Arc-flash Assessment for High-Voltage Transmission Lines with Non-Communication Assisted Protection

Jahangir Khan
Stations Engineering, BC Hydro
Burnaby, BC, Canada V3N4X8
mjakhan@ieee.org

Jen Coote
Protection and Control Planning
BC Hydro
Burnaby, BC, Canada V3N4X8

***Abstract*—Arc-flash hazard assessment on high-voltage transmission lines is a challenge particularly due to lack of established methods, standards and tools. In a previous work, BC Hydro's approach to address this issue has been outlined, which primarily relies on the 'EPRI method' implemented in a semi-automated spreadsheet tool. This work builds on that approach and extends to cases involving transmission lines that are not protected using high-speed communication. Unique challenges for such scenarios include: varying fault current and fault clearing time along a line, uncertainty around fault impedance, and multi-step fault clearing. This work demonstrates an approach to assess arc-flash hazard for transmission lines with non-communicated assisted protection, and presents key results and observations.**

***Index Terms*—Arc-flash, transmission line, line protection, incident energy.**

I. INTRODUCTION

An arc-flash is the release of hazardous energy due to an arcing fault between phases, neutral or ground. This hazard phenomenon is typically manifested through intense heat, light and projectiles ejected toward nearby workers [1–3]. Arc-flash is distinctly different from an arc-blast, which is a supersonic shockwave produced when an uncontrolled arc vaporizes metal conductors. Both are part of the same arc fault, and are often referred to as simply an arc-flash. However, from a safety standpoint, they are treated separately. This article focuses only on arc-flash phenomenon, leaving arc-blast for a separate treatment.

As part of BC Hydro's mandate to provide safe, reliable, affordable and clean electricity throughout the province of British Columbia, a number of safety programs are regularly executed – arc-flash being one of them. A system-wide arc-flash assessment conducted in 2016–2020 resulted in significant system improvement and elevated awareness. Key aspects of this assessment, particularly focusing on high-voltage transmission systems were previously presented in [4]. Subsequent to that, in 2022–2023, the transmission line incident energy (IE) levels were revisited using an updated system basecase. In doing so the following factors were considered:

- Hazard conditions and work scenarios: Only single-line-to-ground (SLG) faults are considered as multiphase fault scenarios were deemed to be relatively less likely.

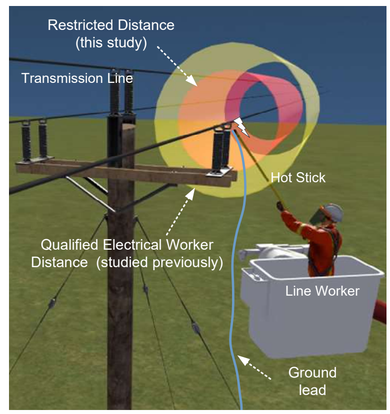

Fig. 1. Hazard scenario: erroneous attempts to apply grounding on energized line while worker approaches 'restricted work' distance

- Working distance and limits of approach (LOA): For all voltage levels, 'restricted work' distance is considered to be the worker distance. This implies use of a closer (i.e., conservative) distance compared to what has been considered before [4] (see Figure 1).
- Hazardous IE threshold: A 9 cal/cm^2 threshold of IE is used to identify cases that are of concern. This was stipulated in 2017 NESC (Rule 410A3b) for exposures involving single-phase arcs in open air. See [5] for relevant information[1].

A brief literature search on recent publications indicates progress on various fronts such as, comparative analysis of underlying methods [6], considerations for live-line work [7], and detailed observations on asymmetrical fault current [8]. However, in general, BC Hydro's approach in addressing this problem remains unchanged.

Similar to the previous study [4], a system-wide screening was done using a generalized sensitivity analysis for each kV class from 60 kV to 500 kV. In addition, circuit-specific

[1]Readers are encouraged to consult the latest edition of the National Electrical Safety Code (NESC) for the most up-to-date information (https://standards.ieee.org/products-programs/nesc/).

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IE calculation was conducted considering full-availability of communication-assisted protection for all transmission lines.

A unique aspect of this round of assessment is IE calculation for scenarios with non-communication assisted protection, especially for 60 kV and 138 kV lines. Detailed fault data (fault current along incremental distances and corresponding clearing time) are used in this case. In the absence of communication-assisted protection, IE levels on such lines rely on fault currents and corresponding clearing times in multiple steps. Note that multi-step clearing implies isolating a two-terminal faulted line sequentially from the near-end first, then from the far-end. For multi-terminal lines there may be many more steps involved.

Fault impedance is generally assumed to be zero (i.e., only bolted faults are considered). However, for detailed analysis on 60 kV and 138 kV circuits (with non-communication assisted protection) a conservative approach is taken where three sets of fault impedances are considered. These are: low (bolted faults: 0 Ω), medium (5 Ω), and high (50 Ω for 60 kV, and 75 Ω for 138 kV lines). Note that reactive element of the impedance is considered to be zero, implying fault impedance is identical to fault resistance.

While the above is closer to the real-world scenarios, the overall process of calculating IE becomes complicated, especially when hundreds of lines are in question. This article outlines a semi-automated and advanced method for IE calculation of high-voltage transmission lines, and presents sample results.

II. Incident Energy Calculation

Key assumptions, notes and considerations regarding the method applied in IEcalculation are briefly listed below:

- All overhead high-voltage (HV) transmission lines, from 60 kV to 500 kV, are assessed. Transmission cables are not in the scope of this study.
- IE calculations are based on the 'EPRI Method' [2]. In absence of a more suitable method this is found to be relevant for large gaps/arcs and HV systems [9, 10] .
- Statistical Adjustment Factor (SAF) stated in the EPRI report [2] is considered to be 1. In other words, only averaged values (mean) of the observed test results are considered.
- Issues surrounding selection, categorization and acquirement of personal protective equipment (PPE) are not in the scope of this assessment.
- All the work scenarios pertain to live-line work with reclosing blocked. To this end, it should be noted that various cases were considered and consulted with field crews, which included: inadvertent grounding; insulator changeover; contaminated insulated tools; mishandling or loss of control of insulated tool; visual inspection of faulty line switches; flashover between insulator tie wire and bonded pole hardware; induction, charging or load current arcs; phase-to-phase arc; mis-operation of uninsulated equipment (e.g., crane) and portable switch operation. The studied scneario (see Figure 1) in this work relates to majority of those.
- The fault calculations are based on 'present-stage' system basecase, which are intended to be repeated at regular intervals.
- Note that modeling of arc phenomenon (arc properties, arc path etc.) was excluded from this work.

The EPRI empirical equations are suitable for single phase arc-flash scenarios in high-voltage transmission lines where the phase-to-phase distances are large enough to exclude escalation of a single phase arc-flash to adjacent phases. The range within which this method is generally applicable is summarized in Table I.

TABLE I
EPRI Arc Test Parameter Range

Parameter	Description
Gap Orientation	Vertical
Gap Length (m)	0.31-1.5
Working Distance (m)	0.31-1.2
Current (kA RMS)	8-40
Duration (s)	0.033-0.2
Electrode Material	Stainless Steel

The relevant EPRI empirical equations are:
Average voltage gradient (in $kV\ peak/m$):

$$E_{ave} = [0.0000112G^{-8} + 1.19 + (0.069G^{-1.239} - 0.0126)I_{arc} \quad (1)$$

Incident thermal energy flux (in $cal/(s.cm^2)$):

$$\phi = (6.7E_{ave}I_{arc}G^{0.58})(3.281D)^{-1.58G^{-0.152}} \quad (2)$$

Finally, the IE (in cal/cm^2):

$$E = \phi \times t \quad (3)$$

Where G is the arc gap length (m), D is the working distance (m), I_{arc} is the arc current in kA (rms), and t is the duration of the arc current in $second$. The independent variables listed above (G, D, I_{arc} and t) effectively determine the IE levels. These parameters are listed in Table II.

TABLE II
Summary of Input Parameters

Voltage (kV)	Clearing time		Arc gap (m)	Distance (m)
	Cycles	Sec.		
60	11	0.18	0.30	0.9
138	8	0.13	0.35	1.1
230	6	0.10	0.45	1.4
287	4	0.07	0.50	1.7
360	4	0.07	0.70	2.1
500	4	0.07	0.85	2.7

For detailed analysis, more specific information is used particularly for 60 kV and 138 kV non-communication assisted protection scenarios. Note that one key input, arc current, is

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not listed above. This is because this information is directly gathered from the system basecase.

III. Protection Modelling and Automation

BC Hydro's non-communicated assisted transmission line protection for SLG faults is primarily inverse-time ground overcurrent elements. Some transmission lines will also have high-speed ground elements such as instantaneous overcurrent or distance elements that detect faults on some portion of the transmission line. There are many factors that make these high-speed elements difficult to set without risk of misoperation: mutual coupling, electrically short lines, and lack of sufficient current to name a few. Some modern line protection relays will also have ground definite-time overcurrent elements with response times somewhere between inverse-time and high-speed elements.

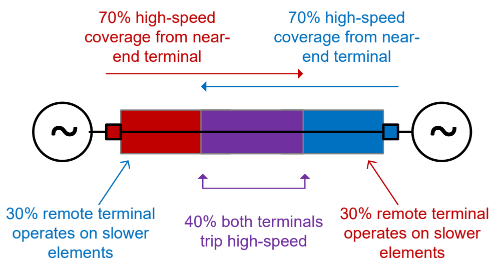

Fig. 2. A two-terminal line with overlapping high-speed ground protection elements

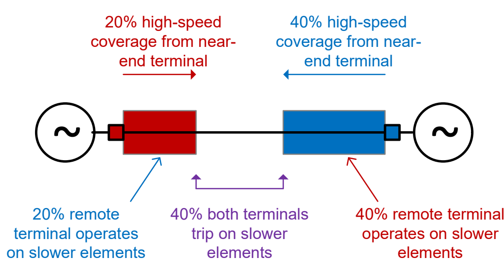

Fig. 3. A two-terminal line without overlapping high-speed ground protection elements

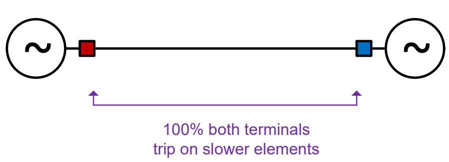

Fig. 4. A two-terminal line without high-speed ground protection elements

There may be locations along the transmission line in which protection from each terminal detects and isolates the fault in a comparable time as communicated assisted protection, i.e. clearing time from Table I. This is illustrated in Figure 2 by the overlapping high-speed elements shown in purple in the middle portion of the line.

When the ground inverse-time or definite-time overcurrent elements operate for a fault location, the time to isolate the fault is longer. The near-end terminal may trip on a high-speed element first, with the remote terminal tripping on a slower element afterwards. This is shown by the red and blue sections in Figure 2 and 3.

There may be locations where neither line terminal operates on a high-speed element, such as the middle portion of Figure 3 or all of Figure 4. Moreover, there may be lines without any high-speed elements applied at all, which is also illustrated by Figure 4. These lines would have multiple terminals detecting and isolating the fault from the slower inverse-time overcurrent elements.

Figures 2, 3 and 4 could be examples of three different lines, or they could be examples of the same line with different fault impedances applied. In this case, they are illustrated to match the line shown in the results section of this paper when applying 0 Ω, 5 Ω, and 50 Ω (for 60 kV) faults respectively.

In this updated assessment we wanted to determine the fault levels and clearing times for faults at various locations along the line and with different fault impedances no matter the protection scheme. It would be a very manual process to step through each stage of a fault and evaluate the fault current and clearing time for each subsequent step. Therefore, to conduct this work in an automated fashion, the system basecase was outfitted with models of all the transmission line ground inverse-time overcurrent, instantaneous overcurrent, definite-time overcurrent, and distance elements automatically linked from the protection relay database. Some protection relays, such as electromechanical relays, were manually modelled in the system basecase. Communication assisted protection was not modelled even if it was applied to certain lines.

The built-in fault clearing summary tool, using the stepped event analysis function, was then used to provide the resulting fault currents and protection clearing times for each stage assuming the key assumptions from Section II. The stepped-event analysis also modelled the interruption time of the circuit breakers in addition to the protection response time.

The output from these results were then post processed to determine the resulting IE for each step. The results are summarized in the following section.

IV. Results

To address various uncertainties and to develop a comprehensive understanding of transmission arc-flash hazards, the IE levels are assessed using three approaches:

1) General sensitivity analysis for all kV classes: Communication-assisted fault clearing scenarios are studied with clearing times extended from 0 toward 10 seconds (distance along a line is not observed).
2) Circuit-specific IE for all kV classes: Communication-assisted fault clearing scenarios are studied with observations along incremental distances along a line (clearing time is based on Table II).

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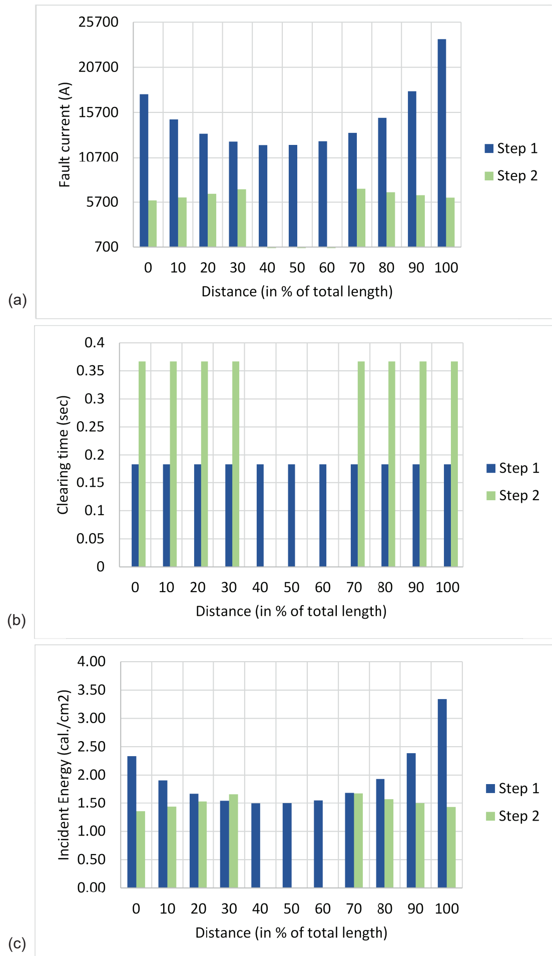

Fig. 5. IE for bolted fault (i.e., 0 Ω) for a 60 kV line

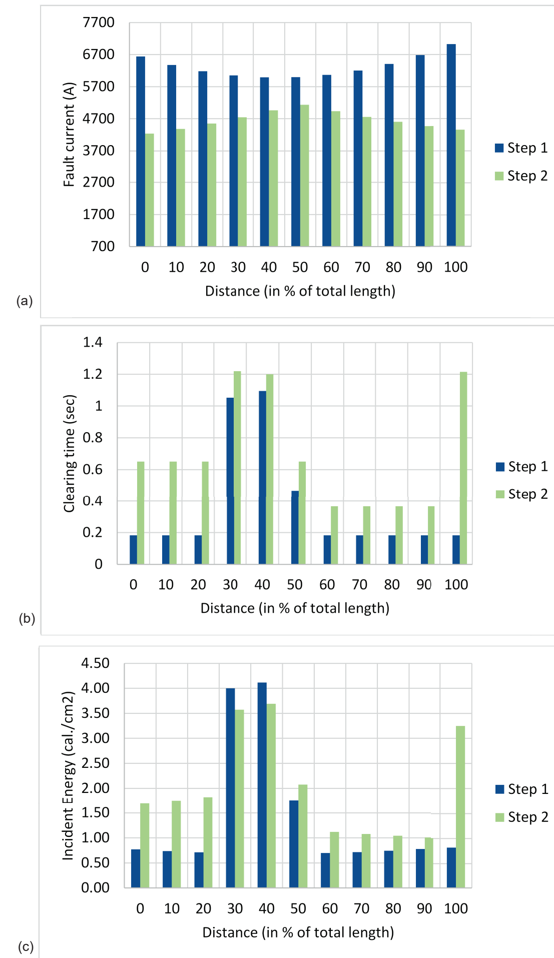

Fig. 6. IE for fault with 5 Ω impedance for a 60 kV line

3) Circuit-specific assessment for 60 kV and 138 kV: Modeled-relay information and associated fault current and fault clearing time are used to calculate IE levels for each circuit along incremental distances assuming no circuits have communication-assisted protection (as described in Section III).

The first two assessments yield results that are similar to what have been previously reported in [4]. Therefore, these are excluded hereinafter. The focus of this article is on the third assessment. The intent of this calculation is to identify circuits that may exhibit IE levels higher than 9 cal/cm^2 assuming communication-assisted protection does not exist or is not available. These lines are to be assessed further for PPE selection, administrative control or other measures.

The general steps involved are: (a) each 60 kV and 138 kV circuit is modeled to show the fault current and the fault clearing time along its entire distance (at 10% interval) under various steps (i.e., terminals involved in clearing the fault); (b) if zero fault current is not observed after the last step of fault clearing (due to numerical issues or the relays have not been modelled mostly related to customer-owned substations) additional checks are performed. This is done using assumed eventual clearing at 2, 5 and 20 seconds. The corresponding IE is calculated for each step and location (i.e., distance interval) for each line; and (c) the above is repeated for three levels of fault impedances: low (bolted faults at 0 Ω), medium (5 Ω), and high (50 Ω for 60 kV, and 75 Ω for 138 kV). Key results for a 60 kV lines are shown in Figure 5, Figure 6, and Figure 7 for three fault impedance cases. Each plot consists of (a) fault current, (b) fault clearing time and (c) IE against percentage-distance (at 10% intervals) of the line.

Among 150 transmission circuits that were studied, two double-circuit 60 kV lines showed IE from 9 to 600 cal/cm^2 (for 0 Ω case and 50 Ω case). Four single-circuit 60 kV lines exhibited IE from 9 to 25 cal/cm^2. It was recommended to conduct de-energized work following approved work procedures until further review is completed. This may include approaches to reduce the IE, develop engineered solutions, revise protection settings and/or establish appropriate work procedures. At 138 kV level no transmission circuits exceeded IE of 9 cal/cm^2.

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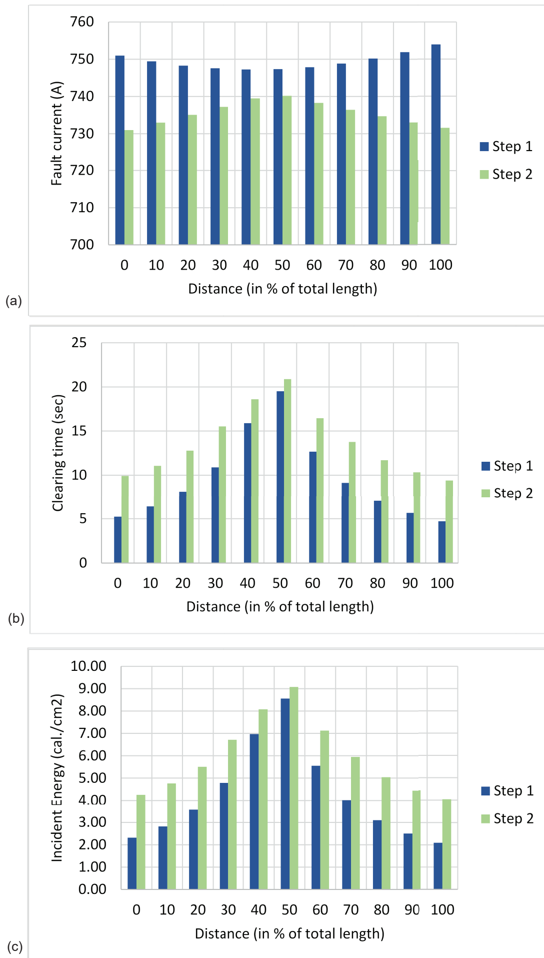

Fig. 7. IE for fault with 50 Ω impedance for a 60 kV line

V. Conclusion

This updated arc-flash assessment has provided a deeper understanding of incident energy (IE) across BC Hydro's transmission system, particularly for 60 kV and 138 kV circuits without communication-assisted protection. By incorporating detailed protection relay modeling, stepped-event analysis, and varying fault impedance scenarios, the study has highlighted locations where IE may exceed the 9 cal/cm^2 threshold established by the NESC. While the majority of circuits remain within acceptable limits, several 60 kV lines demonstrated elevated IE values, underscoring the need for enhanced safety measures.

The findings reinforce the importance of conservative assumptions, comprehensive modeling, and automation in hazard evaluation. They also emphasize the necessity of proactive mitigation strategies. Ultimately, this work advances BC Hydro's ongoing commitment to worker safety and operational reliability, ensuring that transmission line hazards are systematically identified, assessed, and managed.

Throughout the course of this work, particularly at the latter stage, improvement needs (precision, comprehensiveness and speed) were identified. Follow-up discussions with key stakeholders identified that future works may include

- revisiting high-impedance fault cases (as opposed to assessing only 0 Ω, 5 Ω and 50/75 Ω cases).
- introducing more line segments (e.g., 5% interval as opposed to 10% interval).
- updating software tools and spreadsheets (e.g., preparing scripts for in-house tool and/or generating results directly from the system basecase).
- revisiting EPRI method including definitions of arc gaps, arc impedance and statistical adjustment factors (SAF).
- assessing phase-to-phase and other fault scenarios including a review of credible scenarios where arc hazards may pose a threat. This may include arc hazard under reclosing scenarios.
- including the 230 kV system for circuit-specific reviews as there are instances of lines that do not have communication assisted protection. Transmission lines with voltages higher than 230 kV are assumed to have communication assisted protection and were considered outside of scope.
- modelling communication assisted protection in the basecase and re-running the study to see if the scheme operates at high-speed for all assumed fault locations and fault impedances. This could be for all transmission voltages including ones greater than 230 kV.

It is anticipated that future arc hazard assessments will incorporate some of these observations.

VI. Acknowledgement

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