Benchmarking power station voltage dip performance to meet the grid code requirements

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Abstract

This study examines the bearing of a retrospective regulatory framework that requires power-generating units to have a degree of resilience to disturbances that originate in an integrated power system (IPS). Such frameworks are important to prevent interruptions of plant processes that can result in the interruption of power-generating capacity.

The regulatory framework requirements of the South African National Grid Code form the background to the study. Typical power plant design and operating philosophy, the available technology and the literature examined in the study enriches this background. Included in the technology review and literature study are the characteristics of the disturbances that can originate in an integrated power system and how these disturbances come into play within the electrical reticulation system of the power plant. The literature study evaluated potential inherent power plant design disturbance resilience, historical and current means and measures implemented.

The South African Grid Code in terms of GCR 9 requirements was benchmarked with other available countries' grid codes or similar network governances to identify resultant problems that affect the degree of resilience of power plants to disturbances that originate in an integrated power system (IPS).

The research process involved a comparison between power plant design voltage operating limits and international standards applicable to the equipment used at power plants. The assessment of the international standards, the grid code voltage operating limits and the power plant design parameter provided the first indication of GCR 9 compliance and revealed additional problem areas.

The analysis was conducted using historical and current means and measures implemented at power-generating units that provide resilience to typical characteristically defined disturbances.

The study resulted in the identification of a specific problematic area that has resulted in power-generating capability interruptions. The subsequent process involved the investigation, definition, design, testing and implementation of a solution.

The study revealed that power-generating units designed prior the existence of the national grid have a high degree of resilience to disturbances that originate in an integrated power system (IPS).

Key Words: disturbances, disturbance resilience, regulatory framework, power generation.

OPSOMMING

Hierdie studie ondersoek die invloed van 'n terugwerkende regulerende raamwerk wat van ŉ kragopwekkingsaanleg vereis om weerstandigheid te bied teen versteurings wat voorkom in 'n geïntegreerde kragstelsel. Hierdie versteurings lei tot die onderbreking van kragopwekkingsvermoë en moet daarom deur sodanige raamwerke aangespreek word.

Die regulerende raamwerkvereistes soos dit gestipuleer is in die Suid-Afrikaanse Nasionale Kragnetwerkkode dien as die agtergrond tot die studie. Die literatuurstudie bied ŉ oorsig oor die tipiese kragopwekkingseenheidontwerp en bedieningsfilosofie en die beskikbare tegnologie. Die ondersoek na die beskikbare tegnologie sluit die kenmerke van die versteurings wat kan ontstaan in ŉ geïntegreerde kragstelsel in en kyk na hoe hierdie versteurings ervaar word binne die elektriese netwerkstelsel van ŉ kragopwekkingsaanleg. Die studie evalueer die inherente kenmerke van kragopwekkingaanleg-ontwerpe wat weerstandigheid bied teen versteurings en historiese en huidige toepassings en maatreëls wat in werking is.

Die vereistes wat vervat is in Regulasie 9 van die Suid-Afrikaanse Krag Netwerkkode is met ander beskikbare lande se kragnetwerkkodes of soortgelyke netwerkregulasies vergelyk om die weerstandigheid van ŉ kragopwekkingsaanleg teen versteurings wat voorkom in 'n geïntegreerde kragstelsel, te bepaal.

Die kragopwekkingsaanlegontwerp se operasionele spanningslimiete is vergelyk en gemeet teen die internasionale standaarde vir groot toerusting wat gebruik word by kragopwekkingsaanlegte. Die internasionale standaarde, die kragnetwerkkode se bedryfstelsel-spanningslimiete, en die kragopwekkingaanleg-ontwerpparameters is beoordeel om sodoende te identifiseer of die bogenoemde aan die reëls van Regulasie 9 van die kragnetwerkkode voldoen. Addisionele probleem areas is bykomend identifiseer.

Die historiese en huidige toepassing en die maatreëls wat in werking is by kragopwekkingsaanlegte is ontleed om die mate van weerstandigheid teen versteurings te identifiseer.

Tydens die studie is 'n spesifieke probleem-area wat gelei het tot ’n onderbreking in kragopwekkingsvermoë, geïdentifiseer. 'n Oplossing is ondersoek, omskryf, ontwerp, getoets en geïmplementeer.

Die studie het getoon dat kragopwekkingsaanlegte wat ontwerp is voor die bestaan van die nasionale netwerkkode 'n hoë mate van weerstandigheid het teen versteurings wat voorkom in 'n geïntegreerde kragstelsel.

Sleutelwoorde: versteurings, versteuringsweerstandig, regulerende raamwerk, kragopwekkingsaanlegte.

Declaration of Originality

I declare that this dissertation is a presentation of my own original research, conducted under the supervision of Prof JA de Kock. Whenever contributions of others are involved, every effort is made to indicate this clearly, with due reference to the literature. No part of this research has been submitted in the past, or is being submitted, for a degree or examination at any other University.

2018-03-17

HJ van Staden | Date

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LIST OF SYMBOLS AND ABBRIVIATIONS

Abbreviation	Description
°C	Degree Celsius
A	Ampere
AC	Alternating current
Ah	Ampere per hour
ANSI	American National Standards Institute
ARC	Automatic reclosing
ASD	Adjustable speed drive
AVR	Automatic voltage regulator
BIL	Basic insulation level
C	Current
CPU	Central processing unit
CSU	Control and supervisory unit
CVT	Constant voltage transformer
DC	Direct current
DCS	Distributed control system
DOL	Direct on line
DPI	Dip proof inverter
Dx	Distribution division
EMC	Electromagnetic compatibility
EUT	Equipment under test
FTS	Fast transfer scheme
GCR	Grid code requirement
Hz	Hertz
HV	High voltage
IEC	International Electrotechnical Commission
IED	Intelligent electronic device
IEV	International Electrotechnical Vocabulary
IGBT	Insulated-gate bipolar transistor
I_n	Nominal current
IPS	Integrated power system

Abbreviation	Description
kV	Kilovolt
kVA	Kilovolt ampere
LA	Lead acid
LC	Inductor capacitor
LV	Low voltage
MCB	Miniature circuit breaker
mm	Millimetre
ms	Millisecond
mV	Millivolt
MVA	Megavolt ampere
MV	Medium voltage
MW	Megawatt
PIT	Process immunity time
pf	Power factor
p.u.	Per unit
OFAF	Oil forced air forced
ONAN	Oil natural air natural
PLC	Programmable logic controller
RAL	Reichs-Ausschuss für Lieferbedingungen
Rev	Revision
RGB	Red-green-blue (colour model based on additive colour primaries)
RMS or rams	Root mean square
SANS	South African National Standards
s	Second
THD	Total harmonic distortion
Tx	Transmission division
UPS	Uninterruptable power system
µs	Microsecond
V	Volt
var	Volt-ampere reactive
V_{nom}	Nominal voltage

Abbreviation	Description
VSD	Variable speed drive

CHAPTER 1

INTRODUCTION

1.1 Background

The uninterrupted operation of a power plant is dependent on a steady and quality power supply. Disturbances in the supply voltage of a power plant as a result of disturbances that originated in the integrated power system (IPS) can interrupt plant processes. This can result in the interruption of power-generating capacity, unsafe plant conditions or damage to the plant.

Figure 1 (Voltage dip occurrences in high voltage (HV) systems NRS 048-7 [1]) illustrates actual voltage dip occurrences in the transmission system over a four-year period. The data indicate that voltage dips of a magnitude of greater than 30% and shorter than 200 ms have a high probability of occurring in South African HV and extra high voltage (EHV) networks.

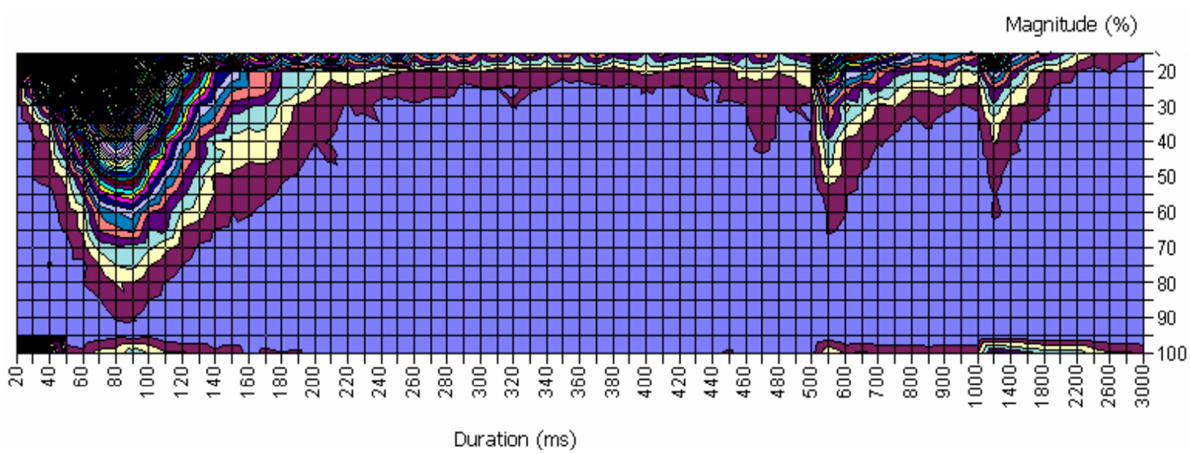


Figure 1: Voltage dip occurrences in HV systems [1]

The National Grid Code governs the connection requirements for generators, distributors and end-use customers [2]. GCR 9 [2] stipulates the operational needs of the user. This includes prescriptions on the external supply disturbance withstand capability for any unit or power station connected to the transmission system. Figure 2 provides an illustration of the external supply voltage disturbance capability levels required by GCR 9. The aim of the regulation is to significantly reduce the probability of supply interruption as a result of actual voltage disturbances that occur on the transmission system.

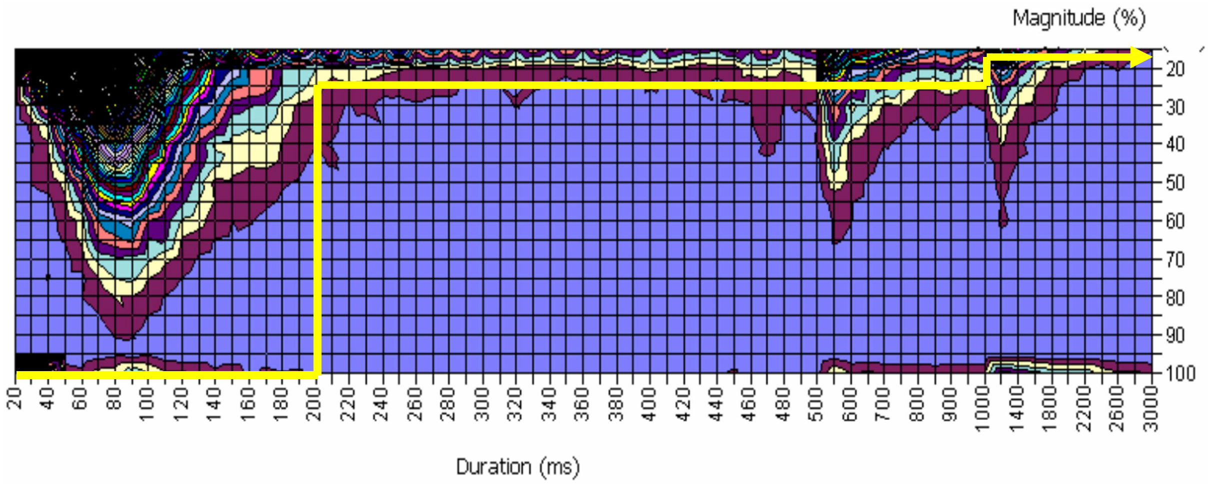


Figure 2: GCR 9 external supply voltage disturbance withstand capability [2]

The majority of power stations were designed and built prior to the National Grid Code coming into effect, this being the regulatory framework that governs compliance by any unit or power station connected to the transmission system.

Eskom undertook the development of equipment to improve the resilience of a power plant to external supply disturbance and the improvements were subsequently implemented. Numerous power-generating capability interruptions and trips as a result of control supply interruptions in the absence of a supply disturbance, have created doubt about the effectiveness of the implemented supply disturbance resilience measures.

This study analysed the characteristics of the IPS-generated disturbances to determine the potential risks or impact on a power plant. This includes an evaluation of the behaviour of power plant equipment during disturbances.

In addition to the above, the discussion focuses on power plant design parameters and historical and current measures implemented at power-generating units to evaluate if they provide sufficient resilience to these specific disturbances.

The study also interrogates historic, available and new technologies for application and effectiveness within old power plants to ensure the required voltage immunity.

The study follows with a compliance evaluation of the respective equipment utilized within a power plant compared to the requirements stipulated in the regulatory framework and applicable international standards.

Following the understanding of the impact of these disturbances on affected plant and compliance verification to regulatory requirements and standards, key aspects such as weaknesses, limitations and plant design deficiencies are identified and partial or full compliance to the operational needs are established.

1.2 PROBLEM STATEMENT

The need for this work originated from the adoption of the National Grid Code. As mentioned above, this retrospective regulatory framework requires that power-generating units must have a degree of resilience to disturbances that originate in an integrated power system (IPS).

Given Eskom's efforts described above, the bearing of the retrospective regulatory framework has to be examined and analysed. Examination includes a comparison between the different technical parameters in the grid code, international standards and the power plant design parameters.

1.3 DELIMITATIONS

The scope of this dissertation is limited to only one of the grid code requirements, namely GCR 9 of the South African Grid Code – Network Code. The voltage unbalance requirement stipulated in GCR 9 is not included in this dissertation and should be studied separately.

The study evaluates a power plant design from 1980. This design precedes the introduction of the South African Grid Code – Network Code in 2007.

1.4 STUDY OBJECTIVE

The objective of this study is to benchmark power station voltage dip performance compliance to a retrospective regulatory framework for the resilience of power plant exposed to disturbances in the integrated power system. Failing to comply or to illustrate a reasonable plan to comply with the regulatory framework can result in the power plant's licence to generate power for injection into the network being revoked.

Another objective is to identify some of the root causes of power-generating interruptions and unit trips as a result of the technology implemented under the current operating conditions of power plants.

Achieving the required voltage condition resilience ensures that the power-generating unit is a more reliable contributor to the national grid, which in turn will be more resilient against supply disturbances that originate in the IPS.

A further benefit of this research is the guidance that the results offer to future power plant projects with regard to meeting the supply disturbance resilience requirements stipulated by the regulatory framework.

1.5 DISSERTATION STRUCTURE

Chapter 1 presents an introduction and background to a typical power plant electrical design philosophy and operation.

Chapter 2 discusses different types of voltage disturbances and their causes. It also considers the effect of voltage disturbances on electrical equipment used at a power plant. International standards applicable to electrical equipment in an effort to evaluate if the voltage tolerances specified are adequate to verify compliance to GCR 9.

Chapter 3 presents the problems that can be expected within a power plant as a result of supply disturbances and the effects of a voltage dip and short interruption on the performance of a power system with motor loads. The chapter offers a comparison between the GCR 9 voltage condition parameters and the power plant design parameters. The technical data sheet, as depicted by international standards, of individual equipment is measured against the GCR 9 voltage condition parameters and the power plant design parameters. This evaluation provides the first indication of compliance problems and additional problematic areas that have to be addressed.

Chapter 4 defines a user requirement to address the deficiency identified in Chapter 3 to ensure supply disturbance resilience for a power plant. This is done by means of an analysis of tests conducted or of available actual electrical fault incidents that have occurred within the power plant that caused a supply disturbance within the electrical reticulation system.

The chapter continues with a compliance evaluation of the equipment utilized within a power plant compared to the requirements stipulated in the regulatory framework and applicable international standards. Following the establishment of an understanding of the impact of disturbances on an affected plant and of the verification of compliance regulatory requirements and standards, key aspects such as weaknesses, limitations and plant design deficiencies are identified and partial or full compliance to the operational needs are established.

Finally, Chapter 5 present the conclusion on compliance to a retrospective regulatory framework for the resilience of power stations exposed to disturbances in the interconnected power system. It also identifies areas for future studies.

1.6 DEFINITION AND DISCUSSION OF IMPORTANT TERMS

The following two standards of the International Electrotechnical Commission (IEC) for international electrotechnical vocabulary (IEV) are used throughout the study:

- IEC 60050-161 of 1990 International Electrotechnical Vocabulary (IEV) – Chapter 161: Electromagnetic compatibility [3].
- IEC 60050-441 of 1984 International Electrotechnical Vocabulary – Chapter 441: Switchgear, control gear and fuses [4].

Voltage Dips – A voltage dip is defined as “a sudden reduction of the voltage at a particular point of an electricity supply system below a specified dip threshold followed by its recovery after a brief interval.

> NOTE 1 Typically, a dip is associated with the occurrence and termination of a short circuit or other extreme current increase on the system or installations connected to it.

NOTE 2 A voltage dip is a two-dimensional electromagnetic disturbance, the level of which is determined by both voltage and time (duration)."

Voltage unbalance – Voltage unbalance is defined as "condition in a polyphase system in which the RMS values of the line (phase) voltages (fundamental component) or the phase angles between consecutive line voltages are not all equal."

Voltage immunity (to a disturbance) – The ability of a device, equipment or system to perform without degradation in the presence of a specified voltage disturbance.

CHAPTER 2

LITERATURE REVIEW

The primary purpose of this chapter is to provide the electrical design philosophy of a typical power station designed prior to the National Grid Code taking effect. The chapter also provides information on types of voltage disturbances and causes of voltage dips to evaluate the impact on the power plant. The discussion thereafter moves to the theory and behaviour of specific equipment utilized within a power plant to analyse the impact of supply disturbances on a power plant and to identify potential risks and deficiencies within the existing electrical design. This includes theory on contactors, behaviour of contactors during voltage dips, the effect of momentary voltage dips on the operation of induction motors and the effect of voltage dips on converters. The chapter explains the background, application and operating philosophy of installed dip proofing devices. Practices and technology used to provide voltage immunity in the industry and specific at power plants receive attention.

The study consults international standards applicable to specific equipment to extract the specific requirements applicable to the equipment related to this study.

The power plant design parameters together with operational experience data are used to determine the first level of compliance to the grid code requirements.

All the information gathered as part of the literature study is required in the later chapters for the evaluation of the effectiveness of the existing measures inherent in the plant design and implemented dip proofing equipment.

2.1 POWER STATION ELECTRICAL OPERATING DESIGN PHILOSOPHY, MV AND LV RETICULATION SYSTEM

2.1.1 GENERAL

In order to be able to analyse the impact that voltage disturbances that originate in an integrated power system can have on a power station, the power station electrical MV and LV reticulation [5], electrical design and operating philosophy must be explained.

This section provides information on the electrical MV and LV reticulation system, electrical design and operating philosophy of a power station designed in the 1980s. Such power stations represent the largest part of the Eskom fleet prior to the formulation of the National Grid Code.

The information on the MV and LV reticulation system is required to evaluate the propagation of a supply disturbance through the electrical reticulation system at a power plant. The electrical plant design parameters are required to benchmark compliance with the South African Grid Code in terms of GCR 9 and international standards. Detailed technical information is needed to develop a model for the power plant to simulate the impact of supply disturbances and potential disturbance resilience in the electrical design.

The general design parameters are listed in Table 1.

Table 1: General electrical design parameters [5]

Nominal voltage	Neutral earthing	Maximum symmetrical fault MVA	Basic insulation level (BIL) kV Peak	60 seconds 50Hz withstand kV RMS	Creapage distance (line to line/line to earth/insulator creapage) mm
11000 V AC	Low resistance	600	95	28	270/200/240
3300 V AC	Low resistance	250	45	16	110/70/70
380 V AC	Solid	32	-	2	25/25/25
220 V DC	Floating	Fuse protected	-	2	25/25/25
50 V DC	Floating	Fuse protected	-	1	13/13/13
Positive and negative 24 V DC	Centre solid	Fuse protected	-	1	13/13/13

The functional requirement specifies that all electrical equipment required for the operation of the power station should be capable of operating under normal and continuous abnormal conditions as described below:

Normal power supply conditions (extremes of these parameters may occur simultaneously);

- Voltage : 0.95 to 1.05 of nominal;
- Frequency : 0.975 to 1.025 of nominal;
- Voltage unbalance : Negative sequence 0.02 of the nominal positive sequence voltage;
- Waveform : 5% maximum amplitude deviation from sine wave voltage.

Abnormal power supply conditions:

- Continuous for up to 6 hours;
  - o Voltage : 0.90 to 1.10 of nominal, with depressions to 0.75 of nominal for 10 s;
  - o Frequency : 0.95 to 1.05 of nominal (The sum of absolute percentage voltage variation and absolute percentage frequency variation will not exceed 10);
  - o Voltage unbalance : Negative sequence 0.03 of the nominal positive sequence voltage;
- Transient:

Table 2: Transient abnormal supply conditions [5]

Voltage	Frequency
Complete interruption for 1 s	0.975 to 1.025 of nominal
Depression to 0.75 of nominal for up to 10 s	0.975 to 1.025
Depression to 0.75 of nominal for up to 5 s	0.93 to 1.0 of nominal
Depression to 0.70 of nominal for up to 3 s	0.95 to 1.0 of nominal
Depression to 0.85 of nominal for up to 1 hour with further deviation to 0.70 of nominal for up to 10 s	0.975 to 1.0 of nominal

The auxiliaries essential for the safe shutdown of the unit are supplied from a 380 V board with diesel generator backup on each unit with the requirement that power is restored within 30 s and only essential auxiliaries will start.

Uninterrupted power supplies are required for emergency supplies and are provided from a DC source:

- The 220 V DC supplies are used for protection. Two independent protection systems are provided, each with a dedicated supply and 4 hours autonomy for all six of the power-generating units. A bus section can be closed between the two station distribution boards to supply both protection schemes from one source rated for the total loads.
- A separate 220 V DC supply is provided on each unit for high power equipment required for emergency shutdown and rundown of the turbines and generator, and includes emergency lubrication pumps.
- 50 V DC supplies are used for telecommunications, mimic and supervisory equipment.
- The positive and negative 24 V DC supplies are used for control and instrumentation equipment.

2.1.2 STATION COMMON POWER SUPPLIES

The station power supply is common for the auxiliary plant and is shared by all the power-generating units. Two 11 kV station boards can both be supplied from a single 45 MVA 88/11 kV station transformer, or each can have its own. The station transformer is equipped with an automatic on-load tap-changer and is connected to the distribution 88 kV network.

The 11 kV station boards 1 and 2 is normally supplied from 11 kV unit boards 1A and 2A, indicating the adjacent power-generating unit 11 kV unit board A and the second adjacent power-generating unit 11 kV unit board A respectively. The 45 MVA station transformers serve as an alternative supply source when unit transformers 1A or 2A are unavailable.

From 11 kV station board 1 and 2, several 11 kV ring-mains are provided. The principle ring-main links the station boards with 11 kV boards in three substations around the power station terrace. The normal configuration of the 11 kV ring-mains is open rings, in other words, each

11 kV board will have a bus-section breaker and the main ring must be split with one of the bus-section breakers open.

Where duplication of step-down transformers is provided the two transformers are connected to different sides of the 11 kV board.

Low voltage distribution boards are also provided with bus-sections switches or interconnectors. The transformer capability is sufficient so that one transformer can supply all the loads with the bus-section or interconnector closed.

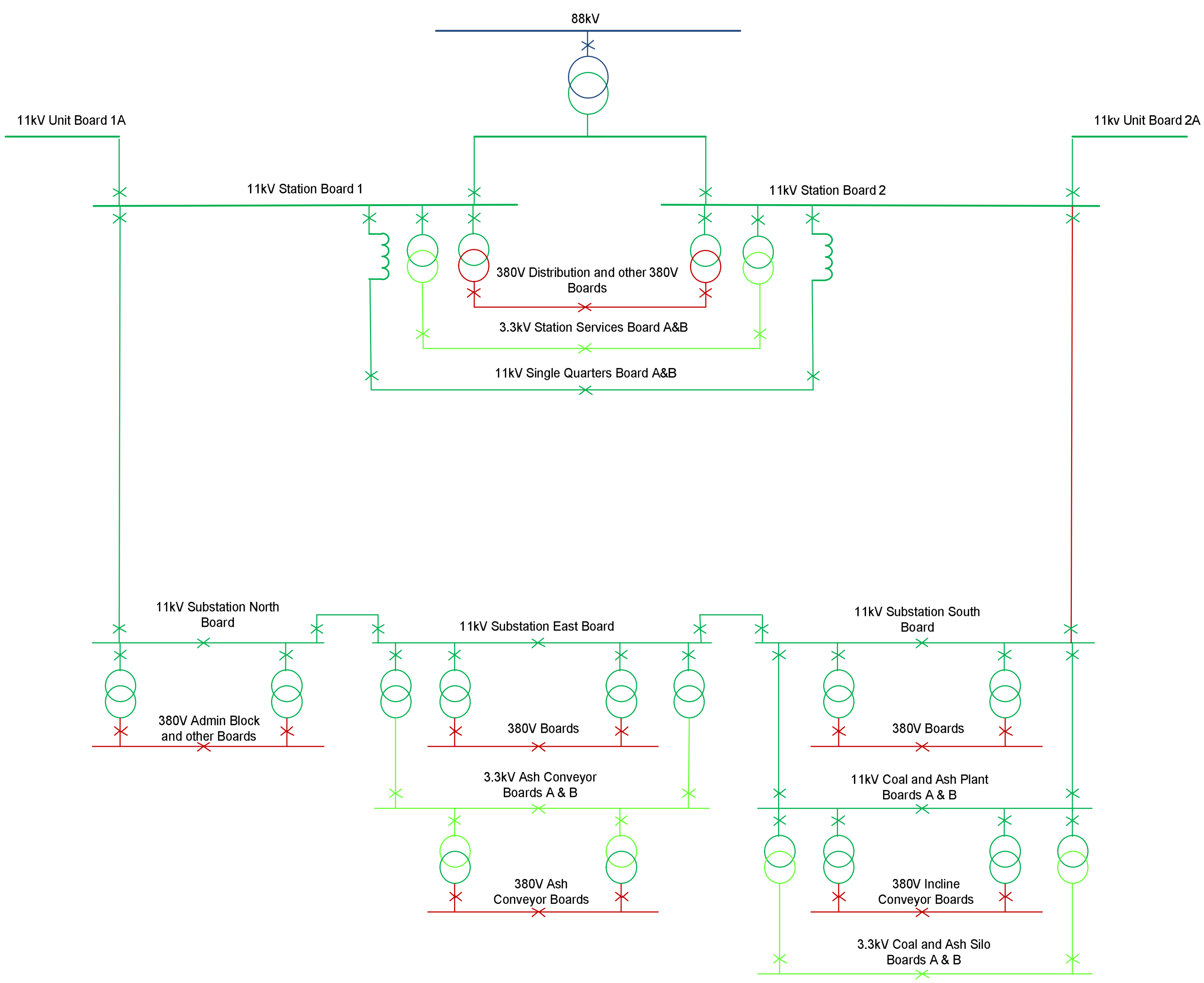


Figure 3: 11 kV ring main [5]

Table 3: Legend – designated voltage colour code

Colour	Voltage level	Description of designated voltage colour code
	765 kV	firebrick – (RAL: 3024 – RGB: 246,40,23)
	400 kV	turquoise – (RAL: 6027 – RGB: 64,224,208)
	275 kV	gold – (RAL: 1032 – RGB: 212,160,23)
	132 kV	blue – (RAL: 4008 – RGB: 0,0,255)
	88 kV	dark blue – (RAL: 5022 – RGB: 0,0,139)
	33 kV	silver (RAL: 7035 – RGB: 190,190,190)
	18 kV to 22 kV	pink – voltage generated by main generator (RAL: 4010 – RGB: 255,0,255)
	11 kV	dark green (RAL: 6028 – RGB: 0,100,0)
	6.6 kV	orange (RAL: 2008 – RGB: 255,105,0)
	3.3 kV	green (RAL: 6029 – RGB: 0,255,0)
	450 V to <1 kV	slate grey (RAL: 7037 – RGB: 101,115,131)
	220 V, 230 V, 380 V, 400 V	400 V – domestic reticulation (including single-phase) – brown (RAL: 3016 – RGB: 194,34,23)
	spare	spare – white (RAL: 9003 – RGB: 255,255,255)
	earth	black (RAL: 9005 – RGB: 0,0,0)

Three major 11 kV substations, designated North, East and South, are located at points around the perimeter of the station and these are linked together to form one ring main. Each of these 11 kV boards supply all the local loads configured as single feed or a dual feed when more security of supply is required or as a supplementary ring-feed basis.

Features of the arrangement of these boards are:

- The substation North A and B supply the 380 V admin block boards, 380 V electrical workshop and station crane boards.
- The substation East boards A and B supply the 3.3 kV ash conveyor boards 1A, 1B, 2A and 2B via duplicated radial feeds. In addition, the 380 V cooling water pump house and water plant East boards A and B are fed from the substation East boards.
- On a duplicate radial feed basis the substation South board supplies inter alia the 11 kV coal and ash plant boards A and B, and through these boards the entire coal

incline conveyor and coal storage system, including a portion of the ash handling system.

- The overland coal conveyors are supplied from the 11 kV station boards 2 only in abnormal operation conditions.

Duplicate radial feeds are obtained from station boards 1 and 2 respectively and are configured as follows:

- 380 V water plant boards 1A and 1B
- 380 V water plant boards 2A and 2B
- 380 V fire pumps distribution boards A and B
- 3.3 kV station services boards A and B
- 275 kV yard 380 V boards A and B
- 380 V distribution boards A and B.

2.1.3 UNIT POWER SUPPLIES

The 11 kV power supplies to each unit are derived from two 20/11 kV unit transformers connected directly to the low voltage terminals of the generator transformer. The high voltage side of the generator transformer is connected to the 275 kV yard via a high voltage circuit breaker. The low voltage terminals of the generator transformer are connected via a generator circuit breaker.

The 11 kV unit boards, designated A and B, may be coupled by means of a bus-section circuit breaker. The bus-section circuit breaker should be utilized when one unit transformer is out of service. Unit boards 1 A and 2 A have a connection to station boards 1 and 2 respectively. Under normal operating conditions, unit transformer 1 A will supply both 11 kV unit boards 1A and 11 kV station board 1. Similarly, unit transformer 2 A will supply 11 kV unit board 2A and 11 kV station board 2. The additional station loads on the 20/11 kV unit transformer 1A and 2A require a transformer with a dual rating of 35/58 MVA. The higher capacity is obtained with the forced cooling in service (OFAF) [6]. The remaining unit transformers of unit 1 and 2 and of the other four units have a rating of 35 MVA with natural cooling (ONAN) [6].

The interconnection between 11 kV station board 1 and 11 kV unit boards 1A is extended to 11 kV station board 1 and 11 kV unit board 1A is extended to 11 kV unit boards 3A and 5A. Similarly, the interconnection between 11 kV station board 2 and 11 kV station board 2A is extended to 11 kV unit board 4A and 6A. These interconnections are primarily for commissioning when the unit is run-up with the 275 kV high voltage back-feed unavailable.

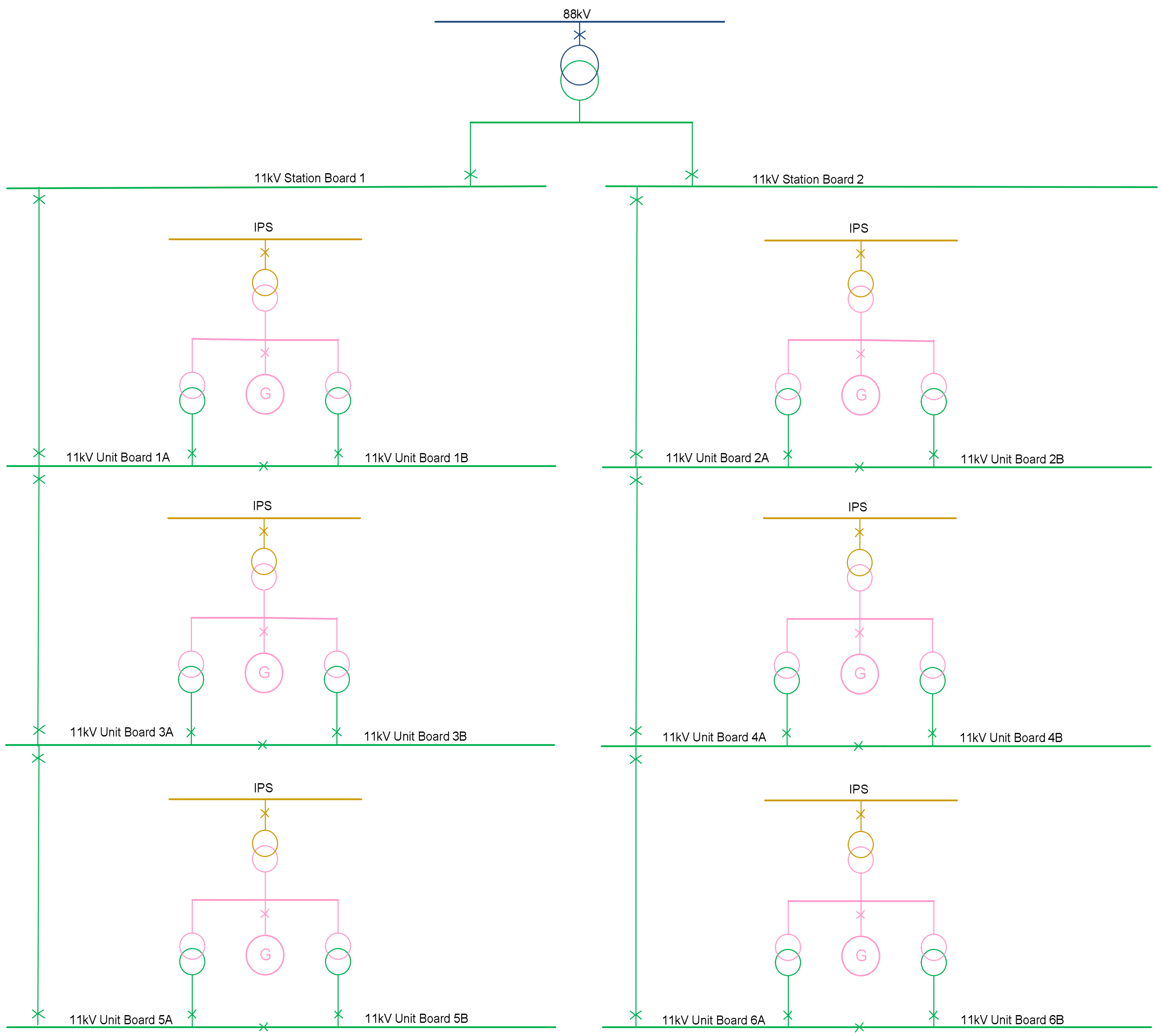


Figure 4: 11 kV station board configuration [5]

The 50% electric feed pump motors A and B are fed from 11 kV unit boards A and B respectively. All other large motors are fed from four 3.3 kV service boards. The 3.3 kV service boards A and C are fed from 11 kV unit board A and 3.3 kV service boards B and D are fed from 11 kV unit board B. Bus-section circuit breakers are provided between 3.3 kV service boards A and B, and between 3.3 kV service boards C and D. The service transformers are 11/3.3 kV 12.5 MVA transformers.

Smaller motors are supplied from the 380 V unit boards A and B via a 1600 kVA, 11 kV/400 V unit transformer. Each unit has a 380 V diesel generator board, fed from either 11 kV unit board A or B or one of a pair of 250 kVA diesel generators via a 3.3 kV/400 V 1600 kVA transformer.

Standby supplies to the 380 V unit boards A and B and the 380 V diesel generator board are available from a 1600 kVA 11 kV/400 V standby transformer, which feeds the 380 V unit standby boards. Standby transformers from units 1 and 3 are fed from station board 1, and standby transformers for units 4 to 6 are fed from substation North board.

Additional loads are supplied from the following switchboards:

- 380 V precipitator board A
- 380 V precipitator board B

These boards are fed directly from 11 kV unit boards A and B respectively via 1600 kVA, 11 kV/400 V transformers:

- 380 V CW unit board A are supplied from 380 V unit board A
- 380 V CW unit board B are supplied from 380 V unit board B

These boards are also linked by means of a bus-section.

The 380 V unit lighting board consists of an essential and non-essential section with the non-essential section fed via a 1250 kVA 11 kV/400 V transformer on each unit. To avoid losing the lighting on a unit in the event of a unit trip, the non-essential unit lighting boards are supplied from station auxiliary supply systems as follows:

- Unit 1 fed from 11 kV station board 1
- Unit 2 fed from 11 kV station board 2
- Units 4 to 6 fed from 11 kV substation North board

The essential section is fed from the 380 V unit diesel generator board.

To permit maintenance of the unit lighting transformer an interconnection is provided between unit lighting boards 1 and 2, 3 and 4, and 5 and 6.

The 380 V fuel oil plant board A and B are fed directly from 11 kV unit boards A and B respectively via 1600 kVA, 11 kV/400 V transformers and can be linked via a bus-section provided.

The 380 V ash bunker board is supplied from a 1250 kVA, 11 kV/400 V transformer on each unit. To permit maintenance on the ash bunker transformer, an interconnection is provided between ash bunker boards 1A and 1B, 2A and 2B and also between 3A and 3B.

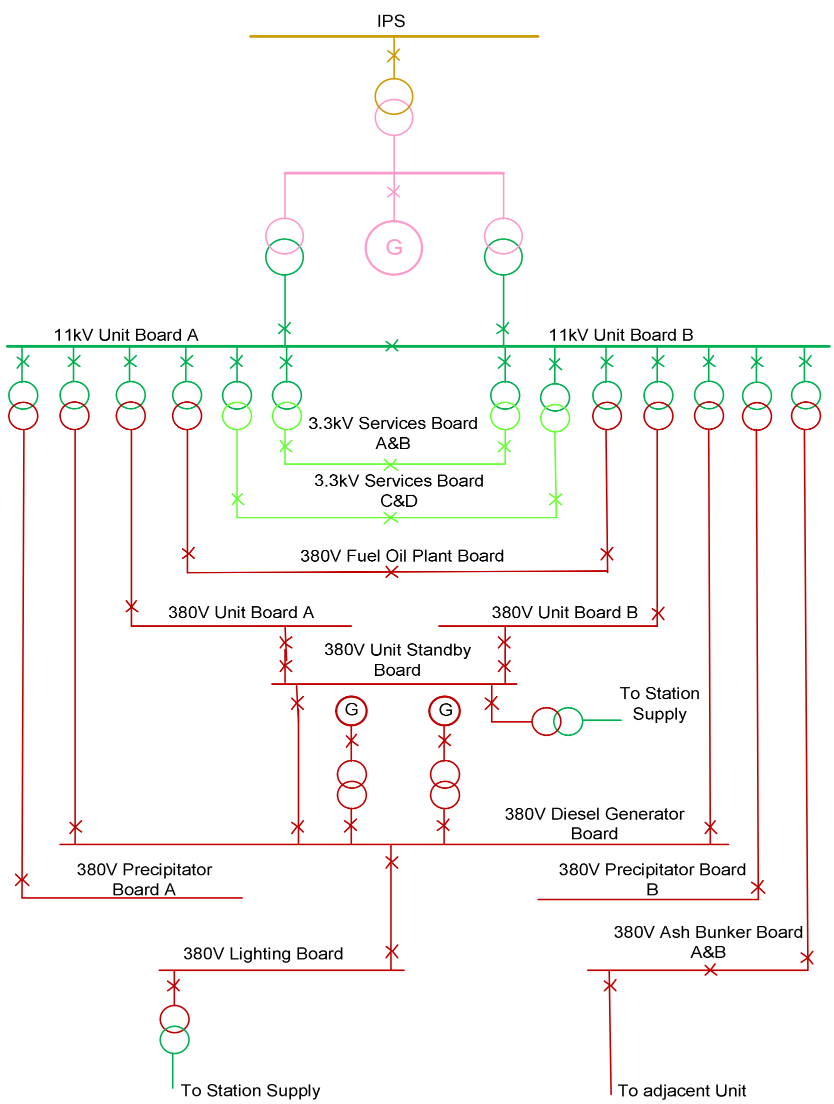


Figure 5: 11 kV station board configuration [5]

2.1.4 DC AND EMERGENCY AC SUPPLY SYSTEMS

The DC and emergency AC supply systems are designed to:

- allow safe shutdown of the plant if normal power supplies are interrupted;
- maintain communication, instrumentation and protection facilities for certain periods after loss of normal power supplies;
- provide emergency lighting;
- keep the plant in a state of readiness, where practicable, for rapid re-start when normal power supplies are restored; and to
- prevent critical instrumentation from tripping plant in the event of short breaks in normal power supplies.

The 380/220 V AC emergency power is provided for general station loads and boiler/turbo-generator loads by diesel generators. This emergency power should become available within 30 s after normal supplies have been interrupted and is utilized for emergency lights and auxiliary plant, which are essential for safe shutdown of the main plant units. Equipment power from this source should be suitable for voltage deviations between +10% and -15% and frequency limits 47.0 Hz to 53.0 Hz.

DC emergency power is provided at 220 V, 50 V and positive 24 V and negative 24 V by means of batteries with battery charger power from normal AC power, with the diesel generators as a back-up supply.

The 220 V DC is used for protection relays, circuit breaker tripping and closing. Another 220 V DC power source is provided for limited emergency lighting, valve actuators and oil pumps essential for safe shutdown of the main plant. The equipment voltage tolerance is 187 V DC to 242 V DC.

The 50 V DC power is used for communications, tele-control and alarm equipment associated with the system control and load despatch installation.

The positive and negative 24 V DC power is used for control and instrumentation equipment and alarm systems for the power-generating unit and directly associated auxiliary plant. The equipment voltage tolerance is 20.4 V DC to 26.5 V DC.

The battery standby times when normal AC supply is unavailable for the different type of loads are:

- power line carriers, telemetry, tele-control and telephone equipment – 8 hours;
- radio voice channel and supervisory equipment – 24 hours;
- protection, tripping and closing circuits – 8 hours.

2.1.5 STATION EMERGENCY SUPPLIES

The sources of emergency power are:

- 2 x 1250 kVA AC diesel generators;
- duplicated 1120 Ah (Ah rating for 10 hours) 220 V DC station batteries and chargers;
- 200 Ah 50 V DC communications battery and charger (positive earthed);
- 150 Ah 50 V DC tele-control battery and charger;
- 50 Ah 50 V alarm and supervisory battery and charger.

The 220 V DC station batteries 1 and 2 supply main 1 and main 2 protection scheme and tripping coils. The 220 V DC station battery 1 supplies main 1 protection schemes, including units 1 to 6 main 1 protection scheme through 220 V DC unit boards 1A to 6A. The 220 V DC station battery 2 supplies main 2 protection scheme, including units 1 to 6 main 2 protection scheme through 220 V DC unit boards 1B to 6B. A bus-section is provided between 220 V DC station board 1 and 2, and the battery standby time for this configuration is 2 hours.

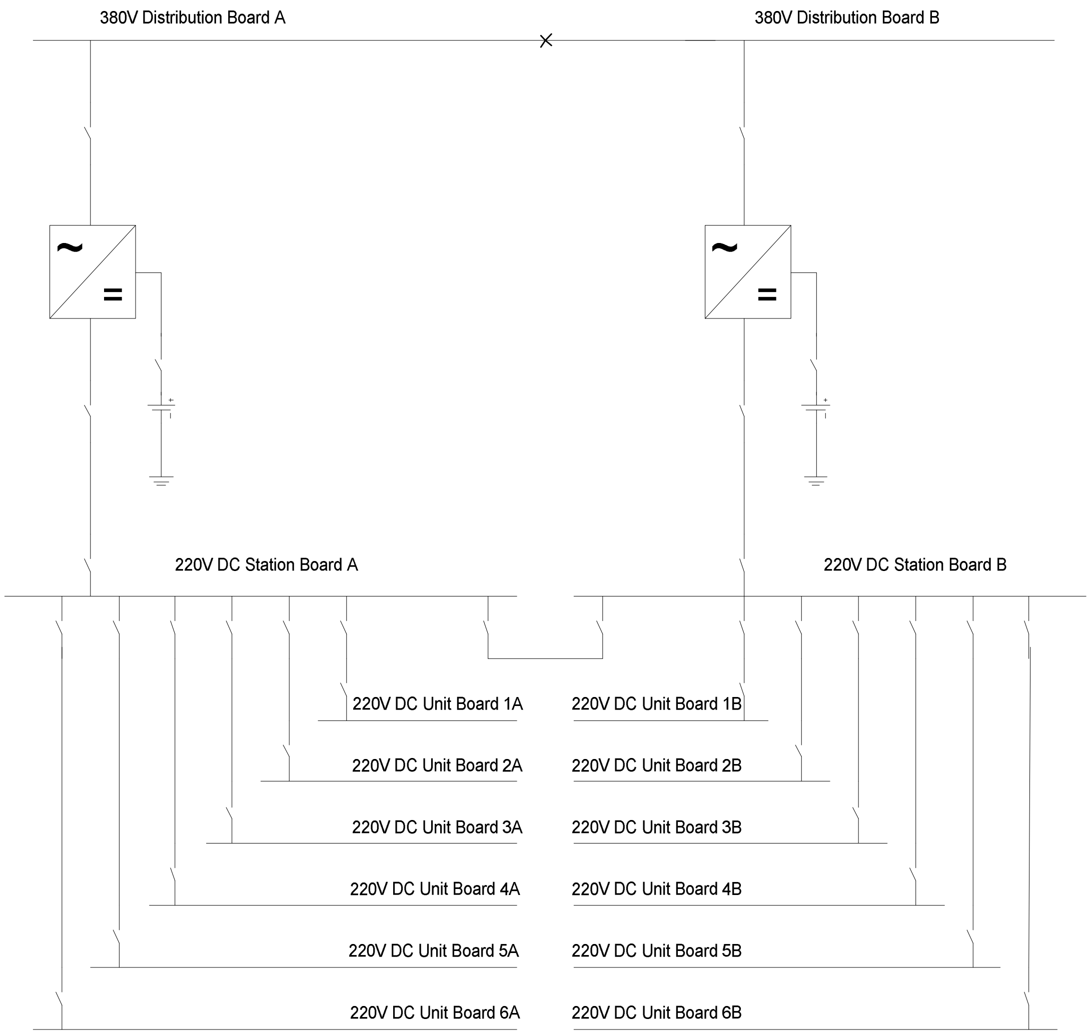


Figure 6: DC station supply configuration [5]

The positive and negative 24 V DC supply for station control and instrumentation is provided via two fully redundant 24 V DC battery and charger combinations in series with the common (zero volt) earthed.

All the foregoing battery chargers are supplied from the 380 V station diesel generator board via 11 kV station board 1. On failure of the 11 kV station board, diesel generators 1 and 2 are started. The first diesel generator to reach rated speed and synchronizing conditions closes onto the board and the other runs for a pre-set time before shutting down. The 380 V station diesel generator board supplies the station battery room ventilators.

2.1.6 UNIT EMERGENCY SUPPLIES

The sources of emergency unit power are:

- 220 V DC unit boards A and B, fed from 220 V DC station boards;
- 220 V DC boards for protection and tripping;
- two 1250 kVA AC diesel generators;
- 1540 Ah (Ah rating for 10 hours) 220 V unit battery and 525 A charger for motors and lighting; and
- duplicated positive and negative 24V DC control and instrumentation battery and charger combinations, positive 24 V DC 1540 Ah and negative 24V DC 200 Ah.

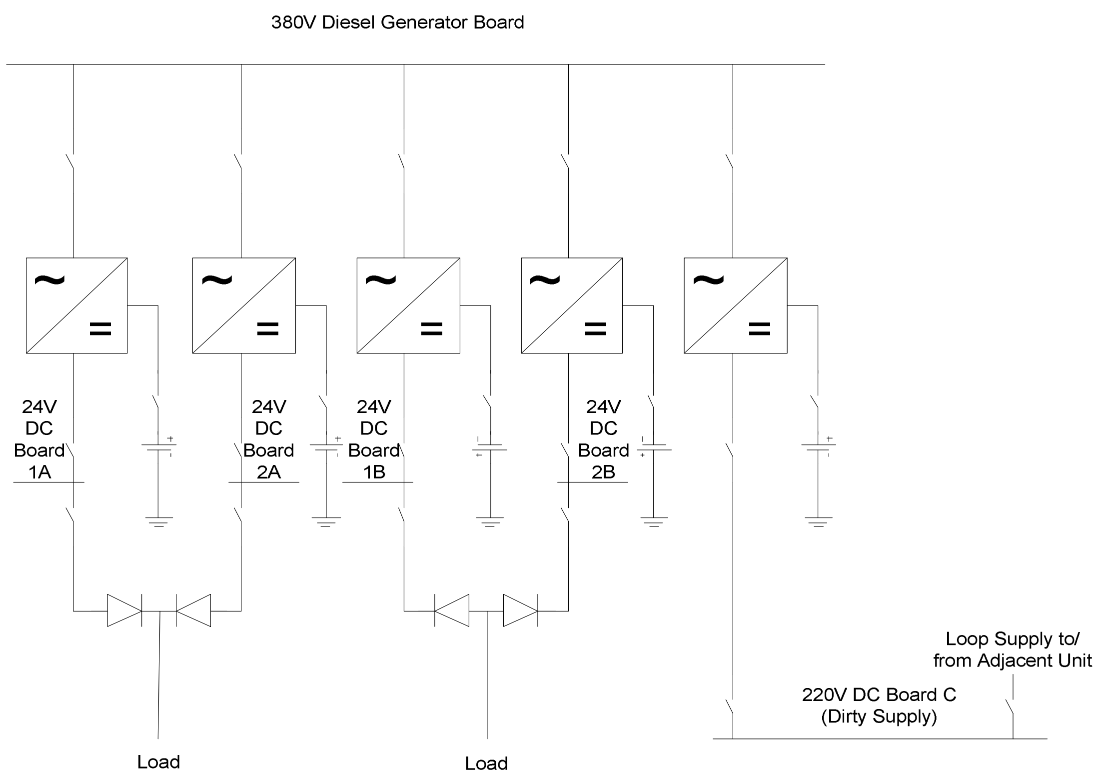


Figure 7: DC unit supply configuration [5]

The 220 V DC supplies to main protection, closing and tripping circuits are derived from 220 V DC station board 1, reticulated via 220 V DC unit board A. Main 2 protection scheme supplies are similarly distributed from 220 V DC station board 2 via 220 V DC unit board B.

The unit 220 V DC battery/charger combination is provided to feed 220 V DC unit board C, which supplies all the emergency oil pump motors, control block emergency lights and the DC valve and solenoid panel.

All breaker spring rewind circuits are AC fed from voltage transformers on the switchboard.

The positive 24 V DC and negative 24 V DC supplies to the unit control and instrumentation and unit alarms are provided in duplicate. Duplicated feeds to all critical loads are decoupled at each load by means of diodes.

The 220 V DC unit battery charger is supplied from the 380 V unit diesel generator board, which is normally energized from 11 kV unit board A or B. Should the supply from the duty 11 kV unit board fail, its feeder is tripped and the feeder from the standby 11 kV unit board is closed. Should the supply from the standby board be faulty, this feeder is also tripped and both diesels start.

In addition to the unit battery charger, the 380 V unit diesel generator board feeds the turbine and main feed pump turning gear, essential valve drives, essential lighting, the unit control room ventilation and air filtration, computer and equipment room air-conditioning, and unit battery room ventilators.

2.1.7 HV YARD DC SUPPLIES

A duplicated 200 Ah 10-hour battery standby time 220 V DC batteries and chargers and duplicated 430 Ah 10-hour battery standby time 50 V carrier batteries and chargers are installed in the 275 kV yard relay house.

2.1.8 DIESEL GENERATORS

The diesel generator board supplies all the essential loads for safe shutdown of the unit or station or keeping the plant in a state of readiness for restart. Two 11 kV feeders from 11 kV unit boards A and B are provided, each with 100% capability for the entire diesel generator board load and starting capability of the largest motor. Two 3.3 kV diesel generators are provided as back-up with the same capability as the 11 kV feeders.

All control circuitry is supplied from the associated DC supplies. Manual tripping and closing facilities are available, subjected to synchronism verification with any feeder and interlocking.

The auto control philosophy is as follows:

- An undervoltage detected on any feeder trips the associated breaker following a specified time delay.
- Failure of the bus voltage initiates an attempt to close the alternative incoming breaker.
- The alternative incoming feeder is also energized.
- If the alternative incoming feeder is not energized and remains in a tripped state, both diesel generators are started. The first diesel to generate rated voltage is switched onto the diesel generator board and the second generator idles for a preselected period of time, after which it is shutdown and ready for a start.

2.2 OPERATING PHILOSOPHY FOR SYSTEM FAILURE CONDITIONS

2.2.1 ISLANDING OF THE POWER PLANT

For a fault on the IPS causing the unit HV breaker to open, for example bus-strips of the local HV yard, bus-zone trips and underfrequency load shedding, the power-generating unit will reduce load to the level required by the unit auxiliaries. This is referred to as “islanding” of the unit.

2.2.2 UNIT FAULT

For an electrical fault that occurs close to the generator terminals, the protection will initiate a trip to the generator circuit breaker [7]. Supply to the power-generating unit auxiliaries will continue via a back-feed from the IPS through the generator transformer and unit transformers. In the case of unit 1 and unit 2, which supplies station board 1 and 2 respectively, supply will continue via a back-feed from the IPS through the generator transformer and unit transformers.

2.2.3 GENERATOR TRANSFORMER FAILURE

For a generator transformer failure, the fault should be segregated from all sources. The generator circuit breaker [7] is opened to segregate the generator power source and the HV breaker is opened to segregate the IPS power source. In the case of units 1 and 2, the supply to the respective unit and one of the station boards will be interrupted. The diesel generators will be required to shutdown the unit, while supply to the respectively affected station board can be established via the station transformer or bus-section between the station boards. In the case of unit 3 to unit 6, the diesel generators will be required to shut down the unit while an alternative supply via the standby 380 V transformer can be established.

2.2.4 UNIT TRANSFORMER FAILURE

For a unit transformer failure, the fault should be segregated from all sources. The generator circuit breaker is opened to segregate the generator power source and the HV breaker is opened to segregate the IPS power source. In the case of units 1 and 2, the supply to the respective unit and one of the station boards will be interrupted. The diesel generators will be required to shut down the unit, while supply to the respectively impacted station board can be established via the station transformer or bus-section between the station boards. In the case of units 3 to 6, the diesel generators will be required to shut down the unit, while an alternative supply via the standby 380 V transformer can be established. When the faulty unit transformer is isolated by removing the flexible connection, the feeder breaker is isolated and the bus-section between the 11 kV unit boards is closed, the unit can be started and operated at full load, provided the electric feed pumps used for start-up are supplied from the station transformer. The 11 kV ring main should be used in the case of a unit A transformer failure.

2.2.5 3.3 KV SERVICE TRANSFORMER FAILURE

For a 3.3 kV service transformer failure, the unit power-generating capacity will reduce by 50% due to the unavailability of one draught group of primary air fans. Power generation at 80% to 90% of the capacity can be achieved through isolation of the faulty transformer and closing of the bus-section. The 3.3 kV service transformer capacity determines the unit power-generating capability (capacity) after a failure.

2.2.6 380 V UNIT TRANSFORMER FAILURE

If one 11 kV/400 V unit transformers supplying a 380 V unit board A or B fail, 50% of the unit power-generating capability will be interrupted. In the case of supply failing to 380V unit board A and B, total unit power-generating capability will be interrupted. Alternative supply via the 380 V unit standby board can be configured manually.

Failure of any of the 11 kV/400 V transformers supplying the 380 V diesel generator board will initiate an automatic change-over to the alternative transformer. If an alternative transformer is not available, the automatic starting of the diesel generator will be initiated. The 380 V standby board can be utilized to manually supply the 380 V diesel generator board.

2.2.7 FAILURE OF STATION TRANSFORMER

If a failure of the station transformer should occur when in service, the supply to the station board will be interrupted. Unit 1 or 2 supply system should be configured to supply station board 1 or 2 respectively.

2.2.8 CONSTANT VOLTAGE TRANSFORMERS USED IN THE STABILIZED POWER SUPPLIES

Stabilized power supplies were used to supply power to the motor control circuits at power plants as indicated in Figure 10. A constant voltage transformer (CVT) is used to ensure that the load voltage remains within tolerance during voltage dips on the input. Figure 9 illustrates the typical configuration. If the input supply is interrupted, the chop-over will change to the alternative supply. A similar configuration is also used to provide power to programmable logic controllers (PLC) on the outside plant.

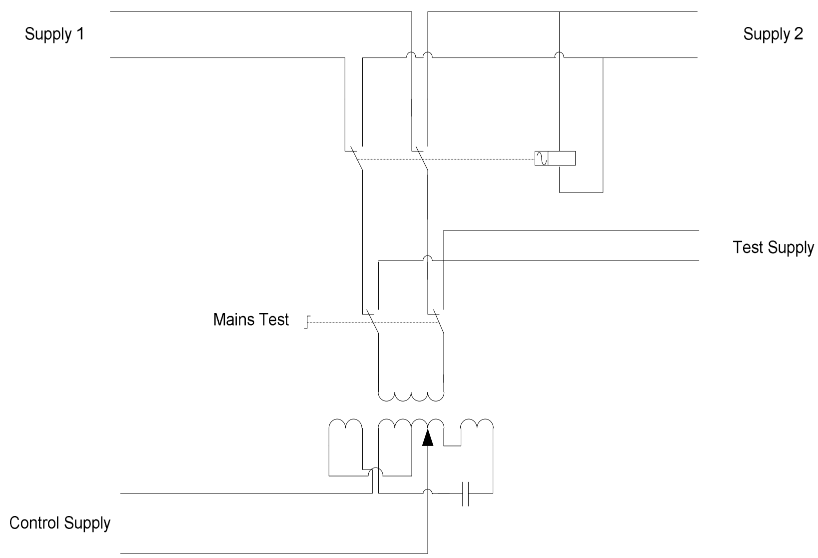


Figure 8: Stabilized power supply diagram [5]

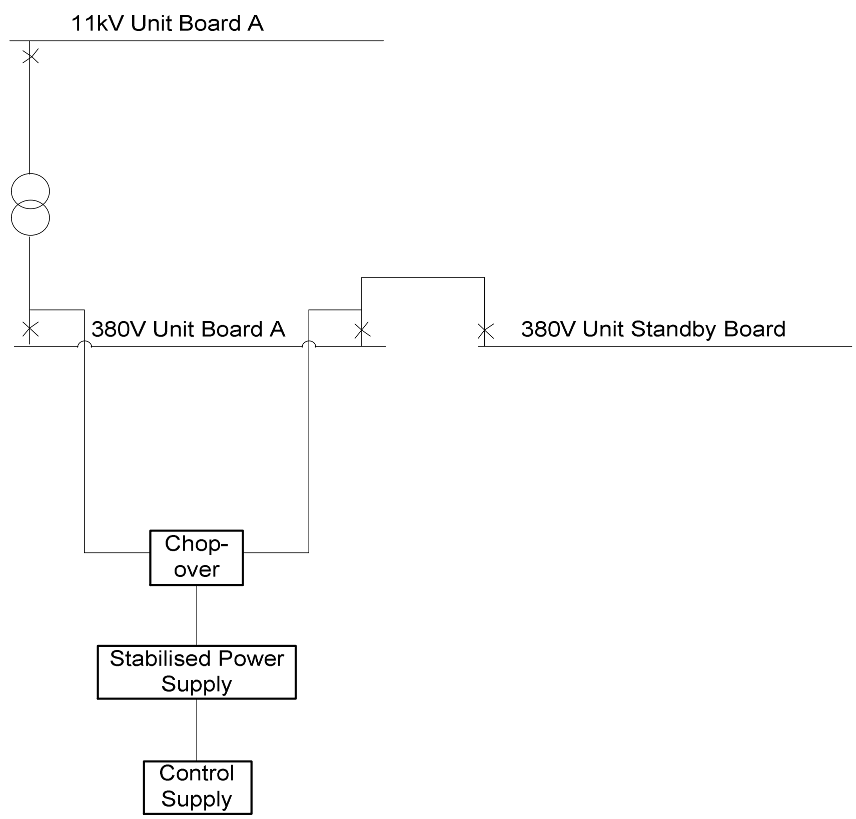


Figure 9: Stabilized power supply configuration

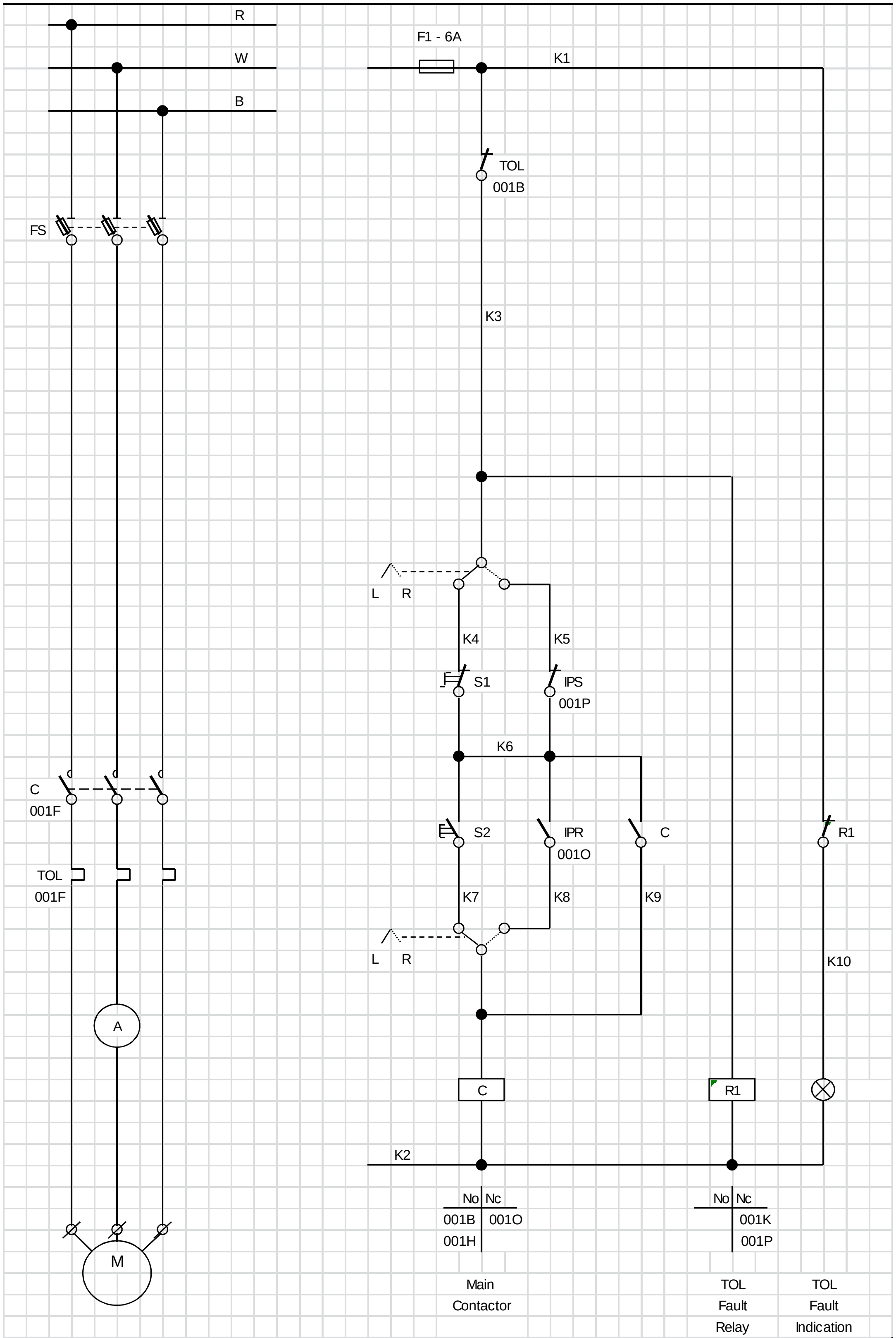


Figure 10: Typical motor starting circuit

The constant voltage transformers (CVT) use the unique principle of ferro-resonance, in other words the operation of a transformer in the region of magnetic saturation (see Figure 11) [6]. When the iron core of a transformer is in saturated, relatively large changes in winding current will result in very small changes in magnetic flux. Winding current and magnetic flux are proportional to the input and output voltage respectively. This means that relatively large changes in input voltage result in small changes in output voltage: this being the fundamental purpose of an automatic voltage regulator.

Figure 11 shows a simplified version of a magnetization curve to demonstrate this concept. In the saturation region of the curve (red), a large change in input voltage results in a small change in output voltage. Operation in the saturated region has the disadvantage of very poor electrical efficiency. Standard power transformers are designed to operate in the normal range (blue) where electrical efficiency is much higher. While standard power transformers have some minimal capacity for voltage regulation, their primary purpose is to transform voltage from one level to another (e.g. convert 480 V to 200 V) with high efficiency.

Operation in the saturated region also produces another undesirable effect, namely sinewave distortion. As shown in Figure 11, most ferro-resonant transformers incorporate an LC (inductor-capacitor) circuit ("tank circuit") tuned to the AC frequency to effectively filter out any distortion.

Stabilized power supply devices are designed and adjusted to supply resistive loads. If the load has a power factor of less than 0.9 lagging, the output voltage is lowered on inductive loads and raised on capacitive load. Inductive loads must be compensated by appropriate compensating capacitors. Care should be taken when switching off the load that no undue capacitive loading occurs.

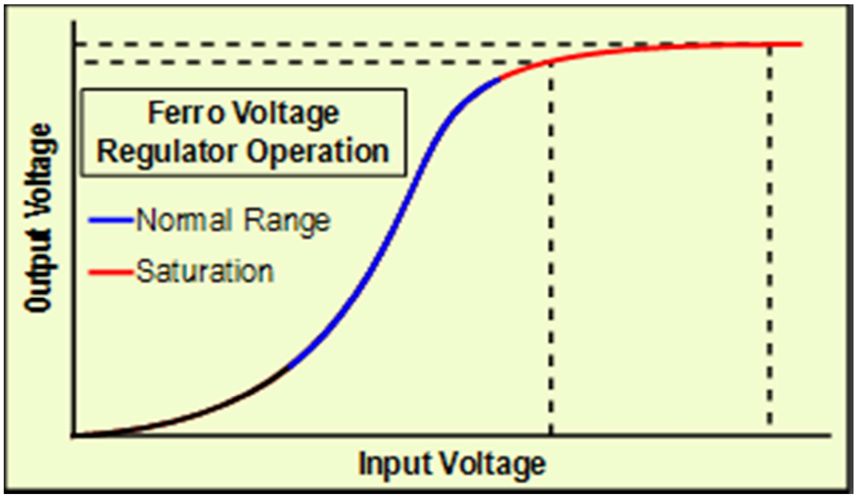


Figure 11: CVT voltage regulator operation [6]

2.3 LINE INTERACTIVE VOLTAGE DIP PROOFING DEVICE

A dip proofing voltage device was developed to replace the stabilized power supply units installed at power plants. Installation of the line interactive voltage dip proofing devices started in 1990. The voltage dip proofing device is a line interactive device [8], which had a stored energy device to provide control supply to the contactors during a short voltage interruption or voltage dip.

2.3.1 LINE INTERACTIVE VOLTIGE DIP PROOFING DEVICE TOPOLOGY

The line-interactive UPS [8] topology comprises of a static transfer switch and a bi-directional AC to DC converter/inverter (see Figure 12).

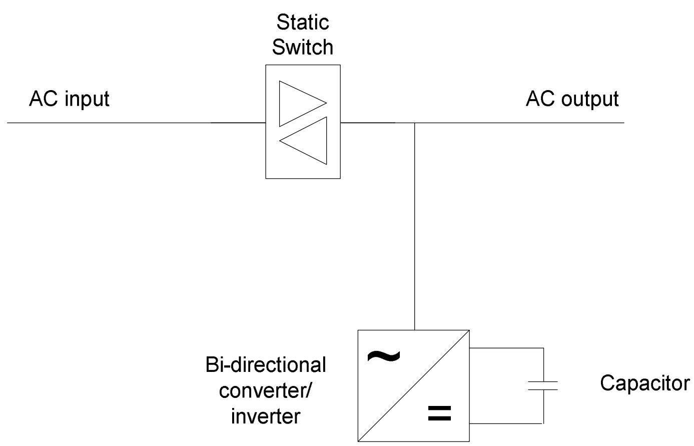


Figure 12: Supply and load voltage waveform [8]

The bi-directional AC to DC converter and inverter serves to provide output voltage conditioning, capacitor charging, or both. The output frequency is dependent upon the AC input frequency. When the AC input supply voltage or frequency is out of the pre-set tolerances, the static transfer switch interrupts the AC input and the inverter maintains continuity of load power from the energy stored in the capacitor. The inverter will continue to supply load power depending on the availability of stored energy. When the AC input supply returns within the pre-set parameters, the inverter will synchronize its generated power with the input supply and transfer to input AC supply. The converter will re-charge the capacitor.

2.3.2 LINE INTERACTIVE VOLTIGE DIP PROOFING DEVICE THEORY OF OPERATION

This section describes the theory of operation of the specific line interactive voltage dip proofing device [9] utilized at power plants. During standby operation, the static switch supplies power directly to the control voltage bus. The inverter is switched off and the capacitors are charged to the full operating voltage. The supply voltage is constantly monitored for deviations. Should there be a deviation from V_{nom} that is greater than the pre-set value, the static switch is switched off (i.e. opened) and the inverter is activated. The switchover takes less than 700 µs. If the voltage recovers within a pre-set time, the dip proof inverter (DPI) [9] synchronizes the inverter supply to the incoming voltage by switching on the static switch and recharging the capacitors for the next dip.

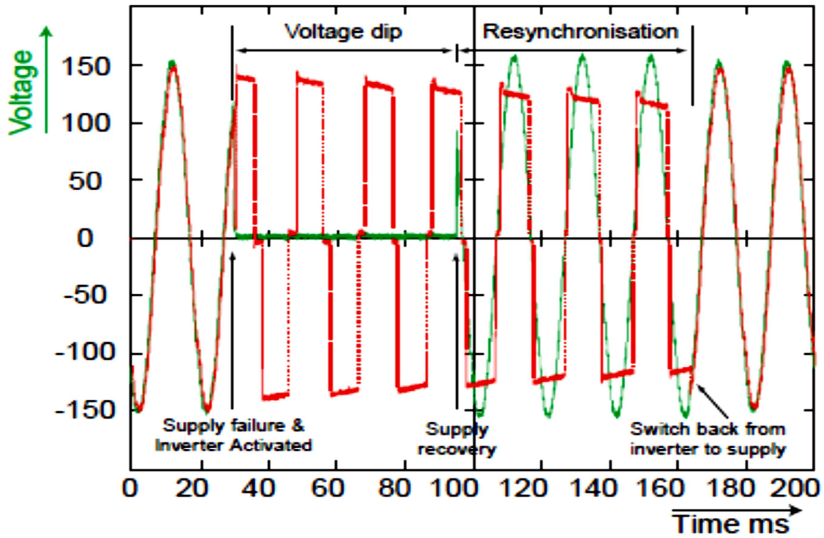


Figure 13: Supply and load voltage waveform [9]

Figure 13 shows the supply voltage in green and the load voltage in red before, during and after a supply interruption. At 45 ms the supply voltage is interrupted and the inverter is activated, supplying the square wave supply to the load. The DPI is heavily loaded to show the inverter regulation method. The stepped square wave becomes wider as the storage capacitors discharge, thus maintaining the RMS value of the output. The magnified waveform in Figure 14 indicates that the transfer to inverter power is very fast (<700 μs). When the supply recovers within the pre-set voltage, the inverter output is synchronized with the supply before the load is switched back and the inverter is deactivated. The resynchronization period in this example was 3.5 cycles.

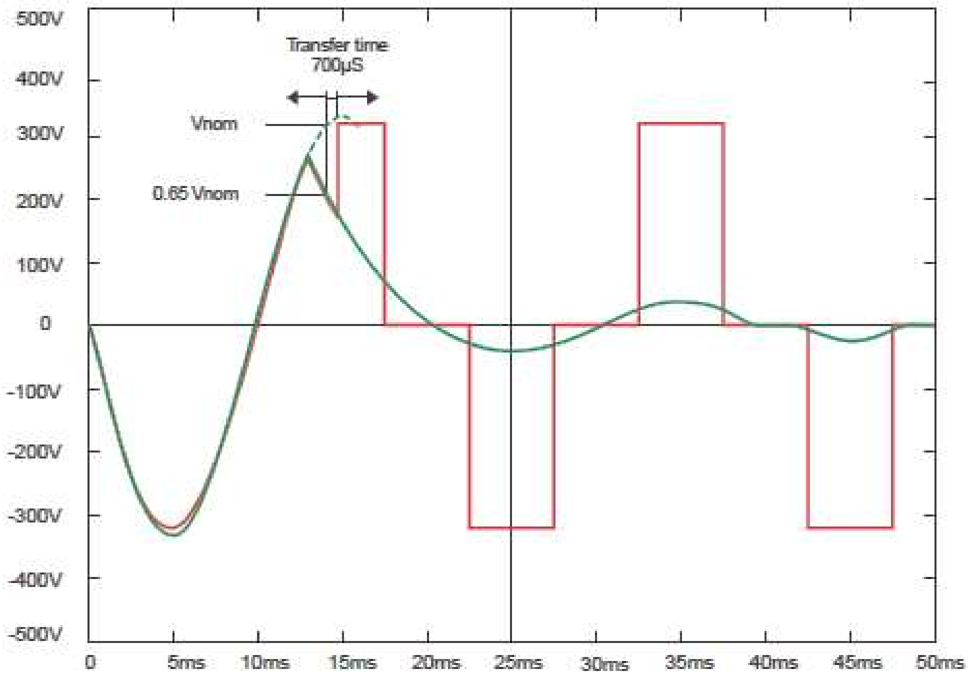


Figure 14: Supply and Load Voltage Waveform at Transfer [9]

2.3.3 DPI UP-TIME AS A FUNCTION OF LOAD

With reference to the DPI brochure [9], the time a DPI can sustain supply to the load can be calculated using the following equation:

$t = (\eta C V_s)/(I_{\_load} \cos\varphi)$ (1)

Where:

t	-	DPI up-time
η	-	DPI efficiency factor
C	-	Value of DPI storage capacitors
V_s	-	Load voltage
$I_{\_load}$	-	Load current
$\cos\varphi$	-	Load power factor

From equation (1) it is evident that the DPI up-time is dependent on the load power factor with resistive and reactive loads that yield the shortest and longest times respectively.

2.4 SOUTH AFRICA (ZAF) – GRID CODE REGULATORY FRAMEWORK EXTERNAL SUPPLY DISTURBANCE WITHSTAND CAPABILITY (GCR 9)

The Grid Code Requirement 9 (GCR 9) [2], titled "External Supply Disturbance Withstand Capability", states that any unit or power station equipment shall be designed to have resilience against disturbances generated in the IPS. The tables below summarize the requirements of GCR 9 and the three-phase voltage dip magnitude and fault ride-through times are illustrated as a voltage envelope graph to compare with the grid code requirements of some other countries later in the dissertation.

The anticipated voltage conditions at the point of connection:

- Voltage deviation as per Table 4.

Table 4: South African voltage deviation limits [2]

Normal Operating Conditions	
Minimum Voltage (p.u.)	**Maximum Voltage (p.u.)**
0.90	1.10

- The three-phase voltage dip magnitude and fault ride-through times as per able 5 and voltage envelope as indicated in Figure 15, provide that during the three-minute period immediately following the end of the 200 ms, 2000 ms, or 60000 ms period, the actual voltage remains within the limits stipulated in Table 4.

  The 2000 ms time period stated in the GCR 9 paragraph above contradicts the 1000 ms stipulated for a 0.75 p.u. voltage dip. The 1000 ms time-period appears later on in this study as it was used to perform the simulations described in Chapter 3.

Table 5: South African voltage dip magnitude and fault ride -through times [2]

Voltage Dip Magnitude Level expressed in p.u.	Fault Ride-Through Times in ms
0	200
0.75	1000
0.85	60000

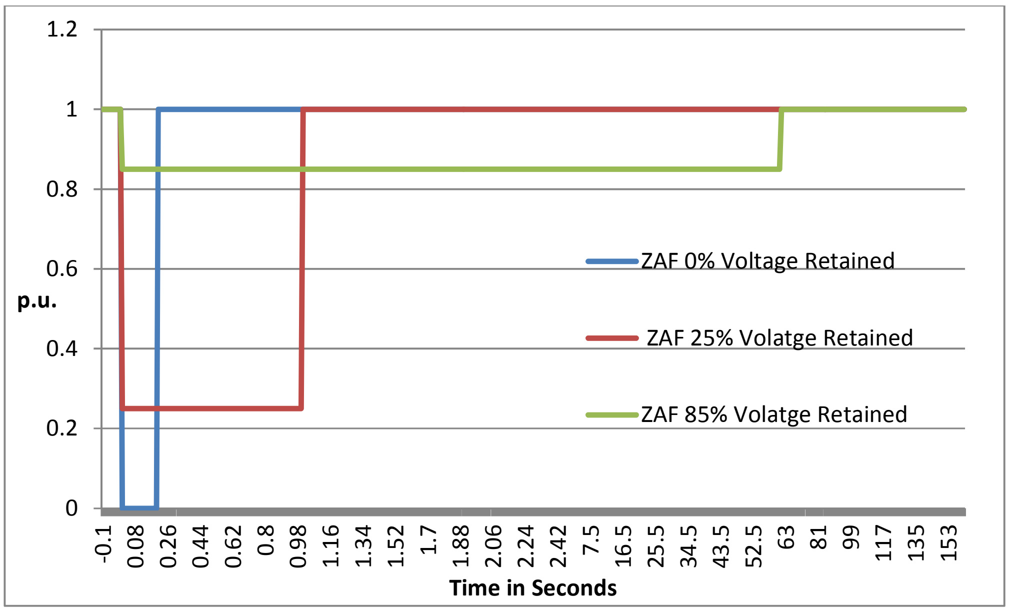


Figure 15: Voltage envelope in South African grid code [2]

The acceptable IPS voltage ranges following a disturbance are 0.90 p.u. and 1.10 p.u.. This is not shown on this graph, 1.0 p.u. was used for the system condition prior and after the incident. Other requirements include:

- The phase voltage unbalance of not more than 3% negative phase sequence voltage or the magnitude of one phase may not be lower than 5% than any of the other two for six hours or both.
- A V/Hz requirement of less than 1.10 p.u..
- A requirement to withstand the following ARC cycle for single-phase faults on the transmission lines connected to the power station:

  - Single-phase fault – single-phase trip – one-second single-phase ARC dead time – single-phase ARC – single-phase fault – three-phase trip – three-seconds three-phase ARC dead time – three-phase ARC – single-phase fault – three-phase trip – lock out. This only applies where synchronism is maintained.
- A requirement to withstand the following ARC cycle for multi-phase faults (phase-to-phase or three-phase) on the transmission lines connected to the power station:
  - Three-phase fault – three-phase trip – three-second three-phase ARC dead time – three-phase ARC – three-phase fault – three-phase trip – lock-out.

The following routine and prototype response tests are stipulated in the grid code [2] to demonstrate capabilities:

- A prototype survey/test is applicable to all new power plants that connect to the IPS or power plants in which major modifications have been made that may be critical to system supply frequency or voltage magnitude deviations. A voltage magnitude deviation survey is required for plants using dip proofing inverters (DPI).
- Routine testing and surveying is applicable to all power plants to review the frequency deviation survey, voltage magnitude deviation survey and dip proofing inverter integrity testing every six years. Dip proofing inverter integrity testing should also be carried out every six years.

The purpose is to confirm that the power plant and its auxiliary supply loads conform to the requirements of supply frequency and voltage magnitude deviations as specified under GCR9.

The scope is all critical plant equipment or systems that are likely to cause tripping of a unit or parts of a unit or that are likely to cause a multiple-unit trip (MUT).

The procedure and acceptance criteria are stipulated as:

- *Frequency deviation survey*: Carry out a survey on the capability of the critical plant to confirm that it will resume normal operation for *frequency* deviations as defined in GCR 9. A *unit* or *power station* shall not trip or unduly reduce load for system *frequency* changes in the range specified in GCR 9.
- *Voltage magnitude deviation survey*: Carry out a survey on the capability of the critical plant to confirm that it will resume normal operation for voltage deviations as defined in

GCR 9. Also consider protection and other tripping functions on the critical plant. A *unit* or *power station* must not trip or unduly reduce load for system voltage changes in the range specified in GCR 9. It is required that all findings of the voltage magnitude deviation survey must be documented.

- *Dip proofing inverter (DPI)* integrity testing: DPI and any other equipment must be tested according to the OEM requirements. A report should be submitted to the system operator one month after the testing. Routine studies and survey reports should be submitted one month after expiry of the due date. It is required that all results of the dip proofing inverter integrity testing must be documented.

2.5 ORIGINS AND CHARACTERISTICS OF THE VOLTAGE DISTURBANCES EXPERIENCED BY POWER PLANTS

This section studies the causes and characteristics of disturbances in the supply voltage of a power plant as a result of disturbances that originate in the integrated power system (IPS). Voltage characteristic transformation as the voltage disturbance propagates from its origin in the IPS through the power plant electrical reticulation is considered.

2.5.1 SHORT INTERRUPTIONS (TEMPORARY LOSS OF SUPPLY)

The supply to a power plant can be temporarily interrupted for a short duration without interruption of the plant process due to system inertia [10], [11]. In plant areas where short supply interruptions can interrupt the power plant processes, essential uninterruptable supply is utilized to maintain control of the plant so that it can resume operation immediately after supply restoration or maintain operation of the process and to prevent plant damage or unsafe conditions [12]. Sources of short interruptions experienced by a power plant are usually automatic reclose (ARC) dead times of breakers in the transmission and distribution networks and delays in switching between different supply sources.

2.5.1.1 SHORT INTERRUPTIONS DURING AUTOMATIC RECLOSURE (ARC) DEAD TIME

The dead time for a three-phase automatic reclosure (ARC) network is normally 3 s and this causes an interruption in supply for 3 s. For a single-phase trip, which is a partial loss of supply, the ARC dead time is set to 1 s [2].

2.5.1.2 VOLTAGE SUPPORT FROM GENERATORS AND SUB-SYSTEM

Resilience to disturbances as stipulated in GCR 9 of synchronous generators is required to prevent load rejection operation that will initiate a load surge on generators connected to the IPS. Voltage support is provided by generators and sub-systems that remain connected to the IPS during supply disturbances.

The automatic voltage regulator has to respond to changes in the operating conditions required for a power plant. This ranges from raising the voltage before synchronizing to managing the voltage within specified time limits, following load rejection or responding to load change requirements. The detail operation of the synchronous generator and sub-system is discussed in Section 2.7 to explain how voltage support is provided. The discussion also includes the limitations of the generator and sub-system.

2.5.1.3 BACK EMF OF MOTORS DURING INTERRUPTIONS

When the supply to an on-load power plant is interrupted, the motors may generate power back to the electrical reticulation system and the voltage will not instantaneously reduce to zero. Motors with low inertias and high load torques can stall rapidly and the back EMF voltage will decay quickly due to a loss in shaft speed. For large motors with high inertia, the terminal voltage decay is as long as one-and-a-half seconds [11]. The back EMF provides power to other small inertia low load torque motors connected to the same electrical reticulation system.

2.5.2 ELECTRICAL FAULTS

There will be a voltage deviation on the supply voltage during a short circuit on the supply side or within the plant’s medium or low voltage reticulation system. The voltage deviation can be 100% because of a short circuit within the plant’s medium or low voltage reticulation system, with added impact of longer clearing times.

2.5.2.1 SHORT CIRCUITS

The voltage disturbance experienced within the power plant during a short circuit will depend on the impedance and location of the fault. The voltage disturbance for faults with low impedance will be significant even up to 100% voltage disturbance. As the impedance of the fault increases, the voltage disturbance will decrease and the impact on the plant reduced. The behaviour of induction motor drives during a fault was measured within a power plant configuration (see Figure 16).

Following the fault, the induction motor drives will lose speed and once the fault is segregated by the protection systems, the motor drives connected to the supply will re-accelerate [13]. On weak supply systems, in other words systems with low fault current, the current drawn by the large induction motor load or the total induction motor load in an effort to re-accelerate may affect the terminal voltage and potentially result in an overload condition. The current drawn by the motor is dependent on the load torque, the inertia of the motor drive and the duration of the fault. High inertia drives ($H > 6$) will draw a fraction of the starting current following a fault of less than 100 ms. The currents drawn by the motor drive will approach full starting current and duration during acceleration following a longer sustained fault. The voltage curves and apparent power drawn for different fault durations are shown in Figures 17 to 22 [11]. The voltage during the fault may not necessarily remain the same as the impedance of the fault may vary.

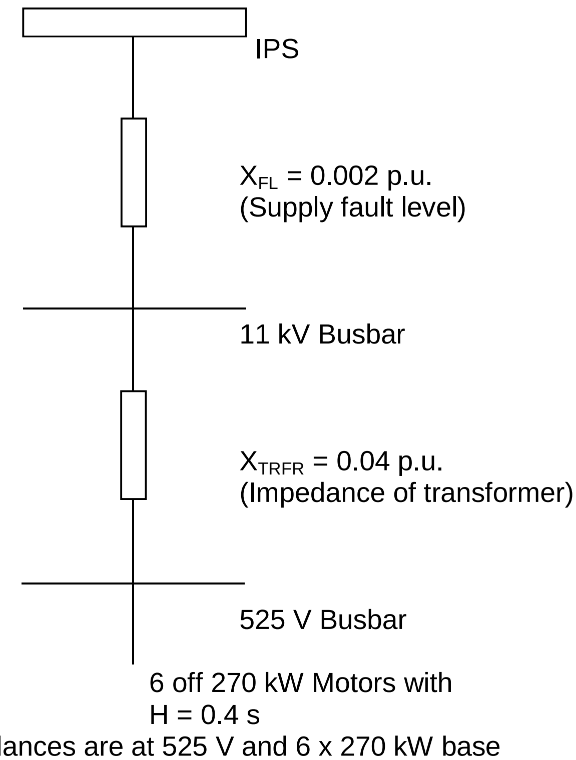


Figure 16: Electrical configuration

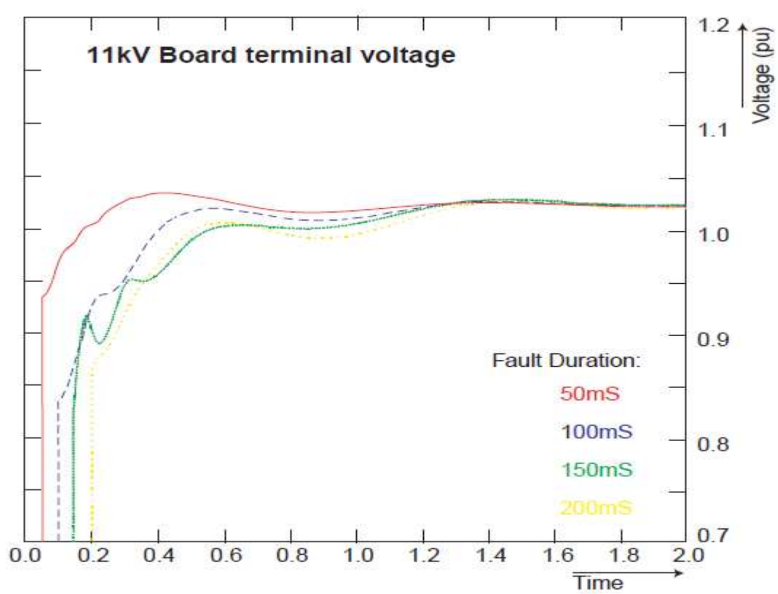


Figure 17: 11 kV board terminal voltage for fault durations of 50 ms to 200 ms [11]

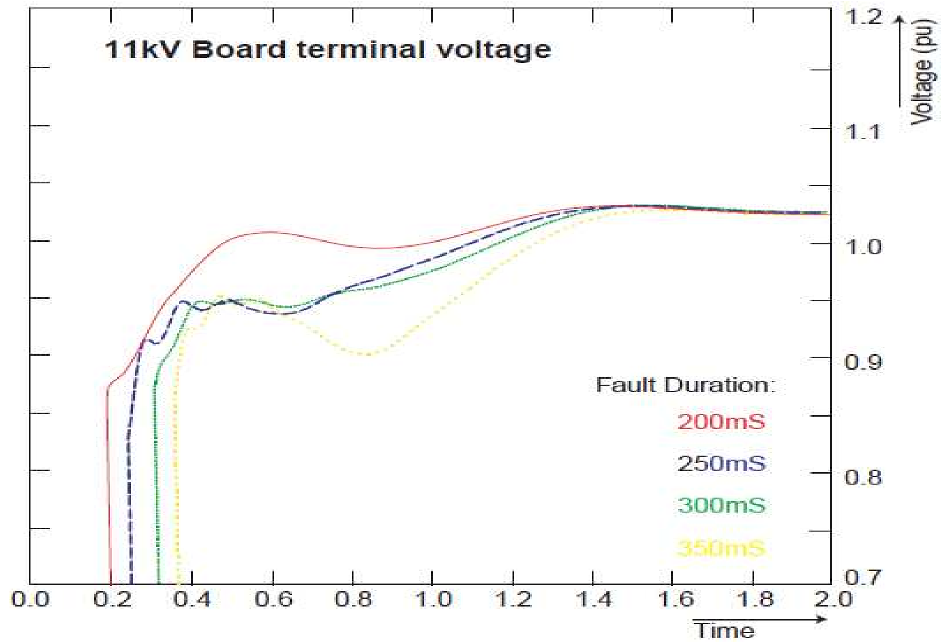


Figure 18: 11 kV board terminal voltage for fault durations 200 ms to 350 ms [11]

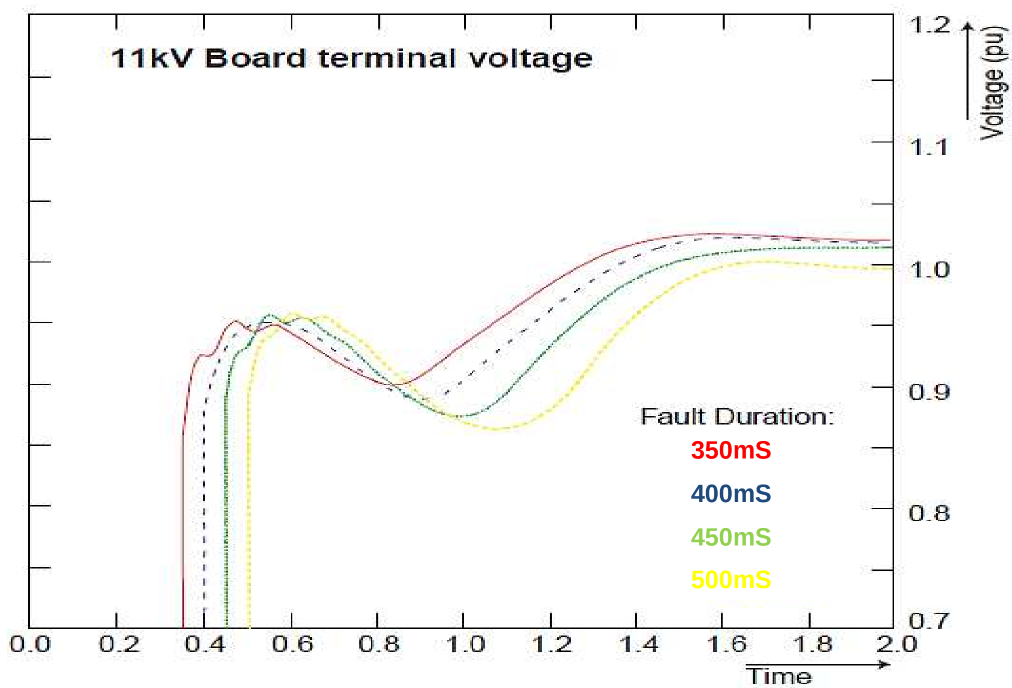


Figure 19: 11 kV board terminal voltage for fault duration 350 ms to 500 ms [11]

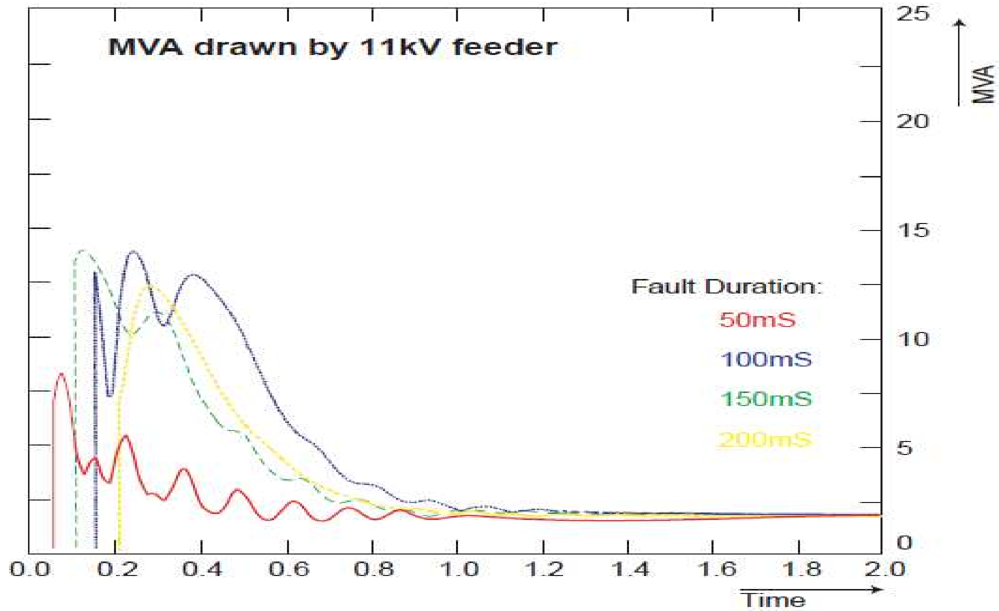


Figure 20: 11 kV board apparent power drawn for fault durations 50 ms to 250 ms [11]

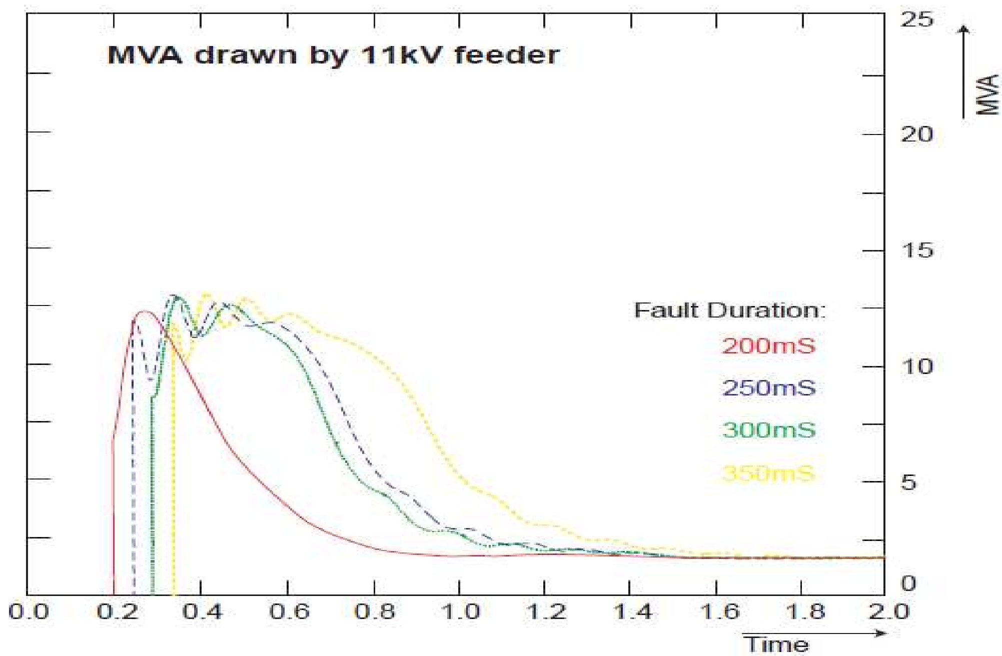


Figure 21: 11 kV board apparent power drawn for fault durations 200 ms to 350 ms [11]

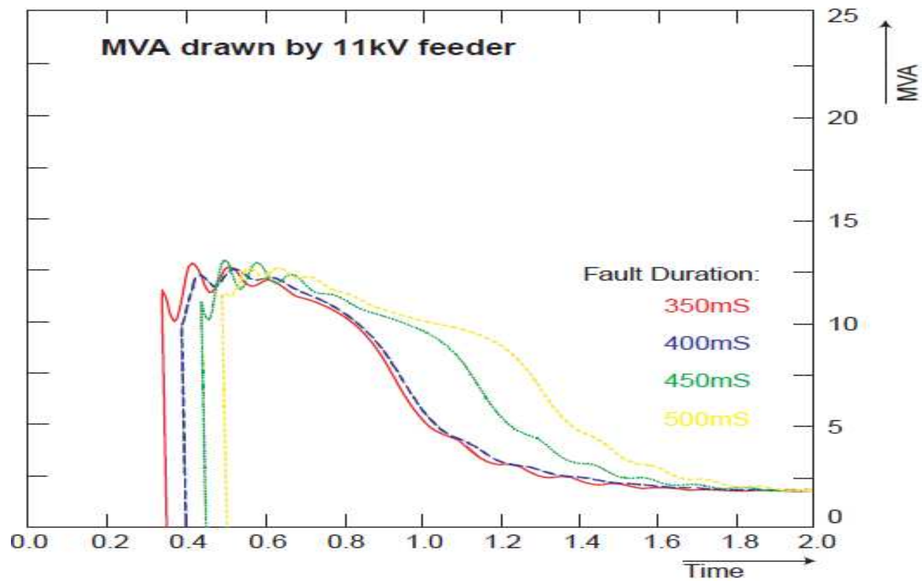


Figure 22: 11 kV board apparent power drawn for fault durations 350 ms to 500 ms [11]

The graphs also illustrate the importance of the protection schemes to clear the fault in the shortest possible time to limit the impact on the rest of the plant.

2.5.2.2 FAR END OF LINE TRIPPING DURING FAULT

When a fault occurs on one of several parallel feeders in the IPS connected to a power plant, the time within which the fault is cleared by the protection within the power plant and within the IPS could differ. Figure 23 [11] offers an illustration of the expected terminal voltage for a scenario where the far end of the line breaker opens after the plant breaker for a fault occurring in the plant electrical reticulation system.

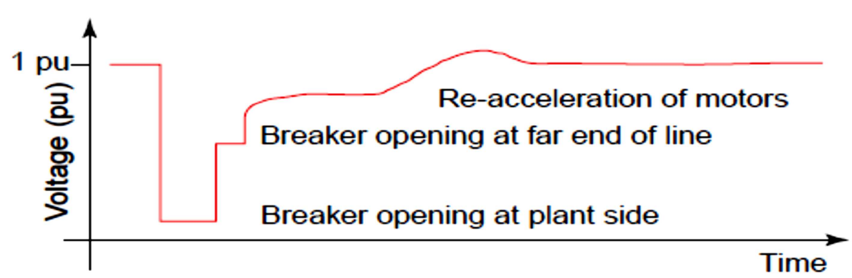


Figure 23: Voltage during a severe short circuit close to the point of supply and cleared by line protection [14]

2.5.3 LOAD SWITCHING

Supply voltage deviations can occur because of switching loads within the power plant reticulation system. The voltage deviation is more significant during large direct on-line induction motor starting within the power plant reticulation system because of the limited transformer capacity. Figure 24 illustrates a typical direct-on-line motor starting voltage graph and Figure 25 shows a voltage graph during transformer energizing.

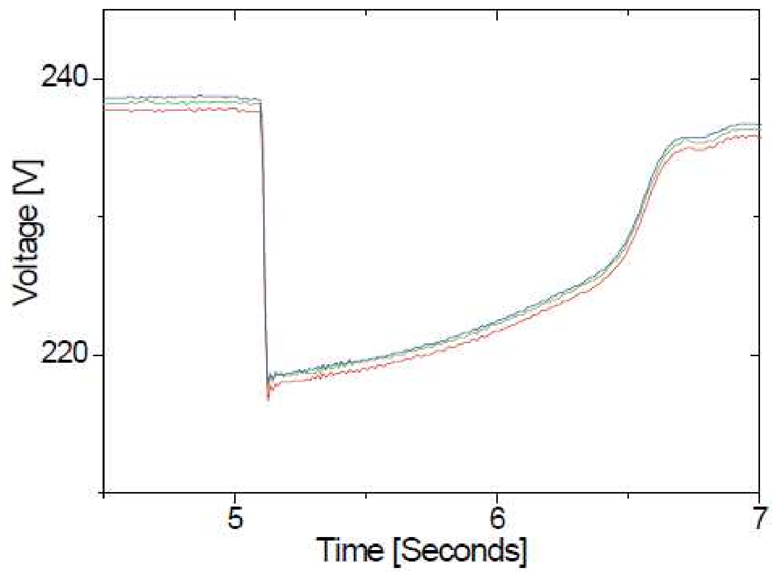


Figure 24: Voltage dip during motor starting [15]

The characteristic of the voltage dips due to direct-on-line starting of large three-phase motors have similar voltage magnitude reduction and voltage recovery slopes in all three phases and is therefore symmetrical [15].

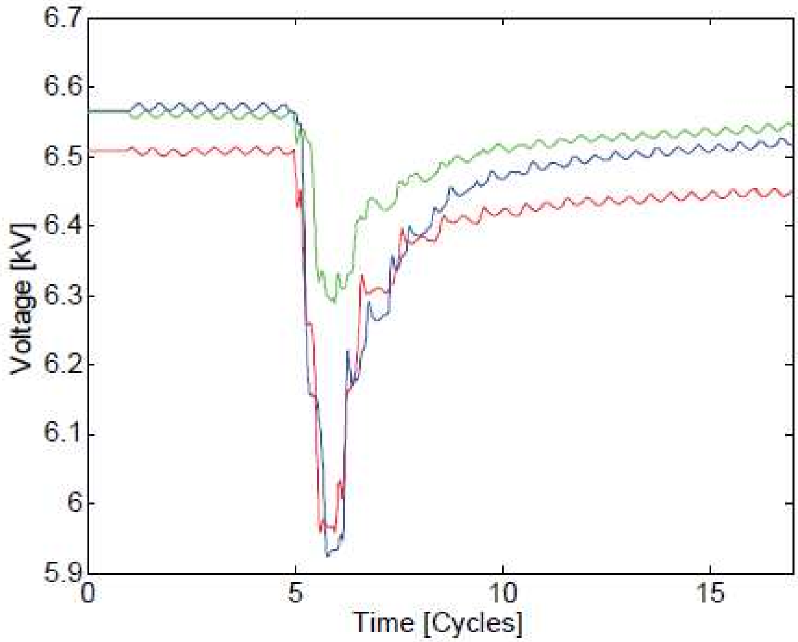


Figure 25: Voltage dip per phase during transformer energizing [15]

The voltage dips during transformer energizing have different characteristics in that they have different voltage magnitudes and voltage recovery slopes in all three the phases. They are therefore asymmetrical. The difference in voltage magnitudes and recovery slopes are a result of the difference in dv/dt, the resultant DC offset and saturation of the magnetic core [16], [6].

A large harmonic distortion where especially the values of the even harmonics significantly increase, is a typical characteristic of the voltage dip during transformer energizing.

Following the clearance of a fault in the IPS, another voltage dip can be experienced after auto-reclosing of breakers. The re-energizing results in the saturation of all the transformers, causing a high inrush current and therefore a voltage dip. The voltage recovery time is dependent on the dip magnitude and duration, point-on-wave of dip initiation and ending, source impedance and locations of transformers and their residual fluxes.

2.5.4 NETWORK SWITCHING

IPS switching or medium- and low voltage reticulation system switching can result in voltage deviations. A fast transient voltage change followed by a dynamic condition before settling at the new steady state load angle can result from paralleling supplies at different load angles. Transient changeover is normally fast and unlikely to have an effect on a normal electrical plant. Electronic equipment is normally susceptible to fast transients.

2.5.5 POWER SWINGS

Power swings between power plants connected to the IPS can occur due to a change in the load angle requirements, because of sections of the IPS being disconnected or segregated due to a fault.

During a large power swing on the network, the terminal voltage at a plant can oscillate at a frequency between 0.1 Hz and 2 Hz, with minimum voltage values as low as 65% [11]. Such power swings normally last only for a few seconds, but under severe weak interconnected network conditions, the oscillations may continue for several tens of seconds. The electrical equipment of an industrial plant, if correctly designed, can continue operation during such voltage dips. This type of voltage dip is unlikely to occur at an industrial plant, which is supplied from a strong point in the supply network. Large power stations usually have high fault levels that provide a high degree of resilience to voltage dips because of power swings. It is only the standby rural supply that may be weak.

2.5.6 SUPPLY UNBALANCE

An unbalance in supply can result from single line-to-ground, phase-to-phase, or two phase-to-ground faults and the energizing of large transformers. Unbalance in supply is defined as unsymmetrical sags [17], [18]. Load and transformer connections to the reticulation system can alter the type of sag experienced by the loads connected to the reticulation system.

The impact of negative phase sequence components [10] in the supply on the induction motor drive behaviour are speed loss, increased current and torque.

It is therefore important that not only the magnitude of the voltages, but also the negative phase sequence component, are monitored as part of the motor protection.

2.5.7 VOLTAGE DIP PROPAGATION

Voltage dip characteristic changes occur following an electrical fault, when moving from the IPS to the medium voltage (MV) reticulation system and when moving from the MV to low voltage (LV) reticulation system, as illustrated in Figure 3 and Figure 5. The grounding arrangements and transformer winding connections will have an impact on the voltage characteristics experienced within the electrical reticulation from a fault that occurred within the IPS. The distinction between the influence of the different grounding arrangements and transformer winding connections for three general types of transformer arrangements is as follows:

- Yy transformers, grounded on both sides – transformers that do not have any impact on the voltages;
- Dd transformer or Yy transformer that is not grounded – transformers that remove the zero-sequence voltage in part or completely. A three-winding Yyd transformer removes only a part of the zero-sequence voltage.
- Dy transformers – transformers that change phase-to-phase voltages into phase-to-neutral voltages (and the other way around) and that remove the zero-sequence voltage. Table 6 illustrates the voltage propagation changes in magnitude and phase angles for different types of voltage dips for different transformer winding/grounding connections.

Figure 26 illustrates the instantaneous voltage waveforms for different types of voltage dips [10], [15] as a result of faults experienced within a three-phase system. The three voltage dip classifications are:

- Voltage dip Type III – a drop in voltage magnitude that occurs in all three phases and is equal in magnitude;
- Voltage dip Type II – a drop in voltage magnitude that occurs mainly in one of the phase-to-phase voltages;
- Voltage dip Type I – a drop in voltage that occurs mainly in one of the phase-to-ground voltages.

Voltage magnitudes and phase angles of the voltage dips measured at the lower voltage levels are additionally influenced by the (large) motor loads, different supply sources and power-generating units connected.

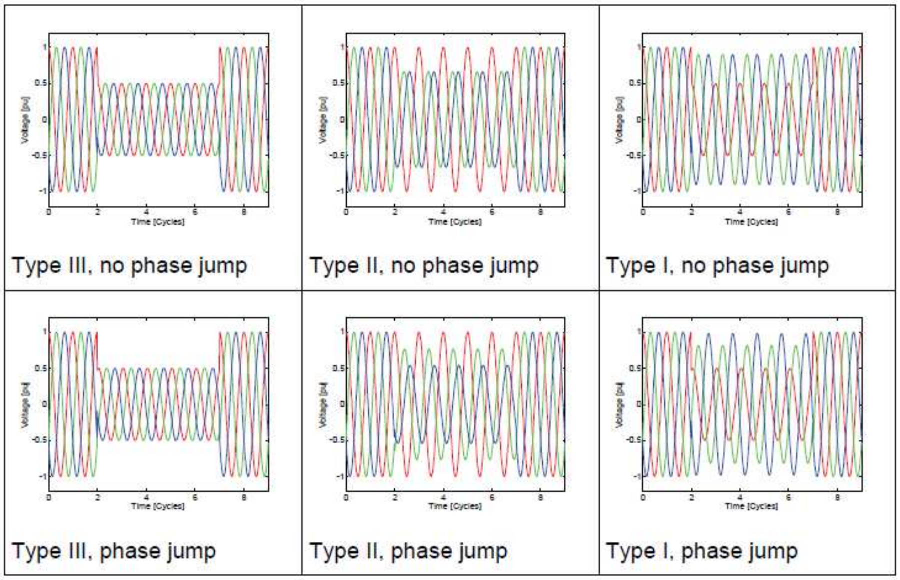


Figure 26: The instantaneous voltage waveforms for different types of voltage dips due to faults that may occur in a three-phase system, without (top) and with (bottom) characteristic phase-angle jump [15]

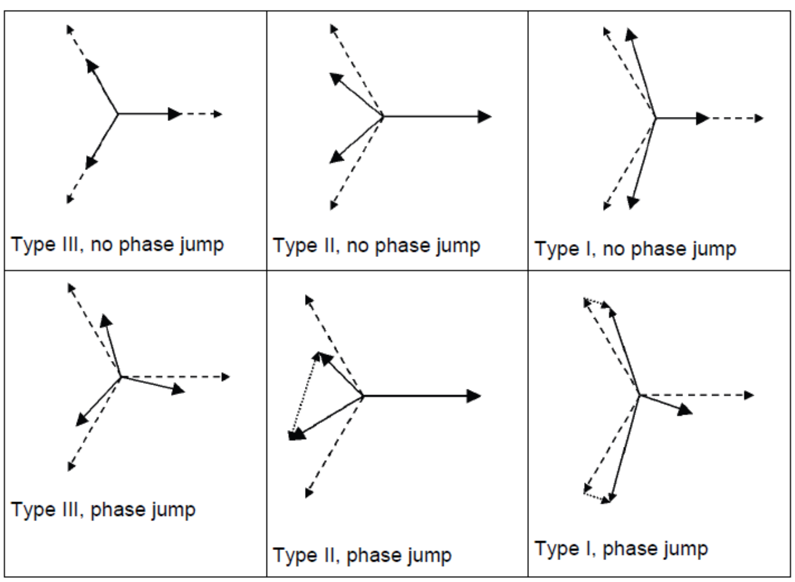


Figure 27: The phasor diagrams for different types of voltage dips due to faults that may occur in a three-phase system without (top) and with (bottom) characteristic phase-angle jump [15], [10]

The dip characteristic voltage has a magnitude and a phase angle that are typically different from those of the pre-event voltage. The difference in phase angle between the pre-event voltage and the (during-event) characteristic voltage is referred to as the “characteristic phase-angle jump”.

Table 6: Changes in event segments due to transformer winding connections [10], [15]

Type of fault	Dip at faulted voltage level	Dip after one Dy transformer	Dip after two Dy transformers
Three-phase	Type III	Type III	Type III
Single-phase in a solidly-grounded network	Type I with a zero-sequence voltage	Type II	Type I
Single-phase in a non-solidly-grounded network	Zero-sequence voltage only	No dip	No dip
Two-phase	Type II	Type I	Type II
Two-phase-to-ground in a solidly-grounded network	Type II with a zero-sequence voltage	Type I, but with a bigger drop in magnitude in all phases than the common Type I	Type II, but with a bigger drop in magnitude in all phases than the common Type II
Two-phase-to-ground in a non-solidly grounded network	Type II with a zero-sequence voltage	Type I	Type II

In summary, the information presented in Figure 26, Figure 27 and Table 6 is representative of a load that has a constant impedance during the fault. When large motor loads or generators are connected to the reticulation system, it will influence the voltage dip characteristic.

The motor load and power generation from the rotating machines will have a low impedance for the negative-sequence component. Any asymmetrical voltage dip will result in a high negative-sequence current. The negative-sequence voltage will be damped when moving away from the fault towards the load, and the asymmetrical condition tends to become more symmetrical.

The motor load and power generated by rotating machines will initially maintain the positive-sequence voltage. The result is that the drop in positive-sequence voltage becomes smaller further away from the fault. For long-duration dips, the positive-sequence voltage may drop during the later stage of the dip when the motors draw higher currents during reacceleration.

2.6 POTENTIAL IMPACT OF VOLTAGE DISTURBANCES ON POWER PLANTS

A power plant has daily exposure to voltage disturbances that originate in the IPS as a result of electrical faults, load switching, power swings and network switching. This section probes the effect the voltage disturbance has on electrical equipment to evaluate the resilience of an older power plant against voltage disturbances as stipulated in GCR 9.

2.6.1 IMPACT OF VOLTAGE DIPS ON THE POWER-GENERATING PROCESS

When a voltage dip occurs on the supply of a power plant, various parts of the power generation process will rapidly approach a point where the process must be stopped to protect the plant. Evaluating the impact of voltage dips on individual electrical power plant equipment can verify if the power plant design ensures a high degree of resilience against disturbances that originates in the IPS.

A further objective would be to design the plant so that it is able to return to service as quickly as possible following an interruption in power-generating capacity because of a fault in the IPS [2].

Analysing the potential impact of voltage disturbances on a power plant requires a more in-depth study of the function of specific electrical equipment utilized at power plants and the behaviour during voltage disturbances.

2.6.2 CONTACTORS

The purpose of contactors is to control large currents and voltages with small control currents and voltages and to facilitate remote control. Contactors for motor starting and stopping are used on LV circuits within the power plant. The power supply controlling the contactors is taken directly from the associated busbar supply voltage.

Voltage dips cause electrically held-in contactors to drop out and this interrupts the power-generating capability or affect the reliability and availability of a power plant. Voltage dips can also be a consequence of the direct-on-line starting of induction motors within the power plant. Contactors are identified as a weak link in many processes during voltage dips [19], [20], [21], [22], [23], [24].

The time it takes for a contactor to drop out depends on the current that flows in the coil when the voltage dip occurs and the place in the voltage cycle where the voltage dip occurs [25], [26], [27].

The higher the source impedance, the slower the flux decay. Accurate information of the actual impact of the source impedance on the contactor dip behaviour is not reported and further research is required.

The theory around contact shuttering can be considered as the early stage of contactor drop-out and a condition to take note of when specifying the source of supply.

In order to ensure resilience to disturbances that originate in an integrated power system (IPS), it is important to evaluate the behaviour of contactors under the different circumstances experienced during disturbances.

The IEC 60947-4-1 standard [28] for contactors does not require that the behaviour of contactors during disturbances be measured as part of type testing, or that contactors be designed and manufactured with the required voltage dip immunity that is experienced within power plants. A comprehensive understanding of the behaviour of contactors during these disturbances is required to improve disturbance resilience of power plants.

2.6.2.1 ELECTROMAGNETIC CONTACTOR BASICS

A typical contactor consists of four basic parts [27], [29]:

- The exciting (control) coil;
- The fixed core (armature) magnetic circuit, and
- The spring-loaded movable core, and
- The fixed and moveable contacts.

The magnetic circuit comprises of two parts, the stationary fixed core, which has the exciting coil wound around it, and the moveable core (yoke), which is spring-loaded. The yoke is mechanically linked to a contact arrangement, the main current carrying contacts and a number of auxiliary contacts. For a DC-powered exciting coil, the generated magnetic field is constant with time and therefore the electromagnetic force generated is too. However, in the case of an AC-powered exciting coil, the magnetic field generates alternating forces that decrease to zero during every crossing zeros. To ensure that the attractive force contains a useful unidirectional component as the alternating current moves through the crossing zeros, a shading coil in the magnetic circuit adjacent to each air-gap is provided. Eddy currents are introduced in the shading rings because of the time variation of the alternating magnetic flux crossing the pole face. The eddy currents in the shading ring generates a magnetic flux out of phase with the exciting coil-generated magnetic flux, ensuring that the net flux through the pole faces does not decay to zero [29].

The current in the control circuit coil induces a magnetic field that flows through the fixed core, the moving core and the air gaps between the pole faces (see Figure 28). The field tries to reduce the air gap by producing a strong attractive force. If this force is stronger than the spring S_1 force that pushes the yoke away from the armature, the yoke will move to close the air gap. The mechanical link in turn will operate the contact arrangement. A cushioning spring S_2 is provided with the contacts to reduce the impulsive effect as the pole faces meet.

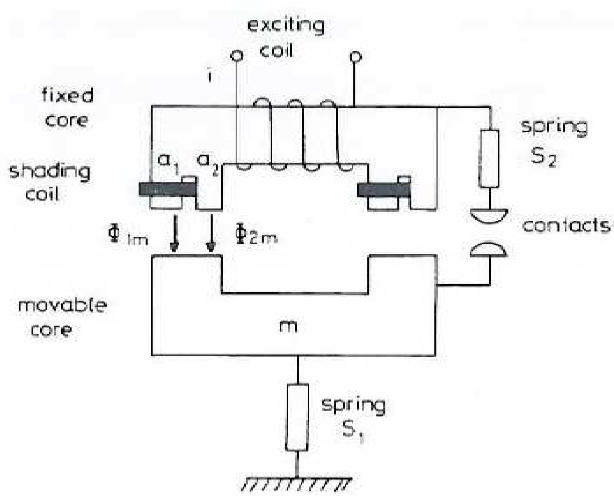


Figure 28: Basic arrangement of electromagnetic contactor [30], [29]

Where:

ø_{1m}, ø_{2m} = peak flux by shading ring and on pole face respectively;

a_1, a_2 = pole face areas at which flux ø_{1m} and ø_{2m};

S_1, S_2 = springs;

i = current;

m = moveable core.

The induced current in the shading coil causes flux ø_{1m} to lag the flux remaining in the pole face ø_{2m} by an angle θ. The electromagnetic force considering unidirectional and oscillatory aspects is:

$$F = \text{ø}^2_{1m}/(4\mu_0 a_1 \upsilon^2_1) + \text{ø}^2_{2m}/(4\mu_0 a_2 \upsilon^2_2) - \text{ø}^2_{1m}/(4\mu_0 a_1 \upsilon^2_1) \cos 2\omega t - \text{ø}^2_{2m}/(4\mu_0 a_2 \upsilon^2_2) \cos 2(\omega t-\theta) \quad (2)$$

Where:

υ_1, υ_2 = leakage factor for flux ø_{1m} and ø_{2m};

θ = phase angle between pole flux ø_{1m} and ø_{2m};

F = electromagnetic force;

μ_0 = absolute permeability;

d_1 = air-gap length.

When making $\text{ø}_{1m} = \text{ø}_{2m}$ and $\theta = \pi/2$, the oscillating components of the force will cancel and the noise generated by the contactor will be significantly reduced. When the yoke moves towards the armature, the air-gap length presented by d_1 decreases to zero. The flux ø_{1m} and ø_{2m} increases significantly, which results in stronger forces as the gap closes.

The force at a specific air gap is approximately proportional to the square of the voltage. No useful mathematical equation can be derived to represent the nonlinear variation of the leakage flux with the gap length variation during contactor closing. Experimental results indicate the relationship between the electromagnetic force and nonlinear variation of leakage flux during the closing operation. With reference to Figure 29:

- Curve 1illustrates the electromagnetic force at rated voltage;
- Curve 2 illustrates the electromagnetic force at reduced voltage;
- Curve 3 illustrates the combined opposing force of springs S1 and S2; and
- Curve 4 illustrates the electromagnetic force with recovery of supply voltage.

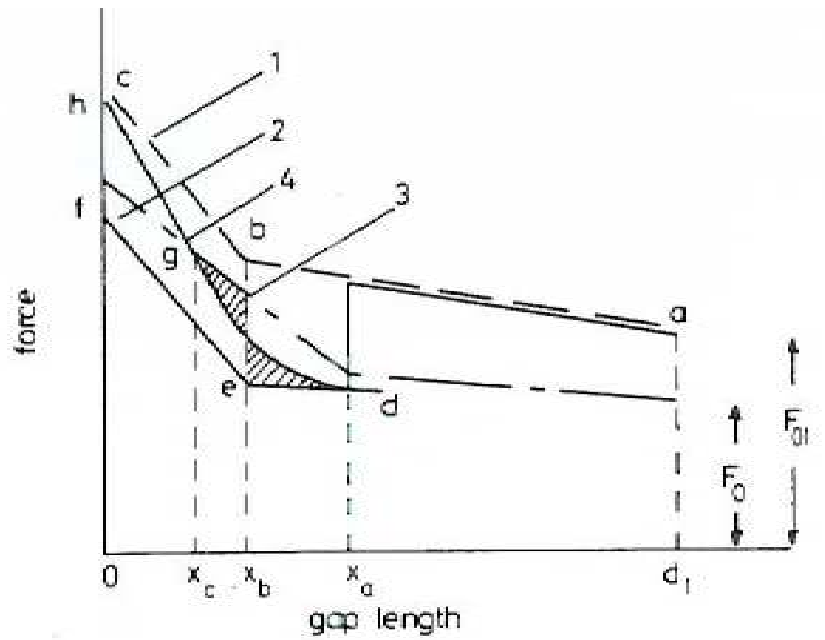


Figure 29: Force/air-gap length characteristic of an electromagnetic contactor [30]

Where:

d_1 = air-gap length in rest position;

x_a = air-gap length when electrical contacts meet;

x_b = air-gap length at break point of electromagnetic force characteristic.

At air-gap length x_a when the moving core pole face meets the stationary core face and the electrical contacts closes to allow starting current to flow to the electrical motor, the voltage at the supply dips and therefore the exciting coil supply also dips. The electromagnetic force produced is presented by the *def* curve (see Figure 29). The mechanical spring forces opposing the produced electromagnetic force cause the moving core to move at a reduced velocity until the air-gap length have reduced to point x_b. Due to the smaller air-gap length, the electromagnetic force increases and the moving core is accelerated forward again. If the moving contact velocity reaches zero before air-gap length position x_b, the spring force will be greater than the electromagnetic force and the contactor will re-open. This signifies the onset of contactor chattering and can continue until the voltage recovers. As the voltage recovers before the air-gap has completely closed, the electromagnetic force presented by curve *dgh* will increase to move the moving core to position x_c, at which the moving core velocity should be zero, presenting an adequately closed contactor. A secondary impact of contactor chattering is a sequence of very fast openings and closings of the main current-carrying contacts that generates electric arcs [27], [31], [32]. Effective arc extinguishing cannot be attained during contactor chattering, and erosion of the contacts will occur. The reliability of the contactor to start a motor can be jeopardized.

2.6.2.2 CONTACTOR BEHAVIOUR DURING VOLTAGE DIPS

The time it takes for a contactor to drop out depends on the current that flows in the coil when the voltage dip occurs and the place where the voltage cycle occurs in the voltage dip occurs [21], [25], [26], [27], [33].

Contactor voltage tolerance curves were drafted from a practical evaluation in a laboratory. They are illustrated in Figures 30 to 33. Figure 30 and Figure 31 illustrates the voltage tolerance curves, indicating the impact of the voltage dip magnitude and duration and the impact of the point-on wave when the voltage dip occurs. The area above the graph reflects the voltage dip and duration at which the contactor did not drop out (“pass”) and the area below the graph reflects the voltage dip and duration at which the contactor did drop out (“fail”). The difference between a voltage dip occurring at the voltage peak (indicated as V(90º)) and at voltage crossing zero (indicated as V(0º)) is as a result of the energy stored in the magnetic circuit. The stronger the magnetic field at the point on the voltage cycle when the voltage dip occurs, the more immune is the contactor. Due to the lagging power factor of the contactor coil (inductive), contactors are more sensitive to voltage dips occurring at the voltage peak when the lagging current is crossing zero. The power factor and lagging phase angle for different manufacturers and types of contactors deviates [25] and at the current crossing zero, the contactor will be the most sensitive to a short duration voltage dip.

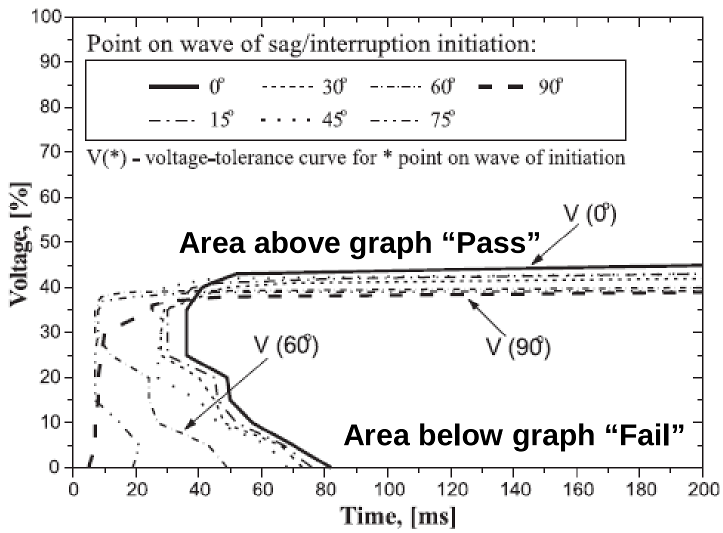


Figure 30: Influence of point-on-wave of dip initiation; indication of pass and fail area [21]

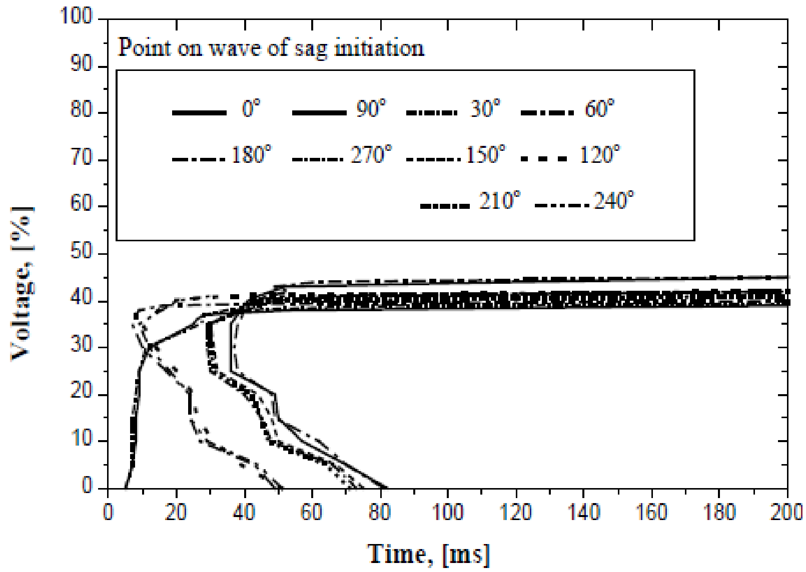


Figure 31: Illustration of quarter-cycle symmetry for point-on-wave influence [21]

Figures 32 and 33 illustrate that longer period voltage dip immunity at point-on-wave V(0º) is 5% to 10% more than a voltage dip occurring at point-on-wave V(90º).

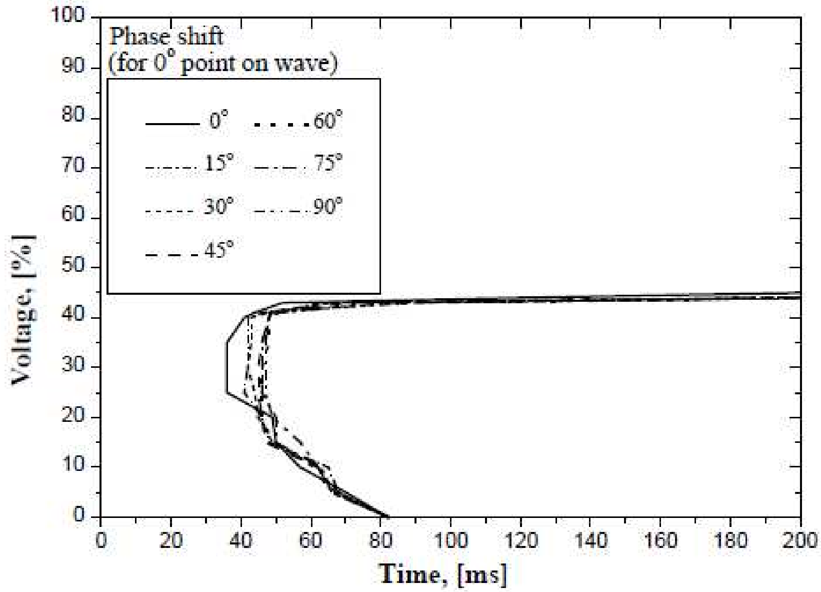


Figure 32: Influence of phase shift (0° point-on-wave) [21]

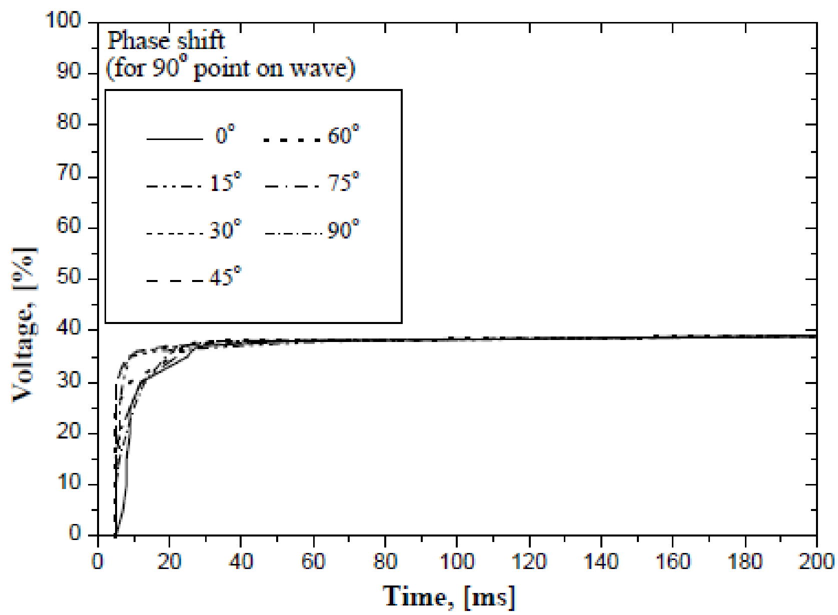


Figure 33: Influence of phase shift (90° point-on-wave) [21]

Figures 34 and 35 illustrate that a phase-angle-jump [10] on the contactor behaviour has less influence than the impact from point-on-wave. Figures illustrate the behaviour of contactors exposed to a non-rectangular, two-stage voltage dip of the same parameters for individual stages, but in different order. For the two-stage voltage dip illustrated in Figure 34, the contactor did disengage, but for the two-stage voltage dip illustrated in Figure 35, the contactor remained engaged, illustrating that the shape of the voltage dip can influence the behaviour of the contactor.

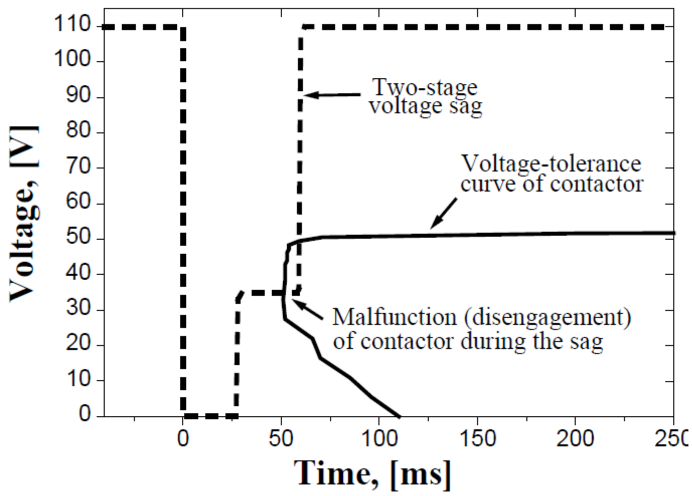


Figure 34: Influence of voltage dip shape on the sensitivity of AC-contactor – contactor disengages [21]

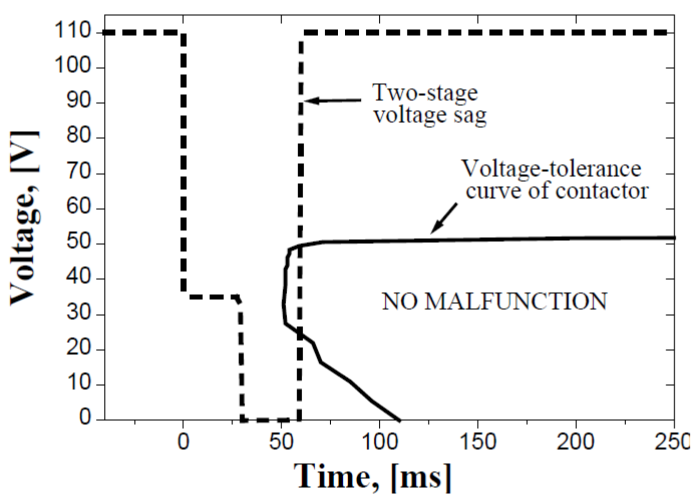


Figure 35: Influence of voltage dip shape on the sensitivity of AC-contactor – contactor remains engaged [21]

Figure 36 presents a comparison of the approximated voltage-tolerance curves for different contactors obtained from different surveys to illustrate the vast difference between contactors in the market. The area labelled as “pass” represents dips with magnitude and duration to which contactors are immune, and the area labelled as “fail“ represents dips for which contactors will disengage.

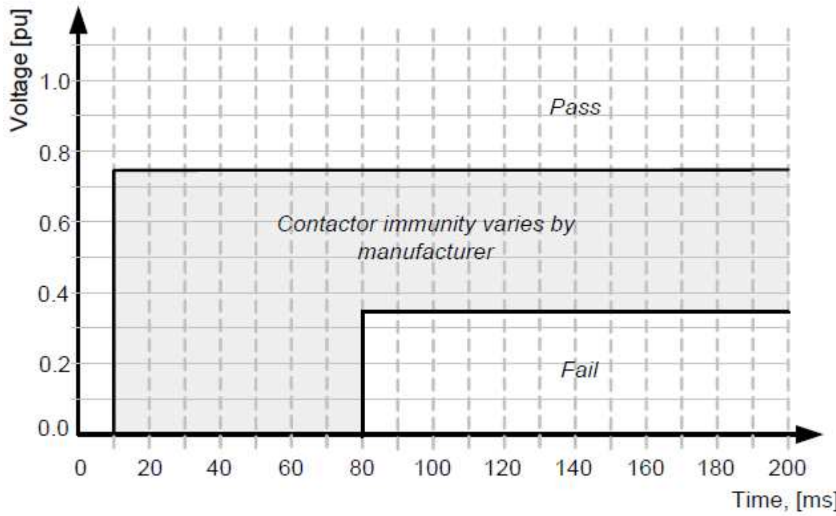


Figure 36: Best case and worst-case voltage-tolerance curves for AC-coil contactors from different manufacturers [15]

Figure 36 presents a comparison of approximated voltage-tolerance curves for different contactors obtained from different surveys to illustrate the vast difference between contactors in the market. The area labelled as “pass” represents dips with magnitude and duration to which contactors are immune and the area labelled as “fail“ represents dips for which contactors will disengage.

2.6.2.3 CONTACTOR POWER REQUIREMENTS

In order to evaluate the power requirements of an electromagnetic contactor, two configurations of the contactor must be considered. The first is closing operation of the contactor and the second the closed core [29] configuration. Measured data [29] for a 220 V AC and 60 Hz contactor for the two configurations, illustrated that the power consumption requirement to close the contactor is 15 times the power required for the closed core configuration. It is also evident that the power factor varies significantly from 0.82 to 0.1 [25].

Table 7: Measured data; (a) closing operation; (b) closed core configuration for closing operation configuration

Parameter	Unit	Value (a)	Value (b)
I_{rms}	mA	268	50.50
V_{rms}	V	218	222
P	W	48.3	3.2
Q	VA	33.10	10.90
S	var	58.60	11.40
pf		0.82	0.29
R_w	Ω	534	534

Table 8: Measured data for three different sizes contactors indicating the difference between the p.f. and power requirements for closed operation and closed core configuration [25]

Contactor size	Closing operation		Closed core configuration.		Drop-off voltage
	VA	cosΦ	VA	cosΦ	
Small (<50 A)	70	0.8	10	0.29	53%
Medium (50 A-200 A)	350	0.5	45	0.15	68%
Large >200 A	1750	0.5	125	0.1	65%

2.6.2.4 CONTACTOR CONTROL CIRCUIT INTERNATIONAL STANDARDS

The IEC standard 60947-1, 2007 [34], [28] stipulates under clause 7.2.1.2, titled “Limits of operation of contactors and power-operated starters”, that:

> *Unless otherwise stated in the relevant product standard, electromagnetic and electro-pneumatic equipment shall close with any control supply voltage between 85% and 110% of its rated value U_s and an ambient air temperature between –5 ℃ and + 40 ℃. These limits apply to DC or AC as appropriate. For pneumatic and electro-pneumatic equipment, unless otherwise stated, the limits of the air supply pressure are 85% and 110% of the rated pressure. Where a range of operation is given, the value of 85% shall apply to the lower limit of the range, and the value of 110% to the upper limit of the range.*

For electromagnetic and electro-pneumatic equipment, the drop-out voltage shall not be higher than 75% of the rated control supply voltage U_s, nor lower than 20% of U_s in the case of AC at rated frequency, or 10% of U_s in the case of DC.

The limits within which equipment with an electronically controlled electromagnet, shall drop-out and open fully, are:

- for DC: 75% to 10% of their rated control supply voltage U_s,
- for AC: 75% to 20% of their rated control supply voltage U_s, or 75% to 10% of their rated control supply voltage U_s if specified by the manufacturer.

In the case of coils, the limiting drop-out values apply when the coil circuit resistance is equal to that obtained at –5 ℃. This may be verified by a calculation based on the values obtained at normal ambient temperature.

The drop-out time may have to be specified for particular applications.

With reference to the latest revisions of IEC 60947-4-1, 2012 [28] standards applicable to contactors used within power plants, the characteristics of electrical and electronic control circuits are:

- type of current;
- rated frequency or DC;
- rated control circuit voltage U_c (AC, DC);
- rated control supply voltage U_s (AC, DC), where applicable;
- nature of external control circuit devices (contacts, sensors, optocouplers, electronic active components, etc);

– power consumption.

NOTE 1 In case of an electrical control circuit there is a distinction between the control circuit voltage U_c, which is the voltage that would appear across the "a" contacts (see 2.3.12) in the control circuit, and control supply voltage U_s. The control supply voltage U_s, which is the voltage applied to the input terminals of the control circuit of the equipment, may be different from the control circuit voltage due to the presence of built-in transformers, rectified, resistors, etc.

NOTE 2 In case of an electronically control circuit a distinction is made between the control circuit voltage U_c, which is the controlling input signal, and the control supply voltage U_s, which is the voltage applied to energize the power supply terminals of the control circuit equipment. The control supply voltage U_s may be different from U_c due to the presence of built-in transformers, rectifiers, resistors, electronic circuitry, etc.

The rated control circuit voltage and rated frequency, if any, are the values on which the operating and temperature-rise characteristics of the control circuit are based. The correct operating conditions are based on a control supply voltage value of not less than 85% of its rated value, with the highest value of control circuit current flowing at no more than 110% of its rated value.

The electronic part of an electronically controlled electromagnet may form an integral part or a separate part, provided it is an intrinsic function of the device. In both cases, the device should be tested with this electronic part mounted as in normal use.

Annex U gives examples and illustrations of different circuit configurations.

The ratings and characteristics of control circuit devices have to comply with the requirements of IEC 60947-5-1 [35] (see the note of Clause 1).

With reference to IEC 60947-5-1, the following are the characteristics of control circuit devices. Switching elements should be stated in these terms where such terms are applicable:

– type of equipment (see 4.2);
– rated and limiting values for switching elements (see 4.3);

– utilization categories of switching elements (see 4.4);

– normal and abnormal load characteristics (see 4.3.5);

– switching overvoltage (see 4.9).

2.6.3 INDUCTION MOTOR RESPONSE TO VOLTAGE DIPS

During the start of large motor drives at a power plant, the voltage within the electrical reticulation system is allowed to dip to an acceptable level. The motor drives connected to the same electrical reticulation system are exposed to the voltage disturbance that occurs during the start of large motor drives. The maximum allowable voltage dip level determines the lowest voltage at which motor drives are required to continue operation. This maximum volt drop determines a voltage disturbance resilience level as part of the power plant design.

The section analyses the effect of a voltage disturbance within the electrical reticulation system and the response of motor drives to evaluate resilience against disturbances as defined by GCR 9.

Power plant design start-up is a systematic process of starting up sub-groups of the process. Individual circuits are designed accordingly. The collective starting current drawn by the motor drives following a voltage disturbance can exceed the feeder circuit current rating, causing the protection to operate and interrupting the process.

2.6.3.1 EFFECT OF VOLTAGE DIPS ON DOL INDUCTION MOTORS

When the supply voltage to the induction motor dips, the speed of the motor decreases and this results in current and torque fluctuations. Depending on the motor drive torque-speed characteristics, the magnitude and duration of the voltage dip determines if the induction motor can recover when the voltage amplitude recovers. If the voltage dip magnitude and duration exceed the limits for the specific motor drive, the motor can stall and the protection is set to interrupt the supply. The acceleration process of the motor following a voltage dip is dynamically similar than that of a motor starting with large inrush currents. Depending on the voltage magnitude and duration during and after the voltage dip and the protection settings, the supply to the motor can be tripped.

2.6.3.2 FACTORS DETERMINING THE BEHAVIOUR OF INDUCTION MOTORS

The following factors determine this behaviour [36], [26].

2.6.3.2.1 FAULT VOLTAGE DIP AND VOLTAGE RECOVERY

The voltage dip and recovery following an electrical fault on the electrical reticulation system depend on:

- the location of the fault;
- the type of fault;
- the fault clearance time, and
- the electrical system configuration and loads.

A solid three-phase fault (Type III [10]) results in the worst case of instability, causing the voltage to be reduced to zero until the protection has cleared the fault, followed by a two-phase-to-ground fault, then phase-to-phase, and lastly phase-to-ground. The reserve or spinning power-generating capacity [37] and the back-generation dependant on load dynamics [14] of the motors connected to the electrical reticulation system affect the voltage drop, voltage recovery, dependant on fault impedance and recovery. Voltage swing will occur before the voltage recovers to normal. This is more evident in cases where the fault is cleared quickly, while there is a longer and more gradual recovery for more sustained faults (see Figure 38). Figure 37 indicates the voltage dip and recovery following an electrical three-phase fault cleared after 8 cycles and 24 cycles respectively. Figure 39 indicates the RMS-voltage-per-phase graphs for a fault-caused voltage dip with a longer voltage recovery due to motor load.

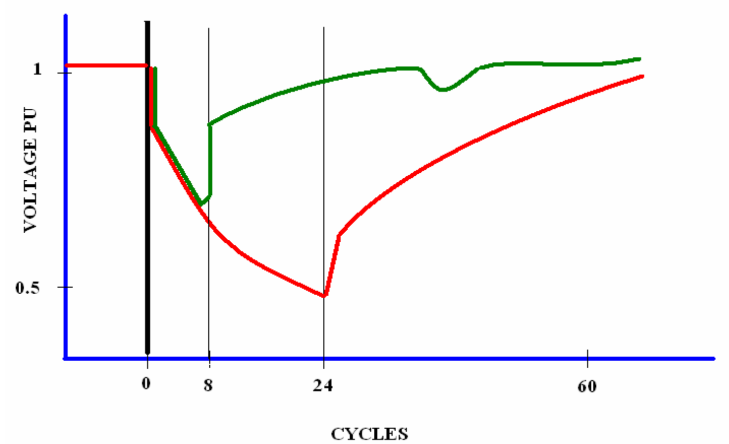


Figure 37: Voltage dip and recovery following an electrical fault cleared after 8 cycles and 24 cycles respectively [36]

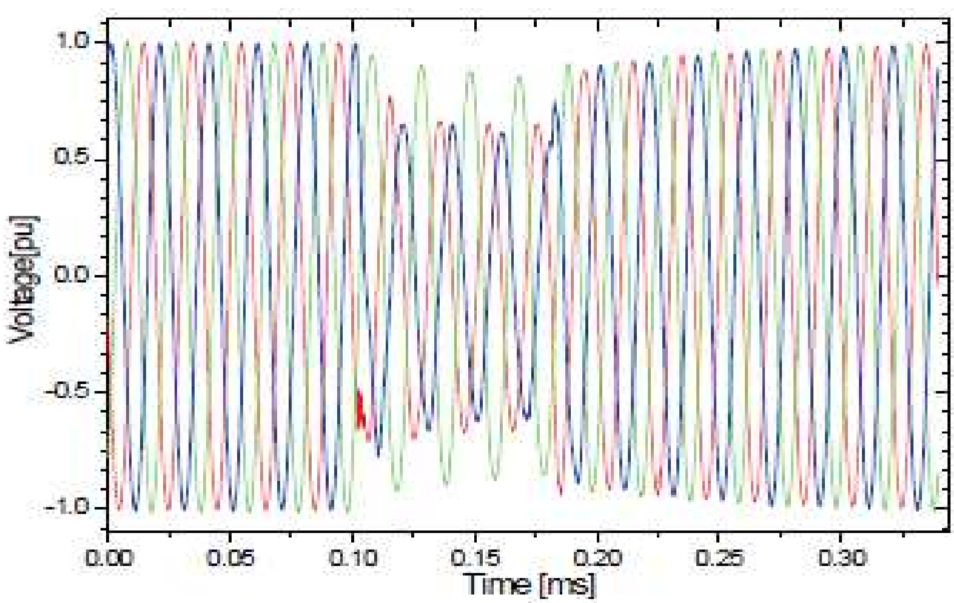


Figure 38: Typical fault-caused voltage dip with a longer voltage recovery due to motor load – instantaneous voltages [15]

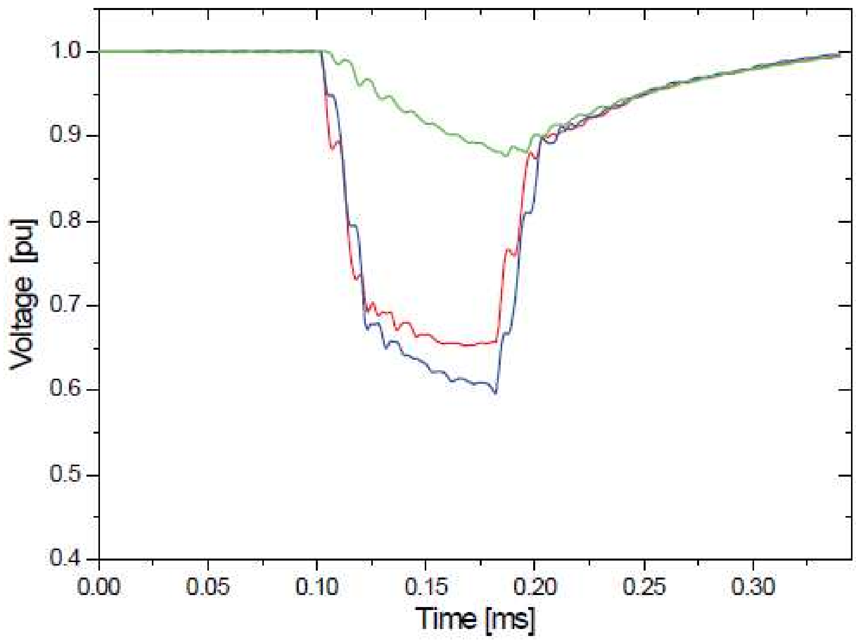


Figure 39: Typical fault-caused voltage dip with a longer voltage recovery due to motor load RMS voltages [15]

2.6.3.2.2 MOTOR SPEED LOSS

The steady-state characteristic of an induction motor at the point of the voltage dip holds that the motor torque reduces proportionally to the square of the motor terminal voltage [38]. The slip increases with an increase in the line current. Loads with low-inertia constant torque characteristics have significant speed loss over time and stall. Loads with high inertia and the load torque varying as a function of the speed, have less speed loss and may be able to recover (see Figure 40). Although the motor can recover, the process requirements and parameters for a start-up may not be valid.

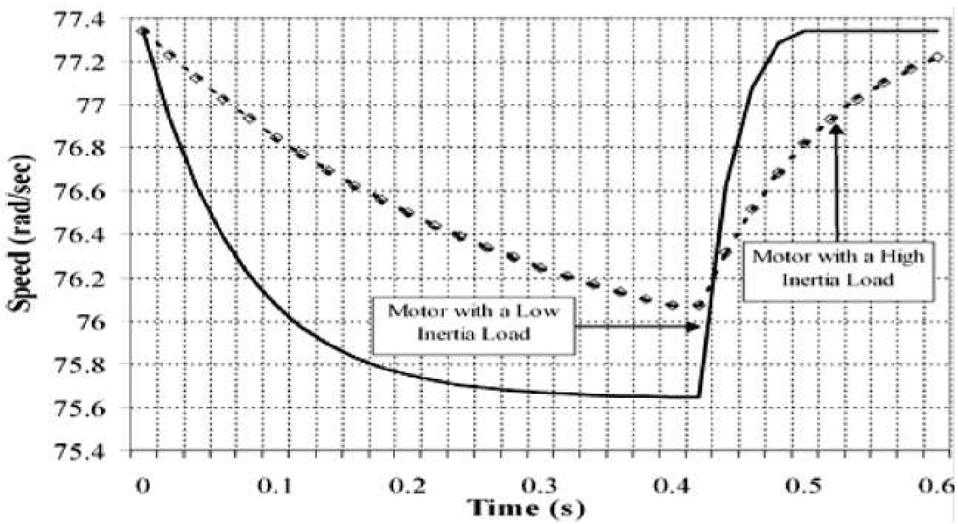


Figure 40: DOL IM speed change with respect to high and low load inertia [39]

Asymmetrical dips (Type I and II [10], [17]) also result in speed loss and current and torque fluctuations. The current and torque peaks are dependent on the point-on-wave of dip initiation and the torque is oscillatory during the dip [39]. The speed reduction is typically less than for balanced symmetrical voltage dips (see Figure 41).

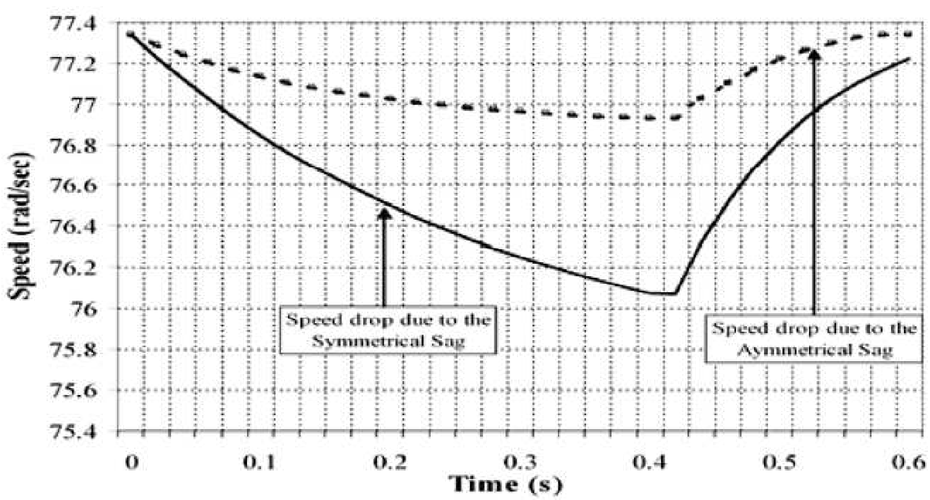


Figure 41: Induction motor speed change with respect to balanced and unbalanced dips [39]

2.6.3.2.3 MOTOR ACCELERATION

Depending on the motor drive torque-speed characteristics, the magnitude and duration of the voltage dip determine if the induction motor can recover when the voltage amplitude recovers. If the voltage dip magnitude, or duration, or both exceed the limits for the specific motor drive, the motor can stall, and depending on the protection settings, this can interrupt the supply. The acceleration process of the motor following a voltage dip is dynamically similar to a motor starting with large starting currents [40]. The starting currents required to accelerate the load can be insufficient to ensure a fast recovery due to the supply current being limited as a result of the supply impedance. If the available power is much greater than the required power for re-acceleration, the recovery is faster. Depending on the voltage magnitude, or duration, or both during and after the voltage dip and the protection settings, the supply to the motor can be tripped. Depending on the electrical motor and load characteristics and protection settings, the response, i.e. speed drop and recovery, meaning acceleration or stall, will be different [13] when exposed to the same voltage dip. As the motor loads, which can re-accelerate pass through the breakdown torque points [38], the currents drawn will reduce.

2.6.3.2.4 TRANSIENT CHARACTERISTICS

During a sudden change in the supply voltage, sub-transient and transient electrical phenomena can occur in the induction motor. During a voltage dip, the induction motor feeds back into the supply or fault due to the trapped magnetic flux [38]. The lagging reactive power drawn by the motor will suddenly be reduced and the voltage recovery is delayed by the load dynamics, especially in the absence of available reactive resources [14], [17], [41].

The following observations are based on simulated data [40] of a three-phase short circuit cleared after 150 ms and normal supply available thereafter:

- The flux decayed rapidly to below 30% after 100 ms (see Figure 42);
- The torque decayed rapidly with negative peak up to 4 times p.u. torque and current transient peaks up to 5 times the p.u. current (see Figure 43 and Figure 44 respectively);

- At the point prior to supply recovery, the remaining flux in the motor was negligible and motor speed reduction of approximately 10% (see Figure 42 and Figure 43 respectively);
- A rapid torque decay with negative peak up to 4.0 times p.u. was noticed (see Figure 43);
- The transient torque following supply recovery is relatively small, but the transient current was in excess of 5.0 times p.u. (see Figure 44).

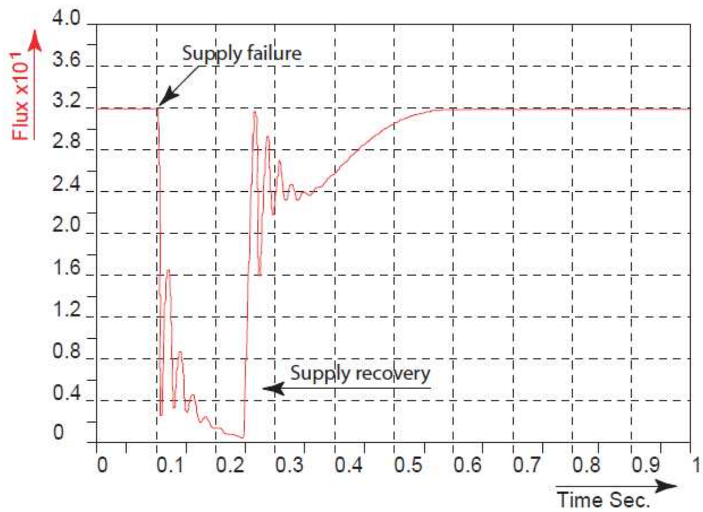


Figure 42: Motor flux (p.u.) during supply failure, motor remains connected to the supply [40]

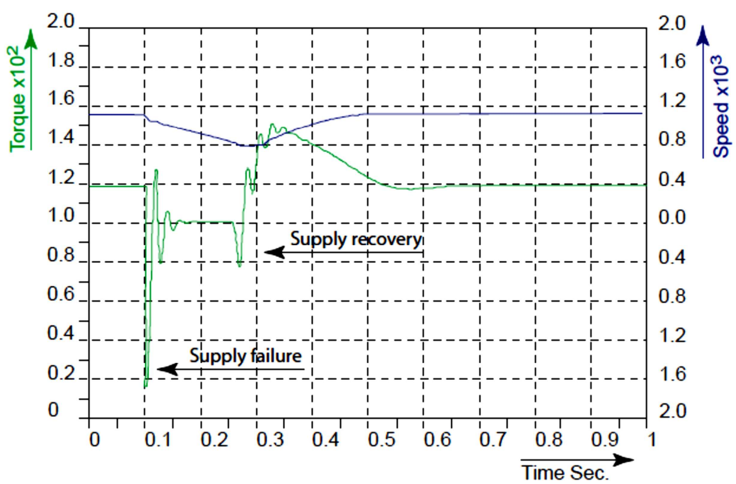


Figure 43: Motor torque (p.u.) and speed during supply failure, motor remains connected to the supply [40]

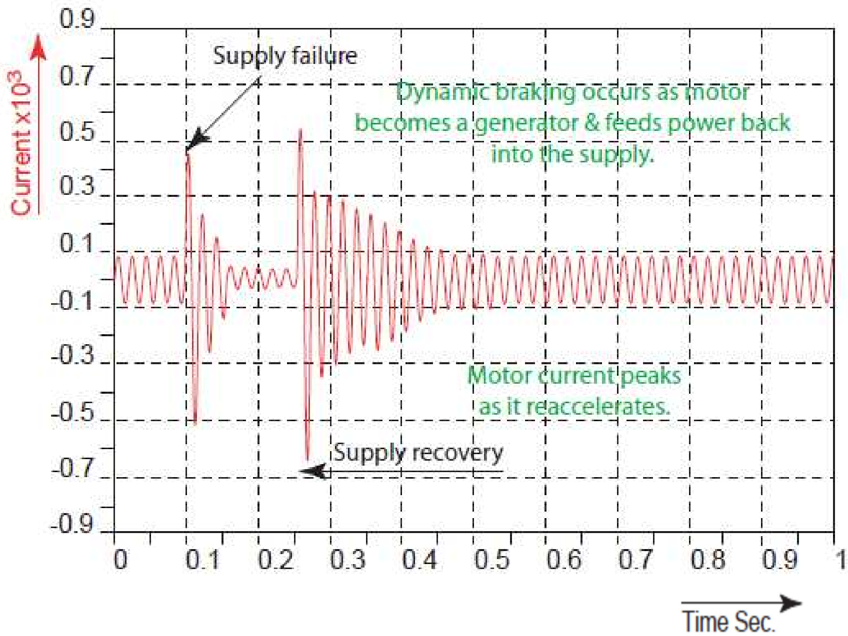


Figure 44: Motor current (p.u.) during supply failure, motor remains connected to the supply [40]

The transient currents and torques will mechanically stress the motor insulation in the overhang, strain the drive shaft and the foundations, but this is no more severe than normal direct on-line starting.

2.6.3.2.5 RECLOSING AND AUTOTRANSFER OF POWER

To prevent interruptions in the operations, automatic transfer schemes have been implemented according to which the power supply feed is quickly transferred from the normal supply to an alternative supply [40]. A fast reclosing philosophy can also be implemented to limit the transients. Data from a case where the same size motor as above is disconnected from the supply and reconnected after 280 ms when the residual voltage is of opposite phase reveals that the decay in flux (see Figure 45) is much slower and the electromagnetic torque of the motor becomes zero at the point of disconnection (see Figure 46). At the point of transfer to alternative supply, a large negative peak torque of 8.8 p.u. was seen. Due to the alternative supply being out of phase, a large current transient of 12.9 p.u. was seen for a short period. The high transient torque pulses can cause serious mechanical damage to the drive train.

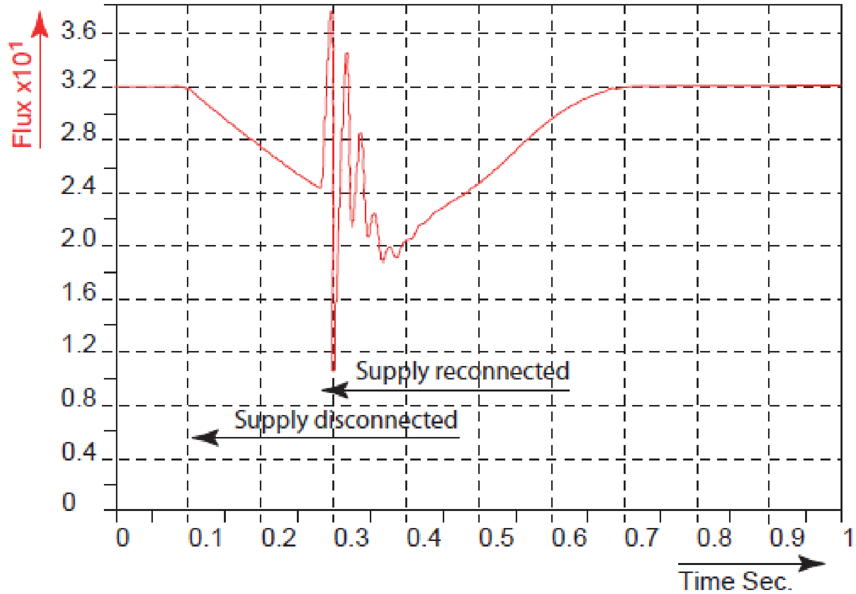


Figure 45: Motor flux (p.u.) during supply failure – the motor is disconnected from the supply during the interruption [40]

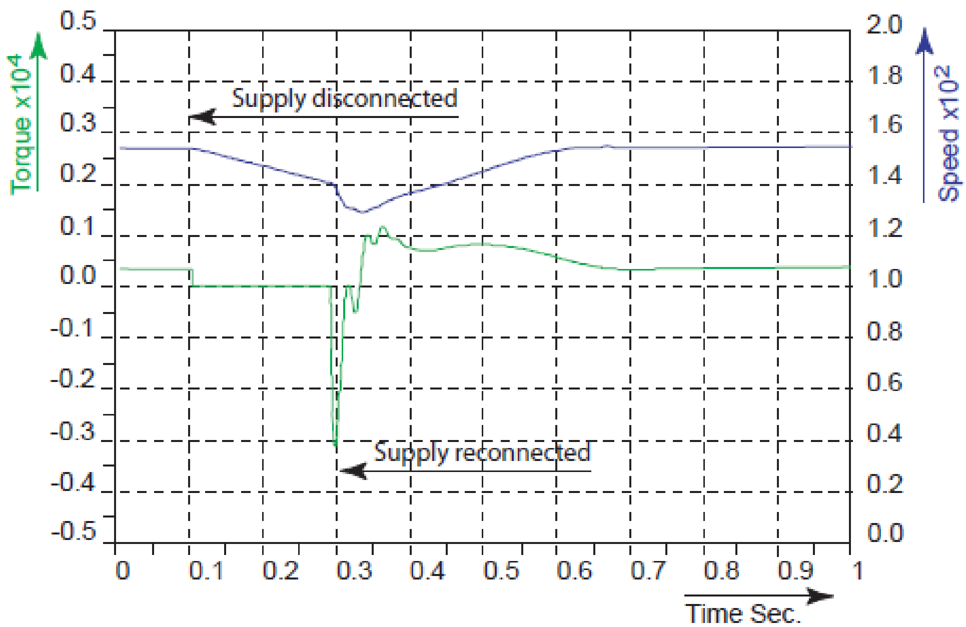


Figure 46: Motor torque (p.u.) and speed variation during a supply failure – the motor is disconnected from the supply during the interruption [40]

One could consider a fast reclosing philosophy where the contactor drops out after 1 cycle following a three-phase short circuit fault and recloses after 280 ms to a healthy supply. The flux decays rapidly to 0.2 p.u. at the point of contactor drop-out and recovers to 1.6 p.u.

thereafter (see Figure 48). During the open circuit period the flux continues to decay, but with a slower time constant. At the point of re-connection, the flux in the motor is lower than for the auto-transfer case above. The rapid decay torque negative peak associated with the short circuit is still evident (see Figure 49). A rapid decay torque negative peak is also seen during supply re-connection. A current transient in excess of 7.0 p.u. is drawn after the supply is reconnected (see Figure 50).

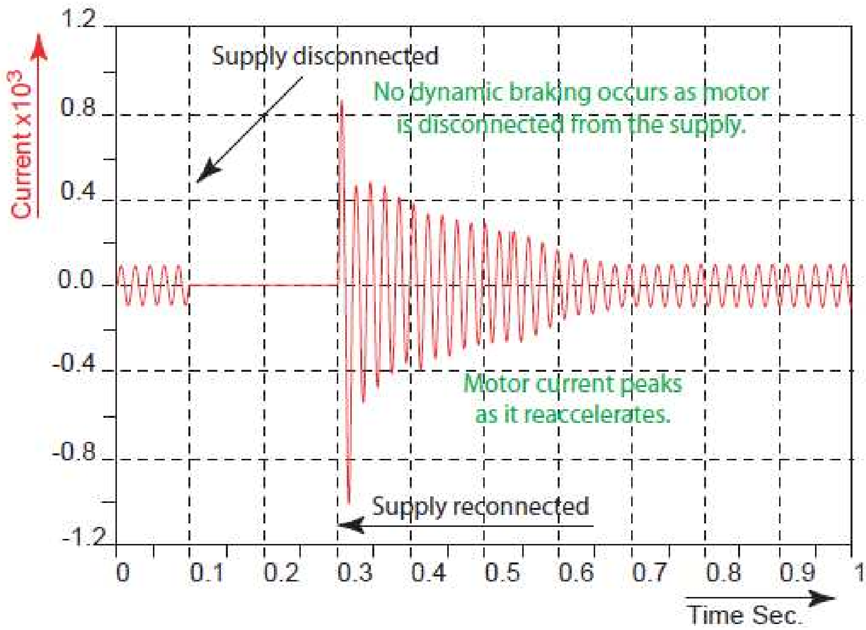


Figure 47: Motor current (p.u.) during supply failure – the motor is disconnected from the supply when the contactor drops-out after one cycle and is reconnected after 280 ms [40]

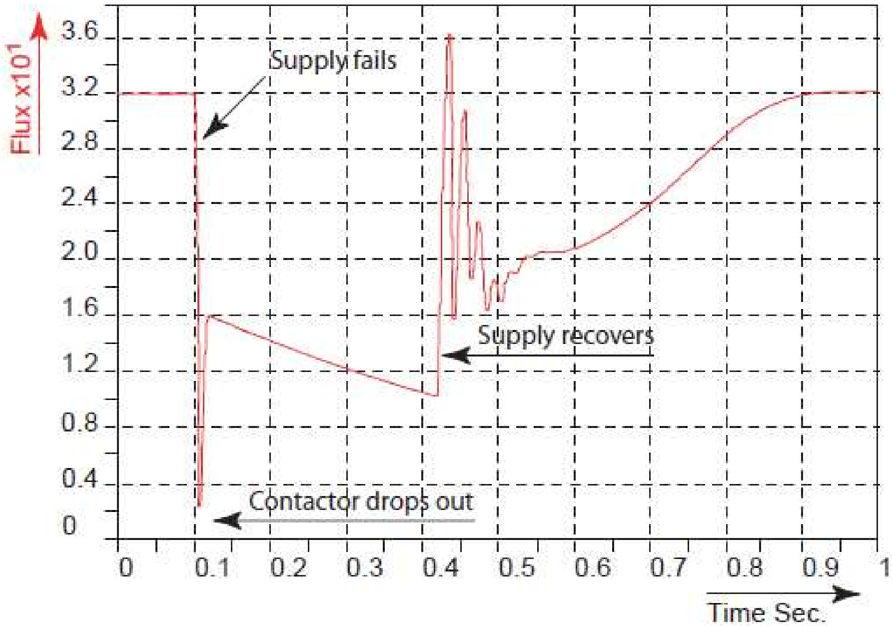


Figure 48: Motor flux (p.u.) during a supply failure – the motor is disconnected from the supply when the contactor drops out after one cycle and is reconnected after 280 ms [40]

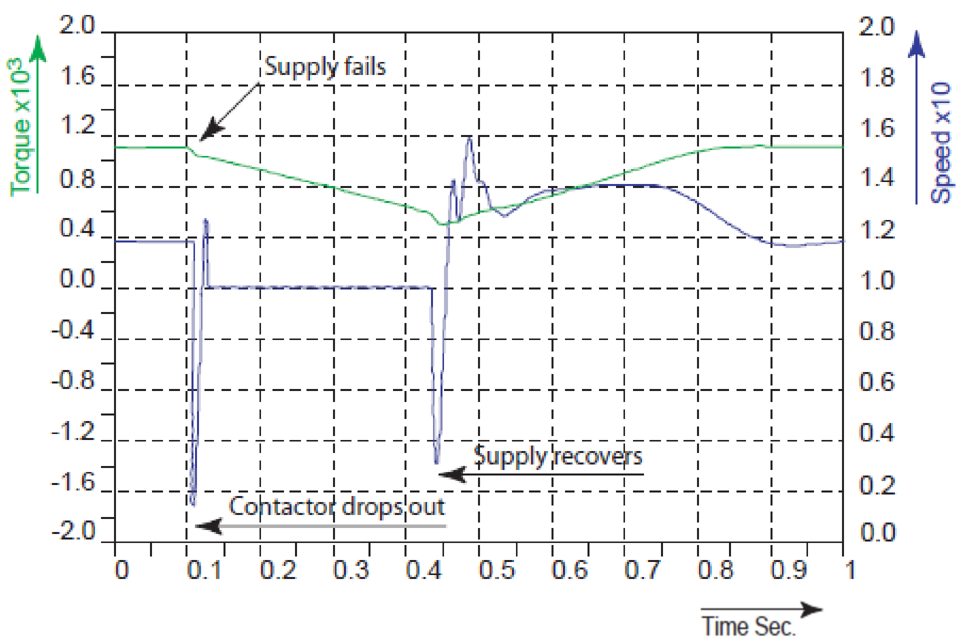


Figure 49: Motor torque (p.u.) and speed variation (p.u.) during supply failure – the motor is disconnected from the supply when the contactor drops out after one cycle and is reconnected after 280 ms [40]

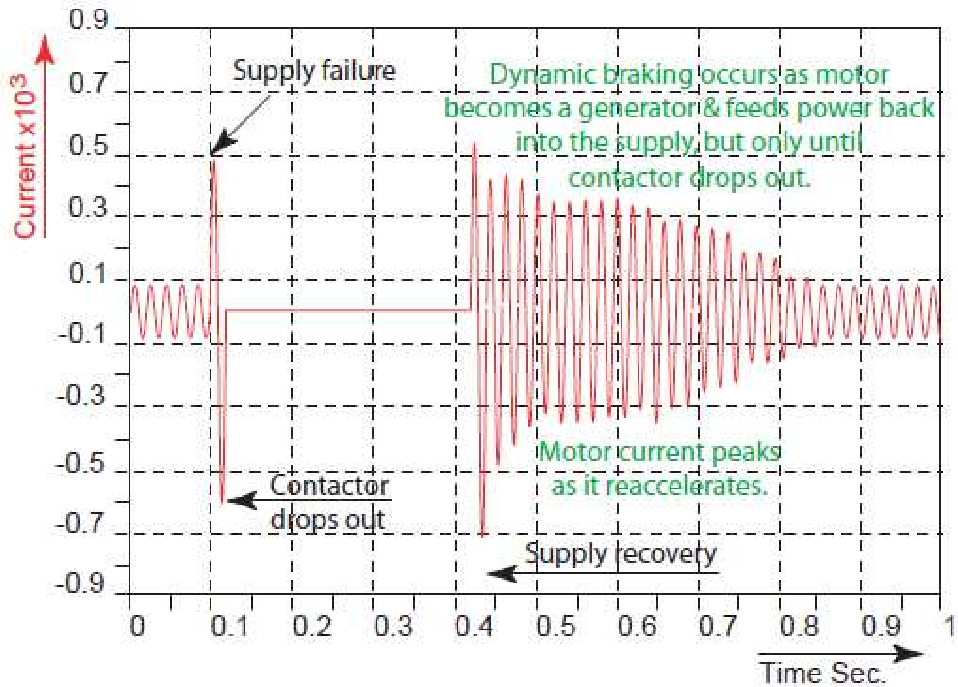


Figure 50: Motor current (p.u.) during supply failure – the motor is disconnected from the supply when the contactor drops out after one cycle and is reconnected after 280 ms [40]

2.6.4 VARIABLE SPEED DRIVES

A variable speed frequency drive (VSD) controls the torque or speed of an induction motor by converting the fixed supply frequency and voltage to an adjustable frequency and voltage. The VSD consists of a rectifier producing DC onto a DC bus equipped with capacitors and an inverter. The behaviour of a VSD during a voltage dip depends on the hardware topology, the control algorithm and load conditions.

Figure 51 illustrates the voltage tolerance curve of an open loop (volt/hertz) controlled VSD during a symmetrical voltage dip. The DC bus capacitors will discharge to maintain the voltage for a period, which is a function of the loading conditions. The VSD will trip if the voltage decays below the set minimum voltage. VSDs with a simple control algorithm and poor hardware topology will not compensate for the voltage dip and the motor will be exposed to reduced voltage and therefore develop lower torque. An open loop control VSD will not correct the motor speed and at voltage recovery, the capacitors will recharge, drawing high currents that can cause line overload protection. The VSD will draw high currents to accelerate the motor, causing the VSD overload protection to operate. Field-oriented control schemes are utilized to compensate for a voltage dip and to prevent VSD overload protection to operate. A VSD can compensate for the speed reduction as part of closed loop control by increasing the frequency of the applied motor voltage, provided the available torque is higher than the load torque [42].

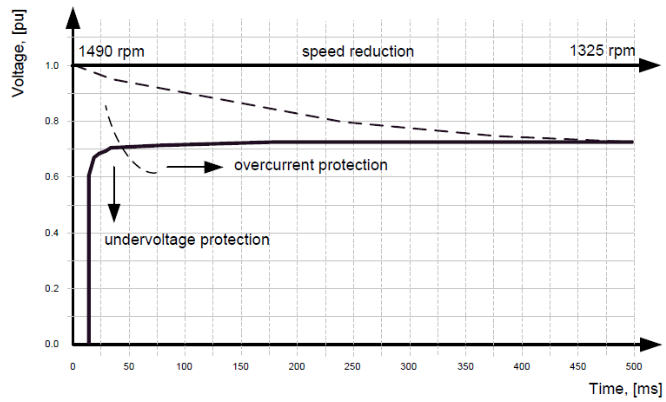


Figure 51: Voltage tolerance curve and speed reduction for an open loop control VSD subjected to symmetrical voltage dips [42]

Figure 52 illustrates the impact mechanical loading has on the VSD immunity for symmetrical voltage dips. During lower load requirements, the energy the motor requires during the dip will be lower and the DC bus voltage decay will be slower to reach the undervoltage limit. In contrast, as the load decreases, the ripple on the DC bus decreases and the horizontal line on the voltage tolerance curve approaches the undervoltage setting value. The undervoltage protection setting value is dependent on the DC bus voltage prior to the voltage dip. The time it takes to trip is dependent on the load condition, the DC bus voltage prior to the voltage dip and the undervoltage setting value. This is approximated by the following formula [15]:

$$t_{trip} = C(U^2_{dc\ pre\text{-}dip} - U^2_{dc\ min})/2P \qquad (3)$$

$U_{dc\ pre\text{-}dip}$ = DC bus voltage prior to dip

$U_{dc\ min}$ = undervoltage setting value

C = DC bus capacitance

P = electric power required to drive the load

t_{trip} = time to trip

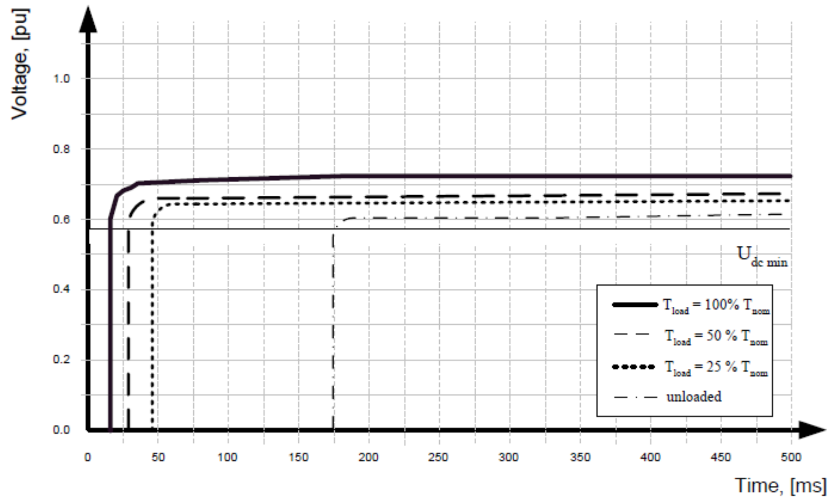


Figure 52: Impact on VSD immunity for different loading conditions for symmetrical voltage dips [42]

Figure 53 illustrates the impact of different load profiles and Figure 54 shows motor speeds on the voltage tolerance curve and variances in VSD dip immunity due to different load requirements.

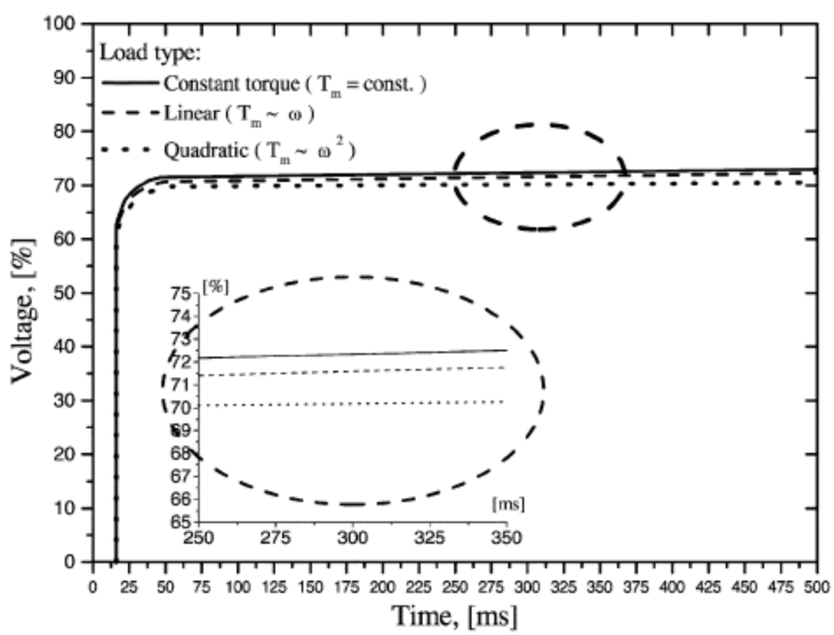


Figure 53: Impact of different loading requirements on VSD immunity for symmetrical voltage dips [42]

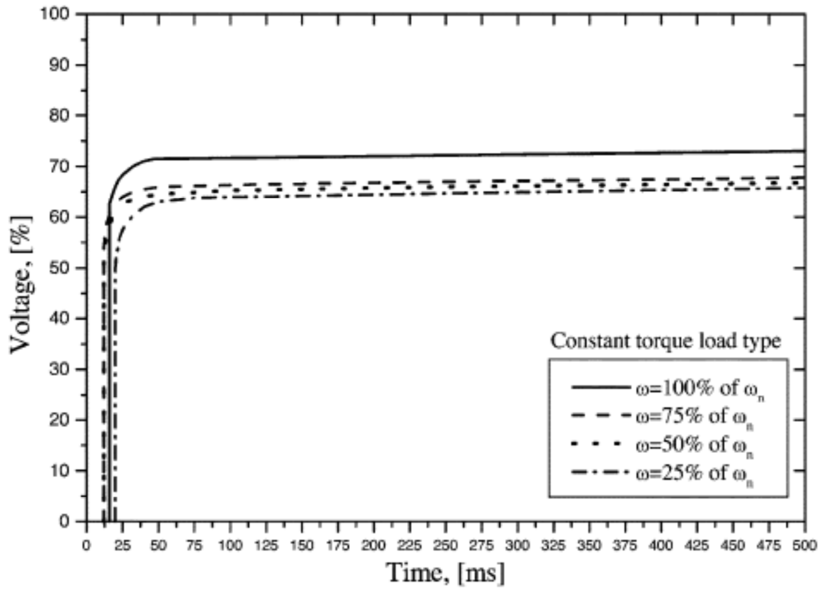


Figure 54: Impact of different motor speeds on VSD immunity for symmetrical voltage dips [42]

In order to improve the ride-through capability of a VSD during a voltage dip, additional inductance may be required to limit the capacitor charging currents at voltage recovery [43], [44].

For asymmetrical voltage dips (Type I and Type II), depending on the voltages during the dip, the DC bus capacitors may be charged. During a Type I voltage dip the three-phase rectifier will react as a single-phase rectifier and the DC bus is charged at twice the supply frequency. The DC bus ripple will increase and different currents will flow through the full-bridge rectifier [45]. Provided the voltage does not decrease to the undervoltage setting value, the VSD can ride-through the voltage dip. The behaviour is dictated by the DC bus capacitance and undervoltage setting value. Although the overload protection of the drive may not have been activated, other protection functionality like phase loss protection can trip the drive. Figure 55 illustrates the impact of total harmonic distortion prior to the voltage dip on the VSD immunity [46]. The effect is less resilience against a voltage dip from the voltage tolerance curve. Measurements on a drive confirmed the simulated results [42]. During asymmetrical voltage dip conditions, the power requirements are transferred to the phase with the highest remaining voltage, resulting in increased currents. Further voltage reduction can be experienced at the equipment terminals, depending on the source impedance.

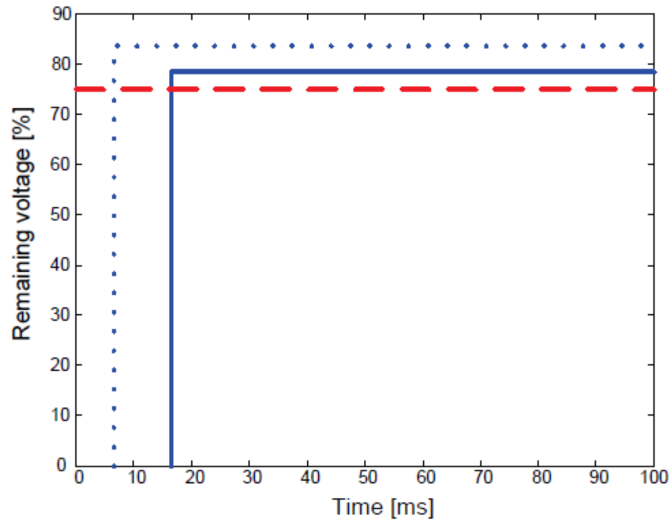


Figure 55: Simulated voltage-tolerance curves for both sinusoidal (solid line) and non-sinusoidal pre-dip supply voltage with THD = 3.5% (dotted line) with reduced pre-dip voltage magnitude [43]

Figure 56 and Figure 57 illustrate the impact of asymmetrical voltage dips on a VSD. Figure 56 illustrates the voltage tolerance curve for a scenario (Type I unbalanced dip) with a large voltage reduction in one phase-to-neutral voltage. The magnitude of the other two phases voltages are varied, worsening the immunity. Figure 57 illustrates the voltage tolerance curve for a scenario (Type II unbalanced dips) with a large voltage reduction in two phases, phase-to-neutral voltages. The magnitude of the other phase-to-neutral voltage is varied.

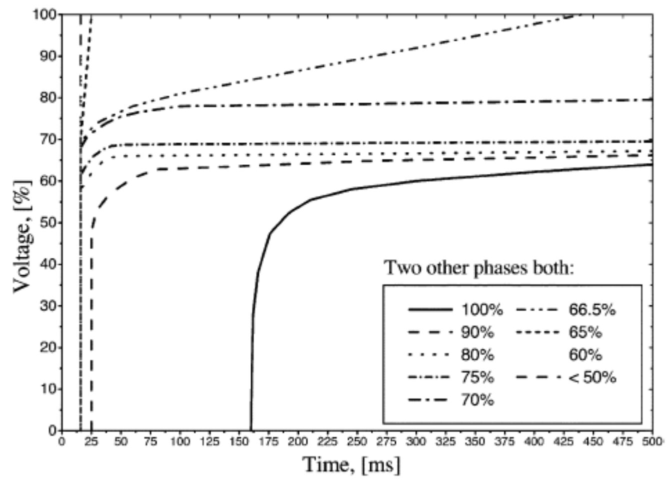


Figure 56: Voltage-tolerance curves of ASD for Type I unbalanced dips (with reduction in one phase-to-neutral voltage); voltage in two other phases [42]

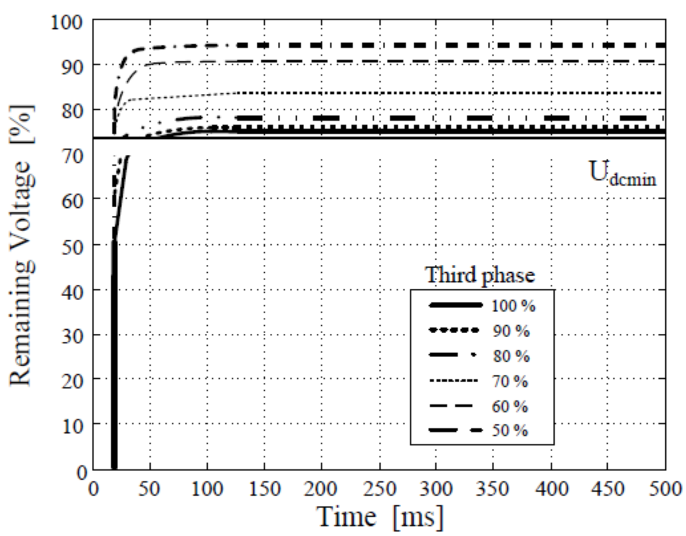


Figure 57: Voltage-tolerance curves of ASD for Type II unbalanced dip (with reduction in two phase-to-neutral voltages); voltage in the third phase is the additional parameter [42]

Kinetic buffering with the use of high inertia loads can be implemented to improve the inertia ride-through capability of the VSD [47] if the process can tolerate a speed reduction.

Active front-end (AFE) IGBT rectifiers [48], [44] can be added to the VSD, resulting in sinusoidal line currents and a facility to regenerate energy back into the supply. The VSD is energized as a passive diode rectifier and the IGBTs are enabled. The rectifier regulates the DC bus voltage during a voltage dip, provided the AC line currents remains below the current limit of the rectifier. Overload or loss of synchronization can trip the VSD [48]. During loss of synchronization the IGBT pulses are disabled and the rectifier operates in a passive mode. During a VSD trip as a result of a voltage dip, the motor control is released to allow free spinning. Following voltage recovery, the drive can be activated manually or automatically. If the motor is still spinning, the automatic restart has to detect the speed of the motor in order to synchronize. Without motor speed sensors, the restart can take up to several seconds.

2.6.5 CONTROL EQUIPMENT

Control equipment such as programmable logic controllers (PLC) or distributed control systems (DCS) are used to control industrial processes. A typical PLC or DCS will consist of a power supply, central processing unit (CPU) and digital and analogue input/output (I/O) modules. The inputs are processed by the software hosted in the CPU, from which outputs are generated to perform process control functions. Field instruments are normally not powered from the PLC or DCS. If a voltage dip occurs that is larger than the equipment can tolerate, the process operation must be shut down in a controlled way. In order to ensure the required dip immunity, robust power sources must be provided, typically in the form of UPSs.

2.6.6 PROTECTION

The South African Grid Code in terms GCR 9 [2] stipulates the external supply disturbance withstand capability for any unit or power station connected to the IPS. The protection settings applied at a power plant contributes to achieving this objective. Protection settings that are too conservative in terms of protecting equipment and plant will segregate the plant equipment that is required to maintain the process for power generation. Voltage support during supply disturbances as a result of the back EMF from the motor drives will be interrupted when the protection has operated.

The settings used within protection relays are essential to ensure adequate protection of the plant, but should not interrupt plant processes unnecessary. Coordination between the incoming supply, transformer, MV switchgear and motor protection relay settings is required.

The following points are of importance:

- the coordination of electrical protection relay settings with the dynamic currents, which will flow when the voltage recovers after a voltage dip;
- the undervoltage relay settings and their associated timers on the entire plant should be coordinated to ensure maximum plant availability during a voltage dip without exceeding the capability of the equipment;
- the selection of appropriate undervoltage curves to ensure optimal equipment performance.

2.6.6.1 MV AND LV PROTECTION PHILOSOPHY FOR POWER PLANTS

A review of the implemented MV and LV protection philosophy is needed to analyse the operation and expected response of a power plant and to evaluate compliance to GCR 9 [49].

2.6.6.2 UNDERVOLTAGE

During an extended three-phase undervoltage condition, the protection is configured to trip all motor feeder circuits. Fuse fail protection is also provided. This philosophy is required to prevent reacceleration of motors while running down to prevent shaft overstressing, prevent overloading and tripping of upstream circuits as a result of the motors drawing starting current during simultaneous reacceleration.

Typical settings:

- Undervoltage = 0.70 x nominal voltage;
- Time delay = < 3 s.

2.6.6.3 INSTANTANEOUS OVERCURRENT PROTECTION

It is required that instantaneous overcurrent protection be provided on all MV motors to protect against phase-to-phase faults. This protection is required to operate instantaneously.

Typical settings:

- Instantaneous overcurrent pick-up = 1.10 to 1.50 x starting current.

2.6.6.4 EARTH FAULT PROTECTION

Each MV motor should have earth fault protection. No grading with any other protection is required, but a short time delay is used to prevent incorrect operation due to third harmonics during motor starting. A stabilizing resistor is required when the earth fault current is limited.

Typical settings:

On solidly grounded systems:

- Current pick-up = 0.10 to 0.40 x full load current;
- IDMT time multiplier = 0.10 to 0.20 or
- DT delay = 0.1 s to 0.3 s.

On resistance grounded systems:

- Current pick-up = 0.10 to 0.40 x fault current;
- DT delay = 0.2 s to 0.5 s.

2.6.6.5 NEGATIVE PHASE SEQUENCE PROTECTION

Each MV motor will have negative phase sequence protection and the motor capability will be specified by the motor manufacturer. The requirement of negative phase sequence protection is to safeguard the motor rotor against overheating. An inverse time characteristic is representative of thermal overload for negative phase protection and a definite time characteristic for single phasing.

Negative phase sequence currents result from asymmetrical faults or unbalanced system conditions. Motor negative phase sequence protection must be graded with the generator negative phase sequence protection and the undervoltage protection. Long-term current unbalance is therefore not considered.

Typical settings:

- NPS IDMT current pick up = 0.10 to 0.20 x full load current;

- Time multiplier = 0.10 to 0.50;
- Single-phasing time = 1.0 s to 2.0 s (this must be graded with the undervoltage protection).

2.6.7 LV MOTOR UNDERVOLTAGE PROTECTION PHILOSPHY

The LV motor undervoltage protection philosophy implemented at power plants states that undervoltage detection can be done in three ways:

- Three-phase undervoltage protection is required to trip all motor feeder circuits if an undervoltage condition occurs.
- Dip proof inverters that will sustain the control supply for 1 s during short voltage interruptions and voltage dips and after the 1 s interrupts the supply if the line voltage did not recover can be installed, or
- In the case of a voltage dip or short supply interruption, a signal from the distributed control system (DCS) must de-energize the contactors if the line supply is not restored within 1 s.

This is required to prevent motor re-acceleration while running down causing shaft overstressing, preventing an overload condition from occurring and tripping the upstream circuits due to all on-line motors drawing close to start-up currents simultaneously.

Typical settings:

- Undervoltage = 0.70 x nominal voltage;
- Time delay = < 1.0 s.

2.7 SYNCHRONOUS GENERATOR AND SUBSYSTEMS

The synchronous generator will experience disturbances that originate in the IPS and this will cause a sudden change of the stator winding voltage and load demand. The potential risk is that the synchronous generator can experience a pole slip and severe mechanical stresses [38].

The requirement from the South African Grid Code is that the synchronous generator remains in synchronism and connected to the IPS during disturbances as stipulated in GCR 9.

The following aspects of generators and sub-systems are evaluated in section 2.7:

How are generators and its subsystems affected by voltage dips?

a Transient stability of the generator;

b Generator protection functions can trip, segregating the generator from the IPS, e.g. overvoltage, loss of field and NPS current protection;

c Excitation system limiters can impede the voltage support from the generator, respond to three-phase (positive sequence voltage dips) only. Single-phase dips will not see AVR respond;

d Contactors on subsystems can drop-out due to voltage dips, interrupting the supply and potentially the process, e.g. inside the AVR/governor/small pumps e.g. aux lube oil. Contactors and the potential impact on the process were evaluated in section 2.6.2.

How can the generator aid the recovery of the power plant during and after a voltage dip?

a AVR action to distant short circuits;

b Different types of AVR can improve response, e.g. evaluating static and rotating AVRs, and self-excited (static exciters) vs separately excited (brush and brushless exciter) systems.

2.7.1 TRANSIENT STABILITY OF SYNCHRONOUS GENERATORS

2.7.1.1 SYNCHRONOUS GENERATOR POWER LIMITS

In order to ensure that the synchronous generator operates at safe limits, there are three physical limits that have to be considered during the operation of a synchronous generator:

- thermal;
- mechanical; and
- electromagnetic.

The physical limits and how close the generating plant is operating to the physical limits determine the extent to which the generator and sub-systems can respond to conditions that result from a supply disturbance and provide voltage support. Exceeding the physical limits will result in damage to the generator and sub-system.

2.7.1.1.1 THERMAL LIMITS

Thermal limits [38], [50] determine the maximum temperature rise equipment the generator can withstand before permanent damage will occur that will affect equipment health and performance. The major cause of losses on the rotor is the field winding resistive losses. If the field current exceeds a certain level, the I^2R losses will increase to a level exceeding the insulation temperature withstand capability, causing insulation failure or degradation in the field winding. The field current is therefore controlled and this controls the induced excitation in the armature winding.

The rotor heating limit sets $|E|_{max}$. Similarly, excessive armature currents will cause the stator temperature to rise. The stator heating limit sets $|I_A|_{max}$. In steady state, this limit is the rated current of the machine. The heating limits can be drawn as locii on the phasor diagram (see Figure 58):

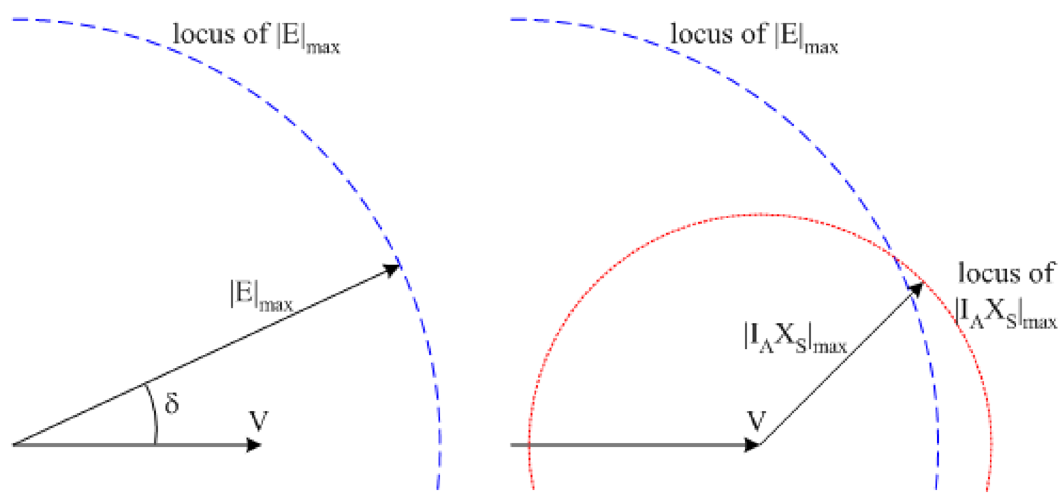


Figure 58: Heating limits as locii on the phasor diagram [38], [50]

2.7.1.1.2 MECHANICAL AND ELECTROMAGNETIC LIMITS

The input power to the generator is limited by the physical capability of the prime mover [37], [38]. The prime mover limit sets the maximum output power from the generator $P_{max} = |E\sin\delta|_{max}$. The final limit correlates with the mechanical input and the ability of the generator to electromagnetically generate a torque equal and opposite to the prime mover driving mechanical torque. The equations above illustrate that the torque is the cross product of two electromagnetic fields or a function of the sine of the angle between *V* and *E*. At a set excitation, as the mechanical torque increases, the rotor will accelerate, increasing δ and the electromagnetic torque. This negative feedback will continue until the electromagnetic and mechanical torques balance out. If the generator is operating with δ close to 90° when the rotor accelerates, δ increases past 90°, the electromagnetic torque dec reases and positive feedback occurs, causing the rotor to accelerate further past synchronism and result in zero output power and possible damage to the synchronous generator. The static stability limit is set at δ = 90° (see Figure 59).

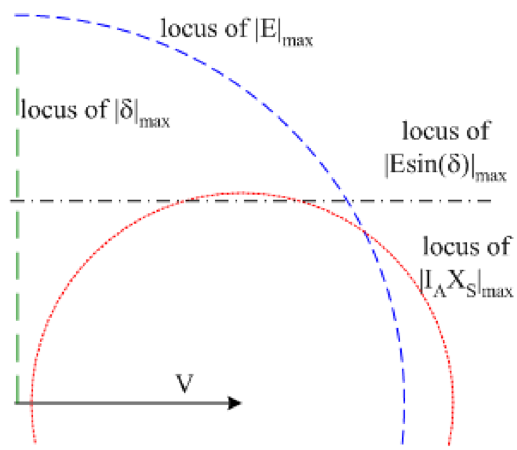


Figure 59: Static stability limit [37], [38]

2.7.1.1.3 POWER LIMITS

The phasor diagram limits can be used to describe the synchronous generator operation limits. In order to present the power limits on the capability curve, the voltage phasor is converted into power phasor.

$$P = 3\,V_{ø}I_A\cos\theta \tag{4}$$

$$Q = 3\,V_{ø}I_A\sin\theta \tag{5}$$

$$S = 3V_{ø}I_A \tag{6}$$

Where:

$P_{max} = 3\ V_{ø}E_A/X_s$ (P_{max} is when $\delta = 90º$) (7)

In order to reflect the limits in terms of power, reactive power and apparent power, the phasor diagram can be scaled by $3V/X_S$ to obtain power and reactive power limits (see Figure 60):

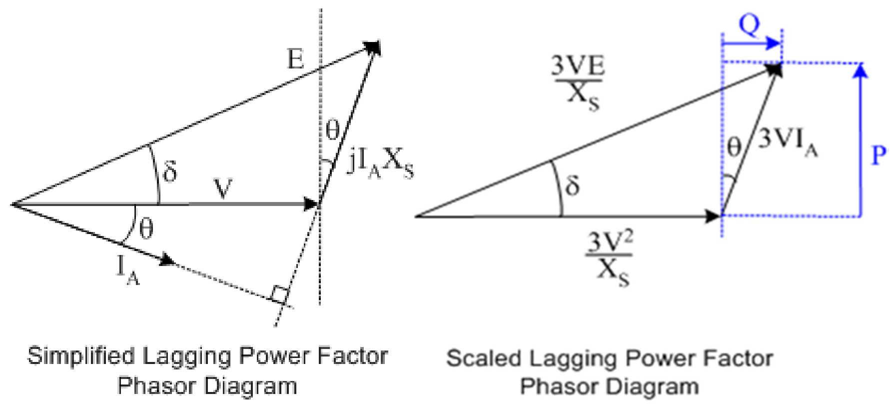


Figure 60: Simplified lagging power factor phasor diagram and scaled lagging power factor phasor diagram [38]

In the above diagram, real power is on the y-axis and reactive power is on the x-axis.

2.7.1.1.4 SYNCHROUNOUS GENERATOR CAPABILITY DIAGRAM

The limits from the above phasor diagrams are depicted on a P-Q plot below to illustrate the synchronous generator capability diagram (see Figure 61).

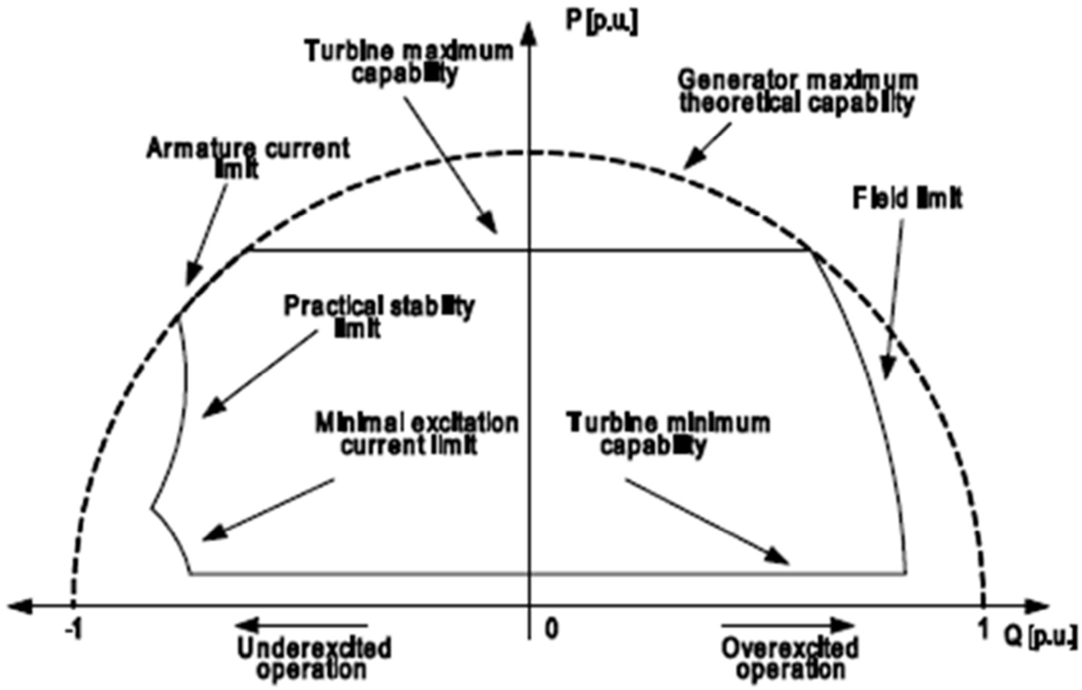


Figure 61: Operating limitations in synchronous generator P-Q diagram

The steady-state limits on synchronous generator operation are:

- Rotor heating limit: sets $|E|_{max}$
- Stator heating limit: sets $|S|_{max}$ and $|I_A|_{max}$
- Prime mover limit: sets P_{max}, and
- Static stability limit: $\delta = 90°$.

The heating limits in the end region of the armature (see Figure 62) determines the capability of the generator in the underexcited condition as indicated on the P-Q curve of Figure 61.

The end-turn leakage flux enters and exits perpendicular to the stator lamination (see Figure 62), which causes eddy currents in the laminations and leads to localized heating in the end region. The high field currents due to the overexcited condition keep the retaining ring saturated to limit the end leakage flux. However, in the underexcited condition, the field current is low and the retaining ring is not saturated, which allows an increase in armature end leakage flux.

The flux produced by the armature current during an underexcited condition contributes to the flux produced by the field current. Therefore, the end-turn flux enhances the axial flux in the end region and the generator output is limited depending the allowable heating limits.

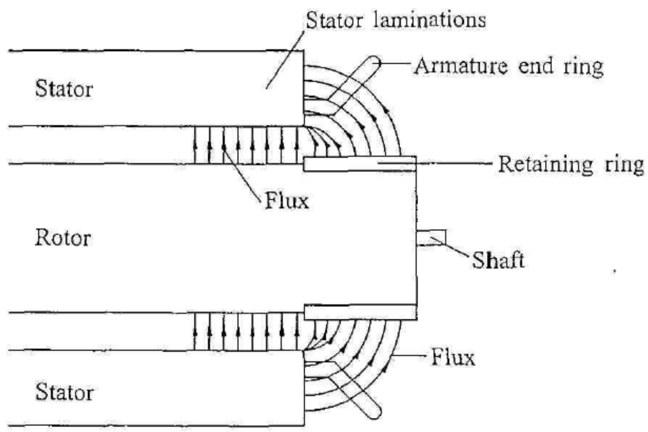


Figure 62: Sectional view of generator end region [51]

In a large leading power factor operating condition (importing reactive power), the generator tends to fall out of synchronism with the network. A static limit of stability determines the maximum power with which the generator can be loaded without falling out-of-step. The ability to maintain synchronism in case of a disturbance decreases as the generator operating point approaches the stability limit. In order to mitigate this risk, the generator is operated below the stability limit by limiting the minimal excitation current and the maximum synchronous generator load angle (practical stability limit) [51], [52].

The load angle is used to indicate how close the generator is to the static stability limit. The load angle increases with an increase in active load, and the larger the angle, the closer the generator gets to the stability limit with an increasing risk of falling out of synchronism. Load angle is defined as the angle between the induced voltage and the network voltage and it rises proportionally to the growth of the active load [51].

2.7.1.2 GENERATOR PROTECTION

Disturbances that originate in the IPS will cause a sudden change of the stator winding voltage and load demand experienced by the synchronous generator. This section discusses protection functions used at power plants applicable for this scenario. The objective of the generator protection functions is to ensure that the physical limits that will cause damage to the generator are not exceeded.

The activation of any of these protection functions to prevent damage to the generator will trip the generator and voltage support from the generator will be unavailable.

The following protection functions are used at power plants [53]:

- NPS protection safeguards the generator rotor against overheating caused by the induced currents because of asymmetrical faults in the network or unbalanced system conditions.
- Overvoltage protection prevents damage to insulation.
- Generator pole slip protection. A generator pole slip can be caused by a number of conditions, leading to an increase in rotor angular position beyond the generator transient stability limits. Some of the causes of pole slipping are:
    - large network disturbances;
    - faults on the electrical network close to the generator;
    - weak tie between the network and the generator (tripping of transmission lines);
    - loss of generator field (field winding or excitation supply failure); and
    - operating the generator in an excessive underexcited mode.
- Back-up impedance protection is in place for phase faults with a suitable delay, for cases when the corresponding main protection fails to operate.
- The loss of field current protection monitors the generator operating conditions:
    - Stage 1 provides an alarm for indicating a low field current condition (Admittance only).

o Stage 2 initiates a trip for a complete loss of field current.

- An undervoltage protection function provides an alarm only for an undervoltage greater than 0.70 p.u. for longer than 2.5 s.
- An overload protection function provides an alarm only for an overload greater than 1.05 p.u.

2.7.1.2.1 VOLTAGE AND FREQUENCY LIMITS FOR GENERATORS

The following operational conditions as stipulated by IEC 60034-3 [54] have to be considered:

- Voltage control and reactive power capability: With reference to IEC 60034-3 [54], the generators must be rated capable of continuous operation between 95% and 105% of rated terminal voltage, producing continuously the rated apparent power at a power factor between 0.95 underexcited (leading) and 0.90 overexcited (lagging) without any component exceeding the temperature limits as specified. The effects of frequency variation on the rating are in accordance with IEC 60034-1 [55] zone A.

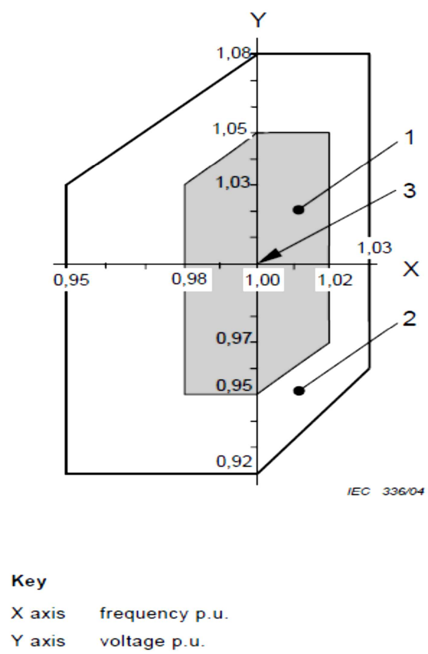


Figure 63: Voltage and frequency limits for generators [55]

- Undervoltage: the generators are rated capable of operation during voltage variations between 92% and 108% as per IEC 60034-1 [55] zone B for limited time durations and the frequency of the occurrences.

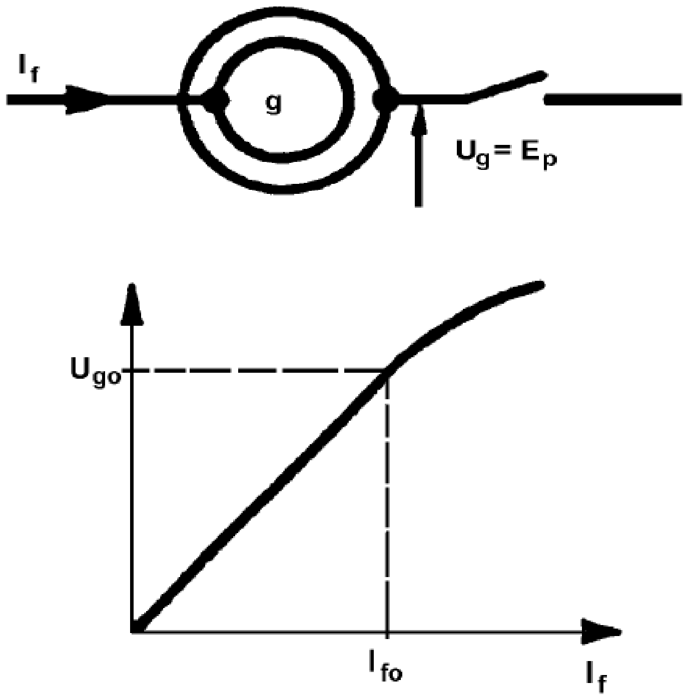
2.7.2 EXCITATION SYSTEMS

Excitation systems have a controlling impact on the generator dynamic performance. This controls terminal voltage, ensures stable operation with the network and other generators and contributes to transient stability subsequent to a fault in the IPS. The excitation system contributes to maintain the system operating parameters within permissible operating range to keep the power-generating unit auxiliaries in service, ensuring availability of power-generating capacity. The section below discusses the theory of operation of the excitation system created an understanding of the behaviour during a voltage dip that originates in the IPS, with a characteristic as defined in the South African Grid Code. Different excitation systems are briefly discussed as different types of excitation systems have different characteristics.

2.7.2.1 THE TASK OF THE EXITATION SYSTEM

The DC current that is required to create the magnetic field in the rotor of the generator is provided by the excitation system. The field current determines the generator terminal voltage in an islanded condition and the reactive power when connected to an IPS [38], [56].

For an islanded generator condition at rated speed, the terminal voltage U_g is a function of the field current I_f and follows the no-load field current I_{fo} (see Figure 64). The terminal voltage is determined by the induced rotor voltage. The islanded condition must be controlled by the AVR pre-synchronizing and when the generator is segregated from the IPS.



U_g – generator terminal voltage

I_f – field current

I_{fo} – field current no-load

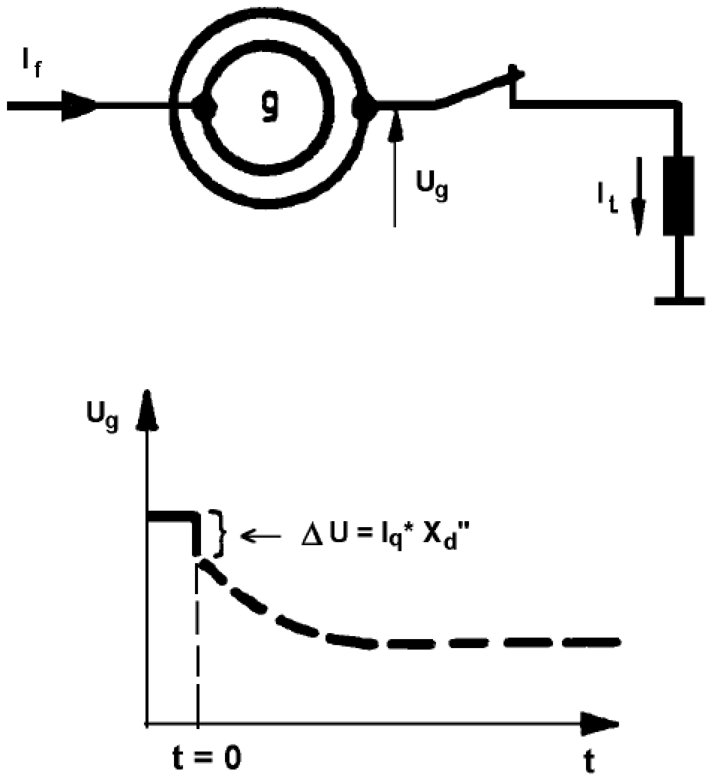
E_p – induced voltage

g – generator

Figure 64: No-load operation of synchronous machine [38], [56]

If the generator supplies auxiliary loads [37] only, it is referred to as isolated or island operation [2]. The voltage and frequency are determined by a single power-generating unit and controls. Connecting additional loads current I_L requirements causes a voltage variation (see Figure 65). The field current will be varied to compensate for the voltage deviation ΔU that appears across the reactance between induced voltage E_p and terminal voltage U_g [38], [51]. The field winding resistance R_f is negligible in this respect.

The AVR cannot eliminate the initial voltage drop, but has an effect at the beginning of the exponential part. The AVR has to control this condition as part of a power-generating unit to prevent a total interruption in the process, maintaining terminal voltage. This has the benefit of a faster return to service i.e. synchronizing to the network following islanding operation and fault clearing [2]. Islanding capability is also a requirement in the National Grid Code for new build power plants.



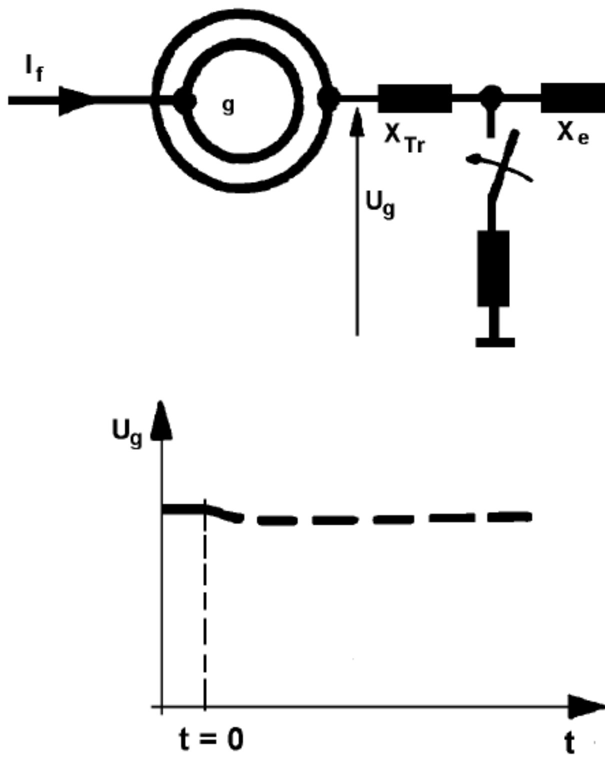
R_f – field winding resistance

ΔU – voltage deviation

I_L – load current

Figure 65: Isolated or island operation of a synchronous machine [38], [56]

When connected to a network, connecting additional loads creates a small voltage deviation as the current is distributed according to the reactance ratio X_{Tr}/X_e (see Figure 66).



X_{Tr} – transformer reactance

X_e – network reactance

Figure 66: Network-connected operation of synchronous machine [38], [56]

When connected to a network, the voltage and the frequency are determined by the network and the AVR does not control the generator output voltage. The reactive power is determined by the field current. The amount of power generated is determined by the prime mover. The speed of the prime mover is fixed, but the torque can be adjusted by adjusting the power on the prime mover via the governor. Increasing excitation above the level required to achieve no load nominal voltage will in effect increase the reactive current flowing from the generator to the load. Decreasing the excitation will have the opposite effect, resulting in the import of reactive power from the network.

2.7.3 THE BEHAVOUR OF THE GENERATOR SUB-SYSTEM

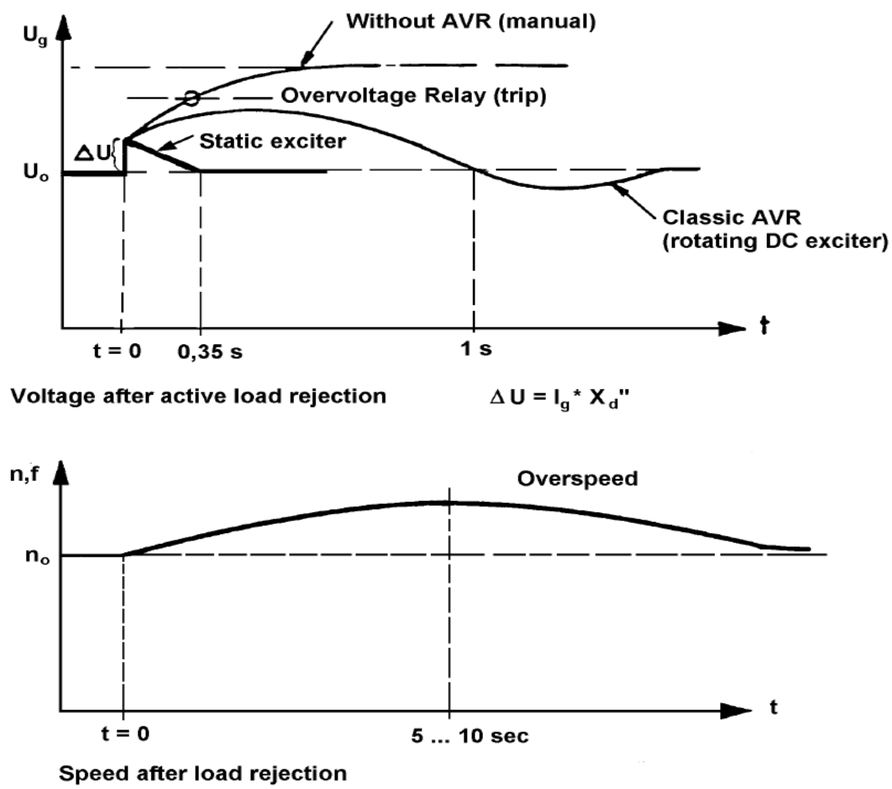
The AVR has to respond to changes in the operating conditions required for a power plant. This ranges from raising the voltage before synchronizing, to managing the voltage within specified limits following load rejection, to responding to load change requirements. The behaviour of the AVR and different types of AVR during these transients are evaluated.

2.7.3.1 GENERATOR DISTURBANCES

During load change conditions, the generator remains connected to the network, while during a load rejection condition the generator is isolated from the network. The impact of electrical short circuits is determined by the distance from the fault. A distant short circuit occurs in the network with the reactance of the generator transformer in between. A short circuit close to the generator initiates segregation of the generator via a generator circuit breaker [7] and effectively results in load rejection by the generator. During distant short circuits, the generator has to support the network until the fault is cleared.

2.7.3.2 GENERATOR LOAD REJECTION

A sudden voltage increase occurs following the segregation of the generator from the network and the significant decrease in load to zero (see Figure 67). The voltage variation is dependent on how quickly the AVR can control the voltage. The decrease of the reactive load current to zero unavoidably causes an immediate voltage rise $\Delta U = I_{reactive}\ X''_d$. A sub-transient reactance of 0.2 p.u. for a rejection of 0.5 p.u. reactive current realizes an instantaneous voltage rise of 10%. The response of the AVR is to slow since it is unable to control this instantaneous voltage rise. Without an AVR, the voltage will rise until the maximum value defined by the synchronous reactance is reached. The lag-time corresponds to the no-load time constant T_{do}. The AVR will eliminate this further voltage rise and will control the voltage to within the specified limits [38], [56]. It is also evident that the response of a static exciter system is faster than a rotating type exciter system. The response time is dependent on additional time constant from the exciter. Voltage variations are mainly related to reactive current variations. The active current causes only small voltage drops within the generator. As a result of the prime driver to provide the power, the generator speed increases following the segregation of the load until the prime driver energy is removed.



$I_{reactive}$ – reactive load current

$X''_{d.}$ – sub-transient reactance

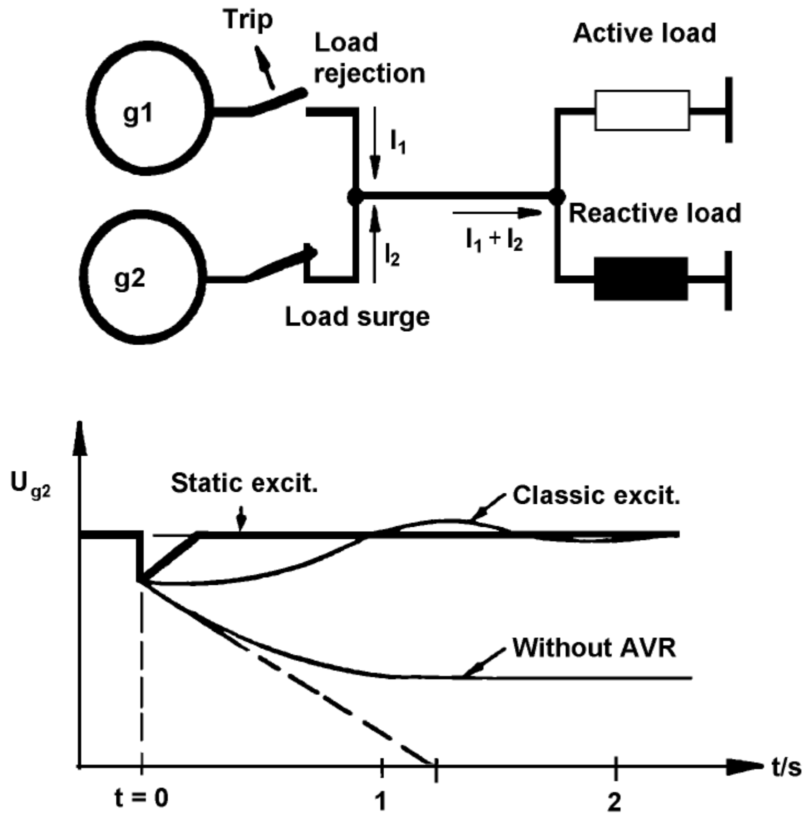
T_{do} – no-load time constant

n_0 – speed prior to load rejection

Figure 67: Load rejection operation [37], [38], [56]

2.7.3.3 LOAD SURGE

The load rejection operation of a generator initiates a load surge on generators connected to the same network and this has a great impact on generators connected to the same HV bus (see Figure 68). The voltage-time curve illustrates the effect on a generator that has to pick up the additional load as a result of another generator rejecting load. With self-excited generators, the ceiling excitation is reduced and undervoltage protection can be activated, causing more generators to segregate from the grid, having an even larger impact on the network.



g_1 – generator 1

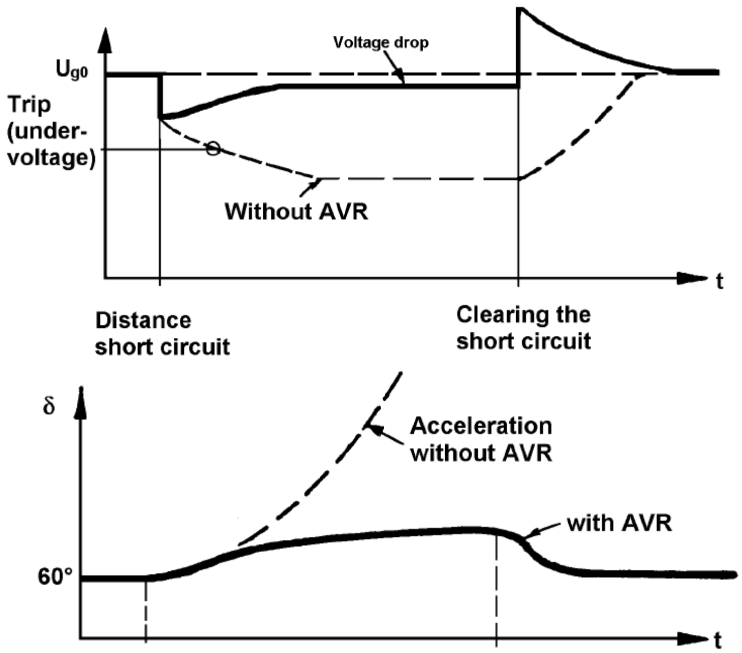
g_2 – generator 2

U_{g2} – generator 2 terminal voltage

Figure 68: Load surge operation [37], [38], [56]

2.7.3.4 DISTANT SHORT CIRCUIT OPERATION

A distant short circuit results in a large reactive surge for the generator (see Figure 69). A short circuit at medium electrical distance causes overcurrent and undervoltage. The overcurrent and undervoltage can be withstood for a short time interval. The AVR would have to respond by providing maximum excitation to maintain the voltage and to increase the synchronizing torque. Inadequate response by the AVR will cause the voltage to drop to the point that the undervoltage protection will activate. When the fault is cleared, the voltage will increase as per the load reduction operation. High power-generating capacity machines are operated at large load angles close to the maximum torque capability. Therefore, during voltage dips, it is important for the synchronizing torque $AM_{ds} = E_p*U_N$ to be kept constant or even increased by an increase in the flux. The AVR is required to react automatically. This normal function should not be confused with limiting the load angle in an underexcited operating condition. The flux cannot be controlled to influence the voltage of a single-phase and the AVR will have limited response to a single-phase voltage dip.



δ – power or torque angle

M_{ds} – inertia constant

E_p – induced voltage

U_N – network voltage

Figure 69: Distant short circuit operation [37], [38], [56]

2.7.3.5 TERMINAL SHORT CIRCUIT OPERATION

The most severe disturbances occur when a short circuit occurs on or close to the generator terminals and are characterized by an extremely high overcurrent [38]. The protection should segregate the generator from the network to limit the impact of the fault current and damage. The voltage will dip significantly and even decrease to zero. Figure 70 illustrates the theoretical smoothed mean value of the stator current. After increasing to the peak value, the current decreases exponentially with the load time constant T_d.

For excitation systems connected to the terminal voltage, the generator current will fade away due to unavailable supply voltage. A compounded circuit can be used to supply the excitation system to overcome this situation.

A high current is induced in the rotor circuit during a short circuit that occurred close to the generator in an attempt to maintain the voltage on the generator terminals. The overcurrent protection should be graded with the short-time overcurrent capability of the thyristor converter in the AVR. Any overcurrent protection operation will result in the segregation of the generator from the IPS and therefore the loss of voltage support by the generator. The same applies to the field breaker and the field discharge resistor.

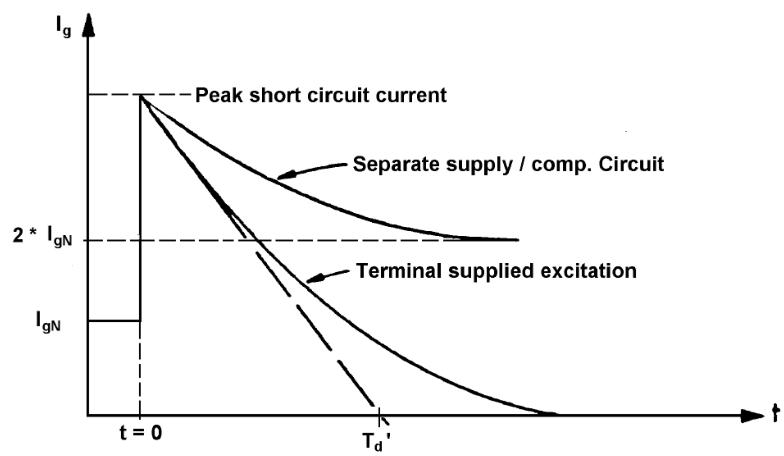


Figure 70: Terminal short circuit operation [37], [38], [56]

2.7.4 DIFFERENT EXCITATION SYSTEMS

The main functions of the excitation system are to provide variable DC current with short time overload capability to control the generator terminal voltage. The section below describes the three main types of excitation systems to understand the operational behaviour during generator disturbances.

2.7.4.1 BRUSHED EXCITERS

Referring to Figure 71 below, the brushed excitation system comprises of two DC generators, namely a main exciter and a pilot exciter, both connected to the synchronous generator main shaft in series. The main exciter provides the synchronous generator field winding voltage through brushes and slip rings, while the pilot exciter supplies the main exciter field winding. The two DC generators provide power amplification for the control system. The automatic voltage regulator (AVR) varies the excitation to maintain a constant synchronous generator terminal voltage or to control the reactive power delivered to the network. A fault in the IPS may result in a sudden voltage decrease across the terminal of the generator. The exciter has to react quickly to recover and maintain the voltage. Manufacturers limit the voltage rise and duration in order not to exceed the thermal capability. The advantages of a brushed exciter system are that a low power external DC source is used to increase the power via the pilot exciter and main exciter. The following are considered drawbacks:

- As a result of the large field winding time constants of two excitation circuits and armature windings, a slow time response is experienced.
- Exciter shafts and mechanical couplings add additional shaft torsion frequencies to the turbine-generator shaft.
- Brush gear wear and require maintenance.
- High power transfer via brushes onto slip rings causing pitting.

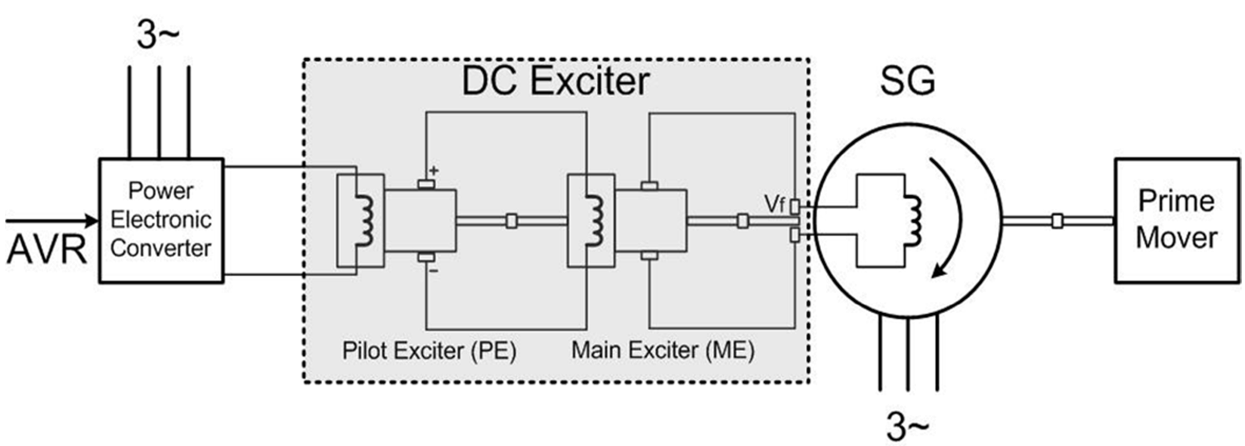


Figure 71: Brush exciter [56]

2.7.4.2 BRUSHLESS EXCITERS

An AC exciter (see Figure 72) consists of a rotating armature and stationary field. The output is rectified by solid-state rectifier elements mounted on the rotating structure and fed directly to the main generator's field winding. Compared to the DC exciter, the three-phase rectifier replaces the commutator, slip rings and brushes, i.e. the commutator (mechanical rectifier) is replaced by an electronic rectifier. The stator-based field winding of the AC exciter is controlled from the AVR. The static power converter has a relative high rating, as only one step of power amplification is performed through the AC exciter.

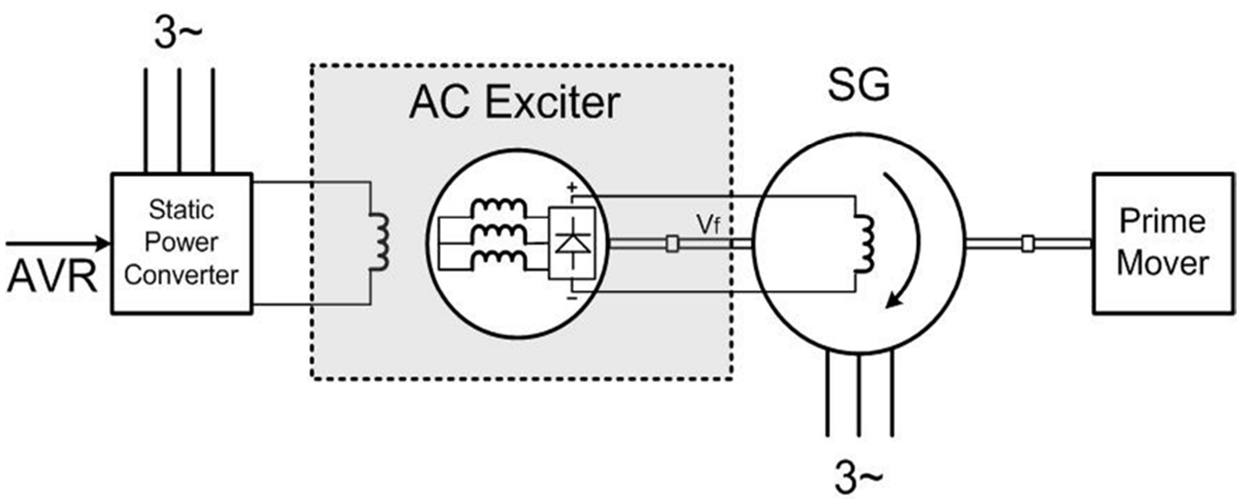


Figure 72: Brushless exciter [56]

2.7.4.3 STATIC EXCITERS

For a static excitation system (see Figure 73), the excitation power is provided from the generator terminals. The excitation transformer steps down the generator voltage to a value that corresponds with the maximum field voltage. The rectifier converts the AC voltage to a DC voltage. The rectifier comprises of several parallel-connected three-phase thyristors bridges. The fully controlled bridge allows the reversal of the polarity in the generator field. This effects a high controlling speed during built-up and during reduction of the field current. A field breaker together with a discharge resistor is used to establish rapid de-excitation of the generator. Insufficient residual voltage is available during generator run-up for initial excitation. An additional power source has to be provided for the initial excitation, a separate DC source is normally utilized for the initial excitation.

Voltage regulation is done with the AVR. The generator voltage is measured and compared with the reference value. The difference between actual value and reference value of the generator voltage controls the position of the gate pulses, created in the gate control unit. After pulse amplification, the pulses are led to the pulse transformer of each thyristor. In addition, field current limiters and a load angle limiter as well as protection and supervision units are integrated into the voltage regulator.

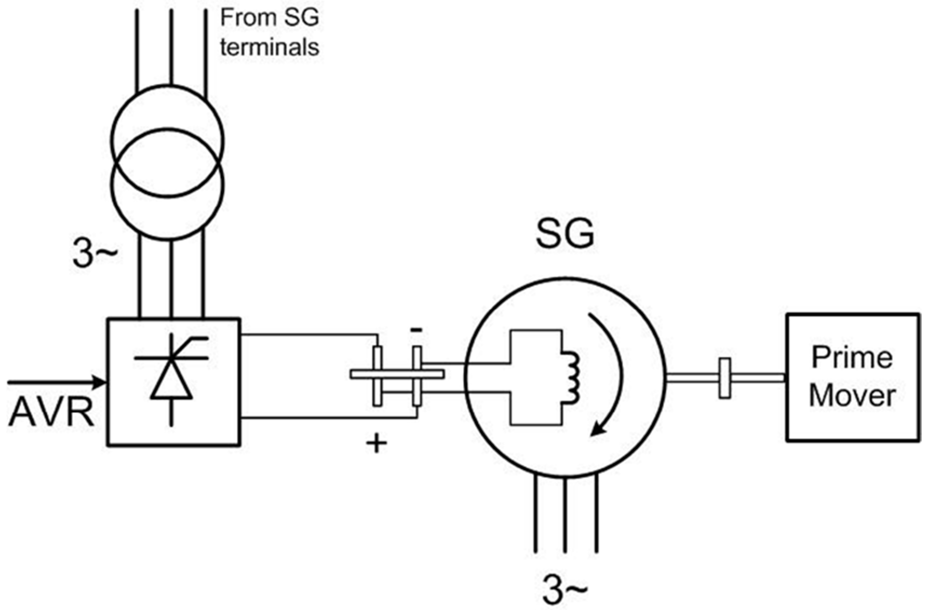


Figure 73: Static exciter [56]

2.8 SUMMARY

The electrical design information with regard to a power plant prior to the existence of the South African Grid Code reveals that the electrical design specifications were aimed at ensuring uninterruptable power generation during certain abnormal supply conditions without damage to a plant.

The supply to a power plant can be temporarily interrupted for a short duration without interruption of the plant process due to system inertia. In plant areas where short supply interruptions can interrupt the power plant processes, essential uninterruptable supply is utilized to maintain control of the plant so that it can resume operation immediately after supply restoration or maintain operation of the process and to prevent plant damage or unsafe conditions.

The voltage disturbance experienced within the power plant during a short circuit is dependent on the impedance and location of the fault.

Voltage support is provided by generators and sub-systems that remain connected to the IPS during supply disturbances. The initial voltage support will be from the large number of motor loads at a power plant that will generate power back to the electrical reticulation system. The automatic voltage regulator will further respond to changes in the operating conditions required for a power plant.

The behaviour of individual power plant electrical equipment when exposed to voltage dips provides evidence that a degree of disturbance resilience is accomplished.

The literature study also identified a potential risk between the characteristics of contactors and the line interactive UPS used to provide uninterruptable power supply during voltage dips.

Variable speed frequency drives was also identified as equipment used at a power plant with a high potential risk of interrupting the process during a voltage dip.

The generator protection and sub-system limiters can impede on the ability of the generator to provide voltage support during voltage dips. Static excitation systems provide faster response to voltage fluctuation.

Ensuring voltage immunity entails a combination of aspects within the power plant that have to be implemented correctly. An engineering solution should therefore be considered during the power plant design.

CHAPTER 3

PROBLEM IDENTIFICATION ANALYSIS

3.1 INTRODUCTION

The preceding chapter considered the behaviour of a power plant's electrical equipment during a voltage dip. Equipment used at power plants can be specified to continue operation during voltage dips. International standards applicable to specific equipment normally defines an input voltage tolerance or can be referred to for the requirement for which equipment must have supply disturbance resilience. The South African Grid Code in terms of GCR 9 defines the supply disturbance resilience requirements for power plants connected to the IPS. This chapter follows with a benchmarking of the South African Grid Code in terms of the GCR 9 requirement against other available grid codes or similar network governances.

The South African Grid Code voltage operating limits are compared and measured against international standards of major equipment used at power plants and the power plant design parameters.

Alignment between the international standards, the grid code voltage operating limits and the power plant design parameters provide the first indication of GCR 9 compliance or additional problematic areas.

3.1.1 INTERNATIONAL GRID CODE REQUIREMENTS WRT NETWORK DISTURBANCES

The grid code requirements on disturbances occurring in the IPS of different countries are discussed to compare the South African Grid Code GCR 9 with other grid codes. The main similarities and differences are discussed in this section. The grid codes of the following countries are reviewed:

Germany [57] (DEU) [58];

Ireland [59] (IRL) [58];

India [60] (IND) [58];

Jordan [61] (JOR) [58];

Kenya [62] (KEN) [58];

Namibia [63] (NAM) [58];

Nigeria [64] (NGA) [58];

Pakistan [65] (PAK) [58];

Rwanda [66] (RWA) [58];

Sudan [67] (SDN) [58];

Tanzania [68] (TZA) [58];

Uganda [69] (UGA) [58];

The United Kingdom [70] (GBR) [58];

Western Australia [71] (AU-WA) [58];

Zimbabwe [72] (ZWE) [58].

The voltage envelope is specified by the specific country. The protection and circuit breaker operating times determine the fault clearing time and therefore the fault ride-through requirements are a derivative of these restrictions and are applicable to the power-generating unit.

3.1.1.1 GERMAN GRID CODE

The requirements applicable to a power-generating unit (excluding renewable energy) connected to an IPS in the event of network disturbances are quoted directly from the grid code [57]:

The anticipated voltage conditions at the point of connection:

- Voltage deviation as per Table 9:

Table 9: German voltage deviation limits [57]

Normal Operating Conditions	
Minimum Voltage (p.u.)	**Maximum Voltage (p.u.)**
0.85	None provided

A voltage dip magnitude is not specified, but the requirement is that for three-phase faults close, the generating unit of a specified magnitude should not lead to instability. A 100% voltage dip magnitude is used for the maximum fault clearing time as indicated in Table 10 and the voltage envelope is as indicated in Figure 74.

Table 10: German voltage dip magnitude and fault ride-through times [57]

Voltage Dip Magnitude Level expressed in p.u.	Fault Ride-Through Times in ms
0	150

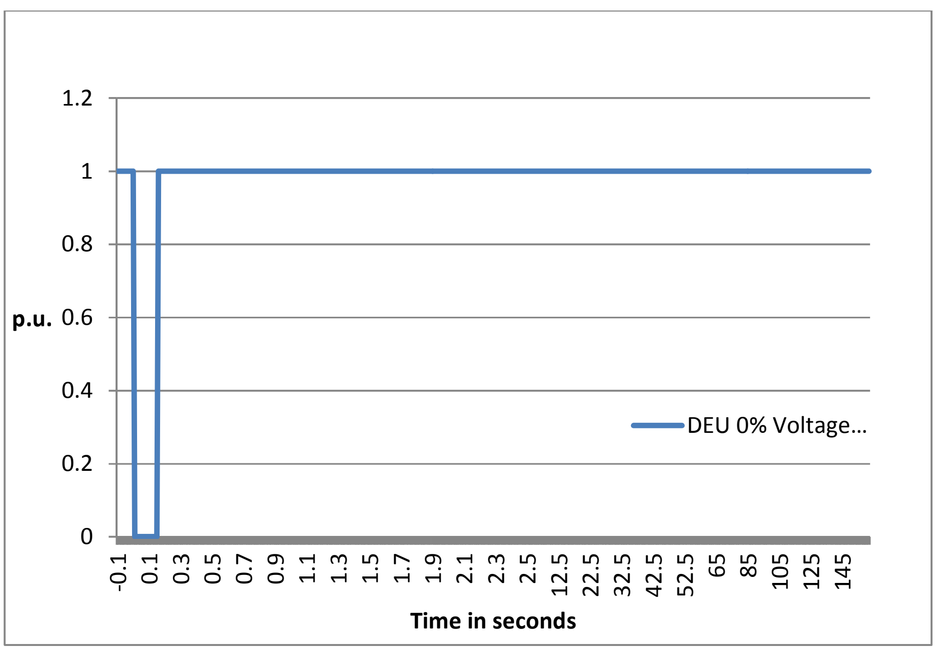


Figure 74: Voltage envelope – German grid code

3.1.1.2 IRISH GRID CODE

The anticipated voltage conditions at the point of connection include voltage deviation as per Table 11 for the different transmission voltages:

Table 11: Irish voltage deviation limits [59]

Voltage – (kV rms)	Normal Operating Conditions	
Nominal	Maximum Voltage in p.u.	Minimum Voltage in p.u.
400	1.05	0.875
220	1.11	0.90
110	1.10	0.88

Table 12: Irish voltage dip magnitude and fault ride-through times [59]

Voltage Dip Magnitude Level expressed in p.u.	Fault Ride-Through Times in ms
0.05	150
0.50	450

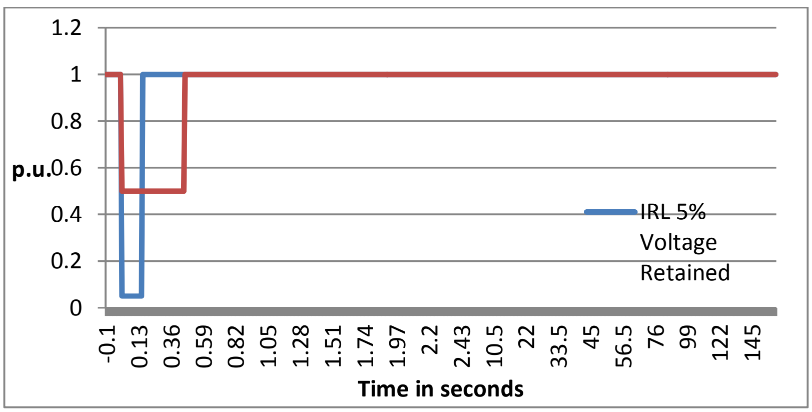


Figure 75: Voltage envelope – Irish grid code

The acceptable IPS voltage ranges following a disturbance are listed in Table 11 and are not shown on this graph, 1.0 p.u. was used for the system condition prior and post incident.

3.1.1.3 INDIAN GRID CODE

The anticipated voltage conditions at the point of connection include voltage deviation as per Table 13 for the different transmission voltages:

Table 13: Indian voltage deviation limits [60]

Voltage – (kV rms)	Normal Operating Conditions	
Nominal	Maximum Voltage in p.u.	Minimum Voltage in p.u.
400	1.05	0.90
220	1.11	0.90
132	1.10	0.90

Due to no voltage dip magnitude specified, it is stipulated that for a three-phase fault the generating unit shall withstand the disturbance until the back-up protection operates. A 100% voltage dip magnitude for the maximum fault clearing time (2 times main protection fault clearing time) is considered as indicated in Table 14 and the voltage envelope is indicated in Figure 76.

Table 14: Indian voltage dip magnitude and fault ride-through times [60]

Voltage – (kV rms)	Voltage Dip Magnitude Level expressed in p.u.	Fault Ride-Through Times in ms
800 kV class and 400 kV	0	200
220 kV and 132 kV	0	320

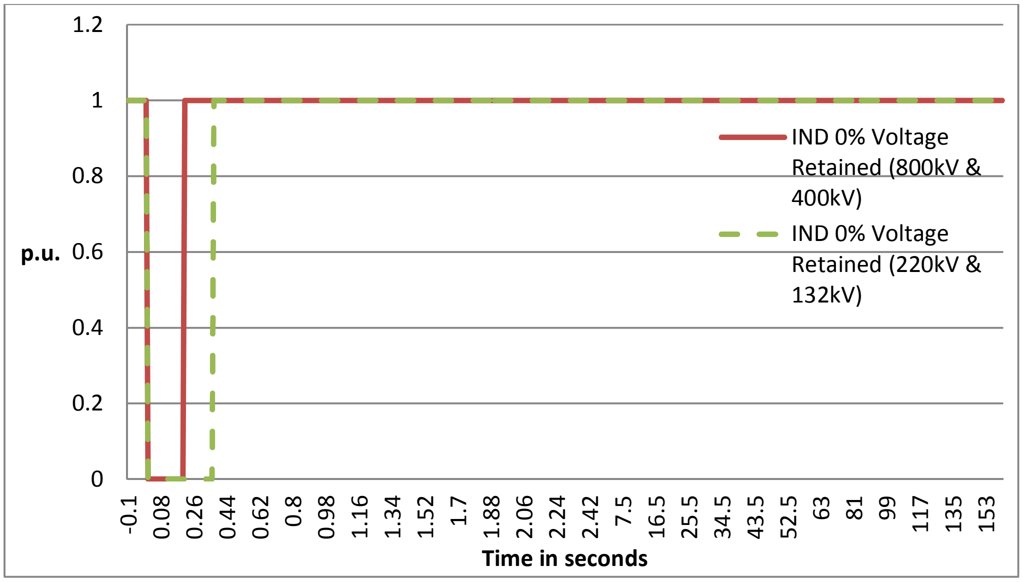


Figure 76: Voltage envelope – Indian grid code

The acceptable IPS voltage ranges following a disturbance are listed in Table 13 and are not shown on this graph, 1.0 p.u. was used for the system condition prior and post incident.

3.1.1.4 JORDANIAN GRID CODE

The anticipated voltage conditions at the point of connection include the voltage deviation as per Table 15 for the different transmission voltages:

Table 15: Jordanian voltage deviation limits [61]

Voltage – (kV rms)	Normal Operation		System Stress and Fault Condition	
Nominal	Maximum in p.u.	Minimum in p.u.	Maximum in p.u.	Minimum in p.u.
400	1.05	0.95	1.10	0.90
220	1.05	0.95	1.10	0.90
132	1.10	0.90	1.15	0.85

The maximum voltage dip magnitude specified in the grid code of Jordan for the different transmission networks are listed in Table 16. The maximum fault clearing times were used for the fault ride-through times. Figure 77 provides the voltage envelope.

Table 16: Jordanian voltage dip magnitude and fault ride-through times [61]

Voltage – (kV rms)	Voltage Dip Magnitude Level expressed in p.u.	Fault Ride-Through Times in ms
400	0.90	300
220	0.90	300
132	0.85	300

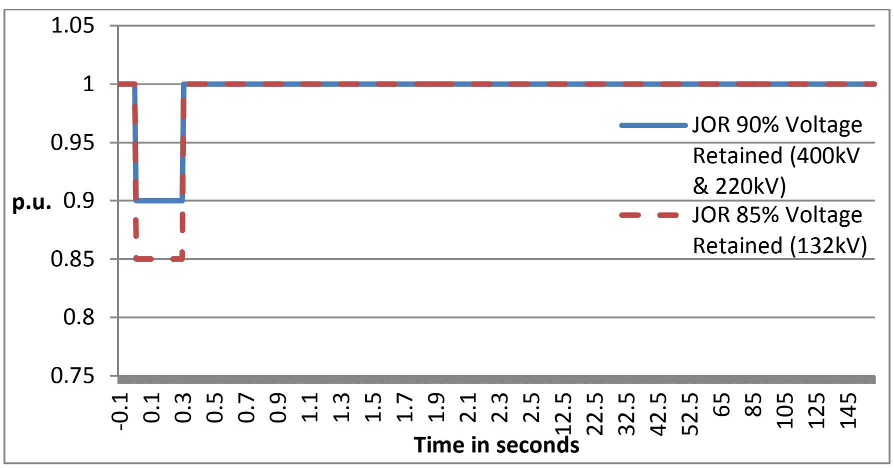


Figure 77: Voltage envelope – Jordanian grid code

The acceptable IPS voltage ranges following a disturbance are listed in Table 15 and are not shown on this graph, 1.0 p.u. was used for the system condition prior and post incident.

3.1.1.5 KENYIAN GRID CODE

The anticipated voltage conditions at the point of connection include voltage deviation as per Table 17 for the different transmission voltages:

Table 17: Kenyian voltage deviation limits [62]

Normal Operating Conditions	
Minimum Voltage (p.u.)	**Maximum Voltage (p.u.)**
0.90	1.10

Table 18: Kenyian voltage dip magnitude and fault ride-through times [62]

Voltage Dip Magnitude Level expressed in p.u.	Fault Ride-Through Times in ms
0	175
0.80 - 1.10	6000000
0.90 - 1.10	180000

The three-phase voltage dip magnitude and fault ride-through times are as per Table 18 and as per the voltage envelope (see Figure 78). Following the end of the 175 ms, the voltage deviation can be 0.85 p.u. - 1.10 p.u. for a period of ten minutes and thereafter 0.90 p.u. - 1.10 p.u. for a period of three minutes as listed in Table 18.

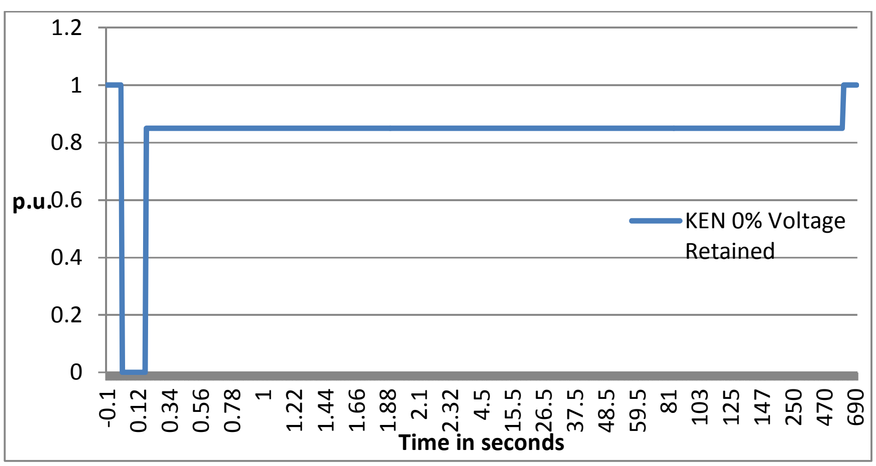


Figure 78: Voltage envelope – Kenyian grid code

The acceptable IPS voltage ranges following a disturbance are listed in Table 17. The acceptable continuous voltage limits are not shown on this graph, 1.0 p.u. was used for the system condition before and after the incident.

3.1.1.6 NAMIBIAN GRID CODE

The Namibian grid code requirements with regard to voltage deviation limits, voltage unbalance and voltage dip magnitude and ride-through time are similar to the South African grid code, with a difference in the ride-through time for a 75% voltage magnitude dip.

The anticipated voltage conditions at the point of connection include voltage deviation as per Table 19:

Table 19: Namibian voltage deviation limits [63]

Normal Operating Conditions	
Minimum Voltage (p.u.)	**Maximum Voltage (p.u.)**
0.90	1.10

The three-phase voltage dip magnitude and fault ride-through times are seen in Table 20 and the voltage envelope in Figure 79). These are provided that during the three-minute period immediately following the end of the 200 ms, 2000 ms, or 60000 ms period the actual voltage remains within the limits stipulated in Table 20.

Table 20: Namibian voltage dip magnitude and fault ride-through times [63]

Voltage Dip Magnitude Level expressed in p.u.	Fault Ride-Through Times in ms
0	200
0.75	2000
0.85	60000

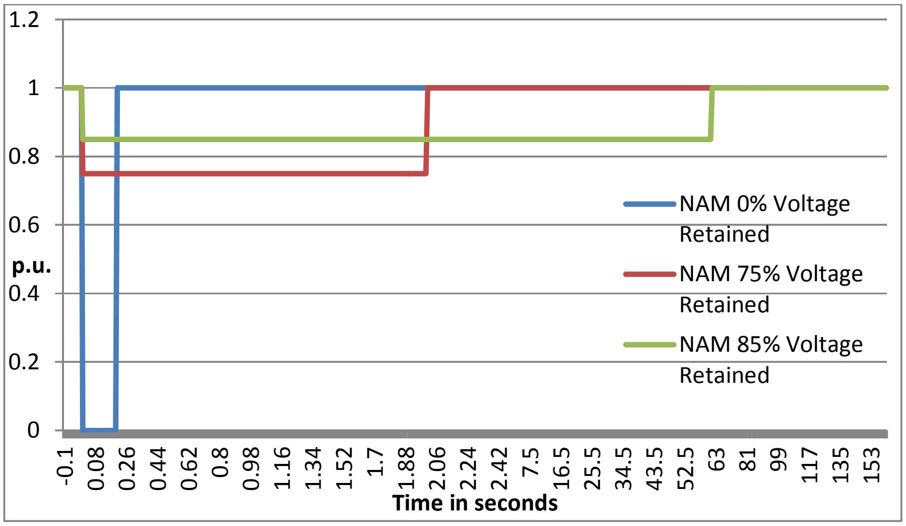


Figure 79: Voltage envelope – Namibian grid code

The acceptable IPS voltage ranges following a disturbance are 0.90 p.u. and 1.10 p.u. and are not shown on this graph, 1.0 p.u. was used for the system condition prior and post incident.

3.1.1.7 NIGERIAN GRID CODE

The anticipated voltage conditions at the point of connection include voltage deviation as per Table 21 for the different transmission voltages:

Table 21: Nigerian voltage deviation limits [64]

Voltage level	Normal Operating Conditions		Stress of Fault Conditions	
	Minimum Voltage (p.u.)	Maximum Voltage (p.u.)	Minimum Voltage (p.u.)	Maximum Voltage (p.u.)
330 kV	0.95	1.05	0.90	1.10
132 kV	0.90	1.098	0.85	1.148
33 kV	0.94	1.06	0.89	1.11

Voltage level	Normal Operating Conditions		Stress of Fault Conditions	
	Minimum Voltage (p.u.)	Maximum Voltage (p.u.)	Minimum Voltage (p.u.)	Maximum Voltage (p.u.)
16 kV	0.95	1.05	0.90	1.10
11 kV	0.95	1.05	0.90	1.10

Since no voltage dip magnitude is specified, a 100% voltage dip magnitude for the maximum fault clearing time i.e. back-up protection to operate, is considered (see Table 22) and voltage envelope (see Figure 80). The fault clearance times are 60 ms for busbar protection on 330 kV and 132 kV and 80 ms for distance protection on 330 kV and 132 kV. The Nigerian grid code requires that the generating unit must be able to withstand a phase-to-phase fault for the period that the back-up protection will take to clear the fault.

Table 22: Nigerian voltage dip magnitude and fault ride-through times [64]

Voltage – (kV rms)	Voltage Dip Magnitude Level expressed in p.u.	Fault Ride-Through Times in ms
330 kV and 132 kV	0	120

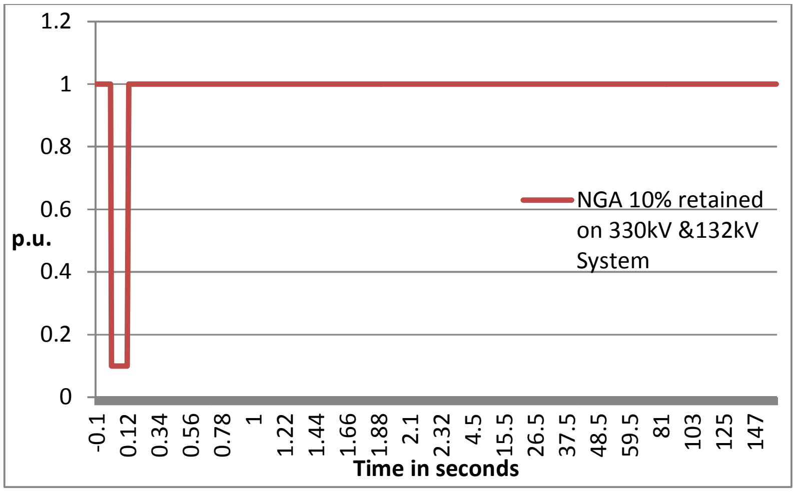


Figure 80: Voltage envelope – Nigerian grid code

The acceptable IPS voltage ranges following a disturbance are stipulated in Table 21 and are not shown on this graph, 1.0 p.u. was used for the system condition prior and post incident.

3.1.1.8 PAKISTIAN GRID CODE

The anticipated voltage conditions at the point of connection include voltage deviation as per Table 23 for the different transmission voltages:

Table 23: Pakistan voltage deviation limits [65]

Voltage level	Normal Operating Conditions		Stress of Fault Conditions	
	Minimum Voltage (p.u.)	Maximum Voltage (p.u.)	Minimum Voltage (p.u.)	Maximum Voltage (p.u.)
500 kV	0.95	1.08	0.90	1.10
220 kV	0.95	1.08	0.90	1.10
132 kV	0.95	1.08	0.90	1.10

The Pakistan grid code does not specify a voltage dip magnitude, but stipulates that the back-up fault clearance time should be 9 cycles (180 ms) for a permanent three-phase fault.

Table 24: Pakistan voltage dip magnitude and fault ride-through times [65]

Voltage Dip Magnitude Level expressed in p.u.	Fault Ride-Through Times in ms
0	180

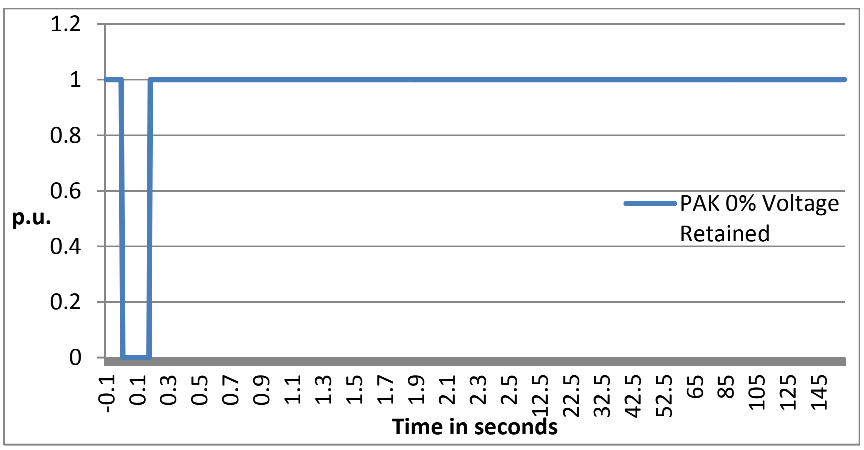


Figure 81: Voltage envelope – Pakistan grid code

The acceptable IPS voltage ranges following a disturbance are stipulated in Table 23 and are not shown on this graph, 1.0 p.u. was used for the system condition prior and post incident.

3.1.1.9 RWANDAN GRID CODE

The Rwandan grid code requirements with regard to voltage deviation limits, voltage unbalance and voltage dip magnitude and ride-through time are similar to the South African grid code, with a difference in the ride-through time for a 75% voltage magnitude dip.

The anticipated voltage conditions at the point of connection:

- Voltage deviation as per Table 25:

Table 25: Rwandan voltage deviation limits [66]

Normal Operating Conditions	
Minimum Voltage (p.u.)	**Maximum Voltage (p.u.)**
0.90	1.10

The three-phase voltage dip magnitude and fault ride-through times are as in Table 26) and voltage envelope are as in Figure 82), provided that during the three-minute period immediately following the end of the 200 ms, 2000 ms, or 60000 ms period, the actual voltage remains within the limits stipulated in Table 26.

Table 26: Rwandan voltage dip magnitude and fault ride-through times [66]

Voltage Dip Magnitude Level expressed in p.u.	Fault Ride-Through Times in ms
0	200
0.75	2000
0.85	60000

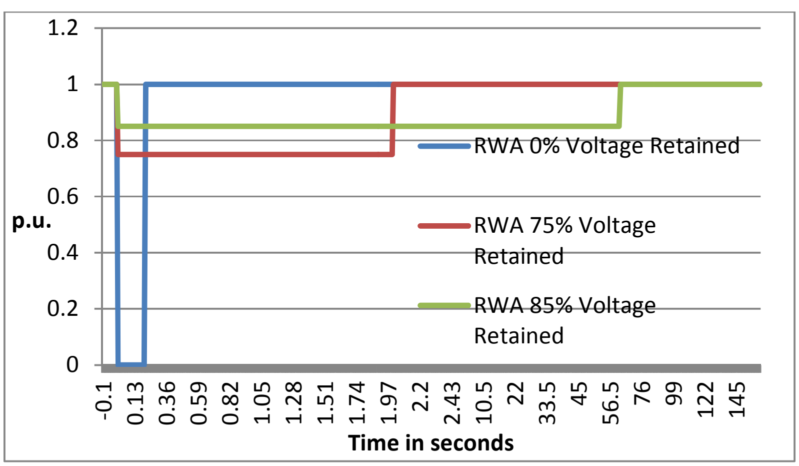


Figure 82: Voltage Envelope – Rwandan grid code

The acceptable IPS voltage ranges following a disturbance are 0.90 p.u. and 1.10 p.u. and are not shown on this graph, 1.0 p.u. was used for the system condition prior and post incident.

A three-phase fault withstand capability is not stipulated because of the radial nature of the IPS. It not currently designed for (N-1) operation.

3.1.1.10 SUDANESE GRID CODE

The anticipated voltage conditions at the point of connection include voltage deviation as per Table 27 for the different transmission voltages:

Table 27: Sudanese voltage deviation limits [67]

Normal Operating Conditions		Long Period Voltage Dip and Swell (one-half cycle to less than 1 minute)	
Minimum Voltage (p.u.)	**Maximum Voltage (p.u.)**	**Minimum Voltage (p.u.)**	**Maximum Voltage (p.u.)**
0.95	1.05	0.10 to 0.90	1.10 to1.80

The Sudanese grid code does specify a voltage dip magnitude of between 10% to 90% for a short period. The back-up trip fault clearing times are used for the fault ride-through times (see Table 28) and voltage envelope (see Figure 83).

Table 28: Sudanese voltage dip magnitude and fault ride-through times [67]

Voltage – (kV rms)	Voltage Dip Magnitude Level expressed in p.u.	Fault Ride-Through Times in ms
500 kV	0.10	235
220 kV and 110 kV	0.10	250

Voltage – (kV rms)	Voltage Dip Magnitude Level expressed in p.u.	Fault Ride-Through Times in ms
<110 kV	0.10	270

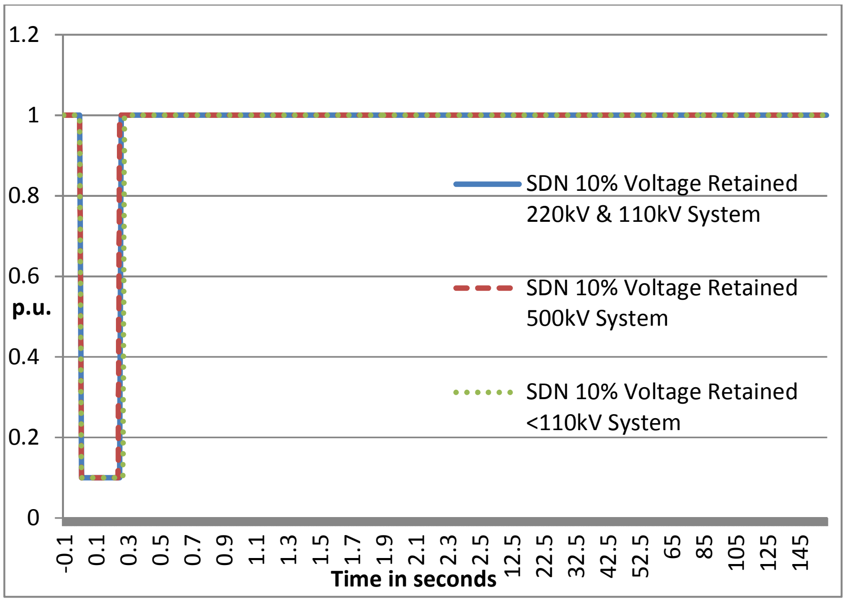


Figure 83: Voltage envelope – Sudanese grid code

3.1.1.11 UGANDAN GRID CODE

The anticipated voltage conditions at the point of connection voltage deviation as per Table 29 for the different transmission voltages:

Table 29: Ugandan voltage deviation limits [69]

Minimum Voltage (p.u.)	Maximum Voltage (p.u.)
0.94	1.06

Note: No specific voltage dip magnitude or fault ride-through capability is specified in the Ugandan grid code.

3.1.1.12 THE UNITED KINGDOMGRID CODE

The anticipated voltage conditions at the point of connection include voltage deviation as per table 30 for the different transmission voltages:

Table 30: United Kingdom's voltage deviation limits [70]

Super Grid	Voltage level	Normal Operating Conditions	
		Minimum Voltage (p.u.)	Maximum Voltage (p.u.)
X	400 kV	0.95	1.05
X	275 kV	0.90	1.10
	132 kV	0.10	1.10

The United Kingdom grid code stipulates that for a solid three-phase fault, the fault clearance time should be within 140 ms and that the supergrid voltage on the onshore IPS may take longer than 140 ms to recover to 90% (see Figure 84).

Table 31: United Kingdom's voltage dip magnitude and fault ride-through times [70]

Voltage Dip Magnitude Level in p.u.	Fault Ride-Through Times in ms
0	140

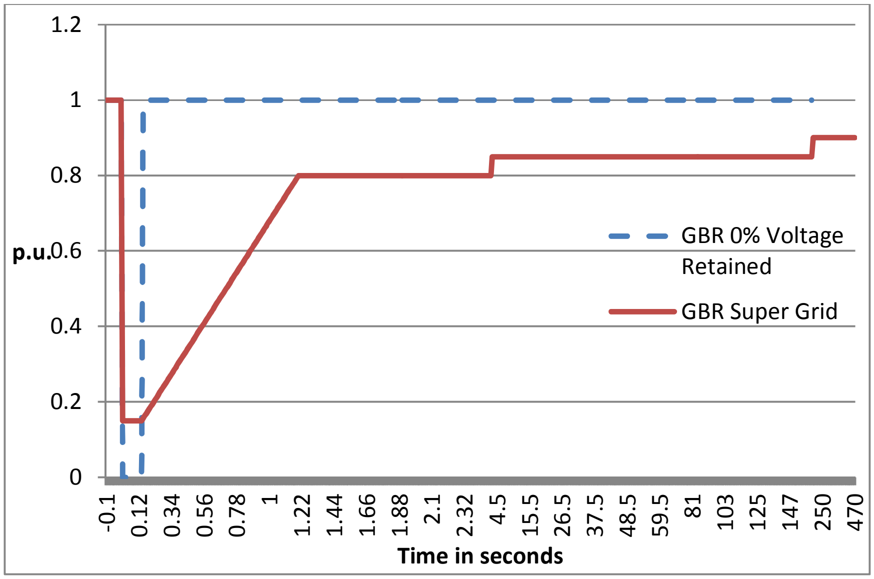


Figure 84: Voltage envelope – United Kingdom grid code

The acceptable IPS voltage ranges following a disturbance are indicated in Table 30 and are not shown on this graph, 1.0 p.u. was used for the system condition before and after the incident.

3.1.1.13 WESTERN AUSTRALIA GRID CODE

The anticipated voltage conditions at the point of connection include voltage deviation as per Table 32 for the different transmission voltages:

Table 32: Western Australian voltage deviation limits [71]

Normal Operating Conditions	
Minimum Voltage (p.u.)	**Maximum Voltage (p.u.)**
0.9	1.1

The Western Australian grid code does specify a voltage dip magnitude of 100% for 450 ms and thereafter a recovery of the voltage to 20% voltage dip magnitude for ten seconds. The voltage envelope is as indicated in Figure 85.

Table 33: Western Australian voltage dip magnitude and fault ride-through times [71]

Voltage Dip Magnitude Level expressed in p.u.	Fault Ride-Through Times in ms
0	450
Followed by 0.80	10000

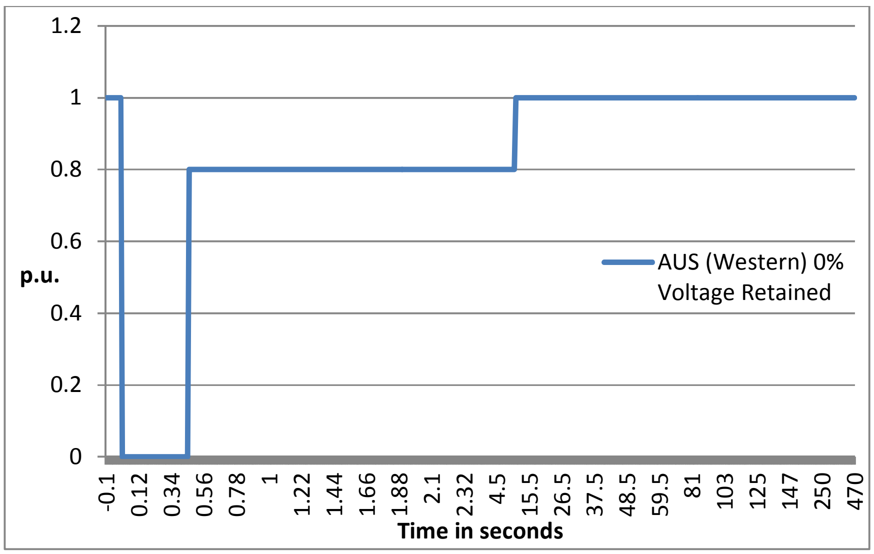


Figure 85: Voltage envelope – Western Australia grid code

The acceptable IPS voltage ranges following a disturbance are 0.90 p.u. and 1.10 p.u. and are not shown on this graph, 1.0 p.u. was used for the system condition before and after the incident.

3.1.1.14 ZIMBABWEAN GRID CODE

The anticipated voltage conditions at the point of connection include voltage deviation as per Table 34 for the different transmission voltages:

Table 34: Zimbabwean voltage deviation limits [72]

Main Transmission Grid	Voltage level kV	Normal Operating Conditions		Stress of Fault Conditions	
		Maximum Voltage (p.u.)	Minimum Voltage (p.u.)	Maximum Voltage (p.u.)	Minimum Voltage (p.u.)
X	400	1.05	0.95	1.05	0.8925
X	330	1.048	0.95	1.10	0.90
	220	1.054	0.95	1.10	0.90
	132	1.05	0.95	1.098	0.90
	110	1.05	0.95	1.10	0.90
	88	1.05	0.95	1.10	0.90
	66	1.05	0.9	1.098	0.85
	33	1.0515	0.9515	1.1	0.9
	11	1.0545	0.954	1.1	0.9

Table 35: Zimbabwean protection operating times [72]

Voltage System Levels kV	Protection Operating Times in ms
400	100
330	100
220	100
132	160
110	160

Voltage System Levels kV	**Protection Operating Times in ms**
88	160
66	160
33	200
22	200
11	200

The Zimbabwean grid code allows for a voltage dip magnitude of 20% maximum and states that a voltage dip magnitude of 30% following the clearance of a fault is not acceptable and must be investigated. The voltage deviation limits and fault ride-through time are given (see Table 36), as is voltage envelope (see Figure 86).

Table 36: Zimbabwean voltage dip magnitude and fault ride-through times [72]

Voltage Dip Magnitude Level expressed in p.u.	**Fault Ride-through Times in ms**
0.80	500
1.20	500

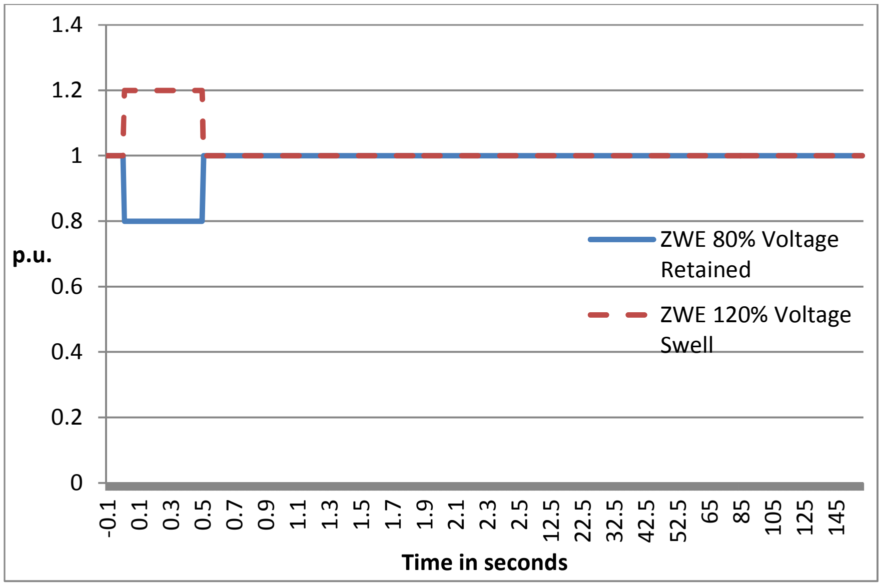


Figure 86: Voltage envelope – Zimbabwean grid code

The acceptable IPS voltage ranges following a disturbance are indicated in Table 35 and are not shown on this graph, 1.0 p.u. was used for the system condition prior and post incident.

3.1.2 INTERNATIONAL GRID CODE IPS DISTURBANCE IMMUNITY SUMMARY

The majority of the grid codes reviewed stipulate some form of immunity for disturbances that occur in the IPS. There are different derivatives in terms of the voltage dip magnitude and ride-through times in the grid codes of different countries. The commonality between the majority of the grid codes is concern about the impact directly following an incident and therefore the requirement that power plants must have a degree of resilience so that power-generating capability is not interrupted following the disturbances.

3.2 VOLTAGE OPERATING LIMITS COMPARISON – GCR 9 VS STANDARDS VS DESIGN PARAMETER

In order to perform a comparison of the power plant design parameters and the GCR 9 operating voltage requirements, the frequency variation limits between the grid code and the power plant design parameters should be considered. Figure 87 provides the frequency variation limits stipulated in GCR 6 [2]. The power plant design is for a voltage deviation of 0.75 p.u.; the lowest operating frequency, i.e. 46.5 Hz for a 5 second duration, while the GCR

6 requirement is 47.5 Hz for 6 s before the generator is allowed to island or trip. The power plant design therefore meets the GCR 6 operating frequency limits. The comparison in Table 39 provides the GCR 9 voltage depression limits and duration versus the power plant data.

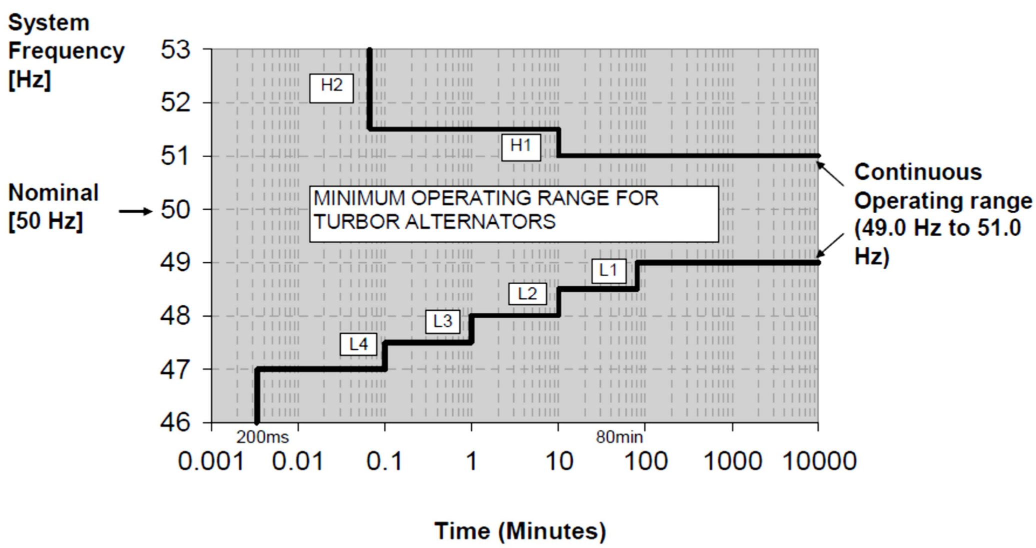


Figure 87: Frequency variations stipulated in GCR 6 [2]

Table 37: Voltage operating limits GCR 9 vs power plant

National Grid Code GCR 9		**Power Plant Design [5]**	
Voltage p.u.	**Frequency p.u.**	**Voltage p.u.**	**Frequency p.u.**
Depression to 0 of nominal up to 200 ms	1.03 up to 10 minutes to 0.94 for 200 ms	Depression to 0 of nominal up to 1000 ms	0.975 to 1.025 of nominal
Depression to 0.75 of nominal for up to 1 s	0.95 up to 6 s to 1.03 up to 10 minutes	Depression to 0.75 of nominal for up to 10 s	0.975 to 1.025
		Depression to 0.75 of nominal for up to 5 s	0.93 to 1.0 of nominal

National Grid Code GCR 9		**Power Plant Design [5]**	
Voltage p.u.	**Frequency p.u.**	**Voltage p.u.**	**Frequency p.u.**
		Depression to 0.70 of nominal for up to 3 s	
Depression to 0.85 of nominal for up to 60 s	0.95 up to 6 seconds to 1.03 up to 10 minutes	Depression to 0.85 of nominal for up to 1 hour with further deviation to 0.7 of nominal for up to 10 s	0.975 to 1 of nominal

IEC standards, specifically the SANS equivalent, are generally used within the power plant environment and were therefore used to do the comparison.

Table 38: Voltage operating limits GCR 9 vs power plant equipment IEC standards

Electrical Plant	**IEC Standard**	**Technical requirement details**	**Comments**
Generators	IEC 60034-3:2007 Rotating electrical machines Part 3: Specific requirements for synchronous generators driven by steam turbines or combustion gas turbines	The generator shall be designed to withstand without failure a short circuit of any kind at its terminals, while operating at rated load and 1.05 p.u. rated voltage, provided the maximum phase current is limited by external means to a value that does not exceed the maximum phase current obtained from a three-phase short circuit. “Without failure” means that the generator shall not suffer	

Electrical Plant	IEC Standard	Technical requirement details	Comments
		damage that causes it to trip out of service, though some deformation of the stator winding might occur.	
Generators	IEC 60034-1: 2010, Rotating electrical machines – Part 1: Rating and performance IEC 60034-3:2007 Rotating electrical machines Part 3: Specific requirements for synchronous generators driven by steam turbines or combustion gas turbines	With reference to IEC60034-3 [47] the generators must be rated capable of continuous operation between 95 and 105% of rated terminal voltage, producing continuously the rated MVA at a power factor between 0.95 underexcited (leading) and 0.90 overexcited (lagging) without any component exceeding the temperature limits as specified. The effects of frequency variation on the rating are in accordance with IEC 60034-3 Zone A. Undervoltage: The generators are rated capable of operation during voltage variations between 92% and 108% as per IEC 60034-1 [55] Zone B for limited time durations and the frequency of the occurrences.	The latest IEC for generators does not stipulate continuous operation at ±10 nominal voltage.
Motors	IEC 60034-1: 1994, Rotating electrical machines – Part 1: Rating and performance	PDS rated input voltage ±10% (at the point of coupling PC), according to class 2 defined in IEC 61000-2-4 (see also 5.2.2.1 and 5.2.2.2 of IEC 61800-3). NOTE – Short time voltage variation beyond the levels specified may result in interruption of operation or	

Electrical Plant	IEC Standard	Technical requirement details	Comments
		tripping. If continuous operation is necessary, an agreement is required between the user and the supplier/manufacturer.	
	IEC 60034-1: 2010, Rotating electrical machines – Part 1: Rating and performance	The generators are rated capable of operation during voltage variations between 92% and 108% as per IEC 60034-1 [55] zone B for limited time durations and the frequency of the occurrences.	
Variable speed drives	IEC 61800-1, Adjustable speed electrical power drive systems – Part 1: General requirements – Rating specifications for low voltage adjustable speed DC power drive systems. IEC 61800-3, Adjustable speed electrical power drive systems – Part 3: EMC requirements and specific test methods. SANS 61800-5-2:2008 Adjustable speed electrical power drive systems Part 5-2: Safety requirements — Functional.	Voltage deviations (> 60 s) ± 10% Voltage dip level 0% 1 cycle Voltage dip level 70% 25 cycles Short interruptions Voltage at 0 for 250 cycles.	Performance criteria C is indicated, which is effectively shut down and will therefore interrupt the process.
Emergency supply equipment, battery chargers,	SANS 62040-3: 2012 Uninterruptable power systems (UPS) Part 3: Method of specifying the performance and test	"A UPS conforming to this standard shall be compatible with public low-voltage supplies and be capable of remaining in normal mode of operation when	Due to the stored energy source providing continuous

Electrical Plant	IEC Standard	Technical requirement details	Comments
uninterrup-table power supplies, switch mode power supplies etc.	requirements	connected to an AC input supply presenting characteristics as follows: a) rated voltage; b) r.m.s. voltage variation of ±10% of rated voltage; c) rated frequency; d) frequency variation ±2% of rated frequency; e) for three-phase input, voltage unbalance with an unbalance ratio (NPS) of 5%." NOTE 3 The above limits apply to public low voltage supplies. UPS designed for industrial applications or separately generated supplies may be required to meet more severe conditions. The purchaser should specify such conditions as applicable. In the absence of such information, the manufacturer/supplier may apply experience as to the compatibility of the design for the intended installation.	operation, the rectifier shutdown occurs, generating alarms to the distributed control system. Cycling of batteries can occur.
	SANS 60146-1-1:1991 Semiconductor convertors; General requirements and line commutated convertors Part 1-1: Specifications of basic requirements	Steady state ±10% variation from nominal value. Short time (0.5 cycles to 30 cycles) ±15% variation from nominal value	

Electrical Plant	IEC Standard	Technical requirement details	Comments
Control supply equipment	SANS 60947-1:2015 Low-voltage switchgear and controlgear Part 1: General rules SANS 60947-4-1:2004 Low-voltage switchgear and control gear Part 4-1: Contactors and motor-starters – Electromechanical contactors and motor-starters	"For electromagnetic and electro-pneumatic equipment, the drop-out voltage shall not be higher than 75% of the rated control circuit supply voltage *U*s nor lower than 20% of *U*s in the case of AC at rated frequency, or 10% of *U*s in the case of DC".	
Distributed Control System	SANS 61000-4-11:2005 Electromagnetic compatibility (EMC) Part 4-11: Testing and measurement techniques — Voltage dips, short interruptions and voltage variations immunity tests	Voltage dip level 0% 1 cycle Voltage dip level 70% 25 cycles Short interruptions voltage at 0% for 250 cycles.	

The IEC 61000 -4-11 and IEC 61000-4-34, which define the immunity test methods and range of preferred test levels for electrical and electronic equipment supplied from low-voltage power supply networks for voltage dips, short interruptions, and voltage variations, are often also used to specify the required voltage immunity of equipment. A comparison between these two IEC standards and GCR 9 follows below. Only class 3 is considered for power plant applications as defined by IEC 61000-2-4 [73].

Table 39: Voltage operating limits GCR 9 vs IEC61000-4-11/34 standards

GCR 9	IEC 61000-4-11 and 34
Voltage depression to 0 up to 200 ms	Voltage depression to 0 up to 10 ms
	Voltage depression to 0.40 p.u. for up to 200 ms

GCR 9	**IEC 61000-4-11 and 34**
Voltage depression to 0.75 p.u. for up to 1 s	
	Voltage depression to 0.70 p.u. for up to 500 ms
	Voltage depression to 0.80 p.u. for up to 5 s
Voltage depression to 0.85 p.u. for up to 60 s	

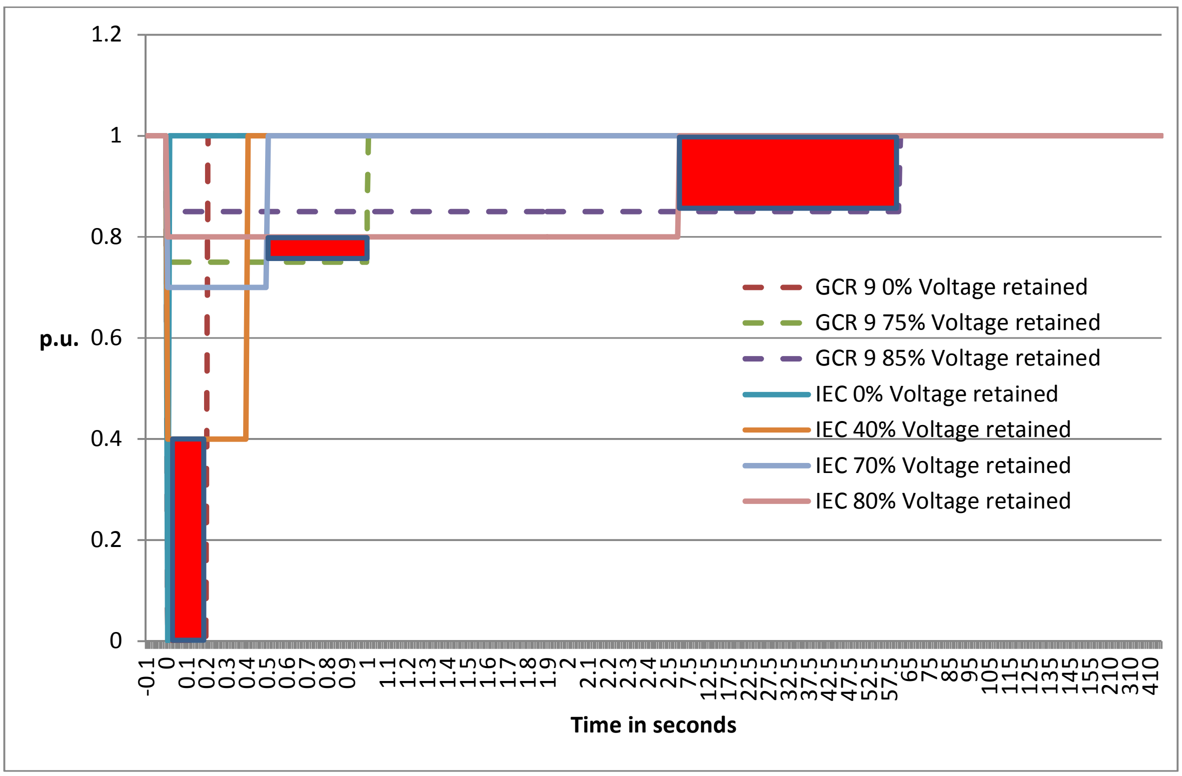


Figure 88: GCR 9 Voltage limits versus IEC 61000-4-11/34

The highlighted red areas indicate the areas not covered by the IEC 61000-4-11 and IEC 61000-4-34 when compared to the GCR 9 limits. It is evident that the IEC provides limited voltage immunity for a 100% voltage dip.

3.3 SUMMARY

The majority of grid codes evaluated in this chapter stipulate a degree of resilience to disturbances generated in the IPS as applicable to power plants. The magnitude of voltage deviation and ride-through period are different in the majority of countries. The ride-through period is mainly determined by the maximum time it will take the protection to clear the fault. It therefore appears that no international alignment exists.

There are similarities in the grid codes for Namibia, Rwanda and South Africa for IPS disturbance resilience, with one major difference in the ride-through period for a 0.75 p.u. voltage deviation. The ride-through period is 2000 ms for Namibia and Rwanda, versus 1000 ms for South Africa. The ride-through period stipulated in the South Africa grid code is concerning due to the 2000 ms stipulated in the paragraph that states that during the 3-minute period immediately following the end of the 200 ms, 2.0 s, or 60 s period, the actual voltage remains within the limits stipulated in Table 4.

The comparison between the plant design parameters and GCR 9 did not reveal additional concerns that should be considered and confirms that the plant design parameters comply with the requirements stipulated in GCR 9.

The comparison between GCR 9 and IEC standards applicable to equipment used within the power plant reveals a number of areas that do not comply with the GCR 9 requirements.

The comparison between GCR 9 and specific IEC 61000-4-11 and IEC 61000-4-34 reveals that a large degree of immunity will be provided when the IEC limits for class 3 is stipulated.

CHAPTER 4

ANALYSIS

4.1 INTRODUCTION

Chapter 4 presents the analysis of data from tests and actual electrical fault incidents that have occurred within power plants and that have caused a supply disturbance within the electrical reticulation system. A functional requirement was derived for an identified problematic area to ensure supply disturbance resilience. Similarities between the exposure of supply disturbances in the IPS and those experienced as a result of actual faults within the electrical reticulation system within a typical power plant are established. The degree of similarities identified provide the necessary assurance that the supply disturbance resilience inherent in the older power plant design is sufficient or lacks compliance with the retrospectively adopted regulatory framework as basis for the assurance quantum.

4.2 ANALYSIS OF CONTROL SUPPLY AT POWER PLANTS

4.2.1 OPERATIONAL EXPERIENCE

From the available data, namely tests and reports, the following failures have been recorded on the specific type line interactive UPSs in use at power plants:

- Tests were conducted as per required routine test [74] at a power plant on the low voltage distribution boards on which different size and type contactors are connected, feeding different motor loads. The test entailed decreasing the control supply voltage to determine the voltage levels at which contactors are dropping out. Contactor drop-out was recorded at levels of 170 V – 175 V on 380 V systems. The full load current on control supply was measured to be between 3 A and 4 A, and with the contactors start dropping out, the current increased to approximately 40 A to energize the contactors again.
- There was overload protection operation on a previous model without any downstream fault. Further tests also revealed that the line interactive UPS would switch off before

the downstream overload protection, normally 6 A type gG [75] fuse or 10 A MCB C curve [76] can clear the short circuit.

- As a result of the installation of the line interactive UPS as a direct replacement of the stabilized power supplies, a supply chop-over can occur and the line interactive UPS will be monitoring the wrong supply [77]. The line interactive UPS can therefore activate for a dip, although no voltage deviation on the supply to the contactors may be present. This carries the risk of an interruption of control supply if the line interactive UPS cannot synchronize with the mains before the stored energy from the capacitor is depleted.
- Unreliability of new equipment models, i.e. component failures UPS [78].
- Tests performed on a line interactive UPS [79] based on the IEC 61000-4-11 standard [80] revealed that the line interactive UPS failed to keep the contactor closed after approximately 38 ms when the voltage dip was greater than 30%. The line interactive UPS is set to activate for an input supply voltage dip greater than 25% to supply the load from the internal stored energy, which has a voltage wave characteristic as indicated in Figure 85. Further tests [79] based on the NRS 048-2 standard [81] revealed that the line interactive UPS illustrated ride-through capability only when 2nd and 3rd harmonics are present in the supply. Figure 90 illustrates the activation of the line interactive UPS because of distortion of the voltage wave, although the RMS value of the voltage is indicating no voltage dip.
- The line interactive UPS and therefore the control supply are connected to the red phase and the undervoltage condition is therefore determined only by what occurs on one phase.

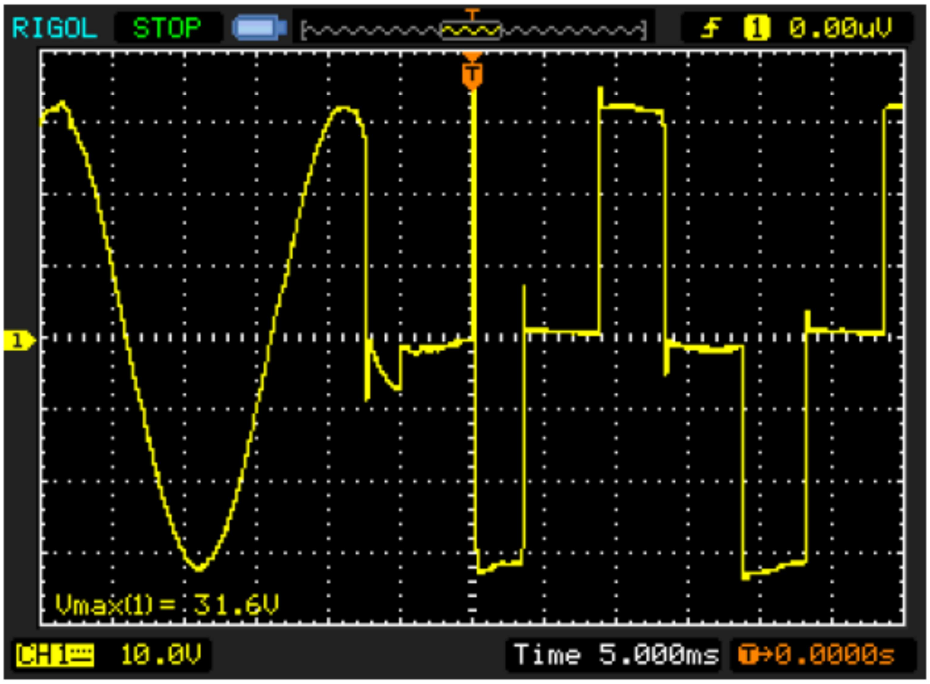


Figure 89: Line interactive UPS output voltage waveform as supply to contactor

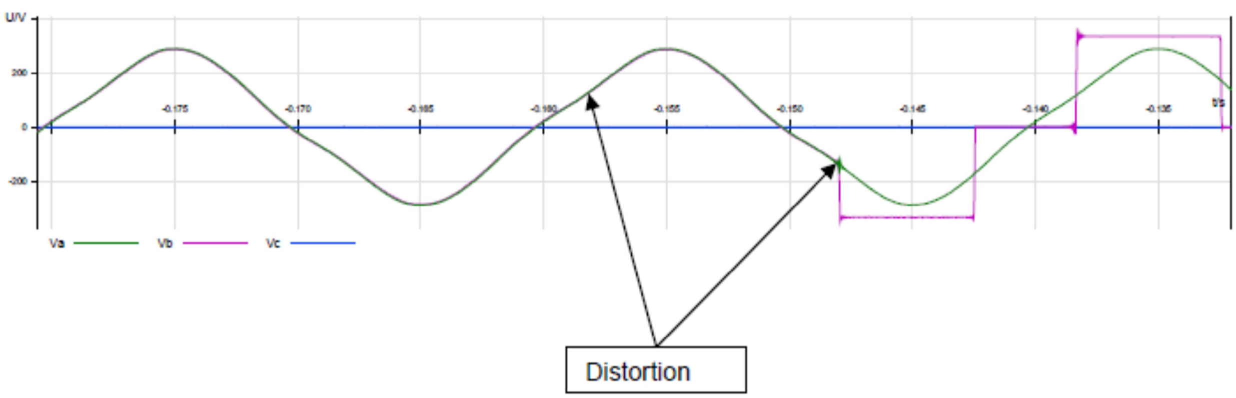


Figure 90: Line interactive UPS activation during voltage wave distortion

4.2.2 GENERAL

As indicated in Chapter 2, the majority of the power plants designed in 1980s were equipped with stabilized power supply units as the source of control supply voltage to provide voltage dip immunity. As a result of poor reliability and the lack of adequate short supply interruption capability from stabilized power supply units, an alternative solution was engineered later on in the 1980s. The engineered solution was a line interactive UPS as described in Chapter 2.

The effective operation of the line interactive UPS [9] to provide voltage dip immunity has been recorded on several occasions [82], [83], [84]. Several incidents were investigated where the line interactive UPS resulted in the interruption of control supply and effectively the interruption of power-generating capacity in the absence of an actual voltage dip, rendering the reliability of the line interactive UPS questionable [85], [86].

Available data and failure reports are analysed in this chapter to determine the suitability and effectiveness of the existing line interactive UPS to ensure the required voltage immunity as stipulated in GCR 9. Alternative options, practices in the industry and technologies are also evaluated.

4.2.3 LINE INTERACTIVE VOLTIGE DIP PROOFING DEVICE OPERATING PHILOSOPHY

The design and operation philosophy of the line interactive UPS installed at power plants to achieve a degree of voltage immunity requires further analysis in this chapter to verify and validate the effectiveness of the equipment to ensure compliance to CGR9.

The fast activation within the first half cycle of the voltage wave is achieved by dividing the voltage sine wave up in time intervals. The peak values of a healthy voltage sine wave at these specific time intervals are stored in the central processing unit. The voltage deviation value at which the line interactive UPS has to activate is adjustable. The setting value at power plants is 25%. The measured peak values at these intervals are then compared with the stored values, and when 3 consecutive deviations >25% are detected, the line interactive voltage dip proofing device is activated. As a result of the zero crossings and the 25% voltage deviation criteria, the first and last 3 ms of the wave before and after crossing zeros are disregarded.

The operating philosophy of the line interactive UPS provides quick activation within 700 µs, following the detection of three consecutive voltage samples measured 140 µs apart. This deviates more than 25% from stored data of a healthy sine wave. The risk of this philosophy is that if the main supply is contaminated with harmonics, the line interactive UPS can activate, but will also fail to synchronise (refer to Figure 96).

The voltage dip magnitude setting of 25% at which the line interactive UPS activates to provide supply to the contactors are inadequate for the operating philosophy employed and for the behavioural characteristics of contactors during a voltage dip. At 25% voltage dip magnitude, the contactor is already experiencing electromagnetic drop-out and following the activation of the line interactive UPS and therefore the recovery of the supply voltage, the contactor will draw energizing current. The energizing current will deplete the stored energy faster and the autonomy of the line interactive UPS to maintain control supply is significantly reduced. The reduced standby period effectively also reduces the time-period the line interactive UPS has to re-synchronize back to mains supply [86].

Furthermore, depending on the point of wave activation of the line interactive UPS and the already decayed magnetic flux, the contactor can be exposed to a further 100% voltage dip for up to 6 ms as a result of the specific line interactive UPS output waveform characteristic (see Figure 89).

4.2.4 CONTROL SUPPLY CONSIDERATIONS FOR POWER PLANTS

The literature study revealed the importance of considering many different aspects related to contactors during a voltage dip. This section analyses effectiveness of the devices installed at power plants in an effort to suggest alternatives for consideration. Due to the history of power interruptions experienced at power plants because of the line interactive UPS installed at power plants, alternative options are evaluated.

The section also analyses possible causes of the malfunctioning of the line interactive UPS and the resultant impact to determine the suitability of the product for application and the effectiveness with which it provides ride-through capability to the power-generating unit during a voltage dip.

4.2.4.1 ALTERNATIVE CONTROL SUPPLY OPTIONS AND EVALUATION FOR POWER PLANTS

The two tables below provide a summary of the different control supply options considered for power plants.

Table 40: Control supply options

Criteria Description	Device			
	Line-interactive UPS [9]	**DC Contactors**	**Latching contactors**	**UPS (Additional requirements to standard UPS)**
Maintenance free	No, correct setup and testing required	No	Yes	No
Cost effective	Yes	No, contactor replacement	No, contactor replacement	Yes, if unnecessary power-generating interruptions are prevented
High reliability	Yes (Not experience at power plants)	Yes	Yes	Yes (redundant systems)
Ultrafast transfer time	Yes	N/A	N/A	Yes (active, in-line load supply)
Suitable for variable loads	Yes	Yes	N/A	Yes (to be specified, large reactive power component)
Ride-through from cycles to seconds	Yes (in-line static transfer switch) – No stored energy depleted because of energizing current.	Yes	Yes	Yes
Accurate ride-through control	No, very sensitive to wave distortions, activation and supply interruption	No, DCS interface required. Management of earth faults.	No, massive control and instrumentation implication DCS interface required	No, DCS interface required

Table 41: Control supply options and considerations – a summary

Solution	Objective: Confidence level in technical solution	Risk	Implementation time frame	Cost	Comment
Solution 1 – UPS (Non-standard, specific operational requirements for use with contactors)	>98%	Low	Solution ready in 1 year, implementation in 3 years.	R1.5 m/ unit	This is a generic engineered solution for reliability and flexibility between different power stations. Undervoltage protection is integrated and can be independent of control and instrumentation .
Solution 2 – Existing device (Further development and improvement)	60%	Medium	Solution ready in 2 years, implementation in 3 years.	R1m and R150 k to R250 k/unit	Power plants one of the largest users, providing operational experience and in-service testing. Major operational concerns.
Solution 3: DC or latching contactors	90%	Medium	1 to 6 years plus.	R3m to R10m /unit?	Chargers and batteries required, contactor retrofit (if possible), control and instrumentation philosophy change and implementation (if possible). Earth fault detection required.

Option 1 is a generic option that can be retrofitted to the majority of power plants without requiring an entire distributed control system upgrade. The high-level engineering and test results for option 1 are further deliberated in this chapter.

4.2.4.2 CONTROL SUPPLY IN-LINE UPS: TECHNICAL AND FUNCTIONAL REQUIREMENTS

Based on the operational experience at power plants, contactor behaviour and the characteristics that should be considered during a voltage interruption or dip, the following requirements in addition to the UPS specifications [87], [88] should be included:

- Rectifier input supply tolerance ±25% – the input supply tolerance requirements should meet the power plant design criteria, which specify that the voltage is allowed to dip to 25% when large motor loads are started. If these criteria are not met by the UPS, alarms will be generated during normal plant operation and the UPS will revert to battery supply;
- Bypass input supply tolerance ±25% – same requirements as above as the bypass supply and input supply have to be from the same source;
- Output power factor 0.1 to 0.9 – determined by the characteristic of contactors, power factor that varies during energizing state to energized state;
- UPS output voltage tolerance +10% to -15%, also required during transients – the best performance characteristic (see Figure 87) available in the UPS IEC standard [8] allows a ±30% voltage deviation for 5 ms during transients. The literature study, operational experience and tests performed on contactors reported contactor drop-out at these voltage levels.

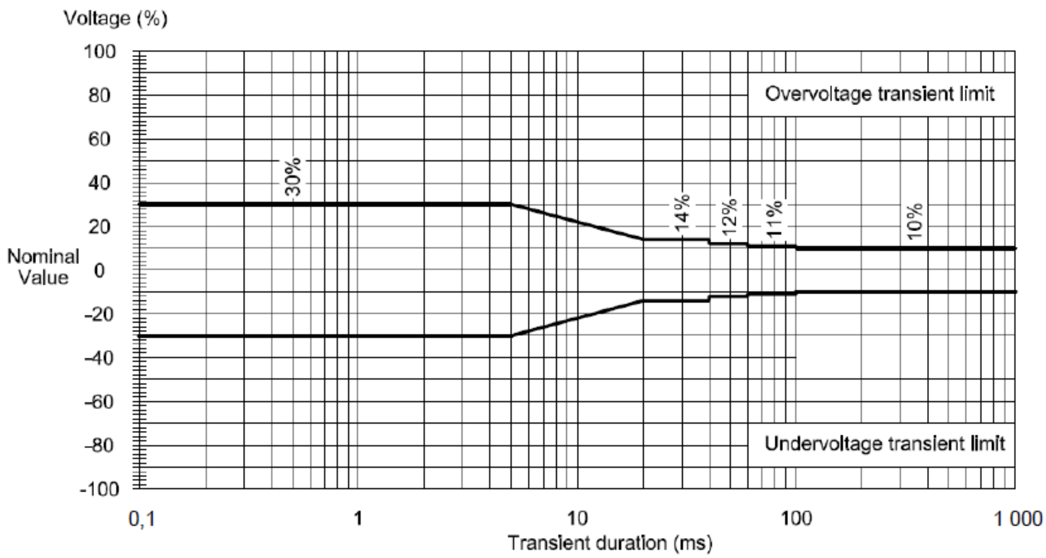


Figure 91: Dynamic UPS output performance characteristic curve 1 [8]

- Overload capability 10 x I_n for 0.5 s – the inverter should be able to supply power to the contactors during energising state and not revert to the bypass during contactor energising. The UPS should revert to bypass only if the inverter has failed.

Functional requirements:

- UPS should be an in-line, providing uninterruptable supply to the contactors, with bypass in case of redundant inverter failure;
- Undervoltage philosophy to interrupt supply to contactors during an actual board supply interruption. Two out of three phases to be monitored to determine a real undervoltage condition;
- Inverter redundancy – hot swappable modules;
- Adequate autonomy to allow for corrective maintenance following redundant rectifier module failure;
- Power supply quality monitoring and recording capability;
- UPS should provide undervoltage protection;

- UPS should be supplied from the same board as the motor loads to monitor an actual undervoltage condition;
- A failure of a single in-line UPS will impact only on 50% of a power-generating unit's capability.

4.2.5 CONTROL SUPPLY UPS TEST RESULTS

The schematic for the newly engineered control supply UPS is provided in Figure 92, with the functionality and compliance to the technical and user requirements as part of the test results and technical data [91]. The majority of the test results were captured with the recorder [89], installed as an integral part of the control supply UPS.

The step load test entails the instantaneous addition and removal of electrical load on the UPS output, to evaluate that the UPS output voltage transient deviation and recovery time is within the specified dynamic output performance limits. For the control supply UPS the voltage limits were +10% and -15%. The test setup is to apply a load equal to the full load capability of the inverter. The voltage waveforms are recoded when the load is removed by switching off the output circuit breaker and adding a 100% load by switching on the output circuit breaker. The test results show (see Figure 93) a 1% voltage increase when 100% load is removed and a 1% voltage decrease when 100% load is applied, within one cycle.

Fault clearing test is performed with the by-pass supply switched off, to proof that the inverter has the capability to clear the fault through the short circuit protection devices installed on the respective contactor circuits used at power plants. The test set-up is to install a 10 A MCB and 6 A fuse circuit downstream of the main 32 A MCB and to apply a short circuit downstream of the 10 A MCB and 6 A fuse. The 32 A MCB is switched to the off position before the inverter is switched on. With the inverter running the 32 A MCB is switched on, the inverter output voltage and current wave forms are recorded. The correct operation of the short circuit protection device is recorded via visual. The test results (see Figure 94 and Figure 95) show a decrease in the voltage to 0 V and a sudden increase in current when the fault is switched into the circuit. The voltage recovers and the current decreases to 0 A within 10 ms following the clearing of the fault through the protection device. This proves that the inverter without bypass, provides adequate power to ensure operation of the short circuit protection devices. Figure 94 shows the test results when a fault is initiated downstream of 32 A MCB (B-curve) on 10 A MCB (C-curve) and Figure 95 for a 6 A gG (NS) fuse.

The input voltage deviation test is performed to proof that the UPS output is maintained during a supply voltage deviation of greater than ±25% without reverting to battery supply. The second part of the test is to proof the undervoltage philosophy. The undervoltage philosophy requires that the supply to contactors be interrupted following a voltage dip longer than 1.5 s. The test setup is to program the undervoltage philosophy into the Vecto II recorder. The input supply voltage on two phases is switched off and the UPS output waveform is recorded. Figure 96 shows that the output is maintained during the interruption of two phases on the input supply. After 1.5 s the inverter output is interrupted.

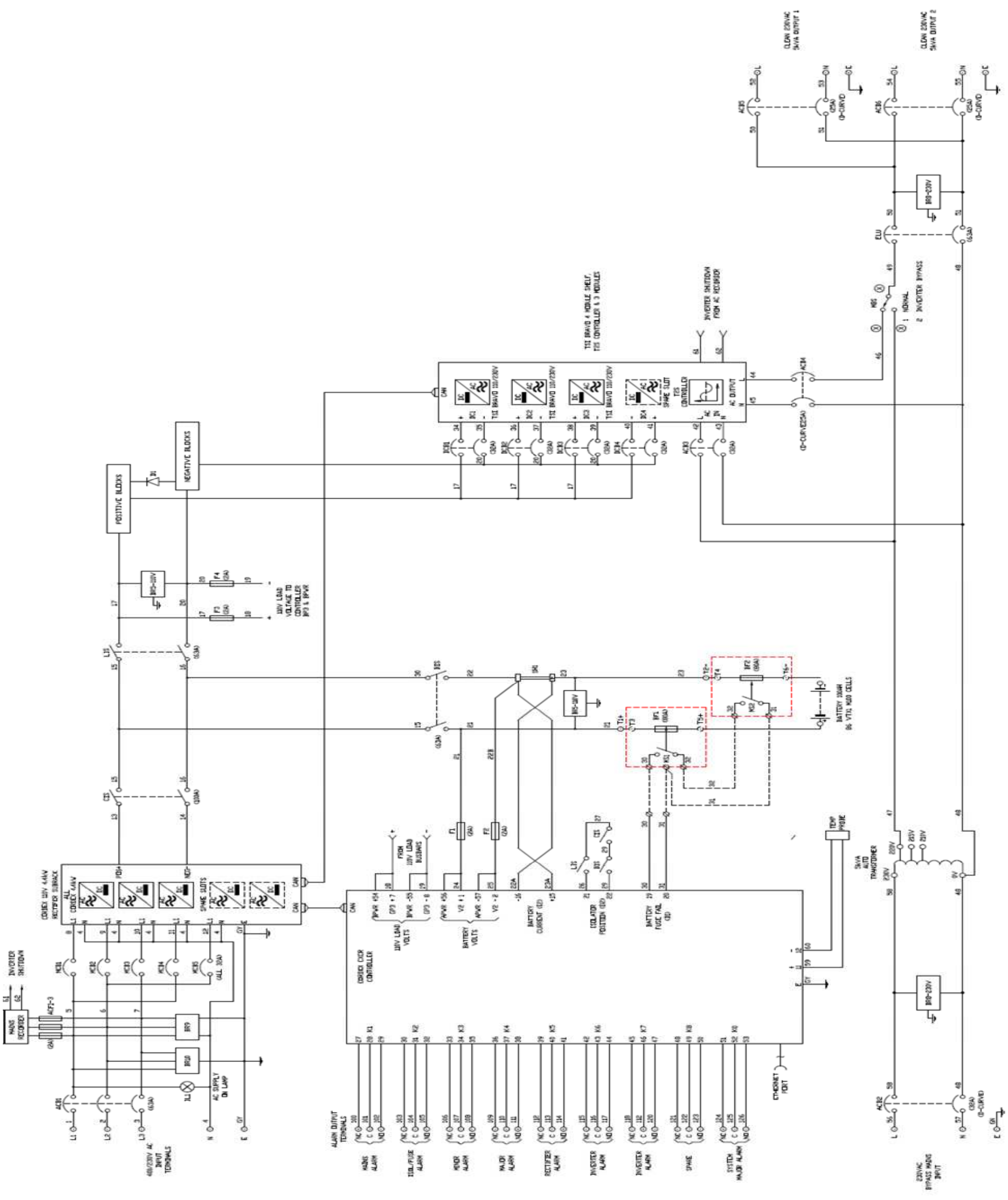


Figure 92: Control supply UPS diagram [90]

Table 42: Legend – phase and output voltages and currents

Colour	Description
	Red line represents red phase input voltage and current
	Green line represents white phase input voltage and current
	Blue line represents blue phase input voltage and current
	Grey line represents ups output voltage and current

Note: All tests were performed with the redundant module unplugged.

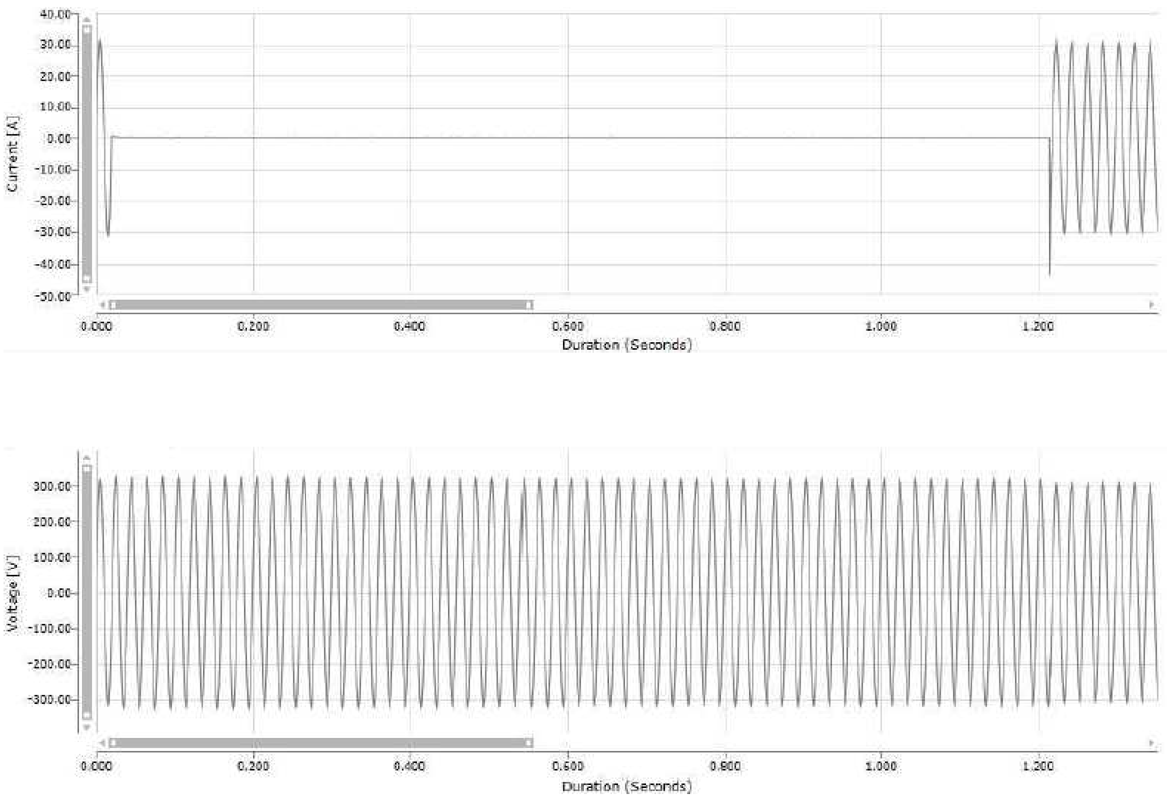


Figure 93: 100% load step change

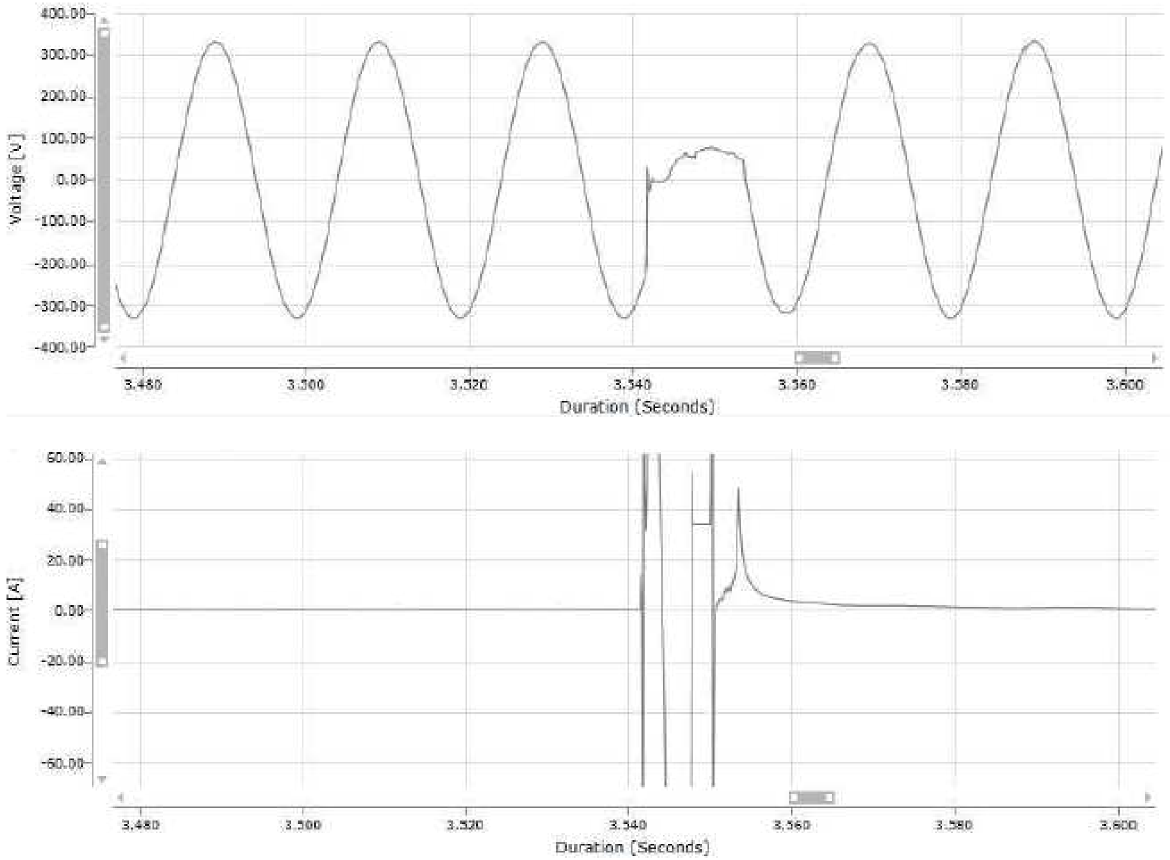


Figure 94: Test result proving that and inverter without bypass provides adequate power to ensure operation of short circuit protection device when fault is initiated downstream of 32 A MCB (B-curve) on 10 A MCB (C-curve)

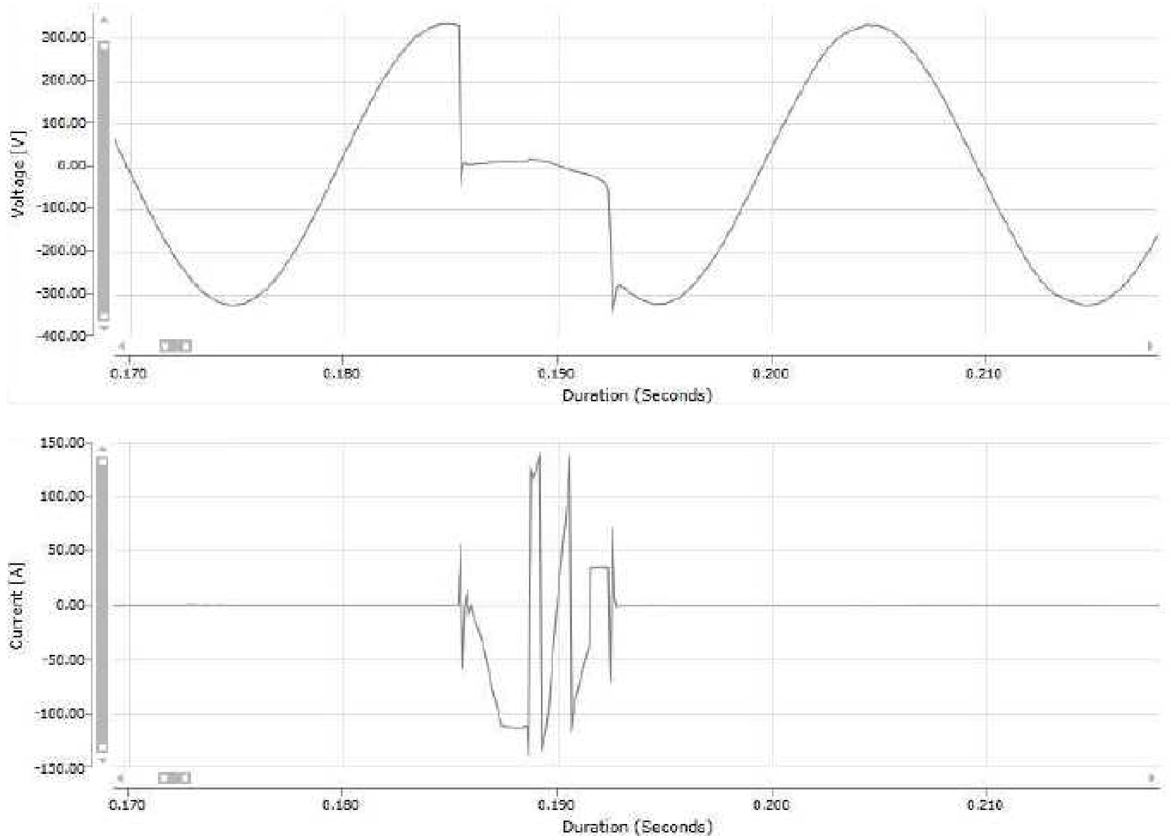


Figure 95: Test result proving that an inverter without bypass provides adequate power to ensure operation of short circuit protection device 6 A gG (NS) fuse

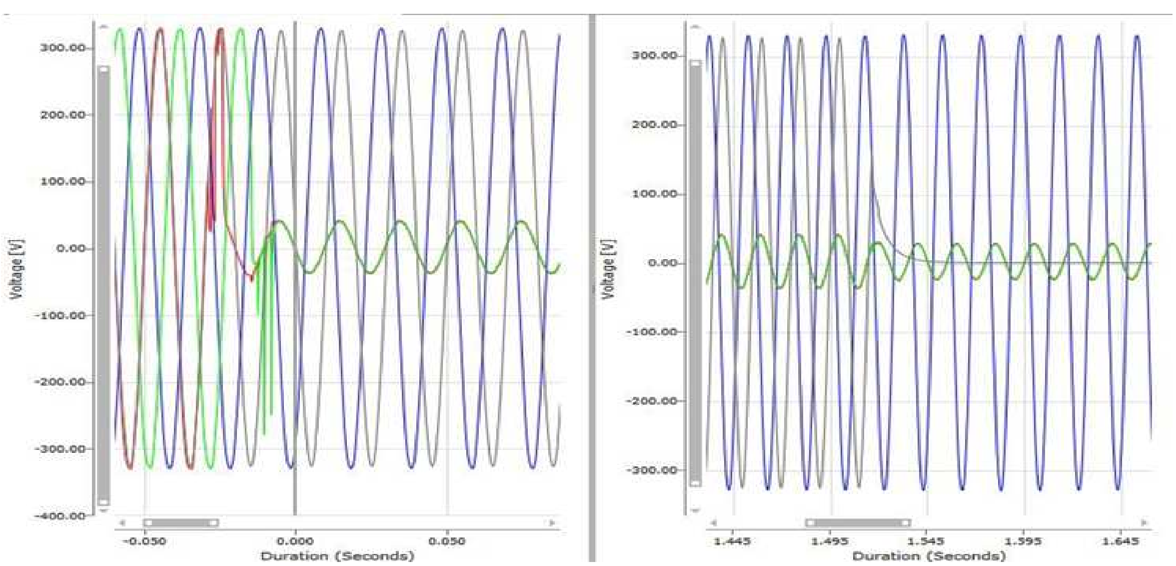


Figure 96: Test results proving that UPS output power is maintained during the failure of two phases and after 1.5 s, the output power is interrupted

4.2.6 CONCLUSION ON CONTROL SUPPLY UPS TEST RESULTS

During the 100% step load change test, no deviation on the output voltage was evident, confirming compliance to the specified output voltage tolerance during transients. The short circuit tests confirmed that the UPS provides adequate power to ensure operation of the typical short circuit protection devices used for control supplies. The grading between the 10 A MCB (C-curve) or 6 A gG (NS) and the 32 A MCB (B-curve) on the output of the UPS is confirmed during the short circuit tests. A summary and verification of the technical and functional requirements compliance is provided in Table 43. The use of this specific in-line UPS to ensure that the supply to contactors during voltage dips is therefore validated.

Table 43: Summary and verification of technical and functional requirements compliance

Technical and Functional Requirements	Verification
Rectifier input supply tolerance ±25%	Technical data sheet 187 V to 90 V AC (de-rated) [91].
Bypass input supply tolerance ±25%	Technical data sheet 150 V to 265 V AC [92] and type test report [93].
Output power factor 0.1 to 0.9	Technical data sheet – full power rating from 0 inductive to 0 capacitive [92].
UPS output voltage tolerance +10% to -15%	100% step load test (see Figure 93).
UPS to be in-line providing uninterruptable supply to the contactors, with bypass in case of redundant inverter failure;	Control supply UPS diagram [90].
Undervoltage philosophy to interrupt supply to contactors during an actual board supply interruption. Two out of three phases to be monitored to	Detail design report for pilot project to replace DPI with control supply UPS [94].

Technical and Functional Requirements	Verification
determine a real undervoltage condition	
Inverter redundancy – hot swappable modules	Detail design report for pilot project to replace DPI with control supply UPS [94].
Adequate autonomy to allow for corrective maintenance following redundant rectifier module failure	100% inverter loading 21.7A AC @ 1.0 pf battery sizing 89 cells ALCAD VTX 1M100C [95].
Adequate autonomy to allow for corrective maintenance following redundant rectifier module failure;	1 hour standby provided by 89 cells ALCAD VTX 1M100C [95] battery at 23.85 A required on DC bus, 91% inverter efficiency [92].
Power supply quality monitoring and recording capability;	Control supply UPS diagram [90] and Vecto II power quality recorder [89].
UPS to provide undervoltage protection.	Detail design report for pilot project to replace DPI with control supply UPS [94]
UPS to be supplied from the same board as the motor loads to monitor an actual undervoltage condition	Detail design report for pilot project to replace DPI with control supply UPS [94].
UPS to be supplied from the same board as the motor loads to monitor an actual undervoltage condition.	Detail design report for pilot project to replace DPI with control supply UPS [94].
A failure of a single in-line UPS will affect only 50% of a power-generating unit’s capability.	Detail design report for pilot project to replace DPI with control supply UPS [94].

4.3 SIMULATIONS

A DigSILENT PowerFactory model developed for the power plant described in Chapter 2 was used to perform simulations for the voltage dips stipulated in CGR 9 as additional verification of compliance to the requirements. The results provide further evidence that the power plant electrical design accomplishes the operational needs of the South African grid code.

A worst-case scenario configuration (see Figure 97) was considered with all power-generating units in service and all HV lines connected. The fault level parameters for this scenario are provided in Table 43 below.

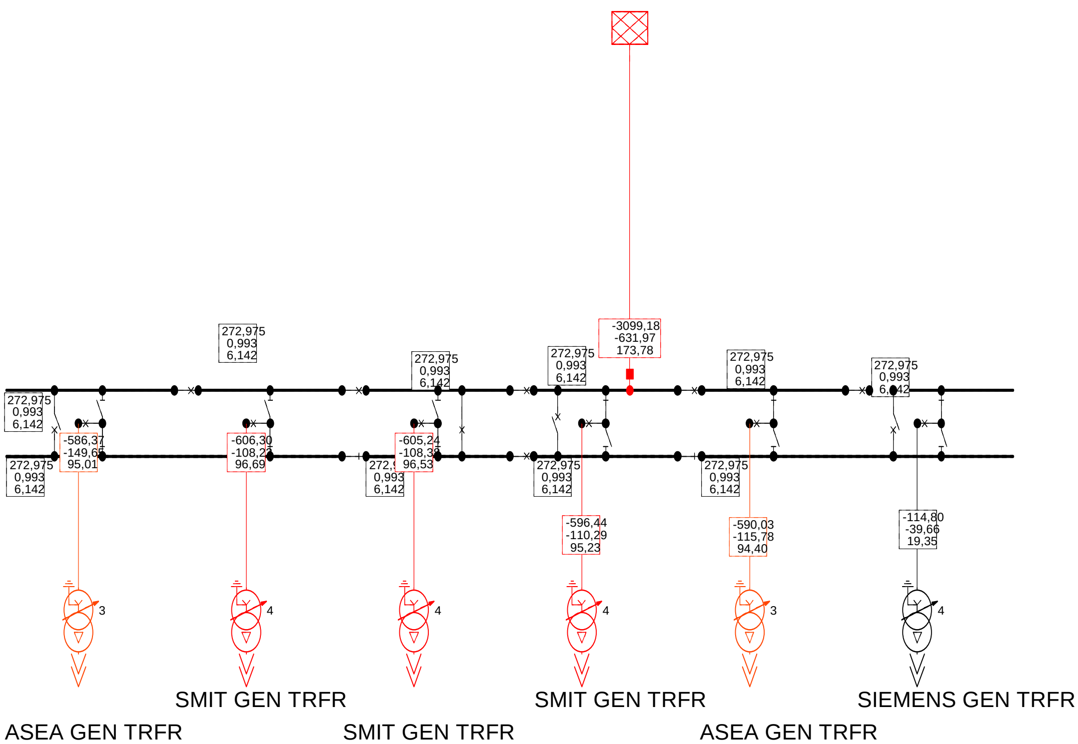


Figure 97: HV network configuration for the power plant

Table 44: Network calculated fault levels

BUSBAR	CIRCUIT NAME	Breaker SAP name	Breaker Manufacturer	Breaker Serial Number	Breaker Installation Date	1-phase CB Rupturing Capacity	1-Phase Fault Level	Circuit Contribution	Current to Break	Breaker Stress	3-Phase Fault Level	Circuit Contribution	Current to Break	Breaker Stress	3-phase CB Rupturing Capacity
						kA	kA	kA	kA	%	kA	kA	kA	%	kA
Lethabo 275 BB	Lethabo Power Station 275/20 T2	Lethabo No2 275kV Gen Bay Bkr	ABB	1HSB0091 6183	2009	50	60.35757	9.626965	50.73061	1%	50.76167	4.89876	45.86291	-8%	50
	Lethabo Power Station 275/20 T1	Lethabo No1 275kV Gen Bay Bkr	ABB	1HSB0091 6178	2009	50	60.35757	7.122819	53.23476	6%	50.76167	4.491828	46.26984	-7%	50
	Lethabo Power Station 275/20 T3	Lethabo No3 275kV Gen Bay Bkr	ABB	1HSB0091 6189	2009	50	60.35757	6.894136	53.46344	7%	50.76167	4.132918	46.62875	-7%	50
	Lethabo Power Station 275/20 T4	Lethabo No4 275kV Gen Bay Bkr	Sprecher & Schuh	2134976-1A-1B-1C	1990	50	60.35757	6.809819	53.54775	7%	50.76167	4.114014	46.64765	-7%	50
	Lethabo Power Station 275/20 T6	Lethabo No6 275kV Gen Bay Bkr	ABB	1HSB0091 6186	2009	50	60.35757	9.092134	51.26544	3%	50.76167	4.626607	46.13506	-8%	50
	Lethabo Power Station 275/20 T5	Lethabo No5 275kV Gen Bay Bkr	Sprecher & Schuh	13073/6/7/8	1984	63	60.35757	8.339778	52.0178	-17%	50.76167	4.417047	46.34462	-26%	63
	Lethabo-Rigi 275_2	Lethabo Rigi No2 275kV Fdr Bay Bkr	ABB	1HSB0104 1056	2009	50	60.35757	1.447743	58.90983	18%	50.76167	0.855744	49.90592	0%	50
	Lethabo-Makalu 275_2	Lethabo Makalu No2 275kV Fdr Bay Bkr	ABB	1HSB0123 1141 A1/B1/C1	2012	50	60.35757	1.4045	58.95307	18%	50.76167	1.995516	48.76615	-2%	50
	Lethabo-Makalu 275_1	Lethabo Makalu No1 275kV Fdr Bay Bkr	ABB	1HSB0091 2077	2009	50	60.35757	1.404387	58.95319	18%	50.76167	1.99494	48.76673	-2%	50
	Lethabo-Rigi 275_1	Lethabo Rigi No1 275kV Fdr Bay Bkr	ABB	1HSB0090 9009	2009	50	60.35757	1.44761	58.90996	18%	50.76167	0.855538	49.90613	0%	50
	Glockner-Lethabo 275_2 S1	Lethabo Glockner No2 275kV Fdr Bay Bkr	AEG	305129A/B/C	1981	57.5	60.35757	2.105433	58.25214	1%	50.76167	3.524418	47.23725	-18%	57.5
	Eiger-Lethabo 275_1 S2	Eiger Lethabo No1 275kV Fdr Bay Bkr	ABB	1HSB0090 9007	2009	50	60.35757	1.287955	59.06962	18%	50.76167	5.423157	45.33851	-9%	50
	Lethabo-Snowdon 275_1	Lethabo Snowdon No1 275kV Fdr Bay Bkr	ABB	1HSB0125 0039-A1/B1/C1	2013	50	60.35757	1.767592	58.58998	17%	50.76167	5.92417	44.8375	-10%	50
	Glockner-Lethabo 275_1 S1	Glockner Lethabo No1 275kV Fdr Bay Bkr	ABB	1HSB0090 07005	2009	50	60.35757	2.105317	58.25226	17%	50.76167	3.523336	47.23833	-6%	50

4.3.1 100% VOLTAGE DIP FOR 200 MS

The simulation illustrates a 100% voltage dip that occurs in the IPS and the corresponding voltages dips experienced within the power plant electrical reticulation on the 11 kV and 380 V side (see Figure 98). A voltage deviation of 85% was seen within the power plant electrical reticulation system. The transformer impedance between the fault and the reticulation within the power-generating unit limit the voltage dip. The short circuit results in a large reactive power surge for the generator. The short circuit also causes an overcurrent and undervoltage condition, the generator current will fade away due to unavailable supply voltage, and the generator reactive power will become almost zero. As a result of the prime mover not being able to respond to remove energy the rotor will accelerate, increasing the load angle (δ). The 200 ms duration is too short for the AVR to respond. Following the clearing of the fault, a sudden increase in reactive power demand occurs due to the re-acceleration of the motor, drawing high currents. A secondary voltage decay of approximately 0.25 p.u. is seen following the recovery of the voltage to 0.5 p.u. to 0.75 p.u.. The AVR responds by providing maximum excitation to maintain the voltage and to increase the synchronizing torque.

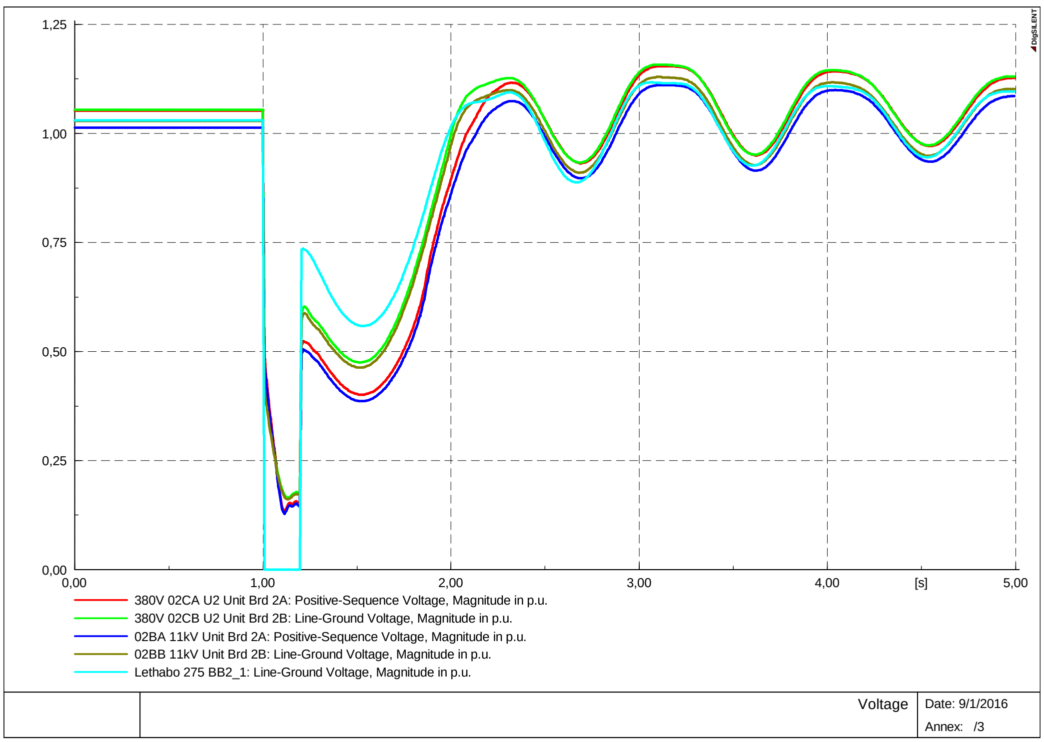


Figure 98: Simulation 100% voltage dip for 200 ms

4.3.2 25% VOLTAGE DIP FOR 1 SECOND

The simulation illustrates a 25% voltage dip for the IPS and the voltages on the 11 kV and 380 V side decreasing down to 75% (see Figure 99). The generator experiences a large reactive power surge and causes overcurrent and undervoltage conditions. The AVR will respond by providing maximum excitation to maintain the voltage and to increase the synchronizing torque, the motor loads will assist in maintaining the voltage. Following the clearing of the fault that caused the voltage to decrease, the voltage will increase with a secondary decrease as the motor loads accelerate.

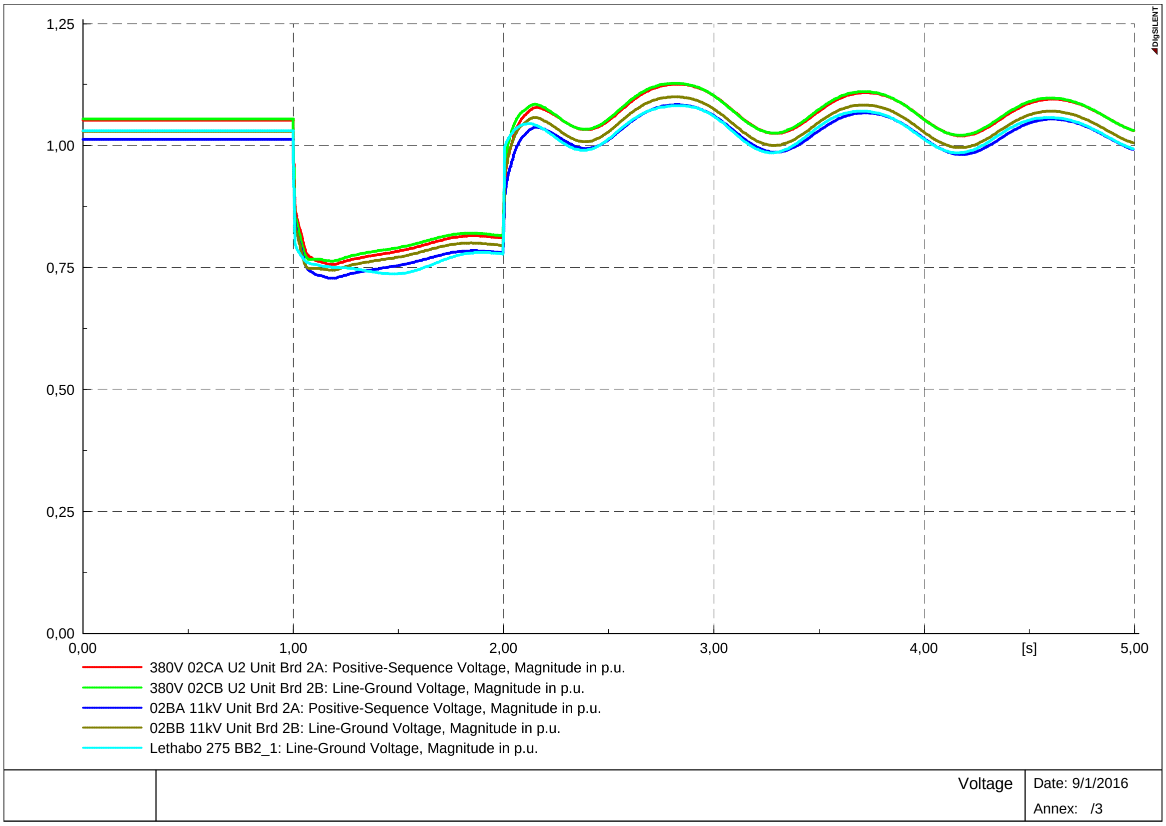


Figure 99: Simulation 25% voltage dip for 1 second

4.3.3 SIMULATED VOLTAGE DIP RESULT ANALYSIS

The correlation between the simulated voltage dip results and the generator disturbance theory in Chapter 2 is evident. The voltage overshoot after fault clearance and severe oscillations can be the result of angular swings (δ). It is expected that the duration and amplitude of the oscillation should be damped sooner by the AVR. Improvement of the AVR model is required to obtain results that correlate better with actual response test performed on a power plant.

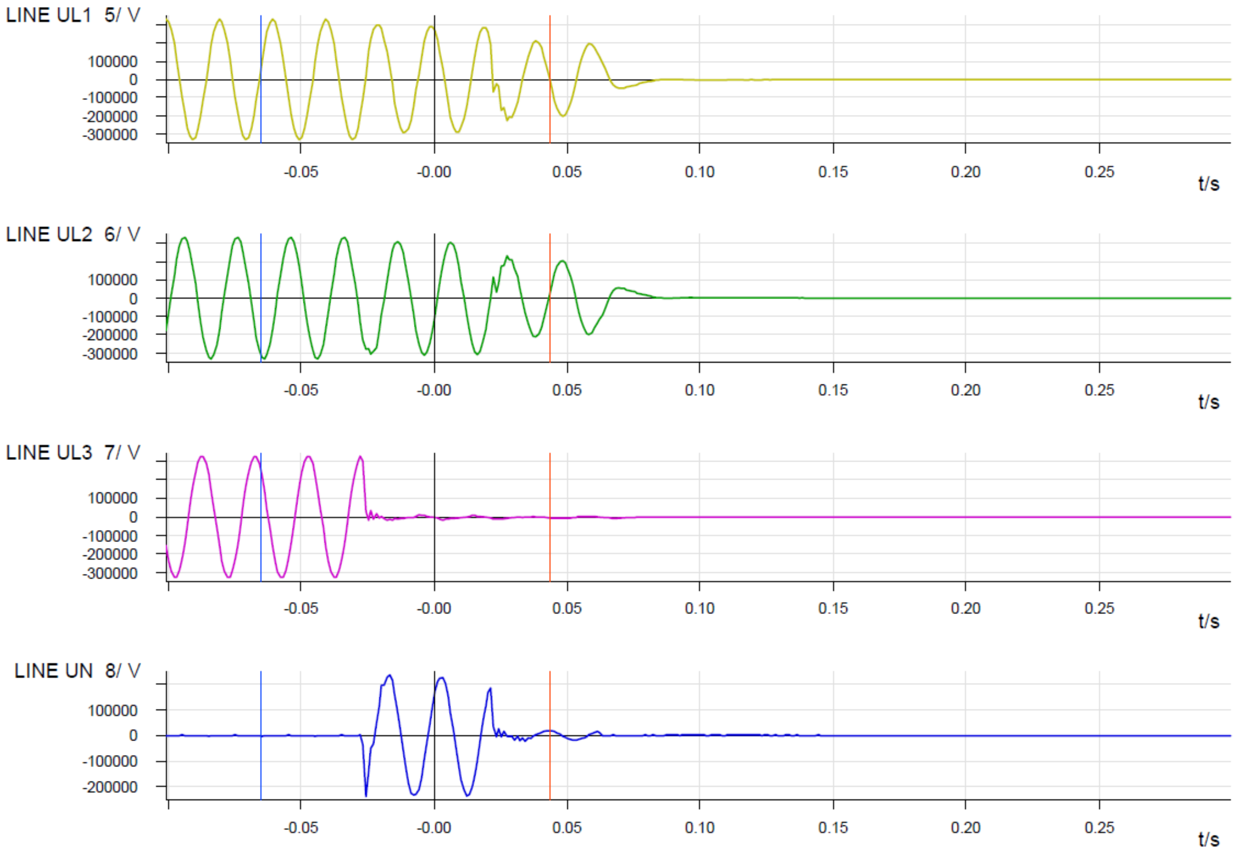
The time duration for the 100% voltage dip of 200 ms is too short for the excitation system to respond to effectively. The excitation system will contribute to maintaining the system operating parameters within permissible operating range to keep the power-generating unit auxiliaries in service and therefore ensuring availability of power-generating capacity.

Verification by developing a power plant model to perform simulations provides further evidence that the power plant complies with the operational needs of the South African grid code in terms of GCR 9.

4.4 MOTOR LOAD BACK-FEED

The data captured at a power plant following an incident quantifies the back-feed capability of motor loads connected in the electrical reticulation system at a power plant. The incident cause was a phase-to-earth fault on the blue phase between the HV side of the generator transformer and the HV breaker, connecting the power-generating unit to the IPS. The house load is approximately 21 MW versus 72 MW when the power plant produces power at full capacity. Due to the location of the fault the generator circuit breaker, HV breaker and MV breakers tripped. The tripping of the MV breakers linking the unit boards to the generator transformer was approximately 40 ms slower than the HV breaker.

Figure 100 indicates the RMS voltage when the 400 kV Blue phase-to-earth fault occurred. At time = 0 the HV breaker and generator circuit breaker tripped. Figure 101 illustrates the currents measured in the neutral and the current contribution measured from the respective loads connected to the unit boards for the 40 ms seconds before the MV breakers opened, segregating the motor loads.



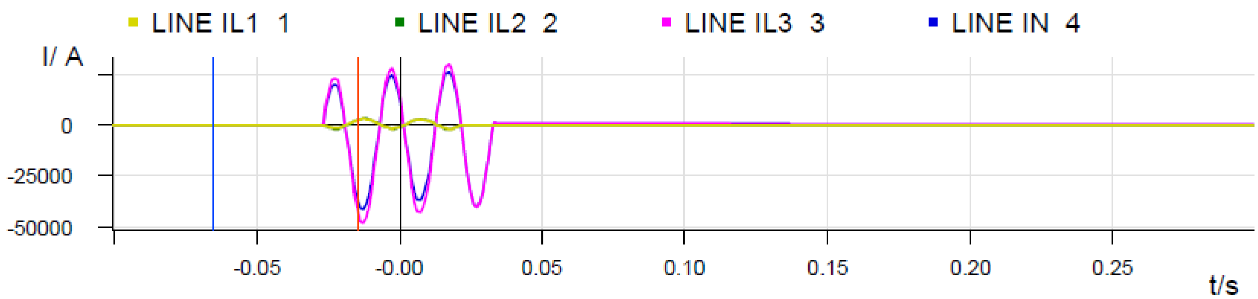
Line UL1 (yellow) – red phase voltage

Line UL2 (green) – white phase voltage

Line UL3 (magenta) – blue phase voltage

Line UN (blue) – neutral voltage

Figure 100: 400 kV blue phase-to-earth fault phase and neutral voltages



Line IL1 (yellow) – red phase current

Line IL2 (green) – white phase current

Line IL3 (magenta) – blue phase current

Line IN (blue) – neutral current

Figure 101: Motor load current contribution

As a result of the MV breakers being 40ms slower than the HV breaker, the current contribution from the motor loads was evident after the HV breaker and generator circuit breaker tripped. The data from this incident illustrates that the motor loads have a significant back-feed capability that will assist with the recovery and maintenance of the voltage following disturbances in the supply voltage of a power plant as a result of disturbances that originated in an integrated power system (IPS). The maximum current contribution can be expected to be the accumulative motor load starting current. The motor loads with the higher inertia will support the motors with the lower inertia.

4.5 PROCESS IMMUNITY FRAMEWORK

A process immunity framework is derived by evaluating the standards applicable to power plant electrical equipment, versus the three-process immunity time (PIT) categories derived from GCR 9 and therefore providing a process immunity compliance indicator as indicated in Table 44.

Table 45: Legend – process immunity compliance indicator

Colour	Description
(green)	No concerns about plant or equipment having the capability or required voltage dip immunity to withstand the specified voltage dip magnitude and duration.
(amber)	Concerns about plant or equipment having the capability or required voltage dip immunity to withstand the specified voltage dip magnitude and duration.
(red)	Plant or equipment not having the capability or required voltage dip immunity to withstand the specified voltage dip magnitude and duration.

Table 46: Process immunity compliance indicator

Electrical Plant Item	Eskom Standard Number and Description	GCR 9			Comments
		Process immunity time (PIT) 1 100% dip for 200 ms	PIT 2 25% dip for 1 second	PIT 3 15% dip for 60 seconds	
Transfor-mers	240-56227520 Large Power Generator Transformers in Power Stations Standard [96]	Voltage dip will be experienced through the entire plant. Process immunity is dependent on other plant having the required immunity. Transformer impedance will reduce	Transformer design to limit voltage dip to maximum 25% during large motor starting. Plant design validated through load flow studies and verified during plant commissioning.	No concern.	

Electrical Plant Item	Eskom Standard Number and Description	GCR 9			Comments
		Process immunity time (PIT) 1 **100% dip for 200 ms**	**PIT 2** **25% dip for 1 second**	**PIT 3** **15% dip for 60 seconds**	
		the severity.			
Motors	240-50237155 New MV Motor Procurement Standard [97]	Compliance is dependent on motor drive inertia. Normally power plant equipment does have adequate inertia to withstand a 100% voltage dip for 200 ms.	Standard for motors specifies this requirement.	No concern.	LV motors normally do not have adequate inertia. On some lubrication systems, sufficient lubrication remains until the motor is restarted. Redundancy is also provided for critical motors feeding from an alternative source.
Variable speed drives	240-64430501 Low Voltage Variable Speed Drive Control Equipment	Not adequately specified.	Adequately specified: Depression to 0.85 of nominal for up to 1 hour with	Normally no concern as this voltage dip magnitude is a standard in	The IEC standard is not aligned with the Eskom stipulated

Electrical Plant Item	Eskom Standard Number and Description	GCR 9			Comments
		Process immunity time (PIT) 1 100% dip for 200 ms	PIT 2 25% dip for 1 second	PIT 3 15% dip for 60 seconds	
	Standard [98]		further drops to 0.7 of nominal for up to 10 seconds.	international standards.	immunity.
Emergency supply equipment, battery chargers and uninterrup-table power supplies	36-815 Specification for Battery Chargers [87] 36-817 Static uninterruptible power supplies [88]	The stored energy back-up will provide the required capability with alarming of main supply failure.	This level of voltage dip immunity was not specified for emergency supply equipment. The stored energy back-up will provide the required capability. As this voltage dip is expected during large motor starting equipment not aligned with having immunity to 25% voltage dip will generate alarms for what should be a normal plant condition	No concern.	

Electrical Plant Item	**Eskom Standard Number and Description**	**GCR 9**			**Comments**
		Process immunity time (PIT) 1 **100% dip for 200 ms**	**PIT 2** **25% dip for 1 second**	**PIT 3** **15% dip for 60 seconds**	
			dictated by motor and transformer design.		
Control supply	240-56227426 Generation MV and LV Protection Philosophy for Power Station Standard [99]	Capability is provided with line interactive uninterruptab le power supply. The design and operating philosophy not preventing contactor drop-out.	Practical tests revealed that contactor drop-out is experienced at 85% voltage as well as further testing indicating that contactor drop-out occurring after 38 ms when voltage has decayed below 70% and line-interactive UPS activates to supply the contactors.	No concern, continuous operation at this voltage level specified in international standards.	
Protection	240-56176215 Generation MV and LV Philosophy for Power Stations [49]	Supplied from emergency supply equipment. The stored energy	Supplied from emergency supply equipment. The stored energy back-up will provide	No concern, continuous operation at this voltage level specified in international	

Electrical Plant Item	Eskom Standard Number and Description	GCR 9			Comments
		Process immunity time (PIT) 1 100% dip for 200 ms	PIT 2 25% dip for 1 second	PIT 3 15% dip for 60 seconds	
	240-56176852 Essential Power Supplies for Power Stations Standard [99]	backup will provide the required capability with alarming of main supply failure.	the required capability with alarming of main supply failure.	standards.	
Distributed Control Systems	240-56176852 Essential Power Supplies for Power Stations Standard [99]	Supplied from emergency supply equipment. The stored energy backup will provide the required capability with alarming of main supply failure.	Supplied from emergency supply equipment. The stored energy backup will provide the required capability with alarming of main supply failure.	No concern, continuous operation at this voltage level specified in international standards.	Control systems not supplied from uninterrupt-able supplies will be a major concern.
Control and Instrumen-tation	240-56176852 Essential Power Supplies for Power Stations Standard [99]	Supplied from emergency supply equipment. The stored energy	Supplied from emergency supply equipment. The stored energy backup will provide the	Continuous rating of ±20% applicable	Some concern due to operating voltage limit range on control and

Electrical Plant Item	Eskom Standard Number and Description	GCR 9			Comments
		Process immunity time (PIT) 1 100% dip for 200 ms	PIT 2 25% dip for 1 second	PIT 3 15% dip for 60 seconds	
		backup will provide the required capability with alarming of main supply failure.	required capability with alarming of main supply failure.		instrumenta-tion equipment available in the industry of ±10% and/or voltage window of 23 V to 27 V.

4.5.1 PROCESS IMMUNITY COMPLIANCE INDICATOR SUMMARY

Verification was done by evaluating internal standards used for power plant electrical equipment for compliance with the CGR 9 requirements to derive a process immunity time (PIT) compliance indicator. The PIT compliance indicator evaluated compliance against each of the three-voltage dip magnitude and duration criteria stipulated in GCR 9. The PIT compliance indicator provides evidence of a degree of assurance that equipment installed as per the power plant standards will accomplish the operational needs of the national grid code in terms of GCR 9. The PIT compliance indicator also identifies criteria areas of concern.

It is also evident that the standard for power plant electrical equipment provides a higher degree of assurance that the operational needs of the national grid code in terms of GCR 9 will be accomplish than the IEC standards.

CHAPTER 5

CONCLUSION AND RECOMMENDATIONS

This chapter offers conclusions on the findings and as recommendations for possible future studies.

The objective of this dissertation is benchmarking power station voltage dip performance compliance to a retrospectively adopted regulatory framework for the resilience of power plant exposed to disturbances in the integrated power system. As a start, an extensive literature study was conducted, considering all individual aspects that form an integral part of the power plant and that can be affected by induced voltage disturbances that originate in the IPS. The literature study highlighted aspects that support and interpose on a power plant's disturbance resilience.

Ensuring voltage immunity entails a combination of aspects within the power plant that have to be implemented correctly. An engineering solution should therefore be considered during the power plant design. The following aspects were identified in this study that requires special deliberation during the design:

- Specifying equipment to have the correct degree of voltage immunity aligned with the regulatory requirements.
- The source impedance can assist in reducing the effect of disturbances that originate in the IPS and acceleration current drawn when the system voltage recovers following the clearance of the fault.
- Correct protection schemes and settings applications – the protection schemes used within the IPS must clear faults within the 200 ms. Protection grading and settings should also be correctly applied to be able to harvest the inherent voltage immunity in the process plant.
- Ensuring control circuit voltage immunity is required to prevent the contactors from interrupting the supply during the defined voltage dip. The inadequacies of the stabilized power supplies and line interactive systems in use at power plants were analysed and identified as a major deficiency in ensuring compliance to a

retrospectively adopted regulatory framework for the resilience of a power plant exposed to disturbances in the IPS. An in-line UPS with specific functional requirements was identified as the most viable solution with a high level of engineering confidence that can be implemented at all power plants. In this study, this design deficiency was identified and different options investigated. The best solution was engineered, designed, extensively tested with detailed test results presented in Chapter 4, and implemented at a power plant from the same period as those considered in this study. The implemented solution was evaluated for a period of six months and has produced positive results for implementation throughout the fleet of power plants.

- Motor protection relays are used on MV motors with settings applied as indicated in Chapter 1. A further discrepancy was identified between the 3 s undervoltage duration on MV circuits versus the 1 s applied on LV systems. A 1 s undervoltage support was not ensured due to the incorrect undervoltage philosophy having been applied. It was incompatible with the characteristic and behaviour of contactors during a voltage dip. During the voltage dip, all motors act as generators. The inherent benefit of this phenomenon was illustrated with data obtained from an actual fault that occurred at a power plant. The reaction from the motors to the voltage dip is instantaneous and much faster than what the capability of the AVR would be. The extent of the motor load contribution to support the voltage during these disturbances was significant and can be expected to have a similar contribution for a three-phase fault, but for a shorter duration. Future power plant designs should consider harvesting the inherent benefit of motor loads and guard against designs that can nullify this beneficial characteristic of motor loads. The undervoltage tolerance time period must be carefully determined to prevent rotating machinery from decelerating to an extent where restoration of the voltage may cause damage to the equipment. The undervoltage tolerance time period should also not be made too short, as this can initiate an undervoltage trip before the overload protection is able to clear a fault. The 3 s undervoltage duration applied at power plants was determined by the longest possible time that overload protection could take to clear any overload condition. The risk when the supply voltage has recovered during deceleration of the motor loads is that all the connected motor loads will draw starting current to re-accelerate and this can exceed the board supply breaker or transformer capability. The load flow studies conducted on the power plant design provides assurance that this is an unlikely risk, as is the three seconds undervoltage tolerance period.

- A comprehensive undervoltage philosophy was developed to keep the plant running for voltage dips of a certain severity and duration and only tripping the plant when this is exceeded. After a power plant capability interruption due to an undervoltage condition, it is important to safely shut down the plant and get it ready for a re-start. Breakers should not remain in a close position as an uncontrolled plant start will occur when the supply is restored. The control philosophy implemented in the DCS is therefore crucial in achieving process voltage immunity.

Developing accurate models and performing simulations provide valuable data on what can be expected at a power plant as a result of disturbances that are generated in the IPS. The simulation data validated the theory and provide assurance of the voltage immunity provided by the electrical plant design. Verification by developing a power plant model to perform simulations provides further evidence that the power plant complies with the operational needs of the South African grid code in terms of GCR 9.

Every voltage dip incident experienced at power plants should be investigated and detailed records should be compiled. The voltage dip records can provide information to determine the power plant's resilience to voltage dips and therefore compliance to GCR 9 or to identify areas of concern.

This study results in the conclusion that that power plants designed prior to the national grid code coming into effect have a high degree of resilience to voltage disturbances that originate in the IPS. The misalignment between IEC standards applicable to equipment used within a power plant environment and the national grid code is one of the biggest risks that can jeopardize the resilience to voltage dips provided by the early power plant designs, as the majority of these power plants are undergoing major refurbishments.

5.1 FUTURE WORK AND STUDIES

Further work is required to develop an optimized power plant-specific undervoltage philosophy to ensure optimized undervoltage protection and to further harvest the inherent undervoltage support that can be provided by equipment installed at power plants.

Further work is also required to develop a South African standard aligned with the regulatory framework applicable to power plants connected to the IPS.

Further research and development is required on fast transfer schemes and utilization within a power plant, in other words the development of a new power plant design and operation philosophy is required.

The installation of the quality of supply recorders provides a facility to record and monitor the LV supply during normal plant operation and following incidents. Downloading and analysing the data will provide valuable information that can be used to improve power plant designs.

Due to the unavailability of accurate information of the actual impact of the source impedance on the contactor dip behaviour, further research in this area is required.

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APPENDIX A – FAULT LEVEL AND LOAD FLOW STUDIES

The POWSYS software was used to perform the fault level and load flow studies. The objective of the studies was to simulate the voltage not dropping below 85% of the nominal voltage, while fault levels do not exceed 600 MVA on any of the 11 kV boards, or 250 MVA on any 3.3 kV board.

A.1 Load FLOW Studies

The following reticulation configurations were considered:

- Unit 1 at full load with the generator synchronized to the network via the generator transformer, and both unit transformers supplying the unit auxiliaries via the 11 kV unit boards and half the station load via 11 kV Station Board A.
    - Start EFP 1A
    - Start EFP 1B with EFP 1A in service
    - Start EFP 1A and 1B simultaneously
    - Start Mill 1C
    - Start FD fan during normal operating loads
    - Start 3.3 kV Ash Conveyor on 3.3 kV Ash Conveyor Board B
    - Start 380 V fuel pump on 380 V Fuel Plant Board
    - Start Compressor on 3.3 kV Station Services Board A
- Commissioning of Unit 6 with 11 kV Unit Board 6A connected to 11 kV Station Board 2 and fed from station transformer and 11 kV Station Board 1 fed from 11 kV Unit Board 1A.
    - Start EFP 6A with half unit start-up load in service.
- Six units in service. 11 kV Station Board 1 fed from station transformer and feeding total station load.
    - Start largest load i.e. compressor on 3.3 kV Station Service Board B

  - o Start largest motor furthest from 11 kV Station Board 1, i.e. ash conveyor on 3.3 kV Ash Conveyor Board B

- Unit 1 at full load with the generator synchronized to the network via the generator transformer and Unit Transformer 1B in service, supplying both the 11 kV unit boards.
  - o Start EFP 1B with EFP 1A in service

A.2 FAULT Studies

- Three-phase faults on all switchboards with system being supplied from:
  - o 11 kV Unit Transformer 1A
  - o Station transformer
- Single-phase faults on all switchboards with system supplied from:
  - o 11 kV Unit Transformer 1A
  - o Station transformer

A.3 Transformer Tap Settings

The worst case tap settings was used to conduct the load flow and fault studies, with all transformer tap settings at nominal tap for 400 V. Under normal operating conditions, only the station transformer, the 3.3 kV station service transformers and the 3.3 kV and 3.3 kV service transformer should be on +5% tap.

A.4 RESULTS OF LOAD FLOW AND FAULT LEVEL STUDIES

A.4.1 Load Flow

The largest volt drop was observed during the simultaneous starting of the EFP 1A and 1B on Unit 1, with all transformers on nominal tap and Unit Transformer 1A supplying the largest portion of the station load. A voltage drop to 86% was noted on 3.3 kV Station Services Board 1 and to 88% on 3.3 kV Coal and Ash Plant Board 1. Therefore, with a +5% tap setting on both transformers, the volt drop will be limited to 90%. For all the other configurations, the voltage will remain above 85%.

A.4.2 Three-phase fault studies

The maximum fault level of 33kA (629 MVA) occurs on 11 kV Unit Board 1A for the configuration Unit Transformer 1A supplying the unit load, the EFP running and half the station load. A large component of the fault current is generated by the EFP and the 3.3 kV motors. The fault current decays rapidly as the motors lose speed. The fault level is 24kA (137 MVA) on the 3.3 kV service boards. A 30kA fault level is possible from the station transformer.

A.4.3 Single-phase fault studies

Low resistance earthing is provided on the 11 kV station boards, 11 kV unit boards and 3.3 kV service boards. Any board directly supplied from any of these boards is connected to the low resistance earthing. The advantage is that the phase to earth fault currents are limited to:

- 11 kV station boards 318A
- 11 kV unit boards 318A
- 3.3 kV service boards 318A

Table A1 Estimated Loads

BOARD	LOAD DESCRIPTION	LOAD (MVA)	
		RUNNING	STANDBY
11 kV Unit Board A Unit Transformers 1A and 2A (58 MVA) and 3A to 6A (35 MVA)	EFP A		11.01
	380 V Precipitator Board A	1.6	
	380 V Unit Board A	1.6	
	380 V Unit Diesel Generator Board	1.6	
		1.6	
	380 V Fuel Oil Plant Board A	9.53	0.5
	3.3 kV Service Board A	8.99	1.94
	3.3 kV Service Board C	20	

BOARD	LOAD DESCRIPTION	LOAD (MVA)	
		RUNNING	STANDBY
	Half Station Load (Units 1 and 2)		
	TOTAL	44.92	13.45
	MAX LOAD	58.37	
11 kV Unit Board B Unit Transformers 1B and 6B (35 MVA)	EFP B		11.01
	380 V Precipitator Board B	1.6	
	380 V Fuel Oil Plant Board B		1.6
	380 V Ash Bunker Board	1.25	
	380 V Unit Board B	1.6	
	380 V Diesel Generator Board		1.6
	3.3 kV Service Board B	7.99	2.77
	3.3 kV Service Board D	9.85	0.29
	TOTAL	22.29	17.27
	MAX LOAD	39.56	
3.3 kV Service Board A	CW Booster Pump A	0.38	
	Condensate Polishing Pump C		0.5
	L.H. F.D. Fan	2.61	
	L.H. P.A. Fan	2.42	
	C.W. Pump A	2.17	
	Condensate Extraction Pump A	1.95	
	TOTAL	9.53	0.5
	MAX LOAD	10.03	
3.3 kV Service	Mill D	1.94	

BOARD	LOAD DESCRIPTION	LOAD (MVA)	
		RUNNING	STANDBY
Board B	Mill E	1.94	
	Mill F	1.94	
	Condensate extraction Pump B		1.95
	C.W. Pump B	2.17	
	C.W. Booster Pump B		0.38
	Turbine Circulating Water Pump C		0.44
	TOTAL	7.99	2.77
	MAX LOAD	10.76	
3.3 kV Service Board C	Mill A	1.94	
	Mill B	1.94	
	Mill C		1.94
	Turbine Circulating Water Pump A	0.44	
	L.H. I.D. Fan	3.88	
	L.P. Drain Pump A	0.29	
	Condensate Polishing Pump A	0.5	
	TOTAL	8.99	1.94
	MAX LOAD	10.93	
3.3 kV Service Board D	R.H. F.D. Fan	2.61	
	R.H. P.A. Fan	2.42	
	R.H. I.D. Fan	3.88	
	L.P. Drain Pump B		0.29

BOARD	LOAD DESCRIPTION	LOAD (MVA)	
		RUNNING	STANDBY
	Turbine Circulating Water Pump B Condensate Polishing Pump B	0.44 0.50	
	TOTAL	9.85	0.29
	MAX LOAD	10.14	
Station Board 1	275 kV Yard 380 V Board A 11 kV Single Quarters Board A 3.3 kV Station Services Board A 380 V Water Plant Board 1A 380 V Water Plant Board 2A 380 V Distribution Board A 380 V Fire Pump Distribution Board A 380 V Unit Lighting Board 1 11 kV Ashing System 11 kV Substation Ring	0.31 3 0.8 0.63 0.83 1.24 0.3 0.63 1 14	
	TOTAL	22.74	
Station Board 2	275 kV Yard 380 V Board B 11 kV Single Quarters Board B 3.3 kV Station Services Board B 380 V Water Plant Board 1B 380 V Water Plant Board 2B 380 V Distribution Board B	0.31 3 0.8 0.63 0.83 1.24	

BOARD	LOAD DESCRIPTION	LOAD (MVA)	
		RUNNING	STANDBY
	380 V Fire Pump Distribution Board B 380 V Security Lighting West 380 V Unit Lighting Board 2 380 V Unit Lighting Board 3 11 kV Ashing System New Vaal Coal Mine 11 kV Substation Ring	0.3 0.1 0.63 0.63 1 3.6 14	
	TOTAL	27.07	
	TOTAL STATION LOAD	49.81	
	With a Diversity Factor of 0.65 Station Load	32.4	
	Maximum Station Load	40	
11 kV Substation North Board A	380 V Security Lighting North 380 V Unit Lighting Board 5 380 V Admin Board A 380 V Electrical Workshop Board	0.1 0.63 1 0.33	
	TOTAL	2.06	
11 kV Substation North Board B	380 V Unit Lighting Board 4 380 V Unit Lighting Board 6 380 V Admin Board B 380 V Station Crane Board 2	0.63 0.63 1 0.2	
	TOTAL	2.46	

BOARD	LOAD DESCRIPTION	LOAD (MVA)	
		RUNNING	STANDBY
11 kV Substation East Board A	380 V Security Lighting East	0.1	
	380 V Water Plant East Board A	0.75	
	380 V Dirty Dam Board	0.6	
	3.3 kV Ash Conveyor Board 1A	1.5	
	380 V C.W. Pumphouse East A	0.4	
	3.3 kV Ash Conveyor Board 2A	1.5	
	TOTAL	4.85	
11 kV Substation East Board B	380 V Shot Blast Board	0.2	
	380 V Water Plant East Board B	0.75	
	3.3 kV Ash Conveyor Board 1B	1.5	
	380 V C.W. Pumphouse East B	0.4	
	3.3 kV Ash Conveyor Board 2B	1.5	
	TOTAL	4.35	
11 kV Substation South Board A and 11 kV Coal and Ash Plant Board A	380 V Substation South A	0.63	
	380 V Security Lighting South	0.1	
	380 V Workshop Board A	0.33	
	380 V Fuel Common Plant Board 1A	0.33	
	380 V Fuel Common Plant Board 2A	0.33	
	380 V Incline Conveyor Board 1A	0.5	
	380 V Incline Conveyor Board 2A	0.28	
	380 V Incline Conveyor Board 3A	0.64	
		1.5	

BOARD	LOAD DESCRIPTION	LOAD (MVA)	
		RUNNING	STANDBY
	3.3 kV Coal and Ash Silo Board 1A 3.3 kV Coal and Ash Silo Board 2A 380 V Central Maintenance Service Board A	1.5 0.6	
	TOTAL	6.74	
11 kV Substation South Board B and 11 kV Coal and Ash Plant Board B	380 V Substation South B 380 V Recarbonation Board 2 380 V Workshop Board B 380 V Fuel Common Plant Board 1B 380 V Fuel Common Plant Board 2B 380 V Incline Conveyor Board 1B 380 V Incline Conveyor Board 2B 380 V Incline Conveyor Board 3B 3.3 kV Coal and Ash Silo Board 1B 3.3 kV Coal and Ash Silo Board 2B 380 V Central Maintenance Service Board B	0.63 0.26 0.33 0.33 0.33 0.5 0.28 0.64 1.5 1.5 0.6	
	TOTAL	6.85	

BOARD	LOAD DESCRIPTION	LOAD (MVA)	
		RUNNING	STANDBY
11 kV Substation Ring	North A North B East A East B South A South B	2.06 2.46 4.85 4.35 6.74 6.85	
	TOTAL	27.31	
	Half Substation Ring Load	14	

Transformer Characteristics

DESCRIPTION	RATING (MVA)	VOLTAGE RATIO (kV)	IMPEDANCE ON PRINCIPAL TAP (%)	TAP SETTING (%)
Generator Transformer	700	20/300	12.6	
Unit Transformers 1A and 2A	58	20/11.5	10	
Unit Transformers 3A to 6A and 1B to 6B	35	20/11.5	7	
Service transformer A, B, C, D	12.5	11/3.3	5.63	+5
380 V Unit Transformers A,B and 380 V Precip Transformers	1.6	11/0.4	5.9	

DESCRIPTION	RATING (MVA)	VOLTAGE RATIO (kV)	IMPEDANCE ON PRINCIPAL TAP (%)	TAP SETTING (%)
380 V Fuel Oil Transformers	1.6	11/0.4	5.9	
380 V Ash Silo Transformers	1.25	11/0.4	5.2	
380 V Lighting Transformers	1.25	11/0.4	5.2	
Station Transformer	45	88/11	6.5	
380 V Distribution Transformers 1 and 2	1.6	11/0.4	5.9	
3.3 kV Station Services Transformers	1.6	11/3.3	5.9	+5
380 V Water Plant Transformers	1	11/0.4	5.9	
3.3 kV Coal and Ash Transformers	3.15	11/3.3	6.2	+5
380 V HV Yard Transformers	0.315	11/0.4	4	