MAGAZINE
Volume 2 | Edition 1 | Spring 2019

Celebrating 20 Years!

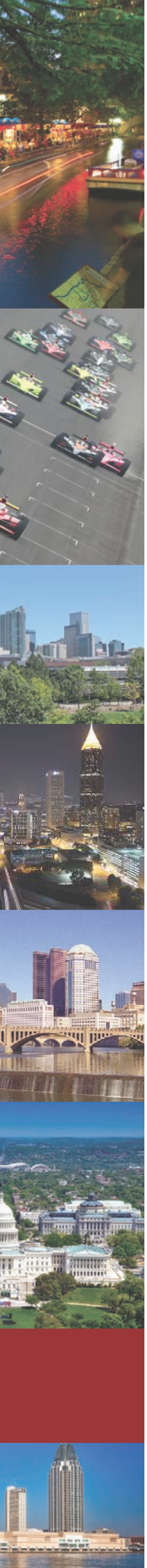
ENSC

April 8th - 11th 2019 | San Francisco, California

Pacific Gas and Electric Company

EATONENSC.COM

EATON
Powering Business Worldwide



It is great to be in San Francisco for our 20th annual ENSC! We could not have picked a better venue and thankful that PG&E wanted to host the event. A couple factoids that I have learned, in preparing for this event, that San Francisco has the 2nd largest Chinatown outside of Asia and the iconic Golden Gate Bridge, as we know is not golden but a reddish orange tint, it's called International Orange. The surprising thing is that the color comes from the primer applied to protect the bridge. The architect loved it so much that he made it the official color.

Besides the great venue, this edition of ENSC magazine contains some great articles. Make sure you check out the articles on Network Testing Philosophy by Richard Hotchkiss for further education and the article on how safety has changed in Network environments written by Tom Thode from Xcel.

For 2020, the ENSC will be heading to Texas to join our host CenterPoint Energy, arrangements are already in work to make sure the educational content continues to give back to the network community.

I look forward to seeing all of you in Texas!

Respectfully,

Mark Faulkner
Product Line Manager
Eaton

ENSC Advisory Council Members:

Maria Ly
Pacific Gas and Electric

Shane Powell
Alabama Power Company

Ryan Bradeen
Avista Corp.

Rick Kernan
Xcel Energy

Robert Spelman
Pepco Holdings Inc.

ENSC Magazine

Tony Oruga, P.E.
Eaton
1520 Emerald Rd.
Greenwood, SC 29649

AntonioROruga@eaton.com
(864) 330-2461

ENSC – The Network Solutions Magazine

TABLE OF CONTENTS

SAVE THE DATE

Hosted by: CenterPoint Energy

Sponsored by: EATON Powering Business Worldwide

April 6th-9th 2020

21st Annual Electrical Network Systems Conference

HOUSTON, TX

Understanding ArcFlash

Dave Loucks, Eaton, Power Solutions Manager

You are likely already acutely aware of the danger of arc flash. You are also likely aware that the danger from an arc flash tends to increase:

- As the available fault current increases,
- As the time you are exposed to the fault current increases and
- As the distance between you and the arc decreases

Unfortunately, in underground utility networks, these factors tend not to work in our favor. Available current can be very high. The time a fault persists can be measured, not in milliseconds, but in many seconds or longer. Many times work is performed in confined spaces, which limits a worker's ability to run away from an arcing event.

But even so when an arc flash event does occur, serious consequences can include:

- Injuries
- Medical bills and insurance rerating
- Fines and potential lawsuits
- Equipment damage
- Delays and downtime
- Impact on employee morale and community public relations

For these reasons every appropriate effort should be taken to understand the potential hazards, train and equip your staff and deploy techniques and programs to minimize the danger of arc flash.

Arc Flash Incident Case Study

In 2015, a highly skilled worker performing upgrades within an Avista 480V network vault experienced an arc flash event. During a routine protector change-out the cableman was working on live equipment and the ladder supporting him slipped. This resulted in a chain reaction of events. The blanket that was used to cover the network protector tank below moved just enough to expose the terminal on the tank. Unfortunately, as the ladder shifted, the tool in the hand of the worker glanced against the terminal housing, and grounded the energized collector bus via a non-insulated tool.

Image of the burned tool held by the worker

The resulting arc flash was severe enough to throw the worker off the ladder with sufficient force to send him across the vault and land against an opposite wall. However, the most severe injuries were facial burns on his forehead, nose, chin and cheeks. While he was wearing PPE, he had removed his protective hood due to the lack of light in the vault as well as the dark face shield which had made it difficult to see. He was wearing safety glasses which may have saved his eyes.

He fully recovered, but he will be the first to tell you that he never wants to experience that again.

What can be done to reduce danger?

With such high currents, the lack of overcurrent tripping and confined spaces, what can be done to reduce the danger of an arc flash event on such a network?

1. **Perform an incident energy analysis**
   Knowing the worst-case incident energy levels should an arcing event occur allows you to take appropriate action to protect people and equipment. This study should be performed by power systems engineers skilled in the study of arc flash and who fully understands the equipment, the settings and the consequences of changes in equipment settings. In this case study, perhaps understanding that a serious face burn was possible might have changed how the work was performed.

2. **Equip staff with appropriate personal protective equipment and tools**
   With the known incident energy levels, you can provide your staff with the right PPE and equipment to keep them safe. Remember, though, PPE should be considered the protection of last resort. An arc flash event can still result in equipment destruction and down service, not to mention potentially receiving bad publicity from either the outage alone, or potentially the fire and explosion that can occur. Also, if the PPE that is provided (like the dark face shield) hinders work, look for alternatives.

3. **Post warning labels and boundary markers**
   Make sure people who have access to areas where arc flash incident energy can exceed the 1.2 cal./cm2 are suitably warned, both with labels that describe the hazard as well as clearly visible "do not cross" boundary markers. In some areas, such as underground vaults, the energy levels could prohibit entering while energized. In our case study above, estimated available fault current was 70 kA – high enough that would, and did, cause a severe injury. However, arc flash hazards are not the only concern. Vault flooding can cause an electrocution hazard. In both cases (high available fault current and possibility of flooding), remote monitoring and control of that vault's assets should be considered.

4. **Implement training program and include periodic refresher classes**
   OSHA requirements and common sense dictate that people receive regular refresher training.

5. **Reduce available fault current (if possible)**
This may not be possible in underground networks, but if higher impedance transformers or open tie switches can be employed to reduce fault current, they should be evaluated to see if that will have a benefit on your circuit. Reducing fault current doesn't, however, always reduce incident energy. In the special case of circuits that are protected with current limiting devices, the extremely fast clearing times of these kinds of devices may result in lower incident energies from higher available fault currents. This may seem counter-intuitive so verify with a power systems engineer trained to perform that analysis.

6. **Shorten clearing times**
Networks are highly available systems where faults are typically cleared not from overcurrent relay operation but from the faults burning clear. However, when working on live equipment the need for service continuity must be balanced by the need to protect the worker. Also, not all circuits are meshed networks. Spot networks and more conventional, radial, loop, ring and primary or secondary selective circuits are also common.
For this reason, certain kinds of protective functions may be possible to include in certain cases.

   a. **Directional and differential relaying**
   Networks commonly use directional Watt and VAR relays to detect the direction of real and reactive energy flowing in a vault and to open a network protector as appropriate. However, this typically addresses faults on the primary side of the network transformer which may be some distance away. For faults occurring within the vault, the directional tripping usually provides less benefit. If it is possible to interrupt power flowing into a vault, it may be possible to install bus differential protection to monitor current entering and leaving a vault. Such a solution would be more likely used on spot networks or on more loop, ring or selective systems.

   b. **Deploy ARMS**
   Similar to the problem with directional and differential sensing, ARMS (Arcflash Reduction Maintenance System) is a method of providing more sensitive overcurrent tripping when equipment must be serviced live. When activated, ARMS removes intentional delays from protective devices while simultaneously reducing the pickup level needed to initiate an instantaneous trip. The highest performing ARMS systems operate far faster than even instantaneous tripping elements. ARMS first became popular in 2011 when it was introduced as a solution to meet article 240.87 in the 2011 National Electrical Code. Note that there are other solutions mentioned in that code section, with each offering certain pros and cons compared to ARMS.

Method	**PROS** *(better than ARMS)*	**CONS** *(not as practical as ARMS)*
Zone Selective Interlocking	Always on vs ARMS needing to be switched on demand	Slower to respond (higher incident energy released than ARMS protected circuit)
Differential relaying	Always on vs ARMS needing to be switched on demand	Expensive (requires large, matched CTs to be mounted on each incoming and outgoing conductor)
Active arc flash mitigation (light)	Could be faster **ONLY** if suitable crowbar device installed	Could nuisance trip from light ejected from switching device under normal operation
Instantaneous setting below arcing current		Complex arcing fault calculations needed (difficult to know precisely). Potentially slower than true ARMS
Instantaneous override below arcing current		Complex arcing fault calculations needed (difficult to know precisely). Potentially slower than true ARMS
An approved equivalent means	Unknown	Risk. Who determines? AHJ?

   c. Deploy Arc Flash relay (light / current) detection
   As mentioned above, detecting the burst of light after an arc flash is only half the battle in reducing energy of an arc flash event. Challenges remaining include:
   - How to quickly extinguish the arc. Considering that to effectively reduce the energy released from an arc flash event, not only must fault be detected, but also extinguished. And this must be done quickly! The peak pressure wave (which occurs within the first ¼ cycle [4.2 ms at 60 Hz]) means that any effective interruption cannot be slower than 4.2 ms (0.25 cyc).
   - Nuisance tripping from rogue light emissions of air break devices. Consider that an air break interrupting device generates a light pulse very nearly identical to a light pulse of an arc flash event. Without sophisticated discrimination, every time that such a device interrupts, there is the potential for nuisance operation from that rogue light emission.
   - Finally, even with the most sophisticated discrimination (usually with a combination of light

and current sensing and other tricks), detecting the fault is only half the battle – the current must still be interrupted fast enough to justify the investment. This is a problem when using mechanical devices. Such devices having moving contacts with mass and inertia. It doesn't matter if an arc flash is detected in a nanosecond if the device requires 80 ms to clear the fault! The arc flash will continue for 80 ms. The explosive peak pressure wave (4.2 ms till peak) has long since occurred and the commensurate operator injury and equipment destruction has occurred along with it.

Actions to reduce arc flash risk

While many of the technologies listed above are quite applicable in many utility systems, they aren't as relevant to underground networks and vaults. The constrained space, lack of overcurrent tripping as well as the extremely high available fault levels (by design), make these locations dangerous places for live work.

For this reason, companies should examine practical methods of performing the tests, monitoring and maintenance remotely.

1. **Adopt remote operation**
   Removing the worker from the vicinity means that the eyes, ears, touch, nose and ability to move things is no longer on site either. Not only is the situational awareness lost, but the ability to open, close, disconnect and move things is lost. A suitable replacement to a physical worker will change based on what would have needed to have been done by that worker.
   a. **Remote monitoring**
      Network protectors have, for many years, included communications that can be integrated into existing SCADA systems. Later enhancements allowed those same protectors to integrate safely and securely into encrypted utility IT networks. But can the telemetry system provide the information that a local worker would have been able to provide? The answer (and cost) depends on what you need, and how fast you need it. Some examples include
      i. Protector state (closed, open/floating, open/locked out, etc.)
      ii. Current (phase circuit as well as control)
      iii. Voltages (both circuit as well as control)
      iv. Phase angle (differential across NWP)
      v. Watt and VAR (magnitude and direction)
      vi. Temperature (transformer, protector, vault)
      vii. Presence of water
      viii. Sound and vibration
   b. **Remote control**
      When monitoring alone isn't sufficient, and actions such as opening and closing or even permanently disconnecting protectors is needed, something else besides a telemetry system may be needed. With network protectors, in addition to the ability to act upon ROBO (remote open / block open) commands, some network protectors take this a step further and permit remote racking of the switching device to add another level of protection.
2. **Predict and prevent faults**
   Network cabling can be subject to water encroachment, animal and insect infestation and just general degradation due to age. In several cities, as early as 1925, networks were an accepted method of supplying power. With cables and terminations under our streets potentially being over 70 years old, how might those bad cables be located? This will be a topic for an article in the next issue, but essentially there are several methods.
   a. By comparing, normalizing and filtering currents and voltages collected from a diverse set of metering devices (NWP, AMI, substation meters and relays, etc.), a real-time state-estimation analysis is performed. The result of this analysis is compared to the offline model of the system. Excessive voltage drop can point to cleared limiters or other failures in continuity between two points. Also, higher than normal resistance on a set of phase conductors means that those conductors will heat (and potentially degrade and fail) more quickly.
   b. Arcing ground faults may persist for extended times during which they consume power in a "stochastic" (random) method that is detectable using algorithms that can measure randomness in the current and voltage patterns.
   c. In medium voltage systems such as switchgear, corona and partial discharge events are detectable using embedded computer systems connected to I/O that can retrieve high frequency electromagnetic emissions from those discharge events.
   d. Using temperature and IR (pyrometer) sensing of conductors, terminations and equipment, early warning of faster than normal degradation can be detected. Failing connections, for example, have higher resistance. Higher resistance means greater voltage drop and higher heat loss. Arrhenius equations can be applied to estimate the reduction in equipment service live.
3. **Redirect blast energy**
   One final consideration is the use of arc-resistant equipment. Arc resistant equipment is designed to contain and redirect any internal arc flash event's energy safely away for a worker.
4. **Isolate Network Protector**
   A network protector should be completely dead before working on the equipment. If the station breaker is opened, then the primary is de-energized but other network protectors on that same feeder are also opened - dropping contingency.

   The best option is the use of a localized primary switch on the medium voltage side of the network transformer. This will avoid having other network protectors open where the work is being done on the same feeder.

   Note the high voltage side is not the only consideration. The network side is always energized and is not within the confined space of the network enclosure, where work is being done. A disconnect external to the enclosure such as VisoBlock, Pringle switches, or a disconnect link or fuse should be used to fully isolate and protect the worker.

Arc flash events can cause devastating injuries to people, equipment and company's reputations. Take the time to study your system and perform the studies and methods recommended here.

Pacific Gas and Electric System Improvement Plans

Maria Ly, PG&E, Asset Management

Dustin Dear, PG&E, Network Program Manager

Headquartered in San Francisco, Pacific Gas & Electric (PG&E) serves approximately 5.4 million electric customers in northern and central California. Due to recent gas pipeline and wildfire events, scrutiny on safe operations from the public, regulatory, and governmental agencies has never been higher.

PG&E's network system nestles in downtown San Francisco and across the bay in downtown Oakland. It consists of a total of 12 network groups, 69 feeders with approximately 1350 network transformers, network protectors, and approximately 190 circuit miles of primary and 100 circuit miles of secondary cables. These electrical facilities are located in very close proximity to the public. Proactive programs, such as equipment maintenance / replacement and condition monitoring, focus on preventing a catastrophic failure. Although the frequency of these failures can be reduced, the risk cannot be completely eliminated. Underground vault explosions, although not a common occurrence, can result in significant property damage and serious injuries to the public and PG&E personnel.

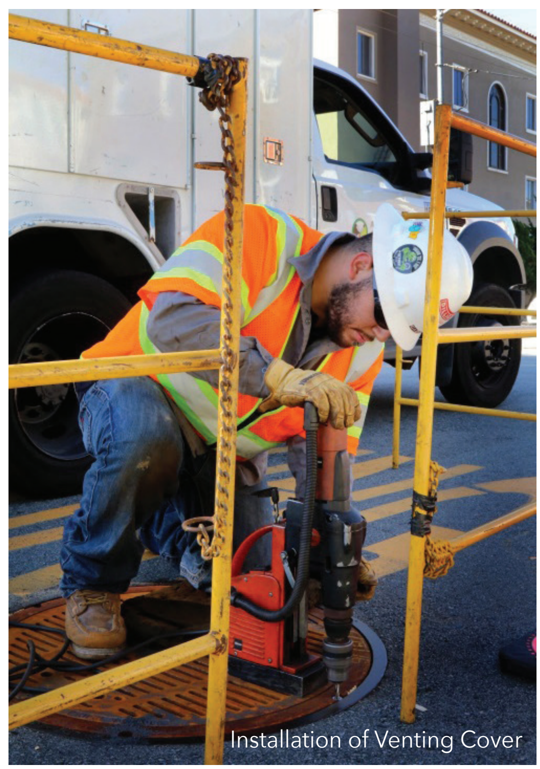
EJIW cover (installed)

Venting Manhole Cover Bracing System

Venting Cover Program

In 2010, PG&E began a program to replace traditional manhole cover with a venting cover, designed to remain in place in the event of an explosion in the vault. These covers are designed to prevent hazards associated with a 250+ pound cover being launch above ground, as well as minimize the explosion energy by reducing oxygen intake. Efficacy testing was performed at the EPRI Lennox facility using a standard PG&E vault and lift-out panels.

PG&E started the program with the Swiveloc covers and more recently installed venting covers manufactured by East Jordan Iron Works (EJIW). Through 2018, PG&E have installed over 5,700 covers, with prioritization based on high pedestrian traffic areas in San Francisco such as parade routes and public market places. This is a system-wide program that will eventually replace most manhole covers in PG&E's electric system, approximately 13,200. Since program inception, there have been a few cable failures where the installed covers have demonstrated to be effective.



Installation of Venting Cover

Some of the key program challenges:

- Standard cover sizes were developed which are applicable for estimated 75% of the locations. The remaining 25% locations would not accommodate the standard covers due to the uniqueness of the original installation (i.e., non-standard size, double lip steel ring, etc.) or require repair work to address vault structure and frame deteriorations. The unit costs of non-standard locations were many times the standard locations. PG&E project team continues to work with the manufacturer to develop additional standards where applicable, streamlining construction tools and labor to lower the per-unit cost.

- Non-standard replacements are mostly done at night due to pedestrian traffic and require multiple permits. These restrictions put a limitation on how many non-standard locations can be completed within a given year.

Cable and Testing

PG&E is taking a proactive approach to replacing underground primary and secondary Network cable that has been in service for several decades. The purpose of the project is to improve safety to our customers in the downtown San Francisco and Oakland Network areas.

PG&E plans to continue the systematic replacement of network cable assets in San Francisco and Oakland. The work involves prioritization, testing, replacing primary and secondary cables and installing new equipment.

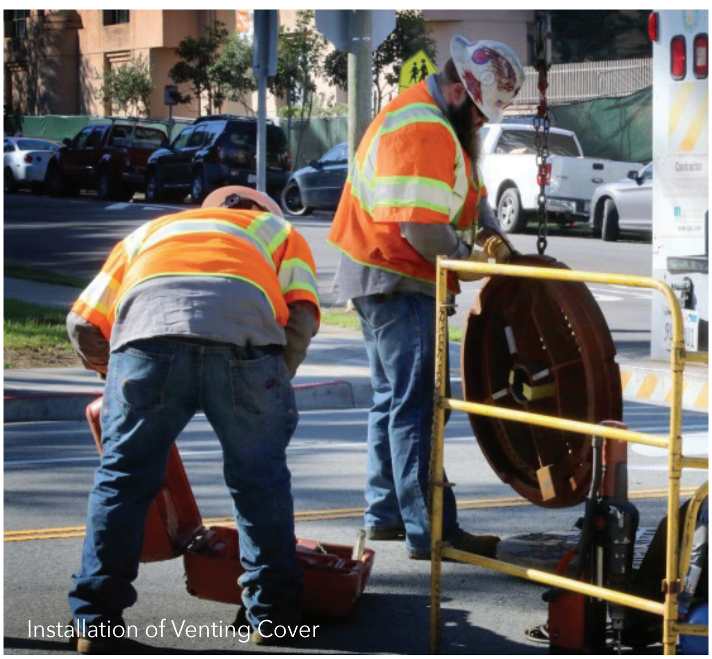
These networks are located in the downtown areas of both San Francisco and Oakland, where there is a significant amount of pedestrian traffic. The inherent design of these systems results in facilities capable of releasing a significant amount of energy if a failure were to occur.

The first step is prioritization based on failure history. PG&E has experienced 85 primary and 21 secondary network cable systems failures incidents from 2008 to 2018. We believe that it is reasonable to anticipate that additional incidents may occur in the future as the network systems age further.

Next, we implement a proactive testing process using both VLF tan delta and partial discharge testing with a focus on the primary 12kV PILC circuits. Then, based on the test results, we only replace parts of the circuits, deferring that sections that tested good. This process allows us to replace more of the cable that is likely to fail and stretch the funding to address more circuits.

Many of the existing 12 kV primary circuits were installed from the 1920s through the 1960s using PILC cable. While PILC cables have proven to be very reliable, many of these facilities are reaching the end of their useful service lives. The associated secondary cables use either paper insulated conductors with a lead sheath, or rubber insulated, polyvinyl chloride or polyethylene insulated conductors. As with the primary cables, these secondary grid cables are also reaching the end of their service lives.

Replacing the primary and secondary grid systems will improve safety and reduce the risk of fires and explosions in the downtown San Francisco and downtown Oakland areas. Primary and secondary cable failures can release a significant amount of energy, which can



Installation of Venting Cover

Internal

result in explosions and manhole cover displacements. In addition, initial failures can cause fires on the cable insulation, which can fill the vault with gases and result in secondary explosions. These explosions may cause personal injury and property damage. The location of these facilities in dense urban environments, combined with failure impacts, increases bystander risks.

As part of the program, we are also installing switches at network feeder outlets and mainline locations. This helps us to meet operational requirements by providing a switching location outside the substation to establish feeder clearance points. Currently, network feeder clearances require that circuit breakers be removed from service prior to performing work. This process is labor intensive, requires that switchmen use special arc flash rated personal protective equipment, and involves physically removing circuit breakers weighing hundreds of pounds from their switchgear and reinstalling them once work has been completed.

Furthermore, the switch installation improves work efficiency by eliminating the need to involve substation personnel for clearing and grounding at the station for feeder clearance work that needs to be performed outside the substation. This also improves emergency response for fault locations outside the substation since Maintenance and Construction crews are able to clear the feeder without having to wait for substation personnel. In addition, fault troubleshooting and isolation will be improved through the installation of new current limiters on the secondary grid cables.

PG&E began replacing 12 kV primary network cables in San Francisco in 2012. Work performed in 2012 and 2013 has provided the Company a better understanding of some of the issues and work procedures associated with the grid replacement. The overall project will continue in future years with the same strategy with continual refinement based on failures, cable testing and replacement.

MV GIS For Network Substations

Shane Powell, Alabama Power Company, Network Distribution Manger

Lucas Coffey, Alabama Power Company, Network Engineer

Alabama Power is headquartered in Birmingham, Alabama and provides electric service to 1.4 million homes, businesses, and industries. Alabama Power's Network is split into three cities (Birmingham, Montgomery, and Mobile). The total network consists of around 500 transformers and 1,200 manholes. Like most Network systems, the infrastructure was installed in the early and mid-1900s. As technology advances the demand to upgrade the Network systems has increased, and Alabama Power is actively upgrading its network systems to accommodate increasing technology. We are upgrading and improving the system is by installing new primary and secondary cable, updating transformer and protectors, installing new communications for SCADA (fiber or LTE), and sometimes rebuilding old substations. All of this as an effort to create a safer and more efficient working environment for the employees.

In the last decade, Alabama Power has embarked on a project to update its oldest substations in downtown Birmingham. Some things that were considered in the design process included most of what you would expect, the switchgear must be reliable and safe. But a few unique obstacles that had to be worked out was the footprint and the growing aesthetic requirements from the city. As is the case for most cities, real-estate is a premium, and because of this obstacle, we had to go back to the drawing board. Instead of going back with a traditional solution, we had to consider other options.

In the process of researching and trying to figure out our best solution to our hurdles, we visited our sister company, Georgia Power, who already had several installations of Siemens GIS on their system. While the initial cost of installation for GIS is higher than AIS, the overall ownership cost over the life of the equipment has proven to be competitive, and the real savings are realized in the land, operation, and maintenance costs. There are also some intangible benefits in security, political capital, and easier zoning approvals. Therefore, we went with Siemens' solution. A few of the deciding factors included safety, Operations, and Maintenance budget implications, reliability, and required footprint. The MV GIS features vacuum interrupter technology for the breakers and low-pressure SF6 gas is used as an insulating medium for all primary components. There is a means of disconnecting by using a three-position switch (CLOSED, OPEN, GROUND).

Let's first talk about the safety features of the switchgear. The below chart shows the comparison of HRC rating between MV GIS and MV Air-insulated switchgear. The switchgear was tested to ANSI/IEEE C37.20.7-2007 arc-resistance/IEC 62271-200 arc-resistance internal arc classification type 2B (Reference from Siemens Energy Inc.) As you can see in the chart, the MV GIS essentially eliminates the risk for an employee operating the switchgear.

Comparison of PPE3 level required for operations

Activity	MV Air-Insulated Switchgear (AIS)1	MV Gas-Insulated Switchgear
Open/close circuit breaker	HRC 2 (door closed)2 HRC 4 (door open)	HRC 0
Isolate circuit	HRC 4 (racking, door open or closed) (Note: isolation in metal-clad requires racking to test or disconnect position)	HRC 0 (operation of three-position switch to open position)
Application of safety grounds	HRC 4	HRC 0

1 Non-arc-resistant
2 HRC = Hazard risk category HRC 0 = lowest level HRC 2 = 8 cal/cm2 PPE HRC 4 = 40 cal/cm2 PPE
3 Derived from tables 130.7 (c) (15) (a) in NFPA 70E-2012

Along with the reduction of arc flash exposure, the change to GIS from Air-insulated switchgear eliminated the demand to rack breakers in and out. Which is an upgrade not only from a safety and longevity of the employee standpoint, but also an improvement on the O&M impact. From a switching and operation safety standpoint, there are shutters interlocked with the switch access to prevent out of sequence operation. The switches are operated under no load conditions and the breaker itself is a vacuum interrupter, so there are no gas decomposition byproducts for normal operation.

I'm sure that most utilities are like us in the fact of trying to reduce O&M costs. According to Siemens, the vacuum interrupters are rated for 10,000 mechanical and 50 full-fault operations. The primary components are virtually maintenance free due to the controlled gas environment. GIS systems only need to be visually inspected every few years depending on the specific manufacturer's recommendations, and the drives only need to be re-greased after about twenty years also depending on the manufacturer's recommendations. Where AIS systems must be inspected and operated every few years. The chart below shows the recommended guidelines from Siemens for their MV GIS (Reference from Siemens Energy Inc.).

Types	**8DA10/8DB10**
Visual inspection	Every 5 years
State inspection	Every 10 years
Maintenance	After 1,000 operating cycles of the disconnectors and grounding switches or after 10,000 operating cycles of the circuit breaker.

These intervals are guidelines which have to be adjusted to the different operating conditions (i.e., dusty environment, frequent condensation, etc.).

The SF6 gas is rated for lightning withstand up to 200kV BIL at 38kV. The gear also has a long operating life of greater than fifty years. The sealed pressure system protects against environmental influences and damage. The division into compartments also limits the amount of SF6 that can be leaked in the event that it does. The single-pole enclosures eliminate the possibility of phase-to-phase faults inside the switchgear and the division of components enables fast fault isolation and locating.

Each cubicle has a compact footprint of two feet wide by five feet deep. See below for a size and footprint comparison for the different types of switchgear available (Reference from Siemens Energy Inc.).

As a network engineer in Birmingham, I am involved with the design and construction of these substations from the standpoint of the underground getaways for overhead and UCD feeders as well as the network feeders. Our cable splicers are also involved with the CONNEX terminations to the switchgear termination boxes. Our most recent substation rebuild checked all of the obstacle boxes from space constraints and city redevelopment restrictions. The city would not allow an open-air sub and the property could not fit the traditional metal-clad switchgear footprint requirement, so GIS was an easy solution. Below is a design view of the sub from the street. Without signage, most people would not know it was a substation. This design includes 115kV GIS and MV GIS.

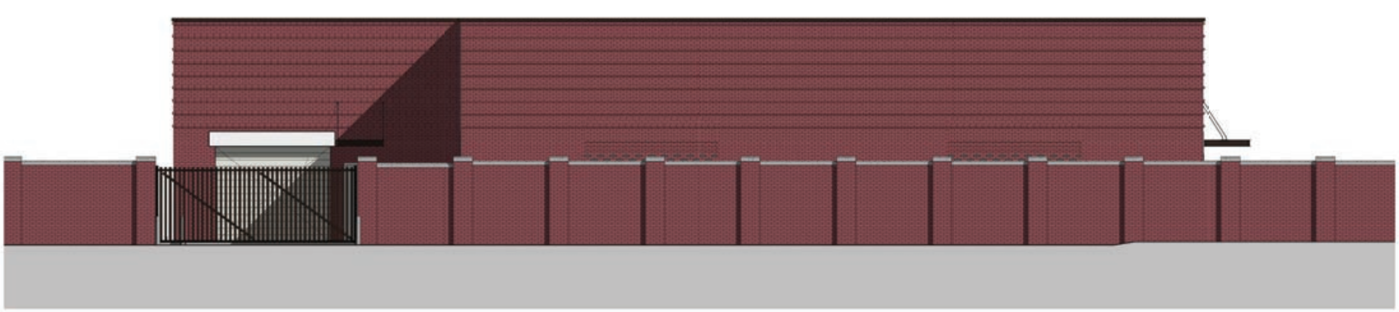
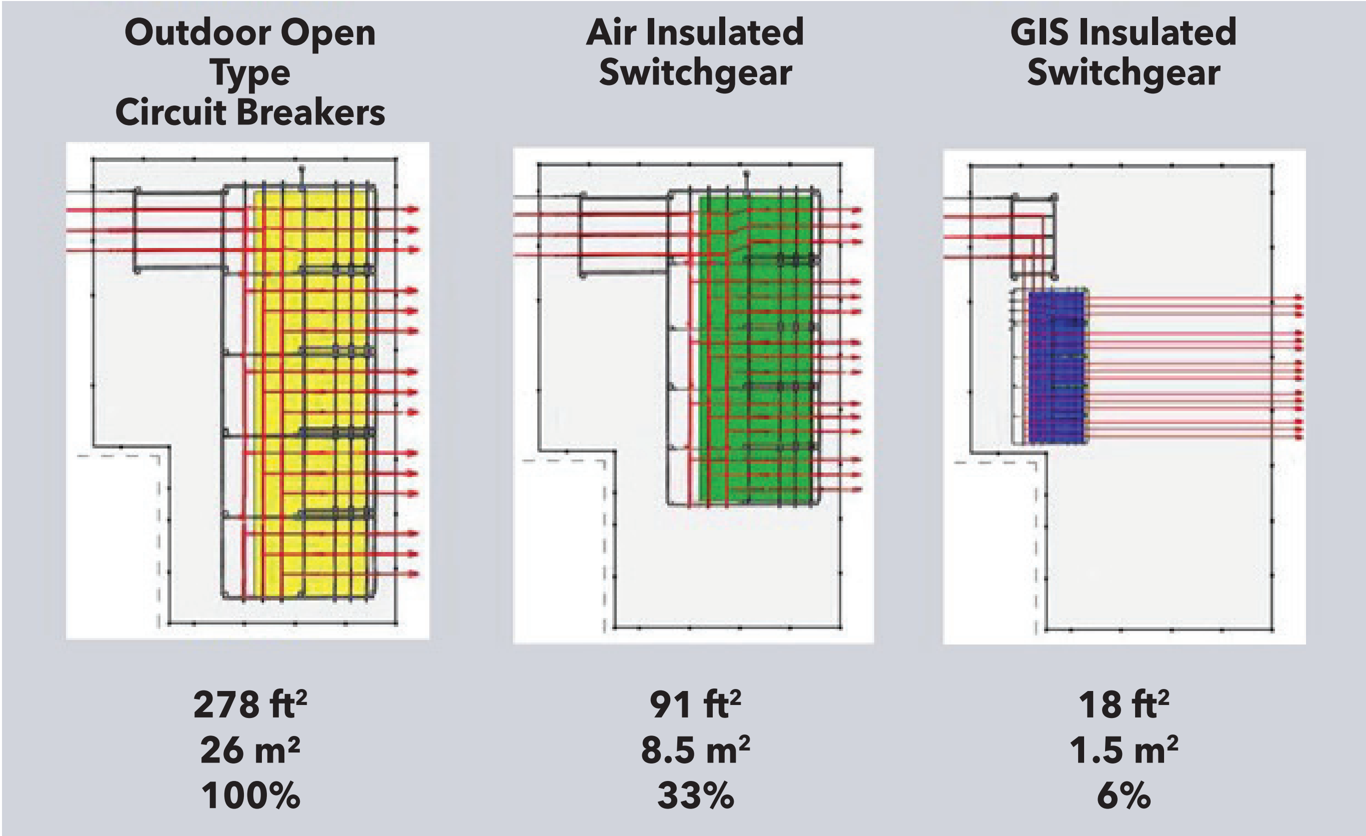
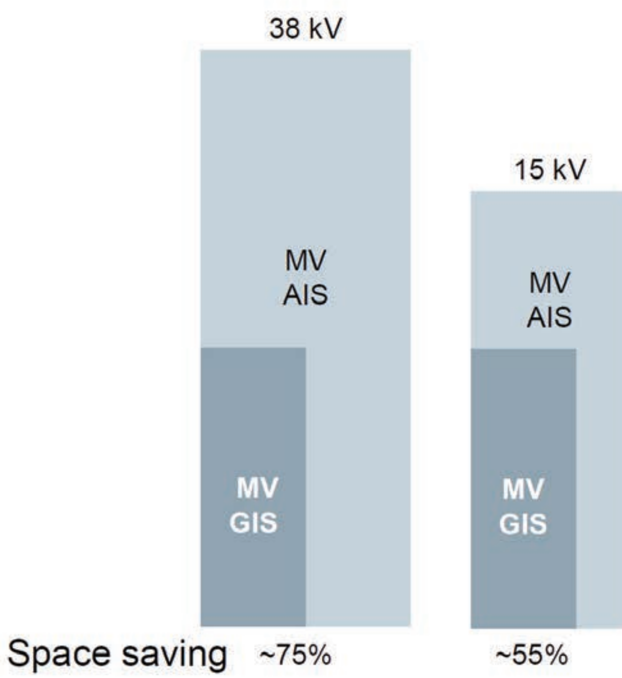


Figure 1. Substation Street View



Footprint comparison (MV AIS and MV GIS - only equipment size considered)



Evaluating Duct Sealing Methods and Materials to Mitigate Risk

Roy Middleton, Mac Products, Network Consultant

The increasing number of manhole events in recent years has drawn attention to the underground urban electrical systems. The conduits integral to these systems can carry the combustible gasses resulting from these events into other manholes and into buildings. Sealing the underground ducts can mitigate this risk along with many others. Improvements in materials and methods have provided additional duct sealing system options. This article will detail the value of an effectively sealed duct system, describe the various options available today and list the keys to making an effective duct seal.

The risks related to underground duct systems in an urban environment

- **Explosions due to gas migration** - Flammable gases from tracking/deteriorated cables travel through the electrical duct system until a source of ignition results in an explosion and fire. Flammable combustion by-products then move through the duct system causing the event to spread. Environmental gas sources such as natural gas leaks and petroleum spills can also enter the electrical duct system and produce similar results. Unsealed service ducts can allow these gasses (including CO) to enter buildings increasing the risks to the public.
- **Fire progression** – Utility transformer vault ducts and service ducts provide a pathway for a fire to spread to a building. Fire stop systems are critical in these installations.
- **Health effects of gas ingress** – The burning of some types of insulation fluids as well as solid dielectric insulation materials can result in gases that can cause serious health issues. Service ducts can provide an entryway into buildings.
- **Water ingress** – Water sources in an urban environment include not only rain water but also water main breaks. Large amounts of water can travel down electrical duct systems and flood vaults and enter building electrical rooms. Water entering building can cause electrical gear failure and extended outages. With the rapid increase in vault installed network monitoring equipment, valuable data can be lost and expensive equipment damaged.

Expanding foams

Two component resins

One component sealants

- **Insect and rodent ingress** – Insects and rodents can cause damage to electrical cables and equipment. They also pose health risks.

The history of duct sealing methods

Over the years a collection of materials have been used to seal ducts including wooden pegs, foam rubber, rags, whatever could be fit in the ducts. In the 60s and 70's expanding foams (spray can products) became available. In the late 80's after some high profile fires involving PCB material, OHSA began requiring the sealing of service ducts to food handling and processing facilities. This increased duct sealing work. Too often this work was not fully planned and materials available were used to meet the required time line. In some cases, it was considered low skill work and more or less a "check box" type of task.

As time pasted and more manhole events began occurring, more importance was placed on duct sealing. High quality expanding two part resins became available that provided the potential of much better seals. More recently, high quality one component flexible sealants have entered the market offering water, gas & fire stop features all in one product. Today's available materials have the potential to make effective duct seals.

<u>The reason many seals fail today is the process in which they are installed.</u> A product's tested specifications are only valid with a consistent proper installation.

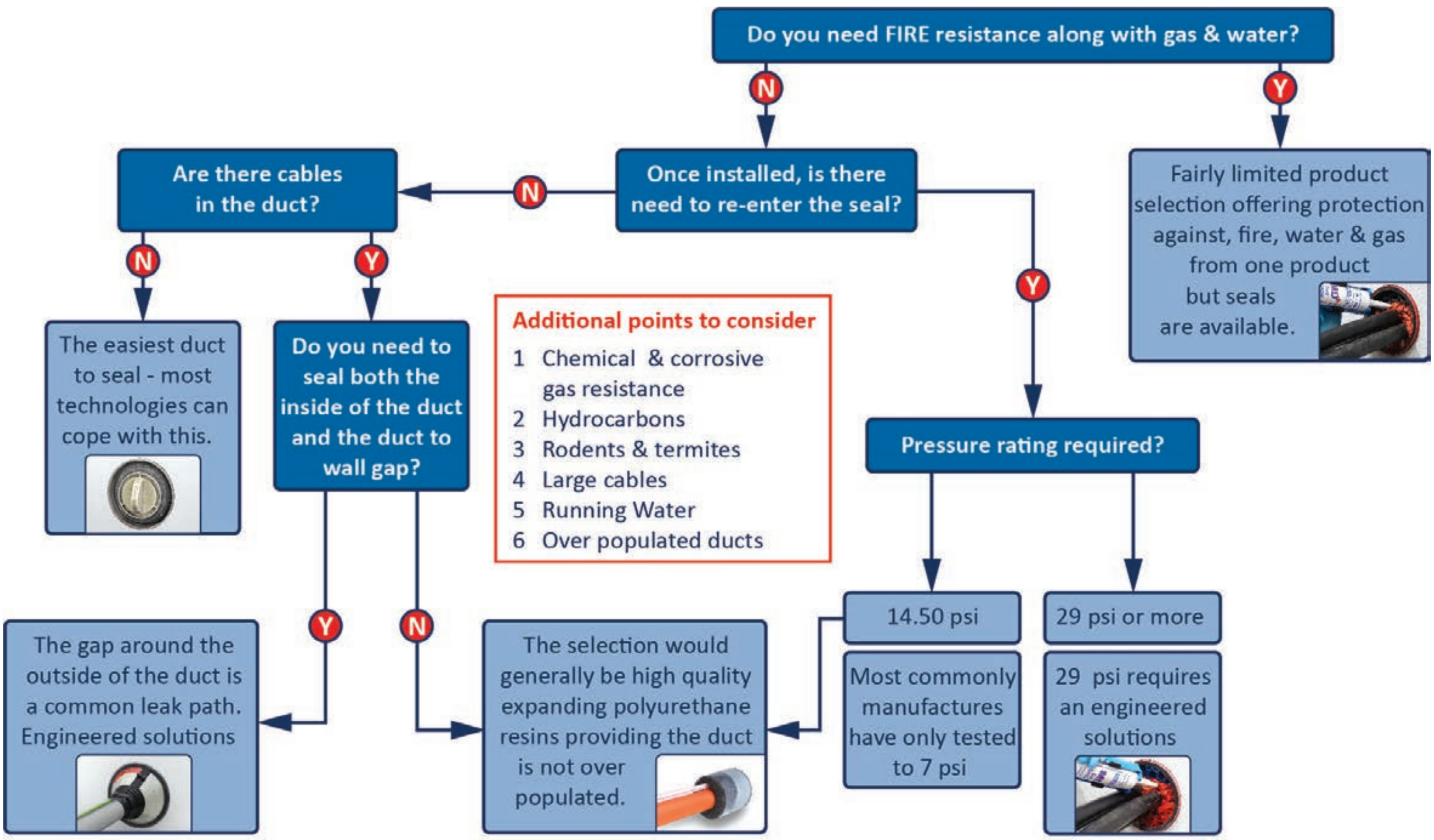
Duct sealing materials available today

- **Expandable foams (spray can)** – These materials have a weak cell structure with about 70% of the cells closed. The rapid expansion rate is about 35 X volume and produces a compression force of 0.67 PSI. It is not resistant to hydro-carbons and weak resistance to water. It is difficult be make an effect seal with this product.
- **High quality expanding polyurethane resins (two component)** – These materials have a strong cell structure with 100% closed cells. The expansion rate is much slower and lower compared to the expanding foams resulting in a higher compression force of 22 PSI. It is resistant to both hydro-carbons and water.

- **Re-enterable one component flexible sealants** – This material is based on a silicone compound, has excellent resistance to chemicals, stays flexible to resist soil and cable movement plus provides for a fire stop. Its excellent adhesion properties provide for up to a 29 psi water and gas block. It has the ability to adapt to most sealing scenarios when used with strong backing systems to support and separate the cables. The support and separation of the cables is vital for an effective seal. An added benefit is that it is easily removable allowing re-access to the duct.

How to select a duct sealing solution

- **It is critical to evaluate the specific duct sealing situation and identify the objectives of the seal. For Example:**
    - Are there cables in the duct, how many?
    - Does water need to be blocked? How much water?
    - Is a fire stop needed?
    - Does the conduit enter a building?
    - Are gases or chemicals a concern?
- Selection should be at the design stage where the seal requirements can be matched to the overall project. Typically, a design specification will require water, gas and perhaps fire-resistance together with specific chemical resistance. The required seal life should also be considered. Every seal manufacturer should be able to provide proof of expected life. Over-engineering the seal design should also be avoided. A duct sealing solution that meets the specific needs of the application is the right solution.
- **Technology Selection chart**



- **Standards to evaluate sealing options**
    - **Pressure resistance** – There is no industry standard for testing cable seal pressure resistance. Manufacturers and utilities perform their own tests. When deciding on test procedures, a minimum of ½ an atmosphere (1/2 bar) should be used. The test conditions should mirror field condition as much as possible.
    - **Flammability** – ISO4589-2 measures the level of oxygen needed for the material to start and sustain burning
    - **Material safety** – Smoke Density ISO 5659
        - Toxic gas emissions
        - ISO5659 measures how thick the smoke is when the material is burnt
        - ISO 5659 / BS EN45545-2:2013 measures the toxic emissions produces when material is burnt

Cables separated

Cables together

Cables supported and separated

Keys to an effective seal

- **Training and preparation** – First read and following the manufacturer's instructions. Like any other job a field mechanic performs, it requires knowledge and skill. Duct sealing solutions should be engineered into the job and training performed in advance of the field work.
- **Sealing system selection** – Most underground urban duct sealing systems will need to block water, gases and be tolerant of hydro-carbons. If the duct enters a building, a fire stop may be needed. Select a sealing system that addresses the risks present.
- **Cable separation** – This is the area where most duct seals will fail; either the product doesn't support cable separation or the installer has failed to separate the cables sufficiently. Without separation, water and gases will simply wick through areas without the sealant.

An Effective duct sealing system looks like this:

Effective seal 1

One part sealant

Effective seal 2

One part sealant

Effective seal 3

Two part expanding resin

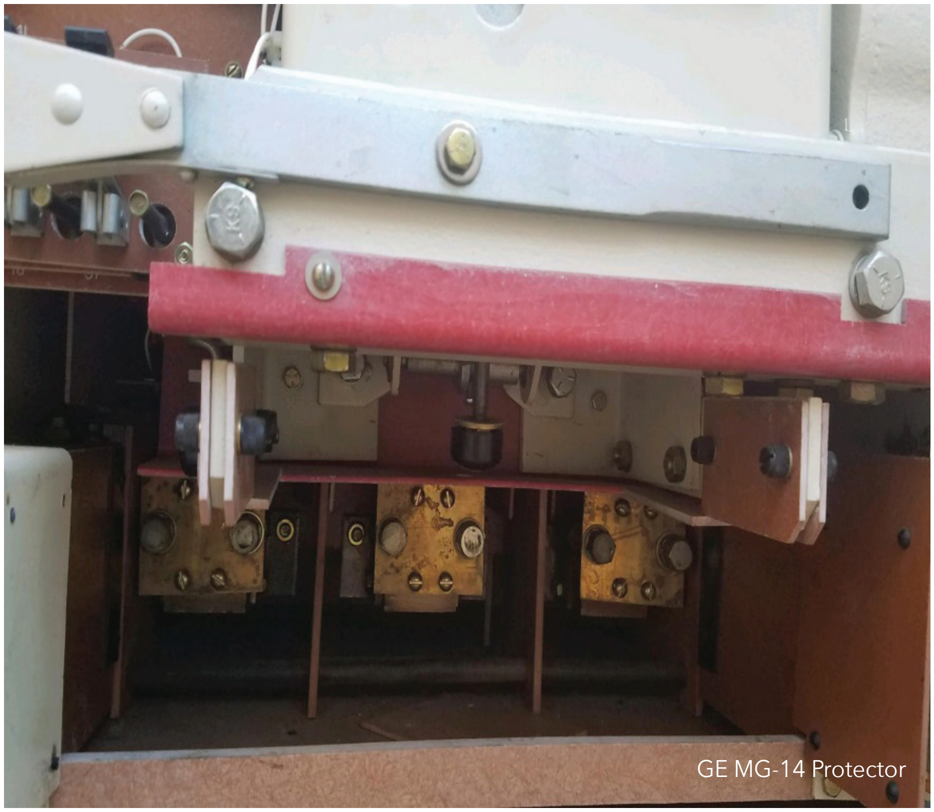
History of Network Safety

Tom Thode, Xcel Energy, Operations Manager

My name is Tom Thode, and I have been in the utility business for 40+ years with more than 33 years in the Denver Underground Network Department. I started at Public Service Company of Colorado in September 1978.

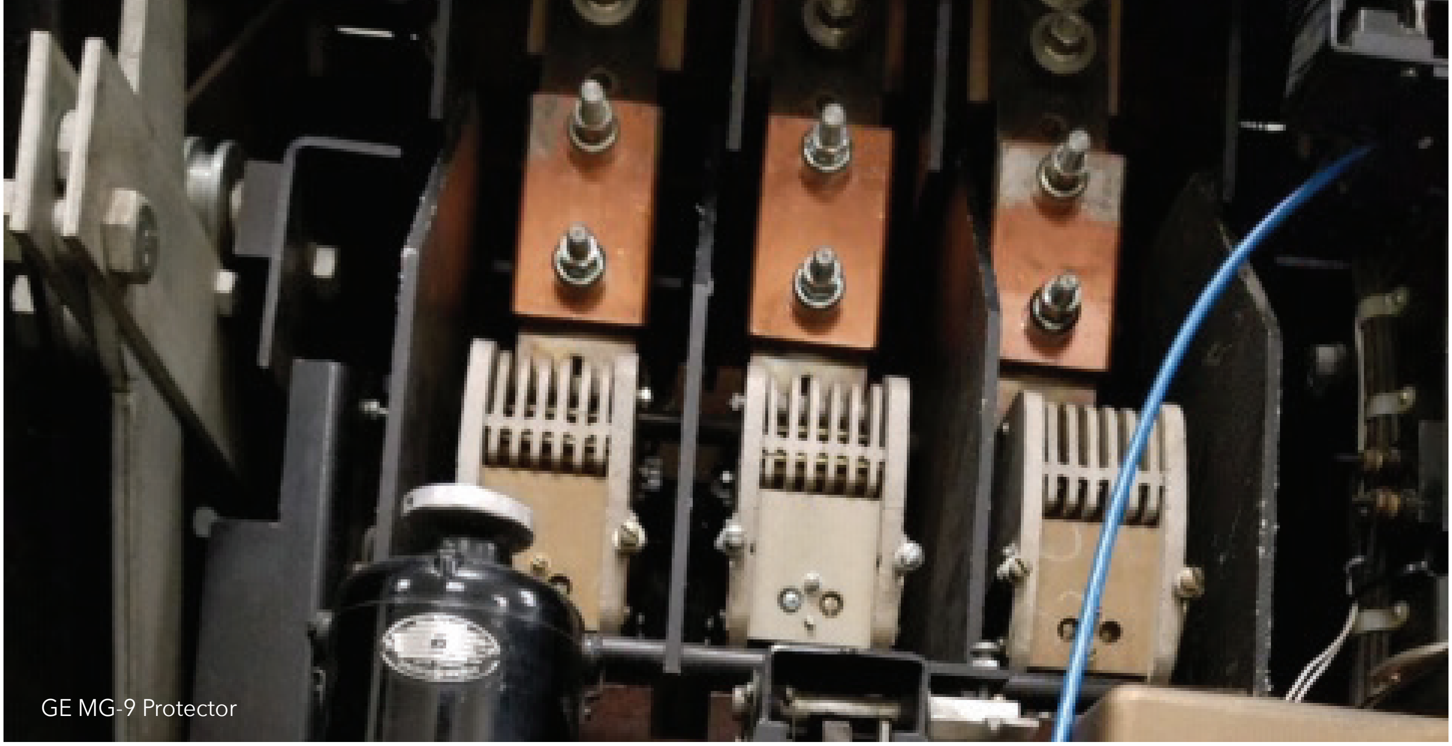
At the time I was hired PPE requirements consisted of a 100% cotton long sleeve shirt, 100% cotton pants/jeans, hard hat, leather gloves, safety glasses and steel toed boots. This attire was appropriate for almost any work assignment given. Employees were issued class 2 rubber gloves for primary work and class 0 rubber gloves for work on energized 277/480V systems. Leather gloves were considered acceptable for work on 125/216V circuits.

During the second year of my apprenticeship in the early 1980's I was assigned to a Maintenance crew. The work assigned to the crew was to test and repair all of the various protectors on the downtown Network system. As the apprentice on the crew my job was to safely "rack out" the protector. Wearing our "approved PPE" the following steps were taken;



GE MG-14 Protector

Eaton CM22 or Richards 313NP Protector



GE MG-9 Protector

1. Move protector handle to the open position
2. Open the door of the protector (no consideration was given to venting).
3. Put on secondary gloves if necessary
4. With a steel handled ratchet and multiple 12″ steel extensions remove the lower slugs. This was done with the transformer/unprotected zone energized.
5. Remove upper slugs or fuses and roll the unit out for testing.

After completing the testing the steps were reversed and the protector was returned to service. The entire time the transformer and unprotected zone were energized.

In the mid 1980's after I had become a journeyman an incident/flash occurred at another utility. This incident resulted in the company reviewing and updating the work practices and safety rules. At this time all of the crews were provided fiberglass extensions to use. These extensions broke regularly as the crews frequently over tightened the nuts on the slugs or fuses. The crews also started de-energizing the transformer before racking out the protector. This step was identified as a Protector Maintenance Operation (PMO). This required opening the appropriate breaker at the substation, verifying at a minimum 2 transformers were de-energized, placing the primary switch on the transformer that protector maintenance was to be performed on in the open position, and then re-energizing the feeder. After the maintenance on the protector was completed a second PMO would be taken to return the transformer and protector to service.

In the early 1990's the company started to send 2 journeyman per year to Greenwood, SC for hands on maintenance training by the protector manufacturer to improve our safety and our work practices. At this time the crews started venting all protectors prior to opening the door and face shields were provided to the employees.

In the early 2000's FR coats were issued to field employees to wear while working on energized equipment and circuits. This was soon followed by 4 Cal FR shirts. This level of protection was deemed adequate for approximately 3 years. At that time the company started providing 8 Cal FR shirts, pants and outer wear.

This was the standard work practice until 2010. At that time the Engineering Manager and I attended the ENSC Conference and the decision was made to install the VaultGard Communications System. Every unit on the Network was to be monitored and controlled by July 2012. This totaled 720 units at the time. After the installation was complete the crews were able to open the protectors from outside the transformer vault in addition to continuing the PMO practice.

In the fourth quarter of 2016 an anonymous complaint was received about arc flash mitigation through-out the company. I presented to a group of leadership that the best option would be to pro-actively eliminate all 277/480V live front breakers from the system over a five year span. Upon approval by senior leadership, we began the replacement of over 300 live front 277/480V protectors. To date we have replaced over 150 of the 300+ 277/480V breakers with CM-52 dead-front network protectors with ARMS.

An additional step is currently under evaluation for implementation. That step would add a fault interrupting load break vacuum switch on the primary side of the transformer that can be operated from outside the transformer vault. This device will eliminate the need for the PMO as the crews will be able to isolate only the transformer and protector to be maintained.

When I look back over my career in the electric utility business and see the changes that have been made, I am very proud of all parties for the advances in safety for the workforce, the willingness to share ideas with our peers, and the innovations to the equipment to minimize the exposure to potential problems. These items have improved the industry more than anyone can imagine. I am not sure what is in store for the future generations of Network employees, but if everyone commits to working safer, requesting shutdowns when needed and sharing improvements across the industry we can have everyone going home safe to their families.

My final thought is a quote from page 1 of our Safety Manual and I truly believe in it

"No job must ever become so routine or so urgent that every safety precaution is not observed".

Network Protector Testing Overview for CM52 with MPCV Relay

Richard Hotchkiss, Eaton, Network Lead Technician

The CM-52 is the easiest Eaton network protector to test.

The main reason is the CM-52 requires no mechanical testing due to the nature of the design. The standard minimum voltage-level testing for the trip circuit (7.5% of nominal) and the motor circuit (73% no go and 80% go) are not necessary. You can certainly still test for these minimum values if you prefer but it is not required. The CM-52 requires only a network relay test with a 3-phase network protector test set.

When performing this testing, it is good practice to check the default settings loaded on the relay. This will let you know when to expect a CLOSE or TRIP command. I have listed the critical settings below:

- CBA (ON)
  CBA is the phase rotation
- ML (ON)
  ML = Master Line
  The closing voltage will vary depending on the magnitude. Typically, the default would be 1.0V for 216V units or 1.5V for 480V units at zero degrees. This means the MPCV relay will give a CLOSE command when the difference between the Network and Transformer magnitude reaches your set ML. Remember that is when the network protector is 480V, 2.2 on the voltage meter on the test set equals a ML value of 1.0. This is because the ratio of the potential transformers used on the network protector is 2.2, in order to step down the relay control voltage to 120VAC.
- ST ML (OFF = Circular Close)
  ST ML = Straight-Line Master-Line
  All closing voltages will match the ML regardless of angle
- PL (-5)
  PL = Phasing Line
  This allows the relay to close between -5 and 90 degrees. If the PL = +5 then the relay would not give a CLOSE command regardless of the phasing voltage at 0 degrees.
- RT (.20%)
  RT = Reverse Trip
  This is .20% of the CT rating not the protector rating e.g. 1600/5 CT, at 180 degrees, the relay will trip at 3.2 amps reverse current.
- TD (0)
  TD = Time Delay
  This setting dictates how much time do you want the protector to remain closed, used to ignore small amounts of backfeed for a certain time duration.
- OC (0%)
  OC = Overcurrent
  If any amount of TD is programmed the relay will automatically default the OC from 0 to 1% of the CT for safety, e.g. 1600/5 CT relay will trip at 16.0 amps on OC.

These are the settings in the relay that we are concerned with when testing or troubleshooting a network protector. We often ask this question to others – "What part of the protector is the most important?" Most will answer, "the Relay," for which we agree. It is good practice when troubleshooting to always look at the MPCV relay to see what it is telling you.

Relay - Yellow Float Light

If the relay is in the Float position it is satisfied with the position of the network protector whether it is in the OPEN or CLOSED state.

Relay - Red Close Light

If the red close-light is on this means the ML/PL has been met and the relay has issued a CLOSE command to the breaker. The next device to operate would be the motor control device followed by the charging or closing motor depending on what style network protector you are testing.

On a CM-52 you would look at the IDM followed by the indicating flags labeled CHARGED or DISCHARGED to determine whether or not the charging motor operated. If the lights on the IDM were not illuminated that would indicate a supply voltage problem which can quickly be verified by measuring the voltage at point one of the relay. On a CM-52 you should always have 120V providing the transformer side of the protector is energized. This wire is labeled L1, anywhere there is a wire labeled L1 on a CM-52 you should have 120V. If point one does not have 120V work your way back to fuse and resistor then to phase "A" transformer for a 216V network protector. If it is a 480V check the secondary of the control power transformer (CPT) then the primary side. The primary side of the CPT is fed from phase "A" and "C" giving you 480V phase-to-phase or 277V phase-to-ground.

Note - do not forget to verify that the outside handle is in the AUTO position and the mechanical interlock is pulled out.

If everything checks out to this point you can take a voltage reading at the EL wire CL3 then CL10 which is accessible without taking the cover off to verify the voltage from the IDM at J1-2 through the Aux switch and the BF2 (be careful not to bridge the frame with probe from the voltmeter).

If your springs are charged but the breaker is not closed your problem is narrowed down to the LS1, LS2 and spring release. To access the LS1, LS2 and spring release the cover will need to be removed.

Relay - Green Trip Light

There are several reasons the relay could be calling for a Trip.

1. Reverse current (breaker remains closed)
2. Incorrect phase rotation
3. Crossed phased
4. Missing potential
5. Grounded potential
6. Network voltage only

If the green trip-light is ON (solid) and the breaker remains closed look at the IDM to see if the lights are ON, if not you can verify supply voltage by checking point one of the relay.

If the MPCV is flashing with a green trip light, it means that someone has the protector locked out via communications.

If the protector is OPEN and the green trip-light is still ON check the following. The relays are shipped with CBA = OFF so you may want to check your phase rotation if this is a new install or a new relay. Checking the six potentials will provide good information but not as much as having the VaultGard. Taking voltage readings from point 5 (Ground) to point 6 (N1), point 7 (T1), point 18 (N2), point 17 (T2), point 13 (N3) and point 12 (T3) will let you know if all the potentials are present and if the voltages are correct. It should always be around 125V. Please see Figure 1 for details.

If one of the six potential voltages is missing then work your way back to the source and do not forget to include the test set leads when troubleshooting. If both the network and transformer voltages are missing on the same phase then check the fuses in the test set. If the voltages are abnormal then check the ground connection.

Checking the six potential voltages and the supply is a good idea whenever you are testing or troubleshooting a network protector. If you are testing a network protector and the Trip values are higher than you except, perform a single-phase test. This will quickly tell you if all three CTs are operating correctly. It should be slightly less than three times. Please note we rarely find that the CT is bad.

You can always check the CTs for continuity. If you have grounded CTs remove the relay (you should also remove the test leads), then points 8, 15 and 11 will ring to ground. Note - we use point 5 for ground. If the CTs are energized remove the relay and test leads. Point 8 will ring to point 7, point 15 will ring to 17 and 11 will ring to 12.

Testing a Network Protector without a Test Set

When troubleshooting a network protector and you find a problem it may not be the network protector. If the relay is not calling for a CLOSE at the right voltage or the relay is not indicating a Trip at the correct current you may want to verify the test set.

Test sets operate on the same principle as a network system. When the network voltages are lower than the transformer voltage the relay will issue a CLOSE command if the voltage difference matches your set ML. If the network protector is closed and you have reverse current the relay will issue a Trip command if the reverse current matches your RT setting

Phasing Volts

Get a couple voltmeters and ammeters (we typically use four). Take the network and transformer leads and configure them in a safe manner (e.g. rubber blankets), connect three voltmeters between N1-T1, N2-T2 and N3-T3. If you have external ports for voltage you can connect the fourth voltmeter as a reference. Connect the supply leads to 216V or 480V (does not matter.) Configure your test set as if you were going to operate a relay to CLOSE, e.g. 0 degrees, PVA = phasing volts "A". Turn the test set on, using a variac, ramp up the phasing volts. Stopping at different values (we typically use 1V, 3V & 5V) to compare all the voltmeters which should be reading about the same. Turn off test set.

Reverse Current

If you are using a clamp on ammeter connect N1-T1, N2-T2 and N3-T3, if you are using an ammeter with leads change leads and move selector switch to AMPS. Configure your test set as if you were going to operate a relay to Trip, e.g. 180 degrees IA = Current Phase "A". Turn test set on, using a variac, ramp up the current. Stopping at different values to compare 1A, 3A, 5A, max the variac out, all the ammeters should be about the same. You will want to perform a single phase Trip as well. When performing this test you will only see current on one phase at a time. Lastly, turn off the test set.

Conclusion

Remember at its basics, a network protector should open on the flow of reverse amperes and automatically re-close based on voltage difference between line and load. Another valuable troubleshooting tool is the flowchart for the CM-52. Please use your phone to take a picture of the QR code below, and it should load this flowchart on your phone, for iPhones it can be saved to reference material in the iBook's library.

CM52 Troubleshooting Flow Charts - AP02405001E

Terminal Configurations

Terminal Number	Input to MPCV-D, 22 or 2x
1 2 3	Common Trip Close
4 5 6	N/A Ground "A" Phase network side voltage
7 8 9	"A" Phase transformer side voltage "A" Phase current N/A
10 11 12	N/A "C" Phase current "C" Phase transformer side voltage
13 14 15	"C" Phase network side voltage N/A "B" Phase current
16 17 18	N/A (Internally tied to point 5) "B" Phase transformer side voltage "B" Phase network side voltage

Figure 1. MPCV Relay Terminal Points

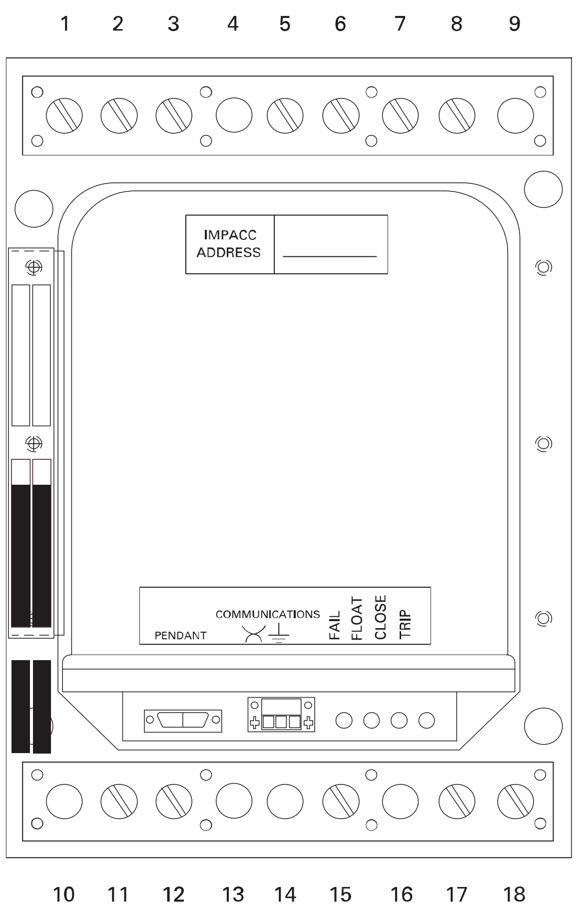


Figure 2.
MPCV Relay Layout

GridAdvisor Insight optical sensors

Shining a light on underground networks with real-time metrology and intelligence

Eaton's GridAdvisor optical sensor is available in a variety of easy-to-install packages with a standardized interface, including the optical standoff insulator voltage sensor and the optical deadbreak elbow adapter sensor.

The status of your underground network shouldn't be a deep, dark secret

Eaton's GridAdvisor™ all-optical medium-voltage and current sensor system provides a highly accurate view of underground networks, resolving the difficult and time-consuming process of diagnosing, troubleshooting and fixing issues.

Retrieving real-time site metrology and intelligence on today's electrical distribution system, substations and underground distribution locations, the GridAdvisor optical sensor platform facilitates unparalleled precision across multiple voltage classes and has the ability to identify potential failures before they occur.

Because the sensor relies on light to sense voltage and current, the solution eliminates problems often caused by other technologies, including high voltage at the test point, false test failures when crews hi-pot the cable, and unwanted leakage current during testing.

To learn more, visit
Eaton.com/opticalsensor

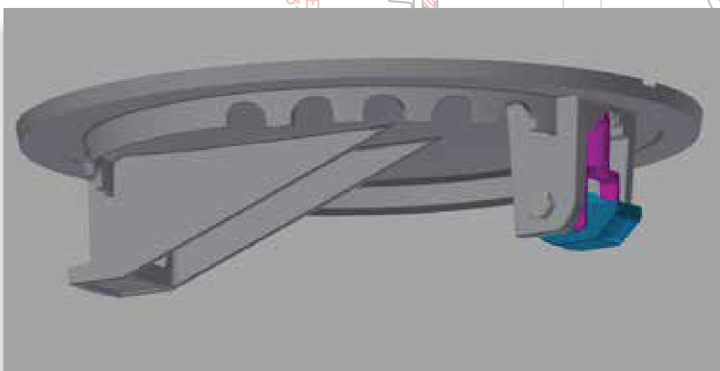
EATON
Powering Business Worldwide

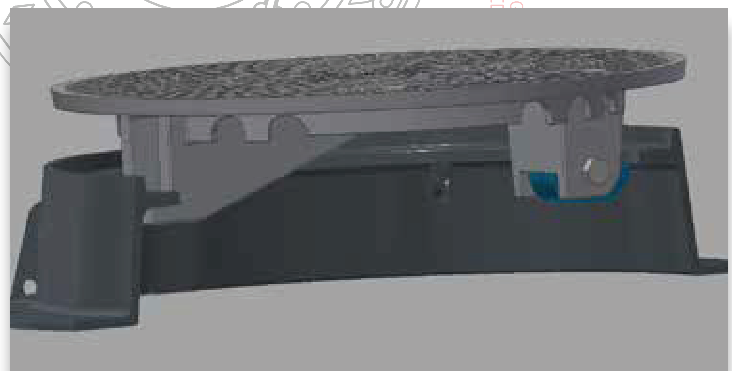
Follow us on social media to get the latest product and support information.

NEENAH FOUNDRY

Mitigating the Damage Caused by Underground Explosive Events

Neenah Foundry's Controlled Pressure Release Manhole Covers eliminate the inherent dangers of flying covers and add a level security to the underground infrastructure.





During an explosive event the upward travel of the CPR cover is limited to a maximum of 4" by an engineered lug and latch. With the help of specially designed exhaust ports the pressure is released 360° downward around the perimeter of the manhole opening.

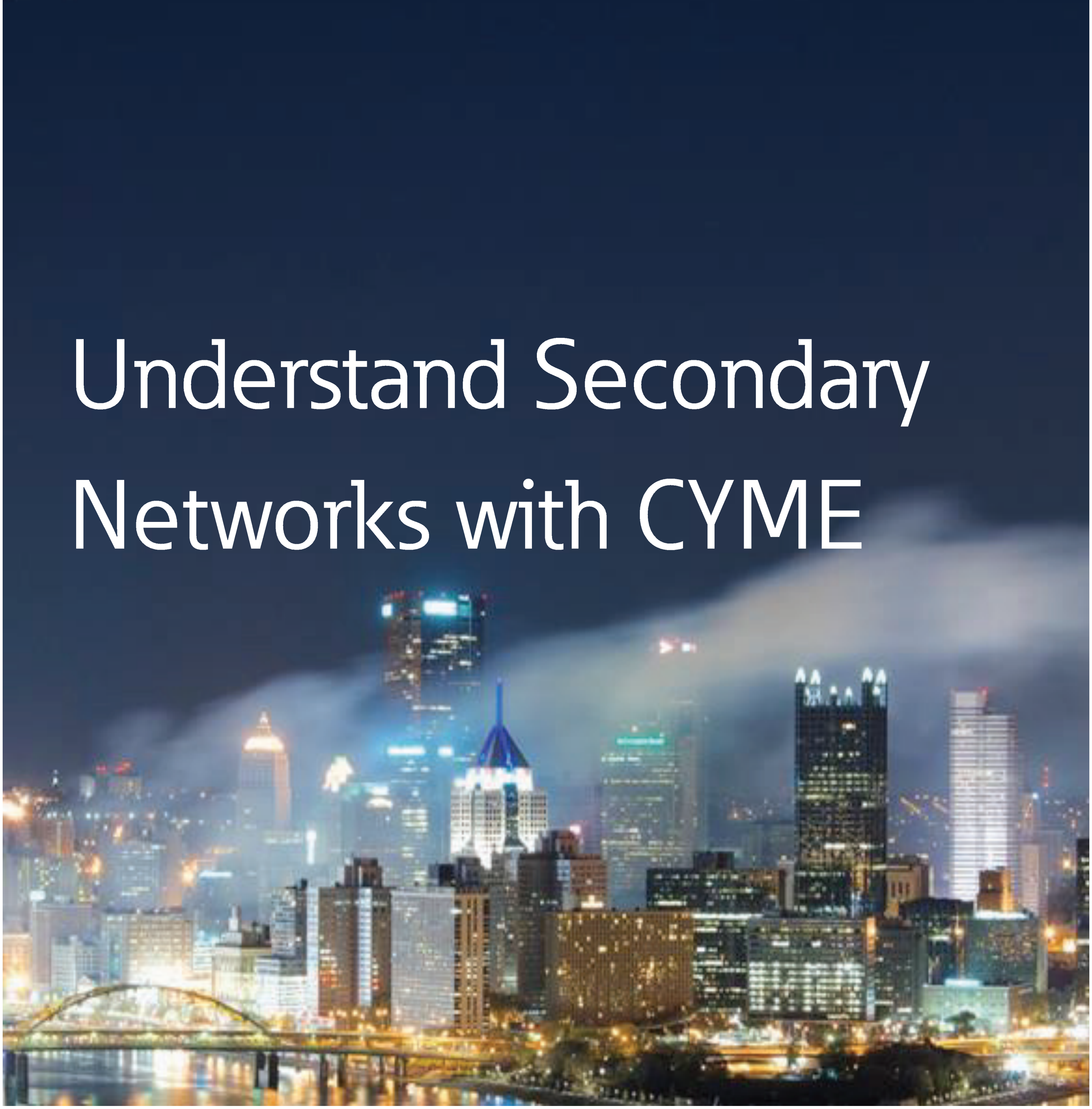
With the help of several Utilities these covers have been tested extensively at EPRI in Lenox MA for over a decade.

Why the CPR cover by Neenah?

- Cover does not leave the frame during an event
- Controlled rise of cover and release of pressure
- Reduces the possibility of injury and property damage
- Successfully tested at EPRI
- Helps prevent theft and unauthorized access
- Works with many existing frames

For more information or to arrange a presentation
visit us at **www.Swiveloc.com**
or call us **920-252-3563**

NEENAH FOUNDRY



EATON
Powering Business Worldwide

CYME Power Engineering Software

CYME offers detailed distribution system modeling and has advanced analytical capabilities, which are perfect for:

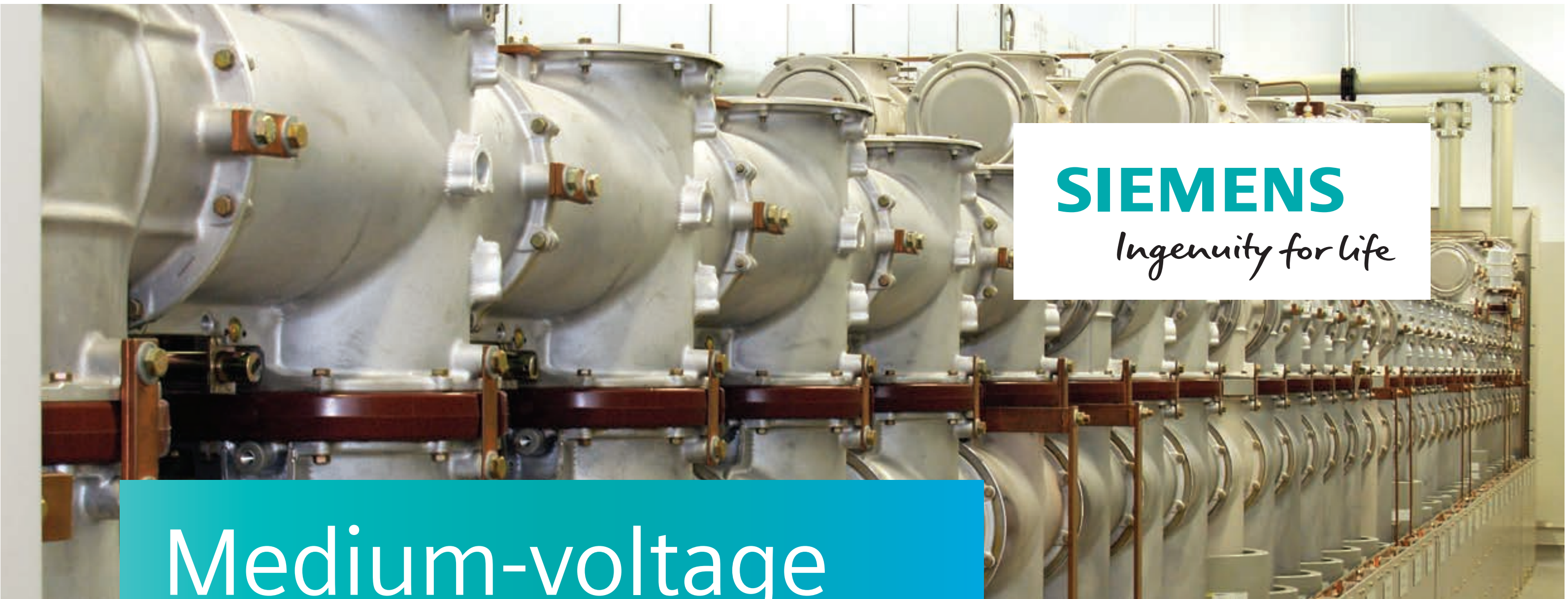
- Network-wide system planning and analysis using historical data and forecasts
- Distributed energy resources hosting capacity analysis and impact studies
- What-if contingency scenarios
- Grid efficiency optimization
- Protection scheme validation
- Power quality and system reliability improvement

Secondary Grid Network Analysis

Tackle the complexity of low-voltage secondary networks with CYME, which offers:

- Detailed modeling of secondary networks components, including network protectors with complete relay settings
- Robust power flow and short circuit algorithms for unbalanced meshed systems
- Load estimation through the processing of telemetry data with the Distribution State Estimator
- Integration to time-series databases and data lakes with the Dynamic Data Pull
- Efficient single- or multi-contingency scenarios (n-p) analysis

Please visit our booth for a live demo of the CYME Software and Solutions at the Electrical Network Systems Conference 2019! For more information, please reach out to us at cymeinfo@eaton.com.



SIEMENS

Ingenuity for life

Medium-voltage gas-insulated switchgear

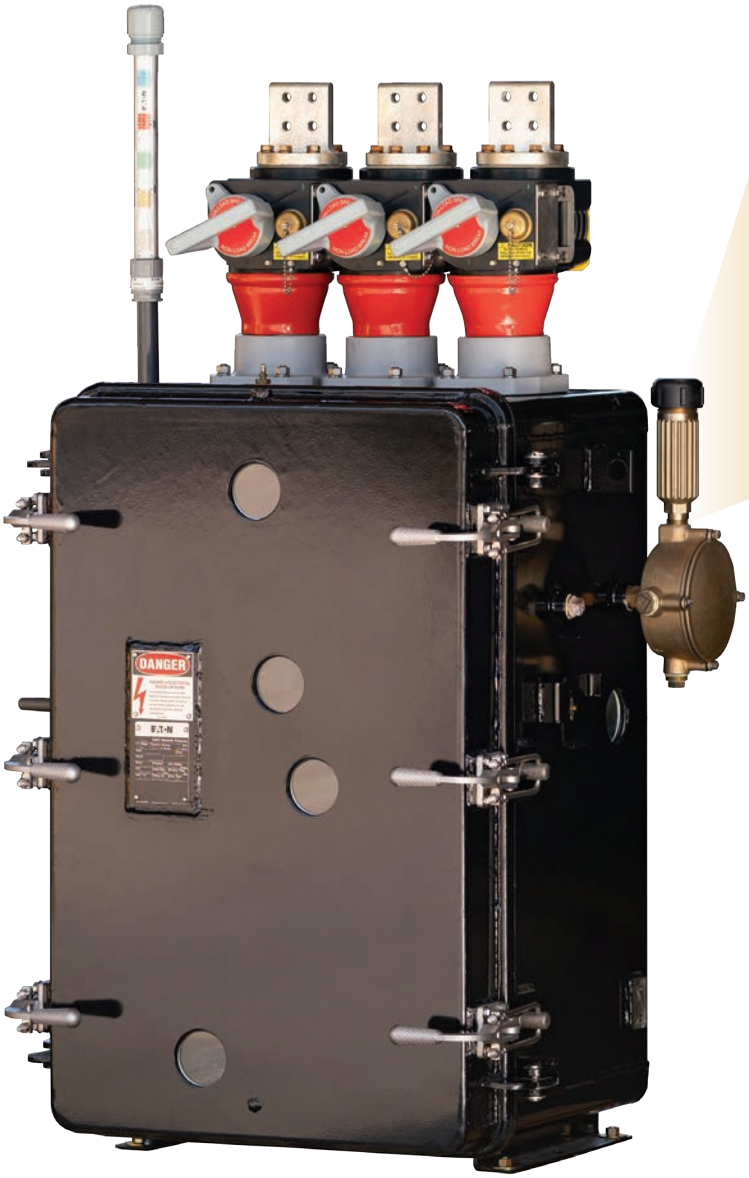
8DA (single bus) and 8DB (double bus), up to 42 kV, 40 kA, 200 kV BIL

Features and benefits:

- Vacuum interrupter - up to 30,000 mechanical operations
- Low pressure SF_6 gas-insulated for insulation only and not for interruption
- Tested for arc-resistance to ANSI/IEEE C37.20.7-2007, type 2B (i.e., with low-voltage compartment door open)
- Significantly reduced personal protective equipment (PPE) needs
- Voltage transformers with primary fused protection per NEC article 240.15(A) and 450.3(C)
- Main busbar expansion without shutdown via optional busbar expansion switch
- Compact - up to 75 percent smaller than air-insulated switchgear
- Maintenance-free primary part
- Meets IEEE and IEC standards
- UL or C-UL Listing available (consult factory)
- Single-phase design eliminates phase-to-phase faults inside the switchgear
- Meets NEC visible disconnect requirement
- Well suited for contaminated environments
- Pair with Siemens protective relays to match any typical application
- Over 100,000 panels worldwide with more than 4,500 installed in North America

RAD (Remote Access Device)

Compact, easy-to-use and plug-and-play for wireless communications for any utility-approved smart device

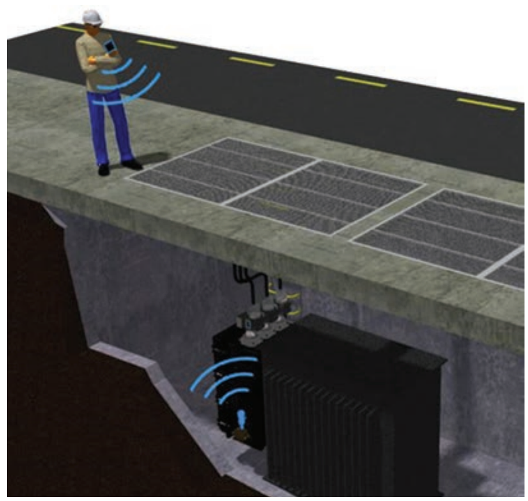


State-of-the-art design unlocks the secret to advanced vault communications

Specifically designed to provide utilities with easy-to-use DNP communications for their network system, Eaton's RAD (Remote Access Device) has output relays and digital inputs to control anything in the vault. The RAD is a key component to provide instant data from the network and system conditions via a local access web add-in (no Apps or software needed), allowing field users to access the network relay, gain network status and control devices from outside the vault or electrical room through wireless communications to a smart device.

The smart design eliminates the need for a plug-in pendant. It controls remote racking device, NP ARMS and OPEN/CLOSES equipment through local communication.

Ideal for new and existing network installations, the plug-and-play design allows for the RAD to be easily integrated into any network system.



Easily retrofittable to existing network protectors regardless of type or vintage, the RAD can be prewired and installed on any new network protectors.

Contact Eaton to learn how the RAD can advance your vault network communications.

EATON
Powering Business Worldwide

Follow us on social media to get the latest product and support information.