Lessons Learned in Static Var Compensator Protection

Aaron Findley, Mychal Hoffman, *POWER Engineers, Inc.*
Dan Sullivan, Jan Paramalingam, *Mitsubishi Electric Power Product Inc.*

***Abstract* — Static VAR Compensators (SVCs) are an increasingly common solution for power system voltage stability problems by providing rapid var support following system disturbances. From a protection perspective, an extensive protection system is typically necessary to ensure the SVC's operating range is available to provide rapid and reliable var support to the power system. SVC protection often involves novel applications of traditional protective relay schemes, and coordination of protective control functions with SVC controls. One example of this is the use of multifunction current differential relays to protect Thyristor Controlled Reactors (TCR) or Thyristor Switched Capacitors (TSC). In these applications some features of modern relay systems, such as harmonic blocking, may serve no purpose but can adversely affect the performance of the protection system if ignored or applied incorrectly.**

This paper provides an overview of common approaches to SVC protection focusing on TSC, TCR, and Harmonic filter branches. An analysis of event reports for TSC and TCR faults are presented to demonstrate the strengths and weaknesses of typical protection methods, and to highlight common misconceptions in the application of differential relays to delta connected reactive elements.

I. Introduction

Static var compensators are shunt-connected static var generators or absorbers whose outputs are varied to control specific parameters of the system. The term "static" is used to indicate that SVCs, unlike synchronous compensators have no moving or rotating main components. A variant is an "SVS" or static var system which is an aggregation of SVCs and mechanically switched capacitors or reactors whose outputs are coordinated.

Each SVC is custom designed to meet the specific system requirements, but commonly include a step down transformer and one or more shunt connected reactive components that are switched or controlled using power electronics. Examples of SVC applications in electric transmission systems are discussed in [B7-B10].

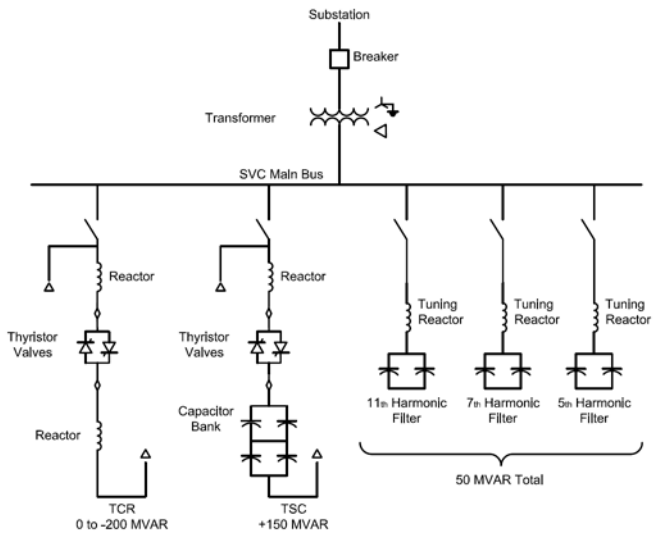

Figure 1: A Typical SVC Single Line Diagram

Following are the basic types of reactive power components which make up all or part of static var systems in addition to traditional fixed reactive components.

- Thyristor-controlled reactor (TCR)
- Thyristor-switched reactor (TSR)
- Thyristor-switched capacitor (TSC)
- Harmonic filters

TSCs and TCRs are the most commonly used components.

Static var systems are capable of controlling individual phase voltages of the buses to which they are connected. They can be used for control of negative-sequence as well as positive-sequence voltage deviations, and are primarily used for three phase control of the power system.

These systems are ideally suited for applications requiring direct and rapid control of voltage since they provide faster response times and repetitive switching capability compared to traditional mechanically switched devices, and can provide continuous and smooth control of vars over the designed rating of the SVC.

I. TSC: Thyristor Switched Capacitors

TSCs consist of capacitor banks split into appropriate sized units, each of which is switched into or out of the system by a

bidirectional switch, often anti-parallel thyristors. In three phase applications, the units are typically connected in delta. An integral cycle control is used where a change can be made every half cycle. Because the capacitor banks will retain some charge after the thyristors have disconnected them from the system, they are switched in when the SVC bus voltage and the capacitor voltages are approximately equal. The implication of this control is that the TSC will always provide rated vars for finite period of time. Generally speaking this type of control does not generate harmonics.

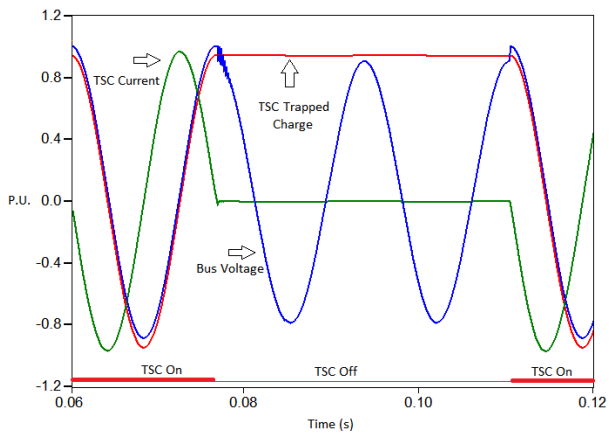

Figure 2: Waveform showing TSC switching

II. Thyristor-controlled reactor (TCR)

The basic elements of a TCR are the reactor in series with a bidirectional switch, often anti-parallel thyristors that conduct on alternating half-cycles depending on firing delay angle of the thyristors. Thyristor-controlled reactors can draw inductive currents ranging from zero to full load currents for the reactor. The TCRs can also be used to selectively cancel out a portion of the vars sourced by a TSC or filter bank. With TCRs an SVC system as a whole is able to both sink or source vars continuously over its rated range. The continuous control of vars requires TCRs be exposed to the system for only a portion of each half cycle. This is accomplished by delaying the firing angle of the thyristors to reduce the total inductive current drawn by the reactors.

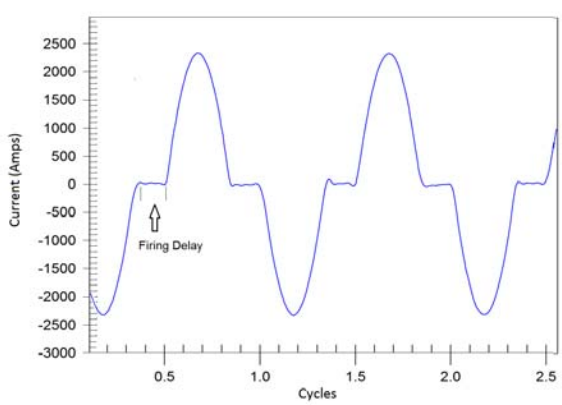

Figure 3: Current trace from an event report showing the non-sinusoidal current draw

Due to the non-sinusoidal current draw, a significant amount of harmonics are generated by the TCR switching.

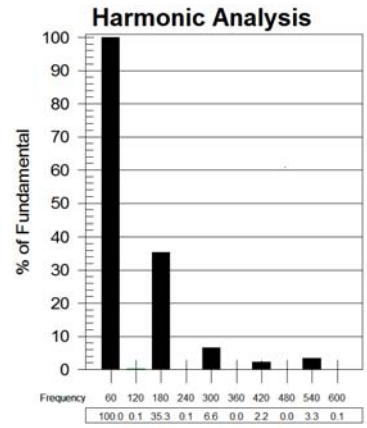

Figure 4: Harmonic analysis for the waveform shown in Figure 3.Harmonic magnitudes are in percentage of measured fundamental current.

Assuming the switching is symmetrical, only odd harmonics are generated and can be calculated using the following equation as a function of the delay angle "a".

$$In(a) = \frac{V}{Xl}\frac{4}{\pi}\left\{\frac{\sin(a)\cos(na) - n\cos(a)\sin(na)}{n(n^2-1)}\right\}$$

Where:

V is the system voltage
Xl is the inductive reactance
a is the delay angle
n is the harmonic.

Figure 5 shows a plot of the relative magnitude of the harmonics over a range of delay angles. Absent from this plot are the triplen harmonics (3rd, 9th, 15th) which are canceled under balanced conditions when the TCR's are delta connected.

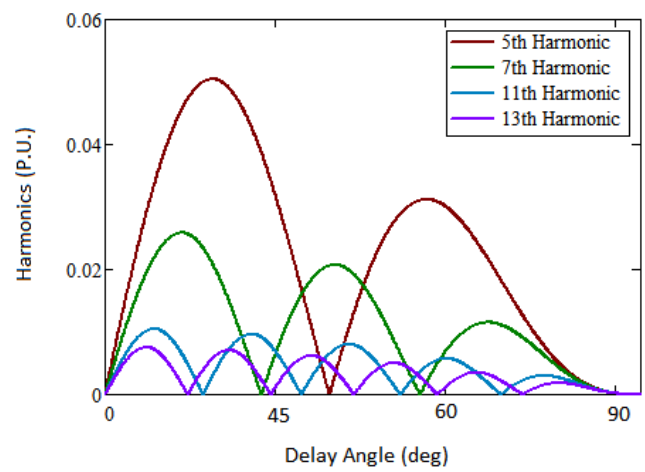

Figure 5: Harmonic content vs.delay angle for a TCR. Harmonic magnitude is in per unit of the maximum fundamental current at a delay angle of 0.

SVCs that employ TCRs typically require harmonic filter banks to deal with the harmonics generated by the operation of the TCR. The size and number of filter banks applied are determined through harmonic performance analysis to limit voltage distortion at the point of connection while minimizing resonance conditions with the power system. Depending on the results of system studies, the filter banks may include a damping resistor to aid in appropriate tuning of each filter bank.

A. RMS vs Filtered currents.

Microprocessor based protective relays typically utilize digital filters within the relay's software to remove any decaying dc offset or harmonics, allowing the protection algorithms to operate on filtered fundamental currents. The relays that captured the events presented in this paper employ low pass filters, scaling, and a full-cycle cosine filter. The cosine filter multiplies successive samples coming from the A/D converter by coefficients sampled from a cycle of a cosine waveform according to the following formula:

$$I_{Filtered} = \frac{2}{R}\sum_{n=0}^{R-1} cos\left(\frac{2\pi n}{R}\right) * I_{[sample-(R-1)]+n}$$

Where:

R is the sampling rate in samples/cycle

The output of this digital filter is a fundamental frequency sinusoidal waveform because the harmonic content has been removed the RMS value of the filtered current will be less than the actual RMS current through the reactor. Figure 6 shows the unfiltered and filtered current measured by a relay on a TCR branch. The harmonic distortion level varies as the SVC's control system adjusts delay angle of thyristor valve as illustrated in Figure 5 above. Typically, the TCR generates the least amount of harmonics when the TCR valves are fully conducting. This is convenient since the filtered current used by protective relays more closely matches the true RMS current as the TCR branch approaches full load.

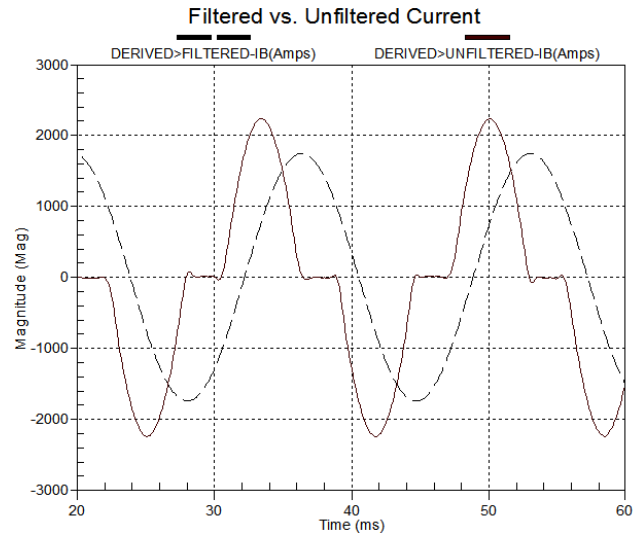

Figure 6: Actual measured unfiltered and filtered TCR current waveforms as seen by the protective relay

Traditionally, the reactive and resistive components that make up SVC filter banks are rated to withstand the harmonic currents generated by the TCR and any background harmonics that are present in the power system. If more sensitive protection is required for some components, such as the damping resistors, protective elements that operate on RMS currents should be used.

II. TCR AND TSC DIFFERENTIAL PROTECTION

Traditional percentage differential protection employs three differential zones, one for each phase of the protected equipment; transformer, bus, etc.

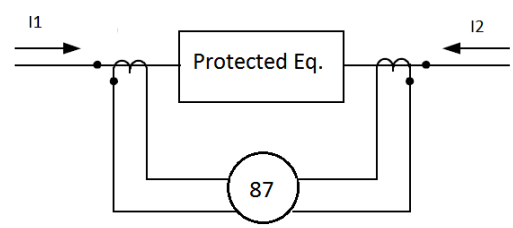

Figure 7: Traditional Differential Protection

The operate current is calculated as the sum of the input currents.

$$I_{op} = |I1 + I2|$$

There are two common methods for calculating the restraint current; average and maximum restraint

$$I_{average\ restraint} = k(|I1| + |I2|)$$

$$I_{\max\ restraint} = max(|I1|, |I2|)$$

A fault is declared when the ratio of operate to restraint current exceeds a predetermined threshold defined by the slope setting.

$$\frac{Iop}{I_{restraint}} > Slope$$

In SVC applications, TCRs and TSCs are typically delta connected. The delta connection often results in the bus work being installed in a phase-over-phase configuration as illustrated in Figure 8.

Figure 8: TCR & TSC Vertical Bus Configuration. Conductors are entering and returning from the thyristors valves located in the control building.

The phase-over-phase configuration is used to minimize the physical size of the SVC yard, relative to a horizontal configuration that is typically used in substation design. One drawback is the vertical phase-over-phase configuration increases the probability of phase-to-phase faults in the delta connected TCR or TSC. Three differential zones are assigned such that each zone will encompass one set of thyristor valves and one reactive component as shown in Figure 8. The zones will overlap at the thyristor CTs.

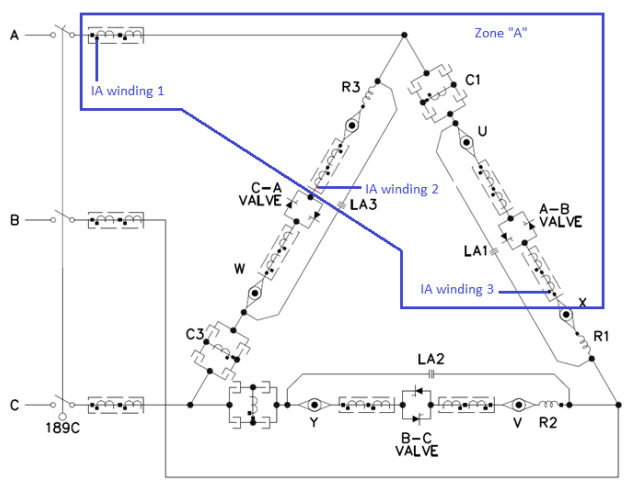

Figure 9: Typical TCR/TSC Differential Zone.

Although the reactors are delta connected, the CT's of each zone effectively wrap a single electrical node and will not require any additional compensation for the phase shift between line and delta currents.

III. Event Analysis TSC Fault

The first example considers a fault that occurred when ice formed on the animal guards of adjacent insulators, resulting in a short circuit between phases of the delta connected, thyristor switched capacitors. Figure 10 shows the location of the fault based on visual inspection of the equipment. The thyristor valves were not conducting at the time of the fault, however when the ice shorted the thyristor valve and tuning reactor, connecting B and C phases through the capacitor bank. The resulting current draw was high in harmonics and of a magnitude near the capacitor bank rating.

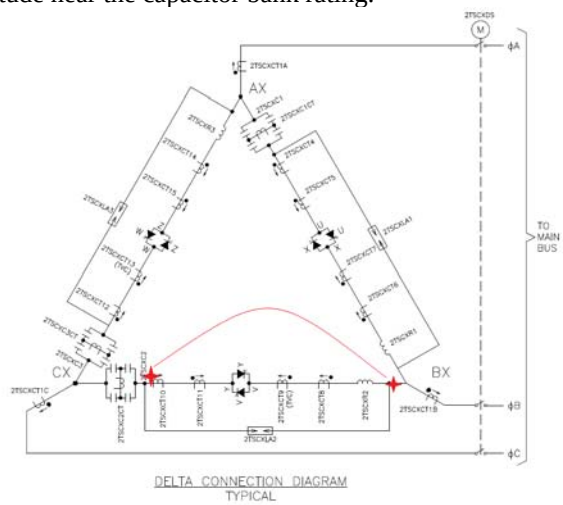

Figure 10: Location of TSC fault.

The differential relay protecting the faulted section failed to operate even though the fault was located within the zone of protection. Because the fault included the capacitor bank impedance, the magnitude of the fault current was limited to the banks rated current. The fault, which started as a line-to-line fault, quickly evolved to include ground. The system had a ground bank installed that provided some ground fault current on an otherwise ungrounded secondary, the fault was ultimately cleared by a ground overcurrent relay. Negative-sequence overcurrent elements also quickly identified the fault but had been set with a longer time delay than the ground overcurrent element.

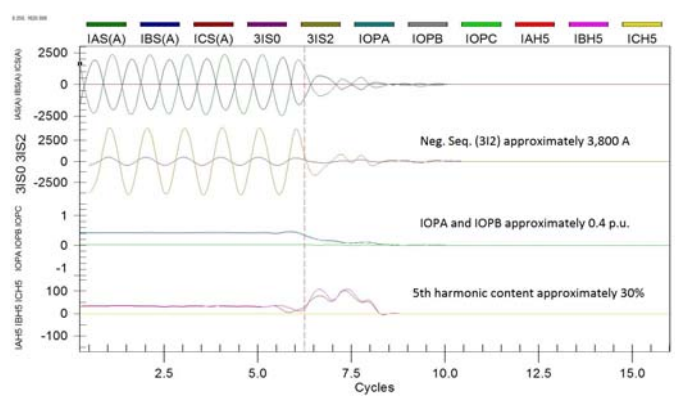

Figure 11: Event report indicating the level of operate, negative-sequence, and hamonic currents.

A review of the relay settings and event report indicated that the ratio of differential to restraint current was sufficient to warrant a trip however, operation of the differential was blocked by the 5th harmonic blocking logic. Further investigation showed that the 5th harmonic blocking threshold had been set at the minimum allowable pickup of 5% of fundamental. The unfiltered event report was retrieved and indicated the level of 5th harmonic current was approximately 30% of fundamental. The high harmonic content is likely due to the presence of reactive elements in the fault path.

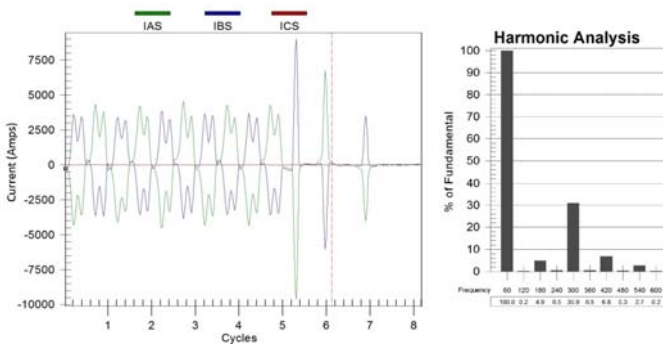

Figure 12: Unfiltered event report showing significant harmonic distortion in the fault current.

A. Harmonic Blocking Logic

Harmonic blocking logic is a feature that is included in differential relays to prevent misoperation of the differential element during inrush or overexcitation conditions commonly associated with transformer energization.

Inrush occurs when a transformer is energized and the residual flux in the transformer core does not align with the ideal instantaneous flux that would exist given the applied voltage. The resulting flux required can be large enough to drive the core into saturation, at which point increasingly higher levels of magnetization current is required to achieve relatively small increases in flux. In severe cases of inrush, the magnetizing current is limited only by the air-core impedance of the transformer windings. Referring to Figure 13, the magnetization current is essentially shunted through the magnetization branch of the transformer equivalent circuit and does not appear on the secondary winding, resulting in a measured differential current.

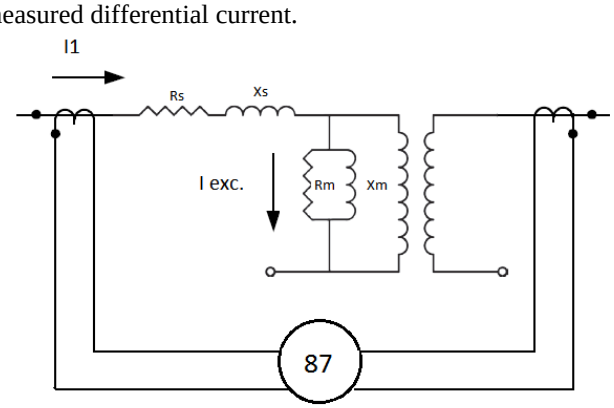

Figure 13: Path of magnetization current in transformer equivalent circuit.

Generally the second or fourth harmonics are used to identify an inrush condition. A similar differential current occurs when a transformer core is overexcited. The flux in a transformer core is proportional to the applied voltage and inversely proportional to the frequency [B3]. When the applied voltage is too high or the frequency too low the resulting transformer core can be driven into saturation. The core saturation results in higher excitation current that is again shunted through the magnetization branch and interpreted as a differential current. The excitation current during AC saturation is high in odd harmonics including the third, fifth, and seventh. The third harmonic is typically the highest as a percentage of fundamental current however, this harmonic is eliminated by either a delta connection of the relay CT's or a simulated delta connection within the relay itself. Therefore a high fifth harmonic content is used to indicate an overexcitation condition.

Given the preceding discussion the following lessons learned can be applied when setting TCR and TSC differential relays.

- Harmonic blocking and restraint are based on detecting the signature harmonics generated by the saturation of a ferromagnetic core. When air core reactors are used in TCRs, these elements are not applicable and should be disabled.
- In transformers, false differential current is produced when the transformer saturates and excitation current entering one winding is shunted through the excitation branch and is not measured leaving the protected zone. In TCR and TSC differential applications the entire reactive element and thyristor valve combination is wrapped by the differential zone. Inrush currents or other transient currents will travel through the zone of protection and be accounted for, no additional restraint or blocking logic is required.

IV. Event Analysis, Trip on Controlled Shutdown

In some installations, the SVC controls will allow for a protection stop or a soft (normal) stop. A protection stop results from either a protective relay or SVC control system trip which both opens the SVC breaker on high-side of the coupling transformer and signals the valve controls to gate block the thyristor valve, stopping conduction. For less critical failures of auxiliary equipment or operator initiated shutdown, the SVC is taken offline in a more gradual manner referred to as a "soft" or "controlled" stop. During a soft stop the SVC output is adjusted to zero and then the SVC breaker is opened to disconnect the SVC from the power system. Then the TCR valves are placed into full conduction for several cycles to allow the TCRs to quickly discharge the energy stored in the filter bank capacitors. The discharge step is required due to the capacitive nature of filter banks, and the desire to be able to quickly bring the SVC back online without waiting up to 5 minutes for the filters to discharge via an internal discharge device. Bringing the SVC back online quickly is particularly critical at installations that are designed to automatically restore operation in a degraded mode following a fault on a TSC or TCR branch. For example, following a fault on a TSC

branch, the SVC can shutdown, open the TSC disconnect, and restart with the TCR and filter banks providing partial functionality. During a controlled shutdown, while the TCR is fully conducting, unbalanced currents will flow between the filter bank and the TCR. The amount of unbalance is dependent on the point on wave at which the TCRs are placed into full conduction.

Figure 14 shows TCR current waveforms and the associated relay response during a controlled SVC shutdown sequence.

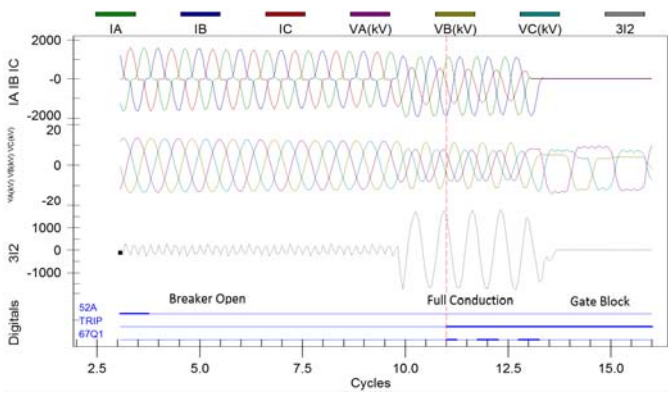

Figure 14: Event report showing the TCR currents and TCR relay response to a controlled shutdown.

The relay was monitoring the delta currents of the TCR and was set to provide phase and negative-sequence overcurrent protection. The trip/event was triggered during the discharge phase of the shutdown when the TCR valves were fully conducting and the relay measured a negative-sequence current of approximately 800A, which is 30% of the rated current. At this point in the shutdown sequence the circuit breaker was already open however, the control system was set up such that any protective trip would also result in the TCR valves being blocked. This can be seen in Figure 13 as the current through the TCR branch was blocked approximately 30ms following the trip. The intended discharge time was closer to 20 cycles. In addition to prematurely halting the filter bank discharge phase, the trip indication would have prevented the TCR from being included in any auto-degraded mode configuration.

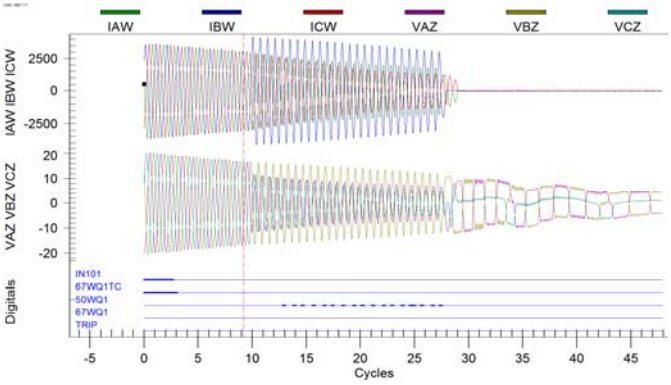

Figure 15: Full shutdown sequence with negative-sequence elements supervised by breaker status.

For reference, Figure 15 shows a full shutdown sequence. The negative-sequence overcurrent element in this relay had been torque controlled by the breaker status to prevent the relay from tripping after the breaker had opened.

This event highlights a few lessons learned for the protection engineer when developing protective relay settings for an SVC:

- Depending on the SVC control design, significant unbalance currents may flow during a shutdown even after the breaker has opened.
- Nuisance trips that occur during a controlled shutdown can interfere with SVC operations, and halt auto-reconfiguration schemes.
- Negative-sequence elements protecting SVC branches should consider any intentionally unbalanced operations, either due to un-symmetrical operation or filter bank discharge.

V. Event Analysis, TCR Fault

Turn to turn faults in air core reactors are notoriously difficult to detect. The change in current measured external to the reactor can be relatively small depending on the location of the fault. In this example, a turn to turn fault developed in a TCR reactor. Sensitively set negative-sequence alarms indicated that the fault may have developed minutes before finally evolving to include an additional phase. Once the fault had coupled to an adjacent phase, the differential elements were able to clear the fault. While event data for this fault is somewhat limited, photos of the damage shown in Figure 18 highlight the destructive nature of turn to turn faults. Since TCRs are typically air core reactors the protection options are further limited as mechanical detection of arcing available in oil filled reactors (such as sudden pressure relays) are not available.

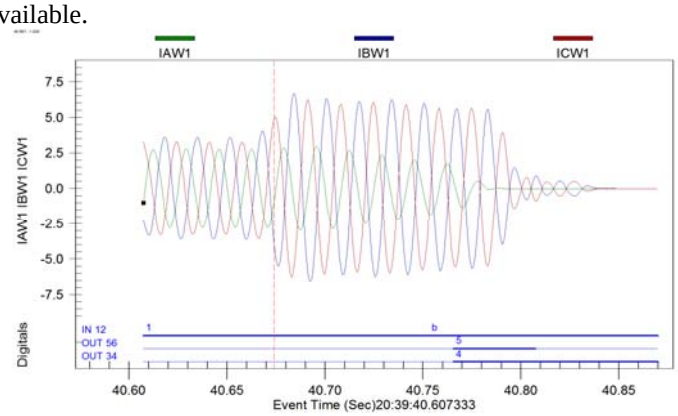

Figure 16: Fault currents in secondary amps as a turn-to-turn fault evolves into a phase fault.

Despite the small current change seen at the reactor terminals, the current magnitude at the point of the fault can be significant. Differential protection is limited for this type of fault because shorting successive windings of the reactor will not alter the overall current through the protective zone. Even if the entire reactor were to be shorted, the sum of the currents through the zone would be zero unless another phase was involved.

The reason turn-to-turn faults are so damaging can best be understood by considering the ideal transformer model. The ratio of primary to secondary current is related to the primary and secondary turns ratio by the familiar equation:

$$I_{SECONDARY} = I_{PRIMARY} \frac{N_{PRIMARY}}{N_{SECONDARY}}$$

When a reactor suffers a turn to turn fault it is essentially behaving as a transformer, with the "secondary" winding being comprised of the few turns that are shorted.

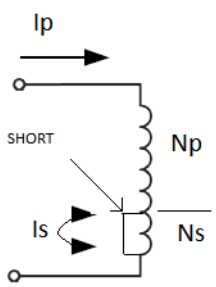

Figure 17: Currents in a turn-to-turn fault

For low level faults with only a few turns involved the effective turns ratio is high leading to large secondary currents circulating in the shorted turns.

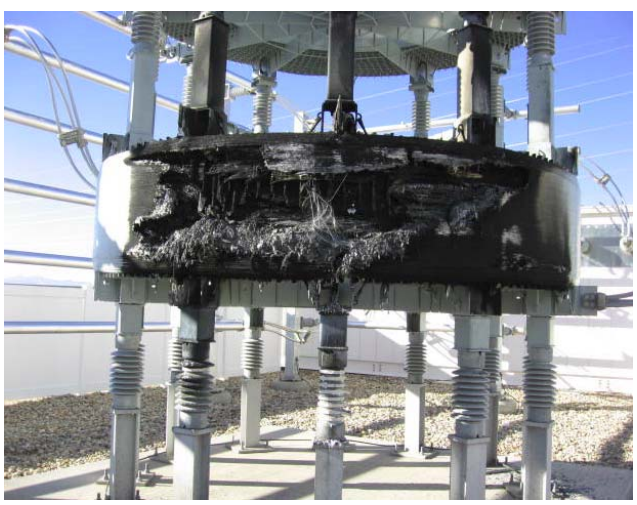

Figure 18: Reactor damage caused by turn-to-to turn fault.

The options for detecting these types of faults are limited. Negative-sequence current elements can detect some of turn-to-turn faults but are less sensitive to lower level faults. Traditional voltage unbalance schemes that rely on the neutral connection of a wye connected reactor bank are also not an option due to the delta connection of the TCRs.

For some SVCs, sensitive unbalance protection could be possible by summing the delta currents directly to measure the reactor unbalance current [B6]. This approach cannot be applied on SVC's that are intended to operate unsymmetrically, and will have to be insensitive to the triplen harmonics that will circulate in the TCR delta connection. The lesson learned from this event is to be aware of the limitations of the applied protection scheme, depending on the SVC design a high degree of sensitivity for all fault types may not be practical.

VI. Conclusion

SVC protection involves atypical applications of traditional protective relay schemes. Some features of modern relay systems, such as harmonic blocking, may serve no purpose but can adversely affect the performance of the protection system if ignored or applied incorrectly. Given the increasingly sophisticated algorithms used in modern microprocessor based relays, it is critical that the protection engineer understand both the intended purpose of each algorithm as well as the context in which they are being applied.

Careful consideration must also be given to the SVC operation and the protection requirements of the power electronics equipment. Protective relays must be coordinated with the SVC's control system protective schemes to prevent the unintended operation of protective relays during shutdown sequences or other periods of intentional unbalanced operation.

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VIII. Biographies

Aaron Findley, P.E. is a protection engineer with POWER Engineers Inc. and is based out of Portland OR. While at POWER Mr. Findley has worked on a wide variety of protective relaying projects ranging from distribution protection up to EHV series compensated line protection and RTDS modeling/testing. He has recently served as the lead protection engineer on several SVC installations. He earned his bachelor's degree in Energy Engineering from the Oregon Institute of Technology in 2010 and is currently registered as a Professional Engineer in the state of California and a member of IEEE.

Mychal Hoffman, P.E. is a registered professional engineer with over 12 years of substation physical and electrical design and testing experience with an emphasis on the implementation of FACTs devices into utility substations. He earned his bachelor's degree in Computer Engineering from South Dakota School of Mines and Technology in 2002 and his master's degree in Electrical Engineering in 2005. During this time he published papers relating to electric load forecasting using Fuzzy Logic-Neural Networks. Prior to joining POWER Engineers, Inc. in 2010, he has worked for Mid-American Energy and Electrical Consultants Inc. Mr. Hoffman is currently a Project Engineer in the Substation Department at POWER Engineers, Inc. He is currently registered in Montana, South Dakota, Pennsylvania, Maryland, Virginia, West Virginia and North Carolina. He is a member of IEEE, NSPE, MSE and the Billings Engineers Club.

Daniel Sullivan, P.E. currently manages Mitsubishi Electric Power Product Inc's (MEPPI) North American Power Electronics Product Line, providing both technical and commercial management of Mitsubishi Electric's Flexible AC Transmission Systems (FACTS) and HVDC business in North America. Dan's leadership of system engineering and sales/marketing teams ensures technical expertise of all FACTS (SVC/STATCOM) products, including engineering and system design aspects from initial planning stages through design, construction, and commissioning of FACTS systems. Mr. Sullivan has authored technical IEEE papers and publications, and lectured at the University of Wisconsin, University of Pittsburgh, and IEEE tutorials on topics such as Dynamic Reactive Power Control, Static Var Compensators, HVDC, and insulation coordination. Dan is a Senior Member of IEEE, registered Professional Engineer in Pennsylvania, earned MSEE degree from University of Pittsburgh and held leadership roles in PES Subcommittees and Working groups on HV Power Electronics.

Jan Paramalingam is a systems engineer in Mitsubishi Electric Power Products, Inc's (MEPPI) Power Electronics Product Line providing engineering design, apparatus engineering, and technical support for Mitsubishi Electric's Flexible AC Transmission Systems (FACTS) business in North America. He has been involved in many SVC projects, and is responsible for design of FACTS systems, including commissioning and testing of system performance. Jan has conducted numerous design and performance studies to determine SVC configuration, component ratings, and assess harmonic performance within the power system. He has a broad technical background of HVDC, FACTS, and Series Compensation products, including engineering and power system analysis aspects from initial planning stages through study, design, construction, and commissioning of FACTS systems. Jan is an active member of the Capacitor and HV Power Electronics Subcommittees within IEEE, and is currently WG P1531 chair.

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