Tripping with the Speed of Light:
Arc Flash Protection

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***Abstract* –** Reducing clearing time is a critical component in reducing arc flash incident energy levels. Additional benefits include reduced collateral damage, lower production downtime and potentially lower personal protective equipment (PPE) requirements. A novel method of fast arc flash detection utilizes long fiber optic light sensors to detect and initiate tripping faster than conventional relaying techniques. This paper discusses application examples as well as two documented arc flash events where this protection was implemented.

***Keywords* –** Arc flash, arc flash hazards, incident energy, personal protective equipment

I. Introduction

Arc flash is not a new phenomenon but interest and concern about the dangers associated with arc flash events has increased dramatically in recent years. This increased awareness and concern is largely due to new guidelines and standards put forth by IEEE (Institute of Electrical and Electronic Engineers), NFPA (National Fire Protection Association), NEC (National Electric Code) and OSHA (Occupational Safety and Health Administration).

IEEE Standard 1584™, "Guide for Performing Arc-Flash Hazard Calculations", contains step-by-step procedures for calculating the available incident energy where workers might be exposed to energized electrical equipment.

NFPA 70E, "Standard for Electrical Safety in the Workplace", adopts the IEEE Standard 1584™ calculation procedures and assigns hazard levels ranging from 0 through 4 to incident energies up to and including 40 cal/cm^2. It also lists typical PPE (Personal Protective Equipment) suit levels appropriate for working near energized electrical equipment at each of the defined hazard levels.

Beginning in 2002, the NEC has included a section requiring the labeling of panels with arc flash hazard warnings. The 2005 NEC added meter-socket locations to the list of locations that need to be marked.

OSHA regulations represent the fourth major impetus behind the increased interest in arc flash hazards. The primary OSHA regulations are in 29CFR 1910 Subparts I and S. These regulations are primarily concerned with hazard assessment and documentation as well as training workers in the proper use of PPE.

II. Arc Flash Calculations IEEE Standard 1584™-2002

IEEE Standard 1584™ contains step-by-step procedures for calculating the available incident energy to which a worker might be exposed. Factors used in the calculations include available (bolted) fault current, voltage, equipment type and construction and grounding method. In addition, there a several constants whose values can be determined or approximated based on tables that are included within the standard.

The incident energy calculation is basically a three-step process consisting of the following:

a. Calculation of two arcing currents from available bolted fault currents
b. Calculation of the normalized incident energy at each arcing current
c. Conversion from normalized to actual incident energy based on actual factors (clearing time, equipment factors, etc.)

The final step listed above consists of converting the previously calculated normalized incident energy to the actual incident energy. This process takes into consideration actual equipment factors and actual fault clearing times based on the protection that is in place. It also assumes that all devices including relays, fuses and breakers operate properly. Two equations are used depending on system voltage.

For applications up to 15 kV [1]:

$$E = C_f E_n \left(\frac{t}{0.2} \right) \left(\frac{610^x}{D^x} \right) \qquad (1)$$

For applications above 15 kV:

$$E = 5.12x10^5 V I_{bf} \left(\frac{t}{D^2} \right) \qquad (2)$$

where:

E_n is the incident energy (cal/cm^2) normalized for a specific time and specific distance from the arc
E is the incident energy (cal/cm^2)
C_f is a calculation factor
1.0 for voltages above 1kV
1.5 for voltages at or below 1kV
t is the arcing time (seconds)
D is the distance from the possible arc point to the person (mm). See Table 1 for typical working distances.
x is the distance exponent from Table 2
I_{bf} is the bolted fault current for three-phase faults (symmetrical RMS)(kA)
V is the system voltage

TABLE 1 – Typical working distances [1]

Classes of Equipment	Typical Working Distance
15 kV switchgear	910 mm
5 kV switchgear	910 mm
Low-voltage switchgear	610 mm
Low-voltage MCCs & panel-boards	455 mm
Cable	455 mm
Other	Determined in the field

TABLE 2 – Equipment factors and voltage classes [1]

System Voltage (kV)	Equipment Type	Typical conductor gap (mm)	Distance x Factor
0.208 - 1	Open Air	10-40	2.000
	Switchgear	32	1.473
	MCC and panels	25	1.641
	Cable	13	2.000
>1-5	Open Air	102	2.000
	Switchgear	13-102	0.973
	Cable	13	2.000
>5-15	Open Air	13-153	2.000
	Switchgear	153	0.973
	Cable	13	2.000

III. Hazard Levels

NFPA 70E assigns relative hazard risk levels depending on the calculated incident energy levels. NFPA 70E also lists an example of typical PPE (Personal Protective Equipment) clothing appropriate to each hazard category. For actual applications, the calculated incident energy must be compared to specific PPE combinations used at the facility being evaluated. The example given in NFPA is shown below in Table 3:

TABLE 3 – PPE Characteristics [2]

Hazard Risk Category	**Typical Protective Clothing Systems**	**Required Minimum PPE Arc Rating (cal/cm^2)**
0	Non-melting, flammable materials (natural or treated materials with at least 4.5 oz/yd^2)	N/A (1.2)
1	FR pants and FR shirt, or FR coverall	4
2	Cotton Underwear, plus FR shirt and FR pants	8
3	Cotton Underwear, plus FR shirt and FR pants and FR coverall	25
4	Cotton Underwear, plus FR shirt and FR pants and multi-layer flash suit	40

Note that the highest defined hazard category is level 4 having an upper limit of 40 cal/cm^2. While PPE is certainly available in ratings well above 40 cal/cm^2, working near exposed energized equipment above 40 cal/cm^2 is discouraged. NFPA 70E notes that “greater than normal emphasis should be placed on de-energizing the equipment” (Annex D.8 FPN) at such high incident energy levels [2]. One possible reason is that PPE is primarily intended for thermal protection. Other factors including physical trauma are very dangerous above 40 cal/cm^2.

IV. Mitigating Strategies

The three most obvious arc flash mitigating strategies are:

a. Reduce the fault current (I_f)
b. Increase the working distance (D)
c. Reduce the clearing time (t)

A. Reducing the fault current

Some protective devices are current limiting by design. Current limiting fuses, for example, are capable of both limiting the magnitude of fault current and duration provided the fault current is within their current limiting range (typically 10-15 times the device rating) [3]. Fault currents below this range must be analyzed like non-current limiting devices (based on the time-current characteristics). Lower level arcing currents can easily result in higher incident energy because the clearing time maybe longer.

Current limiting reactors (CLR) may also be used to limit the available fault current. The disadvantage of a CLR is that it also introduces impedance in the circuit and its associated undesirable voltage drop [4]. In some cases, the cost of a pyrotechnic-operated high-current fault limiter with interrupting ratings exceeding 200kA can be justified [5].

B. Increasing the working distance

Increasing the working distance has a dramatic effect on the incident energy. From equations (1) and (2), it is also apparent that the incident energy level decreases exponentially with increasing working distance. Examples of this strategy include remote racking and the use of extension tools (i.e. hotsticks). However, many tasks may not be able to be accomplished remotely and remote racking devices may not operate as desired.

C. Reducing the clearing time

Referring to equations (1) and (2), it is also evident that the incident energy is directly proportional to the arcing time. The arcing time represents the total fault clearing time. Where a circuit breaker is involved, this time consists of the relay operating time plus the breaker opening time.

According to IEEE Standard 1584™, breaker operating times vary from 1.5 cycles to 8 cycles depending on the class of breaker involved. Table 4 lists the typical operating times referenced in this standard.

TABLE 4 – Power circuit breaker operating times [1]

Circuit breaker rating, type	**Opening time at 60Hz**
Low voltage (molded case) (<1000V) (integral trip)	1.5 cycles
Low voltage (insulated case) (<1000V) (power circuit bkr) (integral trip or relay operated)	3.0 cycles
Medium voltage (1-35 kV)	5.0 cycles
Some high voltage (>35 kV)	8.0 cycles

Relay operating times depend heavily on the type of protection being used. Instantaneous over-current (ANSI device 50) and bus differential (ANSI device 87) are relatively fast with typical operating times of 2-3 cycles. On the other hand, operating times for time over-current elements (ANSI device 51) are very dependent on the current magnitude and can vary from a few cycles to over a second. Time over-current relays are especially slow where coordination with downstream protection requires delayed tripping of upstream relays.

Common methods to reduce the relay operating time include those listed below. Along with each method are listed some advantages (+) and disadvantages (–) of each.

a. Lowered device settings (temporary)
   (+) Inexpensive to implement
   (+) Fairly fast (typically 2-3 cycles)
   (–) Activation requires operator action
   (–) Full selectivity of protection may be lost
   (–) Failure to deactivate could result in undesired tripping
b. Install high impedance bus differential protection
   (+) Fairly fast (typically 2-3 cycles)
   (–) Requires CTs on all circuits
   (–) Prone to CT saturation concerns
c. Install zone interlocking scheme
   (+) Fairly fast (typically 5-10 cycles)
   (+) Inexpensive to implement
   (–) Requires communication between devices
d. Install dedicated arc flash protection
   (+) Very fast (0.15 cycles)
   (+) Fairly inexpensive to implement
   (+) Immune to CT saturation
   (+) Supports arc flash breaker failure protection

V. Dedicated Arc Flash Protection

Arc flash protection is specifically designed to detect and trip for an arc flash event. Arcing time is a critical factor in limiting the damage and risk of personal injury resulting from an arc flash. Consequently, arc flash detection relays must be very fast and typically operate in a few milliseconds. This speed is achieved by detecting the light from an arc flash and by initiating tripping action via solid-state tripping elements.

A. Background of arc flash relaying

An arcing fault instantaneously releases large amounts of radiant energy. The radiant energy includes both light and thermal energy. Light intensities can be thousands of times higher than normal ambient light. This phenomenon is used in arc flash detection relays to achieve faster operating times than is possible with conventional relaying.

Optical sensors detect the sudden increase in light intensity. Instantaneous over-current elements are used as fault detectors to supervise the optical system for security. Only source-connected current transformers (typically at the main breakers) need to be connected. Tripping occurs only if both light and fault current are simultaneously detected. For additional speed, these relays are equipped with high-speed solid state tripping outputs. Total operating time is typically less than 2.5 ms [6].

Arc flash detection systems are stand-alone protection systems. They do not need to be coordinated with existing protection systems. Therefore, it is not necessary to delay tripping for coordination with other protection.

B. First generation arc flash detection relays

Although new to North America, arc flash relays have been around since the early 1990's. Early arc flash protection used only single-point light receptors called "lens sensors". In this system, one or more lens sensors are located in each high voltage compartment where a potential arc flash might occur. Each lens sensor is radially connected to electronics via a clad fiber. Because of the opaque fiber cladding, only the extreme ends of these radial fibers are light sensitive. Each sensor is individually targeted, for more precise location of the arc flash fault. A limited number of sensors may be attached to a common electronic package. Multiple electronic packages are then interconnected to achieve the complete switchgear coverage.

C. Second generation arc flash detection relays

During the year 2000, a second generation of arc flash detection relays was introduced. In addition to the traditional lens sensors mentioned previously, the second generation product also accommodated a radically different type of light sensor, a long unclad fiber optic sensor that can absorb light throughout its length.

There are several advantages to the long fiber sensor technology. First, it dramatically reduces the cost of installation. A single optical fiber sensor can be as long as 200 feet, typically covering the same protection zone associated with conventional bus differential protection but at much lower cost than lens sensors. Second, any concerns about shadows from internal structures that might block the direct exposure to an arc flash are eliminated. Third, if the fiber sensor is configured in a loop, it can provide regular self-checking of the sensor's integrity and continuity, alarming if a problem is detected.

Visible light consists of the light spectrum ranging from 400nm to 700nm wavelengths whereas arc flash test results show that most of the radiated energy is in the range of 200nm to 600nm. Consequently, optical arc flash relays are designed to operate in the lower end of the visible spectrum and slightly lower including ultraviolet light [7].

The optical sensor fiber is available in various lengths up to a maximum of 60m (200 ft). Unlike optical communication fiber, this fiber has no opaque cladding. The lack of opaque fiber cladding allows some of the light to enter through the exposed exterior cylindrical surface, where it propagates back to the electronics. The entire fiber is a sensor, not just the ends of the fiber. This characteristic allows more complete coverage of switchgear cubicles without concern for shadows and without interconnecting a multitude of radial single point light (lens) sensors.

For additional security, the arc flash relay includes a set of conventional 5A current transformer inputs. These are typically connected to the current transformers located on the source side of the main breakers and are used to drive instantaneous phase and ground over-current elements. These over-current elements act as fault detectors, supervising the optical flash detector. They utilize peak-to-peak waveform detectors in order to eliminate delays associated with conventional root-mean-square (RMS) calculations.

In normal operation, both light and over-current must be present simultaneously for tripping to occur. Detection of an intense light alone will not result in a trip unless the system is intentionally set to operate that way (not recommended).

Over-current settings allow different current threshold levels for phase and ground fault currents. High-speed insulated gate bipolar transistors (IGBT) are used to provide two fully trip-rated outputs rather than relatively slow conventional dry contacts. The overall tripping time is a miniscule 2.5ms.

Figure 1 shows a suggested fiber routing path in a single-high main-tie-main switchgear configuration. This illustration only shows the main fiber routing for the right half of the lineup. The fiber route forms a loop traveling from the electronics, through the breaker compartments, returning through the bus compartment with a slight detour through the VT compartment. A second fiber would be routed in a similar path in the left half of the switchgear lineup. The two fibers would overlap in the tie breaker compartment. A flash anywhere along the right-hand fiber route would result in high-speed tripping of the breakers at Main-2 and Tie positions. Similarly, a flash anywhere along the left-hand fiber route would result in high-speed tripping of the breakers at Main-1 and Tie positions.

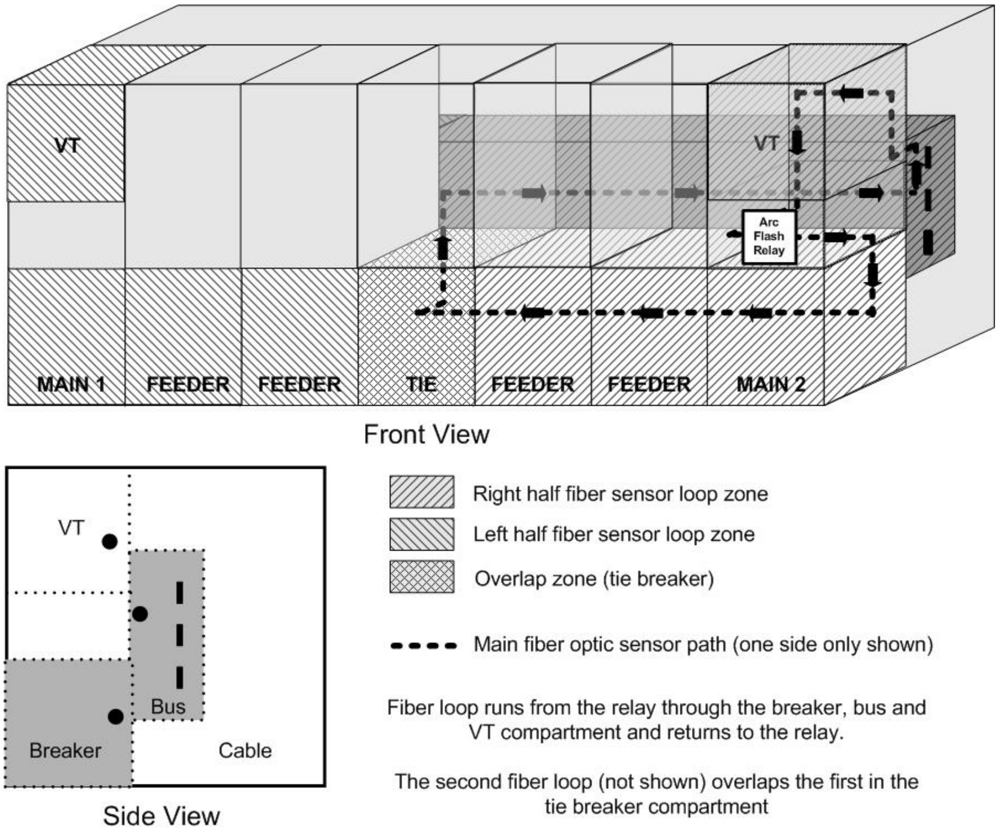


Fig. 1. Suggested fiber sensor routing in single-high switchgear [8]

The routing paths of each fiber should take into account which breaker(s) should be tripped. Each fiber represents a common tripping action or protection zone. Regardless of where the flash occurs along the fiber, the same breakers will be tripped. In order to achieve the desired selectivity, separate fibers should be used for each protective zone along with the appropriate extension units for selectivity in tripping.

Note that the main fiber loop shown in Figure 1 does not enter any of the cable compartments. An arc flash in one of these compartments should only cause the appropriate feeder breaker to be tripped, not the entire bus since a fault in this zone is downstream from the feeder breaker.

There are two ways to handle this situation. One solution is to install individual fiber sensors and their appropriate electronics (extension unit) in each of the cable compartments. This effectively makes each cable compartment a separate arc flash zone. Alternatively, one could use a feeder relay that combines conventional over-current protection with optical arc flash protection using lens sensors mounted in the cable compartment [9].

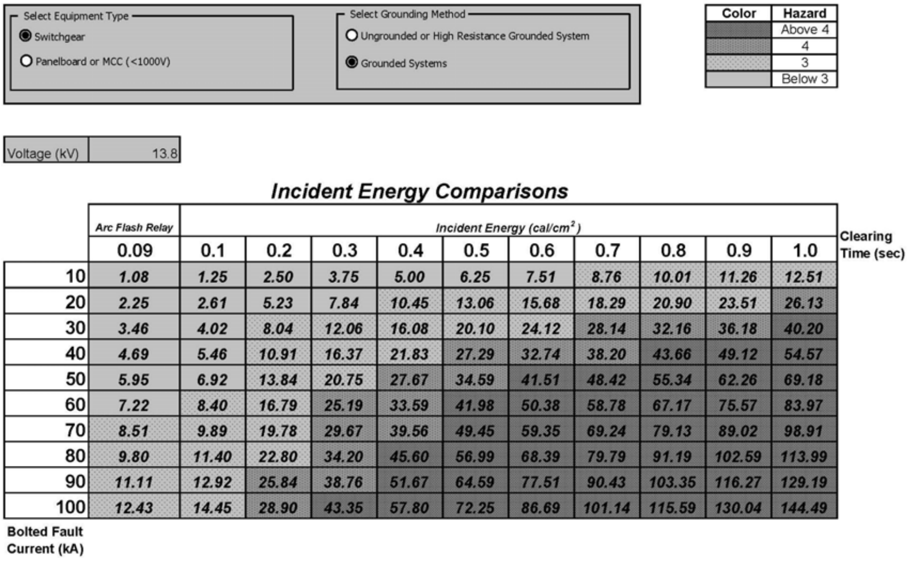
VI. Reducing Incident Energy With Arc Flash Protection

Incident energy is directly proportional to the total clearing time. Table 5 shows this relationship and lists examples of potential incident energies that might be present in 13.8 kV grounded metal-clad switchgear under worst-case assumptions. In this chart, incident energies are shown as a function of total clearing time and available bolted fault current per the IEEE Standard 1584™. Each interior cell shows the calculated incident energy level in cal/cm^2. The column marked "Arc Flash Relay" is based on a total clearing time of 0.9 seconds. This clearing time consists of 2.5ms (arc flash detection) plus 84ms (5 cycles) for the breaker operating time. Cell shading indicates the hazard level as defined by NFPA 70E and listed earlier in Table 3.

Table 5 illustrates the relationship between total clearing time and incident energy. It also illustrates the potential reduction in hazard levels and associated PPE (Personal Protective Equipment) levels when an ultra high-speed arc flash detection system is installed.

How much improvement is realized depends on the speed of the existing protection. The direct and indirect damages associated with an actual arc flash explosion would be smaller and production downtime would likely be shorter as well.

Table 5 - Incident Energy Comparisons



Select Equipment Type
● Switchgear
○ Panelboard or MCC (<1000V)

Select Grounding Method
○ Ungrounded or High Resistance Grounded System
● Grounded Systems

Color	Hazard
■	Above 4
▓	4
░	3
▒	Below 3

Voltage (kV)	13.8

Incident Energy Comparisons

	Arc Flash Relay	Incident Energy (cal/cm^2)										
	0.09	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0	Clearing Time (sec)
10	1.08	1.25	2.50	3.75	5.00	6.25	7.51	8.76	10.01	11.26	12.51	
20	2.25	2.61	5.23	7.84	10.45	13.06	15.68	18.29	20.90	23.51	26.13	
30	3.46	4.02	8.04	12.06	16.08	20.10	24.12	28.14	32.16	36.18	40.20	
40	4.69	5.46	10.91	16.37	21.83	27.29	32.74	38.20	43.66	49.12	54.57	
50	5.95	6.92	13.84	20.75	27.67	34.59	41.51	48.42	55.34	62.26	69.18	
60	7.22	8.40	16.79	25.19	33.59	41.98	50.38	58.78	67.17	75.57	83.97	
70	8.51	9.89	19.78	29.67	39.56	49.45	59.35	69.24	79.13	89.02	98.91	
80	9.80	11.40	22.80	34.20	45.60	56.99	68.39	79.79	91.19	102.59	113.99	
90	11.11	12.92	25.84	38.76	51.67	64.59	77.51	90.43	103.35	116.27	129.19	
100	12.43	14.45	28.90	43.35	57.80	72.25	86.69	101.14	115.59	130.04	144.49	

Bolted Fault Current (kA)

VII. Arc flash relaying in air magnetic switchgear

Optical arc flash relaying is ideally suited to equipment with vacuum or SF6 interrupters, the predominant form of medium voltage circuit technology during recent years. These interrupters are sealed and normal fault interruption is contained within the sealed interrupters. Therefore, any light flash is cause for concern. A simultaneous light flash and fault current detection represents an arc flash event.

Older air magnetic breakers operate differently. In this type of breaker, an arc is drawn in air during normal fault interruption. The arc is extinguished by blow-out coils that create magnetic forces causing the arc to be elongated and segmented. Most of the light is contained within the arc chutes but these chutes are not completely sealed. Concerns have been raised about whether optical arc flash relaying is appropriate for air magnetic circuit breakers. In other words, will sufficient light escape the arc chutes to cause undesired tripping during normal fault clearing?

To answer this question, high-current tests were conducted on medium voltage air magnetic switchgear breakers equipped with optical arc flash relaying [10]. Two representative breakers were chosen for testing, a 13.8-500-5H-1200 (15kV class, 1200A, 500MVA) GE Magneblast™ breaker and a Westinghouse 50DHP™-250-1200 (5kV class, 1200A, 250 MVA) breaker. Each was installed in a single switchgear frame and equipped with ten arc flash relays utilizing long fiber and single-point lens sensor technologies.

The ten arc flash relays represented different optical fiber paths, exposed fiber paths, lens sensor locations and light threshold settings. Downstream three-phase faults were staged at three different levels and each test was run three times.

Tables 6 and 7 represent the results of the medium voltage testing on the Westinghouse DHP™ breaker. Tables 8 and 9 represent the results of the GE Magneblast™ breaker tests.

Table 6
Westinghouse DHP™ Trip Tests
Using Long Fiber Sensor Technology

	3 kA	**10 kA**	**20 kA**
Minimum Light Setting	No	Some(1)	NA(2)
Medium Light Setting	No	No	NA(2)
Maximum Light Setting	No	No	NA(2)

Note 1: Some trips occurred with long fiber exposure. No trips occurred for fibers placed 2 ft. below the top of the arc chutes.

Note 2: Circuit breaker failed during test. However, the arc flash relay correctly tripped for all settings.

Table 7
Westinghouse DHP™ Trip Tests
Using Lens Sensor Technology

	3 kA	**10 kA**	**20 kA**
Minimum Light Setting	Yes	Yes	Yes
Medium Light Setting	Yes	Yes	Yes
Maximum Light Setting	Yes	Yes	Yes

Table 8
GE Magneblast™ Trip Tests
Using Long Fiber Sensor Technology

	3 kA	**10 kA**	**20 kA**
Minimum Light Setting	No	No	No
Medium Light Setting	No	No	No
Maximum Light Setting	No	No	No

Table 9
GE Magneblast Trip Tests
Using Lens Sensor Technology

	3 kA	**10 kA**	**20 kA**
Minimum Light Setting	No	No	No
Medium Light Setting	No	No	No
Maximum Light Setting	No	No	No

The GE Magneblast™ breaker tests indicate that optical arc flash relaying with either technology may be applied. The GE breaker's arc chutes allow relatively little light to escape during normal fault clearing and no arc flash trips occurred for any of the test.

The Westinghouse DHP™ breaker arc chutes allow much more light to escape. In this case, proper positioning of the fiber is critical. Care should be taken to avoid direct exposure of the fiber directly above or near the top of the arc chutes. When the fiber was located two feet below the top of the arc chutes, no trips were recorded. On the other hand, false detection using lens sensors occurred at all fault current levels.

Unfortunately, the complete range of tests could not be completed on the Westinghouse DHP™ breaker because the breaker under test had not been properly reconditioned prior to the test. One phase failed to interrupt during the 20kA fault and the upstream test facility breaker was required to clear the fault. However, all of the arc flash relays did detect this event.

As a result of these tests on older medium voltage air magnetic breakers, it is the generally recommended that any fiber sensor be located well below the top of the arc chutes to minimize exposure to any "normal" light flash as a result of clearing downstream faults. Also, a "straight-through" path is suggested since there is ample light sensitivity built into the system. An uncontrolled arc flash will extend well beyond the arc chutes, greatly increasing the available light.

VIII. Field Experience With Arc Flash Relays

Fortunately, arc flash events are relatively rare although perhaps not as rare as one might think. At the 11th annual IEEE-IAS Electrical Safety Workshop, statistics presented from a National Institute for Occupational Safety and Health study showed that during the period from 1992 through 2001, there were 44,363 electrical-related injuries involving days away from work. The number of nonfatal electrical shock injuries was 27,262, while 17,101 injuries were caused by electric arc flash burns and the amount of time away from work is significantly higher for arc flash burns than as a result of electrical shock injuries [4] [11]. A large percentage of these accidents occur while workers are directly exposed to energized conductors, often during the process of racking breakers in or out.

Over 3,500 arc flash detection systems utilizing long fiber optic sensor technology have been installed in 36 countries worldwide over the past 6 years. There have been at least two documented cases to date where an arc flash accident occurred in medium voltage switchgear protected by arc flash relays utilizing the long fiber sensor technology. These two events are described below.

A. Case #1: Detramovice Power Plant (6/26/2002) [12]

During the morning shift at the Detramovice Power Plant in the Czech Republic on June 26, 2002, two workers were exercising a 6.3 kV breaker that had been withdrawn to its test position. Unfortunately, they forgot that the breaker was closed as they tried to push it into the operation position. The mechanical interlocks were bypassed as they forced the breaker into position. This, in turn, initiated an arc that could have caused extremely serious consequences.

Fortunately, the switchgear was equipped with dedicated arc flash relays utilizing long fiber sensor technology. Within 82 ms, the entire substation was disconnected and a major catastrophe was averted.

Eyewitnesses reported that the cubicle room was full of white sticky smoke from burned plastic but that was the extent of the damage. Repairs consisted of cleaning the breaker and cubicle as well as replacing the breaker rosette and cubicle pins. Figure 2 shows photos taken immediately following the incident. No permanent damage to the installation or surrounding equipment was encountered and the plant was quickly returned to service thanks to the fast reaction time of the arc detection system. More importantly, however, both workers escaped injury and possible death.

Had the arc protection system not been installed, the estimated direct cost of the physical damages could have been as high as $1.6 million USD [13]. Indirect losses including extended loss of production would probably have been many times higher yet.

A similar accident at this same plant occurred in 1979 well before the installation of dedicated arc flash relaying. That incident resulted in 3-day outage. Lost production and equipment damages totaled several million dollars for the event.

Fig. 2. Detmarovice 6/26/02 event photos

B. Case #2: Kemira Grow How event [14]

Kemira Grow How has a fertilizer plant located in Uusikaupunki, Finland. Energy consumption is 18 MVA and the plant also has 7 MVA of on-site generation. Primary products are fertilizers for farms, greenhouses, gardens and forests.

In 2003, the Kemira Grow How plant narrowly avoided a major catastrophe just one day after fiber optic based arc flash relaying had been installed in 1965 vintage medium voltage switchgear.

The arc flash event was initiated when a disconnect switch was opened but failed to extinguish the arc. The disconnect switch that was being opened fed a long underground cable, not normally energized. Due to the capacitive no-load current in the cable, the air disconnector switch could not extinguish the arc. Instead, the arc progressed to the bus compartment, where it evolved into a three-phase bus fault. According to Jari Lintula, Electrical Department Manager, the accident was the result of human error.

Jari Lintula (Manager) and Pentti Laine (Technician) were working in the same room when the flash occurred. Neither was injured although both were a bit shaken.

The just-installed arc flash relaying system detected the arc flash and tripped before the switchgear could sustain any significant damage. The plant was restored to service in a few hours. Had dedicated arc flash relaying not been installed, protection would have depended on conventional over-current relaying. The clearing time would have doubled. The incident energy would have doubled as well. It is difficult to estimate the damage that would have occurred but it would most likely have been quite expensive. One day of lost production costs millions of dollars.

Arc flash relaying was originally installed at this site as insurance to limit the direct and indirect damages associated with an electrical accident. The investment was paid back many times over in one day.

IX. Conclusions

Ultra-fast clearing of arc flash faults is essential in controlling arc flash hazards. Reducing the arcing time through faster detection is the most practical means of lowering incident energy levels and improving workplace safety.

Incident energy is directly proportional to arcing time. Even a few milliseconds improvement may shift hazard levels and PPE requirements to lower categories.

Optically based arc flash relaying is the fastest protection available with a typical operating time of less than 2.5ms. The development of long fiber light sensors have made this protection practical for both new and retrofit applications.

Optical arc flash protection technology has a proven track record with over 5 years experience and over 3,500 installations. Optical arc flash relays are ideally suited to modern vacuum and SF6 breaker technologies where the fault interruption takes place inside a sealed container. However, with proper precautions, optical relay may also be applied to air magnetic breakers as well.

Beyond the installation of dedicated arc flash relaying, arc flash mitigation strategies should also consider replacing older air magnetic breakers (typical operating time of 5 cycles) with modern vacuum and SF6 technology (typical operating time of 3 cycles or less).

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XI. BIOGRAPHIES

Robert A. Wilson is a Regional Technical Manager for ABB Inc. in Houston, Texas. He received his BSEE degree from Purdue University in 1974 and his MSEE degree from Carnegie Mellon University in 1976. He is a Senior Member of IEEE and a Registered Professional Engineer in Texas and Pennsylvania.

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