



# New Implications of Power System Fault Current Limits

*Final Project Report*

**Power Systems Engineering Research Center**

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# Power Systems Engineering Research Center

## **New Implications of Power System Fault Current Limits**

### **Final Project Report**

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## **Power Systems Engineering Research Center**

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## Executive Summary

Fault current analysis is receiving renewed attention in electric power systems. Traditionally, fault current analysis has been used to determine circuit breaker ratings, protective relay settings (and possibly configurations), and safety factors in electrical installations. Increasingly power system operators and planners are realizing that fault current analysis needs to play a broader role in operating practices, and in planning policies and decisions. For example, maximum fault current levels may constrain operations and impose limits on generation siting. Also, new ways of operating power systems and new installed generation sources are changing the fault response of power systems in unanticipated or unappreciated ways. In part, these changes may have been brought about by market forces in power systems that resulted in greater reliance on interconnections for power transactions. But at the distribution level, it is the entry of new generation sources, such as co-generation, distributed generation, and unconventional generation (such as electronically-controlled fuel cells and wind generators) that has motivated reexamination of the purposes and tools of fault current analysis.

This project has explored (1) how fault currents in distribution systems are being affected by new generation sources; (2) new tools for fault analysis; and (3) implications of increased fault currents on protection systems. In particular, the research focused on:

- Changes in maximum fault currents due to new and alternative generation siting
- Online assessment of fault current
- Security-constrained optimal power flow studies with fault current as a constraint
- Interruption of maximum circuit currents
- Three-phase analysis
- Effects of new fault current levels on circuit breaker topology and on operating limits.

To study fault currents in distribution systems with new generation sources, a model and control strategy was developed for inverter-based distributed generators. This is the first published engineering model of an inverter for distributed generation applications. The model enabled fault current studies for this project. More generally, the model shows the direction for future fault current simulations to examine new technical questions. The model is fully specified in this report and is implemented with research grade Simulink software (suitable for inclusion in a Matlab analysis of a subtransmission or primary distribution system with distributed generators).

Two different controllers were modeled: an amplitude controller and an angle difference controller. The controllers were designed in an average power control configuration. In both controllers, the well-known  $dq0$  reference frame was applied to calculate the phase angle of the output voltage and current. The input is the power system frequency. The design allows the inverter to obtain low frequency control signals and the implementation allows for fast computation for the simulations.

The inverter-based distributed generator model was used to conduct various assessments of the effects on fault currents in a distribution system as distributed generation is added. Research findings reinforce intuition about what those effects would be.

- Installation of distributed generation increased fault currents throughout the distribution system. Simulation results illustrate quantitatively that protective relays may react differently to faults when the protection system is designed without considering distributed generation. Simulations also show that changes may be needed in settings of circuit breakers, fuses and relays to meet protection standards. The research makes a contribution to fault current analysis techniques by introducing a new method for calculating these fault current changes due to distributed generation; illustrations of new method are provided for a test system.
- Fault currents increased more in a system with added synchronous machine distributed generators than in a system with added inverter-based distributed generators. The lower effect of inverter-based technologies is due to the electronic control used in inverter designs. Simulations over a range of distributed generation penetration levels showed that the increase in fault currents was sufficient to cause concern about protection and safety for system design that did not consider distributed generation.
- In some cases, protection systems lost coordination upon installation of distributed generators in the test system. This occurred because the time response of inverter controls, and the way power is adjusted in inverter controls is different from conventional synchronous generators. For these analyses, research grade software for protective relay coordination was developed. The software has an innovative graphic capability that allows users to study the evolution in time of the resistance and reactance ‘seen’ by protective relays. Resistance-reactance-time graphics are illustrated for a range of distributed generator penetration levels and for different types of generation controls.
- Unit commitment policies needed to address fault current constraints to avoid circuit breaker failures and safety hazards. A technique was developed and implemented in research grade software to conduct unit commitment with fault current constraints after installing distributed generation.
- To ensure the fault current seen by breakers not exceed their interruption capability, some substation topology/breaker states should be avoided. The effects of substation topology on fault currents are demonstrated for a test system.
- In practical operation, online fault current assessment is necessary to help operators avoid substation operation modes limited by fault current interruption capability.
- Since installation of distributed generation imposes new distribution system costs due to increased fault currents, a method was developed and demonstrated to assign costs of required upgrades to distributed generation installations.

Potential new research areas include (1) design of standardized distributed generation controls; (2) economic efficiency analysis of distribution systems with distributed generation; (3) development of a practical method for unit commitment for systems with a large number of distributed generators; (4) development of production grade software for sub-transmission and distribution system fault analysis for systems with distributed generation; and (5) a verified, production grade, graphic user interface software package for protective relay coordination.

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## Nomenclature

|               |                                                                    |
|---------------|--------------------------------------------------------------------|
| AC            | Alternating current                                                |
| ACF           | Average change of fault current                                    |
| $ACF_{(bus)}$ | Bus ACF                                                            |
| ANSI          | American National Standards Institute                              |
| AVR           | Automatic voltage regulator                                        |
| BTU           | British thermal unit, a unit of energy                             |
| CAAA          | Clean air act amendments                                           |
| CB            | Circuit breaker                                                    |
| CHP           | Combined heat and power                                            |
| CIGRE         | International Council on Large Electricity Systems                 |
| DC            | Direct current                                                     |
| DG            | Distributed generation                                             |
| $DG_{imp}$    | Impedance of distributed generator                                 |
| DOE           | Department of Energy                                               |
| DR            | Distributed resource                                               |
| $E$           | Pre-fault voltage                                                  |
| $E(.)$        | Expected value                                                     |
| EA            | Evolutionary algorithm                                             |
| ECED          | Environmentally constrained economic dispatch                      |
| ED            | Economic dispatch                                                  |
| EIC           | Equal incremental cost (rule, or method)                           |
| EMI           | Electromagnetic interference                                       |
| EP            | Evolutionary programming                                           |
| EPRI          | Electric Power Research Institute                                  |
| EPS           | Electric power system                                              |
| ES            | Evolutionary strategy                                              |
| $E/X$         | Ratio of system voltage and equivalent reactance                   |
| $f_j$         | Function applied in the least squares estimator                    |
| $F$           | Relationship matrix, process matrix                                |
| $F^+$         | Pseudoinverse of the relationship or process matrix                |
| FCL           | Fault current limiter                                              |
| GA            | Genetic algorithm                                                  |
| GP            | Genetic programming                                                |
| HGA           | Hierarchical genetic algorithm                                     |
| $i$           | An arbitrary counter or index, current                             |
| IC            | Current interrupting capability                                    |
| IEC           | International Electrotechnical Commission                          |
| IPP           | Independent power producer                                         |
| $I_{fj}$      | Fault current at bus $j$                                           |
| $I_{f,n}$     | Fault current at bus $n$ before installing new DG                  |
| $I_{DG,n}$    | Fault current at bus $n$ after installing new DGs                  |
| $I_p$         | Injected current at bus $p$                                        |
| $j$           | Complex number $\sqrt{-1}$ , an arbitrary integer counter or index |
| $k$           | Order of the function applied in the least squares estimator       |

## Nomenclature (continued)

|                     |                                                                    |
|---------------------|--------------------------------------------------------------------|
| $\ell_{qr}$         | Primitive line impedance from bus $q$ to bus $r$                   |
| $m$                 | Number of the bus with DG                                          |
| $m$                 | Diagonal matrix of repair rates                                    |
| MBTU                | Millions of BTUs                                                   |
| MM                  | Minimum melting time of a fuse                                     |
| MTG                 | Microturbine generators                                            |
| MCFC                | Molten carbonate fuel cells                                        |
| $n$                 | Number of all historical data                                      |
| $nDG$               | Number of bus with DGs                                             |
| $nbus$              | Total buses in the system                                          |
| NUG                 | Non-utility generator                                              |
| OC                  | Operating cost                                                     |
| OPF                 | Optimal power flow                                                 |
| $p$                 | Number of the coefficient of the least squares estimator           |
| $p$                 | Vector of operational state probabilities of a circuit breaker     |
| PAFC                | Phosphoric acid fuel cells                                         |
| PCC                 | Point of common coupling                                           |
| PEM                 | Proton exchange membrane                                           |
| $P_{DG}$            | Critical power rating of distributed generation                    |
| $Pr(.)$             | Probability of ...                                                 |
| PV                  | Photovoltaic                                                       |
| $q$                 | Number of the historical data (cases)                              |
| $q$                 | Vector of non-operational state probabilities of a circuit breaker |
| $Q_i$               | reactive power generated by DG at bus $i$                          |
| $r$                 | Residual of the least squares estimator                            |
| $R_t$               | spinning reserve at time period $t$                                |
| $R_{xy}$            | Covariance of two variables, $x$ and $y$                           |
| RRRV                | Rate of rise recovery voltage                                      |
| RTS                 | Reliability test system                                            |
| $S_{cost}$          | Transition cost                                                    |
| SFCL                | Superconductor fault current limiter                               |
| SOFC                | Solid oxide fuel cell                                              |
| $SS_{Res}$          | Residual or error sum of squares                                   |
| SRP                 | Salt River Project                                                 |
| $t_{\alpha/2, n-p}$ | Threshold value from Student's $t$ -distribution                   |
| $Ton_i$             | The minimum up time for unit $i$                                   |
| $Toff_i$            | The minimum down time for unit $i$                                 |
| $T_s$               | Simulation time step                                               |
| TC                  | Total clearing time of fuse                                        |
| THD <sub>I</sub>    | Current total harmonic distortion                                  |
| THD <sub>V</sub>    | Voltage harmonic distortion                                        |
| $U_{it}$            | Status of unit $i$ at time period $t$                              |

## Nomenclature (continued)

|                                   |                                                                                 |
|-----------------------------------|---------------------------------------------------------------------------------|
| $UC$                              | Unit commitment                                                                 |
| $UF$                              | Fraction of the total cost paid by utility company                              |
| $V_i^0$                           | Voltage at bus $i$ before installing DG                                         |
| $V_f$                             | Pre-fault voltage                                                               |
| $V_j$                             | Voltage at bus $j$ during fault                                                 |
| $V_{abc}$                         | Line-neutral voltage in $abc$ variable                                          |
| $V_{dq0}$                         | Line-neutral voltage in $dq0$ reference frame                                   |
| $v_{an}(t), v_{bn}(t), v_{cn}(t)$ | Line to neutral voltage in time domain variables                                |
| $V_f$                             | Pre-fault voltage                                                               |
| $V_j$                             | Voltage at bus $j$ during fault                                                 |
| $w$                               | Coefficient vector                                                              |
| $\hat{w}$                         | Estimate value of $w$                                                           |
| $X_0$                             | Zero sequence equivalent reactance of the system                                |
| $X_1$                             | Positive sequence equivalent reactance of the system                            |
| $X$                               | System reactance                                                                |
| $X, \bar{X}$                      | Component $X$ in available / unavailable state                                  |
| $X_d, X_q$                        | Synchronous reactance                                                           |
| $X_d', X_q'$                      | Transient reactance                                                             |
| $X_d'', X_q''$                    | Subtransient reactance                                                          |
| $X/R$                             | Ratio of system equivalent reactance to system equivalent resistance            |
| $y$                               | Output vector of the least square estimation technique                          |
| $Z_{bus}$                         | Bus impedance matrix                                                            |
| $Z_{bus}^+$                       | Positive sequence bus impedance matrix                                          |
| $Z_{bus}^-$                       | Negative sequence bus impedance matrix                                          |
| $Z_{bus}^0$                       | Zero sequence bus impedance matrix                                              |
| $z_{gen}$                         | Generator transient impedance                                                   |
| $z_{DG,\ell}^{(b)}$               | Transient impedance of DG at bus $\ell$ case $b$                                |
| $Z_{orig}$                        | Bus impedance matrix of original system                                         |
| $z_f$                             | Fault impedance                                                                 |
| $Z_{ij,orig}$                     | Diagonal element of bus impedance matrix of the system before installing new DG |
| $Z_{ij,new}$                      | Diagonal element of bus impedance matrix of the system after installing new DG  |
| $Z_{orig}$                        | Bus impedance matrix of original system                                         |
| $z_f$                             | Fault impedance                                                                 |
| $Z_{ij,orig}$                     | Diagonal element of bus impedance matrix of the system before installing new DG |
| $Z_{ij,new}$                      | Diagonal element of bus impedance matrix of the system after installing new DG  |
| $Z_L$                             | Load impedance                                                                  |
| $Z_s$                             | Equivalent impedance of the source side                                         |

## Nomenclature (continued)

|                    |                                                   |
|--------------------|---------------------------------------------------|
| $\Delta I_f $      | Change of fault current due to installing new DGs |
| $\Delta V $        | Change in voltage                                 |
| $\sigma_r^2$       | Variance of residual                              |
| $\hat{\sigma}_r^2$ | Estimation of variance of residual                |
| $\delta_{diff}$    | Difference of phase angle between $V_1$ and $V_2$ |
| $\lambda$          | Failure rate                                      |
| $\Lambda$          | Diagonal matrix of failure rates                  |
| $\mu_x$            | Mean value of $x$                                 |
| $\mu$              | Repair rates                                      |
| $\{\Omega\}$       | Off line analyzed cases                           |

# 1 Fault Currents in Systems with Distributed Generation

---

## 1.1 Background and motivation

Fault currents in power systems determine the ratings of circuit breakers, settings (and possibly configurations) of protective relays, and safety of electrical installations. Once the circuit breakers are in place, relay configurations have been implemented, and the system is designed to be safe for the projected fault currents, there may be some operating and planning implications imposed by maximum fault currents. That is, the fault currents may limit certain operating conditions. There may also be new limits imposed on planning and distributed generation siting. The deregulation of power systems has resulted in increased reliance on interconnections, new nonutility generation, and power transactions. There may be new operating conditions, not seen before, that are limited by fault interruption capability. The appearance of co-generation, distributed generation, and unconventional generation (controlled electronically, for example, in a fuel cell) may also result in change fault response in the system.

## 1.2 Project research objectives

The project research objectives are organized into eight areas:

*Implications of new and alternative generation siting:* Included in the project is the assessment of the ability of the system to handle the increased fault currents due to "merchant plants". Questions such as breaker capability to interrupt fault currents under the worst conditions (e.g., utilization of search algorithms to identify worst conditions) and questions regarding the safety of electrical installations under increased fault currents shall be considered. The appearance of generation in the system that is not controlled as easily as existing units (e.g., IPP owned generation, customer owned distributed generation) may result in changed fault current and changed paths of those currents. There may be limits imposed by existing breakers and protective relay configurations. Non-utility and customer owned generation siting, and the controls of such generation, are an important part of this study. Electronic controllers on alternative generation sources (e.g., fuel cells) should be studied.

*Online assessment of fault current:* There may be a means for the accurate identification of system wide fault currents (or localized fault currents) from system wide (or local) operating data. That is, voltage magnitude changes versus load may give online fault current information much in the same way as state estimation is used to identify voltages, phase angles, and currents. The configuration of such an estimator, and its accuracy in real time should be studied.

*Security constrained OPF with fault current as a limitation:* There may be circumstances in which a security constrained OPF needs to include constraints imposed by fault currents. Distributed and alternative generation may impact these constraints.

*Maximum circuit current interruption:* It is important to identify the maximum levels of fault current that can be interrupted. Present breaker technology imposes an upper bound on the fault current that can be interrupted. In cases that this capability is exceeded, alternate means such as fault limiting technology can be utilized.

*Three phase implications:* The implications of unbalanced faults on circuit operating limits should be studied.

*Topology of circuit breaker connections and their implications on operating limitations:* The implications of the existing configuration of circuit breakers (e.g., in a breaker-and-a-half scheme in a switchyard) on fault current paths needs to be studied. Note that a change of circuit breaker status in the system has fault current implications that must be considered.

*Safety:* Assessing the impact on safety from increased fault currents.

*Solutions:* The use of current limiting devices and algorithms to identify needs and optimal placement of these devices. As the fault currents increase due to system expansion and merchant plants, it may be economically prohibitive to upgrade the entire system. Identification of optimal locations where fault current limiters can be sited may be a practical solution.

### 1.3 Research team

The project research team is listed in Table 1.1.

**Table 1.1 Project research team**

| <i>Researcher</i>     | <i>Location</i>             | <i>Title</i>                |
|-----------------------|-----------------------------|-----------------------------|
| A. Bose               | Washington State University | Dean                        |
| G. Heydt              | Arizona State University    | Regents' Professor          |
| A. P. S. Meliopoulos  | Georgia Tech                | Professor                   |
| Natthaphob Nimpitiwan | Arizona State University    | Graduate research assistant |
| Yang Zhang            | Washington State University | Graduate research assistant |

## **1.4 Potential benefits**

The potential project benefits are:

- Permits system operation at high power levels without compromising fault interruption capability. The system operation is optimized considering the limits imposed by fault currents of new generation sources.
- Identifies system location at which improved fault current interruption is needed.
- Identifies protective relaying settings that are inappropriate for new operating environments.

The expected project outcome is an algorithm for the identification of operating limits imposed by system fault current interruption capability. The algorithm shall be suitable for the preparation of demonstration (prototype) software for operating condition assessment and constrained security dispatch.

## **1.5 Technical approach**

There are four basic areas which form the technical base of this project. They are:

- The modeling of generation alternative sources
- AC fault analysis
- The identification of operating conditions and hardware
- Modification of standard OPF algorithms to accommodate fault current limitations.

In the area of modeling of alternative sources, the main types of generation sources shall be identified, and models of these sources shall be taken from the literature. In the case of DC/AC converters (as in the case of fuel cells), basic research shall be done to obtain the fault current characteristics. The approach taken is basic circuit analysis with verification using PSpice. In the area of fault current analysis, well known methods of fault analysis using the bus impedance matrix. The three phase case shall be modeled as needed using the three phase impedance matrix. Sparse matrix inversion shall be used. The topology of substations shall be used to determine the current flow paths.

Standard fault studies have been used for many years to design substations and specify circuit breaker fault current ratings. The possibility of adding third-party generators in unanticipated portions of the network may require the modification of existing substation topology and hence redesign of the substation. In this project, this problem will be approached in a three-tiered process:

1. A method will be developed to study the various scenarios of third-party generators (their locations, sizes, etc.) and their effect on fault current duties. The objective will be to identify the minimum changes needed to substations for a particular generator scenario.
2. A method will be developed for the redesign of a substation that has already been identified as one needing changes due to the addition of new generation. The objective here will be to minimize the change-over of existing equipment and stay within the limitations of available circuit breaker fault limits. A significant increase in fault duties has many impacts on equipment and lay-out other than circuit breakers.
3. A method will be developed to augment the online security analysis package to check for fault current violations. The main objective here is to add a fault analysis module to the contingency analysis software. For online analysis, the main variable that affects fault currents is the topology and the module needs to be designed to identify topology changes that require the triggering of this analysis.

In the area of operating conditions, the resources of PSERC and our sponsors shall be used to determine the important cases to be considered. The influence of the operating conditions on fault current shall be determined. Also using PSerc resources, the latest circuit breaker limitations shall be documented. The crux of the problem is the integration of all the results into a security constrained OPF. The general concept is the Lagrangian formulation in which the Lagrangian function is augmented with a term that contains the fault limitations. The Kuhn-Tucker method may be used to accommodate inequality constraints. The possibility of the use of genetic algorithms and other ladder-like logic structures to accommodate inequality constraints shall be investigated.

## **1.6 Related work**

Fault current calculation is traditionally done using impedance methods. The essence of the concept is the use of the system  $Z_{bus}$  matrix to find the fault current at system buses. Researchers have examined the flow of fault current including the impact of circuit breaker placement topologies on this flow. Most of the classical work in fault current calculation was done in the 1940 - 1960 time frame.

Also related is the work on security constrained OPF. The method is an optimization method in which additional constraints are used – usually included in the Lagrangian of the problem. Although this proposal is similar to the security constrained OPF, this proposed research is for the inclusion of fault currents as limits to the OPF – this has never been done.

Classical fault current calculation has not included the effects of merchant plants (e.g., IPPs). New developments in deregulation have brought new generation sources to the system. Independent power producers and increased interconnection to utilize power

from interchanges are new factors in fault current calculation. The appearance of distributed generation is also a source of fault current that has not previously been envisioned.

## 1.7 Reports of work from this project

Table 1.2 shows a listing of technical papers and other reports that were prepared for this project.

**Table 1.2 Technical papers and reports prepared for this project**

| Paper                                                                                                                                    | Citation                                                                                                             | Comments                                                                      |
|------------------------------------------------------------------------------------------------------------------------------------------|----------------------------------------------------------------------------------------------------------------------|-------------------------------------------------------------------------------|
| N. Nimpitiwan, G. T. Heydt, "Consequences of Fault Currents Contributed by Distributed Generation"                                       | Intermediate report for project S-20<br>PSERC Publication 04-34                                                      | Available at <a href="http://www.pserc.org">www.pserc.org</a>                 |
| N. Nimpitiwan, G. T. Heydt, "Fault Current Issues for Market Driven Power Systems with Distributed Generation"                           | Proceedings of the North American Power Symposium, Moscow ID, October 2004, pp. 400 - 406<br>PSERC Publication 05-35 | Main results are included in this report                                      |
| N. Nimpitiwan G.T. Heydt, "Fault Current Allocation by the Least Squares Method"                                                         | EEE Power Engineering Society Letters - Paper PESL-00033-2005.R1 accepted 2005.<br>PSERC Publication 5-34            | Main results are included in this report; expected to appear in print in 2005 |
| Q. Binh Dam, A. P. Sakis Meliopoulos, Gerald T. Heydt, Anjan Bose, "IEEE A Breaker-Oriented, Three-Phase IEEE 24-Substation Test System" | Submitted to IEEE Transactions on Power Delivery, September 2005.                                                    | These two papers are contained almost entirely in Chapter 8 of this report    |
| Q. Binh Dam, A. P. Sakis Meliopoulos, "Elements for a Circuit Breaker Reliability Model"                                                 | Submitted to IEEE Transactions on Power Delivery, September 2005.                                                    |                                                                               |

## 1.8 Distributed generation

Deregulation, utility restructuring, technology evolution, environmental policies and increasing electric demand are stimuli for deploying new distributed generation (DG). According to the US Department of Energy (DOE), DG is defined as [1] "the modular electric generation or storage located near the point of use. Distributed generation systems include biomass-based generators, combustion turbines, thermal solar power and photo-

voltaic systems, fuel cells, wind turbines, microturbines, engines/generator sets and storage and control technologies. Distributed resources can either be grid connected or independent of the grid. Those connected to the grid are typically interfaced at the distribution system". According to the IEEE Standard 1547-2003, DG is defined as "Electric generation facilities connected to an area Electric Power System (EPS) operator through a Point of Common Coupling (PCC); a subset of Distributed Resource (DR)" [2]. Reduction of investment in transmission and distribution system upgrades and fast installation are the major benefits to the power utilities. Many applications, such as upgrading the reliability of the power supply, peak shaving, grid support and combined heat and power (CHP), are the major benefits to distributed generation owners.

However, the appearance of co-generation, DG, and unconventional generation may result in unwanted (and often unexpected) consequences. This report focuses on one such unwanted consequence: increased fault current. In this report, focus is given to operation during faulted conditions. Circuit breaker capability and configuration of protective relays that were previously designed for the system without DGs may not safely manage faults. There may be some operating and planning conditions that are imposed by the fault current interrupting capability of the existing circuit breakers and the protective relay configurations. These situations can result in the safety degradation of the electric power system. At present, there is a very low penetration of DG in the United States. However, many indicators imply that DG penetration is increasing. The cited fault current concerns are expected to occur at a significant level of DG penetration. Also, locally DG penetration could be high in some circumstances. The study in [3] shows that the significant penetration level of the Western Energy Coordinating Council (WECC) during the peak load in summer is between 10 – 20 percent. The identification and alleviation of degraded operation of power systems during fault conditions is the main objective of this work.

Assessment of the ability of power systems to manage the increase of fault currents due to DGs should be investigated. The assessment of fault can be separated to two types: assessment prior to DGs installation and online assessment.

#### *Assessment prior to DG installation*

Fault currents in power systems determine the ratings of the circuit interruption devices and the settings of power system protective relays. Once the circuit breakers are in place and relay settings have been implemented, there may be some operating and planning implications imposed by the changing fault current. Fault analysis should be done prior to the installation of a new DG. A protection system and associated circuit interruptions may need to be upgraded or replaced. A method for assigning the costs of upgrading to the customers that have installed DG should be developed. In some cases, entirely new protective relay settings and upgraded circuit breakers may be needed. This is a complicated issue which depends on the type of the customer, the size and the type of the DG equipment, and the operating intention of the DG system. All approaches to allocate the responsibility and the cost of these changes should be on the basis of simple and fair market for every customer and utility. The identification of what is fair and what is simple has not been done for the case of fault currents due to added DGs. These issues are

needed to guarantee safety and reliability of the system which should be covered by the owner of the DG.

### *Online assessment*

The main variables that affect the fault currents are the installation of DGs and the change of system topology. An online assessment of fault current should be developed to assure the safety operation of the system. The online assessment of fault may take the operating data from the supervisory control and data acquisition system (SCADA) and estimate the system wide fault currents. The estimation of fault current from the operating data may be used to estimate the fault current based on the statistical analysis. This online assessment may necessary to help the operator to avoid unsafe operating conditions.

## **1.9 Project objectives**

The main objective of this research is to establish an algorithm for the identification of operating limits imposed by system fault current interruption capability. Also, identify the locations and techniques which improve the fault interruption capability where the protection system needs to be upgraded. For this purpose, the technical approaches for these objectives are:

- Modeling of different types of DG
- AC fault analysis
- The identification of operating conditions and hardware
- Analyze the economic impact on the increasing of fault current
- Online assessment of fault current.

## **1.10 Literature review: an overview**

The subsequent three sections, a brief overview of pertinent literature is given. The overview is organized into three parts:

### Distributed generation

- Distributed generation
- Non-utility generators
- Installing DG
- Impact of DGs on fault current and system protection

### Application standards

- The IEEE Standard 1547
- The IEEE Standard C37.04-1999

### System considerations

- Online assessment of fault current
- Economic impact on the installation of DGs.

### 1.11 Literature review: distributed generation

The size and type of DGs varies over a wide range and definitions and commonly encountered DGs depends on factors such as:

- DOE considers DG range from less than a kW to tens of MW [1T]
- The Electric Power Research Institute (EPRI) considers DGs from a few kW to 50 MW or energy storage devices sited near customer loads [4]
- Gas Research Institute considers DGs between 25 kW to 25 MW [5]
- The International Council on Large Electricity Systems (CIGRE) considers DGs as a generation unit that is not centrally planned, not centrally dispatched and smaller than 100 MW [6].

Since the 1990s, reciprocating engines and gas turbines have been rapidly placed into service. Perhaps this deployment is a result of problems in dealing with transmission issues, and problems in siting conventional generation – but, for whatever reason, protection engineers as well as transmission and distribution engineers have to increasingly deal with problems related to the added DG in the power systems. Reference [1] indicates that the standby DG application continues to grow at approximately 7% per year. Other DG applications, base load and peak load, are growing faster at 11% and 17%, respectively. The market size of these three sectors is about 5 GW in 2004. Figure 1.1 shows the applications for reciprocating engines and gas turbines (less than 20 MW).

The emergence of small and medium size DG arises from two major necessities: inadequacy of efficient power production (both economy and environment friendly) and requirement of high reliability from industrial or commercial customers with a very high value product. Table 1.3 shows approximate data for the cost of DGs per kW [7].

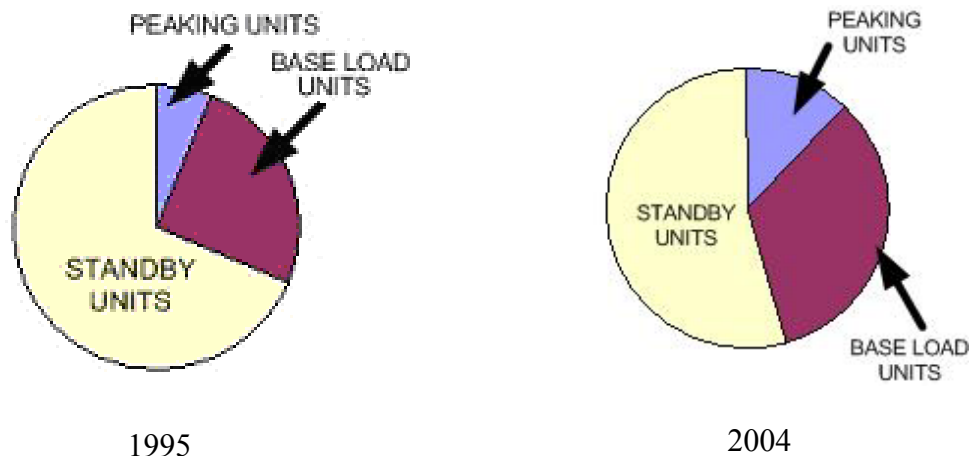


**Figure 1.1 Reciprocating engines and gas turbines less than 20 MW in 1995 and 2004**  
(data from [1])

Distributed generation can appear in different forms, both renewable and nonrenewable. Renewable technologies include fuel cells, wind turbine, solar cell, and geothermal. Non-renewable technologies include combined cycles, cogeneration, combustion turbine and microturbines. References [8, 9] made a brief discussion on DG technologies which are available in the market.

**Table 1.3 Approximate price of DG per kilowatt**

From [7,10]

| <i>Technology</i> | <i>Size Range (kW)</i> | <i>Approximate Cost (\$/kW)</i> |
|-------------------|------------------------|---------------------------------|
| Diesel engine     | 20 - 10,000            | 125 - 300                       |
| Turbine generator | 500 - 25,000           | 450 - 870                       |
| Wind turbine      | 10 - 1,000             | ~ 1,000                         |
| Microturbine      | 30 - 200               | 350 - 750                       |
| Fuel cell         | 50 - 2,000             | 1,500 - 3,000                   |
| Photovoltaic      | < 1 - 100              | ~ 3,000                         |

The theoretical basis of a fuel cell was explored by Sir William Grove in 1839 [9]. Grove discovered that water can be decomposed into hydrogen and oxygen by applying electric current, a process called “electrolysis”. As shown in Figure 1.2, the basic operation of fuel cell is the reverse of electrolysis – the hydrogen and oxygen recombine and electric current is the product of this reaction. There are many types of fuel cells which can be applied to industrial applications, especially CHP. Table 1.4 provides brief information on different types of fuel cells.

#### *Non-utility generators*

Increasing of non-utility generators (NUGs) rapidly increases consideration of effects of distributed generations to the grid. Statistics show that, the proportion of total capacity and DG capacity will grow up to 20 percent or approximately from 40 GW to more than 150 GW by the end of the decade [10].

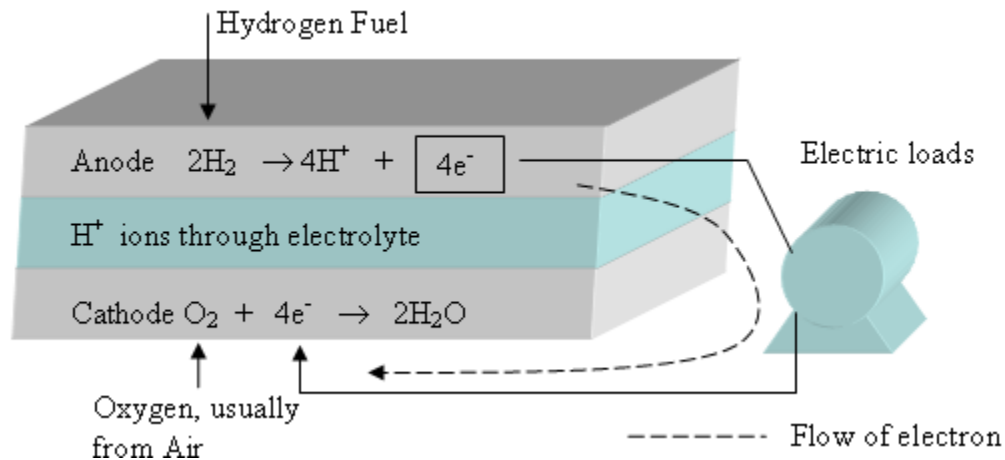


**Figure 1.2 Electrode reactions and charges flow for an acid electrolyte fuel cell**  
From [11]

A problem with electrolysis based technologies is inefficiency, mainly due to resistive heating (due to passage of current through water). There are other processes that have been suggested to produce hydrogen, but all have efficiency concerns.

Microturbine generators (MTGs) were originally developed for military to produce electricity. Normally, an MTG produces high frequency AC. For connecting the high frequency AC output to the grid system, it must be rectified to DC and then inverted to the power frequency. The major advantages of MTG are: ease of installation, simple siting/licensing, and lower capital requirements [9]. Disadvantages relate to the cost of the power electronics needed. In order to obtain high efficiency units, the waste heat from MTGs must be utilized.

**Table 1.4 Data for different type of fuel cells**  
From [11]

| <i>Fuel Cell Type</i>          | <i>Electrolyte</i>              | <i>Charge Carrier</i>         | <i>Operating Temperature</i> | <i>Fuel</i>                                              | <i>Efficiency</i> | <i>Power Range/ Application</i>   |
|--------------------------------|---------------------------------|-------------------------------|------------------------------|----------------------------------------------------------|-------------------|-----------------------------------|
| Proton Exchange Membrane (PEM) | Solid Polymer                   | H <sup>+</sup>                | 50-100 °C                    | Pure H <sub>2</sub>                                      | 35-45%            | 5-250 kW, Automotive or small CHP |
| Phosphoric acid (PAFC)         | Phosphoric acid                 | H <sup>+</sup>                | ~ 220 °C                     | Pure H <sub>2</sub>                                      | 40%               | 200 kW, CHP                       |
| Molten carbonate FC (MCFC)     | Lithium and potassium carbonate | CO <sub>3</sub> <sup>2-</sup> | ~650 °C                      | H <sub>2</sub> , CO, CH <sub>4</sub> , other hydrocarbon | >50%              | 200 kW - MW, CHP                  |
| Solid oxide FC (SOFC)          | Solid Oxide electrolyte         | O <sup>2-</sup>               | ~ 1000 °C                    | H <sub>2</sub> , CO, CH <sub>4</sub> , other hydrocarbon | >50%              | 2 kW - MW, CHP                    |

A photovoltaic (PV) system generates electricity by the direct conversion of the light energy into electricity. The key component of a PV is a solar cell which requires sophisticated semiconductor processing techniques to be manufactured. PV operation can be separated into two parts: conversion of solar energy to electric energy and grid connection system. Simulation of both parts is discussed in [11] using PSpice.

### *Installing DG*

Installing DG at a customer site enhances certain aspects of the power quality of the owners significantly by mitigating the voltage sag during a fault. Most faults on a power system are temporary, like arcing from overhead line to ground or between phase conductors. These temporary faults on a distribution system should be detected and cleared by protection relays and reclosers. During the period of the fault, the voltage in the distribution system drops. This phenomenon is called “voltage sag”. The magnitude of the sag

depends on the line impedance from substation to the fault location. Locally installed distributed generation at a customer site can provide voltage support during fault in the utility transmission system and improve the voltage sag performance. Moreover, DG improves the owner reliability markedly as a typical back up generator can be started up within 2 minutes. Gomez and Morcos in [12] propose a methodology for coordinating the ride through capability of sensitive equipment and overcurrent protection in the presence of DGs. The proposed methodology is accomplished by comparing the computer business equipment manufacturing association (CBEMA) curve of the sensitive equipment with the time/voltage characteristics of protective equipment.

Although there are many advantages of installing DGs, a few operating conflicts cannot be ignored. If there is a high penetration of DGs, the conventional utility supply may not be able to serve the load when the DGs drop off-line [13]. Installing a small or medium DG may not have a significant impact on the power quality indices at the feeder-level. The main reason for this observation is that IEEE Standard 1547 requires that the load be disconnected from the supply feeder after a specified period of time (a rather short time, measured in cycles). The DG, after the cited disconnection, will have no impact on the supply feeder. The DG has a local impact. That is, the local load may be served properly, but others on the common feeder will not experience improvement in voltage regulation.

Installation of DGs has been discussed in many research papers, such as those dealing with the reliability of the distribution system, coordination of protective devices, ferroresonance, frequency control, and consequences of increased fault current [14, 14, 15, 16].

#### *Impact of DGs on fault current and system protection*

Protection system planning is an indispensable part of an electric power system design. Analysis of fault level, pre-fault condition, and post-fault condition are required for the selection of interruption devices, protective relays, and their coordination. Systems must be able to withstand a certain limit of faults that also affects reliability indices. Many classical references are found on this topic, such as [17, 18, 19]. This research relates to a new aspect of fault analysis of power systems: the appearance of DG, perhaps at high levels of penetration, and the effect of DG on fault currents.

In general, addition of generation capacity causes fault currents to increase. The severity of increasing fault current in the system depends on many factors which are penetration level, impedance of DG, the use of Automatic Voltage Regulator (AVR), power system configuration, and the location of DG – approximately in that order. This is a simple consequence of the reduction of the Thevenin equivalent impedance seen at system buses when generation is added to the system. The theory and details of the fault current analysis are discussed in Chapter 3. The consequences of increased fault current from proliferation of distributed generation are briefly discussed as follows:

- *Change in coordination of protective devices:* Figure 1.3 shows a sample distribution system. This system is a primary distribution system that is offered as an example of a distribution system with three DGs. The system is purely radial, three-phase, 4160 V, and is served from a 69 kV subtransmission system at a substation. In the depicted

configuration, the protection system may lose coordination upon installation of a DG. This point is illustrated as follows: before installing distributed generation DG1, if a fault occurs at point 1, fuse A should operate before fuse B. This is due to the upstream fault on the sub-feeder. When DG1 is included on sub-feeder, the fault current flows from DG1 to fault point 1 and fuse B might open before fuse A if the difference between  $I_{FA}$  and  $I_{FB}$  is less than the margin shown in Figure 1.4. The difference between  $I_{FA}$  and  $I_{FB}$  is proportional to characteristics of DG1. Thus, these fuses lose coordination in the case of installed DG1 [16, 17].

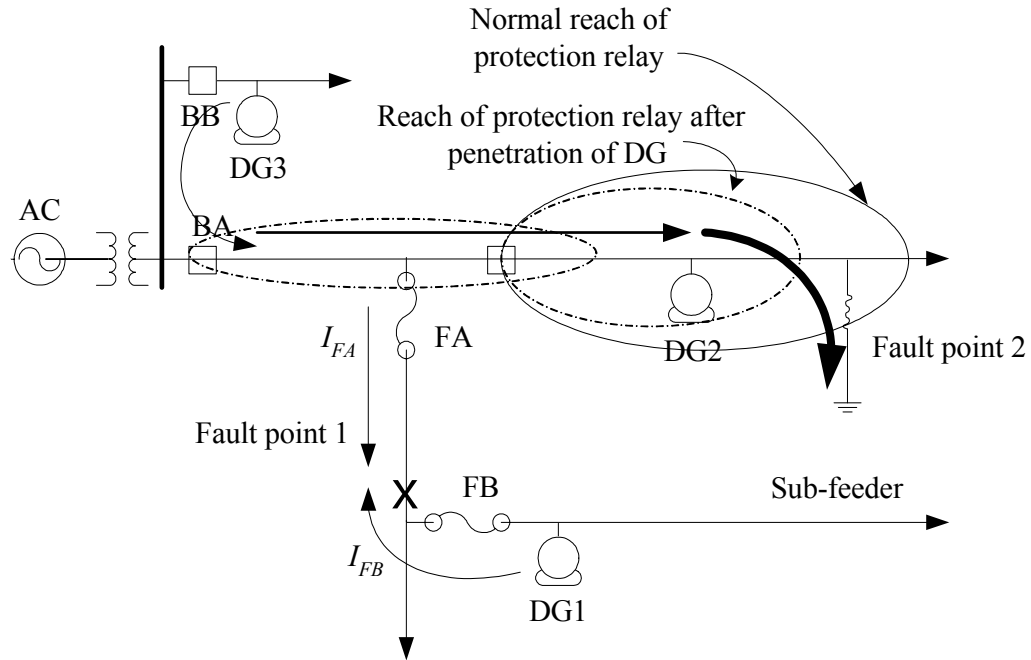


**Figure 1.3 The reach of a protective relay for a small sample distribution system with DGs**  
From Nimpitiwan [20]

- *Nuisance trip:* The increasing of fault current in the grid changes the way that protection system manages faults (relay settings, reclosers, interrupting capability of circuit breakers and fuses). Figure 1.3 shows a relatively large DG3 installed near the substation. In case a fault occurs on feeders other than where DG3 is located, breaker BB might also trip due to the fault current flowing from DG3 to the fault point. This problem can be solved by implementing a directional relay instead of an overcurrent relay. This is a total reconfiguration of the protective relaying.
- *Recloser settings:* Installing a DG on the feeder normally requires the utility to readjust their recloser settings. In general, a DG must detect the fault and disconnect from the system within the recloser interval and leave some durations to clear the fault. Failure to follow this step might cause a persistent fault rather than a temporary one. Reference [21] recommends a recloser interval of 1 second or more. The IEEE Stan-

standard 1547 [2] requires a much shorter time for recloser.

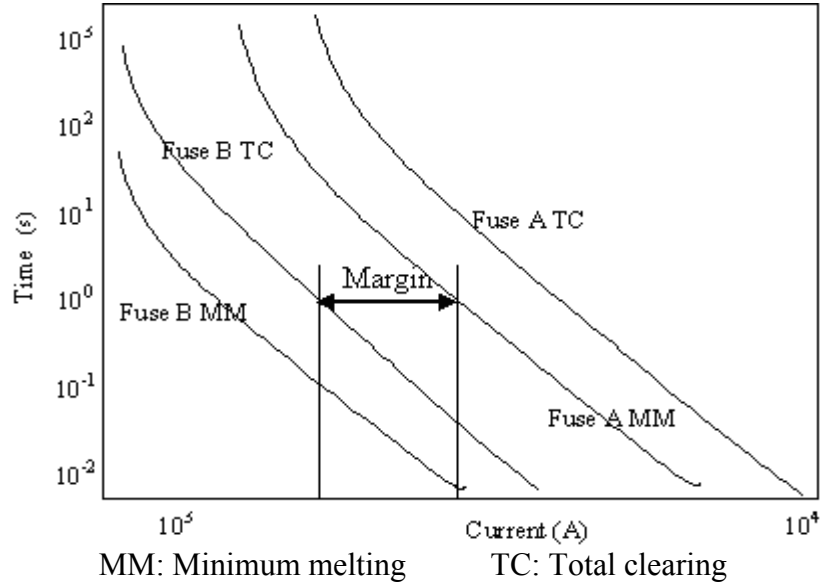


**Figure 1.4 Time-current characteristic of the fuse in the sample system of Figure 1.3**

From Nimpitiwan [22]

- *Safety*: Safety degradation from the failure of protection system may occur because a new DG increases the fault current. If the fault current is higher than the previous level, that is higher than the interrupting capability of circuit breaker, the fault current might persist and cause damage to personnel and equipment.
- *Changing the reach of protective relays*: A DG may reduce the reach of power system protective relaying under certain circumstances. Consider a resistive fault occurring at fault point 2 during the peak load as shown in Figure 1.3. The presence of DG2 in between the fault point and a protective relay might cause a lower fault current which is seen by the protective relay. The DG effectively reduces the reach (i.e., zone) of the relay. This increases the risk of high resistive faults to go undetected. In such a case, backup protection may operate to interrupt a fault. In reference [22], So and Li apply the evolutionary algorithm to set the time coordination of overcurrent relays for a ring fed distribution system with the presences of DGs. The objective of the optimization is to maximize the satisfaction of coordination constraints.

## 1.12 Literature review: IEEE Standards

In this section, the IEEE Standards 1547 [2] and C37.04-1999 [23] are discussed. Standard 1547 relates to DGs and C37.04 relates to fault current interruptions.

### *The IEEE Standard 1547*

This standard provides the specifications and requirements for interconnection of DR with area EPS. According to this standard, DR is defined as sources of electric power including both generators and energy storage technologies. DG is the electric generation facility which is a subset of DR.

The requirements for interconnection of DR under normal conditions specified in the IEEE Standard 1547 are:

- the voltage regulation of the system after installing DG is  $\pm 5\%$  on a 120 volt base at the service entrance (billing meter) [24]
- the DR unit should not cause the voltage fluctuation at the PCC higher than  $\pm 5\%$  of the prevailing voltage level of the local EPS
- the network equipment loading and IC of protection equipment, such as fuse and CB should not be exceeded
- the grounding of the DR should not cause overvoltages that exceed the rating of the equipment in local EPS.

The requirements for interconnection of DR under abnormal conditions are:

- the DR unit should not energize to the area EPS when the area EPS is out of service
- the DR unit should not cause the misoperation of the interconnection system due to Electromagnetic Interference (EMI)
- the interconnection system should be able to withstand the voltage and current surges
- the DR unit should cease to energize the area EPS within the specific clearing time due to abnormal voltage and frequency
- the DR unit should not cause power quality problems higher than specified tolerable limits, such as DG harmonic current injection, flicker and resulting harmonic voltages.

In case the system frequency is lower than 57 Hz, the DR unit should cease to energize to the area EPS within 16 ms. When a fault is detected, the DGs must be disconnected from the electric utility company supply and the DG should pick up the local load. The disconnection is needed because: (1) a fault close to the DG in the supply system must be interrupted and (2) the local DG cannot support the power demands of the distribution system (apart from the local load). The disconnection of the DG from the network must occur rapidly. Table 1.5 shows the IEEE 1547 requirement [2] for disconnection times.

**Table 1.5 Required clearing times for DGs higher than 30 kW  
from IEEE Standard 1547**

Taken from [2]

| <i>Voltage range as percent of base voltage</i> | <i>Clearing time (s)<sup>b</sup></i> |
|-------------------------------------------------|--------------------------------------|
| $V < 50$                                        | 0.16                                 |
| $50 \leq V < 0.88$                              | 2.00                                 |
| $110 < V < 120$                                 | 1.00                                 |
| $V \geq 120$                                    | 0.16                                 |

<sup>b</sup> DR  $\leq$  30 kW, maximum clearing times; DR  $>$  30kW, default clearing times.

Note that the foregoing remarks related to the cost of added equipment and upgrades due to fault currents are separated from the issues related to commonality of technical conditions at DG sites. Most utilities utilize a common set of rules to interconnect the DG to power system, for example:

- Exchange the project information between utility and customer
- Technical analysis by the utility to evaluate the impact of DGs
- Inspection of interconnection and protective equipment by the utility.

These issues are needed to guarantee safety and reliability of the system which should be covered by the owner of the DG.

#### *The IEEE Standard C37.04-1999*

The requirement of sizing the current interrupting capability (IC) of circuit breakers (CBs) is discussed in the IEEE Standard C37.04-1999 [25], “IEEE application guide for AC high voltage circuit breakers rated at symmetrical current basis”. In general, a three phase to ground fault imposes the most severe duty on a CB. However, a single phase to ground may produce a higher fault current than a three phase fault. This condition occurs when the equivalent zero sequence at the point of fault is lower than the positive sequence reactance. Two methods for calculating system short circuit current are proposed in [25], the simplified  $E/X$  method and the  $E/X$  method with adjustment for AC and DC decrements.

The simplified method for calculating system short circuit current requires only a simple  $E/X_I$  calculation for three phase faults or  $3E/(2X_I + X_0)$  for single phase to ground faults, where  $E$  is the highest system pre-fault voltage,  $X_I$  and  $X_0$  are the positive/negative and zero equivalent reactance of the system at the circuit breaker location. For higher accuracy of symmetrical fault current calculations, the impedance of rotating equipment should be multiplied by the impedance multiplier factors given in [25]. Note that the  $E/X$  simplified method is utilized without considering the system resistance,  $R$ . For this rea-

son, this method is applicable only when the  $E/X$  of the system does not exceed 80 percent of the symmetrical interrupting capacity of the breaker [25]. The rated IC of circuit breaker can be selected from the preferred rating schedules in [26].

For higher accuracy than the previous method, the  $E/X$  method with adjustment for AC and DC decrements should be used. This method takes the decrement of the AC and DC components of the fault currents into account by applying factors to  $E/X$  calculation. The multiplying factor depends on the point where the short circuit occurs and the system  $X/R$  ratio as seen from the considering point. After calculating the  $X/R$  ratio, the multiplying factor is given in Figures 1.5 and 1.6. These figures are taken directly from [28] and reproduced here for ease in reading. Note that the system reactance ( $X$ ) is calculated by completely disregarding the system resistance,  $R$ , and vice versa. The resulting product of the system  $E/X$  and the multiplying factor must not exceed the symmetrical IC of the circuit breaker under consideration. Examples of choosing the IC of a circuit breaker are given in [22] and [27].

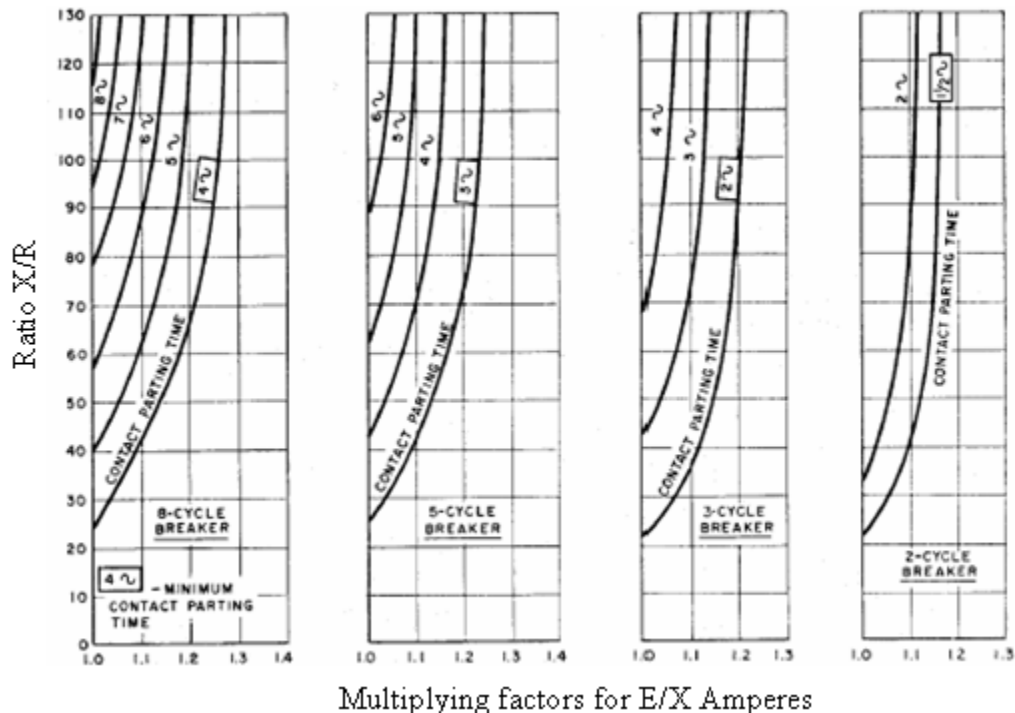


**Figure 1.5 Three phase fault multiplying factors**  
(taken directly from [28])

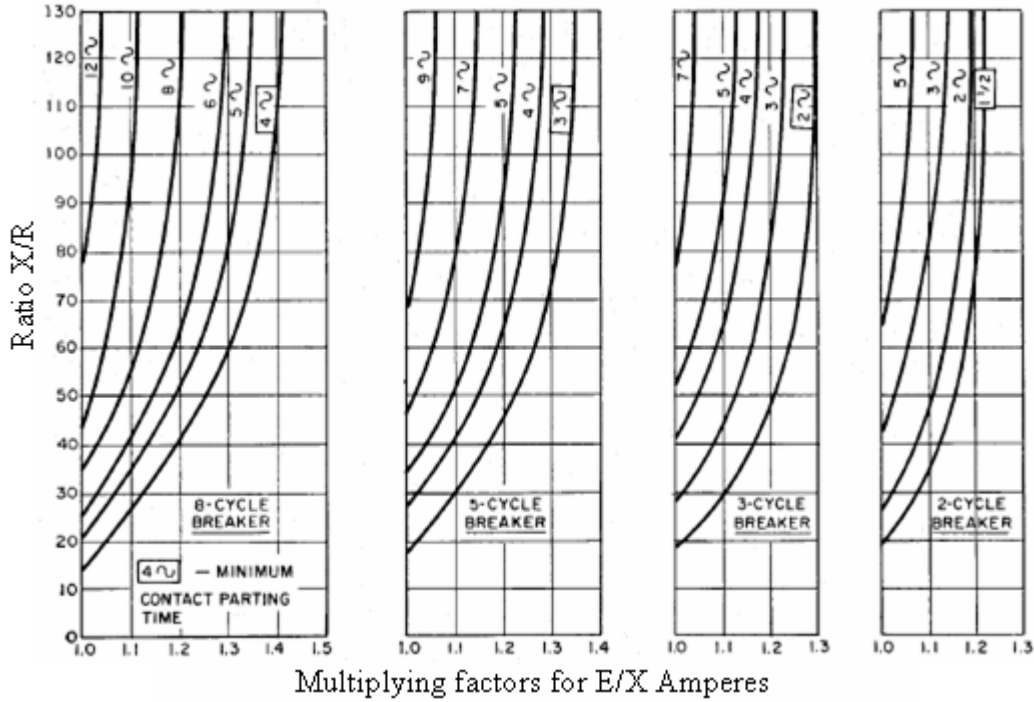


**Figure 1.6 Line-to-ground fault multiplying factors**  
(taken directly from [28])

### 1.13 Literature review: control strategy and design of inverter based DGs

This section discusses the literature review of models of the inverter based DGs. There are many distributed resources that naturally generate DC voltage such as fuel cells, solar cells, and wind turbine. These distributed resources require three phases inverter to inter-connect with the grid system.

The theory of the standalone three phase PWM controller can be found in [27]. The authors discuss the design and control of PWM inverter as a standalone unit. Various types of controller performed in *abc* variables are discussed.

M. Prodanovic and T. C. Green in [28, 29] discuss a control strategy of an inverter based DGs and filter design consideration. The proposed control strategy is separated to three parts: internal inductor current control loop, external power control loop, and phase-locked loop. The current control loop is performed in *dq0* reference frame because of the advantages for instantaneous active and reactive power calculation. The authors claim that applying the proposed control technique offer high quality of output power.

T. Takeshita, T. Masuda and N. Matsui in [30] propose a control strategy for a PWM inverter based DGs. The proposed strategy is performed in the *dq0* reference frame and including a harmonic suppression loop. The harmonic suppression loop creates the opposite phase voltage to reduce the harmonic voltage and current outputs. The effectiveness of the proposed method is verified by the simulation and experimental results.

M. Marwali and A. Keyhani in [31] propose a control strategy of a three phase inverters by applying the internal mode principle. The internal mode principle states that the output voltage and current disturbances can be eliminated by using an adjusted reference signal which composes of the original reference signal and the frequency mode of output disturbances to be eliminated. The simulation and experimental results are shown in this paper. The experimental results presented in the paper verified that the proposed control strategy provides a high power quality output. The control strategy is achieved by using the average power control method. The benefit of the average control method is the ability to reduce the sensitivity of errors from voltage and current measurements.

M. Marwali and A. Keyhani in [32] discuss the load sharing method of the parallel operation of DGs in a standalone power system. The load sharing is done by exchanging the power information among the DGs (e.g., voltage magnitude and power angle). The harmonic control loop is added to guarantee harmonic power sharing under nonlinear loads.

#### **1.14 Literature review: online assessment of fault current and operating economics**

In this section, selected aspects of operating limits and hardware to accommodate fault current are reviewed. Increased system fault currents resulting from the installation of merchant plants which affects the operating economics should be investigated. There may be the circumstances in which a security constrained OPF and unit commitment (UC) needs to include constraints imposed by the IC of circuit breakers or the setting of protective relays. Distributed and alternative generation may impact these constraints. The potential economic impact of fault current contributed by DGs and merchant plants should be analyzed.

##### *Optimal power flow*

Optimal power flow (OPF) studies have been discussed since its introduction in the early 1960s [33]. References [34, 35] have a literature survey in this topic. Classical optimization methods in general can be classified into two groups: direct search methods and gradient-based methods. In direct search methods, the objective function and the constraints are used to guide the search strategy. Since the direct search methods do not require the derivative information, they are often slow and require many function evaluations for convergence. In the gradient based methods, the first (and possibly the second) derivative of the objective and the constraints guide the search strategy. Usually, the gradient based methods converge to the optimal solution faster than the direct search methods. However, gradient based methods may not be capable of solving the non-differentiable or discrete problems.

The majority of the classical techniques to solve nonlinear programming problems discussed in the OPF literatures are:

- lambda iteration method or also called EIC
- gradient method

- Newton's method
- linear programming method
- interior point method.

References [20, 65, 67] have introductions to these topics. Typical objectives of the OPF are minimization of fuel cost, losses and added VARs while maintaining the system constraints. The control variables of the OPF are generator bus voltages, transformer and phase shifter settings and real power at the generator bus. The constraints of the OPF may include generator bus voltages, line flows, transformer capacities and phase angle regulator settings, security constraints, stability constraints, environmental constraints and reliability constraints.

References [36, 37] discuss some difficulties of using the classical techniques to solve the optimization problems, such as:

- The convergence to an optimal solution depends on the chosen initial condition. Inappropriate initial condition makes search direction converge into a local optimal solution.
- The classical techniques are inefficient in handling problem with discrete variables.

The following section illustrates the performance and applicability of the OPF with various constraints.

#### *Stability constrained OPF*

Stability is an important constraint in power system operation. The cost of losing synchronism through a transient instability is high in power systems. A large number of transient stability studies may be needed to avoid this problem. Transient stability may be considered as an additional constraint to the normal OPF with voltage and thermal constraints. In the normal OPF, it is well-understood that the voltage and thermal constraints can be modeled by a set of algebraic equations. However, the stability constrained OPF contains a set of both differential and algebraic equations. The dependence on time is an added level of complexity.

Gan and Thomas in [38] propose a technique to solve this problem by converting the differential- algebraic equations to numerically equivalent algebraic equations. The stability constraints are expressed by the generator rotor angle and the swing equations. LP method with relaxation technique is implemented to solve the OPF problem.

#### *Environmental constraints*

According to the requirements of the Clean Air Act Amendments (CAAA), the electric utility industry has to limit the emission of SO<sub>2</sub> to 8.9 million tons per year and multiple NO<sub>2</sub> to 2 million tons per year [39, 40]. The emission rate of each unit can be expressed as a quadratic function of generation active power output (MW) and heat rate (MBtu/h). Emission control can be included in the conventional ED problem by adding the environmental cost to the normal dispatch.

Several authors [41, 42, 43, 44] apply Evolutionary Algorithm (EAs) to solve the ED problem. The EAs are computer-based problem solving systems. These methods mathematically replicate the mechanisms of natural evolution as the key elements in their design and implementation. Four different EAs are genetic algorithms (GAs), evolutionary strategy (ES), evolutionary programming (EP) and genetic programming (GP). Deb in [42] describes the theory of the multi-objective optimization by applying the EA.

Wong and Yuryevich in [43] apply the EP technique to solve the environmentally constrained economic dispatch (ECED) problem. The EP technique is based on the mechanics of natural selection. Basically, EP searches for the optimal solution by evolving population candidate solutions over a number of generations or iterations. A new population or *individual* is produced from an existing population through a process called “mutation”. Individuals in each generation and the mutate population compete with each other through a competition scheme. The winning individuals from the competition scheme form a next generation. The process of evolution may be terminated by two stopping criteria: stop after a specified number of iterations or stop when there is no significant change in the best solution.

Yalcinoz and Altun in [45] and Ma, El-Keib and Smith in [46] propose a solution for ECED problem using modified genetic algorithm. The objective function consists of three terms which are the production cost, emission functions of SO<sub>2</sub> and NO<sub>2</sub>. The authors conclude that the proposed GA algorithm is appropriate to be applied to solve the ECED problem.

The foregoing advanced intelligent based algorithms are reasonably well documented in the literature, but there are no known actual applications in operational power system dispatch.

#### *Unit commitment*

Unit commitment (UC) is the problem of determining the optimal schedule of committing (i.e., making available for dispatch) generation subject to operating constraints. The UC problem has been studied extensively. Various mathematical approaches to solve the UC problem have been proposed, such as priority listing, dynamic programming (DP), Lagrangian relaxation (LR), evolutionary programming and integrated algorithm. In general, the constraints that must be satisfied of the unit commitment are system power balance, unit generation limits, minimum/maximum up and down time, spinning reserve and constraint on voltage magnitude. Padhy in [45] gives an overview concept and a bibliographical survey on UC problem.

Siu, Nash and Shawash in [46] propose a real time scheduling of ten hydro units by applying an expert system and DP. The expert system is used to eliminate the infeasible and undesirable solutions. The DP is used to solve the optimal unit commitment problem.

Application of the genetic algorithm (GA) is demonstrated to solve the UC problem in many papers. Feasibility of GA to solve the UC problem in real scale power system has

been examined in [47, 48, 49]. GA is an adaptive search technique based on the principles and mechanisms from natural evolution (i.e., fitness evaluation, selection, crossover and mutation). However, the major limitation on GA technique is the large computational time requirement.

Reference [50, 51] solve the short term UC problem by applying a hybrid genetic algorithm and taboo search method (TS). In the first step, the GA which has a good global optima search is applied to give the initial solutions. Then, in the second step, the TS is applied to give the solution near a local optima. The authors utilize the TS to solve the UC problem because it has a better performance on local optima search.

Ma and Shahidehpour in [52] discusses the unit commitment with the transmission security and voltage constraints. The problem is decomposed into two parts: unit commitment problem and transient security / voltage constraint. The UC problem is solved by applying the augmented Lagrangian relaxation method. The dynamic programming is used to search optimal commitment for generating units.

#### *Online assessment of fault current*

Srinivasan and Lanford [53] propose a short circuit current estimation technique. The fault current estimation technique is based on the statistical analysis of the voltage and current variations during system disturbances. However, the proposed equations are applicable limited to some system configurations. The general equations for estimating various bus types in the system are need to be developed.

## **2 Model of Inverter Based Distributed Generation**

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### **2.1 Inverter based generation sources**

Generation resources are traditionally synchronous generators, and modeling of these machines is well known and applied. Unlike conventional sources, power generated in fuel cells, solar sources and some microturbines is DC. In the case of these resources, an inverter is needed to interface with the AC system network. Also, recent developments in the operation of power systems have suggested that inverter based generation sources may be used for synchronous machines. That is, the synchronous generator is isolated from the AC system through an AC / AC converter in order to isolate the dynamics of the network from the local synchronous generator. Whatever the motivation, it is appropriate to examine inverter based generation sources and their impact on fault response in power systems. The inverter and its controls are described in this chapter. Pulse Width Modulation (PWM) is used as the base technology for the inverters described here. The models are programmed in Simulink.

The model of the inverter based DG presented in this chapter is accomplished under the assumption that the input voltage from DC sources to the PWM inverter are regulated by using DC/DC converters and chopper circuits. The analysis and design of the voltage regulator circuits are discussed in [54, 55, 56].

### **2.1 Control of inverter based distributed generations**

Inverter based DGs operate as controlled voltage sources connected to the grid system through a step up transformer. The step up transformer with delta – delta connection (4 kV/12.47 kV) eliminates the zero sequence components from inverter to the grid. Figure 2.1 shows the connection of inverter based DG to the grid system.

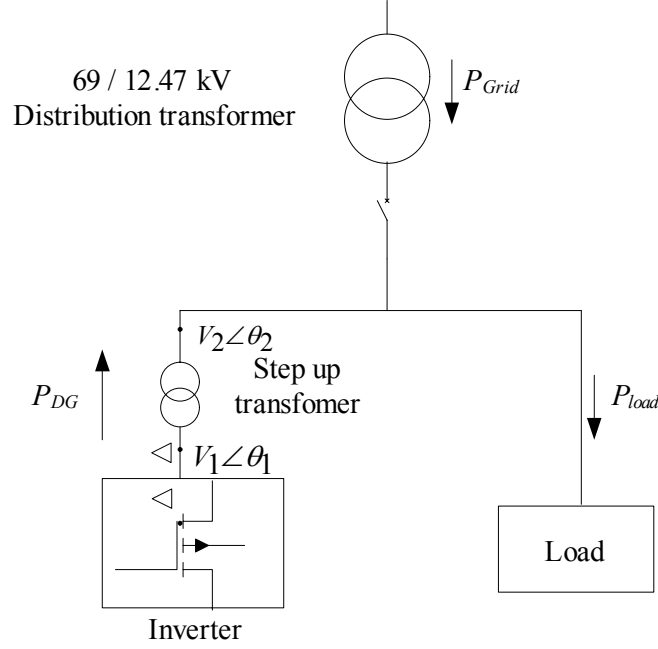


**Figure 2.1 Inverter based DG connecting to the grid system**

Consider the active power of an inverter based DG, denominated as  $P_{DG}$ . Let  $P_{DG}$  be at the output of the inverter. The active power  $P_{DG}$  is an average of the instantaneous power  $p_{DG}(t)$ . The average is taken over at least one cycle – but, more likely, taken over a time period measured in seconds if mechanical dynamics are to be studied. The active power output of the inverter based DG could be estimated as,

$$P_{DG} = \frac{|V_1||V_2|}{X} \sin(\delta) \quad (2.1)$$

where  $|V_1|$ ,  $|V_2|$  are the voltage magnitudes at the primary and secondary sides of the step up transformer and  $\delta$  is the difference of phase angle between  $V_1$  and  $V_2$ . Equation (2.1) is a simplistic representation of  $P_{DG}$  because:

- Inverter losses are ignored.
- Inverter dynamics are ignored.
- Equation (2.1) is an elementary model based on lossless AC circuit theory, and no source dynamics are modeled. For example, in a fuel cell, the DG source at the fuel cell terminals may not be constant.

In this development, (2.1) is not used. Instead, a full calculation of the real part of  $VI^*$  is used. It is expected that the relatively long time dynamics of  $\delta(t)$  are well modeled using  $\text{Re}\{VI^*\}$  because  $V$  and  $I$  are rms values averaged over at least one cycle. Figure 2.2 shows the control model for the inverter based DG. The control strategies are to generate the balanced three phase voltage and to control the power output of the inverter. The controller consists of two control loops:

- the amplitude controller
- the angle difference controller.

The amplitude and angle difference controller provide the modulating signal to the pulse width modulation signal generator. The harmonics from the PWM inverter is filtered out by an LC low pass filter. The cutoff frequency,  $f_c$ , should be set low enough to block harmonics but high enough provide the attenuation of harmonics of the inverter voltage.

### Amplitude controller

There is no standard design for an inverter for the application described here. However, the following is a generic discussion of a PWM based design. In a PWM inverter, the key control elements are the amplitude controller and the phase controller. The amplitude controller provides the balanced three phase output voltage to the grid at the desired voltage amplitude. As shown in Figure 2.3, the amplitude controller consists of a phase locked loop (PLL) and a PI controller.

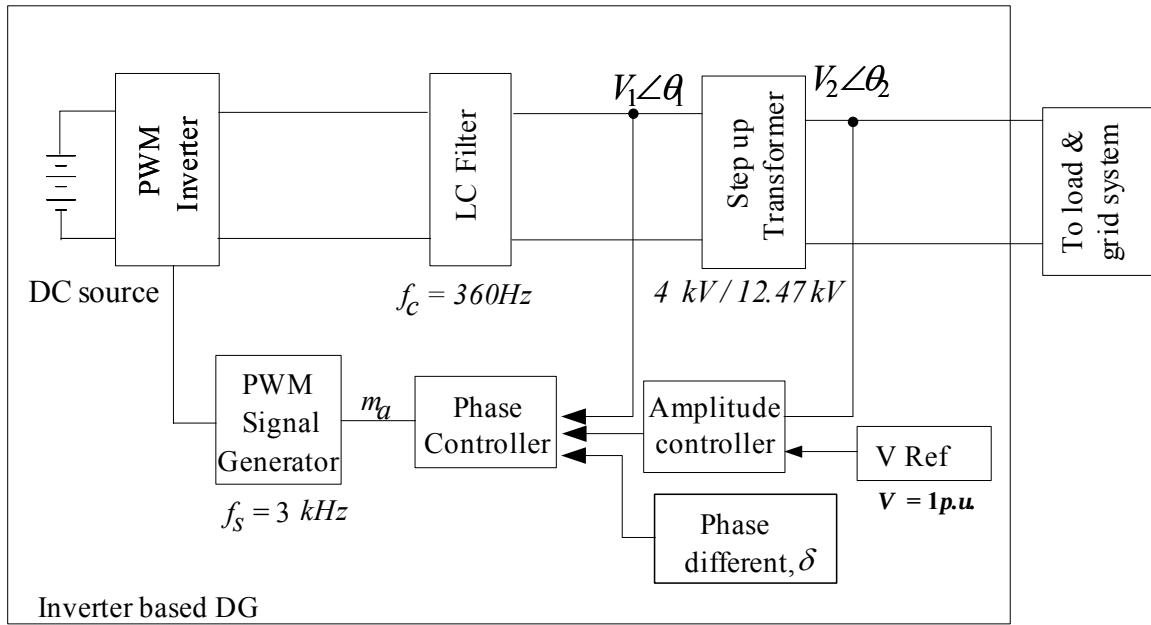


**Figure 2.2 Control model for inverter based DG**

The output voltage of the DG,  $V_2$ , is transformed via a time dependent transformation. The transform used is the  $dq0$  transformation. This transformation has the property of frequency domain shifting the input phase voltages to a low frequency voltage. Also, high frequency terms occur. In this discussion, it is assumed that the high frequency terms that occur in the  $dq0$  transformed variables are filtered out. The control is performed in  $dq0$  reference frame because of the advantage for the instantaneous voltage angle calculation. Details of the  $dq0$  transformation are discussed in Appendix B and [57]. The transform equations from  $v_{abc}$  to  $v_{dq0}(t)$  is

$$\begin{bmatrix} v_d(t) \\ v_q(t) \\ v_0(t) \end{bmatrix} = \frac{2}{3} \begin{bmatrix} \cos(\omega_e t) & \cos(\omega_e t - \frac{2\pi}{3}) & \cos(\omega_e t + \frac{2\pi}{3}) \\ -\sin(\omega_e t) & -\sin(\omega_e t - \frac{2\pi}{3}) & -\sin(\omega_e t + \frac{2\pi}{3}) \\ \frac{1}{2} & \frac{1}{2} & \frac{1}{2} \end{bmatrix} \begin{bmatrix} v_{an}(t) \\ v_{bn}(t) \\ v_{cn}(t) \end{bmatrix} \quad (2.2)$$

and the inverse transform from  $V_{dq0}$  to  $V_{abc}$  is

$$\begin{bmatrix} v_a(t) \\ v_b(t) \\ v_c(t) \end{bmatrix} = \begin{bmatrix} \cos(\omega_e t) & -\sin(\omega_e t) & 1 \\ \cos(\omega_e t - \frac{2\pi}{3}) & -\sin(\omega_e t - \frac{2\pi}{3}) & 1 \\ \cos(\omega_e t + \frac{2\pi}{3}) & -\sin(\omega_e t + \frac{2\pi}{3}) & 1 \end{bmatrix} \begin{bmatrix} v_d(t) \\ v_q(t) \\ v_0(t) \end{bmatrix}$$

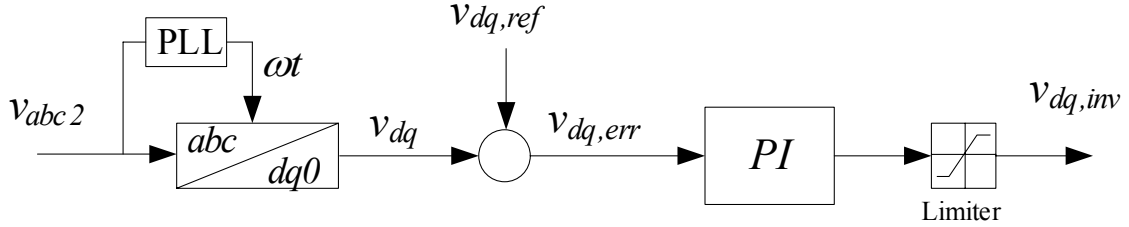


**Figure 2.3 Amplitude controller**

Note that the constant in the transform equation, (2.2), can be chosen arbitrarily. This is related to the inverse of transformation. For example, in (2.2), the constant is  $2/3$  and the constant of inverse transform is  $1$ .

The time domain variables  $v_{an}(t)$ ,  $v_{bn}(t)$  and  $v_{cn}(t)$  mainly consist of “power frequency” components (i.e., 60 Hz components). The  $dq0$  transformation is time varying with DC and power frequency components. Therefore,  $v_d(t)$ ,  $v_q(t)$  and  $v_0(t)$  generally contain DC, 60 Hz, and 120 Hz components. This is a consequence of the property that the Fourier transform (FT) of a product is the convolution of the FTs of the component multipliers. If a low pass filter is applied to the vector  $\begin{bmatrix} v_d(t) & v_q(t) & v_0(t) \end{bmatrix}$ , then  $\begin{bmatrix} v_d & v_q & v_0 \end{bmatrix}$  results. The latter vector is nearly DC, under balanced sinusoidal steady state conditions, and often well suited for control purposes. More discussion of the  $dq0$  transformation for this application appears in Appendix B. For purposes of designing and modeling a controller rms voltage of  $v_{an}(t)$ ,  $v_{bn}(t)$ ,  $v_{cn}(t)$ ,  $v_d(t)$ ,  $v_q(t)$ , and  $v_0(t)$  are used. These rms values are denoted as  $V_{an}$ ,  $V_{bn}$ ,  $V_{cn}$ ,  $V_d$ ,  $V_q$ , and  $V_0$ . The same notation is used for current.

A proportional plus integral (PI) controller minimizes the error signal, that is, the difference between the reference signal and the instantaneous voltages  $v_d(t)$  and  $v_q(t)$ .

### Phase controller

The phase controller provides a phase difference,  $\delta_{diff}$ , between  $V_1$  and  $V_2$  (see Figure 2.1). The value of the phase difference,  $\delta_{diff}$  and approximate power flow can be calculated from (2.1). A model of the phase controller is shown in Figure 2.4. Inputs to the phase controller,  $V_1$  and  $V_2$ , are transformed to  $dq0$  reference frame. The phase of  $V_1$  and  $V_2$  can be calculated as,

$$\theta = \tan^{-1} \left( \frac{V_d}{V_q} \right)$$

In the phase controller, a PI controller is applied to minimize the error of specified power output value,  $P_{ref}$ . The output average power of the inverter based DG is measured as the output from a low pass filter. The cut-off frequency of the low pass filter has to be set at the appropriate value to attenuate the disturbance from measurement, but high enough to provide a good transient response of the phase controller. The output of the PI controller is added to the phase of  $V_1$  and used to calculate the required amplitude and phase of the modulating signal. The last step in the phase difference controller is to transform the modulating signal back to the  $abc$  reference frame. The complete model of inverter based DG in Matlab Simulink is shown in Figure 2.5. A single tuned filter is installed at the output terminal of the inverter based DG to attenuate the 3<sup>rd</sup> current harmonic.

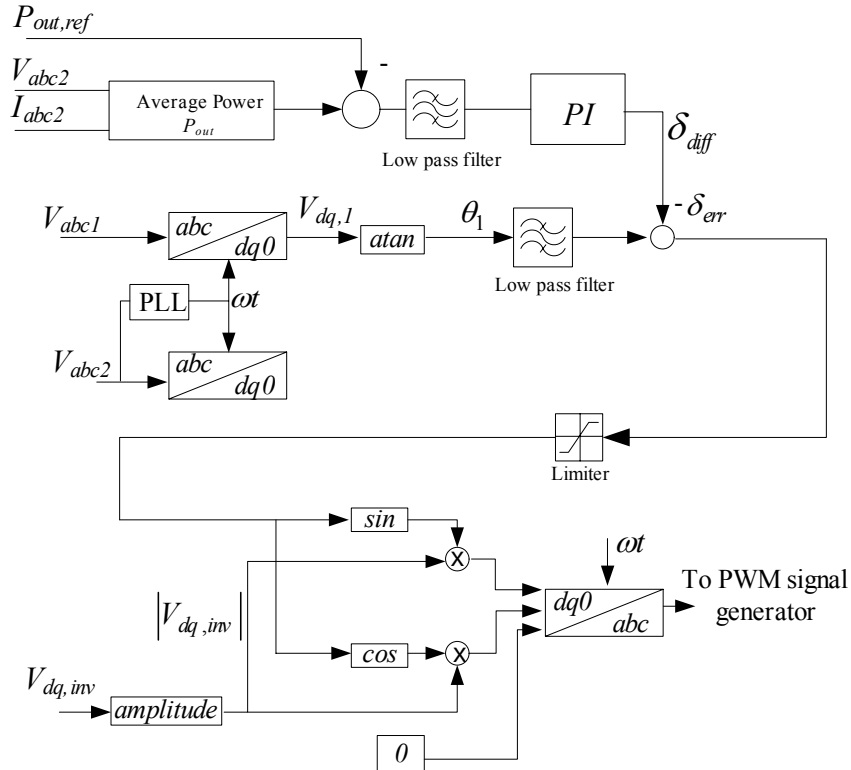


**Figure 2.4 Phase controller**

## 2.2 Illustration of inverter based distributed generation

In this section, the dynamic performance of the model of the inverter based DG as discussed in Section 2.2 is examined. Although a specific design is shown here for illustrative purposes, experience in working with inverter based DG models indicates that the approach taken here may be valid in the 10 kVA – 20 MVA class. Output voltage and current at the terminal of the inverter based DG from the simulation are recorded for the analysis in the frequency domain. The illustrative cases are separated into two parts:

- stand alone operation (disconnected from the grid), Case 2.1
- DG connected to the grid, Case 2.2.

Stand alone operation (disconnected from the grid), Case 2.1

In Case 2.1, the simulation is built with a local load and an inverter based DG which is disconnected from the grid system. The purpose of the simulation in Case 2.1 is to show the transient response of the inverter based DG due to the change of load. In the case of the stand alone operation, the inverter requires only the amplitude controller to set the voltage at the reference point. The output power varies depending on the load. The inverter based DG parameters used in the simulation are shown in Table 2.1.

**Table 2.1 Characteristics of an inverter based distributed generation for simulations; Cases 2.1 and 2.2**

| DG characteristics                                        | Parameter  |
|-----------------------------------------------------------|------------|
| Switching frequency, $f_s$                                | 3 kHz      |
| Three phase output voltage, $V_o$                         | 12.47 kV   |
| Rated frequency                                           | 60 Hz      |
| Short circuit impedance of the step up transformer (7 MW) | 0.1 p.u.   |
| Active power output                                       | 2-6 MW     |
| Reactive power output                                     | 0-3 MVar   |
| Power factor                                              | 0.8-1      |
| Simulation time step                                      | 50 $\mu$ s |
| DC input voltage to the inverter                          | 5 kV       |

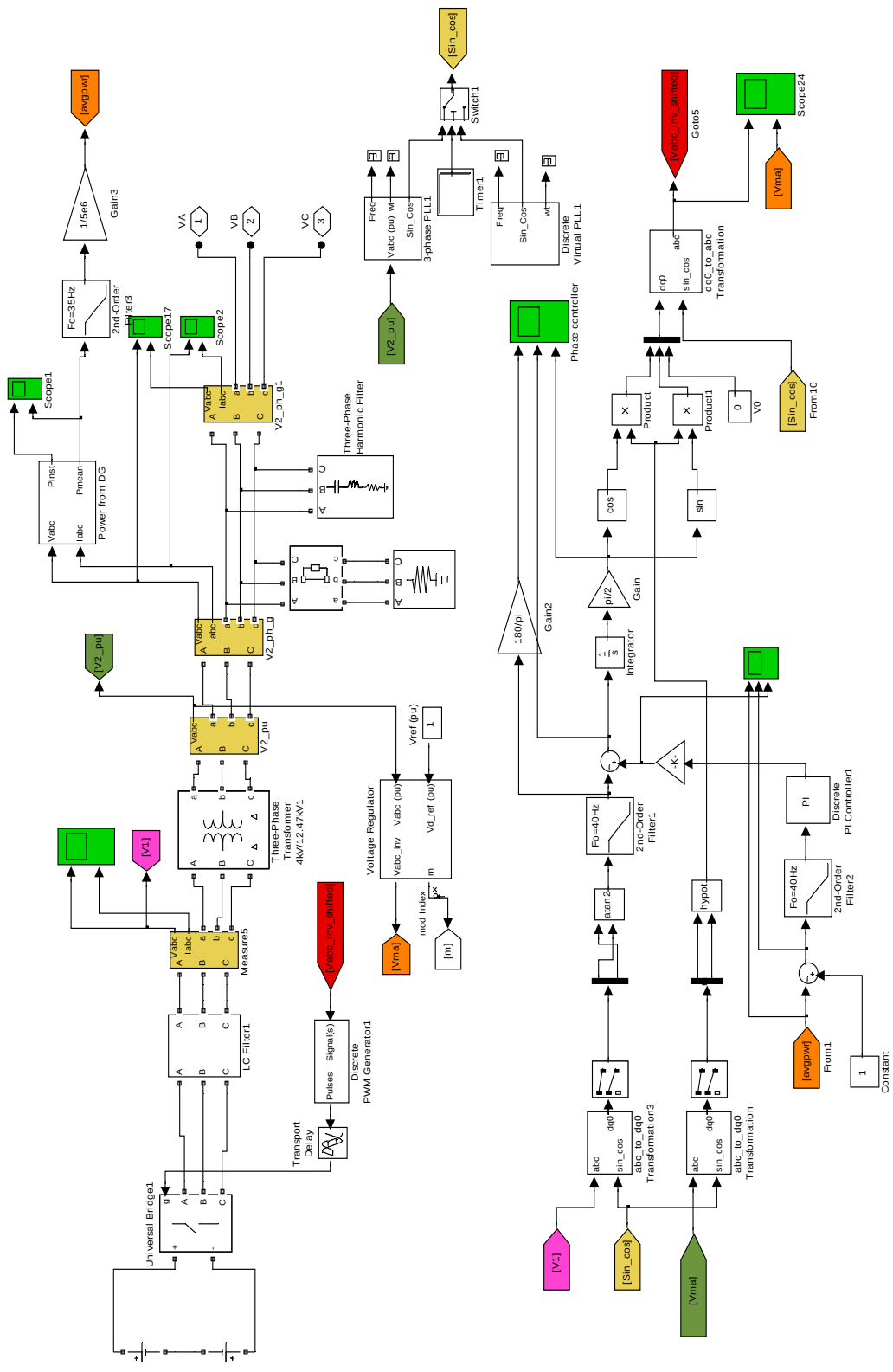


Figure 2.5 Model of inverter based distributed generation in Matlab Simulink

The simulation time is from  $t = 0.0$  to  $0.3$  s with simulation time step,  $T_s = 50 \mu\text{s}$ . The three phase output voltage is set at  $1.0$  p.u. or  $12.47$  kV. To demonstrate the dynamic performance of the inverter based DG, after reaching the steady state, the load is changed from  $3$  MW /  $0.1$  MVAR to  $5$  MW /  $0.1$  MVAR at  $t = 0.15$  s. Figures 2.6 and 2.7 show the output line to neutral voltage and current of the inverter based DG, respectively. Note that, in Figure 2.6, a voltage swell occurs during the change of the load. In this case, the voltage swell is approximately 5 percent of the nominal operating voltage. Figure 2.8 depicts the modulation index (ma) in the amplitude controller which is used to control the switching of PWM generator.

According to the specific design and the indicated operating condition, after reaching the steady state, the total harmonic distortion (THDI and THDV) are  $1.36$  and  $0.66$  percent, respectively. Figures 2.9 and 2.10 depict the harmonic content of the output voltage and current of inverter based DG in Case 2.1. Note that the plots are shown in semi logarithmic scale.

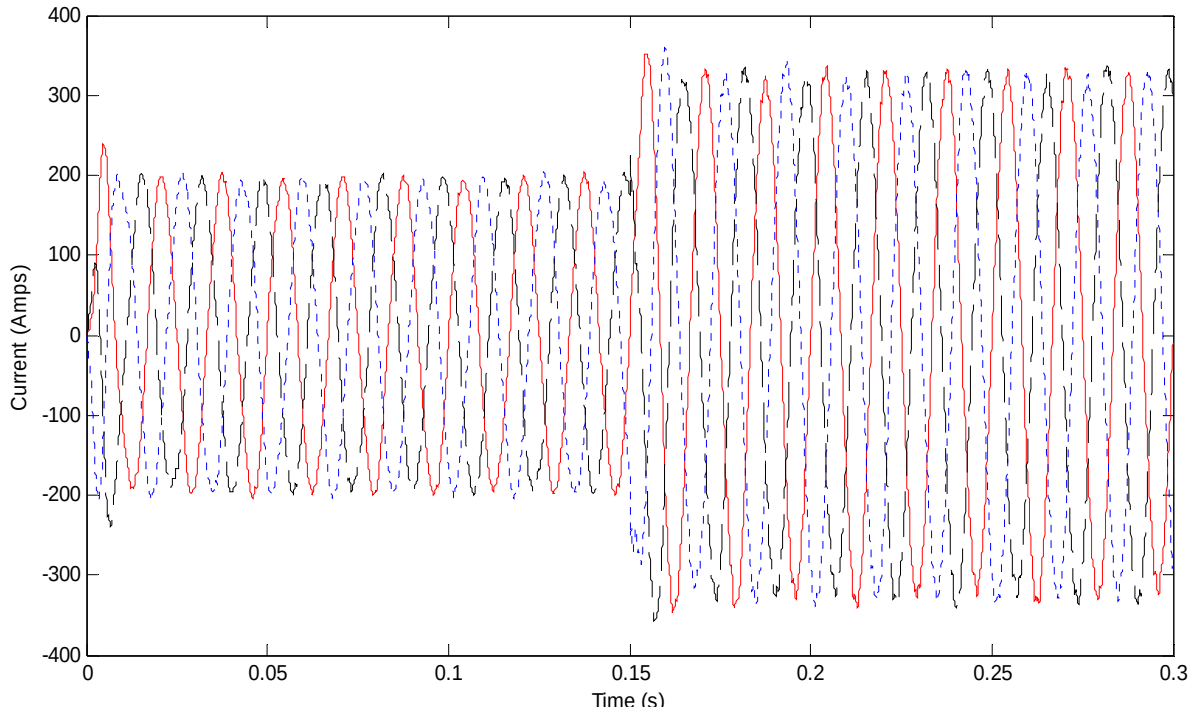


**Figure 2.6 Output current of the inverter based DG (stand alone)  
with load change at  $t = 0.15$  s, Case 2.1**

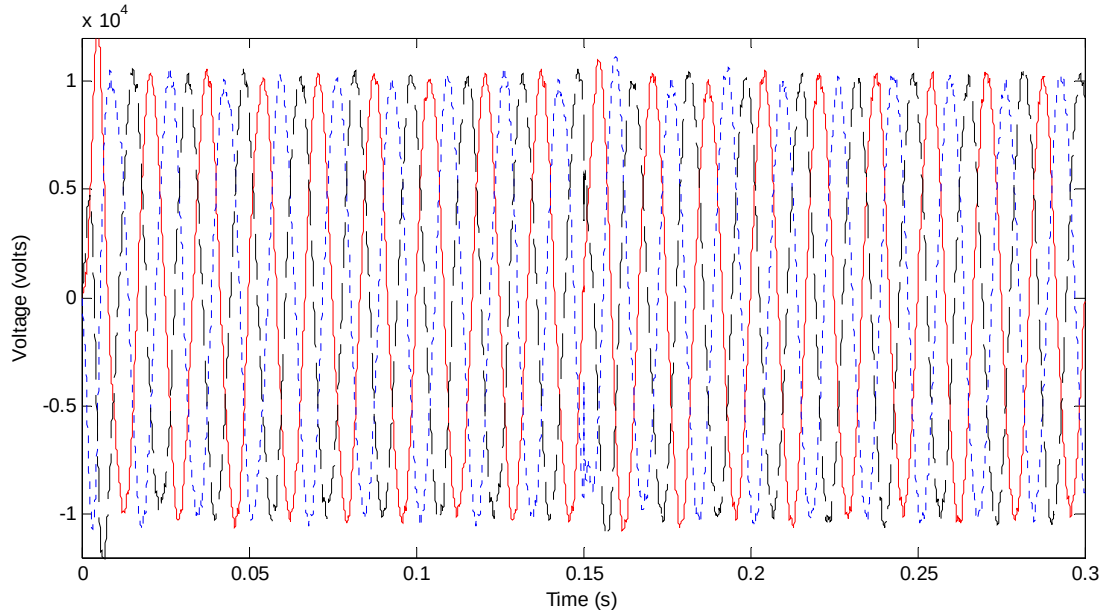


**Figure 2.7 Output voltage of the inverter based DG (stand alone) with load change at  $t = 0.15$  s, Case 2.1**

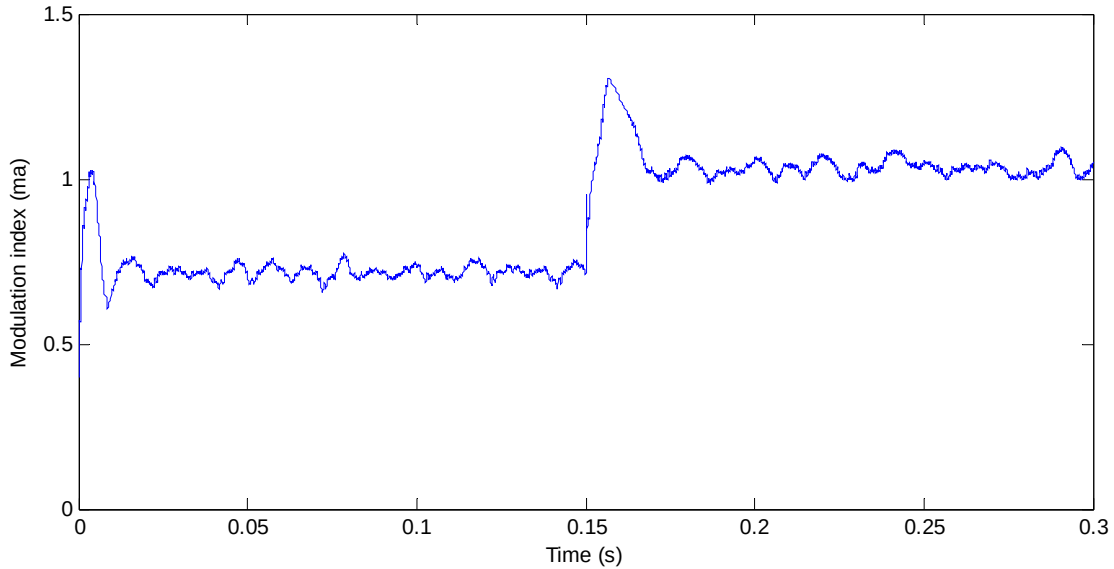


**Figure 2.8 Modulation index (ma) of the inverter based DG (stand alone) with load change at  $t = 0.15$  s, Case 2.1**

The average active and reactive power output (average over one cycle) is shown in Figures 2.11-12. The active power changed from 4 MW to 6 MW at  $t = 0.15$  s. Note that the inverter output follows the load demands and the transient response time is in the range of 20-30 ms.

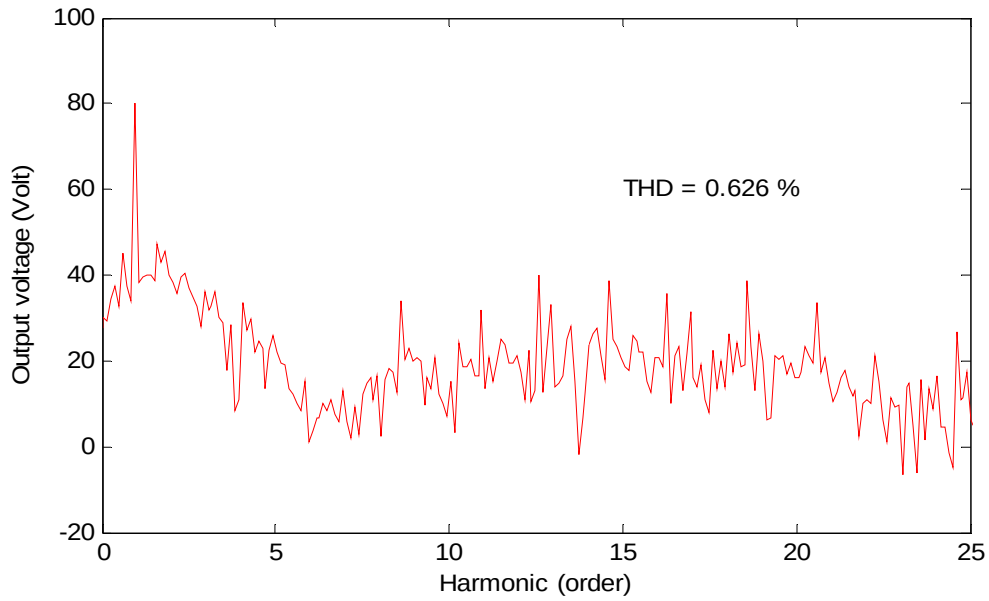


**Figure 2.9 Harmonic content of the output line-neutral voltage from inverter based DG with a stand alone operation, Case 2.1**

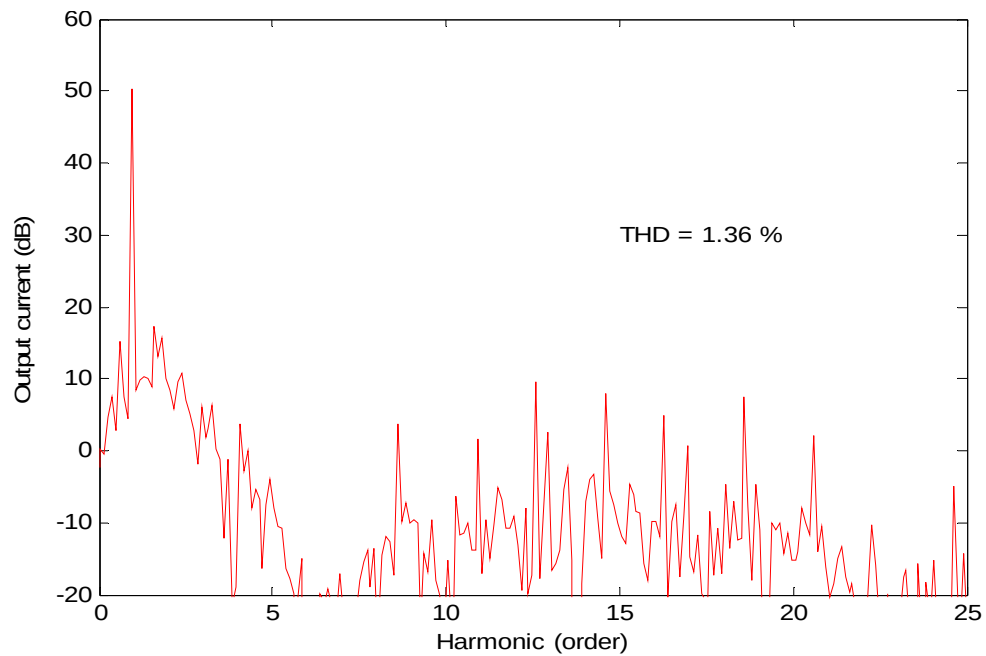


**Figure 2.10 Harmonic content of the output current from inverter based DG with a stand alone operation, Case 2.1**

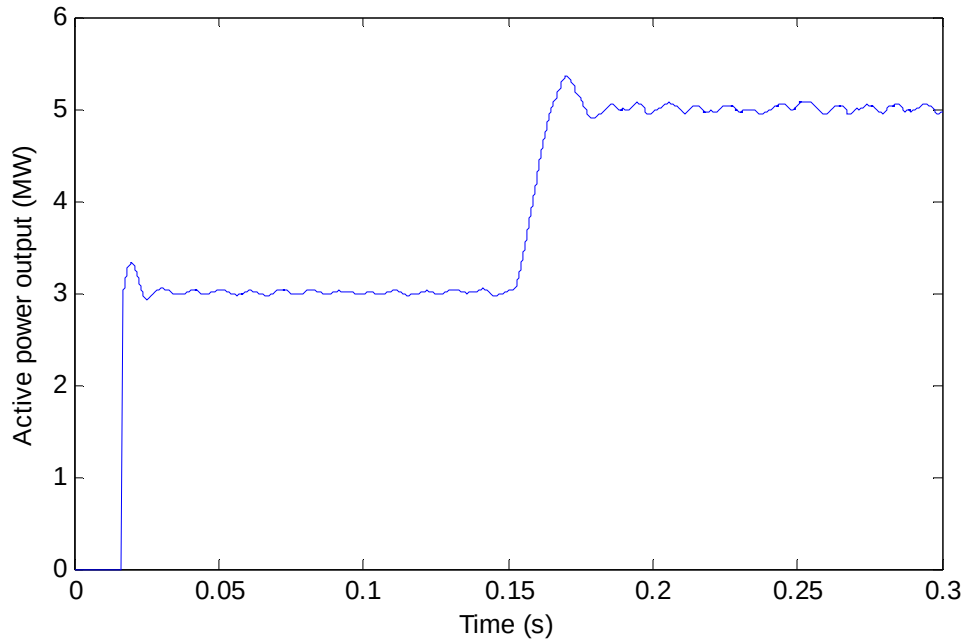


**Figure 2.11 Active power output of inverter based DG with a stand alone operation, Case 2.1**

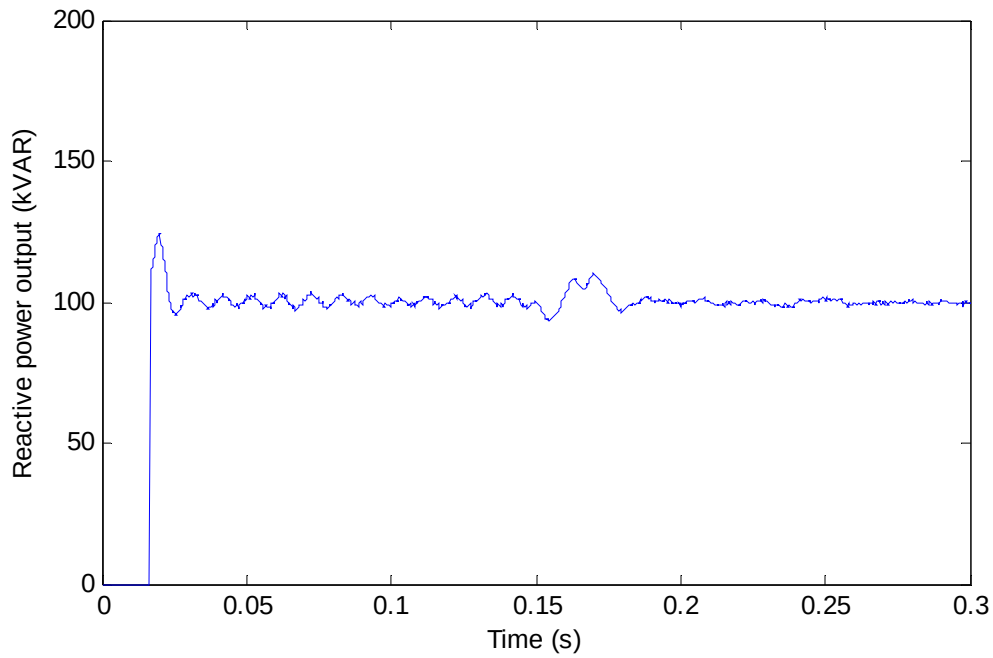


**Figure 2.12 Reactive power output of inverter based DG with a stand alone operation, Case 2.1**

### *DG connected to the grid, Case 2.2*

In Case 2.2, a simple system configuration with an inverter based DG connected to the grid is given as an illustration as shown in Figure 2.1. In this case, the amplitude controller is required to control the voltage at the reference point (1 p.u.). The angle difference controller is required to control the active power output of the inverter based DG. The simulation is built with an inverter based DG connected to the 69 kV subtransmission system through a 16 MVA, delta-wye 12.47/69 kV transformer with impedance of 0.1 p.u. The 69 kV subtransmission system is considered to be an infinite bus. The inverter based DG is applied to serve a local loads, 15 MW / 1.5 MVAR (power factor = 0.995), at 12.47 kV. Unlike Case 2.1, where the inverter based DG is programmed to control the constant output voltage at 1 p.u., the inverter based DG in Case 2.2 generates a specified active power output and also a specified output voltage. The inverter based DG parameters used in the simulation are the same as specified in Case 2.1 and shown in Table 2.1. The amplitude controller of the DG is programmed to generate the output voltage at 1.0 p.u. and the angle difference controller is programmed to provide the output at 5 MW.

According to the specific design, the output current of the inverter, based in time and frequency domains, are shown in Figures 2.13 and 2.14. The graphs show the operation of the inverter based DG at 5 MW, 1.45 MVAR with power factor 0.96. The analysis in frequency domain is accomplished by applying the fast Fourier transform (FFT). The THD of the output current of the DG is 1.67 % for the case illustrated.

For the indicated operating condition, the voltage measured at the secondary side of the distribution transformer or PCC is 0.99 p.u. The plot of the line-neutral output voltage is shown in Figure 2.15. The spectrum of the output voltage is shown in Figure 2.16 and the THD of the output voltage is 0.67%.

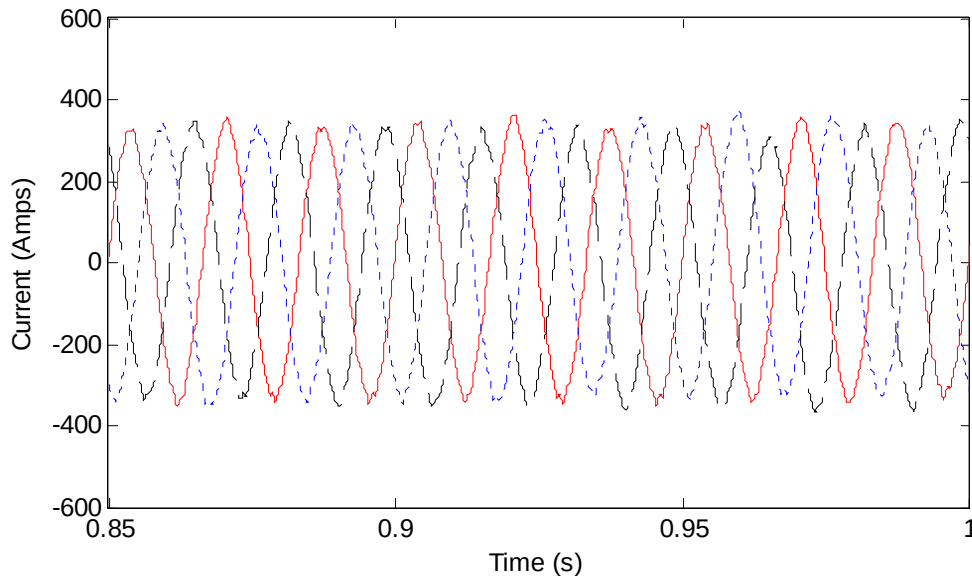


**Figure 2.13 Output current of the inverter based DG – steady state operation illustrated with power output 5 MW, Case 2.2**

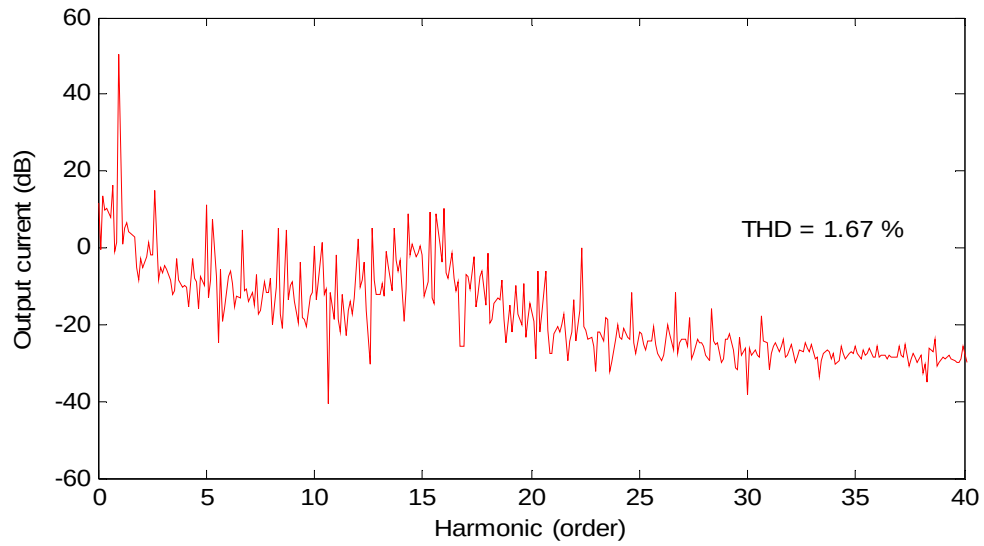


**Figure 2.14 Harmonic content of the output current from inverter based DG – steady state operation illustrated with power output 5 MW, Case 2.2**

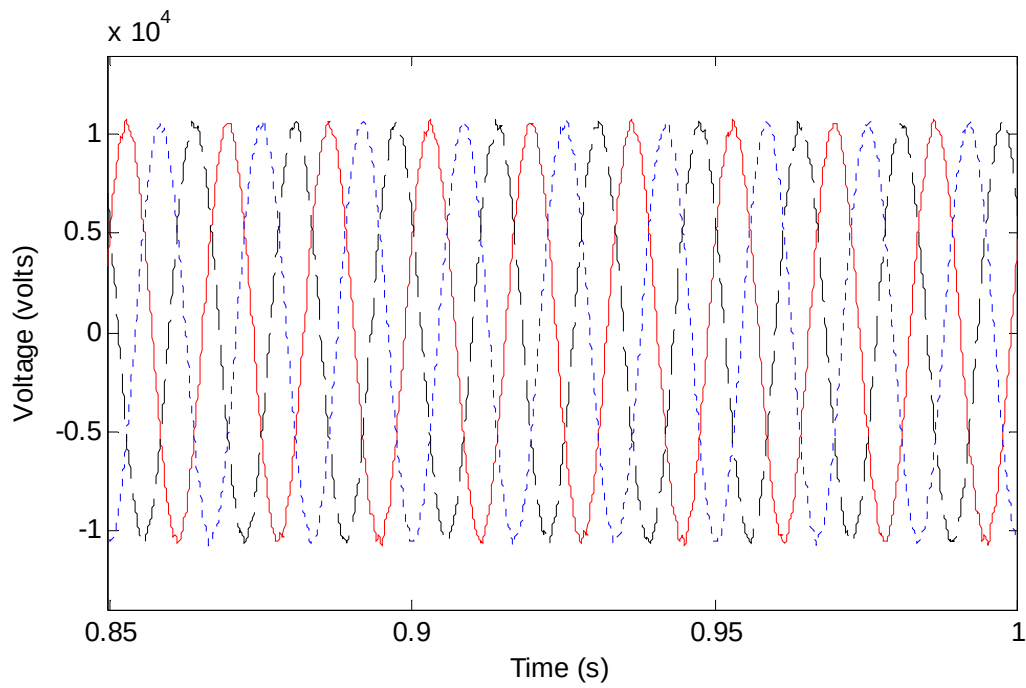


**Figure 2.15 Line – neutral voltage measured at PCC – steady state operation illustrated with power output 5 MW, Case 2.2**

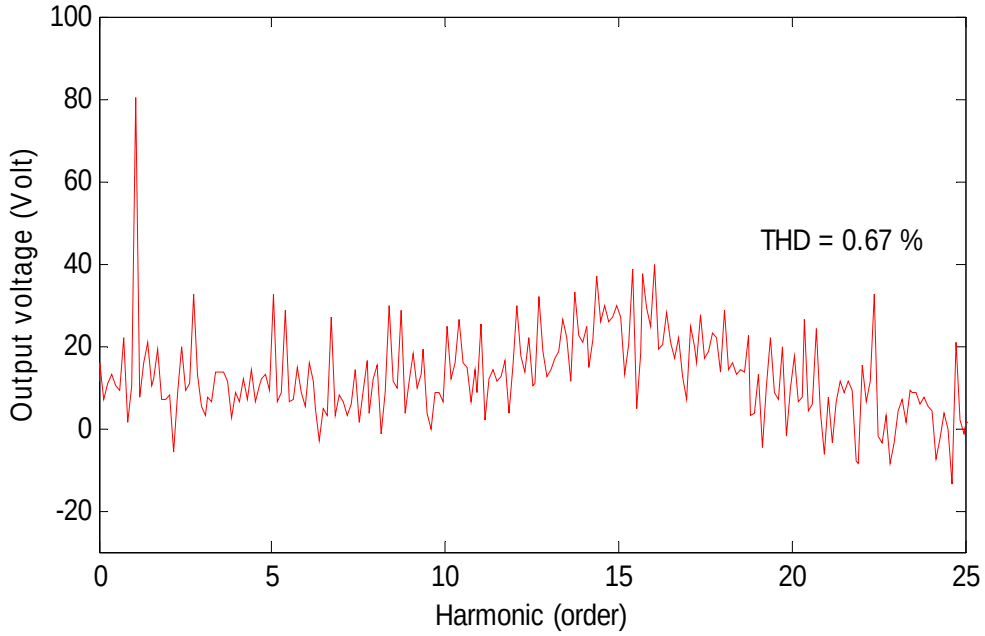


**Figure 2.16 Harmonic content of the line-neutral voltage at PCC – steady state operation illustrated with power output 5 MW, Case 2.2**

The plot of the active and reactive power from the DG is shown in Figures 2.17-2.18. The plot shows power averaged over one cycle. Notice from Figures 2.17 and 2.18 that the inverter based DG with the previously presented control strategy takes approximately 500-600 ms to reach a steady state output (from the relaxed state). Figure 2.19 shows the power factor of the inverter based DG under different reference voltages and active power outputs.

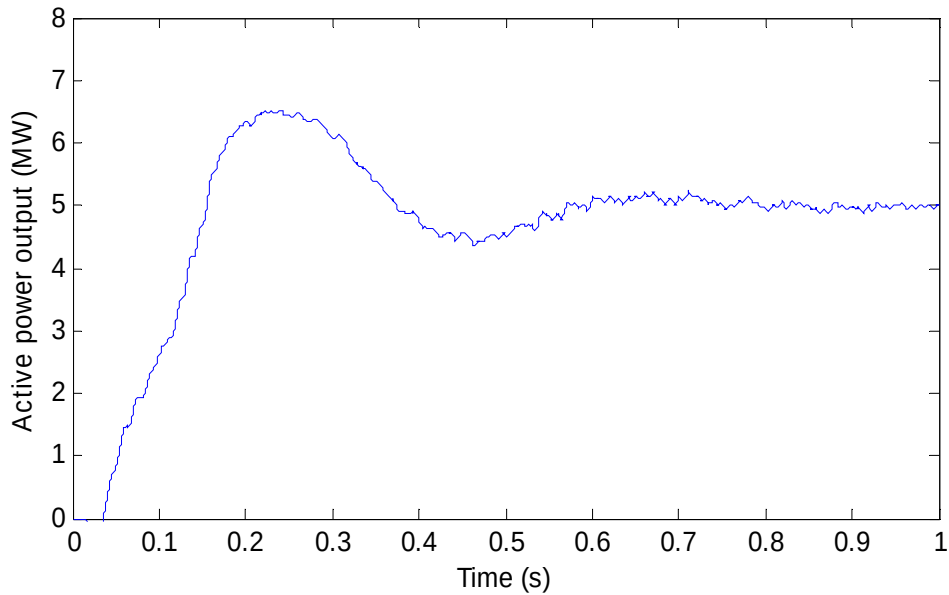


**Figure 2.17 Active power output (averaged over one cycle) of inverter based DG – steady state operation illustrated with power output 5 MW, Case 2.2**

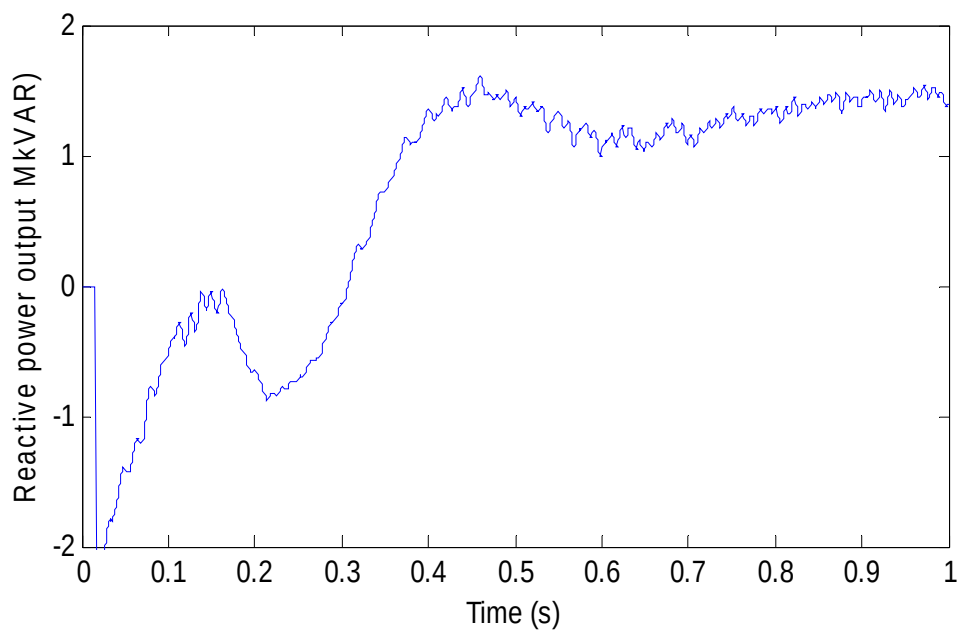


**Figure 2.18 Reactive power output (averaged over one cycle) of inverter based DG – steady state operation illustrated with power output 5 MW, Case 2.2**

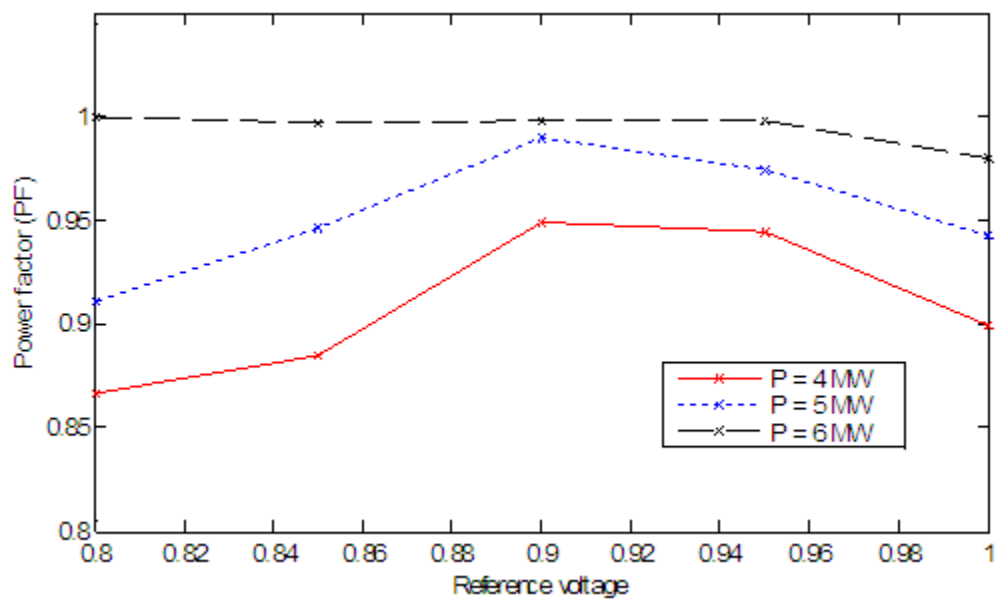


**Figure 2.19 Power factor of the inverter under different reference voltage, Case 2.2**

### 2.3 Active power output and current harmonic distortion

This section discusses the variation of the total harmonic distortion of the output current under different active power outputs of the inverter based DG when the inverter is connected to the grid. The analysis is done by applying the parameters of inverter as in Table 2.1 and the test system as indicated in Case 2.2. In this analysis, the active power output of the inverter based DG is varied from 1-7 MW with the reference voltage,  $V_{ref}$ , at 1 p.u.

The plot of current THD versus active power output ( $P_{out}$ ) of the inverter based DG with the parameters indicated in Table 2.1 is shown in Figure 2.20. The current THD of the inverter varies depending on the active/reactive power outputs and the amplitude of the output voltage. Note that the current THD near the rated MW of the inverter (5 MW) is relatively low.

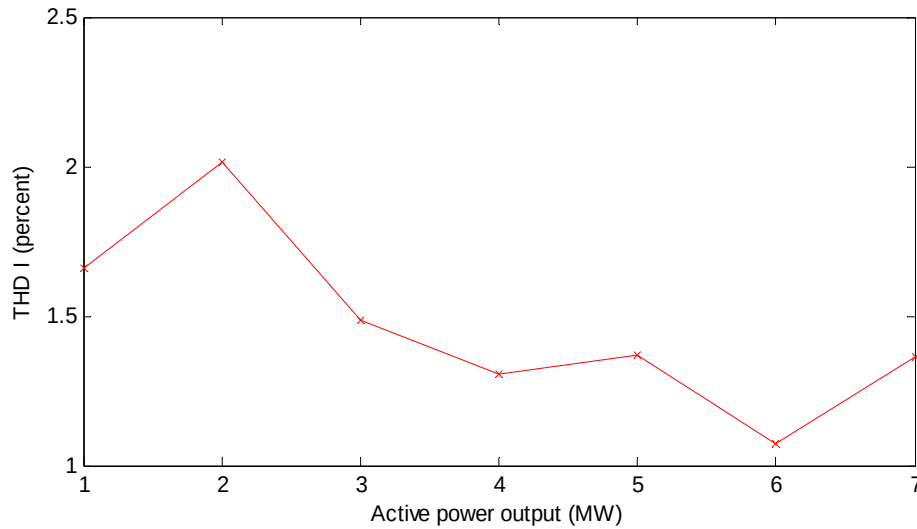


**Figure 2.20 Plot of active power output vs. THD current of inverter based DG with  $V_{ref} = 1.0$ , Case 2.2**

### 2.4 Conclusions

This chapter describes a control strategy of an inverter based DG in a distribution system. Two distinct controllers are discussed: an amplitude controller, and an angle difference controller. The controllers are designed in an average power control configuration. In both controllers, the rotational reference frame or abc to dq0 transformation is applied to calculate the phase angle of the output voltage and current. The input of the abc to dq0 transformation is the power frequency of the grid system which is detected by a phase locked loop (PLL) at the PCC. The advantage of the abc to dq0 transformation is the ability to obtain low frequency control signals and rapid calculations.

The illustrative cases in Section 2.3 show the operation of an inverter based DG during normal operation (steady state): stand alone operation (Case 2.1) and a DG connected to

the grid system (Case 2.2). From the simulation results presented, the controls of active power and output voltage of the inverter based DG have been accomplished while maintaining acceptable power quality. Several examples are included in Cases 2.1 and 2.2 to illustrate the capabilities of the model. The proposed model is assumed to be appropriate for the analysis of a power system in the presence of inverter based DGs.

### 3 Impact of Distributed Generation on Protective Relaying

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#### 3.1 Protection planning

Protection system planning is an indispensable part of an electric power system design. Analysis of fault level, pre-fault condition, and post-fault condition are required for the selection of interruption devices, protective relays, and their settings and coordination. Installation of DG increases the fault current throughout the system. For synchronous machine DGs, the increase of fault current due to DG installed depends on many factors, such as DG size, transient impedance, location, and pre-fault voltage of the DG. Analysis of fault current by modifying the traditional algorithm (i.e., analysis of bus impedance matrix) is discussed.

There are many technologies for distributed resources beyond the conventional synchronous machine DGs such as fuel cells, wind turbines, solar cells, and microturbines. These DGs require electronic interfaces to interconnect with the utility grid. Hence, these DGs are so called “inverter based DGs.” Model of the inverter based DGs may be complicated due to complex controls. Therefore, fault analysis of the system with the inverter based DGs by the traditional algorithm may not be easy.

This chapter demonstrates a simulation technique which can be applied to access the impact of installation of DGs (i.e., synchronous machine DGs as well as inverter based DGs) in a subtransmission system. A test bed is produced for illustrative purposes and this test system is denominated as the Thunderstone system. Salt River Project (SRP), a large electric utility company in Phoenix, AZ, supplied the Thunderstone system shown in Figure 3.1 as a test bed. The Thunderstone system is connected to 230 kV transmission system at bus Thunder1, considered as the system slack bus. The voltage level at 230 kV from slack bus is stepped down to 69 kV at the Thunderstone substation, shown in Figure 3.1. The taps of substation transformer at 230 kV and the 12 kV distribution transformers usually operate higher than 1.0 p.u. to reduce the effect of voltage drop in the distribution level. The Thevenin equivalent impedance of 230 kV bus is  $0.75728+j6.183$  ohm per phase. Note that capacitors are installed at the load sites to improved power factors. System parameters of the Thunderstone system are shown in Appendix A.

This chapter is organized as follows: Section 3.2 presents the impact on increase of fault current due to synchronous machine DGs by modifying the conventional fault current calculation. Section 3.3 discusses a simulation technique used to analyze the dynamic performance and the impact on the protection system of the system with DGs. The simulation technique can be used to analyze the system including both synchronous and inverter based DGs. Section 3.4 provides the simulation results of an illustrative case and applications to protective relaying. Finally, Section 3.5 draws conclusions.

### 3.2 Impact on fault current – theory

Fault analysis by means of an impedance matrix can be applied to evaluate the increase of fault current due to installation of DGs. This section discusses the fault analysis of the system with new synchronous machine DGs by modifying the algorithm of the conventional fault current calculation [22]. Positive sequence models are often adequate for balanced short circuit studies which determine the fault response of DGs [58]. In order to calculate the fault current of the system with new synchronous machine DGs, the new impedance matrix needs to be evaluated. For inverter based systems,  $Z_{bus}$  methods are not appropriate because an inverter (plus its controls) is not a constant impedance.

Of course, for all DGs, source model parameters need to be known. The technique which is used to identify the parameters of synchronous machine DGs (i.e., transient impedance of the synchronous machines and open circuit voltage) is well studied. However, a model of inverter based DGs may be complicated due to complex controls, or may be less well understood and accepted. A simulation technique is recommended and illustrated in the following sections.

Assume that the original system can be represented by the original impedance matrix,  $Z_{bus,orig}$ . In this analysis, two synchronous machine DGs are installed at buses  $k$  and  $m$ . Figure 3.2 depicts a system with two newly added DGs. The synchronous machines are simply modeled by transient impedances of  $Z_{DG,k}$  and  $Z_{DG,m}$  and open circuit voltages as shown in Figure 3.2. After the addition of the synchronous machine DGs, buses  $p$  and  $q$  are added to the system.

The relationship between the bus voltages, the injected current  $I_{DG,i}$ , and the elements of bus impedance matrix are given as,

$$\begin{aligned} V_1 &= V_1^0 + I_{DG,p} Z_{1k} \\ V_2 &= V_2^0 + I_{DG,p} Z_{2k} \\ &\vdots \\ V_k &= V_k^0 + I_{DG,p} Z_{kk} \\ V_{DG,p} &= V_k^0 + I_{DG,p} (Z_{kk} + Z_{DG,k}) \\ V_{DG,q} &= V_m^0 + I_{DG,q} (Z_{mm} + Z_{DG,m}), \end{aligned}$$

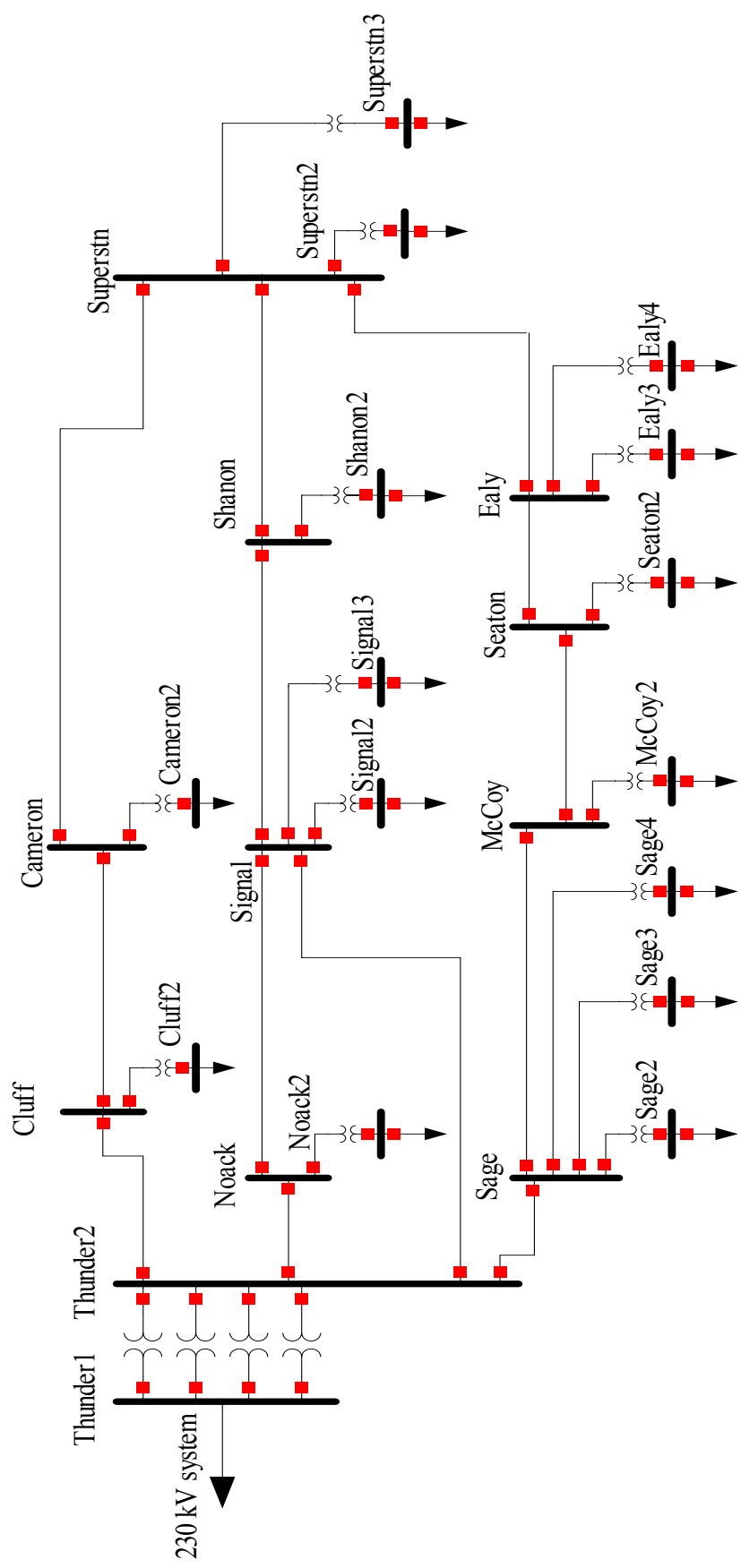


**Figure 3.1 Thunderstone 69 kV transmission system**

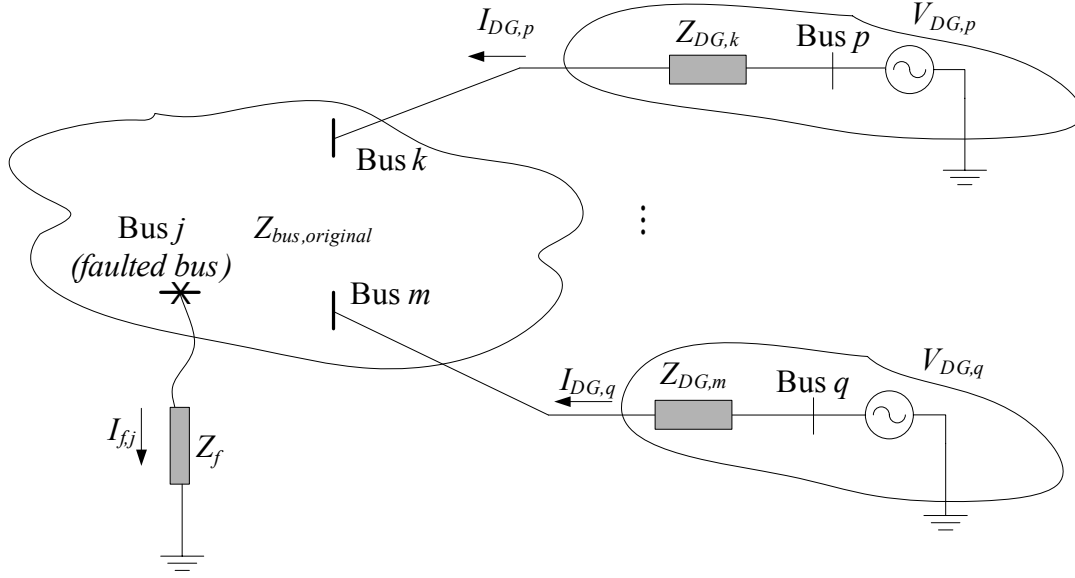


**Figure 3.2** An illustrated system with new DGs added to bus k and m

where  $V_i$  is the voltage after installing the DGs,  $V_i^0$  is the voltage at bus  $i$  before installing the DGs,  $V_{DG,i}$  and  $I_{DG,i}$  are the voltage and injected current of newly added bus to the system, and  $Z_{DG,i}$  is the impedance of synchronous generator installed at bus  $i$ . These system equations including the new DGs can be written in matrix form as

$$\begin{bmatrix} V_{orig} \\ \hline V_{DG,p} \\ V_{DG,q} \end{bmatrix} = \begin{bmatrix} Z_{bus,orig} & \begin{matrix} Z_{1k} & Z_{1m} \\ Z_{2k} & Z_{2m} \\ \vdots & \vdots \\ Z_{nk} & Z_{nm} \end{matrix} \\ \hline \begin{matrix} Z_{k1} & Z_{k2} & \dots & Z_{kn} \\ Z_{m1} & Z_{m2} & \dots & Z_{mn} \end{matrix} & \begin{matrix} Z_{kk} + Z_{DG,k} & Z_{km} \\ Z_{mk} & Z_{mm} + Z_{DG,m} \end{matrix} \end{bmatrix} \begin{bmatrix} I_{orig} \\ \hline I_{DG,k} \\ I_{DG,m} \end{bmatrix} \quad (3.1)$$

where  $m$  and  $k$  are buses with DGs,  $Z_{bus,orig}$  is the bus impedance matrix of the system before installing DGs. Applying Kron's reduction to (3.1) [59], therefore,

$$Z_{bus,new} = Z_{bus,orig} - Z_{col,DGs} Z_{common}^{-1} Z_{row,DGs} \quad (3.2)$$

where

$$Z_{col,DGs} = \begin{bmatrix} Z_{1k} & \dots & Z_{1m} \\ Z_{2k} & \dots & Z_{2m} \\ \vdots & \vdots & \vdots \\ Z_{nk} & \dots & Z_{nm} \end{bmatrix},$$

$$Z_{common} = \begin{bmatrix} Z_{kk} + Z_{DG,k} & & & Z_{mk} \\ & \ddots & & \\ & & Z_{mm} + Z_{DG,m} & \\ Z_{km} & & & \end{bmatrix},$$

$$Z_{row,DGs} = \begin{bmatrix} Z_{k1} & Z_{k2} & \cdots & Z_{kn} \\ \vdots & \vdots & \vdots & \vdots \\ Z_{m1} & Z_{m2} & \cdots & Z_{mn} \end{bmatrix}$$

Note that  $n$  is number of buses in the system not counting  $p$  and  $q$  where  $p$  and  $q$  are DG buses. After calculating new  $Z_{bus}$  matrix, the three phase fault current at bus  $j$  can be calculated as

$$I_j = \frac{V_j}{Z_{jj,new} + z_f} = I_{fj} \quad (3.3)$$

where  $Z_{jj,new}$  is the diagonal element of bus  $j$  in the modified bus impedance,  $V_j$  is the pre-fault voltage of bus  $j$  and  $Z_f$  is the fault impedance.

#### *An illustrative example (a system with new synchronous machine DGs)*

This brief example illustrates the fault current calculation by applying the modify bus impedance matrix as discussed in the previous section. The illustrative case is a simple distribution system with 4 buses. The original system is represented by the bus impedance matrix in p.u.,

$$Z_{bus,orig} = \begin{bmatrix} j0.717 & j0.610 & j0.533 & j0.580 \\ j0.610 & j0.732 & j0.640 & j0.697 \\ j0.533 & j0.640 & j0.717 & j0.670 \\ j0.580 & j0.697 & j0.670 & j0.763 \end{bmatrix}$$

Suppose that two synchronous machine DGs are installed into the system at bus 3 and bus 4 with transient impedances of  $j0.5$  and  $j1.0$  p.u., respectively. The illustrative example is depicted in Figure 3.3.

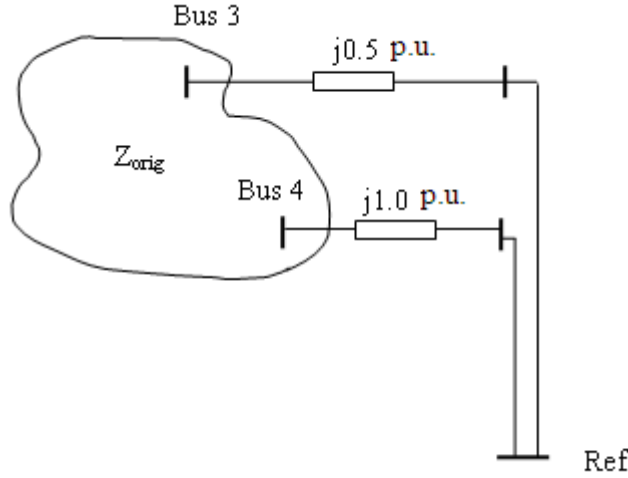


**Figure 3.3 A simple 4-bus system with new DGs at bus 3 and 4**

From (3.2), new bus impedance matrix of the system with newly added DGs can be calculated as

$$Z_{bus,new} = Z_{bus} -$$

$$\begin{bmatrix} j0.533 & j0.580 \\ j0.640 & j0.670 \\ j0.717 & j0.670 \\ j0.670 & j0.763 \end{bmatrix} \begin{bmatrix} j0.717 + j0.5 & j0.670 \\ j0.670 & j0.763 + j1 \end{bmatrix}^{-1} \begin{bmatrix} j0.533 & j0.640 & j0.717 & j0.670 \\ j0.580 & j0.670 & j0.670 & j0.763 \end{bmatrix}$$

$$Z_{bus,new} = \begin{bmatrix} j0.424 & j0.258 & j0.163 & j0.206 \\ j0.258 & j0.310 & j0.195 & j0.247 \\ j0.163 & j0.195 & j0.240 & j0.197 \\ j0.206 & j0.247 & j0.197 & j0.283 \end{bmatrix}$$

Assume that the prefault voltage of the system is 1 p.u. at each bus. The three phase fault current can be calculated by applying (3.3),

$$I_j = \frac{V_j}{Z_{jj,new} + z_f}.$$

Table 3.1 shows the results of replacing diagonal elements of  $Z_{bus,new}$  into Equation (3.3) and the change of fault currents after installing new DGs.

As shown in Table 3.1, from the simple 4-bus system represented by  $Z_{bus}$  matrix, the fault currents are increased after installing new DGs into the system. Note that the change of

fault current,  $\Delta|I_f|$  “spreads” throughout the system. Intuitively, that is, because fault current propagates throughout the network, so does the change in  $I_f$ .

**Table 3.1 Summary of calculation for the simple 4-bus system shown in Figure 3.3**

| Bus | Fault current before installing DG (p.u.) | Fault current after installing DG (p.u.) | $\Delta I_f $ (%) |
|-----|-------------------------------------------|------------------------------------------|-------------------|
| 1   | 1.39                                      | 2.36                                     | 96.8 %            |
| 2   | 1.37                                      | 3.23                                     | 135.7 %           |
| 3   | 1.39                                      | 4.17                                     | 200 %             |
| 4   | 1.31                                      | 3.53                                     | 169.5 %           |

The model of the added generation used above is the conventional model of a synchronous generator. Not all DGs are conventional synchronous generators. Many DGs are energy sources that produce DC which is used as the input to an inverter which ultimately interfaces with the AC system. The controls of that inverter determine how the inverter is ‘seen’ by the network. The full treatment of inverter based DGs may not be as easy as these remarks and procedures. DG controls are not standardized and control modeling is problematic. The following sections in this chapter propose the simulation technique to study the fault response of the system after installing inverter based DGs and/or synchronous machine DGs.

### 3.3 Simulation strategies

As discussed in the previous section, the analysis of fault current of the system with the presence of inverter based DGs is complicated. Hence, a simulation technique performed in Matlab Simulink is proposed. The major advantage of the simulation technique is the ability to evaluate the response of the system with complicated elements (e.g., power electronic elements). In this chapter, the strategies of the dynamic simulations of the system with synchronous machine DGs and/or inverter based DGs are discussed based on Matlab Simulink 6.0 environments.

Simulink is a software package for modeling, simulating, and analyzing dynamic systems. A graphical user interface (GUI) for building models as block diagrams is provided. The power system block sets (PSB) in Simulink are developed at TEQSIM Inc. and Hydro-Quebec. The PSB library contains Simulink blocks that represent common components and devices found in electrical power networks (e.g., transformer, transmission line, synchronous machine, and constant impedance / power load).

The simulation of synchronous machine DGs in Simulink is derived from voltage equations and flux linkage equations expressed in the rotational reference frame. Details of the synchronous machine model are discussed in [11,60]. The model of inverter based DGs are discussed in Chapter 3.

The simulation of the power system in Simulink is accomplished by creating the time model state space representation of the system. The simulation is performed by applying the numerical differential equations solvers (e.g., trapezoidal method, Adams method, modified Rosenbrock method and the Runge-Kutta method) [61]. The results of simulations, such as voltages and currents measured in the system, can be recorded for further analysis.

In general, the simulation time steps are 50 microseconds. This is recommended as a typical figure for a 60 Hz system. The simulation interval in the illustrative examples shown is 0 – 1 second. Longer simulation times are unlikely to be needed, but could be easily accommodated using the indicated software.

### **3.4 Application of the simulation technique to protective relaying: the impact of DGs on system protection**

In this section, the Thunderstone system is used as a test bed to illustrate the simulation technique (data given in Appendix A). The impact of the presence of synchronous generators and inverter sources to the test bed system is investigated. The illustrative cases are separated into three parts: no DGs in the system in Case 3.1, the system with synchronous machine DGs in Case 3.2 and the system with inverter based DGs in Case 3.3. Summary of the illustrative cases are provided in Table 3.2

In Cases 3.2 and 3.3, to study the fault response of the Thunderstone system with DGs presence, synchronous machine DGs and inverter based DGs are installed at various locations. Parameters of the synchronous machine DGs applied in the simulations (in Case 3.2) are identical and shown in Table 3.1. Same as the inverter based DGs (in Case 3.3), all machine parameters are identical and shown in Table 3.1 of Chapter 3. In all cases, a bolted fault in the Thunderstone system occurs at the midpoint of the transmission line between Superstition and Ealy (69 kV) at  $t = 0.4$  s. The fault is cleared at 500 ms or 100 ms after fault occurs. This 100 ms fault is a commonly selected duration time for fault analysis. The impedance ( $Z$ ), resistance ( $R$ ) and inductance ( $X$ ) measured from (i.e., “seen” from) various buses are measured near the DGs such as, Ealy2 (12.47 kV bus), Superstition (12.47 kV bus), transmission line from Shanon to Superstition (69 kV) and transmission line from Ealy to Superstition (69 kV). Measurement points in the Thunderstone system are shown in Figure 3.4. Note that per unit base used in all illustrative cases is 100 MVA.

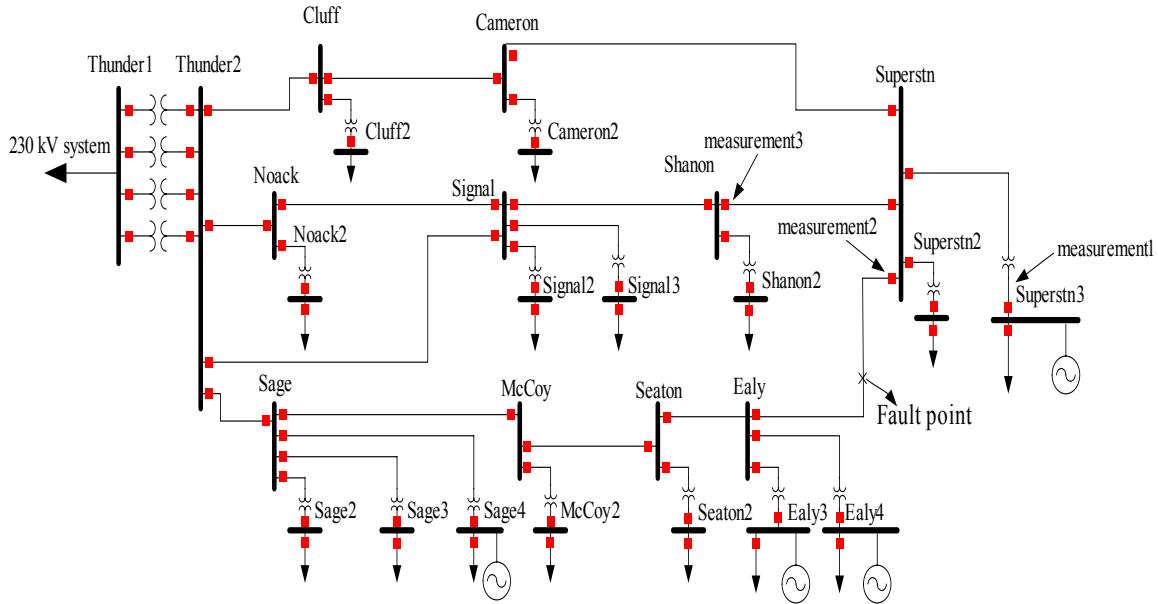


**Figure 3.4 The Thunderstone system with measurement points**

For the purposes of this presentation, the notation and procedures of power system protective relaying are used with regard to  $Z$ ,  $R$ , and  $X$ . These quantities are ratios of rms volts to rms amps, and the rms is carried out over one cycle (i.e., 1/60 s). The measurement at bus Ealy1 and Superstition1 is detected at the point of common coupling (PCC) or the point of DR connection at secondary side of 69/12.47 kV distribution transformer. The analysis is performed by assuming that all DGs have constant power output and loads in the system at 12.47 kV buses are considered as constant impedance loads.

In both Cases 3.2 and 3.3, DGs are installed into 12.47 kV buses at four locations: Sage4, Superstition3, Early1 and Ealy2. The generation capacity of each synchronous DG in Case 3.2 and inverter based DG in Case 3.3 are 5 MW. The penetration level in the system is approximately 7% based on the total load of Thunderstone system (300 MVA).

For purposes of graphic illustration, two devices are used. A three dimensional plot can be used to depict the behavior of  $X$ ,  $R$  versus time. The three dimensional plots in Matlab is equipped with ability to zoom-in, zoom-out and rotate graphs to any orientations. This ability cannot be completely demonstrated in this report. However, the plots of  $X$ ,  $R$  versus time are shown in various angles. Although interesting in appearance, these plots may be difficult to understand, and therefore a two dimensional plot is used, namely  $|Z|$  versus time. The cylinder in the plots of  $X$ - $R$  vs. time represents characteristic of the impedance relay. The impedance relay operates when the impedance measured at the bus falls within the cylinder (80% of the line impedance for protection zone 1 and 120% for zone 2). Also note that the circle in the  $X$ - $R$  plots represents the characteristic of the impedance relay. The rotating graphic capability appears to be useful to conceptualize the  $R$ - $X$ - $t$  character-

istic. For example, if only the  $R$ - $X$  plane is needed (i.e., the time of entry of a trajectory into a zone of protection of a relay), the plot may be rotated so that  $t$  is perpendicular to the page (or computer screen). If the time dial setting is needed, the plot is rotated  $45^\circ$  so that the entry of the trajectory into the zone of protection is visible. Other interpretations of rotated plots are also possible.

The results of calculating root-mean-square voltages and currents for relaying applications are shown in the plots of  $X$ - $R$ ,  $X$ - $R$  vs. time and impedance vs. time. The plots of  $X$ - $R$  and  $X$ - $R$  vs. time are separated into 3 durations: before fault ( $T_s = 0.3$ – $0.4$  s), during fault ( $T_s = 0.4$ – $0.5$  s) and after the fault is cleared ( $T_s = 0.5$ – $1.0$  s).

**Table 3.2 Summary of the illustrative cases**

| <i>Case</i> | <i>Total Output of Syn-chronous machine DG</i>               | <i>Total Output of Inverter-Based DG</i>                     | <i>Source model</i>                              | <i>Type of Fault</i>                                       | <i>Fault duration</i> |
|-------------|--------------------------------------------------------------|--------------------------------------------------------------|--------------------------------------------------|------------------------------------------------------------|-----------------------|
| 3.1         | None                                                         | None                                                         | Thevenin equivalent $Z-V$ supply                 | 3 Phase bolted fault between Superstition and Ealy (69 kV) | 0.4 – 0.5 s           |
| 3.2         | 4 locations (4x5 MW): Sage4, Superstition3, Early1 and Ealy2 | None                                                         | Park's Equations                                 | 3 Phase bolted fault between Superstition and Ealy         | 0.4 – 0.5 s           |
| 3.3         | None                                                         | 4 locations (4x5 MW): Sage4, Superstition3, Early1 and Ealy2 | Constant power inverter model given in Chapter 2 | 3 Phase bolted fault between Superstition and Ealy (69 kV) | 0.4 – 0.5 s           |

**Table 3.3 Synchronous machine parameters**

| <i>Machine parameter</i>    |         | <i>Synchronous DG*</i> |
|-----------------------------|---------|------------------------|
| Rated MVA                   |         | 5 MVA                  |
| Rate output voltage         |         | 4.16 kV                |
| Step up transformer (7 MVA) |         | 0.074 p.u.             |
| Synchronous reactance       | $X_d$   | 1.305 p.u.             |
|                             | $X_q$   | 0.474 p.u.             |
| Transient reactance         | $X_d'$  | 0.202 p.u.             |
|                             | $X_q'$  | 0.243 p.u.             |
| Subtransient reactance      | $X_d''$ | 0.15 p.u.              |
|                             | $X_q''$ | 0.18 p.u.              |

\*Per unit base: 5 MVA, 4.16 kV (machine); 7 MVA, 4.16 kV (transformer)

*Case 3.1 Simulation of three phase to ground bolted fault at Ealy (69 kV) of the Thunderstone system with no DG*

In Case 3.1, no DG is installed in the Thunderstone system. A three phase bolted fault occurs at the middle of the line between Superstition and Ealy (69 kV). The purpose of the Case 3.1 is to compare the fault response of the system with other cases.

Figures 3.5 and 3.6 show the voltage and current measured at the fault location. The plots of  $X-R$ ,  $X-R$  vs. time and the impedance vs. time measured at bus Superstition (12.47 kV) are shown in Figures 3.7-9. The plots of impedance of the transmission line between Superstition and Ealy are shown in Figures 3.10-11. The plots of impedance of the transmission line between Shanon and Superstition (69 kV) are shown in Figures 3.12-14.

In Figures 3.7-8, the plots of  $X-R$  vs. time and  $X-R$  indicate that the fault is not detected by the relay at bus Superstition in the system without DGs. In Figures 3.10-11, the fault is detected by the distance relay when the plots fall in the cylinder at  $t = 0.4027$  s. Since the fault occurs at 0.4 s, it takes 2.7 ms for the three phase fault to be detected by the distance relay in Case 3.1.

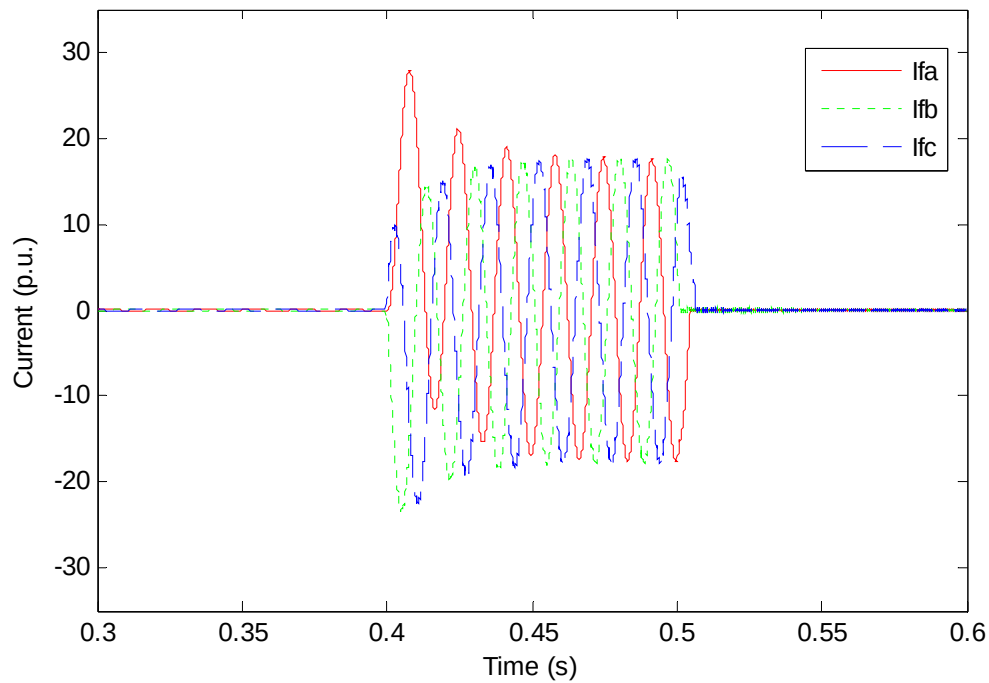


**Figure 3.5 Fault current at the fault point with no DG in the system, Case 3.1**  
(Per unit base: 100 MVA, 69 kV)

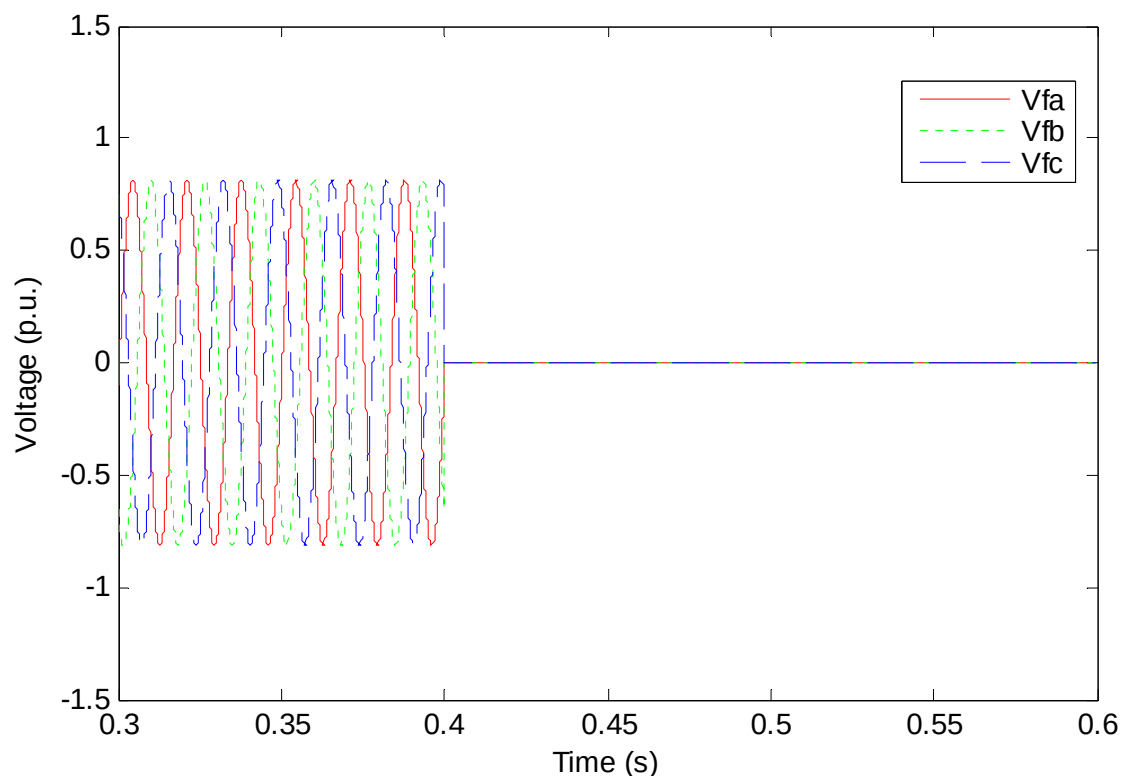


**Figure 3.6 Fault voltage (line-neutral) at the fault point with no DG in the system, Case 3.1**  
 (Per unit base: 100 MVA, 69 kV)

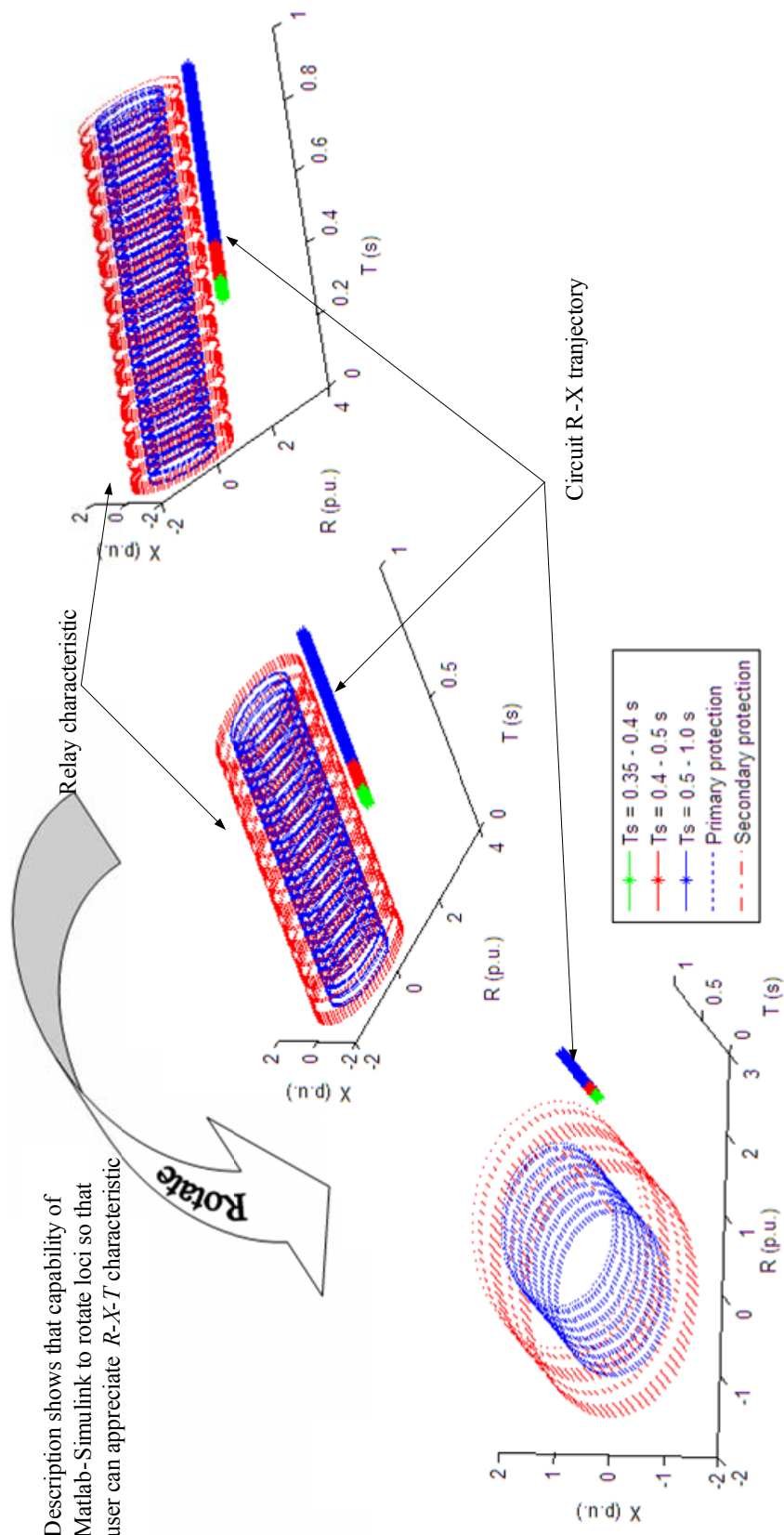


**Figure 3.7 Plot of  $X$ - $R$  vs. time at Superstition3 (12.47 kV), Case 3.1**  
(Per unit base: 100 MVA, 12.47 kV)

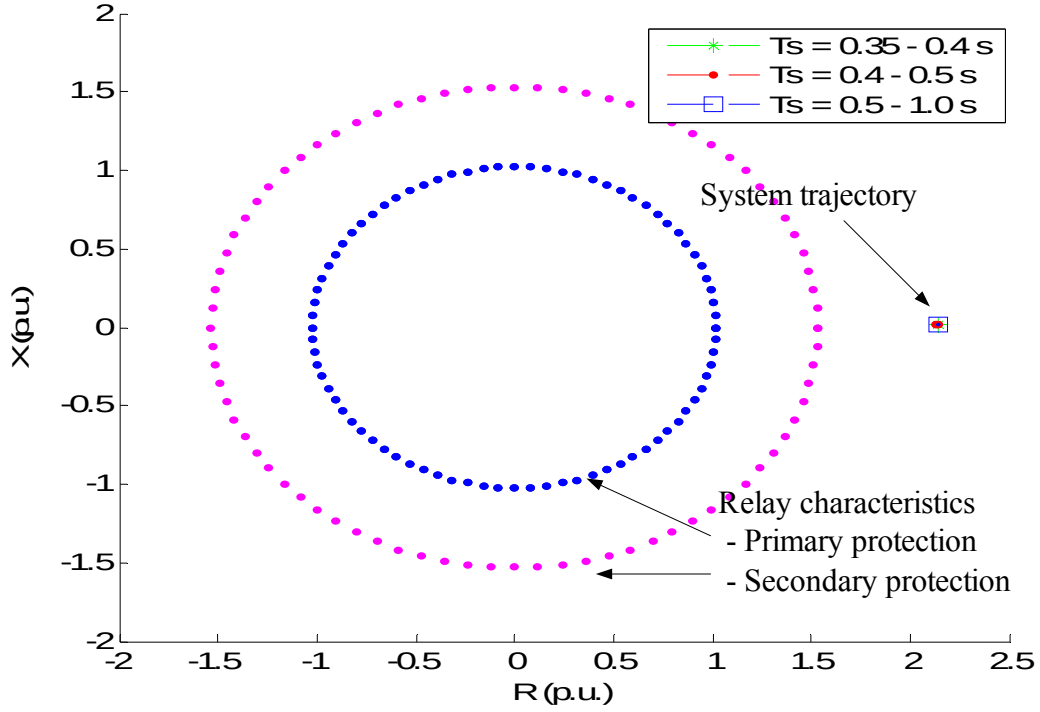


**Figure 3.8 Plot of  $X$ -  $R$  at Superstition3 (12.47 kV), Case 3.1**  
(Per unit base: 100 MVA, 12.47 kV)

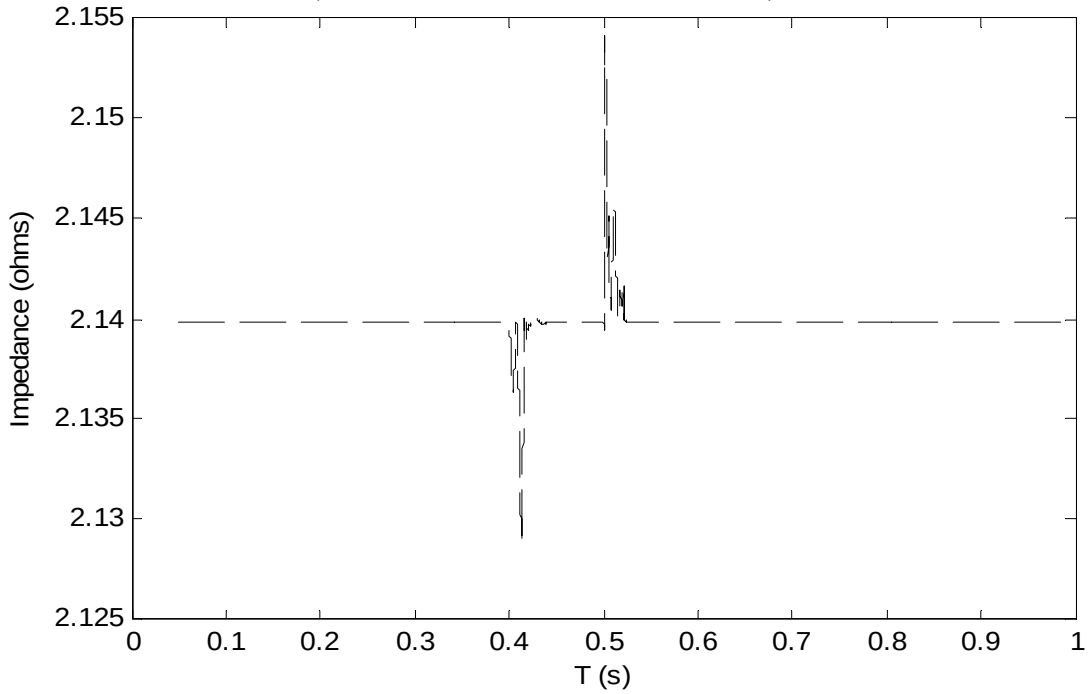


**Figure 3.9 Plot of magnitude of impedance seen at Superstition3 (12.47 kV) vs. time, Case 3.1**  
(Per unit base: 100 MVA, 12.47 kV)

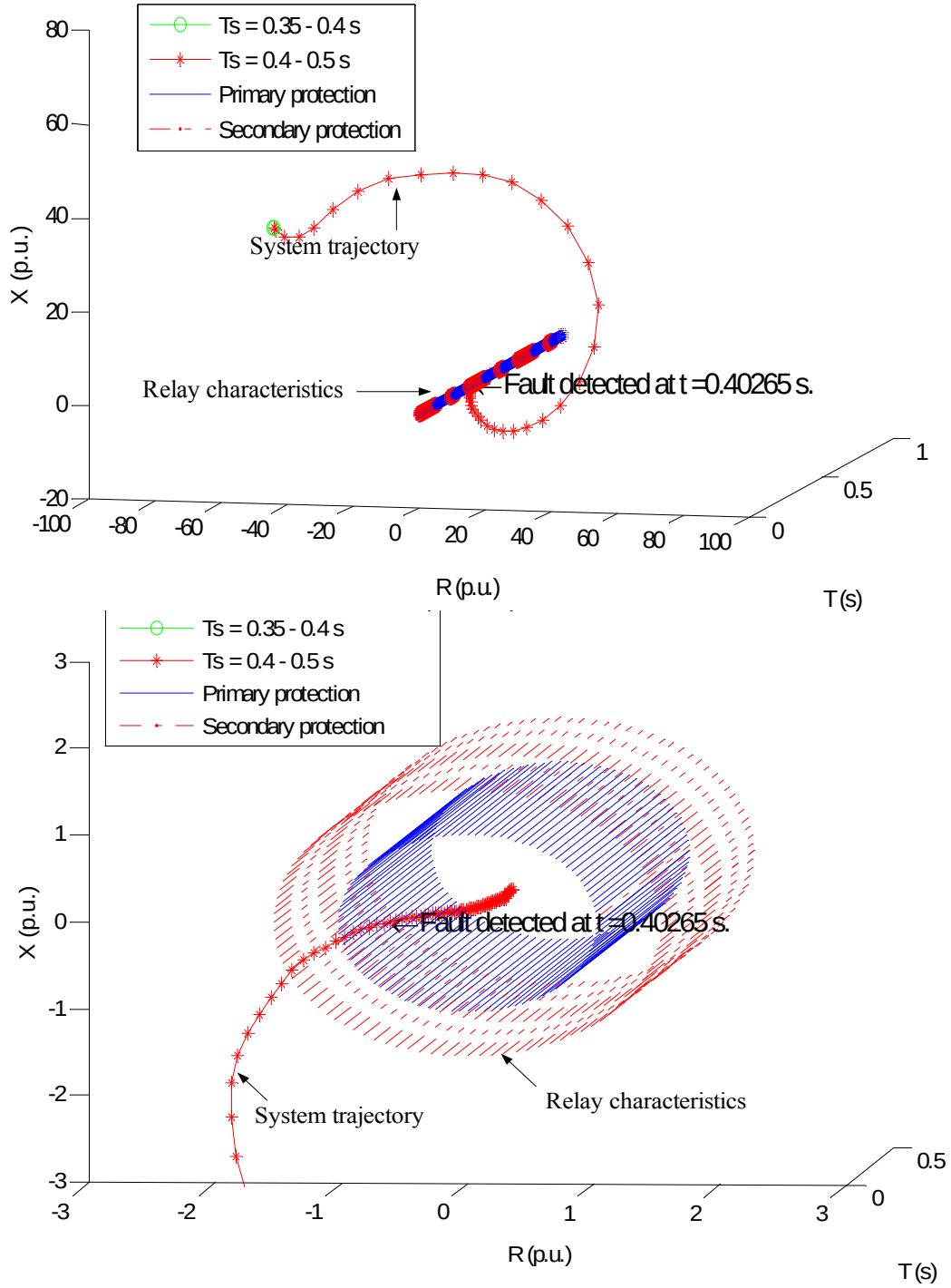


**Figure 3.10 (a) Plot of X- R vs. time seen by the distance relay at transmission line from Superstition to Ealy (69 kV), Case 3.1 (b) zoom-in view (Per unit base: 100 MVA, 69 kV)**

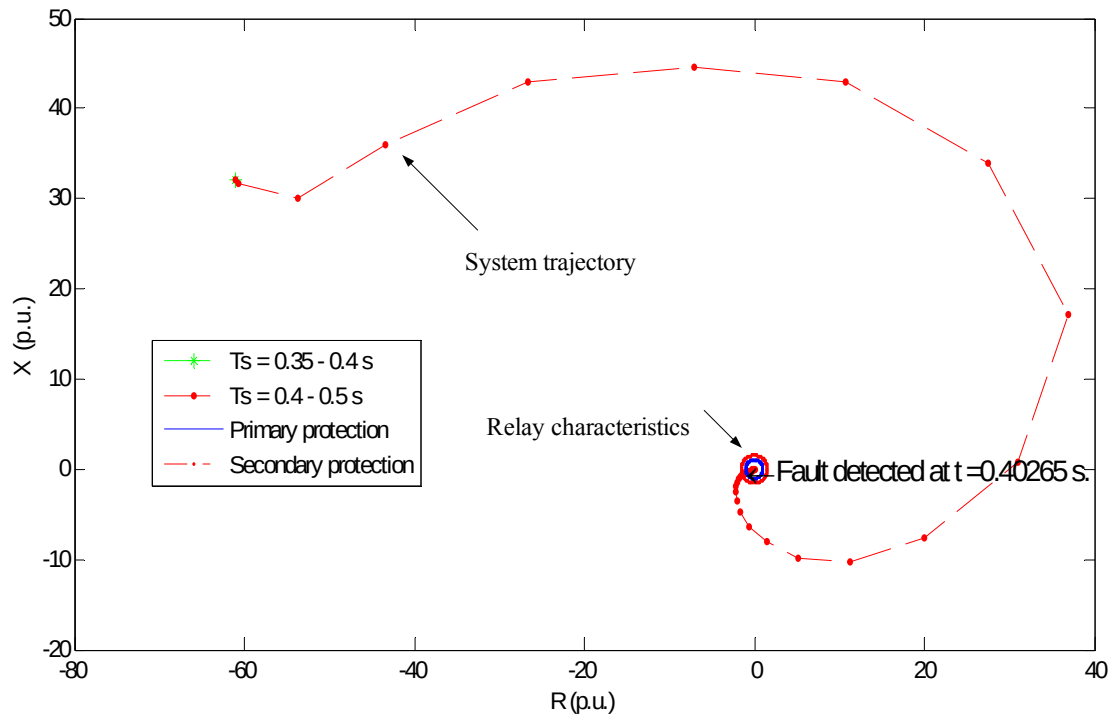


**Figure 3.11 (a) Plot of  $X$ - $R$  seen by the distance relay at transmission line from Superstition to Ealy (69 kV), Case 3.1 (b) zoom-in view**  
(Per unit base: 100 MVA, 69 kV)

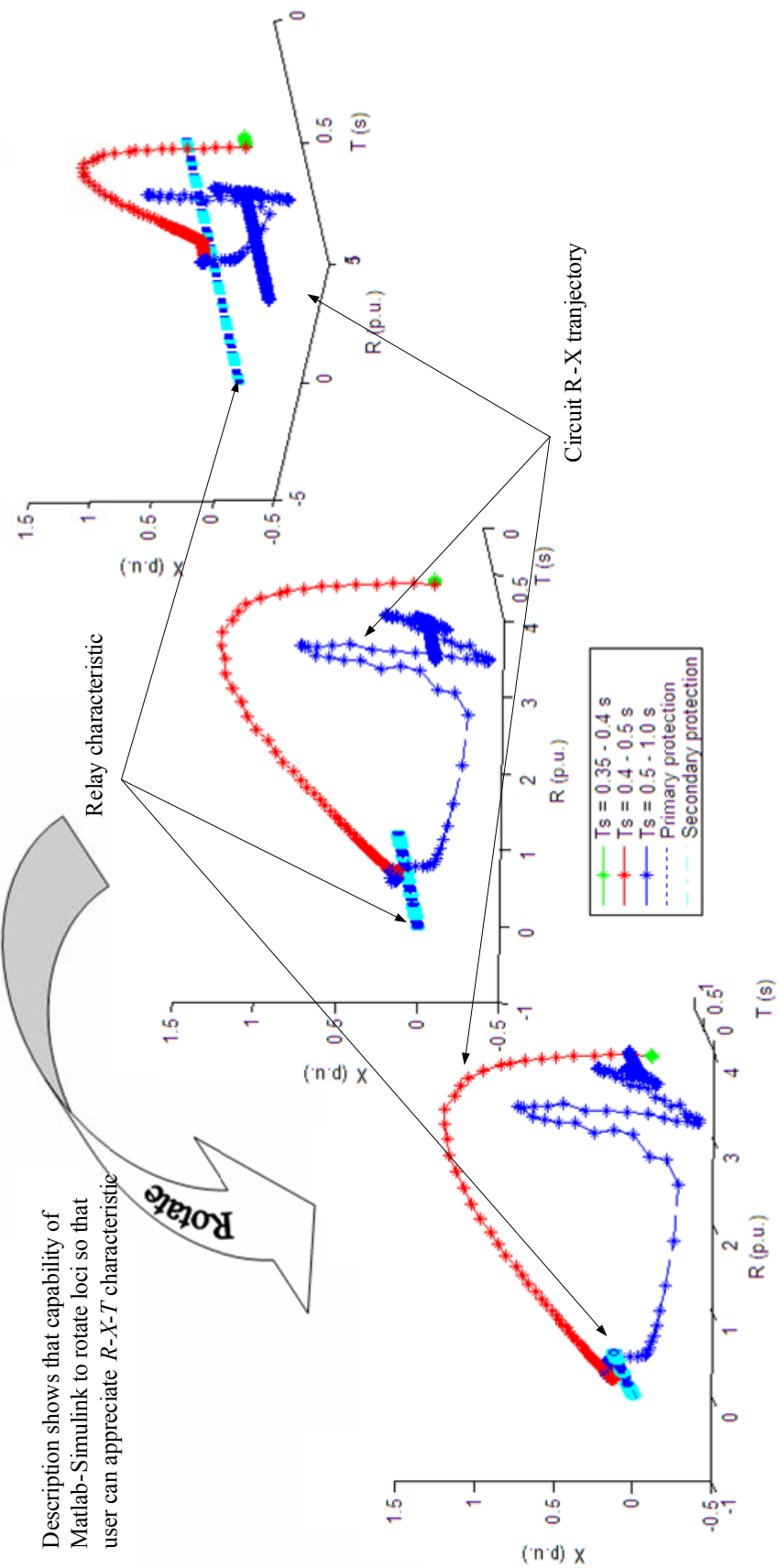


**Figure 3.12 Plot of  $X$ -  $R$  vs. time seen by distance relay at transmission line between Shanon-Superstition (69 kV), Case 3.1**  
 (Per unit base: 100 MVA, 69 kV)

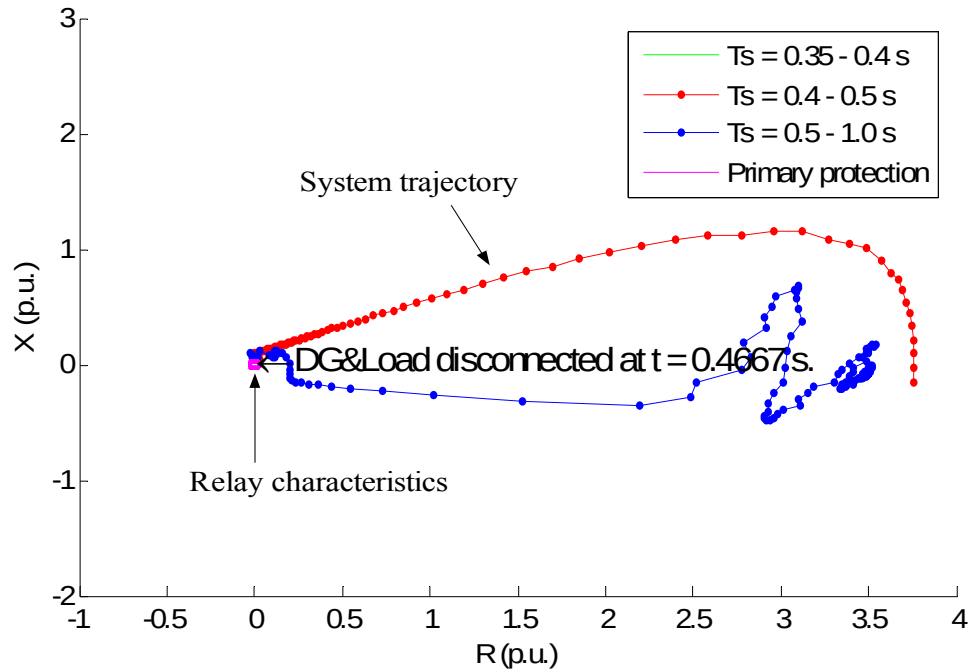


**Figure 3.13 Plot of  $X$  and  $R$  seen by distance relay at transmission line between Shanon-Superstition (69 kV), Case 3.1**  
(Per unit base: 100 MVA, 69 kV)

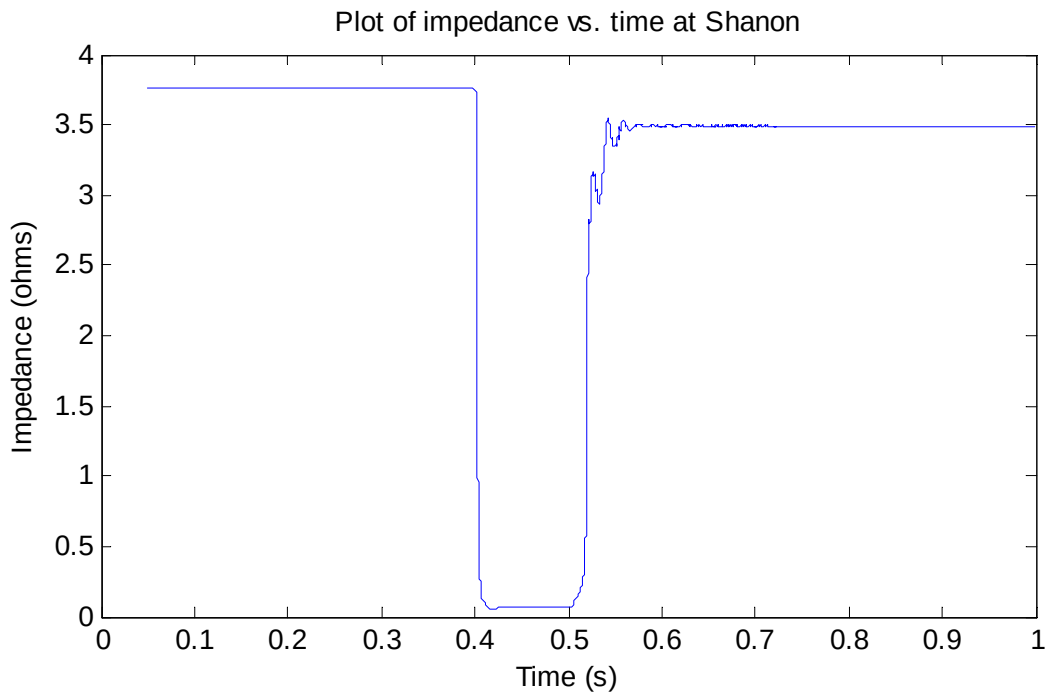


**Figure 3.14 Plot of magnitude of impedance seen by distance relay at transmission line between Shanon-Superstition (69 kV), Case 3.1**

*Case 3.2 Simulation of three phase to ground bolted fault at bus Ealy (69 kV) of the Thunderstone system with four synchronous machine DGs*

In Case 3.2, four synchronous machine DGs are installed in the Thunderstone system: Sage4, Superstition3, Early1 and Ealy2. A three phase bolted fault occurs at the middle of the line between Superstition and Ealy (69 kV). The fault starts at 0.4 s and is cleared at 0.5 s.

Figures 3.15 and 3.16 show the voltage and current measured at the fault location. In Figure 3.17-19, the plots of  $X-R$  and  $X-R$  vs. time indicate that the fault is detected by the impedance relay at bus Superstition3 (12.47 kV). Note that the  $X-R$  plot when the fault is detected fall into the lower half of the circle. This indicates that the fault current flows from the DG at bus Superstition3 to the fault point. The fault is detected at bus Superstition3 at  $t = 0.4130$  s.

The plots of impedance of the transmission line between Superstition and Ealy are shown in Figures 3.20-21. The fault is detected at  $t = 0.4024$  s. Due to the increase of fault current after installing the DGs the fault is detected faster than it does in Case 3.1. The plots of impedance of the transmission line between Shanon and Superstition (69 kV) are shown in Figures 3.22-24.

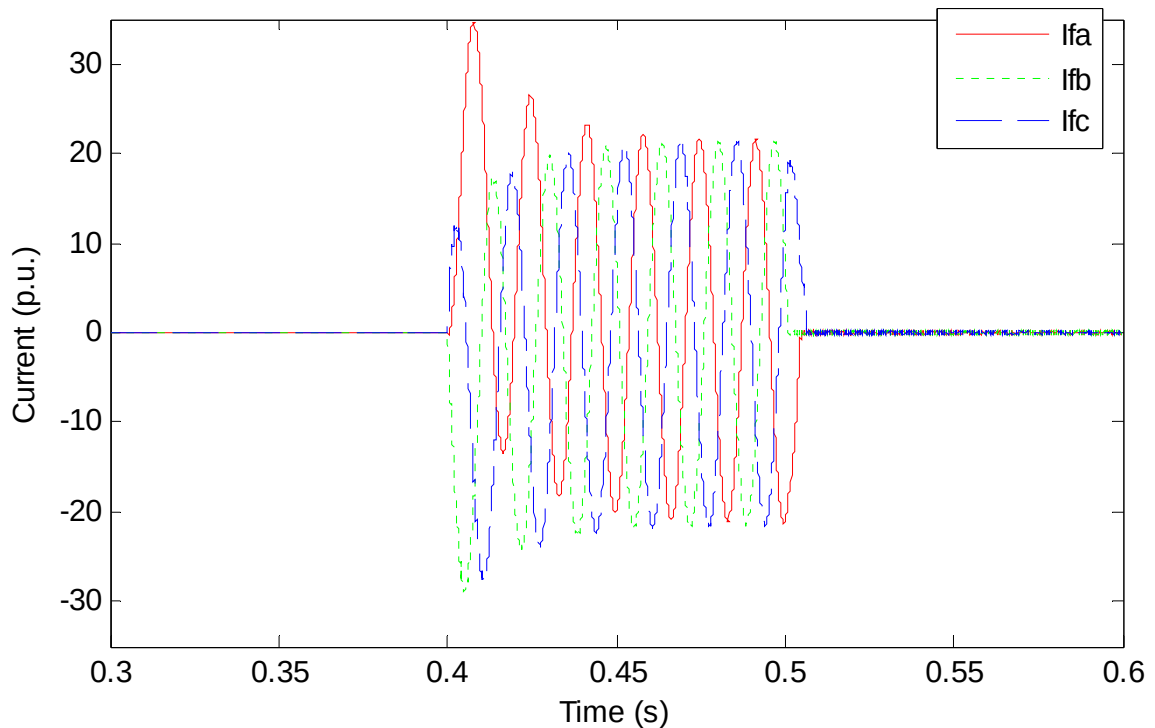


**Figure 3.15 Fault current at the fault point with four synchronous machine DGs in the system, Case 3.2**  
(Per unit base: 100 MVA, 69 kV)

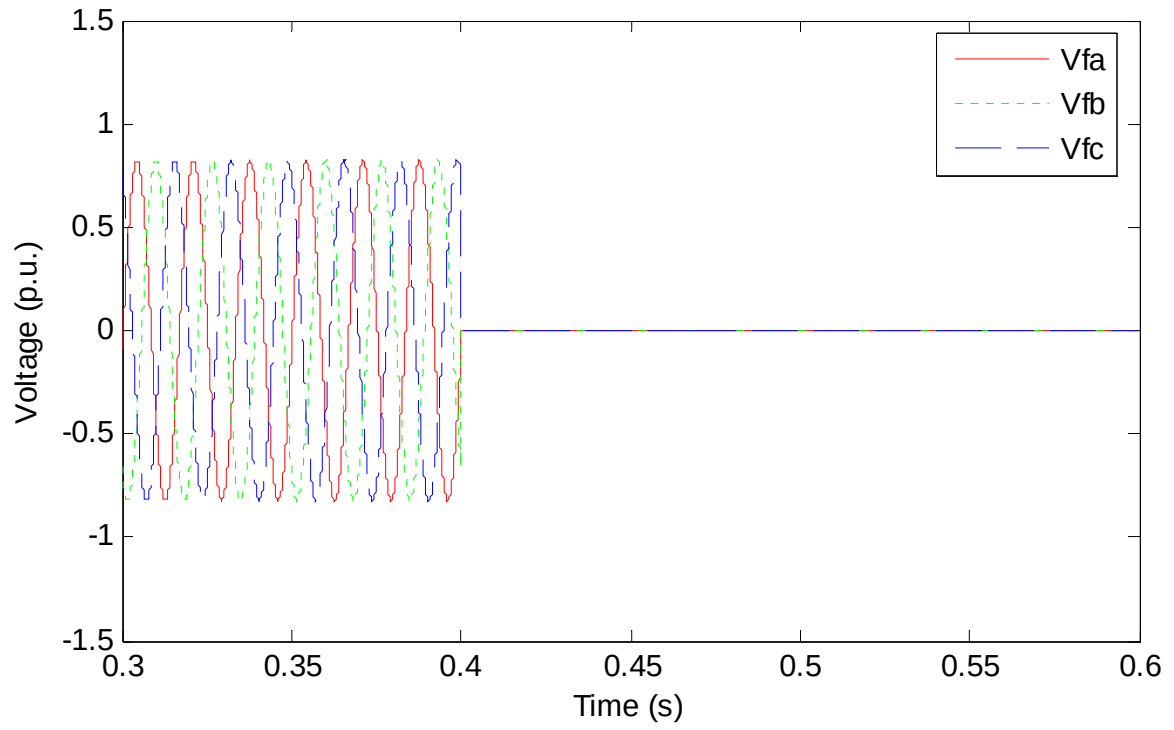


**Figure 3.16 Fault voltage at the fault point with four synchronous machine DGs in the system, Case 3.2**  
(Per unit base: 100 MVA, 69 kV)

Description shows that capability of Matlab -Simulink to rotate loci so that user can appreciate  $R$ - $X$ - $T$  characteristic

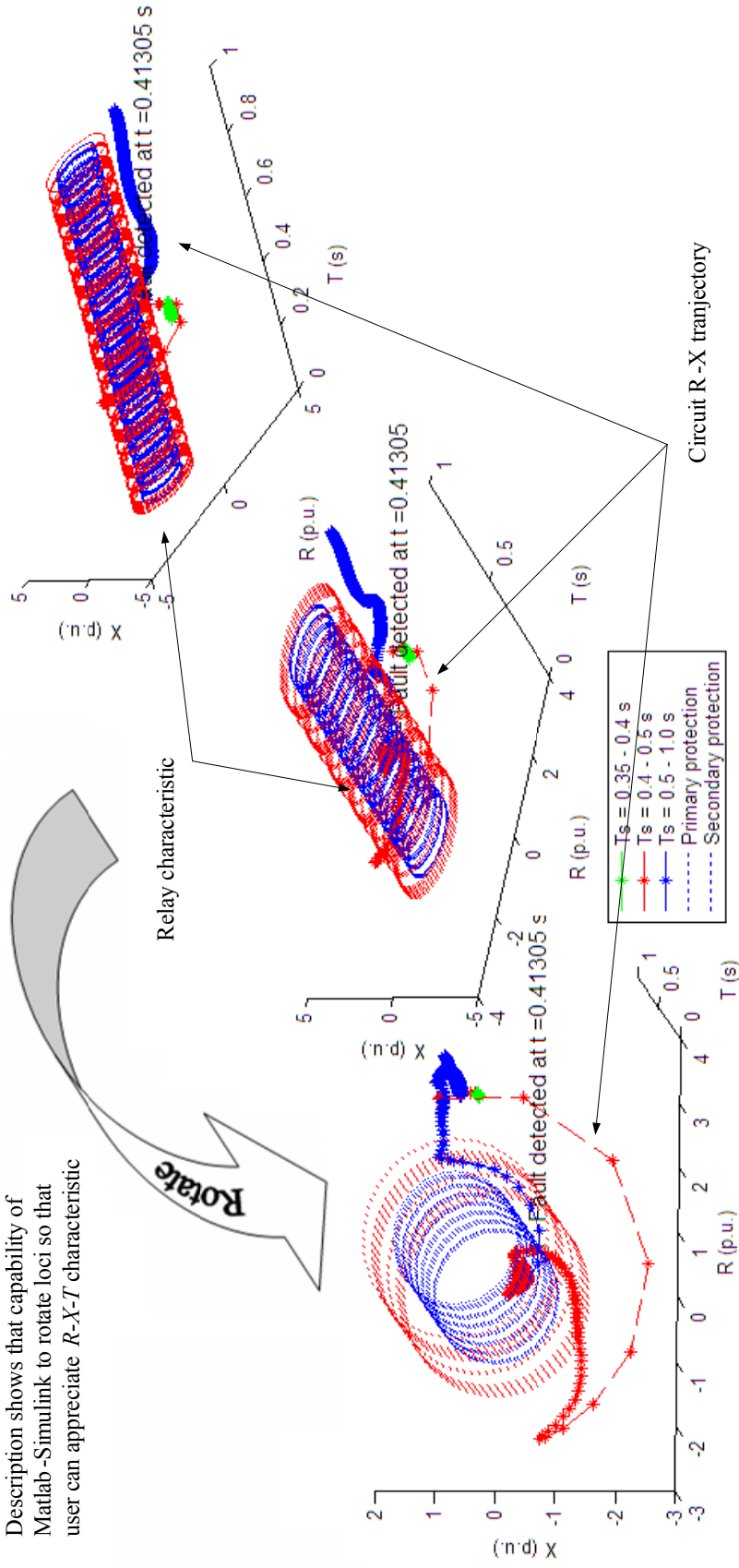


**Figure 3.17 Plot of  $X$ - $R$  vs. time at Superstition3 (12.47 kV), Case 3.2**  
(Per unit base: 100 MVA, 12.47 kV)

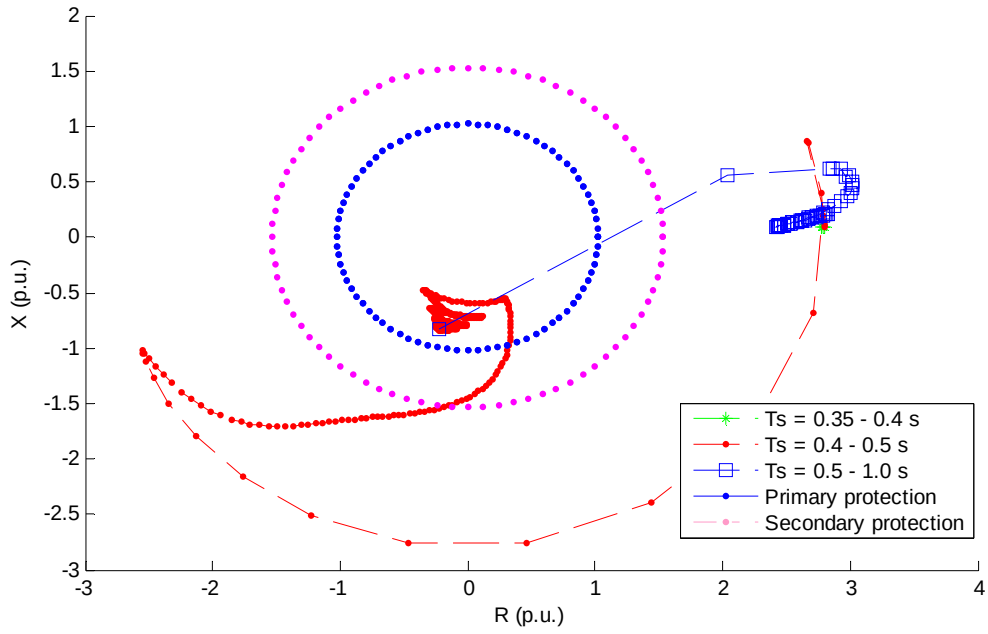


**Figure 3.18 Plot of  $X, R$  at Superstition3 (12.47 kV), Case 3.2**  
(Per unit base: 100 MVA, 12.47 kV)

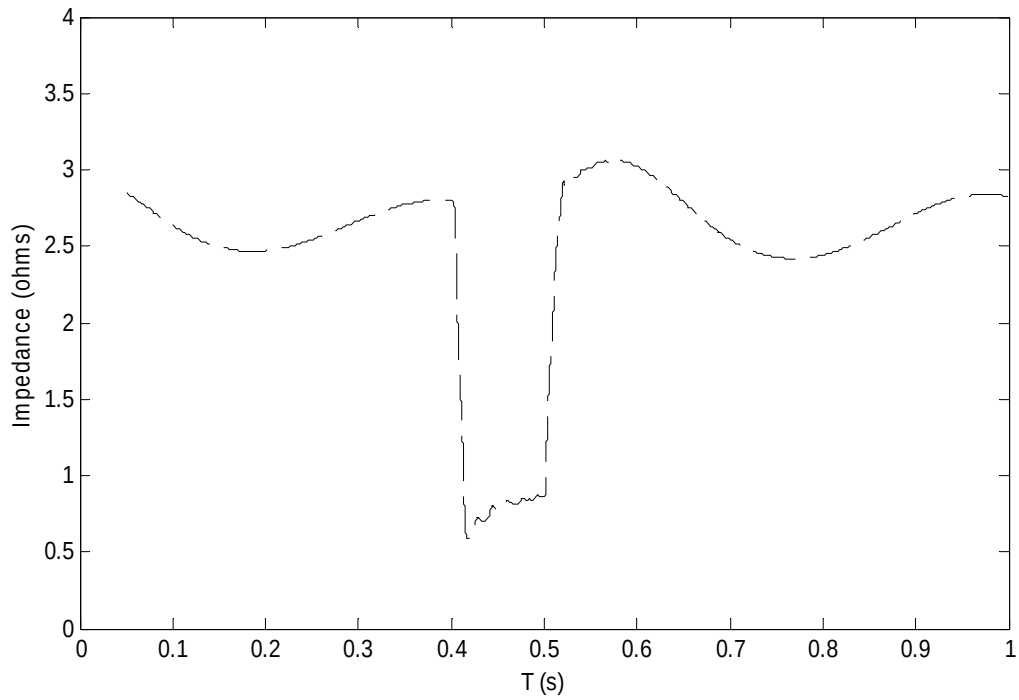


**Figure 3.19 Plot of magnitude of impedance seen at Superstition3 (12.47 kV) vs. time, Case 3.2**

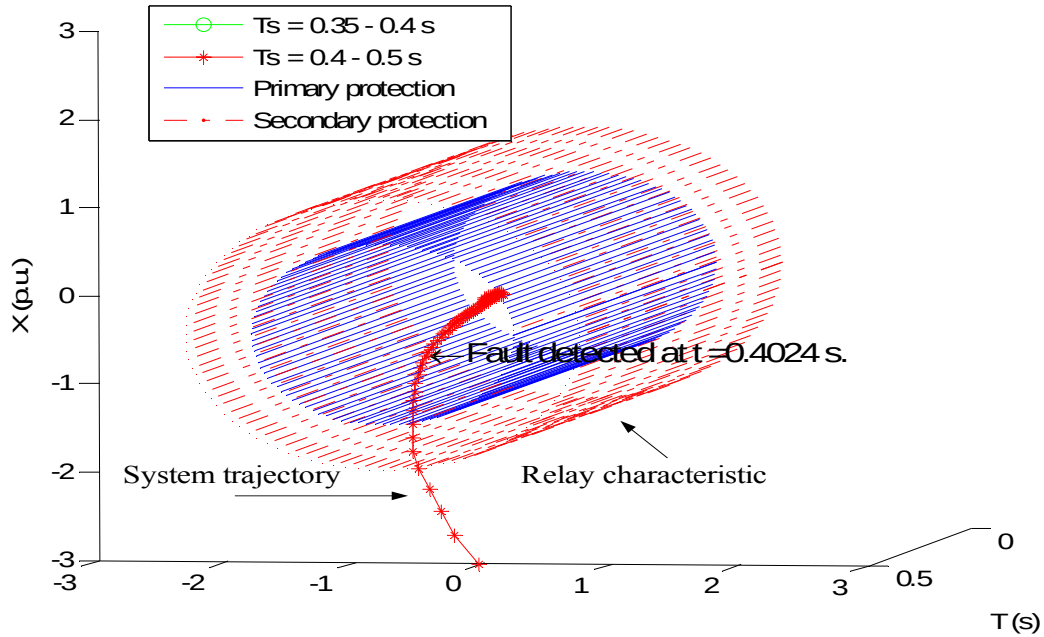


**Figure 3.20 (a) Plot of  $X$ -  $R$  vs. time seen by the distance relay at transmission line from Superstition to Ealy (69 kV), Case 3.1 (b) zoom-in view**  
(Per unit base: 100 MVA, 69 kV)

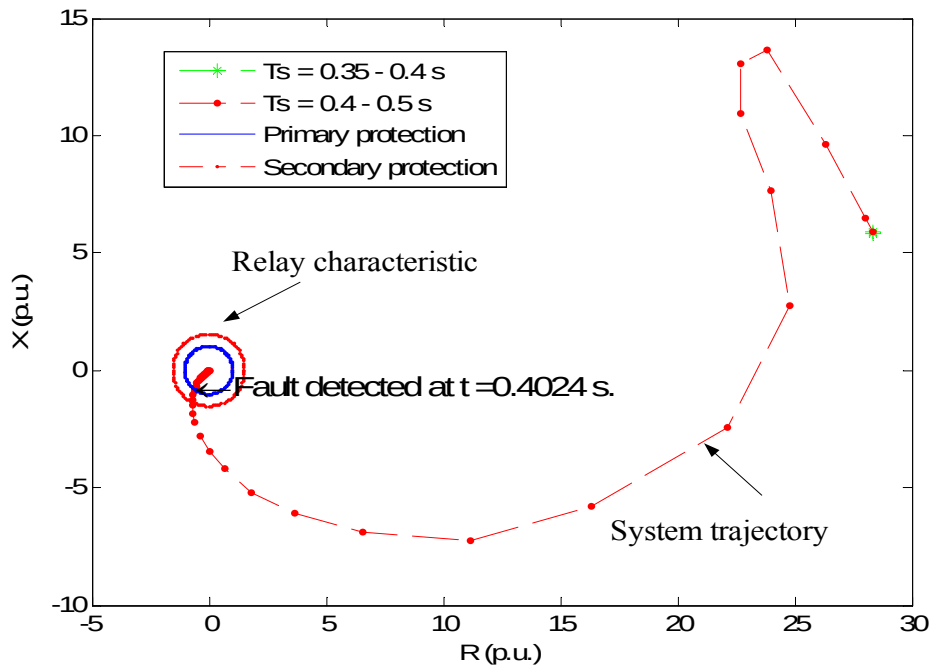


**Figure 3.21 (a) Plot of  $X$ -  $R$  seen by the distance relay at transmission line from Superstition to Ealy (69 kV), Case 3.1 (b) zoom-in view**  
(Per unit base: 100 MVA, 69 kV)

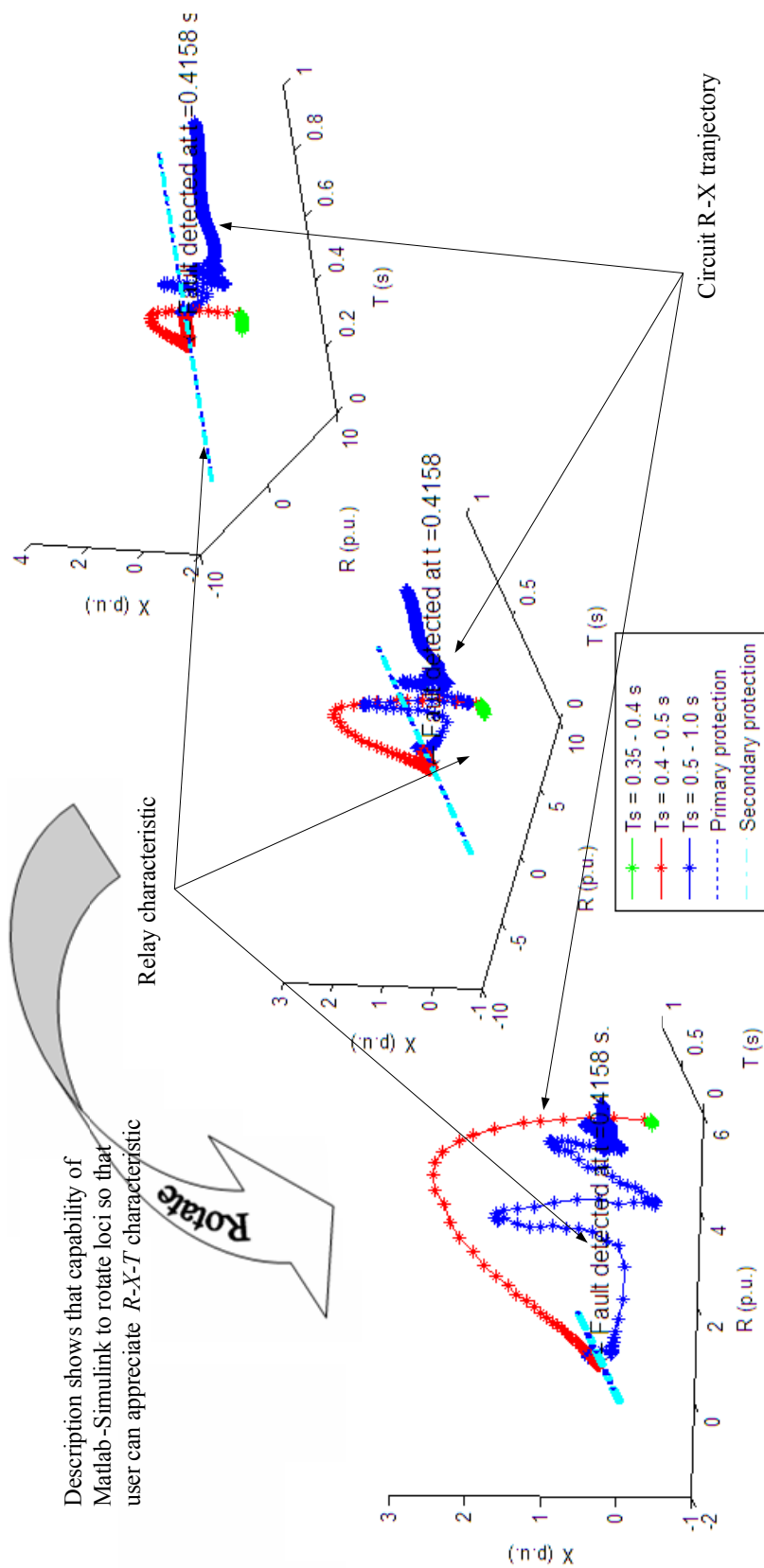


**Figure 3.22 Plot of  $X$ - $R$  vs. time seen by distance relay at transmission line between Shanon-Superstition (69 kV), Case 3.2**  
 (Per unit base: 100 MVA, 69 kV)

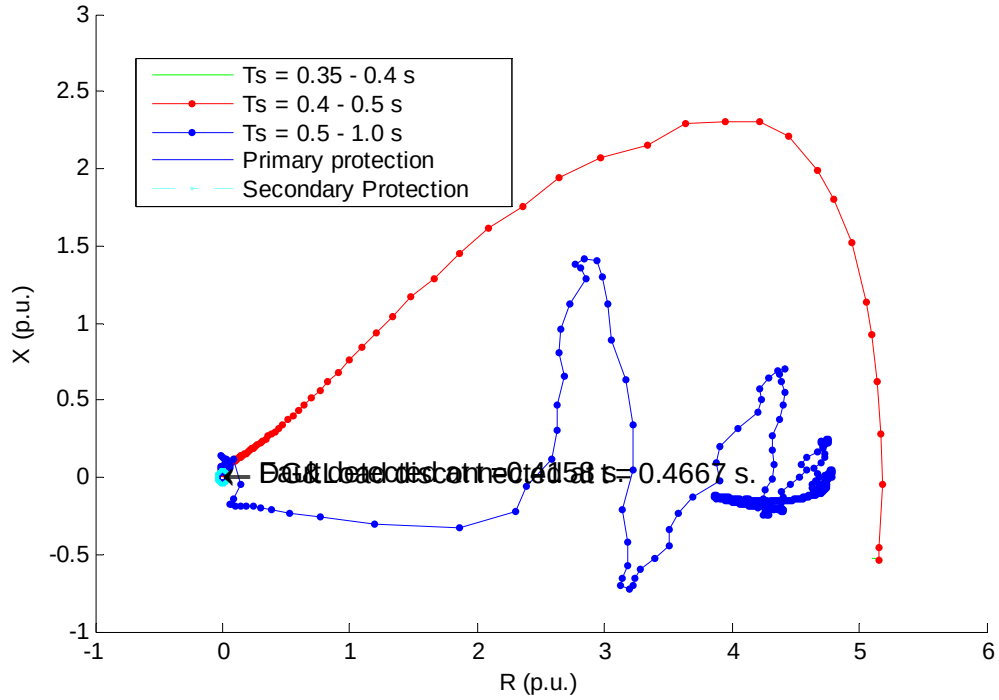


**Figure 3.23 Plot of  $X$  and  $R$  seen by distance relay at transmission line between Shanon-Superstition (69 kV), Case 3.2**  
(Per unit base: 100 MVA, 69 kV)

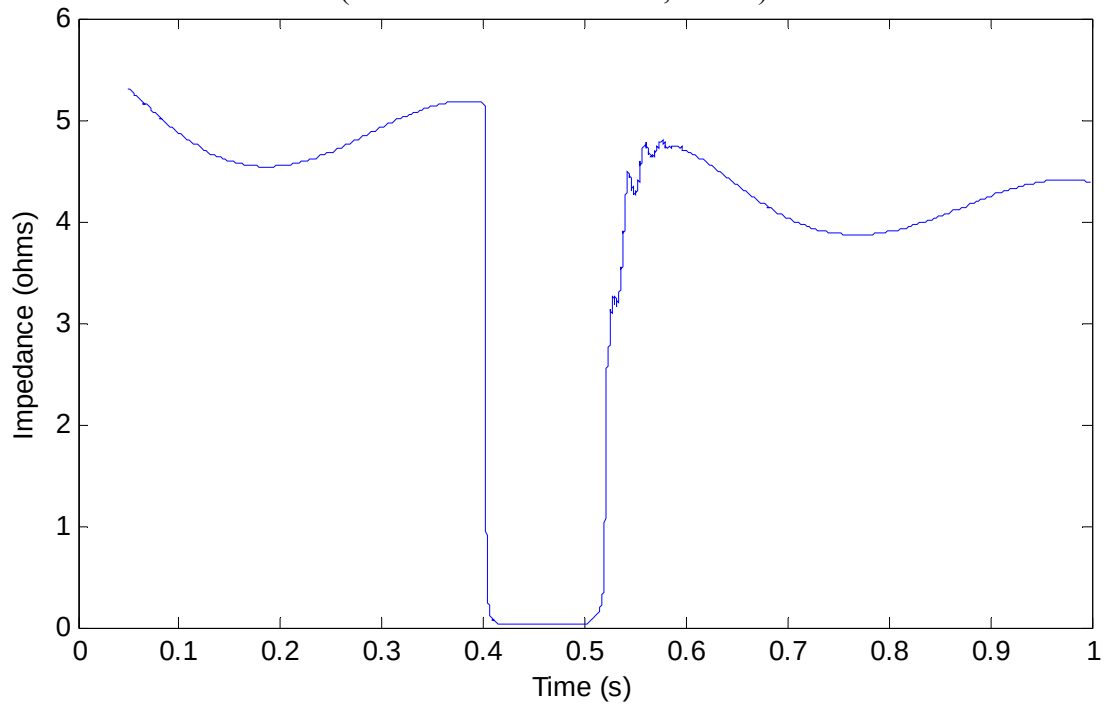


**Figure 3.24 Plot of magnitude of impedance seen by distance relay at transmission line between Shanon-Superstition (69 kV), Case 3.2**

*Case 3.3 Simulation of three phase to ground bolted fault at bus Ealy (69 kV) with DGs of the Thunderstone system with four inverter based DGs*

In Case 3.3, four inverter based DGs are installed into the Thunderstone system: Sage4, Superstition3, Early1 and Ealy2. The capacity of each DG is 5 MW which is identical to the DGs in Case 3.2. A three phase bolted fault occurs at the middle of the line between Superstition and Ealy (69 kV). The fault starts at 0.4 s and is cleared at 0.5 s.

Figures 3.25 and 3.26 show the voltage and current measured at the fault location. In Figure 3.27-29, the plots of  $X-R$  and  $X-R$  vs. time indicate that the fault is not detected by the impedance relay at bus Superstition3 (12.47 kV). The fault current flows from the inverter based DG at bus Superstition3 to the fault point is not high enough to be detected by primary protection system.

The plots of impedance of the transmission line between Superstition and Ealy are shown in Figures 3.30-3.32. The fault is detected at  $t = 0.4024$  s. Due to the increase of fault current after installing the DGs the fault is detected faster than it does in Case 3.1. The plots of impedance of the transmission line between Shanon and Superstition (69 kV) are shown in Figures 3.33-35.

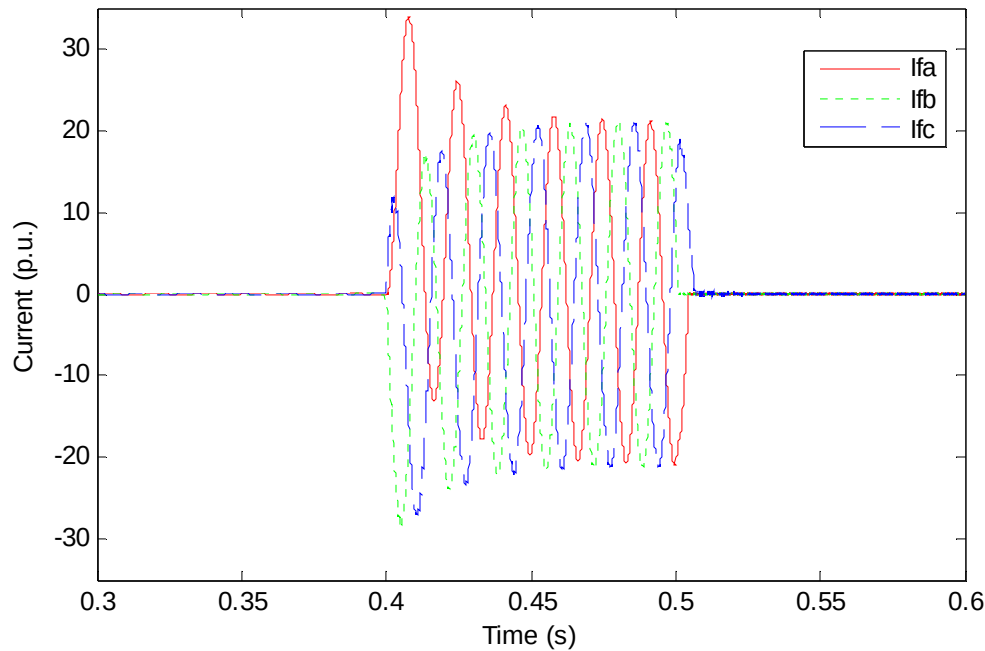


**Figure 3.25 Fault current at the fault point with four synchronous machine DGs in the system, Case 3.3**  
(Per unit base: 100 MVA, 69 kV)

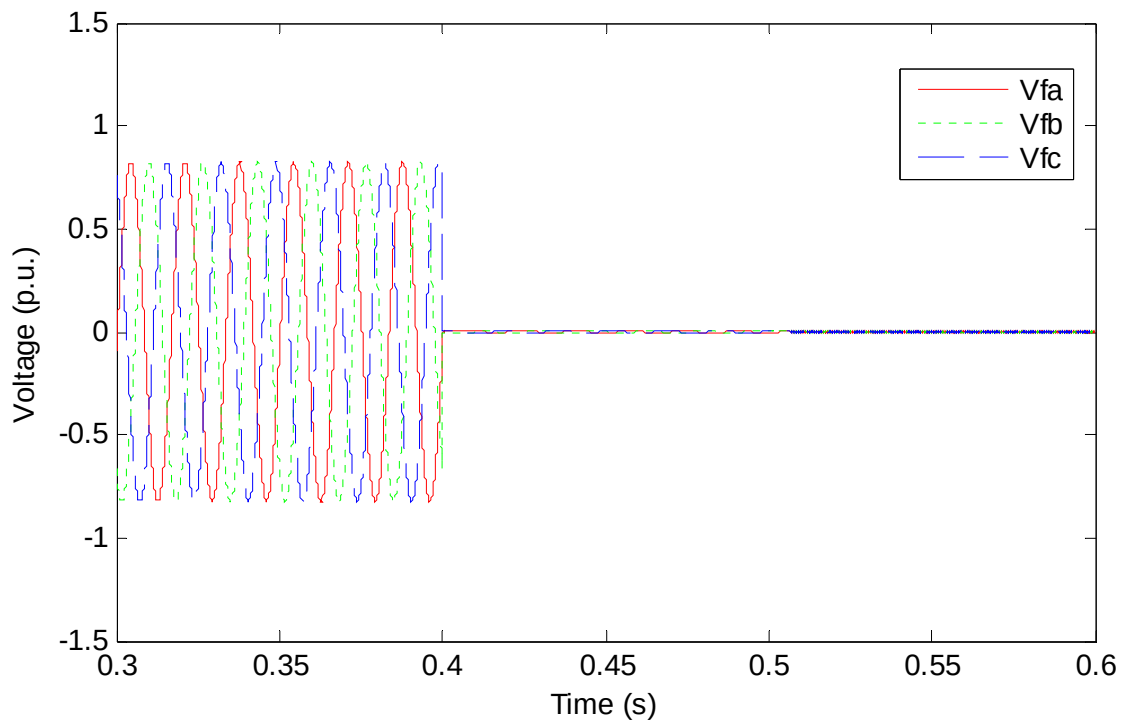


**Figure 3.26 Fault voltage at the fault point with four synchronous machine DGs in the system, Case 3.3**  
(Per unit base: 100 MVA, 69 kV)

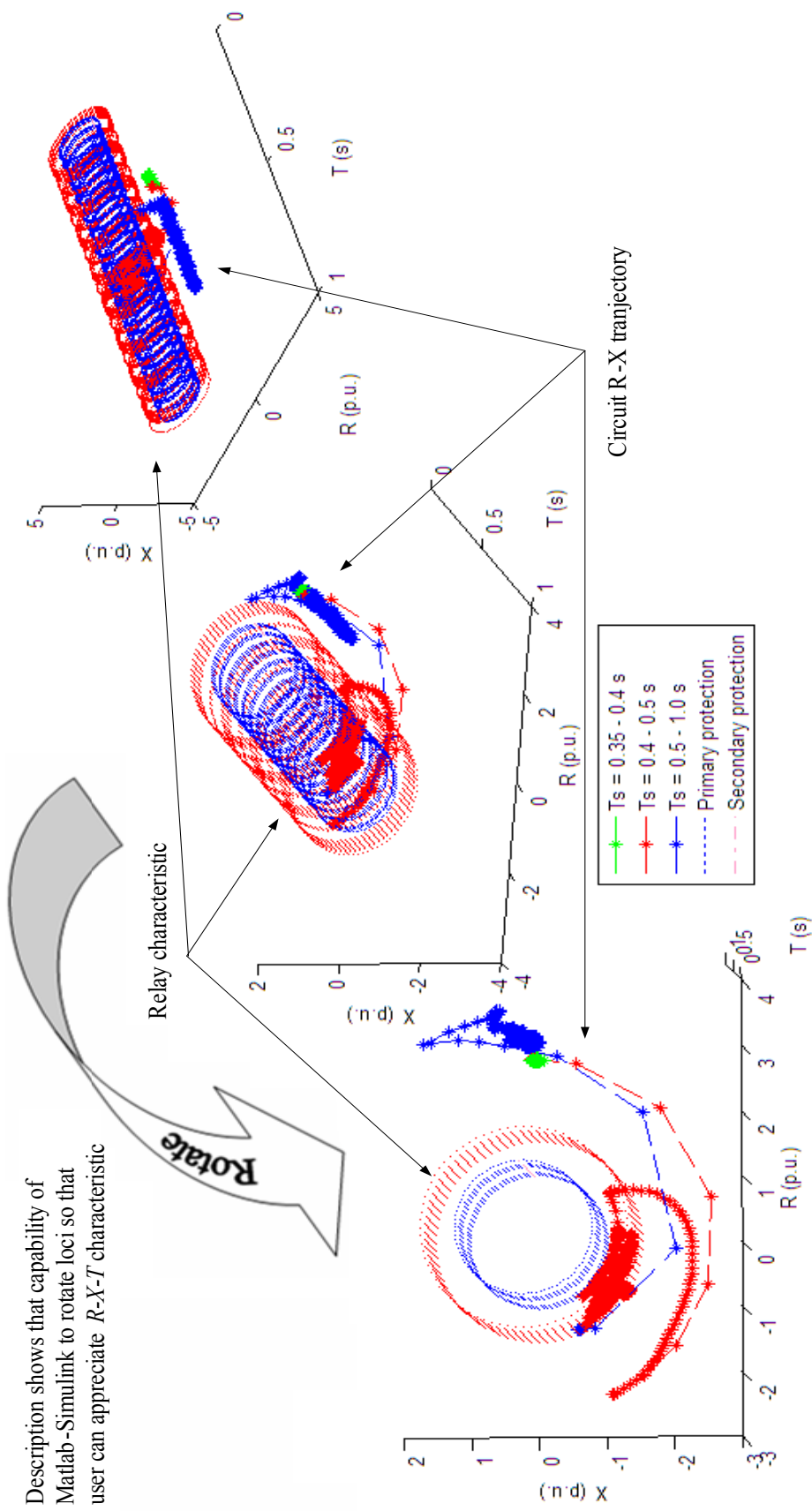


**Figure 3.27 Plot of  $X$ - $R$  vs. time at Superstition3 (12.47 kV) with various angles, Case 3.3**  
(Per unit base: 100 MVA, 12.47 kV)

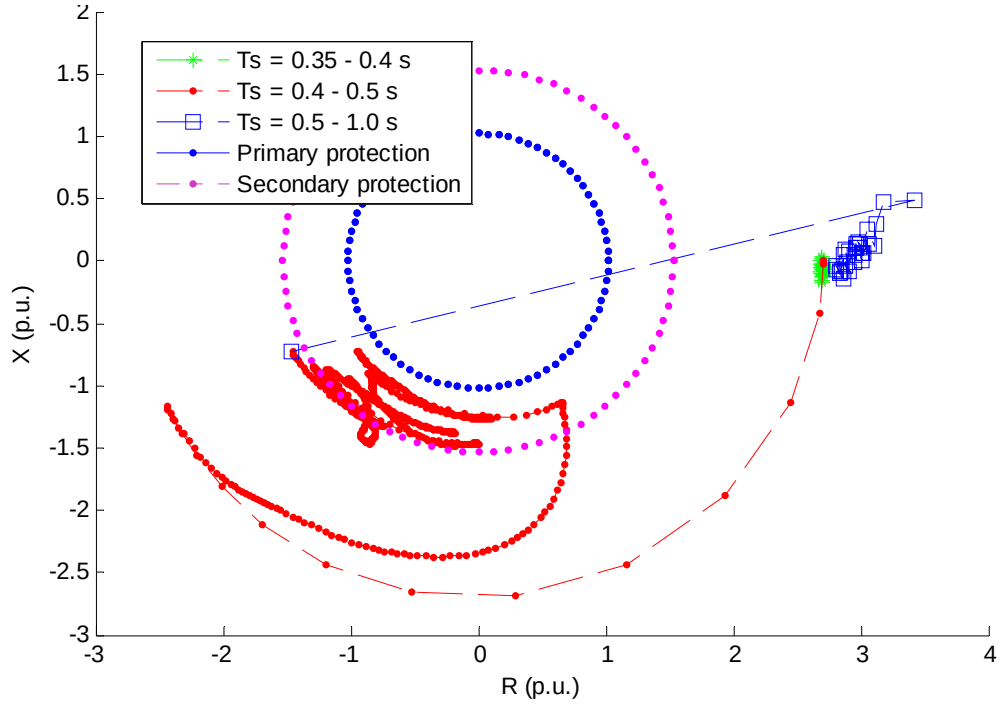


**Figure 3.28 Plot of  $X, R$  at Superstition3 (12.47 kV), Case 3.3**  
(Per unit base: 100 MVA, 12.47 kV)

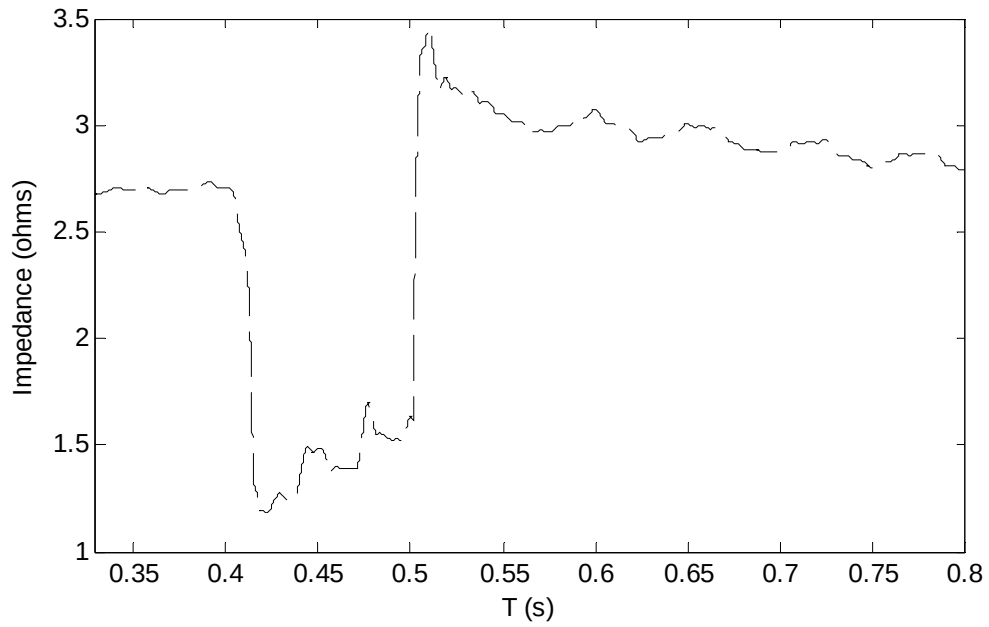


**Figure 3.29 Plot of magnitude of impedance seen at Superstition3 (12.47 kV) vs. time, Case 3.3**

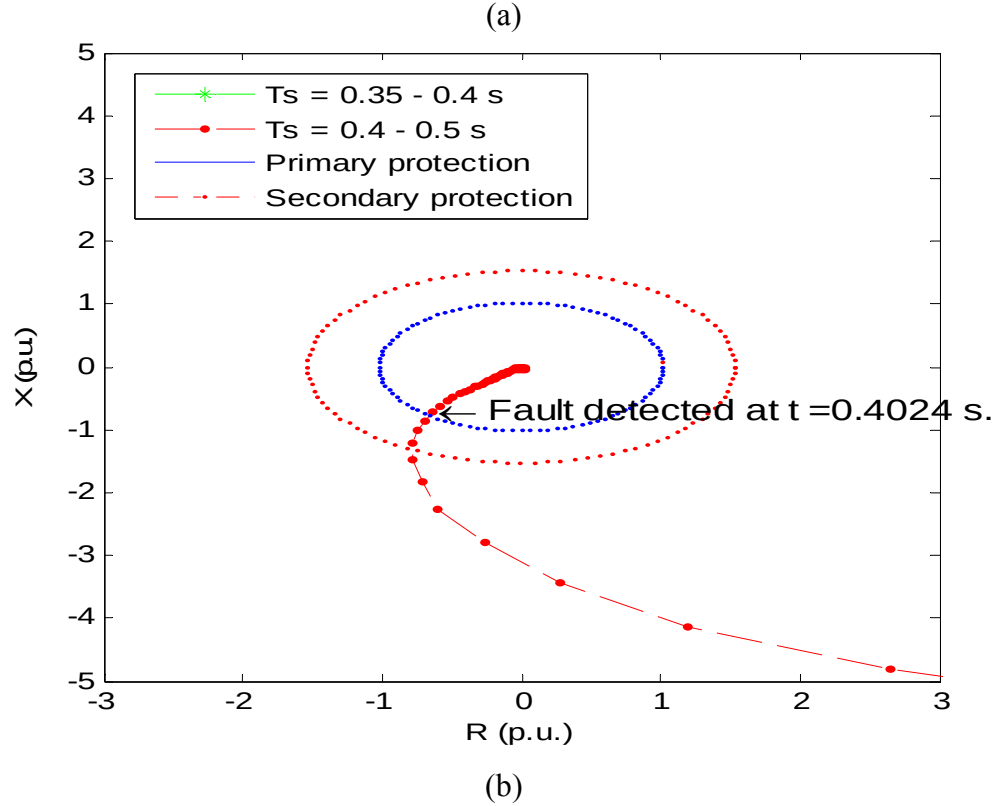
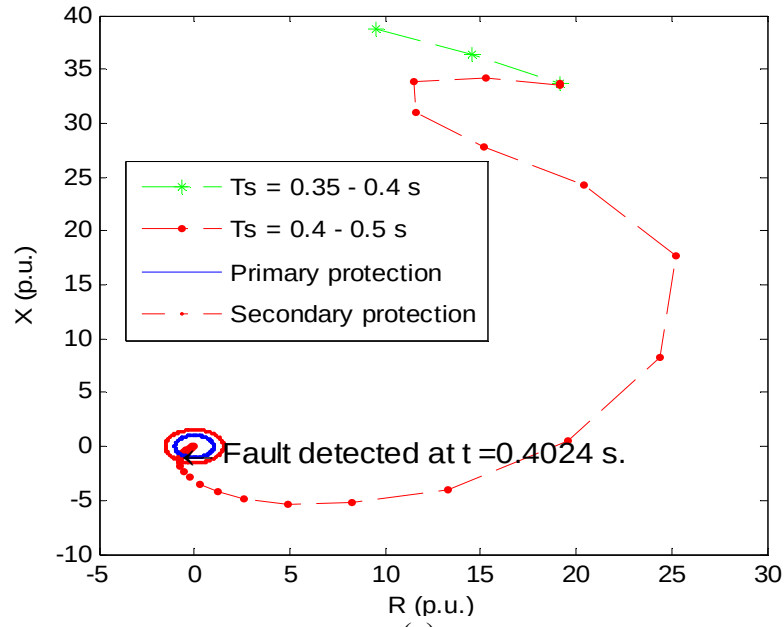


**Figure 3.30 (a) Plot of X- R seen by the distance relay at transmission line from Superstition to Ealy (69 kV), Case 3.3 (b) zoom-in view**  
(Per unit base: 100 MVA, 69 kV)

Description shows that capability of Matlab-Simulink to rotate loci so that user can appreciate  $R$ - $X$ - $T$  characteristic

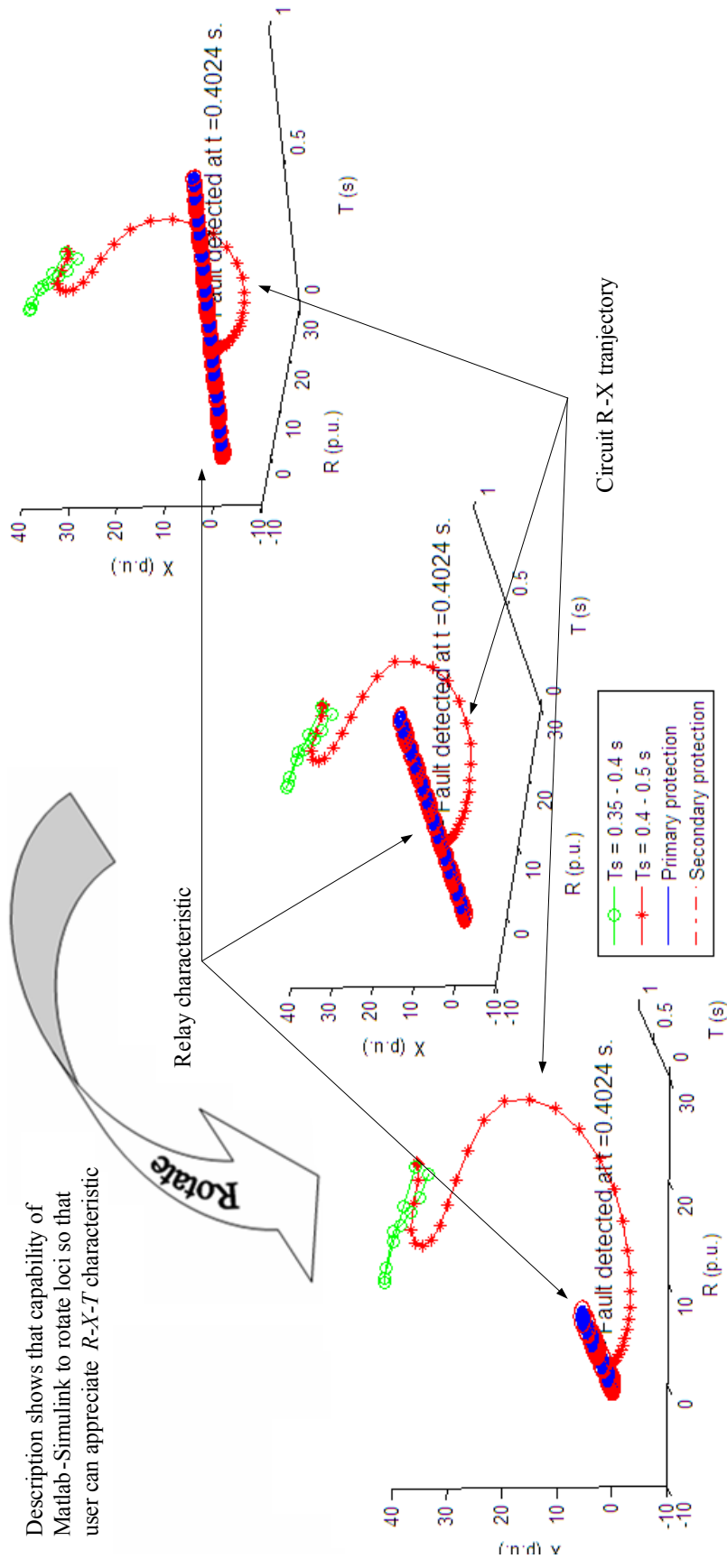


**Figure 3.31** Plot of  $X$ - $R$  vs. time seen by the distance relay at transmission line from Superstition to Ealy (69 kV),  
**Case 3.3**  
 (Per unit base: 100 MVA, 69 kV)

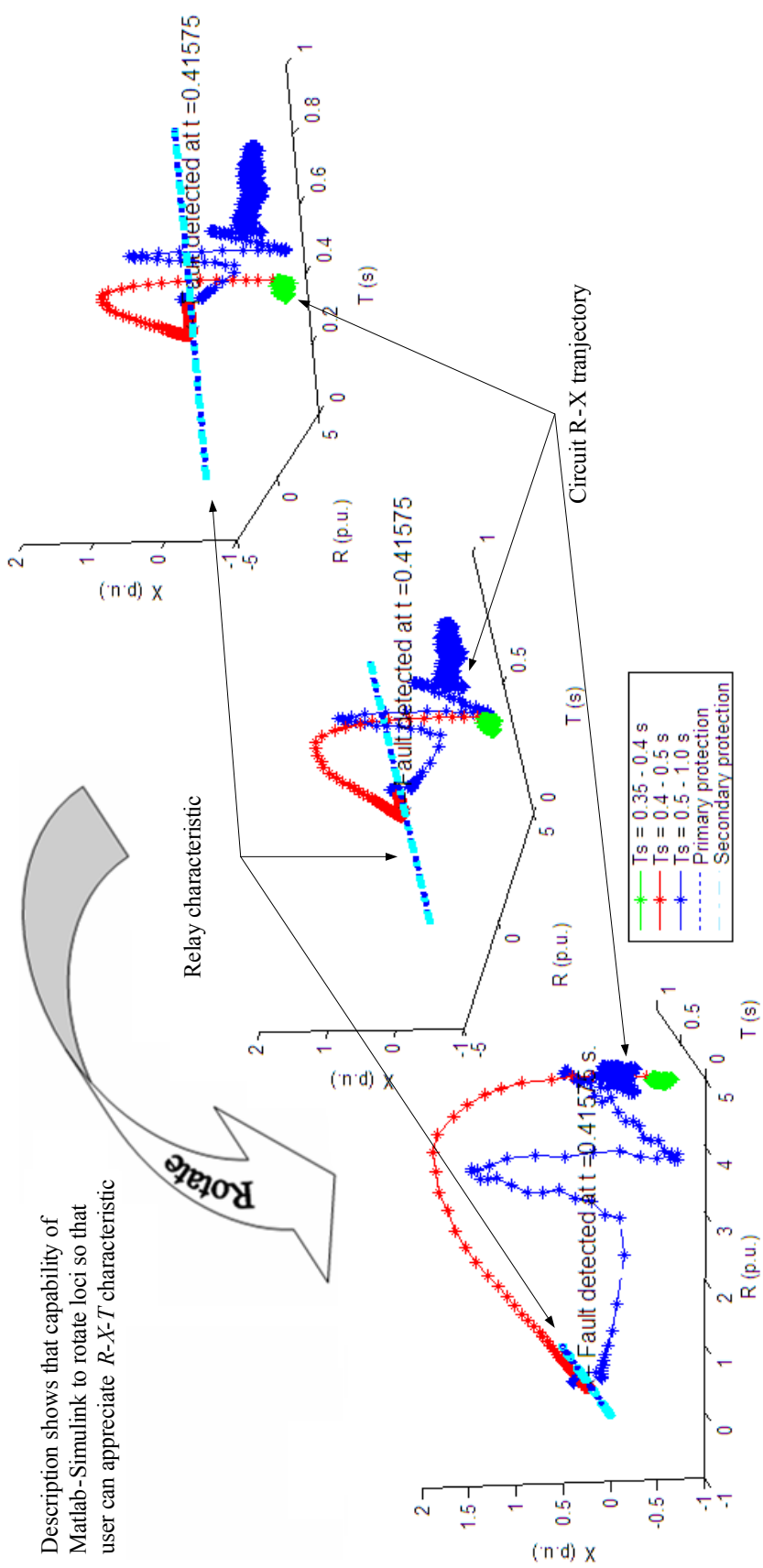


**Figure 3.32 Plot of  $X$  and  $R$  seen by distance relay seen from bus Superstition at transmission line between Shanon-Superstition (69 kV), Case 3.3**  
(Per unit base: 100 MVA, 69 kV)

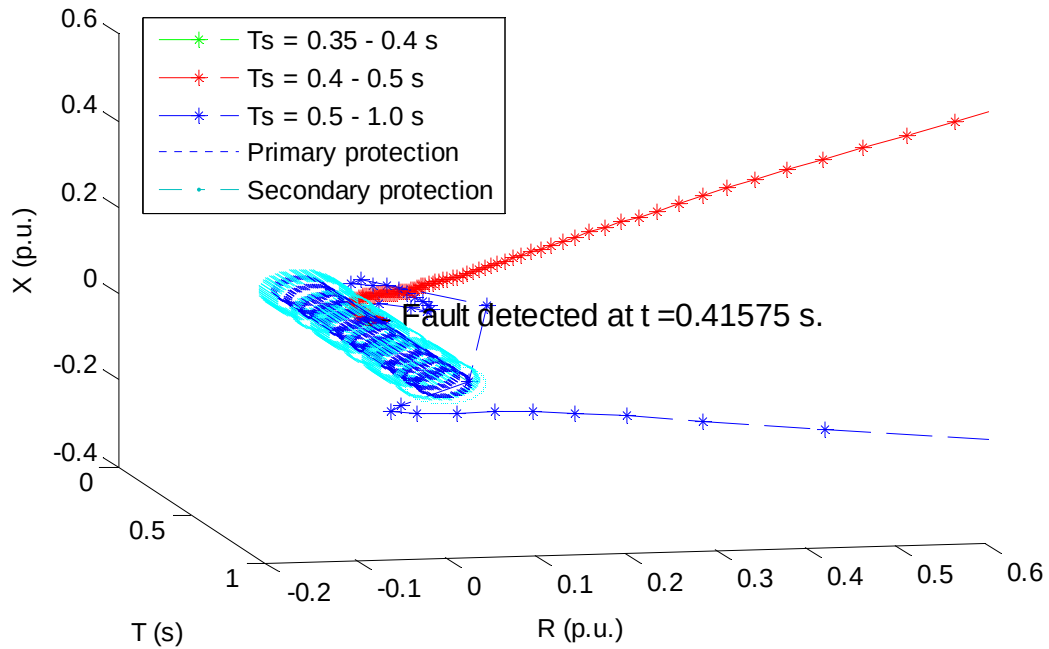


**Figure 3.33 Zoom-in view of  $X$  and  $R$  seen by distance relay from bus Superstition at transmission line between Shanon-Superstition (69 kV), Case 3.3**  
(Per unit base: 100 MVA, 69 kV)

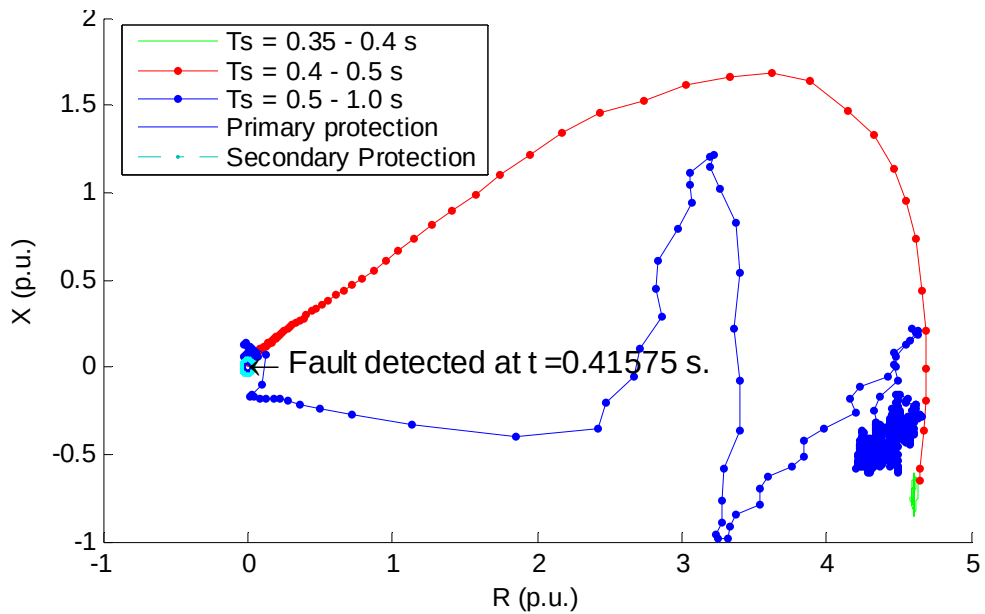


**Figure 3.34 Plot of  $X$  and  $R$  seen by distance relay from bus Superstition at transmission line between Shanon-Superstition (69 kV), Case 3.3**  
(Per unit base: 100 MVA, 69 kV)

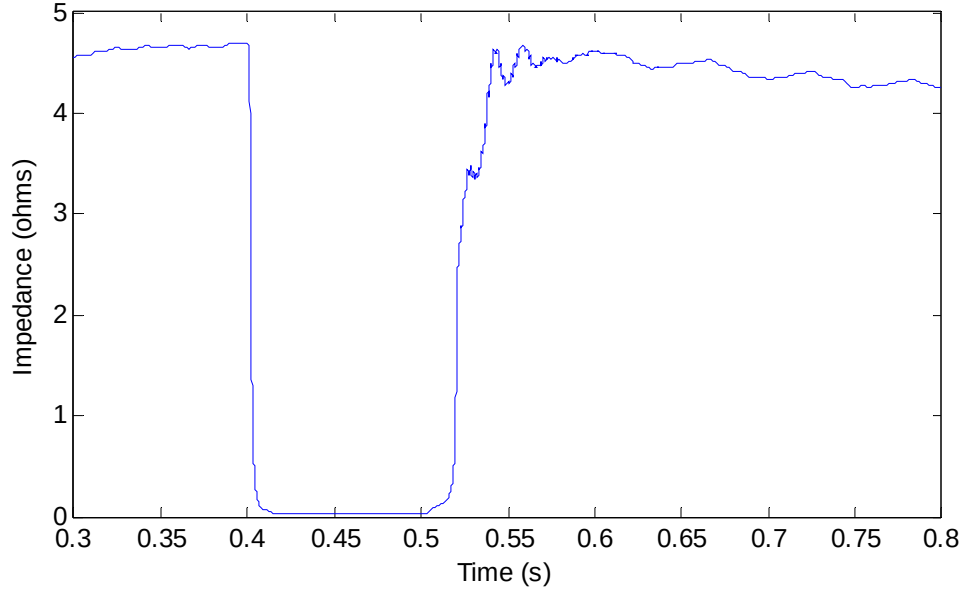


**Figure 3.35 Plot of magnitude of impedance seen by distance relay at transmission line between Shanon-Superstition (69 kV), Case 3.3**

### 3.5 Conclusions

This chapter discusses the fault analysis of the subtransmission system with the presence of DGs. The modified bus impedance matrix is applied in the illustrative example (Section 3.2) to calculate the fault current of the Thunderstone system with synchronous machine DGs. This can be used to design the size of protection system such as circuit breaker (CB), fuse and relays. However, it is inconvenient to applied this method to analyze the system with inverter based DGs because of inverters are nonlinear. A simulation technique is proposed to analyze the system dynamic and change of the fault response of the system with inverter based DGs. Simulations of the synchronous and inverter based DGs in subtransmission system are presented in this chapter. The Thunderstone system is applied as the test bed. The model of inverter based DGs in illustrative example (Case 3.3) is discussed in Chapter 2. Simulation results are summarized in Table 3.4.

Conclusions can be drawn from the simulations in this chapter as:

- Installation of DGs in the distribution system increases the fault current throughout the system. This situation may change the way protective relays react to the faults. Circuit breakers, fuses and setting of relays may need to be adjusted to the new appropriate range.
- The simulation results show that severity of increase of fault current from synchronous machine DGs is higher than that from inverter based DGs. Fault currents from the three-phase to ground bolted fault in Cases 3.1-3 are shown in Figure 3.36.
- The protection system may lose coordination upon installation of DGs. This point is illustrated as follows: before installing distributed generation (Case 3.1), distance relay at Superstition3 (12.47 kV) should not operate to clear the fault. This is due to the

upstream fault on the subtransmission system. The fault should be cleared by the distance relays of the line between Superstition and Ealy (69 kV). When synchronous machine DGs are installed (Case 3.2), the fault current flows from DG at Superstition3 to the fault point and the relay at Superstition3 (12.47 kV) might operate (see Figure 3.7). This situation depends on the coordination of protections system before installing DGs. Thus, the protection system might lose coordination for the case of installed synchronous machine DGs. However, in Case 3.3, when a three-phase fault occurs at the middle of the line between Superstition and Ealy, the fault current from inverter based DGs are less severe than in Case 3.2. Simulation results show that distance relay at Superstition3 does not detect the fault. The protection system operates the same as in Case 3.1 to clear the fault.

- The results of simulation can be used to analyze the setting of relays in the system with the present of DGs. For example, Figure 3.37 shows the operation time of the distance relay at Superstition3 (12.47 kV). This plot provides the important information to analyze the coordination of the protection system.

**Table 3.4 Summary of the simulations, Cases 3.1 – 3.3**

| Location of measurements                                                                                       | Case 3.1<br>Figures | Case 3.2<br>Figures | Case 3.3<br>Figures |
|----------------------------------------------------------------------------------------------------------------|---------------------|---------------------|---------------------|
| Voltage and Current at the fault point                                                                         | 3.5, 3.6            | 3.15, 3.16          | 3.25, 3.26          |
| <i>X-R</i> and <i>X-R</i> -time seen by distance relay at Superstition3 (12.47 kV)                             | 3.7, 3.8            | 3.17, 3.18          | 3.27, 3.28          |
| Impedance vs. time seen by distance relay at Superstition3 (12.47 kV)                                          | 3.9                 | 3.19                | 3.29                |
| <i>X-R</i> and <i>X-R</i> -time seen by distance relay at transmissionline between Superstition – Ealy (69 kV) | 3.10, 3.11          | 3.20, 3.21          | 3.30, 3.31          |
| <i>X-R</i> and <i>X-R</i> -time seen by distance relay at transmissionline between Superstition – Ealy (69 kV) | 3.12, 3.13          | 3.22, 3.23          | 3.32, 3.33          |
| Impedance vs. time seen by distance relay at Shanon-Superstition                                               | 3.14                | 3.24                | 3.34                |

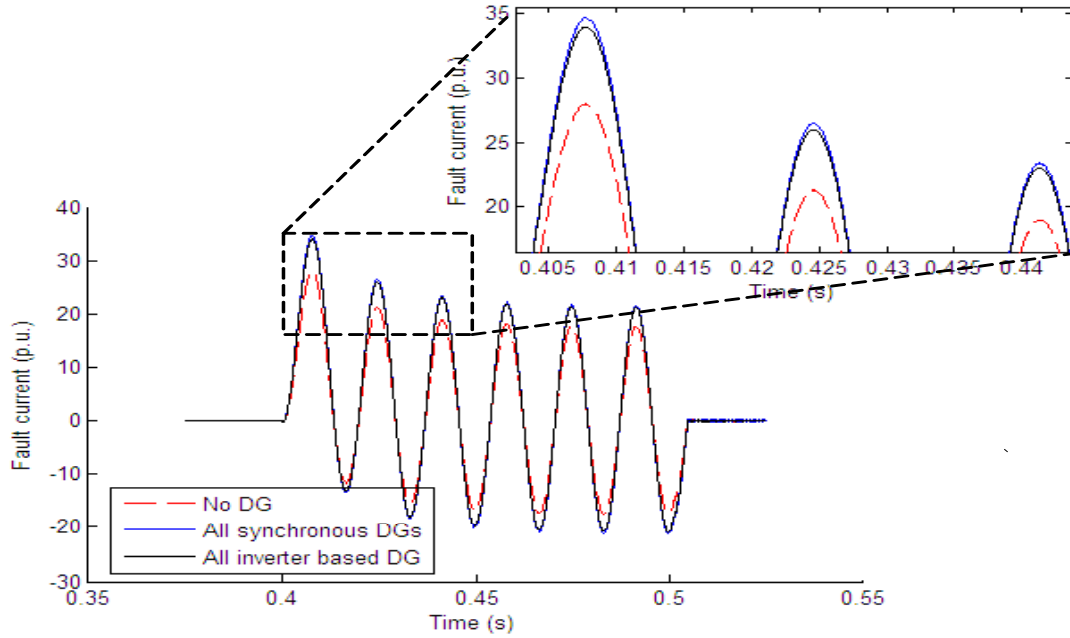


**Figure 3.36 Comparison of the fault currents (p.u.) from three phase to ground bolted fault at the middle of the line between Superstition – Ealy (69 kV), Cases 3.1-4.3**  
(Per unit base: 100 MVA, 69 kV)

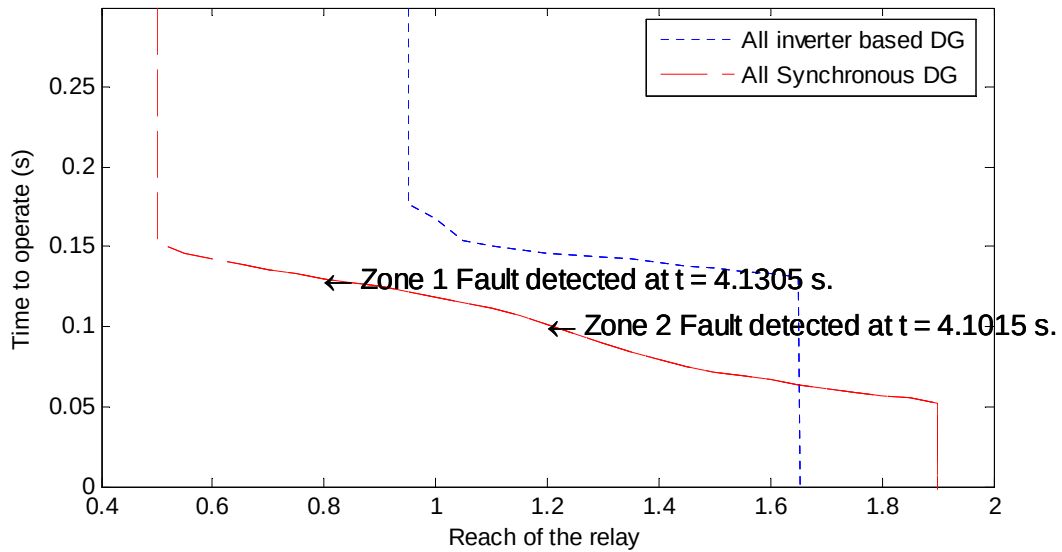


**Figure 3.37 Plot of time to operation of the distance relay at bus Superstition3 (12.47 kV) vs. reach of the relay, Cases 3.2 and 3.3**  
(Per unit base: 100 MVA, 12.47 kV)

## 4 Online Calculations with Distributed Generation

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### 4.1 Introduction

Analysis of fault current by applying the conventional technique is well studied in many references such as [19-21]. This procedure is standardized and considered critical. Calculation of fault current in the conventional technique is based on the system parameters and system configuration. That is, all parameters of the system, such as line parameters, transformers and loads, are required in the conventional technique.

K. Srinivasan, C. Lafond and R. Jutras propose a fault current estimation technique in [55]. The proposed technique applies a statistical knowledge to evaluate three phase bolted fault current of a load bus in a distribution system. The calculation is accomplished by using the variations of voltage and current measured at the load. The voltage and current variations are created from changes of the load. These variations may be used to estimate the fault current at the measured location. Parameters and configuration of the system is not required in this estimation technique. Based on the fault current estimation technique, the fault current at the measurement locations can be estimated by using only the filed measurement data. The method in [55] is essentially based on a statistical analysis and this concept is adapted here for the case of DG penetration.

In practical operation, the increase of fault current in a system may also occur due to the installation of new DGs, change of system configuration, or change of breaker topology. This estimation technique can be used to secure the system from the increase of fault current. The online assessment of fault current is necessary to inform the operator to avoid these unsafe operation conditions or provide functions of alarming.

This chapter demonstrates the online fault current estimation technique. A test bed, denominated as the Thunderstone system, is produced for illustrative purposes. The Thunderstone system is described in Section 3.1.

This chapter is organized as: Section 4.2 discusses the theory of online fault current estimation, Section 4.3 Illustrative example on the test bed system. Section 4.4 discusses the interpretation of the results from online estimation technique.

### 4.2 Summary of existing work – fault current estimation

This section discusses the theory and equations used in the fault current estimation technique. By applying this technique, fault current at major load points can be estimated based on voltage and current measurements at each load point. Voltage and current variations, due to the change of loads, at the estimated point are used in this calculation. The voltage and current are recorded in rms values. The voltage and current variation might occur from the load side or the source side or happen simultaneously. The recorded signals, normally a few hundred snapshots, are used as the input of this calculation.

Equations used in this estimation technique are derived from system voltage equations at a point of coupling common (PCC). The Thevenin equivalent circuit of a power system at a PCC can be depicted in Figure 4.1. The load in Figure 4.1 is represented by a constant impedance. The voltage equations of the Thevenin equivalent circuit can be written as:

$$V = E - IZ_s \quad (4.1)$$

$$V = IZ_L \quad (4.2)$$

where  $V$  is the voltage at a PCC,  $I$  is the current to the load,  $Z_s$  is the equivalent impedance of the source side,  $E$  is the equivalent voltage at the source side,  $Z_L$  is the load impedance.

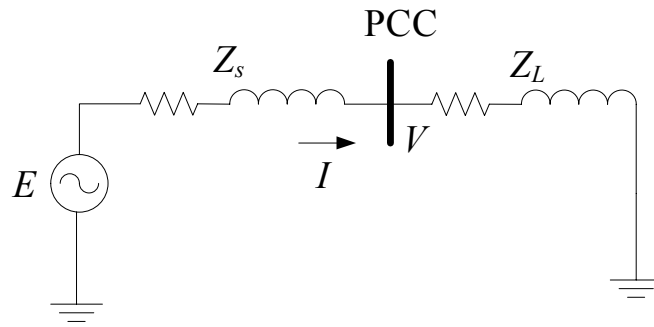


**Figure 4.1 The Thevenin equivalent circuit at a PCC**

As mentioned in the previous section, the fault current estimation is based on the analysis of voltage and current variations. The fault current estimation is derived by applying the analysis of small signal variations. The derivation is done under the assumption that the second order terms are negligible. From (4.1-4.2), voltage equations with small signal variations can be written as follow [55],

$$V + \delta V = (E + \delta E) - (I + \delta I)(Z_s + \delta Z_s)$$

$$V + \delta V = (I + \delta I)(Z_L + \delta Z_L)$$

or

$$\delta Z_L = \frac{\delta V}{I} - \frac{V}{I^2} \delta I \quad (4.3)$$

$$\frac{\delta E}{I} - \delta Z_s + \frac{(E - V)}{I^2} \delta I = \frac{\delta V}{I}. \quad (4.4)$$

Multiply (4.4) by (4.3) and take the average over a large number of measured voltages and currents, equation (4.4) can be expressed as [55],

$$E - V = \frac{I^* R_{VV} - V^* R_{VI}}{V^* \frac{R_{II}}{I} - I^* \frac{R_{VI}}{I}} \quad (4.5)$$

where  $R_{xy}$  is the covariance of variables  $x$  and  $y$ .

Note that, from (4.5), the fault current estimation is partially related to the covariance of the voltage and current at the estimated bus. The covariance of two variables,  $x$  and  $y$ , provides a statistical measure of how strongly correlated these variables are. The definition of the covariance of complex variables  $x$  and  $y$ ,  $R_{xy}$ , is given by [62],

$$\begin{aligned} R_{xy} &= \langle (x - \mu_x)(y - \mu_y) \rangle \\ &= \langle x_i y_i \rangle - \mu_x \mu_y, \end{aligned}$$

where  $\mu_x = \langle x_i \rangle$  and  $\mu_y = \langle y_i \rangle$  is the mean value of  $x_i$  and  $y_i$ . Note that the impedance of the load side,  $Z_L$ , has no statistical correlation with the impedance of source side,  $Z_s$ . In other words, the impedance of the load size is statistically independent from the impedance of source side (see Figure 4.1). Hence, the covariance of variable  $Z_L$  and  $Z_s$  is zero ( $R_{Z_L Z_s} = 0$ ). Same reason can be applied to source voltage,  $E$ , and load impedance,  $Z_L$ . The covariance of variable  $E$  and  $Z_s$  is zero ( $R_{EZ_s} = 0$ ).

From (4.1) and (4.5), the equivalent impedance of the system,  $Z_s$ , at the PCC is

$$Z_s = \frac{I^* R_{VV} - V^* R_{VI}}{V^* R_{II} - I^* R_{VI}^*}. \quad (4.6)$$

where  $I^*$  represents the complex conjugate of  $I$ .

The fault current,  $I_f$ , at buses with measurement can be expressed, from (4.1) and (4.6), as

$$I_f = \frac{V + I Z_s}{Z_s} = I + \frac{V}{Z_s} = I + V \frac{(V^* R_{II} - I^* R_{VI}^*)}{(I^* R_{VV} - V^* R_{VI})}. \quad (4.7)$$

### 4.3 Illustrative example – application to the subtransmission system with distributed generation

In this section, the Thunderstone system as shown in Figure 3.1 is used as the test bed system to demonstrate the fault current estimation technique. To evaluate the accuracy of the estimation technique, fault current at some load buses calculated by using the conventional algorithm are compared to the calculation by the estimation technique. As also mention in Chapter 3, installation of DGs increases faults current throughout the system.

The demonstration in this section shows the ability to detect the increased of fault current due to these DGs. The demonstrations in this chapter are separated to 2 cases:

- Thunderstone system without DG denominated as “Case 4.1”.
- The Thunderstone system with DGs denominated as “Case 4.2”. In this case, DGs are installed at 5 locations. Parameters of DGs and locations are shown in Table 4.1

In both cases, assume that voltage and current are recorded at 12 kV load buses at 7 locations: Cameron, Cluff2, Signal3, Shanon2, Sage2, Ealy3, Ealy4 and Seaton. Figure 4.1 redraws the Thunderstone system with the measurement points and location of DGs.

**Table 4.1 Locations and parameters of DGs in Case 4.2**

| Locations     | Size (MVA) | Transient impedance (p.u.)* |
|---------------|------------|-----------------------------|
| Superstition3 | 10.0       | $0.005+j*1.25$              |
| Seaton2       | 20.0       | $0.005+j*1.12$              |
| Ealy3         | 30.0       | $0.005+j*1.13$              |
| Ealy4         | 45.0       | $0.005+j*0.9$               |
| Sage3         | 40.0       | $0.005+j*0.95$              |

\* Per unit based on machine rating MVA, 12.47 kV

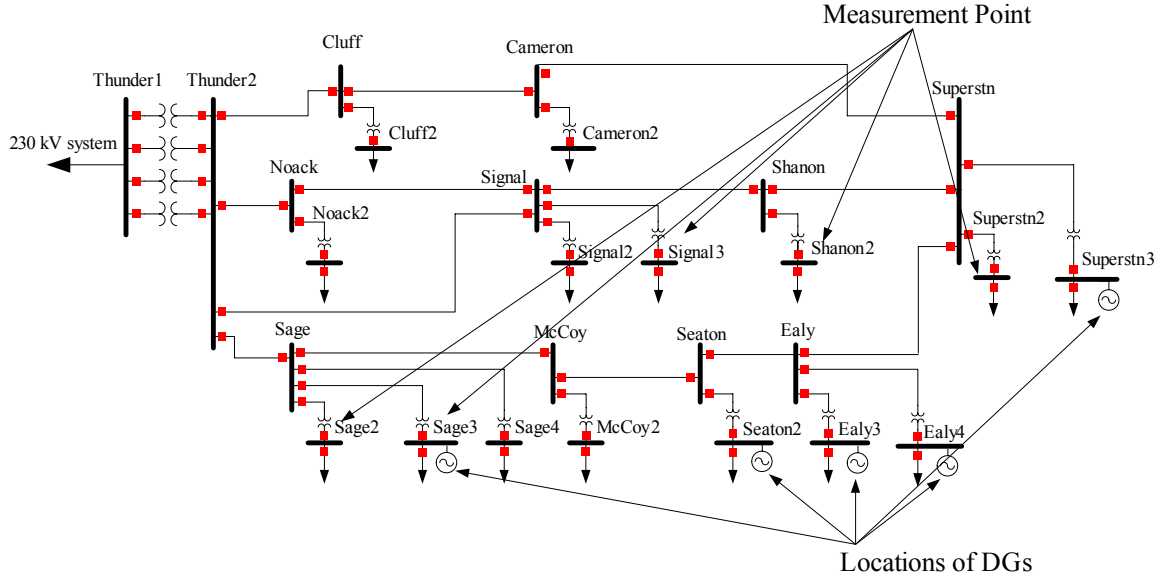


**Figure 4.2 The Thunderstone system with five DGs and measurement points**

The conventional fault current calculation is discussed in Section 3.2 and [22]. Three phase fault current at each bus, in Cases 4.1 and 4.2, can be calculated by (3.3). The pre-fault voltage in (3.3) is given by the load flow solution of the system. The diagonal element of the bus impedance matrix of bus  $j$ ,  $Z_{jj}$ , can be calculated by (3.2).

In the fault current estimation technique, the calculation is done based on variations of voltage and current rms measurements due to the change of loads. Instead of actual measurements over a period of time, voltage and current measurements from one hundred events used in this demonstration are created from the results of load flow calculations. Changes of active and reactive power of loads in each event are generated pseudorandomly by following the Gaussian distribution. The intent is not to claim that operating points and DG levels are random variables but only to illustrate the variation of fault response with load and operating point. The variations of active and reactive power of loads in the system are quantified by mean values and standard deviations of the loads. In the illustrative examples, mean values of active and reactive power are given in Table A.2 (Appendix A). In each event, the standard deviations of active and reactive power of each load are fixed at 5 and 0.4, respectively.

Three phase bolted fault current at each bus is calculated by applying (4.7). Results of calculation from the conventional technique and the estimation technique are shown Tables 4.2 and 4.3. Plots of the fault current calculation by the estimation technique are shown in Figures 4.2-4.5. For example, the histogram in Figure 4.2 shows the amplitude of the fault current at bus Signal3 versus the number of occurrences in Cases 4.1 and 4.2. The dotted line in the plots represents the average value of the estimated fault currents. Note that the error of the fault current estimation from the conventional technique is in the range of 5 percent. The cited tables and figures are for given selection of statistics of

operating point in this example. It is expected that similar results would be formed for other probability distributions.

**Table 4.2 Three phase fault current of the Thunderstone system “without DG”, Case 4.1**

| Bus                              | Three phase fault current (p.u.)  |                                     | Error (Percent) |
|----------------------------------|-----------------------------------|-------------------------------------|-----------------|
|                                  | Conventional Calculation, $ I_f $ | Estimation Technique, $ \bar{I}_f $ |                 |
| Cameron (5) <sup>*</sup>         | 18.84                             | 19.05                               | 1.11            |
| Signal3 (11) <sup>**</sup>       | 12.37                             | 12.90                               | 4.31            |
| Shanon2 (13) <sup>**</sup>       | 14.37                             | 14.77                               | 0.85            |
| Superstition2 (15) <sup>**</sup> | 10.83                             | 11.07                               | 2.23            |
| Sage2 (18) <sup>**</sup>         | 11.43                             | 11.74                               | 2.70            |
| McCoy2 (20) <sup>**</sup>        | 14.66                             | 14.53                               | 0.85            |
| Seaton (21) <sup>**</sup>        | 17.68                             | 17.38                               | 1.69            |

\* Per unit based on 12 MVA, 12.47 kV

\*\* Per unit based on 100 MVA, 69 kV

**Table 4.3 Three phase fault current of the Thunderstone system “with DGs”, Case 4.1**

| Bus                              | Three phase fault current (p.u.) <sup>*</sup> |                                     | Error (Percent) |
|----------------------------------|-----------------------------------------------|-------------------------------------|-----------------|
|                                  | Conventional Calculation, $ I_f $             | Estimation Technique, $ \bar{I}_f $ |                 |
| Cameron (5) <sup>*</sup>         | 19.89                                         | 19.98                               | 0.45            |
| Signal3 (11) <sup>**</sup>       | 12.50                                         | 12.96                               | 3.67            |
| Shanon2 (13) <sup>**</sup>       | 14.58                                         | 14.89                               | 2.17            |
| Superstition2 (15) <sup>**</sup> | 10.94                                         | 11.16                               | 1.90            |
| Sage2 (18) <sup>**</sup>         | 11.57                                         | 11.75                               | 1.59            |
| McCoy2 (20)                      | 14.83                                         | 14.79                               | 0.28            |
| Seaton (21) <sup>**</sup>        | 19.67                                         | 19.82                               | 0.76            |

\* Per unit based on 100 MVA, 12.47 kV

\*\* Per unit based on 100 MVA, 69 kV

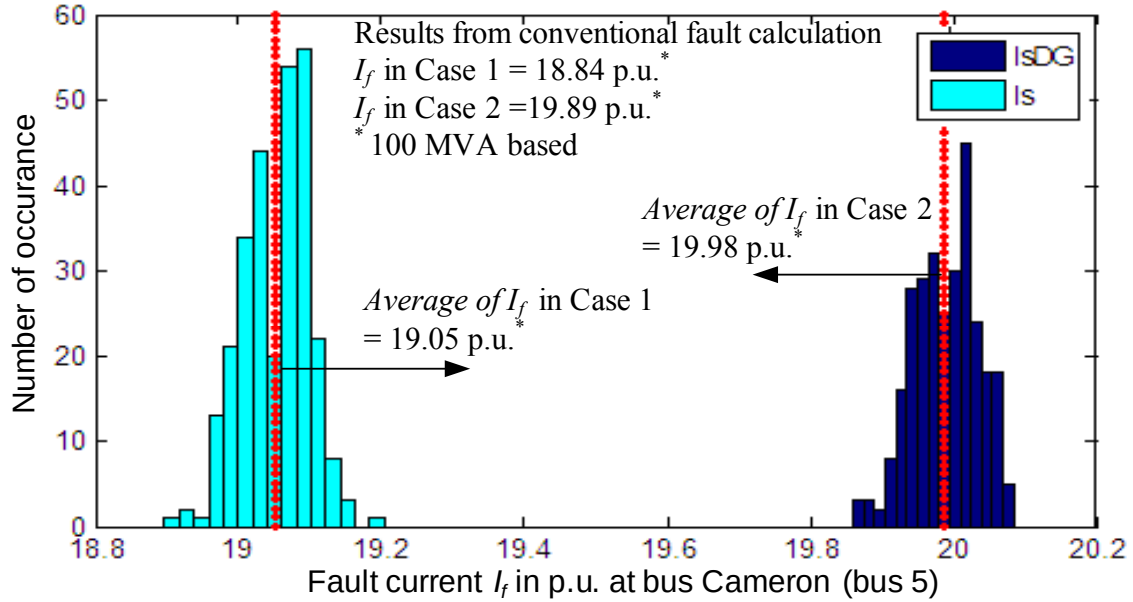


**Figure 4.3 Three phase bolted fault current at bus Cameron from the estimation technique**  
 (Per unit based on 100 MVA, 69 kV)

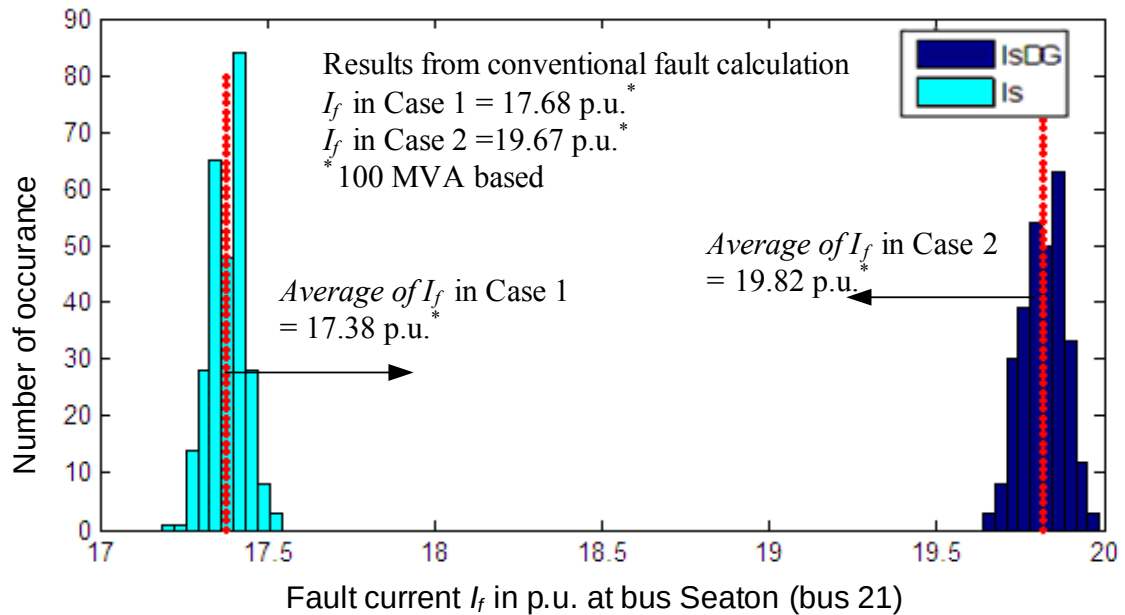


**Figure 4.4 Three phase bolted fault current at bus Seaton from the estimation technique**  
 (Per unit based on 100 MVA, 69 kV)

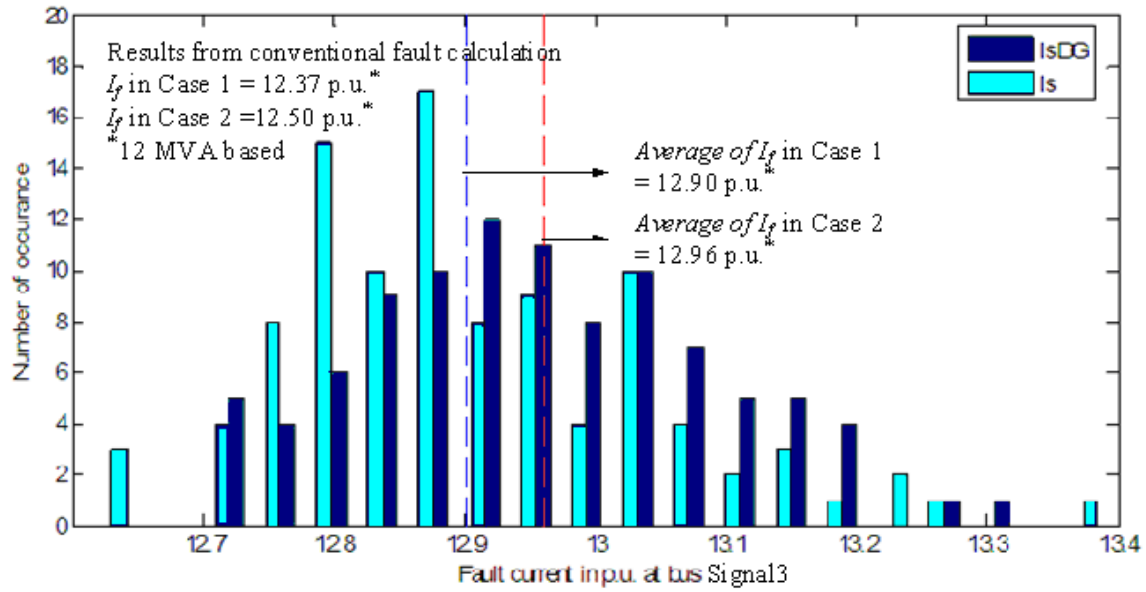


**Figure 4.5 Three phase bolted fault current at bus Signal3 from the estimation technique**  
 (Per unit based on 12 MVA, 12.47 kV)

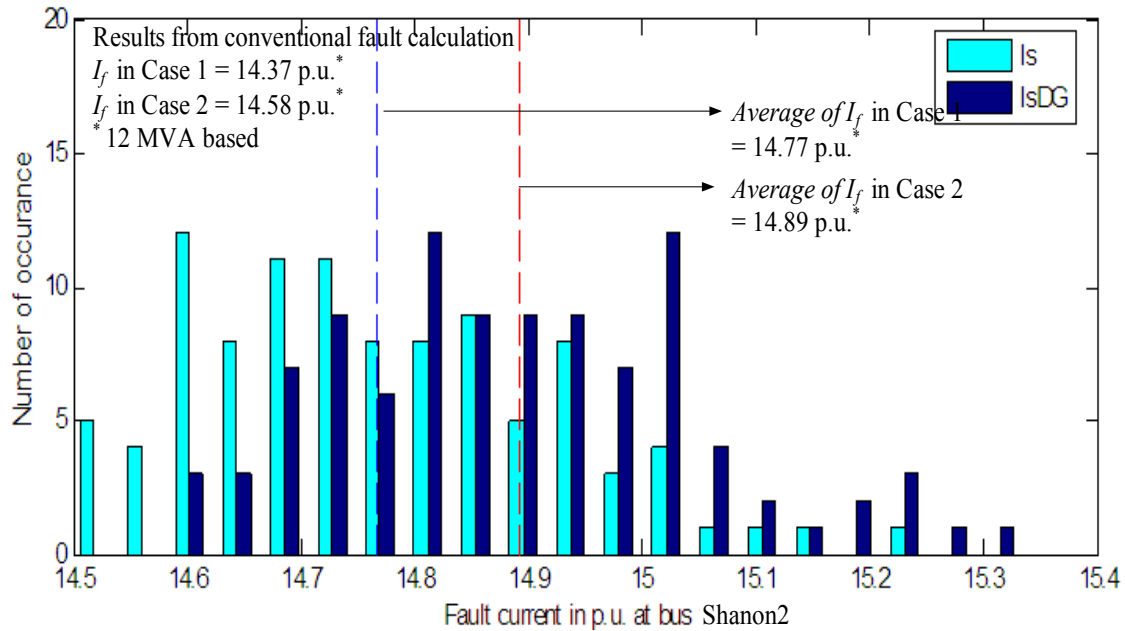


**Figure 4.6 Three phase bolted fault current at bus Shanon2 from the estimation technique**  
 (Per unit based on 12 MVA, 2.47kV)

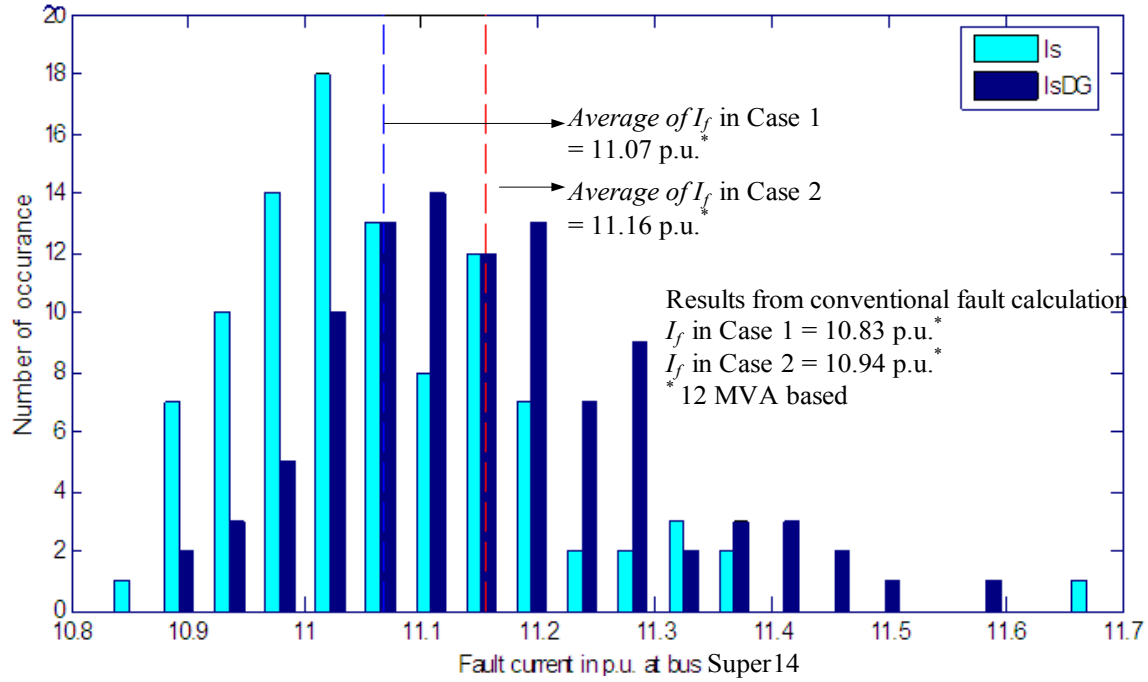


**Figure 4.7 Three phase bolted fault current at bus Superstition4 from the estimation technique**  
 (Per unit based on 12 MVA, 2.47kV)

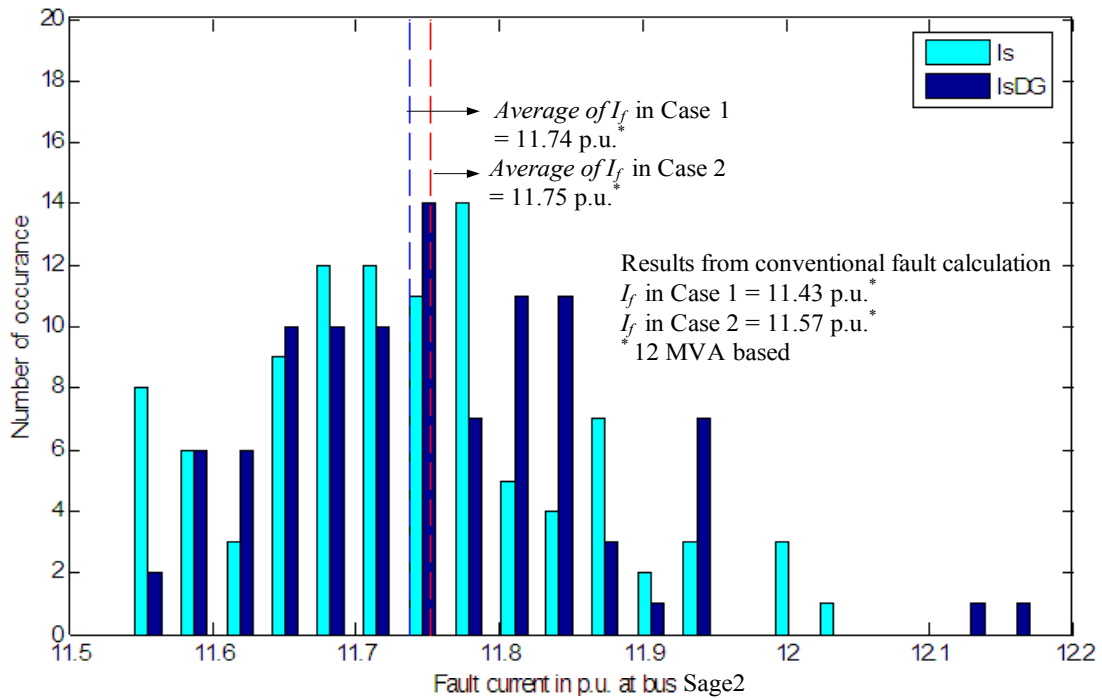


**Figure 4.8 Three phase bolted fault current at bus Sage2 from the estimation technique**  
 (Per unit based on 12 MVA, 12 kV)

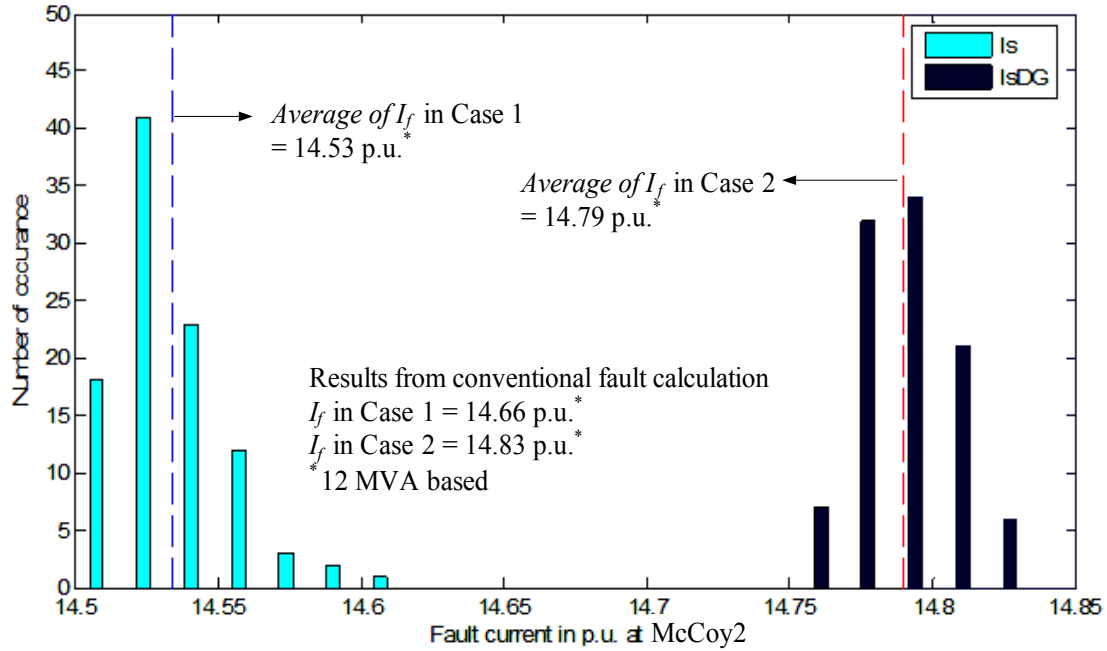


**Figure 4.9 Three phase bolted fault current at bus McCoy2 from the estimation technique**  
(Per unit based on 12 MVA, 12.47kV)

#### 4.4 Online assessment of fault current

The fault current estimation discussed in the previous sections provides a technique to calculate the fault from the voltage and current measurements. In practical, these voltage and current variations can be taken from the supervisory control and data acquisition system (SCADA). By applying the technique shown here, the increase of fault current attributed to DGs or change of system topology can be observed without knowing the change of a specific system parameters. The results of fault current estimation should be compared to the interrupting capability of circuit breaker in each location. This estimation technique can be utilized as an online assessment of the fault current which is necessary to inform the operator to avoid insecure operating conditions.

## 5 Average Change of Fault Current due to the Installation of Distributed Generation

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### 5.1 Approach to characterizing fault current in the presence of distributed generation

Power system planning is one of the indispensable parts of electric power system design. Analysis of fault level, pre-fault condition, and post-fault condition are required for the selection of interruption devices, protective relays, and their coordination. Systems must be able to withstand a certain limit of fault current which also affects reliability indices.

The appearance of co-generation, distributed generation, and unconventional generation collectively known as distributed resources (DRs) may result in the change of the fault response. Circuit breaker capability and configuration of protective relays that were previously designed for the system without DRs may not safely accommodate faults. In order to assess the severity (i.e., amplitude) of the increase in fault current in the system due to installing DRs, fault current analysis has to be done, and this procedure is standardized and considered critical.

This chapter is organized as follows: In Section 5.2, a new index called “*ACF*” is proposed as a new system-wide measure of the change in fault current in the system. In Section 5.3, an estimation technique is proposed to calculate the *ACF* value of a system. The application of the proposed estimation technique is illustrated in Section 5.4. Sections 5.5 and 5.6 discuss the confidence interval of the least squares estimator coefficients and the mean response of the *ACF*, respectively.

### 5.2 Average change of fault current

At this point, a new index is suggested for the purpose of quantifying the increase of fault current system-wide. The severity of increase of fault currents in the system can be indicated by applying a new index, the Average Change of Fault current (*ACF*),

$$ACF = \frac{\sum_{n=1}^{nbus} \left| \frac{I_{f,n} - I_{fDG,n}}{I_{f,n}} \right| \times 100}{(\text{number of } 69 \text{ kVbus} - 1)} \quad (5.1)$$

where  $I_{f,n}$  is the fault current at bus  $n$  before installing a new DR,  $I_{fDG,n}$  is the fault current at bus  $n$  after installing new DRs, and  $nbus$  is the total number of buses in the system. The ‘minus 1’ in the denominator of (5.1) allows for no change in fault current at the system slack bus. Note that

$$\left| \frac{I_{f,n} - I_{fDG,n}}{I_{f,n}} \right| \times 100$$

is the percent change of amplitude of the fault currents at the 69 kV buses.

The foregoing concept is that an index be utilized to determine the percentage of upgrade costs that should be equitably attributed to owners of new DRs. If a single DR is added, there is no issue on the attribution of cost. However, if several DRs are installed – more or less at the same time – it may not be clear as to who should pay for upgrade costs. The envisioned concept is that costs associated with the purchase and installation of circuit protection hardware, including circuit breakers, shall be evaluated at the time that the added DRs are commissioned. Only synchronous generator DRs are addressed in this paper – although inverter based DRs are predominant at the lower power levels. The issues of inverter based DRs deserve special attention.

One of the applications of ACF is to indicate the severity of the increase of fault currents in the system due to the installation of each DG or merchant plant. The least squares method for calculating the ACF is discussed in the following sections.

### 5.3 Least squares estimate of ACF

The ACF index, however, is not simply calculated because several complex subprocedures must be done. One way to reduce complexity is to create the estimator of the ACF for a given system on the basis of several previously analyzed cases. Figure 5.1 shows the approach. Details of the least squares estimate of ACF are discussed as follows.

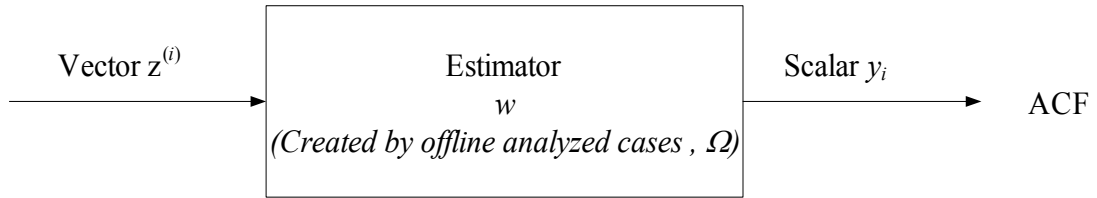


**Figure 5.1 Conceptual diagram of a least squares estimator**

In Figure 5.1, offline, previously calculated cases are denoted as the set  $\Omega$ . In each of the cases in  $\Omega$ , a datum vector  $z^{(i)}$  is used. The superscript  $(i)$  refers to the sample number. When the vector  $z^{(i)}$  are arranged in a matrix, for all cases in  $\Omega$ , the matrix  $Z$  results. Similarly, the ACF resulting from the use of vector  $z^{(i)}$  is denoted as the scalar value  $y_i$ . When all the case results in  $\Omega$  are arranged in a matrix, the vector  $y$  results. The question of how  $y_i$  is related to  $z^{(i)}$  (for case  $i$  in  $\Omega$ ) is now considered. Let several functions of  $z^{(i)}$  appear in a linear combination to generate  $y_i$

$$y_i = \text{Linear combination } \{f_1(z^{(i)}), f_2(z^{(i)}), \dots\}. \quad (5.2)$$

The  $f_k$  functions may be linear or nonlinear. But (5.2) is a linear combination of the  $f_k(Z^{(i)})$  scalar functions.

At this point, relate the linear combination concept above to the calculation of ACF. Note that the ACF in case  $i$  (in  $\Omega$ ) depends on the impedance of newly added DGs at  $m$  different locations. That is,  $m$  DGs are added, and the ACF is calculated. Then

$$y_i = ACF_i = \sum_{j=1}^k \sum_{\ell=1}^m w_{j,\ell} f_j \left( z_{DG,\ell}^{(i)} \right). \quad (5.3)$$

In (5.3),  $w_{j,\ell}$  denotes the linear combination coefficients mentioned in (5.2). The intent is that the  $y_i$  be a formula for ACF in case  $i$ , and the formula should have constant coefficients (i.e., the  $w_{j,\ell}$  coefficients are not a function of  $i$ ). Also note in (5.3) that  $k$  is the number of functions used in the linear combination shown in (5.2). For example, if  $k = 2$ ,  $y_i$  is a linear combination of  $f_1(z_{DG,\ell})$  and  $f_2(z_{DG,\ell})$  for all newly added DGs.

Consider of cases in the sample ensemble  $\Omega$ . That is, in (5.3),  $i = 1, 2, \dots, q$ . From the vector  $y$  as a  $q$ -vector of calculated ACF values in each of the  $q$  cases in  $\Omega$ . Then, the method of minimum least squares is to minimize the scalar residual  $r$ ,

$$r^2 = \left( y_i - \sum_{j=1}^k \sum_{\ell=1}^m w_{j,\ell} f_j(z_{DG,\ell}^{(i)}) \right)^2. \quad (5.4)$$

Note that when  $r = 0$ , all ACF values in  $\Omega$  calculated by (5.3) agree with the correct (full calculations) values  $y_i$ . The  $w_{j,\ell}$  coefficients may be arranged in a vector as follows

$$w = \begin{bmatrix} w_{1,1} \\ w_{1,2} \\ w_{1,3} \\ \vdots \\ w_{1,m} \\ w_{2,1} \\ w_{2,2} \\ \vdots \\ w_{2,m} \\ w_{3,1} \\ \vdots \\ w_{k,m} \end{bmatrix}.$$

Thus, Equation (5.3) can be written as

$$ACF = y = Fw \quad (5.5)$$

and the least squares estimate of the vector of linear combination coefficients,  $\hat{w}$ , is

$$\hat{w} = F^+ y \quad (5.6)$$

where  $F^+$  denotes the pseudoinverse. For this case,  $F^+$  is  $(F'F)^{-1}F'$  [63, 64], and  $F$  is a  $q$  by  $mk$  matrix,

$$F = \begin{matrix} & \xleftarrow{\quad mk \quad} \xrightarrow{\quad} \\ \begin{matrix} \uparrow \\ q \\ \downarrow \end{matrix} & \begin{bmatrix} f_1(z_{DG,1}^{(1)}) & f_1(z_{DG,2}^{(1)}) & \cdots & f_1(z_{DG,m}^{(1)}) & f_2(z_{DG,1}^{(1)}) & \cdots & f_k(z_{DG,m}^{(1)}) \\ f_1(z_{DG,1}^{(2)}) & & & & & & f_k(z_{DG,m}^{(2)}) \\ \vdots & & & & & & \vdots \\ f_1(z_{DG,1}^{(q)}) & & & & & & f_k(z_{DG,m}^{(q)}) \end{bmatrix} \end{matrix} \quad (5.6)$$

where  $z_{DG,a}^{(b)}$  refers to the impedance of a newly added DG at bus  $a$  for case  $b$  in  $\{\Omega\}$ . References [64-66] document the unbiased least squares approach indicated by (5.6). To review, Equation (5.6) is

$$\begin{aligned} \hat{w} &= \text{Estimate of } w \\ &= F^+ y \end{aligned}$$

where  $\hat{w}$  is an  $mk$  vector,  $y$  is a  $q$  vector and  $F^+$  is a  $q$  by  $mk$  matrix. To assist the reader in following the mathematics, Table 5.1 is offered.

In the foregoing, the general case of  $k$  terms is used to estimate ACF for each newly added DG bus. The selection of  $k$  and the functional forms of the  $f_j, j = 1, \dots, k$  terms in (5.3) need to be made.

In this application, the least squares estimator is applied to calculate the ACF of the system corresponding to the impedance of DGs as shown in Figure 5.1. The unknown system can be modeled as the following functions that are linear in the  $w$  terms,

$$\text{First order } (k = 1): \quad ACF_i = y_i = \sum_{\ell=1}^m w_{1,\ell} \cdot |z_{DG,\ell}^{(i)}| \quad (5.7a)$$

$$\text{Second order } (k = 2): \quad ACF_i = y_i = \sum_{\ell=1}^m w_{1,\ell} \cdot |z_{DG,\ell}^{(i)}| + \sum_{\ell=1}^m w_{2,\ell} \cdot |z_{DG,\ell}^{(i)}|^2 \quad (5.8b)$$

Third order ( $k = 3$ ):

$$ACF_i = y_i = \sum_{\ell=1}^m w_{1,\ell} \cdot |z_{DG,\ell}^{(i)}| + \sum_{\ell=1}^m w_{2,\ell} \cdot |z_{DG,\ell}^{(i)}|^2 + \sum_{\ell=1}^m w_{3,\ell} \cdot |z_{DG,\ell}^{(i)}|^3 \quad (5.8c)$$

$$\text{Reciprocal of } |Z_{DG,\ell}| \text{ } (k = 1): \quad ACF_i = y_i = \sum_{\ell=1}^m w_{1,\ell} \cdot |z_{DG,\ell}^{(i)}|^{-1} \quad (5.8d)$$

Reciprocal of  $|Z_{DG,\ell}|$  squares ( $k = 2$ ) :

$$ACF_i = y_i = \sum_{\ell=1}^m w_{1,\ell} \cdot |z_{DG,\ell}^{(i)}|^{-1} + \sum_{\ell=1}^m w_{2,\ell} \cdot |z_{DG,\ell}^{(i)}|^{-2} \quad (5.8e)$$

Reciprocal of  $|Z_{DG,\ell}|$  cubes ( $k = 3$ ) :

$$ACF_i = y_i = \sum_{\ell=1}^m w_{1,\ell} \cdot |z_{DG,\ell}^{(i)}|^{-1} + \sum_{\ell=1}^m w_{2,\ell} \cdot |z_{DG,\ell}^{(i)}|^{-2} + \sum_{\ell=1}^m w_{3,\ell} \cdot |z_{DG,\ell}^{(i)}|^{-3} \quad (5.8f)$$

where  $z_{DG,\ell}^{(i)}$  is the impedance of the added DGs in case  $i$  and  $w_{1,\ell}$ ,  $w_{2,\ell}$  and  $w_{3,\ell}$  is the coefficient of the first, the second and the third order, respectively.

Calculation of the linear coefficient vector,  $w_{j,\ell}$ , used in (5.6) is comparable to the parameter estimation techniques [64, 65]. Equation (5.5) from the least squares method can be written in the state estimation sense as,

$$Hx = z$$

where  $x$  or the coefficients of linear function is equivalent to the coefficient vector,  $w$ , the incident matrix  $H$  is equivalent to the relationship matrix  $F$  shown in (5.7) and  $z$  or the vector of measured values is equivalent to the vector of the ACF.

**Table 5.1 Dimensions of several quantities used in the least squares estimation of ACF**

| <i>Quantity</i>   |                                                        | <i>Rows</i> | <i>Columns</i> |
|-------------------|--------------------------------------------------------|-------------|----------------|
| $r$               | Residual of the least squares estimation               | 1           | 1              |
| $y$               | Vector of output data from linear combination          | $mk$        | 1              |
| $y_i$             | Value of ACF                                           | 1           | 1              |
| $f_1, f_2, \dots$ | Functions used to approximate ACF                      | 1           | 1              |
| $z^{(i)}$         | Vector of input data for estimate, case ( $i$ )        | $m$         | 1              |
| $Z$               | Matrix of input data for estimate, all case            | $q$         | $m$            |
| $w_{j\ell}$       | Element of vector $w$ , linear combination coefficient | 1           | 1              |
| $w$               | Linear combination coefficient                         | $mk$        | 1              |
| $F$               | Relationship matrix                                    | $q$         | $mk$           |
| $F^+$             | Pseudoinverse of relationship matrix                   | $q$         | $mk$           |
| $\hat{w}$         | Estimate of linear combination coefficient             | $mk$        | 1              |
| $m$               | Number of bus with possibly DG added                   | 1           | 1              |
| $k$               | Order of the ACF model                                 | 1           | 1              |
| $q$               | Number of case in $\Omega$                             | 1           | 1              |

#### 5.4 Application of the least squares method to the Thunderstone test bed system, Case 5.1

To illustrate the application of the proposed index, a sample system is used to demonstrate the potential economic impact due to the high levels of DG and merchant plant penetration. The Thunderstone system as shown in Figure 3.4 is used as the test bed system to demonstrate the calculation of the coefficient matrix,  $W_{mk}$ , and an application of the ACF index. Details of the Thunderstone system are discussed in Chapter 3. All system parameters are shown in Appendix A. By applying the reciprocal of  $|Z_{DR}|$  cubes model,

$$ACF_i = y_i = \sum_{\ell=1}^m w_{1,\ell} \cdot |z_{DG,\ell}^{(i)}|^{-1} + \sum_{\ell=1}^m w_{2,\ell} \cdot |z_{DG,\ell}^{(i)}|^{-2} + \sum_{\ell=1}^m w_{3,\ell} \cdot |z_{DG,\ell}^{(i)}|^{-3} \quad (5.8)$$

In this calculation, the least squares estimator model is created from 500 cases each with a different  $Z_{DR}$ . The impedances of DRs installed at 12 kV buses are pseudorandom, uniformly distributed. The transient impedances of each DR are in the range  $0.005+j0.83$  to  $0.005+j0.92$  per unit. From (5.9), the ACF model can be written as

$$ACF = \sum_{j=1}^k \sum_{i=1}^m w_{j,i} f_j(Z_{DR,i}) = FW$$

where  $f_j$  is a function applied in the power series (i.e.,  $|Z_{DR}|^{-k}$ ) and  $F$  is the matrix of  $f_j(Z_{DR,i})$  terms. The coefficient vector,  $W$ , calculated using the least squares method is  $W = (F'F)^{-1} F'(ACF)$ . This is comparable to the parameter estimation technique in [65].

Assume that the DGs are installed at 6 locations: Cameron2, Signal3, Seaton2, Ealy3, Ealy4 and Sage3. The transient impedances of each DG are shown in Table 5.2.

**Table 5.2 List of the buses with new DG in Case 5.1**

| <i>Bus name</i> | <i>Transient impedance of the DG<br/>(p.u.)</i> |
|-----------------|-------------------------------------------------|
| Cameron2 (6)    | $0.005 + j0.81$                                 |
| Signal3 (11)    | $0.005 + j0.90$                                 |
| Seaton2 (22)    | $0.005 + j0.83$                                 |
| Ealy3 (24)      | $0.005 + j0.85$                                 |
| Ealy4 (25)      | $0.005 + j0.92$                                 |
| Sage3 (26)      | $0.005 + j0.84$                                 |

The coefficient vector of the model is calculated by applying (5.6). Note that the coefficient vector,  $w$ , can be separated into  $k$  groups depending on the order of each model. For example, in the reciprocal of  $z_{DG,\ell}$  cubes ( $k = 3$ ), the first order coefficient of the coefficient vector,  $w_{1,\ell}$ , is  $m$  by one sub-vector. For this reason, the coefficient vector,  $w$ , is  $mk$  by one vector. The coefficient vector,  $w$ , of the Thunderstone system is,

$$w = \begin{bmatrix} w_{1,\ell} \\ w_{2,\ell} \\ w_{3,\ell} \end{bmatrix}$$

where

$$w_{1,\ell} = \begin{bmatrix} 2.2048 \\ 2.5609 \\ 1.7878 \\ 2.3637 \\ 2.3148 \\ 2.7164 \\ 2.4916 \\ 2.3671 \\ 2.3834 \\ 2.6878 \\ 2.8195 \\ 2.8508 \\ 2.3576 \\ 2.2561 \end{bmatrix}, w_{2,\ell} = \begin{bmatrix} -1.1148 \\ -1.2409 \\ -0.8427 \\ -1.1276 \\ -1.1037 \\ -1.1208 \\ -1.1090 \\ -1.1408 \\ -1.2601 \\ -1.2799 \\ -1.1144 \\ -1.4519 \\ -1.2003 \\ -1.1449 \end{bmatrix} \text{ and } w_{3,\ell} = \begin{bmatrix} 0.2317 \\ 0.2641 \\ 0.1711 \\ 0.2298 \\ 0.2259 \\ 0.2100 \\ 0.2113 \\ 0.2252 \\ 0.2692 \\ 0.2643 \\ 0.2006 \\ 0.2991 \\ 0.2523 \\ 0.2447 \end{bmatrix}.$$

The impedance of the added DGs in this case is

$$|z_{DG}| = [0 \quad 0.81 \quad 0 \quad 0 \quad 0.90 \quad 0 \quad 0 \quad 0 \quad 0 \quad 0.83 \quad 0.85 \quad 0.92 \quad 0.84 \quad 0].$$

The ACF of the system from (5.8) is

$$ACF = y = \begin{bmatrix} 0.0000 \\ 1.2345 \\ 0.0000 \\ 0.0000 \\ 1.2500 \\ 0.0000 \\ 0.0000 \\ 0.0000 \\ 0.0000 \\ 0.0000 \\ 1.2048 \\ 1.1765 \\ 1.0869 \\ 1.1905 \\ 0.0000 \end{bmatrix}^t \hat{w}_{1,\ell} + \begin{bmatrix} 0.0000 \\ 1.5241 \\ 0.0000 \\ 0.0000 \\ 1.5624 \\ 0.0000 \\ 0.0000 \\ 0.0000 \\ 0.0000 \\ 0.0000 \\ 1.4515 \\ 1.3840 \\ 1.1814 \\ 1.4172 \\ 0.0000 \end{bmatrix}^t \hat{w}_{2,\ell} + \begin{bmatrix} 0.0000 \\ 1.8816 \\ 0.0000 \\ 0.0000 \\ 1.9530 \\ 0.0000 \\ 0.0000 \\ 0.0000 \\ 0.0000 \\ 0.0000 \\ 1.7488 \\ 1.6282 \\ 1.2842 \\ 1.6871 \\ 0.0000 \end{bmatrix}^t \hat{w}_{3,\ell} \quad (5.9)$$

$$= 10.63 \, \%.$$

Note that the ACF from the conventional fault calculation is 10.87 %. The error from the least squares estimator compared to the conventional fault calculation is 2.25 %.

The accuracy of the least squares model can be measured by the norm of the scalar residual  $r_i$ ,

$$\frac{\|r\|}{\|F\hat{w}\|} = \frac{\|y - F\hat{w}\|}{\|F\hat{w}\|} \text{ p.u.},$$

where  $y$  is the vector ACF from the conventional fault calculation (full calculation).

In this calculation, the least squares estimator is created from 500 cases. The impedances of DGs installed at 12-kV buses are generated randomly under the same base MVA. Among the model in (5.8), the reciprocal of  $Z_{DG,\ell}$  cubes shown in (5.8f) has the highest accuracy. Norm of the scalar residual of each model is shown in Table 5.3. The histogram of the residual from the least squares model is shown in Figure 5.2.

**Table 5.3 Norm of the residual in Case 5.1**

| <i>Model</i>                    | <i>Equation</i> | <i>Norm of residual*</i> |
|---------------------------------|-----------------|--------------------------|
| First order                     | (5.8a)          | 0.135                    |
| Second order                    | (5.8b)          | 0.0432                   |
| Third order                     | (5.8c)          | 0.0127                   |
| Reciprocal of $ z_{DG,\ell} $   | (5.8d)          | 0.046                    |
| Reciprocal of $ z_{DG,\ell} ^2$ | (5.8e)          | 0.00655                  |
| Reciprocal of $ z_{DG,\ell} ^3$ | (5.8f)          | 0.00119                  |

\* expressed as a fraction, e.g., 0.135 = 13.4%

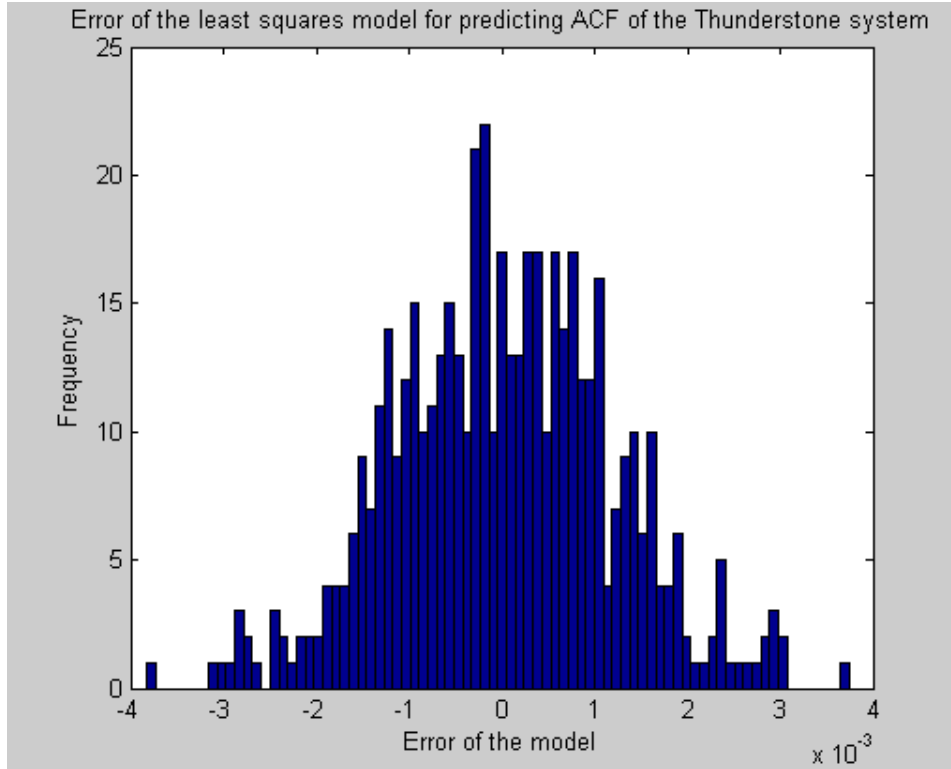


**Figure 5.2 Residual of the least squares estimator, Case 5.1 (residual expressed as a fraction as in Table 5.3)**

Note that (5.10) can be independently written as 14 components according to fourteen 12 kV buses. Each component  $ACF_{(bus)}$ , called “Bus ACF”, relates to the contribution of the DG to the total ACF. The plot of Bus ACF and the total ACF is shown in Figure 5.3. For instance, the contribution of the DG at bus 6 (Cameron2), 11 (Signal3), 22 (Seaton2), 24 (Ealy3), 25 (Ealy4) and 26 (Sage3) to ACF are

$$ACF_{(6)} = 2.5609 \cdot \frac{1}{|z_{DG,6}|} - 1.2409 \cdot \frac{1}{|z_{DG,6}|^2} + 0.2641 \cdot \frac{1}{|z_{DG,6}|^3}, \quad (5.10a)$$

$$ACF_{(11)} = 2.3148 \cdot \frac{1}{|z_{DG,11}|} - 1.1037 \cdot \frac{1}{|z_{DG,11}|^2} + 0.2259 \cdot \frac{1}{|z_{DG,11}|^3}, \quad (5.11b)$$

$$ACF_{(22)} = 2.6878 \cdot \frac{1}{|z_{DG,22}|} - 1.2799 \cdot \frac{1}{|z_{DG,22}|^2} + 0.2643 \cdot \frac{1}{|z_{DG,22}|^3}, \quad (5.11c)$$

$$ACF_{(24)} = 2.8195 \cdot \frac{1}{|z_{DG,24}|} - 1.1144 \cdot \frac{1}{|z_{DG,24}|^2} + 0.2006 \cdot \frac{1}{|z_{DG,24}|^3}, \quad (5.11d)$$

$$ACF_{(25)} = 2.8508 \cdot \frac{1}{|z_{DG,25}|} - 1.4519 \cdot \frac{1}{|z_{DG,25}|^2} + 0.2991 \cdot \frac{1}{|z_{DG,25}|^3}, \quad (5.11e)$$

$$ACF_{(26)} = 2.3576 \cdot \frac{1}{|z_{DG,26}|} - 1.2003 \cdot \frac{1}{|z_{DG,26}|^2} + 0.2523 \cdot \frac{1}{|z_{DG,26}|^3}. \quad (5.11f)$$

Figure 5.4 shows the comparison of the least squares estimator model and the conventional fault calculation. The accuracy of the least squares estimator when the DG transient impedance lies between  $j0.5$  to  $j1.5$  p.u., which is the usual range, is tolerable. Reasons for the error are:

- the historical data used to create the model ranges from  $j0.5$  to  $j1.5$  p.u.
- the pre-fault voltage is not included into the model. However, while calculating the historical data, the pre-fault voltages after installing DGs are updated and applied to the fault current calculation. For this reason, results of the pre-fault voltages after installing DGs are also included into the calculation of the ACF.

### 5.5 Confidence interval of the least squares estimator coefficient

Assuming that the residuals of the least squares estimator are normally and independently distributed with mean zero and variance,  $\sigma_r^2$ . The linear coefficient vector,  $\hat{w}$ , is normally distributed with the mean vector  $w$  and the covariance matrix  $\sigma_r^2 (F'F)^{-1}$ . For the same reason, the marginal distribution of any least squares estimator,  $\hat{w}_{j,\ell}$ , is normal with mean  $w_{j,\ell}$  and variance  $\sigma_r^2 C_{jj}$ , where  $C_{jj}$  is the  $j$ th diagonal element of the  $(F'F)^{-1}$  matrix.

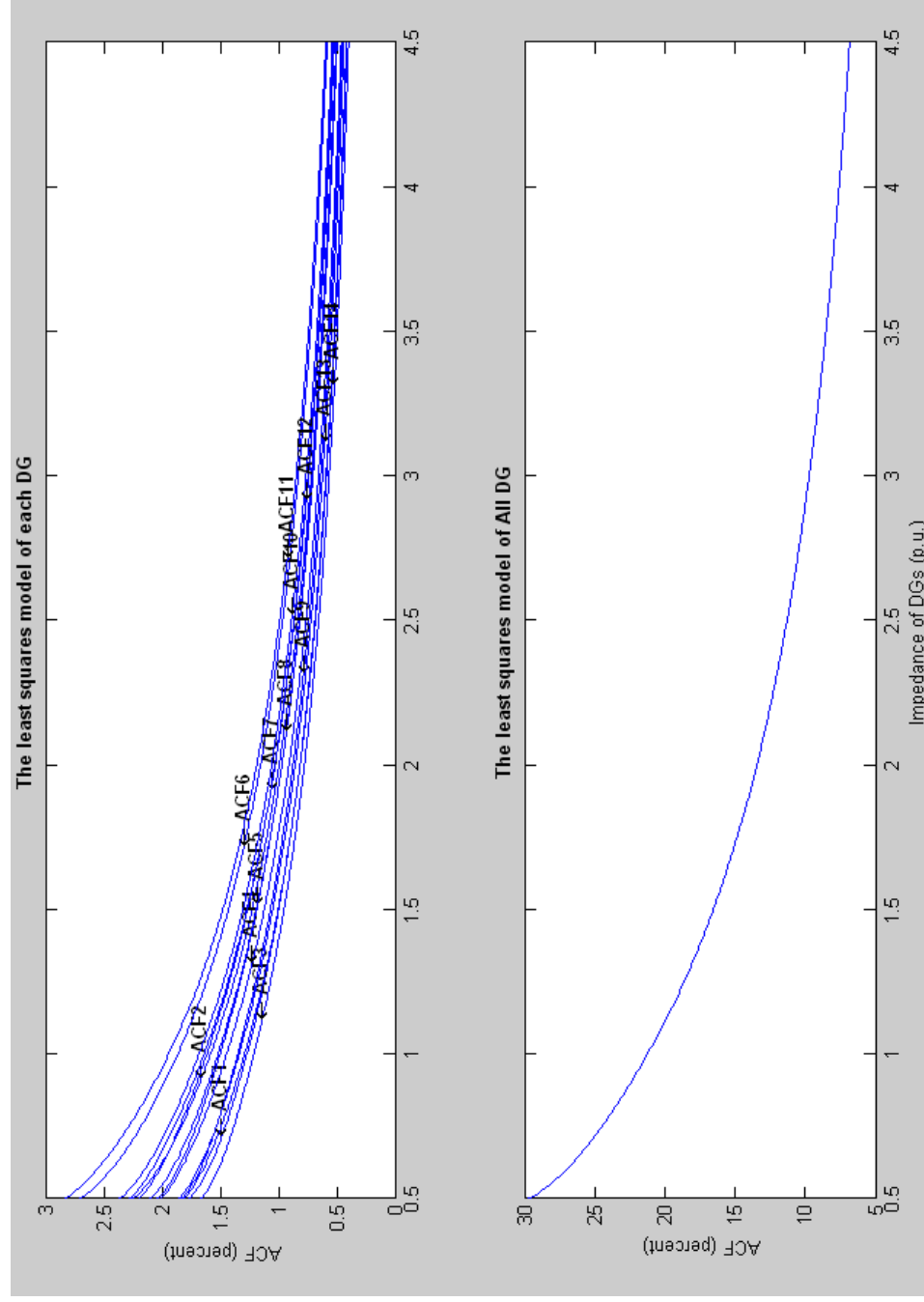


**Figure 5.3 Plot of the bus ACF and the total ACF, Case 5.1**

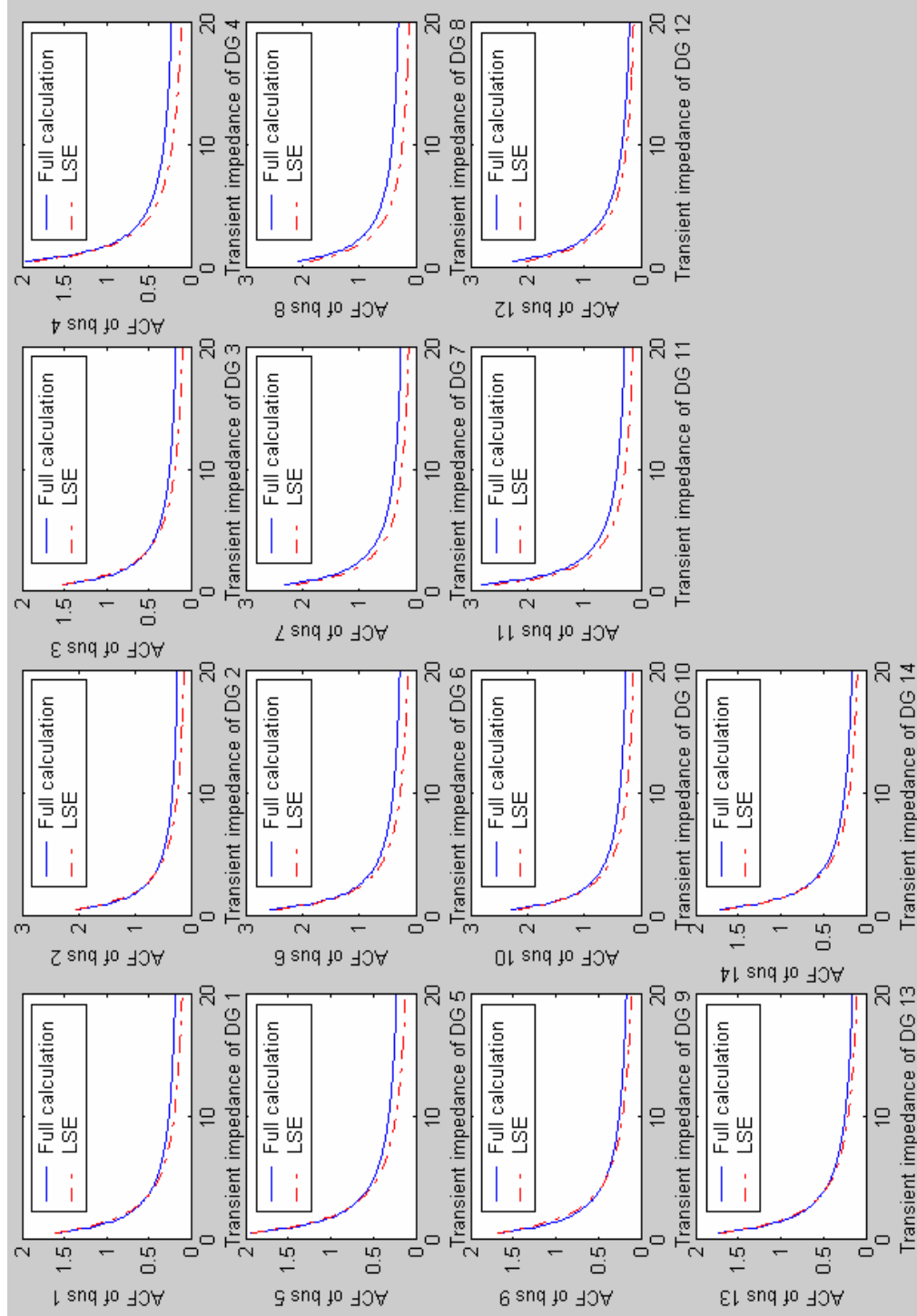


**Figure 5.4 Comparison between the full fault calculation and the least squares estimator model, Case 5.1**

Therefore, the  $100(1-\alpha)$  percent confidence interval for the least squares estimator coefficient  $w_{j,\ell}$  is [64]

$$\hat{w}_{j,\ell} - t_{\alpha/2, n-p} \sqrt{\hat{\sigma}_r^2 C_{ii}} \leq w_{j,\ell} \leq \hat{w}_{j,\ell} + t_{\alpha/2, n-p} \sqrt{\hat{\sigma}_r^2 C_{ii}}, \quad (5.11)$$

where  $t_{\alpha/2, n-p}$  is the value from  $t$ -distribution,  $n$  is the number of all historical data,  $p$  is number of coefficient of the least squares estimator and  $\hat{\sigma}_r^2$  is the estimation of variance of residual. The estimation of variance of residual,  $\hat{\sigma}_r^2$  is,

$$\hat{\sigma}_r^2 = \frac{SS_{Res}}{n-p} = \frac{y'y - \hat{w}'F'y}{n-p},$$

where  $SS_{Res}$  is the residual sum of squares [64].

Applying (5.12), the 95 percent confidence intervals on the coefficient of the ACF model for the Thunderstone system, Case 5.1, are shown in Table 5.4

## 5.6 Confidence interval estimation of the mean response of ACF

Define a particular situation when the input of the ACF model is

$$f_0 = [f_1^{(0)}(z_{DG,1}) \cdots f_1^{(0)}(z_{DG,m}) \quad f_2^{(0)}(z_{DG,1}) \cdots f_2^{(0)}(z_{DG,m}) \quad f_3^{(0)}(z_{DG,1}) \cdots f_3^{(0)}(z_{DG,m})].$$

For example, if considering the reciprocal of  $|z_{DG,\ell}|^3$  as the ACF model, the input matrix of the ACF model is,

$$f_0 = [|z_{DG,1}|^{-1} \cdots |z_{DG,m}|^{-1} \quad |z_{DG,1}|^{-2} \cdots |z_{DG,m}|^{-2} \quad |z_{DG,1}|^{-3} \cdots |z_{DG,m}|^{-3}].$$

The ACF value can be estimated as  $\hat{ACF}$  at a particular point by applying (5.8f),

$$\hat{ACF} = \hat{y} = \sum_{\ell=1}^m \hat{w}_{1,\ell} \cdot |z_{DG,\ell}|^{-1} + \sum_{\ell=1}^m \hat{w}_{2,\ell} \cdot |z_{DG,\ell}|^{-2} + \sum_{\ell=1}^m \hat{w}_{3,\ell} \cdot |z_{DG,\ell}|^{-3}.$$

**Table 5.4 Confidence interval of the coefficient of the ACF model, Case 5.1**

| <i>Model coefficient,<br/><math>w_{j,\ell}</math></i> | <i>Ninety five percent<br/>confidence interval</i> | <u>95% confidence interval</u><br>Coefficient $w_{j,\ell}$ |
|-------------------------------------------------------|----------------------------------------------------|------------------------------------------------------------|
| 2.2048                                                | $\pm 0.2650$                                       | 0.1202                                                     |
| 2.5609                                                | $\pm 0.2433$                                       | 0.0950                                                     |
| 1.7878                                                | $\pm 0.2457$                                       | 0.1374                                                     |
| 2.3637                                                | $\pm 0.2564$                                       | 0.1085                                                     |
| 2.3148                                                | $\pm 0.2470$                                       | 0.1067                                                     |
| 2.7164                                                | $\pm 0.2310$                                       | 0.0850                                                     |
| 2.4916                                                | $\pm 0.2503$                                       | 0.1005                                                     |
| 2.3671                                                | $\pm 0.2548$                                       | 0.1076                                                     |
| 2.3834                                                | $\pm 0.2554$                                       | 0.1072                                                     |
| 2.6878                                                | $\pm 0.2830$                                       | 0.1053                                                     |
| 2.8195                                                | $\pm 0.2372$                                       | 0.0841                                                     |
| 2.8508                                                | $\pm 0.2695$                                       | 0.0945                                                     |
| 2.3576                                                | $\pm 0.2477$                                       | 0.1051                                                     |
| 2.2561                                                | $\pm 0.2572$                                       | 0.1140                                                     |
| -1.1148                                               | $\pm 0.2195$                                       | 0.1969                                                     |
| -1.2409                                               | $\pm 0.2001$                                       | 0.1613                                                     |
| -0.8427                                               | $\pm 0.2009$                                       | 0.2384                                                     |
| -1.1276                                               | $\pm 0.2126$                                       | 0.1885                                                     |
| -1.1037                                               | $\pm 0.2021$                                       | 0.1831                                                     |
| -1.1208                                               | $\pm 0.1879$                                       | 0.1676                                                     |
| -1.1090                                               | $\pm 0.2057$                                       | 0.1855                                                     |
| -1.1408                                               | $\pm 0.2113$                                       | 0.1852                                                     |
| -1.2601                                               | $\pm 0.2104$                                       | 0.1670                                                     |
| -1.2799                                               | $\pm 0.2342$                                       | 0.1830                                                     |
| -1.1144                                               | $\pm 0.1945$                                       | 0.1745                                                     |
| -1.4519                                               | $\pm 0.2254$                                       | 0.1552                                                     |
| -1.2003                                               | $\pm 0.2052$                                       | 0.1710                                                     |
| -1.1449                                               | $\pm 0.2126$                                       | 0.1857                                                     |
| 0.2317                                                | $\pm 0.0579$                                       | 0.2499                                                     |
| 0.2641                                                | $\pm 0.0523$                                       | 0.1980                                                     |
| 0.1711                                                | $\pm 0.0521$                                       | 0.3045                                                     |
| 0.2298                                                | $\pm 0.0559$                                       | 0.2433                                                     |
| 0.2259                                                | $\pm 0.0526$                                       | 0.2328                                                     |
| 0.2100                                                | $\pm 0.0485$                                       | 0.2310                                                     |
| 0.2113                                                | $\pm 0.0537$                                       | 0.2541                                                     |
| 0.2252                                                | $\pm 0.0556$                                       | 0.2469                                                     |
| 0.2692                                                | $\pm 0.0552$                                       | 0.2051                                                     |
| 0.2643                                                | $\pm 0.0617$                                       | 0.2334                                                     |
| 0.2006                                                | $\pm 0.0505$                                       | 0.2517                                                     |
| 0.2991                                                | $\pm 0.0601$                                       | 0.2009                                                     |
| 0.2523                                                | $\pm 0.0541$                                       | 0.2144                                                     |
| 0.2447                                                | $\pm 0.0559$                                       | 0.2284                                                     |

The variance of the  $\hat{ACF}$  is

$$Var(\hat{ACF}) = \sigma^2 f_0'(F'F)^{-1} f_0.$$

Therefore,  $100(1-\alpha)$  percent confidence interval on the mean response of the ACF model with  $f_0$  as the input is [64],

$$\hat{ACF}_0 - t_{\alpha/2, n-p} \sqrt{\hat{\sigma}_r^2 f_0'(F'F)^{-1} f_0} \leq E(ACF|f_0) \leq \hat{ACF}_0 + t_{\alpha/2, n-p} \sqrt{\hat{\sigma}_r^2 f_0'(F'F)^{-1} f_0}. \quad (5.12)$$

For instance, the 95 percent confidence interval of ACF of the Thunderstone system with new DGs shown in Table 5.2 for Case 5.1 is,

$$10.63 - t_{0.025, 467} \sqrt{\hat{\sigma}_r^2 f_0'(F'F)^{-1} f_0} \leq E(ACF|f_0) \leq 10.63 + t_{0.025, 467} \sqrt{\hat{\sigma}_r^2 f_0'(F'F)^{-1} f_0},$$

or

$$10.53 \leq E(ACF|f_0) \leq 10.819.$$

There is ninety five percent probability that the true ACF of Case 5.1 stays in the indicated interval. Table 5.5 shows the confidence interval of the mean response of the ACF model with various percent confidence,  $\alpha$ .

**Table 5.5 Percent confidence and their confidence intervals for the mean response of the ACF of the Thunderstone system, Case 5.1**

| <i>Percent confidence</i> | <i>Confidence interval,<br/><math>E(ACF f_0)</math></i> |
|---------------------------|---------------------------------------------------------|
| 98                        | $10.63 \pm 0.21$                                        |
| 95                        | $10.63 \pm 0.18$                                        |
| 90                        | $10.63 \pm 0.15$                                        |
| 80                        | $10.63 \pm 0.12$                                        |

## 6 Implications of Fault Current for Unit Commitment

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### 6.1 Introduction

This chapter introduces a study on the implications of operating economics imposed by increased fault current due to the addition of DGs and/or merchant plans to a power system. In some cases, especially when the system has high penetration level, the fault current after connecting these generation sources may be higher than the interrupting capability of some circuit breakers (CBs) in the system. This means that the CBs may fail to interrupt fault current and may create a safety hazard.

Increased system fault currents resulting from DG installation and the effects of increased fault currents on operating economics is discussed in this chapter. A technique used to evaluate the unit commitment (UC) with fault level constraint after installing DGs is analyzed, and an example is given.

Unit commitment is the problem of determining the optimal schedule of committing (i.e., making available for dispatch) generation subject to operating constraints. The operating constraints include minimum start up / shut down times and the generator maximum and minimum limits. The general objective of the UC problem is to minimize the system total operating cost while satisfying all of the constraints so that a given security level can be met. Fault level constraints (FLCs) are considered as one of the constraints in the UC problem.

### 6.2 Unit commitment problem formation

The UC problem is to find the schedule up / down (i.e., commit / decommit) for available units and their generation levels at each period of time in the time horizon. This is done in order to minimize the total operating cost (OC) while satisfying various constraints.

*Objective function*

The UC problem can be formulated as,

$$OC = \min \sum_t^T \sum_{I=1}^L [P_{\text{cost}}(t, I) + S_{\text{cost}}(t-1, J : t, I)]$$

where

- Production cost can be modeled as a quadratic function,

$$P_{\text{cost}}(t, I) = \sum_i^I (a_i + b_i P_{it} + c_i P_{it}^2).$$

- Transition cost,  $S_{cost}$  is the total start up / shut down cost of each unit of the time  $t$ . The start up cost depends on the number of hours it has been off-line (hot start/cold start).

### Constraints

The constraints for the problem are

- Power flow equation of the power network
- The inequality constraint on reactive power generation at each  $PV$  bus. The reactive power output must stay in the specific range,

$$Q_i^{\min} < Q_i < Q_i^{\max}.$$

- The inequality constraint on voltage magnitude  $|V|$  of each PQ bus

$$V_i^{\min} < V_i < V_i^{\max}.$$

- Unit generation limits: generation of unit  $i$  at time  $t$  is limited by minimum and maximum physical and operational limits,

$$G_{it}^{\min} < G_{it} < G_{it}^{\max}.$$

- Spinning reserve constraint: the spinning reserve is the total amount of power generation available from all units minus the present load and losses. The reserve is a specified amount or percent of the forecasted peak demand of each period.

$$\sum_{i=1}^N P_{\max,i} \cdot U_{it} \geq Load_t + R_t.$$

In this illustration, the spinning reserved is fixed at 10 percent of the forecasted peak demand

- Fault current level constraints: three phase fault currents  $|I_{fi}|$  can be calculated by applying (3.2) and (3.3), where

$$|I_{fi}| < IC_i.$$

- Unit minimum up and down time constraints. Once the unit is running or decommitted, there is a minimum time before changing its status.

$$Ton_i \geq Tup_i$$

and

$$Toff_i \geq TDown_i.$$

### Short term commitment schedules

Unit commitment is frequently done on a weekly or monthly basis with a time resolution of about one hour. For small generating units such as DGs, a smaller time resolution might be used, and a much shorter time horizon may be employed. In the subsequent section, some experimental results are shown utilizing a time resolution of one hour and a time horizon for the study of one day. The examples are intended as illustrations but the time resolution and horizon may not be illustrative of all DG applications.

### 6.3 Illustrative examples

To illustrate the results from a dynamic programming / unit commitment study (DPUC), a 24 hour schedule of the test bed system (see Figure 3.1) is used to demonstrate the potential economic impact due to the high levels of DG and merchant plant penetration. The Thunderstone system is used as the test bed system. Details of the Thunderstone system are discussed in Section 3.1. All parameters are shown in Appendix A.

In this demonstration, eight DGs are installed at the 12 kV buses of the sample system. The CBs at the bus with DGs is assumed to be upgraded by the owners. It is assumed that the power delivered from the grid is limited at 200 MVA. Tables 6.1-6.3 show the data of several DGs and merchant plants. Note that the per unit reactances are given on the DG unit base.

The results of the DPUC study are shown in the Table 6.5-6.6. In Table 6.5, the following factors are modeled:

- Minimum start up and shut down times
- Operating cost using a quadratic cost function
- Start up and shut down costs
- Spinning reserve requirements
- Distinction between hot start and cold start in start up costs.

With reference to the Tables 6.5 and 6.6, in Table 6.5, a ‘0’ denotes a decommitted unit, and ‘1’ denotes a committed unit. The system demand is listed in Table 6.5 as ‘load’. Losses are not modeled for this study. Note that ‘spinning reserve’ requirements are 10% of the forecast demand. Table 6.4 lists the location of DG used in this study.

**Table 6.1 Generating unit characteristics for example**

| <i>Unit#</i> | <i>Min<br/>(MW)</i> | <i>Max<br/>(MW)</i> | <i>Hot start<br/>Cost(\$)</i> | <i>Cold start<br/>Cost(\$)</i> | <i>Cold start<br/>Time(h)</i> | <i>Shut Down<br/>Cost(\$)</i> |
|--------------|---------------------|---------------------|-------------------------------|--------------------------------|-------------------------------|-------------------------------|
| Grid         | -                   | 200                 | -                             | -                              | -                             | -                             |
| 1            | 3                   | 11                  | 150                           | 500                            | 3                             | 150                           |
| 2            | 3                   | 10                  | 120                           | 450                            | 3                             | 130                           |
| 3            | 1                   | 8                   | 130                           | 400                            | 3                             | 110                           |
| 4            | 3                   | 15                  | 170                           | 620                            | 2                             | 150                           |
| 5            | 1                   | 7                   | 35                            | 130                            | 2                             | 90                            |
| 6            | 3                   | 12                  | 250                           | 500                            | 4                             | 160                           |
| 7            | 1                   | 6                   | 30                            | 100                            | 5                             | 20                            |
| 8            | 5                   | 13                  | 45                            | 150                            | 3                             | 125                           |

**Table 6.2 Unit fuel costs for example**

| Unit # | <i>Initial conditions</i><br>Hours off line (-)<br>Hours online (+) | <i>Cost coefficients*</i> |        |         |
|--------|---------------------------------------------------------------------|---------------------------|--------|---------|
|        |                                                                     | $a_i$                     | $b_i$  | $c_i$   |
| Grid   | -                                                                   | 450                       | 4.500  | 0.03653 |
| 1      | 2                                                                   | 580                       | 9.910  | 0.00690 |
| 2      | 1                                                                   | 600                       | 10.100 | 0.00630 |
| 3      | 3                                                                   | 720                       | 12.500 | 0.01850 |
| 4      | -1                                                                  | 481                       | 9.210  | 0.00487 |
| 5      | -1                                                                  | 580                       | 11.300 | 0.00900 |
| 6      | -1                                                                  | 550                       | 9.810  | 0.00620 |
| 7      | 2                                                                   | 610                       | 11.500 | 0.00800 |
| 8      | 3                                                                   | 575                       | 9.950  | 0.00650 |

\*The units of the  $a_i$  are dollars, the  $b_i$  are in \$/MWh, and the  $c_i$  are in \$/(MW)<sup>2</sup>h

**Table 6.3 Unit transient impedances  $X'_d$** 

| <i>New DG at bus</i> | <i>DGs impedance</i><br>(per unit)* | <i>Machine rating</i><br>(MVA) |
|----------------------|-------------------------------------|--------------------------------|
| 6                    | $0.005 + j0.40$                     | 11.0                           |
| 11                   | $0.005 + j0.30$                     | 10.1                           |
| 15                   | $0.005 + j0.37$                     | 8.3                            |
| 16                   | $0.005 + j0.25$                     | 15.0                           |
| 22                   | $0.005 + j0.59$                     | 7.1                            |
| 24                   | $0.005 + j0.33$                     | 12.2                           |
| 25                   | $0.005 + j0.65$                     | 6                              |
| 26                   | $0.005 + j0.35$                     | 13.0                           |

\* per unit based on the machine rating and 12.47 kV

**Table 6.4 Location and type of DG used in sample study**

| <i>DG number</i> | <i>DG location (bus number)</i> |
|------------------|---------------------------------|
| 1                | Cameron2                        |
| 2                | Signal13                        |
| 3                | Super14                         |
| 4                | Super15                         |
| 5                | Seaton2                         |
| 6                | Early3                          |
| 7                | Early4                          |
| 8                | Sage3                           |

**Table 6.5 Unit scheduling: without fault current limitation**

| <i>Period</i> | <i>Status</i> |   |   |   |   |   |   |   |   | <i>Max Gen<br/>(MW)</i> | <i>Load<br/>(MW)</i> | <i>Cost<br/>(\$)</i> | <i>Total<br/>cost (\$)</i> |
|---------------|---------------|---|---|---|---|---|---|---|---|-------------------------|----------------------|----------------------|----------------------------|
|               | <i>Grid</i>   | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 |                         |                      |                      |                            |
| 1             | 1             | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200.0                   | 155.1                | 2561.7               | 2561.7                     |
| 2             | 1             | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 215.0                   | 195.0                | 3683.8               | 6245.5                     |
| 3             | 1             | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 215.0                   | 195.3                | 3069.1               | 9314.7                     |
| 4             | 1             | 0 | 0 | 0 | 1 | 0 | 1 | 0 | 0 | 227.0                   | 196.0                | 4542.7               | 13357.3                    |
| 5             | 1             | 0 | 0 | 0 | 1 | 0 | 1 | 0 | 0 | 227.0                   | 197.0                | 4559.6               | 16916.9                    |
| 6             | 1             | 0 | 0 | 0 | 1 | 0 | 1 | 0 | 1 | 240.0                   | 210.0                | 5265.0               | 21331.9                    |
| 7             | 1             | 0 | 0 | 0 | 1 | 0 | 1 | 0 | 1 | 240.0                   | 212.0                | 5299.0               | 25631.0                    |
| 8             | 1             | 1 | 0 | 0 | 1 | 0 | 1 | 0 | 1 | 251.0                   | 226.0                | 6040.4               | 31171.3                    |
| 9             | 1             | 1 | 0 | 0 | 1 | 0 | 1 | 0 | 1 | 251.0                   | 227.2                | 5061.2               | 36232.5                    |
| 10            | 1             | 1 | 0 | 0 | 1 | 1 | 1 | 0 | 1 | 258.0                   | 230.5                | 6656.9               | 42019.5                    |
| 11            | 1             | 1 | 0 | 0 | 1 | 1 | 1 | 0 | 1 | 258.0                   | 231.5                | 6674.1               | 47693.5                    |
| 12            | 1             | 1 | 0 | 0 | 1 | 1 | 1 | 0 | 1 | 258.0                   | 230.2                | 6651.8               | 53345.3                    |
| 13            | 1             | 0 | 0 | 0 | 1 | 0 | 1 | 0 | 0 | 227.0                   | 162.2                | 4015.0               | 56725.3                    |
| 14            | 1             | 0 | 1 | 0 | 1 | 0 | 1 | 0 | 0 | 237.0                   | 215.1                | 4850.7               | 61576.0                    |
| 15            | 1             | 1 | 0 | 0 | 1 | 0 | 1 | 0 | 1 | 251.0                   | 220.3                | 5943.0               | 66844.0                    |
| 16            | 1             | 1 | 0 | 0 | 1 | 0 | 1 | 0 | 1 | 251.0                   | 226.5                | 5049.0               | 71893.1                    |
| 17            | 1             | 1 | 0 | 0 | 1 | 0 | 1 | 0 | 1 | 251.0                   | 225.2                | 6026.6               | 76919.6                    |
| 18            | 1             | 1 | 0 | 0 | 1 | 0 | 1 | 0 | 1 | 251.0                   | 228.1                | 5076.8               | 81996.5                    |
| 19            | 1             | 1 | 0 | 0 | 1 | 0 | 1 | 1 | 1 | 257.0                   | 230.1                | 6687.0               | 87783.5                    |
| 20            | 1             | 0 | 0 | 0 | 1 | 0 | 1 | 0 | 1 | 240.0                   | 215.5                | 5359.2               | 92312.6                    |
| 21            | 1             | 0 | 0 | 0 | 1 | 0 | 1 | 0 | 1 | 240.0                   | 214.1                | 5335.0               | 96647.7                    |
| 22            | 1             | 0 | 0 | 0 | 1 | 0 | 1 | 0 | 1 | 240.0                   | 212.1                | 5300.7               | 100948.4                   |
| 23            | 1             | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200.0                   | 175.4                | 2798.2               | 103746.5                   |
| 24            | 1             | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200.0                   | 160.5                | 2113.3               | 105859.8                   |

**Table 6.6 Unit scheduling: with fault current limitation**

| <i>Period</i> | <i>Status</i> |   |   |   |   |   |   |   |   | <i>MaxGen</i><br>(MW) | <i>Load</i><br>(MW) | <i>Cost</i><br>(\$) | <i>Total cost</i><br>(\$) |
|---------------|---------------|---|---|---|---|---|---|---|---|-----------------------|---------------------|---------------------|---------------------------|
|               | <i>Grid</i>   | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 |                       |                     |                     |                           |
| 1             | 1             | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200.00                | 155.1               | 2561.7              | 2561.7                    |
| 2             | 1             | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 215.00                | 195.0               | 3683.8              | 6245.5                    |
| 3             | 1             | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 215.00                | 195.3               | 3069.1              | 9314.7                    |
| 4             | 1             | 0 | 0 | 0 | 1 | 0 | 1 | 0 | 0 | 227.00                | 196.0               | 4542.7              | 13357.3                   |
| 5             | 1             | 0 | 0 | 0 | 1 | 0 | 1 | 0 | 0 | 227.00                | 197.0               | 4559.6              | 16916.9                   |
| 6             | 1             | 0 | 0 | 0 | 1 | 0 | 1 | 1 | 0 | 233.00                | 210.0               | 4459.1              | 21376.0                   |
| 7             | 1             | 1 | 0 | 0 | 1 | 0 | 1 | 0 | 0 | 238.00                | 212.0               | 5317.7              | 26213.7                   |
| 8             | 1             | 1 | 1 | 1 | 1 | 0 | 1 | 0 | 0 | 256.00                | 226.0               | 6772.2              | 32835.9                   |
| 9             | 1             | 1 | 1 | 1 | 1 | 0 | 1 | 0 | 0 | 256.00                | 227.2               | 6792.6              | 38628.5                   |
| 10            | 1             | 1 | 1 | 1 | 1 | 0 | 1 | 0 | 0 | 256.00                | 230.5               | 6849.1              | 44477.6                   |
| 11            | 1             | 1 | 1 | 1 | 1 | 0 | 1 | 0 | 0 | 256.00                | 231.5               | 5866.4              | 50344.0                   |
| 12            | 1             | 1 | 1 | 1 | 1 | 0 | 1 | 0 | 0 | 256.00                | 230.2               | 6843.9              | 56188.0                   |
| 13            | 1             | 0 | 0 | 0 | 1 | 0 | 1 | 0 | 0 | 227.00                | 162.2               | 4015.0              | 59593.0                   |
| 14            | 1             | 0 | 1 | 0 | 1 | 0 | 1 | 0 | 0 | 237.00                | 215.1               | 4520.7              | 64113.6                   |
| 15            | 1             | 1 | 1 | 0 | 1 | 0 | 1 | 0 | 0 | 248.00                | 220.3               | 5990.2              | 69253.8                   |
| 16            | 1             | 1 | 1 | 1 | 1 | 0 | 1 | 0 | 0 | 256.00                | 226.5               | 6780.7              | 75434.5                   |
| 17            | 1             | 1 | 1 | 0 | 1 | 0 | 1 | 0 | 0 | 248.00                | 225.2               | 5184.8              | 80619.3                   |
| 18            | 1             | 1 | 1 | 1 | 1 | 0 | 1 | 0 | 0 | 256.00                | 228.1               | 6807.9              | 86557.2                   |
| 19            | 1             | 1 | 1 | 1 | 1 | 0 | 1 | 0 | 0 | 256.00                | 230.1               | 6842.2              | 92399.4                   |
| 20            | 1             | 1 | 0 | 0 | 1 | 0 | 1 | 0 | 0 | 238.00                | 215.5               | 4618.4              | 97017.8                   |
| 21            | 1             | 1 | 0 | 0 | 1 | 0 | 1 | 0 | 0 | 238.00                | 214.1               | 5354.0              | 101371.8                  |
| 22            | 1             | 1 | 0 | 0 | 1 | 0 | 1 | 0 | 0 | 238.00                | 212.1               | 5319.4              | 105691.2                  |
| 23            | 1             | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200.00                | 175.4               | 2823.2              | 108514.3                  |
| 24            | 1             | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200.00                | 160.5               | 2113.3              | 110627.6                  |

When fault current limitations are added to the DPUC, the unit commitment will change. This occurs because in the progress of the dynamic programming algorithm, each state is checked versus fault current maxima. That is, for every state in the dynamic programming chart, the fault currents at all system busses are calculated. If a fault current exceeds the  $IC_i$  (which come from the design of the fault current interruption equipment), the DPUC state is considered to be a ‘forbidden state’. The results of the modified DPUC are shown in Table 6.6.

As shown in the Tables 6.5 and 6.6, the total cost of operations for unit scheduling with and without the fault level constraints are 105,859.8 and 110627.6 \$, respectively. Note that the unit scheduling of the systems are changed when the total MW capacity of each period is higher than 240 MW while in this example is period 6. In this period, the unit schedule when the FCL constraint is ignored are  $\{1,0,0,0,1,0,1,0,1\}$ . This unit combination violates the FCL constraint while  $\{1,0,0,0,1,0,1,1,0\}$  comply with the constraint but it is more expensive. Figure 6.1 shows the forecasted demand and total MW capacity in each period. The increase of fault current creates some forbidden states in DPUC which might be the cheapest path. For this reason, when including the FCL constraint, the smaller units with higher transient impedance and higher fuel cost are interconnected to serve the demand.

For the examples shown, a one hour time resolution is used, and the study is carried over a time horizon of 24 hours. Other (perhaps shorter, e.g., 30 minute) time resolutions might be used, and other time horizons (perhaps shorter, e.g., 6 hours) might be used depending on the specifics of the DG types, available load forecast, and start up / shut down cost characteristics.

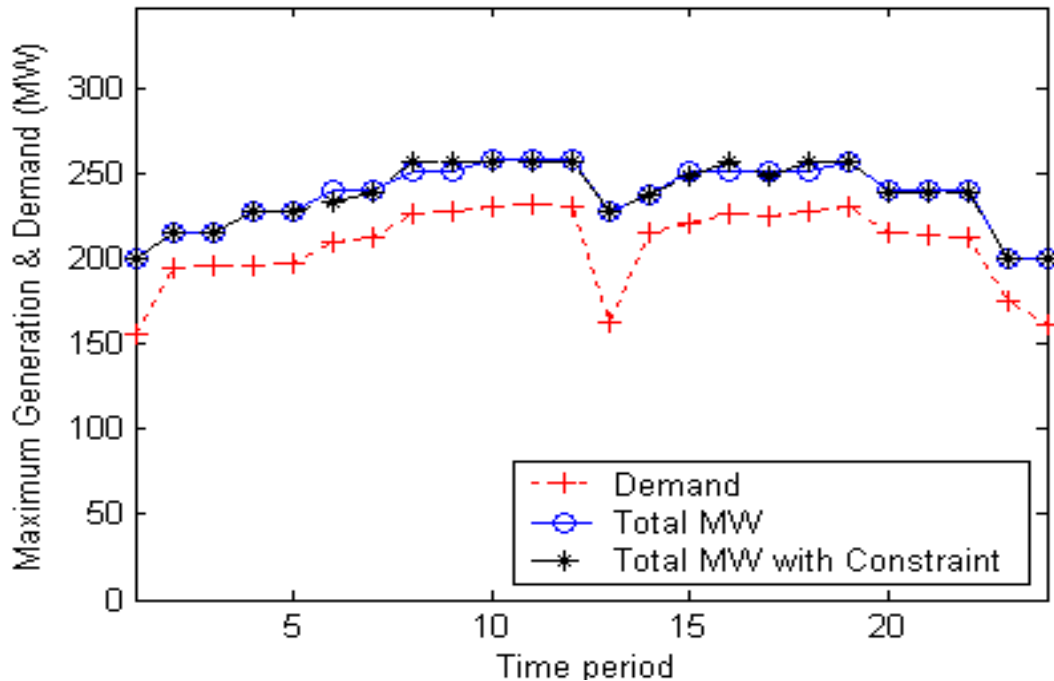


**Figure 6.1 Total MW capacity committed and demand in each period**

## 6.4 Conclusions

There are advantages that arise from installing DGs in power systems, such as improving reliability, potentially improving power quality, and potentially enhancing the environment. However, a well planned system is also required to avoid problems from system generation capacity additions. The UC problem with fault level constraint is discussed in this paper. The modification of system impedance matrix is utilized to evaluate increased fault currents.

Application of dynamic programming for solving the unit commitment problem with fault current level constraint is demonstrated. The case study shows that the generation of the merchant plants under the fault current level constraint may result in higher cost of operation than the operation without this constraint.

## 7 Online Assessment of Fault Current Considering Substation Topology

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### 7.1 Consideration of substation topology

In this section, the work of Bose and Zhang is summarized for the project [XXX]. The appearance of new generation sources in power systems result in higher fault currents. Higher fault currents may limit certain operating conditions because the maximum fault current seen by installed circuit breakers may be larger than their ratings. In this paper, increased system fault currents resulting from new generation sources are discussed. The implications of the existing topology of circuit breaker connections on fault current paths are studied. To ensure that the system operates while satisfying the constraints imposed by increased fault currents and circuit breaker interruption capability, a method to design the software of online assessment of fault current is given.

With the increase of electricity consumption, new generation sources are added into the power systems. The appearance of co-generation, distributed generation and unconventional generation may result in changed fault response in the system. In general, addition of generation capacity causes fault currents to increase. At the same time, the deregulation of power systems has resulted in increased reliance on interconnections, new non-utility generation, and power transactions. There may be new operating conditions, not seen before, that are limited by fault interruption capability. Circuit breakers, which are designed and coordinated for the original power systems, may have less fault current interruption capability after these changes. This means that the ratings of circuit breakers, which are designed to be safe for the old power systems, will limit certain operating conditions.

In some cases, new circuit breakers and protective relay methods are needed. But, it is not practical to replace all the existing equipments. In fact, with the software of online assessment of fault current, the power systems may operate at high power levels without compromising fault interruption capability. Increased system fault currents resulting from new generation sources are discussed by a numerical example of modified IEEE 14 bus. The paper also studies the implications of the existing topology of circuit breaker connections on fault current paths. Different circuit breaker states have different fault current implications. To ensure the fault current seen by breakers not exceed their interruption capability, some substation topology/breaker states should be avoided. In practical operation, the software of online fault current assessment is necessary to help the operator avoid the operation mod of the substation limited by fault current interruption capability.

## 7.2 The IEEE 14 bus system

As mentioned before, addition of generation capacity generally causes fault currents to increase because of the reduction of the Thevenin equivalent impedance seen at system buses. Figure 7.1 is the one line diagram of the modified IEEE 14 bus system. The only difference between this system and the standard IEEE 14 bus system is the addition of a small generator, 10 MVA, with subtransient impedance 12%, at bus 5. To get the worst subtransient fault current, the case of three-phase short circuit was used for calculation. The fault current calculation method used by this paper is classic bus impedance matrix, which could be found in [20, 21]. New calculation method can be found in [65, 66].

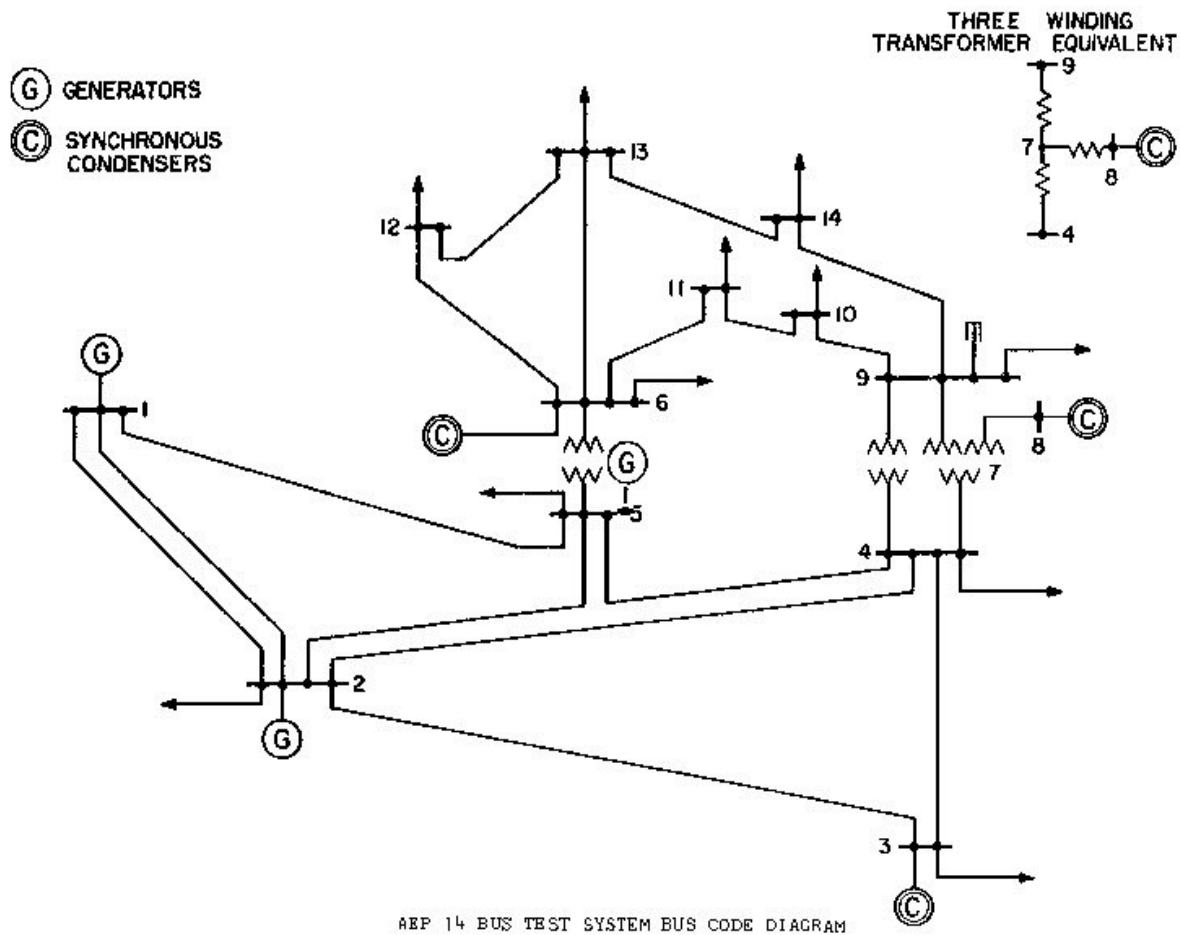


**Figure 7.1 One line diagram of modified IEEE 14 bus system**

Table 7.2 is the calculation results of fault current before and after such a small generator is installed into the system. The notation  $|I_f|$  denotes the amplitude of subtransient three-phase short circuit fault current at each bus. We can see from the calculation result that, the installation of the generator increases the fault currents in every bus. What is more, the fault current increases most at the bus 5 where the generator is installed. If the rating

of the circuit breakers in the substation at bus 5 is 14 p.u., the largest fault current seen by circuit breakers will exceed their interruption capability. Some operating situations will be limited unless the new breakers are installed. In the next part of the paper, how fault currents path through each circuit breakers in the substation and which one will see the largest fault current are studied. In this problem, the topology of the circuit breaker connections is the most important factor.

**Table 7.1 Fault currents before and after the installation of a small generator**

| <i>Faulted Bus</i> | <i> If  before installation<br/>(p.u.)</i> | <i> If  after installation<br/>(p.u.)</i> | <i>Percent change<br/>(%)</i> |
|--------------------|--------------------------------------------|-------------------------------------------|-------------------------------|
| 1                  | 17.931                                     | 18.221                                    | 1.62                          |
| 2                  | 20.266                                     | 20.735                                    | 2.31                          |
| 3                  | 11.207                                     | 11.336                                    | 1.15                          |
| 4                  | 13.307                                     | 13.898                                    | 4.44                          |
| 5                  | 13.202                                     | 14.200                                    | 7.56                          |
| 6                  | 8.872                                      | 8.985                                     | 1.27                          |
| 7                  | 7.858                                      | 7.956                                     | 1.24                          |
| 8                  | 7.286                                      | 7.313                                     | 0.37                          |
| 9                  | 6.876                                      | 6.951                                     | 1.10                          |
| 10                 | 5.314                                      | 5.360                                     | 0.87                          |
| 11                 | 4.810                                      | 4.846                                     | 0.76                          |
| 12                 | 3.894                                      | 3.916                                     | 0.58                          |
| 13                 | 5.373                                      | 5.415                                     | 0.79                          |
| 14                 | 3.747                                      | 3.769                                     | 0.57                          |

### 7.3 Fault current paths within a substation

Different topologies of the substation have different fault current paths. Once we find the relationship between the topology of the substation and the fault currents through each breaker, we will be able to avoid those operating situations limited by the interruption capability of breakers.

The objective of the calculation here is to find out which breaker sees the largest fault current and if this fault current exceeds the rating of the breaker. In the example of modified IEEE 14 bus, the largest fault current seen by circuit breakers at the bus 5 exceeds breakers' interruption capability. Now, study the fault current paths under different substation topologies. Two kinds of circuit breaker connection schemes are considered, one is breaker-and-a-half and the other is ring bus. The details of these two connections and their protection can be found in [67, 68].

The fault current paths within a substation are determined by several factors, including 1) the substation topology, which is determined by circuit breaker states; 2) fault locations; 3) the parameters of circuit breakers. Before finding the breaker seeing the maximum fault current, all these three kinds of information should be ready. The substation topolo-

gies are available from EMS/SCADA system. The information of circuit breakers provided by EMS/SCADA system includes the names of breakers, their states and the bus segments they are connected to. One can build the substation topology according to these data. Usually, the parameters of circuit breakers for the same voltage level within a substation are the same.

Once the substation topology is established, the fault currents through each breaker can be calculated by the method of nodal analysis, which is based on the following reasonable assumptions:

- 1) Fault currents injected over transmission lines are equivalent to ideal current sources
- 2) The resistance of bus bar is negligible
- 3) All the breakers have the same resistance.

The input fault currents through each line are obtained by fault analysis. Then, the fault current through each breaker is calculated by the following formula,

$$V_n = G^{-1} \times I_{fi} \quad (7.1)$$

$$I_{cbi} = (V_j - V_k) / R \quad (7.2)$$

Where  $V_n$  denotes the nodal voltage,  $G$  the conductance matrix,  $I_{fi}$  injected fault current through the  $i$ th transmission line,  $I_{cbi}$  the fault current seen by  $i$ th circuit breaker,  $R$  the resistance of circuit breakers,  $V_j, V_k$  the voltages of the two ends of the  $i$ th circuit breaker.

The breaker seeing the maximum fault current may be different for different fault locations. It is necessary to calculate all possible cases with different fault locations given a substation topology. Figure 7.2 shows the flowchart of how to find the circuit breaker seeing the maximal fault current for all possible fault locations with a given substation topology. The whole procedure is illustrated by the numerical example of modified IEEE 14 buses system we used in Section 7.2. It is necessary to find which breaker sees the maximum fault current in the substation at bus 5.

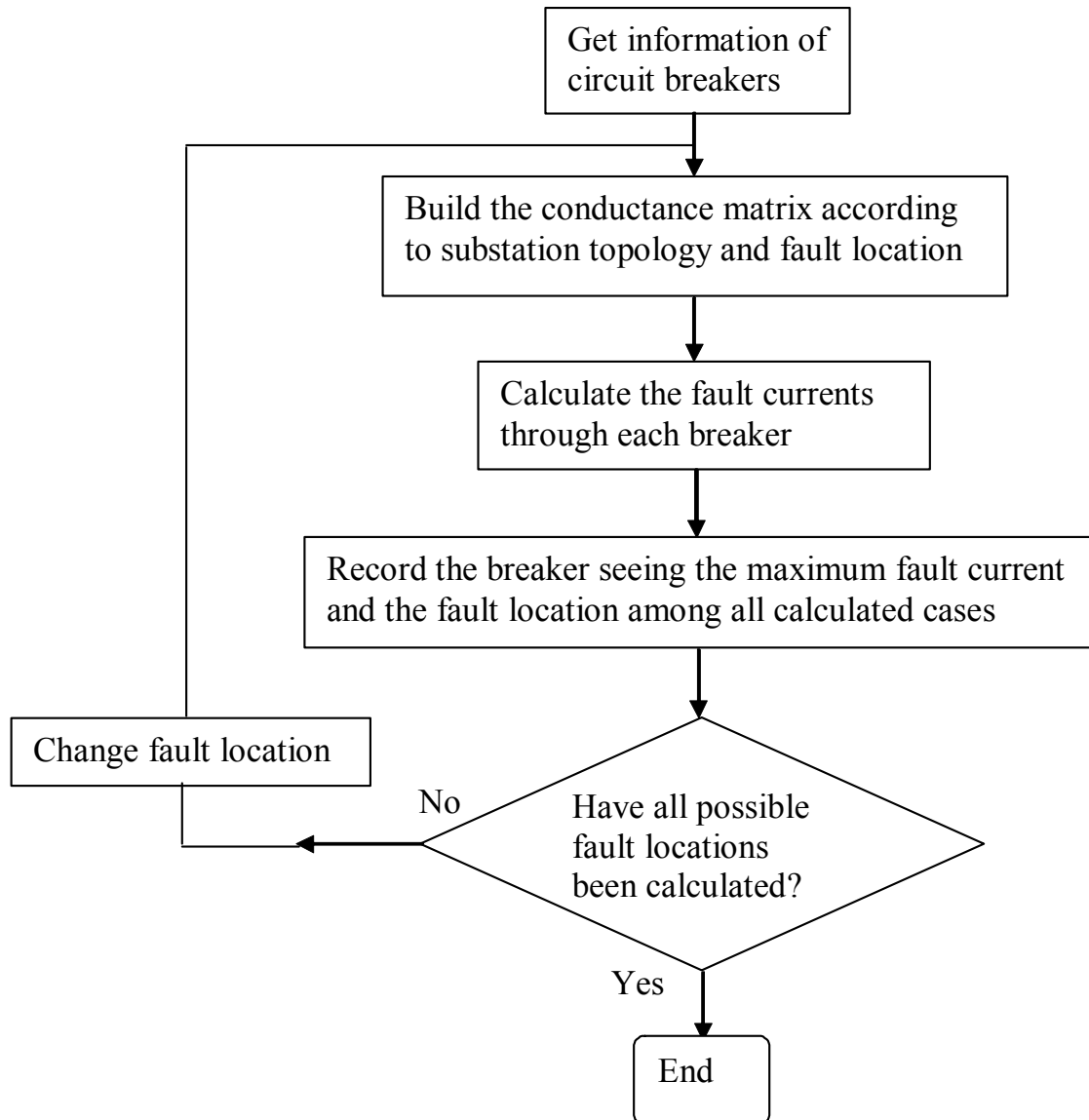


**Figure 7.2** Flowchart of finding the breaker seeing the maximum fault current

**Table 7.2 Information of circuit breakers in the substation at Bus 5**

| <i>Circuit breaker</i> | <i>State</i> | <i>From bus segment</i> | <i>To bus segment</i> |
|------------------------|--------------|-------------------------|-----------------------|
| $B_1$                  | 1            | $S_1$                   | $S_7$                 |
| $B_2$                  | 1            | $S_2$                   | $S_1$                 |
| $B_3$                  | 1            | $S_8$                   | $S_2$                 |
| $B_4$                  | 1            | $S_3$                   | $S_7$                 |
| $B_5$                  | 1            | $S_4$                   | $S_3$                 |
| $B_6$                  | 1            | $S_8$                   | $S_4$                 |
| $B_7$                  | 1            | $S_5$                   | $S_7$                 |
| $B_8$                  | 1            | $S_6$                   | $S_5$                 |
| $B_9$                  | 0            | $S_8$                   | $S_6$                 |

From the EMS/SCADA system, it is possible to get the information of all breakers in the substation at bus 5 as shown in Table 7.2, with circuit breaker  $B_9$  open. From these data, we can build the conductance matrix used by nodal analysis. Suppose that the breaker connection scheme of this substation is a breaker-and-a-half connection.

Figure 7.3 is the substation topology of bus 5 and its equivalent circuit. In Figure 7.3,  $I_g$  denotes the fault current generated by the small generator,  $I_{load}$  the equivalent current of the load at bus 5 when the fault occurs.  $I_{15}$ ,  $I_{25}$ ,  $I_{45}$ ,  $I_{65}$  are the fault currents input into bus 5 from bus 1, 2, 4 and 6.  $\blacksquare$  denotes a closed breaker,  $\square$  an open breaker,  $B_i$  the  $i$ th breaker and  $S_i$  the  $i$ th bus segment. The fault location shown in Figure 7.3 is  $S_7$ .

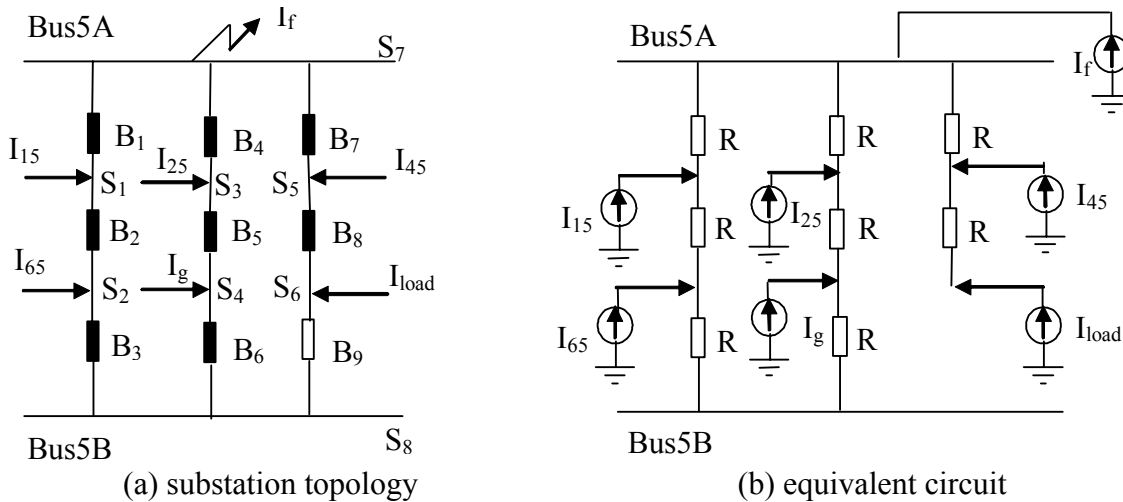


**Figure 7.3 Substation topology and its equivalent circuit --- breaker-and-a-half**

With a certain substation topology, fault current paths and breakers seeing the maximal fault current will be different for different fault locations. Table 7.3 is the calculation results of maximal fault currents seen by breakers with different substation topology and different fault locations. The breaker connection scheme is break-and-a-half, shown in Figure 7.4.

**Table 7.3 Breakers seeing maximal fault currents (breaker-and-a-half)**

| <i>Substation Topology</i> | <i>Fault location</i> | <i>Breaker seeing the largest fault current</i> | <i>Largest fault current (p.u.)</i> | <i>Exceed rating?</i> |
|----------------------------|-----------------------|-------------------------------------------------|-------------------------------------|-----------------------|
| All are closed             | $S_6$                 | $B_8$                                           | 7.7012                              | No                    |
| $B_3$ is open              | $S_2$                 | $B_2$                                           | 12.1315                             | No                    |
| $B_6$ is open              | $S_4$                 | $B_5$                                           | 13.2164                             | No                    |
| $B_9$ is open              | $S_6$                 | $B_8$                                           | 14.1717                             | Yes                   |
| $B_2, B_3$ open            | $S_7$                 | $B_1$                                           | 14.2                                | Yes                   |

Ring bus connection schemes are shown in Figure 7.4. There are two cases, one ring and two rings, which are shown in Figure 7.4 (a) and Figure 7.4 (b) separately. Calculation results are shown in Table 7.4.

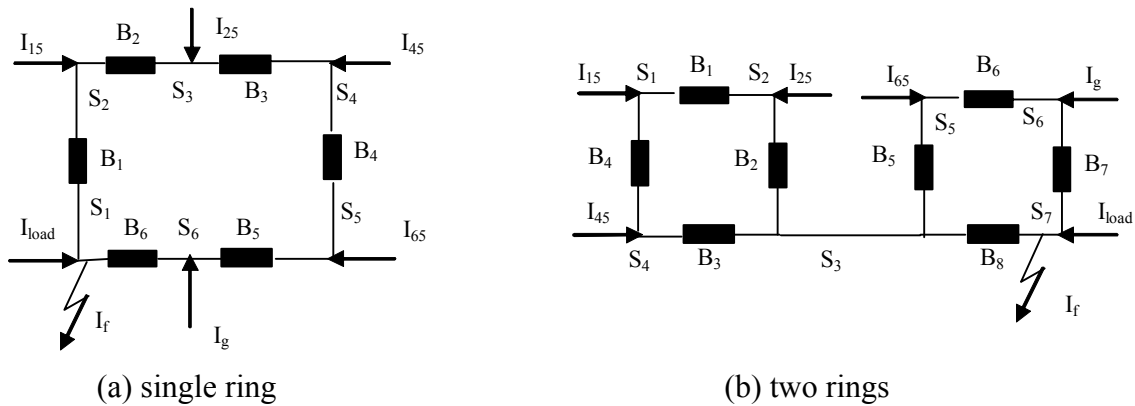


**Figure 7.4 Breaker connection of the substation at bus 5 --- ring bus**

**Table 7.4 Breakers seeing maximal fault currents (ring bus)**

| <i>Connection Type</i> | <i>Fault Location</i> | <i>Substation Topology</i> | <i>Breaker seeing the largest fault current</i> | <i>Largest Fault Current (p.u.)</i> | <i>Exceed rating?</i> |
|------------------------|-----------------------|----------------------------|-------------------------------------------------|-------------------------------------|-----------------------|
| Single ring            | $S_1$                 | All are closed             | $B_1$                                           | 7.8516                              | No                    |
| Single ring            | $S_1$                 | $B_1$ is open              | $B_6$                                           | 14.1710                             | Yes                   |
| Two rings              | $S_7$                 | All are closed             | $B_8$                                           | 9.6154                              | No                    |
| Two rings              | $S_7$                 | $B_8$ is open              | $B_7$                                           | 14.1710                             | Yes                   |

#### 7.4 Operation conditions limited by breaker ratings

According to the earlier analysis, the addition of new generation sources will increase the fault current. In some cases, the fault current will be greater than the interruption capability of the breakers. One way to resolve the problem is to update all the breakers that will probably see fault currents greater than their ratings. But, it is impractical and uneconomical to renew all the breakers at one time. In fact, only a few operation conditions will result in violations of interruption capability. In the following analysis, we try to find out what substation topology will result in violation. In practical operation, the system will be safe if these operation conditions are avoided.

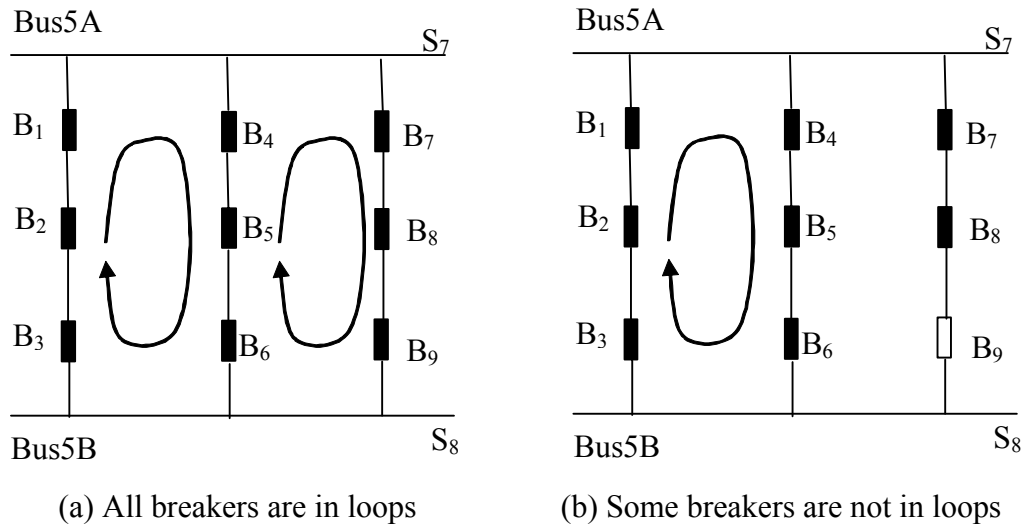


**Figure 7.5 Different substation topology with breaker-and-a-half connection scheme**

From the calculation results shown earlier, we may find some rules that will simplify our approach of searching the breaker seeing the maximal fault current larger than its rating. Consider breaker-and-a-half connection scheme first. One can see from the data of Table 7.3 that, if all the closed breakers form one or more loops, then there is no violation of interruption capability. If some breakers are not in loops, there may be violations of inter-

ruption capability. For example, in Figure 7.5 (a), all breakers form two loops, according to Table 7.3, there is no violation of interruption capability. In Figure 7.5 (b), breaker  $B_9$  is open so that  $B_7$  and  $B_8$  are not in a loop. One can see that, if fault occurs at bus segment  $S_6$ , breaker  $B_8$  sees the maximal fault current, which is larger than its rating. If all closed breakers form no loops, one can say for certain that there must be violation of interruption capability because the whole fault current will pass through one breaker. In some situations when some breakers are not in loops, it is possible that there is no violation, such as the second and the third situations of Table 7.3. This is because part of fault current injects into the ground directly and passes no breakers if the fault occurs at some bus segments connecting one transmission line.

A similar conclusion can be drawn for ring bus. From Table 7.4, we can see that, if all the closed breakers form one or more loops, shown in Figure 7.6 (a), there is no violation of interruption capability. If one or more breakers are open, shown in Figure 7.6 (b), there may be violations and the violations happened to those breakers not in loops.

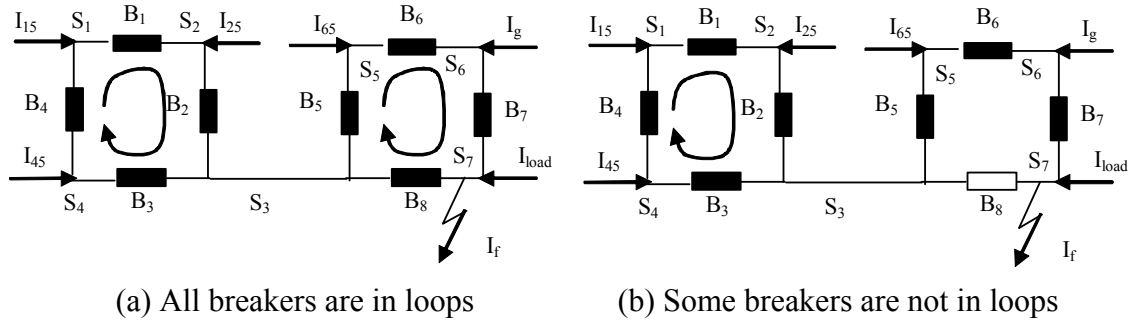


**Figure 7.6 Different substation topology with breaker-and-a-half connection scheme**

In fact, the above conclusions hold in an intuitive way. In loops, each fault current injected into the loop through transmission lines is separated into two parts, so that all injected fault currents distribute in loops evenly. The more the loops, the more evenly they distribute. Then, breakers in loops will not see fault currents larger than their ratings. In some extreme situations, some injected fault currents can be so large that some breakers in loops see fault currents larger than their ratings. For these situations, new circuit breakers with higher ratings should be installed to guarantee the safe operation of the power system. Generally speaking, a few installations of small generators will not increase fault current so much that there is violation of interruption capability for breakers in loops.

## 7.5 An alternative way to assess fault current

From the earlier analysis we know that in some operation conditions, the fault currents seen by breakers will exceed their interruption capability. In practical operation, online assessment of fault current is necessary to inform the operator to avoid these unsafe operation conditions. Take advantage of the conclusions we draw in the last part, we may have an easy way to develop the software of online fault current assessment. Figure 7.7 is the flowchart of such a kind of software. The software works as described in the subsequent paragraph.

The software runs automatically and periodically. The period will be adjustable according to the practical needs. First, the software gets the necessary data from SCADA system and State Estimation program. Then the data are used to identify the topology of the whole system and substations. The addition of new generators should all be considered as the change of topology because it will increase the fault current considerably. If the system topology changes, the software will recalculate the fault currents at each bus. Otherwise, the software will check if the substation topology changes. If there is no change, the software will restart from data collection after some time delay. Whenever there is system or substation topology change, the software will search for violations of circuit breaker interruption capability. Because the maximal fault current seen by single breaker is no more than the system fault current, the software only need to find those substations whose breaker ratings are less than system fault currents. If all closed breakers form one or more loops, according to the conclusions drawn in Section 7.4, there is no violation. If some closed breakers are not in loops, the software will check if the maximum fault currents seen by these breakers are larger than their ratings. If there is any breaker interruption capability violation, it will alarm the operator. The software may also give some advices on the operation conditions that will not result in violation of interruption capability. The software can be run manually when necessary.

## 7.6 Conclusions

With the appearance of new generation sources and new operating conditions in the power system, the fault currents become larger and larger. Circuit breakers, which are designed and coordinated for the original power systems, may have less fault current interruption capability after these changes. One way to resolve this problem is to update all the breakers that have insufficient interruption capability. Another way is to avoid those operation conditions that are limited by the insufficient interruption capability of circuit breakers. The software of online assessment of fault current is necessary to help the operator to avoid unsafe operation conditions.

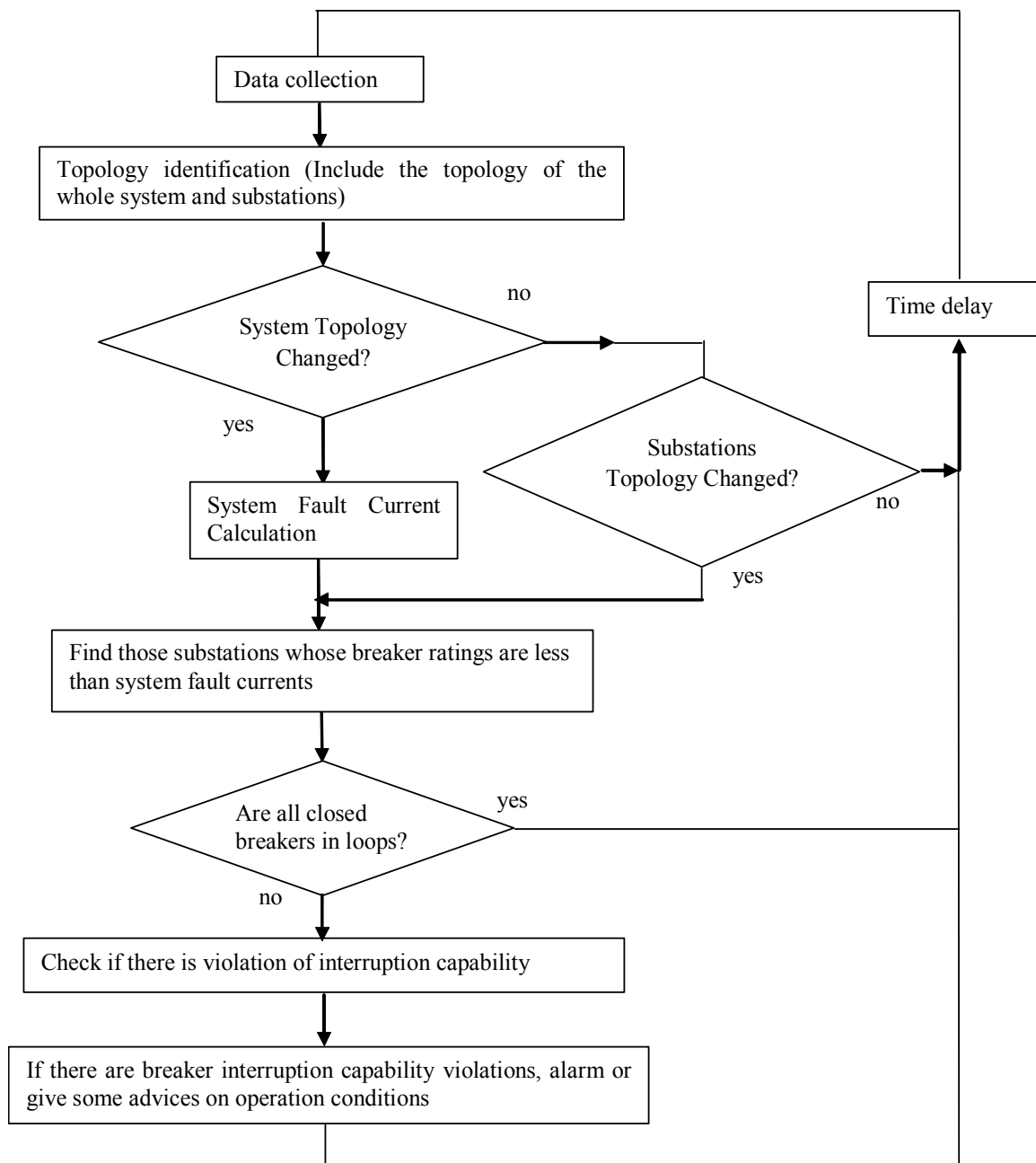


**Figure 7.7 Flowchart of online assessment of fault current**

## 8 Circuit Breaker Issues

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### 8.1 Circuit breaker issues

In this chapter, two technical papers are reproduced on the subject of circuit breaker issues and fault currents. The papers are:

- Q. Binh Dam, A. P. Sakis Meliopoulos, Gerald T. Heydt, Anjan Bose, “IEEE A Breaker-Oriented, Three-Phase IEEE 24-Substation Test System,” Submitted to IEEE Transactions on Power Delivery, September, 2005.
- Q. Binh Dam, A. P. Sakis Meliopoulos, “Elements for a Circuit Breaker Reliability Model,” Submitted to IEEE Transactions on Power Delivery, September, 2005.

The papers were produced as main results of this research project. The abstracts of the work are as follows:

#### “IEEE A Breaker-Oriented, Three-Phase IEEE 24-Substation Test System”

Accurate bus-oriented, three-phase modeling of power systems is desirable for advanced applications and has become practical due to increased computational capability. To assist research activities in this area, this paper presents a breaker-oriented three-phase model of the IEEE 24-bus reliability test system (RTS). The model is available in electronic form at the site: <http://www.ap-concepts.com>. The proposed model is intended for use in research for three-phase power flows, fault analysis, transient stability and evaluation of fault currents through specific breakers, evaluating the risks of breaker failures resulting from increased fault currents and other similar applications.

#### “Elements for a Circuit Breaker Reliability Model”

A physically based circuit breaker reliability model is presented. Such a reliability model is needed to address circuit breaker adequacy concerns brought about by increased fault current levels caused by utility and non-utility generation additions. The key aspects of the breaker reliability model are: (a) modeling each breaker component with a Markov Chain that matches historical reliability data and (b) postulating a relationship between the Markov Chain parameters and the fault current levels that the breaker experiences. The proposed breaker reliability model captures the effects of increased fault currents on breaker performance. The model is expected to be very useful for identifying breakers that may be at high risk due to increased fault currents and for planning preventive breaker maintenance or establishing operating procedures to avoid breaker failures.

### 8.2 IEEE breaker-oriented, three-phase 24-Substation test system

The IEEE Reliability Test System was developed by the IEEE Reliability subcommittee and publicized in 1978. The purpose of this system was to provide a benchmark system

for testing reliability methods. The benchmark system complements other IEEE standardized systems which have offered engineers and researchers common test beds on which to test their algorithms [71]. Over the years, the reliability test system has been used for testing reliability methods but also for a variety of other analysis methods. The original RTS was a 24 bus system but recently a 96 bus system was also developed. Recent interest in analysis methods that are based in more detailed models of the power system has generated the need for a test system that will support these efforts. For example, three phase models are being used for state estimators, improved fault analysis, three phase power flow and other. In addition, concerns about breaker adequacy as fault currents increase have generated the need for fault analysis methods that provide individual breaker fault currents, that is, fault analysis with models that explicitly represent the breaker topology. As these methods develop, it will be expedient to have a benchmark system for testing and comparing these methods. The significance of the detailed model approach is to accommodate realistic circuit breaker configurations that accurately mimic actual system performance in the field.

This paper proposes a breaker-oriented three-phase model of the original IEEE 24-Bus Reliability Test System with complete definition of all relative data. While most of the parameters of the original “reliability test system as reported in [71] are matched with the new model, much of the information, such as substation configuration at load/generation buses, protective relay configurations” [78], are not available in the original paper and they are assumed and assigned in a way that is representative and typical of actual substations. The purpose of this paper is to (a) provide the substation configurations, which are missing in [71] and (b) convert the system model into a three-phase model. The proposed test system converts each bus of the original system into a substation with specific breaker configuration. The breaker-oriented model opens the door to improved simulation procedures where individual circuits and transformers can be isolated in the same way as in an actual system. In addition, in-depth analysis of effects of post-fault conditions, scheduled outages or system maintenance can be carried out. In addition, each transmission line in the original IEEE 24-bus RTS is replaced with a physically based three phase transmission line with parameters so selected as to closely match the positive sequence parameters of the original system. Some additional modifications include updated fuel costs to reflect recent trends in the energy market.

### 8.3 Motivation

Contemporary electric networks were designed many decades ago to meet the energy demand of that time – basically power exchange under emergency conditions. Generating units are constantly being added to the network to feed steadily increasing loads and expand a deregulated power market. The addition of supplemental generation capacity has a major side effect however, since it contributes to higher fault currents [75]. The devices which were once selected decades ago to meet system needs of that time must now handle more power and higher fault currents. The appearance of both synchronous generator distributed generation, as well as inverter based distributed generation, lowers the effective driving point impedance at nearby system buses and thereby raises the fault duty.

This in turn generates a major safety problem for interrupting devices, because their ability to clear faults becomes questionable. Reliability is at stake, since breakers are the last barrier to protect other parts of a circuit or a network against faults [76]. And studies have shown that breakers and switches are among the components being the most involved in system failures [Ross/Welch/Willis]. The importance of this issue has also generated the need for more accurate fault analysis methods to better evaluate the risks from increased fault currents. These concerns can be addressed with detailed models and analysis methods that utilize a breaker-oriented three-phase model of the system.

Present analysis methods do not explicitly include circuit breakers in their models, they are assumed to be at the “closed” position and they are simply neglected. Breaker arrangements at network buses are neither represented nor accounted for in current standards (ANSI/IEC). Therefore, with such methods, it is not possible to compute the actual fault current in each individual breaker and check the breaker interrupting capability. A recent paper has addressed the importance of this topic [72]. Another recent paper offers the concept of the use of a Matlab/Simulink model to analyze faults in systems with inverter based distributed generation [81].

Detailed fault current analysis issues have been addressed with a three-phase model that is derived from the IEEE 24-bus RTS. The proposed model explicitly represents breaker arrangements and all power system models are physically modeled maintaining their three phase structure and the actual impedances of each phase and mutual impedances among phases. This paper describes the test system that has been used for the evaluation of the methodology.

#### **8.4 Modified IEEE 24-bus model, similarities, differences and improvements to the original IEEE 24-bus system specification**

The proposed breaker-oriented three-phase system in this paper is mostly derived from the original specification of the IEEE 24 bus reliability test system. The approach that has been used to develop the breaker-oriented three-phase model is as follows: (a) each power line has been replaced with a three phase physically based model with positive sequence parameters approximately equal to that of the original system, and (b) each node of the original system has been replaced with a substation with specific bus arrangement (ring, breaker and a half, etc.). In addition, some parameters of various components have been modified to better reflect present conditions. The changes are described next.

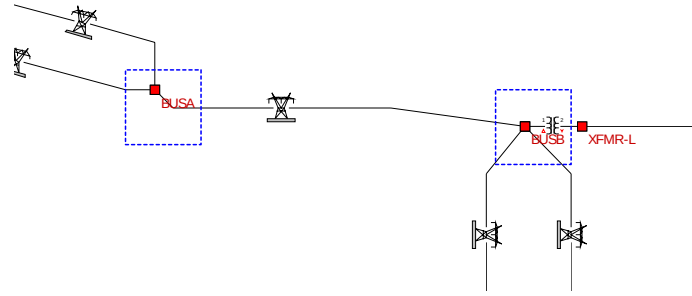


**Figure 8.1 Example bus-oriented system model**

### 8.5 Buses and substations

In the original reliability test system, different transmission lines simply converge at buses to connect generators or to serve loads. The modeling process treated each of the buses as a single point. This representation of the network has a downside, since it does not take the topology of the connections into account. The lack of topology details at the buses, as it is illustrated in Figure 8.1, has been mentioned in [72]. The proposed modification of the IEEE 24 bus RTS addresses this problem by explicitly including bus arrangements at each node, and the location of each circuit breaker, as part of the network model. Figure 8.1 illustrates the bus-oriented model and Figure 8.2 illustrates the corresponding breaker-oriented model of the same system. The bus arrangement shown in Figure 8.2 has been arbitrarily selected.

The arbitrary selection of bus arrangement follows usual design procedures and practices. As an example consider bus 230 of the IEEE 24 bus RTS. This bus has three units and four circuits. The bus is replaced with a substation of specific breaker arrangement as illustrated in Figure 8.3. Note that a breaker-and-a-half scheme has been arbitrarily selected for this substation. Note that the arrangement shown in Figure 8.3 is consistent with standard design practices of substations. The overall procedure amounts to replacing each bus of the original IEEE 24 bus RTS with a substation. To make the overall model interesting and more realistic, we have selected a mix of bus arrangements, such as breaker and a half, double breaker etc. Therefore the proposed test system includes substations of various breaker arrangements and therefore of different reliability levels. A summary of substation topology is provided in Appendix D. The complete model is posted on the web site given in the abstract and it is available to anyone wishing to experiment with this model.

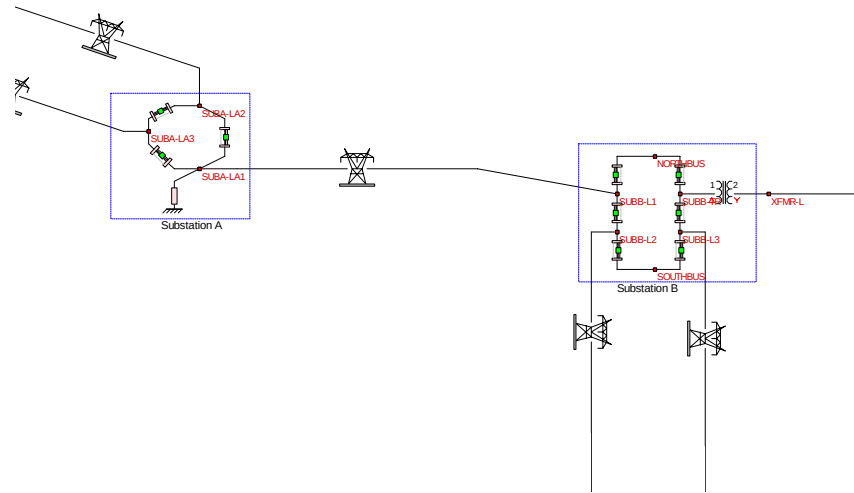


**Figure 8.2 Breaker-oriented model of Figure 8.1 system**

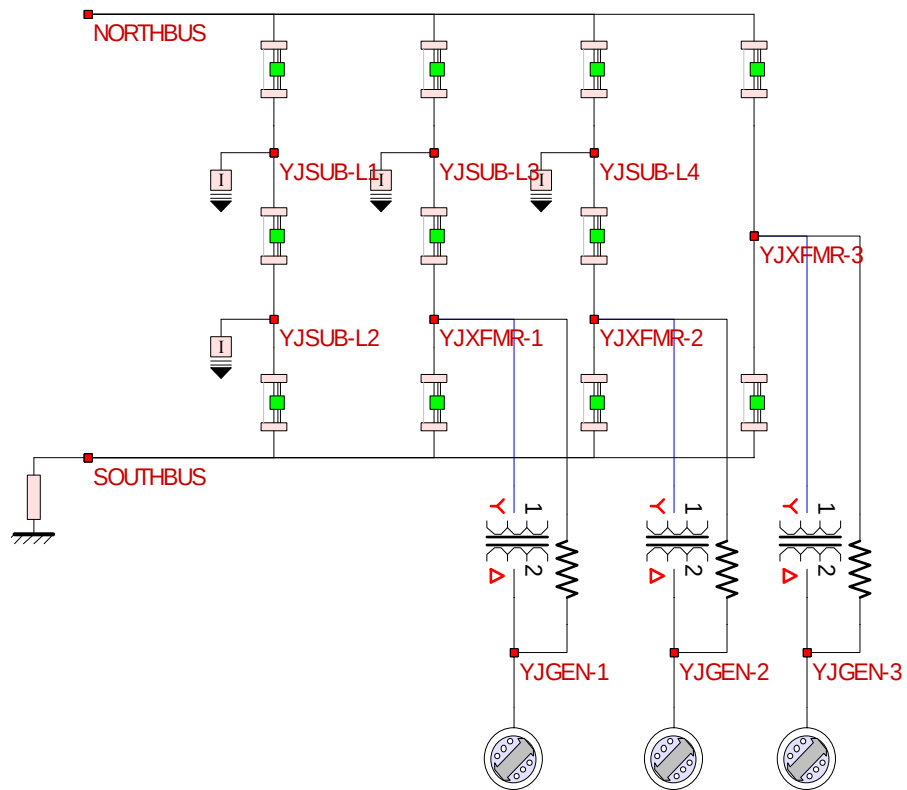


**Figure 8.3 Breaker oriented model of Substation 230**

## 8.6 Generating units

The generating unit parameters are as found in the original IEEE 24 bus RTS data. This section details the changes of interest for network analysis.

### *Generator Transient Reactance*

As an addition to the original IEEE 24 Bus RTS, we also provide additional parameters for the internal model of the generators. The most important parameters for the purpose of network fault and stability analysis are the subtransient and transient reactances. Typical generating unit parameter values are used for this data.

### *Fuel Costs*

Updated fuel costs have been used in the cost model of the generator to reflect the recent trends in the energy market. The costs listed in Table 8.1 are estimates for the United States [73], [74] and [71].

**Table 8.1 Generator fuel costs**

| Fuel    | Cost (\$/MMBtu) | Remarks                         |
|---------|-----------------|---------------------------------|
| Coal    | 1.5             | Rounded from \$1.41 in Oct 2004 |
| Nuclear | 0.60            | This is the 1979 price          |
| Oil #2  | 10              | Rounded from \$9.89 in Oct 2004 |
| Oil #6  | 5.5             | Rounded from \$5.31 in Oct 2004 |

The operating costs of each generator per hour are modeled with a quadratic function. The procedure to obtain the quadratic coefficients of the cost function are described in [77], and in the generator document on the website. The required data can be found in the Generating Unit Operating Cost Data Table, and the fuel cost table [71].

Recent energy data shows sources, such as natural gas, that were not used in 1979. These energy sources today represent a large fraction of the production and therefore should be included in a test system. Generation technology also has evolved for traditional energy sources, and the efficiency of thermal generators has improved. Updates to the data in [71] may be necessary to reflect this. For consistency, however, the proposed test system uses generator data as close as possible to the original IEEE 24 Bus RTS data.

Table A-4 in Appendix A shows detailed characteristics of the generating units used in the IEEE reliability test system, and provides the data required to implement the generators using common simulation software. The same data can be found in the generator document on the website given in the abstract.

**3-Phase Overhead Transmission Line** Accept

230kV Transmission Line, BUS110 to BUS140 Cancel

|                                           |                |         |
|-------------------------------------------|----------------|---------|
| <b>Phase Conductors</b>                   | Type           | ACSR    |
|                                           | Size           | TERN/OD |
| <b>Shields/Neutrals</b>                   | Type           | HS      |
|                                           | Size           | 5/16HS  |
| <b>Tower/Pole</b>                         | Type           | 101A    |
|                                           | Circuit Number | 1       |
| Structure Name: JellowJacket              |                |         |
| <b>Tower/Pole Ground Impedance (Ohms)</b> |                |         |
| R =                                       | 25.0           | X = 0.0 |
| Line Length (miles): 29.5                 |                |         |
| Line Span Length (miles): 0.1             |                |         |
| Soil Resistivity (Ohm-Meters): 100.0      |                |         |

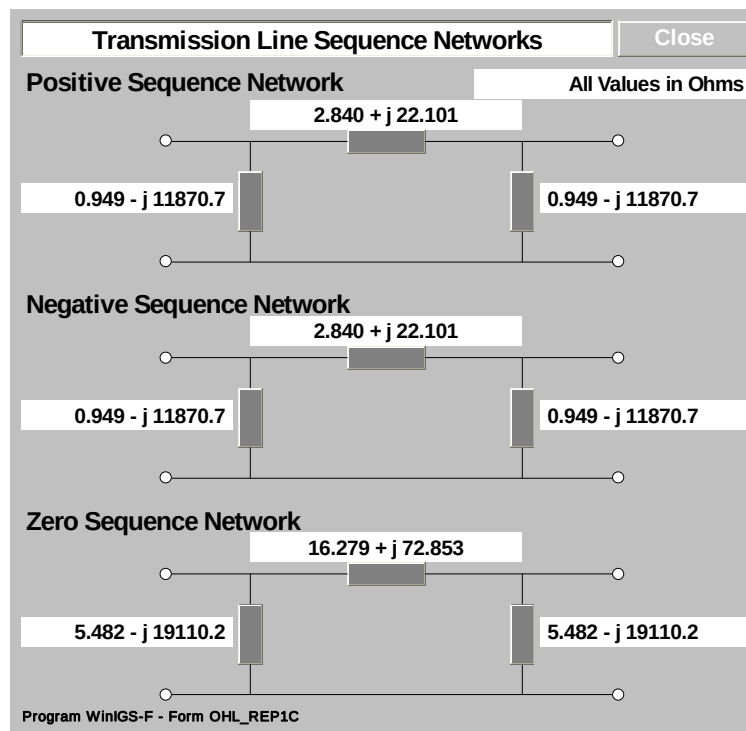
GA. Power H-Frame Wood Pole TOWER

|                         |                       |                         |
|-------------------------|-----------------------|-------------------------|
| <b>Bus Name, Side 1</b> | <b>Circuit Number</b> | <b>Bus Name, Side 2</b> |
| BUS110-2                | 1                     | BUS140-2                |

|                                             |                               |       |
|---------------------------------------------|-------------------------------|-------|
| <b>Failure &amp; Repair Rates</b>           | <b>Operating Voltage (kV)</b> | 230.0 |
| Failure Rate (per year)                     | Insulation Levels (kV)        |       |
| 0.39                                        | FOW (Front of Wave)           | 230.0 |
| Repair Rate (per year)                      | BIL (Basic Insulation Level)  | 230.0 |
| 796.3636                                    | AC (AC Withstand)             | 230.0 |
| <input type="checkbox"/> Insulated Shields  |                               |       |
| <input type="checkbox"/> Transposed Phases  |                               |       |
| <input type="checkbox"/> Transposed Shields |                               |       |

Program WinIGS-F - Form IGSF\_M102

(a) Physically based line model



(b) Pi-equivalent circuit

Positive Sequence Series Impedance

$0.0054 + j0.0418$  p.u. or  $2.8566 + j22.1122$  ohms

Figure 8.4 Example of physically based three phase line model (Circuit 110-140)

## **8.7 Transmission lines**

The original IEEE 24-bus RTS system represents each transmission line with its positive sequence parameters. Each transmission line model has been replaced with a physical model of the transmission line and the length of the line including phase conductor type and size, shield wire(s) type and size, and tower configuration. The parameters have been selected in such a way that the positive sequence model of the line is approximately equal to the positive sequence model of the same line in the original 24 bus RTS. As an example, Figure 8.4 shows the parameters of a physically based transmission line, the positive sequence model of the line and the positive sequence model of the same line in the original IEEE RTS. The details of the transmission line parameters are given in Table A-3 in Appendix A, as well as in the corresponding document on the website given in the abstract.

## **8.8 Voltage correction devices**

No change has been made from the original IEEE RTS data. In the proposed test system however, the rating of the voltage correction devices has been adjusted to obtain acceptable voltage levels across the network. The voltage correction device document on the website contains the selected values.

## **8.9 Conclusions on the IEEE breaker-oriented, three-phase 24-substation test system**

The three-phase system presented in this paper is the result of a conversion of the IEEE Reliability Test System from a bus-oriented, positive sequence model (equivalent per phase system) to a breaker-oriented three-phase model. Each bus in the original model has been replaced by a substation containing an explicit bus arrangement and connection scheme of transmission lines, loads, transformers and generators. The substation models are an integral part of the network model. The proposed implementation also uses a representation of transmission lines based on physical parameters, and contains updated fuel costs which reflect current prices in the energy market. The purpose of the substation circuit breaker detail is to reflect the real life existence of substation configurations.

The breaker-oriented three-phase model adds a new level of detail in network models while retaining the merits of the original IEEE 24 Bus RTS. With a model which includes substations and their bus-breaker arrangements, new analysis methods can be developed that are more realistic than the present technology. We hope that the proposed test system will help the development of more sophisticated and realistic methodologies of the usual power system analysis problems.

## 8.4 Introduction to circuit breaker reliability

Present electric power networks were designed decades ago to meet the demand of energy of that time, and are continuously expanded with more power generation units to supply steadily increasing loads. Deregulation and the construction and commissioning of merchant power plants (IPPs) have changed the predictability of fault current levels and the orderly planning and design of the system to deal with the increased fault currents. The expansion of the generation capacity raises a major problem since it increases the level of fault currents [75]. Devices selected for the electric infrastructure planned decades ago must now handle the interruption of higher fault currents. This is a major safety problem for interrupting devices, because their ability to clear faults becomes questionable. Reliability is at stake, since breakers are the last barrier to protect other parts of a network against faults [76]. And studies have shown that breakers and switches are among the components being the most involved in system failures [88].

Because electric power outages have a tremendous impact on communities, preventing system failures (and increasing the reliability of the system) has become a top priority for operators. To meet higher fault current requirements, redesigning and replacing outdated portions of a network would be the easiest option if the cost was not unrealistic (millions must be spent on a single upgrade of equipment). Replacing all the equipment at the same time may not be economically feasible. The other option is failure prediction. Although this is not an exact science, wise preventive maintenance can help avoiding extended system outages. If preventive maintenance does not appear sufficient, failure prediction can still help to identify critical parts of the system for which replacement is unavoidable.

The aim of this section is to propose a breaker reliability model which can serve as a tool to predict failures. The main innovation of the proposed model is to combine the model of the natural aging of breakers with operational data that define the level of fault currents that a breaker will experience.

This section is presented as follows: we first discuss the reliability of the individual components of circuit breakers, using Markov chains. Then we construct a single Markov chain for the entire breaker. We compute the transition rates of such a Markov chain to include intrinsic component failures, failures from interrupting fault currents and repairs. These transition rates constitute the core of the breaker reliability model, and are the key to predict the probability of device failures in the short and long term.

The frequency and statistical distribution of fault currents flowing in devices plays an important role in determining the transition rates. Indeed, higher fault currents means higher risk of destruction for circuit breakers. The distribution of fault currents is computed using a breaker-oriented network model proposed by the authors as it is illustrated in Figure 8.5. The computed fault current distributions through a breaker are used to define specific transition rates of the Markov chain and therefore to predict the probabilities of breaker failures.

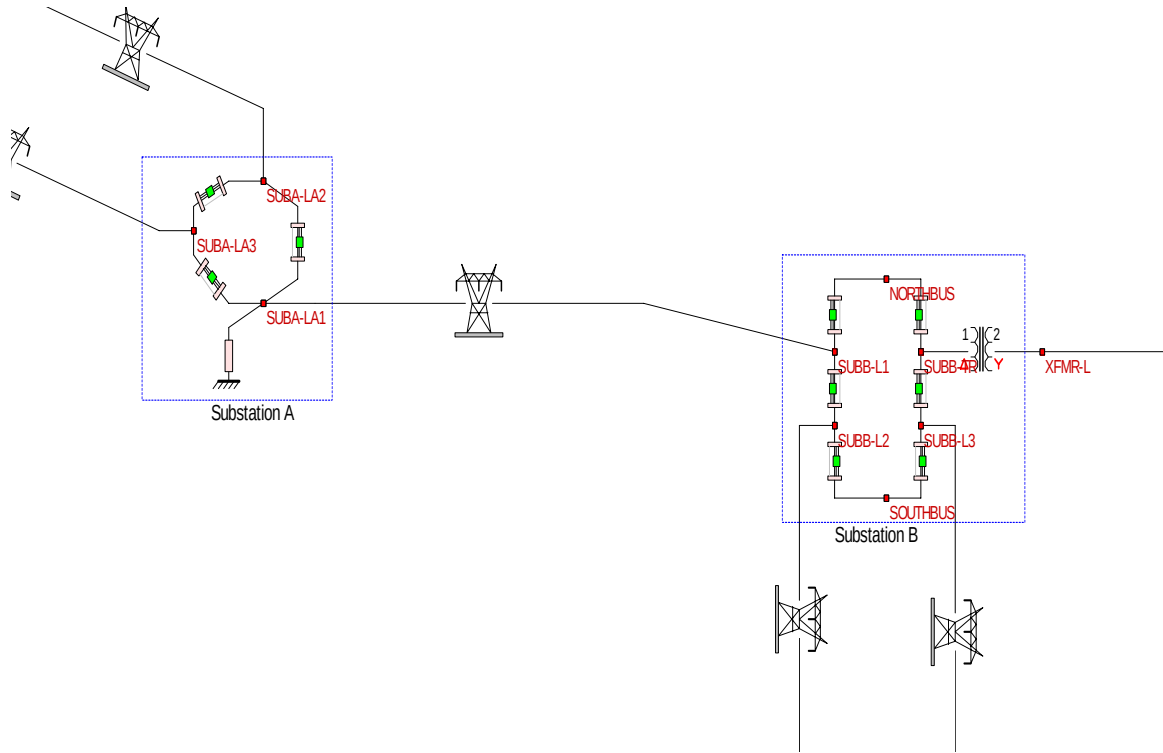


**Figure 8.5 Illustration of the breaker-oriented network model**

Finally, with the knowledge of the breaker failure rate, we provide a basis for studying the evolution of the parameters of the Markov chains following the tripping operation of fault currents.

## 8.5 Summary of breaker components

The first task in constructing the breaker model is to identify the major components of a breaker and to model each component with a Markov chain. The parameters of the Markov model for each component are affected by the fault currents that the breaker will experience. For the purpose of the discussion in this paper, the circuit breaker structure is a simplified version consisting of four main components listed in Table 8.2. Other circuit breaker models have been proposed and can be found in Lindquist, Bertling and Natti, Kezunovic. Table 8.2 also gives examples of failures for each breaker component used in this discussion. Formal definitions of breaker duties and failures can be found in Lindquist, Bertling.

**Table 8.2 Breaker Components and types of failures**

| Component               | Example of Failures                                                                                                                                                     |
|-------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Relay (R)               | Failure to detect fault currents                                                                                                                                        |
| Trip Mechanism (TM)     | Failure to initiate separation of the plates (spring, pneumatic, hydraulic, or magnetic)                                                                                |
| Mechanical Support (MS) | Failure to bring the plates to the fully open position (comply with speed requirements and travel distance)<br>e.g. bad grease, obstacles in plate motion, broken arms. |
| Base Plates (BP)        | Failure to interrupt the arc (dielectric properties of the gap), or plates fail to separate because of welding.                                                         |

## 8.6 Reliability of individual breaker parts

### *State Space and Transitions*

Each component of the breaker can cycle between an operational or non-operational state. This process is modeled as a continuous-time Markov chain. This is possible assuming that failures are independent of the component history of failures and repairs (exponential model). Other reliability models can be supported by utilizing a multi-state Markov model, but this issue is not discussed in this paper. We also assume, for this section only, that breaker parts are independent, with their own failure and repair rates, and that only one component may fail or be repaired at any time (no simultaneous failures or repairs). The Markov chains and the variables used are summarized in Figure 8.6.

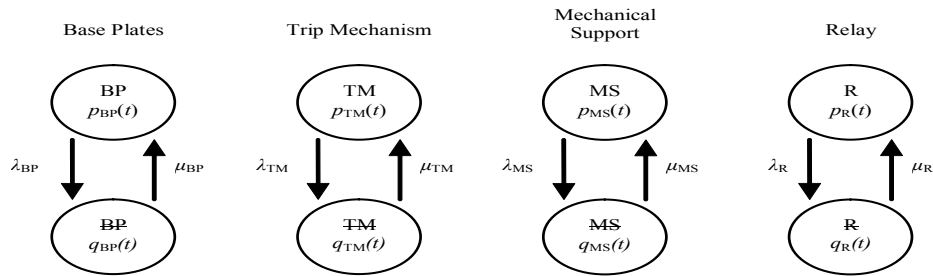


**Figure 8.6 Markov chains of each breaker component**

X,  $\overline{X}$ : component X in available/unavailable state  
 $p_X$ ,  $q_X$ : availability/unavailability probabilities  
 $\lambda_X$ ,  $\mu_X$ : component failure and repair rates

### State Probabilities

The differential equations that govern the transitions for each breaker component from the operational to the non-operational state are developed in [82], and reviewed in Appendix D. The matrix form is as follows,

$$\frac{d}{dt} \begin{bmatrix} p_{BP} \\ p_{TM} \\ p_{MS} \\ p_R \\ q_{BP} \\ q_{TM} \\ q_{MS} \\ q_R \end{bmatrix} = \begin{bmatrix} -\lambda_{BP} & 0 & 0 & 0 & +\mu_{BP} & 0 & 0 & 0 \\ 0 & -\lambda_{TM} & 0 & 0 & 0 & +\mu_{TM} & 0 & 0 \\ 0 & 0 & -\lambda_{MS} & 0 & 0 & 0 & +\mu_{MS} & 0 \\ 0 & 0 & 0 & -\lambda_R & 0 & 0 & 0 & +\mu_R \\ +\lambda_{BP} & 0 & 0 & 0 & -\mu_{BP} & 0 & 0 & 0 \\ 0 & +\lambda_{TM} & 0 & 0 & 0 & -\mu_{TM} & 0 & 0 \\ 0 & 0 & +\lambda_{MS} & 0 & 0 & 0 & -\mu_{MS} & 0 \\ 0 & 0 & 0 & +\lambda_R & 0 & 0 & 0 & -\mu_R \end{bmatrix} \begin{bmatrix} p_{BP} \\ p_{TM} \\ p_{MS} \\ p_R \\ q_{BP} \\ q_{TM} \\ q_{MS} \\ q_R \end{bmatrix}$$

A compact form can be written by grouping p's and q's,

$$\frac{d}{dt} \begin{bmatrix} p \\ q \end{bmatrix} = \begin{bmatrix} -\Lambda & \mathbf{M} \\ \Lambda & -\mathbf{M} \end{bmatrix} \begin{bmatrix} p \\ q \end{bmatrix}$$

where:  $\Lambda$  is the diagonal matrix of failure rates,

$\mathbf{M}$  is the diagonal matrix of repair rates.

$p$  is the vector of operational state probabilities

$q$  is the vector of non-operational state probabilities

The system of equations can be reduced to four variables by substituting  $q_x = 1 - p_x$  in the matrix differential equation,

$$\frac{d}{dt} \begin{bmatrix} p_{BP} \\ p_{TM} \\ p_{MS} \\ p_R \end{bmatrix} = -(\Lambda + \mathbf{M}) \begin{bmatrix} p_{BP} \\ p_{TM} \\ p_{MS} \\ p_R \end{bmatrix} + \mathbf{M} \begin{bmatrix} 1 \\ 1 \\ 1 \\ 1 \end{bmatrix}$$

The probabilities for each state and component satisfy,

$$\begin{aligned} p_x + q_x &= 1 \\ 0 \leq p_x \leq 1, \quad 0 \leq q_x \leq 1 \end{aligned}$$

The initial conditions represent a fully operational breaker, with component probability of availability set to one, and probability of failure set to zero,

$$\begin{bmatrix} p(0) \\ q(0) \end{bmatrix} = \begin{bmatrix} [1] \\ [0] \end{bmatrix}$$

The solution to this differential equation gives the probability of successful operation (or failure) of each individual breaker component [82],

$$\begin{bmatrix} p(t) \\ q(t) \end{bmatrix} = \begin{bmatrix} p(0) \\ q(0) \end{bmatrix} e^{At}, \quad \text{and} \quad \begin{cases} p_X(t) = \frac{\mu_X}{\lambda_X + \mu_X} + \frac{\lambda_X}{\lambda_X + \mu_X} \exp(-(\lambda_X + \mu_X)t); \\ q_X(t) = \frac{\lambda_X}{\lambda_X + \mu_X} - \frac{\lambda_X}{\lambda_X + \mu_X} \exp(-(\lambda_X + \mu_X)t); \end{cases}$$

$$p_X(\infty) = \frac{\mu_X}{\lambda_X + \mu_X}; \quad q_X(\infty) = \frac{\lambda_X}{\lambda_X + \mu_X}.$$

The system of differential equations can be generalized to any number of independent components with independent failure rates. As long as there is no common failure mode, the matrices  $\Lambda$  and  $M$  will remain diagonal and the probabilities will keep the same form.

Most processes which involve individual (independent) components (such as circuit breakers) can take advantage of this independent Markov chain model. Normal failure and repair cycles of the components fall into this category. However, common failure modes cannot use this simple model. The inclusion of common mode failures is addressed elsewhere in this chapter.

## 8.7 Markov chain modeling for circuit breakers

The single-failure restriction prevents using separate Markov chains to model common-mode failures involving two or more components as the result of a single event. On the other hand, a Markov model for the entire circuit breaker should include the rates for common-mode failures in addition to independent component failures.

### State Space

Each combination of the operational states of the plates, relay, trip mechanism and mechanical support, constitutes a state for the entire device. A total of 16 states can be generated from the four breaker components (Table 8.3). The state of the circuit breaker at a given time becomes the new random variable, which also obeys the Markov property.

**Table 8.2 State enumeration table and incidence matrix**

| #  | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 |
|----|---|---|---|---|---|---|---|---|---|----|----|----|----|----|----|----|
| R  |   | ! |   | ! |   | ! |   | ! |   | !  |    | !  |    | !  |    | !  |
| MS |   |   | ! | ! |   |   | ! | ! |   |    | !  | !  |    |    | !  | !  |
| TM |   |   |   |   | ! | ! | ! | ! |   |    |    |    | !  | !  | !  | !  |
| BP |   |   |   |   |   |   |   |   | ! | !  | !  | !  | !  | !  | !  | !  |

! indicates a non-operational component

The 16 breaker states can be sorted by degrees of failure indicating how many components are working or not working (Table 8.4). State 1 and state 16 (no failure and com-

plete failure respectively) are the extreme states. All other intermediate states are derated states. A derated state may or may not lead to breaker malfunction in case that the breaker is called to trip.

**Table 8.3 Classification of breaker states**

| Type of State                                                                                                  | State Numbers       |
|----------------------------------------------------------------------------------------------------------------|---------------------|
| Breaker is (fully) operational, all elements function properly                                                 | 1                   |
| Exactly one element is out of service, either the relay, trip mechanism, mechanical support or the base plates | 2, 3, 5, 9          |
| Exactly two elements are not operational                                                                       | 4, 6, 7, 10, 11, 13 |
| Exactly three elements are not functioning                                                                     | 8, 12, 14, 15       |
| Breaker has no component capable of service                                                                    | 16                  |

## 8.8 Transition diagrams

### *Single-Failure/Repair Transition Diagram*

Under the single-failure assumption, a transition is possible between two states if there is exactly one change in the component states, i.e. if exactly one mark changes between two columns of Table 8.3. The resulting transition diagram is shown in Figure 8.7. Each direction and type of line in the diagram corresponds to the change of state of the same component. For example, vertical lines always correspond to the trip mechanism. Transitions 1-2, 3-4, 5-6, 7-8 etc. involve the relay. Transitions are bidirectional since both failure and repair are possible (arrows not represented).

Transitions involving only one component failure/repair are used to model normal aging and environment effects on the device. They can also serve in cases where fault interruption affects only one component of the device.

### *Transition Diagrams Involving Two or More Components*

Unlike the separate Markov chain model of the breaker elements, the Markov chain for the whole device allows two or more components to fail simultaneously as the result of a single event (common-mode failure). The common-mode failures of concern come from fault interruption resulting in damage to several pieces of equipment. Transitions involving several components simultaneously simply consist of the cumulative path of the transitions for individual components. Although these transitions are shown on separate figures for clarity (Figures 8.8 and 8.9), the actual model consists of only one diagram with all transitions shown in Figures 8.7 through 8.9 superimposed.

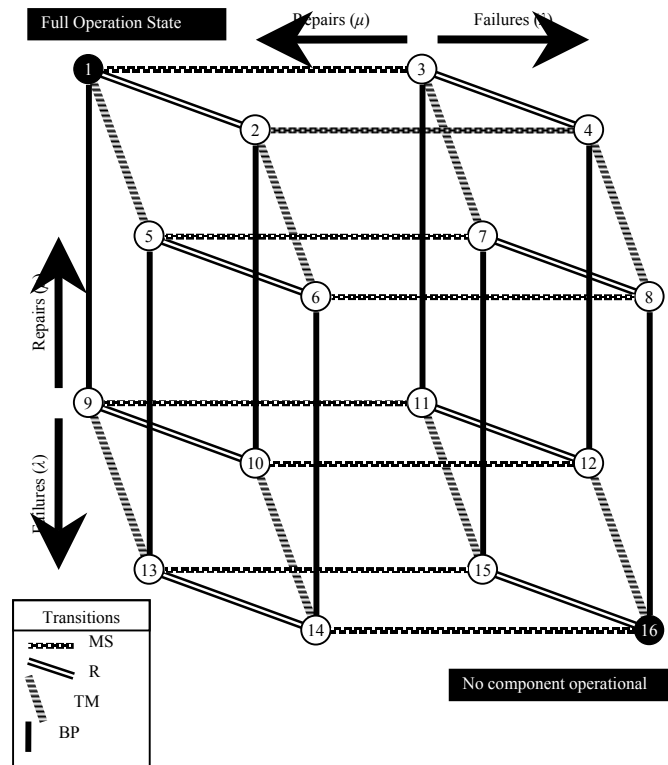


Figure 8.7 The general state space for the entire circuit breaker

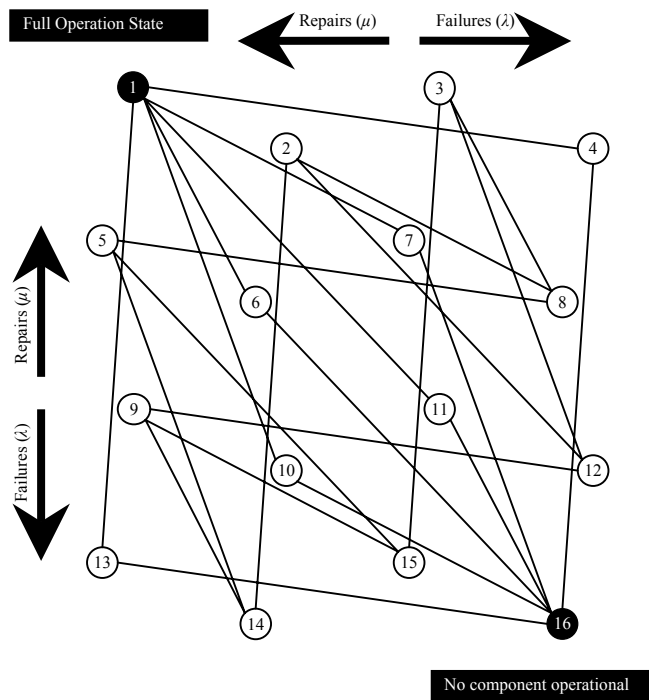


Figure 8.8 Transitions involving the failure/repair of two breaker components

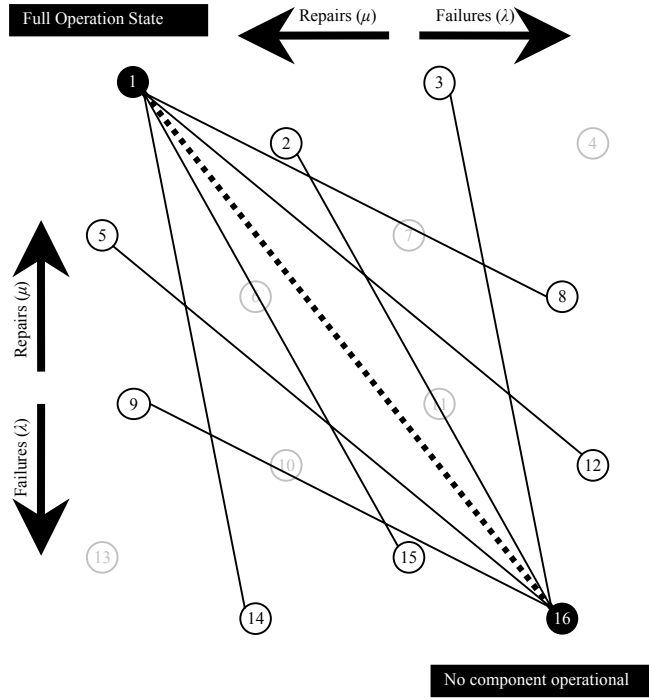


**Figure 8.9 Transitions involving the failure/repair of three breaker components**

The ultimate and direct transition from working state to complete failure is represented with a dotted line. Unreachable states with a triple failure transition are grayed.

## 8.9 Computation of state probabilities

There are two equivalent approaches to compute the probabilities for the sixteen breaker states illustrated in Figure 8.6 (single failures only). These approaches are discussed next.

### *Combining the Probabilities of Individual Component Availability*

As already stated above, each state in Figure 8.6 is a combination of the state of breaker elements. Because we assumed the components were independent, we can multiply the state probabilities of the components to obtain the corresponding state probability of the breaker.

For example, in state number 4, the plates (BP) and the trip mechanism (TM) are both working, and the mechanical support (MS) and the relay (R) are not working. Therefore, the probability for this state is, for any instant of time,

$$p_3(t) = p_{BP} \times p_{TM} \times q_{MS} \times q_R = p_{BP} \times p_{TM} \times (1 - p_{MS}) \times (1 - p_R)$$

The sum of the breaker state probabilities is forced to 1 simply because the sixteen n states are mutually exclusive and their union forms the sure event, i.e.,

$$\sum_{i=1}^{16} p_i(t) = 1$$

### *Using the Transition Diagram (Single Failures)*

The differential equations for the state probabilities can also be obtained from the transition diagram. Also, note that the transition diagram must be utilized in the case of common-mode failures as explained earlier.

State 6 will serve as an example. From the state-transition diagram (Figure 8.6), the probabilities differential equations are,

$$\begin{aligned} p_6(t + \Delta t) = & p_6(t) \times (1 - (\lambda_{MS} + \lambda_{BP} + \mu_{TM} + \mu_R)\Delta t) + \\ & p_2(t)\lambda_{TM}\Delta t + p_5(t)\lambda_R\Delta t + p_8(t)\mu_{MS}\Delta t + p_{14}(t)\mu_{BP}\Delta t \\ \frac{dp_6(t)}{dt} = & -(\lambda_{MS} + \lambda_{BP} + \mu_{TM} + \mu_R)p_6(t) + \\ & p_2(t)\lambda_{TM} + p_5(t)\lambda_R + p_8(t)\mu_{MS} + p_{14}(t)\mu_{BP} \end{aligned}$$

(2 paths to failures, 2 paths to repairs, states 2, 5, 8, 14 are adjacent to state 6)

The probability transition matrix is obtained by first writing the differential equation for each state probability and then grouping the equations for all states,

$$\frac{d\mathbf{p}(t)}{dt} = \mathbf{p}(t) \cdot \mathbf{A}$$

Since new breakers work properly, the initial conditions for the differential equation are:  $\mathbf{p}(t=0) = [1, 0, 0, \dots, 0]$ . In addition, the state probabilities must also satisfy the equation below for the reasons mentioned above,

$$\sum_{i=1}^{16} p_i(t) = 1$$

Off-diagonal terms (i, j) have the failure/repair rate from state i to state j. Diagonal terms, denoted by  $(-\sum)$ , are the negative sum of failure and repair rates of all transitions from the current state to an adjacent state (transition rates found in the same row). The sum of all elements in each row of the transition matrix is zero.

For example, the item in row 7/column 7 in A should read,

$$a_{7,7} = -(\mu_{TM} + \mu_{MS} + \lambda_R + \lambda_{BP})$$

The numerical solution gives the probability of having the breaker in any of the 16 states at any time. Because we assumed only one failure can happen at any time, the probabili-

ties are the same as in the separate Markov chain model. In the next paragraph, this assumption will not hold and the results will be different.

### *Computation of State Probabilities with Multiple Failures*

When multiple simultaneous failures (common mode failures) are allowed in the model, it is no longer possible to simply multiply the probabilities of states as if they were independent. The probability differential equations must be obtained from the transition diagram and then solved to provide the state probabilities.

State 6 will again serve as an example. From Figures 8.7 to 8.10, state 6 has three paths to failures, three paths to repairs, and states 1, 2, 5, 8, 14 and 16 are adjacent to state 6.

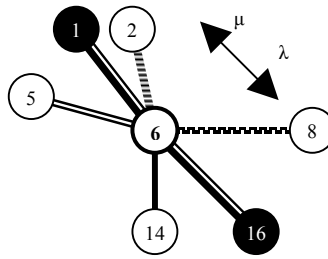


**Figure 8.10 Possible transitions to and from state 6**

The differential equations for the dynamics of state 6 are,

$$\begin{aligned} \frac{dp_6}{dt} = & -(\lambda_{MS} + \lambda_{BP} + \lambda_{MS+BP} + \mu_{TM} + \mu_R + \mu_{TM+R})p_6 + \\ & p_1\lambda_{TM+R} + p_2\lambda_{TM} + p_5\lambda_R + p_8\mu_{MS} + p_{14}\mu_{BP} + p_{16}\mu_{MS+BP} \end{aligned}$$

The form of the probability transition matrix, initial conditions and sum of probabilities are similar to the previous case,

$$\begin{aligned} \frac{d\mathbf{p}(t)}{dt} &= \mathbf{p}(t) \cdot \mathbf{A} \\ \mathbf{p}(t=0) &= [1, 0, 0, \dots, 0]. \\ \sum_{i=1}^{16} p_i &= 1 \end{aligned}$$

As in the previous case, off-diagonal terms (i, j) have the failure/repair rate from state i to state j, or zero if the transition is not possible. Diagonal terms are the negative sum of failure and repair rates found in the same row.

For example, row/column 5 in A should read,

$$a_{5,5} = -(\mu_{TM} + \lambda_R + \lambda_{MS} + \lambda_{BP} + \lambda_{R+MS} + \lambda_{R+BP} + \lambda_{MS+BP} + \lambda_{R+MS+BP})$$

The solution to the system of differential equations gives the probability of having the breaker in any of the 16 states at any instant of time.

At this point, the probability of each breaker state can be computed from the state diagrams. However, it requires the knowledge of the transition (failure) rates, which will be covered next.

### 8.10 Breaker reliability and fault currents

Whether a breaker performs its intended function or fails is determined by the magnitude of fault currents flowing through the breaker: currents near or above the breaker rating are of concern. Therefore, the following three parameters are of paramount importance to the breaker reliability: (a) the likeliness of faults, (b) the distribution of fault currents and (c) whether the breaker actually opens to clear a fault.

### 8.11 Probability for fault conditions at a circuit breaker

Fault probabilities on transmission networks can be modeled using Poisson distributions [89] with parameters determined from historical data. For a particular transmission line  $k$ , the number of faults per unit time (year) and per unit length (100 miles),  $N_{k0}$  is known. If  $L_k$  is the length of the line (in the same unit length), the expected number of faults online  $k$  per year is  $N_k = N_{k0} \times L_k$ .

The total fault rate  $\lambda$  at a given substation is the sum of the failure rates on all transmission lines (superimposition of Poisson processes on each line),

$$\lambda = \sum_k N_k \quad (\text{Number of faults per year})$$

Note that each breaker at a substation conducts some current from every line, and is therefore exposed to this total failure rate. In terms of the Poisson distribution, the probability of experiencing  $n$  faults during a period of time is,

$$\Pr(X = n) = \frac{\lambda^n e^{-\lambda}}{n!}, \quad (n \geq 0)$$

The probability of having no fault during the same time is,

$$\Pr(X = 0) = \frac{\lambda^0 e^{-\lambda}}{0!} = e^{-\lambda}$$

Having one or more faults is complementary to having no fault. Thus the probability for one or more faults to occur,

$$\Pr(X > 0) = 1 - \Pr(X = 0) = 1 - e^{-\lambda}$$

For example, a 10-mile transmission line with 10 faults per year per 100 miles will have a fault with probability,  $\Pr(X > 0) = 63\%$  over 1 year ( $\lambda = 10 \times 10/100 = 1$ ).

## 8.12 Distribution of fault currents through a circuit breaker

To compute the distribution of fault currents for a circuit breaker, it is necessary to include the circuit breakers in the network model. A Monte-Carlo simulation of faults is performed on all transmission lines and substations of the network model. A methodology for fault analysis in network models with explicit representation of circuit breakers has been proposed by the authors [92]. An example of fault current distribution is shown in Figure 8.11. Figure 8.12 shows the relative density of fault currents and load current through the circuit breaker.

Because a circuit breaker only operates when faults occur in circuits under its protection, not all the fault currents of Figure 8.11 contribute to breaker damage. For example, a fault in Florida will have no impact on a breaker in New York.

Because the problem is to know whether a breaker will successfully clear a fault when it has to, faults outside the protecting range of the breaker are ignored. A distribution of fault currents linked to a breaker operation can be obtained by limiting the Monte Carlo simulation to faults on the part of the network within the protection zone of the breaker relay. Note that a particular breaker may belong to more than one protection zone.

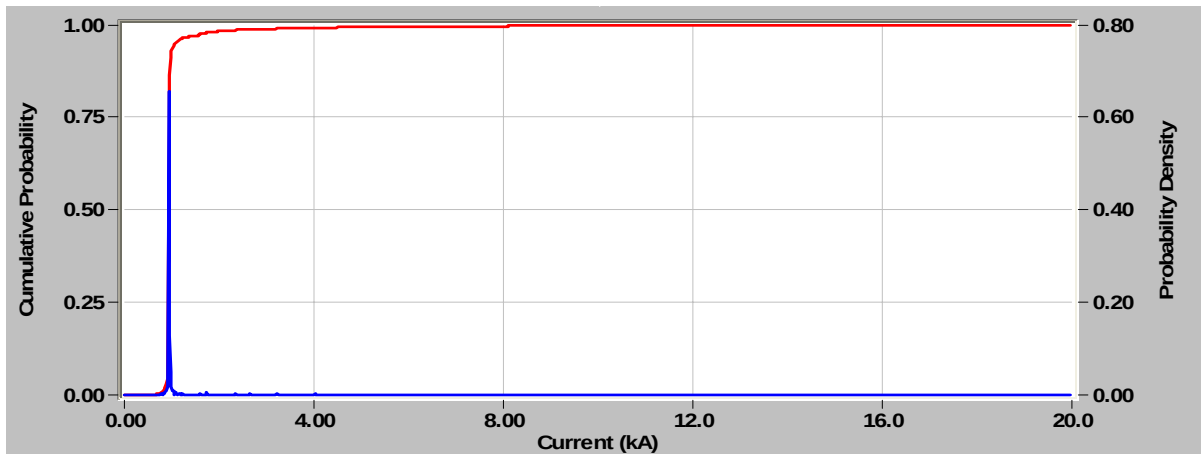


**Figure 8.11 Hypothetical distribution of fault currents  $w(\text{IF})$ ; number of cases (probability density) vs. current magnitude**

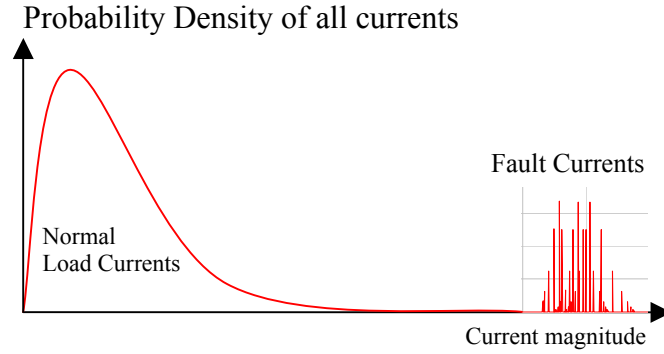


**Figure 8.12 Combined distribution of load and fault currents**

### 8.13 Accounting for the DC offset

Fault currents consist of a sinusoidal (symmetric) component, plus a DC (asymmetric) component that decays exponentially with time. The initial magnitude and decaying time of the DC offset is governed by the X/R ratio, known from line data,

$$I_{F \max} = I_F \sqrt{1 + 2e^{-\frac{2R}{L}t_1}}$$

where  $t_1$  is the time from the beginning of the fault inception.

The offset generated by the DC component increases the RMS value of the fault current, which brings the current closer to the breaker rating. At the inception of the fault ( $t_1 = 0$ ), we have  $I_{F \max} = I_F \sqrt{3}$ . Fortunately, we do not seek interruption of faults instantaneously, but rather after several (2-10) cycles, which gives time to the DC offset to partly vanish. The value of interest of the fault current RMS can be computed at the clearance time, when breakers are tripped. Since only the AC component of fault currents is computed, we can scale the fault distribution in a way that accounts for the DC component.

### 8.14 Breaker interrupting capability

A circuit breaker which is fully operational (state 1 in the state diagram) will interrupt low currents ( $I < I_0$ ) successfully with high probability. These currents may represent fault currents anticipated at the design phase of the system and should be significantly below the breaker rating. When the fault current  $I_F$  reaches some threshold  $I_0$ , the probability to fail to clear the fault increases. The breaker manufacturer may guarantee certain failure rates for selected current values, including the rated current  $I_N$ . If the fault current increases over the maximum breaker capability ( $I_F > I_1$ ), the device will fail to clear the fault in all circumstances.

Many functions can model the increased probability of failures with the fault current. For simplicity, we postulate that a piecewise linear function will determine the failure probability to interrupt any fault current  $I_F$  (Figure 8.13). This function depends on the state of the breaker, and will be denoted  $p_{Fk}(I_F)$  for current  $I_F$  and state  $k$ .

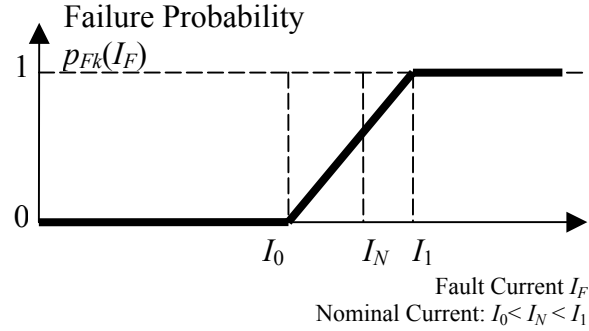


**Figure 8.13 Breaker failure probability vs. current magnitude for a given state**

### 8.15 Probability of failure to interrupt a fault current regardless of the current magnitude

In order for a breaker to fail, the following three events must happen:

- There is a fault on the breaker protection zone,
- The magnitude of fault currents is such that the breaker may fail to interrupt it (i.e.,  $I_F > I_0$ ),
- The breaker is called to duty and must open the circuit.

For a fault current of magnitude  $I_F$ , the interrupting device will fail to interrupt  $I_F$  with the probability  $p_{Fk}(I_F)$  (assuming the device is in state  $k$ ). The probability to fail to interrupt any fault current is thus the weighted sum of all the probabilities  $p_{Fk}(I_F)$ , where the weight associated with  $p_{Fk}(I_F)$  is the probability density of  $I_F$ ,  $w(I_F)$ ,

$$\sum_{I_F} w(I_F) p_{Fk}(I_F) \quad \text{for a discrete distribution}$$

$$\int_0^{\infty} w(I_F) p_{Fk}(I_F) dI_F \quad \text{for a continuous distribution}$$

To take fault currents into account, we multiply the sum and integral above by the probability that a fault occurs on a transmission line, i.e.  $(1 - e^{-\lambda})$ . The overall probability  $P_{BFk}$  of a breaker to fail to interrupt any fault current, during the period of time used to define  $\lambda$ , is,

$$P_{BFk} = (1 - e^{-\lambda}) \sum_{I_F} w(I_F) p_{Fk}(I_F) \quad (\text{discrete distribution})$$

$$P_{BFk} = (1 - e^{-\lambda}) \int_0^{\infty} w(I_F) p_{Fk}(I_F) dI_F \quad (\text{continuous case})$$

## 8.16 Transitions and common mode failures

If there were no fault, individual parts of a circuit breaker would fail at their own rate, and the diagram in Figure 8.7 would constitute a sufficient model. However, fault interruption may damage one or more components at a time, especially at high currents. To account for common mode failures, the diagrams of Figures 8.7 to 8.9 are superimposed, and the resulting state diagram contains all possible transitions from one state to another. The failure rates for each transition account for the following,

- Intrinsic component failure
- Breaker failure from overstress condition (arcing)
- Single or multiple component failure after successful fault clearance.

Intrinsic component failure rates are out of the scope of this paper. Such rates can be obtained from manufacturer or historical data.

Means to compute the other rates will be discussed next. To reduce clutter in the equations, we introduce the expected probability to fail to clear a fault in state k (see Figures 4.1 and 4.3 for notations),

$$E[p_{Fk}] = \int_0^{\infty} p_{Fk}(I_F) w(I_F) dI_F$$

Similarly, the expected probability of successful fault interruption is,

$$E[1 - p_{Fk}] = \int_0^{\infty} [1 - p_{Fk}(I_F)] w(I_F) dI_F = 1 - E[p_{Fk}]$$

The rate at which a circuit breaker fails to clear a fault (overstress conditions) from state i is,

$$\lambda E[p_{Fi}]$$

If the breaker fails to clear a fault, the equipment will be destroyed by arcing, and  $\lambda E[p_{Fi}]$  will be added to the transition from state i to state 16 in the state diagram.

The rate at which the breaker successfully interrupts the fault from state i and survives is,

$$\lambda (1 - E[p_{Fi}])$$

In the event the breaker survives the fault, the consequences can range from no damage at all to the failure of all breaker components, depending on the severity of the fault.

Let  $\beta_{ij}$  denote the probability to use the transition from state  $i$  to state  $j$  due to the damage from fault interruption. Note that if  $i = j$ , then the breaker remains in its current state, so the sum of transition probabilities is one,

$$\sum_j \beta_{ij} = 1$$

If the breaker survival rate is high (and the fault current relatively low), then  $\beta_{ij}$  should be close to zero since only little failure may occur. On the other hand, if the survival rate is low and the current is relatively high, then  $\beta_{ij}$  should be higher.

The contribution to the transition rate is obtained by multiplying  $\lambda (1 - E[p_{Fi}])$  by  $\beta_{ij}$ .

In summary, the transition rates can be obtained as follows:

For all  $j, k \in [1, 16], j \neq k$  :

$$\lambda_{j,k} = \lambda(1 - E(p_{Fj}))\beta_{j,k} + \lambda_{0j,k} \text{ (if applicable)}$$

$$\lambda_{k,16} = \lambda(1 - E(p_{Fk}))\beta_{k,16} + \lambda_{0k,16} \text{ (if applicable)} + \lambda E(p_{Fk})$$

$$\sum_{k=1}^{16} \beta_{j,k} = 1$$

$$\beta_{j,k} \geq 0$$

where :

$\lambda_{j,k}$  : total rate of the  $j, k$  transition (from state  $j$  to state  $k$ ),

$\lambda_{0j,k}$  : rate of the  $j, k$  transition due to individual component failure only (does not include failure resulting from faults),

$\beta_{j,k}$  : fraction of the rate of successful fault interruption, applied to the  $j, k$  transition (accounts for the failure of given types of components as a result of clearing a fault).

The case  $j, k$  equal means there is no damage to the breaker.

## 8.17 Accelerated aging

The apparition of fault currents is independent of the aging process, which normally takes place in all components. Aging is characterized by an increasing number of failures or higher failure rates near the end of the lifetime of a product. Normal aging falls outside the scope of this paper, and will not be discussed here.

Because of the independence of aging and faults, the transition rates of the Markov models do not include aging or damage of the device from arcing, even if the fault was successfully cleared. Damage by arcing or welding accelerates the aging of the breaker by

making it more vulnerable to subsequent faults. Accelerated aging increases failure rates at given transitions of the breaker Markov chain.

Damage of the breaker can also lower the probability of success of subsequent interruption operations, and the curve of the failure rates as a function of the fault current would be shifted to the left (see Figure 8.15). Note that changing the failure rate after successful current switching does not violate the Markov property. However, the Markov chain may no longer be homogeneous in time. To account for accelerated aging due to the fault currents, the failure rates of the circuit breaker can be incremented following some rules. The key parameter in this increase is  $p_{Fi}(I_F)$ , because it represents the severity of the fault. The change in the failure rate between states  $i$  and  $j$  will be called  $\Delta\lambda_{ij}$ . The change in the repair rates will be called  $\Delta\mu_{ij}$ .

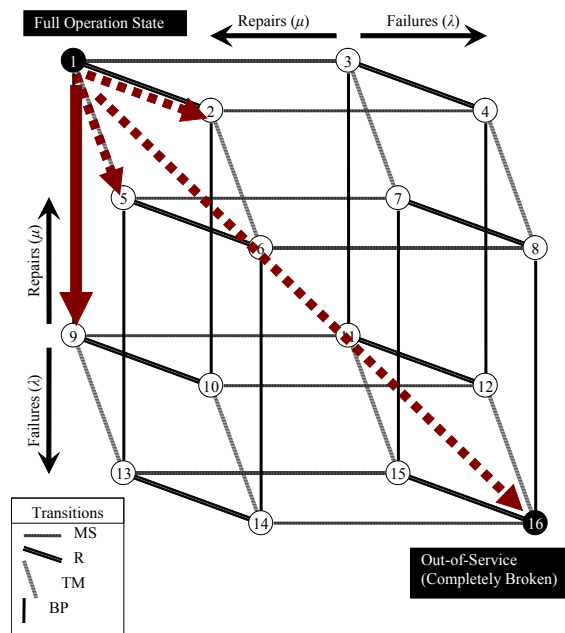


**Figure 8.14 Modified state space transitions (dotted lines) due to damage caused by switching**

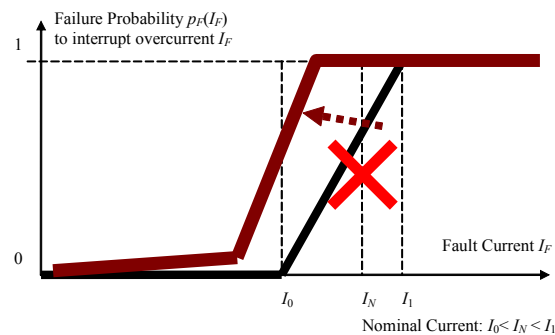


**Figure 8.15 Modified breaker failure probability vs. current after interruption of overrated faults**

If  $p_{Fi}(I_F) = 0$ , no change should occur in the failure rate ( $\Delta\lambda_{ij} = 0$ ).

If  $p_{Fi}(I_F) = 1$ , the equipment is destroyed and the transition rate to state 16 would go to infinity ( $\Delta\lambda_{ij,16} = \infty$ ).

However, this case does not happen since the transition would have been passed at the time of the fault.

The following possible expression for  $\Delta\lambda_{ij}$  is proposed,

$$\Delta\lambda_{ij} = \gamma_{ij} \frac{p_{Fi}(I_F)}{1 - p_{Fi}(I_F)}$$

where  $\gamma_{ij}$  is a nonnegative coefficient associated with the transition from state  $i$  to state  $j$ , depending on the nature of the fault. For Markov chains,  $\Delta\lambda_{ij}$  must still be such that

$$\sum_j \lambda_{ij} + \Delta\lambda_{ij} + \mu_{ij} + \Delta\mu_{ij} = 0 \quad \text{for all } i \text{ (rows).}$$

The expected value of  $\Delta\lambda_{ij}$  under fault conditions is,

$$E(\Delta\lambda_{ij}) = \int_{I_{F \min}}^{I_{F \max}} \gamma_{ij} \frac{p_{Fi}(I_F)}{1 - p_{Fi}(I_F)} w(I_F) dI_F$$

Over one full period of time,

$$E(\Delta\lambda_{ij}) = (1 - e^{-\lambda}) \int_{I_{F \min}}^{I_{F \max}} \gamma_{ij} \frac{p_{Fi}(I_F)}{1 - p_{Fi}(I_F)} w(I_F) dI_F$$

The same remarks can be made for  $\Delta\mu_{ij}$ .

After a fault has been cleared, the operation-failure cycle repeats itself with new parameter values as described in the course of this paper. A simulation of faults at specific times and locations on the network would show the evolution of the failure rates for the entire device lifetime.

## 8.18 Numerical example

The proposed breaker reliability model is demonstrated on the IEEE RTS network. The IEEE RTS has been converted into a breaker oriented model and each bus has been replaced with a substation. We focus on a breaker located at the substation 230 (bus 23). We consider two scenarios. The first scenario involves the IEEE RTS system as described in the original publication. The second scenario assumes that two large IPPs

(four-generating unit each) have been added to the system. For each of the scenarios we compute the projected reliability of the selected breaker.

The neighborhood of substation 230 is depicted in Figure 8.16 before (to the left) and after (right) the addition of two power plants and substations, SUB230-A, SUB230-C. Each new plant has four generators totaling a capacity comparable to the existing plant at substation 230.

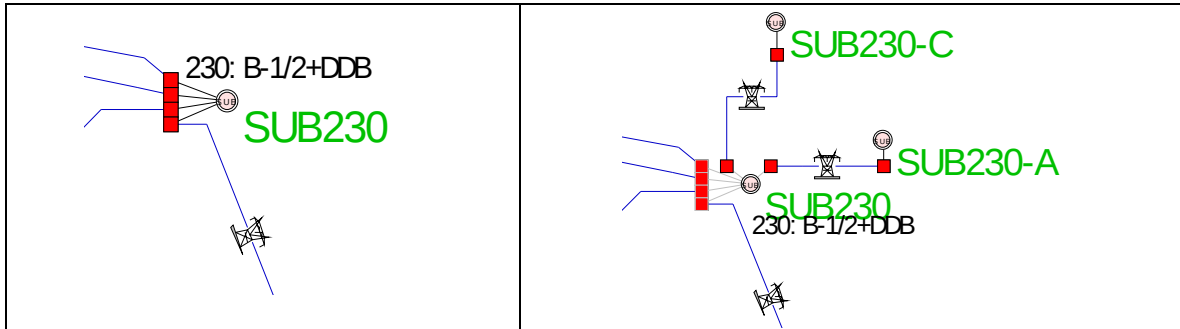


**Figure 8.16 Substation 230 before and after connection to new power plants**

Connection to the new plants is provided at substation 230, by means of a new breaker arrangement (Figure 8.17).

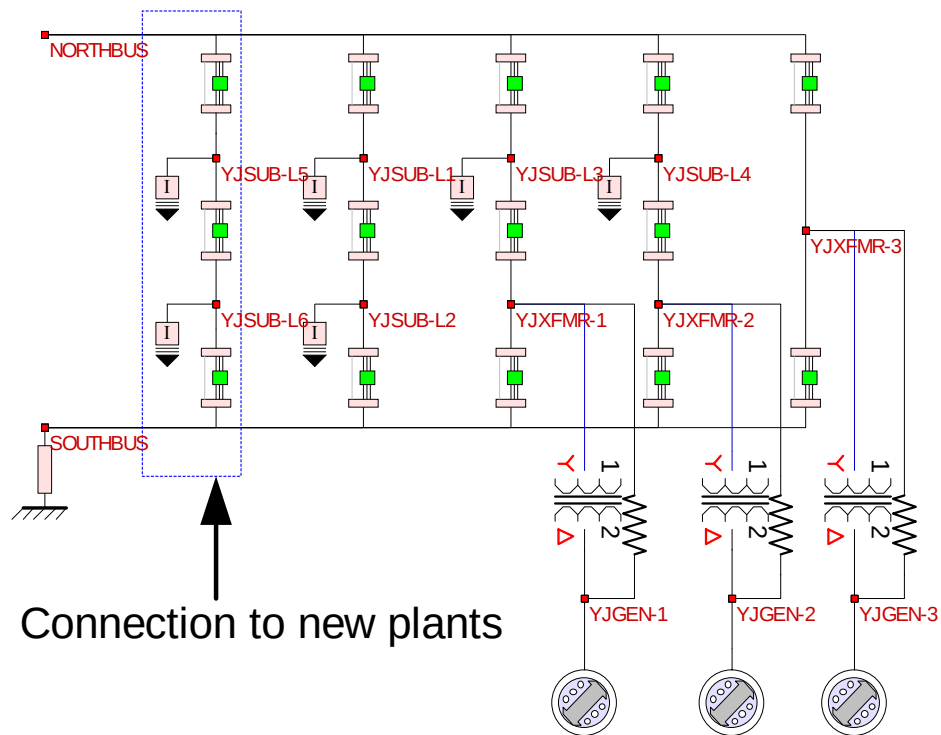


**Figure 8.17 The new breaker arrangement at substation 230**

In the following, we focus on the breaker connecting node YJSUB-L3 to node YJXFMR-1. The fault currents through this breaker are computed, and their distributions are shown in Figures 8.19 (first scenario) and 8.20 (second scenario).

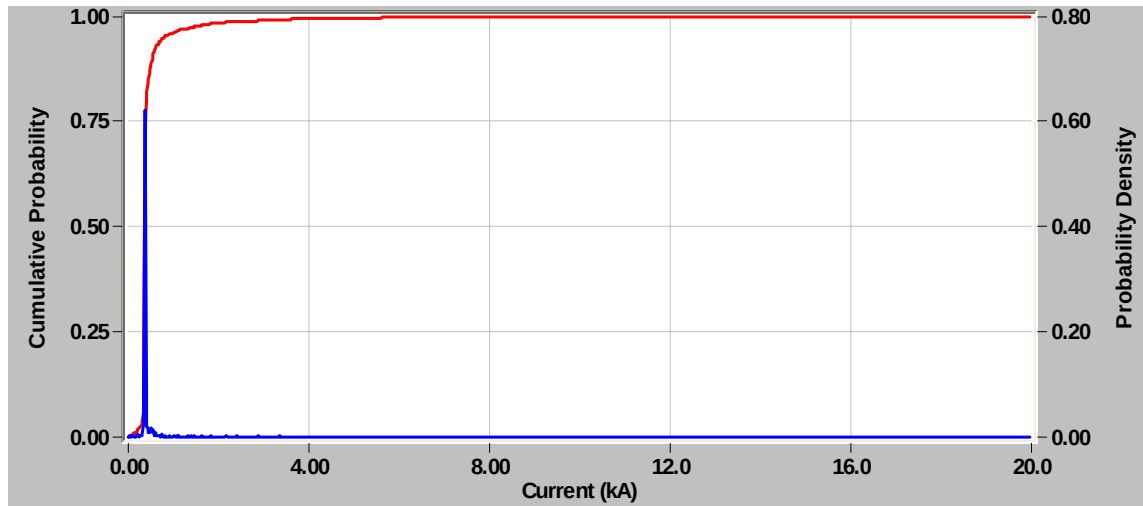


**Figure 8.18 Distribution of fault currents before expansion, highest fault current is 8.2 kA**

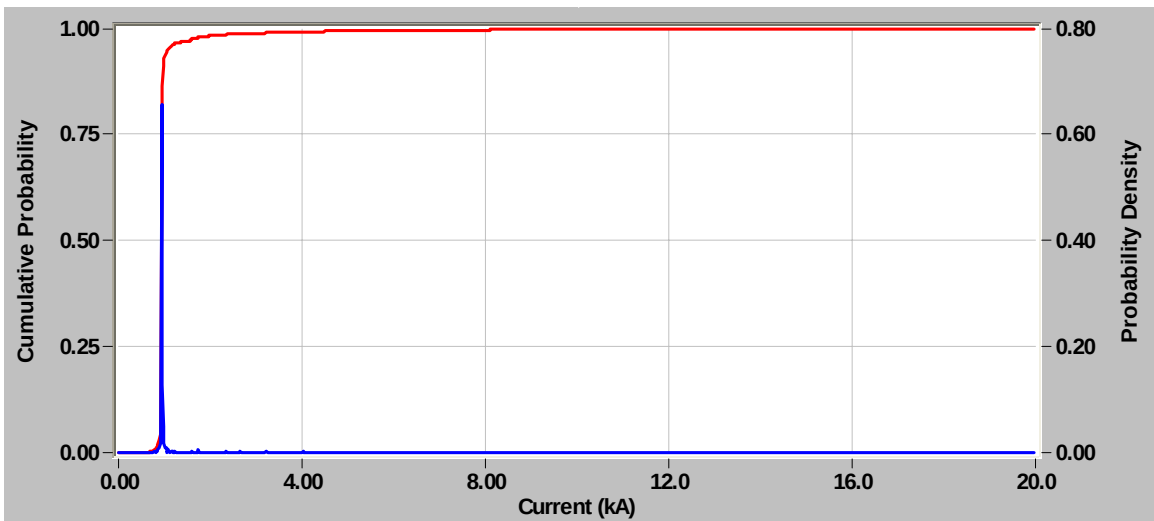


**Figure 8.19 Distribution of fault currents after expansion, highest fault current is 19.7 kA.**

The breaker-and-a half arrangement at substation 230 allows fault currents to split between the two bus bars. To prevent this, one of the bus bars is removed by opening to top row of circuit breakers. In this case the highest fault currents are 16.2 kA before, and 17.7 kA. These values are much higher than the initial 8.2 kA. While the particular numerical values are not important, the increase of the available fault current is important in the

sense that if the system was designed to handle the fault duty of the original system with certain margin, the large increase of the fault current will make the system vulnerable to catastrophic failure.

The next step is to compute the probability for such a failure. For a breaker to actually fail, it needs to be triggered. The previous fault current distributions account for all faults in any part of the network. The currents for faults on lines protected by this breaker have a different distribution.

### **8.19 Conclusions on circuit breaker reliability**

The ability to predict breaker failures is a primary concern in order to keep the equipment working as long as possible. The methodology presented in this paper provides all the key elements to construct a breaker reliability model. The Markov chains obtained from the analysis include the fault current distributions, the rating and interrupting capabilities of the breaker, the failure and repair rates of its individual components as well as failure rates for the whole device. These Markov chains make it possible to determine failure probabilities of a breaker in the short and long term, including the effect of severe fault levels. Finally, the methodology also provides a basis for evaluating the effects of breaker damage by arcing to the parameters of the model.

## 9 Conclusions and Recommendations

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### 9.1 Project conclusions

According to the demands of clean energy, high reliability and power quality for sensitive loads, the demand of renewable generation sources is gradually rising. Renewable generation sources, such as fuel cells, microturbines, solar cells and wind turbines, are mostly based on electronic inverters. These inverters interface with the AC network result in changing of the fault response throughout the system. In order to analyze the effects from the increase of fault current due to the installation of inverter based DGs, model of these DGs are need to be studied. The model of inverter based DGs proposed in Chapter 2 are accomplished by applying the  $abc$  to  $dq0$  transformation. The control strategy can be separated into two parts: voltage controller and angle difference controller. Simulation results of the stand alone operation and the grid connection of the inverter based DG are analyzed in both time and frequency domains.

Fault calculations in power systems are used to determine the interrupting capability of circuit breakers. The calculation of fault current at the system buses is done conventionally by applying the system  $Z_{bus}$  matrix. The effects of merchant plants, such as independent power producers (IPP), are not taken into consideration in the classical fault current calculation. New developments in deregulation have brought new generation sources to the system. The appearance of DGs is a cause of increasing fault currents that has not previously been envisioned. A modification of the conventional fault current calculation is discussed in Section 3.2 to accommodate fault calculation in the case of addition of DGs.

However, especially with the presence of inverter based DG, the calculation of fault current by applying the  $Z_{bus}$  matrix may not be convenient due to the complexity in estimating the transient impedance of the inverter based DGs. Chapter 3 discusses a simulation strategy which can be applied to calculate the fault current and also the coordination of protection systems. Model of the inverter based DG described in Chapter 2 are used in illustrative examples in the case with the presence of inverter based DGs. Two dimensional plots of  $R$  vs.  $X$  and three dimensional plots of  $t$ ,  $R$  and  $X$  seen by protective relay are used as a tool to visualize the system trajectory. General conclusions drawn from the results of simulation in Chapter 3 are:

- Installation of DGs in the distribution system increases the fault current throughout the system.
- The equivalent impedance seen by the system in case of synchronous machine DGs is higher than that of the inverter based DGs. Hence, inverter based generation sources appear to be ‘softer’ in the sense that their fault currents are not as severe as in the case of synchronous machine sources.
- Depending on the penetration level, locations, type of DGs, the protection system may lose coordination upon installation of DGs.

- The results of simulation as shown in Chapter 3 provide the important information to analyze the coordination of the protection system.

Chapter 4 describes the fault current estimation technique. The fault current estimation is done based on the statistical analysis of voltage and current variations. The estimation technique is applied to the test bed system at some locations. This estimation technique can be utilized as an online assessment of the fault current which is necessary to help the operator to avoid unsafe operating conditions.

Chapter 5 introduces an index called “ACF” which can be used to quantify the increase of fault current system-wide. Also, a method to approximate the ACF of a particular system is proposed. The least squares method is applied to estimate the coefficients of the ACF model. One of the applications of the ACF is to assign the cost of protective upgrades due to the commissioning of the several DRs. The general conclusion on the basis of testing is that the ACF is accurate in the 10% range. Note that, it is suggested to use the ACF as a system-wide measure, but it is not suggested to replace the standardized methods to represent individual bus fault currents.

Chapter 6 discusses the implications of operating economics imposed by increased fault current due to the addition of DGs and/or merchant plans to a power system. The UC problem with the fault level constraints is solved by applying the dynamic programming. The general conclusion can be drawn from the illustrative case in Chapter 6 that the generation of the merchant plants under the fault current level constraint may result in higher cost of operation than the operation without this constraint. The main results of Chapter 8 are:

- The three-phase system presented is the result of a conversion of the IEEE Reliability Test System from a bus-oriented, positive sequence model (equivalent per phase system) to a breaker-oriented three-phase model. Each bus in the original model has been replaced by a substation containing an explicit bus arrangement and connection scheme of transmission lines, loads, transformers and generators. The substation models are an integral part of the network model. The proposed implementation also uses a representation of transmission lines based on physical parameters, and contains updated fuel costs which reflect current prices in the energy market. The purpose of the substation circuit breaker detail is to reflect the real life existence of substation configurations.
- The breaker-oriented three-phase model adds a new level of detail in network models while retaining the merits of the original IEEE 24 Bus RTS. With a model which includes substations and their bus-breaker arrangements, new analysis methods can be developed that are more realistic than the present technology. We hope that the proposed test system will help the development of more sophisticated and realistic methodologies of the usual power system analysis problems.

The main subjects of this report are tabulated in Table 9.1.

## 9.2 Potential new research areas

The following sections are the potential research areas related to power system fault current due to DGs:

### *Dollar cost of upgrading*

For specific applications of DG, the cost of upgrading protection and interruption devices should be considered. This dollar cost should be allocated properly. Minimizing the upgrade cost is one possibility. Sharing the cost is another alternative. The applications of the ACF concept in this report together with other new indices are a further alternative. The economic issues need to be analyzed in detail. The nonlinear relationship between  $|I_f|$  and CB cost should be considered. Also, issues of the sequencing of DG installations should be considered. For example, if DGs are installed at A, B, and C and cost is allocated; then DGs are installed at D, E, and F, the final stage installation is different from if the installation sequence were {A, E, F}. Then {B, C, D} (for example).

### *Optimal siting of DGs*

Many governments in the industrial countries, especially in Group of eight (G8), have a target to substantially reduce the emission of greenhouse gas. This results in the gradually increase of the investment in the electricity from renewable sources and CHP plants. According to [69], British government expects that 10 percent of electric energy consumed in 2010 will be provided by renewable sources and CHP. As a consequence, approximately three thousand installations of renewable sources and one thousand CHP are expected to be installed in distribution networks. This is probably a trend of the world energy market in the next decade. For this reason, it is necessary to develop a technique to locate the optimal siting of DRs. The objective of this optimization is to minimize the cost of system operation and the system upgrades. The possible technical approaches are Lagrangian relaxation and evolutionary algorithms (i.e., genetic algorithms, ant colony and taboo search)

**Table 9.1 Summary of the topics in this report**

| <i>Topic</i>                                                                                  | <i>Innovative concept</i> | <i>Classical concept</i> | <i>Presented in</i> |
|-----------------------------------------------------------------------------------------------|---------------------------|--------------------------|---------------------|
| Model of the inverter based DGs                                                               | ✓                         | ✓                        | Chapter 2           |
| Fault current calculation                                                                     |                           | ✓                        | Section 3.2         |
| Increasing of fault current due to installing DGs                                             | ✓                         |                          | Chapter 3           |
| Calculation of fault current with the present of DGs                                          | ✓                         | ✓                        | Section 3.2         |
| Simulation strategies for the system with DGs (i.e., inverter based, synchronous machine DGs) | ✓                         |                          | Chapter 3           |
| Online assessment of fault current with the presence of DGs                                   | ✓                         | ✓                        | Chapter 4           |
| Average Change of Fault (ACF) index                                                           | ✓                         |                          | Section 5.2         |
| Application of the least squares method to approximate the ACF                                | ✓                         |                          | Section 5.3         |
| Allocation of cost of upgrades                                                                | ✓                         |                          | Section 5.4         |
| Implication of fault current increase on UC problem                                           | ✓                         |                          | Chapter 6           |

## APPENDIX A

### System Parameters of the Thunderstone System

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This appendix shows the detail of system parameters of the Thunderstone system, such as line parameters, transformer impedance, loads and impedance of DGs. All parameters are used in the experiments in Chapter 3 and Chapter 4.

**Table A.1 Transmission line parameter for the Thunderstone system**

| 69 kV Line |          |          | Per unit impedance @100°C<br>(100 MVA Base) |           |           |           |           |           |
|------------|----------|----------|---------------------------------------------|-----------|-----------|-----------|-----------|-----------|
| #          | FROM     | TO       | <i>RI</i>                                   | <i>XI</i> | <i>GI</i> | <i>BI</i> | <i>G2</i> | <i>B2</i> |
| 1          | Cluff    | Thundrst | 0.00232                                     | 0.01552   | 0         | 0.0004    |           |           |
| 2          | Cluff    | Cameron  | 0.00253                                     | 0.01636   | 0         | 0.00044   | 0         | 0.00046   |
| 3          | Superst3 | Cameron  | 0.01245                                     | 0.07996   | 0         | 0.00223   | 0         | 0.00223   |
| 4          | Noak     | Thundrst | 0.00235                                     | 0.01295   | 0         | 0.00035   | 0         | 0.00034   |
| 5          | Noak     | SignalBu | 0.00439                                     | 0.024     | 0         | 0.00064   | 0         | 0.00065   |
| 6          | Shannon  | SignalBu | 0.00756                                     | 0.03097   | 0         | 0.00038   | 0         | 0.00038   |
| 7          | Shannon  | Superst4 | 0.00861                                     | 0.03572   | 0         | 0.00045   | 0         | 0.00045   |
| 8          | SignalBu | Thundrst | 0.01562                                     | 0.05749   | 0         | 0.00076   |           |           |
| 9          | Seaton   | SignalBu | 0.00868                                     | 0.03194   | 0         | 0.00042   |           |           |
| 10         | Sage     | Thundrst | 0.00436                                     | 0.02435   | 0         | 0.00064   | 0         | 0.00063   |
| 11         | McCoy    | Sage     | 0.00691                                     | 0.02809   | 0         | 0.00035   |           |           |
| 12         | McCoy    | Seaton   | 0.00649                                     | 0.02638   | 0         | 0.00033   |           |           |
| 13         | Ealy     | Seaton   | 0.00869                                     | 0.03517   | 0         | 0.00043   | 0         | 0.00043   |
| 14         | Ealy     | Superst1 | 0.01113                                     | 0.04134   | 0         | 0.00054   |           |           |

**Table A.2 Load bus data for the Thunderstone system**

| <i>Bus</i>   | <i>MW</i> | <i>MVAR</i> |
|--------------|-----------|-------------|
| Cluff        | 22        | 0.5         |
| Cameron      | 27.1      | 0.5         |
| Noack        | 21.6      | 0.8         |
| SignalBU     | 43.8      | 2.1         |
| Bay 3        | 22.3      | 0.3         |
| Bay 4        | 21.5      | 1.8         |
| Shanon       | 23.3      | 2.3         |
| Superstition | 39.6      | 3           |
| Bay 2        | 16        | 3.2         |
| Bay 3        | 23.6      | 0.2         |
| Sage         | 56.4      | 6.5         |
| Seaton       | 23.2      | 2.6         |
| Ealy         | 30        | 2.4         |
| Bay 2        | 21.4      | 0.4         |
| Bay 4        | 8.6       | 2           |
| McCoy        | 0         | 0           |

**Table A.3 Substation transformer (230/69 kV) at Thunderstone substation**

| PU on a 100 MVA base |          |             |
|----------------------|----------|-------------|
| <i>R</i>             | <i>X</i> | <i>Bmag</i> |
| 0.002                | 0.06     | 0           |
| 0.001                | 0.06     | 0           |
| 0.001                | 0.07     | 0           |
| 0.001                | 0.06     | 0           |

**Table A.4 Distribution transformers in the Thunderstone system**

| FROM         | Bus<br>kV | To                  | Bus<br>kV | Rated<br>MVA | p.u. at Rated MVA |          | <i>Bmag</i> |
|--------------|-----------|---------------------|-----------|--------------|-------------------|----------|-------------|
|              |           |                     |           |              | <i>R</i>          | <i>X</i> |             |
| Cluff        | 69        | Cluff LD1           | 12        | 12           | 0.024             | 0.0742   | 0           |
| Cameron      | 69        | Cameron LD1         | 12        | 15           | 0.02              | 0.078    | 0           |
| Ealy LD1     | 69        | Ealy LD2            | 12        | 15           | 0.0198            | 0.0779   | 0           |
| Ealy LD2     | 69        | Ealy LD4            | 12        | 10           | 0.0388            | 0.074    | 0           |
| Mccoy        | 69        | Mccoy LD2           | 12        | 15           | 0.0197            | 0.0758   | 0           |
| Noack        | 69        | Noack LD2           | 12        | 12           | 0.0232            | 0.076    | 0           |
| Sage         | 69        | Sage LD2            | 12        | 12.5         | 0.0422            | 0.0725   | 0           |
| Sage         | 69        | Sage LD3            | 12        | 12.5         | 0.0228            | 0.0744   | 0           |
| Sage         | 69        | Sage LD4            | 12        | 12.5         | 0.0228            | 0.0741   | 0           |
| Seaton       | 69        | Seaton LD1          | 12        | 12           | 0.0238            | 0.0733   | 0           |
| Shanon       | 69        | Shannon LD2         | 12        | 15           | 0.0198            | 0.0763   | 0           |
| SignalBU     | 69        | Signal LD3          | 12        | 12           | 0.037             | 0.069    | 0           |
| SignalBU     | 69        | Signal LD4          | 12        | 12           | 0.0243            | 0.073    | 0           |
| Superstition | 69        | Superstition<br>LD2 | 12        | 12           | 0.0233            | 0.083    | 0           |
| Superstition | 69        | Superstition<br>LD3 | 12        | 12           | 0.0239            | 0.1028   | 0           |

## APPENDIX B

### The $dq0$ Reference Frame

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#### B.1 Introduction

This appendix provides the basic concepts and interpretation of the reference frame theory. The reference frame theory is commonly applied in analysis of three phase electrical machine models. Voltage equations and inductances of induction machines and synchronous machines are functions of rotor speed. In other words, the inductances and voltages of these machines are time varying variables. R. H. Park, H. C. Stanley, G. Kron and D. S. Brereton [70] introduce changes of variables in the analysis of electric machines. A change of variables, so called “real transformations or  $dq0$  transformation”, are employed in the analysis of electric machines to eliminate the complexity of the differential equations with time varying variables.

The real transformation refers the machines variables to a frame of reference that can be chosen to rotate at an arbitrary angular velocity. The appropriate speed of rotation,  $\omega$ , should be assigned to a particular application. For example, in the analysis of synchronous machine, the reference frame is set to fixed with the speed of rotor ( $\omega = \omega_r$ ) to eliminate the time varying inductances in the voltage equations. The transformation with the velocity of reference frame at  $\omega = \omega_r$  is first introduced by R. H. Park and is called “Park’s transformation”.

#### B.2 Transform equation

A change of variables to an arbitrary reference frame can be expressed as [59, 62, 61],

$$f_{dq0} = T_{dq0} f_{abc} \quad (\text{B.1})$$

where  $f$  in (B.1) represents variables, such as voltage, current, and flux linkage,  $f_d f_q$  and  $f_0$  are the variables in direct-axis, quadrature-axis, and zero sequence respectively,

$$f_{dq0}^T = [f_d \quad f_q \quad f_0],$$

$$f_{abc}^T = [f_a \quad f_b \quad f_c],$$

$$T_{dq0} = \frac{2}{3} \begin{bmatrix} \cos \theta & \cos(\theta - \frac{2\pi}{3}) & \cos(\theta + \frac{2\pi}{3}) \\ \sin \theta & \sin(\theta - \frac{2\pi}{3}) & \sin(\theta + \frac{2\pi}{3}) \\ \frac{1}{2} & \frac{1}{2} & \frac{1}{2} \end{bmatrix},$$

$$\omega_e = \frac{d\theta}{dt}.$$

The angular displacement,  $\theta$ , can be expressed as

$$\theta = \int_0^t \omega_e dt$$

where  $\omega_e$  is the angular velocity depends on the purpose of a particular analysis. It is assumed that  $\omega_e$  is constant and therefore  $\theta = \omega_e t$ .

The inverse transformation can be expressed as

$$T_{dq0}^{-1} = \begin{bmatrix} \cos \theta & -\sin(\theta) & 1 \\ \cos(\theta - \frac{2\pi}{3}) & -\sin(\theta - \frac{2\pi}{3}) & 1 \\ \cos(\theta + \frac{2\pi}{3}) & -\sin(\theta + \frac{2\pi}{3}) & 1 \end{bmatrix}.$$

Note that the  $dq0$  transformation described above must be applied to the instantaneous values, not the *rms* values. Also note from (B.1) that the direct axis and quadrature axis are orthogonal to each other. The zero sequence, last row of (B.1) is not associated with the arbitrary reference frame.

One of the important properties of the arbitrary reference frame is the energy and power conservation. That is, the energy and power in time domain representation of a signal is equal to the energy and power in the arbitrary reference frame. The total instantaneous power can be written in *abc* variables as

$$P_{abc} = v_{an} i_a + v_{an} i_a + v_{cn} i_c.$$

The total instantaneous power written in the arbitrary reference frame,  $dq0$ , is

$$P_{dq0} = P_{abc} = \frac{3}{2} (v_d i_d + v_q i_q + 2v_0 i_0).$$

The 3/2 factor is required due to the constant used in the transformation. Illustrative examples in the following sections are used to demonstrate the properties of the transformation. Two types of signal are demonstrated: balance three phase voltage with harmonics in Case B.1 and unbalance three phase voltage with harmonics in Case B.2.

### B.3 Transformation of a balanced three phase signal (Case B.1)

To demonstrate the application of the  $dq0$  transformation to a balanced three phase signal, a three phase sinusoidal voltage,  $v_{abc}(t)$ , with power frequency ( $\omega = 377$  rad/s) is used as illustrative case denominated as Case B.1. Case B.1 illustrates the sinusoidal steady state with voltage harmonics  $h = 1, 2, 3, \dots$  in the sequences  $+, -, 0, +, \dots$ . Simplified notation of phase-neutral voltages  $\{v_{an}(t), v_{bn}(t), v_{cn}(t)\}$  as  $\{v_a(t), v_b(t), v_c(t)\}$ , the waveform in Case B.1 is defined as

$$v_a(t) = 50 \cos \omega t + 15 \cos 5\omega t + 5 \cos 9\omega t \quad (\text{B.2})$$

$$v_b(t) = 50 \cos(\omega t - \frac{2\pi}{3}) + 15 \cos 5(\omega t - \frac{2\pi}{3}) + 5 \cos 9(\omega t - \frac{2\pi}{3}) \quad (\text{B.3})$$

$$v_c(t) = 50 \cos(\omega t + \frac{2\pi}{3}) + 15 \cos 5(\omega t + \frac{2\pi}{3}) + 5 \cos 9(\omega t + \frac{2\pi}{3}). \quad (\text{B.4})$$

Note that in (B.2) – (B.4), the  $\{v_a(t), v_b(t), v_c(t)\}$  are represented in zero-peak instantaneous volts. Assume that, in the transform matrix, the initial condition of angular displacement,  $\theta(t=0)$ , is set to zero and the angular velocity of the reference frame,  $\omega_e$ , is fixed at the power frequency. Waveform and frequency spectrum of the balanced three phase voltage are shown in Figure B.1. Note that in Figure B.1, the amplitude spectrum of  $v_a(t)$  is  $|V_a(h\omega_e)|$  and this is shown in volts zero-peak. The amplitude spectra  $|V_b(h\omega_e)|$  and  $|V_c(h\omega_e)|$  are identical to  $|V_a(h\omega_e)|$ . Note that the illustrative waveform has fifth and ninth harmonics. By applying (B.1), the three phase voltage can be written in arbitrary reference as

$$\begin{bmatrix} v_d(t) \\ v_q(t) \\ v_0(t) \end{bmatrix} = \frac{2}{3} \begin{bmatrix} \cos \theta & \cos(\theta - \frac{2\pi}{3}) & \cos(\theta + \frac{2\pi}{3}) \\ \sin \theta & \sin(\theta - \frac{2\pi}{3}) & \sin(\theta + \frac{2\pi}{3}) \\ \frac{1}{2} & \frac{1}{2} & \frac{1}{2} \end{bmatrix} \begin{bmatrix} v_a(t) \\ v_b(t) \\ v_c(t) \end{bmatrix}$$

or

$$\begin{bmatrix} v_d \\ v_q \\ v_0 \end{bmatrix} = \begin{bmatrix} 50 + 15 \cos 6\omega t \\ 15 \sin 6\omega t \\ 5 \cos 9\omega t \end{bmatrix}. \quad (\text{B.6})$$

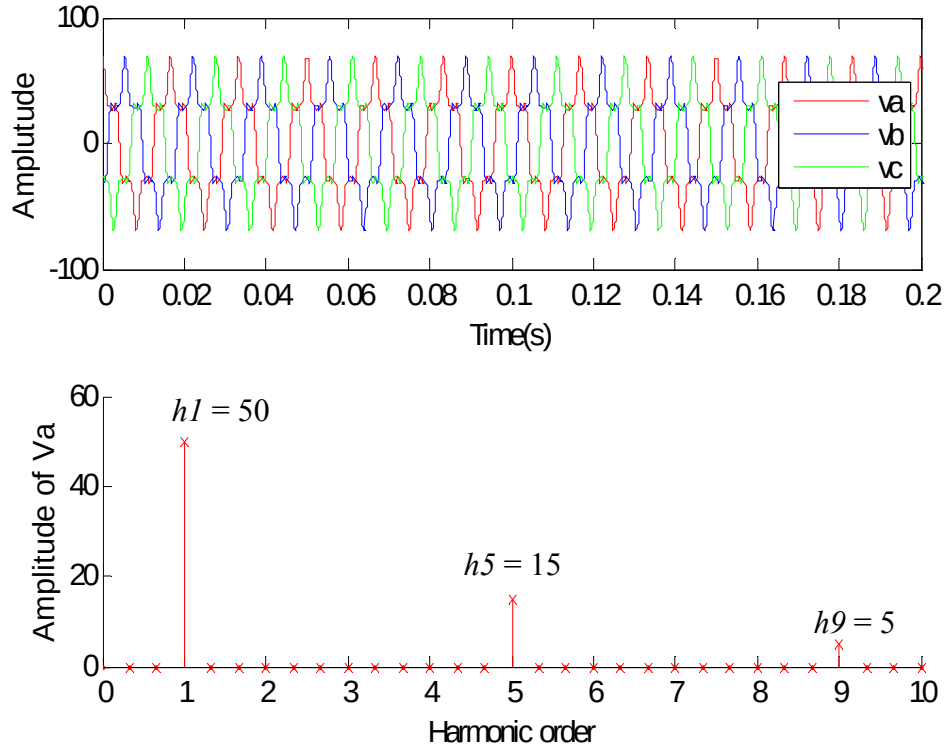


**Figure B.1** Line to neutral voltage waveform ( $a, b, c$  variables) and amplitude of harmonic content, Case B.1

The results of  $dq0$  transformation in time domain and frequency domain are depicted in Figures B.2 and B.3, respectively. Note that, from (B.2)-(B.4) and Figure B.3, the amplitude of the fundamental frequency given in (B.2)-(B.4) becomes the dc component in the direct axis after transforming associated with the velocity of reference frame at  $\omega_e = 377$ . The fifth harmonic in (B.2)-(B.4) is converted to the sixth harmonics in both direct and quadrature axes. Also note that the dc component and the triple harmonics (ninth harmonics in this case) appear in the zero sequence. This conclusion as well as other generalizations will be discussed later.

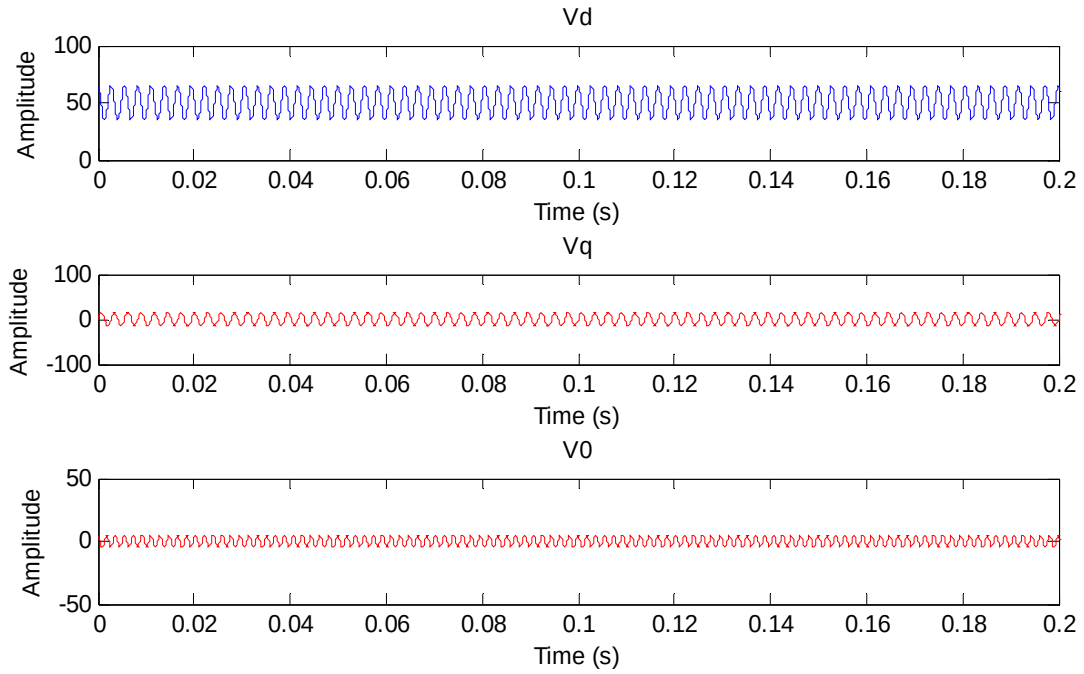


**Figure B.2 Three phase waveform in  $dq0$  rotational reference frame with angular velocity,  $\omega = 377$  rad/s, Case B.1**

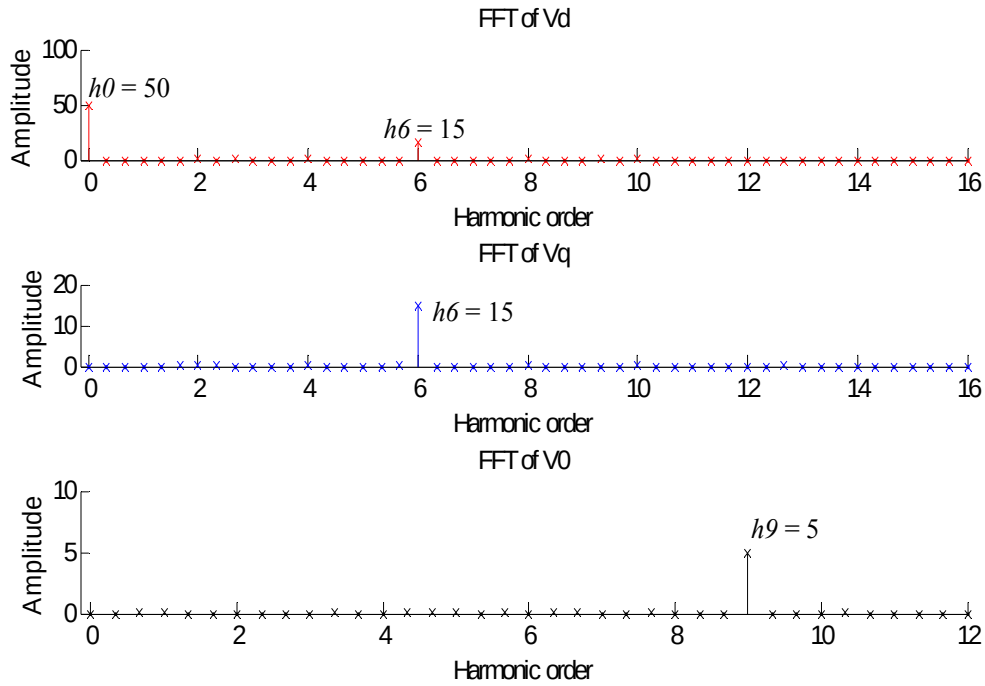


**Figure B.3 Amplitude frequency spectrum of the balanced three phase signal in the  $dq0$  rotational reference frame, Case B.1**

#### B.4 Transformation of an unbalanced signal with harmonics (Case B.2)

This case demonstrates the transformation of an unbalanced three phase signal which can be expressed as

$$v_a(t) = 100 \cos \omega t + 10 \cos 5\omega t + 5 \cos 9\omega t \quad (\text{B.5})$$

$$v_b(t) = 90 \cos(\omega t - \frac{2\pi}{3}) + 8 \cos 5(\omega t - \frac{2\pi}{3}) + 4 \cos 9(\omega t - \frac{2\pi}{3}) \quad (\text{B.6})$$

$$v_c(t) = 80 \cos(\omega t + \frac{2\pi}{3}) + 6 \cos 5(\omega t + \frac{2\pi}{3}) + 3 \cos 9(\omega t + \frac{2\pi}{3}). \quad (\text{B.7})$$

Note that the signal composed, unbalanced power frequency components (unbalanced harmonic contents 5<sup>th</sup> and 9<sup>th</sup> harmonics). Plots of the signal in time domain and frequency domain for Case B.2 are shown in Figure B.4. As in Case B.1, the units depicted are all instantaneous (i.e., zero-peak) volt.

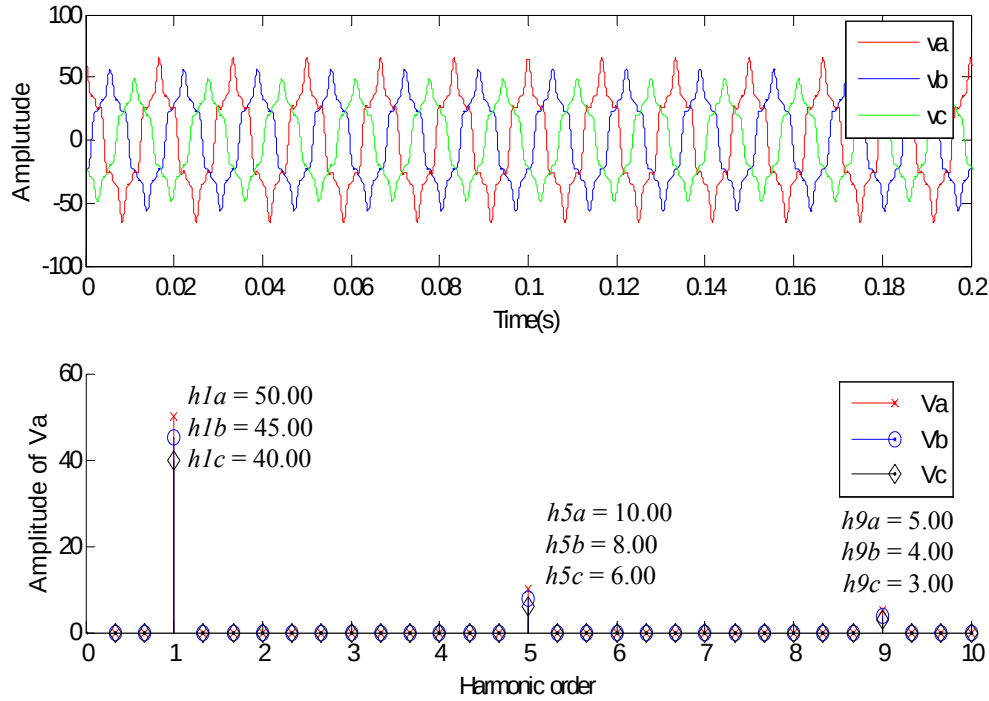


**Figure B.4 Line to neutral voltage waveform ( $a$ ,  $b$ ,  $c$  variables) and amplitude of harmonic content, Case B.2**

Transformation of the signal in Case B.2 associated with the velocity of reference frame is done by applying (B.1). Assume the angular velocity of the reference frame,  $\omega_e$ , is 377 rad/s. The transformed signal in time domain and frequency domain are shown in Fig-

ures B.5 and B.6, respectively. From the results of transformation in Figures B.5 and B.6, note that:

- Due to the unbalanced component in the fundamental component, there exists a dc component and second harmonic in the direct axis,  $v_d(t)$ . In the quadrature axis,  $v_q(t)$ , there exists a second harmonic component. In the zero sequence, there is a fundamental frequency component.
- The unbalanced non-triple harmonic signal, the fifth harmonic in Case B.2, creates a sixth harmonic with the same amplitude in both direct and quadrature axes. There exists a fifth harmonic in the zero sequence component.
- The unbalanced triple harmonic signal, the ninth harmonic in this case, creates the eighth and tenth harmonics in the direct and quadrature axes. There also exists the ninth harmonic in the zero sequence component.

The analysis of the  $dq0$  transformation is accomplished analytically by using the Symbolic toolbox provided in Matlab (not shown here). Properties of the synchronous rotational reference frame transformation can be drawn as shown in Table B.1

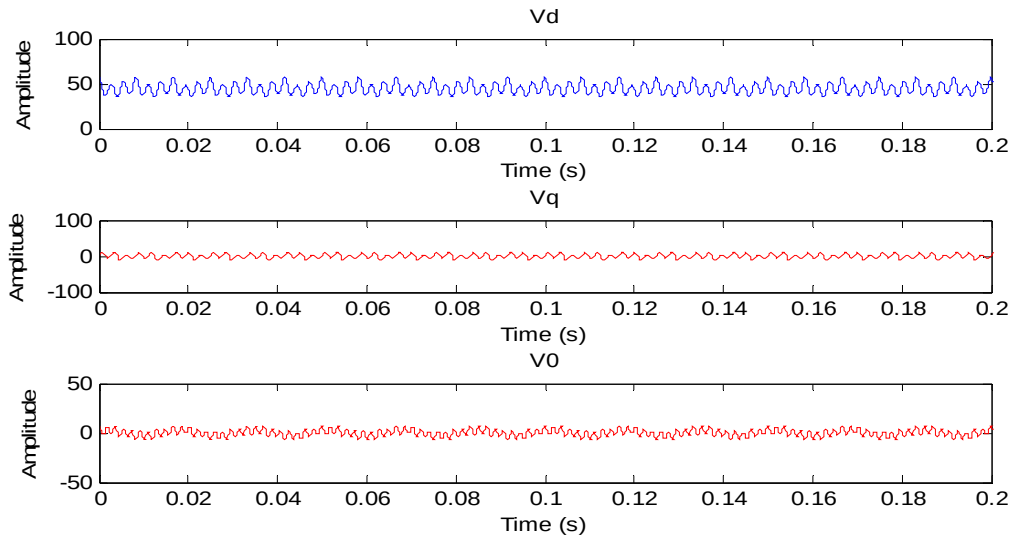


**Figure B.5 Three phase waveform in  $dq0$  rotational reference frame with angular velocity,  $\omega_e = 377$  rad/s, Case B.2**

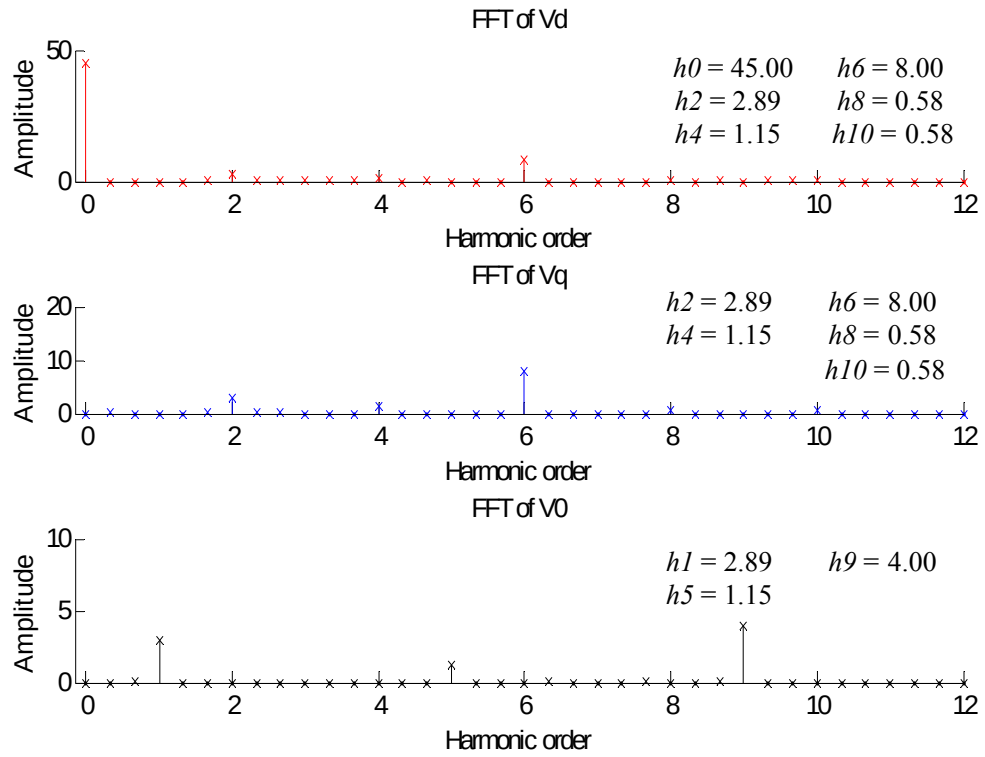


**Figure B.6 Frequency spectrum of the balanced three phase signal in the rotational reference frame, Case B.2**

**Table B.1 Properties of the  $dq0$  transformation for sinusoidal steady state signals**

| $abc$                                                                      | $dq0$                                                                                                                                                           | $dq0$                                                                                                                                                                                                                           |
|----------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Frequency component                                                        | Balanced signal <sup>(2)</sup>                                                                                                                                  | Unbalanced signal <sup>(3)</sup>                                                                                                                                                                                                |
| DC component <sup>(1)</sup>                                                | <ul style="list-style-type: none"> <li>• DC component in <math>f_0</math></li> </ul>                                                                            | <ul style="list-style-type: none"> <li>• Fundamental component in <math>f_d</math> and <math>f_q</math>.</li> <li>• DC component in <math>f_0</math>.</li> </ul>                                                                |
| Fundamental frequency                                                      | <ul style="list-style-type: none"> <li>• DC component in <math>f_d</math></li> </ul>                                                                            | <ul style="list-style-type: none"> <li>• DC component and second harmonic in <math>f_d</math>.</li> <li>• DC component and Second harmonic in <math>f_q</math></li> <li>• Fundamental component in <math>f_0</math>.</li> </ul> |
| Non triple harmonics,<br>$3k \pm 1^{th}$ order<br>( $k = 1, 2, 3, \dots$ ) | <ul style="list-style-type: none"> <li>• <math>3k^{th}</math> harmonic in <math>f_d</math> and <math>f_q</math></li> <li>• <math>f_0</math> is zero.</li> </ul> | <ul style="list-style-type: none"> <li>• <math>3k^{th}</math> harmonic in <math>f_d</math> and <math>f_q</math></li> <li>• <math>3k \pm 1^{th}</math> harmonic in <math>f_0</math></li> </ul>                                   |
| Triple harmonics,<br>$3k^{th}$ order<br>( $k = 1, 2, 3, \dots$ )           | <ul style="list-style-type: none"> <li>• <math>f_d</math> and <math>f_q</math> is zero.</li> <li>• <math>3k^{th}</math> harmonic in <math>f_0</math></li> </ul> | <ul style="list-style-type: none"> <li>• <math>3k \pm 1^{th}</math> harmonic in <math>f_d</math> and <math>f_q</math></li> <li>• <math>3k^{th}</math> harmonic in <math>f_0</math></li> </ul>                                   |

(1) Not shown in example cases

(2) Illustrated as Case B.1

(3) Illustrated as Case B.2

### B.5 Transformation of a low pass filtered unbalanced signal with harmonics

With reference to Table B.1, considers the case of a low pass filtered signal obtained from the  $dq0$  variables (See Figure B.7). If the  $f > f_0$  components are rejected by the low pass filter, Table B.2 results.

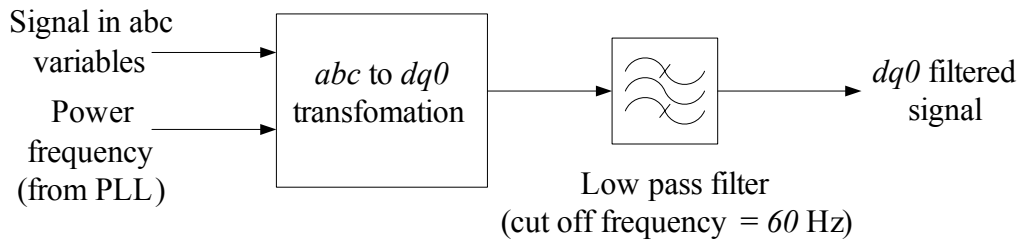


**Figure B.7 Signal in  $dq0$  variables with low pass filter**

**Table B.2 Properties of the  $dq0$  transformation with low pass filter for the sinusoidal steady state**

| $abc$                                                                      | $dq0$                                                               | $dq0$                                                                                          |
|----------------------------------------------------------------------------|---------------------------------------------------------------------|------------------------------------------------------------------------------------------------|
| Frequency component                                                        | Balanced signal                                                     | Unbalanced signal                                                                              |
| DC component <sup>(1)</sup>                                                | • DC component in $f_0$                                             | • Fundamental component in $f_d$ and $f_q$ .<br>• DC component in $f_0$ .                      |
| Fundamental frequency                                                      | • DC component in $f_d$                                             | • DC component in $f_d$ .<br>• DC component in $f_q$ .<br>• Fundamental component in $f_0$ .   |
| Non triple harmonics,<br>$3k \pm 1^{th}$ order<br>( $k = 1, 2, 3, \dots$ ) | • $3k^{th}$ harmonic in $f_d$ and $f_q$ is zero<br>• $f_0$ is zero. | • $3k^{th}$ harmonic in $f_d$ and $f_q$ is zero<br>• $3k \pm 1^{th}$ harmonic in $f_0$ is zero |
| Triple harmonics,<br>$3k^{th}$ order<br>( $k = 1, 2, 3, \dots$ )           | • $f_d$ and $f_q$ is zero.<br>• $3k^{th}$ harmonic in $f_0$ is zero | • $3k \pm 1^{th}$ harmonic in $f_d$ and $f_q$ is zero<br>• $3k^{th}$ harmonic in $f_0$ is zero |

(1) Usually does not occur in AC systems

## B.6 The case of arbitrary time domain signals

Consider the three phase voltage  $\{v_{an}(t), v_{bn}(t), v_{cn}(t)\}$  where the voltages are not in the sinusoidal steady state. That is, the voltages are arbitrary signals. As an example, Figure B.8 shows a three phase PWM inverter connected to a three phase source with source inductance and resistance (where  $R, L$  of the source are unequal). This is case B.3 offered as an example of a generalized case. Let  $S$  be closed at  $t = 0$ . Figure B.9 shows the time domain representation of the inverter supply voltages. The amplitude spectra  $\{V_{an}(h\omega_e), V_{bn}(h\omega_e), V_{cn}(h\omega_e)\}$  are shown in Figure B.10. Note that the amplitude spectra are only part of the FFT: the phase spectra are not shown here. In Figure B.10, the amplitude spectra are shown versus harmonics of 60 Hz, labeled  $h$ . The actual Fourier spectrum of these voltages are continuous in  $\omega$ , and only for convenience depicted as an FFT with resolution  $\Delta\Omega = 60$  Hz in Figure B.10. The actual resolution in the calculation shown in Figure B.10 is

$$\begin{aligned}\Delta\Omega &= \frac{2\pi}{N\Delta T} \\ &= \frac{2\pi}{(334)(1/60)} = 1.129 \text{ rad/s.}\end{aligned}$$

Also, the FFT shown in Figure B.10 depicts only a part of the FFT calculated to avoid the mirror image effect

$$V(k\Delta\Omega) = [V((N - k - 1)\Delta\Omega)], \quad k = 0, 1, 2, \dots, N/2.$$

The  $dq0$  voltages are shown in Figure B.11. The corresponding amplitude frequency spectra depend on which time window is used. For example, the time window  $[\frac{12}{60}, \frac{13}{60}]$  second and  $[\frac{13}{60}, \frac{14}{60}]$  second results are shown in Figure B.12.

Note that in Figure B.12, the predominant  $dq0$  signals are in the  $d$  and  $q$  components for the time windows depicted. This agrees qualitatively with Table B.1.

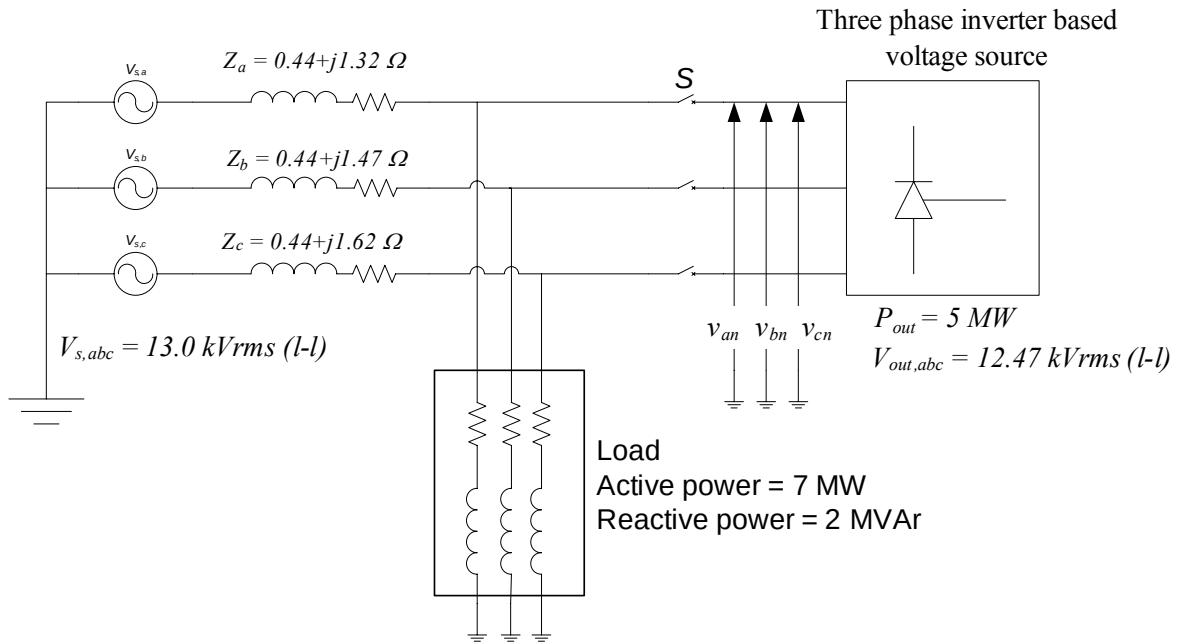


**Figure B.8 Three phase PWM inverter connected to a three phase sinusoidal voltage through unbalance impedances**

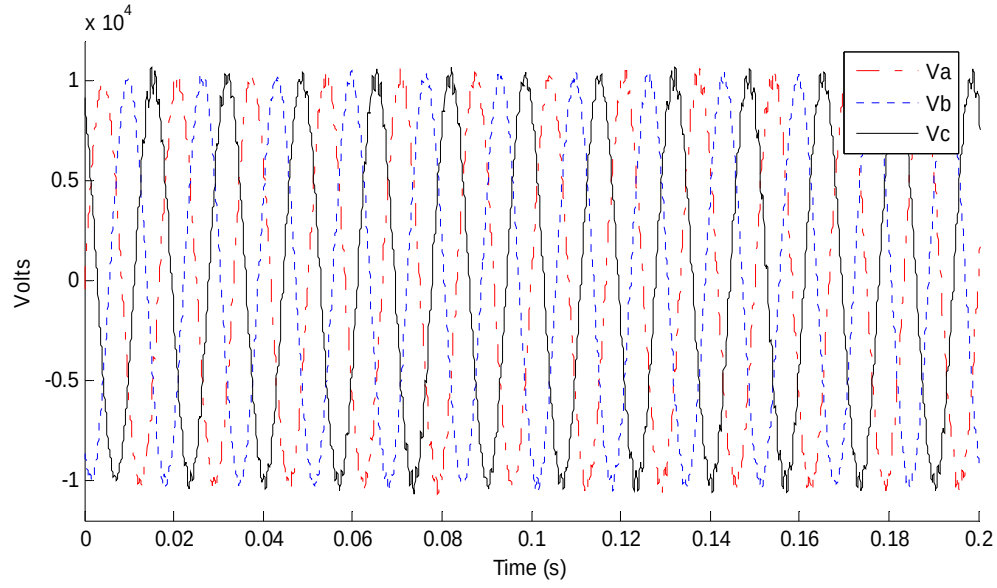


**Figure B.9 Time domain representation ( $abc$  variables) of the inverter supply voltages  $\{v_{an}, v_{bn}, v_{cn}\}$**

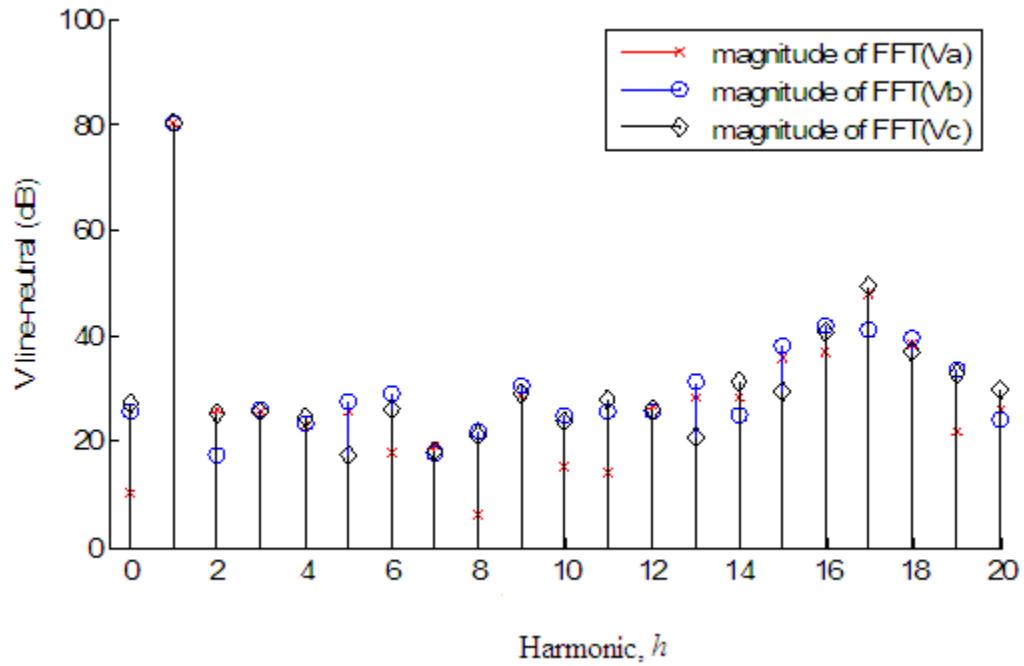


**Figure B.10 Amplitude spectra of  $V_{an}(h\omega_e)$ ,  $V_{bn}(h\omega_e)$ , and  $V_{cn}(h\omega_e)$  calculated over time window,  $t_w = 0.2 - 0.21667$  s**

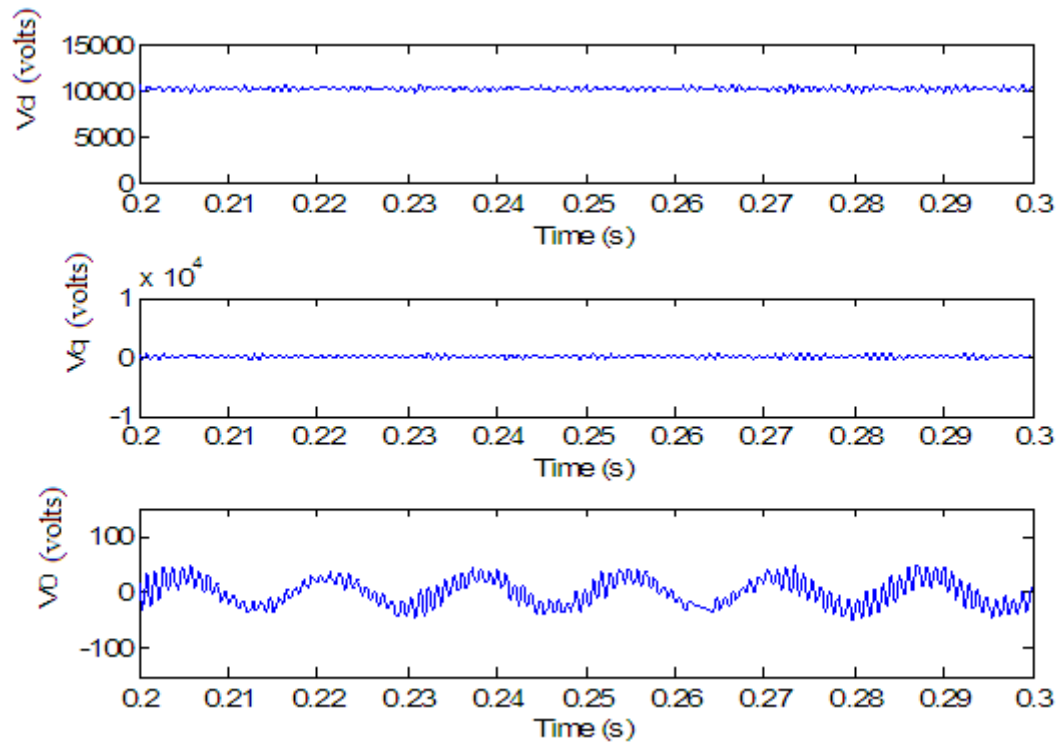


**Figure B.11 Time domain representation ( $dq0$  variables) of the inverter supply voltages**

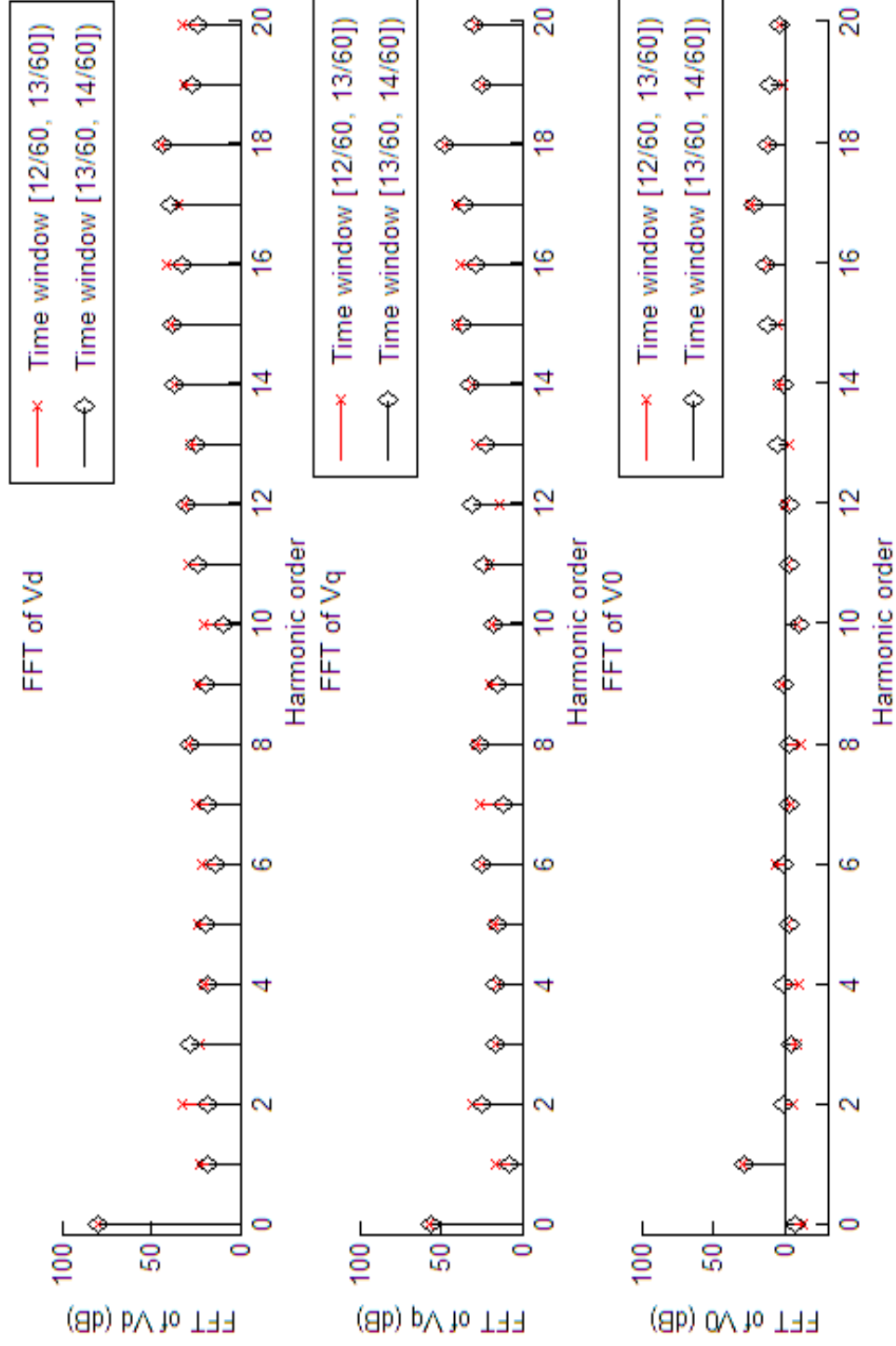


Figure B.12 Amplitude frequency spectra of the voltages in  $dq0$  variables with the time window  $[12/60, 13/60]$  and  $[13/60, 14/60]$  second

## APPENDIX C

### List of Conditions for all the Experiments

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This appendix shows the summary of the experiment in this report. All experiments in Chapter 3 and Chapter 4 are simulated based on the Thunderstone system.

**Table C.1 Summary of the case studies**

| <i>Case</i> | <i>Locations of DG</i>                                               | <i>Varied parameters</i>                      | <i>Target of experiments</i>                                                |
|-------------|----------------------------------------------------------------------|-----------------------------------------------|-----------------------------------------------------------------------------|
| 2.1         | stand alone operation (dis-connected from the grid)                  | MW power output                               | Illustrates the operation of inverter                                       |
| 2.2         | DG connected to the grid                                             | MW power output                               | Illustrates the operation of inverter                                       |
| 3.1         | Cameron2, Signal3, Sage3, Seaton2                                    | Number and locations of DGs in the system     | Severity of the change of fault current                                     |
| 3.2         | Seaton, Cameron2, Signal3, Sage3                                     | AVR turn on/off                               | Severity of the change of fault current                                     |
| 3.3         | Cameron2, Signal3 Sage3, Seaton2                                     | Impedance of DGs                              | Severity of the change of fault current                                     |
| 4.1         | Cameron2, Signal3, Seaton2, Ealy3, Ealy4, Sage3.                     | Impedance of DGs, location of new DGs         | Illustrates application of the least squares estimator to calculate the ACF |
| 5.1         | Cameron2, Signal3, Seaton2, Ealy3, Ealy4 and Sage3                   | Impedance of DGs, location of new DGs         | Demonstrate the estimation of ACF                                           |
| 4.2         | Cameron2 Signal3 Seaton2 Ealy3 Ealy4 Sage3.                          | Impedance of DGs, location of new DGs         | Shows the bus locations which need to be upgraded                           |
| 5.1         | Superstition (14) Early (23) Signal (9) Cameron (5)                  | Without considering the operating limitations | Operating implication imposed by the increase fault current                 |
| 5.2         | Superstition (14) Early (23) Signal (9) Cameron (5)                  | Consider the operating limitations            | Operating implication imposed by the increase fault current                 |
| 6.1         | Cameron2, Signal13, Super14, Super15, Seaton2, Early3, Early4, Sage3 | Impedance of DGs, location of new DGs         | Application of dynamic programming for solving the UC problem with FLC      |

## APPENDIX D

### The Modified IEEE 24-Substation Reliability Test System

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This appendix presents the modified IEEE 24 Bus Reliability Test System Model (24-bus system). The 24-bus system has been modified by converting all the nodes to substations with specific breaker arrangements. Examples of breaker arrangements are provided in Table D.1. The topology of each substation in the proposed network is derived from the standard bus arrangements shown in Table D.1. Tables D.2 and D.3 provide the specific selections made for each substation in the proposed test system. Figure D.1 shows the overall proposed breaker oriented 24 substation system. Table D.4 provides a summary of the generator data. Table D.5 provides a summary of the Transmission lines data.

The substation arrangements provide a more realistic model to study the reliability of the system or perform a number of other important analysis procedures such as fault analysis and transient stability. The complete substation bus arrangements are posted on the web site given in the abstract.

**Table D.1 Standard bus arrangements**

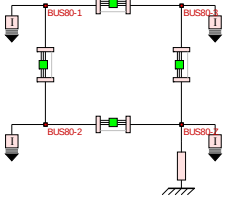
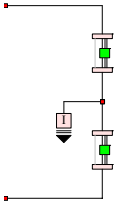
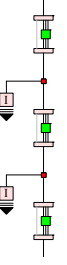
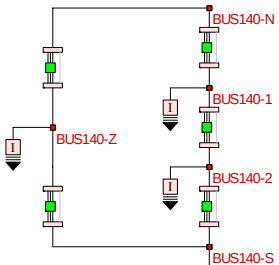
|                                                                                                                                             |                                                                                                                                                                          |
|---------------------------------------------------------------------------------------------------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
|                                                           |                                                                                      |
| <p><b>Ring Bus (RB)</b><br/>A cyclic circuit (ring) where two transmission lines are separated with one breaker.</p>                        | <p><b>Double Bus – Double Breaker (DDB)</b>, with lines separated from each common bus by one breaker.</p>                                                               |
|                                                          |                                                                                      |
| <p><b>Breaker-and-a-Half (B<sup>1</sup>/<sub>2</sub>)</b>, which sequence is Bus, Breaker, Interface, Breaker, Interface, Breaker, Bus.</p> | <p><b>(B<sup>1</sup>/<sub>2</sub>+DDB):</b><br/><b>A combination</b> of Breaker-and-a-Half and Double Bus – Double Breaker, mostly to handle odd numbers of breakers</p> |

**Table D.2 Substation data**

| Bus Arrangement                                       | Number of Substations | Substation Numbers                 |
|-------------------------------------------------------|-----------------------|------------------------------------|
| Double Bus / Double Breaker (DDB)                     | 3                     | 70, 130, 220                       |
| Breaker-and-a-half (B½)                               | 8                     | 10, 20, 30, 90, 100, 110, 160, 210 |
| Mixed Double Bus/Breaker and Breaker-and-a-half (DB½) | 5                     | 140, 150, 170, 180, 230            |
| Ring Buses (RB)                                       | 8                     | 40, 50, 60, 80, 120, 190, 200, 240 |

Number of Breakers: 186

**Table D.3 Bus-breaker arrangement by substation number**

|      |    |    |    |    |    |    |     |    |    |     |
|------|----|----|----|----|----|----|-----|----|----|-----|
| Bus  | 10 | 20 | 30 | 40 | 50 | 60 | 70  | 80 | 90 | 100 |
| Type | B½ | B½ | B½ | RB | RB | RB | DDB | RB | B½ | B½  |

|      |     |     |     |     |     |     |     |     |     |     |     |     |     |     |
|------|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|
| Bus  | 110 | 120 | 130 | 140 | 150 | 160 | 170 | 180 | 190 | 200 | 210 | 220 | 230 | 240 |
| Type | B½  | RB  | DDB | DB½ | DB½ | B½  | DB½ | DB½ | RB  | RB  | B½  | DDB | DB½ | RB  |

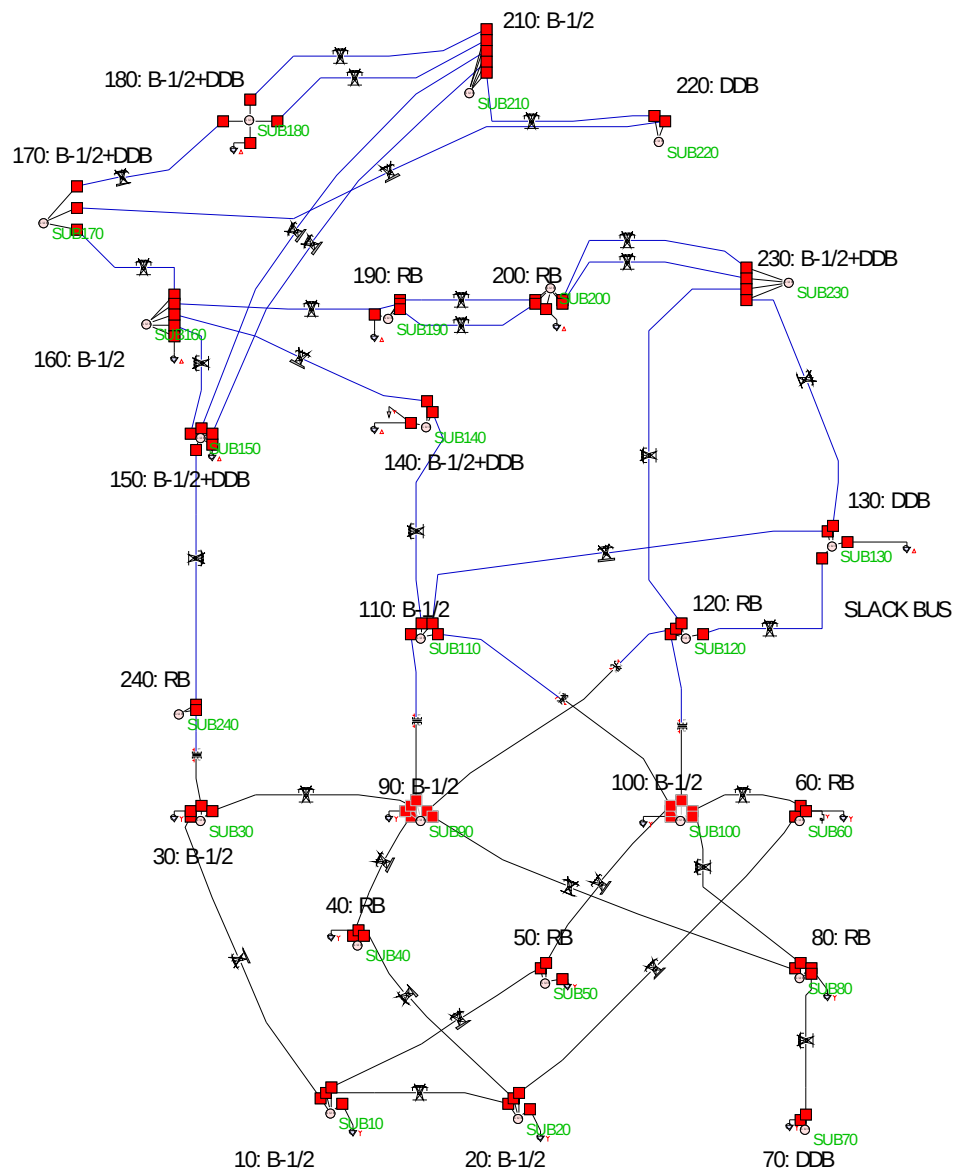


**Figure D.1 Modified IEEE 24 substation reliability test system network**

**Table D.4 Generator data by plant power and fuel**

| Type       | Power      |       |      |     | Reliability |        | Operating Cost |        | Fuel    | Power Plant Cost Coefficients |          |           |
|------------|------------|-------|------|-----|-------------|--------|----------------|--------|---------|-------------------------------|----------|-----------|
|            | P          |       | Q    |     | $\lambda$   | $\mu$  | O&M part       |        | Fuel    | Final Cost Coefficients       |          |           |
|            | Max        | Min   | Min  | Max | 1/MTTF      | 1/MTTR | a              | b      | Cost    | a                             | b        | c         |
|            | MW         |       | MVAR |     |             |        | \$/h           | \$/MWh | \$/MBtu | \$/h                          | \$/MWh   | \$/MW/MWh |
| Fossil oil | <b>12</b>  | 2.4   | 0    | 6   | 2.9796      | 146    | 13.70          | 0.9    | 5.5     | 86.38524                      | 56.56404 | 0.328412  |
| Turbine    | <b>20</b>  | 16    | 0    | 10  | 19.467      | 175.2  | 0.685          | 5      | 10      | 400.6849                      | 130      | 0         |
| Hydro      | <b>50</b>  | 10    | -10  | 16  | 4.4242      | 438    | 0.001          | 0.001  | 0       | 0.001                         | 0.001    | 0         |
| Coal       | <b>76</b>  | 15.2  | -25  | 30  | 4.4694      | 219    | 86.76          | 0.9    | 1.5     | 212.3076                      | 16.0811  | 0.014142  |
| Fossil oil | <b>100</b> | 25    | 0    | 60  | 7.3         | 175.2  | 97.03          | 0.8    | 5.5     | 781.521                       | 43.66146 | 0.052672  |
| Coal       | <b>155</b> | 54.25 | -50  | 80  | 9.125       | 219    | 123.9          | 0.8    | 1.5     | 382.2391                      | 12.38826 | 0.008342  |
| Fossil oil | <b>197</b> | 68.95 | 0    | 80  | 9.2211      | 175.2  | 112.4          | 0.7    | 5.5     | 832.7575                      | 48.58041 | 0.00717   |
| Coal       | <b>350</b> | 140   | -25  | 150 | 7.6174      | 87.6   | 179.8          | 0.7    | 1.5     | 665.1094                      | 11.84954 | 0.004895  |
| Nuclear    | <b>400</b> | 100   | -50  | 200 | 7.9636      | 58.4   | 228.3          | 0.3    | 0.46    | 395.3749                      | 4.42318  | 0.000213  |

**Table D.5 System data**

|        |     | Line Specification |            |        | Physical Parameters & Actual Impedances |       |            |          | Failure/Repair Rates |      |          |
|--------|-----|--------------------|------------|--------|-----------------------------------------|-------|------------|----------|----------------------|------|----------|
| From   | To  | L                  | R          | X      | Conductor Type                          | L     | R          | X        | $\lambda$            | MTTR | M        |
| Bus    | Bus | mi                 | pu/100 MVA |        |                                         | mi    | pu/100 MVA |          | 1/year               | hrs  | 1/year   |
| ACSR / |     |                    |            |        |                                         |       |            |          |                      |      |          |
| 1      | 2   | 3                  | 0.0026     | 0.0139 | GrosBeak/SSAC                           | 3.5   | 0.002594   | 0.013883 | 0.24                 | 16   | 547.5    |
| 1      | 3   | 55                 | 0.0546     | 0.2112 | ACSR / Flicker/SD                       | 51.82 | 0.052598   | 0.210832 | 0.51                 | 10   | 876      |
| 1      | 5   | 22                 | 0.0218     | 0.0845 | ACSR / Flicker/SD                       | 20.73 | 0.021109   | 0.084468 | 0.33                 | 10   | 876      |
| 2      | 4   | 33                 | 0.0328     | 0.1267 | ACSR / Flicker/SD                       | 31.8  | 0.031624   | 0.126595 | 0.39                 | 10   | 876      |
| 2      | 6   | 50                 | 0.0497     | 0.192  | ACSR / Flicker/SD                       | 47.1  | 0.047839   | 0.191688 | 0.48                 | 10   | 876      |
| 3      | 9   | 31                 | 0.0308     | 0.119  | ACSR / Flicker/SD                       | 29.2  | 0.029716   | 0.118947 | 0.38                 | 10   | 876      |
| 4      | 9   | 27                 | 0.0268     | 0.1037 | ACSR / Flicker/SD                       | 25.45 | 0.025907   | 0.103685 | 0.36                 | 10   | 876      |
| 5      | 10  | 23                 | 0.0228     | 0.0883 | ACSR / Flicker/SD                       | 21.67 | 0.022065   | 0.088296 | 0.34                 | 10   | 876      |
| ACSR / |     |                    |            |        |                                         |       |            |          |                      |      |          |
| 6      | 10  | 16                 | 0.0139     | 0.0605 | T2WaxWing                               | 15.1  | 0.013743   | 0.06045  | 0.33                 | 35   | 250.2857 |
| 7      | 8   | 16                 | 0.0159     | 0.0614 | ACSR / Flicker/SD                       | 15.07 | 0.01535    | 0.061414 | 0.3                  | 10   | 876      |
| 8      | 9   | 43                 | 0.0427     | 0.1651 | ACSR / Flicker/SD                       | 40.5  | 0.04117    | 0.164891 | 0.44                 | 10   | 876      |
| 8      | 10  | 43                 | 0.0427     | 0.1651 | ACSR / Flicker/SD                       | 40.5  | 0.04117    | 0.164891 | 0.44                 | 10   | 876      |
| 11     | 13  | 33                 | 0.0061     | 0.0476 | ACSR / Tern/OD                          | 33.6  | 0.00612    | 0.047607 | 0.4                  | 11   | 796.3636 |
| 11     | 14  | 29                 | 0.0054     | 0.0418 | ACSR / Tern/OD                          | 29.5  | 0.005375   | 0.041805 | 0.39                 | 11   | 796.3636 |
| 12     | 13  | 33                 | 0.0061     | 0.0476 | ACSR / Tern/OD                          | 33.6  | 0.00612    | 0.047607 | 0.4                  | 11   | 796.3636 |
| 12     | 23  | 67                 | 0.0124     | 0.0966 | ACSR / Tern/OD                          | 68.1  | 0.012341   | 0.096251 | 0.52                 | 11   | 796.3636 |
| 13     | 23  | 60                 | 0.0111     | 0.0865 | ACSR / Tern/OD                          | 61    | 0.011069   | 0.086272 | 0.49                 | 11   | 796.3636 |
| 14     | 16  | 27                 | 0.005      | 0.0389 | ACSR / Tern/OD                          | 27.4  | 0.004993   | 0.038832 | 0.38                 | 11   | 796.3636 |
| 15     | 16  | 12                 | 0.0022     | 0.0173 | ACSR / Tern/OD                          | 12.2  | 0.002225   | 0.017298 | 0.33                 | 11   | 796.3636 |
| 15     | 21  | 34                 | 0.0063     | 0.049  | ACSR / Tern/OD                          | 34.55 | 0.006292   | 0.048951 | 0.41                 | 11   | 796.3636 |
| 15     | 21  | 34                 | 0.0063     | 0.049  | ACSR / Tern/OD                          | 34.55 | 0.006292   | 0.048951 | 0.41                 | 11   | 796.3636 |
| 15     | 24  | 36                 | 0.0067     | 0.0519 | ACSR / Tern/OD                          | 36.6  | 0.006664   | 0.05185  | 0.41                 | 11   | 796.3636 |
| 16     | 17  | 18                 | 0.0033     | 0.0259 | ACSR / Tern/OD                          | 18.3  | 0.003337   | 0.025943 | 0.35                 | 11   | 796.3636 |
| 16     | 19  | 16                 | 0.003      | 0.0231 | ACSR / Tern/OD                          | 16.3  | 0.002973   | 0.023109 | 0.34                 | 11   | 796.3636 |
| ACSR / |     |                    |            |        |                                         |       |            |          |                      |      |          |
| 17     | 18  | 10                 | 0.0018     | 0.0144 | T2FlyCatcher                            | 10.55 | 0.001789   | 0.014399 | 0.32                 | 11   | 796.3636 |
| 17     | 22  | 73                 | 0.0135     | 0.1053 | ACSR / Tern/OD                          | 74.25 | 0.013423   | 0.110961 | 0.54                 | 11   | 796.3636 |
| 18     | 21  | 18                 | 0.0033     | 0.0259 | ACSR / Tern/OD                          | 18.3  | 0.003337   | 0.025943 | 0.35                 | 11   | 796.3636 |
| 18     | 21  | 18                 | 0.0033     | 0.0259 | ACSR / Tern/OD                          | 18.3  | 0.003337   | 0.025943 | 0.35                 | 11   | 796.3636 |
| 19     | 20  | 27.5               | 0.0051     | 0.0396 | ACSR / Tern/OD                          | 27.9  | 0.005084   | 0.03954  | 0.38                 | 11   | 796.3636 |
| 19     | 20  | 27.5               | 0.0051     | 0.0396 | ACSR / Tern/OD                          | 27.9  | 0.005084   | 0.03954  | 0.38                 | 11   | 796.3636 |
| 20     | 23  | 15                 | 0.0028     | 0.0216 | ACSR / Tern/OD                          | 15.2  | 0.002772   | 0.02155  | 0.34                 | 11   | 796.3636 |
| 20     | 23  | 15                 | 0.0028     | 0.0216 | ACSR / Tern/OD                          | 15.2  | 0.002772   | 0.02155  | 0.34                 | 11   | 796.3636 |
| 21     | 22  | 47                 | 0.0087     | 0.0678 | ACSR / Tern/OD                          | 47.8  | 0.008692   | 0.067671 | 0.45                 | 11   | 796.3636 |

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