



Transient Testing of Protective Relays: Study of Benefits and Methodology

Final Project Report

Power Systems Engineering Research Center

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Power Systems Engineering Research Center

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Executive Summary

The operational security of the power system depends upon the successful performance of the thousands of relays that protect the system from cascading failures, that protect equipment, and that help balance load with generation when system frequency is too low or too high. The failure of a relay to operate as intended may jeopardize the stability of the entire system and equipment in it. In fact, major system failures after a disturbance are more likely to be caused by unintended protective relay operation rather than by the failure of a relay to take an action at all.

Appropriate relay testing provides one line of defense against relay failures. Relay testing can help validate the design of relay logic, compare the performance of different relays, verify selection of relay settings, identify system conditions that might cause unintended relay operation, and carry out post-event analysis to understand the causes of unintended or incorrect relay actions.

Relay testing improvements need to continue because of the new demands placed on relays from power system conditions that are more variable in the past, because of high customer expectations for power delivery reliability, and because of changing relay technologies. The research described in this report describes new approaches for testing distance relays, generator protection relays, and underfrequency load shedding relays. Results are provided for actual relay testing.

Part I: Distance Relay Tests (Texas A&M University)

Distance relay testing can evaluate relay performance, calibrate relay settings, and identify system conditions that could cause unexpected relay operation. Developing a relay testing methodology requires consideration of how to model the power system to simulate specific system disturbances, how to select and generate test scenarios, and how to execute relay tests efficiently. The efficiency and effectiveness of relay testing can be enhanced with a test case library containing scenarios that enable consistent yet robust testing. In this research, a laboratory was used to test three different distance relays using a proposed test methodology with associated test tools and test case library. The testing focused on protective relay operation under transients. Conformance and compliance tests were conducted.

- *Conformance Test:* The objective is to test the basic functionality of a relay, to verify its operating characteristics, to calibrate the relay settings, and to implement periodic maintenance testing. Statistical performance data are collected on relay operating characteristics and tripping times using wide-ranging disturbance conditions generated through simulation.
- *Compliance Test:* The objective is to test if actual relay performance matches expected performance under atypical yet possible power system conditions. The trip/no trip responses and relay operating time performance are measured under specific scenarios. Compliance tests can be used in a post-event analysis to analyze the causes of an unwanted relay operation.

The IEEE Power System Relaying Committee (PSRC) reference model and IEEE 14-bus system were used to simulate disturbance scenarios. Software programs were developed for automated testing for creating test cases, executing batch tests, and

collecting relay event reports. The test case library included test scenarios, records from digital fault recorders (DFRs) and blackout scenarios of interest.

Test results provided information that was not documented in the relay manuals, and that definitely could affect proper coordination and performance of the relaying schemes. The conformance test results indicated that relay operating characteristics should be carefully selected applied to improve the dependability of the relaying scheme. The compliance test results indicated that the zone 3 relays operated incorrectly in a few unusual power system operating conditions. Thus, quadrilateral operating characteristic may be needed to assure correct relay responses.

Part II: Generator Relay Tests (Georgia Institute of Technology)

Protective generator relays are usually tested against simplified generator models or simplified test signals. Many factors may vary with the location and generator, including the impedances of the network to where the generator is connected to, operating point, grounding arrangements, etc. The testing also should ensure that the settings of the relay are consistent with the intended protection scheme. Generator relay tests using realistic models of the generator and the electric power system can verify consistent behavior of a relay regardless of the protected generator, and assert that the intended protection schemes are robust for a variety of fault conditions.

A comprehensive testing platform was built to reproduce and simulate conditions in the system as close to reality as possible. The platform included (a) a power system simulator to accurately compute short-circuit conditions as seen in an actual system by the protective relays; (b) a signal conditioning unit that reproduces the simulated voltages and currents at relay instrumentation voltage and current level, as if they were delivered by actual potential and current transformers; and (c) a set of procedures to conduct and validate the different tests of the generator relay, including relay connections, software configuration, and different test scenarios. A comprehensive set of generator transient events were created to exercise all the functions of a modern generator relay.

For accurate testing, as many common characteristics of all generators are needed to simulate generator responses that are as close to field observations as possible. To achieve the highest accuracy possible, the software platform included a full time domain, transient, two-axis synchronous generator model with access to generator windings for fault creation in the windings.

The simulation software models the power system more accurately than most other existing approaches. The simulation software is based on full three-phase models of power system components that are described by their physical parameters. The simulator accurately simulates the dynamics of the models by using the quadratic numerical integration method, which is more precise compared to other methods commonly used methods in power system analysis.

Using virtual relay testing, configuration and waveform data were sent directly to the inputs of the relay functions, and the relay outputs were processed on the host computer with the benefits of specialized analysis software. Virtual testing facilitates relay testing by eliminating the constraints of a hardware setup, including waveform generation, wiring, and communications.

Comprehensive transient testing was conducted on two different generator protective relays. The detailed results are given in the report.

Part III: Underfrequency Load Shedding Relay Tests (Wichita State University Researchers)

If insufficient generation is available on the system to maintain stability, non-critical loads can be removed (or shed) from the system to restore a balanced condition. Such methods of automatic load shedding are designed as a last resort to prevent a major system outage. Underfrequency load shedding (UFLS) relays detect overload conditions by sensing low system frequency and shedding enough load to rebalance generation and load, and reestablish the nominal frequency. UFLS relays are able to automatically restore load after frequency recovery. UFLS is an effective and reliable method that helps to prevent blackouts.

A review of the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, prepared by the U.S.-Canada Power System Outage Task Force, indicates that, during the cascading events leading up to the widespread blackout:

- UFLS relays operated properly, according to their settings
- Settings for some UFLS relays may not have been appropriate for their applications
- Regardless of settings, load shedding by UFLS and undervoltage relays would not be expected to mitigate the magnitude of events that occurred during this disturbance.

While UFLS relays appeared to operate as set during the 2003 blackout, a number of issues regarding their operation were nevertheless identified. These issues, which are not addressed by conventional relay test methods, include the effects on relay operation of:

- Rate of change of frequency
- Continuous, rather than step, changes in frequency
- Rapid fluctuations, including both increases and decreases, in frequency
- Overfrequency events
- Other events identified by simulation or recording of actual events.

To address these issues, two test protocols, which go beyond those tests usually performed using commercial UFLS relay test systems, were developed. The conformance test protocol subjects a relay to a series of tests whose values are determined by the relay specifications. The application test protocol subjects the relay to events generated through simulations of a typical system using electromagnetic transients software. A third set of tests can also be performed if actual recorded event data is available. Recorded events can be played back in the laboratory to determine relay response to actual events.

Both conformance and application tests were performed on two commonly-used digital UFLS relays. Relay response was out of manufacturers' specifications for some of the tests. Industry team members indicated, that the magnitude of the errors identified were well within tolerances expected by industry, and that such errors had no practical effect on the relays' abilities to shed load as expected during underfrequency events.

Future Work:

It has been recognized that forming a library of test cases using records from blackouts or common power system model would be quite beneficial. Developing methodology and tools for both laboratory and field testing aimed at evaluating how GPS synchronized IEDs, including relays, will perform under various operating conditions is also needed.

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1.0 Introduction

This report summarizes results from PSERC project T-30, “Transient Testing of Protective Relays: Study of Benefits and Methodology”, which was a joint project conducted by Texas A&M University (TAMU), Georgia Institute of Technology (GaTech) and Wichita State University (WSU).

The TAMU team focused on the study of distance relay behavior under transient and dynamic conditions. The GaTech team studied generator protection test requirements and developed test methods. The WSU team approached load shedding relay test requirements and performed series of tests to evaluate their performance. All activities were aimed at specifying test requirements that reflect some difficult real time scenarios and implementing novel test methodology and tools to perform such tests.

2.0 Part I: Distance Relay Test (TAMU)

2.1 Introduction

The security and reliability of power system highly depend on the performance of the thousands of relays. The correct operation of protective relay is supposed to clear the fault, as well as reduce and/or eliminate the impact of disturbances on power system. On the contrary, unintended or incorrect operation may further deteriorate the system condition and even jeopardize the stability of the entire system. A review of major system disturbances, such as blackouts, indicates that a fatal consequence of a disturbance is more likely to be caused by an unintended operation of a protective relay rather than the non-action [1].

Appropriate relay testing should help validate the design of the relay logic, compare the performance of different relays, verify selection of relay settings, identify vulnerable conditions apt to causing unintended operations, and carry out post-event analysis for the understanding of unintended or incorrect relay behavior. Many scientists and engineers have put much effort in developing testing tools and methodologies. The Power System Relaying Committee of the IEEE Power Engineering Society formed the working group for Relay Performance Testing (I-13) in 1989, which promoted development of new relay test approaches.

This section of the report describes the test classification, methodology, power system modeling, test scenario generation, and creation of library of test case for testing distance relays for transmission line protection. It also comments on implementation and execution of tests on distance relays in TAMU's lab, as well as on the results obtained by such tests.

According to the difference in the input signals, the relay tests can be classified into two categories: phasor-based and transient-based.

Phasor-based relay tests: Predefined phasors representing different pre-fault and fault condition are used. Test waveforms can be derived by simulation from a simple power system model. The ideal sinusoidal signals are then replayed into relay inputs. By adjusting the magnitude and angle of the signals, the operating characteristic of a relay is measured and compared to a generic one or the one given by the vendor.

Phasor-based relay testing method is a traditional one, which was widely used in the field in the past. This steady state method cannot represent an actual situation during a fault and may not be used to fully verify the security or dependability of a relay [2].

Transient-based relay tests: Transient signals used during testing represent actual transients generated during faults. They are replayed into a relay through a digital simulator. The transient signals can be obtained from simulated fault scenarios or recorded waveforms from substations. Results of transient-based relay testing are more

accurate than those of traditional phasor-based methods because the waveforms are much closer to the real fault signals [3].

2.2 Test Methodology

The test methodology including comprehensive power system modeling, generating test scenarios, automating simulation and forming test case library is given as follows:

- Select “standard” power system models suitable for creating different disturbance scenarios.
- Generate a set of test scenarios through simulation, and/or collect disturbances of interest from digital fault recorder (DFR) and blackout events. Form a library of test cases for easy reuse and utilization as a reference.
- Automate the simulation to minimize the test time.
- Implement comparative tests for a set of different relays with similar functions.
- Collect relay response events, analyze the results and summarize them in a test report with comparative results.

2.2.1 Test Classification

The transient tests for distance relay were the focus of the TAMU group study. Two different types of tests with different test objectives are defined: conformance test and compliance test. The transient-based method is used to implement the conformance and compliance test on distance relays at TAMU labs.

Conformance Test: The objective is to test the basic functionality of the relays, verify the operating characteristics, calibrate relay settings and implement periodic maintenance test. The concern of this test is the statistical performance related to the relay operating characteristic and tripping time. To fulfill this test, a batch of test cases with a variety of disturbance conditions including faults and non-faults are generated through simulation.

Compliance Test: The objective of compliance application test is to verify whether a relay can operate correctly under peculiar circumstances in power system particularly during abnormal operating conditions. That is to say, this type of test is to investigate the compliance feature that “real” performance of a protective relay complies with its expected performance. The concern of this test is the trip/no trip response and relay operating time performance under specific scenarios. A typical example is the use of the recorded data to analyze causes of an unwanted relay operation in a post-event analysis.

2.2.2 Test System Model

Power System Model for Conformance Test

Two power system models are used to simulate disturbances for the conformance test and compliance test: IEEE PSRC system and IEEE 14-bus system respectively. A reference model created by IEEE Power Engineering Society Power System Relaying Committee (PSRC) used for conformance test is described in [4]. The one-line diagram is given in Figure 2.1. This system has three sources, four buses and single and parallel mutual-coupled overhead transmission lines. The detailed model is shown as Figure 2.2.

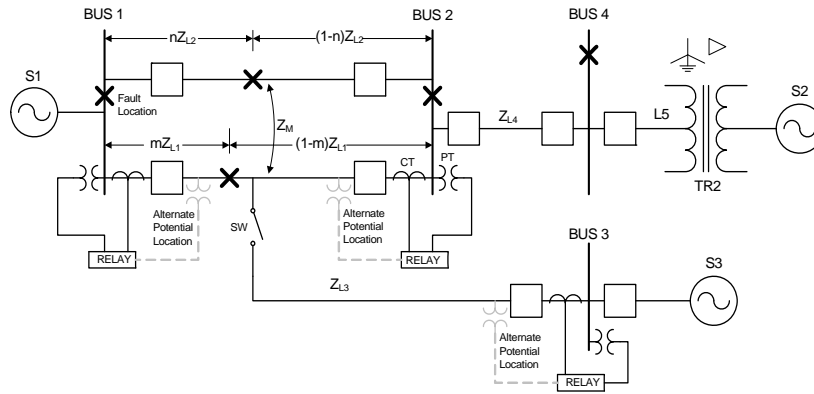


Figure 2.1: One-line diagram for IEEE PSRC system

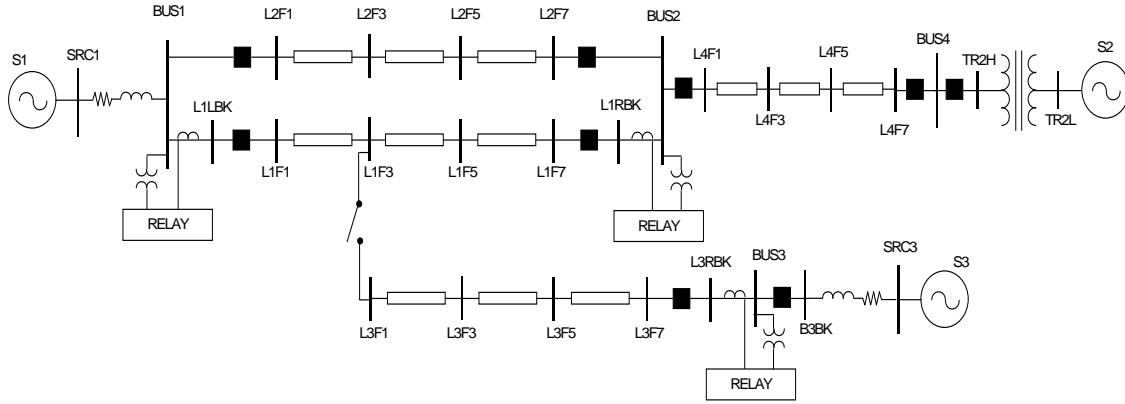


Figure 2.2: Detailed model for IEEE PSRC system

The ATPdraw implementation is given in Figure 2.3. This model is used for manual simulation by setting various individual scenarios.

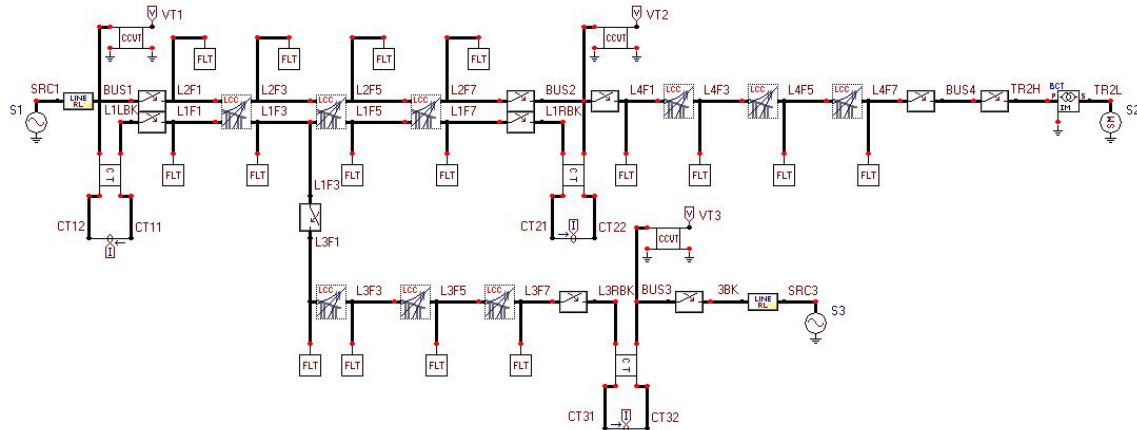


Figure 2.3: ATPdraw model for IEEE PSRC system

Power System Model for Compliance Model

The one-line diagram and ATPdraw model for IEEE 14-bus system are given as Figure 2.4 and Figure 2.5 [5]. It has 5 synchronous machines, 20 branches, 11 constant impedance loads, circuit breakers, and voltage and current measurements. Various power system disturbances can be simulated on this model as well as specific operating state study to find vulnerable conditions apt to cause relay unintended operations.

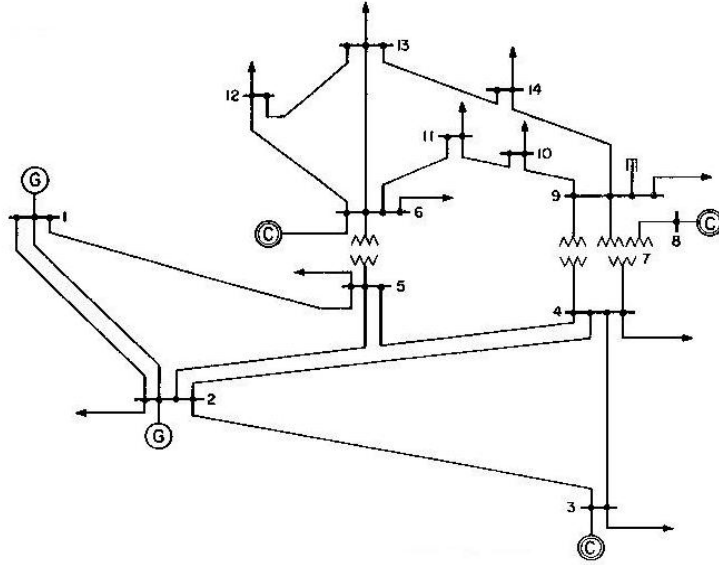


Figure 2.4: One line model for IEEE 14-bus system

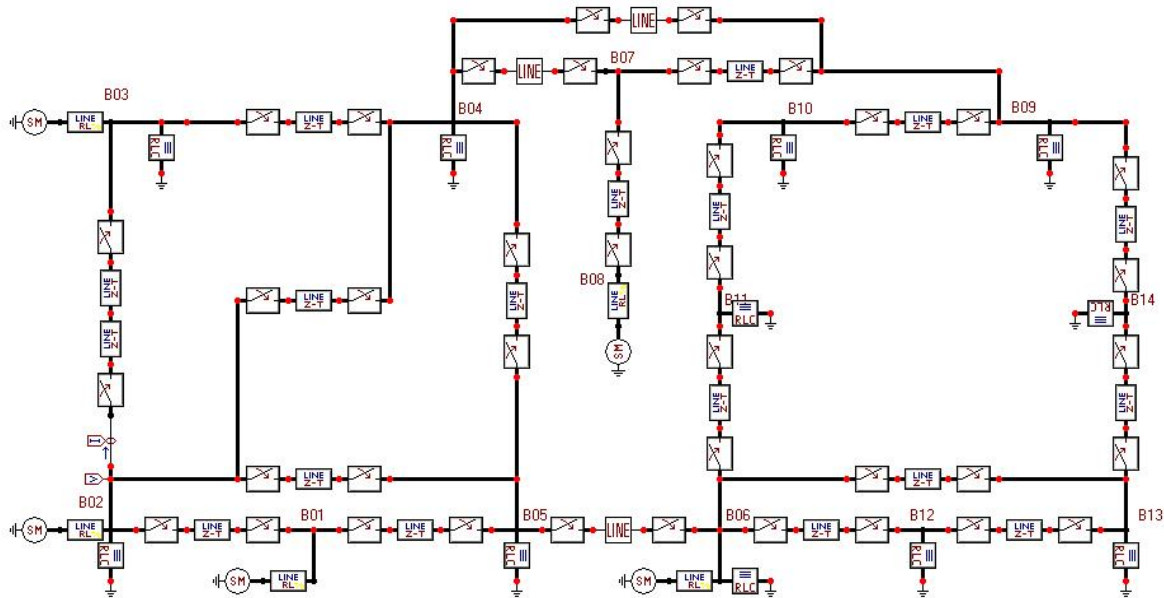


Figure 2.5: ATPdraw model for IEEE 14-bus system

2.2.3 Test Scenarios Generation

Test Scenarios for Conformance Test

The IEEE PSRC reference system is used for conformance tests. Both automatic and manual simulation can be implemented in ATP [6]. The Batch simulation program is developed in MATLAB for PSRC reference model system is developed based on the text version of *atp* file [7]. The simulation block diagram is given in Figure 2.6. This set up can automatically simulate different fault scenarios with different fault types, locations, resistances and inception angles. The output of the waveforms can be PL4, MAT (converted by PL42MAT program) and COMTRADE (converted by PL42COM program). The ATPdraw model is developed for manually generating test cases as shown in Figure 2.7. For the batch simulation, the fault point should be within 10%-90% of the line length because an ATP basic model has limitation for distributed line model. For the fault positions between 0% and 10% between 90% and 100%, ATPdraw model is used. For each simulation, fault type, location, resistance and inception angle in this case need to be set manually and one scenario is generated at one time.

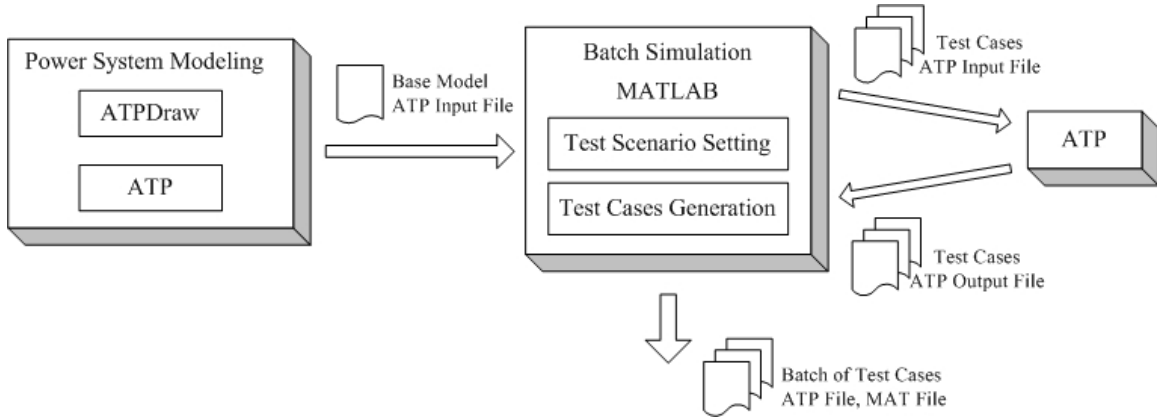


Figure 2.6: Batch simulation program block diagram

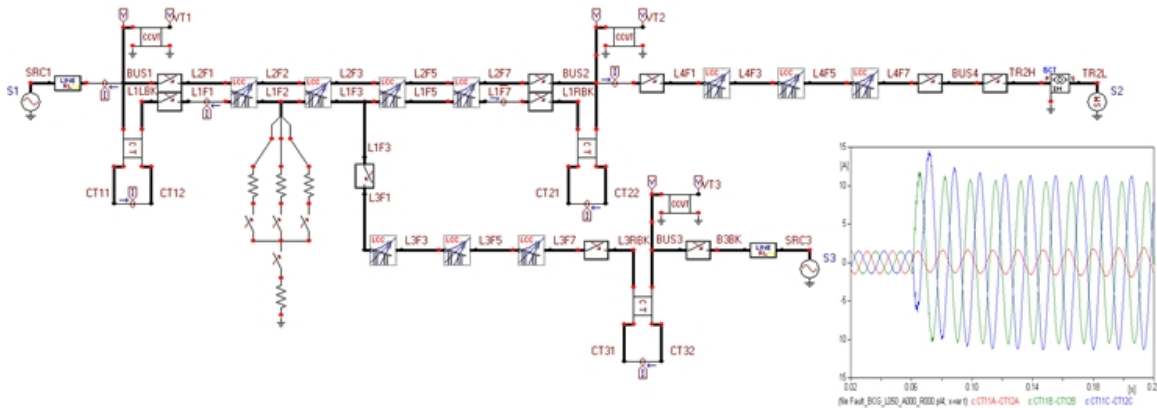


Figure 2.7: ATPdraw model for manual simulation

For the conformance test using the IEEE PSRC reference system, two categories of scenarios are chosen: fault scenarios and non-fault scenarios. The detailed test items are given in Table 2.1 and Table 2.2.

a) *Fault Scenarios (dependability)*

F1 – Internal Fault: Verify whether the relay has successfully detected internal faults.

F2 – External Fault: Verify whether the relay has not tripped for faults outside the protected zone.

F2-1: faults on Line 2

F2-2: faults on Line 4

F3 – One-End-Open Internal Fault: Verify the ability of the relay to detect a fault with no infeed.

F4 – Switch onto Fault: Verify the ability of the relay to detect a fault immediately after closing the line.

F4-1: Bus-side Potential Transformer

F4-2: Line-side Potential Transformer

F5 – Fault during Power Swing: Verify the ability of the relay to trip properly when a fault occurs during a power swing.

F6 – Internal Fault during Frequency Fluctuation: Verify the capability of relay to trip properly when the system frequency fluctuates within a normal range.

F6-1: Frequency increases to 60.5Hz

F6-2: Frequency decreases to 59.5Hz

Table 2.1: Fault Scenarios for Conformance Test

Condition	Type	Location [%]	Inception Angle [deg]	Resistance [Ω]
F1	AG, BC, BCG	0, 50, 70, 90	0, 45, 90	0, 5, 10, 25
	ABC			0
F2-1	AG, BCG	10, 50, 90	0, 45, 90	0, 10, 25
	BC, ABC			0
F2-2	AG, BC, BCG, ABC	0, 50, 90	0, 45, 90	0
F3	AG, BCG	0, 50, 90	0, 45, 90	0, 5
	BC, ABC			0
F4-1	AG, BCG	0, 50, 90	0, 45, 90	0, 25
	BC, ABC			0
F4-2	AG, BCG	0, 50, 90	0, 45, 90	0, 25
	BC, ABC			0
F5	AG, BCG, BC, ABC	0, 50, 90	0, 45, 90	0
F6-1	AG, BCG, BC, ABC	50, 90	0, 45, 90	0
F6-2	AG, BCG, BC, ABC	50, 90	0, 45, 90	0

For the batch simulation, the fault point should be within 10%-90% of the line length (ATP limitation for distributed line model). For the positions within 0% and 100%, please note that the ATPdraw model is used.

b) No-fault Scenarios (security)

N1 – Line Closing: Verify the ability of the relay not to trip when line closing occurs.

N1-1: Bus-side Potential Transformer

N1-2: Line-side Potential Transformer

N2 – Loss of Potential: Verify the ability of the relay not to trip in case of loss of phase voltage inputs.

N3 – Loss of Load: Verify the ability of the relay not to trip in case of loss of load.

N4 – Restoring the Potential: Verify the ability of the relay not to trip in case of restoring the voltage inputs.

N5 – Power Swing: Verify the ability of the relay not to trip during a power swing condition.

N6 – Load Encroachment: Verify the capability of the relay not to trip during heavy load.

Table 2.2: Non-fault Scenarios for Conformance Test

Condition	SW status	Object	Operation
N1	Open	Line 1 breakers	Three phases close after 2 cycles
			Phase A close after 2 cycles
			Phase B, C close after 2 cycles
N2	Close	Source S1, S2, S3	Remove S1, S2, S3 respectively after 2 cycles
			Remove S2, S3 after 2 cycles
			Remove S1, S2, S3 simultaneously after 2 cycles
			Remove S1, then S2 after 2 cycles, then S3 after 2 cycles
N3	Open	Bus 4 breaker	Open Bus 4 breaker after 2 cycles
		Bus 2 breaker	Open Bus 2 breaker after 2 cycles
	Close	SW	Open SW after 2 cycles
N4	Close	Source S1, S2, S3	Restore S1, S2, S3 respectively after 2 cycles
			Restore S2, S3 after 2 cycles
			Restore S1, S2, S3 simultaneously after 2 cycles
			Restore S1, then S2 after 2 cycles, then S3 after 2 cycles
N5	Open	Line 1	Power swing occurs after three-phase fault on Line 1
N6	–	Line 1	Increase the load on Bus 2 from normal to maximum

For load encroachment scenarios, the use of different impedances measured by relays at Bus 1 represents the various level of load increase. According to the system parameters, the secondary impedances under normal load and maximum load are 57.4Ω and 7.86Ω respectively. Four conditions whose corresponding secondary impedances are 31.88Ω , 22.34Ω , 12.74Ω and 7.90Ω were selected as the scenarios to execute the load encroachment logic testing.

Test Scenarios for Compliance Test

The first task for the application of compliance test is to select those possible scenarios which may cause relay unintended operation. Two approaches named steady state approach and dynamic state approach are proposed to achieve this task.

Steady state approach: This approach uses the steady state methods to find some transmission lines that are designated as vulnerable lines due to stressed operating conditions. Those important lines must have high security of the protection scheme. For a given system, topology processing method [8] will find the lines, such as tie-lines, or single-connection lines whose outage will disconnect the generator, load or even part of an area, parallel lines, long lines, etc. Power flow method is used to identify transmission lines which may have overload conditions and whose connected buses may have low voltage problems. Under such conditions, the apparent impedance seen by distance relays may fall into their backup protection zones. They may trip the lines and trigger the cascading outage.

Dynamic state approach: This approach studies the protective relays in dynamic conditions such as the case when after the fault and its clearing, the power swing occurs, which may confuse some distance relays as the apparent impedance may fall into the protection zones. The relays may operate as not intended and cause conditions that may result in further tripping. The dynamic apparent impedance phasors can be retrieved from the time domain transient stability analysis and such waveforms are evaluated to select the power system scenarios of interest for the application relay tests [9].

For a large system, the number of relays that need to be carefully evaluated in detail will be greatly reduced by using this approach. By having a digital relay model embedded in EMTP/ATP [10] one can select a group of scenarios that could cause relay unwanted operation. The EMTP/ATP relay model can be connected to the transmission line models from the list created by the steady state and dynamic state study selections. We can obtain each relay actions through a set of contingency scenarios. If incorrect relay operation is found, that scenario will be recorded and saved into the test case library, which will be used to validate behavior of physical relays.

The following conditions were used for tests using the IEEE 14-bus system for the compliance test:

- [A1]: Single 3-phase fault with critical clearing time (CCT) at the base load condition: to verify relay operation (blocking) during stable power swing.
- [A2]: Single 3-phase fault with critical clearing time (CCT) at the increased load condition: to verify relay operation (blocking) during stable power swing and overload conditions.
- [A3]: Two successive 3-phase faults, first fault with fixed clearing time, second with CCT, at the base load condition: to verify relay operation (blocking) during stable power swing.
- [A4]: Two successive 3-phase faults, first fault with fixed clearing time, second with CCT, at the increased load condition: to verify relay operation (blocking) during stable power swing and overload.

To see relay performance during out of step condition both at the base load and overload conditions, the following tests are performed:

- [A5]: Out of step: single 3-phase fault with clearing time larger than CCT at the base load condition.

- [A6]: Out of step: single 3-phase fault with clearing time larger than CCT at the increased load condition.
- [A7]: Out of step: two successive 3-phase faults, first fault with fixed clearing time, second with clearing time larger than CCT, at the base load condition.
- [A8]: Out of step: two successive 3-phase faults, first fault with fixed clearing time, second with clearing time larger than CCT, at the increased load condition.

Table 2.3: Test scenarios for Compliance Tests

	Purpose	Test Sequence	Test Variations
[A1]	Verify the relay ability not to trip at stable power swing	3-phase fault, with critical clearing time (CCT), base load condition	Fault location: 10%, 50%, 90%
[A2]	Verify the relay ability not to trip at stable power swing and overload conditions	3-phase fault, with critical clearing time (CCT), increased load condition	Same as above
[A3]	Verify the relay ability not to trip at stable power swing	Two successive 3-phase faults, first with fixed clearing time, second with CCT, base load condition	Same as above
[A4]	Verify the relay ability not to trip at stable power swing and overload conditions	Two successive 3-phase faults, first with fixed clearing time, second with CCT, increased load condition	Same as above
[A5]	To see the relay performance at out of step condition	3-phase fault, with clearing time larger than CCT, base load condition	Same as above
[A6]	To see the relay performance at out of step condition	3-phase fault, with clearing time larger than CCT, increased load condition	Same as above
[A7]	To see the relay performance at out of step condition	Two successive 3-phase faults, first with fixed clearing time, second with clearing time larger than CCT, base load condition	Same as above
[A8]	To see the relay performance at out of step condition	Two successive 3-phase faults, first with fixed clearing time, second with clearing time larger than CCT, increased load condition	Same as above

The purpose of those test scenarios is to study the influence of stable power swing, out of step and overload conditions on distance relays.

2.2.4 Test Case Library

For each of the relay types considered, a library of power system models and disturbance scenarios was created. As shown in Figure 2.8, the test scenarios generated for the application of conformance test and compliance test are placed into the library. The abnormal power system operating conditions and vulnerable transmission lines which may cause relay unintended operations can also be described and stored into the library. The scenarios of interest from digital fault recorder (DFR) records and blackout events can be added to the library as well. The test case library can be used widely as reference test cases for relay performance evaluation and trouble shooting.

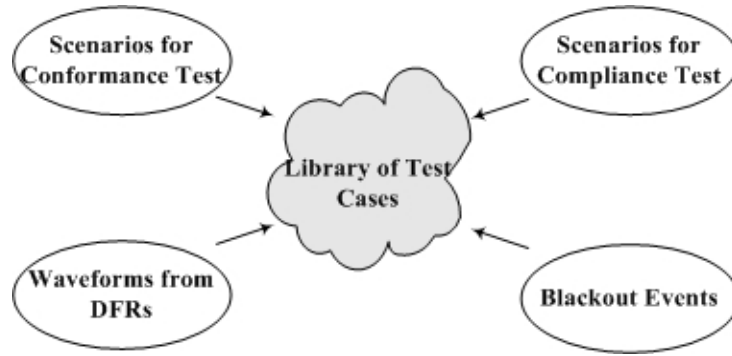


Figure 2.8: Test case library

2.3 Test Implementation

Two automatic conversion programs are developed in C++. One is to convert from MAT file (generated through MATLAB/ATP) to RLA file (Relay Assistant software [11] file), whose interface is shown in Figure 2.9. Another is to convert from ATP file to COMTRADE file [12], as shown in Figure 2.10.



Figure 2.9: Program interface for converting MAT file to RLA file

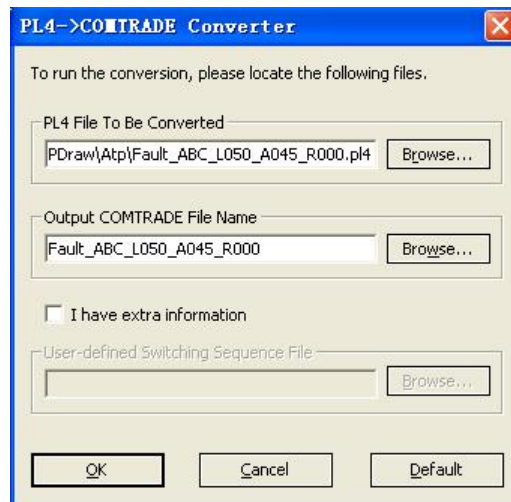


Figure 2.10: Program interface for converting ATP file to COMTRADE file

2.3.1 Test Procedure

The procedure of performing relay test is described as follows:

1) Generate test scenarios. Test cases (ATP, MAT or COMTRADE file) are generated through batch simulation program (ATP and MATLAB) and/or cases of interest are selected from digital fault recorder (DFR) files or blackout event files.

2) Convert Data format. The program developed in C++ is used to automatically convert various formats of test cases to the format which can be recognized by Relay Assistant software, such as COMTRADE.

3) Create test session. The test session is created by loading selected test cases with Relay Assistant software. Each test session contains specific scenarios sorted by different types of disturbances or power system operating conditions. For example, the fault session can be sorted by fault type, location, inception angle and resistance. Figure 2.11 and Figure 2.12 show the loading process and the loaded waveforms displayed in Relay Assistant software user interface.

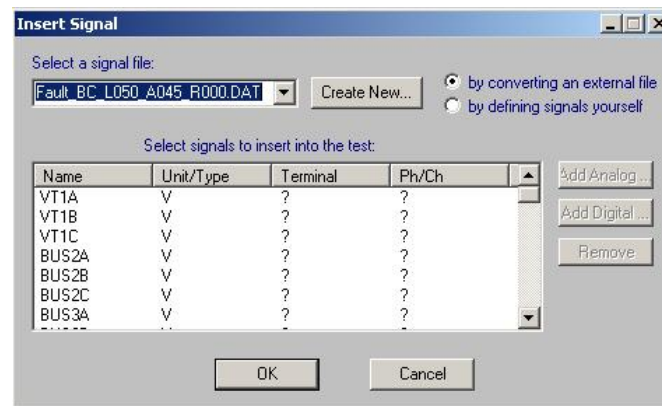


Figure 2.11: Example for loading test cases

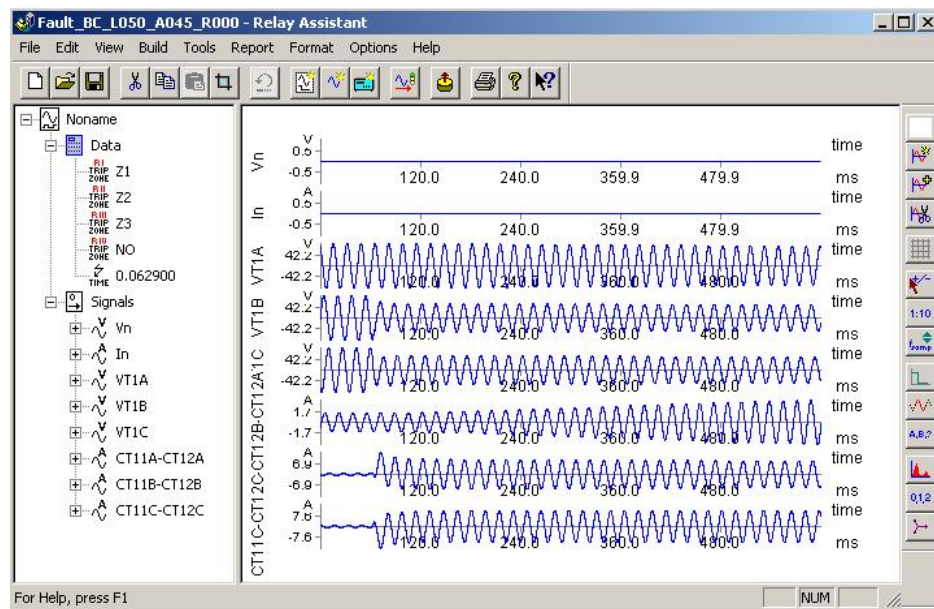


Figure 2.12: Example for waveforms displayed by Relay Assistant software

4) Set protective relays. The relay settings group corresponding to a given transmission line and protection scheme is activated from the relay front-panel buttons or through the relay setting program.

5) Execute simulation. The signal waveforms (voltage and current) are sent to the digital simulator to generate the “real” voltage and current signals for relays.

6) Collect relay response or event report. The relay responds to the input signals for each case and generates an event report containing the detailed operation information. The trip signals are captured by simulator as output signals and used to automatically calculate an operation feature such as tripping time. The event reports are collected by the file retrieval program for further study. Figure 2.13 and Figure 2.14 show the relay response captured by Relay Assistant software and event report containing oscillography data recorded as COMTRADE file.

RELAY # 1			RELAY # 2		
Operation	Trip time	Outcome	Operation	Trip time	Outcome
Expected	Min 0.01 Max 0.1	Passed	Expected	Min 0 Max 0	
Actual	Trip 0.0249	Ok	Actual	0	

RELAY # 3			RELAY # 4		
Operation	Trip time	Outcome	Operation	Trip time	Outcome
Expected	Min 0 Max 0		Expected	Min 0 Max 0	
Actual	0		Actual	0	

Buttons: OK, Cancel

Figure 2.13: Example of test result for internal fault

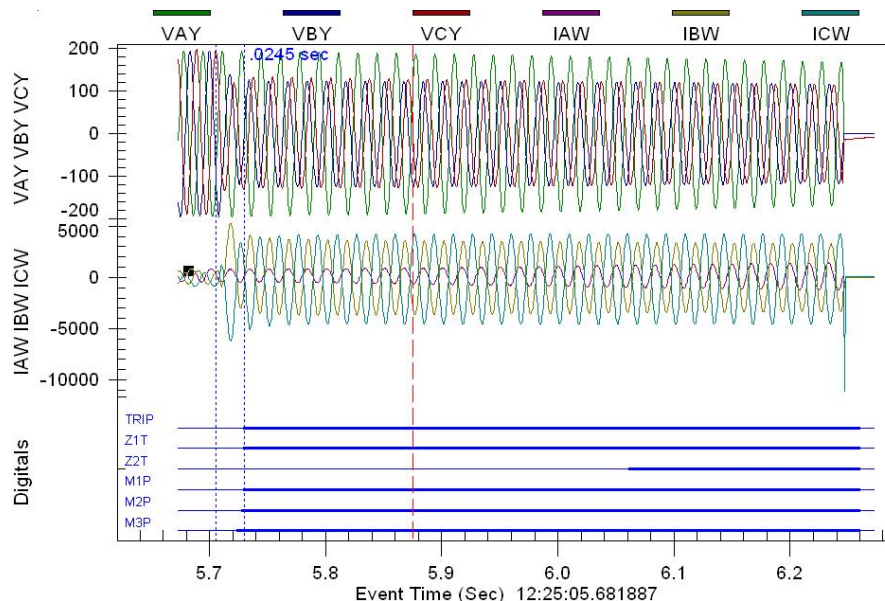


Figure 2.14: Example of event report shown as oscillograph

Figure 2.15 gives the framework for software implementation.

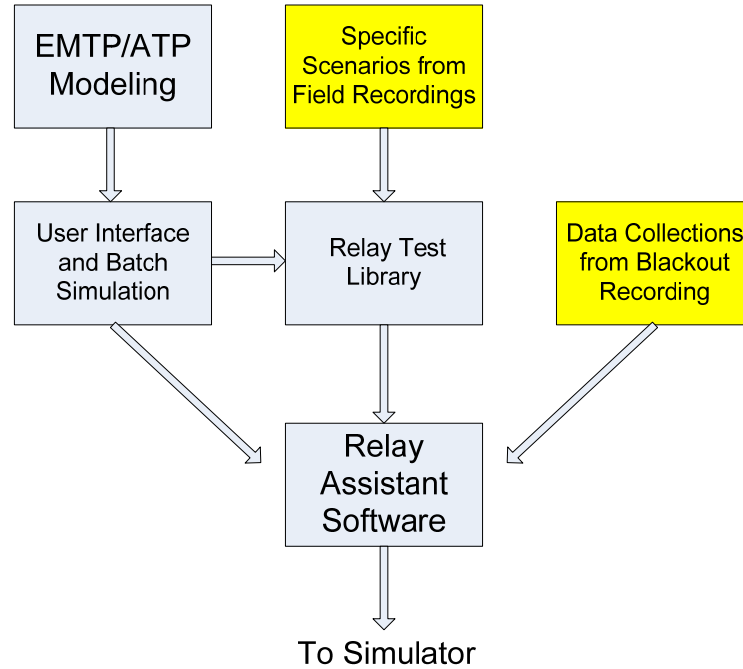


Figure 2.15: Software framework for relay testing

By executing the simulation, the signal waveforms (voltage and current) are sent from computer to the digital simulator I/O box to generate the “real” voltage and current for the relays. The distance relay will respond to the waveforms and send trip signal to the simulator digital (contact) inputs if a fault is detected. Also the digital inputs can be sent to relays through simulator digital outputs for certain purpose, such as the trip circuit breaker signal, etc. Then the trip signal and event report are collected to analyze the relay performance. Field recordings can also be replayed in Relay Assistant software to test relays.

2.3.2 Laboratory Setup

The laboratory setup is shown in Figure 2.16. The major components include a PC used to run related software programs, a digital simulator used to generate “real” voltage and current signals and the physical relay under test. A commercial software program called Relay Assistant residing on the PC communicates with digital simulator. It is capable of sending transient voltage and current data and receiving contact status data [11]. The digital simulator applies the voltage and current waveforms to the relay and records the relay trip contact status. A relay setting software program residing on the PC communicates with the relay to configure relay settings and an automated relay file retrieval software program residing on the PC communicates to the relay to automatically retrieve relay event reports triggered by certain pre-set conditions. The connections between computer, digital simulator (amplifiers and D/A converters), and distance relay are marked in Figure 2.16.

The test environment including the software and hardware as shown in Figure 2.17 describes the flow of relay test execution.

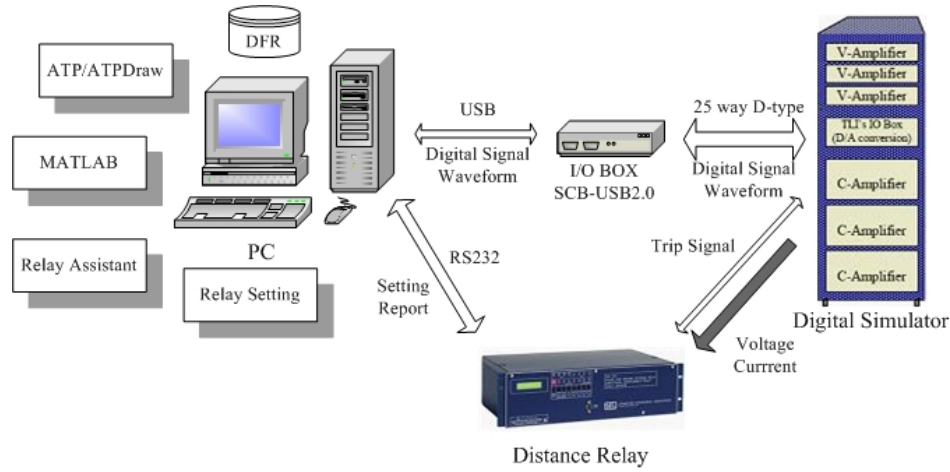


Figure 2.16: Laboratory setup for relay testing

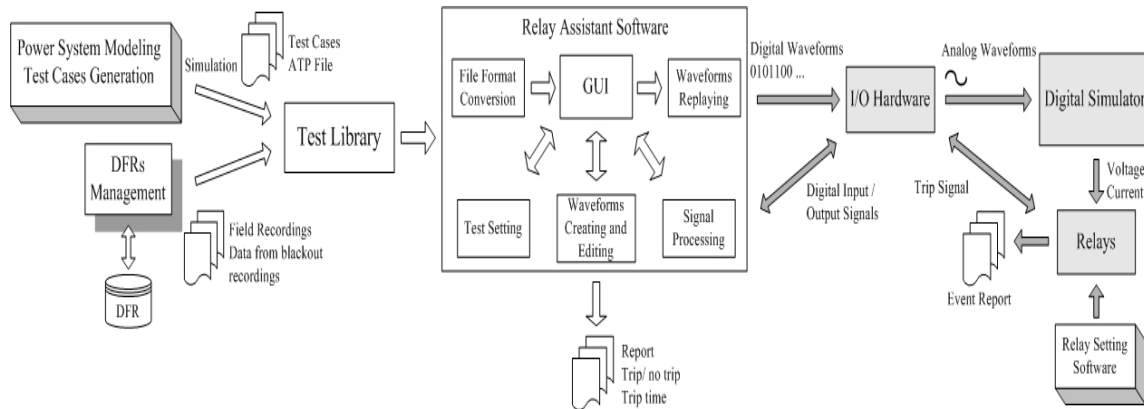


Figure 2.17: Block diagram for relay test environment

2.4 Test Results

The SEL 321, SEL 421 and GE D60 distance relays were selected for the study. Table 2.4 lists their functions and software used for interfacing with computer. Comparative study was carried out to evaluate these relays' performance.

Table 2.4: Functions and software for selected distance relays

Type	Function	Manual	Software
SEL-421	High-speed Line Protection, automation, and control system	[13][14]	SEL-5030 [15]
SEL-321	Phase and ground distance relay	[16]	SEL-5010 [17]
GE-D60	Transmission line distance relay	[18]	UR Setup [19]

2.4.1 Power System Data for Conformance Test

For the Conformance Test, IEEE PSRC system is used. Relays are applied at Bus1 to protect Line 1. Figure 2.18 shows the one-line diagram of transmission line model and relay's position. Table 2.5 lists the power system data for this application.

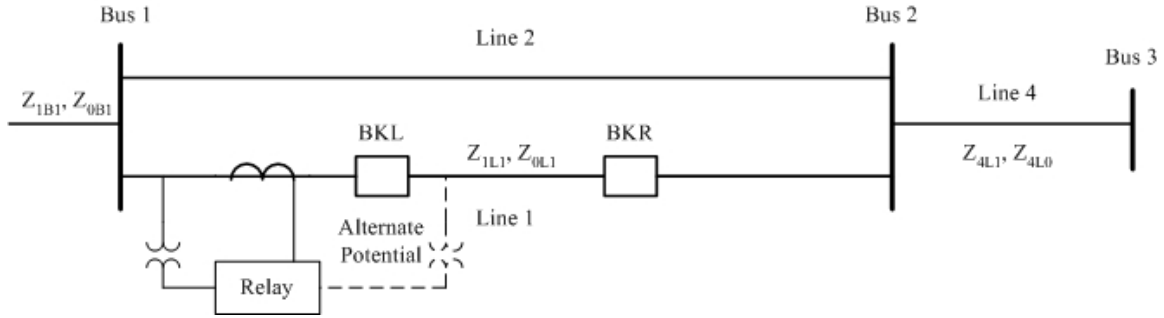


Figure 2.18: One-line diagram of the transmission line model for Conformance Test

Table 2.5: Power system data for Conformance Test

Parameter	Value
Nominal system line-to-line voltage	230kV
Nominal relay current	5A secondary
Nominal frequency	60Hz
Line 1 length	45miles
Line 1 impedances: Z_{1L1} , Z_{0L1}	$41.0 \angle 84.2^\circ$ primary, $113.2 \angle 81.7^\circ$ primary
Zero-sequence mutual coupling: Z_{0M}	$72.23 \angle 80.2925^\circ$ primary
Source Bus1 impedances: Z_{1B1} , Z_{0B1}	$17.78 \angle 69.93^\circ$ primary, $8.79 \angle 72.12^\circ$ primary
Line 4 impedances: Z_{4L1} , Z_{4L2}	$33.77 \angle 82.92^\circ$ primary, $70.44 \angle 81.23^\circ$ primary
PTR (potential transformer ratio)	230kV: 100V = 2300
CTR (current transformer ratio)	2kA: 5A = 400
Ratio of CTR to PTR: k	0.1739
Phase rotation	ABC

In order to calculate relay settings, the power system impedance should be converted from primary to secondary using ratio k . Table 2.6 lists the corresponding secondary impedances.

Table 2.6: Secondary impedances for Conformance Test

Parameter	Value
Line 1 impedances: Z_{1L1} , Z_{0L1}	$7.13 \angle 84.2^\circ$ secondary, $19.68 \angle 81.7^\circ$ secondary
Zero-sequence mutual coupling: Z_{0M}	$12.56 \angle 80.2925^\circ$ secondary
Source Bus1 impedances: Z_{1B1} , Z_{0B1}	$3.09 \angle 69.93^\circ$ secondary, $1.53 \angle 72.12^\circ$ secondary
Line 4 impedances: Z_{4L1} , Z_{4L0}	$5.87 \angle 82.92^\circ$ secondary, $12.25 \angle 81.23^\circ$ secondary

2.4.2 Power System Data for Compliance Test

For the Compliance Test, IEEE 14-Bus system is used. Relays are applied at Bus2 to protect the transmission line between Bus2 and Bus3. Figure 2.19 gives the one-line diagram of transmission line model and relay's position. Table 2.7 lists the power system data for this application.

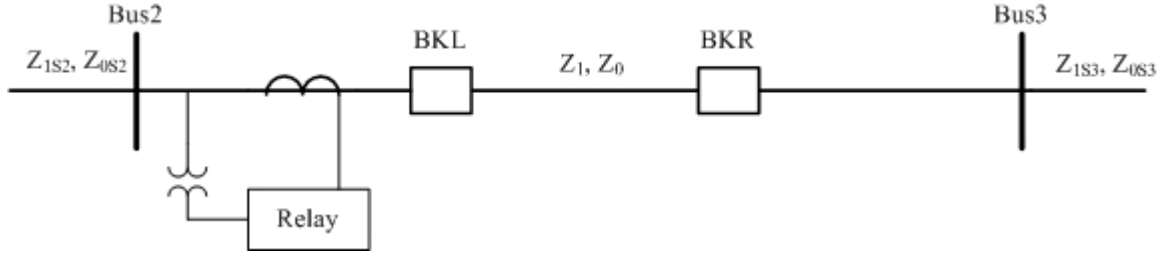


Figure 2.19: One-line diagram of the transmission line model for Compliance Test

Table 2.7: Power system data for Compliance Test

Parameter	Value
Nominal system line-to-line voltage	138kV
Nominal relay current	5A secondary
Nominal frequency	60Hz
Line length	33miles
Line 1 impedances: Z_{1L1} , Z_{0L1}	$20.35 \angle 76.64^\circ$ primary, $50.88 \angle 76.59^\circ$ primary $1.48 \angle 76.64^\circ$ secondary, $3.69 \angle 76.59^\circ$ secondary
PTR (potential transformer ratio)	138kV: 100V = 1380
CTR (current transformer ratio)	500A: 5A = 100
Ratio of CTR to PTR: k	0.0725
Phase rotation	ABC

2.4.3 Distance Relay Setting

To fully test the relay functionality and operating characteristic three zone protection schemes are applied in three selected relays. These applications are for a single circuit breaker, three-pole tripping cases. Some functions, such as power swing, load encroachment, etc, are applied as well to calibrate the relay performance during particular power system operating conditions.

The applied functions are described as follows:

- Three zones of phase (mho) and ground (mho) distance protection
 - ✧ Zone 1 – forward-looking, instantaneous under reaching protection, covers 80% of the protected line.
 - ✧ Zone 2 – forward-looking, time-delayed trip covers 100% of the protected line.
 - ✧ Zone 3 – forward-looking, time-delayed trip covers 100% of the protected line, backup protection for the adjacent downstream line.

- Switch Onto Fault (SOTF) protection, fast tripping when the circuit breaker closes (This item is not applicable for Compliance Test).
- Power swing, Out-of-step logic, prevents unintended tripping when power swing occurs.
- Load encroachment logic, prevents unintended tripping during increasing load conditions.

Table 2.8 gives a brief summary of the functions applied for conformance test and compliance test. The setting tables for tested relays are given in Appendix A.1. They provide the crucial setting values for both conformance test and compliance test so that the test can be repeated.

Table 2.8: Functions table applied for test

Function/Element	Conformance Test	Compliance Test
Fault Location	Enabled	Enabled
Phase Distance	Mho 3-Zone	Mho 3-Zone
Ground Distance	Mho 3-Zone	Mho 3-Zone
Switch Onto Fault	Enabled	Disabled
Power Swing/ Out of Step	Enabled	Enabled
Load Encroachment	Enabled	Enabled

2.4.4 Test Results and Analysis

According to the number of test repetitions for each test scenario, the test approach can be divided into two classes: “random” tests and “statistical” tests. For the “random” tests, each test case is applied only once, and the relay responses (trip or no trip, trip zone and trip time) are recorded. For the “statistical” tests, some interesting scenarios are selected and repeated 30 times, and the relay responses of each test are recorded to calculate the trip or no trip rate, maximum trip time, minimum trip time, mean trip time and deviation of trip time if the relays trip. The comparative results among the three relays are studied as well.

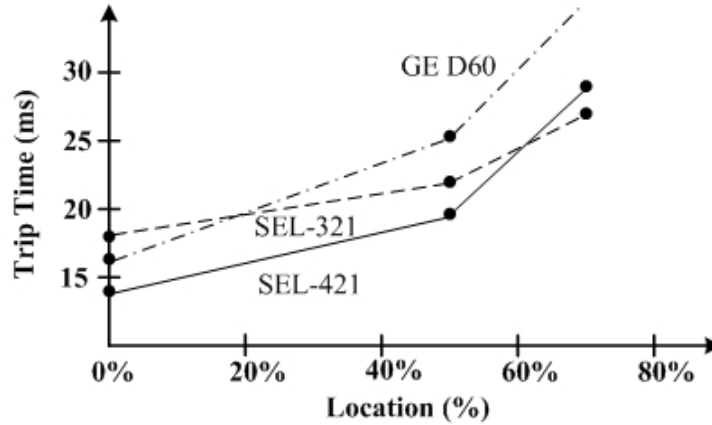
The complete test results for all the test items listed in section 2.3.3 (Test Scenarios Generation) as shown in Table 2.1, 2.2 and 2.3 for the three selected distance relays can be found in Appendix A.2. Two examples to describe how the statistical test results would look like are given here.

One example obtained by executing conformance test on SEL-421 relay is given in Table 2.9. In this example, different test cases were simulated for different type of faults, locations, and inception angles. Each test is repeated 30 times, and statistical methods are used for determining operating time for the tested relay. One can notice very interesting results with respect to differences in operating times for different fault conditions as well as differences between maximal and minimal values of operating time for the same fault condition.

Table 2.9: Example of statistical test results

Type	Loc [%]	α [deg]	Trip Zone	No.T	MeanT [ms]	MaxT [ms]	MinT [ms]	Devtn [ms]
AG	50	0	I	30	22.57	24.30	20.60	0.85
AG	70	45	I	30	28.32	30.90	27.40	0.82
AG	90	90	II	30	318.20	357.1	313.4	7.87
BC	50	0	I	30	24.71	26.40	22.50	0.79
BC	70	45	I	30	28.64	30.30	26.80	0.83
BC	90	90	II	30	356.23	357.1	355.1	0.59
BCG	50	0	I	30	18.73	20.10	17.90	0.58
BCG	70	45	I	30	29.72	31.20	28.10	0.65
BCG	90	90	II	30	365.47	370.3	360.0	1.12
ABC	50	0	I	30	20.88	21.90	20.00	0.61
ABC	70	45	I	30	31.25	33.40	29.30	0.97
ABC	90	90	II	30	359.65	361.3	357.2	1.41

Another example obtained by applying conformance test is given in Figure 2.20. The figure depicts a comparative analysis of trip time vs. fault incidence location for three distance relays. Trip time shown in this figure is obtained statistically after several tests cases are repeated. Relays are set to operate in zone 1 covering 80% of the line. An interesting outcome is that the trip time, for some relays, becomes much longer than expected.

**Figure 2.20: Example of comparative test results**

In general, the three relays operated correctly but some exceptions still exist as shown in Table 2.10, which summarizes their performance.

Table 2.10: Summary for relays' performance

Test Items	SEL-421	SEL-321	GE D60
F1	Wrong trip Zone (Z1→Z2), delayed trip time.	Wrong trip Zone (Z1→Z2), delayed trip time.	Wrong trip Zone (Z1→Z2), delayed trip time.
F2	Zone 3 failed to trip	Zone 3 failed to trip	Zone 3 failed to trip
F3-F6	Correct	Correct	Correct
N1-N6	Correct	Correct	Correct
A1-A7	Correct	Correct	Correct

For the unexpected operations that occurred in scenarios F1, details are given in Appendix A.2 as shown in Table A.3, A.15 and A.27. It appears that the increased fault resistance caused the incorrect operations. Even SEL-321 failed to trip when the resistance increased to 10Ω . All these incorrect operations occurred because of the use of Mho characteristic distance element. The situation can be improved by applying the Quadrilateral characteristic for the distance element.

Zone 3 relay failed to trip as a backup protection for the adjacent downstream line under the condition of Phase A to ground fault at the 90% location of the adjacent line. Results are given in Table A.5, A.17 and A.29. Practically zone 3 protection elements are set to trip breakers after certain time delay from the time the phase distance element or ground distance element picks up so that coordination with zone 1 and zone 2 relays is achieved. In this application, the time delay was set to commonly used 60 cycles. From the Figure 2.21 captured from SEL-421 relay event, we can clearly see that ground distance element Z3G picked up instantaneously after single phase-to-ground fault occurred. Then a power swing developed followed, which appeared as fault type transition to the relay and caused phase distance element M3P to pick up. However, the apparent impedance seen by the relay changed due to the impact of developed power swing. Thus, the both two protection elements Z3G and M3P could not pickup and hold the pickup state for the preset time delay (used to coordinate with zone 1 and zone 2 relays), which finally resulted in failing to trip the breakers. Special protection scheme should be applied to improve the relaying system for this condition. This test case is added to the test case library as an interesting condition used to evaluate relay dependability feature.

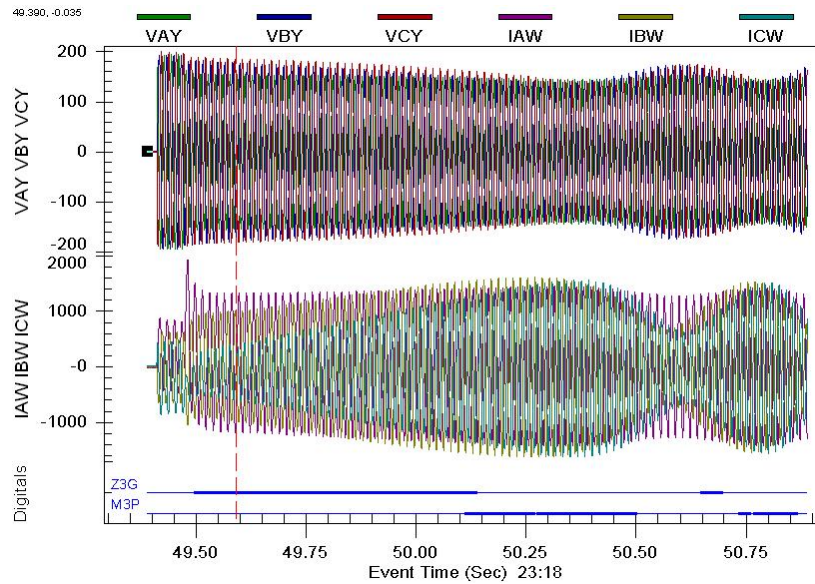


Figure 2.21: Three-phase voltage and current waveforms from relay event

There are some cases that relays operated during non-faulted conditions, such as power swing conditions listed in conformance test scenarios N5 as shown in Table 2.2 and compliance test scenarios A1-A4 as shown in Table 2.3, and load encroachment conditions listed in conformance test scenarios N6 as shown in Table 2.2. These

unintended relay operations were improved by utilizing out-of-step function and load encroachment function respectively, which are residing in relays as protection elements. Moreover, proper settings are essential for relaying scheme to solve the corresponding situations. Figure 2.22 and Figure 2.23 present these two functions and their parameters. Settings for the cases tested in the project can be found in Appendix A.1. These cases discussed above are related to the relay security characteristics, which can also be added to the test case library.

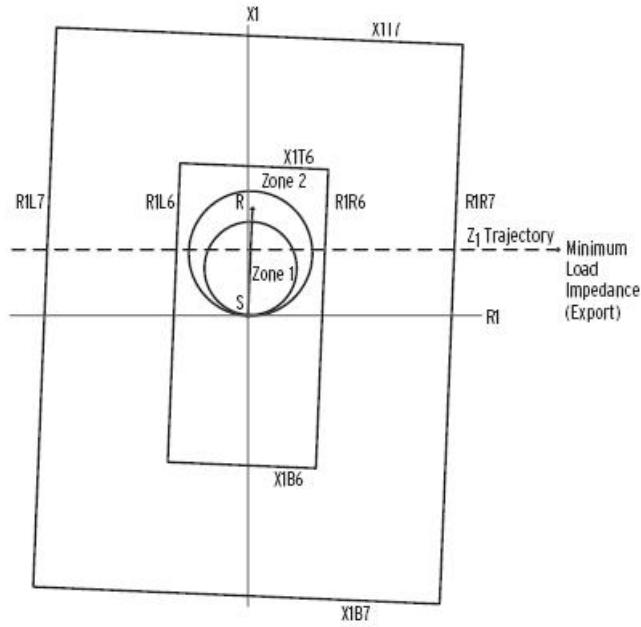


Figure 2.22: Out-of-step function and parameters

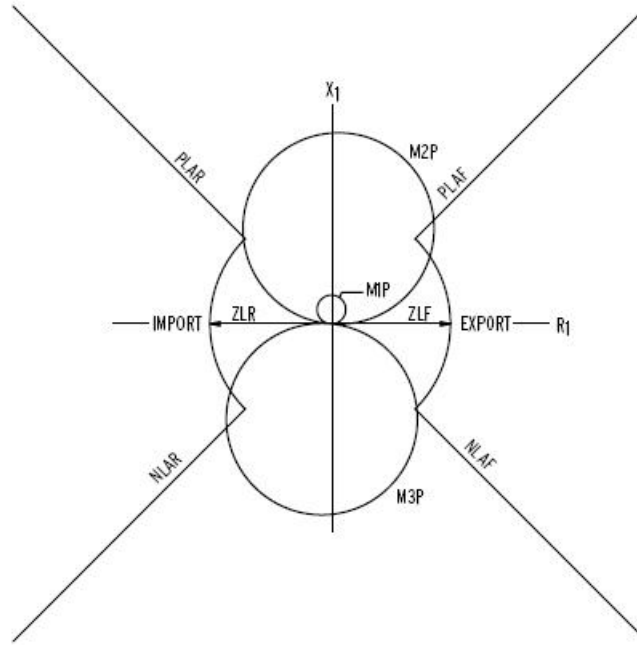


Figure 2.23: Load encroachment function and parameters

These results provide important information which was not documented in the relay manuals, and which definitely may affect proper coordination and application performance of the relaying schemes. The conformance test results evaluate the operating features and indicate that other function elements should be applied to improve the dependability of the relaying scheme. The compliance test results indicate that the zone 3 relays operated incorrectly during some unusual power system operating conditions. Thus, some special schemes should be carried out to improve these situations.

2.5 Future Work

The unintended operation of protective relays may cause cascades when power system operates in abnormal conditions such as increasing heavy loads followed by multiple line trips. Appropriate relay test can help evaluate relay performance, calibrate relay settings and figure out the vulnerable conditions apt to causing relay unwanted operation. The proposed test methodology includes the issues how to model power system used to generate disturbances and study specific conditions, how to select and generate test scenarios, and how to execute relay test in efficient way. An idea of forming a common model to be used in industry for simulating transmission line disturbances and faults, including cascading events, as well as forming a test case library for relay users so that the test scenarios can be used repeatedly as a reference when evaluating or purchasing relays should be pursued in the future.

3.0 Part II: Generator Relay Test (GaTech)

3.1 Overview

This document describes a comprehensive test platform for transient testing of protective relays and its application to generator relay testing. Comprehensive transient testing of generator relays requires testing for a variety of events that should exercise all the functions of a modern generator relay. Most of the work has been focused on defining the events for which the generator relays should be tested. We refer to these as “comprehensive set of generator transient events”. The implementation of testing of generator relays against these events requires an engine for creating the transient data for these events and a platform to feed the transient data into a generator relay. For this purpose a new, physically-based generator model was developed (two axes model with access to generator windings for fault creation in the windings). The model has been useful in creating the transient data for the defined events. In addition, a platform for feeding the transient data into a system of amplifiers that create the actual voltages and currents to be fed into the generator relay has been developed. The overall project approach is illustrated in Figure 3.1.

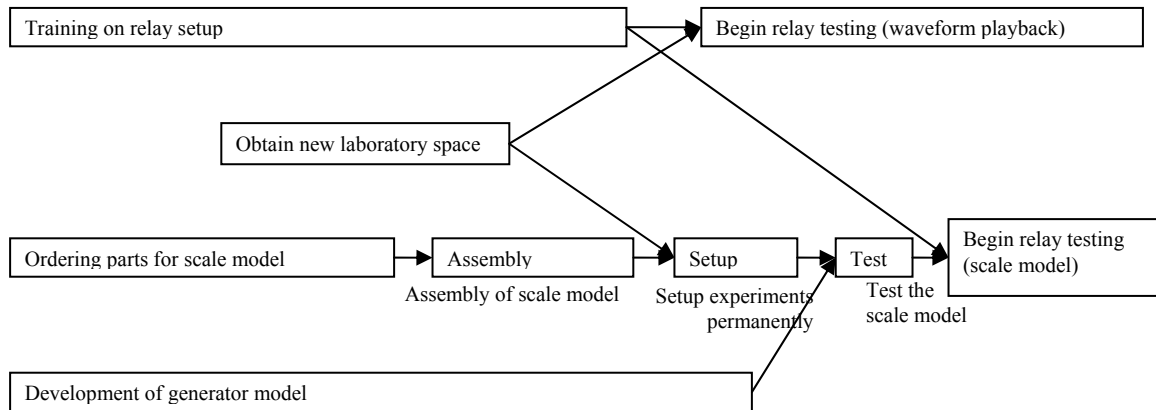


Figure 3.1: Overall project approach

This part of the report is organized as follows:

Section 3.2 describes the platform for testing generator relays.

Section 3.3 describes the generator relay testing procedure.

Section 3.4 presents testing results and observations.

Section 3.5 provides a number of observations and conclusions.

There are several appendices supporting this report. Appendix B.1 provides a typical modern generator relay connection. Appendix B.2 provides a comprehensive list of events for testing generator relays. Appendix B.3 provides the high fidelity generator model that is part of the high fidelity simulator. The simulator is used to create the events

listed in Appendix B.2. Appendix B.4 provides example generator relay responses to specific events. Finally, Appendix B.5 provides the structure of the COMTRADE file. The COMTRADE standard is used for exchange of testing cases.

3.2 Description of Platform

This section describes the platform for generator relay testing. The platform consists of software and hardware that can create the appropriate signals at the correct voltage levels for inputting into the relays. The section provides an overview of both the software and the hardware. The actual relays that are tested are (a) the Beckwith M3425-A, and (b) the SEL 300G generator relays. These relays were donated by Beckwith and SEL. A description of the relays is provided followed by the testing hardware and software.

3.2.1 Generator Protection Relays

3.2.1.1 Beckwith M3425-A

One of the relays used in this study is the Beckwith M3425-A generator protection relay, illustrated in Figure 3.2. It was kindly donated by its manufacturer, whose support is hence greatly appreciated. The software to communicate with the relay through a serial or Ethernet connection is provided by the manufacturer. The provided software can be used to define relay parameters and protection scheme and retrieve recorded waveform data. Many aspects of the operation of this relay are described in a comprehensive instruction manual [20].



Figure 3.2: The Beckwith M3425-A generator protection relay

3.2.1.2 SEL 300-G

The second relay used in this study is the SEL 300-G illustrated in Figure 3.3. It has also been donated by Schweitzer Engineering Laboratories (SEL), and their support has been instrumental in the setup of the laboratory.



Figure 3.3: The SEL 300-G generator protection relay

3.2.2. Overview of the Testing Platform

A flexible testing platform has been developed to perform protective relay testing. The overall testing platform is illustrated in Figure 3.4. The testing platform can reproduce the voltage and current waveforms seen in the field by protective relays. Such simulated signals are then sent to the different inputs of the tested relay. Specifically, these signals are generated by simulating the power system under study on a computer. An event is simulated in the system, and voltage and current waveforms at the location of the VT and CT that are connected to the relay are recorded. With proper scaling factors, these waveforms replicate the outputs of voltage transformers (VTs) or current transformers (CTs). The recorded computer waveforms are then transformed into electrical signals using a D/A converter and an amplifier. Finally, each output of the D/A converter-amplifier block is equivalent to the output of a VT or a CT, and is sent to the proper input of the relay under test. The constituent parts of the testing platform of Figure 3.4 are described in detail in sections 3.2.3 and 3.2.4.

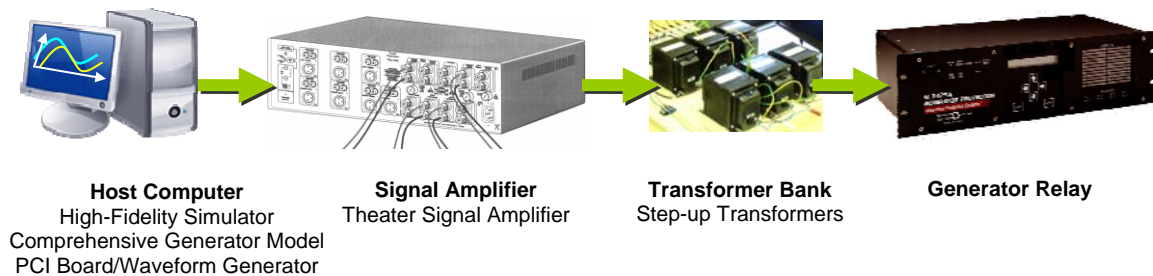


Figure 3.4: Overview of the testing platform

3.2.3 Software

The first component of the testing platform is the high-fidelity simulation software (program WinIGS-T). This computer program models the power system more accurately than most of the other existing approaches. Precise models of power system components allow an accurate simulation of a variety of events encountered by protective relays. The ability to simulate these events in a laboratory setup provides a benchmark for the robustness of the parameters entered in the considered generator protection schemes. In this section a concise description of the software is provided. Elsewhere in the report this software is utilized to develop transient waveforms for testing generator relays. The data are stored in COMTRADE format and therefore can be used by other testing devices.

3.2.3.1 High-Fidelity Modeling and Simulation

The simulation software is based on full three-phase models of power system components that are described in terms of their physical parameters. An example is provided in Figure 3.5. Models include transmission lines, transformers, circuit breakers, and synchronous generators. All connections between the different models are explicitly represented with bus-bar links and switchgear. This approach uses actual device parameters instead of

equivalent sequence parameters. The simulator accurately simulates the dynamics of the models by using the quadratic numerical integration method, which is more precise compared to other methods commonly used in power system analysis. The quadratic integration method has significant advantages in terms of numerical properties and can hence provide realistic results for a complete range of generator, transformer, and transmission line events that can be tested in a laboratory setting.

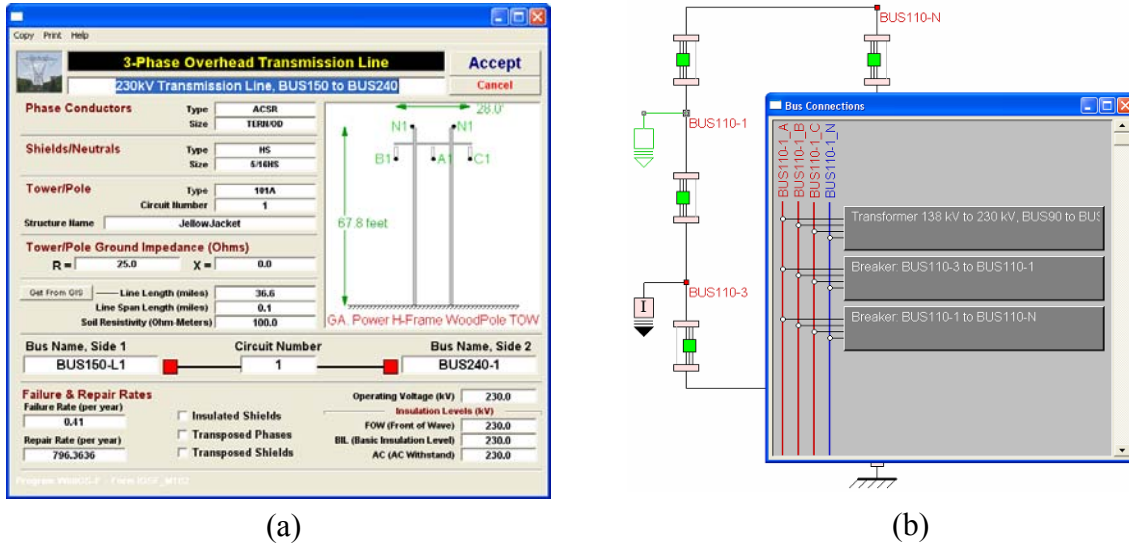


Figure 3.5: Sample model definitions in the high-fidelity simulator software: (a) transmission line physical design parameters and (b) three-phase substation bus connections

3.2.3.2 Comprehensive Generator Model

The focus of this part of the project is on testing generator relays. It is therefore desirable to capture as many characteristics common to all of the generators as possible to simulate a response of the generator that is as close to field observations as possible. To achieve the highest accuracy possible, the software platform includes a full time domain, transient, two-axis synchronous generator model. This model is described in greater detail in Appendix B.3. Figure 3.6 illustrates the user interface for this model. The generator model is physically based, with explicit representation of the actual stator and rotor physical windings. Faults can therefore be simulated anywhere in the coils of the generator, without any model complications and therefore this model can be used to study and test the effectiveness of 100 % stator protection schemes. Harmonics generated by the actual, non-sinusoidal winding layout are also accurately simulated, resulting in a complete and accurate generator representation.

Three Phase Synchronous Machine

Generator (Two Dumper Windings)

Rated L-L Voltage: 25.0 kV
 Rated 3-Phase Power: 100.0 MVA
 Frequency: 60.0 Hz

Number of Poles: 4
 Per Unit Inertia: 2.0 sec

Resistance (Ohms)

Phase Winding	0.026
Field Winding	0.0754
D-Damper Winding	0.08099
Q-Damper Winding	0.09581

Mutual-Inductance

MR	102.3477 mH
MF	91.8807 mH
MD	23.023 mH
MQ	15.7768 mH

Stator Inductance

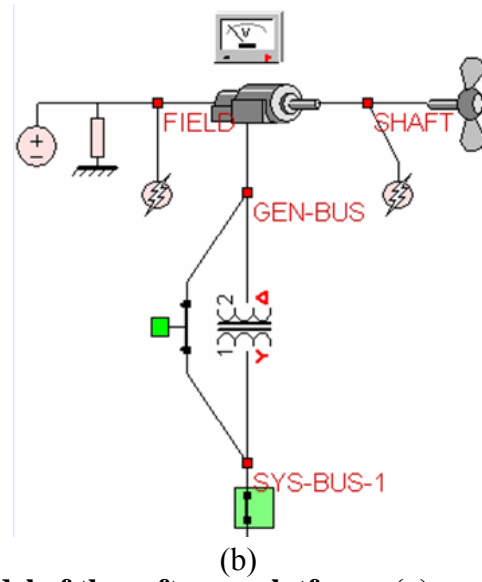
Ls	25.5684 mH
Ms	8.0847 mH
Lm	0.9945 mH

Rotor Inductance

Lf	461.5728 mH
LD	28.2594 mH
LQ	12.6763 mH

Circuit Number: 1

GEN BUS: Output Bus
 FIELD: Field Terminal
 SHAFT: Generator Shaft Terminal



(a) (b)
Figure 3.6: Comprehensive generator model of the software platform: (a) parameter definition window and (b) visual representation of the connection points

3.2.3.3 Waveform Generation from Scenario Analysis

The simulation software has the capability to output the computed (simulated) waveforms in the IEEE COMTRADE format [21]. The COMTRADE format is commonly used between equipment manufacturers to exchange transient waveform data. The main characteristics of COMTRADE files are compactness and ease of implementation. Once recorded, the waveforms can be transferred to a computer for offline analysis and further processing. A description of the IEEE COMTRADE format for the purpose of relay testing can be found in Appendix B.5.

Within the simulation software there is output processing software that can present the data in various forms, for example, the rms value of a certain waveform, the frequency of a certain waveform, the phase angle of a certain waveform, etc. In other words, the COMTRADE file may contain a number of time domain waveforms of physical quantities, such as voltages and currents, also and computed waveforms such as phasors, frequency, etc. Figure 3.7 illustrates these capabilities.

Using the above procedures a number of events have been simulated and the results stored in COMTRADE format. These events will be described in subsequent sections. The actual COMTRADE files have been uploaded in a web site for use by persons involved in this project. The link to this web site is: <http://www.xyz.com/>.

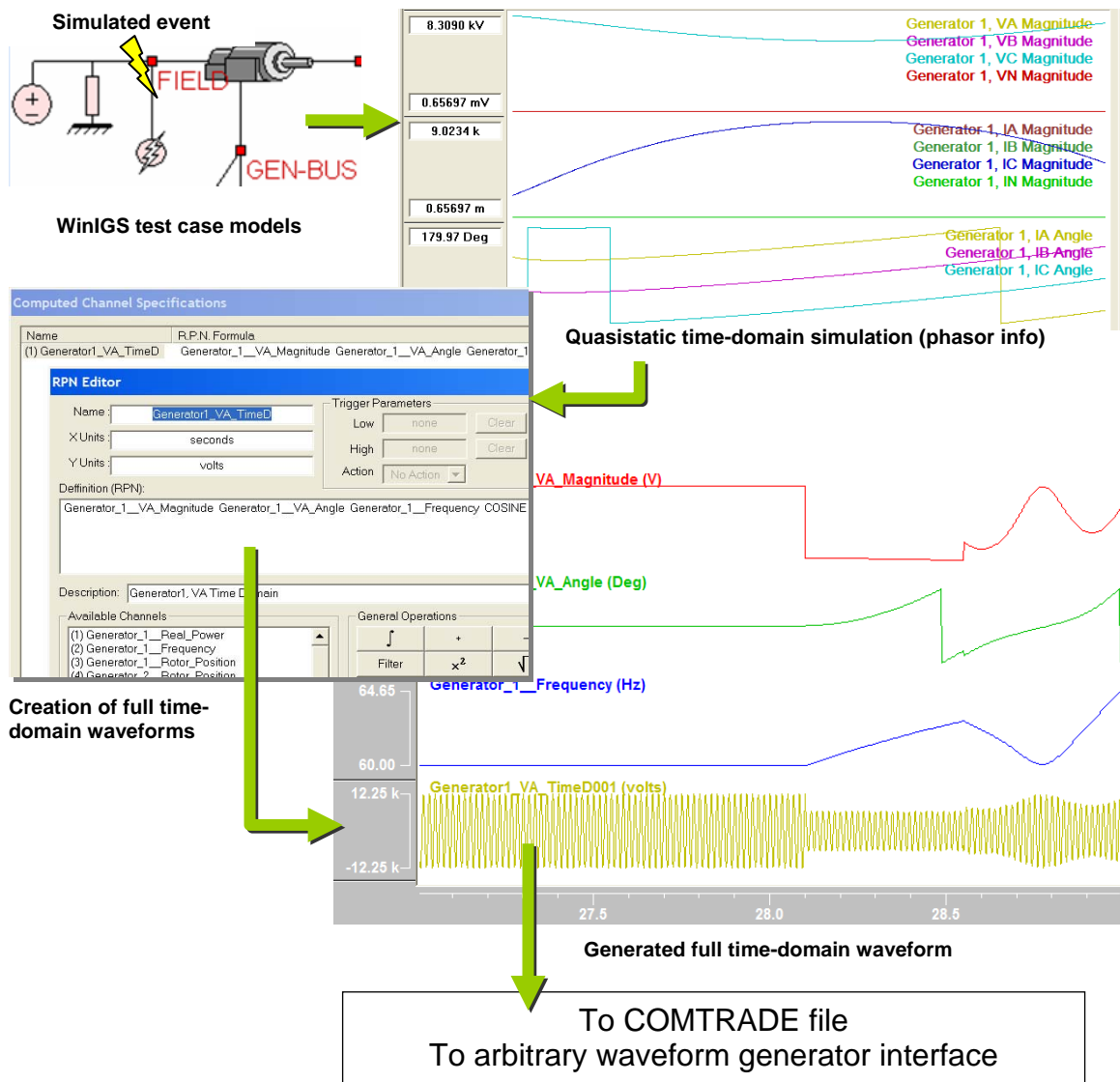


Figure 3.7: Simulation output in various forms stored in a COMPTRADE file

3.2.3.4 Summary

The implementation of the software portion of the relay testing platform is summarized in Figure 3.8.

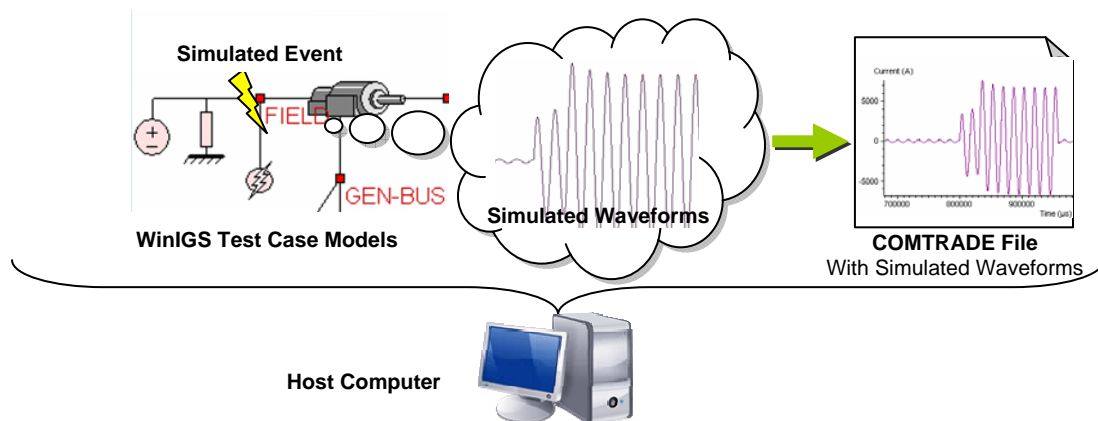


Figure 3.8: Summary of the software portion of the testing platform

3.2.4 Test Bench

The second component of the testing platform is a test bench to reproduce conditions in an actual power system that the tested relays have to protect.

3.2.4.1 Waveform Generator

After simulating the power system, waveforms of interest are recorded and played back to different types of relays. A computer-controlled waveform generator is utilized to generate voltage and current signals from the stored COMTRADE files. A D/A converter and signal generator from National Instruments translates waveform data to analog signals. The 10 V generated signals are amplified using theater sound equipment. The 30 V outputs of the sound equipment (audio amplifiers) are then stepped up to standard relay voltages and currents (69 V or 115 V and 1 A or 5 A) through a transformer bank. The final signals are directly sent to the relays, as they replicate the outputs of the VTs and CTs in an actual power system. The layout of the test bench is presented in Figure 3.9. A picture of the actual setup is shown in Figure 3.10.

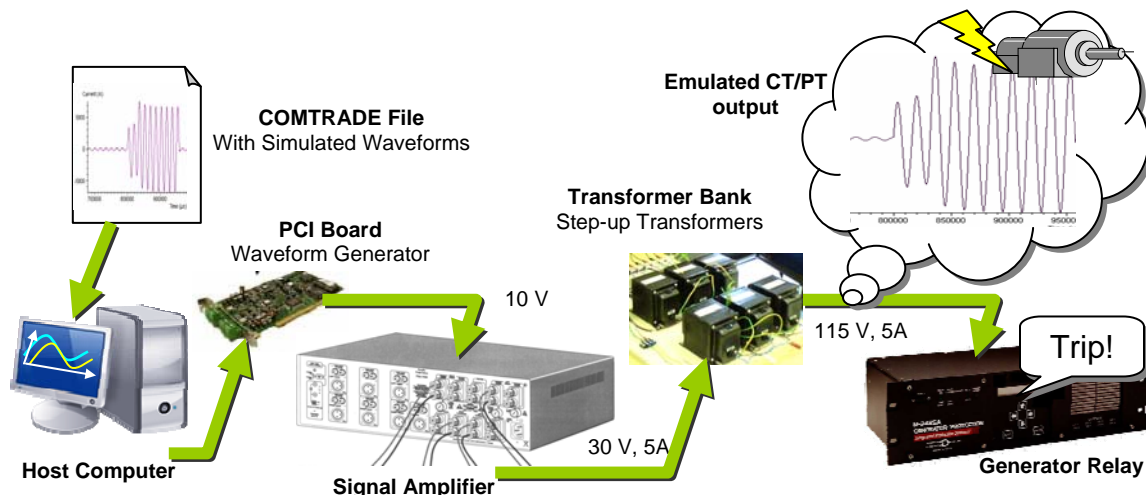


Figure 3.9: Test bench layout



Figure 3.10: Picture of the actual laboratory setup

3.2.4.2 Scale Model

In addition to the previously described testing platform, an alternative testing method has been developed using a scaled power system model. The scale model represents a simplified power system consisting of three substations, a generating substation, and two transmission substations. The scaling factor is 1000:1. Despite the scaling, the model includes all major elements of an actual power system, including transmission lines, a source behind a step-up transformer, circuit breakers, disconnect switches, as well as potential and current transformers for instrumentation. The source utilizes the output of the waveform generator mentioned above. The scale model is used to test transient relay response under actual rather than simulated conditions. Such conditions may also include imbalances (inherent imbalances from transmission line construction) and asymmetrical conditions (one or two phases disconnected). The model itself does not replicate the effect of the rest of the system to the voltage source, since there is no feedback loop between the two. The scale model is integrated with the rest of the testing platform as it is illustrated in Figure 3.11. Construction details of the scaled power system are described in [33], [34].

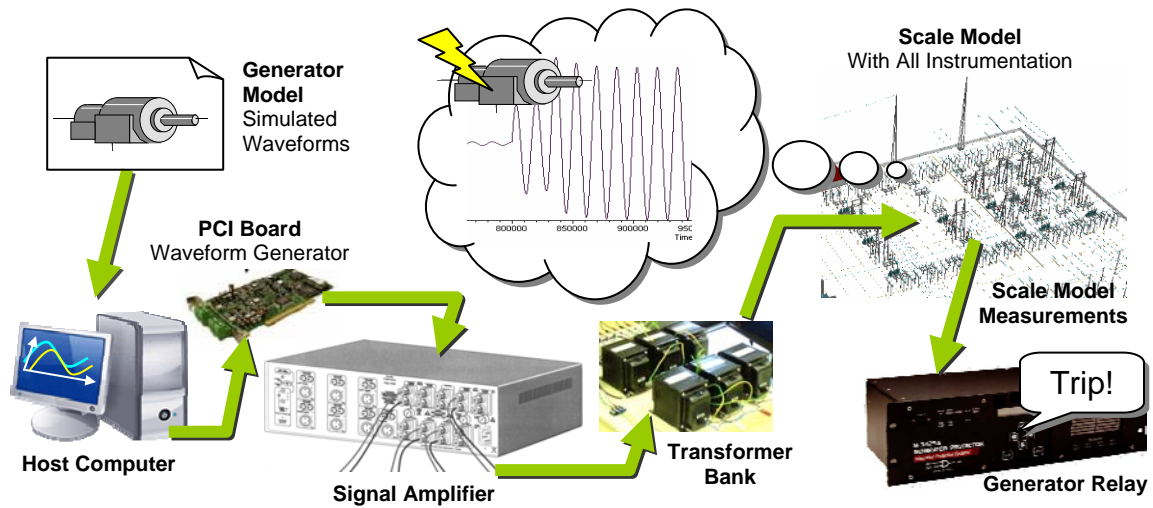


Figure 3.11: Test bench layout for relay testing with a scale model

3.2.4.3 Auxiliary Independent Voltage and Current Channels

Relay testing utilizing either of the two systems described above requires the use of independent voltage and current channels to generate the input signals to the relays at the appropriate level. Specifically, the output of the scaled model of the power system or the output of the COMTRADE data converted into analog are in general low level signals. The independent voltage and current channels simply amplify these signals to levels appropriate for input to the relays under test.

The independent voltage and current channels are designed to accept the output of (a) the PC-controlled D/A converter and the existing theater amplifier or (b) the output of the scaled power system model. As an example, the schematic of the voltage channel is illustrated in Figure 3.12, and its actual layout is shown in Figure 3.13.

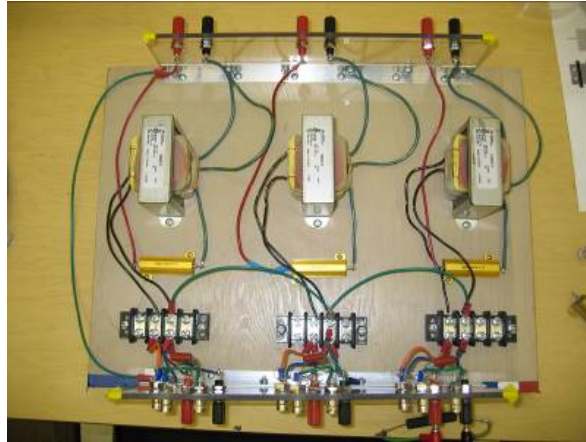


Figure 3.13: Three-phase auxiliary voltage channels for relay and PMU testing
(actual layout)

The independent current channels have a similar design. For generator relay testing, a minimum of four independent voltage channels and three independent current channels are required.

3.2.5 Virtual Relay Testing

For completeness we discuss the process of virtual relay testing. The basic idea/objective of the virtual relay testing is to test the manufacturers relay software directly without the need to generate actual voltage and current inputs to the relay. Thus, the principle of virtual testing is to perform the tests using only the binary code of the relay firmware. Configuration and waveform data can be directly sent to the inputs of the relay functions, and the relay outputs can be processed on the host computer with the benefits of specialized analysis software. As a result, virtual testing eliminates the constraints of a hardware setup, including waveform generation, wiring, and communications, and facilitates the testing of the relays. Therefore, all the relay testing is performed on a host computer as it is illustrated in Figure 3.14.

There is one major obstacle to virtual relay testing, however. Specifically, manufacturers must be willing to provide the binaries of their relay functions, and this is currently not the case. This approach also requires that manufacturers document the interface parameters of their algorithms before the tests can be performed. Possible applications of virtual relay testing are described in [22] and [23].

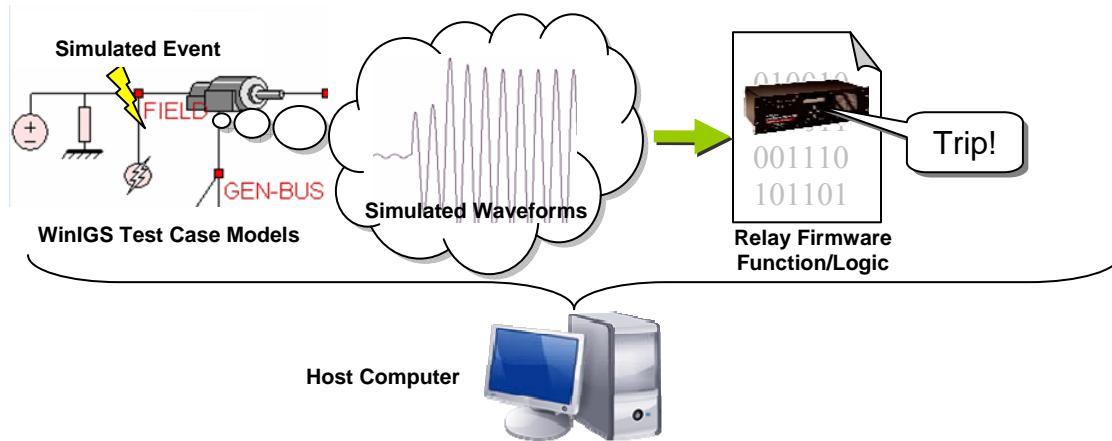


Figure 3.14: Virtual relay testing principle

3.3 Generation Relay Testing Setup

This section presents the generator relay testing procedure. A test system has been created for testing generator relays. The test system has been so selected as to be able to create the events required for a comprehensive transient generator testing, i.e., cable of creating all the transient events that are pertinent to generator relay operation.

3.3.1 Purpose

Protective relays are usually tested against simplified generator models that do not account for variations in the electrical properties of the generator. Many factors such as soil properties may vary with the location and generator and affect the grounding impedance. Relays with identical settings and protecting the same type of generators are expected to respond identically to a given power system event since the protection schemes are digitally implemented. In reality, the responses may vary because the relays operate in slightly different environments. Also, the waveforms seen by a relay may be affected by factors internal or external to the system. More generally, it is necessary to ensure the settings entered by protection engineers are consistent with the intended protection scheme. The purpose of the tests is to verify a consistent behavior of the relays regardless of the protected generator and to check that the intended protection schemes are robust against the actual parameters of the system.

3.3.2 Event Simulation and Testing Procedure

The testing procedure for the available generator relays is as follows, and it can also be applied to other types of protective relays. A set of events, including faults, imbalances, over- and under-excitation is applied to a test system, and the behavior of the different relay functions are checked against the intended protection scheme. The tests concern all individual functions of the relay for each event, as some scenarios call certain functions to target or trip and other functions to remain passive. The robustness of the applied protection scheme is tested using different variants of the test system, where differences consist in minor changes in the generator parameters. For both variants of the system, a

response that is identical to the intended protection scheme is expected.

3.3.3 Description of Test System #1

The first test system is illustrated with the following simplified network model in Figure 3.15.

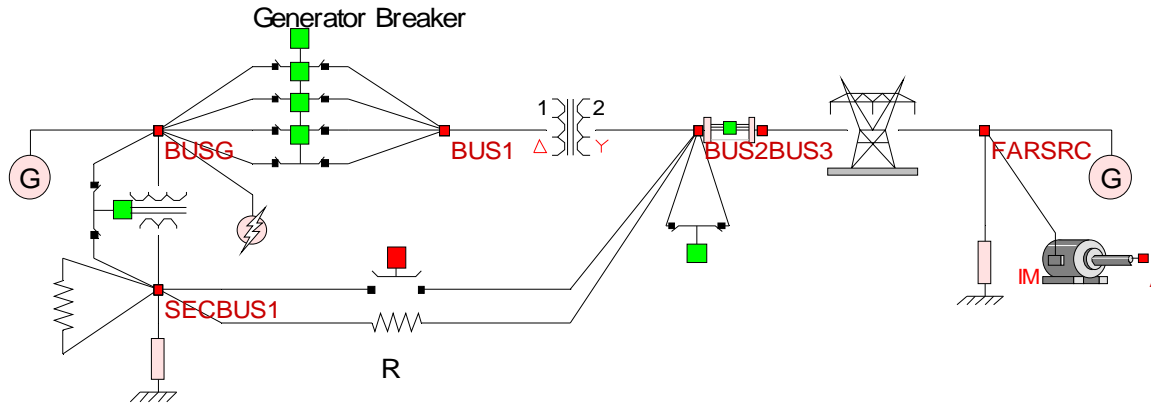


Figure 3.15: Network schematic of test system #1

The test system above includes most aspects of the generator configuration. Specifically, the network above consists of a comprehensive generator model behind a step-up transformer, connected to an infinite source via a transmission line. An equivalent load is present at the infinite source side to represent load conditions in the rest of the system. The grounding connections of the generator and the transformer secondary are an integral part of the test system. It is extremely important for all grounding aspects to be accurately modeled. Indeed, the magnitude of ground fault currents is tied with the impedance of the ground connection. As a result, explicit, comprehensive models of the generator and transformer grounding are provided. The grounding scheme includes a low-rated resistor at the secondary of a grounding transformer placed between the generator neutral and the remote earth. Moreover, solid and resistive grounding can be modeled for both the generator and the transformer.

With such a comprehensive model of generator grounding, it is possible to simulate a wide range of conditions and submit the resulting voltage and current waveforms to the generator protection relay for testing.

3.3.3.1 Generator Model

The full time transient generator model developed for this project is described in Appendix B.3.

This is a 800 MVA, 15 kV generator operating at 60 Hz.

Line-to-neutral voltage: 8.66 kV

Nominal (base) current: $I_{Base} = \frac{800}{15\sqrt{3}} = 30.8 \text{ kA}$

3.3.3.2 Generator and Transformer Grounding

The test system provides an explicit model for generator and transformer grounding. The grounding scheme in the test case is equivalent to the one illustrated in Figure 3.16.

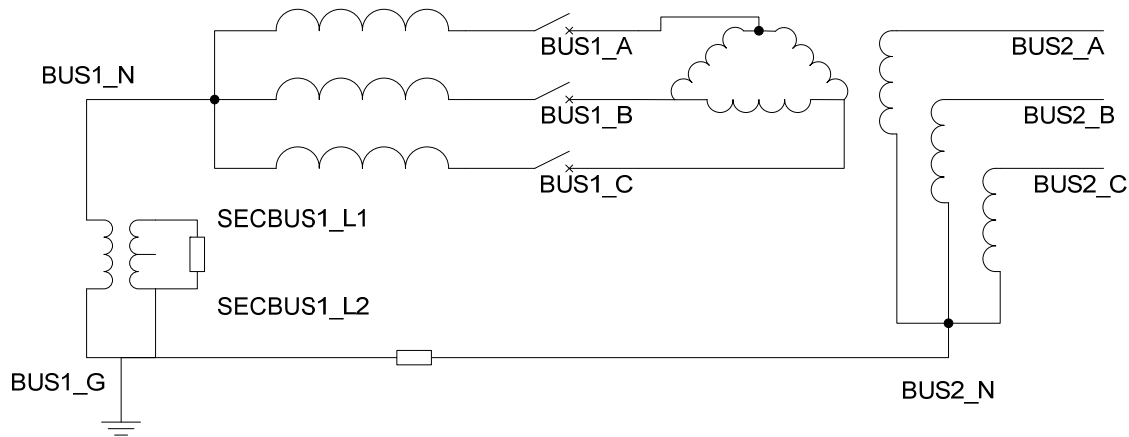


Figure 3.16: Generator and step-up transformer grounding scheme

The grounding resistor is $1\ \Omega$ behind a 8.66 kV/240 V single-phase grounding transformer that sits between the generator neutral and the earth (Figure 3.17). The low-side of the grounding transformer is connected to the same remote earth. The neutral of the high-side of the step-up transformer is also connected to the same remote earth through a grounding path. Note that the grounding path for the step-up transformer has a resistance of $5\ \Omega$.

Single Phase Transformer/Centertapped Secondary		Accept
Title: Transformer with Secondary Centertap (Single Phase)		Cancel
Transformer Rating (kVA)	15.0	
Side 1 kV Rating	8.66	
Side 2 kV Rating	0.24	
Series Resistance (pu)	0.005	
Series Reactance (pu)	0.035	
Side 1	Terminal Names	Side 2
BUS1_N		SECBUS1_L1
		SECBUS1_NN
BUS1_G		SECBUS1_L2
	1	
Circuit Number		

Figure 3.17: Settings for the generator grounding transformer

3.3.3.3 Step-up Transformer Model Settings

The transformer is a delta-wye step-up 600 MVA transformer. Low-side voltage is 15 kV, high-side transmission voltage is 230 kV (Figure 3.18).

3-Phase Transformer [Cancel] [Accept]

Transformer (Two-Winding, Three-Phase)

Side 1 Bus
 BUS1A
 15.0 kV
☒ Delta ☐ Wye

Side 2 Bus
 BUS2
 230.0 kV
☐ Delta ☒ Wye

Phase Connection
☒ Standard ☐ Alternate

Transformer Rating (MVA): 600.0
 Winding Resistance (pu): 0.004
 Leakage Reactance (pu): 0.075
 Nominal Core Loss (pu): 0.002
 Nominal Magnetizing Current (pu): 0.005

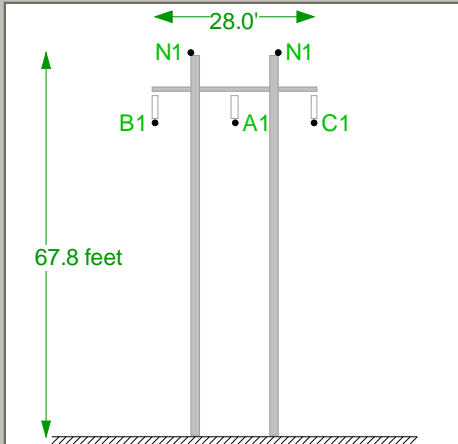

Tap Setting (pu): 1.0
 Minimum (pu): 1.0
 Maximum (pu): 1.0
 Number of Taps: 1
 Circuit Number: 1

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Figure 3.18: Settings for the generator step-up transformer

3.3.3.4 Transmission Line Parameters

The transmission line is a 10-mile section with three phase overhead conductors and shield wires. The line operates at 230 kV (Figure 3.19).

3-Phase Overhead Transmission Line				Accept	
Three-Phase Overhead Transmission Line				Cancel	
Phase Conductors	Type	ACSR			
	Size	JOREE			
Shields/Neutrals	Type	HS			
	Size	5/16HS			
Tower/Pole	Type	101A			
	Circuit Number	1			
Structure Name		JellowJacket			
Tower/Pole Ground Impedance (Ohms)					
R =		25.0		X = 0.0	
<div style="display: flex; justify-content: space-between;"> Get From GS <div> Line Length (miles) <input type="text" value="10"/> Line Span Length (miles) <input type="text" value="0.1"/> Soil Resistivity (Ohm-Meters) <input type="text" value="100.0"/> </div> </div>					
					
GA. Power H-Frame WoodPole TOWER					
Bus Name, Side 1		Circuit Number		Bus Name, Side 2	
<input type="text" value="BUS4"/>		<input type="text" value="1"/>		<input type="text" value="FARSRC"/>	
 <div style="margin-top: 10px;"> <input type="checkbox"/> Insulated Shields <input type="checkbox"/> Transposed Phases <input type="checkbox"/> Transposed Shields </div>		<div style="display: flex; justify-content: space-between;"> <div> Operating Voltage (kV) <input type="text" value="230.0"/> Insulation Level (kV) FOW (Front of Wave) <input type="text" value="100.0"/> BIL (Basic Insulation Level) <input type="text" value="100.0"/> AC (AC Withstand) <input type="text" value="100.0"/> </div> </div>			

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Figure 3.19: Settings for the transmission line in the test system

3.3.3.5 Equivalent Source and Infinite Bus

The source at the infinite bus has parameters illustrated in Figure 3.20 below.

Three Phase Source Behind Impedance

Accept

Equivalent Infinite Source

Cancel

Source Voltage

Line to Neutral kV

Line to Line kV

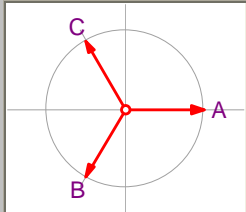
Phase Angle Degrees

Phase Sequence
☒ Positive
☐ Negative
☐ Zero

Circuit Number

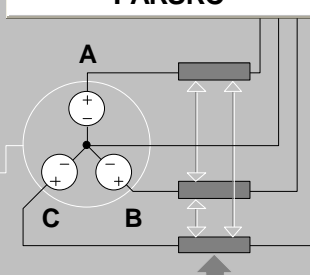
Update L-N

Update L-L



Bus Name

FARSRC



Source Impedance


		Ohms	PU
Positive Sequence	Resistance	0.13225	0.002
	Reactance	11.903	0.18
Negative Sequence	Resistance	0.26450	0.004
	Reactance	13.886	0.21
Zero Sequence	Resistance	0.52900	0.008
	Reactance	5.2900	0.08

Update Ohms

Update PU

Base

<input type="text" value="800.0"/>	MVA
<input type="text" value="230.0"/>	kV(L-L)
<input type="text" value="2.008"/>	kA
<input type="text" value="66.125"/>	Ohms



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Figure 3.20: Settings for the equivalent source at the infinite source

3.3.3.6 Instrumentation Channels

Instrument channels are set as follows:

- Generator high-side PT: 15,000:120 (base line-to-neutral voltage is 8.66 kV and 69 V for the high and low side respectively, and the generator is moderately grounded (not solidly grounded))
- Generator neutral PT: 4:1 (measurement taken from low-side of grounding transformer, ratio 240:69 \approx 3.5)
- Generator CT, low-side and high-side (standard ratio): 35,000:5 (base current is 30.8 kA)
- Generator neutral CT: 240:5 (measurement from secondary of grounding transformer, max current 240 A)
- PT/CT correction factor: we assume instrumentation channels are perfect. Therefore, all additive correction factors are set to zero, and all multiplicative correction factors

are set to unity.

3.3.4 Description of Test System #2

The second test system is depicted in Figure 3.21. The system consists of three generators operating at 15, 18, and 20 kV (Figure 3.22, Figure 3.23, Figure 3.24), three-phase and single-phase loads attached at the generator buses, and transmission lines connecting the generators together. There is an additional load between generators 1 and 3. All generators are behind step-up transformers that bring the voltage to 115 kV nominal. Like the first test system, the neutral of each generator is connected to a grounding transformer that carries a small resistance at its secondary. Meters capture the voltage and current phasors out of the phase terminals of the generator and the neutral. The meters also capture the frequency, real and reactive power, and rotor angle. The system is equipped with fault logic models to simulate a range of system events and monitor the response of the relay. The main focus is on Generator 1 (to the left in the figure). Waveforms with fault events are recorded for this generator and played back in the tested relays. This system is the starting point for a number of the tests described in this document, and the system is modified to accommodate some of the scenarios simulated.

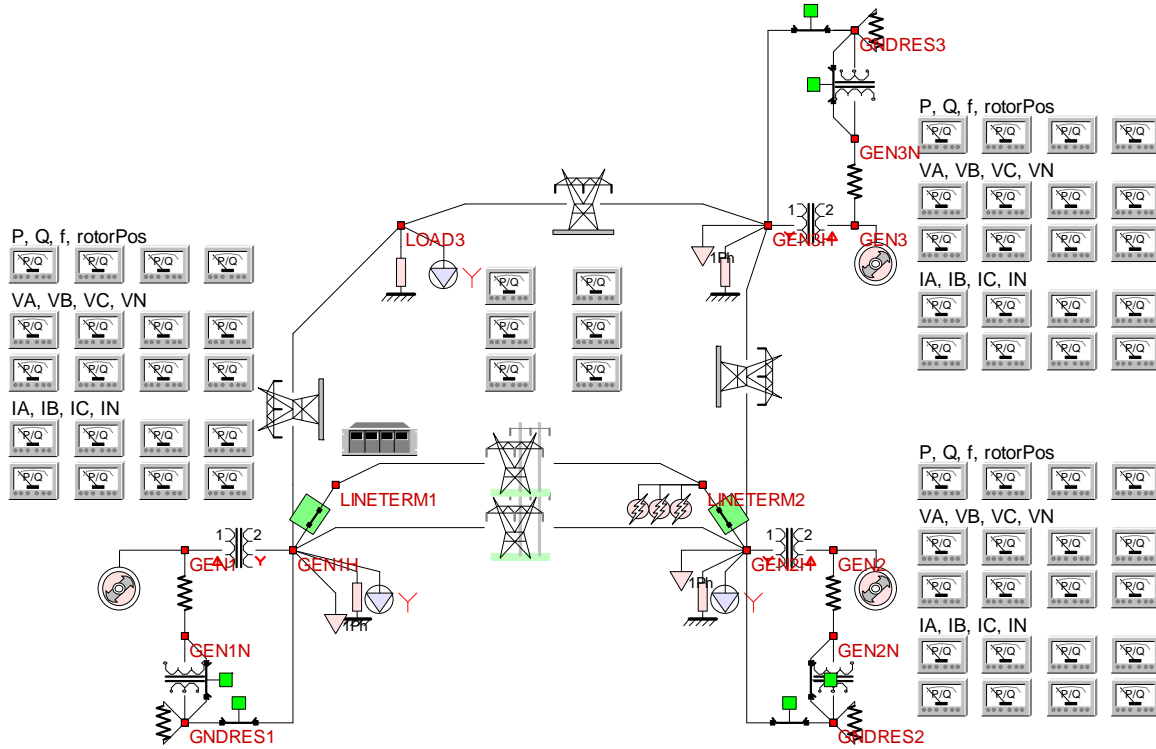


Figure 3.21: Network schematic of test system #2

Synchronous Generator Model

Accept

Cancel

Generating Unit 1

Machine Identifier NA

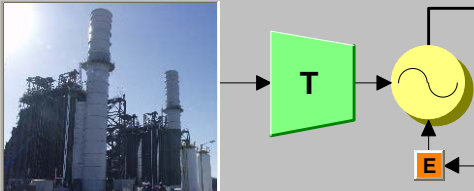
Circuit Number 1

Machine Status

☒ In Service
 ☐ Out of Service

Power Bus

GEN1



Controls

☒ PV Control
 ☐ PQ Control
 ☐ Slack

Nominal Voltage (kV)

15.0

Voltage Setpoint (pu)

1.0

Voltage Regulated Bus

GEN1

Other Parameters

Per Unit Inertia Constant

2.5

	Output Power	Minimum Power	Maximum Power	
Real	90.0	0.0	100.0	MW
Reactive	0.0	-50.0	50.0	MVar

Reactive Power Allocation Factor

1.0

Source Impedance		Ohms	PU	Base	
Positive Sequence	Resistance	0.0022500	0.001	100.0	MVA
	Reactance	0.40500	0.18	15.000	kV
Negative Sequence	Resistance	0.0022500	0.001	3.849	kA
	Reactance	0.42750	0.19	2.250	Ohms
Zero Sequence	Resistance	0.0022500	0.001		
	Reactance	0.22500	0.1		

Update Ohms

Update PU

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Figure 3.22: Parameters for Generator 1 (Test System #2)

Synchronous Generator Model

Accept

Cancel

Generating Unit 2

Machine Identifier NA

Circuit Number 1

Machine Status

☒ In Service
 ☐ Out of Service

Power Bus

GEN2

Controls

☐ PV Control
 ☐ PQ Control
 ☒ Slack

Per Unit Inertia Constant 3.0

Nominal Voltage (kV)

18.0

Voltage Setpoint (pu)

1.0

Voltage Regulated Bus

GEN2

Reactive Power Allocation Factor

1.0

	Output Power	Minimum Power	Maximum Power
Real	90.0	0.0	300.0
Reactive	0.0	-100.0	100.0

	Ohms	PU	Base
Positive Sequence	Resistance	0.0010800	0.001
	Reactance	0.19440	0.18
Negative Sequence	Resistance	0.0010800	0.001
	Reactance	0.20520	0.19
Zero Sequence	Resistance	0.0010800	0.001
	Reactance	0.10800	0.1

	Ohms	PU	Base
Positive Sequence	Resistance	0.0010800	0.001
	Reactance	0.19440	0.18
Negative Sequence	Resistance	0.0010800	0.001
	Reactance	0.20520	0.19
Zero Sequence	Resistance	0.0010800	0.001
	Reactance	0.10800	0.1

Source Impedance

	Ohms	PU	Base
Positive Sequence	Resistance	0.0010800	0.001
	Reactance	0.19440	0.18
Negative Sequence	Resistance	0.0010800	0.001
	Reactance	0.20520	0.19
Zero Sequence	Resistance	0.0010800	0.001
	Reactance	0.10800	0.1

	Ohms	PU	Base
Positive Sequence	Resistance	0.0010800	0.001
	Reactance	0.19440	0.18
Negative Sequence	Resistance	0.0010800	0.001
	Reactance	0.20520	0.19
Zero Sequence	Resistance	0.0010800	0.001
	Reactance	0.10800	0.1

Update Ohms

Update PU

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Figure 3.23: Parameters for Generator 2 (Test System #2)

Synchronous Generator Model

Accept

Cancel

Generating Unit 3

Machine Identifier NA

Circuit Number 1

Machine Status

☒ In Service
 ☐ Out of Service

Power Bus

GEN3

Controls

☒ PV Control
 ☐ PQ Control
 ☐ Slack

Nominal Voltage (kV)

20.0

Voltage Setpoint (pu)

1.0

Voltage Regulated Bus

GEN3

Per Unit Inertia Constant
2.5

	Output Power	Minimum Power	Maximum Power	
Real	140.0	0.0	200.0	MW
Reactive	0.0	-50.0	50.0	MVar

Reactive Power Allocation Factor
1.0

Source Impedance		Ohms	PU	Base	
Positive Sequence	Resistance	0.0020000	0.001	200.0	MVA
	Reactance	0.40000	0.2	20.000	kV
Negative Sequence	Resistance	0.0020000	0.001	5.774	kA
	Reactance	0.38000	0.19	2.000	Ohms
Zero Sequence	Resistance	0.0020000	0.001		
	Reactance	0.20000	0.1		

Update Ohms

Update PU

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Figure 3.24: Parameters for Generator 3 (Test System #2)

3.3.5 Beckwith Relay Setup

3.3.5.1 Connections and Wiring

A schematic of the connections between the relay and the generator are shown in Figure B.1 in Appendix B.1. This schematic is mostly derived from the connections diagrams in the relay manual [20], and it would apply in the case of an actual generator protected by the Beckwith relay. In this study, however, the generator instrumentation is simulated with software and reproduced using a signal generator and amplifier. The connections and wiring between the signal amplifier and the generator relay are shown in Figure B.6 in Appendix B.1.

3.3.5.2 Communications

The relay can be configured from a remote computer using serial communications through a null-modem cable. Alternatively, the relay can be configured using an Ethernet connection or even the front panel. The focus of this document is on serial communications to take advantage of the manufacturer-provided configuration software. The Beckwith M3425-A relay is built to listen to requests sent in a specific format known

as the BECO communications protocol (see [24] and [25] for more information). As a result, the relay does not check the presence of a “client” or provide a prompt interface with common terminal programs. When the relay receives a well-formed request, it responds by constructing a formatted message that the client can retrieve. Response messages may include requested data from the client such as set points, output status, and full oscillograph records. While it is possible to implement this protocol independently, the provided configuration software is a better choice for an initial approach. The software makes the protocol requirements transparent to the user by translating basic setup information into a request with the appropriate format.

3.3.5.3 Setup Software

The provided software consists of two separate computer programs: IPSCOM and IPSutility. IPSCOM is a general program to setup, monitor, and retrieve relay configuration and status data. It can translate and display the information retrieved from the relay in a number of textual and graphical ways. While most parameters of the relay can be set via IPSCOM, the program does not provide manual control of the output contacts. IPSutility is a lightweight program that can perform a limited number of operations. While very limited compared to IPSCOM, IPSutility can take control of the output contacts.

A procedure to setup the relay and retrieve information is described in the following subsections.

3.3.5.4 General settings

Establishing communications with the relay when it is connected to a computer through a null-modem cable is very simple using the provided software:

- The communications port is set to COM1.
- The baud rate can be set to the highest supported value (9600 bps).
- Other fields are left untouched.

General settings pertain to the calibration of the relay and the availability of a number of features. The IPSCOM program provides the user interface to define the general settings (Figure 3.25).

SETUP SYSTEM

Nominal Frequency: 60 Hz C.T. Secondary Rating: 5 A

Nominal Voltage: 69.0 50.0 V 140.0 V Delta-Y Transform
☒ Disable ☐ Delta - AB ☐ Delta - AC

Nominal Current: 5.00 0.50 A 6.00 A

Input Active State: 6 5 4 3 2 1
☒ Open ☒ Open ☒ Open ☒ Open ☒ Open ☒ Open
☒ Close ☒ Close ☒ Close ☒ Close ☒ Close ☒ Close Input Active State Expanded

V.T. Configuration: ☒ Line to Ground ☐ Line to Line ☐ Line-Ground to Line-Line

59/27 Mag. Select: ☒ RMS ☐ DFT 50DT ☐ Enable
Split Phase Differential: ☒ Disable

Phase Rotation: ☒ ABC ☐ ACB

V.T. Phase Ratio: 125.0 : 1 1.0 6550.0

V.T. Neutral Ratio: 4.0 : 1 1.0 6550.0

V.T. Vx Ratio: 1.0 : 1 1.0 6550.0

C.T. Phase Ratio: 7000 : 1 1 65500

C.T. Neutral Ratio: 48 : 1 1 65500

Pulse Relay
Outputs: 1 2 3 4 5 6 7 8

Latched Outputs
Outputs: 1 2 3 4 5 6 7 8 Pulse Relay Expanded Outputs

Injection Frequency for F64S: 20 Hz Latch Relay Expanded Outputs

Relay Seal-In Time
OUT 1: 30 8160 cycles
2: 30
3: 30
4: 30
5: 30
6: 30
7: 30
8: 30 2 cycles

Relay Seal-In Time Expanded
OUT 9: 30 8160 Cycles 30 OUT 17
10: 30 18
11: 30 19
12: 30 20
13: 30 21
14: 30 22
15: 30 23
16: 30 2 Cycles 30

NOTE : Pulse / Latched Relay Outputs should be selected in 2 steps.
i) Deselect Latched / Pulse Relay Outputs and Save.
ii) Select Pulse / Latched Relay Outputs and Save.

Save Cancel

Figure 3.25: General relay settings dialog box

The user interface for general relay settings also provides inputs for the following parameters:

- nominal current and voltage, CT and PT configuration and ratios, according to the generator nominal voltage and current, and the instrumentation channel parameters defined in section 3.3.3;
- state of the inputs: closed or open;
- seal-in time for each of the channels.

Nominal CT secondary current and base frequency cannot be changed as they are built into the relay at the time of purchase.

3.3.5.5 Individual functions

Individual functions are configured using a specific screen for each function. The intrinsic of each function is described in the instructions book of the relay. The IPSCOM program also provides displays that summarize the parameters and status of all functions

in the relay.

3.3.5.6 GPS Synchronization

The tested relays can both synchronize their clocks to a signal provided from a GPS antenna. Both relays have an IRIG-B input that enables this capability.

3.3.6 Simulation of Power System Events

The high-fidelity simulation software allows faults to be placed anywhere in the system. Faults can be simulated anywhere along transmission lines, circuit connectors, as well as inside the windings of generator models and transformers. A number of events can be simulated with this model. First are faults outside of the generator and outside the protection range of the generator relay. These events include faults at the transformer or along the transmission line. For these events, the generator relay should not perform any action, unless a certain amount of time has elapsed. Second are events inside the protection range of the relay and events that concern the generator itself. These events include ground faults inside the generator, turn-to-turn faults along the stator of the generator, rotor faults, and excitation failures. The test simulates these generator events, and the response of the relays to such events is noted. The simulated events can be reproduced using WinIGS and following the suggested procedure provided in Appendix B.2.

3.3.7 Reporting Tests and Simulated Events

The tests are reported in a relay response chart that contains a comprehensive set of events used to test the response of each of the functions of the relay. Two copies of the document are needed for each series of tests: one for the test itself and one for the intended response of the relay for each of the events listed.

We provide a procedure to reproduce each event in the test system using the WinIGS software in Appendix B.2. An example response chart of the relay for each of the events simulated is given in Appendix B.4.

3.4 Basic Event Triggering and Oscillographic Record Analysis

3.4.1 Beckwith M3425-A

The Beckwith relay has the capability to record and store waveforms for a time window that covers an event in the system. 16 oscillograph channels are available to record and store various events. The waveform data can be downloaded at a later time to a remote computer using the IPSCOM program or any software that is compatible with the communication protocols of the relay.

3.4.1.1 Manual Event Triggering and Retrieval

It is possible to trigger the oscillograph and record measurements even if the relay does not detect any event in the system. The following was performed for this basic operation:

- Generate three-phase, balanced sinusoidal voltages, RMS value 69 V, in positive sequence (120 degrees apart) using the waveform generator.
- Feed the voltage measurement inputs V_A , V_B , V_C with the generated voltages (pins 38 to 43 at the back of the relay).
- Close output contact number 8 using the IPSutility.

With the default settings of the relay, closing an output contact using IPSutility triggers the oscillograph and records a target hit. Upon contact closing, visual feedback is provided by the relay with the target LED, the oscillograph trigger LED, and the output contact LED illuminated. In addition, the relay flashes target information on the front panel display (Figure 3.26).

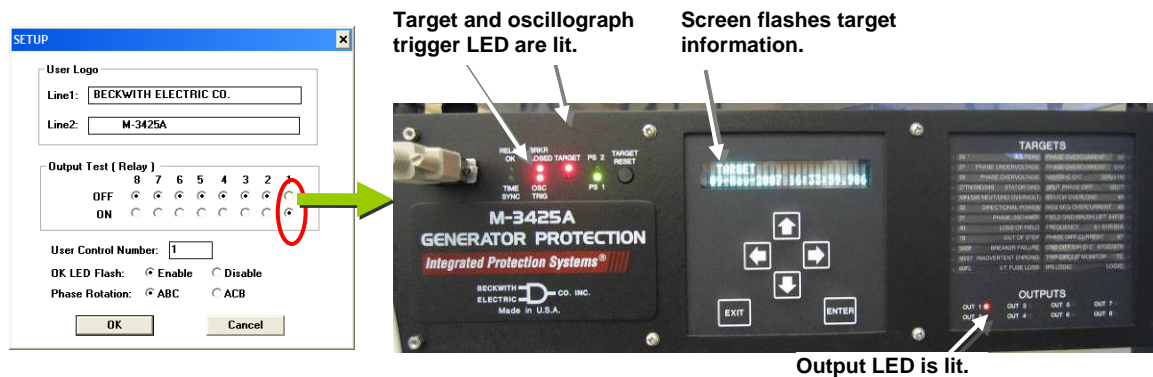


Figure 3.26: Manual output contact control with IPSutility and visual feedback from the relay

The records generated from this event can be viewed and/or erased using the IPSCOM program. Specifically, the oscillographic data can be downloaded in two formats: COMTRADE or the proprietary Beco format (Figure 3.27). For compatibility, files are downloaded in the COMTRADE format. Note that the relay can store up to 16 oscillograph records. The maximum number of records available can be configured from the relay front panel or the configuration software.

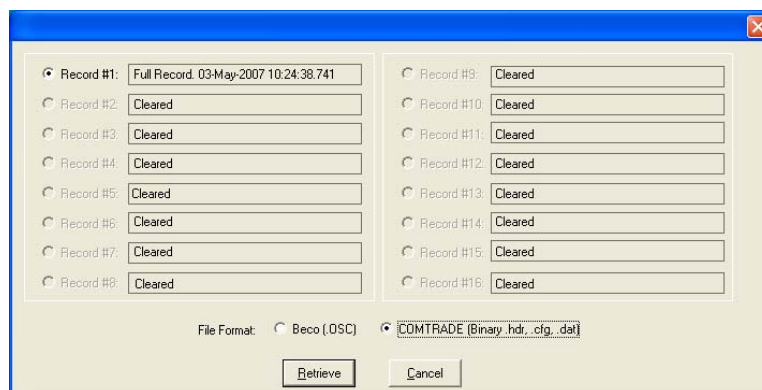


Figure 3.27: The oscillograph retrieval screen

3.4.1.2 Oscillographic Record Analysis

The waveform records comply with the 1999 version of the COMTRADE standard. The record consists of three files: a text configuration file, a data file in the binary format specified in the standard, and a header file. The configuration file is shown in Appendix E. Twelve analog measurement channels include the three line voltages, the six phase currents on each side of the coils, the neutral voltage and current, and one multi-purpose voltage. The file has provisions for 40 status channels, but only 14 channels are utilized to record the state of the 8 outputs and 6 inputs.

Having fed the relay with generated waveforms, the downloaded COMTRADE data can be visualized to check consistency of the relay setup. The IGS-XFM program [22] and the Waveform Analyzers software [23], both developed at Georgia Tech for the study of protective relaying, can be used to display the data. Figure 3.28 shows an excerpt of the generated voltages seen by the relay. In addition, the figure includes a plot of the status of the output contact that has been toggled.

By default, the length of the retrieved oscillographic record is 4.6 seconds. There are 4480 data points sampled at 960 Hz (16 times the base system frequency). Records may contain up to 472 cycles (7.8 seconds duration) at this fixed sampling rate. As expected, the recorded values for the voltage waveforms are about 97 V peak, and a RMS value that is stabilized between 68.80 and 68.95 V. The phases follow the positive sequence order. The plot for Output 8 shows its status changing from zero (open) to one (closed). Additionally, if the voltage inputs start less than 4 seconds before the output contact is triggered, the oscillograph is able to record the connection of the relay to the voltage source (Figure 3.29).

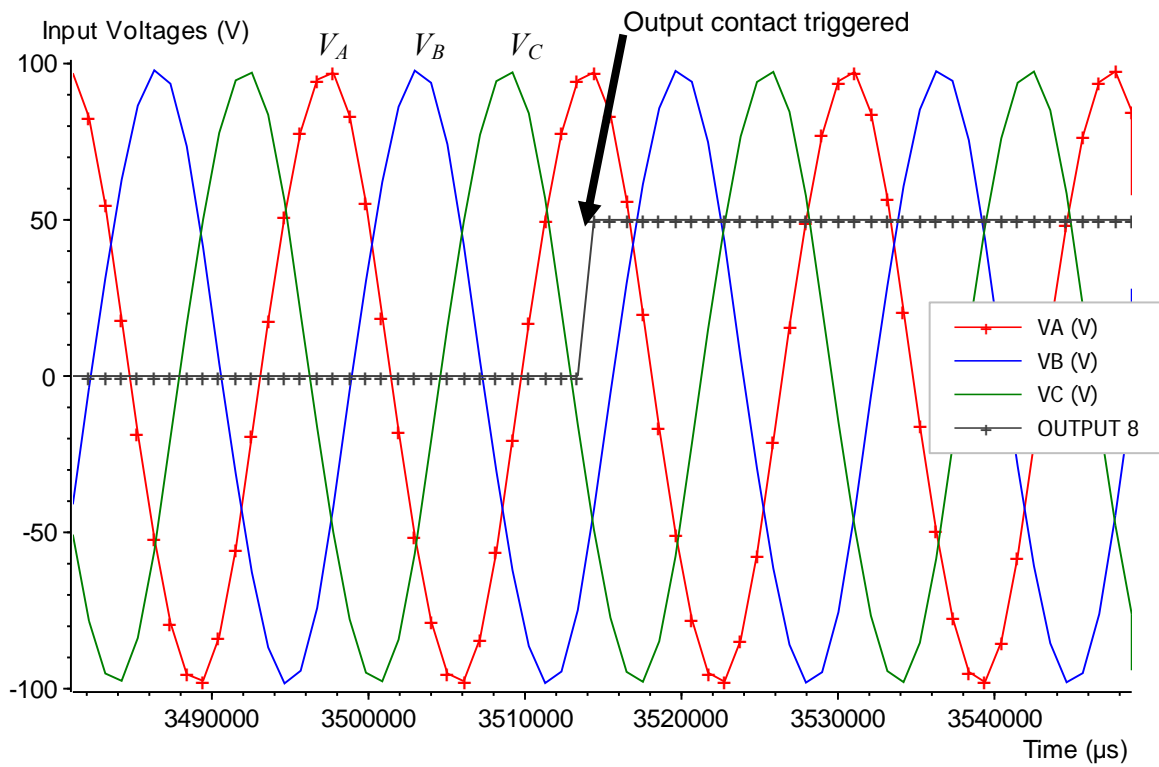


Figure 3.28: Graphical sample of the waveforms and state of the output contact

(Scaled up) recorded by the Beckwith relay. For readability, data points are shown for phase A voltage and output contact status only

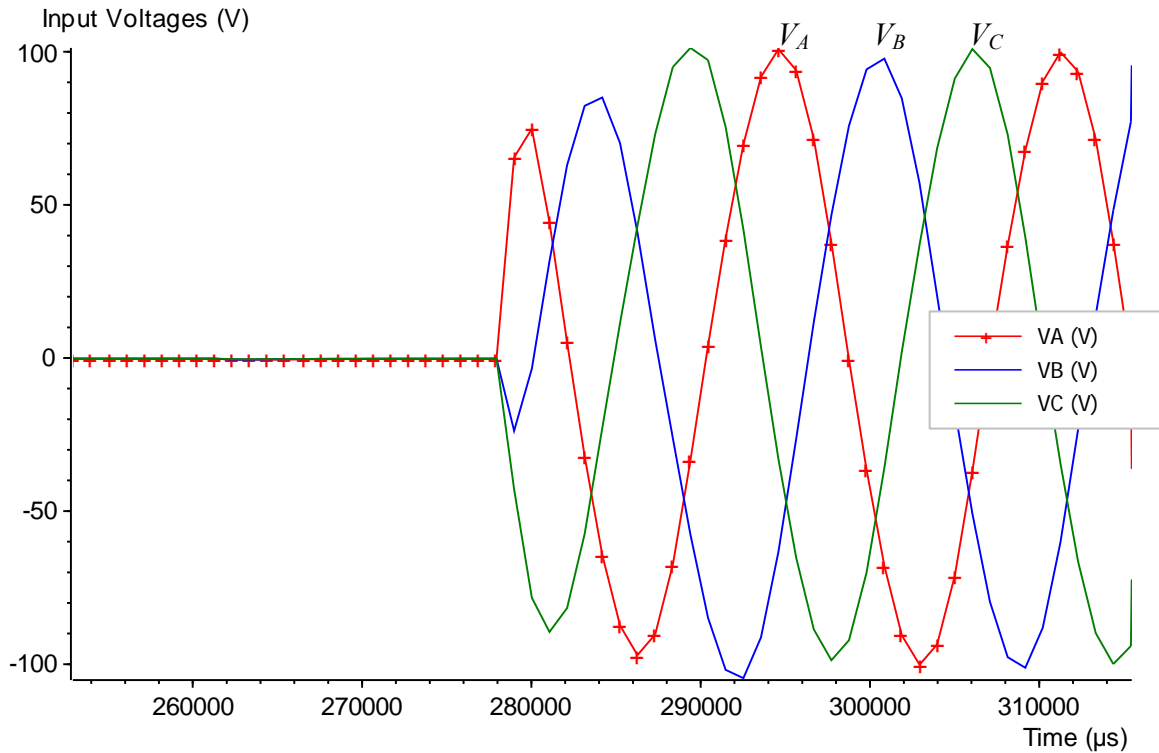


Figure 3.29: Records of the initiation of the voltage supply to the relay

3.4.2 SEL 300-G

The setup for the 300-G relay is performed through the SEL Acseleator QuickSet software [15]. The system settings applied for the M3425-A relay are entered in the 300-G relay as well. The 300-G relay has the capability to record and store waveforms for time windows of different lengths to cover a variety of events in the system. The number of oscillograph records available is only limited by memory. The waveform data can be downloaded at a later time to a remote computer using the Acseleator program.

The records generated from this event can be viewed and/or erased using the provided configuration software. Oscillograph data is downloaded in a proprietary event file (CEV) format before it can be converted to COMTRADE by the viewing software.

3.4.2.1 Event Triggering, Retrieval, and Analysis

It is possible to manually trigger the oscillograph and record measurements even if the relay does not detect any event in the system. This can be done directly using the configuration software.

The waveform records comply with the 1991 version of the COMTRADE standard. The record consists of three files: a text configuration file, a data file in text format, and a header file. The file contains 12 analog measurement channels: phase, neutral, and

ground currents, phase and neutral voltages, power supply voltage, one multi-purpose voltage, and a record of the frequency. The file has provisions for over 400 status channels. The state of each function, output, and related variables is recorded in the file as well. The downloaded COMTRADE data can be visualized using the IGS-XFM program and the Waveform Analyzers software. By default, the length of the retrieved oscillographic record is 256 data samples at 960 Hz (16 times the base system frequency, total 266 ms). Analysis of event waveforms is described in the test case showing the same waveform sent to both relays for comparison.

3.5 Equations for the Protection Variables

This section presents the basic protection variables in generating unit protective relays. It defines the notation and some basic tests to determine the proper connection to the inputs of the relay.

3.5.1 Notation

Variable	Description	Functions
\tilde{I}_{Nom}	Nominal CT secondary current (5 A)	All
\tilde{I}_{Pickup}	Pickup current (at CT secondary)	All
\tilde{I}_{Op}	Operating current (at CT secondary)	87
$\tilde{I}_{Restraint}$	Restraint current (at CT secondary)	87
Suffix $_X$	Corresponding variable on phase X on high-voltage side of generator (X is A , B , or C)	All
Suffix $_x$	Corresponding variable on phase x on neutral side of generator (x is a , b , or c)	All

3.5.2 Setup 1 – Single Current Source at Neutral Side Only

$$\tilde{V}_a = \tilde{V}; \quad \tilde{V}_b = \tilde{V}e^{-j120^\circ}; \quad \tilde{V}_c = \tilde{V}e^{-j240^\circ}; \quad \tilde{V} = 1.0e^{j\omega t} \text{ p.u.}$$

$$\tilde{I}_A = \tilde{I}_B = \tilde{I}_C = 0; \quad \tilde{I}_a = \tilde{I}; \quad \tilde{I}_b = \tilde{I}e^{-j120^\circ}; \quad \tilde{I}_c = \tilde{I}e^{-j240^\circ}; \quad \tilde{I} = I(t)e^{j\omega t}.$$

This setup reproduces a turn-to-ground fault on all three windings of the generator simultaneously. In this case, the neutral current is equal to three times the zero sequence current which is also zero with all three windings shorted to the ground simultaneously. As a result, the neutral voltage can be neglected, and $\tilde{I}_N = 0, \tilde{V}_N = 0$.

3.5.3 Setup 2 – Same Currents In and Out

$$\tilde{V}_a = \tilde{V}; \quad \tilde{V}_b = \tilde{V}e^{-j120^\circ}; \quad \tilde{V}_c = \tilde{V}e^{-j240^\circ}; \quad \tilde{V} = 1.0e^{j\omega t} \text{ p.u.}$$

$$\tilde{I}_A = \tilde{I}_a = \tilde{I}; \quad \tilde{I}_B = \tilde{I}_b = \tilde{I}e^{-j120^\circ}; \quad \tilde{I}_C = \tilde{I}_c = \tilde{I}e^{-j240^\circ}; \quad \tilde{I} = I(t)e^{j\omega t}.$$

No current is lost in any phase from the neutral to the transformer side of the generator. This setup reproduces operating conditions that do not involve a fault or abnormal conditions within the generator windings, and may also represent turn-to-turn fault conditions.

3.5.4 Operating Current and Restraint Current

Operating current:

$$\tilde{I}_{Op_X} = CTC \times \tilde{I}_X - \tilde{I}_x = \tilde{I}_X - \tilde{I}_x \text{ (assumes matching CTs and correction factor CTC = 1)}$$

Restraint current:

$$\tilde{I}_{Restraint_X} = \frac{CTC \times \tilde{I}_X + \tilde{I}_x}{2} = \frac{\tilde{I}_X + \tilde{I}_x}{2} \text{ (same assumption)}$$

3.6 Individual Protection Function Tests (M-3425A)

3.6.1 Common Procedures

The M-3425A relay offers protection engineers the possibility to use different sets of parameters simultaneously for the same relay function. This is as if the same function was duplicated within the relay. In particular, each set of parameters includes a different pickup level/zone and a different time delay. This is very useful for testing purposes as it is possible to compare different settings in parallel or to compare different settings with the same reference. Applicable functions, with at least two available sets of parameters, are as follows:

21, 24 (definite time only), 27, 27TN, 32, 40, 49, 50, 50DT, 59, 59N, 59X, 64F, 81, 81A, 81R, 87, IPSLogic

Functions not listed above have only one set of parameters and cannot benefit from this common procedure:

24 (inverse time), 25, 46, 50N, 50BF, 50/27, 51N, 51V, 59D, 60FL, 64B, 64S, 67N, 78, 87GD, BM, TC

3.6.1.1 Time Delay Testing

In one of the parameter sets used as a reference, the time delay is set to the lowest value possible (1 cycle in most cases, which is an almost instantaneous output trigger), and a reference output channel is selected. For each of the remaining parameter sets, the time delay is set to values in increments up to the maximum possible delay, and an output other than the reference output is selected. The pickup setting is the same in all the parameter sets. Because the different parameter sets available can be enabled simultaneously, it is possible to compare the behavior of the function with different time delays in a single run. Specifically, the output switching times determine the accuracy of the time delays in the relay.

3.6.1.2 Pickup Testing

In one of the parameter sets used as a reference, the pickup setting is set to the lowest value possible. For the remaining parameter set(s), the pickup is set to values in increments up to the maximum range possible. The time delay in all the parameter sets is set to the minimum delay possible (in most cases 1 cycle for almost instantaneous tripping). Because the different parameter sets available can be enabled simultaneously, it is possible to compare the behavior of the function with different pickup settings in a single run. Specifically, the levels where the functions trigger determine the accuracy of

the pickup setting in the relay.

3.6.2 Function 87 – Phase Differential

3.6.2.1 Description

This function trips when the operating current I_{Op} exceeds a value that is a function of the restraint current. For the Beckwith relay, we think the equation of the characteristic, in term of RMS values, is

$$I_{Op} = \begin{cases} \max(I_{Pickup}, I_{Restraint} \times slope) & \text{if } I_{Restraint} < 2I_{Nom} \\ I_{Restraint} \times 4 \times slope & \text{otherwise} \end{cases}$$

The function takes one slope parameter and one pickup parameter. The function activates designated outputs after a set delay. The characteristic is shown in Figure 3.30. Settings for the IPSCOM program are shown in Figure 3.31.

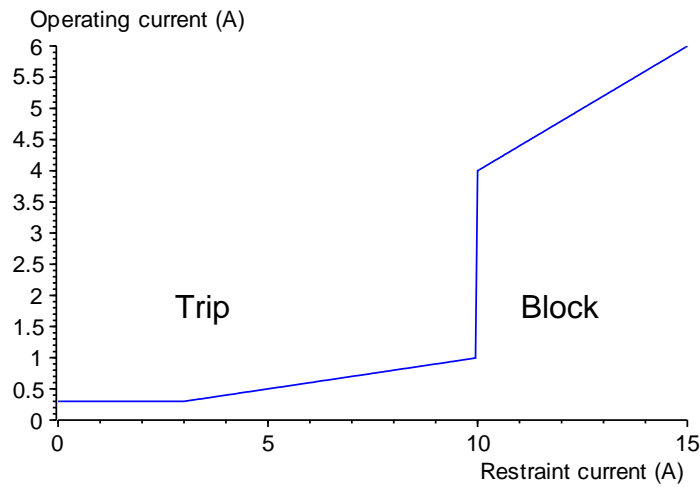


Figure 3.30: Characteristic of Function 87 function with 0.3 A pickup and 10% slope

Figure 3.31: Settings for the differential relay function

3.6.2.2 Setup 1 – Single Current Source at Neutral Side Only

Assuming $I(t) < 2 I_{Nom}$, the relationship between operating and restraint current becomes

$$\tilde{I}_{Op_X} = \tilde{I}_X - \tilde{I}_x = -\tilde{I}_x; \quad \tilde{I}_{Restraint_X} = \frac{\tilde{I}_X + \tilde{I}_x}{2} = \frac{\tilde{I}_x}{2};$$

Thus, $\tilde{I}_{Op_X} = -2\tilde{I}_{Restraint_X}$, and $I_{Op_X} = 2I_{Restraint_X}$.

3.6.2.3 Minimum Pickup and Dropout Level Test (Setup 1)

For the minimum pickup test, the slope coefficient must be made passive, i.e.

$$I_{Restraint} \times slope < I_{Pickup} \quad \text{for all } I_{Restraint} < 2I_{Nom}$$

The slope coefficient becomes passive (does not affect the characteristic below $2 I_{Nom}$) when

$$slope \leq \frac{I_{Pickup}}{2I_{Nom}}.$$

Since the relay does not report function pickup in any of its outputs, we reduce the delay from pickup to trigger to the minimum possible which is 1 cycle. The relay is set to trigger Output #2 after one cycle. To test the function, we look in the recorded waveforms the time when Output 2 changes from zero (inactive) to one (active).

The function is tested first with each neutral-side current input energized individually while the others remain unenergized. Then, the function is tested with all three currents active.

The first round of tests consist of applying a current ramp from 0 to 1.0 p.u., increasing at 0.05 p.u./s, and to note at which RMS value of the current the relay picks up/triggers the function. For record purposes, the time refers to the time origin of the waveforms retrieved from the relay. Note that the relay does not provide outputs for function targets; therefore, targets are estimated using the 1-cycle delay setting entered for this relay function. The results are shown in Table 3.1.

Table 3.1: Function 87, trigger and target times and corresponding current

Run ID	Phases	Trigger time (μs)	Trigger RMS (A)	Est. target time (μs)	Est. target RMS (A)	Time for 1.00 A RMS
1011_171402	A	+1232544	0.99507	+1216929	0.98645	+1314783
1011_172345	B	+1232544	0.99800	+1216929	0.99292	+1261692
1011_173446	C	+1220052	0.99142	+1204437	0.98689	+1283553
1011_150058	All	+1220052	0.98615	+1204437	0.98340	+1436580

Remarks: The M3425-A has a current accuracy of $\pm 3\%$ or 0.1 A. The current record is offset by approximately -0.13 A, and this offset is observable when no current is flowing

through the relay. Some errors may occur when retrieving oscillograph records (corrupted files, e.g. in 20071011_173446).

In the second round of tests, a sinusoidal waveform in a triangular envelope is utilized to trigger the relay function and activate Output #2. The objective is to show that the output contact (here Output #2) is deactivated when the RMS current falls to a value below the pickup level defined for the relay. Settings are 0.80 A pickup, delay 1 cycle, slope 1 %, and waveform with triangular envelope from 0 to 0.6 p.u. and 0.6 p.u. to 0 at 0.1 p.u./s.

Again, each phase is tested individually for differential current pickup. An example of recorded waveforms for the test on phase A is shown in Figure 3.32. Trigger and drop-out times are shown in Table 3.2 and compared with the times computed RMS values reach the pickup setting.

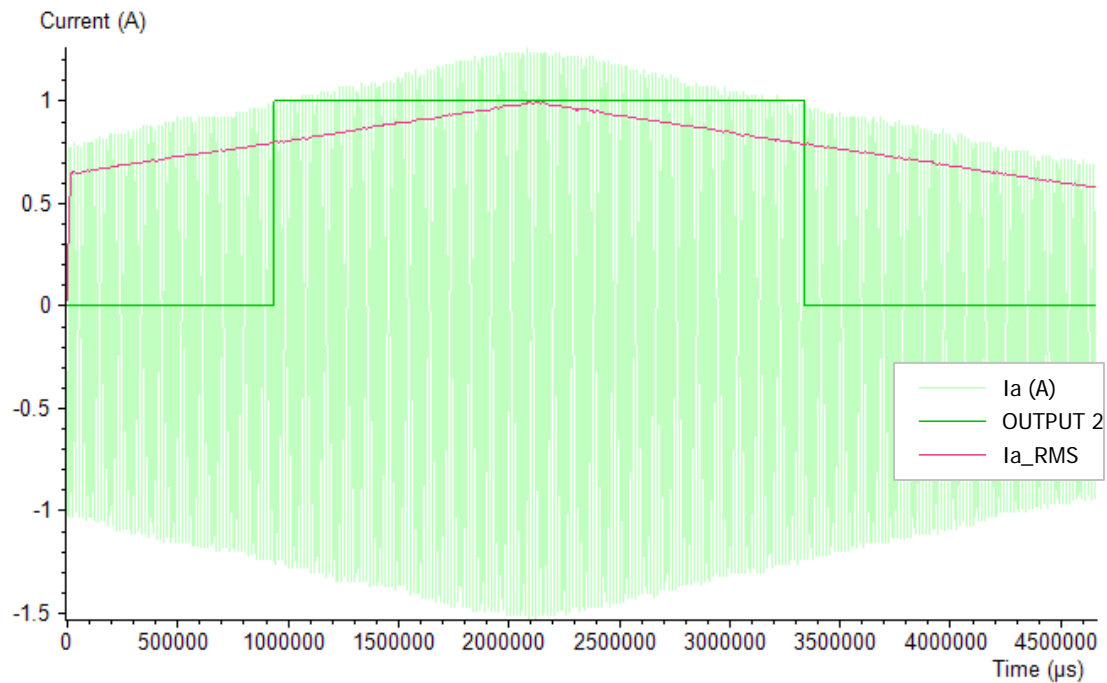


Figure 3.32: Function 87, phase differential, waveforms for the combined pickup and dropoff tests

Table 3.2: Function 87, trigger and drop-out times and corresponding currents

Run ID	Phases	Trigger time (μs)	Trigger RMS (A)	Drop-out time (μs)	Drop-out RMS (A)	Time for 0.80 A RMS up	Time for 0.80 A RMS down
1015_112933	A	+936900	0.798317	+3339528	0.789908	+937941	+3279150
1015_111904	B	+941064	0.790976	+3422808	0.790298	+961884	+3369717
1015_110813	C	+936900	0.801595	+3335364	0.790668	+933777	+3276027

3.6.2.4 Test of Slope (Setup 1)

It is not possible to test the slope using setup 1

since $I_{Op} = 2I_{Restraint} = slope \times I_{Restraint}$, $I_{Restraint} < 2I_{Nom} \Rightarrow slope = 2$, and the slope factor cannot be greater than 1.

3.6.3 Function 27 – Phase Undervoltage

3.6.3.1 Description

This function operates after a specified delay when the voltage on certain phases drops and remains below a specified value.

General generator settings: these settings reproduce a voltage sag at the bus of the generator: Triangular signal, maximum = 64 V RMS, minimum = 57 V, Slope at 0.03 p.u./s. The entire event lasts about 5 seconds.

3.6.3.2 Pickup Test (Setup 1)

The three sets of parameters are defined with voltage thresholds: 62 V, 60 V, and 58 V. The time delay is set to the minimum possible (1 cycle). The response of the relay is shown in Figure 3.33. Results are shown in Table 3.3.

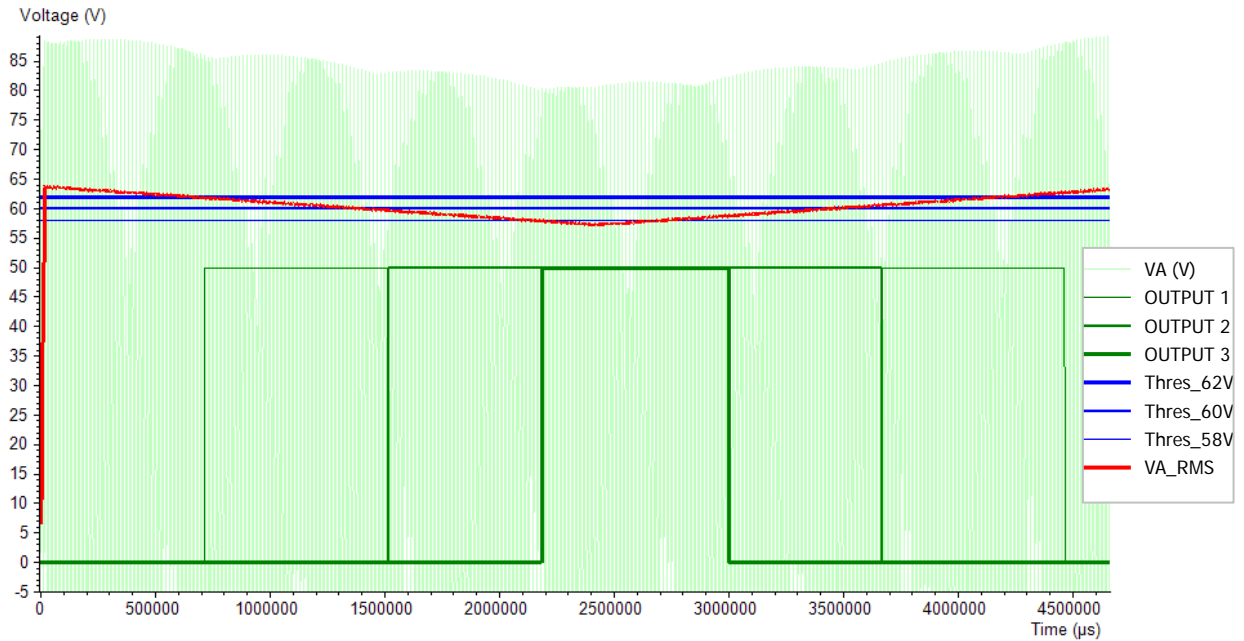


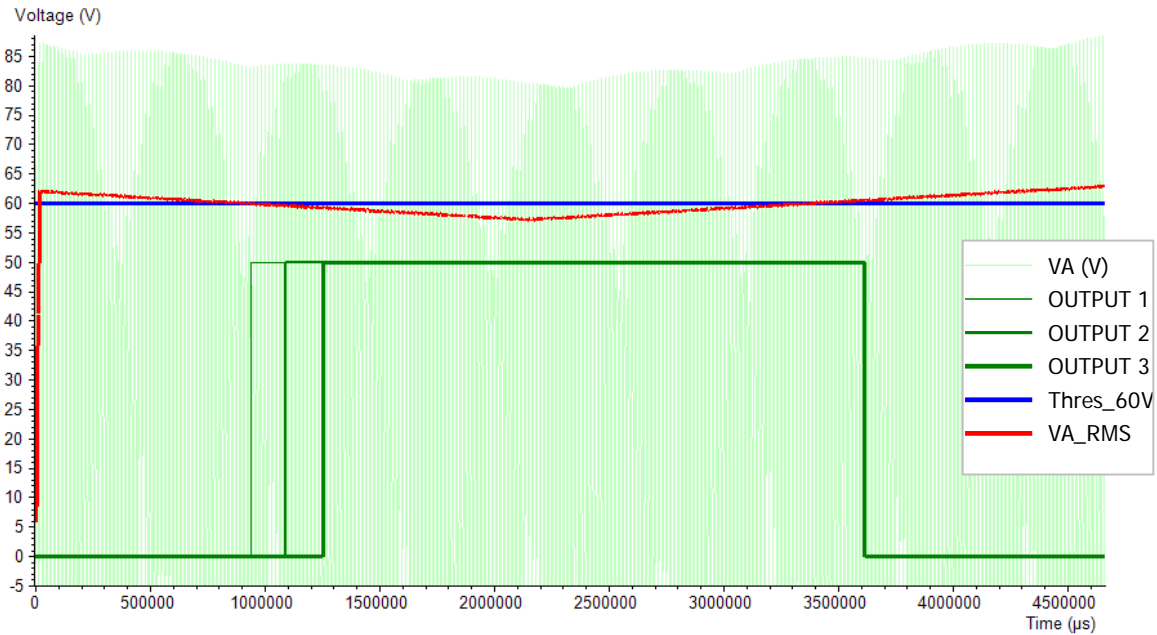
Figure 3.33: Function 27, phase undervoltage, waveforms from pickup and dropoff test

Table 3.3: Function 27, times and voltage levels for function trigger and release

	Set pickup level (V)	Measured trigger level (V)	Measured release level (V)	Time V settles under pickup level	Trigger time	Time V settles above pickup level	Release time
Output 1	62	61.79	62.78	678732	716208	4210845	4463808
Output 2	60	59.63	60.64	1413678	1515696	3468612	3664320
Output 3	58	57.92	58.83	2163198	2186100	2726379	2998080

3.6.3.3 Time Delay Test (Setup 1)

The threshold for the function is set to 60 V for all parameter sets. The delays are 1 cycle, 10 cycles, and 20 cycles. The response of the relay is shown in Figure 3.34.

**Figure 3.34: Function 27, phase undervoltage, waveforms from time delay test**

Pickup voltage is 60.04 V. Note that from data, the relay waits until the RMS voltage on phase A drops below 60.00 V for 4 sampling periods. The difference with the previous experiment is that all settings have the same dropoff delay of 0.23 s (13.8 cycles) after the RMS voltage permanently stays above 60.00 V. The dropoff voltage is 60.61 V. Results

are shown in Table 3.4.

Table 3.4: Function 27, time delay test results

	Set delay (cycles)	Measured delay w.r.t. Output 1 (cycles)	Operated RMS voltage (V)
Output 1	1	N/A	60.04
Output 2	10	8.99424	59.72
Output 3	20	18.9878	59.33

To check for time delay accuracy and check that the relay does not operate below the time delay, all delays are set at 4 seconds (240 cycles). Then, the triangular function is fed to the relay. As expected, there was no operation. Note that the general target LED and the LEDs in the target pane are not illuminated, unless an output contact is triggered. In particular, the target LEDs remains unlit voltage drops below the threshold and returns above the threshold before the timeout has elapsed.

3.7 Expanded Test Scenarios

This section discusses a number of scenarios for testing generator relays that may involve the triggering of multiple protective functions of the relay. For each one of the composite scenarios, the appropriate data files in COMTRADE format have been generated and briefly described in this section. The actual data can be found in the project web site.

3.7.1 Mock Generator Acceleration

3.7.1.1 Tested Functions

The following protection functions are included:

- 24 (V/Hz),
- 27 (undervoltage),
- 50 (overcurrent),
- 51V (inv. time overcurrent w/ voltage restraint),
- 59 (overvoltage),
- 81 (overfrequency).

For each protection function to be tested appropriate events are generated and stored in COMTRADE format. These events have been uploaded to the project web site.

3.7.1.2 Description

This test scenario is meant to demonstrate the capabilities of the laboratory setup described in section 3.2. Using Test System #1, a fault with an acceleration of the rotor of the generator is simulated by configuring the voltage source to produce a voltage and frequency ramp. For this experiment, the current is kept in phase with the voltage by placing a symmetric resistive load between the phases and the neutral. Simulated voltages vary from 12.3 to 14.5 kV L-L (57 to 67 V at the relays). Currents in each phase change

from 10.6 to 12.3 kA (1.52 to 1.75 A at the relay). The frequency changes from 60 to 62 Hz. All the changes take place in 3 seconds, while the waveforms are recorded through the relays. The objective is to observe changes in the transient response as the voltages and currents gradually rise. Finally, the voltage and current supply is discontinued after 3 seconds to simulate circuit breaker operation. Recording continues beyond 3 seconds to capture lingering changes in the relay status.

3.7.1.3 Example Results

Waveforms were recorded for the M-3425A relay only. Oscillograph data is retrieved from the relay in IEEE binary COMTRADE format. The retrieved waveforms for the phase voltages and outputs are shown in Figure 3.35. In particular, several changes in the different output signals can be observed while the voltage ramps up.

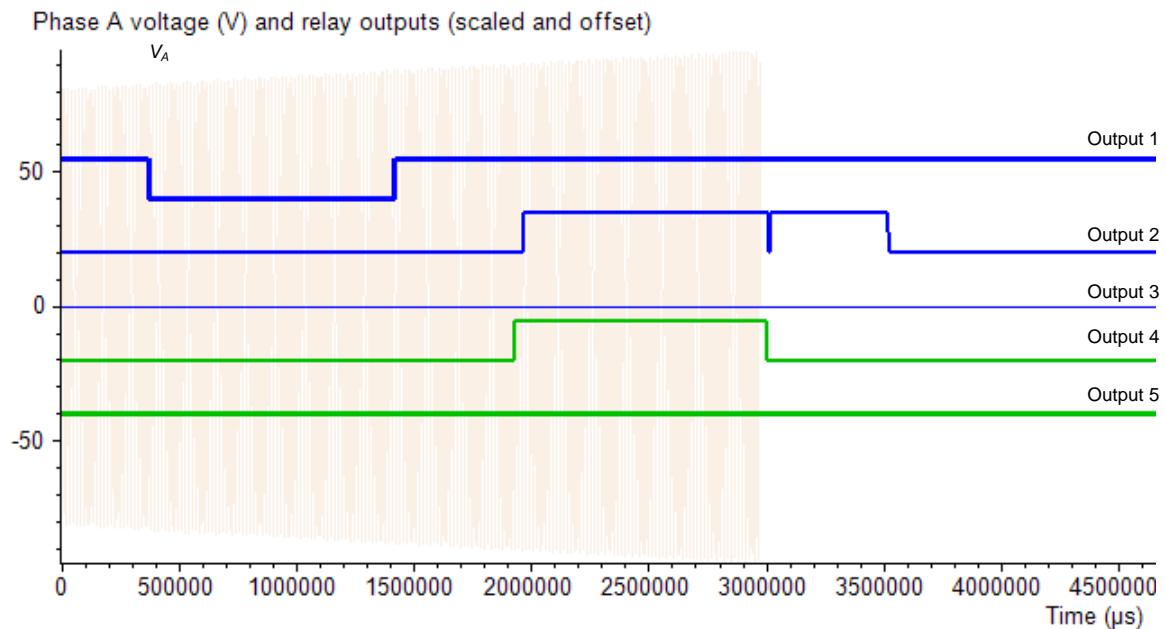


Figure 3.35: M-3425A relay retrieved waveforms for the protection scenario

The protection settings and actual behavior are shown in Table 3.5 in relay metrics. The protection scheme responded as expected despite simplifications in the experiment. The frequency function failed to start in this particular trial, but responded in another run with slightly different conditions.

Table 3.5: Settings for selected protection functions

Function	Setting	Delay	Out-put	Expected response	Observed response
24 (V/Hz)	1.15	30 cycles	3	No trip	No trip
27 (undervoltage)	58 V	1 cycle	1	Must release	Released VA = 58 V
50 (overcurrent)	1.60 A	1 cycle	2	Must trip	Tripped IA = 1.68 A
51V (inv. time overcurrent w/ voltage restraint)	1.60 A	2.0 dial	4	Check	Tripped
59 (overvoltage)	62 V	1 cycle	1	Must trip	Tripped
81 (overfrequency)	61 Hz	3 cycles	5	Must trip	No trip
All other functions	---	---	3	No trip	No trip

3.7.2 Three-Phase Fault with Unstable Swings after Clearance

3.7.2.1 Tested Functions and Events

Functions: 21 (distance), 32 (directional power), 27 (phase undervoltage), 50 (overcurrent), 78 (out-of-step), 81* (frequency).

Events: 3-phase fault on transmission line, generator motoring, reactive power transfer, system frequency increase/variations, system instability after fault clearing.

3.7.2.2 Description

Test System #2 is modified to include the fault logic to reproduce a three-phase fault on one of the lines that connects Generator 2 (see Figure 3.21). The fault lasts 0.45 s and is cleared by opening the circuit breakers at both ends of the considered line. The transient swings are observed after the fault is cleared. The settings are selected for the system to become unstable after fault clearance. This example is derived from transient stability test systems.

3.7.2.3 Generated Waveforms and Relay Response

Captures of voltage and current waveforms from Generator 1 sent to the relays are shown in Figure 3.36. Waveforms for Generators 2 and 3 are similar. There are a few phenomena common to unstable generator swings: voltage swings increase in magnitude, transitions of the units from generating to motoring, and vice-versa, high fault currents, acceleration of generator frequency, and drifting of rotor position. Considering the individual relay functions, we expect the relays to trip for power reversal, frequency increases, rotor position drifts, overcurrents, undervoltages, and so on. It is also desirable

to obtain a single response of the relays to this event, which is the triggering of the out-of-step relay function (78) along with an indicator stating “Unstable swing.”

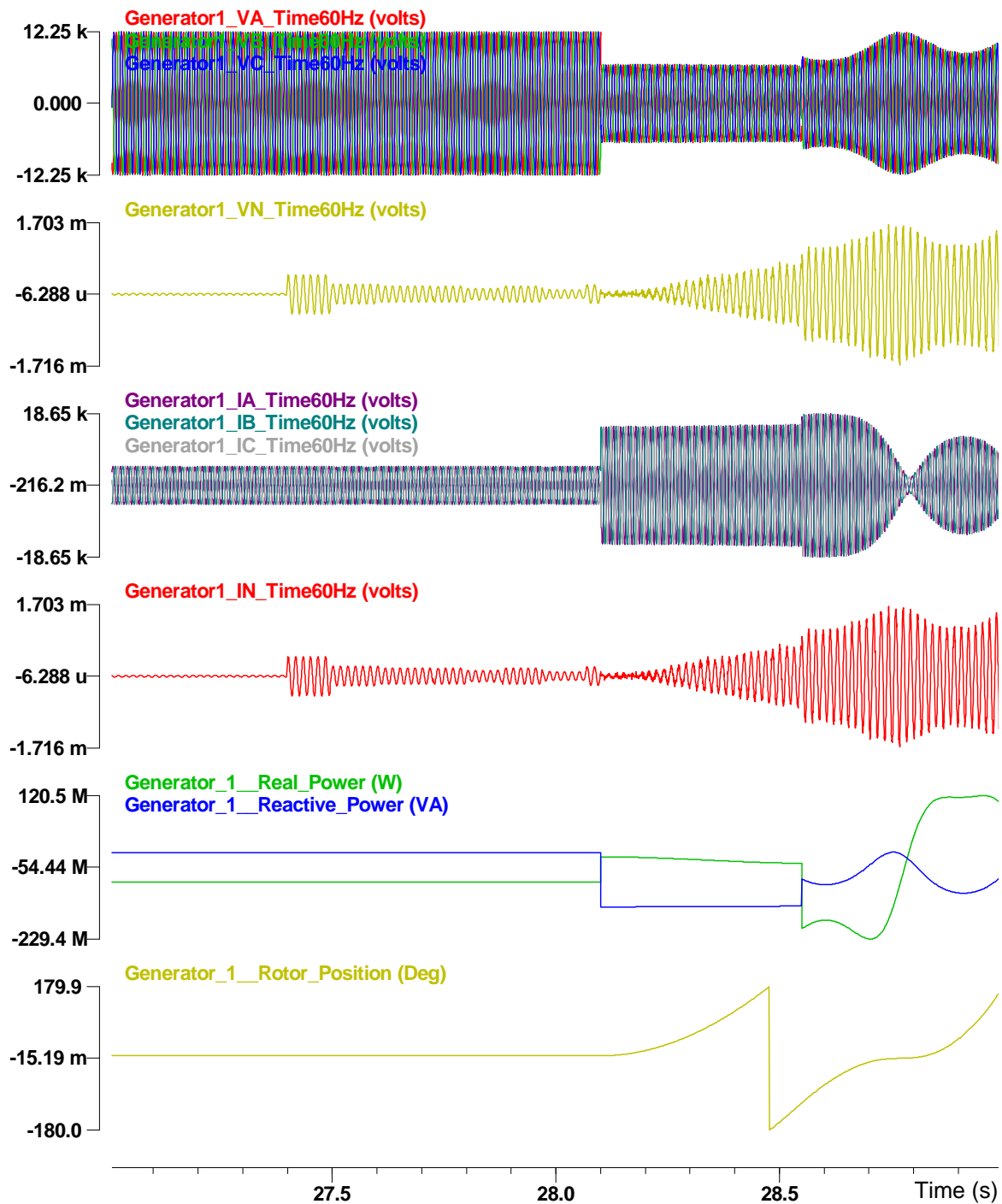


Figure 3.36: Capture of the waveforms sent to the relays for Test System #2

3.7.3 Wide-Area Partial Load Shedding

3.7.3.1 Functions and Events Tested

Functions: 81* (frequency),

Events: 10 % reduction of load (P and Q), sudden partial loss of load, frequency increase/variations.

3.7.3.2 Description

Wide-area load shedding occur from the action of utilities or system operators when load is in excess of the available power from the generators in service. Note that different entities have called the population for voluntary load cuts (such as turning off lights), simultaneously, region or nation-wide, for a short duration (five minutes), from the order of 10 %. A simultaneous drop in load can lead to an undesired response from the system. Using Test System #2, 10 % of the three-phase loads is shed after 1 second of simulation (Figure 3.37). The responses of the generators are observed.

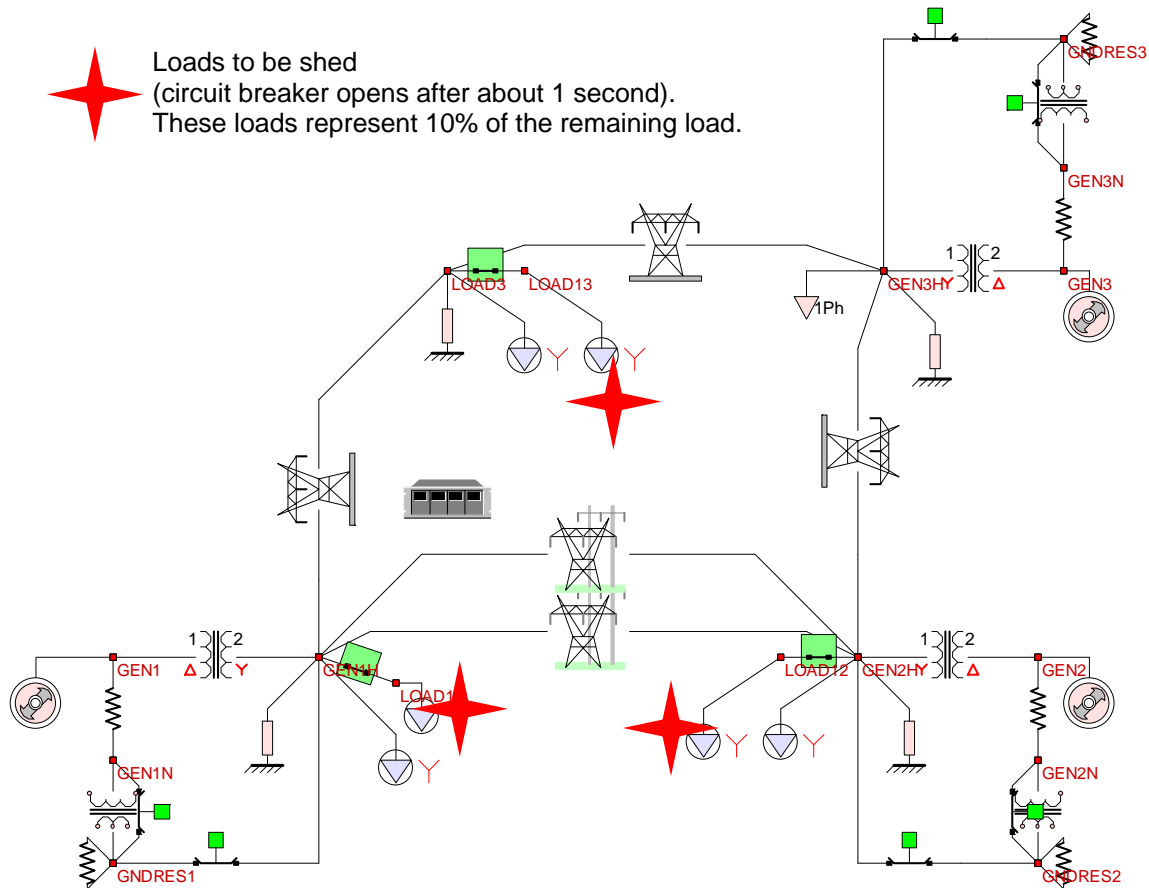


Figure 3.37: Principle for wide area partial load shedding

3.7.3.3 Generated Waveforms and Relay Response

Averaged values are shown in Figure 3.38.

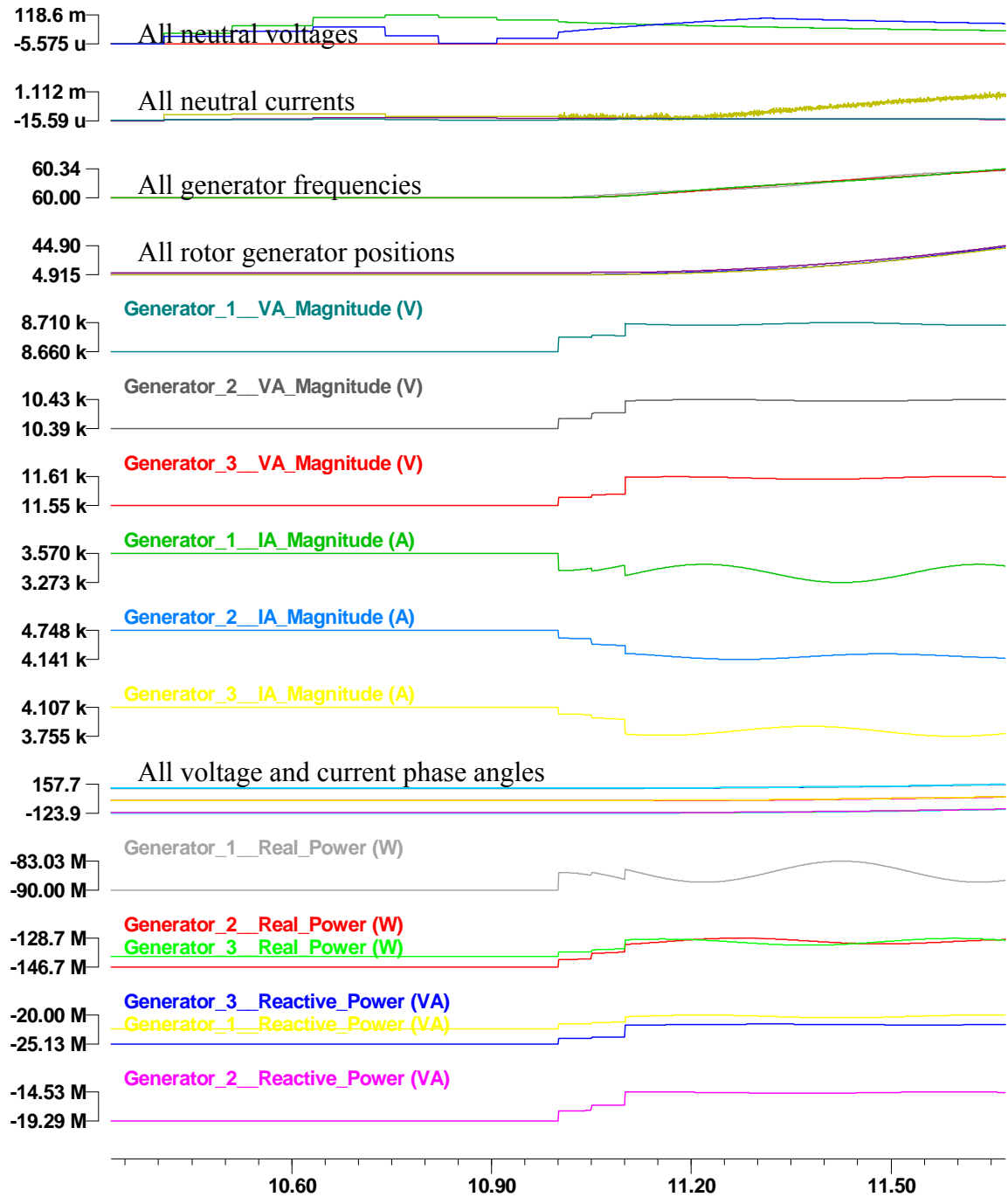


Figure 3.38: RMS values of electric quantities until one second after load drop

With the load reduced by 10 %, a similar drop and slight swing in current, real and reactive power is observed. The voltage at the generator terminals increases by less than

1 % and remains at that level. Note that the phase angles of all the electric quantities does not exhibit fast variations compared to unstable swings, but all angles do increase. Similarly, the frequency increases up to 60.5 Hz one second after load has been cut. Rotor angles seem to drift at a similar rate as well. In this situation, there is no overcurrent, under/overvoltage, or fast swings. Only the frequency increases, and the phenomenon may not be detected until after a second. After a second, frequency relays are likely to pickup the frequency variation and trip the generators. Small swings of power and currents go undetected. The expanded simulation over 8 seconds is shown in Figure 3.39.

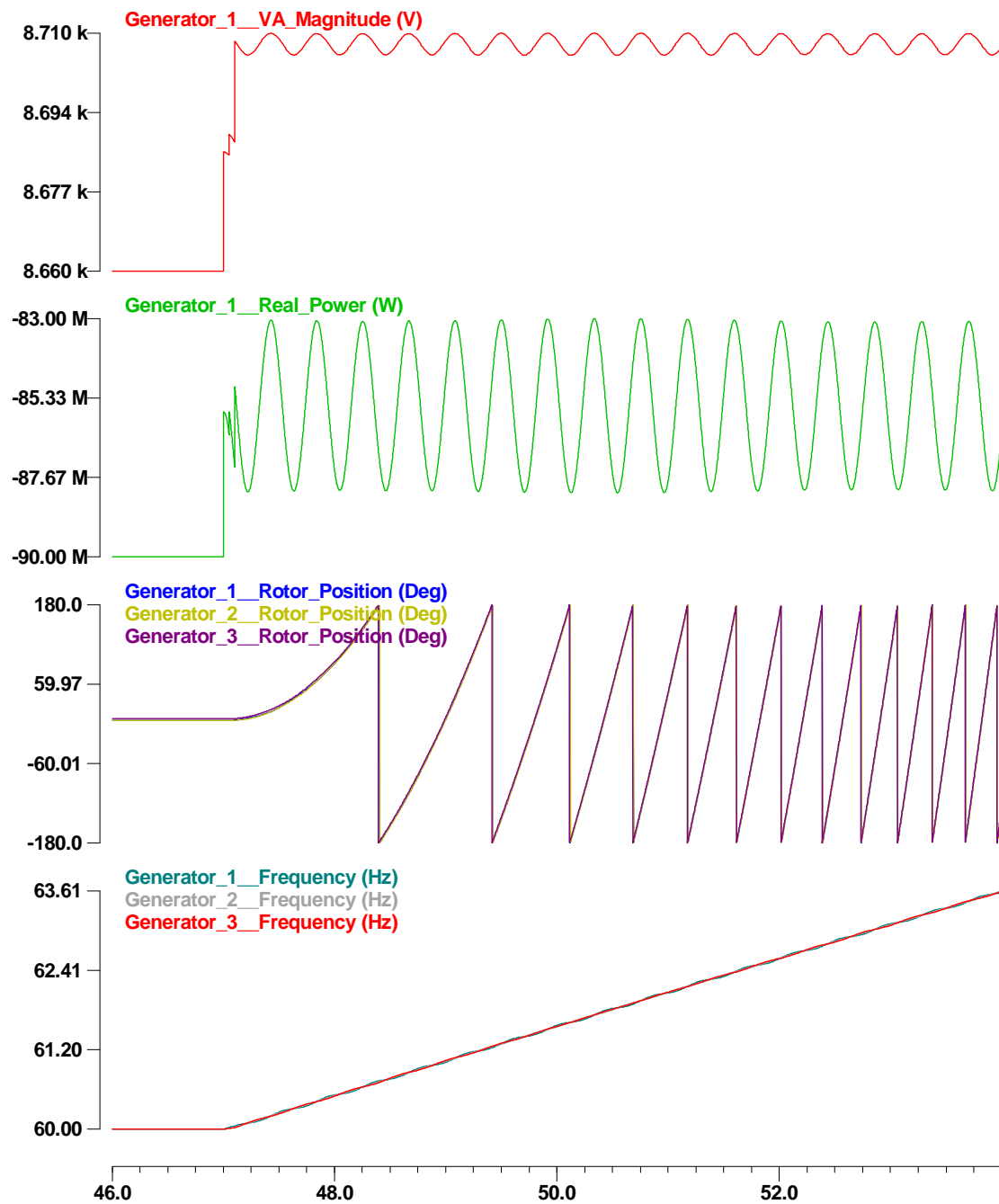


Figure 3.39: Expanded simulation shows continuous increase of generator frequency and rotor slip

3.7.4 Inadvertent Generator Breaker Operation

3.7.4.1 Functions and Events Tested

Events: Sudden loss of load (Generator 1), load exceeds generating capacity (Generators 2 and 3), frequency increases or decreases, stator overloads.

Functions: 81* (frequency), 50 (overcurrent).

3.7.4.2 Description

Using Test System #2, a circuit breaker is placed on the high side of Transformer 1. The circuit breaker is open after one second of simulation (simulation over 2 seconds).

3.7.5 Generated Waveforms and Relay Response

The responses of Generators 1 to 3 are shown in Figure 3.40. Note that RMS voltages and currents are plotted. The first thing to remark is that Generator 1 accelerates dramatically to 70 Hz after losing the load. Generators 2 and 3 slow below 59 Hz in less than one second to compensate for the additional burden. The evolution of rotor positions and phase angles of all electrical variables reflect the fast changes in frequency. Synchronism must be achieved again before Generator 1 can be reconnected.

For generator 1, the voltage increases by 5 % upon loss of load. The voltage decrease for Generators 2 and 3 is about 2 %, while their current rises by 45 % and 21 % respectively. The change in voltage is not likely to be detected by the relays; however, the relays will most likely react to the instantaneous, significant increase in the stator current.

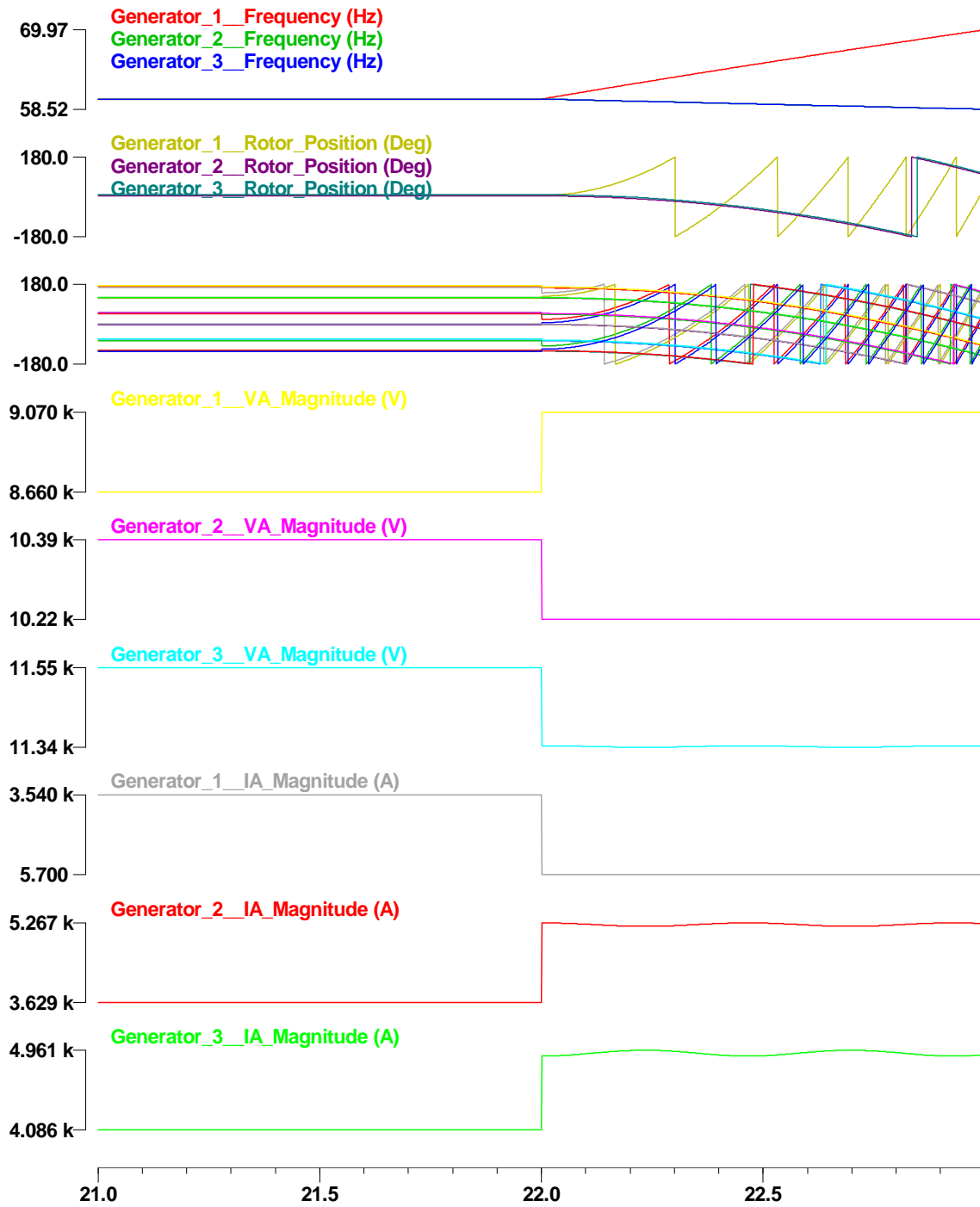


Figure 3.40: Waveforms captured for inadvertent breaker operation

3.7.5 Disconnected Phase

3.7.5.1 Functions and Events Tested

Events: disconnected phase, imbalances.

Functions: 49 (negative sequence), *N (neutral-related functions), 27 (undervoltage), 46 (phase current balance), 47 (phase voltage balance), 50 (overcurrent), 59 (overvoltage).

3.7.5.2 Description

Test System #2 is modified to include per-phase breakers, so phases can be disconnected independently of each other. The switches/breakers are located at the high-side of the step-up transformer for Generator 1 and at the load connected to that generator (see Figure 3.41). The first experiments involve opening one and two phases of the generator breaker. The second type of experiments deals with opening one and two phases of the three-phase load connected to Generator 1.

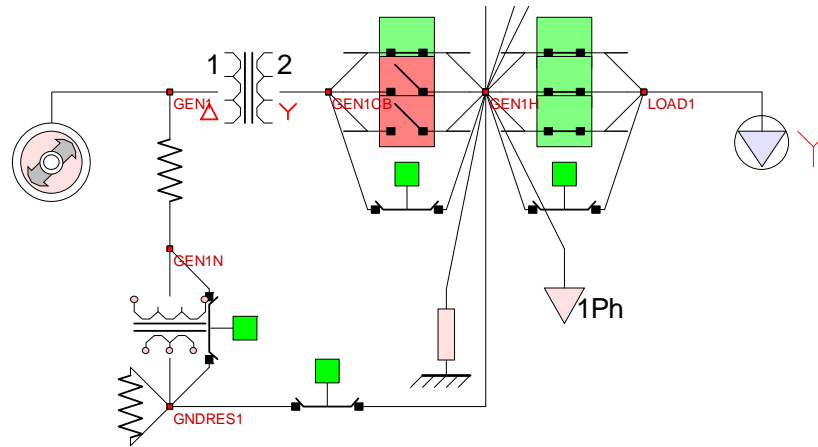


Figure 3.41: Generator 1 and load with per-phase circuit breakers

3.7.5.3 Generated Waveforms and Relay Response

The response of the system is observed in Figure 3.42, Figure 3.43, Figure 3.44 and Figure 3.45. Relays should trigger on imbalance and frequency increase/swings. Large voltage and current swings should be detected with instantaneous threshold functions.

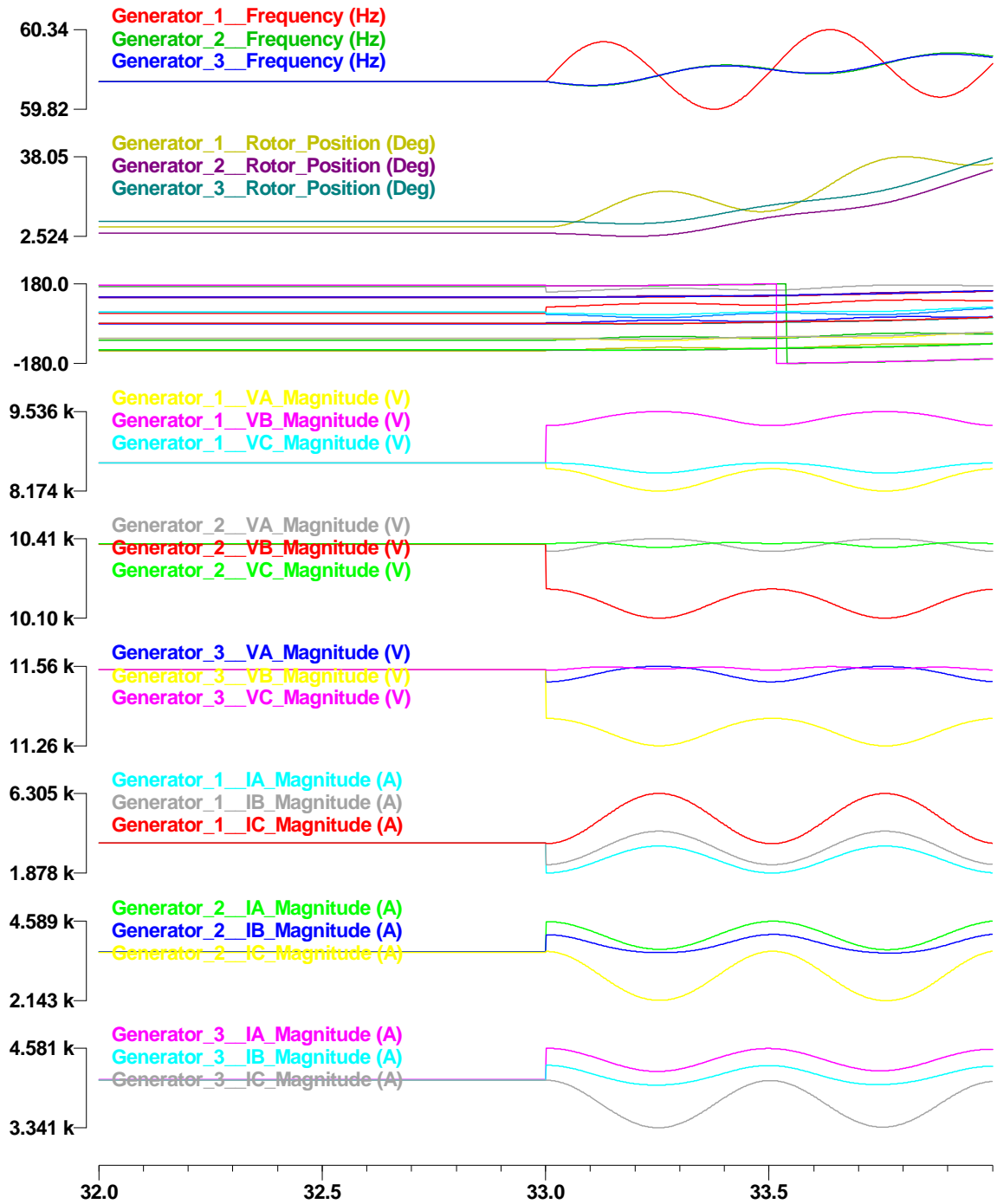


Figure 3.42: Response of the system after opening phase A of Generator 1

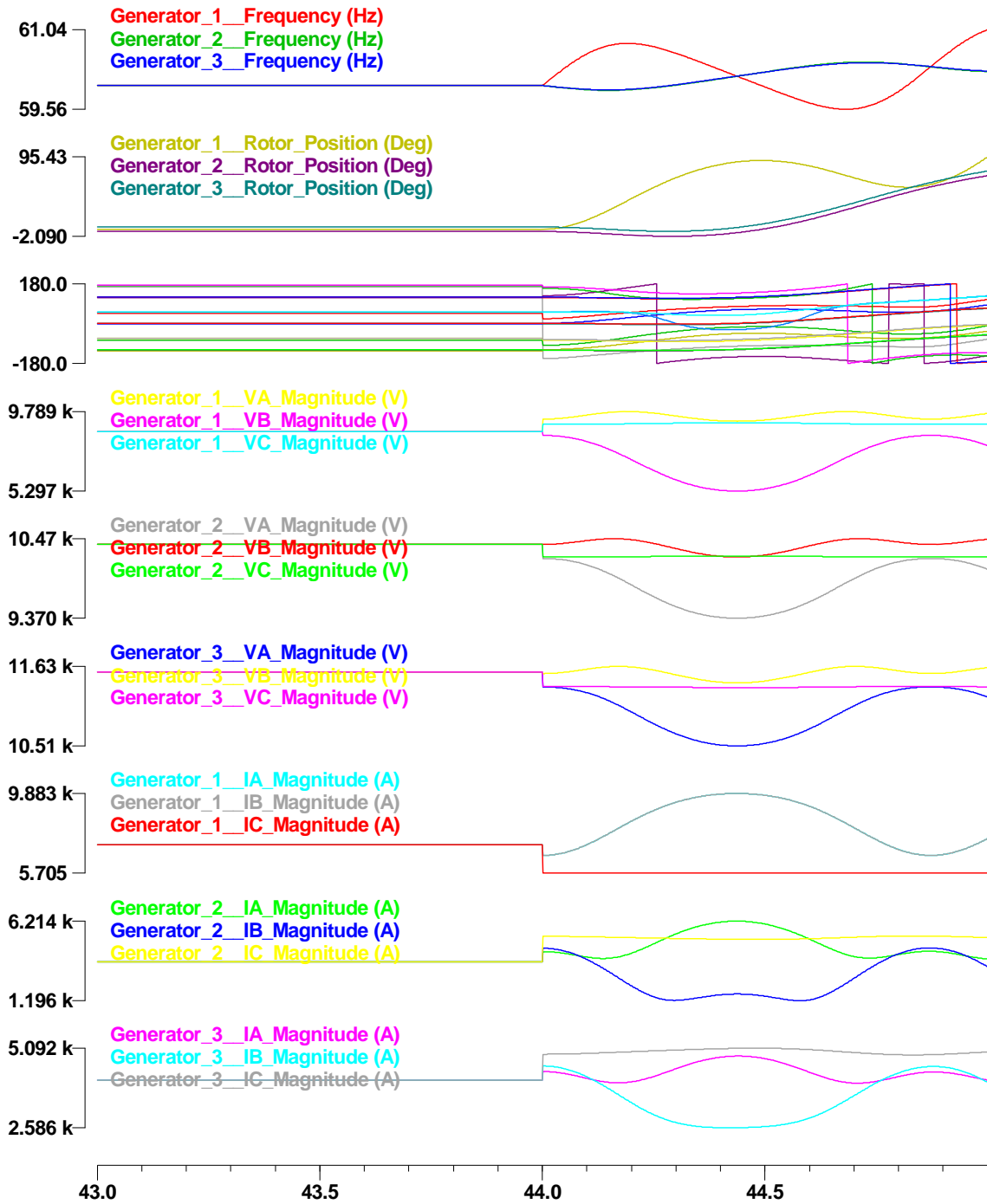


Figure 3.43: Response of the system after opening phases B and C of Generator 1

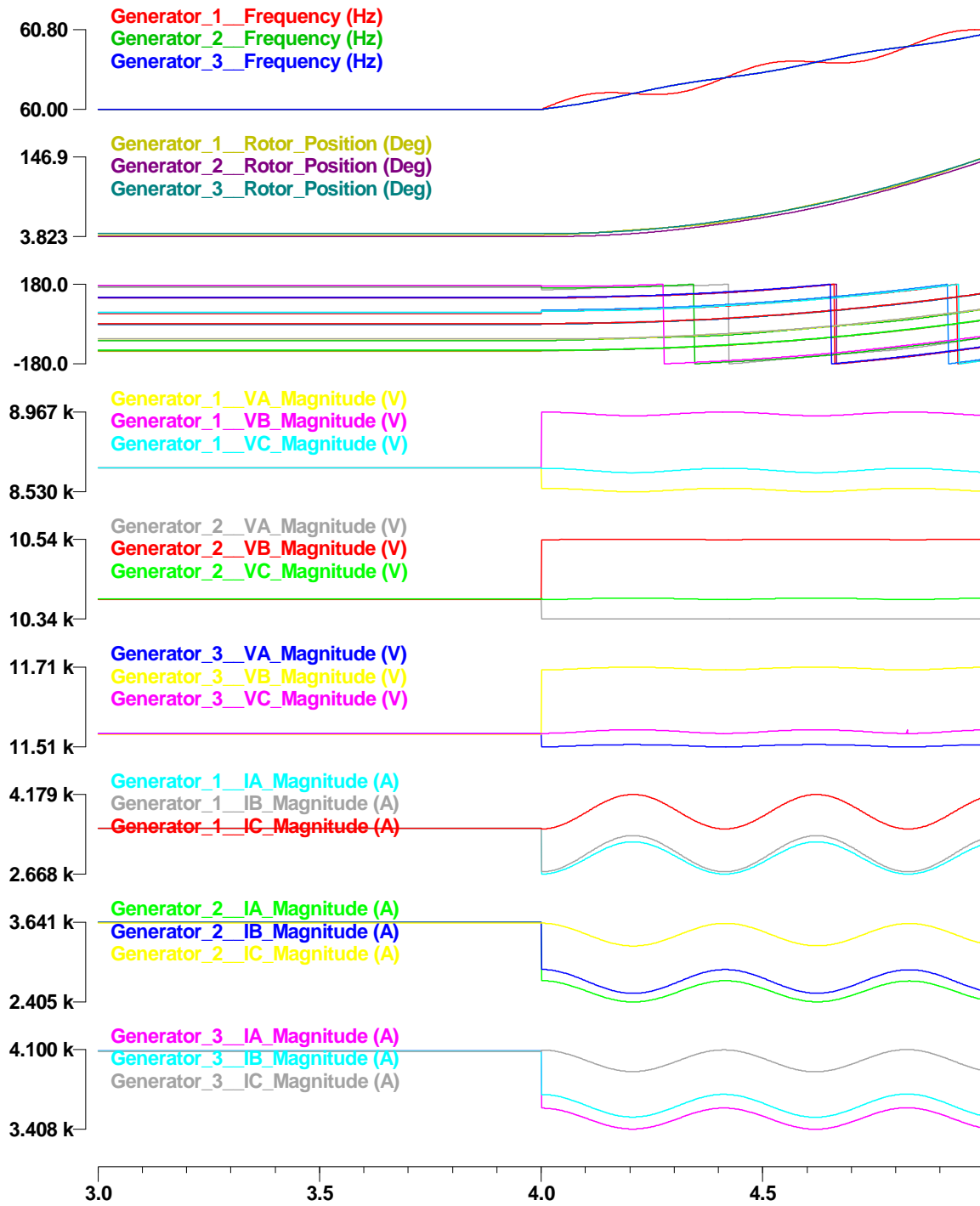


Figure 3.44: Response of the system after opening phase A of Load 1

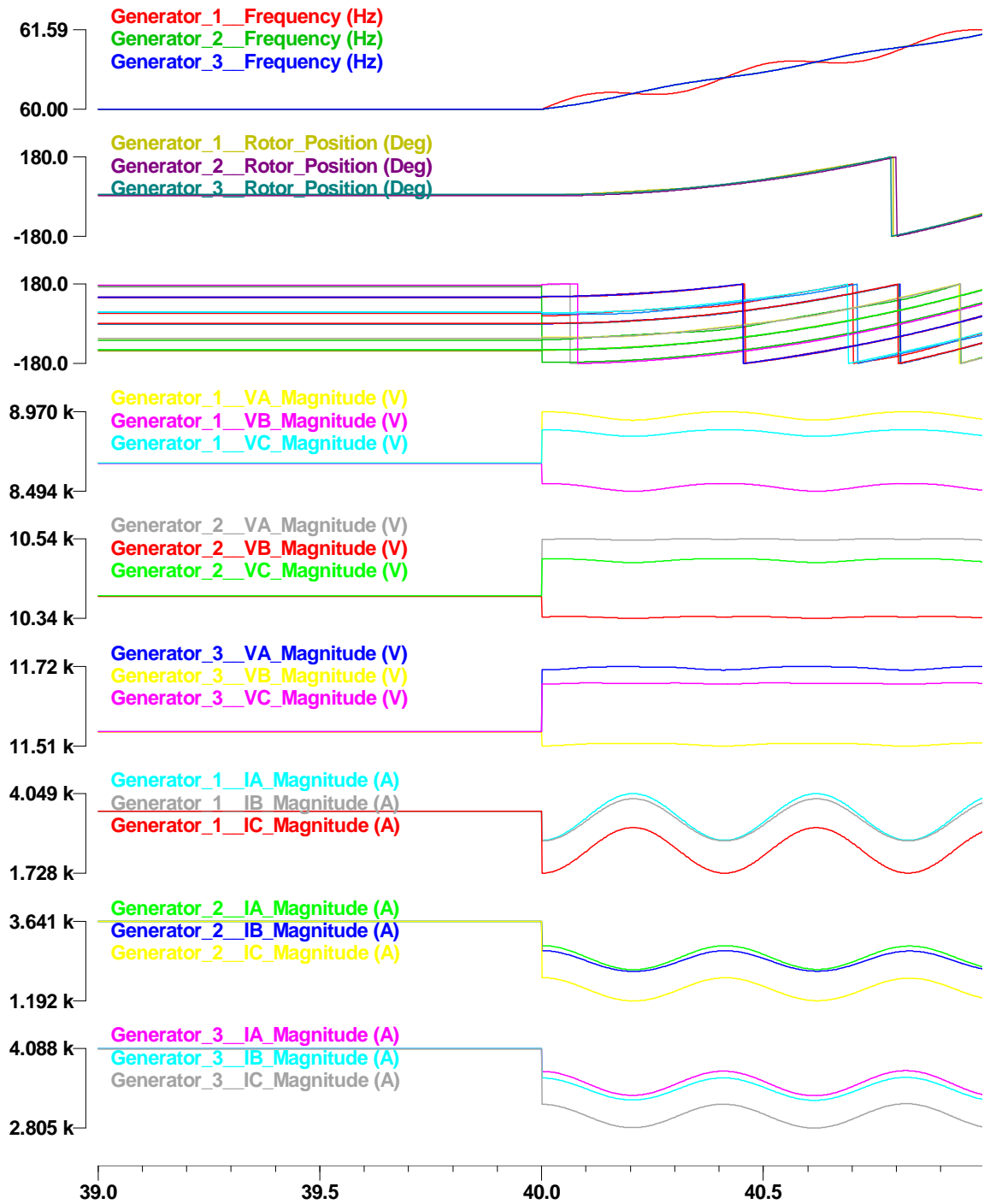


Figure 3.45: Response of the system after opening phases B and C of Load 1

3.7.6 Three-Phase Fault followed by Generator Breaker Operation – Test on Both Relays

3.7.6.1 Functions and Events Tested

Events: three-phase fault, all phases disconnected.

Functions: 21 (distance) (not implemented), 27 (undervoltage), 50 (overcurrent) (not implemented).

3.7.6.2 Description

Test System #2 is modified to include the fault logic to reproduce a three-phase fault at the step-up transformer of the generator. The fault starts at 00:47:05.200 and lasts 80 ms (5 cycles) before it is cleared by opening the generator circuit breaker.

3.7.6.3 Comparison of Generated Waveforms and Relay-Recorded Waveforms

The voltages seen at the generator terminals (as sent to the relays) are shown in Figure 3.46. The voltage waveforms are sent to both the M-3425A and the 300-G relays for comparison. Although current is also simulated in the test case, the current waveform generator converter is not complete, and functions 21 and 50 in particular cannot be tested. Overall, this test case reflects the closest setup of the desired laboratory setup for relay testing, where simulated waveforms are fed into multiple relays.

The M-3425A relay reports the voltages seen at its terminals whereas the 300-G relay reports the voltages as they should be at the PT based on input voltages. As a result, the retrieved voltage records for both relays are put together so that they fit on the same voltage scale and visible within the same display window. The superimposed relay records for the voltage on phase A are shown in Figure 3.47. As expected, the voltage recordings of the relays and the simulated voltages are consistent.

The statuses for the phase undervoltage function (27) for both relays are plotted in Figure 3.48. The 300-G relay shows consistency in the triggering of the function. When applying repeated loops of the voltage waveforms shown, regular switching can be heard. Surprisingly, it is not quite the case for the M-3425A relay. First, the relay seems to “miss” one out of every three faults. Even with 1 cycle trigger delay, the M-3425A does not trigger its assigned output (Output 1) until after 7 cycles. In Figure 3.48, the dropoff from the previous fault is visible.

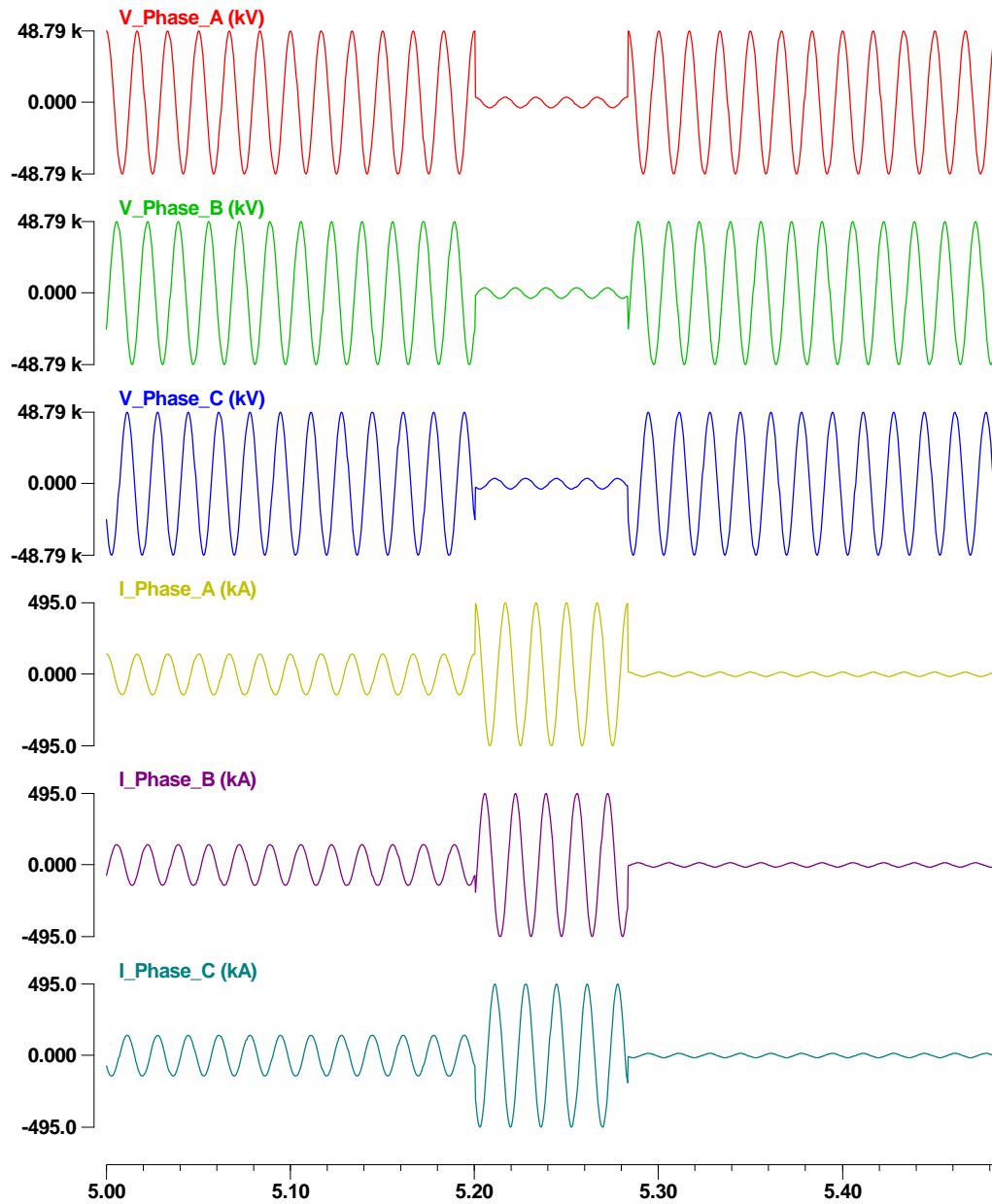


Figure 3.46: Response on a three-phase fault followed by opening of generator breaker

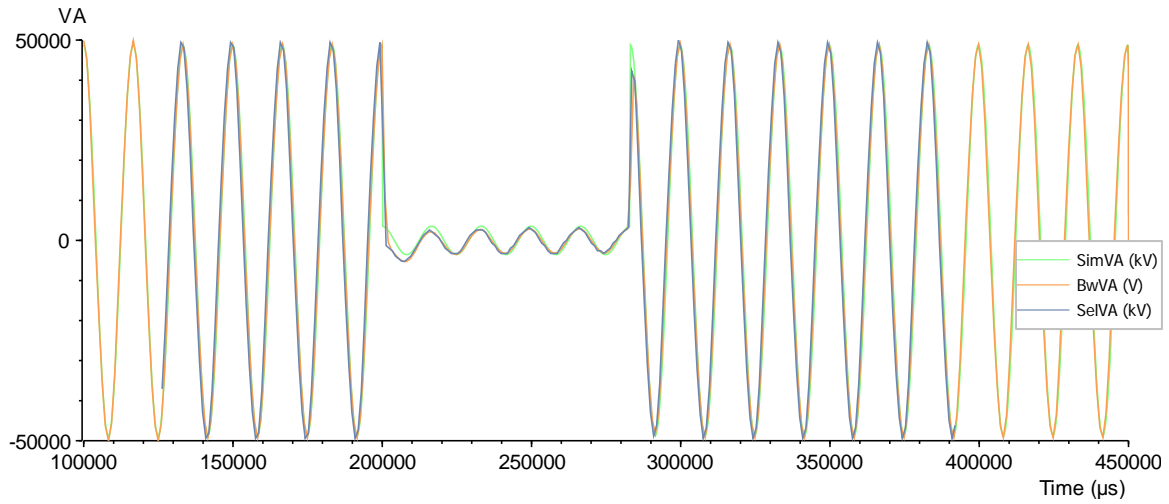


Figure 3.47: Superimposed relay measurements of phase A voltage after display scaling time shifting

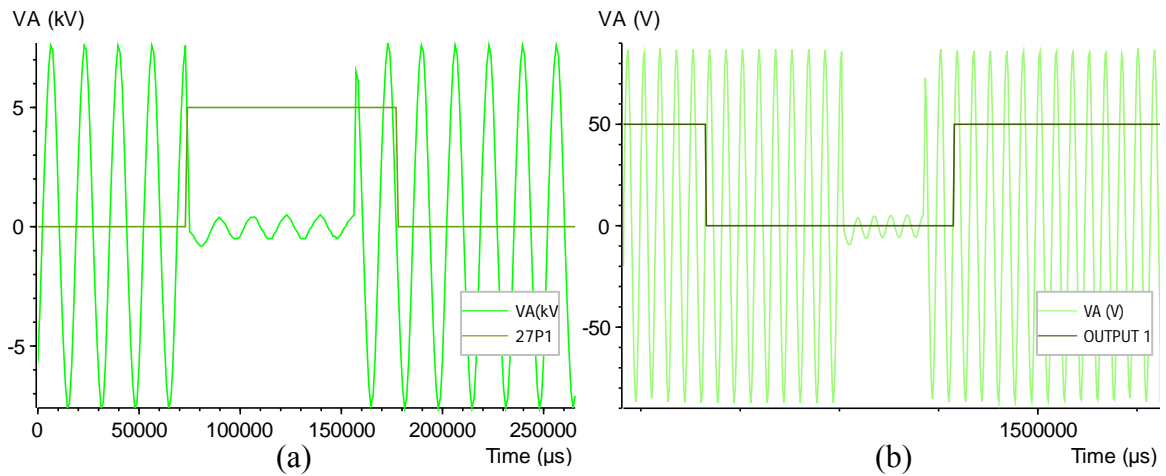


Figure 3.48: Phase undervoltage output from (a) the 300-G and (b) the M-3425A relay

3.8 Future Work

This project resulted in a library of events for transient testing of several key relay functions. Considering the fact that many manufacturers of relays are moving in the direction of incorporating phasor measurement capabilities into the relays, it is a natural extension to apply these developed methods for the testing of these new relays and in particular the functions that depend on GPS synchronization. For example, generator relays with GPS synchronization provide an improved protection function against unstable generator swings. The performance of this function is dependent upon the GPS synchronization accuracy. New transient testing procedures can be developed for these types of relays as an extension of the methodologies discussed in this section.

4.0 Part III: Load Shedding Relay Test (WSU)

4.1 Introduction

4.1.1 Background

Generation and demand must be continuously balanced in an ac system. During balanced conditions, frequency is constant, at its nominal value. The nominal frequency in North America is 60 Hz, while some countries maintain the frequency at 50 Hz.

Deviations from nominal frequency occur when generation and load are unbalanced. The frequency increases when generation is greater than load and decreases when generation is less than load. Frequency therefore can effectively indicate a balanced condition of generation and load.

With continuously changing load, generating units automatically adjust their output to follow load for small frequency deviations. Automatic generation control (AGC) operates to restore frequency back to the nominal value. A significant imbalance between generation and load, however, can exceed the AGC system's ability, causing the power system to fail, and those failures may cascade across a large part of the interconnected system.

4.1.2 Under-frequency Load Shedding (UFLS) Relay Introduction

If insufficient generation is available on the system to maintain stability, non-critical loads can be removed (shed) from the system to restore a balanced condition and prevent system failure. Such methods of automatic load shedding are designed as a last resort to prevent a major system outage [1].

UFLS relays are used to detect overload conditions by sensing low system frequency and shedding enough load to rebalance generation and load, and reestablish the nominal frequency. UFLS relays are able to automatically restore load after frequency recovery. UFLS is an effective and reliable method that helps to prevent blackouts.

Each UFLS relay may utilize a different method of frequency measurement based on its manufacturer and technology. The following three types of UFLS relays are employed in power system protection [26]:

- Electromechanical relays
- Solid-state (static) relays
- Microprocessor (digital) relays

UFLS relays play an important role in the current restructured power system. The interconnected network expands the influence of UFLS relays to protect the whole electric power system. The final report on the August 14, 2003 blackout in the U.S. and Canada concludes that one of the three principle reasons for the widespread blackout is

“the relay protection settings for the transmission lines, generators and under-frequency load shedding in the northeast may not be entirely appropriate and are certainly not coordinated and integrated to reduce the likelihood and consequences of a cascade nor were they intended to do so” [1] [27]. The contributions of UFLS relays to the blackout are reviewed in section 4.2.

4.1.3 UFLS Tests

The importance of UFLS relaying in preventing cascading outages warrants further testing beyond the standard acceptance tests specified by manufacturers. A new test protocol to meet these needs was developed for this project and is presented in section 4.4 of this report. The tests are specified in two parts, conformance and application tests. The objectives of conformance tests are, similar to acceptance tests, to test the relay’s function, verify its operating characteristics and calibrate the relay’s settings. Application tests focus on how the relay performs during a specific event such as blackout or islanding. Data for application tests can be obtained from simulations or from recorders operating during the event. Application tests allow testing under realistic and relevant conditions.

4.1.4 UFLS Research

During planning for this project, a number of issues regarding UFLS relays were raised by PSERC industrial members. These included:

- A time delay, in addition to the time delay setting, has been observed in some UFLS relays. This delay is investigated and quantified.
- Time delay settings are often given in cycles. Because frequency is changing during the operation of a UFLS relay, it is important to verify whether this delay is based on nominal frequency or actual frequency.
- Validation testing of UFLS relays is usually done with discrete changes in frequency. Members wanted tests performed with continuous frequency decay.

Other issues identified during the course of the project are:

- Because many UFLS relays use zero-crossing as the method of calculating frequency, distortion of the voltage waveform may obscure the point of the zero crossing and affect the relay’s performance [26].
- Voltage magnitude may also affect the operation of UFLS relays, and an understanding of these effects is important to a relay user. Each relay’s specifications must be referenced when specifying the voltage levels for under-voltage testing [26] [27].

The tests specified and the results presented in this report go beyond those usually performed using commercial UFLS relay test systems. Some commercial systems are capable of presenting waveforms contained in COMTRADE files to a relay under test, but no standard files exist for such testing [27]. Such tests are presented as a result of this project. Most commercial UFLS test systems still use pure sine waves for testing. A protocol for testing with distorted waveforms is presented here.

4.1.5 Report Organization

Section 4.2 of this report provides a summary of the 2003 North American blackout report's findings on UFLS operation [1]. Section 4.3 presents the UFLS relay test system used at Wichita State, including system hardware and software. Section 4.4 presents protocols for UFLS conformance and applications tests. Test results for two commonly-used UFLS relays are presented in Section 4.5, with complete data shown in Appendix C.1. Test interpretations are discussed in Section 4.6, followed by conclusions and suggestions for further work in Section 4.7.

4.2 Review of UFLS Relay Operation during the 2003 North American Blackout

4.2.1 Background

This is a review of the blackout final report [1] for references to load shedding relays. UFLS and other relay protection settings are one of the three principal reasons given for the blackout:

“Based on the investigation to date, the investigation team concludes that the cascade spread beyond Ohio and caused such a wide spread blackout for three principal reasons...

...Third, the evidence collected indicates that the relay protection settings for the transmission lines, generators and under-frequency load-shedding in the northeast may not be entirely appropriate and are certainly not coordinated and integrated to reduce the likelihood and consequences of a cascade—nor were they intended to do so.” [1, p. 73]

More specifically, regarding load shedding relays [1]:

“Automatic load-shedding measures are designed into the electrical system to operate as a last resort, under the theory that it is wise to shed some load in a controlled fashion if it can forestall the loss of a great deal of load to an uncontrollable cause. Thus there are two kinds of automatic load-shedding installed in North America—under-voltage load-shedding (UVLS), which sheds load to prevent local area voltage collapse, and under-frequency load shedding (UFLS), which is designed to rebalance load and generation within an electrical island once it has been created by a system disturbance.”

“Automatic under-voltage load-shedding (UVLS) responds directly to voltage conditions in a local area. UVLS drops several hundred MW of load in pre-selected blocks within urban load centers, triggered in stages when local voltage drops to a designated level—likely 89 to 92% or even higher—with a several second delay. The goal of a UVLS scheme is to eliminate load in order to restore reactive power relative to demand, to prevent voltage collapse and contain a voltage problem within a local

area rather than allowing it to spread in geography and magnitude. If the first load-shed step does not allow the system to rebalance, and voltage continues to deteriorate, then the next block of UVLS is dropped. Use of UVLS is not mandatory, but is done at the option of control area and/or reliability council. UVLS schemes and trigger points should be designed to respect the local area's system vulnerabilities, based on voltage collapse studies.

As noted in Chapter 4, there is no UVLS system in place within Cleveland and Akron; had such a scheme been implemented before August, 2003, shedding 1,500 MW of load in that area before the loss of the Sammis-Star line might have prevented the cascade and blackout."

"Automatic under-frequency load-shedding (UFLS) is designed for use in extreme conditions to stabilize the balance between generation and load after an electrical island has been formed, dropping enough load to allow frequency to stabilize within the island. All synchronous generators in North America are designed to operate at 60 cycles per second (Hertz) and frequency reflects how well load and generation are balanced—if there is more load than generation at any moment, frequency drops below 60 Hz, and it rises above that level if there is more generation than load. By dropping load to match available generation within the island, UFLS is a safety net that helps to prevent the complete blackout of the island, which allows faster system restoration afterward. UFLS is not effective if there is electrical instability or voltage collapse within the island."

The report concludes that UFLS, but not UVFL, operated during the cascading failures in attempts to stop the cascade. But the effects of load shedding were not sufficient:

"It must be emphasized that the entire northeast system was experiencing large scale, dynamic oscillations in this period. Even if the UFLS and generation had been perfectly balanced at any moment in time, these oscillations would have made stabilization difficult and unlikely." [1. p. 92]

The final report divides the blackout into seven phases. Most of the UFLS relays that operated did so during phases 6D and 7, the final phase.

"In phase 6D, Cleveland area load was disconnected by automatic under-frequency load-shedding (approximately 1,300 MW), and another 434 MW of load was interrupted after the generation remaining within this transmission "island" was tripped by under-frequency relays. This sudden load drop would contribute to the reverse power swing." [1, p.88]

"In phase 7 (16:10:46 to 16:12 EDT), the large electrical island in the northeast had less generation than load, and was unstable with large power surges and swings in frequency and voltage. As a result, many lines and generators across the disturbance area tripped, breaking the area into several electrical islands. Generation and load within these smaller

islands was often unbalanced, leading to further tripping of lines and generating units until equilibrium was established in each island.” [1, p.75]

The report’s conclusion on UFLS relay operation was that the relays operated as set, but the settings may not have been optimal for system protection during cascading outages:

“Protective relay settings on transmission lines operated as they were designed and set to behave on August 14. In some cases line relays did not trip in the path of a power surge because the apparent impedance on the line was not low enough—not because of the magnitude of the current, but rather because voltage on that line was high enough that the resulting impedance was adequate to avoid entering the relay’s target zone. Thus relative voltage levels across the northeast also affected which areas blacked out and which areas stayed on-line.”

“Power swings and voltage fluctuations caused by some initial events as seen on August 14 can cause other lines to detect high currents and low voltages that appear to be faults, even if faults do not actually exist on those other lines. Protective relay systems work well to protect lines from damage and to isolate them from the system under normal and abnormal system conditions.”

“When power system operating and design criteria are violated because several outages occur simultaneously, commonly used protective relays that measure low voltage and high current cannot distinguish between the currents and voltages seen in a system cascade from those caused by a fault. This leads to more and more lines being tripped, widening the blackout area.” [1, p. 73-74]

“Automatic load-shedding relay protection must avoid premature tripping. It must be coordinated to reduce the likelihood of system break-up, and once break-up occurs, to maximize an island’s chances for electrical survival. [1, p. 92]

The report further concludes that UFLS operation while the system was still experiencing dynamic conditions significantly reduced the beneficial effects of UFLS:

“Examination of the loads and generation in the Eastern New York island indicates before 16:10:00 EDT, the area had been importing electricity and had less generation on-line than load. At 16:10:50 EDT, seconds after the separation along the Total East interface, the eastern New York area had experienced significant load reductions due to under-frequency load-shedding—Consolidated Edison, which serves New York City and surrounding areas, dropped over 40% of its load on automatic UFLS. But at this time, the system was still experiencing dynamic conditions—as illustrated in Figure 6.26, frequency was falling, flows and voltages were oscillating, and power plants were tripping off-line.”

“Had there been a slow islanding situation and more generation on-line, it might have been possible for the Eastern New York island to rebalance given its high level of UFLS. But the available information indicates that events happened so quickly and the power swings were so large that rebalancing would have been unlikely, with or without the northern New Jersey and southwest Connecticut loads hanging onto eastern New York. This was further complicated because the high rate of change in voltages at load buses reduced the actual levels of load shed by UFLS relative to the levels needed and expected. [1, p. 98]

The report suggests that future protection systems should allow more coordination among various transmission and generation relays:

“Protective relays are designed to detect short circuits and act locally to isolate faulted power system equipment from the system—both to protect the equipment from damage and to protect the system from faulty equipment. Relay systems are applied with redundancy in primary and backup modes. If one relay fails, another should detect the fault and trip appropriate circuit breakers. Some backup relays have significant “reach,” such that non-faulted line overloads or stable swings may be seen as faults and cause the tripping of a line when it is not advantageous to do so. Proper coordination of the many relay devices in an interconnected system is a significant challenge, requiring continual review and revision. Some relays can prevent resynchronizing, making restoration more difficult.”

“System-wide controls protect the interconnected operation rather than specific pieces of equipment. Examples include controlled islanding to mitigate the severity of an inevitable disturbance and under-voltage or under-frequency load shedding. Failure to operate (or misoperation of) one or more relays as an event developed was a common factor in several of the disturbances.”

UFLS and UVLS protection schemes resulted from recommendations made after previous blackouts [1, p. 109]. It appears that load shedding relays operated properly, according to their settings, during the 2003 blackout. But such operation was not adequate to maintain system stability, and existing relays and protection schemes could not be expected to mitigate such a fast-moving cascade.

4.3 UFLS Relay Test System

4.3.1 UFLS Relay Test System Overview

An existing relay test system [28] was upgraded and used for UFLS testing at Wichita State. Figure 4.1 shows the configuration of this system, and Figure 4.2 shows the actual lab setup. As shown in Figure 4.1, digital signals such as recorded waveforms, simulated waveforms produced by an electromagnetic transients simulation [29], and arbitrary

programmed signals can be produced and played by a PC workstation. The digital waveform is converted to analog by a high-resolution D/A converter. Then the analog signal is sent to a power amplifier to obtain the voltage applied to the relay. This voltage or current is sent to both the test relay and a datalogger. The test relay will respond to the voltage and send a trip signal to the datalogger when the relay operates. By analyzing the applied waveform and trip signal, relay performance can be evaluated. If the test relay is equipped with a communication port, the computer can read information from the relay or modify the relay settings.

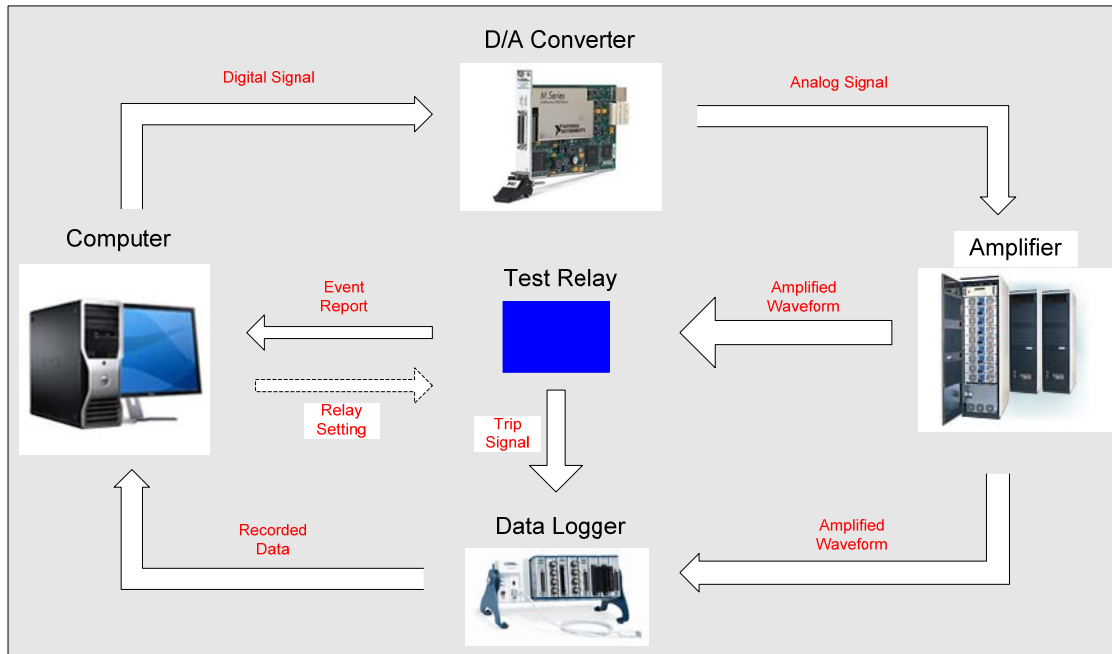


Figure 4.1: Configuration of UFLS relay test system



Figure 4.2: UFLS relay test system

4.3.2 UFLS Relay Test System Hardware

The major components of this UFLS relay test system are a desktop computer (PC), digital-to-analog (D/A) converter, power amplifier, datalogger, and relay under test. The PC is used for producing digital test waveforms, performing results analysis, and modifying relays settings (for relays with a communication port). Application software to generate and analyze waveforms, control relays, and perform simulations, is installed on this PC.

A high-resolution D/A converter is used for converting the digital signal produced by the PC into an analog signal. The power amplifier is used for amplifying the analog signal for input to the relay. The characteristics of the power amplifiers available at Wichita State are shown in Table 4.1.

Table 4.1: Characteristic of power amplifiers

Three independent current sources	12 A rms, 10 kHz
One current source	80 A rms, 20 kHz
Three independent voltage sources	130 V rms, 10 kHz
Single- or three-phase voltage source	6 kVA, 120 V to 500 V, Full power to 1 kHz, Distortion to 20 kHz

The datalogger is used for recording the signals from power amplifiers as well as the relay tripping signal from relay. Because the voltage or current received by the test relay is identical to the one received by datalogger, relay performance can be evaluated by comparing this voltage or current waveform and relay trip signal.

The relay under test can be an electromechanical, solid state, or microprocessor relay. The relay receives the amplified analog signal and trips according to its setting. The relay setting can be modified by the relay panel or by PC (for relays with a communication port).

4.3.3 Software

Software is installed on the computer in order to produce the UFLS relay test waveforms. As shown in Figure 4.3, the UFLS relay test system can produce test waveforms from recorded signals, simulated signals, and arbitrary signals produced in software.

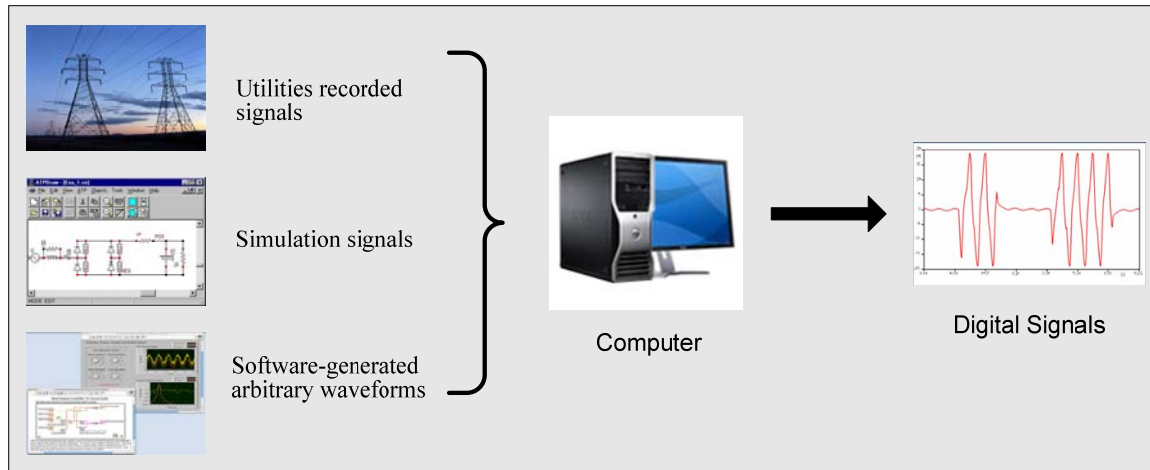


Figure 4.3: UFLS relay test system software

This relay test system can evaluate the relay performance during a specific event, such as blackout or islanding. Data of such specific events come from recorders such as digital fault recorders that were operating during the events, or from power system simulation software. Arbitrary waveform software is used in this relay test system to produce specific waveforms such as pure sine waves, frequency ramping, harmonic distortion, and variable voltage magnitudes.

4.3.4 Under-frequency Load Shedding Relays

This UFLS relay test system can test the three types of UFLS relays which are available for application in load shedding schemes. These three types of UFLS relays are electromechanical relays, solid-state (static) relays, and digital (microprocessor) relays. In this project, two commonly-used digital UFLS relays were provided by their manufacturers for testing. The specifications of each relay are shown in Table 4.2 and Table 4.3 respectively.

Table 4.2: Relay 1 specifications

Frequency Setpoint	Range	40.10 – 65.00 Hz
	Accuracy	±0.01 Hz
Time delay	Range	2.00 – 16000.00 cycles
	Accuracy	0.25 cycles or ±0.1% of setting

Table 4.3: Relay 2 specifications

Frequency Setpoint	Range	40.00 – 70.00 Hz
	Accuracy	±0.01 Hz
Time delay	Range	3 cycles – 990 seconds
	Accuracy	±1.0 cycle; ±2% of the setting or ±25ms, whichever is greater

4.4 Under-frequency Load Shedding Relay Test Scenarios

In this project, two UFLS relay test categories, conformance tests and application tests, have been designed and implemented. For both test categories, different scenarios are performed to validate two key settings of UFLS relays: pickup frequency and time delay.

4.4.1 Conformance Test

Conformance tests verify that the UFLS relay operates within manufacturer's specifications for various scenarios. Usually the relay's specification is given under the assumption that this relay is designed to operate with pure, undistorted waveforms. The relay's specification under distorted waveforms is not usually available, but this can be important to relay application and is included in the test protocol for this project. Test waveforms include pure sine waves, frequency ramping, harmonic distortion, and varying voltage magnitudes.

4.4.2 Test Waveforms

4.4.2.1 Test Waveform Description

The test waveforms are classified into the following categories:

- Pure sinusoidal waveforms: The UFLS relay test system generates pure waveforms like those used by manufacturers and utilities in conventional acceptance tests.
- Frequency ramping waveform (df/dt): Waveform signals with a discrete change in frequency are normally used to test UFLS relays. However, the discrete change cannot represent real situations where the frequency decays more gradually and continuously. The UFLS relay test system allows a user to select different values of df/dt , the frequency decay rate. Figure 4.4 shows four such values of df/dt , 0.1 Hz/sec, 0.2 Hz/sec, 0.4 Hz/sec, and 0.6 Hz/sec.

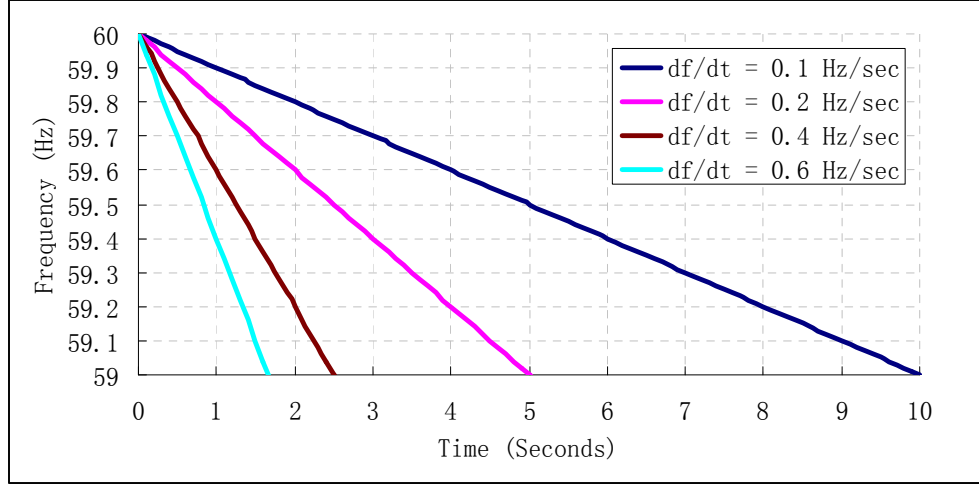


Figure 4.4: Frequency decay

- Harmonic waveform: Voltages with harmonic distortion may cause UFLS relay misoperation. The reason is that harmonics can cause early, late, or multiple zero crossings, which can affect the zero-crossing frequency measurements still used in some commercial UFLS relays. Total harmonic distortion (THD) is normally used for measuring harmonic distortion levels, and it is defined as follows [30]:

$$THD = \frac{\sqrt{H_2^2 + H_3^2 + \dots + H_N^2}}{H_1} \quad 4.1$$

where $H_2, H_3 \dots H_N$ are the amplitudes of harmonics and H_1 is the amplitude of the fundamental. The UFLS relay test system allows a user to choose the values of $H_1, H_2, H_3 \dots H_N$ to produce a specified THD. Figure 4.5 shows a combination of common harmonic voltages (5th, 7th, 11th, and 13th).

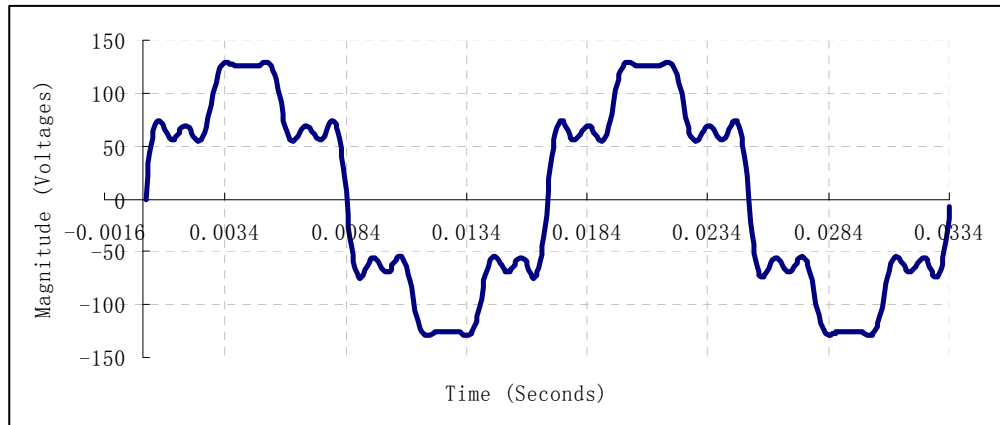


Figure 4.5: Voltage with 5th, 7th, 11th, and 13th harmonics

- Variable voltage magnitude waveform: Voltages magnitudes may change significantly during frequency excursions. UFLS relays commonly have an under-voltage block function, which serves to block load shedding when voltage to the relay is lost, and to block operation during fault conditions. Because voltage can vary rapidly during cascading outages, it is still important to evaluate UFLS performance under variable magnitude voltage. The UFLS relay test system allows a user to specify different voltage magnitudes. Figure 4.6 shows a voltage waveform with 6 cycles depressed.

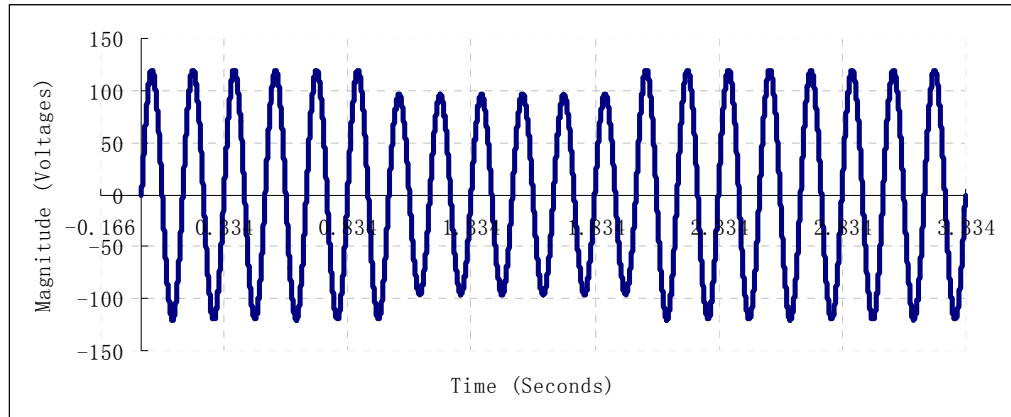


Figure 4.6: Variable voltage magnitude

4.4.2.2 Test Procedure

The test procedure for conformance tests is as follows:

- Pickup frequency test: Test the pickup frequency at varying pickup frequency settings and rates of change of frequency. The minimum and maximum pickup frequencies are specified by manufacturers. Pickup frequencies that include the minimum and maximum, and several in between, are selected, with emphasis on those usually used in practice. The rate of change of frequency df/dt is varied from 0.1Hz/sec to 0.9 Hz/sec in 0.1 Hz/sec increments.
- Time delay test: Pickup frequency tests are performed with time delay settings of 6, 16, 36, and 66 cycles, and actual time delays are recorded. The tests are repeated at the following specific pickup frequencies and time delays:
 - ◆ 59.3 Hz, 15 second delay
 - ◆ 59.5 Hz, 30 second delay
- Under-voltage frequency block test: The pickup frequency test is repeated at 55.0 Hz, 57.0 Hz, and 59.0 Hz settings with decay rates of 0.1 Hz/sec and 0.9Hz/sec, at 85%, and 115% voltage.
- Harmonic distortion test: The pickup frequency test is repeated at 55.0 Hz, 57.0 Hz, and 59.0 settings with decay rates of 0.1 Hz/s and 0.9Hz/s, with
 - ◆ 5% 5th harmonic
 - ◆ 5% 11th harmonic

- ◆ a combination of the most common harmonic voltages:

$$V_{distortion} = 1/5 \cdot V_5 + 1/7 \cdot V_7 + 1/11 \cdot V_{11} + 1/13 \cdot V_{13} \quad 4.2$$

- ◆ 5% 11th + 5% 13th harmonics

4.4.3 Application Test

Application tests focus on how the UFLS relay performs during a specific event, such as cascading blackout or islanding. Data for application tests come from simulations of the events or recorders operating during the events. The UFLS relay test system can utilize these recorded data to test a relay. A simulated 13-bus power system has also been developed at Wichita State.

4.4.3.1 13-Bus System Description

A transient power system model has been adapted for application tests. This system is an equivalent of a 13 bus system [31]. Figure 4.7 shows the single line diagram of the test system. The rating of the synchronous machine connected to bus 3 is 200 MVA. An IEEE type 1 Automatic Voltage Regulator (AVR) is used to represent the excitation control of the generator, as shown in Figure 4.7. Part of the system is represented by its Thevenin equivalent, and bus 13 is the load bus. The tie line between bus 1 and bus 7 can be designed as a single or double circuit transmission line. The complete model and data for the 13 bus system are given in Appendix C.2.

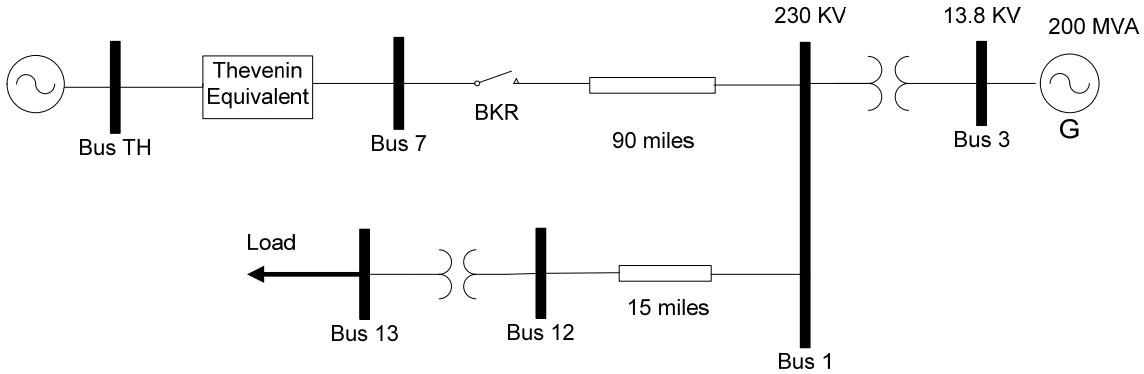


Figure 4.7: Single line diagram of 13-bus equivalent system

The modeling of loads is complicated by the complexity of aggregated loads on the system. In order to simulate the effects of load on system voltage and frequency changes, the load at bus 13 is modeled by different compositions of resistive and inductive loads (different power factors). Typically, power factor is varied from unity to 0.6 lagging in increments of 0.1.

4.4.3.2 Simulation without UFLS Scheme

In this scenario, no UFLS scheme is implemented on the 13 bus system. The single tie line between bus 1 and bus 7 is opened at 1 second. Figure 4.8 shows the comparison of frequency responses of the generator for different compositions of load at bus 13.

Simulation results reveal that the frequency decay rate increases as inductive load is increased. The voltage at bus13, however, decreases as the inductive load is increased.

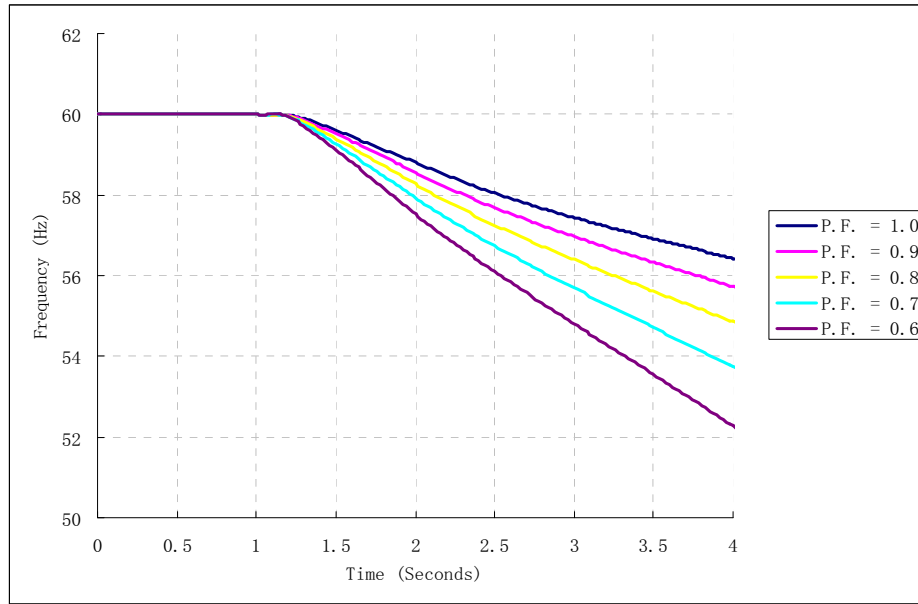


Figure 4.8: Generator frequencies without UFLS implementation

4.4.3.3 Simulation with UFLS Scheme

In this scenario, a UFLS scheme is implemented at bus 13. The settings of the UFLS relay are shown in Table 4.4 [32]. The single tie line between bus 1 and bus 7 is opened at 1 second. Figure 4.9 shows the comparison of frequency response of the generator after implementing a single-step UFLS scheme at bus 13 (10% shedding at 59.3 Hz). Figure 4.10 shows the comparison of frequency responses of the generator after implementing a two-step UFLS scheme at bus 13 (10% shedding at 59.3 Hz and 10% shedding at 58.9 Hz). As shown in Figure 4.10, system frequencies based on different compositions of load were recovered after implementing the UFLS scheme. The minimum frequency (saddle point in the curve), however, decreases as the inductive load is increased. For all different compositions of load, 20% of the load has to be shed in 2 steps in order to recover the frequency. Table 4.5 shows the time of load shedding for different compositions of load. Table 4.5 reveals that the higher the inductance load percentage, the earlier the UFLS relay operates.

Table 4.4: Settings of UFLS scheme

Amount of Load to be Dropped	Minimum Frequency Setpoint
10%	59.3 Hz
10%	58.9 Hz
10%	58.5 Hz

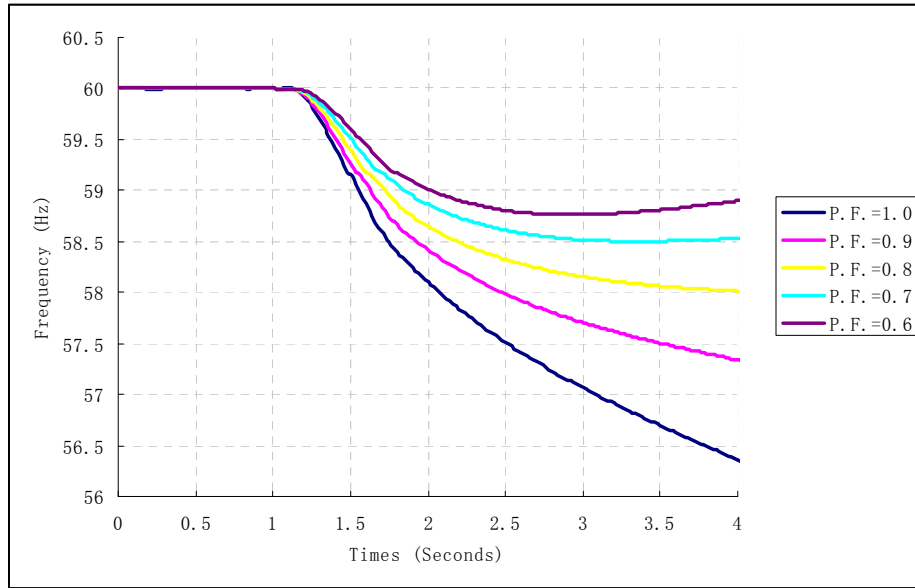


Figure 4.9: Generator frequencies with UFLS implementation (1 step)

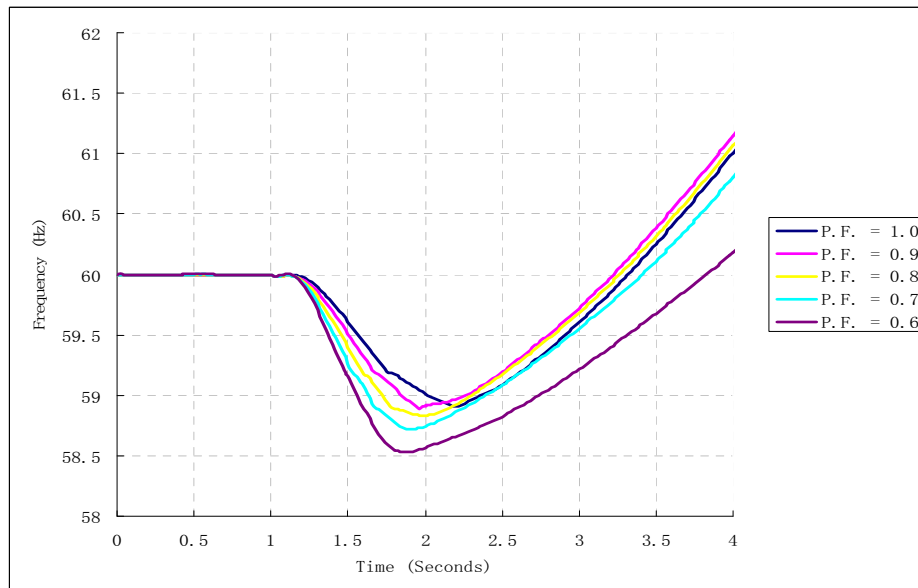


Figure 4.10: Generator frequencies with UFLS implementation (2 step)

Table 4.5: Load shedding time

Load Composition	Time for first 10% Load Shedding	Time for Second 10% Load Shedding
P.F. = 1.0	1.752 Second	2.204 Second
P.F. = 0.9	1.663 Second	1.953 Second
P.F. = 0.8	1.588 Second	1.780 Second
P.F. = 0.7	1.525 Second	1.666 Second
P.F. = 0.6	1.471 Second	1.588 Second

4.4.3.4 Test Procedure

The application test procedure is:

- Apply different input waveforms from the scenarios described in section 4.4.3.2 and 4.4.3.3 to the UFLS relay being tested. At a setting of 59.3 Hz and 58.5 Hz, the simulated waveform without the UFLS scheme (Figure 4.8) is applied. At a setting of 58.9 Hz, the simulated waveform with the single-step UFLS scheme (Figure 4.9) is applied. At a setting of 60.5 Hz, 61.0 Hz and 61.7 Hz, the simulated waveform with the two-step UFLS scheme (Figure 4.10) is used.
- Test the pickup frequency at the following settings:
 - Underfrequency settings: 59.3 Hz, 58.9 Hz and 58.5 Hz.
 - Overfrequency settings: 60.5 Hz, 61.0 Hz and 61.7 Hz
- Record the actual pickup frequency to verify the relay operation.

4.5 UFLS Relay Test Results

The test methodology presented in the previous section for conformance and application tests is applied to two commonly used underfrequency load shedding relays, which were provided by their manufacturers for use in the project. One is static relay and the other one is digital relay.

4.5.1 Conformance Tests

Conformance tests include pickup frequency and time delay tests. Waveforms with different rates of frequency change, total harmonic distortion (THD), and variable voltage magnitudes are applied to the relays.

4.5.1.1 Pickup Frequency Test

The test results for pickup frequency testing are shown in Table 4.6-4.9. Table 4.6 presents test results of relay 1 when tested at 100% input voltage and 0% THD. Table 4.7 shows the test results of relay 1 tested at 100% input voltage and 5% THD. Table 4.8 shows the results of relay 2 tested at 100% voltage and 0% THD. Table 4.9 shows the results of relay 2 tested at 100% input voltage and 5% THD.

4.5.1.2 Time Delay Test

Test results for time delay tests are shown in Tables 4.10-4.17. Table 4.10 and Table 4.11 show test results for relay 1 with 100% input voltage and 0% THD at different rates of frequency change (0.1 and 0.9 Hz/sec. respectively). Table 4.12 and Table 4.13 show test results for relay 1 with 100% input voltage and 5% THD at 0.1 and 0.9 Hz/s respectively. Table 4.14 and Table 4.15 show the test results for relay 2 with 100% input voltage and 0% THD at 0.1 and 0.9 Hz/s respectively. Table 4.16 and Table 4.17 show the results for relay 2 with 5% THD at 0.1 and 0.9 Hz/sec respectively.

4.5.2 Application Tests

Test scenarios outlined in section 4.4.3, representing realistic conditions, are simulated and applied to the relays. The actual pickup frequencies are recorded. The application test results are shown in Table 4.18 and Table 4.19.

For complete results, including testing at different input voltages (100%, 85% and 115% of nominal) and different rates of frequency change (0.1, 0.5 and 0.9 Hz/s), please refer to Appendix C.1.

Table 4.6: Actual pickup frequency in Hz (100% Voltage, 0% THD, Relay 1)

Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/second)								
	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
40.10	40.09	40.09	40.08	40.08	40.07	40.06	40.06	40.04	40.04
55.00	55.00	54.99	54.98	54.98	54.98	54.97	54.97	54.96	54.96
55.30	55.30	55.29	55.29	55.28	55.28	55.27	55.27	55.27	55.26
55.60	55.60	55.59	55.59	55.58	55.58	55.57	55.56	55.56	55.56
55.90	55.90	55.89	55.89	55.89	55.87	55.87	55.87	55.87	55.86
56.20	56.20	56.19	56.19	56.18	56.18	56.17	56.17	56.16	56.16
56.50	56.50	56.49	56.49	56.49	56.48	56.47	56.47	56.46	56.46
56.80	56.80	56.79	56.79	56.78	56.78	56.78	56.77	56.77	56.76
57.10	57.10	57.09	57.09	57.09	57.08	57.07	57.07	57.07	57.06
57.40	57.40	57.39	57.39	57.38	57.38	57.38	57.37	57.37	57.37
57.70	57.70	57.69	57.69	57.68	57.68	57.67	57.67	57.67	57.67
58.00	58.00	57.99	57.99	57.98	57.98	57.97	57.97	57.97	57.97
58.30	58.30	58.29	58.29	58.29	58.28	58.27	58.27	58.26	58.26
58.60	58.59	58.59	58.59	58.58	58.58	58.58	58.57	58.57	58.57
58.90	58.90	58.89	58.89	58.89	58.88	58.87	58.87	58.86	58.86
59.20	59.20	59.19	59.19	59.18	59.18	59.18	59.17	59.17	59.17
59.50	59.50	59.49	59.49	59.48	59.48	59.47	59.47	59.47	59.46
59.80	59.80	59.79	59.79	59.78	59.78	59.78	59.77	59.77	59.77
60.10	60.10	60.11	60.11	60.12	60.12	60.12	60.13	60.14	60.13
60.40	60.40	60.41	60.42	60.42	60.42	60.43	60.44	60.43	60.44
60.70	60.70	60.71	60.71	60.72	60.73	60.72	60.73	60.74	60.73
61.00	61.00	61.01	61.02	61.02	61.02	61.03	61.03	61.03	61.04
61.30	61.31	61.31	61.31	61.31	61.32	61.32	61.33	61.34	61.33
61.60	61.60	61.61	61.61	61.62	61.62	61.63	61.62	61.63	61.64
61.90	61.90	61.91	61.91	61.92	61.92	61.92	61.93	61.94	61.93
62.20	62.21	62.21	62.21	62.21	62.22	62.23	62.22	62.23	62.24
62.50	62.50	62.51	62.51	62.52	62.52	62.52	62.53	62.54	62.53
62.80	62.80	62.81	62.81	62.81	62.82	62.83	62.82	62.83	62.84
63.10	63.10	63.11	63.11	63.12	63.12	63.12	63.13	63.14	63.13
63.40	63.40	63.41	63.41	63.41	63.42	63.43	63.42	63.43	63.44
63.70	63.70	63.71	63.71	63.72	63.72	63.72	63.73	63.73	63.73
64.00	64.00	64.01	64.01	64.02	64.02	64.03	64.02	64.03	64.04
64.30	64.30	64.31	64.31	64.32	64.33	64.32	64.33	64.34	64.33
64.60	64.60	64.61	64.61	64.62	64.62	64.63	64.62	64.63	64.64
64.90	64.90	64.91	64.91	64.92	64.92	64.92	64.93	64.94	64.93
65.00	65.00	65.01	65.01	65.01	65.02	65.03	65.02	65.03	65.04

Table 4.7: Actual pickup frequency in Hz (100% Voltage, 5% THD, Relay 1)

Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)	Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)							
	0.1		0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
40.10	40.09	40.10	40.09	40.08	40.07	40.07	40.06	40.06	40.04	40.04
55.00	55.00	55.00	54.99	54.98	54.98	54.98	54.97	54.96	54.96	54.96
55.30	55.30	55.90	55.89	55.89	55.89	55.87	55.88	55.87	55.87	55.86
55.60	55.60	57.10	57.09	57.09	57.09	57.08	57.07	57.07	57.07	57.06
55.90	55.90	58.00	57.99	57.99	57.98	57.98	57.97	57.97	57.97	57.97
56.20	56.20	58.90	58.89	58.89	58.89	58.87	58.87	58.87	58.87	58.86
56.50	56.50	60.10	60.11	60.11	60.12	60.12	60.12	60.13	60.14	60.13
56.80	56.80	61.00	61.01	61.01	61.02	61.02	61.03	61.03	61.03	61.04
57.10	57.10	61.90	61.91	61.91	61.92	61.92	61.92	61.93	61.94	61.93
57.40	57.40	63.10	63.11	63.11	63.12	63.12	63.12	63.13	63.14	63.13
57.70	57.70	64.00	64.01	64.01	64.01	64.02	64.03	64.02	64.03	64.04
58.00	58.00	65.00	65.01	65.01	65.01	65.02	65.03	65.02	65.03	65.04
58.30	58.30									
58.60	58.59									
58.90	58.90									
59.20	59.20									
59.50	59.50									
59.80	59.80									
60.10	60.10									
60.40	60.41									
60.70	60.70									
61.00	61.00									
61.30	61.31									
61.60	61.60									
61.90	61.90									
62.20	62.21									
62.50	62.50									
62.80	62.80									
63.10	63.10									
63.40	63.40									
63.70	63.70									
64.00	64.00									
64.30	64.30									
64.60	64.60									
64.90	64.90									
65.00	65.00									

Table 4.8: Actual pickup frequency in Hz (100% Voltage, 0% THD, Relay 2)

Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)	Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)							
	0.1		0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.01	40.01
55.00	54.97	55.00	54.98	54.97	54.97	54.97	55.27	54.97	54.98	54.98
55.30	55.12	57.10	56.96	56.96	57.26	56.94	56.94	57.28	56.95	56.94
55.60	55.55	58.90	58.86	58.86	58.85	58.85	58.85	58.85	58.85	58.90
55.90	56.05	61.00	60.99	60.98	60.99	60.98	60.98	60.98	60.98	61.00
56.20	56.19	64.00	64.06	64.06	64.06	64.05	64.05	64.04	64.05	64.02
56.50	56.67	70.00	70.24	70.23	70.22	70.23	70.21	70.23	70.22	70.21
56.80	56.79									
57.10	56.96									
57.40	57.43									
57.70	57.66									
58.00	58.08									
58.30	58.22									
58.60	58.71									
58.90	58.86									
59.20	59.35									
59.50	59.52									
59.80	59.66									
60.10	60.16									
60.40	60.32									
60.70	60.68									
61.00	60.98									
61.30	61.35									
61.60	61.67									
61.90	61.83									
62.20	62.35									
62.50	62.49									
62.80	62.66									
63.10	63.20									
63.40	63.35									
63.70	63.82									
64.00	64.06									
64.30	64.28									
64.60	64.60									
64.90	64.93									
70.00	69.98									

Table 4.9: Actual pickup frequency in Hz (100% Voltage, 5% THD, Relay 2)

Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz)	Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)							
	0.1		0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
40.00	40.00	40.00	40.00	39.99	40.00	39.99	39.99	40.00	40.01	40.01
55.00	54.97	55.00	54.97	54.98	54.98	54.97	54.97	54.98	54.96	54.99
55.30	55.43	57.10	57.29	56.94	57.30	57.29	57.29	57.26	56.94	57.29
55.60	55.57	58.90	58.87	58.86	58.86	58.87	58.87	58.87	58.84	58.90
55.90	56.04	61.00	61.00	60.98	60.98	60.99	61.00	60.98	60.97	61.01
56.20	56.19	64.00	64.05	64.05	64.05	64.05	64.06	64.06	64.04	64.05
56.50	56.66	70.00	70.22	69.72	69.88	70.23	70.21	70.21	70.26	70.22
56.80	56.80									
57.10	56.95									
57.40	57.42									
57.70	57.59									
58.00	58.08									
58.30	58.22									
58.60	58.70									
58.90	58.86									
59.20	59.38									
59.50	59.52									
59.80	59.64									
60.10	60.18									
60.40	60.69									
60.70	60.85									
61.00	60.99									
61.30	61.55									
61.60	61.66									
61.90	62.20									
62.20	62.29									
62.50	62.49									
62.80	62.76									
63.10	63.21									
63.40	63.34									
63.70	63.91									
64.00	64.06									
64.30	64.21									
64.60	64.78									
64.90	64.93									
70.00	70.22									

Table 4.10: Actual time delay (100% Voltage, 0% THD, 0.1 Hz/sec Rate of Frequency Change, Relay 1)

Frequency Setpoint (Hz)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.10	40.09	6	6.0	40.04	16	16.0	40.00	36	36.0	40.00	66	66.0
55.00	55.00	6	6.0	54.96	16	16.0	54.89	36	36.0	54.78	66	66.1
55.90	55.90	6	6.0	55.86	16	16.0	55.79	36	36.0	55.68	66	66.1
57.10	57.09	6	6.0	57.06	16	16.0	56.99	36	36.0	56.88	66	66.1
58.00	58.00	6	6.0	57.96	16	16.0	57.89	36	36.0	57.79	66	66.1
58.90	58.90	6	6.0	58.86	16	16.0	58.79	36	36.0	58.69	66	66.1
60.10	60.10	6	6.0	60.14	16	16.0	60.21	36	36.0	60.30	66	65.9
61.00	61.01	6	6.0	61.04	16	16.0	61.10	36	36.0	61.20	66	65.9
61.90	61.90	6	6.0	61.94	16	16.0	62.00	36	36.0	62.10	66	65.9
63.10	63.10	6	6.1	63.14	16	16.0	63.20	36	36.0	63.30	66	65.9
64.00	64.00	6	6.0	64.03	16	16.0	64.10	36	36.0	64.19	66	66.0
65.00	65.00	6	6.0	65.04	16	16.0	65.10	36	36.1	65.19	66	66.1
59.30		15 sec	15.38 sec									
59.50		30 sec	31.65 sec									

Table 4.11: Actual time delay (100% Voltage, 0% THD, 0.9 Hz/sec Rate of Frequency Change, Relay 1)

Frequency Setpoint (Hz)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.10	40.04	6	5.9	40.00	16	15.9	40.00	36	35.9	40.00	66	66.0
55.00	54.96	6	6.0	54.63	16	16.0	53.97	36	36.1	52.98	66	66.8
55.90	55.86	6	6.0	55.53	16	16.0	54.88	36	36.2	53.90	66	66.8
57.10	57.06	6	5.9	56.74	16	16.0	56.10	36	36.1	55.15	66	66.8
58.00	57.97	6	6.0	57.65	16	16.0	57.03	36	36.1	56.09	66	66.8
58.90	58.86	6	6.0	58.55	16	16.0	57.93	36	36.2	57.01	66	66.7
60.10	60.13	6	6.1	60.43	16	16.0	61.02	36	35.9	61.92	66	65.3
61.00	61.04	6	6.0	61.35	16	16.0	61.93	36	35.9	62.80	66	65.3
61.90	61.93	6	6.0	62.22	16	16.0	62.81	36	35.9	63.67	66	65.4
63.10	63.15	6	6.1	63.42	16	16.0	63.99	36	35.9	64.83	66	65.4
64.00	64.04	6	6.0	64.32	16	16.0	64.88	36	35.9	65.72	66	65.5
65.00	65.03	6	6.0	65.31	16	16.1	65.87	36	36.1	66.70	66	66.1
59.30		15 sec	19.52 sec									

Table 4.12: Actual time delay (100% Voltage, 5% THD, 0.1 Hz/sec Rate of Frequency Change, Relay 1)

Frequency Setpoint (Hz)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.10	40.09	6	6.0	40.04	16	16.0	40.00	36	36.0	40.00	66	66.0
55.00	55.00	6	6.0	54.96	16	16.0	54.89	36	36.0	54.78	66	66.1
55.90	55.90	6	6.0	55.86	16	16.0	55.79	36	36.0	55.68	66	66.1
57.10	57.10	6	6.0	57.06	16	16.0	56.99	36	36.0	56.89	66	66.1
58.00	58.00	6	6.0	57.96	16	16.0	57.89	36	36.0	57.79	66	66.1
58.90	58.90	6	6.0	58.86	16	16.0	58.79	36	36.0	58.69	66	66.0
60.10	60.10	6	6.0	60.14	16	16.0	60.20	36	36.0	60.30	66	65.9
61.00	61.01	6	6.0	61.04	16	16.0	61.10	36	36.0	61.20	66	65.9
61.90	61.90	6	6.0	61.94	16	16.0	62.00	36	36.0	62.10	66	65.9
63.10	63.10	6	6.0	63.14	16	16.0	63.20	36	36.0	63.30	66	65.9
64.00	64.00	6	6.0	64.03	16	16.0	64.10	36	36.0	64.19	66	66.0
65.00	65.00	6	6.0	65.03	16	16.0	65.10	36	36.0	65.19	66	66.1
59.30		15 sec	15.38 sec									
59.50		30 sec	31.65 sec									

Table 4.13: Actual time delay (100% Voltage, 5% THD, 0.9 Hz/sec Rate of Frequency Change, Relay 1)

Frequency Setpoint (Hz)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.10	40.04	6	6.0	40.00	16	15.9	40.00	36	36.0	40.00	66	66.0
55.00	54.96	6	6.0	54.64	16	16.0	53.97	36	36.1	52.98	66	66.9
55.90	55.86	6	6.0	55.53	16	16.0	54.88	36	36.1	53.90	66	66.9
57.10	57.06	6	6.0	56.74	16	16.0	56.10	36	36.1	55.15	66	66.8
58.00	57.96	6	6.0	57.66	16	16.0	57.03	36	36.1	56.07	66	66.8
58.90	58.86	6	5.9	58.55	16	16.0	57.94	36	36.2	57.01	66	66.7
60.10	60.13	6	6.0	60.45	16	16.0	61.04	36	35.9	61.92	66	65.3
61.00	61.04	6	6.0	61.35	16	16.0	61.93	36	35.9	62.80	66	65.3
61.90	61.93	6	6.0	62.23	16	16.0	62.81	36	35.9	63.67	66	65.3
63.10	63.13	6	6.0	63.42	16	16.0	63.99	36	35.9	64.83	66	65.4
64.00	64.04	6	6.0	64.33	16	16.1	64.89	36	35.9	65.72	66	65.5
65.00	65.04	6	6.0	65.31	16	16.1	65.87	36	36.1	66.71	66	66.1
59.30		15 sec	19.52 sec									

Table 4.14: Actual time delay (100% Voltage, 0% THD, 0.1 Hz/sec Rate of Frequency Change, Relay 2)

Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.00	39.99	6	6.3	40.00	16	15.3	40.00	36	33.3	39.98	66	61.5
55.00	55.01	6	5.9	54.97	16	15.4	54.96	36	33.4	54.97	66	62.6
57.10	57.29	6	5.4	57.03	16	16.4	56.95	36	34.5	57.28	66	63.6
58.90	58.86	6	5.4	58.85	16	13.4	58.86	36	34.5	58.84	66	58.6
61.00	61.00	6	6.4	61.01	16	15.4	61.00	36	36.4	61.00	66	57.3
64.00	64.06	6	6.5	64.06	16	13.5	64.05	36	35.5	64.06	66	63.4
70.00	70.17	6	6.0	70.13	16	16.0	70.23	36	27.0	70.23	66	64.0

Table 4.15: Actual time delay (100% Voltage, 0% THD, 0.9 Hz/sec Rate of Frequency Change, Relay 2)

Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.00	40.01	6	6.3	40.00	16	16.4	39.94	36	34.0	39.94	66	65.9
55.00	54.91	6	6.0	54.92	16	12.5	54.93	36	33.8	54.96	66	66.7
57.10	57.26	6	6.4	57.10	16	16.5	57.27	36	33.8	56.93	66	65.7
58.90	59.02	6	6.4	58.88	16	16.5	58.76	36	30.8	58.78	66	61.6
61.00	61.01	6	5.4	60.97	16	16.4	60.98	36	36.1	61.01	66	63.4
64.00	64.04	6	6.5	64.06	16	15.4	64.09	36	33.2	64.11	66	62.1
70.00	69.98	6	6.0	70.11	16	16.0	70.25	36	33.8	70.28	66	62.3

Table 4.16: Actual time delay (100% Voltage, 5% THD, 0.1 Hz/sec Rate of Frequency Change, Relay 2)

Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.00	40.00	6	6.3	40.00	16	16.3	40.00	36	34.3	39.99	66	61.5
55.00	55.07	6	5.9	54.97	16	15.4	54.98	36	34.4	54.97	66	64.5
57.10	56.95	6	5.4	56.96	16	16.4	57.26	36	35.5	56.94	66	57.5
58.90	58.85	6	5.4	58.85	16	14.4	58.85	36	33.5	58.85	66	61.6
61.00	60.99	6	6.5	61.00	16	15.4	60.99	36	33.4	61.01	66	57.3
64.00	64.06	6	6.5	64.05	16	16.5	64.05	36	35.5	64.06	66	64.4
70.00	70.22	6	5.0	70.21	16	16.0	70.236	36	28.0	70.23	66	57.0

Table 4.17: Actual time delay (100% Voltage, 5% THD, 0.9Hz/sec Rate of Frequency Change, Relay 2)

Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.00	40.00	6	6.3	39.96	16	15.4	39.97	36	36.0	39.94	66	65.9
55.00	54.91	6	5.9	54.97	16	15.5	54.95	36	34.8	54.90	66	62.7
57.10	57.28	6	6.4	57.29	16	16.5	56.88	36	31.8	57.22	66	61.7
58.90	58.90	6	6.4	58.82	16	13.5	58.76	36	30.8	58.76	66	60.6
61.00	60.99	6	6.4	61.00	16	15.4	61.06	36	31.1	61.15	66	59.4
64.00	64.06	6	6.5	64.08	16	13.4	64.07	36	34.2	64.12	66	60.1
70.00	69.98	6	6.0	70.24	16	14.0	70.22	36	35.8	70.28	66	61.3

Table 4.18: Application test of relay 1 (Time Delay: 2 Cycles)

Power Factor	Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz) Test no.1	Actual Pickup Frequency (Hz) Test no.2	Actual Pickup Frequency (Hz) Test no.3
1	60.5	60.398	60.364	60.396
0.9	60.5	60.377	60.381	60.440
0.8	60.5	60.400	60.385	60.389
0.7	60.5	60.386	60.374	60.389
0.6	60.5	60.396	60.373	60.362
1	61.0	60.995	60.990	61.001
0.9	61.0	61.001	61.008	61.004
0.8	61.0	60.993	61.072	60.991
0.7	61.0	61.069	60.988	60.996
0.6	61.0	60.997	60.992	61.000
1	61.7	61.743	61.730	61.732
0.9	61.7	61.720	61.739	61.730
0.8	61.7	61.734	61.735	61.729
0.7	61.7	61.727	61.732	61.728
0.6	61.7	61.679	61.664	61.680
1	59.3	59.414	59.409	59.391
0.9	59.3	59.401	59.389	59.384
0.8	59.3	59.401	59.382	59.395
0.7	59.3	59.374	59.367	59.357
0.6	59.3	59.375	59.400	59.413
1	58.9	58.845	58.854	58.857
0.9	58.9	58.905	58.987	58.916
0.8	58.9	58.836	58.833	58.848
0.7	58.9	58.387	58.383	58.396
0.6	58.9	58.885	58.902	58.888
1	58.5	58.303	58.302	58.300
0.9	58.5	58.647	58.412	58.304
0.8	58.5	58.329	58.388	58.274
0.7	58.5	58.298	58.302	58.281
0.6	58.5	58.286	58.290	58.283

Table 4.19: Application test of relay 2 (Time Delay: 3 Cycles)

Power Factor	Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz) Test no.1	Actual Pickup Frequency (Hz) Test no.2	Actual Pickup Frequency (Hz) Test no.3
1	60.5	60.374	60.352	60.367
0.9	60.5	60.357	60.375	60.366
0.8	60.5	60.367	60.358	60.379
0.7	60.5	60.370	60.360	60.359
0.6	60.5	60.339	60.360	60.325
1	61.0	60.981	61.001	60.994
0.9	61.0	61.006	60.998	60.990
0.8	61.0	60.991	60.988	60.985
0.7	61.0	60.998	60.979	61.006
0.6	61.0	60.979	60.974	60.984
1	61.7	61.717	61.712	61.712
0.9	61.7	61.713	61.719	61.719
0.8	61.7	61.696	61.712	61.713
0.7	61.7	61.706	61.707	61.711
0.6	61.7	61.683	61.664	61.633
1	59.3	59.428	59.387	59.420
0.9	59.3	59.401	59.405	59.399
0.8	59.3	59.428	59.290	59.083
0.7	59.3	59.426	59.429	59.413
0.6	59.3	59.175	59.368	59.422
1	58.9	58.851	58.862	58.851
0.9	58.9	58.842	58.866	58.847
0.8	58.9	58.897	58.916	59.107
0.7	58.9	59.313	59.290	59.285
0.6	58.9	58.390	58.381	59.322
1	58.5	58.672	58.675	58.666
0.9	58.5	58.682	58.682	58.672
0.8	58.5	58.666	58.372	58.323
0.7	58.5	58.675	58.621	58.668
0.6	58.5	58.336	58.330	58.315

4.6 Interpretation of the Results

4.6.1 Conformance Tests

The two relays operated differently under conformance tests. In some cases the relays operated outside their specifications. For relay 1, pickup frequencies deviated from the setpoint, and the deviation increased with increasing frequency decay rate. For the same relay, time delays were outside specifications for high decay rates and long time delays.

For relay 2, actual pickup frequencies deviated from the setpoint and in some cases, were out of specification. There is no trend in deviation regarding frequency decay rate for this relay. Time delays were within specifications except at 0.9 Hz/sec rate of frequency change and long time delay settings.

Discussion with utility users of these relays, however, indicate that the errors, while outside specifications, are still very small, and are inconsequential for the users.

4.6.2 Application Tests

The specific dynamic test cases are applied to the relays. The actual pickup frequencies are recorded. Both relays operated quite accurately at over-frequency setpoints (60.5, 61.0 and 61.7 Hz). Some deviations are observed at underfrequency settings (59.3, 58.9 and 58.5 Hz).

4.6.3 Error Analysis

UFLS testing requires very high accuracy in both delay time and frequency measurements for accurate results. Because measured errors were very small, the test system was reevaluated for its ability to discern such small variations in time and frequency.

The accuracy of the relay test system depends upon the accuracy of each component of the testing environment, including the waveform generators and the datalogging equipment. Accuracy specifications for the two relays tested and the datalogger used are:

- Test Relay 1 ($\pm 0.01\text{Hz}$, 0.25 cycle)
- Test Relay 2 ($\pm 0.01\text{Hz}$, 1 cycle)
- Datalogger (100ppm or 0.0001% of the sampling rate)

Frequency is obtained by measuring time at each zero crossing, calculating the time difference from the previous zero crossing, and inverting to obtain frequency. Once the trip frequency is reached, cycles are counted until the time delay is reached, at which time the relay should actually trip. For this method, the accuracy of both the datalogger and relay may contribute error to the results.

In order to verify the error, the information from the datalogger is analyzed. Table 4.20 shows data recorded during relay testing. The voltage 0 column is the input voltage to the relay, stepped down through a voltage transformer. The voltage 1 column is the operation of relay's output contact, which goes from approximately zero to a positive value when the contact closes. The frequency of each cycle is calculated using interpolation to improve accuracy. The pickup frequency was set at 55Hz. Time delay was set at 6 cycles.

Table 4.20: Data for pickup frequency test (55 Hz Frequency Setpoint)

Row	Voltage 0 (Volt)	Voltage 1(Volt)	Calculated Frequency (Hz)	Remark
51466	0.026034	-0.677606	55.294	Zero crossing
51467	0.041324	-0.636893		
51468	-0.320540	-0.591092		
51469	-0.292508	-0.504578		
continue	continue	continue		
51644	0.680957	-0.382441		
51645	0.686053	-0.242492		
51646	0.326738	-0.306105		
51647	0.331834	-0.303560		
51648	-0.012191	-0.293382		
51649	-0.001998	-0.211957	54.983	Above setting frequency
continue	continue	continue		
51826	0.652925	-0.031296		
51827	0.637635	-0.016029		
51828	0.296158	-0.069464		
51829	0.288513	-0.008395		
51830	-0.040223	-0.018574		
51831	-0.045320	-0.000762		
continue	continue	continue		
52008	0.635087	0.271503	54.959	Below setting frequency
52009	0.614700	0.330027		
52010	0.298706	0.317304		
52011	0.270674	0.340205		
52012	-0.055513	0.337660		
52013	-0.080996	0.393640		
continue	continue	continue		
52192	0.288513	0.503055		
52193	0.245191	0.503055		
52194	-0.060610	0.464887		
52195	-0.106480	0.469976	54.959	Relay pickup here
continue	continue	continue		
52284	-0.139608	-0.222136		
52285	-0.075900	-0.303560		
52286	0.209514	-0.608904		
continue	continue	continue		
52374	0.298706	0.449619		
52375	0.219708	0.518322		
continue	continue	continue		
53179	-2.817910	0.457253		
53180	-2.687950	3.121370		Contact close here

(Source: NI VI Logger, Scan rate: 0.0001 second, Number of scans: 65404)

According to Table 4.20, the last cycle before the frequency decays to the set value of 55.0 Hz ends at row 51647 and 51648. By interpolating between row 51647 and 51648, the zero crossing is estimated at:

$$t_1 = 51647 * 0.0001s + 0.0001s * \frac{0.331834}{0.331834 - (-0.0121912)} = 5.16479s$$

The zero crossing one cycle before this is at:

$$t_2 = 51467 * 0.0001s + 0.0001s * \frac{0.0413239}{0.0413239 - (-0.32054)} = 5.14671s$$

The period is:

$$T = t_1 - t_2 = 0.018s$$

Frequency can be calculated as follows:

$$f = \frac{1}{T} = 55.294Hz$$

At 55.294Hz, the relay does not trip because the frequency is still above the trip frequency.

The next zero crossing is at rows 51829 and 51830. By interpolating between Row 51829 and 51830, the zero crossing is estimated at:

$$t_3 = 51829 * 0.0001s + 0.0001s * \frac{0.288513}{0.288513 - (-0.0555129)} = 5.18298s$$

The zero crossing one cycle before this is at row 51647 and 51648 which is t_1 .

The period is:

$$T = t_3 - t_1 = 0.018s$$

Frequency can be calculated as follows:

$$f = \frac{1}{T} = 54.983Hz$$

The relay may trip here since the frequency is less than the setting. Possible time error (e) in one cycle, based on datalogger specs, can be shown as follows:

$$e = \frac{T}{0.0001} * 0.0001s * 0.0001 = 1.819 * 10^{-6}s$$

And the possible error in frequency calculation is:

$$f_{error1} = \frac{1}{(T + e)} = 54.978Hz$$

$$f_{error2} = \frac{1}{(T - e)} = 54.989Hz$$

With consideration of datalogger error, the actual relay trip frequency was in the range from 54.98 Hz to 54.99 Hz. The relay could trip within specs at this point, because its specified accuracy of +/- 0.01Hz could allow 54.99 Hz to be sensed as 55.00 Hz. There is a corresponding possibility that the relay will not trip even when the measured frequency is calculated to be slightly (within 0.01 Hz) over the frequency setting.

In the next cycle, the zero crossing is at rows 52011 and 52012. By interpolating between rows 52011 and 52012, the zero crossing is estimated at:

$$t_4 = 52011 * 0.0001s + 0.0001s * \frac{0.270674}{0.270674 - (-0.05551)} = 5.201183s$$

The zero crossing one cycle before this is at Row 51829 and 51830 which is t_3 .

The period is:

$$T = t_4 - t_3 = 0.018s$$

Frequency can be calculated as follows:

$$f = \frac{1}{T} = 54.9595Hz$$

The relay trips at this point. The pickup frequency is recorded at 54.96 Hz.

With consideration of test component's error, the obtained result may deviate from the actual one. In this specific case of the setting at 55Hz and 6 cycle time delay, the measured pickup frequency can be either 55.00Hz or 54.96 Hz. while the recorded time delay could vary between 6 cycles and 7 cycles.

4.7 Future Work

While the simulations provide good data for application tests, actual field data would greatly enhance the testing protocol. A library of such recorded data should be developed.

A new IEEE guide [26] addresses issues regarding frequency relay testing. These issues should be considered to improve the test system and protocol.

Although most of widely used relays today employ the zero-crossing technique to measure frequency, some of new frequency relays may apply the other technologies. The other frequency measuring techniques should be investigated, and if necessary, algorithms for testing such relays should be developed and incorporated into the test protocols.

5.0 Conclusion

5.1 Distance relays

This report describes a test lab setup developed at Texas A&M University for testing distance relays. The test procedure of relay test implementation on the platform and the use in relay testing are also presented. Three different distance relays are selected to implement relay tests using the proposed methodology and tests results are given at the end. The proposed test methodology together with the test tools and test case library composes a comprehensive test environment for evaluating the dependability and security features of protective relays.

In the course of study it became apparent that a differentiation between *Conformance Test* and *Compliance Test* should be made to help focus on different types of design and application tests. The *Conformance test* objective is to test the basic functionality of the relays, verify the operating characteristics, calibrate relay settings and implement periodic maintenance test. The concern of this test is the statistical performance related to the relay operating characteristic and tripping time. To fulfill this test, a batch of test cases with a variety of disturbance conditions including faults and non-faults are generated through simulation. The *Compliance test* objective is to verify whether a relay can operate correctly under peculiar circumstances in power system particularly during abnormal operating conditions. This type of test is to investigate the compliance feature that “real” performance of a protective relay complies with its expected performance. The concern of this test is the trip/no trip response and relay operating time performance under specific scenarios. A typical example is the use of the recorded data to analyze causes of an unwanted relay operation in a post-event analysis.

The test results have shown that in the future it will be equally important to test relays for dependability and security of operation. While the loss of security that resulted in over tripping may have not been a concern in the future, due to heavily overloaded lines the unwanted trips can lead to a cascading event ending in a black out. This report has shown how the testing for security may be implemented.

5.2 Generator Relays

This report describes the configuration, simulation, and instrumentation requirements for evaluating the performance of generator protection relays under realistic transient conditions, as they may be encountered in a practical electric power system. As a result, a comprehensive testing platform has been built to reproduce and simulate conditions in the system as closely to reality as possible. The report presented the testing platform with an emphasis on generator protective relays. The highlights of the platform include (a) a power system simulator to accurately compute short-circuit conditions as seen in an actual system by the protective relays; (b) a signal conditioning unit that reproduces the simulated voltages and currents at relay instrumentation voltage and current level, as if

they were delivered by actual potential and current transformers; and (c) a set of procedures to conduct and validate the different tests of the generator relay, including relay connections, software configuration, and the different test scenarios.

An immediate application of the developed methodology and data base is to test the settings of specific generator relays and the degree of coordination of the various relay functions.

A future research direction would be to use the developed methodology in reverse mode, i.e. for the purpose of estimating the model of the generator. Accurate generator modeling remains an issue. Approaches to estimate the generator model in real time, while they exist, have not provided robust performance and the resulting model does not exhibit satisfactory agreement with observed generator response. It is expected that the developed generator model can provide a real time estimation methodology that will be robust and will result in an accurate generator model. The attractiveness of the approach is that the entire procedure can be performed within the generator relay.

5.3 Underfrequency Load Shedding Relays

This report presents a new methodology specifically designed for UFLS relay testing. The tests include conformance and application tests. Philosophies of testing are discussed and test protocols are presented.

Test protocols provide realistic and relevant tests to more accurately simulate conditions relays may encounter in service. While much relay testing is done with pure sinusoidal waveforms, the protocols include distorted waveforms. Dynamic test cases are also provided to test relays under specific conditions. The cases provided are from simulations, but actual recorded data can also be used when available.

Two common UFLS digital relays were tested under the new protocol. The results show the two relays operated differently during tests. Some small deviations from manufacturers' specifications were observed. The deviations recorded in application tests are larger than those resulting from conformance tests. Discussions with utility users, however, indicate that the deviations observed are inconsequential for the users.

The accuracy of testing components may contribute error to the acquired results. The report analyzes how the error of testing components can affect the test results. Higher accuracy can be achieved by upgrading to higher accuracy hardware, e.g., a datalogger with higher sampling rate.

6.0 Project Publications

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Appendix A: Line Distance Relay Test

A.1 Relay Settings

Relays are set according to the test plan discussed in section 2 and the reference provided by vendors [13], [14], [16], [18]. Table A.1 and Table A.2 are setting tables for SEL-421 relay for implementing conformance test and application test respectively. Setting tables for SEL-321 relay are neglected because of the same parameters and similar setting names. Figure A.1, A.2 and A.3 are given to present the settings for GE D60 instead of listing parameters. For SEL-421 and SEL-321, the setting names come from the SEL 5030 and SEL 5010 respectively which are software used for manage relays [15], [17]. For GE D60, these figures are generated by EnerVista UR Setup software [19].

Table A.1: Setting table for SEL-421 for Conformance Test

Setting Name	Value	Setting Name	Value
SID Station Identifier	230kV BUS1	Z1D Zone 1 Time Delay	0.0
RID Relay Identifier	SEL-421-1	Z2D Zone 2 Time Delay	20.0
NUMBK	1	Z3D Zone 3 Time Delay	60.0
BID 1 Breaker 1 Identifier	Breaker 1-Line 1	ESOTF Switch-Onto-Fault	Y
NFREQ	60	ESPSTF	N
PHROT	ABC	EVRST	Y
ESS	N	52AEND	10.0
CTRW	400	SOTFD	10.0
PTRY	2300	CLSMON	IN102
VNOMY	100	EOOS Out-of-Step	Y
Z1MAG	7.13	OOSB1 Block Zone 1	Y
Z1ANG	84.2	OOSB2 Block Zone 2	Y
Z0MAG	19.68	OOSB3 Block Zone 3	N
Z0ANG	81.7	OSBD	2.5
EFLOC Fault Location	Y	OSBLTCH	Y
LL Line Length (mile)	45	EOOST	N
E21P	3	X1T7	23.42
Z1P Zone 1 Reach	5.71	X1T6	8.56
Z2P Zone 2 Reach	7.13	R1R7	19.16
Z3P Zone 3 Reach	18.87	R1R6	4.3
Z1PD Zone 1 Time Delay	0.0	ELOAD	Y
Z2PD Zone 2 Time Delay	20.0	ZLF	6.29
Z2PD Zone 3 Time Delay	60.0	ZLR	6.29
E21MG	3	PLAF	45.0
Z1MG Zone 1 Reach	5.71	NLAF	-45.0
Z2MG Zone 2 Reach	7.13	PLAR	135.0
Z3MG Zone 3 Reach	18.87	NLAR	225.0
E21XG	N	E50P	1
Z1GD Zone 1 Time Delay	0.0	50P1P Level 1 Pickup	3.23
Z2GD Zone 2 Time Delay	20.0	67P1D Level 1 Time Delay	0.0
Z3GD Zone 3 Time Delay	60.0	67P1TC	1
k0M1	0.587	DIR3	F
k0A1	-3.92	TR Trip	Z1T OR Z2T OR Z3T
ECDDTD	Y	TRSOTF	M2P OR Z2G OR M3P OR Z3G

Table A.2: Setting table for SEL-421 for Compliance Test

Setting Name	Value	Setting Name	Value
SID Station Identifier	138kV BUS2	Z3MG Zone 3 Reach	3.67
RID Relay Identifier	SEL-421-1	E21XG	N
NUMBK	1	Z1GD Zone 1 Time Delay	0.0
BID 1 Breaker 1 Identifier	Breaker 1-Bus 2	Z2GD Zone 2 Time Delay	20.0
NFREQ	60	Z1D Zone 1 Time Delay	0.0
PHROT	ABC	Z2D Zone 2 Time Delay	20.0
ESS	N	Z3D Zone 3 Time Delay	60.0
CTRW	100	ESOTF Switch-Onto-Fault	N
PTRY	1380	EOOS Out-of-Step	Y
VNOMY	100	OOSB1 Block Zone 1	Y
Z1MAG	1.48	OOSB2 Block Zone 2	Y
Z1ANG	76.64	OOSB3 Block Zone 3	N
Z0MAG	3.69	OSBD	3.05
Z0ANG	76.59	OSBLTCH	Y
EFLOC Fault Location	Y	EOOST	I
LL Line Length (mile)	33	OSTD	0.625
E21P	3	X1T7	7.89
Z1P Zone 1 Reach	1.18	X1T6	2.14
Z2P Zone 2 Reach	1.78	R1R7	6.84
Z3P Zone 3 Reach	3.67	R1R6	1.09
Z1PD Zone 1 Time Delay	0.0	ELOAD	Y
Z2PD Zone 2 Time Delay	20.0	ZLF	1.81
Z2PD Zone 3 Time Delay	60.0	ZLR	1.81
E21MG	3	PLAF	45.0
Z1MG Zone 1 Reach	1.18	NLAF	-45.0
Z2MG Zone 2 Reach	1.78	PLAR	135.0
Z3GD Zone 3 Time Delay	60.0	NLAR	225.0
k0M1	0.726	DIR3	F
k0A1	-3.67	TR Trip	Z1T OR Z2T OR Z3T
ECDTD	Y	ER Event Report Trigger	M2P OR Z2G OR M3P OR Z3G

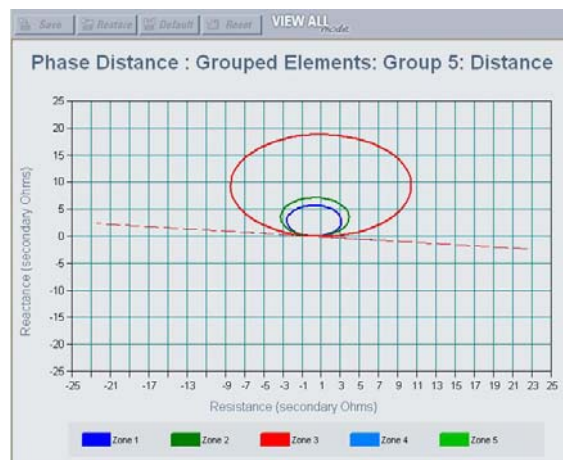


Figure A.1: Phase distance protection

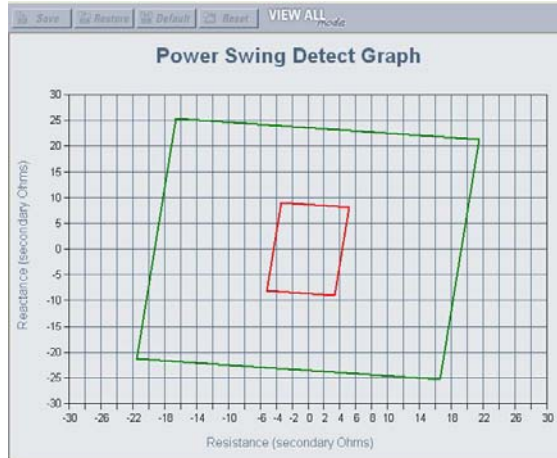


Figure A.2: Power swing protection

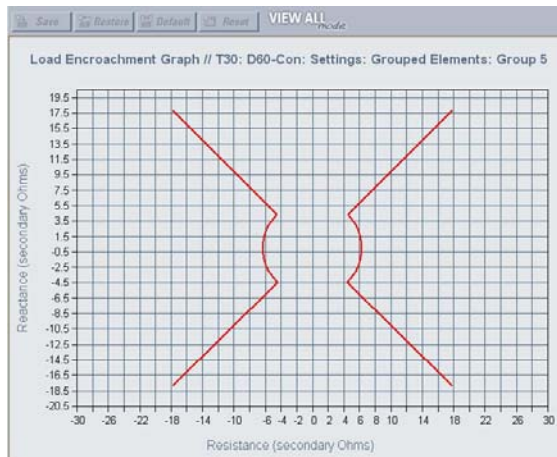


Figure A.3: Load encroachment protection

Note: Since GE D60 does not have the protection element special for the switch onto fault condition, a combination of Line Pickup and Phase IOC is applied using FlexLogic to realize this function.

A.2 Test Results

Table A.3: Test results for condition F1 for SEL-421

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time[s]
AG	0	0	0	Y	1	0.0127
AG	0	45	0	Y	1	0.0141
AG	0	90	0	Y	1	0.0136
AG	50	0	0	Y	1	0.0192
AG	50	0	5	Y	1	0.0232
AG	50	45	0	Y	1	0.0203
AG	50	45	5	Y	1	0.0238
AG	50	90	0	Y	1	0.0242
AG	50	90	5	Y	1	0.0253
AG	70	0	0	Y	1	0.0308
AG	70	0	5	Y	2	0.3549
AG	70	0	10	Y	2	0.3595
AG	70	45	0	Y	1	0.0294
AG	70	45	5	Y	2	0.3537
AG	70	45	10	Y	2	0.3577
AG	70	90	0	Y	1	0.0343
AG	70	90	5	Y	2	0.3570
AG	70	90	10	Y	2	0.3591
AG	90	0	0	Y	2	0.3553
AG	90	45	0	Y	2	0.3583
AG	90	90	0	Y	2	0.3585
BC	0	0	0	Y	1	0.0170
BC	0	0	5	Y	1	0.0162
BC	0	0	25	Y	1	0.0232
BC	0	45	0	Y	1	0.0176
BC	0	45	5	Y	1	0.0199
BC	0	45	25	Y	1	0.0230
BC	0	90	0	Y	1	0.0186
BC	0	90	5	Y	1	0.0213
BC	0	90	25	Y	1	0.0244
BC	50	0	0	Y	1	0.0233
BC	50	0	5	Y	1	0.0242
BC	50	45	0	Y	1	0.0242
BC	50	45	5	Y	1	0.0246
BC	50	90	0	Y	1	0.0230
BC	50	90	5	Y	1	0.0237
BC	70	0	0	Y	1	0.0268
BC	70	0	5	Y	1	0.0302
BC	70	45	0	Y	1	0.0280
BC	70	45	5	Y	1	0.0299
BC	70	90	0	Y	1	0.0264
BC	70	90	5	Y	1	0.0284
BC	90	0	0	Y	2	0.3578
BC	90	0	5	Y	2	0.3576

BC	90	45	0	Y	2	0.3597
Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time[s]
BC	90	45	5	Y	2	0.3584
BC	90	90	0	Y	2	0.3567
BC	90	90	5	Y	2	0.3573
BCG	0	0	0	Y	1	0.0163
BCG	0	0	25	Y	1	0.0172
BCG	0	45	0	Y	1	0.0152
BCG	0	45	25	Y	1	0.0163
BCG	0	90	0	Y	1	0.0160
BCG	0	90	25	Y	1	0.0187
BCG	50	0	0	Y	1	0.0246
BCG	50	0	25	Y	1	0.0238
BCG	50	45	0	Y	1	0.0249
BCG	50	45	25	Y	1	0.0247
BCG	50	90	0	Y	1	0.0225
BCG	50	90	25	Y	1	0.0237
BCG	70	0	0	Y	1	0.0272
BCG	70	0	10	Y	1	0.0270
BCG	70	45	0	Y	1	0.0285
BCG	70	45	10	Y	1	0.0290
BCG	70	90	0	Y	1	0.0277
BCG	70	90	10	Y	1	0.0267
BCG	90	0	0	Y	2	0.3579
BCG	90	0	25	Y	2	0.3645
BCG	90	45	0	Y	2	0.3646
BCG	90	45	25	Y	2	0.3643
BCG	90	90	0	Y	2	0.3613
BCG	90	90	25	Y	2	0.3604
ABC	0	0	0	Y	1	0.0167
ABC	0	45	0	Y	1	0.0148
ABC	0	90	0	Y	1	0.0155
ABC	50	0	0	Y	1	0.0200
ABC	50	45	0	Y	1	0.0217
ABC	50	90	0	Y	1	0.0219
ABC	70	0	0	Y	1	0.0280
ABC	70	45	0	Y	1	0.0312
ABC	70	90	0	Y	1	0.0283
ABC	90	0	0	Y	2	0.3601
ABC	90	45	0	Y	2	0.3603
ABC	90	90	0	Y	2	0.3578

Table A.4: Test results for condition F2-1 for SEL-421

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time [s]
AG	10	0	0	N	–	–
AG	10	0	10	N	–	–
AG	10	45	0	N	–	–
AG	10	45	10	N	–	–
AG	10	90	0	N	–	–
AG	10	90	10	N	–	–
AG	50	0	0	N	–	–
AG	50	0	25	N	–	–
AG	50	45	0	N	–	–
AG	50	45	25	N	–	–
AG	50	90	0	N	–	–
AG	50	90	25	N	–	–
AG	90	0	0	N	–	–
AG	90	0	25	N	–	–
AG	90	45	0	N	–	–
AG	90	45	25	N	–	–
AG	90	90	0	N	–	–
AG	90	90	25	N	–	–
BC	10	0	0	N	–	–
BC	10	45	0	N	–	–
BC	10	90	0	N	–	–
BC	50	0	0	N	–	–
BC	50	45	0	N	–	–
BC	50	90	0	N	–	–
BC	90	0	0	N	–	–
BC	90	45	0	N	–	–
BC	90	90	0	N	–	–
BCG	10	0	0	N	–	–
BCG	10	0	10	N	–	–
BCG	10	45	0	N	–	–
BCG	10	45	10	N	–	–
BCG	10	90	0	N	–	–
BCG	10	90	10	N	–	–
BCG	50	0	0	N	–	–
BCG	50	0	25	N	–	–
BCG	50	45	0	N	–	–
BCG	50	45	25	N	–	–
BCG	50	90	0	N	–	–
BCG	50	90	25	N	–	–
BCG	90	0	0	N	–	–
BCG	90	0	25	N	–	–
BCG	90	45	0	N	–	–
BCG	90	45	25	N	–	–
BCG	90	90	0	N	–	–
BCG	90	90	25	N	–	–
ABC	10	0	0	N	–	–
ABC	10	45	0	N	–	–

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time[s]
ABC	10	90	0	N	–	–
ABC	50	0	0	N	–	–
ABC	50	45	0	N	–	–
ABC	50	90	0	N	–	–
ABC	90	0	0	N	–	–
ABC	90	45	0	N	–	–
ABC	90	90	0	N	–	–

Table A.5: Test results for condition F2-2 for SEL-421

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time [s]
AG	0	0	0	Y	3	1.0206
AG	0	45	0	Y	3	1.0194
AG	0	90	0	Y	3	1.0214
AG	50	0	0	Y	3	1.0221
AG	50	45	0	Y	3	1.0201
AG	50	90	0	Y	3	1.0246
AG	90	0	0	N	–	–
AG	90	45	0	N	–	–
AG	90	90	0	N	–	–
BC	0	0	0	Y	2	0.3642
BC	0	45	0	Y	2	0.3644
BC	0	90	0	Y	2	0.3631
BC	50	0	0	Y	3	1.0320
BC	50	45	0	Y	3	1.0333
BC	50	90	0	Y	3	1.0312
BC	90	0	0	Y	3	1.0339
BC	90	45	0	Y	3	1.0351
BC	90	90	0	Y	3	1.0322
BCG	0	0	0	Y	2	0.3660
BCG	0	45	0	Y	2	0.3633
BCG	0	90	0	Y	2	0.3746
BCG	50	0	0	Y	3	1.0399
BCG	50	45	0	Y	3	1.0397
BCG	50	90	0	Y	3	1.0394
BCG	90	0	0	Y	3	1.0431
BCG	90	45	0	Y	3	1.0453
BCG	90	90	0	Y	3	1.0421
ABC	0	0	0	Y	3	1.0219
ABC	0	45	0	Y	3	1.0249
ABC	0	90	0	Y	3	1.0200
ABC	50	0	0	Y	3	1.0239
ABC	50	45	0	Y	3	1.0279
ABC	50	90	0	Y	3	1.0198
ABC	90	0	0	Y	3	1.0317
ABC	90	45	0	Y	3	1.0337
ABC	90	90	0	Y	3	1.0249

Table A.6: Test results for condition F3 for SEL-421

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time [s]
AG	0	0	0	Y	1	0.0231
AG	0	45	0	Y	1	0.0210
AG	0	90	0	Y	1	0.0229
AG	50	0	0	Y	1	0.0236
AG	50	0	5	Y	1	0.0247
AG	50	45	0	Y	1	0.0222
AG	50	45	5	Y	1	0.0237
AG	50	90	0	Y	1	0.0236
AG	50	90	5	Y	1	0.0253
AG	90	0	0	Y	1	0.3614
AG	90	45	0	Y	1	0.3590
AG	90	90	0	Y	1	0.3602
BC	0	0	0	Y	1	0.0162
BC	0	45	0	Y	1	0.0168
BC	0	90	0	Y	1	0.0204
BC	50	0	0	Y	1	0.0226
BC	50	45	0	Y	1	0.0244
BC	50	90	0	Y	1	0.0227
BC	90	0	0	Y	2	0.3605
BC	90	45	0	Y	2	0.3607
BC	90	90	0	Y	2	0.3608
BCG	0	0	0	Y	1	0.0174
BCG	0	45	0	Y	1	0.0166
BCG	0	90	0	Y	1	0.0191
BCG	50	0	0	Y	1	0.0240
BCG	50	0	5	Y	1	0.0229
BCG	50	45	0	Y	1	0.0241
BCG	50	45	5	Y	1	0.0244
BCG	50	90	0	Y	1	0.0226
BCG	50	90	5	Y	1	0.0235
BCG	90	0	0	Y	2	0.3592
BCG	90	45	0	Y	2	0.3604
BCG	90	90	0	Y	2	0.3600
ABC	0	0	0	Y	1	0.0159
ABC	0	45	0	Y	1	0.0161
ABC	0	90	0	Y	1	0.0180
ABC	50	0	0	Y	1	0.0208
ABC	50	45	0	Y	1	0.0227
ABC	50	90	0	Y	1	0.0221
ABC	90	0	0	Y	2	0.3615
ABC	90	45	0	Y	2	0.3654
ABC	90	90	0	Y	2	0.3645

Table A.7: Test results for condition F4-1 for SEL-421

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Unit	Trip Time [s]
AG	0	0	0	Y	SOTF	0.0159
AG	0	0	25	Y	SOTF	0.0211
AG	0	45	0	Y	SOTF	0.0141
AG	0	45	25	Y	SOTF	0.0181
AG	0	90	0	Y	SOTF	0.0153
AG	0	90	25	Y	SOTF	0.0182
AG	50	0	0	Y	SOTF	0.0208
AG	50	0	25	Y	SOTF	0.0217
AG	50	45	0	Y	SOTF	0.0187
AG	50	45	25	Y	SOTF	0.0212
AG	50	90	0	Y	SOTF	0.0207
AG	50	90	25	Y	SOTF	0.0205
AG	90	0	0	Y	SOTF	0.0255
AG	90	0	25	Y	SOTF	0.0252
AG	90	45	0	Y	SOTF	0.0249
AG	90	45	25	Y	SOTF	0.0239
AG	90	90	0	Y	SOTF	0.0227
AG	90	90	25	Y	SOTF	0.0264
BC	0	0	0	Y	SOTF	0.0144
BC	0	45	0	Y	SOTF	0.0185
BC	0	90	0	Y	SOTF	0.0165
BC	50	0	0	Y	SOTF	0.0154
BC	50	45	0	Y	SOTF	0.0175
BC	50	90	0	Y	SOTF	0.0177
BC	90	0	0	Y	SOTF	0.0191
BC	90	45	0	Y	SOTF	0.0210
BC	90	90	0	Y	SOTF	0.0202
BCG	0	0	0	Y	SOTF	0.0151
BCG	0	0	25	Y	SOTF	0.0142
BCG	0	45	0	Y	SOTF	0.0145
BCG	0	45	25	Y	SOTF	0.0138
BCG	0	90	0	Y	SOTF	0.0144
BCG	0	90	25	Y	SOTF	0.0163
BCG	50	0	0	Y	SOTF	0.0162
BCG	50	0	25	Y	SOTF	0.0185
BCG	50	45	0	Y	SOTF	0.0189
BCG	50	45	25	Y	SOTF	0.0182
BCG	50	90	0	Y	SOTF	0.0201
BCG	50	90	25	Y	SOTF	0.0215
BCG	90	0	0	Y	SOTF	0.0194
BCG	90	0	25	Y	SOTF	0.0187
BCG	90	45	0	Y	SOTF	0.0215
BCG	90	45	25	Y	SOTF	0.0206
BCG	90	90	0	Y	SOTF	0.0209
BCG	90	90	25	Y	SOTF	0.0205
ABC	0	0	0	Y	SOTF	0.0148
ABC	0	45	0	Y	SOTF	0.0150

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Unit	Trip Time [s]
ABC	0	90	0	Y	SOTF	0.0156
ABC	50	0	0	Y	SOTF	0.0160
ABC	50	45	0	Y	SOTF	0.0142
ABC	50	90	0	Y	SOTF	0.0157
ABC	90	0	0	Y	SOTF	0.0183
ABC	90	45	0	Y	SOTF	0.0190
ABC	90	90	0	Y	SOTF	0.0189

Table A.8: Test results for condition F4-2 for SEL-421

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Unit	Trip Time [s]
AG	0	0	0	Y	SOTF	0.0150
AG	0	0	25	Y	SOTF	0.0242
AG	0	45	0	Y	SOTF	0.0155
AG	0	45	25	Y	SOTF	0.0192
AG	0	90	0	Y	SOTF	0.0151
AG	0	90	25	Y	SOTF	0.0146
AG	50	0	0	Y	SOTF	0.0252
AG	50	0	25	Y	SOTF	0.0298
AG	50	45	0	Y	SOTF	0.0249
AG	50	45	25	Y	SOTF	0.0284
AG	50	90	0	Y	SOTF	0.0198
AG	50	90	25	Y	SOTF	0.0223
AG	90	0	0	Y	SOTF	0.0282
AG	90	0	25	Y	SOTF	0.0316
AG	90	45	0	Y	SOTF	0.0296
AG	90	45	25	Y	SOTF	0.0304
AG	90	90	0	Y	SOTF	0.0243
AG	90	90	25	Y	SOTF	0.0240
BC	0	0	0	Y	SOTF	0.0141
BC	0	45	0	Y	SOTF	0.0183
BC	0	90	0	Y	SOTF	0.0190
BC	50	0	0	Y	SOTF	0.0188
BC	50	45	0	Y	SOTF	0.0178
BC	50	90	0	Y	SOTF	0.0216
BC	90	0	0	Y	SOTF	0.0181
BC	90	45	0	Y	SOTF	0.0171
BC	90	90	0	Y	SOTF	0.0218
BCG	0	0	0	Y	SOTF	0.0150
BCG	0	0	25	Y	SOTF	0.0154
BCG	0	45	0	Y	SOTF	0.0146
BCG	0	45	25	Y	SOTF	0.0189
BCG	0	90	0	Y	SOTF	0.0144
BCG	0	90	25	Y	SOTF	0.0174
BCG	50	0	0	Y	SOTF	0.0191
BCG	50	0	25	Y	SOTF	0.0194
BCG	50	45	0	Y	SOTF	0.0188
BCG	50	45	25	Y	SOTF	0.0185
BCG	50	90	0	Y	SOTF	0.0219

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Unit	Trip Time [s]
BCG	50	90	25	Y	SOTF	0.0222
BCG	90	0	0	Y	SOTF	0.0193
BCG	90	0	25	Y	SOTF	0.0177
BCG	90	45	0	Y	SOTF	0.0201
BCG	90	45	25	Y	SOTF	0.0185
BCG	90	90	0	Y	SOTF	0.0221
BCG	90	90	25	Y	SOTF	0.0219
ABC	0	0	0	Y	SOTF	0.0148
ABC	0	45	0	Y	SOTF	0.0162
ABC	0	90	0	Y	SOTF	0.0150
ABC	50	0	0	Y	SOTF	0.0228
ABC	50	45	0	Y	SOTF	0.0331
ABC	50	90	0	Y	SOTF	0.0327
ABC	90	0	0	Y	SOTF	0.0322
ABC	90	45	0	Y	SOTF	0.0331
ABC	90	90	0	Y	SOTF	0.0333

Table A.9: Test results for condition F5 for SEL-421

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time [s]
AG	0	0	0	Y	1	0.0149
AG	0	45	0	Y	1	0.0150
AG	0	90	0	Y	1	0.0146
AG	50	0	0	Y	1	0.0204
AG	50	45	0	Y	1	0.0213
AG	50	90	0	Y	1	0.0242
AG	90	0	0	Y	2	0.3608
AG	90	45	0	Y	2	0.3562
AG	90	90	0	Y	2	0.3514
BC	0	0	0	Y	1	0.0195
BC	0	45	0	Y	1	0.0209
BC	0	90	0	Y	1	0.0203
BC	50	0	0	Y	1	0.0247
BC	50	45	0	Y	1	0.0255
BC	50	90	0	Y	1	0.0250
BC	90	0	0	Y	2	0.3535
BC	90	45	0	Y	2	0.3415
BC	90	90	0	Y	2	0.3341
BCG	0	0	0	Y	1	0.0167
BCG	0	45	0	Y	1	0.0203
BCG	0	90	0	Y	1	0.0201
BCG	50	0	0	Y	1	0.0255
BCG	50	45	0	Y	1	0.0256
BCG	50	90	0	Y	1	0.0234
BCG	90	0	0	Y	2	0.3502
BCG	90	45	0	Y	2	0.3528
BCG	90	90	0	Y	2	0.3564
ABC	0	0	0	Y	1	0.0174
ABC	0	45	0	Y	1	0.0182
ABC	0	90	0	Y	1	0.0166
ABC	50	0	0	Y	1	0.0255
ABC	50	45	0	Y	1	0.0333
ABC	50	90	0	Y	1	0.0310
ABC	90	0	0	Y	2	0.3671
ABC	90	45	0	Y	2	0.3663
ABC	90	90	0	Y	2	0.3659

Table A.10: Test results for condition F6-1 for SEL-421

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time [s]
AG	50	0	0	Y	1	0.0202
AG	50	45	0	Y	1	0.0206
AG	50	90	0	Y	1	0.0234
AG	90	0	0	Y	2	0.3531
AG	90	45	0	Y	2	0.3546
AG	90	90	0	Y	2	0.3547
BC	50	0	0	Y	1	0.0248
BC	50	45	0	Y	1	0.0237
BC	50	90	0	Y	1	0.0217
BC	90	0	0	Y	2	0.3561
BC	90	45	0	Y	2	0.3553
BC	90	90	0	Y	2	0.3543
BCG	50	0	0	Y	1	0.0252
BCG	50	45	0	Y	1	0.0249
BCG	50	90	0	Y	1	0.0227
BCG	90	0	0	Y	2	0.3596
BCG	90	45	0	Y	2	0.3587
BCG	90	90	0	Y	2	0.3586
ABC	50	0	0	Y	1	0.0216
ABC	50	45	0	Y	1	0.0229
ABC	50	90	0	Y	1	0.0219
ABC	90	0	0	Y	2	0.3595
ABC	90	45	0	Y	2	0.3597
ABC	90	90	0	Y	2	0.3527

Table A.11: Test results for condition F6-2 for SEL-421

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time [s]
AG	50	0	0	Y	1	0.0203
AG	50	45	0	Y	1	0.0206
AG	50	90	0	Y	1	0.0221
AG	90	0	0	Y	2	0.3558
AG	90	45	0	Y	2	0.3567
AG	90	90	0	Y	2	0.3606
BC	50	0	0	Y	1	0.0239
BC	50	45	0	Y	1	0.0244
BC	50	90	0	Y	1	0.0240
BC	90	0	0	Y	2	0.3588
BC	90	45	0	Y	2	0.3602
BC	90	90	0	Y	2	0.3586
BCG	50	0	0	Y	1	0.0229
BCG	50	45	0	Y	1	0.0253
BCG	50	90	0	Y	1	0.0238
BCG	90	0	0	Y	2	0.3626
BCG	90	45	0	Y	2	0.3647
BCG	90	90	0	Y	2	0.3632
ABC	50	0	0	Y	1	0.0218
ABC	50	45	0	Y	1	0.0233
ABC	50	90	0	Y	1	0.0224
ABC	90	0	0	Y	2	0.3637
ABC	90	45	0	Y	2	0.3651
ABC	90	90	0	Y	2	0.3645

Table A.12: “Statistical” test results for internal faults for SEL-421

Type	Loc [%]	α [deg]	Rf [Ω]	Trip Zone	No. T	Mean T [ms]	Max T [ms]	Min T [ms]	Devtn [ms]
AG	50	0	5	I	30	22.57	24.30	20.60	0.85
AG	70	45	0	I	30	28.32	30.90	27.40	0.82
AG	90	90	0	II	30	318.20	357.10	313.40	7.87
BC	50	0	5	I	30	24.71	26.40	22.50	0.79
BC	70	45	0	I	30	28.64	30.30	26.80	0.83
BC	90	90	0	II	30	356.23	357.10	355.10	0.59
BCG	50	0	25	I	30	18.73	20.10	17.90	0.58
BCG	70	45	10	I	30	29.72	31.20	28.10	0.65
BCG	90	90	0	II	30	365.47	370.30	360.00	1.12
ABC	50	0	0	I	30	20.88	21.90	20.00	0.61
ABC	70	45	0	I	30	31.25	33.40	29.30	0.97
ABC	90	90	0	II	30	359.65	361.30	357.20	1.41

Table A.13: Test results for no-fault scenarios for SEL-421

Type	Operation	Trip / NoTrip	Trip Zone	Trip Time [s]
N1-1	Three phases close after 2 cycles	N	—	—
N1-1	Phase A close after 2 cycles	N	—	—
N1-1	Phase B, C close after 2 cycles	N	—	—
N1-2	Three phases close after 2 cycles	N	—	—
N1-2	Phase A close after 2 cycles	N	—	—
N1-2	Phase B, C close after 2 cycles	N	—	—
N2	Remove S1 after 2 cycles	N	—	—
N2	Remove S2 after 2 cycles	N	—	—
N2	Remove S3 after 2 cycles	N	—	—
N2	Remove S2, S3 after 2 cycles	N	—	—
N2	Remove S1, S2, S3 simultaneously after 2 cycles	N	—	—
N2	Remove S1, then S2 after 2 cycles, then S3 after 2 cycles	N	—	—
N3	Open Bus 2 breaker after 2 cycles	N	—	—
N3	Open Bus 4 breaker after 2 cycles	N	—	—
N3	Open SW after 2 cycles	N	—	—
N4	Restore S1 after 2 cycles	N	—	—
N4	Restore S1 after 2 cycles	N	—	—
N4	Restore S1 after 2 cycles	N	—	—
N4	Restore S2, S3 after 2 cycles	N	—	—
N4	Restore S1, S2, S3 simultaneously after 2 cycles	N	—	—
N4	Restore S1, then S2 after 2 cycles, then S3 after 2 cycles	N	—	—
N5	Power swing after three-fault occurred on Line1	N	—	—
N6	Secondary Impedance: 31.88	N	—	—
N6	Secondary Impedance: 22.34	N	—	—
N6	Secondary Impedance: 13.74	N	—	—
N6	Secondary Impedance: 7.90	N	—	—

Table A.14: Compliance test result for SEL-421

Type	Loc [%]	Fault Type	Load Condition	Trip / no trip on Fault	CCT[s]	Trip / no trip on Power Swing or Out of Step
A1	10	Single 3-phase	Base	Y	0.346	N
	50			Y	0.550	N
	90			Y	0.716	N
A2	10	Single 3-phase	Over	Y	0.346	N
	50			Y	0.550	N
	90			Y	0.716	N
A3	10	Two 3-phase	Base	Y	0.346	N
	50			Y	0.550	N
	90			Y	0.716	N
A4	10	Two 3-phase	Over	Y	0.346	N
	50			Y	0.550	N
	90			Y	0.716	N
A5	10	Single 3-phase	Base	Y	0.716	Y
	50			Y	1.016	Y
	90			Y	1.432	Y
A6	10	Single 3-phase	Over	Y	0.716	Y
	50			Y	1.016	Y
	90			Y	1.432	Y
A7	10	Two 3-phase	Base	Y	0.716	Y
	50			Y	1.016	Y
	90			Y	1.432	Y
A8	10	Two 3-phase	Over	Y	0.716	Y
	50			Y	1.016	Y
	90			Y	1.432	Y

Table A.15: Test results for condition F1 for SEL-321

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time[s]
AG	0	0	0	Y	1	0.0164
AG	0	45	0	Y	1	0.0147
AG	0	90	0	Y	1	0.0170
AG	50	0	0	Y	1	0.0211
AG	50	0	5	Y	1	0.0216
AG	50	45	0	Y	1	0.0209
AG	50	45	5	Y	1	0.0228
AG	50	90	0	Y	1	0.0238
AG	50	90	5	Y	1	0.0230
AG	70	0	0	Y	1	0.0297
AG	70	0	5	Y	2	0.3622
AG	70	0	10	N	–	–
AG	70	45	0	Y	1	0.0308
AG	70	45	5	Y	2	0.3575
AG	70	45	10	N	–	–
AG	70	90	0	Y	1	0.0298
AG	70	90	5	Y	2	0.3605
AG	70	90	10	N	–	–
AG	90	0	0	Y	2	0.3544
AG	90	45	0	Y	2	0.3566
AG	90	90	0	Y	2	0.3575
BC	0	0	0	Y	1	0.0136
BC	0	0	5	Y	1	0.0132
BC	0	0	25	Y	1	0.0213
BC	0	45	0	Y	1	0.0147
BC	0	45	5	Y	1	0.0167
BC	0	45	25	Y	1	0.0201
BC	0	90	0	Y	1	0.0145
BC	0	90	5	Y	1	0.0169
BC	0	90	25	Y	1	0.0212
BC	50	0	0	Y	1	0.0213
BC	50	0	5	Y	1	0.0239
BC	50	45	0	Y	1	0.0218
BC	50	45	5	Y	1	0.0235
BC	50	90	0	Y	1	0.0198
BC	50	90	5	Y	1	0.0225
BC	70	0	0	Y	1	0.0257
BC	70	0	5	Y	1	0.0273
BC	70	45	0	Y	1	0.0258
BC	70	45	5	Y	1	0.0288
BC	70	90	0	Y	1	0.0244
BC	70	90	5	Y	1	0.0262
BC	90	0	0	Y	2	0.3543
BC	90	0	5	Y	2	0.3631
BC	90	45	0	Y	2	0.3545
BC	90	45	5	Y	2	0.3627
BC	90	90	0	Y	2	0.3539

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time[s]
BC	90	90	5	Y	2	0.3607
BCG	0	0	0	Y	1	0.0233
BCG	0	0	25	Y	1	0.0219
BCG	0	45	0	Y	1	0.0149
BCG	0	45	25	Y	1	0.0231
BCG	0	90	0	Y	1	0.0181
BCG	0	90	25	Y	1	0.0251
BCG	50	0	0	Y	1	0.0230
BCG	50	0	25	Y	1	0.0303
BCG	50	45	0	Y	1	0.0217
BCG	50	45	25	Y	1	0.0317
BCG	50	90	0	Y	1	0.0213
BCG	50	90	25	Y	1	0.0285
BCG	70	0	0	Y	1	0.0248
BCG	70	0	10	Y	1	0.0332
BCG	70	45	0	Y	1	0.0255
BCG	70	45	10	Y	1	0.0265
BCG	70	90	0	Y	1	0.0244
BCG	70	90	10	Y	1	0.0254
BCG	90	0	0	Y	2	0.3559
BCG	90	0	25	Y	2	0.3530
BCG	90	45	0	Y	2	0.3543
BCG	90	45	25	Y	2	0.3532
BCG	90	90	0	Y	2	0.3565
BCG	90	90	25	Y	2	0.3536
ABC	0	0	0	Y	1	0.0137
ABC	0	45	0	Y	1	0.0133
ABC	0	90	0	Y	1	0.0134
ABC	50	0	0	Y	1	0.0192
ABC	50	45	0	Y	1	0.0214
ABC	50	90	0	Y	1	0.0200
ABC	70	0	0	Y	1	0.0248
ABC	70	45	0	Y	1	0.0275
ABC	70	90	0	Y	1	0.0262
ABC	90	0	0	Y	2	0.3536
ABC	90	45	0	Y	2	0.3541
ABC	90	90	0	Y	2	0.3545

Table A.16: Test results for condition F2-1 for SEL-321

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time [s]
AG	10	0	0	N	—	—
AG	10	0	10	N	—	—
AG	10	45	0	N	—	—
AG	10	45	10	N	—	—
AG	10	90	0	N	—	—
AG	10	90	10	N	—	—
AG	50	0	0	N	—	—
AG	50	0	25	N	—	—
AG	50	45	0	N	—	—
AG	50	45	25	N	—	—
AG	50	90	0	N	—	—
AG	50	90	25	N	—	—
AG	90	0	0	N	—	—
AG	90	0	25	N	—	—
AG	90	45	0	N	—	—
AG	90	45	25	N	—	—
AG	90	90	0	N	—	—
AG	90	90	25	N	—	—
BC	10	0	0	N	—	—
BC	10	45	0	N	—	—
BC	10	90	0	N	—	—
BC	50	0	0	N	—	—
BC	50	45	0	N	—	—
BC	50	90	0	N	—	—
BC	90	0	0	N	—	—
BC	90	45	0	N	—	—
BC	90	90	0	N	—	—
BCG	10	0	0	N	—	—
BCG	10	0	10	N	—	—
BCG	10	45	0	N	—	—
BCG	10	45	10	N	—	—
BCG	10	90	0	N	—	—
BCG	10	90	10	N	—	—
BCG	50	0	0	N	—	—
BCG	50	0	25	N	—	—
BCG	50	45	0	N	—	—
BCG	50	45	25	N	—	—
BCG	50	90	0	N	—	—
BCG	50	90	25	N	—	—
BCG	90	0	0	N	—	—
BCG	90	0	25	N	—	—
BCG	90	45	0	N	—	—
BCG	90	45	25	N	—	—
BCG	90	90	0	N	—	—
BCG	90	90	25	N	—	—
ABC	10	0	0	N	—	—
ABC	10	45	0	N	—	—

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time [s]
ABC	10	90	0	N	–	–
ABC	50	0	0	N	–	–
ABC	50	45	0	N	–	–
ABC	50	90	0	N	–	–
ABC	90	0	0	N	–	–
ABC	90	45	0	N	–	–
ABC	90	90	0	N	–	–

Table A.17: Test results for condition F2-2 for SEL-321

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time [s]
AG	0	0	0	Y	3	1.0200
AG	0	45	0	Y	3	1.0177
AG	0	90	0	Y	3	1.0169
AG	50	0	0	Y	3	1.0219
AG	50	45	0	Y	3	1.0196
AG	50	90	0	Y	3	1.0210
AG	90	0	0	N	–	–
AG	90	45	0	N	–	–
AG	90	90	0	N	–	–
BC	0	0	0	Y	2	0.3613
BC	0	45	0	Y	2	0.3618
BC	0	90	0	Y	2	0.3596
BC	50	0	0	Y	3	1.0219
BC	50	45	0	Y	3	1.0221
BC	50	90	0	Y	3	1.0199
BC	90	0	0	Y	3	1.0246
BC	90	45	0	Y	3	1.0256
BC	90	90	0	Y	3	1.0243
BCG	0	0	0	Y	2	0.3629
BCG	0	45	0	Y	2	0.3610
BCG	0	90	0	Y	2	0.3773
BCG	50	0	0	Y	3	1.0222
BCG	50	45	0	Y	3	1.0224
BCG	50	90	0	Y	3	1.0195
BCG	90	0	0	Y	3	1.0246
BCG	90	45	0	Y	3	1.0265
BCG	90	90	0	Y	3	1.0251
ABC	0	0	0	Y	2	0.4062
ABC	0	45	0	Y	2	0.4032
ABC	0	90	0	Y	2	0.4182
ABC	50	0	0	Y	3	1.0186
ABC	50	45	0	Y	3	1.0208
ABC	50	90	0	Y	3	1.0188
ABC	90	0	0	Y	3	1.0258
ABC	90	45	0	Y	3	1.0262
ABC	90	90	0	Y	3	1.0247

Table A.18: Test results for condition F3 for SEL-321

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time [s]
AG	0	0	0	Y	1	0.0322
AG	0	45	0	Y	1	0.0341
AG	0	90	0	Y	1	0.0328
AG	50	0	0	Y	1	0.0342
AG	50	0	5	Y	1	0.0339
AG	50	45	0	Y	1	0.0316
AG	50	45	5	Y	1	0.0349
AG	50	90	0	Y	1	0.0332
AG	50	90	5	Y	1	0.0339
AG	90	0	0	Y	2	0.3679
AG	90	45	0	Y	2	0.3685
AG	90	90	0	Y	2	0.3668
BC	0	0	0	Y	1	0.0152
BC	0	45	0	Y	1	0.0156
BC	0	90	0	Y	1	0.0175
BC	50	0	0	Y	1	0.0205
BC	50	45	0	Y	1	0.0212
BC	50	90	0	Y	1	0.0219
BC	90	0	0	Y	2	0.3570
BC	90	45	0	Y	2	0.3598
BC	90	90	0	Y	2	0.3585
BCG	0	0	0	Y	1	0.0249
BCG	0	45	0	Y	1	0.0227
BCG	0	90	0	Y	1	0.0182
BCG	50	0	0	Y	1	0.0212
BCG	50	0	5	Y	1	0.0263
BCG	50	45	0	Y	1	0.0231
BCG	50	45	5	Y	1	0.0221
BCG	50	90	0	Y	1	0.0215
BCG	50	90	5	Y	1	0.0221
BCG	90	0	0	Y	2	0.3583
BCG	90	45	0	Y	2	0.3589
BCG	90	90	0	Y	2	0.3592
ABC	0	0	0	Y	1	0.0150
ABC	0	45	0	Y	1	0.0142
ABC	0	90	0	Y	1	0.0144
ABC	50	0	0	Y	1	0.0195
ABC	50	45	0	Y	1	0.0206
ABC	50	90	0	Y	1	0.0211
ABC	90	0	0	Y	2	0.3589
ABC	90	45	0	Y	2	0.3588
ABC	90	90	0	Y	2	0.3593

Table A.19: Test results for condition F4-1 for SEL-321

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Unit	Trip Time [s]
AG	0	0	0	Y	SOTF	0.0087
AG	0	0	25	Y	SOTF	0.0084
AG	0	45	0	Y	SOTF	0.0073
AG	0	45	25	Y	SOTF	0.0072
AG	0	90	0	Y	SOTF	0.0069
AG	0	90	25	Y	SOTF	0.0070
AG	50	0	0	Y	SOTF	0.0108
AG	50	0	25	Y	SOTF	0.0161
AG	50	45	0	Y	SOTF	0.0089
AG	50	45	25	Y	SOTF	0.0151
AG	50	90	0	Y	SOTF	0.0107
AG	50	90	25	Y	SOTF	0.0138
AG	90	0	0	Y	SOTF	0.0168
AG	90	0	25	Y	SOTF	0.0248
AG	90	45	0	Y	SOTF	0.0161
AG	90	45	25	Y	SOTF	0.0220
AG	90	90	0	Y	SOTF	0.0164
AG	90	90	25	Y	SOTF	0.0227
BC	0	0	0	Y	SOTF	0.0071
BC	0	45	0	Y	SOTF	0.0124
BC	0	90	0	Y	SOTF	0.0092
BC	50	0	0	Y	SOTF	0.0098
BC	50	45	0	Y	SOTF	0.0138
BC	50	90	0	Y	SOTF	0.0100
BC	90	0	0	Y	SOTF	0.0139
BC	90	45	0	Y	SOTF	0.0134
BC	90	90	0	Y	SOTF	0.0130
BCG	0	0	0	Y	SOTF	0.0066
BCG	0	0	25	Y	SOTF	0.0069
BCG	0	45	0	Y	SOTF	0.0071
BCG	0	45	25	Y	SOTF	0.0080
BCG	0	90	0	Y	SOTF	0.0078
BCG	0	90	25	Y	SOTF	0.0076
BCG	50	0	0	Y	SOTF	0.0087
BCG	50	0	25	Y	SOTF	0.077
BCG	50	45	0	Y	SOTF	0.0116
BCG	50	45	25	Y	SOTF	0.0133
BCG	50	90	0	Y	SOTF	0.0105
BCG	50	90	25	Y	SOTF	0.0096
BCG	90	0	0	Y	SOTF	0.0139
BCG	90	0	25	Y	SOTF	0.0148
BCG	90	45	0	Y	SOTF	0.0129
BCG	90	45	25	Y	SOTF	0.0143
BCG	90	90	0	Y	SOTF	0.0110
BCG	90	90	25	Y	SOTF	0.0128
ABC	0	0	0	Y	SOTF	0.0068
ABC	0	45	0	Y	SOTF	0.0079

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Unit	Trip Time [s]
ABC	0	90	0	Y	SOTF	0.0077
ABC	50	0	0	Y	SOTF	0.0090
ABC	50	45	0	Y	SOTF	0.0093
ABC	50	90	0	Y	SOTF	0.0082
ABC	90	0	0	Y	SOTF	0.0104
ABC	90	45	0	Y	SOTF	0.0124
ABC	90	90	0	Y	SOTF	0.0109

Table A.20: Test results for condition F4-2 for SEL-321

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Unit	Trip Time [s]
AG	0	0	0	Y	SOTF	0.0082
AG	0	0	25	Y	SOTF	0.0079
AG	0	45	0	Y	SOTF	0.0077
AG	0	45	25	Y	SOTF	0.0076
AG	0	90	0	Y	SOTF	0.0080
AG	0	90	25	Y	SOTF	0.0078
AG	50	0	0	Y	SOTF	0.0112
AG	50	0	25	Y	SOTF	0.0164
AG	50	45	0	Y	SOTF	0.0085
AG	50	45	25	Y	SOTF	0.0159
AG	50	90	0	Y	SOTF	0.0102
AG	50	90	25	Y	SOTF	0.0133
AG	90	0	0	Y	SOTF	0.0176
AG	90	0	25	Y	SOTF	0.0256
AG	90	45	0	Y	SOTF	0.0171
AG	90	45	25	Y	SOTF	0.0233
AG	90	90	0	Y	SOTF	0.0163
AG	90	90	25	Y	SOTF	0.0230
BC	0	0	0	Y	SOTF	0.0080
BC	0	45	0	Y	SOTF	0.0113
BC	0	90	0	Y	SOTF	0.0079
BC	50	0	0	Y	SOTF	0.0078
BC	50	45	0	Y	SOTF	0.0125
BC	50	90	0	Y	SOTF	0.0109
BC	90	0	0	Y	SOTF	0.0144
BC	90	45	0	Y	SOTF	0.0130
BC	90	90	0	Y	SOTF	0.0112
BCG	0	0	0	Y	SOTF	0.0072
BCG	0	0	25	Y	SOTF	0.0061
BCG	0	45	0	Y	SOTF	0.0069
BCG	0	45	25	Y	SOTF	0.0073
BCG	0	90	0	Y	SOTF	0.0068
BCG	0	90	25	Y	SOTF	0.0075
BCG	50	0	0	Y	SOTF	0.0081
BCG	50	0	25	Y	SOTF	0.0098
BCG	50	45	0	Y	SOTF	0.0123
BCG	50	45	25	Y	SOTF	0.0145
BCG	50	90	0	Y	SOTF	0.0103

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Unit	Trip Time [s]
BCG	50	90	25	Y	SOTF	0.0102
BCG	90	0	0	Y	SOTF	0.0143
BCG	90	0	25	Y	SOTF	0.0150
BCG	90	45	0	Y	SOTF	0.0132
BCG	90	45	25	Y	SOTF	0.0147
BCG	90	90	0	Y	SOTF	0.0117
BCG	90	90	25	Y	SOTF	0.0136
ABC	0	0	0	Y	SOTF	0.0073
ABC	0	45	0	Y	SOTF	0.0076
ABC	0	90	0	Y	SOTF	0.0080
ABC	50	0	0	Y	SOTF	0.0074
ABC	50	45	0	Y	SOTF	0.0084
ABC	50	90	0	Y	SOTF	0.0088
ABC	90	0	0	Y	SOTF	0.0107
ABC	90	45	0	Y	SOTF	0.0101
ABC	90	90	0	Y	SOTF	0.0111

Table A.21: Test results for condition F5 for SEL-321

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time [s]
AG	0	0	0	Y	1	0.0151
AG	0	45	0	Y	1	0.0169
AG	0	90	0	Y	1	0.0172
AG	50	0	0	Y	1	0.0204
AG	50	45	0	Y	1	0.0225
AG	50	90	0	Y	1	0.0248
AG	90	0	0	Y	2	0.3625
AG	90	45	0	Y	2	0.3603
AG	90	90	0	Y	2	0.3598
BC	0	0	0	Y	1	0.0159
BC	0	45	0	Y	1	0.0192
BC	0	90	0	Y	1	0.0164
BC	50	0	0	Y	1	0.0231
BC	50	45	0	Y	1	0.0229
BC	50	90	0	Y	1	0.0238
BC	90	0	0	Y	2	0.3662
BC	90	45	0	Y	2	0.3553
BC	90	90	0	Y	2	0.3612
BCG	0	0	0	Y	1	0.0148
BCG	0	45	0	Y	1	0.0186
BCG	0	90	0	Y	1	0.0178
BCG	50	0	0	Y	1	0.0232
BCG	50	45	0	Y	1	0.0226
BCG	50	90	0	Y	1	0.0242
BCG	90	0	0	Y	2	0.3582
BCG	90	45	0	Y	2	0.3608
BCG	90	90	0	Y	2	0.3564
ABC	0	0	0	Y	1	0.0144
ABC	0	45	0	Y	1	0.0149
ABC	0	90	0	Y	1	0.0157
ABC	50	0	0	Y	1	0.0211
ABC	50	45	0	Y	1	0.0225
ABC	50	90	0	Y	1	0.0229
ABC	90	0	0	Y	2	0.3577
ABC	90	45	0	Y	2	0.3600
ABC	90	90	0	Y	2	0.3595

Table A.22: Test results for condition F6-1 for SEL-321

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time [s]
AG	50	0	0	Y	1	0.0223
AG	50	45	0	Y	1	0.0207
AG	50	90	0	Y	1	0.0250
AG	90	0	0	Y	2	0.3567
AG	90	45	0	Y	2	0.3543
AG	90	90	0	Y	2	0.3551
BC	50	0	0	Y	1	0.0221
BC	50	45	0	Y	1	0.0213
BC	50	90	0	Y	1	0.0211
BC	90	0	0	Y	2	0.3556
BC	90	45	0	Y	2	0.3565
BC	90	90	0	Y	2	0.3549
BCG	50	0	0	Y	1	0.0213
BCG	50	45	0	Y	1	0.0225
BCG	50	90	0	Y	1	0.0203
BCG	90	0	0	Y	2	0.3548
BCG	90	45	0	Y	2	0.3554
BCG	90	90	0	Y	2	0.3537
ABC	50	0	0	Y	1	0.0206
ABC	50	45	0	Y	1	0.0208
ABC	50	90	0	Y	1	0.0204
ABC	90	0	0	Y	2	0.3548
ABC	90	45	0	Y	2	0.3570
ABC	90	90	0	Y	2	0.3555

Table A.23: Test results for condition F6-2 for SEL-321

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time [s]
AG	50	0	0	Y	1	0.0241
AG	50	45	0	Y	1	0.0212
AG	50	90	0	Y	1	0.0238
AG	90	0	0	Y	2	0.3588
AG	90	45	0	Y	2	0.3572
AG	90	90	0	Y	2	0.3575
BC	50	0	0	Y	1	0.0211
BC	50	45	0	Y	1	0.0209
BC	50	90	0	Y	1	0.0201
BC	90	0	0	Y	2	0.3581
BC	90	45	0	Y	2	0.3610
BC	90	90	0	Y	2	0.3597
BCG	50	0	0	Y	1	0.0219
BCG	50	45	0	Y	1	0.0215
BCG	50	90	0	Y	1	0.0213
BCG	90	0	0	Y	2	0.3578
BCG	90	45	0	Y	2	0.3606
BCG	90	90	0	Y	2	0.3594
ABC	50	0	0	Y	1	0.0189
ABC	50	45	0	Y	1	0.0217
ABC	50	90	0	Y	1	0.0209
ABC	90	0	0	Y	2	0.3578
ABC	90	45	0	Y	2	0.3595
ABC	90	90	0	Y	2	0.3583

Table A.24: “Statistical” test results of internal faults for SEL-321

Type	Loc [%]	α [deg]	Rf [Ω]	Trip Zone	No. T	Mean T [ms]	Max T [ms]	Min T [ms]	Devtn [ms]
AG	50	0	5	I	30	21.95	25.60	21.80	0.65
AG	70	45	0	I	30	30.12	33.60	29.70	0.66
AG	90	90	0	II	30	358.45	360.30	351.40	1.34
BC	50	0	5	I	30	24.66	26.90	22.70	0.72
BC	70	45	0	I	30	25.64	29.30	24.10	0.59
BC	90	90	0	II	30	358.42	360.70	352.20	1.51
BCG	50	0	25	I	30	28.24	30.50	26.90	0.59
BCG	70	45	10	I	30	25.86	27.90	24.00	0.45
BCG	90	90	0	II	30	359.08	362.70	355.20	1.27
ABC	50	0	0	I	30	20.05	21.30	19.20	0.46
ABC	70	45	0	I	30	26.85	28.40	26.10	0.58
ABC	90	90	0	II	30	355.71	358.10	353.5	1.03

Table A.25: Test results of no-fault scenarios for SEL-321

Type	Operation	Trip / No Trip	Trip Zone	Trip Time [s]
N1-1	Three phases close after 2 cycles	N	—	—
N1-1	Phase A close after 2 cycles	N	—	—
N1-1	Phase B, C close after 2 cycles	N	—	—
N1-2	Three phases close after 2 cycles	N	—	—
N1-2	Phase A close after 2 cycles	N	—	—
N1-2	Phase B, C close after 2 cycles	N	—	—
N2	Remove S1 after 2 cycles	N	—	—
N2	Remove S2 after 2 cycles	N	—	—
N2	Remove S3 after 2 cycles	N	—	—
N2	Remove S2, S3 after 2 cycles	N	—	—
N2	Remove S1, S2, S3 simultaneously after 2 cycles	N	—	—
N2	Remove S1, then S2 after 2 cycles, then S3 after 2 cycles	N	—	—
N3	Open Bus 2 breaker after 2 cycles	N	—	—
N3	Open Bus 4 breaker after 2 cycles	N	—	—
N3	Open SW after 2 cycles	N	—	—
N4	Restore S1 after 2 cycles	N	—	—
N4	Restore S1 after 2 cycles	N	—	—
N4	Restore S1 after 2 cycles	N	—	—
N4	Restore S2, S3 after 2 cycles	N	—	—
N4	Restore S1, S2, S3 simultaneously after 2 cycles	N	—	—
N4	Restore S1, then S2 after 2 cycles, then S3 after 2 cycles	N	—	—
N5	Power swing after three-fault occurred on Line1	N	—	—
N6	Secondary Impedance: 31.88	N	—	—
N6	Secondary Impedance: 22.34	N	—	—
N6	Secondary Impedance: 13.74	N	—	—
N6	Secondary Impedance: 7.90	N	—	—

Table A.26: Compliance test result for SEL-321

Type	Loc [%]	Fault Type	Load Condition	Trip / no trip on Fault	CCT[s]	Trip / no trip on Power Swing or Out of Step
A1	10	Single 3-phase	Base	Y	0.346	N
	50			Y	0.550	N
	90			Y	0.716	N
A2	10	Single 3-phase	Over	Y	0.346	N
	50			Y	0.550	N
	90			Y	0.716	N
A3	10	Two 3-phase	Base	Y	0.346	N
	50			Y	0.550	N
	90			Y	0.716	N
A4	10	Two 3-phase	Over	Y	0.346	N
	50			Y	0.550	N
	90			Y	0.716	N
A5	10	Single 3-phase	Base	Y	0.716	Y
	50			Y	1.016	Y
	90			Y	1.432	Y
A6	10	Single 3-phase	Over	Y	0.716	Y
	50			Y	1.016	Y
	90			Y	1.432	Y
A7	10	Two 3-phase	Base	Y	0.716	Y
	50			Y	1.016	Y
	90			Y	1.432	Y
A8	10	Two 3-phase	Over	Y	0.716	Y
	50			Y	1.016	Y
	90			Y	1.432	Y

Table A.27: Test results for condition F1 for GE D60

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time[s]
AG	0	0	0	Y	1	0.0146
AG	0	45	0	Y	1	0.0145
AG	0	90	0	Y	1	0.0160
AG	50	0	0	Y	1	0.0247
AG	50	0	5	Y	1	0.0244
AG	50	45	0	Y	1	0.0229
AG	50	45	5	Y	1	0.0230
AG	50	90	0	Y	1	0.0248
AG	50	90	5	Y	1	0.0259
AG	70	0	0	Y	1	0.0296
AG	70	0	5	Y	2	0.3609
AG	70	0	10	Y	2	0.3621
AG	70	45	0	Y	1	0.0308
AG	70	45	5	Y	2	0.3601
AG	70	45	10	Y	2	0.3583
AG	70	90	0	Y	1	0.0302
AG	70	90	5	Y	2	0.3589
AG	70	90	10	Y	2	0.3587
AG	90	0	0	Y	2	0.3615
AG	90	45	0	Y	2	0.3602
AG	90	90	0	Y	2	0.3588
BC	0	0	0	Y	1	0.0164
BC	0	0	5	Y	1	0.0178
BC	0	0	25	Y	1	0.0180
BC	0	45	0	Y	1	0.0189
BC	0	45	5	Y	1	0.0188
BC	0	45	25	Y	1	0.0244
BC	0	90	0	Y	1	0.0180
BC	0	90	5	Y	1	0.0190
BC	0	90	25	Y	1	0.0211
BC	50	0	0	Y	1	0.0225
BC	50	0	5	Y	1	0.0255
BC	50	45	0	Y	1	0.0251
BC	50	45	5	Y	1	0.0254
BC	50	90	0	Y	1	0.0231
BC	50	90	5	Y	1	0.0244
BC	70	0	0	Y	1	0.0279
BC	70	0	5	Y	1	0.0366
BC	70	45	0	Y	1	0.0286
BC	70	45	5	Y	1	0.0346
BC	70	90	0	Y	1	0.0282
BC	70	90	5	Y	1	0.0328
BC	90	0	0	Y	2	0.3586
BC	90	0	5	Y	2	0.3650
BC	90	45	0	Y	2	0.3598
BC	90	45	5	Y	2	0.3658
BC	90	90	0	Y	2	0.3597

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time[s]
BC	90	90	5	Y	2	0.3632
BCG	0	0	0	Y	1	0.0178
BCG	0	0	25	Y	1	0.0182
BCG	0	45	0	Y	1	0.0191
BCG	0	45	25	Y	1	0.0187
BCG	0	90	0	Y	1	0.0173
BCG	0	90	25	Y	1	0.0167
BCG	50	0	0	Y	1	0.0235
BCG	50	0	25	Y	1	0.0233
BCG	50	45	0	Y	1	0.0256
BCG	50	45	25	Y	1	0.0260
BCG	50	90	0	Y	1	0.0245
BCG	50	90	25	Y	1	0.0243
BCG	70	0	0	Y	1	0.0267
BCG	70	0	10	Y	1	0.0279
BCG	70	45	0	Y	1	0.0288
BCG	70	45	10	Y	1	0.0295
BCG	70	90	0	Y	1	0.0271
BCG	70	90	10	Y	1	0.0282
BCG	90	0	0	Y	2	0.3595
BCG	90	0	25	Y	2	0.3591
BCG	90	45	0	Y	2	0.3609
BCG	90	45	25	Y	2	0.3589
BCG	90	90	0	Y	2	0.3636
BCG	90	90	25	Y	2	0.3593
ABC	0	0	0	Y	1	0.0166
ABC	0	45	0	Y	1	0.0171
ABC	0	90	0	Y	1	0.0158
ABC	50	0	0	Y	1	0.0221
ABC	50	45	0	Y	1	0.0219
ABC	50	90	0	Y	1	0.0234
ABC	70	0	0	Y	1	0.0292
ABC	70	45	0	Y	1	0.0302
ABC	70	90	0	Y	1	0.0270
ABC	90	0	0	Y	2	0.3546
ABC	90	45	0	Y	2	0.3592
ABC	90	90	0	Y	2	0.3593

Table A.28: Test results for condition F2-1 for GE D60

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time [s]
AG	10	0	0	N	–	–
AG	10	0	10	N	–	–
AG	10	45	0	N	–	–
AG	10	45	10	N	–	–
AG	10	90	0	N	–	–
AG	10	90	10	N	–	–
AG	50	0	0	N	–	–
AG	50	0	25	N	–	–
AG	50	45	0	N	–	–
AG	50	45	25	N	–	–
AG	50	90	0	N	–	–
AG	50	90	25	N	–	–
AG	90	0	0	N	–	–
AG	90	0	25	N	–	–
AG	90	45	0	N	–	–
AG	90	45	25	N	–	–
AG	90	90	0	N	–	–
AG	90	90	25	N	–	–
BC	10	0	0	N	–	–
BC	10	45	0	N	–	–
BC	10	90	0	N	–	–
BC	50	0	0	N	–	–
BC	50	45	0	N	–	–
BC	50	90	0	N	–	–
BC	90	0	0	N	–	–
BC	90	45	0	N	–	–
BC	90	90	0	N	–	–
BCG	10	0	0	N	–	–
BCG	10	0	10	N	–	–
BCG	10	45	0	N	–	–
BCG	10	45	10	N	–	–
BCG	10	90	0	N	–	–
BCG	10	90	10	N	–	–
BCG	50	0	0	N	–	–
BCG	50	0	25	N	–	–
BCG	50	45	0	N	–	–
BCG	50	45	25	N	–	–
BCG	50	90	0	N	–	–
BCG	50	90	25	N	–	–
BCG	90	0	0	N	–	–
BCG	90	0	25	N	–	–
BCG	90	45	0	N	–	–
BCG	90	45	25	N	–	–
BCG	90	90	0	N	–	–
BCG	90	90	25	N	–	–
ABC	10	0	0	N	–	–
ABC	10	45	0	N	–	–

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time [s]
ABC	10	90	0	N	–	–
ABC	50	0	0	N	–	–
ABC	50	45	0	N	–	–
ABC	50	90	0	N	–	–
ABC	90	0	0	N	–	–
ABC	90	45	0	N	–	–
ABC	90	90	0	N	–	–

Table A.29: Test results for condition F2-2 for GE D60

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time [s]
AG	0	0	0	Y	3	1.0217
AG	0	45	0	Y	3	1.0182
AG	0	90	0	Y	3	1.0193
AG	50	0	0	Y	3	1.0240
AG	50	45	0	Y	3	1.0205
AG	50	90	0	Y	3	1.0251
AG	90	0	0	N	–	–
AG	90	45	0	N	–	–
AG	90	90	0	N	–	–
BC	0	0	0	Y	2	0.3632
BC	0	45	0	Y	2	0.3649
BC	0	90	0	Y	2	0.3628
BC	50	0	0	Y	3	1.0190
BC	50	45	0	Y	3	1.0228
BC	50	90	0	Y	3	1.0230
BC	90	0	0	Y	3	1.0267
BC	90	45	0	Y	3	1.0280
BC	90	90	0	Y	3	1.0253
BCG	0	0	0	Y	2	0.3650
BCG	0	45	0	Y	2	0.3653
BCG	0	90	0	Y	2	0.3637
BCG	50	0	0	Y	3	1.0204
BCG	50	45	0	Y	3	1.0228
BCG	50	90	0	Y	3	1.0226
BCG	90	0	0	Y	3	1.0239
BCG	90	45	0	Y	3	1.0261
BCG	90	90	0	Y	3	1.0263
ABC	0	0	0	Y	2	0.3675
ABC	0	45	0	Y	2	0.3677
ABC	0	90	0	Y	2	0.3639
ABC	50	0	0	Y	3	1.0204
ABC	50	45	0	Y	3	1.0213
ABC	50	90	0	Y	3	1.0208
ABC	90	0	0	Y	3	1.0267
ABC	90	45	0	Y	3	1.0279
ABC	90	90	0	Y	3	1.0264

Table A.30: Test results for condition F3 for GE D60

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time [s]
AG	0	0	0	Y	1	0.0280
AG	0	45	0	Y	1	0.0275
AG	0	90	0	Y	1	0.0284
AG	50	0	0	Y	1	0.0288
AG	50	0	5	Y	1	0.0296
AG	50	45	0	Y	1	0.0282
AG	50	45	5	Y	1	0.0294
AG	50	90	0	Y	1	0.0287
AG	50	90	5	Y	1	0.0282
AG	90	0	0	Y	2	0.3613
AG	90	45	0	Y	2	0.3595
AG	90	90	0	Y	2	0.3608
BC	0	0	0	Y	1	0.0272
BC	0	45	0	Y	1	0.0274
BC	0	90	0	Y	1	0.0289
BC	50	0	0	Y	1	0.0280
BC	50	45	0	Y	1	0.0291
BC	50	90	0	Y	1	0.0282
BC	90	0	0	Y	2	0.3599
BC	90	45	0	Y	2	0.3588
BC	90	90	0	Y	2	0.3593
BCG	0	0	0	Y	1	0.0267
BCG	0	45	0	Y	1	0.0266
BCG	0	90	0	Y	1	0.0277
BCG	50	0	0	Y	1	0.0259
BCG	50	0	5	Y	1	0.0282
BCG	50	45	0	Y	1	0.0285
BCG	50	45	5	Y	1	0.0276
BCG	50	90	0	Y	1	0.0299
BCG	50	90	5	Y	1	0.0297
BCG	90	0	0	Y	2	0.3594
BCG	90	45	0	Y	2	0.3601
BCG	90	90	0	Y	2	0.3618
ABC	0	0	0	Y	1	0.0276
ABC	0	45	0	Y	1	0.0282
ABC	0	90	0	Y	1	0.0274
ABC	50	0	0	Y	1	0.0272
ABC	50	45	0	Y	1	0.0271
ABC	50	90	0	Y	1	0.0277
ABC	90	0	0	Y	2	0.3586
ABC	90	45	0	Y	2	0.3599
ABC	90	90	0	Y	2	0.3590

Table A.31: Test results for condition F4-1 for GE D60

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Time [s]
AG	0	0	0	Y	0.0139
AG	0	0	25	Y	0.0146
AG	0	45	0	Y	0.0137
AG	0	45	25	Y	0.0128
AG	0	90	0	Y	0.0129
AG	0	90	25	Y	0.0142
AG	50	0	0	Y	0.0165
AG	50	0	25	Y	0.0205
AG	50	45	0	Y	0.0157
AG	50	45	25	Y	0.0181
AG	50	90	0	Y	0.01175
AG	50	90	25	Y	0.0186
AG	90	0	0	Y	0.0226
AG	90	0	25	Y	0.1374
AG	90	45	0	Y	0.0203
AG	90	45	25	Y	0.1402
AG	90	90	0	Y	0.0201
AG	90	90	25	Y	0.1390
BC	0	0	0	Y	0.0125
BC	0	45	0	Y	0.0135
BC	0	90	0	Y	0.0141
BC	50	0	0	Y	0.0148
BC	50	45	0	Y	0.0172
BC	50	90	0	Y	0.0170
BC	90	0	0	Y	0.0177
BC	90	45	0	Y	0.0189
BC	90	90	0	Y	0.0197
BCG	0	0	0	Y	0.0122
BCG	0	0	25	Y	0.0130
BCG	0	45	0	Y	0.0140
BCG	0	45	25	Y	0.0144
BCG	0	90	0	Y	0.0129
BCG	0	90	25	Y	0.0141
BCG	50	0	0	Y	0.0157
BCG	50	0	25	Y	0.0164
BCG	50	45	0	Y	0.0144
BCG	50	45	25	Y	0.0184
BCG	50	90	0	Y	0.0161
BCG	50	90	25	Y	0.0146
BCG	90	0	0	Y	0.0182
BCG	90	0	25	Y	0.0174
BCG	90	45	0	Y	0.0210
BCG	90	45	25	Y	0.0218
BCG	90	90	0	Y	0.0191
BCG	90	90	25	Y	0.0204
ABC	0	0	0	Y	0.0128
ABC	0	45	0	Y	0.0143

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Time [s]
ABC	0	90	0	Y	0.0134
ABC	50	0	0	Y	0.0140
ABC	50	45	0	Y	0.0147
ABC	50	90	0	Y	0.0151
ABC	90	0	0	Y	0.0173
ABC	90	45	0	Y	0.0199
ABC	90	90	0	Y	0.0173

Table A.32: Test results for condition F4-2 for GE D60

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Time [s]
AG	0	0	0	Y	0.0143
AG	0	0	25	Y	0.0147
AG	0	45	0	Y	0.0132
AG	0	45	25	Y	0.0140
AG	0	90	0	Y	0.0125
AG	0	90	25	Y	0.0135
AG	50	0	0	Y	0.0166
AG	50	0	25	Y	0.0211
AG	50	45	0	Y	0.0167
AG	50	45	25	Y	0.0193
AG	50	90	0	Y	0.0160
AG	50	90	25	Y	0.0184
AG	90	0	0	Y	0.0213
AG	90	0	25	Y	0.1376
AG	90	45	0	Y	0.0193
AG	90	45	25	Y	0.1405
AG	90	90	0	Y	0.0197
AG	90	90	25	Y	0.1384
BC	0	0	0	Y	0.0132
BC	0	45	0	Y	0.0147
BC	0	90	0	Y	0.0146
BC	50	0	0	Y	0.0152
BC	50	45	0	Y	0.0181
BC	50	90	0	Y	0.0154
BC	90	0	0	Y	0.0179
BC	90	45	0	Y	0.0190
BC	90	90	0	Y	0.0203
BCG	0	0	0	Y	0.0124
BCG	0	0	25	Y	0.0127
BCG	0	45	0	Y	0.0124
BCG	0	45	25	Y	0.0133
BCG	0	90	0	Y	0.0137
BCG	0	90	25	Y	0.0140
BCG	50	0	0	Y	0.0148
BCG	50	0	25	Y	0.0164
BCG	50	45	0	Y	0.0158
BCG	50	45	25	Y	0.0177
BCG	50	90	0	Y	0.0152

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Time [s]
BCG	50	90	25	Y	0.0148
BCG	90	0	0	Y	0.0170
BCG	90	0	25	Y	0.0179
BCG	90	45	0	Y	0.0210
BCG	90	45	25	Y	0.0207
BCG	90	90	0	Y	0.0211
BCG	90	90	25	Y	0.0212
ABC	0	0	0	Y	0.0135
ABC	0	45	0	Y	0.0127
ABC	0	90	0	Y	0.0130
ABC	50	0	0	Y	0.0139
ABC	50	45	0	Y	0.0146
ABC	50	90	0	Y	0.0141
ABC	90	0	0	Y	0.0178
ABC	90	45	0	Y	0.0165
ABC	90	90	0	Y	0.0171

Table A.33: Test results for condition F5 for GE D60

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time [s]
AG	0	0	0	Y	1	0.0152
AG	0	45	0	Y	1	0.0155
AG	0	90	0	Y	1	0.0163
AG	50	0	0	Y	1	0.0242
AG	50	45	0	Y	1	0.0232
AG	50	90	0	Y	1	0.0267
AG	90	0	0	Y	2	0.3633
AG	90	45	0	Y	2	0.3642
AG	90	90	0	Y	2	0.3601
BC	0	0	0	Y	1	0.0191
BC	0	45	0	Y	1	0.0189
BC	0	90	0	Y	1	0.0194
BC	50	0	0	Y	1	0.0254
BC	50	45	0	Y	1	0.0266
BC	50	90	0	Y	1	0.0240
BC	90	0	0	Y	2	0.3332
BC	90	45	0	Y	2	0.3226
BC	90	90	0	Y	2	0.3176
BCG	0	0	0	Y	1	0.0196
BCG	0	45	0	Y	1	0.0197
BCG	0	90	0	Y	1	0.0200
BCG	50	0	0	Y	1	0.0251
BCG	50	45	0	Y	1	0.0271
BCG	50	90	0	Y	1	0.0247
BCG	90	0	0	Y	2	0.3576
BCG	90	45	0	Y	2	0.3608
BCG	90	90	0	Y	2	0.3588
ABC	0	0	0	Y	1	0.0185
ABC	0	45	0	Y	1	0.0175
ABC	0	90	0	Y	1	0.0184
ABC	50	0	0	Y	1	0.0232
ABC	50	45	0	Y	1	0.0234
ABC	50	90	0	Y	1	0.0247
ABC	90	0	0	Y	2	0.3614
ABC	90	45	0	Y	2	0.3621
ABC	90	90	0	Y	2	0.3617

Table A.34: Test results for condition F6-1 for GE D60

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time [s]
AG	50	0	0	Y	1	0.0234
AG	50	45	0	Y	1	0.0232
AG	50	90	0	Y	1	0.0264
AG	90	0	0	Y	2	0.3614
AG	90	45	0	Y	2	0.3602
AG	90	90	0	Y	2	0.3606
BC	50	0	0	Y	1	0.0242
BC	50	45	0	Y	1	0.0259
BC	50	90	0	Y	1	0.0237
BC	90	0	0	Y	2	0.3598
BC	90	45	0	Y	2	0.3595
BC	90	90	0	Y	2	0.3597
BCG	50	0	0	Y	1	0.0259
BCG	50	45	0	Y	1	0.0249
BCG	50	90	0	Y	1	0.0228
BCG	90	0	0	Y	2	0.3595
BCG	90	45	0	Y	2	0.3607
BCG	90	90	0	Y	2	0.3588
ABC	50	0	0	Y	1	0.0217
ABC	50	45	0	Y	1	0.0229
ABC	50	90	0	Y	1	0.0234
ABC	90	0	0	Y	2	0.3610
ABC	90	45	0	Y	2	0.3621
ABC	90	90	0	Y	2	0.3589

Table A.35: Test results for condition F6-2 for GE D60

Type	Loc [%]	Inception Angle [deg]	Resistance [Ω]	Trip / no trip	Trip Zone	Trip Time [s]
AG	50	0	0	Y	1	0.0250
AG	50	45	0	Y	1	0.0222
AG	50	90	0	Y	1	0.0227
AG	90	0	0	Y	2	0.3607
AG	90	45	0	Y	2	0.3603
AG	90	90	0	Y	2	0.3593
BC	50	0	0	Y	1	0.0211
BC	50	45	0	Y	1	0.0260
BC	50	90	0	Y	1	0.0245
BC	90	0	0	Y	2	0.3596
BC	90	45	0	Y	2	0.3594
BC	90	90	0	Y	2	0.3587
BCG	50	0	0	Y	1	0.0212
BCG	50	45	0	Y	1	0.0250
BCG	50	90	0	Y	1	0.0240
BCG	90	0	0	Y	2	0.3598
BCG	90	45	0	Y	2	0.3596
BCG	90	90	0	Y	2	0.3583
ABC	50	0	0	Y	1	0.0229
ABC	50	45	0	Y	1	0.0230
ABC	50	90	0	Y	1	0.0234
ABC	90	0	0	Y	2	0.3607
ABC	90	45	0	Y	2	0.3594
ABC	90	90	0	Y	2	0.3582

Table A.36: “Statistical” test results for internal faults for GE D60

Type	Loc [%]	α [deg]	Rf [Ω]	Trip Zone	No. T	Mean T [ms]	Max T [ms]	Min T [ms]	Devtn [ms]
AG	50	0	5	I	30	24.78	25.40	23.80	0.21
AG	70	45	0	I	30	31.12	32.80	30.40	0.17
AG	90	90	0	II	30	359.04	360.30	358.1	0.18
BC	50	0	5	I	30	25.92	26.80	24.90	0.19
BC	70	45	0	I	30	27.79	29.10	27.00	0.20
BC	90	90	0	II	30	359.97	361.40	359.20	0.19
BCG	50	0	25	I	30	23.86	24.60	22.80	0.17
BCG	70	45	10	I	30	30.05	31.70	29.40	0.22
BCG	90	90	0	II	30	363.43	370.50	358.4	0.20
ABC	50	0	0	I	30	21.92	23.90	21.1	0.23
ABC	70	45	0	I	30	30.04	31.90	29.5	0.18
ABC	90	90	0	II	30	360.56	362.10	359.60	0.20

Table A.37: Test results of no-fault scenarios for GE D60

Type	Operation	Trip / No Trip	Trip Zone	Trip Time [s]
N1-1	Three phases close after 2 cycles	N	—	—
N1-1	Phase A close after 2 cycles	N	—	—
N1-1	Phase B, C close after 2 cycles	N	—	—
N1-2	Three phases close after 2 cycles	N	—	—
N1-2	Phase A close after 2 cycles	N	—	—
N1-2	Phase B, C close after 2 cycles	N	—	—
N2	Remove S1 after 2 cycles	N	—	—
N2	Remove S2 after 2 cycles	N	—	—
N2	Remove S3 after 2 cycles	N	—	—
N2	Remove S2, S3 after 2 cycles	N	—	—
N2	Remove S1, S2, S3 simultaneously after 2 cycles	N	—	—
N2	Remove S1, then S2 after 2 cycles, then S3 after 2 cycles	N	—	—
N3	Open Bus 2 breaker after 2 cycles	N	—	—
N3	Open Bus 4 breaker after 2 cycles	N	—	—
N3	Open SW after 2 cycles	N	—	—
N4	Restore S1 after 2 cycles	N	—	—
N4	Restore S1 after 2 cycles	N	—	—
N4	Restore S1 after 2 cycles	N	—	—
N4	Restore S2, S3 after 2 cycles	N	—	—
N4	Restore S1, S2, S3 simultaneously after 2 cycles	N	—	—
N4	Restore S1, then S2 after 2 cycles, then S3 after 2 cycles	N	—	—
N5	Power swing after three-fault occurred on Line1	N	—	—
N6	Secondary Impedance: 31.88	N	—	—
N6	Secondary Impedance: 22.34	N	—	—
N6	Secondary Impedance: 13.74	N	—	—
N6	Secondary Impedance: 7.90	N	—	—

Table A.38: Compliance test result for GE D60

Type	Loc [%]	Fault Type	Load Condition	Trip / no trip	CCT[s]	Trip / no trip
A1	10	Single 3-phase	Base	Y	0.346	N
	50			Y	0.550	N
	90			Y	0.716	N
A2	10	Single 3-phase	Over	Y	0.346	N
	50			Y	0.550	N
	90			Y	0.716	N
A3	10	Two 3-phase	Base	Y	0.346	N
	50			Y	0.550	N
	90			Y	0.716	N
A4	10	Two 3-phase	Over	Y	0.346	N
	50			Y	0.550	N
	90			Y	0.716	N
A5	10	Single 3-phase	Base	Y	0.716	Y
	50			Y	1.016	Y
	90			Y	1.432	Y
A6	10	Single 3-phase	Over	Y	0.716	Y
	50			Y	1.016	Y
	90			Y	1.432	Y
A7	10	Two 3-phase	Base	Y	0.716	Y
	50			Y	1.016	Y
	90			Y	1.432	Y
A8	10	Two 3-phase	Over	Y	0.716	Y
	50			Y	1.016	Y
	90			Y	1.432	Y

Appendix B: Generator Relay Test

B.1 Generator Relay Protection Scheme and Connections

The protection scheme to be reproduced to test the generator protection relays are shown in Figure B.1. The figure shows what measurements the relay accepts, namely high-side voltage, high-side and low-side currents, neutral currents and voltages, and zero sequence currents and voltages. All measurements are connected to a specific measurement channel of the relay. The relay has 12 inputs total, and all 12 inputs are utilized to test the different protection schemes supported by the relay. A detailed schematic of the same protection scheme is shown in Figure B.2 for the M-3425A relay and Figure B.3 for the 300G relay. The figures all come from the data sheets available from the relay manufacturers. The connections for the typical protection scheme shown in these figures enable a number of functions that are identified in Figure B.4 by their number.

The developed laboratory setup does not use measurements from actual CTs or VTs. Instead, the CT and VT signals are simulated using the software platform and recreated using a waveform generator. Part of the waveform generator is a theater amplifier that scales the output of the D/A converter from 10 V to 30 V. For voltage measurements, the output of the amplifier is brought to the nominal voltage of the relay (69 V) using a booster transformer bench. The final cabling is shown in Figure B.5.

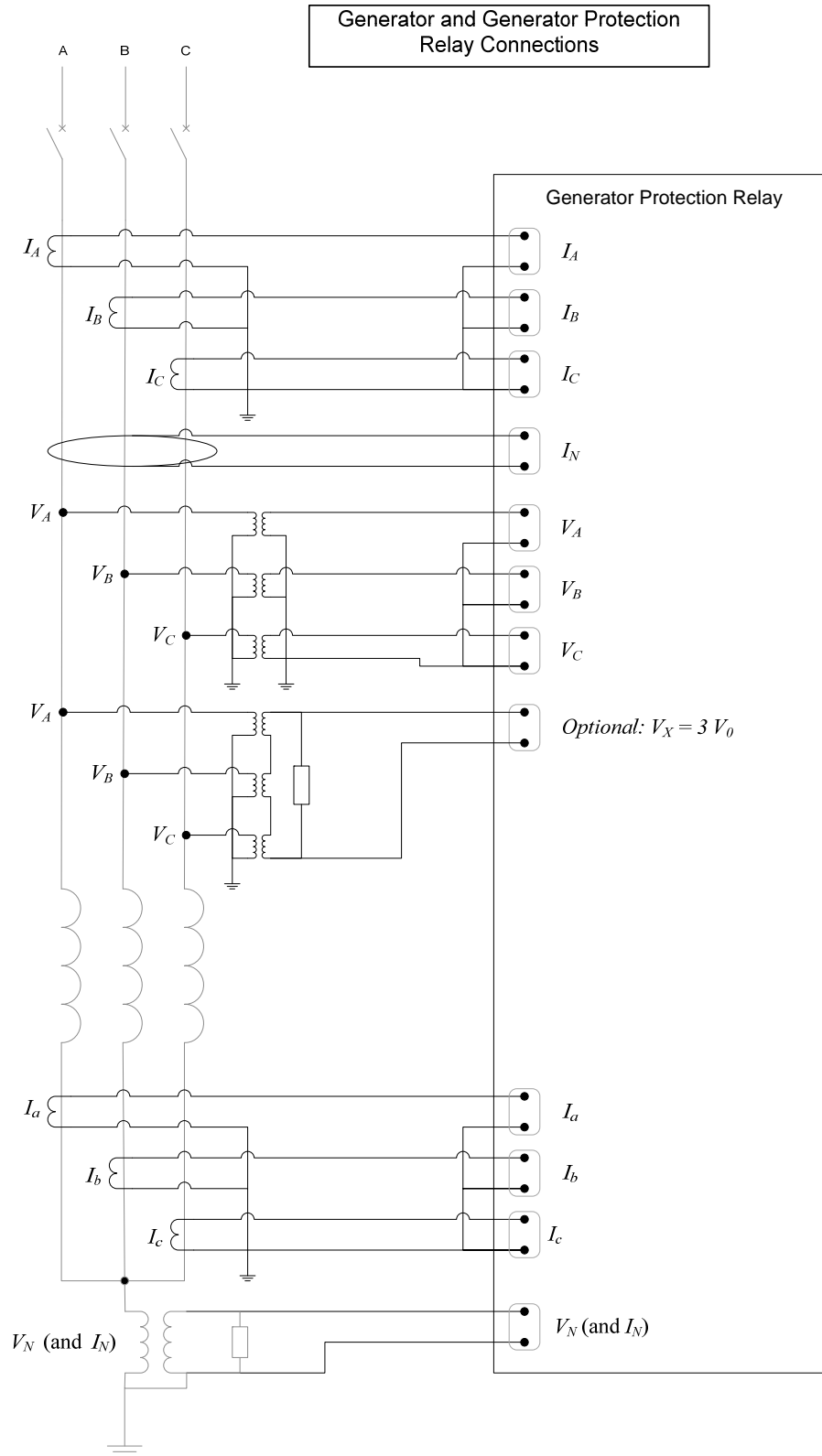


Figure B.1: Instrumentation connections of the generator protection relays

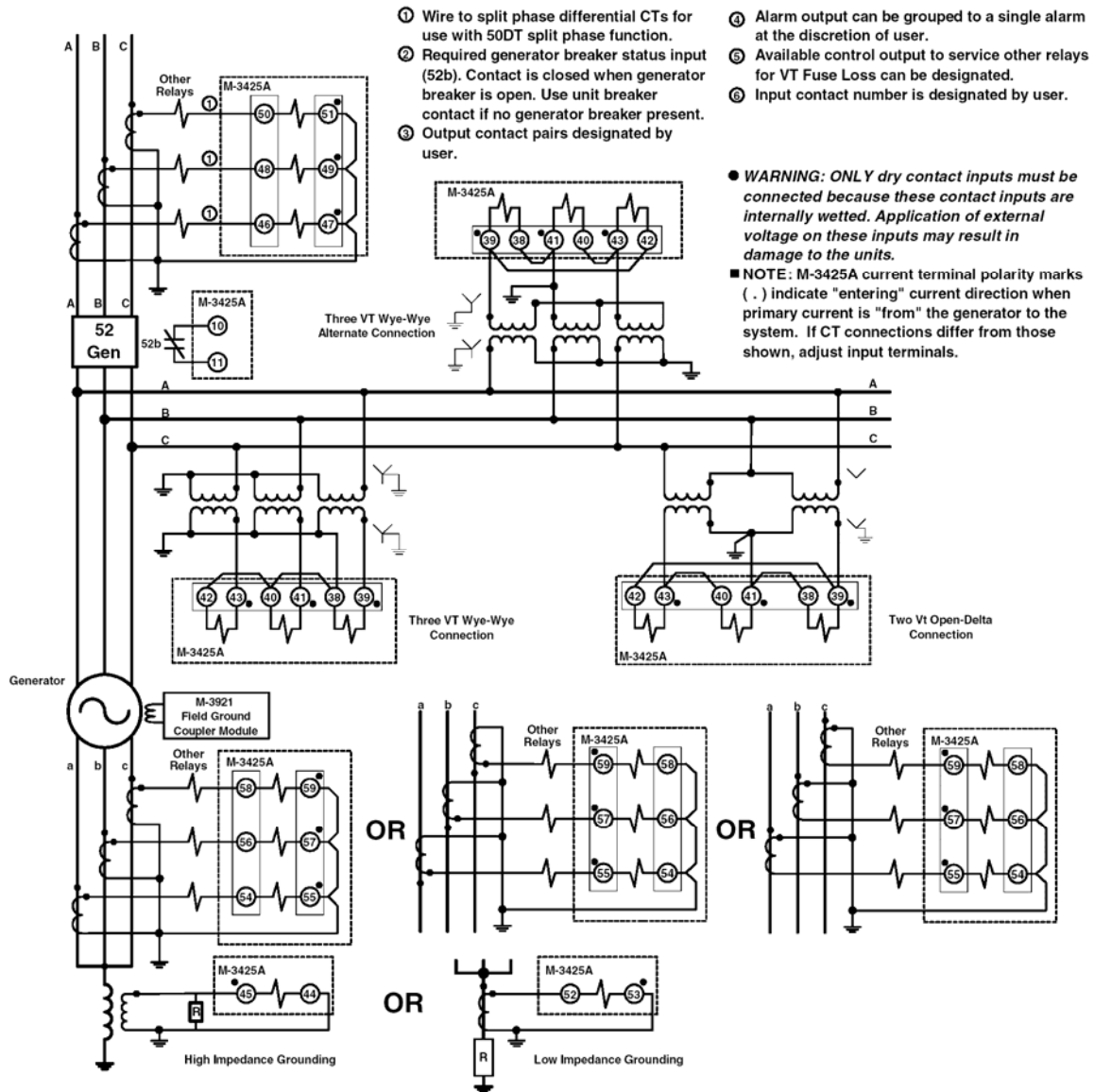


Figure B.2: M-3425A detailed connections of measurement channels to relay inputs for a typical protection scheme (taken from [20] page 2–10)

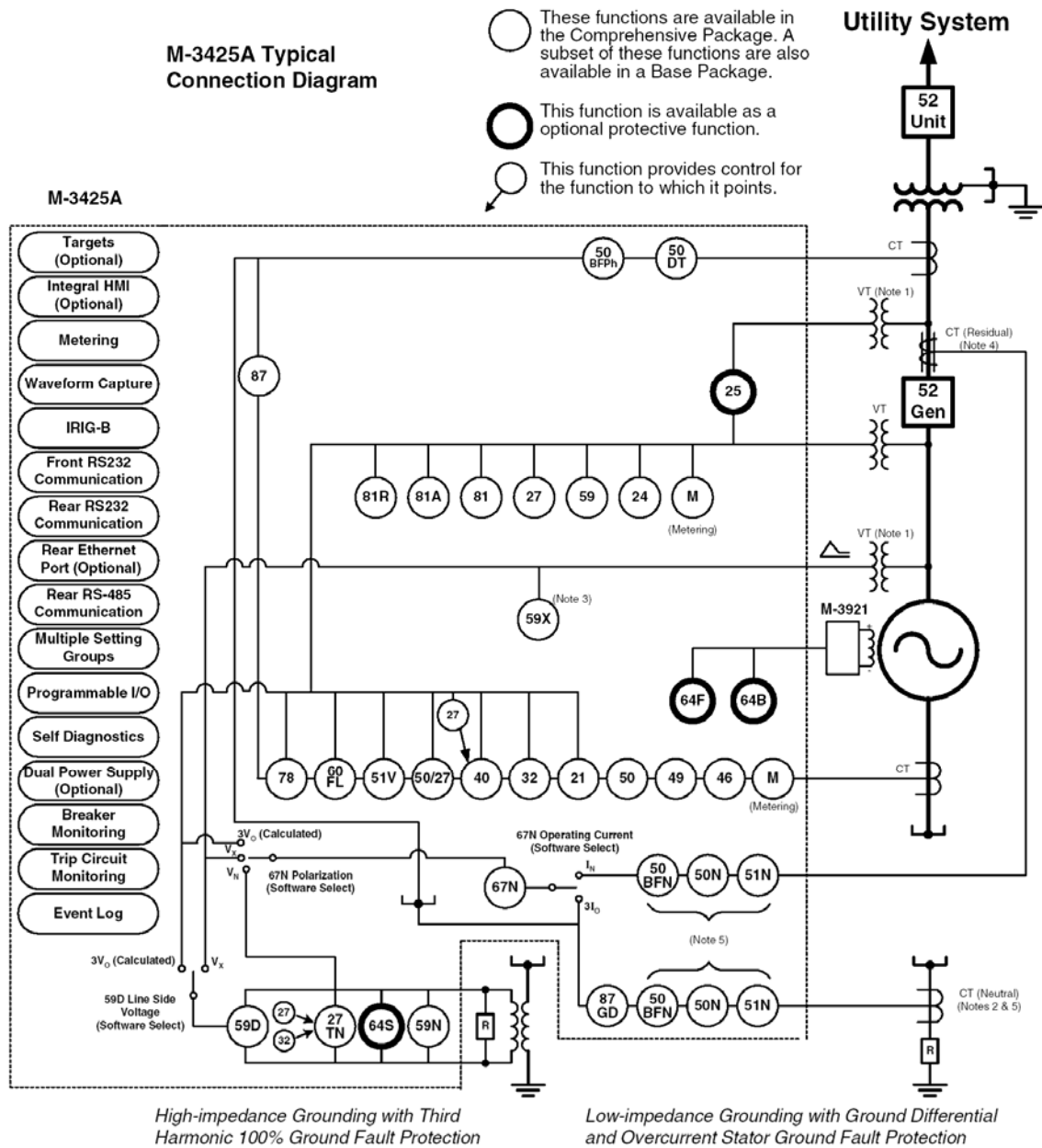


Figure B.3: M-3425 functions available from typical voltage and current wirings to the relay (taken from [20], page 2–5)

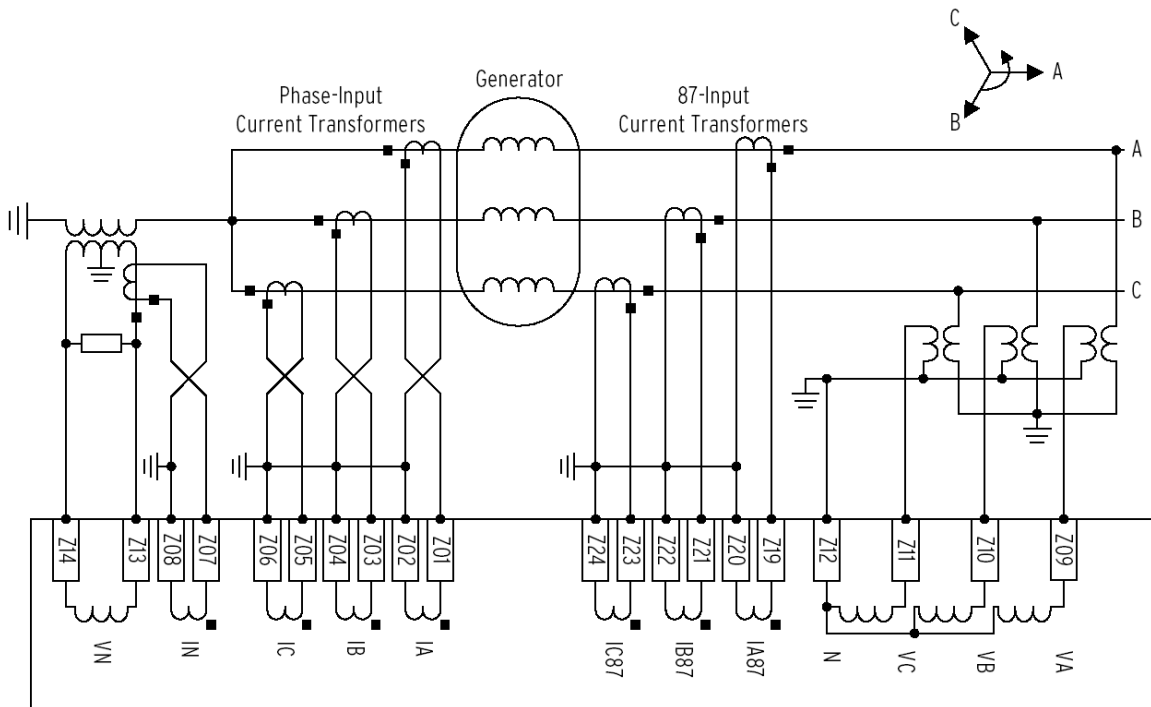


Figure B.4: Typical connection diagram for the 300G relay (available from the manufacturer data sheet)

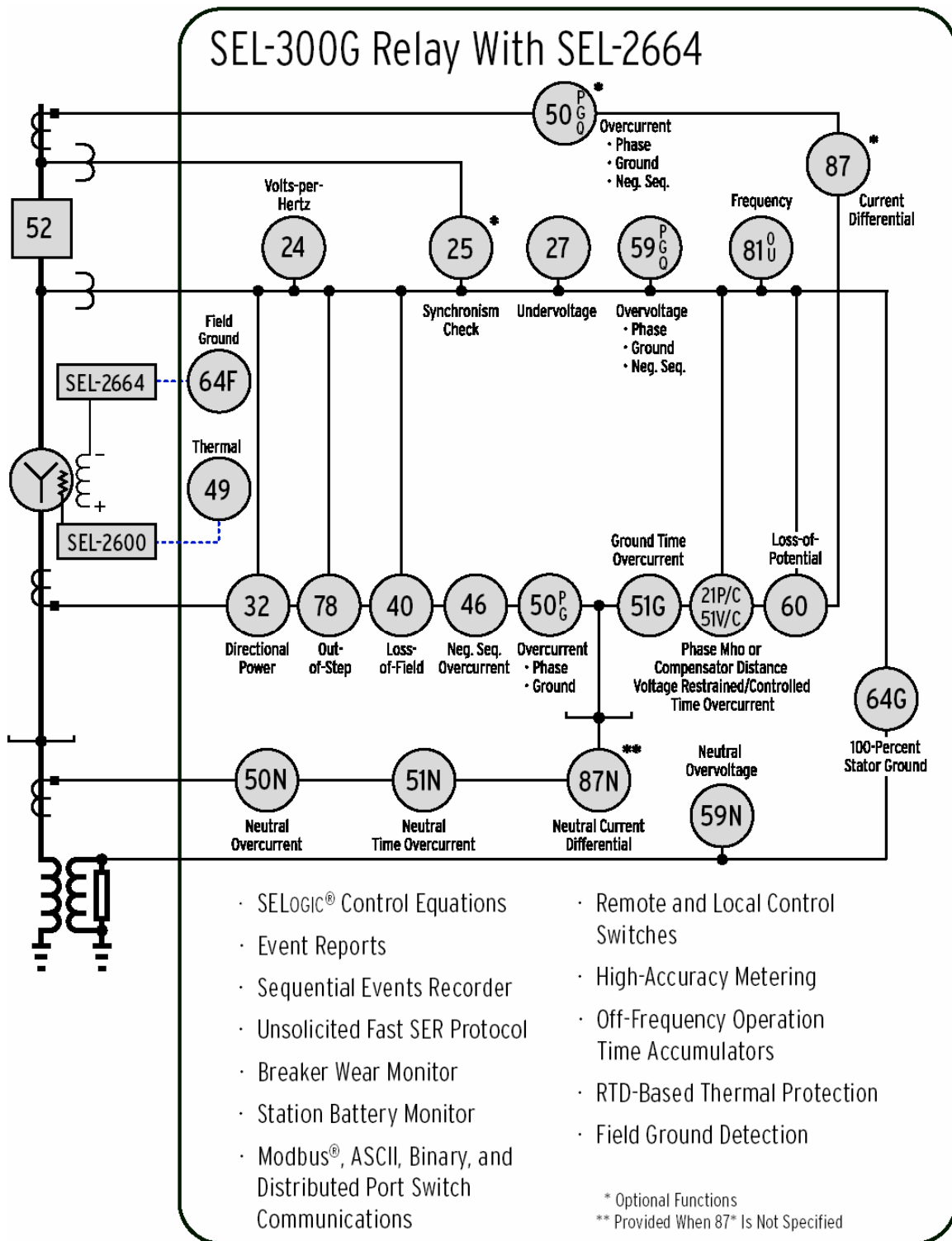


Figure B.5: 300G functions available from typical voltage and current wirings to the relay (available from the manufacturer data sheet)

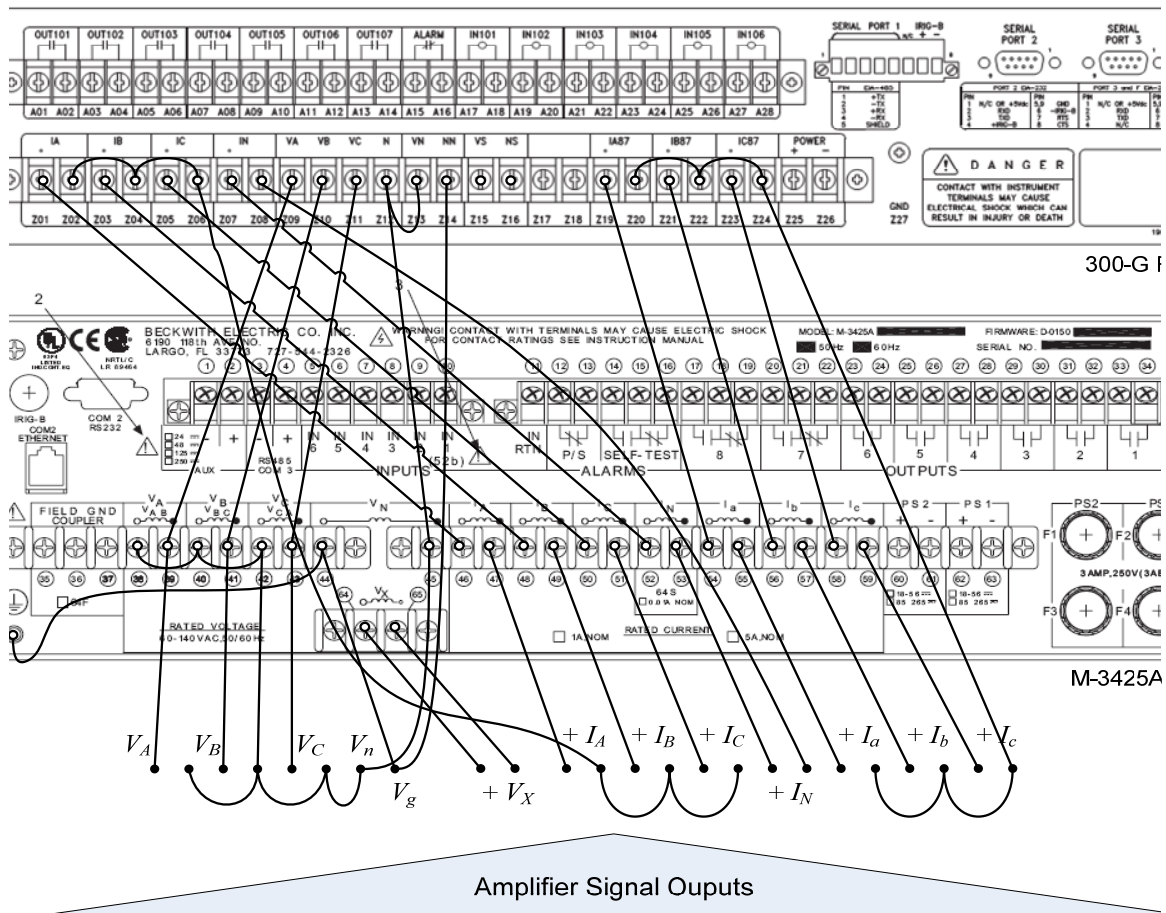


Figure B.6: Connections between signal amplifiers and the tested generator relays

B.2 List of Generator Events for Relay Testing

This Appendix describes the suggested procedures for reproducing specific events to test the generator relay. In reality, several of these events may happen simultaneously as a result of a larger event in the power system, such as a fault or a large-scale action on the system. The present capabilities of the proposed generator model (see Appendix B.3) for transient events simulation are also listed in this appendix.

Events	Procedure to Reproduce	Generator Model Support
SLG Fault HV Side	Place a SLG fault on the HV-side of transformer/line.	N/A
LLG Fault HV Side	Place a LLG fault on the HV side of the transformer/line.	N/A
LL Fault HV Side	Place a LL fault on the HV side of the transformer/line.	N/A
3Ph Fault HV Side	Place a 3ph fault on the HV side of the transformer/line.	N/A
SLG Fault LV Side	Place a SLG fault on the LV-side of transformer/connector.	N/A
LLG Fault LV Side	Place a LLG fault on the LV side of the transformer/connector.	N/A
LL Fault LV Side	Place a LL fault on the LV side of the transformer/connector.	N/A
3Ph Fault LV Side	Place a 3ph fault on the LV side of the transformer/connector.	N/A
Stator-Ground Fault 0-100%	Create a terminal at a designated turn in the stator. Place a SLG fault at the created terminal.	Included
Stator Turn-to-Turn Fault (winding1, winding2) (same phase)	Create a terminal at two designated turns (on same phase) (generator model required). Place a short-circuit between the two created terminals.	Included
Stator Turn-to-Turn Fault (winding1, winding2) (different windings)	Create a terminal at two designated turns (on two different phases) (generator model required). Place a short-circuit between the two created terminals.	Included
Rotor-Ground Fault 0-100%	Create a terminal at a designated turn in the rotor (generator model required). Place a SLG fault at the created terminal.	Included
Rotor Turn-to-Turn Fault (winding1, winding2) (same phase)	Create a terminal at two designated turns (on same phase) (generator model required). Place a short-circuit between the two created terminals.	Included
Rotor Turn-to-Turn Fault (winding1, winding2) (different phases)	Create a terminal at two designated turns (on two different phases) (generator model required). Place a short-circuit between the two created terminals.	Included
Disconnected Rotor Brushes	?	Model extension
Disruption of Exciter	Turn the exciter off or apply an excitation voltage of zero.	Included
Loss of Prime Mover	Use governor fault logic to cancel prime mover torque	Included
P Load > P Generation (rated)	Increase the rated P of the equivalent load above the rated P of the generators.	Included (governor output limit)
P Load << P Generation (rated)	Decrease the rated P of the equivalent load below the rated P of the generators.	Included
Q Load > Q Generation (rated)	Increase the rated Q of the equivalent load above the rated Q of the generators.	Included (exciter saturation)
Q Load << Q Generation (rated)	Decrease the rated Q of the equivalent load below the rated Q of the generators.	Included
Generator Motoring (%)	Adjust the power flow so that the generator receives power.	Included
Reactive Power Transfer (power, direction)	Adjust power flow to the desired Q output of the generator.	Included (exciter

Events	Procedure to Reproduce	Generator Model Support
		setting)
Disconnected Phase / Breaker Stuck Pole	Open a phase of the generator breaker.	N/A
(Sudden) Loss of Load	Open one or several phases of the circuit breaker protecting the load.	N/A
System Frequency Drop/Increase	See increase the load above ratings of all the generators.	N/A
Variation in System Frequency	Ditto	N/A
Transformer Winding Fault (one phase only)	Create a terminal at two designated turns (on same phase) (transformer model required). Place a short-circuit between the two created terminals.	N/A
Loss of VT fuse / Loss of Instrumentation	The output of the voltage/current transformers is set to zero by opening the CT connector or short-circuiting the VT.	N/A
Starting Generator in Sync with System	Ramp up generator and synchronize.	Model extension
Inadvertent Energizing by Control Circuits	Start the exciter and stator by bypassing the command circuits.	Model extension
Generator Breaker Fails to Open	Simulate a breaker failure.	N/A
Generator Open Breaker Flashover	Simulate a breaker failure.	N/A
Excess Breaker Duty	Compute the expected duty and compare to rating of the breaker.	N/A
System Instability after Disturbance Clearing	Simulate a fault, clear it after a critical delay that will make the system unstable.	N/A

B.3 High-Fidelity Generator Model for Event Simulation

B.3.1 Introduction

A comprehensive generator model has been developed to recreate the power system events listed in Appendix B.2 with the desired accuracy. The model consists of a generating unit with a synchronous generator and its control subsystems for 3-phase power system analysis. This appendix describes the full time-domain model that is used for transient analysis. The model includes representation of the synchronous generating units and the generator control systems, such as exciter and turbine-governor subsystems. The model is first presented in its usual compact form. Subsequently, the model is quadratized. The dynamic models are also integrated using the quadratic integration rule, yielding the quadratic algebraic companion form. Finally, fault models are also included so that internal faults and disturbances can be represented and simulated (such as loss of excitation, loss of prime mover, internal winding faults, etc).

A small number of scenarios shown in Appendix B.2 are not presently directly supported by the generator model. They are marked as “model extension.” As the generator model is further extended, support for these test cases will be progressively completed.

B.3.2 Synchronous Machine Full Transient Time-Domain Model

This model is used for full time-domain transient simulation of a synchronous generator with two damper windings. The current time domain model is based on a linear flux current relation, however, it can be easily extended to include nonlinear effects and harmonics.

1. Compact Model

Figure B.7 illustrates the electrical subsystem model of a synchronous machine with two damper windings as a set of mutually coupled circuits.

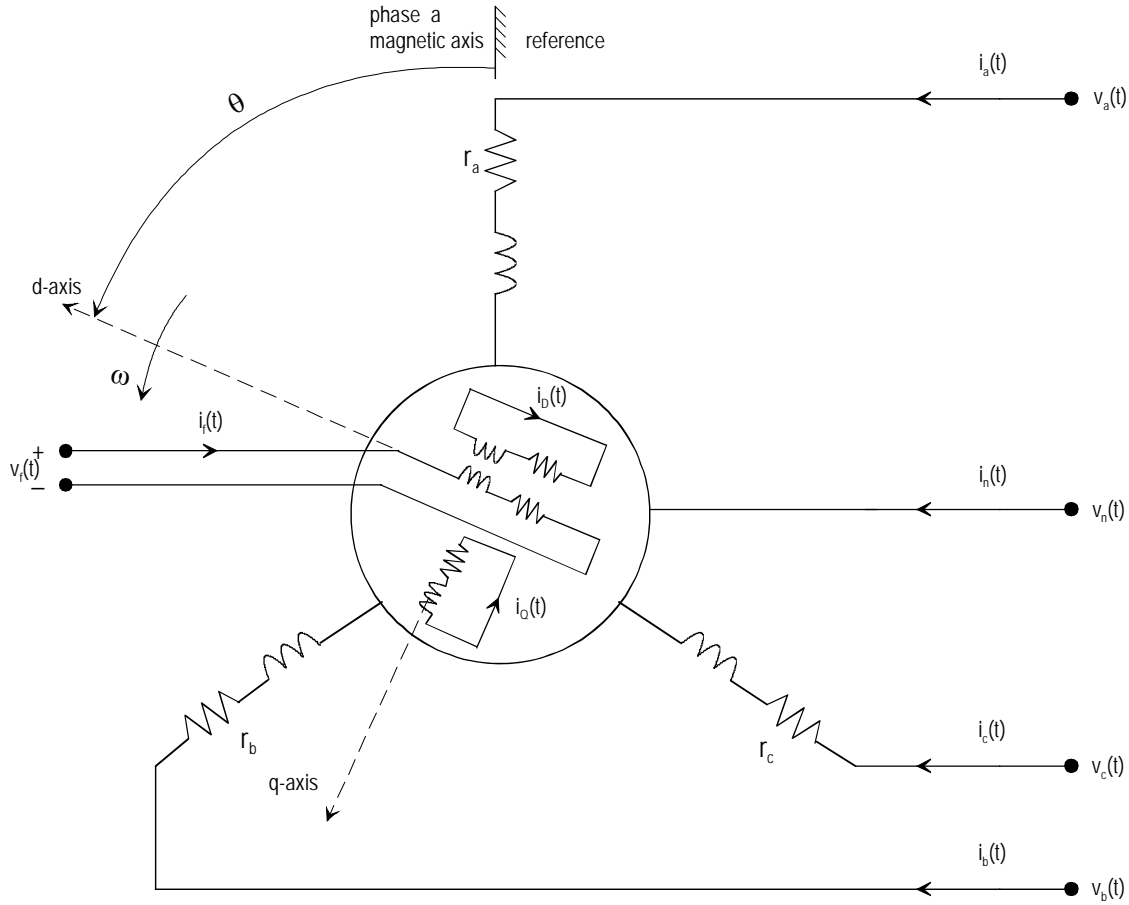


Figure B.7: Electrical model of a synchronous machine as a set of mutually coupled windings

Figure B.8 illustrates the model of the mechanical subsystem of the synchronous machine, which is a rotating mass subject to a mechanical torque as well as an electromagnetic torque.

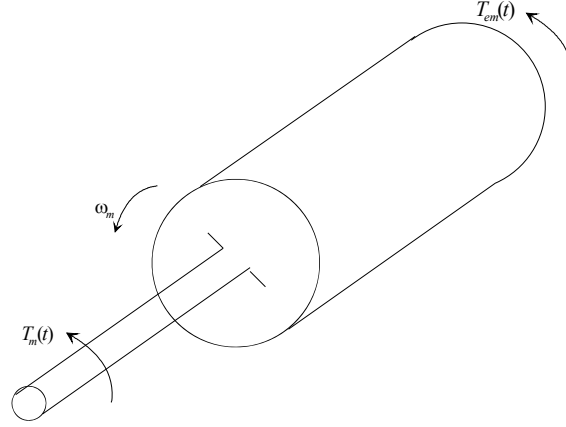


Figure B.8: Mechanical model of synchronous machine as a rotating mass

(1) Electrical Equations

Straightforward circuit analysis leads to the derivation of an appropriate mathematical model. In Figure B.7, the stator and rotor windings of the synchronous machine are: three phase stator windings, a , b , and c , a field winding, f , and two damper windings D , Q acting along the d - and q - axes respectively, with d -axis pointing to the positive magnetic axis of the field winding. It is assumed that the phase windings are wye-connected. Note that all inductors are mounted on the same magnetic circuit and thus they are all magnetically coupled. The angular position of the rotating rotor $\theta_m(t)$ is of the form:

$$\theta_m(t) = \omega_{sm} t + \delta_m(t) + \frac{\pi}{p} \quad (C.2.1)$$

where ω_{sm} is the mechanical synchronous speed; p is the number of poles.

With $\theta(t) = \frac{p}{2} \theta_m(t)$, $\omega_s = \frac{p}{2} \omega_{sm}$, $\delta(t) = \frac{p}{2} \delta_m(t)$, then we have:

$$\theta(t) = \omega_s t + \delta(t) + \frac{\pi}{2} \quad (C.2.1a)$$

The quantities $\theta(t)$, ω_s , $\delta(t)$ are now referring to electrical quantities, and are the electrical angle, the electrical synchronous angular velocity and the power angle respectively.

Application of Kirchhoff's voltage law and Faraday's Law to the circuit of Figure B.7 yields

$$v_{abc}(t) = R_{abc} i_{abc}(t) + \frac{d}{dt} \lambda_{abc}(t) + \Gamma v_n(t) \quad (C.2.2)$$

$$0 = i_a(t) + i_b(t) + i_c(t) + i_n(t) \quad (C.2.3)$$

$$v_{fDQ}(t) = R_{fDQ} i_{fDQ}(t) + \frac{d}{dt} \lambda_{fDQ}(t) + E v_{fn}(t) \quad (C.2.4)$$

where

$$v_{abc}(t) = [v_a(t) \quad v_b(t) \quad v_c(t)]^T$$

$$v_{fDQ}(t) = [v_f(t) \ v_D(t) \ v_Q(t)]^T = [v_f(t) \ 0 \ 0]^T$$

$$i_{abc}(t) = [i_a(t) \ i_b(t) \ i_c(t)]^T$$

$$i_{fDQ}(t) = [i_f(t) \ i_D(t) \ i_Q(t)]^T$$

$$\lambda_{abc}(t) = [\lambda_a(t) \ \lambda_b(t) \ \lambda_c(t)]^T$$

$$\lambda_{fDQ}(t) = [\lambda_f(t) \ \lambda_D(t) \ \lambda_Q(t)]^T$$

$$R_{abc} = \text{diag}(r_a \ r_b \ r_c) = \text{diag}(r \ r \ r)$$

$$R_{fDQ} = \text{diag}(r_f \ r_D \ r_Q)$$

$$\Gamma = [1 \ 1 \ 1]^T$$

$$E = [1 \ 0 \ 0]^T$$

$\lambda_{abc}(t)$ is the vector consisting of magnetic flux linkages of phase **a**, **b**, and **c**. $\lambda_{fDQ}(t)$ is the vector consisting of magnetic flux linkages of the field winding **f**, the **D**-damper winding, and the **Q**-damper winding.

In equations (C.2.2) and (C.2.4), the magnetic flux linkages are complex functions of the rotor position and the electric currents flowing in the various windings of the machine. Assuming a linear flux-current relationship, the magnetic flux linkages of the phase *a*, *b*, and *c* windings are:

$$\lambda_a(t) = L_{aa}i_a(t) + L_{ab}i_b(t) + L_{ac}i_c(t) + L_{af}i_f(t) + L_{aD}i_D(t) + L_{aQ}i_Q(t)$$

$$\lambda_b(t) = L_{ba}i_a(t) + L_{bb}i_b(t) + L_{bc}i_c(t) + L_{bf}i_f(t) + L_{bD}i_D(t) + L_{bQ}i_Q(t)$$

$$\lambda_c(t) = L_{ca}i_a(t) + L_{cb}i_b(t) + L_{cc}i_c(t) + L_{cf}i_f(t) + L_{cD}i_D(t) + L_{cQ}i_Q(t)$$

$$\lambda_f(t) = L_{fa}i_a(t) + L_{fb}i_b(t) + L_{fc}i_c(t) + L_{ff}i_f(t) + L_{fD}i_D(t) + L_{fQ}i_Q(t)$$

$$\lambda_D(t) = L_{Da}i_a(t) + L_{Db}i_b(t) + L_{Dc}i_c(t) + L_{Df}i_f(t) + L_{DD}i_D(t) + L_{DQ}i_Q(t)$$

$$\lambda_Q(t) = L_{Qa}i_a(t) + L_{Qb}i_b(t) + L_{Qc}i_c(t) + L_{Qf}i_f(t) + L_{QD}i_D(t) + L_{QQ}i_Q(t)$$

L_{ii} is the self-inductance of winding *i*, while L_{ij} ($i \neq j$) is the mutual inductance between windings *i* and *j*. Many of the inductances in above equations are dependent on the position of the rotor, which is time varying. Thus these inductances are time dependent. We can apply the same procedure to the rotor windings, which results in the following matrix notation:

$$\begin{bmatrix} \lambda_{abc}(t) \\ \lambda_{fDQ}(t) \end{bmatrix} = \begin{bmatrix} L_{ss}(\theta(t)) & L_{sr}(\theta(t)) \\ L_{rs}(\theta(t)) & L_{rr} \end{bmatrix} \begin{bmatrix} i_{abc}(t) \\ i_{fDQ}(t) \end{bmatrix} \quad (C.2.5)$$

where

$$L_{ss}(\theta(t)) = \begin{bmatrix} L_{aa}(\theta(t)) & L_{ab}(\theta(t)) & L_{ac}(\theta(t)) \\ L_{ab}(\theta(t)) & L_{bb}(\theta(t)) & L_{bc}(\theta(t)) \\ L_{ac}(\theta(t)) & L_{bc}(\theta(t)) & L_{cc}(\theta(t)) \end{bmatrix}$$

$$L_{sr}(\theta(t)) = \begin{bmatrix} L_{af}(\theta(t)) & L_{aD}(\theta(t)) & L_{aQ}(\theta(t)) \\ L_{bf}(\theta(t)) & L_{bD}(\theta(t)) & L_{bQ}(\theta(t)) \\ L_{cf}(\theta(t)) & L_{cD}(\theta(t)) & L_{cQ}(\theta(t)) \end{bmatrix}$$

$$L_{rs}(\theta(t)) = L_{sr}^T(\theta(t))$$

$$L_{rr} = \begin{bmatrix} L_{ff} & L_{fD} & L_{fQ} \\ L_{fD} & L_{DD} & L_{DQ} \\ L_{fQ} & L_{DQ} & L_{QQ} \end{bmatrix}$$

L_{aa} , L_{bb} , and L_{cc} are the stator self-inductances, and generally depend on rotor position. An approximate expression of this dependence is:

$$L_{aa}(t) = L_s + L_m \cos(2\theta(t))$$

$$L_{bb}(t) = L_s + L_m \cos(2\theta(t) - 2\pi/3)$$

$$L_{cc}(t) = L_s + L_m \cos(2\theta(t) + 2\pi/3)$$

where L_s is the self-inductance due to space-fundamental air-gap flux and the armature leakage flux; the additional component that varies with 2θ is due to the rotor saliency.

A typical variation of L_{ii} is shown in Figure B.9.

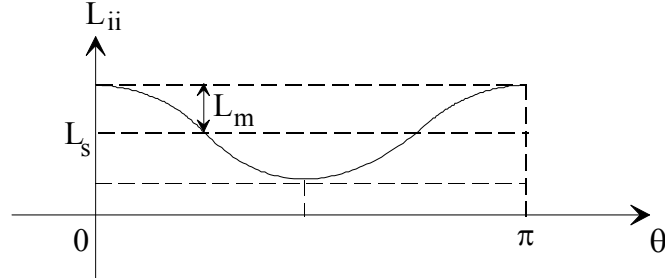


Figure B.9: Stator self-inductance as a function of θ

L_{ff} , L_{DD} , and L_{QQ} are the rotor self-inductances. They are approximately constant:

$$L_{ff} = L_f \quad L_{DD} = L_D \quad L_{QQ} = L_Q$$

L_{ab} , L_{bc} , and L_{ca} , are the stator mutual inductances. They are negative and depend on the rotor position $\theta(t)$. Approximate expressions for these functions are:

$$L_{ab}(t) = L_{ba}(t) = -M_s - L_m \cos 2\left(\theta(t) + \pi/6\right) = -M_s - L_m \cos(2\theta(t) + \pi/3)$$

$$L_{bc}(t) = L_{cb}(t) = -M_s - L_m \cos 2\left(\theta(t) - \pi/2\right) = -M_s - L_m \cos(2\theta(t) - \pi)$$

$$L_{ca}(t) = L_{ac}(t) = -M_s - L_m \cos 2\left(\theta(t) - 7\pi/6\right) = -M_s - L_m \cos\left(2\theta(t) - \pi/3\right)$$

A typical variation of L_{ij} is shown in Figure B.10.

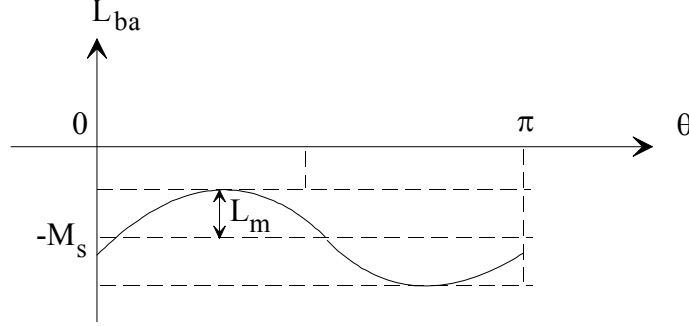


Figure B.10: Mutual inductance between stator windings

L_{fD} , L_{DQ} , and L_{Qf} are the rotor mutual inductances, assumed constant and independent of $\theta(t)$, because the rotor windings are stationary with one another:

$$L_{fD} = L_{Df} = M_R \quad L_{DQ} = L_{QD} = 0 \quad L_{Qf} = L_{fQ} = 0.$$

L_{af} , L_{bf} , and L_{cf} are the mutual inductances between stator and rotor windings. They depend on the rotor position $\theta(t)$ as follows:

$$L_{af}(t) = L_{fa}(t) = M_F \cos \theta(t)$$

$$L_{bf}(t) = L_{fb}(t) = M_F \cos\left(\theta(t) - 2\pi/3\right)$$

$$L_{cf}(t) = L_{fc}(t) = M_F \cos\left(\theta(t) - 4\pi/3\right) = M_F \cos\left(\theta(t) + 2\pi/3\right)$$

Similarly,

$$L_{aD}(t) = L_{Da}(t) = M_D \cos \theta(t)$$

$$L_{bD}(t) = L_{Db}(t) = M_D \cos\left(\theta(t) - 2\pi/3\right)$$

$$L_{cD}(t) = L_{Dc}(t) = M_D \cos\left(\theta(t) - 4\pi/3\right) = M_D \cos\left(\theta(t) + 2\pi/3\right)$$

The damper winding Q is orthogonal to the D winding. According to our definition of rotor d-axis and q-axis, we have:

$$L_{aQ}(t) = L_{Qa}(t) = M_Q \cos\left(\theta(t) - \pi/2\right) = M_Q \sin \theta(t)$$

$$L_{bQ}(t) = L_{Qb}(t) = M_Q \cos\left(\theta(t) - \pi/2 - 2\pi/3\right) = M_Q \sin\left(\theta(t) - 2\pi/3\right)$$

$$L_{cQ}(t) = L_{Qc}(t) = M_Q \cos\left(\theta(t) - \pi/2 - 4\pi/3\right) = M_Q \sin\left(\theta(t) - 4\pi/3\right) = M_Q \sin\left(\theta(t) + 2\pi/3\right)$$

Actually the inductances are perturbed from sinusoidal variation with harmonics. Generally speaking, these harmonics are kept low with the use of distributed coils, double

layers and fractional pitch. The inclusion and effect of harmonics can be included in the above formulation. In the current model, however, these phenomena are omitted.

We can see that the inductance matrix in equation (C.2.5) is time dependent and nonlinear because many inductances are trigonometric functions of $\theta(t)$.

In summary the model of the electrical subsystem of the synchronous machine is

$$v_{abc}(t) = R_{abc} i_{abc}(t) + \frac{d}{dt} \lambda_{abc}(t) + \Gamma v_n(t) \quad (C.2.2)$$

$$0 = i_a(t) + i_b(t) + i_c(t) + i_n(t) \quad (C.2.3)$$

$$v_{fdQ}(t) = R_{fdQ} i_{fdQ}(t) + \frac{d}{dt} \lambda_{fdQ}(t) \quad (C.2.4)$$

$$\begin{bmatrix} \lambda_{abc}(t) \\ \lambda_{fdQ}(t) \end{bmatrix} = \begin{bmatrix} L_{ss}(\theta(t)) & L_{sr}(\theta(t)) \\ L_{rs}(\theta(t)) & L_{rr} \end{bmatrix} \begin{bmatrix} i_{abc}(t) \\ i_{fdQ}(t) \end{bmatrix} \quad (C.2.5)$$

(2) Mechanical System

The dynamics of the synchronous machine rotor is determined by the motion equations:

$$J \frac{d\omega_m(t)}{dt} = T_m(t) + T_e(t) + T_{fw}(t) \quad (C.2.6)$$

$$\frac{d\theta_m(t)}{dt} = \omega_m(t) \quad (C.2.7)$$

where J is the rotor moment of inertia;

$T_m(t)$ is the mechanical torque applied on the rotor shaft by a prime mover system;

$T_e(t)$ is the electromagnetic torque developed by the generator;

$T_{fw}(t)$ is the friction and windage torque;

$\theta_m(t)$ is the mechanical rotor position;

$\omega_m(t)$ is the mechanical rotor speed.

Based on the power balance in the synchronous machine, the electromagnetic torque, $T_e(t) = \frac{P_{cf}(t) - P_{em}(t)}{\omega_m(t)} = \frac{\partial w_{fld}(t)}{\partial \theta_m}$, is determined by the amount of power converted from electrical power into mechanical power, $P_{em}(t)$ and the amount of power in the coupling field between stator and rotor, $P_{cf}(t) = \frac{dw_{fld}(t)}{dt}$, and can be computed by differentiating the field energy function $w_{fld}(t)$ w.r.t. the rotor mechanical position $\theta_m(t)$, using the principal of virtual work displacement, using the fact that $\omega_m(t) = \frac{d\theta_m}{dt}$. The total power converted from mechanical into electrical is:

$$P_{em}(t) = \left(\frac{d\lambda_{abc}(t)}{dt} \right)^T i_{abc}(t) + \left(\frac{d\lambda_{fDQ}(t)}{dt} \right)^T i_{fDQ}(t)$$

or

$$P_{em}(t) = e_{abc}(t)^T i_{abc}(t) + e_{fDQ}(t)^T i_{fDQ}(t) \quad (C.2.8)$$

Since this procedure is quite tedious if we work in actual phase quantities, another, more simple and practical, way of computing the electromagnetic torque is to go backwards from the torque expression in the d-q-o reference frame, after applying the d-q-o transformation. This procedure provides the following relationship for the electromagnetic torque:

$$T_e(t) = -\frac{1}{\sqrt{3}} \cdot (i_a(t)\lambda_b(t) - i_a(t)\lambda_c(t) + i_b(t)\lambda_c(t) - i_b(t)\lambda_a(t) + i_c(t)\lambda_a(t) - i_c(t)\lambda_b(t)) \quad (C.2.9)$$

The friction and windage torque can be modeled as a quadratic function of the rotational speed of the rotor:

$$T_{wf}(t) = -(D_{fw} \cdot \omega_m(t) + D'_{fw} \cdot \omega_m(t)^2) \quad (C.2.10)$$

In summary the model of the mechanical subsystem of the synchronous machine is:

$$J \frac{d\omega_m(t)}{dt} = T_m(t) + T_e(t) + T_{fw}(t) \quad (C.2.6)$$

$$\frac{d\theta_m(t)}{dt} = \omega_m(t) \quad (C.2.7)$$

$$T_e(t) = -\frac{1}{\sqrt{3}} \cdot (i_a(t)\lambda_b(t) - i_a(t)\lambda_c(t) + i_b(t)\lambda_c(t) - i_b(t)\lambda_a(t) + i_c(t)\lambda_a(t) - i_c(t)\lambda_b(t)) \quad (C.2.9)$$

$$T_{wf}(t) = -(D_{fw} \cdot \omega_m(t) + D'_{fw} \cdot \omega_m(t)^2) \quad (C.2.10)$$

$$\theta_m(t) = \omega_{sm}t + \delta_m(t) + \frac{\pi}{p} \quad (C.2.1)$$

Multiplying equations (C.2.6), (C.2.7) and (C.2.1) by $p/2$ and substituting we get the equivalent equations including the electrical quantities $\omega(t)$, $\theta(t)$, $\delta(t)$, instead of the mechanical $\omega_m(t)$, $\theta_m(t)$, $\delta_m(t)$.

$$\frac{2J}{p} \frac{d\omega(t)}{dt} = T_m(t) + T_e(t) \quad (C.2.11)$$

$$\frac{d\theta(t)}{dt} = \omega(t) \quad (C.2.12)$$

$$T_e(t) = -\frac{1}{\sqrt{3}} \cdot (i_a(t)\lambda_b(t) - i_a(t)\lambda_c(t) + i_b(t)\lambda_c(t) - i_b(t)\lambda_a(t) + i_c(t)\lambda_a(t) - i_c(t)\lambda_b(t)) \quad (C.2.13)$$

$$T_{wf}(t) = -(D_{fw} \cdot \omega_m(t) + D'_{fw} \cdot \omega_m(t)^2) \quad (C.2.14)$$

$$\theta(t) = \omega_s t + \delta(t) + \frac{\pi}{2} \quad (C.2.15)$$

We have derived electrical and mechanical equations for the synchronous machine. They are quite complex because some model equations are nonlinear and time varying.

(3) Summary of Compact Model

Combining the equations described in the previous two sections we get the compact model of the synchronous generator. The equations are renumbered to make the model description mode legible.

$$v_{abc}(t) = R_{abc} i_{abc}(t) + \frac{d}{dt} \lambda_{abc}(t) + \Gamma v_n(t) \quad (\text{cm.1})$$

$$i_n(t) = -i_a(t) - i_b(t) - i_c(t) \quad (\text{cm.2})$$

$$0 = r_f i_f(t) + \frac{d\lambda_f(t)}{dt} - v_f(t) + v_{fn}(t) \quad (\text{cm.3})$$

$$i_{fn}(t) = -i_f(t) \quad (\text{cm.4})$$

$$T_m(t) = J \frac{d\omega_m(t)}{dt} - T_e(t) - T_{wf}(t) \quad (\text{cm.5})$$

$$0 = \frac{d\theta_m(t)}{dt} - \omega_m(t) \quad (\text{cm.6})$$

$$0 = \theta(t) - \frac{p}{2} \theta_m(t) \quad (\text{cm.7})$$

$$0 = \omega(t) - \frac{p}{2} \omega_m(t) \quad (\text{cm.8})$$

$$0 = -\theta(t) + \omega_s t + \delta(t) + \frac{\pi}{2} \quad (\text{cm.9})$$

$$0 = R_{DQ} i_{DQ}(t) + \frac{d\lambda_{DQ}(t)}{dt} \quad (\text{cm.10})$$

$$0 = \lambda_{abc}(t) - L_{ss}(\theta(t)) i_{abc}(t) - L_{sr}(\theta(t)) i_{DQ}(t) \quad (\text{cm.11})$$

$$0 = \lambda_{DQ}(t) - L_{rs}(\theta(t)) i_{abc}(t) - L_{rr} i_{DQ}(t) \quad (\text{cm.12})$$

$$0 = T_e(t) + \frac{1}{\sqrt{3}} \cdot i_{abc}(t) \cdot \begin{bmatrix} 0 & 1 & -1 \\ -1 & 0 & 1 \\ 1 & -1 & 0 \end{bmatrix} \cdot \lambda_{abc}(t) \quad (\text{cm.13})$$

$$0 = T_{wf}(t) + (D_{fw} \cdot \omega_m(t) + D'_{fw} \cdot \omega_m(t)^2) \quad (\text{cm.14})$$

where:

$$R_{DQ} = \text{diag}(r_D \quad r_Q).$$

$$\lambda_{DQ}(t) = [\lambda_D(t) \quad \lambda_Q(t)]^T$$

2. Quadratic Model

Based on the analysis of the previous section and the presented compact model the following expanded quadratized model can be obtained. Additional state variables are introduced to expand the model and make it easier to formulate and to cast it in quadratic form. The set of state variables and the state numbering of the model is:

External States:

Index	Variable	Description
0	$v_a(t)$	terminal voltage of stator phase A (kV)
1	$v_b(t)$	terminal voltage of stator phase B (kV)
2	$v_c(t)$	terminal voltage of stator phase C (kV)
3	$v_n(t)$	terminal voltage of stator neutral (kV)
4	$v_f(t)$	terminal voltage of rotor field winding (kV)
5	$v_{fn}(t)$	terminal voltage of rotor field winding neutral (kV)
6	$T_m(t)$	mechanical torque at machine shaft (MNm)

Internal States:

Index	Variable	Description
7	$e_a(t)$	derivative of stator phase A flux (kV)
8	$e_b(t)$	derivative of stator phase B flux (kV)
9	$e_c(t)$	derivative of stator phase C flux (kV)
10	$e_f(t)$	derivative of rotor field flux (kV)
11	$e_D(t)$	derivative of D-damper flux (kV)
12	$e_Q(t)$	derivative of Q-damper flux (kV)
13	$\theta_m(t)$	rotor angular position w.r.t. a stationary reference axis (rad)
14		machine mechanical shaft speed (rad/s)
15	$c(t)$	$\cos(\theta(t))$ [state 22]
16	$s(t)$	$\sin(\theta(t))$ [state 22]
17		machine accelerating torque (MNm)
18	$T_e(t)$	machine electrical torque (MNm)
19	$T_{fw}(t)$	friction and windage torque (MNm)
20	$y_1(t)$	internal variable y1 (rad/s)
21	$y_2(t)$	internal variable y2 (rad/s)
22	$\theta(t)$	electrical rotor position angle (rad)
23	$\omega(t)$	machine electrical shaft speed (rad/s)
24	$\delta(t)$	machine power angle (rad)
25	$i_a(t)$	current through stator phase A (kA)
26	$i_b(t)$	current through stator phase B (kA)

Index	Variable	Description
27	$i_c(t)$	current through stator phase C (kA)
28	$i_f(t)$	current through field winding (kA)
29	$i_D(t)$	current through rotor d-axis damper-winding (kA)
30	$i_Q(t)$	current through rotor q-axis damper-winding (kA)
31	$\lambda_a(t)$	flux linkage through stator winding of phase A (kWb)
32	$\lambda_b(t)$	flux linkage through stator winding of phase B (kWb)
33	$\lambda_c(t)$	flux linkage through stator winding of phase C (kWb)
34	$\lambda_f(t)$	flux linkage through rotor field winding (kWb)
35	$\lambda_D(t)$	flux linkage through rotor d-axis damper-winding (kWb)
36	$\lambda_Q(t)$	flux linkage through rotor q-axis damper-winding (kWb)
37		stator self inductance, phase A (H)
38	$L_{bb}(t)$	stator self inductance, phase B (H)
39	$L_{cc}(t)$	stator self inductance, phase C (H)
40	$L_{ab}(t)$	stator mutual inductance, phases AB (H)
41	$L_{bc}(t)$	stator mutual inductance, phases BC (H)
42	$L_{ca}(t)$	stator mutual inductance, phases CA (H)
43	$L_{ba}(t)$	stator mutual inductance, phases BA (H)
44	$L_{cb}(t)$	stator mutual inductance, phases CB (H)
45	$L_{ac}(t)$	stator mutual inductance, phases AC (H)
46	$L_{af}(t)$	stator-rotor mutual inductance, AF (H)
47	$L_{bf}(t)$	stator-rotor mutual inductance, BF (H)
48	$L_{cf}(t)$	stator-rotor mutual inductance, CF (H)
49	$L_{fa}(t)$	stator-rotor mutual inductance, FA (H)
50	$L_{fb}(t)$	stator-rotor mutual inductance, FB (H)
51	$L_{fc}(t)$	stator-rotor mutual inductance, FC (H)
52	$L_{aD}(t)$	stator-rotor mutual inductance, AD (H)
53	$L_{bD}(t)$	stator-rotor mutual inductance, BD (H)
54	$L_{cD}(t)$	stator-rotor mutual inductance, CD (H)
55	$L_{Da}(t)$	stator-rotor mutual inductance, DA (H)
56	$L_{Db}(t)$	stator-rotor mutual inductance, DB (H)
57	$L_{Dc}(t)$	stator-rotor mutual inductance, DC (H)
58	$L_{aQ}(t)$	stator-rotor mutual inductance, AQ (H)

Index	Variable	Description
59	$L_{bQ}(t)$	stator-rotor mutual inductance, BQ (H)
60	$L_{cQ}(t)$	stator-rotor mutual inductance, CQ (H)
61	$L_{Qa}(t)$	stator-rotor mutual inductance, QA (H)
62	$L_{Qb}(t)$	stator-rotor mutual inductance, QB (H)
63	$L_{Qc}(t)$	stator-rotor mutual inductance, QC (H)

Through Variables:

Index	Variable	Description
0	$i_a(t)$	current through stator winding of phase a
1	$i_b(t)$	current through stator winding of phase b
2	$i_c(t)$	current through stator winding of phase c
3	$i_n(t)$	current through stator neutral
4	$i_f(t)$	current through rotor field winding
5	$i_{fn}(t)$	current through rotor field winding (neutral side)
6	$T_m(t)$	mechanical torque applied on the machine shaft (MNm)

The model equations are:

External equations:

$$i_a = i_a(t)$$

$$i_b = i_b(t)$$

$$i_c = i_c(t)$$

$$i_n = -i_a(t) - i_b(t) - i_c(t)$$

$$i_f = i_f(t)$$

$$i_{fn} = -i_f(t)$$

$$T_m = T_m(t)$$

Internal equations:

$$\frac{d\lambda_a(t)}{dt} = e_a(t)$$

$$\frac{d\lambda_b(t)}{dt} = e_b(t)$$

$$\frac{d\lambda_c(t)}{dt} = e_c(t)$$

$$\frac{d\lambda_f(t)}{dt} = e_f(t)$$

$$\begin{aligned}
\frac{d\lambda_D(t)}{dt} &= e_D(t) \\
\frac{d\lambda_Q(t)}{dt} &= e_Q(t) \\
\frac{d\theta_m(t)}{dt} &= \omega_m(t) \\
\frac{d\omega_m(t)}{dt} &= \frac{1}{J} T_{acc}(t) \\
\frac{dc(t)}{dt} &= y_1(t) \\
\frac{ds(t)}{dt} &= y_2(t) \\
0 &= T_{acc}(t) - T_e(t) - T_m(t) - T_{fw}(t) \\
0 &= T_e(t) + \frac{1}{\sqrt{3}} (i_a(t)\lambda_b(t) - i_a(t)\lambda_c(t) + i_b(t)\lambda_c(t) - i_b(t)\lambda_a(t) + i_c(t)\lambda_a(t) - i_c(t)\lambda_b(t)) \\
0 &= T_{wf}(t) + D_{wf}' \omega_m(t) + D_{wf}' \omega_m(t)^2 \\
0 &= y_1(t) + s(t) \cdot \omega(t) \\
0 &= y_2(t) - c(t) \cdot \omega(t) \\
0 &= \theta(t) - \frac{p}{2} \theta_m(t) \\
0 &= \omega(t) - \frac{p}{2} \omega_m(t) \\
0 &= \delta(t) - \theta(t) + \omega_s t + \frac{\pi}{2} \\
0 &= e_a(t) + r_a i_a(t) - v_a(t) + v_n(t) \\
0 &= e_b(t) + r_b i_b(t) - v_b(t) + v_n(t) \\
0 &= e_c(t) + r_c i_c(t) - v_c(t) + v_n(t) \\
0 &= e_f(t) + r_f i_f(t) - v_f(t) + v_{fn}(t) \\
0 &= e_D(t) + r_D i_D(t) \\
0 &= e_Q(t) + r_Q i_Q(t) \\
0 &= \lambda_a(t) - L_{aa}(t) i_a(t) - L_{ab}(t) i_b(t) - L_{ac}(t) i_c(t) - L_{af}(t) i_f(t) - L_{aD}(t) i_D(t) - L_{aQ}(t) i_Q(t) \\
0 &= \lambda_b(t) - L_{ba}(t) i_a(t) - L_{bb}(t) i_b(t) - L_{bc}(t) i_c(t) - L_{bf}(t) i_f(t) - L_{bD}(t) i_D(t) - L_{bQ}(t) i_Q(t) \\
0 &= \lambda_c(t) - L_{ca}(t) i_a(t) - L_{cb}(t) i_b(t) - L_{cc}(t) i_c(t) - L_{cf}(t) i_f(t) - L_{cD}(t) i_D(t) - L_{cQ}(t) i_Q(t) \\
0 &= \lambda_f(t) - L_{fa}(t) i_a(t) - L_{fb}(t) i_b(t) - L_{fc}(t) i_c(t) - L_{ff}(t) i_f(t) - M_R i_D(t) - L_{fQ}(t) i_Q(t) \\
0 &= \lambda_D(t) - L_{Da}(t) i_a(t) - L_{Db}(t) i_b(t) - L_{Dc}(t) i_c(t) - M_R i_f(t) - L_{DD}(t) i_D(t) - L_{DQ}(t) i_Q(t) \\
0 &= \lambda_Q(t) - L_{Qa}(t) i_a(t) - L_{Qb}(t) i_b(t) - L_{Qc}(t) i_c(t) - L_{Qf}(t) i_f(t) - L_{QD}(t) i_D(t) - L_{QQ}(t) i_Q(t) \\
0 &= L_{aa}(t) - L_s - L_m c(t)^2 + L_m s(t)^2
\end{aligned}$$

$$\begin{aligned}
0 &= L_{bb}(t) - L_s - L_m \cos\left(\frac{2\pi}{3}\right)c(t)^2 + L_m \cos\left(\frac{2\pi}{3}\right)s(t)^2 + 2L_m \sin\left(\frac{2\pi}{3}\right)c(t)s(t) \\
0 &= L_{cc}(t) - L_s - L_m \cos\left(\frac{2\pi}{3}\right)c(t)^2 + L_m \cos\left(\frac{2\pi}{3}\right)s(t)^2 - 2L_m \sin\left(\frac{2\pi}{3}\right)c(t)s(t) \\
0 &= L_{ab}(t) + M_s + L_m \cos\left(\frac{\pi}{3}\right)c(t)^2 - L_m \cos\left(\frac{\pi}{3}\right)s(t)^2 - 2L_m \sin\left(\frac{\pi}{3}\right)c(t)s(t) \\
0 &= L_{bc}(t) + M_s + L_m \cos(\pi)c(t)^2 - L_m \cos(\pi)s(t)^2 + 2L_m \sin(\pi)c(t)s(t) \\
0 &= L_{ca}(t) + M_s + L_m \cos\left(\frac{7\pi}{3}\right)c(t)^2 - L_m \cos\left(\frac{7\pi}{3}\right)s(t)^2 + 2L_m \sin\left(\frac{7\pi}{3}\right)c(t)s(t) \\
0 &= L_{ba}(t) - L_{ab}(t) \\
0 &= L_{cb}(t) - L_{bc}(t) \\
0 &= L_{ac}(t) - L_{ca}(t) \\
0 &= L_{af}(t) - M_F c(t) \\
0 &= L_{bf}(t) - M_F \cos\left(\frac{2\pi}{3}\right)c(t) - M_F \sin\left(\frac{2\pi}{3}\right)s(t) \\
0 &= L_{cf}(t) - M_F \cos\left(\frac{4\pi}{3}\right)c(t) - M_F \sin\left(\frac{4\pi}{3}\right)s(t) \\
0 &= L_{fa}(t) - L_{af}(t) \\
0 &= L_{fb}(t) - L_{bf}(t) \\
0 &= L_{fc}(t) - L_{cf}(t) \\
0 &= L_{aD}(t) - M_D c(t) \\
0 &= L_{bD}(t) - M_D \cos\left(\frac{2\pi}{3}\right)c(t) - M_D \sin\left(\frac{2\pi}{3}\right)s(t) \\
0 &= L_{cD}(t) - M_D \cos\left(\frac{4\pi}{3}\right)c(t) - M_D \sin\left(\frac{4\pi}{3}\right)s(t) \\
0 &= L_{Da}(t) - L_{aD}(t) \\
0 &= L_{Db}(t) - L_{bD}(t) \\
0 &= L_{Dc}(t) - L_{cD}(t) \\
0 &= L_{aQ}(t) - M_Q s(t) \\
0 &= L_{bQ}(t) - M_Q \cos\left(\frac{2\pi}{3}\right)s(t) + M_Q \sin\left(\frac{2\pi}{3}\right)c(t) \\
0 &= L_{cQ}(t) - M_Q \cos\left(\frac{4\pi}{3}\right)s(t) + M_Q \sin\left(\frac{4\pi}{3}\right)c(t) \\
0 &= L_{Qa}(t) - L_{aQ}(t) \\
0 &= L_{Qb}(t) - L_{bQ}(t) \\
0 &= L_{Qc}(t) - L_{cQ}(t)
\end{aligned}$$

Note that $L_{fQ} = L_{Qf} = 0$ and $L_{DQ} = L_{QD} = 0$ since the Q and D windings are

perpendicular.

The model is a 64-order model consisting of 64 states: 7 external states and 57 internal. Of the internal states 10 are dynamic and 47 algebraic. The model consists of 10 differential and 54 algebraic equations. The number of equations is equal to the number of states, thus the model is consistent. The state vector is defined as:

$$X = \begin{bmatrix} X_V^T & X_e^T & X_{mech}^T & X_I^T & X_\lambda^T & X_{L1}^T & X_{L2}^T \end{bmatrix}^T$$

where

$$X_V = \begin{bmatrix} v_a & v_b & v_c & v_n & v_f & v_{fn} & T_m \end{bmatrix}^T,$$

$$X_e = \begin{bmatrix} e_a & e_b & e_c & e_f & e_D & e_Q \end{bmatrix}^T,$$

$$X_{mech} = \begin{bmatrix} g_m & \omega_m & c & s & T_{acc} & T_e & T_{fw} & y_1 & y_2 & g & \omega & \delta \end{bmatrix}^T,$$

$$X_I = \begin{bmatrix} i_a & i_b & i_c & i_f & i_D & i_Q \end{bmatrix}^T,$$

$$X_\lambda = \begin{bmatrix} \lambda_a & \lambda_b & \lambda_c & \lambda_f & \lambda_D & \lambda_Q \end{bmatrix}^T,$$

$$X_{L1} = \begin{bmatrix} L_{aa} & L_{bb} & L_{cc} & L_{ab} & L_{bc} & L_{ca} & L_{ba} & L_{cb} & L_{ac} & L_{af} & L_{bf} & L_{cf} & L_{fa} & L_{fb} & L_{fc} \end{bmatrix}^T$$

,

$$X_{L2} = \begin{bmatrix} L_{aD} & L_{bD} & L_{cD} & L_{Da} & L_{Db} & L_{Dc} & L_{aQ} & L_{bQ} & L_{cQ} & L_{Qa} & L_{Qb} & L_{Qc} \end{bmatrix}^T.$$

The through variables are:

$$I = \begin{bmatrix} i_a & i_b & i_c & i_n & i_f & i_{fn} & T_m & 0 & \dots & 0 \end{bmatrix}^T$$

B.3.3 Excitation System Model

The basic function of an excitation system is to provide direct current to the synchronous machine field winding and control the performance of the generating unit in terms of voltage and reactive power flow as well as the enhancement of system stability. This is achieved by controlling the field voltage and thereby the field current. The elements of an excitation system and a functional block diagram of a typical system are shown in Figure B.11.

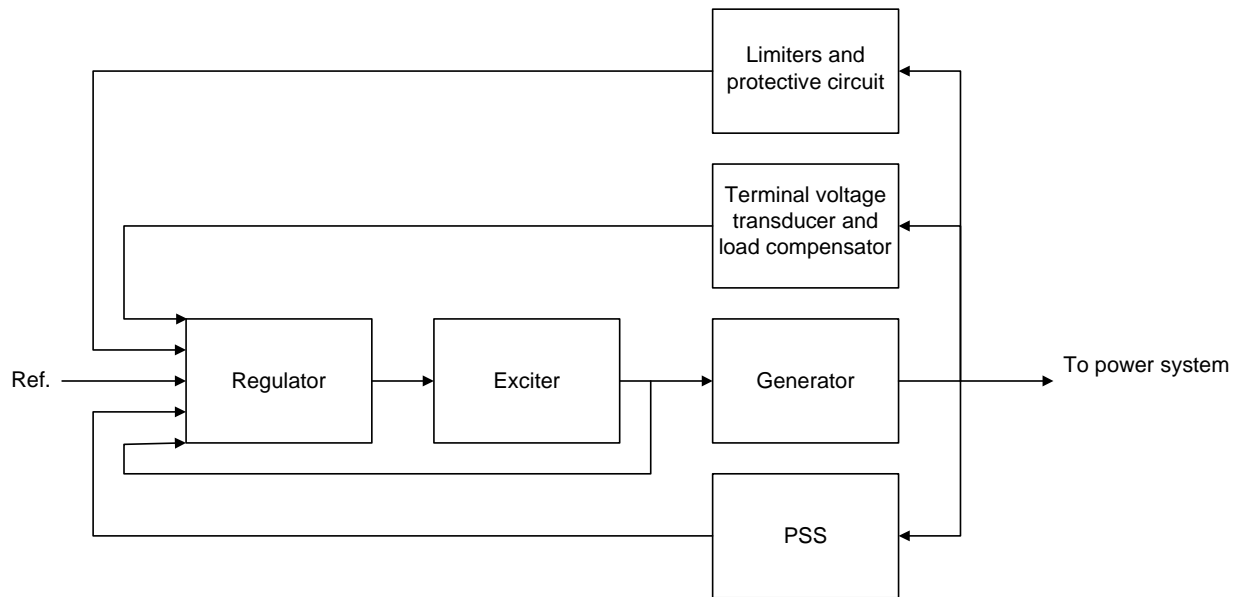


Figure B.11: Elements of a generator excitation system

1. *Constant Excitation Model (no exciter dynamics)*

In this model the dynamic effects of the excitation and voltage regulation system are ignored. In the full time domain transient analysis it is assumed that a constant DC voltage source is connected to the field terminal that can act as an ideal voltage source, a voltage source with internal resistance or as an ideal current source.

Three operating modes are specified for the time domain model:

The model provides a constant DC field voltage to the generator field terminal. The field voltage does not change during transient operation of the generator, but is kept constant. It is equivalent to connecting an ideal constant DC source to the generator field.

The model operates as a constant DC voltage source behind an internal impedance. It is equivalent to connecting a DC voltage source with an internal impedance to the field terminal of the generator. The internal EMF of the DC source is constant, but the field voltage is not constant, as there is a voltage drop across the internal source impedance that is proportional to the field current.

The model provides a constant DC field current value to the generator field winding. The field current is kept constant during the transient operation of the generator. It is equivalent to connecting an ideal current source to the generator field winding. This mode may cause numerical problems in the time domain simulation, because of the step changes in the field winding current, due to the series connection of a current source with an inductor. Therefore, its implementation might not be practical.

(1) Compact Model

Three modes of operation are defined:

- (a) Constant field voltage mode,
- (b) DC voltage source mode, and
- (c) Current source mode.

(a) Constant field voltage mode

The constant field voltage mode assumes that the field voltage is specified and remains constant. The simpler way to represent this mode of operation is by a minor internal modification of the synchronous generator model. More specifically, the states $v_f(t)$ and $v_{fn}(t)$ are converted from external to internal and the field terminal is removed. The two external equations for the above states are replaced by the internal equations:

$$v_f(t) = V_{\text{specified}}$$

$$v_{fn}(t) = 0$$

Note, that special care needs to be taken in this case, in case a loss of excitation fault is to be applied. In that case, the only possible and meaningful fault that can be considered is a full loss of excitation, in which case the applied voltage becomes zero. This is equivalent to replacing the above two equations by:

$$v_f(t) = 0$$

$$v_{fn}(t) = 0$$

(b) DC voltage source mode

The DC voltage source mode assumes that a constant, non-ideal DC source, with an internal impedance (Figure B.12) is connected to the field terminal, supplying the field voltage.

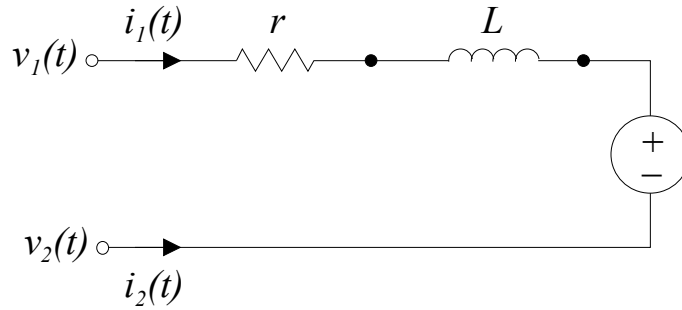


Figure B.12: Voltage source with internal impedance

The compact model is:

$$i_1(t) = g(v_1(t) - v_2(t)) - gL \frac{di_1(t)}{dt} - gV_{DC} \quad (\text{C.3a.1})$$

$$i_2(t) = -i_1(t) \quad (\text{C.3a.2})$$

where $g = \frac{1}{r}$ is the conductance of the resistor and V_{DC} denotes the voltage value of the source.

(c) Current Source

The current source diagram is illustrated in Figure B.13.

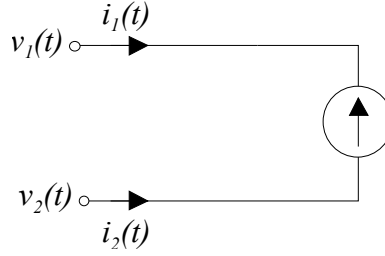


Figure B.13: Current source circuit

The compact model is:

$$i_1(t) = -I_{DC} \quad (\text{C.3a.3})$$

$$i_2(t) = -i_1(t) \quad (\text{C.3a.4})$$

I_{DC} denotes the value of the current source.

(2) Quadratic Model

(a) Constant field voltage mode

The above compact model is linear and simple in formulation. There is, therefore, no need for quadratization or casting it into the standard quadratized form.

(b) DC voltage source mode

The model can be rewritten in a standardized form as:

$$i_1(t) = i_L(t) \quad (\text{C.3a.5})$$

$$i_2(t) = -i_L(t) \quad (\text{C.3a.6})$$

$$\frac{di_L(t)}{dt} = y_1(t) \quad (\text{C.3a.7})$$

$$0 = v_L(t) - v_1(t) + v_2(t) + r i_L(t) + V_{DC} \quad (\text{C.3a.8})$$

$$0 = y_1(t) - \frac{1}{L} v_L(t) \quad (\text{C.3a.9})$$

(c) Current Source

The above compact model is linear and simple in formulation. There is, therefore, no need for quadratization or casting it into the standard quadratized form.

2. Generic Exciter Model

This model of the excitation system assumes that a DC generator is acting as the excitation system of the unit. The model is similar to the DC exciter model, but it is a little bit simpler and more generic. The exciter is again modeled as a DC source with internal impedance connected to the field terminal, as with the constant excitation model. However, now the DC source is not constant. It is assumed to be a DC motor and its armature is connected to the field of the generator. The source impedance is simply the armature impedance of the DC machine.

(1) Compact Model

The voltage source with internal resistance is illustrated in Figure B.14.

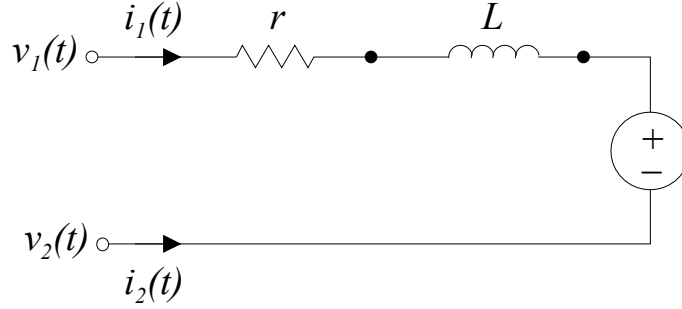


Figure B.14: DC armature circuit with internal impedance

The compact model, if no limits are imposed is:

$$i_1(t) = g(v_1(t) - v_2(t)) - gL \frac{di_1(t)}{dt} - gV_{DC} \quad (\text{C.3b.1})$$

$$i_2(t) = -i_1(t) \quad (\text{C.3b.2})$$

$$T_E \frac{dV_{DC}(t)}{dt} = -(K_E + S_E(V_{DC}(t))) \cdot V_{DC}(t) + V_R(t) \quad (\text{C.3b.3})$$

$$T_A \frac{dV_R(t)}{dt} = -V_R(t) + K_A R_f(t) - \frac{K_A K_F}{T_F} V_{DC}(t) + K_A (V_{ref.} - V_t(t) + V_s(t)) \quad (\text{C.3b.4})$$

$$T_F \frac{dR_f(t)}{dt} = -R_f(t) + \frac{K_F}{T_F} V_{DC}(t) \quad (\text{C.3b.5})$$

where $g = \frac{1}{r}$ is the conductance of the resistor. The function $S_E(V_{DC})$ models the saturation of the exciter. Its form has not been decided yet. If no exciter saturation is modeled then $S_E(V_{DC}) = 0$. The first differential equation represents the dynamics of the DC machine. The armature dynamics are neglected. The second differential equation models the voltage regulator. $V_{ref.}$ is a model input, while $V_t(t)$ is a feedback of the unit terminal voltage that is to be regulated. It can be uncompensated or compensated, to accommodate parallel operation of two units connected at the same bus, using load compensation. The last differential equation models the dynamic behavior of the stabilizing transformer or the system.

If non-windup limits are imposed to the voltage regulator output the compact model becomes:

$$\text{If } V_R^{\min} < V_R(t) < V_R^{\max}$$

$$i_1(t) = g(v_1(t) - v_2(t)) - gL \frac{di_1(t)}{dt} - gV_{DC} \quad (\text{C.3b.6})$$

$$i_2(t) = -i_1(t) \quad (\text{C.3b.7})$$

$$T_E \frac{dV_{DC}(t)}{dt} = -(K_E + S_E(V_{DC}(t))) \cdot V_{DC}(t) + V_R(t) \quad (\text{C.3b.8})$$

$$T_A \frac{dV_R(t)}{dt} = -V_R(t) + K_A R_f(t) - \frac{K_A K_F}{T_F} V_{DC}(t) + K_A (V_{ref.} - V_t(t) + V_s(t)) \quad (\text{C.3b.9})$$

$$T_F \frac{dR_f(t)}{dt} = -R_f(t) + \frac{K_F}{T_F} V_{DC}(t) \quad (\text{C.3b.10})$$

$$\text{else if } V_R(t) \leq V_R^{\min} \text{ and } \frac{dV_R(t)}{dt} < 0$$

$$i_1(t) = g(v_1(t) - v_2(t)) - gL \frac{di_1(t)}{dt} - gV_{DC} \quad (\text{C.3b.11})$$

$$i_2(t) = -i_1(t) \quad (\text{C.3b.12})$$

$$T_E \frac{dV_{DC}(t)}{dt} = -(K_E + S_E(V_{DC}(t))) \cdot V_{DC}(t) + V_R(t) \quad (\text{C.3b.13})$$

$$V_R(t) = V_R^{\min} \quad (\text{C.3b.14})$$

$$\frac{dV_R(t)}{dt} = 0 \Leftrightarrow 0 = -V_R(t) + K_A R_f(t) - \frac{K_A K_F}{T_F} V_{DC}(t) + K_A (V_{ref.} - V_t(t) + V_s(t)) \quad (\text{C.3b.15})$$

$$T_F \frac{dR_f(t)}{dt} = -R_f(t) + \frac{K_F}{T_F} V_{DC}(t) \quad (\text{C.3b.16})$$

$$\text{else if } V_R(t) \geq V_R^{\max} \text{ and } \frac{dV_R(t)}{dt} > 0$$

$$i_1(t) = g(v_1(t) - v_2(t)) - gL \frac{di_1(t)}{dt} - gV_{DC} \quad (\text{C.3b.17})$$

$$i_2(t) = -i_1(t) \quad (\text{C.3b.18})$$

$$T_E \frac{dV_{DC}(t)}{dt} = -(K_E + S_E(V_{DC}(t))) \cdot V_{DC}(t) + V_R(t) \quad (\text{C.3b.19})$$

$$V_R(t) = V_R^{\max} \quad (\text{C.3b.20})$$

$$\frac{dV_R(t)}{dt} = 0 \Leftrightarrow 0 = -V_R(t) + K_A R_f(t) - \frac{K_A K_F}{T_F} V_{DC}(t) + K_A (V_{ref.} - V_t(t) + V_s(t)) \quad (\text{C.3b.21})$$

$$T_F \frac{dR_f(t)}{dt} = -R_f(t) + \frac{K_F}{T_F} V_{DC}(t) \quad (\text{C.3b.22})$$

$$\text{else if } V_R(t) \leq V_R^{\min} \text{ and } \frac{dV_R(t)}{dt} \geq 0$$

$$i_1(t) = g(v_1(t) - v_2(t)) - gL \frac{di_1(t)}{dt} - gV_{DC} \quad (\text{C.3b.23})$$

$$i_2(t) = -i_1(t) \quad (\text{C.3b.24})$$

$$T_E \frac{dV_{DC}(t)}{dt} = -(K_E + S_E(V_{DC}(t))) \cdot V_{DC}(t) + V_R(t) \quad (\text{C.3b.25})$$

$$T_A \frac{dV_R(t)}{dt} = -V_R(t) + K_A R_f(t) - \frac{K_A K_F}{T_F} V_{DC}(t) + K_A (V_{ref.} - V_t(t) + V_s(t)) \quad (\text{C.3b.26})$$

$$T_F \frac{dR_f(t)}{dt} = -R_f(t) + \frac{K_F}{T_F} V_{DC}(t) \quad (\text{C.3b.27})$$

$$V_R(t) = V_R^{\min} \quad (\text{C.3b.28})$$

$$\text{else if } V_R(t) \geq V_R^{\max} \text{ and } \frac{dV_R(t)}{dt} \leq 0$$

$$i_1(t) = g(v_1(t) - v_2(t)) - gL \frac{di_1(t)}{dt} - gV_{DC} \quad (\text{C.3b.29})$$

$$i_2(t) = -i_l(t) \quad (\text{C.3b.30})$$

$$T_E \frac{dV_{DC}(t)}{dt} = -(K_E + S_E(V_{DC}(t))) \cdot V_{DC}(t) + V_R(t) \quad (\text{C.3b.31})$$

$$T_A \frac{dV_R(t)}{dt} = -V_R(t) + K_A R_f(t) - \frac{K_A K_F}{T_F} V_{DC}(t) + K_A (V_{ref.} - V_t(t) + V_s(t)) \quad (\text{C.3b.32})$$

$$T_F \frac{dR_f(t)}{dt} = -R_f(t) + \frac{K_F}{T_F} V_{DC}(t) \quad (\text{C.3b.33})$$

$$V_R(t) = V_R^{\max} \quad (\text{C.3b.34})$$

(2) Quadratic Model

The models are presented assuming the limits are imposed. If not, then the model is equivalent with the case that the limits are not hit. The model can be rewritten in a standardized form as follows:

$$\text{If } V_R^{\min} < V_R(t) < V_R^{\max}$$

$$i_1(t) = i_L(t) \quad (\text{C.3b.35})$$

$$i_2(t) = -i_L(t) \quad (\text{C.3b.36})$$

$$V_s(t) = V_s(t) \quad (\text{C.3b.37})$$

$$\frac{dV_{DC}(t)}{dt} = y_1(t) \quad (\text{C.3b.38})$$

$$\frac{dV_R(t)}{dt} = y_2(t) \quad (\text{C.3b.39})$$

$$\frac{dR_f(t)}{dt} = y_3(t) \quad (\text{C.3b.40})$$

$$\frac{di_L(t)}{dt} = y_4(t) \quad (\text{C.3b.41})$$

$$0 = y_1(t) + \frac{K_E}{T_E} V_{DC}(t) - \frac{1}{T_E} V_R(t) + \frac{1}{T_E} S_E(t) \cdot V_{DC}(t) \quad (\text{C.3b.42})$$

$$0 = y_2(t) + \frac{1}{T_A} V_R(t) - \frac{K_A}{T_A} R_f(t) + \frac{K_A K_F}{T_A T_F} V_{DC}(t) - \frac{K_A}{T_A} (V_{ref.} - V_t(t) + V_s(t)) \quad (\text{C.3b.43})$$

$$0 = y_3(t) + \frac{1}{T_F} R_f(t) - \frac{K_F}{T_F^2} V_{DC}(t) \quad (\text{C.3b.44})$$

$$0 = y_4(t) - \frac{1}{L} v_L(t) \quad (\text{C.3b.45})$$

$$0 = v_L(t) - v_1(t) + v_2(t) + r i_L(t) + V_{DC}(t) \quad (\text{C.3b.46})$$

$$0 = S_E(t) - S_E[V_{DC}(t)] \quad (\text{C.3b.47})$$

else if $V_R(t) \leq V_R^{\min}$ and $y_2(t) < 0$

$$i_1(t) = i_L(t) \quad (\text{C.3b.48})$$

$$i_2(t) = -i_L(t) \quad (\text{C.3b.49})$$

$$V_s(t) = V_s(t) \quad (\text{C.3b.50})$$

$$\frac{dV_{DC}(t)}{dt} = y_1(t) \quad (\text{C.3b.51})$$

$$0 = V_R(t) - V_R^{\min} \quad (\text{C.3b.52})$$

$$\frac{dR_f(t)}{dt} = y_3(t) \quad (\text{C.3b.53})$$

$$\frac{di_L(t)}{dt} = y_4(t) \quad (\text{C.3b.54})$$

$$0 = y_1(t) + \frac{K_E}{T_E} V_{DC}(t) - \frac{1}{T_E} V_R(t) + \frac{1}{T_E} S_E(t) \cdot V_{DC}(t) \quad (\text{C.3b.55})$$

$$0 = y_2(t) \quad (\text{C.3b.56})$$

$$0 = y_3(t) + \frac{1}{T_F} R_f(t) - \frac{K_F}{T_F^2} V_{DC}(t) \quad (\text{C.3b.57})$$

$$0 = y_4(t) - \frac{1}{L} v_L(t) \quad (\text{C.3b.58})$$

$$0 = v_L(t) - v_1(t) + v_2(t) + r i_L(t) + V_{DC}(t) \quad (\text{C.3b.59})$$

$$0 = S_E(t) - S_E[V_{DC}(t)] \quad (\text{C.3b.60})$$

else if $V_R(t) \geq V_R^{\max}$ and $y_2(t) > 0$

$$i_1(t) = i_L(t) \quad (\text{C.3b.61})$$

$$i_2(t) = -i_L(t) \quad (\text{C.3b.62})$$

$$V_s(t) = V_s(t) \quad (\text{C.3b.63})$$

$$\frac{dV_{DC}(t)}{dt} = y_1(t) \quad (\text{C.3b.64})$$

$$0 = V_R(t) - V_R^{\max} \quad (\text{C.3b.65})$$

$$\frac{dR_f(t)}{dt} = y_3(t) \quad (\text{C.3b.66})$$

$$\frac{di_L(t)}{dt} = y_4(t) \quad (\text{C.3b.67})$$

$$0 = y_1(t) + \frac{K_E}{T_E} V_{DC}(t) - \frac{1}{T_E} V_R(t) + \frac{1}{T_E} S_E(t) \cdot V_{DC}(t) \quad (\text{C.3b.68})$$

$$0 = y_2(t) \quad (\text{C.3b.69})$$

$$0 = y_3(t) + \frac{1}{T_F} R_f(t) - \frac{K_F}{T_F^2} V_{DC}(t) \quad (\text{C.3b.70})$$

$$0 = y_4(t) - \frac{1}{L} v_L(t) \quad (\text{C.3b.71})$$

$$0 = v_L(t) - v_1(t) + v_2(t) + r i_L(t) + V_{DC}(t) \quad (\text{C.3b.72})$$

$$0 = S_E(t) - S_E[V_{DC}(t)] \quad (\text{C.3b.73})$$

$$\text{else if } V_R(t) \leq V_R^{\min} \text{ and } y_2(t) \geq 0$$

$$i_1(t) = i_L(t) \quad (\text{C.3b.74})$$

$$i_2(t) = -i_L(t) \quad (\text{C.3b.75})$$

$$V_s(t) = V_s(t) \quad (\text{C.3b.76})$$

$$\frac{dV_{DC}(t)}{dt} = y_1(t) \quad (\text{C.3b.77})$$

$$0 = V_R(t) - V_R^{\min} \quad (\text{C.3b.78})$$

$$\frac{dR_f(t)}{dt} = y_3(t) \quad (\text{C.3b.79})$$

$$\frac{di_L(t)}{dt} = y_4(t) \quad (\text{C.3b.80})$$

$$0 = y_1(t) + \frac{K_E}{T_E} V_{DC}(t) - \frac{1}{T_E} V_R(t) + \frac{1}{T_E} S_E(t) \cdot V_{DC}(t) \quad (\text{C.3b.81})$$

$$0 = y_2(t) + \frac{1}{T_A} V_R(t) - \frac{K_A}{T_A} R_f(t) + \frac{K_A K_F}{T_A T_F} V_{DC}(t) - \frac{K_A}{T_A} (V_{ref.} - V_t(t) + V_s(t)) \quad (\text{C.3b.82})$$

$$0 = y_3(t) + \frac{1}{T_F} R_f(t) - \frac{K_F}{T_F^2} V_{DC}(t) \quad (\text{C.3b.83})$$

$$0 = y_4(t) - \frac{1}{L} v_L(t) \quad (\text{C.3b.84})$$

$$0 = v_L(t) - v_1(t) + v_2(t) + r i_L(t) + V_{DC}(t) \quad (\text{C.3b.85})$$

$$0 = S_E(t) - S_E[V_{DC}(t)] \quad (\text{C.3b.86})$$

$$\text{else if } V_R(t) \geq V_R^{\max} \text{ and } y_2(t) \leq 0$$

$$i_1(t) = i_L(t) \quad (\text{C.3b.87})$$

$$i_2(t) = -i_L(t) \quad (\text{C.3b.88})$$

$$V_s(t) = V_s(t) \quad (\text{C.3b.89})$$

$$\frac{dV_{DC}(t)}{dt} = y_1(t) \quad (\text{C.3b.90})$$

$$0 = V_R(t) - V_R^{\max} \quad (\text{C.3b.91})$$

$$\frac{dR_f(t)}{dt} = y_3(t) \quad (\text{C.3b.92})$$

$$\frac{di_L(t)}{dt} = y_4(t) \quad (\text{C.3b.93})$$

$$0 = y_1(t) + \frac{K_E}{T_E} V_{DC}(t) - \frac{1}{T_E} V_R(t) + \frac{1}{T_E} S_E(t) \cdot V_{DC}(t) \quad (\text{C.3b.94})$$

$$0 = y_2(t) + \frac{1}{T_A} V_R(t) - \frac{K_A}{T_A} R_f(t) + \frac{K_A K_F}{T_A T_F} V_{DC}(t) - \frac{K_A}{T_A} (V_{ref.} - V_t(t) + V_s(t)) \quad (C.3b.95)$$

$$0 = y_3(t) + \frac{1}{T_F} R_f(t) - \frac{K_F}{T_F^2} V_{DC}(t) \quad (C.3b.96)$$

$$0 = y_4(t) - \frac{1}{L} v_L(t) \quad (C.3b.97)$$

$$0 = v_L(t) - v_1(t) + v_2(t) + r i_L(t) + V_{DC}(t) \quad (C.3b.98)$$

$$0 = S_E(t) - S_E[V_{DC}(t)] \quad (C.3b.99)$$

B.3.4 Prime Mover System Model

The prime mover system converts the prime sources of electrical energy into mechanical energy that is applied to the generator and therefore converted into electrical energy. The prime mover governing systems control the active power produced by the unit and the system frequency. This function is commonly referred to as load-frequency control or automatic generation control (AGC). A functional block diagram of a prime mover system is illustrated in Figure B.15.

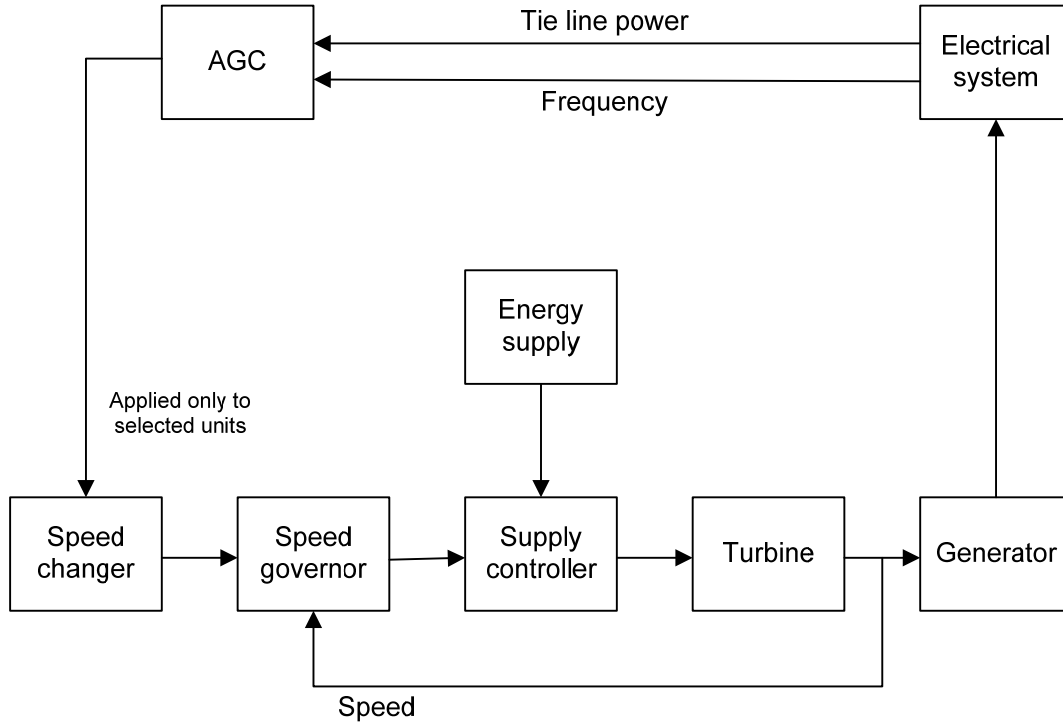


Figure B.15: Elements of a generator prime mover system

1. Compact Model

The compact model of a generic turbine-governor system is a second order dynamical system. The governor is represented as a single time-delay unit and the turbine as a second time delay until. Nonlinearities are introduced in the system by the conversion of mechanical power to mechanical torque and by adding a non-windup limiter that limits

the output of the governor. Two operating modes are defined: (a) the unit is not on AGC (automatic generation control) and (b) the unit is on AGC. In the first case a feedback is taken from the electrical power produced by the unit; this is compared to a power production setpoint and the error is the input of the governor system. In the second case, where the unit is on AGC, the speed setpoint is provided as reference and it is compared to a speed feedback. The error is fed to the governor system after being amplified by the droop of the unit. Based on the above description four modes of operation are defined: (1) Unit is not on AGC, limits are not considered; (2) unit is not on AGC, limits are considered; (3) unit is on AGC, limits are not considered; (4) unit is on AGC, limits are not considered.

(1) Unit is not on AGC, limits are not considered

The compact model is of the form:

$$T_G \frac{dP_T(t)}{dt} = P_{set} - P_m(t) - P_T(t)$$

$$T_t \frac{dP_m(t)}{dt} = P_T(t) - P_m(t)$$

$$T_m(t) = \frac{P_m(t)}{\omega_m(t)}$$

(2) Unit is not on AGC, limits are considered

The compact model is of the form:

If $P^{\min} \leq P_T(t) \leq P^{\max}$

$$T_G \frac{dP_T(t)}{dt} = P_{set} - P_m(t) - P_T(t)$$

else if $P_T(t) < P^{\min}$ and $\frac{dP_T(t)}{dt} < 0$

$$P_T(t) = P^{\min}$$

$$\frac{dP_T(t)}{dt} = 0 \Leftrightarrow P_{set} - P_m(t) - P_T(t) = 0$$

else if $P_T(t) > P^{\max}$ and $\frac{dP_T(t)}{dt} > 0$

$$P_T(t) = P^{\max}$$

$$\frac{dP_T(t)}{dt} = 0 \Leftrightarrow P_{set} - P_m(t) - P_T(t) = 0$$

$$T_t \frac{dP_m(t)}{dt} = P_T(t) - P_m(t)$$

$$T_m(t) = \frac{P_m(t)}{\omega_m(t)}$$

(3) Unit is on AGC, limits are not considered

The compact model is of the form:

$$T_G \frac{dP_T(t)}{dt} = P_{set} - \frac{1}{R} \cdot (\omega_{set} - \omega_m(t))$$

$$T_t \frac{dP_m(t)}{dt} = P_T(t) - P_m(t)$$

$$T_m(t) = \frac{P_m(t)}{\omega_m(t)}$$

(4) Unit is on AGC, limits are considered

The compact model is of the form:

If $P^{\min} \leq P_T(t) \leq P^{\max}$

$$T_G \frac{dP_T(t)}{dt} = P_{set} - \frac{1}{R} \cdot (\omega_{set} - \omega_m(t))$$

else if $P_T(t) < P^{\min}$ and $\frac{dP_T(t)}{dt} < 0$

$$P_T(t) = P^{\min}$$

$$\frac{dP_T(t)}{dt} = 0 \Leftrightarrow P_{set} - \frac{1}{R} \cdot (\omega_{set} - \omega_m(t)) = 0$$

else if $P_T(t) > P^{\max}$ and $\frac{dP_T(t)}{dt} > 0$

$$P_T(t) = P^{\max}$$

$$\frac{dP_T(t)}{dt} = 0 \Leftrightarrow P_{set} - \frac{1}{R} \cdot (\omega_{set} - \omega_m(t)) = 0$$

$$T_t \frac{dP_m(t)}{dt} = P_T(t) - P_m(t)$$

$$T_m(t) = \frac{P_m(t)}{\omega_m(t)}$$

2. Quadratic Model

The model can be brought into the standard quadratic form by the introduction of additional state variables:

(1) Unit is not on AGC, limits are not considered

The model in standard form is:

$$T_m(t) = w(t)P_m(t)$$

$$\frac{dP_T(t)}{dt} = y_1(t)$$

$$\frac{dP_m(t)}{dt} = y_2(t)$$

$$0 = y_1(t) + \frac{1}{T_G} P_T(t) + \frac{1}{T_G} P_m(t) - \frac{1}{T_G} P_{set}$$

$$0 = y_2(t) + \frac{1}{T_t} P_m(t) - \frac{1}{T_t} P_T(t)$$

$$0 = \omega_m(t)w(t) - 1$$

(2) Unit is not on AGC, limits are considered

The model in standard form is:

If $P^{\min} \leq P_T(t) \leq P^{\max}$

$$T_m(t) = w(t)P_m(t)$$

$$\frac{dP_T(t)}{dt} = y_1(t)$$

$$\frac{dP_m(t)}{dt} = y_2(t)$$

$$0 = y_1(t) + \frac{1}{T_G} P_T(t) + \frac{1}{T_G} P_m(t) - \frac{1}{T_G} P_{set}$$

$$0 = y_2(t) + \frac{1}{T_t} P_m(t) - \frac{1}{T_t} P_T(t)$$

$$0 = \omega_m(t)w(t) - 1$$

else if $P_T(t) < P^{\min}$ and $y_1(t) < 0$

$$T_m(t) = w(t)P_m(t)$$

$$\frac{dP_m(t)}{dt} = y_2(t)$$

$$0 = P_T(t) - P^{\min}$$

$$0 = y_1(t)$$

$$0 = y_2(t) + \frac{1}{T_t} P_m(t) - \frac{1}{T_t} P_T(t)$$

$$0 = \omega_m(t)w(t) - 1$$

else if $P_T(t) > P^{\max}$ and $\frac{dP_T(t)}{dt} > 0$

$$T_m(t) = w(t)P_m(t)$$

$$\frac{dP_m(t)}{dt} = y_2(t)$$

$$0 = P_T(t) - P^{\max}$$

$$0 = y_1(t)$$

$$0 = y_2(t) + \frac{1}{T_t} P_m(t) - \frac{1}{T_t} P_T(t)$$

$$0 = \omega_m(t)w(t) - 1$$

(3) Unit is on AGC, limits are not considered

The model in standard form is:

$$T_m(t) = w(t)P_m(t)$$

$$\frac{dP_T(t)}{dt} = y_1(t)$$

$$\frac{dP_m(t)}{dt} = y_2(t)$$

$$0 = y_1(t) - \frac{1}{RT_G} \omega_m(t) + \frac{1}{RT_G} \omega_{set}(t) - \frac{1}{T_G} P_{set}$$

$$0 = y_2(t) + \frac{1}{T_t} P_m(t) - \frac{1}{T_t} P_T(t)$$

$$0 = \omega_m(t)w(t) - 1$$

(4) Unit is on AGC, limits are considered

The model in standard form is:

$$\text{If } P^{\min} \leq P_T(t) \leq P^{\max}$$

$$T_m(t) = w(t)P_m(t)$$

$$\frac{dP_T(t)}{dt} = y_1(t)$$

$$\frac{dP_m(t)}{dt} = y_2(t)$$

$$0 = y_1(t) - \frac{1}{RT_G} \omega_m(t) + \frac{1}{RT_G} \omega_{set}(t) - \frac{1}{T_G} P_{set}$$

$$0 = y_2(t) + \frac{1}{T_t} P_m(t) - \frac{1}{T_t} P_T(t)$$

$$0 = \omega_m(t)w(t) - 1$$

$$\text{else if } P_T(t) < P^{\min} \text{ and } \frac{dP_T(t)}{dt} < 0$$

$$T_m(t) = w(t)P_m(t)$$

$$\frac{dP_m(t)}{dt} = y_2(t)$$

$$0 = P_T(t) - P^{\min}$$

$$0 = y_1(t)$$

$$0 = y_2(t) + \frac{1}{T_t} P_m(t) - \frac{1}{T_t} P_T(t)$$

$$0 = \omega_m(t)w(t) - 1$$

$$\text{else if } P_T(t) > P^{\max} \text{ and } \frac{dP_T(t)}{dt} > 0$$

$$T_m(t) = w(t)P_m(t)$$

$$\frac{dP_m(t)}{dt} = y_2(t)$$

$$0 = P_T(t) - P^{\max}$$

$$0 = y_1(t)$$

$$0 = y_2(t) + \frac{1}{T_t} P_m(t) - \frac{1}{T_t} P_T(t)$$

$$0 = \omega_m(t)w(t) - 1$$

B.4 Example Response Chart for Generator Relay Testing Events

This Appendix provides the chart with the expected relay response for each of the simulated events listed in Appendix B.2.

[illegible]

B.5 IEEE COMTRADE Standard Information for Relay Testing

B.5.1 A Primer on the IEEE COMTRADE File Format

The IEEE COMTRADE computer file format is commonly used for compatibility when distributing or exchanging instrumentation records among different entities. The standard ensures that all the parties involved are on the same page and deal with the same information. In addition, the standard has made the presentation of data simple enough so it can easily be implemented on a computer, and the files are structured in such a way that makes it possible for a person to look up basic information. The standard was first approved in 1991 and revised in 1999 [21]. Note that generally speaking, the 1999 version is a superset of the initial 1991 version. As a result, awareness of the version utilized is necessary to anticipate any misinterpretation of the data. This section briefly describes important aspects of the COMTRADE format. Please refer to the full text of the standard [21] for detailed information.

A waveform record in IEEE COMTRADE format consists of three computer files that share the same name, but have different extensions. The purpose of each file is outlined in Table B.1.

Table B.1: Type, extension, and purpose of the three COMTRADE file types

File Type	Extension	Purpose
Configuration file	.CFG	Provides information about the record and the measurements it contains
Data file	.DAT	Contains the raw measurement data in a compacted form
Header file (optional)	.HDR	Contains other relevant information for the user

B.5.1.1 The Configuration File

The configuration file is a text file in which each line has a specific meaning. Also, in each line, each piece of information is delimited by commas, and the position of the information within the line confers it a special meaning. A configuration file downloaded from the Beckwith relay is used as an example that illustrates the layout of the configuration file.

BECKWITH ELECTRIC CO. , 150,1999	Title, device ID, standard version
52,12A,40D	Number of channels: total, analog, digital
1, VA,,V,0.0353,0,-0082,-32767,32767,0001.4, 1,S	Analog channel information (in this order): - number, label, phase, circuit ID, - units, - scale and offset factors, - skew, - min and max encoded value, - CT/PT primary and secondary ratings, - S or P to represent a primary or secondary reading.
2, VB,,V,0.0353,0,-0082,-32767,32767,0001.4, 1,S	
3, VC,,V,0.0353,0,-0069,-32767,32767,0001.4, 1,S	
4, VX,,V,0.0353,0,-0053,-32767,32767,0001.4, 1,S	
5, VN,,V,0.0353,0,-0040,-32767,32767,0001.0, 1,S	
6, IA,,A,0.0105,0,00000,-32767,32767,00010,1,S	
7, IB,,A,0.0105,0,00020,-32767,32767,00010,1,S	
8, IC,,A,0.0105,0,00035,-32767,32767,00010,1,S	
9, IN,,A,0.0105,0,00385,-32767,32767,00010,1,S	
10, Ia,,A,0.0105,0,00016,-32767,32767,00010,1,S	
11, Ib,,A,0.0105,0,00019,-32767,32767,00010,1,S	
12, Ic,,A,0.0105,0,00047,-32767,32767,00010,1,S	
1, OUTPUT 1,,0	Digital/status channels (in this order): - number, - label, - phase, - circuit ID, - default status value (0 or 1).
2, OUTPUT 2,,0	
3, OUTPUT 3,,0	
4, OUTPUT 4,,0	
5, OUTPUT 5,,0	
6, OUTPUT 6,,0	
7, OUTPUT 7,,0	
8, OUTPUT 8,,0	
9, NOT USED,,0	
10, NOT USED,,0	
11, NOT USED,,0	
12, NOT USED,,0	
13, NOT USED,,0	
14, NOT USED,,0	
15, NOT USED,,0	
16, NOT USED,,0	
17, NOT USED,,0	
18, NOT USED,,0	
19, NOT USED,,0	
20, NOT USED,,0	
21, NOT USED,,0	
22, NOT USED,,0	
23, NOT USED,,0	
24, NOT USED,,0	
25, INPUT 1,,0	
26, INPUT 2,,0	
27, INPUT 3,,0	
28, INPUT 4,,0	
29, INPUT 5,,0	
30, INPUT 6,,0	
31, NOT USED,,0	
32, NOT USED,,0	
33, NOT USED,,0	
34, NOT USED,,0	
35, NOT USED,,0	
36, NOT USED,,0	
37, NOT USED,,0	
38, NOT USED,,0	
39, NOT USED,,0	
40, NOT USED,,0	
60	
1	System operating frequency (Hz)
960,04480	Sampling rate count
15/03/2007,11:03:17.895000	Sampling rate, last index at sampling rate
15/03/2007,11:03:21.402000	Date, time of first data sample (dd/MM/yyyy)
BINARY	Date, time of trigger point (dd/MM/yyyy)
1	File type: ASCII or binary
	Time stamp multiplication factor

B.5.1.2 The Data File

Data files contain raw, encoded values of the waveform records. Actual values of the measurements x_{Actual} are encoded in integer format to compact the data while preserving a good accuracy level. As a result, the range of values for the encoded measurements x_{Coded} is between -99999 to $+99999$ (-32767 to $+32767$ in binary data files where numbers are converted to 16-bit integers). The values are scaled and offset for each measurement channel according to the scale factor a and the offset number b specified in the configuration file, and following the equation

$$x_{Actual} = a x_{Coded} + b.$$

Digital channels use 0 or 1 to store status variables.

In text data files (supported for both 1991 and 1999 versions of COMTRADE), each recorded time instant occupies one line. For every time instant, channel values appear in the order defined in the configuration file. Values are delimited with commas. If there is no data for a given time instant, a blank is utilized instead of an actual number.

In binary data files introduced with COMTRADE 1999, each time instant occupies a fixed amount of memory equal to the number of bytes necessary to store sample number (32 bits), time (32 bits), analog (16 bits/channel), and digital channels (16 bits for every partial of full group of 16 channels). Records for time instants and channel values are placed next to each other with no separators.

Many programming platforms provide functions to deal with comma-separated values or fixed-length records. As a result, the focus of the standard is the data itself rather than the algorithms to access the data.

B.5.1.3 The Header File

The optional header file was introduced with the 1999 COMTRADE revision. The file is intended to contain additional information relevant to the data, to the attention of the user. Header files have no specific format constraints or restrictions and do not participate in the processing of the data.

B.5.1.4 Time Stamp and Protective Relay Testing

Since it takes different times (order of microseconds) for faults propagate to different measurement locations, the time stamp is the only reference available to position the measurements relatively to each other. An accurate time stamp is critical for fault analysis involving waveform data from instruments at different distances from the computer system. With GPS-synchronized devices, the accuracy of the time stamp helps mitigating the inconsistencies between the received waveforms.

The COMTRADE format provides time stamp information in three forms: two time stamps for the beginning of the record and the beginning of the event, and a time stamp multiplication factor. The time stamp multiplication factor should be combined with the sampling rate to determine the actual time increment between samples.

Appendix C: Load Shedding Relay Test

C.1 Test Results

Table C.1: Actual pickup frequency in Hz (100% Voltage, 0% THD, Relay 1)

Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/second)								
	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
40.10	40.09	40.09	40.08	40.08	40.07	40.06	40.06	40.04	40.04
55.00	55.00	54.99	54.98	54.98	54.98	54.97	54.97	54.96	54.96
55.30	55.30	55.29	55.29	55.28	55.28	55.27	55.27	55.27	55.26
55.60	55.60	55.59	55.59	55.58	55.58	55.57	55.56	55.56	55.56
55.90	55.90	55.89	55.89	55.89	55.87	55.87	55.87	55.87	55.86
56.20	56.20	56.19	56.19	56.18	56.18	56.17	56.17	56.16	56.16
56.50	56.50	56.49	56.49	56.49	56.48	56.47	56.47	56.46	56.46
56.80	56.80	56.79	56.79	56.78	56.78	56.78	56.77	56.77	56.76
57.10	57.10	57.09	57.09	57.09	57.08	57.07	57.07	57.07	57.06
57.40	57.40	57.39	57.39	57.38	57.38	57.38	57.37	57.37	57.37
57.70	57.70	57.69	57.69	57.68	57.68	57.67	57.67	57.67	57.67
58.00	58.00	57.99	57.99	57.98	57.98	57.97	57.97	57.97	57.97
58.30	58.30	58.29	58.29	58.29	58.28	58.27	58.27	58.26	58.26
58.60	58.59	58.59	58.59	58.58	58.58	58.58	58.57	58.57	58.57
58.90	58.90	58.89	58.89	58.89	58.88	58.87	58.87	58.86	58.86
59.20	59.20	59.19	59.19	59.18	59.18	59.18	59.17	59.17	59.17
59.50	59.50	59.49	59.49	59.48	59.48	59.47	59.47	59.47	59.46
59.80	59.80	59.79	59.79	59.78	59.78	59.78	59.77	59.77	59.77
60.10	60.10	60.11	60.11	60.12	60.12	60.12	60.13	60.14	60.13
60.40	60.40	60.41	60.42	60.42	60.42	60.43	60.44	60.43	60.44
60.70	60.70	60.71	60.71	60.72	60.73	60.72	60.73	60.74	60.73
61.00	61.00	61.01	61.02	61.02	61.02	61.03	61.03	61.03	61.04
61.30	61.31	61.31	61.31	61.31	61.32	61.32	61.33	61.34	61.33
61.60	61.60	61.61	61.61	61.62	61.62	61.63	61.62	61.63	61.64
61.90	61.90	61.91	61.91	61.92	61.92	61.92	61.93	61.94	61.93
62.20	62.21	62.21	62.21	62.21	62.22	62.23	62.22	62.23	62.24
62.50	62.50	62.51	62.51	62.52	62.52	62.52	62.53	62.54	62.53
62.80	62.80	62.81	62.81	62.81	62.82	62.83	62.82	62.83	62.84
63.10	63.10	63.11	63.11	63.12	63.12	63.12	63.13	63.14	63.13
63.40	63.40	63.41	63.41	63.41	63.42	63.43	63.42	63.43	63.44
63.70	63.70	63.71	63.71	63.72	63.72	63.72	63.73	63.73	63.73
64.00	64.00	64.01	64.01	64.02	64.02	64.03	64.02	64.03	64.04
64.30	64.30	64.31	64.31	64.32	64.33	64.32	64.33	64.34	64.33
64.60	64.60	64.61	64.61	64.62	64.62	64.63	64.62	64.63	64.64
64.90	64.90	64.91	64.91	64.92	64.92	64.92	64.93	64.94	64.93
65.00	65.00	65.01	65.01	65.01	65.02	65.03	65.02	65.03	65.04

Table C.2: Actual pickup frequency in Hz (85% Voltage, 0% THD, Relay 1)

Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)	Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)							
	0.1		0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
40.10	40.09	40.10	40.09	40.08	40.08	40.07	40.06	40.06	40.04	40.04
55.00	55.00	55.00	54.99	54.98	54.98	54.98	54.98	54.96	54.96	54.96
55.30	55.30	55.90	55.89	55.89	55.88	55.88	55.87	55.87	55.86	55.85
55.60	55.60	57.10	57.09	57.09	57.09	57.08	57.07	57.07	57.07	57.06
55.90	55.90	58.00	57.99	57.99	57.98	57.98	57.98	57.97	57.97	57.97
56.20	56.20	58.90	58.89	58.89	58.88	58.88	58.87	58.87	58.86	58.86
56.50	56.50	60.10	60.11	60.11	60.12	60.12	60.12	60.13	60.14	60.13
56.80	56.80	61.00	61.01	61.02	61.02	61.02	61.03	61.03	61.03	61.04
57.10	57.10	61.90	61.91	61.91	61.92	61.92	61.92	61.93	61.94	61.93
57.40	57.40	63.10	63.11	63.11	63.12	63.12	63.12	63.13	63.14	63.13
57.70	57.70	64.00	64.01	64.01	64.02	64.02	64.03	64.02	64.03	64.04
58.00	58.00	65.00	65.01	65.01	65.01	65.02	65.02	65.02	65.03	65.04
58.30	58.30									
58.60	58.60									
58.90	58.90									
59.20	59.20									
59.50	59.50									
59.80	59.80									
60.10	60.10									
60.40	60.40									
60.70	60.70									
61.00	61.00									
61.30	61.30									
61.60	61.60									
61.90	61.90									
62.20	61.20									
62.50	62.51									
62.80	62.81									
63.10	63.11									
63.40	63.40									
63.70	63.70									
64.00	64.01									
64.30	64.30									
64.60	64.60									
64.90	64.90									
65.00	65.00									

Table C.3: Actual pickup frequency in Hz (115% Voltage, 0% THD, Relay 1)

Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)	Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)							
	0.1		0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
40.10	40.09	40.10	40.09	40.08	40.08	40.07	40.06	40.06	40.04	40.04
55.00	55.00	55.00	54.99	54.99	54.98	54.98	54.97	54.97	54.96	54.96
55.30	55.30	55.90	55.89	55.89	55.88	55.87	55.87	55.87	55.86	55.86
55.60	55.60	57.10	57.09	57.09	57.09	57.08	57.07	57.07	57.06	57.06
55.90	55.90	58.00	57.99	57.99	57.98	57.98	57.97	57.97	57.97	57.97
56.20	56.20	58.90	58.89	58.89	58.89	58.88	58.87	58.87	58.86	58.86
56.50	56.50	60.10	60.11	60.11	60.12	60.12	60.12	60.13	60.14	60.13
56.80	56.80	61.00	61.01	61.02	61.02	61.02	61.03	61.02	61.03	61.04
57.10	57.10	61.90	61.91	61.91	61.92	61.92	61.92	61.93	61.94	61.93
57.40	57.40	63.10	63.11	63.11	63.12	63.12	63.12	63.13	63.14	63.13
57.70	57.70	64.00	64.01	64.01	64.02	64.02	64.03	64.02	64.03	64.04
58.00	58.00	65.00	65.01	65.01	65.01	65.02	65.03	65.02	65.03	65.04
58.30	58.30									
58.60	58.59									
58.90	58.90									
59.20	59.20									
59.50	59.50									
59.80	59.80									
60.10	60.11									
60.40	60.40									
60.70	60.70									
61.00	61.00									
61.30	61.30									
61.60	61.60									
61.90	61.90									
62.20	62.21									
62.50	62.50									
62.80	62.80									
63.10	63.11									
63.40	63.40									
63.70	63.71									
64.00	64.00									
64.30	64.30									
64.60	64.60									
64.90	64.90									
65.00	65.00									

Table C.4: Actual pickup frequency in Hz (100% Voltage, 5% THD, Relay 1)

Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)	Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)							
	0.1		0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
40.10	40.09	40.10	40.09	40.08	40.07	40.07	40.06	40.06	40.04	40.04
55.00	55.00	55.00	54.99	54.98	54.98	54.98	54.97	54.96	54.96	54.96
55.30	55.30	55.90	55.89	55.89	55.89	55.87	55.88	55.87	55.87	55.86
55.60	55.60	57.10	57.09	57.09	57.09	57.08	57.07	57.07	57.07	57.06
55.90	55.90	58.00	57.99	57.99	57.98	57.98	57.97	57.97	57.97	57.97
56.20	56.20	58.90	58.89	58.89	58.89	58.87	58.87	58.87	58.87	58.86
56.50	56.50	60.10	60.11	60.11	60.12	60.12	60.12	60.13	60.14	60.13
56.80	56.80	61.00	61.01	61.01	61.02	61.02	61.03	61.03	61.03	61.04
57.10	57.10	61.90	61.91	61.91	61.92	61.92	61.92	61.93	61.94	61.93
57.40	57.40	63.10	63.11	63.11	63.12	63.12	63.12	63.13	63.14	63.13
57.70	57.70	64.00	64.01	64.01	64.01	64.02	64.03	64.02	64.03	64.04
58.00	58.00	65.00	65.01	65.01	65.01	65.02	65.03	65.02	65.03	65.04
58.30	58.30									
58.60	58.59									
58.90	58.90									
59.20	59.20									
59.50	59.50									
59.80	59.80									
60.10	60.10									
60.40	60.41									
60.70	60.70									
61.00	61.00									
61.30	61.31									
61.60	61.60									
61.90	61.90									
62.20	62.21									
62.50	62.50									
62.80	62.80									
63.10	63.10									
63.40	63.40									
63.70	63.70									
64.00	64.00									
64.30	64.30									
64.60	64.60									
64.90	64.90									
65.00	65.00									

Table C.5: Actual pickup frequency in Hz (85% Voltage, 5% THD, Relay 1)

Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)	Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)							
	0.1		0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
40.10	40.09	40.10	40.09	40.08	40.07	40.07	40.06	40.06	40.04	40.04
55.00	55.00	55.00	54.99	54.99	54.98	54.98	54.98	54.96	54.96	54.96
55.30	55.30	55.90	55.89	55.89	55.88	55.88	55.87	55.87	55.86	55.86
55.60	55.60	57.10	57.09	57.09	57.09	57.08	57.07	57.07	57.06	57.06
55.90	55.90	58.00	57.99	57.99	57.98	57.98	57.98	57.97	57.97	57.96
56.20	56.20	58.90	58.89	58.89	58.89	58.88	58.87	58.87	58.86	58.86
56.50	56.50	60.10	60.11	60.11	60.12	60.12	60.12	60.13	60.14	60.13
56.80	56.80	61.00	61.01	61.02	61.02	61.02	61.03	61.02	61.03	61.04
57.10	57.10	61.90	61.91	61.91	61.92	61.92	61.92	61.93	61.94	61.93
57.40	57.40	63.10	63.11	63.11	63.12	63.12	63.12	63.13	63.14	63.13
57.70	57.70	64.00	64.01	64.01	64.02	64.02	64.03	64.02	64.03	64.04
58.00	58.00	65.00	65.01	65.01	65.01	65.02	65.03	65.02	65.03	65.04
58.30	58.30									
58.60	58.59									
58.90	58.89									
59.20	59.20									
59.50	59.50									
59.80	59.80									
60.10	60.10									
60.40	60.41									
60.70	60.70									
61.00	61.00									
61.30	61.30									
61.60	61.60									
61.90	61.90									
62.20	62.20									
62.50	62.50									
62.80	62.80									
63.10	63.10									
63.40	63.40									
63.70	63.70									
64.00	64.01									
64.30	64.30									
64.60	64.60									
64.90	64.90									
65.00	65.00									

Table C.6: Actual pickup frequency in Hz (115% Voltage, 5% THD, Relay 1)

Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)	Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)							
	0.1		0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
40.10	40.09	40.10	40.09	40.08	40.07	40.07	40.06	40.06	40.04	40.04
55.00	55.00	55.00	54.99	54.98	54.98	54.98	54.98	54.97	54.96	54.96
55.30	55.30	55.90	55.89	55.89	55.88	55.88	55.87	55.87	55.87	55.86
55.60	55.60	57.10	57.09	57.09	57.09	57.08	57.07	57.07	57.07	57.06
55.90	55.90	58.00	57.99	57.99	57.98	57.98	57.97	57.97	57.97	57.96
56.20	56.20	58.90	58.89	58.89	58.88	58.88	58.87	58.88	58.86	58.86
56.50	56.50	60.10	60.11	60.11	60.12	60.12	60.12	60.13	60.14	60.13
56.80	56.80	61.00	61.01	61.01	61.02	61.02	61.03	61.02	61.03	61.04
57.10	57.10	61.90	61.91	61.91	61.92	61.92	61.92	61.93	61.94	61.93
57.40	57.40	63.10	63.11	63.11	63.12	63.12	63.12	63.13	63.14	63.13
57.70	57.70	64.00	64.01	64.01	64.02	64.02	64.03	64.02	64.03	64.04
58.00	58.00	65.00	65.01	65.01	65.01	65.02	65.03	65.02	65.03	65.04
58.30	58.29									
58.60	58.60									
58.90	58.90									
59.20	59.20									
59.50	59.50									
59.80	59.80									
60.10	60.10									
60.40	60.40									
60.70	60.70									
61.00	61.00									
61.30	61.31									
61.60	61.60									
61.90	61.90									
62.20	62.20									
62.50	62.51									
62.80	62.80									
63.10	63.11									
63.40	63.40									
63.70	63.70									
64.00	64.00									
64.30	64.30									
64.60	64.60									
64.90	64.90									
65.00	65.00									

Table C.7: Actual pickup frequency in Hz (100% Voltage, 0% THD, Relay 2)

Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)	Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)							
	0.1		0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.01	40.01
55.00	54.97	55.00	54.98	54.97	54.97	54.97	55.27	54.97	54.98	54.98
55.30	55.12	57.10	56.96	56.96	57.26	56.94	56.94	57.28	56.95	56.94
55.60	55.55	58.90	58.86	58.86	58.85	58.85	58.85	58.85	58.85	58.90
55.90	56.05	61.00	60.99	60.98	60.99	60.98	60.98	60.98	60.98	61.00
56.20	56.19	64.00	64.06	64.06	64.06	64.05	64.05	64.04	64.05	64.02
56.50	56.67	70.00	70.24	70.23	70.22	70.23	70.21	70.23	70.22	70.21
56.80	56.79									
57.10	56.96									
57.40	57.43									
57.70	57.66									
58.00	58.08									
58.30	58.22									
58.60	58.71									
58.90	58.86									
59.20	59.35									
59.50	59.52									
59.80	59.66									
60.10	60.16									
60.40	60.32									
60.70	60.68									
61.00	60.98									
61.30	61.35									
61.60	61.67									
61.90	61.83									
62.20	62.35									
62.50	62.49									
62.80	62.66									
63.10	63.20									
63.40	63.35									
63.70	63.82									
64.00	64.06									
64.30	64.28									
64.60	64.60									
64.90	64.93									
70.00	69.98									

Table C.8: Actual pickup frequency in Hz (85% Voltage, 0% THD, Relay 2)

Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)	Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)							
	0.1		0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
40.00	40.00	40.00	39.99	39.98	40.00	39.99	39.99	40.00	40.01	40.01
55.00	54.97	55.00	54.97	54.97	54.98	55.27	54.99	55.00	54.96	54.98
55.30	55.12	57.10	57.08	56.95	57.28	56.94	57.28	57.29	56.94	57.29
55.60	55.56	58.90	58.85	58.87	58.85	58.86	58.85	58.87	58.86	59.22
55.90	56.04	61.00	60.99	60.98	60.99	60.99	60.99	60.97	60.98	61.00
56.20	56.20	64.00	64.05	64.04	64.04	64.06	64.06	64.07	64.04	64.05
56.50	56.67	70.00	70.25	70.22	69.70	70.23	70.24	70.24	70.23	70.22
56.80	56.81									
57.10	56.95									
57.40	57.43									
57.70	57.72									
58.00	58.07									
58.30	58.21									
58.60	58.72									
58.90	58.87									
59.20	59.36									
59.50	59.50									
59.80	59.66									
60.10	60.17									
60.40	61.31									
60.70	60.62									
61.00	60.99									
61.30	61.36									
61.60	61.66									
61.90	61.81									
62.20	62.34									
62.50	62.50									
62.80	62.65									
63.10	63.20									
63.40	63.34									
63.70	63.51									
64.00	64.06									
64.30	64.28									
64.60	64.35									
64.90	64.92									
70.00	70.24									

Table C.9: Actual pickup frequency in Hz (115% Voltage, 0% THD, Relay 2)

Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)	Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)							
	0.1		0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
40.00	40.00	40.00	39.99	40.00	40.00	40.00	40.00	40.00	40.00	40.01
55.00	54.97	55.00	54.97	54.97	54.97	54.98	54.97	55.30	55.01	54.98
55.30	55.43	57.10	56.95	56.97	57.29	56.96	57.31	56.97	56.96	56.94
55.60	55.57	58.90	58.85	58.86	58.86	58.86	58.85	58.85	58.86	58.86
55.90	56.03	61.00	60.99	61.00	60.99	61.00	60.98	60.98	60.98	60.99
56.20	56.18	64.00	64.06	64.05	64.06	64.05	64.05	64.05	64.05	64.08
56.50	56.66	70.00	70.23	70.23	69.70	70.22	70.23	70.24	70.15	70.22
56.80	56.80									
57.10	56.95									
57.40	57.41									
57.70	57.59									
58.00	57.99									
58.30	58.22									
58.60	58.71									
58.90	58.86									
59.20	59.37									
59.50	59.52									
59.80	59.65									
60.10	60.18									
60.40	60.59									
60.70	60.64									
61.00	60.98									
61.30	61.54									
61.60	61.62									
61.90	62.20									
62.20	62.35									
62.50	62.50									
62.80	62.66									
63.10	63.22									
63.40	63.34									
63.70	63.91									
64.00	64.06									
64.30	64.20									
64.60	64.34									
64.90	64.92									
70.00	70.21									

Table C.10: Actual pickup frequency in Hz (100% Voltage, 5% THD, Relay 2)

Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)	Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)							
	0.1		0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
40.00	40.00	40.00	40.00	39.99	40.00	39.99	39.99	40.00	40.01	40.01
55.00	54.97	55.00	54.97	54.98	54.98	54.97	54.97	54.98	54.96	54.99
55.30	55.43	57.10	57.29	56.94	57.30	57.29	57.29	57.26	56.94	57.29
55.60	55.57	58.90	58.87	58.86	58.86	58.87	58.87	58.87	58.84	58.90
55.90	56.04	61.00	61.00	60.98	60.98	60.99	61.00	60.98	60.97	61.01
56.20	56.19	64.00	64.05	64.05	64.05	64.05	64.06	64.06	64.04	64.05
56.50	56.66	70.00	70.22	69.72	69.88	70.23	70.21	70.21	70.26	70.22
56.80	56.80									
57.10	56.95									
57.40	57.42									
57.70	57.59									
58.00	58.08									
58.30	58.22									
58.60	58.70									
58.90	58.86									
59.20	59.38									
59.50	59.52									
59.80	59.64									
60.10	60.18									
60.40	60.69									
60.70	60.85									
61.00	60.99									
61.30	61.55									
61.60	61.66									
61.90	62.20									
62.20	62.29									
62.50	62.49									
62.80	62.76									
63.10	63.21									
63.40	63.34									
63.70	63.91									
64.00	64.06									
64.30	64.21									
64.60	64.78									
64.90	64.93									
70.00	70.22									

Table C.11: Actual pickup frequency in Hz (85% Voltage, 5% THD, Relay 2)

Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)	Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)							
	0.1		0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
40.00	40.00	40.00	40.00	40.00	39.99	39.97	39.99	40.00	40.00	40.00
55.00	54.97	55.00	54.98	54.98	54.97	55.03	54.96	54.98	54.97	54.99
55.30	55.30	57.10	57.29	56.94	57.28	57.28	57.29	57.29	57.16	57.28
55.60	55.56	58.90	58.85	58.86	58.85	58.85	58.85	58.87	58.84	58.85
55.90	56.04	61.00	60.99	61.00	60.97	60.98	60.99	60.98	60.98	60.99
56.20	56.19	64.00	64.06	64.06	64.07	64.06	64.05	64.06	64.05	64.07
56.50	56.67	70.00	70.08	69.73	69.71	70.21	70.22	70.24	70.24	70.22
56.80	56.80									
57.10	56.97									
57.40	57.43									
57.70	57.58									
58.00	58.08									
58.30	58.27									
58.60	58.73									
58.90	58.88									
59.20	59.37									
59.50	59.51									
59.80	59.65									
60.10	60.18									
60.40	60.33									
60.70	60.80									
61.00	60.99									
61.30	61.39									
61.60	61.67									
61.90	62.23									
62.20	62.36									
62.50	62.51									
62.80	62.64									
63.10	63.21									
63.40	63.34									
63.70	63.90									
64.00	64.05									
64.30	64.20									
64.60	64.32									
64.90	64.93									
70.00	70.21									

Table C.12: Actual pickup frequency in Hz (115% Voltage, 5% THD, Relay 2)

Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz)	Frequency Setpoint (Hz)	Rate of Frequency Change (Hz/s)							
	0.1		0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
40.00	40.00	40.00	40.00	40.00	39.99	39.99	40.00	40.00	40.00	40.00
55.00	54.97	55.00	54.98	54.97	54.96	54.97	54.97	55.02	54.96	54.98
55.30	55.24	57.10	57.29	56.94	57.28	57.28	57.29	56.97	56.95	57.19
55.60	55.57	58.90	58.85	58.86	58.85	58.86	58.86	58.87	58.85	58.85
55.90	55.72	61.00	60.99	60.98	60.98	60.97	60.98	60.99	60.98	60.99
56.20	56.19	64.00	64.06	64.05	64.05	64.05	64.04	64.06	64.06	64.04
56.50	56.65	70.00	70.24	70.21	69.71	70.24	70.16	70.11	70.23	70.22
56.80	56.79									
57.10	56.96									
57.40	57.43									
57.70	57.58									
58.00	58.07									
58.30	58.27									
58.60	58.71									
58.90	58.86									
59.20	59.37									
59.50	59.49									
59.80	59.70									
60.10	60.17									
60.40	60.69									
60.70	60.84									
61.00	60.99									
61.30	61.52									
61.60	61.67									
61.90	62.23									
62.20	62.36									
62.50	62.50									
62.80	62.65									
63.10	63.20									
63.40	63.33									
63.70	63.93									
64.00	64.06									
64.30	64.20									
64.60	64.34									
64.90	64.92									
70.00	70.22									

Table C.13: Actual time delay (100% Voltage, 0% THD, 0.1 Hz/sec Rate of Frequency Change, Relay 1)

Frequency Setpoint (Hz)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.10	40.09	6	6.0	40.04	16	16.0	40.00	36	36.0	40.00	66	66.0
55.00	55.00	6	6.0	54.96	16	16.0	54.89	36	36.0	54.78	66	66.1
55.90	55.90	6	6.0	55.86	16	16.0	55.79	36	36.0	55.68	66	66.1
57.10	57.09	6	6.0	57.06	16	16.0	56.99	36	36.0	56.88	66	66.1
58.00	58.00	6	6.0	57.96	16	16.0	57.89	36	36.0	57.79	66	66.1
58.90	58.90	6	6.0	58.86	16	16.0	58.79	36	36.0	58.69	66	66.1
60.10	60.10	6	6.0	60.14	16	16.0	60.21	36	36.0	60.30	66	65.9
61.00	61.01	6	6.0	61.04	16	16.0	61.10	36	36.0	61.20	66	65.9
61.90	61.90	6	6.0	61.94	16	16.0	62.00	36	36.0	62.10	66	65.9
63.10	63.10	6	6.1	63.14	16	16.0	63.20	36	36.0	63.30	66	65.9
64.00	64.00	6	6.0	64.03	16	16.0	64.10	36	36.0	64.19	66	66.0
65.00	65.00	6	6.0	65.04	16	16.0	65.10	36	36.1	65.19	66	66.1
59.30		15 sec	15.38 sec									
59.50		30 sec	31.65 sec									

Table C.14: Actual time delay (100% Voltage, 0% THD, 0.5 Hz/sec Rate of Frequency Change, Relay 1)

Frequency Setpoint (Hz)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.10	40.07	6	6.0	40.00	16	16.0	40.00	36	36.0	40.00	66	66.0
55.00	54.98	6	6.0	54.80	16	16.0	54.43	36	36.1	53.88	66	66.5
55.90	55.88	6	6.0	55.70	16	16.0	55.34	36	36.1	54.79	66	66.5
57.10	57.08	6	5.9	56.90	16	16.0	56.55	36	36.1	56.02	66	66.4
58.00	57.98	6	6.0	57.81	16	16.0	57.46	36	36.0	56.94	66	66.4
58.90	58.88	6	6.0	58.71	16	16.0	58.36	36	36.1	57.85	66	66.4
60.10	60.12	6	6.0	60.28	16	16.0	60.61	36	35.9	61.12	66	65.6
61.00	61.02	6	6.0	61.19	16	16.0	61.51	36	35.9	62.01	66	65.6
61.90	61.92	6	6.0	62.08	16	16.0	62.41	36	36.0	62.89	66	65.6
63.10	63.12	6	6.0	63.28	16	16.0	63.59	36	36.0	64.07	66	65.6
64.00	64.02	6	6.0	64.18	16	16.0	64.49	36	36.0	64.96	66	65.7
65.00	65.02	6	6.0	65.17	16	16.1	65.49	36	36.0	65.94	66	66.1
59.30		15 sec	17.51 sec									

Table C.15: Actual time delay (100% Voltage, 0% THD, 0.9 Hz/sec Rate of Frequency Change, Relay 1)

Frequency Setpoint (Hz)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.10	40.04	6	5.9	40.00	16	15.9	40.00	36	35.9	40.00	66	66.0
55.00	54.96	6	6.0	54.63	16	16.0	53.97	36	36.1	52.98	66	66.8
55.90	55.86	6	6.0	55.53	16	16.0	54.88	36	36.2	53.90	66	66.8
57.10	57.06	6	5.9	56.74	16	16.0	56.10	36	36.1	55.15	66	66.8
58.00	57.97	6	6.0	57.65	16	16.0	57.03	36	36.1	56.09	66	66.8
58.90	58.86	6	6.0	58.55	16	16.0	57.93	36	36.2	57.01	66	66.7
60.10	60.13	6	6.1	60.43	16	16.0	61.02	36	35.9	61.92	66	65.3
61.00	61.04	6	6.0	61.35	16	16.0	61.93	36	35.9	62.80	66	65.3
61.90	61.93	6	6.0	62.22	16	16.0	62.81	36	35.9	63.67	66	65.4
63.10	63.15	6	6.1	63.42	16	16.0	63.99	36	35.9	64.83	66	65.4
64.00	64.04	6	6.0	64.32	16	16.0	64.88	36	35.9	65.72	66	65.5
65.00	65.03	6	6.0	65.31	16	16.1	65.87	36	36.1	66.70	66	66.1
59.30		15 sec	19.52 sec									

Table C.16: Actual time delay (85% Voltage, 0% THD, 0.1 Hz/sec Rate of Frequency Change, Relay 1)

Frequency Setpoint (Hz)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.10	40.10	6	6.0	40.05	16	16.0	40.00	36	36.0	40.00	66	66.1
55.00	55.00	6	6.0	54.96	16	16.0	54.89	36	36.0	54.78	66	66.1
55.90	55.90	6	6.0	55.86	16	16.0	55.79	36	36.0	55.68	66	66.1
57.10	57.09	6	6.0	57.06	16	16.0	56.99	36	36.0	56.88	66	66.1
58.00	58.00	6	6.0	57.96	16	16.0	57.89	36	36.0	57.79	66	66.1
58.90	58.89	6	6.0	58.86	16	16.0	58.79	36	36.0	58.69	66	66.0
60.10	60.10	6	6.0	60.14	16	16.0	60.20	36	36.0	60.31	66	65.9
61.00	61.00	6	6.0	61.04	16	16.0	61.10	36	36.0	61.20	66	65.9
61.90	61.91	6	6.0	61.94	16	16.0	62.00	36	36.0	62.10	66	66.0
63.10	63.11	6	6.0	63.14	16	16.0	63.20	36	36.0	63.30	66	66.0
64.00	64.01	6	6.0	64.04	16	16.0	64.10	36	36.0	64.19	66	66.0
65.00	65.00	6	6.0	65.03	16	16.1	65.10	36	36.0	65.19	66	66.1
59.30		15 sec	15.38 sec									
59.50		30 sec	31.65 sec									

Table C.17: Actual time delay (85% Voltage, 0% THD, 0.5 Hz/sec Rate of Frequency Change, Relay 1)

Frequency Setpoint (Hz)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.10	40.07	6	6.0	40.00	16	16.0	40.00	36	36.0	40.00	66	66.0
55.00	54.98	6	6.0	54.80	16	16.0	54.43	36	36.1	53.88	66	66.5
55.90	55.88	6	6.0	55.70	16	16.0	55.34	36	36.1	54.79	66	66.5
57.10	57.08	6	5.9	56.90	16	16.0	56.55	36	36.1	56.02	66	66.4
58.00	57.98	6	6.0	57.81	16	16.0	57.46	36	36.1	56.94	66	66.4
58.90	58.88	6	6.0	58.70	16	16.0	58.37	36	36.0	57.85	66	66.4
60.10	60.12	6	6.0	60.28	16	16.0	60.61	36	35.9	61.12	66	65.6
61.00	61.02	6	6.0	61.19	16	16.0	61.51	36	35.9	62.01	66	65.6
61.90	61.92	6	6.1	62.08	16	16.0	62.40	36	35.9	62.89	66	65.7
63.10	63.13	6	6.0	63.27	16	16.0	63.60	36	36.0	64.07	66	65.6
64.00	64.02	6	6.0	64.18	16	16.1	64.49	36	36.0	64.96	66	65.7
65.00	65.02	6	6.0	65.17	16	16.1	65.49	36	36.1	65.95	66	66.1
59.30		15 sec	17.51 sec									

Table C.18: Actual time delay (85% Voltage, 0% THD, 0.9 Hz/sec Rate of Frequency Change, Relay 1)

Frequency Setpoint (Hz)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.10	40.04	6	5.9	40.00	16	15.9	40.00	36	35.9	40.00	66	66.0
55.00	54.96	6	5.9	54.63	16	16.0	53.97	36	36.1	52.98	66	66.8
55.90	55.86	6	6.0	55.53	16	16.0	54.88	36	36.2	53.90	66	66.9
57.10	57.06	6	6.0	56.74	16	16.0	56.10	36	36.1	55.15	66	66.8
58.00	57.96	6	6.0	57.65	16	16.0	57.03	36	36.1	56.07	66	66.8
58.90	58.86	6	5.9	58.55	16	16.0	57.93	36	36.2	57.01	66	66.7
60.10	60.13	6	6.0	60.43	16	16.0	61.02	36	35.9	61.92	66	65.3
61.00	61.04	6	6.0	61.33	16	16.0	61.92	36	35.9	62.80	66	65.3
61.90	61.93	6	6.0	62.22	16	16.0	62.81	36	35.9	63.66	66	65.3
63.10	63.13	6	6.0	63.42	16	16.0	63.99	36	35.9	64.83	66	65.4
64.00	64.04	6	6.0	64.33	16	16.0	64.89	36	35.9	65.71	66	65.5
65.00	65.04	6	6.0	65.31	16	16.0	65.87	36	36.1	66.70	66	66.1
59.30		15 sec	19.52 sec									

Table C.19: Actual time delay (115% Voltage, 0% THD, 0.1 Hz/sec Rate of Frequency Change, Relay 1)

Frequency Setpoint (Hz)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.10	40.09	6	6.0	40.04	16	16.0	40.00	36	36.0	40.00	66	66.0
55.00	55.00	6	6.0	54.96	16	16.0	54.89	36	36.0	54.78	66	66.1
55.90	55.89	6	6.0	55.86	16	16.0	55.79	36	36.0	55.68	66	66.1
57.10	57.09	6	6.1	57.06	16	16.0	56.99	36	36.0	56.88	66	66.1
58.00	58.00	6	6.0	57.96	16	16.0	57.89	36	36.0	57.79	66	66.1
58.90	58.90	6	5.9	58.86	16	16.0	58.79	36	36.0	58.69	66	66.0
60.10	60.11	6	6.0	60.14	16	16.0	60.20	36	36.0	60.31	66	66.0
61.00	61.00	6	6.0	61.04	16	16.0	61.10	36	36.0	61.20	66	65.9
61.90	61.90	6	6.0	61.94	16	16.0	62.00	36	36.0	62.10	66	65.9
63.10	63.11	6	6.0	63.14	16	16.0	63.20	36	36.0	63.29	66	66.0
64.00	64.00	6	6.0	64.04	16	16.0	64.10	36	36.0	64.19	66	66.0
65.00	65.00	6	6.0	65.03	16	16.1	65.10	36	36.0	65.19	66	66.0
59.30		15 sec	15.38 sec									
59.50		30 sec	31.65 sec									

Table C.20: Actual time delay (115% Voltage, 0% THD, 0.5 Hz/sec Rate of Frequency Change, Relay 1)

Frequency Setpoint (Hz)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.10	40.07	6	6.0	40.00	16	16.0	40.00	36	36.0	40.00	66	66.0
55.00	54.98	6	6.0	54.80	16	16.0	54.43	36	36.1	53.88	66	66.5
55.90	55.87	6	6.0	55.70	16	16.0	55.34	36	36.1	54.80	66	66.5
57.10	57.08	6	6.0	56.90	16	16.0	56.55	36	36.1	56.02	66	66.4
58.00	57.98	6	6.0	57.81	16	16.0	57.46	36	36.0	56.94	66	66.4
58.90	58.88	6	5.9	57.81	16	16.0	58.37	36	36.0	57.85	66	66.4
60.10	60.12	6	6.0	60.28	16	16.0	60.62	36	35.9	61.12	66	65.6
61.00	61.02	6	6.0	61.19	16	16.0	61.51	36	35.9	62.00	66	65.6
61.90	61.92	6	6.0	62.08	16	16.0	62.41	36	36.0	62.89	66	65.7
63.10	63.12	6	6.0	63.28	16	16.0	63.59	36	36.0	64.08	66	65.6
64.00	64.02	6	6.0	64.18	16	16.1	64.50	36	36.0	64.95	66	65.7
65.00	65.02	6	6.0	65.17	16	16.1	65.49	36	36.0	65.94	66	66.1
59.30		15 sec	17.51 sec									

Table C.21: Actual time delay (115% Voltage, 0% THD, 0.9 Hz/sec Rate of Frequency Change, Relay 1)

Frequency Setpoint (Hz)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.10	40.04	6	6.0	40.00	16	15.9	40.00	36	35.9	40.00	66	66.0
55.00	54.96	6	6.0	54.64	16	16.0	53.97	36	36.1	52.98	66	66.9
55.90	55.86	6	6.0	55.53	16	16.0	54.88	36	36.1	53.90	66	66.9
57.10	57.06	6	5.9	56.74	16	16.0	56.10	36	36.1	55.15	66	66.8
58.00	57.96	6	6.0	57.65	16	16.0	57.03	36	36.1	56.09	66	66.8
58.90	58.86	6	5.9	58.55	16	16.0	57.93	36	36.2	57.01	66	66.8
60.10	60.13	6	6.0	60.45	16	16.0	61.04	36	35.9	61.92	66	65.3
61.00	61.05	6	6.0	61.35	16	16.0	61.93	36	35.9	62.80	66	65.3
61.90	61.93	6	6.0	62.24	16	16.0	62.81	36	35.9	63.67	66	65.4
63.10	63.13	6	6.1	63.42	16	16.0	63.99	36	35.9	64.83	66	65.4
64.00	64.04	6	6.0	64.32	16	16.0	64.89	36	35.9	65.72	66	65.5
65.00	65.04	6	6.0	65.31	16	16.1	65.88	36	36.1	66.70	66	66.1
59.30		15 sec	19.52 sec									

Table C.22: Actual time delay (100% Voltage, 5% THD, 0.1 Hz/sec Rate of Frequency Change, Relay 1)

Frequency Setpoint (Hz)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.10	40.09	6	6.0	40.04	16	16.0	40.00	36	36.0	40.00	66	66.0
55.00	55.00	6	6.0	54.96	16	16.0	54.89	36	36.0	54.78	66	66.1
55.90	55.90	6	6.0	55.86	16	16.0	55.79	36	36.0	55.68	66	66.1
57.10	57.10	6	6.0	57.06	16	16.0	56.99	36	36.0	56.89	66	66.1
58.00	58.00	6	6.0	57.96	16	16.0	57.89	36	36.0	57.79	66	66.1
58.90	58.90	6	6.0	58.86	16	16.0	58.79	36	36.0	58.69	66	66.0
60.10	60.10	6	6.0	60.14	16	16.0	60.20	36	36.0	60.30	66	65.9
61.00	61.01	6	6.0	61.04	16	16.0	61.10	36	36.0	61.20	66	65.9
61.90	61.90	6	6.0	61.94	16	16.0	62.00	36	36.0	62.10	66	65.9
63.10	63.10	6	6.0	63.14	16	16.0	63.20	36	36.0	63.30	66	65.9
64.00	64.00	6	6.0	64.03	16	16.0	64.10	36	36.0	64.19	66	66.0
65.00	65.00	6	6.0	65.03	16	16.0	65.10	36	36.0	65.19	66	66.1
59.30		15 sec	15.38 sec									
59.50		30 sec	31.65 sec									

Table C.23: Actual time delay (100% Voltage, 5% THD, 0.5 Hz/sec Rate of Frequency Change, Relay 1)

Frequency Setpoint (Hz)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.10	40.07	6	6.0	40.00	16	15.9	40.00	36	36.0	40.00	66	66.0
55.00	54.98	6	6.0	54.80	16	16.0	54.43	36	36.1	53.88	66	66.4
55.90	55.88	6	6.0	55.70	16	16.0	55.34	36	36.1	54.79	66	66.5
57.10	57.08	6	6.0	56.90	16	16.0	56.55	36	36.0	56.02	66	66.4
58.00	57.98	6	6.0	57.81	16	16.0	57.46	36	36.0	56.94	66	66.4
58.90	58.88	6	5.9	58.71	16	16.0	58.37	36	36.0	57.85	66	66.4
60.10	60.12	6	6.0	60.28	16	16.0	60.62	36	35.9	61.12	66	65.6
61.00	61.02	6	6.0	61.19	16	16.0	61.52	36	35.9	62.01	66	65.6
61.90	61.92	6	6.0	62.08	16	16.0	62.41	36	36.0	62.89	66	65.6
63.10	63.12	6	6.0	63.28	16	16.0	63.59	36	35.9	64.07	66	65.7
64.00	64.02	6	6.0	64.18	16	16.0	64.49	36	36.0	64.95	66	65.7
65.00	65.02	6	6.0	65.17	16	16.0	65.49	36	36.1	65.94	66	66.1
59.30		15 sec	17.51 sec									

Table C.24: Actual time delay (100% Voltage, 5% THD, 0.9 Hz/sec Rate of Frequency Change, Relay 1)

Frequency Setpoint (Hz)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.10	40.04	6	6.0	40.00	16	15.9	40.00	36	36.0	40.00	66	66.0
55.00	54.96	6	6.0	54.64	16	16.0	53.97	36	36.1	52.98	66	66.9
55.90	55.86	6	6.0	55.53	16	16.0	54.88	36	36.1	53.90	66	66.9
57.10	57.06	6	6.0	56.74	16	16.0	56.10	36	36.1	55.15	66	66.8
58.00	57.96	6	6.0	57.66	16	16.0	57.03	36	36.1	56.07	66	66.8
58.90	58.86	6	5.9	58.55	16	16.0	57.94	36	36.2	57.01	66	66.7
60.10	60.13	6	6.0	60.45	16	16.0	61.04	36	35.9	61.92	66	65.3
61.00	61.04	6	6.0	61.35	16	16.0	61.93	36	35.9	62.80	66	65.3
61.90	61.93	6	6.0	62.23	16	16.0	62.81	36	35.9	63.67	66	65.3
63.10	63.13	6	6.0	63.42	16	16.0	63.99	36	35.9	64.83	66	65.4
64.00	64.04	6	6.0	64.33	16	16.1	64.89	36	35.9	65.72	66	65.5
65.00	65.04	6	6.0	65.31	16	16.1	65.87	36	36.1	66.71	66	66.1
59.30		15 sec	19.52 sec									

Table C.25: Actual time delay (85% Voltage, 5% THD, 0.1 Hz/sec Rate of Frequency Change, Relay 1)

Frequency Setpoint (Hz)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.10	40.10	6	6.0	40.04	16	16.0	40.00	36	36.0	40.00	66	66.1
55.00	55.00	6	6.0	54.96	16	16.0	54.89	36	36.0	54.78	66	66.1
55.90	55.89	6	6.0	55.86	16	16.0	55.79	36	36.0	55.68	66	66.1
57.10	57.09	6	6.0	57.06	16	16.0	56.99	36	36.0	56.89	66	66.1
58.00	58.00	6	6.0	57.96	16	16.0	57.89	36	36.0	57.79	66	66.1
58.90	58.89	6	6.0	58.86	16	16.0	58.79	36	36.0	58.69	66	66.0
60.10	60.10	6	6.0	60.14	16	16.0	60.20	36	36.0	60.30	66	65.9
61.00	61.00	6	6.0	61.04	16	16.0	61.10	36	36.1	61.20	66	65.9
61.90	61.91	6	6.0	61.94	16	16.0	62.00	36	36.0	62.10	66	65.9
63.10	63.11	6	6.1	63.13	16	16.0	63.20	36	36.0	63.29	66	65.9
64.00	64.01	6	6.0	64.04	16	16.0	64.10	36	36.0	64.19	66	66.0
65.00	65.00	6	6.0	65.03	16	16.0	65.10	36	36.1	65.19	66	66.1
59.30		15 sec	15.38 sec									
59.50		30 sec	31.65 sec									

Table C.26: Actual time delay (85% Voltage, 5% THD, 0.5 Hz/sec Rate of Frequency Change, Relay 1)

Frequency Setpoint (Hz)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.10	40.07	6	6.0	40.00	16	16.0	40.00	36	36.0	40.00	66	66.0
55.00	54.98	6	6.0	54.80	16	16.0	54.43	36	36.1	53.88	66	66.5
55.90	55.88	6	6.0	55.70	16	16.0	55.34	36	36.1	54.79	66	66.4
57.10	57.07	6	6.0	56.90	16	16.0	56.55	36	36.0	56.02	66	66.5
58.00	57.98	6	6.0	57.81	16	16.0	57.46	36	36.1	56.95	66	66.4
58.90	58.88	6	5.9	58.71	16	16.0	58.37	36	36.0	57.85	66	66.4
60.10	60.12	6	6.0	60.28	16	16.0	60.62	36	35.9	61.12	66	65.6
61.00	61.02	6	6.0	61.19	16	16.0	61.51	36	36.0	62.01	66	65.6
61.90	61.92	6	6.0	62.08	16	16.0	62.40	36	35.9	62.89	66	65.6
63.10	63.12	6	6.0	63.28	16	16.0	63.60	36	35.9	64.07	66	65.6
64.00	64.02	6	6.0	64.18	16	16.0	64.49	36	36.0	64.96	66	65.7
65.00	65.02	6	6.0	65.17	16	16.0	65.48	36	36.0	65.94	66	66.1
59.30		15 sec	17.51 sec									

Table C.27: Actual time delay (85% Voltage, 5% THD, 0.9 Hz/sec Rate of Frequency Change, Relay 1)

Frequency Setpoint (Hz)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.10	40.04	6	5.9	40.00	16	15.9	40.00	36	35.9	40.00	66	66.0
55.00	54.96	6	5.9	54.63	16	16.0	53.97	36	36.1	52.98	66	66.9
55.90	55.86	6	6.0	55.53	16	16.0	54.88	36	36.1	53.90	66	66.8
57.10	57.06	6	5.9	56.74	16	16.0	56.10	36	36.1	55.15	66	66.8
58.00	57.96	6	6.0	57.65	16	16.0	57.03	36	36.1	56.09	66	66.8
58.90	58.86	6	5.9	58.55	16	16.0	57.93	36	36.1	57.01	66	66.7
60.10	60.13	6	6.0	60.43	16	16.0	61.02	36	35.9	61.92	66	65.3
61.00	61.04	6	6.0	61.35	16	16.0	61.93	36	35.9	62.80	66	65.3
61.90	61.93	6	6.0	62.24	16	16.0	62.80	36	35.9	63.67	66	65.4
63.10	63.14	6	6.1	63.41	16	16.0	64.00	36	35.9	64.83	66	65.4
64.00	64.04	6	6.0	64.32	16	16.1	64.89	36	35.8	65.71	66	65.5
65.00	65.04	6	6.0	65.31	16	16.0	65.88	36	36.1	66.70	66	66.1
59.30		15 sec	19.52 sec									

Table C.28: Actual time delay (115% Voltage, 5% THD, 0.1 Hz/sec Rate of Frequency Change, Relay 1)

Frequency Setpoint (Hz)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.10	40.09	6	6.0	40.04	16	16.0	40.00	36	36.0	40.00	66	66.1
55.00	54.99	6	6.0	54.96	16	16.0	54.89	36	36.0	54.78	66	66.1
55.90	55.90	6	6.0	55.86	16	16.0	55.79	36	36.0	55.68	66	66.1
57.10	57.10	6	6.0	57.06	16	16.0	56.99	36	36.0	56.88	66	66.1
58.00	58.00	6	6.0	57.96	16	16.0	57.89	36	36.0	57.79	66	66.1
58.90	58.90	6	5.9	58.86	16	16.0	58.79	36	36.0	58.69	66	66.0
60.10	61.11	6	6.0	60.14	16	16.0	60.21	36	36.0	60.30	66	65.9
61.00	61.00	6	6.0	61.04	16	16.0	61.10	36	36.0	61.20	66	65.9
61.90	61.90	6	6.0	61.93	16	16.0	62.00	36	36.0	62.10	66	66.0
63.10	63.10	6	6.0	63.14	16	16.0	63.20	36	36.0	63.30	66	65.9
64.00	64.00	6	6.0	64.04	16	16.0	64.10	36	36.0	64.19	66	65.9
65.00	65.00	6	6.0	65.03	16	16.0	65.10	36	36.1	65.19	66	66.1
59.30		15 sec	15.38 sec									
59.50		30 sec	31.65 sec									

Table C.29: Actual time delay (115% Voltage, 5% THD, 0.5 Hz/sec Rate of Frequency Change, Relay 1)

Frequency Setpoint (Hz)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.10	40.07	6	6.0	40.00	16	16.0	40.00	36	36.0	40.00	66	66.0
55.00	54.98	6	6.0	54.80	16	16.0	54.43	36	36.1	53.88	66	66.5
55.90	55.88	6	6.0	55.70	16	16.0	55.34	36	36.1	54.79	66	66.5
57.10	57.07	6	6.0	56.90	16	16.0	56.55	36	36.1	56.02	66	66.5
58.00	57.97	6	6.0	57.81	16	16.0	57.46	36	36.1	56.94	66	66.4
58.90	58.88	6	6.0	58.71	16	16.0	58.37	36	36.0	57.85	66	66.4
60.10	60.12	6	6.0	60.28	16	16.0	60.62	36	35.9	61.12	66	65.6
61.00	61.02	6	6.0	61.18	16	16.0	61.52	36	35.9	62.01	66	65.6
61.90	61.92	6	6.0	62.08	16	16.0	62.40	36	36.0	62.89	66	65.6
63.10	63.12	6	6.0	63.28	16	16.0	63.59	36	36.0	64.07	66	65.6
64.00	64.02	6	6.0	64.18	16	16.0	64.49	36	36.0	64.96	66	65.7
65.00	65.02	6	6.0	65.17	16	16.1	65.48	36	36.1	65.94	66	66.1
59.30		15 sec	17.51 sec									

Table C.30: Actual time delay (115% Voltage, 5% THD, 0.9 Hz/sec Rate of Frequency Change, Relay 1)

Frequency Setpoint (Hz)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Tripped Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.10	40.04	6	6.0	40.00	16	15.9	40.00	36	36.0	40.00	66	66.0
55.00	54.96	6	6.0	54.64	16	16.0	53.97	36	36.1	52.98	66	66.9
55.90	55.86	6	6.0	55.53	16	16.0	54.88	36	36.1	53.90	66	66.9
57.10	57.06	6	6.0	56.74	16	16.0	56.10	36	36.1	55.15	66	66.8
58.00	57.96	6	6.0	57.65	16	16.0	57.03	36	36.1	56.09	66	66.8
58.90	58.86	6	5.9	58.55	16	16.0	57.93	36	36.1	57.01	66	66.7
60.10	60.13	6	6.0	60.43	16	16.0	61.04	36	35.9	61.92	66	65.3
61.00	61.04	6	6.0	61.35	16	16.0	61.93	36	35.9	62.80	66	65.3
61.90	61.93	6	6.1	62.22	16	16.0	62.80	36	35.9	63.67	66	65.4
63.10	63.13	6	6.1	64.32	16	16.0	63.99	36	35.8	64.83	66	65.4
64.00	64.04	6	6.0	64.32	16	16.1	64.89	36	35.9	65.72	66	65.5
65.00	65.04	6	6.0	65.31	16	16.1	65.87	36	36.0	66.70	66	66.1
59.30		15 sec	19.52 sec									

Table C.31: Actual time delay (100% Voltage, 0% THD, 0.1 Hz/sec Rate of Frequency Change, Relay 2)

Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.00	39.99	6	6.3	40.00	16	15.3	40.00	36	33.3	39.98	66	61.5
55.00	55.01	6	5.9	54.97	16	15.4	54.96	36	33.4	54.97	66	62.6
57.10	57.29	6	5.4	57.03	16	16.4	56.95	36	34.5	57.28	66	63.6
58.90	58.86	6	5.4	58.85	16	13.4	58.86	36	34.5	58.84	66	58.6
61.00	61.00	6	6.4	61.01	16	15.4	61.00	36	36.4	61.00	66	57.3
64.00	64.06	6	6.5	64.06	16	13.5	64.05	36	35.5	64.06	66	63.4
70.00	70.17	6	6.0	70.13	16	16.0	70.23	36	27.0	70.23	66	64.0

Table C.32: Actual time delay (100% Voltage, 0% THD, 0.5 Hz/sec Rate of Frequency Change, Relay 2)

Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.00	40.00	6	6.3	39.99	16	16.3	39.96	36	33.7	39.99	66	66.7
55.00	54.98	6	5.9	54.96	16	15.4	54.96	36	35.6	54.93	66	63.1
57.10	56.95	6	5.4	56.94	16	15.5	56.94	36	35.6	56.90	66	61.1
58.90	58.87	6	6.4	58.86	16	16.5	58.86	36	35.6	58.80	66	62.1
61.00	60.99	6	4.4	60.99	16	16.4	60.95	36	36.3	61.04	66	56.9
64.00	64.05	6	6.5	63.96	16	16.5	64.07	36	34.3	64.07	66	64.0
70.00	70.21	6	6.0	70.25	16	13.1	70.18	36	35.9	70.25	66	63.6

Table C.33: Actual time delay (100% Voltage, 0% THD, 0.9 Hz/sec Rate of Frequency Change, Relay 2)

Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.00	40.01	6	6.3	40.00	16	16.4	39.94	36	34.0	39.94	66	65.9
55.00	54.91	6	6.0	54.92	16	12.5	54.93	36	33.8	54.96	66	66.7
57.10	57.26	6	6.4	57.10	16	16.5	57.27	36	33.8	56.93	66	65.7
58.90	59.02	6	6.4	58.88	16	16.5	58.76	36	30.8	58.78	66	61.6
61.00	61.01	6	5.4	60.97	16	16.4	60.98	36	36.1	61.01	66	63.4
64.00	64.04	6	6.5	64.06	16	15.4	64.09	36	33.2	64.11	66	62.1
70.00	69.98	6	6.0	70.11	16	16.0	70.25	36	33.8	70.28	66	62.3

Table C.34: Actual time delay (85% Voltage, 0% THD, 0.1 Hz/sec Rate of Frequency Change, Relay 2)

Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.00	40.00	6	6.2	40.01	16	16.3	40.00	36	33.3	39.96	66	62.5
55.00	55.04	6	5.9	54.98	16	14.4	54.97	36	36.4	54.97	66	58.5
57.10	57.29	6	6.4	57.05	16	15.4	57.29	36	36.5	56.93	66	64.6
58.90	58.87	6	5.4	58.86	16	13.4	58.85	36	32.5	58.85	66	59.6
61.00	61.00	6	6.4	60.99	16	14.4	60.99	36	33.4	61.01	66	58.3
64.00	64.01	6	6.5	64.03	16	16.5	64.06	36	34.4	64.06	66	63.4
70.00	70.23	6	5.0	70.21	16	14.0	70.23	36	34.0	70.22	66	65.0

Table C.35: Actual time delay (85% Voltage, 0% THD, 0.5 Hz/sec Rate of Frequency Change, Relay 2)

Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.00	39.99	6	6.3	39.98	16	15.3	39.99	36	35.7	39.92	66	61.7
55.00	55.04	6	6.0	54.97	16	15.5	54.94	36	31.6	54.94	66	65.1
57.10	57.29	6	6.4	56.96	16	15.5	57.27	36	36.6	56.91	66	63.1
58.90	58.85	6	6.4	58.86	16	16.5	58.84	36	34.6	58.84	66	64.1
61.00	60.99	6	4.4	61.00	16	16.4	61.05	36	30.3	61.00	66	63.9
64.00	64.06	6	6.5	64.05	16	16.5	64.07	36	33.3	64.09	66	59.5
70.00	70.12	6	6.0	70.24	16	13.0	70.24	36	32.9	70.27	66	59.6

Table C.36: Actual time delay (85% Voltage, 0% THD, 0.9 Hz/sec Rate of Frequency Change, Relay 2)

Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.00	40.00	6	6.3	39.98	16	15.4	39.98	36	36.0	39.74	66	64.9
55.00	54.95	6	6.0	54.95	16	14.5	54.91	36	32.8	54.97	66	66.7
57.10	56.94	6	5.4	56.95	16	15.5	56.83	36	27.8	56.87	66	60.6
58.90	59.22	6	5.4	58.83	16	13.5	58.78	36	31.8	58.72	66	60.6
61.00	61.00	6	5.4	60.98	16	15.4	61.05	36	32.1	61.17	66	52.5
64.00	64.06	6	6.5	64.07	16	14.4	64.04	36	34.2	64.13	66	58.1
70.00	70.23	6	6.0	70.23	16	16.0	70.22	36	35.8	70.29	66	59.3

Table C.37: Actual time delay (115% Voltage, 0% THD, 0.1 Hz/sec Rate of Frequency Change, Relay 2)

Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.00	39.99	6	6.2	39.99	16	16.3	40.00	36	35.3	39.99	66	65.5
55.00	55.01	6	5.9	54.97	16	14.4	54.96	36	30.4	54.96	66	61.6
57.10	56.95	6	6.4	56.95	16	14.4	56.96	36	36.4	57.29	66	63.6
58.90	58.86	6	6.4	58.84	16	14.4	58.86	36	33.5	58.85	66	62.6
61.00	60.98	6	6.4	60.98	16	16.4	60.99	36	35.4	61.00	66	59.3
64.00	64.06	6	6.5	64.02	16	16.5	64.06	36	35.4	64.06	66	64.4
70.00	70.19	6	6.0	70.23	16	14.0	70.23	36	34.0	70.24	66	57.0

Table C.38: Actual time delay (115% Voltage, 0% THD, 0.5 Hz/sec Rate of Frequency Change, Relay 2)

Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.00	40.00	6	6.3	39.99	16	16.3	39.97	36	34.7	39.96	66	64.7
55.00	54.98	6	5.9	54.97	16	15.4	54.97	36	36.6	54.93	66	63.1
57.10	56.96	6	6.4	56.96	16	16.5	57.08	36	36.6	56.92	66	64.1
58.90	58.86	6	6.4	58.85	16	16.5	58.84	36	35.6	58.81	66	61.1
61.00	60.99	6	4.4	61.00	16	14.4	61.02	36	30.3	61.08	66	55.9
64.00	64.05	6	6.5	64.04	16	16.5	63.95	36	36.3	64.08	66	63.0
70.00	70.22	6	6.0	70.24	16	14.0	70.24	36	34.9	70.02	66	61.6

Table C.39: Actual time delay (115% Voltage, 0% THD, 0.9 Hz/sec Rate of Frequency Change, Relay 2)

Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.00	40.01	6	6.3	40.01	16	16.4	39.98	36	36.0	39.92	66	64.9
55.00	54.91	6	6.0	54.98	16	16.5	54.97	36	35.8	54.96	66	66.7
57.10	56.93	6	5.4	56.91	16	13.5	57.08	36	36.8	56.91	66	64.7
58.90	58.84	6	5.4	58.80	16	12.5	58.78	36	30.8	58.83	66	65.6
61.00	60.97	6	6.4	60.99	16	16.4	61.00	36	35.1	61.12	66	56.4
64.00	64.04	6	6.5	64.03	16	16.4	64.06	36	35.2	64.07	66	63.1
70.00	70.23	6	6.0	70.24	16	14.0	70.27	36	32.8	70.29	66	59.3

Table C.40: Actual time delay (115% Voltage, 5% THD, 0.1 Hz/sec Rate of Frequency Change, Relay 2)

Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.00	40.00	6	6.3	40.00	16	16.3	40.00	36	34.3	39.99	66	61.5
55.00	55.07	6	5.9	54.97	16	15.4	54.98	36	34.4	54.97	66	64.5
57.10	56.95	6	5.4	56.96	16	16.4	57.26	36	35.5	56.94	66	57.5
58.90	58.85	6	5.4	58.85	16	14.4	58.85	36	33.5	58.85	66	61.6
61.00	60.99	6	6.5	61.00	16	15.4	60.99	36	33.4	61.01	66	57.3
64.00	64.06	6	6.5	64.05	16	16.5	64.05	36	35.5	64.06	66	64.4
70.00	70.22	6	5.0	70.21	16	16.0	70.236	36	28.0	70.23	66	57.0

Table C.41: Actual time delay (115% Voltage, 5% THD, 0.5 Hz/sec Rate of Frequency Change, Relay 2)

Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.00	40.00	6	6.3	39.99	16	16.3	39.96	36	33.7	39.95	66	63.7
55.00	55.04	6	5.9	54.94	16	13.4	54.94	36	33.6	54.91	66	60.1
57.10	56.94	6	6.4	57.30	16	16.5	57.01	36	36.6	56.94	66	66.1
58.90	58.86	6	6.4	58.84	16	13.5	58.86	36	36.6	58.85	66	65.1
61.00	61.00	6	5.4	60.98	16	15.4	61.01	36	35.3	61.06	66	57.9
64.00	64.06	6	6.5	64.05	16	16.5	64.05	36	36.3	64.07	66	63.5
70.00	70.23	6	5.1	70.24	16	14.0	70.22	36	35.9	70.26	66	59.6

Table C.42: Actual time delay (115% Voltage, 5% THD, 0.9 Hz/sec Rate of Frequency Change, Relay 2)

Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.00	40.00	6	6.3	39.96	16	15.4	39.97	36	36.0	39.94	66	65.9
55.00	54.91	6	5.9	54.97	16	15.5	54.95	36	34.8	54.90	66	62.7
57.10	57.28	6	6.4	57.29	16	16.5	56.88	36	31.8	57.22	66	61.7
58.90	58.90	6	6.4	58.82	16	13.5	58.76	36	30.8	58.76	66	60.6
61.00	60.99	6	6.4	61.00	16	15.4	61.06	36	31.1	61.15	66	59.4
64.00	64.06	6	6.5	64.08	16	13.4	64.07	36	34.2	64.12	66	60.1
70.00	69.98	6	6.0	70.24	16	14.0	70.22	36	35.8	70.28	66	61.3

Table C.43: Actual time delay (85% Voltage, 5% THD, 0.1 Hz/sec Rate of Frequency Change, Relay 2)

Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.00	39.99	6	6.3	39.99	16	16.3	39.99	36	32.3	39.99	66	63.5
55.00	55.01	6	5.9	54.97	16	16.4	54.98	36	35.4	54.97	66	65.6
57.10	57.28	6	6.4	57.29	16	14.4	57.03	36	36.5	56.95	66	64.6
58.90	58.85	6	5.4	58.87	16	14.4	58.86	36	34.5	58.84	66	62.6
61.00	61.00	6	4.4	60.99	16	16.4	60.99	36	33.4	61.00	66	62.3
64.00	64.05	6	6.5	64.06	16	14.5	64.05	36	34.4	64.06	66	64.4
70.00	70.23	6	6.0	70.22	16	14.0	70.21	36	28.0	70.23	66	64.0

Table C.44: Actual time delay (85% Voltage, 5% THD, 0.5 Hz/sec Rate of Frequency Change, Relay 2)

Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.00	40.00	6	6.3	39.99	16	16.4	39.98	36	34.7	39.91	66	59.7
55.00	54.98	6	6.0	54.97	16	14.4	54.94	36	33.6	54.95	66	65.1
57.10	57.05	6	6.4	57.12	16	16.4	56.95	36	35.6	56.88	66	59.1
58.90	58.86	6	6.4	58.84	16	13.5	58.86	36	34.6	58.81	66	60.1
61.00	61.01	6	4.4	61.00	16	13.4	60.97	36	36.3	61.04	66	63.9
64.00	64.06	6	6.5	64.06	16	14.5	63.99	36	36.3	64.07	66	63.5
70.00	70.21	6	6.0	70.23	16	16.0	70.12	36	35.9	70.23	66	62.6

Table C.45: Actual time delay (85% Voltage, 5% THD, 0.9 Hz/sec Rate of Frequency Change, Relay 2)

Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.00	40.00	6	6.3	39.87	16	10.4	39.97	36	36.0	39.94	66	66.9
55.00	54.95	6	5.9	54.95	16	14.5	54.97	36	36.8	54.92	66	63.7
57.10	57.29	6	6.4	57.29	16	16.5	57.21	36	29.8	56.83	66	58.6
58.90	58.85	6	6.4	58.84	16	14.5	58.78	36	31.8	58.80	66	63.6
61.00	61.00	6	5.4	60.99	16	16.4	61.06	36	30.1	61.17	66	52.5
64.00	64.05	6	5.5	64.06	16	16.4	64.02	36	35.7	64.15	66	58.1
70.00	70.06	6	6.0	70.18	16	16.0	70.25	36	35.8	70.02	66	63.3

Table C.46: Actual time delay (115% Voltage, 5% THD, 0.1 Hz/sec Rate of Frequency Change, Relay 2)

Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.00	40.01	6	6.2	40.00	16	16.3	40.00	36	35.3	39.94	66	65.5
55.00	55.01	6	5.9	54.98	16	16.4	54.95	36	27.4	54.97	66	58.5
57.10	56.95	6	6.4	57.28	16	15.4	57.01	36	36.5	56.95	66	64.6
58.90	58.86	6	6.4	58.86	16	14.4	58.86	36	35.5	58.84	66	62.6
61.00	60.99	6	6.4	60.98	16	15.4	61.00	36	32.4	60.99	66	60.3
64.00	64.06	6	6.5	64.05	16	15.5	64.06	36	35.4	64.06	66	62.4
70.00	70.23	6	5.0	70.20	16	16.1	70.24	36	32.0	70.20	66	61.0

Table C.47: Actual time delay (115% Voltage, 5% THD, 0.5 Hz/sec Rate of Frequency Change, Relay 2)

Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.00	40.00	6	6.2	39.98	16	15.3	39.96	36	33.7	39.95	66	63.7
55.00	55.04	6	5.9	54.96	16	15.4	54.96	36	34.6	54.95	66	65.1
57.10	56.95	6	6.4	57.29	16	15.5	56.95	36	35.6	57.28	66	65.1
58.90	58.86	6	6.4	58.86	16	16.5	58.85	36	36.6	58.83	66	63.1
61.00	60.99	6	6.4	60.90	16	16.4	61.04	36	29.3	61.00	66	63.9
64.00	64.05	6	6.5	64.06	16	16.4	64.06	36	35.3	64.08	66	62.5
70.00	70.22	6	6.0	70.15	16	16.0	70.10	36	35.9	70.26	66	60.6

Table C.48: Actual time delay (115% Voltage, 5% THD, 0.9 Hz/sec Rate of Frequency Change, Relay 2)

Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)	Actual Pickup Frequency (Hz)	Time Delay Setpoint (Cycles)	Actual Time Delay (Cycles)
40.00	40.01	6	6.3	39.99	16	15.4	39.98	36	36.0	39.92	66	64.9
55.00	54.95	6	5.9	54.97	16	16.5	54.98	36	36.8	54.93	66	64.7
57.10	57.11	6	6.4	57.26	16	14.5	56.93	36	35.8	56.90	66	62.7
58.90	58.85	6	6.4	58.81	16	12.5	58.83	36	34.8	58.85	66	66.6
61.00	61.00	6	5.4	60.97	16	16.4	61.04	36	32.1	61.07	66	59.4
64.00	64.07	6	5.0	64.07	16	15.4	64.07	36	35.2	64.08	66	62.1
70.00	70.05	6	6.0	70.20	16	16.0	70.21	36	35.8	70.24	66	63.3

Table C.49: Application test of relay 1 (Time delay: 2 Cycles)

Power Factor	Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz) Test no.1	Actual Pickup Frequency (Hz) Test no.2	Actual Pickup Frequency (Hz) Test no.3
1	60.5	60.398	60.364	60.396
0.9	60.5	60.377	60.381	60.440
0.8	60.5	60.400	60.385	60.389
0.7	60.5	60.386	60.374	60.389
0.6	60.5	60.396	60.373	60.362
1	61.0	60.995	60.990	61.001
0.9	61.0	61.001	61.008	61.004
0.8	61.0	60.993	61.072	60.991
0.7	61.0	61.069	60.988	60.996
0.6	61.0	60.997	60.992	61.000
1	61.7	61.743	61.730	61.732
0.9	61.7	61.720	61.739	61.730
0.8	61.7	61.734	61.735	61.729
0.7	61.7	61.727	61.732	61.728
0.6	61.7	61.679	61.664	61.680
1	59.3	59.414	59.409	59.391
0.9	59.3	59.401	59.389	59.384
0.8	59.3	59.401	59.382	59.395
0.7	59.3	59.374	59.367	59.357
0.6	59.3	59.375	59.400	59.413
1	58.9	58.845	58.854	58.857
0.9	58.9	58.905	58.987	58.916
0.8	58.9	58.836	58.833	58.848
0.7	58.9	58.387	58.383	58.396
0.6	58.9	58.885	58.902	58.888
1	58.5	58.303	58.302	58.300
0.9	58.5	58.647	58.412	58.304
0.8	58.5	58.329	58.388	58.274
0.7	58.5	58.298	58.302	58.281
0.6	58.5	58.286	58.290	58.283

Table C.50: Application test of relay 2 (Time delay: 3 Cycles)

Power Factor	Frequency Setpoint (Hz)	Actual Pickup Frequency (Hz) Test no.1	Actual Pickup Frequency (Hz) Test no.2	Actual Pickup Frequency (Hz) Test no.3
1	60.5	60.374	60.352	60.367
0.9	60.5	60.357	60.375	60.366
0.8	60.5	60.367	60.358	60.379
0.7	60.5	60.370	60.360	60.359
0.6	60.5	60.339	60.360	60.325
1	61.0	60.981	61.001	60.994
0.9	61.0	61.006	60.998	60.990
0.8	61.0	60.991	60.988	60.985
0.7	61.0	60.998	60.979	61.006
0.6	61.0	60.979	60.974	60.984
1	61.7	61.717	61.712	61.712
0.9	61.7	61.713	61.719	61.719
0.8	61.7	61.696	61.712	61.713
0.7	61.7	61.706	61.707	61.711
0.6	61.7	61.683	61.664	61.633
1	59.3	59.428	59.387	59.420
0.9	59.3	59.401	59.405	59.399
0.8	59.3	59.428	59.290	59.083
0.7	59.3	59.426	59.429	59.413
0.6	59.3	59.175	59.368	59.422
1	58.9	58.851	58.862	58.851
0.9	58.9	58.842	58.866	58.847
0.8	58.9	58.897	58.916	59.107
0.7	58.9	59.313	59.290	59.285
0.6	58.9	58.390	58.381	59.322
1	58.5	58.672	58.675	58.666
0.9	58.5	58.682	58.682	58.672
0.8	58.5	58.666	58.372	58.323
0.7	58.5	58.675	58.621	58.668
0.6	58.5	58.336	58.330	58.315

C.2 13-Bus Test System

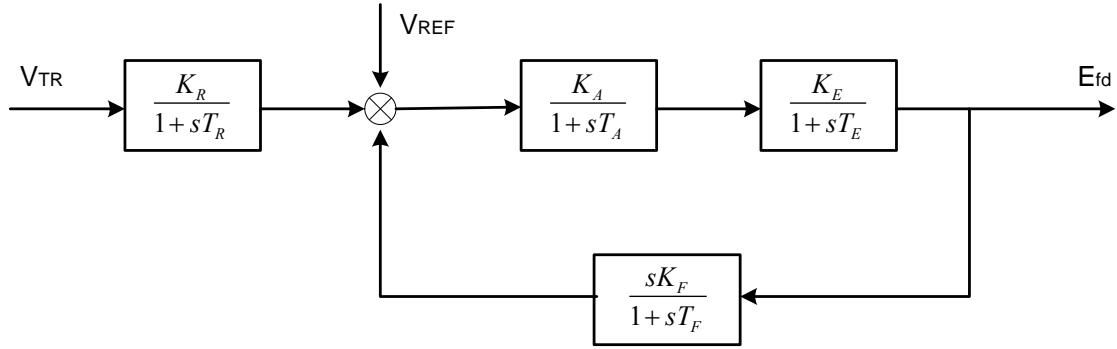


Figure C.1: Excitation system model for synchronous machine

Table C.51: Exciter data

K_A	T_A	K_E	T_E	K_F	T_F	K_R	T_R
400	0.02	1	0.015	0.03	0.5	0.524	0.03

Table C.52: Generator data

R_a	X_l	X_d	X_q	X_d'	X_q'	X_d''	X_q''
0.001	0.15	1.7	1.64	0.2383	1.64	0.185	0.185
T_{d0}'	T_{q0}'	T_{d0}''	T_{q0}''	X_0	J		
6.1949	0	0.0287	0.075	1.4	0.181		

```

C .....CIRCUIT DATA.....
C BUS1__BUS2__BUS3__BUS4__RR__LLLL__RR__LLLL__RR__LLLL__
51THEVA BUS7A .13 23.71 0
52THEVB BUS7B .06 39.99 0
53THEVC BUS7C 0
C BUS1__BUS2__BUS3__BUS4__RR__LL__CC__RR__LL__LC__RR__LL__CC__
1BUS1A BUS12A 2.914240.834.26247 0
2BUS1B BUS12B 2.370719.587-.06032.993440.714.27339
3BUS1C BUS12C 2.317816.307-.05132.370719.587-.06032.914240.834.26247
C BUS1__BUS2__BUS3__BUS4__RR__LL__CC__LENGTH 0 0 0BLANK__
-1BUS7A BKR2A 0.3167 3.222.00787 144.4 0 0 0 1
-2BUS7B BKR2B 0.0243 .9238 .0126 144.4 0 0 0 0
-3BUS7C BKR2C 0
C BUS1__BUS2__BUS3__BUS4__RR__LL__CC__
BUS12ABUS13A 70.16 1
BUS12BBUS13BBUS12ABUS13A 0
BUS12CBUS13CBUS12ABUS13A 0
C Saturable transformer component.
TRANSFORMER DELTAB 0
9999
1GEN3A GEN3B .1263 13.8 1
2BUS1A 35.08132.79 0
TRANSFORMER DELTAB DELTBC 0
1GEN3B GEN3C
2BUS1B
TRANSFORMER DELTAB DELTBA 0
1GEN3C GEN3A
2BUS1C
BLANK card terminates circuit data

```

Figure C.2: Branch data of 13-bus equivalent system