EBP

Estimation Based Protection Relay
--Application to Distribution System
With High DER Penetration

Georgia Tech Team
Dr. A. P. Meliopoulos
Dr. G. J. Cokkinides
Kaiyu Liu

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1. Overview

This document presents the application of the estimation based protection (EBP) relay on the distribution system. The study aims to provide a solution to the IEEE 1547-2018 protection issues. The EBP relay has been developed for transmission and generation systems and is equally applied to distribution systems. The performance of the EBP relay is evaluated for distribution system with high penetration of distributed energy resources (DERs).

The first issue investigated is the influence of the DER penetration on the EBP relay. One major impact of the DER penetration is the bidirectional power flow on radial distribution systems. High penetrations of DERs can change the direction of power flow and further influence fault current levels. As shown in Fig.1.1, when a short-circuit fault happens at Bus DB5, the fault current through relay R1 is reduced with the introduction of DER. At the same time, the fault current contribution of the DER increases the fault current through relay R2. This affects the operation of existing current-based protection schemes as they are primarily designed for radial systems with unidirectional flows. Other impacts of DERs include the desensitizing of various protective relay functions (such as differential, distance and directional functions), exceeding interrupting rating of protective devices and causing nuisance fuse blowing. EBP identifies faults by checking the consistency between redundant measurements and the protection zone model, irrespectively of direction or level of fault currents. However, there is one obstacle to apply the EBP to distribution systems. Ideal implementation of the EBP requires a high-fidelity protection zone model and measurements should exist at all boundaries of the protection zone. This is not always true for distribution systems since we may not have measurements at all boundaries due to the typical existence of unmeasured loads and DERs. Concerning this issue, the EBP is desensitized through parameterized chi-square test to give larger tolerance to the inconsistency between the available measurements and the dynamic protection zone model. The influence of the unavailability of measurements at some or all distributed loads and DERs is investigated by case.

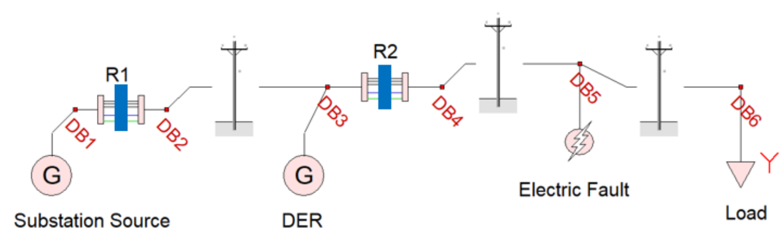


Figure 1.1 Example of DER integration into a distribution system

The other issue investigated is the detection of the open-circuit fault (downed conductor). The traditional downed conductor detection technologies mainly rely on the high frequency components of the arcing current or the voltage and current unbalance. Unfortunately, none of the downed conductor detection techniques that have been developed are totally reliable in that they may fail to trip or that they can be tripped by other events. Besides, existing methods to determine the location of the downed conductor assume that the network is radial. With the integration of DERs, these methods are no longer valid and new approach is needed to locate the downed conductor. IEEE Std. 1547-2018 has also established a requirement for detecting the open conductor condition. It is also noticed that due to the electrical coupling or magnetic coupling, the transformer can reproduce a full voltage on the open conductor phase. This may cause the DER to attempt to enter service after tripping in response to the open phase. EBP relay can provides a effective and reliable solution to the problem with no extra cost.

The report is organized as follows. Chapter 2 describes the distribution system model creation and the merging units setting in WinIGS-T, a time domain simulation program. The measurement and distribution feeder models are exported into a set of files that is readable by the Estimation Based Protection (EBP) program. Chapter 3 describes the simulation of the events and the store of COMTRADE format files. Chapter 4 describes a model translation procedure from OpenDSS to WinIGS. The RIV209 is built in WinIGS according to the OpenDSS files. Chapter 5 presents dynamic state estimation algorithm as the generated events and the model of the protection zone are fed into software WinXFM-EBP. Chapter 5 presents the case study.

Distribution systems are subjected to various types of faults while they are in operation. These faults in power system are mainly classified into two types, namely open and short circuit faults. Whereas short-circuit faults on distribution lines can be readily detected and cleared by overcurrent protection, it is challenging to detect open-circuit faults on distribution lines. The detection of open circuit faults is a core issue of developing a reliable and stable protection scheme for distribution system.

The open circuit fault is caused by broken or dropped conductor and malfunctioning of circuit breaker or fuse in one or more phases. Single- and two-phase open conditions can produce the unbalance of the power system voltages and currents that causes customers suffering from abnormal electricity supply or loss of power.

In response to the challenge, manufactures and researchers are trying to provide reliable protection to detect the open circuit fault. The estimation based protection is one of the schemes proposed to solve the emerging problems. Estimation based protection, a.k.a. “setting-less protection”, has been developed for transmission and generation systems and can be equally applied to distribution systems. The application is driven by the new infrastructure in distribution systems in terms of data acquisition (merging units, GPS synchronization, microPMUs, etc.) and communication systems (utilities are increasingly using fiber and LTE networks for communications at the distribution level).

There are also limitations in the application of the setting-less protection in distribution systems. Ideal implementation of the state estimation based protection requires that measurements exist at all boundaries of the protection zone. This is always true for transmission level protections zones. For distribution systems, for example protecting a particular section of a distribution circuit, we may not have measurements at all boundaries due to the typical existence of loads without measurements along the distribution section. The issue of non-availability of measurements at the distributed loads along the distribution circuit and its effect on the estimation based protection is being investigated. In general, we address the issue of incomplete measurement set for the setting-less relay and its performance under these conditions.

Preliminary results of the investigation of setting-less to detect open-circuit fault with incomplete instrumentation are presented in this report. For this investigation we considered a typical distribution system. Protection zones were defined as sections of distribution lines between switching devices, i.e. breakers, and/or reclosers. The available measurements are selected voltages at the end of the distribution lines and currents through the distribution lines. The parametrized chi-square test is used to adjust the sensitivity and selectivity of the relay. In the test, we set the standard deviation of each measurement equal to the measurement error times a parameter k.

2. Description of the EBP Relay

The estimation based protection (EBP) was introduced as a robust solution to address the following issues: (a) complexity of present day protection and control systems, EBP provides a simple secure and reliable approach without the need to coordinate with other relays, (b) reduced fault currents due to the increasing converter interfaced generation; EBP does not depend on fault current levels, (c) new characteristics of fault currents due to IBRs, i.e. reduced or lack of negative and zero sequence fault currents, fault evolution, etc.; EBP is immune to these issues, and (d) required speed in detecting faults; EBP detects fault in fraction of milliseconds with security.

The basic idea of the setting-less protection relay has been inspired by the differential protection function (no coordination needed), but it is different than differential protection, which is depicted in Figure .

In differential protection, the electric currents at all terminals of a protection zone are measured, and their weighted sum must be equal to zero (generalized Kirchhoff's current law {KCL}). As long as the sum is zero or near zero, no action is taking. In DSE based protection, all existing measurements in the protection zone are utilized. Specifically, currents and voltages at the terminals of the protection zone, as well as voltages, currents inside the protection zone (as in capacitor protection) or speed, temperature and torque in case of rotating machinery or any other internal measurements. Then, the dynamic model of the device (consisting of physical laws such as KCL, KVL, motion laws, thermodynamic laws, etc.) is used to provide the inter-relationships among all measured quantities. When there is no fault within the protection zone, the measurements should satisfy the dynamic model of the protection zone.

The process is mathematically formulated as a dynamic state estimation (DSE), which provides a quantitative assessment of how well the measurements of the zone fit its dynamic model in real-time. A preferred implementation is to use merging units to obtain measurements which are streamed to the setting-less relay through a process bus. The measurements are processed with a dynamic state estimation which computes the best estimate of the protection zone states. It also computes the goodness of fit or the probability that the measurements "fit" the zone model within the accuracy of the metering used (via the well-known chi-square test). A low probability indicates abnormalities/faults in the protection zone. The chi-square test typically returns a probability of 100% for healthy protection zones and 0% for a protection zone with any type of internal fault.

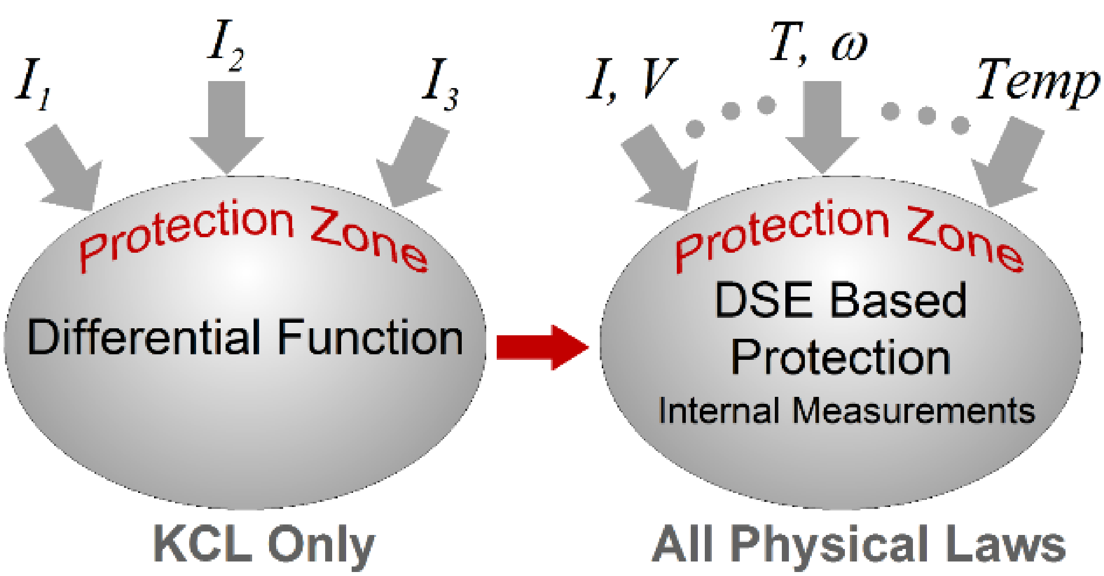


Figure 2.1: The EBP Relay Concept

An example of operation of an EBP relay is shown in Figure 2-2. The protection zone is a section of a distribution line belonging to one of the partner utilities. The figure illustrates a simulation of two successive faults and the response of the EBP. The first fault is an internal fault and initiates at time 0.429s. The second fault is outside the protection zone and initiates at 0.938s. Each of the faults persist for 0.215 seconds. For brevity we show the voltage and currents at the two ends of the distribution line section of the faulted phase only. The last three traces (5, 6 and 7) show part of the computations from the dynamic state estimation. Trace 5 shows the compute chi-square, i.e. the sum of the residuals squared. Note only during the internal fault this quantity is substantially higher than zero. It indicates the difference between the model of the protection zone and the measurements. Trace 6 provides the probability that the measurements are consistent with the model of the protection zone within the accuracy of the measurements. Note that this probability goes to zero only during the internal fault and it is 1.0 for the rest of the time except with one short burst during a transient around time 1.152 sec. Finally, trace 7 provides the trip signal.

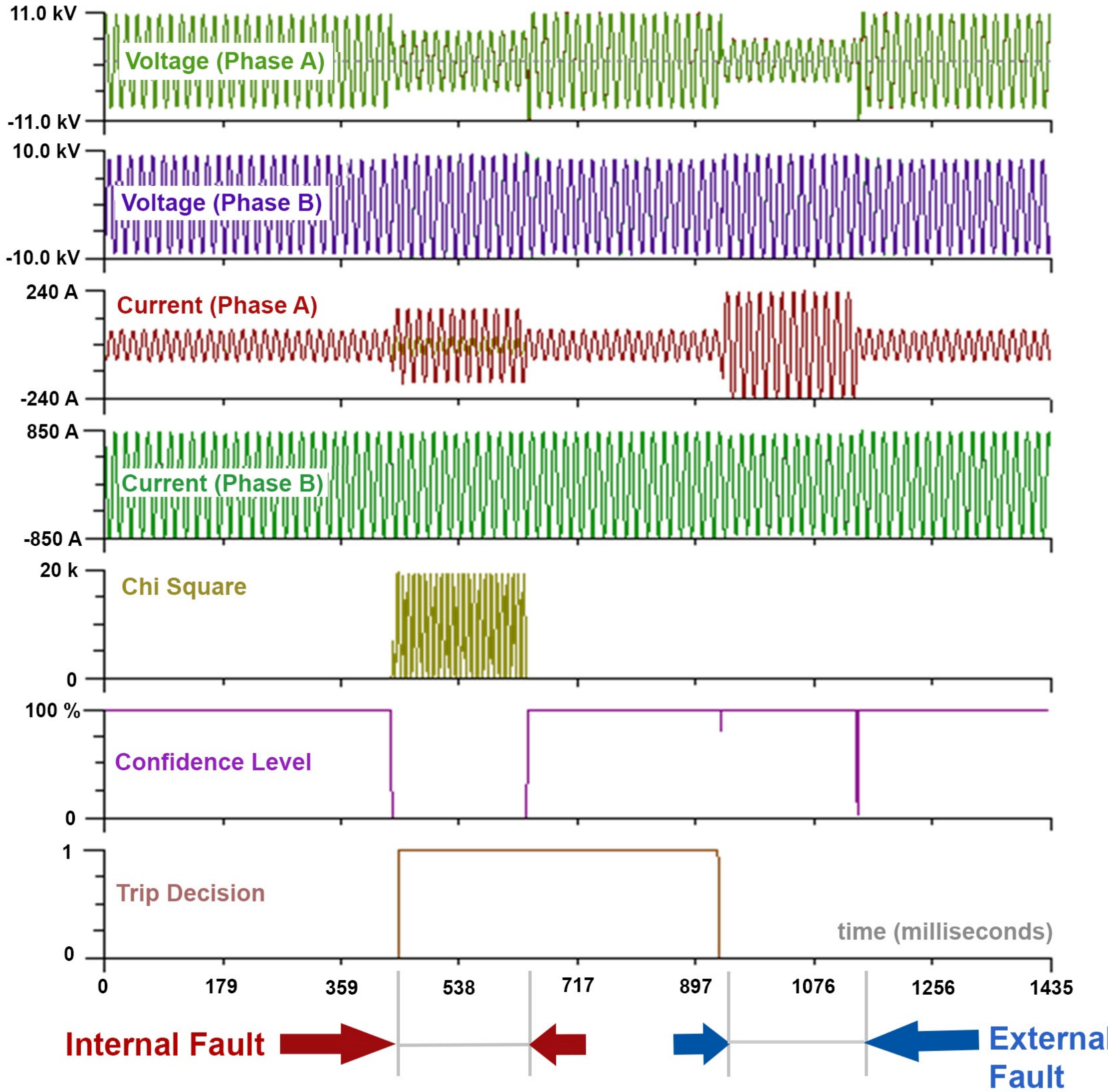


Figure 2-2: Sample EBP Results on a Distribution Circuit for Internal and External Faults

3. Introductory Example – Open Conductor Detection with Two-Ended Measurements

This section describes the application of the EBP on a specific protection zone. The detailed information of the protection zone, including merging units, models of the distribution line, is provides in section 3.1. It also describes the simulated event 1 and provides the resulting performance of the EBP relay during event 1 in section 3.2.

3.1 Description of the Protection Zone

The time domain model built in WinIGS-T is shown in Figure 3.1.1. The time domain model includes a 115-kV source and a 13.8-kV distribution system. The power devices and merging units of the protection zone also included in system model. The protection zone, as shown in Figure 3.1.1, consists of three sections of distribution lines of total length of 2.3 miles, two switches at the boundaries of the protection zone and two merging units. The parameter dialogs of the distribution line and the conductor are illustrated in Figure 3.1.2 and Figure 3.1.3, respectively. The operating voltage in Figure 3.1.2 and the ampacity in Figure 3.1.3 are chosen as the norm factor for the voltage and current measurements. The length of distribution line sections between Buses DB6, DB7 and DB8 are 1.0, 0.5 and 0.8 mile respectively.

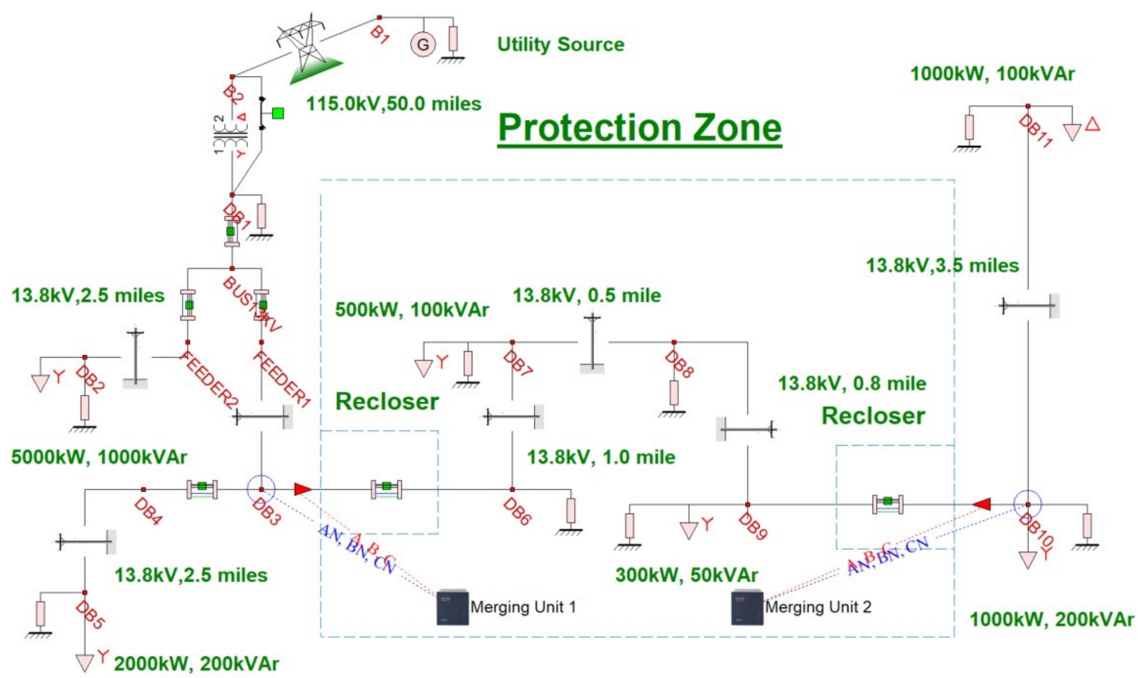


Figure 3.1.1: Protection Zone for Event 1

In this example, two merging units are set up to monitor the phase currents and line-to-neutral voltages in the protection zone. Merging unit 1 has one set of voltage measurements at Bus DB3 and one set of current measurements at Bus DB3 flowing to Bus DB6. Merging unit 2 has one set of voltage measurements at Bus DB 10 and one set of current measurements at Bus DB10 flowing to Bus DB9. The instrumentation channel lists of the four merging units are illustrated in Figure 3.1.4 to 3.1.5. The list includes the parameters (name, type, device, etc.) of the instruments. The case information and instrumentation channels of the merging units are listed in Table 3.1. There is no measurement at the loads. The wire diagram of the protection zone is shown in Figure 3.1.6.

The measurement definition and device model data are generated and stored in the following data files:

- DistributionLine_1.TDMDEF (Measurement Definition File)
- DistributionLine_1.TDSCAQCF (Device Model File)

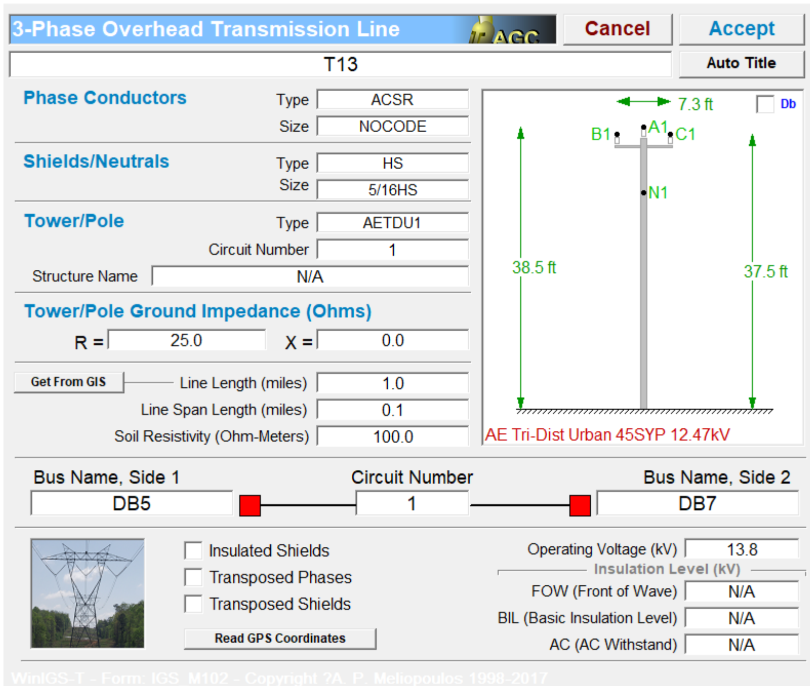
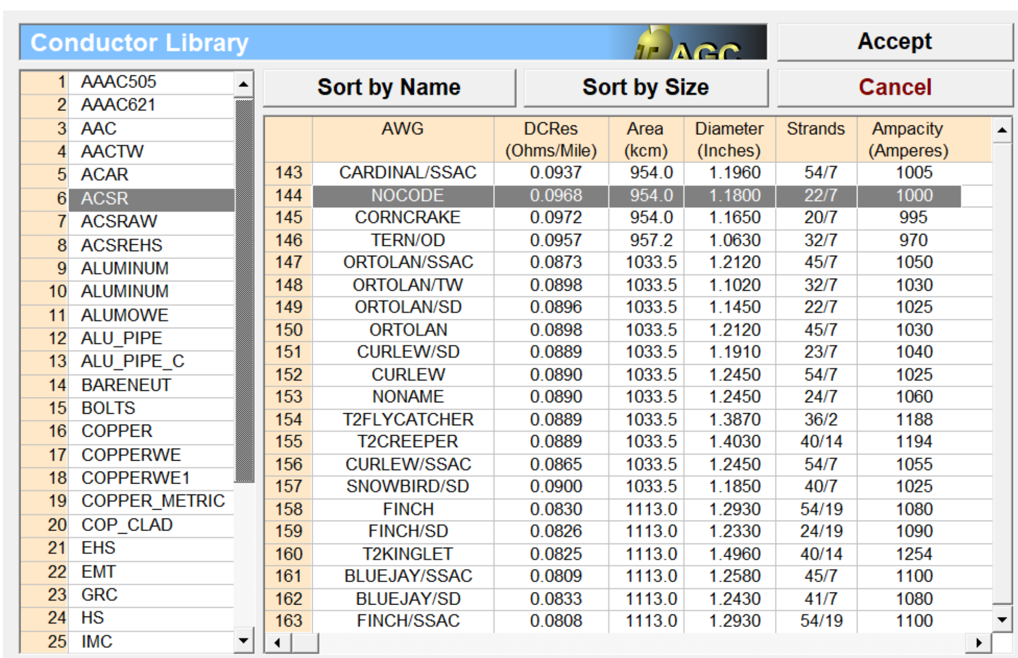
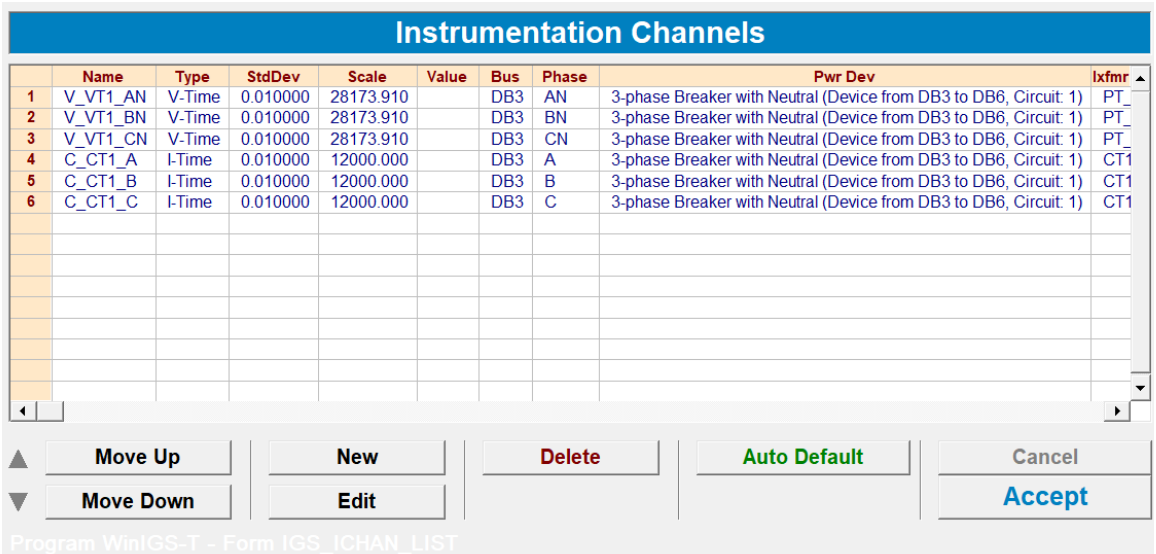


Figure 3.1.2: Parameters of the Distribution Line



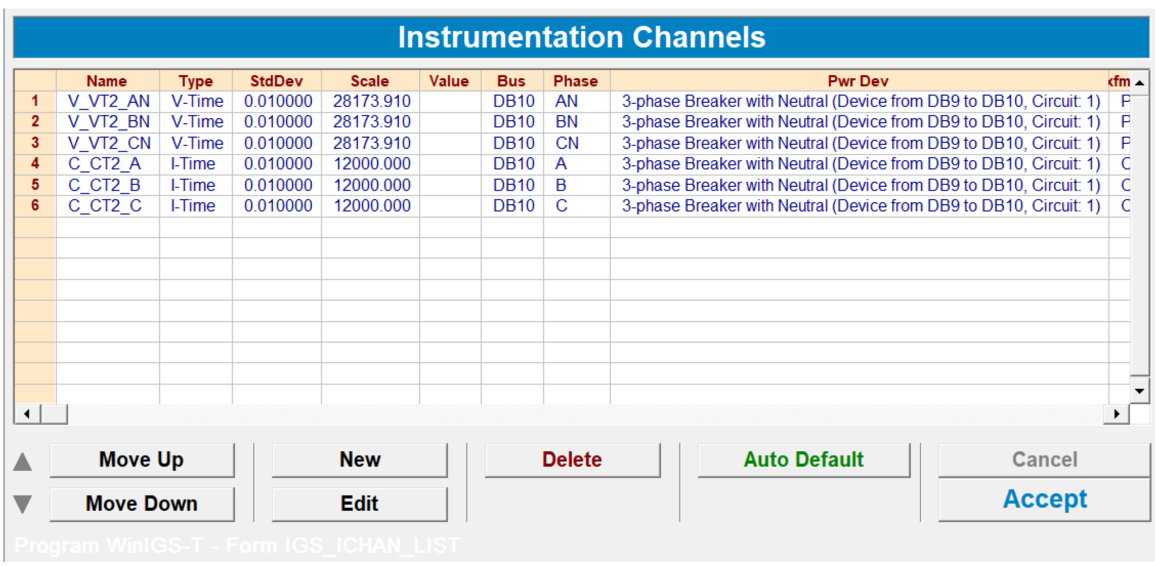
	AWG	DCRes (Ohms/Mile)	Area (kcm)	Diameter (Inches)	Strands	Ampacity (Amperes)
143	CARDINAL/SSAC	0.0937	954.0	1.1960	54/7	1005
144	NOCODE	0.0968	954.0	1.1800	22/7	1000
145	CORNCRAKE	0.0972	954.0	1.1650	20/7	995
146	TERN/OD	0.0957	957.2	1.0630	32/7	970
147	ORTOLAN/SSAC	0.0873	1033.5	1.2120	45/7	1050
148	ORTOLAN/TW	0.0898	1033.5	1.1020	32/7	1030
149	ORTOLAN/SD	0.0896	1033.5	1.1450	22/7	1025
150	ORTOLAN	0.0898	1033.5	1.2120	45/7	1030
151	CURLEW/SD	0.0889	1033.5	1.1910	23/7	1040
152	CURLEW	0.0890	1033.5	1.2450	54/7	1025
153	NONAME	0.0890	1033.5	1.2450	24/7	1060
154	T2FLYCATCHER	0.0889	1033.5	1.3870	36/2	1188
155	T2CREEPER	0.0889	1033.5	1.4030	40/14	1194
156	CURLEW/SSAC	0.0865	1033.5	1.2450	54/7	1055
157	SNOWBIRD/SD	0.0900	1033.5	1.1850	40/7	1025
158	FINCH	0.0830	1113.0	1.2930	54/19	1080
159	FINCH/SD	0.0826	1113.0	1.2330	24/19	1090
160	T2KINGLET	0.0825	1113.0	1.4960	40/14	1254
161	BLUEJAY/SSAC	0.0809	1113.0	1.2580	45/7	1100
162	BLUEJAY/SD	0.0833	1113.0	1.2430	41/7	1080
163	FINCH/SSAC	0.0808	1113.0	1.2930	54/19	1100

Figure 3.1.3: Parameters of the Distribution Line Conductor



	Name	Type	StdDev	Scale	Value	Bus	Phase	Pwr Dev	Ixfmr
1	V_VT1_AN	V-Time	0.010000	28173.910		DB3	AN	3-phase Breaker with Neutral (Device from DB3 to DB6, Circuit: 1)	PT_
2	V_VT1_BN	V-Time	0.010000	28173.910		DB3	BN	3-phase Breaker with Neutral (Device from DB3 to DB6, Circuit: 1)	PT_
3	V_VT1_CN	V-Time	0.010000	28173.910		DB3	CN	3-phase Breaker with Neutral (Device from DB3 to DB6, Circuit: 1)	PT_
4	C_CT1_A	I-Time	0.010000	12000.000		DB3	A	3-phase Breaker with Neutral (Device from DB3 to DB6, Circuit: 1)	CT1
5	C_CT1_B	I-Time	0.010000	12000.000		DB3	B	3-phase Breaker with Neutral (Device from DB3 to DB6, Circuit: 1)	CT1
6	C_CT1_C	I-Time	0.010000	12000.000		DB3	C	3-phase Breaker with Neutral (Device from DB3 to DB6, Circuit: 1)	CT1

Figure 3.1.4: Merging Unit 1 Instrumentation Channel List Dialog



	Name	Type	StdDev	Scale	Value	Bus	Phase	Pwr Dev	xfm
1	V_VT2_AN	V-Time	0.010000	28173.910		DB10	AN	3-phase Breaker with Neutral (Device from DB9 to DB10, Circuit: 1)	P
2	V_VT2_BN	V-Time	0.010000	28173.910		DB10	BN	3-phase Breaker with Neutral (Device from DB9 to DB10, Circuit: 1)	P
3	V_VT2_CN	V-Time	0.010000	28173.910		DB10	CN	3-phase Breaker with Neutral (Device from DB9 to DB10, Circuit: 1)	P
4	C_CT2_A	I-Time	0.010000	12000.000		DB10	A	3-phase Breaker with Neutral (Device from DB9 to DB10, Circuit: 1)	C
5	C_CT2_B	I-Time	0.010000	12000.000		DB10	B	3-phase Breaker with Neutral (Device from DB9 to DB10, Circuit: 1)	C
6	C_CT2_C	I-Time	0.010000	12000.000		DB10	C	3-phase Breaker with Neutral (Device from DB9 to DB10, Circuit: 1)	C

Figure 3.1.5: Merging Unit 2 Instrumentation Channel List Dialog

Table 3.1: Instrumentation Channels of Merging Units in Protection Zone

Case Number	MU Name	Voltage Channels	Current Channels	# of Measurements of this Case
Example 3	Merging Unit 1	AN, BN, CN at bus DB5	A, B, C at bus DB6 flowing towards DB7	36
	Merging Unit 2	AN, BN, CN at bus DB9	A, B, C at bus DB9 flowing towards DB8	

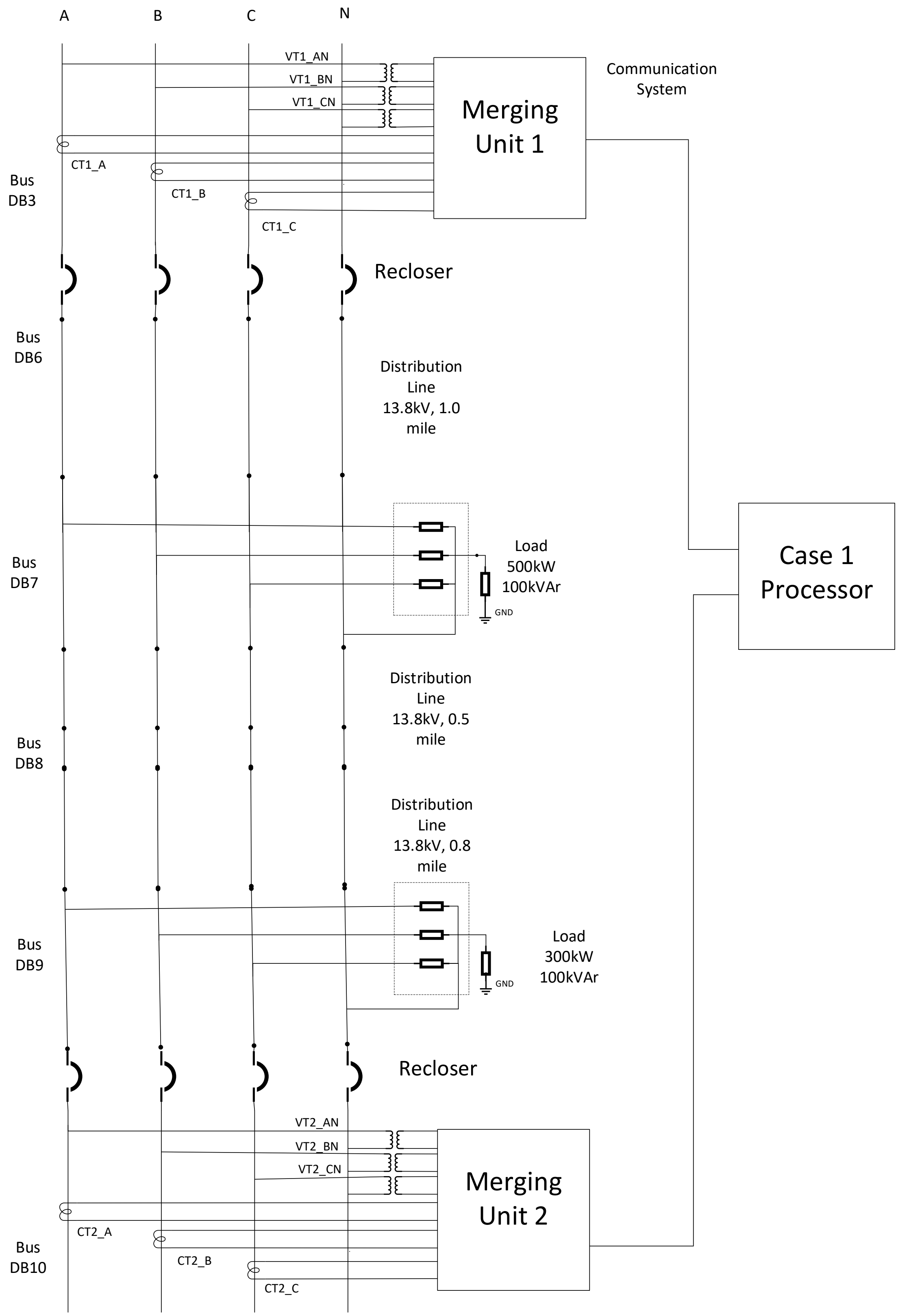


Figure 3.1.6: Wire Diagram for Event 1

3.2 Simulation and Test Results of Event 1

This section describes the generation of event 1 used to test the protection relay. The time domain model in WinIGS-T is used to simulate the load variation along the distribution section and faults at different places. The specific information of the load variation and fault is provided in section 3.2.1. It also presents the testing results of the event in section 3.2.2.

3.2.1 Description for Event 1 – Open Conductor

The single-phase breaker model is used to simulate an open conductor condition within the protection zone as shown in Figure 3.2.1.

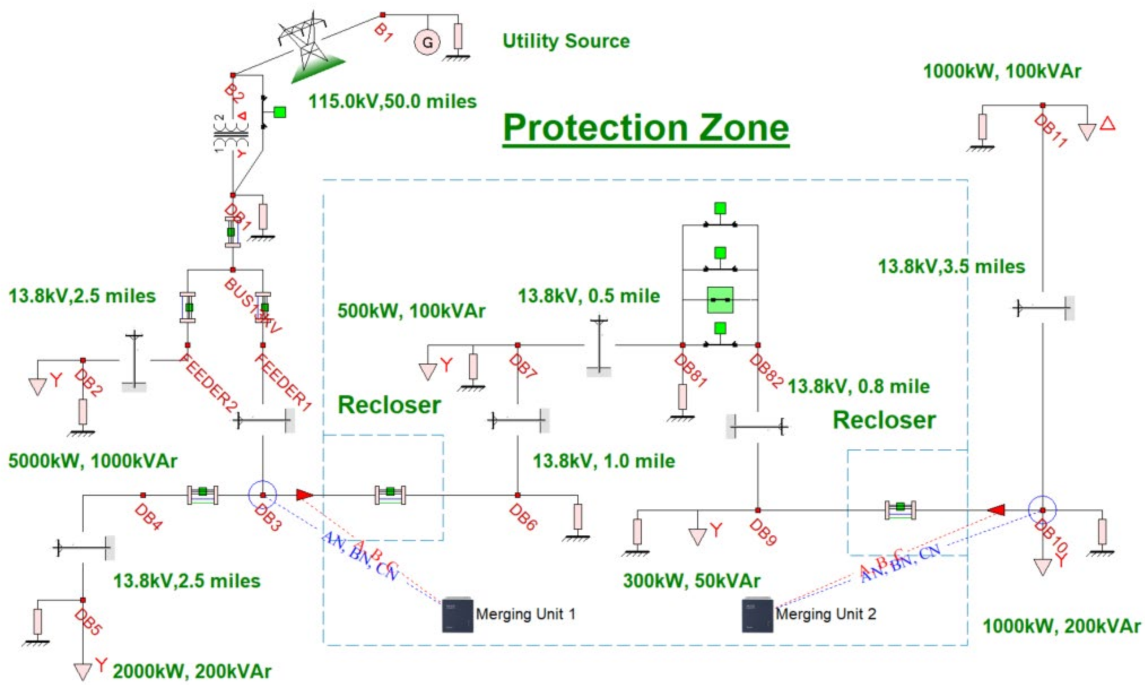


Figure 3.2.1: Network Time Domain Model Built in WinIGS-T

The diagrams for fault model are shown in Figures 3.2.2. Fault is defined as single-phase fault happened at phase B. This is a fault occurring inside the protection zone which should be cleared by opening the two breakers connected to this zone. The fault is initiated at 1.0second from the start of the simulation. The simulation results are shown in Figures 3.2.3 and 3.2.4.

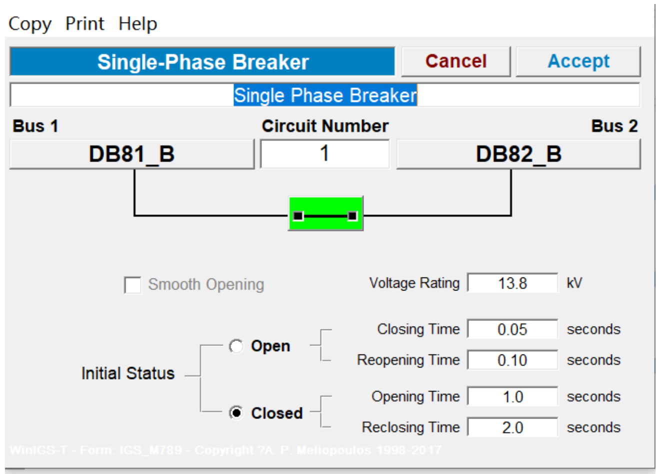


Figure 3.2.2: Fault 1 between Phase A and Neutral at Bus DB8

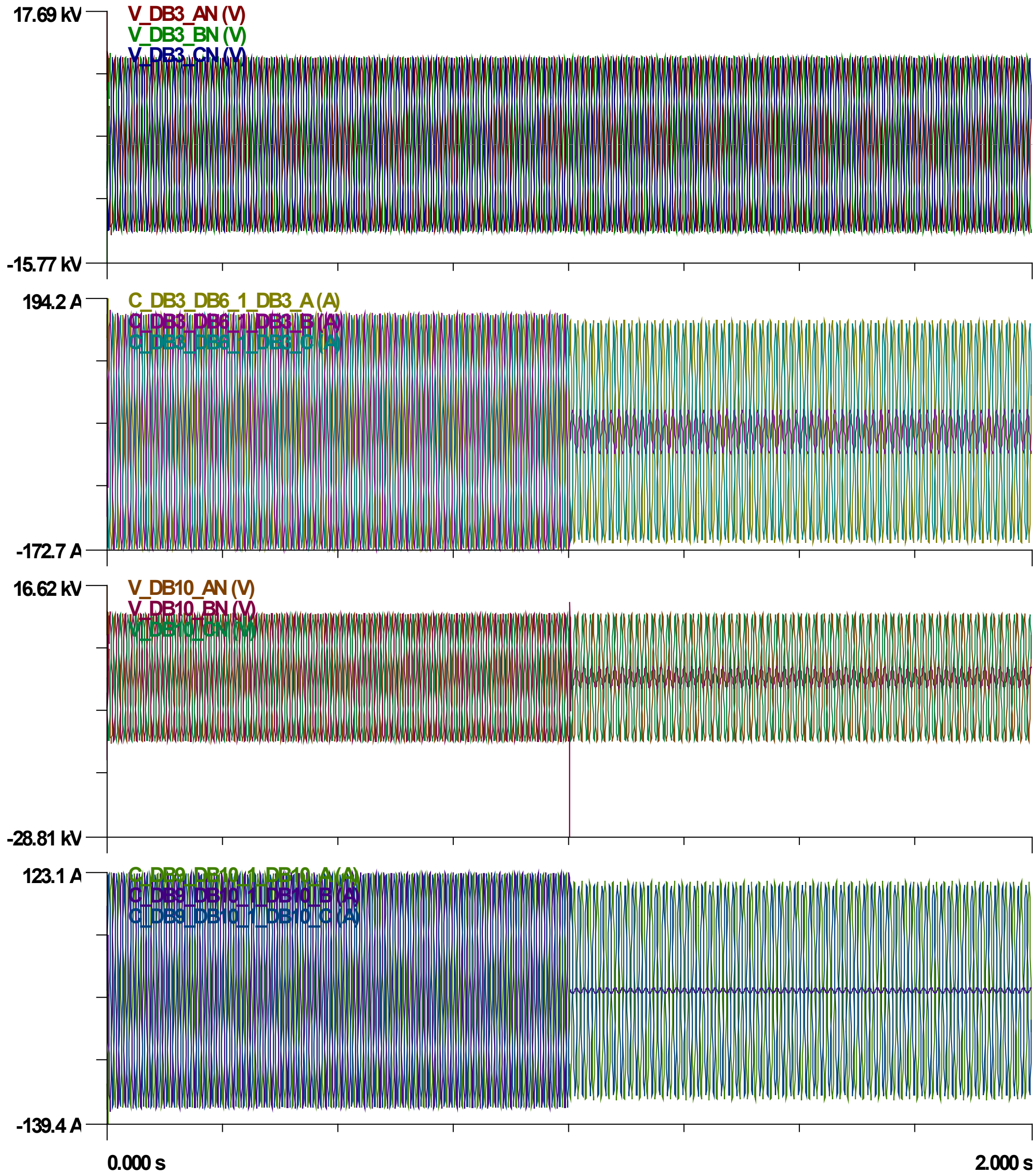


Figure 3.2.3: Voltage and Current Measurements Obtained from Merging Unit 1 and Merging Unit 2 (1)

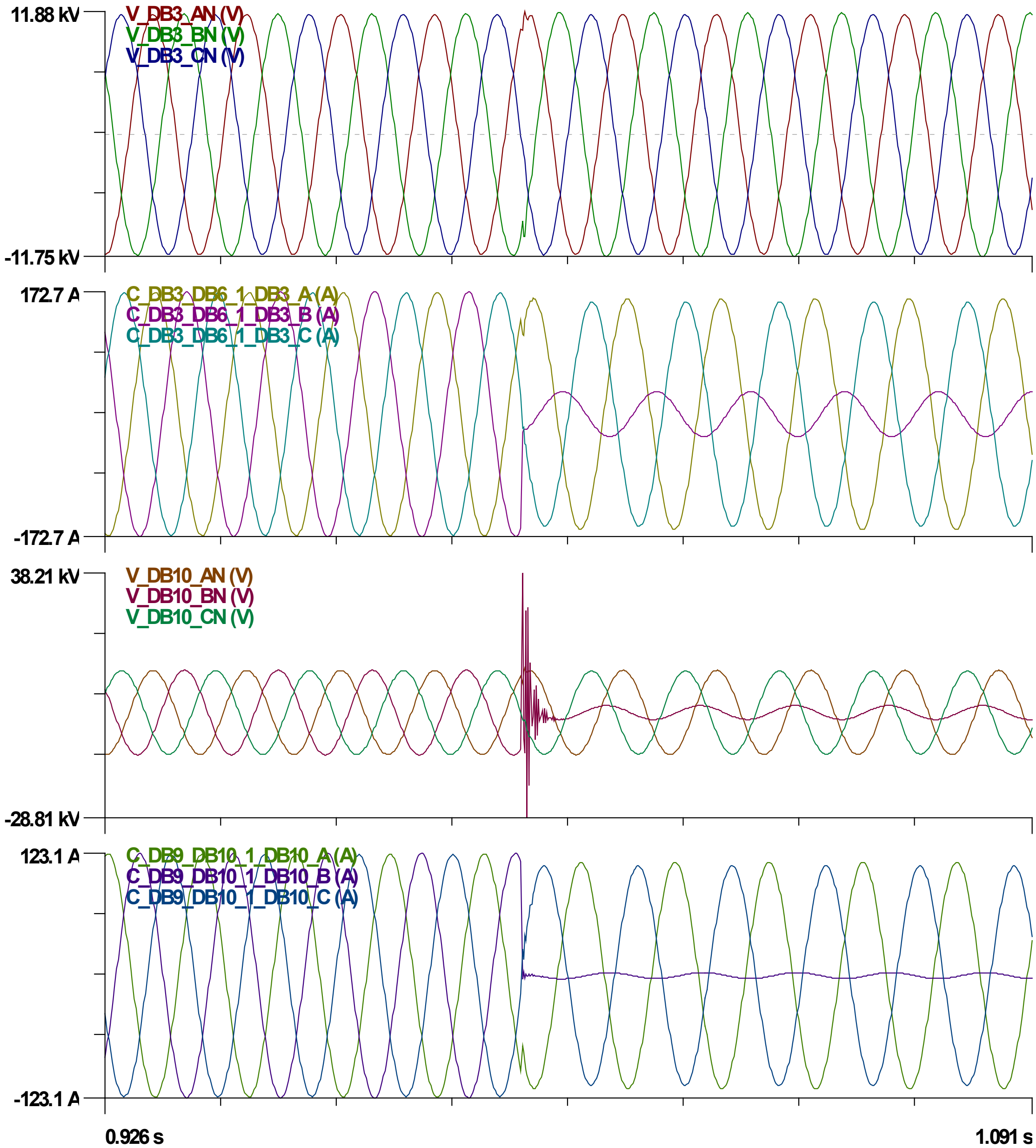


Figure 3.2.4: Voltage and Current Measurements Obtained from Merging Unit 1 and Merging Unit 2 (2)

3.2.2 EBP Results for Event 1

This section presents the results obtained from the EBP relay for the use case and events described in last section. The EBP relay is implemented within the WinXFM Program.

The relay setting is shown in Figure 3.2.5. Averaged confidence level to Trip the Relay calculated by

Averaged Cl to trip the relay=1-Td/Tr=80%

In other words, the relay will trip if the averaged confidence level is lower than80% for 0.3s.

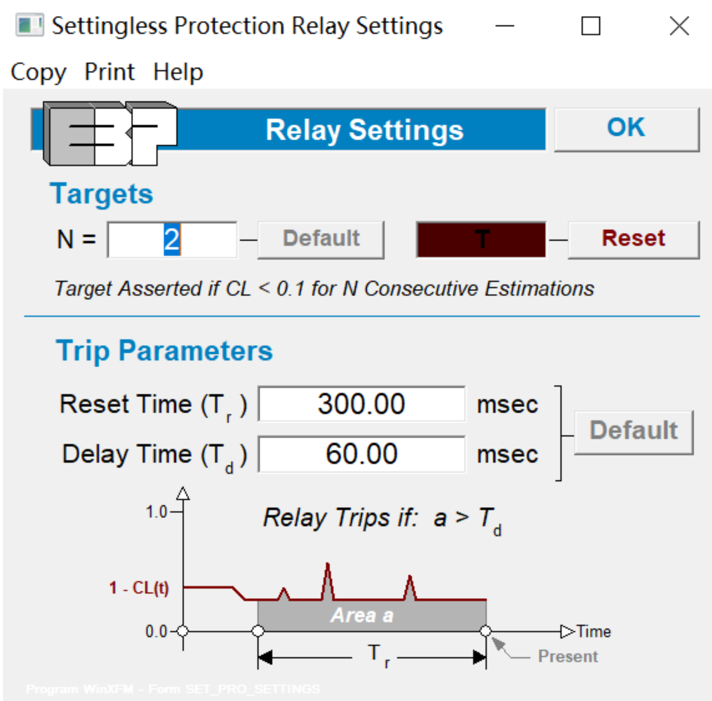


Figure 3.2.5: Relay Setting for Event 1

The selected performance metrics of the event are illustrated in Figures 3.2.5. The selected performance metrics are chi-square value, confidence level, trip decision, voltages and current of two terminals of the protection zone. Though observation of Figure 3.2.6 and 3.2.7, we find that the proposed protection scheme can detect open circuit fault correctly

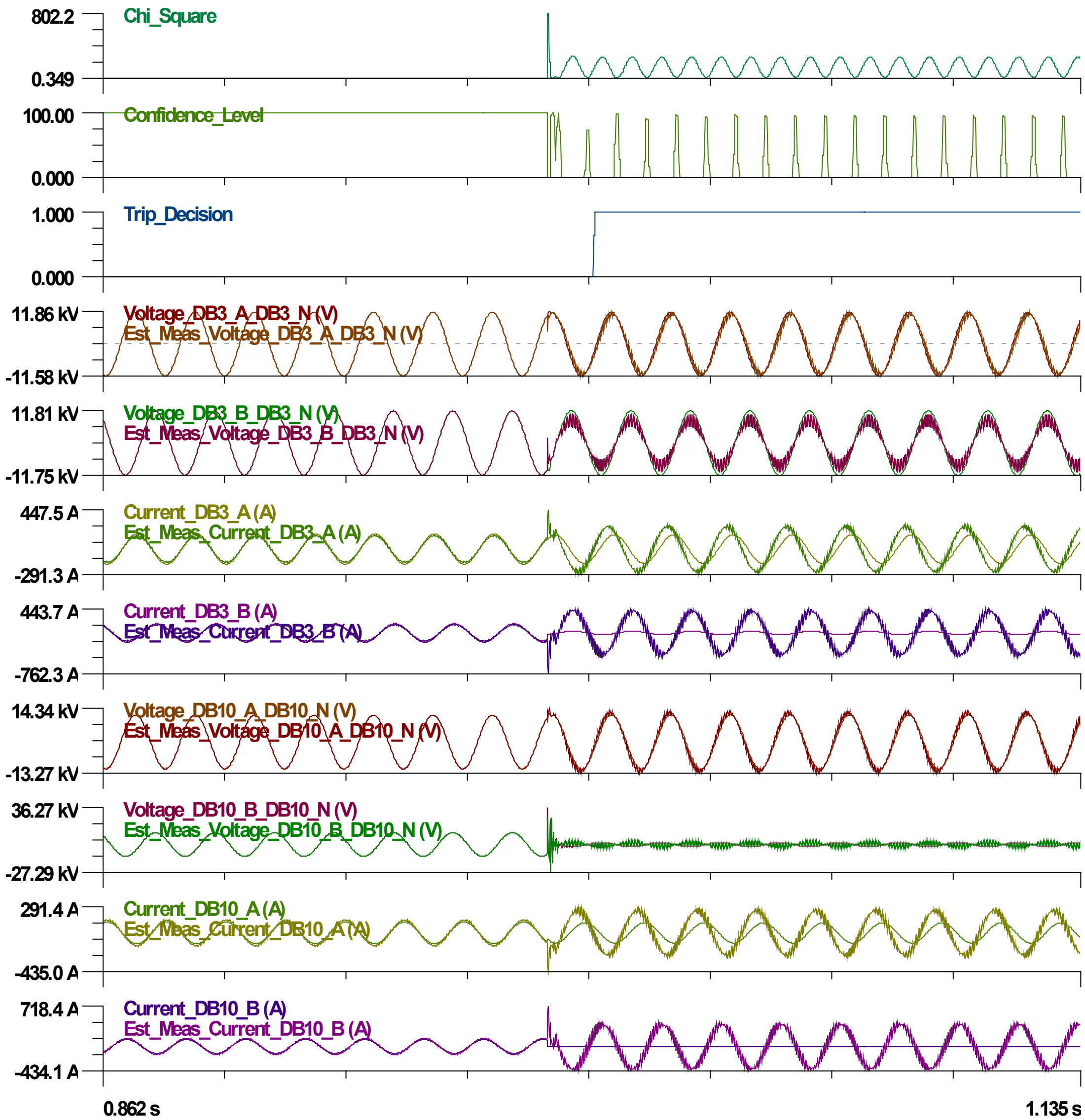


Figure 3.2.6: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of the Testing Results of Event 1

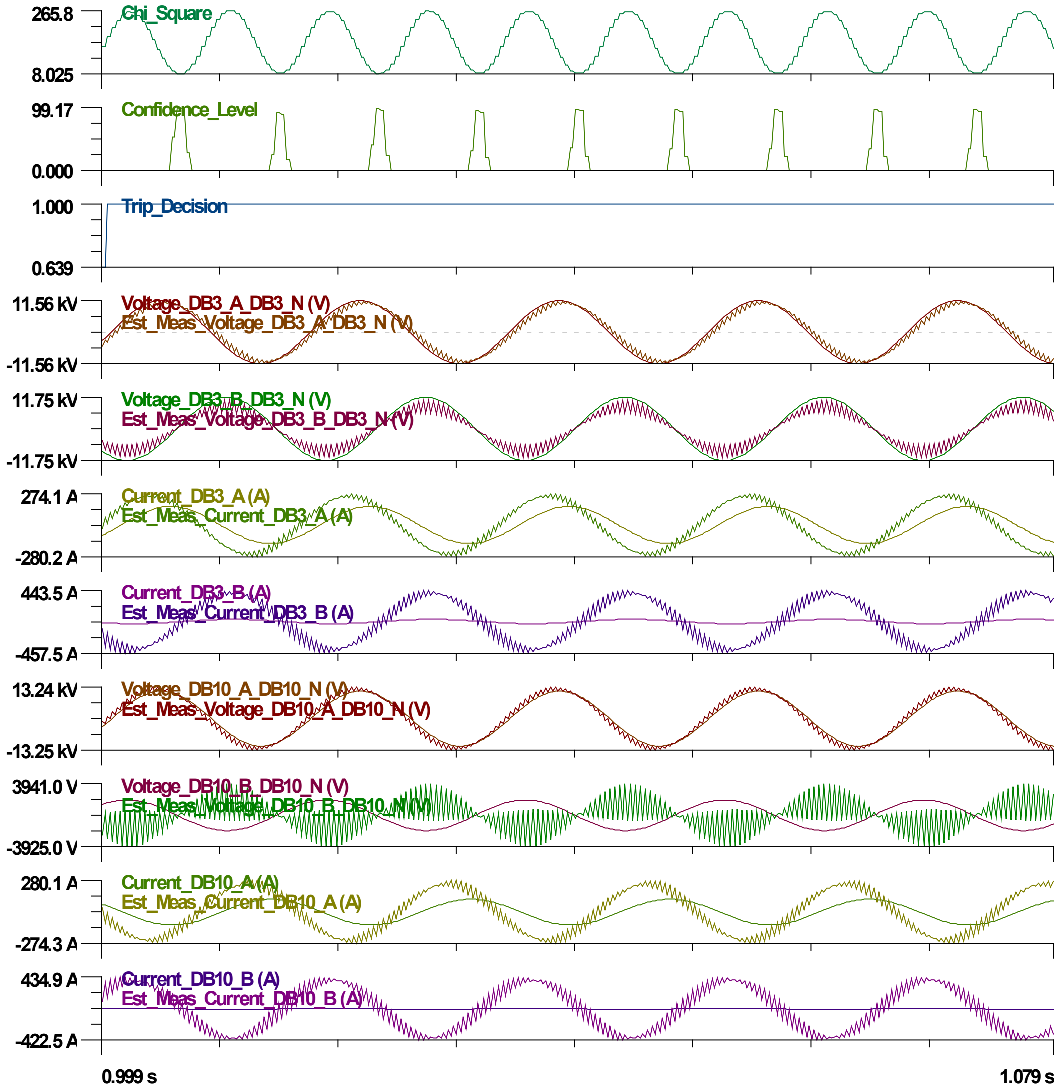


Figure 3.2.7: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of the Testing Results of Event 1 After the Fault Happens

4. Test Example: Four-Feeder Distribution System, RIV 209 system

This section describes the application of the EBP on a specific protection zone of the RIV 209 system. First, the protection zone is described.

4.1 Description of the Protection Zone

The RIV 209 system is built in WinIGS-T is shown in Figure 4.1.1. The power devices and merging units of the protection zone also included in system model. The protection zone, as shown in Figure 4.1.1, consists of four sections of distribution lines, two switches at the boundaries of the protection zone and two merging units. The diagram also includes merging units that capture the three-phase voltages and currents at the two ends of the protection zone. Existing PV and utility source locations are indicated with blue arrows in the figure and the PV source outputs 1MW power in total. The parameter dialogs of the distribution lines are illustrated in Figure 4.1.2.

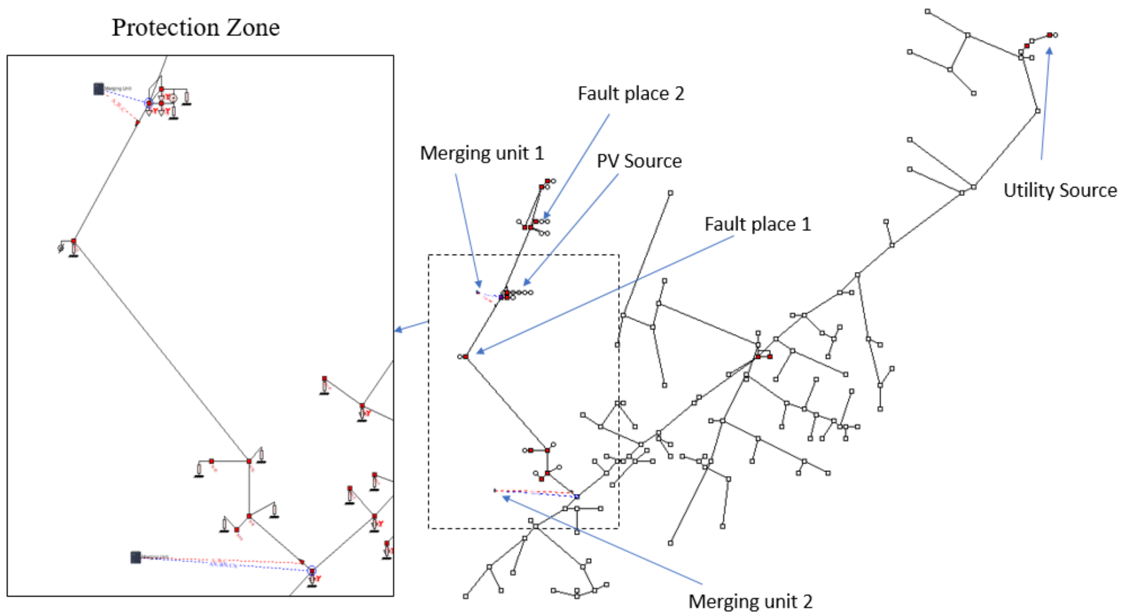
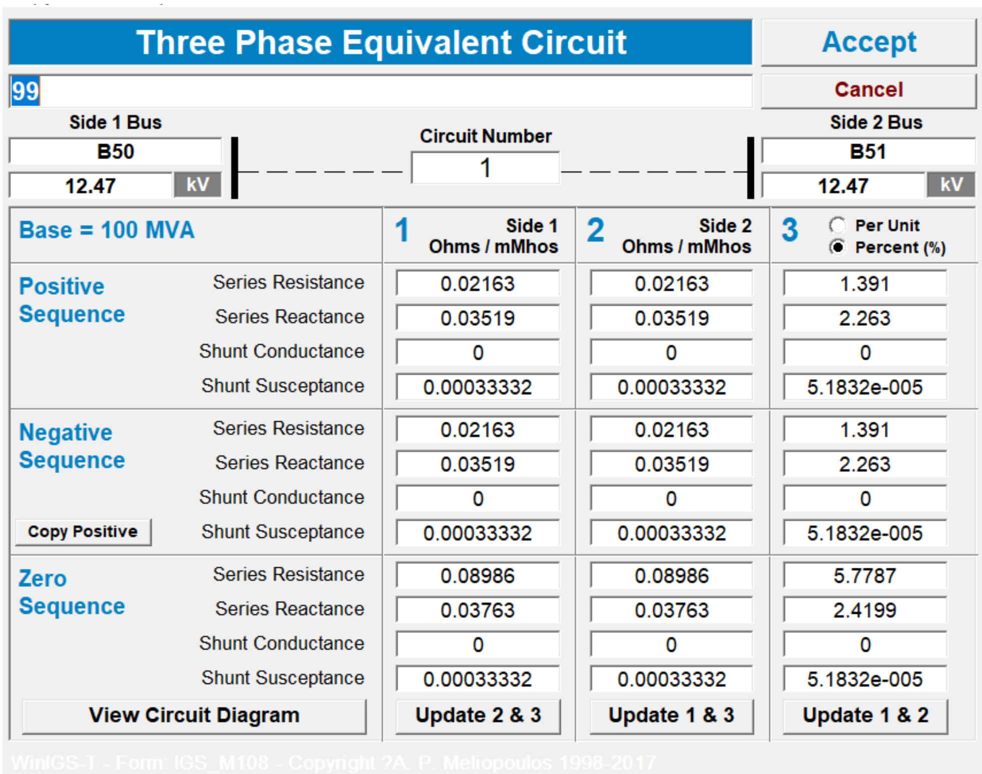


Figure 4.1.1: Protection Zone for Event 1

In this example, two merging units are set up to monitor the phase currents and line-to-neutral voltages in the protection zone. Merging unit 1 has one set of voltage measurements at Bus B50 and one set of current measurements at Bus B50 flowing to Bus B51. Merging unit 2 has one set of voltage measurements at Bus B 20 and one set of current measurements at Bus B20 flowing to Bus B21. The instrumentation channel lists of the four merging units are illustrated in Figure 4.1.3 to 4.1.4. The list includes the parameters (name, type, device, etc.) of the instruments. The case information and instrumentation channels of the merging units are listed in Table 4.1. The measurement definition and device model data are generated and stored in the following data files:

- RIV209_FourLinePro.TDMDEF (Measurement Definition File)
- RIV209_FourLinePro.TDSCAQCF (Device Model File)



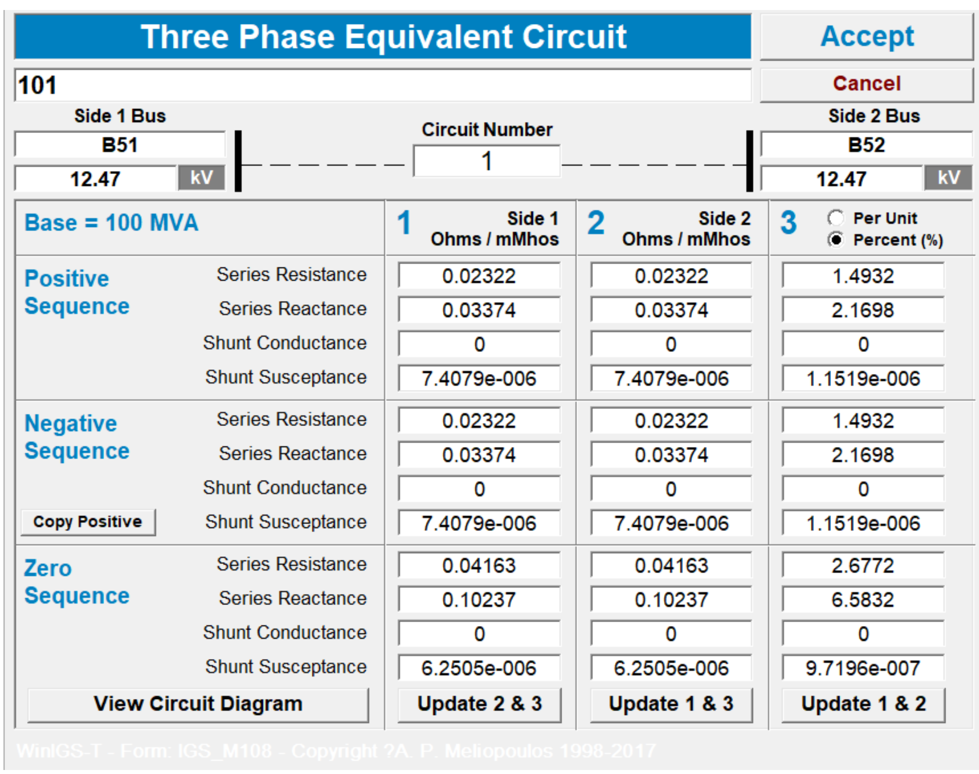
Three Phase Equivalent Circuit — Accept — Cancel

99

Side 1 Bus: B50, 12.47 kV — Circuit Number: 1 — Side 2 Bus: B51, 12.47 kV

Base = 100 MVA		1 Side 1 Ohms / mMhos	2 Side 2 Ohms / mMhos	3 Per Unit / Percent (%)
Positive Sequence	Series Resistance	0.02163	0.02163	1.391
	Series Reactance	0.03519	0.03519	2.263
	Shunt Conductance	0	0	0
	Shunt Susceptance	0.00033332	0.00033332	5.1832e-005
Negative Sequence	Series Resistance	0.02163	0.02163	1.391
	Series Reactance	0.03519	0.03519	2.263
	Shunt Conductance	0	0	0
Copy Positive	Shunt Susceptance	0.00033332	0.00033332	5.1832e-005
Zero Sequence	Series Resistance	0.08986	0.08986	5.7787
	Series Reactance	0.03763	0.03763	2.4199
	Shunt Conductance	0	0	0
	Shunt Susceptance	0.00033332	0.00033332	5.1832e-005
View Circuit Diagram		Update 2 & 3	Update 1 & 3	Update 1 & 2

WinIGS-T - Form: IGS_M108 - Copyright ?A. P. Meliopoulos 1998-2017



Three Phase Equivalent Circuit — Accept — Cancel

101

Side 1 Bus: B51, 12.47 kV — Circuit Number: 1 — Side 2 Bus: B52, 12.47 kV

Base = 100 MVA		1 Side 1 Ohms / mMhos	2 Side 2 Ohms / mMhos	3 Per Unit / Percent (%)
Positive Sequence	Series Resistance	0.02322	0.02322	1.4932
	Series Reactance	0.03374	0.03374	2.1698
	Shunt Conductance	0	0	0
	Shunt Susceptance	7.4079e-006	7.4079e-006	1.1519e-006
Negative Sequence	Series Resistance	0.02322	0.02322	1.4932
	Series Reactance	0.03374	0.03374	2.1698
	Shunt Conductance	0	0	0
Copy Positive	Shunt Susceptance	7.4079e-006	7.4079e-006	1.1519e-006
Zero Sequence	Series Resistance	0.04163	0.04163	2.6772
	Series Reactance	0.10237	0.10237	6.5832
	Shunt Conductance	0	0	0
	Shunt Susceptance	6.2505e-006	6.2505e-006	9.7196e-007
View Circuit Diagram		Update 2 & 3	Update 1 & 3	Update 1 & 2

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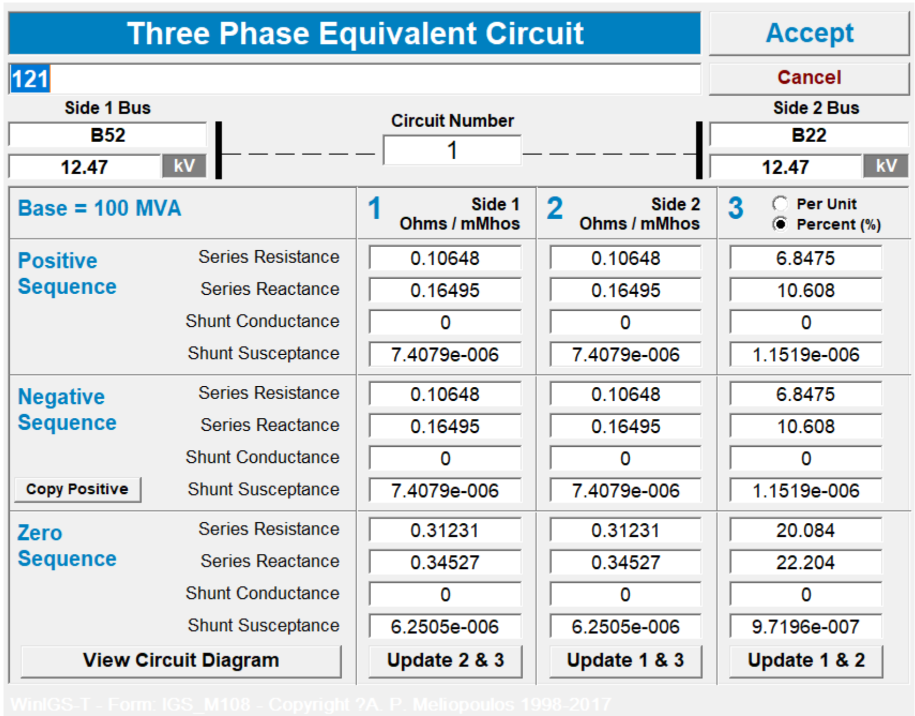


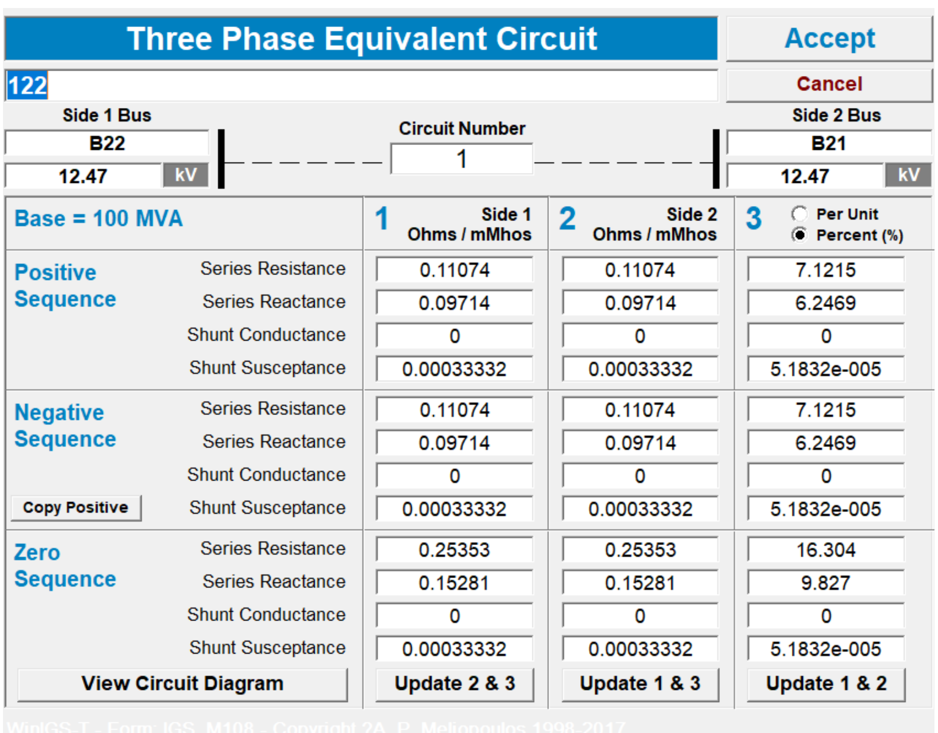
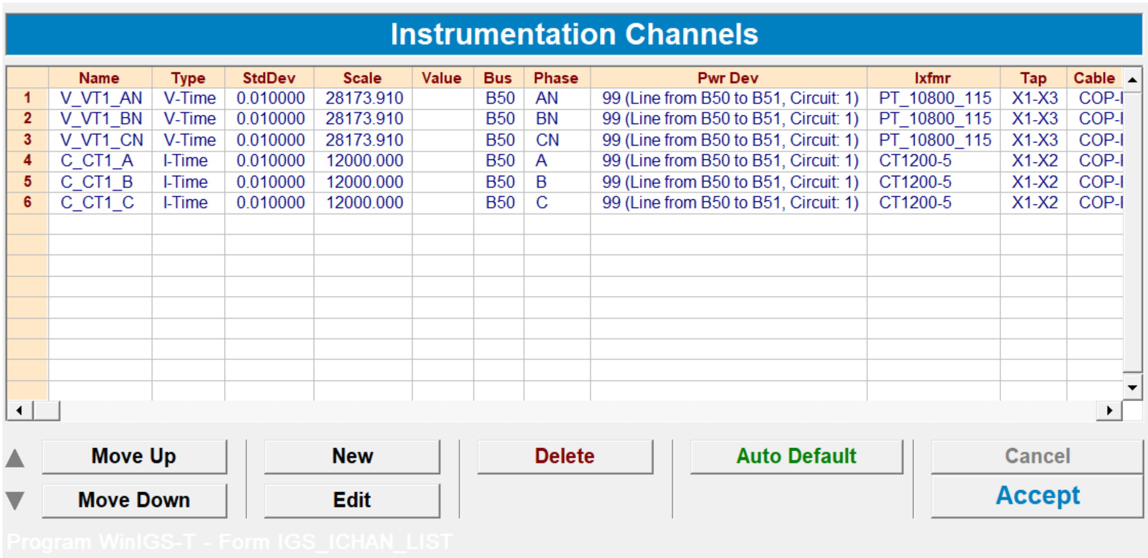
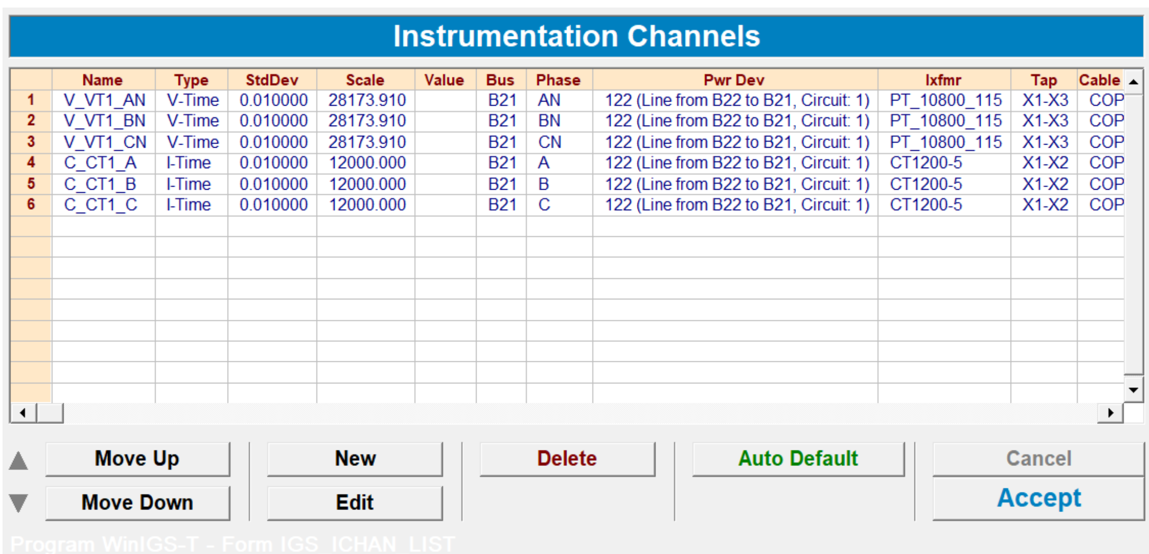


Figure 4.1.2: Parameters of the Distribution Line



	Name	Type	StdDev	Scale	Value	Bus	Phase	Pwr Dev	Ixfmr	Tap	Cable
1	V_VT1_AN	V-Time	0.010000	28173.910		B50	AN	99 (Line from B50 to B51, Circuit: 1)	PT_10800_115	X1-X3	COP-I
2	V_VT1_BN	V-Time	0.010000	28173.910		B50	BN	99 (Line from B50 to B51, Circuit: 1)	PT_10800_115	X1-X3	COP-I
3	V_VT1_CN	V-Time	0.010000	28173.910		B50	CN	99 (Line from B50 to B51, Circuit: 1)	PT_10800_115	X1-X3	COP-I
4	C_CT1_A	I-Time	0.010000	12000.000		B50	A	99 (Line from B50 to B51, Circuit: 1)	CT1200-5	X1-X2	COP-I
5	C_CT1_B	I-Time	0.010000	12000.000		B50	B	99 (Line from B50 to B51, Circuit: 1)	CT1200-5	X1-X2	COP-I
6	C_CT1_C	I-Time	0.010000	12000.000		B50	C	99 (Line from B50 to B51, Circuit: 1)	CT1200-5	X1-X2	COP-I

Figure 4.1.3: Merging Unit 1 Instrumentation Channel List Dialog



	Name	Type	StdDev	Scale	Value	Bus	Phase	Pwr Dev	Ixfmr	Tap	Cable
1	V_VT1_AN	V-Time	0.010000	28173.910		B21	AN	122 (Line from B22 to B21, Circuit: 1)	PT_10800_115	X1-X3	COP
2	V_VT1_BN	V-Time	0.010000	28173.910		B21	BN	122 (Line from B22 to B21, Circuit: 1)	PT_10800_115	X1-X3	COP
3	V_VT1_CN	V-Time	0.010000	28173.910		B21	CN	122 (Line from B22 to B21, Circuit: 1)	PT_10800_115	X1-X3	COP
4	C_CT1_A	I-Time	0.010000	12000.000		B21	A	122 (Line from B22 to B21, Circuit: 1)	CT1200-5	X1-X2	COP
5	C_CT1_B	I-Time	0.010000	12000.000		B21	B	122 (Line from B22 to B21, Circuit: 1)	CT1200-5	X1-X2	COP
6	C_CT1_C	I-Time	0.010000	12000.000		B21	C	122 (Line from B22 to B21, Circuit: 1)	CT1200-5	X1-X2	COP

Figure 4.1.4: Merging Unit 2 Instrumentation Channel List Dialog

Table 4.1: Instrumentation Channels of Merging Units in Protection Zone

MU Name	Voltage Channels	Current Channels	# of Measurements of this Case
Merging Unit 1	AN, BN, CN at bus B50	A, B, C at bus B50 flowing towards B51	12
Merging Unit 2	AN, BN, CN at bus B21	A, B, C at bus B21 flowing towards B20	

4.2 Simulation and Test Results of Event 1

This section describes the generation of event 1 and presents the testing results. The RIV209 model in WinIGS-T is used to simulate short-circuit faults at different places. The specific information of fault is provided in section 4.2.1. It also presents the testing results of the event in section 4.2.2.

4.2.1 Description of Event 1

Based on the RIV209 model, we define events, simulate the events and store the results in COMTRADE format. For the above stated purpose, we use the fault model with clearing logic to simulate the faults inside and outside the protection zone. Two unmeasured load branches (50kW, 10kVAr each) are connected to bus B51 and bus B52.

Two faults are simulated in the event. The faults are non-permanent. The diagrams for fault model are shown in Figures 4.2.1 to 4.2.1. Fault 1 is defined as a phase to neutral fault at Bus B22. This is a fault occurring inside the protection zone which should be cleared by opening the two breakers connected to this zone. The fault is initiated at 0.5 second from the start of the simulation and lasts 0.2 second.

Fault 2 is defined as a phase to neutral fault at Bus B32. This is a fault occurring outside protection zone and therefore the breakers of the protection zone should not operate. The fault is initiated at 1.0 second from the start of the simulation and lasts 0.2 second.

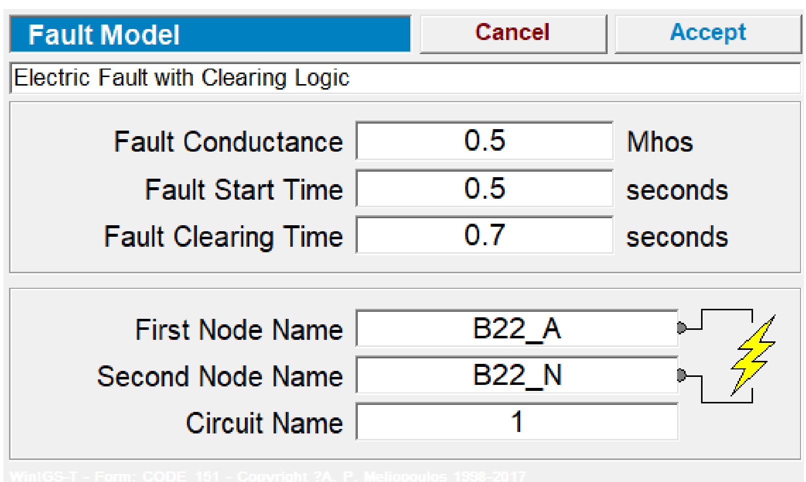


Figure 4.2.1: Fault 1 between Phase A and Neutral at Bus DB8

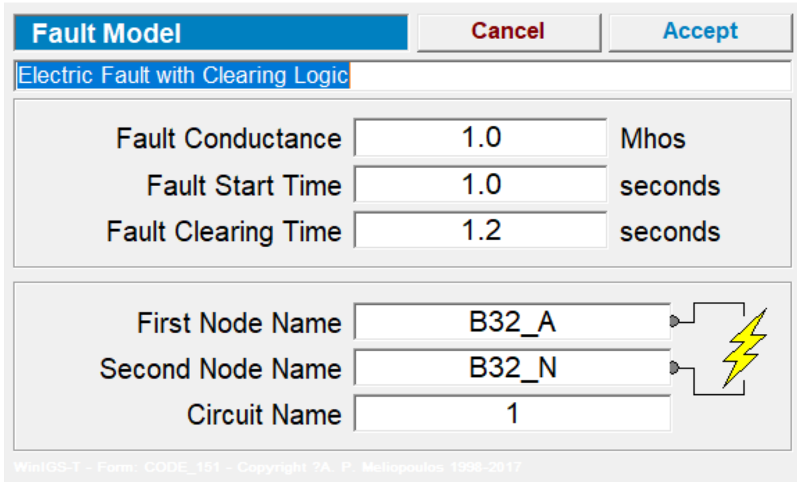


Figure 4.2.2: Fault 2 between Phase A and Neutral at Bus DB8

The voltages and currents captured by the two merging units are plotted in Figure 4.2.3. The fault current of the external fault is higher than that of the internal fault due to the setting of the fault conductance.

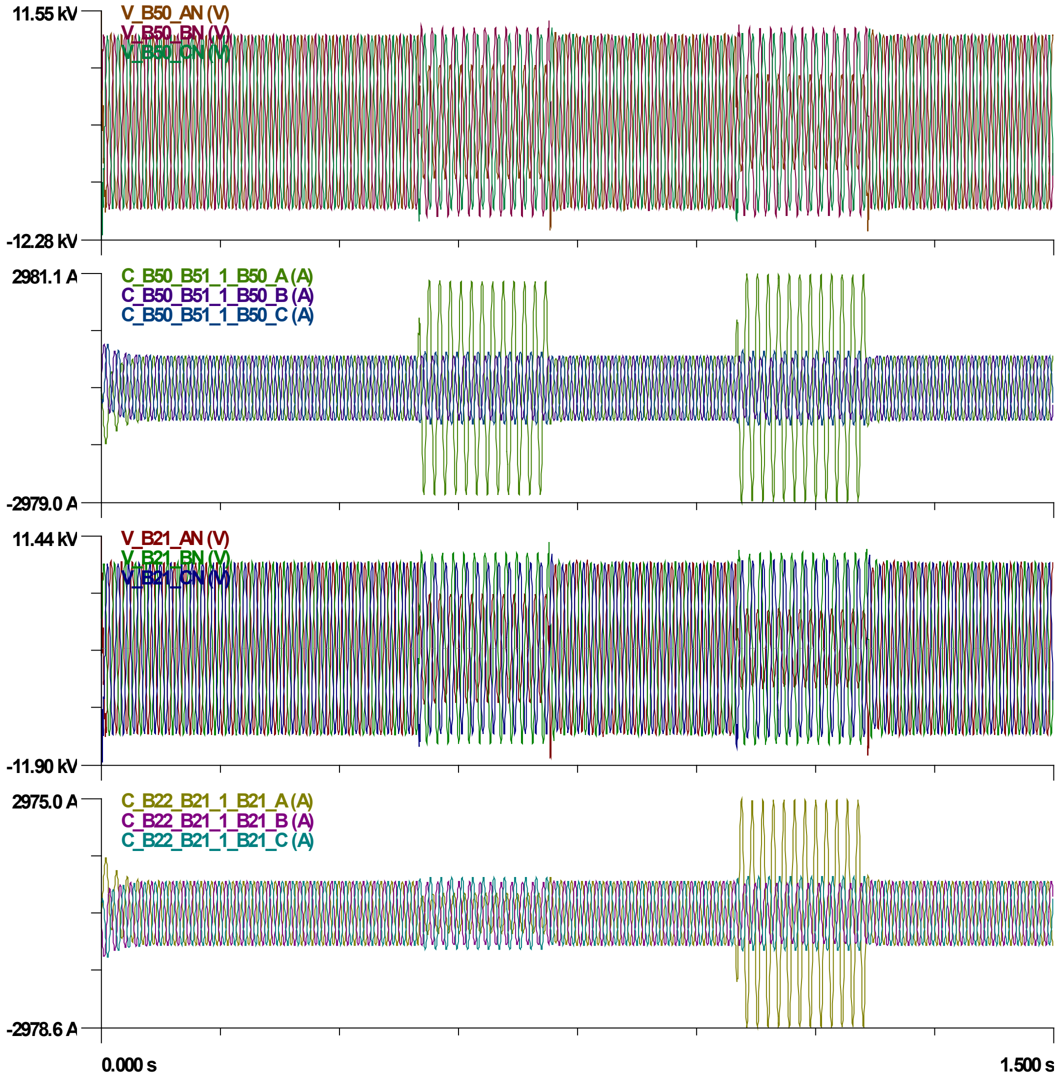


Figure 4.2.3: Voltage and Current Measurements Obtained from Merging Unit 1 and Merging Unit 2

4.2.2 EBP Results for Event 1

This section presents the results obtained from the EBP relay for the use case and events described in last section. The EBP relay is implemented within the WinXFM Program.

The relay setting is shown in Figure 4.2.4. Averaged confidence level to Trip the Relay calculated by

Averaged CI to trip the relay=1-Td/Tr=50%

In other words, the relay will trip if the averaged confidence level is lower than 50% for 0.3s.

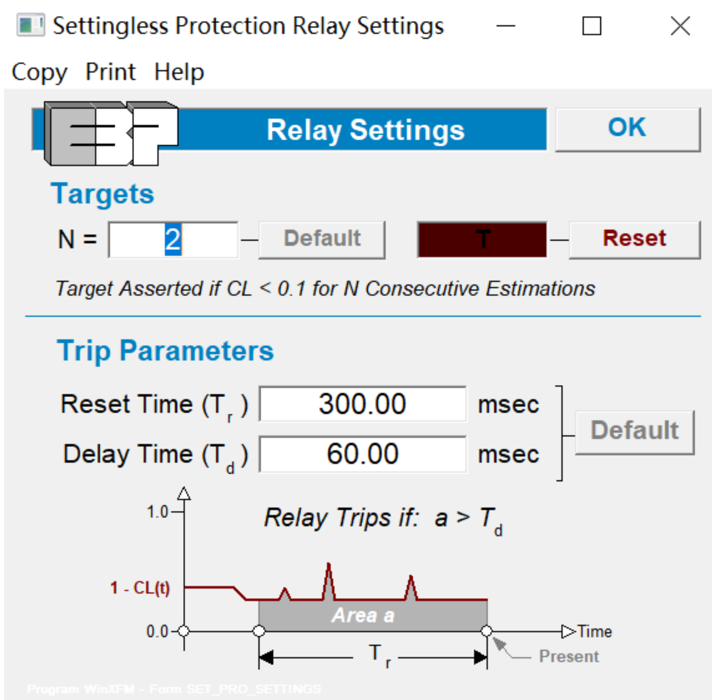


Figure 4.2.4: Relay Setting for Event 1

The selected performance metrics of the event are illustrated in Figures 4.2.5 and 4.2.6. The selected performance metrics are chi-square value, confidence level, trip decision, voltages and current of two terminals of the protection zone. Though observation of Figure 4.2.5, The EBP relay indicates a high confidence level before the fault happens. When the internal fault occurs at t=0.5 sec, the confidence level drops to 0%, which clearly indicates abnormality in the system and a trip decision is issued after a user selected time delay. The confidence level also remains high when the external fault occurs, and the relay does not trip for the external fault. The estimation-based protection scheme works properly in the presence of DERs and unmeasured load branches.

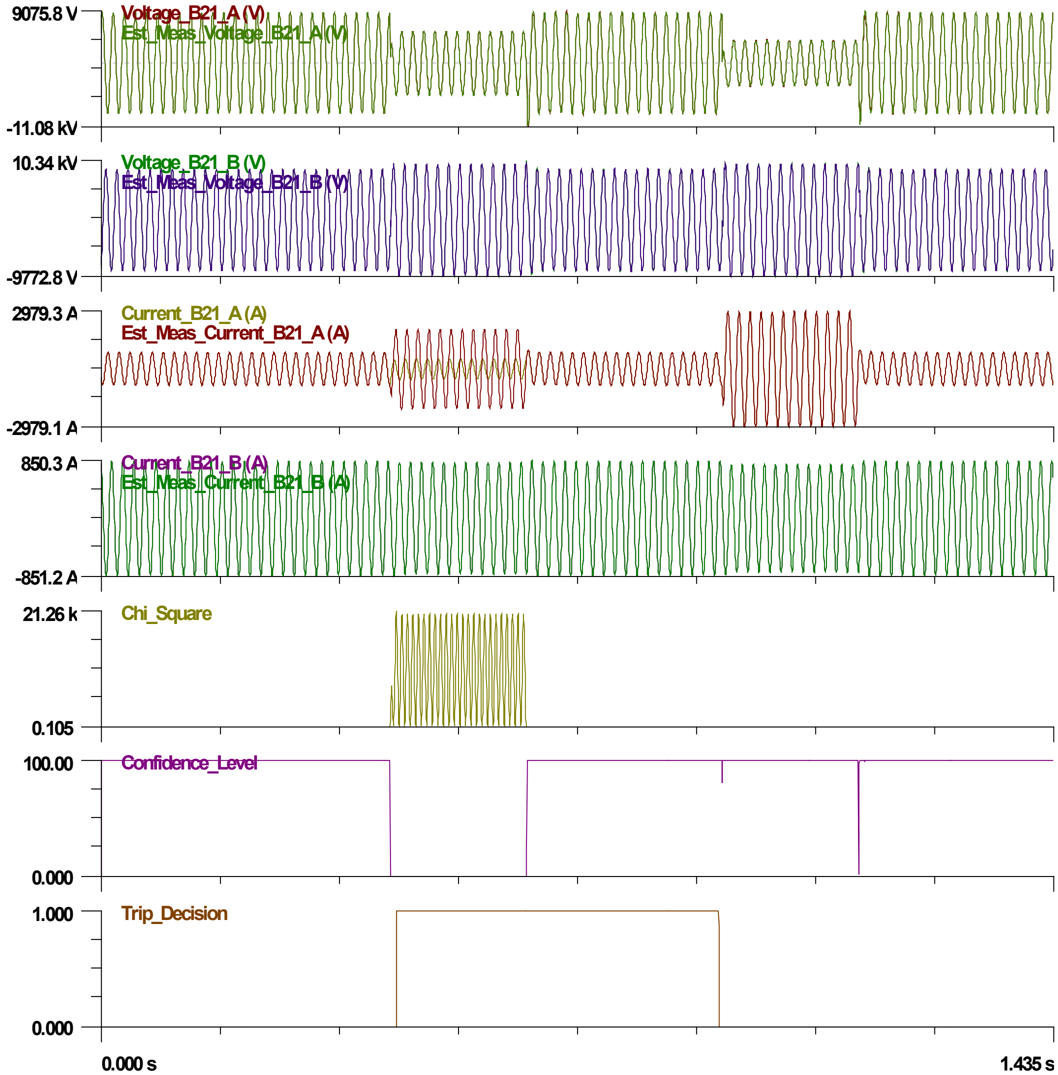


Figure 4.2.5: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of the Testing Results of Event 1 (Whole Time Period)

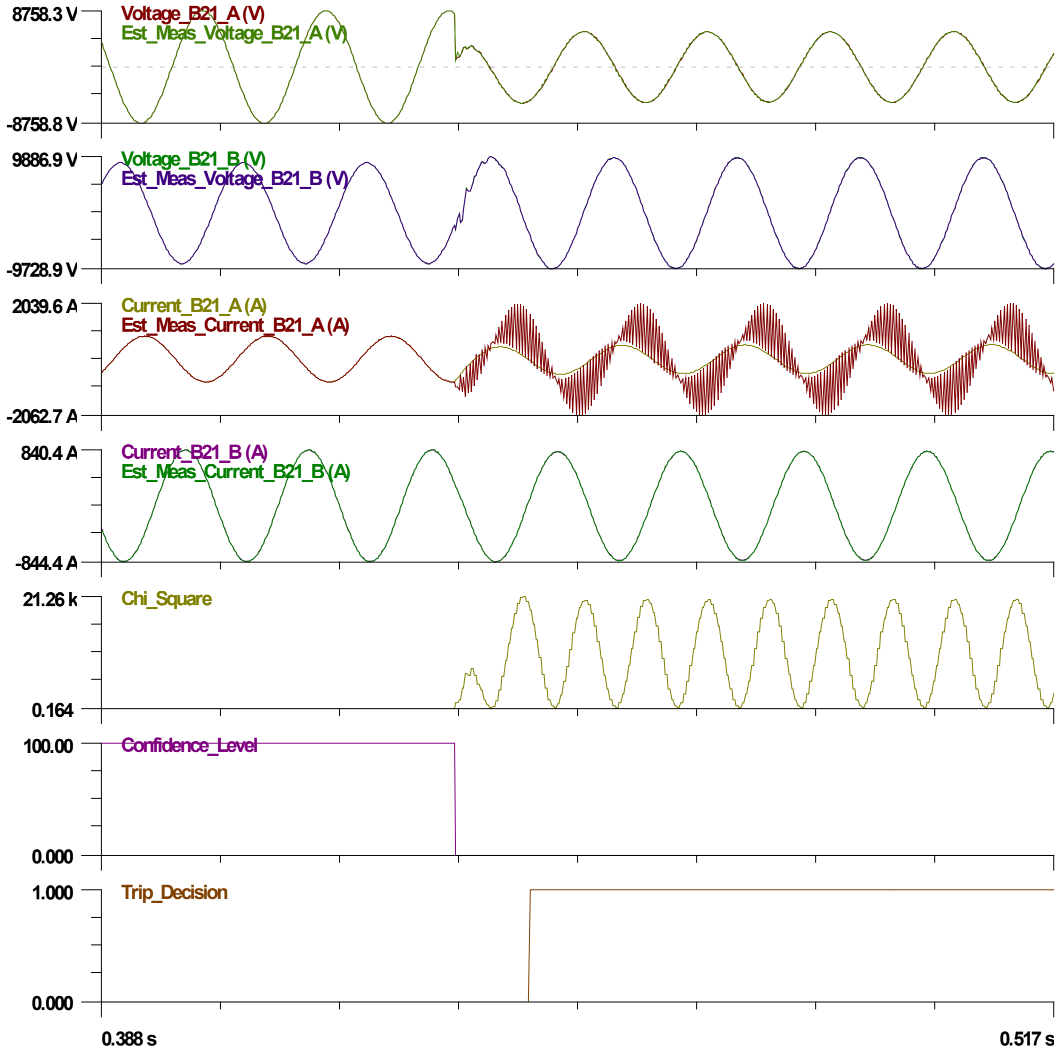


Figure 4.2.6: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of the Testing Results of Event 1 (Internal Fault)

4.3 Simulation and Test Results of Event 2

This section describes the generation of event 2 and presents the testing results. The RIV209 model in WinIGS-T is used to simulate open-circuit faults at different places. The specific information of fault is provided in section 4.3.1. It also presents the testing results of the event in section 4.3.2.

4.3.1 Description for Event 2

Based on the RIV209 model, we define events, simulate the events and store the results in COMTRADE format. For the above stated purpose, we use the single-phase breaker model to simulate the open circuit fault inside the protection zone.

Two faults are simulated in the event. The faults are non-permanent. The diagrams for fault model are shown in Figures 4.3.1 to 4.3.2. Fault 1 is defined as a downed conductor fault happens at bus B22. This is a fault occurring inside the protection zone which should be cleared by opening the two breakers connected to this zone. The fault is initiated at 0.5 second from the start of the simulation and lasts 0.2 second.

Fault 2 is defined as a downed conductor fault happens at bus B32. This is a fault occurring outside protection zone and therefore the breakers of the protection zone should not operate. The fault is initiated at 1.3 second from the start of the simulation and lasts 0.2 second.

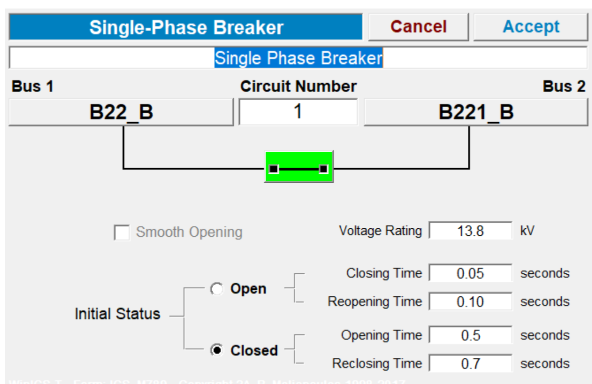


Figure 4.3.1: Downed Conductor Fault 1

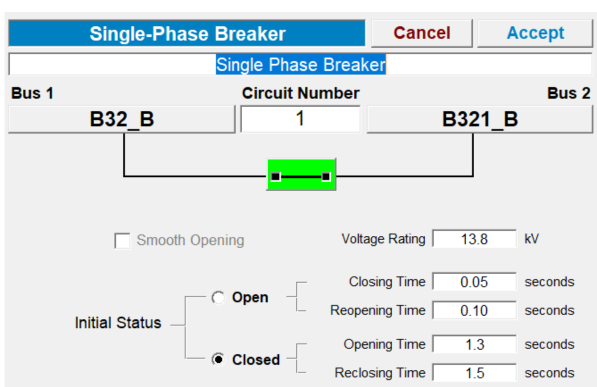


Figure 4.3.2: Downed Conductor Fault 2

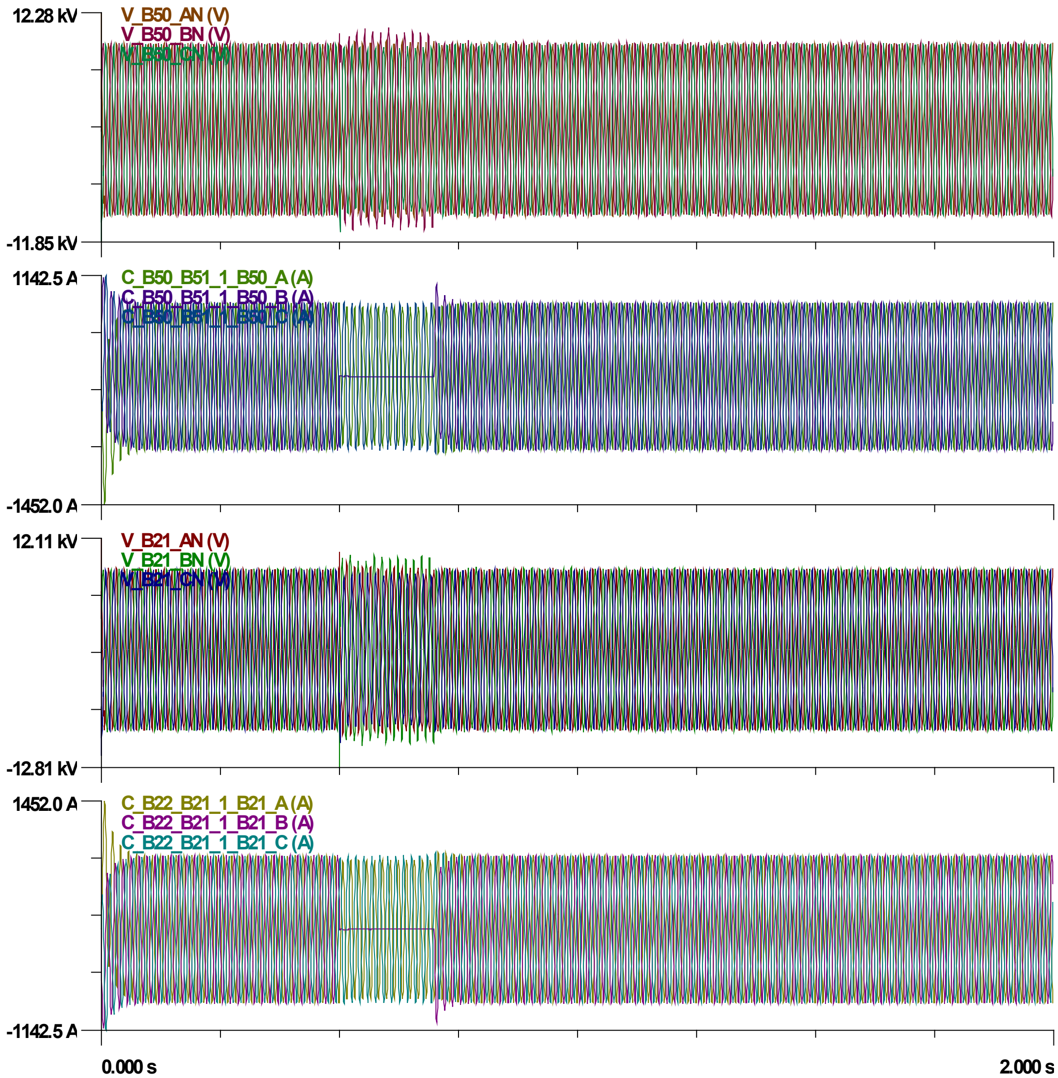


Figure 4.3.3: Voltage and Current Measurements Obtained from Merging Unit 1 and Merging Unit 2

4.3.2 EBP Results for Event 2

This section presents the results obtained from the EBP relay for the use case and events described in last section. The EBP relay is implemented within the WinXFM Program.

The relay setting is shown in Figure 4.3.4. Averaged confidence level to Trip the Relay calculated by

Averaged CI to trip the relay=1-Td/Tr=50%

In other words, the relay will trip if the averaged confidence level is lower than 50% for 0.3s.

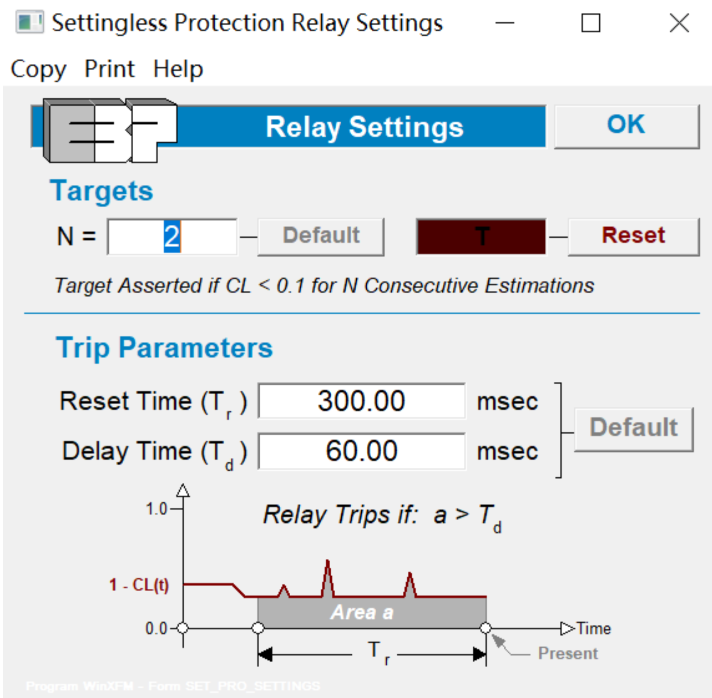


Figure 4.3.4: Relay Setting for Event 2

The selected performance metrics of the event are illustrated in Figures 4.3.5 and 4.3.6. The selected performance metrics are chi-square value, confidence level, trip decision, voltages and current of two terminals of the protection zone. Though observation of Figure 4.3.5, we find that the downed conductor inside the protection zone leads to drastic drop of the confidence level and is detected by the relay. The downed conductor outside the protection zone only causes a fluctuation in the confidence level for a short period of time. The estimation-based protection scheme works properly in detecting the downed conductor.

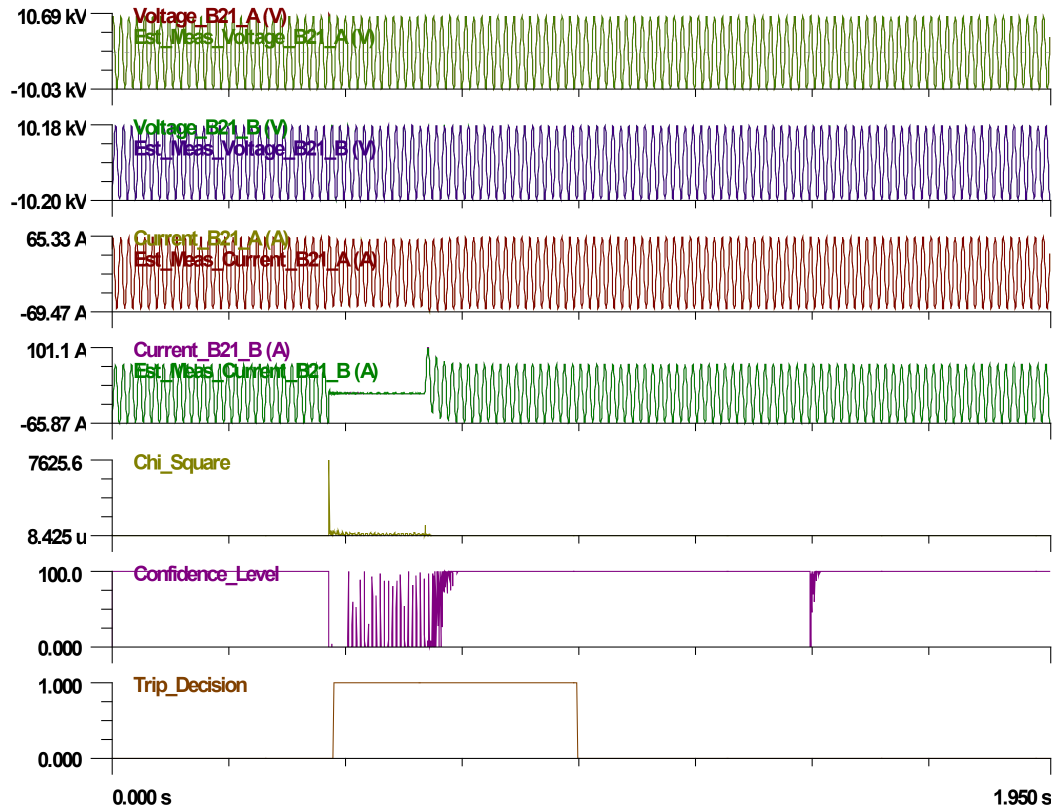


Figure 4.3.5: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of the Testing Results of Event 2 (Whole Time Period)

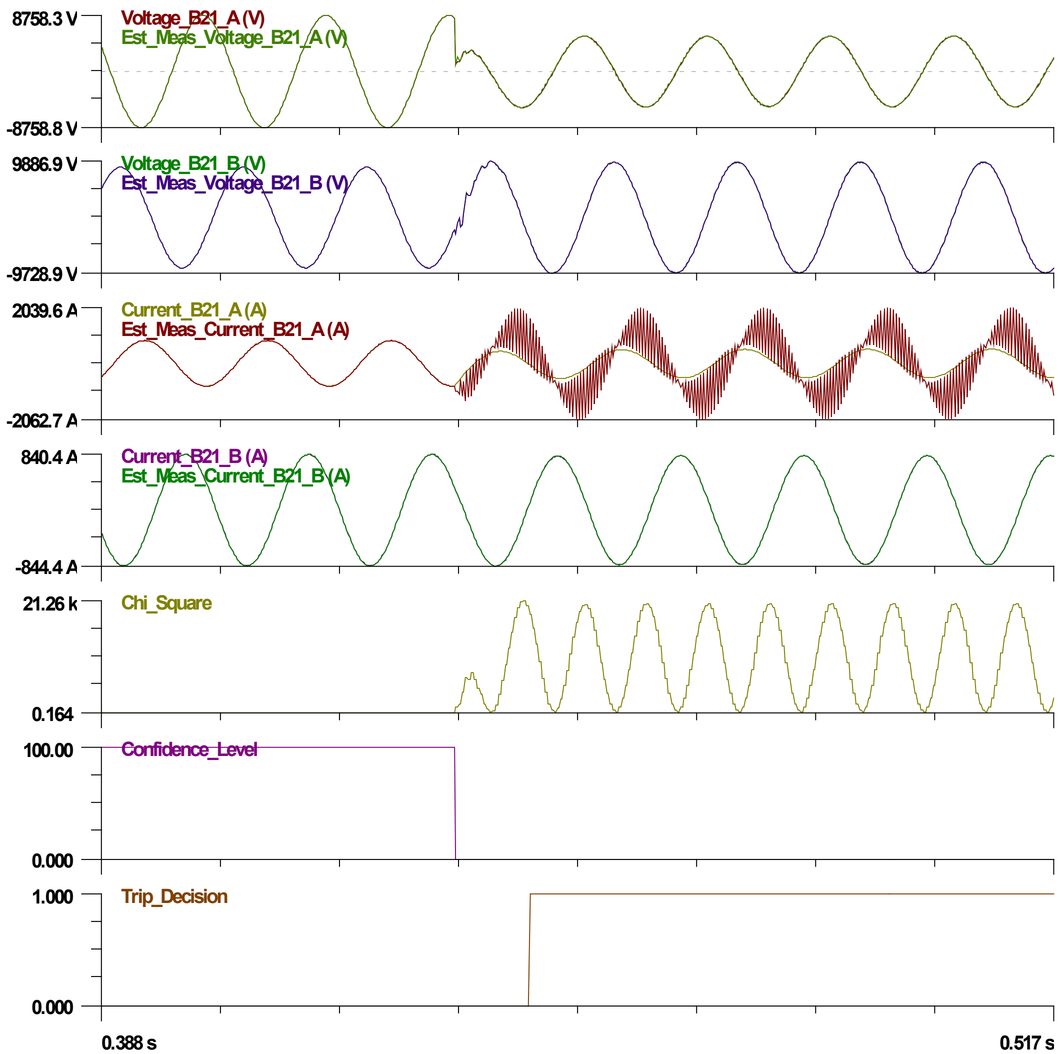


Figure 4.3.6: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of the Testing Results of Event 2 (Downed Conductor Inside the Protection Zone)

5. Parametric Study of EBP Performance Under Different Load Conditions and Fault Types

This section presents a parametric study of the performance of the EBP relay. For this purpose, a specific protection zone is used. Load and fault types are varying and the performance of the EBP relay is recorded.

5.1 Creating Events with Different Load Conditions

For the above stated purpose, we use WinIGS-T to define events, simulate the events and store the results in COMTRADE format. Two Y-connected loads are connected at Bus DB7 and DB8 and events are simulated with different load conditions. Figure 3.2.1 shows the load model and load model parameter dialog. The COMTRADE files generated with different load conditions are named according to Table 3.1.

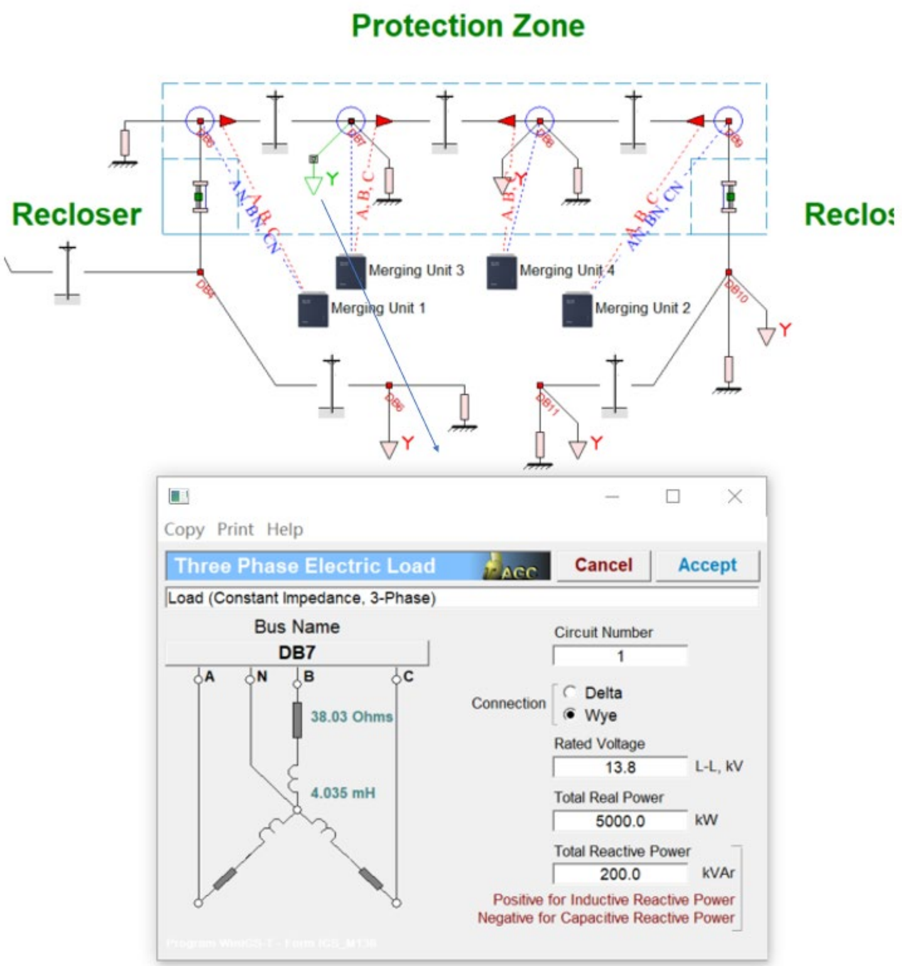


Figure 3.1.1: Network Model with Load at Bus DB7 and DB8

Two faults are simulated in each event and the faults are described below:

Fault 1 is defined as a phase A to neutral fault at bus **DB 11** (an external fault). Figure 3.2.1 shows the fault model and fault model parameters dialog. This is a fault occurring outside protection zone and therefore the breakers of the protection zone should not operate. The fault is initiated at 0.6 second from the start of the simulation and lasts 0.2 second. The fault conductance is set to be 1.0 Mhos.

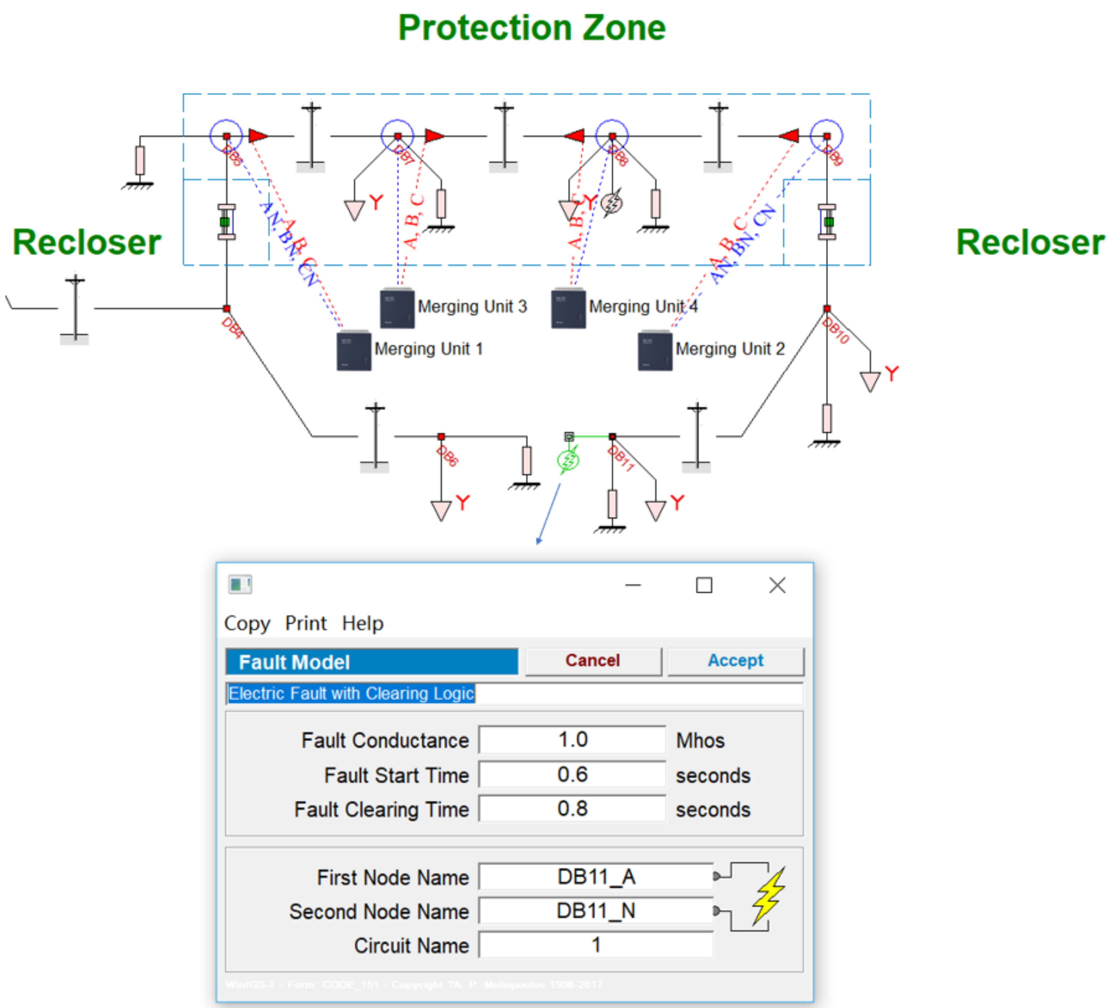


Figure 3.1.1: Network Model with Fault between Phase A and Neutral at Bus DB10

Fault 2 is defined with a phase A to neutral fault at bus **DB8** within the protection zone. Figure 3.1.2 shows the fault model and fault model parameters dialog. This is a fault occurring inside the protection zone which should be cleared by opening the two breakers connected to this zone. The fault is initiated at 1.4 seconds from the start of the simulation and lasts 0.2 second. The fault conductance is set to be 1.0 Mhos.

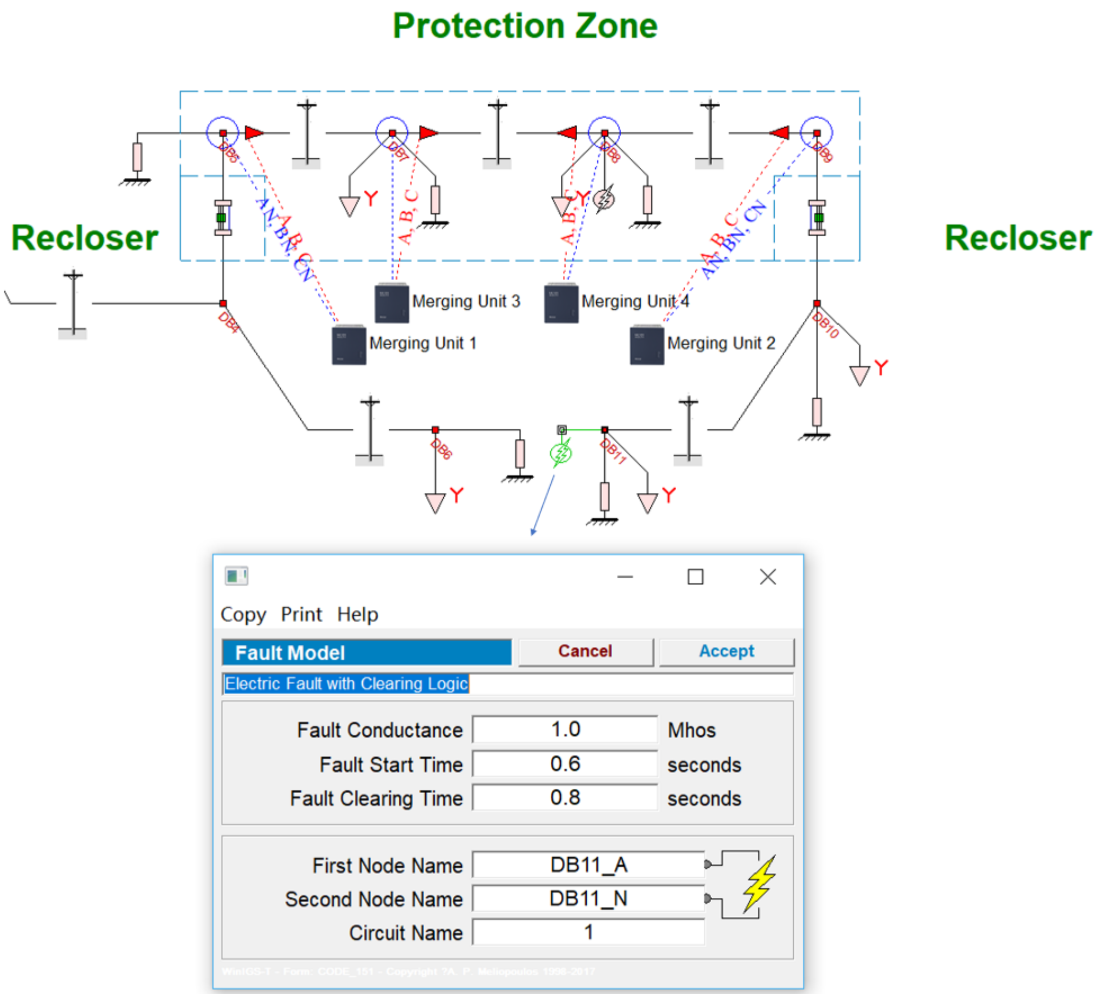


Figure 3.1.2: Network Model with Fault between Phase A and Neutral at Bus DB8

The simulation is executed for a period of two seconds. The measurements generated during the simulation are stored in a COMTRADE file. Figure 3.1.3 shows the time domain simulation parameters dialog where the simulation time step, duration, as well as the COMTRADE output is specified. Note that the time step is selected to match the standard merging unit sampling rate at 80 samples per cycle. For a 60 Hz system this is achieved by selecting the time step at:

$$\Delta t = 1{,}000{,}000 \,/\, (\, 60 \times 80 \,) = 208.333 \text{ microseconds.}$$

The voltages and currents captured by the four merging units with two typical load conditions are plotted in Figure 3.1.4 to Figure 3.1.5.

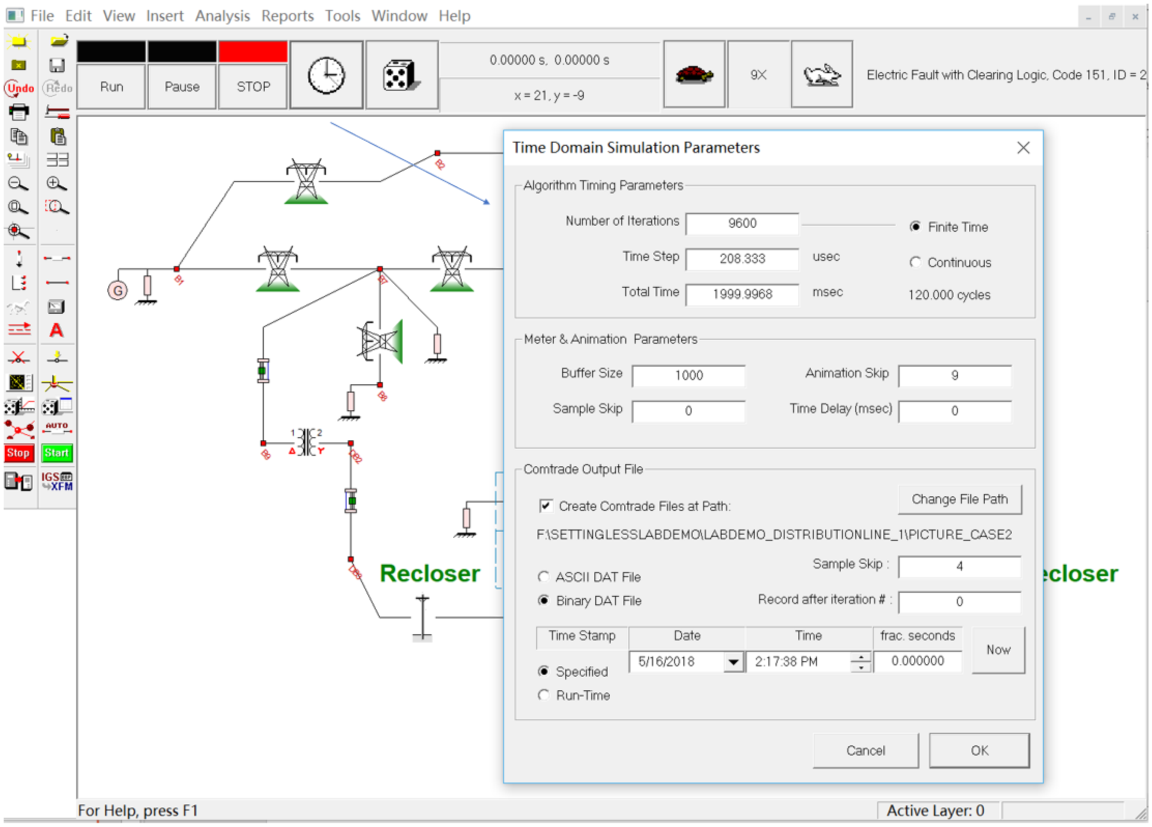


Figure 3.1.3: Time Domain Simulation Parameters Dialog

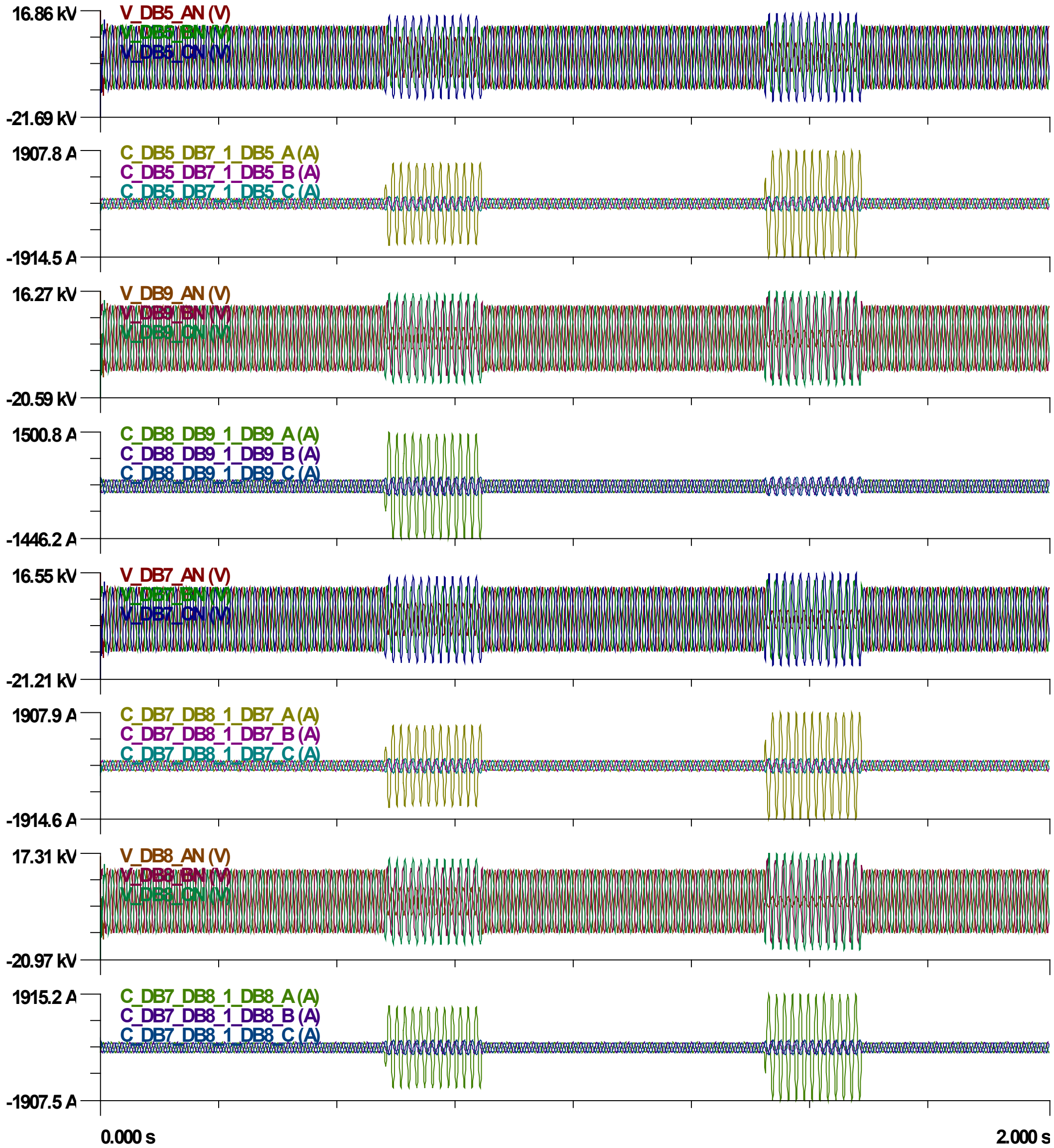


Figure 3.1.4: Voltage and Current Measurements Obtained from four merging units with No Load

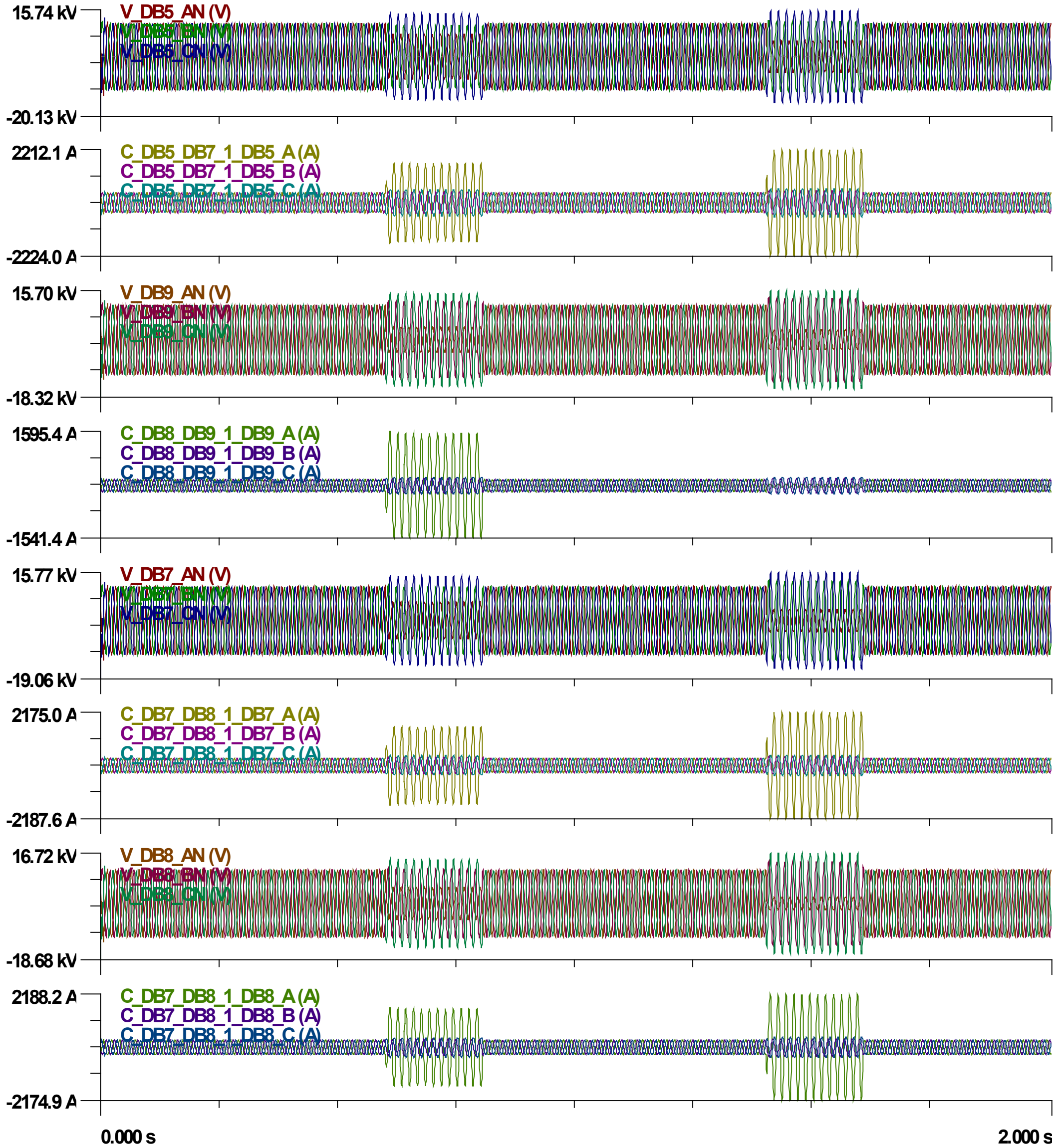


Figure 3.1.5: Voltage and Current Measurements Obtained from four merging units with two 2000 kW loads

Table 3.1: The generated COMTRADE configuration and data files

Merging Unit	Bus DB7 Load	Bus DB8 Load	COMTRADE Configuration and Data Files
Merging Unit 1	No Load	No Load	DistributionLine1_Load_NoLoad.cfg DistributionLine1_Load_NoLoad.dat
	500 kW	500 kW	DistributionLine1_Load_500500.cfg DistributionLine1_Load_500500.dat
	500 kW	2000 kW	DistributionLine1_Load_5002000.cfg DistributionLine1_Load_5002000.dat
	2000 kW	2000 kW	DistributionLine1_Load_20002000.cfg DistributionLine1_Load_20002000.dat
	2500 kW	2500 kW	DistributionLine1_Load_25002500.cfg DistributionLine1_Load_25002500.dat
	3000 kW	3000 kW	DistributionLine1_Load_30003000.cfg DistributionLine1_Load_30003000.dat
Merging Unit 2	No Load	No Load	DistributionLine2_Load_NoLoad.cfg DistributionLine2_Load_NoLoad.dat
	500 kW	500 kW	DistributionLine2_Load_500500.cfg DistributionLine2_Load_500500.dat
	500 kW	2000 kW	DistributionLine2_Load_5002000.cfg DistributionLine2_Load_5002000.dat
	2000 kW	2000 kW	DistributionLine2_Load_20002000.cfg DistributionLine2_Load_20002000.dat
	2500 kW	2500 kW	DistributionLine2_Load_25002500.cfg DistributionLine2_Load_25002500.dat
	3000 kW	3000 kW	DistributionLine2_Load_30003000.cfg DistributionLine2_Load_30003000.dat
Merging Unit 3	No Load	No Load	DistributionLine3_Load_NoLoad.cfg DistributionLine3_Load_NoLoad.dat
	500 kW	500 kW	DistributionLine3_Load_500500.cfg DistributionLine3_Load_500500.dat
	500 kW	2000 kW	DistributionLine3_Load_5002000.cfg DistributionLine3_Load_5002000.dat
	2000 kW	2000 kW	DistributionLine3_Load_20002000.cfg DistributionLine3_Load_20002000.dat
	2500 kW	2500 kW	DistributionLine3_Load_25002500.cfg DistributionLine3_Load_25002500.dat
	3000 kW	3000 kW	DistributionLine3_Load_30003000.cfg DistributionLine3_Load_30003000.dat
	3500 kW	3500 kW	DistributionLine3_Load_35003500.cfg DistributionLine3_Load_35003500.dat

5.2 Creating Events with Different Fault Types

We use WinIGS-T to simulate the fault events and store the results in COMTRADE format. The events are simulated with three different type of faults and the fault impedances are adjusted to change the fault current level. The purpose is to test the performance of the protection scheme with reduced fault current level. The events of three different types of fault are defined below.

Event A is defined as a phase A to neutral fault at bus **B8** (an internal fault). Figure 3.2.1 shows the fault model and fault model parameters dialog. The fault is initiated at 0.4 seconds from the start of the simulation and lasts 0.2 second.

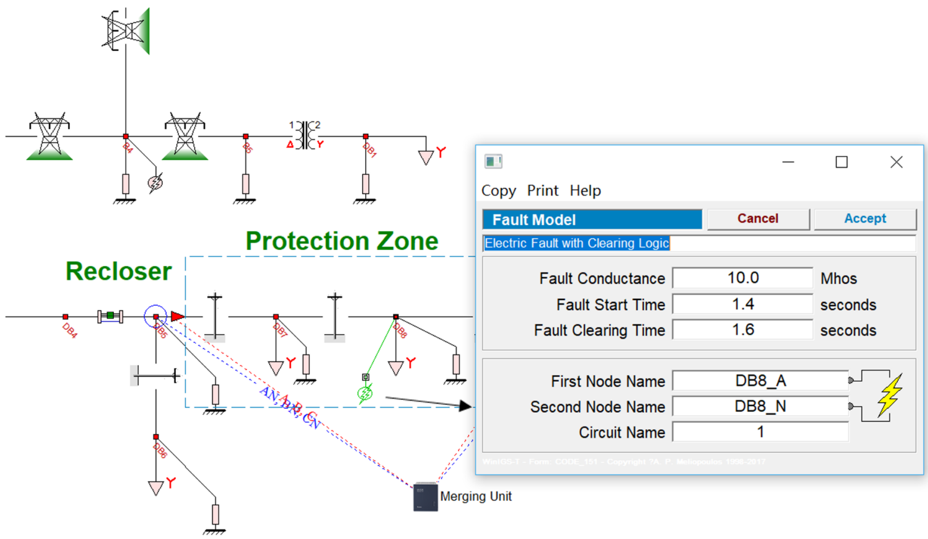


Figure 3.2.1: Network Model with Fault between Phase A and Neutral at Bus B8

Event B is defined as a phase A to phase B at bus **B8** (an internal fault). Figure 3.2.2 shows the fault model and fault model parameters dialog. The fault is initiated at 0.4 seconds from the start of the simulation and lasts 0.2 second.

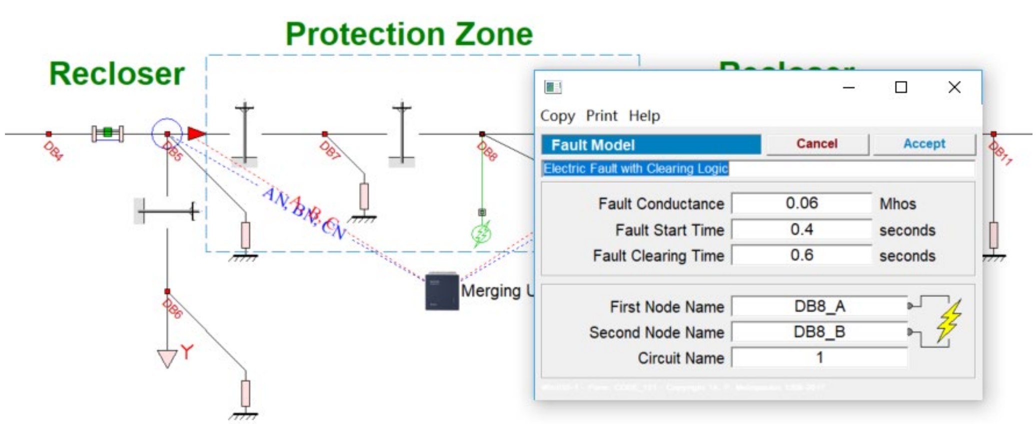


Figure 3.2.2: Network Model with Fault between Phase A and Phase B at Bus B8

Event C is defined as a three phase fault at bus **B8** (an internal fault). Figure 3.2.3 shows the fault model and fault model parameters dialog. The fault is initiated at 0.4 seconds from the start of the simulation and lasts 0.2 second.

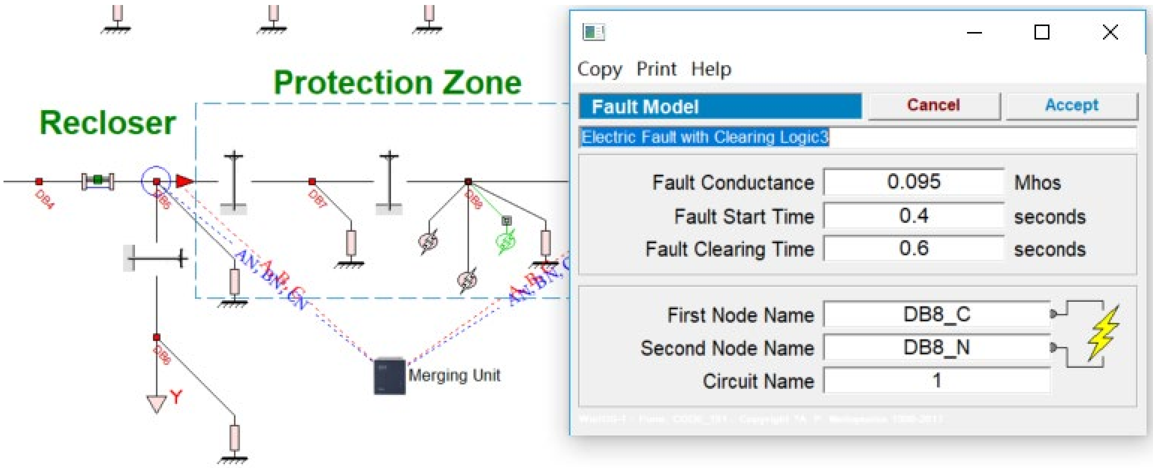


Figure 3.2.3: Network Model with Three Phase Fault at Bus B8

Similar work is done for three different cases (with different measurement sets). The COMTRADE files generated for case 1 with different faults are named according to Table 3.2. The files generated for the other two cases are named in the same way. The voltages and currents captured by the four merging units with two typical load conditions are plotted in Figure 3.2.4 to Figure 3.2.6.

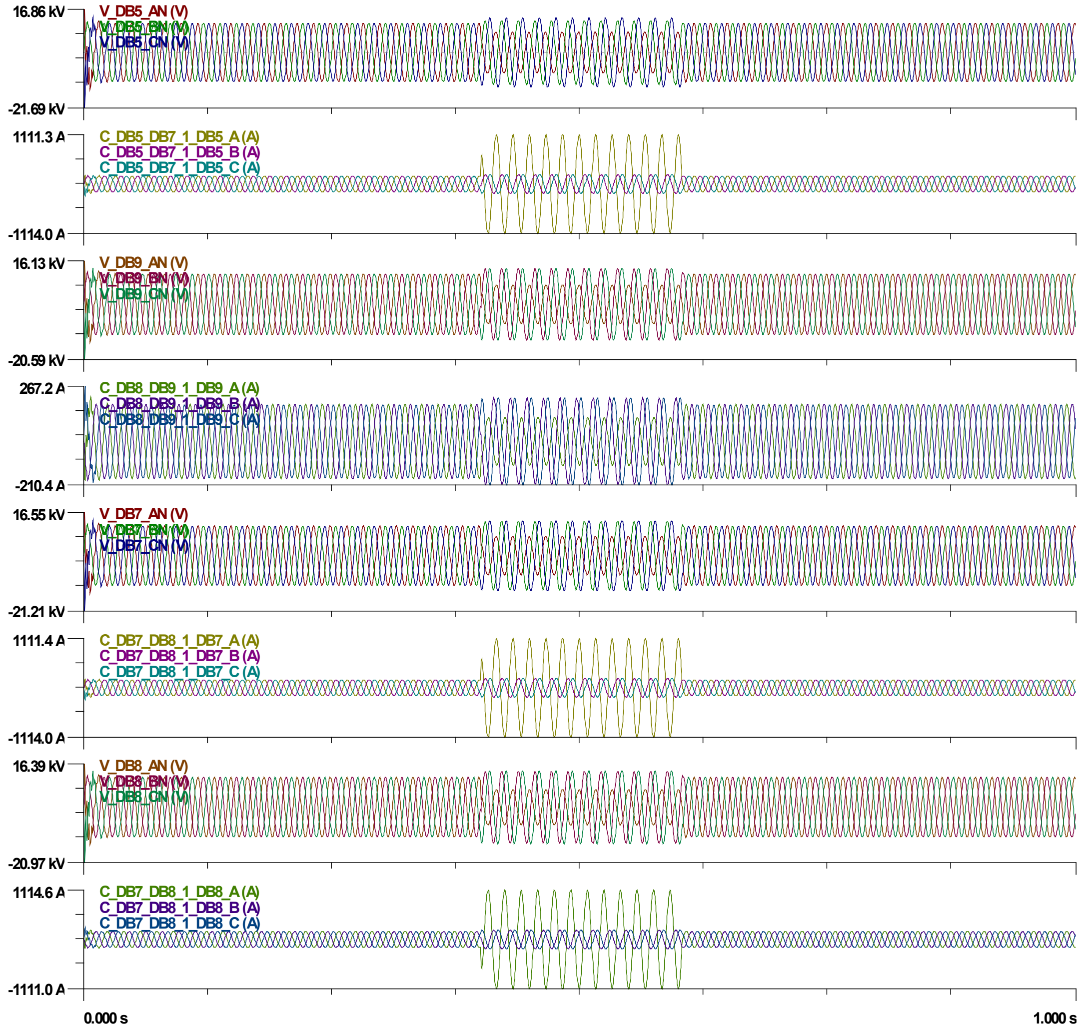


Figure 3.2.4: Voltage and Current Measurements Obtained from four merging units with a 1000A single line-to-ground fault

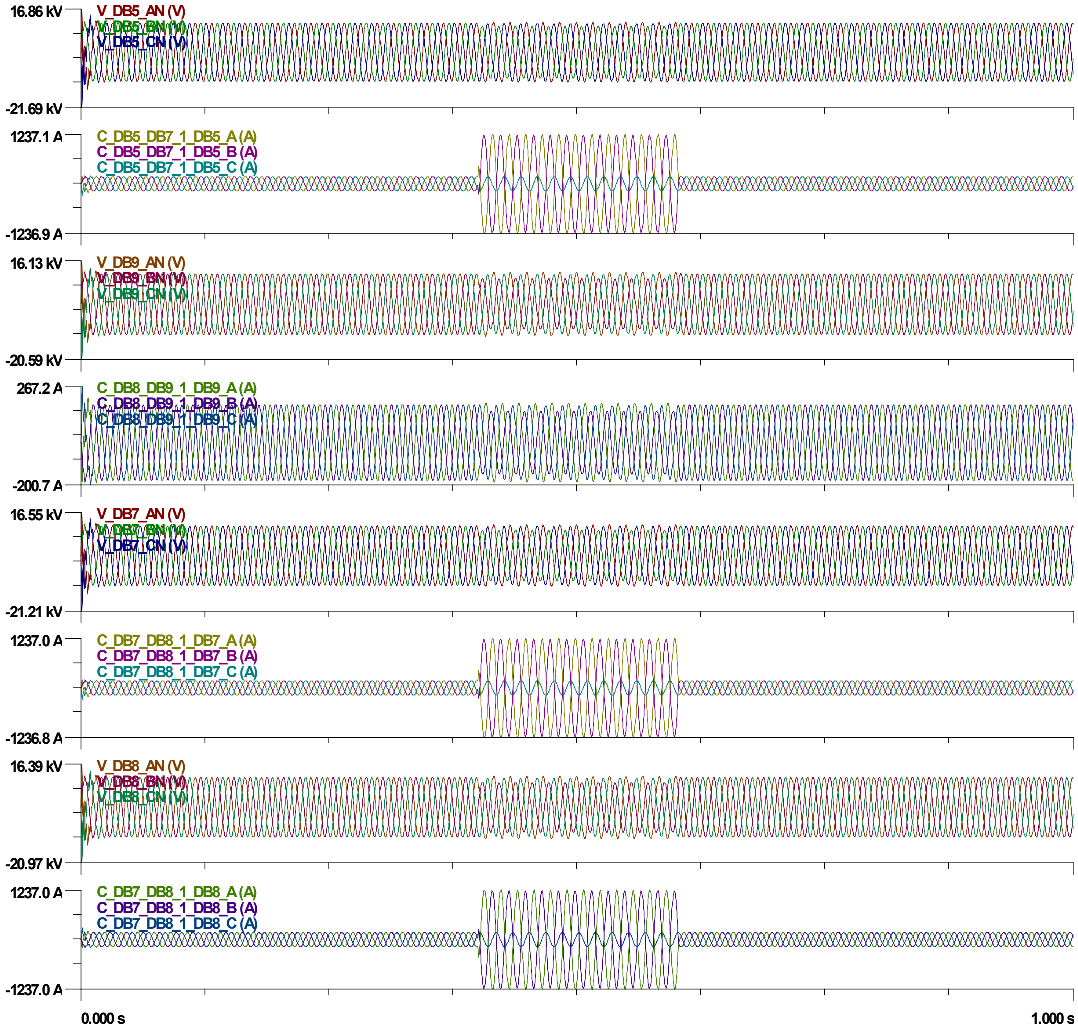


Figure 3.2.5: Voltage and Current Measurements Obtained from four merging units with a 1000A line-to-line fault

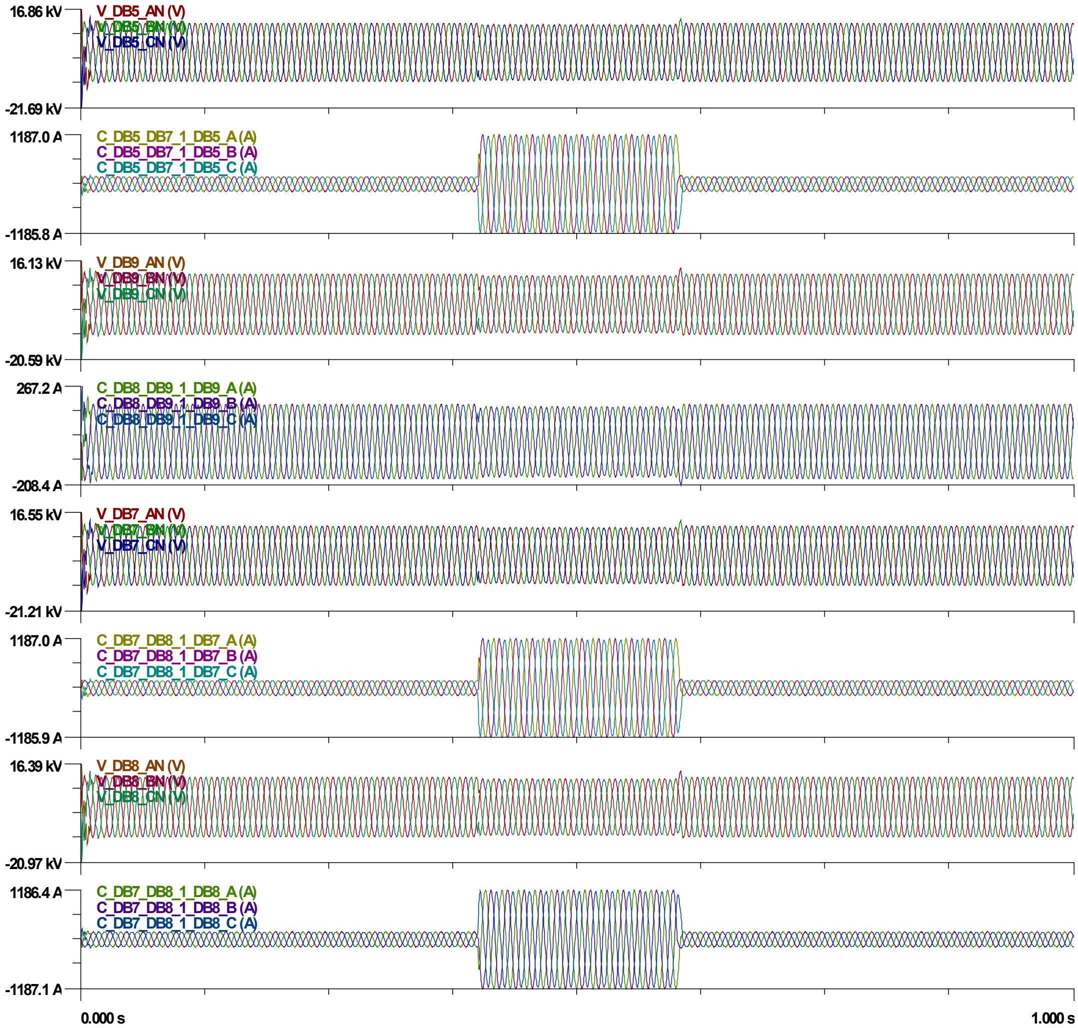


Figure 3.2.6: Voltage and Current Measurements Obtained from four merging units with a 1000A three phase fault

Table 3.2: The generated COMTRADE configuration and data files

Fault Type	Fault Impedance	Fault Current	COMTRADE Configuration and Data Files
Single Phase Fault	0.15 Mhos	1000A	DISTRIBUTIONLINE1SINGLEPHFAULT_1000.cfg DISTRIBUTIONLINE1SINGLEPHFAULT_1000.dat
	0.042 Mhos	400A	DISTRIBUTIONLINE1SINGLEPHFAULT_400.cfg DISTRIBUTIONLINE1SINGLEPHFAULT_400.dat
	0.03 Mhos	300A	DISTRIBUTIONLINE1SINGLEPHFAULT_300.cfg DISTRIBUTIONLINE1SINGLEPHFAULT_300.dat
	0.0195 Mhos	200A	DISTRIBUTIONLINE1SINGLEPHFAULT_200.cfg DISTRIBUTIONLINE1SINGLEPHFAULT_200.dat
	0.0095 Mhos	100A	DISTRIBUTIONLINE1SINGLEPHFAULT_100.cfg DISTRIBUTIONLINE1SINGLEPHFAULT_100.dat
Phase to Phase Fault	0.06 Mhos	1000A	DISTRIBUTIONLINE1PH_PHFAULT_1000.cfg DISTRIBUTIONLINE1PH_PHFAULT_1000.dat
	0.02 Mhos	400A	DISTRIBUTIONLINE1PH_PHFAULT_400.cfg DISTRIBUTIONLINE1PH_PHFAULT_400.dat
	0.016 Mhos	300A	DISTRIBUTIONLINE1PH_PHFAULT_300.cfg DISTRIBUTIONLINE1PH_PHFAULT_300.dat
	0.01 Mhos	200A	DISTRIBUTIONLINE1PH_PHFAULT_200.cfg DISTRIBUTIONLINE1PH_PHFAULT_200.dat
	0.005 Mhos	100A	DISTRIBUTIONLINE1PH_PHFAULT_100.cfg DISTRIBUTIONLINE1PH_PHFAULT_100.dat
Three Phase Fault	0.095 Mhos	1000A	DISTRIBUTIONLINE1THREEPHFAULT_1000.cfg DISTRIBUTIONLINE1THREEPHFAULT_1000.dat
	0.036 Mhos	400A	DISTRIBUTIONLINE1THREEPHFAULT_400.cfg DISTRIBUTIONLINE1THREEPHFAULT_400.dat
	0.027 Mhos	300A	DISTRIBUTIONLINE1THREEPHFAULT_300.cfg DISTRIBUTIONLINE1THREEPHFAULT_300.dat
	0.018 Mhos	200A	DISTRIBUTIONLINE1THREEPHFAULT_200.cfg DISTRIBUTIONLINE1THREEPHFAULT_200.dat
	0.009 Mhos	100A	DISTRIBUTIONLINE1THREEPHFAULT_100.cfg DISTRIBUTIONLINE1THREEPHFAULT_100.dat

6. EBP Relay Evaluation Results – Parametric Study

This section presents a parametric study and performance assessment of the EBP relay under various loading conditions of the distribution feeder.

6.1 EBP Results with Different Load Conditions

This section presents the results obtained from the EBP relay for the use case and events described in Section 6. The EBP relay has been implemented within the WinXFM Program. The user interface of the EBP program is illustrated in Figure 6.1.1.

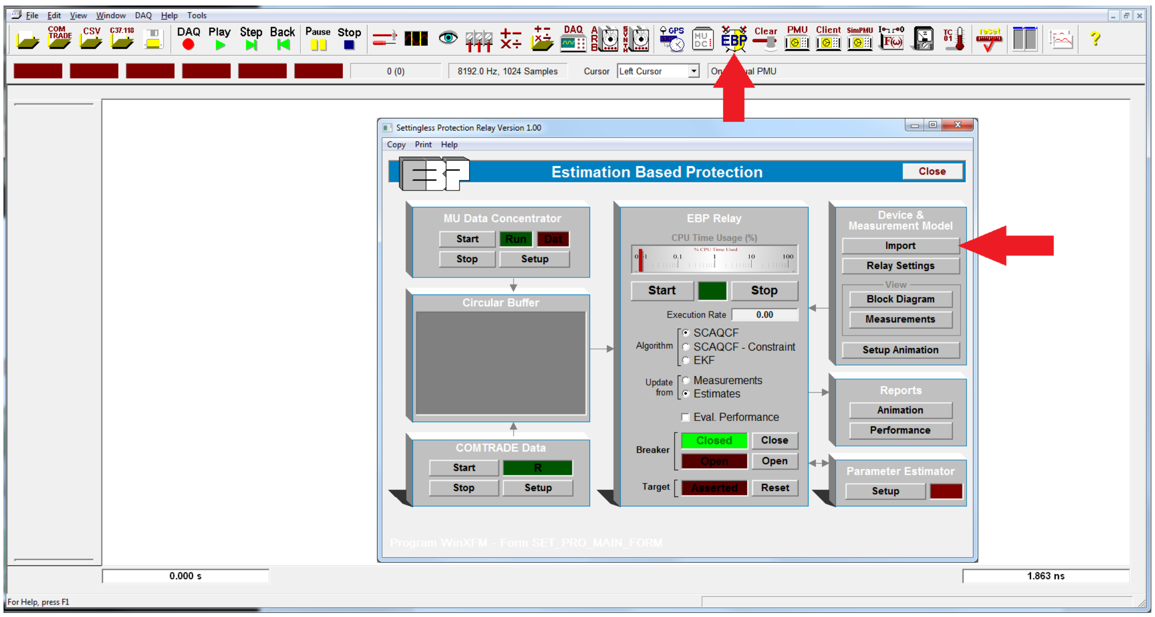


Figure 6.1.1: The EBP Main Setup Form in the WinXFM Program

To run the EBP relay using the Event A data, execute the WinXFM program and open the WinXFM file:

DistributionLine_Protection1

Note: this file is provided with this report under the file name DistributionLine_Protection1*.xfm*

The "*Device and Measurement File*" dialog is shown in Figure 6.1.2. The Device and Measurement files are selected for different cases as below:
Case1: Three distribution lines and merging unit 1 and 4

- DistributionLine_1.TDMDEF (Measurement Definition File)
- DistributionLine_1.TDSCAQCF (Device Model File)

Case 2: Three distribution lines and merging unit 1, 2 and 4

- DistributionLine_2.TDMDEF (Measurement Definition File)
- DistributionLine_2.TDSCAQCF (Device Model File)

Case 3: Three distribution lines and merging unit 1, 2, 3 and 4

- DistributionLine_3.TDMDEF (Measurement Definition File)
- DistributionLine_3.TDSCAQCF (Device Model File)

The model domain and model kind are selected as “**Time Domain**” and “**Algebraic Companion Form**”. The selected protection zone devices are listed and the active column is checked as illustrated in Figure 6.1.2.

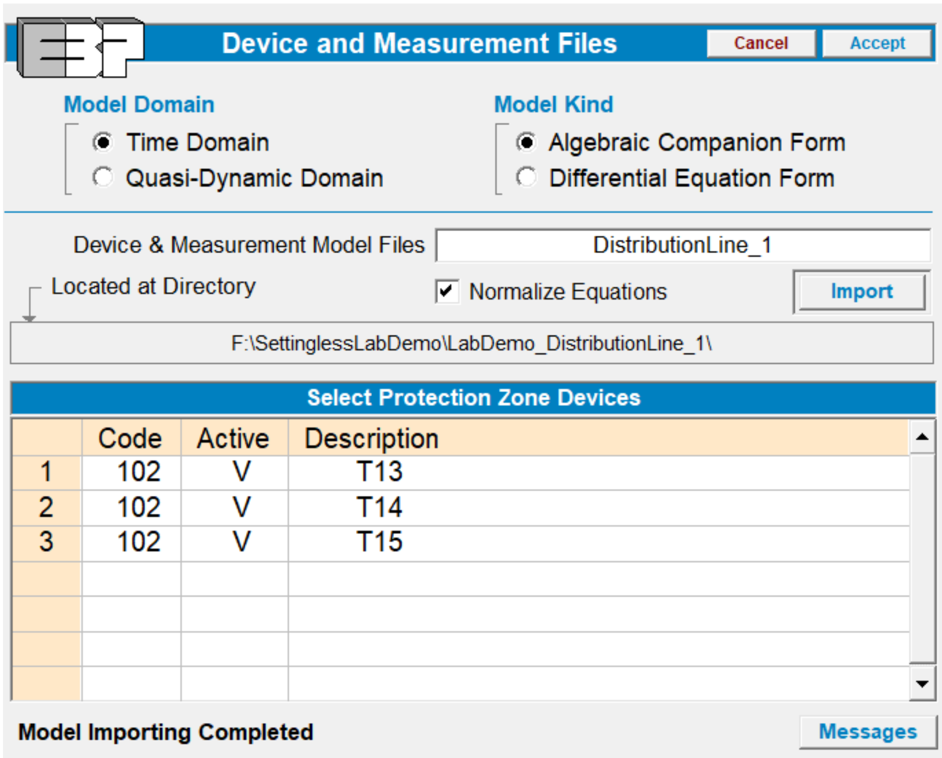


Figure 6.1.2: Importing Zone 1 Device and Measurement Definition Files

The simulated events are imported through the COMTRADE Data Playback dialog (shown in Figure 6.1.3). The **COMTRADE File Name** field indicates the Event that has been selected. The following rate are set for the program:

- Playback rate is set at **4800** samples per second for 60 Hz systems.
- Speed Factor radio button is selected and the speed factor is set to 5.0.

The speed factor option allows the relay response to be observed in slow motion. Otherwise, if you select the real-time option, the playback will occur in real time and the whole process will be completed in a shout time, i.e., the duration of the waveform data stored in the COMTRADE file.

Click on the **Close** button to close the COMTRADE Data Playback dialog.

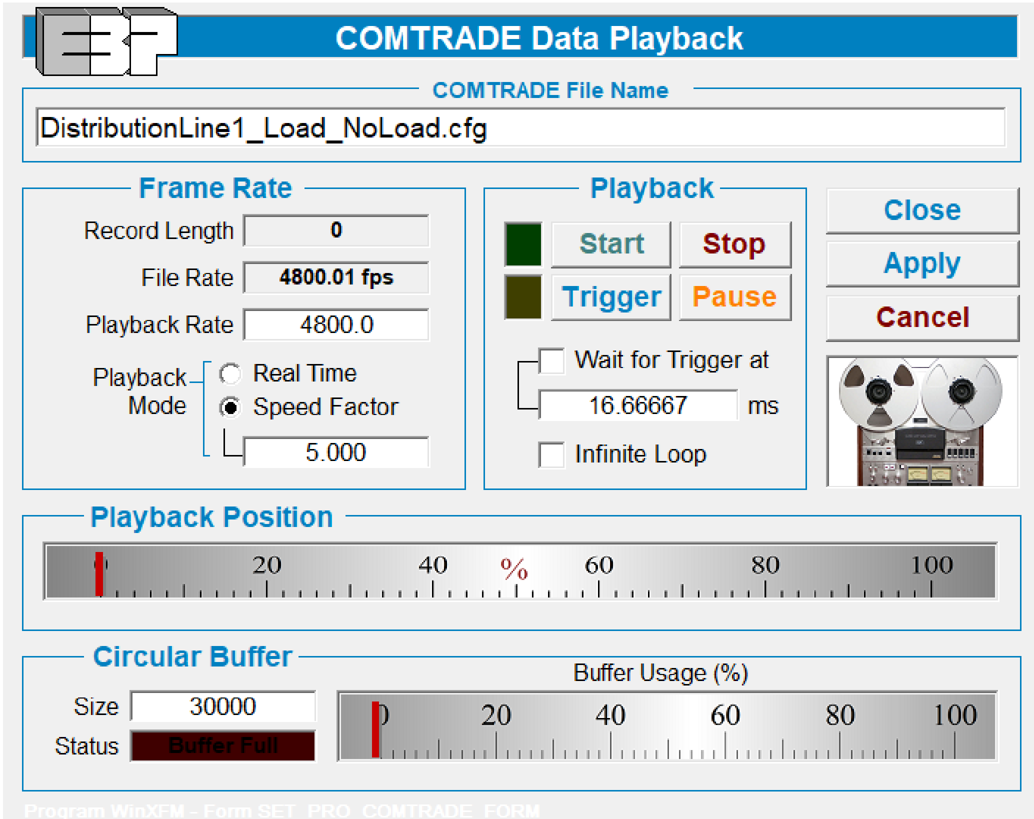


Figure 6.1.3: Selecting the COMTRADE data files for Playback

After the event and the model are imported, the system is ready to execute the EBP relay using the Event data. The performance metrics of the events with different load condition are illustrated in Figure 6.1.4 to Figure 6.1.21. Note that the confidence level remains a high level before the fault and during the external fault. The confidence level reaches to zero immediately upon the internal fault. The event information and corresponding figures are summarized in Table 6.1. A list of available channels for plotting is shown in Figure 6.1.22.

Table 6.1: The Figures Corresponding to the Events

Case Number	Bus DB7 Load	Bus DB8 Load	Figures
Case 1	No Load	No Load	Fig 4.1.4 and Fig 4.1.5
	2000 kW	2000 kW	Fig 4.1.6 and Fig 4.1.7
	2500 kW	2500 kW	Fig 4.1.8 and Fig 4.1.9
Case 2	No Load	No Load	Fig 4.1.10 and Fig 4.1.11
	2500 kW	2500 kW	Fig 4.1.12 and Fig 4.1.13
	3000 kW	3000 kW	Fig 4.1.14 and Fig 4.1.15
Case 3	No Load	No Load	Fig 4.1.16 and Fig 4.1.17
	2000 kW	2000 kW	Fig 4.1.18 and Fig 4.1.19
	2500 kW	2500 kW	Fig 4.1.20 and Fig 4.1.21

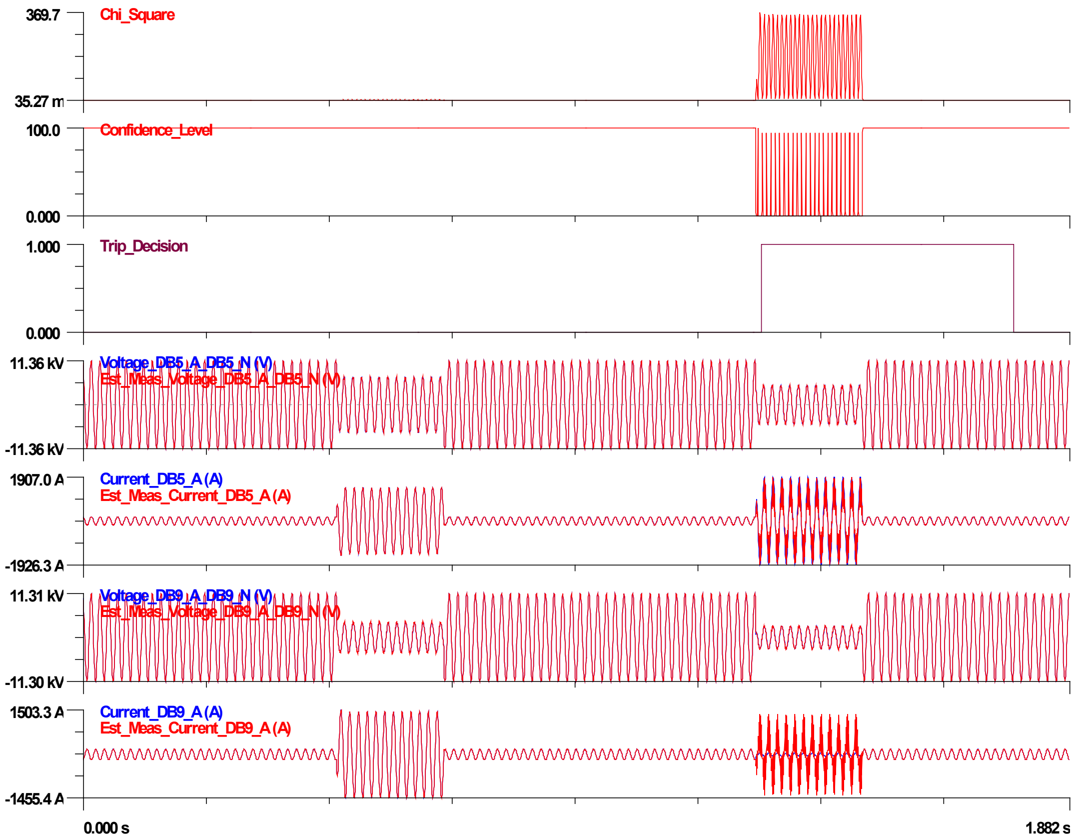


Figure 6.1.4: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Whole Event with No Load of Case 1

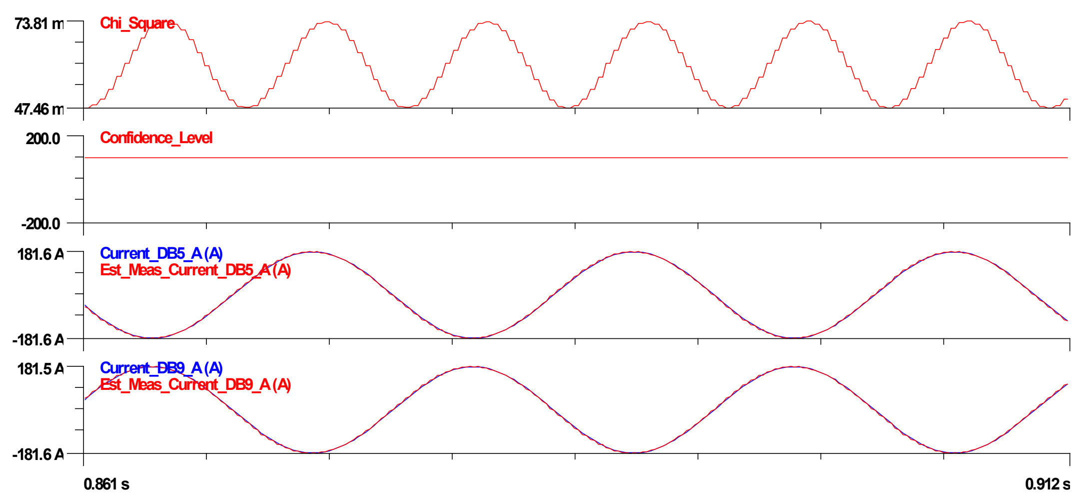


Figure 6.1.5: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value before fault with No Load of Case 1

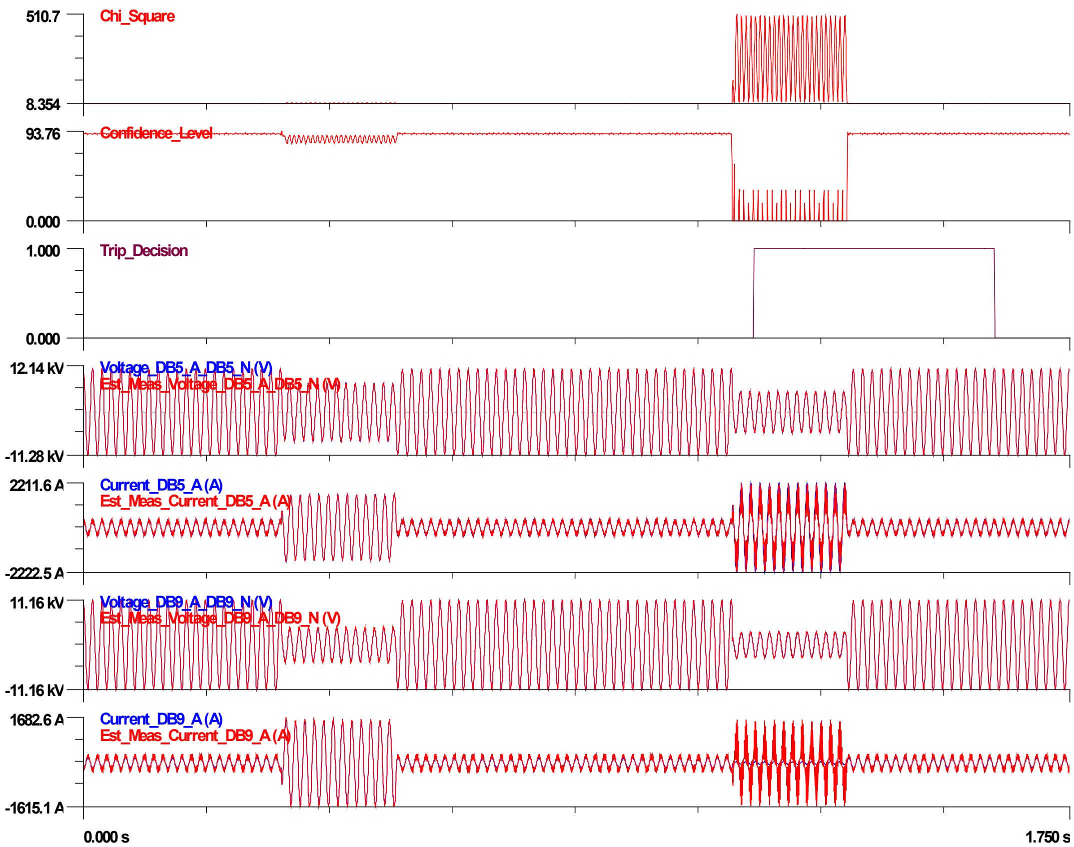


Figure 6.1.6: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Whole Event with two 2000kW Load of Case 1

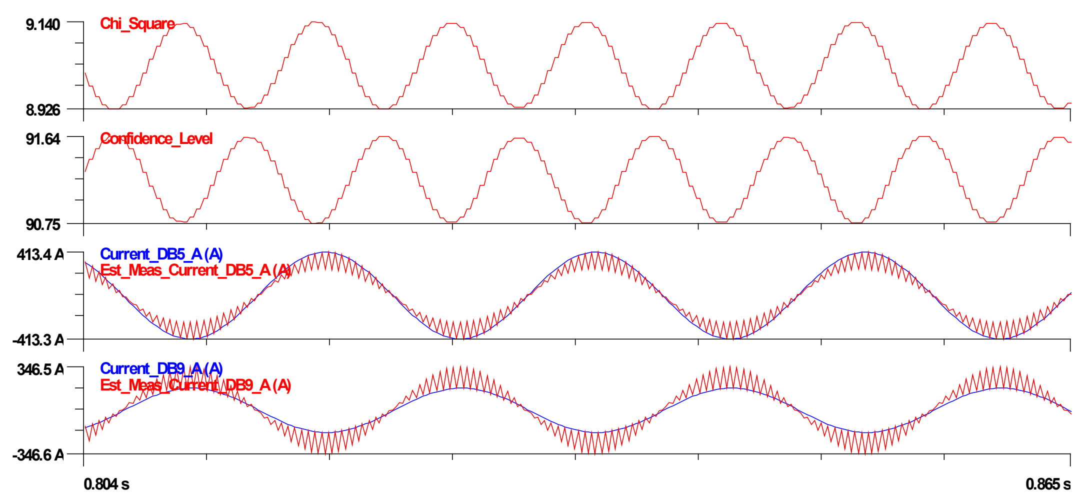


Figure 6.1.7: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value before fault with Two 2000kW Load of Case 1

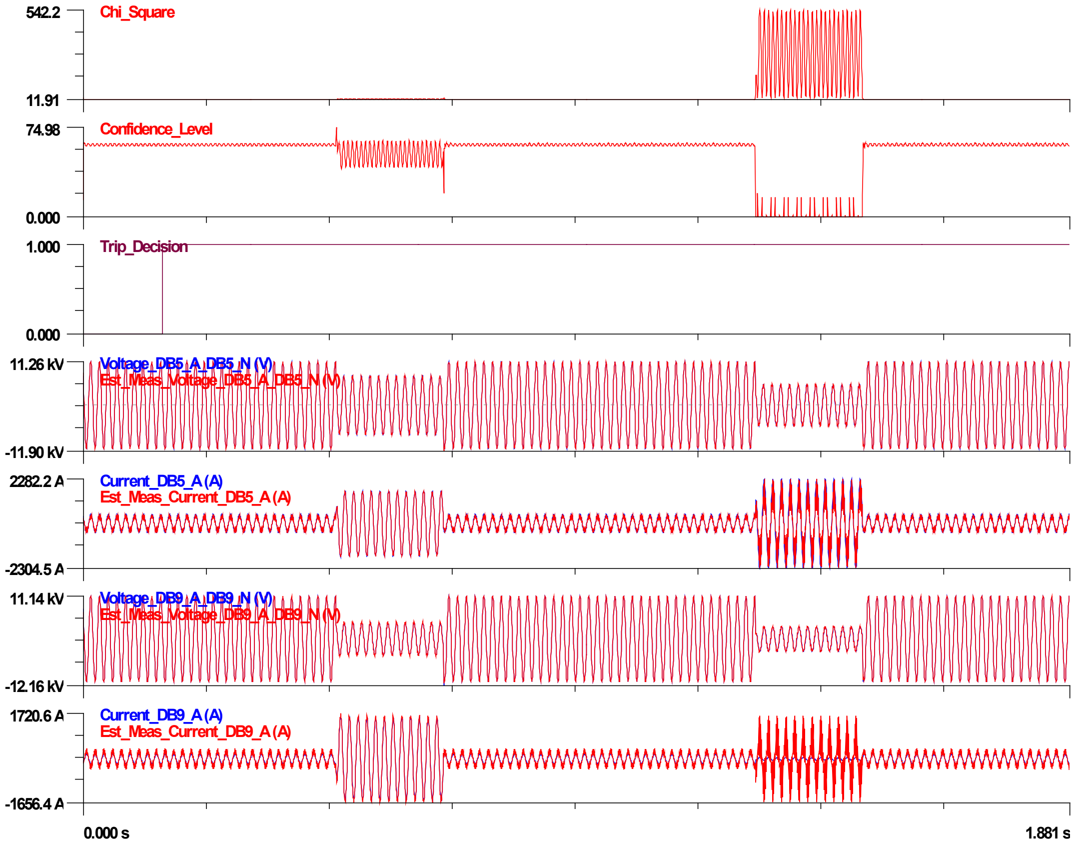


Figure 6.1.8: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Whole Event with two 2500kW Load of Case 1

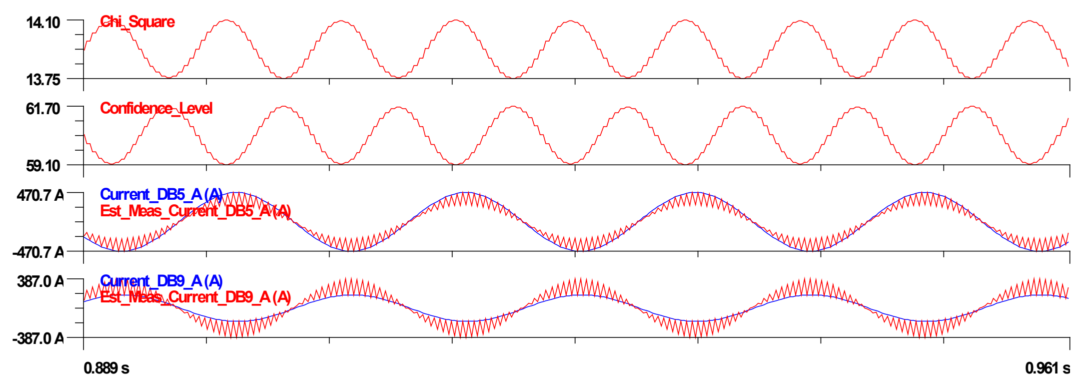


Figure 6.1.9: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value before fault with two 2500kW Load of Case 1

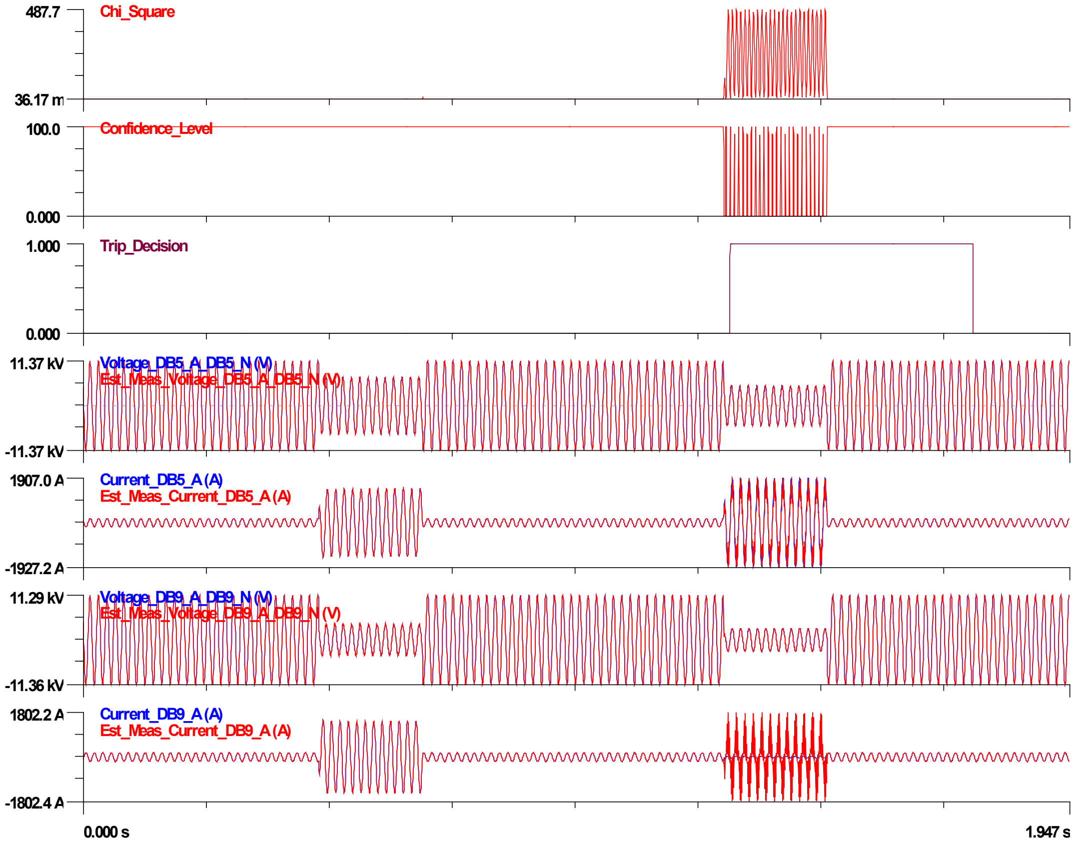


Figure 6.1.10: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Whole Event with No Load of Case 2

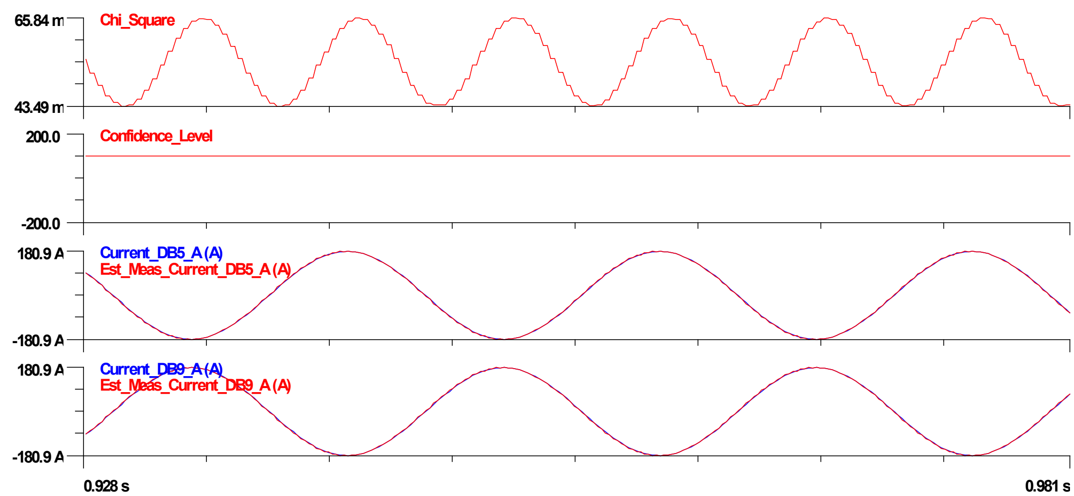


Figure 6.1.11: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value before fault with No Load of Case 2

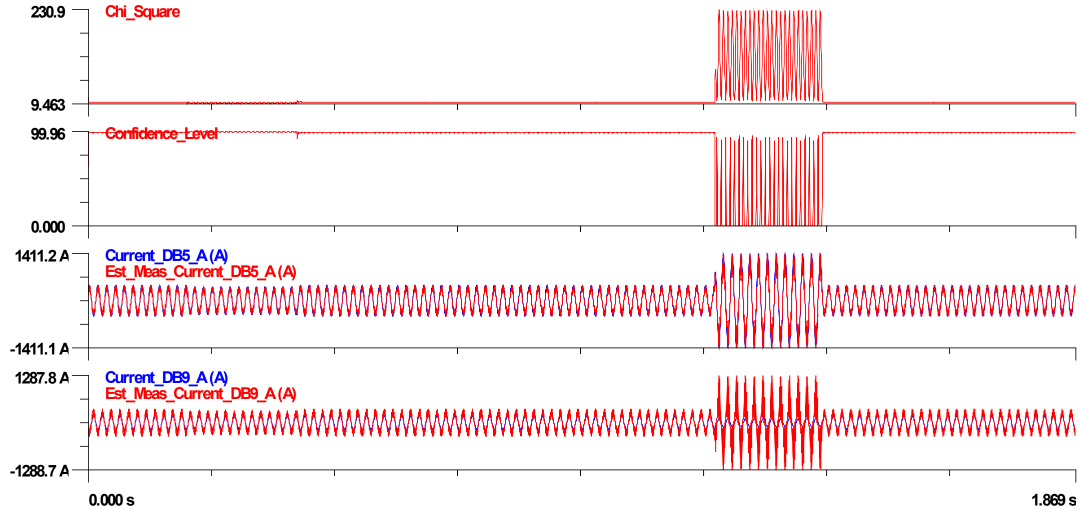


Figure 6.1.12: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Whole Event with two 2500kW Load of Case 2

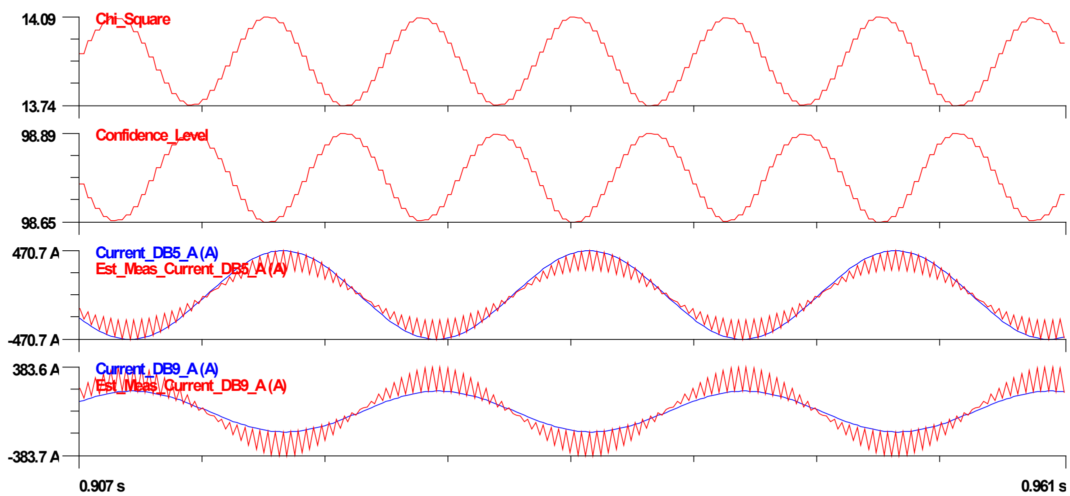


Figure 6.1.13: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value before fault with two 2500kW Load of Case 2

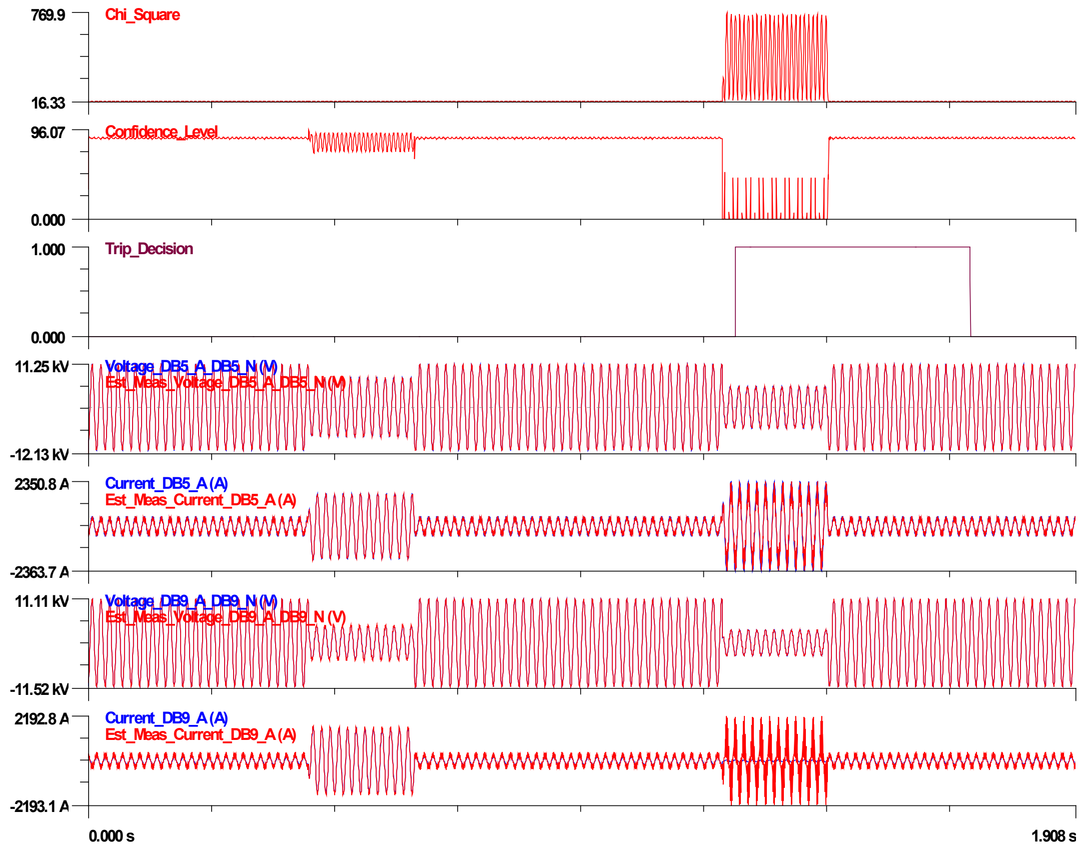


Figure 6.1.14: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Whole Event with two 3000kW Load of Case 2

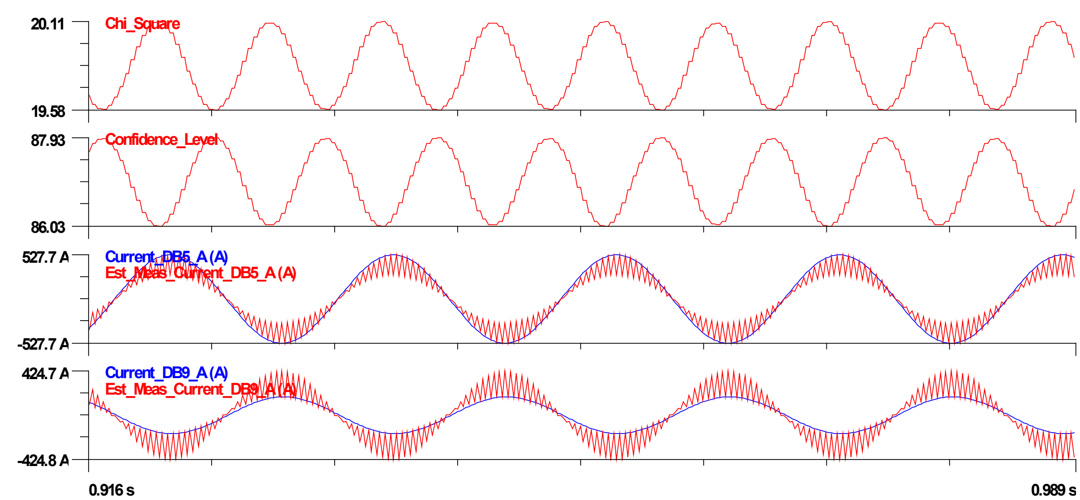


Figure 6.1.15: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value before fault with two 3000kW Load of Case 2

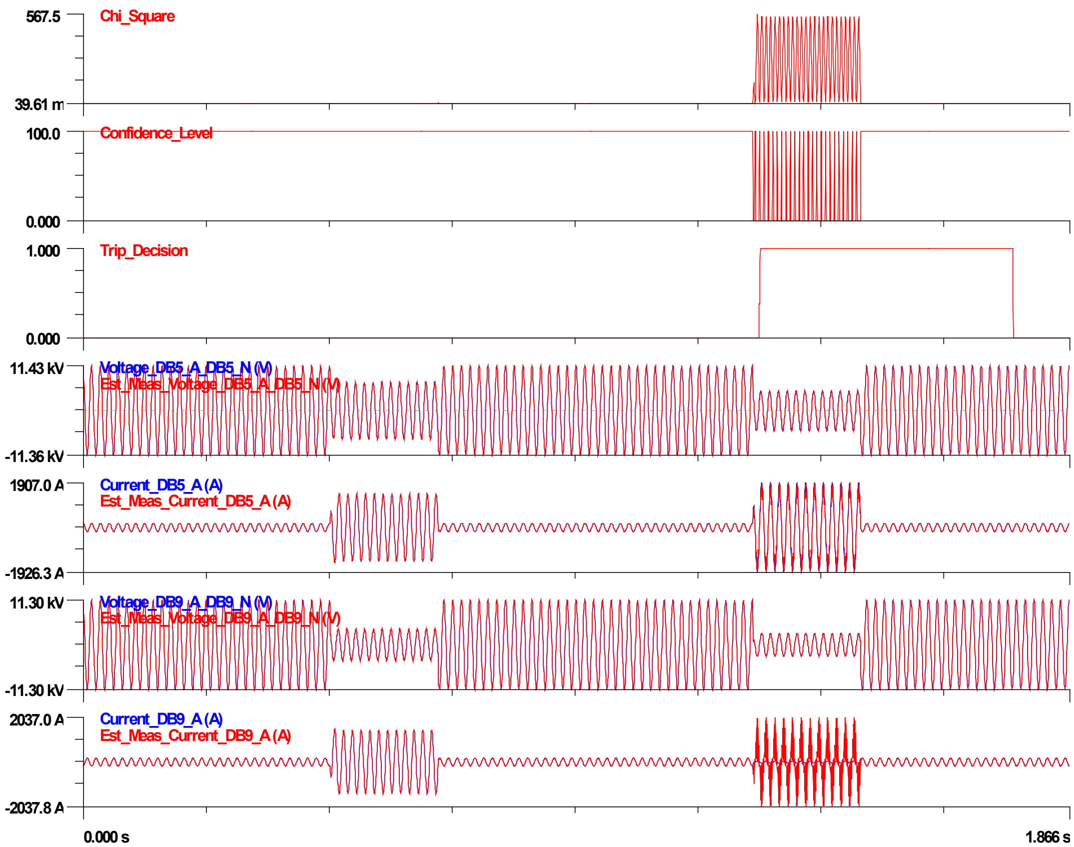


Figure 6.1.16: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Whole Event with No Load of Case 3

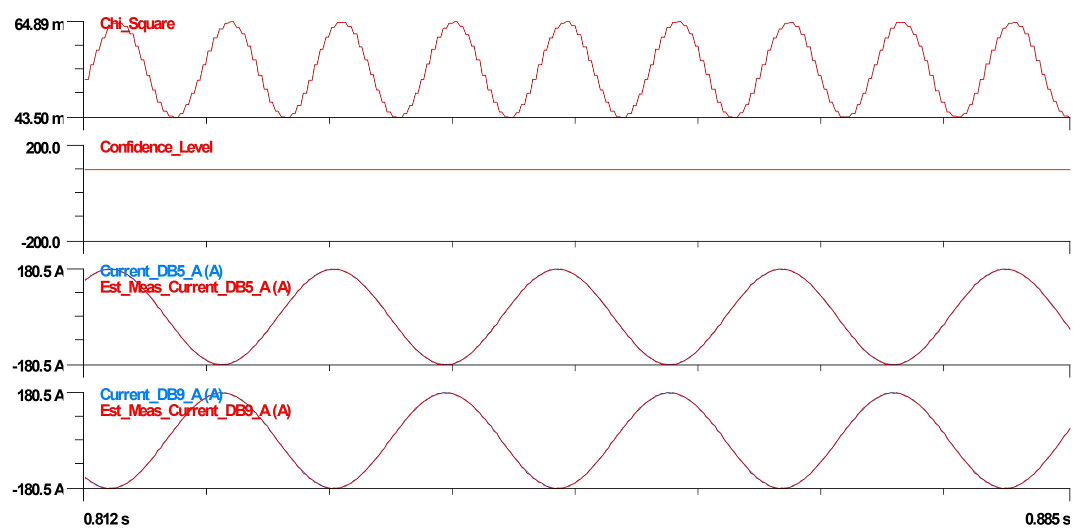


Figure 6.1.17: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value before fault with No Load of Case 3

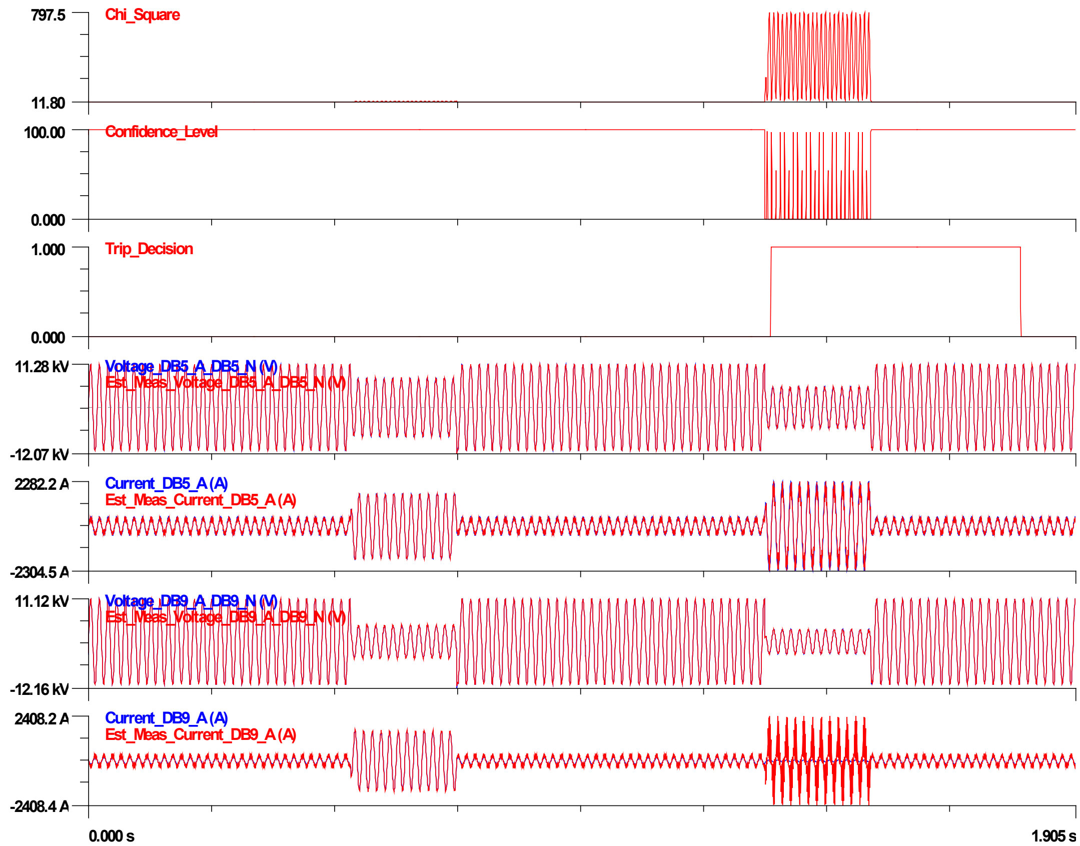


Figure 6.1.18: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Whole Event with two 2500kW Load of Case 3

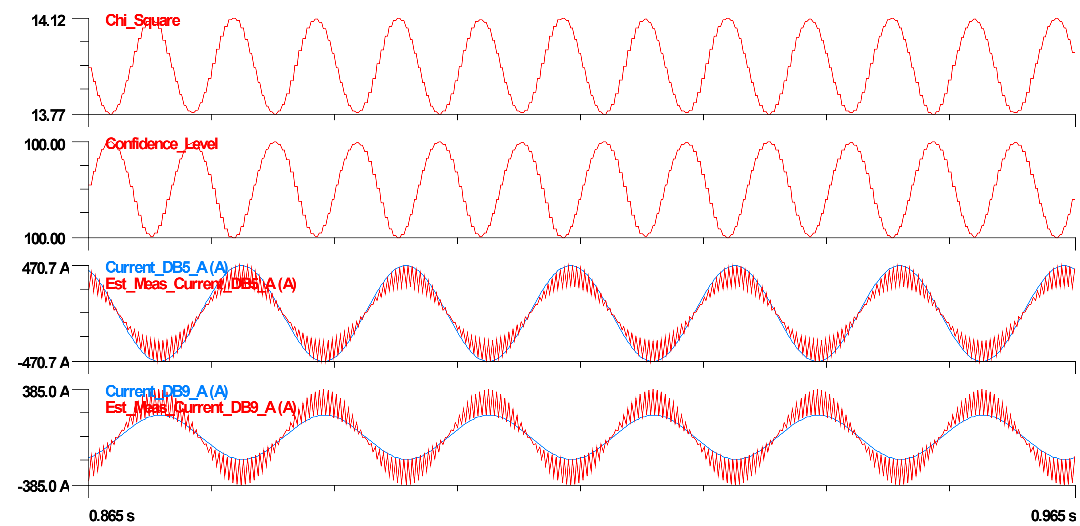


Figure 6.1.19: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value before fault with two 2500kW Load of Case 3

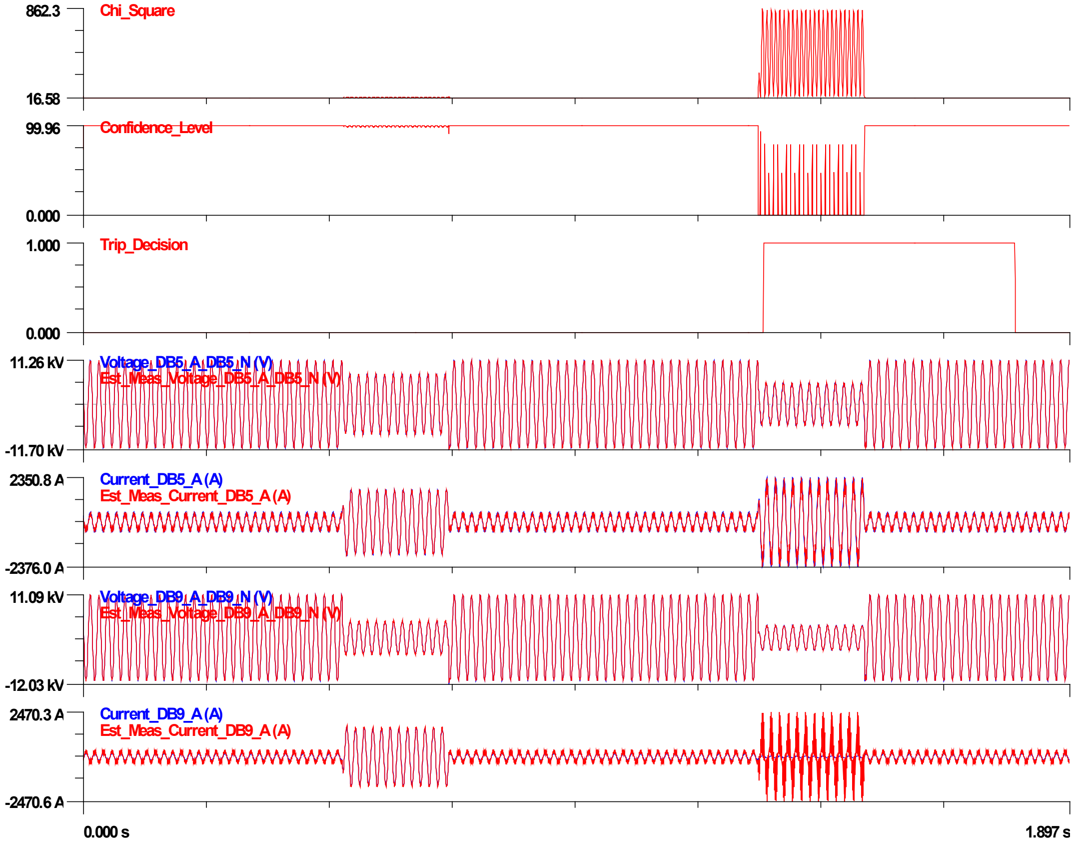


Figure 6.1.20: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Whole Event with two 3000kW Load of Case 3

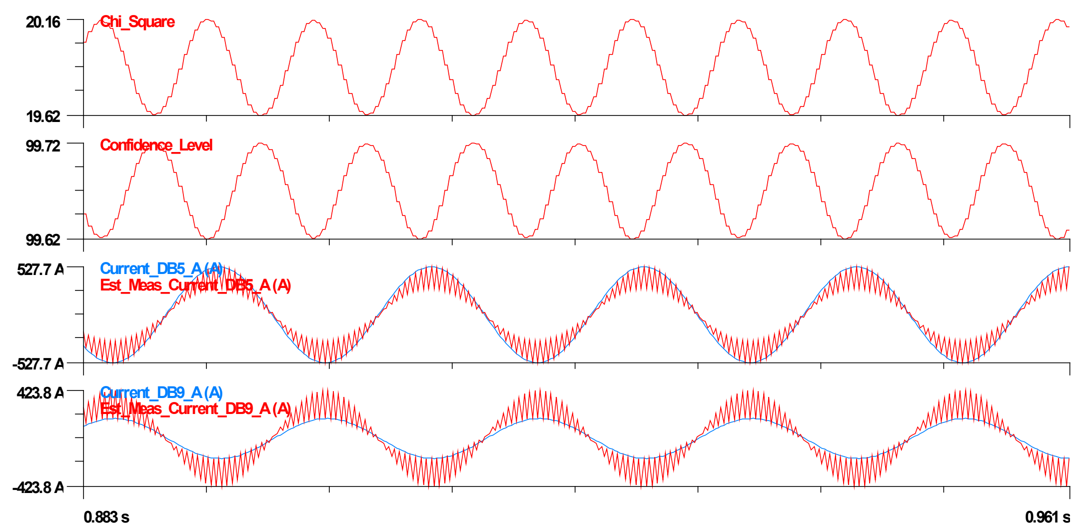


Figure 6.1.21: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value before fault with two 3000kW Load of Case 3

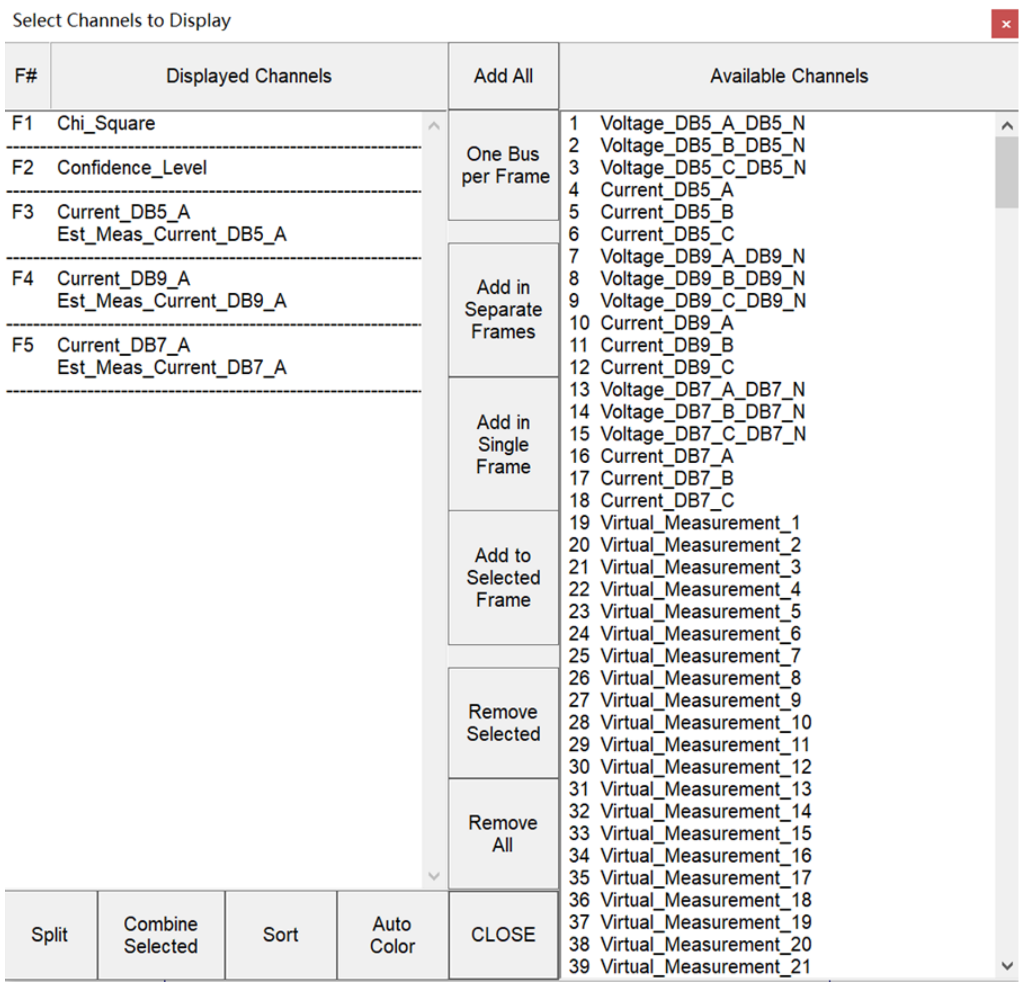


Figure 6.1.22: A List of Available Channels for Plotting

6.2 EBP Results with Different Fault Types

To test the performance of the protection scheme towards different fault type and reduced fault current level, the performance metrics of the events with different fault types are illustrated in Figure 6.2.1 to Figure 6.2.27. The event information and corresponding figures are summarized in Table 6.2.

Table 6.2: The Figures Corresponding to the Events

Merging Unit	Fault Type	Fault current (Magnitude)	Figures
Merging Unit 1	Single Line-to-Ground Fault	1000A	Fig 4.2.1
		400A	Fig 4.2.2
		200A	Fig 4.2.3
	Line to Line Fault	1000A	Fig 4.2.4
		400A	Fig 4.2.5
		200A	Fig 4.2.6
	Three Phase Fault	1000A	Fig 4.2.7
		400A	Fig 4.2.8
		200A	Fig 4.2.9
Merging Unit 2	Single Line-to-Ground Fault	1000A	Fig 4.2.10
		400A	Fig 4.2.11
		200A	Fig 4.2.12
	Line to Line Fault	1000A	Fig 4.2.13
		400A	Fig 4.2.14
		200A	Fig 4.2.15
	Three Phase Fault	1000A	Fig 4.2.16
		400A	Fig 4.2.17
		200A	Fig 4.2.18
Merging Unit 3	Single Line-to-Ground Fault	1000A	Fig 4.2.19
		400A	Fig 4.2.20
		200A	Fig 4.2.21
	Line to Line Fault	1000A	Fig 4.2.22
		400A	Fig 4.2.23
		200A	Fig 4.2.24
	Three Phase Fault	1000A	Fig 4.2.25
		400A	Fig 4.2.26
		200A	Fig 4.2.27

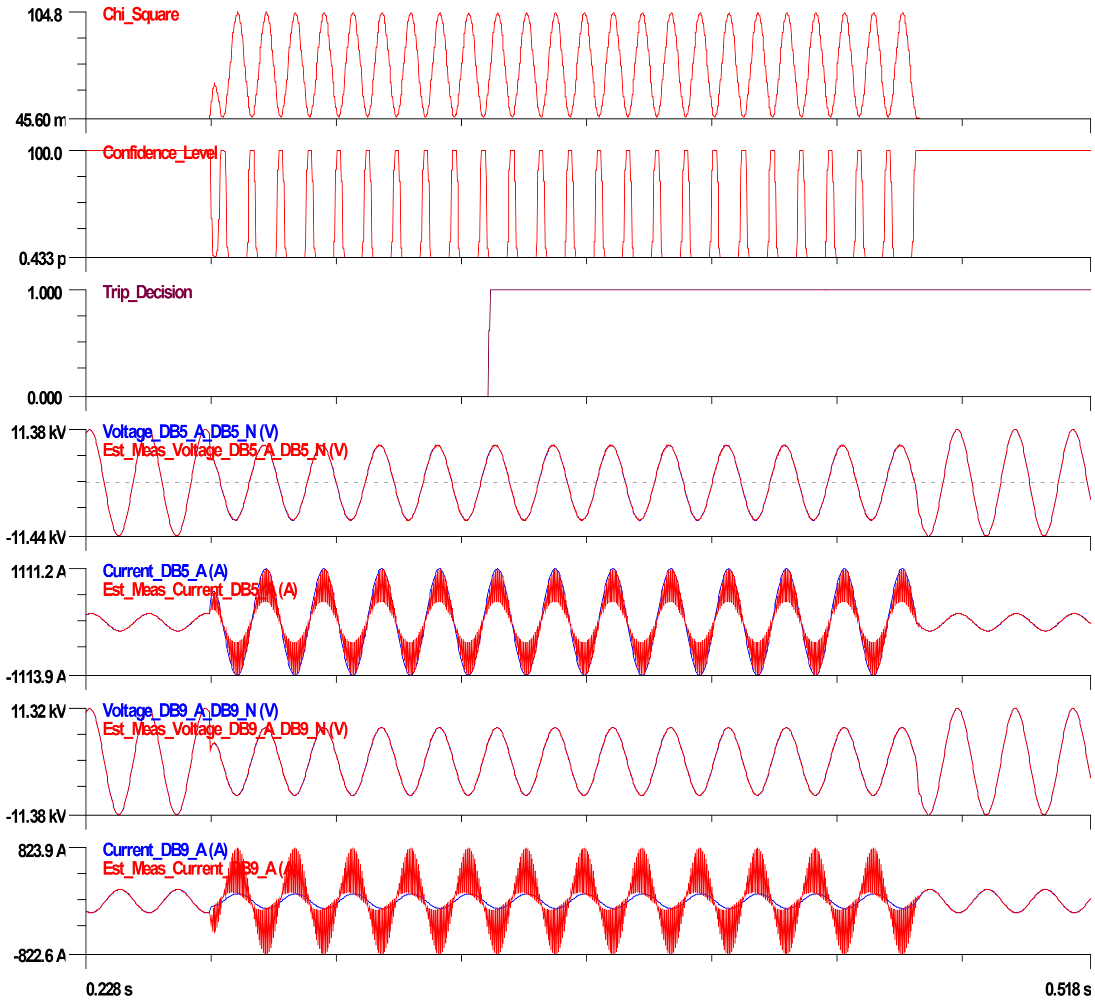


Figure 6.2.1: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 1000A Single Line-to-Ground Fault of Case 1

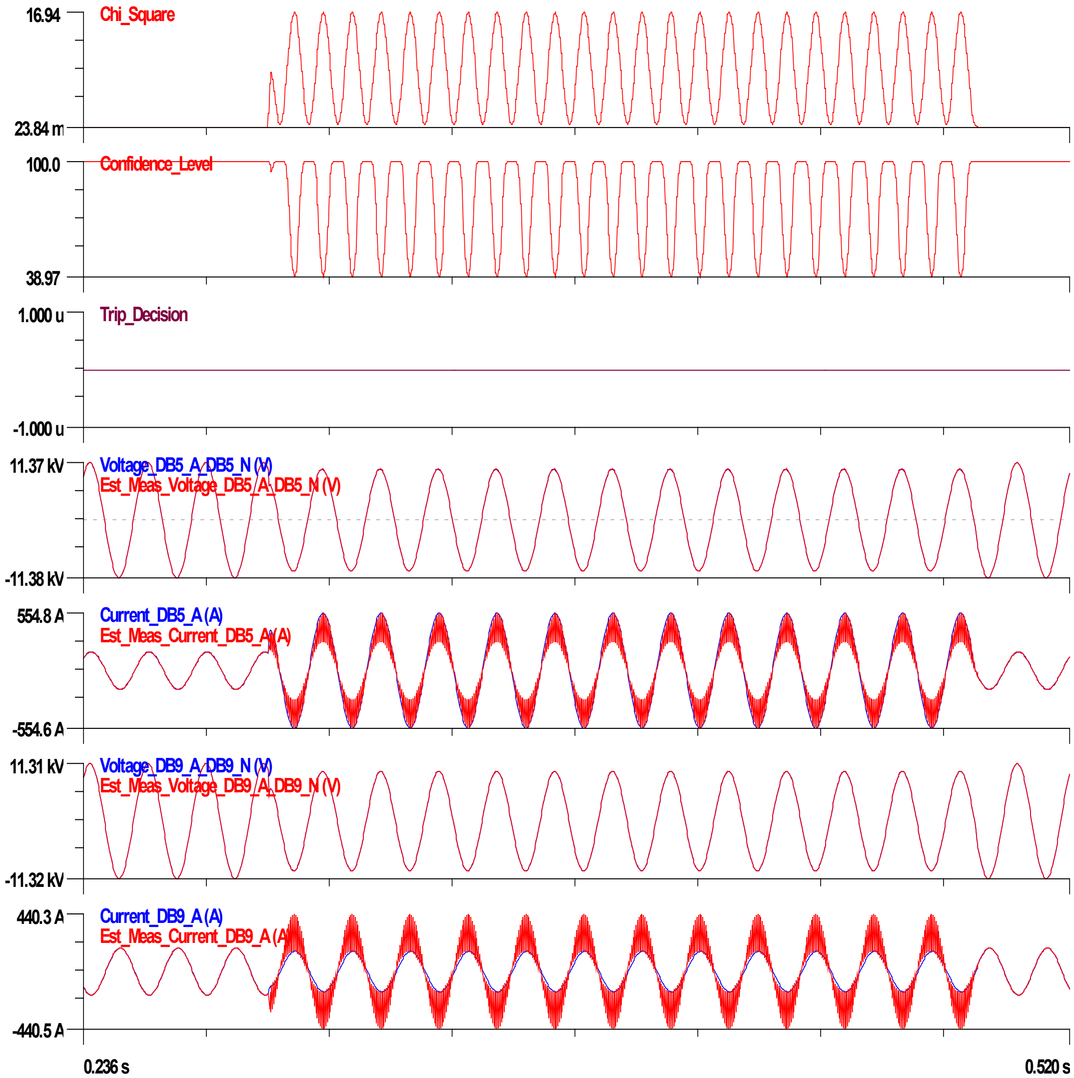


Figure 6.2.2: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 400A Single Line-to-Ground Fault of Case 1

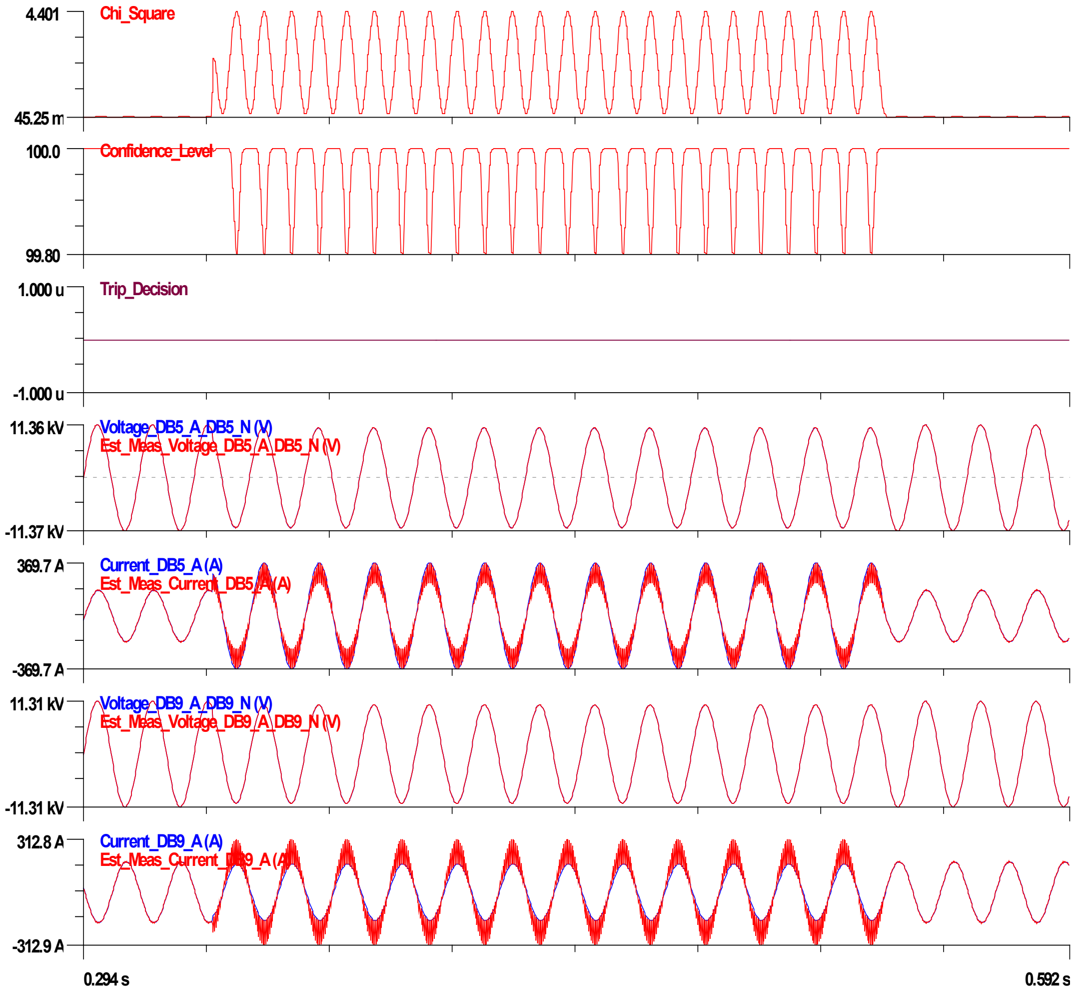


Figure 6.2.3: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 200A Single Line-to-Ground Fault of Case 1

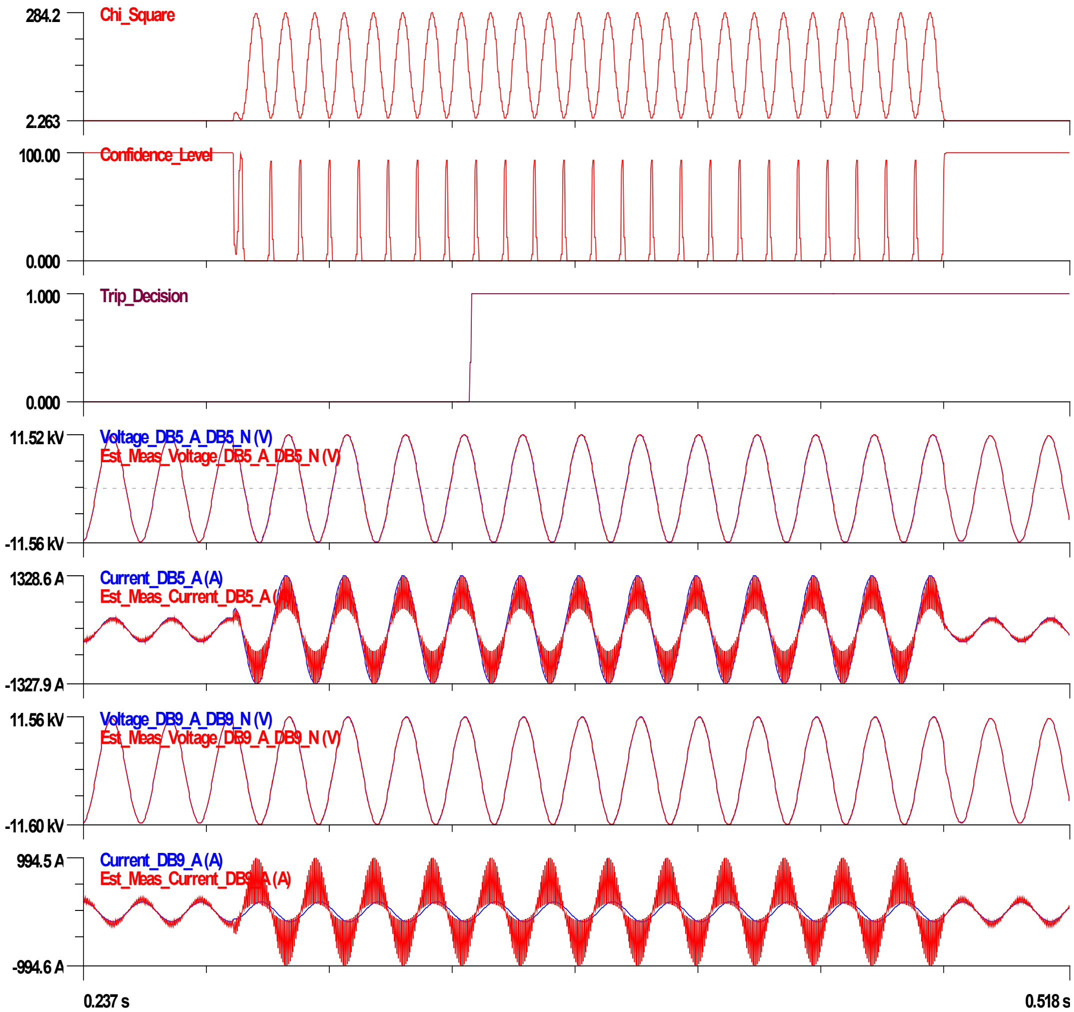


Figure 6.2.4: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 1000A Line-to-Line Fault of Case 1

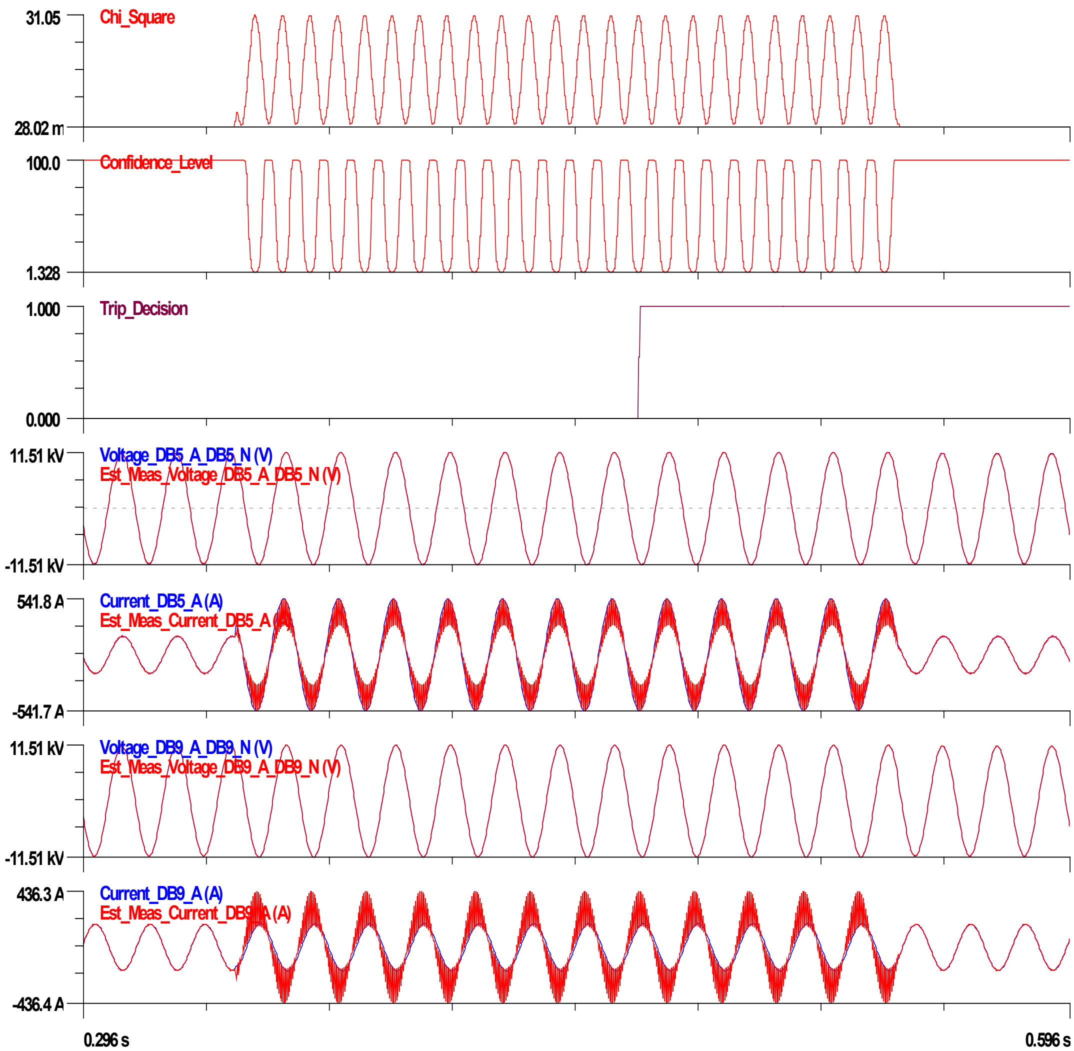


Figure 6.2.5: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 400A Line-to-Line Fault of Case 1

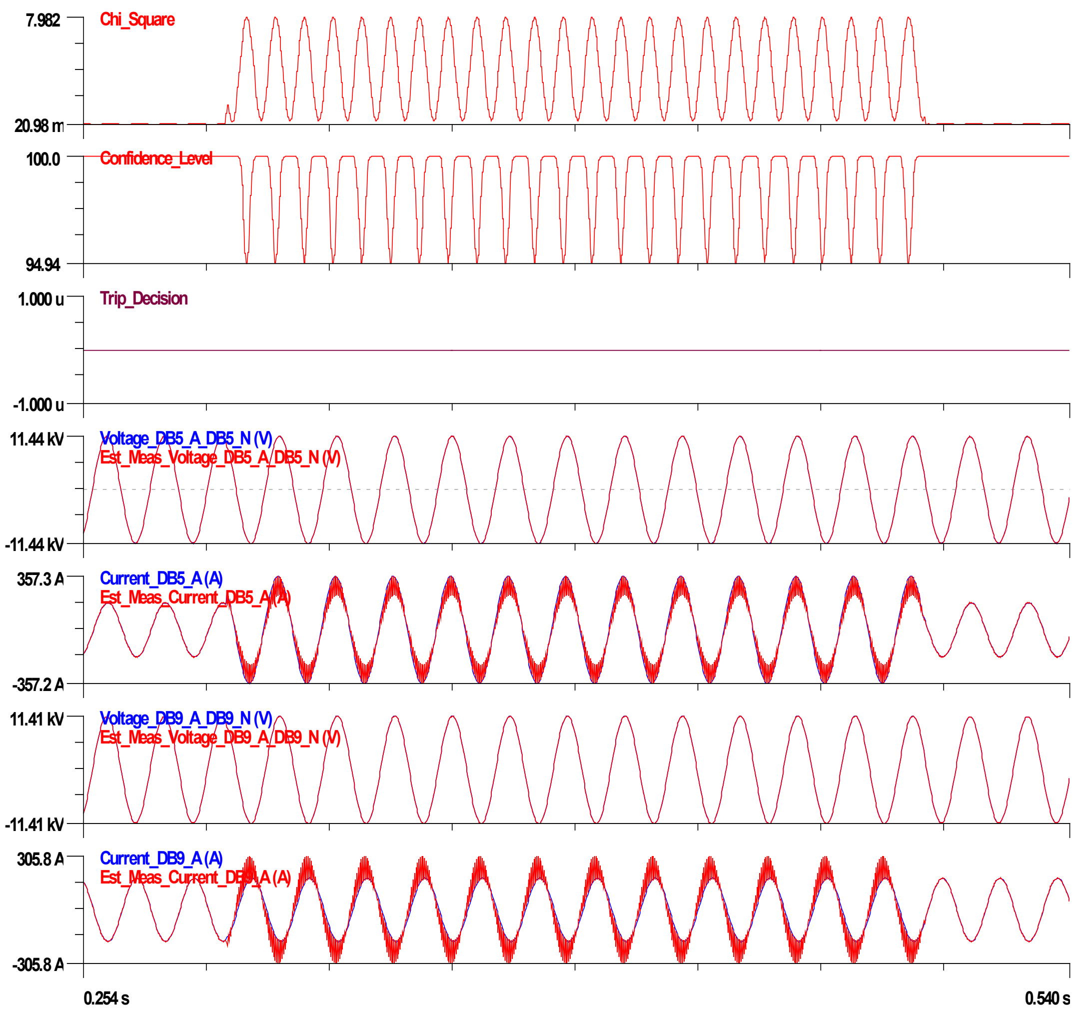


Figure 6.2.6: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 200A Line-to-Line Fault of Case 1

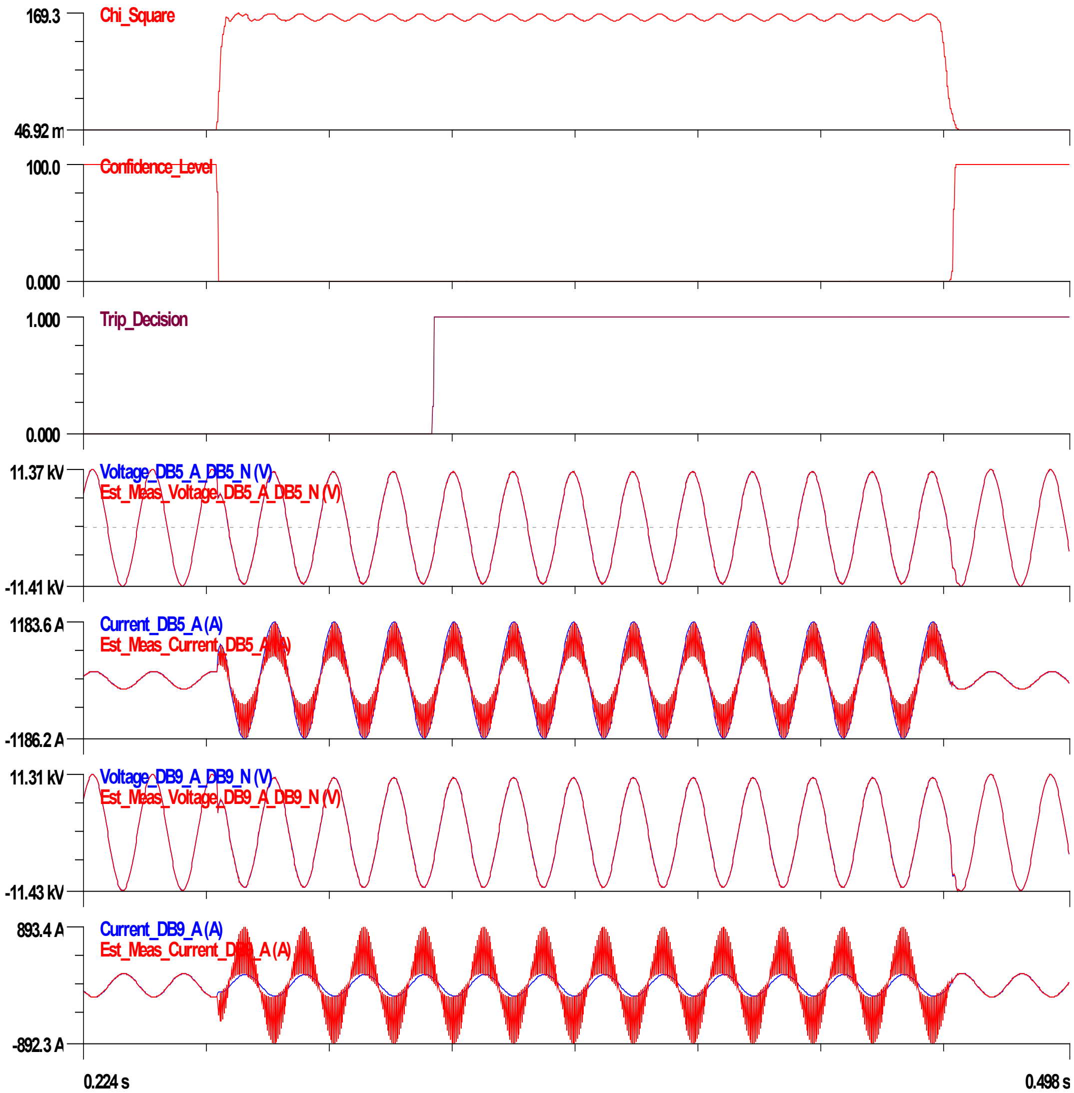


Figure 6.2.7: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 1000A Three Phase Fault of Case 1

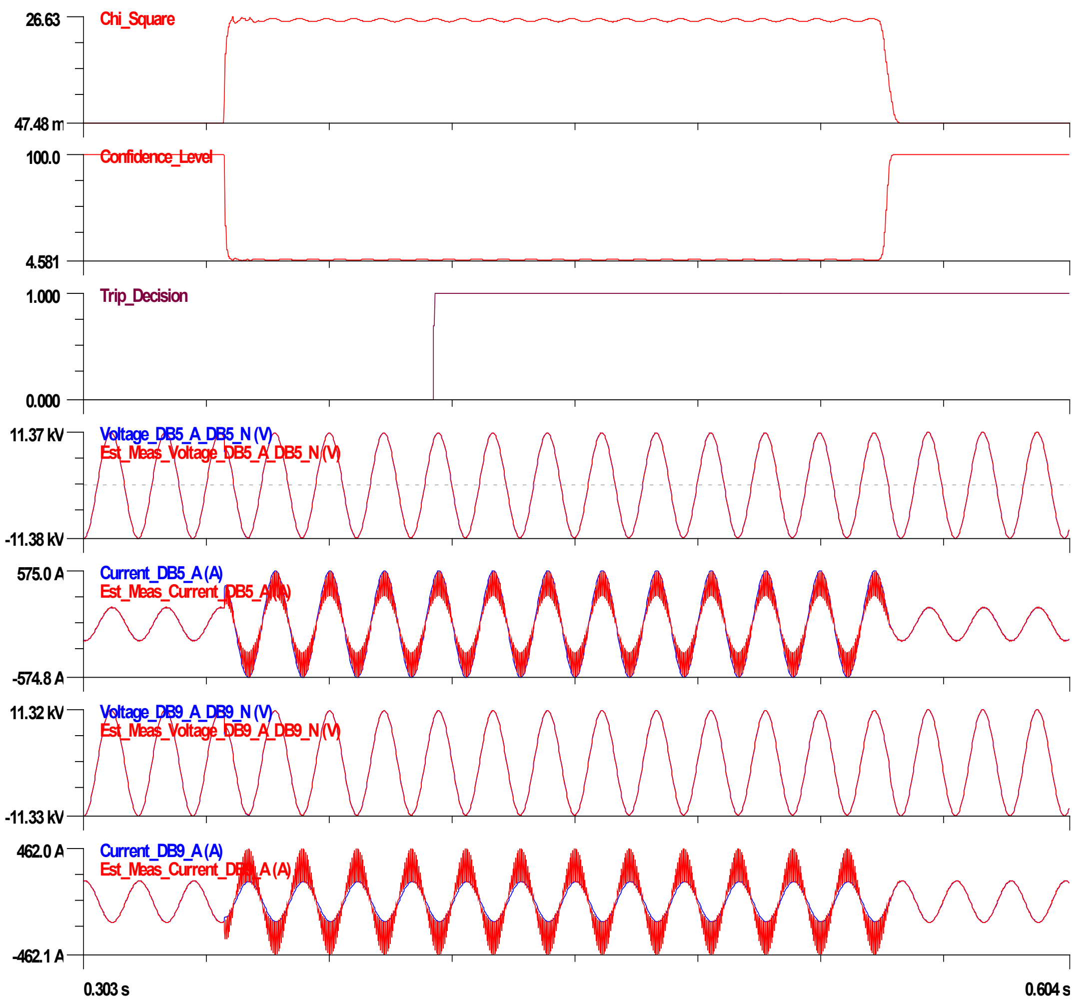


Figure 6.2.8: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 400A Three Phase Fault of Case 1

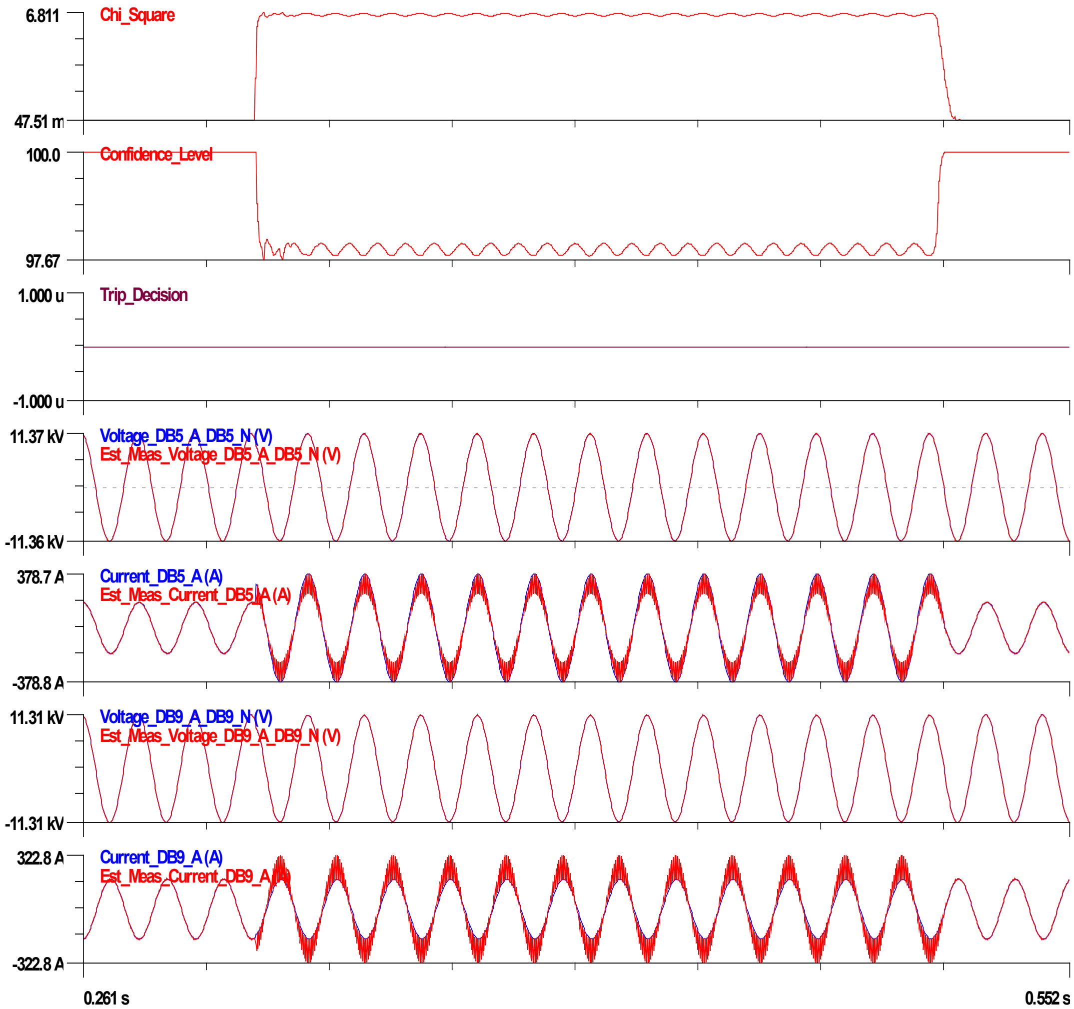


Figure 6.2.9: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 200A Three Phase Fault of Case 1

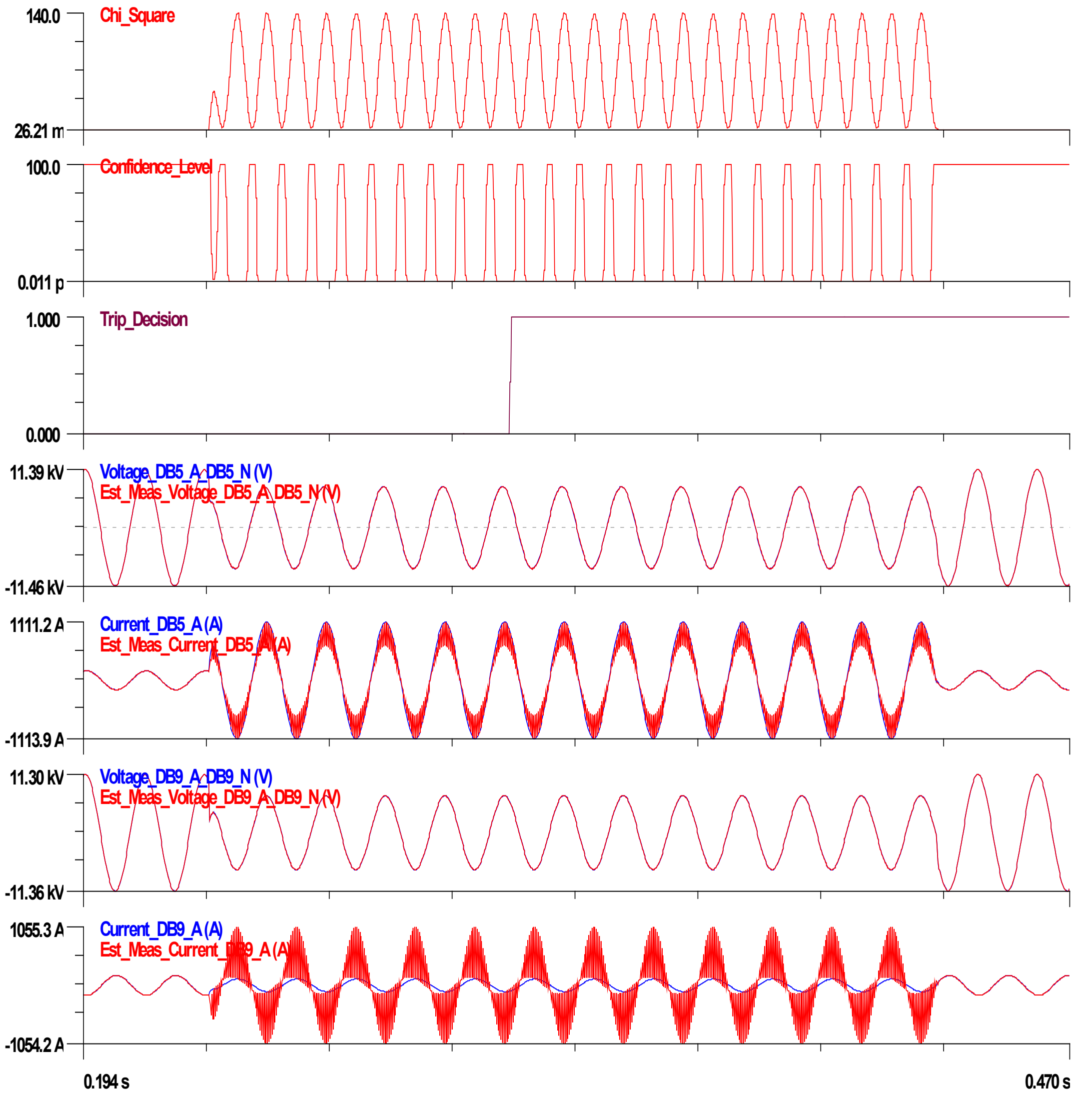


Figure 6.2.10: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 1000A Single Line-to-Ground Fault of Case 2

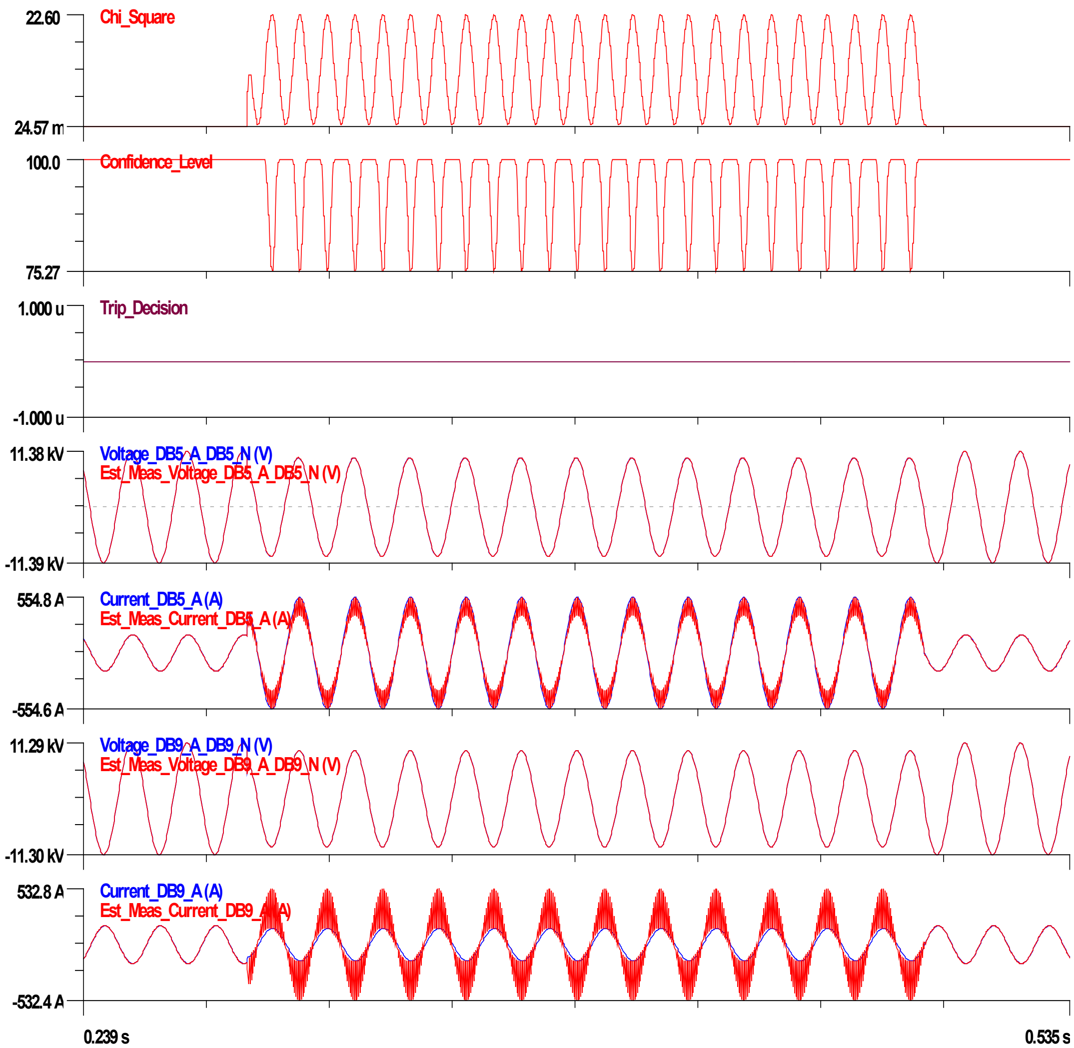


Figure 6.2.11: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 400A Single Line-to-Ground Fault of Case 2

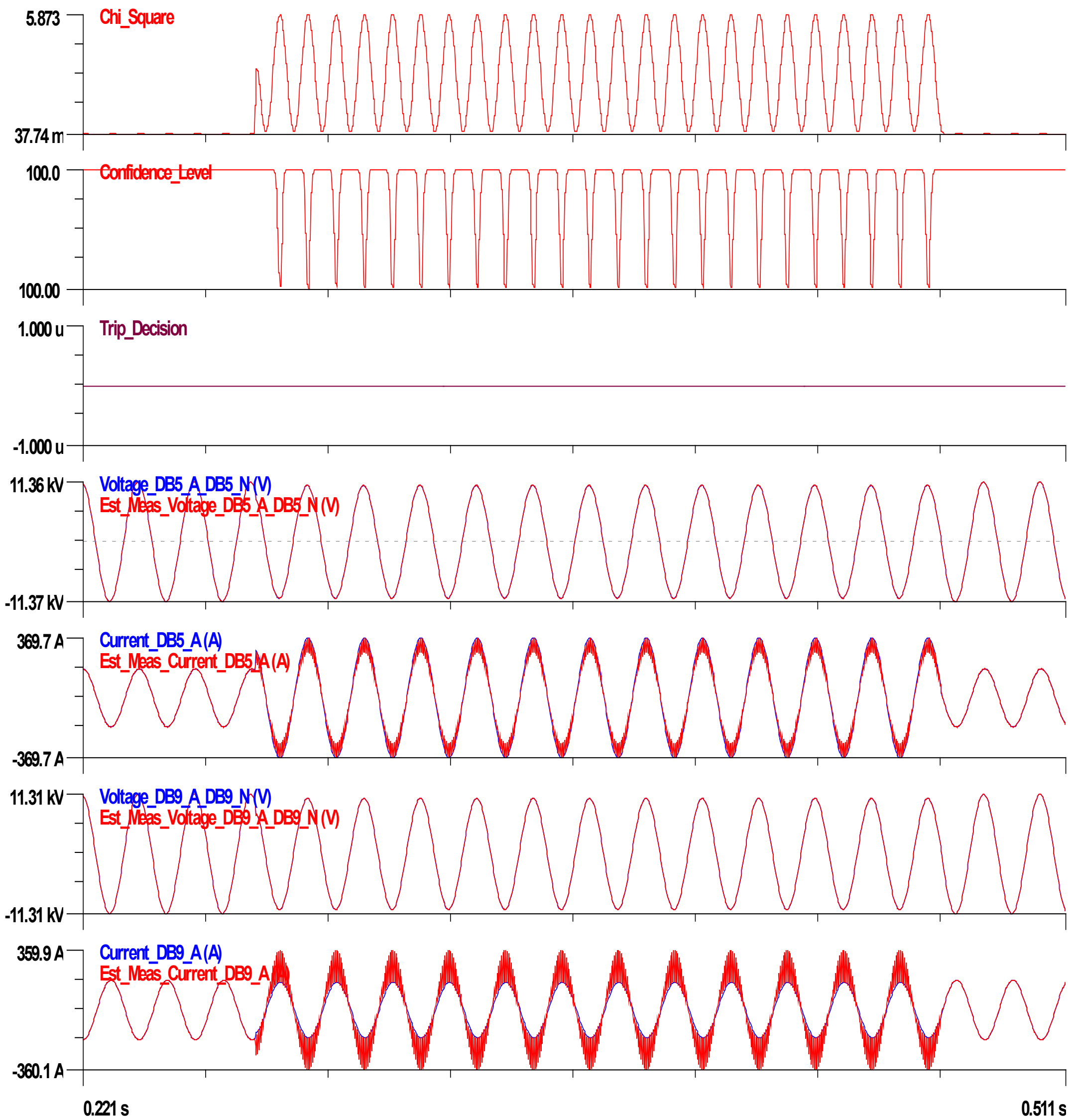


Figure 6.2.12: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 200A Single Line-to-Ground Fault of Case 2

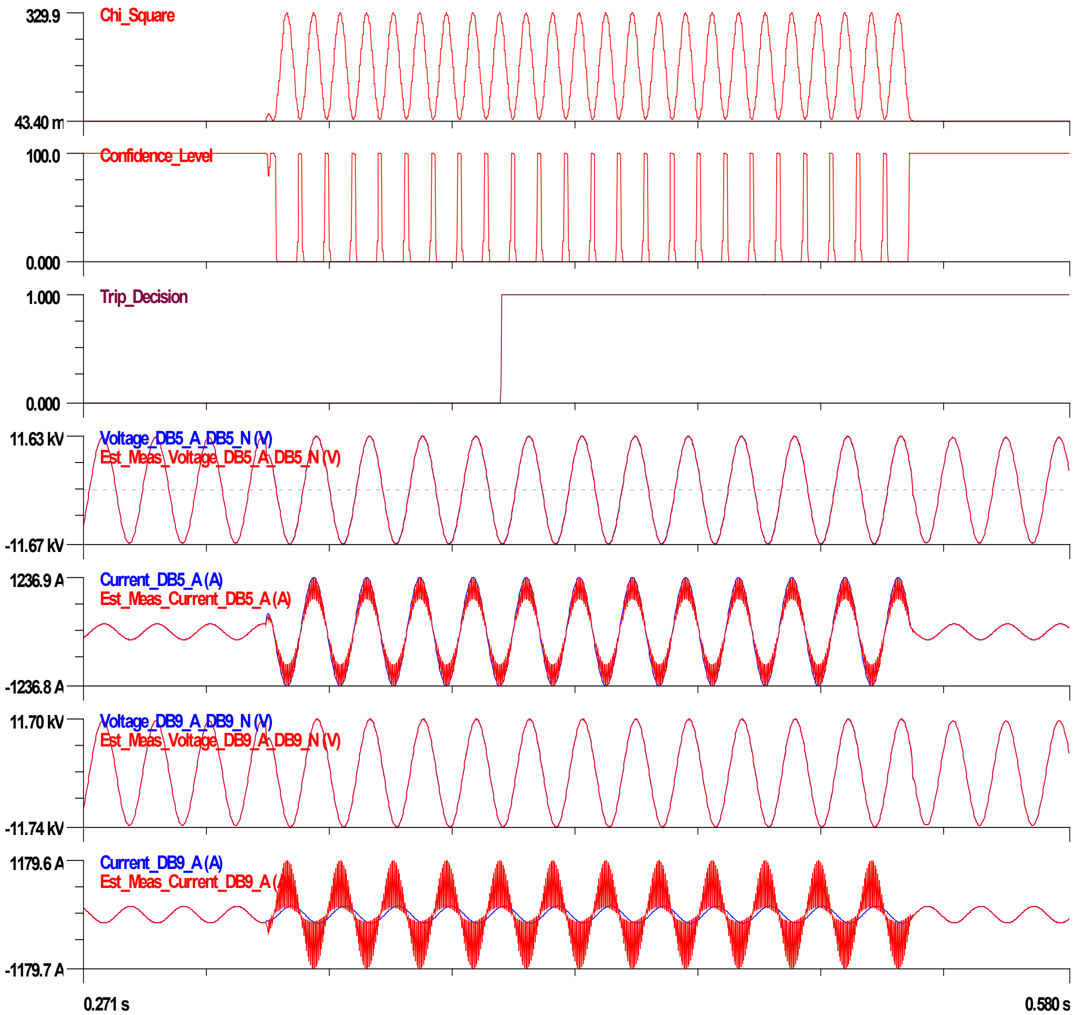


Figure 6.2.13: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 1000A Line-to-Line Fault of Case 2

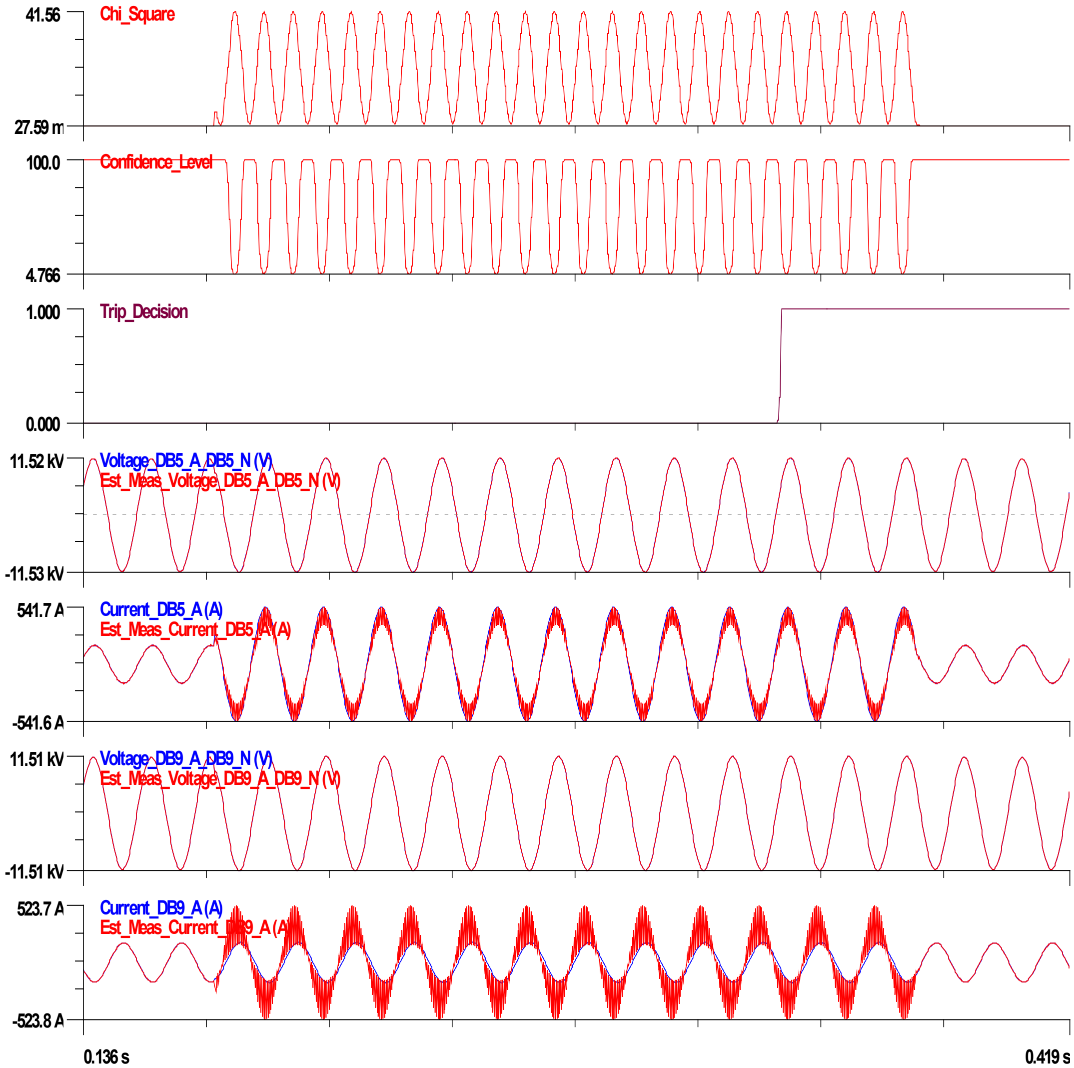


Figure 6.2.14: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 400A Line-to-Line Fault of Case 2

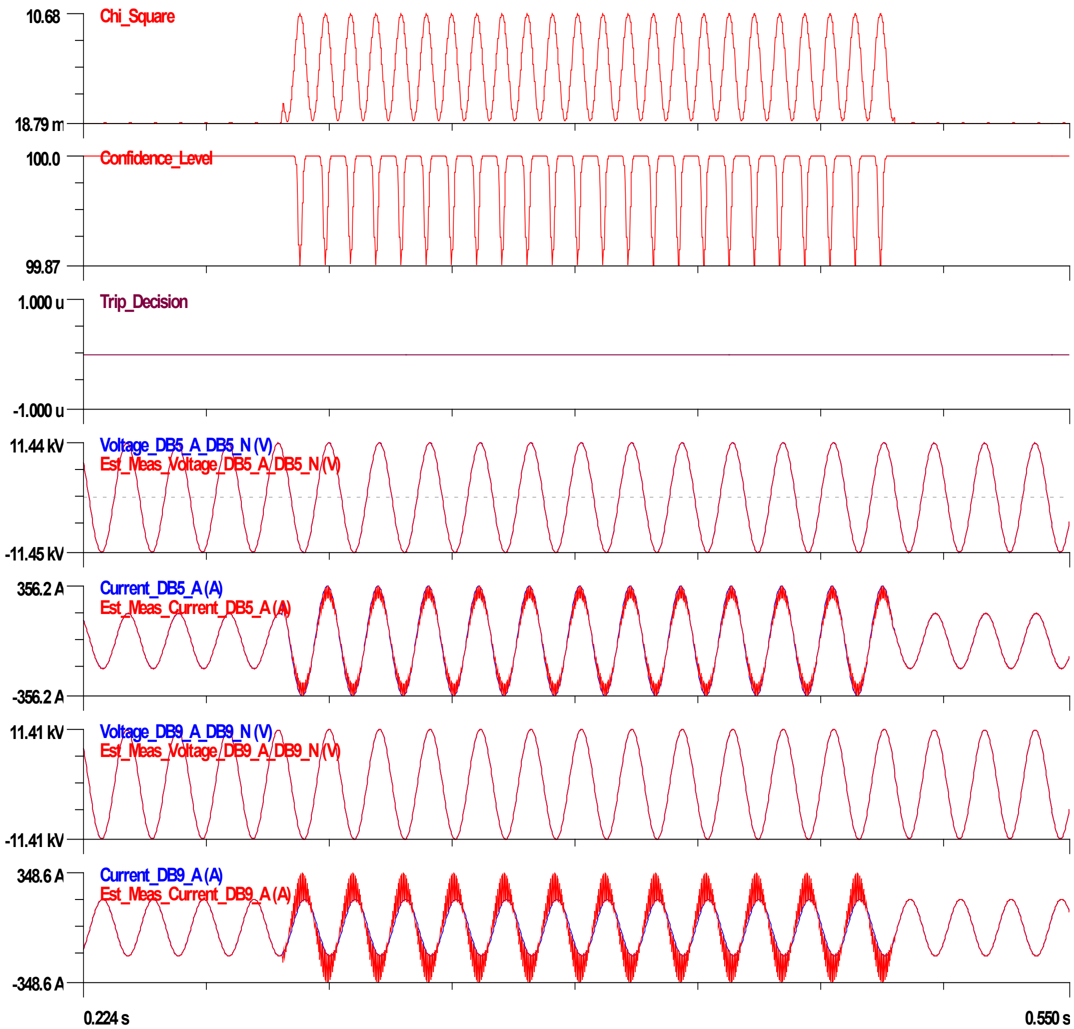


Figure 6.2.15: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 200A Line-to-Line Fault of Case 2

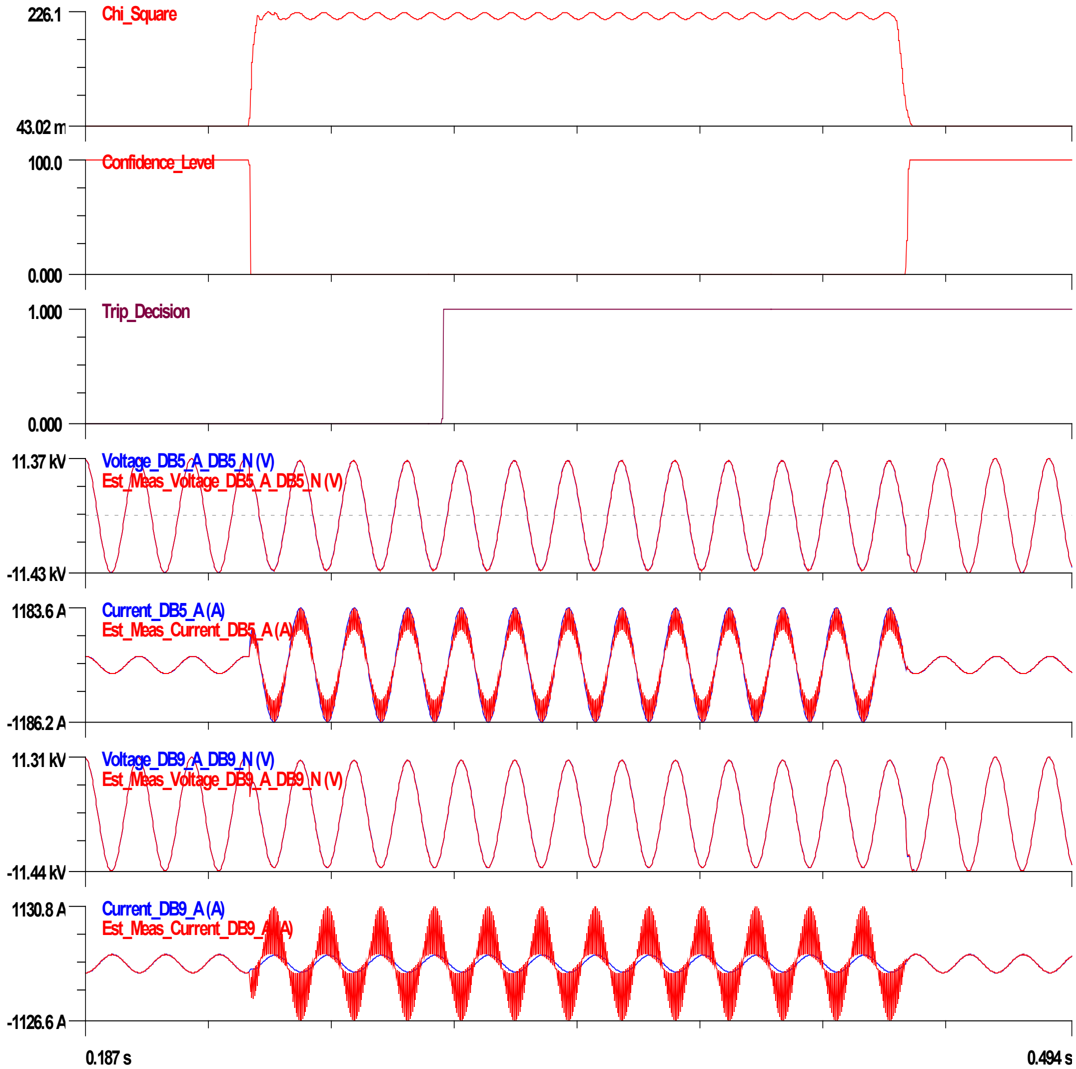


Figure 6.2.16: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 1000A Three Phase Fault of Case 2

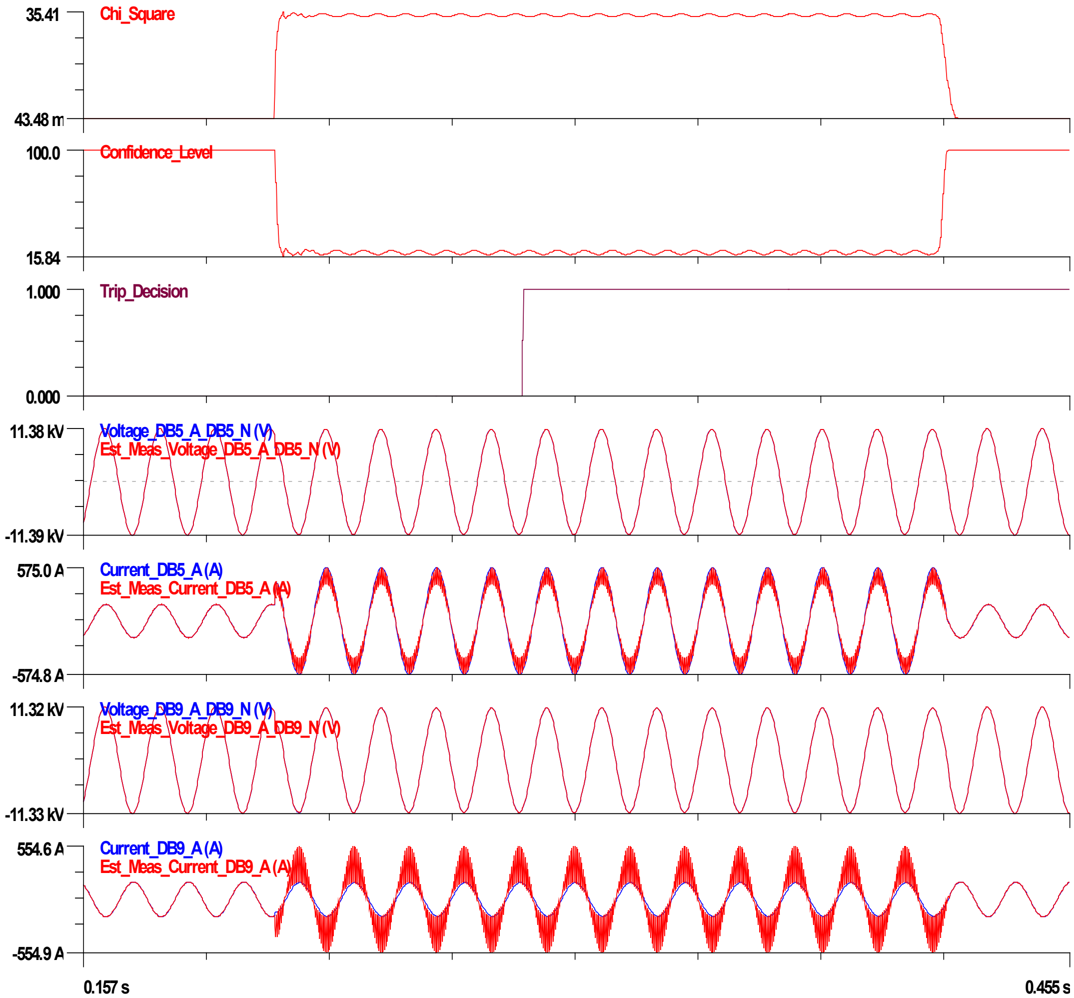


Figure 6.2.17: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 400A Three Phase Fault of Case 2

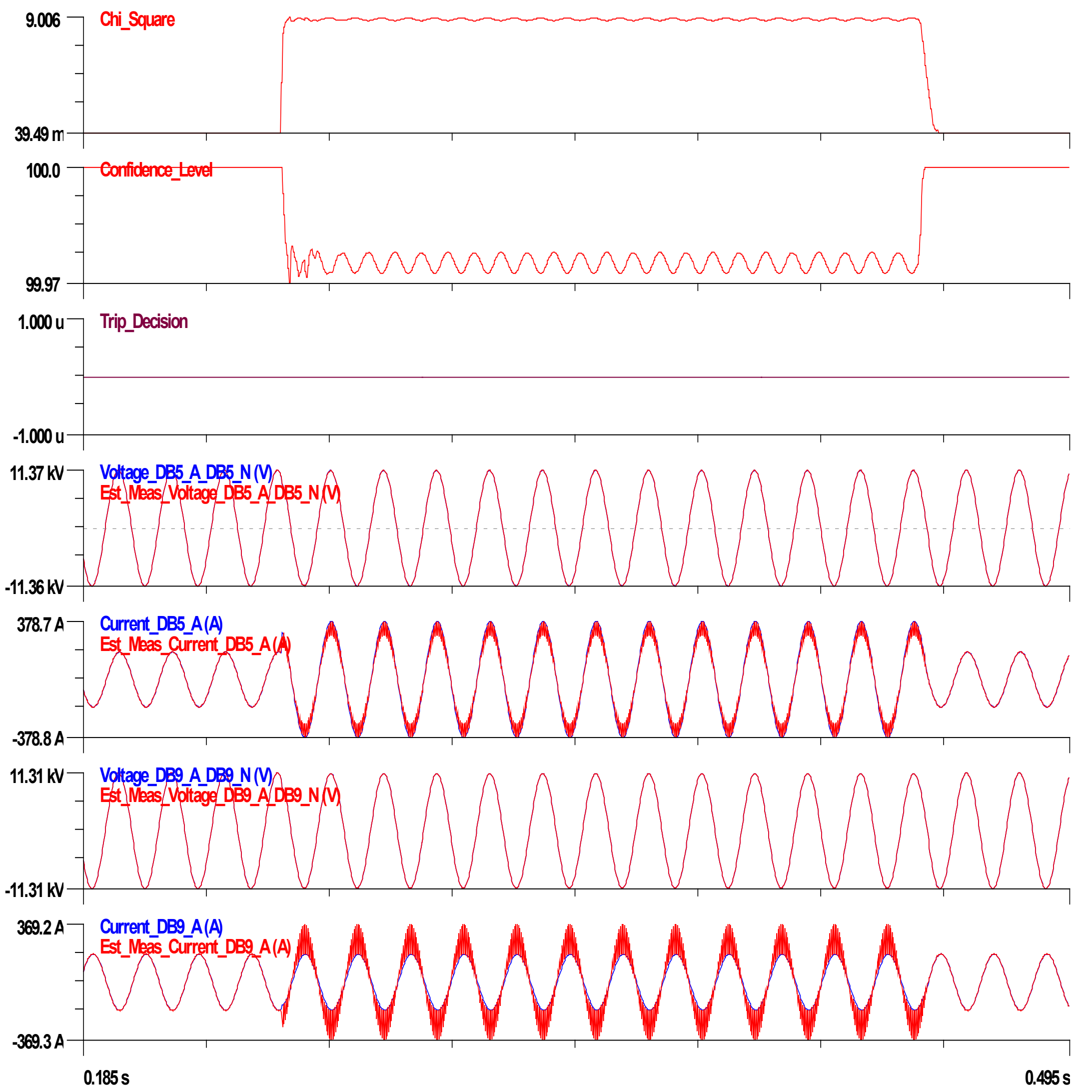


Figure 6.2.18: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 200A Three Phase Fault of Case 2

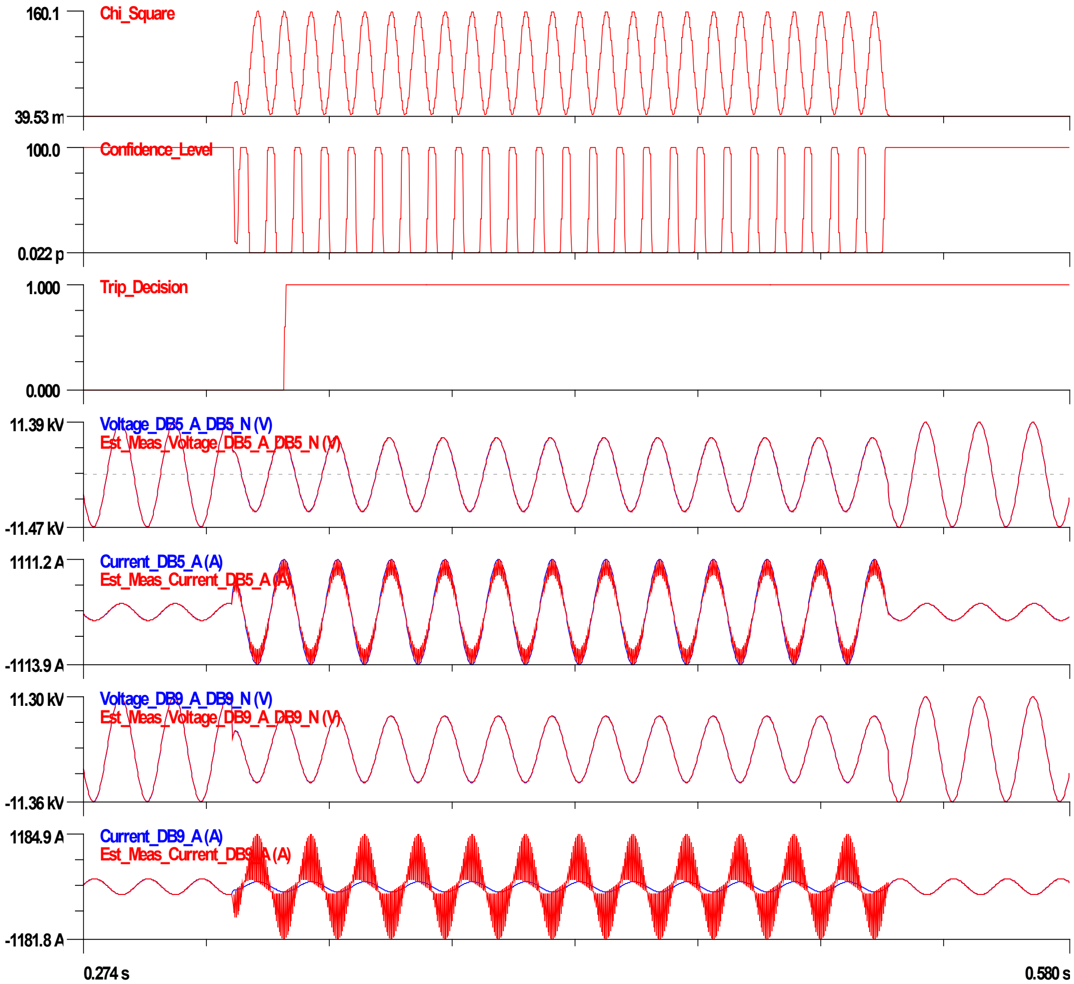


Figure 6.2.19: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 1000A Single Line-to-Ground Fault of Case 3

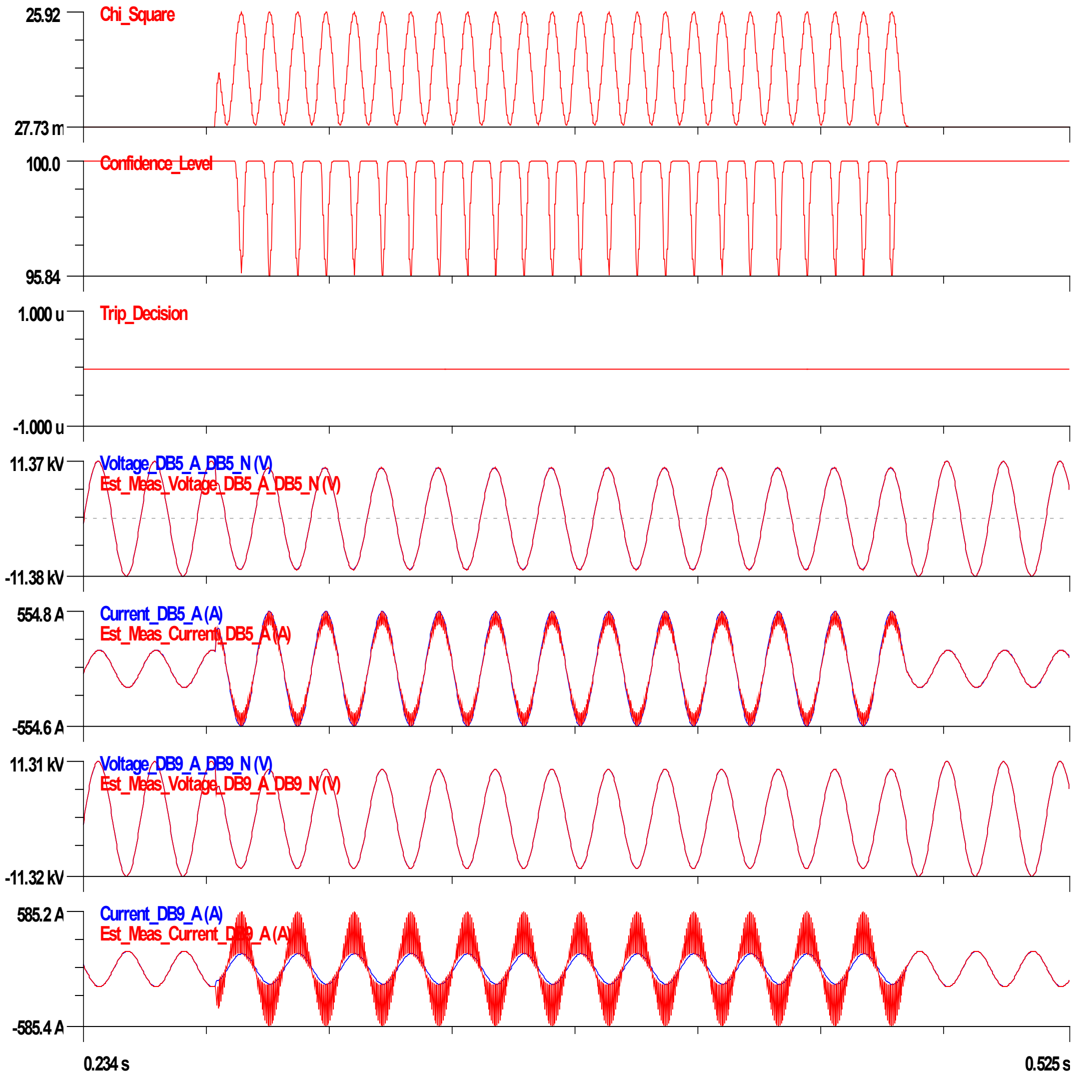


Figure 6.2.20: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 400A Single Line-to-Ground Fault of Case 3

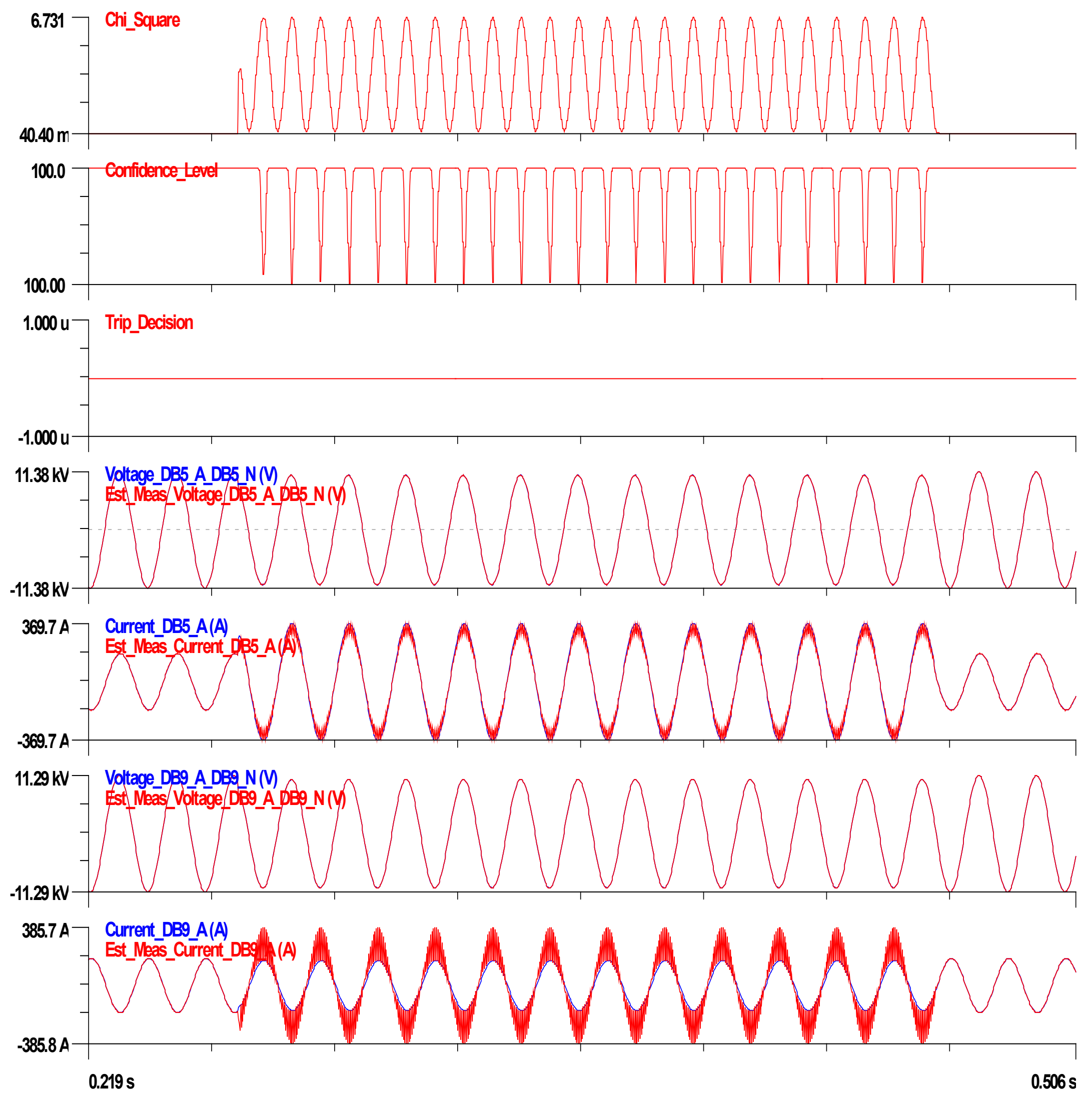


Figure 6.2.21: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 200A Single Line-to-Ground Fault of Case 3

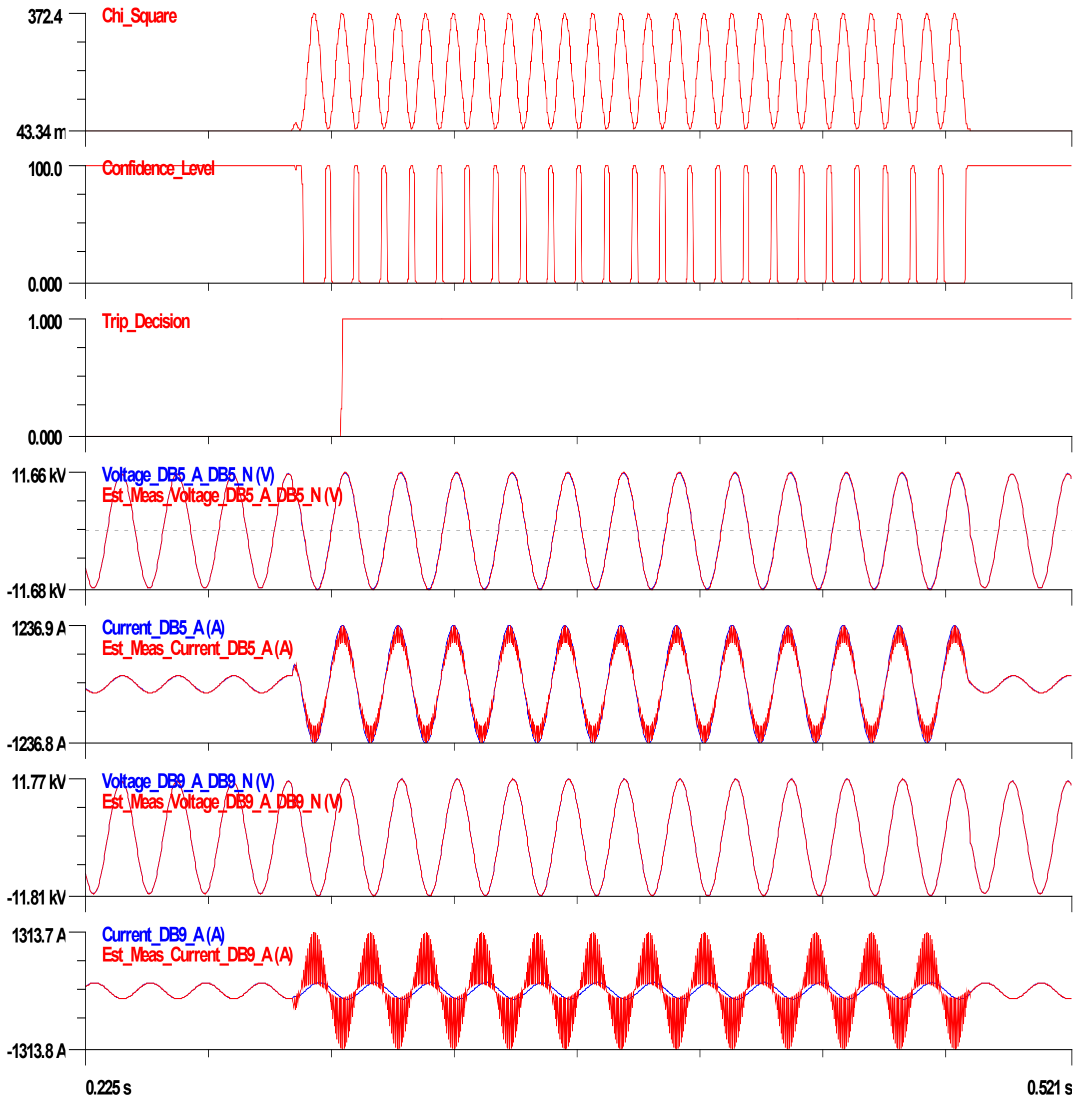


Figure 6.2.22: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 1000A Line-to-Line Fault of Case 3

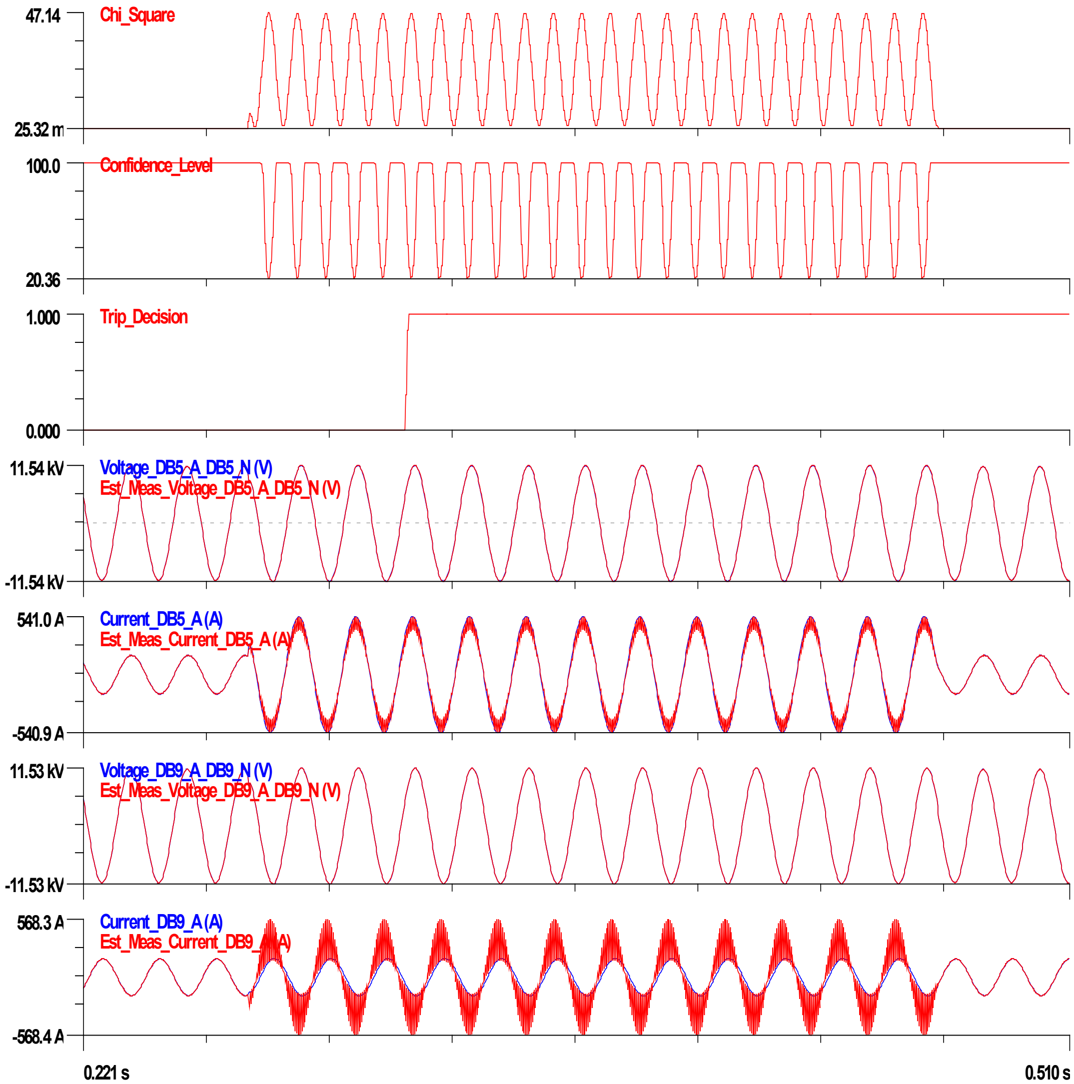


Figure 6.2.23: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 400A Line-to-Line Fault of Case 3

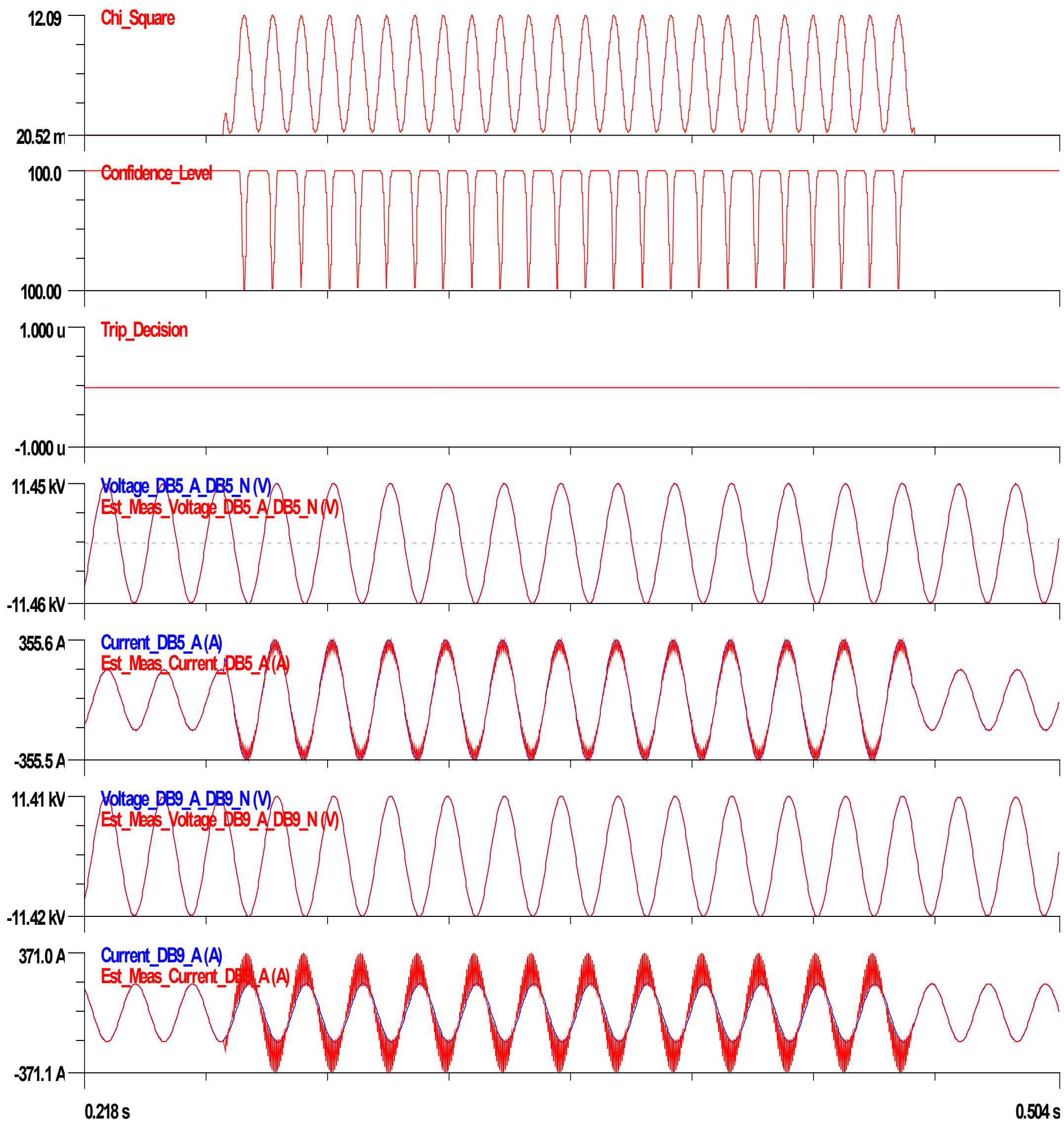


Figure 6.2.24: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 200A Line-to-Line Fault of Case 3

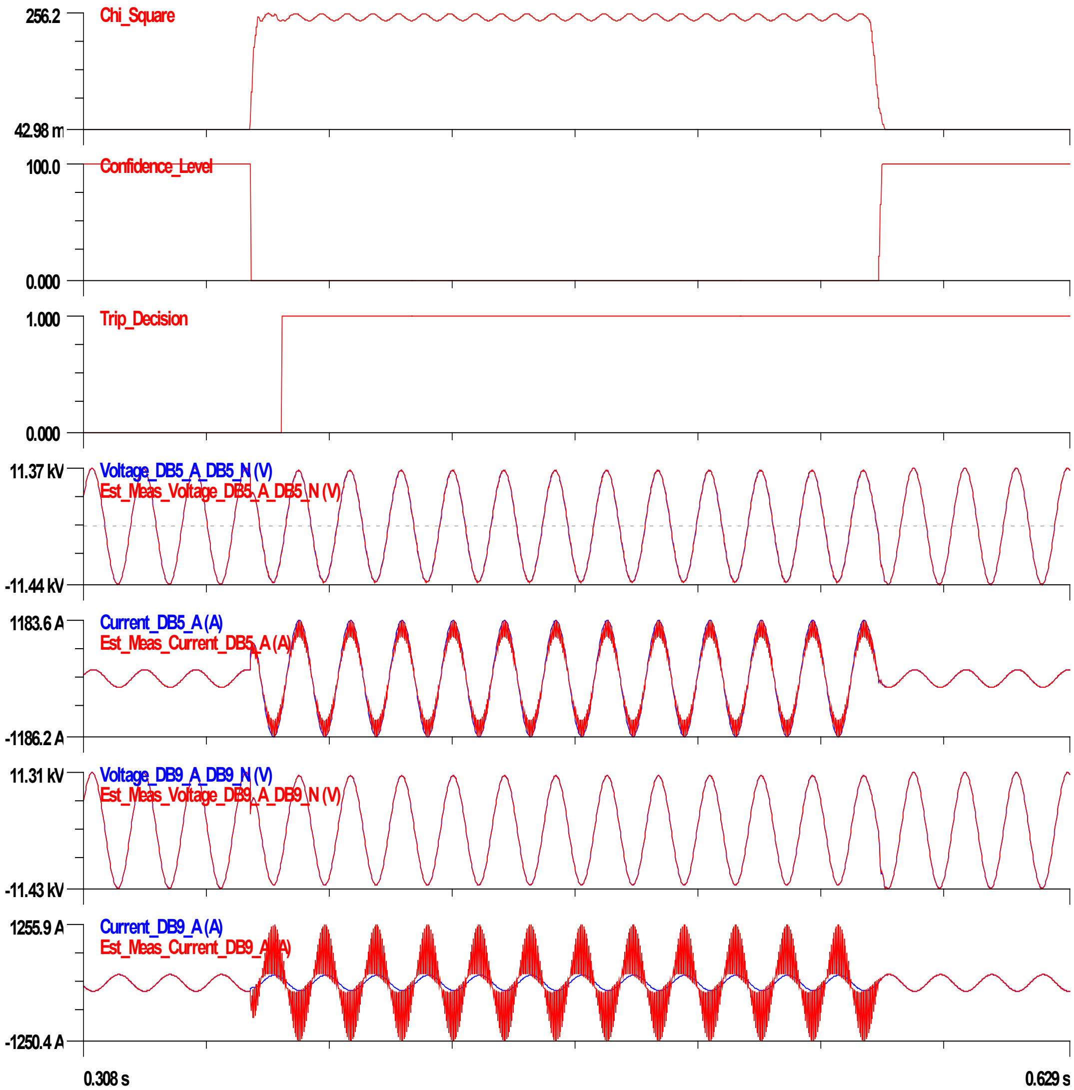


Figure 6.2.25: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 1000A Three Phase Fault of Case 3

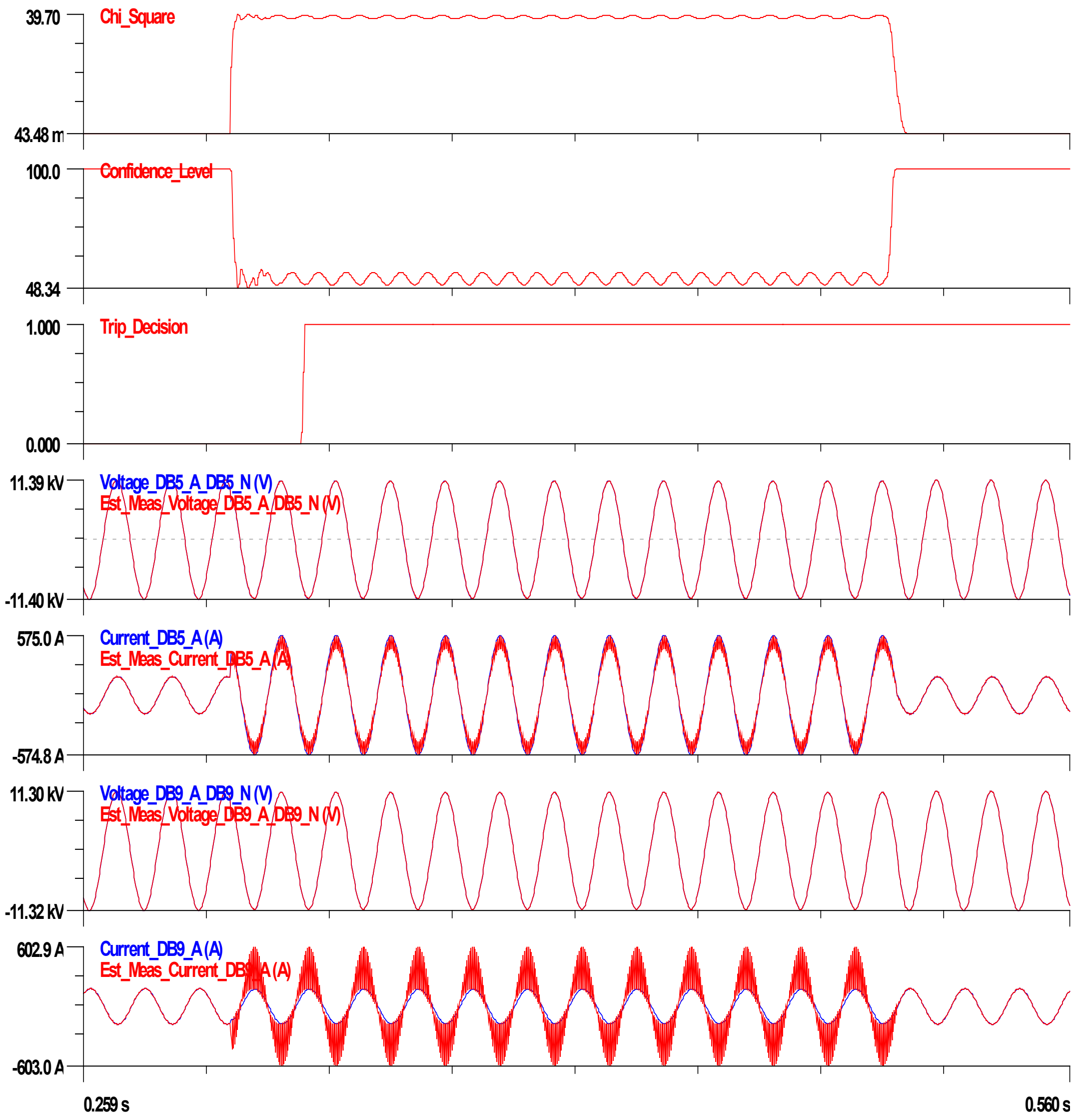


Figure 6.2.26: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 400A Three Phase Fault of Case 3

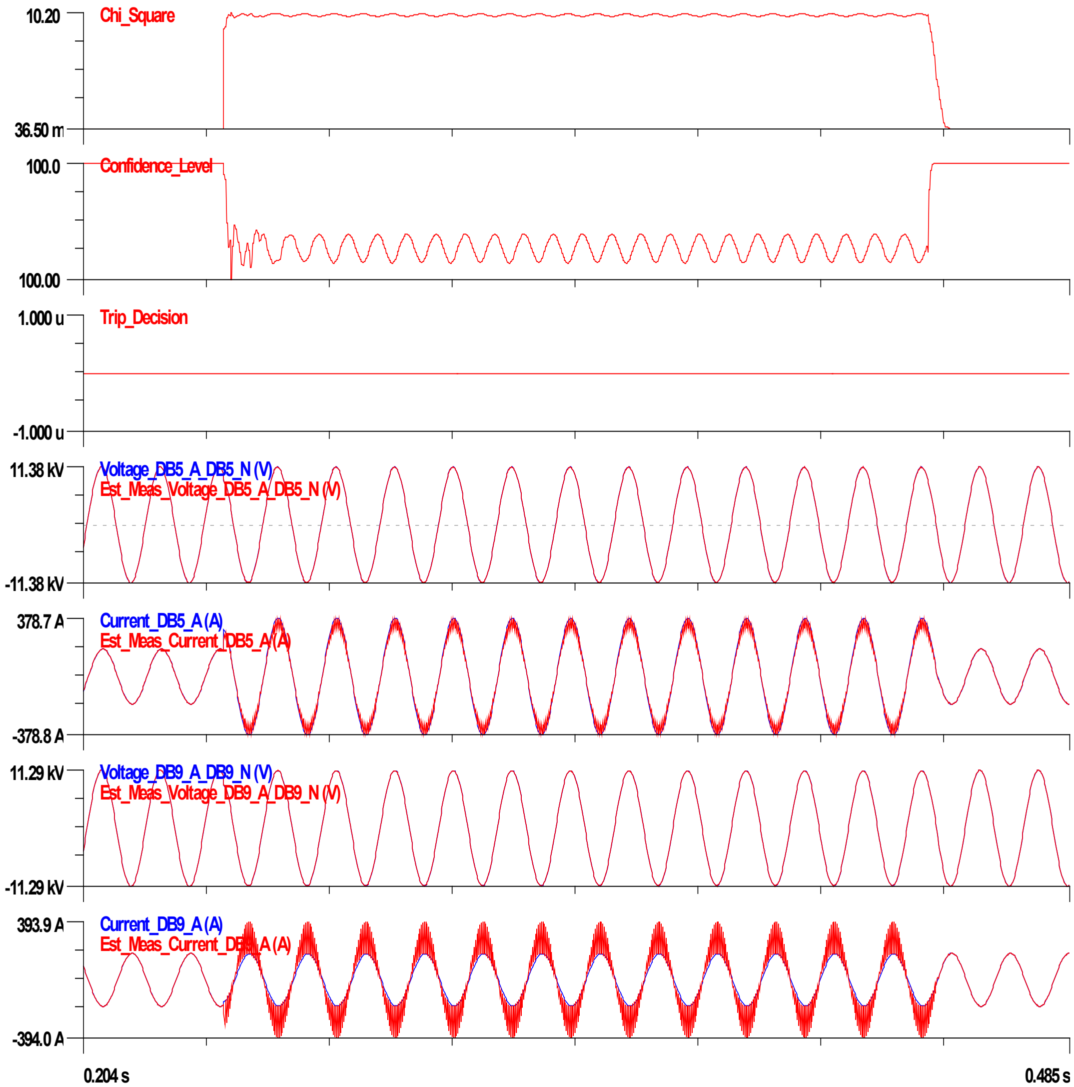


Figure 6.2.27: Some Actual/Estimated Measurements, Confidence Level, and Chi_Square Value of Event with 200A Three Phase Fault of Case 3

6.3 Summary of Results with Different Load Conditions

Several events are simulated with different load conditions in section 6.1. The observed chi-square value, confidence level and some actual/estimated measurements values of the three test cases with different load conditions are summarized in Table 6.3 to 6.5. The max chi-square value and min confidence level refers to the maximum chi-square value and minimum confidence level before the fault.

Table 6.3: The Observed Protection Metrics of Case 1 with Different Load Condition

DB7 Load	DB8 Load	Max Chi_Square	Min Confidence Level	DB5_A Actual Mag	DB5_A Estimated Mag	DB9_A Actual Mag	DB9_A Estimated Mag
No load	No Load	0.073	100%	179.4A	181.6A	179.4A	181.5A
500kW	500kW	0.752	100%	240.7A	238.6A	178.3A	224.3A
500kW	2000kW	3.736	99.93%	326.9A	324.4A	177.6A	285.0A
2000kW	500kW	3.697	99.93%	327.2A	325.3A	177.7A	285.4A
2000kW	2000kW	9.142	90.75%	413.4A	410.8A	177.0A	345.8A
2500kW	2500kW	14.10	59.10%	470.7A	467.9A	176.5A	386.3A
3000kW	3000kW	20.13	21.46%	527.7A	524.7A	176.1A	426.4A

Table 6.4: The Observed Protection Metrics of Case 2 with Different Load Condition

DB7 Load	DB8 Load	Max Chi_Square	Min Confidence Level	DB5_A Actual Mag	DB5_A Estimated Mag	DB9_A Actual Mag	DB9_A Estimated Mag
No load	No Load	0.066	100%	179.4A	180.8A	179.4A	180.8A
500kW	500kW	0.741	100%	240.7A	239.0A	178.3A	223.0A
500kW	2000kW	4.121	100%	326.9A	324.7A	177.6A	304.3A
2000kW	500kW	4.151	100%	327.2A	325.3A	177.7A	262.5A
2000kW	2000kW	9.128	99.97%	413.4A	411.2A	177.0A	344.7A
2500kW	2500kW	14.09	98.65%	470.7A	468.3A	176.5A	383.6A
3000kW	3000kW	20.12	86.02%	527.7A	525.2A	176.1A	423.5A

Table 6.5: The Observed Protection Metrics of Case 3 with Different Load Condition

DB7 Load	DB8 Load	Max Chi_Square	Min Confidence Level	DB5_A Actual Mag	DB5_A Estimated Mag	DB9_A Actual Mag	DB9_A Estimated Mag
No load	No Load	0.065	100%	179.4A	180.5A	179.4A	180.5A
500kW	500kW	0.743	100%	240.7A	239.0A	178.3A	223.0A
500kW	2000kW	4.353	100%	326.9A	324.9A	177.6A	315.9A
2000kW	500kW	4.367	100%	327.2A	325.4A	177.7A	252.0A
2000kW	2000kW	9.149	100%	413.4A	411.5A	177.0A	344.7A
2500kW	2500kW	14.12	100%	470.7A	468.7A	176.5A	385.0A
3000kW	3000kW	20.16	99.62%	527.7A	525.6A	176.1A	425.0A
3500kW	3500kW	27.24	93.81%	584.5A	581.8A	175.7A	463.5A

Though observation, we find that:
(1) the proposed protection scheme can discriminate the internal fault from the external fault in many events that we simulated so far with total lack of measurements at the distributed loads and distributed energy resources; this performance was maintain with loads up to 20% of the feeder capacity;
(2) as the load without measurements increases, the chi-square value increases and the confidence level drops.
(3) The chi-square value of the three cases remain same level with the same load. However, the case with more measurement sets has a higher confidence level due to redundancy.

6.4 Summary of Results with Different Fault Types

Several events are simulated with different fault types in section 6.2. The observed chi-square value, confidence level and some actual/estimated measurements values of the three test cases with different fault types are summarized in Table 5.4. The fault are high impedance fault and the fault current is lower than the norm current of the line. The max chi-square value and min confidence level refers to the maximum chi-square value and minimum confidence level during the fault.

Table 6.6: The Observed Protection Metrics of the three Cases with Different Fault Types

Case Number	Fault Current (Magnitude)	Single Line-to-ground Fault		Line-to-Line Fault		Three Phase Fault	
		Max Chi_Square	Min Confidence Level	Max Chi_Square	Min Confidence Level	Max Chi_Square	Min Confidence Level
1	1000	104.8	0.00%	285.0	0.00%	168.3	0.00%
	400	16.92	39.09%	31.05	1.328%	26.16	5.179%
	300	9.515	89.07%	20.01	21.97%	14.91	53.09%
	200	4.418	99.80%	7.977	94.95%	6.759	97.76%
	100	1.193	100.00%	2.061	100.00%	1.788	100.00%
2	1000	139.4	0.00%	328.4	0.00%	224.6	0.00%
	400	22.59	75.32%	41.38	4.956%	34.81	17.56%
	300	12.73	99.40%	26.81	52.84%	19.80	87.18%
	200	5.865	100.00%	10.67	99.87%	8.926	99.98%
	100	2.739	100.00%	2.725	100.00%	2.316	100.00%
3	1000	160.0	0.00%	373.6	0.00%	254.4	0.00%
	400	25.90	95.87%	46.84	21.22%	39.40	49.71%
	300	14.52	99.99%	30.36	86.50%	22.40	98.89%
	200	6.727	100.00%	12.05	100.00%	9.870	100.00%
	100	1.776	100.00%	3.078	100.00%	2.608	100.00%

Though observation, we find that:
(1) the setting-less relay is more sensitive to line-to-line faults and three phase faults compared to single line-to-ground faults;
(2) the setting-less relay is not able to recognize some high impedance fault with small fault current.

6.5 Summary of Results with Parameterized Chi-square Test

For parameterized chi-square test. The goodness of fit between the model and the measurements is quantified by:

$$\xi = \sum_{i=1}^{n} \left(\frac{h_i(x) - z_i}{k\delta_i} \right)^2$$

where set the standard deviation of each measurement equal to the accuracy of the measurement error times k.

The observed chi-square value, confidence level and some actual/estimated measurements values of the three test cases with different k values are summarized in Table 6.7. The max chi-square value and min confidence level refers to the maximum chi-square value and minimum confidence level during the fault.

Table 6.7: The Observed Protection Metrics with Different k Values

K value	Fault Current (Magnitude)	Single Line-to-ground Fault		Line-to-Line Fault		Three Phase Fault	
		Max Chi_Square	Min Confidence Level	Max Chi_Square	Min Confidence Level	Max Chi_Square	Min Confidence Level
1	1000	10443	0.00%	28420	0.00%	16822	0.00%
	400	1686.9	0.00%	3122.5	0.00%	2615.0	0.00%
	300	951.3	0.00%	2003.7	0.00%	1491.3	0.00%
	200	439.61	0.00%	796.03	0.00%	675.6	0.00%
	100	118.9	0.00%	206.2	0.00%	178.8	0.00%
2.5	1000	1669.3	0.00%	4547.2	0.00%	2691.6	0.00%
	400	269.9	0.00%	499.6	0.00%	418.4	0.00%
	300	152.2	0.00%	320.6	0.00%	238.6	0.00%
	200	70.32	0.00%	127.3	0.00%	108.1	0.00%
	100	19.03	26.73%	32.99	0.742%	28.61	2.671%
5	1000	415.7	0.00%	1136.8	0.00%	672.9	0.00%
	400	67.67	0.00%	124.9	0.00%	104.6	0.00%
	300	38.04	0.149%	80.16	0.00%	59.65	0.00%
	200	17.68	34.28%	31.91	1.028%	27.03	4.896%
	100	4.756	99.68%	8.204	94.26%	7.153	97.02%
10	1000	104.8	0.00%	285.0	0.00%	168.3	0.00%
	400	16.92	39.09%	31.05	1.328%	26.16	5.179%
	300	9.515	89.07%	20.01	21.97%	14.91	53.09%
	200	4.418	99.80%	7.977	94.95%	6.759	97.76%
	100	1.193	100.00%	2.061	100.00%	1.788	100.00%
20	1000	25.98	5.433%	71.24	0.00%	42.06	0.038%
	400	4.217	99.85	7.717	95.69%	6.543	98.11%
	300	2.378	100%	5.003	99.57%	3.728	99.93%
	200	1.099	100%	1.990	100.00%	1.690	100.00%
	100	0.298	100%	0.513	100.00%	0.432	100.00%

Though observation, we find that:
By adjusting k value, we can adjust the sensitivity of the relay. A larger k value means the relay can work with heavier load without load measurements, but also make the fault with low current level unidentified.

7. Summary and Conclusions

In the previous applications, the EBP has shown great advantages in protecting modern distribution system. These advantages include:

Sensitivity: The EBP shows great sensitivity in detecting different types of faults with different fault current level (section 6) in the protection zone. While traditional current based protection scheme is desensitized with the fault current contribution from the PVs, the EBP can still detect the faults with a reduced fault current level (section 4).

Speed: The EBP detects the faults in less than one cycle as shown in section 3 and 4. The fault detection speed can be further accelerated by choosing a smaller reset time T_r when required.

Selectivity: The EBP can differentiate internal and external faults as shown in section 3 and 4.

Accuracy: The EBP only operates the fault condition located inside the protection zone. The EBP operated correctly with unmeasured load branches inside the protection zone (section 6.1 and 6.3) and external fault.

There is a trend for more metering in distribution systems to enable better protection of the new active distribution system. In this case the EBP rely will provide even better performance.

Appendix A: Model Conversion from OpenDSS to WinIGS

This section describes a model translation procedure from OpenDSS to WinIGS. The problem is stated as follows. Given model DSS files and a bus coordinate DSS file, we translate the device models obtained from DSS files to those that can be read by WinIGS. The flow chart of the whole procedure is briefly shown in Figure A.1.

As we can see from the figure, the program starts from reading model DSS files and a bus coordinate file as given information. The program treats these models and bus coordinates information as objects and store them in the specific arrays in each device class (e.g., load class, transformer class, line class, etc.). Next, the program processes the buses. Since the length of some bus names in DSS file is larger than nine, we have to rename the bus names from the bus coordinate DSS file so that the renamed bus names are acceptable by WinIGS. Therefore, the program first renames the buses and creates a mapping list between the original bus names from DSS and the renamed buses. The next step is to create a base voltage list at each bus. The reason for this step is: (1) All the device models in WinIGS need to be assigned a rated voltage while some device models in DSS file do not have the rated voltage (e.g., distribution line model). Thus, the program is not able to determine the rated voltage for these devices if no such information is given from DSS files; (2) The rated voltage of some devices defined in DSS file are not consistent with the rated voltages of other devices at the same bus. For instance, the primary side rated voltage of a single-phase three-winding transformer is 7.2 kV, thus, the line-to-line voltage base at that bus is 12.4708 kV. However, the rated voltage of other devices at that bus is defined as 12.47 kV. Therefore, the inconsistency occurs between these two rated voltages, and the bus base voltage list can be used to unify them. The last step in bus processing procedure is to scale the bus coordinates. This step is due to the fact that the bus coordinates from DSS file has decimals, and some buses may even share the same coordinates, however, WinIGS only accepts integer bus coordinates and does not allow two buses with same coordinates. Thus, the bus scaling step is necessary. After the bus processing procedure, we have finished all the preparations and we are able to translate the models into WinIGS format. The conversion step is simply from object to object. To be more specific, we convert the objects from DSS file with all the parameters (device name, bus name, bus coordinates, rated voltage, rated power, etc.) to the objects with the parameters that can be read by WinIGS. Once all these steps are done, we output the translated models into WinIGS NMF file.

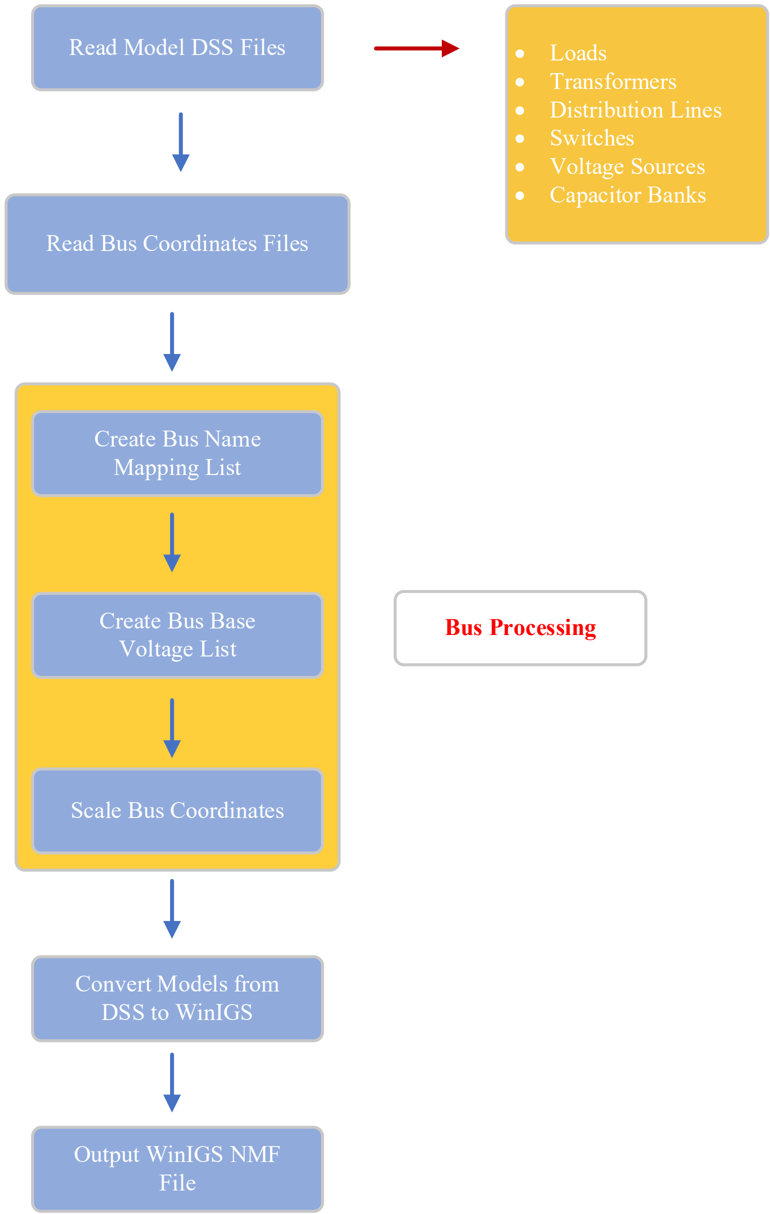


Figure A.1: Program Flow Chart for Model Conversion from OpenDSS to WinIGS

A.1 Importing OpenDSS Model

This section introduces the process of reading the device information (including device parameters and bus coordinates) from the OpenDSS files and storing the data into specific class according to device types. The devices include load, transformer, line, switch, voltage source, PV system and capacitor. The program treats the models read from DSS files as objects and store them in the specific arrays in each device class (e.g., capacitor class, load class, transformer class, etc.).

The general process of importing the OpenDSS file is shown in Figure A.1.1. After choosing the OpenDSS file, the file is read line by line and the strings are stored in array. If the order is "new", we create a new device class according to the device type. If the order is "edit", we find the device class we already created that has the same device name and revise accordingly. For each parameter of the device, we define a corresponding variable in the device class and the data are stored in the device class. In the following part, the import of different types of device is introduced. The parameters of device in OpenDSS and their counterpart variables in device class are presented in tables in each section. In OpenDSS, the bus coordinates are usually separately listed in a file with bus names.

The parameters of a load model in DSS file are described by OpenDSS scripts. An example script is as follows.

new load.1_1 phases=3 bus1=183213D0.1.2.3 kv=34.5 conn=wye model=2 kw=1.650 kvar=4.550

The table below shows the parameters listed in the script in DSS file and their corresponding variables in the load device class.

Table A.1: Parameters of Loads in OpenDSS

Model in OpenDSS	Class Defined for Storing Data		Definition
	Type	Variable Name	
Name	CString	m_sDeviceName	Device Name
Phases	int	m_iTotalPhaseNumber	Total Number of Phases
Bus	CString	m_sBusName	Bus Name
kv	double	m_dRatedVoltage	Rated Voltage (kV)
conn	CString	m_sConnectionType	Connection Type: wye, delta, etc
model	int	m_iModelType	Model Type
kw	double	m_dRealPower	Real Power (kW)
kvar	double	m_dReactivePower	Reactive Power (kVAr)

The parameters of a transformer model in DSS file are described by OpenDSS scripts. An example script is as follows.

new transformer.53 phases=1 buses=(177534D0.1 177548D0.1) conns=(w w)
~ kvs=(19.919 7.200) kvas=(333.33 333.33) xhl=6.37857

The table below shows the parameters listed in the script in DSS file and their corresponding variables in the transformer device class.

Table A.2: Parameters of Transformers in OpenDSS

Model in	Class Defined for Storing Data	Definition

OpenDSS	Type	Variable Name	
Name	CString	m_sDeviceName	Device Name
Phases	int	m_iTotalPhaseNumber	Total Number of Phases
Buses	vector<CString>	m_vsBusName	Vector of Bus Name
conns	vector<CString>	m_vsConnection	Vector of Connection Type
kvs	vector<double>	m_dRatedVoltage	Vector of Rated Voltage (kV)
kvas	vector<double>	m_dReactivePower	Vector of Reactive Power (kVAr)
xhl	double	m_dXhl	percent reactance (high side to low side)

The parameters of a line model in DSS file are described by OpenDSS scripts. An example script is as follows.
new line.1 phases=3 bus1=183213D0.1.2.3 bus2=183235D0.1.2.3
~ r1=0.03024 x1=0.05872 r0=0.07785 x0=0.14430 c1=0.01965 c0=0.01658
The table below shows the parameters listed in the script in DSS file and their corresponding variables in the line device class.

Table A.3: Parameters of Lines in OpenDSS

Model in OpenDSS	Class Defined for Storing Data		Definition
	Type	Variable Name	
Name	CString	m_sDeviceName	Device Name
Phases	int	m_iTotalPhaseNumber	Total Number of Phases
Bus1	CString	m_sBusName1	Bus Name 1
Bus2	CString	m_sBusName1	Bus Name 2
R1	double	m_dR1	Positive-sequence Resistance, ohms per unit length
X1	double	m_dX1	Positive-sequence Reactance, ohms per unit length
R0	double	m_dR0	Zero-sequence Resistance, ohms per unit length
X0	double	m_dX0	Zero-sequence Reactance, ohms per unit length
C1	double	m_dC1	Positive-sequence Capacitance, micro Siemens per unit length
C0	double	m_dC0	Zero-sequence Capacitance, micro Siemens per unit length

The parameters of a switch model in DSS file are described by OpenDSS scripts. An example script is as follows.
new line.Louisa_375 bus1=sourcebus bus2=172064D0 phases=3 switch=yes

The table below shows the parameters listed in the script in DSS file and their corresponding variables in the switch device class.

Table A.4: Parameters of Swtiches in OpenDSS

odel in OpenDSS	Class Defined for Storing Data		Definition
	Type	Variable Name	
Name	CString	m_sDeviceName	Device Name
Phases	int	m_iTotalPhaseNumber	Total Number of Phases
Bus1	CString	m_sBusName1	Bus Name 1
Bus2	CString	m_sBusName1	Bus Name 2
Switch	bool	m_bSwitch	0: not a switch, 1: a switch

The parameters of a switch model and a PV system model in DSS file are described by OpenDSS scripts. An example script of a switch is as follows.
new circuit.Louisa_375 bus1=sourcebus phases=3 basekv=34.5 r1=0.1757 x1=5.1779 r0=0.1543 x0=4.9923 pu=1.075
An example script of a PV system is as follows.
new pvsystem.Whitehouse_Solar phases=3 bus1=1744764D0.1.2.3 kv=34.50 pmpp=20000.00 kva=20000.00 irradiance=0.01
The table below shows the parameters listed in the script in DSS file and their corresponding variables in the voltage source device class.

Table A.5: Parameters of Voltage Sources and PV Systems in OpenDSS

Model in OpenDSS	Class Defined for Storing Data		Definition
	Type	Variable Name	
Name	CString	m_sDeviceName	Device Name
Phases	int	m_iTotalPhaseNumber	Total Number of Phases
Bus1	CString	m_sBusName	Bus Name
Basekv	double	m_dBaseKV	Base or Rated Line-to-line kV
R1	double	m_dR1	Positive-sequence Resistance, ohms per unit length
X1	double	m_dX1	Positive-sequence Reactance, ohms per unit length
R0	double	m_dR0	Zero-sequence Resistance, ohms per unit length
X0	double	m_dX0	Zero-sequence Reactance, ohms per unit length
pu	double	m_dPU	Actual per unit at which the source is operating
kv	double	m_dBaseKV	Base or Rated Line-to-line kV

pmpp	double	m_dPmpp	rated max power of the PV array for 1.0 kW/sq.m irradiance and a user-selected array temperature
kva	double	m_dkVA	Rated Power
irradiance	double	m_dIrradiance	irradiance

The parameters of a capacitor model in DSS file are described by OpenDSS scripts. An example script is as follows.
new capacitor.N8537 phases=3 bus1=49149   conn=wye kv=13.198 kvar=900.0 enabled=yes
The table below shows the parameters listed in the script in DSS file and their corresponding variables in the capacitor device class.

Table A.6: Parameters of Capacitors in OpenDSS

Model in OpenDSS	Class Defined for Storing Data		Definition
	Type	Variable Name	
Name	CString	m_sDeviceName	Device Name
Phases	int	m_iTotalPhaseNumber	Total Number of Phases
Bus1	CString	m_sBusName1	Bus Name 1
conn	CString	m_sConnectionType	Connection Type: wye, delta, etc
kv	double	m_dBaseKV	Base or Rated Line-to-line kV
kvar	double	m_dReactivePower	Reactive Power (kVAr)
enabled	bool	m_bEnabled	0: not enabled, 1:enabled

The bus coordinates are also described by OpenDSS scripts. An example script is as follows.
RIVBUS   2211495.58800 240615.94000   0.00000
The script for one bus coordinate has three elements. The first one is the bus name, the second and third ones are the x coordinate and y coordinate, respectively. Table A.7 shows the parameters of bus coordinates.

Table A.7: Parameters of Bus Coordinates

Model in OpenDSS	Class Defined for Storing Data		Definition
	Type	Variable Name	
Bus Name	CString	m_sBusName	Bus Name
X Coordinate	double	m_dXCoordinate	Coordinate on X axis
Y Coordinate	double	m_dYCoordinate	Coordinate on Y axis

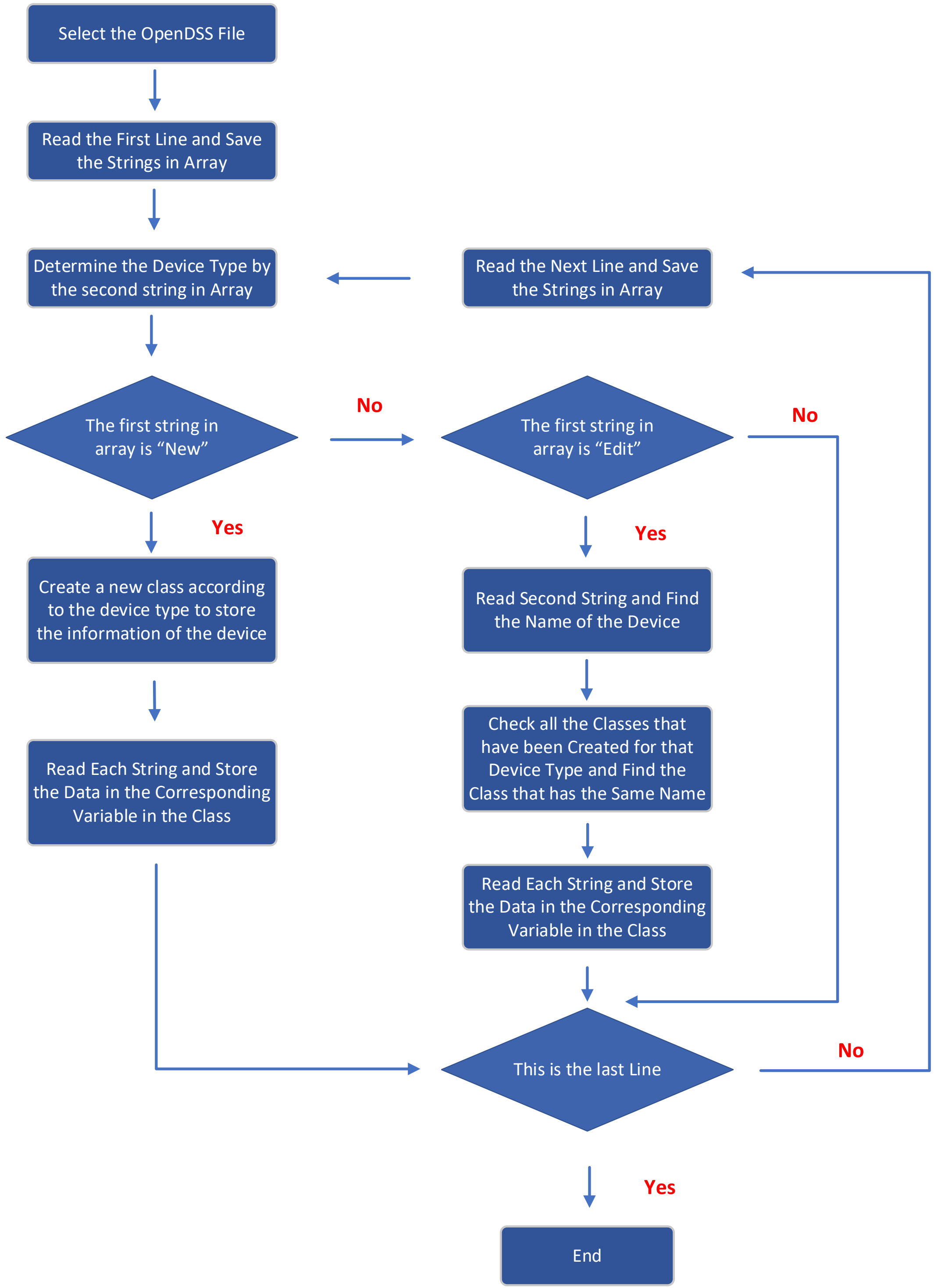


Figure A.1.1: Program Flow Chart for Importing Opendss Model

A.2 Bus Processing

This step creates a mapping list between the bus names from DSS file and bus names for WinIGS. The reason for this step is that WinIGS only accepts the length of a bus name less or equal to nine characters, however, the length of some bus names in DSS file is greater than nine. Therefore, we have to rename the bus names from DSS file and create a mapping lists between the old names and the new ones.
The naming rule is as follows.
We rename the bus name as: XXXXabcde, where
XXXX: Feeder Name (e.g., LOHO, B, etc.);
abcde: bus number (from 00000 to 99999).
The naming procedure is to renumber the bus names obtained from DSS file and use the naming rule described above to name these buses. The end result is stored in the array: vBusNameMapping.
Example: Name1 = vBusNameMapping[i][0]; Name2 = vBusNameMapping[i][1];
i: the i-th bus in DSS file;
Name1: the bus name obtained from DSS file;
Name2: the renamed bus for WinIGS.

This step creates a base voltage list for the new bus name list. The reason for this step is: (1) All the device models in WinIGS need to be assigned a rated voltage, but some device models in DSS file do not have the rated voltage (e.g., distribution line model). Thus, the program is not able to determine the rated voltage for some devices if no such information is given from DSS file; (2) The rated voltage of some devices defined in DSS file are not consistent with the rated voltages of other devices at the same bus. For instance, the primary side rated voltage of a single-phase three-winding transformer is 7.2 kV, thus, the line-to-line voltage base at that bus is 12.4708 kV. However, the rated voltage of other devices at that bus is defined as 12.47 kV. Therefore, the inconsistency occurs between these two rated voltages. And the base voltage list can be used to unify them.
The procedure of creating the bus base voltage list is as follows.
Step 1: Initialize Bus Base Voltage List vBusKVBase;
Dimension of vBusKVBase: nBusName by 1, where nBusName is the total bus number in this feeder.
Step 2: Go through all DSS devices that have the rated voltage values, i.e., capacitor bank, load, transformer, voltage source; Extract their rated voltages and assign those to the corresponding buses in vBusKVBase;
Step 3: Process the line and switch models. Go through the bus names in these two models. If one bus in a line/switch model has its rated voltage in vBusKVBase while the other bus does not have its rated voltage in the list, then set that rated voltage to the bus with no rated voltage in the vBusKVBase list. Keep iteration until all the elements in vBusKVBase are non-zero.

The end result of this step is the array vBusKVBase with all non-zero elements.
Example: dRatedVoltage = vBusKVBase[i];
i: the i-th bus in DSS bus file;
dRatedVoltage: the rated line-to-line voltage at that bus.

This step scales the bus coordinates obtained from DSS files. The reason for this step is that the bus coordinates obtained from the DSS file has decimals, and some buses may even share the same coordinate. Therefore, we have to scale them into reasonable and integer values so that the buses can be shown more clearly in WinIGS. In this step, both the X coordinate and Y coordinate are scaled. The scaling rule is to restrict the coordinates in the range from 0 to 10000, and the coordinates are scaled in the following formula: y=ax+b, where x is the coordinate obtained from DSS file, y is the bus coordinate in WinIGS, a is the scaling factor, and b is the offset.

The procedure of finding the coefficients a and b for X coordinates and Y coordinates is as follows.
Step 1: Find the max and min values for X coordinates and Y coordinates, respectively. And these values are stored in dXCoordinateMax, dXCoordinateMin, dYCoordinateMax, and dYCoordinateMin.
Step 2: Compute the scaling factors and offset.
dXCoordinateScale = 10000 / (dXCoordinateMax - dXCoordinateMin);
dXCoordinateOffset = - dXCoordinateMin * dXCoordinateScale;
dYCoordinateScale = 10000 / (dYCoordinateMax - dYCoordinateMin);
dYCoordinateOffset = - dYCoordinateMin * dYCoordinateScale;
Step 3: Scale the bus coordinates for each bus, and store the new bus coordinates to the array vScaledBuses;
For each bus, we do the following:
vScaledBuses[i]->m_sBusName = vImportedBuses[i] -> m_sBusName;
vScaledBuses[i]->m_dXCoordinate = dXCoordinateScale * vImportedBuses [i]->m_dXCoordinate + dXCoordinateOffset;
vScaledBuses[i]->m_dYCoordinate = dYCoordinateScale * vImportedBuses [i]->m_dYCoordinate + dYCoordinateOffset;

where vImportedBuses is the array read from the bus coordinate DSS file, and it has the same structure as the array vScaledBuses.
Step 4: Check if the scaled buses share the same coordinates, if yes, slightly change the coordinates. Keep iteration until no buses share the same coordinates.
Example: If i-th bus and j-th bus share the same coordinates, then do the following:
vScaledBuses[j]->m_dXCoordinate = vScaledBuses[i]->m_dXCoordinate + 1;
vScaledBuses[j]->m_dYCoordinate = vScaledBuses[i]->m_dYCoordinate + 1;

The end result of this step is the array vScaledBuses.
Example: BusName = vScaledBuses[i]->m_sBusName;
dX = vScaledBuses[i]->m_dXCoordinate;
dY = vScaledBuses[i]->m_dYCoordinate;
where BusName is the bus name at i-th bus in DSS bus file, dX is the scaled x coordinate value; dY is the scaled y coordinate value.

A.3 Convert Models from OpenDSS to WinIGS

This section introduces the detailed conversion procedure from the OpenDSS models to the models in WinIGS format. To be more specific, we first find the corresponding device in WinIGS and set the parameters of the device in WinIGS according to the parameters in OpenDSS models. Since some of the WinIGS models has neutral phase, we have to add the ground impedance model to connect the neutral phase to the ground and connect the neutral phase of two buses of a single device by connector. The detailed conversion procedure for each device class is illustrated below.

A.3.1 Load Model Conversion

There are three types of loads appear in the examples, three-phase constant impedance load, two-phase constant impedance load and single-phase constant impedance load. The parameters of the load models in DSS file are described by OpenDSS scripts. The definitions of the parameters are shown in Table A.8. The WinIGS load model has following elements: device name, numerical ID, coordinates, circuit number, interface names and parameters (rated voltage, real power and reactive power, etc.). The three-phase loads and single-phase loads are translated into three phase loads (M136) and single-phase load (M135) in WinIGS, respectively. The two-phase loads are translated into two single-phase loads in WinIGS. The detailed procedure of generating a WinIGS load model is described in the following sections.

Table A.8: Parameters and Definitions of Loads in OpenDSS

Parameter	Definition
Name	Device name
Phases	Number of Phases, this load. Load is evenly divided among phases.
Bus1	Bus to which the load is connected. May include specific node specification.
kv	Nominal rated (1.0 per unit) voltage, kV, for load. For 2- and 3-phase loads, specify phase-phase kV. Otherwise, specify actual kV across each branch of the load. If wye (star), specify phase-neutral kV. If delta or phase-phase connected, specify phase-phase kV.
conn	={wye or LN | delta or LL}. Default is wye.
model	Integer code for the model to use for load variation with voltage. Valid values are: 1:Standard constant P+jQ load. (Default) 2:Constant impedance load.
kw	Total base kW for the load. Normally, you would enter the maximum kW for the load for the first year and allow it to be adjusted by the load shapes, growth shapes, and global load multiplier.
kvar	Specify the base kvar for specifying load as kW & kvar. Assumes kW has been already defined.

A sample three phase constant impedance load script in OpenDSS is shown as:
new load.146_2 phases=3 bus1=190047D0.1.2.3 kv=34.5 conn=wye model=2 kw=228.150 kvar=68.900

The table below shows the parameters translated from the script in DSS file.

Table A.9: Converted Parameters of a Three-Phase Constant Impedance Load Model in WinIGS

Three-Phase Constant Impedance Load Model in WinIGS	
Object	Three-Phase Constant Impedance Load (M136)
Object Name	146_2
Number of Phases	3
Bus Name and Phases	B128
Rated Voltage	34.5 kV
Real Power	228.150 kW
Reactive Power	68.9 kVAr
Connection Type	Wye

The corresponding device in WinIGS is shown in the figure below.

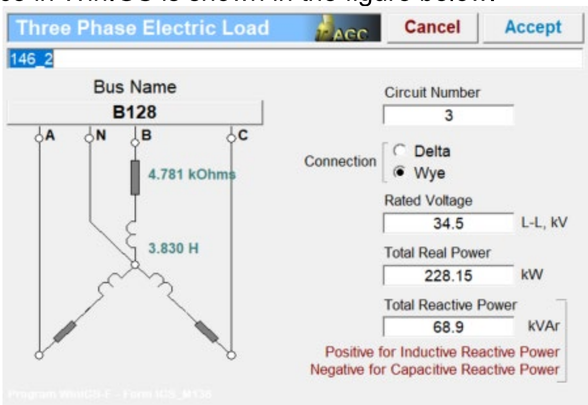


Figure A.3.1: Constant Impedance Three-Phase Load in WinIGS

The detailed conversion of a load is illustrated below:
Device Code: MODEL 136
Device Name: the same model name from DSS file
Numerical ID: device number (e.g. 00001) in the whole feeder.
Coordinates: Notice that the location of a load in OpenDSS is determined by one pair of x and y coordinate, but the location of a load in WinIGS is determined by two pairs of x and y coordinates. Therefore, we set the two pairs of x and y coordinates the same, and they are scaled from the coordinates from DSS as follows.
x1 = vScaledBuses[i]->m_dXCoordinate;
y1 = vScaledBuses[i]->m_dYCoordinate;
x2 = x1;
y2 = y1,
where (x1, y1) and (x2, y2) are the two pairs of coordinates for WinIGS.
Circuit Number: the number of circuits in parallel at same bus.
Interface Names: interface name is constructed from bus name mapping list and the phase.
Parameters:
Rated Voltage: The same as the rated voltage (kV) obtained from DSS file.
Real Power: kw (obtained from DSS file);
Reactive Power: kvar (obtained from DSS file);
Connection Type: Wye or Delta (obtained from DSS file)

A.3.2 Transformer Model Conversion

There are three types of transformers appear in the examples, three-phase transformer, two-phase transformer and single-phase transformer. The parameters of the load models in DSS file are described by OpenDSS scripts. The WinIGS transformer model has following elements: device name, numerical ID, coordinates, circuit number, interface names and parameters. The three-phase two-winding transformer and single-phase two-winding transformer are translated into three phase transformer (M104) and single-phase transformer (M290) in WinIGS, respectively. The two-phase transformers are translated into two single-phase transformers in WinIGS. The detailed procedure of generating a WinIGS transformer model is described in the following sections.

Table A.10: Parameters and Definitions of Transformers in OpenDSS

Parameter	Definition
Name	Device Name
Phases	Number of phases this transformer. Default is 3.
Buses	Use this to specify all the bus connections at once using an array. Example: New Transformer.T1 buses="Hibus, lowbus"
conn	Connection of this winding {wye*, Delta, LN, LL}. Default is "wye" with the neutral solidly grounded.
kvs	Use this to specify the kV ratings of all windings at once using an array. Example:New Transformer.T1 buses="Hibus, lowbus" ~ conns=(delta, wye)~ kvs=(115, 12.47) See kV= property for voltage rules.
kvas	Use this to specify the kVA ratings of all windings at once using an array.
xhl	Use this to specify the percent reactance, H-L (winding 1 to winding 2). Use for 2- or 3-winding transformers. On the kVA base of winding 1. See also X12.

A sample three phase transformer script in OpenDSS is shown as:

```
new transformer.130 phases=3 buses=(190287D0.1.2.3 190303D0.1.2.3) conns=(w w)
~   kvs=(34.500 12.470) kvas=(1000.00 1000.00) xhl=6.72633
edit transformer.130 taps=[1 1.08]
```

The three-phase transformer is translated into three-phase transformer in WinIGS. The table below shows the parameters translated from the script in DSS file.

Table A.11: Converted Parameters of a Three-phase Transformer Model in WinIGS

Three-Phase Two-Winding Transformer Model in WinIGS	
Object	Three-Phase Transformer (M104)
Object Name	130
Number of Phases	3
Bus Names	B142

	B143
Rated Voltage	Primary Side: 34.5 kV
	Secondary Side: 12.47 kV
Connection Type	Wye, Wye
Phase Connection Type	Standard
Power Rating	1 MVA
Winding Resistance	0.004 pu
Leakage Reactance	0. 0672633 pu
Nominal Core Loss	0.0003 pu
Nominal Magnetizing Current	0.001 pu
Tap Setting	1.08
Min Tap	0.9
Max Tap	1.1

The corresponding device in WinIGS is shown in the figure below.

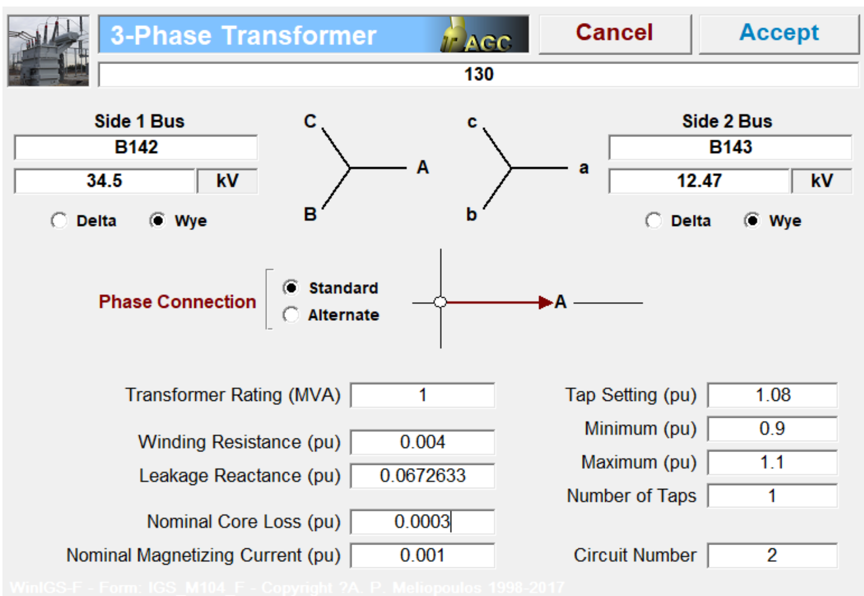


Figure A.3.2: Three-Phase Transformer in WinIGS

The detailed conversion is illustrated below:
Since the DSS file does not provide nominal core loss and nominal magnetizing current, we set these two variables as 0.0003 pu and 0.001 pu, respectively. Winding Resistance is set to be 0.004 pu, which is the default value of the transformer model in OpenDSS.
Device Code: MODEL 104
Device Name: The same model name from DSS file plus “_1” for the first device and “_2” for the second device
Numerical ID: Device number (e.g. 00001) in the whole feeder.
Coordinates:

x1 = vScaledBuses[i]->m_dXCoordinate;
y1 = vScaledBuses[i]->m_dYCoordinate;
x2 = x1;
y2 = y1,
where (x1, y1) and (x2, y2) are the two pairs of coordinates for WinIGS.
Circuit Number: the number of circuits in parallel at same bus.
Interface Names: interface name is constructed by bus names.
Parameters:

Rated Voltage: the rated voltage obtained from DSS file / $\sqrt{3}$.
Rated Power: The same as the rated power obtained from DSS file;
Winding Resistance: Default value in OpenDSS;
Leakage Reactance: the value obtained from DSS (xhl);
Nominal Core Loss: 0.0003 pu;
Nominal Magnetizing Current: 0.001 pu;
Tap Setting: the value obtained from DSS or default value (1.0)
Max Tap: Default Value 1.1
Min Tap: Default Value 0.9.

A.3.2 Line Model Conversion

There are three types of lines appear in the examples, three-phase line, two-phase line and single-phase line. The parameters of the line models in DSS file are described by OpenDSS scripts. The WinIGS line model has following elements: device name, numerical ID, coordinates, circuit number, interface names and parameters. The detailed procedure of generating a WinIGS line model is described in the following sections.

Table A.12: Parameters and Definitions of Transformers in OpenDSS

Parameter	Definition
Name	Device Name
Phases	Number of phases, this line.
bus1	Name of bus to which first terminal is connected.Example: bus1=busname (assumes all terminals connected in normal phase order) bus1=busname.3.1.2.0 (specify terminal to node connections explicitly)
bus2	Name of bus to which 2nd terminal is connected.
r1	Positive-sequence Resistance, ohms per unit length. Setting any of R1, R0, X1, X0, C1, C0 forces the program to use the symmetrical component line definition. See also Rmatrix.
x1	Positive-sequence Reactance, ohms per unit length. See also Xmatrix
r0	Zero-sequence Resistance, ohms per unit length.
x0	Zero-sequence Reactance, ohms per unit length.
c1	Positive-sequence capacitance, nf per unit length. See also Cmatrix and B1.
c0	Zero-sequence capacitance, nf per unit length. See also B0.
rmatrix	Resistance matrix, lower triangle, ohms per unit length. Order of the matrix is the number of phases. May be used to specify the impedance of any line configuration. Using any of Rmatrix, Xmatrix, Cmatrix forces program to

	use the matrix values for line impedance definition. For balanced line models, you may use the standard symmetrical component data definition instead.
xmatrix	Reactance matrix, lower triangle, ohms per unit length.
cmatrix	Nodal Capacitance matrix, lower triangle, nf per unit length.

A sample three phase line script in OpenDSS is shown as:
new line.93 phases=3 bus1=183235D0.1.2.3 bus2=183310D0.1.2.3
~ r1=0.25137 x1=0.36903 r0=0.62346 x0=0.80040 c1=0.01965 c0=0.01658 // len=0.74542

The three-phase line is translated into three-phase line in WinIGS. The table below shows the parameters translated from the script in DSS file.

Table A.13: Converted Parameters of a Three-phase Line Model in WinIGS

Three-Phase Distribution Line Model in WinIGS		
Object		Three-Phase Equivalent Circuit (M108)
Object Name		93
Number of Phases		3
Bus Names		B109
		B120
Rated Voltage		Side 1: 34.5 kV
		Side 2: 34.5 kV
Positive Sequence	Series Resistance	0.25137 ohm
	Series Reactance	0.36903 ohm
	Shunt Conductance	0
	Shunt Susceptance	7.4079e-6 mMho
Negative Sequence	Series Resistance	0.25137 ohm
	Series Reactance	0.36903 ohm
	Shunt Conductance	0
	Shunt Susceptance	7.4079e-6 mMho
Zero Sequence	Series Resistance	0.62346 ohm
	Series Reactance	0.80040 ohm
	Shunt Conductance	0
	Shunt Susceptance	6.2505e-6 mMho

The corresponding device in WinIGS is shown in the figure below.

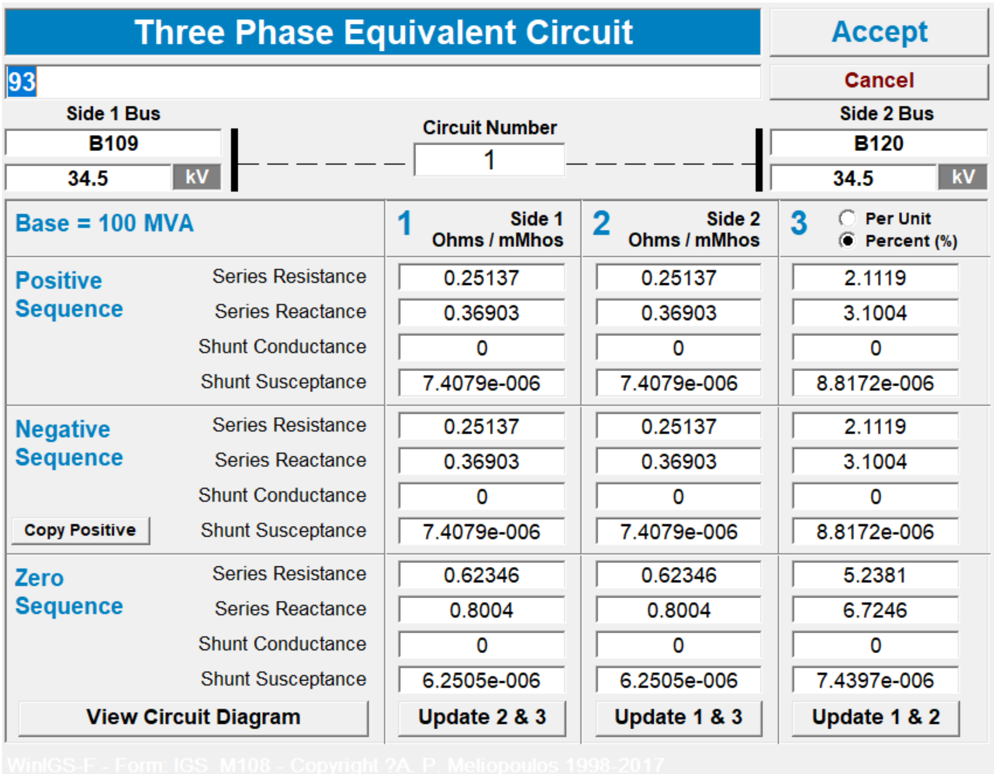


Figure A.3.3: Three-Phase Line in WinIGS

The detailed conversion is illustrated below:
Device Code: MODEL 108 (three-phase)
Device Name: the same model name from DSS file.;
Numerical ID: device number (e.g. 00001) in the whole feeder.
Coordinates:
x1 = vScaledBuses[i]->m_dXCoordinate;
y1 = vScaledBuses[i]->m_dYCoordinate;
x2 = x1;
y2 = y1,
where (x1, y1) and (x2, y2) are the two pairs of coordinates for WinIGS.
Circuit Number: the number of circuits in parallel at same bus.
Interface Names: interface name is constructed by bus names.
Parameters:
Rated Voltage: Obtained from vBusKVBase.
Positive/Negative Sequence Series Resistance: R1;
Positive/Negative Sequence Series Reactance: X1;
Zero Sequence Series Resistance: R0;
Zero Sequence Series Reactance: X0;
Positive/Negative Shunt Conductance: 0.0
Positive/Negative Shunt Susceptance: $2\pi * \mathrm{f} * \mathrm{C1} * e^{-6}$;
Zero Sequence Shunt Conductance: 0.0;
Zero Sequence Shunt Susceptance: $2\pi * \mathrm{f} * \mathrm{C0} * e^{-6}$;

A.3.2 Source Model Conversion

A sample utility source script in OpenDSS is shown as:
new circuit.RIV209 bus1=sourcebus phases=3 basekv=46.0 pu=1.00 ang=0 r1=0.3649 x1=2.4595 r0=1.1465 x0=7.8039
edit vsource.source pu=1.04

The utility source is translated into utility source in WinIGS. The table below shows the parameters translated from the script in DSS file.

Table A.14: Converted Parameters of a Utility Source Model in WinIGS

Voltage Source Model in WinIGS		
Object		Three-Phase Equivalent Source (M110)
Object Name		RIV209
Number of Phases		3
Bus Names		source
Source Voltage (line-to-line)		47.84 kV
Rated Power		100 MVA
Rated Voltage		46.0 kV
Positive Sequence	Resistance	0.3649 ohm
	Reactance	2.4595 ohm
Negative Sequence	Resistance	0.3649 ohm
	Reactance	2.4595 ohm
Zero Sequence	Resistance	1.1465 ohm
	Reactance	7.8039 ohm

The corresponding device in WinIGS is shown in the figure below.

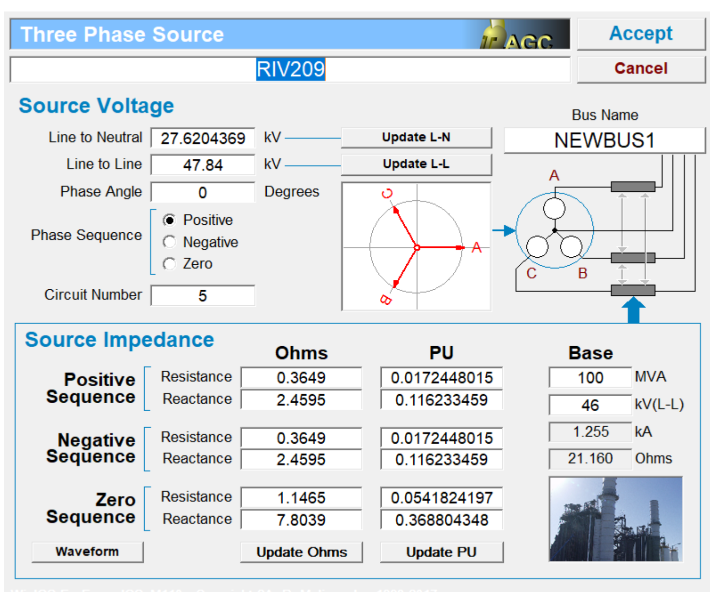


Figure A.3.4: Utility Source in WinIGS

The detailed conversion is illustrated below:
MODEL 110
Device Name: the same model name from DSS file.;
Numerical ID: device number (e.g. 00001) in the whole feeder.
Coordinates:
x1 = vScaledBuses[i]->m_dXCoordinate;
y1 = vScaledBuses[i]->m_dYCoordinate;
x2 = x1;
y2 = y1,
where (x1, y1) and (x2, y2) are the two pairs of coordinates for WinIGS.
Circuit Number: the number of circuits in parallel at same bus.
Interface Names: interface name is constructed by bus names.
Parameters:
Line to Line Voltage: BaseKV * pu;
Rated Voltage: Obtained from BasekV;
Rated Power: Obtained from the parameters in DSS file;
Positive/Negative Sequence Resistance: r1 (Obtained from DSS file);
Positive/Negative Sequence Reactance: x1 (Obtained from DSS file);
Zero Sequence Resistance: r0 (Obtained from DSS file);
Zero Sequence Reactance: x0 (Obtained from DSS file).

A.3.2 Switch Model Conversion

The parameters of the switch models in DSS file are described by OpenDSS scripts. The WinIGS switch model has following elements: device name, numerical ID, coordinates, circuit number, interface names and parameters. The detailed procedure of generating a WinIGS switch model is described in the following sections.

Table A.15: Parameters and Definitions of Transformers in OpenDSS

Parameter	Definition
Name	Device Name
Phases	Number of phases, this line.
bus1	Name of bus to which first terminal is connected.Example: bus1=busname (assumes all terminals connected in normal phase order) bus1=busname.3.1.2.0 (specify terminal to node connections explicitly)
bus2	Name of bus to which 2nd terminal is connected.
switch	{y/n | T/F} Default= no/false. Designates this line as a switch for graphics and algorithmic purposes. SIDE EFFECT: Sets r1 = 1.0; x1 = 1.0; r0 = 1.0; x0 = 1.0; c1 = 1.1 ; c0 = 1.0; length = 0.001; You must reset if you want something different.

A sample switch script in OpenDSS is shown as:
new line.SHE215 bus1=SHELO bus2=SHEBUS phases=3 switch=yes

The switch is translated into switch in WinIGS. The table below shows the parameters translated from the script in DSS file.

Table A.16: Converted Parameters of a Switch Model in WinIGS

Switch Model in WinIGS	
Object	Primary Bus Connector (M192)
Object Name	RIV209
Number of Phases	3
Bus Names	B53
	B52
Connection for Phase A, B, and C	Closed
Neutral Connection Existence	Exist
Neutral Switch	Closed
Ground Switch Existence	Not Exist

The corresponding device in WinIGS is shown in the figure below.

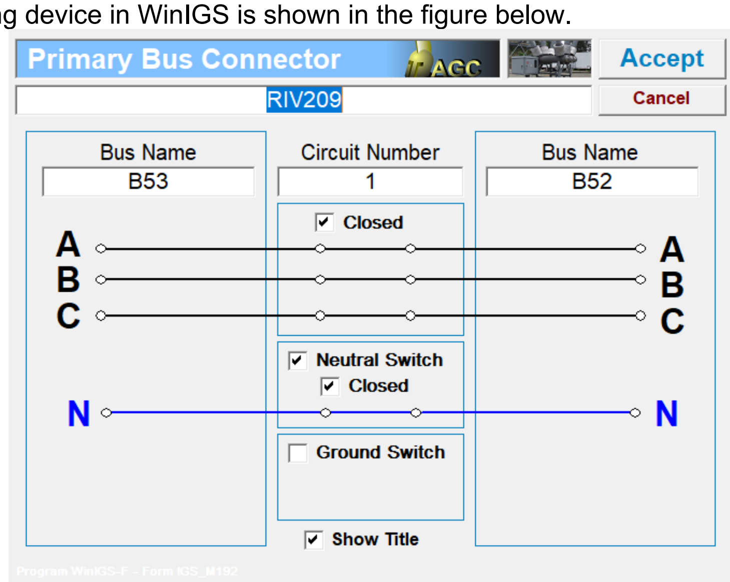


Figure A.3.5: Switch in WinIGS

The detailed conversion is illustrated below:
Device Code: MODEL 192
Device Name: the same model name from DSS file.;
Numerical ID: device number (e.g. 00001) in the whole feeder.
Coordinates:
x1 = vScaledBuses[i]->m_dXCoordinate;
y1 = vScaledBuses[i]->m_dYCoordinate;
x2 = x1;
y2 = y1,
where (x1, y1) and (x2, y2) are the two pairs of coordinates for WinIGS.
Circuit Number: the number of circuits in parallel at same bus.
Interface Names: interface name is constructed by bus names obtained from the DSS file.
Parameters:
Connection for Phase A, B, and C: Closed.
Neutral Connection Existence: Exist;
Neutral Switch: The same status as the connection for phase A, B, and C;
Ground Switch Existence: not exist.

A.3.2 Capacitor Bank Model Conversion

The parameters of the switch models in DSS file are described by OpenDSS scripts. The WinIGS switch model has following elements: device name, numerical ID, coordinates, circuit number, interface names and parameters. The detailed procedure of generating a WinIGS switch model is described in the following sections.

Table A.17: Parameters and Definitions of Capacitor Banks in OpenDSS

Parameter	Definition
Name	Device Name
Phases	Number of phases
Bus1	Name of bus to which first terminal is connected.Example: bus1=busname (assumes all terminals connected in normal phase order) bus1=busname.3.1.2.0 (specify terminal to node connections explicitly)
conn	={wye | delta |LN |LL} Default is wye, which is equivalent to LN
kv	For 2, 3-phase, kV phase-phase. Otherwise specify actual can rating.
kvar	Total kvar, if one step, or ARRAY of kvar ratings for each step. Evenly divided among phases. See rules for NUMSTEPS.
enabled	{Yes|No or True|False} Indicates whether this element is enabled.

A sample capacitor bank script in OpenDSS is shown as:
new capacitor.N8509 phases=3 bus1=82179 conn=wye kv=13.198 kvar=1200.0 enabled=yes

The capacitor bank is translated into capacitor bank in WinIGS. The table below shows the parameters translated from the script in DSS file.

Table A.18: Converted Parameters of a Capacitor Bank Model in WinIGS

Capacitor Bank Model in WinIGS	
Object	Three-Phase Capacitor Bank (M116)
Object Name	N8509
Bus Name	B41
Rated Voltage	13.198 kV
Rated Power	900 kVA
Connection	Wye

The corresponding device in WinIGS is shown in the figure below.

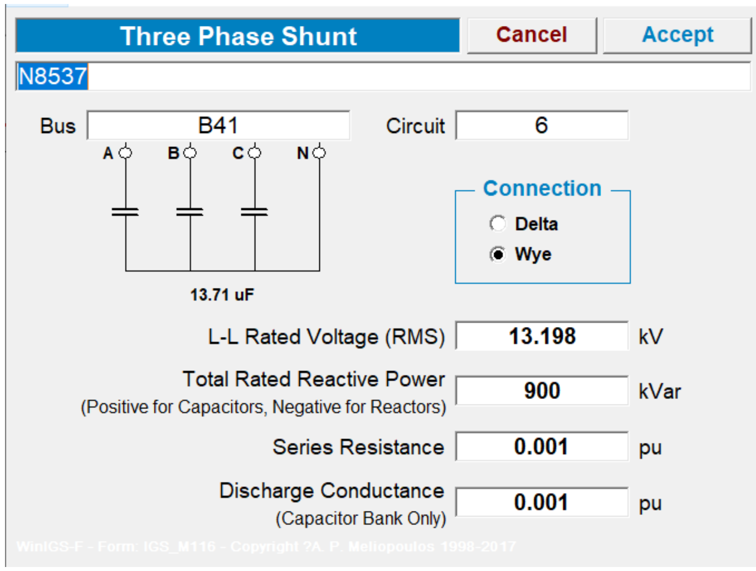


Figure A.3.6: Capacitor Bank in WinIGS

The detailed conversion is illustrated below:
Device Code: MODEL 116
Device Name: the same model name from DSS file.;
Numerical ID: device number (e.g. 00001) in the whole feeder.
Coordinates:
x1 = vScaledBuses[i]->m_dXCoordinate;
y1 = vScaledBuses[i]->m_dYCoordinate;
x2 = x1;
y2 = y1,
where (x1, y1) and (x2, y2) are the two pairs of coordinates for WinIGS.
Circuit Number: the number of circuits in parallel at same bus.
Interface Names: bus name from bus name mapping list.
Parameters:
Rated Voltage: the same as the rated voltage obtained from DSS file.
Rated Power: the same as the one obtained from DSS file.
Connection Type: the same as the one obtained from DSS file.

Appendix B: Description of an EBP Relay

To create an estimation based protective relay (EBP, a.k.a. setting-less relay), the model of the protection zone, the setting of the merging units and the mapping of the measurements are needed. The protection zone model is the formulated network level model of the protected power devices. The setting of the merging units includes instrumentation channels and measurement parameters to be used by the EBP relay. The mapping of the measurements refers to the type and location of the measurements.

With the protection model and the mapping of the measurement, the actual measurements are expressed in terms of the states of the protection zone model. To realize the observability and increase the redundancy, three other measurement types (derived measurements, virtual measurement, pseudo measurements) are introduced. The process of creating these measurements is discussed in chapter B.4.

B.1 Generating the Protection Model

The first step to create an EBP relay is to generate the protection model. The protection zone includes the protected power devices and the breakers/switches that enable the protection zone. The model of the protection zone is generated in WinIGS-T in the SCAQCF syntax. There are two steps to generating the protection model: generating device model for the devices included in the protection zone and formulating the network model. The modeling approach for devices starts from a physically-based model, which is a set of equations describing the physical characteristics of a device with states and control variables. Then, a quadratization procedure is applied so that the highest order in the model equations is less than or equal to two. Since the physically-based model may contain differential terms that reflect the dynamics, the quadratic integration method is applied to transform the differential equations to algebraic equation. The result of this procedure is an object-oriented interoperable syntax called State and Control Algebraic Quadratic Companion Form (SCAQCF). After the devices in the protection zone are modeled, the next procedure is to formulate the network SCAQCF model using the SCAQCF device models and the mapping lists from devices to the network.

The model is expressed as a compact device model at the beginning. A quadratization procedure is then applied to the compact model. This procedure consists of introducing additional variables to reduce higher order terms to nonlinear terms of highest order two. The result is a state and control quadratized device model (SCQDM) shown as below:

$$i(t) = Y_{eqx1}\mathbf{x}(t) + Y_{equ1}\mathbf{u}(t) + D_{eqxd1}\frac{d\mathbf{x}(t)}{dt} + C_{eqc1}$$

$$0 = Y_{eqx2}\mathbf{x}(t) + Y_{equ2}\mathbf{u}(t) + D_{eqxd2}\frac{d\mathbf{x}(t)}{dt} + C_{eqc2}$$

$$0 = Y_{eqx3}\mathbf{x}(t) + Y_{equ3}\mathbf{u}(t) + \begin{Bmatrix} \vdots \\ \mathbf{x}(t)^T \left\langle F_{eqxx3}^i \right\rangle \mathbf{x}(t) \\ \vdots \end{Bmatrix} + \begin{Bmatrix} \vdots \\ \mathbf{u}(t)^T \left\langle F_{equu3}^i \right\rangle \mathbf{u}(t) \\ \vdots \end{Bmatrix} + \begin{Bmatrix} \vdots \\ \mathbf{u}(t)^T \left\langle F_{equx3}^i \right\rangle \mathbf{x}(t) \\ \vdots \end{Bmatrix} + C_{eqc3}$$

$$\mathbf{h}(\mathbf{x},\mathbf{u}) = Y_{hfeqx}\mathbf{x}(t) + Y_{hfequ}\mathbf{u}(t) + \begin{Bmatrix} \vdots \\ \mathbf{x}(t)^T F_{hfeqxx}^i \mathbf{x}(t) \\ \vdots \end{Bmatrix} + \begin{Bmatrix} \vdots \\ \mathbf{u}(t)^T F_{hfequu}^i \mathbf{u}(t) \\ \vdots \end{Bmatrix} + \begin{Bmatrix} \vdots \\ \mathbf{u}(t)^T F_{hfequx}^i \mathbf{x}(t) \\ \vdots \end{Bmatrix} + C_{hfeqc}$$

$$\text{Constraints: } \mathbf{h}(\mathbf{x},\mathbf{u}) \le \mathbf{0},\ \mathbf{u}_{\mathbf{hmin}} \le \mathbf{u} \le \mathbf{u}_{\mathbf{hmax}},\ \ |\mathbf{du}| \le \mathbf{u}_{\mathbf{hllim}}$$

$$\text{Model Dimensions: } \mathrm{n}_{equ1}, n_{equ2}, n_{equ3}, n_{state}, n_{control}, n_{Feqxx}, n_{Fequu}, n_{Fequx}, n_{fconst}, n_{Ffeqxx}, n_{Ffequu}, n_{Ffequx}$$

$$\text{Connectivity: } nn_t, ivn, inn, onn, S_{st}$$

$$\text{Normalization Factors: } x_{NF}, e_{NF}, u_{NF}, h_{NF}$$

where: $i(t)$ is the terminal through variable vector, $\mathbf{x}(t)$ is state variable vector, Y matrices are linear coefficients, D matrices are differential coefficients, C vectors are constants, F matrices are nonlinear coefficients, **h** denotes functional constraints, $\mathbf{u}_{\min}$, $\mathbf{u}_{\max}$ are lower and upper bounds for control variables, $\mathbf{u}_{\text{hlim}}$ denotes the maximum permissible control variable excursions to maintain linearization error below a threshold.

The SCQDM is then integrated for the purpose of converting it into an algebraic model. The quadratic integration method is adopted, and the integration process transforms the SCQDM into a state and control algebraic quadratic companion form (SCAQCF) as shown below:

$$\begin{Bmatrix} i(t) \\ 0 \\ 0 \\ i(t_m) \\ 0 \\ 0 \end{Bmatrix} = \mathbf{e}_{\mathbf{lhs}} = Y_{eqx}\mathbf{x} + \begin{Bmatrix} \vdots \\ \mathbf{x}^T \left\langle F_{eqxx}^i \right\rangle \mathbf{x} \\ \vdots \end{Bmatrix} + Y_{equ}\mathbf{u} + \begin{Bmatrix} \vdots \\ \mathbf{u}^T \left\langle F_{equu}^i \right\rangle \mathbf{u} \\ \vdots \end{Bmatrix} + \begin{Bmatrix} \vdots \\ \mathbf{u}^T \left\langle F_{equx}^i \right\rangle \mathbf{x} \\ \vdots \end{Bmatrix} - B_{eq}$$

$$B_{eq} = -N_{eqx}\mathbf{x}(t-h) - N_{equ}\mathbf{u}(t-h) - M_{eq}I(t-h) - K_{eq}$$

$$\mathbf{h}(\mathbf{x},\mathbf{u}) = Y_{feqx}\mathbf{x} + Y_{fequ}\mathbf{u} + \begin{Bmatrix} \vdots \\ \mathbf{x}^T \left\langle F_{feqxx}^i \right\rangle \mathbf{x} \\ \vdots \end{Bmatrix} + \begin{Bmatrix} \vdots \\ \mathbf{u}^T \left\langle F_{fequu}^i \right\rangle \mathbf{u} \\ \vdots \end{Bmatrix} + \begin{Bmatrix} \vdots \\ \mathbf{u}^T \left\langle F_{fequx}^i \right\rangle \mathbf{x} \\ \vdots \end{Bmatrix} + C_{feqc}$$

$$\text{Constraints: } \mathbf{h}(\mathbf{x},\mathbf{u}) \le \mathbf{0}, \mathbf{u}_{\mathbf{min}} \le \mathbf{u} \le \mathbf{u}_{\mathbf{max}},\ \ |\mathbf{du}| \le \mathbf{u}_{\mathbf{llim}}$$

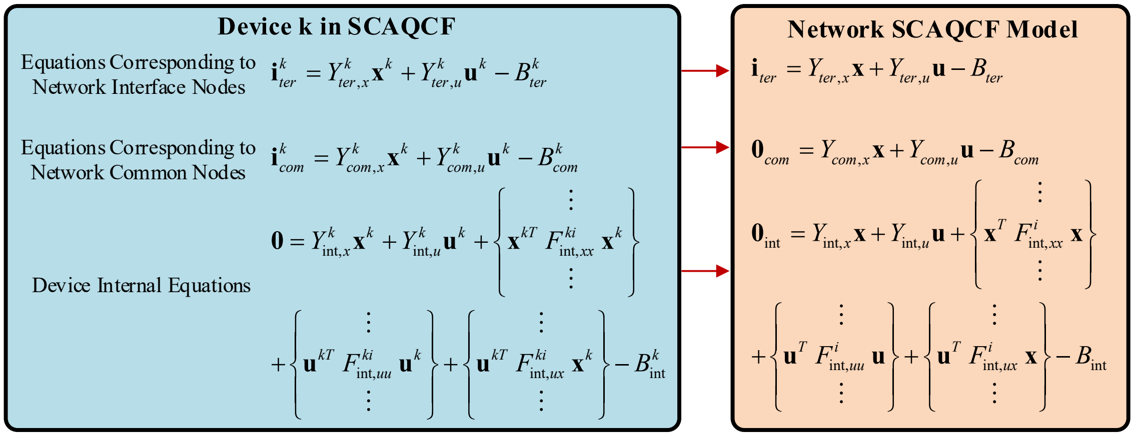
$$\text{Model Dimensions: } n_{equ}, n_{state}, n_{control}, n_{Feqxx}, n_{Fequu}, n_{Fequx}, n_{fconst}, n_{Ffeqxx}, n_{Ffequu}, n_{Ffequx}$$

$$\text{Connectivity: } nn_t, ivn, inn, onn, S_{st}$$

$$\text{Normalization Factor: } x_{NF}, e_{NF}, u_{NF}, h_{NF}$$

$$\text{Units: } xUnit, eUnit, uUnit, hUnit$$

The protection zone can contain several power devices. It is necessary to formulate the models of the power devices into a network-level model. Given n device SCAQCF models in a selected section, the first task is to create the network-level SCAQCF syntax as shown in Figure 2.1.1. In general, a device SCAQCF model consists of three types of equations: a) equations corresponding to the network interface nodes, b) equations corresponding to the network common nodes, and c) device internal equations. To formulate the network SCAQCF model, we keep types a and c equations and replace the states and controls in terms of devices by the states and controls in terms of the network. For type b equations from different devices but corresponding to a same common node, we apply KCL at each node which provides one equation for each node and which eliminates the through variables. These equations are in terms of the states and controls of the network. During this task, we first create the mapping lists (states, controls, equations) from devices to the network based on the device connectivity. Then, the network SCAQCF model is automatically created by device SCAQCF models in this network and the mapping lists. The output of this step is the network SCAQCF model listed in Figure 2.1.1. Note that in the network SCAQCF model, the equations with the current i on the left-hand side denote the through variables flowing into the network through the interface nodes, and all the other equations with zero value on the left-hand side are the device internal equations and the zero sum of equations at the common nodes derived from KCL.



Note:
1) the superscript k denotes the device number k;
2) "ter" refers to terminal, "com" refers to common node, "int" refers to internal.

Figure B.1.1: Network SCAQCF Model Formulation

WinIGS-T program provides a tool to automatically generates the model of the user selected protection zone in the SCAQCF syntax. The protection zone model is generated by selecting the power devices belonging to the protection zone and execute the SCAQCF Export command of the Tools menu. The output device model file ends with TDSCAQCF contains the model of the selected devices in SCAQCF syntax and the mapping of the devices.

B.2 Setting Up the Merging Units

Merging unit is responsible for acquiring the voltage and current signals from mutual transformer, and also processing, coding, sending these signals to the digital substation system. Setting up the merging units properly is crucial to create an EBP relay. To specify the data that the merging units provide to the EBP relay, the instrumentation channel and measurement parameters to be used by the EBP relay are determined.

In WinIGS-T, the instrument channels can be modeled in the merging unit. Figures B.2.1 to B.2.2 illustrate examples of setting up a voltage and a current instrumentation channel, respectively. A WinIGS-T instrumentation channel model includes models of the instrument transformer, instrumentation cable, burdens, and data acquisition device. A short description of the instrumentation channel parameters is presented in Table B.1. The **Burden** is the equivalent resistance of the burdens attached to the instrument transformer secondary. The resistance is large for a voltage instrument channel and small for a current instrument channel. The **Max Peak Value** is set according to data acquisition device specifications. For example, the GE Merging unit voltage and current max peak values can be derived from the voltage and current range specifications shown in Figure B.2.3. Note that the range is specified in RMS so these values must be multiplied by to obtain the peak values (i.e.: 325.3 Volts and 282.8 Amperes). The characteristics of the potential transformer and current transformer are shown in Figures B.2.4 and B.2.5.

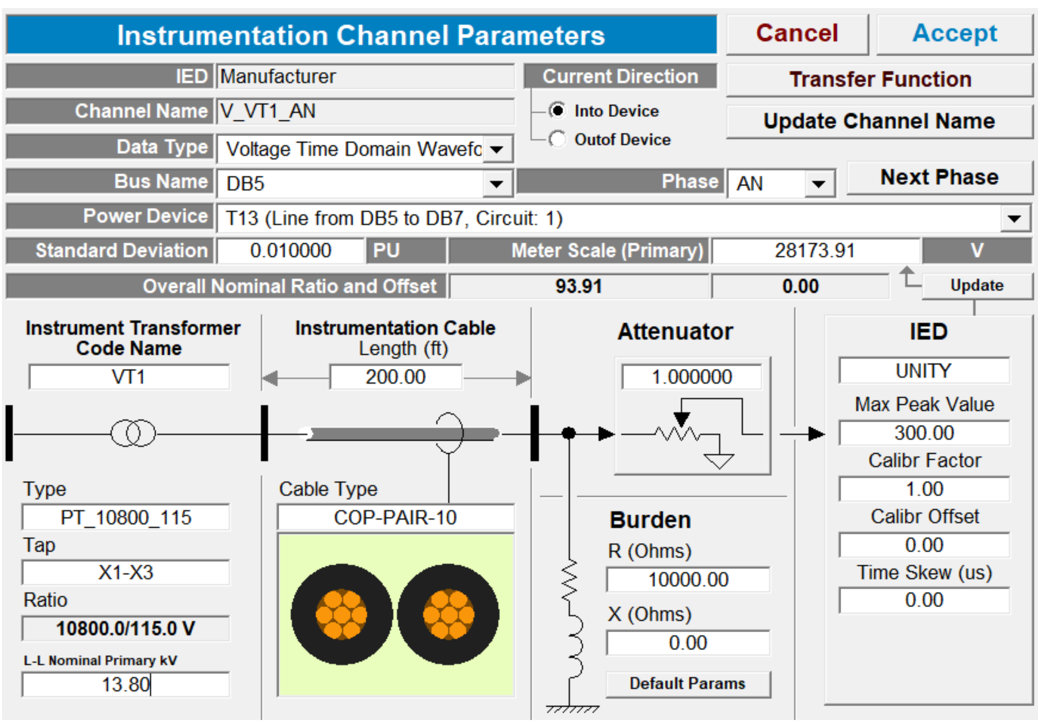


Figure B.2.1: Example of a Voltage Instrumentation Channel Dialog

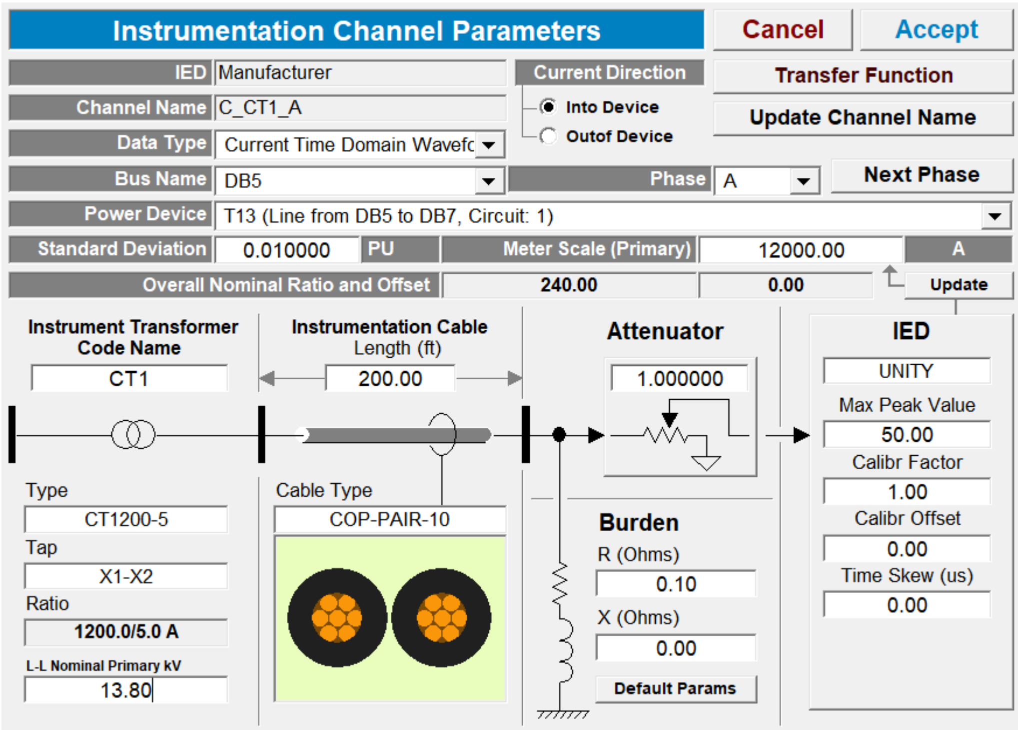


Figure B.2.2: Example of a Current Instrumentation Channel Dialog

Table B.1: Instrumentation Channel Parameters – User entry Fields

Parameter	Description
Data Type	Specifies the type of the measured quantity. Valid options for merging units are Voltage Time Domain Waveform and Current Time Domain Waveform.
Bus Name	The bus name where the measurement is taken
Power Device	Identifies the power device into which the current is measured (not used for voltage measurements)
Phase	The phase of the measured quantity (A, B, C, N, etc.)
Current Direction	The direction of current flow which is considered positive. For example, checking into device indicates that the positive current flow is into the power device terminal (See also Power Device parameter above)
Standard Deviation	Quantifies the expected error of the instrumentation channel in per unit of the maximum value that the channel can measure (See also channel scale parameter).
Meter Scale	The maximum peak value that the channel can measure defined at the instrument transformer primary side. Note that this value can be directly entered by the user, or automatically computed from the instrument transformer and data acquisition device characteristics. In order to automatically compute the, click on the **Update** button located below the Meter Scale field.
Instrument	An identifier of the instrument transformer associated with this channel.

Transformer Code Name	Note that WinIGS uses this identifier to generate the channel name. For example, the phase A voltage channel is automatically named V_VT1_AN, if the instrument transformer name is set to VT1.
Instrument Transformer **Type** and **Tap**	Selects instrument transformer parameters from a data library. The library includes parameters needed to create instrument channel models such as turns ratio, frequency response, etc. To select an instrument transformer model, click on the **type** or **tap** field to open the instrument transformer data library dialog (See also Figure 2.2.5 and Figure 2.2.6)
L-L Nominal Primary Voltage	The line to line voltage at the instrument transformer primary side.
Instrumentation Cable Length	The length of the instrumentation cable connecting the instrument transformer secondary with the data acquisition device.
Cable Type	The instrumentation cable type and size. Clicking on this field opens the cable library selection window. Note that if the desired cable is not found in the library, a cable library editor is available allowing adding and modifying cable parameters (See WinIGS-T user's manual for details).
Attenuator	Attenuation value of any additional voltage or current reduction divider. Set to 1.0 if none.
Burden	The equivalent resistance of the burdens attached to the instrument transformer secondary.
IED	Selects data acquisition device from a IED library. This setting retrieved the data acquisition device frequency response for the purpose of applying error correction. Set to UNITY if this information is not available.
Maximum Peak Value	Set to the maximum instantaneous (peak) voltage or current value that will not saturate the data acquisition device input. This value can be found in data acquisition device specifications. For example, the GE Merging unit voltage and current max peak values can be derived from the voltage and current range specifications shown in Figure 2.2.7. Note that the range is specified in RMS so these values must be multiplied by $\sqrt{2}$ to obtain the peak values (i.e.: 325.3 Volts and 282.8 Amperes)
Calibration Factor	The channel output is multiplied by this value. Set to 1.0 if none required.
Calibration Offset	This value is added to the channel output. Set to 0.0 if none required.
Time Skew	Time delay in seconds of this channel with respect to time reference. Set to zero for no delay.

CURRENT INPUTS

Nominal Current (In)	5 A	1 A
Nominal frequency	50/60Hz	50/60Hz
Current range (rms)	0.25 ... 200A	0.05 ... 40A
Accuracy	± 0.1 % F.S.	± 0.1 % F.S.
Impedance	3 m Ω	15 m Ω
Burden In	50 m VA	< 0.02 VA
Continuous overload	20A (4 x In)	4A (4 x In)
AC current thermal withstand 1 s (Ith rms)	320A (64 x In)	100A (100x In)
AC current thermal withstand 10 s (Ith rms)	100A (20 x In)	30A (30 x In)
Insulation	> 3.5 kV	> 3.5 kV
Bandwidth	3 k Hz	3 k Hz

VOLTAGE INPUTS

Nominal Voltage (Vn)	115 V
Nominal frequency	50/60Hz
Voltage range	0.02 ... 230 V
Accuracy	± 0.1 % F.S.
Impedance	> 210 k Ω
Burden Vn	< 0.1VA
Continuous overload	240 V
Maximum overload (1 s)	460 V (4 x Vn)
Bandwidth	3 k Hz

Figure B.2.3: Example Input Specifications of a GE MU320 Merging Unit

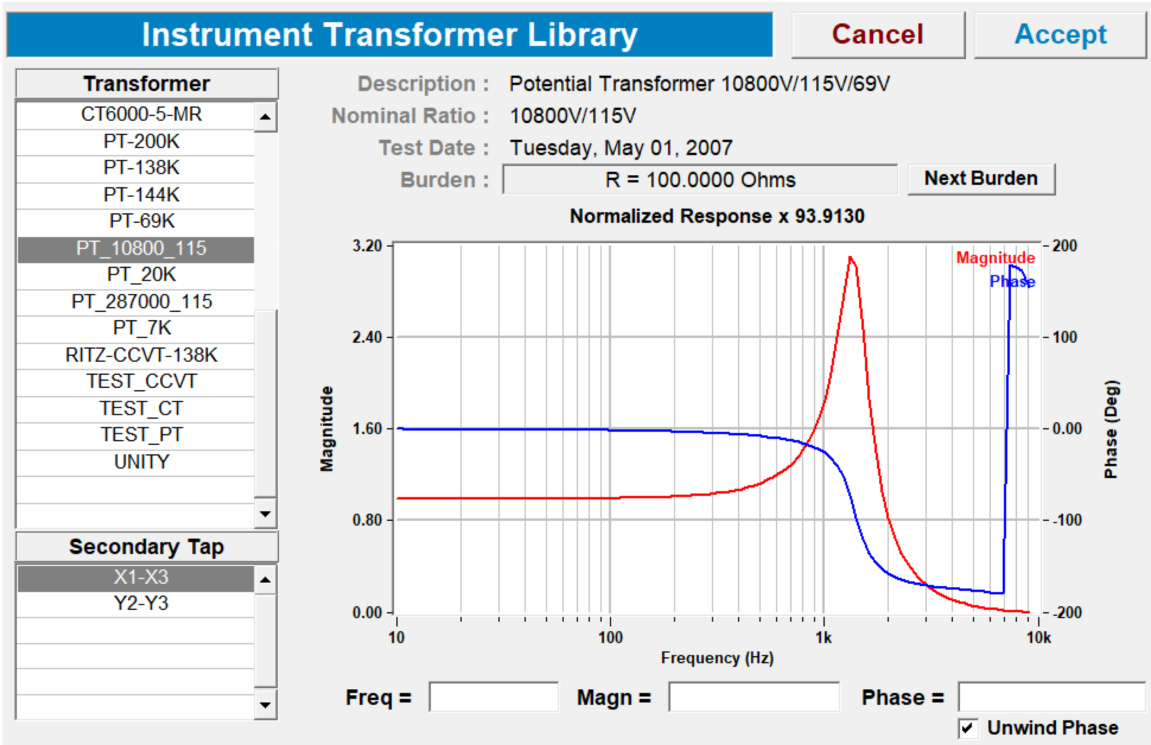


Figure B.2.4: Instrument Transformer Selection Library Dialog for PT

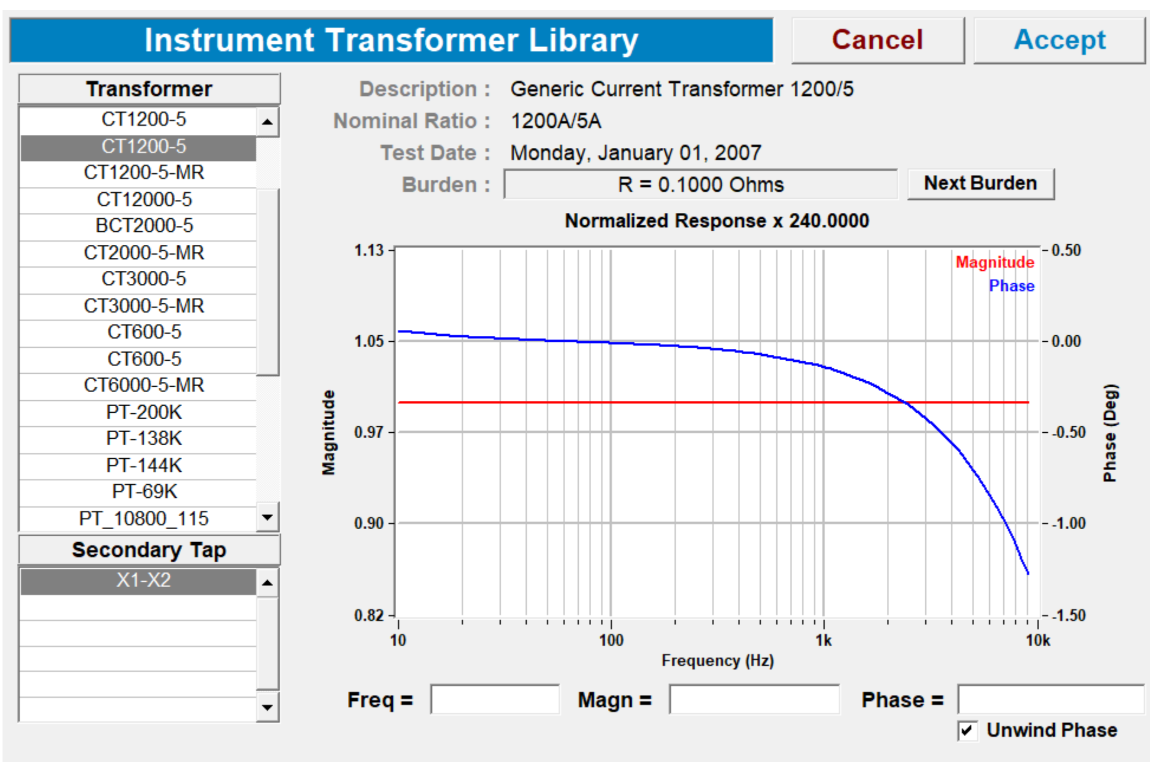


Figure B.2.5: Instrument Transformer Selection Library Dialog for CT

The next step is to define the measurements to be used for the EBP relay, in terms of the defined instrumentation channels. Measurement parameters can be manually created and edited in the measurement parameter dialog illustrated in Figures B.2.6 and B.2.7. The fields in this dialog are briefly described in Table B.2.

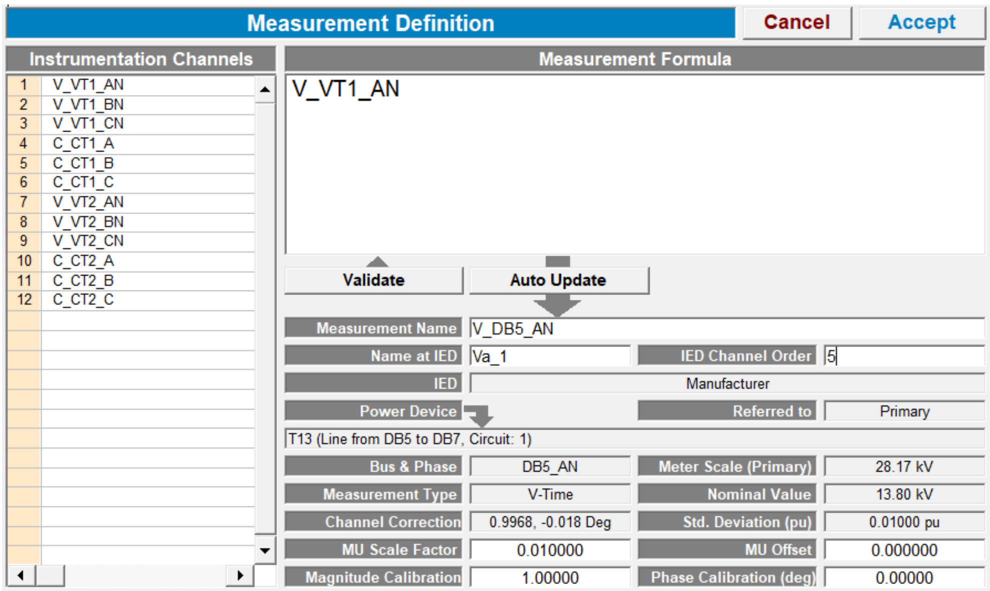


Figure B.2.6: Voltage Measurement Parameters Dialog

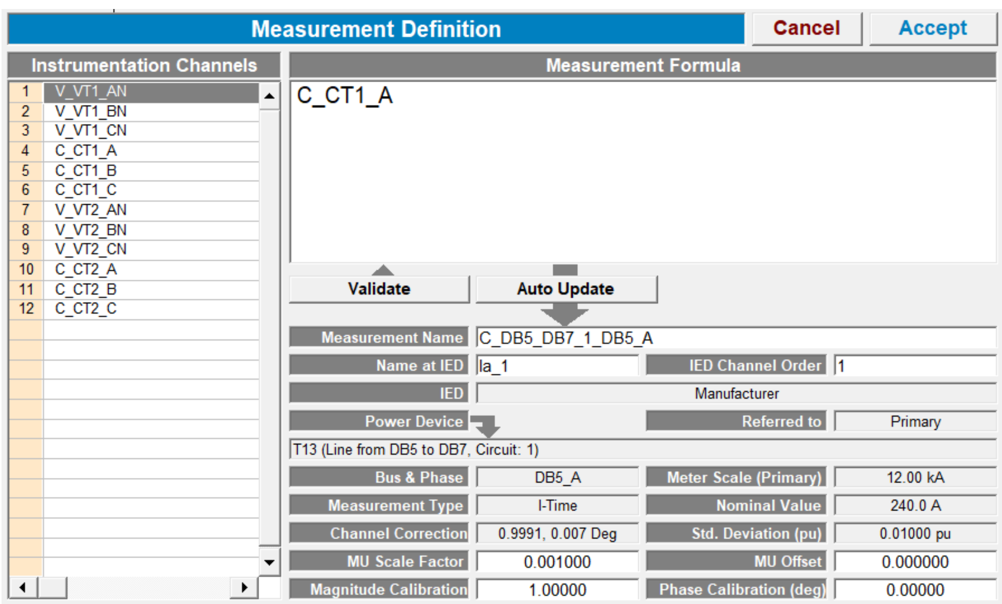


Figure B.2.7: Current Measurement Parameters Dialog

Table B.2: Measurement Parameters – User Entry Fields

Parameter	Description
Measurement Formula	Mathematical expression giving measurement value in terms of instrumentation channel values. Note that the measurement formula for automatically created measurements form instrument channels is simply the instrument channel name. However, a measurement can be manually defined as any expression involving all available instrument channels.
Measurement Name	***Voltage measurements*** names are automatically formed based on the bus name, phase and measurement type. For example, a phase A voltage measurement on Bus DB5 is automatically named V_DB5_AN. Similarly, ***current measurements*** are automatically formed by identifying a power device and a specific terminal into which the measured current is flowing. For example, the phase A current into the transformer at Bus DB5 is named C_DB5_DB7_1_DB5_A, where the part DB5_DB7_1 identifies the power device as circuit 1 connected to the bus DB5, and the part DB7 identifies the terminal into which the measured current is flowing. Note that the name part 1 is the user specified Circuit Name of the distribution line.
Name at IED	The measurement name as defined by the merging unit or other IED used. The default channel names vary with IED manufacturers and IED types. For example, the GE MU320 merging units default channel names are Ia_1, Ib_1, Ic_1, for the current channels and Va_1, Vb_1, Vc_1, for voltage channels.
IED Channel Order	An order number (starting with 1) indicating the ordering of the channels in the Sample Value packets. For example, GE MU320 merging units SV packets have four current channels followed by four voltage channels. Thus, the current channel order numbers are 1, 2, 3, 4 for phase A, B, C N, and the voltage channel order numbers are 5, 6, 7, and 8 for phases A, B, C, and N.
Merging Unit Scale Factor and Merging Unit Offset	These values define the conversion from the 32 bit integer Sample Values to actual values in Volts and Amperes. Specifically: $V_k = a X_k + b$ where Vk is a voltage sample in volts, a is the Scale Factor, Xk is the sample value voltage sample (32 bit integer), and b is the Merging Unit Offset. The default merging unit scale factor for voltage channels is 0.01, while for current channels is 0.001. Default offsets are zero.
Magnitude Calibration and Phase Calibration	Measurement magnitude and a phase angle correction values. Default values are 1.0 and 0.0 respectively.

B.3 Creating the Mapping of the Measurements

After the merging units are set up, the mapping of the measurements needs to be created according to the setting in merging unit. The mapping of the measurements refers to the type and location of the measurements. In regard of types, the measurements for an EBP relay can be voltage measurements, current measurements, temperature measurements or motor speed measurements. For an EBP relay for the distribution system, the voltage measurements and current measurements are the two most common types of measurements. For a voltage measurement (across measurement), the location information includes the device, bus and phase. For a current measurement (through measurement), the location information includes the device, bus, phase and direction.

The mapping of the measurements can also be generated by WinIGS-T program like the model of the protection zone. The mapping of the measurements is generated by selecting the merging units and execute the SCAQCF Export command of the Tools menu. The output measurement definition file ends with TDMDEF contains the information of the measurements (e.g. measurement name, phase, device ID, measurement type, terminal names and so on).

Given the mapping of the measurements and the device SCAQCF models, we first construct the device-level measurement model. For an across measurement, its measurement model is simply a linear combination of the states of the measured device plus a measurement error from this IED, i.e.,

$$z(t) = A\mathbf{x}(t) + \eta$$

where *z(t)* is the measurement, ***A*** is the linear coefficient matrix, ***x(t)*** is the device state vector at time t, and η is the noise introduced by this IED.

For a through measurement, its measurement model is obtained directly from the corresponding equations of the device SCAQCF model, i.e.,

$$z(t) = Y_{zx}\mathbf{x} + Y_{zu}\mathbf{u} + \begin{Bmatrix} \vdots \\ \mathbf{x}^T F_{zx}^i \mathbf{x} \\ \vdots \end{Bmatrix} + \begin{Bmatrix} \vdots \\ \mathbf{u}^T F_{zu}^i \mathbf{u} \\ \vdots \end{Bmatrix} + \begin{Bmatrix} \vdots \\ \mathbf{u}^T F_{zux}^i \mathbf{x} \\ \vdots \end{Bmatrix} - B_z + \eta$$

$$B_z = -N_{zx}\mathbf{x}(t-h) - N_{zu}\mathbf{u}(t-h) - M_z i(t-h) - K_z$$

where *Y*, *N*, *M* matrices are linear coefficient matrices, *F* matrices are nonlinear coefficient matrices, and *K* is the constant term. Once the device-level actual measurement model is formed, the network-level actual measurement model is easily obtained by using the formulated mapping lists that map the states, controls, and equations in the device-level actual measurement model to those in the network-level actual measurement model.

B.4 Creating Derived, Virtual and Pseudo Measurements

To realize the observability and increase the redundancy, four other measurement types are introduced: 1) type I derived measurement: derived from actual measurements based on the system topology, 2) type II derived measurement: generated for missing through variable measurements in any multi-terminal device, 3) pseudo measurement: quantities that are approximately known, and 4) virtual measurements: equations with zero value defined by physical or mathematical laws.

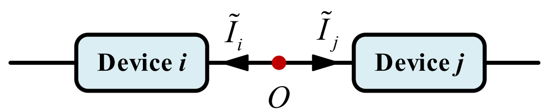


Figure B.4.1: Illustration of Type I Derived Measurement

Type I derived measurement is created by derivation from actual measurements based on the network topology. For instance, as shown in Figure 2.4.1, devices i and j are connected at node O with available current phasor measurement $\tilde{I}_i$. Since no other devices are connected at point O, the current flowing into device j is simply derived as $z = \tilde{I}_j + \eta = -\tilde{I}_i + \eta$, which is a type I derived measurement. Type I derived measurement can also be created based on the device topology. For example, as a distribution line is usually short, its shunt capacitance is quite small. Therefore, if a current measurement at one terminal of this line is available, we can derive a current measurement that has same magnitude but is with opposite phase angle at the other terminal of this line. Such measurement is also considered as a type I derived measurement. By using formulated mapping lists, type I derived measurement model is expressed in terms of variables at network-level as follow, where subscript dI denotes type I derived measurement.

$$z_{dI}(t) = Y_{dI,x}\mathbf{x} + Y_{dI,u}\mathbf{u} + \begin{Bmatrix} \vdots \\ \mathbf{x}^T F_{dI,x}^i \mathbf{x} \\ \vdots \end{Bmatrix} + \begin{Bmatrix} \vdots \\ \mathbf{u}^T F_{dI,u}^i \mathbf{u} \\ \vdots \end{Bmatrix} + \begin{Bmatrix} \vdots \\ \mathbf{u}^T F_{dI,ux}^i \mathbf{x} \\ \vdots \end{Bmatrix} - B_{dI} + \eta$$

$$B_{dI} = -N_{dI,x}\mathbf{x}(t-h) - N_{dI,u}\mathbf{u}(t-h) - M_{dI}i(t-h) - K_{dI}$$

Type II derived measurement is generated for missing through variable measurements in any multi-terminal device that has at least one through quantity actual measurement. Specifically, for an n-terminal device with m terminals having through measurements, the state estimator creates type II derived measurements for the other n-m terminals. Type II derived measurement model is directly obtained from the device SCAQCF model. However, its measurement value is computed from the device SCAQCF model using the estimated states from the last time step. Since the measurement value is not obtained from the current time step, the state estimator assigns a relatively higher measurement error to type II derived measurement compared to the actual measurements from this device (e.g., five times larger than the actual measurement error of this device). By using the mapping lists between devices and the network, type II derived measurement model is expressed in terms of variables at network level as follow, where dII denotes type II derived measurement.

$$z_{dII}(t) = Y_{dII,x}\mathbf{x} + Y_{dII,u}\mathbf{u} + \begin{Bmatrix} \vdots \\ \mathbf{x}^T F_{dII,x}^i \mathbf{x} \\ \vdots \end{Bmatrix} + \begin{Bmatrix} \vdots \\ \mathbf{u}^T F_{dII,u}^i \mathbf{u} \\ \vdots \end{Bmatrix} + \begin{Bmatrix} \vdots \\ \mathbf{u}^T F_{dII,ux}^i \mathbf{x} \\ \vdots \end{Bmatrix} - B_{dII} + \eta$$

$$B_{dII} = -N_{dII,x}\mathbf{x}(t-h) - N_{dII,u}\mathbf{u}(t-h) - M_{dII}i(t-h) - K_{dII}$$

Pseudo measurement models are not directly measured but are quantities for which we know their approximate values. For example, the voltage at a neutral is around zero during normal operations. This voltage can be introduced as a pseudo measurement. Since we do not know the exact value of pseudo measurements, a relatively higher measurement error compared to the actual measurement model is introduced. Pseudo measurement models are also expressed in terms of variables at network level, where subscript p denotes pseudo measurement.

$$z_p(t) = Y_{p,x}\mathbf{x} + Y_{p,u}\mathbf{u} + \begin{Bmatrix} \vdots \\ \mathbf{x}^T F^i_{p,x}\mathbf{x} \\ \vdots \end{Bmatrix} + \begin{Bmatrix} \vdots \\ \mathbf{u}^T F^i_{p,u}\mathbf{u} \\ \vdots \end{Bmatrix} + \begin{Bmatrix} \vdots \\ \mathbf{u}^T F^i_{p,ux}\mathbf{x} \\ \vdots \end{Bmatrix} - B_p + \eta$$

$$B_p = -N_{p,x}\mathbf{x}(t-h) - N_{p,u}\mathbf{u}(t-h) - M_p i(t-h) + K_p$$

Virtual measurement models are provided by the network internal equations reflecting the physical property (e.g., KCL, etc.) of the network. These are directly obtained from the equations with zero value on the left-hand side in the network-level SCAQCF model with a relatively small measurement error compared to actual measurement models, where subscript v refers to virtual measurement model.

$$0 = Y_{v,x}\mathbf{x} + Y_{v,u}\mathbf{u} + \begin{Bmatrix} \vdots \\ \mathbf{x}^T F^i_{v,x}\mathbf{x} \\ \vdots \end{Bmatrix} + \begin{Bmatrix} \vdots \\ \mathbf{u}^T F^i_{v,u}\mathbf{u} \\ \vdots \end{Bmatrix} + \begin{Bmatrix} \vdots \\ \mathbf{u}^T F^i_{v,ux}\mathbf{x} \\ \vdots \end{Bmatrix} + \eta$$

By following all these three tasks and combining network-level actual, derived I and II, pseudo, and virtual measurement models, the final expression of the network measurement model with a similar syntax as the network SCAQCF model is obtained:

$$\mathbf{z}(t) = h(\mathbf{x}) + \boldsymbol{\eta} = Y_{zx}\mathbf{x} + Y_{zu}\mathbf{u} + \begin{Bmatrix} \vdots \\ \mathbf{x}^T F^i_{zx}\mathbf{x} \\ \vdots \end{Bmatrix} + \begin{Bmatrix} \vdots \\ \mathbf{u}^T F^i_{zu}\mathbf{u} \\ \vdots \end{Bmatrix} + \begin{Bmatrix} \vdots \\ \mathbf{u}^T F^i_{zux}\mathbf{x} \\ \vdots \end{Bmatrix} - B_z + \boldsymbol{\eta}$$

$$B_z = -N_{zx}\mathbf{x}(t-h) - N_{zu}\mathbf{u}(t-h) - M_z i(t-h) - K_z$$

By following all these three tasks and combining network-level actual, derived I and II, pseudo, and virtual measurement models, the final expression of the network measurement model with a similar syntax as the network SCAQCF model is obtained.

These measurements can be automatically generated in WinXFM program after the measurement definition model and device model are imported.

B.5 Creating the System model to Generate Events

After the EBP relay is created, simulated events are needed to further test the EBP relay. Generating events for the EBP relay begins by building a system model in WinIGS-T. The system could include the entire or part of the large system (for simulation studies and for generating events) and must also include the models of the protection zone under study. Fault events are defined and simulated by adding the fault model in the system model. The results are stored in COMTRADE file to be further used in the testing procedure.

B.5.1 Creating the Network Time Domain Model

The network time domain model built in WinIGS-T is used to generate simulated events with faults and EBP model file to be used by the EBP relay. The WinIGS-T model include the following components specifically:

- The power devices comprising the EBP protection zone.
- The instrumentation channels available to the EBP relay via merging units.
- The breakers/switches that enable the protection of the zone.

The user interface of WinIGS is shown in Figure B.5.1. We can insert the devices of interest through buttons for inserting devices and connectors. We can insert merging units and meters to observe the states of the devices through buttons for inserting meters.

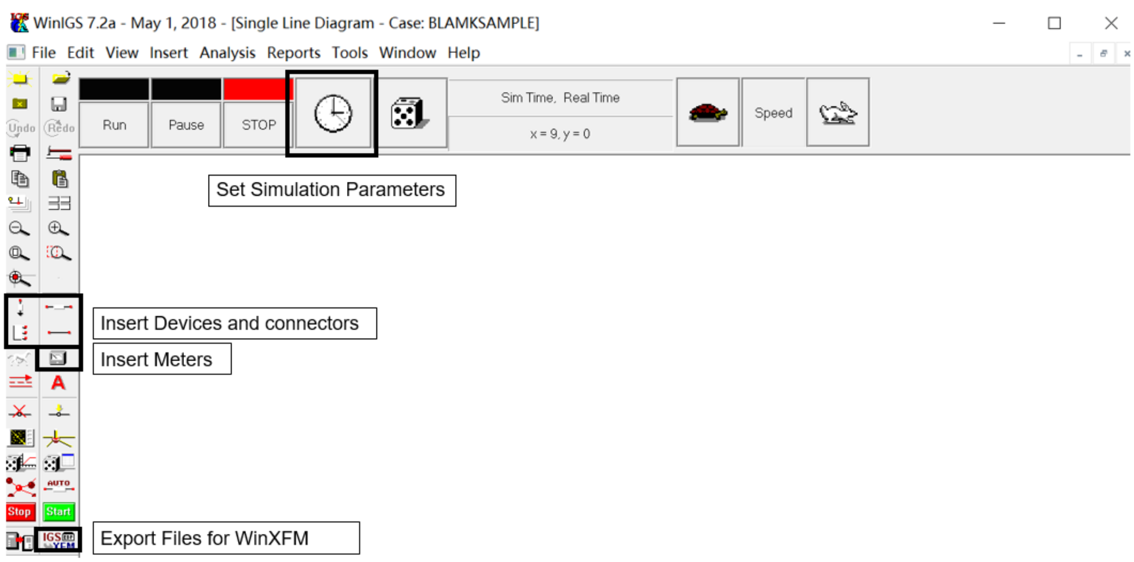


Figure B.5.1: User Interface of WinIGS to Build System Model

B.5.2 Creating Events and Storing in COMTRADE

After the system is established, the next step is to define and simulate events. The fault model is used to define and simulate faults in the system. The diagram for fault setting is shown in Figure B.5.3. We can set the conductance, time and location of the fault.

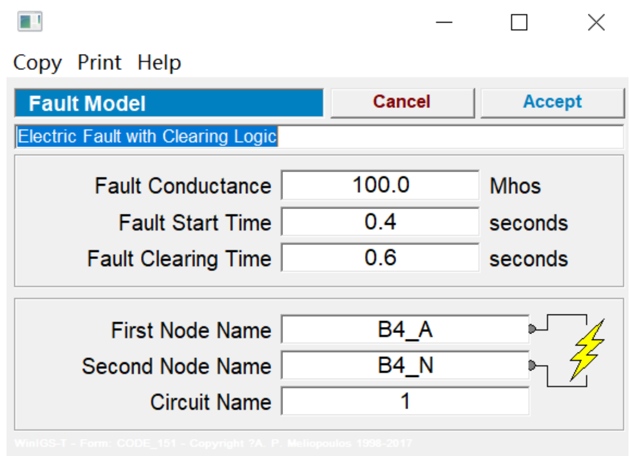


Figure B.5.2: Diagram for Fault Setting

The breaker model is used to connect and disconnect the distributed load along the distribution sections. The diagram for the setting is shown in Figure B.5.3. We can set the initial status, closing time and opening time of the breaker.

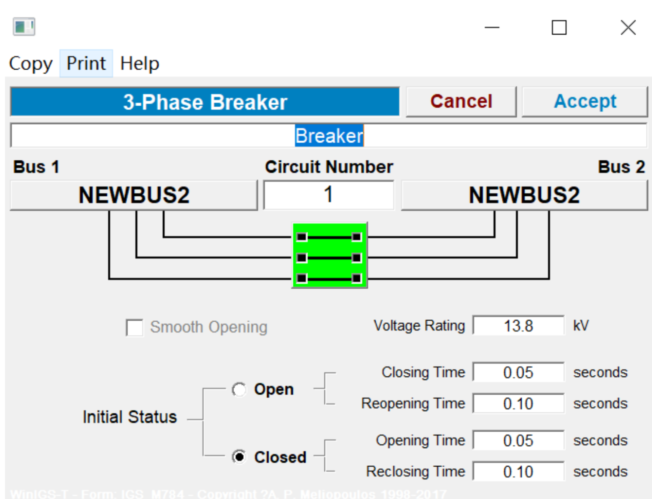


Figure B.5.3: Diagram for Breaker

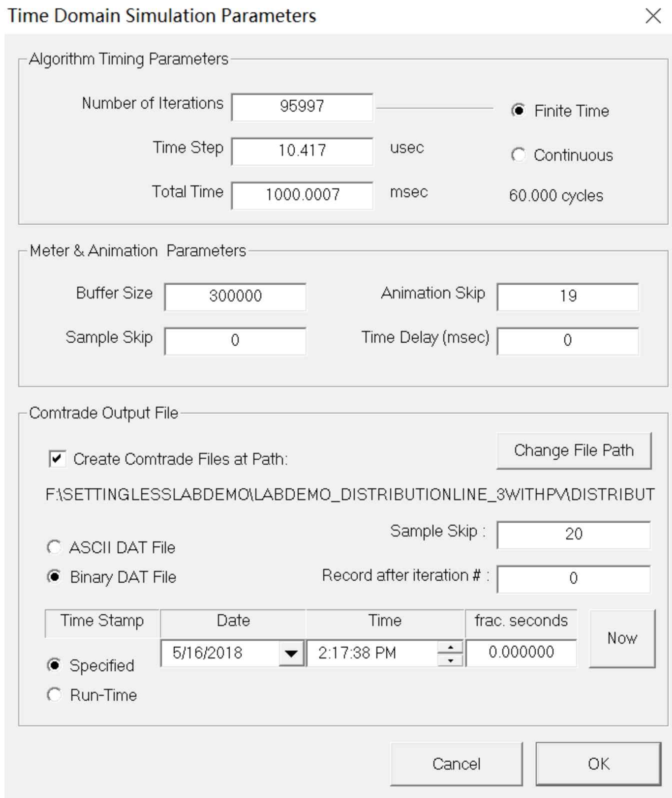


Figure B.5.4: Diagram for Fault Setting

Before running the simulation, it is necessary to set up simulation parameters properly. For the further application in WinXFM, the time step of the simulation is selected to match the standard merging unit sampling rate. Figure B.5.4 shows the time domain simulation parameters dialog where the simulation time step, duration, as well as the COMTRADE output is specified. If the standard merging unit sampling rate is at 80 samples per cycle for a 60 Hz system, the time step is selected as:

$$\Delta t = 1{,}000{,}000 \,/\, (\, 60 \times 80\,) = 208.333 \text{ microseconds.}$$

B.6 Dynamic State Estimation Algorithm

The quasi-dynamic state estimation algorithm is applied on the formulated network measurement model and provides the best estimate of the network model at each time step by applying weighted least square method. The optimization problem is expressed to minimize the sum of the residual squares between measurements and estimated measurements as follows:

$$Minimize \quad J = \left(h\left(\mathbf{x},\mathbf{u}\right)-\mathbf{z}\right)^T W\left(h\left(\mathbf{x},\mathbf{u}\right)-\mathbf{z}\right)$$

where ***W*** is the weight matrix with the weights defined as the inverse of the squared standard deviation δ_1 for each measurement:

$$W = diag\left\{1/\delta_1^2, 1/\delta_2^2, ..., 1/\delta_n^2\right\}.$$

Then we substitute the control vector **u** in *h*(**x,u)** with actual values from DMS, yielding *h(**x**)*. The unknown state vector **x** is obtained by the optimal condition:

$$dJ/d\mathbf{x} = 0$$

To obtain the solution of the nonlinear optimization problem above, we linearize the nonlinear equations by assuming an initial guess $\mathbf{x}^n$, and the residual between the measurements and the linearized measurement model is:

$$\mathbf{r} = h\left(\mathbf{x^n}\right)+H\left(\mathbf{x^n}\right)\left(\mathbf{x}-\mathbf{x^n}\right)-\mathbf{z} = H\left(\mathbf{x^n}\right)\mathbf{x}-\mathbf{z'}$$

where $\boldsymbol{z}' = -h(\boldsymbol{x}^{\boldsymbol{n}}) + H(\boldsymbol{x}^{\boldsymbol{n}})\boldsymbol{x}^{\boldsymbol{n}} + \boldsymbol{z}$ and is computable for each iteration;

$H(\boldsymbol{x}^{\boldsymbol{n}})$ is the Jacobian matrix of $h(\boldsymbol{x})$ at $\boldsymbol{x}^{\boldsymbol{n}}$, and it is denoted as H for simplicity in the following paragraphs.

Now the objective function is in a linear form:

$$Minimize \quad J = \left(H\mathbf{x}-\mathbf{z}'\right)^T W\left(H\mathbf{x}-\mathbf{z}'\right)$$

where the optimal solution is obtained when $\frac{dJ}{dx} = 0$. Therefore, the solution is achieved by the iterative equation:

$$\mathbf{x^{n+1}} = (H^T WH)^{-1} H^T W\mathbf{z'} = \mathbf{x^n} - (H^T WH)^{-1} H^T W(\mathbf{h}\left(\mathbf{x^n}\right)-\mathbf{z})$$

Notice that the algorithm performs state estimation using two consecutive measurements (time t and tm). In addition, the past history terms x(t-h) and i(t-h) are updated by x(t) and i(t) at each time step.

After the solution is obtained, the parameterized chi-square test is performed immediately. The chi-square test is a mathematical method to check the consistency between the measurements and the network model. The goodness of fit between the model and the measurements is quantified by:

$$\xi = \sum_{i=1}^{n}\left(\frac{h_i(x) - z_i}{k\delta_i}\right)^2$$

where set the standard deviation of each measurement equal to the accuracy of the measurement error times k. In the following test, we set k=10. The confidence level is then obtained through the probability function. A high value (e.g., 100%) indicates the measurements matching the system model, and the estimated states and measurements are trustworthy. A low value (e.g., 0%) implies the occurrence of some bad data or hidden failures in the system.

B.7 Testing Procedure for an EBP Relay

This section presents the testing procedure for the EBP relay for the use case and events described in Section 3. The EBP relay has been implemented within the WinXFM Program. The user interface of the EBP program is illustrated in Figure B.7.1.

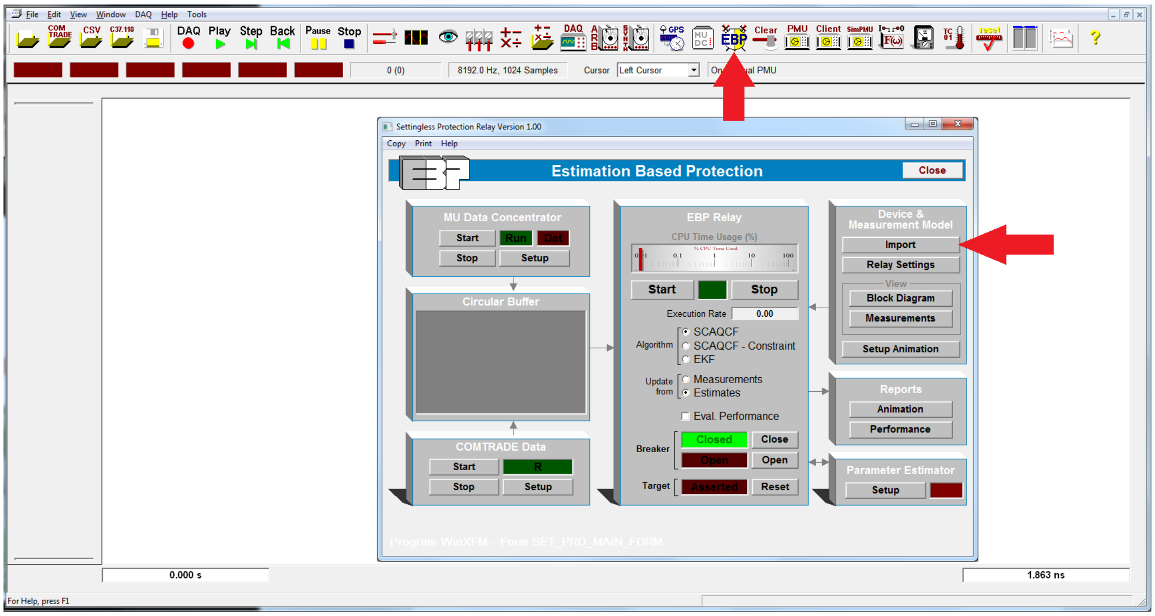


Figure B.7.1: The EBP Main Setup Form in the WinXFM Program

To run the EBP relay using the event data, execute the WinXFM program and open the WinXFM file. It is recommended to save the WinXFM file before import the protection zone model and events.

The "*Device and Measurement File*" dialog is shown in Figure B.7.2. The model domain and model kind are selected as "**Time Domain**" and "**Algebraic Companion Form**". The created measurement definition file and device model file are selected to be imported. Two files are The selected protection zone devices will be listed and the active column will be checked after the files are successfully imported.

The simulated events are imported through the COMTRADE Data Playback dialog (shown in Figure B.7.3). The **COMTRADE File Name** field indicates the Event that has been selected. The following rate are set for the program:

- Playback rate is set at **4800** samples per second for 60 Hz systems.
- Speed Factor radio button is selected and the speed factor is set to 5.0.

The speed factor option allows the relay response to be observed in slow motion. Otherwise, if you select the real-time option, the playback will occur in real time and the whole process will be completed in a shout time, i.e., the duration of the waveform data stored in the COMTRADE file.

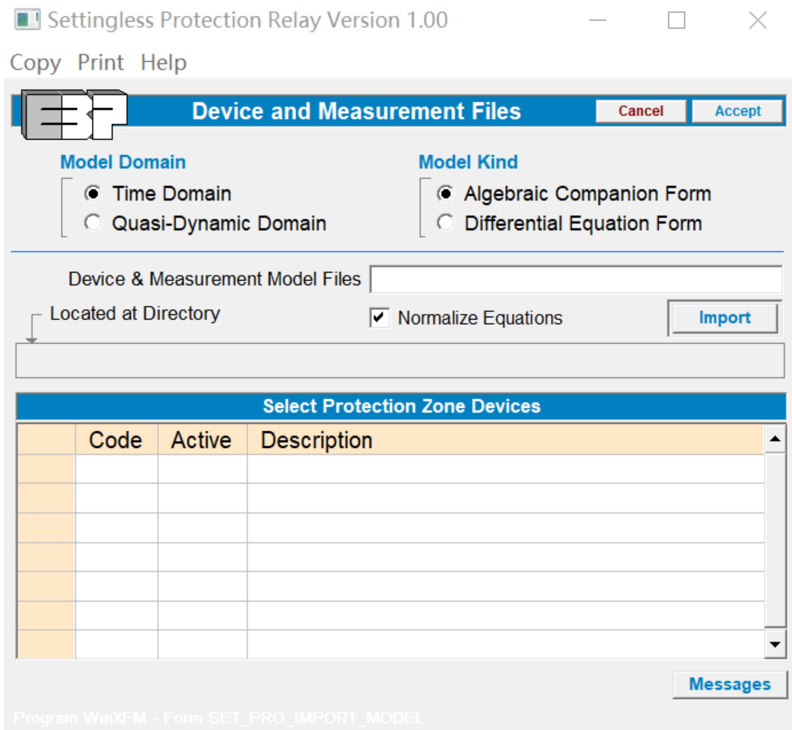


Figure B.7.2: Importing Zone 1 Device and Measurement Definition Files

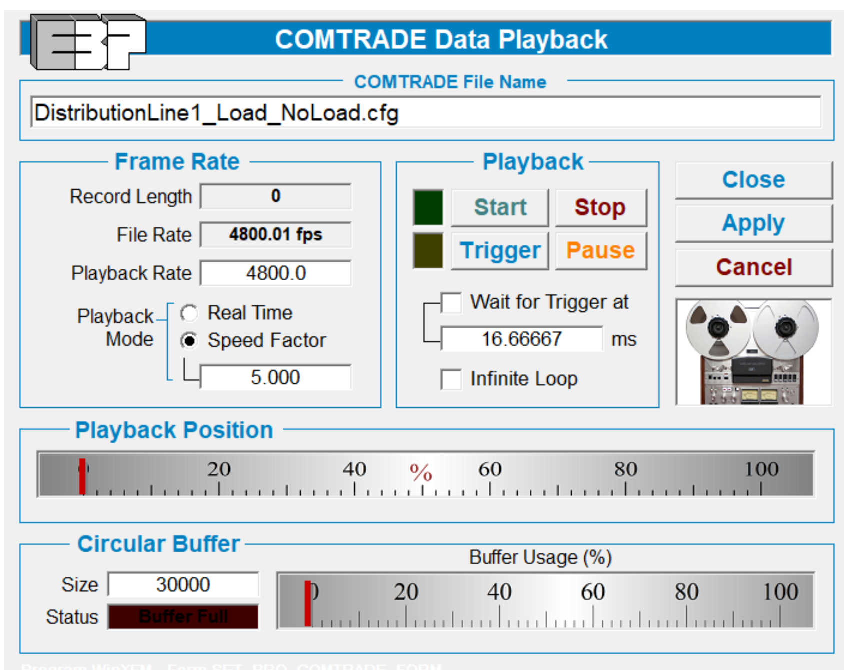


Figure B.7.3: Selecting the COMTRADE data files for Playback

After the event and the model are imported, the system is ready to execute the EBP relay using the Event data.

The relay setting diagram is shown in Figure B.7.4. The EBP results are shown in Figure B.7.5. If the confidence level is less than 0.1 for N (here set to 2) consecutive estimations when running the event, the button for targets in Figure B.7.5 will become red. Two parameters (reset time Tr and delay time Td) are used to determine when the relay will trip for the fault. Averaged confidence level to Trip the Relay calculated by $1\text{-}T_d/T_r$. In other words, the relay will trip if the averaged confidence level is lower than $(1\text{-}T_d/T_r)$ for T_r time.

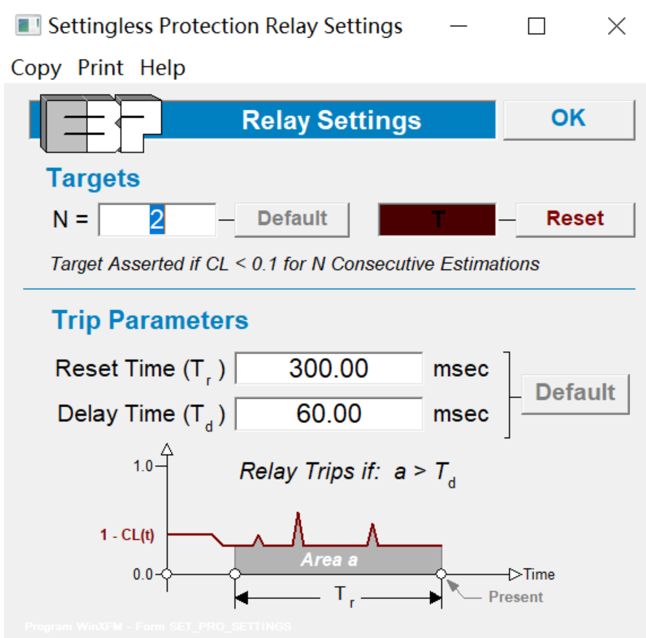


Figure B.7.4: Relay Setting Diagram

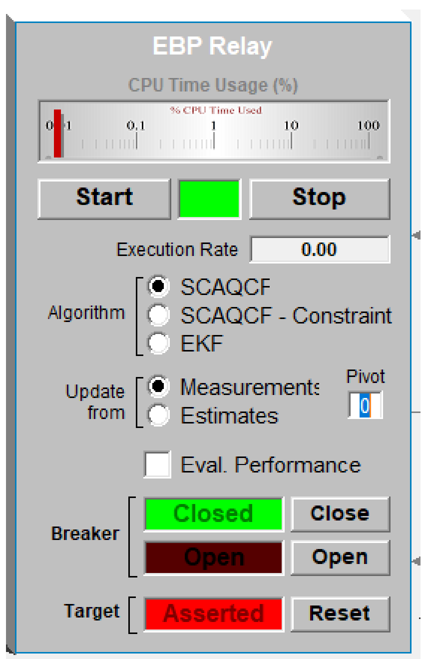


Figure B.7.5: EBP Relay User Interface