Reducing Arc Flash Risk with the Application of Protective Relays

Ray Luna
GE Digital Energy

Brian Cassidy P.E., Jesus Franco
Bayer MaterialScience

1. Abstract

The exposure to an arc flash high incident energy fault to technicians operating low and medium voltage switching equipment is a daily hazard in the workplace and there is an opportunity to improve safety. While PPE protects for first and second degrees burns it does not provide sufficient protection for the impact and forces that a high incident energy arcing fault produces and the gases released. One solution is to reduce the incident energy of the arcing fault.

This paper analyzes methods to reduce the exposure of personnel to high-energy arcing faults, and also defines a method to determine the limits of coordination among protective devices to identify where the selectivity could be jeopardized.

2. Introduction

Extensive studies on arc flash phenomena have been developed since Ralph Lee introduced the Arc Flash as a hazard in the work place [1]. This paper acknowledges these works and introduces awareness to mitigate the effects of the Arc Flash Hazard (AFH) by utilizing modern technology offered in protective relays, as well as to maximize the utilization of existing relays installed in electrical substations.

NFPA 70E [3] defines flash hazard as a dangerous condition associated with the release of energy caused by an electric arc. An Arc Flash (AF) is the result of a short circuit where the fault current is traveling through ionized air. The air provides a higher resistance path to the conduction of electricity and for this reason the resultant current flow could be as low as 43% of the bolted threephase short circuit fault on 480 V buses. The resultant intense heat, flying debris or shrapnel, projected molten cooper and gases released from an arcing fault produces a great amount of arc flash byproduct. The heat produced is calculated in cal/cm^2 and there are no methods to calculate the amount of shrapnel and molten material and gases released at the arcing spot.

The methods developed to calculate the incident energy generated by an arcing fault and the testing data acquired in controlled testing environments, indicates that the faster the fault is cleared, the less the caloric energy that is produced, consequently, the less molten material, shrapnel, and gases released.

Analyzing the settings of existing relaying systems and applying the multiple protection, control, and communication functions of modern protection relays provide implementation solutions of an electrical arc flash safety program in industrial facilities.

In a Petrochemical facility there are two electrical operating modes in a typical workday: Normal Mode and Switching Mode. The content of this paper is developed around these two scenarios, which are defined as follow:

Normal Mode: The normal operating mode is when the power equipment is energized and the load is being served to the production process units with no human interactions. If a non-arcing fault occurs, the protective equipment detects the fault and disconnects the faulted equipment very quickly and safely since there is no arc to damage the equipment. Conversely, if an arcing fault occurs, the protective relaying and other protective equipment should detect the fault but the current flowing will be less than the non-arcing fault and the time to clear the fault could be longer depending on the calculated settings and the equipment installed. The settings of protective relays and the selection of other protection equipment, such as medium and low voltage fuses and low voltage circuit breakers, should be set to minimize the incident energy to a lowest caloric value possible without jeopardizing selectivity.

Switching Mode: The switching operation mode is defined as when personnel execute electrical switching procedures to disconnect loads or to restore power to equipment that was previously disconnected for maintenance or repairs. During this mode of operation, the protection relays settings and the installed fuses and low voltage breakers combine to determine the fault clearing time and the level of incident energy developed if an arcing fault should occur. During switching activities of the power system, the personnel performing maintenance or modifications around energized equipment will be exposed to the dangers of an arcing fault, and the safety of the personnel takes priority over the selectivity of the protection apparatus. This protective apparatus must be set to ensure the reduction of incident energy levels by tripping the up stream breakers very quickly in order to reduce the fault clearing time.

Recognizing the different activities that substation personnel and other employees execute around energized equipment is the first step toward a safer environment, because it allows the identification of potentially dangerous actions that favor the development of arc flash faults.

3. Power System Analysis and Arc Flash Study Parameters

The plant's power system were the arc flash study was executed consists of a 138 KV ring formed by the utility feed and three large substations (figure 1). These substations transform the 138 KV system to 13.8 KV and 34.5 KV networks. The plant has a maximum load of 220 MW, which is fed from a 700 MW generating plant located just outside the plant's property. Some of the Medium Voltage (MV) switchgears are located in these large substations and cables runs on cable trays interconnect four satellite MV substations. The MV switchgear is equipped with a Main-Tie-Main (M-T-M) breaker configuration. The 480 Volt distribution substations are located throughout the plant and also have the M-T-M breaker configuration on the 480-volt side.

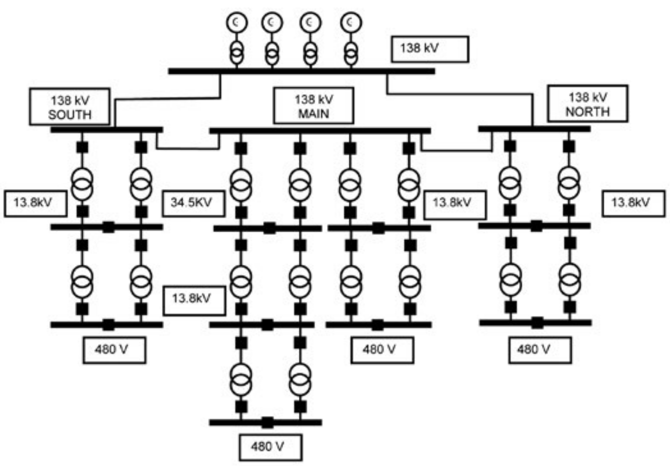

Figure 1.
Simplified one line drawing

Once the operating modes are defined, it will be necessary to identify what is considered a normal operating condition of the power system. The following conditions were defined as normal for the this industrial plant:

1. The power system is normally run with the tie circuit breakers open, except during switching operations. During switching operations, the tie breakers are closed which creates a higher arc flash level and AF labels were designed to indicate this condition.

2. Identify the transformers and buses equipped with differential protection and establish the protection operating times.

3. AF software settings. The software utilized to run the AF study included the following conditions:

    a. The AF calculation method utilized is IEEE-1584-2002 [1].

    b. The maximum fault clearing time is 2 seconds.

    c. The upstream device always clears an arcing fault.

    d. The coordination limits are based on IEEE-1584 for opening times of the circuit breakers (ref. table 1 on IEEE-1584 std.) and the breakers at the plant are periodically tested for compliance.

RECOGNIZING THE DIFFERENT ACTIVITIES THAT SUBSTATION PERSONNEL AND OTHER EMPLOYEES EXECUTE AROUND ENERGIZED EQUIPMENT IS THE FIRST STEP TOWARD A SAFER ENVIRONMENT

4. Selecting Coordination Time Intervals

The factors that can be controlled are in the time-current characteristics of the system protective devices through selecting different curves and settings to reduce the time to clear the arcing fault. These factors include:

- Pickup: the minimum current at which a device actuates. Lower pickup provides arc fault protection for a greater range of fault currents. The pickup should be selected based on the capacity of the equipment installed. The current transformer ratios must also match these capacities in order to optimize the relay settings for arc flash protection.

- Time delay. Shorter time delay reduces time to trip and lowers I^2t.

- Instantaneous pickup. Operating time is typically the minimum possible for the circuit being protected. Lower instantaneous pickup settings reduce arc flash hazard.

Coordination Time Intervals: Tightening up coordination time intervals is a direct and simple way of reducing tripping times and thus reducing t for any given I. Most engineers and many software programs use a 0.3-s minimum coordination time interval between tripping characteristics of series-overcurrent devices. While coordination margins can be securely reduced to 0.25 sec [4] when using digital protective devices, lower margins are acceptable if very specific testing and analysis are performed. In an effort to reduce the coordination time intervals, the operating times of protective relays are periodically tested and the records demonstrate that the tolerances found are per manufacturers instructions manuals. Chart 1 summarizes the circuit breaker (CB) clearing times and relays operating tolerances that were used to determine the coordination interval for reducing arc flash incident energy.

	CB Opening Time in ms	OC Relays Time tolerance in %
LV breakers (integral trip or external relay)	Mfg. Spec: 45 Tested Avg.: 50	
MV breakers	Mfg. Spec: 83 Tested Avg.: 83	
Electromechanical relays		+/- 5
Electronic relays		+/- 3

Chart 1.
Protective equipment operating times

Based on Chart 1 above, the following coordination Time limit is set:

LV and MV systems (480 v thru 34.5 KV): 200 ms

On LV systems the coordination time interval on the fast side is calculated as:

Coordination Time Interval (LV) = (200*0.97) – (50*1.03) = 142 ms

On MV systems the coordination time interval on the fast side is calculated as:

Coordination Time interval (MV) = (200*0.97) - (83*1.03) = 108 ms

If a lockout relay (86) is used in the operation of the protective relay and the tripping of the circuit breaker control logic a time of 8.5 ms must be subtracted from the above calculations.

As shown here, there is more than 100 ms of coordination interval on both voltage levels and the 200 ms coordination time will be used in new calculations to reduce the AF incident energy.

5. Short Circuit Study

To achieve selective coordination it is necessary to understand how the protection devices operate and how the short circuit currents decreases when the short circuit involves the air as the fault media. For the analyzed case, the short circuit and arc-flash current results, consisting of 2000 buses, are summarized in Chart No 2.

Voltage	# Of Buses	AF current in % of bolted Short Circuit span
34.5 KV	54	0
13.8 KV	814	80 -100
5 KV	27	82 -97
480 V	1080	43 - 94

Chart 2.
Short circuit levels

As shown on Chart 2 the LV buses experience the highest reduction of the short circuit current during an arcing fault and the protective apparatus must react to disconnect the faulted equipment during these reduced current conditions.

In order to maintain selective coordination the power systems engineer must update the arc flash calculations when the power system changes, e.g. when old transformers are replaced for equipment with higher capacities or if new loads are added to the existing system. The engineer must also ensure that the protective equipment is calibrated and circuit breakers and switchgears are properly maintained.

6. Normal Operation Mode – Original AF Results

The one line drawing on Figure 2 illustrates the typical AF incident energies that were found with the original settings calculated before the AF phenomena was introduced, chart 3 shows the data in tabular form and figure 3 the protective coordination for the same switchgear. Note the following aspects of the analysis:

1. The working distances was defined as 24 inches for 480 volts switchgear as per IEEE-1584 table 3, and 18 inches for shallow panels with bolt on covers such as the ones found on busducts and junction boxes on the secondary side of MV/LV transformers.

2. The tie breaker is normally open.

3. The AF on the secondary side of the transformer is 142 cal/cm^2; this AF energy would destroy the busduct and would cause extensive damage to the transformer if an arcing fault occurs.

4. The AF on the line side of the circuit breaker is 136 cal/cm^2, this AF applies to the complete switchgear since an arcing fault occurring on the line side of the main breaker would cause extensive damage to the switchgear and would seriously hurt any personnel located around the gear.

5. Figure 4 shows the AF levels for an arcing fault if the tie breaker is closed, which is the case when personnel is executing switching operations for maintenance purposes. This is the worst AF condition and when the presence of personnel around the equipment is most likely to occur.

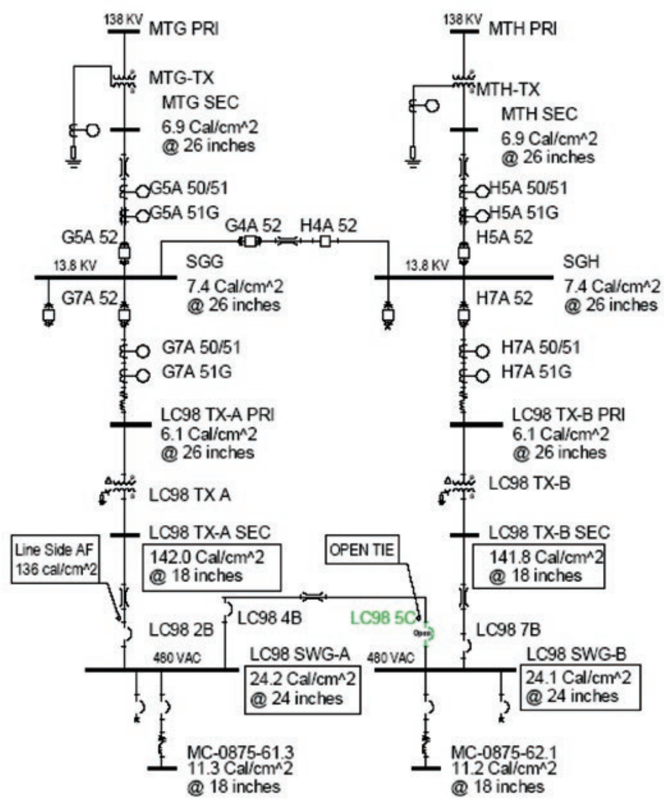

Figure 2.
Typical one line diagram. Open ties operation with AF levels as found

Bus Name 480 V	Protective Device Name	Bus Bolted Fault (KA)	Prot. Dev. Bolted Fault (KA)	Prot. Dev. Arcing Fault (KA)	Trip/ Delay Time (sec)	Brkr Opening Time (sec)	Incident Energy (cal/cm^2)
LC98 SWG-A (LC98 2B LINE SIDE)	G7A 50/51	30.9	29.5	15.4	1.91	0.050	136
LC98 SWG-B (LC98 7B LINE SIDE)	H7A 50/51	29.5	29.5	15.5	1.91	0.050	136
LC98 TX-A SEC	G7A 50/51	32.9	31.5	16.3	1.91	0.080	142
LC98 TX-B SEC	LC98 2B	31.5	31.5	16.4	1.91	0.080	142
LC98 SWG-A	G7A 50/51	30.9	29.5	15.3	0.5	0.080	24
LC98 SWG-B	LC98 7B	29.5	29.5	15.5	0.5	0.080	24

Chart 3.
Typical AF results for the one line shown in Figure 2

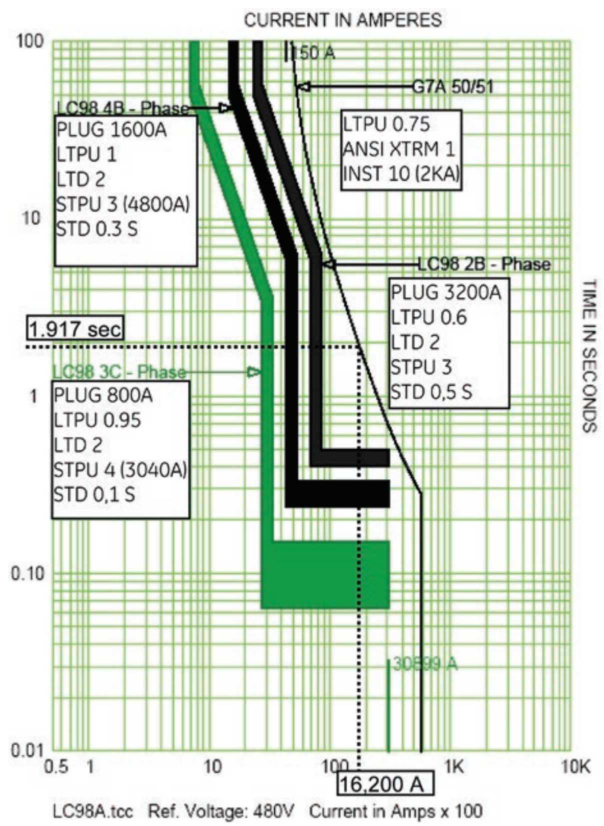

Figure 3.
Coordination chart for the one line diagram shown in Figure 2

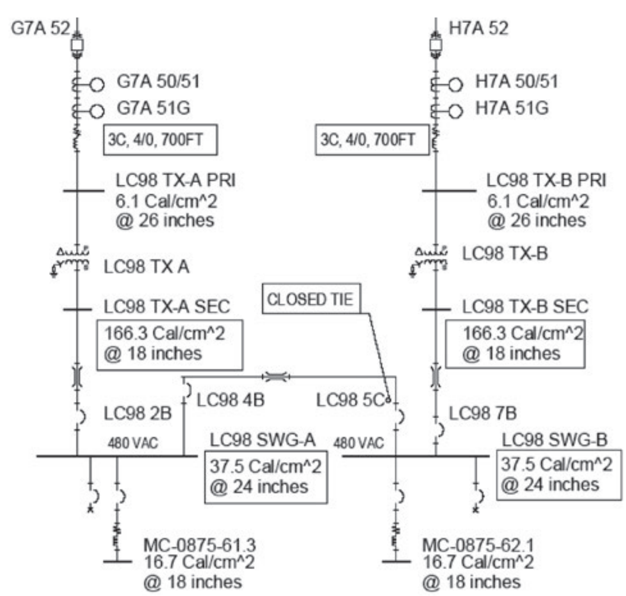

Figure 4.
Closed tie operation. Original AF levels

7. Reducing AF Incident Energy in Normal Operation Mode

As shown in the coordination charts, the LV circuit breakers have the protection unit integrated in the CB assembly and manufacturers provides a current-time characteristic that indicates the time when the main contacts start to open and the final time when the contacts had cleared the fault, on the other hand, the manufacturers of protective relays do not include the circuit breaker operating time since these relays can be used in a variety of circuit breakers. The AF software databases are built with all of these data already programmed and ready to use. In addition, the protection engineer may add relays and breakers not originally included in the database, such is the case of custom curves that the user can implement on modern microprocessor based relays.

In the case of protective relays, where the current-time curve is shown with a single line, the protection engineer must keep in mind the circuit breaker opening time in order to assure coordination during non-arcing faults.

The relays and circuit breakers analyzed in the example above were installed several years ago and they include electronic modules where a versatile set of current-time curves was available. The following conditions were set in order to reduce the arc flash energy during the normal operating conditions of the power system:

1. The coordination time interval was set at 200 msec.
2. Knowing that the power system operates with the tie breakers normally open, the protection settings of the tie and the main breakers can be matched since the tie breaker is closed during switching operation only and is when the maximum safety is required.
3. Set the short time pick up as low as possible in order to maximize the short time delay and to be able to trip quickly on low current arcing faults. Special attention must be given to the inrush currents of large motors connected to MCC's downstream.

The coordination chart on Figure 5 illustrate the new protective device settings, figure 6 is the one line drawing that shows the new AF levels and chart 4 is the tabular output of the AF software and it shows the short circuit currents and timing of the relays to clear the fault.

Bus Name	Protective Device Name	Bus Bolted Fault (KA)	Prot. Dev. Bolted Fault (KA)	Prot. Dev. Arcing Fault (KA)	Trip/ Delay Time (sec)	Brkr Opening Time (sec)	Incident Energy (cal/cm^2)
LC98 SWG-A	LC98 2B	30.4	29.5	15.4	0.335	0.050	17
LC98 SWG-B	LC98 7B	29.5	29.5	15.5	0.335	0.050	17
LC98 TX-A SEC	G7A 50/51	32.4	31.5	16.3	0.5	0.080	41
LC98 TX-B SEC	H7A 50/51	31.5	31.5	16.4	0.5	0.080	41

Chart 4.
AF report with reduced incident energy levels

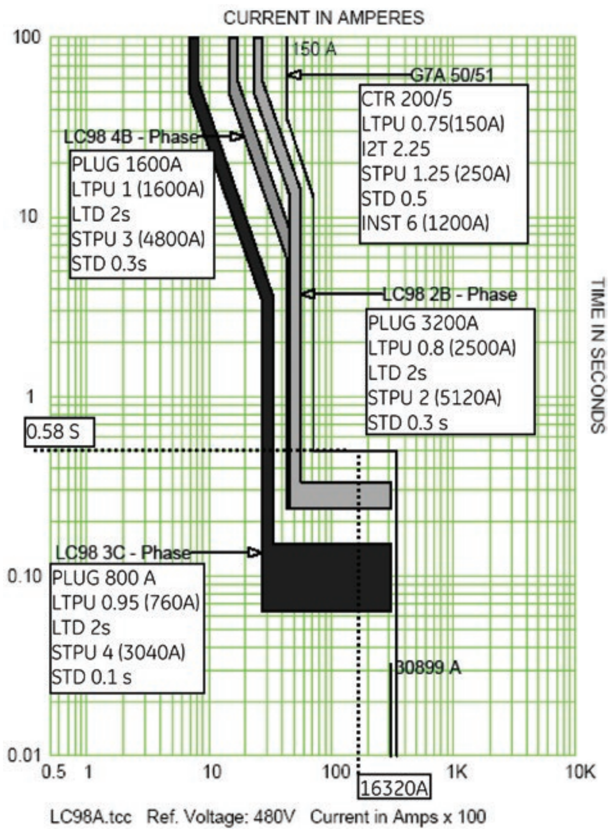

Figure 5.
New relay settings to reduce AF

Bus	Original AF cal/cm²	Improved AF cal/cm²
LC98 TX-A SEC	142	41
LC98 SWA MAIN CB LINE SIDE	136	39
LC98 SWG-A	24	17

Chart 5.
Normal operating mode AF levels

From chart 5 we can deduce that by modifying the relay and circuit breaker settings the AF incident energy can be less damage and the repair time will be subsequently reduced. The protective relays at the MV switchgear have available curves of the I^2t characteristic that replaced the ANSI extremely inverse curve originally used. These curves have the advantage to better coordinate with downstream devices such as LV breakers with integral protective units.

Closed Tie Operation with Improved protection Settings.

The one line diagram on figure 7 illustrates the AF levels during closed tie conditions once the protective device settings were improved to reduce the AF in normal mode of operation. In figure 7 note that the arc flash risk went dangerously high when the tie breakers were closed to allow switching off a transformer for maintenance purposes. The AF level at the line side of the main breakers or busduct is close to 60 cal/cm².

Switching off transformers for maintenance.

A procedure to remove any of the transformers off service once the tie breaker has been closed is to open the feeder breaker at upstream substation first and later open the secondary side circuit breaker. Once the primary breaker is opened at the upstream substation, the busduct AF is reduced to 25 cal/cm².

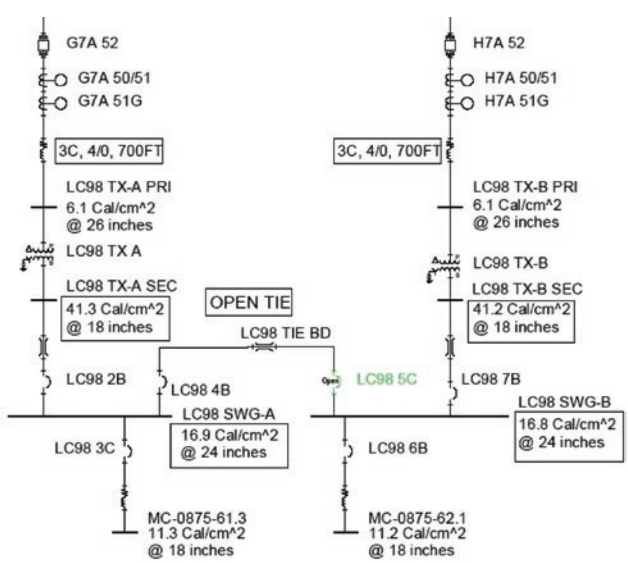

Figure 6.
One Line drawing with reduced AF. Tie breaker is open

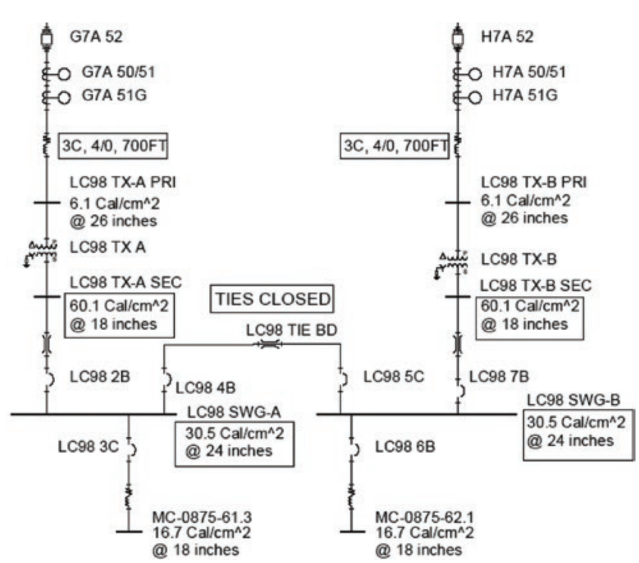

Figure 7.
Closed ties. AF with improved protective device settings

During maintenance activities the power distribution personnel will execute switching maneuvers to de-energize equipment. During these activities, the exposure to an arcing fault is increased. There are several methods to reduce the AF incident energy to lower levels; however, the coordination of the protective devices will be sacrificed.

8. Reducing the AF Incident Energy while in Switching Mode of Operation (Maintenance Mode)

The following conditions are set in order to understand the switching operation mode in regards to arc flash protection:

1. During switching operations and maintenance activities, the primary focus of attention is the safety of the personnel, subsequently, the sacrificing of protection coordination is necessary and the reliability of the power system is jeopardized.
2. An upstream device always clears an arcing fault.
3. The upstream device clearing the fault is normally located in a substation remote to the equipment being operated.
4. The utilization of other mechanical means to protect the personnel, such us PPE and remote controlled breaker racking devices, is not eliminated because of the application of these protective-relaying methodologies.

The following conditions are required to allow the system to implement a switching mode of operation:

1. The relay or breaker with integral protection unit must be able to change settings by the command of a control input or via communications.
2. An alarm to indicate that the relay settings have been changed and that the system is in switching mode of operation must be set.
3. Install Arc flash labels that indicates the incident energy on both modes of operation.

If the existing relays are electromechanical relays or if they are electronic relays but do not have the feature of changing settings groups then consider the addition of an instantaneous overcurrent relay to each feeder. This is also the case for integral-protection circuit breakers where the changing of protection groups is not supported.

The calculations to reduce the AF by modifying the relay settings must start at the lower end of the power system. In our study the lower end becomes the bus of the MCC's that operates at 480 VAC. The integral protection circuit breaker installed at the LV substation is the upstream device that will disconnect the circuit when an arcing fault occurs in the MCC and will be the breaker whose settings would be modified to introduce instantaneous settings during maintenance activities at the MCC level.

THE MAJORITY OF THE TYPICAL CAUSES INVOLVE THE INTERACTION OF PERSONNEL TO CREATE AN ARC FLASH FAULT

For the present paper only discusses the settings on protective relays installed at the MV switchgear that feed power to the MV/LV transformers. It is a common practice to provide a MV circuit breaker at the MV substation and then a long feeder cable feeding power to a MV/LV transformer. As seen in the case presented above, the arc flash incident energy is extremely high on the bus duct and at the line side terminals of the LV main circuit breaker. After studying the case to reduce the high incident energy to a more manageable value, the resultant numbers are not low enough to minimize the damage to the equipment and to reduce the risk imposed on personnel.

The typical causes of an arc flash fault are:

1. Accidental contact with energized parts
2. Tools dropped on energized conductors
3. Wiring errors
4. Improper work procedures
5. Contamination on insulators
6. Lack of maintenance on switchgear
7. Inadequate short circuit ratings

The majority of the typical causes involve the interaction of personnel to create an arc flash fault. The application of temporary protective device settings will reduce the risk of arc flash hazards by reducing the total incident energy should a hazardous situation develops as listed above.

The one-line on figure 8 and chart 6 shows the arc flash levels achieved when a different group of settings are utilized for maintenance activities performed downstream.

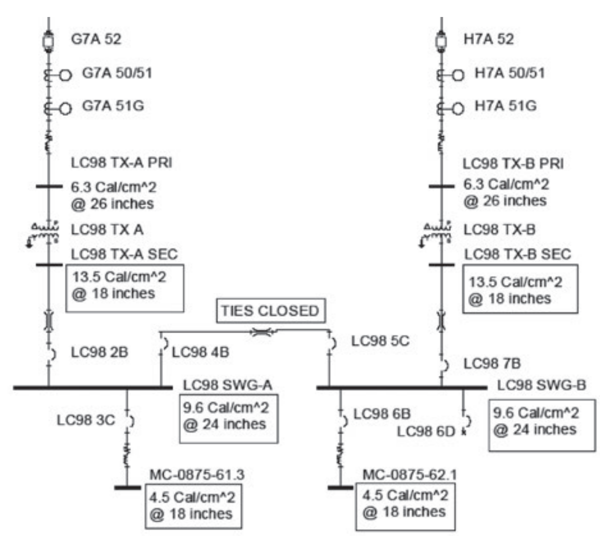

Figure 8.
Maintenance mode of operation; ties closed and minimum protective device settings

Bus Name	Protective Device Name	Bus Bolted Fault (KA)	Protective Device Bolted Fault (KA)	Protective Device Arcing Fault (KA)	Trip/ Delay Time (sec)	Incident Energy (cal/cm^2)
LC98 SWG-A (LC98 2B LINE SIDE)	LC98 2B	57.92	28.56	13.41	0.07	9.6
LC98 SWG-B (LC98 7B LINE SIDE)	LC98 7B	57.91	28.56	13.41	0.07	9.6
LC98 TX-A SEC	G7A 50/51	58.06	30.60	14.36	0.016	12
LC98 TX-B SEC	LC98 7B	58.06	27.46	12.89	0.07	13
MC-0875-61.3	LC98 3C	33.21	33.21	18.28	0.001	4.5
MC-0875-62.1	LC98 6B	33.21	33.21	18.28	0.001	4.5

Chart 6.
Maintenance mode of operation; ties closed and minimum protective device settings

While the arcing fault current remains the same, the tripping times are minimized and the resultant arc flash is reduced drastically. The coordination chart with the new settings group looks as shown on figure 9.

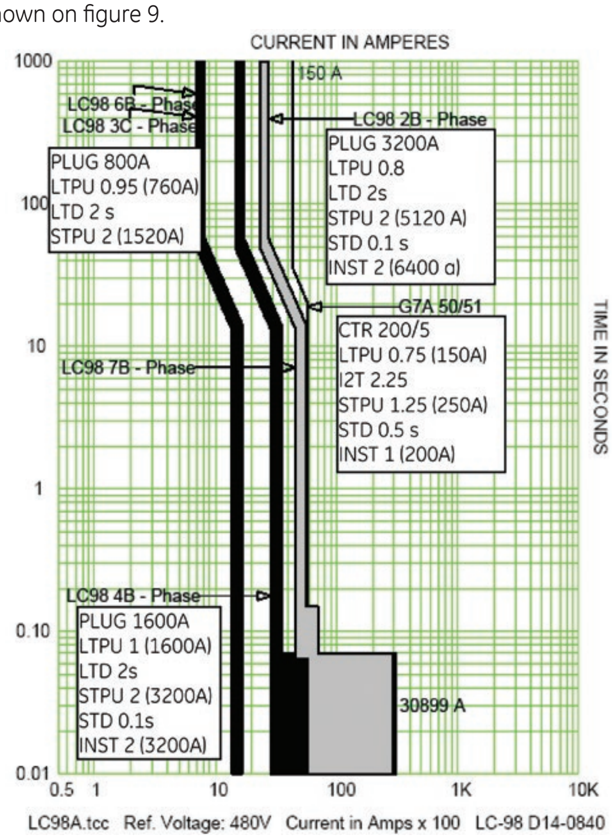

Figure 9.
Coordination chart as when in maintenance mode of operation

9. Methods to Change the Protective Relaying Settings for Switching and Maintenance Operations

1. Local maintenance mode switch. This control switch is wired into a digital input on the electronic protective relay to switch the normal operation group of settings to the maintenance mode. Special attention to the work order must be given since the protective relay and its corresponding control switch will be located remotely to the equipment to be serviced. The standardized work permit must include a field that specifies the location of the device and must include another field to insure that the switch was returned to its normal position once the labor has been completed. A pilot light to indicate this condition provides an easy way to acknowledge the condition of the protection scheme.

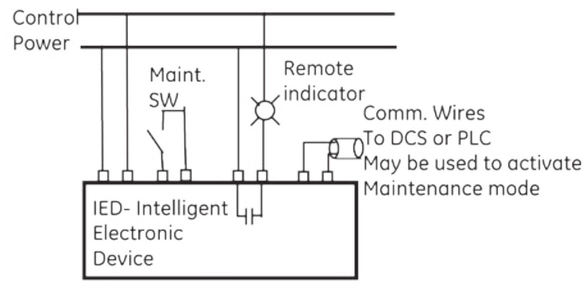

Figure 10.
Maintenance Switch to reduce AF levels during switching operations

2. Addition of a 3 phase Instantaneous Overcurrent Digital relay: If there is a set of three electromechanical relays and there is no intention to replace the relays for a microprocessor based relay; reduction of the AF incident energy could be accomplished by adding a compact instantaneous only digital device that could be added to the existing circuit and would provide the same functionality explained above.

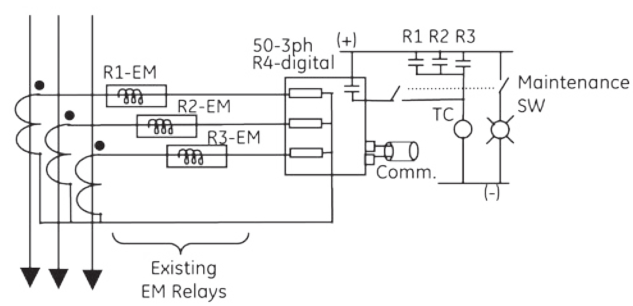

Figure 11.
The addition of an Instantaneous digital OC relay with existing electromechanical relay schemes

3. SCADA Systems. By utilizing the SCADA system in an industrial plant, the protective relay settings could be easily be changed to a different settings group for maintenance purposes during maintenance activities. It also allows the operation of circuit breakers from a remote location, which would reduce the exposure of the personnel during switching operations. Figure 12 is a typical screen where access to relay settings groups and circuit breaker control can be enabled after entering the rightful passwords and permissions.

Figure 12.
Typical SCADA control monitor

GOOSE MESSAGING CAN SIGNIFICANTLY REDUCE ARC INCIDENT ENERGY

10. Other methods for Continuous AF Protection

The following methods would provide continuous AF protection and would reduce the fault's clearing time significantly by automatically detecting the fault and issuing a trip signal once the fault is detected.

1. Zone interlocking via communications. Modern protective relays include protocols, such as, IEC61850 which allows GOOSE messaging amongst relays trough fiber optics. By using interrelay hi-speed I/O capability, blocking signals can be transferred upstream, allowing minimal coordination delays. In the system shown in figure 13, fast clearances can be provided for fault 1 and still maintain coordination for fault 2.

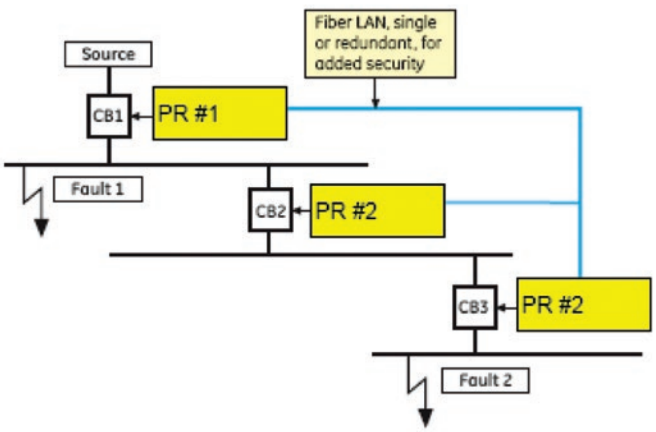

Figure 13.
Zone Interlocking

- Using GOOSE messaging can significantly reduce arc incident energy.
- If the fault is within the zone, no block signal is sent, the relay trips extremely fast.
- Redundant communication networks (LAN) can virtually eliminate the possibility of loosing communication amongst relays due to downed links.

2. Arc Detectors and High Speed Communication: Light sensitive technologies already exist and new technologies using other quantities are being developed to dependably and securely detect the arc flash and accelerate the tripping of the circuit breaker as soon as the arc starts. Arching is accompanied with several forms of energy such as light and heat. Fiber optic sensors can detect light and provide a signal to a protective relay input. The following two arcing fault cases illustrates the application:

• **Case #1.** In reference to figure 14 below, for an arcing fault at the cabling compartment at the load side of the feeder breaker, upon arc detection by the light sensor and supervised by an overcurrent condition, the relay IED #3 will issue a trip signal to the local breaker. If the arcing fault is located just before the location of the CT's or at the line side of the breaker, then IED#3 relay would send a message to IED#2 which would issue an instantaneous trip if an overcurrent condition is detected, reducing the incident energy to a safe amount.

• **Case #2.** For the system illustrated on Figure 14, where the transformer is located far from the main switchgear trough power cables, an arcing fault in the busduct or at the secondary compartment of the transformer would create a very low fault current at the substation feeder breaker and the relay at that location would take a long time to trip creating a very hazardous situation. When the light sensor at IED #2 detects the arc and since there is no overcurrent condition, then the arc detection flag will be send to the upstream device, via high-speed communication protocols. The trip is supervised by an overcurrent condition at the upstream device to assure selectivity.

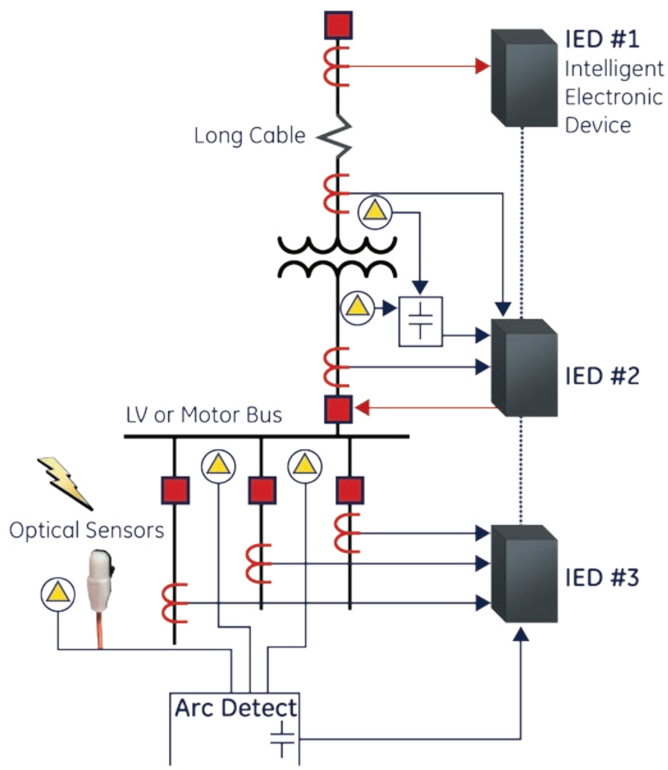

Figure 14.
Light detection and high speed communication technology

11. Conclusions

The modern technologies utilized by microprocessor based protective relays provide the means to accelerate the extinction of the arc produced by short circuits where the air is the conducting material. While appropriate personal protective equipment and increasing the distance of personnel from the electrical switchgear are the first line of defense to protect the people from hazardous risks; a well maintained electrical system, proper coordination studies and modern protective relays are the perfect companion for a safe working environment.

12. References

[1] Ralph H Lee, "The Other Electrical Hazard: Electric Arc Blast Burns". IEEE Transactions on Industrial Applications, Vol 1A-18, No 3, May-June 1982, p246.

[2] IEEE 1584-2002, IEEE Guide for performing Arc-Flash hazard calculations.

[3] Standard for Electrical Safety in the Workplace, NFPA 70E, National Fire Protection Association, 2004.

[4] Leoni, A.R. and Bowen, J., "Improving Safety and Reliability Via Cost-Effective Upgrades of Existing Systems". IEEE Transactions on Industry Applications, Vol. 43, No.1 Jan/Feb 2007.

210611-v3