# AEP Experience With Protection of Three Delta/Hex Phase Angle Regulating Transformers


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# AEP Experience With Protection of Three Delta/Hex Phase Angle Regulating Transformers

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**Abstract—American Electric Power installed three 138 kV, 150 MVA delta/hex phase angle regulating (PAR) transformers on the south Texas transmission grid during 2006. These transformers help optimize power flow on the transmission grid until planned 345 kV line construction projects can be completed to improve the strength of the grid in this portion of the power system. The delta/hex PAR transformer is a new single-tank design that promises to be much more economical to build and install than previous designs—improving the economic viability of deployment of these devices on the transmission grid.**

**This paper addresses the challenges of providing fully redundant, sensitive, and secure protection for all types of faults, including turn-to-turn faults in this type of transformer and its surrounding bus work. The protection system includes a mix of conventional protection concepts and a completely new differential protection system that can compensate for the variable phase angle shift introduced by operation of the PAR transformer. The complete protection system was tested using digital model power system transient testing prior to installation in the field.**

## I. Introduction

American Electric Power (AEP) installed three 138 kV, 150 MVA phase angle regulating (PAR) transformers on the South Texas transmission grid in 2006. These transformers help optimize power flow on the transmission grid.

The simplified equation (neglecting losses and shunt admittances) for the power flow through a transmission line is shown as Equation 1 [1].

$$P = \frac{E_S \bullet E_R}{X_L} \sin \delta \tag{1}$$

Where:

- $E_S$ is the sending end voltage
- $E_R$ is the receiving end voltage
- $X_L$ is the series reactance of the transmission line
- $\delta$ is the angle between the two voltages

Examination of this equation reveals that power flow is largely a function of the angle between the two voltages. If the angle across the line can be regulated, the power flow through the line can be regulated. By introducing an angle that is additive (advance), power flow can be increased. By introducing an angle that is subtractive (retard), the power flow can be reduced.

PAR transformers typically introduce this phase shift by injecting a quadrature voltage into each phase between the source and load bushings of the PAR transformer. For example, a voltage in phase with $V_{BC}$ or $V_{CB}$ would be combined with $V_A$ to produce a phase shift between the S1 and L1 terminals of the transformer. Traditional PAR transformer designs required two transformer cores to accomplish this. With advancements in load tap changer (LTC) technology, a new type of single tank PAR transformer has become available that promises to improve the economic viability of deployment of these devices on the transmission grid. This new configuration is called a delta/hex PAR transformer. Fig. 1 shows a diagram of this device.

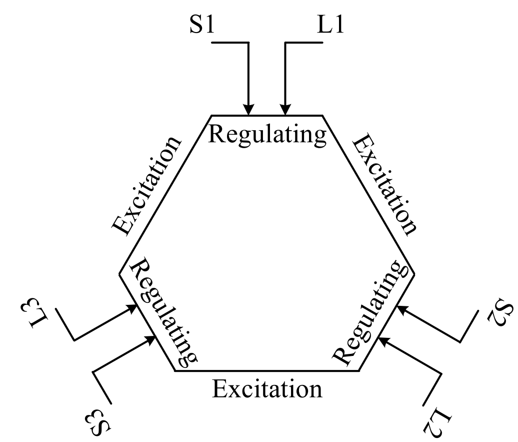


Fig. 1. Delta/Hex PAR Transformer

The three excitation windings and the three regulating windings are connected in a delta/hexagonal configuration. There are two three-phase tap changer mechanisms—one for the source terminals and one for the load terminals. Each tap changer mechanism moves its three terminals up and down the regulating winding to create the phase shift across the transformer. When the two tap changers pass each other, the transformer shifts from advance to retard operation.

The protection standards group at AEP had to develop a plan for implementing a protection scheme that would provide fully redundant, sensitive, and secure protection for all types of faults in the PAR transformer and the surrounding bus work. Traditional percentage restrained transformer differential protection cannot be used due to the continuously variable phase shift across a PAR transformer. There are several other challenges associated with the protection of a PAR transformer as well. The design chosen includes a mixture of traditional protection techniques and a new method based upon the principle of symmetrical components.

The scope of the project included: review of the specifications for the PAR transformer to ensure that current transformers are provided in appropriate locations in the transformer; initial design of the protection system; validation of the system using transient model power system tests; and ensuring that a complete documentation package is created to explain the theory of operation of the protective scheme for design, installation, maintenance, and operations personnel.

## II. Background

AEP installed three, 138 kV, 150 MVA PAR transformers in South Texas in the Electric Reliability Council of Texas (ERCOT) region. At each location, AEP Texas Central Company (TCC) studied the system needs and requirements due to unique system problems. In each case, a PAR transformer provided the best solution. The PAR transformer, in conjunction with other system upgrades, was determined to be the most economical solution to rectify the existing system problems.

To support load in the south Corpus Christi area, ERCOT entered into a Reliability Must Run contract (RMR) to run generation in south Corpus Christi that was planned to be shut down. ERCOT then required the transmission providers to implement permanent transmission solutions such that RMR could be eliminated. As a result, a PAR transformer was installed at the new 345/138 kV Nelson Sharpe substation to effectively accomplish what the local generation had provided, i.e., force power to flow from the 345 kV to the 138 kV system in the Corpus Christi area.

In the Laredo area, the PAR transformer was installed at North Laredo substation to maintain a given power flow during contingency conditions. For example, during loss of the parallel Dilley-to-North Laredo 138 kV transmission line, the 60-mile Asherton-to-North Laredo 138 kV transmission line would become severely overloaded. The idea was to force power flow onto the two remaining 138 kV transmission lines in order to keep the Asherton-to-North Laredo transmission line under the emergency rating.

At the Hamilton Road location, the PAR transformer is needed to regulate power from West Texas into the Del Rio area. The installation of the PAR serves two purposes. The first is to force power flow from West Texas into the Del Rio area such that it off loads the Hamilton Road-to-Uvalde 138 kV transmission line until it can be rebuilt. The second long-term purpose is to limit power flow from West Texas wind generation into Del Rio during high wind periods.

These three PAR transformers provide AEP, as the transmission owner, a cost effective means to support free market generation while preventing overloads on the transmission grid.

## III. PAR Transformer Protection Challenges

It is well understood that differential protection of a zone that includes a transformer has many challenges. The following is a list of some of these challenges:

- Phase shift across the zone
- Zero-sequence discontinuities across the zone
- Current mismatch due to voltage transformation
- Energization inrush
- Recovery inrush after clearing a fault
- Overexcitation

Methods for dealing with each of these problems are well developed for traditional transformers and beyond the scope of this paper. However, many of these same problems are also present for a PAR transformer. In addition, the PAR transformer introduces several unique challenges as well.

### *A. Variable Phase Shift Across the PAR Transformer*

A standard transformer has a fixed phase shift across it. The phase shift can be any increment of 30 degrees leading or lagging (including no phase shift). Differential protection requires that the phase shift across the transformer be compensated such that the currents entering and exiting the zone of protection are offset by 180 degrees so that they sum to zero. For example, a delta/wye transformer may have a 30-degree lagging phase shift. The phase shift in the power transformer is the result of combining $I_A–I_B$, $I_B–I_C$ and $I_C–I_A$ in the delta winding of the power transformer. To compensate for the phase shift, the currents going to the differential element are combined in a way that mirrors the fixed combination of the currents in the power transformer.

In a PAR transformer, the magnitude of the currents from the other two phases that are combined with the phase current is not fixed. It is continuously varied by the position of the tap changer mechanism to create the amount of phase shift required to regulate the power flow to the set point. There is no easy way to combine the currents going to the differential element in a way that mirrors how they are combined in the PAR transformer.

At this point, it is appropriate to elaborate on this idea of phase shift across the transformer. When we say that a transformer has a phase shift of 30 degrees, this is only true of balanced current flow through the transformer. When we have unbalanced current flow, such as would occur during an external fault, the phase shift is not 30 degrees. The unbalanced currents combine in the power transformer and each phase may have a different phase shift. This concept will be important when explaining the new method for protection of a PAR transformer.

### *B. Detection of Turn-to-Turn Faults*

Electrical detection of a turn-to-turn fault is difficult due to the autotransformer effect. High current in the faulted turns is transformed by the ratio of faulted turns to the full winding turns such that it will be relatively small at the terminals of the transformer. Primary sensitive protection for these faults is provided by the sudden pressure relay. However, traditional transformer differential protection provides some degree of turn-to-turn fault protection because the primary and secondary windings are coupled by the iron core and the ampere-turns must match between the windings on the same core. In a turn-to-turn fault, the differential relay will not see the amperes flowing in the faulted turns resulting in a differential condition that can be seen by the differential relay.

Many past approaches to protection of a PAR do not attempt to match ampere-turns across the core. They rely upon treating each winding section as a power system node (similar to a section of bus) and summing the currents entering and exiting a single winding [2]. Differential relays configured in this way cannot see a turn-to-turn fault.

### *C. Saturation of the Series Winding for a Through Fault*

Another difficulty is that a PAR transformer has a series (regulating) winding that directly connects the source and load terminals of the transformer. During an external through fault, high current must flow through this winding. If the voltage drop $I_F \bullet X_T$ across the winding exceeds the volts-per-turn capability of the transformer's iron core, that core leg can saturate, resulting in an overexcitation condition [3]. This can cause the sensitive differential protection to misoperate.

## IV. Solutions

The protection system is required to be fully redundant, sensitive, and secure for all types of faults, including turn-to-turn faults, in the transformer and its surrounding bus work. Fig. 2 shows a protection single line of the PAR Transformer zone. The zone is bounded on the source-side by two circuit breakers in a breaker-and-a-half substation arrangement. On the load-side, the zone is bounded by a line breaker for the transmission line on which the PAR transformer will be regulating power flow. A bypass breaker and Motor Operated Disconnect (MOD) are provided to allow for isolation and bypass of the PAR transformer for maintenance.

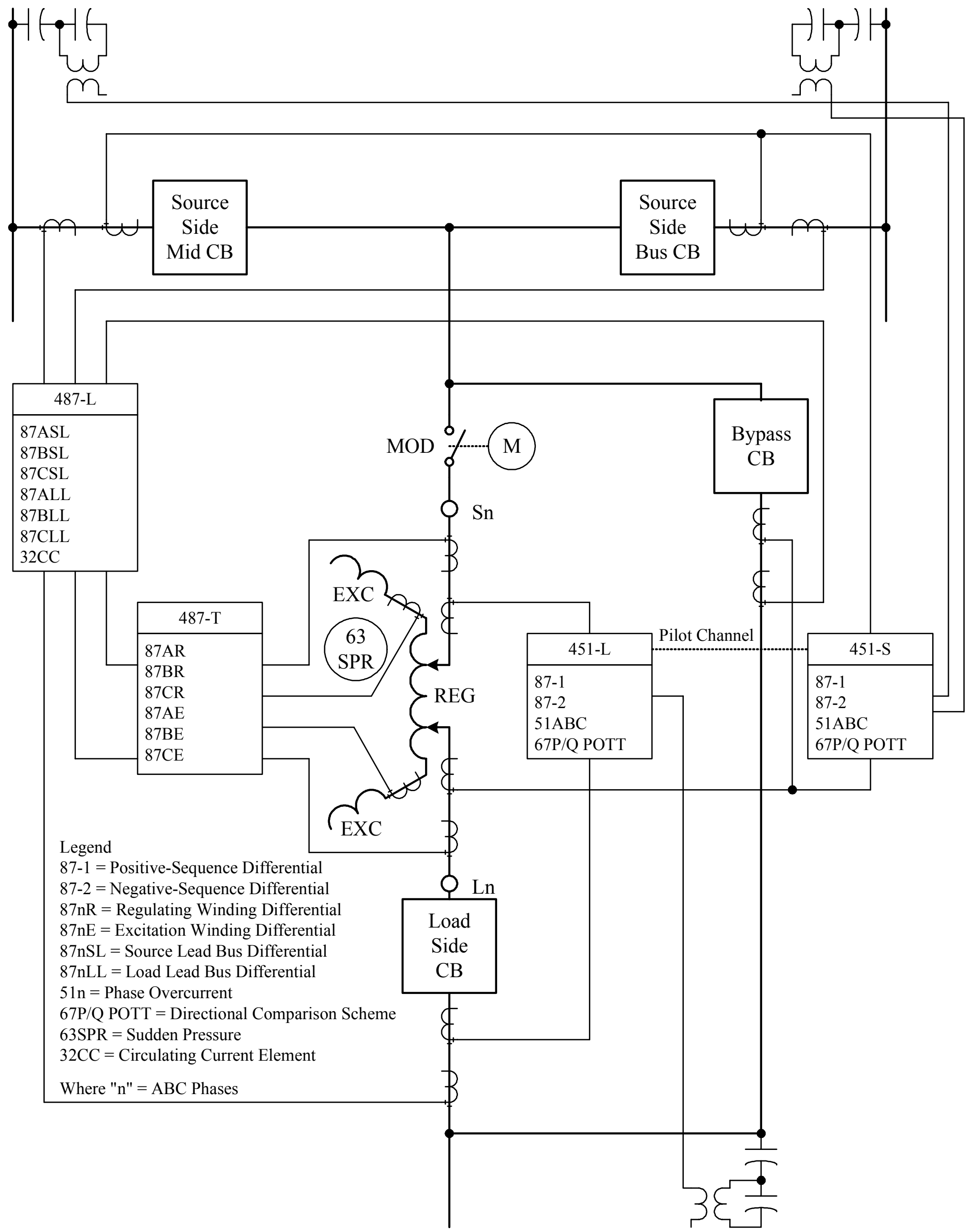


Fig. 2. PAR Transformer Zone, Protection Single-Line Diagram

### A. Primary System

The primary protection system is relatively conventional. It consists of two low-impedance, multirestraint, bus differential relays and the sudden pressure relay.

The bus differential relays are designated as device 487-L (lead zone) and 487-T (transformer zone) in the protection scheme. These relays are applied to provide high speed, sensitive protection for all faults except turn-to-turn faults within the PAR. The PAR transformer zone is broken down into four times three phases for a total of 12 individual subzones. Any fault from a conductor or winding to ground, a conductor to conductor, or a winding to winding will be detected by this protection scheme. Device 487-L protects the source-side and load-side bus work. Device 487-T has six individual zones that cover each of the regulating and excitation windings. By dividing the PAR zone into four subzones, (source lead, load lead, excitation winding, and regulating winding) it will be easily apparent if a fault is internal or external to the PAR.

These differential zones do not match ampere-turns between windings so they are blind to turn-to-turn faults. However, this configuration also makes them immune to transformer differential challenges such as inrush, overexcitation, and series winding saturation. Primary protection for turn-to-turn faults within the PAR is provided by the 63SPR sudden pressure relay.

#### 1) Circulating Current Element

Device 487-L also includes an element that measures the current in the load-side circuit breaker and the bypass circuit breaker to detect circulating current that would occur if the bypass breaker were closed when the PAR is off neutral tap. This element is designated 32CC in Fig. 2. If the circulating current element picks up, it will trip only the load-side circuit breaker to break the parallel path, yet leave the line in service on the bypass circuit breaker.

The phase currents are measured in the load-side circuit breaker and the bypass circuit breaker. From these measurements, an additive and a subtractive current are calculated. The additive current represents the load current down the line. The subtractive current is a measurement of the circulating current in the bypass loop. The ratio of subtractive current to additive current indicates if circulating current is present.

- For even distribution of load current between the parallel branches, the ratio will be 0.
- For the extreme of no load current in one of the branches, the ratio will be 1.
- The only way for the ratio to be greater than 1 is if circulating current is present.

The tripping ratio is set at 1.1. The ratio check is supervised by requiring that the phase currents in each branch must be above a minimum pickup level. The minimum pickup level is set at 0.1 Per Unit of transformer capacity. Each of the three phase currents are measured separately to provide for the case where only one phase of the tap changer mechanism is stuck to cause the off neutral bypass situation.

### B. Alternate System

The alternate protection system consists of two directional overcurrent relays with pilot protection logic and advanced programmable logic. The directional overcurrent relays are designated as device 451-S (source-side) and 451-L (load-side). These relays are configured to provide sequence component differential protection. The new differential elements are implemented in advanced programmable logic. In addition, a directional overcurrent-based permissive overreaching transfer trip (POTT) protection scheme provides security features to the sequence differential elements, as well as additional means of detecting and tripping for internal faults.

#### 1) Principle of Operation, Sequence Differential Elements

Traditional methods of dealing with the phase shift across a transformer involve combining currents in the differential circuits to mimic the combination of currents in the transformer. With a PAR, the amount of current from other phases that is combined into each phase varies with the tap position. Under unbalanced through-fault conditions, the phase currents cannot be easily balanced, so a traditional differential relay will operate incorrectly. The phase shift for balanced currents through a PAR is determined by the tap position of the transformer. Fig. 3a shows the phase currents for balanced load flow through a PAR with approximately 21 degrees lagging phase shift. Fig. 3b shows the positive-sequence components for this set of balanced currents. In Fig. 3 and Fig. 4, the phasors labeled “W1” represent the source-side currents and the phasors labeled “W2” represent the load-side currents. The phase shift for the positive-sequence component is also 21 degrees lagging. Symmetrical components, by definition, are a set of balanced phasors that can be extracted from any three-phase set of unbalanced phasors. The phase shift of the negative-sequence component across the PAR is opposite that for the positive-sequence component. This can be clearly seen in Figs. 4a, 4b, and 4c. Fig. 4a shows the unbalanced phase currents on each side of the PAR for an AG through fault. Fig. 4b shows the positive-sequence components for this set of unbalanced phasors. They are still shifted 21 degrees lagging. Fig. 4c shows the negative-sequence components for this set of unbalanced phasors. The negative-sequence components are shifted 21 degrees leading (the opposite of the positive-sequence component).

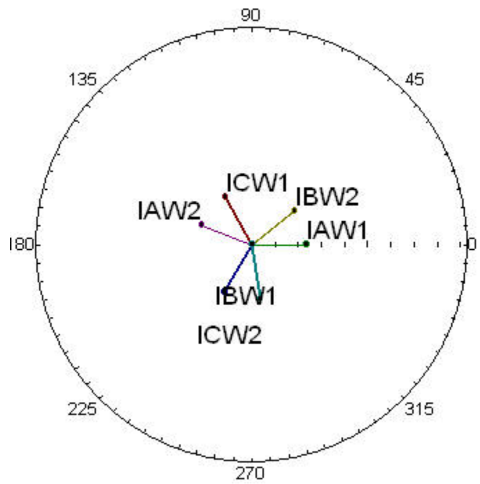


Fig. 3a. Balanced Load Flow, Phase Currents

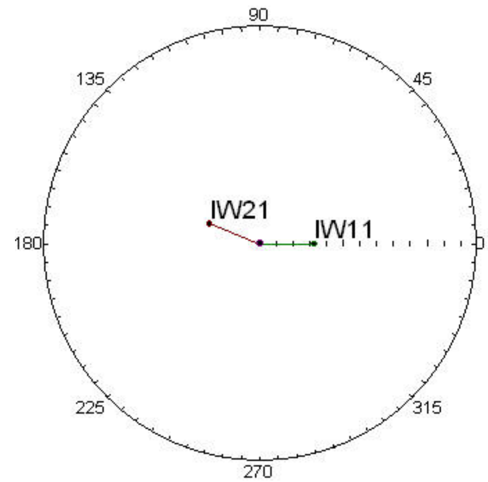


Fig. 3b. Balanced Load Flow, Positive-Sequence Components

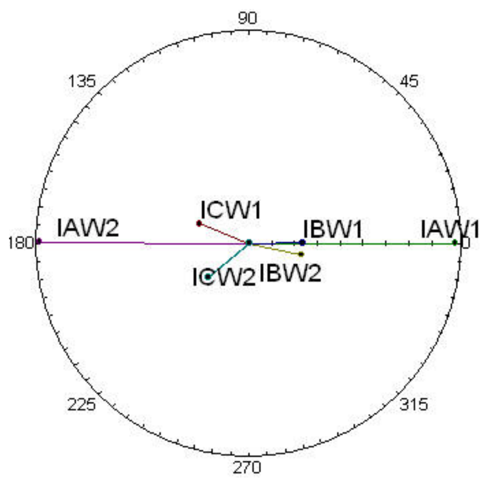


Fig. 4a. Unbalanced AG Through Fault, Phase Currents

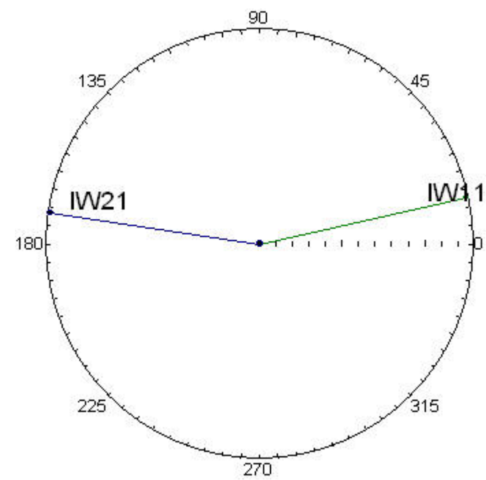


Fig. 4b. Unbalanced AG Through Fault, Positive-Sequence Components

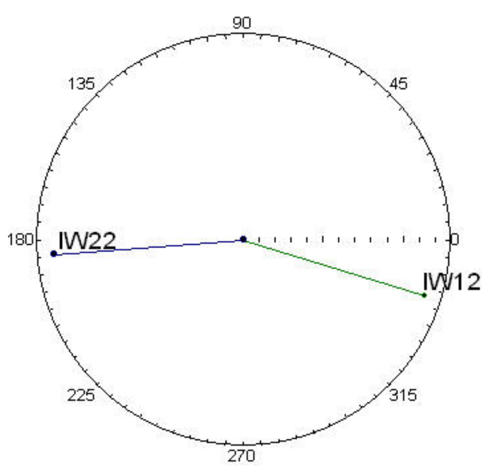


Fig. 4c. Unbalanced AG Through Fault, Negative-Sequence Components

The new differential elements work by extracting the positive- and negative-sequence symmetrical components of the source and load currents. The positive- and negative-sequence currents on the load side of the PAR are then compensated by subtracting the PAR angle phase shift from the positive-sequence component and adding the PAR angle phase shift to the negative-sequence component. Once compensated, operate and restraint quantities are calculated for the positive- and negative-sequence component currents and measured by dual-slope, percentage differential elements to determine if there is an internal fault.

The alternate differential protection system provides protection for all fault types including turn-to-turn faults. The positive-sequence element is responsive to all fault types. The negative-sequence element is responsive to all unbalanced fault types. The negative-sequence element can provide higher sensitivity than the positive-sequence element.

As with any transformer differential relay, these sensitive elements must be made secure from misoperation on initial energization inrush, as well as recovery inrush upon clearing a close-in external fault. Another concern that is specific to a PAR transformer application is saturation of the regulating winding for a through fault. The high current flowing through the regulating winding impedance can cause a large enough voltage drop to overexcite the core. This can also cause the sensitive differential elements to misoperate. The following sections explain how each of these concerns is addressed.

*2) Measuring the Phase Shift Across the PAR for Compensation Purposes*

The two tap changer mechanisms provide binary coded decimal (BCD) signals to indicate their tap position. The relay reads the status of each of the five bits representing the 1, 2, 4, 8, and 10 bits of the BCD signal via contact sensing inputs. See Fig. 5. When an input is asserted, it represents a logical 1, which, when multiplied by the bit's numerical value, can be summed to give the tap position between 1 and 17 (representing Steps 0 through 16). The difference between the positions of the two tap changers gives a signed number that represents the number of tap steps in advance or retard. This value is multiplied by the number of degrees per tap step to provide the angle compensation factor. The angle compensation factor is used to correct the sequence components for phase shift across the PAR.

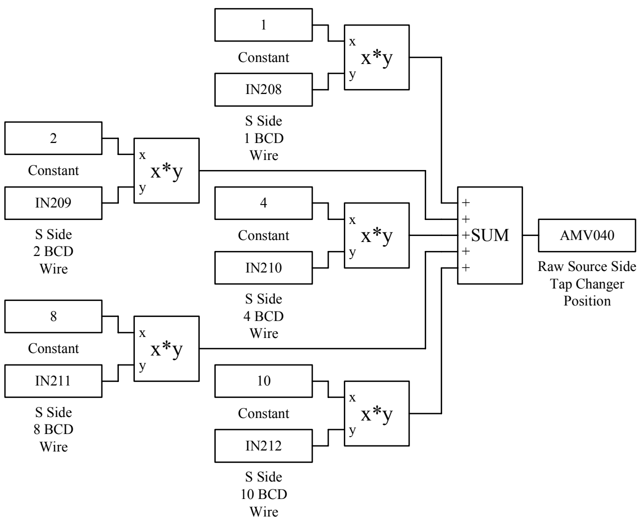


Fig. 5. Decode BCD Tap Position Logic

When the tap changer mechanism is in transition between steps, the BCD signal reads zero. Because zero is an invalid state, logic is included to ignore this state during the transition. Of course, a failure of the mechanism could also result in the BCD signal reading zero indefinitely. So, an alarm is included to indicate that the BCD signal is stuck on zero. Also, because the tap changer mechanism is a mechanical device, it is possible that the BCD bits will not all change state at exactly the same time. Thus, it is necessary to smooth the calculation of the angle compensation factor to allow for such errors. To accomplish this, a smoothing filter that takes a "k" amount of the previous value and adds in a "1–k" amount of the present value is used. The smoothing constant has been set for 0.99 Per Unit of the previous value and 0.01 Per Unit of the present value. The slope characteristic of the differential elements will tolerate several steps mismatch between the actual tap position and the indicated tap position so the delay in the angle compensation factor reaching its new value will not cause a problem under normal operation.

Because the signal from the mechanical tap changer could possibly be in error, it is important to build a reality check into the logic to alarm if the tap position indication is incorrect. This is done by calculating the measured positive-sequence phase shift between the source and load-side. The measured angle is compared to the expected phase shift indicated by the mechanical tap changer signals and an alarm is indicated if these values are off by more than a tap step and a half.

*3) Sequence Component Differential Elements*

As shown in Fig. 2, each relay includes a positive- and a negative-sequence differential element. The angle of the load-side sequence component is adjusted by the angle compensation factor. In the case of the positive-sequence component, we subtract the angle compensation factor. In the case of the negative-sequence component, we add the angle compensation factor. The phase angle compensation of the load-side sequence components occurs in real time. There is no time that the relay is off line or has to change setting groups when the PAR changes taps.

The source and load-side currents are then divided by their respective tap adjust factors to put them in Per Unit so that the operate and restraint quantities for each element can be calculated. The tap adjust factors are required because the ring breakers have a higher CT ratio than the transformer, line breaker, and bypass breaker. The operate quantity is calculated as the phasor sum of the source and compensated load-side currents. The restraint quantity is calculated as the average of the magnitudes of the source and load-side currents.

Once the operate and restraint values are determined, they are checked against a dual slope differential element characteristic as shown in Fig. 5. For the element to be picked up, either of two conditions must be satisfied:

- IOP must be above the MINPU setting,
  AND IRST must be below the IRS1 setting,
  AND the ratio of IOP to IRST must be above the SLOPE 1 setting.
- IOP must be above the MINPU setting,
  AND the ratio of IOP to IRST must be above the SLOPE 2 setting.

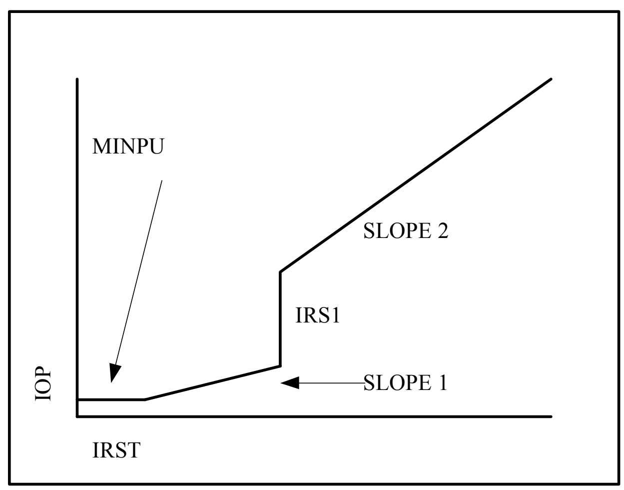


Fig. 5. Dual Slope Differential Characteristic

For the negative-sequence element, an additional check is included that requires the magnitude of the negative-sequence component be some minimum percentage of the magnitude of the positive-sequence component before the negative-sequence differential element is allowed to operate. This "a2" factor is typically set at 10 percent. This check is provided to prevent misoperation of the negative-sequence element for high-level three-phase faults where a false negative-sequence component may be introduced.

TABLE I
DIFFERENTIAL ELEMENT SETTINGS

| Setting | 87-1 Positive Sequence | 87-2 Negative Sequence |
|---|---|---|
| MINPU | 0.50 Per Unit | 0.20 Per Unit |
| SLOPE 1 | 0.25 Per Unit | 0.25 Per Unit |
| IRS1 | 2.50 Per Unit | 2.50 Per Unit |
| SLOPE 2 | 0.80 Per Unit | 0.80 Per Unit |

Table 1 shows the settings that were used for the differential element characteristics. These settings were verified to be suitable during the testing and validation stage of the project.

The sequence component differential elements must be made secure for such differential challenges as series winding saturation and transformer inrush. The following describes the security logic that is included.

*4) Series (Regulating) Winding Saturation*

During an external fault, the current flowing through the regulating winding on the faulted phase will be high. If $I_F \bullet X_T$ exceeds the volts per turn limit on that core leg, it will saturate. Saturation will result in high current in the exciting winding of the same core leg. This will likely cause misoperation of the differential elements. The POTT scheme that will be described in a subsequent section uses both forward and reverse elements. If either relay determines that the fault is in the reverse direction (external to the zone of protection), the sensitive differential elements are blocked.

Each directional overcurrent relay can only declare an external fault on its side of the transformer. Thus, if one of the relays is out of service, or the pilot channel between the two relays is out of service, both relays are blocked from operating. This is why the alternate relaying system is said to work in tandem. Both device 451-S and 451-L must be in service in order for the alternate protection system to operate.

*5) Transformer Energization Inrush*

Transformer inrush can cause differential elements to misoperate due to the high current entering the zone of protection with no through current to provide restraint. The inrush currents can last for a long period of time. Device 451-S and 451-L include SOTF (switch-onto-fault)-like logic to block the sensitive sequence differential elements upon initial energization. This logic is supplemented with a total harmonic distortion (THD) system that blocks the differential element when high levels of harmonics are present in the current as would be the case during transformer inrush. The initial energization inrush blocking logic was set to assert for 10 cycles after the first breaker or switch is closed to energize the transformer.

*6) Recovery Inrush*

A phenomena known as recovery inrush can occur due to an external fault. In this situation, a close-in external fault depresses the voltage on the transformer. When the external breakers open, the short circuit is cleared and the voltage returns to normal causing transformer inrush currents to occur. This condition is addressed by the current reversal logic in the directional overcurrent relay's POTT scheme. During an external fault, the reverse elements in one of the two relays will assert. This sets a current reversal blocking element that has a dropout timer. This dropout timer holds the external fault blocking logic up for a period of time after the external fault has cleared, allowing the sensitive sequence differential elements to be blocked until the recovery inrush condition has passed.

*7) Security Delay Timer*

The supervised differential element outputs are finally conditioned with a security timer before a trip is issued. The security timer is required to prevent operation on the false sequence component differential condition that occurs due to filter transients. The cosine filter, used in the relays for estimating the magnitude and angle of the power system signals, is only valid for continuous signals. When a fault occurs, there is a filter transient during the time that the filter contains some prefault samples and some fault samples. The sequence component filters introduce a transient error as well. These filter transients often result in a short blip of sequence differential for any large step change in currents due to a fault. During testing, we observed that a one-cycle delay was sufficient to ride through the false sequence component differential caused by these filter transients. The security timer also provides delay for the external fault-blocking elements to assert.

*8) 67P/Q POTT System*

A POTT system is enabled in each of the directional overcurrent relays with phase- and negative-sequence directional overcurrent elements. The reverse elements are set to block the differential elements when series-winding saturation is likely. The forward elements are set to 1.15 times the reverse elements to provide a small margin to ensure that the reverse elements operate anytime the forward elements operate. The POTT system provides backup protection for all types of internal faults.

## V. MODELING AND VALIDATION

A real time digital simulator was used to test and validate the complete protection system. A model of the PAR transformer and the surrounding power system was created and a test regimen was developed to ensure that the system would operate as expected when put in service.

### *A. Modeling*

The manufacturer provided information for creating the model of the PAR. The model was required to have the following characteristics.

- The ability to adjust two tap changer positions on the regulating winding.
- Ability to create turn-to-turn faults within the transformer model.
- Model the nonlinear excitation branch of the core to examine inrush and series saturation phenomena.
- Branch current outputs to model the locations of CTs inside the windings of the PAR.

A suitable model was not in the standard pallet of power system equipment models available with the RSCAD® software that we used to create the transient simulation model power system. Thus, it was necessary to work with the supplier of the test system to develop a custom model for the application.

### B. Validation Testing

The validation test plan included a suite of special tests and then a series of batch tests. The special tests are intended to explore specific conditions that would challenge the protection system and to validate the operation of specific features programmed into the system. The batch tests are intended to expose the protection system to a huge number of internal and external faults to determine if it will remain dependable and secure for all fault types.

#### 1) Special Tests

The special tests included the following:

- Security for transformer inrush
- Security for recovery inrush
- Compensation at extreme range of tap changer
- Tap changer read failure alarm
- Turn-to-turn fault sensitivity

Fig. 6 shows one of the events recorded by the real time digital simulator during the “security from recovery inrush” tests. Examination of this figure is quite instructive of how device 451-S and 451-L work together. We can see that device 451-L experienced a short blip of false sequence differential currents upon fault initiation (451L87_1 and 451L87_2). This is due to the cosine and sequence component filter transients. The one-cycle security delay allows the relay to ride through this.

Device 451-L detects the external fault via its reverse directional overcurrent elements and asserts its external fault-blocking element (451LEXT). The external fault-blocking element in device 451-S (451SEXT) asserts shortly thereafter due to the pilot channel delay between the two relays. Device 451-S sees this fault as forward and sends permissive to device 451-L (451LPT). So, the POTT scheme operated as expected.

Upon clearing of the external fault, the current reversal dropout delay timer in the POTT logic holds up the external fault blocking logic to prevent any operation of the differential element on either the filter transient from fault clearing or recovery inrush. Note that there are several blips of the sequence differential elements (451L87_1, 451L87_2, and 451S87_2) after the fault is cleared due to these two phenomena.

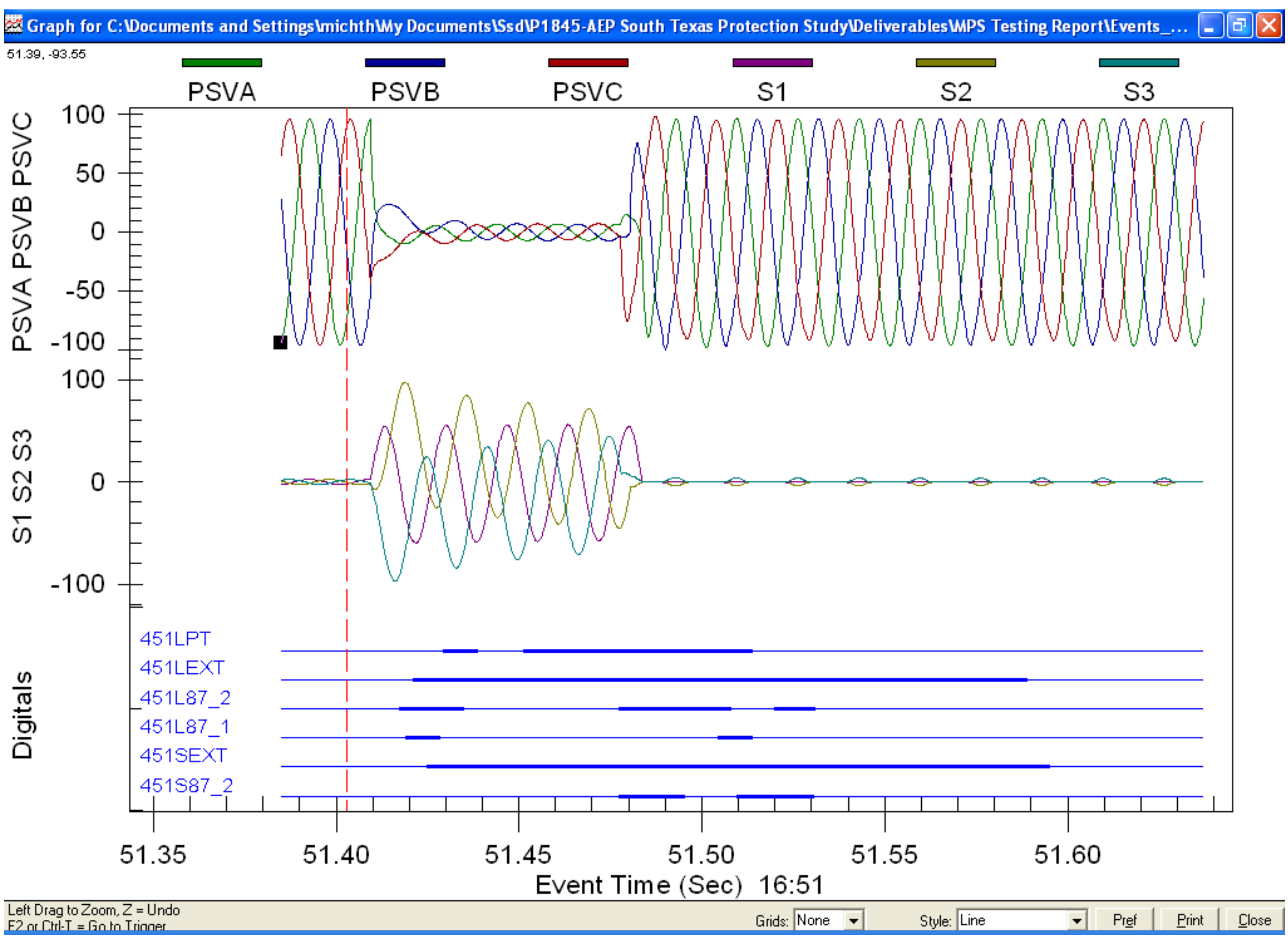


Fig. 6. External ABC Fault Behind the Load-Side

The sensitivity to turn-to-turn faults tests verified that the primary protection system devices, 487-L and 487-T, were blind to these faults as expected. The alternate protection system devices, 451-S and 451-L, were able to detect turn-to-turn faults as low as one tap step on the regulating winding. These tests lead us to the realization that the negative-sequence differential element can provide superior sensitivity for hard-to-detect turn-to-turn faults for all types of transformers. For a conventional, fixed phase-shift transformer, the angle compensation factor would be a fixed constant instead of a variable read from the tap changer mechanism.

*2) Batch Tests*

A total of 210 fault shots were run for two load-flow cases for a total of 420 shots. At each of seven fault locations (four internal, three external), all 10 possible fault types were applied: AG, BG, CG, ABG, BCG, CAG, AB, BC, CA, and ABC. Faults were applied at three different fault inception angles: 0°, 45°, and 90° referenced to VA. The two series of shots were run at tap position three (3) and tap position seven (7). This resulted in load flow through the PAR transformer of 47 MW and 151 MW, respectively.

During the batch tests, we had no cases of overtrip for external faults. We had one case of fail to trip for an internal fault by the alternate protection system. Review of that operation revealed that the directional element in device 451-L momentarily declared an external fault and blocked the sensitive sequence differential elements. The primary protection system correctly tripped at high speed. We reran the series of tests again and were not able to repeat the fail to trip.

## VI. Summary and Conclusions

PAR transformers can help optimize existing transmission system assets by regulating the power flow across transmission system branches. The single tank, delta/hex transformer can be more economical than previous multitank designs, which promise to increase use of these devices on the transmission grid.

PAR transformers present some unique protection challenges. These challenges include:

- Compensating for the variable phase shift introduced by operation of the PAR transformer.
- Electrical detection of turn-to-turn faults.
- Saturation of the series winding during through faults.
- Detection of circulating current to open the parallel path if the PAR is bypassed off neutral.

AEP required that the protection systems for the three new PAR transformer installations be fully redundant for all types of faults. A solution was developed that included a mixture of conventional protection concepts and a completely new differential protection system to meet this objective. The primary protection system uses bus differential-type relays and the sudden pressure relay to cover all faults. The alternate system uses symmetrical components differential for low-grade faults and a directional overcurrent-based POTT system for higher-grade faults.

The new protection system, which was based upon symmetrical components, was developed by going back to fundamental concepts. When using symmetrical components to analyze unbalanced faults through a transformer with a phase shift, we know that the positive-sequence component is shifted by the same amount as normal load flow (because normal load flow is considered balanced). And, we know that the negative-sequence component's phase shift is the opposite of the positive-sequence component's. This principle applies whether the phase shift is an increment of 30 degrees as with a conventional transformer or if the phase shift is variable, as with a PAR transformer.

By reading in the tap changer position to determine the expected phase shift and extracting two sets of balanced phasors (positive- and negative-sequence components) from the currents at the source and load terminals, it is possible to compensate for the continuously variable phase shift introduced by the PAR transformer. And because the protection system relies upon information from the mechanical tap changer position information, it is important to include a reality check in the logic to alarm for errors in the tap changer position readings.

In addition to the sensitive protection provided by the new sequence differential elements, the alternate protection is supplemented by using the directional overcurrent elements and the POTT logic to detect faults in the PAR transformer zone.

Transient simulation is necessary to validate the theory of operation of a new protection concept under realistic conditions. Simulation can also be used to fine tune settings and verify programming. A real time digital simulator, with its closed loop test environment, is an ideal tool for doing this type of testing.

AEP relied on the engineering services division of their supplier to develop the protection design for the PAR transformers. AEP found the solution that they proposed to be a very unique, dependable, and secure design for all protection requirements. The scheme was also very economical, utilizing a total of only four relays. AEP witnessed digital simulator tests and verified the protection design. Because the system is based upon some new concepts, the supplier also provided an instruction manual and detailed logic diagrams that cover the programming and theory of operation of the system. All three installations were placed in service during the summer of 2006.

## VII. Acknowledgment

The authors gratefully acknowledge the contributions of Paul Forsyth and the rest of the RTDS Technologies staff for their assistance in creating a model of the PAR transformer to facilitate testing.

## VIII. References

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## IX. Biographies

**John Burger** has a BSEE from Case Institute of Technology and a MSEE from Fairleigh Dickinson University. He is a Registered Professional Engineer in the states of Ohio and New Jersey. John has over 35 years experience in station and line relay protection and control. He has worked for AEP, primarily in the Protection and Control group, for the last 27 years. John is currently serving as a Staff Engineer in the Protection Metering Engineering and Standards Group with responsibilities for developing protection and control standards, application guides and supporting the relay setting project work. John has responsibility for workload management of the P&C group including the contractor support functions. He shares responsibility for ensuring that new devices to the AEP system are protected and controlled properly with Hank Miller. John has also worked as a Protection and Control Specialist, as part of the AEP Energy Services team, for the People's Republic of China on the Ertan 500 kV Transmission Project. John is a Senior Member of the IEEE, past chairman of the Columbus Chapter of the PES, a member of the IEEE Power System Relay Main Committee, Substation and Communications Subcommittees and chairman of working group H6. He is also currently serving as Chairman of the UCA International Users Group providing technical support for IEC 61850.

**Henry Miller** (Hank) has a BSEE and a BEE from The Ohio State University and a BA Degree in Philosophy from The Pontifical College Josephinum. He is a Registered Professional Engineer in the state of Ohio and holds a patent for a substation steel design. Hank has over 27 years of utility experience in station and line protection and control. Hank is currently working as a Principal Engineer in the Protection Metering Engineering and Standards Group with responsibilities for developing protection and control standards, application guides and supporting the relay setting project work. He shares responsibility for ensuring that new devices to the AEP system are protected and controlled properly with John Burger. Hank is a member of the IEEE.

**Michael J. Thompson** received his BS, Magna Cum Laude from Bradley University in 1981 and an MBA from Eastern Illinois University in 1991. He has broad experience in the field of power system operations and protection. Upon graduating, he served nearly 15 years at Central Illinois Public Service (now AMEREN) where he worked in distribution and substation field engineering before taking over responsibility for system protection engineering. Prior to joining Schweitzer Engineering Laboratories in 2001, he was involved in the development of a number of numerical protective relays. He is a Senior Member of the IEEE and a member of the substation and rotating machinery subcommittees of the IEEE, PES, Power System Relaying Committee. Michael is a registered Professional Engineer in the State of Washington and holds a patent for integrated protection and control system architecture.

## X. Previous Publications

Presented at the Georgia Tech Protective Relaying Conference 2006, Western Protective Relay Conference 2006, Clemson University Power Systems Conference 2007, and Texas A&M Conference for Protective Relay Engineers 2007.

Previously presented at the 2007 Texas A&M
Conference for Protective Relay Engineers.

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