Verifying Series Compensated Line Protection Scheme using Real Time Digital Simulators

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***Abstract*—The Transmission Network Service Provider (TNSP) in South Australia has increased the power transfer capacity of a 275kV double circuit line by installing a fixed 50% series compensation at approximately 50% line length. The design and performance of the line protection scheme has been verified by using Real Time Digital Simulators (RTDS). It is understood that the approach adopted was more rigorous than the accepted industry practice by including sophisticated generator models in the developed system equivalent model and connecting series capacitor controller panels into the closed loop testing. This paper presents the technical challenges and lessons learnt during RTDS testing.**

***Index Terms*—Line Protection, RTDS, SSCI, SSR, Series Capacitor Controller and Closed Loop Testing**

I. INTRODUCTION

THE Australian National Electricity Market (NEM) is the wholesale electricity market for the electrically connected states and territories of eastern and southern Australia. The NEM generates around 200 terawatt hours of electricity annually, supplying approximately 80% of Australia's electricity consumption. Among the interconnected transmission systems, the Heywood Interconnector, which was constructed in 1988, is located between South Australia and Victoria. Historically this interconnector has predominantly been used to import power into South Australia. However over the past few years, the Interconnector has been used to export power from South Australia, made available through the addition of significant amounts of wind generation in the state [1]. In the year of 2012, it was identified that a major market benefit could be achieved by expanding the transfer capacity of the Heywood Interconnector to increase both import and export capability between the two states.

As a result, the high voltage Transmission Network Service Provider (TNSP) in South Australia, has collaborated with the Victorian TNSP to increase the transfer capacity of the Heywood interconnector from 460 megawatts (MW) to 650 MW. As a part of the project, the South Australian TNSP has upgraded the 275 kV double circuit line, which is 308 kilometers (192 miles) long, between northern station (TAIL) and southern station (SEAS) by installing a fixed 50% series compensation at approximately 50% line length. For the sake of simplicity, the South Australian TNSP will, henceforth be referred to as the TNSP. A simplified connection diagram for the region is shown in *Fig 1*.

The insertion of series capacitors creates not only a number of localized challenges for the line protection system, such as voltage and current inversion, but also some unique challenges for the TNSP's regional network. This paper focuses on sharing the lessons learnt during the verification of the protection system using Real Time Digital Simulators (RTDS). In the paper, the technical challenges that were highlighted in this project, line protection requirements and designed protection system will be briefly reviewed. The preparation of RTDS testing will then be discussed. The paper will also describe the lessons and issues that were highlighted on protection system during RTDS testing in more detail. These include Transient Recovery Voltage (TRV), Zone 1 overreach, ground fault direction determination, single pole operation, sub-synchronous oscillation protection and series capacitor controller verifications in the closed-loop testing.

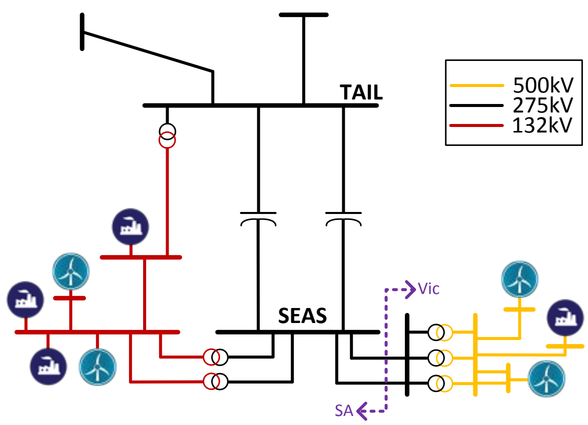


Fig 1. Simplified reginal diagram

II. PROTECTION AND CONTROL SYSTEM REQUIREMENTS

A. *Challenges for Protection Systems*

It is well established that the insertion of the series capacitor creates a number of challenges for the line protection system, such as inconsistent apparent impedance, voltage and current inversion. Similar to uncompensated transmission line protection, the double circuit is embedded with electromagnetic mutual coupling issue for significant zero sequence voltage and current that are difficult for protection relays to determine fault direction or apparent impedance.

As it is demonstrated in *Fig 1*, the significant penetration of renewable generation behind the southern substations could lead to dramatic variations in loading and fault level within a short period of time. The system studies, conducted during the project feasibility phase, identified that under multiple contingencies, there may have been a risk that the phenomena of Sub-Synchronous Resonance Control Interaction (SSCI) and Sub-Synchronous Resonance (SSR) phenomena may have had an impact on the network and connected generation. The study report also identified Transient Recovery Voltage (TRV) issues for the existing Circuit Breakers (CBs) at TAIL and SEAS stations.

The location of the 275kV transmission lines are within the identified high bush fire risk zone in South Australia. This condition mandates the protection relays to be able to accurately detect ground faults with a minimum resistive coverage of 150 Ω over the entire line. Furthermore, for the purpose of system stability, it is essential that the lines are capable of supporting phase segregated single pole tripping and high speed automatic reclosing operations. This requirement necessitates the protection relays have the ability to selectively determine fault type and location under all system conditions.

B. Operational Requirements

In recent years, the increasing renewable energy penetration and flat load profile within South Australia has led to the mothballing and closure of some traditional, fossil fueled generators within the State. This has placed an increased reliance on the availability of the series compensated double circuit, to support the dynamic electricity demand in South Australia. The following list of important operational requirements have been imposed on the line protection design.

1) SSCI protection, which is to remove series capacitors as soon as possible, shall be dependable and secure at all times;
2) Line protections shall be secure, dependable and sensitive to the detection of high resistance faults, required by high bush fire risk; and
3) The phase segregated, single pole tripping and high speed, automatic reclose schemes shall be available regardless of communication channel status.

The philosophy of single-pole tripping (SPT) and reclosing (SPR) for single line to ground (SLG) faults and three-pole tripping (3PT) and lockout (3PL) for multi-phase faults has been applied to the protected lines. Moreover, 3PT shall be executed and reclosing is blocked if any trip or transfer trip is initiated from the following protection functions:

- Time delayed distance protection;
- Directional earth fault protection (level 2 overcurrent element);
- Switch on to fault (SOTF);
- CB failure; and
- Stub protection.

C. Line Protection Scheme

The line protection scheme consists of a current differential and a directional comparison blocking (DCB) scheme for each series compensated circuit. The reason for this arrangement, instead of double differential scheme, is to achieve as much diversity as possible, thereby minimizing the risk of common mode failure. In addition, the DCB scheme is not reliant on the communication infrastructure for security and provides inherent back-up features. The selected unit and non-unit transmission line protection arrangement is also aligned to TNSP’s standard approach for an uncompensated line and allows the deployment of standardized equipment. Thus, it provides a level of comfort gained from operational experience of this arrangement and maintains a rationalization of spares.

It is TNSP’s philosophy that different setting groups (SGs) shall be configured for varying network or system conditions. The assigned SGs, which are shown in *Table 1* below, will be switched manually by the Control Engineer, as required, and no automatic switching has been implemented within the protection relays.

Table 1. Setting group descriptions

SG #	SERVICE CONDITION
1	System normal condition – double circuit and series capacitor in service with operational communication link.
2	Protection contingency – communication channel failure (i.e. pilot scheme blocked)
3	For commissioning purpose only – enhanced safety feature
4	Series capacitors out of service
5	The parallel line is out of service and grounded

D. SSCI Protection

Sub-synchronous interactions are categorized in a group of phenomena that can be described as energy exchange between a generator and a transmission system at frequencies below system nominal frequency [2][3]. SSR tends to occur as the interaction between series compensated system and a conventional generator. SSCI would be usually found as the interaction between series compensated system and a power electronic control system such as Type 3 wind turbine generator converter.

In 2009, a real system SSCI event occurred at a wind farm in Texas that caused significant damage to both series capacitor and wind turbines [2][3]. Another SSCI event was observed in China with very low resonant frequency of 6 ~ 8 Hz in December, 2012 [4]. In the consideration of past events, the possible occurrence of SSCI and SSR events in the region has been studied. The salient objective of the study was to understand the risk imposed on the network and protect the connected generation within the region.

In order to mitigate the risk of SSCI and SSR, appropriate protection devices have been evaluated and commissioned as a part of the project. The protection against SSCI phenomena was achieved by installing two dedicated devices, which operate based on different principles to avoid common mode failure, for each circuit at southern station (SEAS). In addition to the dedicated SSCI protection relays, a duplicated network topology scheme has been commissioned which bypasses the series capacitors in the event of the multiple contingencies that may lead to SSCI. Since the potential SSR issue in the system study was an extremely low risk, to a single peaking generation unit, the deployment of protection devices is still pending at the time of writing this paper.

In addition, a set of event waveforms in COMTRADE[†] format has been generated as a part of system study in order to verify the performance of SSCI protection relays. The event waveforms include system switching and various fault conditions on the regional transmission network. The generated waveforms are categorized as system stable and unstable conditions. The latter, where SSCI oscillation is present, requires the initiation of the series capacitor bypass operation by the SSCI protection relays. The system study also concluded that SEAS station is the optimized location for installing SSCI protection devices instead of the connection points of wind farms in the region. The SSCI protection relays are designed to initiate a bypass of the series capacitors, via protection signaling, if an unstable SSCI condition is detected. One of the objectives in performing RTDS testing is to verify SSCI protection relays and overall protection system performance under simulated SSCI events. Therefore, both SSCI protection relays are also included in the closed loop testing.

III. RTDS Testing Preparation

Prior to RTDS testing, a number of milestones are required to be achieved. The most fundamental step is to verify all involved protection devices via Factory Acceptance Testing (FAT). The purpose of this step is to ensure all protection settings, intended operating characteristics and internal logic are configured correctly according to the intended design. An omission of this basic verification step may lead to the RTDS testing process incurring increased costs through the additional time required for unnecessary de-bugging.

A. Model Preparation

In general, RTDS system consists of many parallel processors and peripherals. The processors compute the mathematic models of the power system components and networks in real time, whilst the peripherals interact with relays or controllers through analogue/digital signals in a closed test loop. Each processing time interval or time step is in the range of 2 to 50 microseconds.

An equivalent network model, which only includes the necessary system to validate the protection devices, is required to be developed in RSCAD software. The software is RTDS proprietary software that is designed specifically for interfacing RTDS simulator hardware. The developed model for this project included the following items:

- Network equivalent model that is centered by transmission line under question;
- CB control logic that includes phase segregated tripping and auto-reclose logic;
- Emulated series capacitor control logic including both bypass CB and spark gap; and
- Fault application logic.

Significant effort has been spent on making sure the fault level data is consistent at the transmission line terminated buses between the developed network equivalent model and the system model which was extracted from the standard power system planning software. The goal of this process is to ensure the analogue injection from RTDS system to the protection relays is close to those in actual system conditions.

The generic generator models are configured to represent the conventional generators in the region. A Doubly-fed induction generator model is configured to represent the wind farms behind SEAS bus. In addition, most transmission lines in the equivalent model are configured using Bergeron models that can accurately reflect line impedance across a wide frequency spectrum.

B. Simulation Conditions

The majority of the tests performed via RTDS system were fault simulations. The purpose of those simulations was to verify protection and control system operations under a comprehensive list of fault scenarios and system conditions. The simulated fault locations are illustrated in *Fig 2* below and the description for each location is listed in *Table 2* in Appendix section.

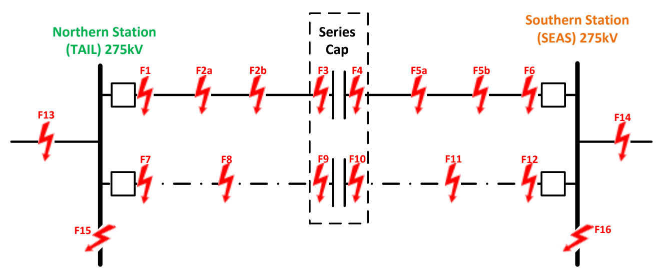


Fig 2. Simulated fault locations during RTDS testing

In addition to the variable fault locations, each fault can be simulated as different types that are described in *Table 3* in Appendix section. Each fault can also be simulated with the following parameters:

- Evolving faults and cross country faults;
- Different fault inception angles (0˚, 45˚ or 90˚ reference to TAIL bus voltage); and
- Adjustable fault durations and resistance.

Various network conditions, operating conditions and relay conditions were also included in the simulation. These system conditions are illustrated in *Table 4* in Appendix section.

[†]*COMTRADE – Common format for TRAnsient Data Exchange for power systems*

As a result, there were thousands of test cases can be simulated if all combinations were executed. Although automatic scripting that is provided by RTDS simulators could test the full complement of the listed scenarios, it was found to be unrealistic and unnecessary to verify relay performance under every combination. The approach adopted was to manually perform the most critical and representative cases in order to ensure the responses from protection relays are satisfactory for the intended design. A number of issues, which are described in more details in Section IV, were identified and corrected during the manual verification. The automatic script testing was then commenced to verify relay performance in a much more comprehensive manner. This approach has been judged as very effective, with almost none re-work for this test project.

IV. Protection Challenges

In general, correct protection performance was highlighted during the testing. However, during the manual simulation component of the RTDS testing, a number of protection performance issues were identified and corrected. This section discusses those performance issues that are considered to be worthy of noting for other similar projects.

A. *Transient Recovery Voltage (TRV)*

One of the major concerns of installing the series capacitor is its impact on the circuit breakers at either end of the transmission line. Trapped charge within the series capacitor may lead to a voltage increase resulting in additional stress on interrupter once the line breakers have opened [7].

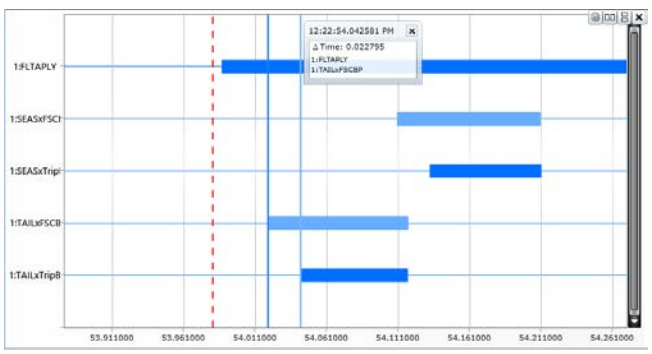


Fig 3. Time delayed local operation

A TRV study was carried out as a part of this project and the study concluded that such risk may arise if the spark gap of series capacitor protection fails to ignite in the presence of high fault current. In order to mitigate this risk, the protection devices at both end of the transmission lines were designed to initiate bypassing of the series capacitor prior to tripping the local, line end circuit breakers. Hence, a total of 21 milliseconds delay has been added in the tripping command if a fault is detected on the line. The added time delay is the upper limit of the permitted time without breaching the fault clearing time under National Electricity Rules (NER). *Fig 3* shows current differential protection operated with approximately 22 milliseconds difference for a 150 ohms high resistance fault that is simulated at F1, which is in front of TAIL terminal.

B. *Zone 1 Overreach*

It is a well-known effect that series compensation introduces errors in impedance estimation for distance protection relay [5]. Under a heavy fault condition such that the series capacitor is removed from service by the triggered spark gap, the distance relay measures correct uncompensated line impedance with 80% coverage. However, the distance relay overreaches for light fault or external fault condition where spark gap is not triggered and series capacitor remains in service.

In order to prevent the distance relay from overreaching, the Zone 1 reach settings have been designed to be configured as 40% of the un-compensated line impedance. However, the distance protection relay at the remote end still overreached during a manual simulation in the testing. The event record for the simulation is shown in *Fig 4*. The test simulated a 3-phase fault at location F12 and Zone 1 was momentarily operated by the relay at TAIL substation for the fault.

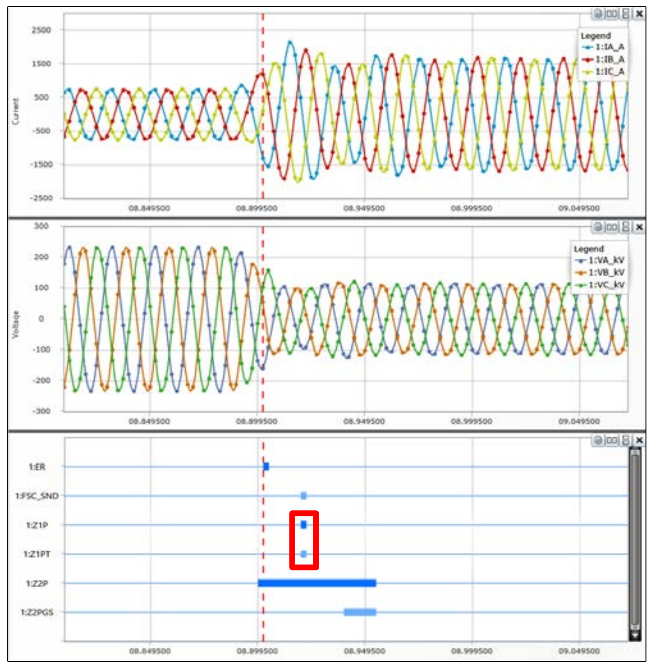


Fig 4. Zone 1 overreach for out of zone fault

According to literature [5][6], the demonstrated test result likely to be due to the sub-harmonic frequency oscillation that is generated from series capacitor and system inductance. Under such condition, the impedance trajectory, which is measured by the remote end relay, is likely to be spiraling through Zone 1 mho-element characteristic even with the reduced reach setting.

In order to resolve the issue, the series compensation function, which is an integral feature within the deployed distance relay, has been applied. The series compensation function calculates the ratio of measured voltage and the calculated voltage that is based on the fault location [5]. If the calculated ratio exceeds a pre-defined threshold, then Zone 1 element is blocked since the fault location is believed to be beyond the series capacitor. Even though the value of the pre-defined ratio is not clearly stated in the manufacturer's documentation or other literature, enabling this function has stabilized the distance protection relay for all external faults simulated during the course of RTDS testing.

C. Directional Element Considerations

The correct determination of ground fault direction is essential for the deployed DCB scheme. The fundamental theory of modern protection relays is to compare the angle difference between sequence network components (i.e. current and voltage). The directional elements applied on the TNSP system are based on the measurement of negative sequence impedance. This technique allows the relay to compare both the sign and magnitude of the calculated impedance [8]. Consequently, it is still able to determine fault direction in the situation where the negative sequence voltage is small during the fault [9]. This technique also offers advantage in eliminating zero sequence mutual coupling effects in double circuit lines.

As general practice, there are two approaches in setting the directional element. One approach is to set based on half of line impedance, which is supplied as 'Auto' setting in the deployed relay [10][11]. The other approach is to configure the threshold settings Z_{2R} and Z_{2F} close to zero such that the sensitivity for forward and reverse ground fault detection is more balanced [8]. The latter approach has been adopted for this application and the threshold settings Z_{2R} and Z_{2F} have been set as 0.6 Ω and 0.1 Ω respectively.

The above settings have resulted in no false-operations of directional element for all simulated cases during RTDS testing. An example test case has been randomly picked from automatic simulations in order to demonstrate the validity of the above settings.

In the test case, an external single phase to ground fault was simulated at TAIL bus (F15) under the operation condition that the parallel line is out of service and grounded. Based on the recorded waveform, the negative sequence quantities can be calculated at any point of time. At one instance after fault inception, V_2 was calculated as 49.42 ∠79˚ and I_2 was 0.18 ∠59.63˚. Both quantities were in secondary values. The following calculation shows the determination of fault direction at that instance with the applied settings.

Settings: $Z_{2F} = 0.1$ $Z_{2R} = 0.6$
Event Phasor: $V_2 = 49.42\angle 79°$ $I_2 = 0.18\angle 59.63°$
Negative Sequence Z:

$$Z_2 = \frac{Re\{V_2 \cdot [I_2 \cdot (1\angle Z_{1ANG})]\}}{(|I_2|)^2} = 117.64$$

Forward Threshold:

$$Z_{2FTH} = \begin{pmatrix} 0.75Z_{2F} - 0.25\left|\frac{V_2}{I_2}\right| \; if\ Z_{2F} \le 0 \\ 1.25Z_{2F} - 0.25\left|\frac{V_2}{I_2}\right| \; if\ Z_{2F} > 0 \end{pmatrix} = -68.51$$

Reverse Threshold:

$$Z_{2RTH} = \begin{pmatrix} 0.75Z_{2R} + 0.25\left|\frac{V_2}{I_2}\right| \; if\ Z_{2R} \ge 0 \\ 1.25Z_{2R} + 0.25\left|\frac{V_2}{I_2}\right| \; if\ Z_{2F} < 0 \end{pmatrix} = 69.09$$

Since the calculated negative sequence impedance is well above the reverse threshold, the relay correctly declared that the fault was in reverse direction. If the 'Auto' setting had been used, the relay would configure the reverse (Z_{2R}) and forward (Z_{2F}) threshold settings as 61.72 Ω and 61.22Ω respectively according to the half of line impedance. Under the same fault condition as just described, the reverse and forward thresholds, Z_{2RTH} and Z_{2FTH}, would be 114.93 Ω and 7.89 Ω respectively based on the 'Auto' settings. In comparison with the calculated negative sequence impedance value of 117.64 Ω, the relay would still declare the fault was in the reverse direction but the margin for this determination is greatly reduced. Hence, the selectivity of directional element with the applied setting is greatly improved over the embedded 'Auto' setting.

D. Single Pole Operation (SPO)

The distance relay has been observed with few false-operations under SPT and SPR conditions. One instance occurred when a single phase to ground fault was simulated at location F1, which is in front of TAIL terminal. The remote end relay at SEAS detected the fault and operated single pole correctly after fault inception. However, the relay made three pole trip after approximately 16 milliseconds since SPO condition was declared. The event record from the fault simulation is shown in *Fig 5* below.

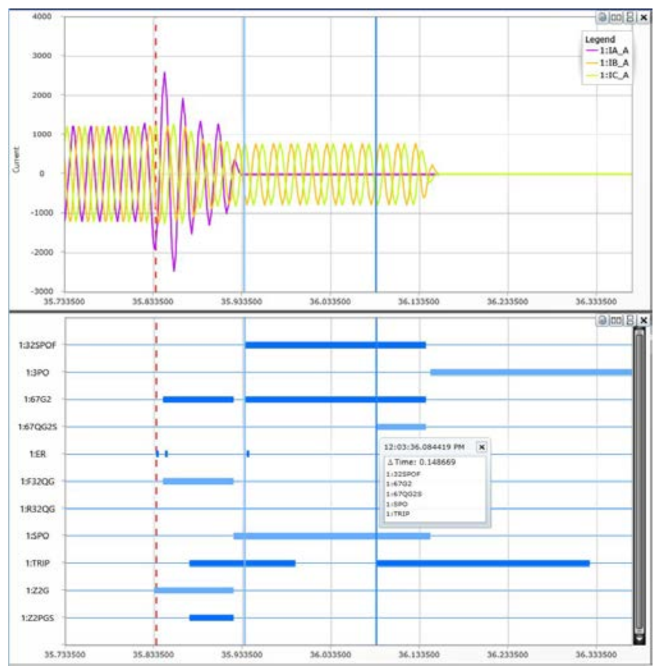


Fig 5. Forward direction mal-operation

The event record showed that Zone 2 and 67G2 elements, as well as the phase selection logic, operated correctly in the relay after fault inception. Once the faulted phase is disconnected, the relay operated 67QG2S (negative sequence and residual directional overcurrent element) since the directional element still declared the fault was in forward direction. In general, for single pole scheme, the relay should block the directional protection elements after SPO condition is detected. This is due to the difficulty to discriminate load or fault direction when one phase is disconnected. As it is shown in *Fig* 5, the F23QG element, which was primarily used for direction determination, operated correctly after SPO situation is detected during the simulation. It is the additional directional element 32SPOF that was asserted and declared forward fault direction. The detailed logic in regarding to 32SPOF and 32SPOR operands were not found in relay manufacturer's documentation. The solution for this mal-operation was to include 'NOT SPO' in the torque control logic of directional overcurrent element. Following the implementation of this solution the issue was not encountered throughout the remainder of the RTDS testing.

The other instance occurred during single phase to ground fault simulation at location F6, which is in front of SEAS terminal. The distance protection relay at SEAS station correctly operated with single pole tripping, but it also determined the fault in the reverse direction and sent a blocking signal to the remote end under SPO condition. This mal-operation caused slow Zone 2 operation and opened all three poles at the remote end. This test case is shown in *Fig 6* below.

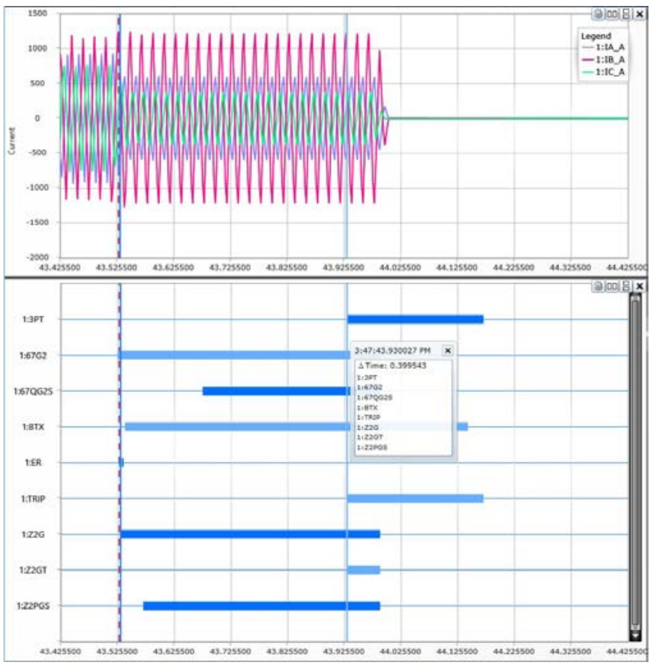


Fig 6. Slow operation at remote end

It has been observed that the DCB scheme of the remote end relay was blocked for the entire period of Zone 2 time delay since the distance relay at SEAS opened the faulted phase. Similar to the previous instance, the problem was due to the false determination of fault direction under SPO condition. The solution was to include 'NOT SPO' in the reverse direction torque control logic. Following the implementation of this solution, the issue was not experienced further throughout the testing.

E. Evolving Fault Simulation

Once the directional torque control has been modified in earth fault protection, a series of evolving fault simulations were performed to the distance relay. An example test case has been chosen to be discussed in this section. The location of the simulated fault was at F2a as shown in *Fig* 2. The first applied fault was an A phase to ground fault with 50 Ω fault resistance and the second one was applied as B phase to ground fault. The time interval between the two faults was 10 cycles. *Fig 7* below demonstrates the performance of the distance relay at SEAS station.

The event record confirmed correct operation by the relay. Single pole operation was made appropriately by the DCB scheme with a subsequent three pole trip after B-G fault was applied. Even though the SPO condition blocked directional overcurrent element, but the 32SPOF operand was asserted correctly for fault direction under the SPO condition. Therefore, the internally operated 32SPOF operand is a useful feature for determining fault direction under SPO condition. It is also worth stressing that if the second fault was applied as high impedance fault, the relay might not be able to operate as 3-pole trip. This limitation was accepted due to the low probability of having high impedance fault in an evolving fault scenario. This identified risk will also be covered by the current differential protection.

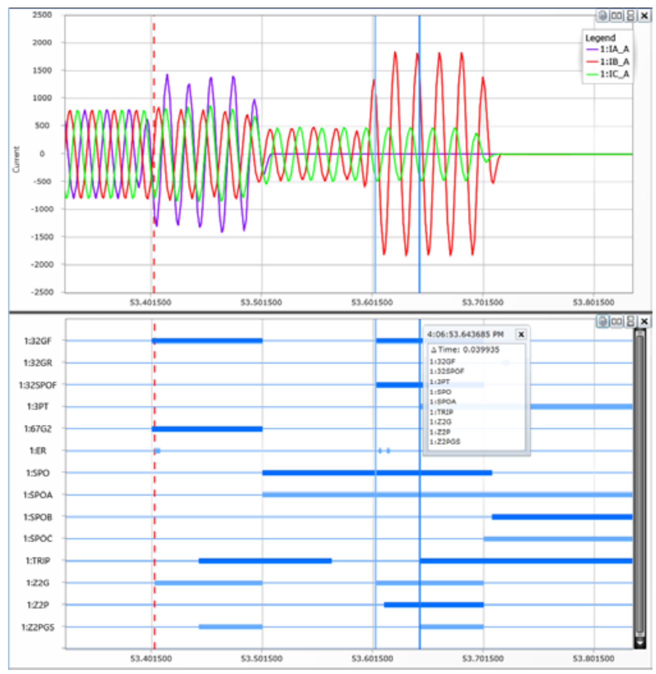


Fig 7. Evolving fault simulation

F. Current Differential Protection Slow Operation

At early stage of manual testing, one test case indicated that the current differential protection operated slowly for high impedance SLG fault. The event record of this case is shown in *Fig 8* below. It was observed that the relay operated current differential protection (87L DIFF OP A) immediately after fault inception. However, the single pole tripping was interrupted several times for a period of approximately 100 milliseconds prior to closing the trip contact.

As it is demonstrated in *Fig 8*, the trip operation has been blocked by open pole detection element which was configured as accelerated mode during the fault simulation. This setting allows the open pole condition to be declared in half a cycle after tripping operand (TRIP PHASE A) is asserted. The open pole condition is then applied internally to block current differential protection operation for single pole scheme according to relay manual. Since the added 21 milliseconds delay to the local protection trip, the assertion of open pole condition has blocked the trip signal as it is observed in the event.

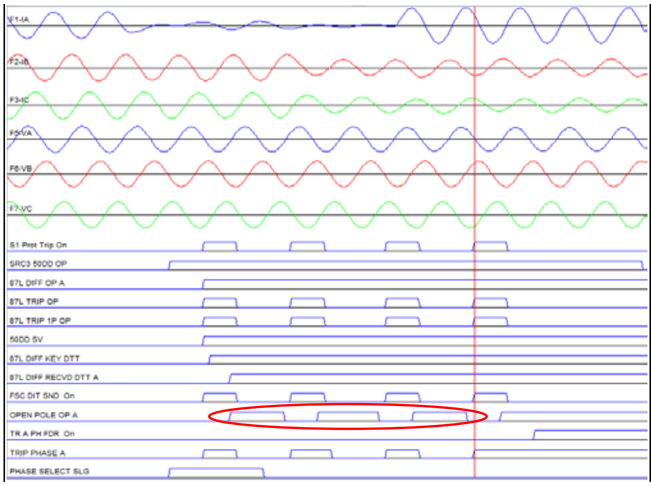


Fig 8. SLG slow operation

This issue was resolved by changing the 'accelerated mode' to 'traditional mode' for open pole detection element. This change allows the open pole to be asserted only after the breaker opens and current disappears. The impact of this change to evolving fault situation is also managed by the internal phase selector logic. As a result, no further issue has been observed during the rest of RTDS testing.

G. *Distance Relay Slow Operation in Contingency Group*

A number of faults were simulated when pilot scheme was out of service and protection relays were switched into the various contingency setting groups. During fault simulations using Setting Group 2, the distance relay at TAIL station was observed with slow operation when an A-G fault was applied at location F1, which is in front of TAIL terminal. The event record for this test case is shown in *Fig 9* below.

In Setting Group 2, the distance relay has been configured to operate with an extended Zone 1 reach incorporating a 10 cycle time delay to provide increased network security against the double circuit faults. As shown in *Fig 9*, Z1G element was asserted as soon as the fault was applied, but it was blocked by the out of step blocking (OSB) element. On the other hand, Z2G element was also asserted, and remained unblocked since the internal element 'OSBA' wasn't asserted during the simulation. The brief interruption of Z2G assertion was due to the relay operation at SEAS station as it is indicated in the current waveform.

Further investigation has revealed that the distance relay requires the implementation of directional negative sequence element to supervise OSB for Zone 1 distance element. As a result, the required supervision element was configured with the pickup level above the measured negative sequence current during normal system swing condition. This change has been proven to resolve the highlighted issue. The change was subsequently confirmed to have no further adverse impacts to protection scheme by the remainder of the RTDS testing.

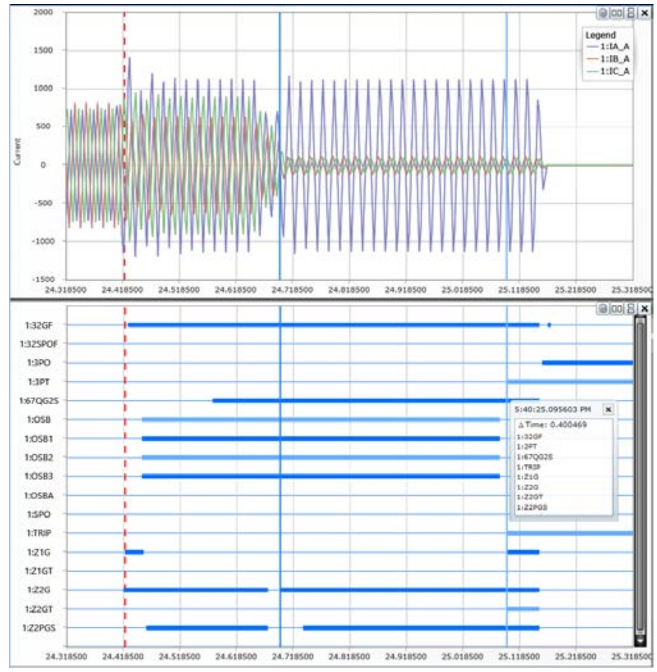


Fig 9. Distance protection slow operation

V. SSCI AND SSR SIMULATIONS

In order to verify both the line protection relay's response and overall protection system performance for SSCI/SSR events, the RSCAD model has been deliberately developed to be able to simulate SSCI/SSR phenomena. Similar to the event which occurred in Texas in 2009, the SSCI simulation was processed such that the windfarms in the region were connected radially with the series capacitor during RTDS testing. As the system study results indicated that undamped SSCI oscillations could arise through multiple coincidental outages. However, SSCI phenomena was not observed in RTDS simulations as expected. This is believed to be caused by the limitation that is combined of RTDS hardware, the size of power system model and the modelled power electronics for real time simulation. As a result, the set of generated waveforms from system study, which are in COMTRADE format, were played back to the protection relays using RTDS system. Both line protection relays and SSCI protection devices responded correctly to the playback events.

SSR phenomena was simulated in a similar manner to the SSCI condition, such that the equivalent generators were connected radially with the series capacitor. By adjusting the rigidity factor of the shaft system in the equivalent generator model, a small magnitude SSR oscillation was observed as it is shown in *Fig 10* below. The perceived electrical oscillation was calculated at 12 Hz. Since the magnitude of the oscillation was approximately 100A, it was questionable if the simulated condition would have any significant impact to the transmission network.

From the exercise of simulating SSCI and SSR conditions using RTDS system, it has been concluded that using open loop testing techniques involving power system analyzing tools (e.g. PSCAD software) to simulate and generate sub-synchronous oscillation waveforms is a more practical and efficient approach. The waveforms generated during the simulations can then be captured and played back to protection relays for more comprehensive and realistic verification.

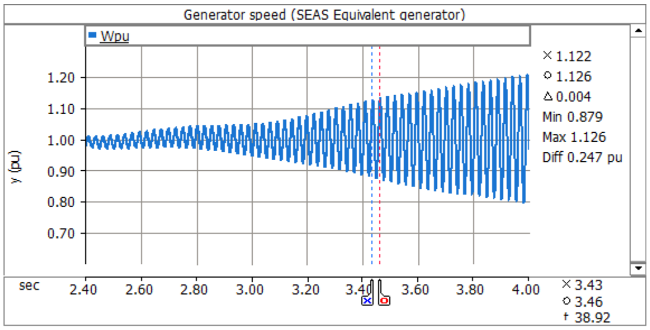


Fig 10. Observed SSR oscillation

VI. Series Capacitor Controller Verification

Many protection functions are provided by the series capacitor protection and control systems, such as overload protection, Metal Oxide Varistor (MOV) thermal protection, spark gap self-ignition, etc. Those protection functions were emulated in RSCAD model for most of RTDS simulations. The series capacitor controller panels were also connected to the closed loop RTDS testing system to verify its protection and control functions during manual simulation stage.

By manually performing hundreds of test cases, the performance of series capacitor protection and control systems was verified to be correct according to the specification. One small error was found that the operating time of the simulated bypass breaker in the control system was different from the specified value. However, this mismatch does not affect the overall behavior of the installed system.

A limitation of the specified MOV accumulated energy was also identified when the spark gap is simulated as failed. Under this situation, the accumulated energy in MOV would quickly rise to approximately 8.2 mega-joules if a solid three phase close-in fault occurred at series capacitor site. The accumulated energy is slightly above the specified limit of the equipment. This is shown in *Fig 11* below that the accumulated energy on A-phase has exceeded the specification. Since the probability of this contingency is very low, this limitation has only been noted to the asset owner in order to be considered further.

VII. In Service Experience

The series capacitors were commissioned into service around the end of July 2016. There have been a number of storm activities in the region, but there has not been any faults on the transmission network to provide natural testing. However, a capacitor unbalance fault was experienced during commissioning stage which led to the series capacitor being by-passed and removed from network. During this fault the line protection and SSCI protection relays were correctly restrained as expected. Capacitance measurements identified failed elements within a capacitor can. The failed can has been replaced and the series capacitor has been re-inserted into service.

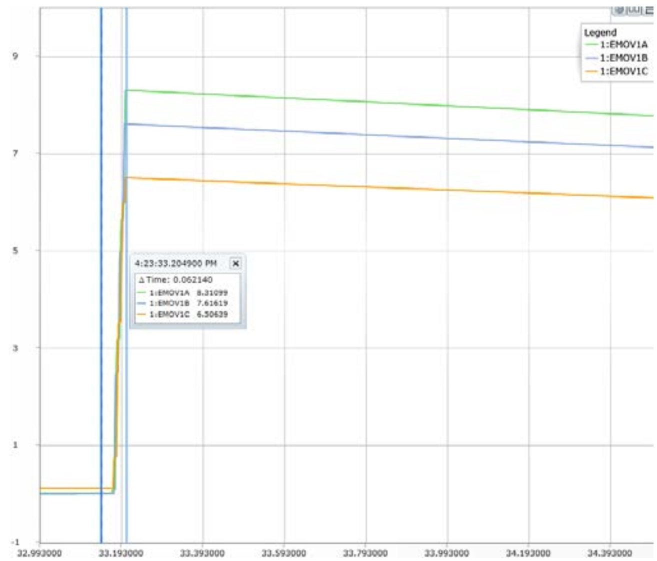


Fig 11. MOV accumulated energy

VIII. Conclusion and Summary

This paper has presented the experience of using RTDS system to verify the design and performance of complex line protection schemes under various fault and network conditions. The RTDS testing has been valued as an effective and crucial process prior to placing the protection system into service. The prepared network model in RSCAD software was sophisticated by including detailed generator models for the purpose of simulating SSCI and SSR phenomenon. The test result has concluded that it would be more effective to verify SSCI/SSR protection via the playback of generated waveforms to protection relays. Although the inclusion of series capacitor panel in the closed loop testing has raised the complexity of testing process, it was considered to be valuable to verify manufacturer’s design functions and identify potential limitations on service conditions.

The verification of line protection schemes has highlighted the challenges of setting the directional elements for ground fault detection. The applied threshold settings for forward and reverse directions have been proven to be more secure than the embedded ‘Auto’ calculations. The direction determination under SPO condition should be considered carefully in the protection design. It is also valuable to verify the performance of protection relays under any special operational requirements via RTDS closed loop testing system.

Appendix

A. *Fault Location Descriptions*

Table 2 below provides the details for each fault location that is illustrated in *Fig 2*.

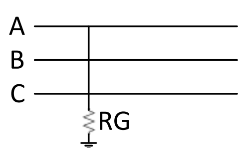
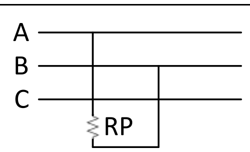
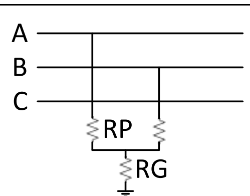
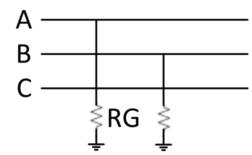
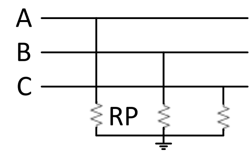
Table 2. Fault location descriptions

Class	Loc.	Description
Internal Faults	F1	Close-in fault at Northern Station
	F2a	Fault at 35% between Northern Station and series capacitor
	F2b	Fault at 70% between Northern Station and series capacitor
	F3	Close-in fault at series capacitor on Northern Station side
	F4	Close-in fault at series capacitor on Southern Station side
	F5a	Fault at 35% between series capacitor and Southern Station
	F5b	Fault at 70% between series capacitor and Southern Station
	F6	Close-in fault at Southern Station
External Faults	F7	Line #2, close-in fault at Northern Station
	F8	Line #2, fault at 50% between Northern Station and series capacitor
	F9	Line #2, close-in fault at series capacitor on Northern Station side
	F10	Line #2, close-in fault at series capacitor on Southern Station side
	F11	Line #2, fault at 50% between series capacitor and Southern Station
	F12	Line #2, close-in fault at Southern Station
	F13	Fault behind Northern Station
	F14	Fault behind Southern Station
	F15	Fault on Northern Station bus
	F16	Fault on Southern Station bus

B. *Fault Type Descriptions*

Table 3 below provides the details for each fault type that was simulated in RTDS testing.

Table 3. Fault type descriptions

Fault Type		Fault Resistance
AG (BG, CG)		Metallic faults: RG = 0.1Ω High Resistive Faults (HRF): RG = 10 - 150Ω
AB (BC, CA)		Metallic faults: RP = 0.1Ω HRF: RP = 2 - 5Ω
ABG (BCG, CAG)		Metallic faults: RP = 0.1Ω, RG = 0.1Ω HRF: RP = 2 - 5Ω, RG = 10 - 150Ω
ABG (BCG, CAG)		Metallic faults: RG = 0.1Ω HRF: RG = 10 - 150Ω
ABC		Metallic faults: RP = 0.1Ω HRF: RP = 2 - 5Ω

C. *System Conditions*

Table 4 below provide the details for different system conditions that was simulated in RTDS testing.

Table 4. System condition descriptions

	No.	Network Condition Description
A	1	Minimum fault level condition
	2	Maximum fault level condition
	No.	**Operation Condition Description**
B	1	FSC bypassed
	2	Adjacent line is out of service and grounded
	3	Line shunt reactor is out of service
	No.	**Relay Condition Description**
C	1	Both relays are in service
	2	Only current differential relay is in service
	3	Only distance relay is in service
	4	Both relays are in contingency group

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