Evaluation of 13kV Dry-Type Shunt Reactor Protection following Near-Miss

Gary L. Kobet, P.E.,
Tennessee Valley Authority
Chattanooga, Tennessee, U.S.
glkobet@ieee.org

***Abstract*—At the end of a bird-caused fault sequence, the protection scheme for a 13kV dry-type shunt reactor left the reactor energized and carrying load current on two phases, which resulted in a more severe fault when the field operator attempted to clear the shunt reactor using manually operated disconnect switches. The operator was not injured but given his proximity to the fault and arc, the result could have resulted in serious injury or much worse. In order to avoid such situations, this paper evaluates the protection scheme for 13kV dry-type shunt reactors, highlighting deficiencies, compares company practices against one industry guide, and describes planned improvements.**

Keywords—shunt reactor; protection; negative sequence relay; tertiary ground fault

I. Introduction

The Tennessee Valley Authority (TVA) is a corporate agency of the United States that provides electricity for business customers and local power companies serving 9 million people in parts of seven southeastern states. The TVA transmission system consists of over 16,000 circuit miles of transmission lines and 513 transmission substations, with transmission operating voltages primarily at 500kV and 161kV. Of those transmission substations, over 30 have one or more 500/161/13kV transformer banks. TVA has 13kV shunt reactor banks installed in 18 of those 500kV substations.

This paper presents a near-miss event which occurred in the 13kV switchyard involving equipment connected to the tertiary bus of one of those 500/161/13kV transformer banks. The circuit breaker that performs the switching for the equipment (shunt reactor banks) is atypically not located on the source side of the equipment, but rather on the neutral end; it merely completes the neutral allowing current to flow. Due to a neutral end “fault,” where an arc occurred outside the normal controlled environment within the circuit breaker, load current began to flow. None of the protective devices were initially able to detect this event, until the arcing produced significant damage. Well after the arcing began, one of the protective devices did pick up--but sent a trip signal to an already open breaker. By the time field personnel arrived to investigate, they witnessed the damage but the arcing had stopped. They then made the assumption that since the circuit breaker was open, it was safe to open the isolating disconnects. This erroneous assumption resulted in a significant arc and resulting three-phase fault. The field operator was using a hotstick to open the disconnects and stood directly underneath the 82kA fault, about 15 feet away. Amazingly, no one was injured.

The paper reviews the application and protection of 13kV shunt reactors at TVA, detailing how the protection failed to properly deenergize the primary equipment. The sequence of events is reviewed, as well as the steps taken as a result of the event. Both short term and long term changes in operational practices and protection design/philosophy are listed, which intend to avoid such situations in the future.

II. Shunt Reactors at TVA

A. General

TVA uses shunt reactors to compensate for excess capacitive reactance of lightly loaded 500kV transmission lines during off-peak periods. When the 500kV system was originally constructed in the 1960s and 1970s, TVA installed 100MVAR (three-phase) oil-filled shunt reactors on selected 500kV line terminals. Over time TVA retired the oil-filled reactors for environmental and operational reasons, opting instead to locate dry-type (air core) shunt reactors in 13kV switchyards and connect them to the 13kV tertiary winding of 500/161/13kV transformers, using vacuum circuit breakers in the neutral end of each shunt reactor bank to switch them in and out of service. TVA has used both single winding and split winding shunt reactors.

B. Description of Installation

Similar to 17 other 500kV substations, the particular substation involved in this event (designed in 1996) has three 13kV shunt reactor banks, each rated 45MVAR three-phase (about 2000 amps at 13kV). Each bank is connected to the 13kV tertiary buswork of the 500/161/13kV transformer bank through dual-blade, non-ganged, manually operated (via hotstick) single-phase disconnect switches. The reactors are switched in/out of service using 13kV vacuum breakers located at the neutral end of the reactors. The reactors are split winding, with each reactor phase consisting of two 8.4 ohm (nominal) inductor coils in parallel (Figure 1). Note there are two stingers per phase, one from split winding, connected to the CTs.

It should be noted that reactor breakers are unlike all other breakers on the system in their location relative to the equipment switched. Typically, a breaker is associated with de-energizing a piece of equipment. However, the function of a reactor breaker is simply to stop and start the flow of load current; the breaker merely makes up the neutral of the reactors (connects the neutral ends of all three phases together) to allow load current to flow through the reactors. Even though a reactor breaker may be open, the reactor remains energized at the tertiary bus potential. The reason that the reactor breaker is not located on the source (power transformer) side of the reactor is due to the available fault current on the tertiary bus, which typically exceeds 70kA (and in some cases over 200kA!). Reactor breakers are not designed to interrupt that magnitude of fault current. By locating the reactor breaker on the neutral side of the reactor, the breaker is never exposed to any current higher than rated reactor load current.

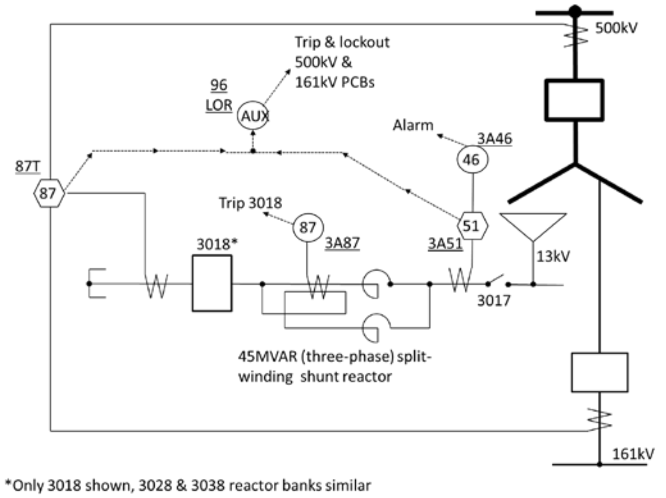

Fig. 1. *Shunt reactor installation*

C. Shunt Reactor Protection

Protection for each shunt reactor consists of current transformers (CT) and relays that together provide fault and abnormal condition (e.g., turn-to-turn short circuit) protection for each reactor winding.

One set of CTs is located between the disconnect switch 3017 and the reactors. Time overcurrent relays (device 3A51) are fed from this set of CTs that provide phase fault protection and trip the transformer bank. Note the time overcurrent pickup is necessarily set higher than rated reactor load current. Also fed from this set of CTs is a negative sequence overcurrent relay (device 3A46) that only sends an alarm.

Another set of CTs is located between the reactors and the neutral breaker (PCB 3018). These CTs receive the two neutral end leads of each split phase reactor. The CTs feed split phase overcurrent relays (3A87) that trip the reactor breaker PCB 3018.

In addition, the 13kV reactor banks are also included in the transformer bank differential zone (see Figure 1)

This protection is duplicated on the other two shunt reactor banks at this location and is typical of split winding shunt reactor banks at all TVA substations.

III. EVENT SEQUENCE

On the afternoon of Friday, May 19, 2017, a bird attempted to land on 13kV Power Circuit Breaker (PCB) 3018 feeding a 45MVAR shunt reactor connecting it to the tertiary of a 500/161/13kV transformer bank. The wings of the bird bridged the reactor-side bushings completing the neutral (Figures 3 & 4). This bridging of the neutral is normally contained within the PCB.

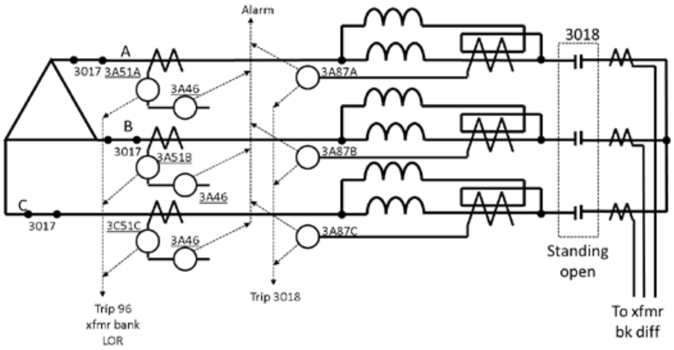

Fig. 2. Shunt reactor protection

With the neutral completed, load current (approximately 2000A) began flowing through each phase of switch 3017 and through each reactor phase. As previously mentioned, the 3A51 time overcurrent relay has a pickup over rated reactor load current, or in this case 3000A; therefore this relay did not pickup. In fact, initially no protective relay would have been expected to pickup:

- The 3A46 negative sequence relay would not have picked up because the three phase currents were balanced, of near equal magnitude and 120 degrees apart;
- the 3A87 split winding differential relays would not have picked up because the same currents initially flowed through each winding of each phase. To the system and to the protection, the effect of the bird bridging the neutral was the same as the reactor breaker closing its contacts.

However, what resulted was an external arc of 2000 amps, which began flowing through the wings of the bird and eventually expanded into the surrounding air. With no means of extinguishing this uncontrolled arc in what became ionized air, the arc continued burning at least 16 minutes. During this time the split winding differential relaying operated, sending a trip signal to the 13kV PCB as designed, but this accomplished nothing as the PCB was already open (had been standing open at least a month) (Figure 5).

After the arc burned itself out, the split-winding CTs and all but two stingers were completely destroyed. A single A-phase stinger and a single C-phase stinger remained, laying on grounded support steel, which completed a circuit for current to flow through the two outer phases (A and C), with no current in B-phase (Figures 6 & 7). In Figure 7, notice two stingers, one from C-phase (furthermost reactor), and one A-phase (nearest reactor), both laying across horizontal support beam below damaged CTs. The A-phase stinger was still laying on grounded support steel; the C-phase stinger fell off later. Remains of the bird were found on the ground on the side of the breaker (side nearest camera angle).

This resulted in actuation of the negative sequence overcurrent relay, which as designed sent an alarm to both the local control house and to the System Operating Center via SCADA. Also note the tertiary ground detection scheme will not pickup for a double-line-to-ground condition on the tertiary bus (explained later).

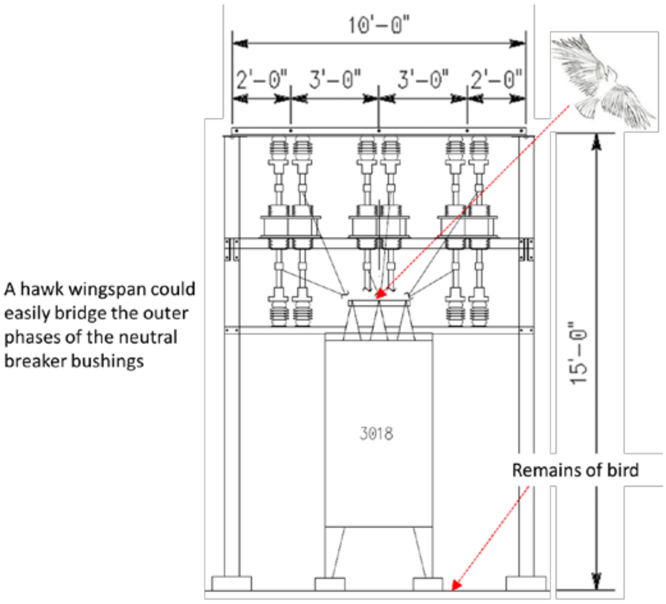

Fig. 3. *Facing breaker (reactor behind), with dimensions*

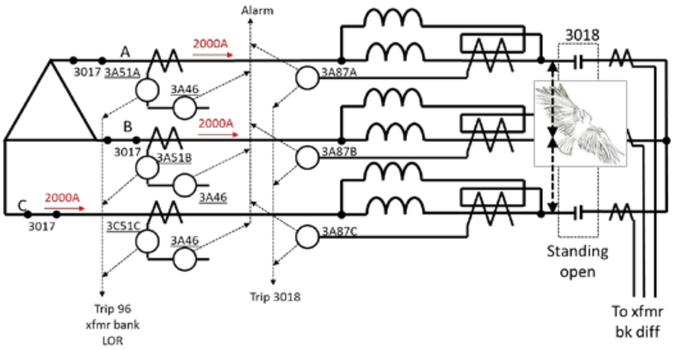

Fig. 4. *Sequence - 15:44 Bird lands on 3018 bridging phases between reactor and breaker*

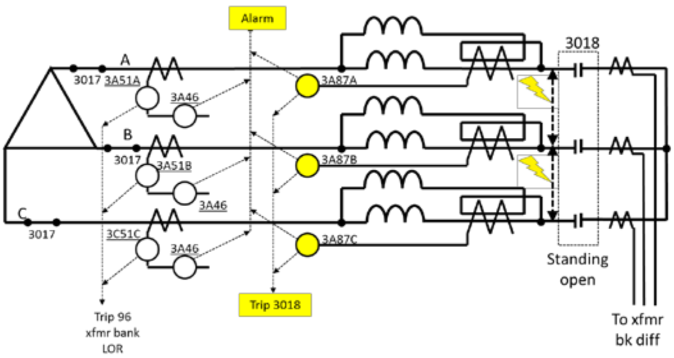

Fig. 5. *Sequence - From 15:44 to 15:58:53 Split winding differential relays operate---sending a trip signal to 3018---which is already open*

On arrival at the station, the field operator noted extensive damage between the reactor and the PCB, but the arc had extinguished. Following discussion with the Transmission Operator (TOp), the field operator checked the PCB open and then proceeded to attempt to clear the reactor/breaker by opening the isolating disconnect switches 3017 (one-at-a-time) on the transformer side of the reactors, using a hotstick, which is normal operating procedure.

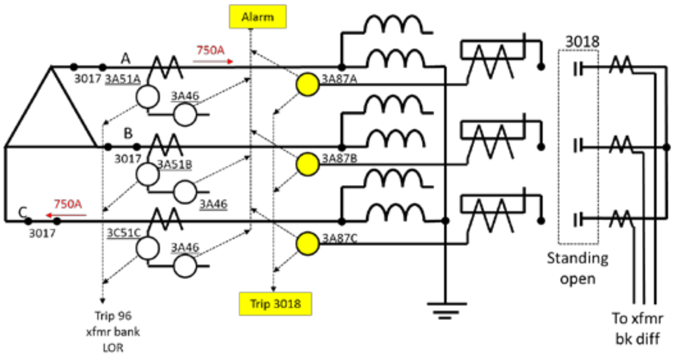

Fig. 6. *Sequence - By 16:00:50 (16 minutes later) Split winding CTs and buswork destroyed, leaving A- and C-phase stingers laying on grounded support steel*

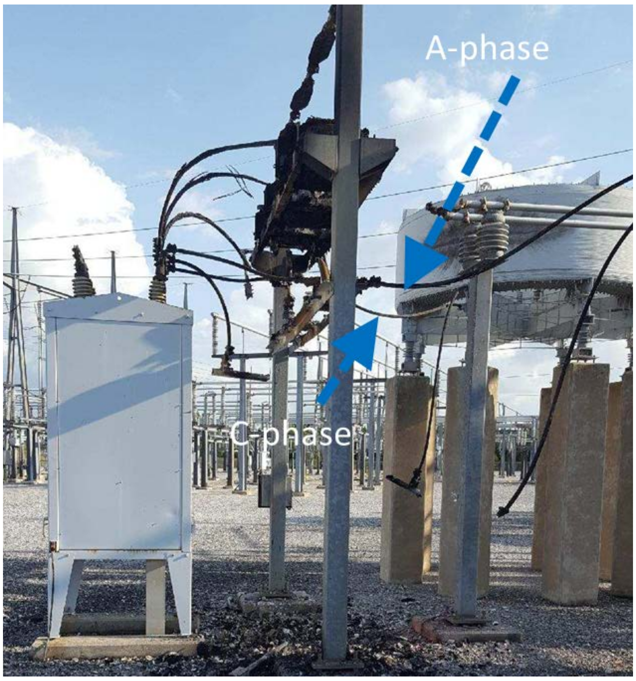

Fig. 7. *Sequence - By 16:00:50 (16 minutes later) Split winding CTs and buswork destroyed, leaving A- and C-phase stingers laying on grounded support steel*

Neither the TOp nor the field electrician/operator was aware the switch was carrying approximately 750 amps of current (13kV/(2*8.4Ω)) (Figure 6). When the field/electrician operator opened A-phase, the switch flashed over. The resulting three-phase fault directly over the head of the field operator was determined to be approximately 82 kA (Figure 10). The transformer bank protection operated properly within 100 milliseconds (5.5 cycles, normal & acceptable) to clear the fault. The operator was not injured, but was badly shaken and could have been seriously injured or much worse, given he was only 15 feet directly beneath the severe arc and fault.

Fig. 8. *Good installation vs damaged installation*

Fig. 9. *Remains of bird*

A summary of the sequence is as follows:

1. Reactor protection 3A87 (split-winding differential) operated at 15:44 but only trips 3018 which was already open;
2. Even though 3018 showed open, two phases were tied together through broken conductors resting on structural steel, between the reactor and the CTs/breaker so that load current was flowing;
3. Negative sequence relay 3A46 only sends alarm, does not trip;
4. Both 3A87 and 3A46 relays indicated a “fault” between the high-side reactor CTs below 3017 and the open 3018 breaker; 3A51 overcurrent relay pickup is 3000A and so this relay never operated during the event
5. Load current flowing on two phases, not enough to operate the transformer bank differential relays
6. Disconnect switch 3017 opened under load
7. Switch flashes over three-phase (82kA)
8. Transformer bank differential relaying trips transformer bank in 100ms (5.5 cycles), deenergizing 13kV switchyard and severely damaged shunt reactor bank 3018.

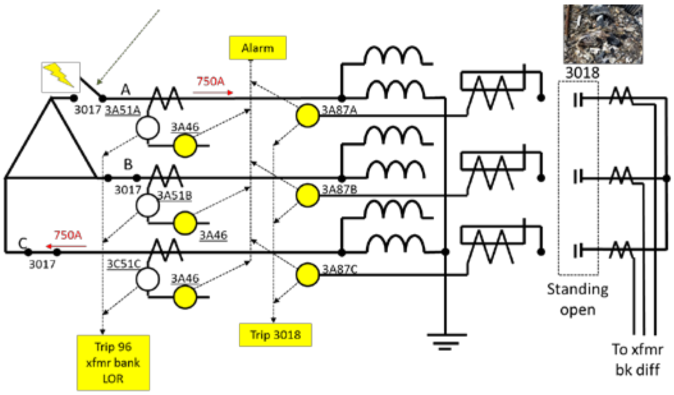

Fig. 10. *Sequence - 18:21:38 Operator attempts to open 3017A under load using hotstick*

Figure 11 shows the location of the fault and the relays that operated.

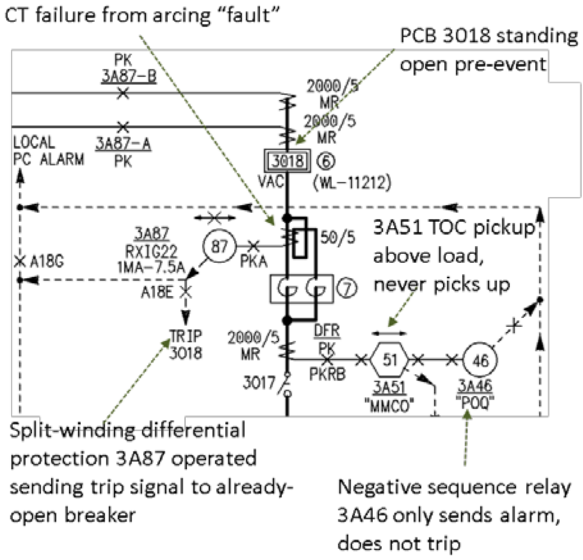

Fig. 11. *Location of damage and relays that operated*

Fig. 12. Side view photo - 3018 shunt reactor, with dimensions

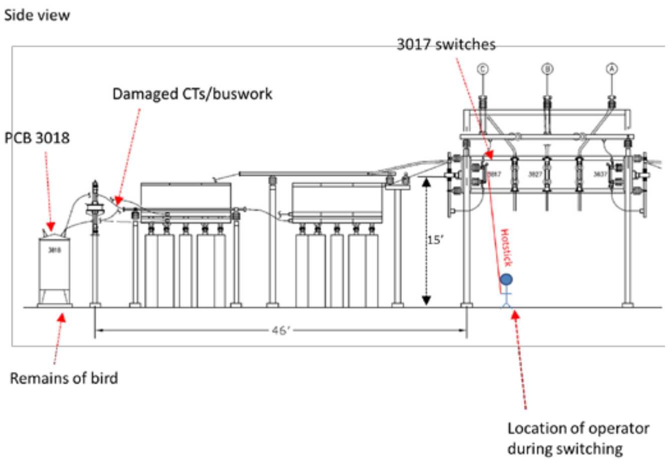

Fig. 13. Side view photo - 3018 shunt reactor, with dimensions

IV. Protection Questions

Two questions were addressed regarding protection, one concerning transformer bank differential protection, and one concerning tertiary bus ground fault detection.

A. Transformer Bank Differential Protection

During the period of time when load current was flowing to two phases of the reactor, it was questioned why the transformer bank differential protection did not operate. TVA reviewed the protection and the conditions and determined the differential relay pickup and slope characteristics prevented that protection from operating (properly restrained). This would be true even if all three 45MVAR shunt reactor banks had been in service.

B. Tertiary Bus Ground Fault Detection

The tertiary ground fault alarm relay 74GB did not operate during this event. It was initially thought this alarm would have activated given the nature of damage. However, all components of this scheme tested successfully with no issues found, including the grounding bank PTs and resistor, the GE HGA relay itself, and the local and SCADA alarms. As a result, it was concluded that a single-phase-to-ground condition did not occur during this event. Either all three phases between the reactor and breaker were grounded, or at least two phases were grounded. Calculations indicated the 74GB would not pickup for two phases grounded (only 188 volts applied to the HGA relay having a 325 volt pickup).

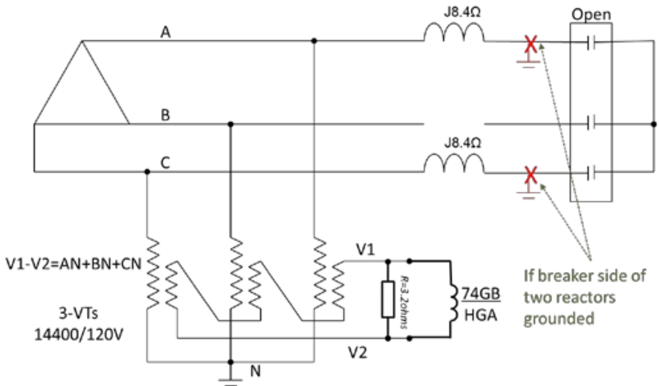

Fig. 14. *Tertiary ground detector - circuit diagram two reactors grounded*

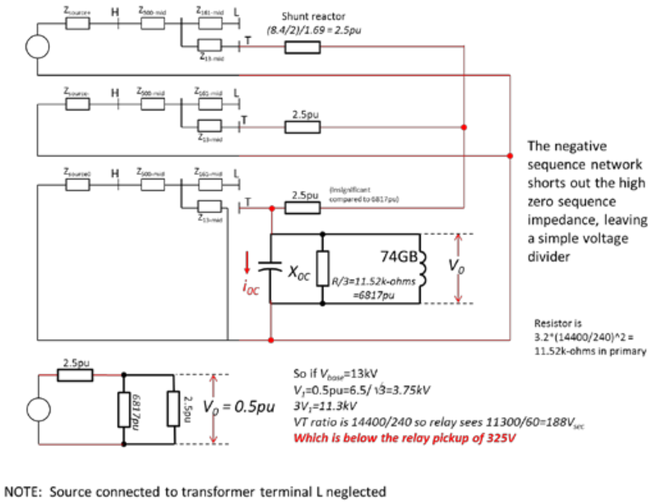

Fig. 15. *Tertiary ground detector - circuit analysis two reactors grounded*

V. Post-Event Actions

Following the event, TVA decided on the following short-term actions to mitigate the danger to personnel and equipment:

- When performing routine or emergency switching on any 13/26kV tertiary bus equipment in 500kV substations, de-energize the 13/26kV yard by de-energizing the 500kV transformer first, perform switching and then re-energize the transformer bank.
- Launch projects to modify shunt reactor protection (16 sites plus 2 future)

- Consider how to deploy a breaker failure protection scheme that could be used to help mitigate this type event (have stakeholders review the scheme to be implemented, including Planning, P&C Design, Operations, Field, etc)
  - Negative sequence relaying should trip reactor breaker (and arm breaker failure) rather than alarm only
  - Once a suitable breaker failure scheme is developed, consider making it the standard
- Alarms should provide clear indication of trouble to operator
- Refresher training for TOp/field:
  - How to handle tertiary bus alarms
  - Stress that these are the only breakers on the TVA system that do not de-energize the equipment (disconnect from source). They simply open the circuit on one end under normal switching operation
- Consider insulating the conductors (e.g., with Raychem or similar material) on 13kV/26kV tertiary buswork (between reactors and breaker only) to prevent animal-caused faults
- Modify the tertiary ground protection to trip the transformer bank within 1 second of receiving a tertiary ground alarm in all 500-kV substations to prevent the possibility of a phase to ground fault evolving into a high-energy multiphase fault
- Add tertiary ground protection to trip the transformer bank at locations not having it (5 sites)

A. Extent of Condition

TVA performed an extent-of-condition with the following findings:

- TVA has 63 shunt reactor banks located at 18 substations, 45MVAR each, rated 13kV, neutral ungrounded.
- Each has a switching device located on the neutral side of the reactor bank that makes up the neutral.
- 40 banks are single winding, 23 are split winding.
- 12 have breaker failure protection (current based only using 50BF).
- 27 have negative sequence elements (split winding reactors only) set to alarm only (remaining have no neg seq at all)
- In all but 2 installations, the overcurrent elements trip the transformer bank LOR (the remaining 2 trip only the reactor breaker).
- Differential/split-phase/unbalance trip the reactor breaker only.

Fig. 16. *Dual-blade non-ganged manually operated (via hotstick) single-phase disconnect switch 3017*

B. Industry Standard for Shunt Reactor Protection

The IEEE Std C37.109-2006 is the Guide for the Protection of Shunt Reactors. Some relevant points regarding the protection of dry type shunt reactors:

- C37.109 implies negative sequence relays will be connected to trip rather than only alarm (subclause 7.4.1): "*…negative sequence overcurrent relays. Relays should be set above the levels of unbalance seen in normal service either due to voltage unbalance or due to manufacturing tolerance of the reactor. Tripping should also be delayed to coordinate with reclosing times during single-phase tripping and reclosing and also with other protection devices that operate external to the reactor.*"
- Regarding tertiary bus ground fault protection, C37.109 states the following:
  - Subclause 7.3 states "*If there is a strong possibility, due to physical arrangement, for example, of a phase-to-neutral fault evolving to a phase-to-phase fault, this fault should be detected as quickly as possible and the reactor isolated by tripping its associated switching device.*"
  - It is "*accepted practice*" to alarm only on tertiary bus ground faults (subclauses 7.4.2), although no guidance is provided on what operators are actually to do on receiving such alarms.
  - Table 4 in subclause 9.0 states for Miscellaneous faults that an Alarm may be provided to provide "*sufficient time required for operators to respond*", although again, no guidance is given on what operators might actually do when the equipment remains energized with a standing alarm.

- Subclause 7.4.3 states, "*…if the bus ground relay only provides an alarm, it is generally considered desirable to keep the reactors in service during the ground fault.*"

- Protection for turn-to-turn faults is typically provided by a voltage unbalance scheme (subclause 7.4.3, Figures 4a and 4b) for single-winding reactors, while a split winding differential using an overcurrent relay is common for split winding reactors (subclause 7.4.3, Figure 5).

C. TVA Standard for Shunt Reactor Protection

The TVA standard addressing shunt reactor protection stated the following:

- Negative sequence relays alarm only.
- Shunt reactor banks are included in the transformer bank differential zone to cover phase-phase and three-phase faults.
- For turn-to-turn fault protection, voltage unbalance with system unbalance compensation is used for single winding reactors, while the split winding differential is used for split winding reactors.
- Breaker failure is to be provided, but is only specified if the reactor bank has a breaker on the bank side (which TVA no longer has).

D. Revisions to TVA Standard for Shunt Reactor Protection

Based on this event, TVA has revised its standard for shunt reactor protection as follows:

TABLE I. REVISED STANDARD - SINGLE WINDING SHUNT REACTOR PROTECTION

Element	Original Design	Revised Design
46 negative sequence	Not installed	Trip reactor breaker & arm BF
51 phase overcurrent	Trip transformer bank	Trip reactor breaker & transformer bank
59 neutral unbalance	Trip reactor breaker	Trip reactor breaker & arm BF
87 reactor winding differential	Trip reactor breaker	Trip reactor breaker & transformer bank
50BF reactor breaker failure	Not installed	Trip transformer bank

TABLE II. REVISED STANDARD - SPLIT WINDING SHUNT REACTOR PROTECTION

Element	Original Design	Revised Design
46 negative sequence	Alarm only	Trip reactor breaker & arm BF
51 phase overcurrent	Trip transformer bank	Trip reactor breaker & transformer bank
87 reactor split winding differential	Trip reactor breaker	Trip reactor breaker & arm BF
50BF reactor breaker failure	Not installed	Trip transformer bank

Note the protection for turn-to-turn faults is provided by the 59N element for single-winding reactor banks, while the 87 reactor split-winding differential provides that protection for split-winding reactor banks (hence, no 59N element for split-winding reactor banks).

Figure 17 shows a functional diagram for the revised standard for split-winding shunt reactor protection.

The revised standard includes redundant primary (A-set/B-set) microprocessor relays capable of all functions listed in Tables I and II and illustrated in Figures 17 and 18.

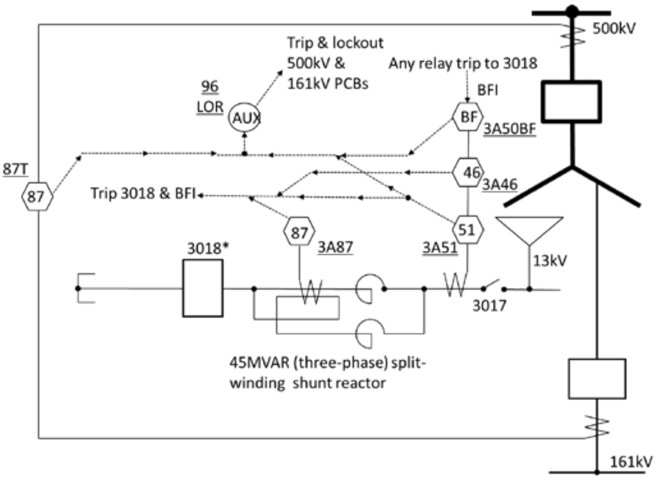

Fig. 17. *Revised standard for split-winding shunt reactor protection*

Note the reactor breaker failure logic will be based on both phase current (50BF) and reactor breaker status (52b) (see Figure 18). Note for the event described in this paper, the reactor breaker was standing open, so current detectors alone would not be sufficient. The lower AND gate in Figure 18 would be necessary for this event, so that with the breaker standing open, any current flow would start the breaker failure timer and proceed to trip and lockout the transformer bank, deenergizing the shunt reactor. Two separate 52b contacts are used for security.

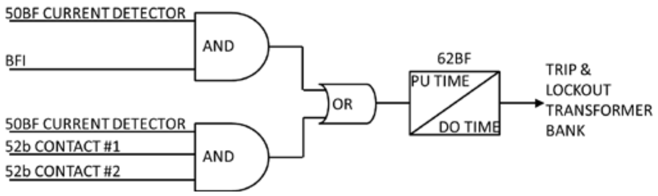

Fig. 18. *Breaker failure logic include 50BF current detector and breaker position*

With these protection changes, the event discussed would have resulted in tripping the transformer bank via breaker failure in less than one second (15 to 20 cycles), deenergizing the arc along with the associated shunt reactor bank. Compare Figures 17 and 18 with Figure 1.

In addition, a tertiary ground fault condition will result in tripping the transformer bank after 15 cycles, rather than alarm only. This decision was based on the conclusion that there is really nothing for the field operator to do once a single phase becomes grounded on the tertiary bus, and should a second phase become grounded, the resulting arc and fault current would be extremely dangerous. Regarding the loss of the transformer bank, this contingency is already studied in the real-time state estimator, and is no worse than losing the transformer bank for any other type of protection system operation.

This function is implemented in the redundant primary microprocessor relays used for the transformer bank differential protection. Three phase tertiary bus voltage is connected to both transformer bank relays which also provide built-in oscillography.

Also regarding tertiary bus ground fault detection, there was some discussion of lowering the pickup from 325 volts to somewhat less than 188 volts, so that the scheme would also pickup on double-line-to-ground faults on the tertiary bus. But it was noted that any such fault between the transformer bank bushings and the reactors would be detected and cleared by the transformer bank differential relaying, and any such “fault” between the reactors and the reactor breaker would be detected and cleared by the revised protection scheme (i.e., negative sequence along with subsequent breaker failure). Thus, the 325 volt pickup will remain the setting for this scheme, as it only needs to detect single-line-to-ground faults.

VI. Conclusion

This event illustrated the need for a thorough evaluation of protection as applied to dry type shunt reactor banks connected to an ungrounded 13kV delta tertiary bus.

Sending alarms to the Transmission Operator is inadequate if appropriate direction is not provided regarding actions to be taken. In this particular case, neither the Transmission Operator nor the field operator understood the significance of the shunt reactor negative sequence overcurrent alarm. The resulting safety risk led to changes in operating practice (no live switching in such 13kV switchyards) and in future design practice (assuring the yard is deenergized automatically by protective relaying on detection of a fault or abnormal operating condition).

It is strongly suggested that other utilities review their operating and protection practices and philosophy for such arrangements in order to limit equipment damage and keep personnel safe.

Acknowledgment

The author would like to thank the TVA Starkville Transmission Service Center for their assistance in analyzing this event.

References

[1] IEEE Std C37.109-2006 Guide for the Protection of Shunt Reactors

[2] TVA ESP-SP-DES-09.100 Substation Project Protection & Control Engineering & Design Standard

Biography

Gary Kobet is an Electrical Engineer for the Tennessee Valley Authority (TVA) in Chattanooga, Tennessee. His responsibilities include machine and voltage stability studies for the operating horizon, developing operating guides, and disturbance analysis. Previously he worked in the System Protection department scoping relaying schemes for transmission and generation projects, as well as developing relay set point calculations. He has performed transient studies using EMTP for transient recovery voltage, ferroresonance, and switching surge overvoltage. Previously he worked as a field engineer and as power quality specialist. Mr. Kobet earned the B.S.E. (electrical) from the University of Alabama in Huntsville in 1989 and the M.S.E.E. from Mississippi State University in 1996. He is a member of the IEEE/PES Power System Relaying and Control Committee, and is a registered professional engineer in the state of Alabama. Presently he is serving on the NERC/IEEE Task Force on Short-Circuit and System Performance Impact of Inverter Based Generation.