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Abstract— **BC Hydro experienced a catastrophic fire involving an autotransformer, initiated by a ground fault on its delta tertiary winding. Typically, delta tertiary ground faults are a low immediate risk and are managed through alarms, allowing for controlled transformer outages. However, this transformer had shunt reactors connected to the delta winding. A decision was made to ground the shunt reactor neutrals to mitigate transient overvoltages on the switching breakers, which had been prone to failures. Despite the activation of high-speed ground fault protection, which responded within a quarter-cycle of the fault's occurrence, the fault rapidly escalated, resulting in a severe transformer fire with significant collateral damage. This paper explores the sequence of events leading up to the fire, discusses the lessons learned, and underscores the necessity of comprehensive disturbance analysis to enhance the safety and reliability of electrical systems.**

Keywords: Tertiary Ground Faults, Shunt Reactors, Transient Recovery Voltage (TRV).

I. Introduction

Shunt reactors are frequently employed in high-voltage (HV) and extra-high-voltage (EHV) systems to control Ferranti overvoltage. This overvoltage can occur at an open or weak line terminal during light load conditions due to the capacitive charging current of the line. While connecting shunt reactors directly to the lines and buses in these systems is common, they are sometimes connected to the tertiary windings of network autotransformers (and referred to as tertiary reactors). Because the reactive power that a reactor absorbs is proportional to the square of its terminal voltage, multiple tertiary reactors are often needed to regulate voltages in HV and EHV systems. These tertiary reactors can be incrementally switched in and out, providing more seamless voltage control than a single HV or EHV shunt reactor and offering a cost-effective solution, depending on their ratings.

Shunt reactors are frequently switched daily to regulate system voltages. The current of a shunt reactor lags the voltage by 90 degrees. When a reactor is switched out, interrupting at the natural current zero and the voltage peak, a trapped charge remains in the natural or stray capacitance of the shunt reactor winding. This charge interacts with the inductance of the disconnected reactor, creating high-frequency oscillations at the network's natural frequency. This interaction can lead to a severe high-frequency transient recovery voltage (TRV) across the breaker contacts, potentially reigniting an arc and causing breaker failure.

HV and EHV shunt reactors are typically solidly grounded, except for those on transmission lines that use single-phase trip and reclose schemes. On these lines, the shunt reactors are grounded through high-impedance neutral reactors, which are often bypassed to limit the TRV across the switching breaker. Conversely, tertiary reactors are usually ungrounded and impose higher TRV stress. Without adequate countermeasures, this stress can significantly increase the risk of breaker failure.

BC Hydro operates 12 kV tertiary reactors connected to the delta tertiary windings of system transformers in multiple locations. These three-phase reactors, connected in a wye configuration, are controlled by circuit breakers equipped with TRV capacitors. These breakers, managed by an automatic volt-ampere reactive (VAR) control scheme, insert and remove the shunt reactors from the tertiary circuit, thereby regulating HV and EHV system voltage. Initially, all reactors had ungrounded neutral buses, but frequent failures of the switching circuit breakers due to high TRV stress during reactor disconnection prompted a re-evaluation.

In the early 2000s, BC Hydro embarked on a program to replace aging 12 kV circuit breakers, including those associated with tertiary reactors. When replacing the breakers, BC Hydro decided to solidly ground the neutral bus of the tertiary reactors to reduce TRV stress on them. Zero-sequence ground overcurrent protection, sensitively set, was added to the tertiary bus, anticipating an increase in ground fault current from nearly zero to approximately three times the reactor's rated current due to the grounding.

In 2015, a bushing-to-ground fault occurred on an autotransformer's 12 kV tertiary winding, which included a shunt reactor with a solidly grounded neutral bus. The newly installed sensitive ground overcurrent protection activated within about 4 milliseconds, issuing a trip to the tertiary reactor switching breaker. However, within 10 milliseconds, the primary arc escalated to a phase-to-phase-to-ground fault on the tertiary bus before the breaker could clear the fault. This fault progression evolved to include other transformer winding terminals, resulting in multiple phase faults and causing a severe fire that inflicted extensive damage to the transformer, rendering it beyond repair.

Before the December 2015 incident, BC Hydro had experienced another autotransformer failure involving a tertiary winding ground fault. At that time, the failure was attributed to aging equipment and the potential link to shunt reactor grounding was not investigated. Following the second failure, a detailed investigation, supported by modern digital relay fault records, revealed that grounding the tertiary reactor neutral contributed significantly to the damage. The investigation determined that if the reactor had been ungrounded, like it was initially, the fault current would have been negligible, preventing the involvement of multiple phases and potentially avoiding severe damage. In response, BC Hydro adopted a policy to revert all tertiary reactors to an ungrounded configuration.

This paper explores the rationale behind BC Hydro's evolving tertiary shunt reactor grounding practices, drawing insights from field experiences and advocating ungrounding them. The paper is organized into five sections. Section II provides background information on tertiary reactor protection, the TRV duty imposed on the circuit breaker during de-energization, and the additional TRV challenges posed by ungrounded shunt reactors. Section III details the events leading to the 2015 autotransformer failure and discusses an earlier incident. Section IV outlines methods to manage TRV duty and the approach adopted by BC Hydro after deciding to revert to ungrounded shunt reactors. Section V concludes by highlighting the lessons learned from the failure events.

II. Tertiary Shunt Reactors

Shunt reactors in power systems compensate for the distributed capacitance of long lines and cables. The distributed capacitance can cause unacceptable Ferranti overvoltage on the weak terminal of a long line (or cable) during light loading conditions or radial operation. Shunt reactors absorb the VARs supplied by the distributed capacitance. Users may require opening all line breakers (with automation interlocks) to avoid prolonged line operation with one terminal closed, even if shunt reactors are used.

Fig. 1 illustrates the situation where the line's distributed capacitance is lumped to define its VAR contribution to the system (Q_C). The user may equip the line with shunt reactors to absorb the VARs (Q_L), preferably on both terminals. Alternatively, if the shunt reactor is only located on one line terminal, it is preferably on the load terminal. System studies and economics determine the amount of compensation (Q_L/Q_C).

Today, shunt reactors are typically directly connected to the HV or EHV network. In the past, as well as today in some countries, reactive compensation was made by connecting shunt reactors to the tertiary windings of transmission system transformers [1]. These transformers are often autotransformers with either an auxiliary stabilizing winding (within the tank) or a tertiary winding (brought out of the tank) so load can be connected to them [2]. The rated voltage of these windings is typically below 52 kV. The reactor connected to the tertiary winding can be as large as 100 MVAR.

HV or EHV shunt reactors connected to the line (or busbars) can be expensive. On long transmission lines that terminate on the system transformers with tertiary delta windings, users may elect to compensate Q_C with one or more shunt reactors connected to the tertiary bus. These tertiary reactors are an economical option and offer operational flexibility by allowing switching one or more reactor banks according to the compensation required by the power system.

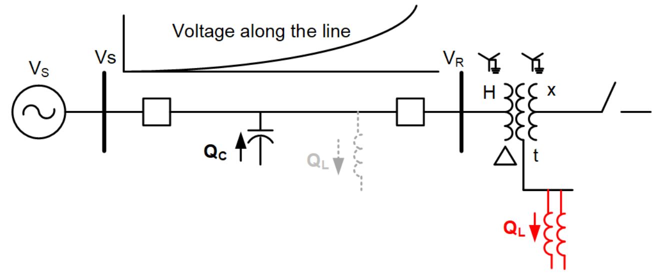

Fig. 1. Tertiary reactors used to compensate a long line's charging current.

A. *Ungrounded Tertiary Reactor Protection*

Shunt reactors connected to the transformer tertiary windings are typically ungrounded [3]. With no intentional return path, the ground fault current is small, usually less than a few amperes from the zero-sequence stray capacitance. Fig. 2 illustrates the sequence network for a ground fault in an ungrounded network, where X0 represents the zero-sequence reactance of the tertiary system. As shown in the figure, a ground fault in an ungrounded network does not modify the voltage/current triangle aside from shifting the neutral point. Therefore, the loads can continue to get the required MVA. The positive-sequence voltage (V1) is still near the source voltage (V_S), and the negative-sequence voltage (V2) equals zero because of negligible ground fault current. The voltage triangle shift is due to the zero-sequence voltage (V0) becoming equal to V_S. Shifting the voltage triangle implies that the faulted phase is at ground potential and the two other healthy phases, phase-to-ground potential are at phase-to-phase potential with respect to ground (i.e., √3 of the phase-to-neutral voltage). This significant rise in the healthy phases increases the insulation requirements. In some cases, large zero-sequence capacitive reactance (X0) can provide enough ground fault current, exceeding 4 to 5 A, which can sustain an intermittent arc in the ionized fault path, causing damaging high-frequency overvoltages. Additionally, zero-sequence capacitance can form a near-60 Hz series resonance circuit with source series inductances, resulting in a neutral inversion phenomenon. This shifts the neutral point outside the voltage triangle, causing voltages higher than the phase-to-phase voltages to appear on the healthy phases [4].

Tertiary reactors are typically dry-type air-core reactors with a single winding; Fig. 3 shows their typical protection practices [5]. The differential (87) element and/or overcurrent (50P/51P) elements provide phase fault protection. The ground overvoltage (59G) element detects ground faults. Dry-type reactors are mounted on insulators with ground clearance and phase-to-phase clearance; therefore, ground faults and phase-to-phase faults are rare. However, some cases of phase-to-phase and three-phase faults have been reported.

In addition, dry-type reactor insulation can fail in many ways, manifesting into the most common fault type—turn-to-turn faults. While 50P/51P elements provide a degree of turn-to-turn fault protection, sensitive turn-to-turn fault protection can be provided by zero-sequence voltage differential (87V) or negative-sequence directional overcurrent (67Q) elements [5] [6] [7].

Because of high reactor terminal fault currents, many utilities employ reactor circuit breakers on the neutral side instead of the terminal side. However, use of a neutral-side breaker introduces challenges, including reactor breaker failure, as discussed in IEEE Std C37.109-2023 Subclause 6.2 [5].

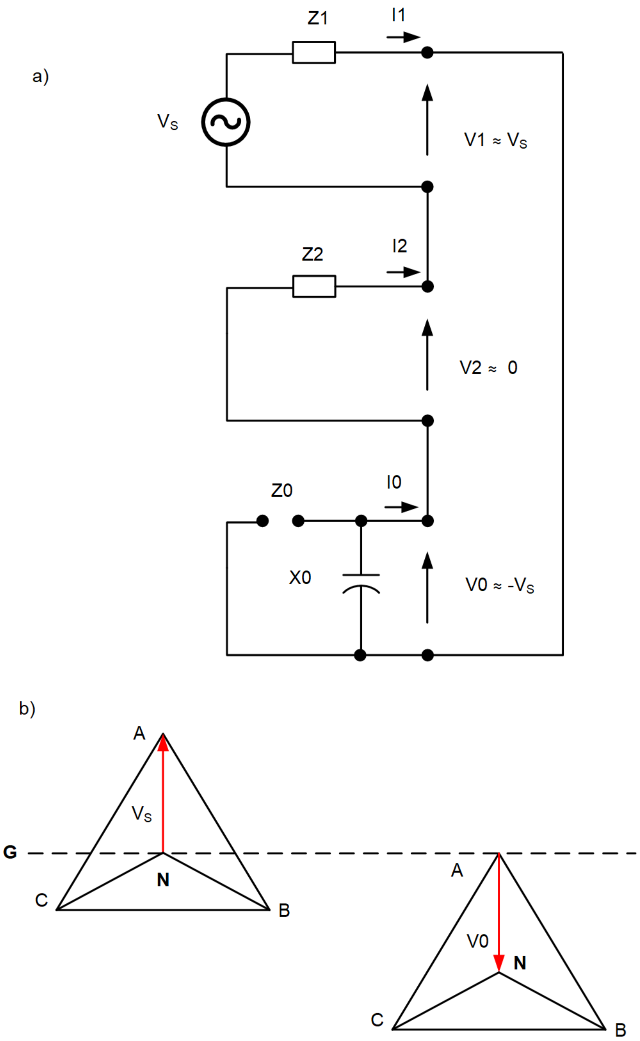

Fig. 2. Single-line-to-ground fault (AG) in an ungrounded system a) sequence network b) behavior of phase-to-ground voltages.

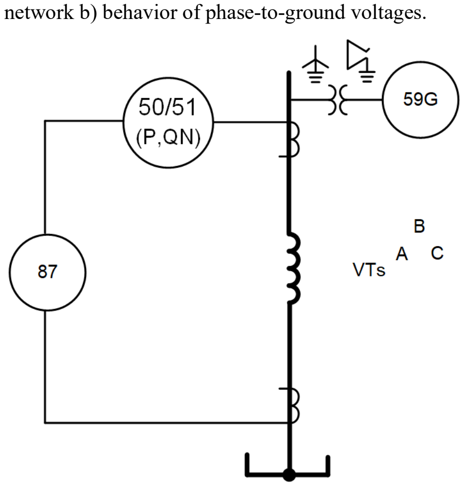

Fig. 3. Protection for an ungrounded tertiary shunt reactor.

B. *Tripping Versus Alarming Considerations for Ungrounded Reactors*

The equipment connected to the ungrounded tertiary is designed to have insulation rated for full phase-to-phase voltage [5]. However, the tertiaries in an air-insulated substation are subject to pollution, which can deteriorate the insulation over time and eventually cause a phase-to-ground fault. Due to the deteriorated insulation, the possibility of a second phase-to-ground fault is higher, especially because the healthy phase-to-ground voltages are elevated by a factor of $\sqrt{3}$ from the phase-to-ground fault. The second phase-to-ground fault may occur within minutes, seconds, or cycles after the initial phase-to-ground fault. Therefore, it is important to consider operating practices related to ground fault protection on ungrounded systems. The operating practices vary amongst utilities and are listed as follows:

- An alarm is issued, followed by a tertiary bus trip sometime later. This practice avoids a forced outage of a potentially crucial network transformer and gives the operator time to transfer loads. BC Hydro has used this practice for several decades without any issues.
- The tertiary bus is tripped immediately. This practice eliminates any risk of a tertiary bus phase-to-phase-to-ground fault. Reference [8] advocates for tripping by sharing field experience where simply alarming for a ground fault in the ungrounded tertiary of a transformer caused catastrophic events and safety risks.

Therefore, based on the bus insulation design, insulation conditions, and criticality of the transformer, the decision of tripping or alarming for a ground fault should be considered in cooperation with the operations department.

C. *Shunt Reactor Switching Challenges*

A shunt reactor deployed to regulate the system voltage may be switched frequently. BC Hydro is a highly radial system with long EHV lines, where shunt reactors may be inserted at night during light load and disconnected in the day during normal load. Shunt reactor switching is typically performed daily. The circuit breakers interrupting the shunt reactor load current introduce high transient voltages, which can lead to the following:

- There can be high TRV across the opening breaker contacts when the current is interrupted. This can cause reignitions that eventually lead to a circuit breaker failure. BC Hydro experienced breaker failures, as noted in the introduction and Section II.D.
- The tertiary reactor can also be subjected to high transient overvoltages. These transient voltages can lead to reactor failure, especially near the reactor terminals. Several such failures have been reported by Xcel Energy [9].

This section briefly outlines the factors affecting the recovery voltage duty imposed upon a circuit breaker when de-energizing a shunt reactor. The first two factors in the following subsections are responsible for high-frequency TRV, while the third subsection relates to power frequency (e.g., 60 Hz) recovery voltage. The influence of these factors is illustrated using field events from EHV applications because we did not have related field events from tertiary reactor applications, but the concepts are similarly applicable.

1) Current Zero Interruption

Circuit breakers used as switching devices are designed to interrupt high short-circuit currents on the order of tens of thousands of amperes, typically at the natural zeros of current waveforms. The load current of shunt reactors can range from hundreds to thousands of amperes, depending on their voltage and MVAR ratings.

The shunt reactor current is an inductive current; therefore, it lags the voltage by 90 degrees. Thus, the voltage is at a positive or negative maximum when the current is interrupted at its natural zero crossing, and the natural or stray capacitance of the disconnected shunt reactor network retains the electric charge. This charged capacitance interacts with the inductance of the disconnected reactor, creating high-frequency resonant voltage oscillations. Fig. 4 illustrates this phenomenon by using a field event recorded by a digital fault recorder with a sampling rate of 5,760 Hz (or 96 samples per cycle).

In the recorded event, a solidly grounded 345 kV, 201 MVAR shunt reactor tripped after a CG fault at its terminal. The reactor bank comprises three single-phase reactors with an inductance (L) of 1.571 H. Capacitively coupled voltage transformers (CCVTs) were used to measure the phase-to-ground voltages (for both reactor and system). Two sets of CCVTs, each with 4 nF (total 8 nF) capacitance, remained connected to the reactor bus after disconnection from the source. The stored energy oscillated between the CCVT capacitances and the reactor at a natural ringdown frequency (f_{LC}) calculated by (1). For this system, we calculate a ringdown frequency of 1,420 Hz by using (2), which is close to the frequency measured from the field event of approximately 1,020 Hz. Data related to additional stray capacitance on the shunt reactor bus were unavailable and not accounted for, so the estimated ringdown frequency of TRV oscillations was higher than measured.

The transient recovery voltage (VABKR, VBBKR, and VCBRK) that the disconnecting breaker was subjected to is the voltage difference between the source voltage (VASYS, VBSYS, and VCSYS) and the shunt reactor voltage (VA, VB, and VC). The crest of the recovery voltage on the B-phase (VBBKR) was 587 kV, approximately 2 pu of the pre-fault 297 kV phase-to-ground peak.

$$f_{LC} = \frac{1}{2 \bullet \pi \bullet \sqrt{L \bullet C}} \tag{1}$$

$$f_{LC} = \frac{1}{2 \bullet \pi \bullet \sqrt{1.571\ H \bullet 8\ nF}} = 1420\ Hz \tag{2}$$

Another example is illustrated in Fig. 5, where high-frequency TRV is recorded from accurate resistive voltage dividers. Due to the size of the resistive dividers, only the A- and C-phase voltage measurements were available. The sampling rate of the recorded data is 1 MHz. The waveforms were recorded during field testing of the normal de-energization of a 500 kV reactor. The ringdown frequency of TRV was 1,534 Hz, and the crest value across the breaker reached 890 kV, slightly greater than 2 pu of the 421 kV phase-to-ground peak. Both Fig. 4 and Fig. 5 demonstrate the significant TRV stress on a breaker when de-energizing a shunt reactor.

Ringdown frequencies of 1 kHz to 5 kHz are typical for HV and EHV systems [3], as in the examples of Fig. 4 and Fig. 5. Shunt reactors connected to transformer tertiaries (at ≤ 52 kV) can have even higher ringdown frequencies, which can further increase TRV stress due to a higher rate of rise of recovery voltage, as explained in Section III.C.4.

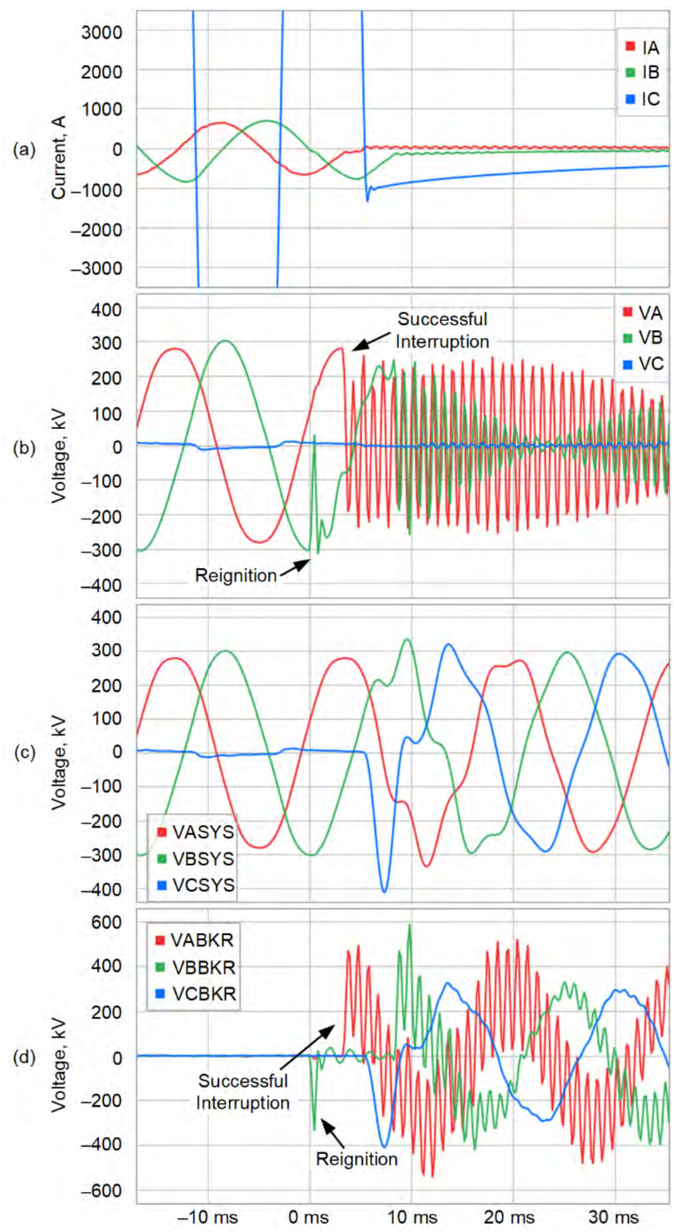

Fig. 4. 345 kV reactor trip following a CG fault showing a) reactor currents, b) reactor voltages, c) system voltages, d) and breaker voltages.

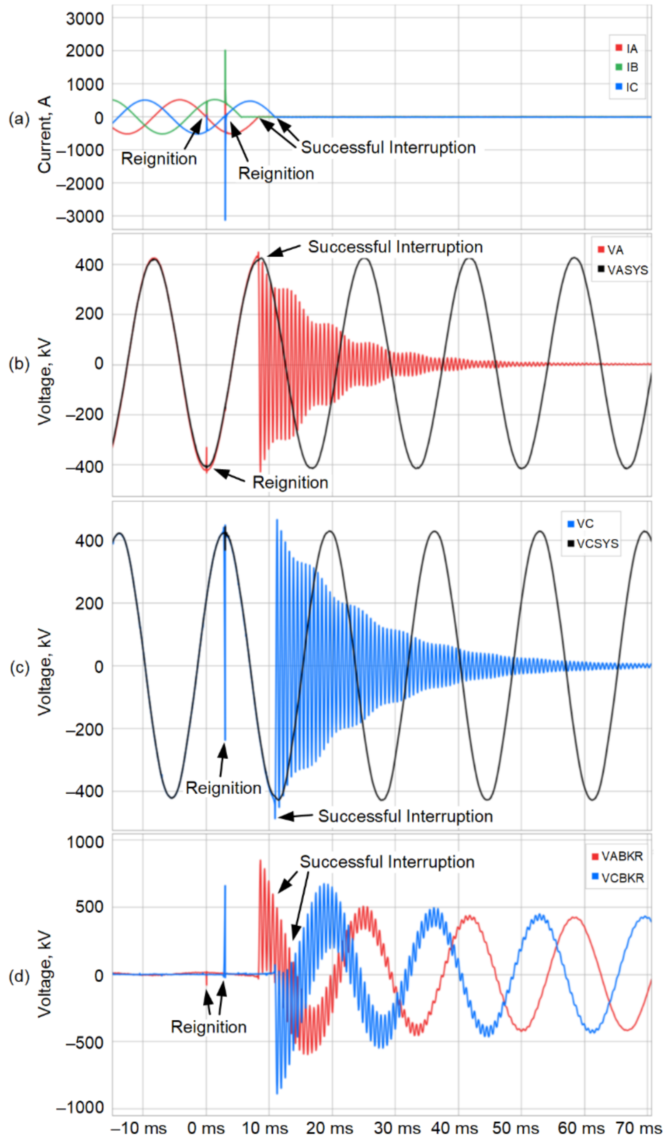

Fig. 5. 500 kV reactor de-energization test measured by resistive voltage dividers showing a) reactor currents, b) A-phase reactor and system voltages, c) C-phase reactor and system voltages, and d) breaker voltages.

2) *Current Chopping*

Circuit breakers are intended to interrupt high short-circuit currents. They risk prematurely interrupting low-magnitude inductive load currents before a natural current zero crossing. When a breaker starts to open, an arc forms across the contacts to interrupt the current. A low-magnitude load current arc can become unstable and interact with the network, introducing negatively damped high-frequency oscillations that cause abrupt current interruption before the natural zero of the load current. This phenomenon of sudden interruption is referred to as current chopping. Current chopping can introduce harmful transient overvoltages that add to the ringdown TRV, as represented by (3) [9].

$$V_{HF} = \sqrt{V_0^{\,2} + \frac{L}{C} \bullet i_C^{\,2}} \tag{3}$$

where:

V_{HF} is the high-frequency component of the TRV.

V_0 is the TRV component from the trapped charge in the capacitance, resulting from current interruption at a natural current zero crossing.

L is the inductance of the shunt reactor.

C is the stray bus capacitance.

i_C is the chopped current.

The value of the chopped current (i_C) depends on the capacitance seen from the circuit breaker terminals (C_t), the number of circuit breaker interrupters (N), and the chopping number of the interrupter (λ), as shown in (4) [3]. The value of C_t includes the source-side capacitance, breaker grading capacitance, and the stray load-side capacitance (C). The chopping number is a characteristic value of the interrupter and is obtained from laboratory tests.

$$i_c = \lambda\sqrt{NC_t} \tag{4}$$

Current chopping causes magnetic energy to be stored in the inductance because the magnetic field cannot change instantly. The stored magnetic energy is released into the stray or surge-control capacitance across the reactor. The energy exchange between inductance and capacitance introduces a transient voltage, referred to as the suppression peak [3]. Fig. 6 shows an example of current chopping where an EHV line was tripped using an air-blast breaker with a 400 Ω opening resistor [10].

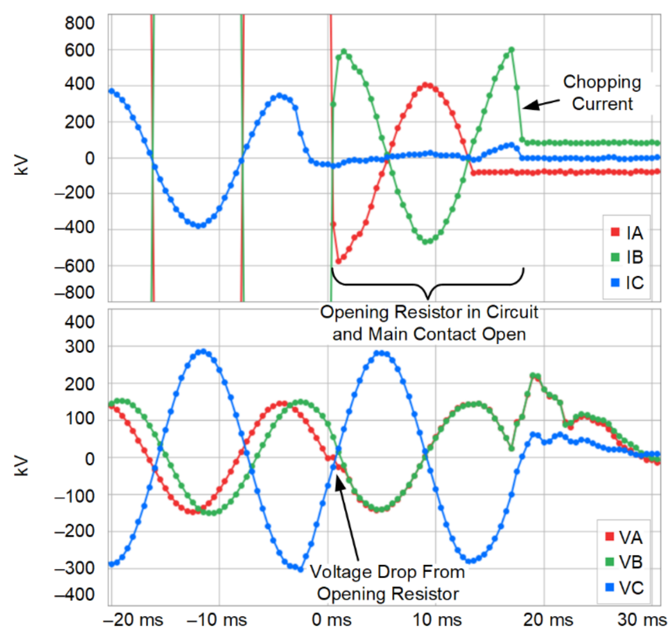

Fig. 6. Current chopping from a field event of 345 kV transmission line air-blast breaker equipped with opening resistors.

For tertiary reactors connected to voltages below 52 kV, [3] considers current chopping a significantly lesser concern than circuit breaker arc voltages. This is because tertiary reactor load currents are considerably higher than those in HV and EHV reactors. While this is generally true, field experience has shown current chopping to be a contributing factor to failures in 34.5 kV and 50 MVAR tertiary reactor applications with rated current less than 1,000 A [9]. The breaker manufacturer noted that the chopped current could be as high as 50 A in that application. Therefore, it is especially beneficial to consult the breaker manufacturer for their recommendations when the chopped current is less than 1000 A.

3) First-Pole-to-Clear Factor

When a breaker opens to de-energize an ungrounded tertiary reactor, the first phase to interrupt is subjected to higher power frequency recovery voltage than the subsequent two phases for a short period because the interruption is yet to occur in those phases. The voltage developed across the breaker contacts of the first phase to open is quantified using the first-pole-to-clear factor, k_{pp}, which is defined as:

$$k_{pp} = \frac{V_C}{V_N} \tag{5}$$

where:

k_{pp} is the first-pole-to-clear factor.

V_C is the power frequency voltage across the breaker contacts of the first phase to interrupt the arc when the other two phases have not yet interrupted.

V_N is the power frequency voltage across the breaker contacts after all three phases have interrupted.

The value of k_{pp} depends upon the reactor grounding when interrupting its load current. k_{pp} can be determined using the sequence impedances of the reactor:

$$k_{pp} = \frac{3}{\frac{X_1}{X_0} + 2} \tag{6}$$

where:

X_1 is the positive-sequence reactance of the reactor.

X_0 is the zero-sequence reactance of the reactor.

In a wye-grounded configuration of a three-phase shunt reactor, X_1 and X_0 are equal for shell construction or three single-phase reactors forming a three-phase bank. X_0 can be less than X_1 for three-phase core construction. Thus, the maximum value of the k_{pp} is 1 in a grounded configuration, indicating that the power frequency recovery voltage is essentially the same in all three phases and equal to the phase-to-ground voltage.

In an ungrounded configuration, X_0 is infinite, thus k_{pp} approaches 1.5, indicating the power frequency recovery voltage on the first phase to clear can be as high as 1.5 pu of the phase-to-ground voltage.

4) Reignition

The three factors discussed earlier impact the breaker TRV. As evident from the breaker voltages in Fig. 4 and Fig. 5, there is a very high rate of rise of recovery voltage (RRRV) when the breaker opens. The breaker has a finite capability to withstand RRRV, as determined by its rate of rise of dielectric strength (RRDS). RRDS is the rate of increase in voltage over time that the circuit breaker can withstand as the contact gap increases [11]. The circuit breaker manufacturer can provide RRDS as a kilovolt-per-millisecond parameter based on statistical data.

If the RRRV exceeds the breaker's RRDS, the breaker is less likely to interrupt the reactor current successfully. If the TRV exceeds the breaker's RRDS, reignition can occur. Reignition corresponds to the resumption of current within a quarter of a power cycle following the initial current interruption [3]. An example of reignition can be seen in Fig. 4 at t = 0 ms (milliseconds), where VB collapses from its peak at an IB current zero crossing. We can also see example reignitions in Fig. 5 on VA at t = 0 ms and VC at t = 2.78 ms near the IA and IC zero crossings, respectively.

Reignitions can significantly erode the breaker contacts, damage the nozzle, and deteriorate reactor insulation. Multiple reignitions can eventually lead to tertiary reactor and circuit breaker failures.

D. *Solid Grounding of Tertiary Reactors*

Over the years, BC Hydro experienced multiple 12 kV circuit breaker failures. These breakers were exclusively used for switching the shunt reactors connected to the tertiary windings of the system transformers. Despite the breakers being installed with 0.125 µF TRV capacitors, as shown in Fig. 7, the failures were attributed to TRV stress from their frequent switching operations.

In the early 2000s, BC Hydro initiated a 12 kV breaker replacement program. As part of this program, BC Hydro decided to ground the neutral bus of the shunt reactors when replacing the breakers. Grounding was intended to reduce the first-pole-to-clear factor and, consequently, power frequency TRV duty on the breakers when switching out the shunt reactor.

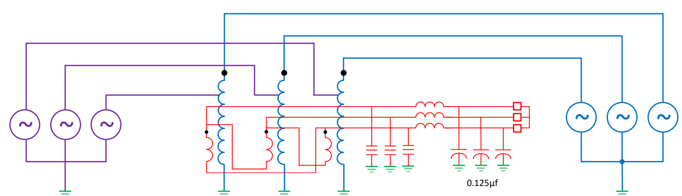

Fig. 7. Tertiary reactor application with switching breaker.

Before grounding the neutral bus of the shunt reactor, ground faults on the delta tertiary winding were expected to produce currents of an ampere. This low-magnitude current did not pose the risk of an intermittent ground arc and harmful resonant phase-to-ground voltages. The anticipated voltage on the healthy phase was limited to phase-to-phase voltage, and the tertiary system was designed as an ungrounded system to withstand them safely. Therefore, ground faults were deemed to pose no immediate risk. These faults were alarmed, rather than tripped, using a 15-cycle time-delayed zero-sequence overvoltage measured on the tertiary bus. This alarm allowed for a planned outage to mitigate the fault, avoiding forced trips of the system transformer and undue reliability risks due to ground faults.

After grounding the shunt reactor, it was recognized that the ground fault current would increase from approximately an ampere to several thousand amperes, approximately three times the reactor's rated load current. Sensitive and instantaneous zero-sequence ground overcurrent protection was added, determined from the measurements of the three-phase currents entering the shunt reactor. This protection was designed to open the switching breaker of the shunt reactor, breaking the ground path and generating an additional ground alarm for corrective action.

III. Field Experience With Solid Grounding of Tertiary Reactors

BC Hydro experienced two transformer failures, one in 2013 and another in 2015. Initially, these failures were thought to be due to the transformers' advanced age. However, the more dramatic failure in 2015 prompted a thorough investigation, revealing that the actual cause was collateral damage from the grounding of tertiary reactors.

This section delves into the 2015 failure, exploring the implications of grounding decisions on tertiary reactors. It provides an in-depth analysis of the incident, where a ground fault on a tertiary bushing terminal, coupled with the solid grounding of the shunt reactor, resulted in significant transformer damage. Additionally, a brief review of the waveform from the 2013 failure highlights that the same grounding decisions contributed to both incidents.

A. The 2015 Blaze and Damage

On December 15, 2015, at 5:40 a.m., a major fire erupted at a BC Hydro substation. Dramatic images, widely circulated on social media, showed massive flames and thick black smoke rising into the pre-dawn sky, as shown in Fig. 8. A nearby resident described hearing a loud bang, likening it to a bomb explosion at the onset of the fire. Firefighters took approximately 3.5 hours to extinguish the blaze, after which BC Hydro's team could enter the site and assess the extent of the damage. The crew confirmed that a 230/64.4/12.6 kV autotransformer sustained catastrophic damage, as evident from Fig. 9.

B. Ground Fault on the Tertiary Bushing: Event Analysis

The burnt transformer was 44 years old and nearing the end of its service life. Initially, it was suspected to have experienced an insulation breakdown that ignited the blaze. However, a different story emerged as physical evidence of the damage, waveforms, and sequence-of-event data became available. A ground fault on a 12.6 kV tertiary bushing terminal initiated a sequence of events that culminated in the catastrophic fire. Typically, a fault on a tertiary bushing would not escalate dramatically. However, in this instance, a decade-old decision to ground the shunt reactors connected to the tertiary winding of the transformer led to a fault that evolved into a significant incident. The grounding aimed to reduce the stress on the breaker during switching operations but inadvertently resulted in considerable collateral damage during the ground fault.

Fig. 8. Blaze at BC Hydro substation on December 15, 2015.

Fig. 9. Transformer damaged by the blaze.

C. The Transformer and its Layout

The damaged autotransformer had a rating of 90/120/150/168 MVA at 230/64.5/12.6 kV. The 12.6 kV delta windings had a tertiary bus connected to a 11.5 kV, 37.5 MVAR shunt reactor, as depicted in Fig. 11. At the 12.6 kV nominal voltage, this is effectively a 45 MVAR reactor. The reactor's nominal load current was 2,062 A at 12.6 kV. It was a three-phase iron-core reactor with a three-legged core construction. Its three phases were connected in a wye configuration, with a switching circuit breaker (12CB1) on the neutral side. A photo of the tertiary reactor and its circuit breaker is shown in Fig. 10. The neutral bus of the shunt reactors was grounded when the old 12CB1 was replaced with a new circuit breaker to reduce TRV stress during de-energization that occurred almost daily.

The transformer's protection was upgraded using modern microprocessor-based relays. The relays' multifunction capability was leveraged to embed reactor protection within the transformer protection. Fig. 11 only shows protection elements relevant to the event analysis: 87T is the primary transformer differential relay; 51RX is the phase and ground reactor protection embedded within the 87T relay; and 51RXS is the tertiary bus overcurrent, also serving as the backup to the 51RX. The 50N and 50NS elements of 51RX and 51RXS protection, respectively, were sensitively set to provide ground overcurrent protection. They were intended to operate quickly for tertiary ground faults anticipated from the neutral grounding of the shunt reactor.

Fig. 10. Shunt reactor and its circuit breaker (left of damaged transformer).

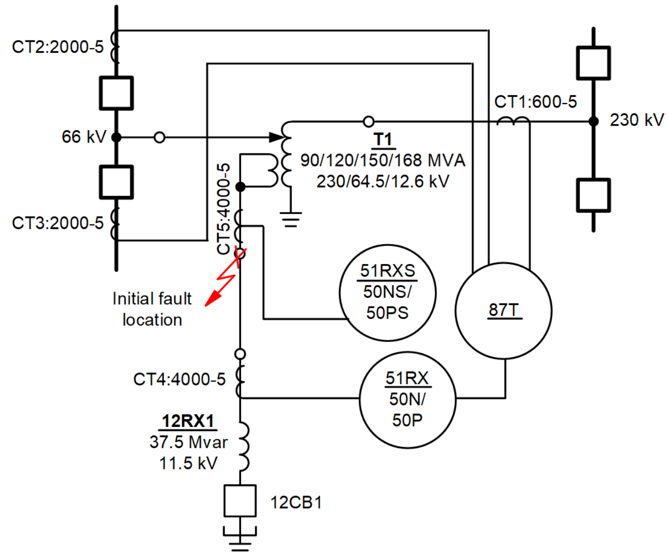

Fig. 11. Protection one-line diagram.

D. *Sequence of Events*

Strong winds contributed to the escalation of the fault on the morning of December 15, 2015. At 5:38 a.m., a terminal-to-ground fault occurred on the autotransformer's 12 kV B-phase bushing; the 12 kV tertiary windings were connected to the grounded shunt reactor. The grounding led to a significant ground fault current (3I0) of approximately 10 kA, establishing a sustained primary arc from the bushing to the ground. The high wind made this arc jump, engulfing the other bushings shortly after.

Fig. 12 shows a top view of the transformer bushings layout, showing the 12 kV and 66 kV low-side bushings next to each other. The fault arc first jumped from the B-phase to the C-phase, evolving to the 12 kV B-to-C-to-ground (BCG) fault. Subsequently, it jumped to the 66 kV A-phase bushing and evolved into a multi-winding fault.

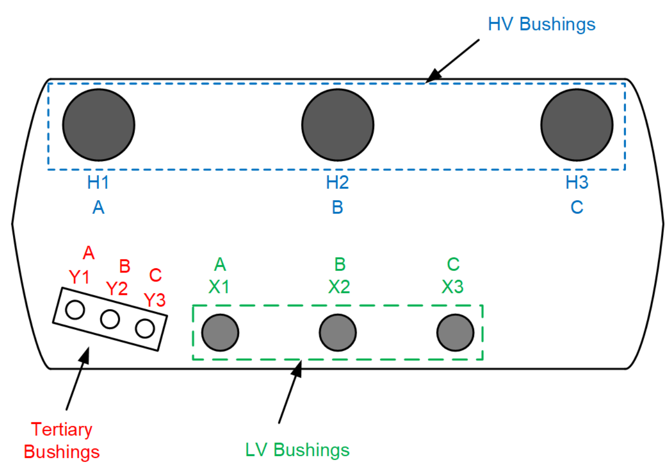

Fig. 12. Layout of the transformer bushings.

Table I outlines the detailed sequence of events synthesized from the data captured by the 87T relay. The reference time (t = 0 milliseconds) corresponds to 5:18 a.m. when the initial ground fault occurred.

TABLE I
DETAILED SEQUENCE OF EVENTS FROM THE 2015 BLAZE

Time in Milliseconds	Event
0	B-phase-to-ground (BG) fault on the 12 kV tertiary bushing occurred
4.2	Sensitive zero-sequence overcurrent protection (50N) operated and sent a trip to open 12CB1
10.4	The primary ground fault current arc jumped to the 12 kV C-phase bushing, evolving into a BCG fault
10.4	Instantaneous phase overcurrent protection (50P) operated and sent a trip to open transformer breakers
25	Transformer primary differential protection (87T) operated
37	The primary fault current arc jumped from the 12 kV bushing to the 66 kV A-phase bushing, introducing an A-phase-to-ground (AG) fault
45	The 230 kV bus breakers opened
53	12CB1 opened
80	The 66 kV bus breakers opened

Fig. 13 presents the current waveforms captured by the 87T relay and the relevant protection elements triggered during the event. The reactor current, the output of CT4, showed a steady load before the fault. Thereafter, a significant zero-sequence current appeared, indicating the start of the ground fault. The shunt reactor's ground overcurrent protection (50N), operating on the CT4 output, triggered approximately 4.2 milliseconds into the fault, followed by the phase overcurrent protection (50P) at 10.4 milliseconds. Around 10.4 milliseconds, the reactor C-phase current began to increase, confirming the evolution of the fault into a phase-to-phase-to-ground fault. At about 37 milliseconds after the initial fault, A-phase current in the 66 kV winding began to increase, confirming the further evolution of the fault into a multi-winding fault. However, the restrained differential element (87R) was already asserted at about 25 milliseconds—before the evolution into a multi-winding fault.

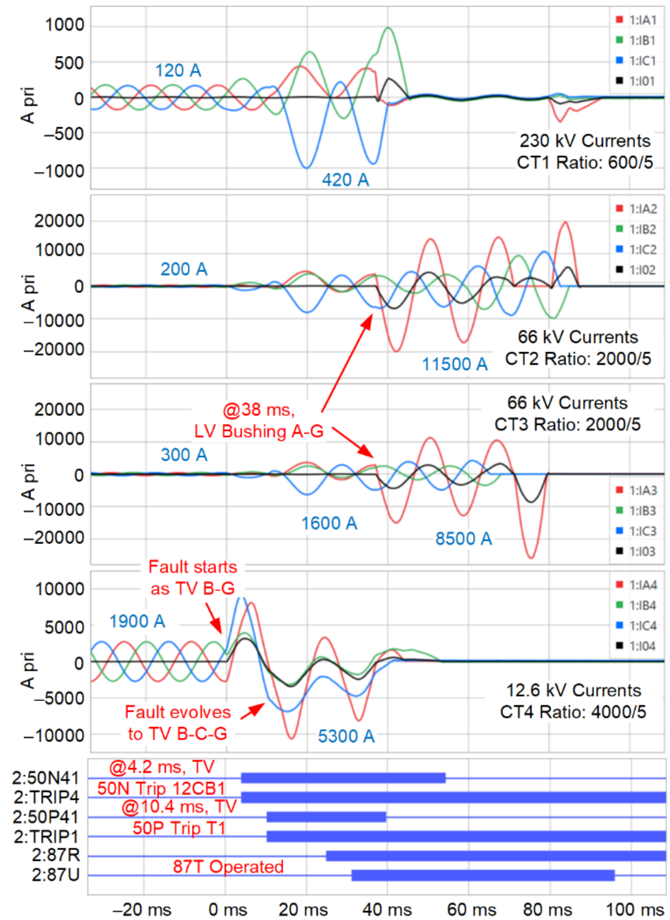

Fig. 13. Event record captured from 2015 blaze showing currents measured by transformer protective relay and protection response.

E. *Validation of the Event*

The sensitively set tertiary ground overcurrent protection (50NS), which also backed up the shunt reactor overcurrent protection, connected to CT5 in Fig. 11 in the tertiary bushing, did not operate. The non-operation confirmed that the ground fault initiation was external to the tertiary winding. The interconnected sequence diagram of the transformer for a single-phase-to-ground fault, as shown in Fig. 14, can be used to illustrate the initiation of the ground fault. The zero-sequence network is an open circuit for a ground fault in front of CT5, which was the reason for the 50NS's non-operation.

Fig. 15 illustrates the positive- (I1), negative- (I2), and zero-sequence (I0) currents in the shunt reactor before and after the ground fault initiation. Initially, for the BG fault, I1 did not change significantly, I2 increased slightly, and I0 increased significantly. We tried to validate the currents by using a short-circuit model and obtained an I1 approximately equal to I0. Referring to the sequence network of Fig. 14 and considering the strong power system (i.e., small Z1 and Z2), the positive-sequence source voltage is imposed across the X1 and X0 of the reactor. The significantly higher I0 compared to I1 could only be because of a lower X0 compared to X1. Our model had X0 = X1. Referring to Section III.C, this three-phase reactor had a three-phase construction and can have significantly lower X0 than X1. By referring to the ratio of I0 to I1 from the event data of Fig. 15, we updated our reactor model X0 = 0.58 • X1.

We did not have the X0 data available for this reactor. A test report from another reactor (with three-phase, three-legged core construction) shows X0 to be 0.65 of its X1, confirming that the 0.58 value we used was reasonable. Table II provides the results of the short-circuit model simulation with only X0 updated. The results very closely match the field data. The ground fault current (3I0) is greater than 10 kA (I0 = 3350 A), which is about five times the reactor nominal current. The reactor's X2 was much higher than the system's Z2, resulting in minimal reactor I2 (as measured by CT5).

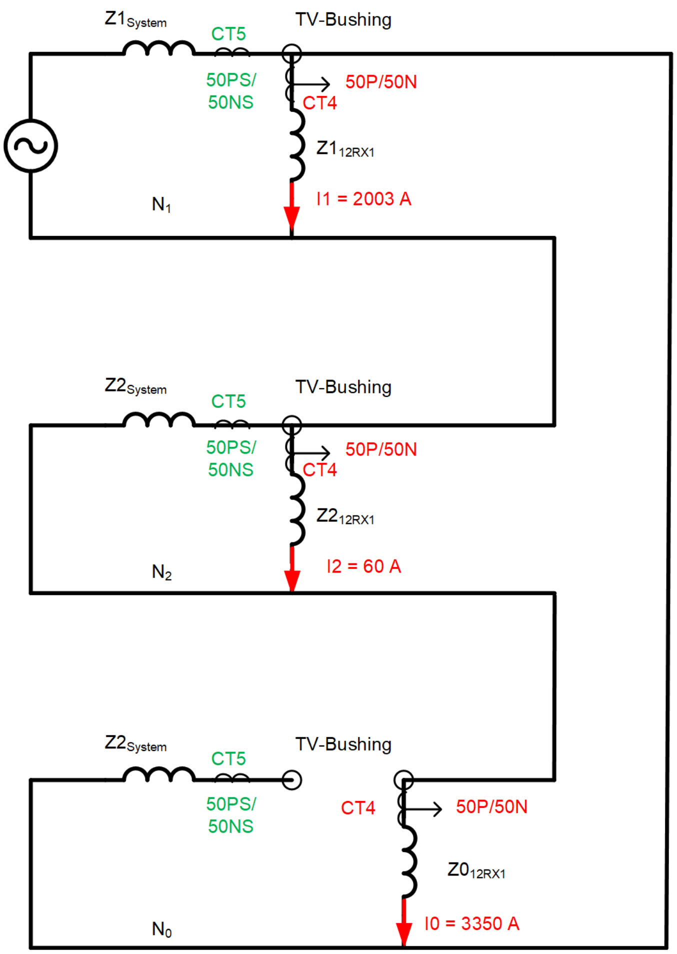

Fig. 14. The interconnected sequence diagram of the transformer for a BG fault.

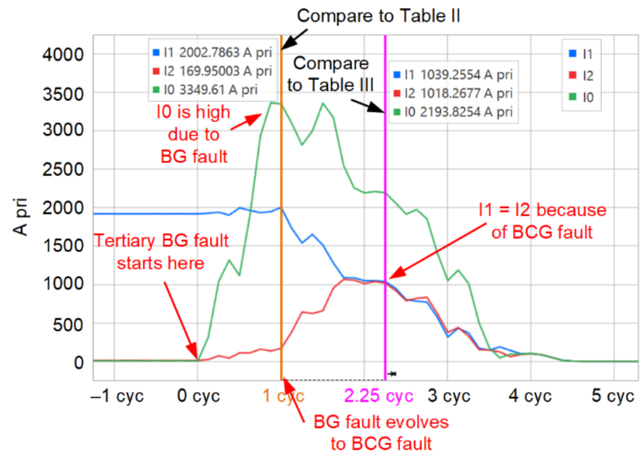

Fig. 15. Reactor positive-, negative-, and zero-sequence current magnitudes.

TABLE II
SEQUENCE COMPONENTS OF THE SHUNT REACTOR CURRENTS FOR THE BG FAULT (FROM SHORT-CIRCUIT MODEL)

Positive (I1)	Negative (I2)	Zero (I0)
2003 A ∠–90°	60 A ∠–152.8°	3350 A ∠–29.9°

Fig. 16 presents the interconnected sequence diagram of the transformer for a BCG fault. Table III lists the sequence components of shunt reactor currents from the short-circuit simulation—the values closely match the field data in Fig 15. I1 and I2 were identical, confirming the evolution from the initial BG fault to BCG.

TABLE III
SEQUENCE COMPONENTS OF THE SHUNT REACTOR CURRENTS AFTER FAULT EVOLVED TO BCG FAULT (FROM SHORT-CIRCUIT MODEL)

Positive (I1)	Negative (I2)	Zero (I0)
1016 A ∠–90°	1016 A ∠–90°	1751 A ∠–90°

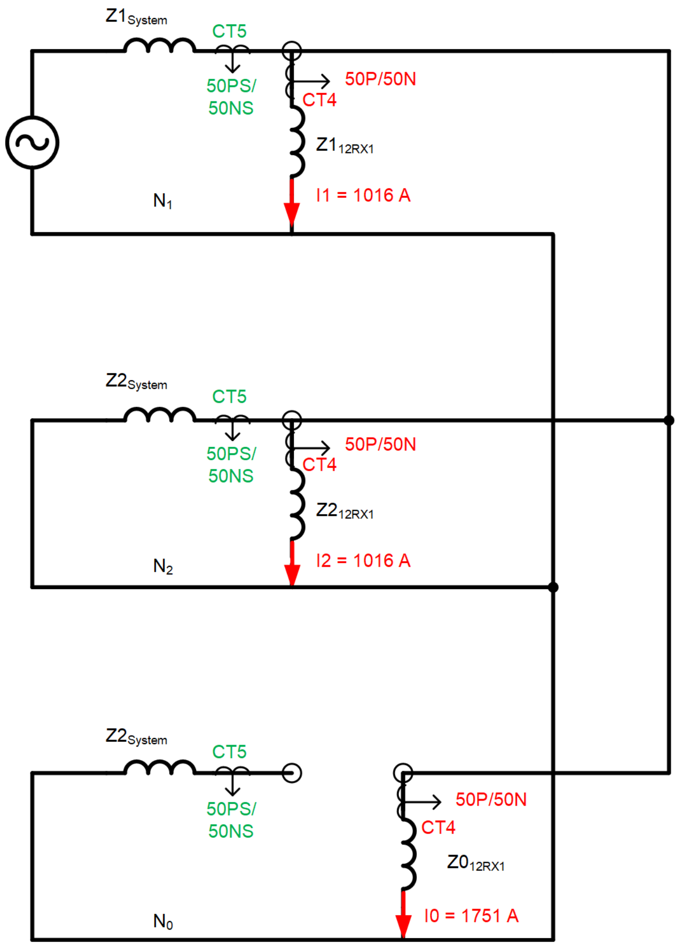

Fig. 16. The interconnected sequence diagram of the transformer for a double-line-to-ground fault.

F. Retrospective on the 2013 Transformer Failure

The detailed analysis of the 2015 failure linked the blaze's ignition to a significant ground fault current caused by the shunt reactor's grounding. In 2013, a ground fault in tertiary winding irreparably damaged another autotransformer. Unlike the second failure (in 2015), it did not result in a significant fire. The grounding of the shunt reactor, a crucial factor in the excessive ground fault current, was not critically examined during the investigation, likely because the transformer was near the end of its service life.

This section revisits waveform recordings from the 2013 failure, as shown in Fig. 17. This figure shows tertiary bus voltage and transformer tertiary currents. An AG fault inside the tertiary winding resulted in the zero-sequence current (3I0) exceeding 2 kA. Without the grounded shunt reactor, the current would have been negligible, triggering only a fault alarm. However, the ground fault current led to a quick trip and fault clearance, though the transformer was still destroyed. Ungrounded reactors could have prevented this significant ground fault, potentially saving the autotransformer.

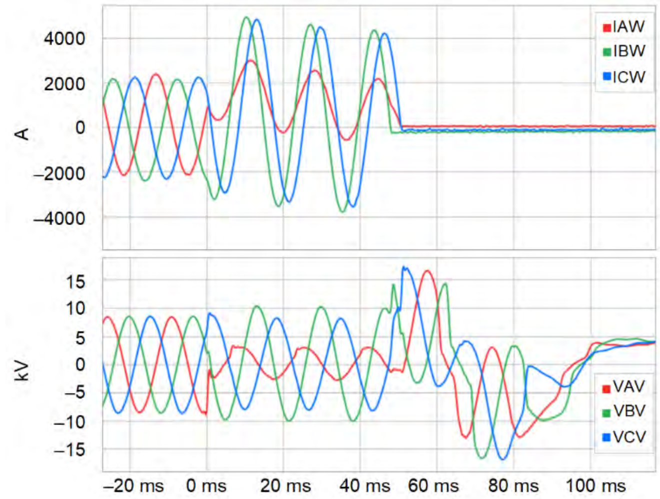

Fig. 17. Transformer tertiary voltages and currents for the 2013 phase-to-ground fault.

IV. Discussion on Tertiary Reactor Grounding and Mitigation of Switching Challenges

Transformer winding faults are rare. Although uncommon, ground faults on the tertiary buses are anticipated due to their nature relative to the transformer. Until the shunt reactors were grounded, these faults were alarmed for and corrective actions on the alarms were managed in a planned manner by BC Hydro. The potential downside of the decision to ground shunt reactors was a forced system outage for an uncommon tertiary ground fault. BC Hydro's Planning, Equipment, and Operational staff determined that the reliability risk from the potential forced outage was acceptable compared to the significant benefit of reducing TRV stress. The risk to the transformer safety from grounding the shunt reactors was not considered.

A. Tertiary Reactor Grounding

The critical insight gained from two failure incidents was that rare winding faults or uncommon ground faults on the tertiary bus can lead to catastrophic transformer damage due to the grounding of shunt reactors. The 2015 failure highlighted that the tight physical spacing at the 12 kV bushing terminals on the transformer's tertiary winding facilitated primary arcs from ground fault currents, which can rapidly escalate into damaging multiphase faults. A retrospective analysis of the 2013 failure indicated that the previously ungrounded tertiary winding, which typically withstands a single-phase-to-ground fault, became vulnerable to damage. Essentially, fault currents that were negligible before grounding the shunt reactors became significant risks to the transformer's integrity because of increased current magnitude after the grounding.

With tertiary shunt reactors across multiple locations, BC Hydro anticipates the possibility of future tertiary ground faults. Following the 2015 event, the risk of transformer failure was deemed unacceptable due to the shunt reactor grounding. Consequently, BC Hydro reversed the previous grounding decision, ungrounding all tertiary shunt reactors and exploring alternative methods to manage TRV stress on switching breakers.

TABLE IV
OVERVOLTAGE AND REIGNITION MITIGATION METHODS [3]

Technique	**Methodology**	**Advantage**	**Disadvantage**
1. Opening resistor	Resistor introduces a phase shift of current relative to voltage, which causes a current interruption at a lower point-on-wave of the voltage. This reduces the recovery voltage.	Very effective on circuit breakers with very high chopping numbers.	Significant mechanical complexity and maintenance requirements of the circuit breaker. Not viable for single pressure SF_6 breakers. Reignitions can still occur.
2. Surge arresters to the ground at the shunt reactor	Limits phase-to-ground overvoltage at shunt reactor.	Passive method.	Effective only when peak overvoltage exceeds the surge arrester protective level. Reignition overvoltage can still occur at up to twice the surge arrester protective level.
3. Surge arrester across circuit breaker	Limits recovery voltage across circuit breaker.	Passive method. Very suitable for circuit breakers ≤ 52 kV used for tertiary shunt reactors.	Adds complexity to the circuit breaker. Surge arrester must withstand forces related to circuit breaker operation.
4. Surge capacitor	Decreases frequency and, consequently, the rate of rise of reactor/load-side.	Reduces rate of rise of reactor voltage. Can mitigate current chopping for vacuum breakers.	Reignitions can still occur. May reduce minimum arcing time so probability of reignitions is unchanged. Requires space.
5. Point-on-wave controlled switching	Initiates the parting of breaker contacts to allow sufficient time for their separation prior to a current zero crossing.	Eliminates reignitions.	Suitable for mechanically consistent breakers with appropriate minimum arcing times. Often requires independent pole-operated (IPO) breakers.
6. High-rating circuit breaker	Breaker is rated to withstand a higher voltage between contacts.	Increased dielectric withstand capability.	Increased cost and increased space requirements.
7. Surge arrester + controlled switching	Combination of surge arrester across circuit breaker and point-on-wave-controlled switching.	Eliminates reignitions and limits overvoltages.	Refer to "3. Surge arrester across circuit breaker" and "5. Point-on-wave controlled switching."

B. Mitigation for Shunt Reactor Switching Challenges

IEEE Std C37.015-2017 [3] provides a comprehensive overview of the different mitigation methods to limit the TRV overvoltage resulting from shunt reactor switching, thereby mitigating reignition. The guide discusses the advantages and disadvantages of the different mitigation methods, as summarized in Table IV [3].

The mitigation techniques applied at BC Hydro were the "2. Surge arresters to the ground at the shunt reactor" and "4. Surge capacitor" listed in Table IV. The surge capacitors chosen were 0.125 µF. These provided adequate mitigation such that there were no related failures.

Point-on-wave controlled switching was not viable because the circuit breakers were gang-operated, i.e., not independent pole-operated (IPO). IPO breakers are often needed for controlled opening of shunt reactors [11] [12] [13].

Replacing the existing circuit breakers with high-rating circuit breakers (rated 72 kV and above) was evaluated. High-rating circuit breakers presented significant cost and physical space constraints, and the existing 12 kV breakers were relatively new. BC Hydro decided to rely upon the existing mitigation approaches: surge arresters and surge capacitors.

For tertiary reactor applications, breakers can be selected using the procedure presented in [3]. Following the procedure, the breaker rating is selected from IEEE Std C37.04-2018, where both the recovery voltage peak and RRRV equal or exceed the T10/T30 TRV values [14]. If the rated current is less than 1,000 A such that current chopping presents a concern [9], an additional margin on the ratings can be used when selecting the breakers.

V. CONCLUSION

Circuit breakers applied in ungrounded systems can experience higher TRV duties than in grounded systems. However, to reduce TRV, grounding the neutrals of shunt reactors connected to a delta tertiary winding of transformers can introduce significant hazards to transformers. The 2015 transformer fire at BC Hydro, which was exacerbated by grounding a shunt reactor on its tertiary bus, starkly illustrates this risk. The incident highlighted the dangers of small spacing among 12 kV bushing terminals, where arcs from ground fault currents can propagate into severe fires. Furthermore, internal ground faults in the tertiary winding pose a high risk of ignition, potentially leading to extensive damage.

BC Hydro's experience underscores the risks involved in grounding tertiary shunt reactors. Before grounding, the operational experience was excellent when alarming for a tertiary ground fault with no significant incidents. However, within a decade of grounding the shunt reactors, BC Hydro experienced two ground faults, resulting in irreparable transformer damage. Consequently, BC Hydro reverted to ungrounding the tertiary shunt reactors. Using 0.125 µF TRV capacitors to decelerate the TRV front, along with grounded surge arresters at the shunt reactor terminal, the switching challenges were mitigated and there were no further incidents.

In summary, while grounding shunt reactors may seem beneficial for TRV management, it can introduce significant hazards, particularly in the context of transformer safety. BC Hydro's experience serves as a cautionary tale, highlighting the importance of carefully evaluating the trade-offs between TRV mitigation and system reliability. The decision to rely on alternative measures, such as TRV capacitors, underscores a strategic approach to safeguarding critical infrastructure without compromising system stability and safety.

VI. Acknowledgments

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VIII. Biographies

Mukesh Nagpal is a senior associate technical consultant at Burns & McDonnell, an IEEE Fellow, and a distinguished IEEE Power & Energy Society lecturer. With over 35 years of experience in electric utility research and power system protection, Mukesh has made notable contributions to the economic, safe, and reliable integration of renewables into the electric grid. He has published approximately 50 technical papers, showcasing his expertise in this field.

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Ritwik Chowdhury received his BS degree in engineering from the University of British Columbia and his MS degree in engineering from the University of Toronto. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2012, where he is presently a principal engineer in research and development. Ritwik holds over 15 patents and has coauthored over 30 technical papers. He was recognized as an exceptional reviewer for *IEEE Transactions on Power Delivery* for three years. He is the chair of the Protection and Control Practices Subcommittee (I-SC) of the IEEE Power System Relaying and Control (PSRC) Committee and the recipient of the 2021 PSRC Outstanding Young Engineer Award. Ritwik is a senior member of IEEE, a member of CIGRE, and a registered professional engineer in the province of Ontario.

Kamal Garg received his MSEE from Florida International University and India Institute of Technology, Roorkee, India, and his BSEE from Kamla Nehru Institute of Technology, Avadh University, India. Kamal worked for POWERGRID India and Black & Veatch for several years at various positions before joining Schweitzer Engineering Laboratories, Inc. (SEL) in 2006. Presently, he is a principal engineer at SEL Engineering Services, Inc. (SEL ES). Kamal has experience in protection system design, system planning, substation design, operation, remedial action schemes, synchrophasors, testing, and maintenance. Kamal is a licensed professional engineer in the U.S. and Canada, senior member of IEEE, and member of many working groups in IEEE Power System Relaying and Control (PSRC) Committee. He holds two patents.

Fernando Calero is a principal engineer at Schweitzer Engineering Laboratories, Inc. (SEL) in the research and development (R&D) division. For 20 years, he was an application engineer in the SEL international organization. His responsibilities included the application, training, and support of SEL products. In 2020, he transferred to the R&D division and is working on projects related to renewable sources, protection, and control. He holds eight patents and has written technical papers on protective relaying, remedial action schemes, and other protection and control applications. He is a registered PE in the state of Florida.

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