An Effective Approach to Retrofit Existing Station Service Distribution Systems in a Hydroelectrical Generating Station

By

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Abstract

A Station Service Distribution System (SSDS) plays an important role in a hydroelectric generating station. It provides a reliable power source to feed various loads inside a generating station. Throughout years of operation, SSDS equipment could fail due to aging, and replacement parts may not be readily available. The utilities are, therefore, facing many challenges in maintaining the SSDS system availability and protecting the safety of the site personnel in generating stations.

This thesis proposes an effective approach and several methodologies to resolve the engineering challenges related to retrofitting an existing station service distribution system in a hydroelectrical generating station. The approach does not follow the traditional technical path, but rather a techno-economic method considering system robustness, operation cost, and safety from a long-term point of view. The approach and methodologies developed in this thesis are evaluated in a case study to validate their applicability.

Conclusions show that the developed approach and methodologies effectively improve the station service distribution system in a hydroelectrical generating station. The same approach and methodologies can be applied to any generating stations facing with similar issues.

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List of Abbreviations

- CSA: Canadian Standard Association
- CLR: Current-Limiting Reactor
- CT: Current Transformer
- DTC: De-energized Tap Changer
- GCB: Generator Circuit Breaker
- HRC: Hazard Risk Category
- IEEE: Institute of Electrical and Electronics Engineers
- LV: Low Voltage
- MV: Medium Voltage
- OLTC: On-Load Tap Changer
- PCB: Polychlorinated Biphenyls
- PPE: Personal Protective Equipment
- PT: Potential Transformer
- SSDS: Station Service Distribution System
- SST: Station Service Transformer
- TCC: Time Current Curve

Chapter 1 - Introduction

Hydroelectricity has been the main source of power generation in Canada for more than a century. In 2015, about 60% of Canada's electricity was produced by hydroelectric generating stations [1]. A hydroelectric generating station produces electricity by having water fall through a directed channel to propel a hydro turbine, which in turn drives a generator. A typical hydroelectric generating station consists of:

- A powerhouse: A building that houses turbines, generators, intake and tailrace gates, control and protection devices, and auxiliary equipment. It is the heart of a generating station where electricity is produced.
- A reservoir: An artificial lake to store water for power generation that provides flood control at the same time.
- A spillway structure: A flood control structure with a number of spillway gates to maintain proper and regulated water level in a reservoir.
- A switchyard: A substation that houses a generator step-up transformers (GSU), high voltage (HV) breakers, HV disconnect switches, and various other electrical equipment. The electricity is stepped-up to a much higher voltage in the switchyard to be transmitted to reduce transmission losses.

Figure 1.1 shows a cross sectional view of a typical hydroelectric generating station.

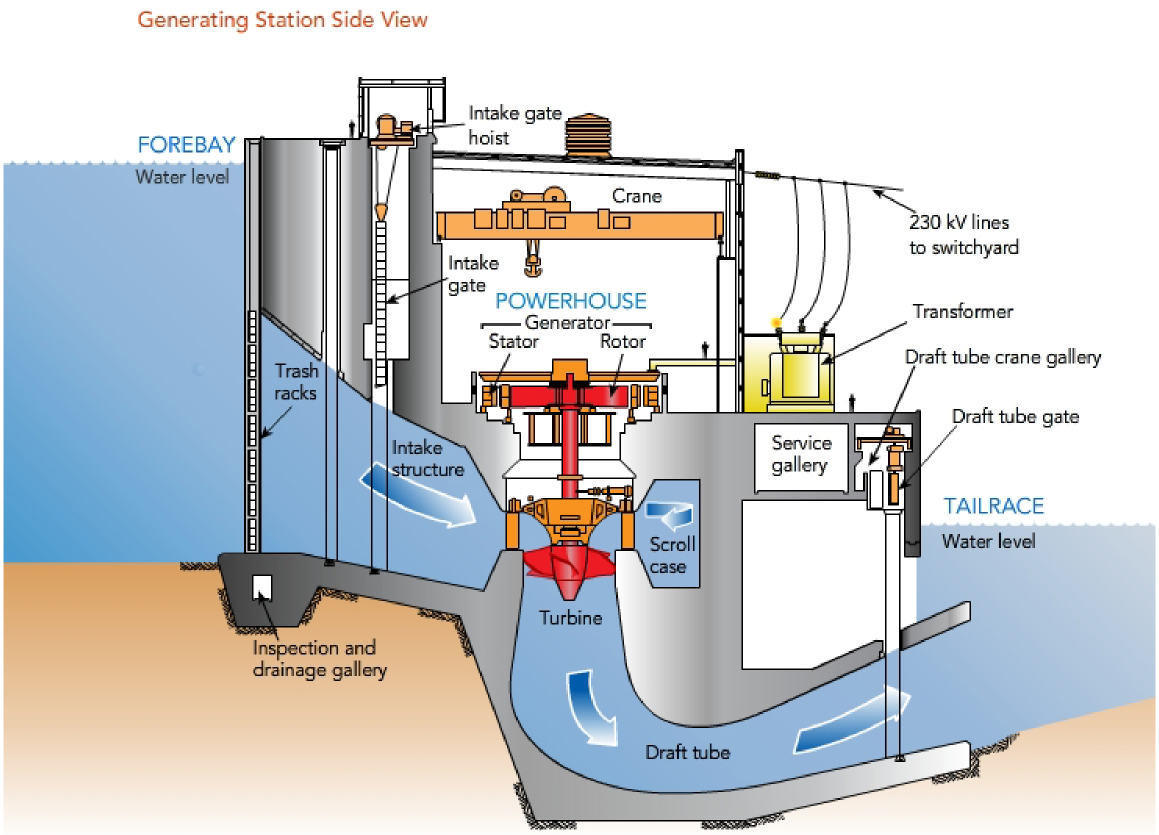


Figure 1. 1 – Cross-sectional view of a generating station intake and powerhouse

Courtesy of Manitoba Hydro [2]

1.1 Problem Definition

A Station Service Distribution System (SSDS) plays an important role in a hydroelectric generating station. It is a key to provide a reliable power source to feed various loads inside a generating station. Throughout years of operation, SSDS equipment could fail due to aging and experience difficult maintenance issues. The utilities are, therefore, facing numerous challenges in maintaining the supply robustness and protecting the safety of the site workers in a generating station. It becomes necessary to retrofit/upgrade existing SSDS systems.

There are design guides published by IEEE for electrical power service systems; they provide essential design criteria and sound practices in general. However, these design guides do not address any ongoing issues with existing generating stations.

A recent literature review indicates that there is no studies or published papers to deal with common engineering challenges (such as high fault level on a generator bus), and how to retrofit and/or improve a station service distribution system in a hydroelectrical generating station.

1.2 Motivations of Research

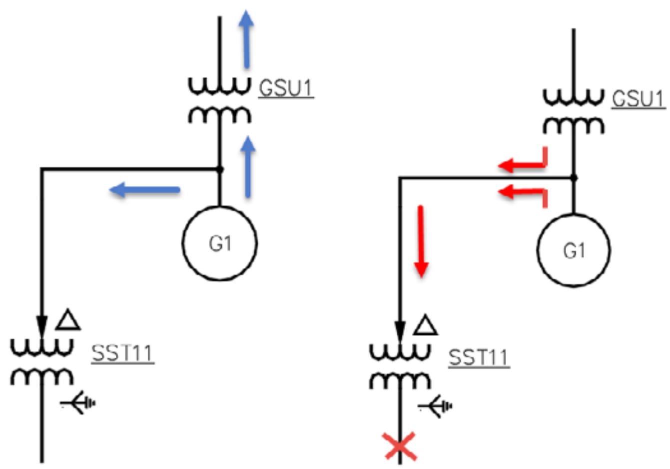
A literature review indicates that there are no well-established approach and procedures to deal with existing hydroelectrical generating station SSDS systems. This thesis aims to develop a systematic approach and several methodologies to resolve technical issues for long-term system availability, operation maintenance, and safety of a hydroelectric generating station.

1.2.1 High Fault Current Level on Generator Bus

Many large hydroelectric generating stations throughout the world directly connect their station service transformer and generator step-up transformer (GSU) to the generator main bus [3]. From a technical standpoint, the generator is the most reliable power source within the entire station. In case one or multiple generators are out of service, it is possible to back-feed the station loads from the outside system grid via a GSU.

However, this scheme leads to high fault current levels on the generator bus; and the SST will be exposed to unacceptable thermal and mechanical stresses upon a fault at its secondary side.

As an example, Figure 1.2(a) shows that each generator bus consists of one generator, one SST transformer, and one GSU transformer. During normal operating conditions, the generator is the source. It deliveries power to the outside grid and supply station loads via SST. Upon a fault on the secondary of the SST transformer, the outside grid and generator behave as sources of current; they all feed the fault location as illustrated in Figure 1.2(b).



(a) (b)

Figure 1. 2 – Current Flow Before and After a Fault Occurs

(a) before the fault occurs; (b) after the fault occurs

1.2.2 Need for Review - Protection System

In general, due to the high fault current level on the generator bus, the station service transformer protection system needs to be reviewed.

Protection CTs are designed to work in their linear region. Once the CT becomes saturated it can introduce unacceptable errors and cause improper operation of the protective devices. As the CT's primary current increases, the voltage across the secondary also increases. If the CT's primary current is many times larger than its rated current, high voltage spikes may be developed and damage the CT insulation [4].

Furthermore, the high fault current may damage the protective equipment. For example, Schweitzer transformer protection relay, SEL-787, is a powerful multifunction relay. It provides transformer over-voltage protection, over-current protection, differential protection, and more. In the specification section of the relay data sheet, it specifies that 1-second thermal limit of the relay CT input is 500 A [5]. If the relay sees more than 500 A current at the CT input, the relay will be damaged.

1.2.3 Non-compliance of Modern Codes and Standards: Arc Flash Hazards

Power generation, transmission, and distribution have been around for over 100 years, and their associated studies are well-established. Arc flash related topics are relatively new but have drawn a great deal of attention to enhance workers' safety. Numerous regulatory bodies and jurisdictions, including NFPA, IEEE, and CSA, have specific codes/standards on these subjects. Utilities are required to comply with the latest version of safety codes and standards.

Arc flash is a condition of sudden release of energy due to an electrical arc [6]. An electrical arc is a flashover through air in electrical equipment from one conductor to another conductor or ground. During an electrical arc flash, air becomes conductive. Highly intense heat, sound blast, and pressure waves can be produced by an electrical arc. The heat produced by the arc can reach up to 35,000 °F, which is four times the surface temperature of the sun. This extremely high temperature can cause serious burn or fatality [7].

Existing hydroelectric generating stations typically rely on overcurrent protection to clear low voltage station service faults. Traditionally, protection coordination is targeted at system availability, which means upon a fault the branch circuit shall be tripped prior to the main feeder circuit. As long as the main feeder circuit breaker and branch circuit breaker settings do not overlap with a margin, from a protection point of view it is considered appropriate. Arc flash hazard analysis defines a new approach for protection. Arc fault current and arc fault duration are the two major factors contributing to the hazard level. Protective devices typically have large setting ranges, and there are no set rules how to set up protective devices; all of these can cause unintentionally high arc flash hazard level.

Arc flash hazard is the total amount of energy, known as incident energy, exposed to human skin at a specified distance. It is measured in J/cm² or cal/cm²; it is common to measure it in cal/cm² in Canada. Table 1.1 summaries the arc flash hazard risk category vs incident energy [7]. Any work whose incident energy exceeds 40 cal/cm² is considered dangerous, since workers cannot be protected from the blast's energy wave.

Table 1. 1 – Arc Flash Hazard Risk Category vs. Incdient Energy

Arc Flash Hazard Risk Category	Incident Energy (cal/cm²)
0	Less than 1.2
1	>1.2 and ≤4
2	>4 and ≤8
3	>8 and ≤25
4	>25 and ≤40

Arc flash incident energy is proportional to the fault current, duration of the fault, and arc flash boundary. However, from historical incident data, the majority of arc flashes occur during equipment maintenance or troubleshooting, when workers accidently interact with energized electrical equipment. High fault current and slow fault clearing time mostly contribute to higher incident energy. Figure 1.3 depicts the relationship between fault current and duration of the fault. Example shows for the same fault current, the longer takes to clear the fault, the higher resulted incident energy is.

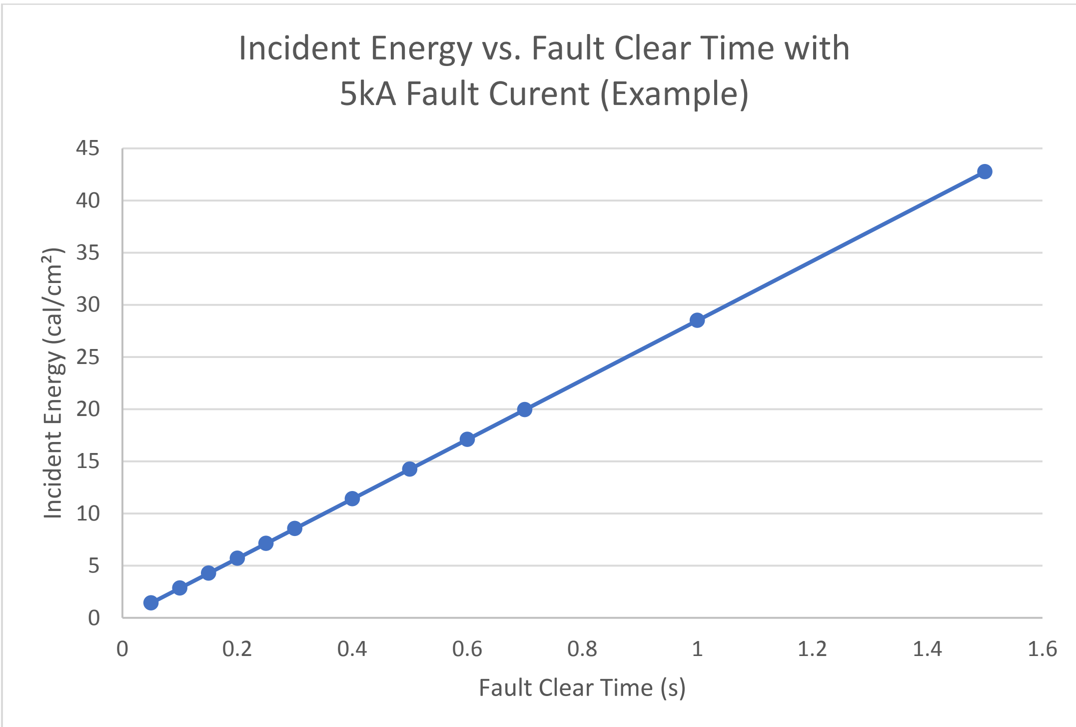


Figure 1.3 - Incident Energy (kA vs time)

1.3 Objective

The objective of this thesis is to develop and evaluate a general approach and several methodologies to resolve the above common issues identified in Section 1.2 for a typical hydroelectric generating station SSDS system. The approach does not follow the traditional technical path, but rather a techno-economic approach considering system robustness and availability, operation cost, and safety from a long-term point of view. The approach and methodologies developed in this thesis are evaluated in a case study to validate their applicability. The same approach and methodologies can be applied to any generating stations facing similar issues.

1.4 Thesis Organization

This thesis is divided into five chapters as described below:

- Chapter 1: Introduces the thesis, describes the problem definition, research motivation, and contributions;
- Chapter 2: Discusses findings of recent journal papers, and identifies shortcomings. Completion of IEEE standards reviews provides the general approach and methodologies guidelines. All the findings from this chapter help to develop the general approach discussed in Chapter 3;
- Chapter 3: Proposes and discusses a new system configuration to retrofit the existing SSDS system. The new configuration is generic and can be applied to any generating stations facing with the similar issues;
- Chapter 4: Applies and evaluates the new system configuration and validates its applicability;
- Chapter 5: Concludes the thesis with a discussion of future work.

Chapter 2 - Literature Review

2.1 Hydroelectric Station Service Distribution System

Existing literature on the topic of hydroelectric generating station service distribution system is quite sparse with the exception of “Station Service Systems for Large Hydroelectric Generating Stations” by Victor Tawtel and Roderick Stuart [3]. This article provides a high-level overview of factors that need to be considered when designing large hydroelectric generating stations. It classifies station service load types, evaluates different locations to tap SST, and provides sizing guidance of a SST. This article was published in 1968 and most of its recommendations and design factors are still valid; however, it does not assess risks associated with each design consideration. Moreover, it does not foresee the common engineering challenges discussed in Chapter 1, and neither provides possible solutions to resolve these technical issues.

2.2 Fault Current Limitation Techniques

It is a common practice to have SST directly connected to the generator bus. However, if the protection system for SST is not well designed, the SST can be catastrophically damaged due to a fault. To reduce thermal and mechanical stresses on the SST upon a fault, it is necessary to limit the fault current level on the generator bus that is seen by the SST. In general, there are two ways to limit the fault current: the first way is to add a current limiting reactor, and the other is to utilize a current limiter [8].

As Terence Hazel discusses in his paper, a current limiter typically has three components: an explosively section-able conductor (virtually zero impedance), a current limiting fuse (high impedance), and a fast trigger device [8]. During normal operation, the current flows through the conductor, which effectively shorts out the current limiting device. Upon detection of a fault current by the trigger device, it ignites the explosive and interrupts the current path on the conductor, and forces the fault current to go through the current limiting fuse. A current limiter is complicated in operation, and requires careful maintenance of the trigger device.

Compared with a current limiter, a current-limiting reactor (CLR) is not only more economical but also has negligible negative effects on the system reliability [9]. Also, it becomes more common to utilize a dry type air core CLR, because an air core reactor has a fixed reactance at all currents, including a high-magnitude fault [10]. This is an important characteristic of an air core reactor. Adding a current-limiting reactor at the feeder side provides partial isolation of the load side from a feeder fault. Moreover, using a CLR on the feeder circuit reduces the required short-circuit interruption capability of a circuit breaker [11].

There are excellent papers that illustrate air core CLR applications in high voltage transmission. It is well known that a CLR can affect both Transient Recovery Voltage

(TRV) and Rate of Rise of Recovery Voltage (RRRV). However, very little has been focused on and studied for medium and low voltage applications inside a hydroelectric generating station powerhouse. None of the resources in literature analyze the effects and mitigation of impacts on medium voltage vacuum breaker associated with CLRs in a hydroelectric generating station SSDS system.

2.3 CT Saturation Determination

In a power system, current is normally too high to be directly measured. A current transformer (CT) is used to make indirectly measurement of the power current.

Like any transformer, the basic concept of CT is electromagnetic induction. When a current flow through the primary winding of a CT, it creates magnetic fields and in turn generates magnetic flux around the core. By the same concept, magnetic flux around the core generates secondary current when the secondary winding connects a load (burden). A CT normally have a single turn or a few turns at the primary winding, and a large number of turns at the secondary winding [12]. The typically secondary current of a CT is either 1A or 5A rated.

Ideally, the CT secondary current shall be in-phase of the primary current, and also shall be proportional to the primary current in magnitude. When a fault current with large magnitude flows the CT primary winding, it is maxed out magnetic flux density of the CT core, then CT is saturated. As mentioned in Chapter 1, once the CT becomes saturated it can introduce unacceptable errors and cause improper operation of the protective devices. There are two types of CT saturation, symmetrical saturation (AC saturation) and asymmetrical saturation (DC saturation). It is very important to exam whether the CT is subjected to AC and/or DC saturation at the given fault current.

AC saturation is due to CT core cannot handle the high magnitude of the primary current for a given burden. When the core reaches the maximum flux density, even though the current is still flowing through the CT primary winding, there is no more magnetic flux change, the CT secondary terminal voltage drops to zero, and hence the secondary current drops to zero as well [12].

DC saturation is caused by a DC offset in the primary current. A high DC offset, can cause CT quickly becomes saturated. The DC offset decays with a DC time constant. The larger X/R ratio, the longer the DC time constant, it takes more cycles to have current peaks becomes symmetrical.

2.3.1 CT AC Saturation Analysis

The following Formula 2.1, cited from Hargrave, Thompson and Heilman’s paper [12], can be used to analyze whether CT is subjected to AC saturation.

$$\frac{I_{fault}}{I_{Prim}} \times \frac{Z_B + R_s}{Z_{B,STD} + R_s} \leq 20 \tag{2. 1}$$

where,

I_{fault} is the maximum fault current that flows through CT primary winding;

I_{Prim} is the CT primary current rating. For example, 400:5A CT, I_{Prim} is 400;

Z_B is the CT secondary burden;

R_s is the CT internal resistance;

$Z_{B,STD}$ is the standard burden of the CT. For example, for a C400 CT, $Z_{B,STD}$ is 4 ohm.

However, it is very unlikely to have a symmetric fault current. When a short-circuit fault occurs, there will always be a DC offset in the short-circuit current; this is known as asymmetrical current. Therefore, it is more practical to analyze CT DC saturation.

2.3.2 CT DC Saturation Analysis

The following Formula 2.2, cited from Hargrave, Thompson and Heilman's paper [12], can be used to analyze whether CT is subjected to DC saturation.

$$\frac{I_{fault}}{I_{Prim}} \times \frac{Z_B + R_s}{Z_{B,STD} + R_s} \times (\frac{X}{R} + 1) \leq 20 \quad (2.\ 2)$$

where,

I_{fault} is the maximum fault current that flows through CT primary winding;

I_{Prim} is the CT primary current rating;

Z_B is the CT secondary burden;

R_s is the CT internal resistance;

$Z_{B,STD}$ is the standard burden of the CT;

$\frac{X}{R}$ is the system *X/R* ratio.

The Formula 2.2 includes system *X/R* ratio to take account of DC offset. The DC offset can cause significant CT saturation. The Formula 2.2 assumes the worst case DC offset waveform, and therefore, is very conservative [12]. However, it provides a handy tool to quickly check whether the given CT is subjected to DC saturation.

2.4 Risk-Based Failure Mode and Effect Analysis (RB-FMEA)

Failure Mode and Effect Analysis (FMEA) has wide applications in manufacturing processes, medical processes, and power systems to identify possible failure modes and causes, and it is a proven way to mitigate the end effects of failures. FMEA is a qualitative approach and is not self-informative. For example, a highly severe but low probably failure mode may have the same scored rating as a less severe with higher probability failure mode.

Risk-Based Failure Mode and Effects Analysis (RB-FMEA) was developed by Salman Kahrobaee and Sohrab Asgarpoor [13]. Unlike the traditional FMEA, the RB-FMEA incorporates the cost associated with possible failure modes. It introduces a new quantitative way for FMEA based on failure probability and the associated cost for the failure rather than a qualitative scaling.

In their paper, Kahrobaee and Asgarpoor developed and used RB-FMEA on wind turbine technologies. For example, they use the resulted Cost Priority Number (CPN) value to find the critical part of the overall wind turbine that is most likely to fail. This method is developed to evaluate different wind turbine technologies. It is a useful tool for designing and manufacturing, but cannot be directly adopted by utility companies.

Utilities have great responsibilities to protect worker safety and the environment. The safety and environmental impacts shall be factored into the overall failure mode analysis. The RB-FMEA model cannot be directly applied to power system analysis and needs improvements and modifications that will be introduced in this thesis.

2.5 Design Guides and Standards

IEEE Standard 666 [14] provides guidance and explains good practices for station service systems in generating stations. It contains examples of single line diagrams and lists typical station service parameters. Safety, reliability, cost, operation, and maintenance are identified as basic design considerations. At minimum, fault considerations and protection coordination shall be evaluated in the design.

2.5.1 Fault Considerations

A short-circuit study is to determine the maximum fault current flowing during an electrical fault. The short-circuit current (fault current) is used to select protective devices and/or to verify short-circuit interrupting capability ratings. There are different types of faults, and they can be classified as three phase faults, phase-to-phase faults, phase-to-ground faults, and phase-to-phase-to-ground faults. Typically bolted symmetrical three phase faults are considered, because it assumes no impedance between the phases and, therefore, often represents the most severe of all fault types mentioned earlier. It is a common practice to perform only three phase fault studies when determining the maximum possible magnitudes of fault currents [15].

2.5.2 Protection Coordination

Protection coordination study is to set protective devices to detect, localize, and interrupt the fault current to minimize the effects of the fault. In a properly designed power system, if an electrical fault occurs on a downstream branch, the branch protective device shall be tripped first; if the branch protective device fails to operate after a given time delay, then the main protective device would operate and provide back-up protection.

Time current curves (TCC) plotted on log-log scale graphs are used to graphically represent how protective devices respond to various levels of overcurrent; they provide a handy tool to review the protective devices coordination. In a TCC plot, current is shown on the horizontal axis with respective voltages, and time is shown on the vertical axis.

Figure 2.1 shows a sample TCC curve [16]. The breaker curves are plotted in light blue and magenta, and the transformer primary fuse curve is plotted in red. The transformer damage curves are plotted in yellow. The solid damage curve represents a de-rating based on winding connection type and the type of fault; the dotted curve represents 100% damage curve. Cable damage curves are in green lines. For a proper protection design, the protecting devices, i.e., breakers, fuses, relays, etc., must be kept to the left of the damage curves. In addition, upon an electrical fault, the branch protection shall be tripped before the main breaker. The main breaker shall serve as backup protection in case the branch circuit breaker fails to operate and interrupt the fault current.

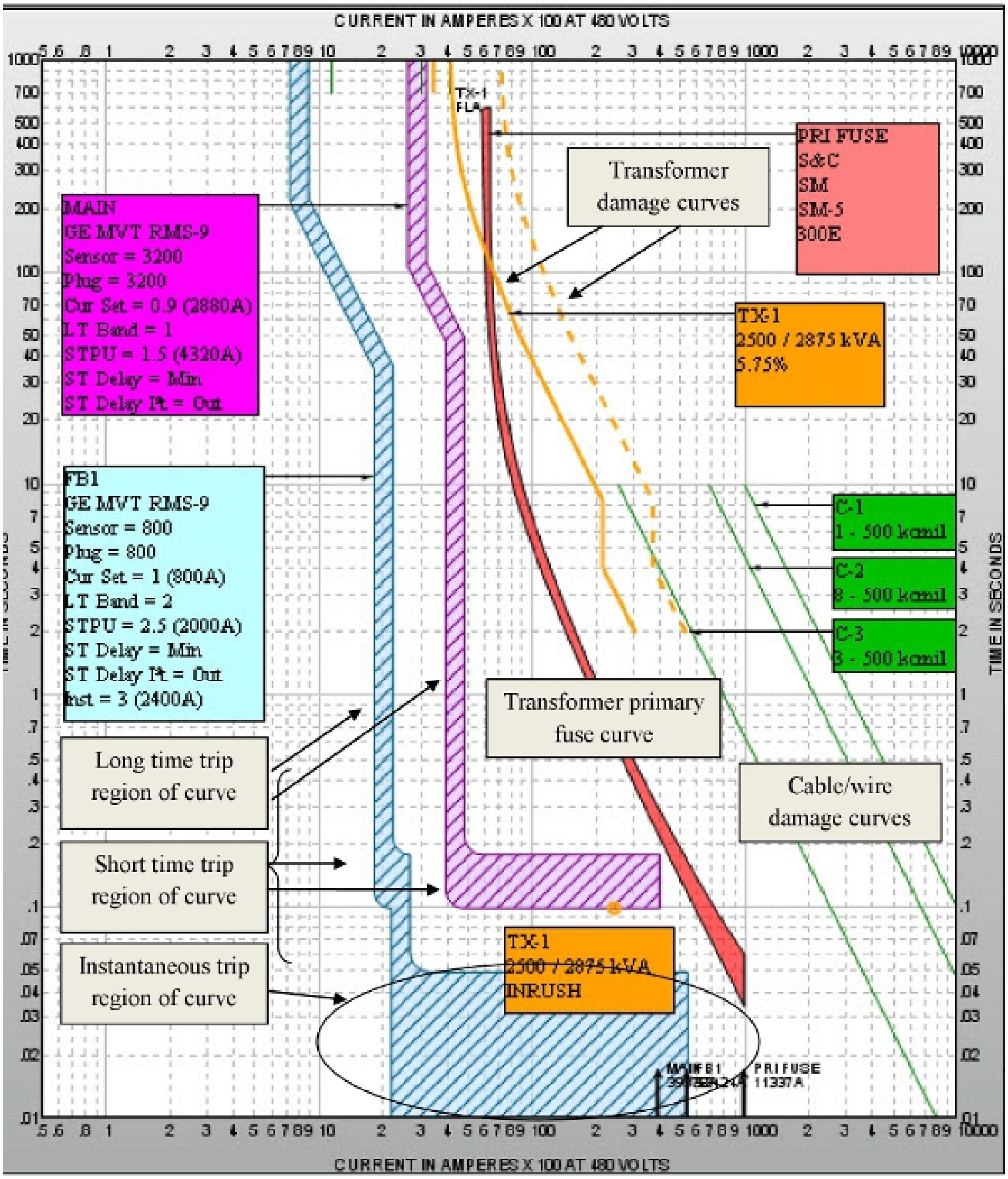


Figure 2. 1 - Sample TCC Curve

Courtesy of David Paul from Maverick Technologies [16]

2.5.3 Modern Industrial Standards for Protective Equipment (Medium- and Low-Voltage Circuit Breakers)

When a short-circuit fault occurs, there will be a DC component in the short-circuit current; this is known as asymmetrical current. The DC component decays with a DC time constant. For the medium and high voltage circuit breakers, the IEEE standard defines the DC time constant as 45 ms, assuming X/R ratio = 17 in a 60 Hz system [17]. The larger X/R ratio, the longer the DC time constant. This could lead to a more difficult scenario to interrupt the short-circuit current.

Unlike MV voltage circuit breakers, which are typically designed and constructed to interrupt the short-circuit current within 5 cycles, low voltage (LV) circuit breakers are typically ½ cycle rated. The currents at ½ cycle after fault initiation are used in calculating the interrupting requirement of low voltage breakers [15]. The circuit breaker interrupting ratings are based on symmetrical rms values. However, most LV circuit breakers operate to interrupt the fault current before the first current peak is reached.

IEEE standards for low voltage breakers have adopted the symmetrical rating structure. Circuit breakers are tested by manufacturers to validate the ability of the device to successfully interrupt the fault current up to the device interruption rating. Depending on the type of the device and its rated short-circuit current, the test current is required to have a specific power factor and test *X/R* ratio. The test setup is summarized in Table 2.1 [18]:

Table 2. 1- LV Circuit Breaker Test Setup

Device Type	Power Factor	Test *X/R*
Low Voltage Power Circuit Breakers (LVPCB)	15%	6.6
Molded Case Circuit Breakers (≤ 10 kA)	50%	1.75
Molded Case Circuit Breakers (> 10 kA but < 20 kA)	30%	3.18
Molded Case Circuit Breakers (≥ 20 kA)	20%	4.9

2.5.4 Arc Flash Hazard Quantification – IEEE 1584

IEEE Standard 1584 provides the most comprehensive formulas to calculate the incident energy releases from an arc flash hazard. The formulas are directly derived from laboratory testing results. The formulas are still widely used and accepted in industrial and commercial sectors for equipment up to 15 kV (3 phase).

The essential analysis process experts from IEEE 1584 are as follows [6]:

1. Calculate the bolted fault current;
2. Determine system voltage and system configuration, either grounded or ungrounded and high resistance grounded;
3. Determine protective equipment operating time;
4. Determine working distance based on equipment and bus gaps;
5. Determine equipment configuration, either open or box;

6. Calculate the arcing currents Ia, and calculate another arcing current equal to 85% of Ia;
7. Calculate incident energy and protection boundary.

The key formula and information to calculate arcing current, incident energy and protection boundary have excerpted from IEEE 1584 and re-stated below [6].

$$\log_{10} Ia = K + 0.662 \times \log_{10} Ibf + 0.966V + 0.00526G + 0.5588V(\log_{10} Ibf) - 0.0304G(\log_{10} Ibf) \quad (2.3)$$

$$\log_{10} Ia = 0.00402 + 0.983 \times \log_{10} Ibf \quad (2.4)$$

$$\log_{10} En = K1 + K2 + 1.081 \times \log_{10} Ia + 0.0011G \quad (2.5)$$

$$E = 4.184 \times Cf \times En \times \left(\frac{t}{0.2}\right) \times \left(\frac{610^x}{D^x}\right) \quad (2.6)$$

$$D_B = \left[4.184 \times Cf \times En \times \left(\frac{t}{0.2}\right) \times \left(\frac{610^x}{E_B}\right)\right]^{\frac{1}{x}} \quad (2.7)$$

where,

Ia is the arcing current (kA);

K is -0.153 for open configuration, and -0.097 for box configuration;

Ibf is symmetrical three-phase bolted fault current (kA);

V is system voltage (kV);

G is the gap between conductors (mm), refer to Table 2.2 for details;

En is incident energy (J/cm^2) normalized for time and distance;

$K1$ is -0.792 for open configuration and -0.555 for box configuration;

$K2$ is 0 for ungrounded or high resistance grounded system and -0.113 for solid grounded system;

E is incident energy (J/cm^2);

Cf is a calculation factor, 1 for voltage above 1kV, and 1.5 for voltage equal or less than 1kV;

t is arcing time;

D is distance from possible arc point to the person (mm);

x is the distance exponent from Table 2.2.

For system voltage less than 1kV, Formula 2.3 shall be used to calculate arcing current, and for system voltage greater than 1kV but less than 15kV, Formula 2.4 shall be used to calculate arcing current.

Table 2. 2- Factors for Arc Flash Incident Energy and Protection Boundary Calculation Excerpt from IEEE 1584 [6]

System voltage (kV)	Equipment type	Typical gap between conductors (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

For a simple radial system, hand calculations using the IEEE 1584 formulas are achievable. To illustrate the process, a spreadsheet is developed by adapting formulas listed in IEEE 1584. Table 2.3 shows results of calculating incident energy, arc flash protection boundary based and arc flash hazard classification. It is a requirement from the standard that incident energy shall also be calculated based on 85% of expected arc current, because 85% of expected arc current takes longer time to clear, thus may result in a higher incident energy.

In the spreadsheet example, the fault current is 12.551 kA at 600 VAC un-grounded system inside a box configuration. The calculated arcing current is 9.689 kA with incident energy of 2.76 cal/cm^2; the overall arc flash risk is classified as category 1 (HRC 1).

The example illustrates the capability of hand calculation with known parameters. However, for non-radial and complex systems, hand calculation using formulas in IEEE 1584 is overly complicated.

Table 2. 3 - Example of Hand Calculation by Using the IEEE 1584 Formulas

Arcing Current		
Parameters	**Value**	**Note**
K =	-0.153	Open Conf.
	-0.097	Box Conf.
Fault Current Ibf (kA) =	12.551	
V (kV) =	0.6	
G (mm) =	25	
Arcing Current Ia (kA) =	9.689477788	
85% of Ia (kA) =	8.236056119	

Incident Energy		
Parameters	**Value**	**Note**
K1 =	-0.792	Open Conf.
	-0.555	Box Conf.
K2 =	0	Un-Gnd
	-0.113	Gnd, HRG
G (mm) =	25	
En (J/cm^2) =	9.924090169	
En (cal/cm^2) =	2.381781641	
85% of En (J/cm^2) =	8.435476644	
85% of En (cal/cm^2) =	2.024514394	
Cf =	1.5	
Arcing time t (s) =	0.018	
Working Dist. D (mm) =	455	
x =	1.641	
Incident Energy E (J/cm^2)	9.068713947	
E (cal/cm^2) =	2.176491347	
85% of E (J/cm^2) =	7.708406855	
85% of E (cal/cm^2) =	1.850017645	

Flash Potential Boundary		
Parameters	**Value**	**Note**
Cf =	1.5	
En =	9.924090169	
Eb =	5	
t (s) =	0.018	
x =	1.641	
Ibf =	12.551	
undary Distance Db (mm) =	654.0085489	
Boundary Distance Db (m) =	0.654008549	

Setting Parameters	
Fault Current Ibf (kA) =	12.551
V (kV) =	0.6
G (mm) =	25
Arcing time t (s) =	0.018
x =	1.641
Configuration (Enclosed or non-Enclosed)	Box Conf.
Ground Configuration	Un-Gronded

Results		
Arcing Current Ia =	9.689	kA
Incident Energy E (Cal/cm^2) =	2.176	J/cm^2
Boundary Distance Db (m) =	0.654	m
Arc Flash Classification	CAT 1	

IEEE 1584 Table 4—Factors for equipment and voltage classes

System voltage (kV)	Equipment type	Typical gap between conductors (mm)	Distance *x* factor
0.208–1	Open air	10–40	2
	Switchgear	32	1.473
	MCC and panels	25	1.641
	Cable	13	2
>1– 5	Open air	102	2
	Switchgear	13–102	0.973
	Cable	13	2
>5–15	Open air	13–153	2
	Switchgear	153	0.973
	Cable	13	2

	J/cm^2	Cal/cm^2
CAT 0	5.00	1.2
CAT 1	16.67	4
CAT 2	33.33	8
CAT 3	104.17	25
CAT 4	166.67	40

	Open Conf.	Box Conf.
K	-0.153	-0.097
K1	-0.792	-0.555
	Un-Gronded	Gnd or HRG
K2	0	-0.113

2.5.5 Arc Flash Hazard Quantification – Constant Energy

What if a work needs to be done without knowing the fault current? In this case, determining the incident energy and arc flash protection boundary will not be possible.

The clearing time of a fault depends on the upper stream protective device or a differential zone protection. *"For a given location, there exists a series of potential arcing fault current magnitudes and theoretical clearing times for which incident energy remains constant"* [19]. The constant energy lines can be plotted with the upper stream protective device TCC curve to determine the arc flash hazard category. This is the easiest and quickest way to quantify the arc flash hazard independently of system maximum available short-circuit.

The governing equation for the constant energy lines is:

$$t = \left(\frac{E}{1.2}\right) \times k \times Ia^{-1.081} \tag{2. 8}$$

where,

E is the incident energy corresponding to different arc flash hazard category, e.g., 1.2 cal/cm^2;

Ia is the magnitude of the arcing current;

k is the unique constant based on various system configuration parameters (refer to Table 2.4).

Table 2. 4 - Constant k Lookup Table [19]

System Voltage (kV)	Calculation Factor (C_f)	Equipment Type	Gap (G) (mm)	Distance factor (x)	Working Distance (D) (mm)	Enclosure Configuration (K_1)	Grounded or Ungrounded (K_2)	Unique Constant (k)
0.208 - 1	1.5	Open Air*	10	2.000	455	-0.792	-0.113	0.6945
							0	0.5354
			40	2.000	455	-0.792	-0.113	0.6437
							0	0.4962
		Switchgear	32	1.473	610	-0.555	-0.113	0.6841
							0	0.5274
		MCC and Panels	25	1.641	455	-0.555	-0.113	0.4304
							0	0.3318
		Cable	13	2.000	455	-0.792	-0.113	0.6893
							0	0.5314
>1 - 5	1.0	Open Air	102	2.000	455	-0.792	-0.113	0.8252
							0	0.6362
		Switchgear*	13	0.973	910	-0.555	-0.113	1.5890
							0	1.2250
			102	0.973	910	-0.555	-0.113	1.2683
							0	0.9778
		Cable	13	2.000	455	-0.792	-0.113	1.0339
							0	0.7970
>5 - 15	1.0	Open Air*	13	2.000	455	-0.792	-0.113	1.0339
							0	0.7970
			153	2.000	455	-0.792	-0.113	0.7252
							0	0.5591
		Switchgear	153	0.973	910	-0.555	-0.113	1.1146
							0	0.8593
		Cable	13	2.000	455	-0.792	-0.113	1.0339
							0	0.7970
* Minumum and maximum values are shown for a range of typical bus gaps (G).								
System parameter values are based on IEEE Standard 1584™-2002, Tables 2, 3, & 4.								

Figure 2.3 illustrates an arc flash hazard assessment by using the constant energy method. As shown in Figure 2.3, there are five constant energy lines have drawn on the circuit breaker TCC curve, each line represents an arc flash hazard risk category level.

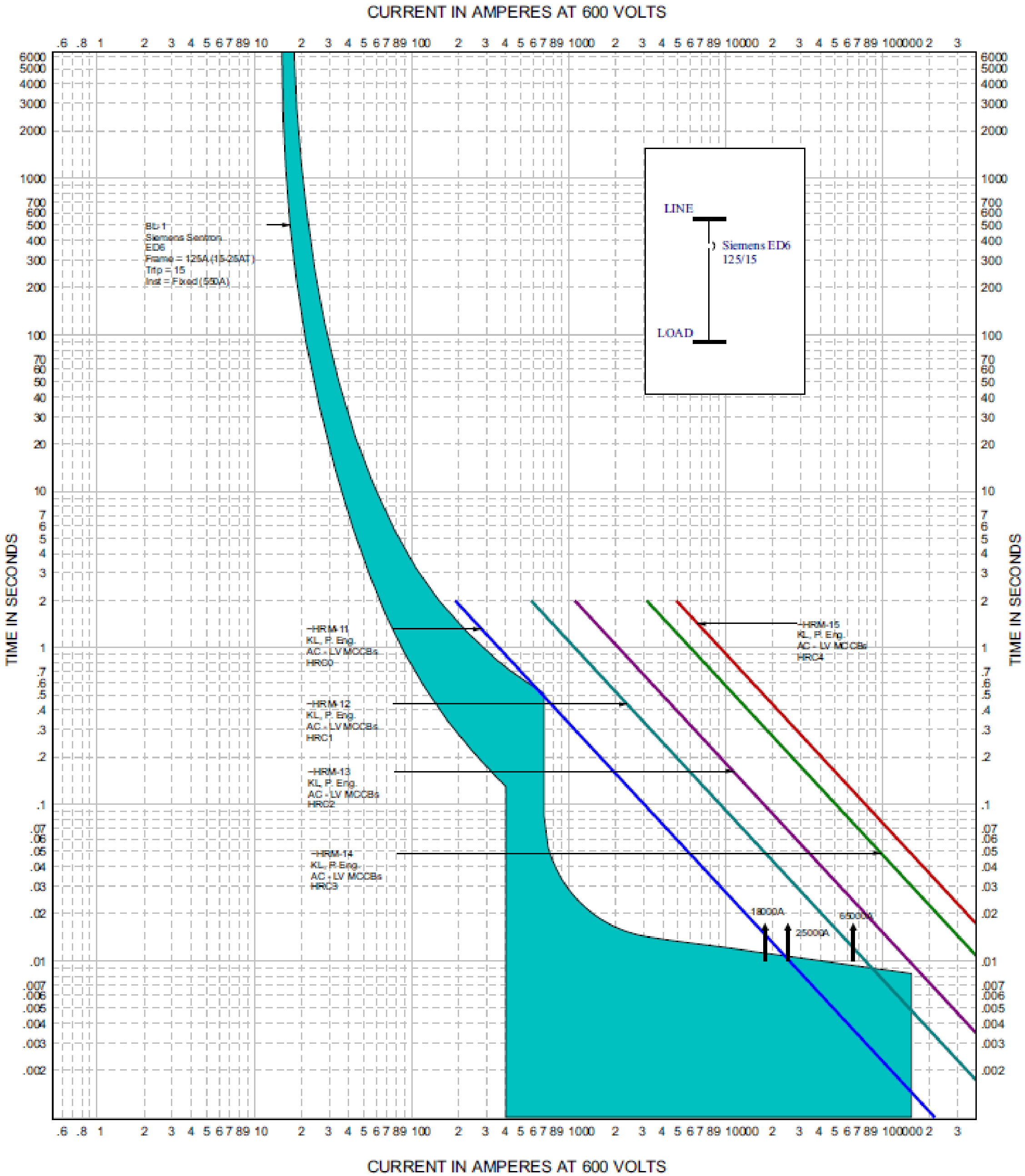


Figure 2. 2 – Example of Constant Energy Arc Flash Assessement

The constant energy lines from left to right represent:

- Blue line: Arc Flash Hazard Risk Category (HRC0);
- Cyan line: Arc Flash Hazard Risk Category (HRC1);
- Purple line: Arc Flash Hazard Risk Category (HRC2);
- Green line: Arc Flash Hazard Risk Category (HRC3);
- Red line: Arc Flash Hazard Risk Category (HRC4);

From right to left, which line intersects with the circuit breaker TCC curve short time trip region first, the arc flash hazard risk category is classified as the next higher level. For example, in Figure 2.3, the blue line (HRC0) line intersects with the breaker short trip region and this breaker is classified as HRC1 risk hazard level. Therefore, downstream any equipment protected by a Siemens ED6 type 15 A molded-case circuit breaker (installed in an electrical panel) is classified as arc flash risk category 1 (HRC 1).

The constant energy line method provides the worst-case energy level and shall only be used as a last resort without the need to perform a detailed short-circuit study. However, the results can be very conservative. The constant energy method adapts IEEE 1584 formulas, and assumes the arcing time lasts up to 2 second. At the 2-second mark, for most cases, it would most likely to be an overcurrent condition rather than a fault. Otherwise, the protective device will trip in the instantaneous region, which results in a much lower incident energy level.

Chapter 3 - Proposed Approach and Methodologies

A general approach and methodologies to retrofit and upgrade the existing SSDS system are proposed in this thesis. The flowchart is also developed for implementing the proposed general approach.

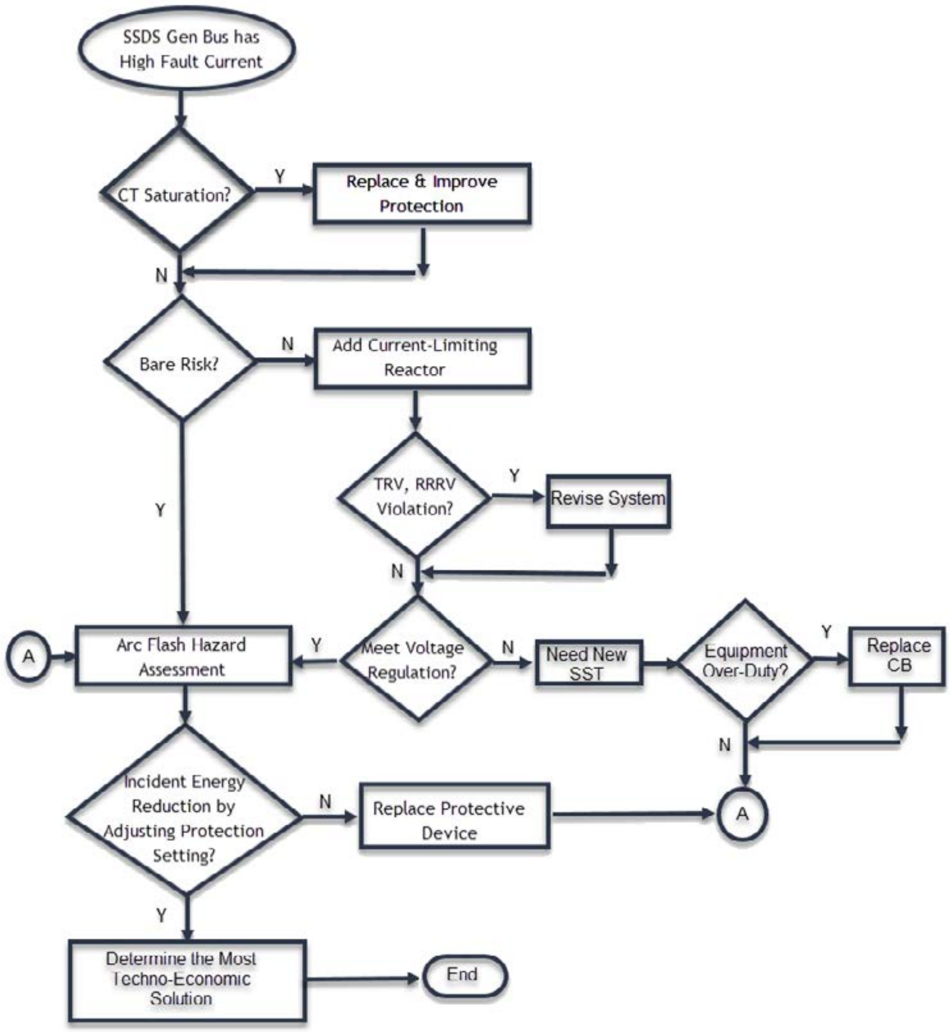


Figure 3. 1- Flowchart of the Proposed Approach

3.1 CT Saturation

Mathematically determining a CT saturation is discussed in Section 2.3. If a CT is found to be saturated upon a fault inception, the CT needs to be replaced to properly protect the critical assets in the hydroelectrical generating station.

A more accurate way is to utilize sophisticated a PSCAD/EMTDC model to simulate the CT behavior upon an electrical fault with actual system and equipment data.

3.2 Adding a Current-Limiting Reactor (CLR)

As identified previously, due to the high magnitude of the fault current on the generator bus, the SST is exposed to excessive thermal and mechanical stresses at fault, potentially creating permanent damages. Currently, there is no medium voltage circuit breaker commercially and economically available to interrupt high generator bus fault current.

From a technical perspective, it is arguable that depending on the magnitude of the maximum available fault current, generator circuit breaker (GCB) might be capable to interrupt the fault current. However, it is not economical and practical to do so. First, the GCB is quite expensive - it might be more expensive than a dry type station service transformer, and there is no cost/benefit to use a GCB to protect a SST. Secondly, GCB is large in size and it might be a challenge to place the GCB inside an existing hydroelectric generating station power house.

Some utilities may decide to bear the risk of damaging critical assets, and accept the prolonged outage. This thesis assumes it is not acceptable, and proposes a systematic approach to resolve the high magnitude of the fault current on the generator bus issue.

From the literature review, the best way is to add an air-core current-limiting reactor into the system to lower the fault current magnitude. The reduced fault current will facilitate the installation of a medium voltage vacuum circuit breaker, providing the capability of clearing SST faults. This allows for the implementation of a differential protection scheme and to clear transformer faults without tripping the generator and GSU protection zones. The medium voltage vacuum breaker also allows transformer switching without interrupting generator operations.

Unlike GCB, a typical medium voltage vacuum circuit breaker is small in size and can be placed in a metal enclosure with arc-resistant construction. The enclosure is a special design to confine the arc flash incident energy with a directed channel and vent to discharge the extremely hot arc flash blast wave. The arc-resistant enclosure is able to minimize the risks and protect workers.

The CLR inductance can be calculated by the following formulas:

$$L_S = \frac{V}{\sqrt{3} \times I_{SCA} \times 2\pi f} \tag{3. 1}$$

$$L_S + L_{CLR} = \frac{V}{\sqrt{3} \times I_{SCB} \times 2\pi f} \tag{3. 2}$$

$$L_{CLR,final} = 1.05 \times 1.5 \times L_{CLR} \tag{3. 3}$$

where,

L_S is the short-circuit inductance from the system;

L_{CLR} is the inductance of the CLR;

V is the system voltage;

I_{SCA} is the short-circuit current of feeder side of CLR (excluding CLR short-circuit current); and

I_{SCB} is the short-circuit current of load side of CLR (including CLR short-circuit current);

In case of a bolted three phase ungrounded fault and accounting for a nominal operating voltage of 5% system over-voltage [20], the equivalent inductance for the first-pole-to-clear is calculated in (3.3).

The disadvantage of adding the current-limiting reactor is, it may cause circuit breaker failure in terms of TRV and RRRV violations, and create a voltage drop to have the service entrance voltage beyond allowable limits. These two issues will be discussed in the following sections.

3.3 TRV & RRRV Analysis

It is commonly known that a current-limiting reactor (CLR) affects both transient recovery voltage (TRV) and Rate of Rise of Recovery Voltage (RRRV).

The TRV is the voltage that appears between the breaker terminals immediately after the current interruption [21]; the breaker selection is considered acceptable if the selected circuit breaker can withstand the TRV, RRRV, and the fault current [20]. If either TRV or RRRV exceeds circuit breaker capability, it will cause a significant stress on the circuit breaker, and ultimately causes breaker failure.

TRV rating of a circuit breaker is defined by an envelope. As per IEEE standard C37.011, a two-parameter envelope is used. The two parameters are [20]:

- U_c = TRV peak value, in kV
- T_3 = Time to reach Uc, in ms

Also, RRRV is defined by U_c divided T_3.

The general characteristics of two parameter envelope for circuit breaker rated 100 kV and below are shown in Figure 4.1, where *Isc* is the rated short-circuit current

[20]. The 0.1*Isc*, 0.3*Isc*, 0.6*Isc* and 1.0*Isc* are also known as T10, T30, T60 and T100, respectively.

If the TRV oscillation cross or beyond the envelope (horizontal line), then it is considered as TRV violation. If the RRRV cross the sloped portion of the envelope, it is considered as RRRV violation. The green, orange, blue, and blue curve shown in Figure 1 provide example of accepted simulated TRV and RRRV results in respect of T10, T20, T60 and T100 envelops.

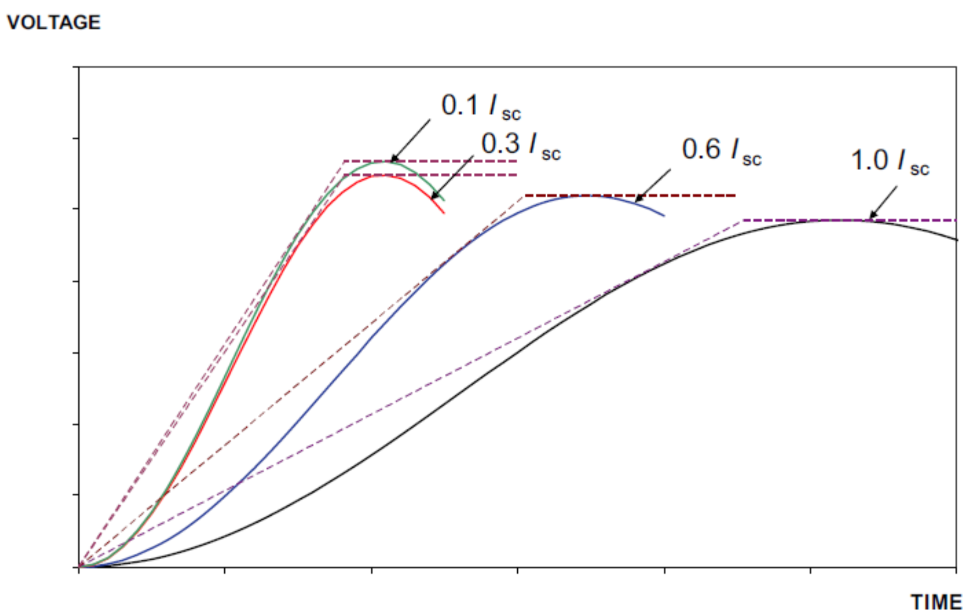


Figure 3. 2- Two Parameter TRV Envelopes for Circuit Breaker below 100 kV [20]

3.3.1 Current-Limiting Reactor Associated TRV and RRRV Violations

In case the TRV or RRRV exceeds the standardized values or circuit breaker capability, there are three common ways to mitigate it:

- Add capacitance across CLR terminals to reduce the TRV frequency;
- Add capacitance across the circuit breaker terminals to reduce the RRRV;
- Select higher interrupting rating or voltage rating for the circuit breaker to lower the requirements of TRV and RRRV

3.4 Voltage Regulations

Given the fact that the generator voltage may swing up to ±5% in normal operating conditions along with the voltage drop across CLR and SST, the voltage at the service entrance point shall be within acceptable voltage ranges specified by CSA C235 standard. Adding a CLR adds an impedance to the feeder system, which in turn reduces the voltage at the service entrance point. The following table is excerpted from CAN3-C235 standard [22] to specify voltage limits.

Table 3. 1 - Recommended Voltage Variable Limits [22]

Table 3

Recommended Voltage Variation Limits for Circuits up to 1000 V, at Service Entrances

Nominal System Voltages	Voltage Variation Limits Applicable at Service Entrances: Extreme Operating Conditions	Normal Operating Conditions		
Single-Phase				
120/240	106/212	110/220	125/250	127/254
240	212	220	250	254
480	424	440	500	508
600	530	550	625	635
Three-Phase 4-Conductor				
120/208Y	110/190	112/194	125/216	127/220
240/416Y	220/380	224/388	250/432	254/440
277/480Y	245/424	254/440	288/500	293/508
347/600Y	306/530	318/550	360/625	367/635
Three-Phase 3-Conductor				
240	212	220	250	254
480	424	440	500	508
600	530	550	625	635

Voltage regulation shall be carefully reviewed to ensure the added current-limiting reactor does not have a negative impact to the station service loads. This thesis has developed a formula to evaluate the voltage regulation of an existing hydroelectric generating station based on:

- Generator output voltage swing;
- Station service transformer tap position;
- Station load profile

Comparing with the transformer and current-limiting impedances, it is assumed that the cable resistance is negligible. The governing equation for service entrance point voltage is:

$$V_{sep} = \left(\left(\frac{V_{gen,out}}{V_{gen,nom}}\right) + \%TC - \%Load \times (Z\% + CLR\%)\right) \times V_r \quad (3.\ 1)$$

where,

V_{sep} is the service entrance point voltage;

$V_{gen,out}$ is the generator output voltage swing; typically +/- 5%;

$V_{gen,nom}$ is the nominal generator output voltage. Since the SST is directly tapped off from the generator bus; $V_{gen,nom}$ can also be the rated HV voltage of the SST;

$\%TC$ is the SST tap position. For de-energized tap changer, it typically has five taps, ±5%, ±2.5% and neutral tap;

$\%Load$ is the station load profile;

$Z\%$ is the SST impedance;

$CLR\%$ is the current-limiting reactor impedance;

V_r is the rated voltage for service entrance point, it can also be the rated LV voltage of the SST.

The developed formula is only applicable if SST is properly sized to meet overall hydroelectric generating station SSDS system load in a single contingency situation. If the resulted service entrances voltage does not meet the standard requirement, one option is to install a new SST with on-load tap changer (OLTC). A typical on-load tap changer (OLTC) has a range of +/- 15% to regulate the transformer secondary system voltage.

The disadvantage of having an OLTC is, OLTC is has higher initial cost, and requires routinely maintenance.

Alternatively, a new SST with smaller impedance is worth to consider. The benefit of using a smaller impedance SST is to compensate the voltage drop caused by current-limiting reactor. The disadvantage is also obvious, it increases the transformer secondary side fault level, and may cause downstream circuit breaker over-duty and failure.

3.5 Short Circuit Fault Level and Equipment Duty

By increasing the short circuit current that a circuit breaker needs to interrupt, it may cause circuit over-duty and failure. If the short circuit current is greater than a circuit breaker’s interruption capability, the circuit breaker is considered over-duty, and needs to be replaced.

The methodology used for equipment duty is in accordance with IEEE Standard C37.010-2016 [17] and IEEE Standard 1015-2006 [18]. The general procedure to calculate the duty cycle is:

- Find the circuit breaker short circuit interruption rating;
- Calculate the short circuit current that the circuit breaker has to interrupt;
- Calculate the system *X/R* ratio and determine whether de-rating applies

For low voltage circuit breaker, in case the system *X/R* ratio is greater than the test *X/R*, the general approach is to increase the fault current to obtain the adjusted ½ cycle duty current. The adjusted ½ cycle duty short-circuit current can be calculated as follows [23]:

$$Iadj = Isymm \times \left\{ \frac{1 + e^{\left[\frac{-2\pi \emptyset sys}{(X/_R)sys}\right]}}{1 + e^{\left[\frac{-2\pi \emptyset test}{(X/_R)test}\right]}} \right\} \tag{3. 2}$$

- where,
- I_{adj} is adjusted ½ cycle duty current (increase fault current)
- I_{symm} is symmetrical short-circuit current
- $(X/_R)sys$ is calculated system *X/R* ratio
- $(X/_R)test$ is device test *X/R* ratio per IEEE standards
- and,

$$\emptyset sys = 0.49 - 0.1 \times e^{\left[\frac{-(X/_R)sys}{3}\right]} \tag{3. 3}$$

$$\emptyset test = 0.49 - 0.1 \times e^{\left[\frac{-(X/_R)test}{3}\right]} \tag{3. 4}$$

3.6 Arc Flash Hazard Mitigation

A general methodology to mitigate arc flash hazards for maintaining an existing hydroelectric generating station is proposed below. Arc flash hazards can be mitigated for existing station by the following procedures:

- Gather all equipment data, such as equipment nameplate information, and cable database;
- Complete a detailed arc flash assessment with the found settings and device information and identify areas that need to be addressed;
- Perform an engineering study and propose new protective settings to be applied, and enable instantaneous trip function whenever possible;
- Label all equipment with warning signs indicating arc flash hazard risk category and arc flash boundary to help workers to be properly dressed;
- Replace the protective device that poses a bottle-neck reducing the incident energy or utilize remote racking devices or remote access tools

It is the best way to mitigate arc flash hazards at the design stage. The following ways can be considered when designing a new hydroelectric generating station:

- Design and procure Type 2B arc-resistance rated equipment whenever possible;
- Design and procure load-break and/or horsepower rated disconnect switches;
- Design bus differential protection;

- Design with redundancy in the system, allowing for equipment maintenance at de-energized state.

For an existing hydroelectric generating station, in order to lower the incident energy, the best way is to adjust the protection settings to clear the fault as quickly as possible while maintaining protection coordination. If adjusting protection setting cannot effectively reduce the incident energy level, the protective device needs to be replaced or the device needs to be de-energized to perform any work.

3.7 White Box Model of RB-FMEA

Kahrobaee and Asgarpoor developed and used Risk-Based Failure Mode and Effect Analysis (RB-FMEA) on wind turbine technologies [13]. It uses the resulted Cost Priority Number (CPN) value to find the critical part of the overall wind turbine that is most likely to fail. It is a powerful tool for the manufacturer, which can have a focus to improve the wind turbine's reliability. However, the RB-FMEA model cannot be directly applied to a power system. If a fault occurs in a power system, and is not detected, it will cause irreversible catastrophic failure and most likely revenue loss. Furthermore, utilities have great safety and environmental responsibilities. Safety and environmental impacts of the failure shall also be factored in the failure mode and effect analysis process.

This thesis proposes a new quantitative approach by adapting RB-FMEA, called white-box model of RB-FMEA. By summing the system components' CPN value, the white-box model of RB-FMEA obtains the overall failure cost of the system in question. It also brings Risk Priority Number (RPN) into the overall analysis process. The total cost then is converted into Net Present Value (NPV) to compare different strategies.

The general procedure of the proposed white-box model of RB-FMEA process is as follows:

- Propose multiple design or maintenance strategies;
- For each strategy failure cost:
  - Determine the location of the failure;
  - Determine the causes of failure;
  - Determine the risk priority number (RPN);
  - Calculate the location cost priority number ($LCPN$);
- Calculate strategy failure cost by summing LCPN;
- Calculate net present value (NPV) of each strategy cost;

The calculation procedure is as follows:

$$RPN(i) = Sr(i) \times Edr(i) \qquad (3.5)$$

$$Cl(i) = Df(i) \times Wn(i) \times Rh(i) \qquad (3.6)$$

$$Cf(i) = Cp(i) + Cl(i) + Rl(i) \qquad (3.7)$$

$$LCPN(i) = Pf(i) \times Cf(i) \times RPN(i) \tag{3.8}$$

$$S_{NPV}(j) = \sum LCPN(i) \times \left\{\frac{1-(1+R)^N}{R}\right\} \tag{3.9}$$

where,

i represents each location of failure;

j represents each strategy failure;

k represents each switching;

R represents the interest rate, in %;

N represents the total year for NPV calculation;

Sr represents the potential safety rating. It indicates potential safety hazards to workers;

- High (3) means fatalities;
- Medium (2) means permanent partial disability;
- Low (1) means temporary disability and minor injury;

Edr represents the environmental damage rating. It represents estimated cost to clean up, in $ value;

Cl represents the labour cost;

Df represents the duration of the failure;

Wn represents the numbers of workers needed;

Rh represents the workers hourly pay;

Cp represents the parts costs;

Cs represents the service cost and equipment rental cost;

Rl represents the revenue loss;

Pf represents the probability of failure. Shall be based on historical data, if not available, reference to (IEEE 493-2007, table 10-4);

Cf represents the overall failure cost;

LCPN represents location cost priority number;

S_{NPV} represents strategy failure cost;

This chapter proposed a systematic approach to retrofit an existing hydroelectrical generating station to address the technical and safety issues. Chapter 4 will use a study case to validate the applicability of the new approach.

Chapter 4 – Application and Evaluation of the General Approach

In this chapter, the developed general approach and methodologies are applied to an existing hydroelectric generating stations as a case study. The existing SSDS in the case study will be reviewed and evaluated in this chapter, as well. The proposed approach and methodologies is used to retrofit the SSDS system and address the following technical issues:

- Removal of aged and redundant medium voltage switchgear
- High fault current level on generator bus
- Review the existing protection system
- Implementation of modern safety codes and standards

The following evaluations will be completed in this chapter:

- Evaluation of new system configuration, in this case, the impact of CLR;
- Evaluation of voltage regulation;
- Evaluation of short circuit and equipment duty;
- Evaluation of arc flash hazard of the new system configuration;
- Evaluation of failure cost.

4.1 Case Study Background

The SSDS system of the studied hydroelectric generating station presently has two voltages systems: a 4.16 kV and a 600 V system. Figures 1.2, 1.3, and 1.4 show an overview of the station service distribution system's single line diagram.

There are three indoor 4/5 MVA, 13.8:4.16 kV station service transformers (SST11, SST21, and SST31), fed from generators 1, 2, and 3, respectively, supplying the 4.16 kV switchgear inside the powerhouse. Each transformer is equipped with an on-load tap changer (OLTC) with a range of +/- 15%. The OLTC is used to regulate the 4.16 kV system, as the generator output voltage may swing up to +/- 5% during normal operating condition.

In addition to feeding the generating station and spillway, at one time, the 4.16 kV system also fed the nearby town sites. However, the generators were often switched on and off as part of the normal operation, causing frequent momentary interruption to the town site feeders. In order to overcome the interference, a make-before-break scheme was added to the 4.16 kV switchgear and was not automated. It needs station operator to manually engage. The complexity of the make-before-break scheme has led to inefficiencies in operation. The station operator need to review the appropriate sequence of steps to perform any switching operation in advance. The town sites are now fed from a separate 25kV distribution system, the make-before-break scheme is no longer required and thus has been abandoned.

There are two 1 MVA, 4.16 kV:600 V station service transformers (SST21 SST22), fed from the 4.16 kV switchgear. Each transformer is capable to supply the entire station loads individually. The 4.16 kV switchgear is at its end of service life, and replacement parts are no longer available. The ring bus in the 4.16 kV switchgear is meant to provide station service distribution system operation flexibility, since each of the two-stage station service transformer line-up is capable to supply the entire station load, the entire 4.16 kV system in the powerhouse can, therefore, be functionally eliminated and removed without any impact on the station operation. However, the 4.16 kV switchgear contains part of the generators and generator step-up transformer (GSU) and station service transformer (SST) protection system. Once the switchgear has been removed, this will lead to unacceptable risk exposure to the generating station's critical assets.

To simplify the explanations, throughout this thesis, only generator G1 station service line-up is explained; generator G2 line-up has an identical configuration to that of G1 line-up. SST3 in the generator 3 line-up of the studied case has failed; therefore, it will not be discussed.

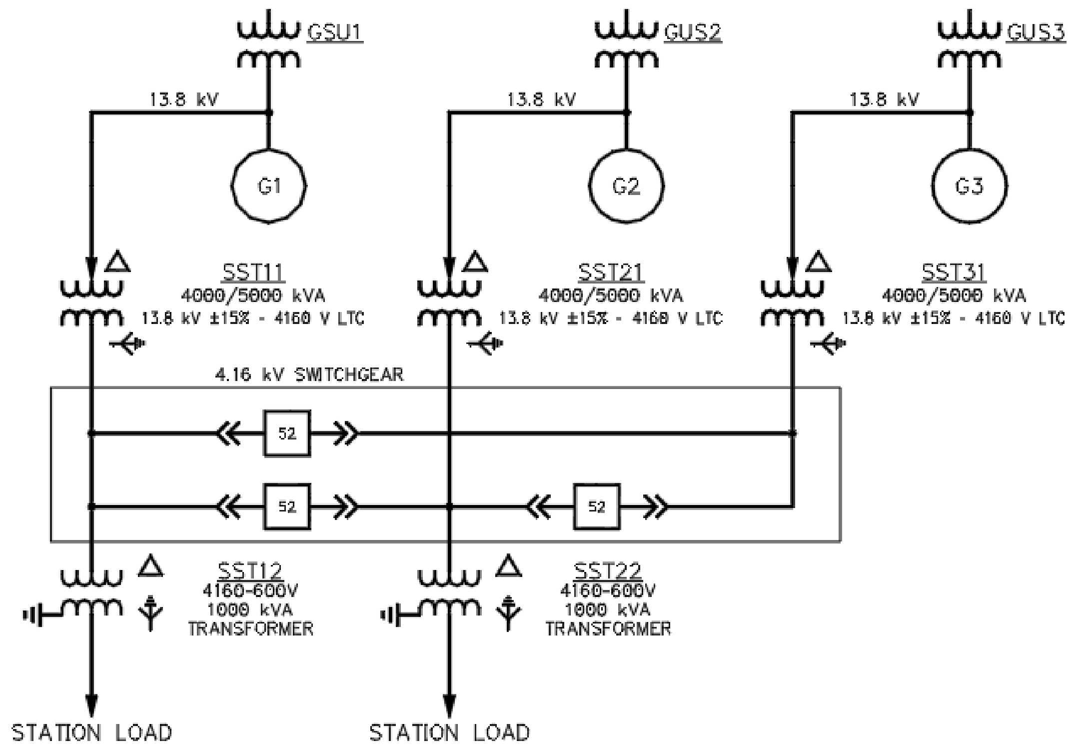


Figure 4. 1 - Station Service Distribution System (SSDS) Single Line Diagram

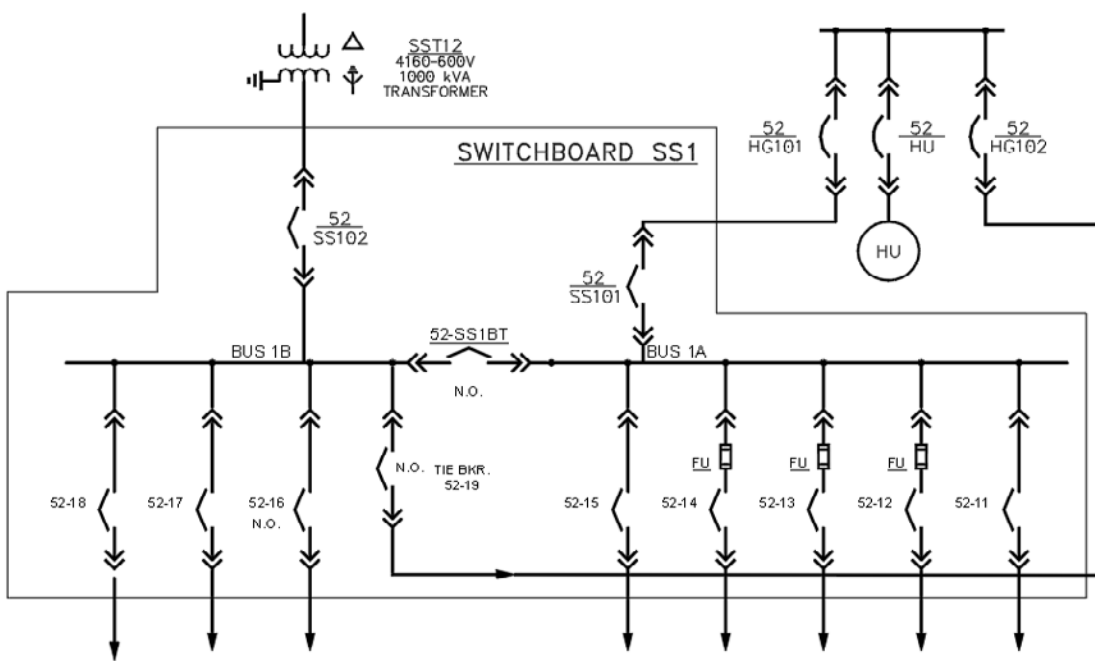


Figure 4. 2 – System Configuration of Load Group 1

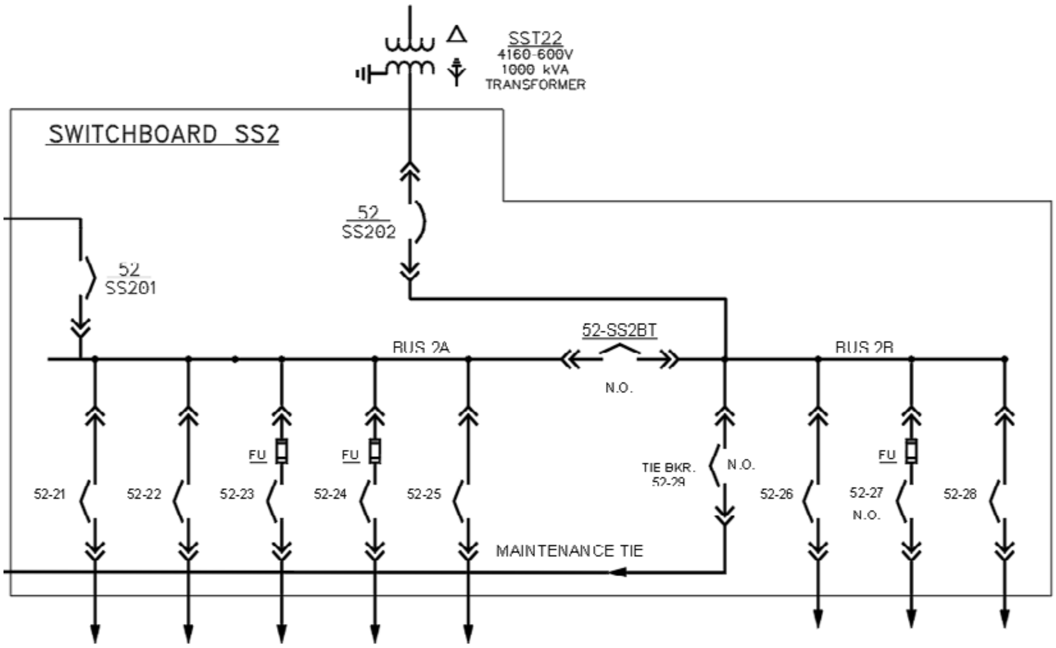


Figure 4. 3 – System Configuration of Load Group 2

4.1.1 Case Study Review

The short circuit fault level and equipment duty evaluations are performed by using EasyPower software. EasyPower is a computer aided engineering tool to analyze electrical power systems. It models the power system in a single line basis with equipment data, and it is capable of performing short circuit analysis, power flow analysis, protective device coordination, and arc flash hazard analysis [23].

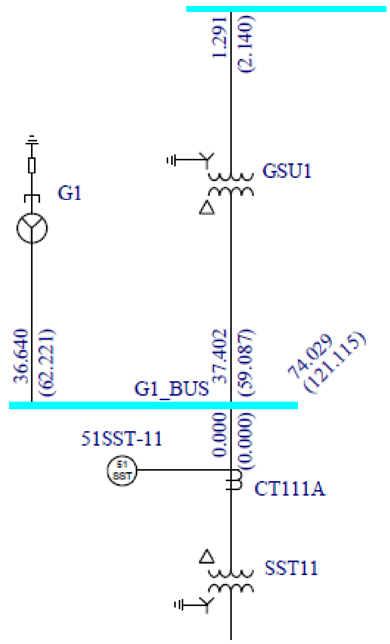


Figure 4. 4 - Generator Bus Fault Current Level

In this case, the available symmetrical short-circuit current on the generator bus is about 74 kA, whose large magnitude will expose the equipment to unacceptable thermal and mechanical stresses when a fault occurs.

In the studied case, there are two sets of 400:5A C400 CTs at the primary side of 13.8:4.16 kV transformer; one CT is connected to the time-delay overcurrent protection, and the other one is to form a differential zone to protect the transformer.

Based on short-circuit study results, the symmetrical short-circuit fault current on the generator bus is 74 kA. It is believed that the two sets of 400:5A CTs at primary side of the 13.8:4.16 kV transformers will be saturated during a fault.

The following information is gathered from the study case, with some assumptions for missing information:

- The CT secondary connects to a mechanical relay with 0.108 Ω burden
- 350 ft of #10 AWG SIS wire is used to link CT and relay. The #10 AWG has resistance of 1 Ω per 1000 ft.
- The actual CT secondary winding resistance is not available, it is assumed the CT has 0.0025 Ω per turn;
- The system *X/R* ratio is 34.91.

Therefore,

- I_{fault} is 74000 A;
- I_{Prim} is 400 A;
- Z_B is (0.108 + 0.35) = 0.458 Ω;
- R_s is 0.0025 × 80 = 0.2 Ω;
- $Z_{B,STD}$ is 4 Ω

By applying the Formula 2.1 and Formula 2.2, it will get

$$\frac{I_{fault}}{I_{Prim}} \times \frac{Z_B + R_s}{Z_{B,STD} + R_s} = \frac{74000}{400} \times \frac{0.658}{4.2} = 28.98 > 20$$

$$\frac{I_{fault}}{I_{Prim}} \times \frac{Z_B + R_s}{Z_{B,STD} + R_s} \times \left(\frac{X}{R} + 1\right) = \frac{74000}{400} \times \frac{0.658}{4.2} \times 35.91 = 1040.7 > 20$$

The 400:5 A C400 CT will be subjected to both AC and DC saturation.

Figure 4.5 shows a PSCAD/EMTDC model to simulate the CT behavior upon an electrical fault. The simulation result is demonstrated in Figure 4.6, which verifies that 400:5A CTs become saturated upon an electrical fault.

The existing protection system is, therefore, believed to be inadequate to protect the SST.

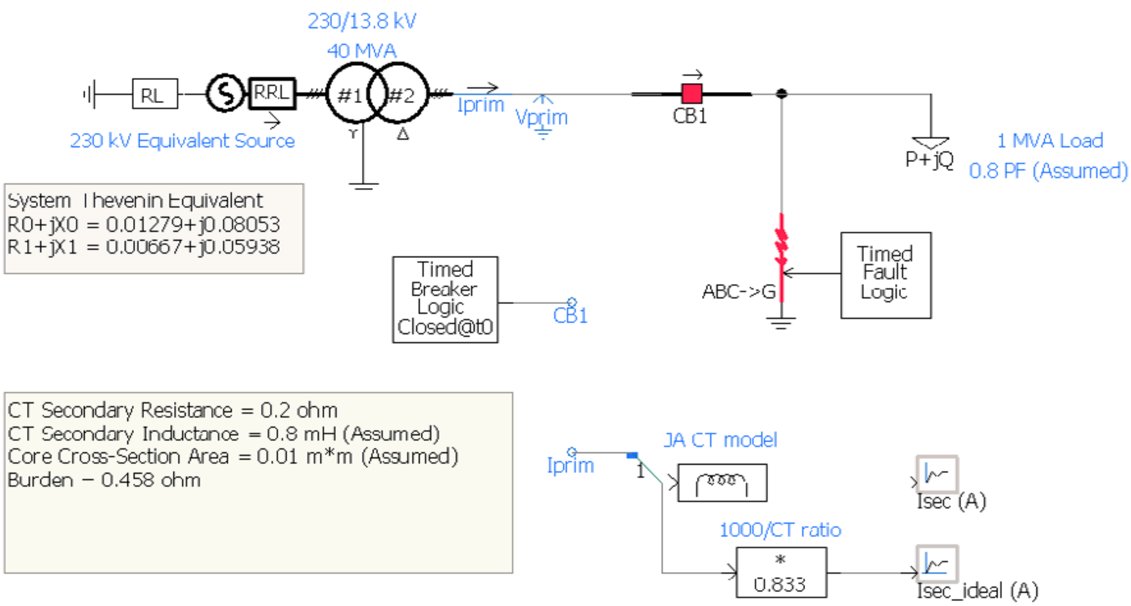


Figure 4. 5 - CT Saturation PSCAD/EMTDC Model

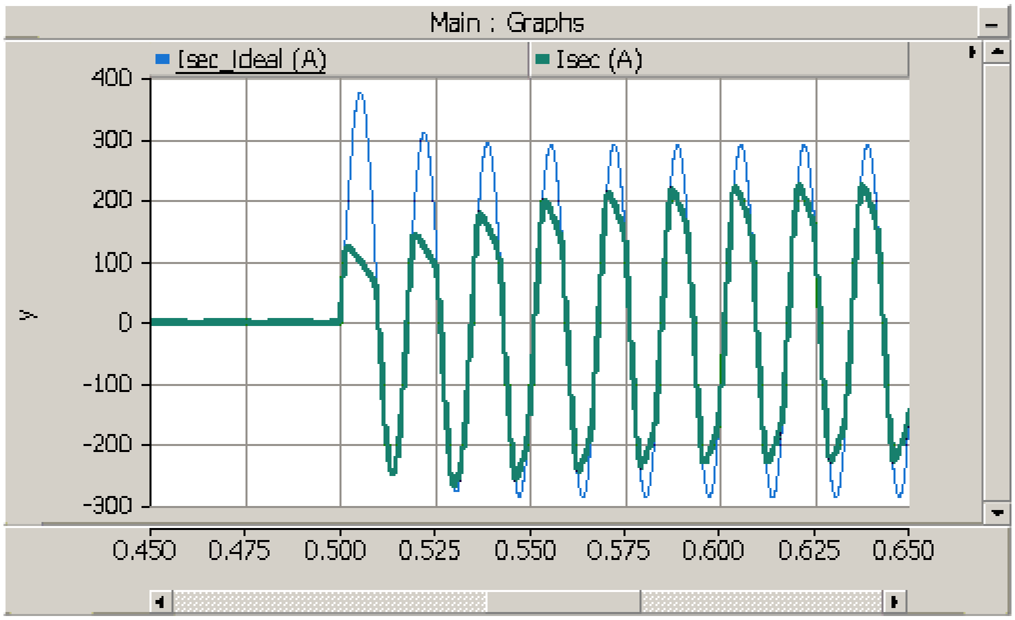


Figure 4. 6 - CT Saturation using PSCAD/EMTDC Results

4.2 New System Configuration

In summary, the new system configuration includes removing the existing two-staged station service transformer and the existing 4.16 kV switchgear, and installing a CLR and a new 13.8:0.6 kV SST in conjunction with new CLRs. Figure 4.7 shows the new system configuration.

The added current-limiting reactors can be placed where the existing 4/5 MVA, 13.8:4.16 kV station service transformers are. The existing 1 MVA, 4.16:0.6 kV station service transformers will be replaced by 1 MVA, 13.8:0.6 kV transformers.

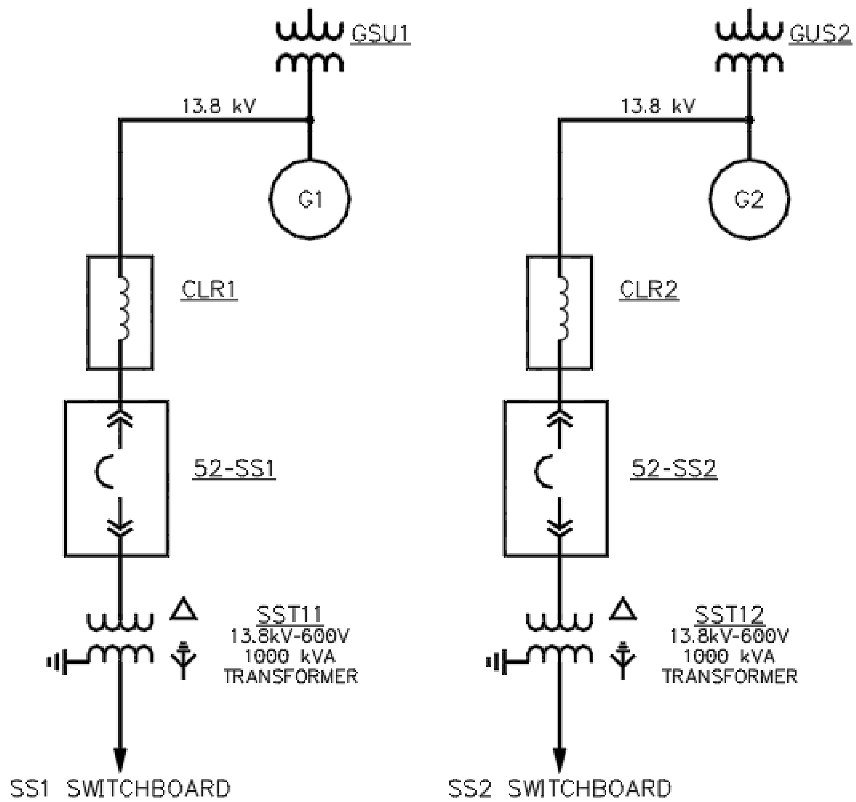


Figure 4. 7 – New System Configuration Electrical Single Line Diagram

In this case, the available symmetrical short-circuit current on the generator bus is about 74 kA, whose large magnitude will expose the equipment to unacceptable thermal and mechanical stresses when a fault occurs. Currently, there is no medium voltage vacuum circuit breaker commercially and economically available to interrupt 74 kA short-circuit current.

In the studied case, the system voltage is $V = 13.8\ kV$, and $I_{SCA} = 74\ kA$. I_{SCB} is targeted to $15\ kA$, which is 60% of a typical medium vacuum breaker's current interruption capability rating. By applying the formulas 3.1, 3.2 and 3.3, the inductance of the CLR for this case study is determined as follows.

$$L_{CLR,final} = 1.77\ mH$$

4.3 Evaluations of the Impact of Current-Limiting Reactor

Unless there is a special requirement, a typical 15 kV medium voltage vacuum circuit breaker has a 25 kA rated interrupting capability. In the new system configuration, the CLR is sized to limit the short-circuit current to 14.3 kA, which is about 60% of the rated interrupting capability. Therefore, when evaluating TRV and RRRV simulation results, T60 envelope is used for the case study.

Although a three-phase ungrounded bolted fault has the highest TRV peak value, this occurrence is considered rare in reality [20]. Therefore, to evaluate the TRV and RRRV impacts, three-phase grounded faults are simulated at the following locations:

- At feeder side of the medium voltage circuit breaker (between CLR and the medium voltage circuit breaker)

- At line side of the medium voltage circuit breaker (between the medium voltage circuit breaker and the 13.8 kV:600 V transformer)

The evaluation is performed using PSCAD/EMTDC simulation platform (refer to Figure 4.8 for the PSCAD/EMTDC simulation model). The worst-case capacitance values used in the PSCAD/EMTDC simulations are referenced to in Tables B.3, B.7, and B.8 from IEEE C37.011 Annex B, and are summarized in Table 4.1. Phase-isolated bus ducts have been used to interconnect the generator terminals, GSU low voltage side and new current-limiting reactor; it is assumed the resistance of the phase-isolated bus bars are zero.

Table 4. 1 - Capacitance Value used in PSCAD/EMTDC Simulation

Equipment	Capacitance (pF)
Current Transformer	75
Vacuum Circuit Breaker	20
Surge Arrester	80

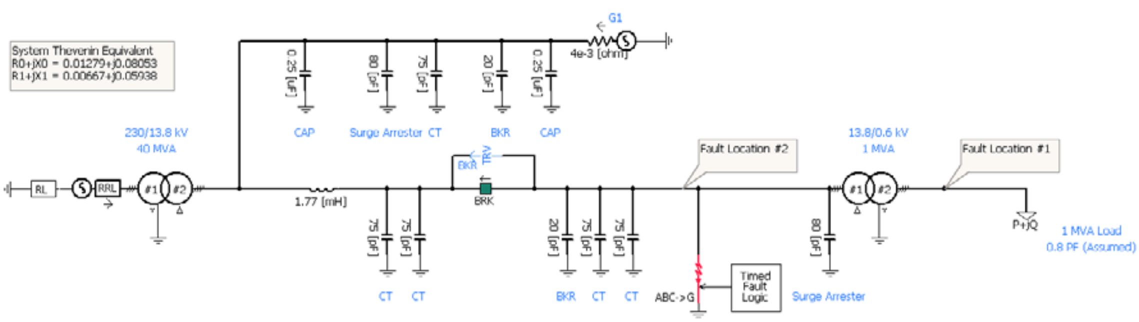


Figure 4. 8 - Initial PSCAD/EMTDC model

Figure 4.9 and Figure 4.10 show the simulation results for fault location #1. As shown in Figure 4.9, the TRV oscillation is well within the T60 envelope. Although the RRRV curve cross the T10 (cyan line), it is still well within T60 envelope (red line). There is no neither TRV or RRRV violation for fault occurs at location #1.

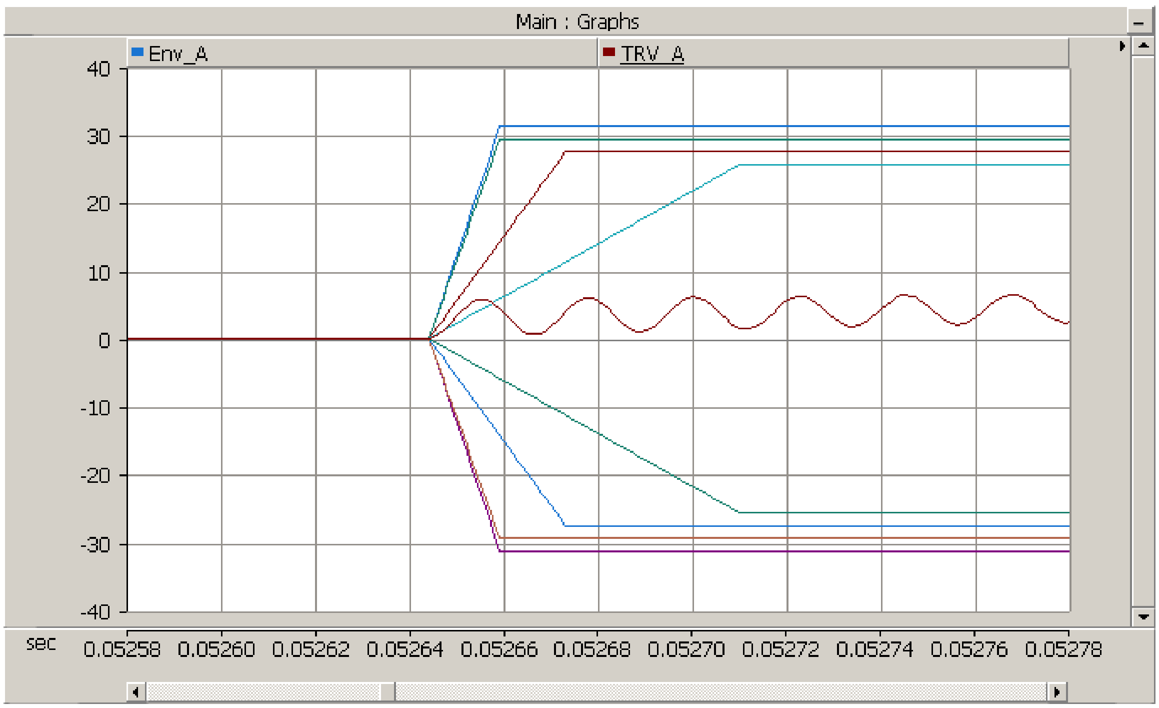


Figure 4. 9 - TRV Plot for Fault Location #1

Figure 4.10 shows the simulation results for fault location #2. As shown in Figure 4.10, the TRV has smaller oscillation within the envelope. There is no neither TRV or RRRV violation for fault occurs at location #2.

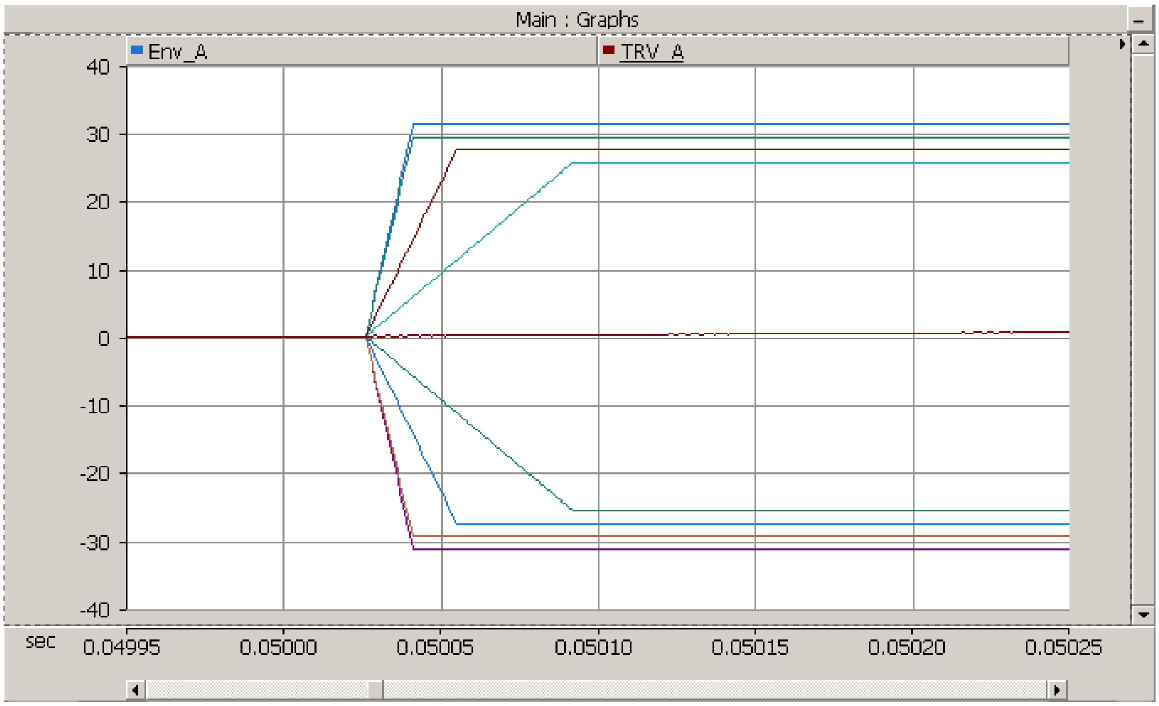


Figure 4. 10 - Enlarged TRV Plot for Fault Location #2

A current limiting reactor installed at the load side of a circuit breaker (in series connection) often faces a high frequency TRV when clearing a fault, which leads to a TRV violation. In the studied case, nearby equipment such as CTs and arresters provide sufficient shunt capacitance resulting in the TRV and RRRV meeting the standardized values. From the above figures, it is concluded that there is no TRV and RRRV violation for fault at both location #1 and location #2. The sized CLR is deemed adequate.

4.3 Protection Re-Modelling

By adding the CLR, the resulting reduced fault current will facilitate the installation of a medium voltage vacuum circuit breaker, and allows for the implementation of a differential protection scheme and to clear a transformer fault without tripping the generator and GSU protection zones. New protection CTs will be added along with the medium voltage circuit breaker to form two overlapped differential protection zones.

The first one is the generator differential protection zone. Due to the removal of the 4.16 kV switchgear, parts of the generators, generator step-up transformer (GSU), and SST protection system will also be removed. It is necessary and important to re-establish the generator differential zone. The second one is the station service transformer differential protection zone. It is a newly created zone to protect the transformer. Figure 4.11 shows the re-modelled protection for the new system configuration.

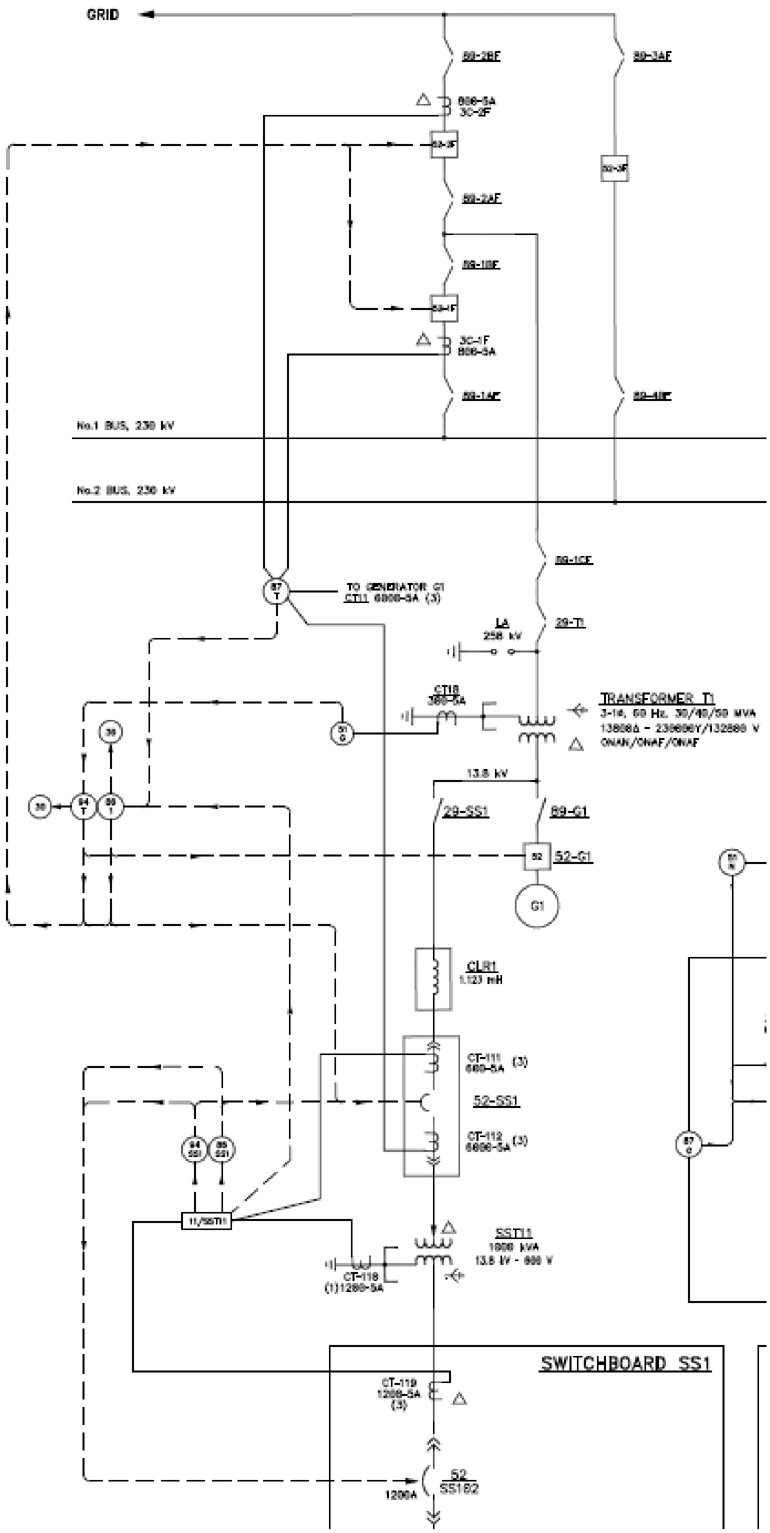


Figure 4. 11– New System Configuration Protection Scheme (Generator G1 line-up)

Below is a brief descriptive overview of the re-modeled protection system with the following scenarios:

- When an overcurrent fault is detected, it trips the MV breaker 52-SS1 and LV station service breaker 52-SS1;
- When a differential fault is detected or critical high transformer winding temperature is detected, it trips the breaker 52-SS1 and 600 V station service breaker 52-SS1.

This protection scheme also includes breaker fail functionality, which will trip the HV breaker 52-1F and 52-2F and generator breaker 52-G1, in case 52-SS1 fails to operate.

The advantage of the new system configuration is by adding the current limiting reactor and circuit breaker to clear a transformer fault without interrupting generation production. The existing system configuration in the case study does not provide this benefit.

4.4 Voltage Regulation

4.4.1 High Impedance Station Service Transformer Model

Selecting high impedance station service transformer helps to reduce the maximum available fault current level on the transformer secondary. In general, for like-for-like replacement, maintaining the same impedance is a sound idea as it maintains the same fault current level on the transformer's secondary. This way it will not over-duty the downstream protective devices. However, in the studied case, since two staged SSTs are removed, it provides an opportunity to investigate a high impedance station service transformer model.

From the short-circuit simulation of the existing system, the symmetrical short-circuit is calculated a 12.692 kA. In order to supply the entire generating station, the new SST shall be rated at 1 MVA, with 962 A on the secondary. Thus, the impedance of the new transformer is calculated as follows.

$$Z\% = \frac{962\,A}{12692\,A} = 7.5\%$$

As shown in Table 4.2, for the high impedance SST model with de-energized tap changer, it does not have a tap position to fulfill the requirements outlined in CSA C235. The only way to compensate the voltage drop of SST and CLR is by adding an on-load tap changer. However, it is a costly approach. For the standard impedance SST model, as long as the de-energized tap changer stays in neutral position, it fulfills service entrance voltage the requirment specified in CSA C235.

Table 4. 2 - Voltage Analysis with High Impedance Transformer Model

Generator Voltage Variation:	5.0%	(worst case)			
SST			From CSA C235 1983		
			Nominal Voltage:	600	V
HV	13.8	kV	Extreme High	635	V
LV	0.6	kV	Normal High	625	V
%Z =	7.50%	transformer	Normal Low	550	V
%Xl =	0.84%	CLR	Extreme Low	530	V
OLTC Regulation	15.0%				

		From CSA C235 1983			
		kV (min)	**kV (rated)**	**kV (max)**	
	Bus Volts	**13.11**	**13.8**	**14.49**	
SST DTC	**Load**	**600**	**600**	**600**	**Pass/Fail**
5.0%	10%	595	625	655	fail
5.0%	50%	575	605	635	marginal
5.0%	100%	550	580	610	marginal
2.5%	10%	580	610	640	fail
2.5%	50%	560	590	620	pass
2.5%	100%	535	565	595	marginal
0.0%	10%	565	595	625	pass
0.0%	50%	545	575	605	marginal
0.0%	100%	520	550	580	fail
-2.5%	10%	550	580	610	marginal
-2.5%	50%	530	560	590	fail
-2.5%	100%	505	535	565	fail
-5.0%	10%	535	565	595	marginal
-5.0%	50%	515	545	575	fail
-5.0%	100%	490	520	550	fail
OLTC	10.0%	600	600	600	pass
OLTC	50.0%	600	600	600	pass
OLTC	100.0%	600	600	600	pass

4.4.2 Standard Impedance Station Service Transformer Model

In the studied case, the first stage SST has an impedance of 7.55%, and the second stage SST has an impedance of 5.65%. The combined impedance of two staged SST is over 13%; the first stage SST is equipped with an on-load tap changer of ±15%. The on-load tap changer not only helps to offset the voltage swing of the generator, but also provides voltage drop compensation for the SSTs.

With the 7.5% impedance and CLR voltage drops, there is a risk that the service entrance voltage may not meet the required voltage ranges specified by CSA C235 standard. Alternatively, it is worth considering and analyzing the standard impedance SST model. Typical impedance for a 1 MVA transformer is 5.75%.

As shown in Table 4.3, as long as the new SST DTC is kept at its neutral position, it meets the 10% to 100% load requirements without violating the voltage regulation specified in CSA standard.

Table 4. 3 - Voltage Analysis with Standard Impedance Transformer Model

Generator Voltage Variation:			5.0%	(worst case)		
SST				From CSA C235 1983		
			Nominal Voltage:		600	V
HV	13.8	kV	Extreme High		635	V
LV	0.6	kV	Normal High		625	V
%Z =	5.75%	transformer	Normal Low		550	V
%Xl =	0.84%	CLR	Extreme Low		530	V
OLTC	15.0%					
Regulation						
			From CSA C235 1983			
			kV (min)	**kV (rated)**	**kV (max)**	
		Bus Volts	**13.11**	**13.8**	**14.49**	
	SST DTC	**Load**	**600**	**600**	**600**	**Pass/Fail**
	5.0%	10%	596	626	656	fail
	5.0%	50%	580	610	640	fail
	5.0%	100%	560	590	620	pass
	2.5%	10%	581	611	641	fail
	2.5%	50%	565	595	625	marginal
	2.5%	100%	545	575	605	marginal
	0.0%	10%	566	596	626	marginal
	0.0%	50%	550	580	610	pass
	0.0%	100%	530	560	590	marginal
	-2.5%	10%	551	581	611	pass
	-2.5%	50%	535	565	595	marginal
	-2.5%	100%	515	545	575	fail
	-5.0%	10%	536	566	596	marginal
	-5.0%	50%	520	550	580	fail
	-5.0%	100%	500	530	560	fail
	OLTC	10.0%	600	600	600	pass
	OLTC	50.0%	600	600	600	pass
	OLTC	100.0%	600	600	600	pass

It is concluded that the adding the current-limiting reactor with a standard impedance transformer has no negative impact on the system voltage regulation requirements.

4.5 Evaluations of Short Circuit Fault Level and Equipment Duty

The methodology used for equipment duty is in accordance with IEEE Standard C37.010-2016 [17] and IEEE Standard 1015-2006 [18]. The general procedure to calculate the duty cycle is:

- Find the circuit breaker short circuit interruption rating;
- Calculate the short circuit current that circuit breaker to interrupt;
- Calculate the system *X/R* ratios and determine whether de-rating applies

The procedure is demonstrated by the studied case, and summarized in Table 4.4 and Table 4.5.

Table 4. 4 - MV Circuit Breaker Short-Circuit Duty Report

Equipment	Ratings			Duties				
Name	Voltage (kV)	1/2 Cycle (kA)	Int* (kA)	1/2 Cycle (kA)	1/2 Cycle %	Int* (kA)	Int* %	*X/R* Ratio
52-SST11	13.8	65	25	36.032	-44.60%	14.317	-42.70%	12.57
52-SST12	13.8	65	25	36.032	-44.60%	14.317	-42.70%	12.57

* Int standard for breaker interrupting capability

Table 4.4 shows the calculated short-circuit and duty values for all medium voltage circuit. The calculated *X/R* ratios for all medium voltage circuit breakers are less than 17; therefore, no de-rating applies. There is no over-duty MV circuit breaker found.

The highlighted fields in Table 4.5 indicates that the calculated system *X/R* ratio is greater than the test *X/R* ratio, which means de-rating shall be applied. Even with the de-rating, there is no over-duty LV circuit breaker.

Table 4. 5 - LV Circuit Breaker Short-Circuit Duty Report

Equipment	Ratings	*X/R*		Isc	Duties	
Name	½ Cycle (kA)	Test	Calculated System	½ Cycle (kA)	½ Cycle (kA)	½ Cycle %
52-SS101	42	6.6	21.14	13.336	15.219	-63.77%
52-SS102	42	6.6	6.1	12.692	12.521	-70.19%
52-SS201	42	6.6	16.93	14.899	16.723	-60.18%
52-SS202	42	6.6	6.1	12.692	12.521	-70.19%
52-11	22	6.6	14.48	15.119	16.737	-23.92%
52-12	200	6.6	2.3	7.929	6.298	-96.85%
52-13	200	6.6	5.29	12.646	12.154	-93.92%
52-14	200	6.6	2.3	7.929	6.298	-96.85%
52-15	22	6.6	4.26	11.825	10.878	-50.55%
52-16	22	6.6	5.83	12.621	12.351	-43.86%
52-17	22	6.6	5.83	10.147	9.930	-54.86%
52-21	22	6.6	4.24	11.815	10.858	-50.64%
52-22	22	6.6	14.25	15.106	16.698	-24.10%
52-23	200	6.6	2.3	7.924	6.294	-96.85%
52-24	200	6.6	2.3	7.924	6.294	-96.85%
52-25	22	6.6	14.32	15.11	16.710	-24.05%
52-26	22	6.6	5.83	12.692	12.420	-43.54%
52-28	22	6.6	5.83	12.692	12.420	-43.54%

If a circuit breaker is found to be in over-duty, it has to be replaced with one that has a higher current interruption capability.

4.6 Evaluations of Arc Flash Hazards and Mitigations

Arc flash analysis defines a new approach for protection. Prior to the arc flash regulations, coordination studies were targeted at system availability, which means upon a fault, the branch circuit shall be tripped prior to the main feeder circuit. Compliance with the arc flash regulations, this may not hold true. Arc fault current and arc fault duration are the two major factors contributing to the hazard level. Traditional protection coordination may take longer clear a fault, in turn, causing higher incident energy.

Without changing out station service low voltage protective devices on the existing generating station, improving protection coordination may reduce the arc flash hazard level [24]. The quicker a protective device clears the fault, the less the resulted incident energy level.

To quantify the improvement of arc flash hazard level by the proposed approach outlined in Chapter 3, arc flash assessments on both existing system configuration and new system configuration are conducted.

4.6.1 Existing SSDS Arc Flash Assessment

Due to inadequate protection, the arc flash hazard risks on 4.16 kV system is very high. They are classified as arc flash risk category 4 (HRC 4) with an arc flash boundary of 489.5” (12.43 m). This is not feasible in the practical world, unless the worker is fully dressed up for arc flash risk category 4 and prepared to be exposed to the potential high risks.

The arc flash hazard assessment results are illustrated in Figure 4.12, 4.13 and 4.14.

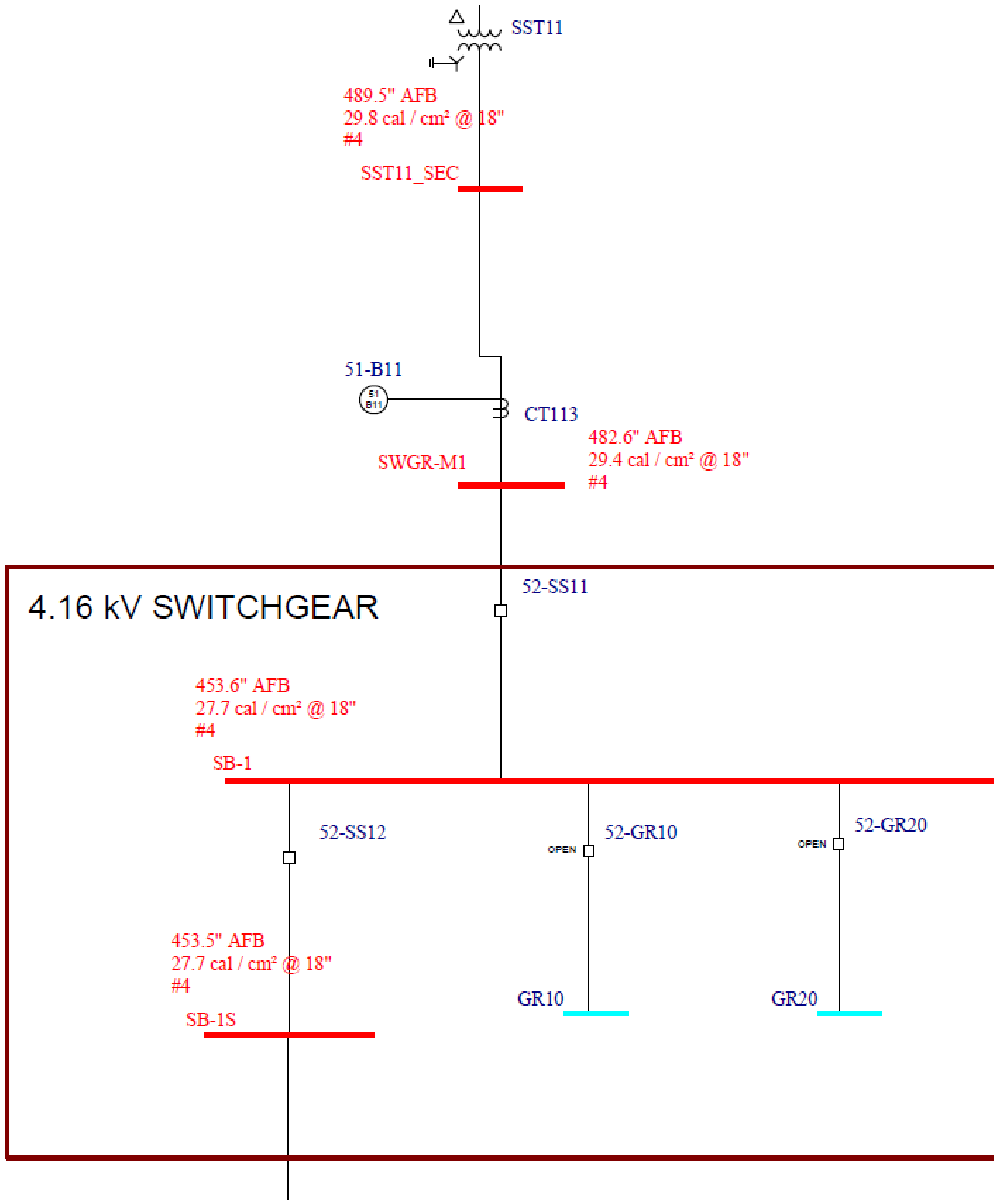


Figure 4. 12 – Section of Arc Flash Assessment on Existing 4.16 kV System

The incident energy level on the 600V SS1 switchboard is even worse than the 4.16 kV system. SS1 switchboard is classified as extremely dangerous, which means no live work shall proceed.

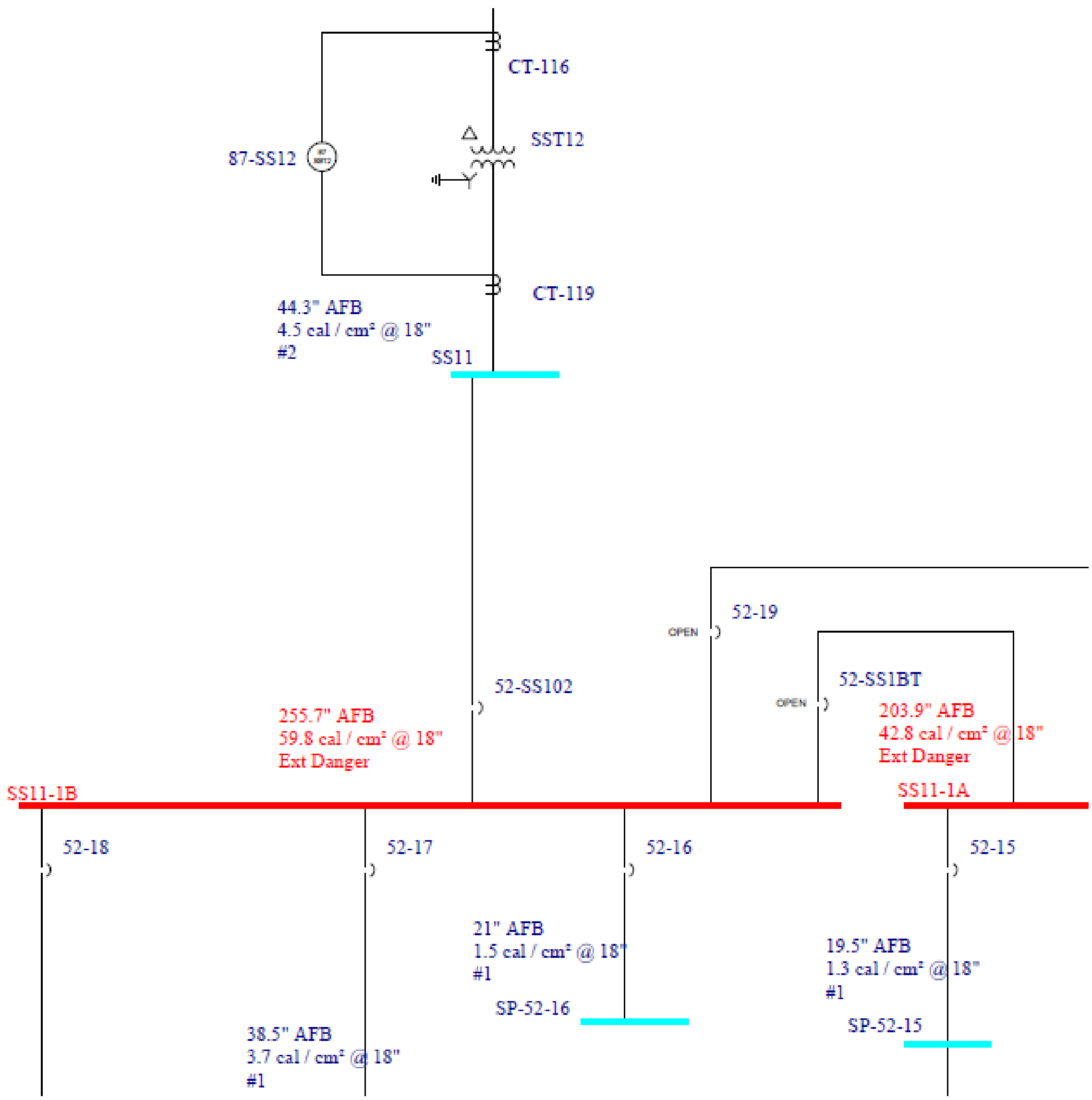


Figure 4. 13 – Arc Flash Assessment of Existing 600 V SS1 Switchboard

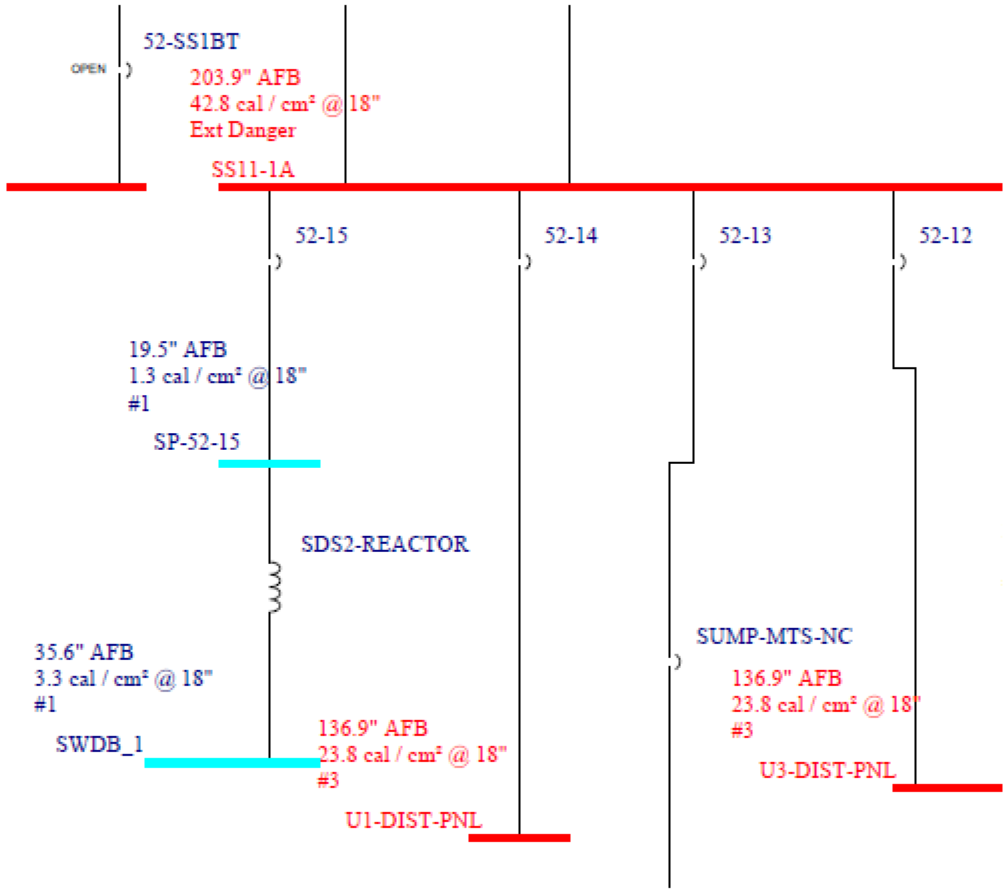


Figure 4. 14 – Arc Flash Assessment of Existing 600 V SS1 Switchboard Loads

4.6.2 New system configuration Arc Flash Assessment

The new system configuration with adjusted protective device setting results in a much safer system. The arc flash assessment indicates all 600 V SS1 switchboard loads are all classified as arc flash risk category 1 (HRC1).

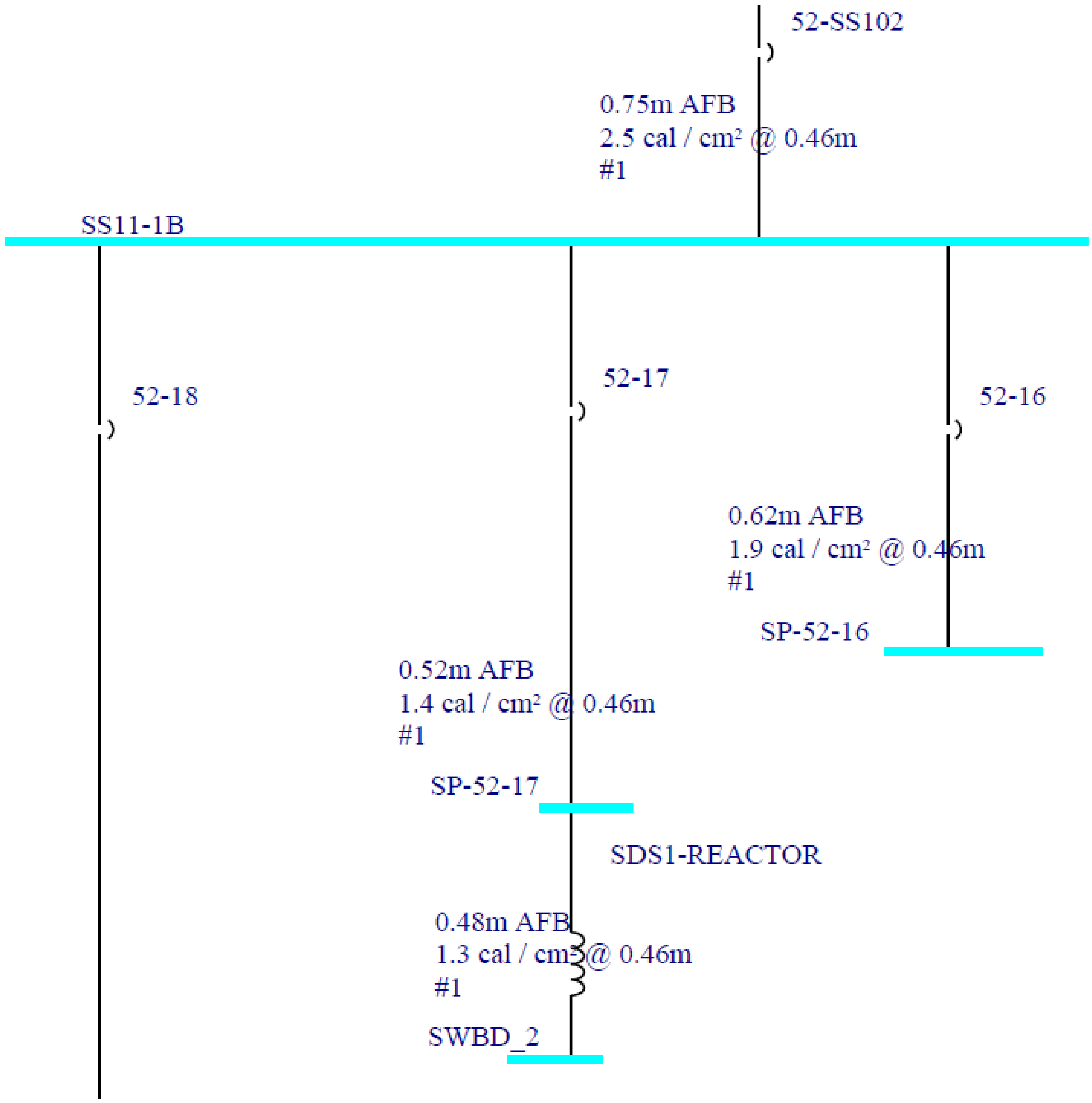


Figure 4. 15 – Arc Flash Assessment of 600 V SS1 Switchboard Load 1 (New Configuration)

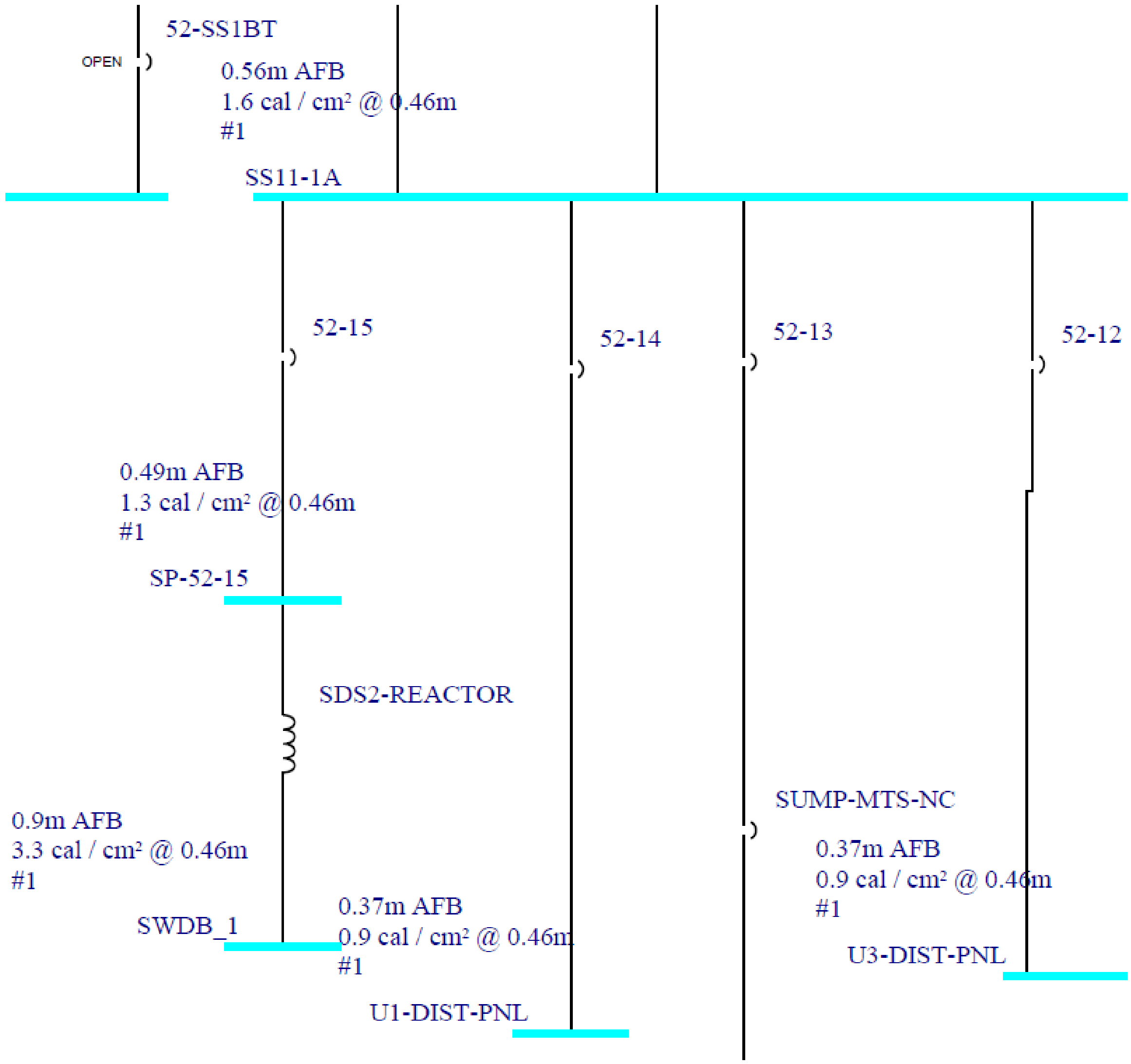


Figure 4. 16 – Arc Flash Assessment of 600 V SS1 Switchboard Load 2 (New Configuration)

4.6.3 Comparison of Arc Flash Assessment Results

An accurate arc flash hazard assessment shall cover various operating conditions, and provide the worst-case analysis. The comparison of arc flash assessment results is summarized in Table 4.6.

Table 4. 6 - Comparison of arc flash assessment results

Arc Fault Bus Name	Existing Configuration			New system configuration		
	Arc Flash Boundary (inches)	Incident Energy (cal/cm2)	Arc Flash Hazard Risk Category	Arc Flash Boundary (inches)	Incident Energy (cal/cm2)	Arc Flash Hazard Risk Category
SP-52-11	24.3	1.9	#1	24.3	1.9	#1
SP-52-15	20.3	1.4	#1	20.3	1.4	#1
SP-52-16	24.3	1.9	#1	24.3	1.9	#1
SP-52-17	20.4	1.4	#1	20.4	1.4	#1
SP-52-22	65.3	8	**#3**	29.4	2.5	**#1**
SP-52-25	24.4	1.9	#1	24.4	1.9	#1
SP-52-26	19	1.3	#1	19	1.3	#1
SP-52-28	24.3	1.9	#1	24.3	1.9	#1
SS11-1A	203.9	42.8	**Ext Danger**	29.5	2.5	**#1**
SS11-1B	203.7	42.8	**Ext Danger**	29.6	2.5	**#1**
SS22-2A	203.9	42.8	**Ext Danger**	29.5	2.5	**#1**
SS22-2B	203.7	42.8	**Ext Danger**	29.6	2.5	**#1**
SWBD_2	35.6	3.3	#1	35.6	3.3	#1
SWBD-3	42.1	4.2	**#2**	20.3	1.4	**#1**
SWDB_1	35.6	3.3	#1	35.6	3.3	#1
U1-DIST-PNL	136.9	23.8	**#3**	15.4	1	**#0**
U2-DIST-PNL	136.9	23.8	**#3**	15.4	1	**#0**
U3-DIST-PNL	136.9	23.8	**#3**	15.4	1	**#0**
U4-DIST-PNL	33.7	3	**#1**	15.4	1	**#0**

It is demonstrated that the new system configuration with adjusted protection settings on the existing protective device can reduce the arc flash hazard level and protect the site personnel.

4.7 Discussion of Keeping the Existing Two-Stage System Configuration

The proposed approach in new system configuration leads to a simpler system configuration as it eliminates unnecessary equipment from the system. Introducing a CLR and a medium voltage circuit breaker not only protects the SST but also improves system operability.

Alternatively, if the utility company decides to bear the risk of damaging critical assets, and accept the prolonged outage, the existing two staged SSTs configuration can be kept. Two stage transformers will be connected by 5kV cable after the switchgear removal. However, whether this first stage transformer is thermally and mechanically capable to withstand 74 kA fault current remains unknown. Utility companies typically do not have detailed transformer design data, and it is necessary to consult with transformer manufacturer for its capability.

Another disadvantage is generation production will be interrupted upon any station service feeder fault, since there is no breaker between the generator bus and the 600 V switchboard.

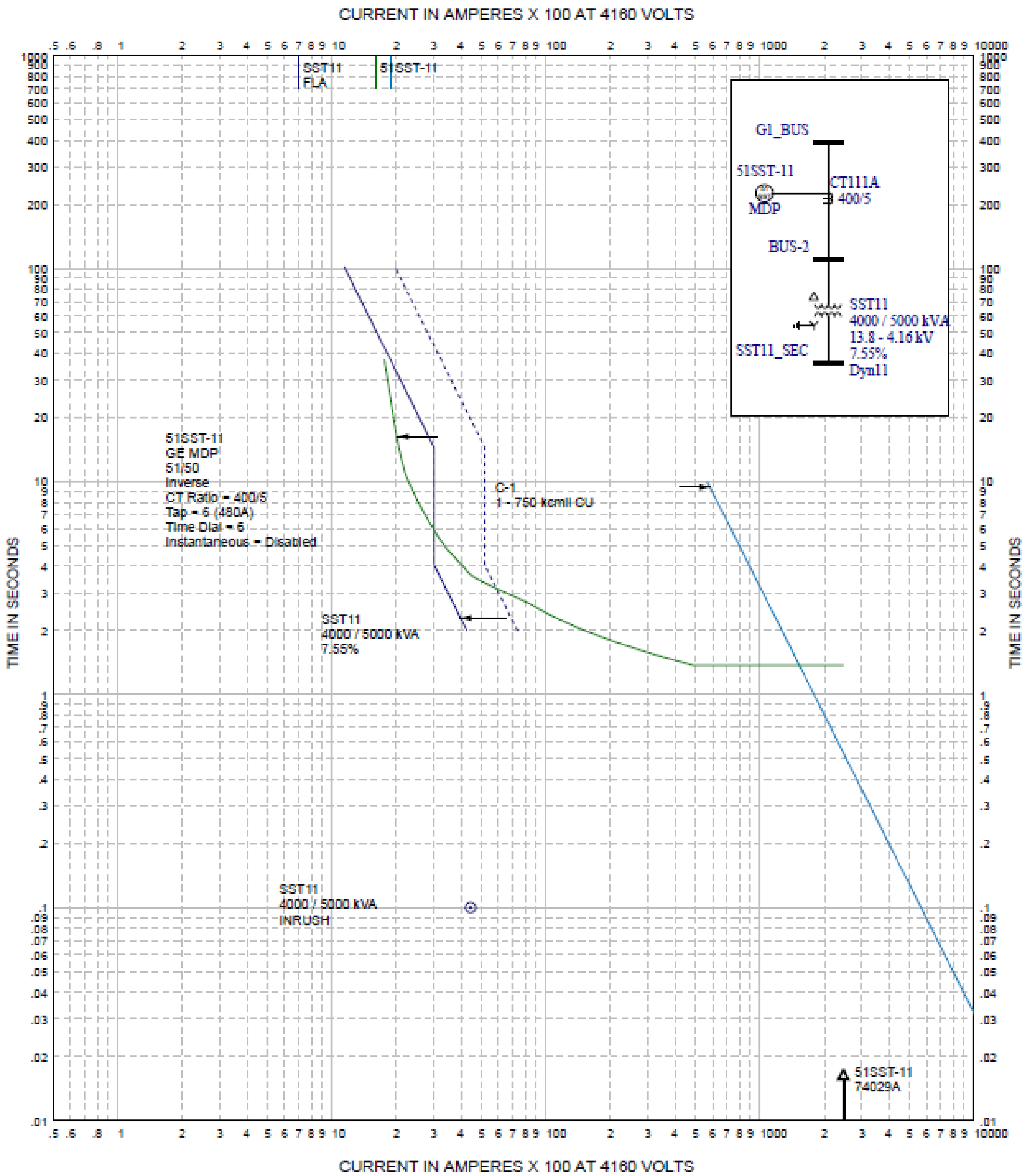


Figure 4. 17 – TCC curve identifying cable damage

4.8 Evaluation of White-Box Model RB-FMEA

To quantify the evaluation, this thesis uses two system models with high-level cost estimations and assumptions for the studied case: (1) the new system configuration and (2) the existing case with two staged configuration with medium voltage circuit breaker installed between the two stages SST as discussed in the previous section.

The NPV calculation assumptions are:

- 5% annual interest rate;
- Generation loss is $27,000 per day;
- 3 groups of 2 workers per group working 24 hours a day (8 hours per group) to locate failure point, assess equipment and temporary remedy work to bring generators back in service;
- Worker's hourly rate is $150;
- Both configurations require new station service transformers;
- 40 years of life expectancy of a station service transformer;
- It takes one day to bring the generator back in service for major incidents for the new system configuration as there is no risks exposed to the generator and GSU. One day allows technicians to perform the generator, GSU and station service feeder equipment and protection system condition checks prior to bringing the generator back in service.

- It takes 5 days to bring the generator back in service for major incidents for the two-staged configuration. Theoretically, after isolation of fault location, the generator can be back in service within one day. Practically, it is not possible. The generator, bus ducts, GSU, station service feeder equipment and protection system need to be re-checked and verified prior to bringing the generator back in service.

The possible failure location and possible causes are identified in Table 4.8. Each failure location can cause generation loss or station service loss. When generation loss occurs, it means revenue loss for the utility company. For the studied case, the new system configuration has no risk exposed to the GSU and generator. After pinpointing the failure location, the generator can be placed back on-line. The white-box model of RB-FMEA process is demonstrated in the following tables.

For both of the new system configuration and the two-staged system configuration, adding the MV circuit breaker creates two overlapped differential protection zones, one is GSU, generator, and CLR differential zone, the other one is the SST differential zone. If a fault occurs inside the GSU, generator and CLR differential zone, the protection will trip the generator and open the generator circuit breaker. Similarly, if a fault occurs inside the SST differential zone, the MV and LV breakers will be tripped open to isolate the transformer from the system without causing a generation loss. The failure locations with associated causes of failure and effects of failure are summarized in Table 4.8.

Table 4. 7 – White-box Model Failure Analysis

White-box Model of RB-FMEA	Location of Failure	Causes of Failure	Effects of Failure
New system configuration	CLR feeder side	Bus failure (at any location)	Generation (Revenue) loss
	CLR	Winding/Components	Generation (Revenue) loss, Station Service loss
	CLR load side	Cable Failure	Generation (Revenue) loss
	Breaker Failure	Fail to open	Generation (Revenue) loss
	SST Primary	Cable Failure	Trip MV breaker, Station Service loss
	SST	Winding/Components	Trip MV breaker, Station Service loss
	SST Sec.	Cable Failure	Trip MV breaker, Station Service loss
Alternative Two-Staged System Configuration	SST11 Primary	Bus failure (at any location)	Generation (Revenue) loss
	SST11	Winding/OLTC/Components	Generation (Revenue) loss
	SST11 Sec.	Cable Failure	Generation (Revenue) loss
	Breaker Failure	Fail to open	Generation (Revenue) loss
	SST12 Primary	Bus failure (at any location)	Trip MV breaker, Station Service loss
	SST12	Winding/Components	Trip MV breaker, Station Service loss
	SST12 Sec.	Cable Failure	Trip MV breaker, Station Service loss

For the new system configuration, the protection is properly designed to detect any fault within the differential protection zones. Current-limiting reactor scores 2 for safety rating due to potential mechanical breakdown, and workers can be injured by the flying debris.

For the two-staged system configuration, it relies on over-current protection to protect the 13.8:4.16 kV transformer. However, the CT will be saturated upon a fault, causing protection failure. The cable and transformer are not properly protected, and more importantly, workers are exposed to electrocution risks. Therefore, scores of 3 are given for fault locations occur at either the primary or secondary of the 13.8:4.16 kV transformer. Similar to CLR, 13.8:4.16 kV transformer scores 2 for safety rating due to potential mechanical breakdown, and workers can be injured by the flying debris. Table 4.8 below provides the safety rating scores for given failure locations and brief explanations.

Table 4. 8 – White-box Model of RB-FMEA Safety Rating Scores

White-box Model of RB-FMEA	Location of Failure	Safety Rating [*Sr*]	Comments
New system configuration	CLR feeder side	1	If the phase isolation bus duct or 15kV cable insulation breakdown or damaged, protection shall detect it, and protects the worker
	CLR	2	Worker may get injured from flying debris, if CLR fails.
	CLR load side	1	If 15kV cable insulation breakdown or damaged, protection shall detect it, and protects the worker
	Breaker Failure	1	No real threat
	SST Primary	1	If 15kV cable insulation breakdown or damaged, protection shall detect it, and protects the worker
	SST	1	No real threat due to much lower fault current
	SST Secondary	1	If 600 V cable insulation breakdown or damaged, protection shall detect it, and protects the worker

Table 4.8 – White-box Model of RB-FMEA Safety Rating Scores (Continued)

Alternative Two-Staged System Configuration	SST11 Primary	3	Due to inadequate protection, workers may be subjected to electrocution
	SST11 SST11 Secondary	2	Due to inadequate protection, SST may be damaged, and workers are subjected injury due to flying debris
		3	Due to inadequate protection, workers may be subjected to electrocution
	SST12 Primary	1	If 5kV cable insulation breaks down or is damaged, protection shall detect it, and protect the worker
	SST12	1	No real threat due to much lower fault current
	SST12 Secondary	1	If 600 V cable insulation breaks down or is damaged, protection shall detect it, and protect the worker

The existing cables contain Polychlorinated biphenyls, known as PCB. PCB is toxic, increase incidence of liver and kidney cancer and extremely persistent. It doesn't breakdown naturally, and difficult to destroy. Since 1977, Canada has banned the sale and production of PCB, and since 1985, it has been illegal to release PCB to environment [25]. Government of Canada has very strict regulations to handle, storage and dispose PCB contaminated materials. The actual cost for handling and disposal of materials contain PCB varies case by case, Table 4.9 lists the cost associated with environmental damage rating for each failure location.

Table 4. 9 – White-box Model of RB-FMEA Environmental Damage Rating

White-box Model of RB-FMEA	Location of Failure	Environment Damage Rating [*Edr*]	Comments
New system configuration	CLR feeder side	$ 200	Damaged material disposal – Cable ($ value assumed, new cable contains no PCB)
	CLR	$ 1,000	Air core, no insulation oil – Material disposal / Salvage ($ value assumed)
	CLR load side	$ 200	Damaged material disposal – Cable ($ value assumed, new cable contains no PCB)
	Breaker Failure	$ 500	Damaged material disposal – Cable ($ value assumed)
	SST Primary	$ 200	Damaged material disposal – Cable ($ value assumed, new cable contains no PCB)
	SST	$ 1,000	Dry type, no insulation oil – Material disposal / Salvage ($ value assumed)
	SST Secondary	$ 200	Damaged material disposal – Cable ($ value assumed, new cable contains no PCB)
Alternative Two-Staged System Configuration	SST11 Primary	$ 20,000	Cable may catch fire, and damage adjacent cables. Existing cable contains PCB. Assumed $10,000 to cleanup fire damage and $10,000 to proper dispose of PCB contaminated cable
	SST11	$ 5,000	Assumed SST severely damaged, and shattered
	SST11 Secondary	$ 200	Damaged material disposal – Cable ($ value assumed, new cable contains no PCB)
	SST12 Primary	$ 500	Damaged material disposal – Cable ($ value assumed, new cable contains no PCB). Damaged material disposal – Cable ($ value assumed)
	SST12	$ 200	Dry type, no insulation oil – Material disposal / Salvage ($ value assumed)
	SST12 Secondary	$ 1,000	Existing cable contains PCB. Assumed $10,000 cleanup and proper disposal of PCB contaminated cable. Damaged material disposal – Cable ($ value assumed)

Table 4. 10 – White-box Model of RB-FMEA Risk Priority Number

White-box Model of RB-FMEA	Location of Failure	Safety Rating [*Sr*]	Environment Damage Rating [*Edr*]	Risk Priority Number [*RPN*] *[PRN] = [Sr]* x *[Edr]*
New system configuration	CLR feeder side	1	$ 200	$ 200
	CLR	2	$ 1,000	$ 2,000
	CLR load side	1	$ 200	$ 200
	Breaker Failure	1	$ 500	$ 500
	SST Primary	1	$ 200	$ 200
	SST	1	$ 1,000	$ 1,000
	SST Secondary	1	$ 200	$ 200
Alternative Two-Staged System Configuration	SST11 Primary	3	$ 20,000	$ 60,000
	SST11	2	$ 5,000	$ 10,000
	SST11 Secondary	3	$ 200	$ 600
	SST12 Primary	1	$ 500	$ 500
	SST12	1	$ 200	$ 200
	SST12 Secondary	1	$ 1,000	$ 1,000

Table 4. 11 – White-box Model of RB-FMEA Labour Cost

White-box Model of RB-FMEA	Location of Failure	[*Cl*]	[*Df*]
		labour costs: [*Cl*] = [*Df*] x [#of men] x [man hour rate]	Duration of Failure, respect to generation loss (hours). Time includes locating failure point, assessing equipment and temporary remedy work to bring generators back on-line
New system configuration	CLR feeder side	$ 7,200	24 hours to replace cables
	CLR	$ 21,600	72 hours to complete condition assessment and temporary bypass CLR if needed
	CLR load side	$ 7,200	24 hours to replace cables
	Breaker Failure	$ 3,600	12 to replace the breaker
	SST Primary	$ 7,200	24 hours to replace cables, does not cause generation loss
	SST	$ 21,600	72 hours to make emergency replacement, doesn’t cause generation loss
	SST Secondary	$ 7,200	24 hours to replace cables, does not cause generation loss
Alternative Two-Staged System Configuration	SST11 Primary	$ 36,000	24 hours to replace cables
	SST11	$ 36,000	120 hours to make emergency replacement
	SST11 Secondary	$ 36,000	24 hours to replace cables
	SST12 Primary	$ 7,200	24 hours to replace cables, does not cause generation loss
	SST12	$ 21,600	72 hours to make emergency replacement, does not cause generation loss
	SST12 Secondary	$ 36,000	24 hours to replace cables, does not cause generation loss

Table 4. 12 – White-box Model of RB-FMEA Failure Cost

White-box Model of RB-FMEA	Location of Failure	[*Cp*]	[*Cl*]	[*Rl*]	[*Cf*]
		Parts costs (temporary remedy equipment, $ value assumed)	labour costs:	Revenue Loss: [*Rl*]	Overall Failure cost: [*Cf*] = [*Cp*] + [*Cl*] + [*Rl*]
New system configuration	CLR feeder side	$ 1,000	$ 7,200	$ 27,000	$ 35,200
	CLR	$ 1,000	$ 21,600	$ 81,000	$ 103,600
	CLR load side	$ 1,000	$ 7,200	$ 27,000	$ 35,200
	Breaker Failure	$ 40,000	$ 3,600	$ 13,500	$ 57,100
	SST Primary	$ 1,000	$ 7,200	$ -	$ 8,200
	SST	$ 150,000	$ 21,600	$ -	$ 171,600
	SST Secondary	$ 1,000	$ 7,200	$ -	$ 8,200
Alternative Two-Staged System Configuration	SST11 Primary	$ 1,000	$ 36,000	$ 135,000	$ 172,000
	SST11	$ 150,000	$ 36,000	$ 135,000	$ 321,000
	SST11 Secondary	$ 1,000	$ 36,000	$ 135,000	$ 172,000
	SST12 Primary	$ 1,000	$ 7,200	$ 27,000	$ 35,200
	SST12	$ 150,000	$ 21,600	$ 81,000	$ 252,600
	SST12 Secondary	$ 1,000	$ 7,200	$ 27,000	$ 35,200

Table 4. 13 – White-box Model of RB-FMEA strategy failure cost

White-box Model of RB-FMEA	Location of Failure	Prob. of Failure [Pf]	[Cf]	[CPN]	[$LCPN$]	[$SNPV$]
		Historical data (IEEE 493-2007)	Overall Failure cost: [Cf]= [Cp] + [Cl] + [Rl]	[CPN] = [Pf] x [Cf] x [RPN]	[$LCPN$] = $\sum CPN$	
New system configuration	CLR feeder side	0.0003	$ 35,200	$ 200	$ 843,942	$ 14,481,274
	CLR	0.00042	$ 103,600	$ 2,000		
	CLR load side	0.00076	$ 35,200	$ 200		
	Breaker Failure	0.02352	$ 57,100	$ 500		
	SST Primary	0.00076	$ 8,200	$ 200		
	SST	0.00042	$ 171,600	$ 1,000		
	SST Sec.	0.00283	$ 8,200	$ 200		
Alternative Two-Staged System Configuration	SST11 Primary	0.0003	$ 172,000	$ 60,000	$6,450,520	110,685,030
	SST11	0.00061	$ 321,000	$ 10,000		
	SST11 Sec.	0.00283	$ 72,000	$ 600		
	SST12 Primary	0.0003	$ 35,200	$ 500		
	SST12	0.00042	$ 252,600	$ 200		
	SST12 Sec.	0.00283	$ 35,200	$ 1,000		

The white-box model of RB-FMEA process was applied to the studied case, and the results demonstrate the applicability of proposed model for hydroelectric generating station. The white-box model of RB-FMEA defines a new quantitative approach for power system design and maintenance strategies.

4.8.1 Evaluation of Operation Life-Cycle Cost with White-Box Model of RB-FMEA

It is anticipated the new system configuration is superior to the alternative two-staged system configuration; the question is by how much.

For the studied case, the new system configuration not only mitigates the potential risks that exposed to the SST, GSU, and generator, but also saves operating cost. The switching of the SST in new system configuration is independent of the generator, thus no revenue loss. For the two-staged system configuration, with every transformer switching, it is required to switch the generator off-line. Table 4.14 shows that the operation life-cycle with the white-box model RB-FMEA is about 13% of the alternative two-staged system configuration.

Table 4. 14 – Operation Life-Cycle Cost with White-Box Model of RB-FMEA

	New system configuration	Alternative Two-Staged System Configuration	
SST switching	13.8:0.6 kV	13.8:4.16 kV	4.16:0.6 kV
Switching Frequency	4	4	4
Labour Cost	$ 300	$ 1,200	$ 300
Generation Loss	$ -	$ 4,500	$ -
Total	$ 1,200	$ 22,800	$ 22,800
NPV of switching	$ 20,591	$ 391,227	$ 391,227
Total NPV of switching	$ 20,591	$ 782,454	
SNPV	$ 14,481,274	$ 14,501,865	
Operation Life-cycle NPV	$ 14,501,865	$ 111,467,484	

Chapter 5 - Contributions, Conclusions, and Future Work

Development of a general approach and methodologies to resolve electrical issues for a hydroelectric generating station SSDS system has been completed in this thesis. This thesis uses a case study to develop a procedure to evaluate and validate the proposed approach to achieve long-term system availability, low operation maintenance, and safety of a SSDS system. It concludes that the same approach, methodologies, and evaluation process can be applied to any generating stations facing similar issues.

The contributions of this thesis are as follows:

- Provision of comprehensive overview of modern industrial design guides and standards;
- Identification of common electrical hydroelectric generating station SSDS system technical and safety issues;
    - Quantify the fault current level on the generator bus using computer simulations (in EasyPower);
    - Confirmed the inadequacy of protection CT by PSCAD/EMTDC;
- Implementation of current-limiting reactor at medium voltage in SSDS system;
    - Evaluation of TRV and RRRV impacts of the proposed CLR
- Development of general equations for voltage regulation analysis;

- Development of a white-box model of RB-FMEA to quantify overall system failure cost;
- Comparison of arc flash hazard assessment results;
- Discussion of arc flash hazard mitigation techniques;
- Validation of general applicability of the proposed approach and methodologies.

As a result of this thesis study, it demonstrated a systematic approach to improve a station service distribution system in a hydroelectrical generating station. The new system configuration not only greatly reduces the stress exposed to SST upon a fault on its secondary, but also improves overall system protection scheme and safety. Furthermore, it makes the maintenance more cost effective. Based on the studies case, over the course of 120 years operation, the operating cost of the new system configuration is less than 4% of the current configuration.

The general approach and methodologies developed in thesis demonstrated a systematic way to resolve technical issues for long-term system availability, operation maintenance, and safety of a hydroelectric generating station.

5.1 Future work

The transient stability of current-limiting reactor shall be studied to analyze how the system reacts when faults or switching operations occur in the generating station. It may allow for ease of the applicability of the proposed approach and methodologies.

Furthermore, from the generator bus fault analysis results, two major contributors are identified to be the generator and GSU transformer. It is worth investigating and developing a general model to effectively interrupt fault current contributed from GSU transformer.

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Appendix A – Detailed Equipment Data Used in the Thesis

Table A. 1 – 230 kV System Data

		Thevenin Equivalent Impedance (pu)		Fault Level	
System Description	Base kV	R0 + jX0	R1 + jx1	31 (kA)	SLG (kA)
Transmission System	230 kV	0.01279+j0.08053	0.00667+j0.05938	4.2	3.8

Table A. 2 - Generators Nameplate Data

Generator	Base (kV)	Rating (MVA)	Irated (kA)	RPM	X/R	X"dv (%)	X'dv (%)
G1	13.8	132.25	5.53	112	102.832	15.1	20.1
G2	13.8	132.25	5.53	112	102.832	15.1	20.1
G3	13.8	132.25	5.53	112	102.832	15.1	20.1
G4	13.8	115	4.81	112	95.9025	15.1	20.1

Table A. 3 - Transformer Nameplate Data

Transformer	HV (kV)	LV (kV)	Type	Class	Temp	MVA	Z	X/R
GSU1	230	13.8	Oil	ONAN/ ONAF/ ONAF	65	90/ 120/ 150	7.23	25.93
GSU2	230	13.8	Oil	ONAN/ ONAF/ ONAF	65	90/ 120/ 150	7.23	25.93
GSU3	230	13.8	Oil	ONAN/ ONAF/ ONAF	65	90/ 120/ 150	7.23	25.93
GSU4	230	13.8	Oil	ONAN/ ONAF/ ONAF	65	90/ 120/ 150	7.23	25.93
SST11	13.8	4.16	Dry	ANAF	65	4/5	7.55	8.26
SST12	4.16	0.6	Dry	AA	65	1	5.58	5.84

Table A.3 - Transformer Nameplate Data (Continued)

SST21	13.8	4.16	Dry	ANAF	65	4/5	7.55	8.26
SST22	4.16	0.6	Dry	AA	65	1	5.58	5.84
SST31	13.8	4.16	Dry	ANAF	65	4/5	7.34	8.26

Table A. 4 - Medium Voltage Circuit Breaker Nameplate Data

MV Breakers	Base (kV)	Mfr	Style	Irated (kA)	Cycles	Max (kV)	Int (kA)
52-GR10	4.16	ITE	5-HK-150	1200	5	4.76	20.825
52-GR20	4.16	ITE	5-HK-150	1200	5	4.76	20.825
52-GR30	4.16	ITE	5-HK-150	1200	5	4.76	20.825
52-GR40	4.16	ITE	5-HK-150	1200	5	4.76	20.825
52-SS11	4.16	ITE	5-HK-150	1200	5	4.76	20.825
52-SS12	4.16	ITE	5-HK-150	1200	5	4.76	20.825
52-SS21	4.16	ITE	5-HK-150	1200	5	4.76	20.825
52-SS22	4.16	ITE	5-HK-150	1200	5	4.76	20.825
52-SS31A	4.16	ITE	5-HK-150	1200	5	4.76	20.825
52-SS31B	4.16	ITE	5-HK-150	1200	5	4.76	20.825
52-SSBT1	4.16	ITE	5-HK-150	1200	5	4.76	20.825

Table A. 5 - Low Voltage Circuit Breaker Nameplate Data

LV Breaker	Base (kV)	Breaker Mfr	Breaker Style	Irated (A)	SC Int (kA)	Trip Mfr	Trip Type
52-11	0.6	West	DS-206	800	22	West	Amptector I-A
52-12	0.6	West	DSL-206	800	200	West	Amptector I-A
52-13	0.6	West	DSL-206	800	200	West	Amptector I-A
52-14	0.6	West	DSL-206	800	200	West	Amptector I-A
52-15	0.6	West	DS-206	800	22	West	Amptector I-A

Table A.5 - Low Voltage Circuit Breaker Nameplate Data (Continued)

52-16	0.6	West	DS-206	800	22	West	Amptector I-A
52-17	0.6	West	DS-206	800	22	West	Amptector I-A
52-18	0.6	West	DS-206	800	22	West	Amptector I-A
52-19	0.6	West	DS-206	800	22	West	Amptector I-A
52-21	0.6	West	DS-206	800	22	West	Amptector I-A
52-22	0.6	West	DS-206	800	22	West	Amptector I-A
52-23	0.6	West	DSL-206	800	200	West	Amptector I-A
52-24	0.6	West	DSL-206	800	200	West	Amptector I-A
52-25	0.6	West	DS-206	800	22	West	Amptector I-A
52-26	0.6	West	DS-206	800	22	West	Amptector I-A
52-27	0.6	West	DS-206	800	22	West	Amptector I-A
52-28	0.6	West	DS-206	800	22	West	Amptector I-A
52-29	0.6	West	DS-206	800	22	West	Amptector I-A
52-HG101	0.6	West	DS-416	1600	42	West	Amptector I-A
52-HG102	0.6	West	DS-416	1600	42	West	Amptector I-A
52-HU	0.6	ITE	KD	3000	75	ITE	(Std)
52-SS101	0.6	West	DS-416	1600	42	West	Amptector I-A
52-SS102	0.6	West	DS-416	1600	42	West	Amptector I-A
52-SS1BT	0.6	West	DS-416	1600	42	West	Amptector I-A
52-SS201	0.6	West	DS-416	1600	42	West	Amptector I-A
52-SS202	0.6	West	DS-416	1600	42	West	Amptector I-A
52-SS2BT	0.6	West	DS-416	1600	42	West	Amptector I-A