Significant Power System Characteristics for Protection Engineers

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In general, protection textbooks and rely instruction manuals cover all essential protection topics very well from their academic and relay application perspectives. However, some unusual and unique power system characteristics impacting system protection are not normally covered in them, but rather presented in a form of technical papers at seminars and conferences.

While pursuing engineering excellence throughout 30+ years of electric utility relaying career, the author has presented quite a few technical papers on unusual and unique topics. This paper is intended to present some of them in a concise and condensed manner, hoping that they will not be forgotten and they will help protection engineers better perform their daily relaying tasks.

1. Doubling of Core-form Transformer Energization Inrush Currents

Two primary objectives of this topic are: recognizing doubled inrush currents in case of core-form transformer energization from the low-voltage side and understanding the cause of doubling.

1.1. Real Life Events

Transformers are generally energized from their high-voltage side. However, a transformer is sometimes required to be energized from its low-voltage side under certain operating conditions, but the energization may not be successful as shown in the following real-life events:

- Event 1: A large station service transformer at a power plant was energized from its low-voltage side, but an instantaneous overcurrent element (*presumably with adequate setting for the transformer size and impedance*) tripped a circuit breaker and blocked the energization.

  Tested and verified doubling: Due to importance of the station service transformer and for the purpose of fine-tuning relay settings, the station service transformer was energized and recorded from both the high-voltage side and the low-voltage side several times. Surprisingly and to our satisfaction, inrush recordings confirmed doubling of the inrush currents in case a core-form transformer is energized from the low-voltage side.

- Event 2: A mobile substation transformer at a distribution substation was energized from its low-voltage side, but the energization was unsuccessful in the same manner as the above event.

1.2. Engineering Discussion

- **Core-form transformer**: It is stated that energizing a core-form transformer from the low-voltage side may result in inrush currents approaching twice the values in the table (*not shown in this paper*). [1]
- In modern days, shell-form transformers are rarely manufactured unless otherwise special-ordered. Therefore, the vast majority, if not all, of power transformers in service are core-form transformers.
- **Crest inrush currents in per unit**: In general, approximate inrush currents shown in textbooks and references are valid when transformers are energized from the high-voltage side. Approximate inrush currents may range 6 to 10 times for large power transformers and 25 to 50 times for small distribution transformers. These crest inrush currents are expressed in per unit of the crest full-load current, so their respective RMS values are much smaller than as shown.
- **Cause of doubling**: Referring to Figure 1, it is generally assumed and expected that the primary impedance in per unit is close to the secondary impedance in per unit, if not the same. If so, energizing a core-form transformer from the low-voltage side would result in the inrush current about the same as for energizing from the high-voltage side. However, in reality, due to transformer design optimization and manufacturing constraints, **the secondary per unit impedance** ends up being **much smaller than the primary per unit impedance**. This is the reason why energizing a core-form transformer from the low-voltage side may result in the inrush current approaching twice the value in case of energizing it from the high-voltage side. [2][3]

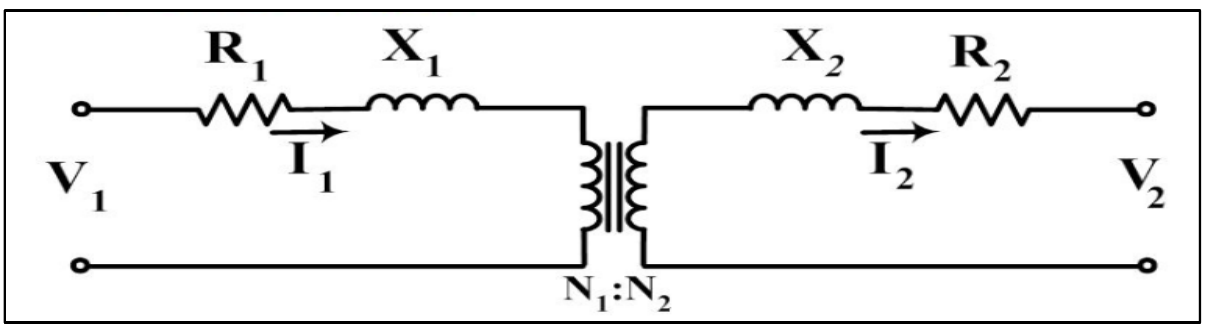

Figure 1. Simplified Two-winding Transformer Equivalent Circuit

1.3. Further Discussion

Unit-connected generator step-up transformers are routinely energized from the low-voltage side without experiencing any doubling of transformer energization inrush currents. It can be easily explained from the fact that a synchronous generator is not capable of generating more than 3 to 4 times the rated current (*Note: X_d" = 0.25 to 0.33*).

2. Unfaulted-phase Voltages up to 140% of the Rated

Two primary objectives of this topic are: clearly understanding the unfaulted-phase voltage rise up to 140% of the rated in case of ground faults (*both SLG and LLG*) and recognizing legitimacy of surge damage claims by customers.

2.1. Real Life Events

- Event 1: Numerous damage claims, citing that all customers claiming damages heard a loud bang and then electrical surges damaged their light bulbs and appliances, were submitted to the serving electric utility. All customers claiming damages were served off two unfaulted phases.
- Event 2: A customer claimed that an electrical surge killed hundreds of his koi fish. The serving electric utility found out that there was a ground fault at the time of koi fish damages but the customer was not served off the faulted phase.

2.2. Engineering Discussion

- **$V_{unfaulted}$ up to 140%**: Referring to Figure 2a), all customers served off two unfaulted phases at the location L, where $Z_0/Z_1 \approx 5$, and beyond are subject to voltages reaching almost 140% of the rated. It can be easily hand-calculated or simulated with short circuit analysis programs. [4][5][6]
- **Quick estimation of $V_{unfaulted}$**: Figure 3 illustrates how and why two unfaulted-phase voltages are raised due to a SLG fault and also graphically shows a step-by-step derivation of the handy "Unfaulted-phase Voltage Calculation" formula as shown below.

$$\mathbf{V_{unfaulted}} = \sqrt{0.75 + \left(0.5 + \frac{\mathrm{K}-1}{\mathrm{K}+2}\right)^2} \ \text{ in per unit,} \ where\ K = \frac{Z_0}{Z_1} \geq 1$$

  As shown in Figure 3, the cause of the undesirable voltage rises is that the voltage drop through the $3I_0$ return path (neutral and ground) is additive to unfaulted-phase voltages. [5][6]
- **Z_0/Z_1 ratio**: For multiple-grounded distribution feeders, having $Z_0/Z_1 \approx 5$ is uncommon but Z_0/Z_1 ranging 3 to 4 is common. At the location with $Z_0/Z_1 = 4$, customers served off two unfaulted phases for a SLG fault are subject to voltages reaching 132% of the rated.
- **Significance of 140%**: Most of utility-grade power equipment are designed to withstand voltage surges up to 140% of the rated without any significant loss of life for a short time. For example, distribution-class surge arresters are designed to discharge at or above 140% of the rated distribution feeder voltage. However, most of the low-voltage equipment used by customers may not be able to withstand such voltage surges.

2.3. Further Discussion

- Presently, over-voltage relaying is not applied for distribution feeders. Even over-voltage relaying cannot eliminate any voltage rises due to ground faults, but can only minimize damages caused by the undesirable voltage rises.
- **Mitigation of the unfaulted-phase voltage rises**: To eliminate the undesirable voltage rises due to ground faults, the Z_0/Z_1 ratio must be lowered by lowering the neutral and earth return path impedance or by installing remote grounding transformers as illustrated in Figure 2b). However, lowering the neutral and earth return path impedance is not as simple as it sounds and it could be financially cost-prohibitive. On the other hand,

installing remote grounding transformers is financially feasible but it creates some relaying challenges because all upstream protective devices towards the substation cannot see any fault current contribution from the remote grounding transformers. [6]

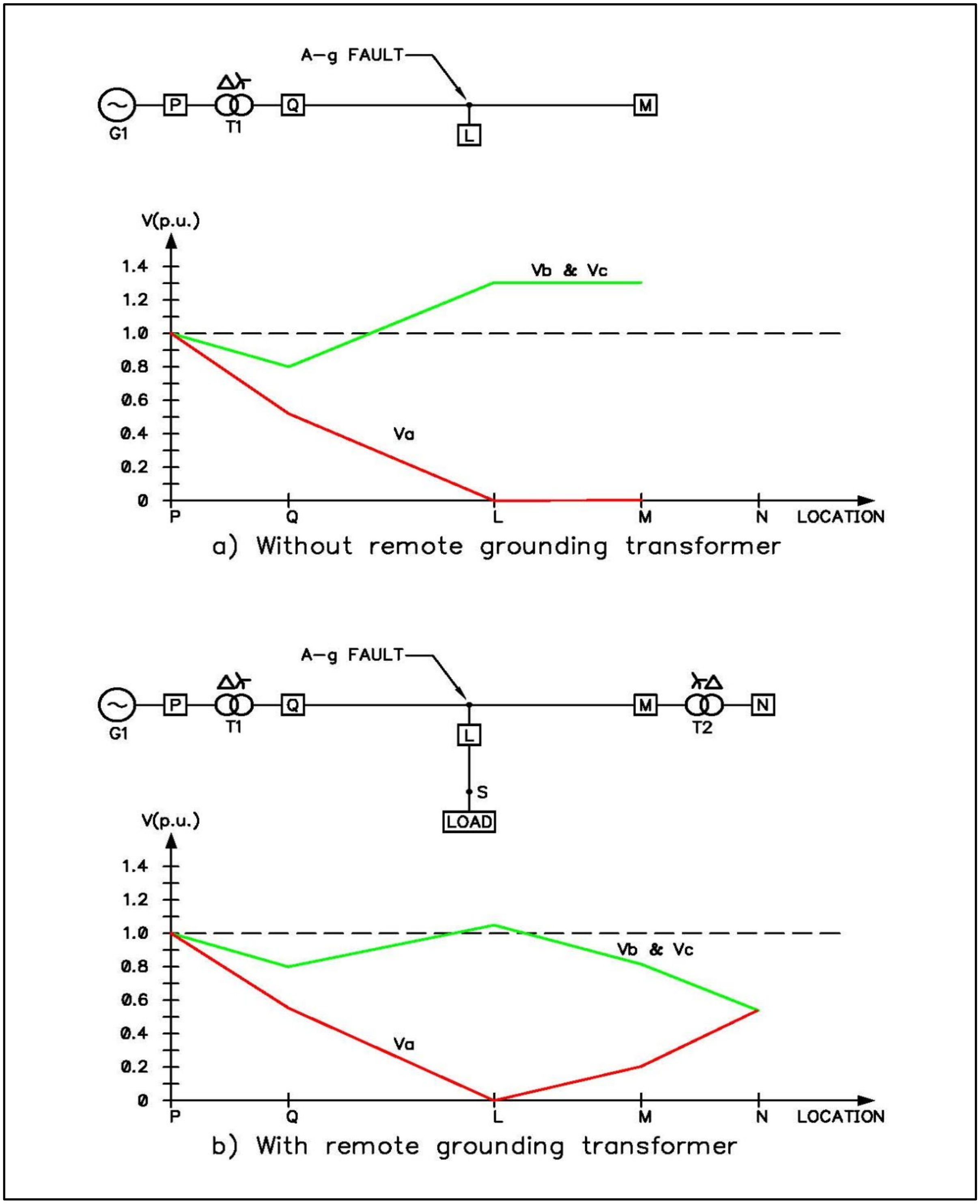

Figure 2. Distribution Feeder Voltage Profile in Case of AG Ground Fault

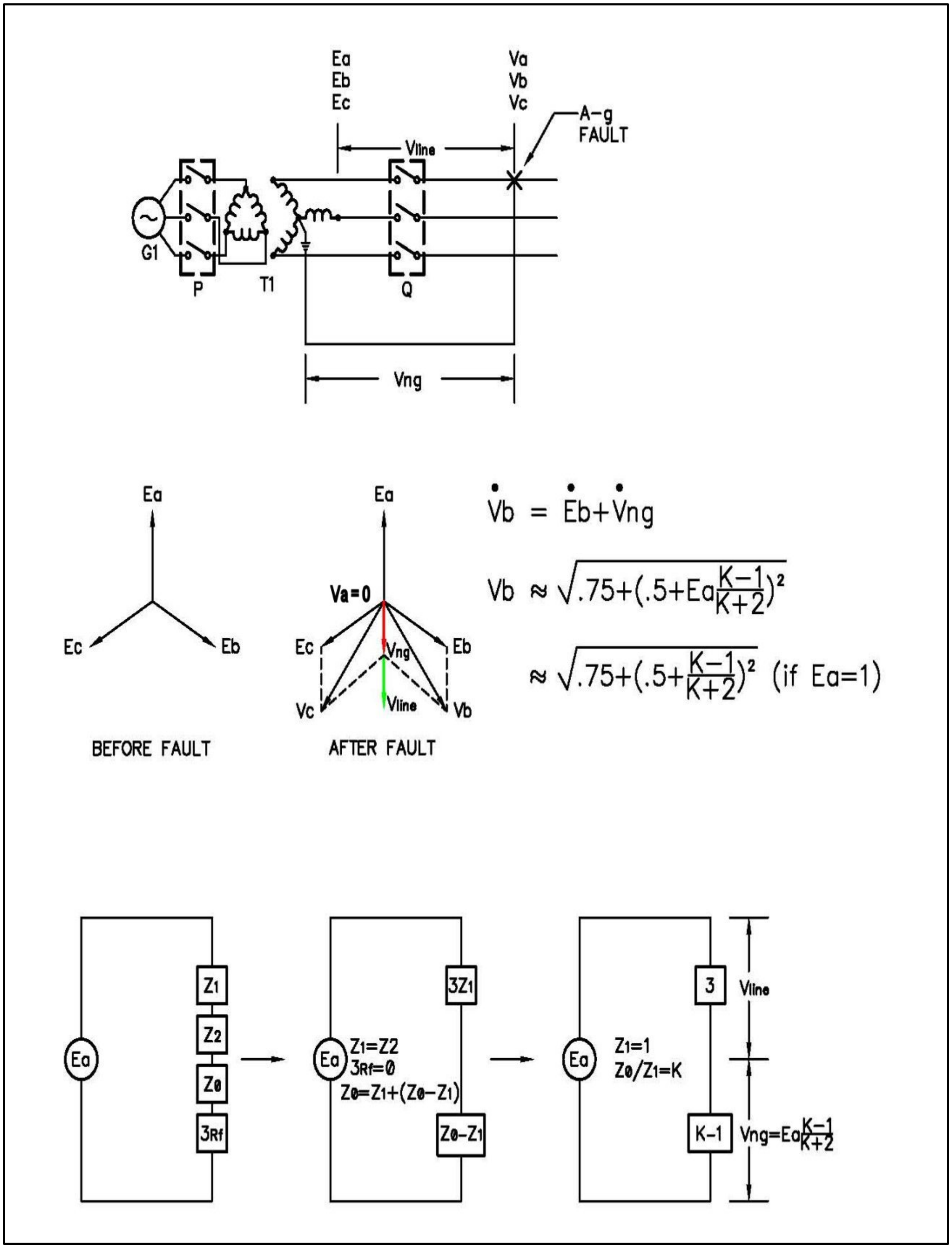

Figure 3. Graphical Illustration of Unfaulted-phase Voltage Rise (*Note: Unfaulted-phase Voltage Calculation formula should not be used if $Z_0/Z_1 \leq 1$.*)

3. Faulted-phase Current Being the Smallest of All

Two primary objectives of this topic are: recognizing when the faulted-phase current being the smallest of all and understanding what may cause such an unlikely abnormality.

3.1. Real Life Event

Faulted-phase current being the smallest of all is seemingly impossible and presumably erroneous. However, the following event and subsequent research prove that it is possible and it is not erroneous.

- Event: Referring to Figure 4a), relays at Station R and Station S detected a BG SLG fault correctly as designed, but the relay at Station T did not and could not identify a BG SLG fault because the faulted B-phase current was smaller than C-phase and A-phase currents. At that time, off the top of everybody's head, the possibility of wiring errors or relay malfunction was suspected.

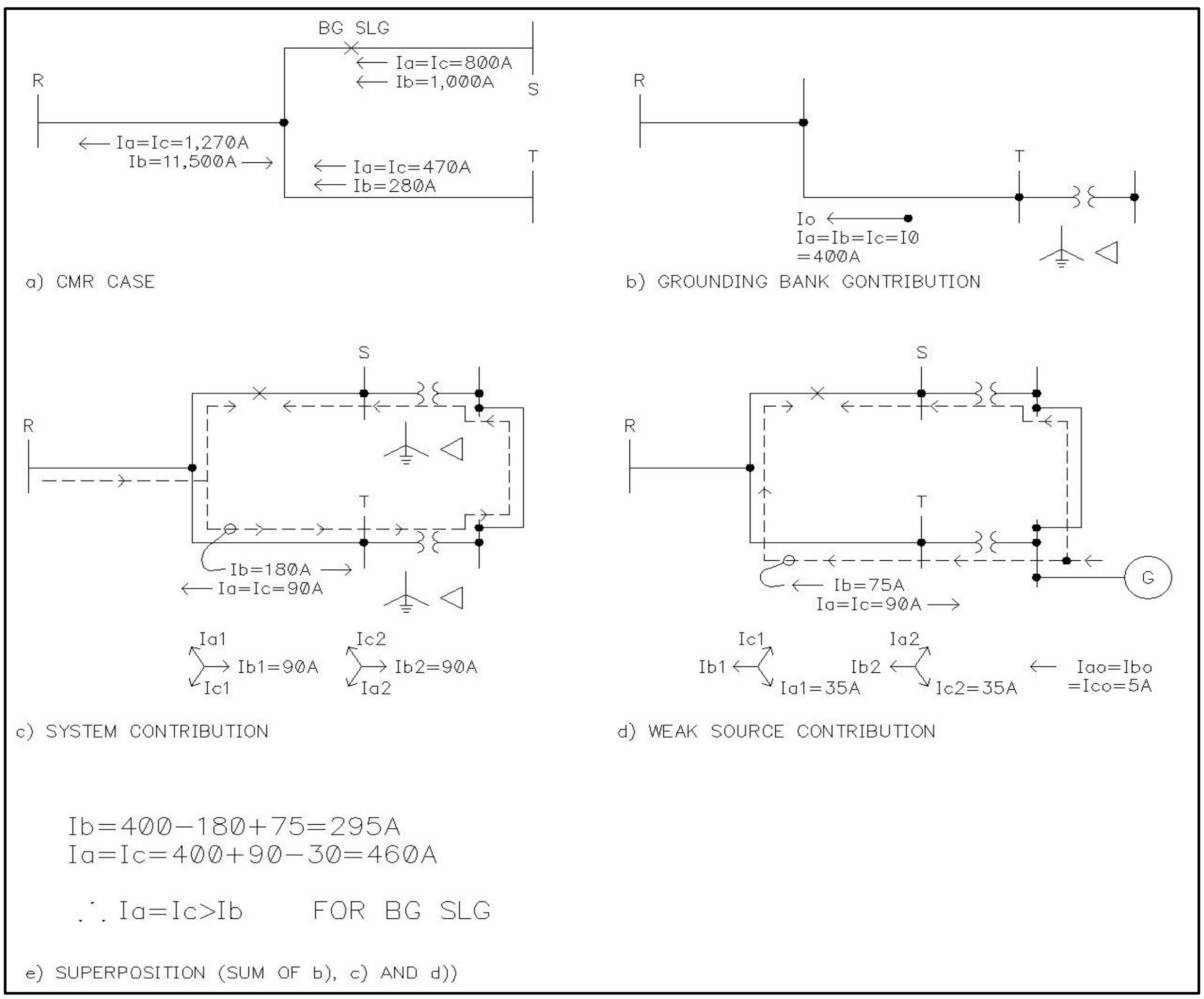

Figure 4. Graphical Explanation of Current Magnitude Reversal (*Note: On the faulted phase at Location T, the incoming and flowing-through currents are opposite to the outgoing currents.*)

3.2. Engineering Discussion

Referring to Figure 4, a faulted-phase current being the smallest of all is graphically illustrated step-by-step and it can be easily simulated with short circuit analysis programs. Making sense or not, it was termed as "**Current Magnitude Reversal**" by the author. [7][8]

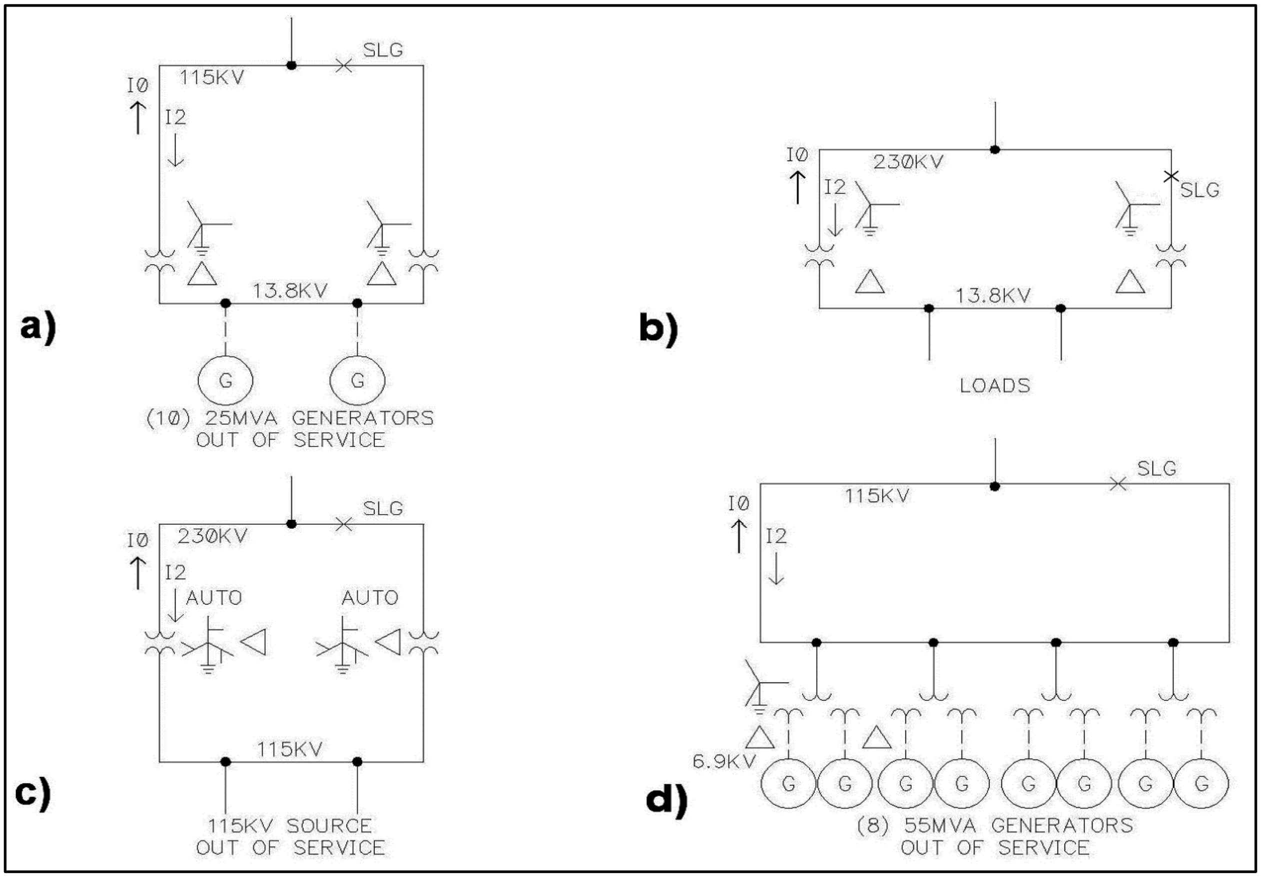

Figure 5. Other Configurations Subject to Current Magnitude Reversal

3.3. Further Discussion

Figure 5 illustrates several circuit configurations subject to current magnitude reversal and indicates that the current magnitude reversal could occur more often than not. [7][8]

4. External Lightning Strikes Causing the Bus Differential Relay Operation

Two primary objectives of this topic are: recognizing external lightning strikes causing the bus differential relay operation and understanding how it happens.

4.1. Real Life Event

- Event: A lightning struck all 3-phase 115kV transmission line conductors at only a span away from a generation switching-station, clearly outside the bus differential relaying zone, but the bus differential relay detected a bus fault and shut down the switching station and power plant.

4.2. Engineering Discussion

- **Difficulty of capturing a lightning impulse**: Referring to Figure 6, a lightning impulse (current or voltage) may last less than 300 micro-seconds and the steep wave-front from 0 to the peak takes approximately 1 micro-second. Therefore, only relays with a high sampling rate can reliably capture lightning impulses. If a lightning impulse is captured, it will look like a needle as shown in Figures 6(c) through 6(e) (*Note: These three sample recordings were recorded with transient fault recorders*). [9][10][11]
- **Lightning impulse propagation**: A lightning impulse can propagate through any current-carrying medium and find the least resistant path to ground. Within the bus differential zone, the least resistant path happens to be through either the bus PT neutral or a set of surge arresters. This is why only CTs at one breaker position captured the lightning impulse striking all three-phase line conductors and consequently triggered the bus differential relay operation. [11]

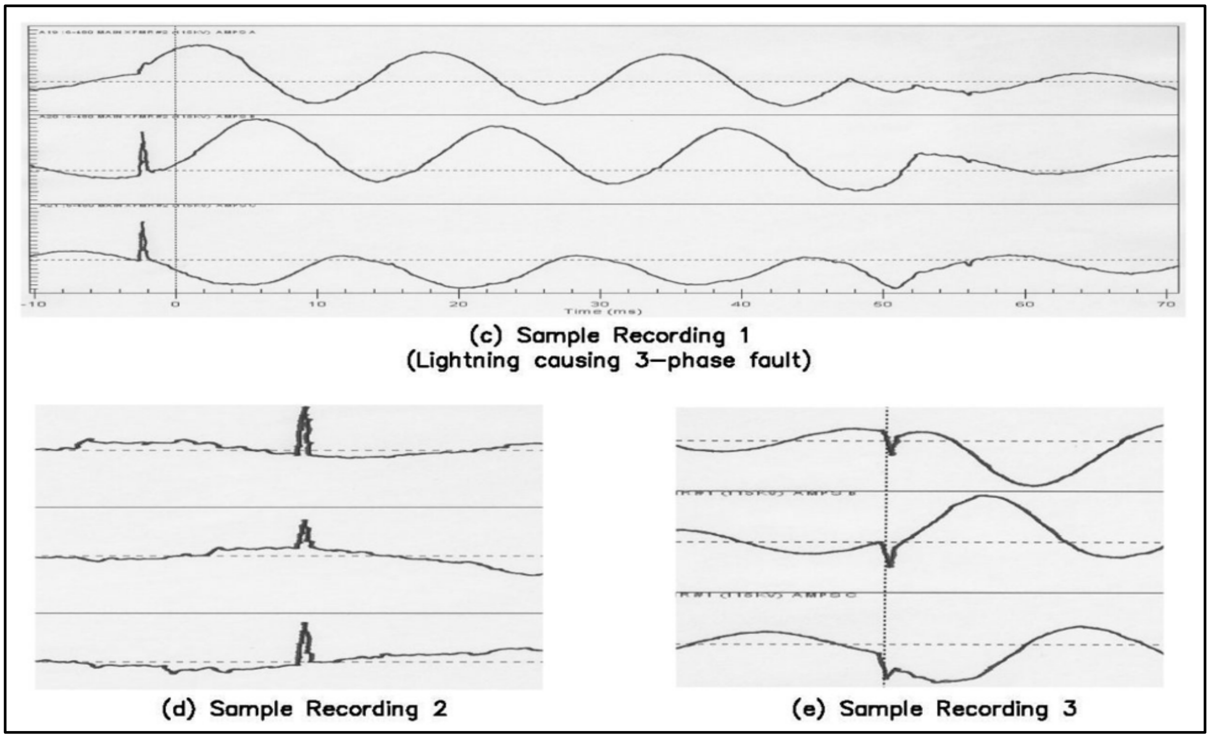

Figure 6. Lightning Impulses, Short and Difficult for Relays to Detect

4.3. Further Discussion

Depending on the crest value of lightning impulse, it may or may not cause flash over insulators as follows:

- If lightning arresters are at or near the lightning-struck spot, they are likely to discharge the lightning impulse to ground.

- **Lightning strike fault**: If the crest value of a lightning impulse is way below BIL of insulators and there is not any surge arrester nearby, the lightning impulse will continue to propagate through a conductor in both directions and try to find the least resistant path to ground.
- **Lightning-caused short circuit fault**: If the crest value of a lightning impulse is above BIL of insulators and there is not any surge arrester nearby, the high crest will cause flash over insulators and result in a ground fault.

Overhead static wire (OHSW) has been a very effective means of lighting protection of transmission lines and substations. It appears that, depending on each individual electric utility's lightning protection philosophy (*primarily based on the number of thunderstorm days per year*), overhead static wires are not installed at all, selectively installed, or installed over every transmission line. Overhead static wires could have prevented the aforementioned bus differential relay operation and power plant shut-down.

5. Use of DC Offset Factor k=0.25 for Practical Purposes and Necessity in the Modified CT Evaluation Formula

Three primary objectives of this topic are: recognizing CT saturation due to system DC offset, understanding why a DC offset factor of k = 0.25 is needed, and understanding some practical options for electric utility protection engineers to consider.

5.1. Real Life Issues and Questions

When **Stan Zocholl** introduced the "**Volt Time Area Method**" of CT performance evaluation and CT sizing (*based on S.D. Moreton's "A Simple Method for the Determination of Bushing-Current-Transformer Characteristics" published in 1943*), many issues and questions were brought up as follows:

- In the old days, protection engineers sized CTs simply based on the Ohm's Law Method with some conservatism or safety margin. It seemed that all CTs, which were sized based on the Ohm's Law Method, had been performing adequately and relay misoperations caused by CT saturation had been very rare. According to the Volt Time Area Method of CT performance evaluation, many CTs in service will saturate for close-in faults. What is this new method all about and what is this new method telling us?
- If the X/R ratio is high in my application, how can we even find CTs satisfying this new method? Our generators' X/R ratios are all 80+. What can we do?

5.2. Engineering Discussion

- One primary difference between the Ohm's Law Method and the Volt Time Area Method is: The Ohm's Law Method does not consider any DC offset-caused CT saturation, but the Volt Time Area Method does with a term "X/R."
- **CT saturation due to system DC offset**: The author reviewed probably thousands of recorded CT secondary current waveforms (*recorded with transient fault recorders and*

digital relays) throughout his electric utility career and found that surprisingly quite a few CTs were saturated.
   - All saturated CTs except one set of CTs actually satisfied the Ohm's Law Method but the system DC offset caused saturation.
   - No DC offset-caused saturation resulted in any failure of relay operation.
- Referring to Figure 7, if a power factor is close to 1 and a fault occurs at the voltage peak, DC offset should be practically zero. However, if a power factor is close to 1 and a fault occurs at the zero crossing of voltage, DC offset could approach 1 per unit.
- **Faults at or near the voltage peak**: Based on the author's review of 200+ sets of recorded current and voltage waveforms (*recorded with transient fault recorders*), all faults occurred at or near the voltage peak and all DC offsets except one case were 0.25 per unit or less. One exception showed approximately 0.4 per unit DC offset. [14]
- Based on principles of surges and high-voltage engineering, arcing should occur at or near the voltage peak. This should be also true even for lightning strikes, to be further discussed later.
- **DC offset factor k and k=0.25**: Based on the author's review of the Volt Time Area Method formula derivation, a term X/R is simply a DC offset of 1 per unit. Considering that all DC offsets were 0.25 per unit or less in real-life systems and technically faults should occur at or near the voltage peak, the author introduced a DC Offset Factor k, as shown below, and k = 0.25 is sufficient for all practical purposes. [14]

$$\left(k \cdot \frac{X}{R} + 1\right) \cdot I_f \cdot Z_b \leq 20$$

- **No DC offset-caused saturation in 0.5(X/R) cycles**: System DC offset decays over time, more specifically at a rate of T = L/R in seconds. Mathematically, X/R cycles corresponds to 2πT seconds and the DC offset level should be negligible in 0.5·(X/R) cycles or πT seconds (*down to 0.01 per unit with k = 0.25*). Therefore, for CTs satisfying the Ohm's Law Method but subject to DC offset-caused saturation, they should not have any saturation in 0.5·(X/R) cycles. This is why DC offset-caused saturation has not resulted in any failure of relay operation, but has definitely caused **delayed operation of relays**. [14]

System Components	X/R Ratio Ranges	Typical X/R Ratio Values
Large generators and hydrogen-cooled synchronous condensers	40 – 120	80
Power transformers	10 – 50	15 - 25
Induction motors	5 – 35	
Small generators and synchronous motors	20 – 35	
Reactors	40 – 120	80
Open conductor lines	2 – 16	5
Underground cables	1 – 3	2

Ohm's Law Method	**Volt Time Area Method** [12]
$\mathbf{I_f \cdot Z_s \le V_s}$ where: I_f is the maximum CT secondary current in amps. Z_s is the CT secondary impedance including the CT winding in ohms. V_s is the CT saturation voltage for a CT tap used in volts and **read from the excitation curve at 10 amps**.	$\mathbf{(X/R + 1) \cdot I_f \cdot Z_b \le 20}$ where: I_f is the maximum fault current in p.u. of CT rating. Z_b is the CT burden in p.u. of standard burden. X/R is the X/R ratio of the primary fault current.
Application Notes: • Time to saturation should be taken into consideration for DC offset. • As a rule of thumb, $I_f \le 75$ amps to accommodate DC offset and fault current increase in the future. • As a rule of thumb, $Z_s \le$ adjusted secondary impedance for a specific tap used. • As a rule of thumb, $I_f \cdot Z_s \le 0.75 \cdot V_s$ to accommodate burden increase in the future. • Some CTs meeting the Ohm's Law method have saturated under certain operating conditions. • It has been suggested recently that the volt time area multiplier should be used for certain applications, re-written as "$(X/R + 1) \cdot I_f \cdot Z_s \le V_s$."	**Application Notes:** • The volt time area multiplier, (X/R + 1), takes care of DC offset. • The standard burden does not include the secondary winding impedance. • CTs meeting the volt time area method will not saturate. • For a high X/R value, it may be impossible to find any CT meeting the above criteria. • The volt time area method can be re-written as "$(X/R + 1) \cdot I_f \cdot Z_b \le V_b$" if I_f is defined as p.u. of 100 amps and V_b is defined as the CT burden voltage in p.u. of C-rated CT burden voltage.

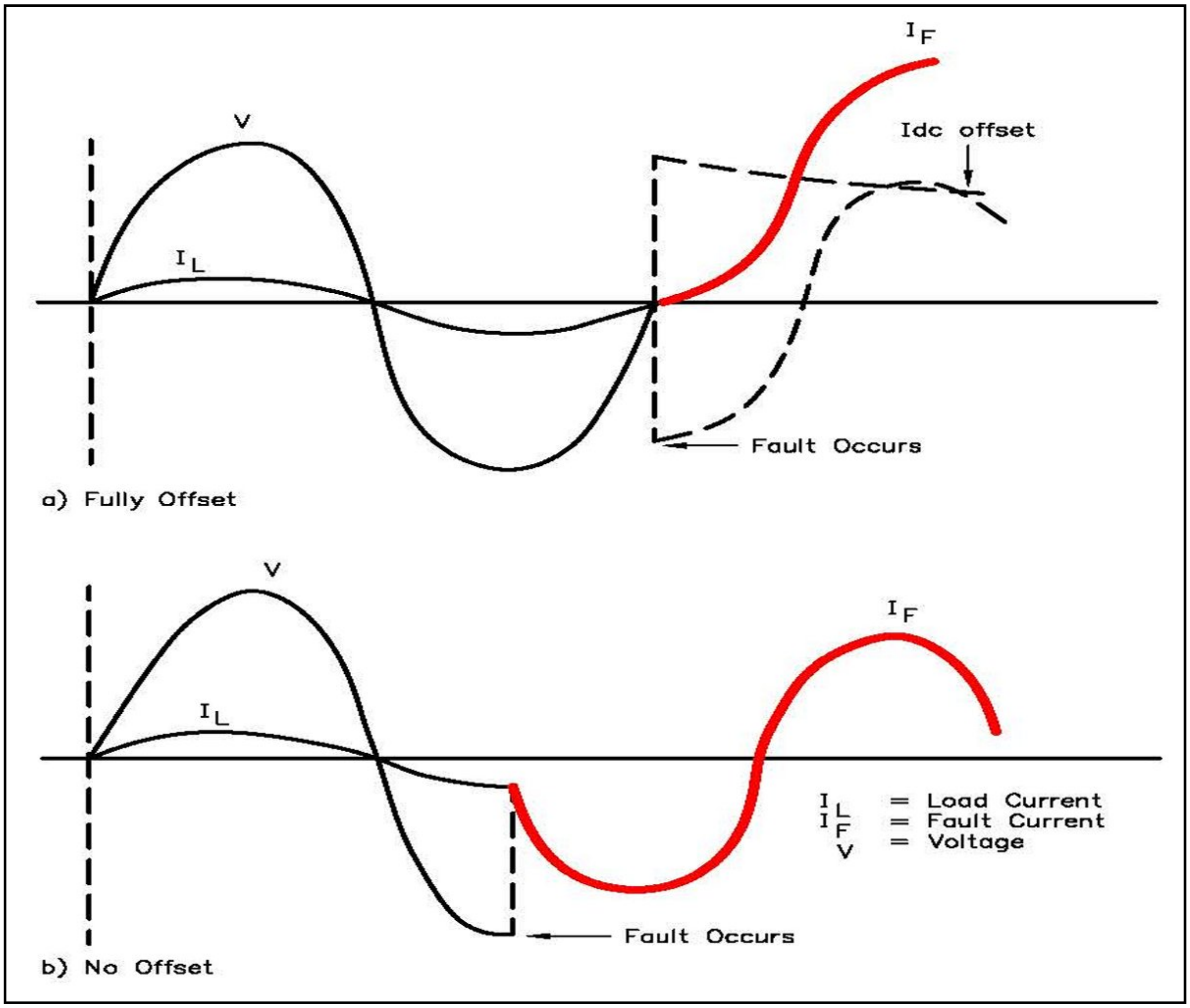

Figure 7. Fundamentals of DC Offset Formation (*Note: For simplicity and illustration purposes, an impedance angle of 90 degrees or purely inductive circuit is assumed*.)

a) Maximum DC offset (*1 p.u. being the peak of I_f*) when a fault occurs at V=0.

b) No offset when a fault occurs at the voltage peak.

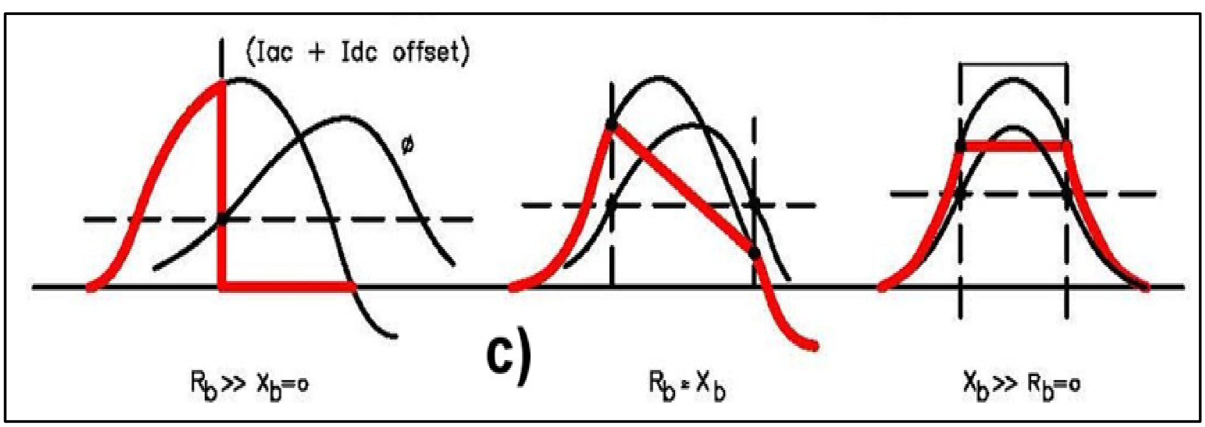

Figure 8. Three Distinguishing Shapes (*Chopped, Decaying, and Flat-topped*) of Saturated CT Secondary Currents

5.3. Further Discussion

- **Lightning strikes at or near the voltage peak**: Technically, lightning is an arcing between thunder clouds and the earth ground. Based on principles of surges and high-voltage engineering, lightning strikes should occur at or near the voltage peak. Furthermore, the author's review of three recorded lightning strike-triggered waveforms also confirmed lightning strikes at or near the voltage peak.
- There are two categories in fault events caused by lightning strikes:
    - **Lightning strike fault**: If the crest value of a lightning impulse is way below BIL of insulators and there is not any surge arrester nearby, the lightning impulse will continue to propagate through a conductor in both directions and try to find the least resistant path to ground. A relay may capture this short impulse and trigger circuit breaker opening.
    - **Lightning-caused short circuit fault**: If the crest value of a lightning impulse is above BIL of insulators and there is not any surge arrester nearby, the high crest will cause flash over insulators and result in a ground fault. Once the ground fault is established, it should be treated as a typical ground fault.
- **Sizing CTs for generating stations**: Knowing that the X/R ratio of generators could be up to 120, trying to satisfy the Volt Time Area Method even with a DC offset factor of k = 0.25 could be intimidating and challenging. However, it may not be so challenging as one may think, taking the following into consideration:
    - Each generator with a X/R ratio of up to 120 can supply fault currents only up to 3 to 4 times the rated current (*Note: X_d" = 0.25 to 0.33*) and they decay over time.
    - For a fault at the generator terminal, the system contribution with a X/R ratio of approximately 20 is much bigger than the generator contribution {(1.7 to 2.3) times the generator contribution}.
    - The burden of digital relays is very small.
- Referring to Figure 8, there are three distinguishing shapes of secondary currents of saturated CTs [14]:
    - **Chopped** look for highly resistive burden
    - **Decaying** look for $R_b \approx X_b$ burden
    - **Flat-topped** look for highly inductive burden

6. Cross-country Fault Analysis with the Simultaneous Fault Analysis

Two primary objectives of this topic are: recognizing patterns of certain cross-country faults and using the simultaneous fault analysis feature of short circuit analysis software.

6.1. Real Life Events

- Event 1: Referring to Figure 9, A-phase conductor of 115kV transmission circuit made a physical contact with A-phase conductor of 12.47kV distribution circuit, causing the following [15][16]:
    - Circuit breakers at both ends of the 115kV line operated as designed.
    - 12.47kV feeder breaker did not operate.

- All distribution-class MOV surge arresters within approximately 1-mile radius from the point of physical contact were damaged by splitting, shattering, or ground lead separation.
- No silicone-carbide surge arresters were damaged.
- Obvious discoloration at the physical contact point.

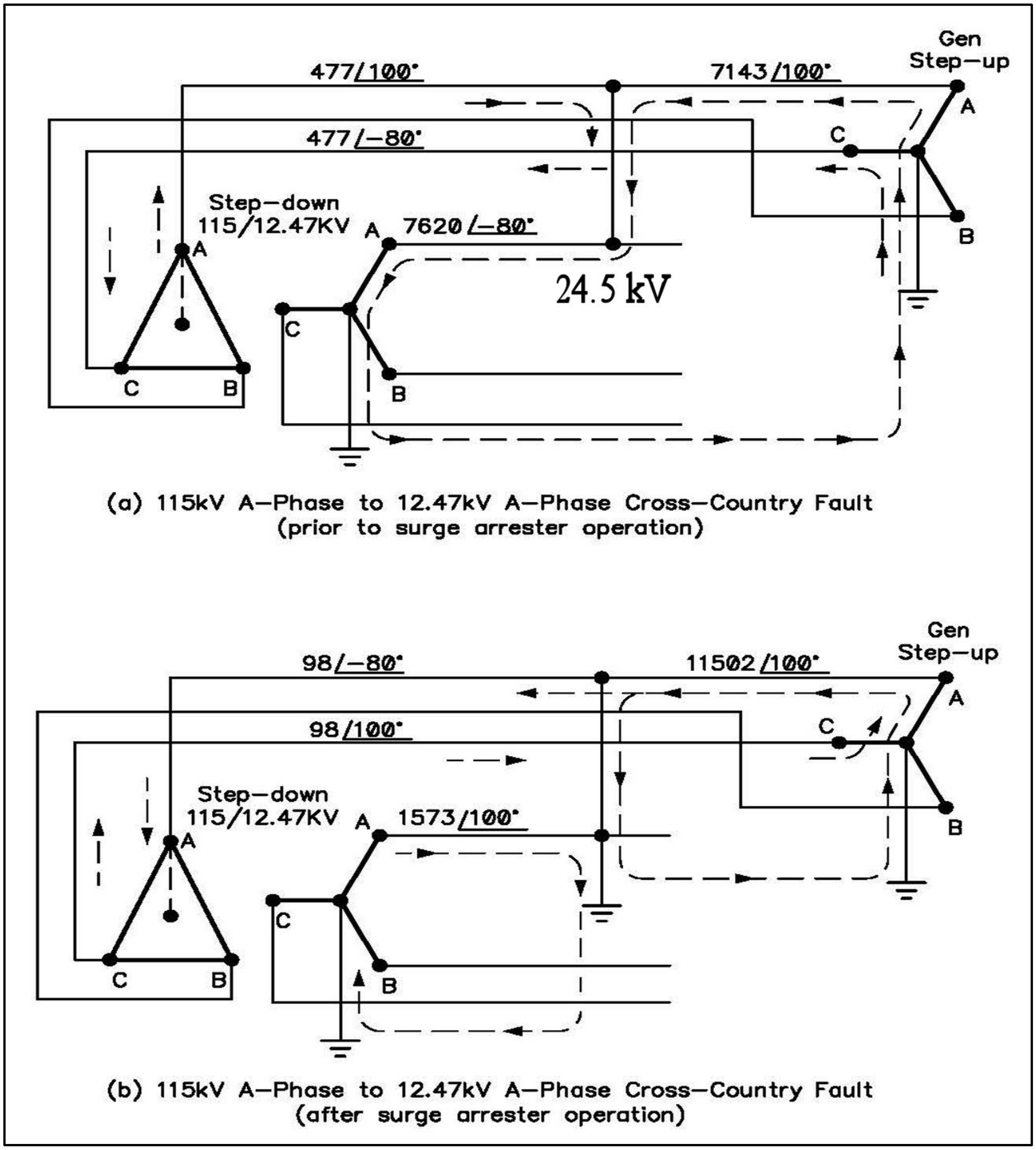

Figure 9. Example of Cross-country Fault between 115kV Transmission Line and 12.47kV Distribution Feeder (*Note: The other end of the 115kV transmission line, a very weak source, is not shown for simplicity and illustration purposes.*)

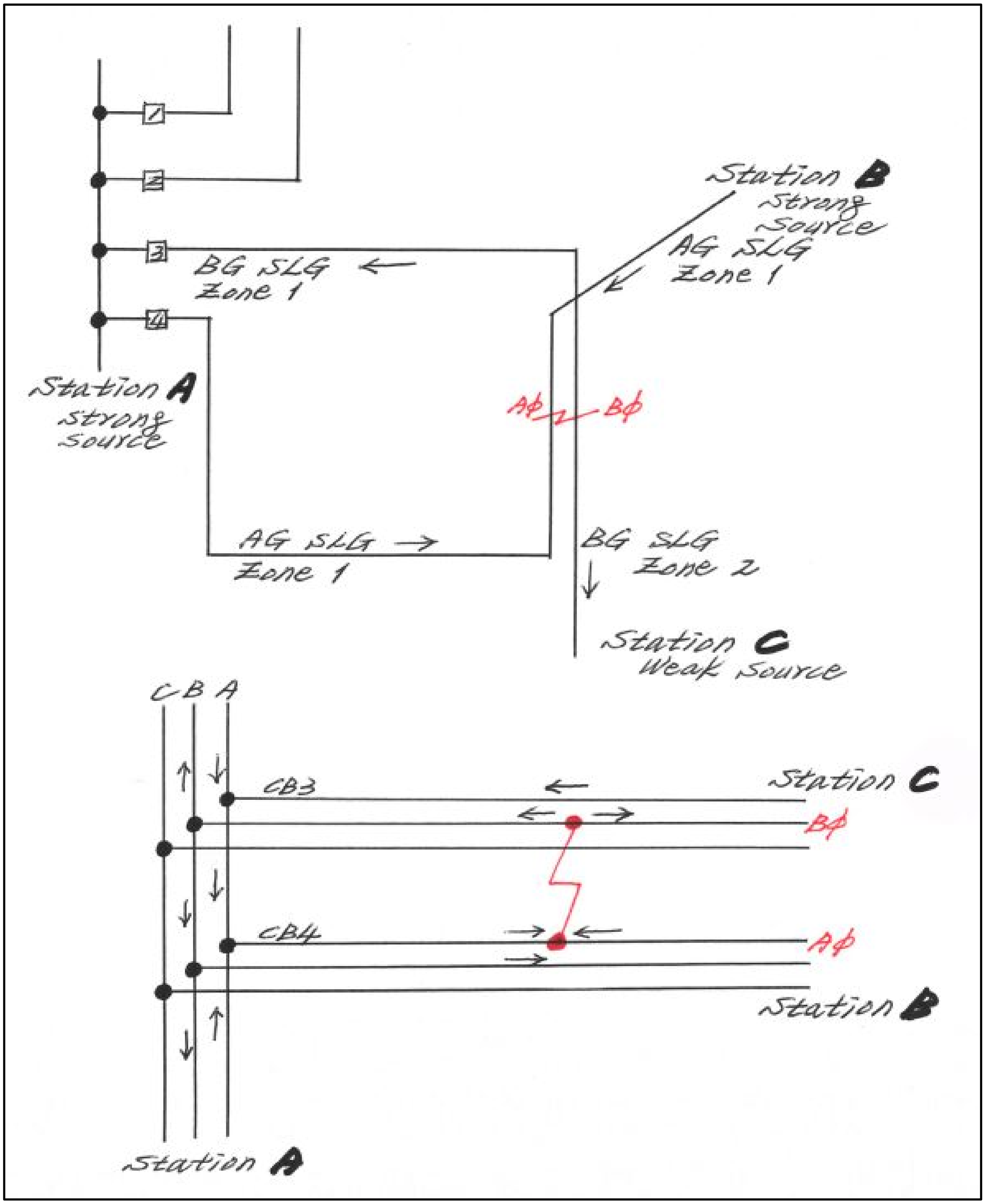

Figure 10. Example of Cross-country Fault between Two 115kV Lines (*Note: Simplified for illustration purposes*)

- Event 2: Referring to Figure 10, B-phase conductor of one 115kV transmission circuit made a contact with A-phase conductor of another 115kV transmission circuit in electrical sense, causing the following [15][16]:

- At Stations A and B 115kV breakers operated as designed.
- A-phase and B-phase fault currents at Breaker 3 were in phase and some zero-sequence current was present, based on the recorded event report.
- A-phase and B-phase fault currents at Breaker 4 were in phase but 180^0 out of phase from the fault currents at Breaker 3, based on the recorded event report. It also indicated presence of some zero-sequence current.
- The event report from Station B indicated a line-line fault.
- 115kV breaker at Station C did not operate.
- A hot air balloon, stuck between the double circuits, appeared to be the culprit.

6.2. Engineering Discussion

- **EMTP or ATP?** In modern days, most of electric utilities are required to perform case studies by NERC reliability standards for planning, operation, and verification of operation validity. For case studies, a set of programs (*i.e., load flow analysis, short circuit analysis, and transient stability analysis*) are used but use of EMTP or ATP is not required as of to date. [15]
- **Simultaneous fault analysis feature** for cross-country faults: Cross-country faults require 6-phase circuit analysis, so the conventional 3-phase short circuit analysis (using 3 sequence components) is not the right tool to use. However, a short circuit analysis program used by most Northwest electric utilities has a simultaneous fault analysis feature allowing cross-country fault case studies.
- **Two-step simultaneous fault analysis** in case of a cross-country fault between a transmission line and a distribution line [15][16]:
  - Step 1, referring to Figure 9(a): Simulation of a cross-country fault between 12.47kV distribution feeder and 115kV transmission line.
    - Recognize that the 7.2kV-rated line cannot withstand 24.5kV at the point of physical contact and so this faulted system is not sustainable.
    - Notice the highly unusual $3I_0$ current flow between the generator step-up transformer neutral and the distribution step-down transformer neutral.
    - **MOV vs. silicone-carbide**: Distribution-class surge arresters (*i.e., MOV and silicone-carbide arresters*) (*typically at every underground cable riser and every distribution transformer*) will discharge at or above 10.1 kV (7.2 x 1.4 = 10.1). In general, discharge voltages of the silicone-carbide surge arresters are higher than those of the MOV arresters.
    - Surge arresters are designed primarily to handle short lightning surges lasting several hundred micro-seconds. Therefore, the distribution-class MOV surge arresters at a sustaining 24.5 kV will discharge and be damaged (e.g., splitting, shattering, ground lead separation, etc.) due to extreme internal pressure.
  - Step 2, referring to Figure 9(b): Simulation of two separate simultaneous faults, one being an AG SLG 115kV line fault and the other being an AG SLG 12.47kV distribution feeder fault.
- **One-step simultaneous fault analysis** in case of a cross-country fault between two same-voltage transmission lines [15][16]:
  - One step, referring to Figure 10: Simulation of a cross-country fault between two 115k transmission lines. This simulation will verify:

- Validity of two faulted-phase currents in phase
- Validity of the line-line fault seen at Station B
- No actual zero-sequence current flow, but relays indicated some zero-sequence current flow. Validity of relays' calculated values and respective responses.
- Legitimacy of all operations.

6.3. Further Discussion

Due to the "Not in My Backyard" mentality of property owners, electric utilities have been highly encouraged or forced to build **double or triple circuits**. Distribution underbuilds are very common these days. Therefore, cross-country faults are likely to happen more often in the future.

Cross-country faults involving at least one transmission circuit should be simulated and analyzed to satisfy NERC reliability standards. Therefore, electric utility protection engineers are highly encouraged to know how to recognize cross-country faults and also how to use the simultaneous fault analysis for cross-country faults, especially two-step process mentioned above.

7. Dynamic Nature of Generator Parameters and Characteristics

Two primary objectives of this topic are: thoroughly understanding complexity of synchronous generators from theoretical and physical aspects, and bridging the gap between academic researches and real-life power systems.

7.1. Real Life Concerns

A research paper was published and presented by a highly recognized research engineer years ago and it was, in the author's mind, an excellent research paper questioning validity of the steady-state stability characteristic upon short circuit faults. It addressed that short circuit faults would lower the generator terminal voltages and so the generator terminal voltages would not be steady-state, without addressing the voltage dependency of other generator parameters. It did not address that all generator parameters (e.g., generator capability curve, subtransient reactance value, transient reactance value, etc.) would also vary upon short circuit faults and they are truly dynamic in nature. [20]

7.2. Engineering Discussion

- **Voltage-dependent generator capability curve**: Referring to Figure 11b), the generator capability curve is not a fixed characteristic but actually voltage-dependent. Unfortunately, textbooks and most of references show a single generator capability curve, similar to Figure 11a) and so it gives an impression that the generator capability curve is a fixed characteristic. [18][20]
- **Dynamic nature of generator parameters**: All generators are controlled by their own governor and excitation system, and a myriad of other parameters are monitored and adjusted. Some of significant characteristics are:

  - Frequency dependency
  - Voltage dependency: For this very reason, unsaturated parameters along with saturation factors are used in the transient stability analysis. Depending on the voltage at any iteration, the unsaturated parameters are appropriately adjusted.
  - Temperature dependency, especially the highly temperature-dependent field winding resistance
- **Complexity of synchronous generators**: "Direct-axis unsaturated open-circuit subtransient time constant" is very long and a mouthful. It really exemplifies the complexity of synchronous generators as it includes, as follows: [17][18][19][20]:
  - Quadrature-axis parameters
  - Saturated parameters
  - Short-circuit parameters
  - Transient and synchronous parameters
  - Reactance, resistance, and other parameters
- **Inertia constant H and hydro damping**: Inertia constant H is mathematically calculated based on mass and rotation. However, hydro turbines must move the water mass in circular and spiral motion in real-life operation. Due to this hydro damping, the actual hydro-generator H is larger than the mathematically calculated H, making hydro generators more stable than what they seem to be.
- **Saturated X_d for steady-state stability analysis**: The commonly-used synchronous reactance X_d is actually an unsaturated value (*Note: In reality, stator cores are somewhat saturated at the 1 per unit terminal voltage, but the saturated synchronous reactance is not normally available.*), which makes synchronous generators unnecessarily less stable under steady-state conditions than what they really are. Therefore, use of the saturated X_d {i.e., $X_{d,saturated} = X_{d,unsaturated} / (0.7 \text{ to } 0.8)$} is recommended for the steady-state stability analysis by GE.
- **Saliency of hydro generators**: It is well known that the saliency of hydro generators makes them more stable than round-rotor generators, but it is not adequately modeled in the transient stability analysis.

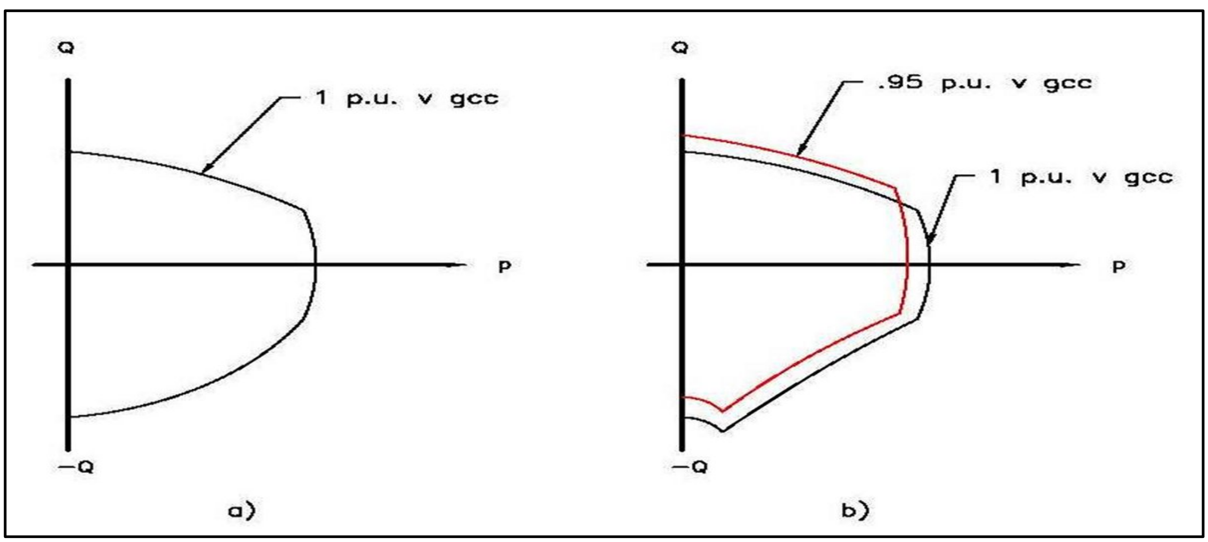

Figure 11. Voltage-dependent Generator Capability

- **Saturated vs. unsaturated**: Saturated subtransient reactance values should be used for the short circuit analysis, but unsaturated values should be used for the transient stability analysis. For the sake of somebody's perceived consistency, using only unsaturated values or saturated values for both the short circuit analysis and the transient stability analysis is simply wrong. [20]

7.3. Further Discussion

Synchronous generators are the most complex and dynamic power system component and they are the true electrical source. They should be treated as seriously as what they really are. Over-simplification or lack of thorough understanding may lead to poor research and erroneous conclusions.

Furthermore, there is a considerable amount of gap between the academic world (textbooks) and the real-life power systems, especially on synchronous generators, and even between field electrical engineers and the real-life systems. Striving to do more with less in our modern relaying industry may not be conducive to better and more, but all participants in the art of protective relaying should continue to strive for better and more, if not for the best.

Conclusion:

This paper presentation was intended as a high-level bullet-point presentation without getting into fine details on these topics that are unusual and unique in nature. Since the topics presented here are not covered or clearly described in relay instruction manuals and protection references, the author sincerely hope that they will not be forgotten and they will help protection engineers better perform their daily relaying tasks.

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