Dynamic Simulations Challenge Protection Performance

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DYNAMIC SIMULATIONS
CHALLENGE PROTECTION PERFORMANCE

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INTRODUCTION

This paper describes some experiences with and the impact of the addition of power system dynamic models to application testing of EHV transmission line protection systems. These models provide useful information, especially in highly stressed systems, during frequency excursions, or where there are applications of synchronizing or synchronism-check functions.

This paper reviews the various forms of test signals that may be applied to relays. It also discusses factors to consider when reducing complex power systems to lumped components. The reduced system should retain features that impose significant challenges to the protection system, while keeping the system simple enough to be modeled by reasonably sized test facilities.

The value of application testing for protection systems is well recognized, especially for complex protection systems. The degree of complexity of test simulations should be balanced with the possible benefit of discovering limitations or challenges that may affect specific applications in a significant manner.

TEST PURPOSES AND SIGNALS

Purposes

The primary purpose of all protection system tests is to ensure that the relays will perform with the required speed, sensitivity, and security for a particular application or group of applications. The need to make this determination varies widely, depending on the circumstances.

Two broad categories of testing are defined in the CIGRE report "Analysis and Guidelines for Testing Numerical Protection Schemes" [1]. These categories are type testing and individual testing.

Type Testing

Type testing is performed on only one protection system of a given design, while individual testing may be performed on every in-service protection system. Type testing is often valuable when you are considering the application of a new type of protection, or are considering a new and complex application of a protection system. Depending on the circumstance, you may choose to rely on manufacturers' type testing or an independent certification organization's type testing, or you may choose to apply specific type tests for individual applications.

BC Hydro has consistently required suppliers of EHV transmission line protection equipment to perform type tests on each unique application. These type tests (referred to as "Model Power System Tests") give BC Hydro sufficient confidence in the dependability of the systems to allow the application of identical redundant transmission protection systems. Reducing the variety of protection systems results in training and spare inventory cost savings that more than pay for the cost of the tests for each unique application. Increased security against undesirable tripping resulting from minimizing the differences between redundant protection is an additional important benefit of using the same protection systems for each specific application. Type testing addresses the question "Is the design suitable for the specific application or group of applications?" [2]
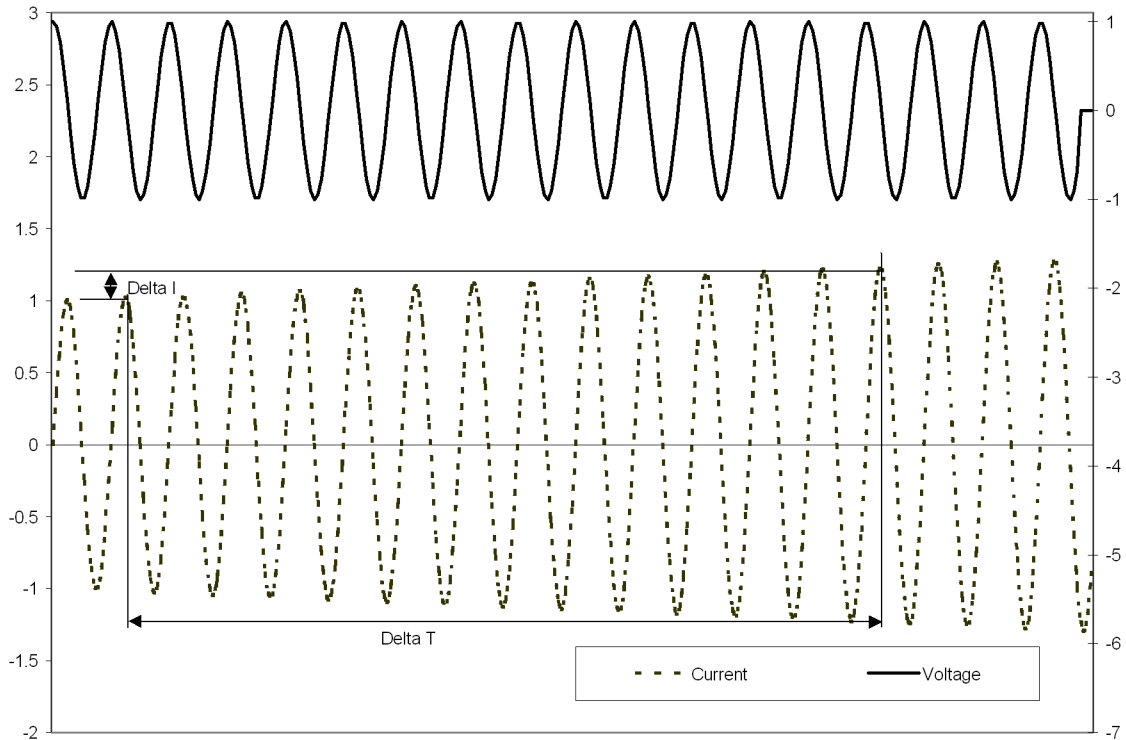
Individual Testing

Individual testing is required for each protective relay and protection system at various times, such as during acceptance, commissioning, or periodically during service. Individual testing addresses the question "Is this device operating according to its design specifications?"

Test Signals

Having decided on the purpose of testing, you should decide upon the type of test signals that should be applied to achieve the purpose. The IEEE Special Publication "Relay Performance Testing" [3] defines three types of test signals that may be considered.

Steady State Signals

Reference [3] describes steady state signals as test signals in which only one signal is varied at a time. The rate of change should be slow enough such that a change smaller than the resolution of the relay should take longer than several times the operating time of the relay. That is, when considering the signals shown in Figure 1, the value of (Delta I)/(Delta T) should be small enough that relay operation can be observed before the test signal has changed to a value beyond the desired resolution of the relay.

Figure 1 Steady State Test Signals

Steady state test signals are commonly used for relay calibration during individual testing. Once you determine that a relay design and settings are correct for the application, it is only necessary to ensure that individual relays conform specifically to the design and have the specified settings applied. Calibration testing using steady state signals verifies that a properly applied and set relay is able to perform as expected.

Correct use of steady state signals for testing relays requires adequately stable and accurate test sources. Such test sources are common equipment for users of protective relays and their use is routine. However, by definition, steady state testing does not address time-related phenomena; therefore, individual testing using these signals is commonly supplemented by testing using dynamic state simulation signals, as described in the following section.

Dynamic State Simulation Signals

For dynamic state simulation testing, only signals of natural power system frequency are presented to the relay. However, the signals are switched from one state to another to simulate various power system states, such as prefault, fault, and post-fault. Figure 2 shows some typical test signals. Note the sharp transition of the current and voltage from prefault to fault quantities. In a real power system, there would be associated nonfundamental frequency transients that are not represented in these signals.
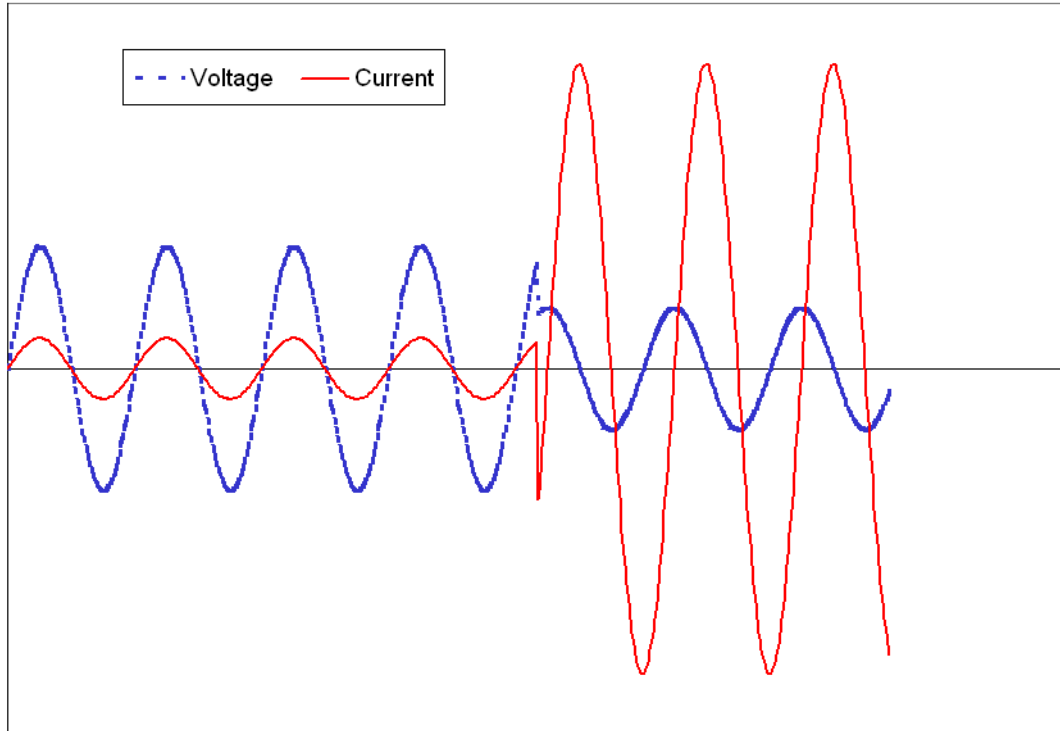
Figure 2   Dynamic State Simulation Signals

The dynamic state simulation signals shown in Figure 2 are often helpful in testing protection systems that filter out all components of the signal except the fundamental frequency. Because the unrealistic and sharp transition of the type shown in Figure 2 is filtered out by many types of relays, these signals are particularly useful for relays that are not intended for particularly high-speed applications or subject to CT saturation.

Most modern relay test sets are capable of having a number of different states of phasor signals programmed into them to be delivered at specified times to the device under test. The phasor signals to be delivered to the device under test are normally calculated from a short-circuit program. The short-circuit program is usually a program that represents the power system in the steady state under balanced or unbalanced short-circuit conditions.

Because the test quantities are readily calculated using conventional short-circuit programs, and then readily delivered using conventional test equipment, they are widely used for type testing and individual testing. Experience has shown that this type of test signal can reveal many potential problems with protection systems [2][4]. However, due to the limitations in correctly representing the transition between fault states, dynamic state simulation test signals may produce incorrect or unrealistic results, particularly in high-speed protection systems.

Transient Simulation Signals

Transient simulation signals reproduce all components of a test signal that are important to the performance of a protection system. The signals shown in Figure 3 are the simulated currents and voltages on one phase of a 230 kV shunt capacitor bank at the instant of energization. The current is severely distorted for several power frequency cycles, and the voltage is somewhat distorted.

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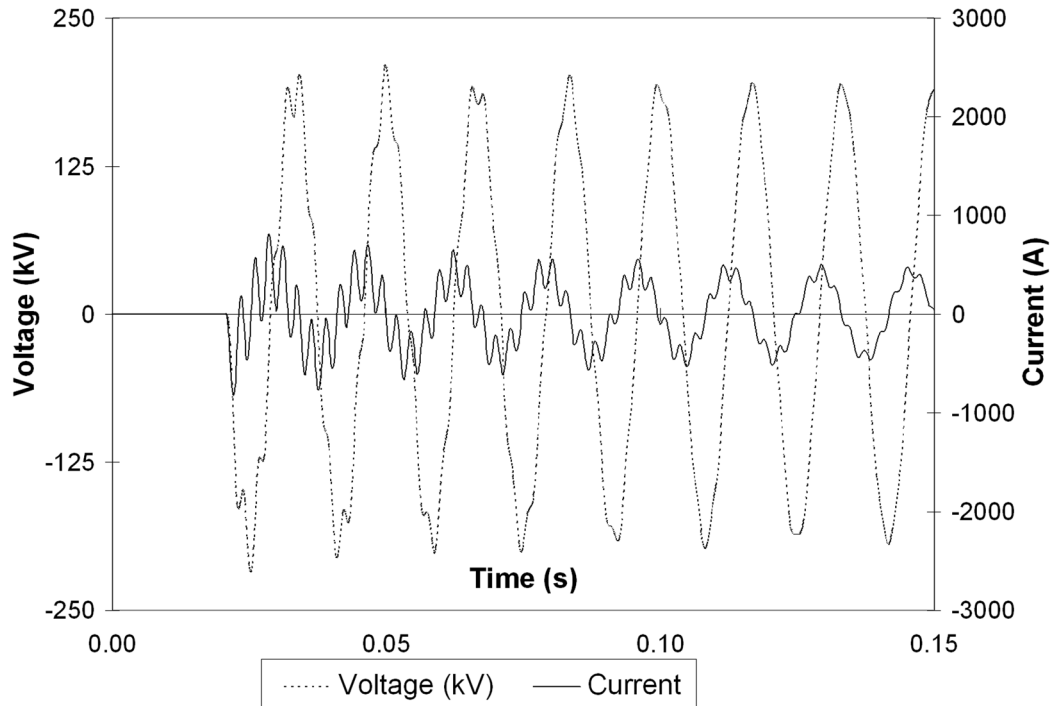
Figure 3   Transient Test Signals

The current shown in Figure 3, for instance, might be injected into an overcurrent relay to test the response of the relay to the high peak current that flows during the first cycles of energization. The response to this type of signal (of a relay used for protecting a capacitor bank) cannot be determined from steady state or dynamic state signals, and is normally also not discernable from the manufacturer's application guide. Therefore, to determine what setting might be applied to a specific type of instantaneous overcurrent relay for which there was no previous experience or applicable rules of thumb, testing by transient simulation is one way to gain insight into what might be a secure setting.

The example of using transient testing for a capacitor bank overcurrent relay is deliberately made very simple as an illustration. Of course, there are usually rules of thumb or application guides that would take the place of transient testing for capacitor bank overcurrent relays. However, in the case of more complex protection systems, such as those used for EHV transmission, the response of high-speed relays to severely distorted signals cannot always (or even usually) be determined through application guides or rules of thumb. Testing of individual applications using transient test signals is often an important aid to developing reliable and fast protection applications and settings.

POWER SYSTEM MODELS

Having determined the need to use transient test signals, the challenge then becomes to determine what parts of the test signal are relevant and important and what power system models should be used to generate the signals. It becomes necessary to understand the various types of power system models as they apply to protective relaying.

Steady State Phasor Models

Steady state phasor models are used for power flow and fault studies. Both study types are based on a network modeled with pure sinusoidal voltage sources connected with impedances and loads, all represented at fundamental frequency.
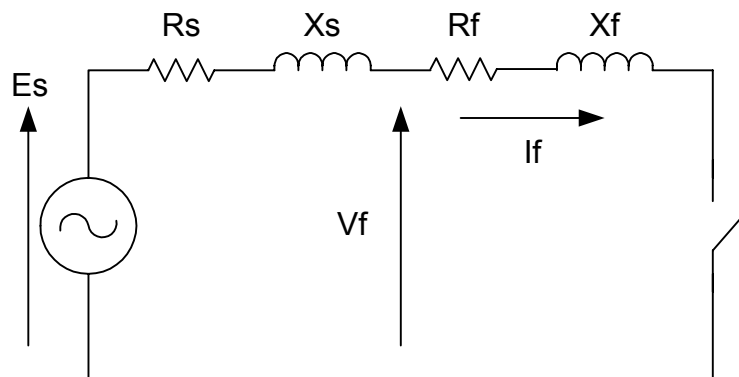
Power Flow Study

The power flow study assumes the system is operating in a steady state condition with all shunts in service and the system voltage magnitudes and angles close to the operating condition under study. Power flow studies model the power system as a balanced three-phase system with balanced voltages and balanced loads. Because the model is balanced, it can be (and is) studied as a single-phase system using positive-sequence voltages and impedances. This simplifies the system model significantly.

Fault Study Model

The fault study model is similar to the power flow study in that it assumes that all voltage sources and network components are balanced and operating in steady state at fundamental frequency. The major difference between the two models is that unbalanced short circuits, open circuits, and loads can be represented on the fault study model. The model will then allow the calculation of voltages and currents at various locations in the presence of balanced or unbalanced short or open circuits so that relay engineers may determine applications and settings that will reliably discriminate between normal conditions and abnormal conditions.

Figure 4 shows a fault study model useful for calculating the steady state voltage and current phasors (Vf and If) that are presented to a relay when the fault switch is closed. In this model, the voltages and currents are not necessarily balanced, but they are represented as steady state solutions. At first consideration, it may seem unrealistic to study a system under steady state short-circuit conditions, because a power system cannot normally continue to operate in steady state under short-circuit conditions. However, the protective relays that initiate removal of the short circuit operate very quickly (often in less than a second). Then it can be understood that relative to the time frame of the relay operation, it is reasonable to assume that the short-circuited system is in a steady state.

Figure 4 Steady State Phasor Model

The fault study model may be used with or without a solved realistic power flow representing the prefault condition. Some fault study models neglect all shunts, including loads and transmission line shunt capacitance, assuming the system is operating at 1.0 per unit voltage and without any

prefault load. This assumption is often sufficiently accurate, because load currents are often negligible when compared with fault currents. However, in some cases, where the effect of prefault loads and voltages is significant, an exact or approximate model of the prefault conditions can be included in the simulation.
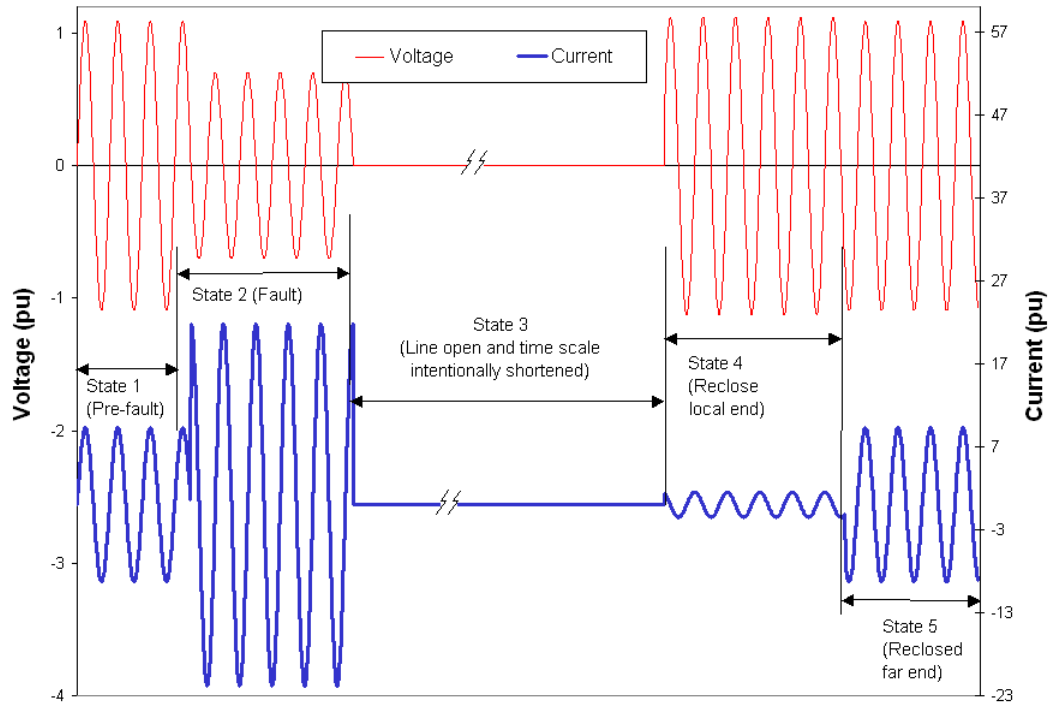
State Simulation

Both the power flow and fault study model are steady state models; therefore, they can be used only in a sequence of simulations to model system conditions that change with time. For instance, the models could be used to represent dynamic situations in a system in a simple sequence, as follows:

1. In the prefault condition, with all elements in service.

2. Under fault conditions, before protective relays operate to isolate the faulted transmission line.

3. During the period of the line terminal open, to allow time for the fault to extinguish.

4. Reclose at one end of the line.

5. Post-fault conditions after the line has been successfully reclosed at both ends.

The above five-stage sequence can be studied as five separate steady state conditions (as shown in Figure 5) for one terminal of a transmission line. These five steady states can be readily transferred to commercial test sets to simulate the changing conditions in a dynamic state simulation test. The plots in Figure 5 show the following conditions:

- **State 1:** The prefault state—the current is in phase with the voltage and at the load value of 1 per unit.
- **State 2:** The fault state—the current magnitude increases and angle lags the voltage. The voltage magnitude is reduced. Note the unrealistic instantaneous discontinuity in the transition to fault current.
- **State 3:** The line terminal is open—note the unrealistic chopping of the current from peak value to zero. Note also that the time scale of the open interval period has been dramatically shortened to allow better resolution of the waveforms during other states.
- **State 4:** The line terminal recloses at the end being monitored. The current magnitude is small and the angle leads the voltage, indicating line charging current. The voltage is also slightly elevated in magnitude.
- **State 5:** The remote line terminal recloses; the current and voltage relationships become in phase with each other, similar to the prefault state of State 1.

Figure 5   Time-Sequenced State Simulation

Note that the waveforms shown in Figure 5 are artificially created by computing sinusoidal waves with the magnitude and phase angles calculated by phasor solutions of the fault study. The fault study itself does not produce a waveform output.

Dynamic Models (for Stability Programs)

Dynamic phasor models are commonly used to study the dynamic behavior of power systems. The most common implementation of this type of model uses a series of solved power flow cases with appropriate adjustment of the system's dynamic parameters between each power flow calculation. These power system dynamic simulations produce an output of fundamental frequency, phasor values in a time-stamped series. Typical resolution of the simulation output is one-quarter to one-half cycle increments. The simulations may include simple models of protective relays, such as mho elements with or without specially shaped characteristics; underfrequency elements; under- or overvoltage elements; or current elements. The relay models in simple simulation studies do not typically include important effects like filter response times or polarizing voltage memory that can affect the protection system performance. Figure 6 shows the various parts of the system that are relevant to dynamic stability studies. This type of program is designed to model various time-dependent system phenomena, such as impedances of short-circuited generators, responses of governors, excitation systems, power system stabilizers, and load dependency on voltage and frequency.

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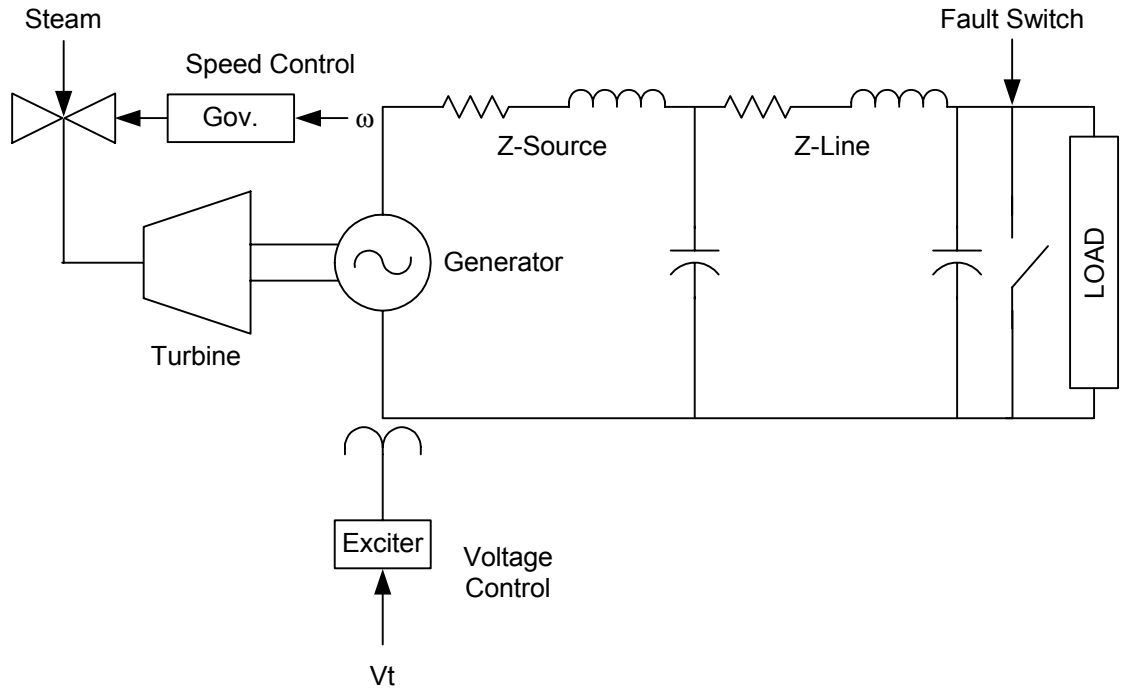
Figure 6   Dynamic Model

Because the dynamic model of Figure 6 is based on the simulation of power frequency phasors, all time-related phenomena must be lower in frequency than the fundamental power system frequency. In practice, this type of model is useful for studying phenomena with a time frame longer than about 50 milliseconds, or three 60 Hz cycles. This means the model is suitable for studying electromechanical phenomena, including the effect of excitation systems, and the slower dynamics of frequency changes and governor response.

The dynamic model is based on a series of power flow solutions. Therefore, it is not suitable for studying unbalanced conditions (open or short circuits) on a phase-by-phase basis, as is done in fault study solutions. However, the effect of unbalanced conditions on the system dynamics can be represented by appropriate adjustment of the positive-sequence series and shunt elements in the network. These adjustments to include the effect of unbalances are automatically applied at the correct instants during the series of power flow solutions.

Similar to the fault study, the electrical measurement output of dynamic model solution programs is not a waveform, but phasor values. However, a difference from the fault study is that the dynamic model produces a series of solutions that combined sequentially represent smooth time varying quantities, such as voltages, currents, apparent impedances, frequency, etc.—all as positive-sequence quantities.

Figure 7 shows the voltages and currents computed by a stability program for the same sequence of events as those shown in Figure 5. For comparison, the magnitudes of voltages and currents computed by the fault study used to compute the phasors on which Figure 5 is based are superimposed on the stability program calculations. While the fault study results are similar, there are significant differences in time response.

Dynamic Plot - Voltages

Dynamic Plot - Line Current
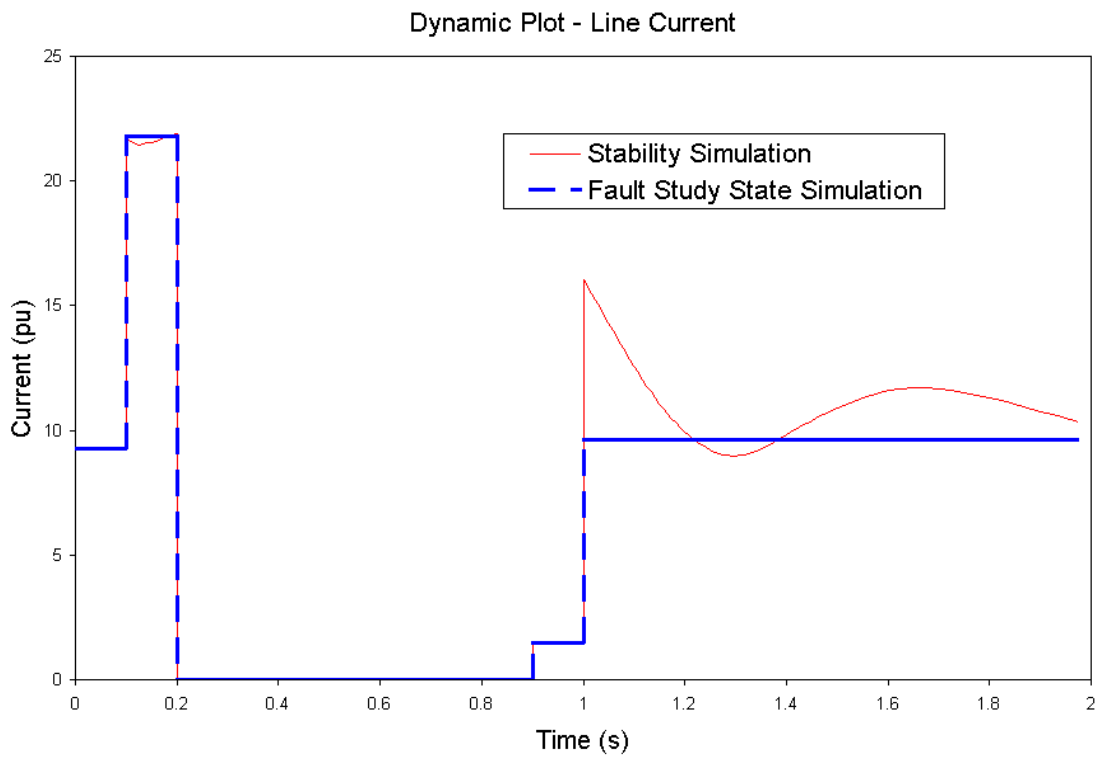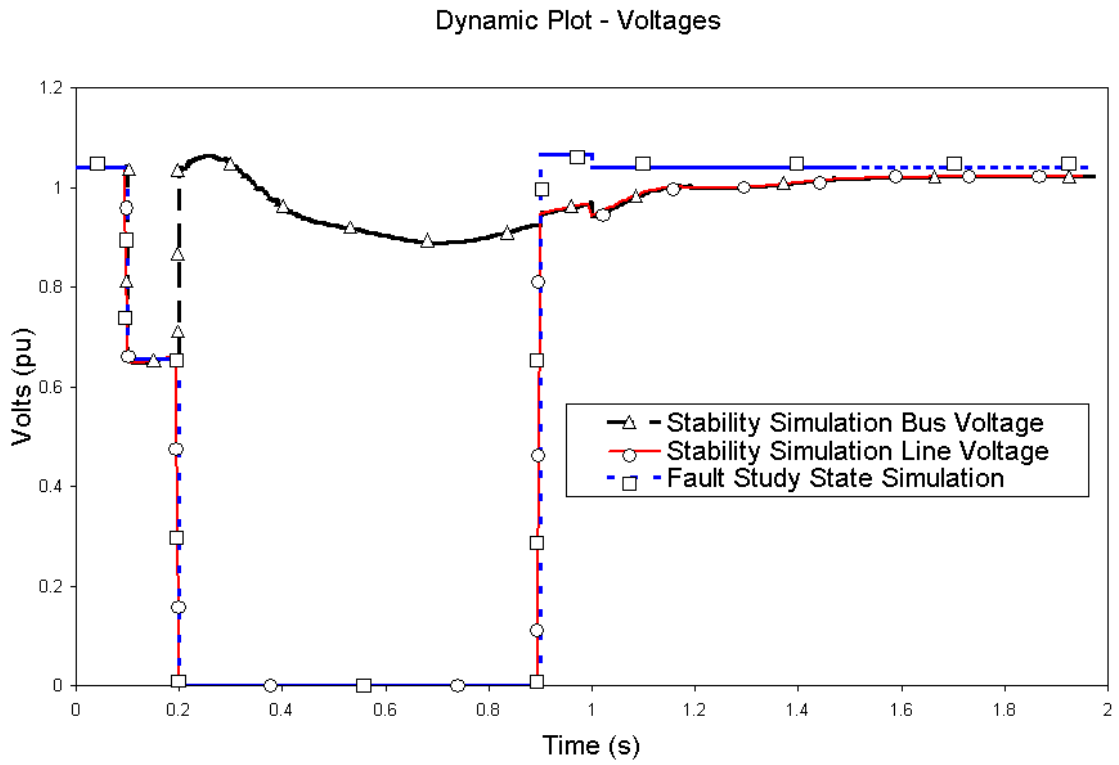
Figure 7   Voltage and Current Phasor Magnitudes for Fault, Trip, and Reclose

The currents and voltage magnitudes are considerably more realistic than the five discrete fault study solutions that attempt to represent the same event. While the fault study based simulation produces the results of five discrete solutions of the network with manually varied parameters, the stability plots in Figure 7 display the results of about 200 discrete solutions of the network with automatically varied parameters. The importance of the differences in modeling to relay performance depends on how closely the measured parameters approach the limits of relay operation (or non-operation).

The signals computed by stability models would be useful for testing the response of relays to dynamic events in the appropriate time frame. Events, such as temporary encroachment on impedance characteristics or relay response to frequency variations, could be usefully simulated on commercial test sets using existing technology. Unfortunately, suitable software is not currently available with commercial test equipment. Such software would allow the time-dependent positive-sequence phasor voltages and currents and time-varying frequency values to be converted to waveforms of appropriate magnitude and angle and frequency.
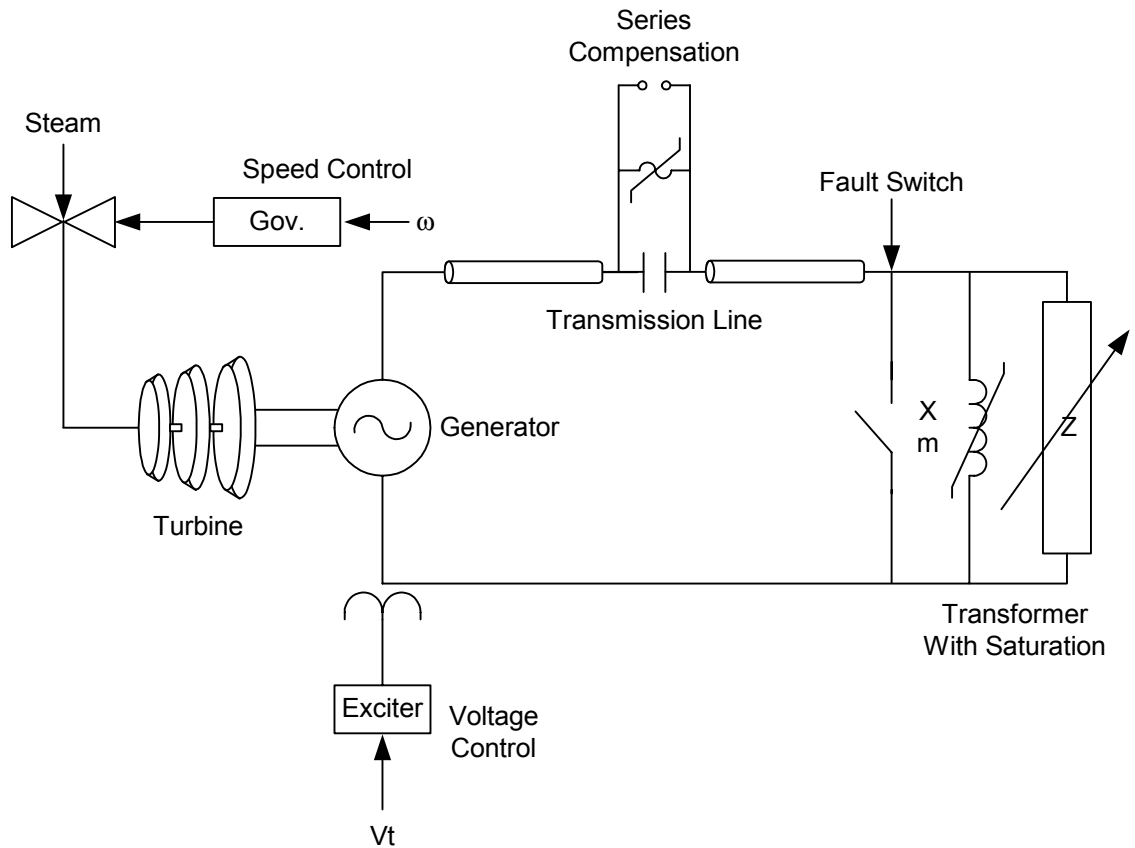
Transient Models

Transient power system models most closely model the real world of power systems. These models simulate the power system on a discrete time basis with representation and resolution of electromagnetic phenomena with a frequency limited only on the upper end by the minimum size of time step that can be practically utilized. With time steps in the region of 1 microsecond, phenomena as fast as lighting surges can be simulated. Switching surges with a rise time in the region of several microseconds are commonly studied with this type of program.

Over a longer time frame, all the effects of dynamic models can also be represented. Furthermore, some additional phenomena, such as the transient offset of fault currents, the nonlinear effects of magnetizing impedances or power electronics, the effects of unbalanced loads, and sources and series impedances that exist in the real world of power systems can also be represented. Simpler computational tools that cannot completely represent the power system ignore many of these phenomena.

A variety of production programs using transient models exist, including EMTP, DCG-EPRI, ATP, EMTDC, PSCAD in North America, and ARENE in Europe. In this paper, this group of electromagnetic transient programs is referred to as "emtp." Most of the more commonly used programs take more than the discrete time step to calculate the solution, and therefore do not run in real time. However, some programs can be run in real time, and these are the most useful for studying relay response to power system phenomena.

Figure 8 shows some of the network phenomena that transient programs can model. The same basic turbine and generator models as the dynamic can be included, as well as the traveling wave effects of transmission lines, the nonlinear series capacitor protection, and the nonlinear magnetizing reactances of transformers.

Figure 8 Transient Model With Dynamics

The application of transient models to test protective relay performance is well established for the more complex applications. However, because the complex applications are often high speed, the effects of electromechanical dynamic phenomena are often not included in the models. As noted in the discussion of the limitations of dynamic state simulation, the transients generated during transition from nonfault to fault conditions are usually important to high-speed protection systems.

Therefore, many transient models used to test protection systems represent generators as fixed voltage sources with fixed speed, on the assumption that the time frame of electromechanical phenomena is not critical to the protection application. However, it is clear from experience that dynamic phenomena can have an effect on relay performance.

This paper will show some of the benefits of including machine dynamics in the transient model. An example of an unexpected operation of a protective relay due to a system frequency change is first presented to illustrate the fact that electromechanical phenomena can affect relay performance.

## Example Impact of Frequency Change on Distance Relay

The following real life situation shows an example of a relay responding to dynamic phenomena in a power system disturbance. A small portion of a power system became isolated with excess generation due to a fault on a single intertie with a larger integrated system. Figure 9 shows a system with a fault at location F. After CB1 opens, about 72 MW of generation becomes isolated

with about 35 MW of load. In the following frequency rise, before the machine governors could regulate frequency, the distance relay shown as Device 21 operated on load current only to isolate an 8 MW generator connected to a 25 kV distribution feeder.
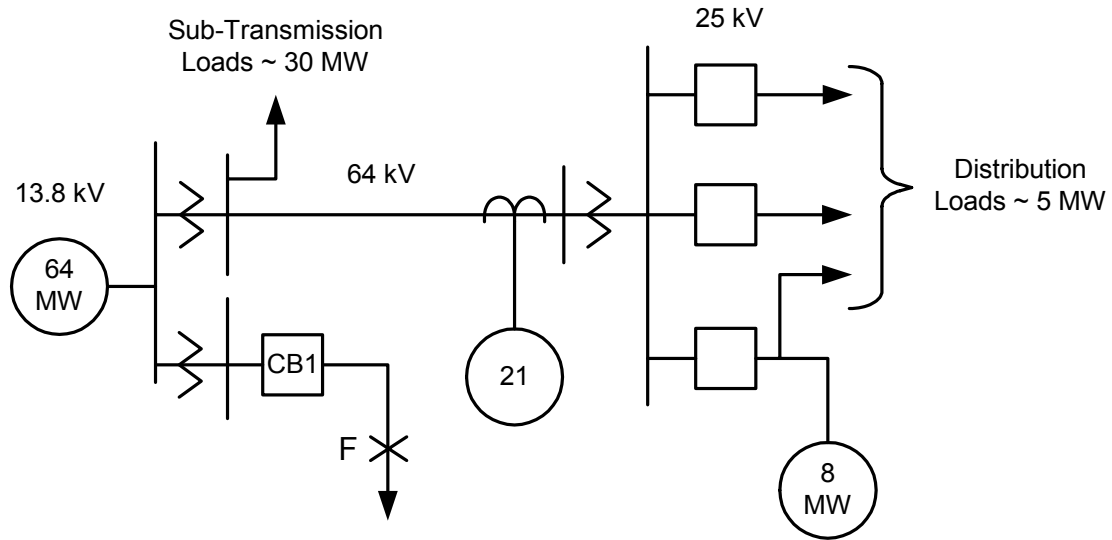
Figure 9   Isolated, Generation Rich Power System

Figure 10 shows the current and voltage measured by the relay Device 21 during the incident. The currents and voltages do not change significantly, but the phase distance elements suddenly start to operate intermittently. When the Zone 1 element operates, the relay trips the distribution connected independent power producer (IPP) unexpectedly. This operation was caused by an incorrect phase relationship between the memory-assisted polarizing voltage with respect to the measured voltage across the internal replica impedance due to the changing frequency of the measured voltage. The frequency at the time of trip was about 63 Hz. The simple mho relay models in a stability program could not have predicted the behavior of this relay.
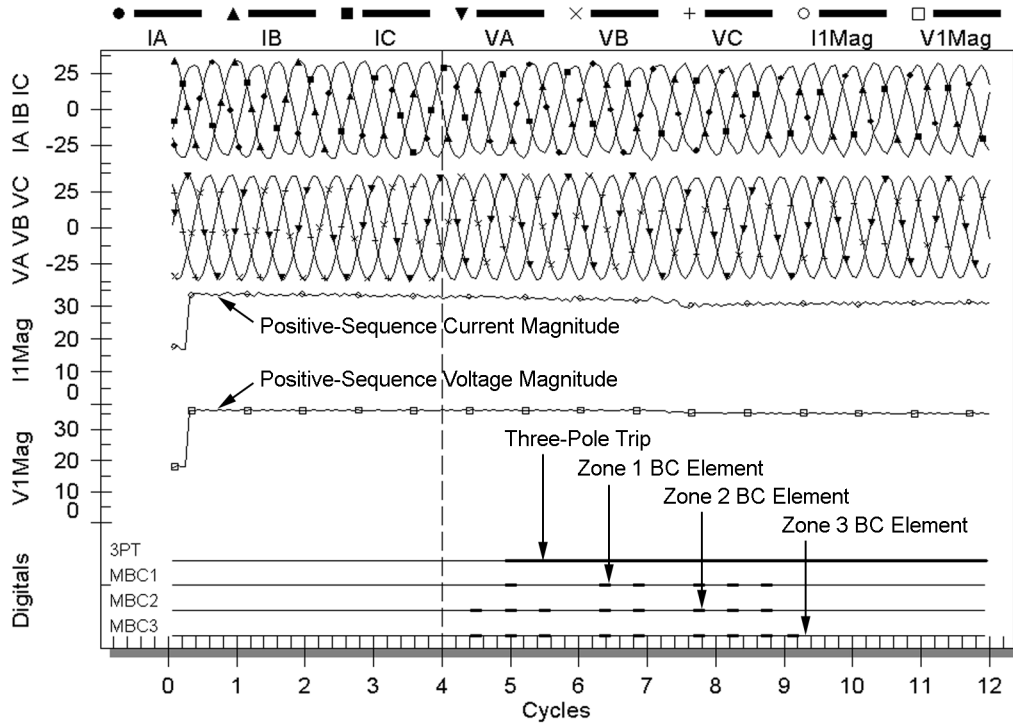
Figure 10 Frequency Rise Affects Distance Elements

If the relay had been tested with the variable frequency and load conditions that it experienced, this type of operation could have been predicted. However at the time of application of this older style of relay, users rarely tested distance relays with variable frequency. Indeed, conventional software available with commercial test sets is not normally able to replicate test voltages and currents with changing frequency under fault or no-fault conditions.

Definitions of Models

Having understood the differences between the various types of models, we can now develop some formal and informal definitions for the purposes of this paper:

- **Steady state models** are phasor based, and used for power flow or fault studies. A series of steady state simulations may be put together for dynamic state simulation testing of relays.

- **Dynamic models** are phasor based and used in stability programs to study dynamic power system phenomena in the time frame longer than about 0.05 seconds. They consist of a series of power flow solutions with parameters automatically adjusted between each solution.

- **Transient models** are based on instantaneous solutions of power system phenomena in time frames much shorter than applicable to stability models. The outputs of these models are instantaneous values of current and voltage in small time steps (much smaller than one power frequency cycle) that may be converted to analog signals for the purposes of testing relays. Transient models may simulate all power system phenomena, including the electromechanical dynamic phenomena simulated in stability programs. However, for the purposes of this paper, we consider simple transient models to not include dynamic phenomena, unless specially indicated as "**Transient models with dynamics**."

PREPARING A PRACTICAL DYNAMIC MODEL FOR STABILITY STUDIES

When dynamic models for power plants (generator, exciter, and governor) are added to a model power system for the purpose of real-time relay testing, the number and detail of these dynamic models is restricted. A reduced-size power flow case with a manageable number of dynamic system models is needed. This small dynamic model needs to retain the important characteristics of the full model, especially for the system disturbance events to be used in the relay testing program.

For relay testing purposes, the model power requires at least the test line adjacent stations and lines to be retained explicitly. To provide an acceptable reduced-size dynamic model, it will usually be necessary to retain more power system data in explicit form, especially the connections to the largest generating stations that are electrically near the test line(s).

Reduction of a full dynamic system model to a small dynamic model requires testing on the full power flow and dynamic model to determine which portions of the power system are electrically remote from the line being tested. The remote portions can be replaced in the power flow data by a voltage source behind an impedance and in the dynamic data by a generator rotor with infinite inertia (a "fixed" rotor).

It is desirable to retain the dynamic model details of generators (and exciters and governors) located near the transmission line(s) under test, along with the interconnecting lines and transformers. Model size constraints usually make it necessary to combine several generators into a single equivalent generator connected by an equivalent transmission system impedance. Comparisons of the full dynamic model and the reduced-size model determine whether these compromises provide a dynamic model that is still acceptable for relay testing purposes.

The specific transient stability program that was used for the dynamic model simulations for this paper is Shaw Power Technologies, Inc. type PSS/E™ (Power System Simulator for Engineering). In later discussions, the simulations using transient models refer to comparison with PSS/E output. However, the comments and comparisons apply to many other commercial stability programs.

IMPLEMENTING A PRACTICAL TRANSIENT MODEL WITH DYNAMICS

Building a practical transient model requires good tools. Historically, the best tool was the analog power system simulator. Constructed from discrete devices configured to replicate the power system, this tool enabled engineers to test the performance of relay systems in real time over a wide range of conditions. Many analog power system simulators included dynamic models. Through the 1980s, this tool was the state of the art.
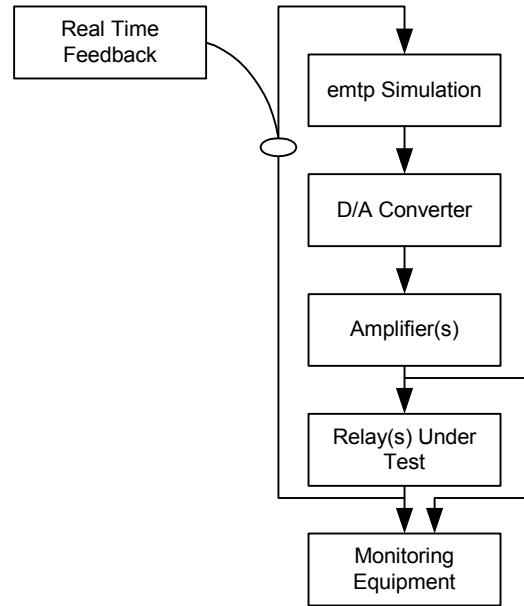
In the early 1990s, the falling cost and increasing performance of the personal computer gave virtually anyone the opportunity to use the electromagnetic transient programs (emtp). With a modest amount of effort, a utility engineer could then essentially reproduce the transient response of any part of the power system. Almost immediately, engineers found ways to play those results back through a protective relay to test its performance. While this open loop (or "playback") testing was arguably less effective than the real-time testing done on the analog simulator, the availability and relatively low cost made it very attractive. Additionally, the tests could be archived and reproduced exactly at any time, making it much easier to compare relay performance in the field with relay performance in the laboratory.

Figure 11 shows the layout of a playback test system. A major disadvantage of this system is that if the relays under test affect the power system (such as by opening breakers), the power system simulation needs to be preset with the anticipated relay performance. Getting the simulation to match the relay performance may take some iterations. Inclusion of dynamic modeling in playback emtp simulations adds an extra dimension of complexity in predicting relay response.
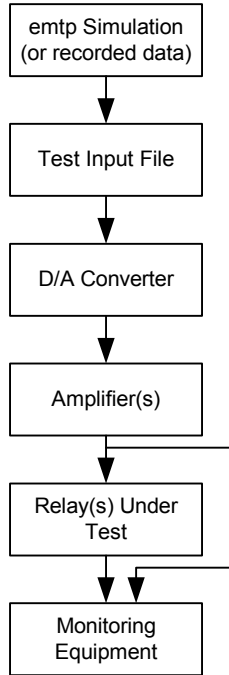
Figure 11 Transient Playback Test System   **Figure 12** Real-Time Transient Test System

The last decade has seen the development of transient programs that can run in real time. One example is the Real Time Digital Simulator (RTDS[TM]) designed to effectively test electrical and electronic devices on a power system model. While resembling emtp in its use and application, the RTDS allows inputs from the device under test to affect the model in real time, much like the analog power system simulator. For example, a digital relay receives currents, voltages, and breaker status inputs from the RTDS test system. The same relay returns a trip contact input to the RTDS test system, which causes the "circuit breaker" within the model to open.

Figure 12 shows the layout of a closed loop real-time test system. There are no test input files to be created (as was the case in Figure 11); therefore, the relay response and effect on the power system does not have to be estimated and simulated in advance. This closed loop capability extends the power of transient simulations to a much broader range (than the simple playback system) of relay testing, including single-pole tripping and reclosing, synchronizing, dynamic performance, and out-of-step functions.

SYSTEM MODEL PREPARATION AND TESTING

The following discussion is limited to the RTDS that is a specific type of real-time digital simulator. However, most of the comments apply in a general sense to typical programs used for transient simulation of power systems in real time. The RTDS (or "simulator," for future reference in this paper) is discussed simply as an example of transient simulation hardware and software because that was the technology used in the test series.

The simulator is limited in the size of the system that it can model. The simulator used for the test series on which this paper is based can simulate a maximum of 142 single-phase nodes and approximately 72 other components, such as generators, lines, transformers, CCVTs, and CTs. The goal was to create a system model that would adequately reproduce the system response to faults but would fit on the simulator.

Prior transient relay testing experience using a simulator without dynamic models suggested that an adequate system model should include a detailed representation of the line under test and system one bus removed. Comparisons of the dynamic system modeled on the simulator to the PSS/E system model verified this assumption.

The first step in preparing the system model is to reduce the whole system to an equivalent. A software utility included with a fault study program was used for this task. The system was reduced from several thousand buses to seven. Figure 13 shows an equivalent system constructed for testing a line (Circuit 5L30) between buses MSA500 and CKY500. There is also a parallel circuit that will be referred to as Circuit 5L32. The test system includes generation, loads, mutually coupled lines, 500 kV cables, series compensation, reactors, transformers, and transfer impedances. This system is also used as the small system stability model in the PSS/E system model. Dynamic machine models are added to the small system as needed to achieve a good match between large and small systems.
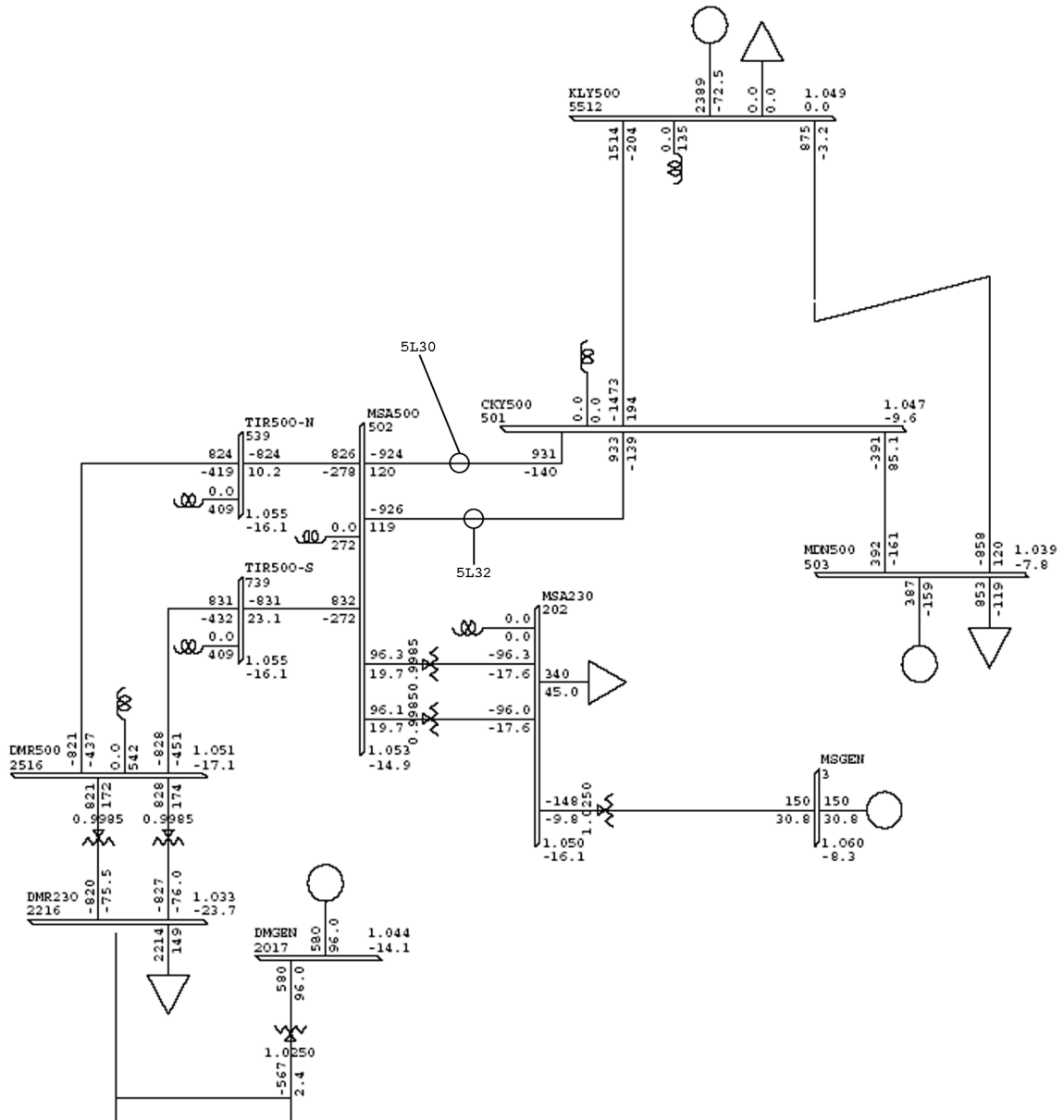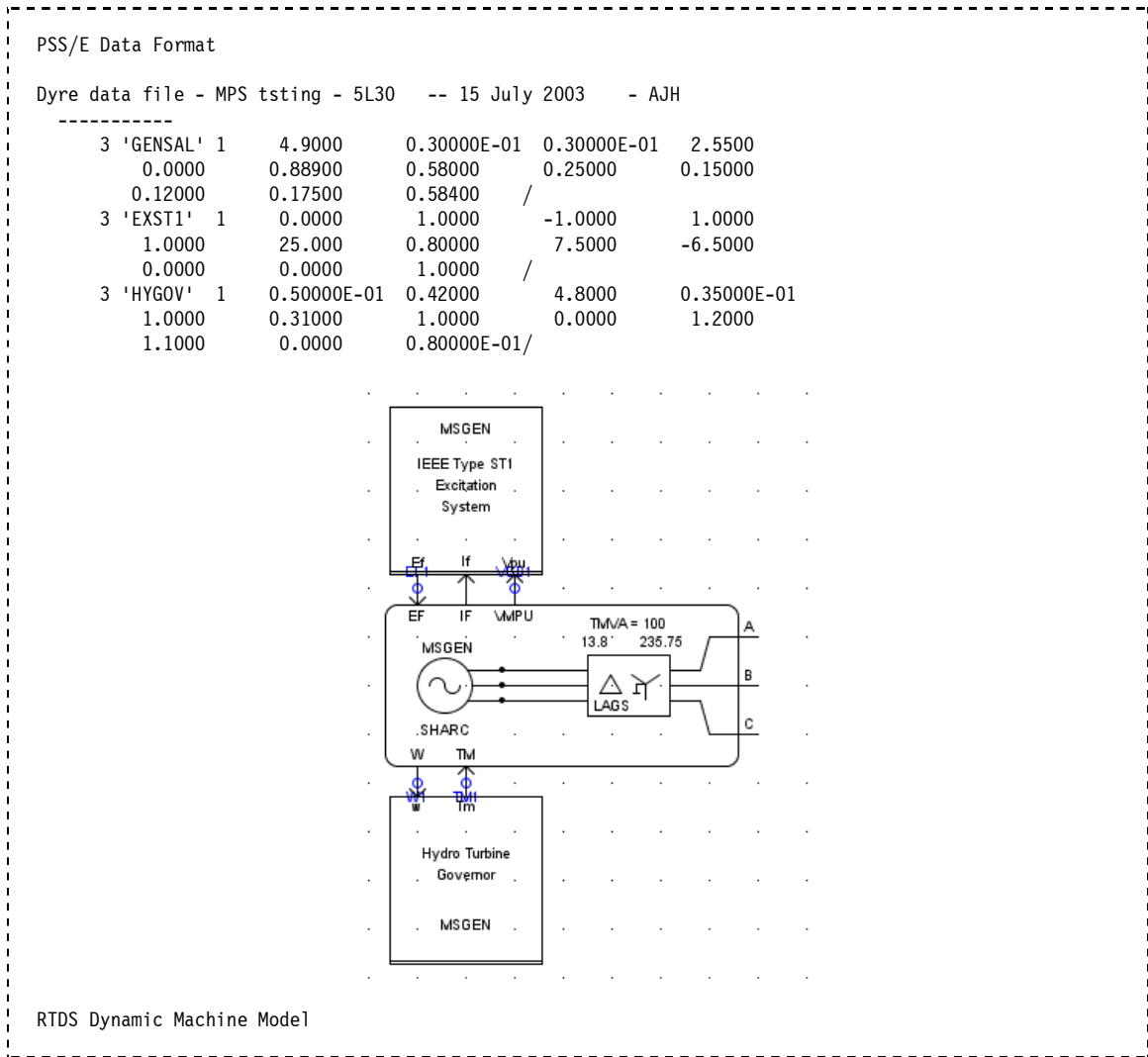
Figure 13   Small System Model

Once all the components have been modeled in the simulator test system, a power flow utility calculates the initial generator voltage magnitudes and angles. One test of the model is that the voltages and power flows calculated by the simulator match those provided by the utility's power flow program. Another test of the model is that fault currents in the model match the system fault study program. These are the usual tests performed on a model developed for transient relay testing and are not discussed further.

Once the small system dynamic model has been developed in PSS/E, the conversion from a static machine model to a dynamic machine model in the simulator is very easy for the user. Two text files containing system, machine, governor, exciter, and stabilizer data are created by PSS/E. These files are the input to a conversion program supplied by the simulator that creates the dynamic machine models. Figure 14 shows one PSS/E file input for a generator, governor, and

exciter system, and the resulting simulator machine model created by the conversion program. Within the simulator icons are all of the data items necessary to define the components.

```
PSS/E Data Format

Dyre data file - MPS tsting - 5L30   -- 15 July 2003    - AJH
   -----------
     3 'GENSAL' 1     4.9000      0.30000E-01  0.30000E-01   2.5500
          0.0000      0.88900      0.58000      0.25000      0.15000
          0.12000     0.17500      0.58400    /
     3 'EXST1'  1     0.0000       1.0000      -1.0000       1.0000
          1.0000      25.000       0.80000      7.5000      -6.5000
          0.0000      0.0000       1.0000     /
     3 'HYGOV'  1     0.50000E-01  0.42000      4.8000       0.35000E-01
          1.0000      0.31000      1.0000       0.0000       1.2000
          1.1000      0.0000       0.80000E-01/
```


Figure 14   Convert Dynamic Machine PSS/E Data to Dynamic Machine Model in RTDS

The final task before relay testing can begin is to compare dynamic results from the simulator to results from the PSS/E small system model. For the small system shown in Figure 13, a three-phase fault followed by an unsuccessful reclose was simulated close to the MSA500 bus on one of the lines to CKY500 (Circuit 5L30). Figure 15 and Figure 16 show simulator and PSS/E MSGEN quantities in the small system. The comparison seems quite good over the two-second-test interval, so it appears that the simulator and PSS/E calculations are in agreement. However, the simulator output includes some higher frequency signals (particularly in the voltage signals) that are not present in the PSS/E output. Some of this high-frequency signal will be because of measuring difficulties (in calculating voltage magnitude and angle from instantaneous values instead of phasor values) and some will be because of high-frequency transients that cannot be simulated by PSS/E.

MS GEN Speed and Angle
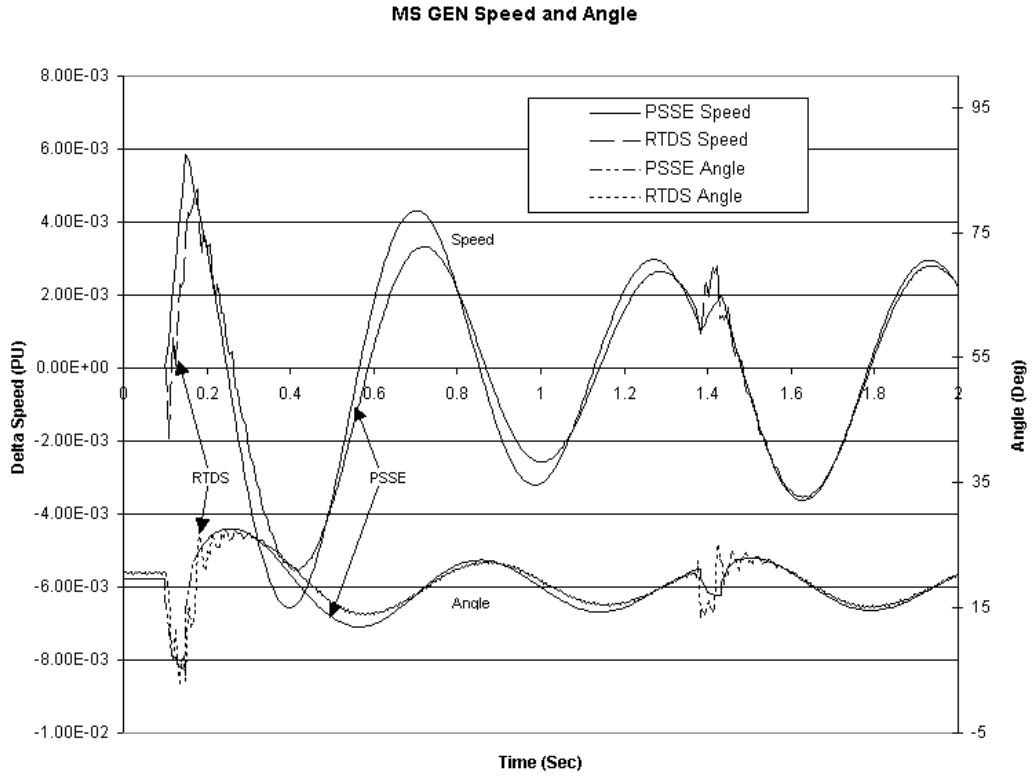
Figure 15   MSGEN Speed and Angle

MSGEN Terminal and Field Volts
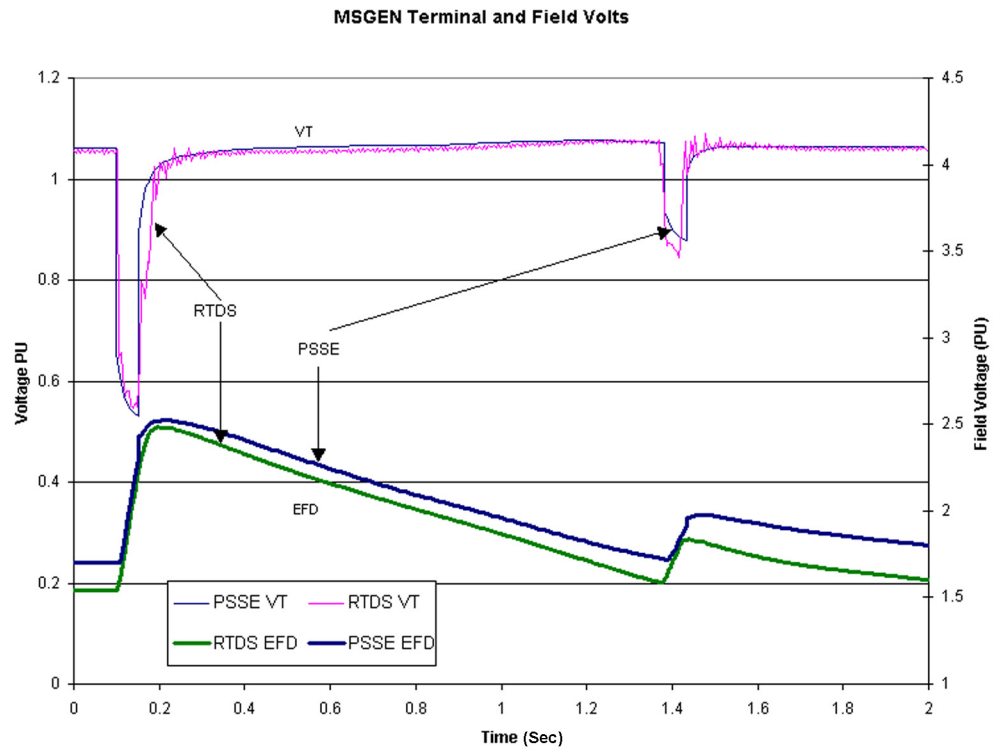

Figure 16   MSGEN Terminal and Field Volts

RELAY TESTING WITH A DYNAMIC MODEL

The RTDS is connected to the relays as shown in Figure 17. Breakers and breaker controls, current transformers, and coupling capacitor voltage transformers (CCVTs) are added to the model, and the relays are wired to the simulator interface. When everything is connected properly and the simulation started, the relays behave as if they were connected to a live power system. A fault on the protected line modeled in the simulator will cause the relays to operate, in turn causing the line breakers in the simulation to open and remove the fault. The line can then be closed manually or by automatic reclosing initiated by the relay, then returned to service. Operating the test system feels quite like operating a real system.
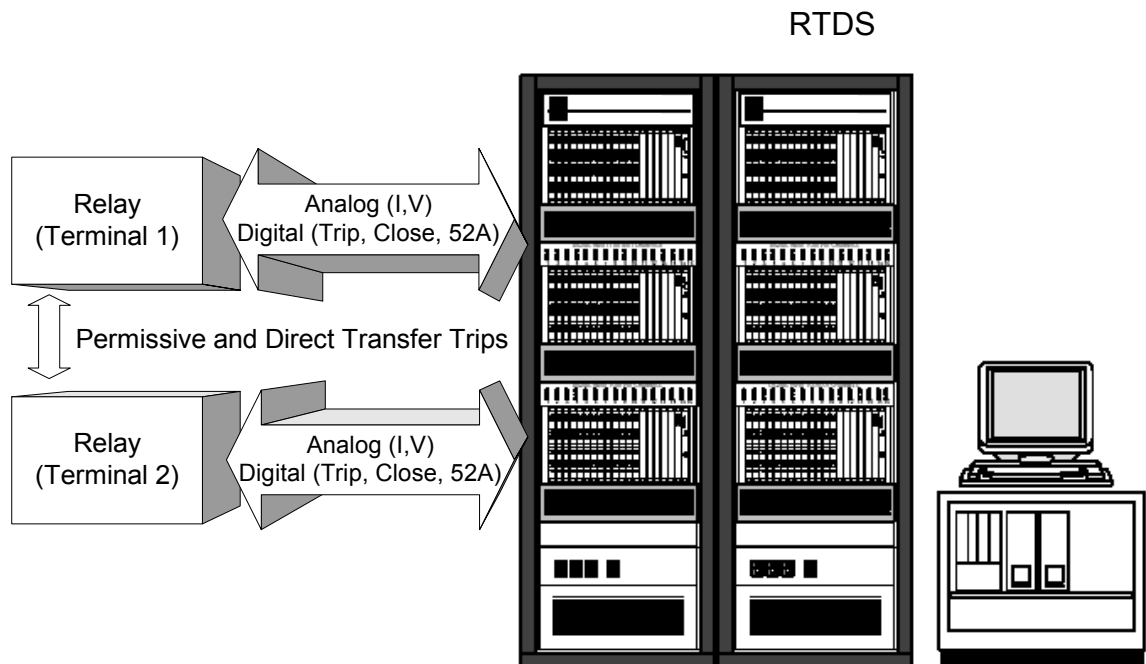

Figure 17   Test System

Many different events can be simulated, including high-resistance, cross-country, evolving, temporary, and permanent faults. Different fault incidence angles can be applied. While it is possible to manually configure the simulator to simulate and record events, it is much easier to apply faults and store fault records in a batch process. Several hundred faults are run and a COMTRADE record made for each fault during each test series. The amount of data generated can become overwhelming. To facilitate review, relay element operating times are stored in a table and plotted. Figure 18 and Figure 19 show different ways of examining the recorded fault data. Figure 18 shows relay operating times for different fault types at one location. Figure 19 shows minimum, maximum, and average relay operating times for all multiphase fault locations. Using the plotted data, you can quickly determine relay performance. The plotted data along with the COMTRADE record of each fault comprise the archived test results.
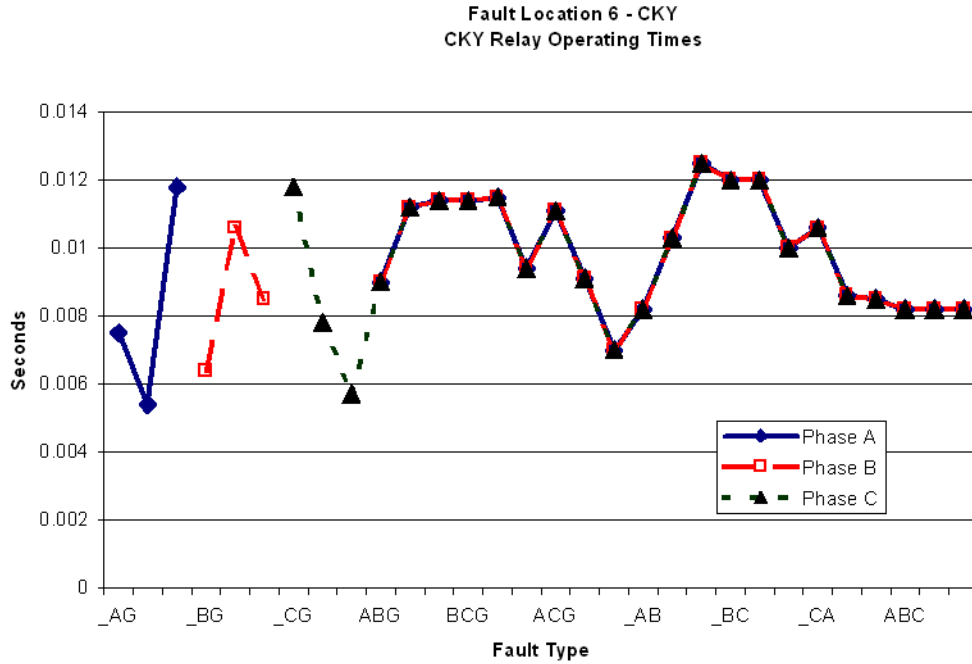
Figure 18 Relay Operating Times for Different Fault Types at One Location
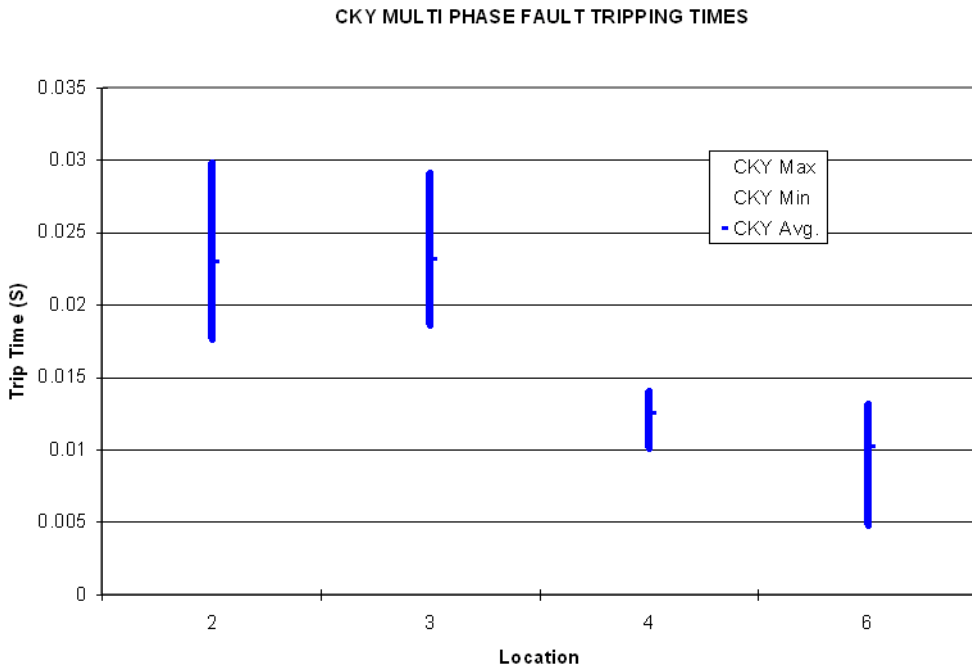
Figure 19 Relay Operating Times for All Phase Locations

SOME EXAMPLE RESULTS

Example 1

Figure 13 shows part of a power system for which some 500 kV transmission line protection systems were being tested. Circuits 5L30 and 5L32 are two parallel 500 kV transmission lines between CKY500 and MSA500 supplying load at MSA230 with some generation. There are two more parallel lines to DMR500 supplying more load and generation at DMR230. The loads at MSA230 and DMR230 always exceed the generation at those stations.

Figure 20, Figure 21, Figure 22, and Figure 23 show the results of power system fault simulations applied to the protective relays, with different results in system response, depending on the type of model and the speed of protection operation.

A three-phase short circuit was simulated near the CKY terminal of 5L30 for each of the four plots. The plots show the real and reactive power flows in Circuits 5L30 and 5L32, and also the waveforms of the three-phase voltages at the MSA 500 kV bus.

In Figure 20, the generator rotors at DMR230 and MSA230 were fixed such that they could not vary in speed (they are "locked"). All other parameters of the system model were retained. About 900 MW of power was imported into the MSA500 station through each of the circuits 5L30 and 5L32. The fault was simulated, and the protection system was allowed to operate in the normal fashion, with normal tripping speed and fault clearing and reclosing. At the CKY500 terminal, the fault was cleared in about 3 cycles (1 cycle for relay Zone 1 operation, plus two cycles for breaker). At the MSA500 terminal, the fault was cleared in about 4 cycles (1 cycle for relay Zone 2 operation, plus one cycle time for permissive trip to be sent from CKY500 to MSA500, plus two cycles for breaker). Real and reactive power flow on Circuit 5L30 was interrupted for about 1.2 seconds, until the line was automatically reclosed at the CKY500 and MSA500 terminals.

Figure 21 shows the results of a test with all parameters the same as in Figure 20, except that the generator rotors were not locked and were allowed to respond to disturbances with their normal electromechanical dynamics. There is little difference between the two system models. The similarity between the two figures illustrates why it is often acceptable to ignore system dynamic response when testing high-speed protection. The power system is usually designed to be affected only slightly by faults with high-speed clearing.

The results of similar simulations are shown in Figure 22 and Figure 23, with an important difference. In these cases, the communications assistance between the two terminals was deliberately disabled. As before, the CKY500 terminal cleared the fault quickly, but this time the MSA500 terminal fault clearing was delayed to about 18 cycles by the Zone 2 timer. For both cases, the voltage at MSA500 is depressed for much longer than was the case for high-speed clearing. Also, since there was no high-speed tripping, the automatic reclosing of circuit 5L30 was blocked as designed. The end result was that the original 900 MW of imported power that was split between two circuits was transferred completely to the unfaulted Circuit 5L32.

The difference between Figure 22 and Figure 23 is much more dramatic than between Figure 20 and Figure 21. The power swings much more in Circuit 5L32 when the generators are allowed to respond as expected. There are also significantly larger voltage fluctuations on the MSA500 bus. The larger power swings on Circuit 5L32 impact the system significantly. The exacerbation of the disturbance by the time-delayed tripping is the reason that automatic reclosing on BC Hydro's

EHV transmission lines is blocked by time-delayed tripping. The intention is to avoid a second large disturbance in the event that the fault that caused tripping was not temporary.

The difference between Figure 22 and Figure 23 demonstrates that modeling of dynamic phenomena is much more important during protection system tests when time intervals of more than a few cycles are involved. In this case, the 18-cycle clearing time by the time-delayed protection had an impact that could be revealed only by dynamic modeling.
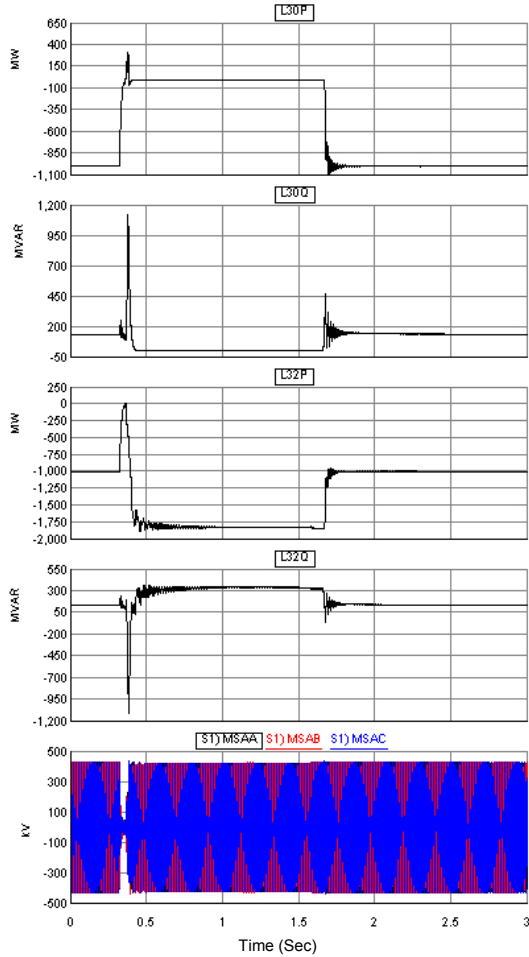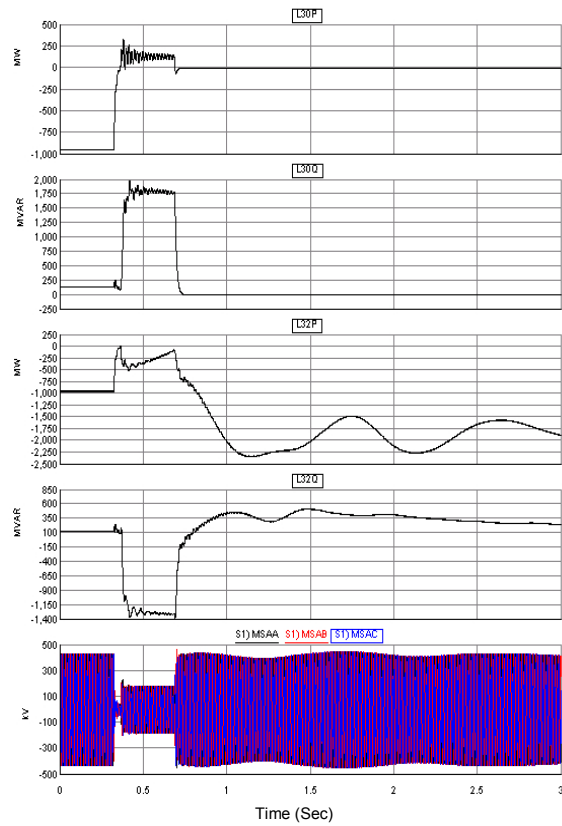

Figure 20   Power System Fault Simulation—
Locked Rotors, Normal Clearing
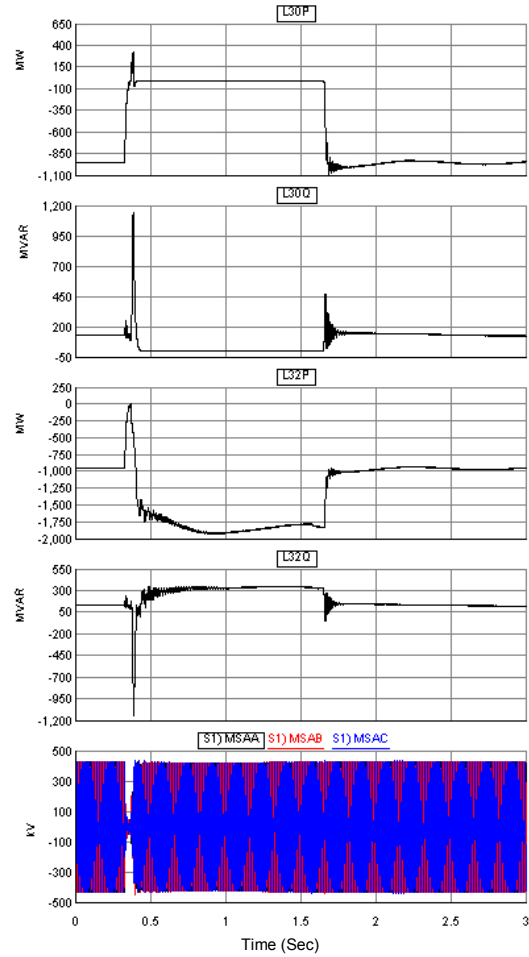
Figure 21   Power System Fault Simulation—
Free Rotors, Normal Clearing

24
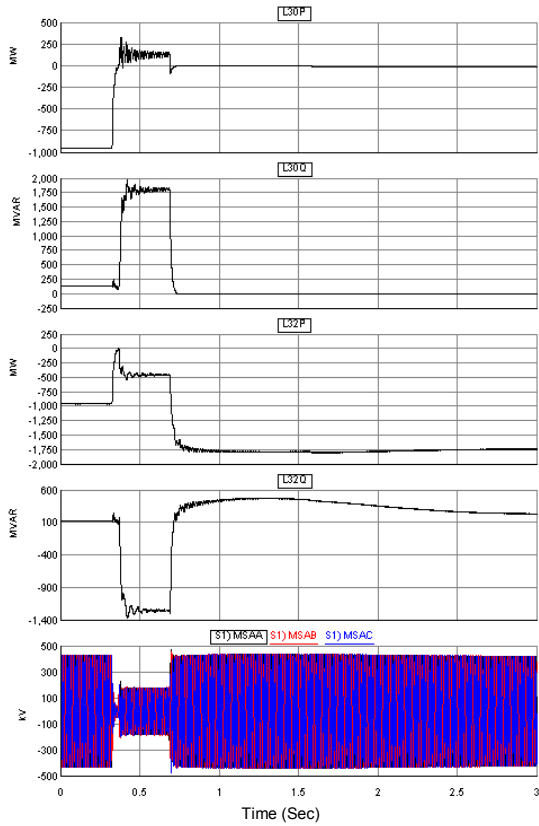
Figure 22 Power System Fault Simulation—
Locked Rotors, Delayed Clearing

Figure 23 Power System Fault Simulation—
Free Rotors, Delayed Clearing

Example 2

Having understood the increased effects of dynamic phenomena over time frames longer than a few cycles, consider the effect on protection systems during a single-phase trip and reclose example. Figure 25 shows the response of a protection system to a single line-to-ground fault simulated with single-phase trip and reclose. The protection system was applied on a 330 km long, 500 kV transmission line (5L98) that was the sole intertie between two large systems shown in Figure 24. The prefault power transmission was close to 1700 MW.
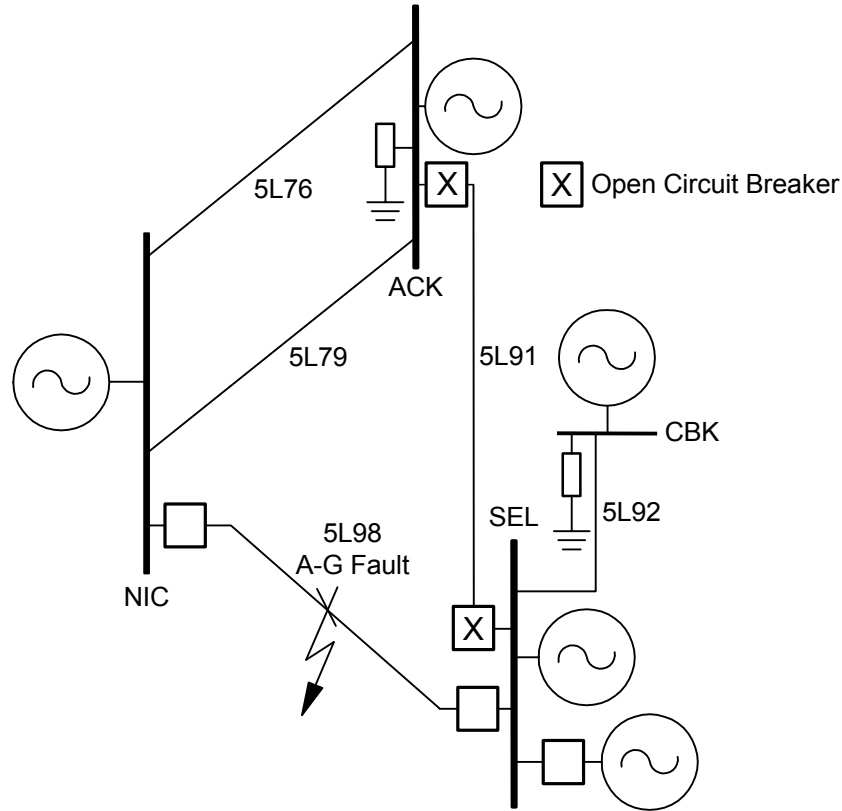
Figure 24   Line 5L98, Nicola to Selkirk

The single line-to-ground fault was simulated complete with preplanned remedial actions. Recognizing that the stability of the intertie would be strained at such a large power transfer, system planners had anticipated that 350 MW of generation should be automatically shed if a single phase tripped under the test conditions. The generation shedding was also simulated in the digital simulator.

As can be seen from Figure 25, the protection system senses the close-in, temporary single line-to-ground fault and correctly trips the faulted phase, at time t = 4 cycles, then successfully automatically recloses at time t = 66 cycles. The large current seen for 30 cycles after the automatic reclose simply indicates that only one of the two circuit breakers at the line terminal was reclosed initially. The current traces show the currents through the two-line terminal breakers individually. Thirty cycles after the first breaker recloses, the second breaker recloses as planned, and the two switches share the load current equally. The transient offset of the initial current in the first breaker to be closed illustrates that a transient simulation is being performed. However, in the case of Figure 25, the rotors of the equivalent generators at the power sending terminal are locked in a similar fashion to the simulations shown in Figure 20 and Figure 22.
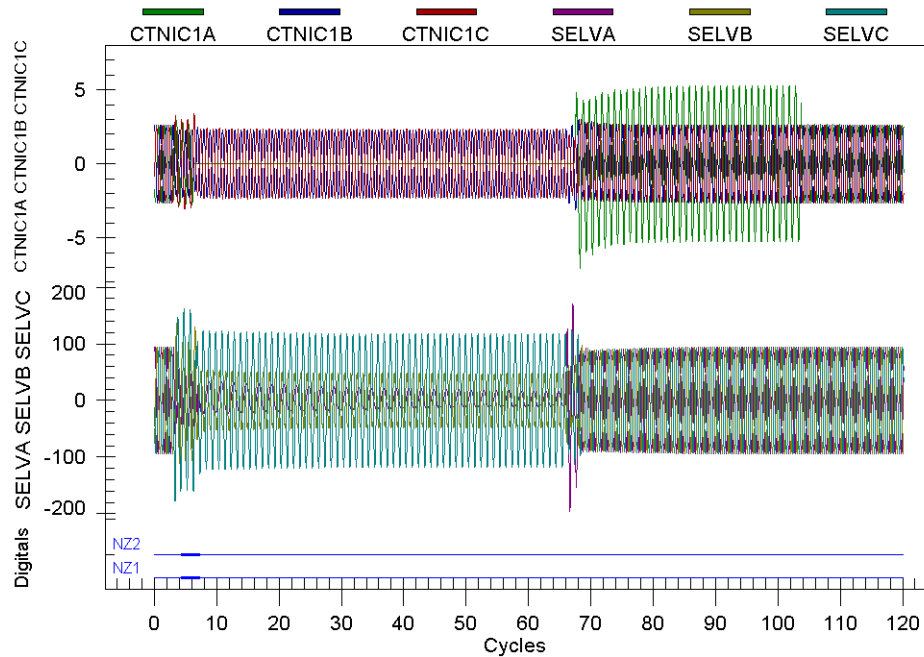
Figure 25   Single-Phase Trip and Reclose Without Dynamics

The simulation was repeated with all parameters the same except that the rotors of the simulated generators were unlocked, with the results shown in Figure 26. Figure 26 shows that the fault was correctly detected and cleared within four cycles (similar to the case in Figure 20).

However, in this second case, the electromechanical advancement of the generator rotor angles at the power sending end was allowed to proceed, as the transfer capability of the transmission line through only two phases instead of three was significantly reduced. Therefore, a significant power swing commenced and increased in severity during the period the single phase was open. At time t = 34 cycles, the apparent impedance presented to the relay at the sending end entered the Zone 2 characteristic. At time t = 52 cycles, the impedance entered the relay Zone 2 characteristic at the receiving terminal and permissive tripping resulted. The relay distance calculation at the receiving terminal is shown in Figure 27. Note the smooth change in the distance calculation during the swing, as opposed to an abrupt transition during a fault. This simulation demonstrated that the planned protection with its settings was not capable of carrying this much power under single-phase tripped conditions. The allowable power flow was reduced to 1350 MW and the protection performed acceptably.
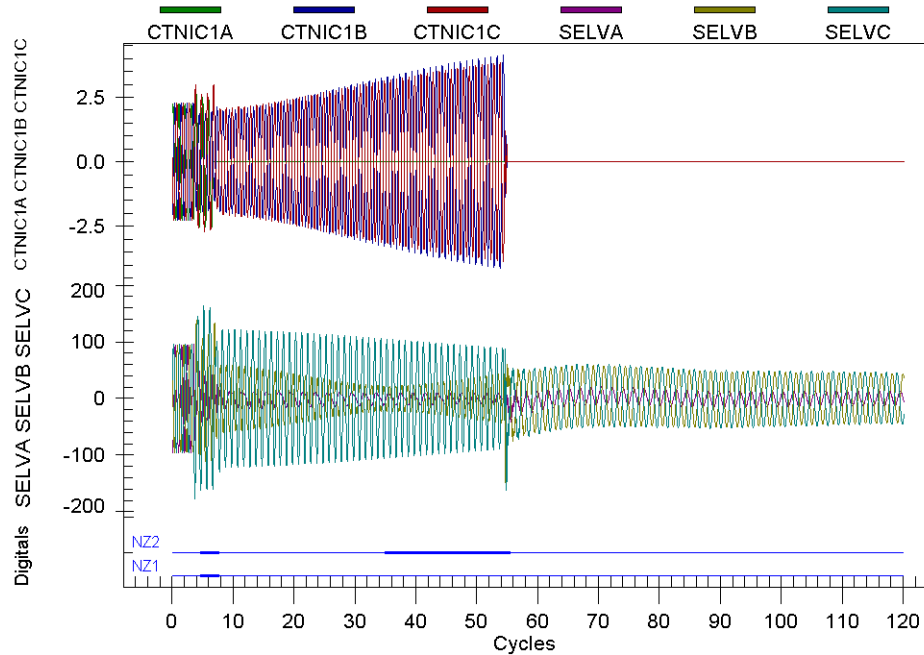
**Figure 26**   Single-Phase Trip and Three-Phase Trip With Dynamics
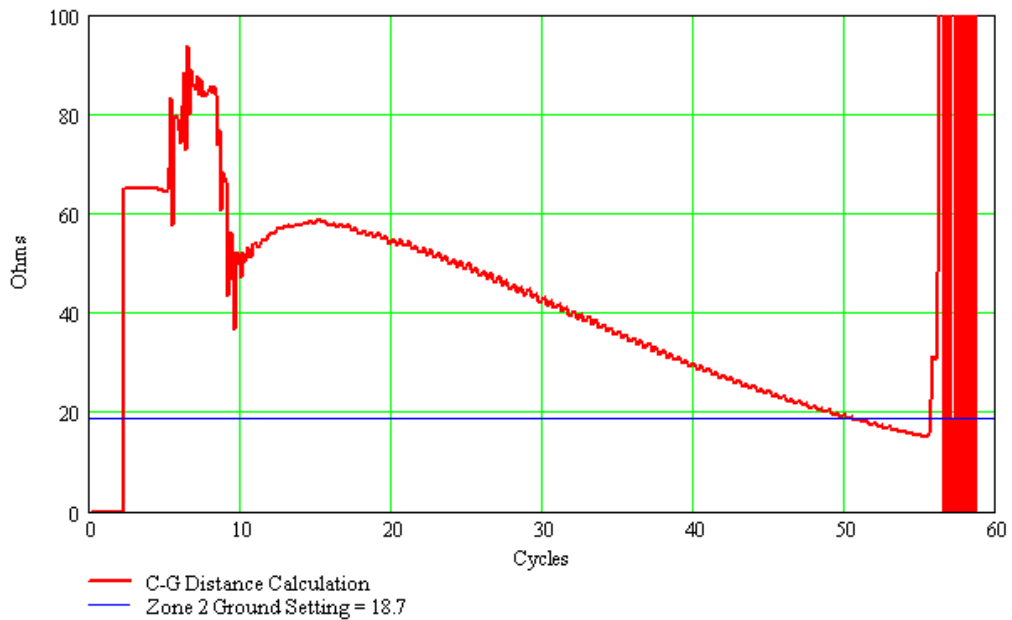
Figure 27   Receiving End Relay C-Ground Distance Calculation During Power Swing

This comparison of the two cases demonstrates how the dynamic representation of the power system in the transient simulation challenged the protection more than if the dynamics had not been represented. The challenge revealed a load transfer limitation that would not otherwise have been identified.
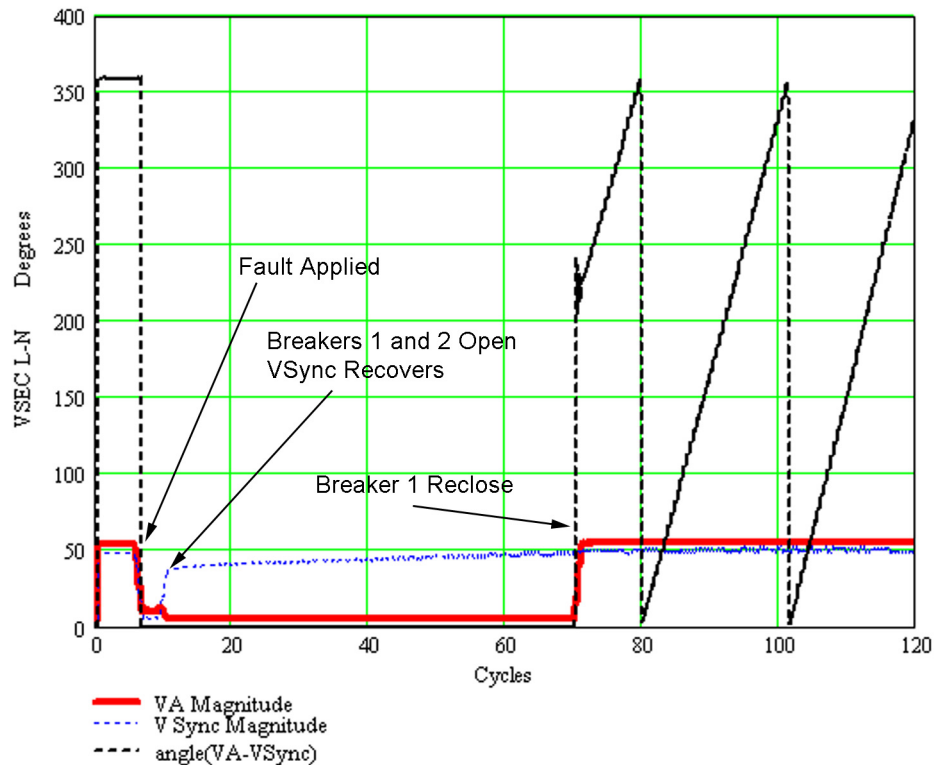
Example 3

While performing tests on a system with dynamic machine models, the system was configured as shown in Figure 28 with one line between two sources. After a multiphase fault on the line under test, Breaker 1 on the left reclosed successfully, but the follower Breaker 2 on the right failed to reclose. Reclosing was supervised by a ±20 degree angle check that did not allow slip between line and synchronizing voltage. Examination of the event report showed that the line voltage was slipping with respect to the synchronizing voltage.
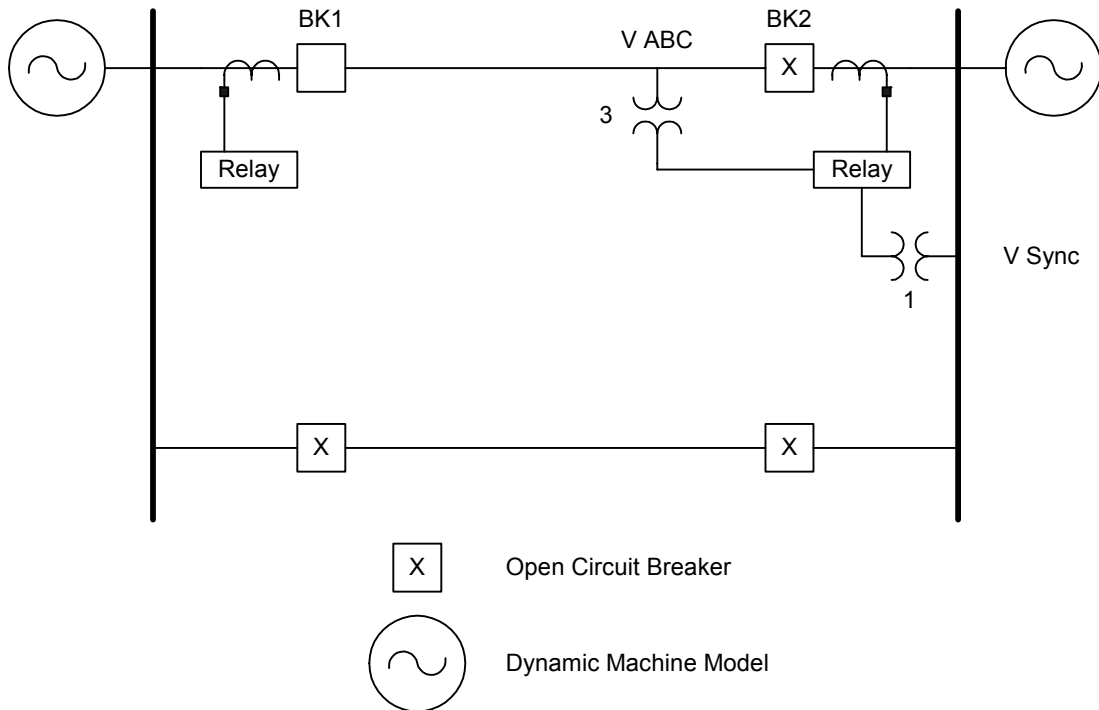
Figure 28   Test System at Unsuccessful Reclose Time

Figure 29 shows the line voltage magnitude, synchronizing voltage magnitude, and the angular difference between the two during the event. After Breaker 1 reclosed, the line voltage was slipping with respect to the synchronizing voltage at a rate of almost 3 Hz. While it was known in advance that a synchronizing check was required at this point in the system, the dynamic machine model provided immediate confirmation of this during the relay test.

Figure 29   Line Voltage, Synchronizing Voltage, and Angle Difference

Example 4

As the 5L98 single-phase tripping example illustrated, dynamic phenomena increase in importance during heavy load transfers and single-phase tripping of transmission lines.

One feature that could decrease the duration of the open-phase interval is secondary arc extinction detection (SAED), as described in [5]. Part of the logic that determines that the secondary arc has extinguished is the increase of voltage (secondary arc recovery voltage) on the faulted phase after the secondary arc has been extinguished. The magnitude of the secondary arc recovery voltage can be determined by transient simulation that models the capacitive and inductive coupling between the faulted phase and the healthy phases. Figure 30 shows the voltages and currents in BC Hydro's circuit 5L30 during a particular sequence of events. The events simulated are as follows.

t < 6 cycles	Circuits 5L30 and 5L32 are both in service under heavy load importing 900 MW each to Malaspina substation.
6 < t < 10 cycles	A simultaneous three-phase fault on Circuit 5L32 and single-phase fault on Circuit 5L30 occurs. Simultaneous faults have occurred on these circuits in the past.
10 < t < 14 cycles	The three-phase fault on Circuit 5L32 is cleared, but the single phase-to-ground fault on Circuit 5L30 has not been cleared yet.

14 < t < 83 cycles	Circuit 5L32 is open three-phase and 5L30 has one phase open.
t = 18 cycles	The secondary arc at the fault is extinguished, and the voltage of the faulted phase jumps from about 22 kV to 46 kV.
t = 58 cycles	Voltage on the faulted phase swings down to a minimum of 25 kV.
83 < t < 86 cycles	Circuit 5L32 is reclosed onto a permanent three-phase fault.
86 < t < 94 cycles	Circuit 5L32 is tripped three-phase again, and the Cheekye end of Circuit 5L30 is successfully reclosed.
94 < t cycles	Circuit 5L30 is reclosed at the follow terminal (Malaspina) and carries the full load that was previously carried by both circuits.

As shown in Figure 30, during the period when there were only two phases carrying the power that was previously carried by six phases, a power swing was started. The voltages started to swing down, and the currents started to swing up. At about t = 55 cycles, the swing started to recover and the voltages started to recover. It is interesting to note that during the power swing, the voltage on the faulted phase that had recovered due to extinction of the secondary arc also started to decrease, to a minimum of about 25 kV.
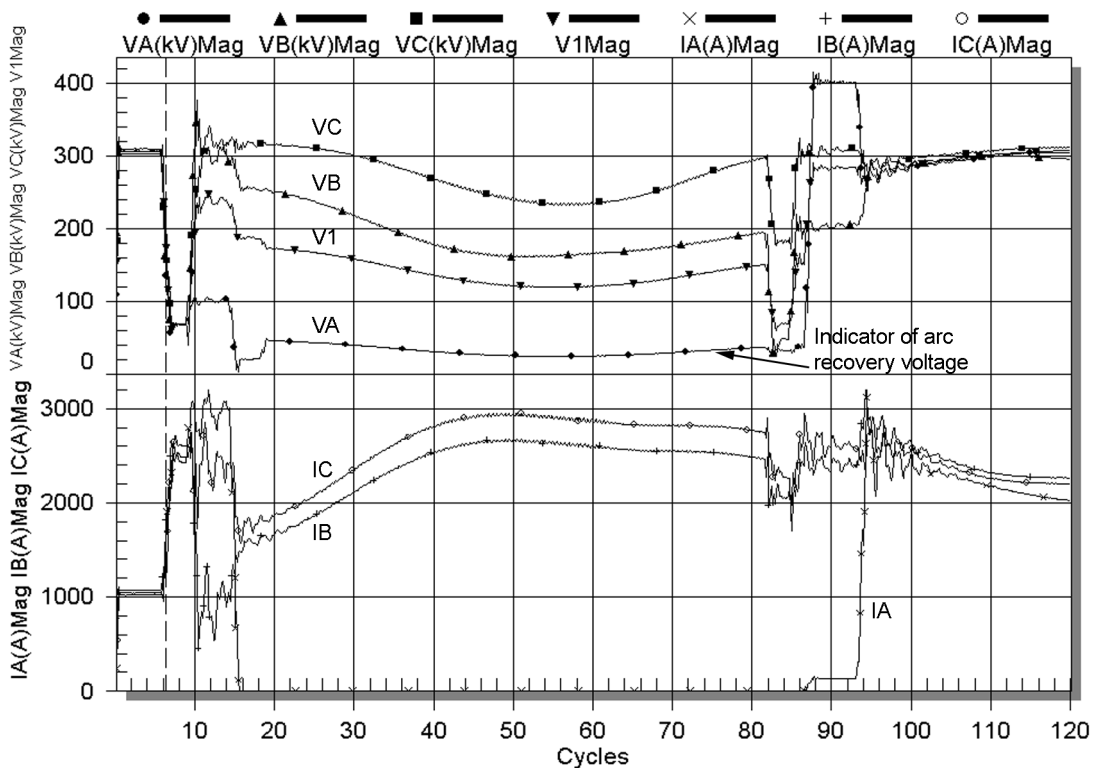
Figure 30   Power Swing During Open Pole Period

This decrease in faulted phase recovery voltage means that the setting of the voltage level detector in SAED logic needs to be chosen with care. Without the consideration of dynamic phenomena, a setting somewhere between 22 kV and 46 kV might have been selected (for example, 36 kV). However, a setting of 36 kV would have been too high to allow dependable

detection of secondary arc extinction if it had occurred near the time t = 55 cycles. The faulted phase voltage increases again to about 36 kV just before the single phase is reclosed.

Simulation of the dynamic phenomena has allowed understanding of the voltage versus time characteristics of the voltage on the faulted phase and optimized selection of the voltage magnitude criterion in the SAED logic.

It should be noted that the simulation of the dynamic phenomena has also allowed observation of the magnitudes of the individual phase voltages during the power swing. This allows more knowledgeable selection of the setting of the voltage function supervising automatic reclosing at the follower terminal. It should also be noted that the positive-sequence voltage magnitude that is calculated by conventional stability programs would not have provided the detailed phase-by-phase voltage information provided by the transient model with dynamic phenomena included.

CONCLUSION

This paper reviewed the various types of test signals that may be applied to protective relays. Various types of power system models that may be used to produce test signals were discussed. It has become clear that modeling of dynamic phenomena in transient models of the power system can provide useful information that can lead to better application and settings of protection systems. The dynamic phenomena are more important when the impact of parameters over a time period of more than a few cycles is investigated.

A real-time digital simulator with dynamic models, in addition to the transient models, provides a comprehensive test system to determine protection performance in the transient time frame (less than a few cycles) and in the longer term dynamic time frame. The dynamic models used for stability studies in a large power system may be reduced to a sufficiently accurate smaller system suitable for a transient simulator with limited capabilities. However, care should be taken to validate the reduced system model against the larger model. Validation checks between the transient simulator and the stability program applied to the reduced model showed satisfactory agreement.

There is a lack of commercial software to convert the output of dynamic programs (time-varying balanced set of three-phase phasors) to continuously varying waveforms (suitable for injection into relays). Such software would facilitate the testing of frequency relays and out-of-step relays for their response to dynamic phenomena using commercial test equipment of lower complexity than the real-time digital simulator.

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BIOGRAPHIES

Charlie Henville received a B.A. and M.A. from Cambridge University in England in 1969 and 1974, respectively, and the Meng. from the University of British Columbia in 1996. He has 26 years of experience with protection engineering and is presently a principal engineer with BC Hydro. He is a member of the IEEE Power System Relay Committee (PSRC) and is active in several working groups. He is presently Secretary of the PSRC.

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Ralph W. Folkers received his B.S. (1973) and M.S. (1993) in Electrical Engineering from Iowa State University. He joined Iowa Public Service in 1978, specializing in substation operations and design, electric metering, and system protection. In 1998 he joined the Research and Development Group of Schweitzer Engineering Laboratories as a Power Engineer and is currently a Research Engineer in the Government Services Division. He has been a registered Professional Engineer in the State of Iowa since 1979.

Rudi Wierckx graduated from the University of Manitoba with a B.Sc. (EE) in 1983 and an M.Sc. in 1985. Between 1985 and 1993, he was employed at the Manitoba HVDC Research Center, working on the development of the RTDS digital simulator. In 1993 he left the Research Center to form RTDS Technologies, Inc. and is currently a director of that company.