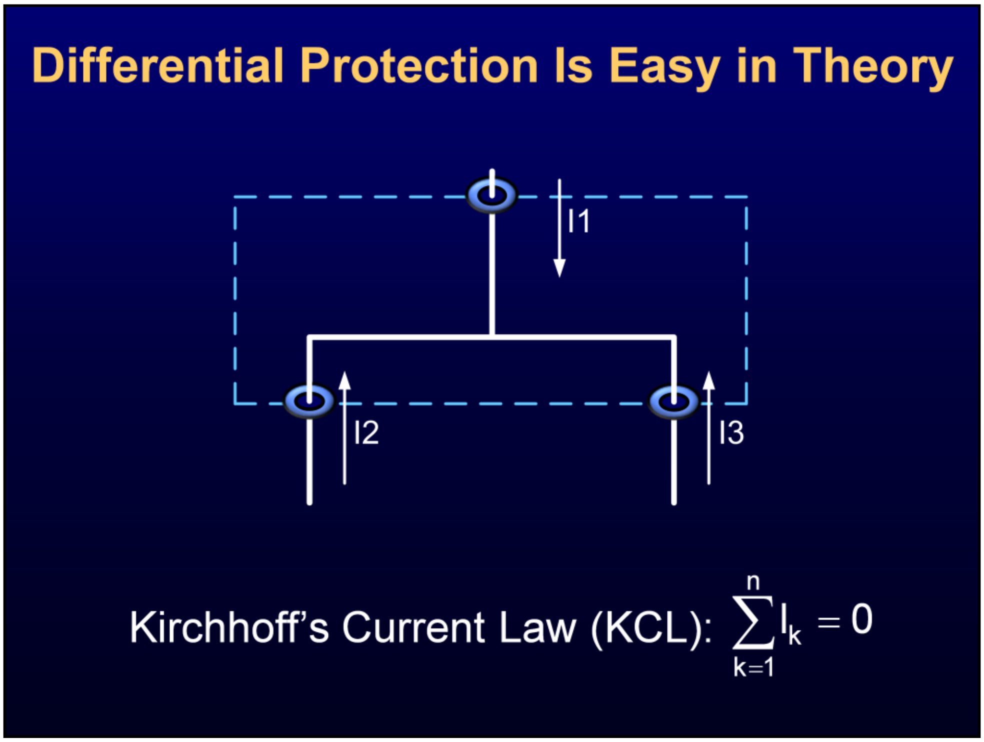
SCHWEITZER ENGINEERING LABORATORIES

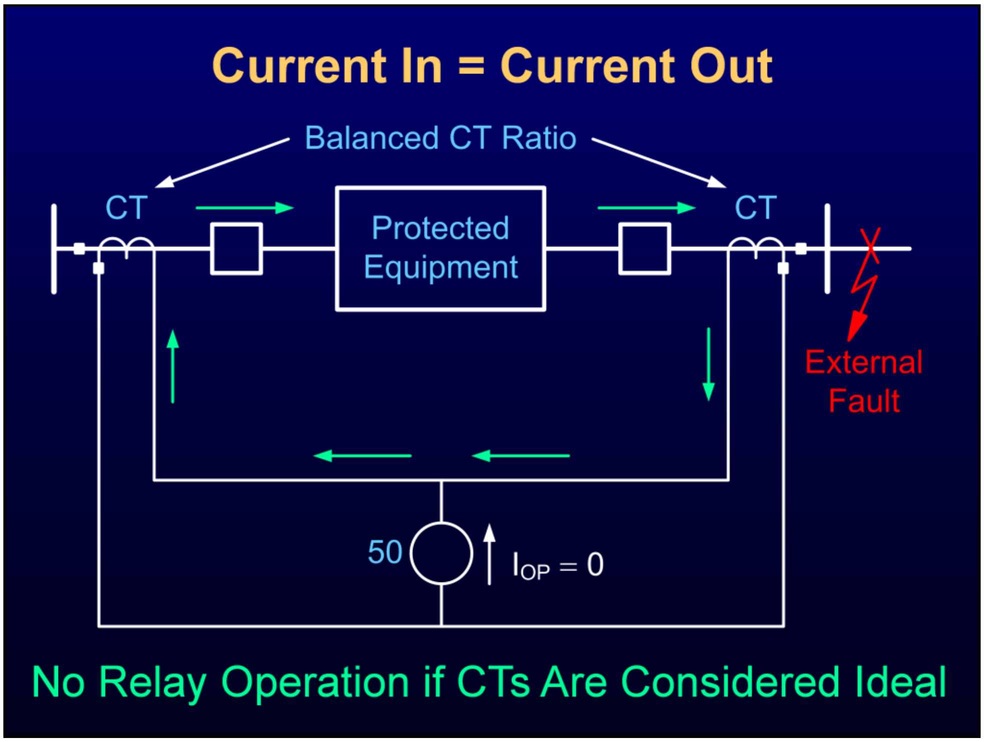
Protection Basics: Differential Protection

Making Electric Power Safer, More Reliable, and More Economical®

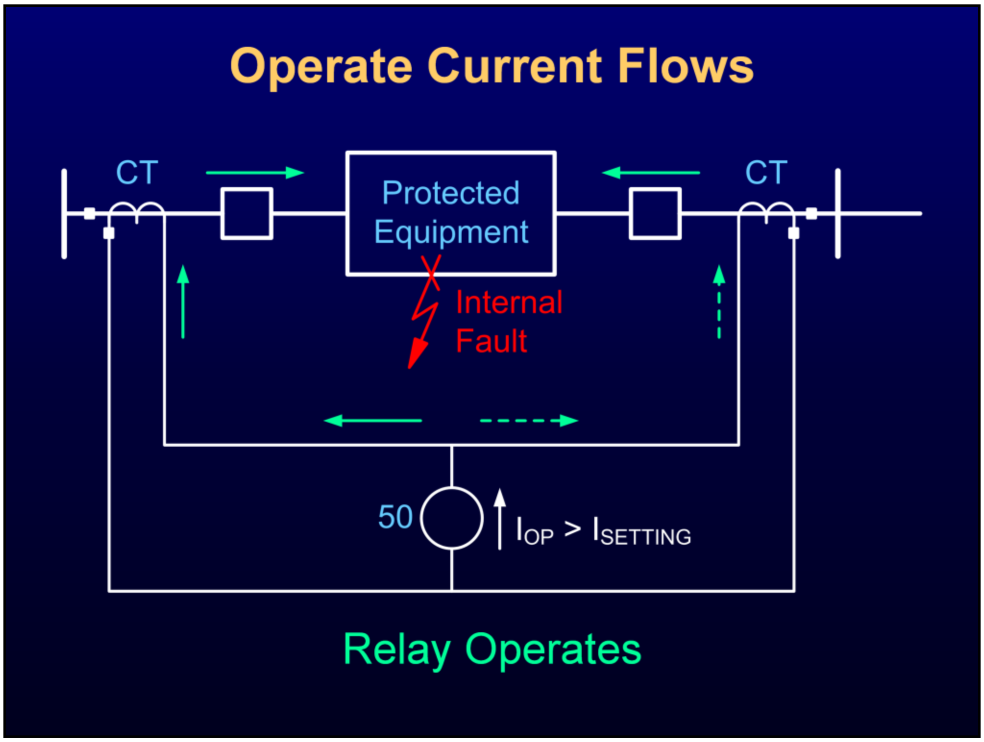


In theory, differential protection is a straightforward undertaking. Following Kirchhoff's Current Law (KCL), the sum of all currents at any node in a circuit must equal zero. Current in must equal current out.

When applying differential protection, current transformers (CTs) are used to measure the current vectors for all currents entering and leaving a circuit. If no faults exist within this differential zone, the sum of the current vectors equals zero.

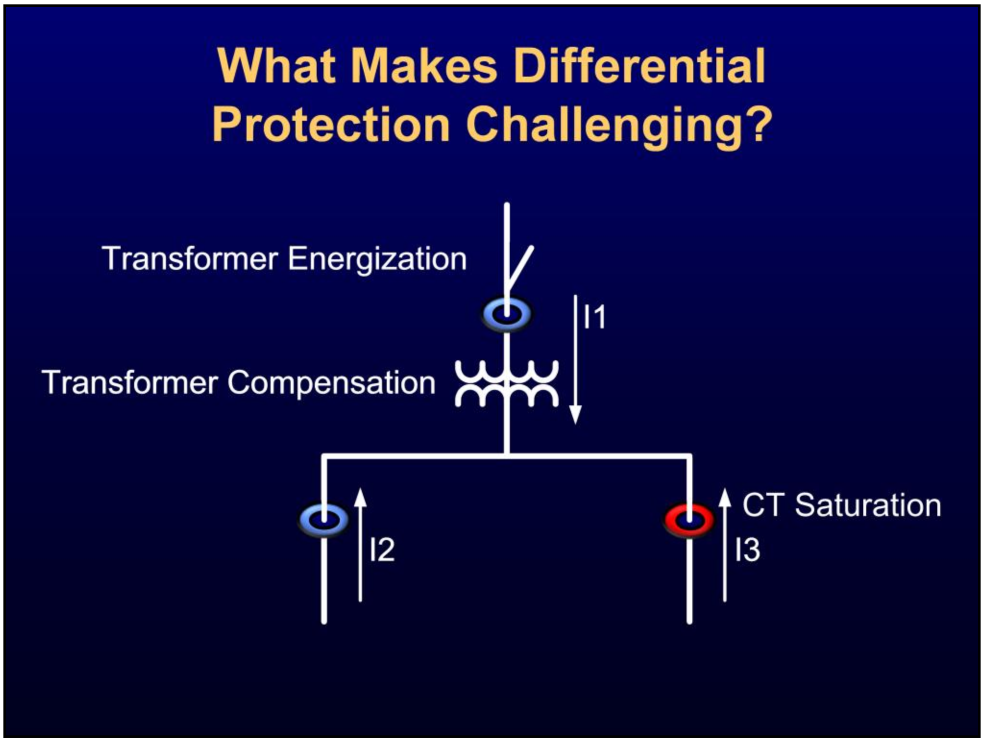


The slide shows the behavior of the simplest differential scheme (using an instantaneous overcurrent relay) during an external fault. If the CTs are considered ideal and identical, the primary and secondary currents at both sides of the protected equipment are equal. There is no operation (differential) current.



For an internal fault, the primary currents allow the secondary currents to produce a differential current through the overcurrent relay. If this differential (operation) current is larger that the relay pickup, then the relay trips both circuit breakers instantaneously.

The characteristics of differential protection can be summarized as follows. The simple concept measures the current entering and exiting the zone of protection. If the currents are not equal, a fault is present. Differential protection provides high sensitivity and high selectivity. The result is relatively high speed.

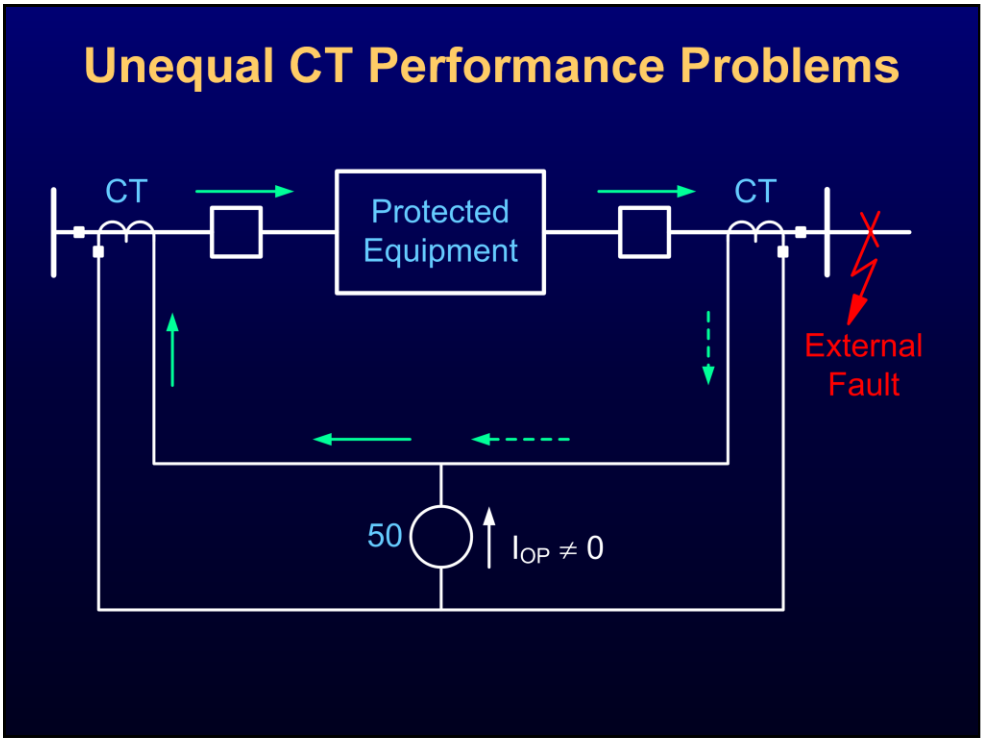


The main challenges to any differential protection scheme come when, under normal operating conditions, the current into the differential zone may not equal the current leaving the zone. This basic protection presentation examines the following differential protection challenges:

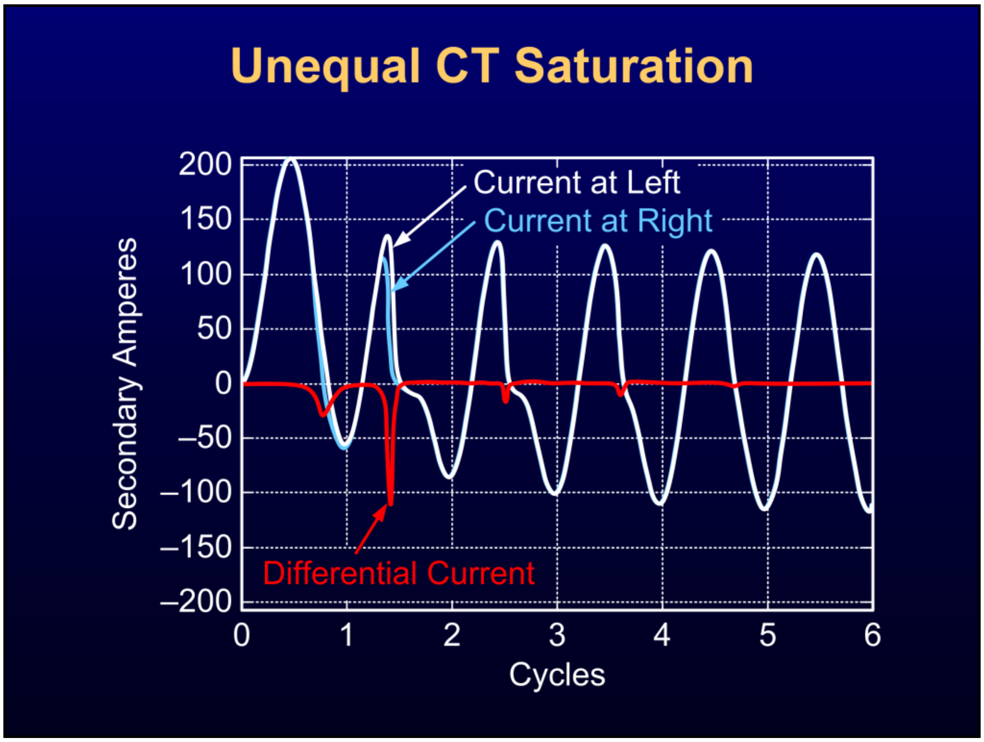
- The addition of a transformer to the differential zone and the methods used to compensate the differential protection.
- The energization of the transformer and how some numerical differential relays deal with transformer inrush.
- CT saturation and its effects on differential protection.

Examine CT Saturation Challenges

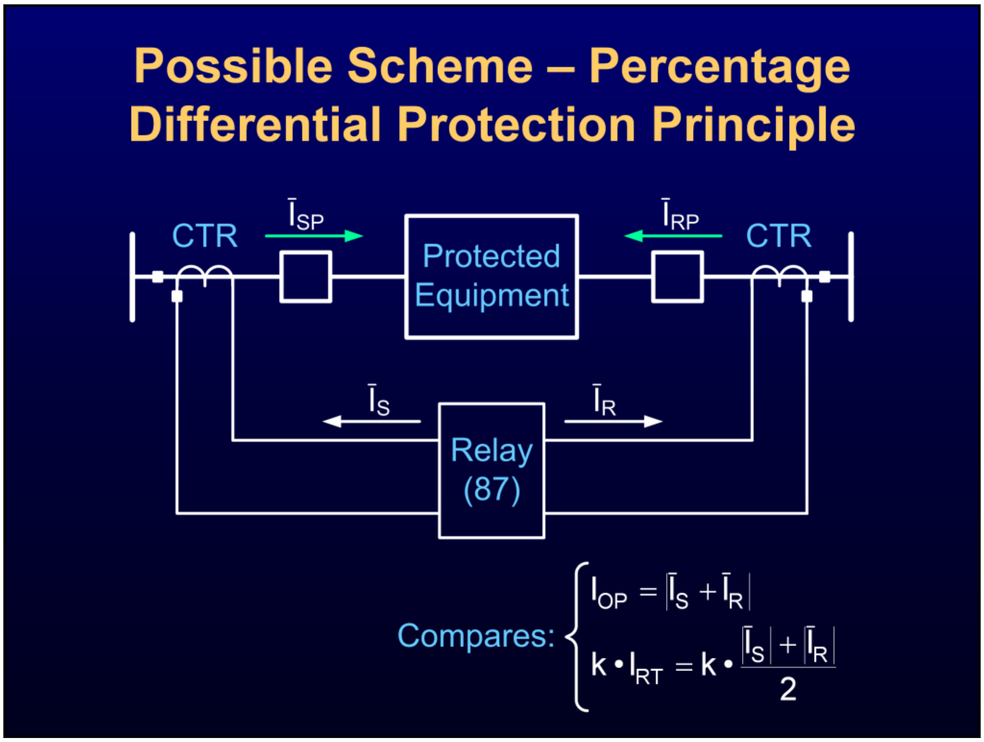
Direct current (dc) offset caused by system X/R ratios and high-fault current during external faults may lead to CT saturation. This section of the presentation examines how the numeric differential relay is designed to compensate for this condition.



All differential protection must deal with the challenge of being secure for large through faults. During a severe external fault, a CT may saturate and supply less than its ratio current. In this case, the currents do not completely cancel, and a false differential current results. When high currents are present, use some measure of through current to desensitize the relay.



The slide shows the results of a simulation produced SEL software. Even though both CTs in this case are similar, slight differences in the CT characteristics create a differential current during saturation.

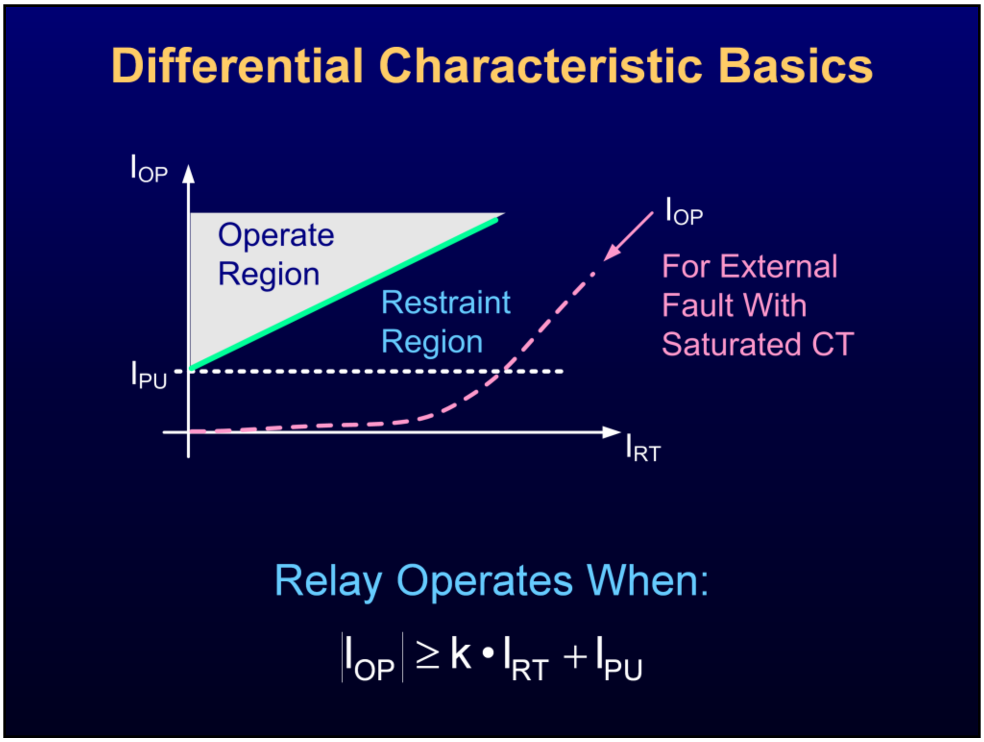


A common variation on the differential concept is the percentage restraint differential relay. The differential elements compare an operate quantity with a restraint quantity.

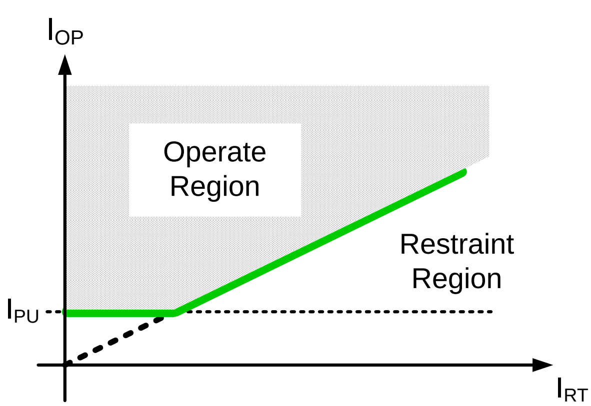
In the scheme, the relay operates when the magnitude of the secondary operate current, $\bar{I}_{OP} = \bar{I}_S + \bar{I}_R$, is larger than a given proportion of the secondary restraint current, I_{RT}. For this particular scheme, the restraint current is chosen to be $I_{RT} = (|\bar{I}_S| + |\bar{I}_R|)/2$. The proportionality constant, *k* (sometimes called the slope), may be adjustable and have typical values from 0.1 to 0.8 (or 10 percent to 80 percent).

The operating principle of percentage differential protection is the same as that for simple differential overcurrent protection. However, in the percentage differential scheme, for a severe external fault, the restraint current becomes large. Then, even if there is a significant operate current, the restraint is large enough to prevent the relay from operating. When the fault is internal, the operate current is considerably larger than the restraint current, resulting in relay operation.

Note: SEL assumes the user understands the common conventions employed in differential protection analysis. The primary currents are generally drawn to indicate current flowing into the protected equipment from both terminals. As a result, the two currents have neither the same sign nor the same angle during normal operation. In reality, during normal operation, the two currents have the same magnitude, but the phasors are 180 degrees apart, assuming properly sized CTs. The user should be aware that some engineers use a different convention.

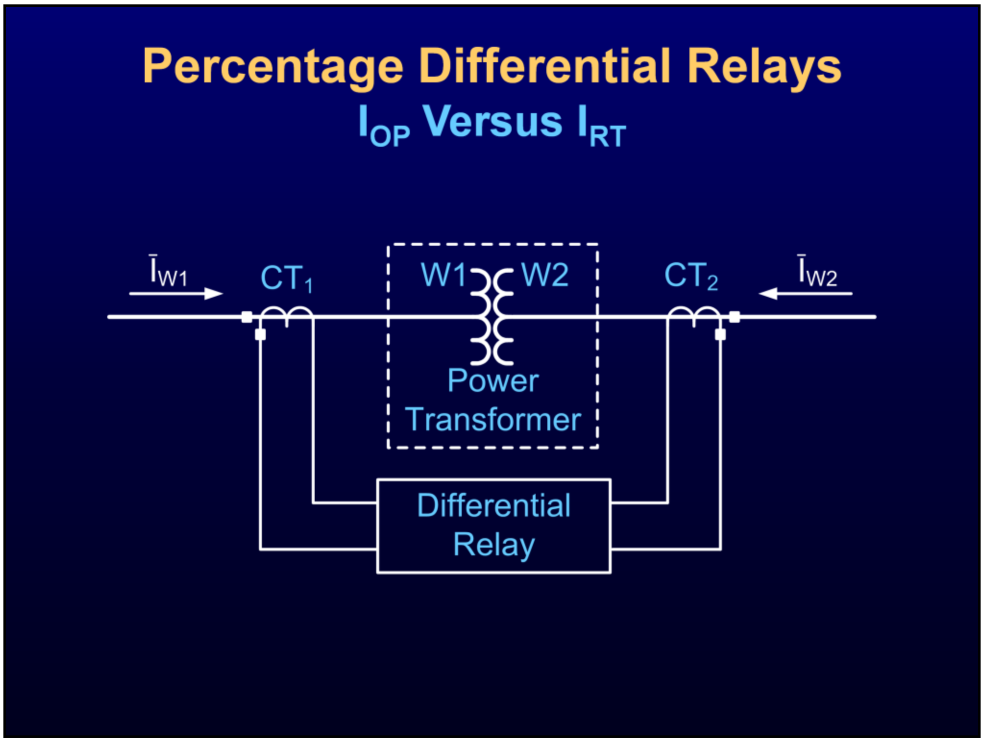


The percentage restraint differential relay is very insensitive to external faults with CT errors. With this design, the sensitivity for internal faults is not sacrificed remarkably because the restraint current is smaller for internal faults. This slide shows one of the most common graphical representations for differential relays. Factor *k* (the slope) is a relay setting, as well as the minimum pickup (I_{PU}). The usual implementation, however, is slightly different in that I_{PU} is stated as a separate condition. In that case, the percentage differential relay curve looks like the following:



Relay Operates When:

$$|I_{OP}| \geq k \bullet I_{RT} \text{ and } |I_{OP}| \geq I_{PU}$$



This slide shows the differential scheme applied to the protection of a power transformer.

$$\bar{I}_{OP} = \bar{I}_{W1}^{sec} + \bar{I}_{W2}^{sec} \qquad kI_{RT} = \frac{k\left(\left|\bar{I}_{W1}^{sec}\right| + \left|\bar{I}_{W2}^{sec}\right|\right)}{2}$$

where:

k is the slope

Super index –sec means secondary.

$\bar{I}_{OP}$ is the operate quantity (also called differential current) obtained as the phasor sum of the winding currents, $\bar{I}_{W1}$ and $\bar{I}_{W2}$.

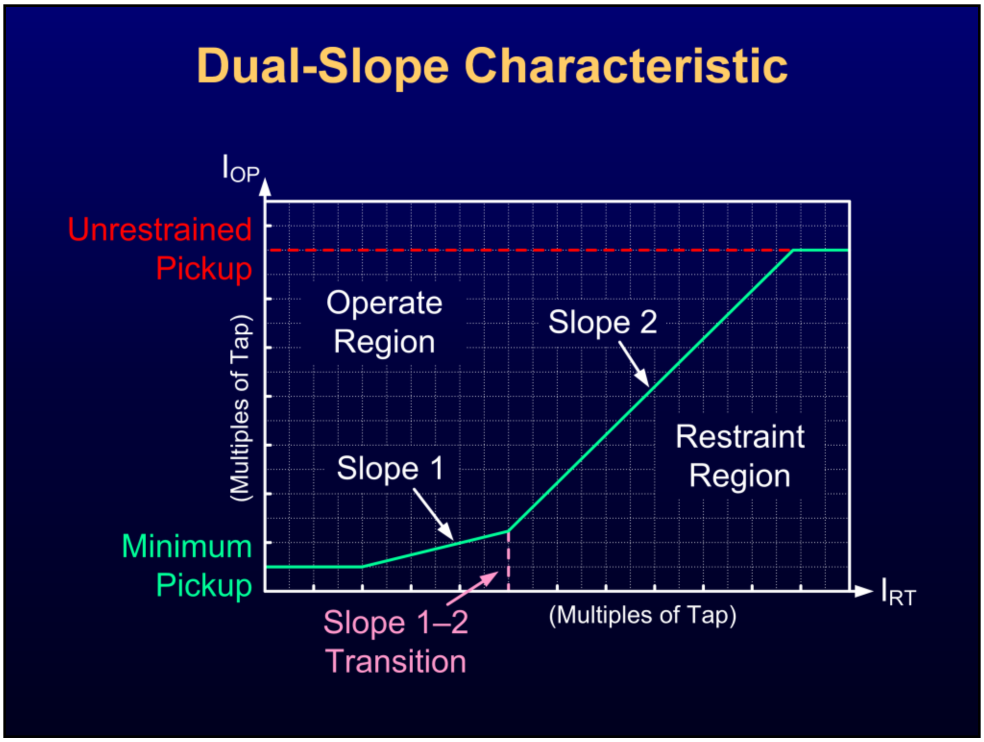
In a percentage restrained differential relay, the operate quantity is compared with a restraint quantity. The operate quantity must exceed a percentage of the restraint quantity for a trip to be issued.

A popular restraint current (suitable for multiwinding transformers) is the scaled scalar sum of the winding currents (average restraint).

Alternative methods are summation restraint (applicable to two-winding applications only) and maximum restraint.

With summation restraint, I_{RT} is the phasor magnitude of the current flowing through the zone of protection. Thus, for through faults, I_{RT} is 2 per unit. For equal currents flowing into the zone of protection, the currents cancel, and I_{RT} becomes 0 per unit.

With maximum restraint, only the largest of the through currents is used as I_{RT}.

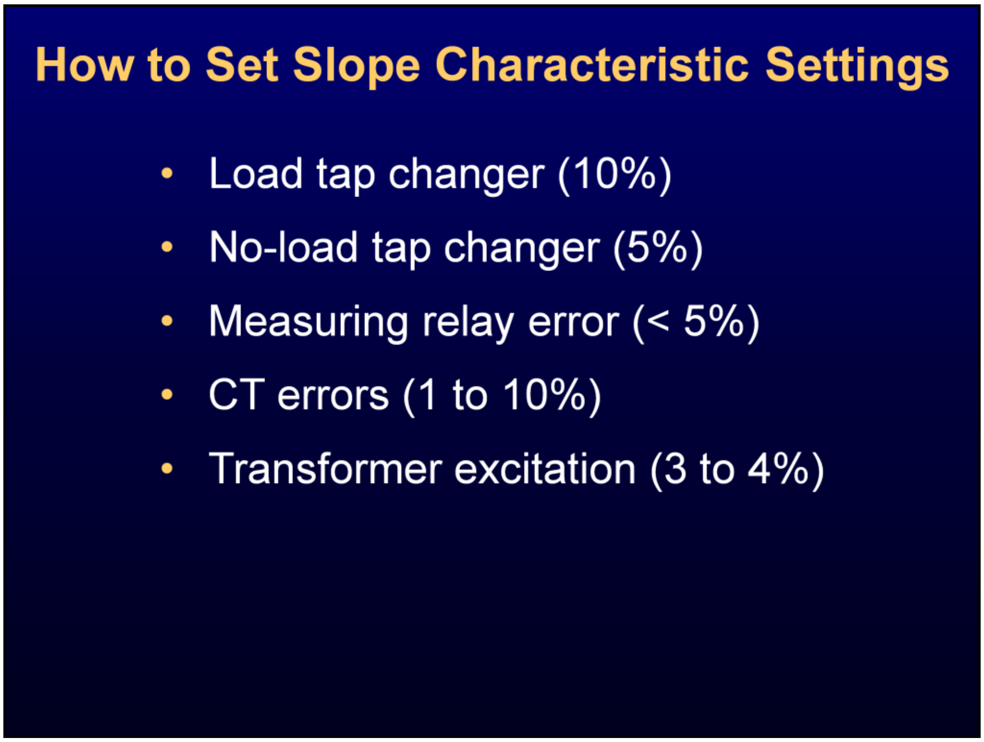


The figure on the slide is a graph of a dual-slope percentage restraint characteristic.

The Y axis represents the operate quantity. The X axis represents the restraint quantity. It is important to note that the quantities are plotted in per unit of tap. The concept of tap is explained shortly.

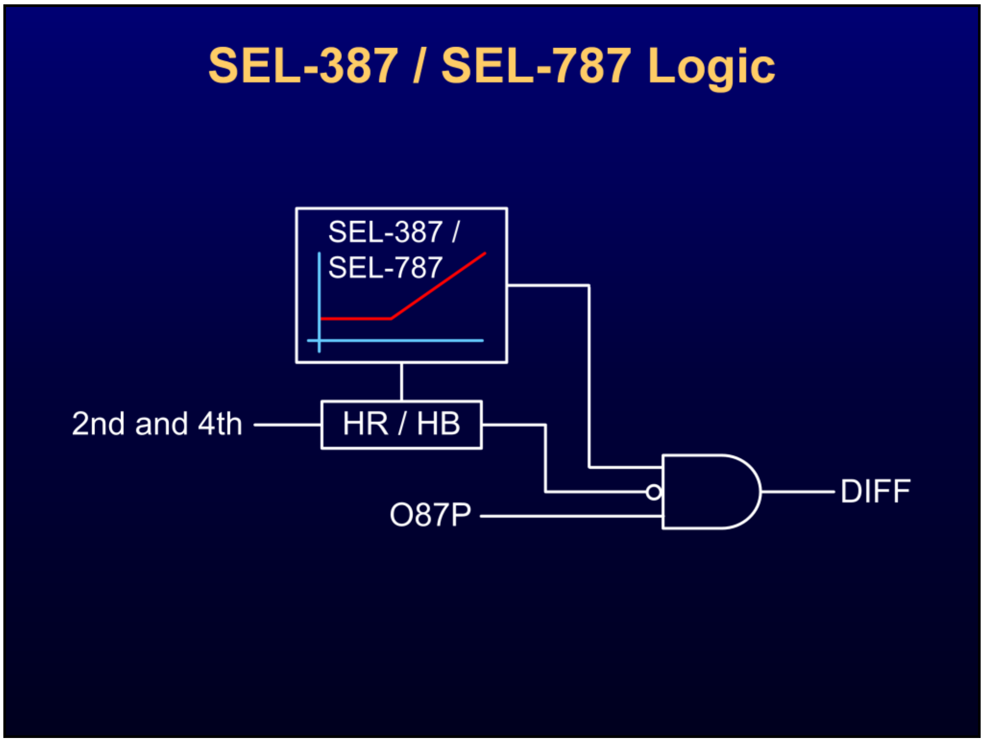
The green line represents the tripping characteristic. The slope of the characteristic labeled Slope 1 is expressed in percent. Thus, the operate current must exceed a certain percentage of the restraint current for a trip to occur. The green horizontal line represents the minimum sensitivity. The minimum sensitivity is necessary to deal with errors at very low magnitudes of operate and restraint.

Because CT errors resulting from saturation are most likely to be a problem at high current levels, the tip up of the characteristic, labeled Slope 2, provides increased restraint at high current levels. At the lower current levels, where the CT performance is likely to be linear, the restraint slope (Slope 1) can be less to provide improved sensitivity to low-level faults.

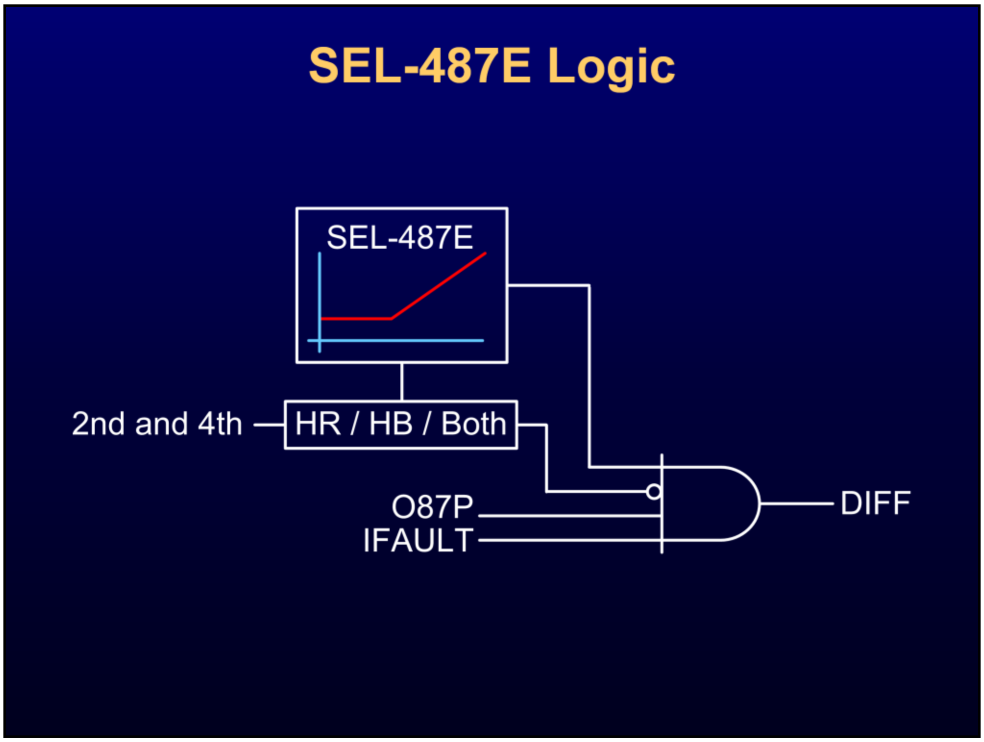


Several factors typically go into selecting the Slope 1 percentage slope setting, including the following:

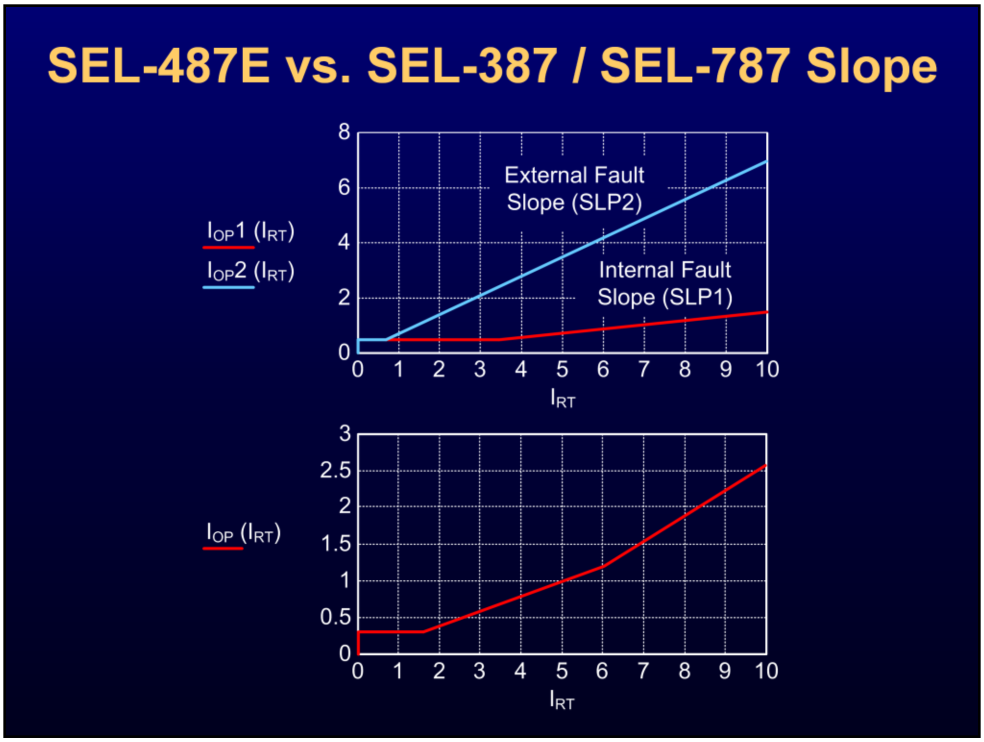
- Load tap changer range – typically 10 percent.
- No-load tap changer – if it can be adjusted without the knowledge of the relay engineer, typically 5 percent.
- Measuring errors of the relay – usually less than 5 percent in a numerical relay.
- CT errors – 1 percent for low-level faults and 10 percent or greater for high-level faults.
- Transformer excitation current – typically 3 to 4 percent. This error is not proportional to the loading of the transformer, so it offsets the error vertically on the characteristic.
- Transition to Slope 2 – at a level greater than normal operation.



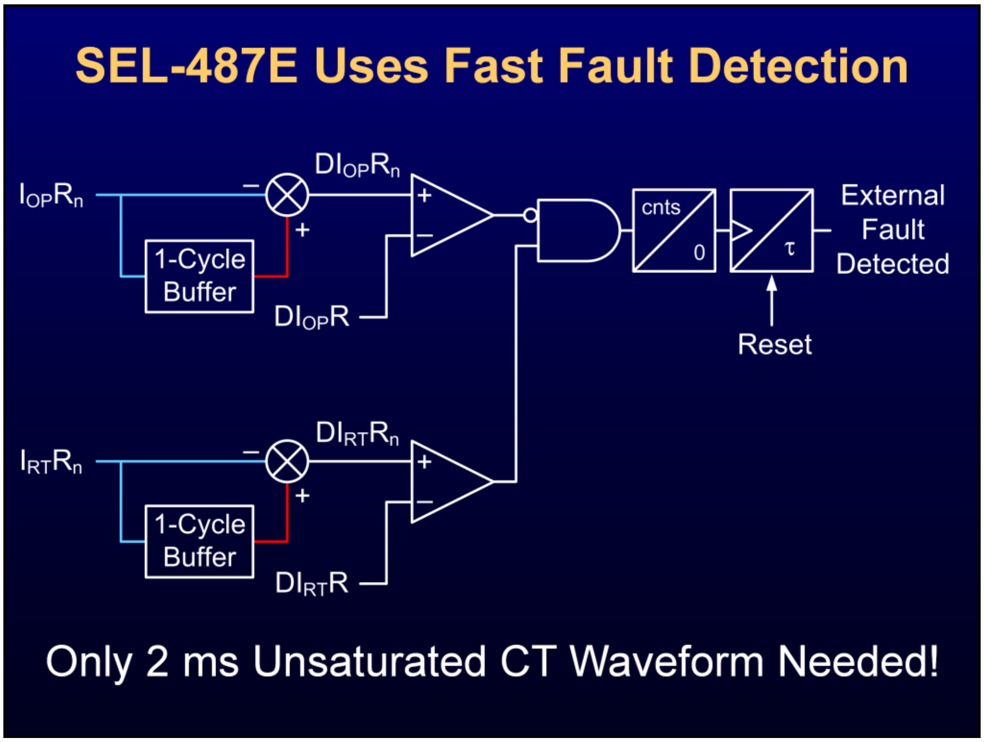
Recent additions to the SEL differential protection relay lineup include the SEL-487E and SEL-787 Transformer Protection Relays. The SEL-787 provides a two-slope method that is also used in the SEL-387 Current Differential and Overcurrent Relays and the SEL-587 Current Differential Relays.



The SEL-487E has a single-slope differential element that uses internal versus external fault detection logic to switch the slope of the differential restraint to a higher (more secure) level when external faults are detected.



While the traditional dual-slope characteristic has been shown to be very reliable for preventing operation during external faults with CT saturation, the single-slope characteristic has been designed to provide high sensitivity for internal faults and rapid transition to the higher slope during external faults. Testing has shown that the adaptive differential element is better at handling evolving faults and external faults with very severe CT saturation.

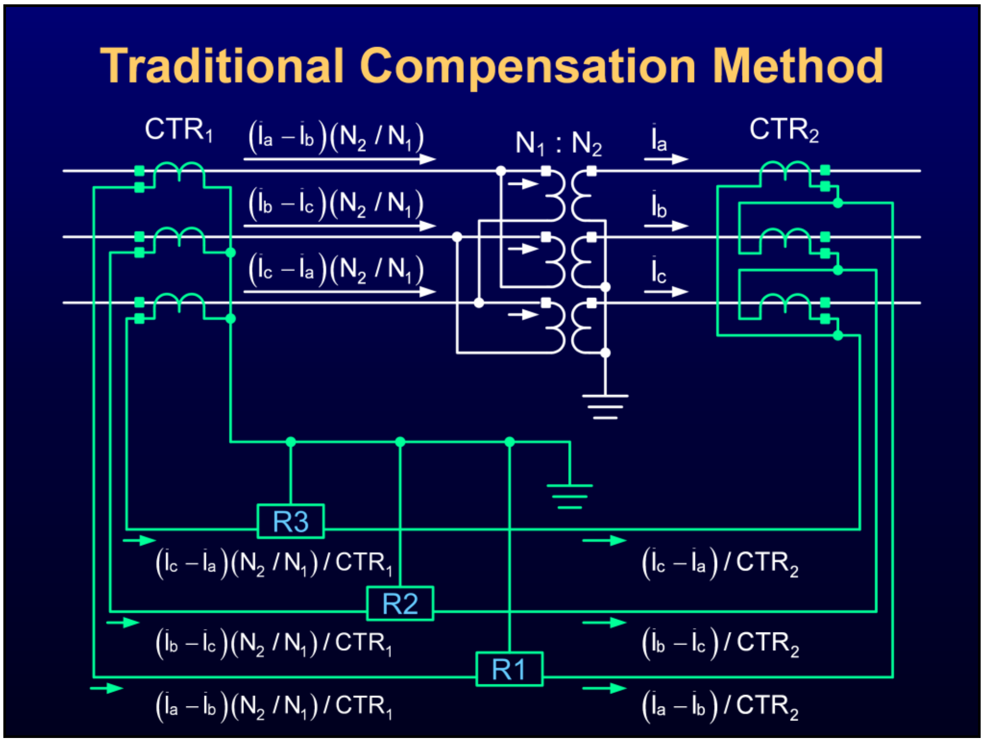


As shown on the previous slide, the SEL-487E only operates with one slope active at a particular instant in time (this allows for greater sensitivity during internal faults and greater restraint during external faults). To accomplish this task, the SEL-487E has an external fault detector that is capable of detecting the presence of an external fault within 2 milliseconds.

The fault detector principle of operation is that for an external fault (through fault), there is no change in the operate current (current in equals current out) before the CT saturates, but restraint current (net through current) does change. The magnitude of the current entering and leaving the transformer during a through fault does change (it increases).

The through-fault detector asserts when it sees a change in the restraint quantity but not in the operate quantity.

Another challenge in differential protection occurs when a transformer is placed within the differential protection zone. The transformer induces differences in current magnitudes within the zone due to the transformation ratio. Differences in transformer winding configurations (delta, wye, and so on) also induce phase angle differences in the current vectors that must be compensated for.



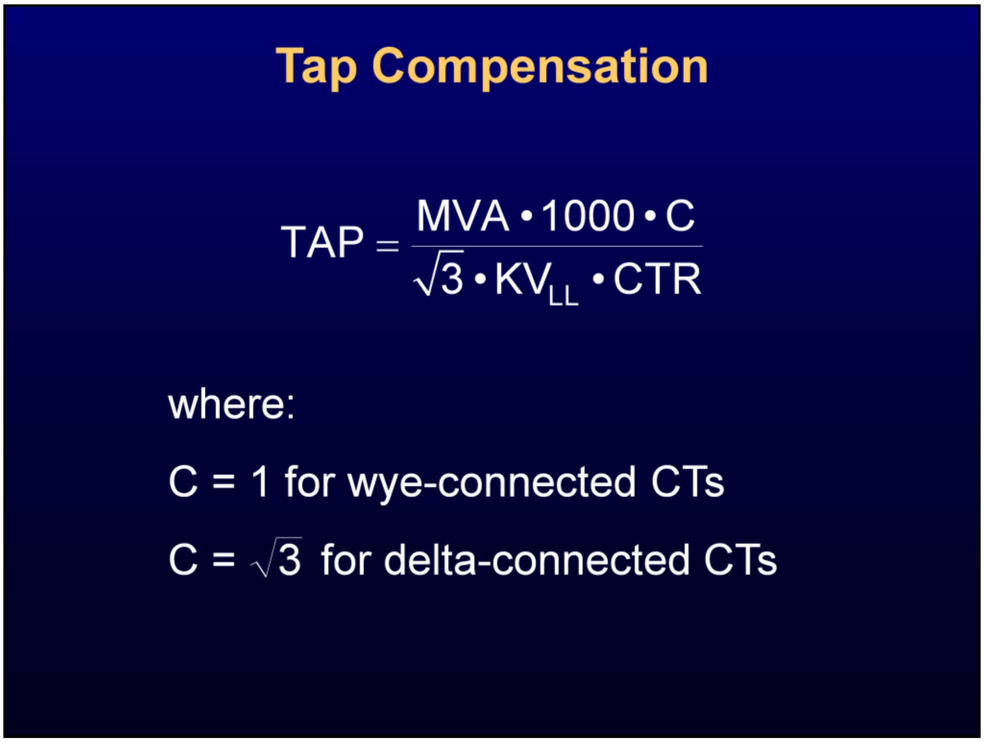
When traditional electromechanical relays are used, the CTs must be properly connected, as shown by the figure on the slide (DAC power transformer).

An alternative is to use low-voltage auxiliary transformers (not covered in this presentation). Note that, in addition to the connection, there must be a certain relationship between the CT ratios.

Ideally, CTR_1 equals CTR_2.

Compensation With Digital Relays

- Current magnitude and phase shift compensation
- Set relay according to transformer characteristics
- Consider all possible connections



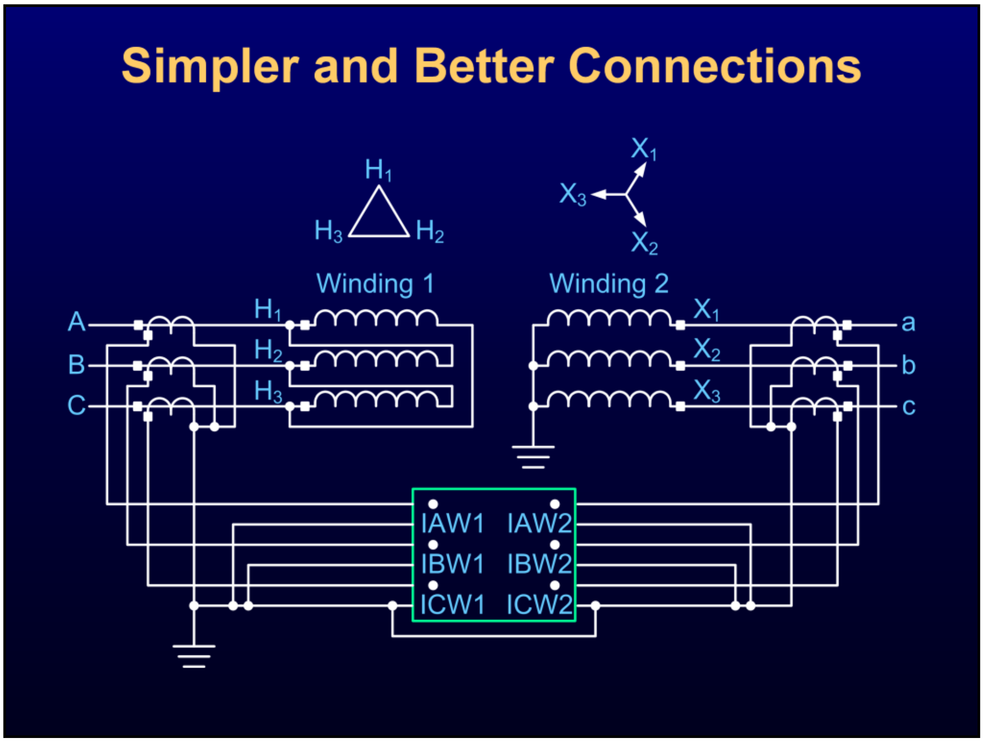
Tap is a setting in a differential relay that specifies the nominal current at full load. In electromechanical relays, the available taps are fixed and limited. The typical electromechanical taps allow for a maximum 5 percent mismatch. The mismatch generally compensates for the CT ratio mismatch between the transformer windings. In digital relays, the available taps are continuous between the specified minimum and maximum.

In the equation on the slide, the term $(MVA \cdot 1000)/(\sqrt{3} \cdot KV_{LL})$ merely defines the transformer full-load current, where:

- MVA is the rating of the transformer, and KV_{LL} is the voltage for that transformer terminal.
- The full-load current is divided by the CT ratio (CTR) to convert it to secondary amperes.
- The factor *C* is used to correct the effective CT ratio for the CT circuit. If the CTs are connected in delta, the effective CT ratio is reduced by √3. If the CTs are connected in wye, there is no compensation required and *C* is 1.

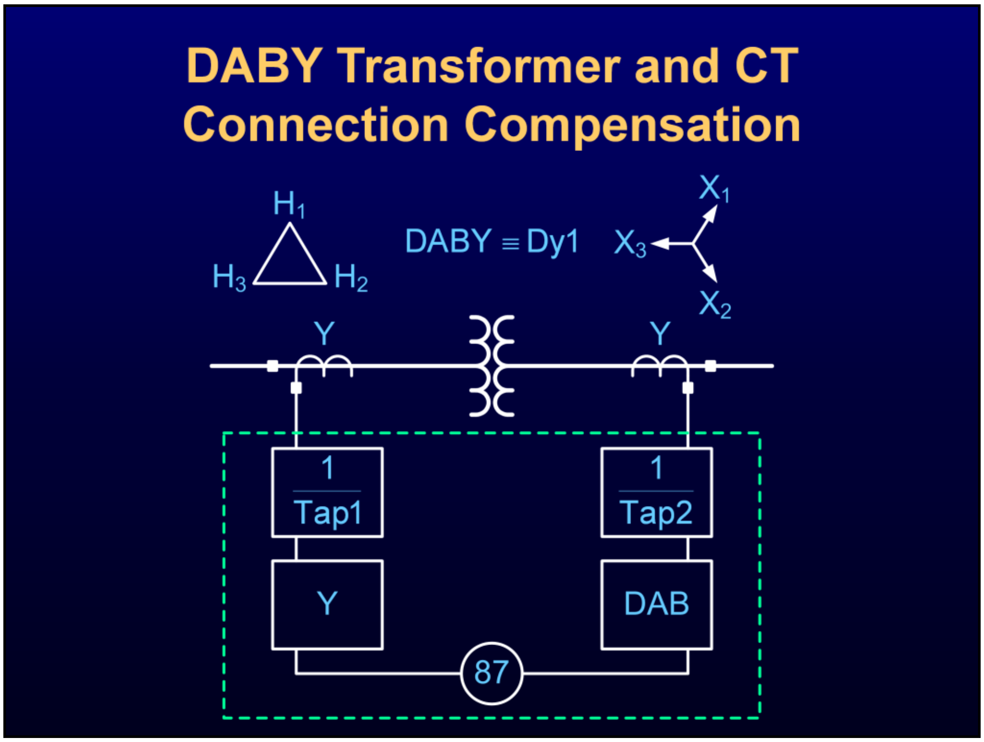
Thus, tap defines 1 per-unit current on the transformer MVA base at each terminal of the differential element.

If, for example, the tap is 5 for Winding 1, the differential element sees a measured current of 2.5 amperes associated with Winding 1 at 0.5 times tap.



With numerical relays, it is possible to connect the CTs in wye and let the relay calculate the delta compensation. This method has the following advantages:

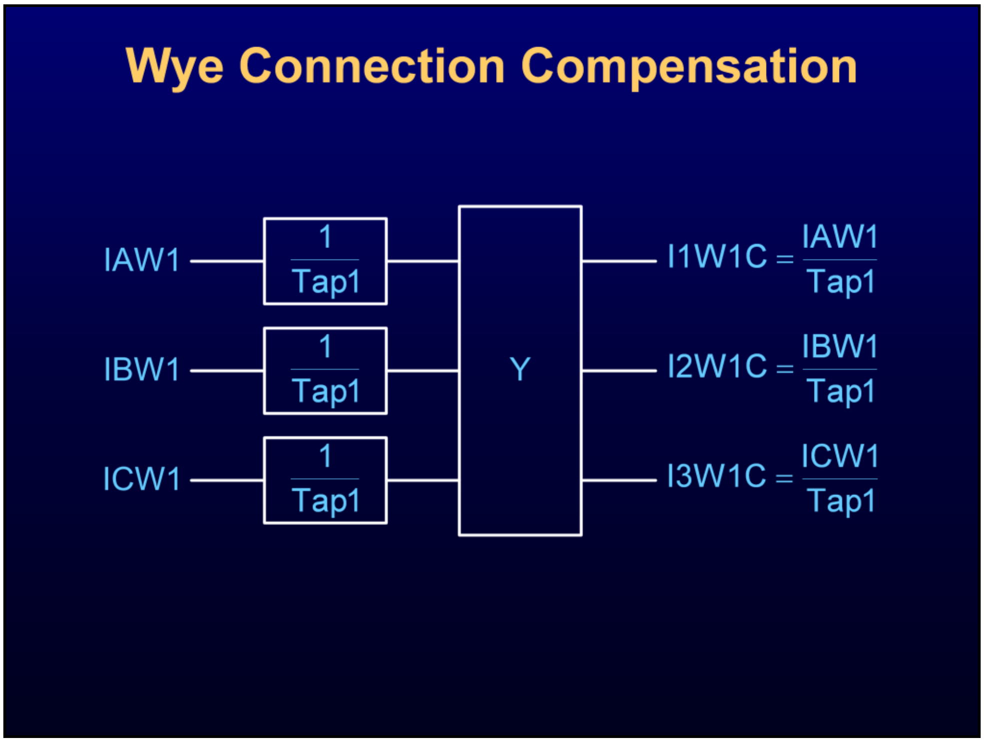
- Dedicated CTs are not required for the differential protection.
- Wye-connected CTs are easier to wire and troubleshoot.
- Wye-connected CTs see three times less lead burden for a three-phase fault than delta-connected CTs, making CT saturation less likely.
- Residual overcurrent protection can be used, whereas delta-connected CTs prevent this protection from being used on that input to the relay.
- With wye-connected CTs, the current that relay phase- and negative-sequence overcurrent elements see is the same as that seen by other overcurrent relays supplied by wye-connected CTs. With delta-connected CTs, these elements see current $\sqrt{3}$ higher. This increases the likelihood of errors in coordination with other phase- and negative-sequence elements.



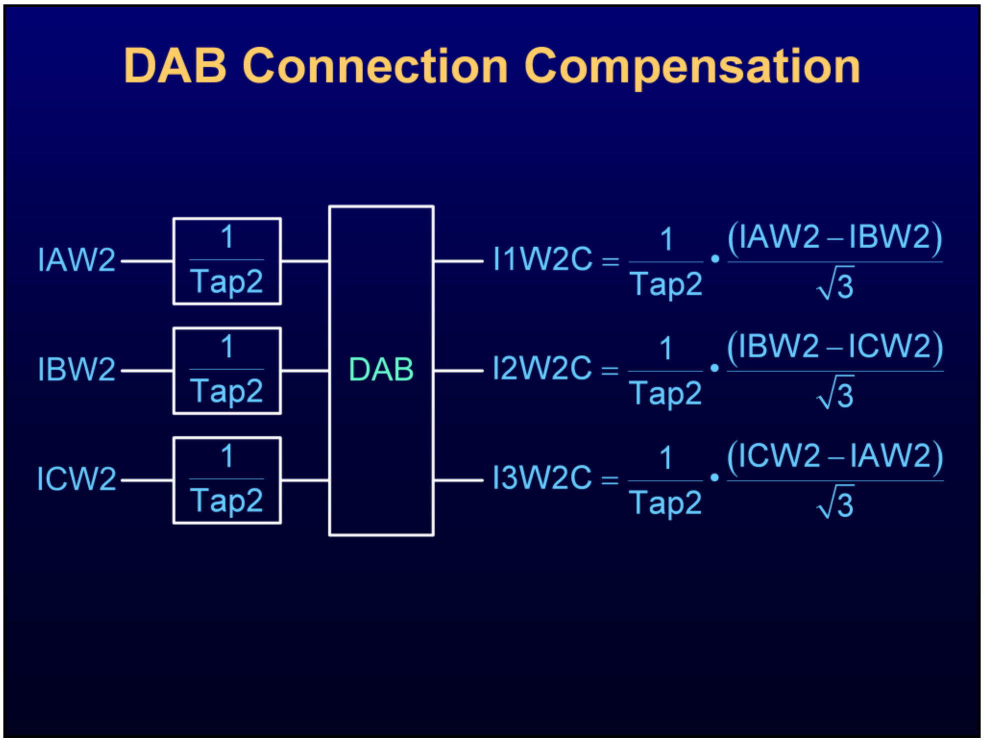
This slide shows a delta-wye transformer with 30-degree lag (ABC phase sequence).

The relay applies tap compensation to put the currents in per unit. It then applies phase compensation by applying current compensation to each input to mirror the power transformer connections on the opposite side. At this point, current in should equal current out.

Note the designation of the DABY transformer as a Dy1. This is an alternative way of describing the transformer connection. The transformer has Winding 1 = delta and Winding 2 = wye. Now imagine the face of a clock. In the phasor diagram, H_1 is pointing straight up at 12 o'clock, and X_1 is lagging by 30 degrees at 1 o'clock. Therefore, a Dy1 transformer is a delta-wye with a 30-degree lagging phase shift.



With wye compensation, the currents are only tap adjusted.

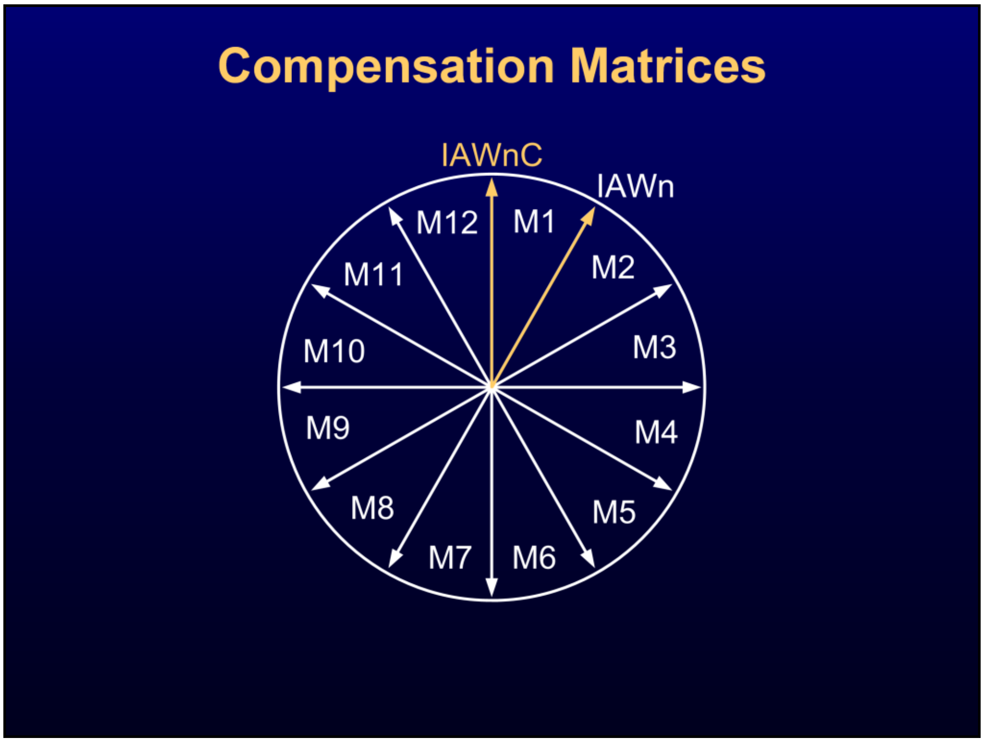


With DAB compensation, the currents are first tap adjusted and then combined mathematically as they would be in a delta $\bar{I}_A - \bar{I}_B$ CT connection. The resultant phasors are divided by the $\sqrt{3}$ factor to eliminate the increase in magnitude caused by the delta phasor subtraction.

For Differential Element 1, the compensated current I1W2C = $(\bar{I}_A - \bar{I}_B)/(\sqrt{3} \bullet \text{tap})$.

For Differential Element 2, the compensated current I2W2C = $(\bar{I}_B - \bar{I}_C)/(\sqrt{3} \bullet \text{tap})$.

For Differential Element 3, the compensated current I3W2C = $(\bar{I}_C - \bar{I}_A)/(\sqrt{3} \bullet \text{tap})$.

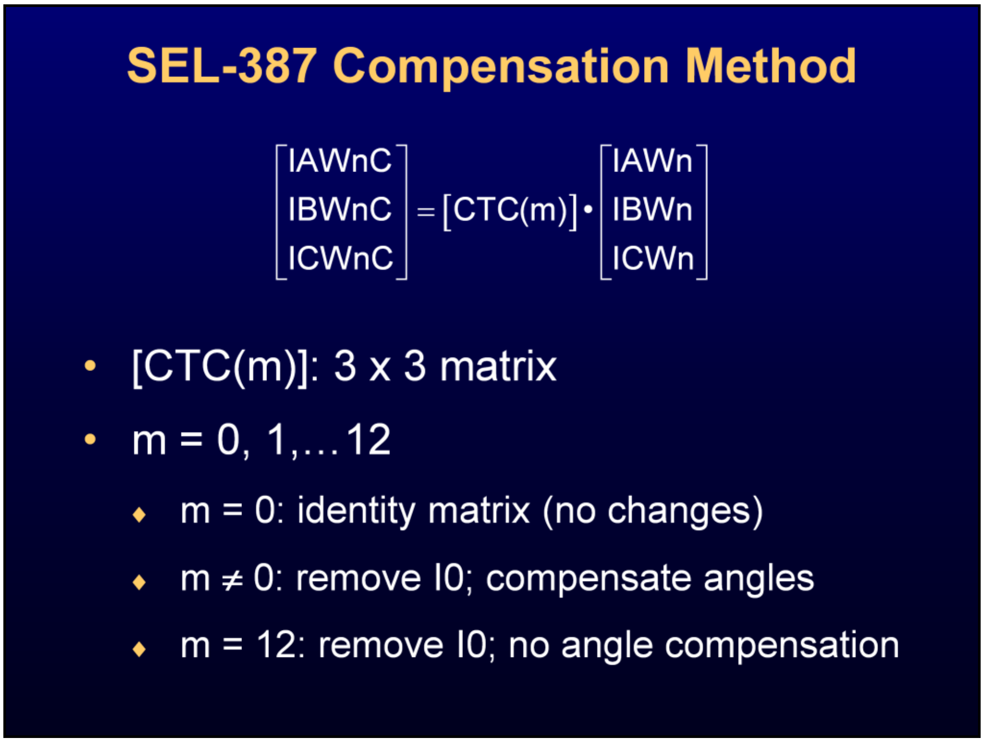


The next several slides describe the twelve compensation matrices used in the SEL transformer differential family of relays.

$$M1 = \frac{1}{\sqrt{3}}\begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix} \quad M2 = \frac{1}{3}\begin{bmatrix} 1 & -2 & 1 \\ 1 & 1 & -2 \\ -2 & 1 & 1 \end{bmatrix} \quad M3 = \frac{1}{\sqrt{3}}\begin{bmatrix} 0 & -1 & 1 \\ 1 & 0 & -1 \\ -1 & 1 & 0 \end{bmatrix} \quad M4 = \frac{1}{3}\begin{bmatrix} -1 & -1 & 2 \\ 2 & -1 & -1 \\ -1 & 2 & -1 \end{bmatrix}$$

$$M5 = \frac{1}{\sqrt{3}}\begin{bmatrix} -1 & 0 & 1 \\ 1 & -1 & 0 \\ 0 & 1 & -1 \end{bmatrix} \quad M6 = \frac{1}{3}\begin{bmatrix} -2 & 1 & 1 \\ 1 & -2 & 1 \\ 1 & 1 & -2 \end{bmatrix} \quad M7 = \frac{1}{\sqrt{3}}\begin{bmatrix} -1 & 1 & 0 \\ 0 & -1 & 1 \\ 1 & 0 & -1 \end{bmatrix} \quad M8 = \frac{1}{3}\begin{bmatrix} -1 & 2 & -1 \\ -1 & -1 & 2 \\ 2 & -1 & -1 \end{bmatrix}$$

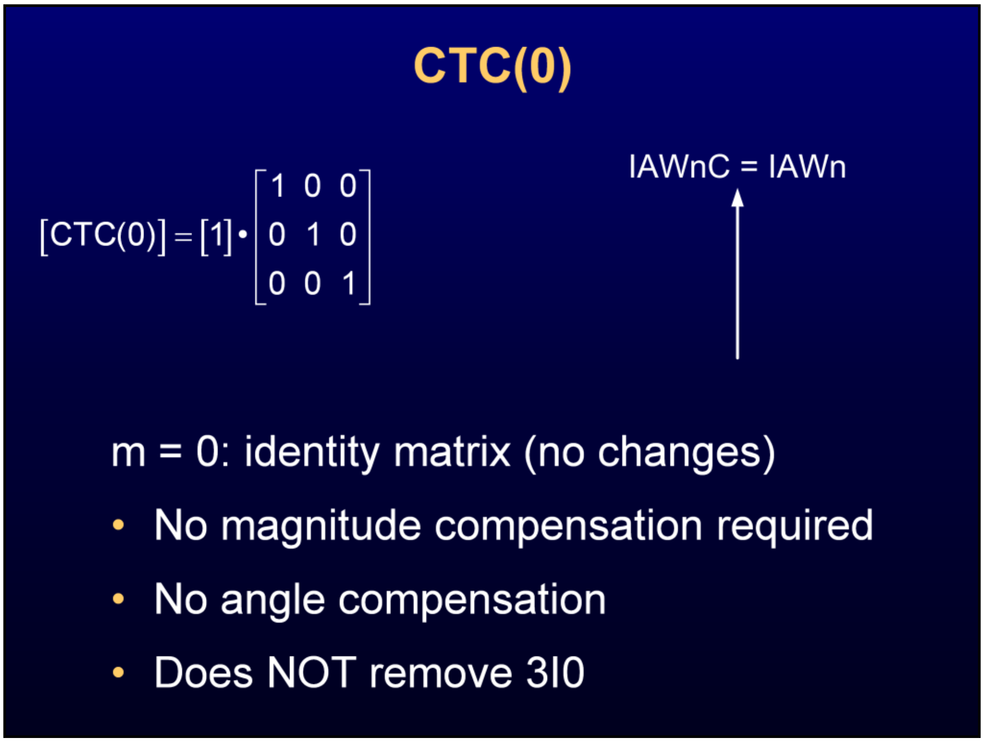
$$M9 = \frac{1}{\sqrt{3}}\begin{bmatrix} 0 & 1 & -1 \\ -1 & 0 & 1 \\ 1 & -1 & 0 \end{bmatrix} \quad M10 = \frac{1}{3}\begin{bmatrix} 1 & 1 & -2 \\ -2 & 1 & 1 \\ 1 & -2 & 1 \end{bmatrix} \quad M11 = \frac{1}{\sqrt{3}}\begin{bmatrix} 1 & 0 & -1 \\ -1 & 1 & 0 \\ 0 & -1 & 1 \end{bmatrix} \quad M12 = \frac{1}{3}\begin{bmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{bmatrix}$$



Some transformer and CT connections require more than 30 degrees of phase shift. The SEL-387 expands on the concept used in the SEL-587 by using settings like the hours on a clock that provide complete 360 degrees of phase shift in 30-degree increments.

The equation shown on the slide illustrates how the compensated currents are obtained from the winding input currents. The input currents, at right, are the Phase A, Phase B, and Phase C currents for one of the four (*n*) winding inputs. Factor [CTC(*m*)] is a 3-by-3 matrix that multiplies the input currents. The compensated values, at left, have a *C* at the end of each name. The parameter *m* is the setting W*n*CTC for Winding *n* and can take a value from 0 to 12. The value of *m* represents the number of 30-degree increments of adjustment necessary to bring normal, balanced (positive-sequence) Winding *n* currents into phase with a selected reference winding. These increments are measured in the counterclockwise (CCW) direction for ABC phase rotation and in the clockwise (CW) direction for ACB phase rotation.

For m = 0, CTC(*m*) is the identity matrix (i.e., ones on the diagonal, zeros elsewhere). The compensated values are thus equal to the input values. For $m \neq 0$, the matrix causes two or three winding currents to be combined to produce each compensated value. For example, if m = 1, the compensated current IAWnC = (IAWn – IBWn)/$\sqrt{3}$, IBWnC = (IBWn – ICWn)/$\sqrt{3}$, and so on. All nonzero values of *m* remove zero-sequence current components. This includes m = 12, which produces zero angle shift (actually 360 degrees), but which removes I0. This compensation is used for a wye winding with wye CTs, where the matrix acts like a zero-sequence current trap connection to prevent misoperation for external ground faults.



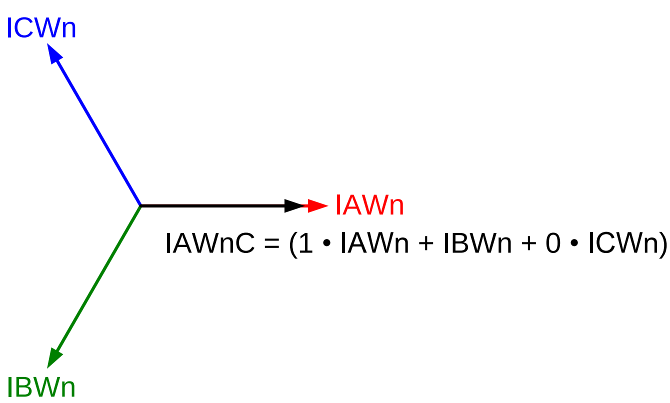
This internal relay equation represents m = 0. The notes on this slide and the following slides all show the equations for the respective matrix shown on the slide.

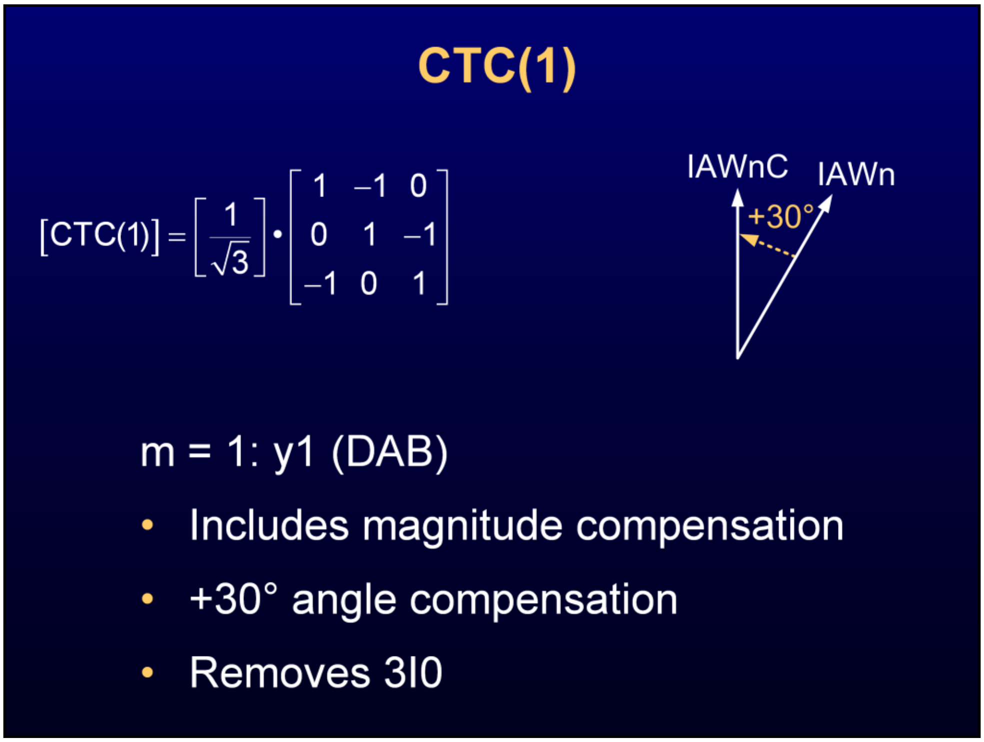
CTC(0)

IAWnC = (1 • IAWn + 0 • IBWn + 0 • ICWn)

IBWnC = (0 • IAWn + 1 • IBWn + 0 • ICWn)

ICWnC = (0 • IAWn + 0 • IBWn + 1 • ICWn)



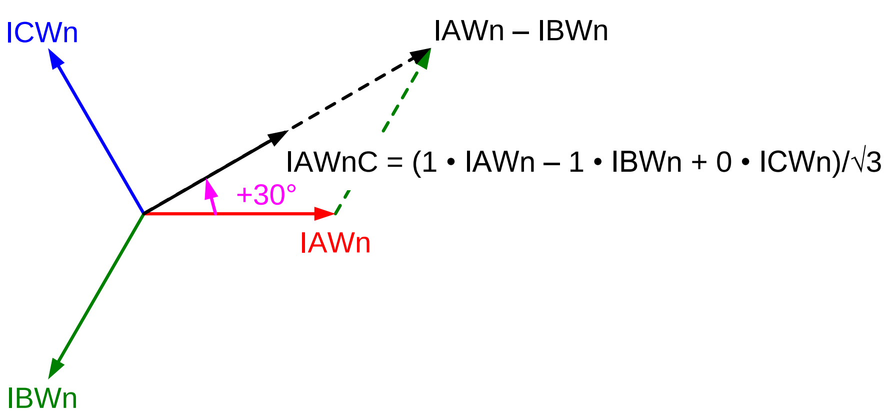


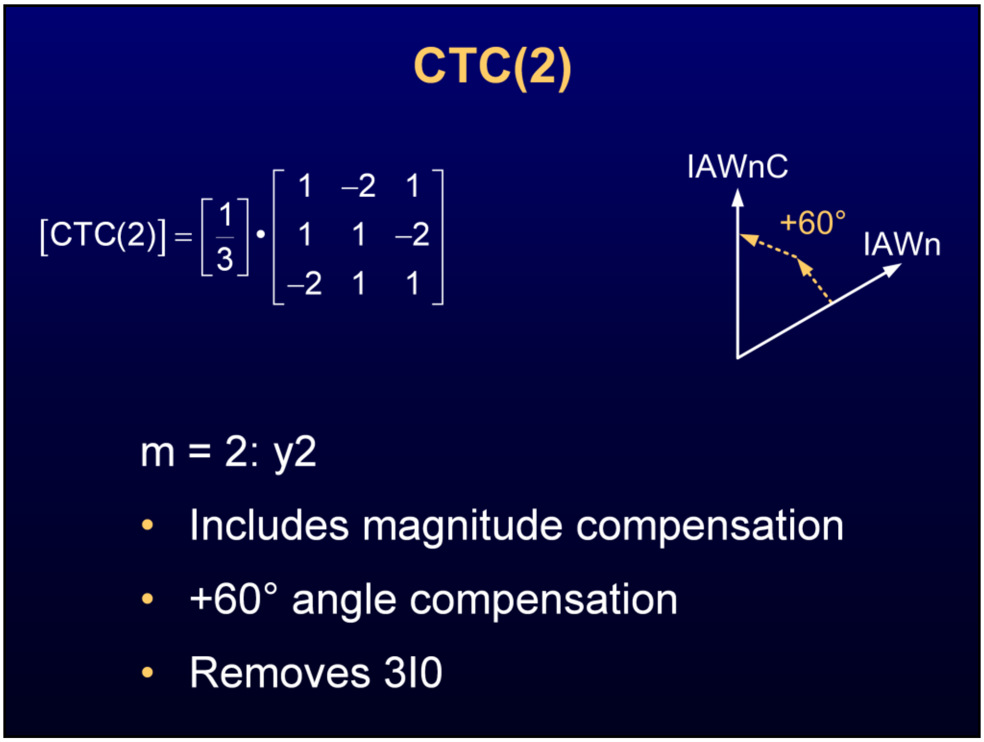
CTC(1)

IAWnC = (1 • IAWn – 1 • IBWn + 0 • ICWn)/√3

IBWnC = (0 • IAWn + 1 • IBWn – 1 • ICWn)/√3

ICWnC = (–1 • IAWn + 0 • IBWn + 1 • ICWn)/√3



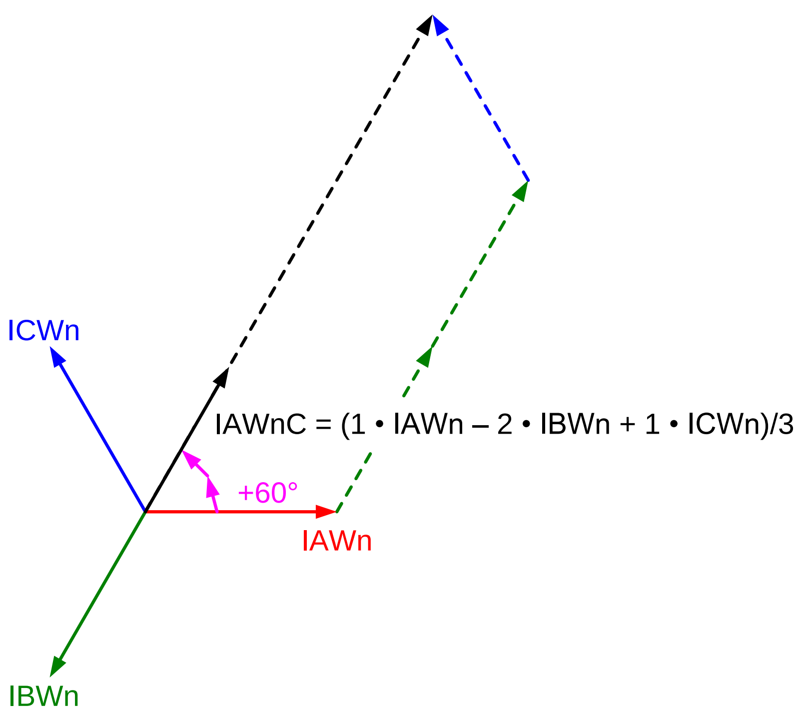


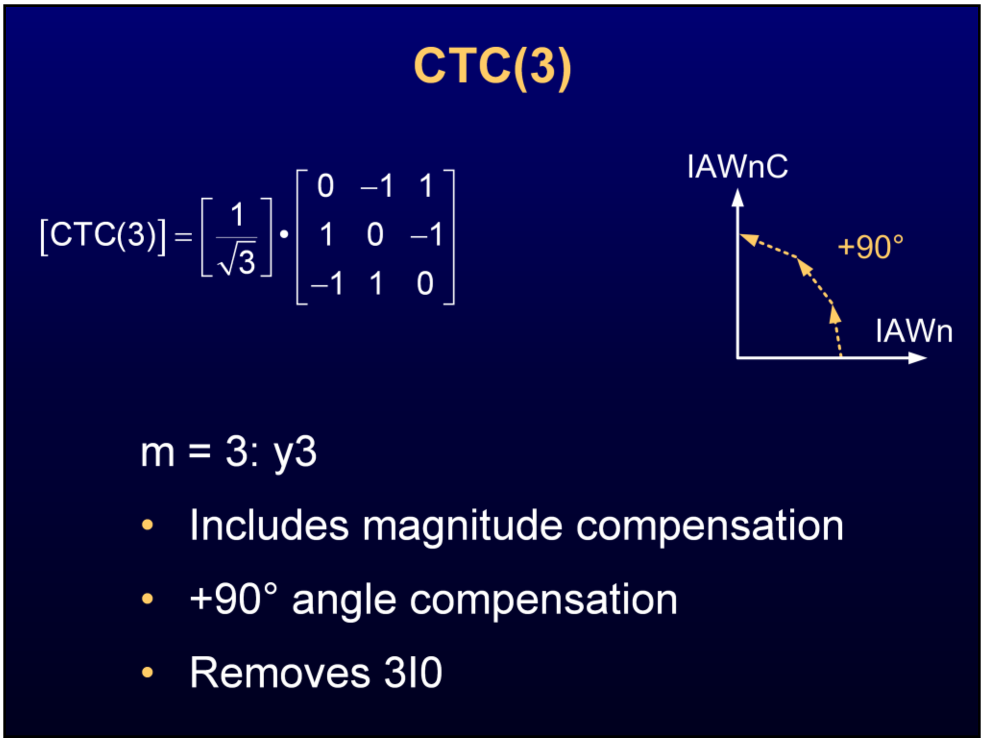
CTC(2)

IAWnC = (1 • IAWn – 2 • IBWn + 1 • ICWn)/3

IBWnC = (1 • IAWn + 1 • IBWn – 2 • ICWn)/3

ICWnC = (–2 • IAWn + 1 • IBWn + 1 • ICWn)/3



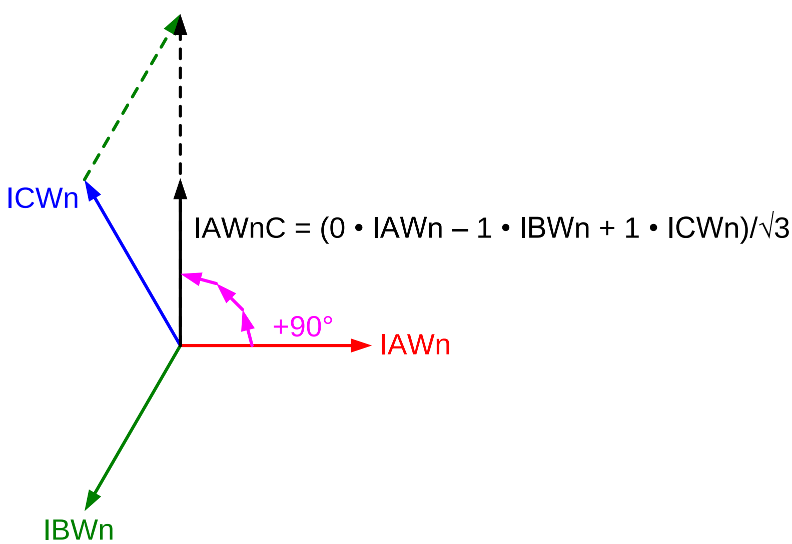


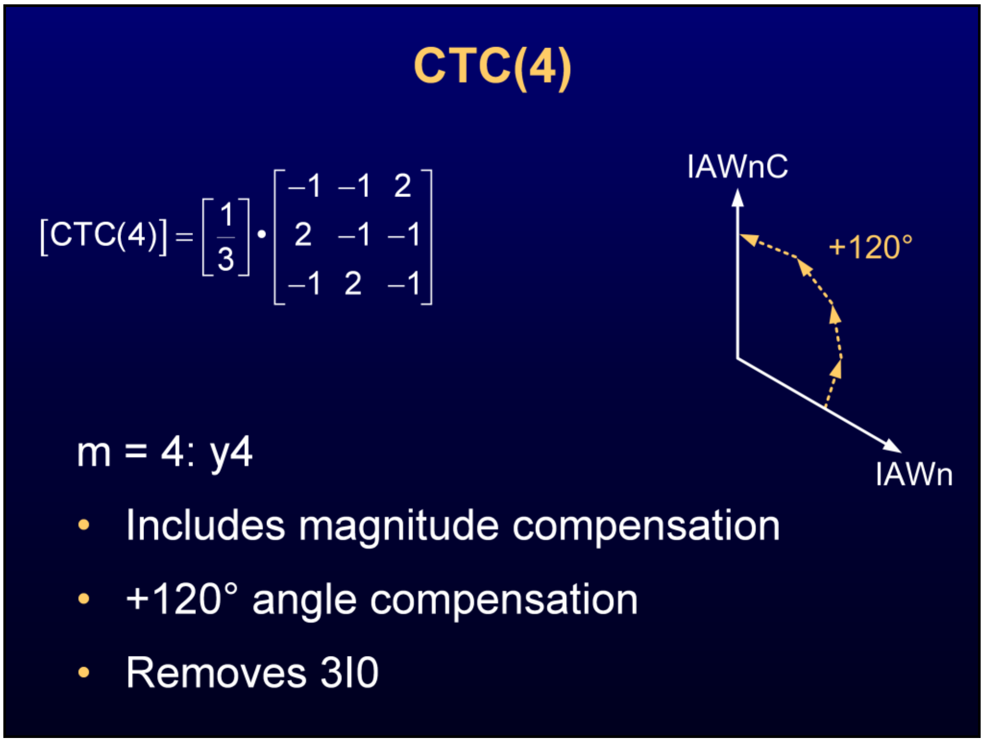
CTC(3)

IAWnC = (0 • IAWn – 1 • IBWn + 1 • ICWn)/√3

IBWnC = (1 • IAWn + 0 • IBWn – 1 • ICWn)/√3

ICWnC = (–1 • IAWn + 1 • IBWn + 0 • ICWn)/√3



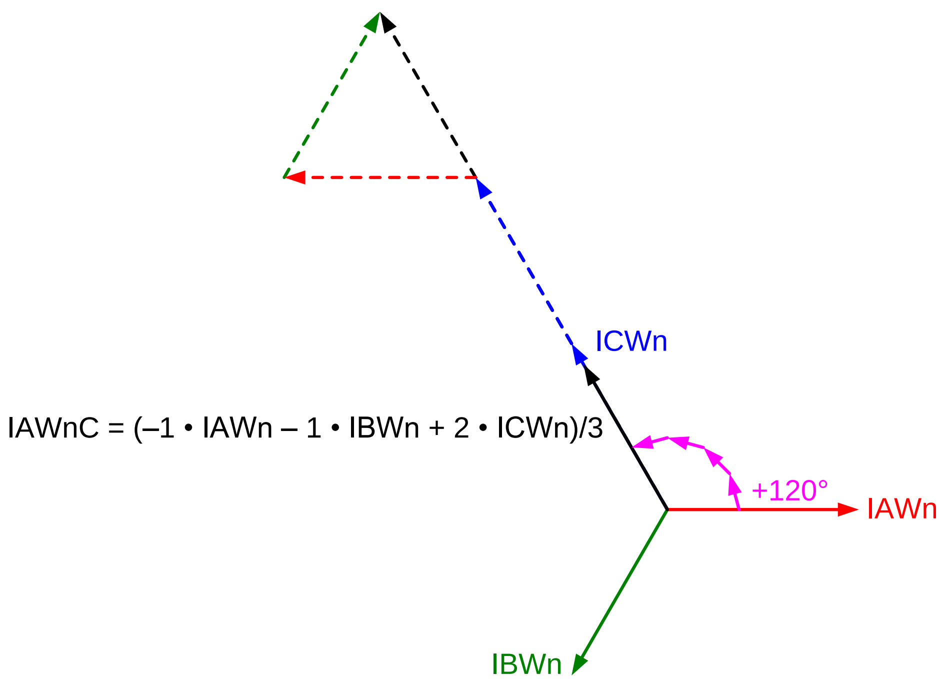


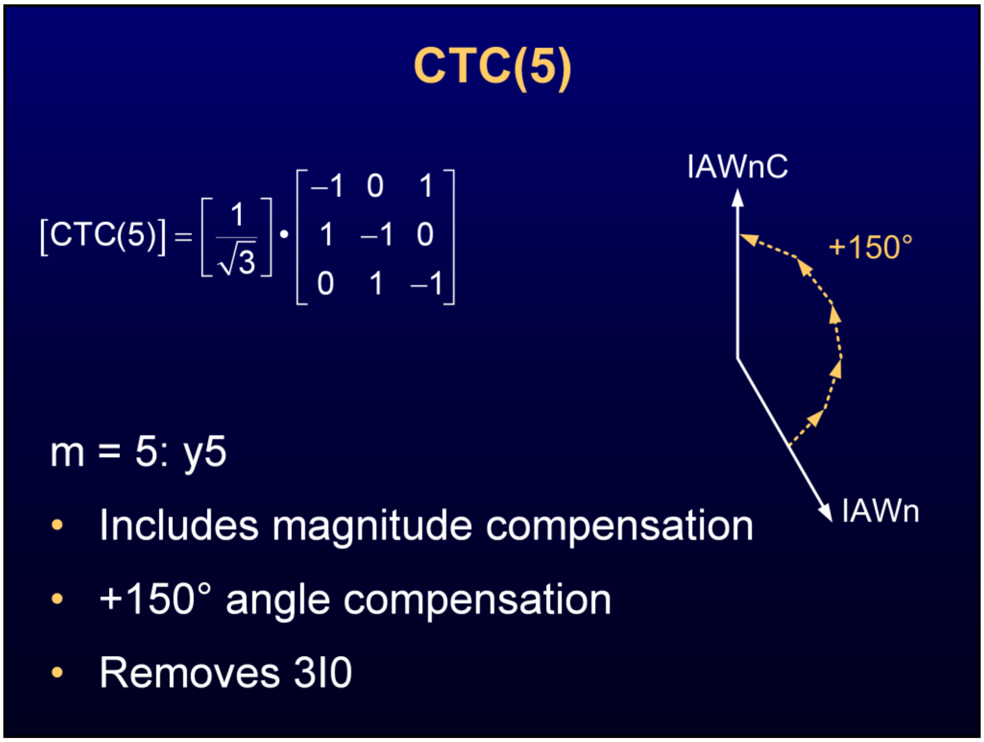
CTC(4)

IAWnC = (–1 • IAWn – 1 • IBWn + 2 • ICWn)/3

IBWnC = (2 • IAWn – 1 • IBWn – 1 • ICWn)/3

ICWnC = (–1 • IAWn + 2 • IBWn – 1 • ICWn)/3



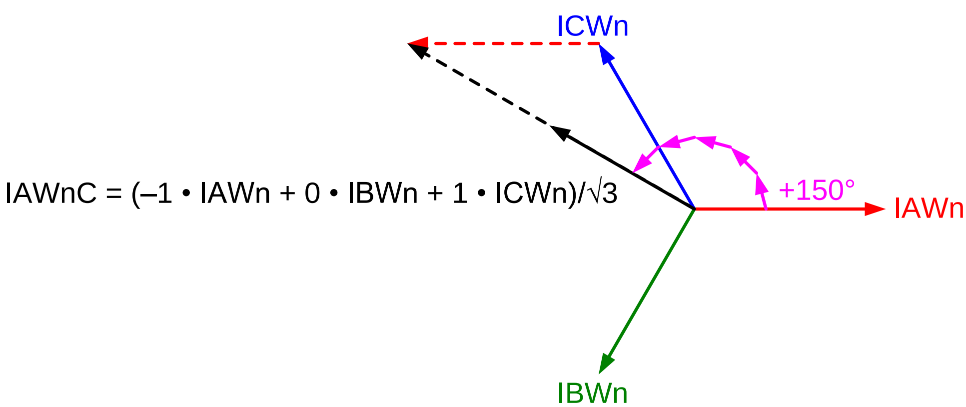


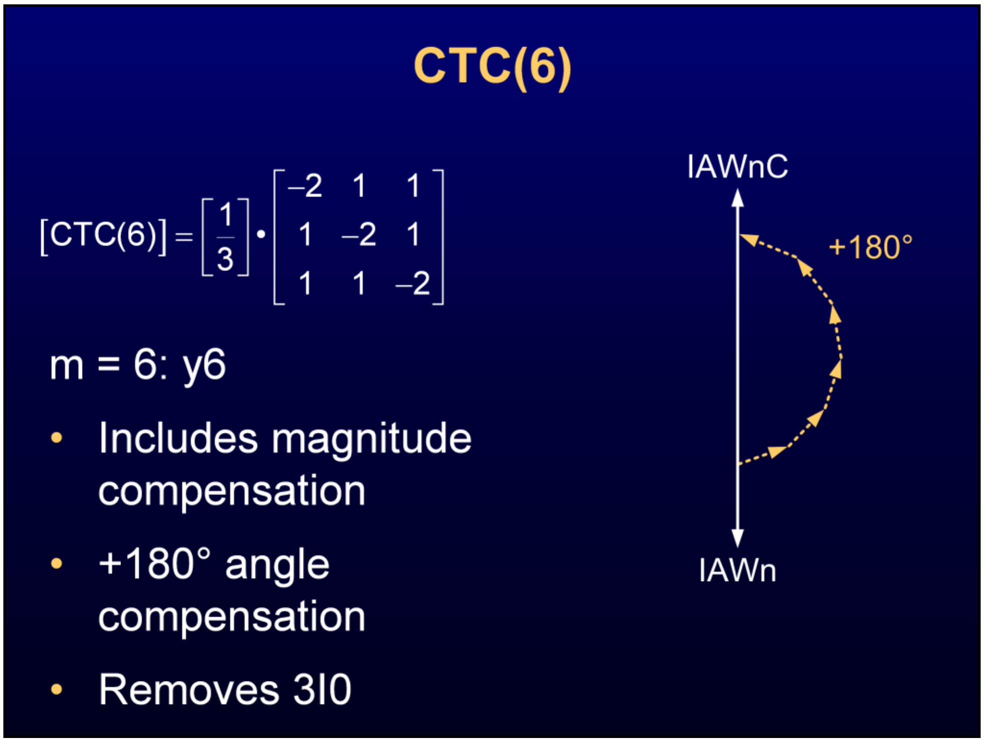
CTC(5)

IAWnC = (–1 • IAWn + 0 • IBWn + 1 • ICWn)/√3

IBWnC = (1 • IAWn – 1 • IBWn + 0 • ICWn)/√3

ICWnC = (0 • IAWn + 1 • IBWn – 1 • ICWn)/√3



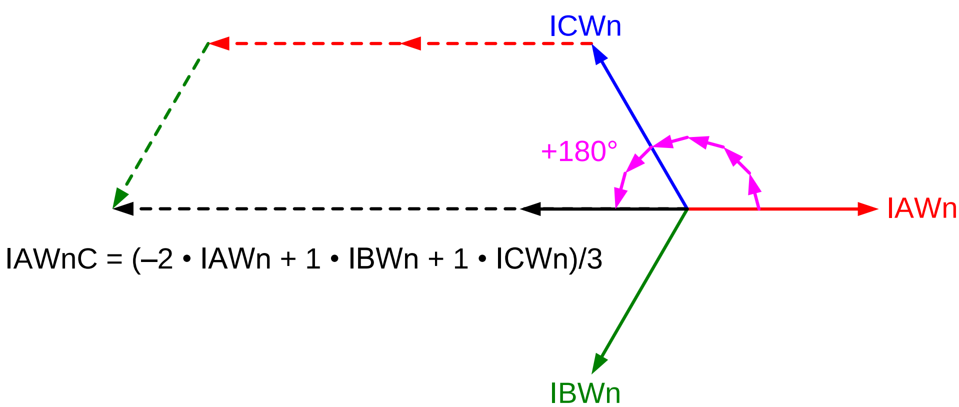


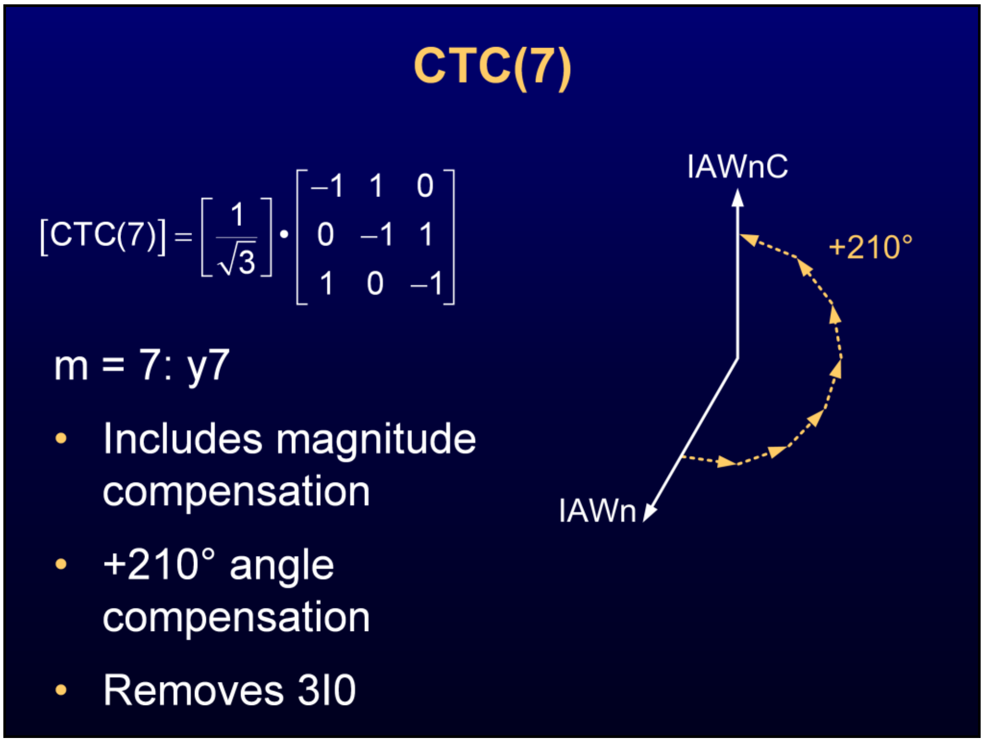
CTC(6)

IAWnC = (–2 • IAWn + 1 • IBWn + 1 • ICWn)/3

IBWnC = (1 • IAWn – 2 • IBWn + 1 • ICWn)/3

ICWnC = (1 • IAWn + 1 • IBWn – 2 • ICWn)/3



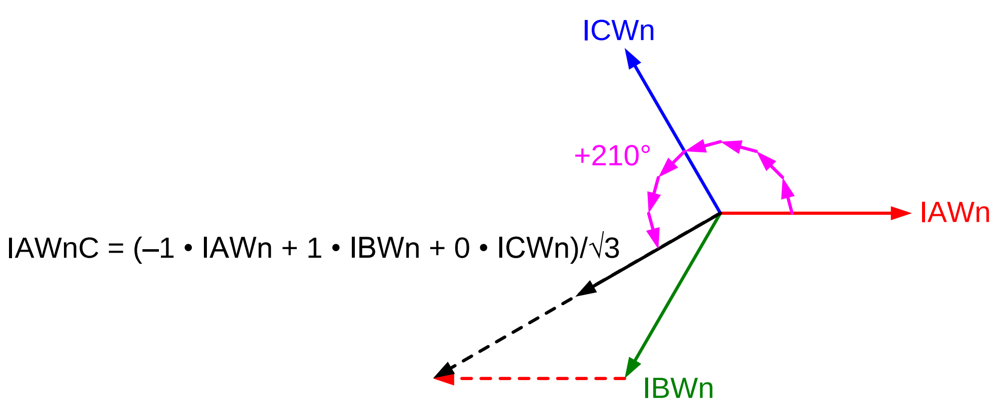


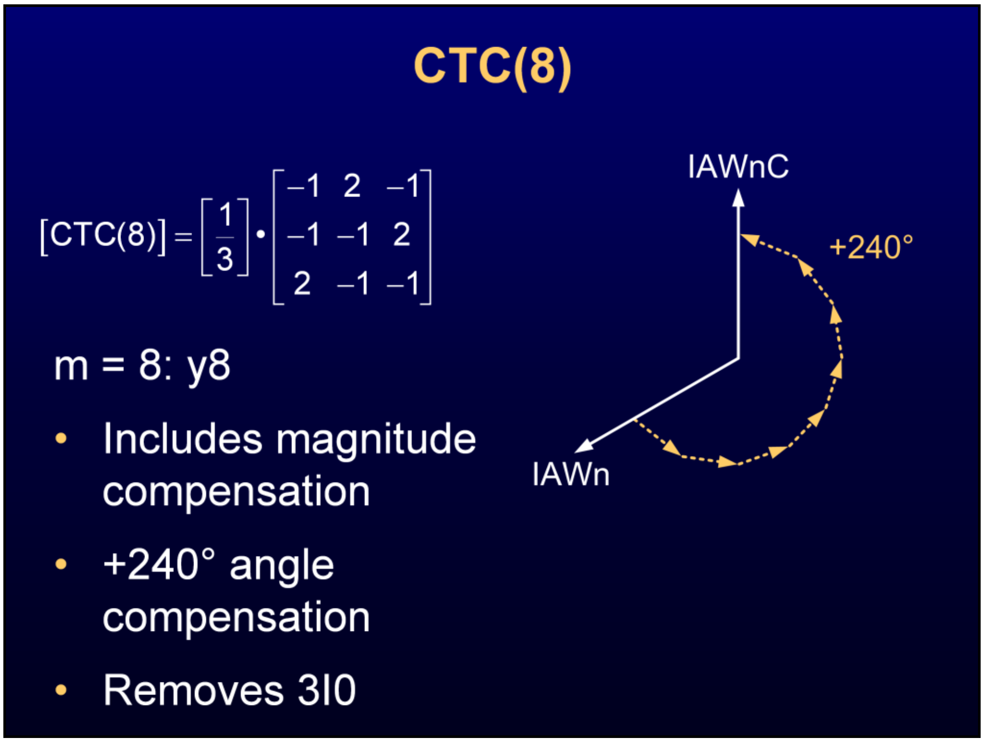
CTC(7)

IAWnC = (–1 • IAWn + 1 • IBWn + 0 • ICWn)/√3

IBWnC = (0 • IAWn – 1 • IBWn + 1 • ICWn)/√3

ICWnC = (1 • IAWn + 0 • IBWn – 1 • ICWn)/√3



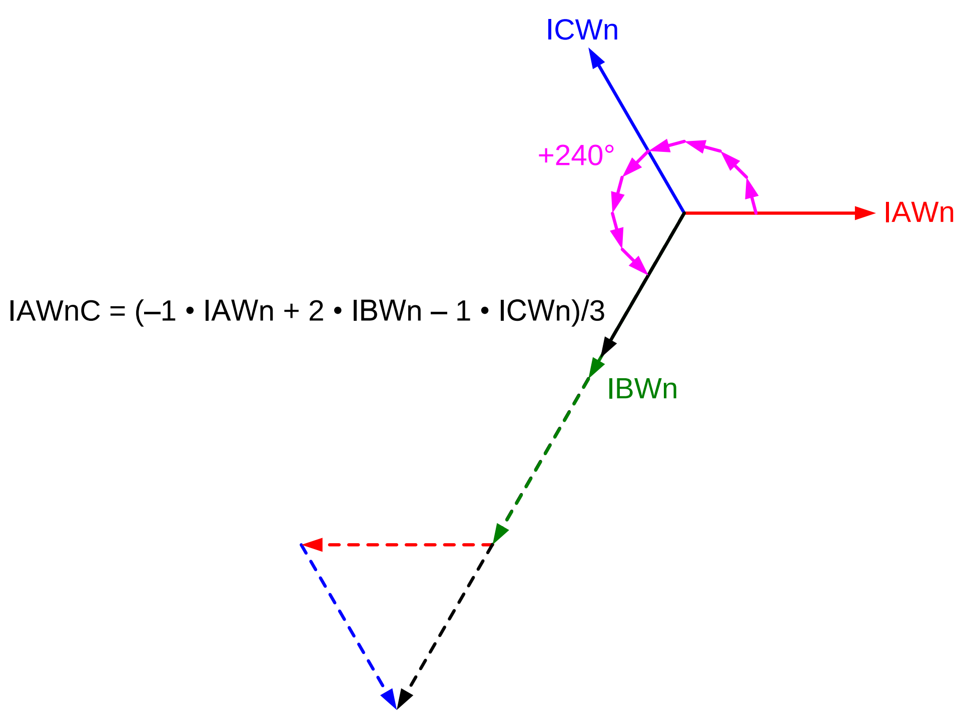


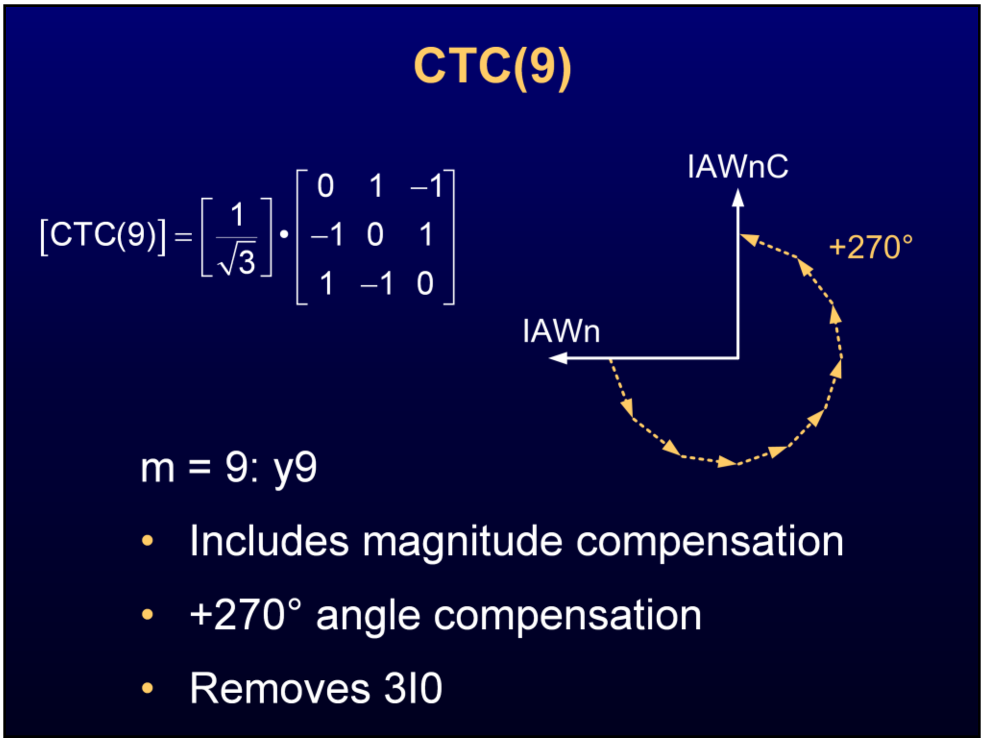
CTC(8)

IAWnC = (–1 • IAWn + 2 • IBWn – 1 • ICWn)/3

IBWnC = (–1 • IAWn – 1 • IBWn + 2 • ICWn)/3

ICWnC = (2 • IAWn – 1 • IBWn – 1 • ICWn)/3



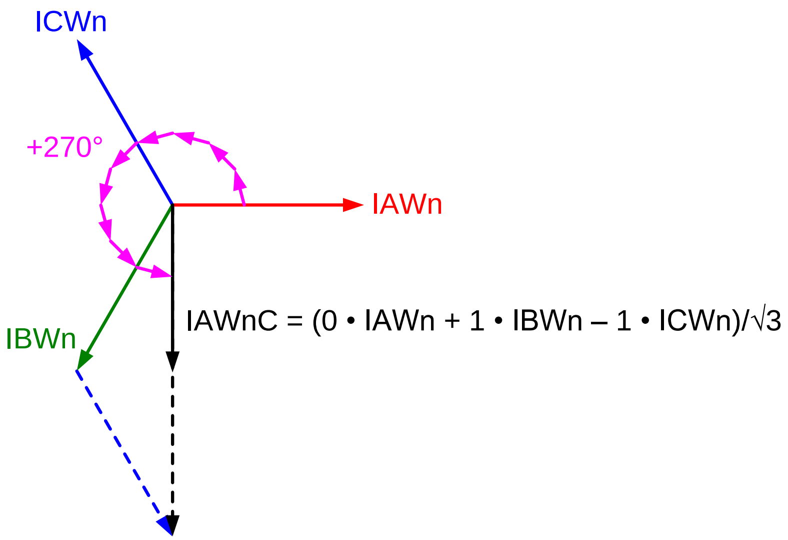


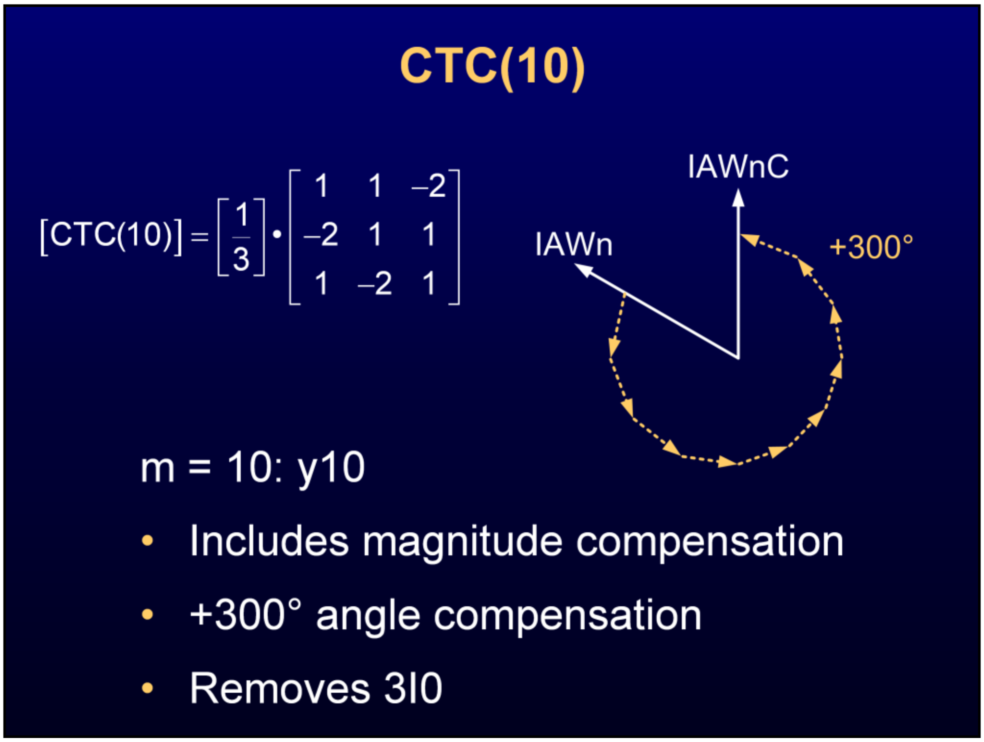
CTC(9)

IAWnC = (0 • IAWn + 1 • IBWn – 1 • ICWn)/√3

IBWnC = (–1 • IAWn + 0 • IBWn + 1 • ICWn)/√3

ICWnC = (1 • IAWn – 1 • IBWn + 0 • ICWn)/√3



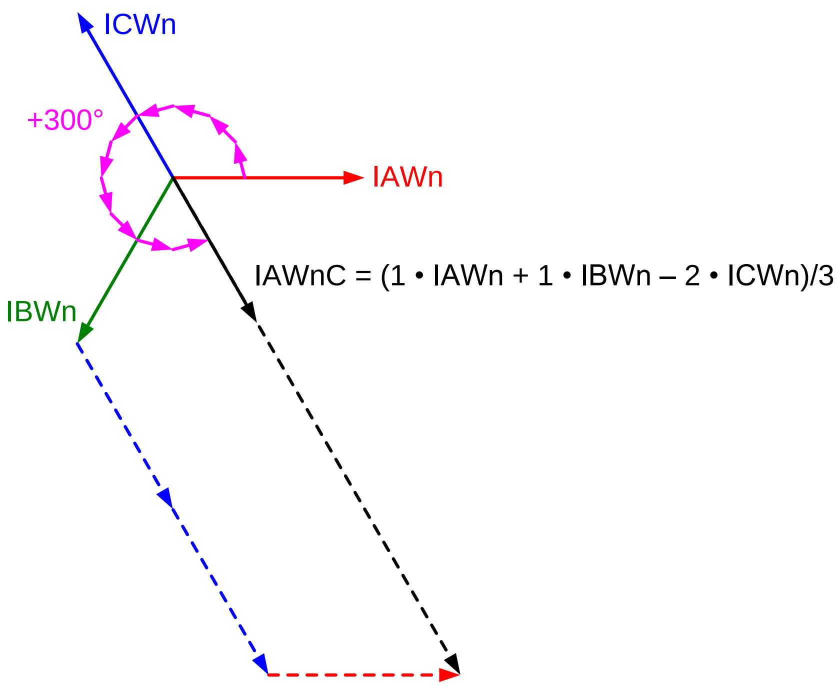


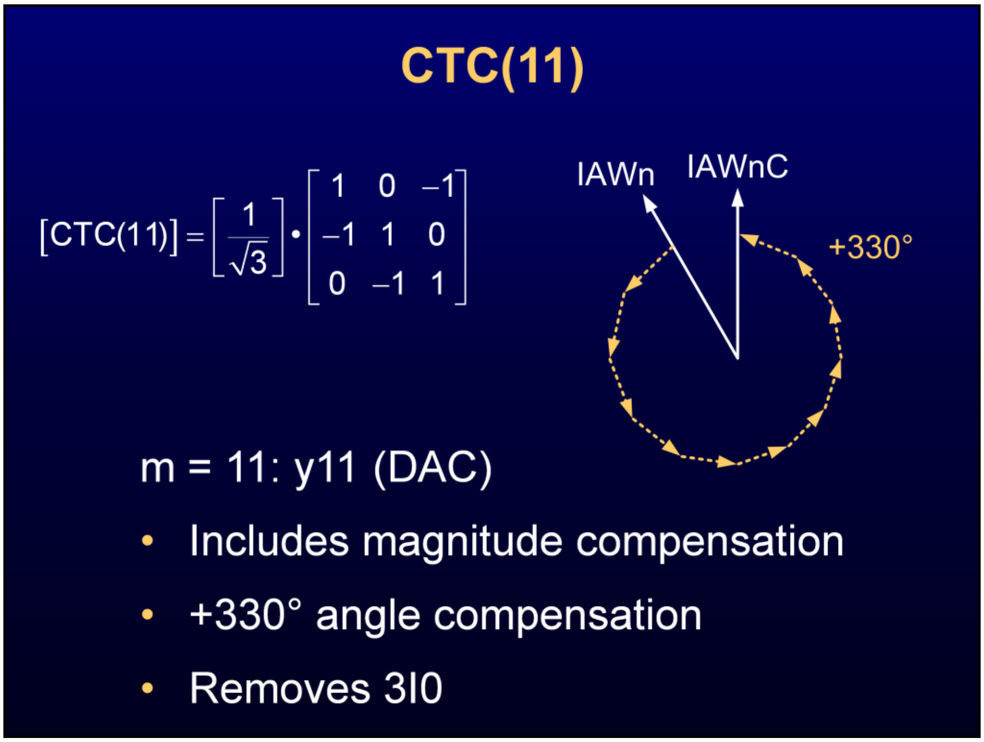
CTC(10)

IAWnC = (1 • IAWn + 1 • IBWn – 2 • ICWn)/3

IBWnC = (–2 • IAWn + 1 • IBWn + 1 • ICWn)/3

ICWnC = (1 • IAWn – 2 • IBWn + 1 • ICWn)/3



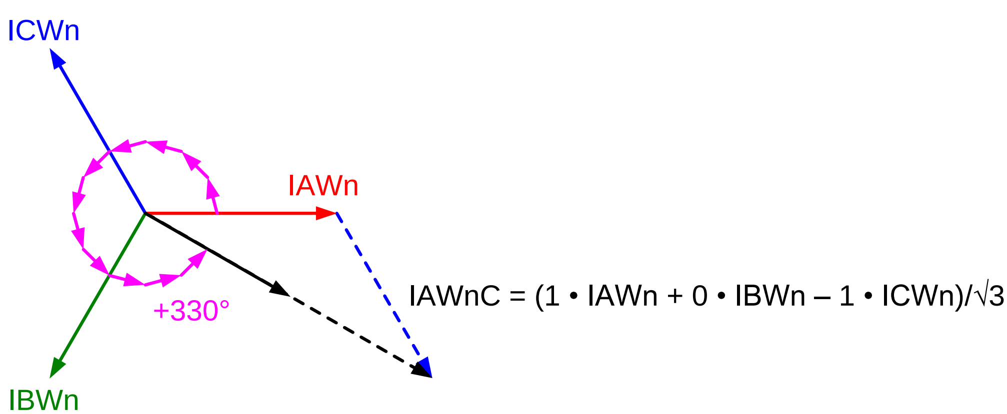


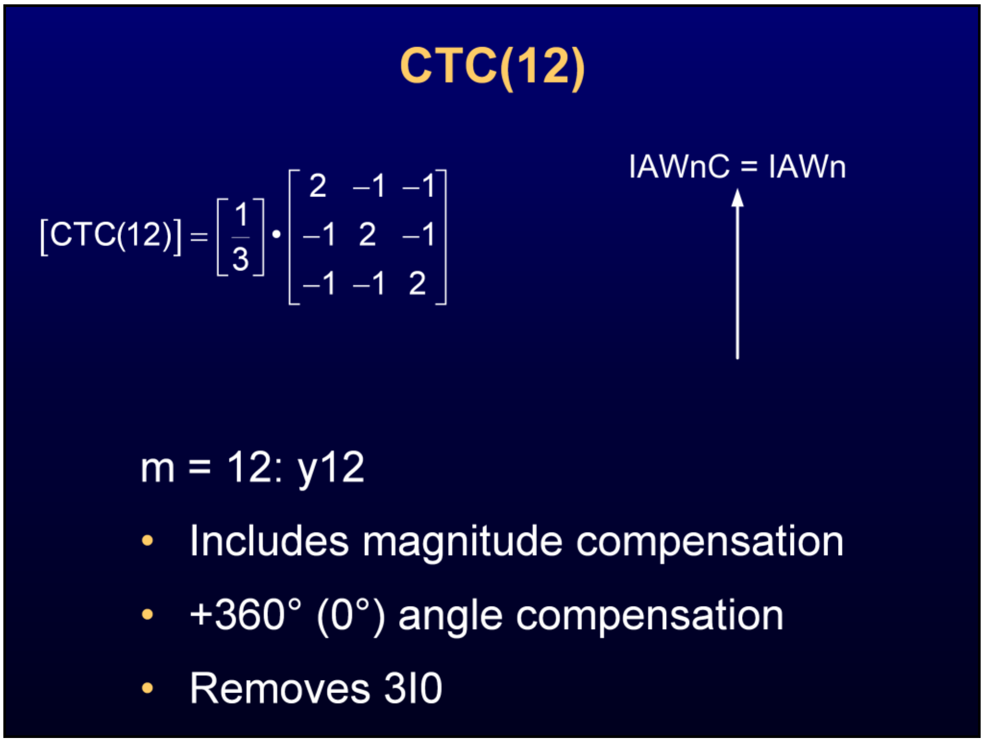
CTC(11)

IAWnC = (1 • IAWn + 0 • IBWn – 1 • ICWn)/√3

IBWnC = (–1 • IAWn + 1 • IBWn + 0 • ICWn)/√3

ICWnC = (0 • IAWn – 1 • IBWn + 1 • ICWn)/√3



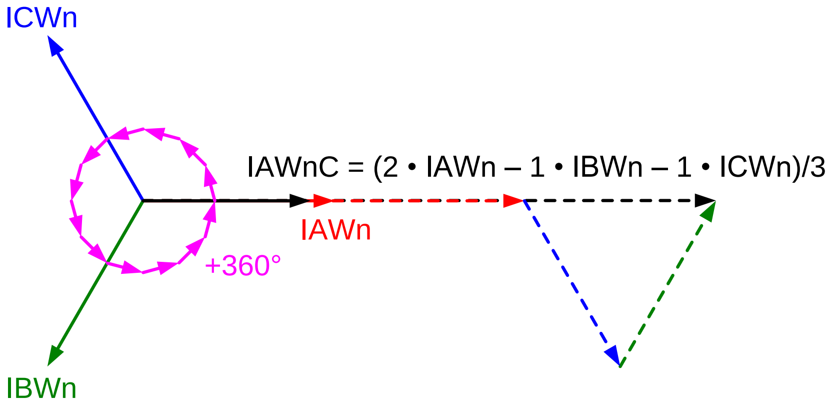


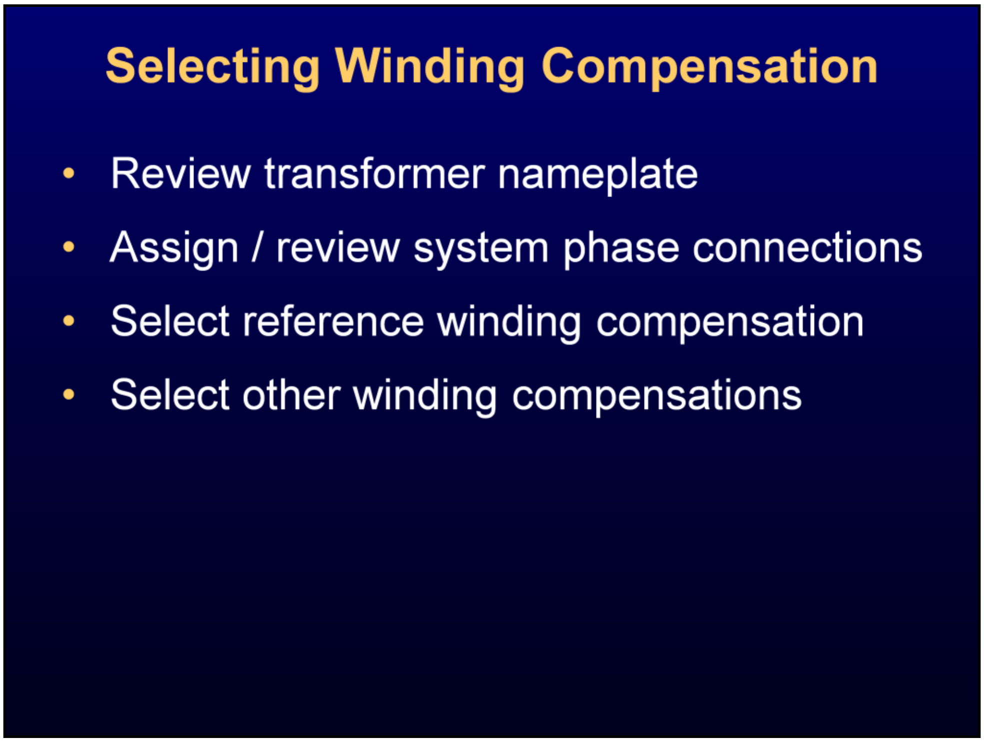
CTC(12)

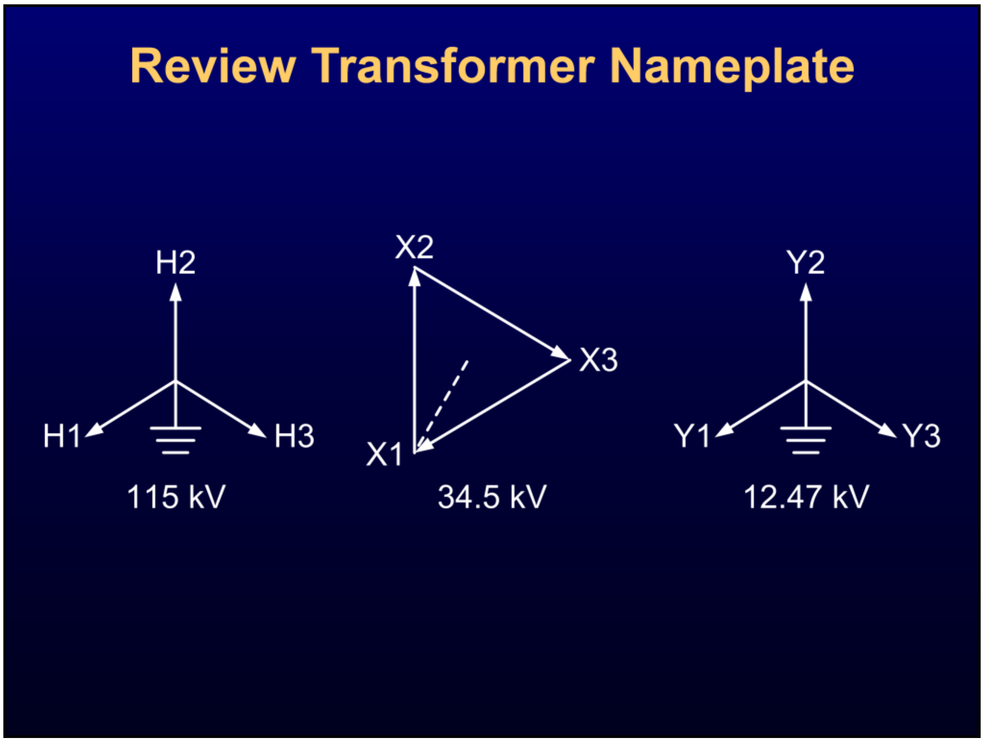
IAWnC = (2 • IAWn – 1 • IBWn – 1 • ICWn)/3

IBWnC = (–1 • IAWn + 2 • IBWn – 1 • ICWn)/3

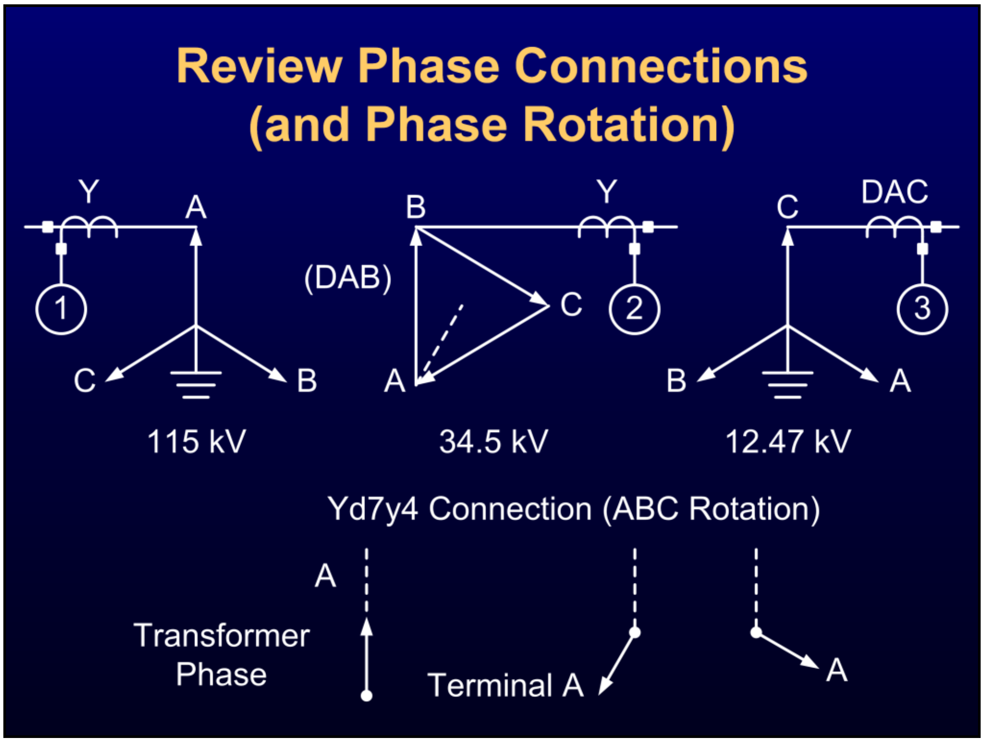
ICWnC = (–1 • IAWn – 1 • IBWn + 2 • ICWn)/3



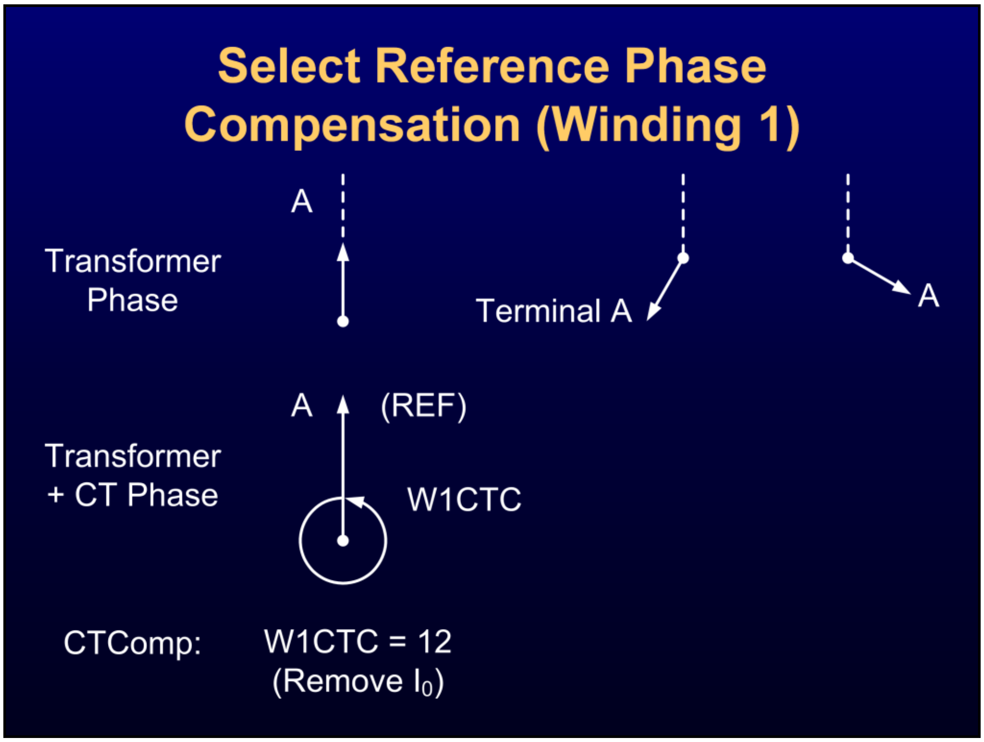

Selecting Winding Compensation
• Review transformer nameplate
• Assign / review system phase connections
• Select reference winding compensation
• Select other winding compensations



The figures on the slide illustrate the typical nameplate drawing information for a wye-delta-wye transformer. The delta (X) winding leads the two wye windings (H and Y) by 30 degrees. Nothing can be determined from this until the power system phase connections are made to the transformer. Nameplates show relative voltage relationships between transformer windings (typically designated with H and X for a two-winding transformer) and wye-winding terminal markings for the third winding on a three-winding transformer. These terminals are connected to the 3 three-phase systems. For example, the high-voltage system may be connected with Phase A to H1, Phase B to H2, and Phase C to H3. Likewise, the low-voltage system may be connected with Phase A to X1, Phase B to X2, and Phase C to X3. However, there is no requirement that the respective phases be connected to the respective transformer terminals. The connections are determined by the phase relationship required between different voltage systems. The respective phase-to-transformer terminal connections are not important on an isolated system. But they are extremely important on networked and open-loop systems where the tie points on these systems must have the same phase relationship between common phases.

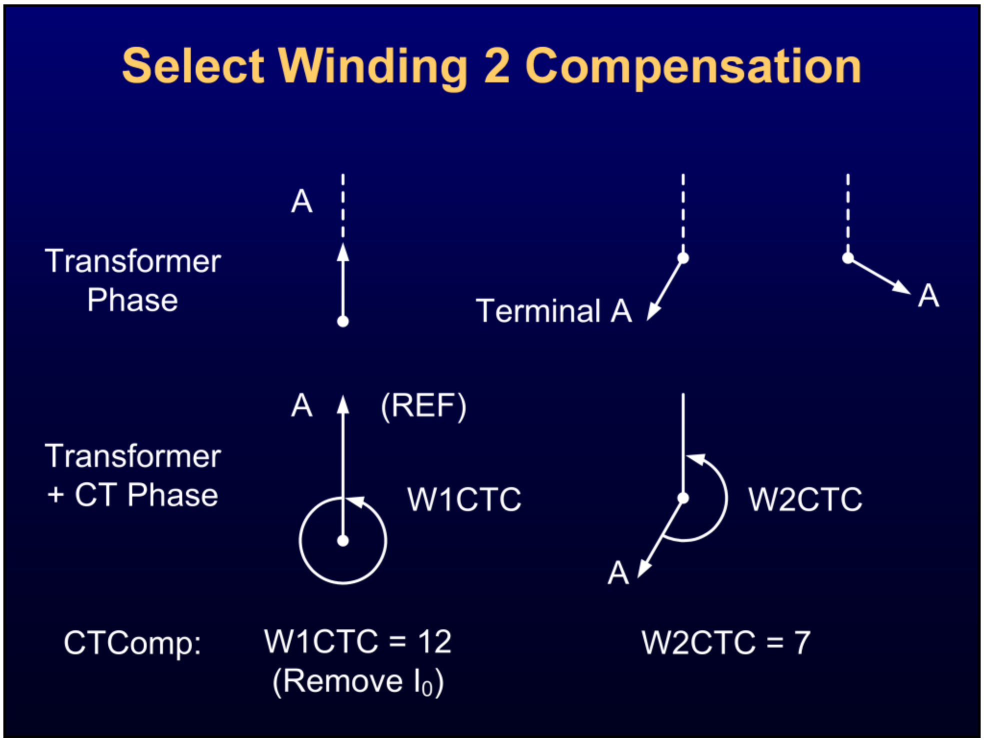


The figures on the slide illustrate the first step in the compensation setting process. The transformer shown is the same three-winding unit shown on the previous slide. However, the phase connections have now been established so the phase relationships can be viewed between windings. This is shown in the lower part of the drawing, where the position of Phase A to neutral voltage for each winding is illustrated with an arrow representing the relative phase relationship. The high-voltage winding is selected as the reference, with its Phase A voltage shown at 12 o'clock, relative to the numbers on a clock. The clock analogy is used to designate the transformer phase connection as Yd7y4, where the high-voltage winding is wye-connected (Y), with the mid-voltage delta winding connected with its respective phase at 7 o'clock (d7), relative to the high-voltage reference phase at 12 o'clock. The low-voltage winding is wye-connected with its respective phase at 4 o'clock (y4), relative to the high-voltage reference phase. With this convention, the reference phase is always shown at 12 o'clock. The relative winding designations are also dependent on system phase rotation. In this case, the designations are defined for ABC phase rotation. The relative winding reference designations indicate how many 30-degree increments the phase needs to rotate in the same direction as the phase rotation to match the angle of the reference phase.

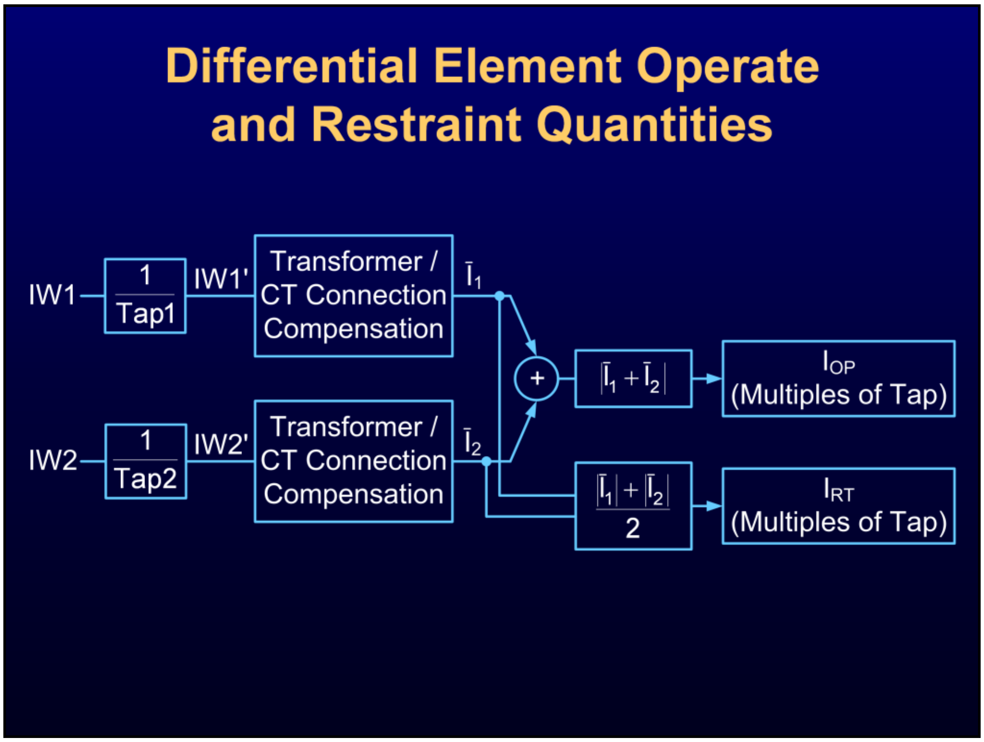


The transformer phase positions from the previous slide are shown at the top of this slide for reference. The next step is to adjust the Phase A positions for the indicated CT connections. The CTs are connected in wye for the first two windings and in a DAC, or 30-degree lagging delta, for the third winding.

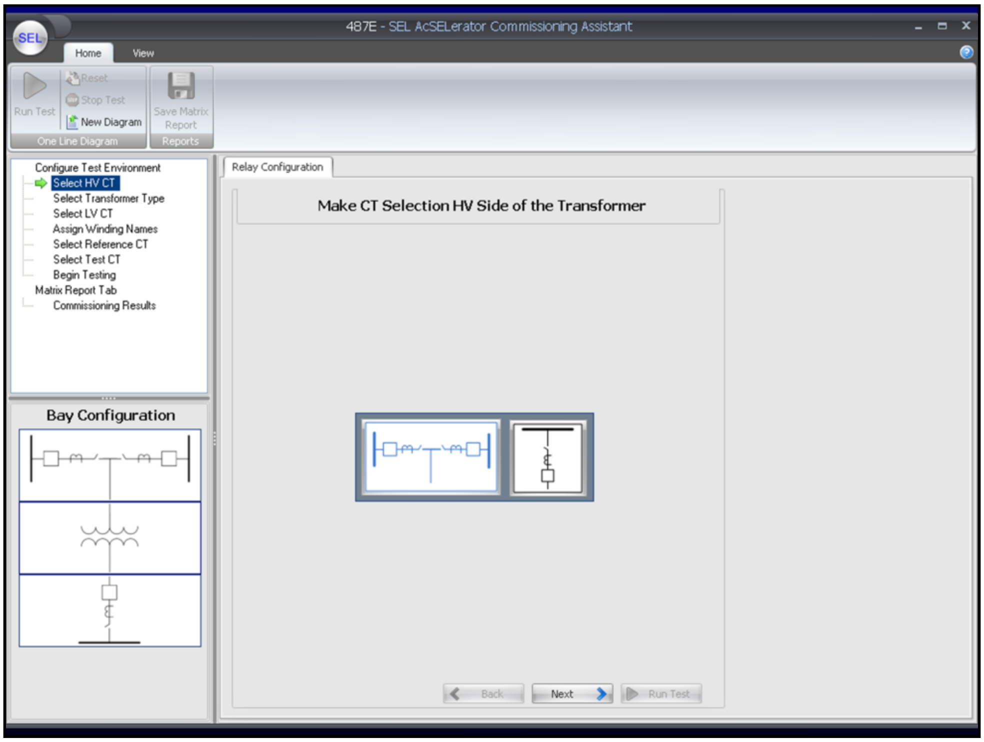
In a grounded wye-grounded wye transformer with a delta tertiary winding, as shown on the slide, the transformer acts as a source of zero-sequence current for external ground faults on the systems connected to the grounded-wye windings. In the high-voltage winding, the wye-connected CTs do not filter this zero-sequence current, thereby creating an unbalanced current flow in the current differential relay unless this zero-sequence current is somehow removed. In a traditional transformer differential relay, the zero-sequence filtering would require the use of delta-connected CTs or a separate zero-sequence current trap made with auxiliary CTs. With microprocessor-based relays, we can use the appropriate nonzero compensation setting to filter out the undesirable zero-sequence current. With the high-voltage winding CTs connected to the relay Winding 1 current input, set Winding 1 current compensation, W1CTC, to 12 to go fully around the clock, removing zero-sequence current in the process. The adjustment, then, is a full 360 degrees, leaving the arrow in the same position but removing the zero-sequence current.



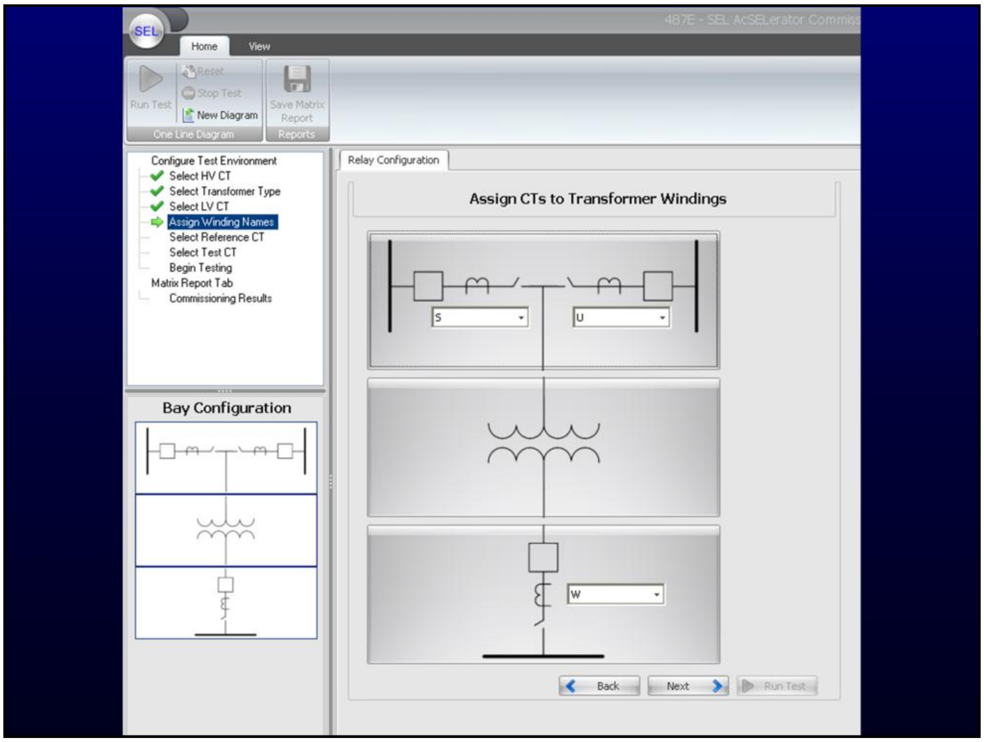
The mid-voltage transformer winding is delta-connected with wye-connected CTs. No adjustment of the phasing arrow is required due to the wye CT connection. The delta winding does not generate zero-sequence current, so no zero-sequence filtering is required. With the mid-voltage CTs connected to Winding 2 inputs on the relay, set Winding 2 compensation, W2CTC, to 7 to rotate the arrow CCW 7 hours or 210 degrees CCW. Thus, this compensated winding aligns with the reference 12 o'clock position. The zero-sequence current filtering provided by this compensation setting is inconsequential because the delta transformer winding produces no zero-sequence current.



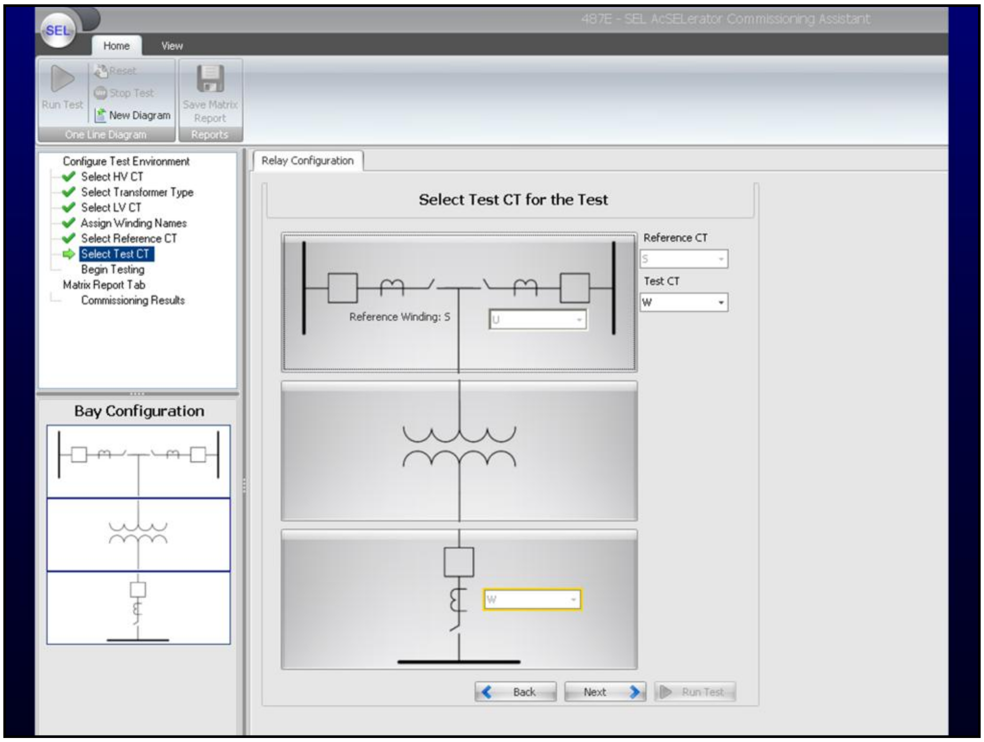
After tap, phase, and zero-sequence compensation, the differential elements develop I_{OP} as the phasor addition of the currents and I_{RT} as the average of the magnitudes of the currents.



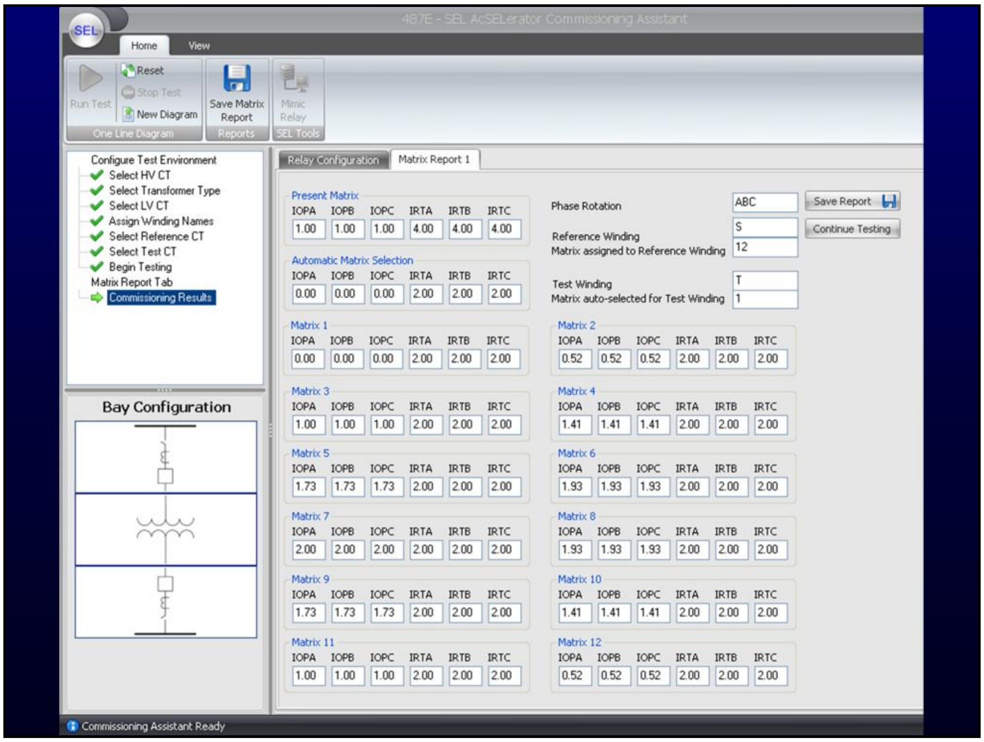
Using the SEL ACSELERATOR QuickSet® SEL-5030 Software Commissioning Assistant is easy. Simply select the Commissioning Assistant tab, and start by defining the one-line diagram of the transformer and interconnecting breakers.



Once the one-line diagram is complete, select the windings that will be used as differential element inputs to the relay.



To conduct tests in the Commissioning Assistant software, assign any two windings to the test. One winding serves as the reference CT and the other as the test CT input. The software then reads the current magnitudes and angles from the relay and compares them with the compensation settings and CT ratios used in the relay.

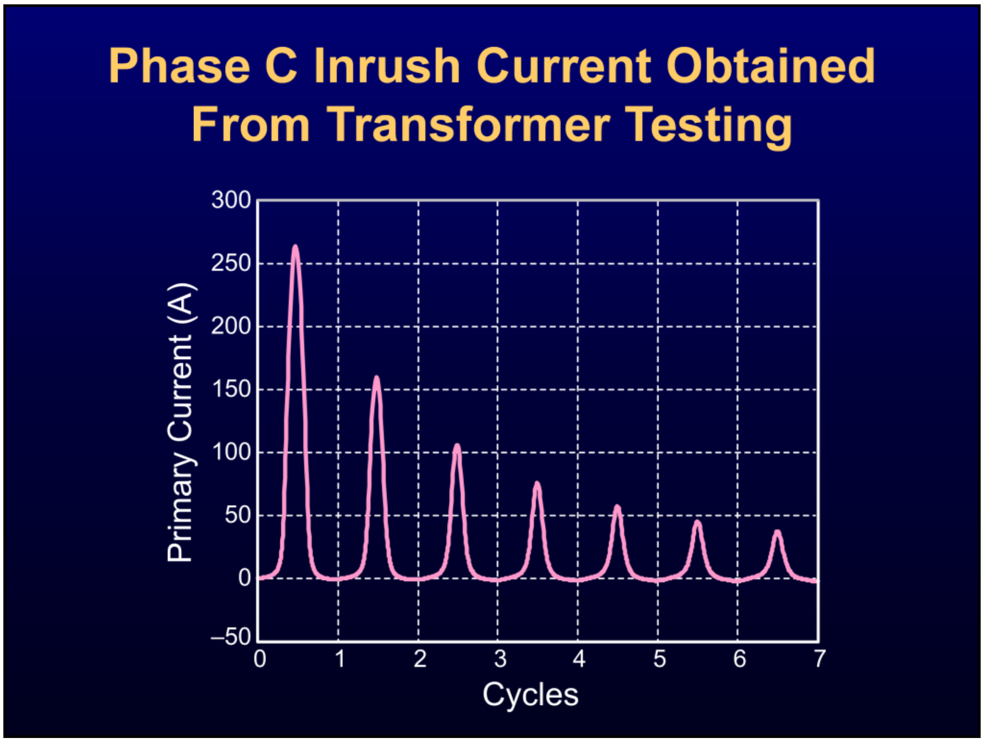


This slide demonstrates the capabilities of the Commissioning Assistant software. The first step is to define the transformer connections and type. The Commissioning Assistant software offers the choice of IEC or IEEE transformer representations.

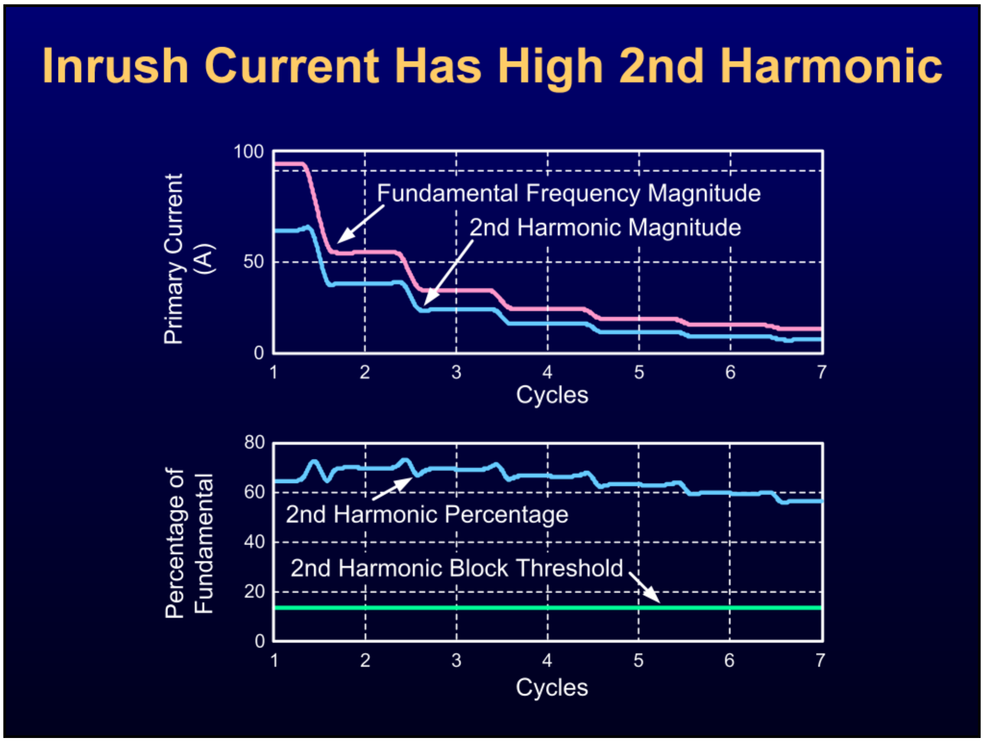
Once the one-line diagram is generated from the transformer configuration screen, the next step is to define and select the reference and test winding inputs of the relay. The Commissioning Assistant software uses one winding input (Winding 1 or Winding 2, in this case) as the reference from which to determine the proper winding compensation setting, as well as check for the proper CT polarity, CT ratio, and phase connections.

If the Commissioning Assistant software finds no problems with the CT polarity, CT ratio, or phase relationships, it generates a screen showing the I_{OP} and I_{RT} for all 12 possible compensation matrices. The Commissioning Assistant software selects the matrix with the lowest I_{OP} as being ideal for the transformer application.

Examine Transformer Inrush Challenges



This slide shows a typical example of inrush current.



Analysis indicates a significant amount of second harmonic in the waveform shown on the slide.

Many transformer differential relays use the second harmonic signature to restrain the relay from operating. The bottom graph on the slide shows a case for which the second harmonic content clearly surpasses 60 percent.

According to empirical results, a relay with an inrush detector with a second harmonic threshold of about 18 percent of the fundamental differentiates inrush currents from actual fault currents, in most cases.

Internal Faults Versus Inrush

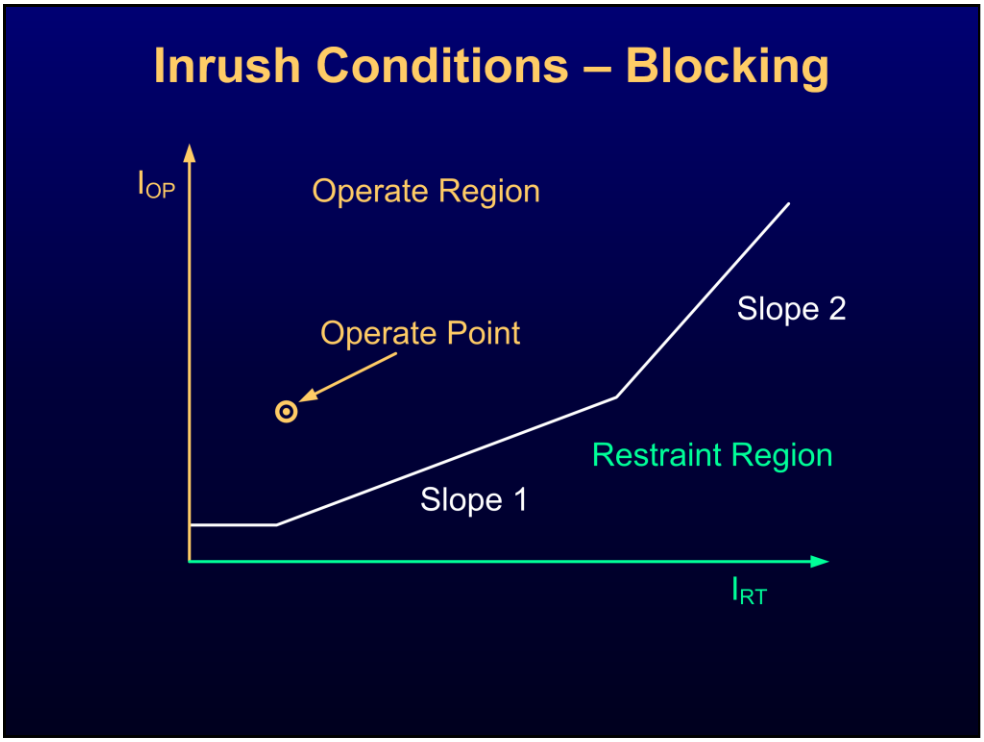
Harmonic-Based Methods

- Harmonic blocking
- Harmonic restraint

Two common current-based methods for discriminating internal faults from inrush conditions use operating current harmonics to restrain or block the differential element.

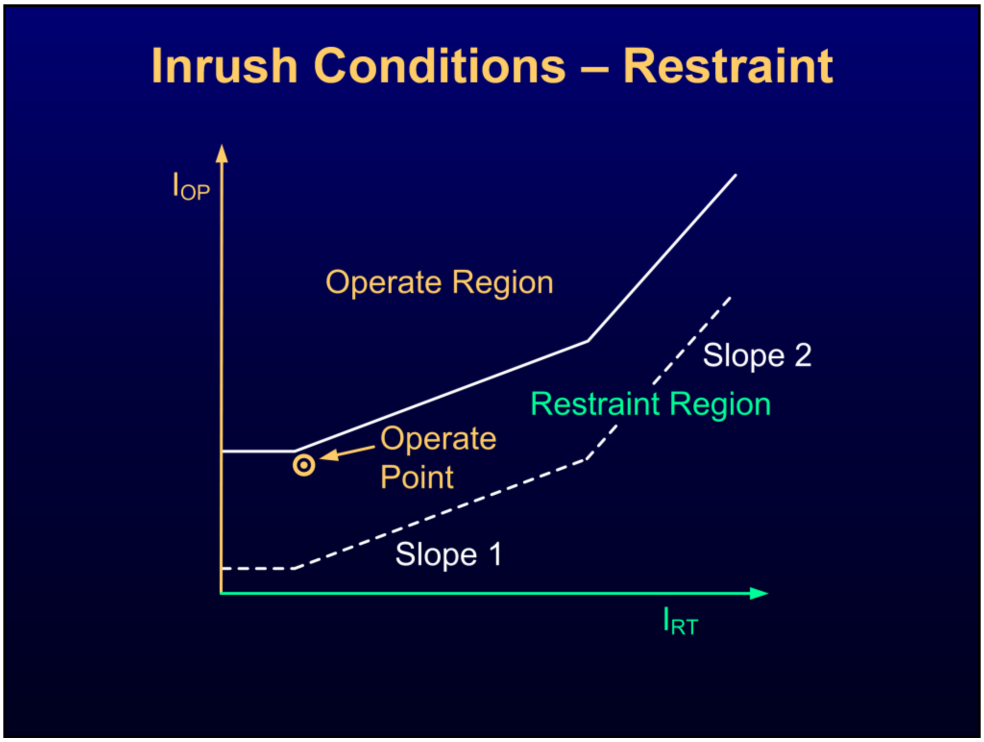
Harmonic blocking uses the magnitude of all or selected harmonics. The harmonics are compared to a threshold setting that blocks the differential element once the operating current harmonic content rises above the threshold setting.

Harmonic restraint uses the magnitudes of all, or selected, harmonics to increase the magnitude of the restraint signal used by the percentage restrained differential element.

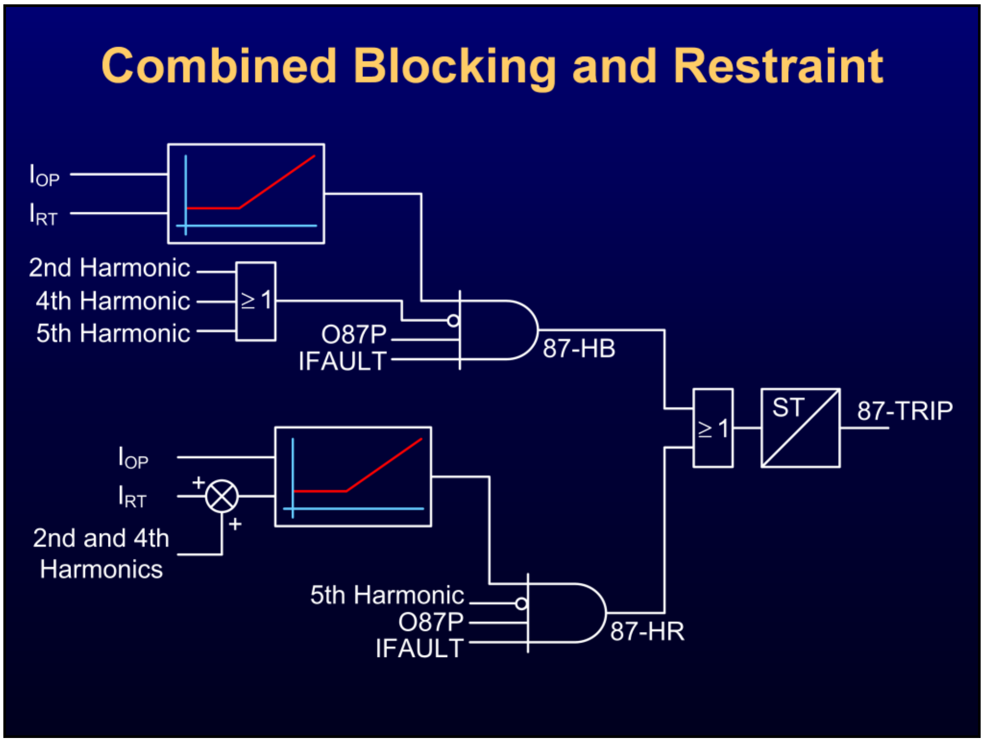


Consider relay operation for the harmonic blocking selection. The operating point ($I_1 - I_2$) is in the trip region, and the transformer should now trip. However, before the trip command is issued, the harmonic conditions are evaluated. If the percentage of harmonics exceeds the setting, relay operation is blocked.

Please note that when set to common blocking, the relay stays blocked for as long as any one of the three differential elements blocks. This can lead to delayed tripping when Phase A, for instance, has a high harmonic content and blocks the relay but a fault develops on Phase B. The relay now remains blocked until the harmonic content in Phase A drops below the setting.



Harmonic restraint raises the transformer characteristic by a constant value *c*, which is the sum of the second and fourth harmonics. This happens independently in each of the three differential elements. For example, Phase A is unaffected by the harmonic content of Phase B and Phase C.



The SEL-487E and SEL-787 allow harmonic blocking and restraint to be combined. This provides the speed of harmonic blocking for inrush conditions that have consistently high levels of second and fourth harmonics and the security of harmonic restraint for inrush conditions that have lower levels of harmonics or erratic harmonic content.

Conclusions

- Apply differential element Slope 2 to compensate for CT saturation
- Set current compensation for phase and magnitude differences across transformers
- Use harmonic blocking and restraint to prevent differential element assertion during inrush

Questions?

Recommended Reading

Available at www.selinc.com

- "Performance Analysis of Traditional and Improved Transformer Differential Protective Relays" by Armando Guzmán, Stan Zocholl, Gabriel Benmouyal, and Hector J. Altuve
- "Considerations for Using Harmonic Blocking and Harmonic Restraint Techniques on Transformer Differential Relays" by Ken Behrendt, Normann Fischer, and Casper Labuschagne