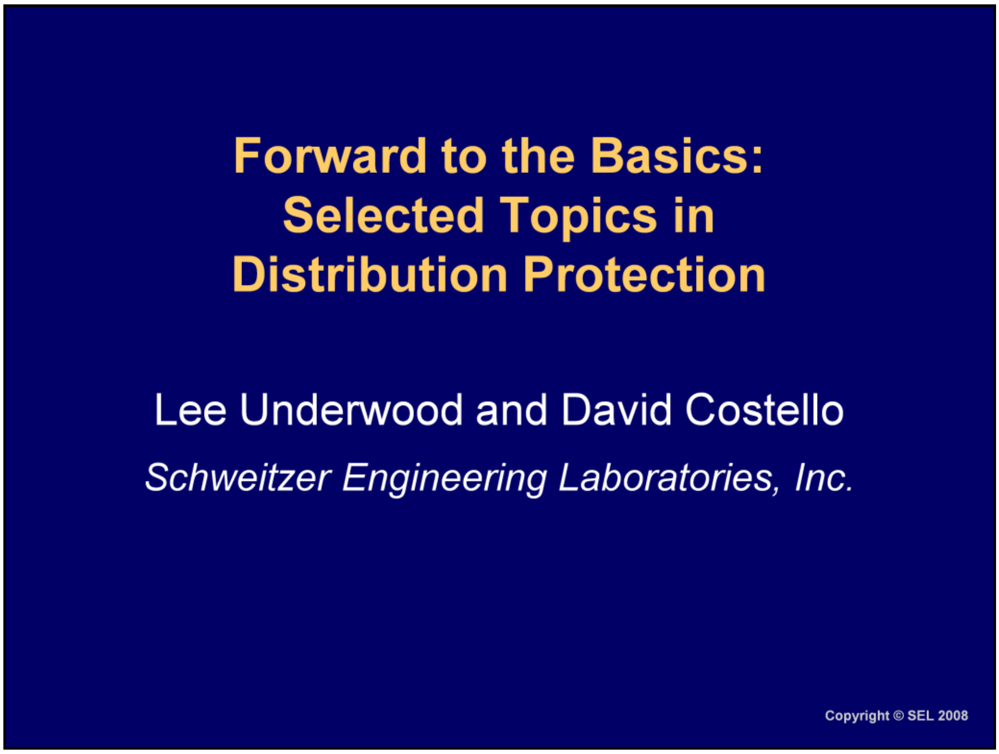
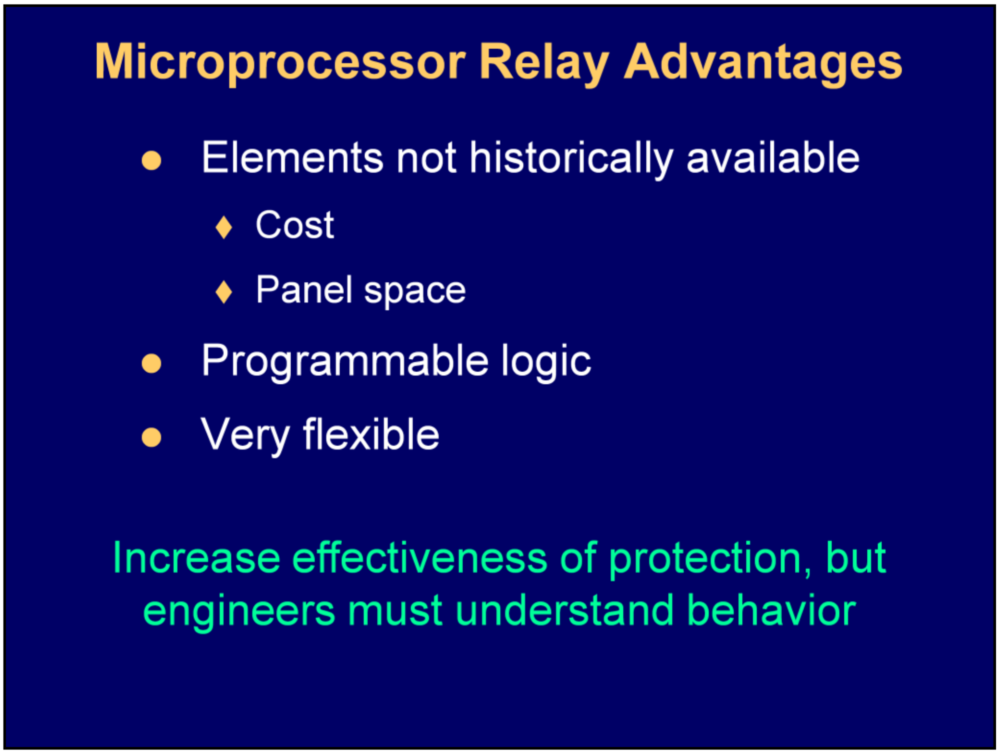
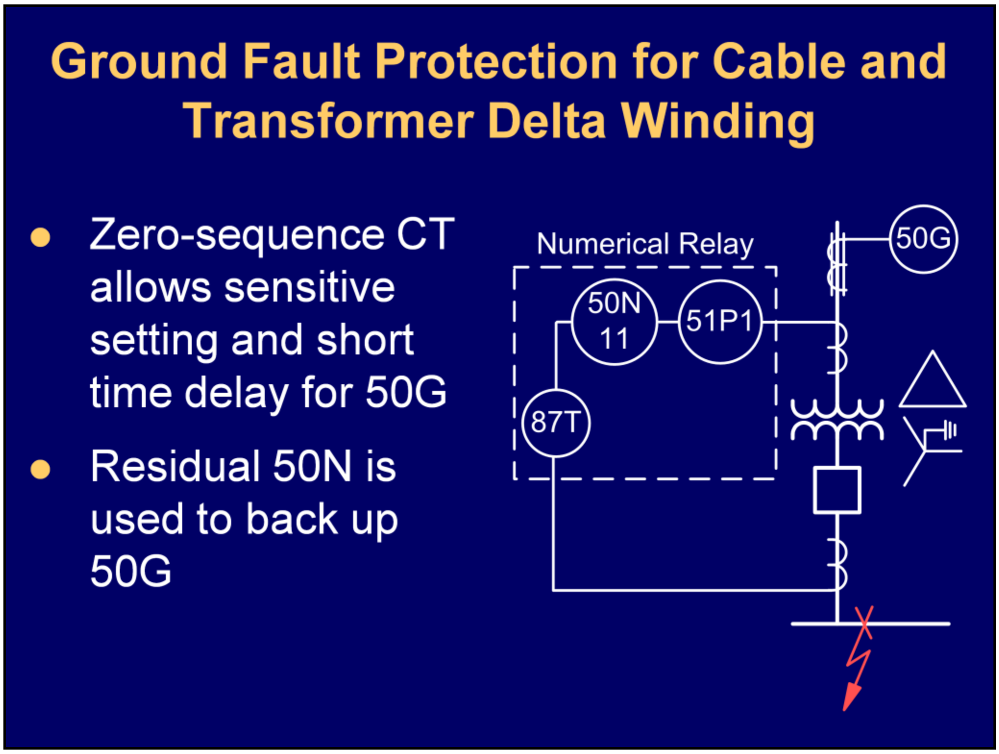


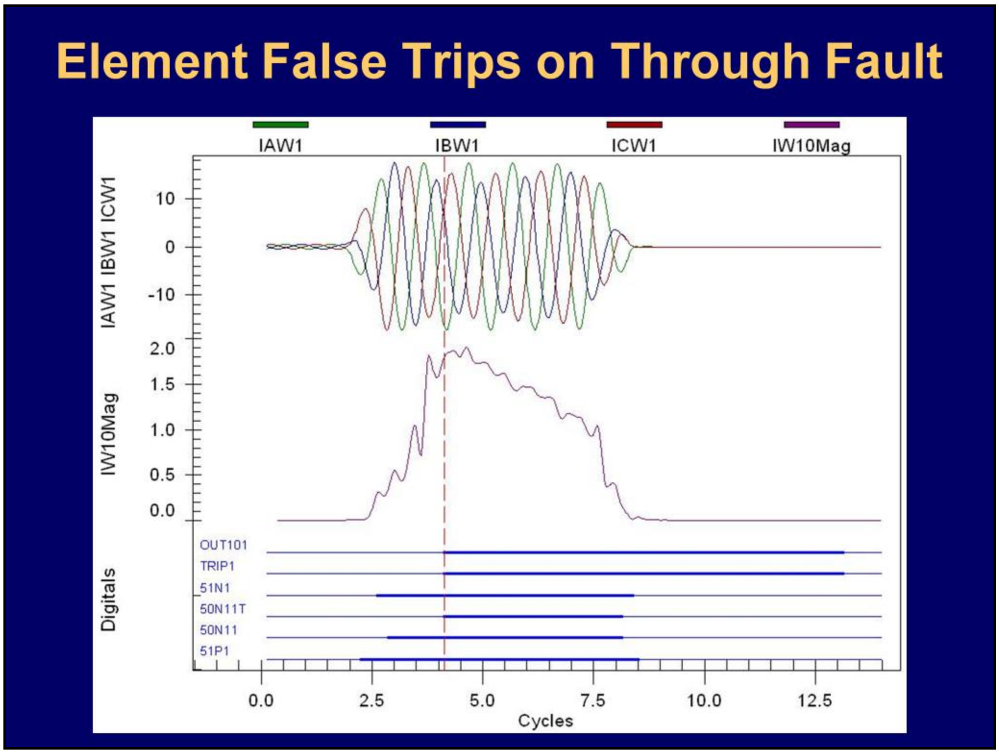
The purpose of this presentation is to present several examples of settings that led to unintended operations of distribution protection. The nature of the unintended operations are explored, and methods for calculating more secure settings will be discussed. Through this review, we show that it is important to understand and follow basic protection principles, no matter what relays we are using.



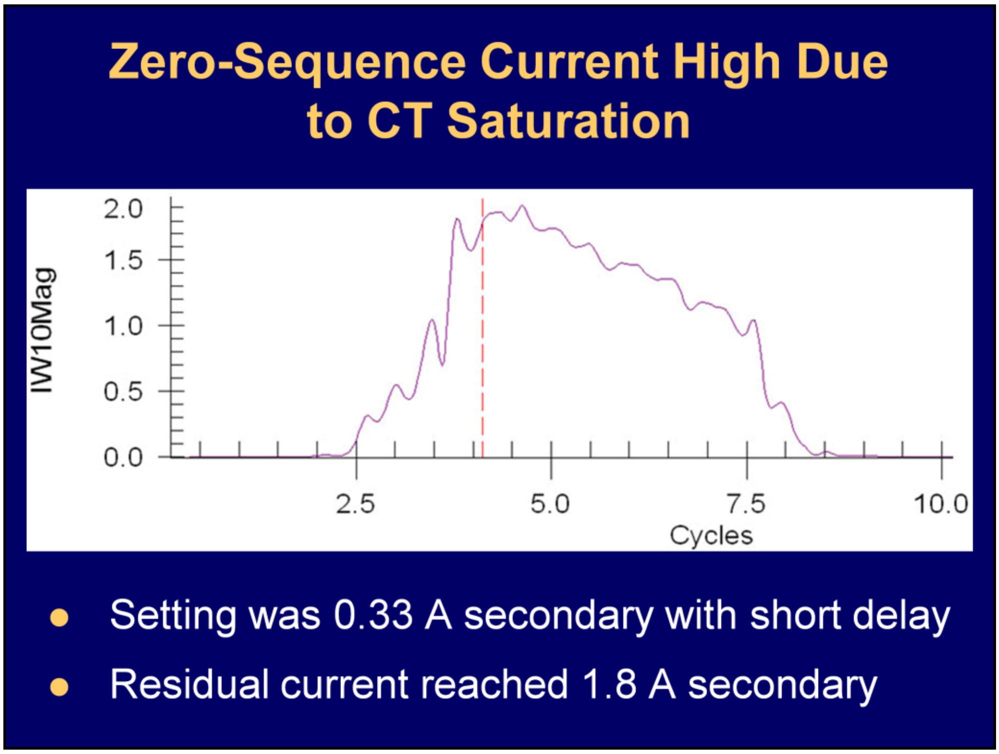
Microprocessor-based relays provide opportunities to increase the effectiveness of equipment protection. These relays allow us to apply protection elements that were not available historically, due to relay cost and available panel space. The availability of programmable logic also increases the flexibility of protection. With these new capabilities, it is important that engineers understand how protection elements will behave in order to avoid misoperations.



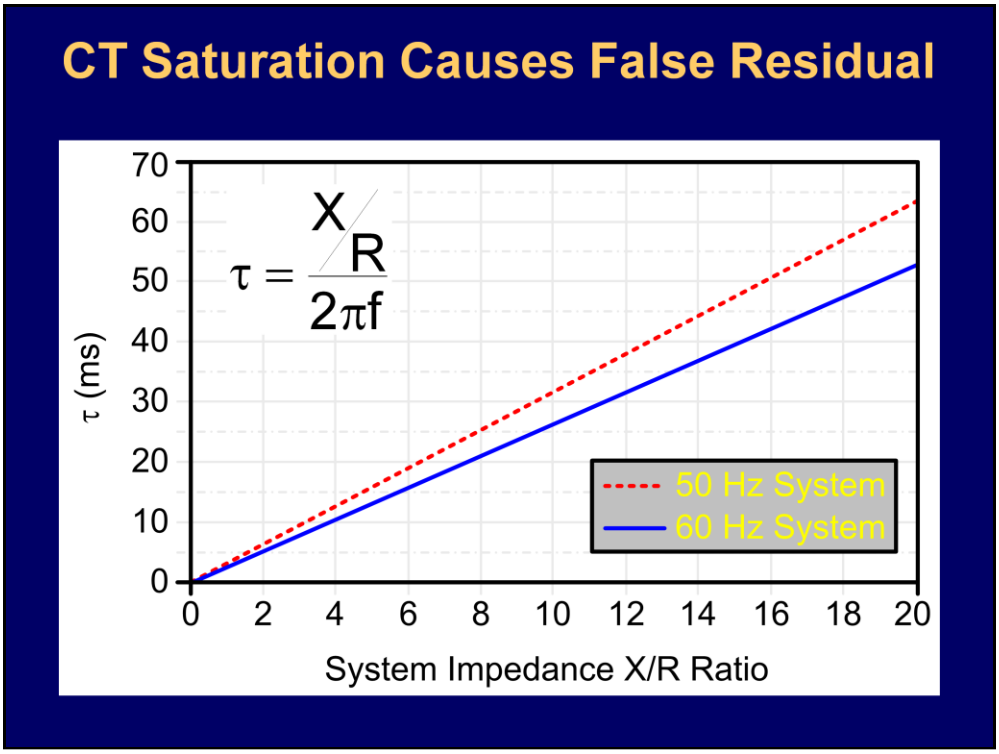
In industrial applications, ground fault protection for transformer delta-connected windings has typically been provided by overcurrent relays connected to zero-sequence current transformers (CTs). Numerical transformer differential relays allow residual overcurrent elements to be set. These residual overcurrent elements operate using the phasor sum of the phase currents. These two types of elements operate on different quantities and cannot be set the same. Residual elements may operate on false residual current due to CT saturation. We will look at what happened in an installation when a three-phase fault occurred on the bus on the low-voltage side of the transformer.



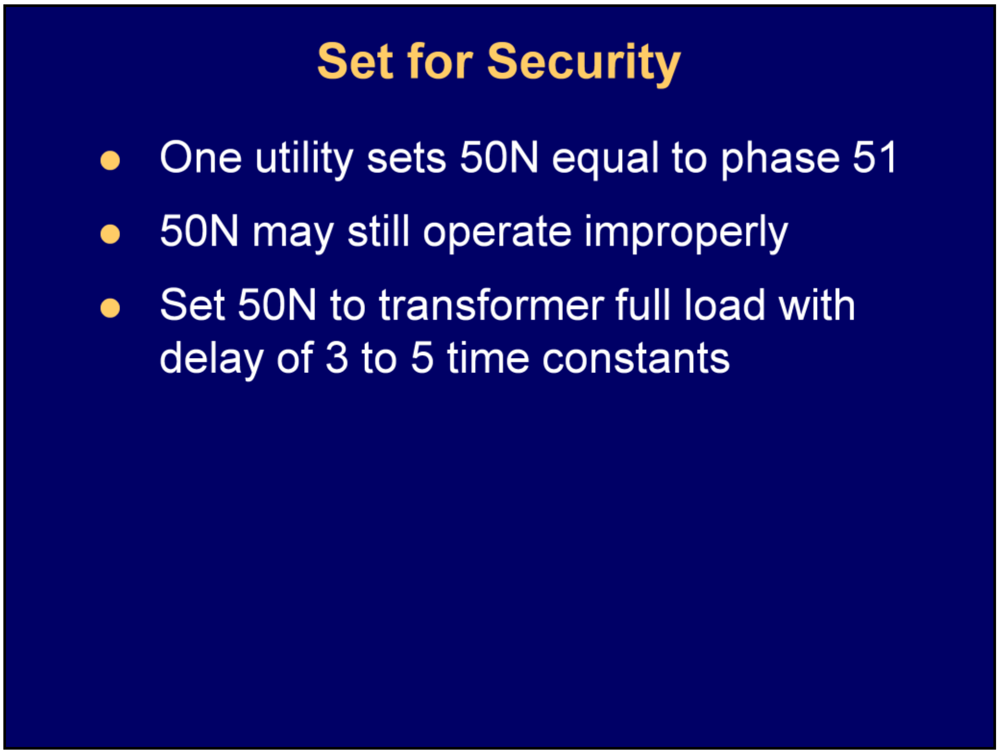
Neither the 50G nor the 50N element is intended to operate for the low-voltage fault. The delta winding should not allow zero-sequence current flow in the primary winding for this fault, yet the event report shows substantial zero-sequence current. 50N11T operated during this fault and caused the transformer to be isolated.



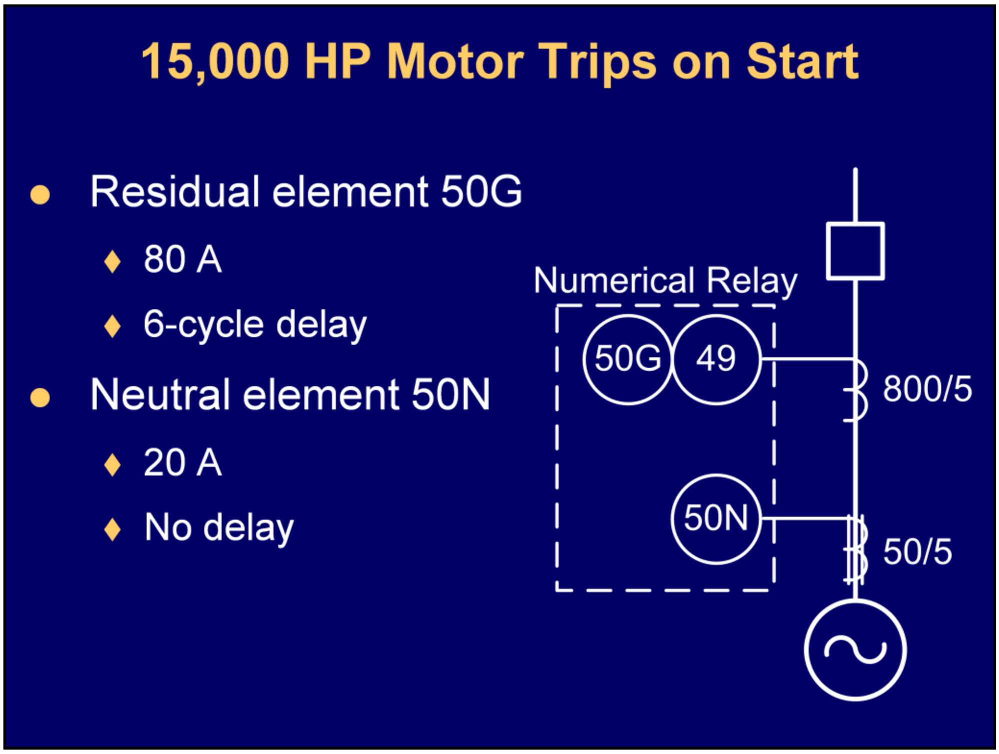
The residual current calculated by the relay was due to differential saturation of the CTs.



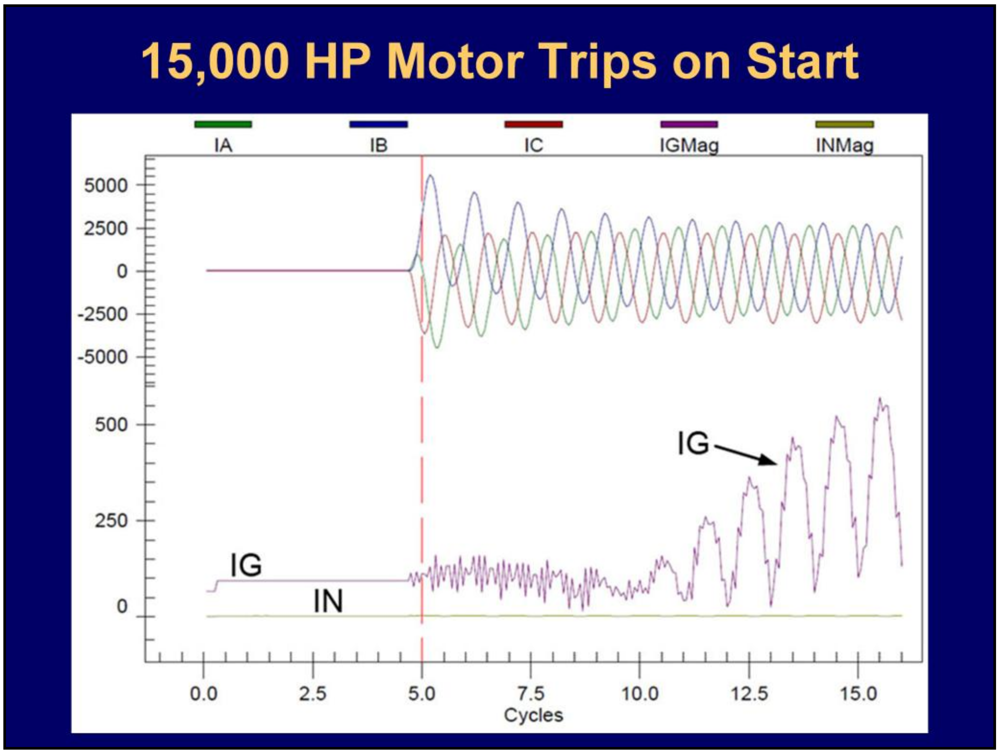
The amount of CT saturation depends on the CT burden, the system X/R ratio, the time of fault inception, and the accuracy of the CT. DC offset causes saturation that subsides according to a time constant (τ). Because the dc offset in each phase will be different, the saturation in each phase will also be different, and false residual can result.



There are several ways residual elements can be set to prevent operation on false residual. One utility sets the instantaneous residual element pickup equal to the pickup of the phase time overcurrent element but applies no delay. This works most of the time, but occasional misoperations of the element have been reported. Another more secure method is to set the residual element pickup to the transformer full-load current and to apply a delay of 3 to 5 time constants, plus some margin.



We will now discuss an improper operation of a residual overcurrent element, which tripped when a large motor was started. Both the residual and zero-sequence CT elements were active in the motor protection relay. Although the 50N element was more sensitive than the 50G element and had no delay, the residual overcurrent element 50G operated when the motor was started.



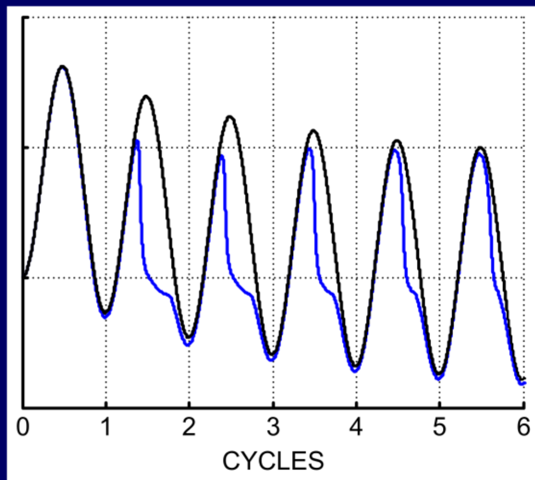
In this unfiltered event report captured with the residual overcurrent element disabled, we can see that the residual current (IG) is quite high, while there is no current (IN) from the zero-sequence CT.

Use Caution With Residual Elements

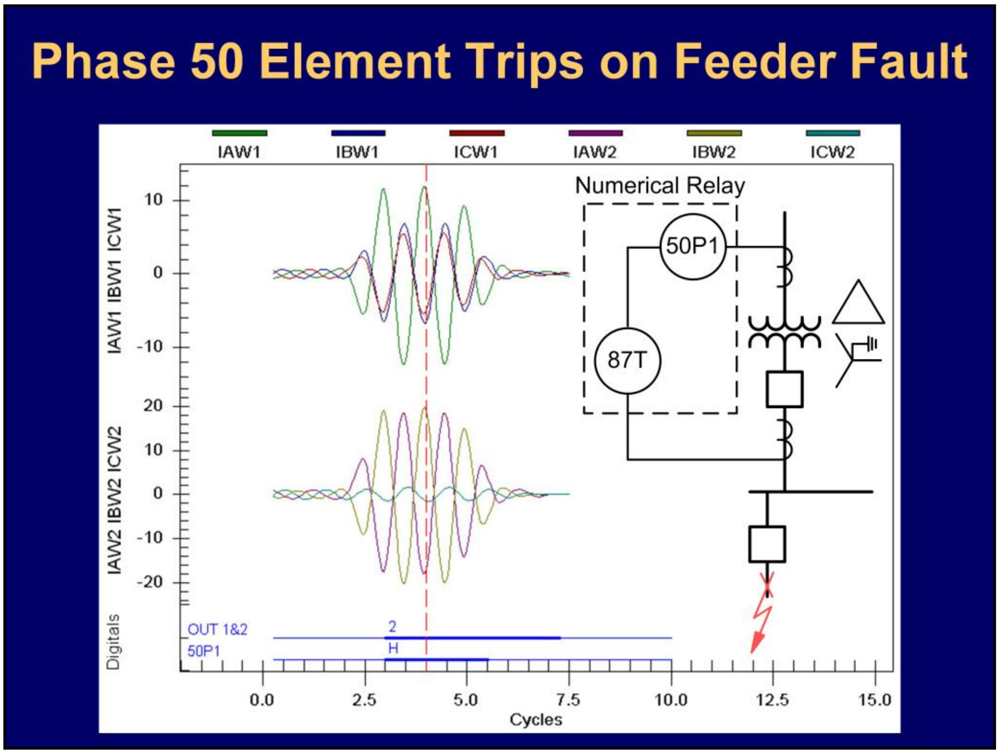
- May operate due to false residual
- Must be less sensitive or delayed
- May be inappropriate on motors, especially resistance-grounded systems

Lessons Learned

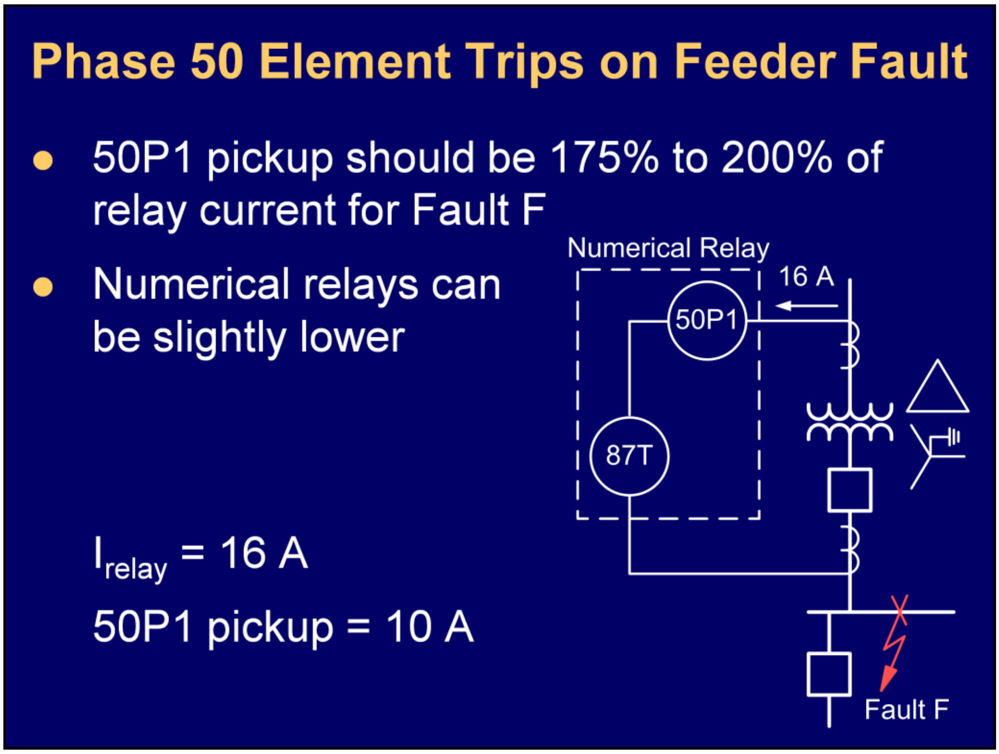
- Understand element labels
- Recognize which element to use
- Know setting criteria
- Consider CT performance



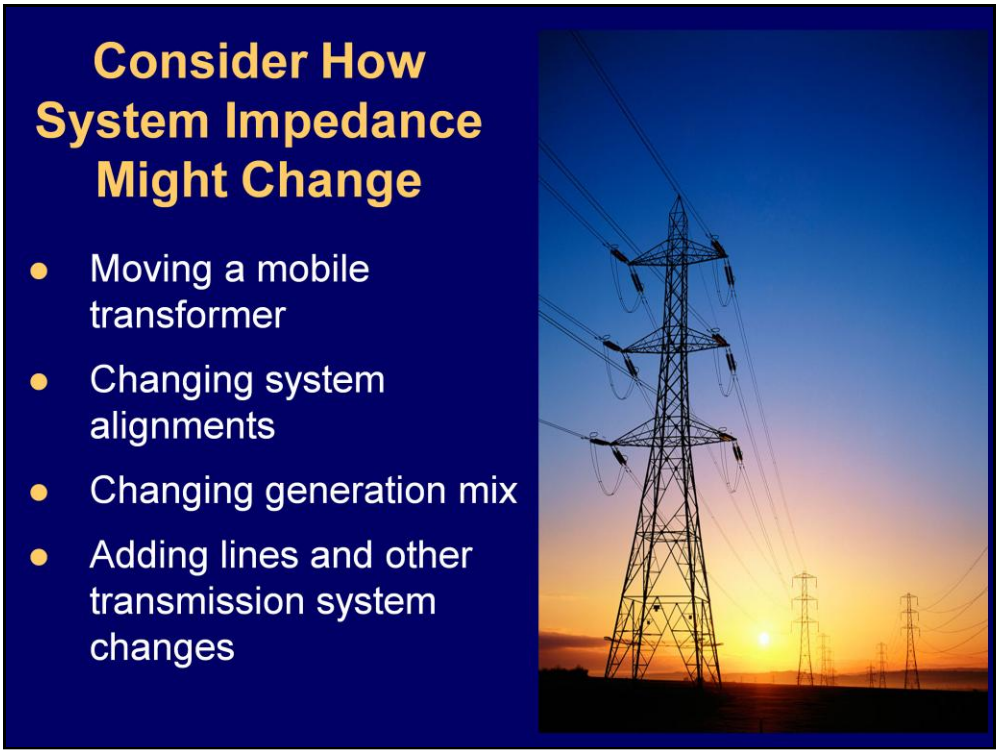
We need to understand the element labels used in each relay, and this means understanding which elements operate using residual currents and which elements operate using the output of the zero-sequence CT. We also need to understand when it is appropriate to use each type of element and how to set the elements. Finally, we must always consider CT saturation when selecting settings.



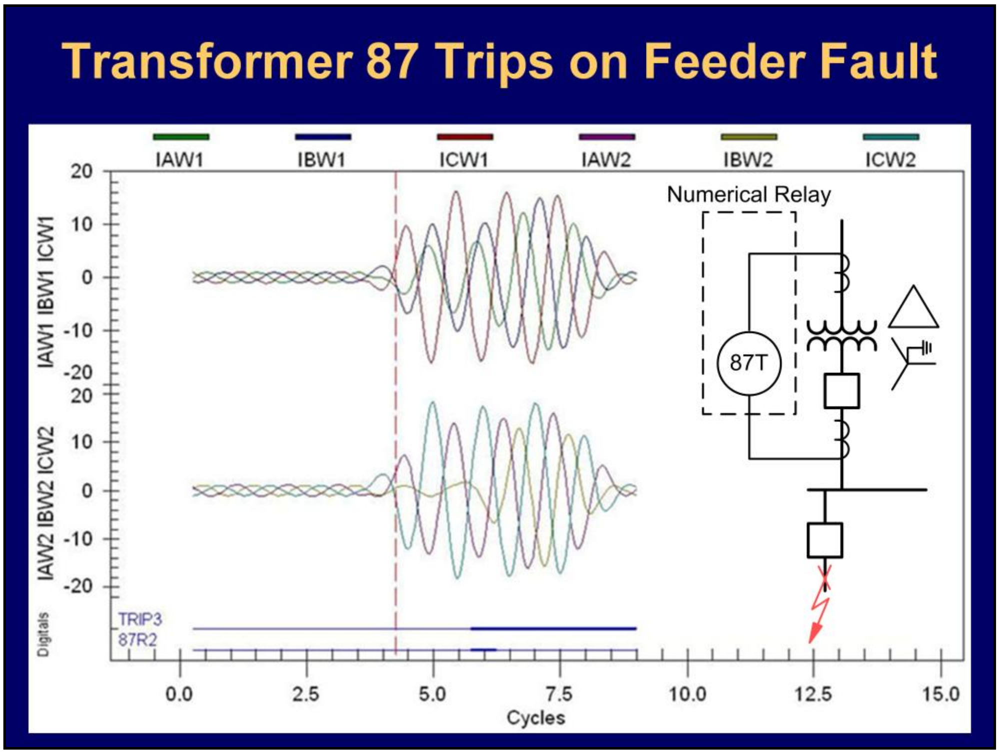
This event report shows the operation of a high-side phase instantaneous element (50P1) when a tree fell across one of the feeders in a retail substation. This tripped the transformer, which, of course, is not desirable for a feeder fault.



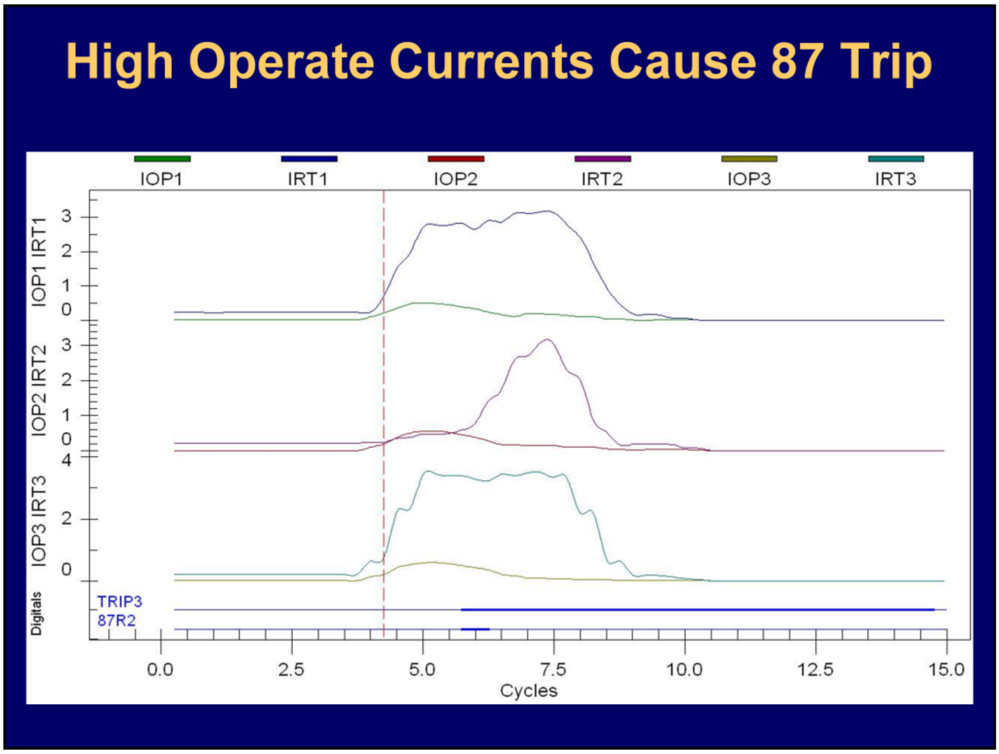
The high-side instantaneous element is traditionally set to 175 to 200 percent of the relay current for a low-voltage fault. This is to ensure that the relay does not overreach and trip for a fault that should be cleared by the feeder relays. In this system, using only the transformer impedance, the expected relay current for a low-voltage fault is about 16 amperes. The relay pickup was set to 10 amperes without any delay, so some transmission system impedance was considered in the setting calculation. However, the actual relay current during the fault was about 12 amperes, and the relay operated. The cause of this became clear when it was learned that this was a mobile transformer. Evidently, the setting calculation assumed a value of system impedance that was valid for a certain location. The transformer was then installed in another location with a lower system impedance, so the relay current for the through fault was higher than expected.



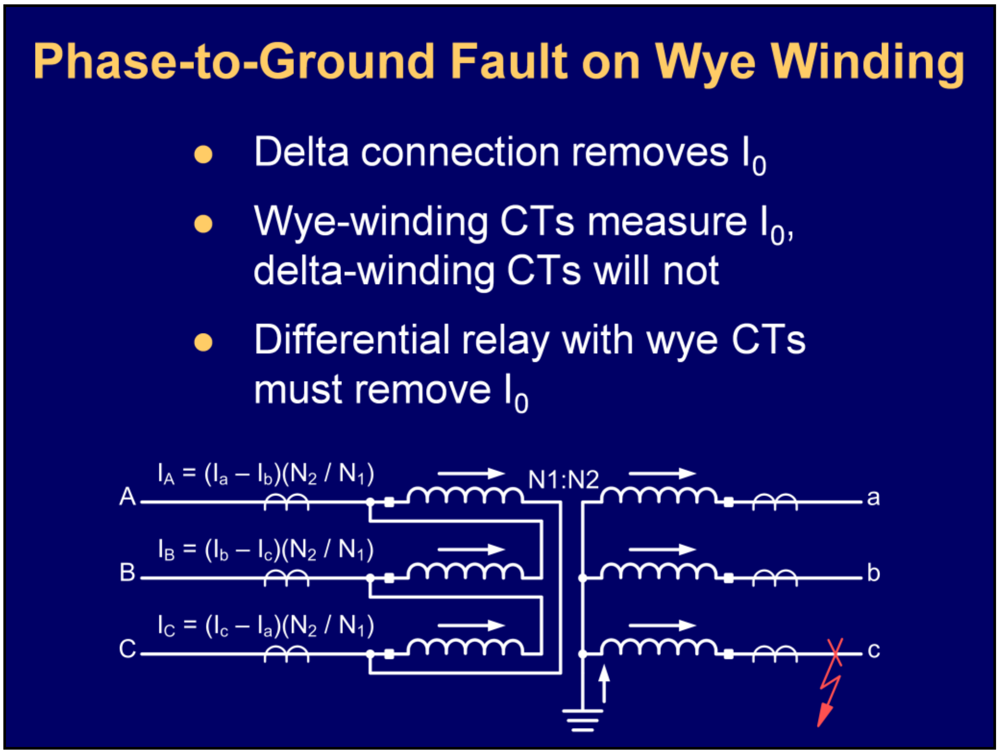
Transmission system impedance was probably considered in the initial setting calculation; otherwise, the relay pickup would not have been set so low. It is always a good practice to make relays as sensitive as possible without sacrificing security. However, always consider how system impedance might change and affect available fault current.



The event on the slide shows a transformer differential relay that tripped on a feeder fault.



This plot shows the operate and restraint currents for the three differential elements. Observe that there is operate current in all three elements and that the operate current in Element 2 exceeded the restraint current.



When a phase-to-ground fault occurs on the low-voltage system, the CTs on the wye winding measure zero-sequence currents. However, the line currents on the high-voltage side of the transformer do not contain any zero-sequence currents. Unless the zero-sequence currents are removed from the wye-winding CT secondary currents, the differential element will operate for an out-of-zone fault.

EM Transformer Differential Relay

CTs Are Delta-Connected on Wye Winding

- Shifts wye currents 30°
- Adjusts current magnitude
- Removes I_0 from wye-winding CT circuits

When an electromechanical differential relay is used, the wye-winding CTs are connected in delta. This applies appropriate phase shift and adjusts the current magnitudes to match the high-voltage line currents. It also removes the zero-sequence current.

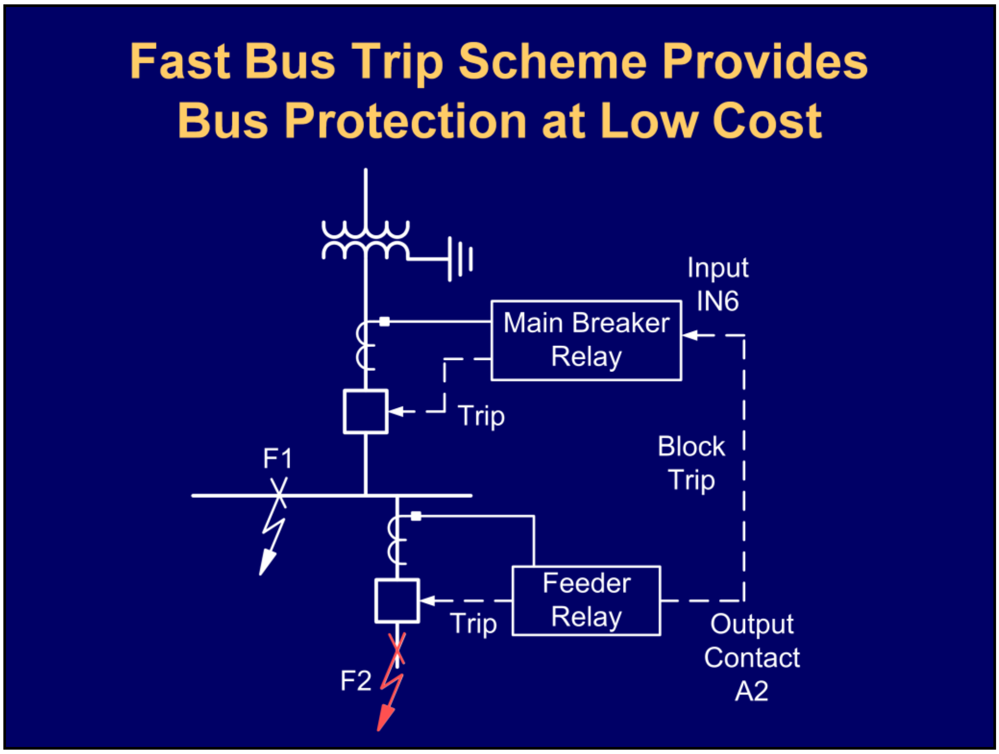
Numerical Transformer Differential Relay

- CTs on both high-voltage and low-voltage windings are usually connected in wye
- Relay removes I_0 through calculations

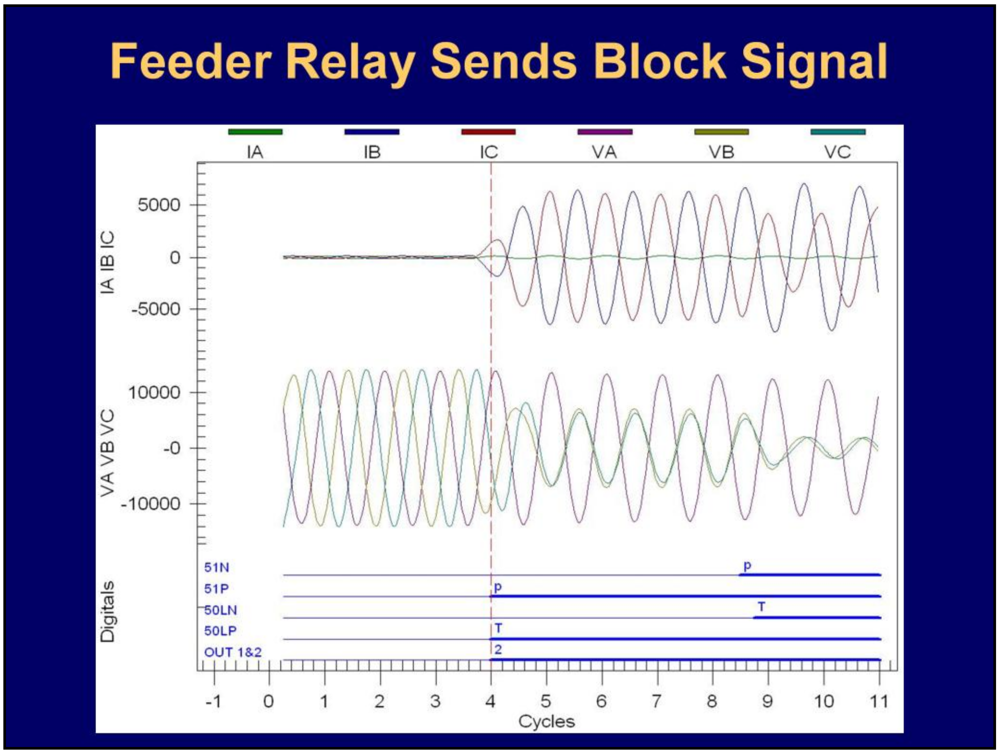
With numerical differential relays, the wye- and delta-winding CTs are usually connected in wye. This has many advantages, as it allows us to set residual elements on these windings, simplifies the settings of phase elements, reduces the CT burden, and simplifies the connections. However, zero-sequence current must still be removed, and the relays must be set properly to do so. In most relays, it is possible to set the relay such that the phase shift is correct but zero-sequence current is not removed.

Lessons Learned

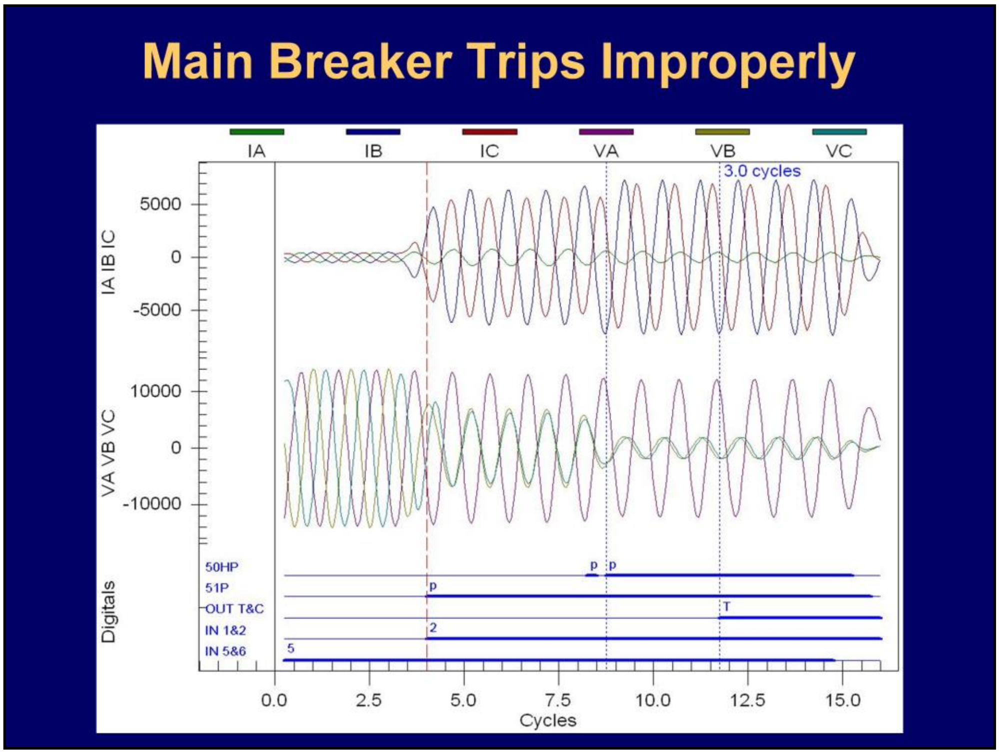
- Understand how numerical relays and connections differ from familiar EM schemes
- Make appropriate settings
  - Compensate for phase shift
  - Correct magnitude
  - Remove I_0



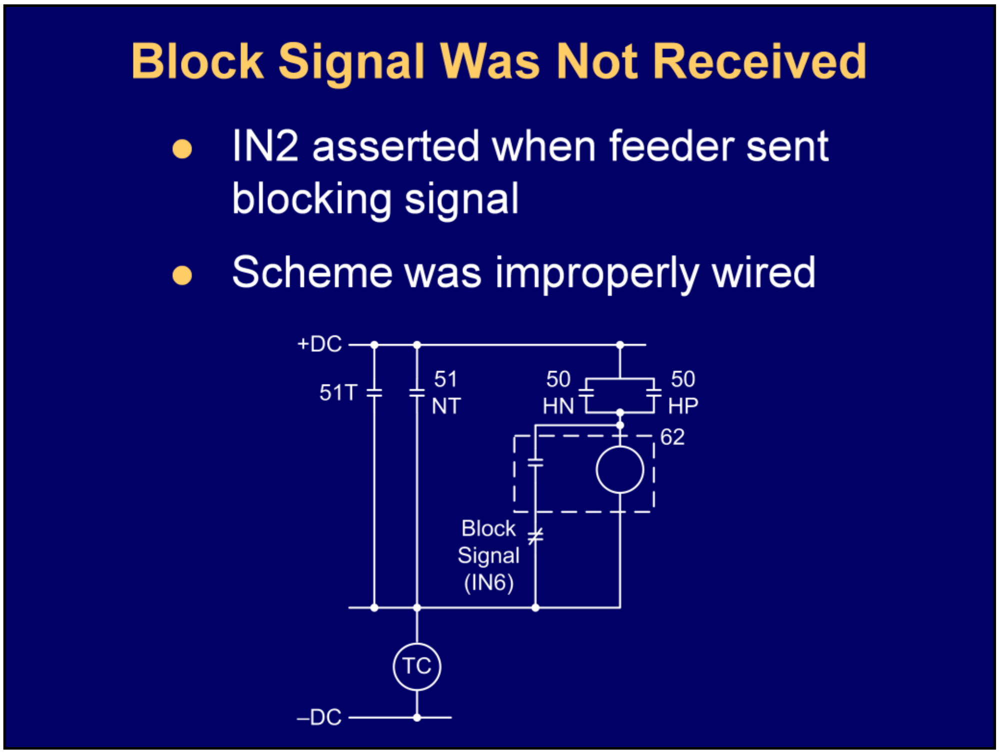
The figure on the slide illustrates the operation of a fast bus trip scheme. Fault F1 is cleared quickly by the definite-time overcurrent element in the main breaker relay. The feeder relay blocks the 50 element via communications or hard-wiring for Fault F2. We will look at what happened when a fault occurred downstream of one of the feeder breakers.



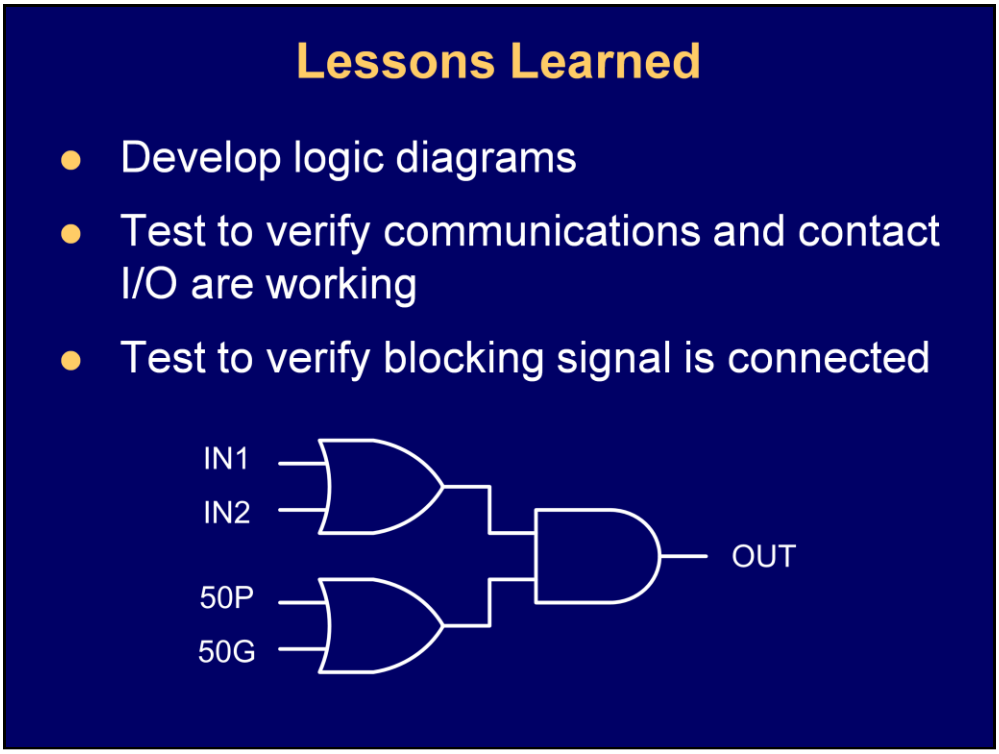
The figure shows the response of the feeder breaker relay when a fault occurred at F2. The phase element (51P) asserts, as expected, and the blocking contact (OUT2) closes.



Shown on the slide is the response of the main breaker relay. IN2 asserts, then 50HP asserts, and the relay trips the main breaker.



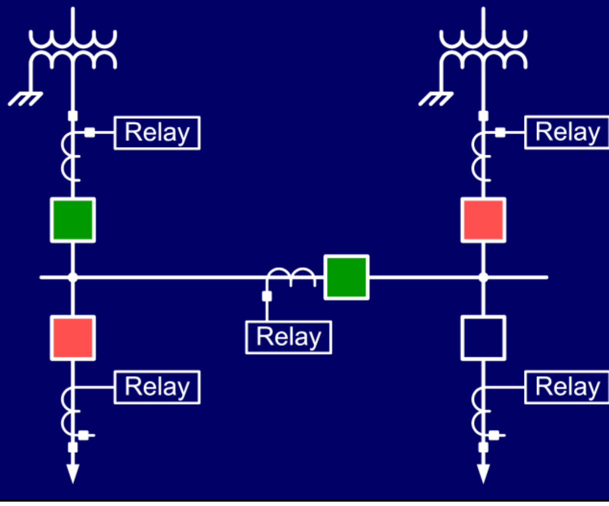
The main breaker is allowed to trip if its instantaneous overcurrent elements operate and the block signal is not received before the timer expires. In this case, recall that IN2 asserted, then the feeder breaker relay sent the blocking signal. The relay was programmed to look for the blocking signal on IN6. The scheme was improperly wired.

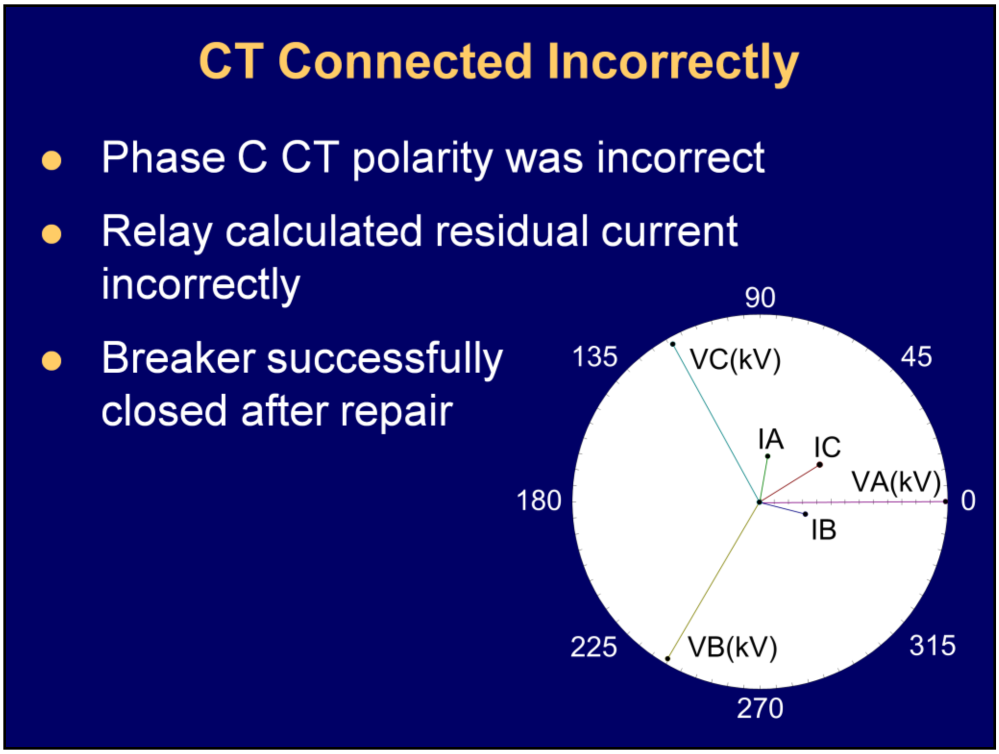


A simple test would have shown that the blocking signal was not connected. In such a test, we would prove that the feeder relay output contacts are working. We would then jumper the blocking contact at the feeder relay, inject current at the main breaker relay, and verify that the relay does not operate.

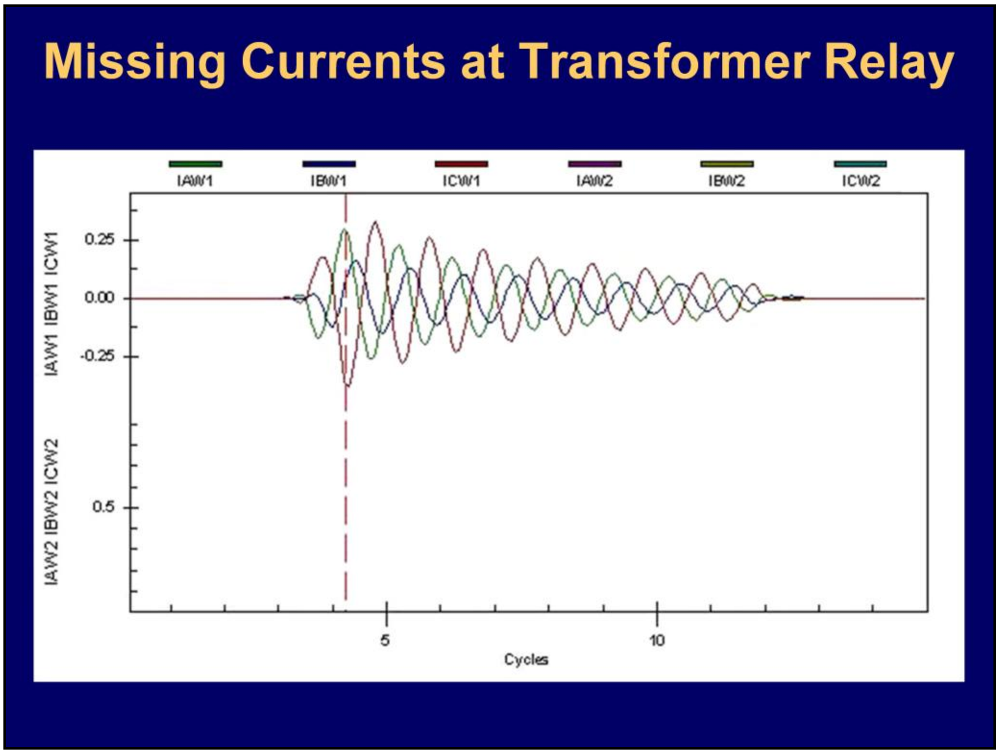
Residual Ground Elements Trip Breaker

- Feeder breaker closed to provide load to commission transformer 87 relay
- Residual overcurrent tripped tie breaker
- Feeder event report shows transformer inrush

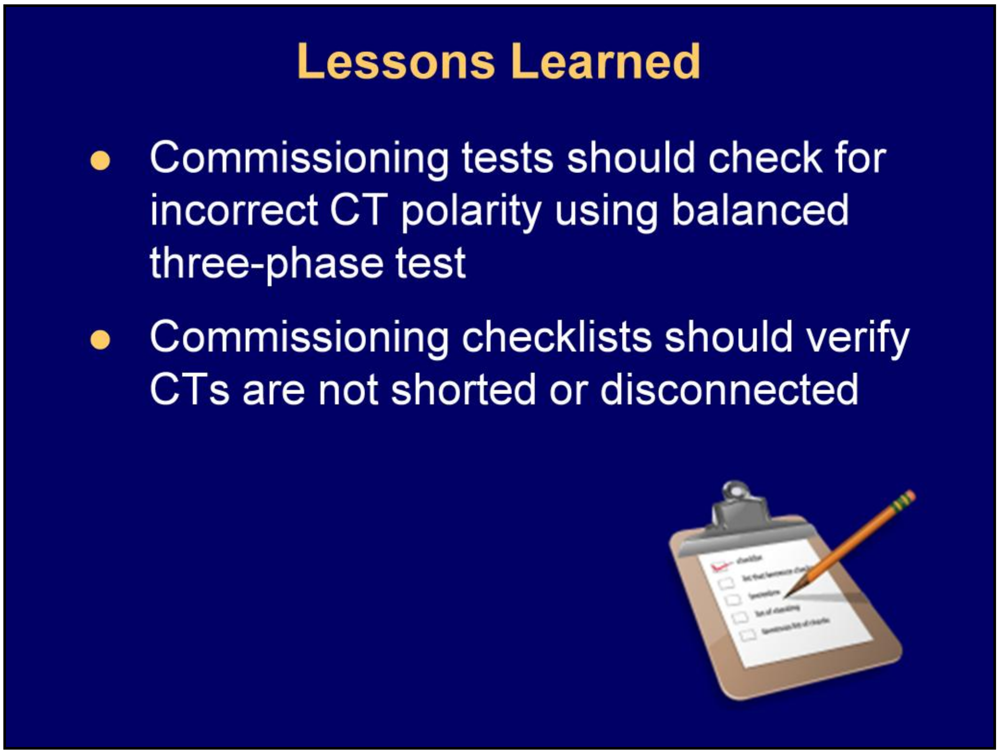




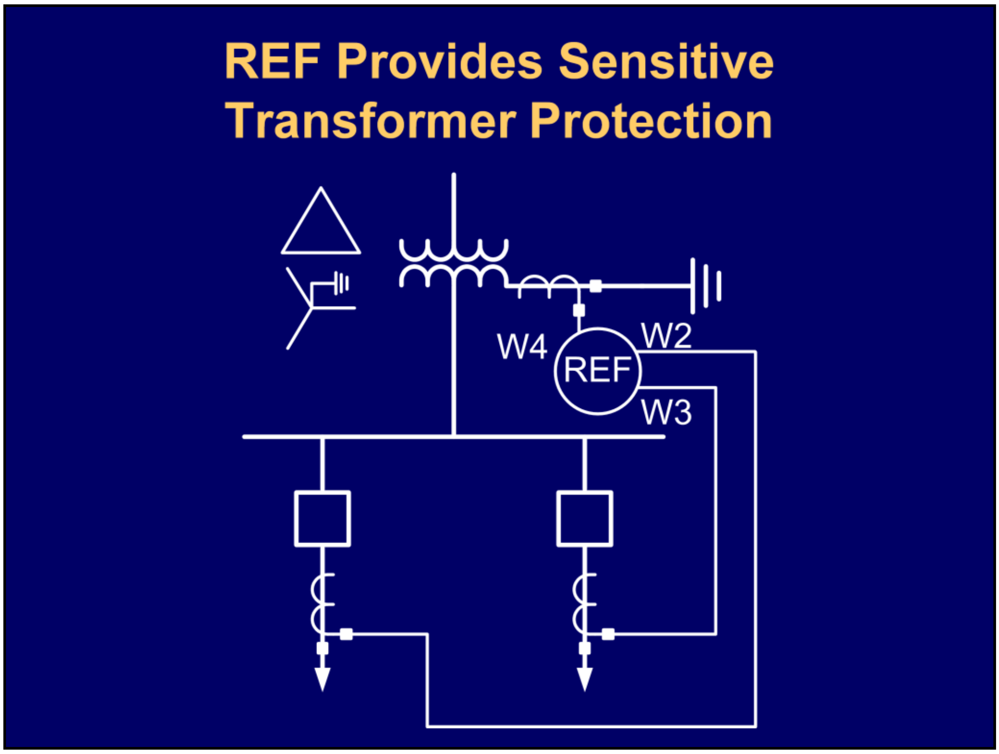
The Phase A and Phase B currents are correct. The current was mainly due to transformer inrush and was lagging the associated voltage. There is a 180-degree phase shift due to the polarity of the tie breaker CTs. The Phase C current, however, is not correct. The polarity of the Phase C CT circuit was rolled. During testing, currents were injected to verify that the CT circuits were connected to the proper phases on the relay. However, this was not a balanced three-phase test. Such a test would have revealed the incorrect polarity because the residual current would have been high.



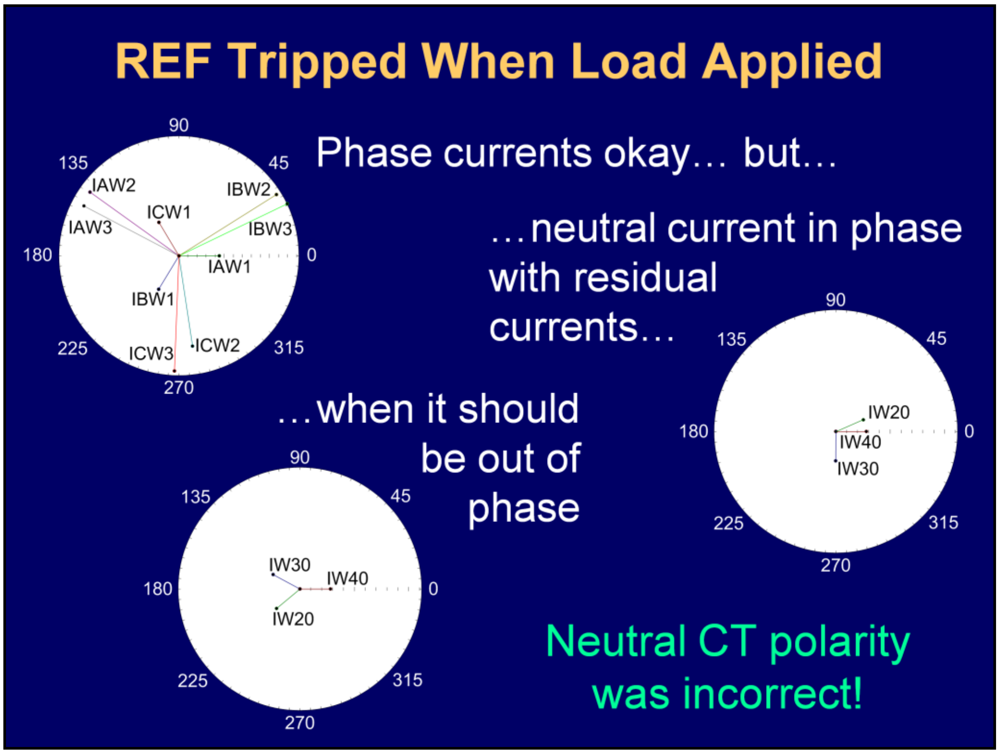
Subsequent review of an event report captured by the transformer differential relay showed that the relay had no low-voltage currents when the feeder breaker was closed. It did not trip because the currents were not very large and because the harmonic blocking asserted. Shorting screws had been left installed on the CTs on both sides of the low-voltage main breaker. While the differential relay would have eventually tripped, the low-side overcurrent relay was effectively out of service due to this oversight.



Commissioning tests and checklists should verify that CT polarity is correct and shorts have been removed. Primary injection testing would have revealed both of these problems.



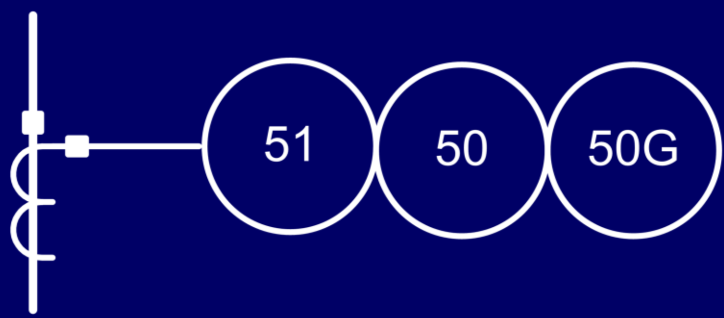
Neutral current is compared to I_0 at the terminals of grounded-wye windings. CTs are connected with polarity away from the transformer. For an internal ground fault, neutral and terminal zero-sequence currents will be nearly in phase. For an external ground fault, neutral and terminal zero-sequence currents will be out of phase.



IW40 is the transformer neutral current. IW20 and IW30 are the residual currents at the terminals of the wye windings.

Overall Lessons Learned

- Numerical relays allow protection to be used in new ways at low cost
- Principles have not changed, but numerical and EM relays may operate differently



Overall Lessons Learned

- Understand operating principles
- Know setting criteria
- Consider various system conditions
- Document settings and programmable logic
- Develop commissioning checklists
- Perform complete scheme tests

Questions?