/7/2017											1	1	1	1	1			
12/8/2017		1	1	1	1	1	1					1	1	1	1			
12/11/2017												1	1	1				
12/12/2017						1	1				1	1	1	1	1			
12/13/2017	1	1	1	1	1	1	1					1	1	1	1			
12/20/2017								1	1									
12/27/2017													1	1	1	1		
12/28/2017			1	1	1	1	1	1				1	**P**	1	1			72
TOTAL HOURS OF CONTROL - 504																		