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Stochastic Assessments of Voltage Sags due to Short Circuits in Electrical Networks

A thesis submitted to the University of Manchester Institute of Science and Technology for the degree of Doctor of Philosophy

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Abstract

Short duration voltage sags due to short circuits are generally considered as a serious power quality/electromagnetic compatibility problem. The main concern at the moment is the tripping of adjustable-speed drives. They can be extremely sensitive to voltage sags and their size makes mitigation methods expensive in investment, maintenance and additional losses. To decide about the suitability of mitigation methods, knowledge is needed about the expected number of sags as a function of magnitude, duration and other characteristics. This knowledge can be obtained through the use of power quality monitors or by means of stochastic prediction methods.

Theoretical studies as well as simple counting of events, have shown that a large fraction of the voltage sags experienced by a sensitive load originate in the transmission and sub-transmission systems. Therefore, special emphasis is needed on monitoring and stochastic assessment studies in transmission and sub-transmission systems. Monitoring has its limitations: the monitoring period can be several years if accurate results are required; the results of system changes are difficult to assess; extrapolation to sites not monitored could give unreliable results. Stochastic prediction techniques do not have these limitations: they give an accurate result immediately.

The main aim of this research has been the development of models and techniques for stochastic prediction of the number of voltage sags in the electrical network. In this thesis, a so-called "method of fault positions" is used to estimate the expected number of voltage sags as a function of their characteristics (magnitude, duration). This method proceeds as follows: for a large number of fault positions in the system under study, the magnitude and duration of the voltage sags at user positions are calculated by using circuit theory techniques. An expected number of fault occurrences for this fault position is determined by using basic power system reliability techniques. The results of all the fault positions are added to obtain the expected number of sags.

The method has been applied to a large transmission system and a distribution system, for which impedance data were obtained and failure rates were estimated. The results of the calculations have been presented in a number of ways: voltage sag tables showing the expected number of sags per year; maps showing the sag at one substation due to faults at many other locations; maps showing the sags at many substations due to a fault at a specific location, and maps showing the expected number of sags per year at all substations. The results are analysed and conclusions are drawn. The possible uses of these techniques are shown by applying them to the IEEE Reliability Test System. In the Reliability Test System, sensitivity analyses are carried out in order to analyse the influence of the system operation on the number of sags. Also, three-phase-faults, single-phase-to-ground and phase-to-phase faults are included. Apart from magnitude and duration, the jump in voltage phase-angle, and the three-phase imbalance are presented in the results.

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He also acknowledges his thanks to his little family, his wife, Maneeja, and his daughter Kawther, for their love, encouragement, understanding and prayers.

Finally, thanks and indebtedness to his parents and his family and his wife family for their unfailing support and prayer.

Declaration

No portion of the work referred to in this thesis has been submitted in support of an application for another degree or qualification of this or any other university or other institution of learning.

To
Maneeja and Kawther
with love

IN THE NAME OF GOD
THE COMPASSIONATE, THE MERCIFUL

List of publications

As a result of the work carried out under this project, the following papers have either been published or submitted for publication,

1. M. R. Qader, M. H. J. Bollen, R. N. Allan, *Stochastic Assessment of Voltage Dips in Large Transmission Networks Theory and case study,* paper excepted for CIGRE 1998, (electromagnetic compatibility; power quality aspects of energy efficient loads and dispersed generation).

2. M. R. Qader, M. H. J. Bollen, R. N. Allan, *Stochastic Prediction of Number of Voltage Sags in Large Transmission System,* paper submitted to IEEE Industrial and Commercial Power System, Edmonton, Canada, May 1998.

3. M. R. Qader, M. H. J. Bollen, R. N. Allan, *Two Methods for Stochastic Assessment of Voltage Sags,* International Conference on Electrical Distribution (CIRED) 1996, Birmingham.

4. M. R. Qader, M. H. J. Bollen, R. N. Allan, *Stochastic Prediction of Voltage Sags in the Reliability Test System,* Power Quality Association Conference, Europe Stockholm, Sweden, June 1997.

5. M. H. J. Bollen, G. Yalcinkaya, J. Pellis, M. R. Qader, *A Voltage Sag Study in a Large Industrial Distribution System,* Conference record of the IEEE industry Application Society, Annual Meeting, Santiago, California, USA, October 1996.

6. M. R. Qader, M. H. J. Bollen, R. N. Allan, *Voltage Sag Prediction and Simulation in the Reliability Test System,* 31st Universities Power Engineering Conference, September1997, UMIST, Manchester, U.K.

7. M. R. Qader, M. H. J. Bollen, *Stochastic Voltage Sag Prediction Technique,* 1995. 32st Universities Power Engineering Conference, September 1996, Herakloin, Create, Greece.

TABLE OF CONTENTS

Abstract.....i

Acknowledgements.....ii

Declaration.....iii

List of publications.....vi

Table of Contents.....vii

1 INTRODUCTION **1**

1.1 Power Quality 1

1.2 Overview of Disturbances 3

1.2.1 Harmonics 5

1.2.2 Interruptions 5

1.3 Voltage Sags 6

1.4 Objective of this Research 8

1.5 Structure of the Thesis 9

2 PROPERTIES OF VOLTAGE SAGS **12**

2.1 Causes of Voltage Sags 12

2.2 Equipment Sensitivity 13

2.2.1 Computers 15

2.2.2 Adjustable-speed drives 16

2.3 Voltage Sag Monitoring 18

2.4 Duration of Voltage Sags 26

2.5 Magnitude of Individual Sags 28

2.6 Non-Rectangular Voltage Sags 30

2.7 Phase-Angle Jumps 33

2.8 Three-Phase Voltage Imbalance 35

2.9 Frequency of Voltage Sags 37
2.9.1 Power Quality Monitor 38
2.9.2 Stochastic Assessment 39
2.9.3 Simple Assessment Technique 39
2.9.4 Presentation of the Results 40

3 STOCHASTIC ASSESSMENT OF VOLTAGE SAGS 44
3.1 Introduction 44
3.2 Stochastic Prediction Techniques 47
3.2.1 Method of Critical Distance 47
3.2.1.1 Application to the 400 kV system 50
3.2.2 Method of Fault Positions 57
3.3 Contour Maps 61
3.4 Voltage Sag Profiles 64
3.5 Concluding Remarks 66

4 FAULT ANALYSIS IN POWER SYSTEMS 67
4.1 Introduction 67
4.2 Symmetrical Components 70
4.2.1 General Principle 70
4.2.2 Theory 72
4.2.3 Sequence impedance and sequence networks 74
4.2.4 Sequence impedances of system elements 78
4.2.4.1 Synchronous machines 79
4.2.4.2 Overhead lines and cables 80
4.2.4.3 Transformers 81
4.3 Fault Current Calculations 83
4.3.1 Single line to ground fault 84
4.3.2 Line to line fault 85
4.3.3 Three phase fault 87
4.4 Network Modelling 89

4.5 Calculation of During-Fault Voltages 91
4.5.1 Short circuit faults 94
4.6 Calculation of the Sag at the Equipment Terminals 101
4.6.1 Transformer phase shifts [39,40] 102

5 TOPOLOGY AND EVALUATION OF THE STOCHASTIC PREDICTION OF VOLTAGE SAGS 106

5.1 Introduction 106
5.2 Power System Network Representation 107
5.2.1 Power Network Model 109
5.2.1.1 Connections 109
5.2.1.2 Normal Sections 109
5.2.1.3 Short Circuits 110
5.2.1.4 Buses 111
5.2.1.5 Loads 112
5.2.2 Bus Impedance Matrix representation (Z_{BUS}) 113
5.3 Bus Impedance Matrix Algorithm 114
5.3.1 Change in the network 117
5.4 Voltage Calculations 117
5.5 Program Implementation 118
5.6 Program Flow Diagram 119
5.7 Validation of the Techniques 122
5.7.1 Phase-Angle Jump 126
5.8 Conclusions 128

6 NUMBER OF VOLTAGE SAGS IN THE DISTRIBUTION SYSTEM 130

6.1 Introductions 130
6.2 System Descriptions 131
6.3 Simulation Results 133
6.3.1 Faults in the Distribution System 134

6.3.2 Faults in the Sub-Transmission System 135
6.3.3 Faults in the Transmission System 137
6.3.4 Cumulative Voltage Sag Table 139
6.4 System Modification 141
6.5 Conclusions 145

7 APPLICATION OF THE TECHNIQUES TO A LARGE TRANSMISSION SYSTEM 147
7.1 Introduction 147
7.2 System Description 149
7.3 During-Fault Voltages 152
7.4 Exposed area 157
7.5 Cumulative Voltage Sag Tables 162
7.6 Voltage Sag Maps 163
7.7 Fault Positions Method and Critical Distance Method 166
7.8 Phase-Angle Jump 177
7.9 Conclusions 180

8 VARIOUS STOCHASTIC ASSESSMENT STUDIES 181
8.1 Introduction 181
8.2 System Description 182
8.3 Simulation results 186
8.3.1 Base Case 186
8.3.2 Influence of Generation 193
8.3.3 Influence of Transformers 199
8.3.4 System Modification by Adding Generators 203
8.4 Other Characteristics of Voltage Sags 209
8.4.1 Imbalance Faults 209
8.4.2 Phase-Angle Jump 213
8.5 Conclusions 221

9 CONCLUSIONS 223

9.1 Introduction 223
9.2 Monitoring and stochastic prediction 224
9.3 Achievements and Contributions 225
9.4 Practical Applications 229
9.5 Suggestions for Future Work 230

References 232

Appendix 1: Changes in the Network 241

Appendix 2: Input and Output of the Software 247

CHAPTER 1

INTRODUCTION

1.1 Power Quality

Good power quality is not easy to define because its measure depends upon the need of the equipment which it is supplying; what is good power quality for a refrigerator motor may not be good enough for a personal computer. An accurate diagnosis of power quality problems is required before a significant reduction in power-related equipment downtime can be achieved [1]. Such a diagnosis is derived from understanding power quality and its effects.

Most electric power is delivered to the consumer as alternating current (AC). As generated, the voltage that drives the power is a sine wave, with a relatively constant magnitude and less than one percent harmonic distortion. Numerous load and system elements introduce variations in the magnitude and harmonic distortion to the voltage supplied to the consumer. Thus, the quality of the delivered voltage could be considered to be diminished from its ideal form and quality. This has been the case ever since electricity was first distributed. However, only recently has power quality become an issue. Apart from this "steady-state distribution", the quality of the delivered power is also diminished through

the occurrence of short-duration events. The most severe one, which has been recognised as a problem for a very long time, is the interruption of the supply. Milder events such as voltage sags and voltage surges are also a concern to some customers.

As the need for more information about power quality became apparent, Key [1] studied major computer-related power quality problems. The ultimate purpose of the method employed by him was to assist electronic equipment users in improving the quality of computer operation; it also introduced a systematic method of analysing power related computer problems. The approach is designed to guide the user towards the successful diagnosis and resolution of power quality-related computer problems. In a similar way, Cooper et. al. [2] focused on maximising reliability and mean time between computer failures and electronics equipment, via improving power quality.

Intermittent power disturbances, capable of disrupting electronic equipment are inherent to both commercial and industrial power systems. Any disruption causing downtime and financial loss, power-related or otherwise, is likely to precipitate a study to determine appropriate corrective action. Hughes et. al. [3] and Ludbrook [12] recommend a way to prevent and cure power quality problems: the approach evaluates how reliable power equipment operation can be achieved scientifically.

Characteristics or measures of poor power quality are not universally accepted, although there are some commonly-used terms to describe the anomalies that cause problems. They may be grouped into voltage disturbances in which the magnitude of the voltage deviates temporarily from the nominal and harmonic distortion, where the wave form departs from a pure sine wave.

1.2 Overview of Disturbances

A classification can approximately be made into two major groups, one concerning short-duration deviations in voltage (voltage disturbances) and the other related to harmonic distortion.

In the ideal situation, the voltage supplied to customer equipment and the resulting load currents are perfect sine waves. However, conditions are never ideal in practice, so these waveforms are always somewhat distorted. This deviation from the perfect sinusoid is usually expressed in terms of harmonics distortion of the voltage and current waveforms.

Voltage disturbances are divided into sags, swells, spikes and interruptions. Figure 1.1 illustrates these disturbances. Voltage sags, where the voltage magnitude is depressed for a period up to several seconds, represents the most common cause of complaint. They are caused by motor starting transients, switching operations or faults on the customers premises or in the electric utility system. A severe sag is likely to cause a sensitive computer, a microprocessor based control or an adjustable-speed drive to trip unless it is equipped with a backup power source. In an automatic processing plant (paper mill, steel plant,...etc) many pieces of equipment are important. Thus the sensitivity of the plant becomes equal to the sensitivity of the most sensitive item. A mild sag can therefore lead to the tripping of the whole plant, which can lead to high costs.

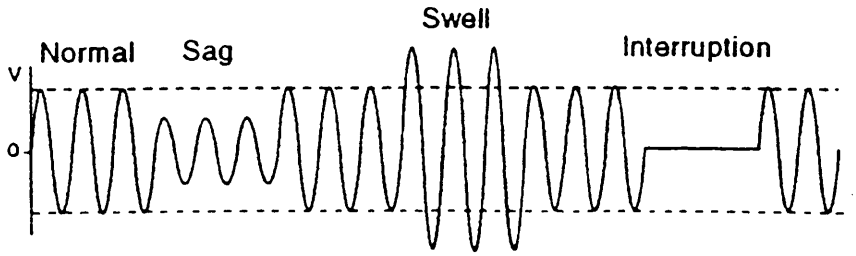


Figure 1.1 Voltage Sag, Swell and Interruption

Other common events that can cause power quality problems are voltage spikes or surges: high-frequency bursts of energy causing extremely high but brief over voltages. These can destroy electronic components.

The spike or swell shown in Figure 1.1 is due to capacitor switching on the distribution circuit. Capacitor switching causes numerous incidents in which sensitive adjustable speed drives trip. Even if the initial spike is not serious the capacitor switching could cause a voltage swell at the D.C bus which could result in the loss of the electronic load.

Industrial and large commercial consumers blame utilities for their losses, and in some cases, threaten to relocate their businesses to obtain better quality power. Since many normal switching operations are conducted by utilities and unavoidable faults in the power system cause some of the problems, many utilities are working with their customers to give them relief from disturbances.

1.2.1 Harmonics

Harmonic distortion is caused by non-linear loads and certain equipment in the utility network. Harmonic distortion is a steady-state phenomenon. When the current drawn by a load is not proportional to the applied voltage, the load is non-linear. The current wave of such a load consists of a fundamental frequency component and components with frequency equal to multiples of the fundamental frequency (harmonics).

The harmonic currents interact with the power system source impedance to create distortion in the voltage sine wave. Harmonics affect not only the nearby electronic loads but also traditional equipment such as transformers, regulators, capacitors and motors. When a distorted voltage is applied to such power equipment, additional losses and heating occur.

Harmonics in the power system can also interfere with communication systems, cause malfunction in control and protection systems, and introduce errors in power meters. The cost to the utility and the customers of such malfunctions includes not only the expense of assisting the situation but also that of lost productivity and the repair or replacement of damaged equipment.

Several strategies are available to reduce or limit the presence of harmonics in the power system. These strategies can be organised into two groups: modification to the power supply and the addition of harmonic filters. If the harmonics are not corrected at the source and are allowed to penetrate into the power system, the quality of the power diminishes.

1.2.2 Interruptions

An interruption is generally defined as a complete loss of voltage at the supply terminals. Interruptions are classified in different ways and according to their duration and cause.

EN 61000 [7] defines an interruption as a condition in which the voltage at the supply terminal is lower than 1% of the declared voltage. A supply interruption can be classified as:

- A long interruption (longer than 3 minutes) caused by a permanent fault.
- A short interruption (up to 3 minutes) caused by a transient fault.

IEEE Std. 1159-1995 [13] defines an interruption as the complete loss of voltage (<0.1 p.u) on one or more phase conductors for a time period of between 0.5 cycles and 3 seconds.

Interruptions are caused primarily by power system faults and equipment failure. During an interruption, the magnitude of the voltage is almost zero and there is no power supply to the equipment. Long interruptions or sustained interruptions result in equipment shut-down. Short interruptions or momentary interruptions cause equipment mal-operation or shut-down depending on the duration of the interruption. Momentary interruptions often cause electronic equipment such as computers, process control devices and adjustable speed drives to trip.

1.3 Voltage Sags

There are a number of different definitions of a voltage sag. The most commonly used definition is: a reduction in voltage with a duration of between half a cycle and several seconds [7]. This might be a functional distinction from a utility point of view but, from a customer point of view, all that matters is whether the equipment trips or not. Some use the term "voltage dip" instead of voltage sag; there is no difference in meaning and in this thesis the term voltage sag is used.

Some authors give a strict duration limit for voltage sags. Everything longer than for

example, one minute (others use one second) is then called an undervoltage. A lower limit of half a cycle is generally used, as for shorter duration phenomena it is hard to determine an rms voltage, which is the basic characteristic of a voltage sag or undervoltage.

Minor details regarding the duration notwithstanding, there is unanimous agreement that voltage sags are usually caused by faults, for example due to operation of circuit breakers or reclosers clearing the fault, or a sudden major load increase somewhere in the electrical system [6,7,8,9]. Although this may vary depending on the type of equipment and its ride-through capability, voltage sags start to become disruptive when the rms voltage drops to lower than 85%-90% [10]. Modern electronic power converters for adjustable speed drives (ASD's), programmable logic controllers (PLC's), and other electronic control equipment can be very sensitive to such voltage sags. Some drop out at about 85% of nominal voltage for sags as short as one half-cycle.

The sag activity actually observed at a particular location is dependent on many factors and must always be treated on a case-by-case basis. However, it is possible to identify some of the factors that influence sag activity and present example data. It is possible to design equipment which can ride-through most sags but this may be more expensive. Accurate estimates of sag magnitude and duration probabilities help system designers to specify appropriate equipment for critical processes. The ability to predict voltage sag characteristics offers opportunities to evaluate alternative configurations and prevent problems with optimum supply and ride-through specifications [6]. Moreover, the application of the method to power systems requires the consideration of a wide range of sensitivity studies. Therefore, the results of the interruption of load points or systems can be assessed to obtain optimal designs. Problems may be avoided by reducing the voltage sag frequency magnitude and duration.

Figure 1.2 shows a distribution network feeding a large industrial customer, "A". This particular customer is situated in a rural area and experiences about 3 sags per year which

are attributed to non-damaging faults on the extensive overhead line network. Figure 1.3 shows the expected rms voltage profile during a fault at point "F" on the 11 kV feeder at the 11 kV busbar it shares with customer "A".

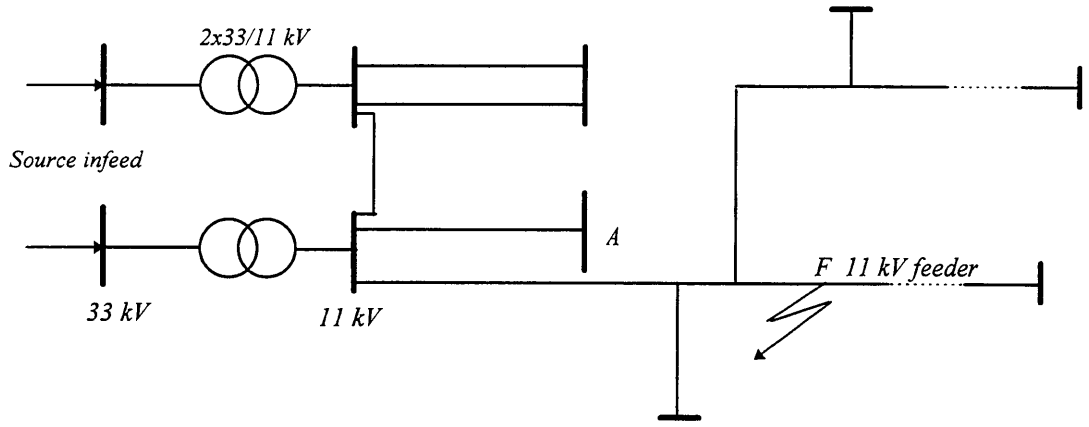


Figure 1.2 Example network supplying customer "A"

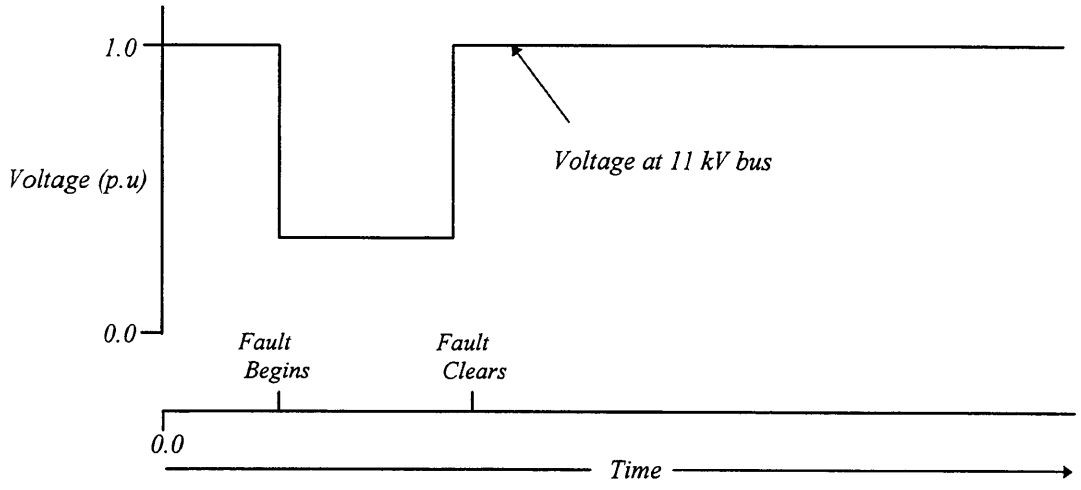


Figure 1.3 RMS Voltage profile at point "A"

1.4 Objective of this Research

As previously discussed, there is interest in the stochastic assessment of the number of voltage sags in the electric network. However, only a few methods have been developed to

calculate the number of voltage sags in the electrical network stochastically. Therefore, the aim of this research is to develop and apply an algorithm to stochastically predict the number of sags.

The scope of this research centres on the development of a technique to obtain the number of voltage sags stochastically for the electrical network.

The different steps undertaken in this project are as follows:

1- The development of a technique to calculate the voltage at a customer bus during and after the fault.
2 - The computer implementation of this technique.
3 - The development of a method for predicting the stochastic properties of the voltage sag in different transmission and distribution systems.
4 - The development of voltage sag tables, which give the expected number of voltage sags of various duration and magnitude at different customer locations within the system.
5 - The development of techniques illustrating the results of the stochastic prediction of the number of voltage sags.

1.5 Structure of the Thesis

Chapter 1, Introduction, giving an overview of power quality, introducing general concepts about voltage sags and proposing the objective and structure of this thesis.

Chapter 2, Properties of voltage sags, presenting the principle theory of voltage sags, summarising causes of voltage sags, their effect on customer equipment, and presentation of results of voltage sags studies.

Chapter 3, Stochastic assessment of voltage sags, presenting the main methods and techniques for the stochastic assessment of voltage sags, considering the state of the art and discussing two methods for the stochastic prediction of voltage sags.

Chapter 4, Fault analyses in power systems, presenting a detailed mathematical model of the current and voltage calculations during faults and discussing the method of the symmetrical components for the calculation of voltage and current in the electrical network.

Chapter 5, Topology and evaluation of the prediction of voltage sags, discussing the algorithms for the electrical network model, presenting the computation methods for the calculation of the number of voltage sags in the electrical network, and discussing the validation of these techniques.

Chapter 6, The number of voltage sags in the distribution system, applying the models and techniques introduced in this thesis to the existing distribution system, discussing the effect of the faults in the system on the number of voltage sags.

Chapter 7, Application of the techniques to the transmission system, applying the techniques to the existing 400 kV National Grid system (U.K), comparing and discussing the results of two stochastic predictions of voltage sags and presenting the results in different ways.

Chapter 8, Various stochastic assessment studies, presenting the methods described in the previous chapters using the IEEE Reliability Test System (RTS), conducting a sensitivity analysis showing the changes in system operation on the frequency of the sags and illustrating the influence of imbalanced faults on the number of voltage sags.

Chapter 9, Conclusions, summarising briefly the work undertaken in this thesis, presenting the aims and achievements and suggesting areas for future work.

CHAPTER 2

PROPERTIES OF VOLTAGE SAGS

2.1 Causes of Voltage Sags

To understand how a sag occurs, one must go back to the transmission or distribution system. Sags occur due to a fault on either one of these systems. Depending on which of the two systems the fault occurs, it can effect either a large or a relatively small number of customers. It is interesting that a fault on a neighbouring utility company, tied to the local utility through the national grid, can cause problems for customers of the local utility [6]. However, it is very unlikely that severe voltage sags occur due to faults on a neighbouring utility as the impedance of the transformer is relatively large [25]. Faults many miles from a sensitive process can be close enough to cause problems. Utility faults are caused by a variety of occurrences: typically the majority of faults are caused by lightning, wind, animals, trees, equipment failure and vehicles. Although there is much activity to prevent faults, it is not possible to eliminate them completely. The extent to which plant equipment is affected by a voltage sag or momentary interruption depends upon the magnitude and

duration of the sag or interruption and the ride-through capability of the equipment.

The use of looped transmission systems to feed large industrial customers has virtually eliminated transmission related momentary interruptions, although customers located on radial distribution feeders may still have problems with momentary interruptions. In general, however, a fault on the distribution system is somewhat different due to the higher impedance of the circuit; therefore the fault will usually only affect both the users on a substation and those on a different circuit. Expressed in percent of the source impedance, the feeder impedance per unit length is larger in distribution systems. Therefore, the exposed area is smaller and the fault influences less customers. A second effect is that the number of customers fed from a distribution substation is less than the number of customers fed from a transmission substation. Again the distribution system faults will influence less customers.

The amount of depression on the line depends upon the available fault current at that location and on the fault impedance. The farther away (electrically) a facility is from the fault, the smaller the effect seen.

The starting of large motors is accompanied by a voltage sag resulting from the inrush of current flowing through the system impedance. For a customer close to large motors, this can have a noticeable or even objectionable effect and may also cause tripping of sensitive equipment. Motor starting causes a long of voltage sag which can also lead to overheating of other motors in the system.

2.2 Equipment Sensitivity

For any system disturbance, the sensitivity of equipment can be characterised. Magnitude and duration are certainly very important, but other factors also influence the sensitivity of

equipment. Some disturbances arise from unavoidable events in the supply itself, such as faults or the starting of a large motor which causes a voltage sag in the network. Others, however, are the result of various uses of electricity which directly alter the waveform of the voltage, impose a particular pattern on its magnitude, or superimpose signalling voltages. For example, voltage imbalance is a condition in which the rms values of the phase voltages or the phase angles between consecutive phases are not equal [24]. References [9,24] illustrate that the individual phase voltage and phase-to-phase voltages are quite different during a single-line-to-ground and line-to-line fault condition on a transformer primary. Some single phase loads will be unaffected and other single phase loads may drop out, even though their sensitivities to voltage sags may be identical. The characteristics of imbalanced voltage sag are described in section 2.8.

Consequently, an examination of the sensitivity of equipment to voltage sags was undertaken. Different types of electrical equipment have different voltage sag withstand capability. Accordingly, it is not easy to define equipment sensitivity due to the many factors affecting the equipment during operations. Equipment sensitive to voltage sag include computing equipment, consumer electronics, adjustable-speed drives, process control, induction motors, synchronous motors, embedded generators, contactors, and some types of lighting. Given below is a description of the two most sensitive pieces of equipment: computers and adjustable speed drives.

The sensitivity of the equipment can be described through the so-called voltage tolerance curve, which plots voltage against duration, and gives the minimum voltage a piece of equipment can tolerate for a certain duration.

2.2.1 Computers

Computer manufacturers usually specify maximum momentary voltage deviations within which their equipment can operate without sustaining error or equipment damage. Computers, process-control equipment, consumer electronics devices, etc. are fed via a single-phase diode rectifier. The voltage sag leads to a drop in the DC voltage behind the rectifier. If the voltage drops too far, the electronics can no longer operate properly, leading to a controlled or non-controlled trip. The transient conditions are defined by amplitude and duration. Figure 2.1 shows an envelope of voltage tolerances that is representative of the present design goal of a cross section of the electronic equipment manufacturing industry. The characteristic was developed by Computer Business Equipment Manufacturing Association (CBEMA) [19]. It can be interpreted by saying that any voltage disturbance with a magnitude and duration between the two curves will not cause problems to computers, that is, the area between the two curves stands for the voltage tolerance. Note that the curve allows a complete loss of voltage for only 0.5 cycles (8.3ms) for a 60 Hz power supply, but permits 80% voltage for 0.5 seconds for a 60 Hz supply.

Different computers have different undervoltage tolerances. The undervoltage tolerance indicates which voltage sags lead to an equipment trip. The voltage tolerance of personal computers varies from 90%, 8 ms to 50%, 250 ms. A voltage tolerance of 50%, 250 ms means that the computer will trip if the supply voltage is below 50% for more than 250 ms. The average personal computer has a voltage tolerance of 50-70%, 60-160 ms.

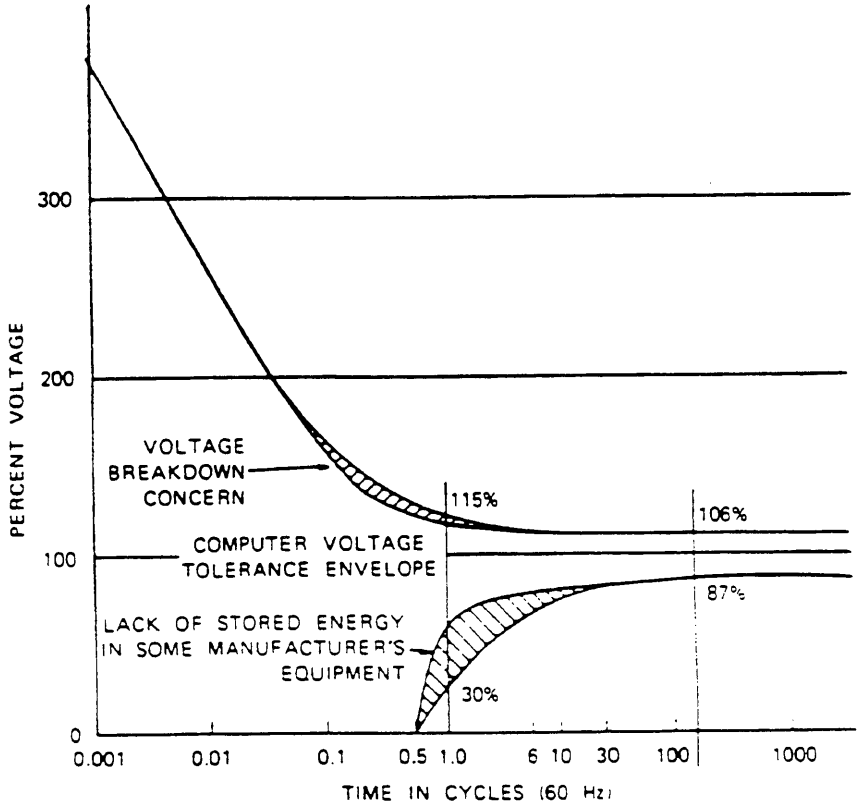


Figure 2.1 Typical computer voltage tolerance [19]

2.2.2 Adjustable-speed drives

Adjustable speed drives (ASDs) are used to control the speed, torque, acceleration, and direction of rotation of a motor. Unlike a constant speed system, the ASD permits the selection of an infinite number of speeds within its operating range. The two basic types of ASDs commonly used today are DC drives and AC drives. DC drives utilise a power converter to convert the fixed AC voltage to an adjustable DC output controlling a DC motor. Adjustable-frequency AC drives convert three-phase 50 Hz input power first to a fixed DC voltage and then to an adjustable frequency and amplitude voltage source for controlling the speed of the induction or synchronous AC motor.

Adjustable speed drives are highly complicated pieces of equipment which can trip due to a number of causes:

- the protection of the rectifier detects the sag as an irregularity and trips the drive to protect its components. The most commonly used method is under voltage protection on the DC bus. Other techniques used are: DC voltage ripple, AC voltage magnitude, delay in diode or thyristor current zero.
- the post-sag inrush current causes the overcurrent protection to trip.
- the electrical part of the drive functions during and after the sag but the mechanical load is too much for it to function properly. This again leads to a controlled or non-controlled trip.

Due to all this, ASDs are very sensitive to voltage sags; the voltage tolerance varies from 85%, 8 ms to 70%, 500 ms, with the majority in the lower most sensitive range.

Other equipment sensitivities classified by the magnitude and duration of voltage sag are summarised in Table 2.1.

Table 2.1 Summarised equipment sensitivity

Type of Equipment	Min Voltage (%)	Max Duration (ms)
Motor starter	50	40
Devices with PLC	50-90	8-20
ASD invertor	82	1.5
ASD rectifier	50-80	2-3
Process controller	70	<8
computerised numerical controlled lath	70	<8
DC drive controller	88	<8
contactors	50-60	20-30
Electromagnetic disconnecting switch	50	10
Electromagnetic relays and starters	50-60	15-40
Ferro-resonant transformer fed sensitive load	50	500
Medical electronic equipment-bed monitor	60	130

2.3 Voltage Sag Monitoring

The purpose of monitoring is to develop a statistically based understanding of power quality in the system. A lot of monitoring data is required to obtain good statistical results, but the cost limitation of monitors results in data having limited practical use. Nowadays, many utilities monitor their power quality automatically. The moment a disturbance occurs, the monitor records the depth, duration and time in addition to some other parameters.

Power quality monitoring results are also very important in analysing the frequency and severity of the voltage sags occurring in a plant. The monitoring results can be compared with historical data, if available, to determine whether certain transmission lines perform worse than others, and disturbance recording forms can be used by plant personnel to record any equipment disturbance which can be attributed to utility faults.

The obvious way to present and store a voltage disturbance is by showing the voltage as a

function of time; this method, however, does not give the most useful information.

Another way of illustrating the monitoring results is the rms (root means square value) variation. RMS variations are generally characterised by the rms value versus time or by the minimum magnitude of the voltage during the event versus the duration of the event.

The rms of an alternating voltage is a measure of the heating which results if the voltage is impressed across a resistive load. In other words, the rms value of an alternating voltage during any given time is the square root of the average value of the square of the voltage during that time. A power quality monitor samples the signals at approximately 100 times the fundamental frequency and temporarily stores these samples. An rms value is calculated every half-cycle or every cycle. When this value is below a certain value a window of the signal (i.e. the "event") is permanently stored.

Figure 2.2 illustrates the rms magnitude and the waveshape of the worst phase during a fault [20]. The monitoring result shows the faulted phase voltage before, during and after the fault. The voltage sag during the fault is clearly shown. The upper curve gives the half-cycle value of the rms voltage over a longer time window. In this curve, it is immediately apparent how severe the voltage sag is: about 25% magnitude for about 150 ms. Note that the recorded duration of the sag is 317 ms whilst the fault-clearing time is less than 200 ms. This is due to the small post-fault component. The total duration of the voltage sag is from the point at which the rms voltage drops below the threshold to where it rises above the threshold again. A small post-fault sag is illustrated clearly in Figure 2.2: it is due to the contribution of equipment in the system similar to motor re-acceleration. The post-fault sag lasts about 167 ms. The lower curve shows the instantaneous voltage. In most cases, all three phases are recorded.

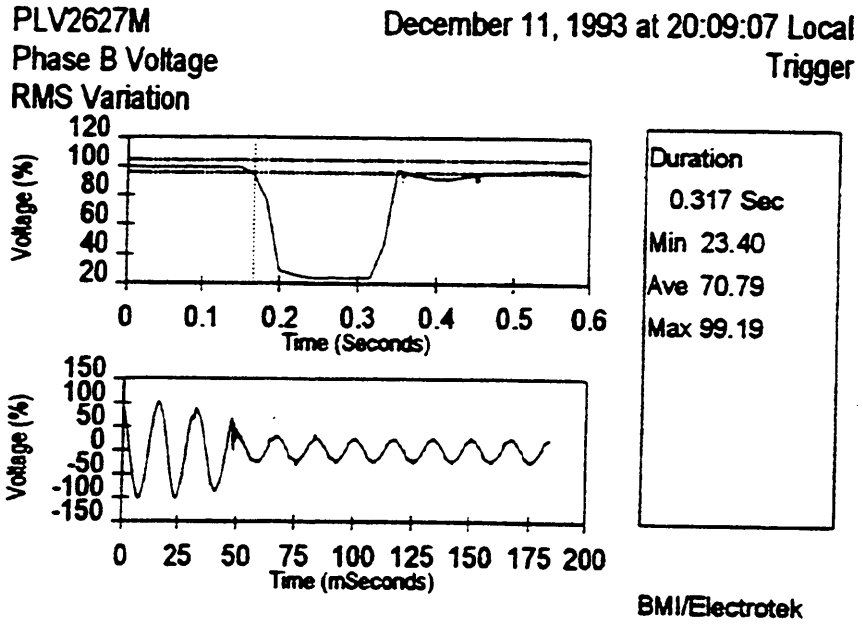


Figure 2.2 Voltage sag recorded [20]

The method of characterising the rms value versus time is suitable for looking at a single site and single events. However, when a whole system is involved or one site either customer or utility over a longer period of time, it may be preferable to look at a range of events. The range of events can be illustrated in many ways. Examples of events over a three month period on the paralleling bus for a multi-bank installation supplying a commercial office building are illustrated on a magnitude-duration plot with a CBEMA curve in Figure 2.3 [20]. The CBEMA curves (one for under voltage, one for overvoltage) are plotted on the same scale and short-duration overvoltages are also plotted in the graph. In this case, most sags are of very little depth.

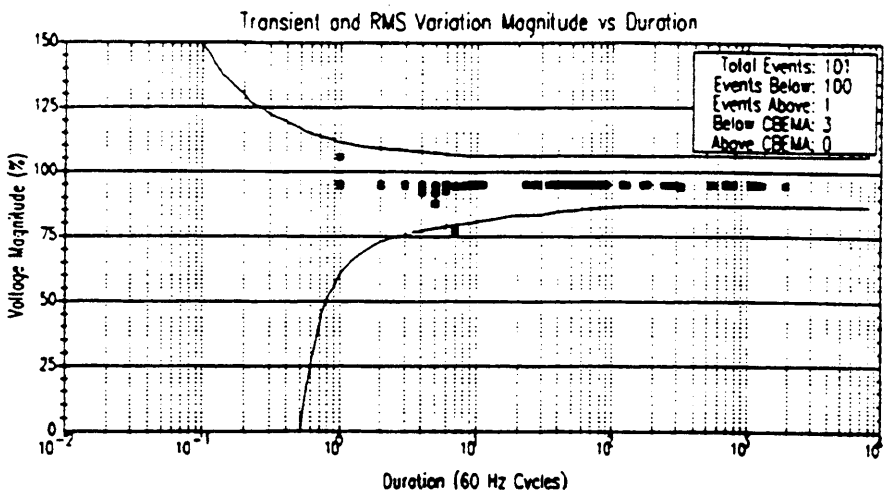


Figure 2.3 Three month magnitude-duration plot [12]

Another method for displaying the monitored results over a three month period is by using a three dimensional rms variation chart. The chart is shown in Figure 2.4 [20]: it can be seen that the majority of the sags are of short duration and little depth. Also, the chart clearly shows how many sags of a certain magnitude and duration have occurred.

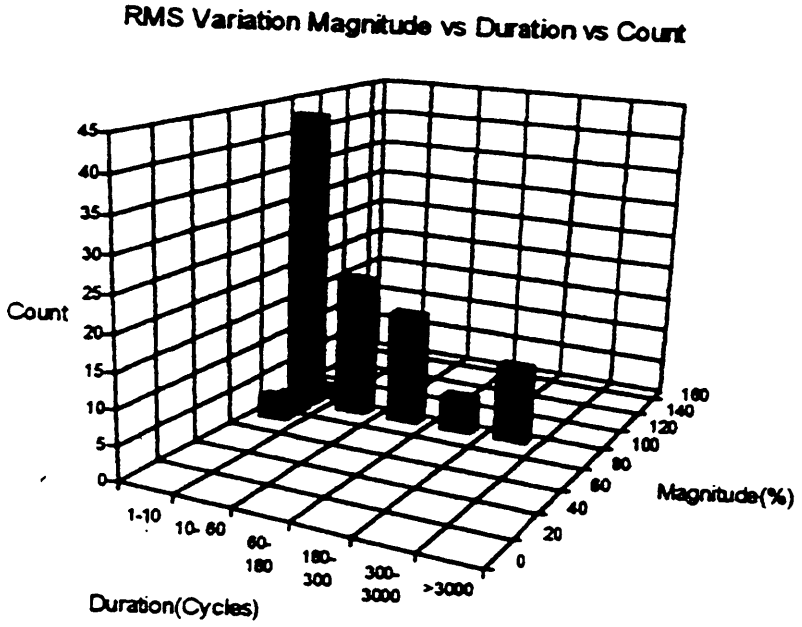


Figure 2.4 Three dimensional rms variation chart [20]

A power quality monitoring survey has put much effort into ensuring that the locations chosen for the monitors comprise a statistically valid data set [21]. However, with a limited number of monitors, the subsequent random selection of sites results in data having some diversity. To characterise the penetration of a power quality disturbance, such as a voltage sag, through the distribution system, monitors are located at a number of different levels throughout the system. Figure 2.5 illustrates a situation in which the position of the monitors was purposely not chosen at random [21]. Hence, a monitor at the 415 V level was placed on a feeder which connected it directly to a monitor at the 11 kV level, and so on, up to the 132 kV level. This allowed analysis of the penetration of voltage disturbances into the distribution system.

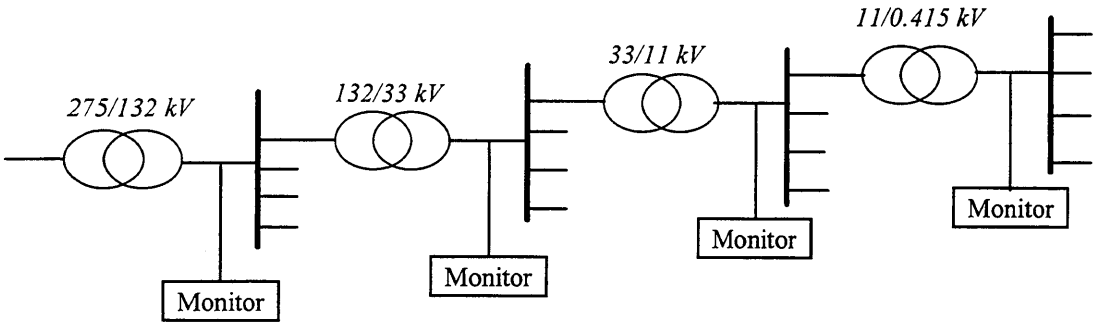


Figure 2.5 Connections of monitoring position [21]

There are numerous techniques to illustrate the monitoring results of power quality. For example, Figure 2.6 gives the sag activity as a function of the time of day [22] whereas Figure 2.7 shows sag activity as function of the time of year [22]. The data for Figure 2.7 comes from a U.S. power quality survey [5].

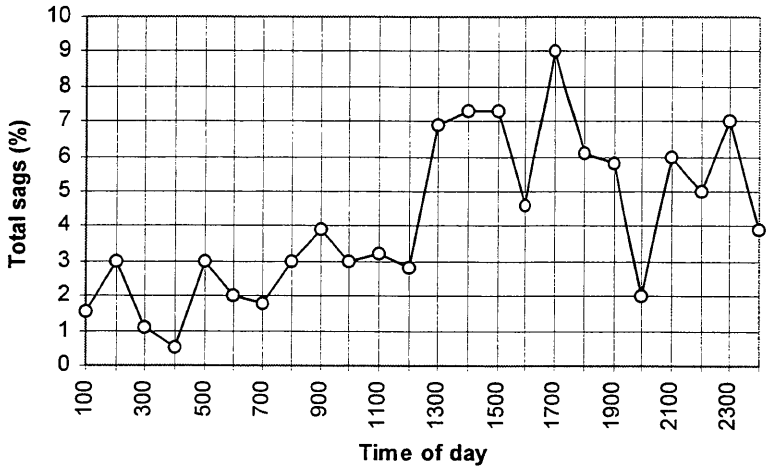


Figure 2.6 Sag activity as a function of time of day [10]

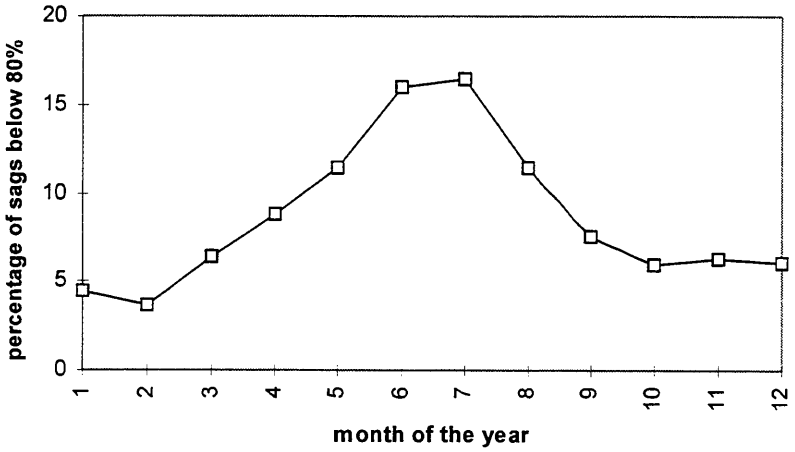


Figure 2.7 Sag activity as function of time of year

Table 2.2 shows the voltage sag and short duration overvoltage [5]; this table provides detailed rms voltage versus duration information over 32,225 days of monitoring at 112 locations. Actual recorded numbers of events in each voltage/duration category are shown. Note that the numbers in this table have to be divided by 88.3 to get the average number of events per year.

Table 2.3 gives the number of sags of different duration and depth from a UK survey [29]. Table 2.4 gives, in a comparable format, the results of one of the American surveys [5]. Each entry gives the average number of sags per site which exceed a certain magnitude and duration. This form of table can be used to understand the number of voltage sags a piece of equipment may experience. For example, equipment in the UK can experience about 6 sags below 70% for a duration of longer than 500 ms.

At the present time, a large number of monitoring surveys are in progress. Reference [28] shows some of the monitoring data gathered from the National Power Laboratory (NPL), Canadian Electrical Association (CEA) and Electrical Power Research Institute (EPRI); it also contains a detailed analysis of monitor capabilities.

Table 2.2 RMS events (rms voltage versus duration) [5]

rms Voltage	0	1cy	2cy	3cy	4cy	5cy	6cy	10cy	20cy	5s	1s	2s	5s	10s	30s	60s	120s
144	0	2	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0
138	0	2	4	9	4	1	4	1	1	0	2	1	0	0	0	0	2
132	6	30	10	29	21	4	17	39	14	7	11	3	2	5	2	4	22
130	11	13	4	9	1	1	6	2	5	4	4	3	1	11	3	8	298
127	29	102	16	60	45	16	118	190	131	331	557	905	694	2956	929	1247	5812
120																	
None																	
104	261	985	330	973	947	300	3235	4263	1826	1960	1313	5330	421	232	18	3	2
100	41	339	147	809	461	61	232	88	41	46	28	435	171	320	67	32	20
96	41	145	36	249	559	169	323	167	56	40	24	8	0	0	0	0	1
90	15	85	28	107	118	27	104	43	24	17	10	4	1	1	0	0	1
84	15	45	15	44	41	16	63	23	14	12	7	3	0	0	0	0	0
78	10	36	20	99	112	24	140	56	35	43	23	6	0	0	0	0	1
60	1	42	15	75	56	18	108	54	39	46	13	9	11	4	1	1	1
10	9	1	1	3	7	5	30	73	80	120	166	301	66	149	57	36	257
0																	

Duration in Cycles or Seconds

Table 2.3 Monitoring results for UK

	Durations (sec)					
Voltage (%)	0.01-0.1	0.1-0.5	0.5-1	1-3	3-20	>20
70-87%	16.7	14.3	1.5	0.5	0.1	-
50-70%	6.1	6.1	0.7	0.1	0.1	-
8-50%	0.1	0.8	0.4	0.1	-	1.1
0%	0.1	0.2	0.2	0.3	0.4	-

Table 2.4 Monitoring Results for the US

	Durations (sec)					
Voltage (%)	0.01-0.1	0.1-0.5	0.5-1	1-5	5-30	>30
70-87%	82	118	24	81	13	1.7
50-70%	7.9	1.4	0.6	0.4	-	0.0
8-50%	3.6	1.1	0.5	0.2	0.2	0.0
0-8%	0.6	1.7	1.4	5.3	2.4	4.0

2.4 Duration of Voltage Sags

The duration of a voltage sag is the time period when the voltage is below a given value. There are two ways of defining the duration of a voltage sag: firstly, by looking at a voltage sag as a voltage depression due to a short-circuit fault, one can define the voltage sag duration as the fault-clearing time. This is a very useful definition for stochastic assessment studies and other system simulations. However, for a power quality monitor, another definition is needed. The method used is that of the rms voltage calculated, for example, every cycle. The voltage sag duration is now defined as the number of cycles during which the rms voltage value is below a certain threshold. In Figure 2.2 a threshold of 90% has been used to determine the sag duration. Typical values used by power quality monitors are 90% and 95%. An example of post-fault sag is shown in Figure 2.8 [16,17]. This figure is calculated in a 10 kV local distribution system due to a three phase short circuit. Large motor loads and generators can cause a long post-fault sag [16,17,18]. The fault clearing time of fault clearing devices is the minimum duration of a voltage sag. The clearing times for some commonly used devices are listed below in Table 2.5 [6]. The minimum value is determined by the circuit breaker, and the range due to the relay setting. For the fuse the range is solely due to variations in the short circuit current.

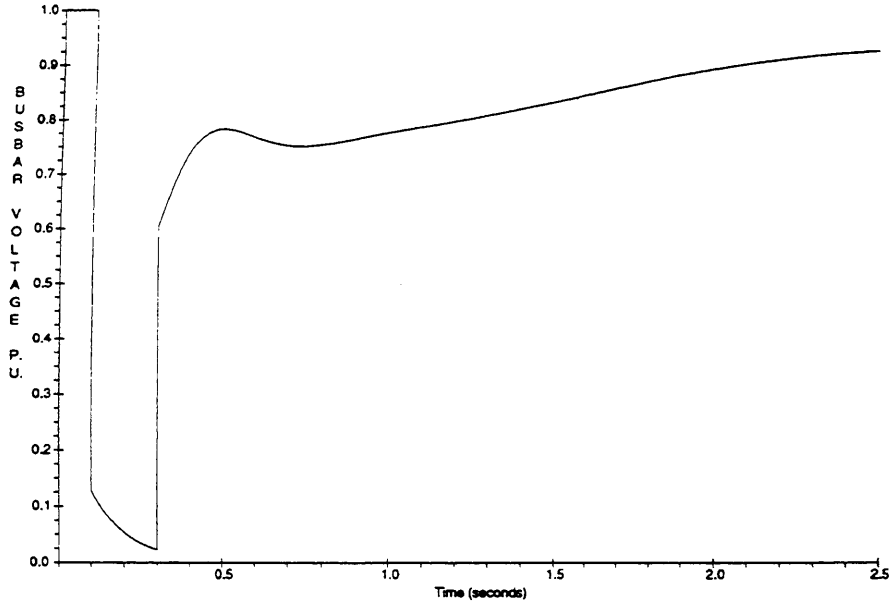


Figure 2.8 Voltage sag at the plants busbar

Table 2.5 Typical clearing time [6]

Type of Fault Clearing Device	Clearing Time in Cycles		Possible Number of Retries
	Typical Minimum	Typical Time Delay	
Expulsion Fuse	0.5	0.5 to 60	None
Current Limit Fuse	0.25 or less	0.25 to 6	None
Electronic Recloser	3	1 to 30	0 to 4
Oil Circuit Breaker	3	1 to 30	0 to 4
SF6 or Vacum Breaker	3	1 to 60	0 to 4

There are more faults on the system than simply those cleared by the protection. Lightning, in particular, is said to cause faults which will extinguish within a few cycles, before the protection is able to clear the fault. From the monitoring results shown in section 2.3, it might be possible to estimate how many self-extinguishing faults there are. A sag lasting less than two cycles is probably a self-extinguishing fault. It is very difficult to estimate how common self-extinguishing faults with a long duration are, but the percentage is

probably small. Another reason for the accuracy of short-duration sags related to lightning is that much of the impulse-suppression equipment employed in the distribution system protects it by momentarily shorting the line.

2.5 Magnitude of Individual Sags

Predicting the magnitude of a voltage sag from a specific fault is essential in the prediction process. It requires the knowledge of network impedances (resistance and reactance of the positive, negative, and zero sequence components), fault impedance, and fault location relative to the sensitive load [6]. It is also necessary to know the pre-sag voltage.

To calculate the magnitude of a sag due to a fault somewhere in a radial system, consider the simple radial system shown in Figure 2.9. The-point-of-common-coupling (PCC) between the fault and the load must be found [25]. The PCC is the point on the network where the path from the source to the load starts to branch off the path from the source to the fault. In a lightly meshed network, it is also sometimes possible to recognise a point-of-common-coupling. In Figure 2.9, Z_1 is the source impedance at the PCC and Z_2 is the impedance between the PCC and fault position. A three-phase fault occurs at the position shown. The positive sequence network is required to calculate the fault voltage. From the equivalent sequence network shown in Figure 2.10, the positive sequence voltage at the load or PCC is

$$\overline{V} = \overline{I}_f \overline{Z}_2 \tag{2.1}$$

Assuming the load current is zero, the pre-fault voltage is equal to 1 pu. Hence, the per unit voltage sag at the load is:

$$\bar{V}_{sag} = \frac{\bar{Z}_2}{\bar{Z}_2 + \bar{Z}_1} \tag{2.2}$$

The same technique can be used to calculate voltage sags for imbalanced faults. Negative and zero sequence impedances must be used, thus creating slightly more difficult calculations.

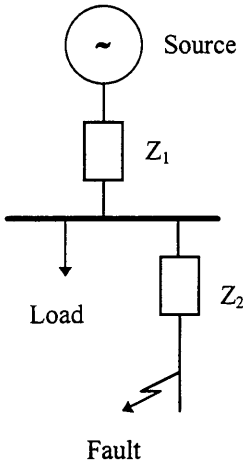


Figure 2.9 Equivalent circuit of radial feeder system

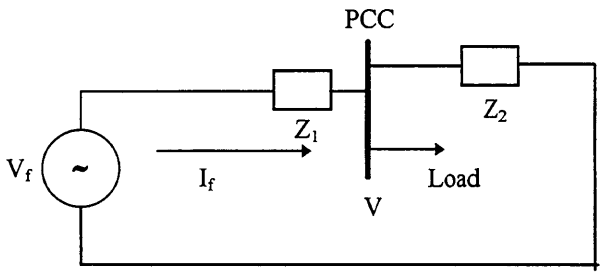


Figure 2.10 Sequence network for a three-phase fault

Complex transmission networks supplying sensitive loads require a computer model which allows the user to predict voltage sag magnitude at the sensitive load for any type of fault anywhere in the network. A short circuit in the electric system will drop the voltage at the fault position to zero. In the electrical neighbourhood of the fault, the other loads will also

see a drop in voltage. The further away the load is from a fault, the less the drop in voltage. The higher the number of faults occurring in the system, the more the influence is on sensitive loads. The details of the voltage calculation for complex networks, which has been adopted in this project, is described in chapter 4.

2.6 Non-Rectangular Voltage Sags

Most studies assume that rms sag magnitude versus time is rectangular. This assumption is not true when the customer load consists of large motors, such as induction machines, synchronous motors and generators. Examples are chemical plants, steel plants and residential areas where air conditioners are popular.

Figure 2.11 shows the rms shape of the voltage sag at a plant busbar located in the 10 kV local distribution system due to a three phase short circuit close to the point-of-common-coupling. This figure was calculated by a transient stability program, IPSA (which employs a simplified induction motor model) [17].

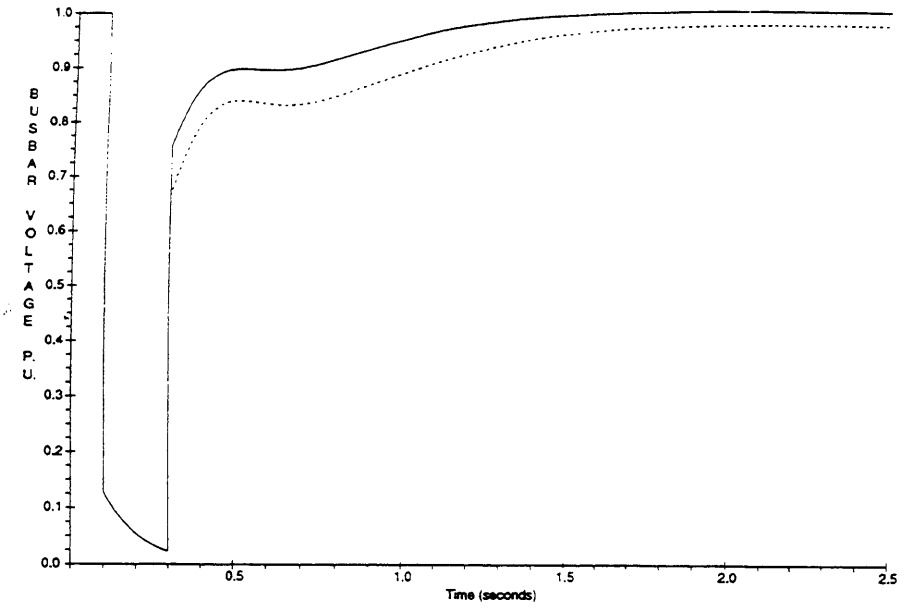


Figure 2.11 Voltage sag at the plant busbar

The shape of the voltage sag is due to a slowing down of the machines during their the sag and re-acceleration when the system fault is cleared [16].This acceleration after fault-clearing may cause an extended post-fault voltage sag. Long post-fault sags, which occur occasionally, have magnitudes between 60% and 90%. The post-fault voltage sag can be especially severe in a system with redundancy through parallel operation. The protection removes the faulted feeder, thus making the supply weaker. The inrush current to the most affected motors has to be supplied through this weakened supply. Severe post-fault voltage sags can cause tripping of the equipment. The motors operate as a generator for the first few cycles during the fault and contribute current to the fault, which results in a non-zero voltage during the fault [16].

Figure 2.12 illustrates a measured voltage sag with a considerable post-fault component [21]. The similarity with Figure 2.11 suggests that there was a large induction motor load somewhere near the fault position. It also becomes clear from the measured voltage that the voltage sags again after the initial recovery. The post-fault motor current contains two components, a large short-duration current immediately after fault clearing which rebuilds air gap flux, and a smaller but long-duration current during the actual acceleration of the motor [17].

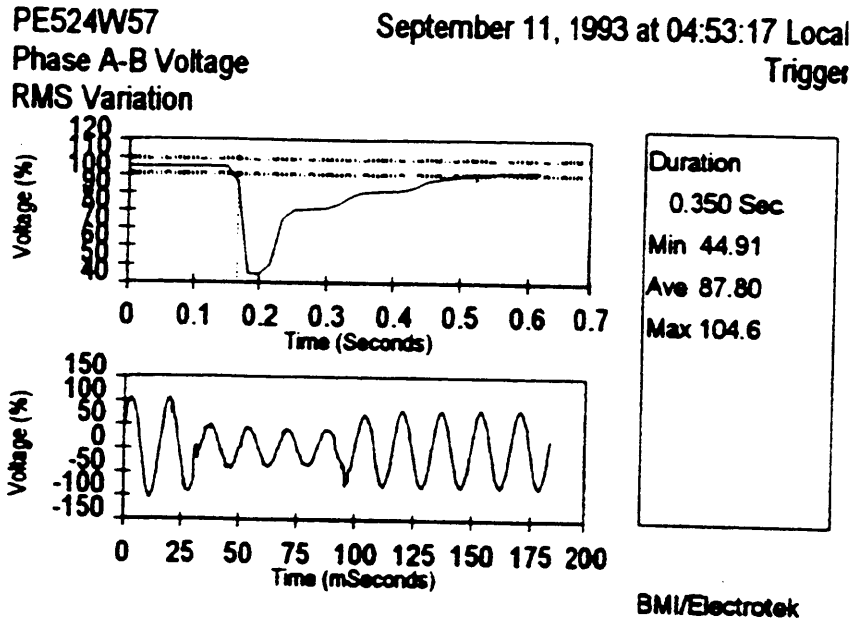


Figure 2.12 Contains a typical waveform and rms plot showing motor influence [20]

2.7 Phase-Angle Jumps

Phase-angle-jumps associated with voltage sags have recently been recognised as a common phenomenon [24,26]. A phase-angle jump is produced if a three phase fault occurs at a feeder that has a different X/R ratio than that of the source. In the case of the X/R ratio being equal, there is no phase-angle jump in the voltage. To explain the phase-angle jump, recall equation (2.2) where,

$$\overline{V}_{sag} = \frac{\overline{Z}_2}{\overline{Z}_2 + \overline{Z}_1}$$

Let $\overline{Z}_1 = R_1 + jX_1$ and $\overline{Z}_2 = R_2 + jX_2$

Therefore,

$$\overline{V}_{sag} = \frac{(R_2^2 + X_2^2) + (R_2R_1 + X_2X_1) + j(R_1X_2 - R_2X_1)}{(R_2 + R_1)^2 + (X_2 + X_1)^2} \tag{2.3}$$

Then, the phase-angle jump of the PCC can be calculated as follows:

$$\phi = \arctan\frac{(R_1X_2 - R_2X_1)}{(R_2R_1 + X_2X_2) + (R_2^2 + X_2^2)} \tag{2.4}$$

Consequently, from equation (2.4) it can be seen that ϕ is zero when the X/R ratios of $\overline{Z}_1$ and $\overline{Z}_2$ are equal. From equation (2.4) it can also be seen that ϕ is negative for three phase faults, since the X/R ratio of the positive sequence of the source is smaller than that

of the line.

The majority of the faults in a power system are imbalanced faults (single-phase or phase-to-phase). Phase-jumps are almost always produced by an imbalanced fault. The phase-angle jumps in a faulted phase are again determined by the X/R ratio of the source and the faulted branch. Moreover, the calculations of a phase-angle jump during an imbalanced fault are more complicated. The voltage equation which is described in chapters 4 and 5, can be used to determined the phase-angle jump in the case of single-phase and phase-to-phase faults.

Additional phase-angle jumps are introduced when the voltage sags caused by imbalanced faults are transferred through a transformer [9,24]. The size of the additional phase-angle jump depends on the winding connection of the transformer and the zero sequence impedance. Transformers with a winding at the primary and the secondary side are of the same connection, the relationships between voltages at both sides are the same, this means that the transformer will not introduce additional phase jumps. However, if the transformer windings are of a different configuration, phase-angle jumps of up to tens of degrees are possible [26].

To explain how a phase-angle jump is introduced by a wye-delta grounded transformer, consider the transformer shown in Figure 2.13A and a single-line-to-ground fault on the primary side of the transformer in phase A. The phase-to-ground voltage in the primary side of phase A will drop, the other two phase (B and C) voltages will not sense any changes, and there will be no phase-angle jumps in any phases in the primary side (Figure 2.13B). The secondary side will sense a drop in the voltage in phases (B and C) and no change in phase A (Figure 2.13B). There will be phase-angle jumps in phases B and C. The details before and after the transformers are of phase-angle jump changing described in chapter 4.6.1.

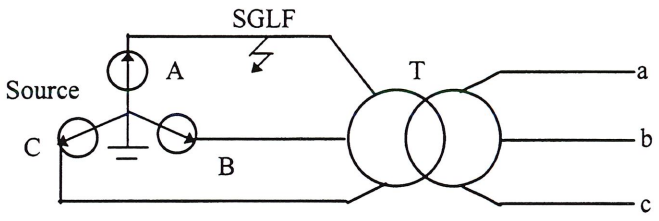


Figure 2.13A Transformer connection

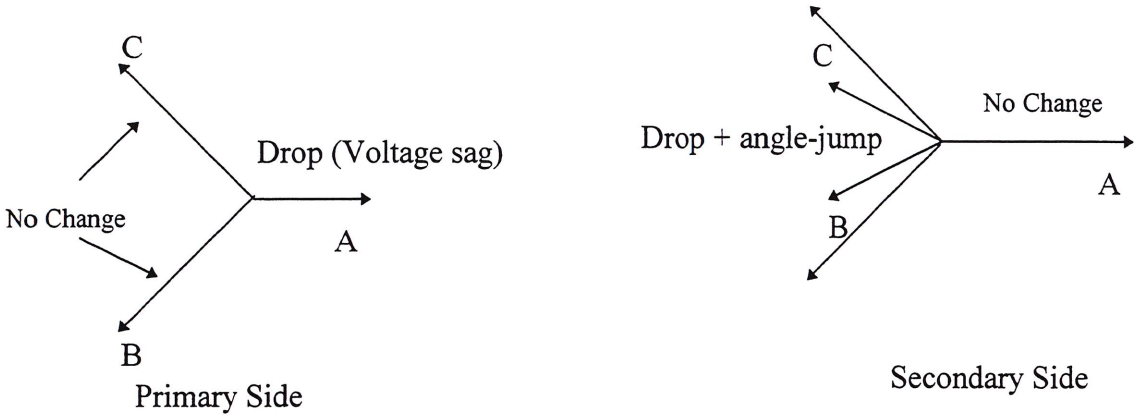


Figure 2.13B Phase-angle jump in the primary and secondary side of the transformer

2.8 Three-Phase Voltage Imbalance

When an unsymmetrical fault occurs on a system which was previously balanced, the current and voltage becomes imbalanced because the phases have become unsymmetrical. The ratio of either the negative or zero-sequence component to the positive sequence component can be used to specify the imbalance. Voltage imbalance is sometimes defined as the maximum deviation from the average of the three-phase voltages or currents divided by the average of the three-phase voltages or currents.

Severe voltage imbalance can result from single-phasing conditions. An imbalanced fault can cause severe voltage imbalance by generating a voltage sag in one or two phases of the system. Therefore, imbalanced three phase voltages can accompany voltage sags. Voltage sags due to an unsymmetrical fault can cause the system to be imbalanced in magnitude as well as in the angle displacement between the phases (phase-angle jump) [24,25]. Reference [24] classifies the imbalance of three phase voltages accompanied with voltage sags into four categories. The four types of sag are denoted as type A, type B, type C and type D. Phasor diagrams for the four types of voltage sag are shown in Figure 2.14; dotted lines indicate the pre-fault voltage phasor and solid lines indicate sags with a magnitude of 50%. For sag type A, all three phases drop by the same amount in magnitude, which can be due to three-phase faults. For sag type B, only one phase drops in magnitude, due to the single-phase-to-ground faults at the same voltage level or after a wye-wye transformer. Voltage sags of type B are experienced by phase-to-ground loads. For sag type C, two phases drop in magnitude and change in phase angle. Voltage sags of type C are due to phase-to-phase faults and single-line-to-ground faults at higher voltage levels. Two phases will experience a phase-angle jump of up to 60 degrees and a change in magnitude of up to 50%. The third phase remains the same. For sag type D, again two phases drop in magnitude and change in phase angle; the third phase only drops in magnitude. Voltage sag of type D is due to phase-to-phase faults and single-line-to-ground faults at higher voltage levels. Two phases will experience a phase-angle jump of up to 30 degrees and a drop in magnitude down to 88%. The third phase drops in magnitude to zero, without phase-angle jumps.

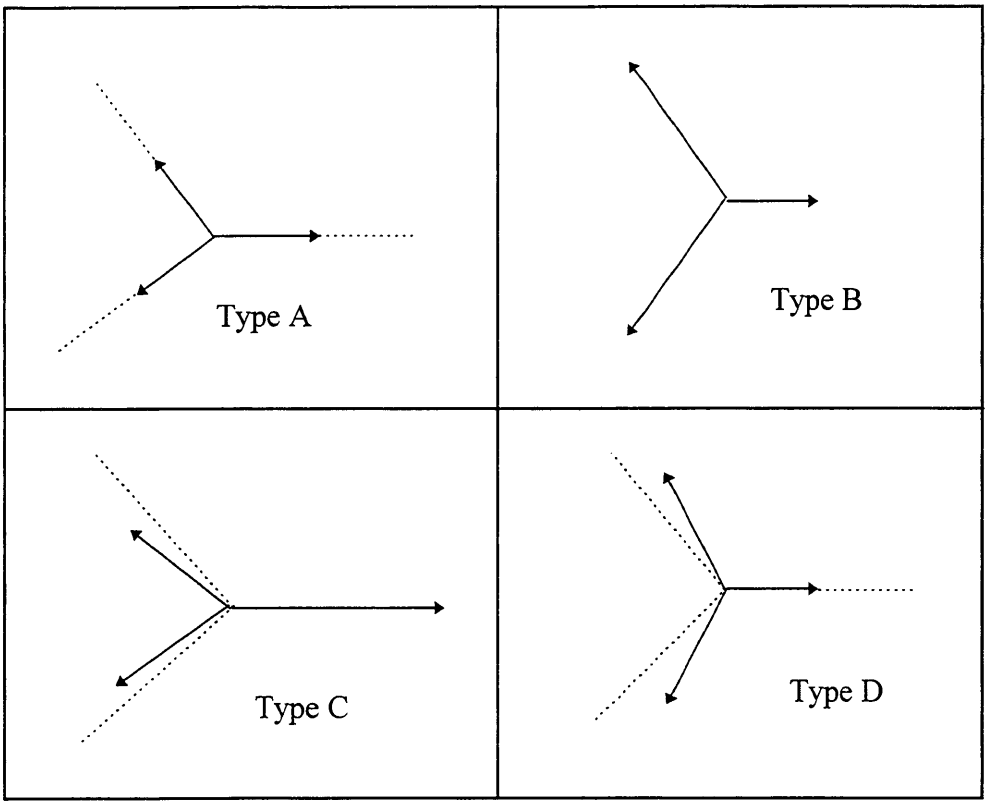


Figure 2.14 Phasor diagram of imbalance voltage

2.9 Frequency of Voltage Sags

There are a number of ways to determine the frequency of voltage sags. One can use a power quality monitor to simply count the number of sags: this is a very commonly used method. An alternative is to use an accurate network impedance model and component reliability data. This will lead to stochastic predictions similar in nature to those obtained in power system reliability evaluation studies [6]. A third option is to use simple assessment techniques leading to an estimation of the expected sag frequency [25].

Reliability of the utility supply usually refers to the number of times or amount of time end-users are without any power for an extended period of time. For stochastic assessment of voltage sags one would be interested in the number of events. The most important reliability data required for this is the failure rate of the equipment in the system, for example, transformers, and lines. The network impedance model in this study needs resistance and reactance of positive negative, and zero sequence components. It is also necessary to know the transformer connections and the pre-sag voltage.

2.9.1 Power Quality Monitor

More and more utilities monitor their power quality automatically. The moment a voltage sag occurs, the monitor records and stores the magnitude, duration and time of occurrence. The monitors automatically record every voltage sag at a certain position. Obtaining accurate information on the expected number of sags at a specific site takes several years or longer, depending on the accuracy of the information required. Nevertheless, monitoring can give some indication about the quality of the supply. Also, site monitoring can give very important information about events in the system and can establish links between equipment trips and system disturbances.

The main aim of monitoring is to develop a statistically-based understanding of power quality in the system. Many data are required in order to obtain good statistical results which requires a prolonged time of monitoring. The cost of monitors limits their use. Also, the resulting data is of limited practical use. However, monitoring does give exact statistical information about voltage sags. The method of monitoring and the presentation of the results has already been discussed in section 2.3.

2.9.2 Stochastic Assessment

Stochastic assessment methods do not have the limitations of power quality monitoring and form an important addition to voltage sag monitoring. These prediction methods are based on techniques also used for power system reliability analysis.

The stochastic assessment technique which was developed in this project consists of three steps:

- Calculating the expected number of short circuit faults.
- Determining voltage sag characteristics, for example, duration and magnitude for each fault situation.
- Combining the output of the above two steps to obtain the expected number, duration and magnitude of sags for specific sites.

The stochastic method can be used to calculate the expected number of short circuit faults for a given fault situation. For first order events, for example short circuits on an otherwise undisturbed system, this follows directly from a knowledge of the failure rates of the system components. This method is discussed in detail in chapter 3.

2.9.3 Simple Assessment Technique

Faults can occur anywhere in the power system. However, only faults in a limited part of the power system lead to a noticeable reduction in voltage at a specific site. The method of critical distance (L_{crit}), proposed by Bollen [25], may be used to find the "exposed area". Any faults within the exposed area will lead to a drop in voltage. For a given point-of-common-coupling, the critical distance gives the maximum (electrical) distance at which a fault causes the voltage to sag below a given value. The expected number of sags can be

calculated by simply adding the expected number of faults within the exposed area. This method is discussed in detail in chapter 3.

The additional advantage of this method is that it provides a rapid tool to estimate the expected number of critical voltage sags at a given customer location. Furthermore, it gives a better understanding of the relationship between voltage sags and the power system structure. This will be important when incorporating power quality concerns in the design of power systems.

2.9.4 Presentation of the Results

Currently, the voltage sag performance of a supply is usually presented in the form of a table showing the expected number of sags that exceed a certain duration and magnitude. Such a table is adopted here to present the results of the stochastic assessment of voltage sags.

To explain how the stochastic voltage sags are presented, Table 2.6 shows a grid of nine sag magnitude ranges arranged in rows and five sag duration ranges arranged in columns [27]. The combination of nine rows and five columns produces a total of 45 magnitude/duration bins. Each measured or predicted sag will have a magnitude and duration that will fit in only one of the 45 bins. The number of bins may vary depending on the co-ordination needs of a particular case.

Table 2.6 Count of event in each bin [15]

	Time Bin in Seconds				
Magnitude Bin	0.0<0.2	0.2<0.4	0.4<0.6	0.6<0.8	>=0.8
>80-90%	1	1	1	1	1
>70-80%	1	1	1	1	1
>60-70%	1	1	1	1	1
>50-60%	1	1	1	1	1
>40-50%	1	1	1	1	1
>30-40%	1	1	1	1	1
>20-30%	1	1	1	1	1
>10-20%	1	1	1	1	1
0-10%	1	1	1	1	1

For example, assume each of the 45 bins has one sag per unit of time, typically one year [27]. Table 2.6 shows this sag per year in each of the 45 bins: this means there are 45 sags per year and the characteristic of each sag fits into a unique bin.

Table 2.7 shows the cumulative number of sag events that are worse than or equal to each magnitude and duration. The row and column headings only show single values instead of ranges. For example, there are 15 sags in the (50% magnitude, 0.4 second) entry in the table. This means that 15 sags will have a magnitude less than or equal to 50% and a duration longer than 0.4 seconds. Therefore, Table 2.7 can be converted into a set of contour lines similar to the elevation contour of the lines on a graphic map shown in Figure 2.15 [27]. The method of contour lines is described in chapter 3.

Table 2.7 Sum of events equal to each magnitude and duration [15]

	Time in Seconds				
Magnitude	0.0	0.2	0.4	0.6	0.8
90%	45	36	27	18	9
80%	40	32	24	16	8
70%	35	28	21	14	7
60%	30	24	18	12	6
50%	25	20	15	10	5
40%	20	26	12	8	4
30%	15	12	9	6	3
20%	10	8	6	4	2
10%	5	4	3	2	1

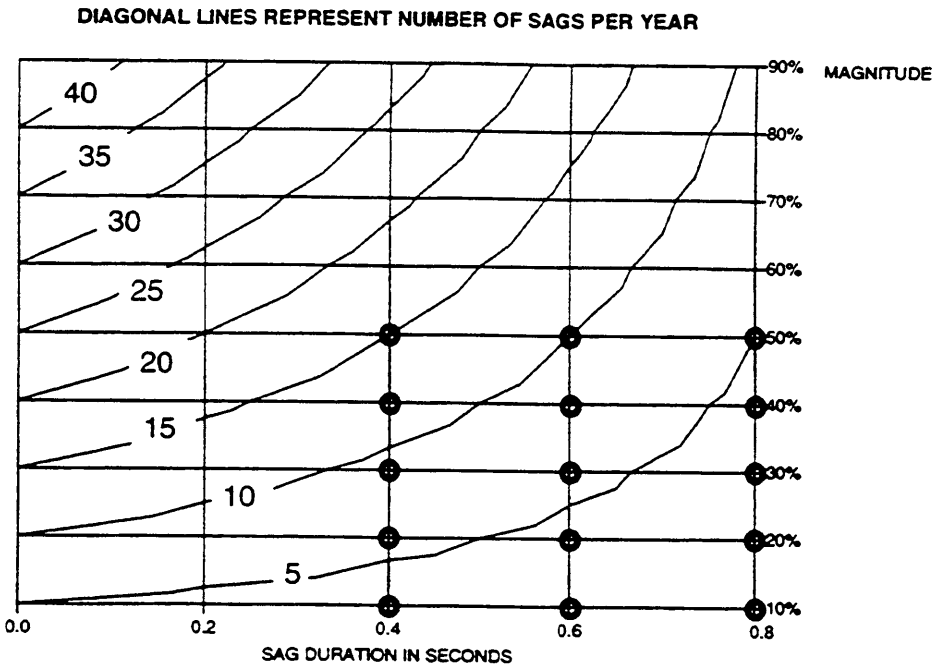


Figure 2.15 Contour plot of table 2.7 [15]

In this project, the cumulative voltage sag table is used to describe the expected number of voltage sags. The cumulative voltage sag table is calculated for each load position by adding the voltage sag table for each fault position in the system. This kind of table gives the expected number of interruptions of load operation at the various customer locations within the network.

CHAPTER 3

STOCHASTIC ASSESSMENT OF VOLTAGE SAGS

3.1 Introduction

Voltage sags, as with other power quality aspects, should be treated as a compatibility problem between equipment and supply. When installing a new piece of equipment, a customer needs to compare the equipment sensitivity with the performance of the supply. Information about equipment sensitivity can be obtained from the manufacturer or through equipment tests. Information about the performance of the supply can be obtained through monitoring of the supply or through predictive stochastic assessment.

Power quality monitoring has proved to be a very useful method of quantifying the average quality of the supply. The survey published in reference [28] provided the comparable data from National Power Laboratory (NPL), the Canadian Electrical Association (CAE) and the Electrical Power Research Institute (EPRI), which illustrated the usefulness of monitoring

results. The results of monitoring the supply for a certain period can be used to estimate the expected number of sags of various durations and magnitudes. Such information can be used to assess how often a certain piece of equipment will trip due to voltage sags, which in turn will help in deciding about the purchase of equipment. Voltage sag monitoring is a very useful method, e.g. for obtaining the average quality of supply for a certain region or country.

Monitoring of single sites has certain limitations, however; for example, voltage sag monitoring can take a long time, especially when one is interested in less-frequent sags. As seen in section 2.3, the number of voltage sags differs considerably throughout the year. This implies that a monitoring period of at least one year is required, even for very frequent sags. There are ways to correct for seasonal and other variations, but they require additional information and assumptions. It is also difficult to obtain information about the effect of system changes from a monitoring study; and extrapolation to sites not monitored could give unreliable results.

An alternative method, without the limitations of voltage sag monitoring, is to perform a stochastic assessment of voltage sags for the site of interest, based on modified methods developed for a power system reliability assessment. By using existing failure statistics this stochastic assessment can lead to accurate site-specific results. Therefore, a fundamental limitation of this method lies with the stochastic input data: the failure rate will not be the same for different lines, but this data is difficult to obtain. This is consequently a limitation of every stochastic prediction method. Monitoring does not have this limitation, but it requires a long time and a large number of monitoring events to obtain the frequency of voltage sags.

Whereas a lot of work has been published on the severity and mitigation of the voltage sag problem and on power quality monitoring, not much work has been done on the stochastic

prediction of voltage sags. A stochastic prediction method for voltage sags is proposed by Conrad et.al.[6,8]. They only take first-order events into account and assume all sags to be rectangular and balanced. Furthermore, they use an existing program to calculate voltages and fault positions have to be chosen manually. The method proposed by Bollen [15] takes higher order events into account by using Monte Carlo simulation. However, this method is very time consuming, has limitations for non-balanced and non-rectangular faults and still requires a manual choice of fault positions. Yalçinkaya and Bollen [30] studied the influence of motor parameters on the number of sags that lead to an interruption of plant operation. They also extended the method proposed by Conrad et.al. [6,8] to non-rectangular sags.

Stochastic prediction methods can give more rapidly updated information on the expected number of sags at a specific site compared to waiting for the statistical results from monitoring. Of course, accurate models and parameters for the system are required. Checking the influence of changing some configuration of the network can be done by the prediction methods as well. Accordingly, Bollen [25] presented a fast method for voltage sag calculation in distribution systems which shows how to calculate the critical voltage and critical area of voltage sags. In addition, it shows that every short circuit within the critical area will lead to a voltage sag below the critical voltage. An approximate expression has been derived for voltage sags due to faults in subtransmission loops or double circuit lines.

In this chapter, stochastic prediction methods are discussed, including the method of critical distance and the method of fault positions.

3.2 Stochastic Prediction Techniques

3.2.1 Method of Critical Distance

The method of critical distance for predicting a voltage sag, as proposed by Bollen [25], is an extension of the method of voltage calculation proposed for the IEEE Gold Book [6]. This method is a very simple prediction technique based on the voltage divider equivalent circuit. The formula of the voltage divider equivalent was discussed in section 2.5. The basis of the method is best explained for three-phase faults; single-phase and phase-to-phase faults can be treated similarly, although some complications may occur. These complications are not essential: for example, the difficulty during single-phase faults is to calculate the voltage in the non-faulted phases at the PCC. In order to calculate these voltages, one needs to know the source impedance, and the voltage at the load bus no longer equals the voltage at the PCC.

To calculate the sag magnitude for a fault somewhere within a radial distribution system, equation (2.3) from chapter 2 can be used:

$$\overline{V}_{sag} = \frac{\overline{Z}_2}{\overline{Z}_2 + \overline{Z}_1} \tag{3.1}$$

Where $\overline{Z}_1 = R_1 + jX_1$ is the source impedance at the point-of-common-coupling (PCC), $\overline{Z}_2 = (r_2 + jx_2)L$ is the impedance between the PCC and the fault, and L is the distance between the PCC and the fault. For three-phase faults, only positive sequence impedance is needed. For single-phase faults one needs to use the sum of positive, negative and zero-sequence impedance, and for phase-to-phase faults the sum of positive and negative sequence impedance. Equation (3.1) neglects the load current, therefore the voltage magnitude in percentage at the load position equals the voltage magnitude in percentage at

the PCC.

Figure 3.1 shows the influence of the distance to the fault and source power on the sag magnitude for a PCC at the Padiham 400 kV substation in the National Grid system (NGC) [31]. Padiham substation is fed through two overhead lines from Penwortham 400 kV and Eggborough 400 kV at distances of 37.46 km and 97.8 km respectively.

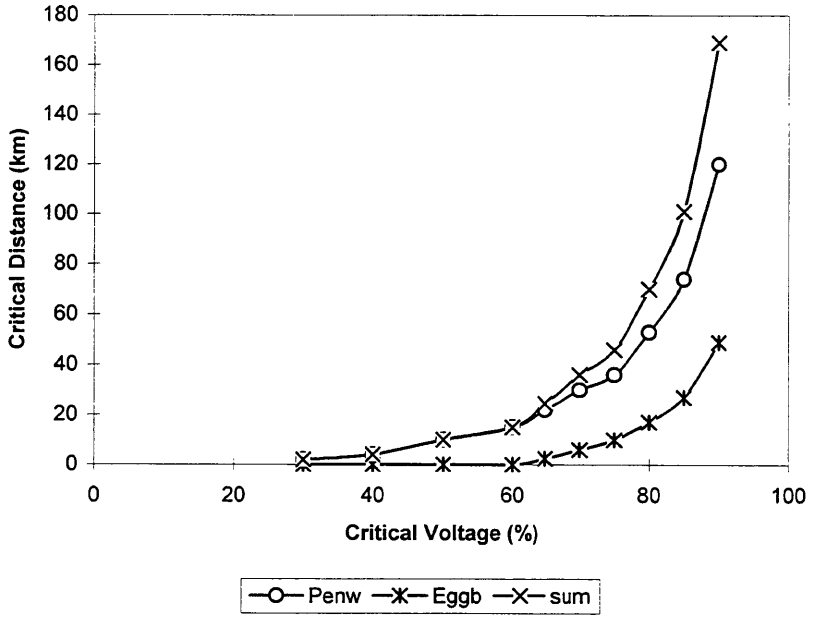


Figure 3.1 Sag magnitude as a function of critical distance for the Padiham 400 kV substation

Assume that there is a critical voltage below which the equipment will trip, and above which it will not trip. Therefore, equation (3.1) can now be used to estimate the expected number of equipment trips. For a given voltage sag, all fault positions are considered for which:

$$\left|\frac{\overline{Z}_2}{\overline{Z}_2+\overline{Z}_1}\right| < \overline{V}_{crit} \tag{3.2}$$

Therefore,

$$V_{crit} = \left| \frac{\bar{z}_2 L_{crit}}{Z_1 + z_2 L_{crit}} \right| \tag{3.3}$$

where L_{crit} is the critical distance, Thus,

$$V_{crit} = \left| \frac{r_2 L_{crit} + jx_2 L_{crit}}{R_1 + jX_1 + r_2 L_{crit} + jx_2 L_{crit}} \right| \tag{3.4}$$

Hence the critical distance is given by the following equation:

$$L_{crit} = \frac{(R_1 r_2 + X_1 x_2) V_{crit} + \sqrt{[(R_1 r_2 + X_1 x_2)^2 - (R_1^2 + X_1^2)(r_2^2 + x_2^2)] V_{crit}^4 + (R_1^2 + X_1^2)(r_2^2 + x_2^2) V_{crit}^2}}{(r_2^2 + x_2^2)(1 - V_{crit}^2)} \tag{3.5}$$

A simplified equation can be obtained while assuming that the X/R ratio of source and feeder are equal:

$$L_{crit} = \frac{Z_1}{z_2} \frac{V_{crit}}{1 - V_{crit}} \tag{3.6}$$

To support the error in equation (3.6), Figure 3.2 illustrates the critical voltage versus the critical distance for a PCC of 11 kV with a short circuit power of 100 MVA for different X/R ratio. The X/R ratio of the source is assumed to be 20. It can be seen that the critical distance, and thus the expected number of sags, increases with critical voltage. The critical distance also increases when decreasing the short-circuit power of the source. Only if there is a large difference in the X/R ratio and a large critical voltage, will the error made by

using the simplified equation be of serious concern. Therefore, the error made by using a simplified equation is acceptable in most cases,

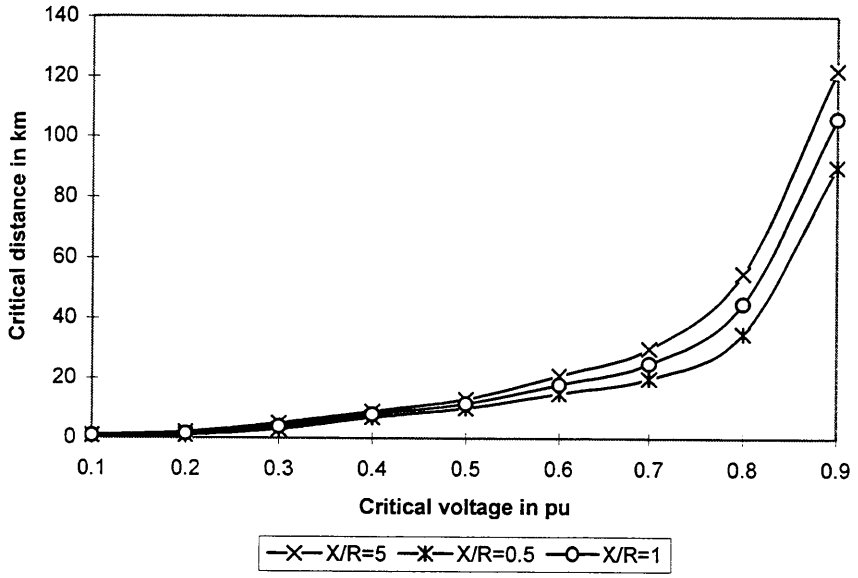


Figure 3.2 Influence of X/R ratio

3.2.1.1 Application to the 400 kV system

In a slightly revised version the method of critical distances has been applied to the 400 kV Padiham substation in the national grid, North of Manchester. The 400 kV grid around Padiham is shown in Figure 3.3A: the substation is fed by a 37.46 km line from Penwortham and a 97.8 km line from Eggborough. A number of lines go South and North Both from Eggborough and from Penwortham. For a fault on the line Padiham-Eggborough, the voltage at the Padiham substation is determined by the fault level contribution from Penwortham . From reference [36] this fault level contribution is found to be 14090 MVA. The impedance Z_1 in Figure 3.3B is thus (0.055+j0.741) % at 100 MVA. For the line impedance of (0.001+j0.018) % per km [36] the critical distance can be calculated from equation (3.6). The results are shown in Figure 3.1 has the curve labelled "Eggb". The

calculations can be repeated for the line to Penwortham. The fault level is now equal to 25242 MVA and the source impedance is (0.03+j0.395) %, resulting in the curve labelled "Penw" in Figure 3.1. The total "exposed length" at the Padiham bus is the sum of these two critical distance. This is presented by the curve labelled "Sum" in Figure 3.1.

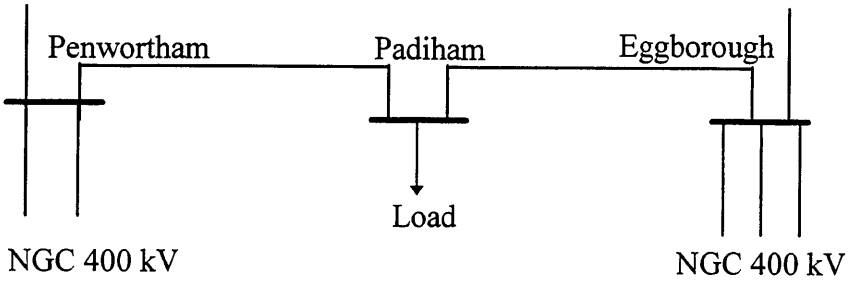


Figure 3.3A 400 kV system around Padiham

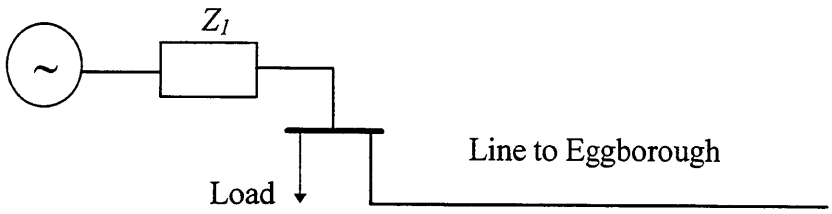


Figure 3.3B Equivalent scheme for faults on the line Padiham-Eggborough

As can be seen in Figure 3.1, the critical distance exceeds the line length for large critical voltages. The radial model no longer holds in this case. In reference [31] the critical distance is calculated from the Eggborough and Penwortham substations. For a fault behind the Eggborough station the sag magnitude can be calculated from the equivalent circuit shown in Figure 3.4. The impedances have the following values:

Z_1 : impedance of infeed from Penwortham at Padiham

Z_2 : fault level at Eggborough minus the faulted line and minus the line to Padiham

Z_3 : impedance of the line between Padiham and Eggborough

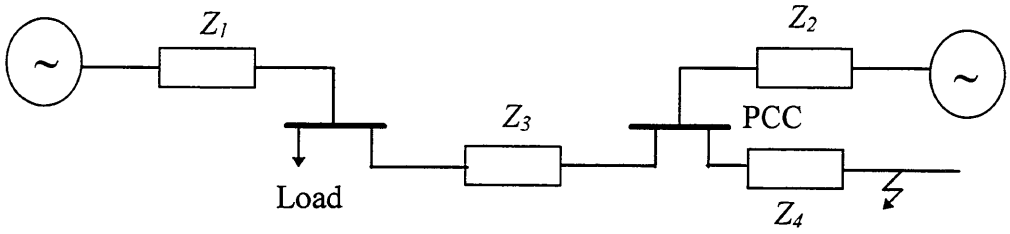


Figure 3.4 Equivalent circuit for a fault behind Eggborough

As before, it is possible to calculate the voltage at the load bus as a function of the distance L between the fault and the remote bus:

$$(1-V_{sag}) = \frac{Z_1}{Z_3 + Z_1}(1-V_{PCC})$$

For a given critical voltage V_{crit} it is possible to calculate a critical distance L_{crit} (using $Z_4 = Lz$):

$$L_{crit} = \frac{Z_2}{z}\left\{\frac{Z_1}{Z_1 + Z_3 + Z_2}\frac{V_{crit}}{1-V_{crit}} - \frac{Z_3}{Z_1 + Z_3 + Z_2}\right\}$$

Where all X/R ratios have been assumed equal.

For faults behind Eggborough, the following values are obtained from reference [36]:

Z_1 = (0.055+j0.741) % at 100 MVA.

Z_3 = (0.0011+j0.0166) % per km

Fault level contribution at Eggborough:

total: 31512 MVA

From Padiham: 3391 MVA

Leading to Z_2 = (0.024+j0.316) %

For faults behind Penwortham, the following values are obtained from reference [36]:

Z_1 = (0.132+j1.94) % at 100 MVA.

Z_3 = (0.0011+j0.018) % per km

Fault level contribution at Penwortham:

total: 25242 MVA

From Padiham: 3818 MVA

Leading to Z_2 = (0.03+j0.395) %

The results are shown in Figure 3.5 by the curve labelled "Eggb" for the fault behind Eggborough substation, and by the curve labelled "Penw" for the faults behind Penwortham substation. The total "exposed length" at the Padiham bus is the sum of these two critical distances. This is presented by the curve labelled "Sum" in Figure 3.5.

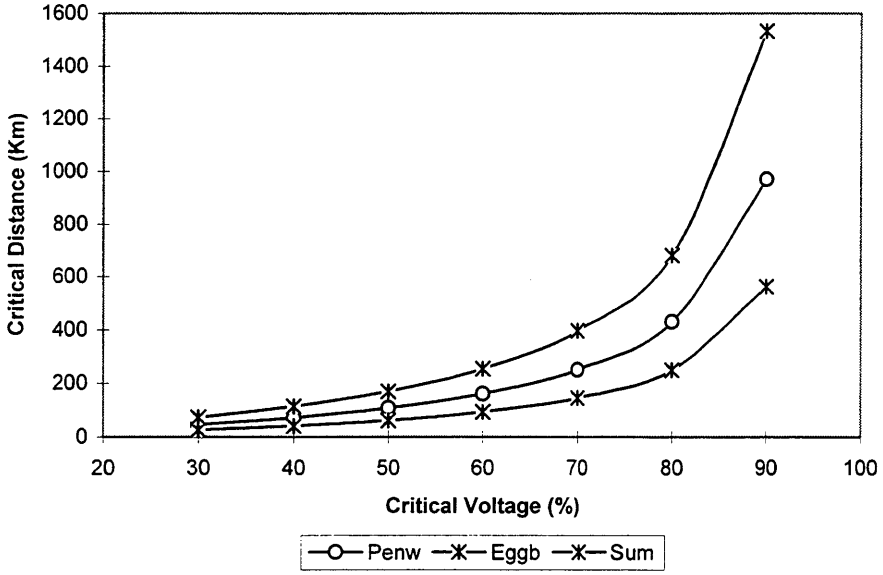


Figure 3.5 Sag magnitude as a function of critical distance for the Padiham 400 kV substation (Adjusted method)

Bollen et.al. [31] used a critical distance method to calculate the exposed area for different voltage levels. Therefore Table 3.1 gives exposed lengths for various voltage levels for three-phase faults. The critical distance increases considerably at higher voltage levels: from about 2 km for 11 kV for 50 % of voltage sags, up to hundreds of kilometres for 400 kV. This increase in critical distance is to some degree compensated for as lower voltage level lines contribute more faults.

Table 3.1 Exposed lengths for various voltage levels for three-phase faults

Voltage (%)	400 V 6MVA	33 kV 1000 MVA	132 kV 5000MVA	400 kV 17000 MVA
90	900m	3.3km	105km	1533km
60	150m	5.5km	17km	255km
30	43m	1.6km	5km	73km

Therefore, to estimate the expected number of sags at a certain load position, the critical distance has to be calculated for every possible PCC: this gives the so-called "exposed area". Every fault within this exposed area will lead to tripping of the equipment. The expected number of sags can be obtained by adding the expected number of faults within the exposed area (failure rate). In cases requires more accurate results, faults in substations, faults behind transformers and variations in failure rate among different feeders can be included for the total number of sags; if a substation consists of (n) outgoing feeders, the total number of sags will equal:

$$N_{sag} = \sum_{i=1}^{n} \lambda_i \; L_{crit} \tag{3.7}$$

Where λ_i the failure rate for feeder *i*.

Hence, from equation (3.6) one can conclude that the contribution of a feeder to the number of sags with a voltage magnitude less than V is proportional to $V/1-V$. As this holds for all feeders, the total number of sags will also show this relationship (3.6). In reference [25], a comparison is made between the theoretical results and the results of voltage sag monitoring. Figure 3.6 clearly confirms the theoretical results with the results of monitoring from three countries, the USA, UK and Norway [25]. The curves are scaled such that they

coincide at 70% voltage. The similarity between theory and measurements is very good, despite the very simple method used to derive equation (3.7).

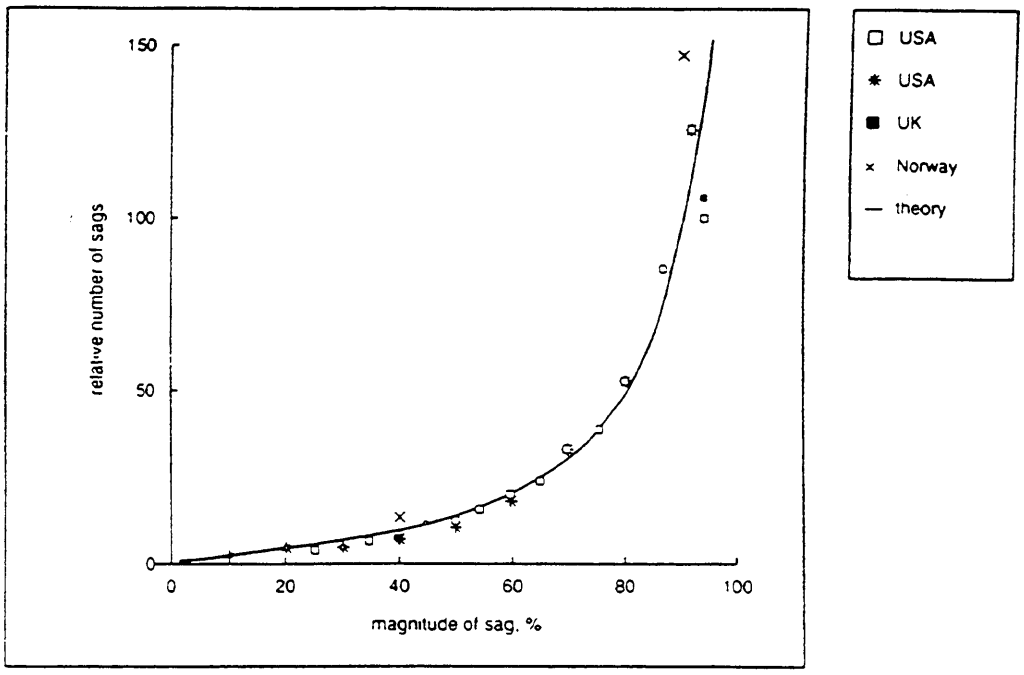


Figure 3.6 Number of sags below certain voltage [25]

For a non-radial network, a similar procedure may be used with some alteration, for instance, treating the network as if it were radial although this is certainly not the case for the complex meshed system. Such an alternative is significant when the critical voltage is between 80% and 90% because large parts of the network will then influence the number of sags. In this case, errors will be introduced by using this simplified method. In most cases this will lead to an under-estimation of the exposed area for large critical voltages.

3.2.2 Method of Fault Positions

In some cases, the method of critical distance is not suitable, for example, when the system is strongly meshed or when the expected number of voltage sags of various durations and magnitudes are sought. In this case, other methods have to be used.

A straightforward method is to calculate the magnitude and duration of the voltage sag for as many faults as needed. After taking the failure rate for each fault into account, the expected number of sags as a function of magnitude and duration can be calculated. This is called the method of fault positions.

The method of fault positions will be part of the new IEEE Std. 493 [6]. A similar technique was used as the basis for a study incorporating voltage sags in the reliability analysis of the electricity supply [14,32].

The method of fault positions has been extended to non-rectangular sags (for example due to post-fault induction motor re-acceleration) [16,32]. By assuming that the voltage tolerance curve of the load is rectangular, the results can be presented in a two-dimensional (magnitude and duration) voltage sag table or chart. The voltage sag table discussed in section 2.7 and voltage sag chart (voltage sag map) is discussed in section 3.3.

The characteristics of voltage sags (magnitude and duration) at equipment terminals are calculated by using a number of faults spread through the system. Each fault position represents faults in a certain part of the system, for example, faults in the substation or faults between 25% and 75% of the distance along a line. An expected number of occurrences per year (the failure rate) is allocated to each fault position.

Consider, as an example, a 100km line as shown in Figure 3.7A. The dots indicate the fault positions. For each fault position a frequency, magnitude and duration are determined, as

shown in the Table 3.2. Failure rates of 8 faults per 100km per year and 10 faults per 100 substations per year have been used. Figure 3.7B shows the subdivision of the line for the fault frequencies. Fault positions 3, 4 and 5 are at 25%, 50% and 75% of the line respectively. Each will represent 1/4 of the line length. The fault positions 2, 6 and 7 represent faults close to the substation. Each will represent 1/8 of the line length. Fault positions 1 and 8 represents faults in the substation, each with the frequency of 0.1 per year.

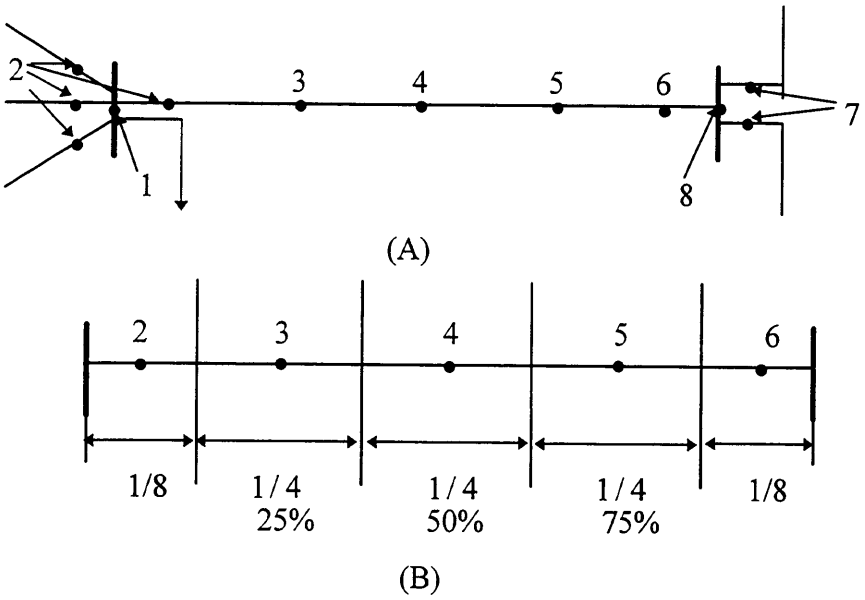


Figure 3.7 Fault positions along a 100 km line

Table 3.2 Frequency magnitude and duration for the fault positions in Figure 3.6.

	Fault position	Frequency	Magnitude	Duration
1	busbar fault in location substation	0.1/yr	0%	180ms
2	fault on a line close to local substation	4/yr	0%	80ms
3	fault at 25% of the line	2/yr	32%	90ms
4	fault at 50% of the line	2/yr	49%	105ms
5	fault at 75% of the line	2/yr	57%	110ms
6	fault at 100% of local line	1/yr	64%	250ms
7	fault at 0% of remote line	2/yr	64%	90ms
8	busbar fault in remote substation	0.1/yr	64%	180ms

The resulting sags (1 through 8 in Table 3.2) are now placed in a table, either in bins or immediately in a cumulative table. Table 3.3 shows how the various sags fit in the bins. Filling in the fault frequencies leads to Table 3.4 or the cumulative version shown in Table 3.5.

Table 3.3 Relation between fault positions in Figure 3.6 and bins

	Duration in (ms)		
Voltage	0-100	100-200	200-300
60-80%	7	8	6
40-60%		4 and 5	
20-40%	3		
0-20%	2	1	

Table 3.4 Expected number of sags for the given magnitude and duration range.

	Duration in (ms)		
Voltage	0-100	100-200	200-300
60-80%	2.0	0.1	1.0
40-60%		4.0	
20-40%	2.0		
0-20%	4.0	0.1	

Table 3.5 Cumulative voltage sag table for the example in Figure 3.6

	Duration in (ms)		
Voltage	0	100	200
80%	13.2	5.2	1.0
60%	10.1	4.1	0.0
40%	6.1	0.1	0.0
20%	4.1	0.1	0.0

The accuracy of the results can be improved by increasing the number of fault positions. Non-rectangular sags can be taken into account by using dynamic generators and load models, phase-angle jumps by working with complex impedances and voltages; three-phase imbalance by including single-phase and phase-to-phase faults.

Generally speaking, voltage sags are not rectangular. But most sags are more or less rectangular, especially those originating at high voltage levels far away from the load. Even for non-rectangular sags, the deep part of the sag is normally rectangular. The assumption that sags are rectangular is thus acceptable for most stochastic prediction studies. Under this assumption the results can be put in a table with duration and depth, and filled with frequencies (expected number of sags per year). Each element of the table gives the expected number of sags for the given duration and depth. This table can be used to estimate how many times a piece of equipment is expected to trip due to voltage sags. The

algorithm for the method of fault positions is described in detail in chapter 5. This method is adopted in this study.

3.3 Contour Maps

Voltage sags are normally characterised by their magnitude and duration. This enables all sags to be arranged in a two dimensional graph of magnitude against duration. A useful way of presenting this is a cumulative voltage sag table which was discussed in section 2.7. The techniques of predicting voltage sags from faults on the power system, which offer a method for estimating the number of sag-related disruptions are discussed in previous sections, 3.2.1 and 3.2.2. respectively.

Table 3.6 shows the cumulative number of voltage sag events. Figure 3.8 shows the contour plots taken from the information in Table 3.7, generated by a computer spreadsheet and graphical program [27]. The contour lines are similar to the elevation contour lines on a geographic map. The lines from lower left to upper right represent the number of sag events per year. Each contour line has a label for number of events.

Table 3.6 Number of sags with different clearing time

	Duration in (ms)		
Voltage (%)	0-100	100-200	200-300
60-80	13.2	5.2	1.0
40-60	10.1	4.1	0.0
20-40	6.1	0.1	0.0
0-20	4.1	0.1	0.0

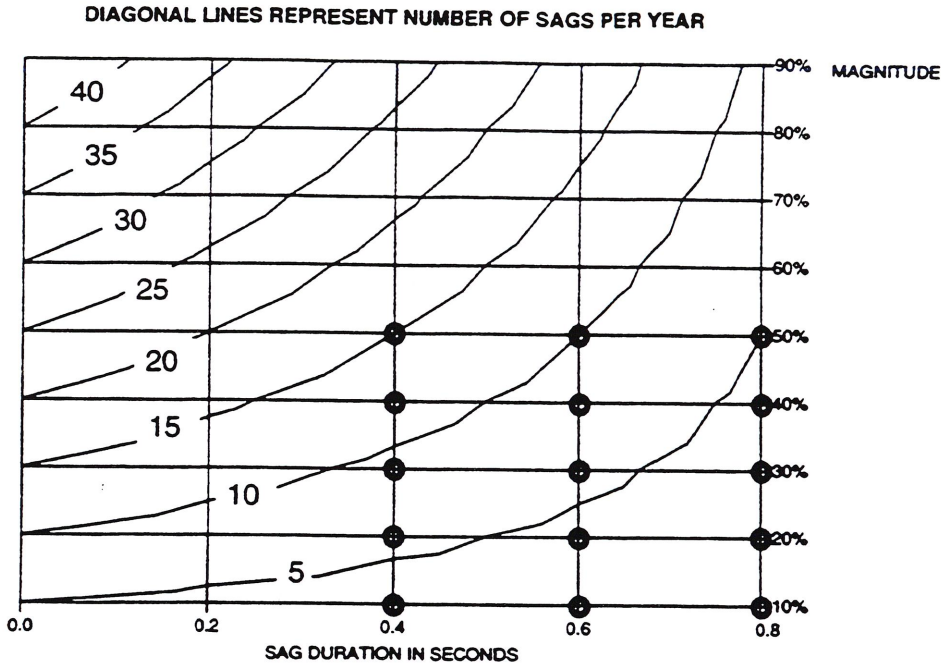


Figure 3.8 Supply sag performance contour and mapping of individual points [27]

Table 3.7 Sum of events worse than or equal to each magnitude and duration [27]

	Time in Seconds				
Magnitude	0.0	0.2	0.4	0.6	.8
90%	45	36	27	18	9
80%	40	32	24	16	8
70%	35	28	21	14	7
60%	30	24	18	12	6
50%	25	20	15	10	5
40%	20	26	12	8	4
30%	15	12	9	6	3
20%	10	8	6	4	2
10%	5	4	3	2	1

Continuing this simple example, the 15 event contour line intersects the 0.4 second vertical line at 50 % magnitude. This means 15 sags will last 0.4 seconds or longer and will have 50% or lower magnitude. The dots on the lower right hand corner of Figure 3.8 show each of the 15 individual sags. There are 15 dots in the rectangular area below and to the right of the contour line. Similarly, the 20 sag contour shows that there are 20 sags worse than or equal to 0.2 second and 50% magnitude.

The advantage of using a contour map becomes clear when equipment voltage tolerance is included. The voltage tolerance curve shows the length of time a piece of equipment can tolerate a certain voltage. For a rectangular voltage tolerance curve such as the one in Figure 3.9, the knee of the curve gives the number of spurious trips. In this case the equipment will trip 15 times per year [27]. If the equipment voltage tolerance curve is non-rectangular a small calculation has to be made [27].

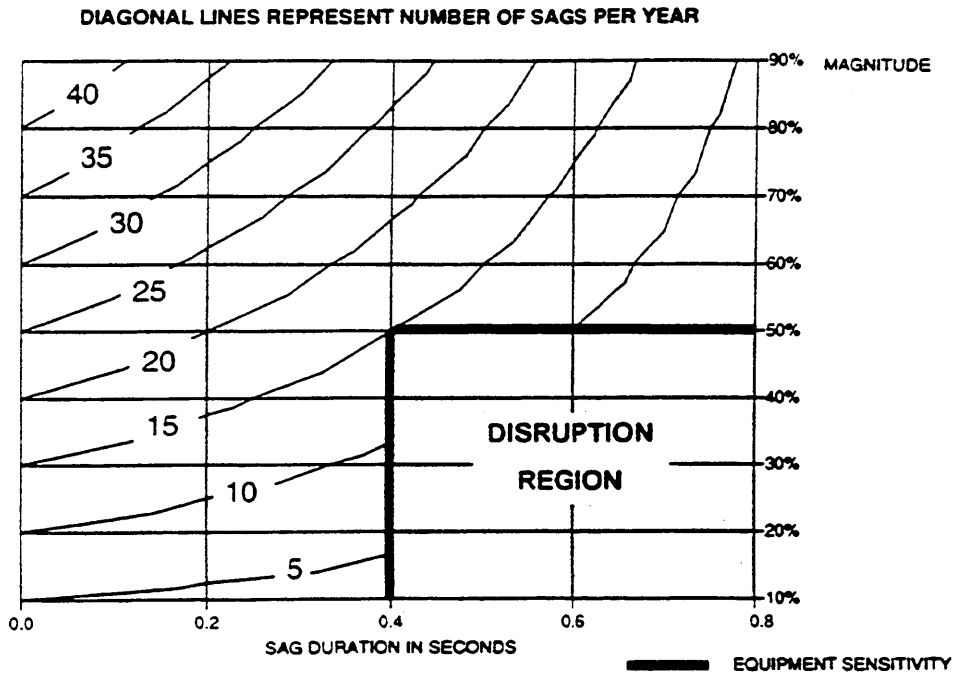


Figure 3.9 Supply sag performance contours and equipment sensitivity [27]

3.4 Voltage Sag Profiles

The concept of a voltage sag profile (map) has been developed to help characterise the whole range of customers connected to a network. This is different to the method of contour maps, described in section 3.3, which gives a detailed characterisation for one customer. The expected voltage sag performance is obtained by performing short circuit simulations to determine the plant voltage sag frequencies as described in section 2.9.4.

The evaluated contour lines of a geographical map of the electrical network can also be represented: each contour line connects points with an equal number of sags below a certain magnitude. Such a contour map shows the variation of power quality through the system. To represent this type of map assume a large transmission system as shown in Figure 3.10 (this system is a non-existing network and the values shown are not based on calculations). After applying any method of stochastic prediction, the cumulative voltage sag table can then be calculated for each substation or bus in the network. The frequency of sags will be shown on the substations or buses. For each magnitude and duration, a different map will result: for example, a voltage sag map has been drawn for the network in Figure 3.10. The figure shows the annual number of sags below 85% lasting for longer than 50 ms. The contour lines group the frequency. Note that these "contour lines" are not contour lines in the strict since. The function representing the sag frequency is only defined for the substations and possibly for the lines, but certainly not for the whole plane. However these contour lines are still considered a useful concept.

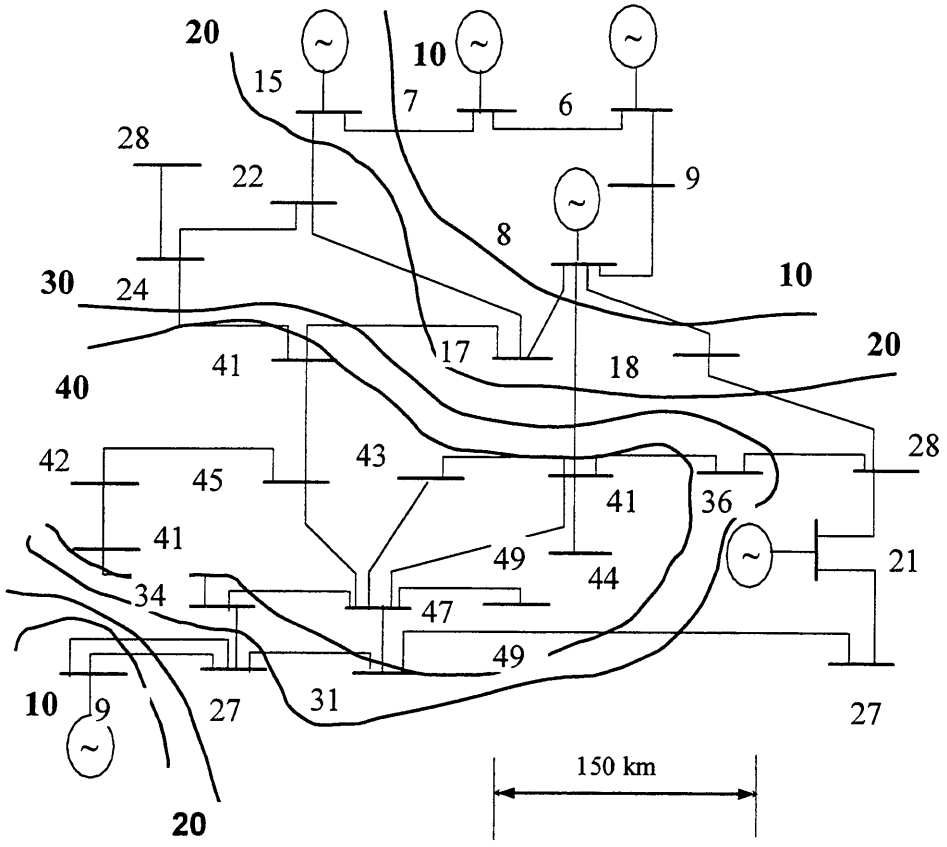


Figure 3.10 Contour map showing the variation of the system power quality for all the customers

From this type of map, the number of sags in the area of interest can be easily obtained. Furthermore, the worst area in the system can be identified and the variation in the number of sags over the system can be seen. Such maps have been used in this work to show the power quality of the system by area to the utility and to the customers. Also, from the voltage sag profiles drawn on the geographical system, the utility can easily assess which part of the system needs to be improved.

3.5 Concluding Remarks

This chapter has reviewed the main features of stochastic prediction of voltage sags and introduced two methods of stochastic prediction. The method of critical distance, as seen, is a fast method of calculating the number of voltage sags for radial networks but in some cases this method is not suitable. This happens, for example, when the system is strongly meshed or when the expected number of voltage sags of various duration and magnitude is sought.

The method of fault positions which is adopted in this study is used as the best alternative. In this method, the accuracy of the result can be increased by increasing the number of fault positions. The results of this method can be treated in many different ways as seen in section 2.9.4, 3.2.2, and 3.4.

CHAPTER 4

FAULT ANALYSIS IN POWER SYSTEMS

4.1 Introduction

A power system fault is defined as any condition or abnormality in the system which involves the electrical failure of primary equipment [39]. According to the type of failure, power system faults can be broadly classified into short-circuit faults, and open-circuit faults. Short-circuit faults can arise from lightning surges and other overvoltages which initiate flashes followed by power arcs, or from mechanical causes or from overcurrent. Open-circuit faults can arise from the maloperation of single-phase switchgear or the operation of fuses [40]. In this chapter the voltage calculations during a short circuit fault in the power system are discussed. Further discussion regarding faults also refers to short circuit faults. Open-circuit faults are more rare and do not normally cause voltage sags. symmetrical component method has been used to calculate the number of voltage sags in the algorithm described in chapter 5.

Fault calculations form an indispensable part of power system design and operation. They involve the determination of voltages and currents in a power system during fault conditions. During the planning and design stage, this information is required to specify the interrupting capacities of circuit breakers, and to ensure that other power system equipment is designed to operate safely under fault conditions.

Three-phase faults are generally considered to be the most severe, while line-to-ground faults are the most frequent. Calculations for three-phase faults are easier than for single-phase faults or line-to-line faults. In this chapter, and in the algorithm, all of them are covered.

Power systems are usually analysed by assuming balanced operation, thus enabling the actual polyphase system to be represented by a single-phase model. To maintain balanced operation, each item in the system plant must be symmetrical [40], i.e. have identical impedances in each line, equal mutual between phases and ground, and equal shunt admittances to ground or neutral. However, a number of localised asymmetries can occur such as, for example, asymmetrical faults or loads. Under these conditions, it is no longer possible to use a single phase model and the polyphase nature of the system has to be taken into account. Since unsymmetrical faults cause unbalanced currents to flow in the system, the method of symmetrical components is very useful in determining the current and voltage in all parts of the system after the occurrence of a fault.

Faults on the power system are considered by applying Thevenin's theorem, which allows the current in the fault to be found by replacing the entire system with a single generator and series impedance. Moderate analysis of unsymmetrical faults may be carried out using the bus impedance matrix. The development of techniques for applying a digital computer program to form the bus impedance matrix makes it feasible to use Thevenin's theorem for short circuit calculations. This approach provides an efficient means of determining short

circuit currents and voltages because these values can be obtained with few arithmetic operations involving only part of the bus impedance matrix.

The use of the bus impedance matrix provides a convenient means for calculating short circuit currents and voltages. One of the distinct advantages of this method is that, once the bus impedance matrix is formed, the elements of this matrix can be used directly to calculate the currents and voltages associated with various types of faults and fault locations. The bus impedance matrix can be easily applied to unsymmetrical faults by realising that the positive, negative and zero-sequence networks may be represented by bus impedance matrices.

Following the construction of the bus impedance matrices, the fault current is determined by using the diagonal element of the impedance matrices which represent the Thevenin impedance of the network at the fault location. When the generator voltages are reinserted into the network, the currents and voltages in the network will be the same as those existing before the fault. Using the principle of superposition, these prefault voltages add to the changes to yield the total voltages existing after the fault occurs.

The pre-fault network is assumed to be without load. In the absence of loads, no currents flow and there are no voltage differences across the branch impedances; all bus voltages throughout the network are then the same as the pre-fault voltage at the fault point. The assumption of no prefault current simplifies the work considerable, and by applying the principle of superposition, the voltages at all buses of the network can be calculated using the corresponding faulted voltage at the fault location and the elements in the column of the impedance matrices corresponding to the fault location.

In the next sections of this chapter, the equations for the calculation of voltages and currents in the faulted system are discussed.

4.2 Symmetrical Components

Power systems are usually analysed by assuming balanced operation, thus enabling the actual polyphase system to be represented by a single-phase model. To maintain balanced operation, each item in the system plant must be symmetrical [40], i.e. have identical impedances in each line, equal mutual impedances between phases and equal admittances to ground or neutral.

However, a number of localised asymmetries can occur such as, for example, asymmetrical faults or loads. Under these conditions, it is no longer possible to use a single phase model and the polyphase nature of the system has to be taken into account. Two methods are commonly used for the analysis of power systems under asymmetrical conditions: the symmetrical component method and the phase frame method [39].

Here, the symmetrical component method is selected due to it being the most appropriate for implementation on a personal computer.

4.2.1 General Principle

The method of symmetrical components provides a means of extending per phase analysis to a polyphase system with unbalanced load or faults. The method was first proposed by C.L. Fortescue [43] in 1918 and is based on the fact that an unbalanced set of (n) phasors can be resolved into (n-1) balanced n-phase system with a different phase sequence, plus one zero phase sequence system. Although Fortescuse's work is applicable to any unbalanced polyphase system, its application to the three-phase system is of most practical interest.

Consider a set of three phasors of the sequence a-b-c, e.g. current I_a , I_b and I_c .This set can be replaced by the sum of three so-called symmetrical component sets, namely:

- The POSITIVE sequence set consisting of three components equal in magnitude, displaced from each other by 120 degrees in phase, and having the same phase sequence as the original phasors.

- The NEGATIVE sequence set consisting of three components equal in magnitude, again displaced from each other by 120 degrees in phase, but now having a phase sequence opposite to that of the original phasors.

- The ZERO sequence set consisting of three components equal in magnitude and with zero phase displacement from each other.

In Figure 4.1 an unbalanced system of voltages is shown with the corresponding system of symmetrical components, by considering a voltage sag of 50% in phase a. The three sets are symbolised by the subscripts 1, 2 and 0 respectively. If each of the a-phase phasors are added, i.e. $V_{a1} + V_{a2} + V_{a0}$, the resultant phasor will be V_a in magnitude and direction; similar reasoning holds for the other two phases.

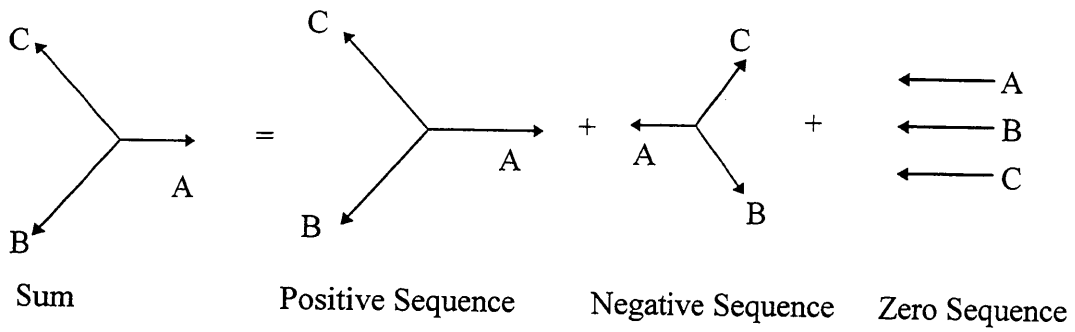


Figure 4.1 Vectorial representation of sequence components.

4.2.2 Theory

The relationship between phase and sequence quantities is:

$$\begin{aligned} I_a &= I_{a1} + I_{a2} + I_{a0} \\ I_b &= a^2 I_{a1} + a I_{a2} + I_{a0} \\ I_c &= a\ I_{a1} + a^2 I_{a2} + I_{a0} \end{aligned} \qquad (4.1)$$

Where $a = -1/2 + 1/2\, j\sqrt{3}$ rotates a phasor by 120 degrees in the anticlockwise direction.

It can also be confirmed that:

$$a^2 = 1\angle 240^o = -\tfrac{1}{2} - j\frac{\sqrt{3}}{2}, \quad a^3 = 1$$

$$1 + a + a^2 = 0 \qquad a^* = a^2$$

Equation (4.1) can be written in matrix form:

$$I_p = T\ I_s \qquad (4.2)$$

where the symmetrical component transformation matrix T is defined as:

$$T = \begin{vmatrix} 1 & 1 & 1 \\ a^2 & a & 1 \\ a & a^2 & 1 \end{vmatrix}$$

The current vector,

$$I_p = \begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix}$$

represents the phase currents and the vector,

$$I_s = \begin{bmatrix} I_1 \\ I_2 \\ I_0 \end{bmatrix}$$

represents the symmetrical component currents.

Inverting (4.2), gives the component currents as a function of the phase currents:

$$I_s = T^{-1} \; I_p \tag{4.3}$$

Where

$$T^{-1} = \frac{1}{3}\begin{vmatrix} 1 & a & a^2 \\ 1 & a^2 & a \\ 1 & 1 & 1 \end{vmatrix}$$

The same equations hold for voltages in addition to currents.

4.2.3 Sequence impedance and sequence networks

For a passive network element operated under balanced or unbalanced conditions, Kirchhoff's voltage law gives:

$$V_p = Z_p \; I_p \tag{4.4}$$

Where V_p is the voltage over the element, I_p the current through the element, and Z_p a 3 X 3 matrix giving the self and mutual impedances in and between phases (phase impedance matrix). Substituting V_s and I_s for V_p and I_p into equation (4.4):

$$V_s = T^{-1} \; Z_p \; T \; I_s \tag{4.5}$$

and defining

$$Z_s = T^{-1} \; Z_p \; T \tag{4.6}$$

$$V_s = Z_s \; I_s \tag{4.7}$$

The importance of symmetrical components lies in Equation (4.6). For typical power system components, the matrix Z_p possesses certain symmetries, such that Z_s is close to diagonal. This means that transforming from a-b-c coordinates to 1-2-0 co-ordinates decouples the sequences.

To illustrate the above, consider the voltage equation for an unsymmetrically loaded machine (generator), in matrix form [41].

$$V_p = E_p - Z_p I_p \tag{4.8}$$

where Z_p for synchronous or induction machines is the 'circulate matrix'[42],

$$Z_p = \begin{vmatrix} Z_k & Z_m & Z_n \\ Z_n & Z_k & Z_m \\ Z_m & Z_n & Z_k \end{vmatrix} \tag{4.9}$$

Using equations (4.2) and (4.4), equation (4.8) can be written:

$$T V = E_p - Z_p T I_s$$

and premultiplying by T^{-1} and using equation (4.6), gives:

$$V_S = T^{-1} E_P - T^{-1} Z_P T I_S = E_S - Z_S I_S \tag{4.10}$$

Evaluating the terms on the right-hand side:

$$E_S = T^{-1} E_P = \frac{1}{3}\begin{vmatrix} 1 & a & a^2 \\ 1 & a^2 & a \\ 1 & 1 & 1 \end{vmatrix} \begin{vmatrix} E_a \\ a^2 E_a \\ a E_a \end{vmatrix} = \begin{vmatrix} E_a \\ 0 \\ 0 \end{vmatrix} \tag{4.11}$$

and

$$Z_s = T^{-1}\begin{vmatrix} Z_k & Z_m & Z_n \\ Z_n & Z_k & Z_m \\ Z_m & Z_n & Z_k \end{vmatrix} T = \begin{vmatrix} Z_k + a^2 Z_m + a Z_n & & \\ & Z_k + a Z_m + a^2 Z_n & \\ & & Z_k + Z_m + Z_n \end{vmatrix} \tag{4.12}$$

At this point, the generator 'sequence impedances' can be defined:

$Z_1 = Z_k + a^2 Z_m + a Z_n$ positive sequence impedance

$Z_2 = Z_k + a Z_m + a^2 Z_n$ negative sequence impedance

$Z_0 = Z_k + Z_m + Z_n$ zero sequence impedance

Using Equations (4.11) and (4.12), Equation (4.10) can be written:

$$V_1 = E_a - Z_1 I_1$$
$$V_2 = 0 - Z_2 I_2$$
$$V_0 = 0 - Z_0 I_0$$

Figure 4.2 shows the sequence networks of a star connected generator with the star point earthed.

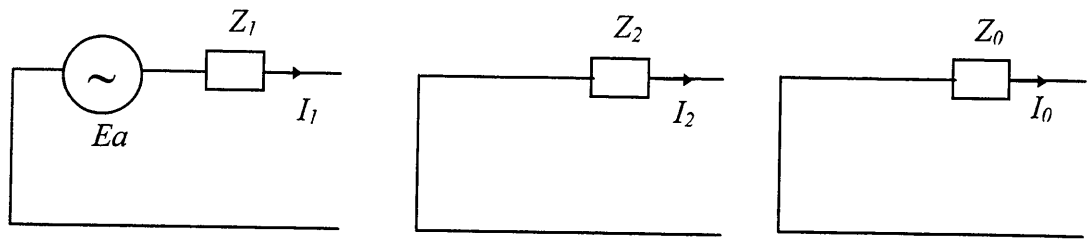


Figure 4.2 Generator sequence network

It can be seen that:

1. As the Z_s matrix is diagonal, there is no coupling between the three sequence component systems
2. Only the positive sequence system has an induced emf. This is always true, since the generator is designed to supply balanced three-phase voltage.

The analysis of an asymmetrical fault on a symmetrical system consists of finding the symmetrical components of the unbalanced currents that are flowing. The single-phase equivalent circuit composed of the impedances to current of any one sequence is called the sequence network for that particular sequence, namely [40].

The POSITIVE sequence network, is the only one has sources of emf and therefore must be identical to the 'phase' equivalent network of the system.

The NEGATIVE sequence network, which must have the same configuration as the positive sequence, also has the same impedances for static elements. Machine reactances are different.

The ZERO sequence network involves impedances which are substantially different from those in the other networks. Neutral impedance to earth Z_g is absent in the positive and negative sequence impedance networks but appears as $3\,Z_g$ in the zero sequence. Since the three phases carry equal zero sequence currents, certain transformer connections offer an infinite impedance, e.g. a delta winding.

These three networks become interconnected when an unbalanced fault is introduced.

Generally, the method of symmetrical components is characterised by:

1. The ability to obtain savings in computer time and storage because the sequence equations for all the balanced network elements are uncoupled.
2. Unbalanced faults are commonly represented as constraint equations which produce a mutual coupling between the otherwise independent sets of sequence equations. For certain types of faults (e.g. simultaneous faults), the method may be quite difficult to apply. Because the form of the constraint equation is variable, it is difficult to treat all types of faults in a uniform manner.
3. The advantage of the method is lost for analysis of networks under fault conditions when the system in its normal state is unbalanced, since Z_s is no longer diagonal [49]. Imbalance may be introduced into the system due to nontransposition of the transmission lines, although this is usually small.

4.2.4 Sequence impedances of system elements

Sequence impedances of power system components can be determined by testing or by analytical means. In either case, the component must be subjected to a set of currents and voltages satisfying the description for the respective sequence system.

The positive and negative sequence impedances of symmetrical, static circuits are identical and equal to normal circuit impedance, because the impedance of such circuits is independent of phase order. The normal circuit impedance is the impedance of the system when it is healthy, and in all respects identical with the usual networks considered; the resistances and reactances are the values usually given to calculate line regulation. The impedance of rotating machines are generally different for each sequence. The sequence impedances of certain items of system plant are discussed below.

4.2.4.1 Synchronous machines

The positive sequence impedance of synchronous machines represents the normal machine (direct axis) reactance. The synchronous X_d, transient X_d' or subtransient X_d'' values must be used depending on whether steady state, transient, or initial short-circuit current values are required [40]. In the study described later in this thesis, the subtransient value X_d'' is used. For the negative sequences, impedance of a rotating machine can be visualised as a transformer with one stationary (the armature) and one rotating winding (the field). Thus, dc in the field produces positive sequence in the stator. Similarly, the dc offset in the stator ac current produces an ac component in the field. In this relative motion model with the one winding rotating at a synchronous speed, negative sequence in the stator results in a double-frequency component in the field. Thus, the negative sequence flux component in the air gap is alternatively between and under the poles at this double frequency. One common expression for the negative sequence impedance of a synchronous machine is by equation (4.13) [46]: or the average of the direct and quadrature axes subtransient reactance. For a round-rotor machines, $X_d'' = X_q''$, so that $X_2 = X_d''$. For a salient-pole machine, X_2 is different, but this is frequently neglected unless calculating a fault very near the machine

terminals. Where normally $X_2 = X_d''$, the negative sequence network is equivalent to the positive sequence network except for the omission of voltage sources [46].

$$X_2 = \frac{X_d'' + X_q''}{2} \tag{4.13}$$

In the zero sequence network, the winding connection and earthing arrangement must be considered. The zero sequence impedance depends upon the nature of the connection between the star point of the windings and the earth and the single-phase impedance of the stator windings in series [44]. Since the three stator currents of the zero sequence component are of equal magnitude and phase, they create equal fluxes, but the fluxes have such magnetic axes that their vectorial sum vanishes. The reactance, which is proportional to the flux-to-current ratio, thus also vanishes. In practice, there is some flux (and reactance) due to leakage fluxes.

4.2.4.2 Overhead lines and cables

The positive and negative sequence series impedances and the shunt capacitance of lines and cable are equal and depend on their geometrical configuration.

The zero sequence impedance depends upon the nature of the return path. When only zero sequence current flows in a line, the current in each phase is identical. The current returns through the ground or overhead ground wires or both. Due to fact that the current is identical in each phase conductor, the magnetic field due to zero sequence current is very different from that caused by positive sequence current. These different results in the zero

sequence inductive reactance vary appreciably with the earth resistivity. It lower when there is an earth wire than when there is not.

4.2.4.3 Transformers

Since the transformer is a static device, its positive and negative sequence impedance is the same and equal to its leakage impedance Z_L.

The zero sequence impedance of transformers depends upon the winding connections, the earthing arrangements and the core construction. For a solidly earthed star winding, zero sequence currents can flow through the windings down to earth. For a star-connected winding with no earth connection, no zero sequence current can flow. In a delta winding, zero sequence currents may be induced (from an associated earthed star winding) and circulate around the closed delta but they cannot appear in the lines.

If the zero sequence currents have an available path and can flow, they again see the leakage reactance in each phase. Core construction affects the zero sequence impedance of transformers by means of the magnetising impedance [42]. In three phase banks of single-phase transformers and in three phase shell cored transformers, the magnetising impedance can be neglected [46], as with the positive and negative sequence network. In three phase core type transformers, the zero sequence flux must be completed through the oil (or air) or tank. The result is a low zero sequence magnetising impedance, so low that it should not be neglected in the equivalent circuit if high precision is required in computations. In practice, it is often neglected due to the lack of precise information.

Considering the above concepts, the zero sequence circuits shown in Table 4.1 are obtained for different winding connections and earthing arrangements of a two-winding transformer

[40]. In the circuits where the magnetising impedance is neglected, Z_0 equals the leakage reactance, Z_l, of the transformer. The value of $3Zg$ must be added to Z_0, if the earthing impedance Zg of a star-earthed winding is not zero. Thus : generally $Z_0 = Z_1 + 3Z_g$.

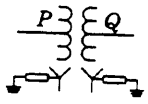
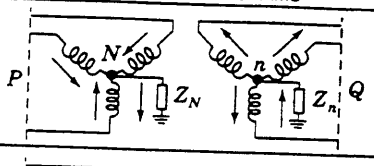
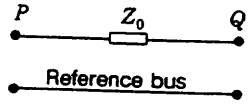
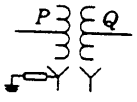
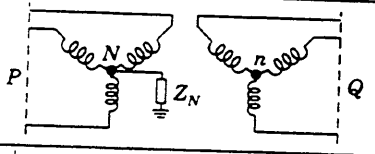
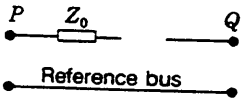
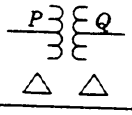
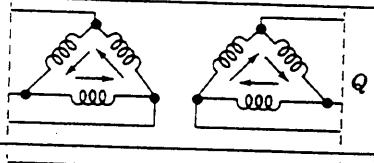
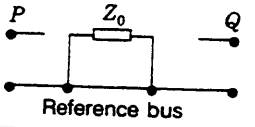
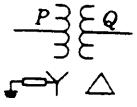
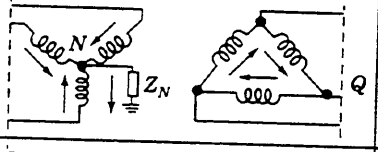
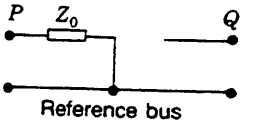
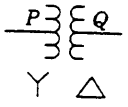
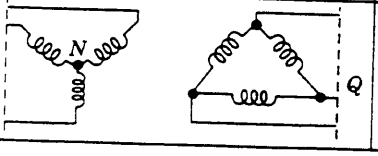
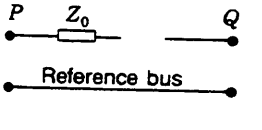
CASE	SYMBOLS	CONNECTION DIAGRAMS	ZERO-SEQUENCE EQUIVALENT CIRCUITS
1			
2			
3			
4			
5			

Table 4.1 Zero sequence circuit of a two winding transformer

4.3 Fault Current Calculations

With the knowledge of the sequence impedance of the system components, three sequence networks can be constructed. These networks are usually represented by two-pole block diagrams, as shown in Figure 4.3. The two poles correspond to the 'fault points' of the system, which are those points at which the fault is attached in the otherwise balanced system. Several important definitions are made in Figure 4.3: first, the direction of sequence currents is assumed to be away from the F terminal or out of the F point. This is because the unbalanced connection is to be attached at F, external to the boxes, and assumed currents are flowing toward this unbalanced connection. Thus the fault current is flowing from F to N at the fault position, and closing from N to F through the rest of the system. Second, the voltage across the sequence network is defined as a rise from N to F, as this makes V_{a1} positive for a normal system. These assumptions are arbitrary but are necessary in order to proceed with problem solving [44].

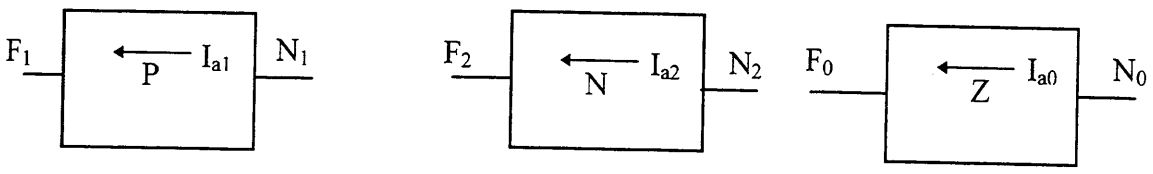


Figure 4.3 Block diagram representation of the sequence network

Once the fault point is determined, the sequence network for each sequence (i) can be analysed where one terminal is the fault point, designated F_i, and the other terminal is the "Zero-potential bus" designated N_i. This is done in the usual way, looking back from terminals F_i and N_i to find the open circuit voltage and the short circuit current or equivalent impedance (for that sequence). The impedance seen is usually designated

Z_1, Z_2 and Z_0, for the positive, negative, and zero sequence networks and represents the Thevenin equivalent impedance to the flow of the sequence currents I_1, I_2 and I_0 respectively [42]. The Thevenin equivalent voltage in the positive sequence network is the open circuit voltage at the fault point and is a phasor quantity. Thevenin equivalent or open circuit voltage in the negative and zero sequence networks are zero because by definition, the only voltage generated in the three-phase system is positive sequence voltage.

The sequence networks can be represented by their Thevenin equivalents as viewed from the fault point. Thus, the positive sequence network is replaced by a driving voltage V in series with an impedance Z_1, and the negative and zero sequence networks by the impedances Z_2 and Z_0, respectively. It should be noted that the voltage V is the prefault voltage at the fault position and Z_1, Z_2 and Z_0 are the impedances of the corresponding sequence networks as measured from the fault position.

4.3.1 Single line to ground fault

At the fault position

$$I_b = I_c = 0$$

$$V_a = I_a \; Z_f$$

Where Z_f is the fault impedance.

Using equations (4.1) and (4.4), the constraints on phase quantities can be transformed to constraints on sequence quantities:

$$I_1 = I_2 = I_0$$

and

$$V_0 + V_1 + V_2 = 3 Z_f \; I_f \qquad (4.14)$$

These conditions can be met by interconnecting the sequence networks in series, as shown in Figure 4.4.

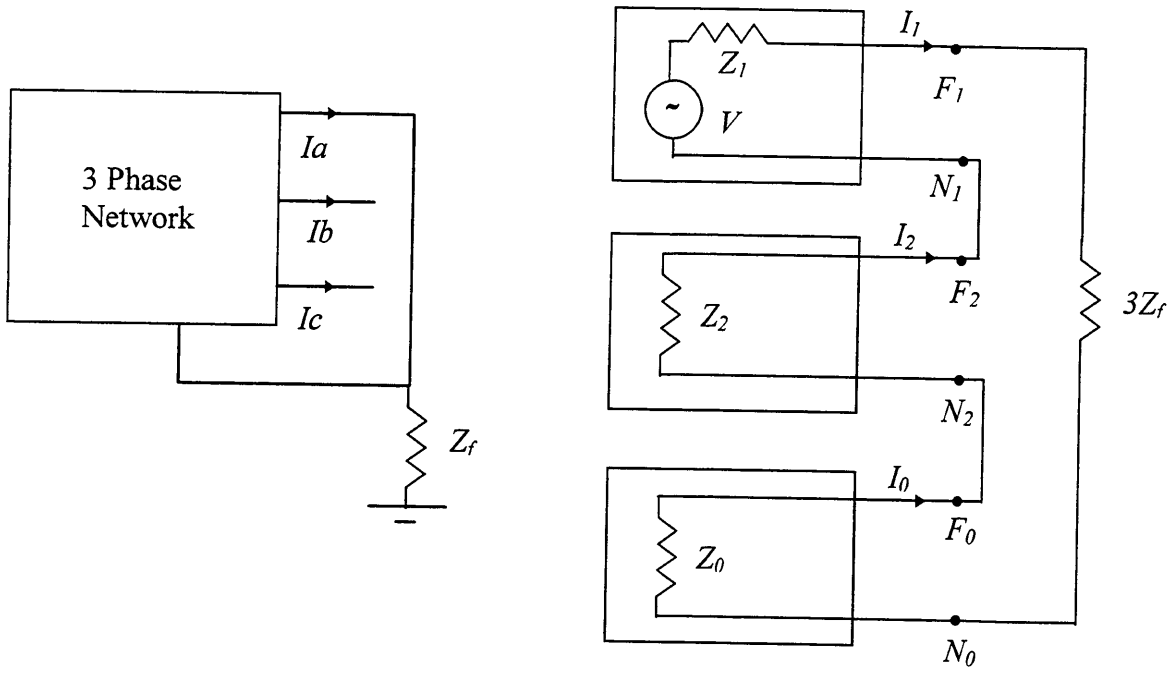


Figure 4.4 Single line to ground fault

4.3.2 Line to line fault

At the fault point

$$I_a = 0$$

$$I_b = -I_c$$

$$V_b = Z_f I_b + V_c$$

Using equations (4.1) and (4.4), the following results are obtained:

$$
\begin{aligned}
I_0 &= 0 \\
I_1 &= -I_2 \\
V_1 &= Z_f\ I_1 + V_2
\end{aligned}
\qquad (4.15)
$$

To satisfy the relations in (4.15), the positive and negative sequence networks are interconnected.

The zero sequence network is open since $I_0 = 0$, as shown in Figure 4.5.

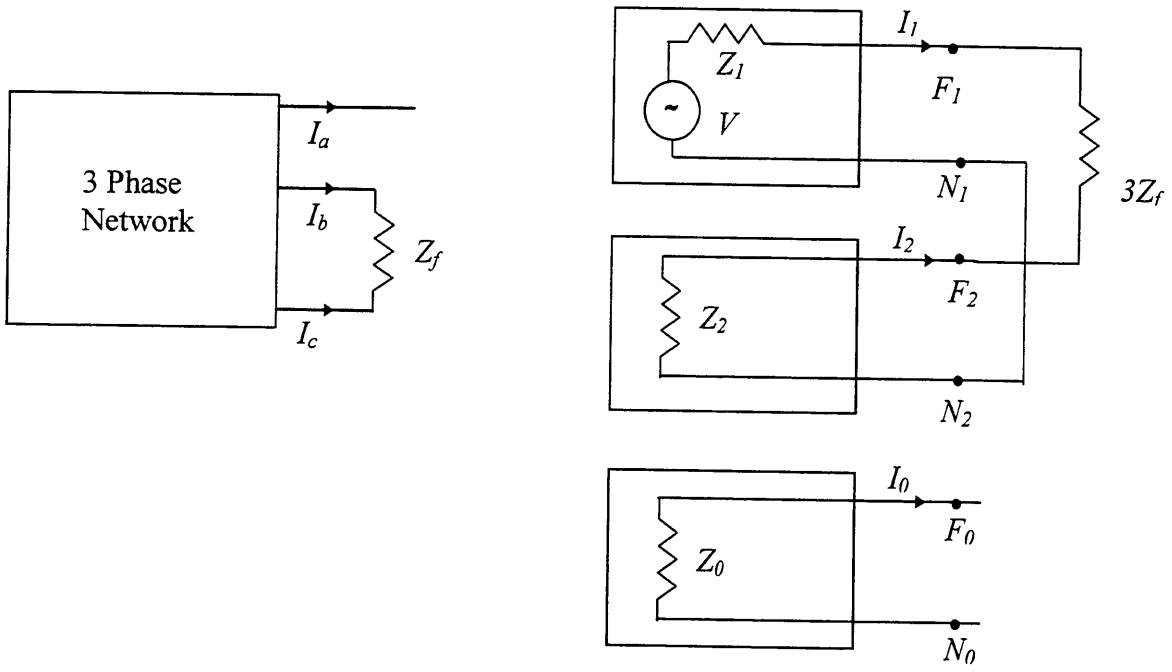


Figure 4.5 line to line fault

4.3.3 Three phase fault

At the fault point,

$$\begin{vmatrix} V_a \\ V_b \\ V_c \end{vmatrix} = \begin{vmatrix} Z_f & 0 & 0 \\ 0 & Z_f & 0 \\ 0 & 0 & Z_f \end{vmatrix} \begin{vmatrix} I_a \\ I_b \\ I_c \end{vmatrix}$$

Using equations (4.6) and (4.7), the following results are obtained:

$$\begin{aligned} V_1 &= Z_f\ I_1 \\ V_2 &= Z_f\ I_2 \\ V_0 &= Z_f\ I_0 \end{aligned} \qquad (4.16)$$

Relations in (4.16) are satisfied by the connection of the sequence networks shown in Figure 4.6.

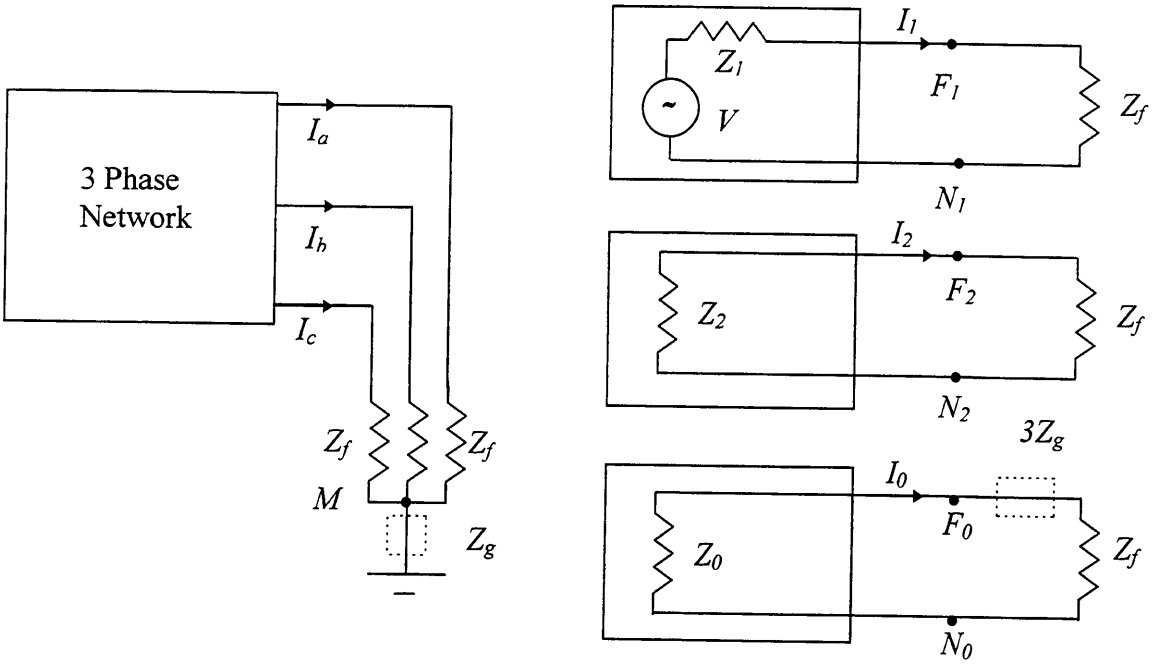


Figure 4.6 Three phase fault

It must be noted that any grounding impedance Z_g between point M and ground in Figure 4.6 must be treated as a zero sequence component and will appear as $3Z_g$ in the zero sequence network. If Z_g has an infinite value, the three phase fault does not involve earth and the zero sequence network is open. However, this does not matter for three-phase faults as the zero sequence network has no deriving voltage so that there is no zero-sequence currents. The same holds for the negative components.

4.4 Network Modelling

Each sequence network is made up of an interconnected set of elements, whose sequence models have already been described. The two basic approaches used to describe a network are the mesh (or loop) and nodal (or bus) methods. Of these, the latter has been found to be particularly suitable for automatic digital computer work. Among the advantages of the nodal approach for a power system network are: easy data preparation, low number of variables and equations compared with the mesh method and cross-over branches which do not introduce any difficulties. Node voltages are therefore used in this study.

Nodal network equations can be formulated with either admittance or impedance parameters. The nodal admittance matrix (Y_{BUS}) of a typical power system is large but sparse and widely used for power system analysis. Due to the fact that the network matrices are very large, sparsity techniques are needed to enhance the computational efficiency of computer programs employed in solving many of the power system problems. The diagonal entries of Y_{BUS} are found by adding the primitive admittance of lines and ties to the reference. The off-diagonal entries are the negative of the admittances of lines between buses. This term is zero if there are no lines between the buses. The Y_{BUS} matrix has several properties: the matrix is complex and symmetric. The matrix is sparse since each bus is connected to only a few nearby buses. Provided that there is a net nonzero admittance tie to the reference bus, Y_{BUS} may be inverted to find V_{BUS} from $I_{BUS} = Y_{BUS}V_{BUS}$.

On the other hand, the bus impedance matrix is equally well favoured for power system fault analysis. It is conceptually simple to invert Y_{BUS} to find the bus impedance matrix Z_{BUS}, but such direct inversion is rarely employed when the system to be analysed has a large order of this matrix [39,42].

In this thesis, the bus impedance matrix (Z_{BUS}) is used. The advantages of the bus impedance matrix are: easy for solving a faulted network which requires changes in the system, represented by adding or removing a branch. The impedance matrix does not require a new inversion for each new fault simulation. The short circuit analysis of a very large electrical system is achieved most efficiently by the use of an impedance matrix.

The impedance matrix contains the driving point impedance of every node with respect to a reference node that has been chosen arbitrarily. The driving point impedance of the node is the equivalent impedance between the node and the reference node. The Z_{BUS} matrix also contains the transfer impedance between each bus of the system and every other bus with respect to the reference bus. The transfer impedances are determined by computing the voltages that exist on each of the other buses of the system, with respect to the reference, when a particular bus is driven by an injection current of unity [50].

The matrix equation relating the Z_{BUS} matrix, the current injected into the nodes I, and the node V voltages are:

$$V = Z_{BUS}\, I$$

The complete short-circuit analysis of the network could be readily obtained with a small amount of additional computation. Remembering, as indicated earlier, that a network under fault conditions could be considered to have only one non-zero node current, one can write the matrix equation as:

$$\begin{vmatrix} V_1 \\ \cdot \\ \cdot \\ V_k \\ \cdot \\ \cdot \\ V_N \end{vmatrix} = \begin{vmatrix} Z_{11} & \cdots & Z_{1k} & \cdots & Z_{1N} \\ \cdot & & \cdot & & \cdot \\ \cdot & & \cdot & & \cdot \\ Z_{k1} & \cdots & Z_{kk} & \cdots & Z_{kN} \\ \cdot & & \cdot & & \cdot \\ \cdot & & \cdot & & \cdot \\ Z_{N1} & \cdots & Z_{Nk} & \cdots & Z_{NN} \end{vmatrix} \begin{vmatrix} 0 \\ \cdot \\ 0 \\ I_k \\ 0 \\ \cdot \\ 0 \end{vmatrix}$$

Where the network is subjected to a single current injection I_k into node K, which is the bus that is in a fault condition. Clearly , column K enables the voltage profile to be determined for the network, when a short circuit occurs on node K , providing that I_k has been, or can be, determined. The element Z_{kk} is the driving point impedance of bus K. The off diagonal element Z_{ik} is the transfer impedance between the other buses and bus K [50].

The full building algorithm of the impedance matrix is discussed in chapter 5.

4.5 Calculation of During-Fault Voltages

In general, during-fault voltage calculations are based on the use of Thevenin's equivalent representation together with the superposition theorem. The former enables the calculation of changes in network voltages and currents due to faults. The latter enables the computation of during-fault quantities by adding these changes to the prefault voltages and currents. In this study, the latter approach is adopted.

Before proceeding with the fault analysis, it is useful to define how the impedance of a network as it would be measured between two different points can be found. Consider the network in Figure 4.7, which represents a three-phase network with different nodes in the

system; it is required to find the impedance between node I_n and the reference node. If a current of 1 p.u. is injected into the network at the node I bus, the bus voltages are:

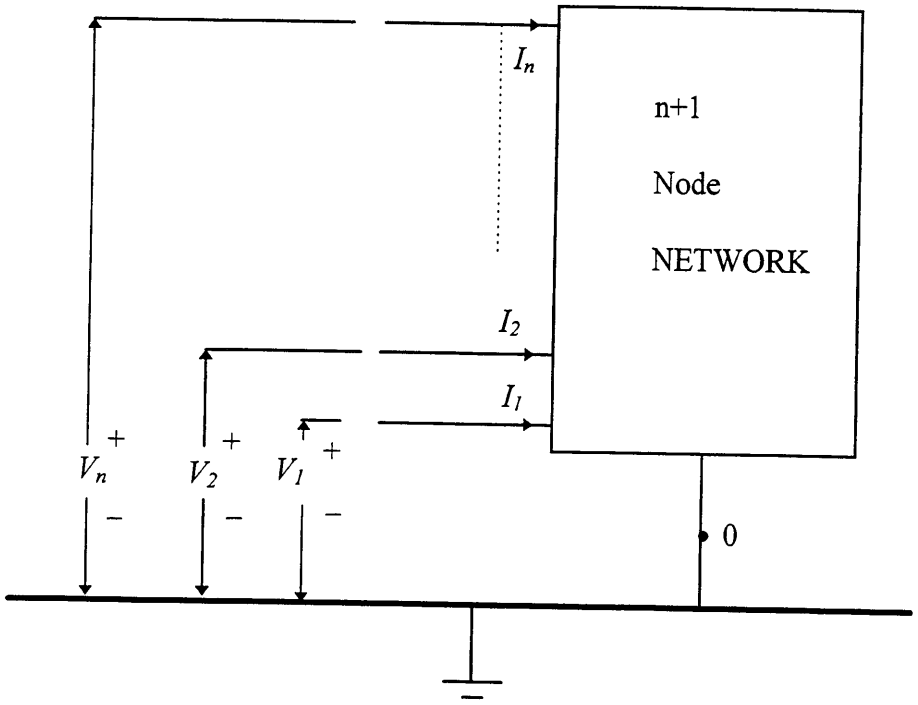


Figure 4.7 An n+1 node network with node 0 as reference

$$\begin{vmatrix} V_1 \\ \cdot \\ \cdot \\ V_I \\ \cdot \\ \cdot \\ V_N \end{vmatrix} = \begin{vmatrix} Z_{11} & \cdots & Z_{1I} & \cdots & Z_{1N} \\ \cdot & & \cdot & & \cdot \\ \cdot & & \cdot & & \cdot \\ Z_{I1} & \cdots & Z_{II} & \cdots & Z_{IN} \\ \cdot & & \cdot & & \cdot \\ \cdot & & \cdot & & \cdot \\ Z_{N1} & \cdots & Z_{NI} & \cdots & Z_{NN} \end{vmatrix} \begin{vmatrix} 0 \\ \cdot \\ 0 \\ 1 \\ 0 \\ \cdot \\ 0 \end{vmatrix} = \begin{vmatrix} Z_{1I} \\ \cdot \\ \cdot \\ Z_{II} \\ \cdot \\ \cdot \\ Z_{NI} \end{vmatrix} \tag{4.17}$$

It is seen that the voltage at node I is,

$$V_I = Z_{II}$$

Thus, the impedance between node I and the reference node is given by the Z_{II} element of the Z_{BUS} matrix [47].

Consider now that it is necessary to find the impedance of the same network as measured between nodes *I* and *J*. If a current of 1 p.u. is injected into node *J* and a current of 1 p.u. is injected into node *I*, then equation (4.17) gives:

$$\begin{vmatrix} V_1 \\ \cdot \\ \cdot \\ V_I \\ \cdot \\ \cdot \\ V_J \\ \cdot \\ \cdot \\ V_N \end{vmatrix} = \begin{vmatrix} Z_{11} & \cdots & Z_{1I} & \cdots & Z_{1J} & \cdots & Z_{1N} \\ \cdot & & \cdot & & \cdot & & \cdot \\ \cdot & & \cdot & & \cdot & & \cdot \\ \cdot & & Z_{II} & & Z_{IJ} & & \cdot \\ \cdot & & \cdot & & \cdot & & \cdot \\ \cdot & & \cdot & & \cdot & & \cdot \\ \cdot & & Z_{JI} & & Z_{JJ} & & \cdot \\ \cdot & & \cdot & & \cdot & & \cdot \\ \cdot & & \cdot & & \cdot & & \cdot \\ Z_{N1} & & Z_{NI} & & Z_{NJ} & & Z_{NN} \end{vmatrix} \begin{vmatrix} 0 \\ \cdot \\ \cdot \\ -1 \\ \cdot \\ \cdot \\ 1 \\ \cdot \\ \cdot \\ 0 \end{vmatrix} = \begin{vmatrix} Z_{1J} - Z_{1I} \\ \cdot \\ \cdot \\ Z_{IJ} - Z_{II} \\ \cdot \\ \cdot \\ Z_{JJ} - Z_{JI} \\ \cdot \\ \cdot \\ Z_{NJ} - Z_{NI} \end{vmatrix} \tag{4.18}$$

It is seen that:

$$V_J - V_I = (Z_{JJ} - Z_{JI}) - (Z_{IJ} - Z_{II}) = (Z_{II} - Z_{IJ}) - (Z_{JI} - Z_{JJ})$$

This last equation gives the impedance between node *I* and *J*.

4.5.1 Short circuit faults

To calculate the effect of a short circuit on voltages in a power system, method would be to build a circuit model of the system, with voltage sources and impedances, to place a switch at the fault position, and to close this switch at the fault (which is called t = 0). However, it turns out to be easier to calculate the changes due to the fault. This is done by short-circuiting all the sources in the circuit model, and switching in one source at the fault positions. This source has the opposite voltage to the voltage in the non-disturbed network [51].

The principle is explained in Figure 4.8 A, B and C. The during-fault voltages (Figure 4.8A) are the sum of the voltages in the non-disturbed system (Figure 4.8B) and the so-called "superimposed quantities" due to the switching on of a voltage source at the fault position.

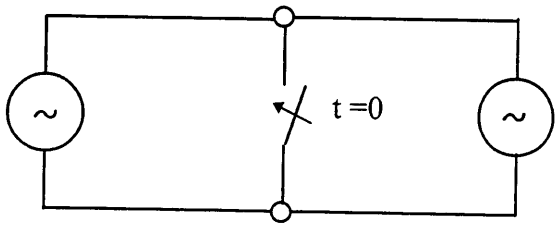


Figure 4.8A During-fault voltage and currents

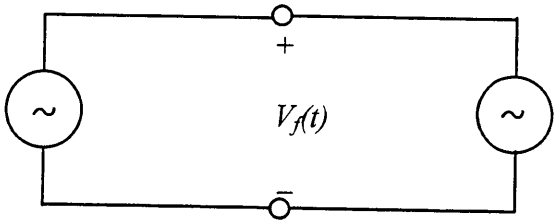


Figure 4.8B Pre-fault voltage and currents

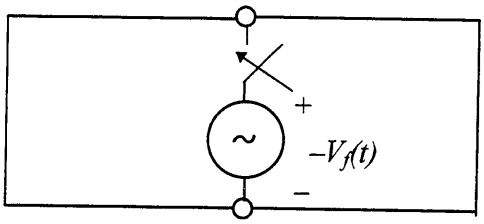


Figure 4.8C Voltage and currents due to the fault

The discussion in this section concerns the second step (changes due to the fault).

Consider an N bus balanced system, whose prefault bus voltage vector is:

$$V_{BUS} = [\, V_1 \;\; V_2 \;\; \ldots\ldots\ldots V_N \,]^T$$

Figure 4.9 shows an N-port equivalent representation for each of the three sequence networks of the N bus system. In this figure, the positive sequence network is represented by a passive network, i.e. all generators are replaced by their equivalent superposition circuits and all the current sources are removed. Equation (4.18) can be written for each of the equivalent sequences as:

$$V_{1BUS} = Z_{1BUS} \;\; I_{1BUS}$$

$$V_{2BUS} = Z_{2BUS} \;\; I_{2BUS} \qquad (4.19,a,b,c)$$

$$V_{0BUS} = Z_{0BUS} \;\; I_{0BUS}$$

Where V_{1BUS} , V_{2BUS} and V_{0BUS} are the positive, negative and zero sequence voltages, i.e.,

$$V_{1BUS} = [V_1^1 \; V_2^1 \; \ldots\ldots\ldots\ldots V_N^1]^T$$

$$V_{2BUS} = [V_1^2 \; V_2^2 \; \ldots\ldots\ldots\ldots V_N^2]^T \qquad (4.20)$$

$$V_{0BUS} = [V_1^0 \; V_2^0 \; \ldots\ldots\ldots\ldots V_N^0]^T$$

I_{1BUS} , I_{2BUS} and I_{0BUS} are the positive, negative and zero sequence injected bus currents, i.e.,

$$I_{1BUS} = [I_1^1 \; I_2^1 \; \ldots\ldots\ldots\ldots I_N^1]^T$$

$$I_{2BUS} = [I_1^2 \; I_2^2 \; \ldots\ldots\ldots\ldots I_N^2]^T$$

$$I_{0BUS} = [I_1^0 \; I_2^0 \; \ldots\ldots\ldots\ldots I_N^0]^T$$

And Z_{IBUS} , Z_{2BUS} and Z_{0BUS} are the positive, negative and zero sequence bus impedance matrixes, i.e.,

$$Z_{1BUS} = \begin{vmatrix} Z_{11}^1 & \cdots & Z_{1I}^1 & \cdots & Z_{1N}^1 \\ \vdots & & \vdots & & \vdots \\ Z_{I1}^1 & \cdots & Z_{II}^1 & \cdots & Z_{IN}^1 \\ \vdots & & \vdots & & \vdots \\ Z_{N1}^1 & \cdots & Z_{NI}^1 & \cdots & Z_{NN}^1 \end{vmatrix}$$

etc.

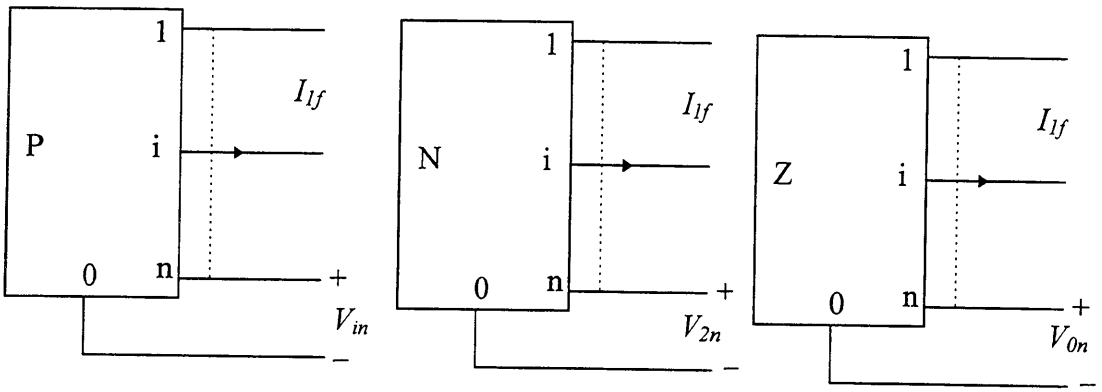


Figure 4.9 N-pole equivalent representation of sequence networks, for the calculation of voltage changes due to a short-circuit fault

Consider that a short circuit fault is applied between node I and the reference node. Let I_f^1 , I_f^2 and I_f^0 be the positive, negative and zero sequence fault currents flowing from bus I into the fault. The bus voltage changes V_{1BUS}, V_{2BUS} and V_{0BUS} due to the fault can be calculated from equation (4.19). This can be done by injecting the change in the node current injection due to the fault at the nodes of the three equivalent sequence networks. Since change in the node current injections only occurs at node I (the faulted node) of each sequence network, and this is equal to the corresponding sequence fault current, the bus voltage changes can be calculated by injecting the currents $-I_f^1$, $-I_f^2$ and $-I_f^0$ respectively only at node I of the positive, negative and zero sequence networks of Figure 4.9. Thus, the vectors I_{1BUS} , I_{2BUS} and I_{0BUS} in equation (4.19) are of the form:

$$I_{1BUS} = \begin{vmatrix} 0 \\ . \\ . \\ -I_f^1 \\ . \\ . \\ 0 \end{vmatrix} \qquad I_{2BUS} = \begin{vmatrix} 0 \\ . \\ . \\ -I_f^2 \\ . \\ . \\ 0 \end{vmatrix} \qquad I_{0BUS} = \begin{vmatrix} 0 \\ . \\ . \\ -I_f^0 \\ . \\ . \\ 0 \end{vmatrix} \quad \text{I-the entry}$$

Therefore, the positive sequence bus voltage changes at all nodes, are:

$$\begin{vmatrix} V_1^1 \\ . \\ . \\ V_I^1 \\ . \\ . \\ V_N^1 \end{vmatrix} = \begin{vmatrix} Z_{11}^1 & . & . & . & Z_{1I}^1 & . & . & . & Z_{1N}^1 \\ . & & & & . & & & & . \\ . & & & & . & & & & . \\ Z_{1I}^1 & . & . & . & Z_{II}^1 & . & . & . & Z_{IN}^1 \\ . & & & & . & & & & . \\ . & & & & . & & & & . \\ Z_{N1}^1 & . & . & . & Z_{NI}^1 & . & . & . & Z_{NN}^1 \end{vmatrix} \begin{vmatrix} 0 \\ . \\ 0 \\ -I_f^1 \\ 0 \\ . \\ 0 \end{vmatrix} = - \begin{vmatrix} Z_{1I}^1 \\ . \\ . \\ Z_{II}^1 \\ . \\ . \\ Z_{NI}^1 \end{vmatrix} I_f^1$$

Similarly, the negative and zero sequence bus voltage changes are:

$$\begin{vmatrix} V_1^2 \\ . \\ . \\ V_I^2 \\ . \\ . \\ V_N^2 \end{vmatrix} = - \begin{vmatrix} Z_{1I}^2 \\ . \\ . \\ Z_{II}^2 \\ . \\ . \\ Z_{NI}^2 \end{vmatrix} I_f^2 \qquad \text{and} \qquad \begin{vmatrix} V_1^0 \\ . \\ . \\ V_I^0 \\ . \\ . \\ V_N^0 \end{vmatrix} = - \begin{vmatrix} Z_{1I}^0 \\ . \\ . \\ Z_{II}^0 \\ . \\ . \\ Z_{NI}^0 \end{vmatrix} I_f^0$$

The post-fault bus voltages can be obtained by the superposition of the prefault bus voltages with the voltage changes due to the fault. Therefore, by noting the positive, negative and zero sequence post-fault voltages as:

$$V_f^1 = [V_{f1}^1 \; V_{f2}^1 \; \ldots\ldots\ldots\ldots\ldots V_{fN}^1]^T$$

$$V_f^2 = [V_{f1}^2 \; V_{f2}^2 \; \ldots\ldots\ldots\ldots\ldots V_{fN}^2]^T$$

$$V_f^0 = [V_{f1}^0 \; V_{f2}^0 \; \ldots\ldots\ldots\ldots\ldots V_{fN}^0]^T$$

Respectively, gives:

$$V_{fK}^1 = V_K - Z_{KI} \, I_f^1$$

$$V_{fK}^2 = - Z_{KI}^2 \, I_f^2 \qquad (4.21a,b,c)$$

$$V_{fK}^0 = - Z_{KI}^0 \, I_f^0$$

for K = 1, 2, …, N

The negative and zero sequence prefault bus voltages are zero, since balanced prefault operating is assumed.

Thus, if the sequence fault currents I_f^1, I_f^2 and I_f^0 are known, the sequence post-fault voltages can be calculated from equation (4.21) for all system buses.

In order to relate the notation of section 4.3 to the notation in this section, the following can be written:

$$V = V_I \ , \ I_1 = I_f^1 \ , I_2 = I_f^2 , I_0 = I_f^0$$

$$Z_1 = Z_{II}^1 , Z_2 = Z_{II}^2 , Z_0 = Z_{II}^0$$

The calculation of the sequence fault currents, using the new notation, follows:

1. Single line to ground fault

from Figure 4.4:

$$I_f^1 = \frac{V_I}{Z_{II}^1 + Z_{II}^2 + Z_{II}^0} , I_f^2 = I_f^1 , I_f^0 = I_f^1$$

2. Line to line faults

from Figure 4.5 :

$$I_f^1 = \frac{V_I}{Z_{II}^1 + Z_{II}^2} , I_f^2 = -I_f^1 \ , \ I_f^0 = 0$$

3. Three phase fault

from Figure 4.6:

$$I_f^1 = \frac{V_I}{Z_{II}^1} \ I_f^2 = 0 , I_f^0 = 0$$

4.6 Calculation of the Sag at the Equipment Terminals

In the previous sections of this chapter, the voltage sags during the fault at the buses and the fault currents for various types of fault were calculated. Therefore, other parts of the network also sense change in the voltage due to the fault in the system. Moreover, voltage sags at any bus should be calculated. Also, the voltage sags at different equipment terminals considered in this section due to different types of faults.

Knowing the symmetrical components I_f^1, I_f^2 and I_f^0 of the fault currents at the faulted bus K, and assuming that the pre-fault voltages are 1 p.u of positive sequence, the sequence voltages at any bus in the network can be calculated using equation (4.21):

1. Single line to ground fault

Voltage sags at any bus in phase components are:

$$V_K^{a,b,c} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} V_K^{0,1,2} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \begin{bmatrix} -Z_{Ki}^1 I_f^1 \\ V_K - Z_{Ki}^2 I_f^2 \\ -Z_{Ki}^0 I_f^0 \end{bmatrix}$$

$$V_K^{a,b,c} = \begin{bmatrix} 1 \\ a^2 \\ a \end{bmatrix} - \begin{bmatrix} Z_{Ki}^0 + 2Z_{Ki}^1 \\ Z_{Ki}^0 - Z_{Ki}^1 \\ Z_{Ki}^0 - Z_{Ki}^1 \end{bmatrix} \frac{1}{Z_{ii}^0 + 2Z_{ii}^1}$$

2. Line to line faults

Voltage sags at any bus in phase components are:

$$V_K^{a,b,c} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} V_K^{0,1,2} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \begin{bmatrix} -Z_{Ki}^1 I_f^1 \\ V_K - Z_{Ki}^2 I_f^2 \\ -Z_{Kif}^{0\ 0} \end{bmatrix}$$

$$V_K^{a,b,c} = \begin{bmatrix} 1 \\ a^2 \\ a \end{bmatrix} + \begin{bmatrix} 0 \\ j\sqrt{3}\, Z_{Ki}^1 \\ -j\sqrt{3}\, Z_{Ki}^1 \end{bmatrix} \frac{1}{2Z_{ii}^1}$$

3. Three phase fault

Voltage sags at any bus in phase components are:

$$V_K^{a,b,c} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} V_K^{0,1,2} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \begin{bmatrix} -Z_{Ki}^1 I_f^1 \\ V_K - Z_{Ki}^2 I_f^2 \\ -Z_{Ki}^0 I_f^0 \end{bmatrix}$$

$$V_K^{a,b,c} = \left(1 - \frac{Z_{Ki}^1}{Z_{ii}^1}\right) \begin{bmatrix} 1 \\ a^2 \\ a \end{bmatrix}$$

4.6.1 Transformer phase shifts [39,40]

In star-star and delta-delta connected transformers, it is always possible to label the phases in such a way that there is no phase shift between corresponding primary and secondary quantities. By convention, this is always done [44]. However, for the star-delta connected

transformer, as seen in Figure 4.10, the positive sequence primary and secondary voltages (and currents) have a 30^0 displacement which is either in the direction of rotation of the phases, or against it, depending on the delta arrangements.

From the phasor diagrams in Figure 4.10, it can be seen that the line to neutral voltages of the first delta arrangement have $+30^0$ displacement, while those of the second delta have -30^0 displacement. From the same figure, it can also be seen that the second delta arrangement is obtained from the first by interchanging the blue and white windings, i.e. by connecting the start of the blue winding in place of the start of the white winding, to the finish of the red. Exactly the same result can be obtained if the blue and white phases of the start winding are interchanged without changing the delta in any way. This means that by changing the phase sequence of the applied voltages on the start winding, a -30^0 phase shift is introduced in the first delta and a $+30^0$ phase shift in the second. The foregoing discussion applied to voltages but the same results also hold for currents.

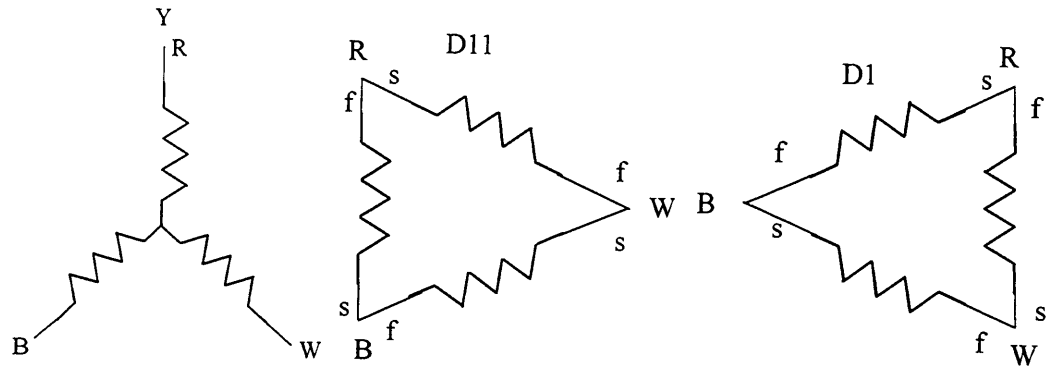
In Summary, the phase shift rule is as follows:

If the transformer imparts a phase shift of +a degrees to the positive sequence set of voltages and currents, the negative sequence voltages and currents will experience shift of –a degrees. The zero sequence currents and voltages are not affected by the transformer phase shift [39].

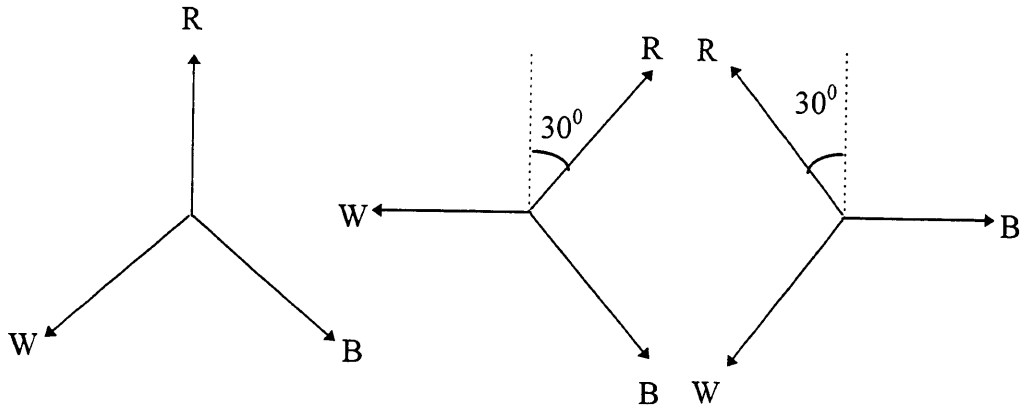
In a fault study involving a single fault [49] using the p.u system, transformer phase shifts do not affect the positive and negative impedance of the transformer. Therefore, it is possible to initially assume an equivalent star-star connection for all the transformers in the positive and negative sequence networks. The study can proceed, on this basis, by the calculation of all sequence current and voltage quantities. At the final stage, the phase quantities are introduced. This is done by phase shifting by $\pm 30^0$ the positive sequence

quantities and $\pm 30^0$ the negative sequence quantities of the those sections of the system which feed or are fed by delta-star transformers.

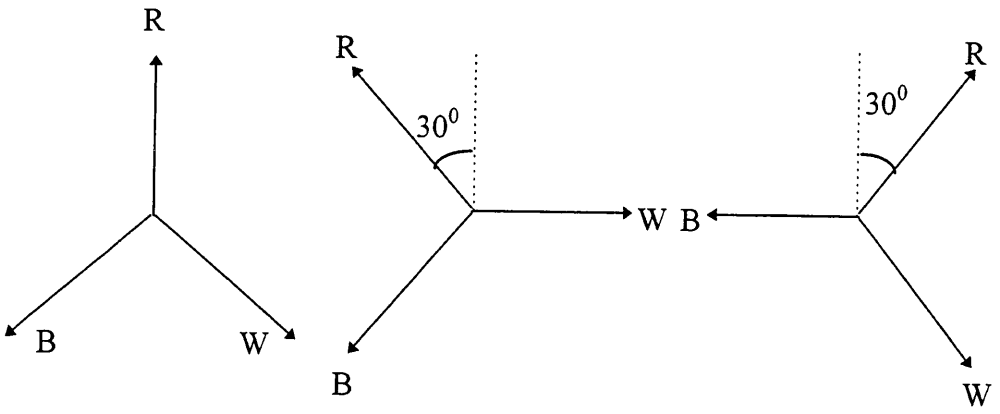
It must also be noted that, in practice, primary and secondary phases are said to correspond when the angle between the phases is at a minimum.



(a) winding connection



(b) positive sequence line to neutral voltages



(C) negative sequence line to neutral voltages

Figure 4.10 positive and negative sequence voltages in YD transformers

CHAPTER 5

TOPOLOGY AND EVALUATION OF THE STOCHASTIC PREDICTION OF VOLTAGE SAGS

5.1 Introduction

Chapters 3 and 4 introduced stochastic prediction techniques for voltage sags and a mathematical equation for voltage calculations in the faulted power system. This chapter enhances the results obtained by introducing an algorithm for studying the frequency of voltage sags in electrical networks. The algorithm makes use of the fault position techniques introduced in chapter 3.

A typical power transmission network spans a large geographical area and involves a large number and variety of network components. This chapter is concerned with the composite

representation of those components. The bus impedance matrix is adopted here for large-scale system analysis.

This chapter introduces formal methods to represent and analyse the network structure. These have been adopted and enhanced from general fault calculations in electrical power networks, as required for the stochastic assessment of frequency of voltage sags. The implementation of the method is described.

5.2 Power System Network Representation

This section concentrates on the results obtained by introducing an algorithm for studying the frequency of voltage sags on electrical network. The algorithm makes use of the fault position techniques introduced in chapter 3.

The network representation is the set of constants, lists and matrices used to depict the structure of a network for computational analysis. The representation used is particularly important to the speed of a topology algorithm because a procedure may be much more efficient with one representation than with another.

In general a network is formed by a combination of nodes (buses) and lines (branches). A line links two nodes. For example, a line could be defined as an ordered pair $K_{(low,\ high)}$ meaning line K from node low to node high (Figure 5.1).

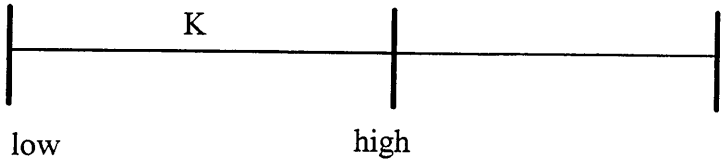


Figure 5.1 Branch between two nodes of a network

As an aid in understanding, the network is often show pictorially as in Figure 5.2. Buses or substations are symbolised by a thick bold line containing the bus index. A branch is shown by a normal line connecting the two buses. Note that two buses can be joined by more than one branch with the same or a different orientation.

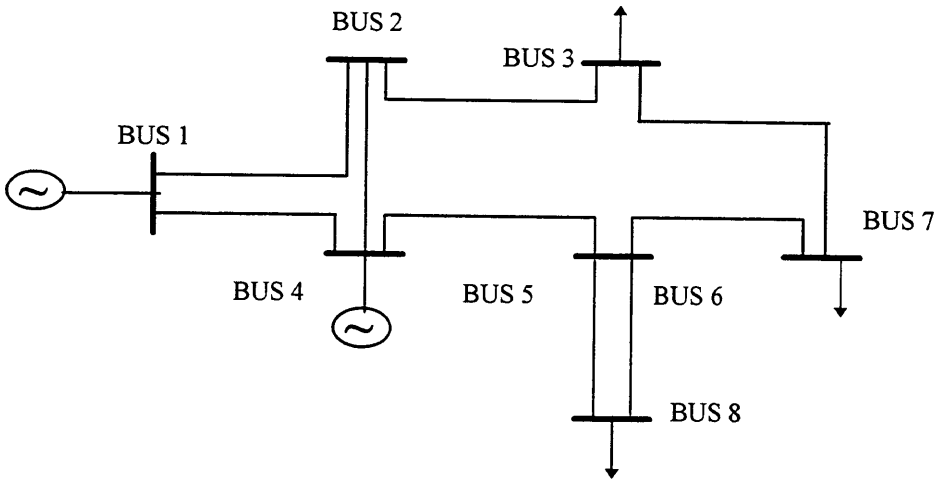


Figure 5.2 Network example

5.2.1 Power Network Model

The purpose of this section is not to give an extensive review of power system modelling theory but to introduce the necessary terms which are used in this chapter. The intention is to avoid confusion since different authors give slightly different definitions for the terms used. The more formal mathematical definitions have been avoided here on purpose. It is not the objective of this chapter to derive a procedure associating a function to each of the branches in the network but is concerned with the development of powerful, efficient and computationally simple tools to establish the state of the network.

5.2.1.1 Connections

A connection in the power system model has a one-to-one relationship with a branch in the electrical network. A branch consists of one or more sections. These sections are series connected electrically as well as stochastically: the total impedance of a branch is the sum of all section impedances; if one section fails the whole connection fails (i.e. the whole branch is removed from the electrical network). A connection is characterised by two node-numbers, its total impedance and data for the sections

5.2.1.2 Normal Sections

A normal section can possess a number of possible short circuit positions. Each short circuit has its own rate of occurrence. A short circuit occurs, the electrical networks impedances change, thus the voltage during the fault is calculated.

5.2.1.3 Short Circuits

Figure 5.3 shows a short circuit in a section. To represent the short circuit, a low-impedance branch is inserted into the electrical network at the fault position and a relay is linked to each circuit. After a certain time, the relays intervene. The times at which the relays intervene are determined by the protection time.

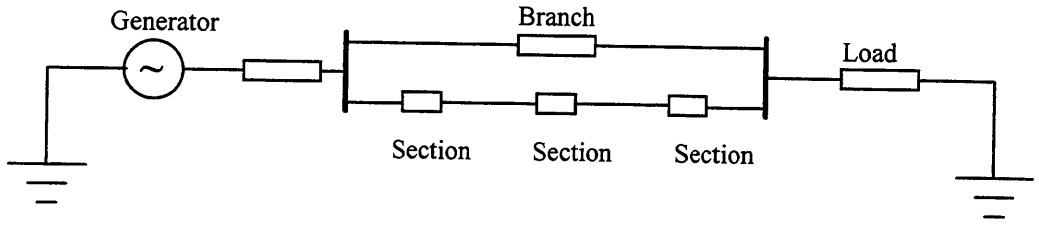


Figure 5.3 Branch in electrical network before a short circuit.

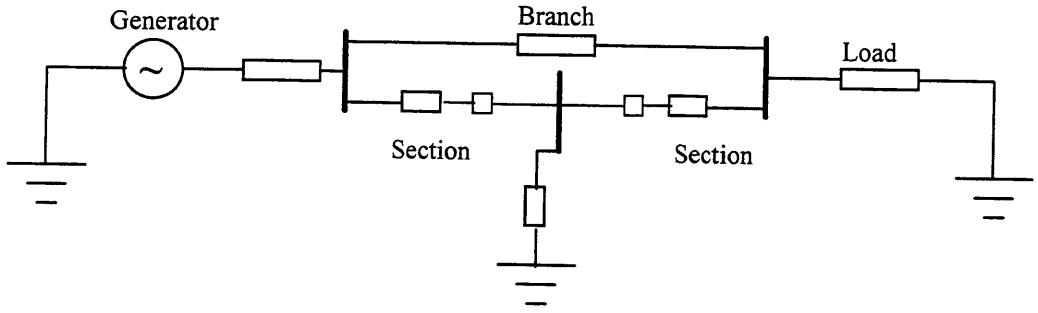


Figure 5.3A Branch in electrical network during a short circuit

Figures 5.3A and 5.3B show what happens meanwhile in the electrical network. A healthy connection consists of a number of section impedances in series. When a short circuit occurs in one of the sections that section split in two and a new created node is created

between the divided section, Figure 5.3B. When the protection intervenes, the whole branch is removed from the electrical network.

Contrary to what is suggested by the figure, the program creates a new node in the electrical network without removing any existing nodes. In the top (Figure 5.3) situation, the three sections are combined into one impedance; in the centre (Figure 5.3A) situation, each section and a half are combined into one impedance.

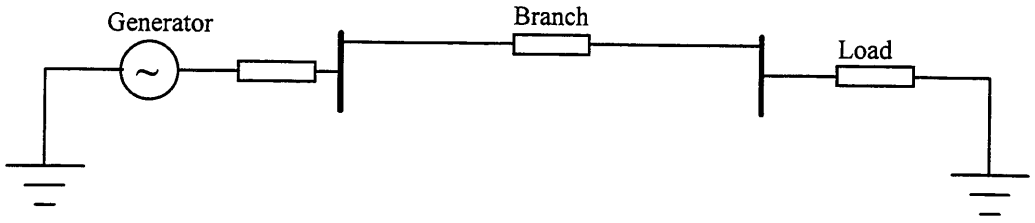


Figure 5.3B Branch in electrical network after a short circuit.

5.2.1.4 Buses

Each bus has one corresponding node in the electrical network. Like a section, a bus can possess a number of possible short circuits. If a short circuit occurs, a small impedance (zero impedance) is connected between the node and ground, the node is "removed" (i.e. all branches leading to that node are removed from the electrical network), short circuits are removed and the node is inserted again by inserting all the branches back into the system.

5.2.1.5 Loads

Loads are artificially introduced in the algorithm in order to index positions at which voltage calculations are needed. Figure 5.4 shows the network representation of a connection with such a load section. The corresponding two branches in series connection are present between ground and one of the "other nodes" . The connection consists of a load section (between ground and the "load node") plus one or more normal sections. This connection is represented by two branches in the electrical network; one branch between ground and the load node and one branch between the load node and the other node.

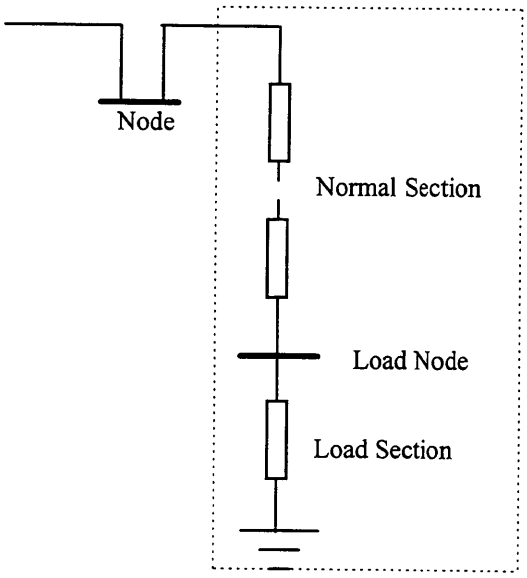


Figure 5.4 Connection with a load section.

5.2.2 Bus Impedance Matrix representation (Z_{BUS})

The bus impedance matrix can be directly constructed element by element using simple algorithms to incorporate one element at a time into the system representation. The work entailed in constructing Z_{BUS} is much greater than that required to construct Y_{BUS} [48] (for more detail, refer to section 4.4). It has been seen, in chapter 4, that each diagonal element of Z_{BUS} reflects important characteristics of the entire system in the form of the Thévenin impedance at the corresponding bus. Unlike Y_{BUS} , the bus impedance matrix of an interconnected system is never sparse and contains zeros only when the system is regarded as being subdivided into independent parts. Such sub-networks, as seen in chapter 4, arise in the zero-sequence network of the system because of delta-connected transformer windings [37,48].

The Z_{BUS} matrix contains the driving point impedance of every node with respect to a reference that has been chosen arbitrarily. The driving point impedance of a node is the equivalent impedance between it and the reference. The Z_{BUS} matrix also contains the transfer impedance between each bus of the system and every other bus with respect to the reference bus. The transfer impedance is determined by computing the voltage that exists on each of the other buses of the system, with respect to the reference, when a particular bus of the system is driven by an injection current of unity [37,44,48]. This was described in detail in chapter 4.

It was recognised very early on that if the Z_{BUS} matrix with the reference bus chosen as the common bus behind the generator transient reactance was available, the complete short-circuit analysis of the network could be readily obtained with a small amount of additional computation. Remembering, as indicated earlier in chapter 4, that a network under fault conditions could be considered to have a single node current.

5.3 Bus Impedance Matrix Algorithm

The Z_{BUS} building algorithm is a method by which line data are sequentially processed to obtain the impedance matrix. To use the building algorithm, a line list is used and one line at a time is processed. Also, the line list must be ordered such that the first line processed is a tie to the reference bus. This is not an unreasonable requirement since there must be at least one tie to the reference bus. Also, at least one bus terminal of all subsequent lines in the line list must be a bus that has been previously seen. This requirement is also reasonable since isolated lines are totally disconnected from the system. These two requirements imply that the Z_{BUS} building algorithm requires line list pre-processing (line ordering). There is a third reason for line ordering which is related to the speed of processing. In the description below, bus 0 is the reference bus.

1. Read line. If the last line has been processed, stop.
2. Read all the buses in the network, and connect all the buses with a high impedance to the reference bus (0), so that even with no branches to other buses it is possible to compute a voltage. Another advantage is that all the other branches are now of the non-radial type, making sure that all the buses are in the matrix. In other words, the size of the matrix is defined.
3. If the line read is the first line processed, simply establish Z_{BUS} as a 1 by 1 matrix consisting of the line impedance 0-1, $Z_{BUS} = \left[z_{01}\right]$.
4. Read the next line. A line connects between buses *p and q: p* is lowest bus number and *q* is the highest bus number, therefore,

$$Z_{BUS} = \left[\begin{array}{c|c} Z_{ORIG} & \begin{matrix} Z_{1L} \\ Z_{2L} \\ \cdot \\ \cdot \\ \cdot \end{matrix} \\ \hline Z_{L1} \quad Z_{L2} \quad \cdot \quad \cdot \quad \cdot & Z_{LL} \end{array}\right]$$

If bus p is a reference (i.e. $p = 0$) then, $Z_{LL} = -Z_{qL} + z$, but if $p \neq 0, \overline{Z}_{LL} = Z_{pL} - Z_{qL} + z$, the proof of this equation is shown in detail in Appendix 1.

Next, perform a Kron reduction of Z_{orig} using the Z_{LL} position as the pivotal element, where any element of $Z_{BUS(modified)}$ is:

$$Z_{ij(\text{mod}\,ified)} = Z_{ij(befor\,ele\,\text{min}\,ation)} - \frac{Z_{iL} Z_{Lj}}{Z_{LL}} \qquad (5.1)$$

Where $i, j = 1...m$ and $L = m + 1$, m is the actual dimension (m*m) of the matrix.

Additional details about the algorithm for constructing Z_{BUS} can be found in the flow chart diagram in Figure 5.5.

A few final remarks about the above algorithm:

- The final Z_{BUS} matrix has a dominant diagonal, therefore the algorithm uses only the upper- half matrix for computations, the lower-half + 1 extra row has a storage function of the normal state situation.
- The most time-consuming steps (m^2) are modifications of existing entries (where m is the order of the matrix).
- All three sequence networks are represented in the same way.

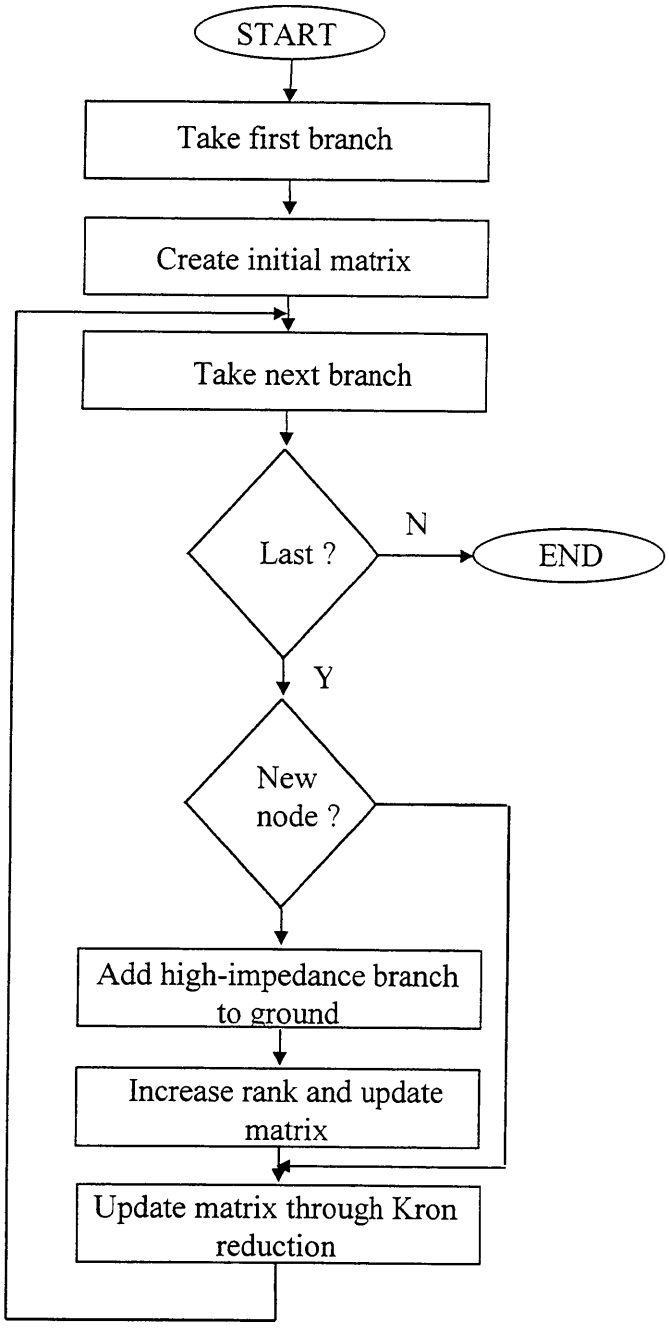


Figure 5.5 Simplified program flow diagram for constructing Z_{BUS}

5.3.1 Change in the network

The bus impedance matrix Z_{BUS} can be modified to reflect changes in the network. These changes may be addition of elements, removal of elements or changes in the impedance of elements.

The method described in section 5.3 based on the algorithm for forming a bus impedance matrix can be applied if elements are added to the network. Then, Z_{BUS} is considered the matrix of the partial network at that stage and the new elements are added one at a time to produce the new bus impedance matrix Z_{BUS} [37].

The procedure to remove elements or to change the impedance of elements is the same. If an element is removed, the modified bus impedance matrix can be obtained by adding, in parallel with the element, a link whose impedance is equal to the negative of the impedance of the element to be removed. If the impedance of an uncoupled element is changed, the modified bus impedance matrix can be obtained by adding a link in parallel with the element, such that the equivalent impedance of the two elements is the desired value. The proof equations are shown in detail in Appendix 1.

5.4 Voltage Calculations

The electrical network is described by using the bus impedance matrix which was defined in section 5.3. This matrix is used to calculate voltages at the load nodes needed for the voltage sags. Within the simulation, the bus impedance matrix is the representation of the current state of the electrical network. Removal and insertion of a branch has consequences for this matrix. This section shows how the matrix is used to calculate voltages at the load

nodes.

The bus impedance matrix, Z, is defined and described in section 5.3. The detail of the sequence current and voltage calculation is shown in chapter 4. It is useful to show how the algorithm of network representation is used to calculate the bus voltages. The following expression is used to calculate the voltage:

$$V = Z_{BUS}\, I \tag{5.2}$$

Where V is the vector of node voltages and I the vector of node currents. The node current is the total current entering or leaving that node. This current is zero for all except the external nodes (in our case the generator nodes). The detailed equations for voltage and current calculations were explained in chapter 4.

5.5 Program Implementation

This section presents the main steps in a program implementation to assess the frequency of the voltage sags in the network. Some of the major steps have already been considered in previous chapters is greater detail and are not repeated. Many small details are omitted for the sake of clarity. The steps are:

1. The components of the network and electrical characteristics are read from an input file.
2. The system impedance of lines, generators and transformers are read from the input file.
3. The generator and load positions of each busbar in the network are read.

4. All fault positions, with their frequency (failure rate) and the type of the fault are read.
5. The positive-sequence and zero-sequence matrices(Z_{BUS}) are constructed as described in the algorithm in section 5.3.
6. For each fault position, the voltage at each load position is calculated using the equation described in chapter 4. The load position has been indexed in the bus matrices as shown in section 5.2.1.5.
7. Voltage magnitude, duration and failure rate of each fault are calculated and stored in different output files with different extensions for each phase. Also, the phase-angle at each load position is calculated.
8. Initialise the voltage sag tables of the three phases, and then calculate the cumulative voltage sag table using the algorithm described in section 3.2.2.
9. The updated table of each load position is saved for each phase in a different file with different extension.

This process can become quite computing intensive for large networks because the faults in the lines need the matrices to be reconstructed by adding a new bus in the network each time. This is illustrated in section 5.3 in detail. The time taken to construct the matrix is proportional to m^2, where m is the matrix size; the matrix size depends on the number of buses in the network.

5.6 Program Flow Diagram

This section presents a detailed program flow diagram of the operations described in previous sections. The flow chart of the program is shown in Figure 5.6 (for the formatting of the input data of the program refer to Appendix 2). Initially, the list of fault positions is

filled with fault positions which are processed one by one. The processing of the fault positions primarily consists of calculating the voltage at load positions during the short circuit (voltage calculations are described in chapter 4, and the algorithm for system representation, in section 5.3). Following the voltage calculation, the voltage sag tables described in section 2.9.4 and the algorithm in section 5.5 are calculated for each load position. Figure 5.6 also shows the flow chart of the voltage sag table algorithm.

The output from the program is shown for a five bus system in Appendix 2 and contains the following:

- Voltage during the fault at each load position, plus the frequency of each fault position and the duration of each fault.
- Voltage sag tables for each load position (frequency of voltage sags).
- Phase angle for each load position.
- Steps 1 to 3 are performed for all the three phases.

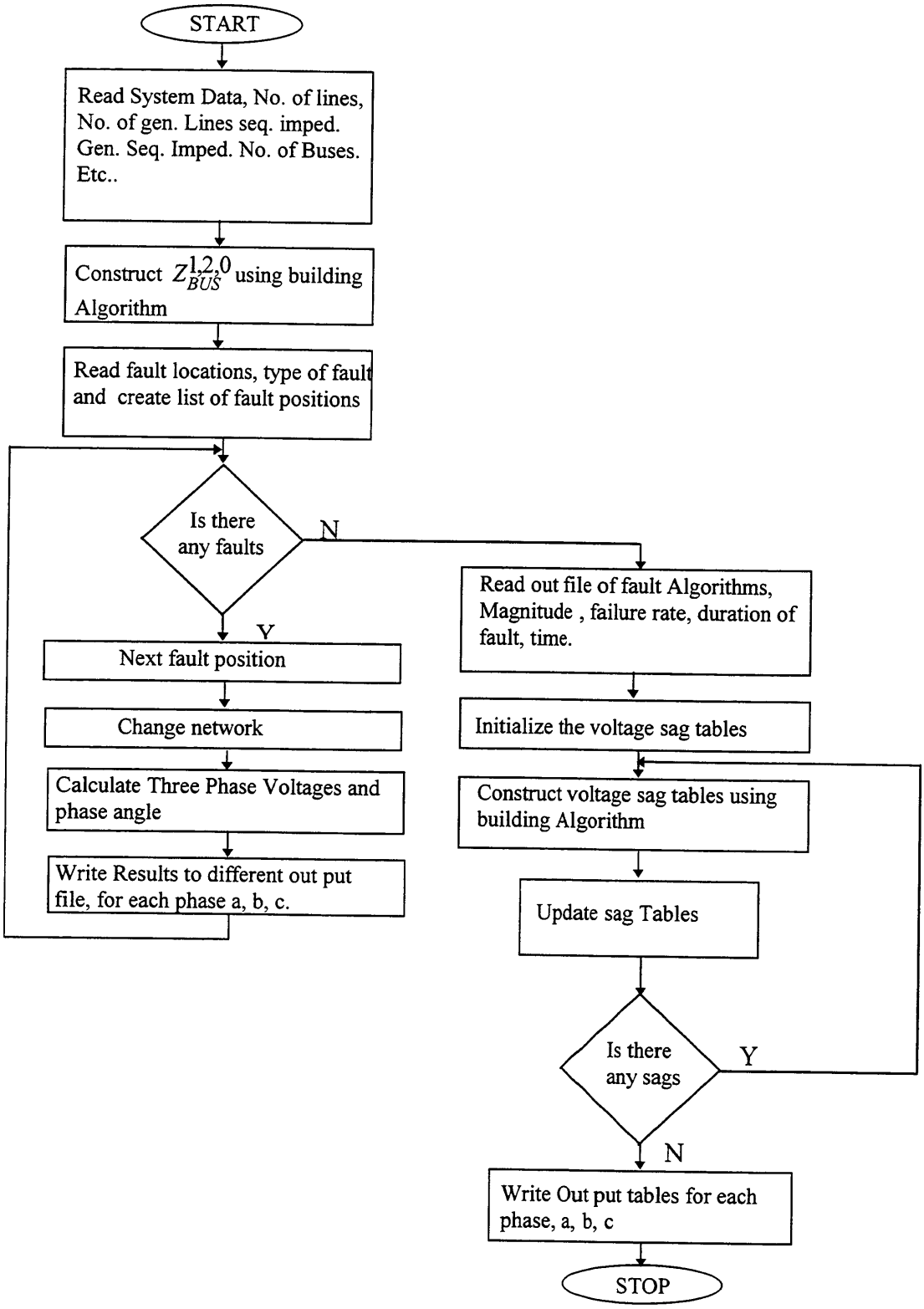


Figure 5.6 Simplified program flow diagram for calculating frequency of voltage sags

5.7 Validation of the Techniques

The evaluation of the number of voltage sags in electrical systems is the most important part of this project. Therefore, it is very important to ensure that all the procedures perform their intended functions. Exhaustive tests were successfully carried out with a single bus radial system. The system is shown in Figure 5.7: it contains an 11 kV supply with a source impedance of Z_1 = 0.1817 Ω and a 100 km radial feeder with an impedance of z = 0.0342 Ω/km.

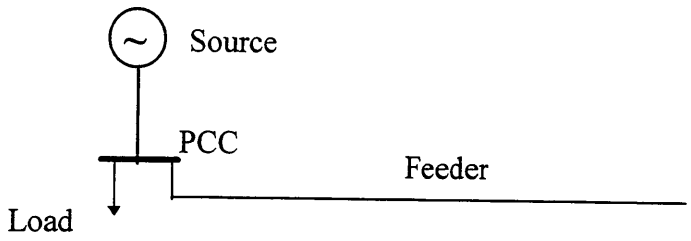


Figure 5.7 Single bus radial system

For this system the method of critical distance and the dedicated fault positions method were applied. These two methods were discussed in detail in chapter 3. For such a radial system the method of critical distances give an exact result. This method as discussed in section 3.2.1 is based on the assumption that X/R ratio of the source and line impedance are equal. In this study both source and feeder have been assumed fully inductive and three-phase faults were applied. The magnitude of the voltage sags as a function of distance L to the 11 kV bus is:

$$V_{sag} = \frac{zL}{Z_1 + zL}$$

As discussed before, the interest of this thesis is to determine the number of sags, but in some cases it is easier to work with the so-called exposed area. This is the total length of a feeder within the critical distance from point-of-common coupling. All plant within the critical distance of the point-of-common-coupling corresponds to the term "exposed area". It is easy to determine the expected number of sags, simply by adding the expected number of faults within the exposed area.

By applying the method of critical distance, the number of voltage sags were calculated for the 11 kV bus. The results of this are the smooth curves illustrated in Figures 5.8 and 5.9. Likewise, applying the method of fault positions, and choosing fault positions at 10,30,50,70 and 90km, the magnitudes of the voltage sags at the point-of-common coupling were calculated. These voltage calculations are correct for the chosen positions, but each fault position represents 20km of line. The underlying assumption is that the sag magnitude is the same for all faults in this 20 km. The results of the method are illustrated in Figure 5.8 as a discontinues line. This figure compares of the two methods. The results from the method of fault positions (discontinues line) can be interpreted for example as every fault between 20 and 40km is represented by one fault position at 30 km. Therefore, the lowest voltage from the discretization of fault positions is about 65.3 %. The figure also shows that the method of fault positions gives a voltage sag which is equal on an average to the exact curve.

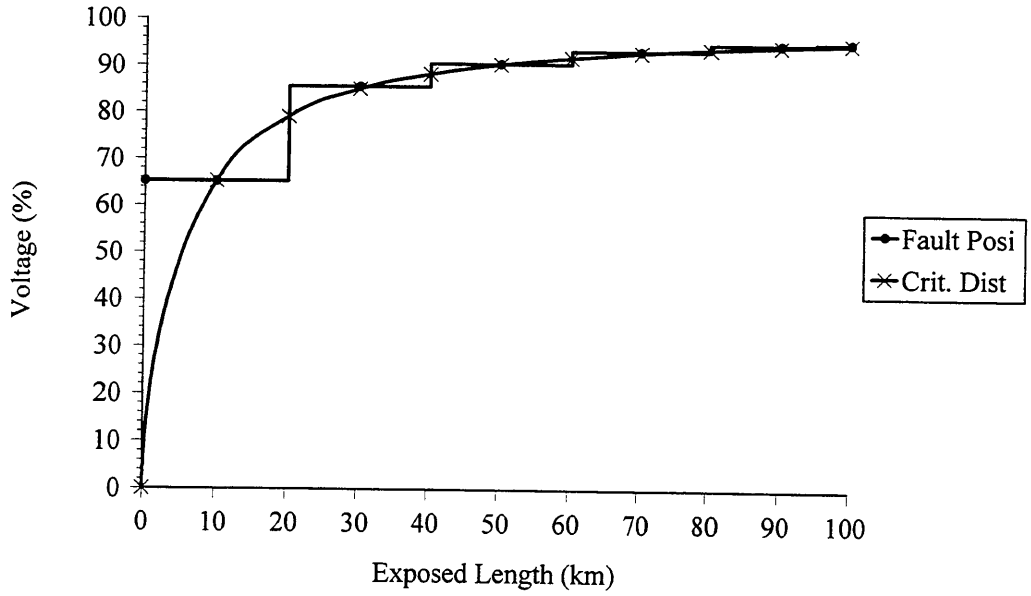


Figure 5.8 Comparison between method of critical distances and fault positions

From Figure 5.8, it easy to determine the exposed length versus voltage magnitude (Table 5.1). It can be clearly seen from Table 5.1 that the method of fault positions under-estimates the number of sags for low sag magnitudes. For example, for voltage sags up to 60% the exposed length is zero, which is not the case with the exact curve (critical distance).

Table 5.1 Exposed length versus voltage sag

	Exposed length (km)	
Voltage Sags (%)	Fault Position	Crit. Dist. (Exact)
20	0	1
40	0	4
60	0	9
80	20	21
90	40	47.5

A higher accuracy is achieved by increasing the number of fault positions. Applying a fault position at each 10km gives the results shown in Figure 5.9. clearly the results converge more towards the exact values. Again, from Figure 5.9 the exposed length versus voltage sags were determined (Table 5.2). The table in this case shows closer correspondence between the two methods.

Table 5.2 Exposed length versus voltage sag

	Exposed length (km)	
Voltage Sags (%)	Fault Position	Crit. Dist. (Exact)
20	5	1
40	5	4
60	5	9
80	25	21
90	45	47.5

Table 5.1 shows a large error in the exposed length, especially for the low sag magnitude (deep sag). Nevertheless, as the number of fault positions is increased, this error is reduced (Table 5.2). So, to obtain more appropriate results from the method of fault positions for the low sag magnitude, additional faults positions closer to the load are needed.

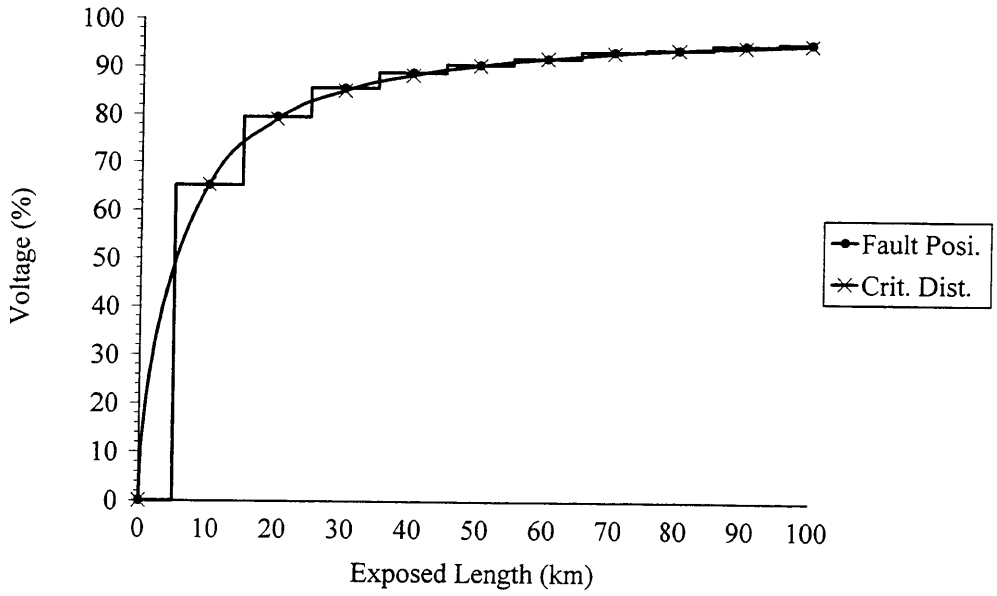


Figure 5.9 Comparison between method of critical distances and fault positions

5.7.1 Phase-Angle Jump

It was pointed out in section 2.7 that some equipment is not only sensitive to the magnitude of the voltage sags but also to the jump in phase angle associated with voltage sags. Therefore, it is very important to ensure that all the procedures used for calculate phase-angle jump are applicable. For the 11 kV radial system discussed in section 5.7, the fault position method has been applied. For such a radial system simple mathematics can be used to obtain an exact result. Therefore, recalling equation (2.4) from chapter 2 which gives the phase-angle jump in the radial system:

$$\phi = \arctan \frac{(R_1 X_2 - R_2 X_1)}{(R_2 R_1 + X_2 X_2) + (R_2^2 + X_2^2)}$$

Where $R_1 + jX_1$ is the source impedance and $R_2 + jX_2$ the feeder impedance. The results from this equation and the method of fault positions are shown in Table 5.3. As expected both calculations give exactly the same results. Also, the shape of these results as shown in Figure 5.10 shows that the phase-jump becomes zero for 1 p.u voltage (no sag).

Table 5.3 Phase-angle jump versus sag magnitude

	Phase-Angle Jump	
Voltage Sags (p.u)	Analytical Calculation	Fault Positions
0.9	-1.6	-1.6
0.8	-3.2	-3.2
0.7	-4.8	-4.8
0.6	-6.5	-6.5
0.5	-8.1	-8.1
0.4	-9.6	-9.6
0.3	-11.3	-11.3
0.2	-12.9	-12.9
0.1	-14.6	-14.6

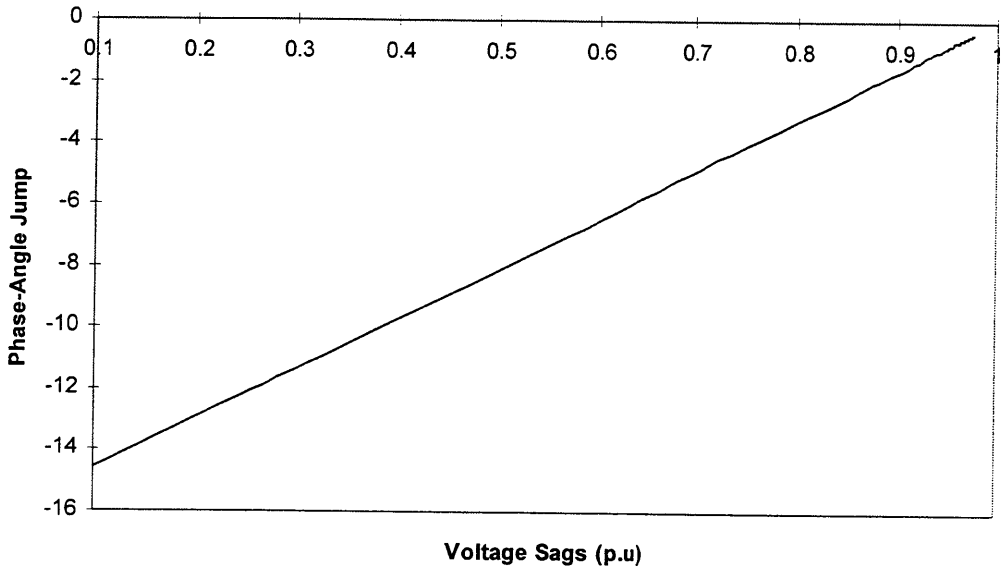


Figure 5.10 The relation between sag magnitude and phase-angle jump

5.8 Conclusions

This chapter has reviewed the basic aspects of electrical system representation and calculation of the number of voltage sags. General expressions have been suggested for modelling the faults in the line. Efficient and general algorithms for system representation and voltage calculations during the fault in the electrical system and calculation of the frequencies of voltage sag stochastically have been discussed. A successful test was carried out using the program by comparing the method of fault positions which was adopted in this project, with the method of critical distance, which gives the exact number of sags for a radial system.

The main advantage of the software is that it provides reliable and rapid information regarding the quality of the output in terms of interruptions and voltage sags. This is interesting for utilities. These results are essential for customers as well as planners in

directing their investment choices. The results given by this method can also be presented in a number of ways as discussed in sections 2.9.4, 3.3 and 3.4.

CHAPTER 6

NUMBER OF VOLTAGE SAGS IN THE DISTRIBUTION SYSTEM

6.1 Introductions

In this chapter, the method of fault positions which was discussed in earlier chapters, is applied to a distribution system. The effect on the number of voltage sags in local distribution systems of faults in the transmission, sub-transmission, local distribution and the combination of the three are discussed. The results are presented as "cumulative voltage sag tables". As addressed earlier, these tables give information about the expected number of sags exceeding certain depths and durations. In this chapter, the option of improving the performance of the system through a local generator is presented.

6.2 System Descriptions

The system studied is shown in Figure 6.1. It is a large chemical industry connected to the public supply at 150 kV. The public supply consists of five 150 kV substations connected to each other. The complete system is connected to a 150 kV public sub-transmission system at one substation (S150-1) through three 10 km overhead lines. The 150 kV public sub-transmission system is fed from a 380 kV transmission system via three transformers. The power in this system is distributed to about 25 plants through a small 150 kV grid and 5 distribution networks with voltage levels of 10 kV and 2 kV. The distribution system is connected to S150-2 via two 150/10.5 kV transformers. Figure 6.1 also shows that a 150 kV system is a strongly meshed network. Moreover, the distribution systems are radial and very few of them are connected to each other.

A total of 396 three-phase fault positions on overhead lines, busbars, and cables have been simulated. On the overhead lines and cables of up to 5 km, one fault position has been simulated. For longer overhead lines and cables, a fault position has been simulated every 5 km. In this study, all voltage levels have been assumed to have the same fault clearing time. This is because the interest of the study lies in determine the during-fault voltage sag only. The substations studied are indicated by 'Sub1', 'Sub2' and 'Sub3' in Figure 6.1. Substations Sub1 and Sub2 are at the10 kV voltage level and substation Sub3 is at the 2 kV voltage level.

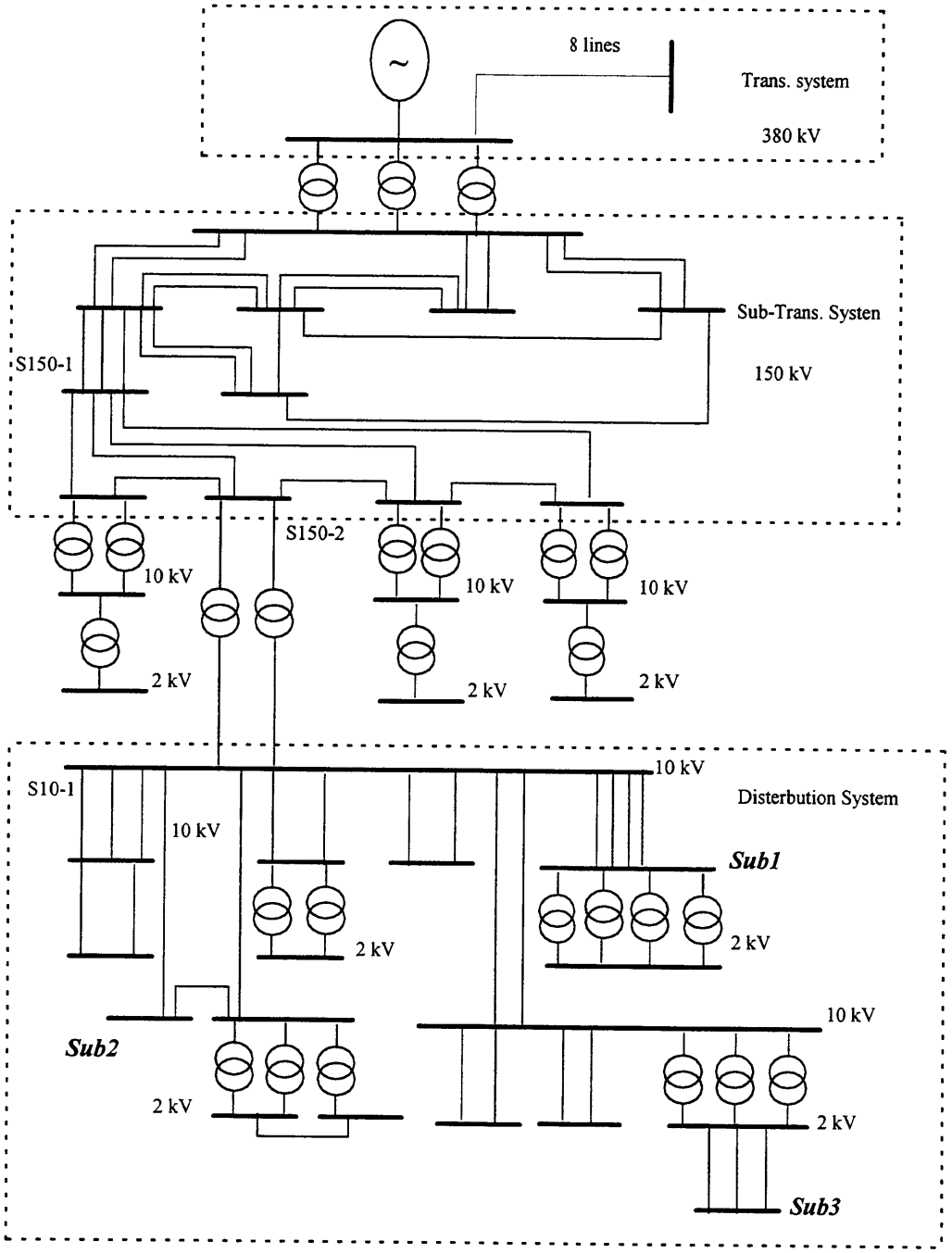


Figure 6.1 Power system studied

† The system parameters were obtained from various sources: data from actual industrial power systems, estimations based on knowledge about the sub-transmission and transmission systems and data from handbooks [30]. The failure rates used for power system components are shown in Table 6.1. The failure rates for a 380 kV transmission system and for a 150 kV sub-transmission system are based on five years of failure statistics [56]. The failure rates of power system components in the 10 kV local distribution system are based on a literature search carried out to obtain failure rate data in distribution systems [57].

Table 6.1 The expected number of faults per year for the power system components

Voltage level	380 kV	150 kV	10 kV
line per km	0.0025	0.00354	--------
Transformer	0.002	0.004	0.005
Busbar	0.002	0.002	0.005
Cable per km	---------	--------	0.01

6.3 Simulation Results

The method of fault positions discussed in chapter 3 has been used to calculate the voltage sags for some of the plants in the distribution system shown in Figure 6.1 (Sub1, Sub2 and Sub3). To obtain an accurate estimate of the expected number of sags at customers locations, every possible fault on the electrical system has to be taken into account. Therefore, for a large number of fault positions in the distribution, sub-transmission and transmission networks, the voltage sags have been determined. The results are presented as numbers of voltage sags. In the following sections, the number of voltage sags is split into three sub-tables. Each of these contains only the number of sags due to the faults in one part of the system (distribution, sub-transmission and transmission system).

† System data has been obtained from S. Brouns at MEGA Limburg and from H. Voncken and others at DSM

6.3.1 Faults in the Distribution System

Table 6.2 illustrates the number of voltage sags due to faults in the local distribution networks for substations Sub1, Sub2 and Sub3. The total number of fault positions applied was 110. These fault positions were applied to the sending and receiving ends of the lines and cables and also to substations and one fault in each current limiting inductor.

Table 6.2 shows the number of voltage sags per phase per year; it can be seen that the number of sags is quite small, but that they are rather deep. The number of voltage sags is strongly dependent on the component failure rates used as mentioned in chapter 3. From the results shown, it can clearly be seen that the number of voltage sags are almost equal in the three substations. This is because these three substations are connected directly to one substation (S10-1). Thus, any fault affecting the voltage at the substation S10-1 directly affects Sub1, Sub2 and Sub3. Because these substations are "electrically" close, for any fault in the distribution system, the substations experience about the same number of voltage sags. It can clearly be seen that at 25 % voltage magnitude, one sag per year occurs. There is some saturation at high voltage magnitudes (90%-80% shallow sags). The saturation is due to short lengths in the distributions system, therefore any faults affect most substations in the distribution network.

Table 6.2 Number of voltage sags due to faults in distribution system

	Number of voltage sags		
Voltage %	Sub1	Sub2	Sub3
90	0.99500	0.99500	0.99500
85	0.99500	0.99500	0.99500
80	0.99500	0.99500	0.99500
75	0.99000	0.99500	0.99000
70	0.88500	0.9700	0.86500
65	0.86500	0.79000	0.86500
60	0.81500	0.76500	0.81500
55	0.64000	0.69500	0.76000
50	0.61000	0.62500	0.71000
45	0.54500	0.55500	0.62000
40	0.38500	0.55500	0.44500
35	0.34500	0.50500	0.44500
30	0.34500	0.46500	0.44500
25	0.34500	0.28500	0.41500
20	0.34500	0.27000	0.41500
15	0.31500	0.26500	0.39000

6.3.2 Faults in the Sub-Transmission System

Table 6.3 gives the expected number of sags per year for the substations indicated by Sub1, Sub2 and Sub3 in Figure 6.1, due to faults in the sub-transmission system. The total number of fault positions applied was 148. It can clearly be seen that the number of voltage sags is much higher than the number of faults in the distribution system. This is due to several reasons: the large total length of the overhead line in the sub-transmission network, and the fact that the outcome of the stochastic prediction is strongly dependent on the number of

fault positions applied to the network. From the results shown in Table 6.3, it can be seen that three industrial distribution systems experience the same number of voltage sags due to faults in the sub-transmission network. This is because the distribution system, as seen in Figure 6.1, is connected to only one bus in the public sub-transmission network. Since this one bus is affected in a certain way by faults in the sub-transmission system, this effect transfers directly to the distribution system.

Table 6.3 also shows saturation in the number of sags at a high voltage magnitude (90%-80% shallow sags). This is due to the limited line length in the sub-transmission system, limiting the number of fault positions. Saturation can also be interpreted as showing that every fault in the system causes the voltage to drop below the given magnitude. Further increasing this magnitude no longer increases the exposed area and thus no longer increases the number of sags within the exposed area. Table 6.3 shows that the number of deep sags (25%-15%) is almost zero for the three studied substations. This is because most faults are electrically distant from the studied distribution substations.

Table 6.3 Number of voltage sags due to faults in Sub-transmission system

	Number of voltage sags		
Voltage %	Sub1	Sub2	Sub3
90	1.44112	1.44112	1.44112
85	1.44112	1.44112	1.44112
80	1.44112	1.44112	1.44112
75	1.15112	1.15112	1.15112
70	1.02312	1.02312	1.02312
65	0.99112	0.99112	0.99112
60	0.92712	0.92712	0.92712
55	0.79712	0.79712	0.79712
50	0.64872	0.64872	0.64872
45	0.45432	0.45432	0.45432
40	0.40232	0.40232	0.40232
35	0.30092	0.30092	0.30092
30	0.24892	0.24892	0.24892
25	0.16472	0.16472	0.16472
20	0.0305	0.0305	0.0305
15	0.0020	0.0020	0.0020

6.3.3 Faults in the Transmission System

The number of voltage sags due to faults in the 380 kV transmission system are illustrated in Table 6.4. The total number of fault positions applied was 138 faults. It can clearly be seen that the number of sags below 50% voltage magnitude is almost zero. This is due to the limited number of fault positions applied. On the other hand, the number of sags of high voltage magnitude (shallow sags) are quite high compared to the deep sags. Moreover, the number of sags decreases steadily towards a low voltage sag magnitude.

Comparing Table 6.4 with Tables 6.2 and 6.3, it can clearly be seen that the number of sags due to faults in the transmission system does not saturate. This indicates that the increase in the number of fault positions in the transmission system increases the number of sags per year in the distribution system, especially for high voltage magnitudes (shallow sags).

Table 6.4 Number of voltage sags due to faults in transmission system

	Number of voltage sags		
Voltage %	Sub1	Sub2	Sub3
90	1.60750	1.60750	1.60750
85	0.80400	0.80400	0.80400
80	0.50400	0.50400	0.50400
75	0.30400	0.30400	0.30400
70	0.20400	0.20400	0.20400
65	0.10400	0.10400	0.10400
60	0.10200	0.10200	0.10200
55	0.10200	0.10200	0.10200
50	0.00400	0.00400	0.00400
45	0.00400	0.00400	0.00400
40	0.00400	0.00400	0.00400
35	0.00400	0.00400	0.00400
30	0.00400	0.00400	0.00400
25	0.00400	0.00400	0.00400
20	0.00400	0.00400	0.00400
15	0.00200	0.00200	0.00200

6.3.4 Cumulative Voltage Sag Table

A cumulative voltage sag table is obtained if the three tables presented above are added (distribution, sub-transmission and transmission simulation results). Table 6.5 illustrates the resulting cumulative voltage sag table for the studied distribution substations (Sub1, Sub2 and Sub3). From Table 6.5, it is clear that the three studied substations experience the same number of sags per year. The information in this table can also be illustrated by Figure 6.2, which shows the number of voltage sags versus the voltage magnitude for the Sub3 substation. From this figure, it can be seen that most deep sags are due to faults in the distribution and sub-transmission systems. This is illustrated in the figure by the curves (Dis and Sub-tra). On the other hand, most shallow sags are due to faults in the three networks (distribution, sub-transmission and transmission system). From the transmission system results, it is very clear that the number of sags increases steadily towards a high magnitude (shallow sags).

Table 6.5 Total number of voltage sags

	Number of voltage sags		
Voltage %	Sub1	Sub2	Sub3
90	4.04362	4.04362	4.04362
85	3.24012	3.24012	3.24012
80	2.94012	2.94012	2.94012
75	2.44512	2.45012	2.44512
70	2.11212	2.19712	2.09212
65	1.96012	1.88512	1.96012
60	1.84412	1.79412	1.84412
55	1.53912	1.59412	1.65912
50	1.26272	1.027772	1.36272
45	1.00332	1.01332	1.07832
40	0.79592	0.96132	0.85132
35	0.64992	0.80992	0.74992
30	0.59792	0.71792	0.69722
25	0.51372	0.45372	0.58372
20	0.3795	0.3045	0.4495
15	0.319	0.265	0.394

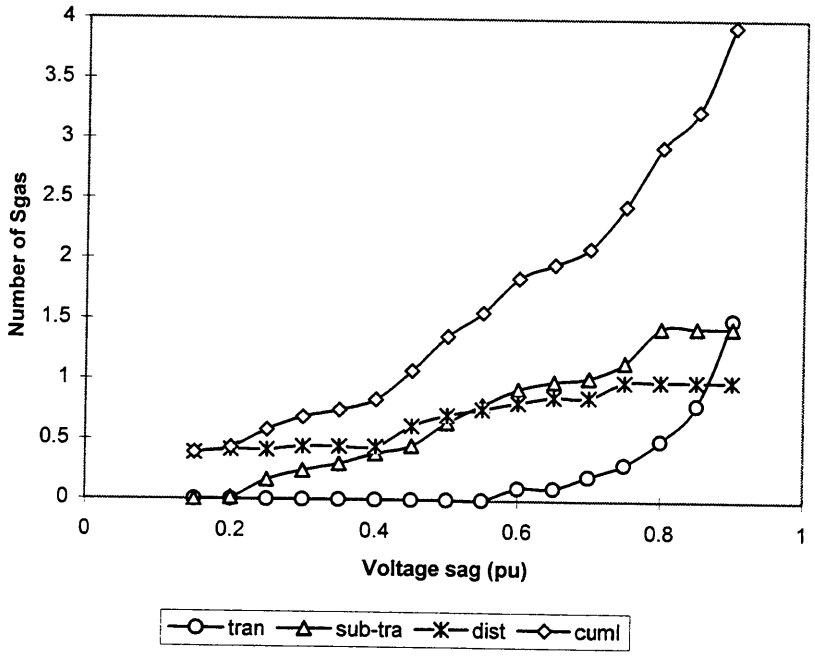


Figure 6.2 Number of voltage sags versus the voltage magnitude for the Sub3

6.4 System Modification

Voltage sags in the system can not be prevented by any method of system changes, but the severity of impact of these sags can be reduced by changing the system configuration. It is possible to reduce the number of voltage sags at the customer positions. The obvious way to improve the system is to reduce the number of short circuit faults and the fault clearing time. However, to implement both would be very expensive. Investment in specific lines is sometimes not suitable because hundreds of kilometres contribute to the exposed length. Another method of reducing the number of sags for local distribution customers is by increasing the fault level at the point-of-common-coupling, which will improve the quality of the supply to the customer. This can be done by installing larger or additional transformers between the supplying substation and customer substations. This reduces the sag depth for customers in the local distribution system but increases it for customers

outside of this system. An alternative method of reducing the number of voltage sags is by installing a local generator in parallel with the main supply. When a fault occurs on the main public supply, the local generator keeps the voltage high at the customer substation. This would benefit most of the customers in the local distribution system.

For the studied system, a local generator of 200 MVA was connected to the 10 kV substation S10-1. The number of voltage sags due to faults in each part of the system was re-calculated. The local generator increases the fault level in the local distribution system. This reduces the severity of sags due to faults in the local distribution system. However, for faults in the transmission and sub-transmission systems, the generator keeps up the voltage in the distribution system. This effect is present, even when the fault level is not increased.

By comparing the results in Tables 6.5 and 6.6, a significant reduction in the number of voltage sags can be seen after installation of a local generator. For example, for a magnitude of 65%, the number of sags is reduced by 25%, and for a magnitude of 45%, the reduction is about 20%.

Figure 6.3 illustrates the number of voltage sags versus voltage magnitude for the Sub3 substation, due to the faults in each individual network. Deep sags are now only due to faults in the distribution system. For faults at a higher voltage level, the local generator keeps up the voltage. The number of voltage sags below 50% is reduced to almost zero for faults in the transmission and sub-transmission systems. Thus, the local generator has a great effect on the number of sags due to faults in the transmission and sub-transmission systems.

Figure 6.4 compares the cumulative number of voltage sags before and after the installation of a local generator; the comparison is shown for the Sub3 substation. The curve indicated by the notation (Nor) shows the number of sags before the installation of a local generator

and the curve indicated by the notation (Mod) shows the situation after the connection of the generator to substation S10-1. Furthermore, this figure illustrates that the shape of the curve after the installation of the generator remains similar to the curve before any changes were made to the system. This clearly indicates that the connection of a local generator in the system reduces the number of sags in the distribution systems.

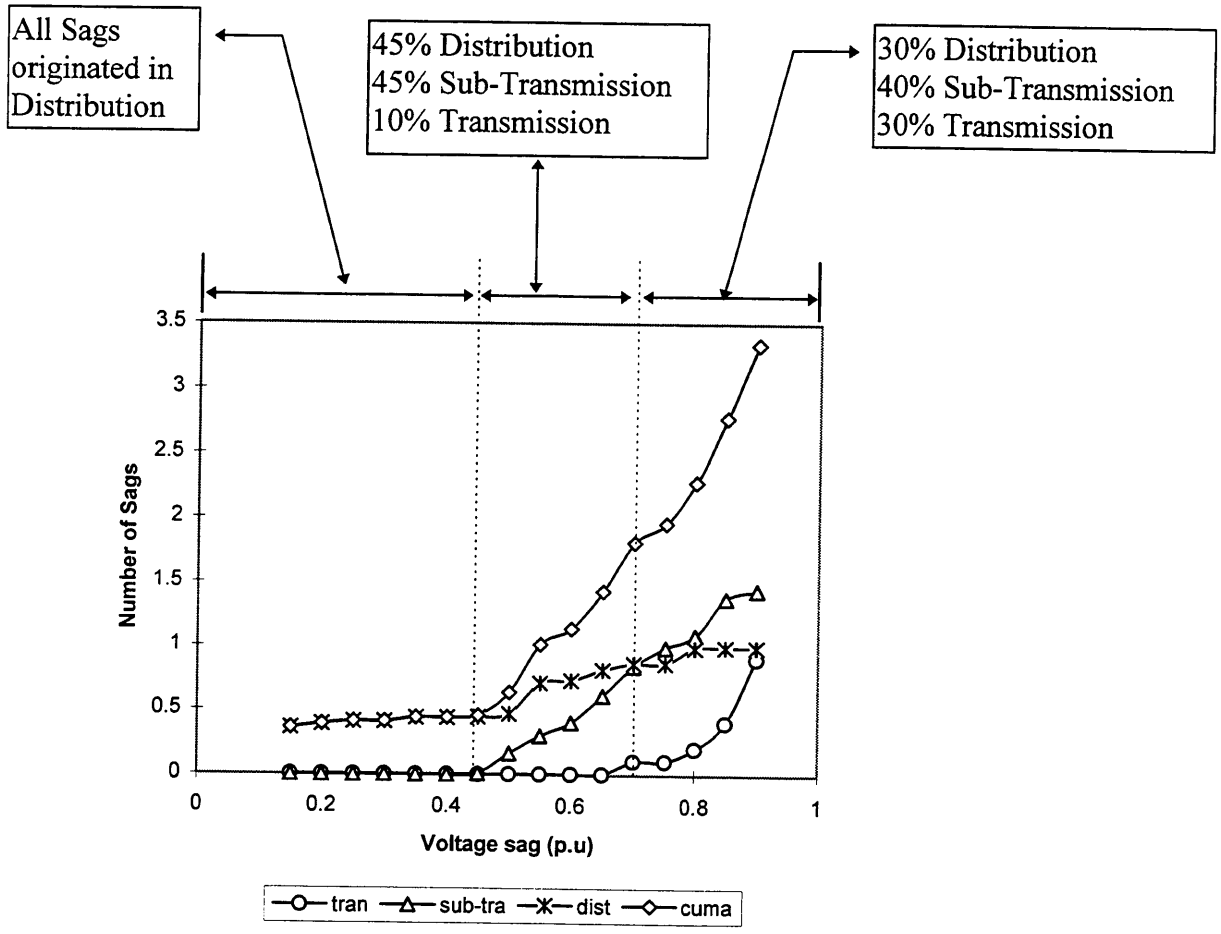


Figure 6.3 Number of voltage sags versus voltage magnitude for the Sub3 after modification

Table 6.6 Total number of voltage sags

	Number of voltage sags		
Voltage %	Sub1	Sub2	Sub3
90	3.34012	3.34012	3.34012
85	2.84012	2.84012	2.84012
80	2.38112	2.28112	2.28112
75	1.96012	1.96012	1.96012
70	1.85092	1.85092	1.85092
65	1.48972	1.48972	1.48972
60	1.12132	1.12132	1.12132
55	0.91792	0.91792	0.91792
50	0.63872	0.63872	0.63872
45	0.4570	0.4570	0.4570
40	0.4424	0.442	0.442
35	0.34	0.34	0.34
30	0.265	0.265	0.265
25	0.265	0.265	0.265
20	0.265	0.265	0.265
15	0.22	0.22	0.22

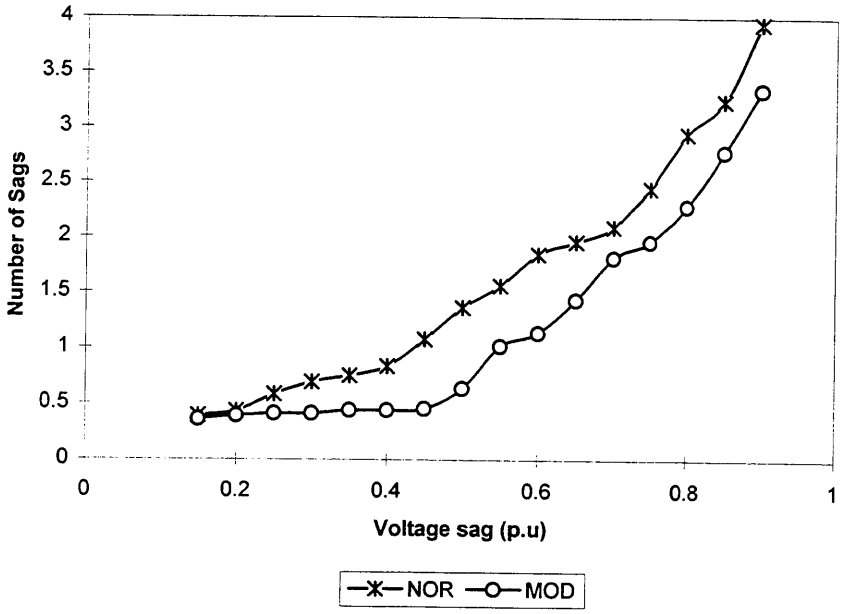


Figure 6.4 Compares the cumulative number of voltage sags before and after the modification

6.5 Conclusions

From the simulation discussed above, it can be concluded that three-phase faults in industrial distribution and sub-transmission systems cause a high number of voltage sags in distribution systems. Faults in the transmission system also contribute to the high number of voltage sags in the local distribution system. Hence, most faults in the system (distribution, sub-transmission and transmission) cause severe voltage sags at customer locations. However, from the characteristics of the voltage sags discussed, it can be concluded that the contribution of faults from different networks can produce different characteristics of voltage sags.

Moreover, modification of the system by inserting a local generator has a great influence on the number of sags in the distribution system. Also, it can be concluded that the local generator reduces the influence of faults in the transmission and sub-transmission on the number of sags in the distribution systems.

CHAPTER 7

APPLICATION OF THE TECHNIQUES TO A LARGE TRANSMISSION SYSTEM

7.1 Introduction

This chapter describes the application of the methods and techniques introduced in previous chapters to a real transmission network. The results have been obtained using a computer program implementing the various algorithms and techniques.

The previous chapters have presented and introduced algorithms and techniques to illustrate the number of voltage sags at the load positions (busbars or substations). In order to use these techniques for network analysis, it is necessary to implement the techniques and algorithms in

a computer program. The requirements and steps involved in such a program have been discussed, principally in chapters 4 and 5.

This chapter deals with the practical application of the concepts expressed in this thesis to a real transmission system. This thesis has to this point focused on the background to the technical issue, introducing the necessary method, solution algorithm and calculation techniques to provide information on relevant aspects of the phenomenon of voltage sags. Once these concepts are implemented, the analysis program can become a design tool. However, it is not the objective of this chapter to show how to use analysis results in a real design procedure, nor to provide a comprehensive review of all the possible techniques, but to illustrate the breadth and depth of the results which can be obtained by reviewing those which are most relevant. Another objective is to show the validity and applicability of these techniques through the program implementation.

The calculation considered and the most relevant aspects of the technique have been described in chapters 3, 4 and 5. The results obtained are in the form of cumulative voltage sag tables and voltages at the load positions for the fault positions given. There are also other sets of variables which can be obtained as results from the stochastic simulation of the network. The resulting number of voltage sags is, as described in chapter 3, strongly dependent on the component failure rates used and the number of fault positions in the simulated system. These are company/system dependent in many cases.

As part of this chapter, special attention is given to the analysis of changes in the number of voltage sags and the exposed area of the network buses.

7.2 System Description

The system used in this study is the National Grid Company (NGC) 400 kV transmission system as at 31 January 1994, which is illustrated schematically in Figure 7.1. The complete generation and transmission network parameter values have been obtained from reference [58]. The total length of all the lines in the 400 kV system is about 13340km. In addition, there are overhead line connections with Scottish Power, and a 2000 MW HVDC link with Electricite de France (EDF), which is connected at the Sellindge substation in Kent. In the simulations reported here, the assumption has been made that there is no connection with Scottish Power, and that at Sellindge, there is a generator connected with a 23 kA fault level. The NGC substations are labelled in Figure 7.1 by a 5 or 6 character code. For example, the Feckenham 400 kV substation has the code FECK4. A full explanation and an index of these substation codes can be found in reference [58]. The generating infeed fault levels of the system were supplied by NGC in reference [58] and used in this study for the 400 kV system. By using these fault levels, the generator site impedances have been calculated using the X/R ratio equal to 20. The system has been simulated for short circuits on all substations and lines. A total of 325 faults have been applied. The number of fault positions modelled depends on the length of the line. For example, a long line has more than two fault positions but a short line only one. All the faults are of the three phase short circuit type. As described in chapter 5, the voltage sags last for the operation of clearing fault time, so a fault clearing time of 200 ms is used for the fault positions. The failure rate assumed for each fault position in the line is 1.34 faults per year per 100km, and the failure rate for each fault position in the substation is 0.08 faults per year per substation.

It should be noted that, although an existing transmission system was modelled, the results should not be directly applied to this system. There are two serious limitations in the model.

- the generator scheduling has been chosen rather arbitrarily.
- a constant failure rate per km has used for all overhead lines.

However, the aim of the study was to show the possibilities of stochastic assessment of voltage sags, which is still achieved despite the model limitations.

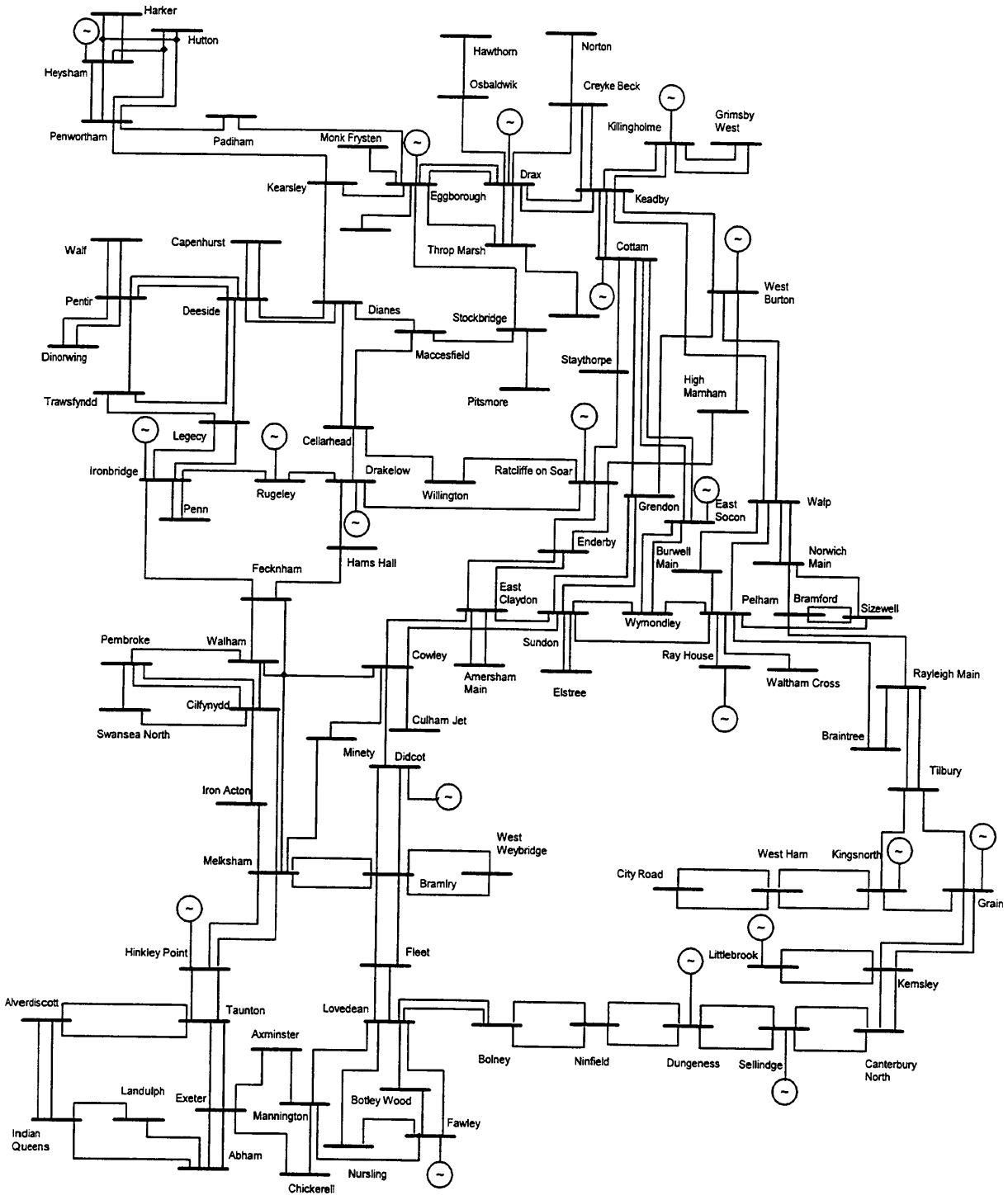


Figure 7.1 National Grid (NGC) 400 kV transmission system (UK)

7.3 During-Fault Voltages

By using the calculations and algorithms presented in the previous chapters, voltage sags have been calculated in the UK 400 kV National Grid System. For the study presented in this thesis 325 fault positions have been used and the voltage magnitudes have been calculated for the 97 buses in the system. The resulting voltages have been placed in a large table which has been used as a basis for further analysis. Presenting the whole table here would require 100 pages of this thesis. To explain the sag analysis done, a small part of the table has been reproduced in Table 7.1. The results in Table 7.1 are the during-fault voltages (i.e. the sag magnitude) for a number of fault positions on the transmission lines (top part of the table) and in substations (bottom part). The sag magnitudes are given for 14 substations in the North of England. The fault positions in the table are geographically in the same region as these substations.

From the table it can be seen that substations near to a fault experience a severe voltage sag. Consider as an example the fault halfway between Padiham and Eggborough (PADI-EGGB 50%). For this fault the voltage in Padiham drops to 27.8%. Note that the voltage in Eggborough only drops to 88.1%. This is due to the much stronger source in Eggborough. Large power stations are located at Eggborough and Drax, electrically close to Eggborough.

The severity of the sags when the faults are close to the bus is a well-known phenomenon. The influence of the distance to the fault on the sag magnitude is represented graphically in Figure 7.2A and Figure 7.2B. Figure 7.2A gives the sag magnitude at a number of substations in the North of England due to a fault halfway between Padiham and Penwortham. This shows that the voltage drops below 90% for a large part of the North of England. Such a fault thus has the potential to cause sag-related equipment-problems for a large number of customers. Figure 7.2A also shown that customers in the North West of England experience

deeper sags than those in the North East. This is, as mentioned before, due to the concentration of generation in the North East.

Figure 7.2B gives the sag magnitude in the South of England due to a fault between Hinkley Point and Melksham, at 25% of the line length from Hinkley Point. Again the voltage drop extends further towards the West than towards the East. This is due to the concentration of generation around London.

The voltage drops below 90% for a large number of substations but below 50% for only one or two substations. The number of customers experiencing a deep sag is thus substantially smaller than the number of customers experiencing a shallow sag.

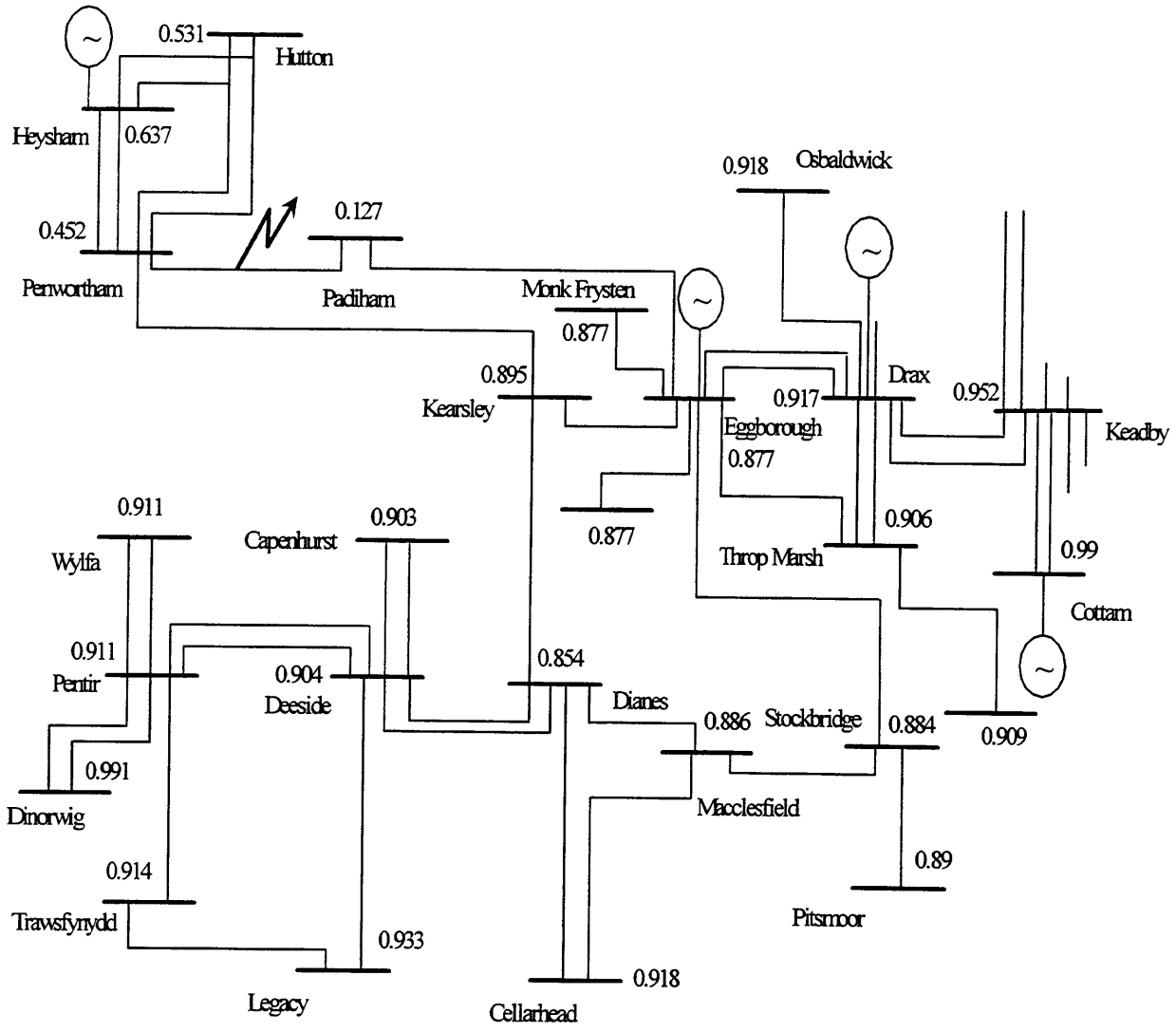


Figure 7.2A Voltage sags due to the fault between Padiham and Penwortham substation

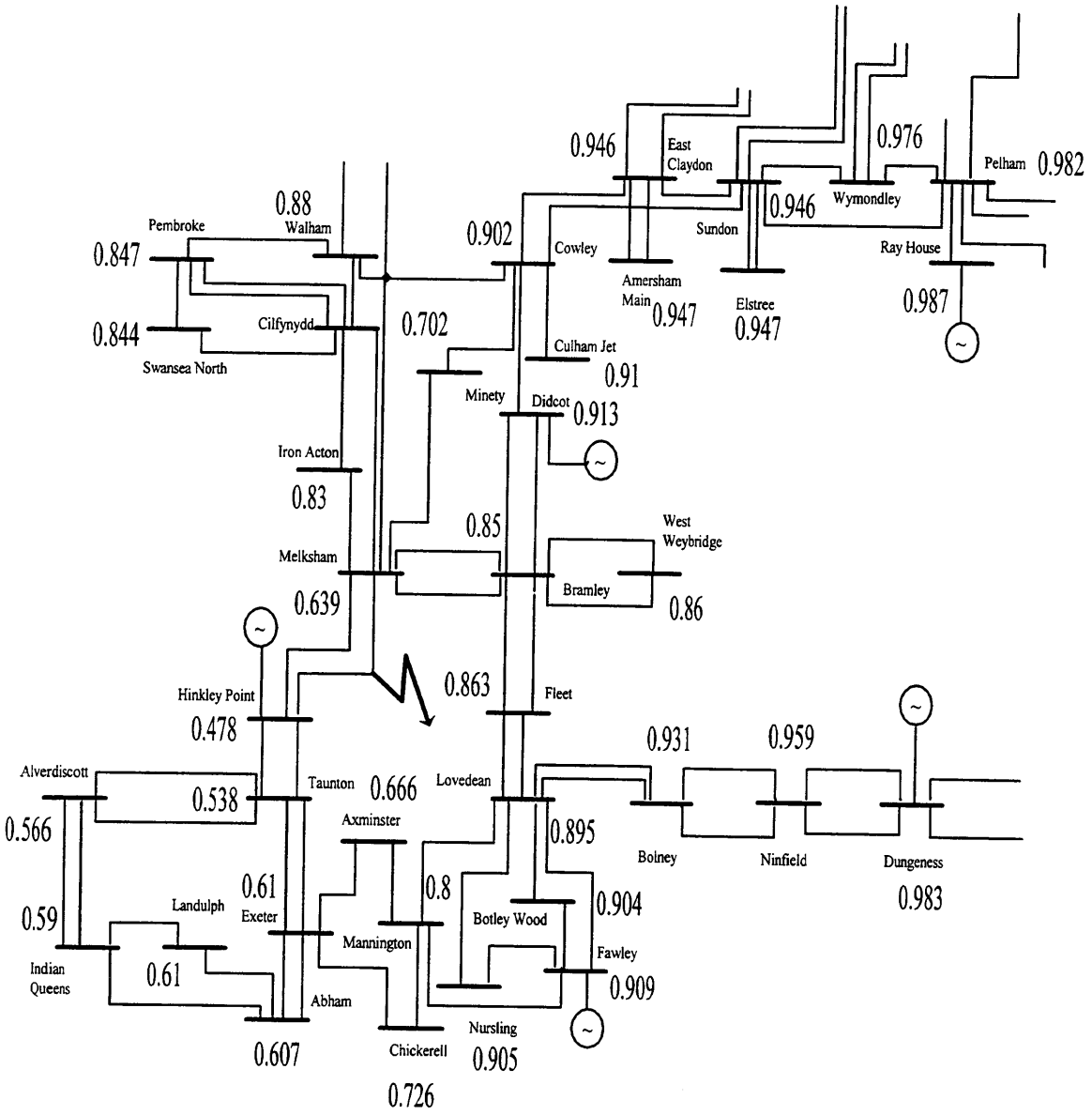


Figure 7.2B Voltage sags due to the fault between Hinkley Point and Melksham substation

Table 7.1 Distribution of the during-fault voltages for some substations

Fault Positions	PADI	MACC	KERS	EGGB	PENE	HEYS	HUTT	STSB	DIAN	DREX	DEES	CELL	THMO	LEGA
RUGL-DRAK 50%	0.947	0.78	0.901	0.94	0.948	0.965	0.956	0.816	0.826	0.962	0.829	0.633	0.952	0.823
RUGL-IRON 50%	0.974	0.914	0.948	0.972	0.974	0.982	0.977	0.927	0.905	0.985	0.819	0.885	0.978	0.752
IRON-LEGA 50%	0.957	0.891	0.914	0.958	0.957	0.971	0.963	0.906	0.836	0.982	0.589	0.899	0.968	0.398
IRON-LEGA 50%	0.957	0.891	0.914	0.958	0.957	0.971	0.963	0.906	0.836	0.982	0.589	0.899	0.968	0.398
LEGA-TRAW 25%	0.952	0.881	0.902	0.953	0.951	0.967	0.958	0.897	0.812	0.98	0.515	0.898	0.964	0.376
LEGA-TRAW 50%	0.956	0.893	0.911	0.958	0.955	0.97	0.962	0.907	0.829	0.983	0.557	0.91	0.968	0.56
LEAG-DEES 50%	0.923	0.812	0.844	0.926	0.921	0.947	0.933	0.838	0.701	0.969	0.224	0.842	0.943	0.226
CELL-DAIN 50%	0.877	0.607	0.757	0.876	0.877	0.917	0.894	0.668	0.546	0.948	0.694	0.492	0.905	0.783
MACC-DAIN 50%	0.837	0.32	0.687	0.826	0.839	0.892	0.862	0.434	0.433	0.93	0.622	0.592	0.867	0.736
MACC-STSB 50%	0.849	0.152	0.743	0.811	0.863	0.908	0.883	0.103	0.597	0.924	0.728	0.564	0.856	0.808
DEES-DAIN 50%	0.894	0.745	0.784	0.898	0.891	0.927	0.907	0.779	0.586	0.959	0.403	0.794	0.922	0.593
DEES-DAIN 50%	0.894	0.745	0.784	0.898	0.891	0.927	0.907	0.779	0.586	0.959	0.403	0.794	0.922	0.593
DEES-CAPE 50%	0.916	0.794	0.828	0.918	0.913	0.942	0.926	0.822	0.67	0.967	0.146	0.83	0.938	0.414
DEES-CAPE 50%	0.916	0.794	0.828	0.918	0.913	0.942	0.926	0.822	0.67	0.967	0.146	0.83	0.938	0.414
EGGB-THMO 50%	0.743	0.742	0.679	0.578	0.807	0.871	0.835	0.707	0.746	0.791	0.83	0.832	0.359	0.881
EGGB-DREX 50%	0.584	0.581	0.481	0.318	0.688	0.791	0.733	0.525	0.588	0.627	0.725	0.727	0.346	0.808
EGGB-DREX 50%	0.584	0.581	0.481	0.318	0.688	0.791	0.733	0.525	0.588	0.627	0.725	0.727	0.346	0.808
PADI-EGGB 25%	0.501	0.841	0.787	0.755	0.769	0.845	0.802	0.822	0.835	0.905	0.89	0.895	0.814	0.923
PADI-EGGB 50%	0.278	0.91	0.859	0.881	0.724	0.815	0.764	0.904	0.896	0.954	0.931	0.938	0.91	0.952
PENW-PADI 50%	0.127	0.886	0.795	0.877	0.452	0.633	0.531	0.884	0.854	0.952	0.903	0.918	0.906	0.933
PENW-HEYS 50%	0.506	0.884	0.778	0.889	0.342	0.387	0.366	0.885	0.844	0.957	0.896	0.915	0.916	0.928
PENW-HEYS 50%	0.506	0.884	0.778	0.889	0.342	0.387	0.366	0.885	0.844	0.957	0.896	0.915	0.916	0.928
PENW-HUTT 50%	0.528	0.889	0.788	0.894	0.371	0.517	0.256	0.89	0.851	0.959	0.901	0.919	0.919	0.931
PENW-HUTT 50%	0.528	0.889	0.788	0.894	0.371	0.517	0.256	0.89	0.851	0.959	0.901	0.919	0.919	0.931
HEYS-HUTT 50%	0.637	0.915	0.837	0.918	0.517	0.48	0.336	0.916	0.885	0.968	0.924	0.938	0.938	0.947
HEYS-HUTT 50%	0.637	0.915	0.837	0.918	0.517	0.48	0.336	0.916	0.885	0.968	0.924	0.938	0.938	0.947
PENT	0.992	0.972	0.984	0.991	0.992	0.995	0.993	0.976	0.973	0.992	0.958	0.959	0.992	0.945
RUGE	0.958	0.834	0.92	0.953	0.959	0.972	0.965	0.86	0.859	0.972	0.829	0.733	0.962	0.801
LEGA	0.932	0.831	0.862	0.934	0.93	0.953	0.94	0.854	0.735	0.972	0.319	0.853	0.949	0
TRAW	0.95	0.878	0.898	0.952	0.949	0.966	0.956	0.894	0.805	0.98	0.492	0.898	0.963	0.558
CELL	0.876	0.428	0.767	0.863	0.879	0.919	0.897	0.525	0.587	0.938	0.711	0	0.894	0.785
WILL	0.956	0.825	0.921	0.949	0.959	0.972	0.965	0.853	0.867	0.956	0.887	0.706	0.956	0.897
MACC	0.842	0	0.72	0.811	0.852	0.901	0.873	0.182	0.537	0.923	0.688	0.489	0.856	0.779
DEES	0.902	0.762	0.801	0.905	0.9	0.933	0.914	0.794	0.617	0.961	0	0.804	0.928	0.321
DAIN	0.745	0.389	0.48	0.754	0.738	0.824	0.776	0.471	0	0.901	0.338	0.514	0.813	0.543
THMO	0.758	0.756	0.698	0.604	0.818	0.878	0.845	0.724	0.76	0.747	0.84	0.84	0	0.888
EGGB	0.391	0.389	0.24	0	0.542	0.693	0.608	0.305	0.398	0.614	0.599	0.604	0.242	0.72
STSB	0.851	0.258	0.756	0.805	0.868	0.911	0.887	0	0.637	0.922	0.755	0.616	0.852	0.827
PADI	0	0.907	0.844	0.889	0.631	0.753	0.684	0.904	0.887	0.957	0.925	0.935	0.916	0.948
PENW	0.249	0.823	0.663	0.831	0	0.329	0.144	0.826	0.763	0.934	0.843	0.871	0.872	0.891
HEYS	0.432	0.866	0.745	0.872	0.244	0	0.148	0.868	0.821	0.95	0.881	0.903	0.903	0.918
KEAR	0.532	0.507	0	0.586	0.503	0.667	0.574	0.526	0.307	0.838	0.54	0.634	0.686	0.682

7.4 Exposed area

The exposed area, as explained earlier in chapter 3, is determined by fixing the customer bus; the voltage at that bus is calculated for all fault positions in the system. The exposed area for the 400 kV NGC system was established for the Legacy and Mannington substations. Figure 7.3 illustrates the exposed area for the two substations, including the fault positions. Different levels of voltage are pictured in the figure. As can be seen, the exposed area is more or less a circle around the substation. It is very clear that the closer the fault is to the substation, the more severe the voltage sag. For example, the Mannington substation can sense a 70% voltage sag for faults on 994km of overhead lines, but a 90% sag for 2699km. Also, from the contour lines of the exposed area a large deviation from the circular shape can be seen for low voltage sags: this deviation is towards large generation sites. For example, for the Legacy substation in the North West of the England, the 80% exposed area is extended towards the North East, due to the large generation stations at Drax and Eggborough. Likewise, there is deviation in the Mannington exposed area boundaries towards Dungeness and Sellindge, where the generator is located. Any faults near these generators leads to a large drop in voltage in the system. Figures 7.4 to 7.6 showing more examples of exposed areas in the system for the substations Deeside, Walham, Bramley, Pelham, Killingholme, and Cellarhead. From Figure 7.3 to 7.6 it also becomes clear that the size of the exposed area varies considerably for different substations. This leads to significant differences in the number of sags experienced at different substations.

Contour lines showing the variation in the voltage sag levels in a system illustrate the power quality over the system. The knowledge of exposed areas for a substation in the 400 kV NGC system assists in the consideration of the equipment supplied from this substation. For example, contactors, which drop out at 50% voltage, have a relatively small exposed area while adjustable-speed drives, which drop out at 90% voltage, may be sensitive to faults over a much wider range of the transmission system.

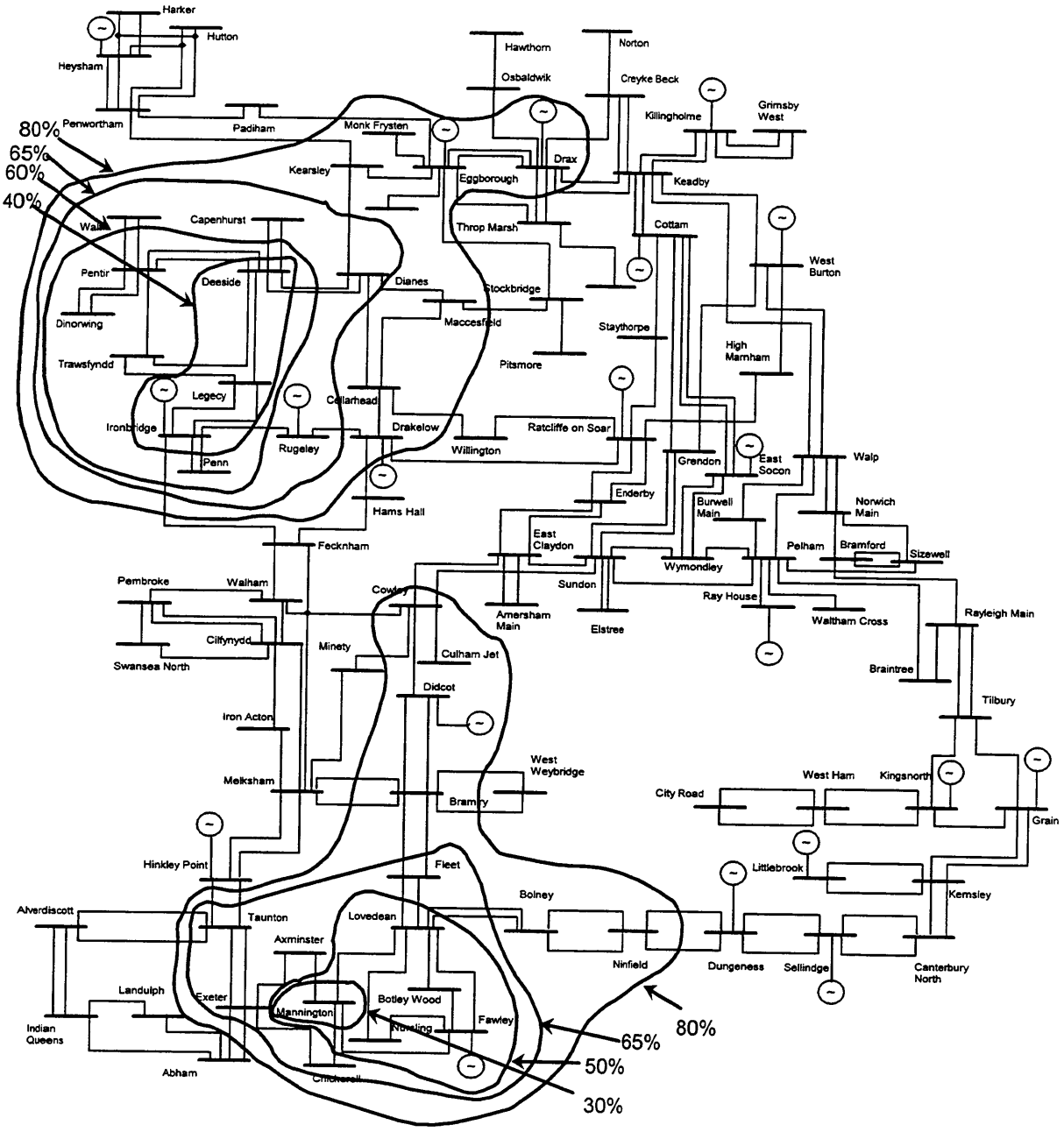


Figure 7.3 Contour lines illustrate exposed area at Legacy and Mannington substations

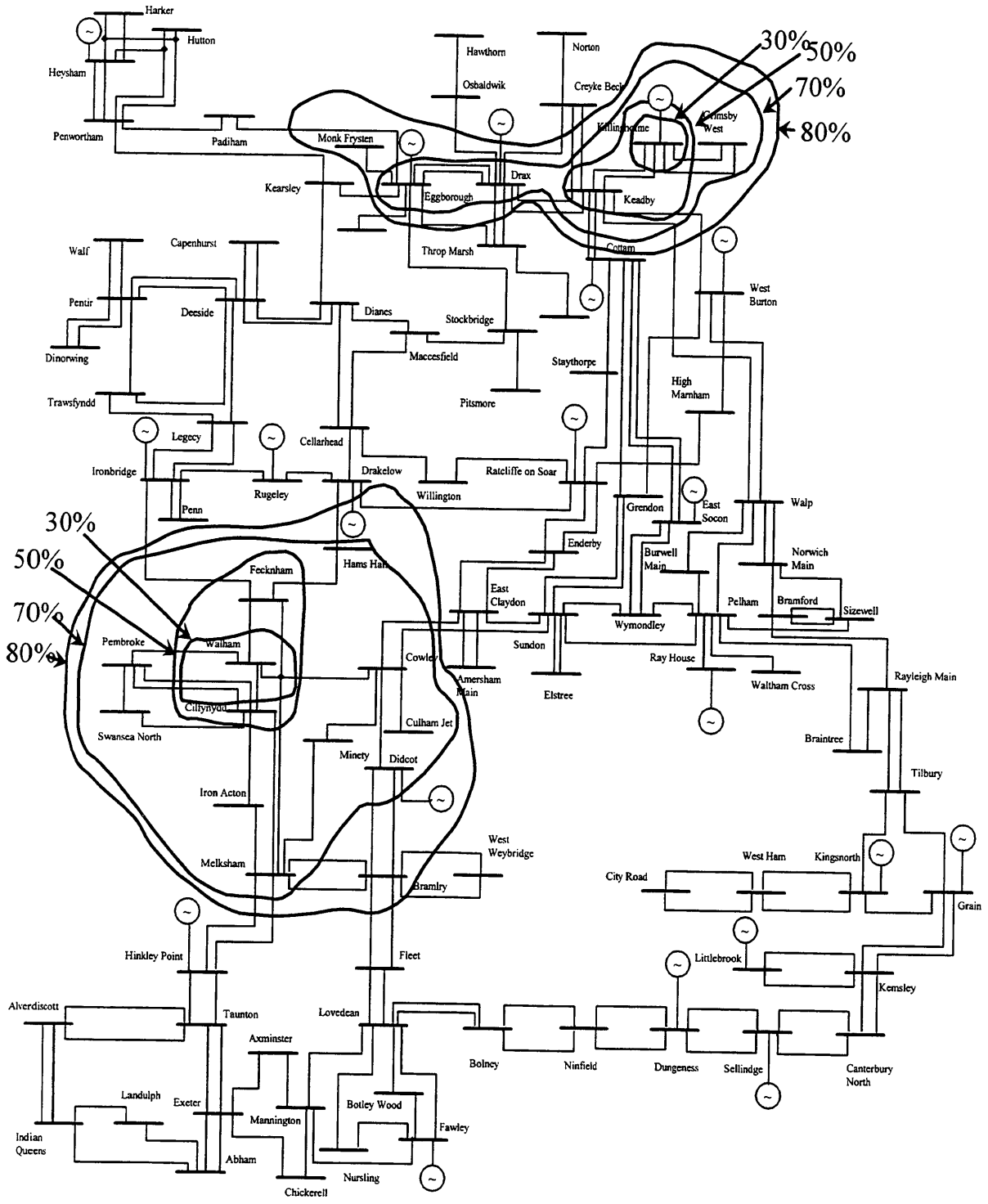


Figure 7.4 Contour lines illustrate exposed area at Walham and Killingholme substations

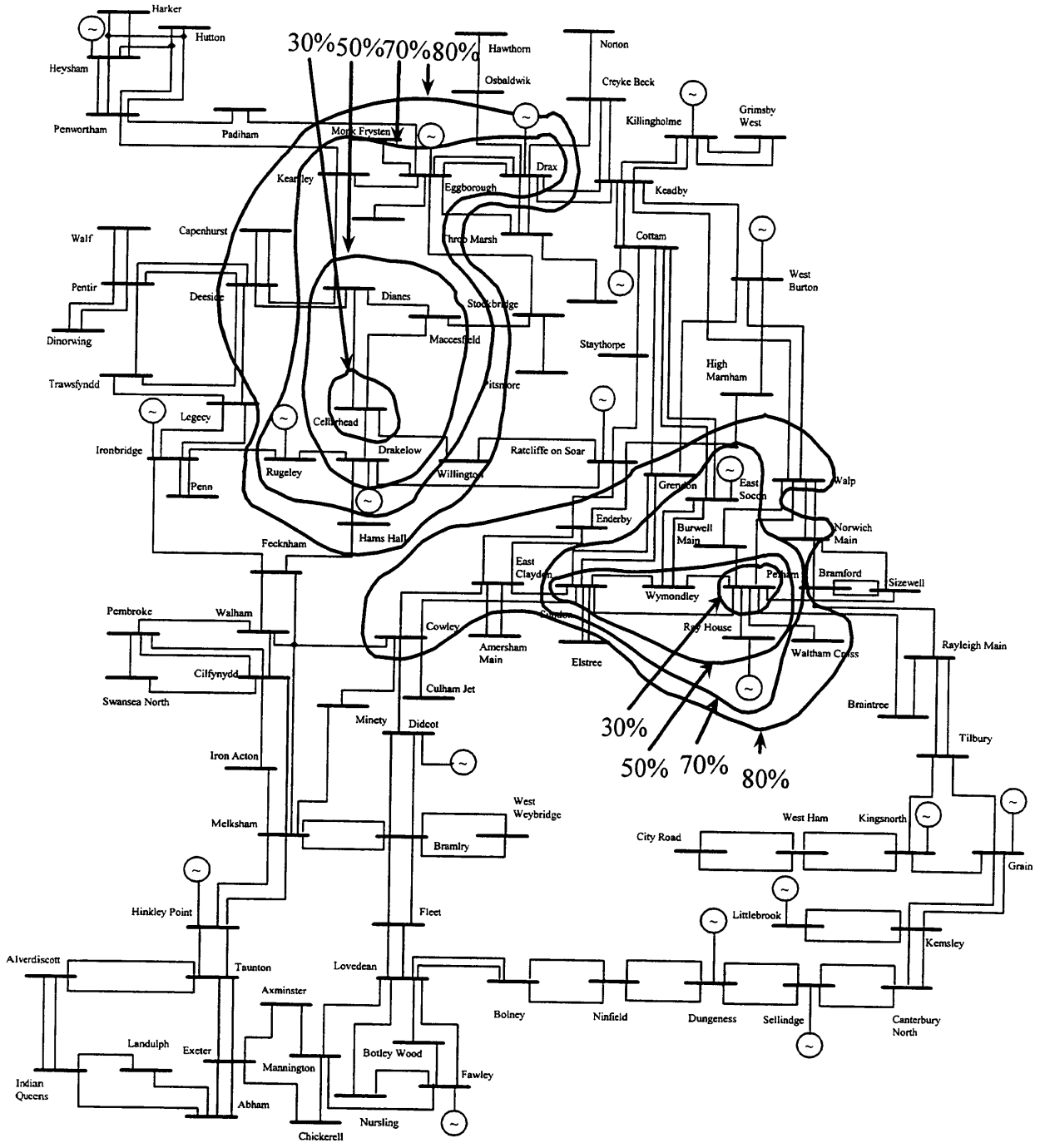


Figure 7.5 Contour lines illustrate exposed area at Pelham and Cellarhead substations

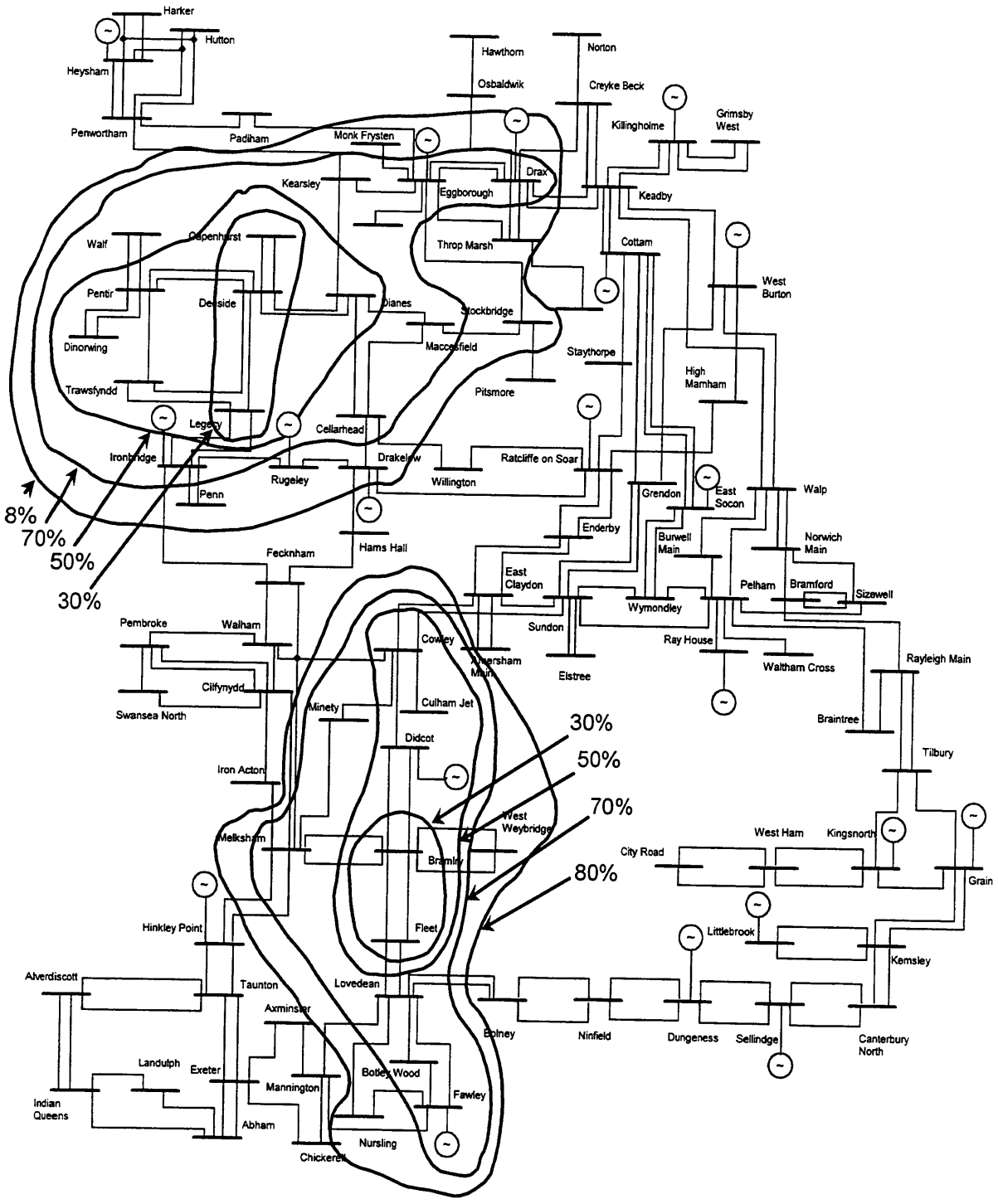


Figure 7.6 Contour lines illustrate exposed area at Deeside and Bramley substations

7.5 Cumulative Voltage Sag Tables

Table 7.2 shows the expected number of voltage sags per year for some 400 kV NGC substations. The table gives the expected number of spurious trips for a piece of equipment with the corresponding voltage tolerance.

Table 7.2 Expected number of voltage sags

Voltage %	Deeside	Walham	Bramley	Pelham	Killingholme	Cellarhead
90	27.95	42.09	36.94	33.21	10.24	31.00
85	21.75	29.41	21.42	22.63	6.66	15.11
80	18.14	22.69	16.72	14.04	5.3	9.47
75	16.07	16.58	8.95	9.35	2.44	7.69
70	14.36	16.42	6.65	8.27	1.76	6.88
65	12.73	15.46	5.55	5.44	1.76	5.20
60	12.73	11.02	3.64	5.36	1.76	3.55
55	9.09	7.98	3.56	3.36	1.76	2.30

Table 7.2 shows the results for the Walham and Deeside substations, which are located far away from the large generator units in the system. A customer fed from these substations can expect a large number of voltage sags. On the other hand, the results for the Bramley and Pelham substations show they experience less voltage sags. This is due to large generator units situated near these substations. The results for the Killingholme and Cellarhead substations, which are situated an average distance from the generators, indicate an average number of voltage sags. Moreover, the expected number of voltage sags further away from the generators is higher than those close to the generators.

In other words, the expected number of voltage sags shown in Table 7.2 can be interpreted using the exposed areas discovered for these substations in Figures 7.4 to 7.6. It is clear that the exposed areas for the Walham and Deeside substations occupy a large area, creating a

large number of voltage sags at these substations. Killingholme and Cellarhead, on the other hand, possess a smaller exposed area, therefore they experience less voltage sags. The substations Bramley and Pelham have exposed areas smaller than those of Walham and Deeside but larger than Killingholme and Cellarhead, therefore, the expected number of sags is average.

7.6 Voltage Sag Maps

The cumulative voltage sag tables can also be presented as a contour line on a geographical map. A voltage sag map of the system connects places with an equal sag frequency; different maps apply to different magnitudes. Such a map indicates power quality variation over a geographical area.

Figures 7.7 and 7.8 illustrate the expected number of voltage sags below 80% and 65% respectively. The figures show that the number of voltage sags is higher in the weak areas of the system. The North West belongs to the weak area whereas the South East has better power quality. In other words, as one proceeds towards the large generator sites, the system experiences a lower number of voltage sags. The average site would experience 10 sags per year below 80% and 20 below 65%.

However, there is a large variation in the number of voltage sags over the system. Average monitoring results will thus not give an accurate indication of the power quality for a specified site for a large system like the 400 kV NGC grid. Such variations are very difficult to predict through monitoring and a long period of time is necessary to attain any level of accuracy. Indeed, for a level of accuracy of 2 percent one would require 25 years for one event frequency per day.

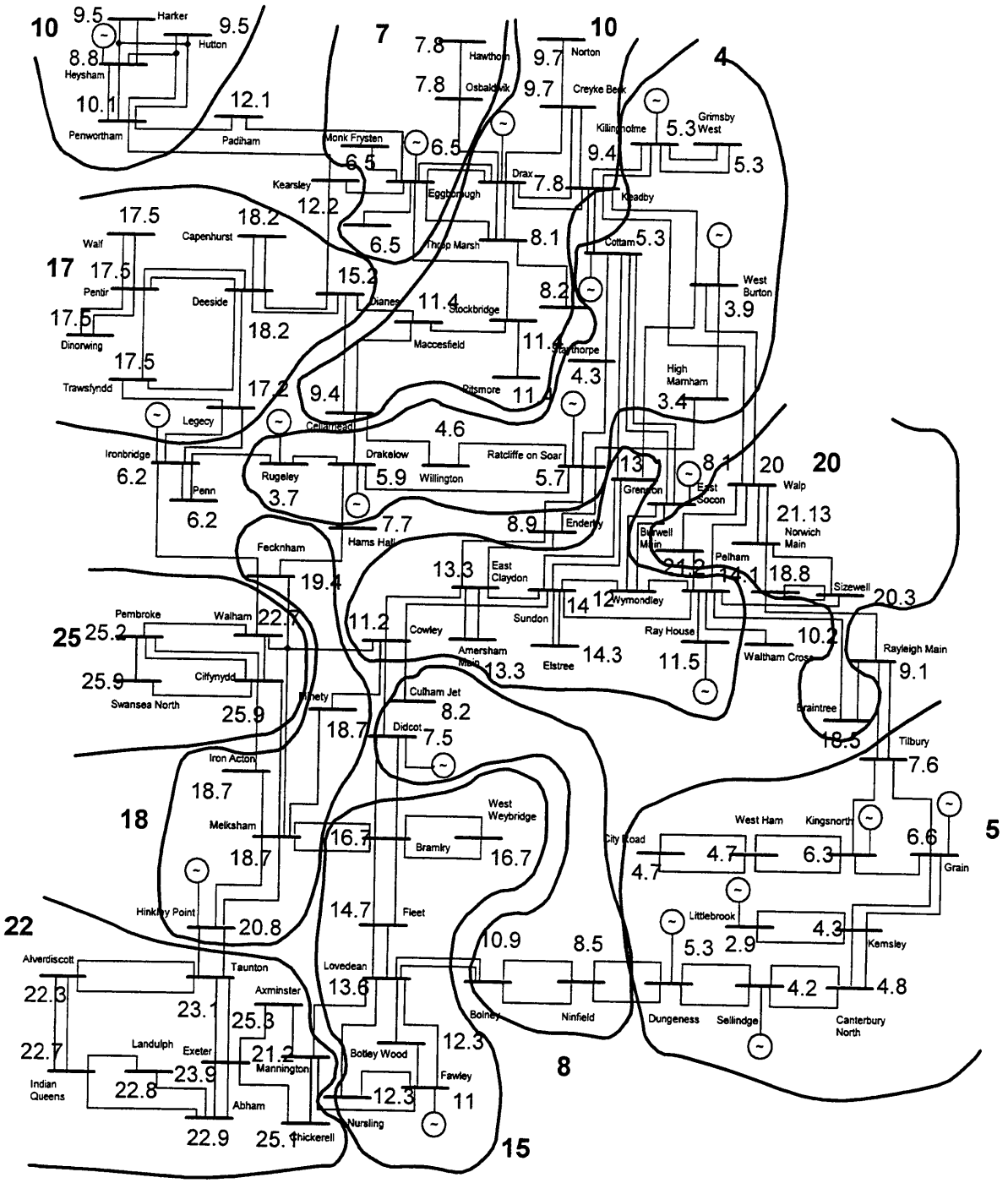


Figure 7.7 Frequency of voltage sags for chosen fault positions below 80%

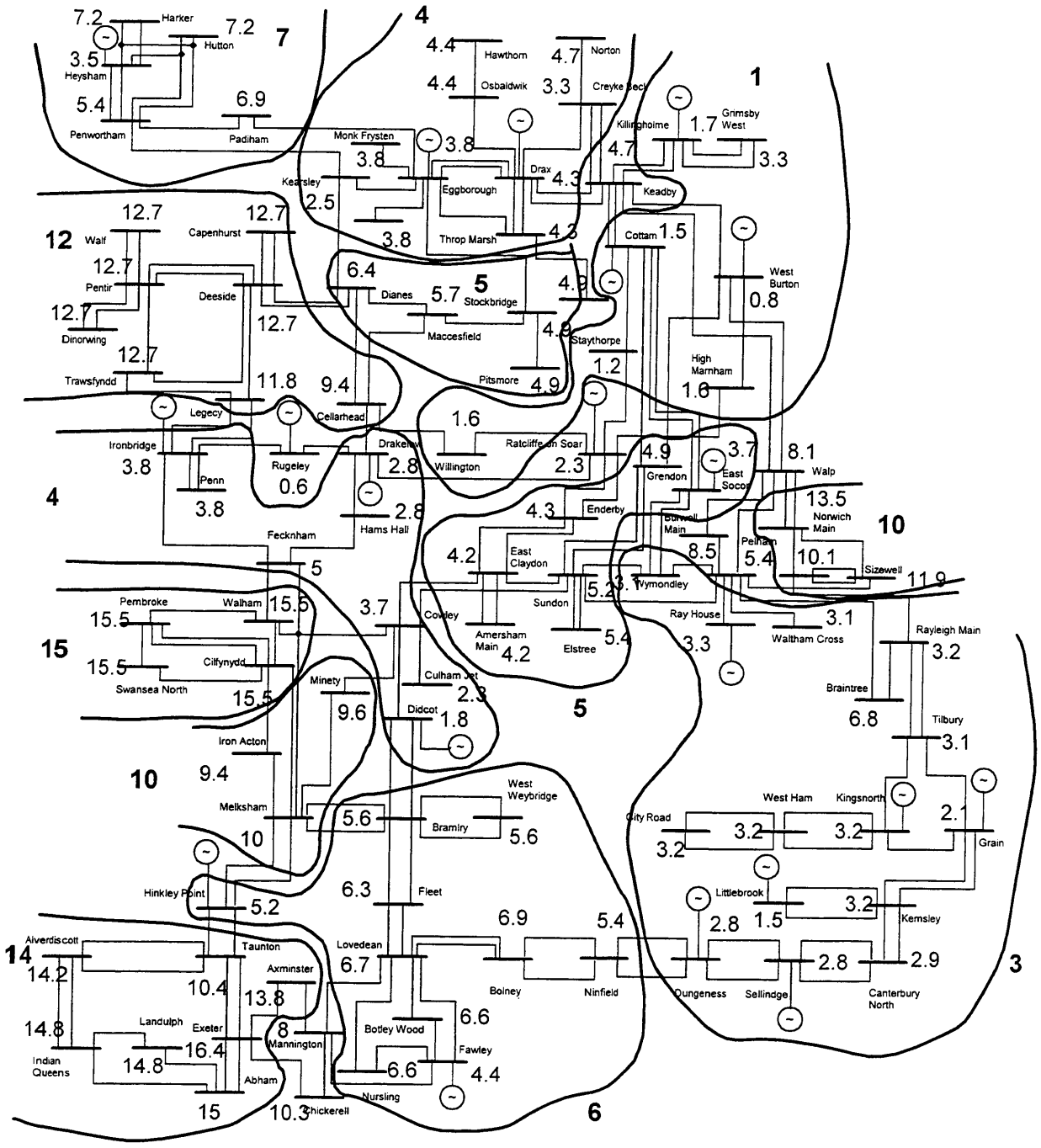


Figure 7.8 Frequency of voltage sags for chosen fault positions below 65%

7.7 Fault Positions Method and Critical Distance Method

In chapter 3, the methods of critical distance and fault positions were discussed. The method of critical distance has been applied to the 400 kV NGC system in section 3.2.1.1. The expected number of sags was calculated for the Padiham substation North of Manchester; the results were illustrated in Figures 3.1 and 3.5. The results are repeated in Table 7.3 [31]. The failure rate used for this comparison was 1.34 faults per year per 100 kilometres of line.

Table 7.3 Exposed lengths calculated using the method of critical distance

	Exposed Length (km)		Number of Voltage Sags	
Voltage %	(1)	(2)	(1)	(2)
30	70	63	1.16	1.16
40	102	98	1.62	1.62
50	146	146	2.25	2.25
60	213	219	3.21	3.21
70	297	340	4.65	5.2
80	380	584	6.39	9.2
90	452	1300	7.58	20.5

Exposed length (1) is the result of the method of critical distance, including the lines behind Eggborough and Penwortham (i.e. one substation away from Padiham). Exposed length (2) has been obtained by assuming that the exposed length is proportional to $V/1-V$. Details of these calculations are shown in section 3.2.1.1.

The results of the method of fault positions are shown in Table 7.4 for the Padiham substation.

Table 7.4 Exposed length using the method of fault positions

Voltage %	Exposed Length (km)	No. of Voltage Sags
30	96	1.29
40	102	1.37
50	221	2.97
60	430	5.77
70	532	7.13
80	899	12.04
90	1544	20.69

Comparing the results of the two methods for the number of sags versus magnitude (Figure 7.9), clearly shows that the results are similar for deep sags. The error for shallow sags is due to a number of assumptions made by using the method of critical distances. For example, the assumption that the network is radial is certainly not true for the meshed 400 kV grid. Such an error has an influence at a voltage of 80% or 90%, when large parts of the network contribute to the number of sags. For smaller voltages, only faults close to the Padiham bus contribute. For that part of the system the radial model used in the method of critical distances is acceptable. The deviation of the method of critical distance and the method of fault positions curve in Figure 7.9 starts at 50% voltage. The error sources lead to an under-estimate of the exposed length for larger voltages.

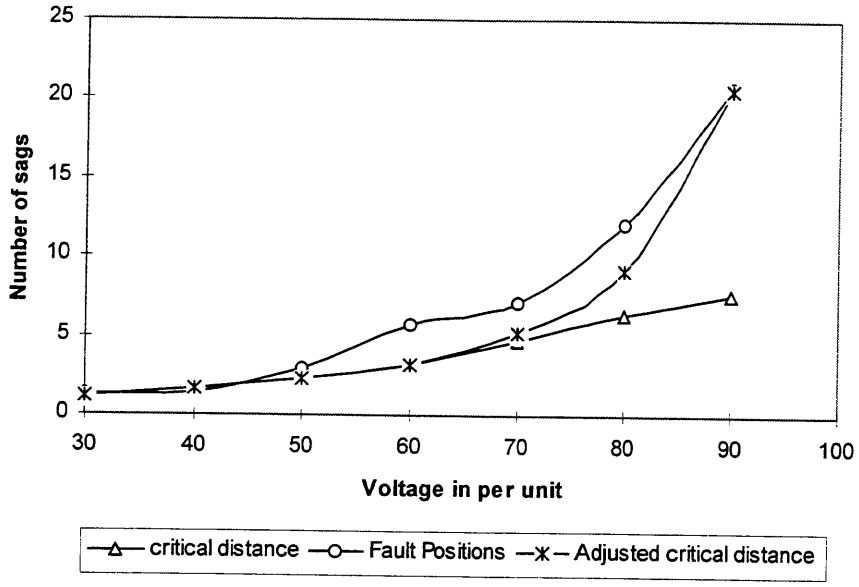


Figure 7.9 Number of sags versus per unit voltage for Padiham

The method of critical distance also neglects the fact that the line behind Penwortham somewhere meets the line behind Eggborough. The influence of lines behind Eggborough and Penwortham can be seen in Figure 7.10. This shows the exposed area around Padiham for a number of sag magnitudes. An equipment-related definition which is often used is: the exposed area is the part of the power system in which short circuits lead to tripping of the equipment. The latter definition assumes that this is a closed and uniquely defined area. This is not always the case as, for example, the fault clearing time can have a significant influence on the trip behaviour of equipment. The first-mentioned definition is used here, realising that the second one is of more practical value. Figure 7.10 shows that faults some distance beyond Penwortham and Eggborough still cause sags in the Padiham substation. Thus, the method of critical distance in its original form again underestimates the number of sags. It is interesting to see in Figure 7.10 how the exposed area is elongated towards the generation near Eggborough and Drax. A fault near these generators causes a severe drop in voltage in Padiham. A large source of relative power is simply cut off.

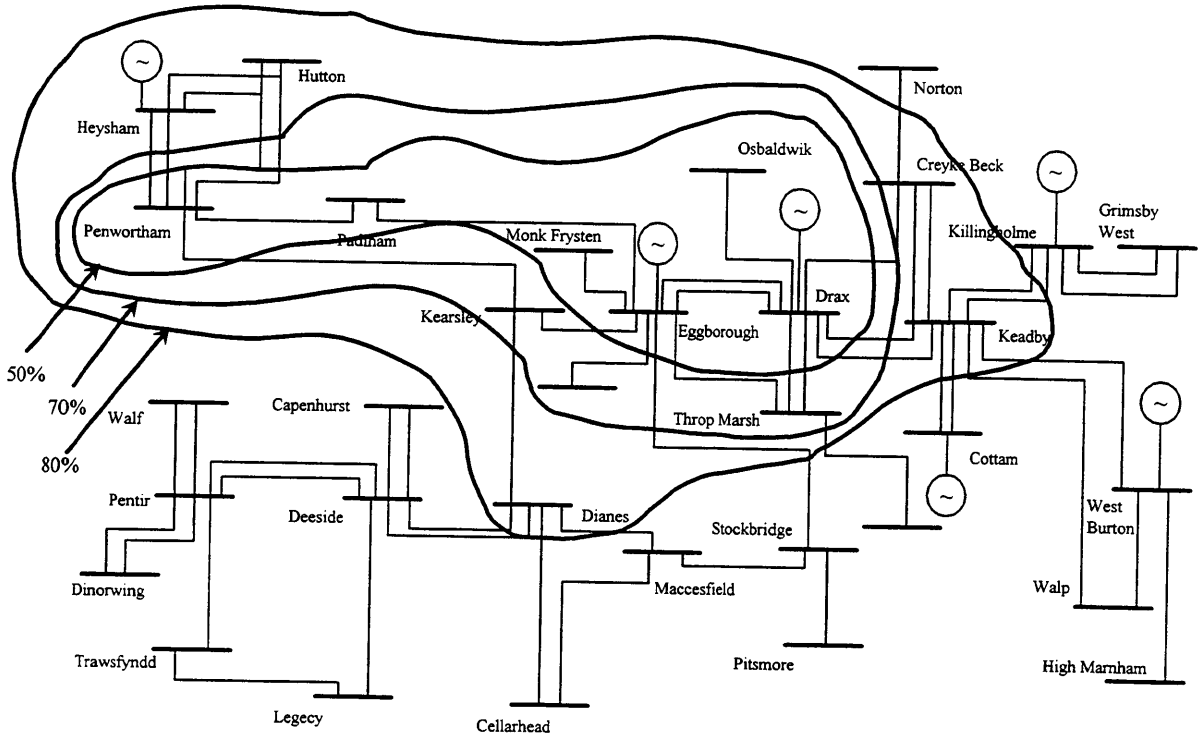


Figure 7.10 Exposed area around Padiham

Figure 7.9 also shows an "adjusted" curve. This adjusted curve was calculated by assuming that the exposed length is proportional to $V/1-V$. In effect this is the same as assuming that the two lines leaving Padiham are infinitely long. It turns out that this gives a reasonable approximation of the number of sags. The result is shown in Table 7.3 as exposed length (2) and as the curve "adjusted critical distance" in Figure 7.9. Comparing the adjusted critical distance with the method of fault positions, shows that they are fairly similar.

To check if this simplification gives acceptable results in general, these calculations have been repeated for nine substations spread throughout the country. The data available for each substation was:

- total fault level for a busbar fault;
- number of 400 kV lines feeding into the station;
- total line impedance and line length for each of these lines.

From the last item it is easy to calculate the feeder impedance per unit length. The other value needed for the method of critical distances, the source impedance, requires some calculations. Consider a substation with three infeeding lines and fault level S. This fault level represents the total fault current for a fault in the substation. If a fault occurs somewhere on one of the lines, the voltage in the substation (the voltage sag) is determined by the fault current flowing from the substation to the fault, not by the total fault current at the fault position. If it is assumed that the three lines contribute equally to the fault current, the fault level needed for the calculations is 2/3 of the total fault level for a busbar fault.

The data used in the calculations is given in Table 7.3 for the nine substations studied. The rather small amount of data needed may be noted, especially when compared to the amount of data needed for the method of fault positions.

Table 7.3 System data needed for the adjusted method of critical distances

Substation	Total Fault Level (kA)	Number of Feeders	Feeder Impedances (%/100 km)					
Trawsfynydd	23.23	3	1.66	1.95	1.95			
Willington	41.57	2	1.86	1.86				
Mannington	19.4	4	1.66	1.66	1.66	1.66		
Rugeley	28.58	2	1.93	1.93				
Walpole	31.32	6	1.66	1.66	1.66	1.66	1.66	1.66
Ninfield	23.26	2	1.66	1.66				
Enderby	34.87	4	1.66	1.66	1.85	1.85		
Ironbridge	33.12	4	1.86	1.86	1.93	1.93		
Grain	83.3	4	1.62	1.55	1.55	1.62		

The results of these calculations are presented in Figures 7.11 to 7.19. The results from the method of fault positions have also been included. Instead of the expected number of sags, exposed lengths have been plotted. The exposed length is the total length of the transmission lines within the exposed area.

In some cases the results are very good (e.g. Mannington, Figure 7.13), in most cases acceptable and in one case (Trawsfynydd, Figure 7.11) there is a rather big difference. But in all cases the trend is clearly the same for both methods: a large increase in number of sags for increasing voltage (sag magnitude).

In any case, despite the possible deviations, the method of critical distances can be used to give an acceptable approximation of the expected number of sags due to faults in the transmission. That the method is useful for mainly-radial distribution systems is clear. The method of critical distances is especially suitable considering the very limited and easily-obtainable amount of data required. Fault levels, feeder impedances and number of feeders appear to be all that is needed. Of course, the method of critical distances might give completely incorrect results for certain systems. The method of fault positions therefore remains an important tool. Also the method of fault positions is more suitable for

incorporation in power system analysis and design software. The method of critical distances is more useful as a manual method of calculation. Further studies are required to assess the limitations of the method of critical distances. A further step in the verification of both the method of fault positions and the method of critical distances is the comparison between the results of stochastic prediction and monitoring results.

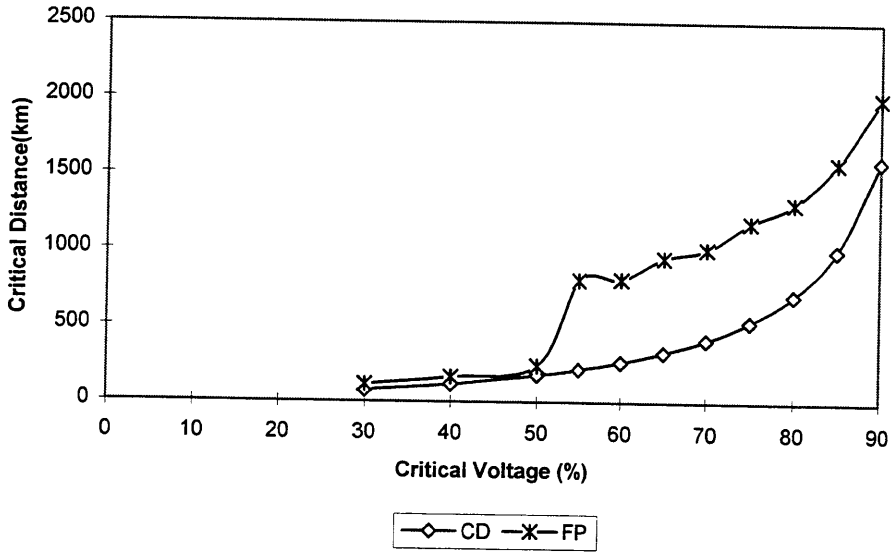


Figure 7.11 Critical voltage versus critical distance for Trawsfynydd substation

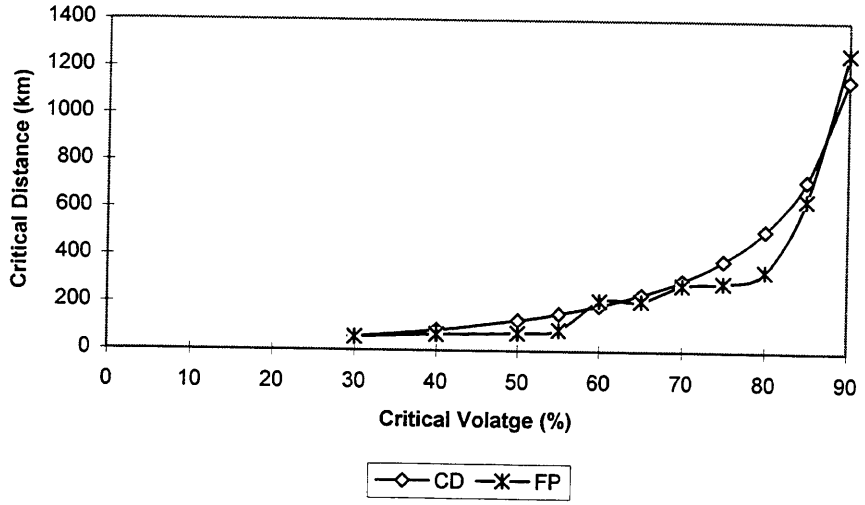


Figure 7.12 Critical voltage versus critical distance for Willington substation

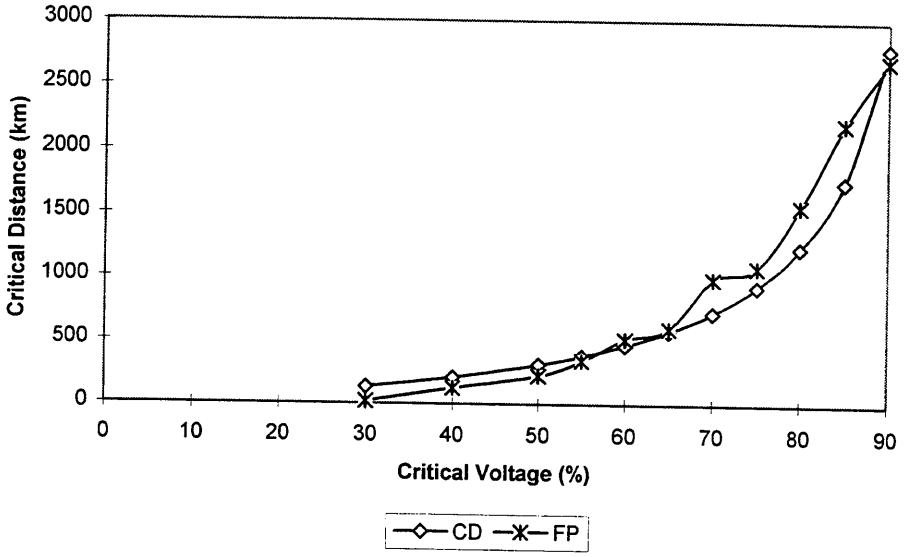


Figure 7.13 Critical voltage versus critical distance for Mannington substation

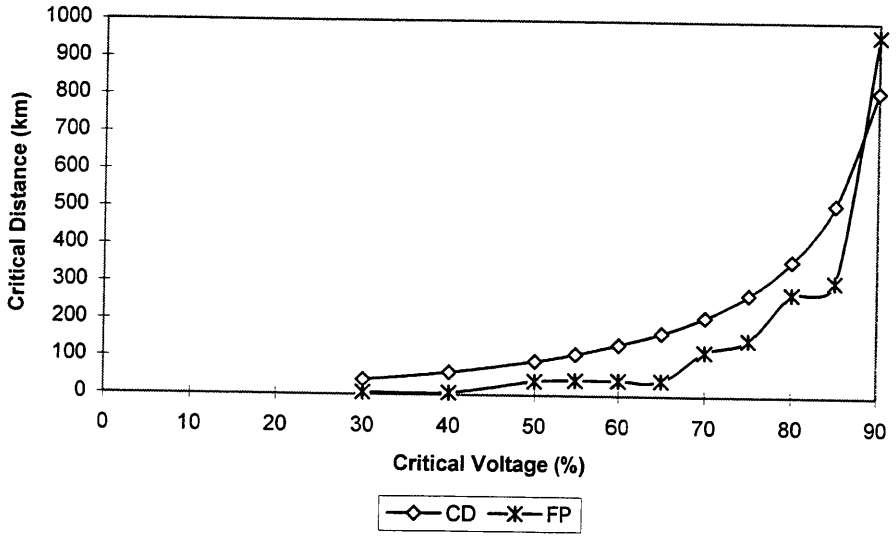


Figure 7.14 Critical voltage versus critical distance for Rugeley substation

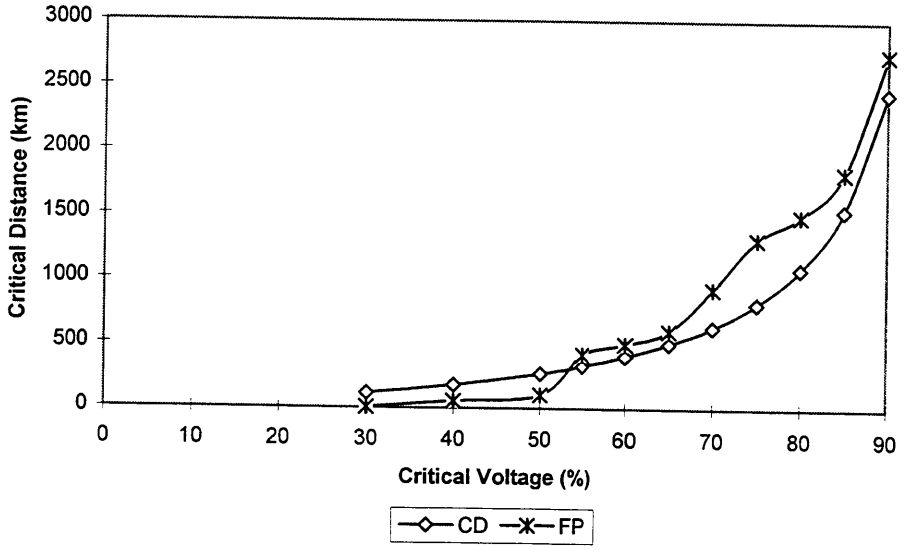


Figure 7.15 Critical voltage versus critical distance for Walpole substation

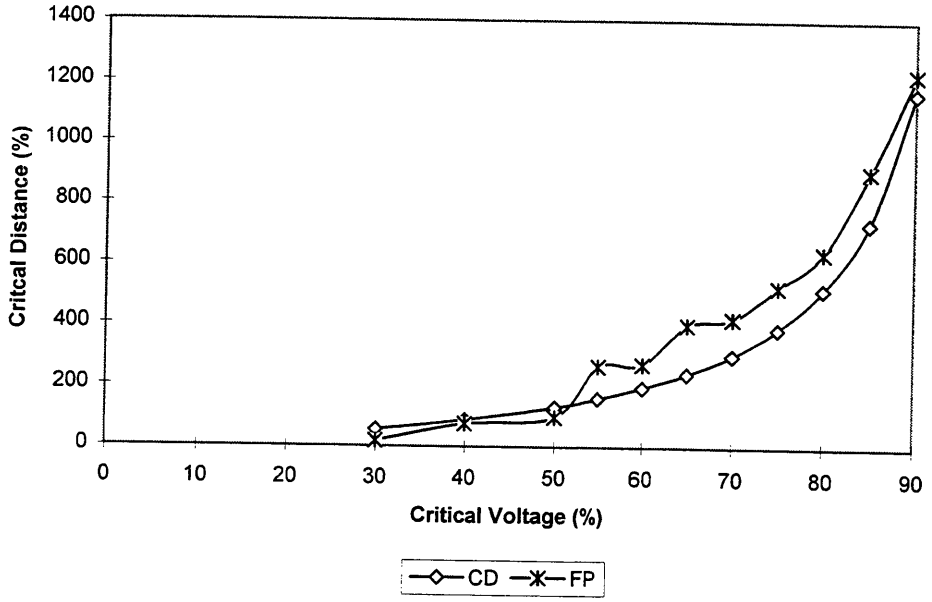


Figure 7.16 Critical voltage versus critical distance for Ninfield substation

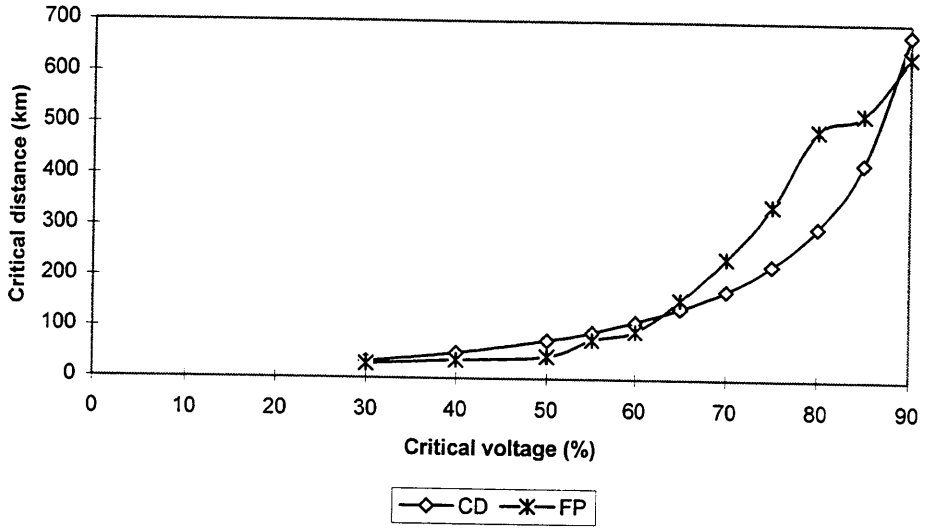


Figure 7.17 Critical voltage versus critical distance for Grain substation

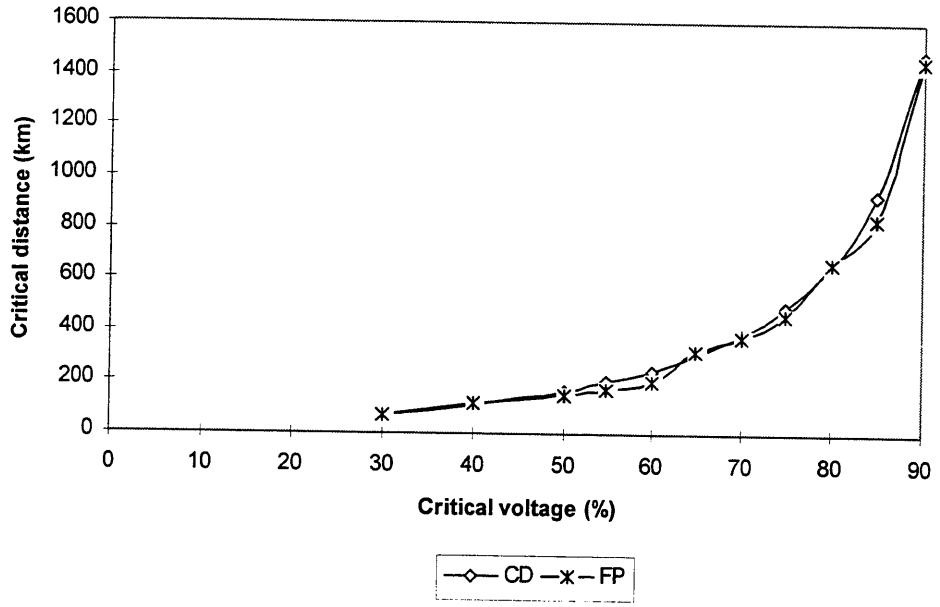


Figure 7.18 Critical voltage versus critical distance for Enderby substation

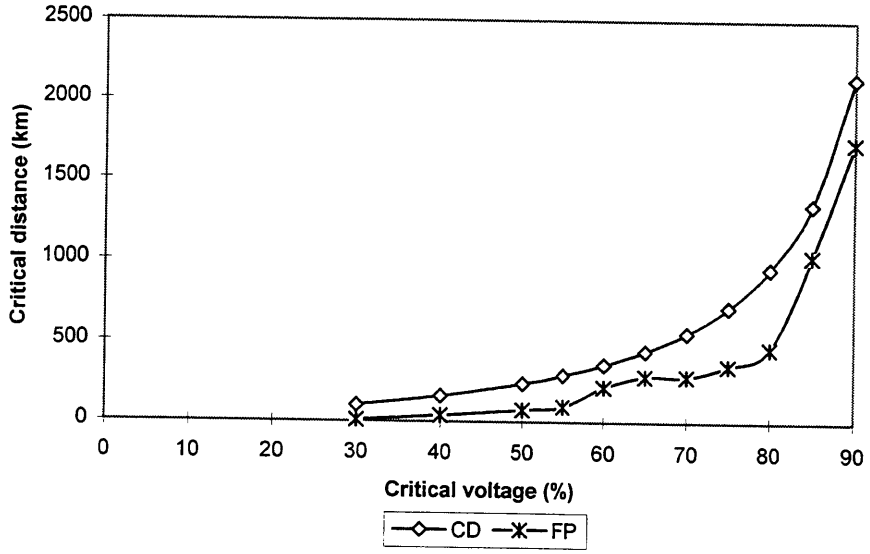


Figure 7.19 Critical voltage versus critical distance for Ironbridge substation

7.8 Phase-Angle Jump

It was pointed out in section 2.7 that some equipment is not only sensitive to the magnitude of the voltage sags but to the jump in phase angle associated with the sag. Even though only magnitudes have been presented till now, the software used actually calculates complex voltages. The phase-angle jump can thus be as easily obtained as the magnitude of sag. Table 7.5 gives the magnitude and phase-angle jumps for some fault positions for some 400 kV substations (Indian Queens, Padiham, Wylfa, Deeside, and Bramley). The table gives voltage magnitude during-fault versus phase-angle jump. It can be seen that as the voltage drops further the phase-angle jump increases, though this trend is not fully consistent. This is because of the different X/R ratios of the transmission lines. The tables indicate that the 400 kV network produces phase-angle jumps up to about 10°, due to the three phase faults in the system. For deep sags large phase-angle jumps occur, but these are less significant.

Figures 7.20 and 7.21 shows the phase-angle jumps for the substations Indian Queens and Wylfa. The horizontal axis gives sag magnitude (pu). It is clear that the phase-angle jump decreases with the increasing sag magnitude. It is a known phenomenon that shallow sags occur due to the faults far away from the substations and that the opposite is true for deep sags. Therefore, Figures 7.20 and 7.21 also can be interpreted as follows: for a fault far away from the substation the voltage drop is small and the phase-angle jump also. In other words: the phase-angle jump decreases when the fault location moves away from the substation.

Indian Queens		Padiham		Wylfa		Deeside		Bramley	
Voltage sag (pu)	Phase-Angle Jump	Voltage sag (pu)	Phase-Angle Jump	Voltage sag (pu)	Phase-Angle Jump	Voltage sag (pu)	Phase-Angle Jump	Voltage sag (pu)	Phase-Angle Jump
1	0	1	0	1	0	1	0	1	0
0.987	-0.087	0.988	0	0.871	-0.444	0.986	-0.641	0.966	-0.215
0.947	-0.421	0.958	-0.157	0.716	-1.112	0.963	-0.229	0.934	-0.107
0.875	-0.835	0.945	-0.187	0.72	-1.187	0.955	-0.192	0.916	-0.152
0.753	-1.425	0.916	-0.378	0.655	-1.469	0.936	-0.206	0.825	-0.246
0.717	-1.635	0.905	-0.173	0.511	-3.265	0.907	-3.28	0.777	0
0.703	-1.879	0.849	-0.169	0.456	-2.42	0.622	-0.905	0.768	-0.154
0.645	-1.789	0.828	-0.141	0.435	-2.401	0.955	-1.735	0.766	-0.261
0.617	-2.269	0.812	-0.283	0.355	-2.657	0.589	-1.468	0.761	-0.277
0.571	-1.626	0.805	-0.3	0.295	-4.909	0.557	-0.937	0.744	-0.285
0.53	-2.329	0.796	-0.133	0.263	-5.047	0.515	-1.102	0.67	-2.116
0.412	-3.065	0.788	-0.352	0.255	-5.486	0.501	-1.331	0.664	-0.318
0.303	-4.886	0.772	-0.293	0.213	-8.917	0.491	-1.64	0.628	-0.65
0.284	-0.052	0.648	-0.587	0.192	-4.685	0.486	-1.389	0.635	-0.417
0.286	-1.053	0.584	-0.711	0.173	-4.145	0.466	-1.638	0.621	-0.486
0.228	-7.547	0.529	-0.63	0.091	-13.042	0.378	-0.751	0.508	-6.847
0.215	-1.755	0.501	-0.905	0.076	-5.173	0.346	-2.261	0.496	-2.499
0.214	-2.541	0.411	-0.991	0.071	-4.243	0.319	-2.424	0.429	-0.982
0.2	-6.616	0.391	-1.4	0.065	-5.809	0.224	-2.552	0.434	-1.285
0.182	-5.572	0.278	-0.1.248	0.057	-6.234	0.185	-21.695	0.335	-1.24
0.126	-10.484	0.127	-0.669	0.007	-30.001	0.146	-22.397	0.234	-1.01

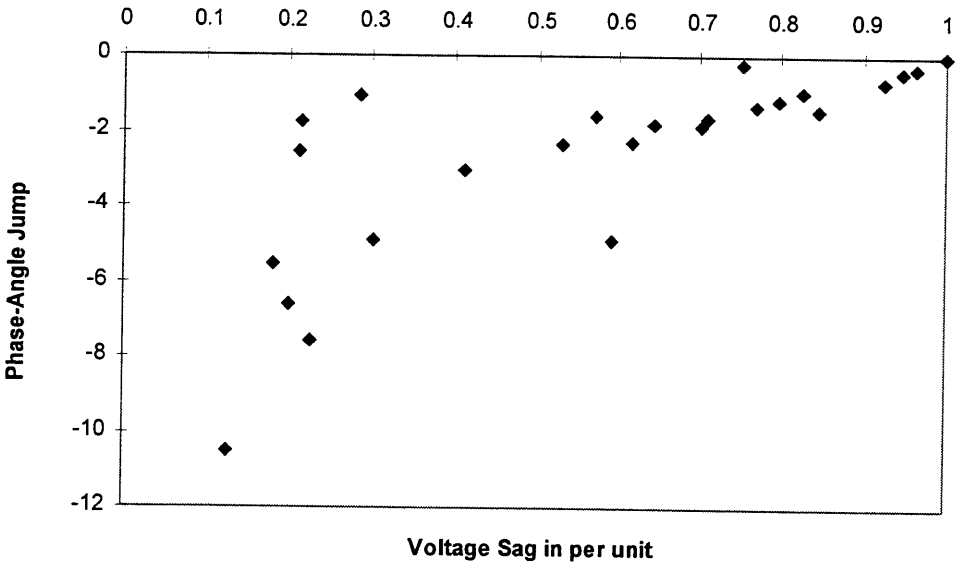


Figure 7.20 Phase-angle jump versus voltage sags for Indian Queen substation

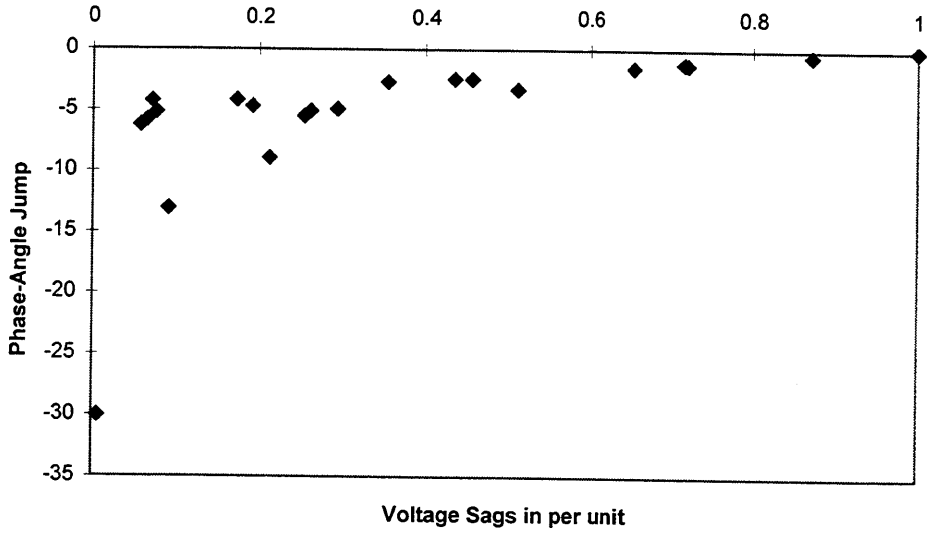


Figure 7.20 Phase-angle jump versus voltage sags for Wylfa substation

7.9 Conclusions

These studies have shown the power and flexibility of the stochastic voltage sag prediction techniques used and the validity of the implemented models. Although the three-phase fault has been assessed, it should be clear that the techniques are not limited to the analysis of these faults. Therefore, it is very straightforward to determine the number of voltage sags in the electrical networks. Furthermore, from the studies shown in this chapter, it can be seen that the method smoothly and rapidly determines the area of poor power quality in a network. The construction of the characteristics simply from monitoring of the system would require considerably greater time.

CHAPTER 8

VARIOUS STOCHASTIC ASSESSMENT STUDIES

8.1 Introduction

This chapter is concerned with the application of the models and techniques proposed in this thesis. The IEEE Reliability Test System (IEEE-RTS) [59] is used to illustrate the algorithms and techniques described in the preceding chapters. In chapter 7, a study was carried out in which a large transmission system was used and all the parameters in the system were fixed. In this chapter, a study is carried out on a smaller system, which gives the opportunity to explore more possibilities without excessive calculation times. The results shown in the following sections provide information that can be obtained using the techniques discussed in this thesis.

A sensitivity analysis associated with the RTS is conducted showing the effect on sag frequency of changing the operation of the system. The influence of different methods of system operation has been studied: installation of a generator in a weak part of the system, removal of generators, transformers, system upgrading by taking transformers out of the system, allocating probabilities and averaging the resulting number of sags to obtain the influence of second-order events. Also, simulations have been conducted including imbalanced faults (single-phase, phase-to-phase).

The results of the stochastic voltage sags for the above studies can be presented in a number of ways. However, the expected number of sags as a function of magnitude and duration is the only way which is of real importance. This function is presented as cumulative voltage sag tables and as contour maps. However, this value, although very important, does not provide any insight into the cause and possible mitigation of the sags. Therefore, a few other ways of presenting the results are also shown here. A voltage sag map of the system connects places having an equal sag frequency; different maps are needed for different magnitudes. Voltage sag maps indicate areas with reduced power quality. The exposed area indicates the origin of all sags which causes nuisance of a certain loads. The borders of the exposed area can be plotted on a map for various critical voltages; the exposed area gives information on the mitigation of nuisance trips, for example by changing the system operation.

8.2 System Description

The IEEE-Subcommittee on the Application of Probability Methods developed a Reliability Test System [59] which includes both generation and transmission facilities. The main objective was to provide a basic model which could be used to test and compare methods

for the reliability analysis of power systems. In this chapter, the RTS is used to demonstrate the ability of the method of fault positions to estimate the frequency of voltage sags.

The Reliability Test System consists of 24 bus locations connected by 38 lines and transformers, as shown in Figure 8.1. The transmission lines are at two voltage levels, 138 kV and 230 kV. The 230 kV system is the top part of Figure 8.1, with 230/138 kV substations at buses 11, 12, and 24. Impedances and failure rates for lines and buses are given in detail in reference [59] and part of this data is shown in Table 8.1. The system as shown in Figure 8.1, consists of seven generator stations at 230 kV: the generators located at bus 22 are hydro units and the generator at bus 14 is a synchronous condenser, the rest are thermal unit generators and 3 generators at 138 kV which are all thermal units. The generator positions, size, and impedances are shown in Table 8.2. From this cluster of stations, a number of high-voltage lines go towards two 230/138 kV substations. At 138 kV, another three generators feed into the system. The total length of transmission lines at 230 kV is 650 miles and at 138 kV is 360 miles. Typical line lengths at 230 kV are 60 miles, and at 138 kV, 30 miles.

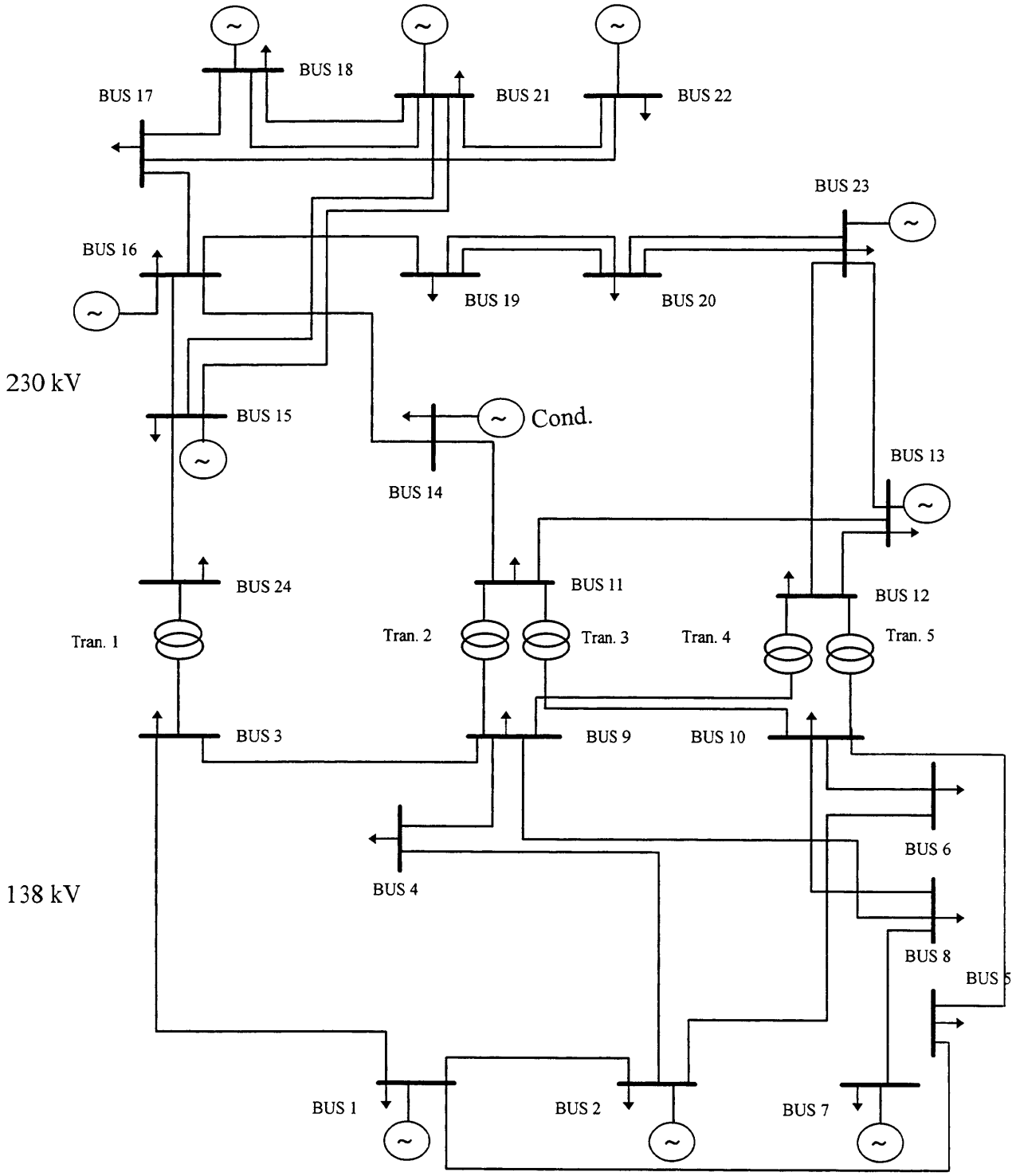


Figure 8.1 Schematic diagram of Reliability Test System (RTS)

Table 8.1 Transmission line length and impedances

Busbar connections		length	Impedance p.u. (100MVA base)			
From	To	miles	R	X	Equipment	occ/yr
1	2	3	0.0026	0.0139	138-kV cable	0.24
1	3	55	0.0546	0.2112	138-kV line	0.51
1	5	22	0.0218	0.0845	138-kV line	0.33
2	4	33	0.0328	0.1267	138-kV line	0.39
2	6	50	0.0497	0.192	138-kV line	0.48
3	9	31	0.0308	0.119	138-kV line	0.38
3	24	0	0.0023	0.0839	Transformer	0.02
4	9	27	0.0268	0.1037	138-kV cable	0.36
5	10	23	0.0223	0.0883	138-kV line	0.34
6	10	16	0.0139	0.0605	138-kV line	0.33
7	8	16	0.0159	0.0614	138-kV line	0.3
8	9	43	0.0427	0.1651	Transformer	0.44
8	10	43	0.0427	0.1651	Transformer	0.44
9	11	0	0.0023	0.0839	Transformer	0.02
9	12	0	0.0023	0.0839	Transformer	0.02
10	11	0	0.0023	0.0839	230-kV line	0.02
10	12	0	0.0023	0.0839	230-kV line	0.02
11	13	33	0.0061	0.0476	230-kV line	0.4
11	14	29	0.0054	0.0418	230-kV line	0.39
12	13	33	0.0061	0.0476	230-kV line	0.4
12	23	67	0.0124	0.0966	230-kV line	0.52
13	23	60	0.0111	0.0865	230-kV line	0.49
14	26	27	0.005	0.0389	230-kV line	0.38
15	16	12	0.0022	0.0173	230-kV line	0.33
15	21	34	0.0063	0.049	230-kV line	0.41
15	21	34	0.0063	0.049	230-kV line	0.41
15	24	36	0.0067	0.0519	230-kV line	0.41
16	17	18	0.0033	0.0259	230-kV line	0.35
16	19	16	0.003	0.0231	230-kV line	0.34
17	18	10	0.0018	0.0144	230-kV line	0.32
17	22	73	0.0135	0.1053	230-kV line	0.54
18	21	18	0.0033	0.0259	230-kV line	0.35
18	21	18	0.0033	0.0259	230-kV line	0.35
19	20	27.5	0.0051	0.0396	230-kV line	0.38
19	20	27.5	0.0051	0.0396	230-kV line	0.38
20	23	15	0.0028	0.0216	230-kV line	0.34
20	23	15	0.0028	0.0216	230-kV line	0.34
21	22	47	0.0087	0.0678	230-kV line	0.45

Table 8.2 Generating units positions and impedances

Bus	Total MW	Impedance (pu) 100MVA base	
		R	X
1	192	0.006611	0.1322
2	192	0.006611	0.1322
7	300	0.003928	0.07857
13	591	0.002155	0.041363
15	215	0.005682	0.11363
16	155	0.007654	0.15714
18	400	0.003076	0.06152
21	400	0.003076	0.06152
22	300	0.005555	0.11111
23	815	0.001886	0.03761

The RTS has been simulated with short circuit positions at all buses and on all branches. A total of 90 fault positions have been applied and all faults were assumed to have an equal clearing time of 200 ms. For each fault position, the voltage during the fault has been calculated. This voltage, plus the failure rates, have been used to obtain the expected number of voltage sags per year.

8.3 Simulation results

8.3.1 Base Case

The RTS has been used as a base case to show the possibilities of stochastic assessment methods for voltage sags. As mentioned before, a voltage sag is caused by a short circuit fault. At the fault position, the voltage drops to zero. Customers further away from the fault experience a voltage sag; the farther the customer is from a fault, the less the drop in voltage. This well-known phenomenon is shown quantitatively in Figure 8.2. A fault was applied halfway between bus 2 and bus 4 and the during-fault voltages (the sag magnitudes) have been calculated for all buses. It can be seen that buses nearer to the fault experience a

deeper voltage sag than those further away; it also becomes clear that the generators are less affected by the fault than other buses. This can be confirmed by applying a fault almost in the middle of the system, at bus 11. Figure 8.3 shows the voltage distributed around the system due to the fault on bus 11: it can be clearly seen that customers nearer to the fault experience deeper sags.

In Figures 8.2 and 8.3, the fault position was fixed and voltage sags were calculated for all customers. Figure 8.4 gives the reverse situation. The customer bus is fixed and the voltage at that bus is calculated for all fault positions. The voltages in Figure 8.4 are the sag magnitudes at bus 4 which are due to faults at the fault positions indicated. As expected, it can be seen again that the voltage sag is more severe for faults closer to the customer bus. From a computational point of view, there is a big difference between Figure 8.2 and Figure 8.4. The voltages in Figure 8.2 hold for one electrical network, thus they can be determined via one matrix calculation. However, each voltage in Figure 8.4 is calculated for a different electrical network, which requires a different matrix calculation for each fault position.

These calculations can be performed for all chosen fault positions, resulting in the expected number of sags for each substation. Again, these can be shown on a map, as done in Figure 8.5 and Figure 8.6. These maps show the variation of power quality through the system. The numbers indicate the expected number of sags per year with magnitudes below 80% and 65% respectively. With the exception of bus 7, it can be seen that the expected number of sags varies by a factor of about two. The worst power quality is found near transformer substations. It can be seen that the number of sags is lower closer to generator stations. This can be explained by the fact that the generators maintain the voltage at local buses. Bus 7 shows a much lower number of sags than the other generator buses. This can be explained by the number of lines connected to bus 7, i.e. there is only one line connected on which faults can cause voltage sags. The other generator stations have up to 5 outgoing lines. This leads to 5 times as many sags.

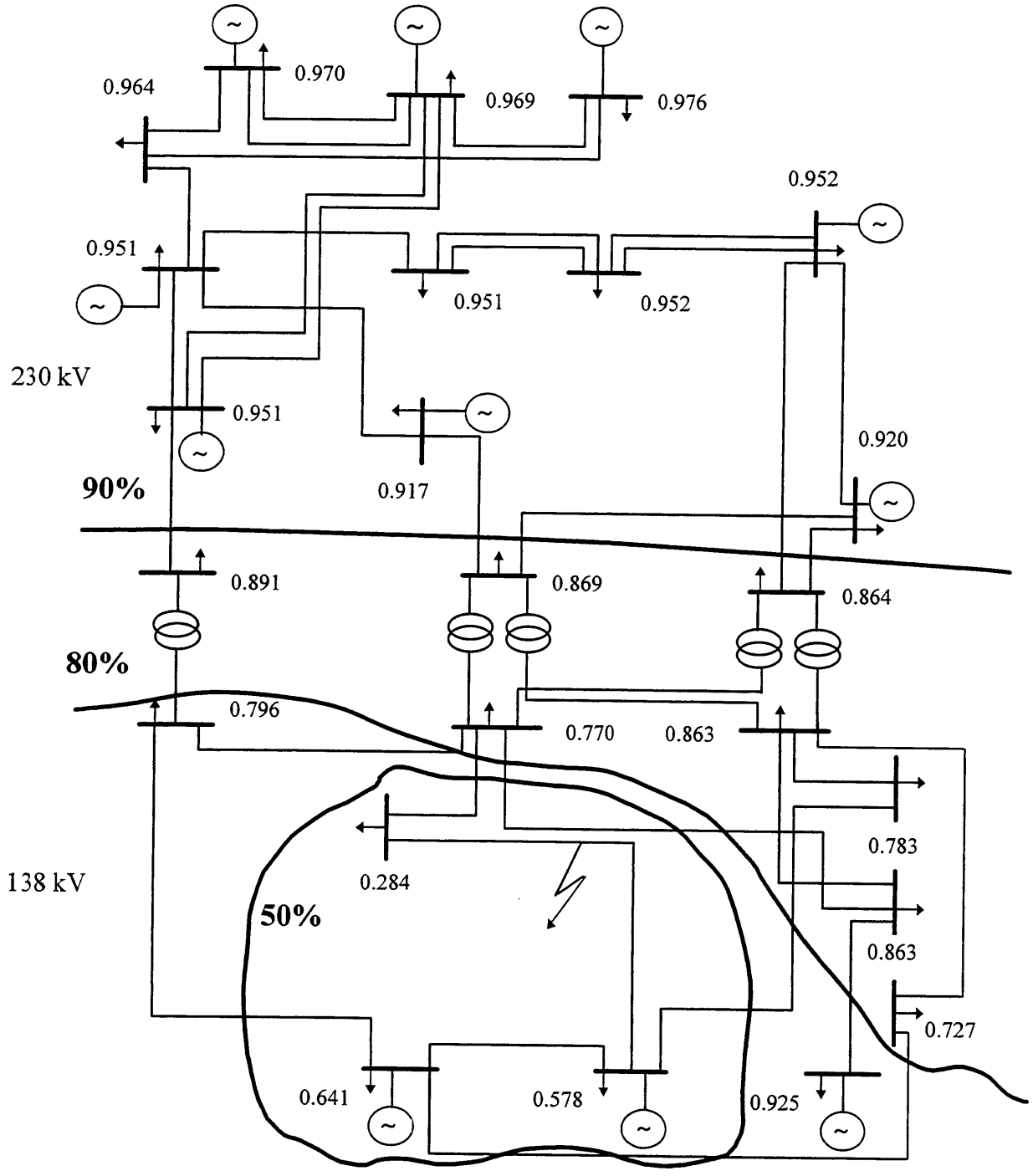


Figure 8.2. Voltage sags (pu) due to fault halfway between bus 2 and bus 4

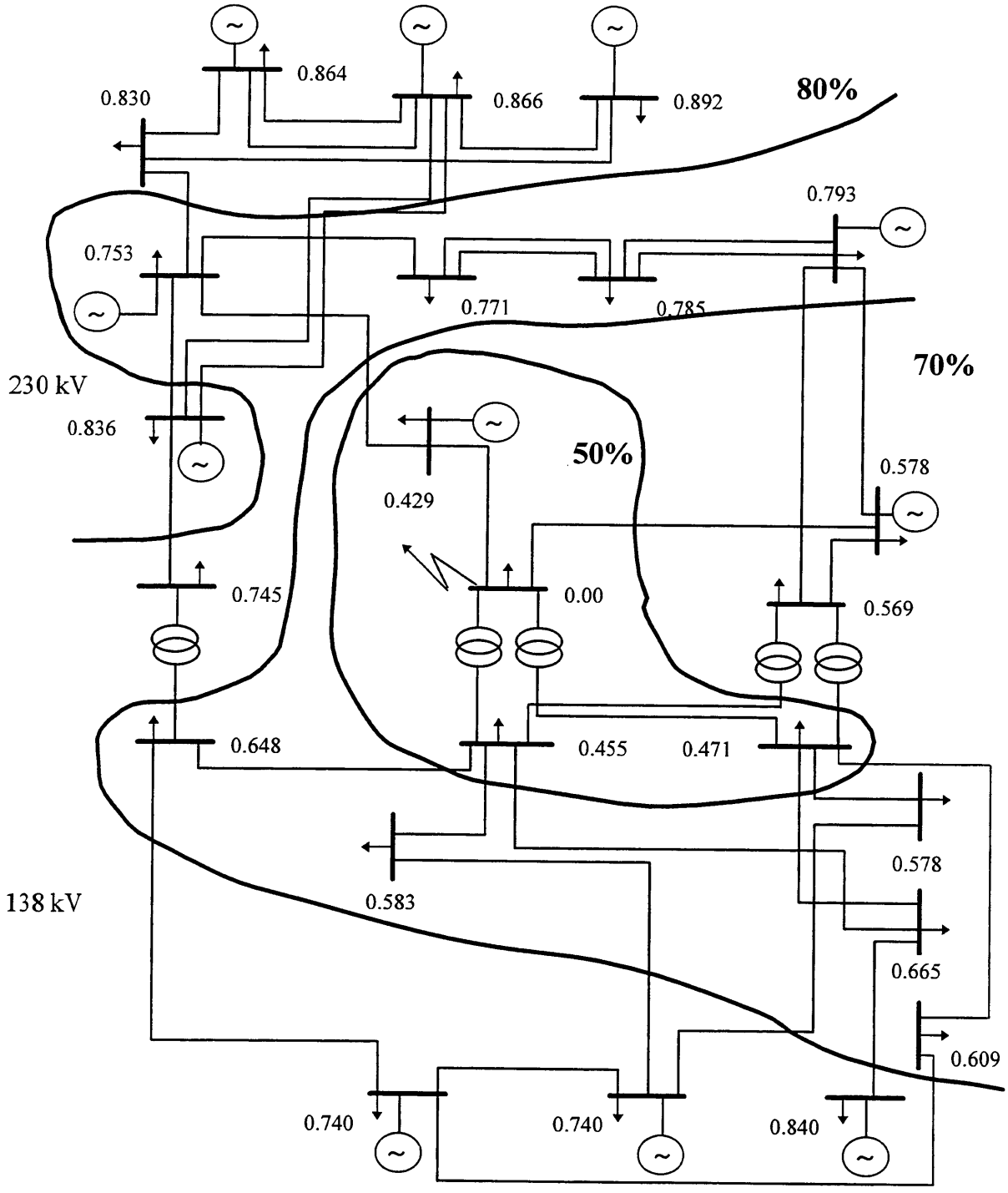


Figure 8.3 Voltage sags (pu) due to fault on bus 11

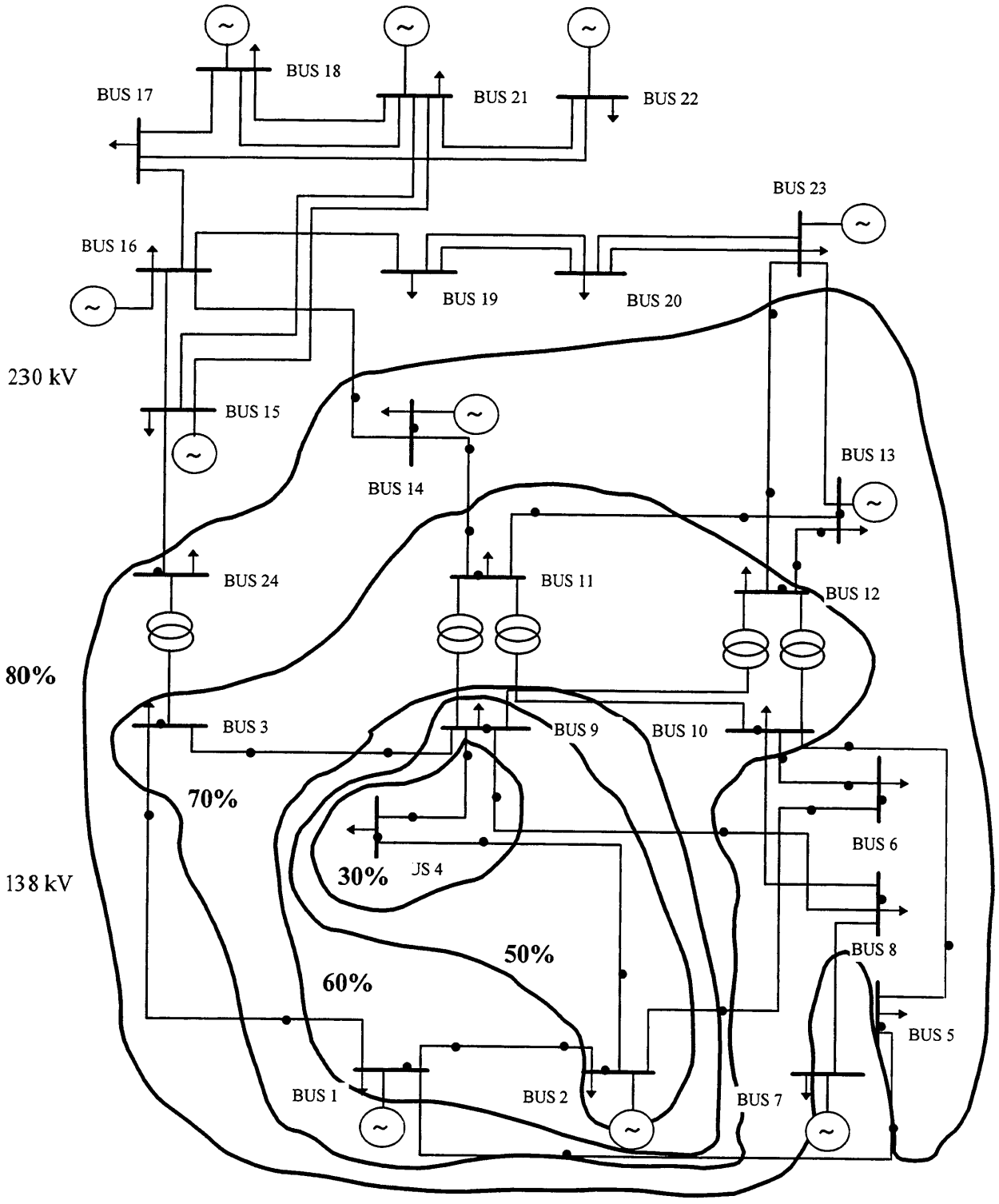


Figure 8.4 Contour lines illustrating exposed area at Bus 4

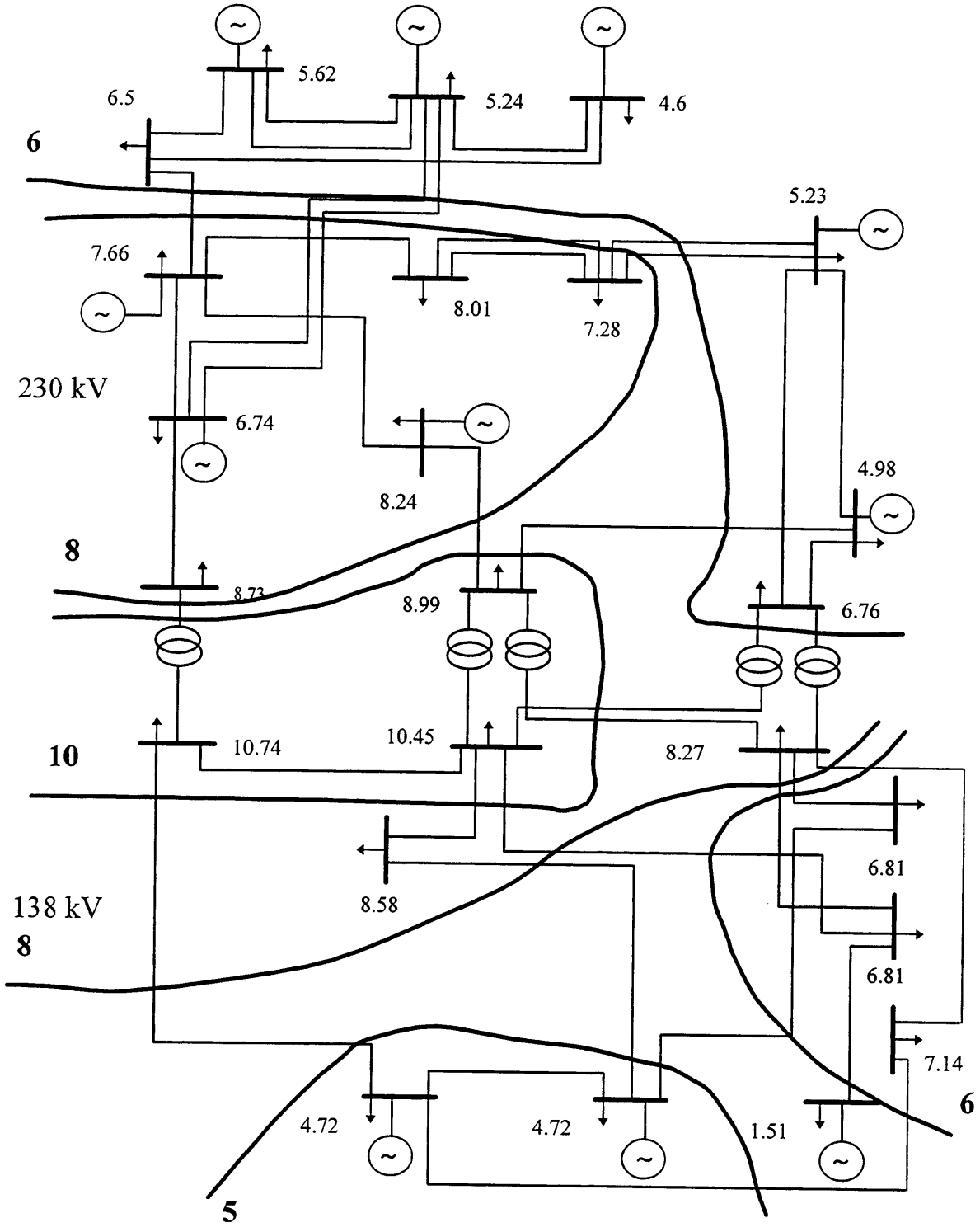


Figure 8.5 Frequency of voltage sags for all chosen fault positions below 80%

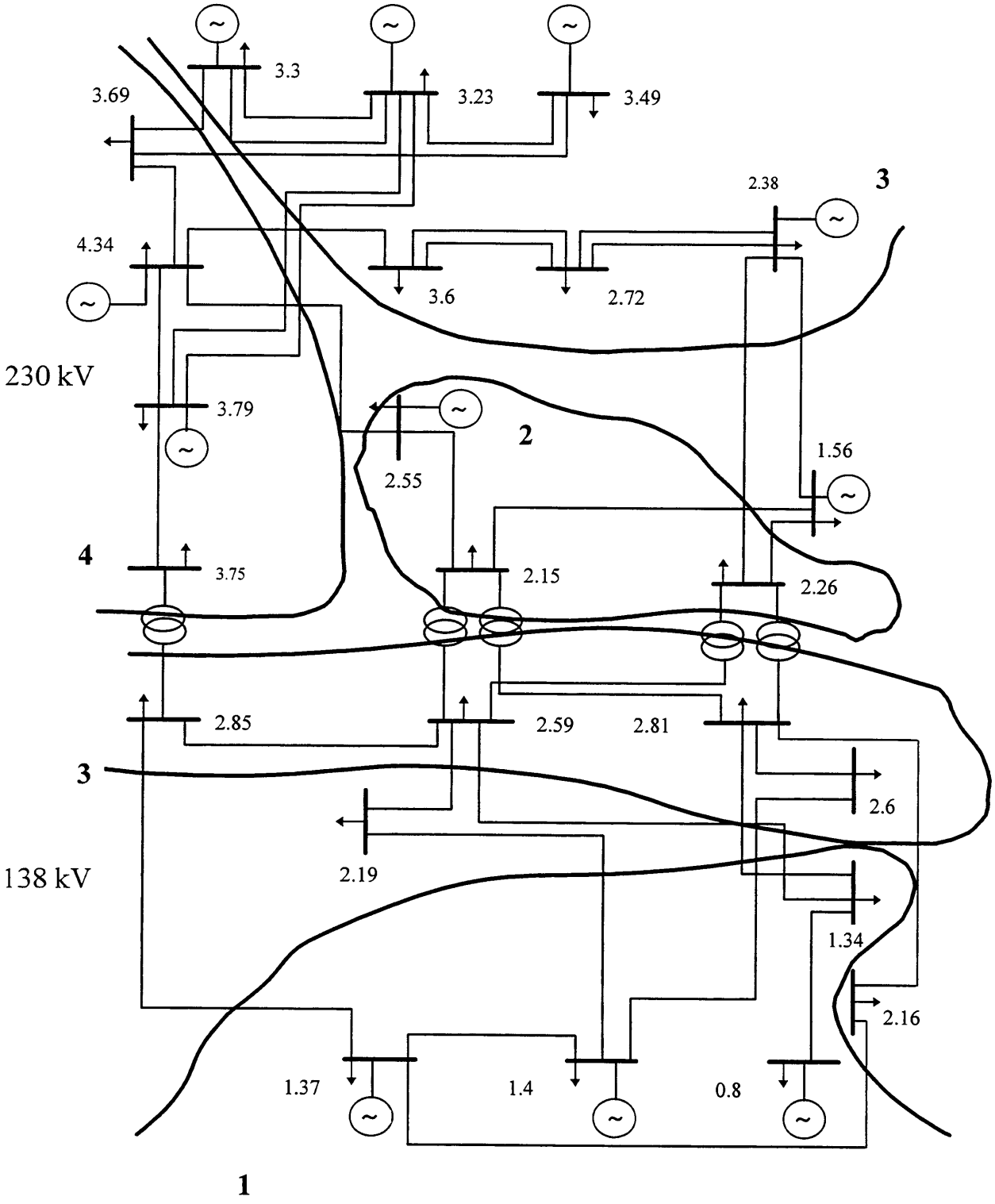


Figure 8.6 Frequency of voltage sags for all chosen fault positions below 65%

It also follows from this study that the number of sags can vary significantly throughout the system. Using the average from a number of power quality monitors as a "typical supply quality" could thus give very different results for many customers.

8.3.2 Influence of Generation

As seen in the previous section, generator stations influence the number of sags at their local buses. Simulations have been performed to further assess the influence of generator stations on the number of sags. Figures 8.7 and 8.8 give the number of sags below 80% and 60% respectively for the situation in which all 138 kV generators are out of operation. A significant increase in the number of sags in the 138 kV system can be seen. This is particularly evident from the exposed area of bus 4 in Figure 8.9 which shows almost every fault in the system leading to the sag at bus 4. This is, of course, because the voltage in the 138 kV system is no longer supported by the local generators. The number of sags is now about equal (12 per year) for all 138 kV buses. The number of sags in the 230 kV substations is not significantly influenced by the outage of the 138 kV generators. Due to the transformer impedance, the 138 kV generators do not have much influence on the voltage at the 230 kV buses.

In reality, the situations in which all 138 kV generators are in operation and the to situations in which they are all out of operation are rare. A more typical situation is that each generator is out of operation for a certain period. Here it has been assumed that each generator station is out of operation during one tenth of the year; it has further been assumed that there is no overlap in these ten periods. For each of these ten situations, the expected number of sags has been calculated for each bus. The expected annual number of sags is now the average of the results from these ten simulations. In stochastic terms this is the weighted sum of the conditional probabilities. The results are shown in Table 8.3, which

gives the number of sags with a magnitude less than 65%. The outage of an individual generator influences the sag frequency for the generator bus and buses near to this. For example, the outage of generator 1 influences bus 1 (i.e. the generator bus) bus 2, bus 4 and bus 6. It can be seen that the influence is largest for the outage of bus 7: the number of sags on the generator bus becomes five times as much. In the case of the other generators, the influence is less severe: about a factor of two. A comparison of the first and the last row for bus 4 in Table 8.3 shows the difference in the average supply. Comparing the first and the last line of Table 8.3 shows that the difference is rather small.

Table 8.4 shows the influence of 138 kV generation on voltage sags with a magnitude of less than 65% for the 138 kV network. The assumption has been made that each 138 kV generator station is out of operation during one third of the year. It has further been assumed that there is no overlap in these three periods. It can clearly be seen by comparing the first row with the last row that there are some cases in which the number of voltage sags is important. Therefore, the influence of generation scheduling is significant for all buses apart for those close to the transformer substations.

This study further indicates that the scheduling of generator stations should be taken into account in a voltage sag study in order to get accurate predictions of the number of sags. Furthermore, in chapter 7, the study concerning the 400 kV NGC system assumed that all generators would be operational. In reality, that is never the case: some generators might only be operational during 25 to 50% of the time. In those cases, the sag frequency for customers close to such generators can be significantly affected.

Table 8.3 Influence of generation on the sag frequency

	138 kV buses										**230 kV buses**													
Case	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
all gen. In	1.34	1.4	2.85	2.19	2.16	2.6	0.8	1.34	2.59	2.81	2.15	2.26	1.56	2.53	3.79	4.34	3.69	3.3	3.6	2.72	3.23	3.49	2.38	3.75
gen.1 out	2.8	2.77	3.24	3.65	3.42	3.16	0.8	1.47	2.65	3.38	2.49	2.6	1.56	2.55	3.81	4.7	3.71	3.32	3.81	2.74	3.25	3.51	2.4	3.79
gen. 2 out	2.43	2.79	3.06	3.77	3.44	3.18	0.8	1.49	2.64	3.4	2.49	2.6	1.56	2.55	3.79	4.6	3.69	3.3	3.79	2.72	3.2	3.49	2.32	3.77
gen. 7 out	1.54	1.4	3.06	2.81	3.2	3.18	4.42	4.42	3.11	3.44	2.32	3.01	1.56	2.55	3.79	4.68	3.69	3.3	3.79	2.74	3.23	3.49	2.38	3.77
gen. 13 out	1.54	1.4	3.44	3.02	3	3.18	0.8	1.49	5.27	4.64	4.89	5.46	4.94	4.25	3.79	5.22	3.69	3.3	4.73	2.74	3.49	3.66	2.79	3.77
gen. 15 out	1.37	1.4	3.04	2.17	2.14	2.58	0.8	1.32	2.6	2.79	2.32	2.6	1.56	2.99	3.98	5.22	3.69	3.3	4.47	2.74	3.49	3.66	2.38	3.77
gen. 16 out	1.37	1.4	3.06	2.17	2.34	2.54	0.8	1.32	2.6	2.79	2.32	2.6	1.56	2.97	4.38	5.22	3.69	3.5	4.47	2.72	3.49	3.66	2.38	4.22
gen. 18 out	1.37	1.4	3.04	2.17	2.34	2.58	0.8	1.32	2.6	2.79	2.32	2.6	1.56	2.97	3.98	5.48	4.98	4.41	4.47	2.74	3.97	3.85	2.38	4.02
gen. 21 out	1.37	1.4	3.04	2.17	2.34	2.58	0.8	1.32	2.6	2.79	2.15	2.6	1.56	2.97	4.39	5.48	4.6	3.97	4.47	2.74	4.14	3.85	2.38	4.22
gen. 22 out	1.37	1.4	3.04	2.15	2.14	2.58	0.82	1.32	2.6	2.79	2.15	2.26	1.56	2.55	3.81	4.7	3.71	3.52	3.81	2.76	3.78	4.24	2.4	3.79
gen. 23 out	1.54	1.4	3.3	2.59	2.82	3.03	0.8	1.51	3.21	3.22	2.51	4.71	2.2	4.21	3.98	5.22	3.69	3.3	6.42	6.71	3.49	3.49	5.83	3.77
Average	1.3	1.65	3.1	2.6	2.7	2.8	1.1	1.7	3	3.2	2.5	3.1	2	2.6	4	4.5	3.9	3.5	4.4	3.1	3.5	3.7	2.5	3.9

Table 8.4 Influence of generation on the sag frequency

case	1	2	3	4	5	6	7	8	9	10
all gen. In	1.34	1.4	2.85	2.19	2.16	2.6	0.8	1.34	2.59	2.81
gen.1 out	2.8	2.77	3.24	3.65	3.42	3.16	0.8	1.47	2.65	3.38
gen. 2 out	2.43	2.79	3.06	3.77	3.44	3.18	0.8	1.49	2.64	3.4
gen. 7 out	1.54	1.4	3.06	2.81	3.2	3.18	4.42	4.42	3.11	3.44
average	2.03	2.09	3.05	3.11	3.06	3.03	1.71	2.18	2.75	3.26

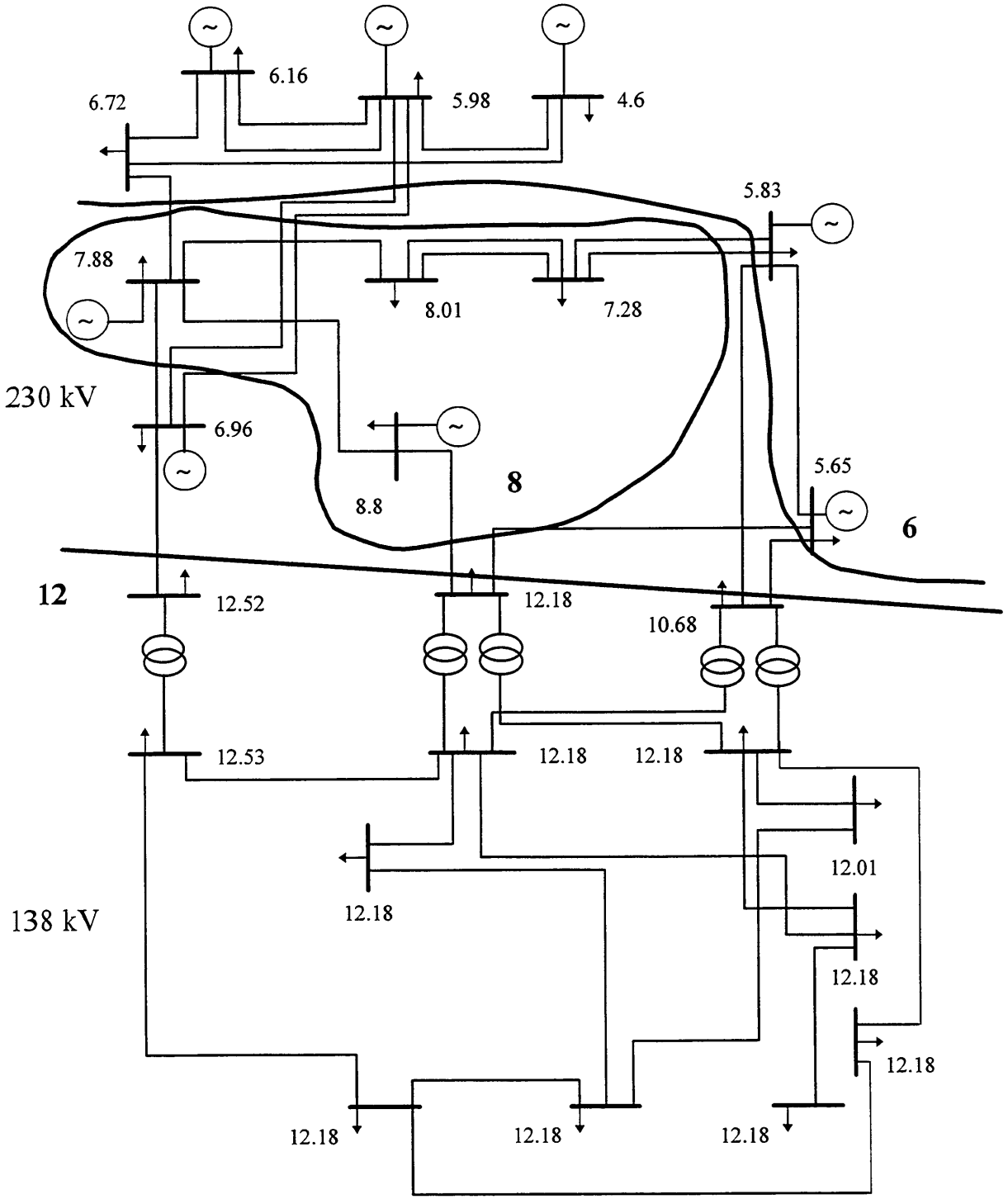


Figure 8.7 Frequency of voltage sags below 80% after removal of 138 kV generators

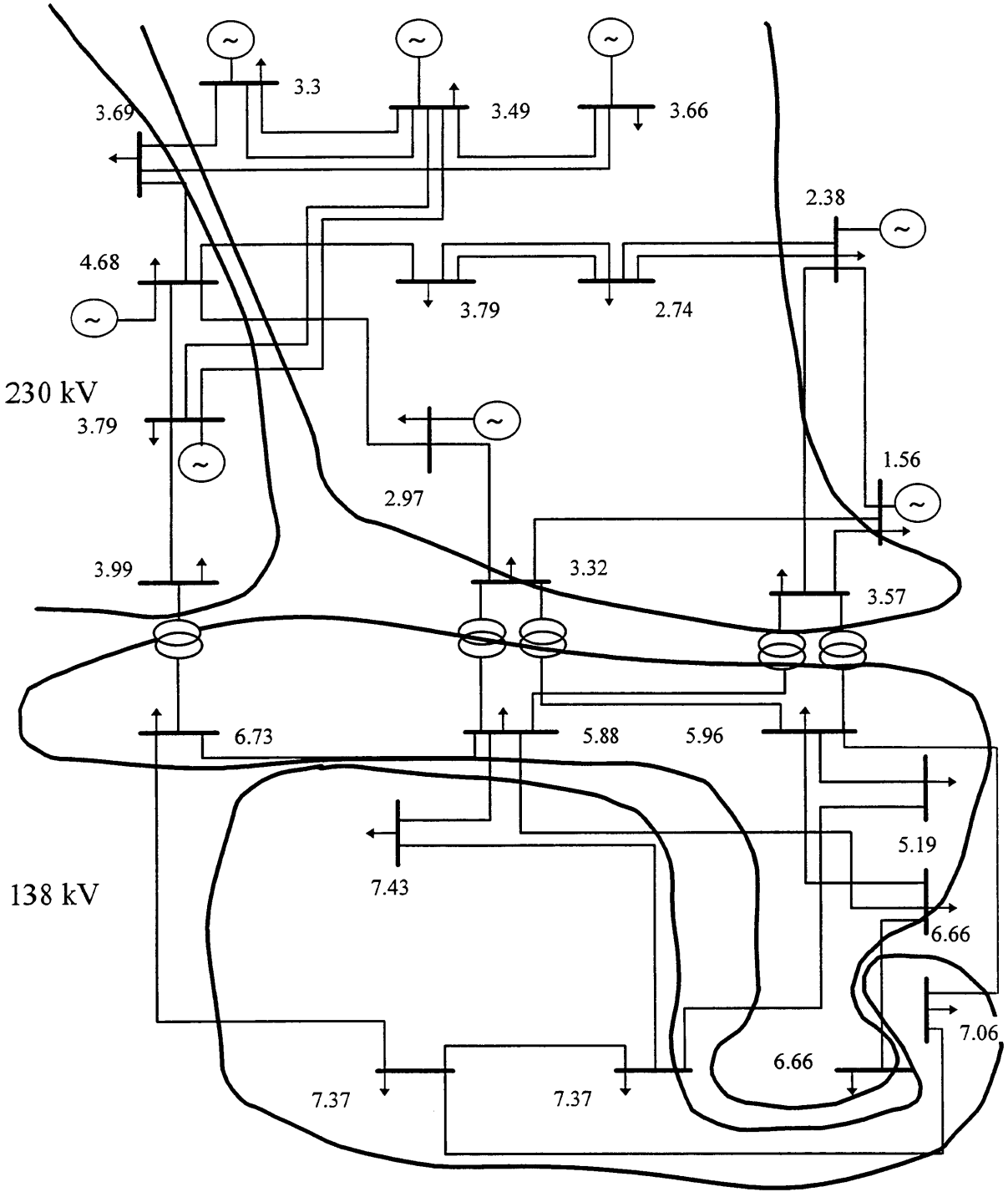


Figure 8.8 Frequency of voltage sags below 65% after removal of 138 kV generators

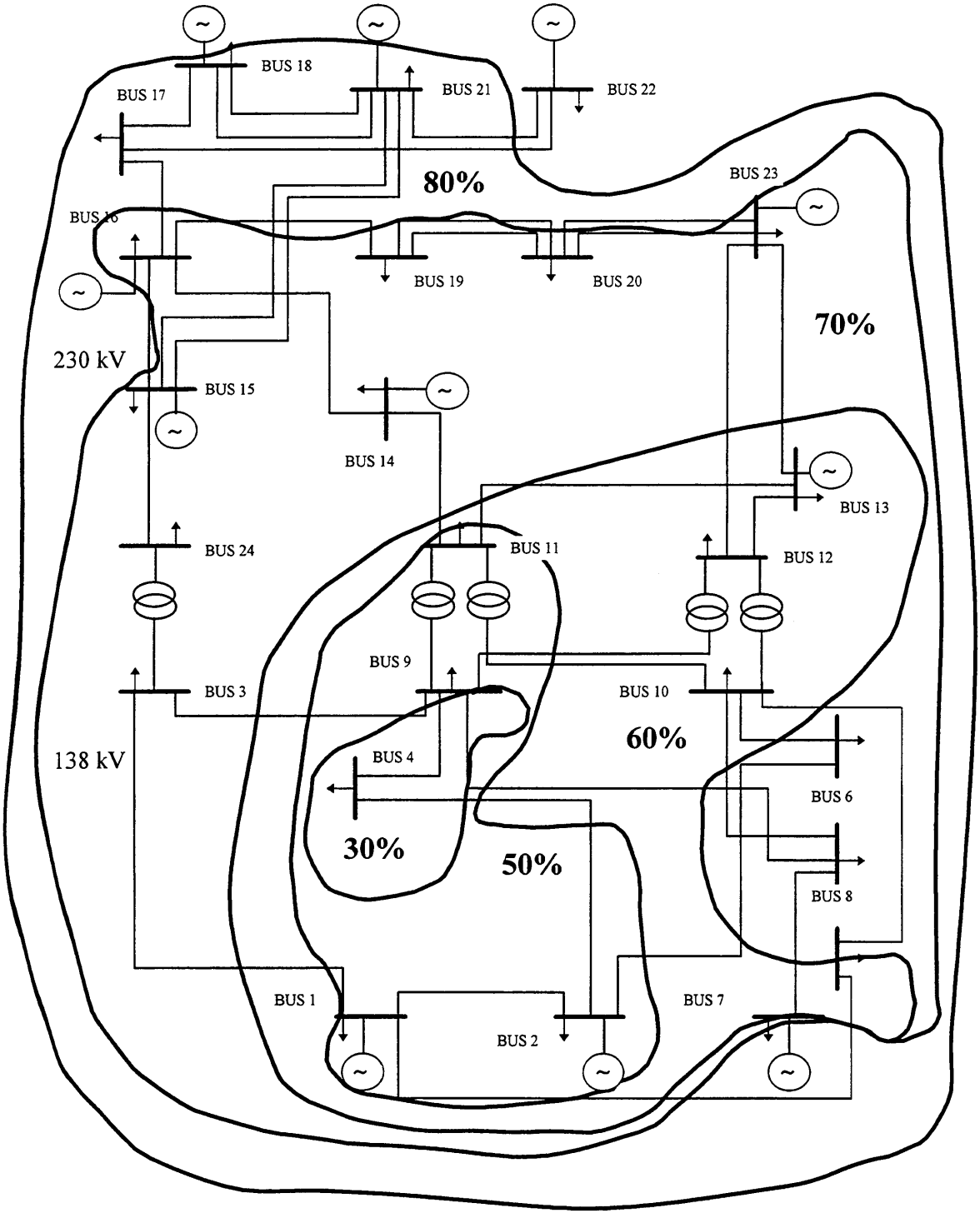


Figure 8.9 Contour lines illustrating exposed area at Bus 4 after removal of 138 kV units

8.3.3 Influence of Transformers

As pictured in the previous sections, transformer stations can experiences large numbers of sags at their buses. Simulations were carried out to assess the influence of the transformers on the number of sags. Five simulations were carried out, each with one of the five transformers out of operation. The number of sags at all buses for these five situations are given in rows 2 through 6 of Table 8.5. The results are for sags below 65%. Other sag magnitudes give similar results. It can be seen that the sag frequency increases significantly in the 138 kV system. When a transformer is out of operation, there is no longer any infeed from the 230 kV system to keep up the voltage. Most 230 kV buses are little affected. The exceptions are buses 11 and 12 which are on the high voltage side of a transformer.

As a next step it has been assumed that each transformer is out of operation during one fifth of the year; it has further been assumed that there is no overlap in these five periods. The expected number of sags for this case is the average of the results form the previous five simulations. It can be seen that the sag frequency about doubles for the 138 kV buses. Furthermore, the simulation has been carried out after upgrading the whole 138 kV network to 230 kV. In other words, the whole system is a 230 kV network. This has been done by replacing the transformers with a zero impedance line between the substations. Therefore, substations 3 and 24, 9 and 11, 10 and 12, now act as one physical location. Upgrading the system leads to an upgrading of the line impedances as well. Therefore, a 130 kV line impedance has been upgraded to a 230 kV impedance. The138 kV generator impedances were unchanged, since these impedances are expressed as per unit on the machine rating.

Table 8.6 compares the number of sags below 80% and 65% with the base case result which is repeated in the table. It can be seen that the number of sags is almost doubled compared with the previous 138 kV network. This is because the faults in a wider area of the system are now affecting these substations. Furthermore, it can clearly be seen that there are some increases in the number of sags in substations near to the previous transformer connections

(bus 13, bus 14, bus 15). This is due to the effect of faults from the previous 138 kV side. However, moving towards the 230 kV generators, the number of sags are not greatly affected. This is because they are electrically far away from the changes. Moreover, it is clear that the influence of the transformers on the number of sags at 230 kV is higher than the removal of the 138 kV generators. Thus, the stochastic study of the number of voltage sags also needs to include the effect of transformer outages in the system and the system designs.

Table 8.5 Influence of transformers on the sag frequency

	138 kV buses										230 kV buses													
Case	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
All Tra. In	1.34	1.4	2.85	2.19	2.16	2.6	0.8	1.34	2.59	2.81	2.15	2.26	1.56	2.53	3.79	4.34	3.69	3.3	3.6	2.72	3.23	3.49	2.38	3.75
Tra.1 out	4.54	4.54	5.74	5.51	5.16	5.02	2.31	4.43	5.74	5.45	3.19	3.66	1.56	2.37	3.79	4.34	3.49	3.3	3.36	2.72	3.49	3.66	2.36	3.81
Tra. 2 out	4.37	4.37	4.52	4.74	4.87	4.9	2.31	4.18	5.5	4.9	2.66	3.65	1.36	2.53	3.79	4.34	3.69	3.3	3.36	2.72	3.23	3.49	2.32	3.89
Tra. 3 out	4.37	4.37	4.52	4.92	4.87	5.1	2.31	4.18	5.5	5.1	2.51	2.98	1.36	2.37	3.79	4.34	2.96	3.3	2.72	2.72	3.23	3.49	2.32	3.89
Tra. 4 out	4.37	4.37	4.96	4.87	4.72	4.31	2.31	4.44	4.92	4.86	2.46	3.05	1.36	2.53	3.79	4.34	2.96	3.3	2.72	2.72	3.23	3.49	2.32	3.89
Tra. 5 out	4.37	4.37	4.98	5.07	4.72	4.49	2.31	4.18	5.1	5.06	2.32	2.95	1.36	2.37	3.79	4.34	2.96	3.3	2.72	2.72	3.23	3.49	2.32	3.89
Average	4.4	4.4	4.94	5.02	4.87	4.75	2.31	4.28	5.35	5.07	2.63	3.26	1.4	2.43	3.79	4.34	3.21	3.3	2.98	2.72	3.28	3.52	2.33	3.23

Table 8.6 Comparison of number of sags below 80% and 65% with the base case result

Bus No.- voltage level	Base case 80% Sags	Upgrading 80% Sags	Increase of 80% Sags (%)	Base case 65% Sags	Upgrading 65% Sags	Increase of 65% Sags (%)
Bus 1-138kV	4.72	9.38	50	1.37	4.74	71
Bus 2-138kV	4.72	9.4	49	1.4	4.96	71
Bus 3-138kV	10.74	12.44	13	2.85	6.05	53
Bus 4-138kV	8.58	10.61	19	2.19	5.45	60
Bus 5-138kV	7.14	10.61	32	2.16	5.62	61
Bus 6-138kV	6.81	10.61	36	2.6	5.63	54
Bus 7-138kV	1.51	6.88	78	0.8	2.65	70
Bus 8-138kV	4.26	8.96	52	1.34	4.03	67
Bus 9-138kV	10.45	10.93	4	2.59	5.56	53
Bus 10-138kV	8.27	10.93	24	2.81	5.56	49
Bus 11-230kV	8.99	10.93	17	2.15	5.56	61
Bus 12-230kV	6.76	10.93	38	2.26	5.56	59
Bus 13-230kV	4.98	9.25	46	1.56	2.51	38
Bus 14-230kV	8.24	12.26	32	2.55	3.96	36
Bus 15-230kV	6.74	9.5	29	3.79	3.65	4
Bus 16-230kV	7.66	10.23	25	4.34	4.64	6
Bus 17-230kV	6.5	7.75	16	3.69	3.69	0
Bus 18-230kV	5.62	6.17	9	3.3	3.3	0
Bus 19-230kV	8.01	9.93	21	3.6	3.6	0
Bus 20-230kV	7.28	9.13	20	2.72	2.84	4
Bus 21-230kV	5.24	5.79	9	3.23	3.23	0
Bus 22-230kV	4.6	4.6	0	3.49	3.49	0
Bus 23-230kV	5.23	7.41	29	2.38	2.46	3
Bus 24-230kV	8.73	12.44	30	3.75	6.05	38

8.3.4 System Modification by Adding Generators

By changing the system configuration, it is possible to reduce the number of voltage sags at the busbars. For the RTS, specific emphasis was put on the inclusion of a local generator.

Generally, it can be stated that increasing the fault level at a certain substation improves the quality of the supply to the customer fed from that substation. This can be done by installing generators at stations of interest to customer and utilities. This reduces the sag depth for the local and surrounding stations in the system. But local generators not only increase the fault level, they keep up the voltage after the removal of the fault.

A 600 MVA generator was connected to bus 24 in the simulated system. The magnitudes of the voltage sags have been calculated again for all the fault positions. The generator increases the fault level for faults around bus 24. This decreases the severity of the sags. Therefore, for faults in the system, the generator reduces the voltage drop, which results in a decrease in the number of sags below a certain magnitude. The total number of voltage sags is shown in Figures 8.10 and 8.11 for voltages below 80% and 65% respectively.

The influence of the local generator can be seen when Figures 8.10 and 8.11 are compared with the number of sags shown in Figures 8.5 and 8.6. A local generator significantly reduces the expected number of voltage sags around bus 24. In buses 3, 4, 9, and 15 the number of sags is reduced to almost half for sags below 80%. It is clear that the connection of the local generator has more of an effect on shallow sags (80%) than on deep sags (65%). Also, it can be seen that the number of sags further away from the modified connected generator does not change.

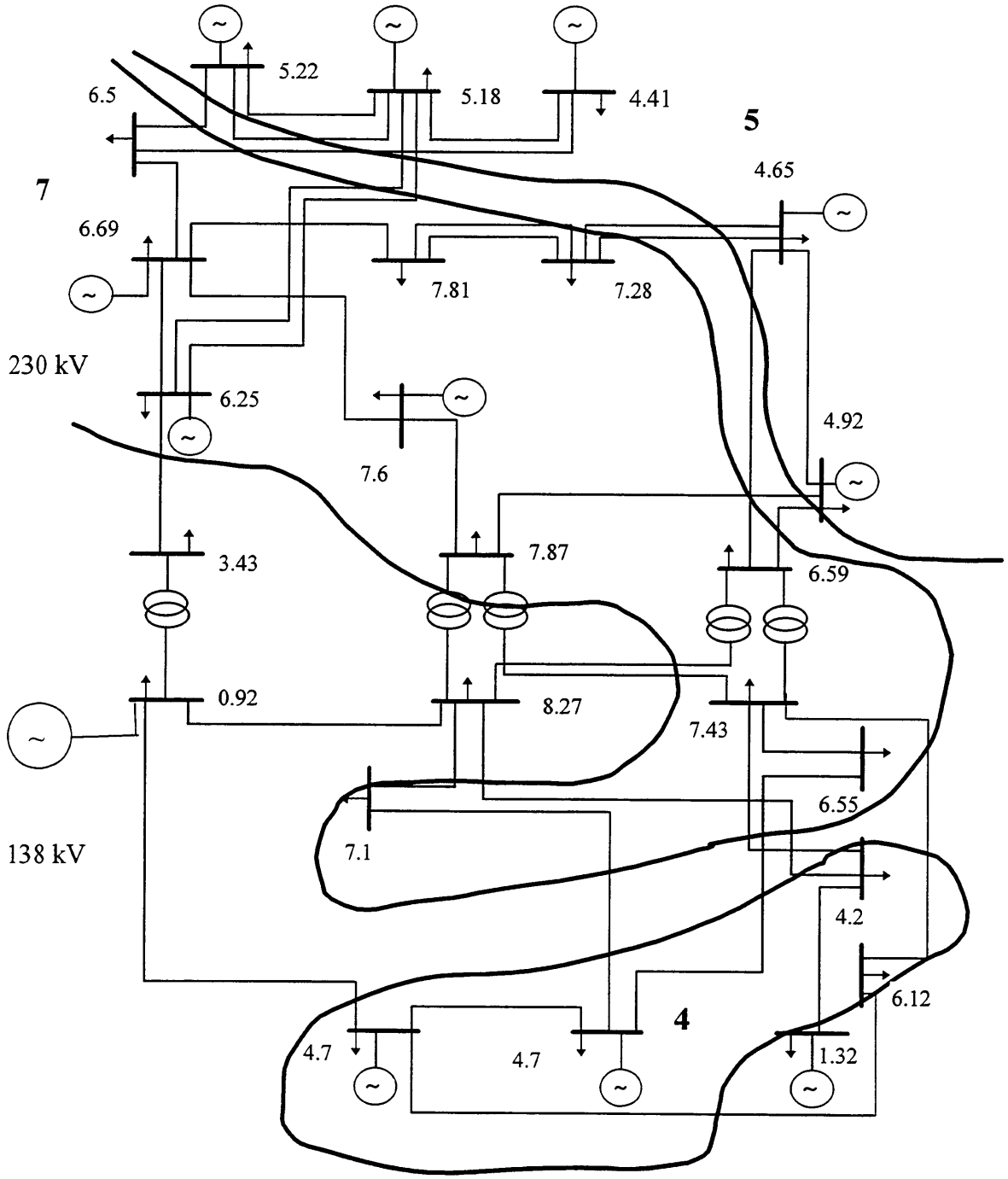


Figure 8.10 Frequency of voltage sags below 80% after insertion 600 MVA generators at bus 24

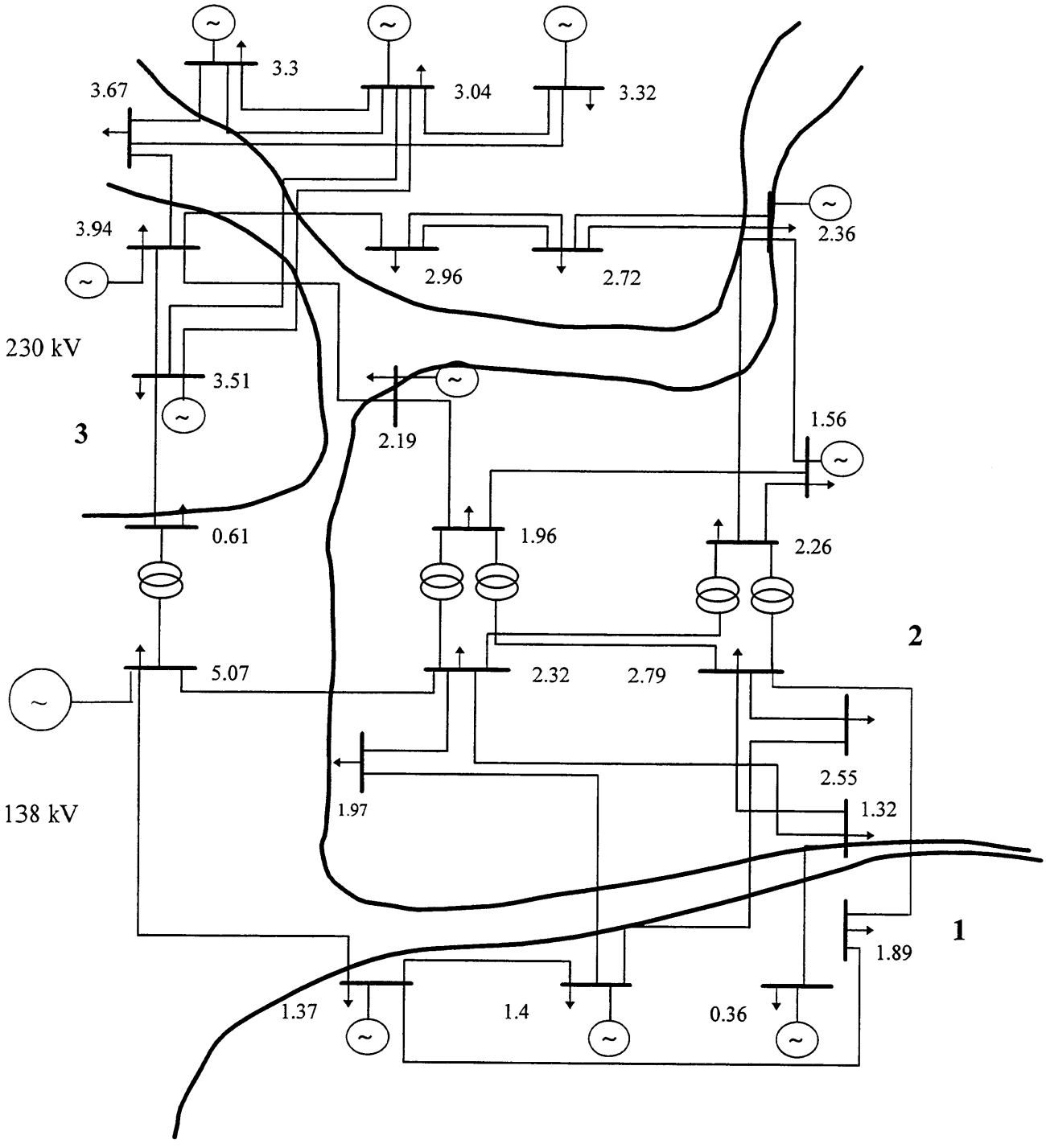


Figure 8.11 Frequency of voltage sags below 65% after insertion 600 MVA generators at bus 24

Figure 8.12 shows the number of voltage sags versus the per unit voltage. This figure compares the situation before and after the local generator is connected at bus 24. It is apparent that the generator influences bus 24: the number of sags is reduced significantly, especially in the case of deep sags. It can also be seen that the shape of the curve has not changed, it has only moved down. This is similar to the theoretical results obtained by Bollen [25] using the critical distance method which uses simple circuit theory calculations. The conclusion of these calculations was that the shape of the number of sags characteristic does not change by connecting local generators. The model used by Bollen for this calculation is similar to the model described in section 3.2.1.1, Figure 3.4. Therefore, by using equations 3.7 and 3.8 from chapter 3, the critical distance can be easily calculated as a function of the critical voltages. Figure 8.13 shows the critical distance for a fault with the PCC at 132 kV for the system shown in Figure 8.14. The curves in Figure 8.13 are from top to bottom: 1 MVA, 10 MVA, and 20 MVA. A transient reactance of 15% has been used [25]. It is clear that the curves do not change.

Further simulations have been conducted to focus on the influence of generator size. Figure 8.15 shows the number of sags versus the generator size at bus 24 for sags below 80%. As expected, the influence on bus 24 is rather large compared with the influence on the other buses which is small. This is related to the fact that the buses are electrically distant from each other. There is some influence on bus 9 (drop of about 15%): apparently bus 9 and bus 24 are electrically close. Therefore, it can be concluded that, as the size of the local generator increases, the number of sags at that bus reduced significantly with little influence on other buses.

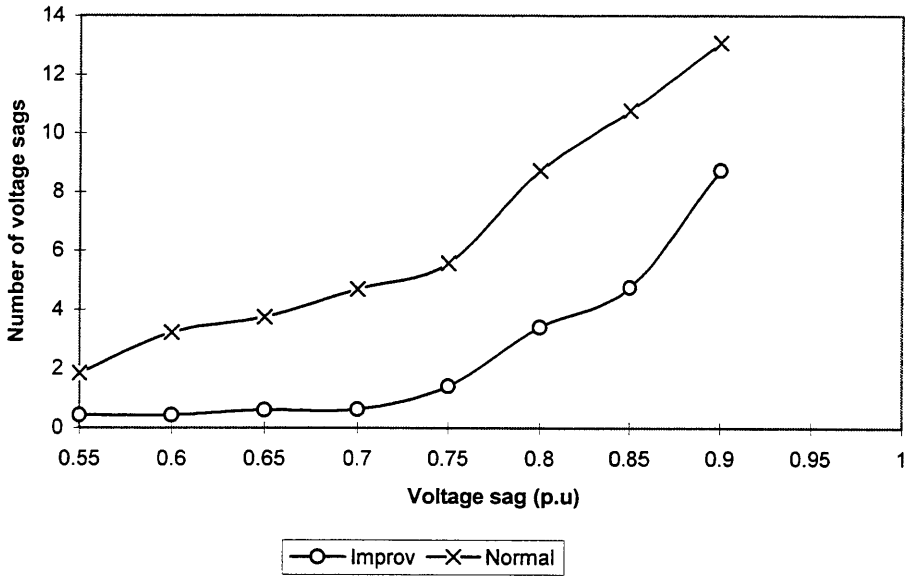


Figure 8.12 Number of the voltage sags versus per unit voltage

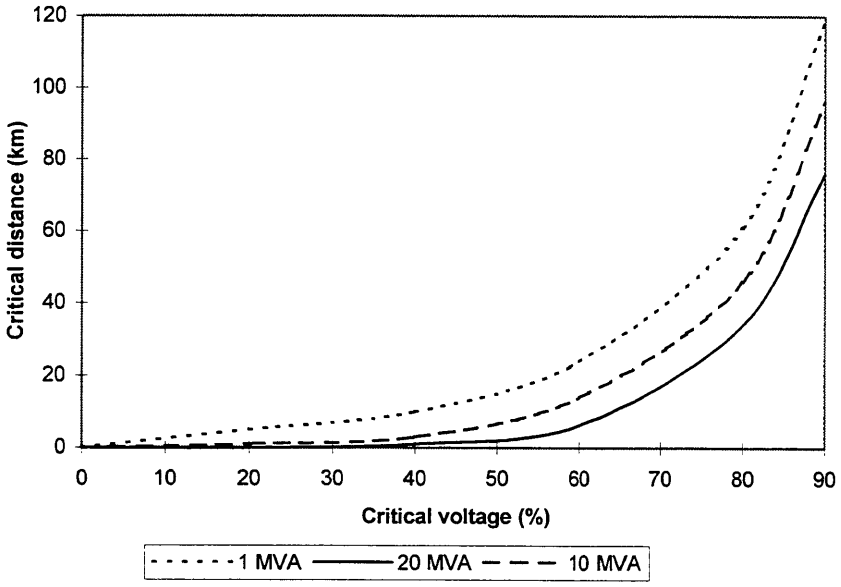


Figure 8.13 Critical distance versus voltage magnitude for a fault with a PCC at 132 kV

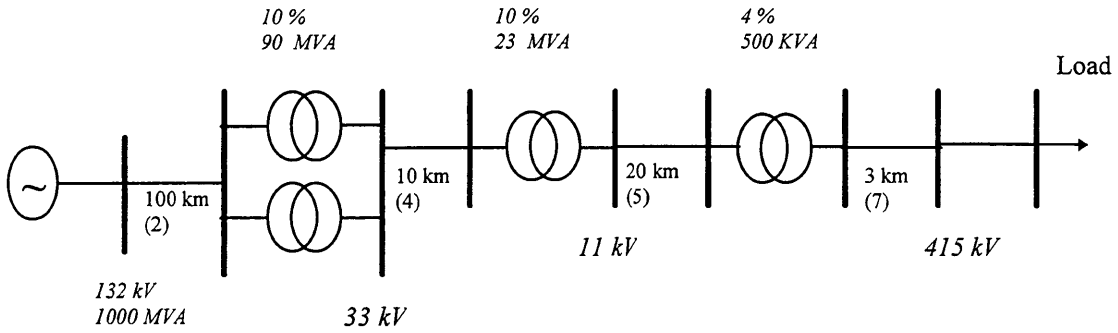


Figure 8.14 Radial distribution system [25]

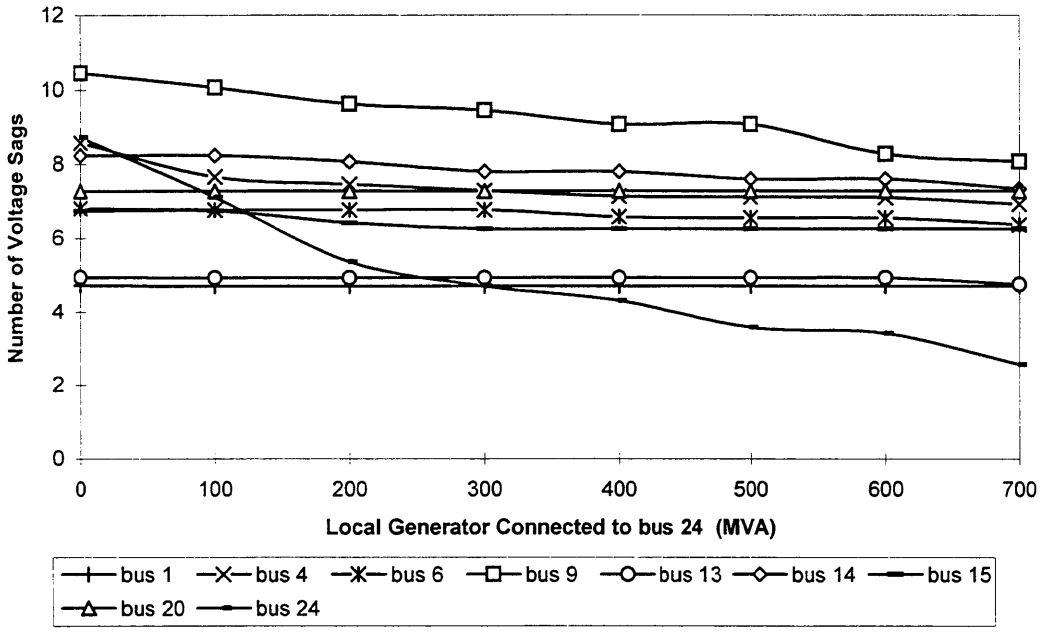


Figure 8.15 Number of voltage sags versus generator size at bus 24 (80%)

8.4 Other Characteristics of Voltage Sags

8.4.1 Imbalance Faults

Most of the faults in a power system are imbalanced faults. These faults are the most common cause of voltage sags in the network. In this section, the influence of imbalanced faults on the number of sags is investigated. The system has been simulated first for three-phase faults and then for single-line-to-ground (SLG) and line-to-line faults (LTL). The expected number of sags has been computed for the worst phase in the system (phase A), by assuming that the imbalanced faults always involve this phase. Furthermore, it has been assumed that the expected annual number of sags is the total of the results from these three simulations. The values used for the failure rates are given in Table 8.7. These values are obtained from reference [31]. Table 8.7 shows a fixed ratio between the failure rates, for example the ratio between SLG to 3-phase is 2.8 and LTL to 3-phase is 1.3. The results are shown in Tables 8.8 and 8.9, which give the number of sags with a magnitude of less than 80% and less than 65%.

From the tables, it can clearly be seen that the number of sags for an imbalanced single-line-to-ground fault are as high as with the three-phase fault. This could be expected, since single-line-to-ground faults have a higher failure rate. Therefore, the effect on the total expected number of sags is very high. Likewise, the number of sags for line-to-line faults is rather less than for single-line-to-ground faults and three-phase faults. This is a well known phenomenon in which the smallest phase voltage remains at 50%, causing more shallow sags. Thus there are less sags below a certain value (section 4.6) which causes the expected number of sags to be small. From the tables, it is clear that the number of sags due to single-line-to-ground faults is about three times higher than the expected number of sags due to three-phase faults, and six times higher than due to line-to-line faults.

Table 8.7 The expected number of faults per year used for the RTS

Busbar Connections		Occurrence/year		
From	To	3-Phase	LTL	SLG
1	2	0.24	0.31	0.65
1	3	0.51	0.66	1.38
1	5	0.33	0.42	0.89
2	4	0.39	0.50	1.10
2	6	0.48	0.62	1.31
3	9	0.38	0.49	1.03
3	24	0.02	0.026	0.054
4	9	0.36	0.46	0.98
5	10	0.34	0.44	0.92
6	10	0.33	0.42	0.89
7	8	0.3	0.39	0.81
8	9	0.44	0.57	1.19
8	10	0.44	0.57	1.19
9	11	0.02	0.026	0.054
9	12	0.02	0.026	0.054
10	11	0.02	0.026	0.054
10	12	0.02	0.026	0.054
11	13	0.4	0.53	1.13
11	14	0.39	0.52	1.11
12	13	0.4	0.52	1.13
12	23	0.52	0.69	1.47
13	23	0.49	0.65	1.39
14	26	0.38	0.51	1.1
15	16	0.33	0.44	0.94
15	21	0.41	0.55	1.16
15	21	0.41	0.55	1.16
15	24	0.41	0.55	1.16
16	17	0.35	0.47	0.99
16	19	0.34	0.45	0.96
17	18	0.32	0.43	0.91
17	22	0.54	0.72	1.53
18	21	0.35	0.47	0.99
18	21	0.35	0.47	0.99
19	20	0.38	0.51	1.1
19	20	0.38	0.51	1.1
20	23	0.34	0.45	0.96
20	23	0.34	0.45	0.96
21	22	0.45	0.6	1.27

Table 8.8 Frequency of voltage sags below 80%

Bus No.	3-Phase	LTL	SLG	Total
Bus 1	4.72	2.49	14.47	21.68
Bus 2	4.72	2.88	14.37	21.97
Bus 3	10.74	8.7	29.04	48.48
Bus 4	8.58	5.54	24.12	38.24
Bus 5	7.14	4.81	21.61	33.56
Bus 6	6.81	4.73	12.54	24.08
Bus 7	1.51	1.04	6.29	8.84
Bus 8	4.26	4	12.88	21.14
Bus 9	10.45	6.96	28.48	45.89
Bus 10	8.27	5.64	23.43	37.34
Bus 11	8.99	5.53	23.76	38.28
Bus 12	6.76	5.72	21.61	34.09
Bus 13	4.98	3.69	15.51	24.18
Bus 14	8.24	8.09	22	38.32
Bus 15	6.74	6.26	19.2	32.2
Bus 16	7.66	7.84	21.84	37.37
Bus 17	6.5	6.64	19.2	32.34
Bus 18	5.62	5.53	18.43	29.58
Bus 19	8.01	7.6	22.9	38.51
Bus 20	7.28	4.4	20.86	32.54
Bus 21	5.24	5.53	18.48	29.25
Bus 22	4.6	5.15	13	22.75
Bus 23	5.23	4.54	17.74	27.51
Bus 24	8.73	6.82	25.45	41

Table 8.9 Frequency of voltage sags below 65%

Bus No.	3-Phase	LTL	SLG	Total
Bus 1	1.37	0.59	4.19	6.15
Bus 2	1.4	0.59	3.97	5.96
Bus 3	2.85	1.51	7.76	12.12
Bus 4	2.19	1.17	7.65	11.01
Bus 5	2.16	1.53	5.76	9.45
Bus 6	2.6	0.81	2.38	5.79
Bus 7	0.8	0.48	2.16	3.44
Bus 8	1.34	1.04	4.61	6.99
Bus 9	2.59	0.88	7.08	10.55
Bus 10	2.81	0.53	7	10.34
Bus 11	2.15	1.13	6.07	9.35
Bus 12	2.26	0.94	7.23	10.43
Bus 13	1.56	0.9	4.57	7.03
Bus 14	2.55	1.52	5.88	9.95
Bus 15	3.79	2.64	11.29	17.72
Bus 16	4.34	1.74	13.33	19.41
Bus 17	3.69	2.53	10.93	17.15
Bus 18	3.3	2.51	10.4	16.21
Bus 19	3.6	2.87	11.23	17.7
Bus 20	2.72	2.57	8.24	13.53
Bus 21	3.23	2.94	10.32	16.49
Bus 22	3.49	2.02	10.33	15.84
Bus 23	2.38	1.75	7.44	11.57
Bus 24	3.75	1.49	12	17.24

8.4.2 Phase-Angle Jump

As pointed out in section 2.7 , some equipment is not only sensitive to the magnitude of a voltage sag but also to the phase-angle jump which is associated with voltage sags. In this section the results of the simulation showing the phase-angle jump in the RTS due to three-phase and imbalanced faults (line-to-line and single-line-to-ground faults) are presented.

Three-Phase Faults

A phase-angle jump is produced if a three-phase fault occurs at a feeder that has a different X/R ratio from that of the source. This has been discussed in detail in section 2.7. As discussed in section 2.8, three-phase faults are classified as type A: all three phases drop by the same amount in magnitude. Figure 8.16 plots phase-angle jumps against voltage sag magnitudes for BUS2. This figure is produced for sags due to faults between buses 2 and 4 only. A total of 35 faults were applied. The minimum phase-angle jump occurred at 0.2 pu voltage magnitude. As the sag magnitude reduces (shallow sag) the phase jump becomes zero. Figure 8.17 shows the phase jump when the faults are distributed around the system (90 fault positions). The curve is not smooth due to the different fault positions and the different X/R ratio from the source impedance at bus 2. In this figure the maximum phase jump occurred at 0.42 sag magnitude: this was again produced as the result of the different X/R ratio between the lines.

Figure 8.18 shows a scatter diagram for all the sags in the system (90 fault positions times 24 buses = 2070 sags). Figure 8.18 shows that most of the phase jumps lie between 1 and 5 degrees. The maximum phase-angle jump is about 9 degrees, and occurs at a voltage of 0.2 pu.

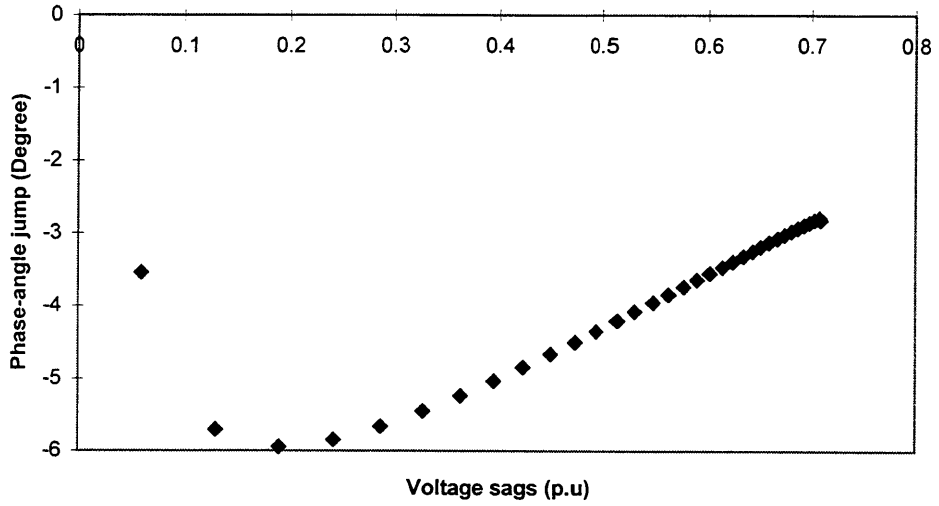


Figure 8.16 Phase-angle jump against voltage sags at bus 2

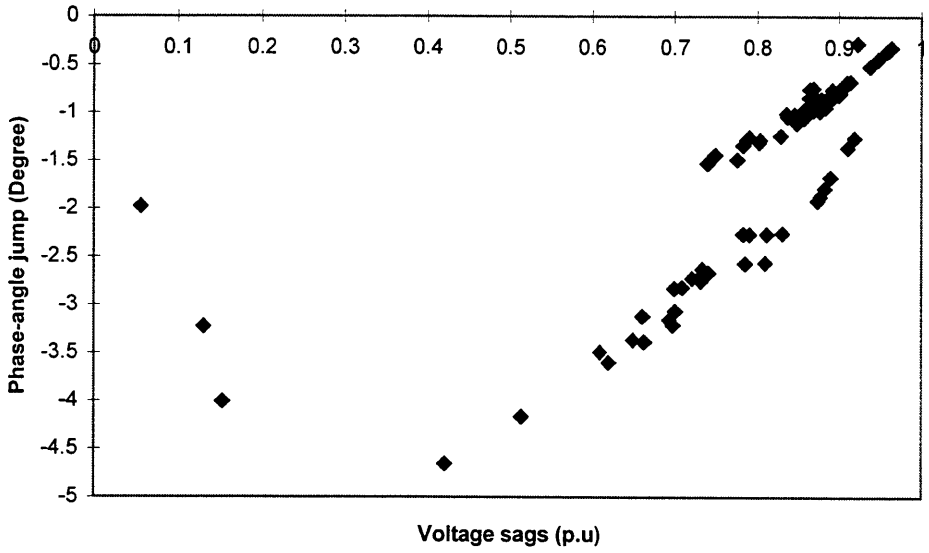


Figure 8.17 Phase-angle jump against voltage sags at bus 2 for 90 fault positions

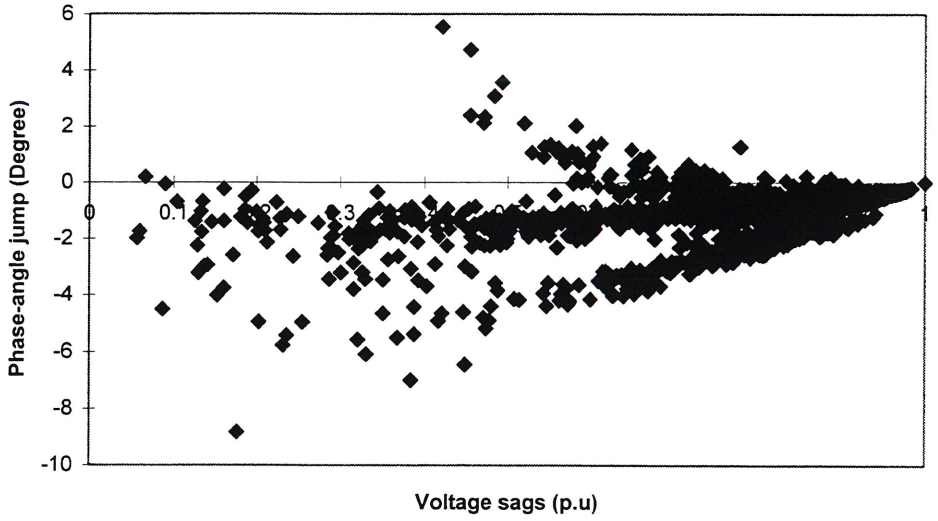


Figure 8.18 Phase-angle jump against voltage sags for 90 fault positions for all the buses

Line-to-Line Faults

Figures 8.19 and 8.20 show the phase-angle jump as a function of per unit voltage for buses 2 and 4 respectively (faulted phases). The faults are between buses 2 and 4. A total of 34 fault positions were applied. Figures 8.21 and 8.22 show the phase-angle jumps at buses 17 and 22 also due to line-to-line faults between buses 17 and 22 only. A total of 57 fault positions were applied this time. These four figures show strong similarities to each other. The phase-angle jump decreases as the voltage sags become more shallow. However, in reality, faults occur not only in one line but all round the system. Figure 8.23 shows the phase-angle jump at bus 4 due to line-to-line faults around the system (90 fault positions). It can be seen from this figure that the phase jump again reduces. The two curves mirror each other and move closer together as the voltage sags become more shallow. These figures, as discussed in section 2.8, are classified by Bollen [24] as voltage sags of type C. Voltage sags of type C are due to line-to-line faults, in which two phases experience a phase-angle jump of 60 degrees with a drop in magnitude of up to 50%. It can clearly be seen in the

figures that the maximum phase jumps (60 degrees) are at 50% magnitude. These studies can also be compared with the theoretical results presented by Bollen [60]. Figure 8.24 shows theoretical results, which can be compared with the other figures shown in this section. Therefore, Figures 8.19, 8.20, 8.21, 8.22, 8.23 and 8.24 are similar in shape.

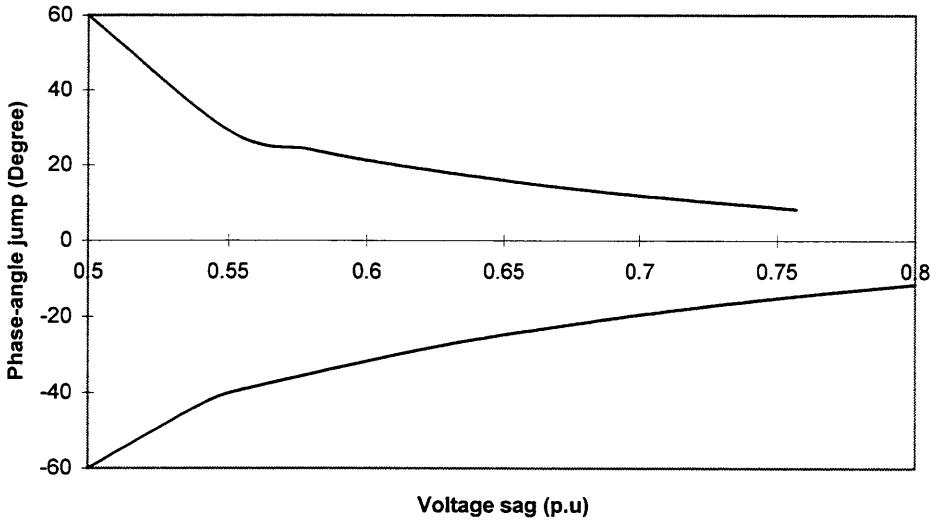


Figure 8.19 Phase-angle jump against voltage sags at bus 2

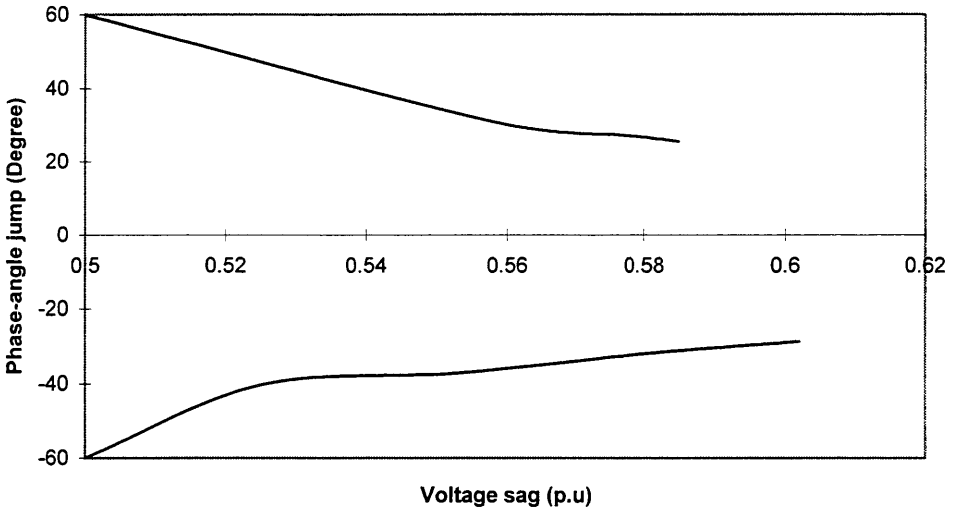


Figure 8.20 Phase-angle jump against voltage sags at bus 4

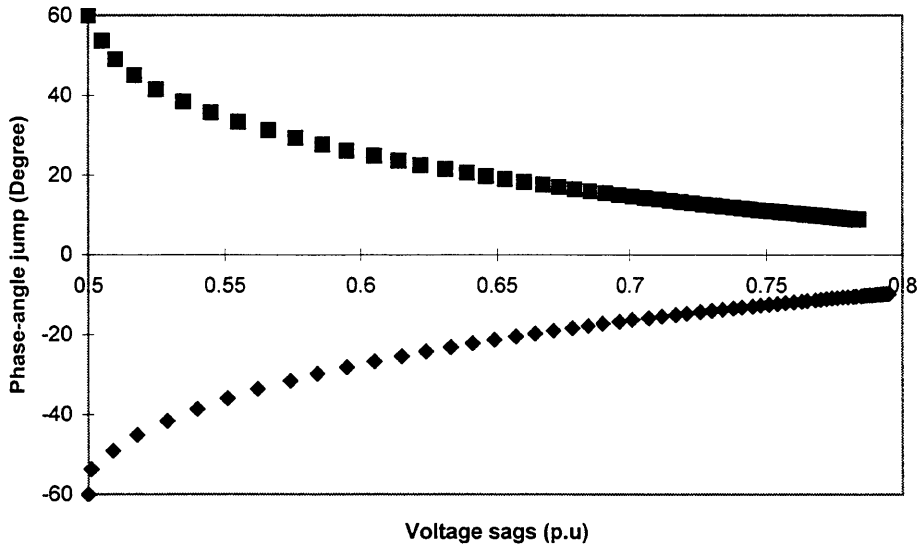


Figure 8.21 Phase-angle jump against voltage sags at bus 17

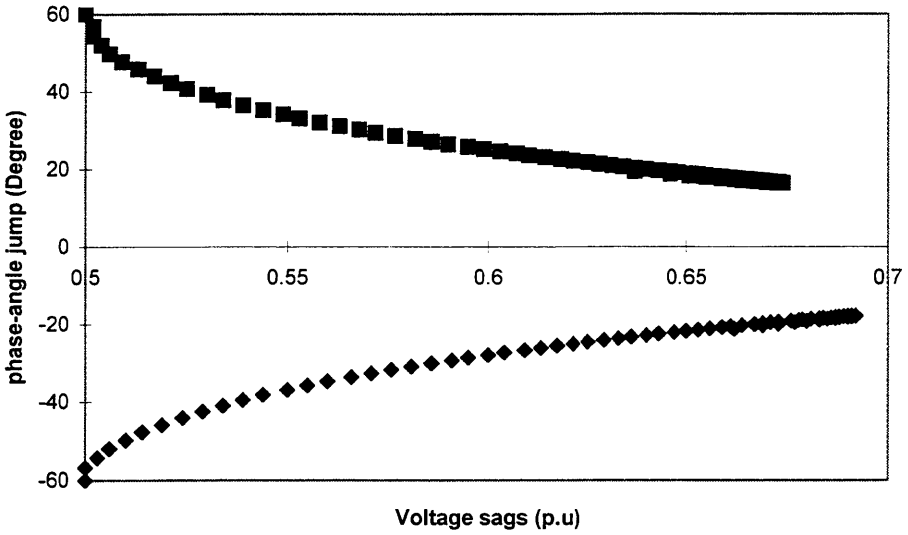


Figure 8.22 Phase-angle jump against voltage sags at bus 22

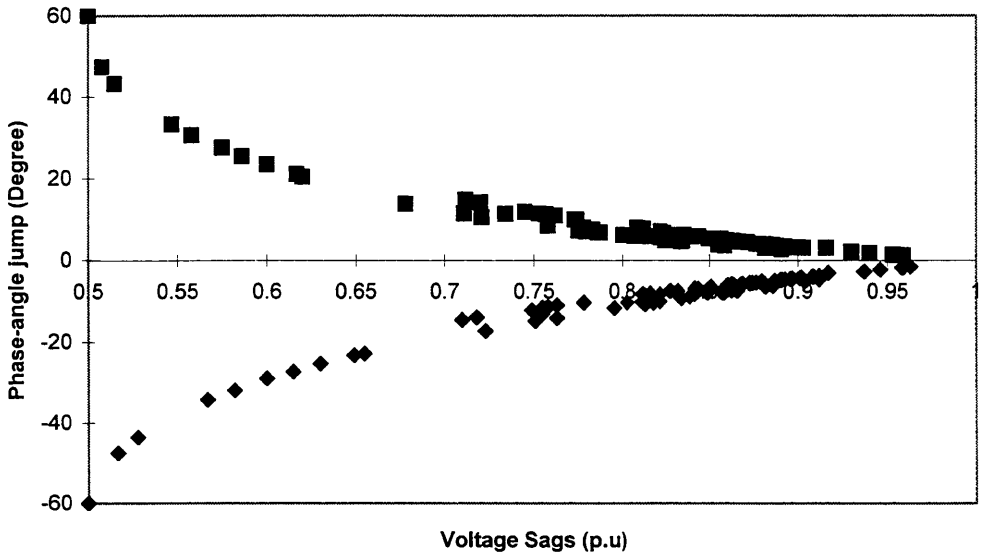


Figure 8.23 Phase-angle jump against voltage sags at bus 4 for 90 fault positions

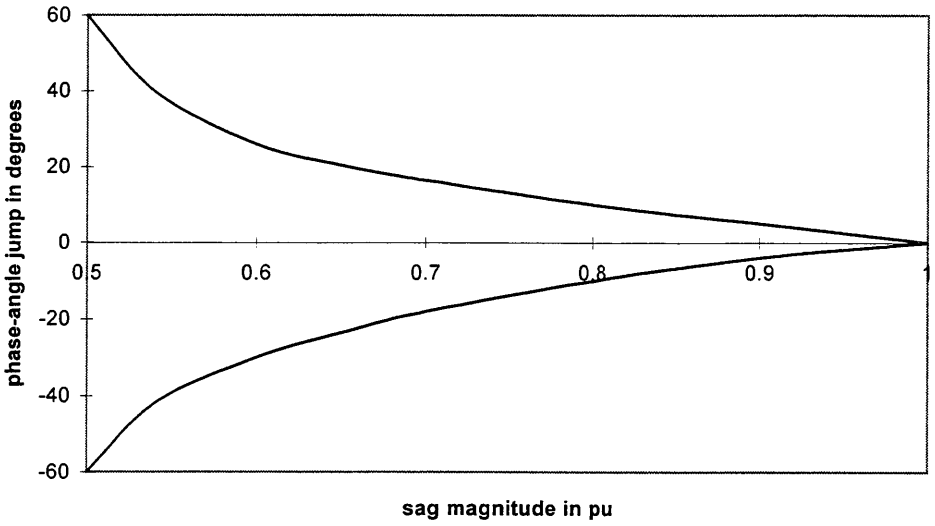


Figure 8.24 Theoretical results of phase-angle jump

Single-Line-to-Ground Faults

Figure 8.25 shows the phase angle-jump at bus 2 due to faults between buses 2 and 4. Again the phase jump decreases as the voltage sag reduces. Figure 8.26 illustrates phase-jumps due to faults in different positions of the system. These figures show the phase-angle jumps in the faulted phase only. The similarity between the two figures can clearly be seen. Therefore, the shape of the phase-jump is not affected by the position of the faults. By comparing these figures with the line-to-line faults, it becomes clear that the single-phase faults produce less severe phase-jumps than phase-to-phase faults. This type of sag and phase-jump are of type B, as discussed in section 2.8. Comparing these figures with the theoretical results (Figure 8.27), the similarity in shape between the figures can be seen.

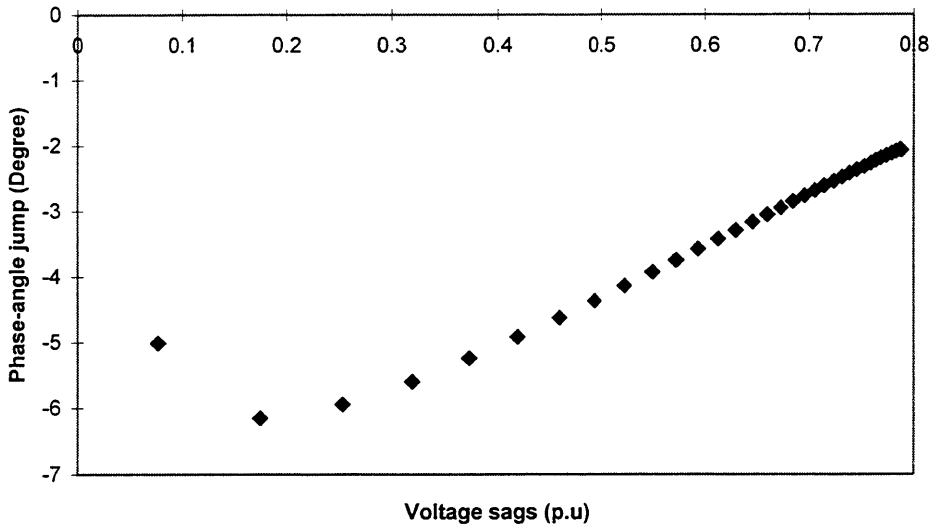


Figure 8.25 Phase-angle jump against voltage sags at bus 2

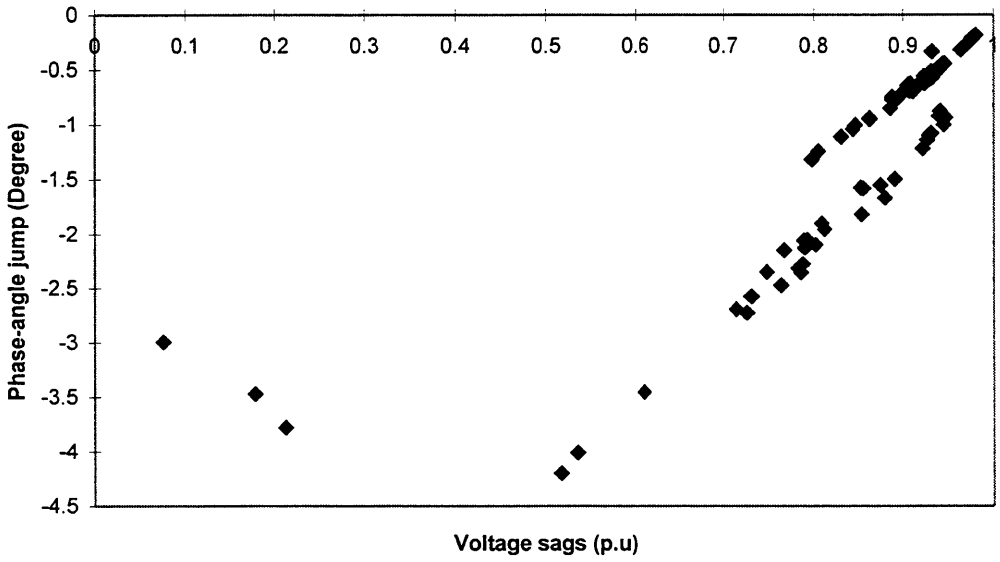


Figure 8.26 Phase-angle jump against voltage sags at bus 2 for 90 fault positions

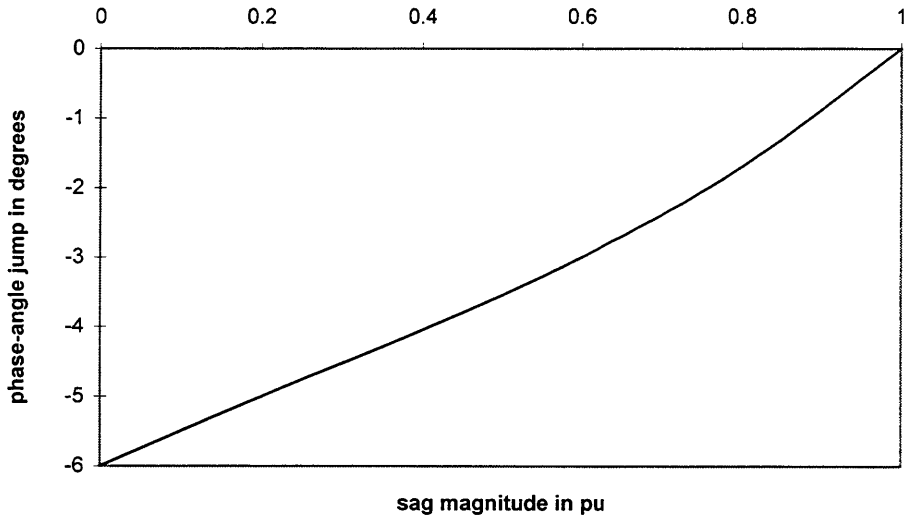


Figure 8.27 Theoretical results of phase-angle jump

8.5 Conclusions

From the above, it can be concluded that stochastic prediction techniques give a rapid solution in estimating the frequency of voltage sags and determining the area of poor power quality in the network. Monitoring on the other hand, requires a lot of time to determine this characteristic. The method proposed in this thesis will provide customers with a practical method of making a comparison between various power distribution systems. It also gives a utility a tool to quantify the voltage sag aspect of the quality of their supply. This will enable customers as well as utilities to make decisions about the necessity of investments to mitigate voltage sags.

Furthermore, from the stochastic prediction studies the influence of system changes during faults in the system can easily be determined, whereas monitoring does not easily provide such information.

The studies performed using the RTS showed that sag frequency can vary significantly throughout the system. Although the RTS is more homogeneous than most existing systems, a factor of up to two was found in sag frequency. Outage studies of generators and transformers have shown that these can influence the number of sags. For accurate results, the scheduling of generator stations and transformers needs to be taken into account in the voltage sag study.

In addition, it is very clear that the phase-angle jump is always associated with voltage sags. The results of the simulation show that different types of faults produce different characteristics of phase-angle jumps which affects sensitive equipment. Also, the simulation shows that imbalance faults have a severe influence on the number of sags.

CHAPTER 9

CONCLUSIONS

9.1 Introduction

Voltage sags have been recognised as an important power quality problem. Most of the earlier work regarding the number of voltage sags in electrical networks has focused on monitoring results. However, very little has been done about the stochastic assessment of the number of voltage sags. This thesis has tackled this problem by modelling the electrical network and progressively expanding into the expected number of voltage sags. It has provided the necessary models, algorithms and techniques for a stochastic assessment of the sag frequency. This chapter briefly reviews the main achievements and contributions made by this research as described in detail in previous chapters. First the main points extracted from the theoretical models and techniques are considered and then the conclusions obtained from their application to the analysis of real cases. This thesis concludes by suggesting some areas for future research.

9.2 Monitoring and stochastic prediction

The interest in voltage sags can be explained almost completely by the increased sensitivity of equipment to voltage sags. To solve this aspect of power quality a compatibility assessment between equipment and supply is needed, either locally or globally. Such an assessment requires data about equipment voltage tolerance and about expected number of voltage sags as a function of magnitude, duration, and possibly some other characteristics. To obtain this data two methods are available: power quality monitoring and stochastic prediction.

Monitoring has shown its usefulness in obtaining the average quality of supply. Power quality monitoring for a single site can give very useful information on common events, but has its limitations for rare events such as the more severe voltage sags. As the occurrence of voltage sags is a random process, stochastic methods to determine the error after a given number of events can be used. The other way around: for a given maximum error it is possible to calculate the minimum number of events that need to occur before the required accuracy is obtained. With a given event frequency it is then possible to calculate the required monitoring interval. The results of such a calculation are presented in Table 9.1. Since the results of the monitoring are needed for a compatibility assessment, they are times required for estimating how often a piece of equipment is expected to trip. Event frequencies (i.e. trip frequencies) of interest are in the order of 1 per month to 1 per year or even lower. From the table it becomes immediately clear that power quality monitoring suffers from severe limitations.

The alternative is to perform a stochastic assessment of voltage sags for the site of interest, based on methods developed for power system reliability assessment. By using existing failure statistics this stochastic assessment leads to accurate site-specific results.

Table 9.1 Monitoring interval required to obtain a given accuracy

	required accuracy		
Event Frequency	50 %	10%	2%
1 per day	2 weeks	1 year	25 years
1 per week	4 month	7 years	200 years
1 per month	1 year	30 years	800 years
1 per year	16 years	400 years	10,000 years

Stochastic prediction of the number of voltage sags with specific characteristics could provide a useful tool to be used in parallel with voltage sag monitoring.

9.3 Achievements and Contributions

The major achievements and contributions of this thesis to the stochastic prediction of number of voltage sags can be summarised as follows:

* The development of a technique to calculate the voltage at a customer bus due to faults in the power system. The symmetrical component method is selected as it is the most appropriate for implementation on a personal computer; it represents the electrical system by a bus impedance matrix.

The advantages of the bus impedance matrix are:

- Easy for solving faulted networks which require changes in the system.
- The impedance matrix does not require a new inversion for each new fault simulation. The short circuit analysis of very large electrical systems is achieved most efficiently by the use of an impedance matrix.

- Easy to create a new node in the electrical network without removing any existing nodes for applying a short circuit on a line.

* A stochastic prediction study for the number of voltage sags in transmission and distribution systems has been introduced.

Stochastic prediction methods can give rapidly updated information of the expected number of sags at a specific site compared with waiting for the statistical results from monitoring. Of course, accurate models and parameters for the system are required. Checking the influence of changing some configurations of the network can be done using these prediction methods. Accordingly, stochastic prediction gives fast results for determining the critical voltages and critical areas in the electrical networks.

The method of fault positions which is a straightforward method to calculate the magnitude and duration of voltage sags for as many faults as needed is used. After taking the failure rate for each fault into account, the expected number of sags as a function of magnitude and duration can be calculated. The method of fault positions which is adopted in this study can be used as a best alternative to monitoring. In the method of fault positions, the accuracy of the result can be increased by increasing the number of fault positions. The results of this method can be treated in many different ways. The method of fault positions will be part of the new IEEE Std. 493.

* Development of computer implementation to estimate the number of voltage sags as a function of duration and magnitude. This can be used as a software tool by utilities to quantify the quality of their supply, by industrial and commercial customers to assess the compatibility between their production process and the supply, and by equipment manufacturers to assess the suitability of their equipment.

Stochastic assessment prediction methods are based on techniques used for power system reliability analysis. The stochastic assessment technique which was developed in this project consists of three steps:

- Calculating the expected number of short circuit faults.
- Determining voltage sag characteristics, for example, duration and magnitude, for each fault situation.
- Combining the output of the above two steps to obtain the expected number of sags for specific sites.

* Analysis of the models and techniques for calculating the frequency of voltage sags automatically in electrical networks and its application for the analysis of real systems.

The program performs a conventional analysis of the electrical system and a calculation of the number of voltage sags. General expressions have been suggested for modelling the faults in the line. Efficient and general algorithms of system representation and voltage calculation during the fault in the electrical system and stochastic calculation of the frequencies of voltage sag have been discussed.

The main advantage of the software is that it provides reliable information, easily available, regarding the quality of the product supplied in terms of interruptions and voltage sags. This is interesting for the utilities. These results are essential for customers as well as planners in directing their investment choices.

* The development of techniques illustrating the results of the stochastic prediction of the number of voltage sags.

- Voltage sag table: a table showing the expected number of sags that exceed a certain duration and magnitude. Such a table is adopted to present the results of the stochastic assessment of voltage sags. The cumulative voltage sag table is calculated for each load position by adding the voltage sag table for each fault position in the system. This kind of table gives the expected number of interruptions of load operations at the various customer locations within the network.

- Voltage sag map: The concept of a voltage sag profile (map) has been developed to help characterise the supply for the whole range of customers connected to the network. From this type of map, the number of sags in the area of interest can be easily read. The worst area in the system can be identified and the variation in the number of sags over the system can be seen.

The algorithms and techniques for stochastic prediction of number of voltage sags and the representation of the results are a contribution to the stochastic assessment of voltage sags. The development methods and techniques provide power quality information for customers and utilities.

The main aim of the research described in this thesis was to develop techniques to calculate the expected number of voltage sags as a function of their characteristics (magnitude, duration, phase-angle jump three and phase imbalance). This will enable utilities to provide customers with the information required to assess the compatibility between equipment and the supply. These tools are also essential when a utility aims to improve the quality of the supply to certain customers. Also, they enable the manufacturers to develop equipment with the appropriate level of voltage sag ride-through. The developed methods are an extension of the reliability assessment of power systems towards quality of the supply. This provides a more complete set of stochastic indicators to describe the performance of an electricity supply system.

9.4 Practical Applications

The practical applications of the concepts and techniques involved in the stochastic assessment were illustrated in chapters 6, 7 and 8. These was done by performing studies on three different systems. Different alternative design configurations were examined. A study was described in chapter 6 to determine the number of voltage sags in a distribution system. It was concluded from the simulation results that faults at different voltage levels can produce different characteristics. Installing a local generator showed a way of mitigating deep sags due to faults at higher voltage levels.

In chapter 7, the methods and the techniques were applied to the 400 kV NGC system. Although three phase faults were assessed, the techniques are not limited to the analysis of these faults. It is straightforward to adopt the algorithms for single-phase and phase-to-phase faults. From the study adopted in chapter 7 it was possible to determine the area of lower power quality in the network.

In chapter 8, various studies were conducted on the IEEE Reliability Test System (IEEE-RTS). This gave more opportunity to make changes without resulting in excessive calculation time. The results provide information about what can be obtained by using these techniques. The stochastic prediction studies can easily determine the influence of system changes, whereas monitoring does not easily provide such information. The studies performed using the RTS showed that the sag frequency can vary significantly throughout the system. Although the RTS is more homogeneous that most existing systems, a factor of two was found in the variation of the sag frequency. Outage studies of generators and transformers had a significant influence on the number of sags. For accurate results, the

scheduling of generators and transformer stations needs to be taken into account in such voltage sag studies.

9.5 Suggestions for Future Work

Despite the achievements accomplished within the framework of this project, the future research into this subject should concentrate on developing efficient models and computational techniques to further enhance the usefulness of the program. Some of the more important aspects are outlined below.

1. Higher Order Events.

   In order to obtain accurate stochastic results, higher order events need to be taken into account. The models described in this thesis only incorporate one event at a time. The inclusion of second or higher order events can reflect a more practical system. Important events in the stochastic prediction studies are: maintenance, generator scheduling and relay failure.

2. Non-Rectangular Voltage Sags

   It has been assumed in this project that the rms sag magnitude versus time is rectangular. This corresponds to the basic assumption that the load current is zero. This assumption is not true when the customer load consists of large motors. Examples are chemical plants, steel plants and residential areas where air conditioners are popular. Therefore, this will require an inclusion of the appropriate machine models. These can be very important in order to determine an exact number of sags which describes all aspects of the system behaviour under all relevant operating conditions.

3. Presentation of Results.

   Some ways of presenting the results of a stochastic assessment study where introduced in this thesis. Utilities and customers are also interested in comparing the results with their equipment sensitivity. Therefore, more equipment behaviour needs to be included in the simulation results. For example, the curve that gives the minimum magnitude that the equipment can withstand for a given sag duration (the so called "voltage tolerance curve") could be included.

4. Extending the Method of Critical Distance.

   The method of critical distance, in its simplest form, could be used to estimate which part of the system needs to be studied by the method of fault positions. The method of critical distances can even be used to estimate the number of fault positions needed. Also, the method of critical distances can be extended using approximated expressions that are valid for meshed transmission systems.

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Appendix One

Changes In The Network

An event in the power system (a short circuit, removal of the faulted branch, repair of the faulted branch) always leads to a change in the electrical network: branches are removed or branches are inserted. The removal of a branch with impedance Z is done by inserting a branch with impedance $-Z$ in parallel. Therefore we only have to discuss the insertion of a branch.

Let $Z_{ii}, i = 1..m, j = 1..m$ be the elements of the impedance matrix and let a new branch with impedance z_{pq} be inserted between the nodes p and q, with $q > p$.

Inserting a Radial Branches

If the added element p-q is a radial branches, the procedure for deterring the element of bus impedance is by injecting a current at the i^{th} bus and calculating the voltage at the q^{th} bus with respect to the reference node as shown in Figure A.1 since all other currents equal zero and letting $I_i = 1\ p.u$, Z_{qi} can be obtained directly by calculating Eq.

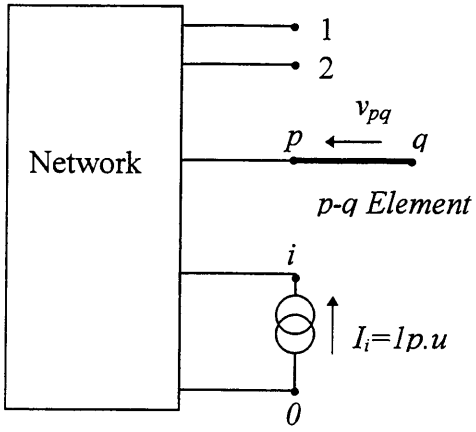


Figure A.1 Injecting Current and Bus Voltage for Calculating of Z_{qi}

The bus voltage associated with the added element and the voltage across the element are related by:

$$E_q = E_p - v_{pq} \qquad (1)$$

The current in the added branch is $i_{pq} = 0$, therefore $v_{pq} = 0$, thus equation (1) with $I_i = 1\ p.u.$ is:

$$Z_{qi} = Z_{pi} \qquad (2)$$

The element Z_{qq} can be calculated by injecting a current at the q^{th} bus and calculating the voltage at that bus and all other bus current equal zero. Letting $I_q = 1\,p.u.$, Z_{qq} can be obtained directly by calculating E_q.

The voltage at buses p and q are related equation (1) and the current through the added element is $i_{pq} = -I_q = -1$, therefore,

$$v_{pq} = -Z_{pq}$$

Therefore, equation (1) with $I_q = 1 p.u$ is:

$$Z_{qq} = Z_{pq} + z_{pq}$$

Furthermore, if p is the reference node

$$Z_{pi} = 0 \qquad i = 1,2,...,m$$

$$i \neq q \qquad \text{and}$$

$$Z_{qi} = 0 \qquad i = 1,2,...,m$$

$$i \neq q$$

Also, $Z_{pq} = 0$, Therefore,

$$Z_{qq} = z_{pq}$$

Inserting a Transversal (Link) Branches

If the added element p-q is a link, the procedure for determining the elements of bus impedance is to connected in series with the added element a voltage source e_l as shown in Figure A.2. This create a hypothetical node l which will be eliminated later. The voltage source e_l is selected such that the current through added link is zero.

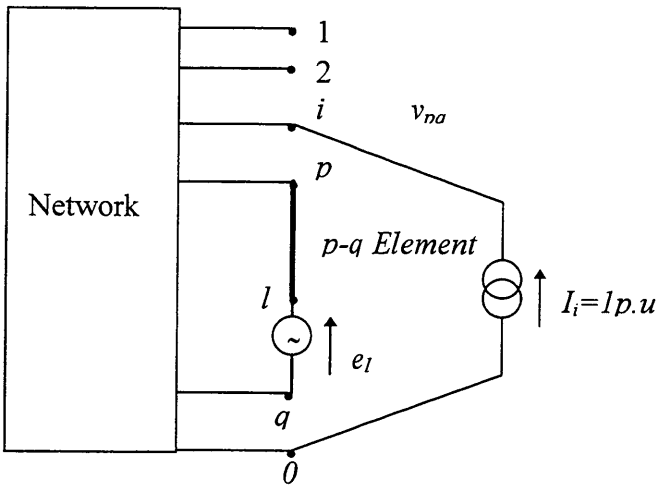


Figure 2.A Injected Current Voltage Source in series with Added Link and Bus Voltage for Calculation of Z_{ll}

Since $e_l = E_l - E_q$ the element Z_{li} can be determined by injecting a current at the i^{th} bus and calculating the voltage at the l_{th} node with respect to bus q. Since all other currents are zero, therefore,

$$\begin{aligned} E_k &= Z_{ki}\, I_i \qquad\qquad k = 1,2,\ldots,m \\ e_l &= Z_{li}\, I_i \end{aligned} \tag{3}$$

Letting $I_i = 1\,p.u$, therefore Z_{li} can be obtained directly by calculating e_l.

The series voltage source is:

$$e_l = E_p - E_q - v_{pl} \tag{4}$$

Since $i_{pq} = 0$, the element p-l can be treated as a branch, the current $i_{pl} = 0$.

Substituting equation (3) in equation (4) with $I_i = 1\ p.u.$

$$Z_{li} = Z_{pi} - Z_{qi} \tag{5}$$

The element Z_{ll} can be calculated by injecting a current at the l_{th} bus with bus q as a reference (E_q=0) and calculating the voltage at the l_{th} bus with respect to bus q, therefore:

$$\begin{aligned} E_k &= Z_{kl}\, I_l \\ e_l &= Z_{ll}\, I_l \end{aligned} \qquad (6)$$

Letting $I_l = 1\,p.u$, Z_{ll} can be obtained directly by calculating e_l.

The current in the element *p-l* is:

$$i_{pl} = -I_l = -1$$

therefore,

$$v_{pl} = -Z_{pq} \qquad (7)$$

Substituting equation (7) in equation (4) with $I_l = 1\,p.u.$

$$Z_{ll} = Z_{pl} - Z_{ql} + z_{pq}$$

Furthermore, if p is the reference node

$$Z_{pi} = 0 \qquad i = 1,2,\ldots,m$$

$$i \neq l \qquad \text{and}$$

$$Z_{li} = -Z_{qi} \qquad i = 1,2,\ldots,m$$

$$i \neq l$$

Also, $Z_{pl} = 0$, Therefore,

$$Z_{ll} = -Z_{ql} + z_{pq}$$

After which the new node l and node q are merged by means of Kron reduction:

$$Z_{ij} = Z_{ij} - \frac{Z_{iL} Z_{Li}}{Z_{LL}} \; ; \; i = 1 .. m \; ; \; j = 1 .. m$$

Table A.1 is showing a summery of the equations for the formation of the bus impedance matrix.

Add *p-q*	*p* is not reference bus	*p* is the reference bus
Radial Branches	$Z_{qi} = Z_{pi}$ $i = 1,2,...m$ $i \neq q$ $Z_{qq} = Z_{pq} + z_{pq}$	$Z_{pi} = 0$ $i = 1,2,...m$ $i \neq q$ $Z_{qq} = Z_{pq}$
Transversal Branches	$Z_{li} = Z_{pi} - Z_{qi}$ $i = 1,2,...m$ $i \neq l$ $Z_{ll} = Z_{pl} - Z_{ql} + z_{pq}$	$Z_{li} = -Z_{qi}$ $i = 1,2,...m$ $i \neq l$ $Z_{ll} = -Z_{ql} + z_{pq}$

Appendix Two

Input and Output of the Software

The current version of the program uses one input file and creates seven output files. For example, the file names are as follows:

RTS.IN input file containing all system data
RRR.PHA all during-sag voltages in phase A
RRR.PHB all during-sag voltages in phase B
RRR.PHC all during-sag voltages in phase C
RRR.ANG all during-sag angles for all three phases

SAG.PHA cumulative voltage sag table for phase A
SAG.PHB cumulative voltage sag table for phase B
SAG.PHC cumulative voltage sag table for phase C

The DOS-command to run the program is as follows

NVOLTSAG <input> <output>

The above files were created by the command

REANIPOS RTS.IN RRR.OUT

The name of the files with cumulative voltage sag tables is determined in one of the last lines of the input file.

CONTENTS OF THE INPUT FILE

This file describes the power system in the form of impedances, the fault positions and the fault frequency. For example, the input file for four bus system is as follows:

*Simulation_Name
RTS-SE-SYSTEM
*Frequency
50.00
*BasePower
100000000

```
*BaseVoltage
400000
*Branch_Data
1 0 1 'GEN   '0.00000 0.20000 0.00000 0.1900 '    '0.00000 0.20000 0.00000  0.19000 GEN  1          SHRT 0 FAIL 0 MAIN 0 ASGDNEW
2 0 1 'LOAD '0.00000 36.0001 0.0000  36.0001 '    '0.00000 36.0000 0.00000  36.0000 LOAD 1          SHRT 0 FAIL 0 MAIN 0 ASGDNEW
                                              /'  '0.00000 0.00010 0.00000  0.00010 NSEC           SHRT 0 FAIL 0 MAIN 0 ASGDNEW
3 0 3 'LOAD '0.00000 36.0001 0.00000 36.0001 '    '0.00000 36.0000 0.00000 36.0000  LOAD 2          SHRT 0 FAIL 0 MAIN 0 ASGDNEW
                                              /'  '0.00000 0.00010  0.00000 0.00010 NSEC           SHRT 0 FAIL 0 MAIN 0 ASGDNEW
4 0 4 'LOAD '0.00000 36.0001 0.00000 36.0001 '    '0.00000 36.0000 0.00000  36.0000 LOAD 3          SHRT 0 FAIL 0 MAIN 0 ASGDNEW
                                              /'  '0.00000 0.00010 0.00000  0.00010 NSEC           SHRT 0 FAIL 0 MAIN 0 ASGDNEW
5 0  4 'GEN   '0.00000 0.20000 0.00000 0.19000'   '0.00000 0.20000 0.00000  0.19000 GEN  2          SHRT 0 FAIL 0 MAIN 0 ASGDNEW
6 1  2 'BRAE2'0.00000 0.08000 0.00000 0.0800 '    '0.00000 0.08000 0.00000  0.08000 TRAN 1 XX11 SHRT 0 FAIL 0 MAIN 0 ASGDNEW
7 2  3  'WBUR '0.00000 0.15000 0.00000 0.50000   "0.00000 0.15000 0.00000  0.50000 NSEC           SHRT 1 FAIL 0 MAIN 0 ASGDNEW
                                              /'  '0.00000 0.00010 0.00000  0.00010 NSEC           SHRT 0 FAIL 0 MAIN 0 ASGDNEW
8 3  4  'BRA  '0.00000 0.08000 0.00000 0.08000'   '0.00000 0.08000 0.00000  0.08000 TRAN 2 XX11 SHRT 0 FAIL 0  MAIN 0 ASGDNEW
*Rail_Data
1  '     '   SHRT 2  FAIL 0  MAIN 0  ASGDNEW
2  '     '   SHRT 3  FAIL 0  MAIN 0  ASGDNEW
3  '     '   SHRT 4  FAIL 0  MAIN 0  ASGDNEW
4  '     '   SHRT 5  FAIL 0  MAIN 0  ASGDNEW
*Load_Data
1  SPYK 1.00  0.00  COST  0.00  0.00
2  SPYK 1.00  0.00  COST  0.00  0.00
3  SPYK 1.00  0.00  COST  0.00  0.00
*Generator_Data
1  1.000    0.00
2  1.000    0.00
*ATS/Swit._Data
*ShortCirc_Data
1 FAIL 1 LLLL  PRIREL 1 0.200 DIST 1
2 FAIL 2 LLLL  PRIREL 1 0.200 DIST 1
3 FAIL 3 LLLL  PRIREL 1 0.200 DIST 1
4 FAIL 4 LLLL  PRIREL 1 0.200 DIST 1
5 FAIL 5 LLLL  PRIREL 1 0.200 DIST 1
*Relays_Defin
1 FAIL 0  FAIL 0  MAIN 0  ASGDNEW  RAIL 3
*Failure_Data
1  DIST 2  REP DIST 3  ASGDNEW
2  DIST 2  REP DIST 3  ASGDNEW
3  DIST 2  REP DIST 3  ASGDNEW
4  DIST 2  REP DIST 3  ASGDNEW
5  DIST 2  REP DIST 3  ASGDNEW
*Maintenance
*Distributions
1  CHAN 100.00
2  CHAN 12.00
3  REAP  1.000
*SagsTableData
SAG  VOLT 0.900  0.500  0.050  DURA 1.250  0.25  OUTP SAG.OUT
*Depend_Branch
*CommonModeFail
.END
```

The definition of each line of the above input file is:

*Simulation_Name
RTS-SE-SYSTEM
*Frequency
50.00
*BasePower
100000000
*BaseVoltage
400000

These data's are not used in the current version of the program

*Branch_Data

```
1 0 1'GEN   '0.00000 0.20000 0.00000 0.1900 '     '0.00000 0.20000 0.00000 0.19000 GEN 1        SHRT 0 FAIL 0 MAIN 0 ASGDNEW
```

These lines define the generators connected to the system. The generators are modelled as ideal voltage sources. The parameters on each line have the following meaning (example values refer to the first line above):

1	branch number
0	starting node (much be zero for a generator branch)
1	ending node
'GEN '	branch name, all branch and section names shall be 8 characters in between quotes
0.000000	real part of positive and negative sequence generator impedance
0.200000	imaginary part of positive and negative sequence generator impedance
0.000000	real part of zero sequence generator impedance
0.190000	imaginary part of zero sequence generator impedance
' '	name of section. This branch only contains one section so it's not needed to give a separate name
0.000000	real part of positive and negative sequence section impedance
0.200000	imaginary part of positive and negative sequence section impedance
0.000000	real part of zero sequence section impedance
0.190000	imaginary part of zero sequence section impedance The branch only contains one section so these impedances are equal to those for the whole branch
GEN	section type, generator section in this case
1	generator number
SHRT	not in use
0	not in use
FAIL	not in use

0 not in use
MAIN not in use
0 not in use
ASGDNEW not in use

```
2 0  1 'LOAD '0.00000 36.0001 0.0000  36.0001  '     '0.00000 36.0000 0.00000  36.0000 LOAD 1      SHRT 0  FAIL 0  MAIN 0  ASGDNEW
                                              /'    '0.00000 0.00010 0.00000  0.00010 NSEC       SHRT 0  FAIL 0  MAIN 0  ASGDNEW
```

These 3 branches are the so-called load branches. They give the positions in the network for which the voltages have to be calculated. But they also represent an impedance to ground.

The meaning of the first line of the load branch description is as follows
(branch 11 used as example)

2	branch number, the branches have to be numbered consecutive, continuing from the generator branches
0	starting node, has to be zero for a load node
1	ending load
'LOAD '	branch name
0.000000	real part of positive and negative sequence branch impedance
36.000100	imaginary part of positive and negative sequence branch impedance
36.0000	real part of zero sequence branch impedance
27.0001	imaginary part of zero sequence branch impedance
' '	section name
0.000000	real part of positive and negative sequence section impedance
36.00000	imaginary part of positive and negative sequence section impedance
36.0000	real part of zero sequence section impedance
27.0000	imaginary part of zero sequence section impedance
LOAD	section type: load branch
1	load branch number
SHRT	not in use
0	not in use
FAIL	not in use
0	not in use
MAIN	not in use
0	not in use
ASGDNEW	not in use

The meaning of the second line is as follows:

/	start of description of new section
' '	section name
0.00000	real part of positive and negative sequence section impedance

0.00010	imaginary part of positive and negative sequence section impedance
0.00000	real part of zero sequence section impedance
0.00010	imaginary part of zero sequence section impedance
NSEC	type of section: normal section. A load branch shall consist of a load section and a normal section
SHRT	not in use
0	not in use
FAIL	not in use
0	not in use
MAIN	not in use
0	not in use
ASGDNEW	not in use

```
7 2 3 'WBUR  ' 0.002600 0.013900 0.00780 0.04170 '     '0.00000 0.15000 0.00000 0.50000 NSEC     SHRT 1 FAIL 0 MAIN 0 ASGDNEW
                                                /'     ' 0.00130 0.00695 0.00390 0.02085 NSEC     SHRT 2 FAIL 0 MAIN 0   ASGDNEW
```

This is a normal branch. This is the branches in which the short circuits take place. Each branch consists of one or more sections. The Fault positions are located in the middle of the sections. There is no limit to the number of sections.

The meaning of the first line of the description of branch 35 is as follows:

7	branch number
2	starting node
3	ending node
'WBUR '	branch name
0.000000	real part of positive and negative sequence branch impedance
0.150000	imaginary part of positive and negative sequence branch impedance
0.000000	real part of zero sequence branch impedance
0.50000	imaginary part of zero sequence branch impedance
' '	section name
0.00130	real part of positive and negative sequence section impedance
0.00695	imaginary part of positive and negative sequence section impedance
0.00390	real part of zero sequence section impedance
0.02085	imaginary part of zero sequence section impedance
NSEC	type of section: normal section
SHRT	short circuit (fault position)
1	number of fault position, in the original program it was possible to have more than one SHRT at the same position. I don't know what this would do to the new version of the software. If there is no fault position in this branch the number 0 shall be used
FAIL	not in use
0	not in use
MAIN	not in use

0	not in use
ASGDNEW	not in use

The meaning of the second line of the description of branch 35 is as follows

/	start of description of new section
' '	section name
0.00130	real part of positive and negative sequence section impedance
0.00695	imaginary part of positive and negative sequence branch impedance
0.00390	real part of zero sequence branch impedance
0.02085	imaginary part of zero sequence section impedance
NSEC	type of section: normal section
SHRT	short circuit (fault position
2	number of fault position
FAIL	not in use
0	not in use
MAIN	not in use
0	not in use
ASGDNEW	not in use

6 1 2 'WBUR ' 0.002300 0.083900 0.00230 0.08390 ' '0.00230 0.08390 0.00230 0.08390 TRAN XX11 SHRT 0 FAIL 0 MAIN 0 ASGDNEW

These are four transformer branches, the data is similar to those for a normal section

6	branch number
1	starting node
2	ending node
'WBUR '	branch name
0.002300	real part of positive and negative sequence branch impedance
0.083900	imaginary part of positive and negative sequence branch impedance
0.00230	real part of zero sequence branch impedance
0.08390	imaginary part of zero sequence branch impedance
' '	section name
0.00230	real part of positive and negative sequence section impedance
0.08390	imaginary part of positive and negative sequence section impedance
0.00230	real part of zero sequence section impedance
0.08390	imaginary part of zero sequence section impedance
TRAN	section type : transformer section
XX11	transformer type X = star grounded D = delta Y = star
SHRT	not in use

0	not in use
FAIL	not in use
0	not in use
MAIN	not in use
0	not in use
ASGDNEW	not in use

*Rail_Data

```
1 '    'SHRT 2 FAIL 0 MAIN 0 ASGDNEW
```

This is a list of all the nodes in the system. In this case fault positions in the substations have been included. The meaning of the description of node 1 is as follows:

1	node number
' '	node name
SHRT	fault position
2	number of fault position. A 0 shall be used in case no fault position is present at this node
FAIL	not in use
0	not in use
MAIN	not in use
0	not in use
ASGDNEW	not in use

*Load_Data

```
1 SPYK 1.00  0.00  COST  0.00  0.00
```

This is a list of all the loads connected to the system. They don't contain any additional information compared to the branch listing

1	load number
SPYK	not in use
1.00	not in use
0.00	not in use
COST	not in use
0.00	not in use
0.00	not in use

*Generator_Data

```
1 1.000   0.00
```

This is a list of all generators connected to the system. The open-circuit voltage of the voltage sources representing the generators, are defined here.

1	generator number
1.000	magnitude of voltage (this shall not exceed 2.56)
0.00	ngle of voltage

*ATS/Swit._Data

not in use

*ShortCirc_Data

1 FAIL 1 TTTT PRIREL 1 0.200 DIST 1

This gives more details of the fault positions defined in the branch and rail data. It defines the type of fault, the relay to intervene and the fault-clearing time. The meaning of the description of fault position 1 is as follows

1	number of fault position
FAIL	reserved word indicating the fail number. Fails are the internal events generated.
1	number of fail event. In this version of the program the fail number shall always be equal to the number of the fault position.
TTTT	fault type TTTT = three-phase fault SSSS = single-line-to-ground fault LLLL = line-to-line fault
PRIREL	reserved word referring to primary relay, this has no meaning here
1	reference to the relay that will clear this fault
0.200	fault-clearing time in seconds, equals the sag duration
DIST	reserved word referring to a distribution or probability, in this case the probability that the primary relay will clear the fault.
1	reference to the probability, a probability of 100% is used here. A non-unity probability requires additional input data.

*Relays_Defin

1 FAIL 0 FAIL 0 MAIN 0 ASGDNEW BRAN 36

This gives additional information about the relays that clear the faults. In the original reliability software this was very important information. In the new voltage sag software not

anymore. There is still a reference to the branch or substation (rail) that will be removed when the relay clears the fault, but that information is no longer used.

1	relay number
FAIL	not in use
0	not in use
FAIL	not in use
0	not in use
MAIN	not in use
0	not in use
ASGDNEW	not in use
BRAN	type of component removed BRAN = branch RAIL = substation or busbar
3	number of branch (or rail) removed

*Failure_Data

```
1  DIST 2  REP DIST 3  ASGDNEW
```

This gives additional information about the various failure events.

1	event number (= fault position number)
DIST	reserved word referring to a stochastic distribution for the time to event
2	reference to sag frequency
REP DIST	reserved word referring to a stochastic distribution for the repair time
3	reference to repair time distribution, this information is not used in the current version of the program
ASGDNEW	not in use

*Maintenance

not in use

*Distributions

```
1  CHAN 100.00
2  CHAN 12.000
3  RAPE 1.000
```

This gives additional information about the probabilities, frequencies and distributions used. The first distribution is the probability that the relays will clear the FAult, which is 100%

1	distribution number

CHAN	type of distribution CHAN = probability 100.00probability in percent, 100% in this case thus the next 20 distributions give sag frequencies.
2	distribution number
CHAN	type of distribution CHAN = probability, but here used as frequency
12.0	event frequency in %, thus there is an event frequency of 0.12 per year associated with this fault position.

The last distribution (3) defines a repair time distribution. This information is not used by the current version of the program.

*SagsTableData

```
SAG  VOLT 0.900  0.500  0.050  DURA 1.250  0.25  OUTP SAG.OUT
```

This line defines the format of the output tables (cumulative sag tables).

SAG	reserved word: cumulative SAG tables
VOLT	reserved word: VOLTage scale
0.900	maximum voltage in the table
0.500	minimum voltage in the table
0.050	voltage interval
DURA	reserved word: DURAtion
1.250	maximum duration
0.25	minimum duration and duration interval
OUTP	reserved word: OUTPut file
SAG.OUT	name of file to which the cumulative sag tables are written

The program will generate three files, one for each phase. In this example they will be names SAG.PHA, SAG.PHB and SAG.PHC. The format of the cumulative voltage sag tables will be as follows:

	0.25 sec	0.50 sec	0.75 sec	1.00 sec	1.25 sec
0.90 pu					
0.85 pu					
0.80 pu					
0.75 pu					
0.70 pu					
0.65 pu					
0.60 pu					
0.55 pu					

*Depend_Branch
*CommonModeFail
.END

CONTENTS OF THE OUTPUT FILES

These files give the voltages at all the load buses during all events. The load buses and the events are defined in the input file RTS.IN. The three files refer to the three phases.

Part of the file RRR.PHA is reproduced below with some comment.

DATA

The file starts with the reserved word .DATA

```
1  0  0.00   0   0.20  0.1200   FA1  0.508 0.417 0.764  FA1   SH1
1  0  0.20  1.00  0.00  0.00000 RE4  1.000 1.000 1.000  RE4   RA3
1  0  0.20  1.00  0.20  0.00000 ER7  1.000 1.000 1.000  ER7
```

Each line gives a time stamp, the voltages at all node buses during one event, an event reference, and the system structure. The structure of the output file comes again from the original reliability analysis program. Each fault position corresponds with three events (each creating one line in the output file):

- fault initiation
- fault clearing
- end of repair of faulted component

The first line gives information about the actual short circuit. This line contains the voltages of interest for the sag prediction program.

1 0 0.00 0 0.20 0.19500	time stamp, not in use
FA1	event reference, in this case FAil event 7, the voltages that follow are thus for fault position 7
0.508 0.417 0.764	voltage for all the load nodes defined in the input file. A total of 24 load nodes were defined in the input file, thus the output file gives 24 voltages. This line should be read as follows: due to a fault at position 7, the voltage at load 1 is 50.8%, at load 2 it is 41.7%, etc.
FA1	event reference again
SH1	description of the system state, only the deviations compared to the healthy state are given. The

deviation in this case is that there is a short circuit at fault position 7.

The second and third line are not used in this program. They give the voltage for the other two events.

RE1	event description: intervention by RElay 4
RA3	system description: branches 38 and 39 are out of operation
ER1	event description: End of Repair of failure 7

THE OUTPUT FILES OF NUMBER OF VOLTAGE SAGS

The number of voltage sags will be calculated for the three phases and the results will be for each phase in different file. These three files give the cumulative sag tables for each load node, for the three tables. The first two tables in SAG.PHA are reproduced below.

	Duration (second)				
Volt pu	0.25000	0.50000	0.75000	1.00000	1.25000
0.90000	0.6000	0.00000	0.00000	0.00000	0.00000
0.85000	0.6000	0.00000	0.00000	0.00000	0.00000
0.80000	0.4000	0.00000	0.00000	0.00000	0.00000
0.75000	0.4000	0.00000	0.00000	0.00000	0.00000
0.70000	0.3000	0.00000	0.00000	0.00000	0.00000
0.65000	0.3300	0.00000	0.00000	0.00000	0.00000
0.60000	0.2000	0.00000	0.00000	0.00000	0.00000
0.55000	0.1000	0.00000	0.00000	0.00000	0.00000

This is the cumulative sag table calculated for phase A of load node 1. Each entry in the table gives the expected number of sags more severe than the given magnitude and duration (thus: of lower magnitude and of longer duration).