

# Innovative Techniques for Mitigating Arc Flash Exposure

David D. Shipp, P.E.

Fellow, IEEE

Eaton Corporation

Warrendale, PA 15086

David M. Wood, P.E.

Member, IEEE

**Abstract—** As more and more industries address arc flash electrical safety concerns, they are discovering high risk associated with what used to be normal maintenance tasks. In many cases, the excessively high arc flash incident energies make it so all maintenance must be done with equipment de-energized which is not always acceptable to the process industries. This paper will address the multiple ways the authors have devised to significantly lower arc flash incident energy exposure by new system design and products, retrofits, retro-fills, equipment modifications, alternate protection settings, etc. In most cases, NFPA 70E-2009 Hazard Risk Category 2 or lower can be obtained. Several real world examples will be discussed.

**Keywords -** NFPA 70E-2009, Incident energy, Flash Protection Boundary, Flash Hazard Analysis, IEEE Std 1584<sup>TM</sup>-2002, Personal Protective Equipment (PPE)

## I. INTRODUCTION

When investigating how to reduce the arc flash exposure to employees and others in a workplace, there are many things to consider. Have your employees been trained on arc flash hazards? Is a safety program in place? Is Personal Protective Equipment (PPE) available for all personnel performing electrical equipment maintenance? Has an arc flash study been performed on your power system? Our experience in performing arc flash studies tells us that there is no one single answer to reduce arc flash hazards; you need a total system approach. This paper will discuss many solutions that can be applied to reduce arc flash hazards and damage to equipment. These solutions are divided into the following seven categories:

- Label Equipment & Train Personnel
- Minimize Risk with Good Safety Practices
- Reduce Available Fault Current
- Reduce Clearing Time
- Move People Further Away
- Redirect Blast Energy
- Prevent Fault

## II. LABEL EQUIPMENT & TRAIN PERSONNEL

Occupational Safety and Health Administration (OSHA) and the National Fire Protection Association (NFPA) 70E-2009 standard now require that all employees working on electrical

equipment be trained in arc flash hazards and that all electrical equipment be labeled with arc flash labels.

Employers must train and certify their workers on arc flash hazards and arc flash safety. There are many ways to do this, including the example training courses shown below:

- Arc-Flash Safety – 4.0 hours, for electricians, technicians or equipment operators whose employers have already declared them to be "qualified" according to OSHA rules but need the new information contained in NFPA 70E-2009
- Electrical and Arc-Flash Safety – 8.0 hours, for electricians, technicians and equipment operators who are not "qualified" but who might be exposed to arc-flash hazards
- Understanding Arc Flash – 8.0 hours; for engineers, safety managers, consultants and electricians

New for NFPA 70E-2009 is the equipment labeling requirement, which the NFPA 70E-2009 states "equipment shall be field marked with a label containing the available incident energy or required level of PPE." There are two ways to determine how to label equipment. One way is using the NFPA 70E-2009 Table 130.7(C) (9) which lists hazard risk category and required PPE per "Tasks Performed on Energized Equipment." The other way is to perform an arc flash study on the power system, which determines the Hazard Risk Category (HRC), Incident energy, and Flash Protection Boundary at all electrical equipment.

### III. MINIMIZE RISK WITH GOOD SAFETY PRACTICES

Minimizing the risk for arc flash hazards using good safety practices is perhaps one of the best ways to mitigate against an arc flash exposure. Good safety practices should include:

- De-Energize Equipment versus “Working It Live” unless increased hazards exist or infeasible due to design or operational limitations.
- Switching remotely (if possible)
- Perform properly scheduled maintenance to your electrical equipment.
- Closing and tightening door latches or door bolts before operating a switch.
- Standing to the side and away as much as possible during switching operations as shown in Figs. 1 and 2.



Figure 1. Bad Practice – Exposed Back of Neck



Figure 2. Good Practice – Entire Body Protected

### IV. REDUCE AVAILABLE FAULT CURRENT (REDUCE INCIDENT ENERGY)

There are few ways to reduce the available fault currents in power systems:

- Operate double-ended substations with a Normally - Open tie during maintenance
- Change out transformer – Smaller kVA and/or higher impedance
- Add Reactors

All of these ways to reduce fault currents sound good in theory, but does lowering the fault current automatically lower the incident energy during an arcing fault? Reducing the available fault current may or may not reduce the incident energy, especially when fuses are used for circuit protection.

As shown in the Time-Current Curve of Fig. 3, the arcing fault current can be very low, especially at equipment located electrically far down in the power system. Also, the arcing fault current can be as low as 33% of the calculated bolted fault current at any particular location per the NFPA 70E-2009. Because of this, many times, when fuses are used for circuit protection, the available fault current is not high enough for the fuse to go into current-limit, hence taking much longer to trip and causing the incident energy and HRC levels to increase. At high available fault currents, the fuse will go into current limit, hence tripping faster and keeping the incident energy and HRC lower.

In the example of Fig. 3, the electronic trip circuit breaker protecting the same circuit can be adjusted for complete coordination and still trip on the low arcing fault current. In this case, the circuit breaker works the best for low available fault current.

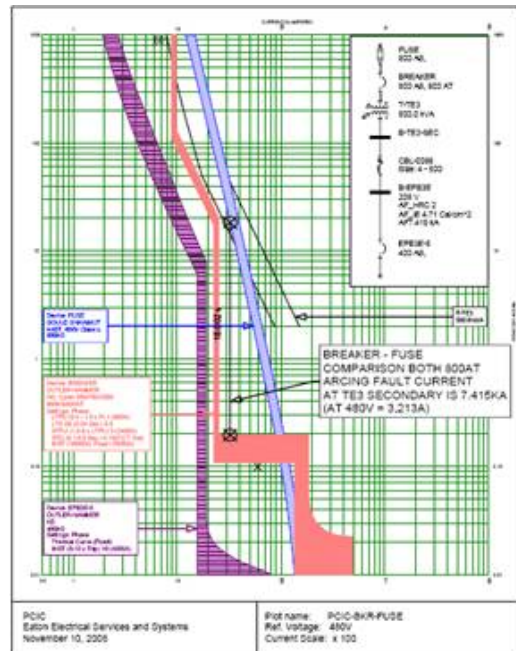


Figure 3. Breaker / Fuse Comparison

But, the point is that there is no “one single answer” to solve arc flash issues in a power system. The best and most comprehensive way to solve arc flash issues in a power system is to conduct an arc flash study. Then from the study, determine each location where the hazard risk category is deemed to be unacceptable by “the Customer”. These locations must then be individually evaluated to determine the most effective means of reducing the incident energy while maintaining the highest degree of reliability.

## V. REDUCE CLEARING TIME

One of the best and most efficient ways to lower the incident energy, which inherently lowers the HRC at electrical equipment, is to clear the fault quicker, hence the protective device trips faster. Many ways and methods to clear a fault faster using various protective devices are described below:

1) Verify breaker trip curves and use “arc flash tested” curves when possible. When evaluating protective devices, it is important to verify that the breaker trip curves are correct (i.e. without built-in conservative tripping tolerance). Many manufacturer’s time-current curves are documented very conservatively, since most were originally created based on conservative coordination. Therefore, many breakers actually trip faster than their publicized curves show.

If available, it is best to use manufacturer “arc flash tested” circuit breaker time-current curves. The arc flash tested breakers also take into consideration the breaker’s inherent current-limiting ability. See the arc flash performance comparison in Table I, which shows actual test data for current-limiting Molded Case Circuit Breakers (MCCB’s) provide faster trip time and lower incident energy compared to “Generic” and “Trip Curve” methods.

For low voltage power breakers, the instantaneous setting can be turned down during maintenance. These breakers are generally 3 cycle breakers, which with proper instantaneous settings would provide an HRC = 2, instead of an HRC of 3 or 4 without the lower instantaneous setting.

TABLE I. INCIDENT ENERGY DETERMINED BY TESTS OF CURRENT-LIMITING MCCB’S

	Incident Energy at Bolted Fault Current		
	Min	Mid	Max
<b>225 A MCCB with Thermal-Magnetic Trip Unit</b>			
Bolted fault current	3.4 kA	35 kA	100 kA
Inc. Energy via IEEE 1584 Table E.1 <b>Generic</b> (Cal/cm <sup>2</sup> )	N/A <sup>1</sup>	1.7	4.7
Inc. Energy via IEEE 1584 & <b>Trip Curve</b> (Cal/cm <sup>2</sup> )	59.6	1.1	2.3
<b>Measured</b> Incident Energy (Cal/cm <sup>2</sup> )	<b>0.08</b>	<b>0.1</b>	<b>0.11</b>
<b>1200 A MCCB with Electronic Trip Unit</b>			
Bolted fault current	20 kA	35 kA	100 kA
Inc. Energy via IEEE 1584 Table E.1 <b>Generic</b> (Cal/cm <sup>2</sup> )	N/A <sup>1</sup>	3.5	9.4
Inc. Energy via IEEE 1584 & <b>Trip Curve</b> (Cal/cm <sup>2</sup> )	218	3.5	5.8
<b>Measured</b> Incident Energy (Cal/cm <sup>2</sup> )	<b>1.86</b>	<b>1.2</b>	<b>1.64</b>

<sup>1</sup> N/A = Not Applicable because it is outside the range of the IEEE 1584 Generic Equation

IEEE 1584 Generic Equation

IEEE 1584 Using Time Current Curve Input

**Tested Value**

2) Implement Bus differential and Zone Selective Interlocking. Bus Differential Protection and Zone Selective Interlocking (ZSI) are other related ways to provide fast tripping of circuit breakers. The concept of bus differential protection (87B) has been around for a very long time. Because of the space and cost aspects, it was typically only

applied at high-voltage or medium-voltage locations. The concept measures 100% of the current into and out of a bus. It requires 3 additional current transformers on every breaker. Simply put,

- If 100% I<sub>IN</sub> = 100% I<sub>OUT</sub>, then no trip
- If 100% I<sub>IN</sub> ≠ 100% I<sub>OUT</sub>, then trip all bus breakers instantaneously

In the 1980s, ZSI was developed as almost an equivalent and cost effective bus differential scheme for low-voltage switchgear. It accomplished almost the same effect as 87B protection but at a fraction of the cost. It substituted a control logic system communicating between feeder breakers and main breakers, thereby eliminating the need for extra CTs and their required space and cost. This control system is built into the electronic and digital trip units of the low-voltage breakers. Its design functionality and use have grown over the last 20+ years. It is available now with up to 3 levels as shown in Fig. 4, although 2 levels (main breaker and feeder breakers) application are the most common.

ZSI is best described visually. Refer to Fig. 4 and assume a high level short circuit occurs on the load side of a feeder breaker. Both the main breaker’s and the feeder breaker’s digital trip units sense the fault. The feeder breaker sends a blocking signal to the main breaker letting it know that the fault is in its zone of protection. The blocking signal tells the main breaker to only trip per its time delayed standard settings (backup to the feeder breakers) while the feeder breaker is the first to clear the fault. However, if the fault occurs in the switchgear, such as on a primary stab fault occurring during racking of the feeder breaker (creating an arc-flash incident to the worker doing the racking), then no blocking signal is sent to the main breaker. Since the main breaker senses the fault but does not receive a blocking signal, its control logic bypasses the short time and ground fault time delay setting characteristics and trips almost instantly. It lowers its time delay settings to approximately 2 cycles, just enough time delay to assure nuisance tripping does not occur. Fig. 4 also shows some of the control wiring that accomplishes ZSI.

When applying ZSI, as an arc-flash solution, one must be aware of the following:

1. It is automatic - no special precautions are required.
2. It only affects the short time delay and ground fault time delay setting characteristics.
3. The arcing fault current must be above the short time pickup settings (STPU) or ground fault pickup (GFPU) settings for ZSI to be initiated and to reduce the arc-flash incident energy.
4. It adds 2 to 3 cycles maximum to the breaker clearing time of 3 cycles compared to an instantaneous trip resulting in 5 to 6 cycles total clearing time (83ms – 100ms).
5. It requires slightly different breaker testing procedures during maintenance and calibration testing.

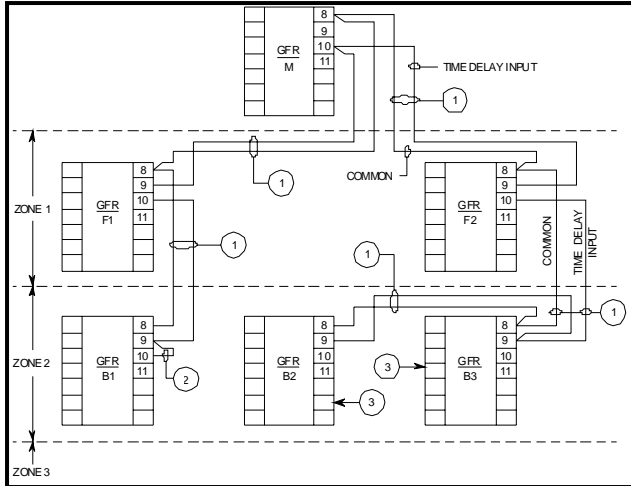


Figure 4. Zone Selective Interlocking



Figure 5. Retrofilled Fuses with Breakers Example

In recent years, some medium-voltage switchgear relays also became available with ZSI. This now permits almost the equivalent of 87B protection for smaller power systems where bus differential relaying would generally not be applied. The logic and theory are identical to the low-voltage version described in this paper. Arc-flash incident energies at medium-voltage have been lowered from over 100 cal/cm<sup>2</sup> to less than 30 cal/cm<sup>2</sup> using ZSI.

3.) Apply a “maintenance switch”. Another very effective way to lower arc flash incident energy is to apply a “maintenance switch”. This option can be retrofitted or purchased new in low voltage and medium voltage protective devices. An external over-ride switch and circuitry are connected to a breaker’s trip unit, and is adjustable between is 2.5X - 10X. The basic operation of the maintenance switch to lower incident energy at downstream protective devices.

When a person wants to perform maintenance, he or she closes the maintenance switch, which automatically over-rides all of the breaker’s delay functions, and causes the breaker to trip without any intentional delay whenever a fault is detected. Next, he or she uses its lockout features and applies a lock for normal lockout – tag-out procedures. Upon completion of the maintenance, the lock is removed, the maintenance switch is manually opened, and all previous trip unit settings are again re-activated, without need for recalibration. Many examples of how a maintenance switch can be applied are given below:

1. Retro-fill Example given in Fig. 5.
  - 2000 A Fuses Supplying 480V Glass Furnaces
  - Incident Energy =61 Cal / cm<sup>2</sup> HRC=Danger
  - Retrofilled Fuses with Breakers
  - 35 Cal / cm<sup>2</sup> with trip Unit
  - 6 Cal / cm<sup>2</sup> with breaker plus built-in maintenance switch

2. Maintenance switch integral to a low voltage breaker electronic trip unit as shown in Fig. 6.

- Has 5 user-selectable levels of protection to choose maximum protection, while avoiding nuisance tripping
- Blue color light emitting diode (LED) indicating “Maintenance Mode”
- Can be remotely activated through Infrared (IR) communication with PDA



Figure 6. Integral Maintenance Switch

3. Multiple Settings Groups.
  - Similar to LV maintenance switch, only for MV applications
  - Used to reduce the trip delay of medium-voltage relays while maintenance is being performed on equipment
  - Requires relay with multiple settings groups capability
4. Example 1 of substations without transformer secondary main breakers (common in older heavy industrials) as shown in Fig. 7.
  - Any Exposure or Racking Feeder breakers – Must be Cleared by Primary Fuse.
  - 100 Cal / cm<sup>2</sup> Exposure



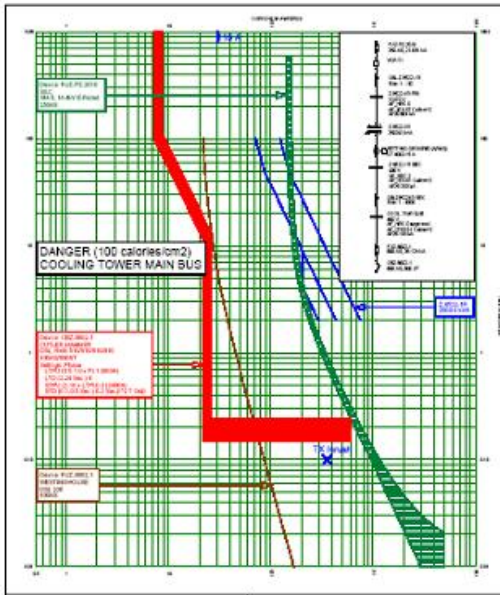


Figure 7. Substations Without Main Secondaries Example 1

5. Example 2 of substation without transformer secondary main breaker as shown in Fig. 8.

- Primary Fuse Only = 594 Cal / cm<sup>2</sup>
- Primary Breaker Only = 289 Cal / cm<sup>2</sup>
- Primary Breaker plus Maintenance Switch of 7.5 Cal / cm<sup>2</sup>
- Use integral maintenance switch in MV breaker of 3.8 Cal / cm<sup>2</sup>

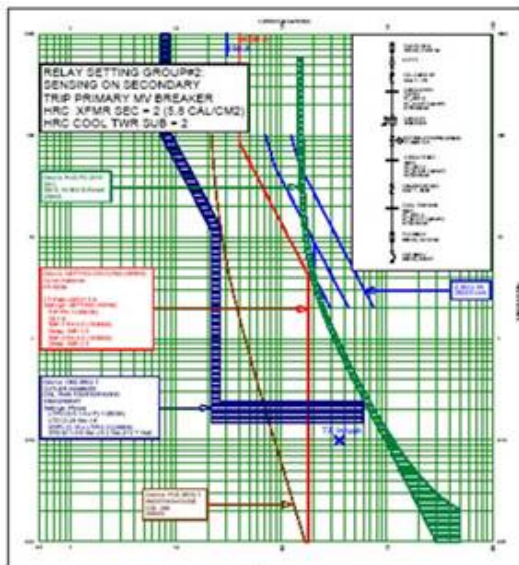


Figure 8. Substation Without Main Secondary Example 2

6. Maintenance switches for substations without transformer secondary main breakers (common in older heavy industrials) as shown in Fig. 9.

- Retro-fill Primary Fuse with MV Breaker

- Sense current at 480V transformer secondary, but trip primary MV breaker
- Use multiple group settings for maintenance switch
- Many variations dependent on MV relay and breaker type (3 cycle, 5 cycle, etc.) fault current available, current sensing location, etc.
- Must meet ANSI/IEEE C37.59

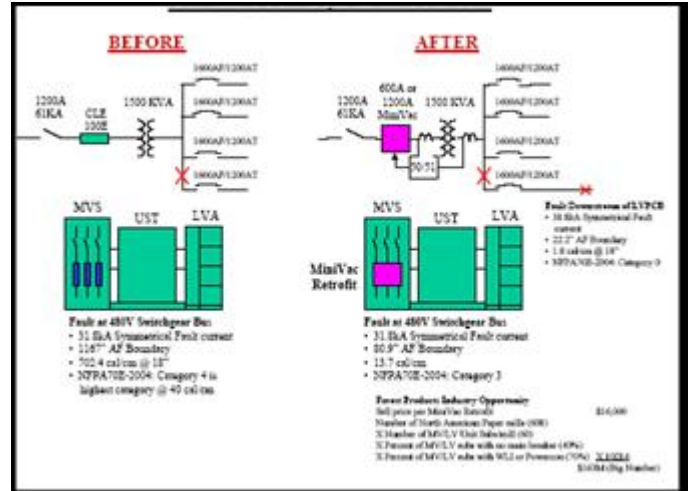


Figure 9. Maintenance Switch for Substation Without Secondary

7. Light Detection Systems (LV or MV)

- Senses light given off by the arc
- Supervised by over current relay (overcurrent+light= operate)
- Can trigger Hi speed S/C device
- Can trip breakers – substitute for 87B
- Extremely fast tripping (breaker time + 1 cycle)

## VI. MOVE PEOPLE FURTHER AWAY

With the changes to NFPA 70E-2009 [1], PPE is now required: 1) anytime something major occurs behind the closed door, i.e. racking a breaker in or out, or 2) causing something to open/close, i.e. manually tripping a breaker or switch with the door closed. This makes the condition of moving people away from the “at risk” area all the more important.

This approach of moving people further away, uses the knowledge that an arc blast expands volumetrically and in to the process, cools dramatically with distance. Distance from the fault always helps. There are certain tasks associated with distance that lend themselves very well to reducing arc flash exposure. The most notable is racking MV and LV breakers. Most ANSI switchgear designs place the worker directly in front of the switchgear cell while racking the breaker. There are ways to lower incident energy exposure during racking.

- De-energize entire lineup
- Put an extension on the racking tool
- Use a robot or remote racking device

Figs. 10 and 11 show examples of a robot and remote racking device respectively. Lack of distance between the

switchgear and wall often limits the use of a racking tool extension. The robot approach allows uses of an umbilical cord and locates the worker up to 50 feet away. The robot must know the number of turns in or out and torque limits of the breaker, so as to not over torque the shaft, jam it with misalignment or cause a failure. The robot should stall and back out if torque limits are exceeded. While such units are available by a specific manufacturer's switchgear, a universal version is more desirable. The universal unit should be programmable to work with a multitude of manufacturer's breakers, sizes and weights.



Figure 10. Conventional Racking (left) compared to Robot (right)



Figure 11. New LV Motor Control Center with Remote Racking Device

The next category is associated with simple switching, even though the door is closed. In Fig. 12, a magnetically coupled solenoid is placed over the control switch. The operator stands outside the arc flash protection boundary and opens or closes the breaker remotely. Fig. 13 shows a variation of this concept for one manufacturer's MV motor starter (Isolation switch).

New system designs can utilize the "station cubicle" design concept standard (pre-1950) in which breakers were installed in cement bunkers with their controls and relaying at the remote end of the room. This prevents the worker from doing anything from in front of the breaker or cell.



Figure 12. Local switching (Left) vs. Remote switching (Right)



Figure 13. New remote switching on MV Motor Starter Isolation switch

## VII. REDIRECT BLAST ENERGY

Arc Resistant switchgear designs are now available in North America. They lend themselves to new installations or complete switchgear replacement only as they are physically larger than conventional designs. Arc resistant switchgear is now recognized by standards [4] and NFPA 70E-2009 also recognizes the special improvements of safety involved with arc resistant switchgear [1]. Type 1 and Type 2 arc resistant switchgear are the practical options available today. Type 1 provides personnel protection only when in front of the switchgear; Type 2 provides protection all the way around the external perimeter of the switchgear. When in its sealed condition, any internal fault arc blast is ported thru a plenum or arc flaps on top of the switchgear to someplace personnel are not located. If ported outside, it cannot be into a classified (hazardous) area. Any internal fault, whether in the breaker compartment, the bus compartment or the cable compartment, must exhaust into this plenum system and not exit anywhere personnel may be located.

Once proven by test to comply with [4], NFPA 70E-2009 [1] allows category zero PPE requirements for racking, breaker operation, etc. as long as the door and assembly are closed and sealed. It should be noted that once the door is open, the breaker is out of its cell, and the cable compartment covers are removed, it is no longer considered arc resistant and appropriate PPE is required. NFPA 70E-2009 [1] recognizes Metal-clad arc resistant switchgear vs. conventional switchgear. Arc Resistant switchgear does not solve all the arc flash issues by itself. Fig. 14 shows a successful lab test of LV arc resistant switchgear (with a plenum). Fig. 15 shows a typical 5kV / 15 kV design. Arc resistant designs are commercially available in MV/LV switchgear and MV motor control centers.

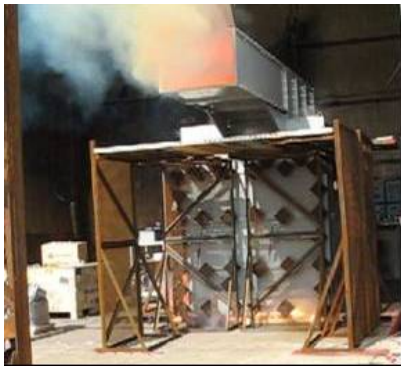


Figure 14. LV Successful Arc Resistant Switchgear Test



Figure 16. "Safety-by-Design" MCC Drawout Bucket



Figure 15. Typical 5kV / 15 kV Arc Resistant Switchgear

### VIII. PREVENT FAULT

This section addresses the industry's "safety by design" concept:

1) Safety By Design. Figs. 16 and 17 show a state-of-the-art LV MCC built with "safety by design". Its design concept is to incorporate bucket draw-out features with shutters or barriers but to do so economically. The three bus stabs can be cranked in and out like draw out switchgear. When in the test or disconnect position, it only has 24 VDC control power inside the bucket (less than 50V), has two individual shutters with a dead air space between them and is classified with a HRC of zero. The inner shutters seal off the bus when the bucket is removed providing further isolation and safety for the cell. For starters Size 4 and smaller, the current limiting characteristics of motor starter breakers and/or current limiting fuses, can make the cable trough also category zero. However, when doing energized trouble- shooting with the door open, the line side of the breaker or fuse in the bucket is exposed and the HRC will be determined by the next upstream device. This particular MCC design is the forerunner of the new proposed IEEE Std 1683 for LV MCCs and is available in new assemblies as well as some retro fits.



Figure 17. New "Safety-by-Design" Motor Control Center

2) Partial Discharge Sensing. Partial Discharge (PD) sensing is another way of predicting faults way before they happen. This technology senses high frequency discharges in insulation systems at MV and HV and can give months of advance warning. It does it with sensors that are typically permanently installed (coupling capacitors, RFCTs, RTD couplers that use the RTD leads as internal antenna) and feeds an external PD relay. This gives continuous on-line monitoring and advises when a problem is occurring, all without the need to remove protective covers. If the cover is not removed, no special PPE requirements are needed. When a problem is alerted, you de-energize that one piece of equipment and correct the problem safely. Fig. 18 shows a typical PD relay and pending switchgear failure respectively. PD technology exists for switchgear, generators, motors and transformers.





Figure 18. Partial Discharge Relay and Switchgear with Pending Failure

3.) Infrared Windows. Another safety by design concept is to install Infrared windows as shown in Fig 19. These windows have bolted covers to access confined spaces with energized components and are judiciously located in assemblies. The bolted metal cover affords the metal integrity when closed and, when open, permits an infra-red camera to quickly and safely take infrared Figures for maintenance purposes. If the main cover is not removed, there are no exposure and no special PPE requirements. The labor savings form not having to remove hundreds of bolts to remove covers, pays for these windows typically in the first year. These infrared windows are available in new and retro fitted applications.



Figure 19. Infrared Windows

4.) Temperature Monitors. Another maintenance tool is the use of temperature monitors. No matter what you do design wise, there are some locations where nothing works to bring the HRC level down to acceptable levels. An example of this is between a transformer and its main secondary breaker – especially if this transformer is protected by a primary fuse. Infrared sensing must be taken when under load and infrared windows do not work (too close). These temperature sensors give you on line sensing without removing any covers as shown in Fig. 20.

#### IX. CONCLUSION

It is the authors' collective opinion that most excessively high incident energy exposures can be mitigated through a variety of

techniques. There is no one single technique that works everywhere and that a total system approach is the best solution. What works in one substation may not work effectively in another substation. Modifications to existing equipment, protective devices, new specifications utilizing “safety by design” concepts, use of robots, alternate maintenance procedures, etc., can all be effectively used to dramatically improve electrical safety. Excessive time in high level PPE should be all but eliminated – most of the time. Many of the techniques and suggested solutions are very cost effective; but even the higher cost solutions are small compared to the costs of dealing with the consequences of a major electrical accident. HRC category 2 or less is achievable for entire facilities.



Figure 20. Remote Temperature Sensing

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#### XI. BIOGRAPHIES

**David M. Wood P.E.** received a BSEET in 1987 from The Pennsylvania State University. Mr. Wood is currently working as a Project Leader for Eaton Electrical Services and Systems Division. His main responsibilities include technical and project leadership to a team of Power System Engineers in the Northeast Region and performing power system studies. Mr. Wood is member of the IEEE and is a Registered Professional Engineer in the States of Pennsylvania and New York.

**David Shipp P.E.**, BSEE '72, Oregon State University. He is a Principal Engineer for Eaton Electrical Systems & Services Division. He is a recognized expert in power system analysis and has worked in a wide variety of industries. He has spent many years performing the engineering work associated with



his present day responsibilities. Responsibilities include a wide range of services covering consulting, design, power quality, arc flash and power systems analysis topics. Over the last few years, he has pioneered the design and application of Arc Flash Solutions – modifying power systems to greatly reduce incident energy exposure. He has written over 65 technical papers on power system analysis topics and has received IAS/IEEE Prize Paper Awards for three of these papers. More than fourteen technical papers have been published in IEEE/IAS national magazines and one in EC&M. He is very

active in national IEEE and helps write the IEEE color book series standards. He presently is the Chair for the IEEE I&CPS sponsored Working Group on Generator Grounding, He spent 10 years as a professional instructor, teaching full time. He occasionally serves as a legal expert witness. He is an IEEE Fellow engineer.