INVESTIGATION OF ELECTRICAL INFRASTRUCTURES FOR MISSION CRITICAL BUILDINGS

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Ph.D. 2021

Abstract

The research programme challenge was to establish optimum reliability for the Royal Bank of Scotland's data centres electrical networks, given such mission critical buildings are vital to business operations, and loss of data centre services in terms of critical equipment outage is likely to negatively affect the UK economy. The Royal Bank of Scotland's data centres are listed with the Committee for Protection of National Infrastructure (*CPNI*), and although despite being of national importance the current industry practice is to design and construct electrical infrastructures in-line with the Uptime Institutes Tier Classification table, which provides a design only approach for equipment topologies and expected annual downtime of critical systems. This approach is based on Inherent Availability (*Ai*) which utilises manufacturers design metrics and does not consider the complexities or issues encountered in an actual mesh connected electrical network i.e., those of an operational state.

Therefore, in this investigation Operational Availability (*Ao*) of the actual data centre electrical network was established through a series of power system model simulations, which included load flow, short circuit analysis, protection device co-ordination and grading, arc flash and load point reliability. Power system models were constructed from the actual installed equipment, site load values and considered all possible operational scenarios and failure modes, with power system simulations being undertaken for every operational scenario that had been outlined in the original design specifications, including symmetrical fault current simulations undertaken at every critical busbar.

The findings from each of the power system studies were analysed against the original system benchmarks, with gap analysis undertaken leading to the formation of a new and improved generalised approach for maximising Operational Availability (*Ao*). Electrical network issues were encountered across a range of power system studies with the more prominent areas including high voltage protection device arrangements and arc flash incidents located on the low voltage switchgear. In fact, over 30% of the electrical equipment investigated did not provide an optimal solution, with each one of these issues being simulated individually and critiqued with power system engineering theories and best practices, allowing subsequent improvements to be achieved. The improved solutions were again simulated for system failure rates thus provided a tangible metric comparison, with estimated outage times being reduced by as much as 45 hours per year.

This new approach was formulated into a flowchart, a Generalised Approach to Improving Data Centre Operational Availability which is an advancement to the current Uptime Institutes Tier Classifications methodology, the approach was validated in this electrical network and reduced estimated outage times by over 45 hours per year. This is a substantial improvement in operational

reliability metrics and the flowchart can be utilised by any other data centre owner i.e., for simulation and improvement of their electrical network with core focus on achieving an actual improvement in Operational Availability (*Ao*) for the exact installed equipment, settings and selected operational configurations.

Acknowledgements

The author gratefully acknowledges the contributions of Chris Gould, Sarath Tennakoon, Moofik Al-Tai and Sandy MacKay for their support and guidance with the development of this research programme. Also, The Royal Bank of Scotland for research project funding support and ETAP for the sponsorship with software and training.

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$V_0\ V_1\ V_2$: Zero, Positive & Negative Phase Sequence Components Respectively

FLC: Full Load Current (A)

I_{dc}: Direct Current Component (A)

I_f: RMS Fault Current (KA)

Ik: RMS Steady State AC Current (A)

Ik'': Symmetrical Short Circuit Current Value (KA)

I_p: Peak Current (KA)

I_s: RMS Secondary Current (A)

I_{sc}: RMS Short Circuit Current (KA)

I_n: RMS Nominal Continuous Current Rating (A)

N: The total number of components installed within a distribution system, that are required to support a given load

N+1: The total number of components installed within a distribution system, that are required to support a given load, with a redundant capacity of +1

2N: Two independent pathways from source to load, each with a total number of components installed within the distribution system enough to support load

P: Active Power (KW)

PF: Power Factor

P.u: Per Unit Value

Q: Reactive Power (KVAr)

S: Apparent Power (KVA)

T_{dc}: Direct Current Decay Time Constant (s)

$Td''\ Td'$: Sub Transient, Transient Time Constant (s)

Td: Protection Relay Time Delay (s)

Ui: Annual Outage Duration at Load Point Expressed as Hours Per Year (hrs./yr.)

λi: Average Failure Rate at Load Point Expressed as Failures Per Year (f/yr.)

$V_a\ V_b\ V_c$: Phase a, b & c RMS Voltages (V)

V_n: Nominal System RMS Voltage (V)

V_p: Primary RMS Voltage (V)

V_s: Secondary RMS Voltage (V)

Vsi: Voltage Security Index

$Xd''\ Xd'\ Xd$: Sub Transient, Transient and Synchronous Reactance Respectively (Ω)

$Z_0\ Z_1\ Z_2$: Zero, Positive & Negative Phase Sequence Impedance Respectively (Ω)

Z_f: Fault Impedance (Ω)

Acronyms and Abbreviations

AC: Alternating Current

ACB: Air Circuit Breaker

Availability: The ability of an item or piece of equipment to sustain its required function over a given period or instant of time

CALC: Handwritten and mathematically calculated numerical values

DC: Direct Current

DNO: Distribution Network Operators

Downtime: Failure or outage of operational systems which leads to negative effects on data centre critical loads

DT: Protection relay Definite Time setting

ECost: Total Energy Cost per annum (£)

E/F: System Earth Fault (L-G)

EMF: Electromagnetic Field

ENA: Energy Networks Association

G59: Energy Networks Association grid code for parallel connections of generators and grid sources

HRC: High Rupturing Capacity fuse

HV: High Voltage

IDMT: Inverse Definite Minimum Time, a characteristic curve for the HV protection relay

Inherent Availability (Ai): An instantaneous probability of whether a component or equipment will be up or down in terms of its desired function. Ai considers manufactures failure data only

INST: Protection relay instantaneous setting

IoT: Internet of Things

IT: Information Technology

LHS: Denotes ‘Left Hand Side’

LT: Protection relay Long Time setting

LV: Low Voltage

MCB: Miniature Circuit Breaker

MCC: Motor Control Cubicle

MCCB: Moulded Case Circuit Breaker

Mean Time Between Failures (MTBF): A Mean Time Between consecutive failures of a component

Mean Time to Repair (MTTR): The Mean Time to Repair (or recover) failed equipment or components

NTCC: Protection relay Non Time Current Curve

O/C: System Overcurrent Fault

OEM: Denotes the Original Equipment Manufacturer

ONAN: Oil Natural (Primary) Air Natural (Secondary) cooling method for distribution transformers

Operational Availability (Ao): An instantaneous probability of whether a component or equipment will be up or down in terms of its desired function. Ao differs from Ai as it considers all downtime - inclusive of failures, logistic or maintenance operations

PDU: Power Distribution Unit, a type of switchgear utilised for electrical supplies to data centre equipment

PNO: Private Network Operators

PPE: Personal Protective Equipment

REF: Protection relay for Restricted Earth Faults

Reliability (Rt): Relates to the success of a system's performance over a given period

RHS: Denotes 'Right Hand Side'

RSO: Remote Switching Operations

SCC: Short Circuit Current

SEF: Protection relay for Sensitive Earth Faults

SIM: A numerical value obtained by simulation software

ST: Protection relay Short Time setting

SWA: Steel Wired Armoured electric cabling

TCC: Protection relay Time Current Curve

UPS: Uninterruptable Power Supply, which provide short term power during grid outage

Uptime: An electrical system being in healthy operational service and feeding critical busbar loads within the data centre

VCB: Vacuum Circuit Breaker

Chapter 1 – Introduction, research aims and objectives

1.0 Introduction

This chapter provides an explanation into the background of mission critical buildings, detailing the key points as to why such buildings are pivotal to the successful operation of the UK economy. Also, highlighting the vast scale of construction and power consumption of such critical infrastructures, providing an insight into the current challenges and what investigations have taken place for understanding the links between electrical engineering and the operation of these buildings, with a given focus on data centre operations and an explanation of the associated differences between inherent and operational availability, and why this is important. Also, detailing the aims and objectives for the research, explaining how they will achieve a contribution of knowledge, and an overview of thesis layout including descriptor of each chapter contents.

1.1 Background

Mission critical buildings are an essential part of business operations, technology is utilised daily in business sectors such as banking and finance, travel and hospitality, hospitals and healthcare services, emergency services, security and intelligence, military, and social media -which all depend on the successful uptime of data centre equipment. Therefore, a data centres existence is to support critical technology equipment allowing successful business operations and delivery of services to customers. Such business services can be critical to the UK economy, with ramification following service outage or equipment failure being catastrophic in terms of significant financial and reputational damages.

This therefore leads onto the designs for mission critical buildings, with a requirement for twenty-four by seven operation which demands a complex range of electrical equipment to support the connected loads and withstand any possible infrastructure emergency or fault scenario. Scenarios such as grid outages, power surges, failure of electromechanical equipment, switching surges, lightning strikes, protection operations and human errors amongst others. The current design approach is utilisation of the Uptime Institutes Tier Classifications table which is a theory based on utilising high Inherent Availabilities (*Ai*) of equipment provided by the manufactures and does not take into consideration the actual site topologies and operational settings. Through application of power system modelling and simulation this research will investigate such operational scenarios of an actual Tier 3 data centre and allow a critique against the current approach.

1.2 Problem Statement

Currently data centres are designed and constructed in-line with the Uptime Institutes Tier Classifications guidelines, analysis of these guidelines has proven that data centres operate correctly but do not maximise their operational performance. This is because the approach is fundamental based on utilising a high redundant capacity and inherent availability metrics provided by each equipment manufacture and does not consider the operational factors, or issues encountered with operational electrical systems. The aim of this project, through system modelling and simulation, is to investigate the operational factors of an actual Tier 3 data centre and establish an approach which will achieve an enhancement on system reliability.

From the literature search in this area know body has yet tried to utilise the investigation of Operational Availability (*Ao*) to supplement or replace the current Uptime Tier Classifications approach, by applying a series of robust power system models and simulations to an actual Tier 3 data centre system with establishment of reliability metrics at each critical busbar i.e., improving or correcting the system imbalances that could be experienced with the Uptime Tier Classifications approach.

1.3 Aims

The aim of this research is to develop a new generalised approach methodology for achieving the optimal electrical power system configuration for data centres, which can be utilised for maximising the uptime reliability metrics for operational equipment and topologies.

The output of this new generalised approach methodology will aim to provide higher reliability metrics in comparison to the current approach, which is utilisation of the Uptime Institutes Tier Classifications table. The Uptime's approach is based on utilising high Inherent Availability (*Ai*) for specified equipment, however no Operational Investigation (*Ao*) or inclusion of operational factors are included within this approach, hence the research aim is based on this gap.

The aim of a new generalised approach methodology will be achieved via creating a suite of power system models which represent an actual Tier 3 data centre electrical network, with an aim of subjecting these models to a series of simulations to establish the optimal operational configurations and achievement of reliability metrics. Simulation results with be critiqued with power system theory and best practices to produce a final robust flowchart outlining the new and improved generalised approach methodology, being capable of application to any other data centre electrical network.

1.4 Objectives

i. **Literature review.**

The literature review will define what types of electrical equipment are installed within data centres, what the typical network configurations and design topologies are, what international standards are available and how they are applied in their design and construction. An analysis of how reliability metrics are measured in data centre electrical networks along with how power system analysis of electrical equipment is undertaken. Alongside these specific data centre aspects, the literature covering theories of power system analysis will be reviewed, including theoretical calculations, modelling, and simulation, with a bias to such equipment located within data centre buildings.

ii. **Audit the data centre system.**

A review of all site documentation available for the RBS data centre electrical network will be undertaken, with an objective to obtain detailed information for its current structure, network configurations and topologies, equipment installed, equipment settings, and possible fault scenarios. This will include reviewing the original design documentation, previous history of electrical studies, manufacturers data, test certification, and historic recording of operational settings. In addition to the review of literature a physical site based deep dive audit will be undertaken, to ensure all operational settings and equipment ratings are as recorded in the documentation. This will include inspecting equipment such as main *DNO* feeders, synchronous generators, power transformers, *UPS*, switchgear, circuit breakers, protection relays and interconnecting cabling. The data extracted from all site equipment will be stored in several settings tables for use in subsequent ETAP modelling and simulations as part of this research program. Settings tables are shown in Appendix II and Appendix III.

iii. **Construct and validate singular power system model components.**

Creating a suite of singular power system model components to represent the actual data centre equipment found at the audit stages, including grid feeder, synchronous generator, *UPS*, power transformers, switchgear, protection relays, and distribution cables. Utilising theoretical calculations as proof of concept for each of the data centre components, i.e. proving accuracy of the model equipment in singular format, with a triangulation of data between theoretical calculation, simulation, and manufacturers specifications before proceeding to build a complete system model. The standardised ETAP model blocks will be modified to the exact operational requirements, ratings, and settings - as shown in Appendix I.

iv. **Construct a complete data centre power system model.**

Utilising the individual model components to construct a complete data centre electrical network in-line with the site documentation and single line diagrams. This will include every electrical pathway and equipment from incoming sources to end load points in the live system. A validation check of system components, connections and measurements will be undertaken with a comparison to installed site metering data.

v. **Benchmarking the original system reliability.**

Requires the creation of a series of load point reliability studies in simulation software to establish the current system performance (overall reliability benchmarking), before subjecting the system to any further power system analysis and investigation. Reliability metrics are to be expressed as an hours per year expected outage for every system load point i.e., main switchgear components and data hall power distribution units etc.

vi. **Power system analysis.**

Compiling a detailed and robust approach to simulation methodology, undertaking a range of ETAP simulations for nominal, design, and emergency operational scenarios, as defined in the data centre audit documentation and original design specification for a Tier 3 and Tier 4 system. Applying a methodical approach with completing the power system studies - load flow, short circuit analysis, protection device grading, and arc flash assessment.

vii. **Analysis of simulation results.**

Analyse results in terms of deviation from international standards IEC60909, IEC 61363, IEEE1584-2018, NFPA 70E 2018, ANSI C84, BS7671, and against power system theories; adaptive Newton Raphson, voltage security index, system voltage drops, symmetrical component analysis, protection grading aspects for Time Current Curve (*TCC*) and Non-Time Current Curve (*NTCC*) functions. Also, validating compliance with operational manuals and tolerances outlined by the original equipment manufacturers.

viii. **Outline system improvements and re-simulate.**

Providing a suite of recommended improvements for operational topologies, equipment settings, and electrical protection grading systems. Update the electrical simulation models accordingly then re-simulate all operational and failure scenarios as per the original study, including undertaking load point reliability analysis at each load point allowing a pre- and post-assessment of system reliability.

ix. **Benchmark the improved system reliability.**

Requires creating a series of load point reliability studies to establish the improved system performance (overall reliability benchmarking), i.e., after subjecting it to extensive power system analysis and investigation and undertaking the recommended system improvements. Reliability metrics are to be expressed as an hours per year expected outage of each system load point i.e., main switchgear components and data hall power distribution units etc. The hours per year outage metric will provide a pre- and post-analysis of reliability performance and substantiate validity of recommendations given.

x. **Create a new and improved generalised approach methodology.**

This objective will require construction of a detailed sequential flowchart of actions, and recommended results for each of the data centre power system studies. The generalised approach methodology will ensure an improvement of Operational Availability (Ao) is achieved in comparison to the current Uptime Institutes Tier Classification approach and can be applied to any data centre electrical network and ensuring it can be utilsied in parallel to the current model. The flowchart will include all technical power system aspects such as load flow, short circuits, protection device grading, arc flash mitigation and load point reliability analysis.

These objectives are timely and important given the demand and growth of data centre buildings is exceeding many other operations, with complex electrical engineering systems underpinning the success of these buildings. Despite being an area with limited research publications available the current findings have expressed a concern over operational reliability. Given the current design approach is to utilise the Uptime Tier Classification table which has been proven to work well but does not apply focus on maximising the reliability of an operational system. Failure of these data centre systems will have significant financial, political, customer and reputational impacts therefore providing an approach to improve operational reliability and reduced the predicted failure rates and outage time is a continuation of advancing this subject area.

1.5 The Research Challenge and PhD Contribution

To understand the current scope of research available for this chosen field, with specific focus on the use and application of electrical equipment and protection schemes, and how they can affect Operational Availability (*Ao*) of data centres. Including the establishment and application of an appropriate power system modelling software which is effective with carrying out simulations for load flow, short circuits, protection device grading, arc flash mitigation and load point reliability analysis.

This research programme is to include a comprehensive audit and literature review of an actual Tier 3 data centre, obtaining all operational topologies, equipment details and operational settings. With this information obtained the challenge will be to build a unique set of singular model components, validate each of them for accuracy against theoretical calculation and the original equipment manufacturers data, which will provide an accurate assessment of the original network and establish its current availability metrics i.e., benchmark the complete original system.

With initial benchmarking completed the next challenge is subjecting the electrical network to a series of complex power system simulations inclusive of load flow, short circuits, protection device grading, arc flash mitigation and load point reliability analysis. This simulation approach will include investigation of all operational configurations, and failure scenarios, with results and parameters critiqued against international standards and more importantly their direct effects on system load point reliability. Results following simulations will allow recommendation for system improvements, which will then be undertaken on the original model components and re-simulated under the same operational and failure scenarios to ensure an improvement of operational availability is obtained i.e., a new reliability metric will be established.

The unique contribution of knowledge is construction of an approach methodology which can be applied to any other data centre electrical network for improvement of Operational Availability (*Ao*), The author will achieve this by utilising the research outcomes to create a new generalised approach flowchart which will have been proven to increase system reliability and achieve an enhancement on the Uptimes Tier Classifications approach. The flowchart will provide optimal guidance and benchmark parameters for each of the power system studies and follow a sequential step by step approach to achieve maximum operational reliability. This approach challenges the current research gap in terms of providing additional operational benefits above the current design approach of considering inherent availability.

1.6 Thesis Organisation

The thesis is organised as follows.

Chapter 1

An explanation into the background of mission critical buildings, detailing the key points as to why such buildings are important and what challenges are present within the industry. Also lists the aims and objectives, PhD contribution, and an overview of thesis layout including all chapter contents.

Chapter 2

A detailed overview of the data centre industry in terms of electrical networks, review of industry equipment, applications, and engineering sciences. Provides further discussion on the six areas of electrical infrastructures which can affect data centre reliability and merging technologies utilised in these buildings. Highlight's limitations of the current approach.

Chapter 3

A detailed overview of the RBS data centre infrastructure in terms of general layout and equipment installed. Provides a proof-of-concept ETAP simulation for singular equipment before progressing with full model construction and simulation.

Chapter 4

Detailing the specification of ETAP electrical model simulations for load flow, fault current analysis, protection grading and arc flash assessment. Also detailing the engineering theories and mathematical equations, international standards and theories utilised in all model simulations.

Chapter 5

Provides ETAP software simulation results and descriptions for; load flow, short circuit analysis, protection grading, arc flash and load point reliability studies, respectively. Including full HV network results and separate section for LV *UPS* systems.

Chapter 6

Consists of the implications associated with the application of electrical protection in data centres, details several options for obtaining improved Time Current Curves (*TCC*), ensuring effective operation of circuit devices & mitigating outages of the infrastructure – both HV & LV equipment. Ultimately increasing the potential Operational Availability (*Ao*) of the critical electrical equipment. Also detailing further considerations and studies for arc flash and its direct correlation to electrical protection settings. Chapter 6.3 providing a generalised approach flowchart with set of optimal conditions for achieving improved data centre Operational Availability (*Ao*).

Chapter 7

Provides research programme conclusions, re-capping on what has been researched, nature of the arguments and key points of how the elements were undertaken. Also details the overall benefits gained with creating a generalised approach methodology for improving operational reliability of data centres, and how this is a unique contribution of knowledge.

Chapter 2 – Literature review

2.0 Introduction

This chapter is a detailed overview of data centre electrical networks, operational configuration of equipment and topologies for a complete low voltage and high voltage electrical system. This includes an in-depth review of the wider field, providing details on the size, complexity and associated international standards, along with an understanding of the challenges faced by the data centre owners, particularly in terms of achieving the most reliable configuration of electrical equipment and how pivotal this is with respect to achieving maximum uptime of critical services. A review of the most critical equipment found in these buildings was undertaken, which included investigations of high voltage power transformers, synchronous generators, uninterruptible power supplies, power distribution units, switchgear, circuit breakers, protection relays, interconnecting cabling, and busbar, and more importantly how these equipment are utilised and configured in this type of infrastructure.

This chapter also provides further discussion on the reliability metrics currently utilised within this field, along with an explanation of the British Standard (BSEN 50600-1) and Uptime Institutes Tier Classifications table. Essentially, outlining how these infrastructures are nominally operated and predicted reliability metrics are obtained. These metrics were also reviewed for scientific content and equations for obtaining both Operational Availability (*Ao*) and Inherent Availability (*Ai*) metrics, including establishing Mean Time To Failure (*MTTF*) and Mean Time To Repair (*MTTR*) - given these metrics are the benchmark for such infrastructures.

2.1 Background

Mission critical infrastructures are vital to the economy [46], at present data centres consume large amounts of electrical energy and publications have predicted such facilities will consume 100 billion KWh at an annual cost of £5.36 billion [53]. This aggressive increase in electrical power is likely to continue into the distant future as technology applications continue to grow and improve [49]. Each year there will be more than 1.2 trillion gigabytes of data created and utilised by: banking facilities, stock exchange, hospital services, and airport traffic control stations [15]. Highlighted in Table 2.1.1 is the scale of such mission critical facilities in terms of gross MW power capacity required to facilitate critical systems [23].

Table 2.1.1 Example Data Centre Power Capacities [23]

DATA CENTRE	LOCATION	CAPACITY (MW)
Google	Council Bluffs, IA	105
	Pryor, OK	49
	Hamina, Finland	19
Apple	Maiden NC	19
	Newark CA	15
Facebook	Lulea, Sweden	70
	Altoona, IA	70
Microsoft	San Antonio, TX	27
Yahoo	Lockport, NY	23

Such growing dependency on these businesses brings an added focus on the consequence of downtime, quite often the Information Technology (*IT*) operations are crucial to the business continuity and if systems become unavailable the operation may be impaired, or even stop completely [49]. The term 'downtime' is largely used to describe a loss of critical *IT* applications which have occurred due to a failure in the facilities infrastructure. Such failures could include the loss of an electrical substation or malfunction of a circuit protection device etc.

System failures need to be mitigated with standby systems and resilient design; this topic will form a pivotal part of this research investigation. Interestingly [15] and [23] indicates data centres on average obtain 2.5 outages a year which equates to 2.84 million hours of global data centre downtime at an estimated financial loss of £200,000 per hour. Mission critical electrical infrastructures such as those utilised in data centres and this research investigation are designed to achieve high reliability and resiliency [49], to minimise such downtime of systems, or indeed occur financial loss for the business.

2.2 Electrical Equipment for Data Centres

The below sections provide an insight and overview of the key equipment located within data centre electrical networks.

2.2.1 High Voltage (HV) Switchboards

High voltage switchboards are commonly located at the source of the data centre electrical distribution system. Such electrical switchgear will interconnect grid feeders, standby generators, and power distribution transformers. Schneider Electrics IEC installation guide identified availability of such high voltage equipment needs to be high [8], thus service factors are an important consideration of design. Other such research details typical architectures for HV data centre networks including single fed, ring main systems, dual feeders, and duplicate busbar topologies. Such configurations of the HV network will affect the system impedance and fault current thus poses a challenge for the electrical protection system, whilst under varied operational and fault scenarios [23] and [26].

2.2.2 Power Transformers

Power transformers are static devices which transform electrical energy, copper windings wound onto an iron core creates a mutual inductance to induce an *EMF* between windings. Primarily research identified that the distribution transformer is utilised to convert voltages levels in the electrical supply system with minimal loss [27], [28], [29]. Dionise and Cooper also indicate transformers in mission critical systems are often operated in a parallel connection feeding a common busbar, or in a duty & standby arrangement as an 'N+X' configuration. However, this connection type may lead to technical complication with magnetising inrush since operation of the transformer circuit breaker whilst on load can lead to high value of residual flux, which can remain within the core until re energisation thus high inrush currents can be obtained in the data centre network [20]. This circumstance poses a challenge for the electrical protection devices i.e., to achieve maximum operational availability during such energising operations. This research programme investigates electrical protection devices of such power transformers during both single and parallel operations.

2.2.3 Busbar and Cabling

Research highlights electrical busbar and cablings are essential component parts of the electrical system, their protection is required to allow for all normal and abnormal operating conditions [8] and [20]. The cabling or busbar design must nominally satisfy full load currents, short circuit currents, overcurrent's, mitigate voltage drop and form part of the indirect protection system. In mission critical facilities failure of such busbar or cabling can lead to downtime of critical plant, with an indication through assessment of facility audits that a significant quantity of installed cabling in data centres not being suitable for the short circuit current levels present, in particular cable feeders in high voltage applications [20].

2.2.4 Standby Generators

Standby generators are vital to a mission critical infrastructure. Most often the generator system will provide alternative power redundancy and resiliency to critical busbar loads during loss or instability of main grid feeders [48], without such equipment the *Ao* of these infrastructures would be significantly reduced. Generator construction is generally a combination of a mechanical prime mover, alternator, governor, fuel tank, electric starter, earthing resistor, and connection to a distribution network via switchgear. Research identifies such standby generators will need to operate as standalone machines and in parallel with main grid feeders, therefore electrical protection can become complex to cover all operations [6], [7], [8]. Application of generator electrical protection is therefore investigated during this research, which included insulation failure, stator protection, L-G faults, rotor protection, overcurrent, loss of prime mover, loss of field, over voltage, differential, and parallel operation with G59 compliance.

2.2.5 Uninterruptable Power Supplies

An Uninterruptible Power Supply (*UPS*) in simplistic terms is a device which provides short term battery standby power to *IT* equipment should utility power supply fail or become unstable. *UPS* provide power in such a way that the transition from utility supplies to battery power is seamless and uninterrupted [25] and [47]. It is identified in [2] and [25] that often in large data centre facilities the double conversion on-line *UPS* modules are utilised, with designs of such units being considered as a standby unit with the addition of a primary power path via an inverter opposed to *AC* mains (as Figure 2.2.5.1).

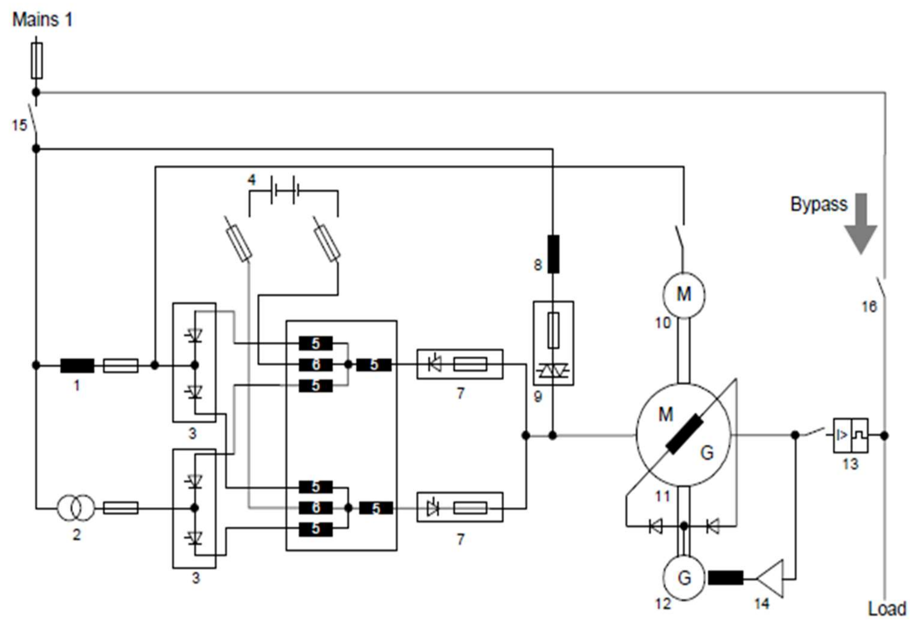


Figure 1.2.5.1 Piller *UPS* Schematic Diagram [14]

Where components are:

1 Commutation choke	10 Pony motor
2 Phase-shift transformers	11 Synchronous machines (converter)
3 6-pulse three-phase bridge rectifier	12 Exciter
4 Battery	13 Overload and short-circuit protection
5 DC link circuit chokes	14 Voltage regulators
6 Battery chokes	15 Input switches
7 Thyristor converters (inverter)	16 Bypass
8 Mains choke	17 Thyristor switch contactors
9 Thyristor switches	

The double conversion *UPS* converts *AC* to *DC* power with application of a rectifier, also *DC* to *AC* with the unit's inverter. Should mains input supply fail to the rectifier batteries are an alternative source of power for the inverter, thus critical load power is maintained. Manufacturers state the uniblock motor generator (Piller) *UPS* construction ensures effective fault clearing capacity with inherent low sub transient reactance, although the infrastructures electrical protection will need to be effective in both auto & manual bypass modes of operation. Both modes of operation were modelled during this research to ensure effective fault clearly of faults and establishing maximum *Ao*.

Research indicates there are many other types of *UPS* which are currently available on the market and choosing one can often be a confusing endeavor with a potential significant impact on the electrical network [3] and [47]. For example, it is generally considered that there are only two types of *UPS* (standby and on-line). There is in-fact five different *UPS* designs as noted below.

i. Standby
ii. Line Interactive
iii. Standby-Ferro
iv. Double Conversion On-Line
v. Delta Conversion On-Line

Specifically relating to this research programme, the *UPS* units investigated are double conversion on-line rotary type, see Figure 2.2.5.1, which are often common within larger commercial applications providing high reliability and a nearly perfect sinewave output. The design configuration is similar to the standby *UPS* except that the primary route for power flow is via the inverter instead of an *AC* main input. In normal operation power is supplied via the mains choke circuit comprising of a thyristor switch and inductor. The synchronous machine operates directly from *AC* line input (mains 1) and because of the sinusoidal current there are practically no system harmonics generated. Since the mains voltage is identical to the motor voltage, a power factor of 0.95 to 1 is typically obtained. The static switch is normally wired to mains 1 but can also be wired to mains 2. The thyristor switch is controlled so that active power flows only in the direction of the motor, although reactive power flows in both directions [3]. In the event of mains 1 failure, the unit prevents power from flowing into loads connected in parallel to the same *AC* system, or into a system short-circuit. The choke limits the reactive current, even when there is a large difference between the motor and mains voltage. If deviation of the primary supply system widely varies from the permissible tolerance range, the thyristor switch is electronically disabled, and the machine is supplied via the rectifier/inverter path. On return of a permissible tolerance range, the thyristor switch is connected automatically during in-phase conditions.

During a mains failure when the set is operating in the battery mode, power contactors are open. This prevents parasitic power voltages at the machine reaching the primary network – which may be isolated – if faults occur in the semiconductors of the rectifier or thyristor switch. The requirements of DIN VDE 0105, whereby semiconductor switches are not permitted for isolating power installations, are therefore fully met. This also applies to the bypass path, which likewise contains either power contactors or circuit breakers according to the type.

Due to redundant paths formed by the rectifier/inverter or battery/inverter or thyristor switch combinations, the manufacturers suggest the entire system achieves an *MTTF* of over 600,000 hours. Depending on the availability of the input line higher values are obtained when the bypass path is taken into consideration [47]. Apart from increasing the reliability, providing the supply via the thyristor switch has further advantages. Firstly, operating the *UPS* set directly from the mains results in a sinusoidal input current for any distorted load current. Secondly, because of the elimination of double energy conversion from three-phase current to direct current and vice versa, the efficiency of the set is further increased. Both modes of operation need to be considered in terms of system short circuit analysis which can be complicated due to the number of parallel units within the electrical network and additional mains synchronous bypass operations. During this research programme the below modes of operation were assessed in terms of short circuit contributions at the relevant connected busbar.

UPS modes of operation

i. 3, 4 or 5 units in parallel, bypass and batteries disconnected.
ii. 3, 4 or 5 units in parallel connected with mains grid for no break transfer.
iii. 5 units connected to batteries in standby mode and disconnected from the grid.
iv. Bypass mode.

2.2.6 Power Distribution Units

Power Distribution Units (*PDU's*) are nominally supplied from a 415Va.c. distribution panel by means of cabling or busbar conductors [49]. Such *PDU's* locate branch circuits which connect the critical load to final overcurrent protection devices. These final circuit overcurrent protection devices must effectively grade with upstream protection to minimise loss of critical loads under a genuine circuit fault [7], [8]. The final circuits will be connected to power distribution rails within the *IT* racks as shown below in Figure 2.2.6.1, this is a common installation method involving branch wiring from multiple protection devices or a central busbar system with 'tap off' points for each enclosure.

Figure 2.2.6.1 IT cabinet electrical supply configuration [25]

2.3 Redundancy and Tier Classifications

Electrical designs for mission critical infrastructures are most often categorised on a metric referred to as a 'Tier rating' or 'N+X redundancy' systems [15], [23], [14]. This Tier rating philosophy provides a classification index which highlights availability and reliability of a given infrastructure and associated equipment. The Uptime Institute identified higher Tier classifications will lead to an inherent robust design for end users critical load, thus led to a more available electrical system with minimised downtime [15]. The 'N+X redundancy' topology explains further that 'N' is defined as the total required amount of equipment to achieve an operational system, therefore increasing N to 2N would double the amount of equipment nominally utilised for operational demand thus increase system reliability [1], [23], [45]. This is shown in Figure 2.3.1, Tier ratings as listed in BSEN50600-1.

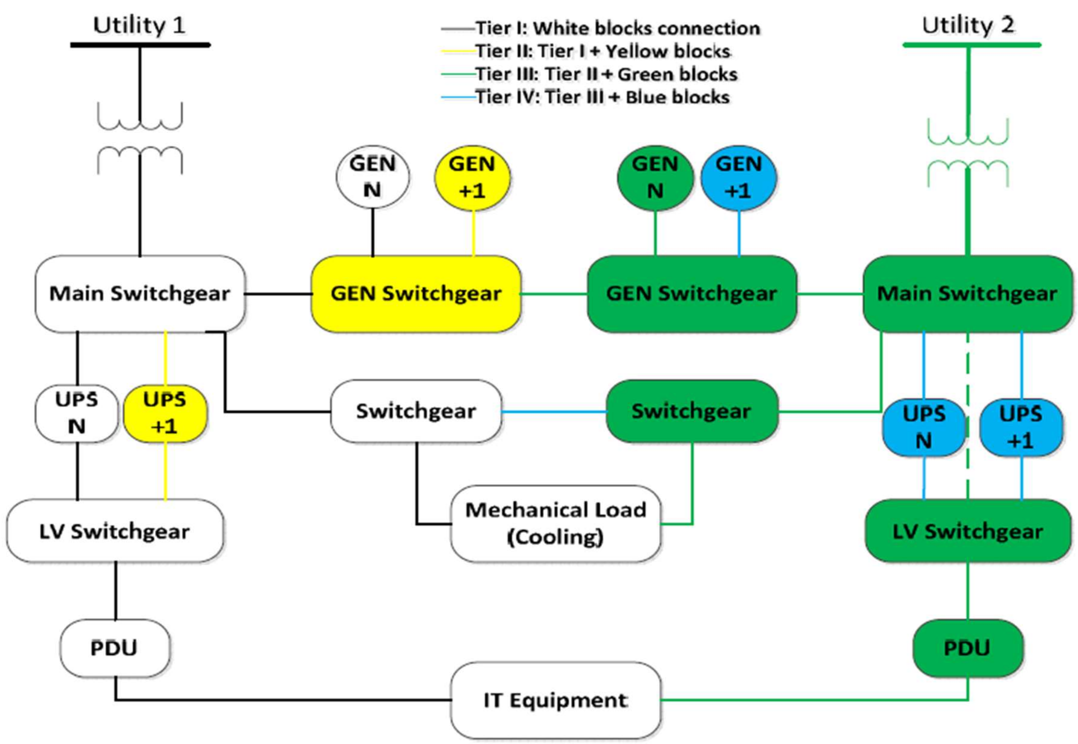


Figure 2.3.1 Tier Rating Single Line Diagram [23]

The N+X configuration may be further increased, in terms of N, to allow for planned outages and system maintenance, for any N+X system reliability can be expressed mathematically as Reliability *R(t)*, which can be found as [44].

$$R(t) = \sum_{x}^{n} \frac{n!}{x!\,(n-x)!}\ \left(e^{-\lambda x}\right)^{x}\ \left(1 - e^{-\lambda x}\right)^{n-x} \tag{1}$$

Where;

x represents the required components of a given distribution system, based on load demand.

n represents the total number of components installed within the distribution system.

$n!$ represents the factorial of n, i.e., if $n = 6$ $n! =$ 6x5x4x3x2x1.

$x!$ represents the factorial of x.

λ represents the probability of failure.

2.4 Tier Classifications

Current Tier classifications index provided by the Uptime Institute (Table 2.4.1), details the typical mission critical electrical infrastructures and associated Tier philosophy. Tier 1 is generally classified as a basic infrastructure with a single distribution path and no system redundancy, therefore all planned and unplanned works in a Tier 1 distribution system would result in downtime of critical load. A Tier 2 also has a single distribution path although several redundant components installed, this system allows certain elements of equipment outages but again distribution paths remain a point of failure. A Tier 3 system is concurrent maintainability with multiple equipment and distribution paths from source to load, in this system typically one path serves the load with another path acting as a standby supply allowing system and equipment maintenance without downtime, this is described as a 2N system [49]. The metric indicated for the most reliable system is therefore categorised as a Tier 4 system which has a clear and distinct different criterion than the other listed Tier ratings. This type of system must be 'fault tolerant' and mitigate any negative operational impact, furthermore the onsite generation is to be considered as primary power source with main grid feeders acting as an economic alternative [24] and [52].

In practice achieving Tier 4 criteria is difficult to obtain due to the complexity of equipment and the issues of mechanical components always having a given failure rate, often the practical element of increased cost may also outweigh the appetite for increased capital spends - for the given tangible reduction in risk.

Table 2.4.1 Uptime Institute Tier Classifications [24]

Uptime Classifications	**Tier 1**	**Tier 2**	**Tier 3**	**Tier 4**
Number of Pathways	1	1	1 Active / 1 Passive	2 Active
Redundancy	N	N+1	N+1	2N
Compartmentalisation	No	No	No	Yes
Concurrently Maintainable	No	No	Yes	Yes
Fault Tolerant	No	No	No	Yes
Expected Total Downtime Per Year (hrs/yr.)	4	2	0.8	0.8
Mean Time To Repair *MTTR* (hrs/yr.)	28	22	1.6	0.4

Where;

N represents the number of electrical supply paths and equipment from feeder source to load.

N+1 represents a 'plus one' (+1) spare capacity or machine for a given load.

2N represents a dual capacity separated supply system.

2.5 Merging Technologies

An overview of the emerging technologies utilised within the electrical networks of data centres. Often requiring standby generator systems operating for an income revenue source to offset capital spend and cost of ownership [50], not necessarily inline or compliant to the Uptime Tier Classifications.

2.5.1 Frequency Response Systems

Frequency Control by Demand Management (*FCDM*), Firm Frequency Response (*FFR*), Smart Frequency Control (*SFC*), all of which enable the operation of facilities standby generators when gird frequency decreases below a desired set point [50]. This is controlled by the National Grid.

2.5.2 Short-Term Operating Reserve (*STOR*)

This is a system which reduces grid demands or increasing on-site private generation with around ten minutes notice from the National Grid and sustaining this operation for approximately one to two hours. Businesses are being paid for being ready to respond to a *STOR* events, and are again receiving further incentives for delivered energy utilisation.

2.5.3 Triad Management

The triad management system is essentially how the National Grid charges businesses for the cost of the transmission network. By reducing load and increasing generation when National Grid demand is at its highest, customers can save or earn money, respectively.

In summary, understanding the above power management technologies it could be suggested current economic targets [50], and an opportunity for reduction of energy with a desire to minimise operational costs of the data centre will continue to provide a substantial challenge to the philosophy provided by Uptime Institute Tier 4 classification [15] i.e., generators acting as primary power source for critical load only. Thus, operational improvement of other Tier classifications in terms of reliability may be desirable in future infrastructure. Therefore, effective electrical protection of critical systems such as generators and *UPS* supplies will allow data centres to benefit from maximum operational availability whilst considering financial implications and reducing costs. One interesting point to note is the given Tier 4 criteria of 'fault tolerant' can have a significant variation & magnitude of meanings for which no tangible evidence is currently available in the current approach.

2.6 Defining Fault Tolerance & Availability Metrics

Research has identified the terms' reliability and availability have specialised technical meanings. Reliability can be described as a systems ability to perform a certain function over a period of specified time, whereas availability is the readiness of a system to perform a function at a specific time [51] and [52]. With these definitions in mind, it becomes apparent that mission critical infrastructures must be both reliable and available to maintain supply for uptime of critical electrical loads in the system. Research identified that availability of an engineering system can be categorised into two specific areas, these are Inherent Availability (*Ai*) and Operational Availability (*Ao*) [1].

Ai is correlated with known manufactures failure rates Mean Time Between Failure (*MTBF*), and Mean Time To Recovery (*MTTR*). With the IEEE standards currently identified in Table 2.6.1 which indicates typical failure probabilities for electrical equipment [1], [20], [21].

Table 2.6.1 IEEE Electrical Equipment *MTBF* Rates

Equipment Type	**Minutes Per Year Outage Times**
HV mains (11, 33 KV)	450
LV mains	90
Diesel Generator Set	360
Uninterruptible power supply (*UPS*)	150

It would therefore be logical to consider the lower a failure rate, and time to repair the more Inherent Availability (*Ai*) would be increased. This statement is supported with a mathematical expression found for *Ai* [1].

$$(Ai) = \frac{MTBF}{MTBF + MTTR} \quad (2)$$

Where;

$MTBF$ represents Mean Time Between Failure of equipment.

$MTTR$ represents Mean Time To Recovery.

An analogy would be to suggest if an electrical system never failed *MTBF* would be infinity, likewise if repairs of failures took zero minutes it would also lead to 100% inherent availability. In practice this is not achievable but currently defines a firm metric for comparison of mission critical infrastructure equipment [22]. However, *Ai* does not consider the importance and practical relevance of Operational Availability (*Ao*). Where, *Ao* explores further technical factors other than those considered with *Ai* which includes investigation of distribution topology, operational layout of substations, cable feeders, relay protection safety grading margins, fault levels, arc flash safety, power quality, load characteristics and maximum demand.

Given the equipment can be uniquely connected, operated, and evaluated individually *Ai* may become less significant whilst investigating the complete system availability, it is often the operational assessment and correlated constraints of electrical infrastructures that can have numerous adverse effects on its reliability [51] and [52], or more specifically operational availability. In short inherent availability may not be the sole success in achieving limited downtime or indeed the best approach.

2.6.1 Six Areas Effecting Data Centre Availability

Research identified there are six main areas which compromise reliability of critical infrastructures, evidence of this claim was based on numerous electrical infrastructure audits in data centre infrastructures [20]. The six indicated areas listed are system electrical protection, system monitoring, surge protection, wiring, grounding, system design and operational availability. *Ao* being mutually exclusive and affected by all other five indicated areas [20]. These issues multiplied by consequences equal system risk [51].

Discussing further the area of system electrical protection, such protection equipment forms part of the complete electrical distribution system. Primarily its role is to provide rapid disconnection of faulty equipment to prevent damage to equipment or users [7] and [8]. Such protection operations should have minimal negative effect on the remaining electrical network, ensuring resilience & reliability is maintained throughout the distribution network [5] and [6], ensuring no critical loads are lost during malfunction or mis-coordination of a protection relay. Protection device types utilised in mission critical facilities are detailed below.

Current Relays

The current relay is one of the most common forms of electrical protection for high voltage networks. Research [6-7] and [9-10] indicate types of current relays which include plain overcurrent and or L-G settings with either Inverse Definite Minimum Time (*IDMT*) or Definite Time characteristics (*DT*). Supplementary to the nominal overcurrent relays there are options for directional elements if voltage connections are also available along with the Current Transformers (*CT*). Other current relay settings include Instantaneous (*INST*) or High Sinusoidal Overcurrent (*HSOC*) along with Sensitive Earth Fault (*SEF*) and Restricted Earth Fault (*REF*). All protection types are investigated in this research programme, in terms of achieving optimal settings for mission critical equipment, Figure 2.6.1.1 shows a typical high voltage protection relay.

Figure 2.6.1.1 Schneider Electric Digital Protection Relay [6]

Historically IDMT current relays were produced as an electromagnetic device which relied on a pivoted metal disc which rotated with torque produced from fluxes and eddy currents, hence disc movement was a function of current. The pivoted disc speed is proportional to the torque, and operating time is inversely proportional to the speed, hence - Inverse Definite Minimum Time relationship exists. Although today's IDMT relays are constructed with digital electronic components the fundamental relationship is unchanged, the below equation displays the theoretical calculation as listed in IEC 60255-3 [10]. Where the given formula for a relay time tripping delay (t).

$$t = TMS\left[\frac{k}{\left(\frac{I}{I_s}\right)^{\alpha} - 1}\right] \tag{3}$$

Where;

I represents the value of applied current.

I_s represents the base value of current setting.

TMS represents the Time Multiplier Setting.

k and α are the constants for given current curve characteristic.

It is interesting to note both K and α are defined constants in the relay which allows for characteristic operating curves to be applied. Such as Very Inverse (*VI*), Extremely Inverse (*EI*), Standard Inverse (*SI*) and numerous other options depending on manufacturing preferences. Research identified the large quantity of characteristic curves are to allow effective time grading between distribution protection devices, to minimise impact of system faults on the remaining healthy network [7] and [10].

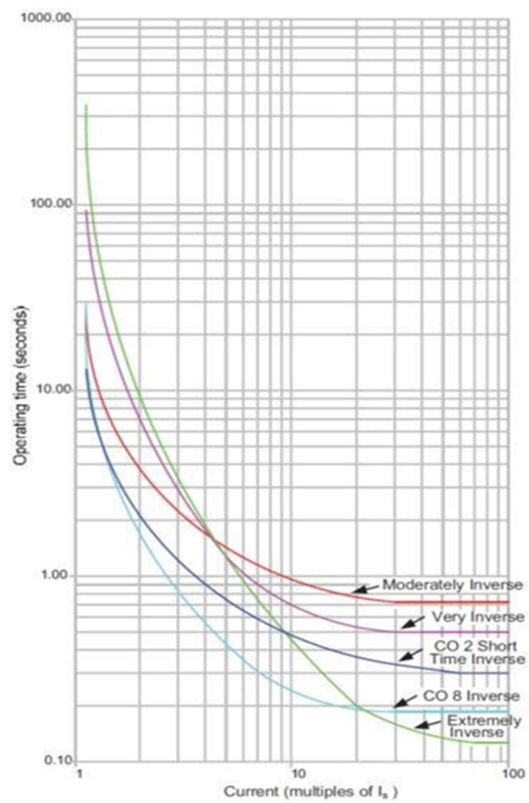


Figure 2.6.1.2 Example IDMT Characteristic Curves [7]

Fuses and Miniature Circuit Breakers

Fuses are proven reliable devices which rupture under overload or short circuit fault conditions to isolate faulty equipment from electrical supply, after such faults fuse devices must be manually replaced before any circuits can be put back into operation, thus provides a challenge in terms of Operational Availability (*Ao*) and necessity for critical spares to limit potential downtime following fuse operations.

Research identified fuses are often categorised into the following three groups [10].

i. High Voltage Fuses > 1000 $V_{a.c.}$ and 40 KA.
ii. Low Voltage Fuses < 1000 $V_{a.c.}$ and 80 KA.
iii. Miniature Fuses (with low current breaking capacity typically < 2 KA).

A common fuse type utilised in both LV and HV distribution applications is the desirable High Rupturing Capacity (*HRC*) type. Research identified this type of fuse has excellent current and energy limiting characteristics with specified manufacturer ratings of 80KA at 400V and 40KA at 11KV [6]. During short circuit conditions *HRC* fuses will operate very quickly, usually in the first quarter of a cycle. However, under overcurrent conditions the fuse element melts uniformly and much slower which may lead to enough deterioration of the fuse element effecting future operating characteristics [7]. For this reason, it has often found that *HRC* fuses are commonly replaced with Air Circuit Breakers (*ACB*) in most commercial applications [10], since enhanced current limiting characteristics of *ACB's* are now available by numerous manufacturers. Research identified improved contact layouts and arc chutes provide opening times of 5ms and a total fault clearance time of approx. 25ms for faults currents in order of 150KA [9] and [10]. Therefore, appropriate selection of *ACB's* can offer robust short circuit protection in-line with *HRC* fuses. Circuit breakers are generally categorised into the following groups [7].

i. Miniature Circuit Breakers (*MCB*).
ii. Moulded Case Circuit Breakers (*MCCB*).
iii. Air Circuit Breakers (*ACB*).

Both *MCB* & *MCCB* nominally provide thermal and magnetic elements for overload and short circuit protection respectively, other larger devices such as *ACB's* also provide earth leakage protection, shunt trip coils, Restricted Earth Fault (*REF*) protection, and under voltage release.

Electrical audits identified a large quantity of *ACB* protection devices are incorrectly set which may lead to malfunction of circuit breakers under network faults, thus negatively effective operational availability *Ao* of electrical systems [20]. It is clear how important effective electrical protection is with respect to achieving a Tier 4 rated 'fault tolerant' system, or an improved Operational Availability (*Ao*) for any other Tier classification, and the challenges posed with protection grading for such a significant type and variety of available electrical protection equipment.

Research indicates critical facilities audited by consultant engineers, found owners were unaware of any coordination study of installed protective devices or were unclear on the original system design [20]. It was reported during such technical audits sample protection settings were analysed and found to provide mismatched protection, and poor selectivity in terms of clearing faults - thus reduced system reliability. With further identification that the performance of electrical systems should be systematically and periodically audited for conformance of standards and regulations [31] and [32], highlighting that companies who perform such technical audits obtain fewer incidents and achieved improved facilities. Key drivers for audits involve the examination, observation, and investigation of electrical systems with a view to identify required remedial action for continuous improved systems.

It is interesting to note architectures of electrical distribution networks within mission critical infrastructures can vary significantly depending on the power requirements, security of supply, and characteristics of the equipment present. All of which can pose challenging effects on both system fault levels, relay settings, protection device types and successful co-ordination of grading schemes. One challenge for mission critical infrastructures is to obtain optimal protection relay settings avoiding malfunction of a relay during any possible network fault type, or operational configuration. This will ensure no critical busbar loads are lost and high Operational Availability (*Ao*) is obtained.

Empirical research also suggests numerous data centre electrical systems have encountered issues with ground fault coordination [20]. Typically, such ground fault protection is applied to main feeders and downstream devices although this was not apparent in audit results. Again, this condition effects primary power reliability. Merlin Gerin [6-7] and [10] identified that predicting performance of an electrical protection scheme with reference to ground faults is essential to obtain the potential network fault levels. To determine such fault levels knowledge of equipment impedances and network configuration is required, consideration must be given to both nominal and short duration arrangements to enable the most advanced application and settings of protective devices within the data centre electrical network.

2.6.2 Defining Fault Levels

Grainger and Stevenson describe fault levels can essentially be calculated at every part of the electrical network [11] or more specifically as a fault tree analysis of all equipment within the data centre [51]. However, an important point to note is system fault studies for three phase electrical systems need to consider both symmetrical and unsymmetrical situations. A symmetrical three phase power system is nominally constructed of three phase conductors with each phase having an identical voltage amplitude and frequency relating to a common reference, and phase difference of 120^0. The common reference being a neutral conductor connected to a common ground. However, it was identified that three phase systems can become unbalanced during faults scenarios which requires further analysis [8], and application of symmetrical components introduced as C.L Fortescue's theorem. With research [12], [18] & [19] stating three unbalanced phasors of a three-phase system can be resolved into three balanced systems phasors. Where the balanced sets components are:

i. Positive sequence components consisting of three phasors which are displaced by 120 degrees from each other, having identical phase sequence as the original phasor.
ii. Negative sequence components of three phasors which are displaced by 120 degrees from each other, having a phase sequence that is opposite to the original phasor.
iii. Zero sequence components of three phasors which are equal in magnitude with zero phase displacement from each other.

Application of this theory for resolution of an unbalanced vector is defined in [3], [5], & [6], and applied during this research programme, with an explanatory vector diagram in Figure 2.6.2.1

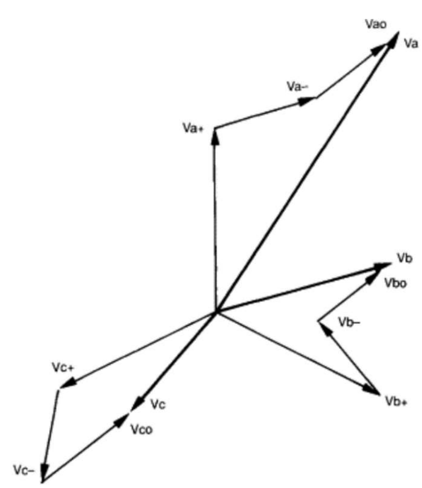


Figure 2.6.2.1 Example Resolution of an Unbalanced Vector [3]

Equations for Phase Voltages Va Vb Vc are:

$$Va = V_1 + V_2 + V_0$$
$$Vb = a^2 V_1 + a V_2 + V_0$$
$$Vc = a V_1 + a^2 V_2 + V_0 \tag{4}$$

Where;

a is a complex number known as operator, $a = 1\angle 120^0$

V_0, V_1, V_2 represent the zero, positive, and negative phase voltage sequence components.

Such sequence components relate to the equipment characteristics and research identified it will affect system fault levels under varied fault types [12] i.e., L-L-L, L-L, L-L-G, L-G. With IEC 60909 [12] short circuit current formulas shown in equations (5), (6), (7), (8).

Three Phases Fault (L-L-L):

$$I_{sc} = \frac{V}{(\sqrt{3}\ x\ Z_1)} \tag{5}$$

Two Phases Fault (L-L):

$$I_{sc} = \frac{V}{(2\ x\ Z_1)} \tag{6}$$

Two Phases to Earth Fault (L-L-G):

$$I_{sc} = \frac{\sqrt{3} * V}{(Z_1 + 2Z_0)} \tag{7}$$

Phase to Earth Fault (L-G):

$$I_{sc} = \frac{\sqrt{3} * V}{(2Z_1 + Z_0)} \tag{8}$$

Where;

$Z_1 = Z_2$

I_{sc} represents short circuit current.

V represents L-L- L Voltage rms.

$Z_0 Z_1 Z_2$ are the zero, positive, and negative phase sequence impedances, respectively.

Schneider Electric IEC Installation guide outlines Thevenin superposition theorem is a proven approach, where IEC 60909 formulas [12] are applied at multiple 'short circuit points' of the electrical network to obtain given fault currents and voltages, thus determining the network characteristics, possible fault paths & failure scenarios [8]. Such analysis is generally applied in a methodical structured process to improve accuracy of results. A documented method [8] is:

i. Define an equivalent voltage source, to represent system voltage prior to fault occurrence.
ii. Calculation of all equipment impedances from source to point of faults, as symmetrical components. For example, generators, *UPS*, transformers, busbars, and cabling.
iii. With (i) and (ii) solved, establish minimum and maximum fault currents. These values can then be applied into network grading studies with protective device characteristics and grading margins modelled to provide a robust approach.

With research information outlined it can be noted how fundamental an electrical protection system can be, with respect to a data centre infrastructure – given the main objective includes operating the electrical systems at maximum resilience, achieving fault tolerance, and the highest operational availability for critical loads. Empirical investigations of fault studies have shown the application of symmetrical component analysis only, and often omitting other important operational factors such as pre fault current load characteristics, parallel standby power, mode of operations and transient impedances of rotating machines [4] and [17]. Such advanced investigations will require an in-depth operational knowledge of the data centre equipment and network configurations. All of which are often overlooked in consultant briefs and available onsite literature [17]. When considering fault currents in the electrical networks multiple values are desired for a range of network design calculations and operational assessments. These values are investigated during this research programme, where the below fault currents were established for all installed switchgear.

i. *RMS* value of symmetrical short current; for breaking capacity, and temperature rise of insulation.
ii. Peak value of symmetrical short circuit current; for making capacity of circuit breakers and switches, also calculation of electrodynamic withstands of enclosures.
iii. Minimum L-L-L short circuit current; to allow protection curves and effective grading.
iv. L-G value of short circuit current; to allow deployment of earth topology and L-G protection settings.

To enable an effective peak current calculation the machine or equipment X/R ratio must be investigated. Ratios between peak transient and steady state currents can estimate an X/R characteristic ratio, with X/R ratios for single equipment being available from equipment manufacturers, although parallel machine operations for data centre electrical networks can lead to complex calculations to establish transient and steady state time domain conditions. Such analysis is applied during the research investigation for both grid and generators operating in synchronism.

Often when calculating generator short circuits, impedance of the generator is far greater than the circuit impedance, therefore an identified calculation is based on the generator's impedance [19]. As the transient current *i(t)* calculation of synchronous machines shown in Eq. (9), note this is for a single machine.

$$i(t) = V\sqrt{2}\left[\left(\frac{1}{Xd''}-\frac{1}{Xd'}\right)e^{-\frac{t}{Td''}}+\left(\frac{1}{Xd'}-\frac{1}{Xd}\right)e^{-\frac{t}{Td'}}+\frac{1}{Xd}\right]\cos(\omega t+\alpha)-\frac{V\sqrt{2}}{Xd''}e^{-\frac{t}{Tdc}}\cos\alpha \tag{9}$$

Where for equations (9) to (12)

α is the angle defining the Voltage phase angle at the instant of fault.

Xd'', Xd', Xd represent the sub transient, transient, and steady state reactance.

Td'', Td', Tdc represent the sub transient, transient, and DC offset time constants.

V represents phase Voltage rms.

Given current *i(t)* is at a maximum when α=0.

Therefore equation (9) can be represented as (10)

$$i(t) = V\sqrt{2}\left[\left(\frac{1}{Xd''}-\frac{1}{Xd'}\right)e^{-\frac{t}{Td''}}+\left(\frac{1}{Xd'}-\frac{1}{Xd}\right)e^{-\frac{t}{Td'}}+\frac{1}{Xd}\right]\cos\omega t-\frac{V\sqrt{2}}{Xd''}e^{-\frac{t}{Tdc}} \tag{10}$$

The current is the sum of *DC* offset component and sinusoidal current [19], with the *DC* offset current given by:

$$idc = -\frac{V\sqrt{2}}{Xd''}e^{-\frac{t}{Tdc}} \tag{11}$$

Therefore, the sinusoidal current for phase a is the sum of sub transient current, transient current and steady state current as (12):

$$ia = V\sqrt{2}\left[\left(\frac{1}{Xd''}-\frac{1}{Xd'}\right)e^{-\frac{t}{Td''}}+\left(\frac{1}{Xd'}-\frac{1}{Xd}\right)e^{-\frac{t}{Td}}+\frac{1}{Xd}\right]\cos\omega t \tag{12}$$

The aperiodic current tends to have a significant value for a short duration, in the range of 10 to 60*ms*, whereas research identified the damped sinusoidal component variables change as machine reactance is variable due to development of the following periods [9] and [19].

a. Sub Transient Td'' lasting for 10 to 20*ms* after fault initiation.
b. Transient Td' lasting for 100 to 400*ms.*
c. Steady State which is to be considered after 400ms i.e., transient.
d. DC offset Tdc.
e. Sum of all four current values (see below Figure 2.6.2.2).

Note: $Xd > Xd'' > Xd'$ which leads to decreasing short circuit current over time.
As shown in Figure 2.6.2.2 (a), (b), (c) & (d) sub transient current, transient current, steady state current and the *DC* offset current respectively [19]. Figure 10 (e) displays the sum of all four currents (a), (b), (c) and (d).

$$Ik'' = V\sqrt{2}\left[\left(\frac{1}{Xd''} - \frac{1}{Xd'}\right) e^{-\frac{t}{Td''}}\right] Sin\ \omega t$$

Sub Transient

$$Ik' = V\sqrt{2}\left[\left(\frac{1}{Xd'} - \frac{1}{Xd}\right) e^{-\frac{t}{Td'}} + \frac{1}{Xd}\right] Sin\ \omega t$$

Transient

$$Ik = \frac{V\sqrt{2}}{Xd}\ Sin\ \omega t$$

Steady State

$$Idc = -\frac{V\sqrt{2}}{Xd''} e^{-\frac{t}{Tdc}}$$

DC Offset

Total Combined

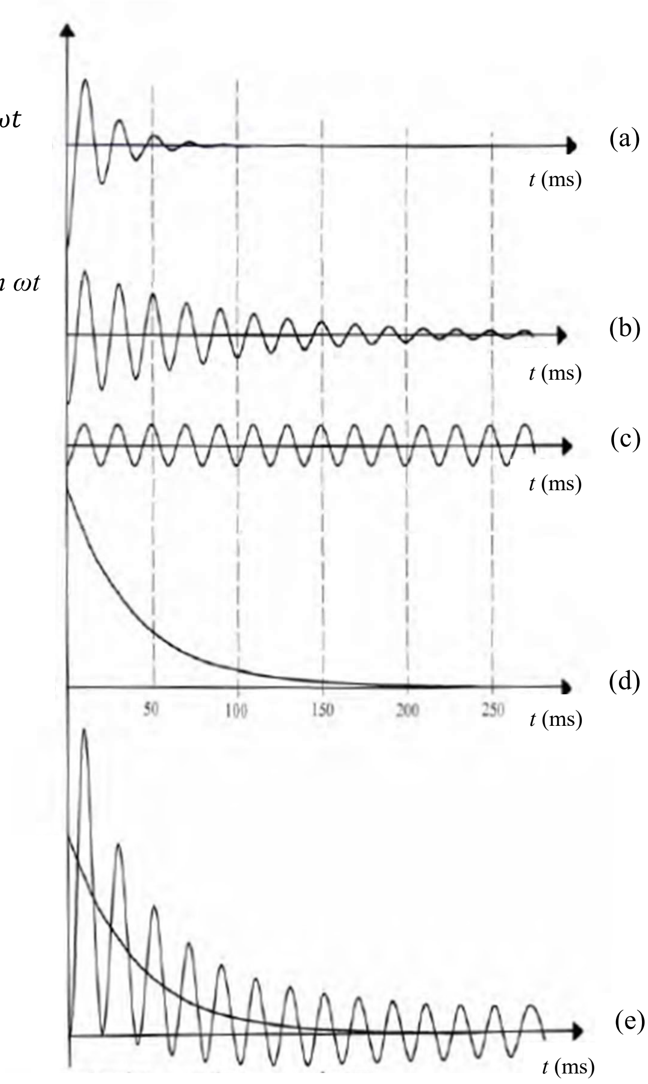


Figure 2.6.2.2 Plots of Short Circuit Current Contributions [19]

Where the figures represent; (a) sub transient current, (b) transient current, (c) steady state current, (d) DC offset current, (e) Sum of (a), (b), (c) and (d).

Synchronous machines form part of an essential standby power systems for mission critical facilities. Often machines will operate in parallel with grid supplies which will contribute to further technical complication and requirement for advanced model simulation. Research identified all power sources should be considered and fault levels obtained for effective protection co-ordination, ensuring maximum Operational Availability (*Ao*) [7], [8], [26]. Such factors were investigated during this research programme, via application of ETAP model simulations to establish the minimum and maximum fault currents possible at each critical busbar. key factors included establishment of Short Circuit Current (*SCC*), confirming:

i. Existing equipment strength and capabilities in terms of making, breaking and short time current withstand.
ii. I^2t protection for thermal ratings of equipment.
iii. Maximum and minimum *SCC* to enable effective protection device co-ordination, and arc flash mitigation.
iv. Phase sequence voltages and currents of unbalanced short circuits, for system protection device evaluation.

2.7 Protection Device Grading & Co-ordination

Electrical equipment such as switchgear, transformers, generators, and cabling within data centres require a varied range of protection devices to safeguard against system faults. In addition to rapid disconnection of faults research identified protection devices need to detect, locate, and initiate removal of faults in minimal time without effecting healthy parts of the electrical network [6] and [10]. This is a pivotal point in terms achieving maximum reliability within a network and uptime of critical data centre equipment. Furthermore, consideration must be given to all operational scenarios of electrical equipment since this in turn will have a correlation to system fault levels and operation of associated protection devices. The requirement for all protection devices, except those directly associated with the fault must remain inoperative and minimise network disruption [9] and [10]. The basis of a protection scheme is therefore designed on i) Safety ii) Reliability iii) Selectivity. A range of operational philosophies can be adopted to achieve an effective electrical protection scheme, a key number of those associated with this research programme are explained below.

2.7.1 Discrimination by Time

A method for radial circuits where discrimination is achieved by providing a minimum trip time setting to the relay closet to the fault, with an increment of time as the protection devices move further upstream from the fault and closer to the incoming supply. In practice this will ensure the relay closest to the fault operates firstly and leaves remaining sections upstream within the network healthy and in service. As noted below research identified it is necessary to leave a minimum grading time interval between devices [10] and [19].

i. Circuit breaker trip times 50 – 150ms.
ii. Relay time delay errors 150ms.
iii. Relay overshoot 100ms.
iv. Relay reset time of 70%, hence the relay must fully rest at 70% nominal current (electromagnetic types only).

Therefore, for all these times to be met a typical grading margin for electromagnetic devices would be 0.4s whereas a more modern solid-state relay and vacuum circuit breaker 0.25s is a more acceptable margin.

2.7.2 Discrimination by Current Magnitude

Impedance from source to load within the power circuit limits current flowing at any given point [6], [9], [19]. Therefore, in theory a carefully selected current setting for a given relay could provide discrimination. In practice, for data centres this is difficult to achieve since its common within distribution networks to have multiple feeders and interconnectors which will significantly affect the fault current at any point. An application where this method is more proven is for power transformer protection where high instantaneous settings can protect the HV winding since a delta wound primary will not have zero sequence currents from the LV side under high L-G currents.

2.7.3 Discrimination by Fault Direction

Current practice in data centre electrical networks is to add sensing or directional elements to relay protection system, which allows a response to both current magnitude and direction [10]. This would be typical of a closed loop ring system with parallel feeders, an important consideration is a polarity check during commissioning to ensure correct operation of the relay and avoid malfunction.

2.7.4 Unit Protection

A protection scheme which locates current transformers at each end of a feeder, transformer, or ‘unit’ of a given piece of plant to be protected, in an interconnected zone. A comparison of currents entering and leaving each end of the zone is undertaken, thus highlights a difference of current magnitude or displacement angle. The following are two important requirements when considering unit protection.

i. Through Fault Stability - If currents entering and leaving the zone are equal protection must not operate.
ii. Sensitivity to Internal Faults - If currents entering and leaving the zone are different by a set value protection must operate.

Research identified a major advantage of unit protection is its speed of operation (typically 200*msec* or less) disconnecting only the plant associated with the fault. However, this can be an expensive protection scheme with a requirement for communications cabling between each end of the given feeder [19].

2.8 Limitations of Current Research

There is currently a known approach for designing the data centre building - Uptime Institutes Approach - which utilises inherent design availability data only and does not provide a generalised approach for simulation of operational conditions or improvement of reliability metrics.

As detailed in this approach the requirements for data centres is for them to be designed and operated to achieve maximise Operational Availability (*Ao*), thus limiting potential downtime of critical systems. Furthermore, such resilient systems drive a requirement to design electrical infrastructures in correlation with the Uptime Institutes Tier ratings or 'N+X' redundancy topologies. Such designs lead to challenges for electrical protection systems since protection equipment will need to be effective for all electrical network configurations, both nominal and redundancy mode of operations, involving many types of complex electrical equipment. This challenge is supported with six indicated areas which can compromise system reliability, with electrical protection being recorded as a cause for concern since site audits carried out by consultants indicated a mismatch of protection and examples of insufficient grading schemes currently in service.

Despite such indicated issues there are fewer research publications available that detail investigations following a complete electrical protection review in such critical infrastructures, or indeed an attempt to indicate which protections and modes of operations are most problematic with respects to achieving maximum Operational Availability (*Ao*). Also, limited data centre research is available that includes the application of load flow, arc flash or load point reliability in the field.

2.9 Chapter Summary

This literature review highlights the limited publications available to drive successful development of electrical infrastructures in data centre environments. Particularly, electrical protection systems and achieving the most robust operational configuration for increased Operational Availability (*Ao*). However, the present research available identified six possible areas with a potential to cause system issues, although no subsequent investigations and discovery of technical details are apparent, particularly for the application of ETAP to create unique models and operational scenarios for data centre electrical equipment and produce a generalised approach which can improve reliability metrics.

Chapter 3 – Defining the RBS System

3.0 Introduction

This chapter consists of a written description of the data centre design parameters, its associated Uptime Institute Tier Classification rating, operational configurations, and information regarding all the installed critical equipment, both LV and HV electrical networks. Chapter 3.1 includes example photographs of the data centre critical equipment, and a completed single line diagram showing the electrical network and all associated power strings for each of the data halls and building services equipment, i.e., encompassing all that has been investigated during the research programme.

Chapter 3.2 details the ETAP power system analysis software in general terms of its features and functions which were applicable to this research programme, including all the simulation calculation methods, validation governance and international standards applicable to the data centre model constructions. The final section of this chapter is a detailed explanation of the singular model components validation, this approach provided a standalone model and simulation for each of the data centre electrical equipment, so they could be critiqued against proven theoretical calculations and the original equipment manufacturers design data before proceeding to build the complete electrical network model and subsequent simulations.

3.1 System Description

The Third Data Centre (*TDC*) building for RBS is in Staffordshire. The *TDC* has been designed as a 7.2 MVA secure computer installation which undertakes technology operations for the RBS banking business. The sites electrical infrastructure is normally supplied by two dedicated 11KV cable circuits from Western Power Distribution 33/11KV substation. The *TDC* electrical network includes installation of on-site standby generation capable of supplying 9 MVA ensuring the total site load is powered in the event of prolonged failure of the Western Power supplies. The on-site generators may operate in parallel with the grid system with current utilisation of the on-site generators for grid balancing solutions. The electrical network is designed as a 2N system from HV incomers to final LV loads. The majority of building load being two 1800m^2 data halls located on the east and west elevations of the building, in total data halls loads are designed for 4.5MW consumption with remaining power capacity for mechanical supplies such as chillers, humidification, ventilation and other general office areas.

The HV network is nominally a closed ring system, comprising of four main switchgear units which in turn supplies sixteen 11/0.415KV distribution transformers. The sixteen Dyn11 distribution transformers comprise of 12x 2.5MVA and 4x 1MVA. Each two transformers feed into a main LV intake as a duty/standby N+1 system, thus a total of 8 main LV intake substations are located on-site. Transformers are in external enclosures and are ONAN construction. Supply conductors at HV&LV include a range of cabling and busbar systems, with protection devices installed at both the HV VCB's and LV ACB's. The site is a twenty-four hours a day seven days a week critical operation with an on-site team of 14 engineers both maintaining and responding to any electrical network issue. The on-site generator system comprises of a HV duplicate busbar switchgear arrangement connecting five synchronous machines with automatic frequency and voltage control as the primary option, also manual synchroniser for additional resilience during periods of failure of the automatic system. Faults on the HV network can therefore vary in magnitude and duration depending on primary power source, both grid connections and standby generators have been assessed in the research programme.

The LV loads comprise of computer equipment supplies which are derived from the Uninterruptable Power Supply (*UPS*) systems and general mechanical loads fed directly from grid sources. In normal operation, the rotary *UPS* electrically isolate the computer supplies from the main supply network with regards to fault levels. Faults in the computer supply network are therefore supplied only by the *UPS*, or by the main system bypass if being utilised. The *UPS* systems have the capability to operate for short term duration in parallel with grid feeders and can also supply fault current into the main grid for short duration.

Below Figure providing examples of the installed LV switchgear and low voltage Air Circuit Breakers (*ACB*).

Figure 3.1.1 Example LV Switchgear and Air Circuit Breakers

Below Figures providing examples of the installed rotary *UPS*.

Figure 3.1.2 Example Piller Rotary *UPS* Equipment

Below Figure providing examples of the installed HV equipment including switchgear, protection relay and Vacuum Circuit Breaker (VCB).

Figure 3.1.3 Example HV Equipment (1/2)

Below Figure providing examples of the installed HV equipment including switchgear, distribution transformer and synchronous generators.

Figure 3.1.4 Example HV Equipment (2/2)

The below single line diagram is the complete *RBS* data centre electrical system, this is what was utilised for the construction of all power system modelling, the single line diagram includes all electrical equipment's from HV incomers to LV loads, with each power string being notated with a colour reference – as it is on the actual site equipment.

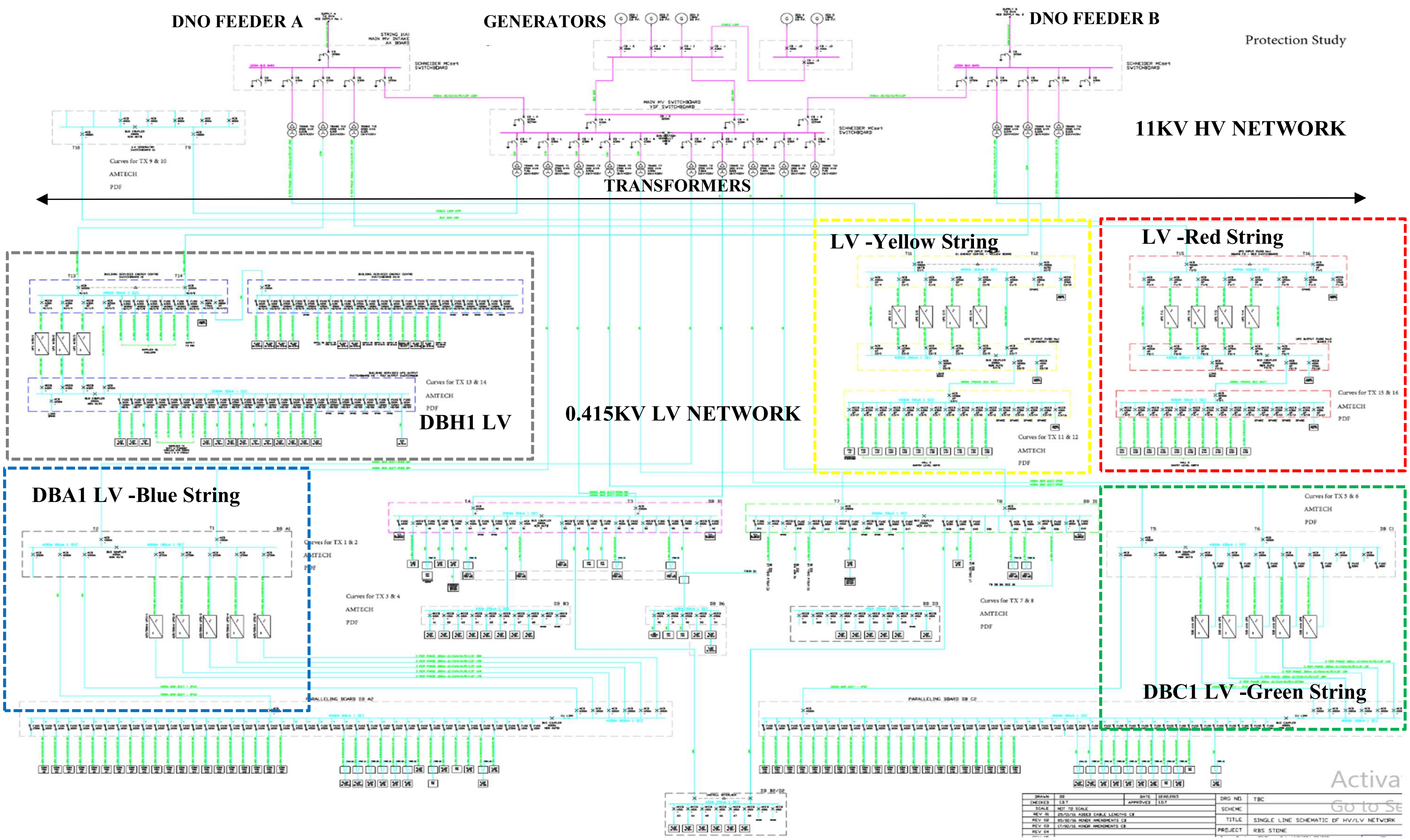


Figure 3.1.5 RBS Data Centre Electrical Network Single Line Diagram

3.2 ETAP Software Applications Overview

ETAP is an electrical power system analysis and operations software that was founded in 1986, providing a suited range of software applications allowing analysis, simulation, monitoring, optimisation, and automation of electrical power systems [34]. In 2018 ETAP was recognised as the gold award winner for product of the year by the consulting engineers' group. ETAP software has a verified and validated set of equipment libraries for cabling, protective devices, power sources and dynamic models. ETAP study results have also been validated with hand calculation, field measurements and industry standards, over 50,000 ETAP licenses are being utilised by many industry sectors, with a 100+ for research and development projects. ETAP software is further supported by 70+ successful audits by several industry bodies and leading standards [34]. The following ETAP modules were utilised during this research programme, with a description provided for each:

3.2.1 Load Flow Module

Creates and validates electrical system models, with features including automatic device evaluation, summary alarms / warnings, result analyser, and intelligent graphics for an efficient load flow programme analyser. ETAP calculates busbar voltages, branch power factors, currents, and power flows throughout the electrical system. The module allows for swing, voltage regulated, and unregulated power sources with multiple power grids and generator connections. It can perform analysis on both radial and loop systems, with selection available for several different calculation methods to achieve optimal accuracy. Features of the load flow functions utilised for data centre simulations includes:

i. Newton-Raphson, a fast decoupled method suited to interconnect systems.
ii. Generator governors with droop mode analysis.
iii. Transformers tap changer.
iv. Multiple loading & generation conditions.
v. Swing and voltage regulated power sources.
vi. Voltage drop calculations.
vii. Alert view for critical & marginal limit violations, in-line with international standards.
viii. Busbar, transformer, and cable overload warning.
ix. Individual demand factors for continuous, intermittent, & spare operating conditions.
x. Multi-report results analyser.

3.2.2 Short Circuit Analysis Module

Allows determination of system fault currents and automatically compares these values against manufacturer short circuit current ratings. Overstressed device alarms are displayed on the single line diagram and included within all short circuit study reports. Analyses the effect of fault currents using ETAP short circuit analysis software, for L-L-L, L-L, L-L-G and L-G faults. Features of the short circuit current analysis module utilised for data centre simulations includes:

i. Application of international standards IEC60909 & IEC61363 to all simulations.
ii. Determines the short circuit worst-case device duty.
iii. Displays critical & marginal busbar alerts for breach of current capacity ratings.
iv. Load terminal short circuit current calculations.
v. Integrates with star protective device coordination for effective grading of system faults.
vi. Transition's fault current values into arc flash analysis simulation model to provide total incident energy and arc flash boundary.
vii. Short circuit reporting for each system busbar.

3.2.3 Protection & Co-ordination Selectivity Analysis Module

ETAP overcurrent device protection and coordination provided an intuitive and logical approach to curve selectivity analysis, offering troubleshooting of data centre false trips, relay operation, and mis-coordination with application of Time Current Curves (*TCC)*, protective device coordination & selectivity, sequence-of-operation, protection zone selection & viewer, automated protection & coordination and verification & validated of protective device libraries. Features of the protection & co-ordination selectivity analysis module utilised for data centre simulations included:

i. AC overcurrent protective device coordination & selectivity.
ii. Graphically adjustable device settings via *TCC* viewer.
iii. Equipment damage curve plotting.
iv. Sequence-of-operation for fault analysis.
v. Verifying & validating protective device libraries.
vi. Performing overcurrent protective device coordination.
vii. Establishing accurate operating characteristics and trip times.
viii. Predicting false trips and relay mis-coordination.
ix. Highlighting of possible protection design issues and crafting solutions for scheme improvement.

3.2.4 Arc Flash Analysis Module

ETAP arc flash analysis software allows an assessment of arc flash hazards and incident analysis. Identifies high risk areas in the electrical power system by simulating and evaluating various mitigation methods in arc flash studies. The arc flash analysis programme is a completely integrated module that solves multiple scenarios to determine highest energy levels present on the network. Features of the arc flash analysis module utilised for data centre simulations includes:

i. Application of arc flash standards to all simulations (IEEE1584-2018 and NFPA® 70E 2018).
ii. Provides 3-phase and *UPS* arc flash hazard calculations.
iii. Considers arc flash in enclosed equipment and switchgear configurations.
iv. Integrated with ETAP short circuit analysis software and star protective device coordination software.
v. Prints arc flash hazard safety labels and PPE requirements on study completion.

3.2.5 Reliability Analysis Module

This module provides the most robust method to efficiently model various power system elements and devices to include their effects on the distribution system reliability, such as fault isolation and load restoration through the operation of switching devices. Features of the reliability analysis module utilised for data centre simulations includes:

i. Modelling reliability characteristics of each component.
ii. Calculating the busbar and load point reliability indices.
iii. Calculating system reliability indices, average failure rates, average outage durations, annual outage duration.

3.3 Chapter Summary

This chapter details the *RBS* data centre system in terms of the construction of its electrical network, operational philosophy and key equipment installed. Providing the single line diagrams of all the electrical network equipment that were key for construction of model simulations. Also, detailing the ETAP power system analysis software and the module features utilised for the research programme including the most applicable for the data centre electrical network i.e., load flow, short circuit analysis, protection co-ordination, arc flash and reliability assessment. A reference of key international standards for each of the power simulation topics has also been included within the software module descriptors, these could be applied with ETAP or other power system simulation software.

Chapter 4 – Simulation Methodology

4.0 Introduction

This chapter displays the single line diagrams of the data centre electrical network that was modelled and simulated in ETAP power system software as part of this research programme. The data centre belongs to the Royal Bank of Scotland and is listed on the governments Committee for Protection of National Infrastructure (*CPNI*), hence optimal system reliability is a key objective.

The simulation analysis of the data centres electrical network included carrying out a suite of power system studies - load flow analysis, short circuit analysis, protection device grading and co-ordination, load point reliability analysis and finally arc flash mitigation. The key to the successful simulation approach was to model and simulate each of the singular data centre electrical components and prove accuracy of all simulation results in-line with theoretical calculations and manufacturer data i.e., before building them into a compete electrical network. Subsequently to this initial step the exiting base electrical network (as single line diagrams 4.1.1 & 4.1.2) was built and assessed with ETAP simulations for establishing current reliability metrics, at each system busbar, before any further power simulations or improvements were obtained. This was to 'benchmark' the current electrical network performance.

Following 'benchmarking' stages the data centre electrical network was subjected to advance simulation of all the possible operational scenarios, with data sets and results analysed against international standards, allowing recommendation for further improvement to the current operational configurations and providing an improved reliability, for of all the installed equipment.

The 'base' network was therefore updated to reflect the recommendations given, this upgraded configuration was also subjected to the exact same simulations as the base model with a final reliability assessment at each busbar, proving the approach had indeed obtained an improving data centre operational configuration and reliability.

Each of the simulations, associated scientific theory, calculations, and the approach taken is explained in detail throughout this chapter.

4.1 Construction and Validation of Model Equipment

Before considering the full simulation model of the data centre it is important to outline each of the individual components were modelled in ETAP and verified against the original manufacturers data and theoretical hand calculation. This approach ensured accuracy of the modelled components simulated for; *DNO* sources, transformers, generators, cables, and *UPS*. Each of the models and calculations are listed in Appendix I. Complied these individual components were utilised to construct the full electrical network data centre model as shown in Figure 4.1.1. Also, Figure 4.1.2 showing more specifically the LV rotary *UPS* system.

ETAP Data Centre Electrical Network Model Single Line Diagrams

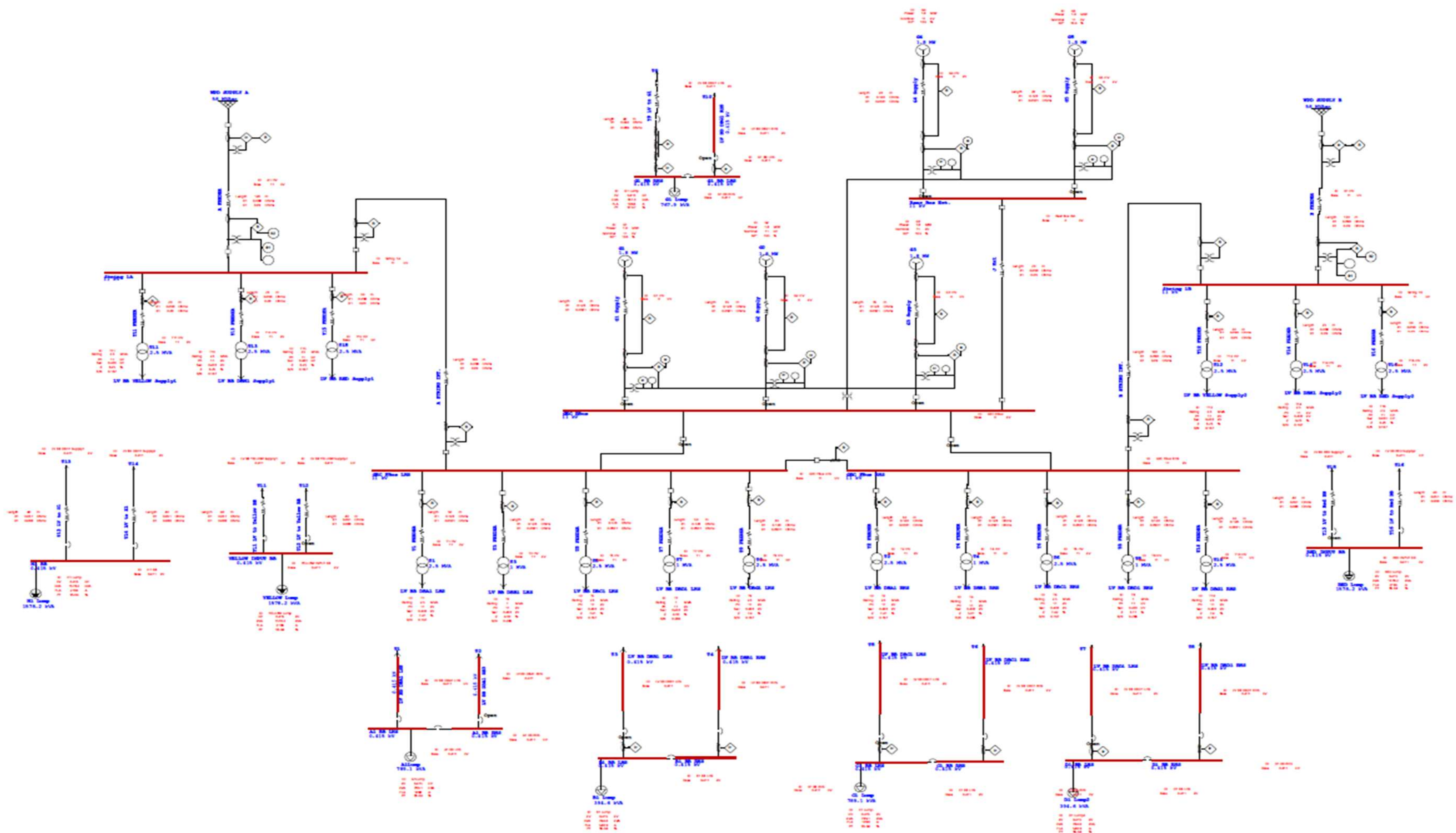


Figure 4.1.1 ETAP Single Line Diagram of the Data Centre Electrical Network

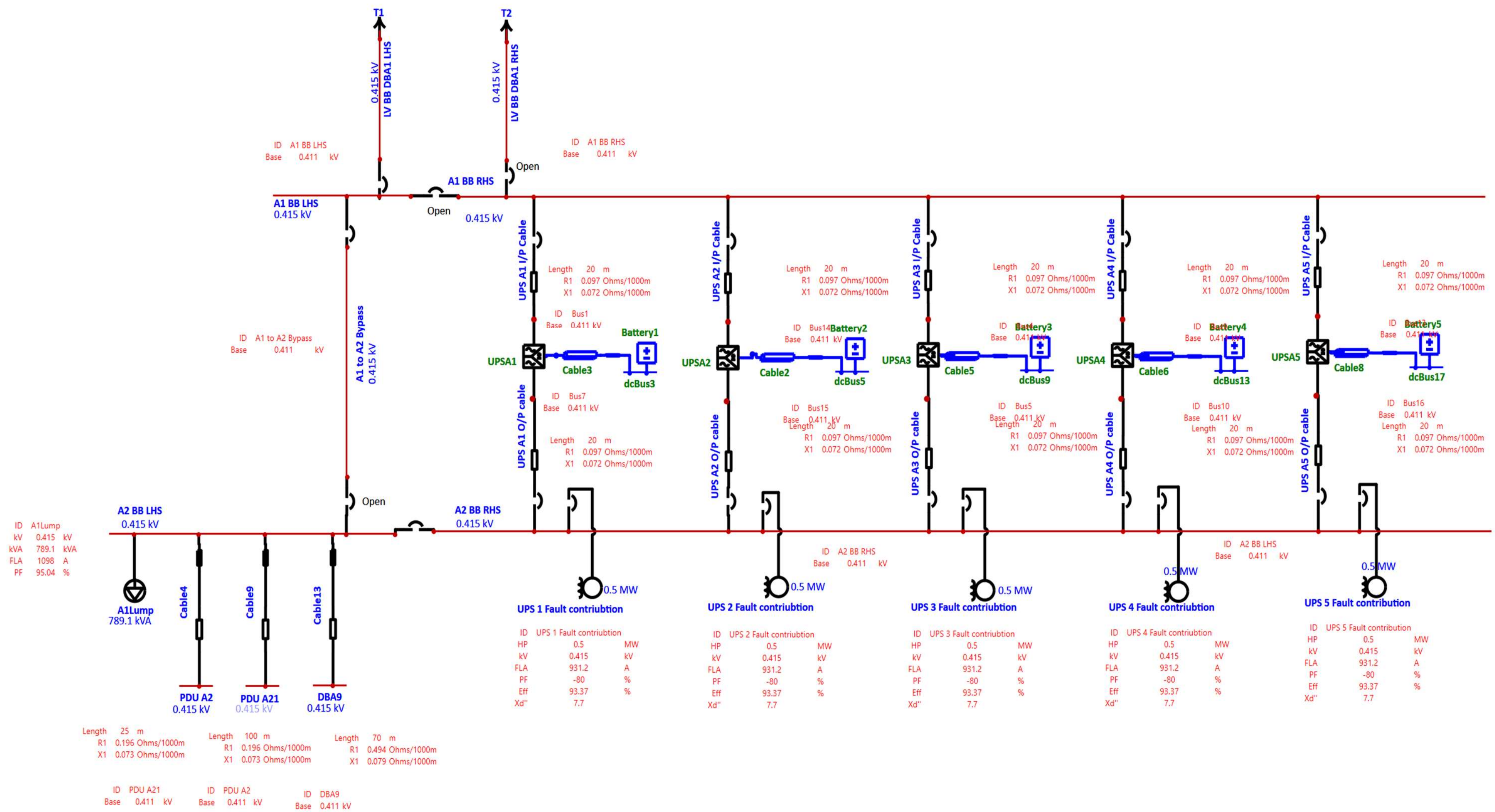


Figure 4.1.2 ETAP Single Line Diagram of the LV *UPS* Network

4.2 Load Flow

Load flow studies are an important engineering analysis of data centre electrical distribution networks to understand steady state fundamental parameters such as voltage magnitude, phase angle, real power, and reactive power flow. Such load flow studies on interconnected mesh systems require numerous complex iterative calculations to provide the most reliable results [38]. For ETAP simulations adaptive Newton Raphson method equation (13) was utilised, allowing a fast responding first order iterative method suited to such a large interconnected system [34] i.e., the adaptive Newton Raphson method is a formula for solving non-linear equations and is suited to interconnected power systems but does require a simulation package and good memory capacity to undertake. Equations (13) to (17) numerically describe relationships between changing the phase angle and the magnitude of a networks voltage in terms of achieved real and reactive power flow in the system.

$$\begin{bmatrix} \frac{\partial P}{\partial \theta} & \frac{\partial P}{\partial |V|} \\ \frac{\partial Q}{\partial \theta} & \frac{\partial Q}{\partial |V|} \end{bmatrix} \begin{bmatrix} \Delta \emptyset \\ \Delta |V| \end{bmatrix} = \begin{bmatrix} \Delta P\ (x) \\ \Delta Q(x) \end{bmatrix} = f(x) \tag{13}$$

Where, for equations (13) to (17)

i & j represent system busbar, V represents Voltage rms at a given busbar, P represents real power (MW), Q represents reactive power (MVAr), θ represents the phase angle at a given busbar.

Taking equation (13) above it can be noted changing the phase angle θ or voltage magnitude $|V|$ affects both the real power (P) and reactive power (Q) power, respectively. It is also identified for power systems both terms listed in (14) are insignificant and can be ignored [30], thus a final derived equation for load flow is listed in equation (15).

$$\left[\frac{\partial Q}{\partial \theta}\right] \left[\frac{\partial P}{\partial |V|}\right] \tag{14}$$

$$\Delta|\theta| = -\left[\frac{\partial P}{\partial \theta}\right]^{-1} \Delta P(x)$$
$$\Delta|V| = -\left[\frac{\partial Q}{\partial |V|}\right]^{-1} \Delta Q(x) \tag{15}$$

The above equation (15) displays a change in real power (*P*) and reactive power (*Q*) is directly correlated to phase angle θ and voltage magnitude |V| respectively. More commonly a matrix (16) is utilised as a simplified expression with associated diagonal elements to solve values at busbar, as in equation (17).

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} j1 & j2 \\ j3 & j4 \end{bmatrix} = \begin{bmatrix} \Delta\theta \\ \Delta|V| \end{bmatrix} \tag{16}$$

Where, diagonal elements of $j1$ equal;

$$\frac{\partial Pi}{\partial \emptyset i} = \sum_{j \neq i} |Vi||Vj||Yij| \cos(\theta ij - \theta i + \theta j) \tag{17}$$

With iterative methods detailed another important element of the simulation approach is establishment of model input data and possible network configurations to evaluate [33]. The procedure for establishing input data for ETAP models includes obtaining.

i. Grid Source Details – set mode of operation as 'swing mode' where voltage nominal (V_n) and phase angle (θ) are required data values.
ii. Generator Sources – real power capacity (MW), rated efficiency, maximum and minimum reactive power (MVAr) and mode of operations i.e., swing or v-control for each power machine was established.
iii. Transformers – primary and secondary voltage ratings, rated power (MW), percentage impedance & X/R ratio, tap changer type including nominal position.
iv. Lumped Loads – located for each low voltage critical busbar to represent actual connected loads, values given in MW and MVAr. Study cases were set to model varying load values for all lumped load types.
v. Busbar – nominal voltage (V_n), rated operating current and type of equipment i.e., switchgear, *MCC* or switchboard.
vi. Study Case – modelling multiple operating conditions of the electrical network, varying load capacities or supply feeders, such as nominal grid or standby generation modes of operation. Methods of calculations specified along with maximum iterations and precision required. Newton Raphson method was applied allowing the minimum and maximum voltages to be established at each critical busbar.

4.2.1 Operational Scenarios for Load Flow Modelling

For the RBS electrical network both nominal and worst-case scenarios for equipment configurations were investigated with ETAP model simulations. Given the installation philosophy is to operate as an N+1 or 2N configuration the objective was to ensure adequacy of each arrangement, i.e., should an online transformer fail the remaining transformer units should be capable of maintaining full load. Given supply continuity underpins availability in-line with Table 4.2.1.1 the Uptime Institutes Classifications, operational load flow assessments in ETAP provided a comparison against this method.

Table 4.2.1.1 Uptime Institute Tier Classifications [2]

Tier Ratings	1	2	3	4
No. of Delivery Pathways	1	1	1 Active 1 Passive	2 Active
Annual Downtime	28.8 hrs	22 hrs	1.6 hrs	0.4 hrs
Site Availability	99.67%	99.75%	99.98%	99.99%

The following three typical distribution switchgear arrangements were assessed during load flow studies, along with all other system busbars in the main electrical network single line diagram as shown in Figure 3.1.4.

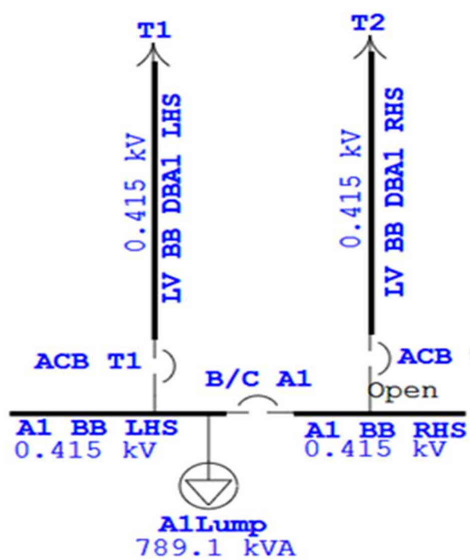


Figure 4.2.1.1 Distribution Board Ref.A1 Switchgear Configuration in ETAP

Where;

T1&T2 are remote node connections to power transformers; Specification 2.5MVA, 11/0.433KV, Dyn11, Zb=7.41% both switchgear feeders are 4000A rated busbar.

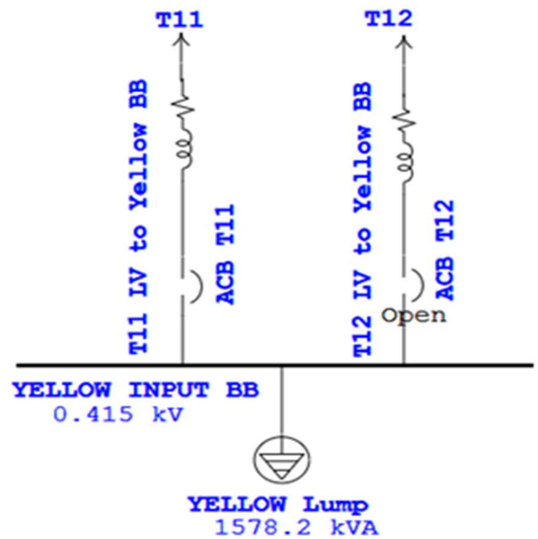


Figure 4.2.1.2 Distribution Board Ref.Y1 Switchgear Configuration in ETAP

Where;

T11&T12 are remote node connections to power transformers; Specification 2.5MVA, 11/0.433KV, Dyn11, Zb=6.25%. Both switchgear feeders are BS5467 XLPE 500mm^2 cables (5 per phase).

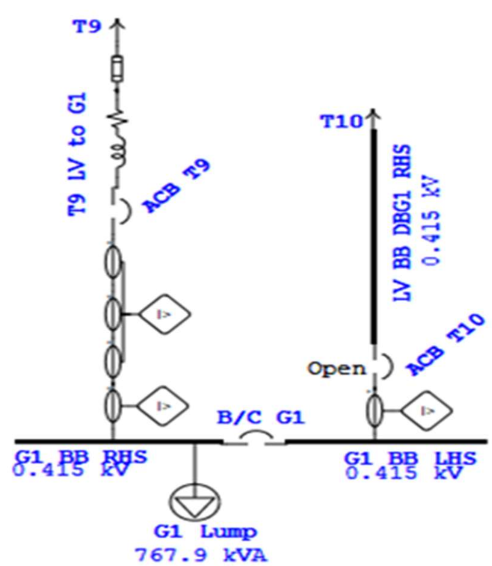


Figure 4.2.1.3 Distribution Board Ref.G1 Switchgear Configuration in ETAP

Where;

T9&T10 are remote node connections to power transformers; Specification 2.5MVA, 11/0.433KV, Dyn11, Zb=7.41%. T10 LV feeder is 4000A busbar, T9 LV feeder comprises of BS5467 XLPE 630mm^2 cables (4 per phase).

Load values applied for each switchgear model in ETAP allowed comparison of Tier 3 & Tier 4 systems, analyising load flow during the following scenarios whilst supplied by either grid feeders or standby generators.

Critical busbar loadings:

i. Normal Operation – 50% of nominal design values to simulate the actual present site loads.
ii. Design Operation – 100% capacity to simulate designed limits of the system.
iii. Emergency Operation - 110% of the design capacity, simulation of the worst-case scenario of operation for the electrical network, obtaining busbar voltage to ensure voltage drop is not an issue for the network equipment.

Along with investigations of the switchgear arrangements, the HV network synchronous generation system was also assessed in ETAP study case simulations, ensuring ISO 8528-1 (2005) continuous operating power ratings were not exceeded, or generator apparent power capabilities were not compromised, as in-line with manufacturer operating curve shown in Figure 4.2.1.4.

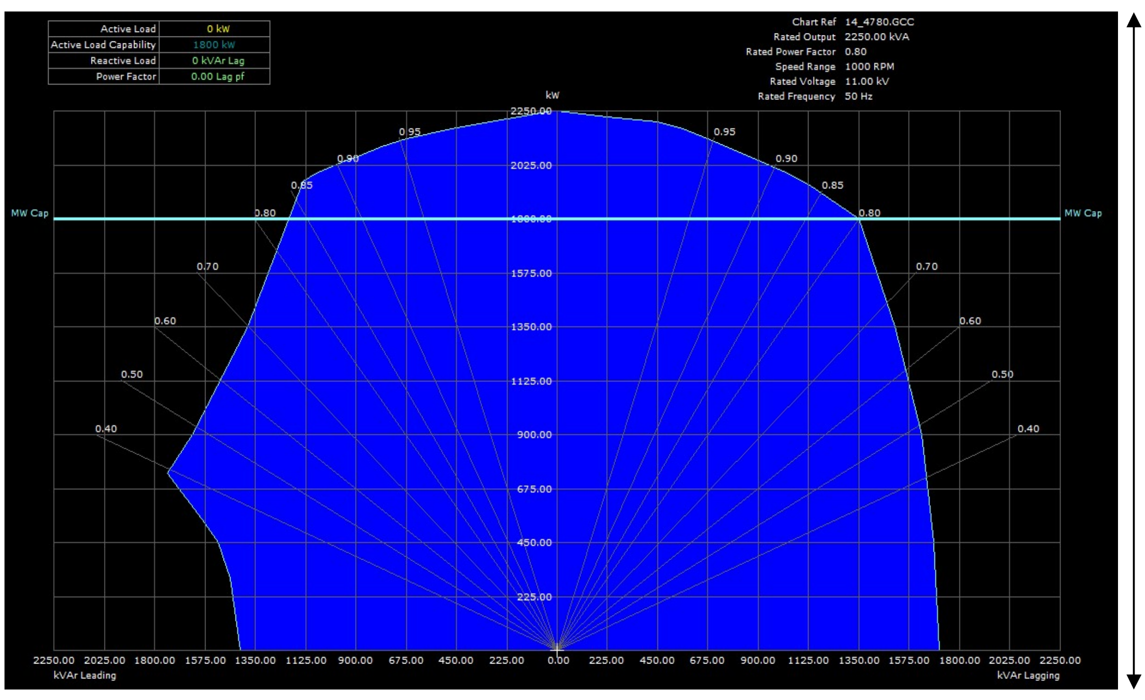


Figure 4.2.1.4 Brush Turbo Generator Power Capability Curve [43]

Ratings of the data centre generator sets are given in apparent power (MVA) at a given power factor, since armature windings are manufactured to allow for a delivered MVA regardless of power factor. Field windings are rated for a given MVA at a specified lagging power factor. Thus, if load power factor is less than that specified for the generator field windings the machine is to produce less apparent power MVA, this relationship is determined by the capability curve. During ETAP study cases simulation values were compared with those provided in the specified manufacturer tolerances. This is an important point since if the system power factor is less than that specified for the generators a cross reference against capability curves is required (Figure 4.2.1.4 indicates the range of operation).

4.2.2 Voltage for critical busbar loads

Voltage drop in an electrical network is related to power flow and characteristic impedance of the connected equipment [6] and [11], thus an important aspect of a load flow study is to ascertain the minimum and maximum busbar voltages, and voltage drops of network feeders [36], [37].

ETAP study cases were set with voltage marginal and critical alarm limits as; over voltage 102% marginal and 105% critical, under voltage 98% marginal and 95% critical. These values are supported by the standards BS7671 [36], and ANSI C84 [37] which provide guidance on voltage tolerance levels in an electrical system. The ANSI C84 standard provides guidance on both optimal and acceptable voltage levels for electrical power systems as shown in Table 4.2.2.1.

Table 4.2.2.1 ANSI C84.1 Voltage limits [37]

ANSI C84.1 System Voltage Limits				
120V to 600V Systems		Systems Exceeding 600V		
Min (% V_n)	Max (% V_n)	Min (% V_n)	Max (% V_n)	
95	105	98	105	Optimal System
92	106	95	106	Acceptable System

Where: % V_n represents the nominal system Voltage rms as a percentage.

It is important to note reference bands given between minimum and maximum levels in Table 4.2.2.1 are to allow for voltage drop in system sub-circuit feeders. Presently the National Electrical Code identified a permissible allowance of 5% whereas the BS7671 IET Wiring Regulations recommend a value of 5% for distribution circuits, and 3% for voltage sensitive equipment. Since the LV busbar investigated in ETAP simulations are at the origin of sub-circuit distribution, margins allocated were 98% marginal & 95% critical. Since a voltage drop of 5% at the origin would not allow a sufficient margin for expected voltage drops in the remaining network circuits. Nominal busbar voltage at 1 P.u was stated as 415Va.c., for all ETAP simulations, with another metric utilised to validate voltage drop in the network Voltage Security Index (*Vsi*) which is discussed in more detail below.

4.2.3 Voltage Security Index

Voltage Security Index (Vsi) was applied at each ETAP simulation busbar, where the equation applied is as equation (18) [38].

$$Vsi = \sum_{i=1}^{NB} \frac{W_{vi}}{2}\left(\frac{|V_i| - |V_i^{sp}|}{\Delta V_i^{Lim}}\right)^2 \tag{18}$$

Where:

$|V_i|$ represents the calculated magnitude of Voltage rms at busbar i

$|V_i^{sp}|$ represents the specified Voltage rms of busbar i

ΔV_i^{Lim} represents the Voltage rms deviation limit of busbar i

NB represents the number of load buses in system.

W_{vi} represents the weighting coefficient of voltage at bus i

Research [35], [38] & [39] suggests W_{vi} and ΔV_{iLim} are taken as 1 and 0.075, respectively. Changing these values will result in a non-alignment to the international standards and potentially busbar voltage deviation in the system. Vsi is a numerical measure of the severity of a given busbar voltage in terms of the magnitude of out of limits present, therefore, to improve system voltage drop factors such as; equipment selection, distributed loadings, operational network configuration, transformer tap changer settings, and embedded generation are to be as assessed in the simulation approach. It is also important to note results from the load flow investigations were utilised to undertake the fault current analysis investigations, and Vsi is utilised to validate simulation voltage drops as a different calculation approach from the BS7671 standard.

4.3 Short Circuit Analysis

The simulation approach to determine fault currents required validation of essential model data including equipment: sub transient, transient and steady state impedance. Also, a pre-commencement load flow study investigation to highlight the optimum equipment configurations allowing further accurate analysis of short circuit currents. With a knowledge of equipment impedance, and sequence components, a Thevenin superposition theorem was applied in simulations investigating multiple 'short circuit points' in the electrical network model, including every system busbar. This process obtained IEC60909 fault currents Ik'' & Ip at each critical busbar, detailing all network fault current characteristics, fault paths, and failure scenarios. This allowed a critique of results against the effects on *Ao* i.e., highlighting potential points of failure in the electrical network, and or requirements of fault ratings of associated connected equipment. This approach assisted with improvement of operational availability and resiliency of such data centre electrical infrastructures (Tier 3).

Furthermore, in addition to fundamental impedance data a range of comprehensive operational factors were investigated during the simulations. Consideration was given to:

i. X/R ratios of network grid feeders, given higher X/R ratio and stored energy of synchronous machines can significantly affect peak fault current levels in the system.
ii. System load characteristics, since pre fault currents are non-zero in an operational electrical network, this included the differing mode of operation for *UPS* systems.
iii. Standby synchronous machines and earth arrangements.

Alongside the system impedances the standby power machines will often provide substantially different fault current characteristics than those associated with nominal grid feeders. Also, considering the requirements to operate nominal grid feeders and standby power machines in parallel i.e., for desired no-break transfers of critical busbar load. To obtain effective peak current (Ip) & direct offset current (idc) calculations for synchronous machines X/R ratios should be investigated, since ratios effect the fault current calculations [11], as equation (19).

$$\frac{X}{R} = f\left(\frac{Ip}{Irms}\right) \tag{19}$$

Where:

I_p represents the Peak current, $Irms$ represents the rms steady state current.

This displays X/R ratio is a function of peak and steady state currents of a given machine or can often be obtained from the Original Equipment Manufacturer (*OEM*).

4.3.1 IEC60909 Simulation Scenarios

Fault currents as indicated in IEC0909 standards were established at each system busbar for both Tier 3 and Tier 4 system configurations, Table 4.3.1.1 lists a series of six simulation models (all possibilities for this HV network), Table 4.3.1.2 highlights the *UPS* scenarios simulated at the LV busbar systems. This approach established the absolute maximum and minimum fault currents in the electrical network.

Table 4.3.1.1 ETAP Simulation Scenarios for all Network Faults

Electrical Power Sources Utilised in ETAP Simulations						
Source Type	Simulation 1	Simulation 2	Simulation 3	Simulation 4	Simulation 5	Simulation 6
DNO supply 1	✓	✓	✓	×	×	×
DNO supply 2	✓	×	✓	×	×	×
Generator 1	×	×	✓	✓	✓	✓
Generator 2	×	×	✓	✓	✓	✓
Generator 3	×	×	✓	✓	✓	×
Generator 4	×	×	✓	✓	×	×
Generator 5	×	×	✓	×	×	×

Where; ✓ represents power sources connected to the network and × represents a power source disconnected.

Table 4.3.1.2 ETAP Simulated Scenarios for all *UPS* Faults

Mode of Operation, Simulated *UPS* Configurations
3 *UPS* Connected in Parallel
4 *UPS* Connected in Parallel
5 *UPS* Connected in Parallel
3 *UPS* + Synchronised to Main Feeders
4 *UPS* + Synchronised to Main Feeders
5 *UPS* + Synchronised to Main Feeders
5 *UPS* on Standby Battery Mode of Operation
Bypass Mode - All *UPS* Offline, Critical Load by Main Feeders

4.4 Protection Grading Co-ordination

A series of ETAP model simulations were created, allowing all the installed protection devices (113 scenarios in total) and associated protection settings to be simulated for all the electrical network operational configurations and fault scenarios (including faults at each system busbar and DNO supply side cable feeder faults). Both phase and ground overcurrent's were investigated along with Non Time Current Curve (*NTCC*) protections such as restricted earth fault, generator protections and pilot differential schemes. All protection grading scenarios investigated were inclusive of:

i. Transformer HV to LV grading discrimination, six scenarios investigated.
ii. HV faults during single DNO supply, five scenarios investigated.
iii. HV faults during dual DNO supplies, seven scenarios investigated.
iv. Discrimination during islanded generator supplies, four scenarios investigated.
v. HV faults during synchronised supplies (DNO & synchronous generators), one scenario investigated.
vi. LV Rotary *UPS* co-ordination with both upstream and downstream devices, plus bypass mode assessment.
vii. Both HV & LV Non Time Current Curve (N*TCC*) protection: G59, SOLKAR unit, restricted L-G (*REF*), Generators ANSI 49RMS, 87M, 46, 32Q, 32P, 81L, 81H, 27, 59.

The simulation approach carried out in ETAP allowed each of the above grading scenarios to be investigated for parameters listed in Table 4.4.1, and an output assessment in terms of an associated grading curve plot, as shown in Figure 4.4.1.

Table 4.4.1 ETAP Protection Co-ordination Assessment Parameters

Equipment Type	**Pick up**	**Full load Amps**	**Damage Curve**	**Acceleration**	**Max Fault Amps**	**Excitation**	**Co-ordination status pass/fail**	**Amps range**	**Co-ordination summary**
Busbar		✓			✓				
Cable/Line	✓	✓	✓		✓				
Generator	✓	✓	✓		✓	✓			
Load	✓	✓			✓				
Motor	✓	✓	✓	✓	✓				
Transformer	✓	✓	✓		✓				
Co-ordination Status					✓		✓	✓	✓

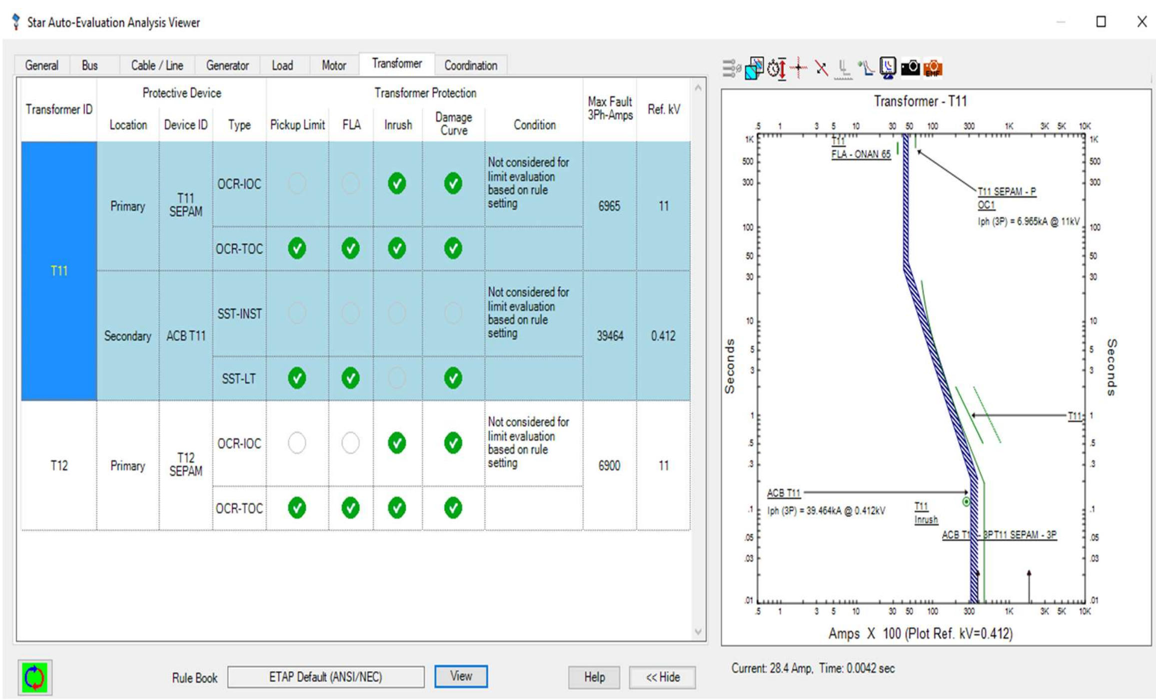


Figure 4.4.1 Example ETAP Simulation Protection Assessment

4.5 Arc Flash Analysis

The main objective of arc flash analysis is to consider an engineer's potential exposure to arc flash energy, highlighting the requirement and specification of Personal Protective Equipment (*PPE*), [5] and [40]. Along with verifying the hazards for electrical equipment. The simulation approach covered all the requirements as detailed by the IEEE 1584 guide [42], in terms of establishing incident energy, arc flash boundary and fault clearing times for each of the installed switchgears and associated protection devices.

Arc flash analysis was therefore performed as a subsequent study following short-circuit and protective-device analysis, since peak current values following short-circuit studies along with disconnection times for electrical circuit protective devices are both required to complete an effective arc flash assessment i.e., without these preceding studies the accuracy of an arc flash assessment is impeded. The arc flash analysis results were utilised to identify the flash-protection boundary and the incident energy at assigned working distances of switchgear equipment, throughout the entire data centre. This approach ensures a safe working environment for site engineers and allows critical preventive maintenance to be undertaken at specified maintenance intervals, supporting the overall condition and uptime of equipment. Investigation of protection device settings and their effects on arc flash parameters also provided a reduction of incident energy, the required time for disconnection, and quantity of *PPE* required for establishing safe working.

4.5.1 IEEE 1584 Calculations

Calculation methods utilised in all simulation models aligned with the IEEE 1584 [42], as equations (20) & (21). Where L-L-L currents are established with the equation for arcing current (*Ia)*.

$$\log(\mathrm{I_a}) = \mathrm{K} + 0.662\log(\mathrm{I_{bf}}) + 0.0966\mathrm{V} + 0.000526\mathrm{G} + 0.5588\mathrm{V}\log(\mathrm{I_{bf}}) - 0.00304\mathrm{G}\log(\mathrm{I_{bf}}) \tag{20}$$

Where;

K = -0.097, representing a fully enclosed switchgear configuration.

I_{bf} represents the L-L-L fault current (KA).

V represent the system nominal voltage rms (KV).

G represents the conductor gap (*mm*).

With the incident energy (E) equation for establishing the J/cm^2 at the given point of fault.

$$E = \left(4.184\, C_f \text{ x } E_n\right)\left(\frac{t}{0.2}\right)\left(\frac{610^x}{D^x}\right) \tag{21}$$

Where;

C_f represents the calculation factor, 1 for system voltage above 1KV, 1.5 for voltages below 1KV.

E_n represents the Incident Energy normalised.

t represents the Arcing time in seconds (s).

D represents the distance of a person from an arc fault (mm).

x represents the distance from circuit interrupter and switchgear assembly (IEEE1584 table for coefficients of 5 circuit breaker types).

4.5.2 Arc Flash Simulation Scenarios

The data centre electrical network is a complex power distribution network with various modes of operation, for which each configuration has a potential to affect the system fault current level, this in-turn impacts on the arc flash assessment. Therefore, preceding the arc flash assessment both overcurrent fault analysis and grading protection requirements must be completed, since the incident level and fault clearing time is correlated to those boundaries i.e., fault current within the electrical system and range of protection device settings.

The simulation approach utilised ETAP arc flash software module to determine the bolted short-circuit current to calculate the individual arcing current contributions and arc fault clearing time of each protective device. This is undertaken by interfacing ETAP Star (protective device selectivity and coordination module) for each critical busbar within the electrical network, during the following three scenarios.

i. Two Distribution Network Operator (*DNO*) cable feeders supplying all connected critical loads (nominal arrangement).
ii. Island mode with standby diesel generators connected to critical loads, i.e., removed from the grid.
iii. Standby generators connected in parallel with the two Distribution Network Operator (*DNO*) cable feeders, for short term parallel G59 no-break transfer of critical load.

Figure 4.5.2.1 is an example *TCC* displaying the benefits of interfacing protection devices and arc flash current, both values can be represented on a single plot with adjustable grading parameters to optimise each given scenario. Along with *TCC* plots for analysis the ETAP arc flash module allowed comprehensive reporting which displayed all arc flash results for every system busbar. These final analysis results were then displayed on arc flash labels which can be located on the actual equipment, as recommended by IEEE 1584 [42]. The arc flash labels contain the necessary information to convey the associated danger to maintenance personnel.

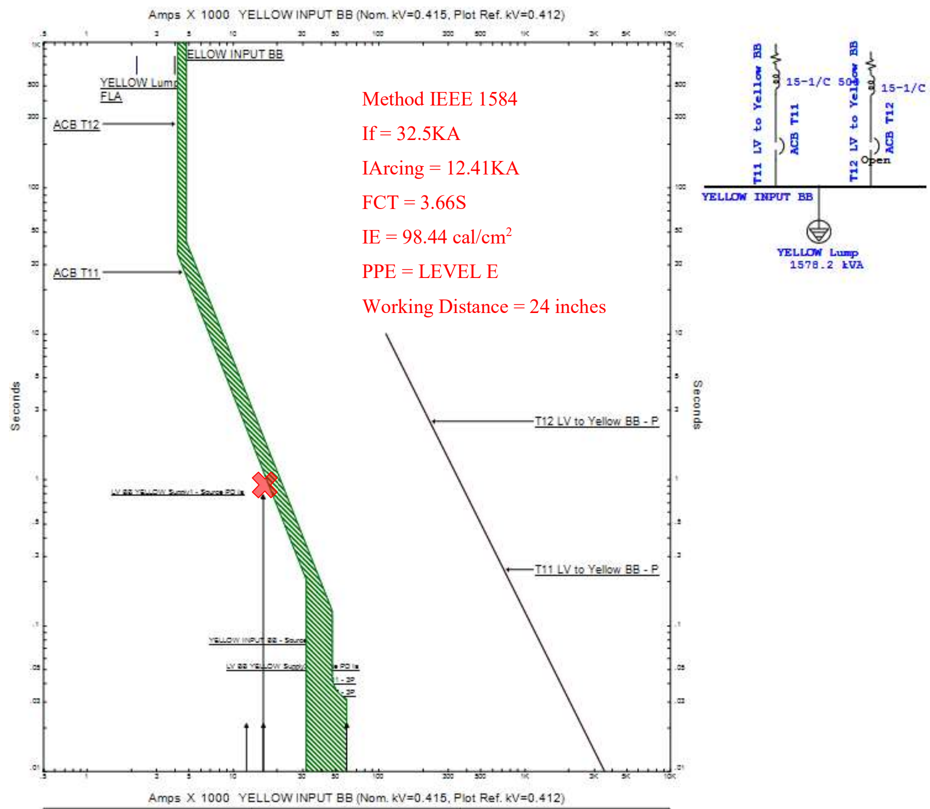


Figure 4.5.2.1 Example Arc Flash Time Current Curve

4.6 Load Point Reliability Analysis

Reliability of the data centre was investigated in terms of; i) Failure rate expressed as failures per year per component ii) Downtime to repair or replace component failures, expressed in hours per failure per year. These metrics were established for every system busbar.

Such load point reliability analysis, selection of equipment and optimal operational configuration can influence the number of forced outages or reduce downtimes. Likewise, system resiliency and tier design assessments can be fully understood in an operational setting. When failures do occur the return to nominal supply should be within minimal time therefore electrical faults should be quickly removed from the remaining network avoiding unnecessary damage to equipment, or loss of connected loads. Research identified that analysis of customer failure statistics show that compared to other portions of electrical power systems, distribution equipment failures contribute as much as 90% towards the unavailability of supply to load [30].

Therefore, numerous simulations were undertaken in ETAP for each critical busbar in the system, these were to highlight and understand the effects of protection device operation and correlating reliability effects on the power system. Simulation failure scenarios of each system busbar were investigated to highlight the reliability indices as below.

i. Load Point Average Failure Rate (*λ)*.
ii. Average Outage Duration (t_{ir}).
iii. Annual Unavailability (*U)*.

Where equations (22) & (23) display the numerical calculations utilised in ETAP for establishing average failure rate and annual outage duration respectively [44].

Average Failure Rate at Load Point *λi* (*f/yr.*):

$$\boldsymbol{\lambda i} = \sum_{j \in Ne} \lambda_{e,j} \tag{22}$$

Where;

$\lambda_{e,j}$ represents the average failure rate of element j.

$j \in Ne$ represents the total number of elements whose fault will interrupt points i.

Annual Outage Duration at Load Point *Ui* (hrs./yr.):

$$\boldsymbol{Ui} = \sum_{j \in Ne} \lambda_{e,j} \; r_{i,j} \tag{23}$$

Where;

$r_{i,j}$ represents the failure duration at load point *i* due to a failed element *j.*

The failure rates recorded from simulations were critiqued against Tier classifications and provided evidence on the effects of *Ao*, and a pre- and post-evaluation of failure rates.

4.7 Chapter Summary

This chapter outlined the *RBS* data centre electrical network in terms of providing a single line diagram of the complete HV/LV network, also detailing the models which were constructed in ETAP. Details have been provided on the simulation procedures, calculations and operational scenarios investigated. Including a range of load flow, actual busbar loadings and *Vsi* indices at each system busbar. Also, detailed the short circuit analysis approach and application of IEC60909 to each simulation, during all six operational scenarios – i.e., inclusive of grid feeders, standby generators, transformers, cabling, and *UPS* configurations, allowing IEC60909 fault current values to be established at system busbar. Detailed the progression of short circuit studies and onto protection device setting analysis, for all 113 devices installed and located in the electrical ETAP model simulations. Over 26 protection grading scenarios including Time Current Curve (*TCC*) devices and Non-Time Current Curve (*NTCC*) assessment, example grading assessments also provide details on the parameters investigated which includes protection relay pick up, full load current values, equipment damage curves, IEC60909 fault current values, and more importantly grading co-ordination between all installed devices.

This chapter also outlined the IEEE 1584 arc flash requirements and how this standard was utilised in the simulation approach, in terms of establishing each system busbar value for arc flash incident energy, arc flash boundary requirements and total fault clearly time. Also, detailing the importance of electrical protection devices settings in terms of how they can effective such arc flash requirements, with further investigation and recommendations given in this research programme. The final simulation approach details the undertaking of load point reliability analysis, within Chapter 4.6 detailing which operational scenarios were investigated in order to achieve an improvement in Operational Availability (*Ao*), This simulation approach was completed as the final study which supports a quantification of improvements suggested during the preceding power system studies i.e. load flow, short circuit analysis and protection device grading i.e. how can improving protection settings support improved Operational Availability (*Ao*).

Chapter 5 – Simulation Results

5.0 Introduction

This chapter includes ETAP software simulation results and associated descriptions for all data centre simulations undertaken. Such as load flow, short circuit analysis, protection grading, arc flash and load point reliability studies, respectively. These results are inclusive of all HV & LV data centre electrical equipment. Load Flow studies highlighted busbar voltage alerts for out of tolerance with the ANSI C84 guidance, with transformer arrangements not currently having an optimal tap setting. Generator stability curves were assessed at the varying connected loads in-line with the original system design and manufacturers recommendations, these modes of operation are expressed in a vector stability curve diagram.

Short circuit simulations highlighted that the present fault current values, and durations present, were more than the installed switchgear ratings and are effected by the associated distribution transformers tap setting and installed relay protection device. These protection relay settings were also found missing an opportunity to reduce arc flash incident energy and limit damage to equipment should a network fault occur. Results are presented in settings tables with all data values included for every busbar in the system. In terms of short circuit contributions, it was also found that the rotary *UPS* units have a significant effect on the overall peak fault current at the switchgear, therefore results provided a recommendation to reduce the number of operational units during any parallel operations i.e., for no-break transfer with grid feeders.

The original system and equipment settings were simulated for reliability, with results providing a hours per year (*hr/yr.*) outage metric for each of the system busbar, with the initial results indicating the predicted outage values were in-excess of the original design values, i.e., those suggested by the Uptime Tier Classifications table. For example, one busbar in the system resulted in a predicted 48 hrs/yr. outage with which an improvement through operational settings achieved a reduction to just 1.27 hrs/yr., this was the case for most system equipment and is explained within the results Chapter 5.5. Each of the power system simulation results have been summarised into a table of parameters for achieving improvement of operational equipment, i.e., in comparison to utilising the Uptime Tier Classification table alone. The basis of these recommendations has been derived from the extensive range of simulations undertaken on this data centre and in-line with the requirements of many international standards relating to electrical power system operations. These improvement parameters can be utilised for any Tier 3 data centre network and have formed a new generalised approach for simulation of such systems, as discussed in Chapter 6.3.

5.1 Load Flow

Figure 5.1.1, 5.1.2 & 5.1.3 represent the typical LV incoming switchgear arrangements. Results tables for these LV switchgears include 50%, 100% and 110% loading to confirm busbar voltage is in-line with ANSI C84. Also, both an N+1 and 2N system simulation was undertaken by operation of ACB T1 or T2, respectively.

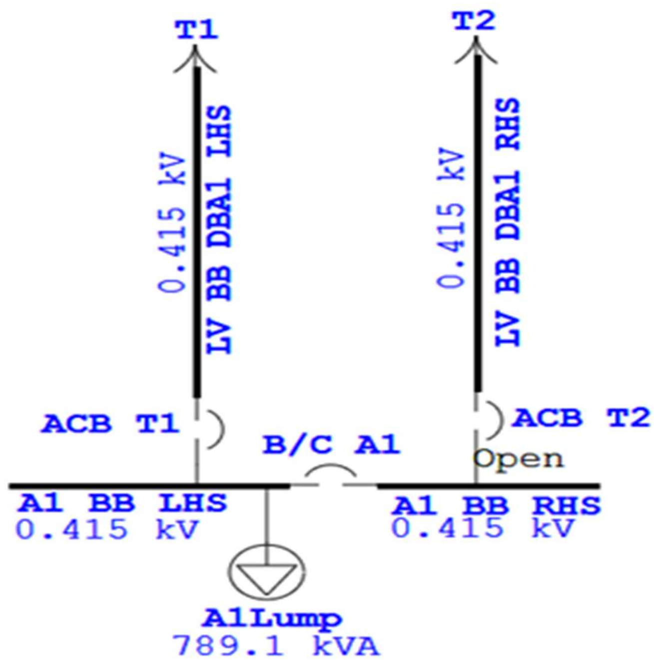


Figure 5.1.1 LV Distribution Board Ref.A1, ETAP Model Block

Where;

T1&T2 are remote node connections to power transformers; Specification 2.5MVA, 11/0.433KV, Dyn11, Zb=7.41%. Both switchgear feeders are 4000A rated busbars.

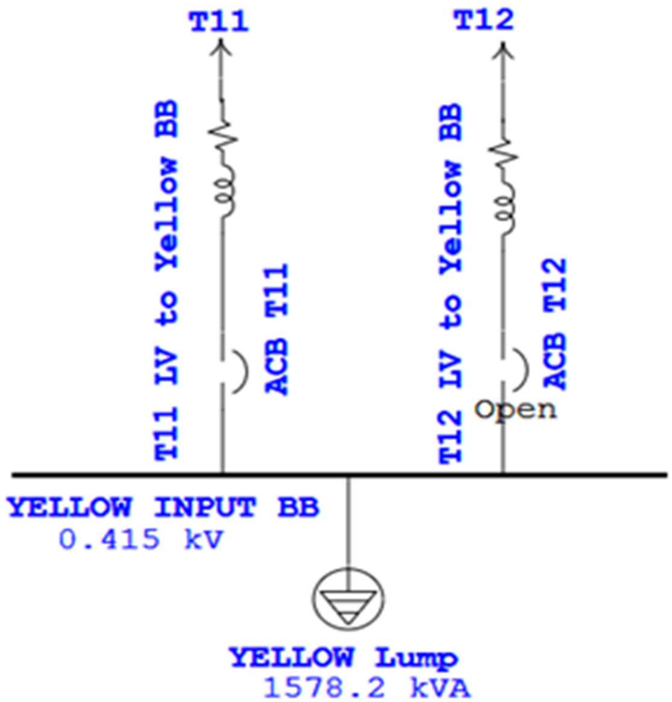


Figure 5.1.2 LV Distribution Board Ref.Yellow, ETAP Model Block

Where;

T11&T12 are remote node connections to power transformers; Specification 2.5MVA, 11/0.433KV, Dyn11, Zb=6.25%. Both Switchgear feeders are BS5467 XLPE 500mm^2 cables (5 per phase).

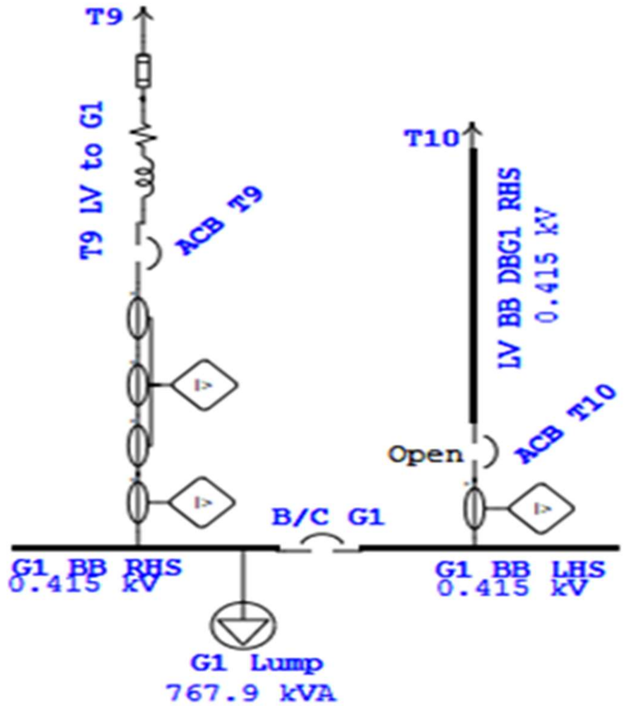


Figure 5.1.3 LV Distribution Board Ref.G1, ETAP Model Block

Where;

T9&T10 are remote node connections to power transformers; Specification 2.5MVA, 11/0.433KV, Dyn11, Zb=7.41%. T10 LV feeder is 4000A busbar, T9 LV feeder comprises of BS5467 XLPE 630mm^2 cables (4 per phase).

Table 5.1.1 Load Flow Scenarios

Scenario 1(a) Tier 3 Configuration – Connected Load Values of 50% Design Parameters						
Busbar ID	Nominal Voltage (V_{L-L})	Simulated Voltage (V_{L-L})	KW Load	KVAr Load	Transformers tap setting	Voltage Security Index (*Vsi*)
LV A1	415	409.1	365	119	5%	0.126
LV Yellow	415	406.4	719	235	5%	0.268
LV G1	415	409	367	81	5%	0.131
Scenario 1(b) Tier 4 Configuration – Connected Load Values of 50% Design Parameters						
LV A1 (T1)	415	410.2	183	60	5%	0.084
LV A1 (T2)	415	410.2	183	60		
LV Yellow (T11)	415	409.4	364	120	5%	0.114
LV Yellow (T12)	415	409.4	364	120		
LV G1 (T9)	415	410.3	199	48	5%	0.080
LV G1 (T10)	415	410.3	369	81		
Scenario 2 (a) Tier 3 Configuration – Connected Load Values of 100% Design Parameters						
Busbar ID	Nominal Voltage (V_{L-L})	Simulated Voltage (V_{L-L})	KW Load	KVAr Load	Transformers tap setting	Voltage Security Index (*Vsi*)
LV A1	415	406.9	721	236	5%	0.238
LV Yellow	415	401.5	1404	459	5%	0.661
LV G1	415	407.8	729	163	5%	0.188
Scenario 2 (b) Tier 4 Configuration – Connected Load Values of 100% Design Parameters						
LV A1 (T1)	415	409.1	364	119	5%	0.126
LV A1 (T2)	415	409.1	364	119		
LV Yellow (T11)	415	407.5	721	238	5%	0.204
LV Yellow (T12)	415	407.5	721	238		
LV G1 (T9)	415	409.8	339	67	5%	0.098
LV G1 (T10)	415	409.3	397	95		
Scenario 3 (a) Tier 3 Configuration – Connected Load Values of 110% Design Parameters						
Busbar ID	Nominal Voltage (V_{L-L})	Simulated Voltage (V_{L-L})	KW Load	KVAr Load	Transformers tap setting	Voltage Security Index (*Vsi*)
LV A1	415	406.4	791	259	5%	0.268
LV Yellow	415	400.5	1537	503	5%	0.763
LV G1	415	407.4	801	179	5%	0.210

Scenario 3 (b) Tier 4 Configuration – Connected Load Values of 110% Design Parameters						
Busbar ID	Nominal Voltage (V_{L-L})	Simulated Voltage (V_{L-L})	KW Load	KVAr Load	Transformers tap setting	Voltage Security Index (*Vsi*)
LV A1 (T1)	415	408.9	400	131	5%	0.135
LV A1 (T2)	415	408.9	400	131		
LV Yellow (T11)	415	407.1	791	261	5%	0.226
LV Yellow (T12)	415	407.1	791	261		
LV G1 (T9)	415	409.6	372	74	5%	0.106
LV G1 (T10)	415	409.1	436	105		

Where;
Highlighted cells indicate a marginal alarm since busbar voltage is <98% or >102%, as recommended by ANSI C84 [37].

5.1.1 Discussion of Load Flow Results

It can be noted in Table 5.1.1 LV DB yellow led to marginal (<98%) system alarms for any given simulated load whilst operating in a Tier 3 configuration. *Vsi* also increased since voltage drops in the simulations were outside of ANSI C84 [37] guidelines. Such voltage drop decrease's reliability and has implications on allowable voltage drops of sub-circuit feeders, thus would not provide the most robust operational configuration.

All Tier 4 configurations simulated reduced voltage drop and achieved an improved *Vsi*, although further complications maybe encountered since parallel impedances due to Tier 4 configuration may significantly increase short circuit current values, requiring further validation against IEC60909 limits.

Voltage drop issues encountered on busbar ID LV yellow were related to the supply cable feeders on the LV side of transformers, in comparison to other system LV busbar which were supplied by busbar. The electrical network investigated has several HV transformers where tap changers were set to the maximum HV tap position (5%). Table 5.1.1.2 displays the simulated effects on voltage security index, and voltage magnitude at the complete range of transformer tap changer settings, along with discussions for achieving optimal settings.

Table 5.1.1.1 Transformer Tap Changer Effects on Load Flow

Tier 3 Configuration – Connected Load 100% of Design Parameters						
Busbar ID	Simulated Voltage (*V*)	KW (*P*)	KVAr (*Q*)	TX Tap Setting	Voltage Security Index (*Vsi*)	Energy Cost per annum (*£m*)
LV Yellow	402	1405	459	5%	0.613	1.231
LV Yellow	411	1475	482	2.5%	0.058	1.292
LV Yellow	422	1549	506	0%	0.178	1.357
LV Yellow	433	1630	533	-2.5%	1.176	1.428
LV Yellow	444	1717	561	-5%	3.052	1.504

Where;

Orange highlighted cells indicate a marginal alarm since busbar voltage is <98% or >102%, and red highlighted cells indicate critical alarm since busbar voltage <95% or >105% of nominal voltage (*Vn*) - as recommended by ANSI C84 [37].

Table 5.1.1.1 displays an optimal tap setting in-line with ANSI C84 [37] and BS7617 voltage limits [36] is either 2.5% or 0%. Since a 2.5% tap setting reduces load flow by 74 KVA when compared to 0% tap, which equates to an operational energy reduction of £75k per annum. Therefore 2.5% would be the optimal setting providing desired busbar voltage under all simulated scenarios and reducing severity of voltage deviations. A recommended range of tap settings were established for all site transformers, positively impacting both operational cost and system voltage drop.

Along with load flow values at simulated busbar the standby generators were assessed at all three load cases. Figure 5.1.1.1 displays one of the five modelled and simulated generators, as can be seen within Table 5.1.1.2 no issues were identified since simulated loads were within manufacturer ratings for apparent power and power factor, respectively. Along with Figure 5.1.1.1.2 which is a graphical display showing the generator vector stability curve at normal, design and emergency load values, and no limits being breached.

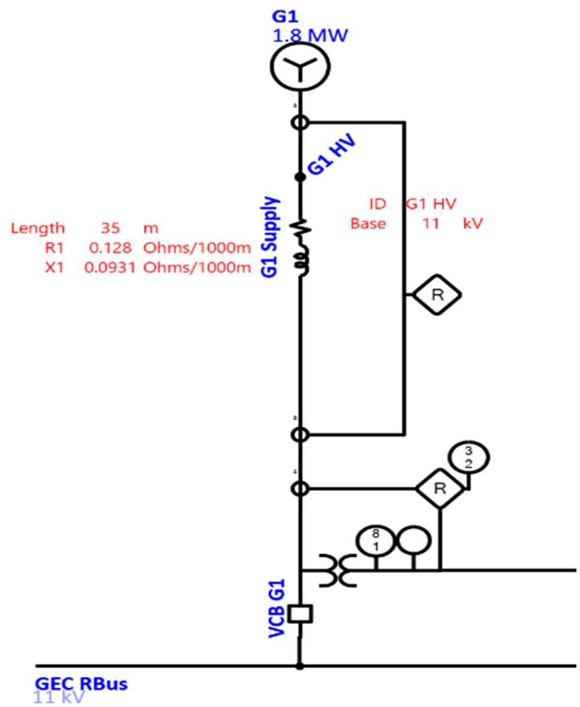


Figure 5.1.1.1 ETAP Generator Model Block

Table 5.1.1.2 Generator Load Flow Capability Checks

Loads Simulated	**KW**	**KVAr**	**KVA**	**PF**
Nominal Connected Site Load (Currently 50% of Design Capacity)	927	293	972	0.95
100% Design Load	1830	614	1930	0.94
Emergency Load (Design +10%)	2007	681	2119	0.94
Generator Manufacturers Operating Limits			**2250**	**0.80**

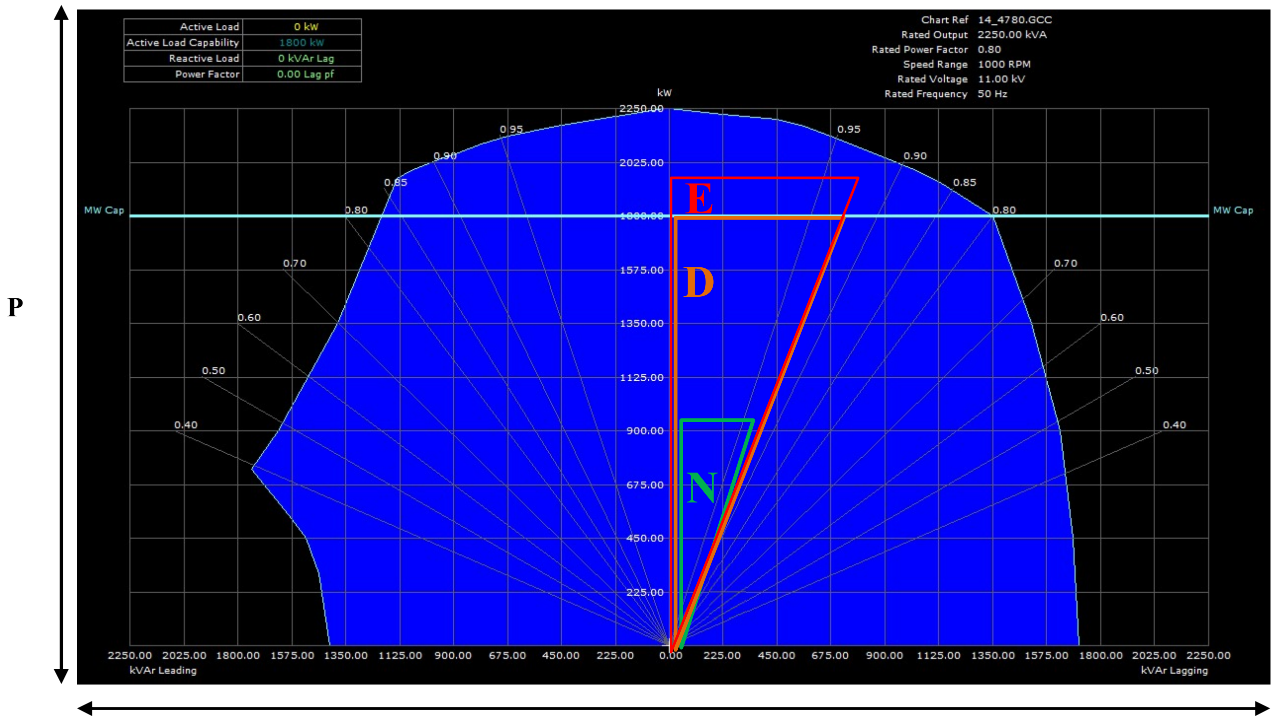


Figure 5.1.1.2 Generator Stability Parameters & Vector Curve

Where,

N = Nominal load, D = Maximum design load, E = Emergency load which is 110/% of design value.

5.2 Short Circuit Analysis

Below Figure 5.2.1 is the complete RBS electrical network which was modelled for short circuit analysis. Simulation results and conclusions indicate study parameters, simulations undertaken, and key points encountered - including establishing Ik'', Ik', Ik and I_{dc}.

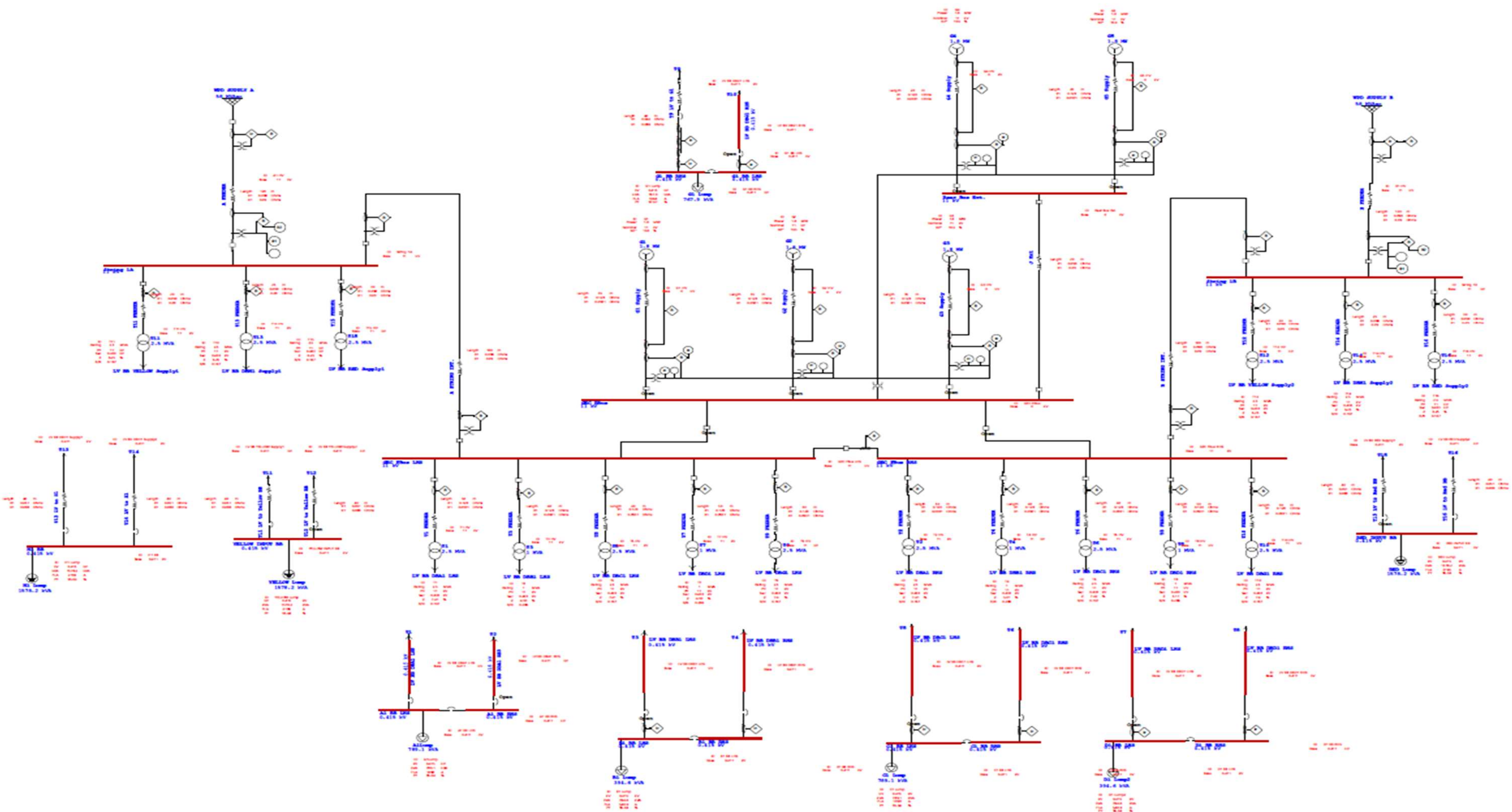


Figure 5.2.1 ETAP Single Line Diagram Utilised for Simulation of Short Circuit Analysis

5.2.1 Discussion of Short Circuit Results

During short circuit simulation lump loads for LV distribution boards were investigated in terms of constant impedance (*Z*) characteristic and constant power (KVA), this was to capture and understand any additional peak current contribution from the electromagnetic storage for constant KVA loads i.e., *UPS*, motors, or generator. Constant power types led to an increased short circuit current contribution of 14.28KA which equated to a busbar *Ik"*of 52 KA, thus highlighted the importance of simulating load characteristics to obtain worst case scenario fault currents in the system before selection of switchgear.

It was also noted increasing the distribution transformer primary tap settings led to a decrease in impedance thus fault currents at the critical busbar are increased, Figure 5.2.2.1.

Simulated high voltage busbar encountered the most significant variation in fault current levels due to impedance variations of *DNO* and standby generator supplies. Simulation levels of L-L-L peak fault current for the high voltage busbar ranged from 9.97KA to 29.28KA thus presented a challenge with respect to obtaining effective electrical protection co-ordination, and disconnection of such electrical system faults, which were investigated further in the protection grading Chapter 5.3.

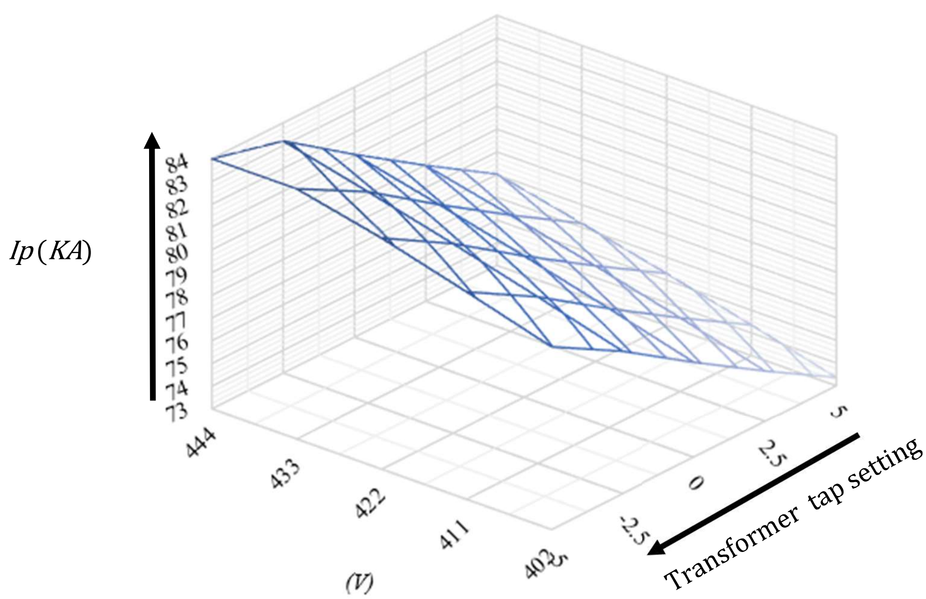


Figure 5.2.1.1 Busbar Fault Currents (*Ik"*) at a Range of Transformer Tap Settings

It was also noted from the simulation results that IEC 60909 fault calculations provided minimal changes in fault current values, and L-G faults currents exceeded the L-L-L values. This was since Z_1=Z_2 and Z_0<Z_1 for the power transformers simulated [40]. Selection of this type of power transformer grounding method (Solid, TN-C) ensures high L-G fault currents which can lead to fast protection clearance capabilities although it is not generally used in common network distribution schemes. Research identified L-G fault levels are generally 0.86 P.u of the L-L-L value [7] and [8]. One important point to note is the peak fault currents (*Ip*) within the HV network varied significantly if either supplied directly by *DNO* feeders or by standby generation (9.97KA to 29.28KA).

Furthermore, a Tier 4 transformer LV supply configuration was not necessarily the most suitable option for this network, despite Tier ratings suggesting such arrangements offer improved resilience [15]. Operation of parallel supply transformers (Tier 4) led to significantly increased peak fault currents, and in this instance came close to exceeding the bracing peak rating of the installed distribution switchgear, thus displayed the importance of such fault studies to select the most resilient mode of operation, since a fault on the critical busbar of such a Tier 4 system is likely to damage the distribution switchgear beyond a serviceable condition, leading to significant outage times. Results from 2N scenarios are in Table 5.2.1.1 scenario 2.

Table 5.2.1.1 Fault Current Values for a Tier 3 & 4 Data Centre Configuration

Scenario 1 – Tier 3 LV Switchgear Configuration		
DB LV Yellow	$\boldsymbol{Ik_{rms}}$ **(KA)**	$\boldsymbol{Ip = Ikrms \times \sqrt{2}}$ **(KA)**
L-L-L	37.76	53.40
L-G	38.82	54.90
L-L	32.70	46.24
L-L-G	39.16	55.38
DB LV A1		
L-L-L	37.46	52.98
L-G	40.79	57.69
L-L	32.44	45.88
L-LG	39.47	55.82
DB LV G1		
L-L-L	34.88	49.33
L-G	35.41	50.08
L-L	30.21	42.72
L-L-G	35.75	50.56
Scenario 2 – Tier 4 LV Switchgear Configuration		
DB LV Yellow	$\boldsymbol{Ik_{rms}}$ **(KA)**	$\boldsymbol{Ip = Ikrms \times \sqrt{2}}$ **(KA)**
L-L-L	60.74	85.89
L-G	66.54	94.10
L-L	52.59	74.37
L-L-G	65.63	92.81
DB LV A1		
L-L-L	60.24	85.19
L-G	69.32	98.03
L-L	52.16	73.77
L-L-G	66.36	93.85
DB LV G1		
L-L-L	59.04	83.50
L-G	65.94	93.25
L-L	51.13	72.31
L-L-G	63.66	90.03

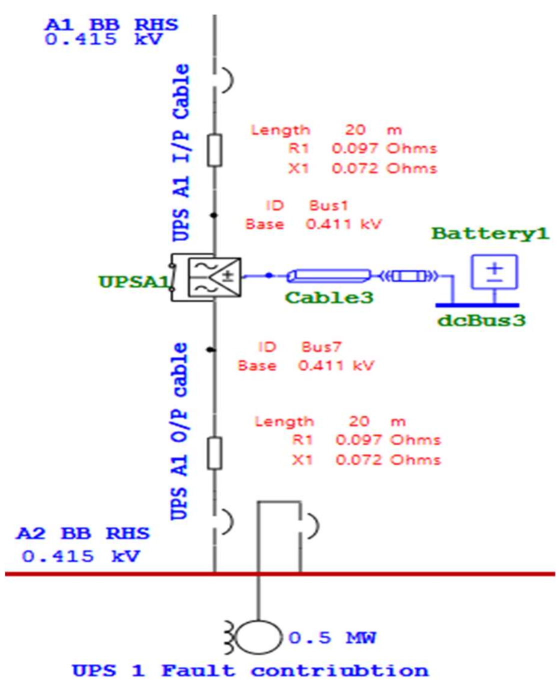
Fault current contributions delivered by the rotary *UPS* system, as Table 5.2.1.2. highlights the significant range of modes of operation available, along with the associated effects on fault currents, in terms of the *UPS* input/output switchboards. In relation to the connected electrical protection devices the clearing capabilities must remain adequate for the minimum possible *UPS* fault current. However, the more problematic quantity in this case was the peak current (*Ip*). Since the *UPS* investigated were of a rotary construction therefore the transient reactance is low thus led to high peak fault currents.

To illustrate further below Figure 5.2.1.2 shows a single *UPS* simulated with associated IEC60909 fault current values, both with and without transient input. Hence a static *UPS* unit would produce much lower peak current (*Ip*). Such increased fault currents from rotary machines also correlated to the arc flash values, in terms of a significant Cal/cm^2 increase which would compromise safety of maintenance workers and lead to a higher demand for safety equipment, as discussed in arc flash analysis Chapter 5.4.

Table 5.2.1.2 *UPS* Fault Contributions

Mode of Operation, simulated *UPS* configurations	***UPS* Input (A1) switchboard fault currents (KA)**			***UPS* Output (A2) switchboard fault currents (KA)**		
	L-L-L (rms)	L-G (rms)	Ip	L-L-L (rms)	L-G (rms)	Ip
3 *UPS* in Parallel	62.26	64.38	88.04	59.09	61.02	83.57
4 *UPS* in Parallel	73.73	73.36	104.27	73.57	77.44	104.04
5 *UPS* in Parallel	85.14	86.62	120.41	87.58	93.18	123.86
3 *UPS* + Synchronised to Main Feeders	64.8	69.39	91.64	64.8	69.39	91.64
4 *UPS* + Synchronised to Main Feeders	78.0	83.85	110.30	78.0	83.85	110.31
5 *UPS* + Synchronised to Main Feeders	91.0	98.53	128.69	91.0	98.53	128.69
5 *UPS* on Standby Battery	38.0	40.0	53.74	56.06	62.13	79.28
Bypass Mode - all *UPS* offline	38.42	40.67	54.33	38.42	40.67	54.33

Where; actual peak current rating of the installed switchgear is100KA.



Fault Type	With transient effect (KA)	Without transient effect (KA)
L-L-L	19.43	12.40
L-G	21.14	11.76
L-L	17.02	10.74
L-L-G	20.21	12.37
Ip	48.61	17.88

Figure 5.2.1.2 Rotary *UPS* ETAP Model Diagram and Simulation Results

5.3 Protection Grading & Co-ordination

5.3.1 Discussion of protection scenario results

This section contains the twenty-six protection scenarios investigated with each group of scenarios displaying a simplified single line diagram with subsequent grading results and discussion. This approach included all overcurrent and unit protections installed within the network. Single line diagrams indicate simulation equipment type, sizing, and configuration changes. Results are presented in Time Current Curve (*TCC*) grading format and written description of issues.

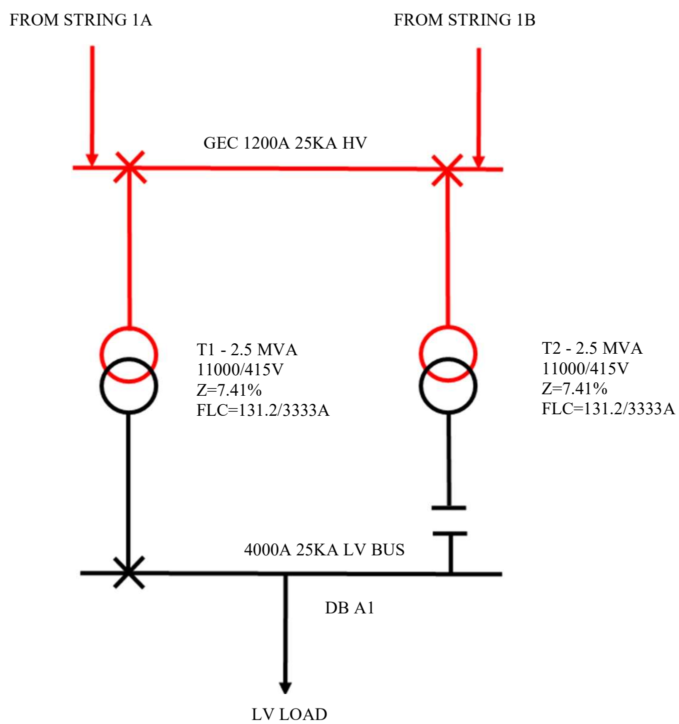


Figure 5.3.1.1 Tier 3 HV Transformer Single Line Diagram, Relating to Protection Scenarios 1 to 6

Protection Scenario 1

Distribution Board A1 - Transformers 1 & 2 Protection Evaluation

Protection evaluation for distribution board DBA1 in terms of the supply equipment and grading of HV to LV protection devices is detailed below. Key points have been highlighted in terms of, inadequacy of settings for equipment protection, unreasonable discrepancies, safety, or compromises of functionality to the overall protection scheme or reliability of the electrical network.

Phase Overcurrent Protections and Equipment Ratings:

i. Transformer 1 and transformer 2 configured to provide a Tier 3 supply to the low voltage 4000A busbar, DBA1. It was found from the overcurrent protection curves Figure 5.3.1.2 the HV relay devices for both transformers (T1&T2) were set differently in terms of overcurrent time delay. There is no apparent beneficial reason to set the HV relays differently, given they have the same transformer rating, neither settings group provided the most effective option.

   Transformer 1 settings:
   Group 1 - trip curve *IEC* standard inverse, It =263A, Td = 2.45s.
   Group 2 – trip curve definite time, It = 1200A, Td = 0.

   Transformer 2 settings:
   Group 1 - trip curve *IEC* standard inverse, It =263A, Td = 0.590s.
   Group 2 – trip curve definite time, It = 1200A, Td = 0.

   Figure 5.3.1.2 displays transformer 1 settings overlap the damage point of the transformer, as outlined by the ANSI/IEEE C57.109 standard. There is no beneficial reason to have such a time delay on the overcurrent protection, settings were improved according to the ANSI/IEEE C57.109 standards. The shift curve on the HV side protection is to be less than 87% of the transformer maximum thermal rating $\mathrm{Tr} = \mathrm{I}^2\,\mathrm{t}$ or 1250A in this case.

ii. Transformer 2 overcurrent time delay of 0.590s failed co-ordination with the transformer LV side *ACB* protection, hence under phase overcurrent faults upstream protection of the transformer may operate before the LV. Whilst in practice it's not essential to grade protection devices on either side of the supply transformer they operate signalling relays within the system, which would indicate to the operator the fault is within the incorrect part of the system and may lead to a delayed restoration of the standby supply. There is no beneficial reason for the current time delay of transformer 2, which is shown in Figure 5.3.1.2.

iii. Transformers 1&2 - HV pick-up settings were 263A. The rated primary current of the transformers is 131.2A, thus pick-up current is currently twice the full load capacity, whilst it is reasonable to allow a small percentage overload such as 125%, the significant value of 263A is not a recommended setting. Likewise, transformer LV rating is 3333A and the LV incoming devices were set with a pick-up of 4000A.

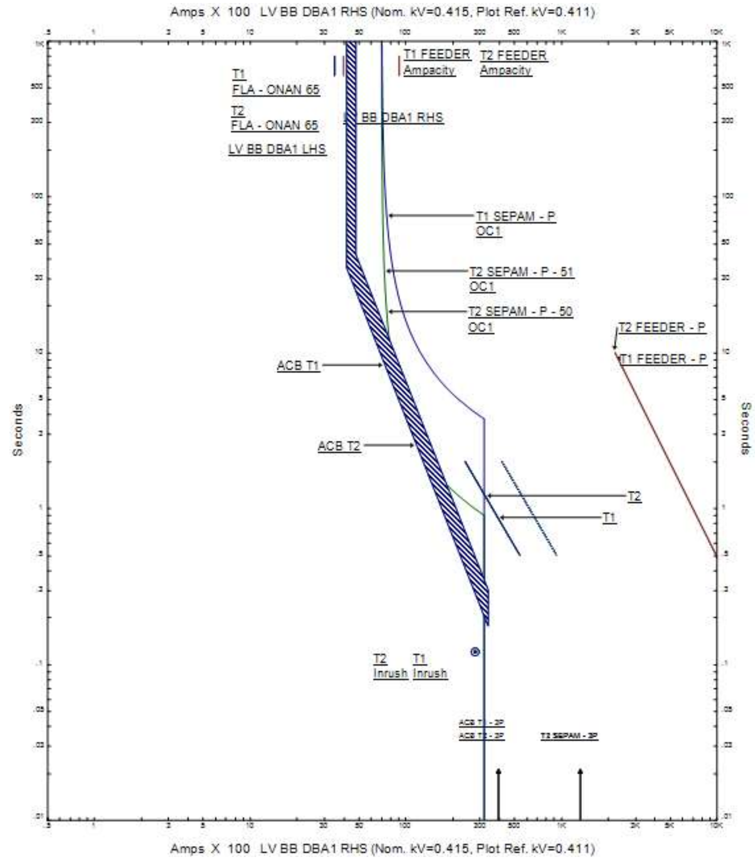


Figure 5.3.1.2 Overcurrent Protection *TCC* for Transformers 1&2, HV & LV Equipment

i. *UPS* input and output low voltage protections are set identical in terms of overcurrent values.

   UPS input settings LT = 1600A, INST = 22400A.
   UPS output settings LT = 1600A, INST = 22400A.

   Whilst there is not a practical benefit in time and current grading the *UPS* input/output (for disconnection purposes), presently the output settings are twice the machines Full Load Current (*FLC*) and not in-line with the manufacture's recommendations. Furthermore, the instantaneous setting is overlapping the transformer incomer (HV) protection thus an *O/C* fault on the output of a *UPS* cable for example may operate the HV transformer protection leading to an unnecessary loss of supply to all online *UPS* machines. Figure 5.3.1.3 *TCC* plot.

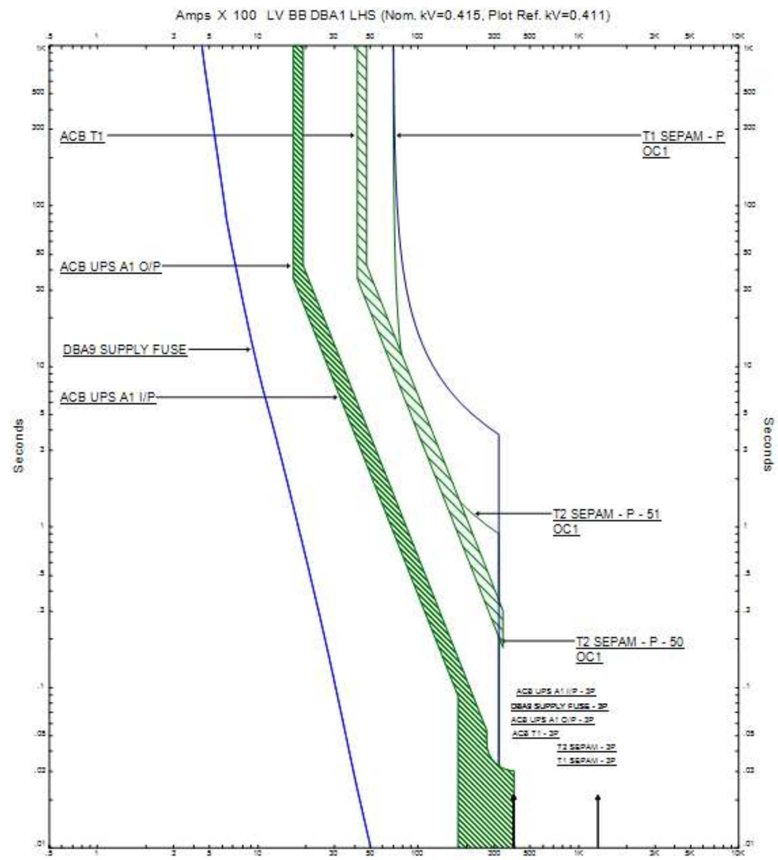


Figure 5.3.1.3 Overcurrent Protection *TCC* for Transfomrers 1&2, HV & LV Including Downstream Devices

Ground Overcurrent Protections and Equipment Ratings:

i. Figure 5.3.1.4 *TCC* ground fault plots both transformers 1&2 ground fault settings, the protection relay is currently set a 3A. This is outside of the manufacturer's recommendation of 0.3 x *FLC*. For this case full load current is.

$$Isc = \frac{2.5\text{MVA}}{(\sqrt{3}\text{ x }11000\ V_{L-L})} = 131.213\text{A}.$$

Therefore, ground setting should be 0.3x131.213 = 39.64A.

ii. Arcing current at DBA1 is *Ia* = 14.59KA with a fault clearing time of 1.957s. This leads to a 62 Cal/cm^2 incident energy, an improvement could be made by applying an instantaneous setting to the main incoming *ACB* circuit protection devices, as discussed in Chapter 5.4.

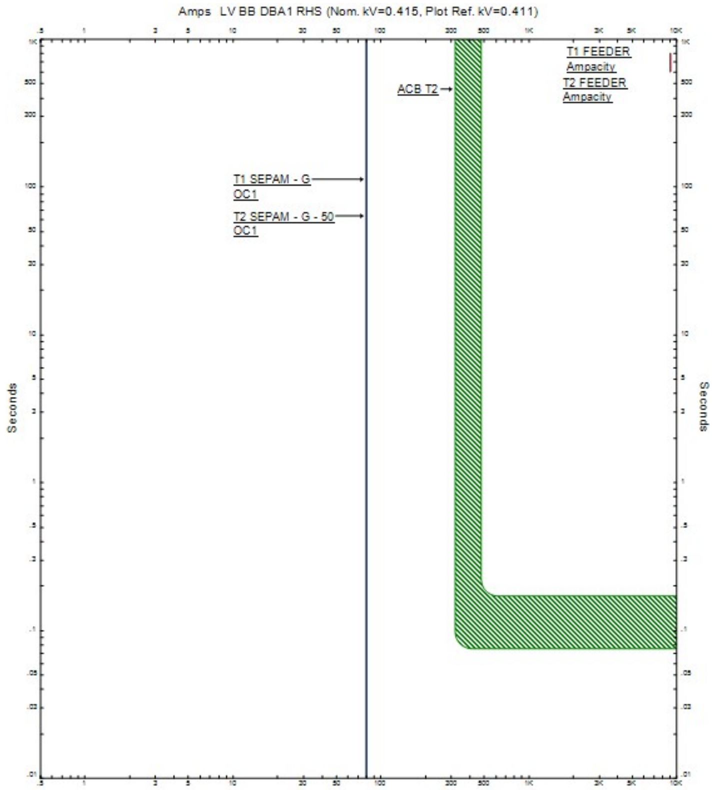


Figure 5.3.1.4 L-G Protection *TCC* for Transformers 1&2, HV & LV Equipment

Protection Scenario 2

Distribution Board C1 - Transformers 5 & 6 Protection Evaluation

i. Transformer HV/LV protections failed co-ordination between 8948A & 31485A, hence under phase overcurrent faults upstream protection of the transformer may operate before the LV devices. Whilst in practice it is not essential to grade devices on either side of the supply transformer it operates signalling relays within the network which would indicate to operators a fault is within the incorrect part of the system and may lead to a delayed restoration of the standby supply i.e., an actual LV fault would be indicated on the HV remote trip indication. The LV IDMT protection curve may be re-configured to address this issue, given current settings are more than the LV busbar rating.

ii. Both transformers 5&6 HV relay pick-up settings are 263A. The rated primary current of the transformers is 131.2A, thus the pick-up was 2 x FLC, whilst it is reasonable to allow a percentage overload, such as 125%, the value of 263A is not a practical setting. Likewise, the transformer LV rating is 3333A and the LV incoming protection devices are set with a pick-up of 5250A, which is also greater than the 4000A rating of the main LV busbar.

iii. Consideration for arc flash levels at the current installed protection settings. The arcing current at DBC1 is Ia = 14.52KA with a fault clearing time of 1.958s. This leads to 62 Cal/cm^2 incident energy, an improvement could be made by applying an instantaneous setting to the main incomer IDMT, as shown is Chapter 6.2.

iv. Arcing current at DBC1 is Ia = 14.52KA with a fault clearing time of 1.958s. This leads to 62 Cal/cm^2 incident energy. Improvement could be made by reduction of settings. Closing both supply transformers onto the busbar increases Ia = 21.39KA and the incident energy to 161 Cal/cm^2 **-** above the rating of available personal protective equipment (*PPE*) i.e., this would not be safe for maintenance activities.

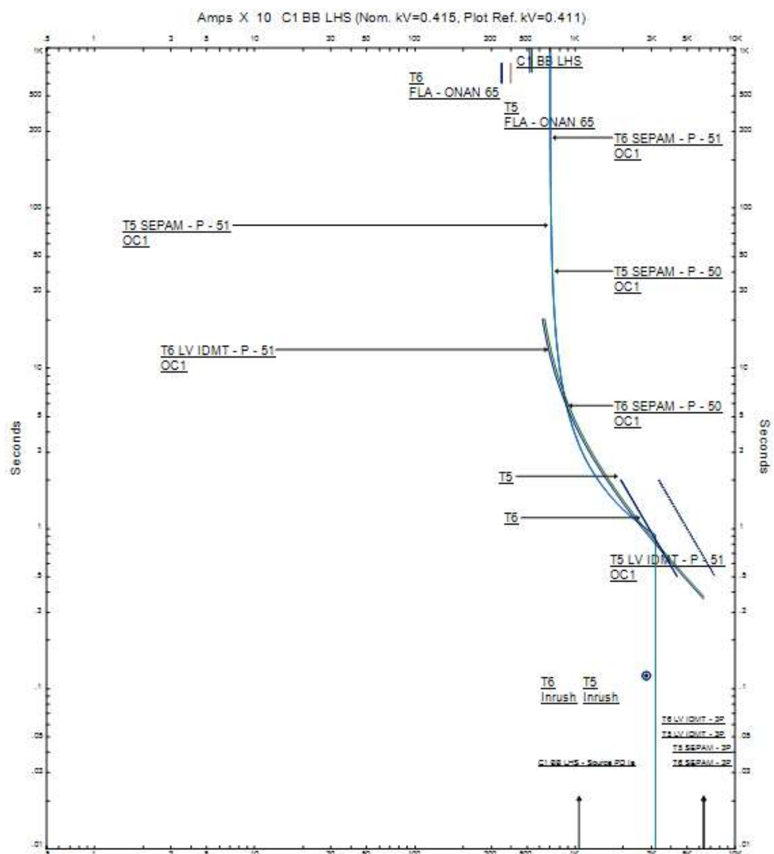


Figure 5.3.1.5 Overcurrent Protection *TCC* for Transformers 5&6, HV & LV Equipment

Protection Scenario 3

Distribution Board B1 or D1 - Transformers 7 & 8 Protection Evaluation

Phase Overcurrent Protections and Equipment Ratings:

i. Transformer HV/LV protections failed co-ordination up to 15.38KA at the LV side of transformer, under phase overcurrent faults upstream protection of the transformer may operate before the LV devices, on INST operation. Whilst in practice it is not essential to grade devices on either side of the supply transformer it operates signalling relays within the network which would indicate to operators a fault is within the incorrect part of the system and may lead to a delayed restoration of the standby supply i.e., an actual LV fault would be indicated on the HV remote trip indication. The LV IDMT protection curve could be re-configured to address this issue.

ii. Transformer 7 & 8 full load current is 52.49/1333A HV & LV, respectively. HV protection relay pick-up is set at 131A which is over 200% of the transformer's capacity. This leads to an LV load capability of approx.3480A whereas the actual busbar ampere capacity is 2000A. The LV IDMT is set with a pick-up of 2400A which again more than the busbar capacity. Therefore, a short circuit on this equipment would lead to an increased disconnection time and damage to components, thus leading to a great outage of critical supplies. The direct effect on *Ao* is discussed in Chapter 6.1.

iii. Arcing current at DBD1 is I_a = 12.31KA with a fault clearing time of 1.26s. This leads to a 28 Cal/cm^2 incident energy. Improvement could be made by reduction of settings at the main incomer.

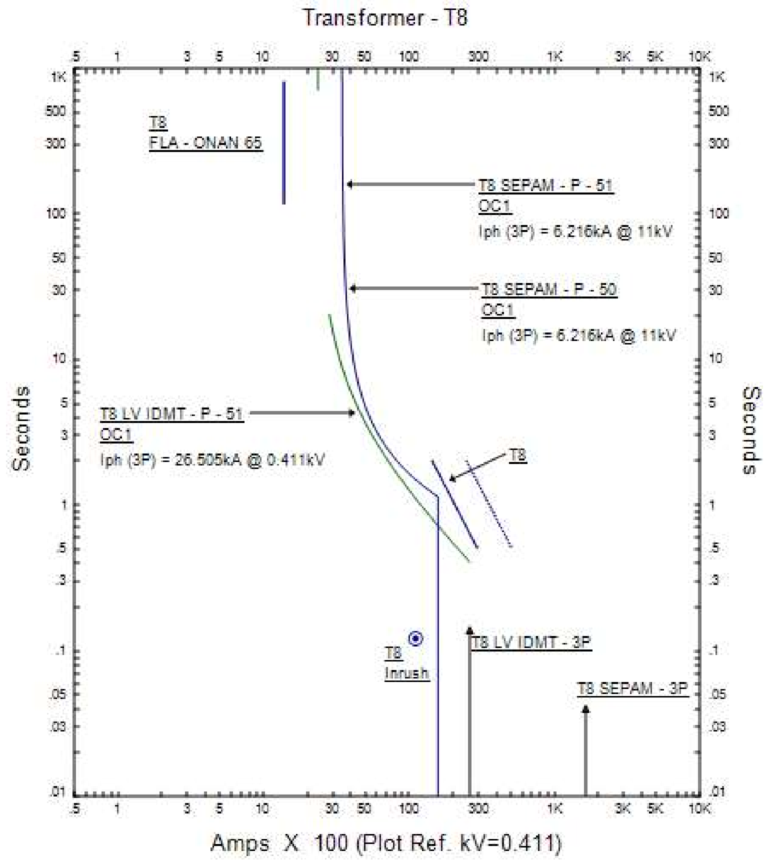


Figure 5.3.1.6 Overcurrent Protection *TCC* for Transformers 7&8, HV & LV Equipment

Ground Overcurrent Protections and Equipment Ratings:

i. Below *TCC* ground fault plot, both transformers 7 & 8 ground fault protection is set to 1.5A. This is to low and outside of the manufacturer's recommendation of 0.3 x *FLC*. Since *FLC* rms is:

$$Isc = \frac{1\text{ MVA}}{(\sqrt{3}\text{ x }11000V_{L-L})} = 52.94\text{A}.$$

Therefore, ground fault setting should be 0.3 x 52.94 = 15.75A.
11000V is L-L_{rms} value.

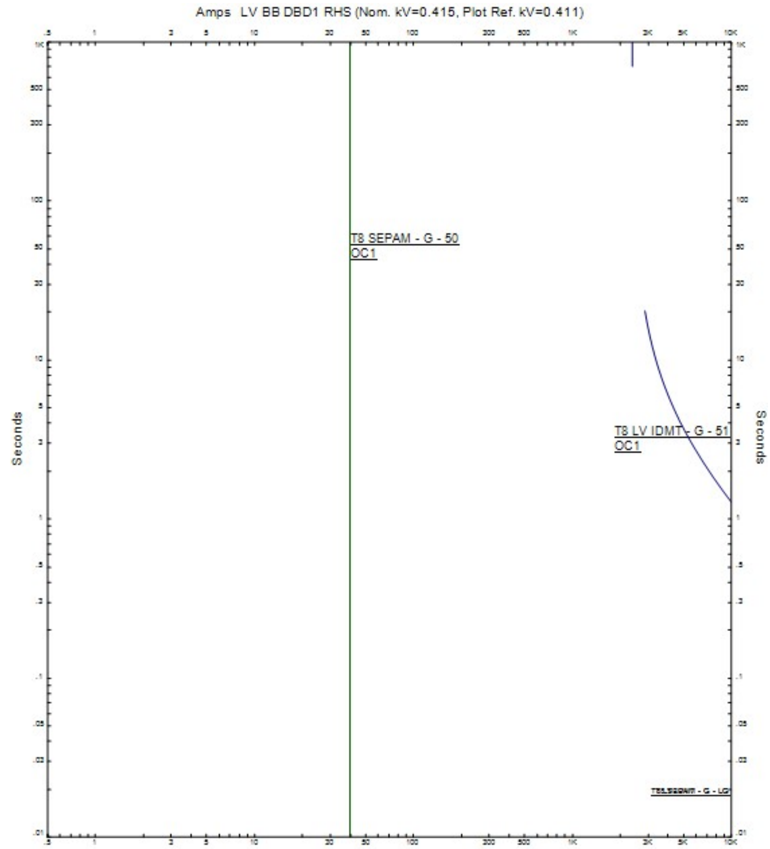


Figure 5.3.1.7 L-G Protection *TCC*, for Transformers 7&8

Protection Scenario 4

Distribution Board R1 or Y1 Transformer 11 & 12 Protection Evaluation

i. Transformer 11 & 12 full load current is 131.2/3333A HV & LV, respectively. HV protection relay pick-up is set at 225A which is significantly greater than the transformers capacity. Also, LV incomer is set to pick up at 4000A which is again above the actual capacity of the transformer - 3333A.

ii. Transformer HV/LV protections failed co-ordination at any overcurrent range at the LV side of the transformer, hence under phase overcurrent faults upstream protection of the transformer may operate before the LV devices on *INST* operation. Whilst in practice it's not essential to grade devices on either side of the supply transformer it operates signalling relays within the network which would indicate to operators a fault is within the incorrect part of the system and may lead to a delayed restoration of the standby supply i.e., an actual LV fault would be indicated on the HV remote trip indication. The LV relay protection curve could be re-configured to improve this.

iii. Arcing current at *DB* Yellow Input is *Ia* = 13.75 KA with a fault clearing time of 2.86 s. This leads to 85 Cal/cm^2 incident energy. Improvement could be made by reduction of settings.

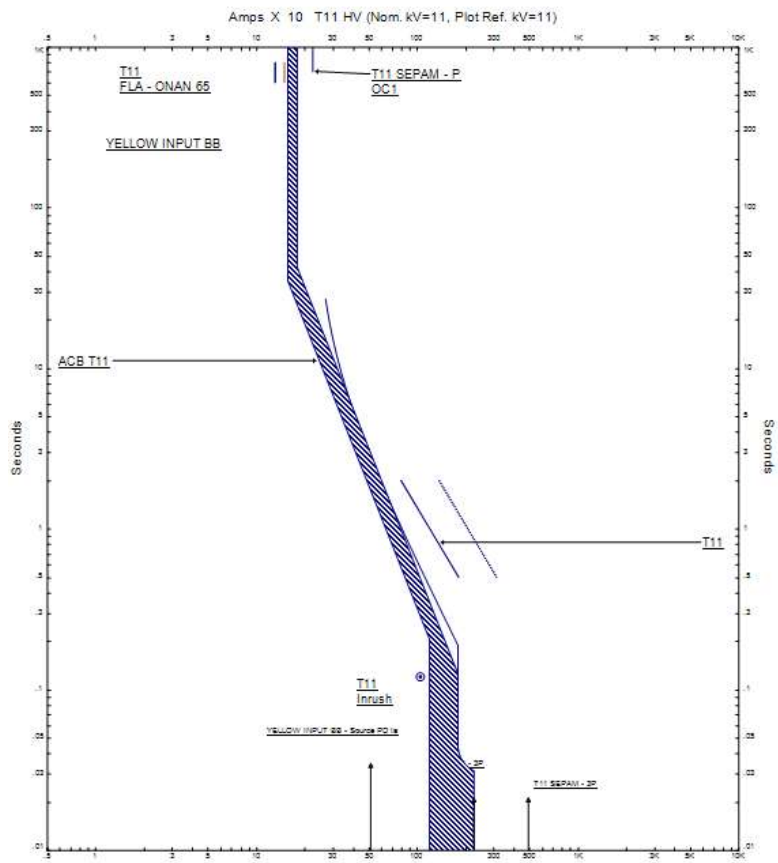


Figure 5.3.1.8 Overcurrent Protection *TCC* for Transformer 11&12, HV & LV Equipment

Protection Scenario 5

Distribution Board H1 Transformer 13&14 Protection Evaluation

i. Transformer 13 & 14 full load current is 131.2/3333A HV & LV, respectively. HV protection relay pick-up is set at 225A which is significantly greater than the transformers capacity. At the current instantaneous setting (1538A/42000A) there is less than 20ms grading margin between the HV & LV devices. Whilst in practice it is not essential to grade devices on either side of the supply transformer it operates signalling relays within the network which would indicate to operators a fault is within the incorrect part of the system and may lead to a delayed restoration of the standby supply i.e., an actual LV fault would be indicated on the HV remote trip indication.

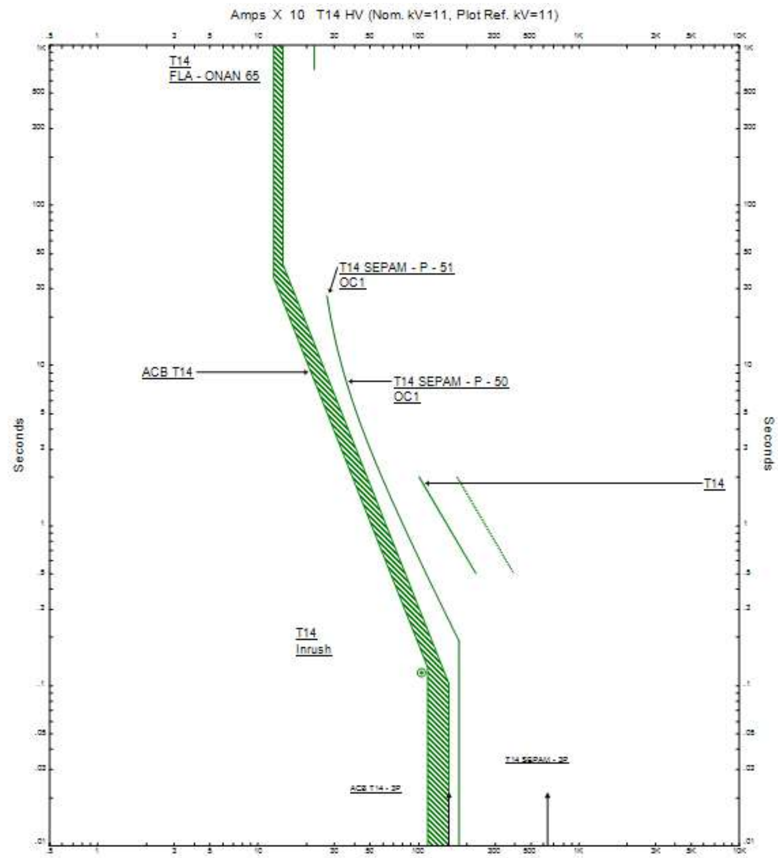


Figure 5.3.1.9 Overcurrent Protection *TCC* for Transformers 13&14, HV & LV Equipment

Protection Scenario 6

Distribution Board G1 Transformer 9&10 Protection Evaluation

DBG1 is a Tier 3 power supply arrangement, for which the relay protections are assessed separately due to the differences in equipment types, which differed from any other LV board within the data centre electrical network.

Transformer 10

Phase Overcurrent Protections and Equipment Ratings:

i. Transformer 10 full load current capacity is 131.2/3333A, HV & LV, respectively. HV protection relay pick-up is set at 225A which is significantly greater than the transformers capacity. The LV incomer at DBG1 is set to pick up at 5250A which is also above the FLC of the supply transformer and exceeding the LV busbar rating of 4000A.

ii. There is no instantaneous setting on the LV incomer therefore an overcurrent fault exceeding 1350A (HV base) would operate the HV protection oppose the desired downstream device closer to the fault. Whilst in practice it is not essential to grade devices on either side of the supply transformer it operates signalling relays within the network which would indicate to operators a fault is within the incorrect part of the system and may lead to a delayed restoration of the standby supply i.e., an actual LV fault would be indicated on the HV remote trip indication.

iii. Arcing current at DB G1 Transformer 10 Ia = 19.29 KA with a fault clearing time of 0.92s. This leads to 39 Cal/cm^2 incident energy.

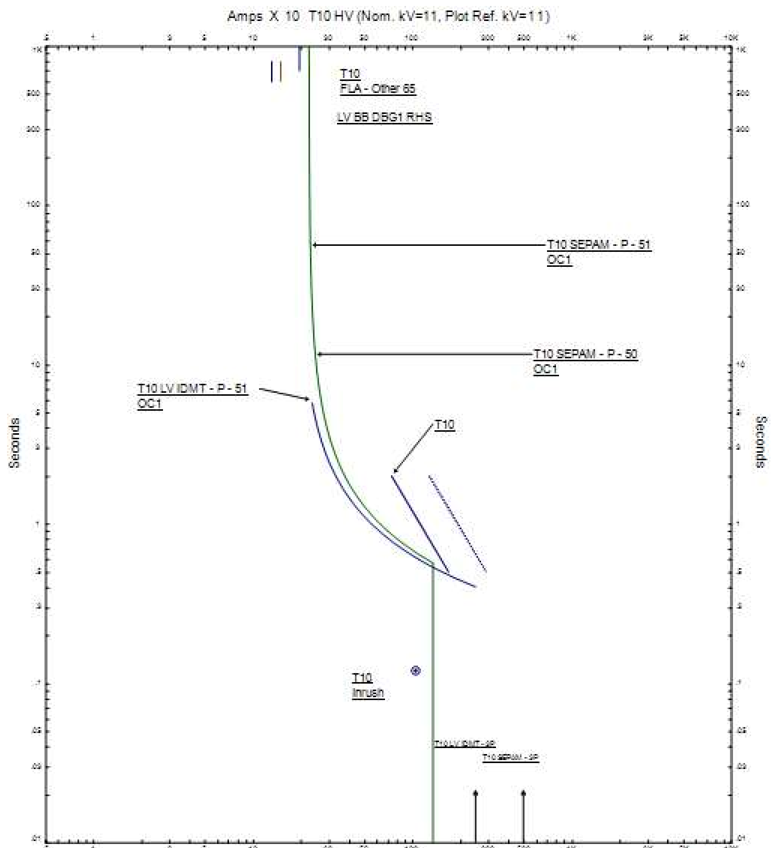


Figure 5.3.1.10 Overcurrent Protection *TCC* for Transformer 10, HV & LV Equipment

Ground Overcurrent Protections and Equipment Ratings:

i. Below *TCC* plot for transformer 10 ground fault protection is set a 3A. This is considerably too low and outside of the manufacturer's recommendation of 0.3 x *FLC*.

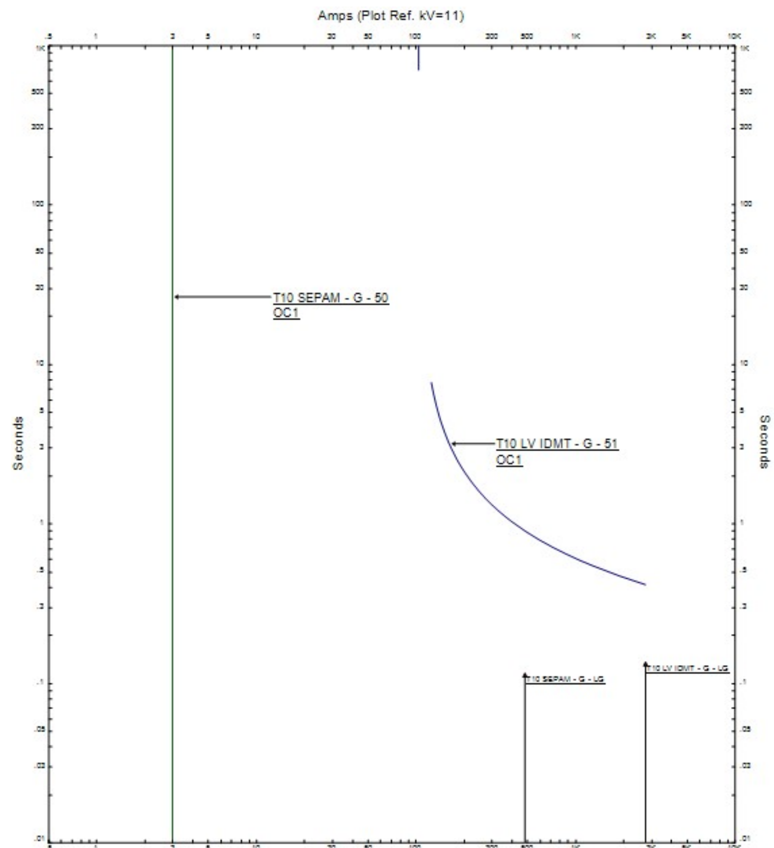


Figure 5.3.1.11 L-G Protection *TCC* for Transformer 10

Transformer 9

Phase Overcurrent Protections and Equipment Ratings:

i. Transformer 9 full load current capacity is 131.2/3333A, HV & LV, respectively. HV protection relay pick-up is set at 187.5A which is allowing at 45% overload margin, this setting could be reduced to 25% as per the original manufacturer's recommendations.

ii. The LV incomer at DBG1 is set to pick up at 1225A which is considerably lower than the actual transformer LV FLC of 3333A. On investigation the LV fuses were fitted in the LV transformer cable box upstream of the LV IDMT. Fuses were BUSSMANN gg 800A 80KA BS88 fuses. The thermal curve of the XPLE SWA LV supply cable is significantly above the

IDMT settings in terms of load current and fault levels thus no additional upstream fuses are required. The upstream fuses do not discriminate with the LV IDMT incomer, thus above 10602A the LV fuses would operate before the LV IDMT relay therefore transformer inter-tripping would be lost.

iii. Transformer 9 HV IDMT setting crosses the damage point of the transformer and should be addressed.

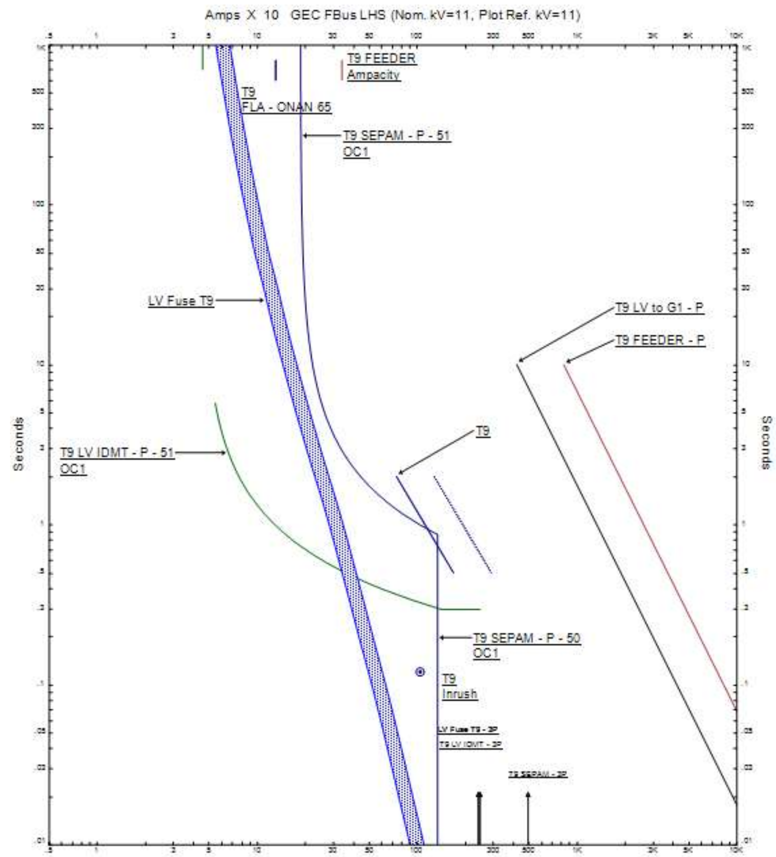


Figure 5.3.1.12 Overcurrent Protection *TCC* for Transformer 9, HV & LV Equipment

Ground Overcurrent Protections and Equipment Ratings:

i. Below *TCC* plot for transformer 9 ground fault protection is set a 3A. This is considerably too low and outside of the manufacturer's recommendation of 0.3 x *FLC*.

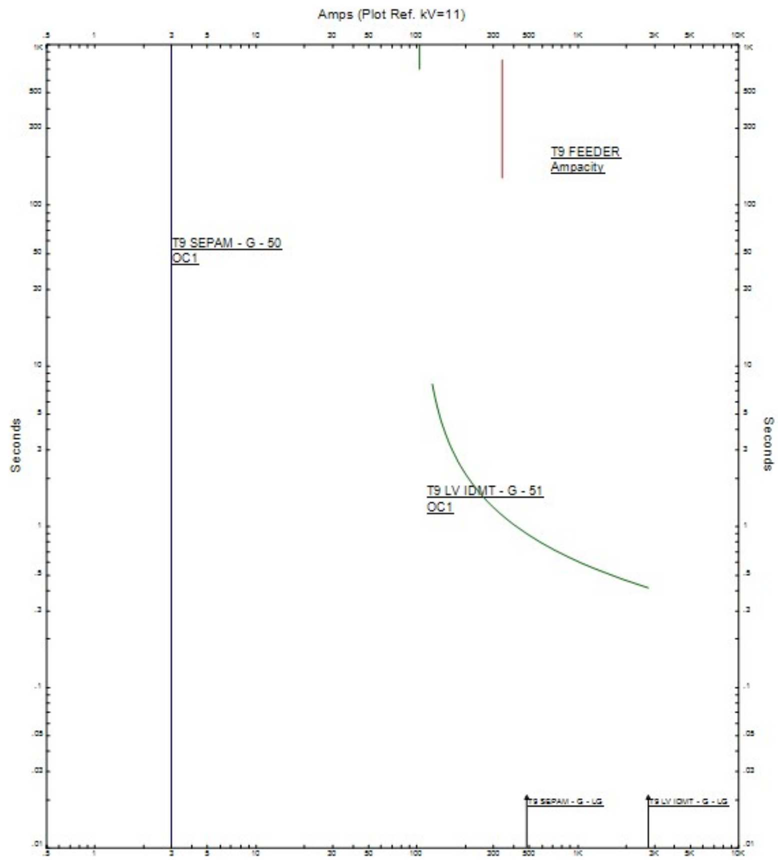


Figure 5.3.1.13 L-G Protection *TCC* for Transformer 9

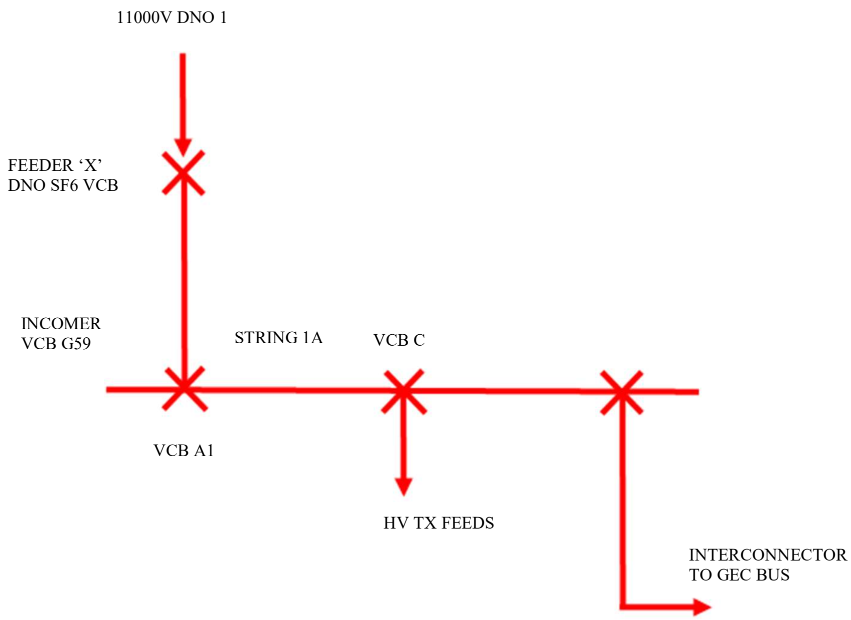


Figure 5.3.1.14 *DNO* & Main Incomer Single Line Diagram, Relating to Protection Scenario 7.

Protection Scenario 7

Assessment of High Voltage Grid Feeder (X) and *VCB* A1

Phase Overcurrent Protections and Equipment Ratings:

i. No 3-phase grading achieved at grid fault levels of 6KA, *DNO* feeder trips at 0.79s whereas A1 SEPAM relay operates at 2.4s, for busbar faults on String 1(A). Under fault conditions this could lead to a pro-longed outage of one of the two site *DNO* supplies.

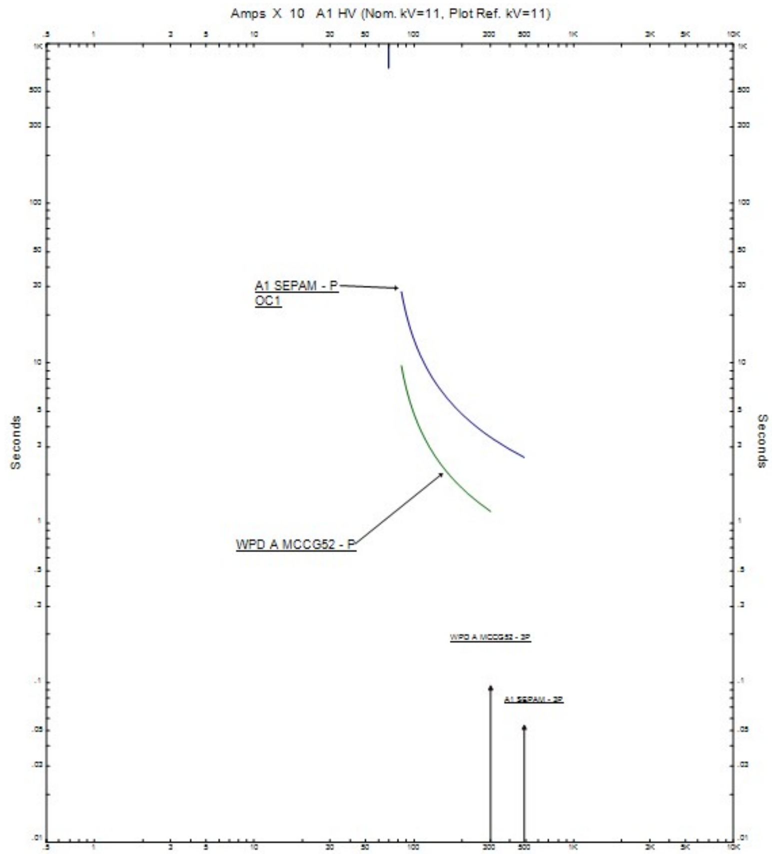


Figure 5.3.1.15 Overcurrent Protection *TCC* for *DNO* grid feeder *VCB* X & Data Centre Main Incomer *VCB* A1

Ground Overcurrent Protections and Equipment Ratings:

i. As shown below failed protection co-ordination for L-G faults at *DNO VCB* X and Main incomer *VCB* A1. *VCB* A1 SEPAM takes longer than 3.0s to clear L-G fault current. Note also B2 & A2 *VCB's* operate with identical settings, therefore a fault on opposite string extensions may result in disconnection of the GEC busbar. *VCB* C has L-G protection, which is set at 600A, currently considerable too high for the system fault current. L-G settings on the main HV ring require improvement to avoid unnecessary outages due to poor fault isolation.

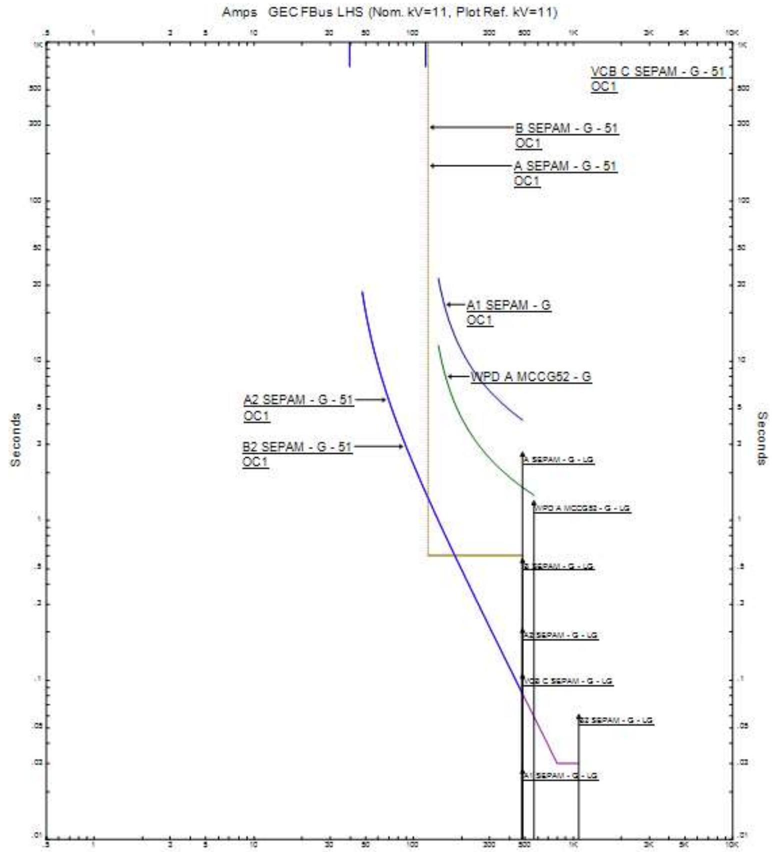


Figure 5.3.1.16 L-G Protection *TCC,* for *DNO* grid feeder *VCB* X & Data Centre Main Incomer *VCB* A1

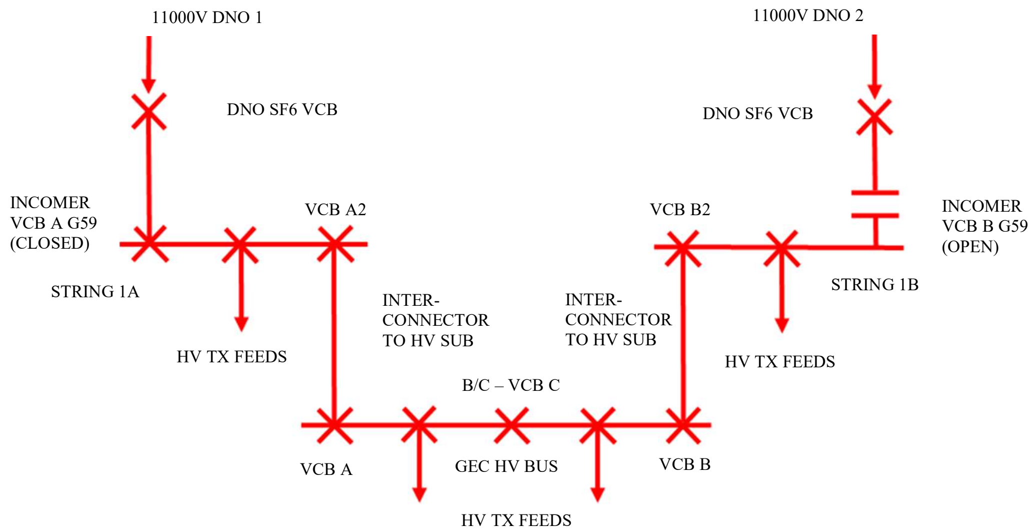


Figure 5.3.1.17 Single Line Diagram of the *DNO* Supply for Evaluation of Protection Scenarios 8 to 11.

Protection Scenario 8

Bus Bar Faults on the HV Ring Main Extensions String 1A or String 1B, whilst supplied by a Single Incomer (DNO)

Phase Overcurrent Protections and Equipment Ratings:

i. A fault current value for L-L-L of ≥2.86KA will operate the definite time settings on VCB A or VCB B with a potential loss of the GEC HV BB and all associated connected loads, 10 No. distribution transformers.

ii. Despite the Definite Time (DT) setting on VCB's A & B there is just 200ms grading for L-L-L faults between VCB A2/B2 against VCB C (bus coupler on GEC HV busbar). A fault on either string 1(A or B) busbar could potentially operate VCB C disconnecting an additional 5 x HV distribution transformers than what is necessarily required to clear such faults.

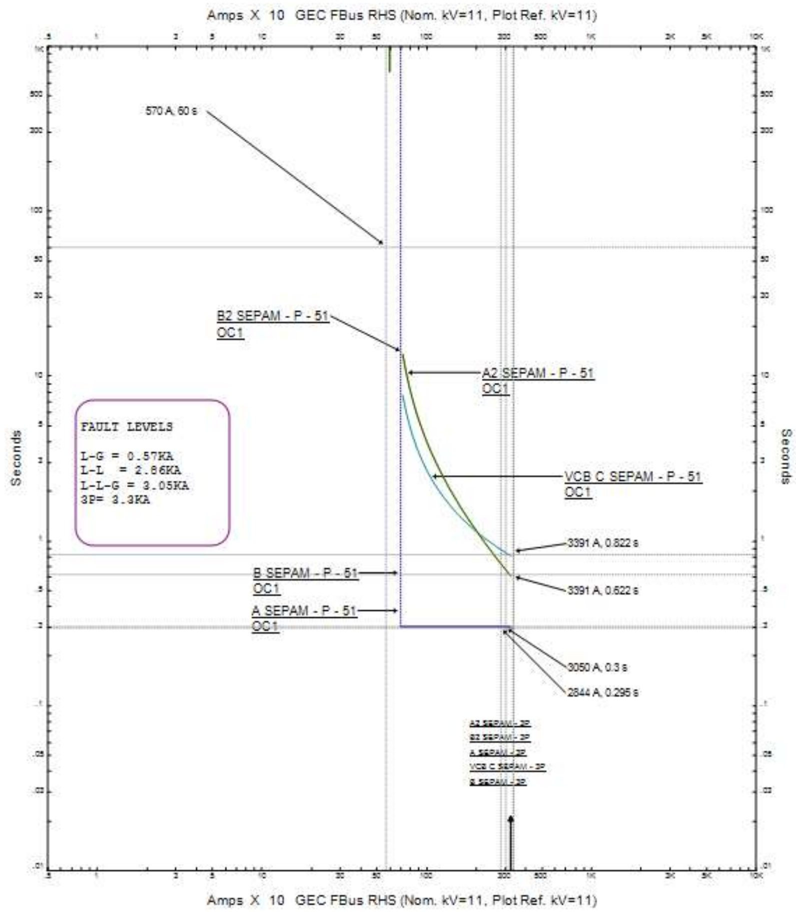


Figure 5.3.1.18 Overcurrent Protection *TCC* for busbar Fault on HV String Extensions

Ground Overcurrent Protections and Equipment Ratings:

i. Although busbar L-G faults are less likely, String 1A/B operates the corresponding *VCB's* A2/B2 thus removing13 No. connected distribution transformers. Not the 3 No. required for a genuine busbar fault on the HV substation extensions, note below TCC plot. A more appropriate range of L-G settings on VCB C could assist with mitigating this issue and improve the current protection scheme.

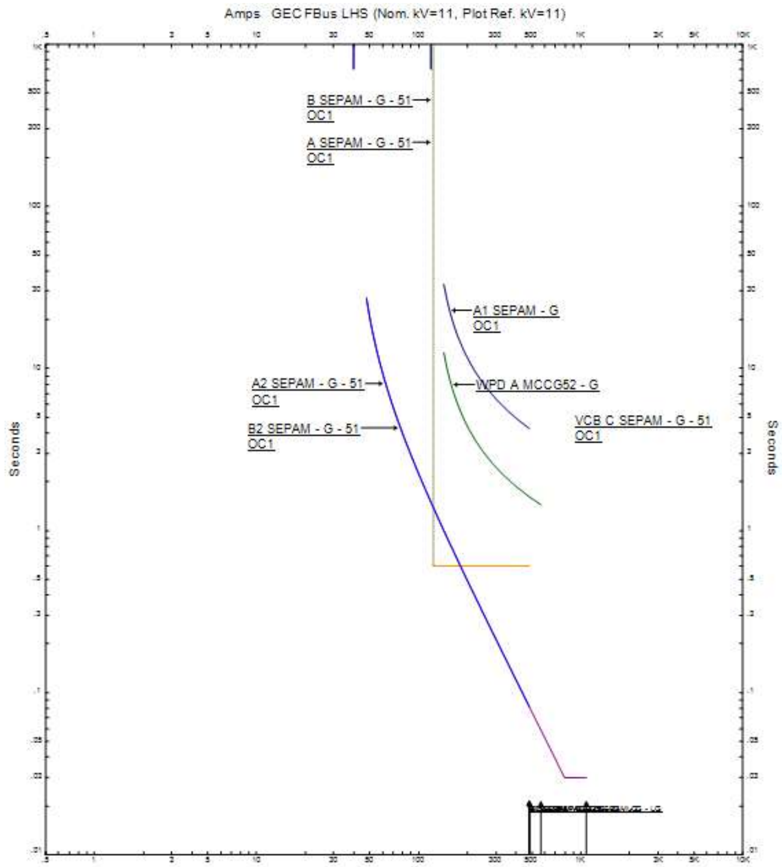


Figure 5.3.1.19 L-G Protection *TCC* Plot for busbar Fault on HV String Extensions

Protection Scenario 9

Single Feeder Network, Transformer supply side fault on String Extensions (String 1A or 1B)

i. No issues for L-L-L, L-L, L-G or L-L-G faults. Transformer SEPAM relays operate before upstream device with good discrimination margins.

Protection Scenario 10

Single Feeder Network, busbar Fault on the Main GEC HV Switchgear

i. All GEC busbar O/C faults, *VCB*A/B operate before ‘C’, so does *VCB*A2/ B2 thus a busbar fault cannot be cleared on the main GEC busbar without losing both sides of the busbar coupler (*VCB* C), during a single feeder network situation. This is an unlikely occurrence although settings on *VCB* C could be improved to mitigate this issue. Likewise, for L-G faults *VCB* A2/B2 would operate since maximum L-G fault is 570A. *VCB* ‘C’ would minimise the disconnection of critical loads, unfortunately L-G setting is currently 600A (*SI* Curve) – there is not enough L-G current to operate this setting in any fault scenario.

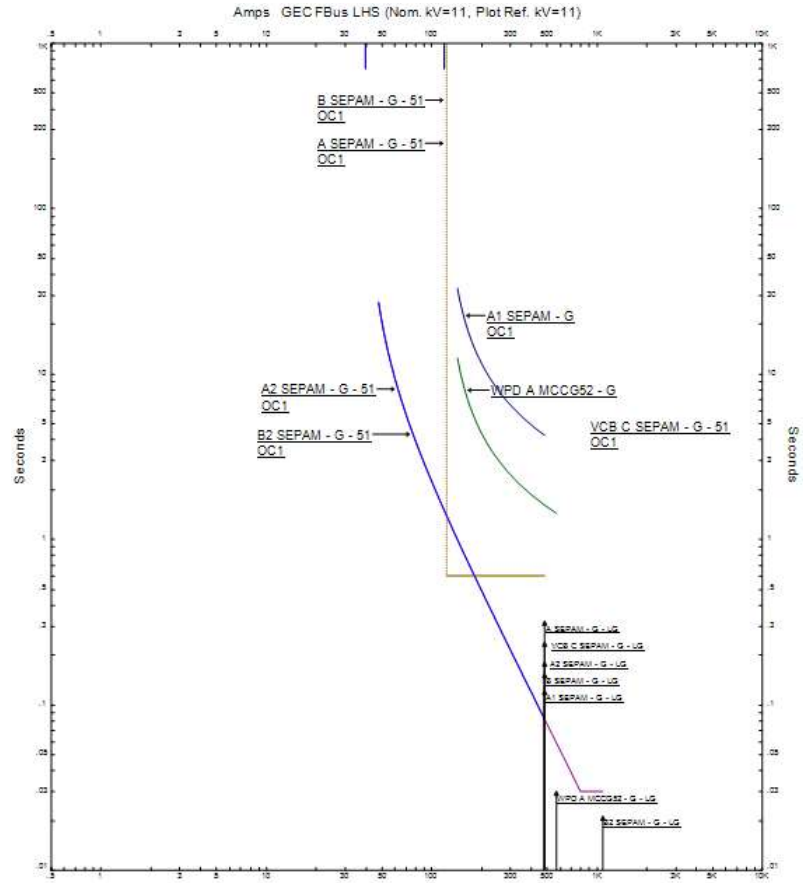


Figure 5.3.1.20 Overcurrent Protection *TCC* plot for L-G Faults at the GEC HV Substation

Protection Scenario 11

Single Feeder Network, Cable Fault on the Supply Side of Transformers Connected to the Main *GEC* HV Switchgear

i. No issues for L-L-L, L-L, L-G or L-L-G faults. Transformer SEPAM relays operate before upstream device, providing good discrimination. Although transformer relay pick-up currents were more than 2 x *FLC* which clips into the *TCC* of the transformer damage point.

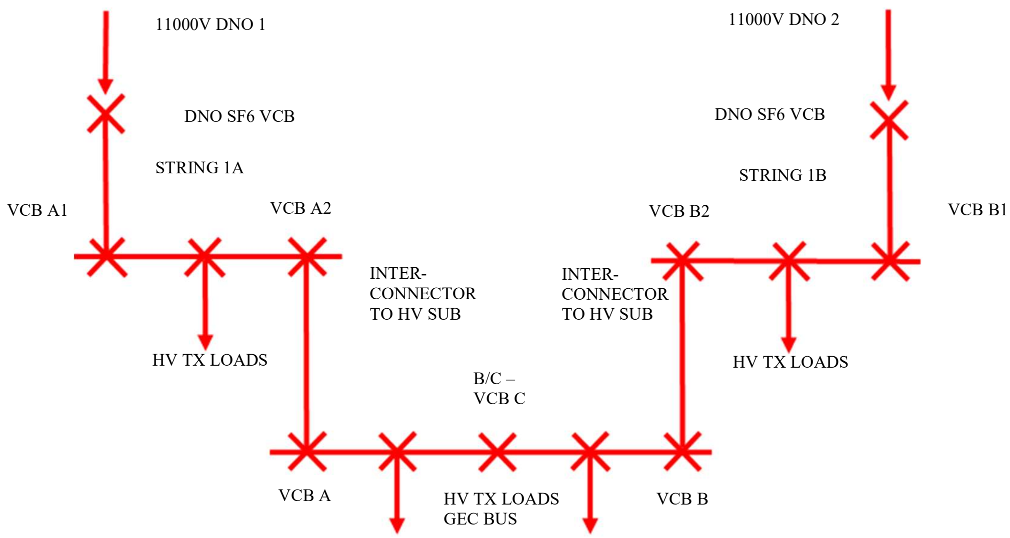


Figure 5.3.1.21 Dual Feeder Network Single Line Diagram, Grid Incomer (*DNO*) Evaluations Relating to Protection Scenarios 12 to 17.

Protection Scenario 12

Busbar Faults on the HV Ring Main Extensions String 1A or 1B

i. No issues noted for L-L-L, L-L, L-G or L-L-G faults. Transformer SEPAM relays operate before upstream device, providing good discrimination.

Protection Scenario 13

Cable Fault on Supply Side of the Transformers Connected to the HV Ring Main Extensions String 1A or 1B

i. No issues noted for L-L-L, L-L, L-G or L-L-G faults. Transformer SEPAM relays operate before upstream device, providing good discrimination. Although transformer relay pick-up currents are more than 2 x *FLC* which clips into the *TCC* of the transformer damage point.

Protection Scenario 14

Busbar Fault on the Main HV GEC Switchgear

i. Failed protection co-ordination for any fault on the *GEC* busbar. Definite time setting of *VCB* A or *VCB* B leads to instantaneous operation & loss of all connected transformer loads, it would be advisable to remove the definite time setting and obtain discrimination between *VCB* C and *VCB* A2/B2. Allowing isolation of either the *LHS* or *RHS* under fault condition. At present settings between *VCB* C and *VCB* A2 or B2 do not allow enough margin for any overcurrent fault, such as L-L, L-L-G or L-L-L faults.

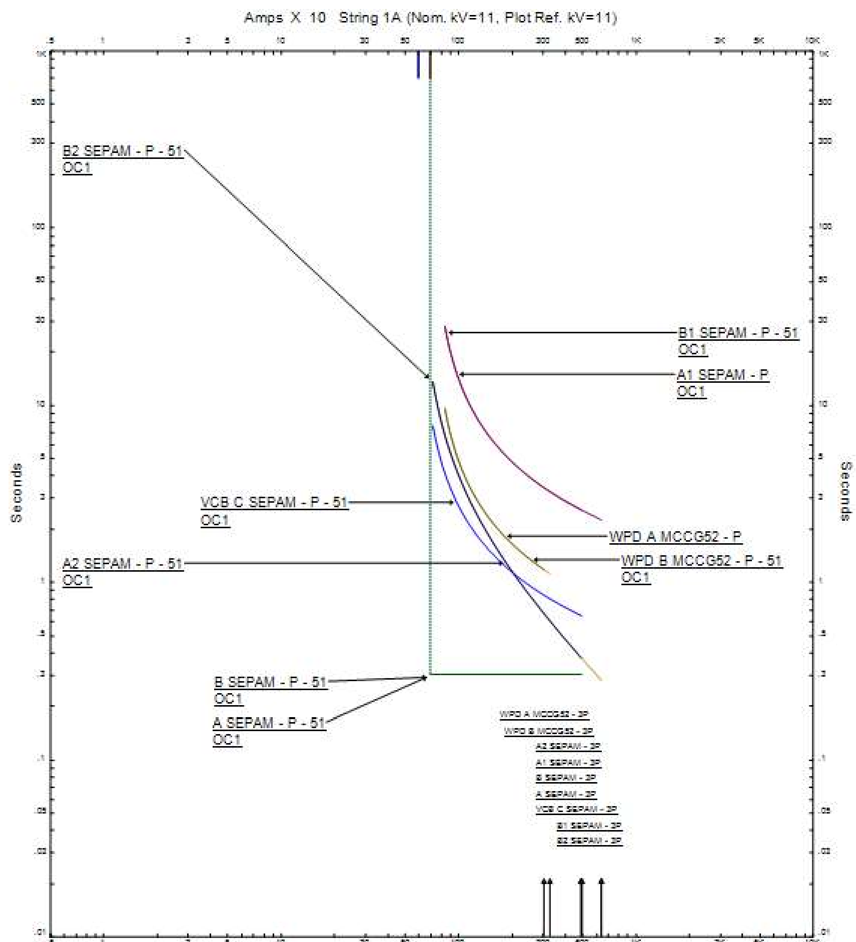


Figure 5.3.1.22 Overcurrent Protection *TCC* for busbar Fault at the Main *GEC* HV Substation

Protection Scenario 15(a)

L-G Faults on the Main HV *GEC* Switchgear

i. Ground fault settings on *VCB* A2 or B2 trip instantaneously thus L-G faults on the *GEC* busbar, either *LHS* or *RHS* disconnects all connected transformers. Ground fault protection on *VCB* C could be investigated to improve this and limit the disconnected loads under a busbar fault, although L-G faults have limited occurrences on busbar constructions.

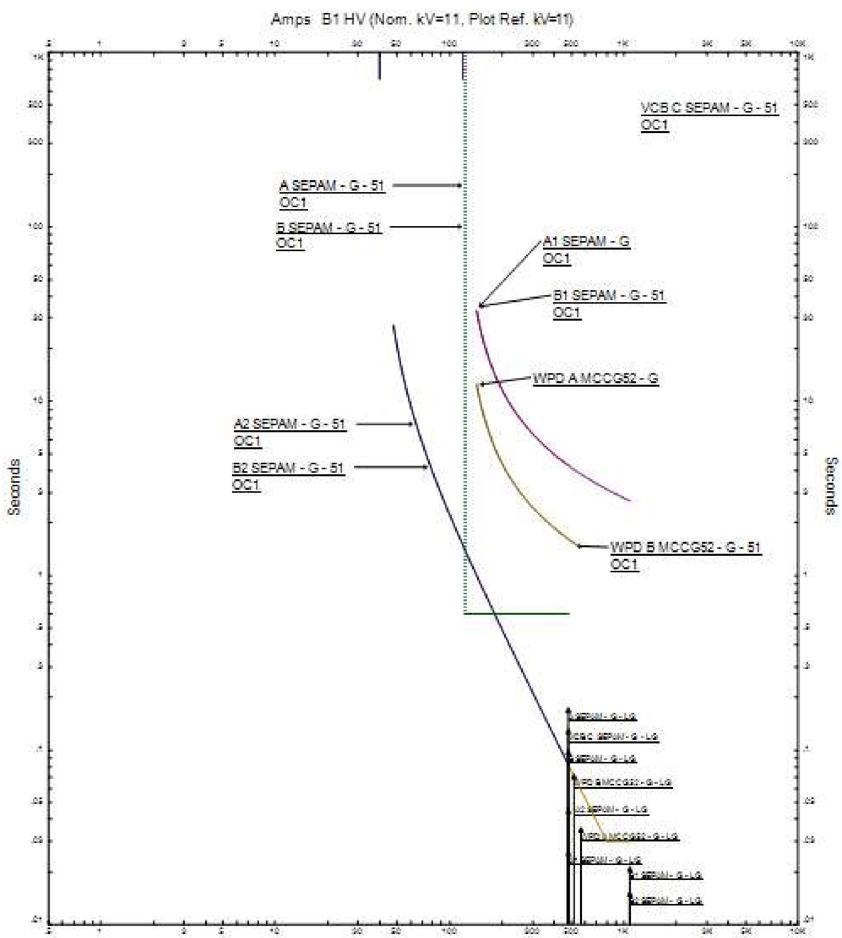


Figure 5.3.1.23 Overcurrent Protection *TCC*, for busbar L-G Fault at the *GEC* HV substation

Protection Scenario 15(b)

Cable Fault located from *DNO VCB* to *VCB* A1 or *VCB* B1(Main *DNO* Incomers)

i. L-L-L fault level at the incoming supply cable is approximately 3KA, due to parallel supplies on the HV network *VCB*A/B definite time settings or A2/B2 tripping of 3005A at 0.66s (upstream of *VCB*A/B if *DT* is removed) operate firstly. The cable fault would remain until the *DNO* protection operates/trips 3044A at 1.14 Secs. This would unnecessarily loose voltage at the *GEC* busbar and one of the HV string extensions (i.e., 2 of 3 substations lost for L-L-L cable from *DNO* to site incomers). This is a significant issue since the *VCB's* either side of the cable fault should remove without impacting on the other substation equipment. Practically for site operators this would pose a significant challenge to restore the site supply given the available time of standby equipment i.e., *UPS* uninterruptable power supply batteries 15 minutes at *FLC*.

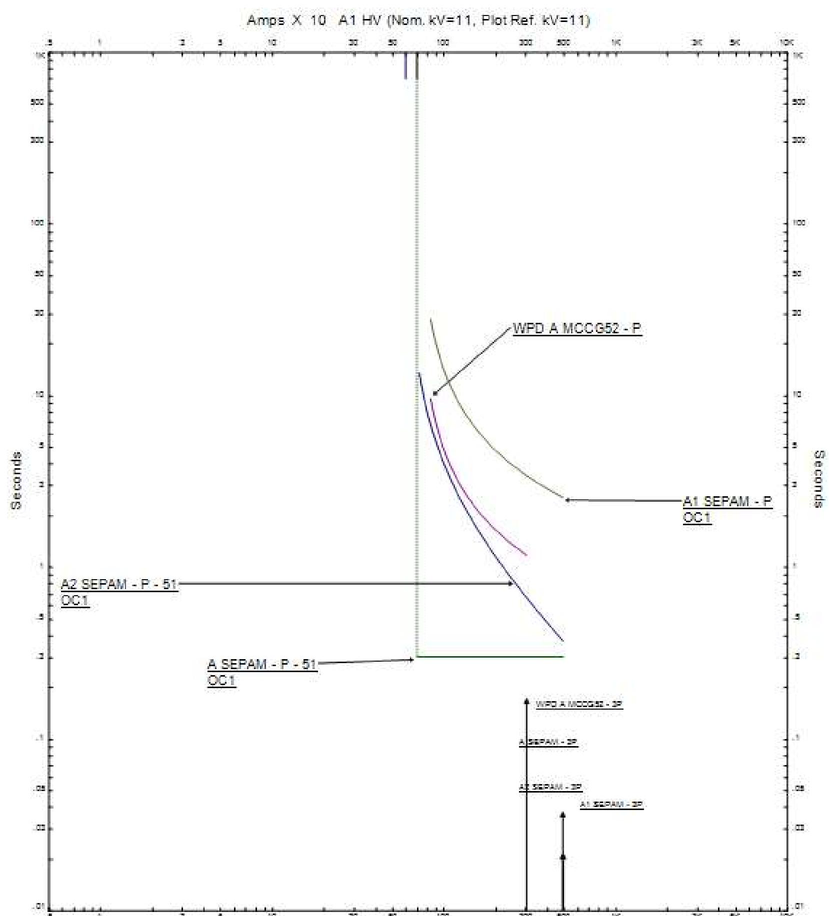


Figure 5.3.1.24 Overcurrent Protection *TCC* plot for Cable Fault at the *DNO* to Main Site Incomer

Protection Scenario 16

Cable Faults on the Supply Side of the Transformers Connected to the HV *GEC* Switchgear

i. Effective grading for phase overcurrent's has been achieved between the *GEC* busbar transformer supply feeders and upstream devices. However, note on the *TCC* a 300ms grading margin between a transformer supply and main *VCB* 'A' or 'B' definite time settings. Therefore, grading margins could be improved.

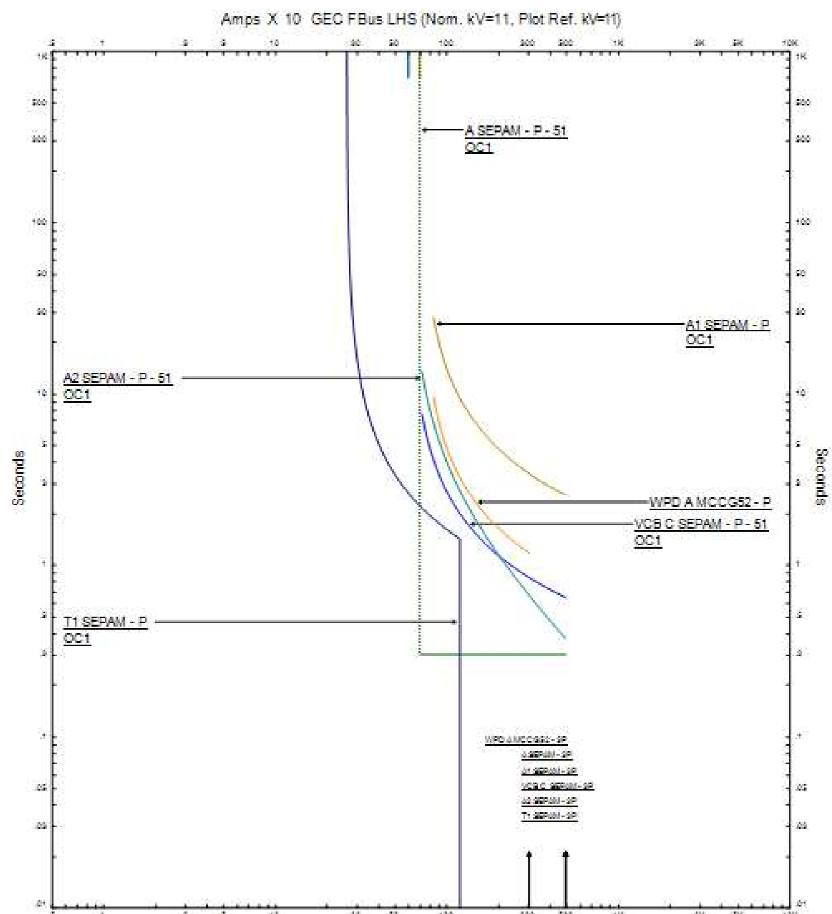


Figure 5.3.1.25 Overcurrent Protection *TCC* for Cable Faults on Transformers Connected to the *GEC* busbar

Protection Scenario 17

Cable L-G faults on the Supply Side of the Transformers connected to the Main HV *GEC* Switchgear

i. The below *TCC* ground fault plot for transformer 1 shows ground fault protection set at 3A rms. This is considerably too low and outside of the manufacturer's recommendation of 0.3 x *FLC* rating.

$$Isc = \frac{2.5\text{MVA}}{\sqrt{3}\text{ x }11000\ V_{L-L}} = 131.213\text{ A rms}$$

Therefore, ground fault setting should be 0.3x131.213 = 39.64A rms

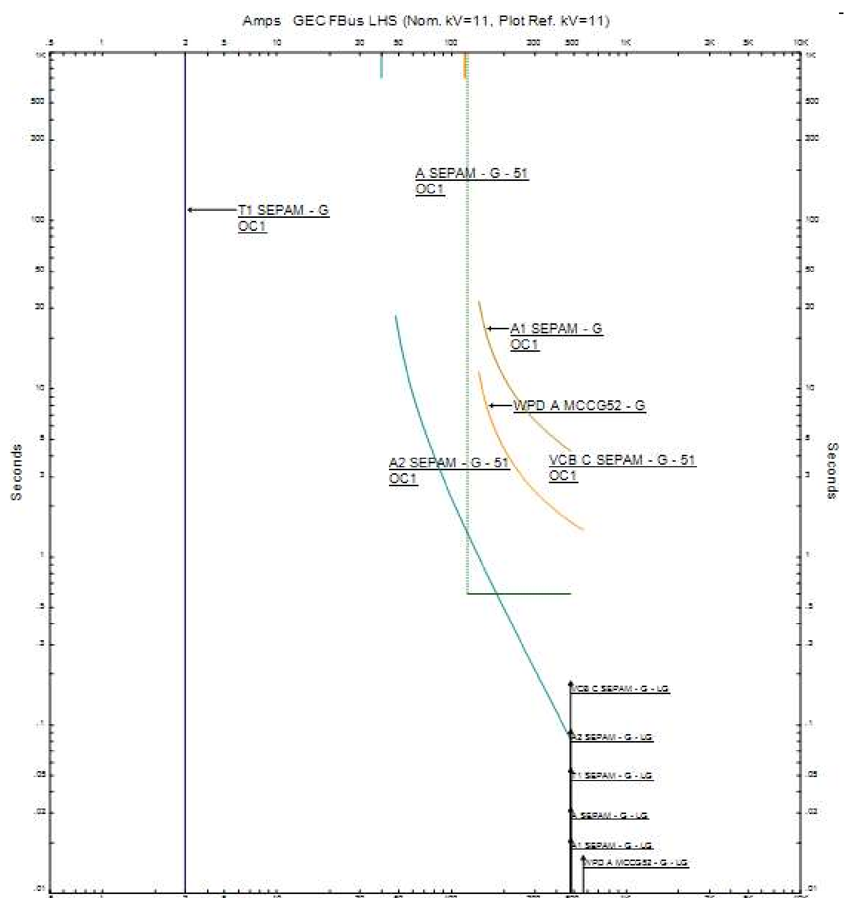


Figure 5.3.1.26 L-G Protection *TCC* Plot for Cable Faults on Transformers Connected to the *GEC* busbar

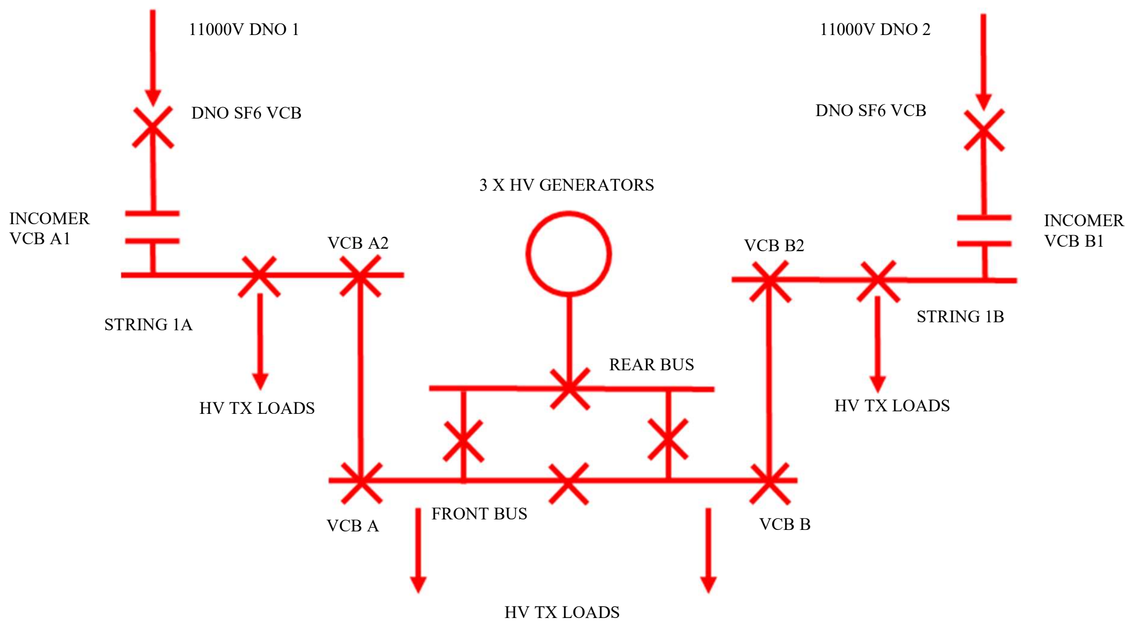


Figure 5.3.1.27 Standby Generators Single Line Diagram, Relating to Protection Scenarios 18 to 21.

Protection Scenario 18

Standby Supply Scenario with busbar Faults on the HV Ring Main Extensions String 1A or 1B

Phase Overcurrent Protections and Equipment Ratings:

i. No issues recorded with regards overcurrent faults, *VCB* A clears L-L-L faults at 4800A at 0.3s which is proceeding *VCB* A2 4841A at 0.4s, both clear before generator protection which operates at 1200A at 0.9s. Therefore, achieves a minimum of 500ms clearance between all protection devices.

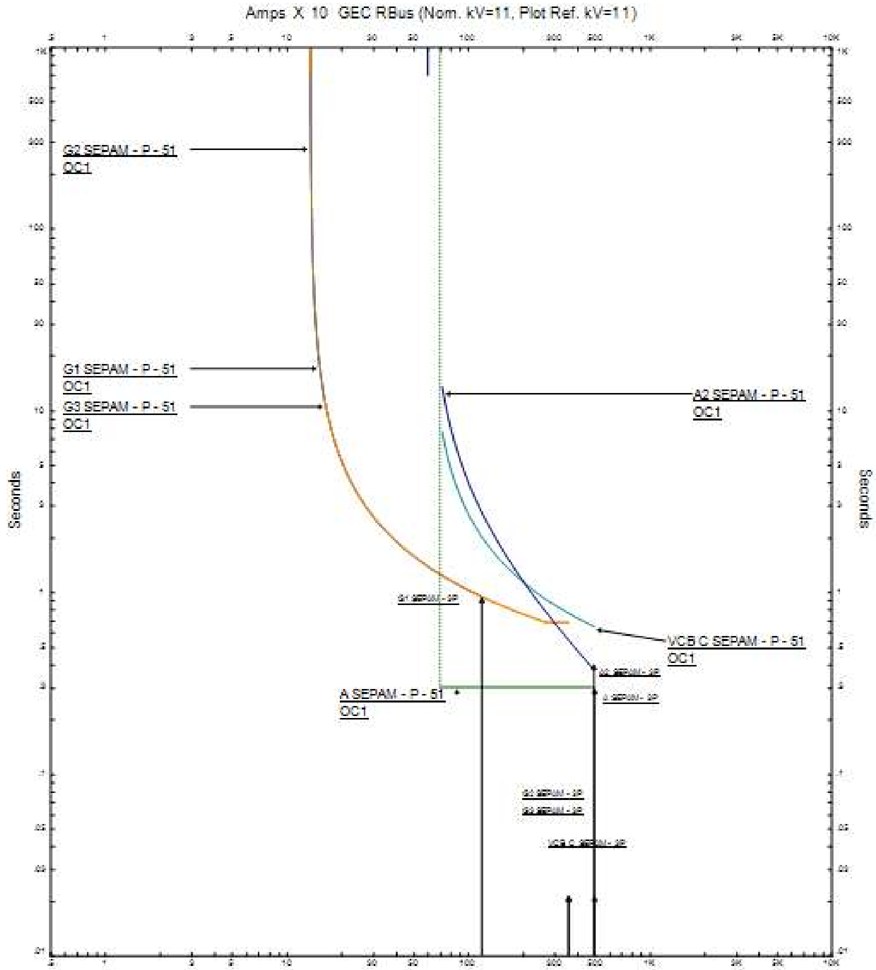


Figure 5.3.1.28 Overcurrent Protection *TCC* for Energy Centre busbar Fault Whilst Supplied by Generators

Ground Overcurrent Protections and Equipment Ratings:

i. *VCB* A or A2 discriminate with generators 1, 2 & 3. Although there is only 100ms clearance between *VCB* A or A2 and generators 4&5. This grading margin could be improved to ensure in the unlikely event of an energy centre substation BB L-G fault, that generators remain online and unaffected. Fault current and operating times are as follows; *VCB* A2 (498A at 0.07s), VBC A (453A at 0.51s), Gens 1to 3 (142A at 0.96s), Gens 4 & 5 (482A at 0.6s).

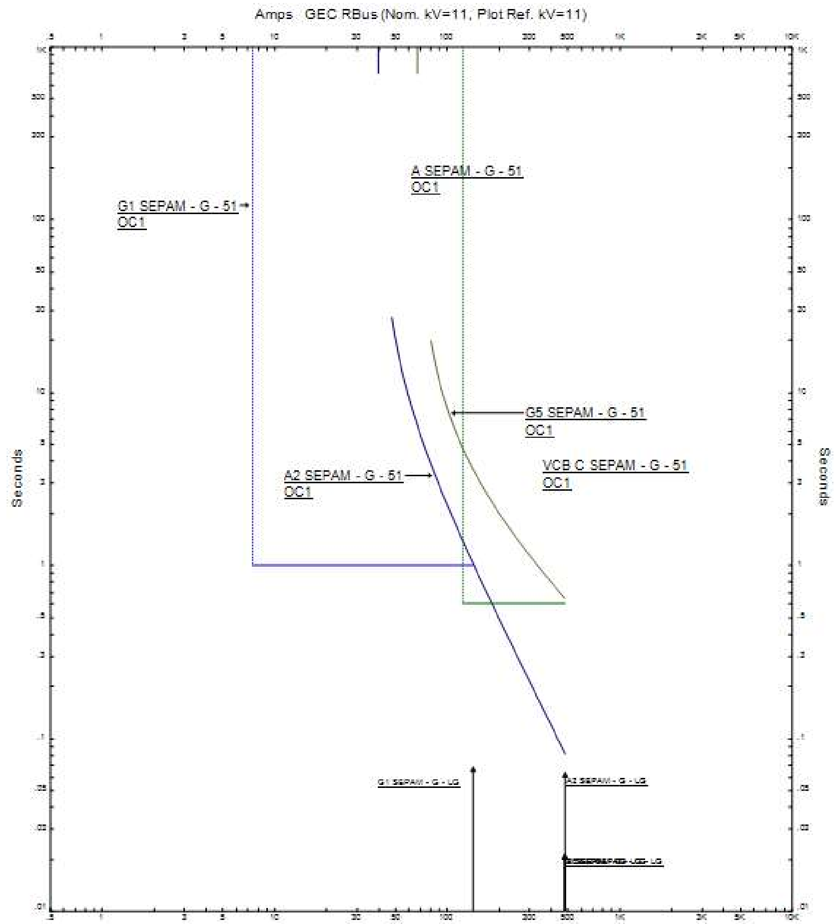


Figure 5.3.1.29 L-G Protection *TCC* for Energy Centre busbar Fault, Whilst Supplied by Generators

Protection Scenario 19

Standby Supply, Faults on the HV Ring Main Extensions, String 1A or 1B (outgoing circuits)

i. No issues recorded for L-L-L, L-G, L-L-G, L-L, Energy centre *BB* outgoing transformer feeder circuit SEPAM relays operate before any upstream protection with good grading margins.

Protection Scenario 20

Standby Supply, Faults on the Main HV *GEC* busbar.

i. For the current protection scheme a *GEC* front busbar *O/C* fault whilst being supplied by the standby generators could not isolate the fault from the busbar, thus supply would be lost (generators). *VCB* 'C' does note discriminated for O/C faults with generators 4 & 5, there is also no protection enabled on *VCB* 'D' or 'E' thus the synchronous engines would continue to feed the faulted *BB* until local engine protection operated and supply was lost from the 11KV *GEC BB*. This could be improved by investigating protection settings on *VCB* 'D' & 'E' and or operating with an open busbar coupler. The L-G setting on *VCB*'C' is also set to pick up at 600A which is well above the L-G currents within the system whilst on generator supply.

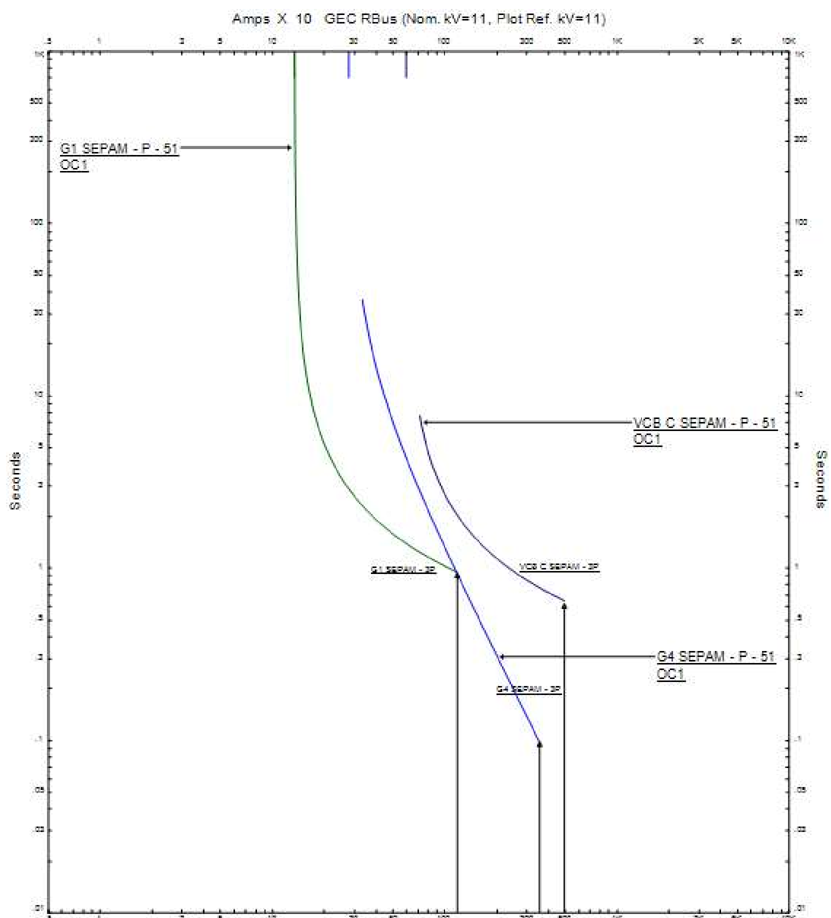


Figure 5.3.1.30 Overcurrent Protection *TCC* Plot for *GEC* busbar Fault, Whilst Supplied by Generators

Protection Scenario 21

Standby Supply, Assessment of Faults on the *GEC* (outgoing circuits)

i. No issues recorded for L-L-L, L-G, L-L-G, L-L. The GEC BB outgoing transformer feeder SEPAM relay operates before any upstream protection with good grading margins.

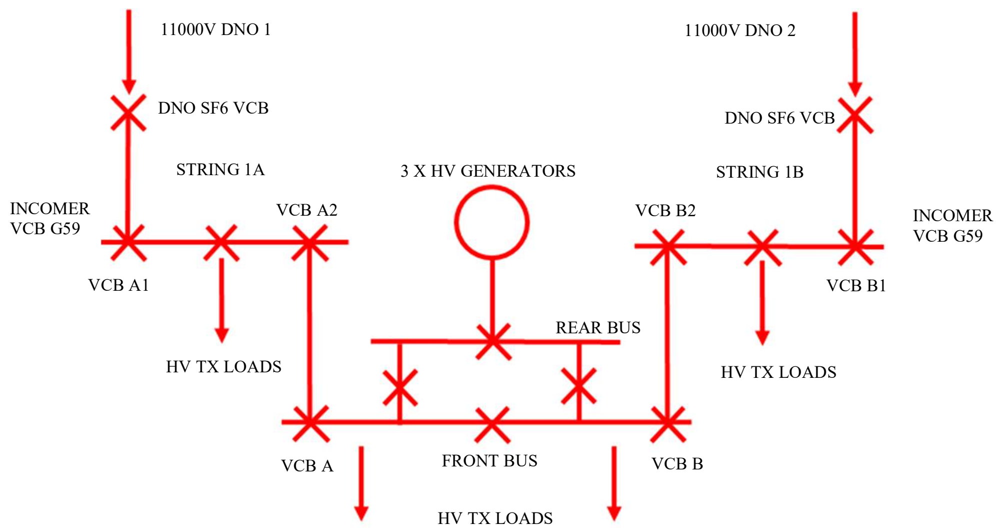


Figure 5.3.1.31 Generators & Grid Feeders Single Line Diagram for Parallel Protection Evaluation Scenario 22.

Protection Scenario 22

Faults on the *DNO* Supply Side whilst in Parallel with Standby Generators

Phase Overcurrent Protections and Equipment Ratings:

i. No issues recorded for L-L-L, L-L or L-L-G. The *WPD* directional protection is first to operate and discriminates well with site protection scheme.

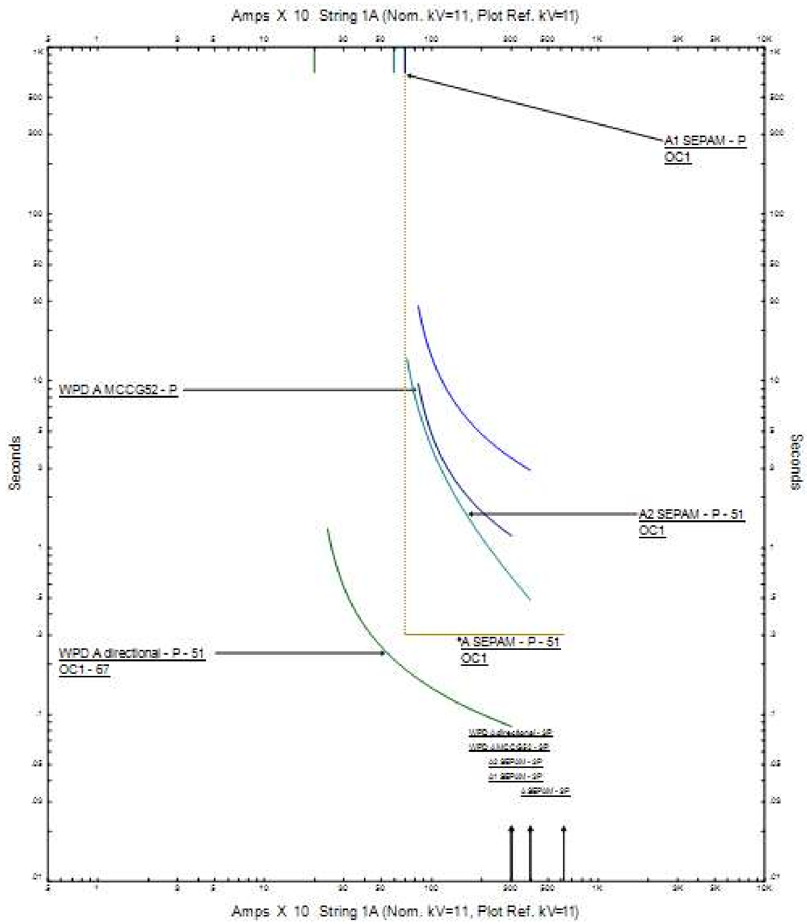


Figure 5.3.1.32 Overcurrent Protection *TCC* for Grid Faults Whilst in Parallel Operation with Generators

Ground Overcurrent Protections and Equipment Ratings:

i. During a L-G fault on the *DNO* supply side *VCB* A2 operates prior to the *DNO* feeder protection, thus the 11KV supply to the energy centre substation (String 1A or 1B) would be disconnected. This would remove three distribution transformers for a non-genuine reason (i.e., fault free and on-load). *VCB* A1 L-G time delay is 2.55s which is significantly too high leading to mis co-ordination with the *DNO*.

Relay Location	L-G Current (A)	Operating Time (S)
VCB A2	485	0.08
WPD (Directional)	572	0.186
VCB A	485	0.59
VCB A1	485	4.27

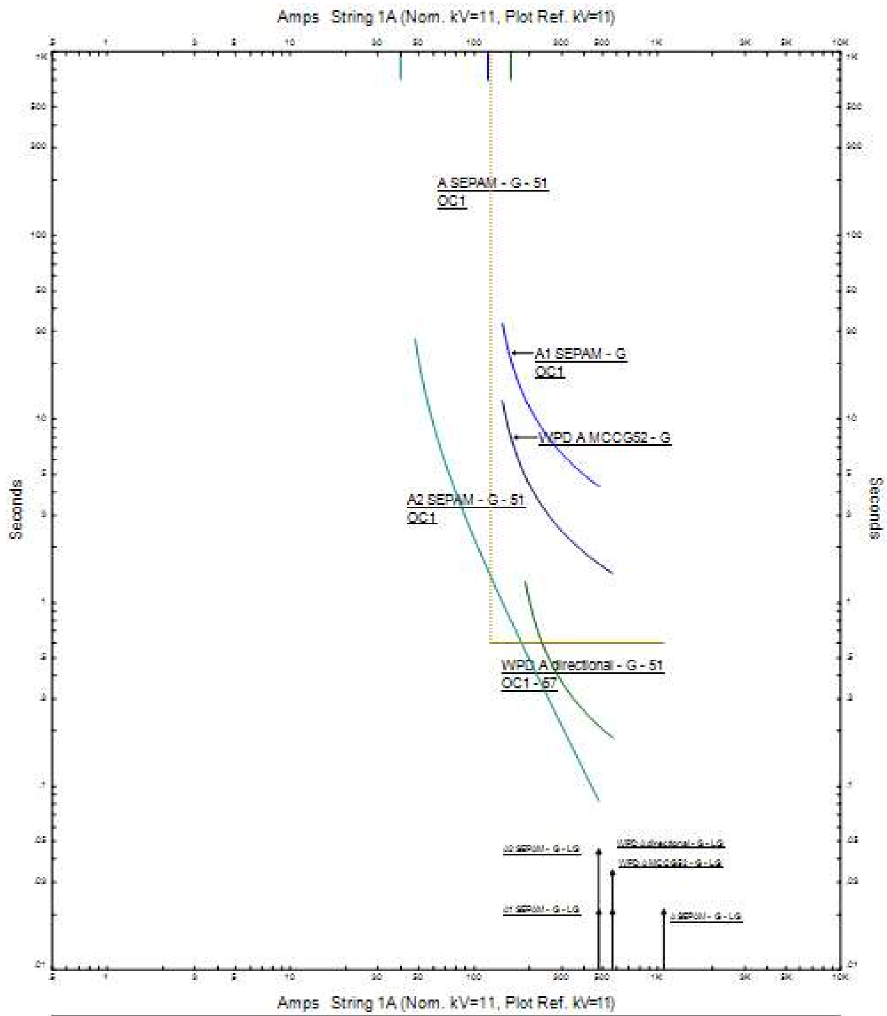


Figure 5.3.1.33 L-G Protection *TCC* Plot for Grid Incomer Faults Whilst in Parallel with Generators

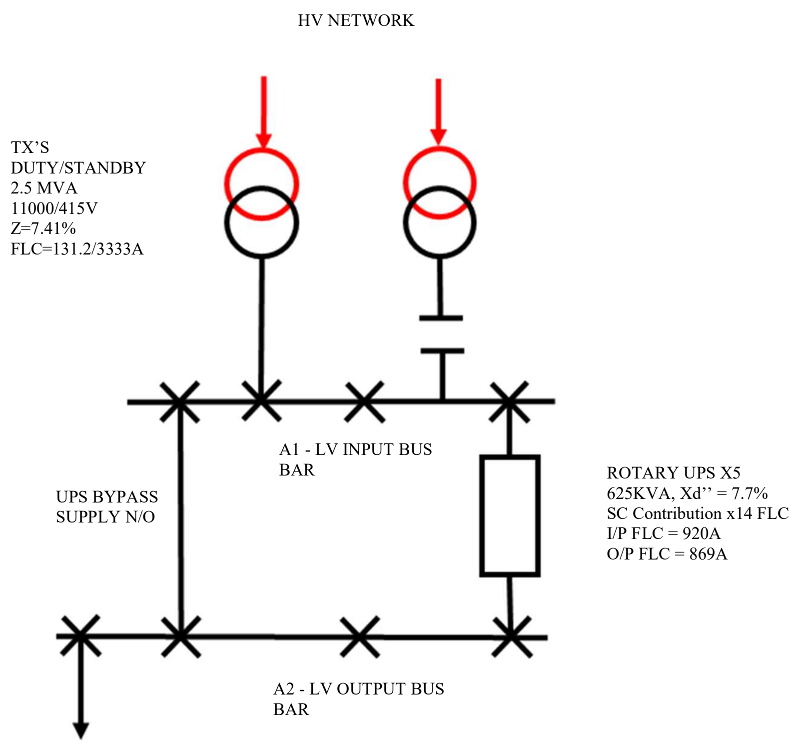


Figure 5.3.1.34 Rotary *UPS* Single Line Diagram, Relating to Protection Scenario 23.

Protection Scenario 23

Rotary *UPS* Assessment for Normal & Failure Modes Including Input and Output Switchgear and Critical Loads.

Phase Overcurrent Protections and Equipment Ratings:

i. All load circuit cable faults for the *UPS* inputs are cleared by local protection with no upstream discrimination issues.
ii. The *UPS* input/output protection relays do not discriminate although there is no benefit or requirement to since operation of either protection will disconnect machine from the network.
iii. For L-L-L faults on the bypass line - Air Circuit Breaker (*ACB*) protections do not discriminate with the upstream transformer feeder, although there is no requirement to.

Ground Overcurrent Protections and Equipment Ratings:

i. No L-G protection settings are present on the *UPS* input ACB's thus a L-G fault on a *UPS* input is likely to operate the main transformer incomer losing supply to all *UPS* units. This would remove supply from critical loads and should be addressed.

ii. L-G faults of *PDU* outgoing supplies from A2 discriminate with *UPS* outputs with adequate grading margins.

iii. Whilst in bypass mode there is insufficient L-G grading between outgoing *PDU* fuses and main transformer incoming protection, hence an L-G on an outgoing circuit may trip the main incomer losing all connected loads. This would remove supply from critical loads and should be addressed.

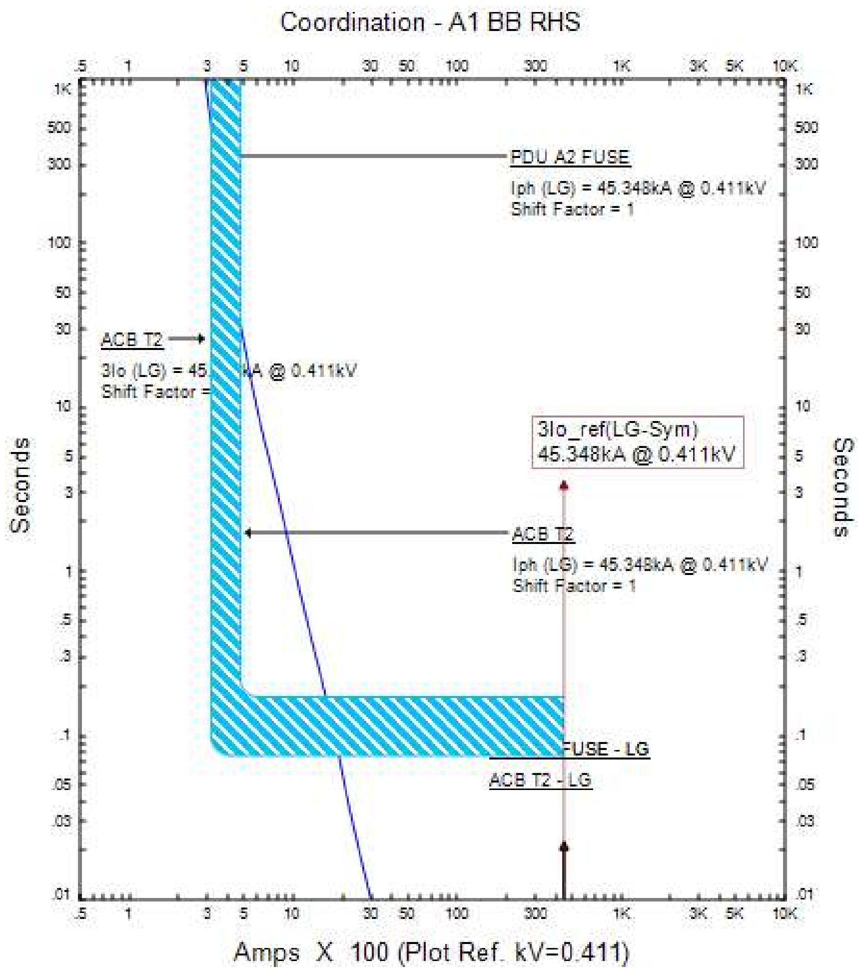


Figure 5.3.1.35 L-G protection *TCC* for Switchgear DBA2 – *UPS* Incomer and Loads during Bypass Mode of Operation

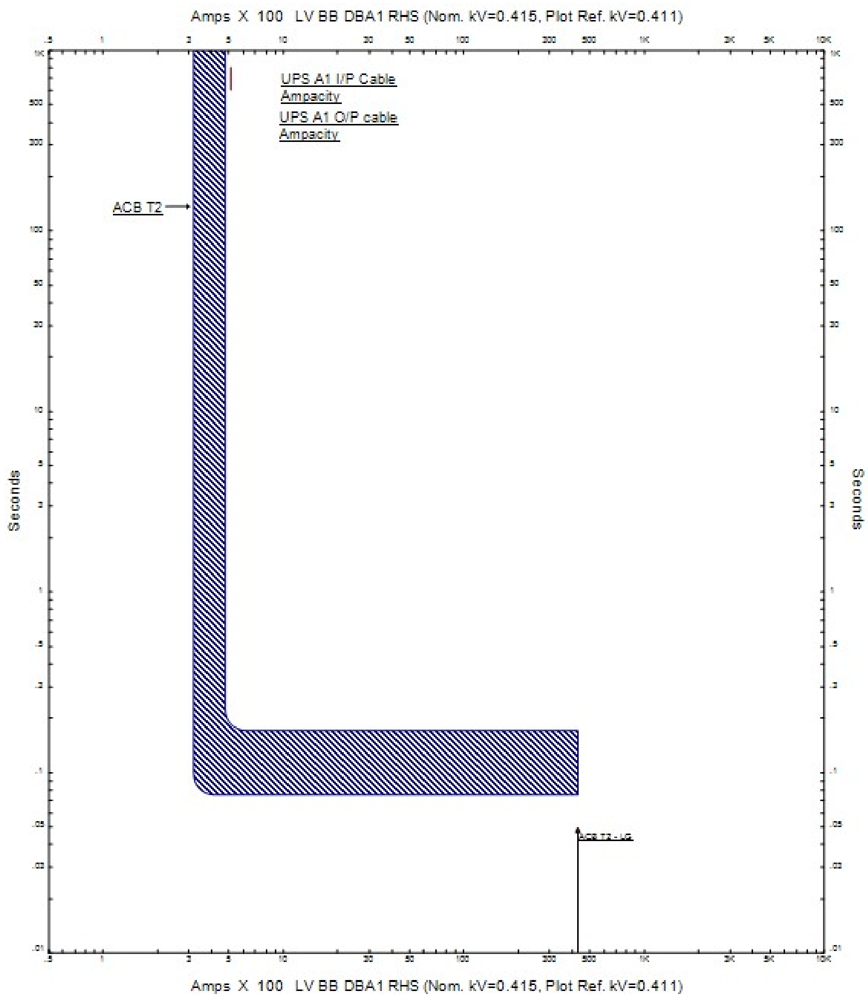


Figure 5.3.1.36 L-G Protection *TCC* plot for Switchgear DBA1 and *UPS* Input ACB's

5.3.2 Non Time Current Curve (*NTCC*) Protection Evaluation

Tables 5.3.2.1 & 5.3.2.2 contain an analysis of the generator Non Time Current Curve (*NTCC*) protection settings. A comments column has been provided against each protection type highlighting any settings out with the manufactures or industry standard guidelines and recommendations.

Protection Scenario 24 - Generator *NTCC* protections.

Generator Data:

Main Ratings		**Impedance** Xd > Xd' > Xd'' and Td' > Td''				**IEC 60909 fault current values (Ik'')**	
Apparent Power (MVA):	2.2 MVA	Xd	136%			L-L-L	1.194 KA
Power factor (PF):	0.8	Xd'	20%	Td'	5.25s	L-L	780 A
Active Power (MW):	1.8 MW	Xd''	10.5%	Td''	0.03s	L-L-G	820 A
Reactive Power (MVAr):	1.16 MVAr		**Grounding**			L-G	160 A
FLA:	118.1 A	Resistor:	42.33 Ω	V_{L-G}	6.351 KV	**CT ratio**	
RPM:	1000	Amp Rated:	150 A	V_{L-L}	11 KV	150/1 - 5P10 - 10VA	

Table 5.3.2.1 Generators Protection Evaluations for Non Time Current Curves (*NTCC*)

Generator Ref No.	**Type of Fault & Required Protection**	**Industry Recommended Relay Settings**	**BS ISO 8528 Operating limits for Class 2 Governors**	**Actual Relay Settings**	**Deviations and Actions Required to Improve Settings**
1,2 & 3	**Phase Overcurrent 50/51** Protection for external phase to phase short circuits	1.2 x In 1.2 x 118.1 = 141.6A. Setting must be no > 2.5 x In or restrained Voltage setting will be required	N/A	135A IEC SI	Increase to 145A to provide full 1.2 x In
4 & 5				280A non-IEC EI	O/C value is approx. 2 x FLC of generator rating, set as 1.2 x In
1, 2 & 3	**L-G 50N/51N** Protection for external line to ground short circuits	Io sum to be greater than 12% of CT rating. Inst setting equal to 0.2 x NER value. IDMT setting of 0.1 x resistor value, curve to be graded against downstream. CT primary is 150 A, so Io @ 12% = 18A. Inst @ 20% = 30A and IDMT @ 10% = 15A	N/A	7.2A DT (Td = 1s)	No IDMT setting present. DT setting of 7.2A is below recommended stability for IO sum i.e., 12% of CT rating (50x0.12 = 18A).
4 & 5				67.5A non-IEC VI	IDMT values not in-line with recommended 10% of NER (150 x 0.1 = 15A) No DT setting of 20% NER value (150x0.2=30A). Curve type is non-IEC therefore pick up of EF would be 1.2x67.5A = 81A
1,2,3,4 & 5	**Machine Differential 87M** Internal L-L short circuit protection of stator	Iset = 0.05 to 0.15 x In Td = 0s	N/A	Is = 8A	Ict = 150/1 8A is 6.77% of FLC. max through fault is 780A (5.2x CT rating) Therefore: 100%- (6.77/5.2) = 98.69% of stator winding protected – good.
1,2,3,4 & 5	**Negative Sequence current 46** Protection against phase imbalance	Iset = 0.15 x In Td = 2-3s delay on activation	N/A	None Present	Set to: In = 118.1 therefore 0.15xIn = 17.72A Td =2.5s

Generator Ref No.	Type of Fault & Required Protection	Industry Recommended Relay Settings	BS ISO 8528 Operating limits for Class 2 Governors	Actual Relay Settings	Deviations and Actions Required to Improve Settings
1,2,3,4 & 5	**Machine Differential 87M** Protection for internal phase to frame short circuits	Iset = 0.2 x In Td = 0	N/A	Is = 8A	Ict = 150/1 8A is 6.77% of FLC. Max through fault is 160A (1.06 x CT rating) Therefore 100%- (6.77/1.06) = 93.61% of stator winding protected – good.
1,2,3,4 & 5	**Reverse Reactive Power 32Q -** Loss of excitation	Qset = 0.3 x Sn Td = 3s	Reactive power sharing between 20 to 100% of Qn is 10% i.e., 0.1 x 116 KVAr	None Present	Sn = 1.16MVAr therefore 0.3 x Sn = 348KVAr
1,2,3,4 & 5	**Reverse Active Power 32P** Motor operation	Pset = 0.05 to 0.2 x Pn Td = 1s	Active power sharing: between 20 to 80% of Pn is 10%, between 80 to 100% of Pn is 5%. Taking 10% as worse case 1800x0.1 = 180KW	225KW (Td =1s)	5% to 20% of Pn = 90KW ~ 360KW
1,2 & 3	**Under or over frequency 81L & 81H**	f ± 2Hz Td = 3s	*ISO load steps Droop mode < 0.05x Fn = 2.5Hz Steady state <0.015xFn =0.75Hz RoCoF 0.01xFn = 0.5Hz *note recovery time Td = 5s	+5Hz (Td = 5s) -5Hz (Td = 1s)	Set to: ISO worse case ±2.5Hz Td = 5s
4 & 5				+3Hz (Td = 0.5s) -5Hz (Td = 0.5s)	
1,2 & 3	**Under voltage 27**	Uset = 0.75 to 0.85 x Un time delay depending on selectivity of the network	*transient during load steps. Sudden power increase in-line with ISO -20% of Vn. Td = 6s	0.85 x Un Td = 3s	Set to: 0.8 x Un Td = 6s
4&5				0.90 x Un Td = 3s	
1,2,3,4 & 5	**Over voltage 59**	Uset = 1.1 x Un Td = 1s	*transient during load steps. Sudden power decreases in-line with ISO +25% of Vn. Td = 6s	1.1xUn Td = 3s	Set to: 1.1 x Un Td= 6s
1,2,3,4 &5	**Reversal in active power 32P** Supplying active power when in parallel with utility & mains fail	Pset = 1 to 2% of: 1.732 x InCT x UnVt Where; InCt = CT rating (A) UnVt = VT rating (V) Td = 0s	n/a	Gen 32P = 225KW Main A1/B1 (*VCB's*) 32P = 1.25MW	Set to: 2% Pset of generators is 57KW (1.732x150x11000) 2% of main feeders is 152KW (1.732x400x11000) Td = 0s

Protection Scenario 25 - G59 *NTCC* protection.

Table 5.3.2.2 analyses the electrical networks G59 settings, against the guidelines for both short- or long-term paralleling conditions. The electrical network within the study is currently operating on a short-term agreement with the local *DNO*.

Table 5.3.2.2 G59 Protection Assessment

Protection Type	Long Term Stage 1 (A)	Long Term Stage 2 (B)	Short Term	*VCB* A1 & *VCB* B1 Settings	Action Required to Improve Settings
U/V 27	-13 % Vn Td = 2.5s	-20 % oVn Td = 0.5s	-6 % Vn Td = 0.5s	-10% Vn Td = 5s	This data centre is a participant in a demand response scheme and should therefore comply with long term settings. A recommendation given to change & test in accordance with (A) & (B) noted in this table.
O/V 59	+10 % Vn Td = 1s	+13 % Vn Td = 0.5s	+ 6 % Vn Td = 0.5s	+10% Vn Td = 0.5s	
O/F 81H	51.5Hz Td =90s	52Hz Td = 0.5s	50.5Hz Td = 0.5s	50.5Hz Td = 0.5s	
U/F 81L	47.5Hz Td = 20s	47Hz Td = 0.5s	49.5Hz Td = 0.5s	47Hz Td = 0.5s	
LOM Vector	± 6 degrees		N/A	N/A	
LOM RoCoF	0.125 Hz/s		N/A	0.8Hz/s	

Where:

Short term settings are applicable for generator systems which only parallel with grids for <5 minutes, and or run more than once per week. *VCB* A1 & *VCB* B1 are the data centres main incoming circuit breakers utilised for parallel operations.

Protection Scenario 26 - SOLKAR Line Differential *NTCC* Protection.

Table 5.3.2.3 is a review of the line differential protection of the two interconnectors within the high voltage electrical network. Protection of the interconnectors is paramount to prevent a complete loss of the network during a ring circuit fault.

Table 5.3.2.3 SOLKAR Unit Protection Assessment

Fault Type	Primary Setting (A)	DNO 1-Fault level (A)	DNO 2-Fault level (A)	Differential between SOLKAR send/receive (A)	Differential expressed as multiple of applied SOLKAR setting	SOLKAR operating time (ms)	Action required to improve settings
L1-G	100	535	557	1092	10.92	<45	L-G setting on DNO 1 or DNO 2 operates within 70ms for a fault ≥ 535A. Leaving just 25ms grading margin, primary setting to be increased.
L2-G	128				8.53		
L3-G	168				6.50		
L1-L2	500	2630	2930	5560	11.12		
L2-L3	500				11.12		
L3-L1	248				22.42		

Protection Scenario 27 – Restricted Earth Fault (*REF*) Protection.

The below is an example of a restricted L-G calculation for a data centre distribution transformer (Transformer 1 feeding switchgear DBA1), calculations were undertaken for all transformer within the electrical network and no issues were identified in term of the actual setting values or required circuit resistors.

Transformer 1 *REF* Calculations:

System Voltage	(V)	415	V
System Frequency	(Hz)	50	Hz
Transformer/Generator Rating	(KVA)	**2,500**	KVA
Transformer Impedance	(Z)	**7.4**	%
CT Primary Ratio	(Cpr)	**3,500**	A
CT Secondary Ratio	(Csr)	**5**	A
CT Vk Setting	(Vk)	**70**	V
CT Rct Setting	(RCT)	**0.4**	Ω
Number of CT's	(n)	4	
Size of CT Lead cabling		**2.5**	mm^2
Cable Resistance per km		7.98	Ω/km
Length of CT Leads		**4**	m
CT Lead Resistance	(Rl)	0.0319	Ω
Instrument Burden	(Rb)	1	VA
Instrument Insulation Value		3,000	V
√3		1.732	
Relay Pin Setting.		**0.500**	
REF Protection Setting		10	%

Transformer Full Load Current (*FLC*)

FLC = (2500 x 1000) / (√3 x 415) FLC = 3478.01 A

Transformer Fault Current (*If*)

If = (100/Z) x FLC If = 47.00 KA

CT Secondary Current (*Ic*)

Ic = (IF/Cpr) x Csr Ic = 67.14 A

Maximum Voltage Across Relay (*Vs*)

Vs = Ic x (RCT + 2 x RL) Vs = 31.14 V

Vs = 67.14 x (0.4 + (2 x 0.06384))

Maximum Volt Settings - CT Knee Point Check

Recommended - CT Vk rating MCAG Protection Relay

$Vk \geq$	$(2 \times Vs)$	$2 \times Vs =$	62.28	V
		Max Volts OK ≤ 70V		

Effective Relay Setting

$Is =$	CT secondary output @ Protection ratio	$Is =$	0.50	A

Stabilising Resistor Value

$Rst =$	$(Vs / Is) - (Rb / Is^2)$	$Rst =$	58.28	Ω

Metrosil Calculation

$Vf =$	$Ic * (Vs / Is)$	$Vf =$	4181.78	V
$Vp =$	$2 * \sqrt{(2 \times Vk) \times (Vf - Vk)}$	$Vp =$	1517.43	V
$Vp =$	$2 * \sqrt{(2 \times 62.28) \times (4181.78 - 62.28)}$	**Metrosil Not Required**		

Where;
Vf represents the voltage level produced due to a secondary fault current within the associated circuit transformer.
Vp represents the voltage level, at a given fault current, which is required to check confirmation of the *REF* relay rating and outlines if an additional metrosil resistor is required (to prevent relay damage). i.e., due to high voltage being produced in the current transformer secondary during an associated network L-G fault.

5.4 Arc Flash

The below Table 5.4.1 displays the results from ETAP scenarios simulated for arc flash analysis. Arc flash values were evaluated at all busbar within both the HV & LV networks.

i. Two Distribution Network Operator (*DNO*) cable feeders supplying all connected critical loads (nominal arrangement).
ii. Island mode with standby diesel generators connected to critical loads, i.e., removed from grid.
iii. Standby generators connected in parallel with the two *DNO* cable feeders, for example as short term parallel G59, no break transfer of critical load.

It is important to note research identified incident energy levels above 1.2 cal/cm^2 can cause second degree burns if maintenance personnel encounter the incident [41]. Likewise, the NFA 70E standard does not provide Personal Protective Equipment (*PPE*) guidelines for incident energy levels exceeding 40 cal/cm^2 due to the associated arc flash blast hazards. Specific guidance within *NFA* 70E Table 130.7 (.c) (15) details *PPE* requirements up to and including 40 cal/cm^2, incident energy levels above this value should be reduced. Furthermore, it is important to note that *PPE* would be a last resort for maintenance operatives if all other preventive methods have been investigated and applied.

In terms of electrical protection devices, a range of topologies and settings can be applied to the network devices to assist in reducing arc fault clearing times, thus lowering the energy incident levels & associated boundary clearances. Chapter 6.2 of this report discusses potential solutions and provides practical examples of how electrical protection grading is intricately linked with arc flash.

Table 5.4.1 ARC Flash Personal Protective Equipment (*PPE*) Analysis

Where, levels G & F indicate total energy levels recorded at a given switchgear was above *NFPA* 70E guidelines, for which *PPE* cannot to purchased. Thus, limiting the safe maintenance and operation of critical data centre equipment.

	Scenario 1 - Network Supplied by two DNO feeders in parallel				Scenario 2 - Network Supplied by one DNO feeder				Scenario 3 -Network Supplied by site generators (x3)			
Switchgear Reference I. D	Total Energy (cal/cm^2)	Arc Flash Boundary (ft)	PPE Levels	Fault Clearing Time (cycles	Total Energy (cal/cm^2)	Arc Flash Boundary (ft)	PPE Levels	Fault Clearing Time (cycles)	Total Energy (cal/cm^2)	Arc Flash Boundary (ft)	PPE Levels	Fault Clearing Time (cycles)
A1 BB LHS	62	29	F	98	66	30	F	123	101	40	G	179
A1 BB RHS	62	29	F	98	84	30	F	123	95	39	F	169
A1 to A2 Bypass	62	29	F	98	66	30	F	123	95	39	F	169
A2 BB LHS	64	30	F	111	70	32	F	140	105	42	G	202
A2 BB RHS	64	30	F	111	70	32	F	140	105	42	G	202
B1 BB LHS	28	17	E	62	29	17	E	72	46	24	F	92
B1 BB RHS	39	21	E	73	38	21	E	80	46	24	F	92
C1 BB LHS	62	29	F	98	66	30	F	123	65	30	F	115
C1 BB RHS	62	29	F	98	66	30	F	123	65	30	F	115
D1 BB LHS	28	17	E	63	29	17	E	73	39	21	E	77
D1 BB RHS	39	21	E	74	38	21	E	81	28	17	E	68
DBA9	0	1	A	3	0	1	A	3	0	1	A	3
G1 BB LHS	1	2	A	1	1	2	A	1	1	2	A	1
G1 BB RHS	3	4	B	4	3	4	B	4	3	4	B	4
GEC Rear BB	N/A				N/A				2	4	A	14
GEC FBus LHS	3	7	B	19	1	4	A	19	2	4	A	14
GEC FBus RHS	3	7	B	19	1	4	A	19	2	4	A	14
H1 BB	93	38	F	141	118	45	G	209	118	45	G	209
PDU A2	0	1	A	1	0	1	A	1	0	1	A	1
PDU A21	0	0	A	1	0	0	A	1	0	0	A	1
RED INPUT BB	80	35	F	127	99	40	F	184	92	38	F	165
String 1A	10	26	D	63	1	4	A	19	2	6	B	19
String 1B	10	26	D	63	5	13	C	63	2	6	B	19
YELLOW INPUT BB	85	36	F	143	104	42	G	205	98	40	F	185

PPE levels	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**>G**
cal/cm^2	**2**	**4**	**8**	**25**	**40**	**100**	**120**	**n/a**

5.5 Load Point Reliability

The below tables display the effects associated with reliability of the electrical network, in terms of potential increased annual outage duration during operation of protective devices in relation to mis co-ordination of settings. Each of the tables include a column indicating the calculated average annual outage duration of a 'healthy network', with a further column providing results for protection operations with both effective time current grading and the increased outage times due to inadequate relay settings.

The summary of protection setting reliability is displayed within each table, as an increased outage time (hours per year) due to the given protection operations. Therefore, to increase reliability of the electrical network an improvement of protection settings is desirable.

Such reliability analysis is in direct relation to the protection device grading results of this report i.e., non-satisfactory grading curves were simulated in terms of reliability effects leading to below results. This provided a numerical quantity to such relay malfunctions and a metric to drive operational improvement, given current research indicates the average cost of data centre downtime is estimated at £200k per hour [15] and [23].

Table 5.5.1 Reliability Analysis for Protection Scenario 7&8

Busbar ID	**Annual Outage Duration (hrs/yr.)**		**Increased outage time due to poor Protection Coordination (hrs/yr.)**
	***VCB* A2/B2 trip (Mis-Coordination)**	***VCB* A1/A2 trip (With Effective Protection Operations)**	
A1 BB LHS	50	1.279	48.72
A1 BB RHS	50	0.902	49.1
A1 HV	50	1.663	48.34
B1 BB LHS	50	6.075	43.92
B1 BB RHS	50	4.848	45.15
B1 HV	50	0.362	49.64
C1 BB LHS	50	6.075	43.92
C1 BB RHS	50	4.848	45.15
D1 BB LHS	50	6.085	43.91
D1 BB RHS	50	4.858	45.14
G1 BB LHS	50	6.272	43.73
G1 BB RHS	50	7.005	42.99
GEC FBus LHS	50	2.029	47.97
GEC FBus RHS	50	1.052	48.95
LV BB DBA1 LHS	50	5.308	44.69
LV BB DBA1 RHS	50	3.329	46.67
LV BB DBB1 LHS	50	5.298	44.7
LV BB DBB1 RHS	50	4.471	45.53
LV BB DBC1 LHS	50	5.298	44.7
LV BB DBC1 RHS	50	4.471	45.53
LV BB DBD1 LHS	50	5.308	44.69
LV BB DBD1 RHS	50	4.481	45.52
LV BB DBG1 LHS	50	5.608	44.39
LV BB DBG1 RHS	50	4.311	45.69
T1 HV	50	0.752	49.25
T2 HV	50	5.308	44.69
T3 HV	50	3.329	46.67
T4 HV	50	5.298	44.7
T5 HV	50	4.471	45.53
T6 HV	50	5.298	44.7
T7 HV	50	4.471	45.53
T8 HV	50	5.308	44.69
T9 HV	50	4.481	45.52
T10 HV	50	4.311	45.69

Table 5.5.2 Reliability Analysis for Protection Scenario 10, 14 & 15

Busbar ID	Annual Outage Duration (hrs/yr.)		Increased outage time due to poor Protection Coordination (hrs/yr.)
	***VCB* A&B DT Trip (Mis Coordination)**	***VCB* A&C Trip (With Effective Protection Operations)**	
A1 BB RHS	50	0.902	49.1
B1 BB RHS	50	4.848	45.15
C1 BB RHS	50	4.848	45.15
D1 BB RHS	50	4.858	45.14
G1 BB RHS	50	6.028	43.97
GEC FBus RHS	50	1.052	48.95
LV BB DBA1 RHS	50	3.329	46.67
LV BB DBB1 RHS	50	4.471	45.53
LV BB DBC1 RHS	50	4.471	45.53
LV BB DBD1 RHS	50	4.481	45.52
LV BB DBG1 RHS	50	4.311	45.69
T2 HV	50	3.329	46.67
T4 HV	50	4.471	45.53
T6 HV	50	4.471	45.53
T8 HV	50	4.481	45.52
T10 HV	50	4.311	45.69

Table 5.5.1 Reliability Analysis for Protection Scenario 17

Busbar ID	Annual Outage Duration (hrs/yr.)		Increased outage time due to poor Protection Coordination (hrs/yr.)
	No trip (With Effective Protection Operations)	**Spurious EF trip of TX1 or TX2 at the Low Voltage setting (Mis Coordination)**	
A1 BB LHS	1.279	4.33	3.051

Table 5.5.4 Reliability Analysis for Protection Scenario 18

Busbar ID	Annual Outage Duration (hrs/yr.)		Increased outage time due to poor Protection Coordination (hrs/yr.)
	***VCB* A2 trip clears EC BB fault (With Effective Protection Operations)**	***VCB* A2 Plus G4 & G5 trip (Mis Coordination)**	
Rear Bus Ext	1.524	51.524	50
G4	6.402	56.402	50
G5	6.402	56.402	50

Table 5.5.5 Reliability Analysis for Protection Scenario 20

Busbar ID	**Annual Outage Duration (hrs/yr.)**		**Increased outage time due to poor Protection Coordination (hrs/yr.)**
	***VCB* D&C trip clear GEC BB Fault (With Effective Protection Operations)**	**Standby engines trip for GEC BB fault (Mis Coordination)**	
A1 BB RHS	0.902	2.902	2
A1 HV	0.362	2.362	2
A1 to A2 Bypass	1.506	3.506	2
A2 BB RHS	1.652	3.652	2
B1 BB RHS	4.848	6.848	2
B1 HV	0.362	2.362	2
C1 BB RHS	4.848	6.848	2
D1 BB RHS	4.858	6.858	2
G1 BB RHS	6.028	8.028	2
G1 HV	6.402	8.402	2
G2 HV	6.402	8.402	2
G3 HV	6.402	8.402	2
G4 HV	6.402	8.402	2
G5 HV	6.402	8.402	2
GEC FBus RHS	1.052	3.052	2
LV BB DBA1 RHS	3.329	5.329	2
LV BB DBB1 RHS	4.471	6.471	2
LV BB DBC1 RHS	4.471	6.471	2
LV BB DBD1 RHS	4.481	6.481	2
LV BB DBG1 RHS	4.311	6.311	2
LV BB DBH1 Supply2	4.176	6.176	2
LV BB RED Supply2	4.181	6.181	2
String 1B	0.752	2.752	2
T2 HV	3.329	5.329	2
T4 HV	4.471	6.471	2
T6 HV	4.471	6.471	2
T8 HV	4.481	6.481	2
T9 HV	4.399	6.399	2
T10 HV	4.311	6.311	2
T12 HV	4.171	6.171	2
T13 HV	4.006	6.006	2
T14 HV	4.176	6.176	2
T16 HV	4.181	6.181	2
YELLOW INPUT BB	5.418	7.418	2
G1	6.402	8.402	2
G2	6.402	8.402	2
G3	6.402	8.402	2

Busbar ID	Annual Outage Duration (hrs/yr.)		Increased outage time due to poor Protection Coordination (hrs/yr.)
	***VCB* D&C trip clear GEC BB Fault (With Effective Protection Operations)**	**Standby engines trip for GEC BB fault (Mis Coordination)**	
G4	6.402	8.402	2
G5	6.402	8.402	2

Table 5.5.6 Reliability Analysis for Protection Scenario 22

Busbar ID	Annual Outage Duration (hrs/yr.)		Increased outage time due to poor Protection Coordination (hrs/yr.)
	***VCB* A2 Trip (Mis Coordination)**	**DNO Feeder Trip (With Effective Protection Operations)**	
LV BB DBH1 Supply1	50	5.908	44.09
LV BB RED Supply1	50	5.913	44.09
LV BB YELLOW Supply1	50	5.903	44.1
T11 HV	50	5.903	44.1
T13 HV	50	5.908	44.09
T15 HV	50	5.913	44.09

Table 5.5.7 Reliability Analysis for Protection Scenario 23(a)

Busbar ID	Annual Outage Duration (hrs/yr.)		Increased outage time due to poor Protection Coordination (hrs/yr.)
	***UPS* Input ACB Trip (With Effective Protection Operations)**	**Main TX incomer ACB Trip (Mis Coordination)**	
A1 BB LHS	5.9859	50	44.01
A1 BB RHS	5.6089	50	44.39
A1 to A2 Bypass	6.2129	50	43.79
A2 BB LHS	8.6087	50	41.39
A2 BB RHS	7.1109	50	42.89
DBA9	8.7407	50	41.26
PDU A2	8.6957	50	41.3
PDU A21	8.7707	50	41.23

Table 5.5.8 Reliability Analysis for Protection Scenario 23(b)

Busbar ID	**Annual Outage Duration (hrs/yr.)**		**Increased outage time due to poor Protection Coordination (hrs/yr.)**
	Circuit fuse trip (With Effective Protection Operations)	**Main bypass ACB Trip (Mis Coordination)**	
A1 BB LHS	5.1589	50	44.84
A1 BB RHS	5.9859	50	44.01
A1 to A2 Bypass	5.5359	50	44.46
A2 BB LHS	7.0929	50	42.91
A2 BB RHS	8.0699	50	41.93
DBA9	7.2249	50	42.78
PDU A2	30	50	20
PDU A21	7.2549	50	42.75

Note the associated protection settings for these reliability scenarios are listed within the Appendix II.

5.6 Chapter Summary

The load flow section details which scenarios were simulated and what issues were encountered, particularly the LV busbar systems in terms of cabling supplies when compared with busbar systems. Effects of the transformers tap setting and associated busbar Voltage Security Index (Vsi). Also, investigation of standby generators for design load scenarios against the manufacturer vector capability curves, power flow and reactive power limits.

Short circuit current analysis results highlight load characteristics can lead to an increase of 14.28KA rms on the LV busbar. Also, the range of HV fault currents due to the electrical network supply options proved challenging for achieving effective protection settings. The 2N systems simulated also increased peak fault currents (Ip) above the rating of installed switchgear, along with rotary *UPS* modules which have a potential to increase busbar fault levels by over 50% of base values, when transient effects are considered.

This chapter also provides details of all twenty-six protection scenarios simulated, over two hundred results in total. Graphical Time Current Curves (*TCC*) with associated descriptions for each scenario, considering both L-G, L-L-G, L-L-L faults. Non Time Current Curve (*NTCC*) protections have also been considered in terms of standby generator protection, differential cable protection, G59 schemes and transformer restricted L-G relay. The coherent link between short circuits, protection grading, and arc flash provides a results tables for each simulated busbar, establishing; incident energy, arc flash boundary, fault clearing time and required *PPE* for safe operation and maintenance of equipment. Over 30% of the actual installed devices did not provide optimal protection co-ordination or arc flash mitigation. Lastly, these protection issues were simulation for results of load point reliability analysis. An expression of hours per year failure (hrs/yr.) or downtime for a given protective device grading scenario issue. Results tables in Chapter 5.6 detail an expected downtime for both a healthy and faulted network scenario, with numerous faults having potential for increasing outage times more than 40 hrs/yr. In-fact with optimal protection settings predicted outage times can be less than 5% of those with mis coordinated protection devices i.e., a 95% improvement can be achieved.

Chapter 6 – Implications & A New Generalised Approach

6.0 Introduction

This Chapter considers the implications associated with this research works, focusing on improving operational configurations of electrical protection systems and ultimately increasing data centre reliability. It is important to note the protection grading scenarios utilised within this Chapter are as those listed within Chapter 5.3. However, in this section each grading scenario has been updated with a new and improved settings configuration. Therefore, each protection relay in all model simulations were updated before re-evaluation and simulations were carried out, which in turn provided a new and improved set of Time Current Curves (*TCC*). These modifications, over 390 for this network, were achieved by utilising the outlined 'improvement parameters' stated in each of the simulations and shown in Appendix IV, each were crafted from a range of international standards and guidance for best practices in electrical power systems, along with an extensive investigation and analysis of this data centre's actual operational settings and available equipment manufacturers guidance.

Options have considered the implications associated with application of electrical protection in data centres specifically, providing key solutions for obtaining improved Time Current Curves (*TCC*), and ensuring effective operation of circuit devices, thus mitigating unnecessary outages of the infrastructure. Ultimately, increasing the potential Operational Availability (*Ao*) of the critical electrical equipment and detailing further considerations for arc flash assessment and its direct correlation to electrical protection settings, and the safety of data centre engineering maintenance staff. Where possible a before and after list of availability metrics have been provided against each protection scenario, with an example *TCC* curve evidencing that tangible benefits which can be achieved with this approach.

Importantly, these findings have allowed formulation of a new approach detailed in Chapter 6.3, which provides a summarised flowchart or generalised approach to improving a data centres operational reliability, this approach can be utilised or applied to any other data centre and was individually formed as part of this research programme, as a contribution of knowledge to this field and an improvement to the existing philosophy, more specifically the Uptime Institutes Tier Classification approach which considers Inherent Availability (*Ai*) only and not the operational factors.

6.1 Improving *AO* metrics with Protective Device Grading

Following on from the listed results in Chapter 5.3, the exact same operational scenarios have been utilised below, i.e., for investigation of how to obtain relay protection grading improvements.

Scenario 1

DBA1 Transformer 1 (T1) & Transformer 2 (T2) Protection Evaluation

i. T1 & T2 settings changed to *IEC EI* curve. Pick up reduced to 165A, thus provide a reasonable overload margin for the base current rating of 131.2A. The proposed new curves within transformer damage point of the transformer, and in-line with IEEE C57.109.

ii. These proposed overcurrent settings improved grading margins. LV to HV devices now segregated by 400*ms* under all short circuit faults, this will eliminate the original grading issues encountered, and will also lead to an effective inter-trip signalling for the operator and quick restoration under genuine system fault, improving operational availability by limiting Mean Time To Repair (*MTTR*).

iii. Below *L-G* fault plot, T1 & T2 ground fault protection displaying a setting of 22.5A, this is in-line with manufacturer's recommendation of 30% transformer *FLC* in comparison to the exiting 3A which is likely to cause spurious trips on transformer energisation.

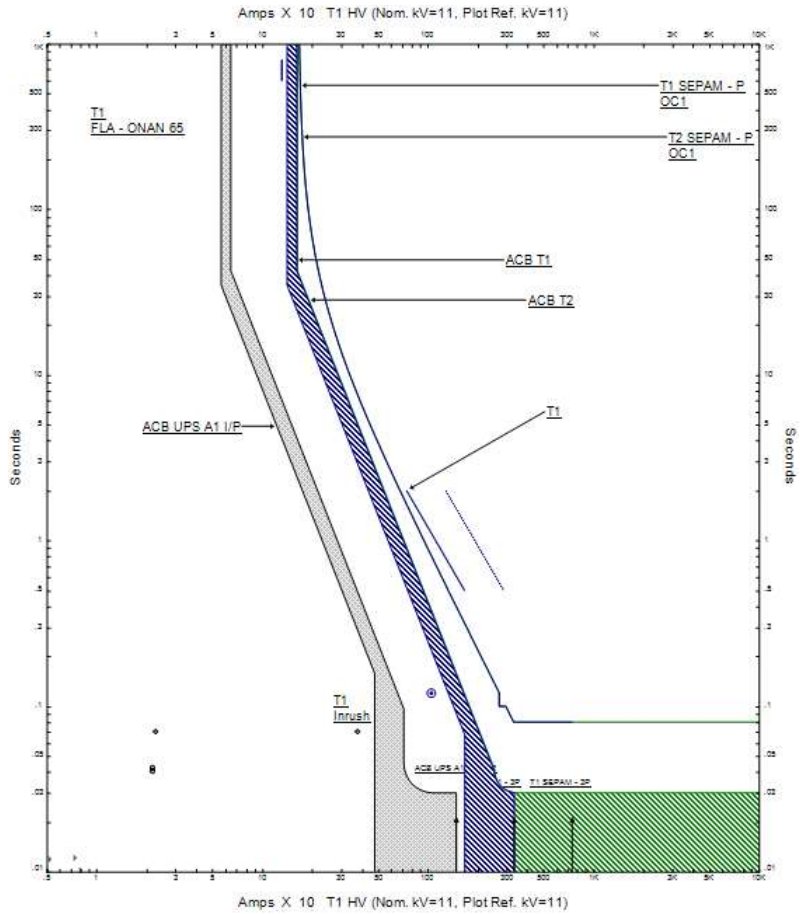


Figure 6.1.1 Overcurrent Protection *TCC* for Transformer 1 & 2, HV & LV Equipment Assessment

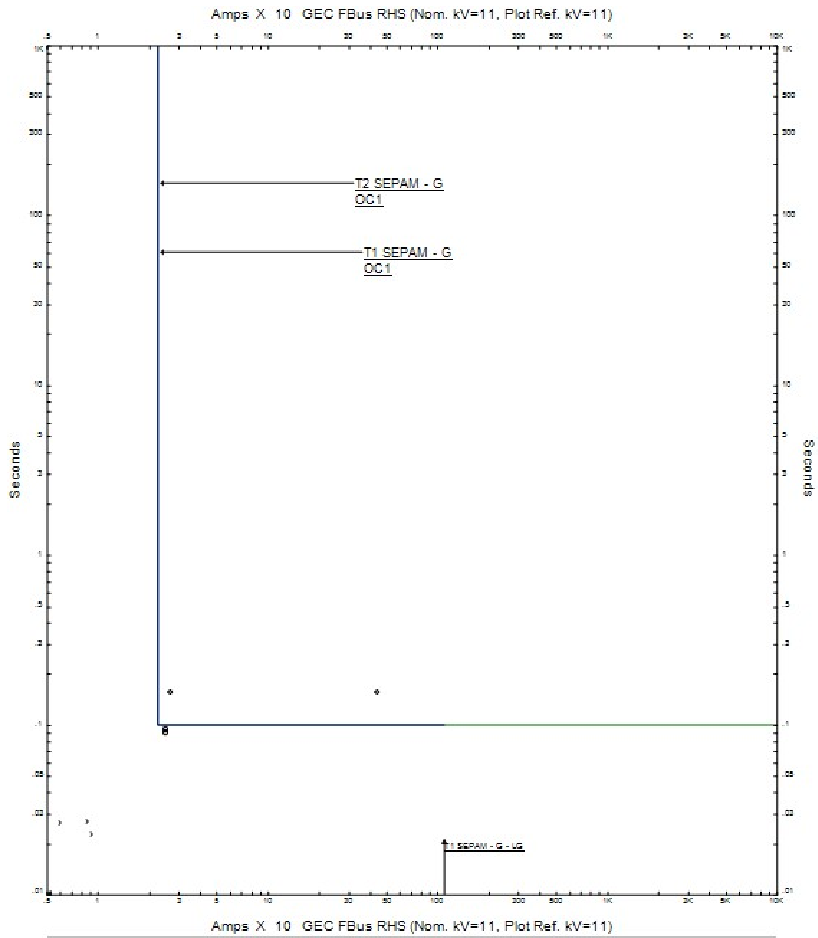


Figure 6.1.2 L-G Protection *TCC* for Transformer 1 & 2

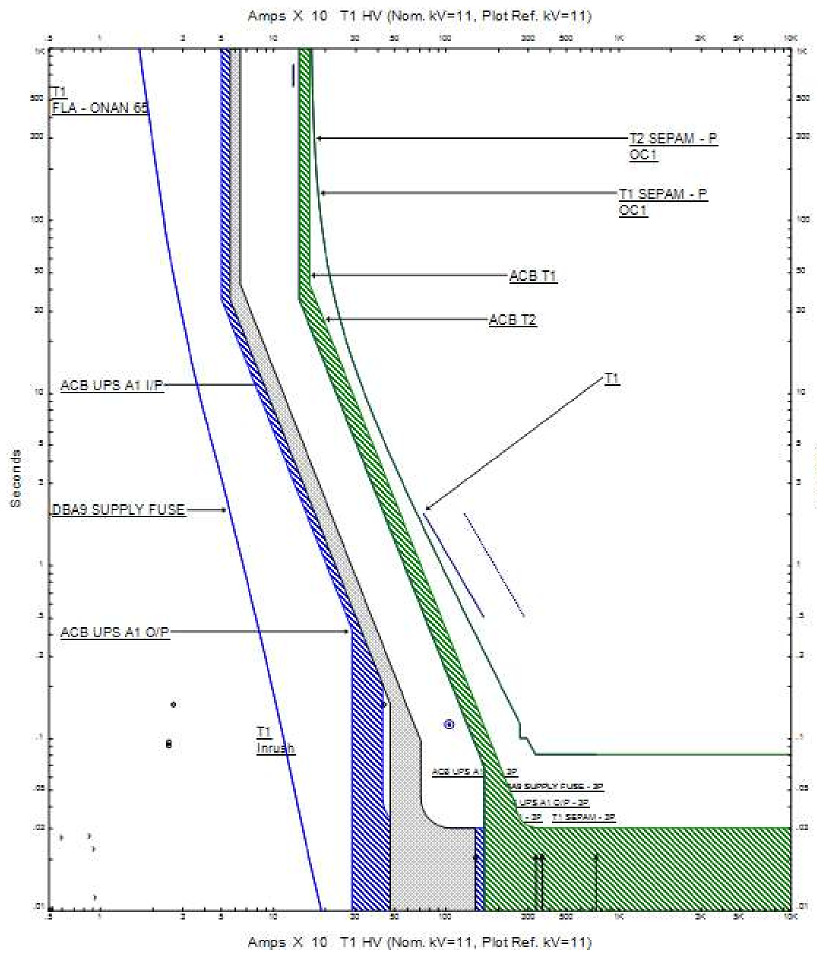


Figure 6.1.3 Overcurrent Protection *TCC* for Transformer 1 & 2, HV & LV Equipment Including Downstream Devices

Scenario 2

DBC1 Transformer 5 (T5) & Transformer (T6) Protection Evaluation

i. Proposed Transformer settings ensure HV & LV protection devices co-ordinate effectively. Noted in the *TCC* plot below devices have, as a minimum, 400*ms* time grading margin between the pick-up current of approximately 4000A through to the short circuit value 42KA. Alongside grading co-ordination, the improvement of settings ensures the inter-trip signalling operates as designed, allowing the network operator to quickly locate and rectify any network faults.

ii. T5 & T6 settings changed to IEC *EI* curve type. Pick up current setting also reduced to 165A, thus a reasonable overload margin allowed for the base current rating of 131.2A. Proposed new curves are within transformer damage point and in-line with IEEE C57.109.

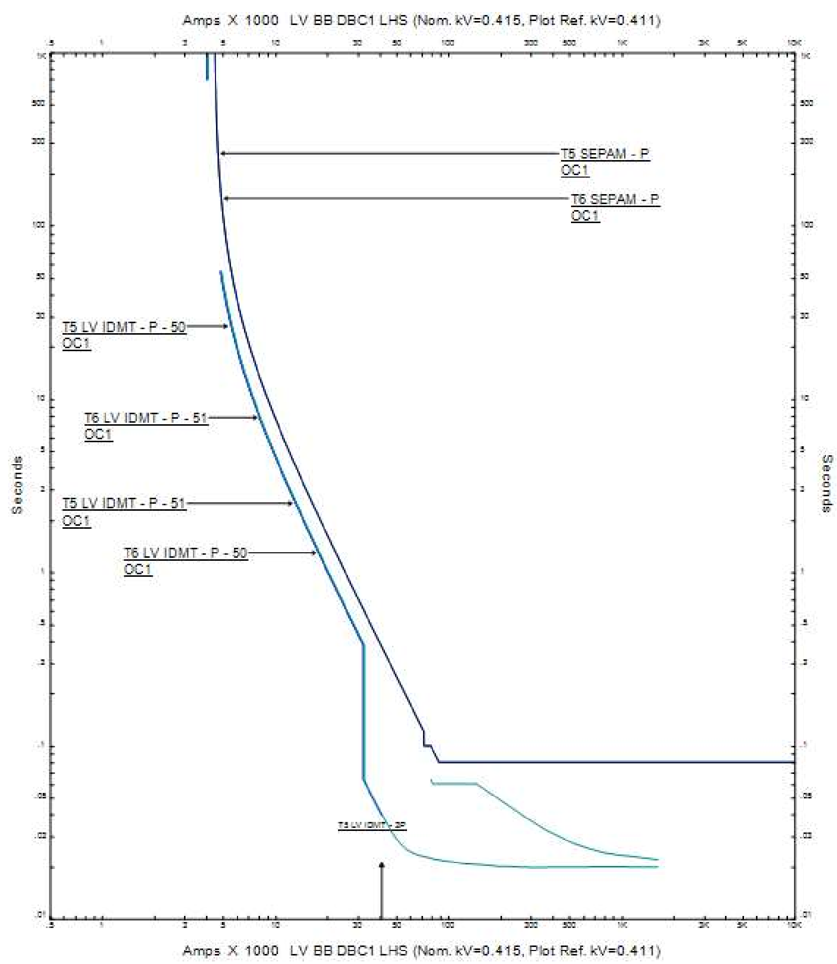


Figure 6.1.4 Overcurrent Protection *TCC* for Transformer 5 & 6, HV & LV Equipment Assessment

i. The below *TCC* ground fault is relative to both T5 & T6 ground fault protection, displaying a setting of 22.5A, this is in-line with manufacturer's recommendation of 30% transformer *FLC* in comparison to the exiting 3A which is more likely to cause spurious trips during transformer energisation.

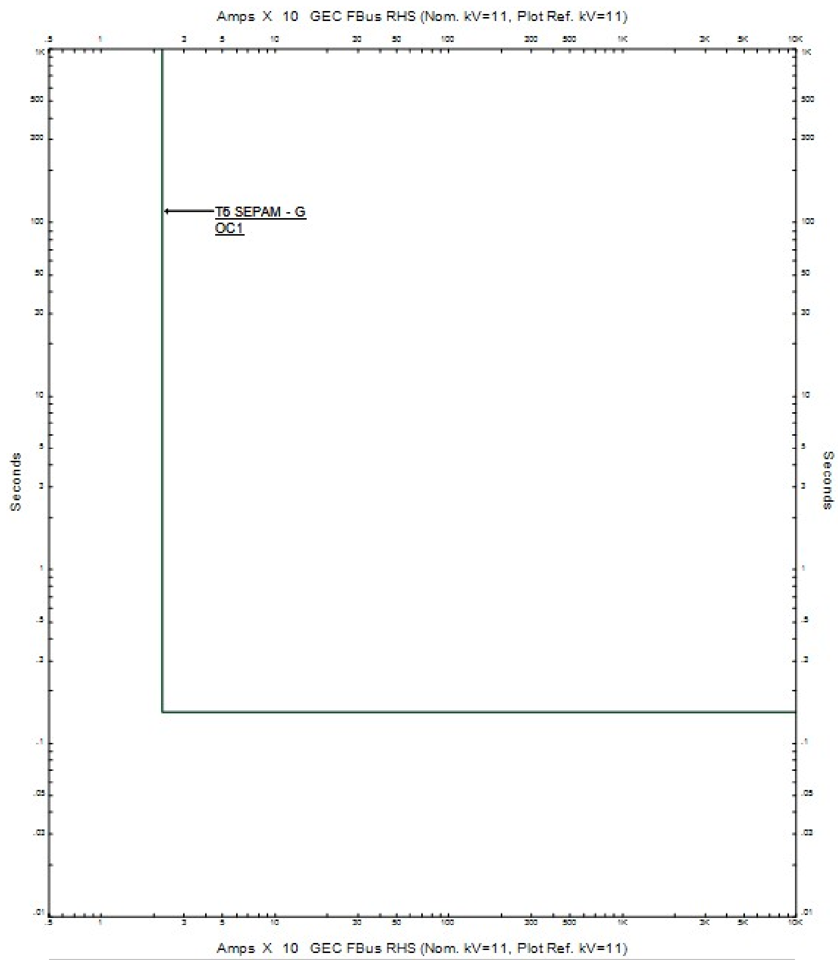


Figure 6.1.5 L-G protection *TCC* for Transformer 5 & 6, HV & LV Equipment Assessment

Scenario 3

DBB1 or D1 Transformers 7 (T7) & Transformer 8 (T8) Protection Evaluation

i. Proposed settings ensure transformer HV & LV protections co-ordination for the full range of present system fault current, with a minimum of 200ms margin. Ensuring inter-trip relays within the network operate effectively and assist operators during network faults for quick restoration. Note TCC plots below of both HV & LV devices.

ii. Pick up current values proposed for both transformer 7 & 8 to the HV & LV settings of 80A/1520A respectfully. These values ensure effective overload margins for the transformer, in comparison to the original settings which exceed 200% of transformer *FLC* ratings.

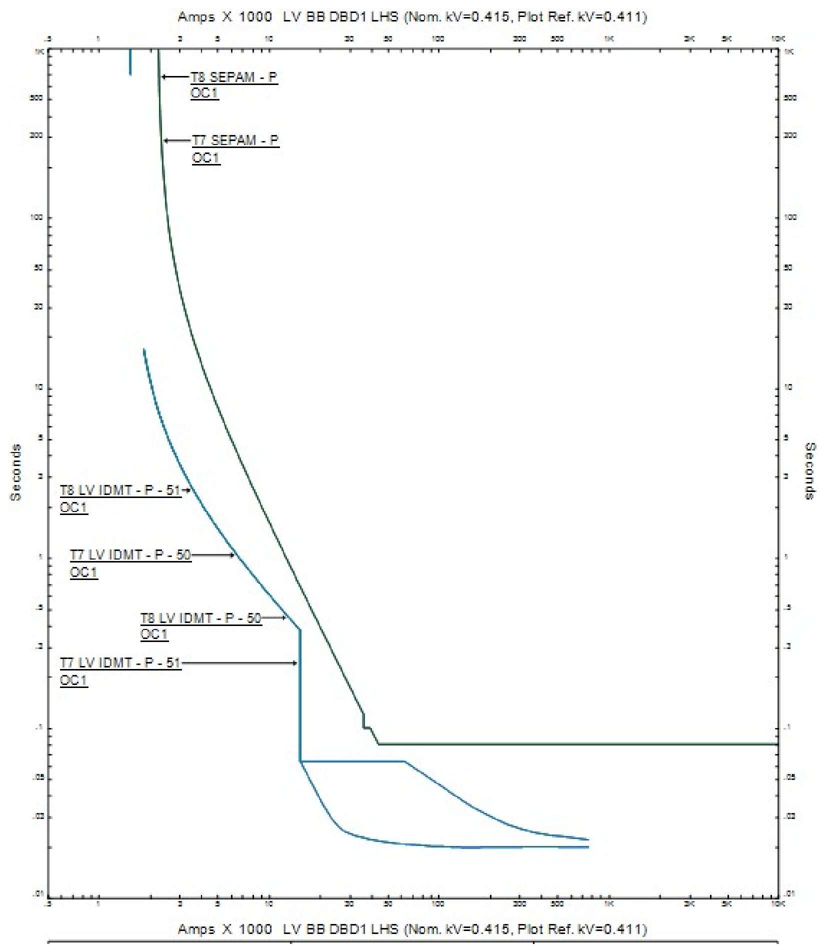


Figure 6.1.6 Overcurrent Protection *TCC* for Transformer 7 & 8, HV & LV Equipment Assessment

iii. Below *TCC* L-G fault plot displays both T7 & T8 ground fault protection set at 11.25A. This is approximately 20% of the transformers rating, as suggested by manufacturer's recommendation, removing possibility for spurious trips on transformer energisation.

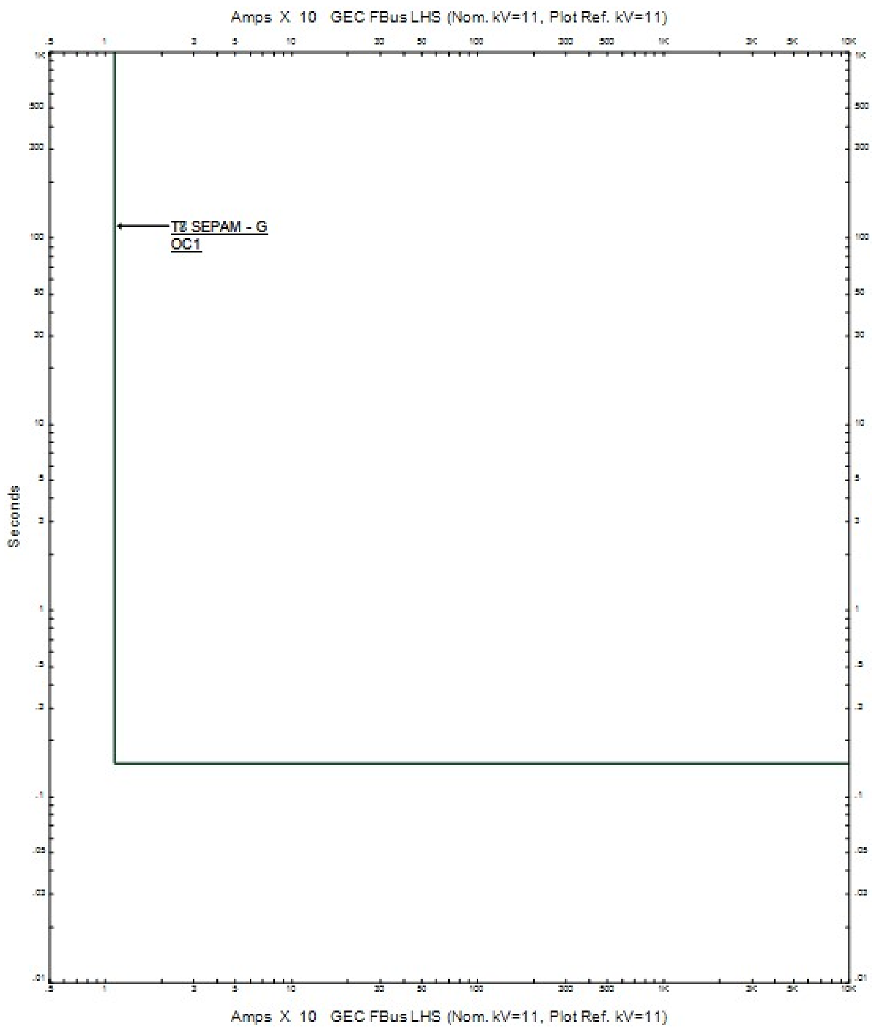


Figure 6.1.7 L-G Protection *TCC* for Transformer 7 & 8, HV & LV Equipment Assessment

Scenario 4

DBR1 or DBY1 Transformer Protection Evaluation

i. Transformer 11 & 12 full load current 131.2/3333A (HV & LV respectively). The proposed protection settings ensure the transformers HV to LV windings provides effective grading and operation of inter-trip relay, i.e., within a minimum of 200*ms* grading at all system fault current levels.

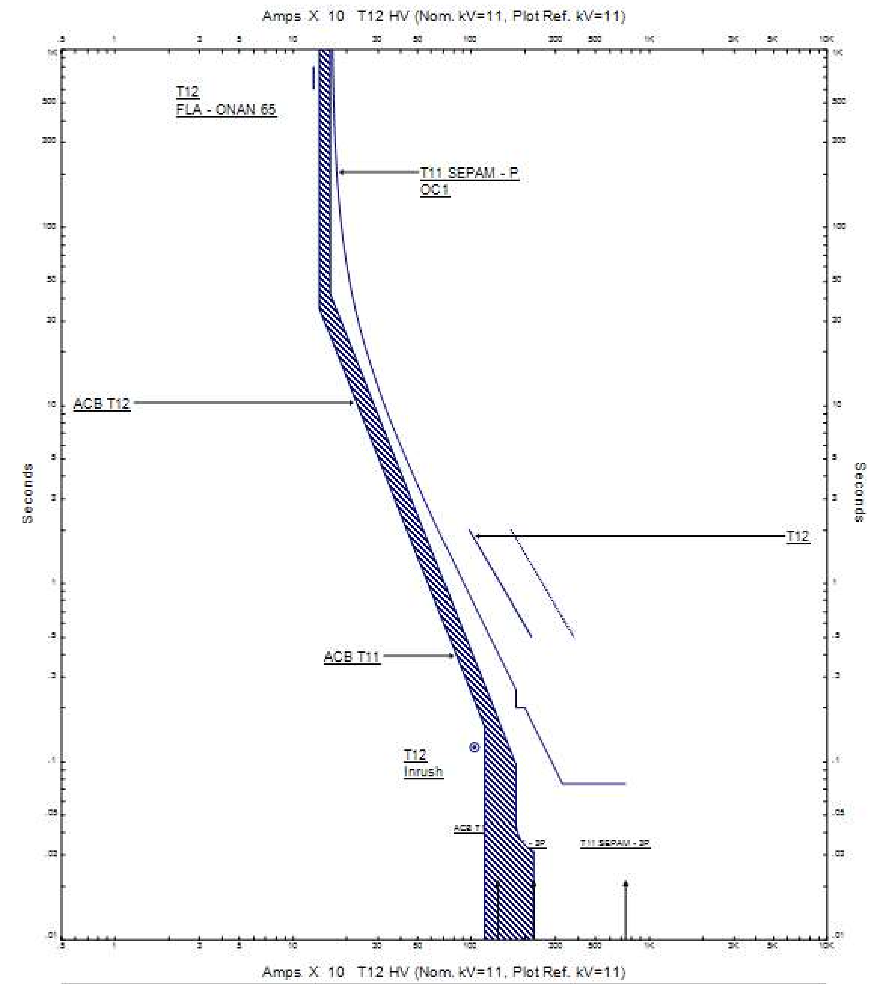


Figure 6.1.8 Overcurrent Protection *TCC* for Transformer 11&12, HV & LV Equipment Assessment

Scenario 5

DBH1 Transformer Protection Evaluation

i. Proposed overcurrent settings utilising manufacture guidance and experimentation with TCC curves improved grading margins. Both the LV & HV devices segregated by 400*ms* under short circuit currents, thus eliminates the original grading margin issues encountered. These settings will also lead to an effective inter-trip signalling for the operator and quick restoration under genuine system fault, improving overall Operational Availability (*Ao*) by limiting *MTTR*.

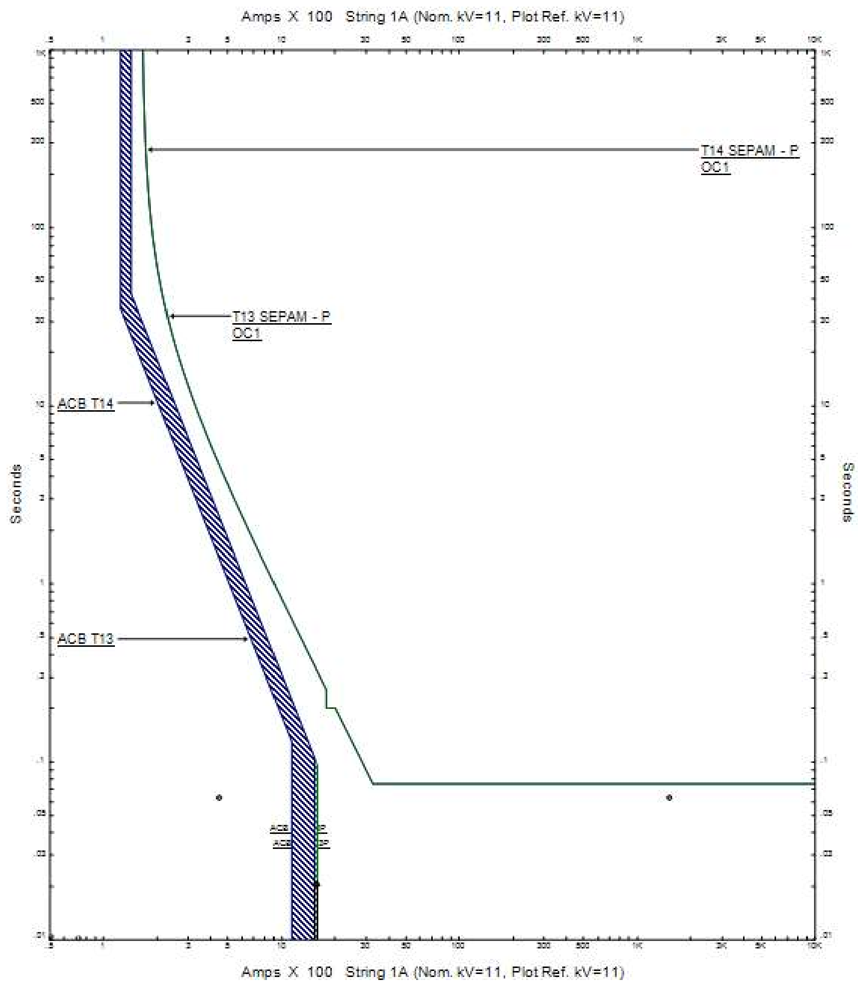


Figure 6.1.9 Overcurrent Protection *TCC* for Transformer 13&14, HV & LV Equipment Assessment

Scenario 6

DBG1 Transformer Protection Evaluation

DBG1 has a duty/standby power supply from transformer 9 & transformer 10, both are detailed separately below due to the differences in supply equipment, which differed from any other LV board within the data centres electrical network.

<u>Transformer 9 (T9)</u>

i. Proposed overcurrent settings for transformer 9 ensures full load current capacity is not exceeded, proposed 150A (pick up) allows adequate margin for overload and is in-line with manufacturer's recommendations.

ii. The recommendation to remove LV fuses since these do not grade with the LV IDMT incoming (upstream) relay, the relay can also be adequately set to protect the LV supply cable with a reduced overload capacity. Settings proposed as *TCC* below; curve *VI*, pick up 1225A, 0.5*s* delay. These proposed settings ensured the transformer damage point is adequately protected and improved the original settings.

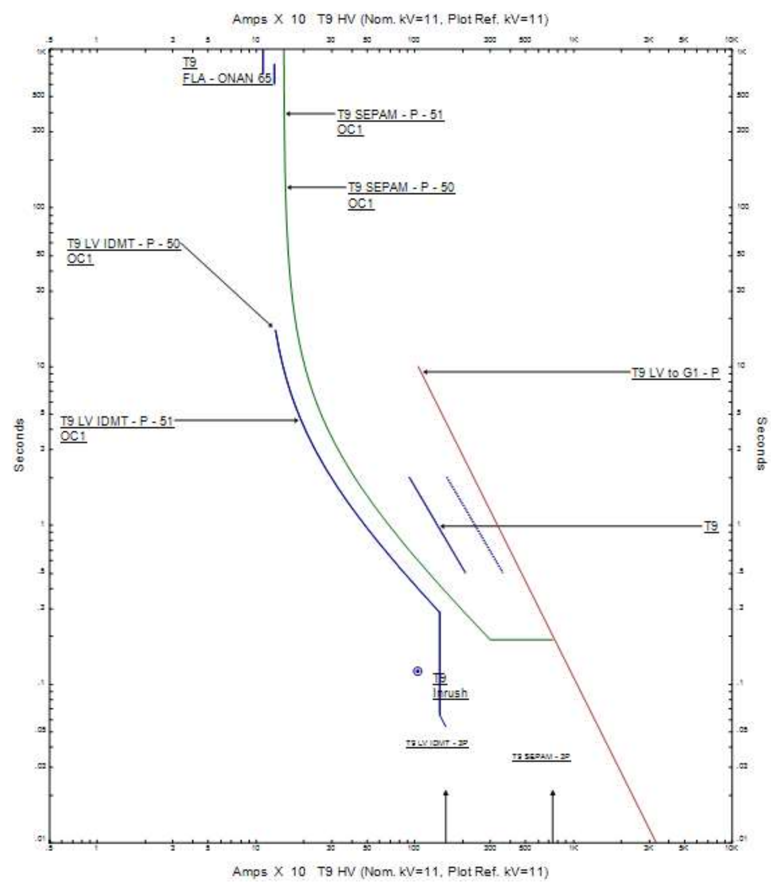


Figure 6.1.10 Overcurrent Protection *TCC* for Transformer 9&10, HV & LV Equipment Assessment

iii. Below *TCC* ground fault plot, both T9 & T10 ground fault protection displaying a setting of 37.5A, this is in-line with manufacturer's recommendation of 30% transformer *FLC* in comparison to the exiting 3A which is likely to cause spurious trips on transformer energisation.

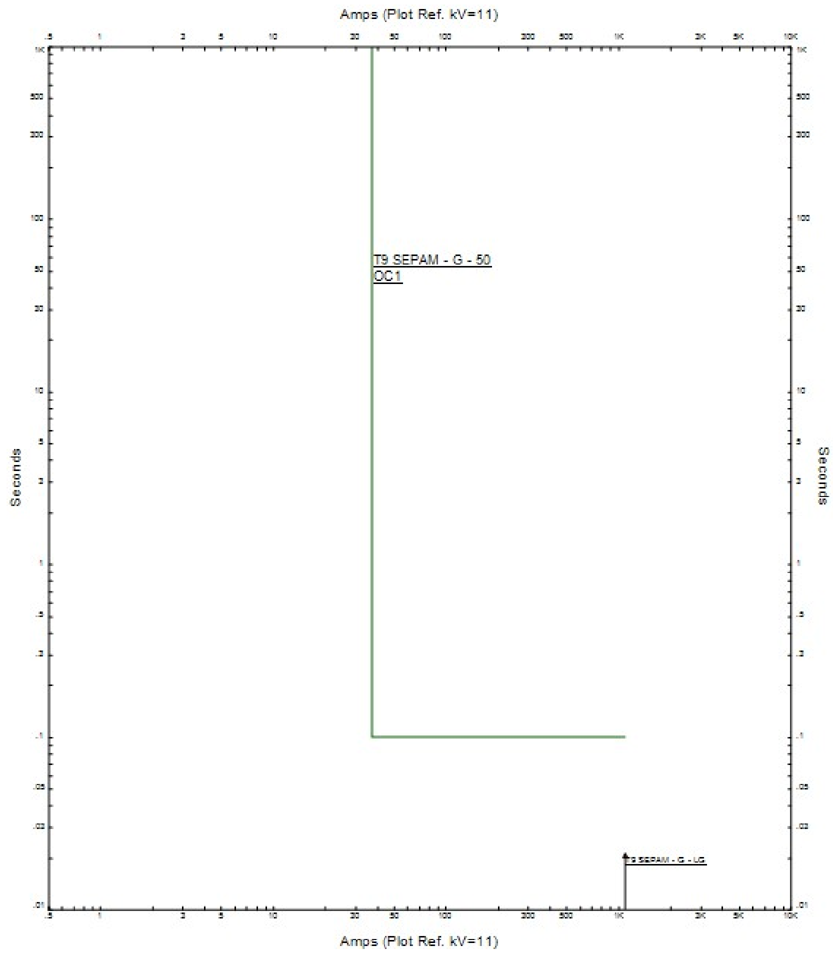


Figure 6.1.11 L-G Protection *TCC* for Transformer 9&10, HV & LV Equipment Assessment

Transformer 10 (T10)

iv. Proposed overcurrent settings for transformer 10 ensures full load current capacity is not exceeded, 150A (pick up) allows adequate margin for overload and is in-line manufacturer's recommendations. The LV incomer at DBG1 is also set at 4250A, i.e., in-line with the LV busbar rating.

v. A recommendation for an instantaneous setting on the LV incomer of 36.2KA since this value ensures grading with the upstream devices and clearance of the L-L-L fault level within approximately 50*ms*. Also, improving inter trip relay functions and restoration of supplies following network fault conditions.

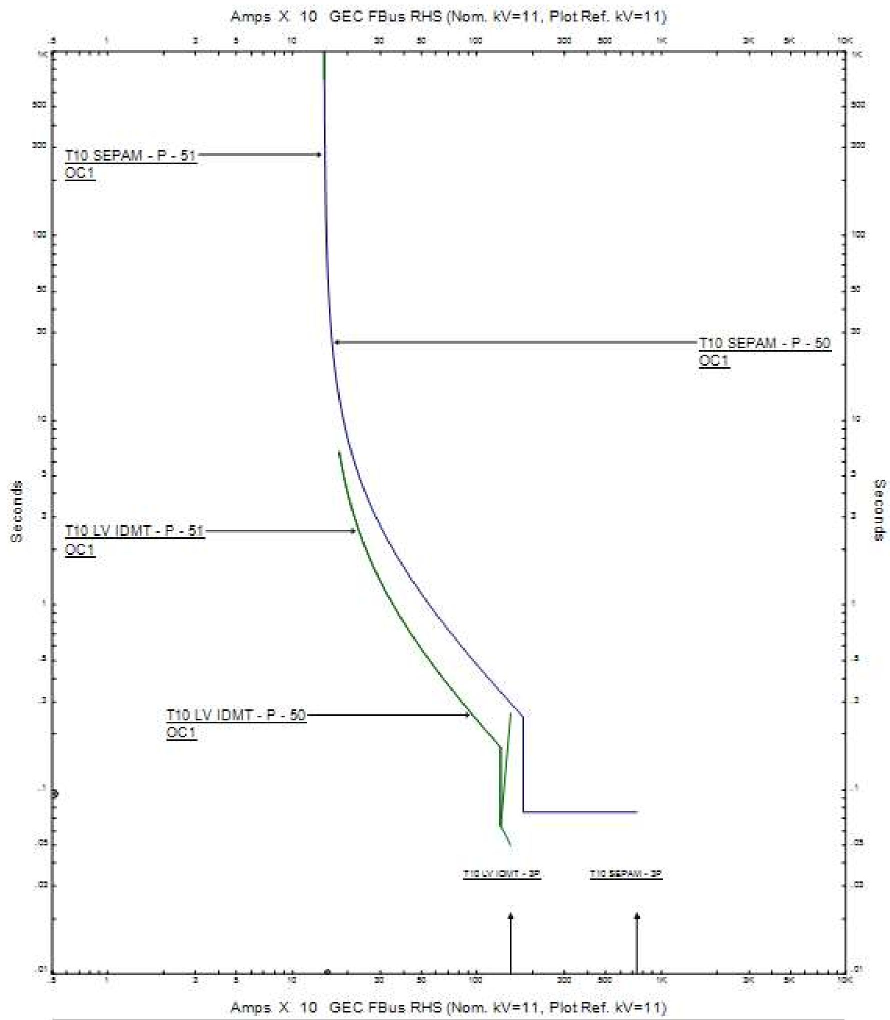


Figure 6.1.12 Overcurrent Protection *TCC* for Transformer 10, HV & LV Equipment Assessment

Scenario 7

Main Site Feeder *VCB* (X) and *VCB* A1 & A2 Protection Evaluations

i. The below *TCC* plot highlights the proposed settings display adequate grading co-ordination for phase overcurrent's between main ring feeders *VCB* 'X', *VCB* A1 & A2. To achieve grading co-ordination the following changes are recommended. Feeder 'X' time delay increased *td* = 0.3*s*. Both A1 & A2 curves to be *IEC* standard inverse, time delays to *td* = 0.6*s* & *td'* = 0.25*s,* respectively. Also note the pick-up current of *VCB* A2 has been decreased to 520A, the existing 600A setting is unnecessarily high for the connected network loads and makes grading margins impossible to achieve. These changes led to an improvement of load point reliability 48.72 hrs/yr., prior to protection setting updates the reliability metric was 50 hrs/yr., reducing to 1.279 hrs/yr. with these listed improvements.

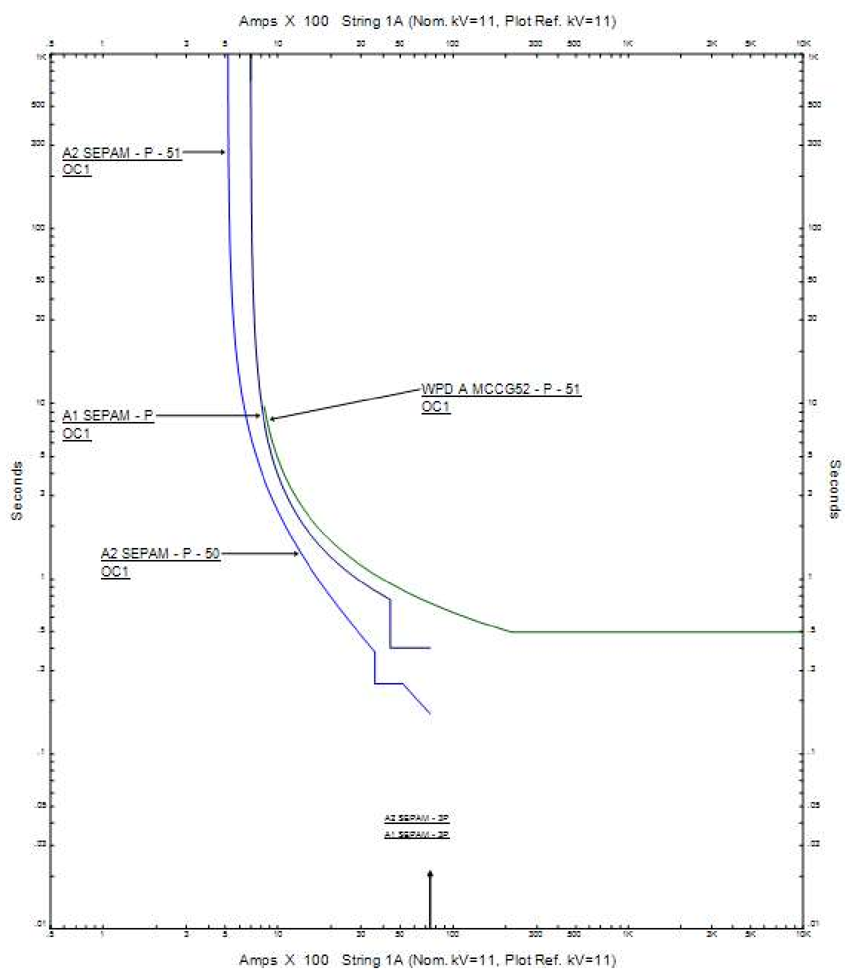


Figure 6.1.13 Overcurrent Protection *TCC* for Data Centre Main Feeders (*VCB's* X, A1, A2)

ii. The below *TCC* plot shows protection co-ordination for L-G faults at DNO X and INCOMER *VCB* A1 achieving grading margins more than 500*ms*. The existing *VCB* A1 SEPAM settings required 3.0*s* to clear L-G faults, operation is now within approximately 0.3*s*. *VCB* C L-G setting reduced in-line with system L-G fault current levels present, ensuring adequate grading with both upstream *VCB* A2 & B2 during L-G faults. These changes led to an improvement of load point reliability 48.72 hrs/yr., prior to protection setting updates the reliability metric was 50 hrs/yr., reducing to 1.279 hrs/yr. with these listed improvements.

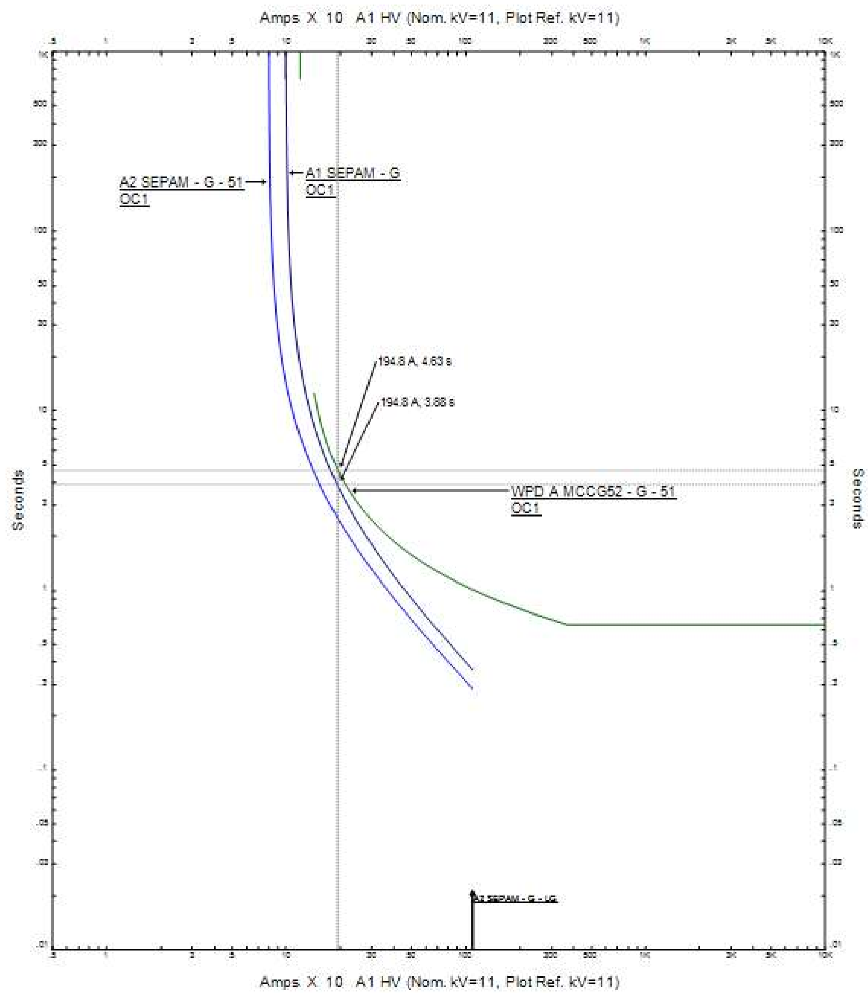


Figure 6.1.14 L-G Protection *TCC* for Data Centre Main Feeders (*VCB's* X, A1, A2)

Scenario 8

Single Feeder busbar Faults on String Extensions *VCB* A/B

i. Proposed the removal of definite time settings for *VCB*'A' & 'B', also new settings for *VCB* 'C' which ensures a clearance with *VCB* 'A2' or 'B2', at least a 300*ms* grading margin. Both recommendations ensure effective operation under fault conditions, disconnecting the minimum amount of equipment within the network, *TCC* plot below displays new curves. These changes led to an improvement of load point reliability 48.72 hrs/yr., prior to protection setting updates the reliability metric was 50 hrs/yr., reducing to 1.279 hrs/yr. with these listed improvements.

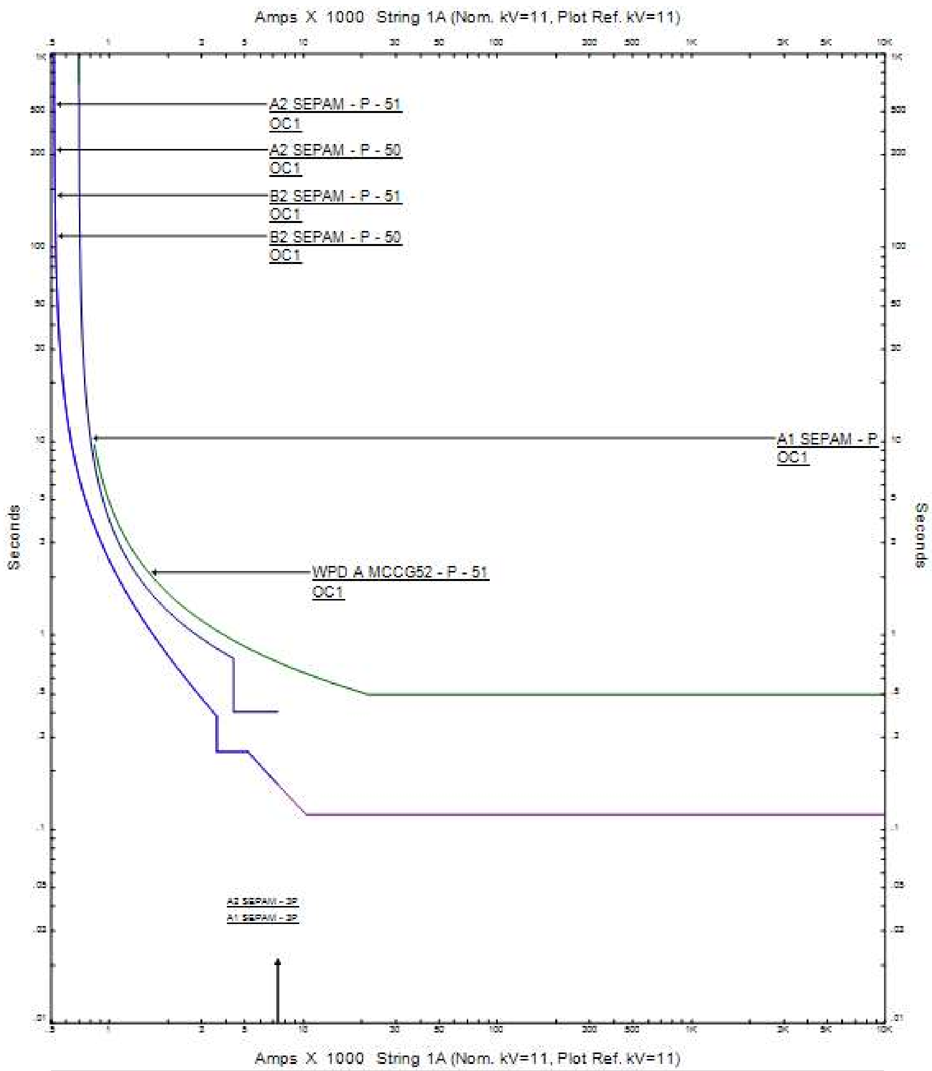


Figure 6.1.15 Overcurrent Protection *TCC* for busbar Faults on the HV Extension Switchgear

ii. Note L-G settings in the below *TCC* plot applied to *VCB* ‘C’ ensured any ground faults on String 1A or 1B does not operate *VCB’s* A2/B2, therefore the 10 x connected distribution transformers are not unnecessarily disconnected during an energy centre L-G fault. *VCB* ‘C’ settings proposed includes curve IEC *VI*, pick up = 66A, td = 0.3*s*. These changes led to an improvement of load point reliability 48.72 hrs/yr., prior to protection setting updates the reliability metric was 50 hrs/yr., reducing to 1.279 hrs/yr. with these listed improvements.

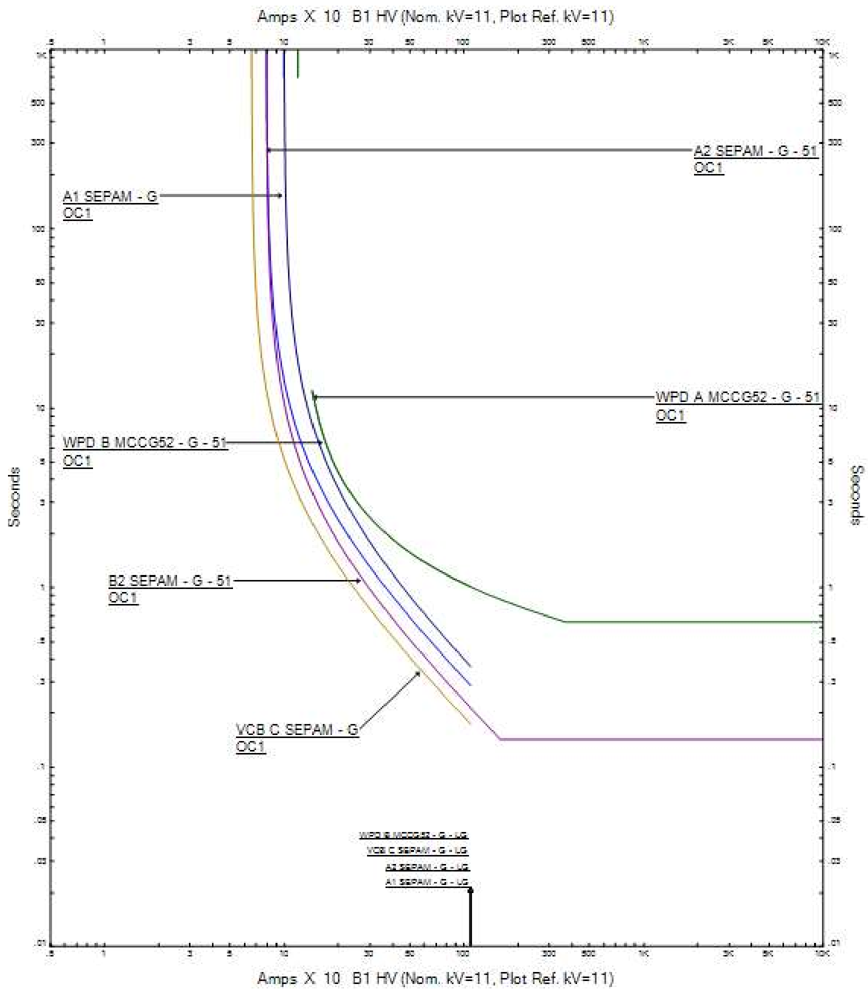


Figure 6.1.16 L-G Protection *TCC* for busbar Faults on the HV Extension Switchgear

Scenario 9

Site supplied by a single *DNO* feeder, Transformer supply side fault on HV String Extension Incoming Switchgears.

i. No issues for L-L-L, L-L, L-G or L-L-G faults. Transformer SEPAM relays operate before upstream device with good discrimination margins.

Scenario 10

Site supplied by a single *DNO* feeder, investigation for faults on the Main HV *GEC* switchgear.

i. Below *TCC* plot displays proposed protection settings on *VCB* C ensuring discrimination with upstream devices for both L-L-L and L-G fault scenarios. Due to the number of series protection devices located in the system only 200*ms* grading margin can be achieved. These changes led to an improvement of load point reliability 49.1hrs/yr., prior to protection setting updates the reliability metric was *50* hrs/yr., reducing to 0.902 hrs/yr. with these listed improvements.

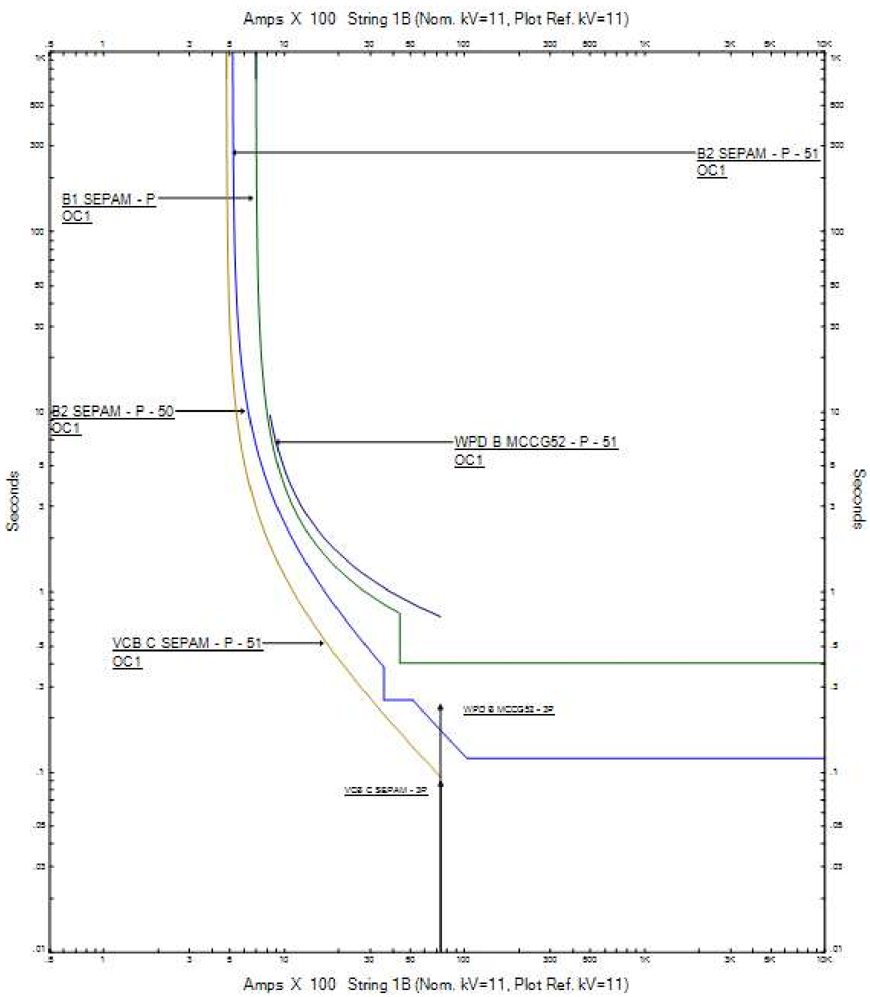


Figure 6.1.17 Overcurrent Protection *TCC* for a busbar Fault on the *GEC* Switchgear, whilst supplied by a Single *DNO* Feeder

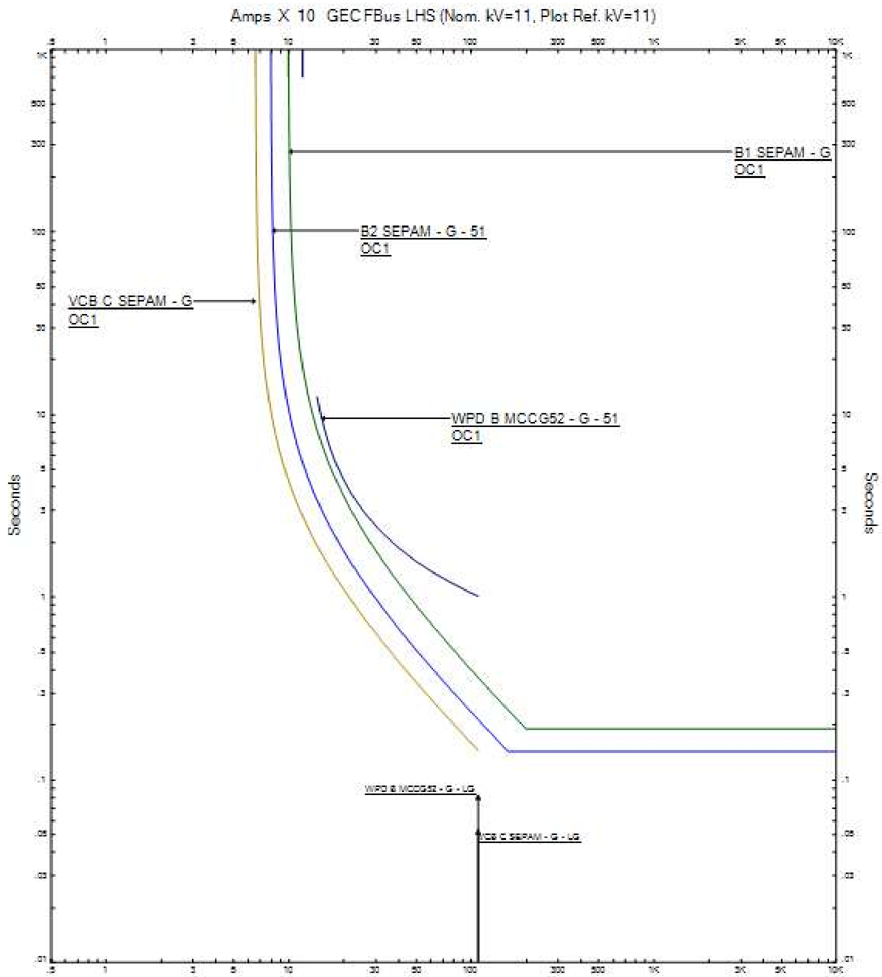


Figure 6.1.18 L-G Protection *TCC* for busbar Faults on the *GEC* Switchgear, whilst being supplied by a Single *DNO* Feeder

Scenario 11

Site supplied by a single *DNO* feeder; Faults investigated on the supply side of Transformers connected to the Main HV *GEC* busbar.

No protection issues encountered for L-L-L, L-L, L-G or L-L-G faults. The transformer SEPAM protection relay operates before upstream devices, providing good discrimination, *FLC* settings for each of the connected transformers is 125% of rated nominal rated current.

Scenario 12

Site supplied by dual *DNO* feeders; Faults investigated on the HV String Extensions (String A&B)

No protection issues encountered for L-L-L, L-L, L-G or L-L-G faults. The transformer SEPAM relays operate before upstream device, providing good discrimination, *FLC* settings for each of the connected transformers is 125% of rated nominal rated current.

Scenario 13

Site supplied by dual *DNO* feeders; Faults investigated on the supply side of transformers connected to the Main HV GEC busbar.

No protection issues encountered for L-L-L, L-L, L-G or L-L-G faults. The transformer SEPAM relays operate before upstream device, providing good discrimination, *FLC* settings for each of the connected transformers is 125% of rated nominal rated current.

Scenario 14

Site supplied by dual *DNO* feeders, investigated busbar phase Faults on the Main HV *GEC* switchgear.

i. Definite time settings removed from *VCB* A&B. Also, settings proposed on *VCB* A2, *VCB* B2 & *VCB* C ensuring effective discrimination for all system fault currents, as shown in the below *TCC*. These changes led to an improvement of load point reliability 48.95hrs/yr., prior to protection setting optimisation the reliability metric was 50 hrs/yr., reducing to 1.052 hrs/yr. with these listed improvements.

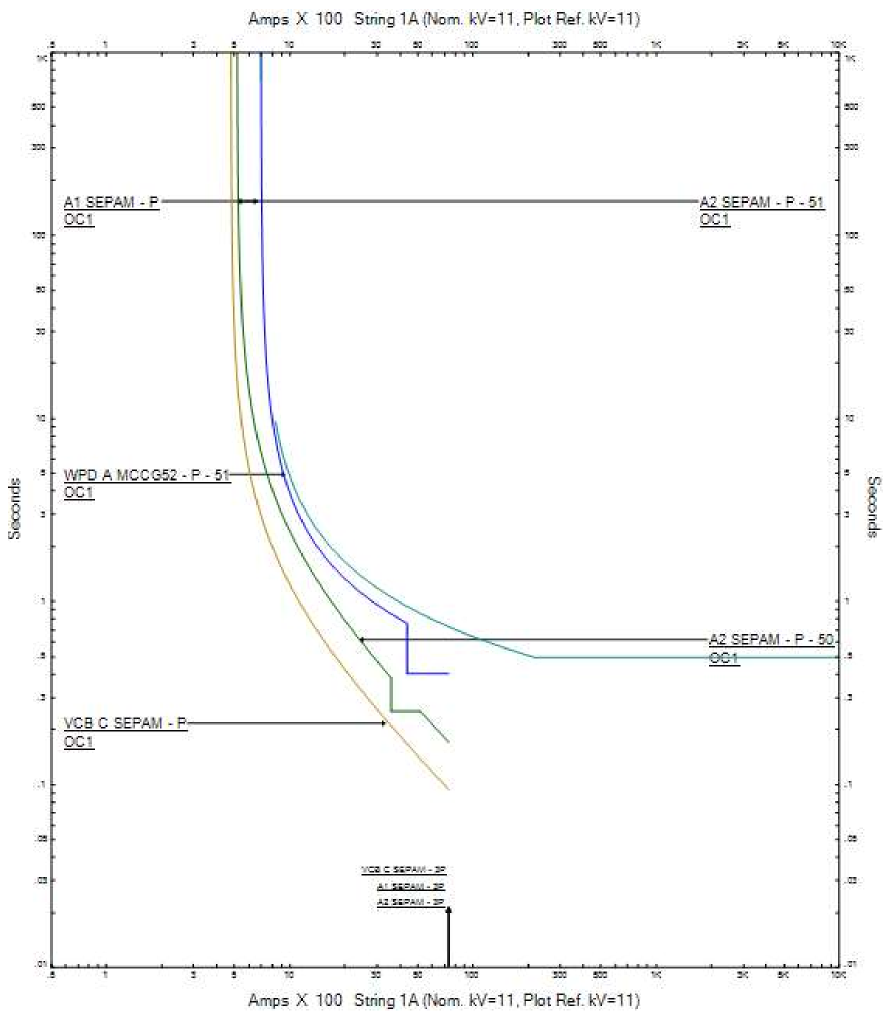


Figure 6.1.19 Overcurrent Protection *TCC* for busbar Faults on the *GEC* Switchgear, whilst being supplied by Dual *DNO* Feeders

Scenario 15a

Site supplied by dual *DNO* feeders, investigated L-G faults on the *GEC* switchgear.

i. *VCB* A2 & B2 instantaneous settings removed, replaced with Time Current Curve (*TCC*) as shown in the below *TCC*, proposed settings on *VCB* C improved overall grading co-ordination for both L-L-L & L-G fault types. These changes led to an improvement of load point reliability 48.95hrs/yr., prior to protection setting optimisation the reliability metric was 50 hrs/yr., reducing to 1.052 hrs/yr. with these listed improvements.

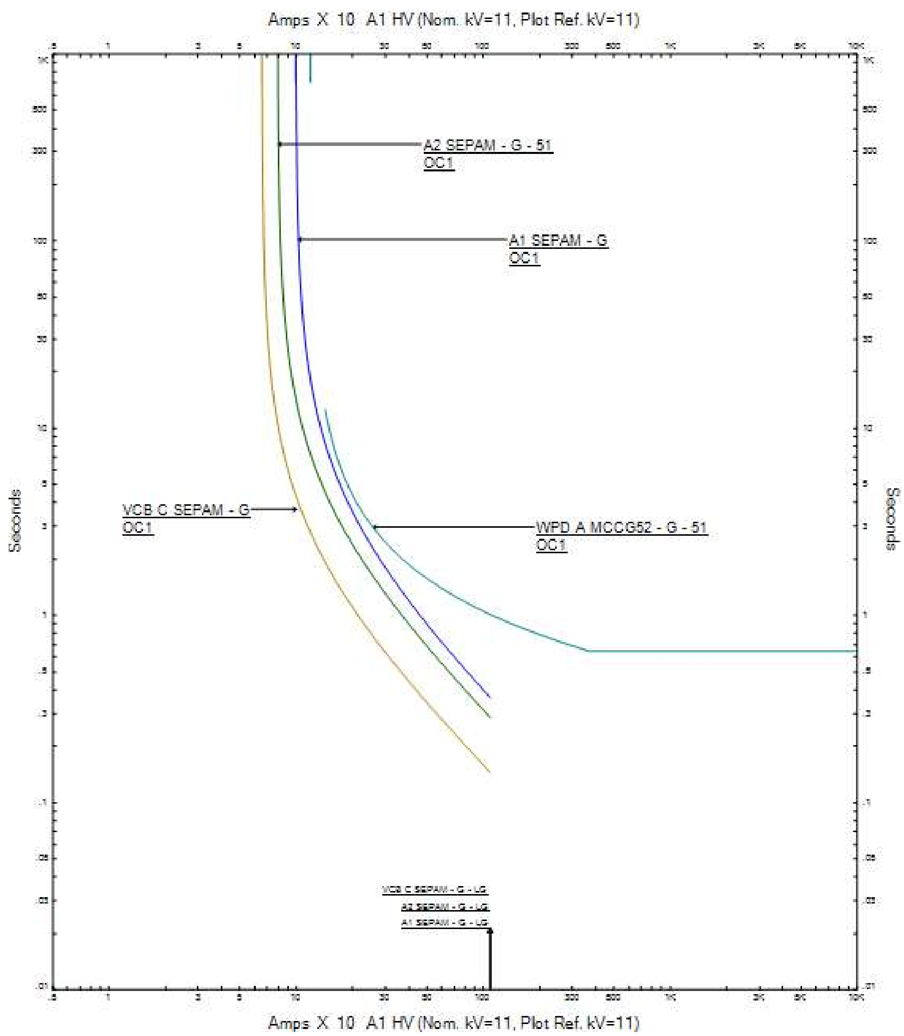


Figure 6.1.20 L-G Protection *TCC* for busbar Faults on the *GEC* Switchgear, whilst being supplied by Dual *DNO* Feeders

Scenario 15b

Site supplied by dual *DNO* feeders, investigated cable faults from WPD *VCB* to *VCB* A1 INCOMER

i. L-L-L fault levels cleared with effective discrimination, noted on below *TCC* plot. Proposed Definite Time (*DT*) settings for *VCB* A2 & *VCB* B2 removed issues with regards to a cable fault between the *DNO* incomers (*WPD VCB*) and either *VCB* A1 or *VCB* B1. A 600*ms* margin was achievable at a network fault level of 3KA. Likewise, proposed L-G setting also improved co-ordination.

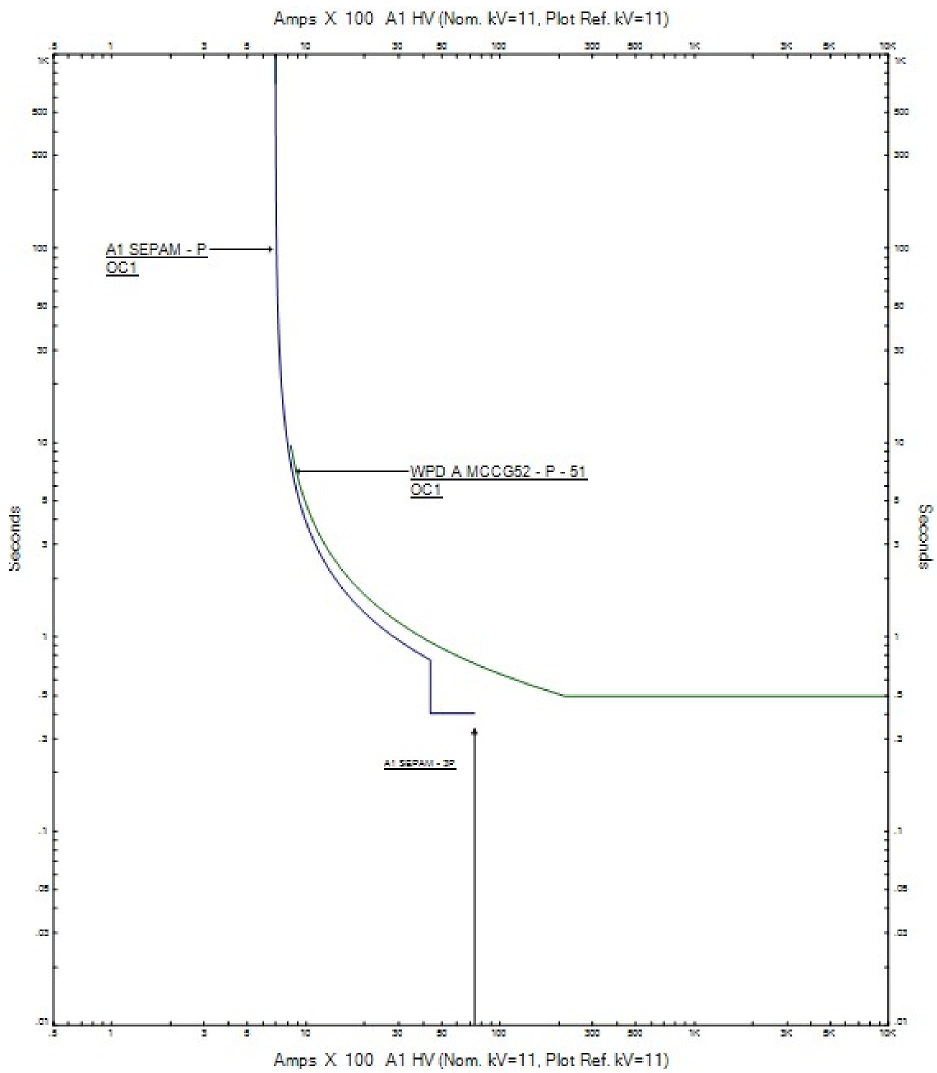


Figure 6.1.21 Overcurrent Protection *TCC* for a Cable Fault on the *DNO* Incomer

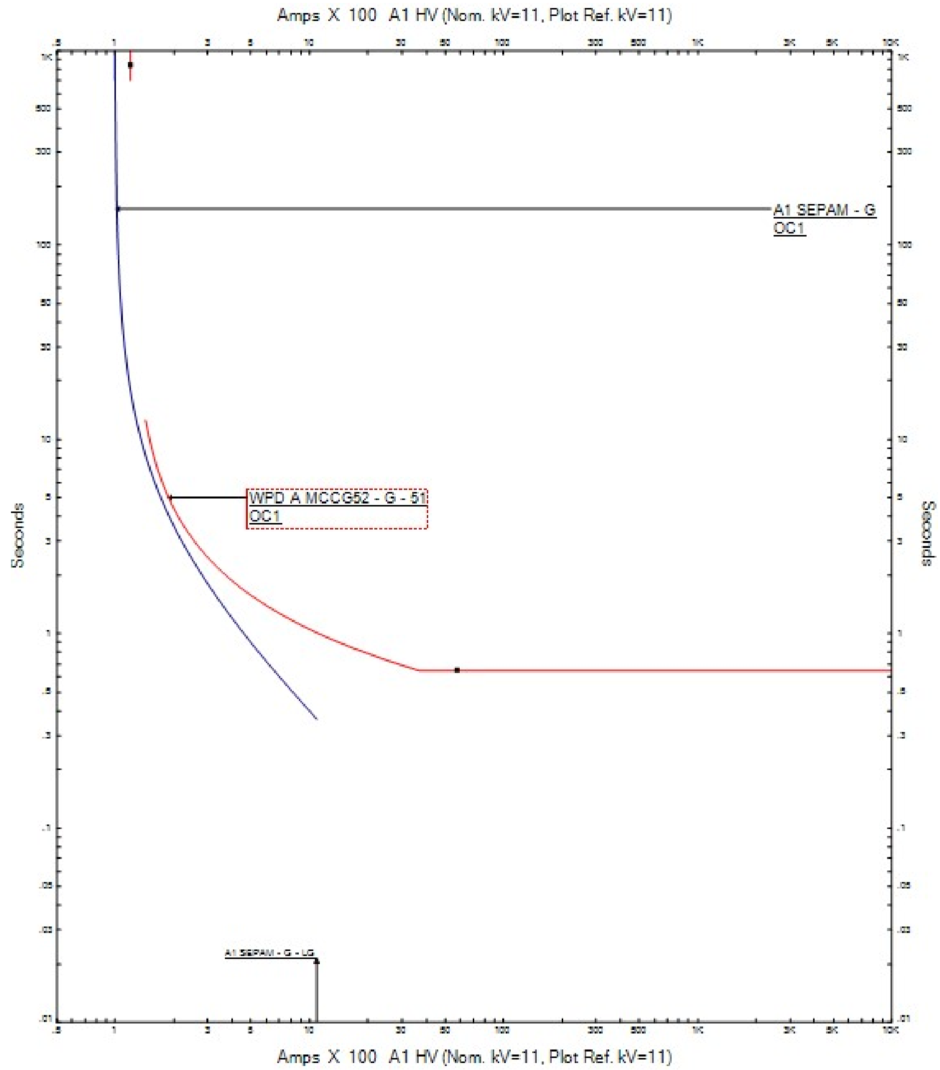


Figure 6.1.22 L-G Protection *TCC* for a Cable Fault on the *DNO* Incomer

Scenario 16

Site supplied by dual feeders, investigated phase faults on the supply side of all Transformers connected to the Main HV *GEC* switchgear.

i. Effective grading for phase overcurrent's with removal of definite time settings from *VCB* 'A' & 'B', a grading margin more than 1s is available between transformer supply protection and related upstream relay devices.

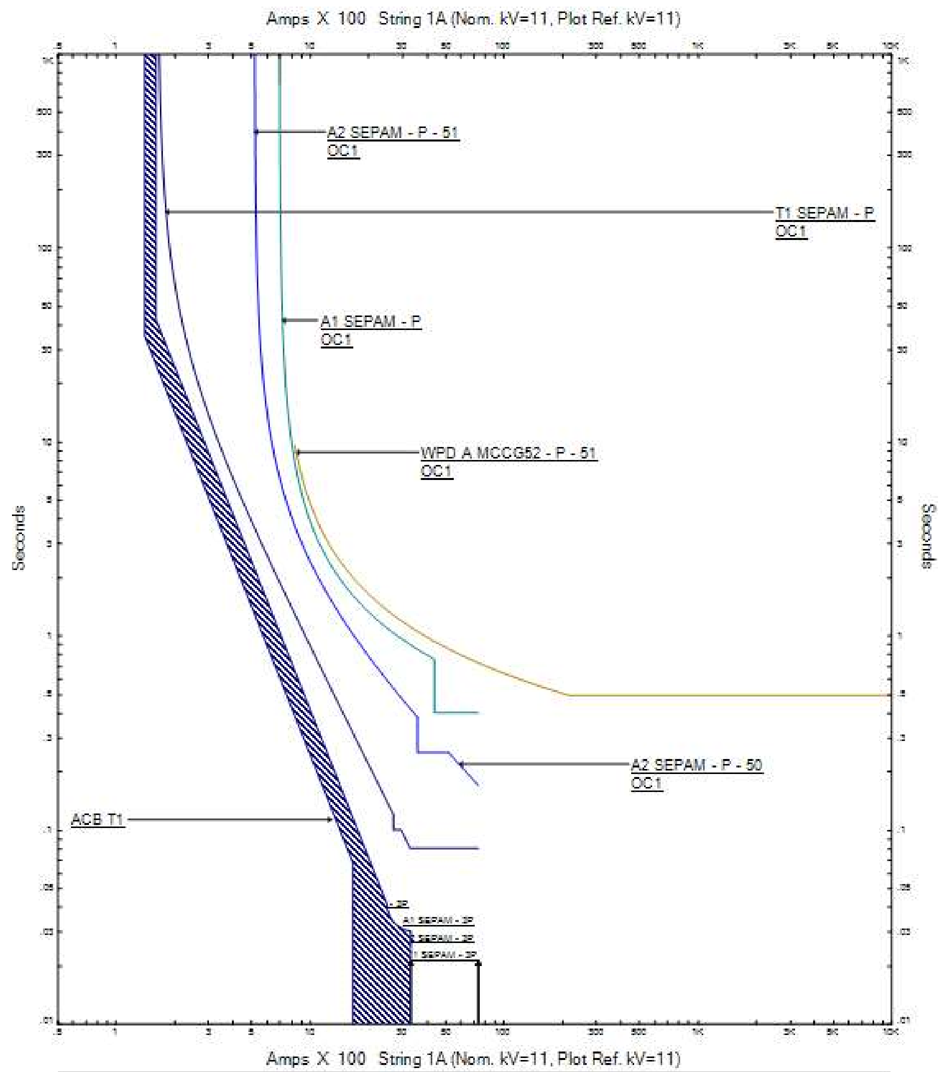


Figure 6.1.23 Overcurrent Protection *TCC* for *DNO* Cable Protection and Downstream Transformer Feeders

Scenario 17

Site supplied by dual *DNO* feeders, investigated L-G faults on the supply side of the Transformers connected to the Main HV GEC switchgear.

i. Proposed L-G settings from WPD incomers to transformer HV loads:
WPD A/B Curve *SI*, I=120A, *td* = 0.325*s*
A1/B1 Curve *IEC VI*, I=100A, *td* = 0.4*s*
A2/B2 Curve *IEC VI*, I=80A, *td* = 0.4*s*
A/B = *DT* setting removed.
TX1 *DT*, *I* = 22A

Below *TCC* settings provided optimal grading co-ordination, also transformer L-G settings are now in-line with *IEC* guidelines. These changes led to an improvement of load point reliability 3.051hrs/yr., prior to protection setting optimisation the reliability metric was 4.33 hrs/yr., reducing to 1.279 hrs/yr. with these listed improvements.

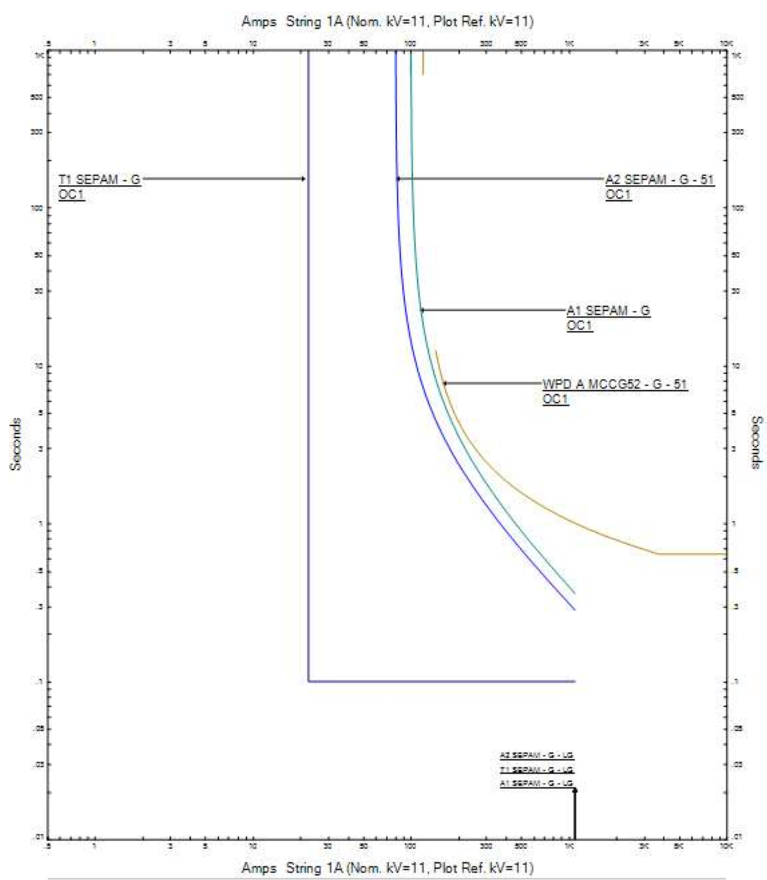


Figure 6.1.24 L-G Protection *TCC* for *DNO* Cable Protection and Transformer Feeders

Scenario 18

Site fed by Standby Generator supply, investigated faults on Energy Centre HV Strings 1A & 1B

i. No issues for clearance of overcurrent faults, *VCB* A clears L-L-L faults at 4800A in 0.3*s* which is proceeding *VCB* A2 4841A in 0.4*s*, both clear before generator protection which operates at 1200A in 0.9*s*. Therefore, achieves a minimum 500*ms* clearance between protection devices.

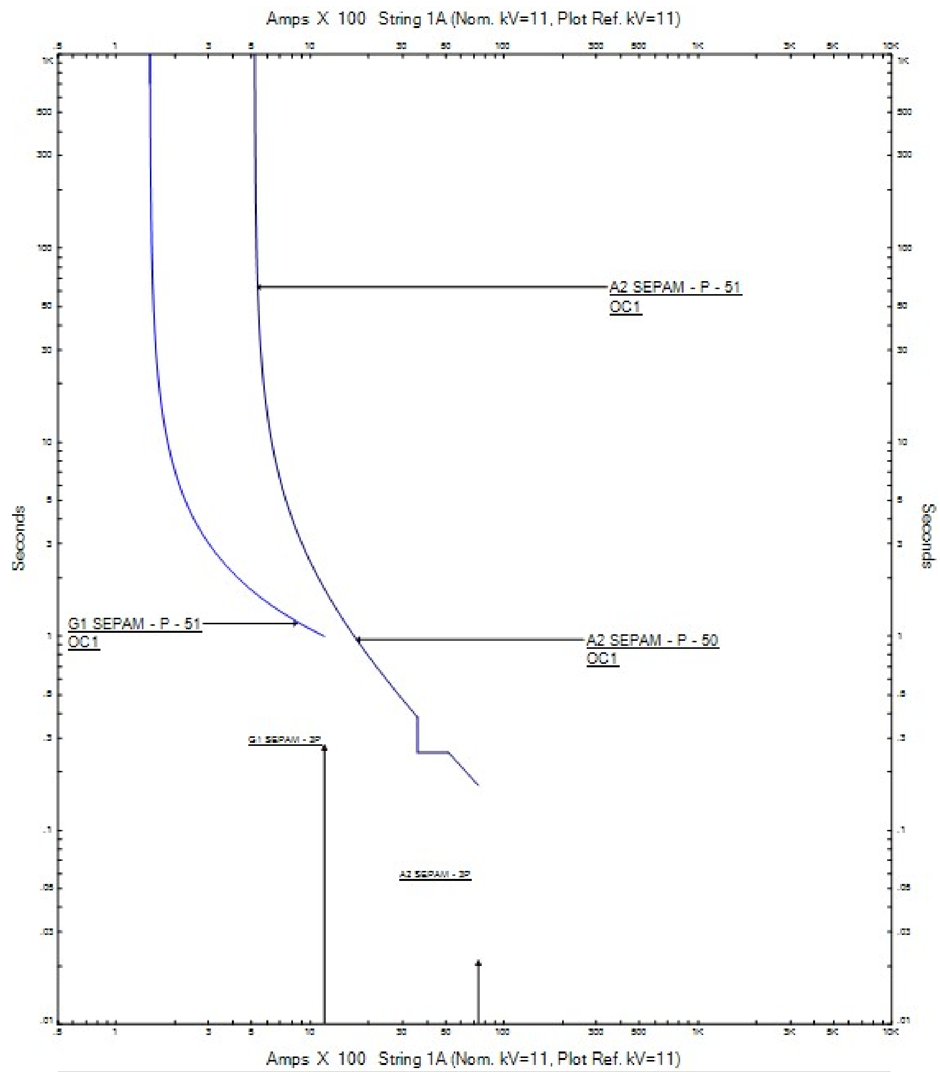


Figure 6.1.25 Overcurrent Protection *TCC* for Energy Centre busbar Faults whilst fed by Standby Generators.

However, a change of generator 4&5 protection settings to align with other generators (1 to 3), provides an overall improved co-ordination – as below *TCC*.

Generators (1 to 5): L-G fault of 139.6A device trips in 1.02*s.*

VCB A2 & *VCB* B2: L-G fault of 1082A device trips in 0.277*s*.

Therefore, the proposed settings achieve improved protection co-ordination. These changes led to an improvement of load point reliability 50 hrs/yr., prior to protection setting optimisation the reliability metric was 56.402 hrs/yr., reducing to 6.402 hrs/yr. with these listed improvements.

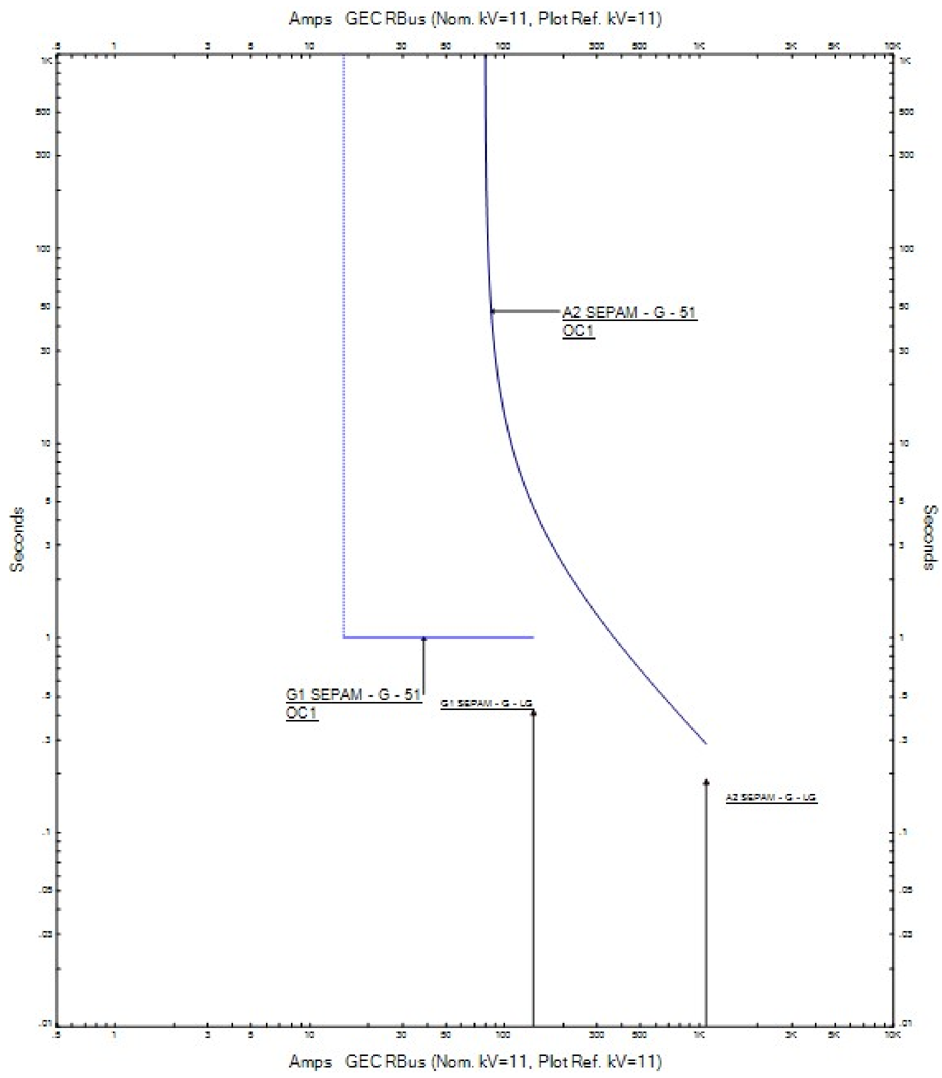


Figure 6.1.26 L-G Protection *TCC* for Energy Centre busbar Faults whilst fed by Standby Generators.

Scenario 19

Site fed via Standby Generator supply, investigated faults on the Energy Centre outgoing circuits i.e., HV transformer cables.

i. No protection issues present for L-L-L, L-G, L-L-G, L-L, energy centre outgoing transformer feeder SEPAM relay operates before any upstream protection devices, with adequate grading margins as shown in the *TCC* below.

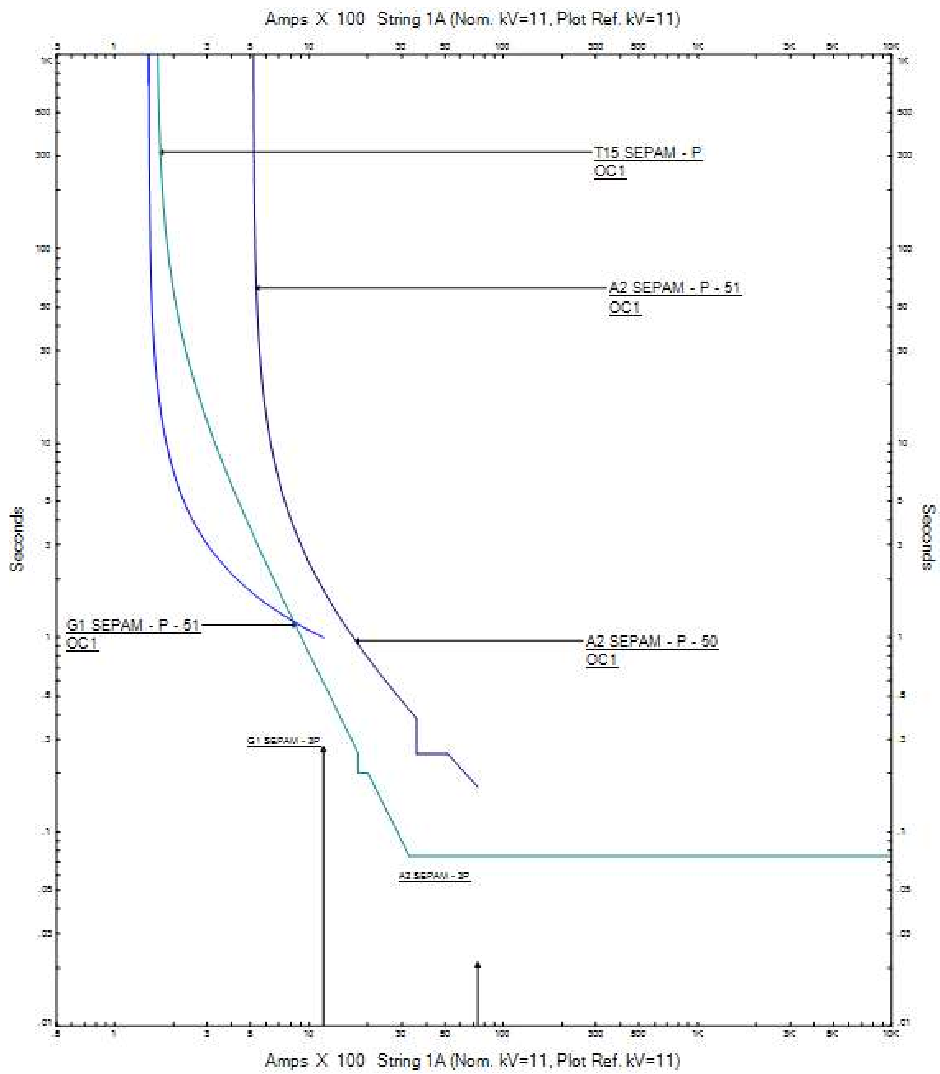


Figure 6.1.27 Overcurrent Protection *TCC* for an Energy Centre busbar Fault whilst fed by Standby Generators.

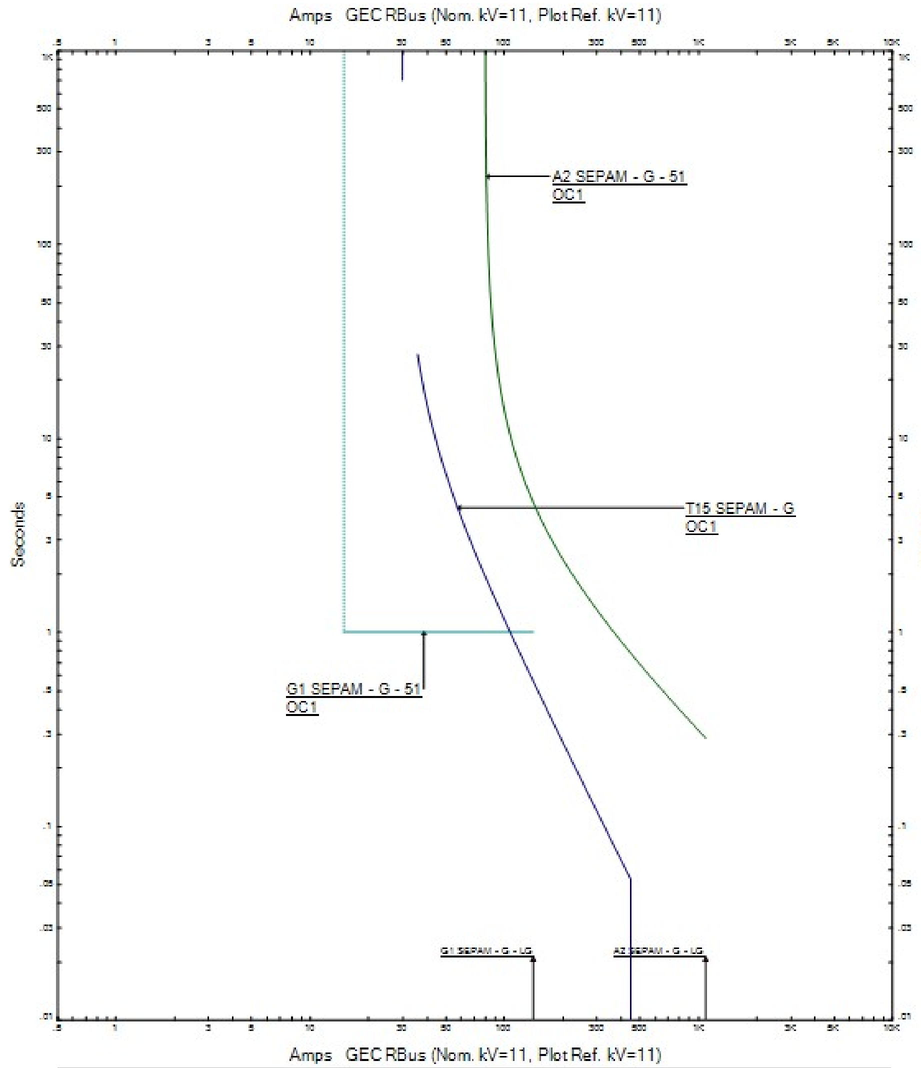


Figure 6.1.28 L-G Protection *TCC* for Energy Centre busbar Faults whilst fed by Standby Generators.

Scenario 20

Site supplied via the Standby Generator; Faults investigated on the Main HV *GEC* switchgear.

The original protection scheme on the *GEC* front busbar provided no co-ordination for overcurrent faults whilst being supplied by standby generators. Therefore, the existing scheme could not isolate a fault from the busbar and supply would be disconnected. *VCB* 'C' did not discriminate for overcurrent faults with generators 4 & 5, also no protection parameter was set on *VCB* 'D' or 'E' thus the synchronous generators would continue to feed a system fault until local engine protection operated and standby supply was tripped from the 11KV *GEC* busbar. Proposed improvements to the following protection settings, both L-L-L & L-G are:

VCB C (L-L-L) – IEC *VI*, *Is* = 540A, *t* = 0.15*s*   *VCB* C (L-G) – IEC *VI*, *Is* = 65A, *t* = 0.3*s*
VCB D & VBC E (L-L-L) – IEC *VI*, *Is* = 480A, *t* = 0.3*s*   *VCB* D/E (L-G) – IEC *VI*, *Is* = 100A, *t* = 0.6*s*

These changes led to an improvement of load point reliability 2 hrs/yr., prior to protection setting updates the reliability metric was 2.902 hrs/yr., reducing to 0.902 hrs/yr. with these listed improvements.

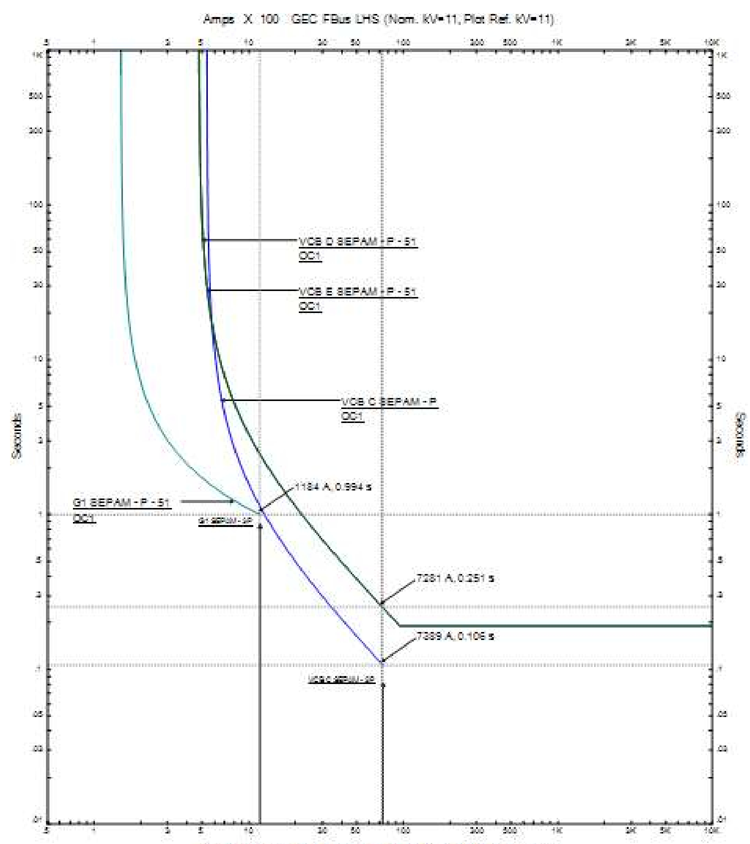


Figure 6.1.29 Overcurrent Protection *TCC* for Ring Main *VCB's* D, E & C

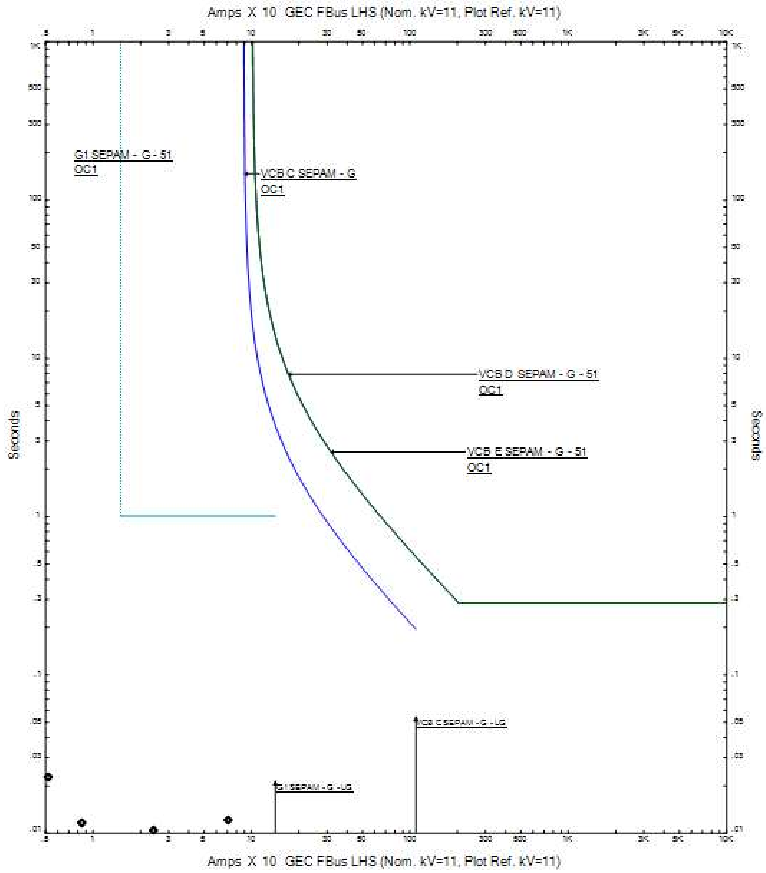


Figure 6.1.30 L-G Protection *TCC* for Ring Main *VCB's* D, E & C

Scenario 21

Site supplied via Standby Generators; Faults investigated on the Main HV *GEC* switchgear outgoing circuits.

No issues for L-L-L, L-G, L-L-G, L-L, All *GEC* switchgear outgoing transformer feeder circuit SEPAM relays operate before any upstream protection with adequate grading margins.

Scenario 22

Faults Investigated on the *DNO* cable feeder side, whilst in Parallel with Standby Generators.

VCB A2 & *VCB* B2 protection settings were recommended as part of other fault scenarios, therefore there is no longer L-L-L & L-G discrimination issues to consider. The *DNO* directional protection operates over 400*ms* quicker than any of the downstream protection devices, as shown below. These changes led to an improvement of load point reliability 44.09 hrs/yr., prior to protection setting optimisation the reliability metric was 50 hrs/yr., reducing to 5.908 hrs/yr. with these listed improvements.

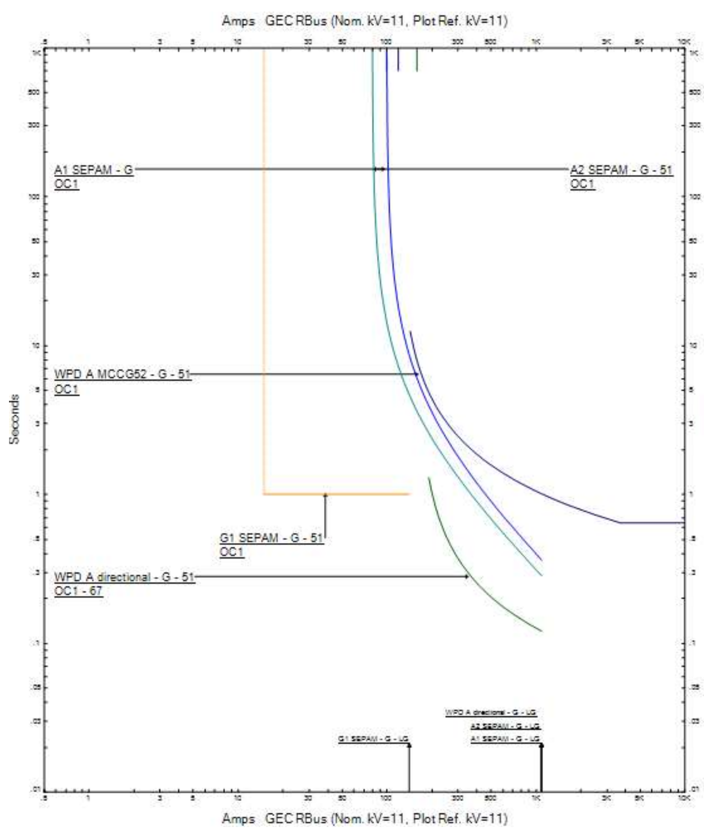


Figure 6.1.31 *DNO* Supply Side Fault whilst in Parallel with Standby Generators

Scenario 23

Rotary *UPS* Protection Assessment for Nominal & Failure Modes, considering both Input and Output Switchgear, Air Circuit Breakers and Associated Critical Load Supplies.

To allow for 150% overload of machines discrimination between the input and output *ACB's* is not possible with the current installed devices, although there is no benefit to achieving this co-ordination since operation of either the input or output *ACB* will remove the unit from operation.

No *L-G* settings were present on the *UPS* input circuit breakers although the supply distribution transformer is delta/star configuration so there is no flow of zero sequence currents in the transformer primary winding for a given secondary L-G fault. Hence, the installed protection scheme is reliant on the overcurrent (L-L-L) setting which discriminated with all downstream devices. Protection settings on the *UPS* primary circuit breakers allows the required 150% overload, as recommended by the manufacturers.

Given the LV distribution switchgear busbar is rated for a continuous current of 4000A, the five *UPS* machines connected at full load require an input current of >5000A therefore the specified machines are overrated given the constraints of the LV switchgear. Likewise, for the HV & LV transformer secondary which is rated at 3333A could not nominally load all 5 *UPS* machines, or 4 as an N+1 system, see Table 6.1.1.

Table 6.1.1 LV Switchgear Distribution Board Ref.A1 Power Ratings

Type of Distribution Equipment	**Nominal Current Rating (A)**	**Total Amperes for N+1 system (N = 4 *UPS* Online)**
Supply transformer (2.5MVA Dyn11)	3333	3333
LV Switchgear input busbar	4000	4000
LV Switchgear output busbar	4000	4000
1 *UPS* Input (without battery charge current)	967	3868
1 *UPS* Input (with battery charge current)	1027	4108 > Ampere rating
1 *UPS* Input (with battery charge & discharge current)	1148	4592 > Ampere rating
1 *UPS* output	902	3608

TCC for scenario 23 showing overcurrent relay aspects.

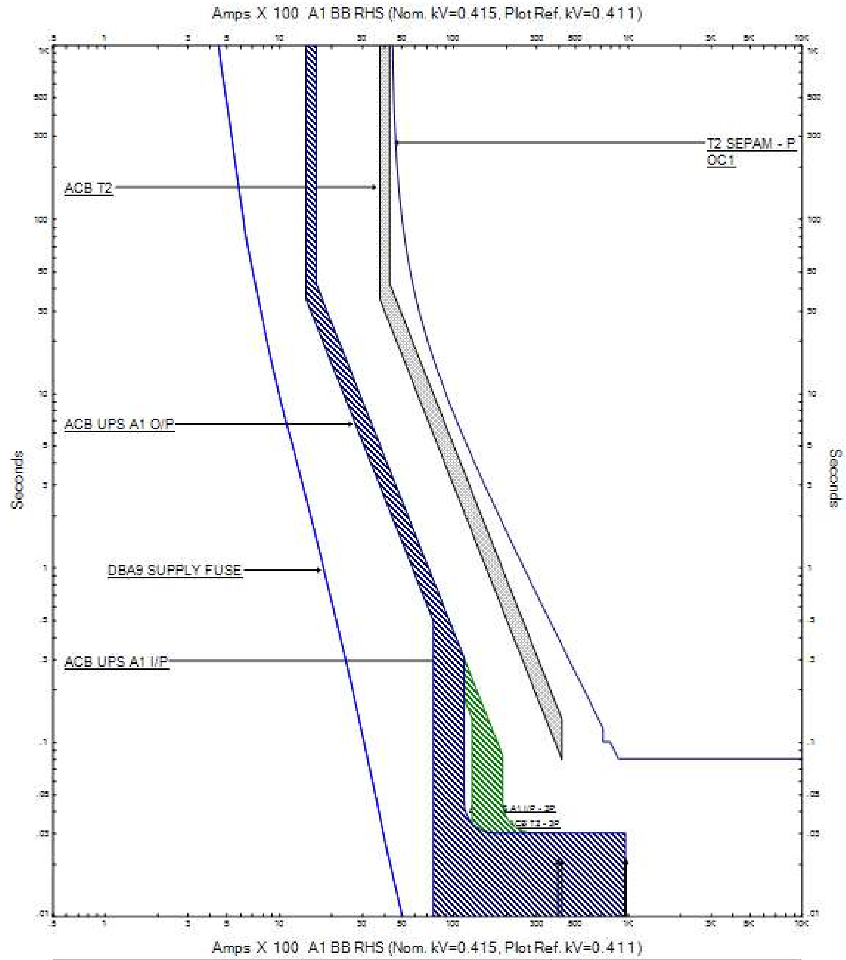


Figure 2 Overcurrent Protection TCC for *UPS* Power Supply String, when on Active Online Mode

TCC for scenario 23 showing overcurrent relay aspects.

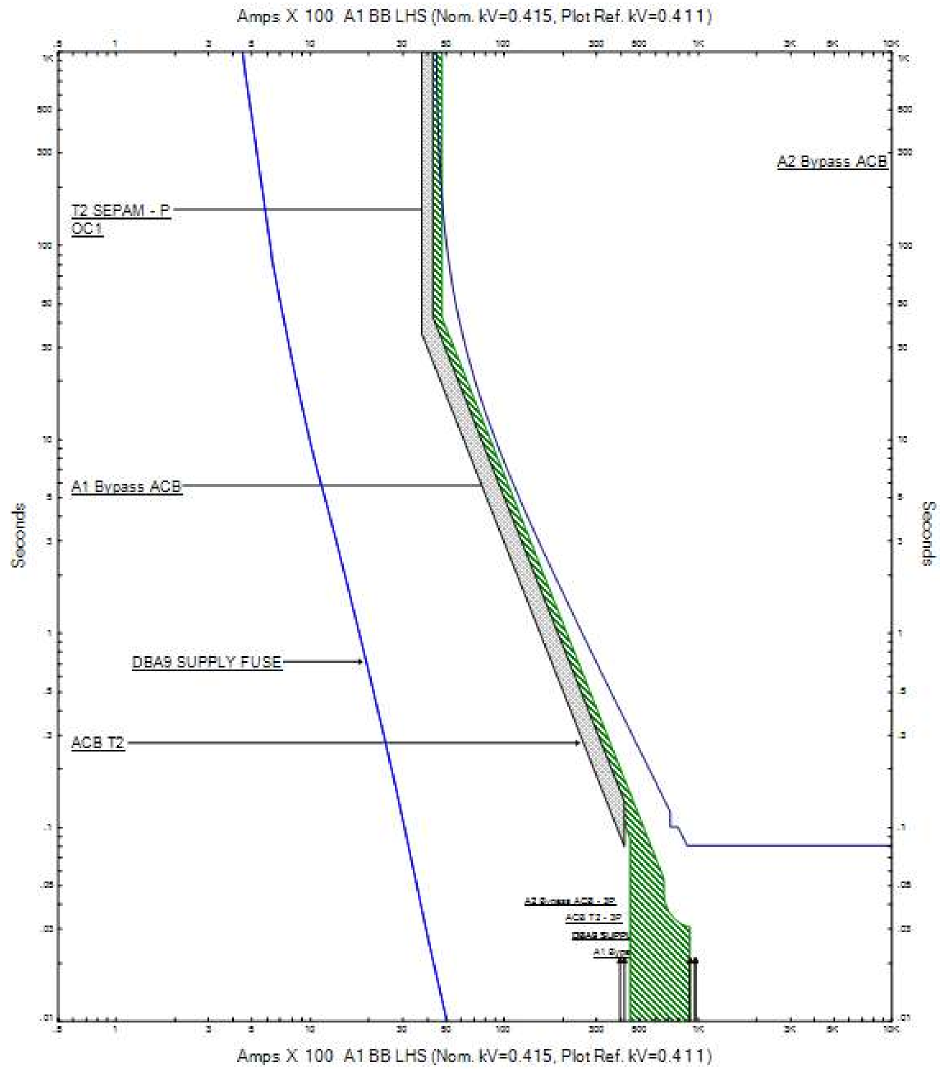


Figure 6.1.33 Overcurrent Protection *TCC* for *UPS* Power Supply String, during Bypass Mode

Ultimately, recommendations to the *UPS* system (scenario 23) led to an improvement of load point reliability 44.84 hrs/yr., prior to protection setting optimisation the reliability metric was 50 hrs/yr., reducing to 5.158 hrs/yr. with these listed improvements.

Scenario 24

Proposed Generator Unit Protections Settings, for all Five Machines Installed within the Data Centre Electrical Network.

Table 6.1.2 Generator Unit Protections

Gen Ref No.	Fault & Protection Type	Recommended Settings (Best Practice)	BS ISO 8528 Operating limits	Actual Relay Settings	Observations on Actual Settings	Proposed Improved Settings (Validated in ETAP)
1 2 3	Protection for external phase to phase short circuits - **Phase Overcurrent 50/51**	1.2 x In = 1.2 x 118.1 = 141.6A. Settings must be no ≥ 2.5 x In or restrained Voltage setting will be required.	n/a	135A IEC SI Curve	Current setting could be increased to 145A to provide full 1.2 x nominal rating.	150A IEC SI Curve
4 5				280A - non-IEC EI Curve	O/C value is approx. double the FLC of the generator rating.	
1 2 3	Protection for external line to ground short circuits - **L-G 50N/51N**	Io sum to be > 12% of CT rating. Inst setting equal to 20% of NER value. IDMT setting of 10% of resistor value, curve to be graded against downstream. CT primary is 150 A, Thus, Io @ 12% = 18A. Inst @ 20% = 30A and IDMT @ 10% = 15A.	n/a	7.2 A DT curve (1s time delay)	No IDMT setting present only DT, 7.2 A is below the recommended stability for IO sum.	30A Definite Time
4 5				67.5 A - non-IEC VI Curve	IDMT values not in-line with recommended 10% of NER value i.e., 15A. Also, no DT setting of 30A. Curve type is non-IEC so pick up of EF setting would be 1.2x67.5A = 81A.	
All Sets	Thermal protection - **Overload 49RMS**	Maximum heat rises - Hset = 115% to 120%. Time constant to be taken from generator spec.	n/a		None present on current scheme.	Thermal protection via mechanical control panel, 1st and 2nd stage alarms.
All Sets	Internal phase to phase short circuit/protection of stator- **Machine Differential 87M**	Iset = 5 to 15% In with no time delay.	n/a	Is = 8A	Ict = 150/1 8A is 6.77% of the full load current. Maximum through fault current is 780A (5.2x CT rating). Therefore; 100%-(6.77/5.2) = 98.69% of stator winding protected	Remain unchanged.

Gen Ref No.	Fault & Protection Type	Recommended Settings (Best Practice)	BS ISO 8528 Operating limits	Actual Relay Settings	Observations on Actual Settings	Proposed Improved Settings (Validated in ETAP)
All Sets	Protection against phase imbalance - **Negative Sequence current 46**	Iset = 15% In with 2-3 sec delay on activation.	n/a		In = 118.1 therefore 15% In = 17.72A With 50% O/L factor 27A.	Set to alarm/latch to 22% of Ib, with 100ms time delay on trip.
All Sets	Protection for internal phase to frame short circuits - **Machine Differential 87M**	Iset = 20% In with no time delay.	n/a	Is = 8A	Ict = 150/1 8A is 6.77% of the full load current. Maximum through fault is 160A (1.06 x CT rating) Therefore; 100%-(6.77/1.06) = 93.61% of stator winding protected	Remain unchanged.
All Sets	Loss of excitation - **Reverse Reactive Power 32Q**	Qset = 0.3 x Sn (Apparent power) with 3 second time delay.	Reactive power sharing between 20 to 100% of Qn		Suggest the following setting. Sn = 1.35MVAr therefore 0.6 x Sn = 810 KVAr	Trip at 810 KVAr with 3S delay
All Sets	Motor operation - **Reverse Active Power 32P**	Pset = 5 to 20% of Pn, 1 second time delay	Active power sharing. Between 20 to 80% of Pn is 10% Between 80 to 100% of Pn is 5%. Taking 10% as worst-case scenario 1800x0.1 = 180KW	225KW with 1s time delay	5% to 20% of Pn = 90KW ~ 360KW	Remain unchanged.
1	**Under or over frequency - 81L & 81H**	Frequency ± 2Hz, time delay of 3s.	During load step changed Hz droop < 5% Fn = 2.5Hz. During steady state operation Hz droop <1.5% Fn = 0.75Hz. Rate of Change of frequency (RoCoF) 0.2 to 1% of Fn = 0.5Hz. Recovery time is 5s.	5Hz 5S delay & -5Hz 1S delay	Mixture of incorrect Hz & time delay, ISO class too worse case is 2.5Hz with 5 second recovery	Set All Generators in-line with ISO speed droop classifications table, given for each Govner type.
2						
3						
4				3Hz 500mS delay & -5Hz 500mS delay		
5						

Gen Ref No.	Fault & Protection Type	Recommended Settings (Best Practice)	BS ISO 8528 Operating limits	Actual Relay Settings	Observations on Actual Settings	Proposed Improved Settings (Validated in ETAP)
All Sets	**Under voltage - 27**	Uset = 0.75 to 0.85 x Un Time delay depending on selectivity of the network.	Transient case i.e. during load steps. Sudden power increase in-line with ISO -20% of Vn. With 6s recovery period.	0.90 x Un 3s delay	Currently set above the recommended 0.75 to 0.85 x Un	0.85 x Un 3s time delay
1 2 3 4 5	**Over voltage - 59**	Uset = 1.1 x Un with approx. 1s time delay	Transient case i.e., during load steps. Sudden power decrease in-line with ISO +25% of Vn. 6s recovery period	1.1 x Un 3s time delay 1.1 x Un 5s time delay	Currently set above recommended ISO time delay requirements.	1.1 x Un 5s time delay
All Sets	Supplying active power when in parallel with utility and main feeders fail - **Reversal in active power 32P**	Pset = 1 to 2% of 1.732 x In CT x Un Vt Where; In Ct = CT rating & Un Vt = VT Voltage rating *Zero-time delay required.	n/a	Gen 32P = 225KW Main A1/B1 32P = 1.25MW	2% Pset of generators is 314 KW (1.732x150x11000) 2% of main feeders is 838 KW (1.732x400x11000)	Set Generators to: 300KW 0.25s time delay. Set main feeders to: 800KW 0.5s time delay.

Scenario 25

Proposed G59 settings

Protection recommendations to align with the *ENA G59,* including site main feeders, generators, and *UPS* systems.

Table 6.1.3 Generator G59 Protection Setting Optimisation

Protection type	**Stage 1 Recommended Setting (Long Term)**	**Stage 2 Recommended Setting (Long Term)**	**Short term 5 minutes per month & once per week max.**	***VCB* A1 & B1 (Existing Settings)**	***VCB* A1 & B1 (Proposed Settings)**
Under voltage ANSI 27	-13 % Vn with 2.5s time delay.	-20 % Vn with 0.5s time delay.	- 6 % Vn with 0.5s time delay.	-10% Vn with 5s time delay.	-10% Vn with 2.5s time delay.
Over voltage ANSI 59	+10 % Vn with 1s time delay.	+13 % Vn with 0.5s time delay.	+ 6 % Vn with 0.5s time delay.	+10% Vn with 500mS time delay.	+10% Vn with 0.5s time delay.
Over frequency ANSI 81H	51.5Hz with 90s with delay.	52Hz with 0.5s time delay.	50.5Hz with 0.5s time delay.	50.5Hz with 0.5s time delay.	52.5Hz with 0.5s time delay.
Under frequency ANSI 81L	47.5Hz with 20s-time delay.	47Hz with 0.5s time delay.	49.5Hz with 0.5s time delay.	47Hz with 0.5s time delay.	47.5Hz with 0.5s time delay.
Loss of Mains (LOM) Vector	6˚ Degrees		N/A	N/A	N/A
LOM Rate of change of frequency (RoCoF)	0.125Hz/s		N/A	0.8Hz/s	N/A – Remove current 0.8Hz/s.

Where; Vn is the nominal system voltage (V_{L-L}) rms.

UPS Synchronising Data

UPS Mains 1 pathway = under voltage -15%, over voltage +10%, over frequency +5%, under frequency -5%

UPS Mains 2 pathway = under voltage -8%, over voltage +8%, over frequency +1%, under frequency -1%

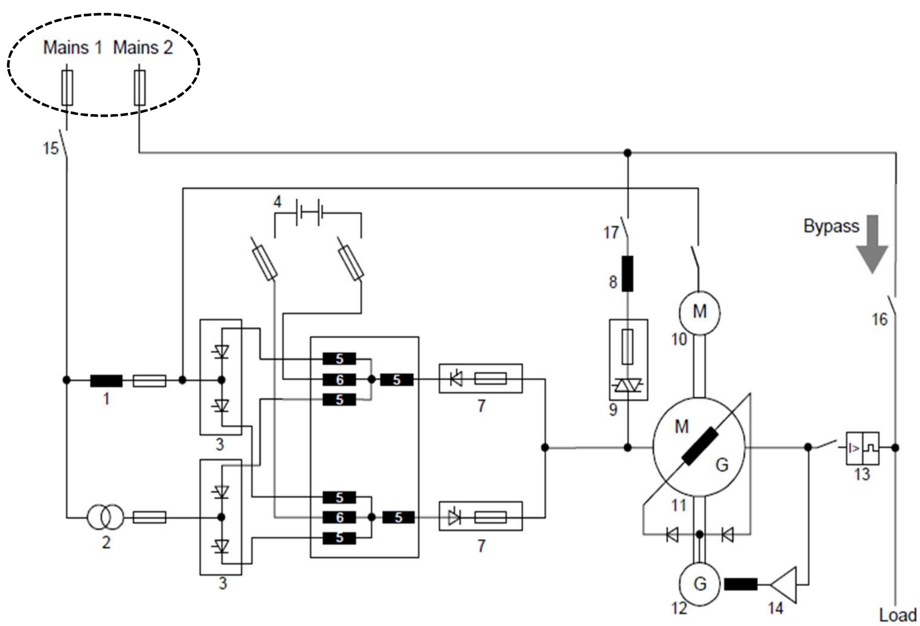


Figure 6.1.34 Rotary *UPS* (UNIBLOCK-R) schematic diagram

Scenario 26

SOLKAR Line Differential Protection Assessment

Below Table 6.14 provides the recommended change to the SOLKAR protection scheme.

Table 6.1.4 SOLKAR Protection Assessment

<table>
<tr><th>Fault Type</th><th>Primary Setting (A)</th><th>Fault Level at VCB A2 (A)</th><th>Fault Level at VCB A (A)</th><th>Differential between SOLKAR send/receive relay units (A)</th><th>Differential expressed as multiple of SOLKAR setting (A)</th><th>SOLKAR Operating Time (ms)</th><th>Observations</th></tr>
<tr><td>L1-E</td><td>100</td><td rowspan="3">535</td><td rowspan="3">557</td><td rowspan="3">1092</td><td>10.92</td><td rowspan="6"><45</td><td rowspan="6">Settings to be changed on VCB A2 & VCB B2, so that the trip time is greater than 1s, achieving an increased margin with SOLKAR protections.</td></tr>
<tr><td>L2-E</td><td>128</td><td>8.53</td></tr>
<tr><td>L3-E</td><td>168</td><td>6.50</td></tr>
<tr><td>L1-L2</td><td>500</td><td rowspan="3">2630</td><td rowspan="3">2930</td><td rowspan="3">5560</td><td>11.12</td></tr>
<tr><td>L2-L3</td><td>500</td><td>11.12</td></tr>
<tr><td>L3-L1</td><td>248</td><td>22.42</td></tr>
</table>

Scenario 27

Transformer Restricted Earth Fault L-G (*REF*) Relay Assessment

No improvement to *REF* protection settings were required following this investigation, in terms of numerical adjustments, however it was found during site testing the inter-tripping between HV & LV Equipment was not connected thus limits the practical effectiveness of the scheme. *REF* protection must inter-trip the corresponding circuit breakers either side of the protected power transformer.

Appendix II displays protection settings tables, covering all the above scenarios and devices. Where, highlighted orange cells suggest an improvement of protection co-ordination can be achieved and an associated set of optional protection relay settings have been provided as part of this research programme. In-fact, for the low voltage distribution system a total of 54 improvements from an existing 337 settings have been proposed along with 339 from the required 1136 high voltage system protection settings too. Highlighting the significant opportunity available to improve data centre electrical protection for increased system Operational Availability (*Ao*). Chapter 6.2 will apply focus on improving these setting further, not just for effective co-ordination but reduction of arc flash.

6.2 Protection Device Grading and Arc Flash Implications

Although protection settings discussed and proposed in Chapter 6.1 (listed in Appendix II) of this report will provide effective discrimination and disconnection of faulty equipment, consideration must also be given to arc flash and the safety of engineering personnel. This is significantly important to the overall uptime of the data centre equipment i.e., allowing maintenance engineers to effectively complete life cycle maintenance activities, respond to issues, or indeed ensure arc flash energy levels do not damage switchgear beyond economical repair, should a fault occur.

Below Table 6.2.1 displays both the 'base' and 'proposed' relay protection settings for achieving effective discrimination, it can be noted the associated incident energy levels are greater than the NFPA 70E or IEEE1584 guidelines, and available *PPE*. Therefore, achieving effective discrimination may not provide mitigation of arc flash hazards and further measures are often required. In this scenario it is likely the switchgear would have to be taken out of service for any scheduled maintenance activity, which naturally incurs additional unwanted downtime and costly shutdown activities for the data centre services. Table 6.2.1 display the arc flash levels for each of the data centre switchboards.

Table 6.2.1 Protection Device Grading and Associated Arc Flash Implications

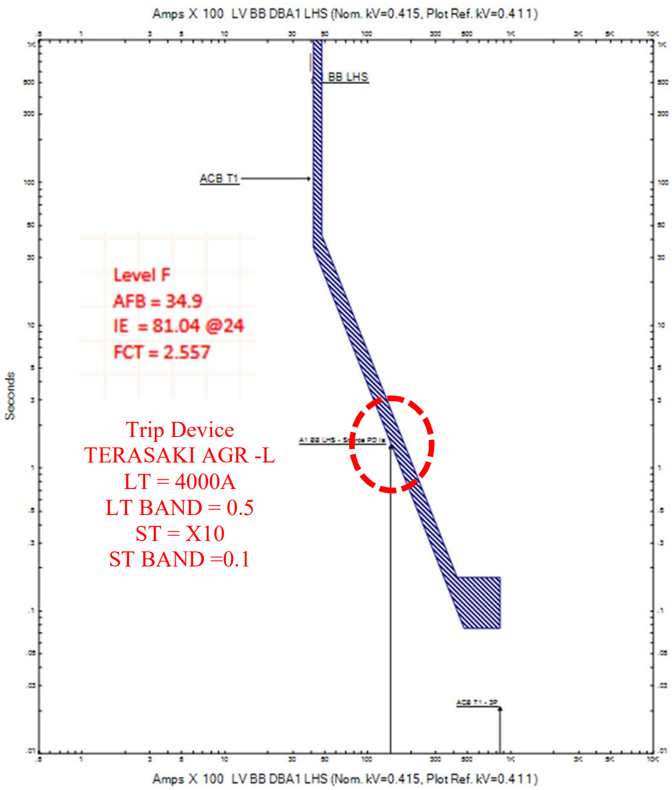
Base Relay Protection Settings							**Proposed Relay Protection Settings for improved Co-ordination.**			
ID	kV	Total Energy (cal/cm²)	Arc Flash Boundary (ft-in)	PPE Level Required	Final FCT (cycles)		Total Energy (cal/cm²)	Arc Flash Boundary (ft-in)	PPE Level Required	Final FCT (cycles)
A1 BB LHS	0.415	256.17	76'3"	> Level G	197.45		310.41	86'11"	> Level G	239.25
A1 BB RHS	0.415	254.54	75'11"	> Level G	196.18		194.98	63'4"	> Level G	150.28
A1 HV	11	6631.85	6'2"	> Level G	63.18		6631.85	6'2"	> Level G	63.18
A1 to A2 Bypass	0.415	254.54	75'11"	> Level G	196.18		194.98	63'4"	> Level G	150.28
A2 BB LHS	0.415	365.43	97'1"	> Level G	266.77		298.86	84'8"	> Level G	218.18
A2 BB RHS	0.415	365.43	97'1"	> Level G	266.77		298.86	84'8"	> Level G	218.18
B1 BB LHS	0.415	27.87	16'11"	Level E	60.97		27.87	16'11"	Level E	60.97
B1 BB RHS	0.415	39.37	21'5"	Level E	72.26		39.37	21'5"	Level E	72.26
B1 HV	11	6634.84	6'2"	> Level G	63.18		9141.75	7'3"	> Level G	87.05
C1 BB LHS	0.415	61.69	29'0"	Level F	94.65		61.69	29'0"	Level F	94.65
D1 BB LHS	0.415	27.96	16'11"	Level E	62.03		27.96	16'11"	Level E	62.03

ID	kV	Total Energy (cal/cm²)	Arc Flash Boundary (ft-in)	PPE Level Required	Final FCT (cycles)		Total Energy (cal/cm²)	Arc Flash Boundary (ft-in)	PPE Level Required	Final FCT (cycles)
D1 BB LHS	0.415	27.96	16'11"	Level E	62.03		27.96	16'11"	Level E	62.03
D1 BB RHS	0.415	39.23	21'4"	Level E	73.02		39.23	21'4"	Level E	73.02
DBA9	0.415	0.332379	0'10"	Level A	2.25		0.332379	0'10"	Level A	2.25
G1 BB LHS	0.415	0.818717	1'7"	Level A	1.3		0.818717	1'7"	Level A	1.3
G1 BB RHS	0.415	2.71	3'6"	Level B	4.3		2.71	3'6"	Level B	4.3
GEC FBus LHS	11	6.93	18'2"	Level C	38.11		4.82	12'6"	Level C	26.54
GEC FBus RHS	11	6.93	18'2"	Level C	38.11		15.93	42'9"	Level D	87.64
GEC RBus	11	1.99	5'0"	Level A	13.5		1.99	5'0"	Level A	13.5
H1 BB	0.415	89.49	37'4"	Level F	132.34		108.82	42'8"	Level G	160.94
LV BB DBA1 LHS	0.415	256.17	76'3"	> Level G	197.45		310.41	86'11"	> Level G	239.25
LV BB DBA1 RHS	0.415	61.69	29'0"	Level F	94.58		61.69	29'0"	Level F	94.58
LV BB DBB1 LHS	0.415	45.62	23'8"	Level F	85.04		45.62	23'8"	Level F	85.04
LV BB DBB1 RHS	0.415	39.37	21'5"	Level E	72.26		39.37	21'5"	Level E	72.26
LV BB DBC1 LHS	0.415	61.68	29'0"	Level F	94.55		61.68	29'0"	Level F	94.55
LV BB DBC1 RHS	0.415	61.69	29'0"	Level F	94.65		61.69	29'0"	Level F	94.65
LV BB DBD1 LHS	0.415	38.25	20'12"	Level E	71.3		38.25	20'12"	Level E	71.3
LV BB DBD1 RHS	0.415	39.23	21'4"	Level E	73.02		39.23	21'4"	Level E	73.02
LV BB DBG1 LHS	0.415	6.71	3'7"	Level C	4.37		6.71	3'7"	Level C	4.37
LV BB DBG1 RHS	0.415	39.86	21'7"	Level E	51.19		34.49	19'7"	Level E	52.81
LV BB DBH1 Supply1	0.415	93.7	13'3"	Level F	61.32		119.02	14'11"	Level G	77.88
LV BB DBH1 Supply2	0.415	102.34	13'10"	Level G	63.06		129.88	15'7"	> Level G	80.03
LV BB RED Supply1	0.415	93.71	13'3"	Level F	61.33		93.71	13'3"	Level F	61.33
LV BB RED Supply2	0.415	93.71	13'3"	Level F	61.32		119.03	14'11"	Level G	77.89

ID	kV	Total Energy (cal/cm²)	Arc Flash Boundary (ft-in)	PPE Level Required	Final FCT (cycles)		Total Energy (cal/cm²)	Arc Flash Boundary (ft-in)	PPE Level Required	Final FCT (cycles)
LV BB YELLOW Supply1	0.415	99.83	13'8"	Level F	70.3		126.2	15'5"	> Level G	88.87
LV BB YELLOW Supply2	0.415	99.82	13'8"	Level F	70.28		126.19	15'5"	> Level G	88.85
PDU A2	0.415	0.359424	0'11"	Level A	0.5		0.359424	0'11"	Level A	0.5
PDU A21	0.415	0.131741	0'5"	Level A	0.5		0.131741	0'5"	Level A	0.5
Rear Bus Ext.	11	1.99	5'0"	Level A	13.5		1.99	5'0"	Level A	13.5
RED INPUT BB	0.415	77.39	33'10"	Level F	119.34		94.91	38'10"	Level F	146.37
String 1A	11	11.5	30'7"	Level D	63.41		9.41	24'11"	Level D	51.91
String 1B	11	11.5	30'7"	Level D	63.41		15.85	42'7"	Level D	87.37
T1 HV	11	451.61	1'7"	> Level G	4.3		788.74	2'2"	> Level G	7.51
T2 HV	11	450.8	1'7"	> Level G	4.3		9225.37	7'4"	> Level G	88
T3 HV	11	451.38	1'7"	> Level G	4.3		2800.3	4'0"	> Level G	26.68
T4 HV	11	451.4	1'7"	> Level G	4.3		9230.12	7'4"	> Level G	87.92
T5 HV	11	466.49	1'8"	> Level G	4.3		2894.04	4'1"	> Level G	26.68
T6 HV	11	451.38	1'7"	> Level G	4.3		9229.78	7'4"	> Level G	87.93
T7 HV	11	450.8	1'7"	> Level G	4.3		2800.19	4'0"	> Level G	26.71
T8 HV	11	450.83	1'7"	> Level G	4.3		9225.79	7'4"	> Level G	88
T9 HV	11	452.08	1'7"	> Level G	4.3		1363.99	2'10"	> Level G	12.97
T10 HV	11	451.96	1'7"	> Level G	4.3		762.03	2'1"	> Level G	7.25
T11 HV	11	451.57	1'7"	> Level G	4.3		758.44	2'1"	> Level G	7.22
T12 HV	11	451.77	1'7"	> Level G	4.3		758.78	2'1"	> Level G	7.22
T13 HV	11	451.3	1'7"	> Level G	4.3		757.99	2'1"	> Level G	7.22
T14 HV	11	451.55	1'7"	> Level G	4.3		758.41	2'1"	> Level G	7.22
T15 HV	11	451.03	1'7"	> Level G	4.3		5456.73	5'7"	> Level G	52.02
T16 HV	11	451.23	1'7"	> Level G	4.3		757.88	2'1"	> Level G	7.22
YELLOW INPUT BB	0.415	82.55	35'4"	Level F	135.17		100.2	40'4"	Level G	164.07

Given arc flash values above level G provide a challenge to maintenance persons safety, other mitigating measures should be applied, such as below Figures 6.2.1 & 6.2.2 providing an example of how relay protection settings can affect arc flash in terms of i) Required arc flash boundary distance from equipment ii) Incident energy iii) Arc fault currents.

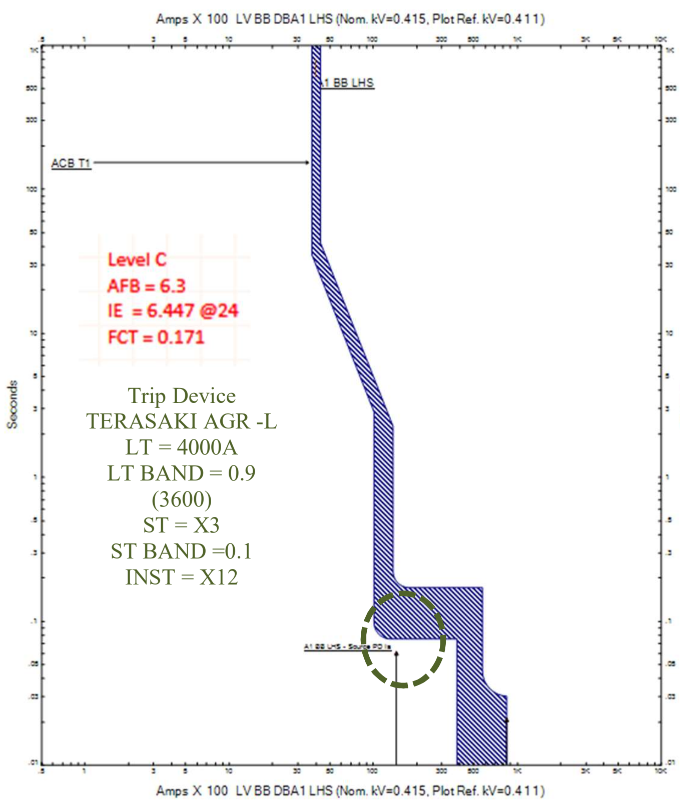
It can also be noted several of the original protection settings achieved a level F *PPE* rating (100+ cal/cm^2), due to the dangerous length of time the relay settings required to clear the arc fault current. Figure 6.2.1 displays an improved range of protection settings, specifically concentrating on an optimal short time setting to reduce the arc fault clearing time and thus lower the incident energy and requirement for such excessive cal/cm^2 *PPE* rating. This approach will allow a significant safety improvement of personnel and reduction in *PPE* requirements, along with a reduction of arcing damage to critical switchgear should a network fault occur.



Noted in the adjacent *TCC* protection curve the red circle indicates the time to clear the arc fault current, which is 2.557*s*. This is because the Short Time (*ST*) setting for this relay is set at *In* x 10 (40KA). There is no reason for such a high setting given the connected loads, including any inrush contributions, are significantly below this value.

Due to the high *ST* setting and long clearing time the *Ie* is significant and poses a challenge with purchasing effective *PPE* or indeed working in the substation given required safety boundary is 34.9ft.

Figure 6.2.1 Arc flash Pre-Protection Setting Assessment



Noted in the adjacent *TCC* protection curve the green circle indicates the time to clear arc fault current, which is 0.171s. This is significantly reduced from the above because the short time setting proposed is x3 (12KA). This setting allows for all connected loads and inrush contributions whilst reducing the arc Incident Energy (*Ie*) and requirements for Personal Protective Equipment.

Given the *Ie* reduced arc fault boundary distance to 6.3ft, this is an improved practical solution to allow safe working on the critical switchgear.

Figure 6.2.2 Arc flash Post Protection Setting Assessment

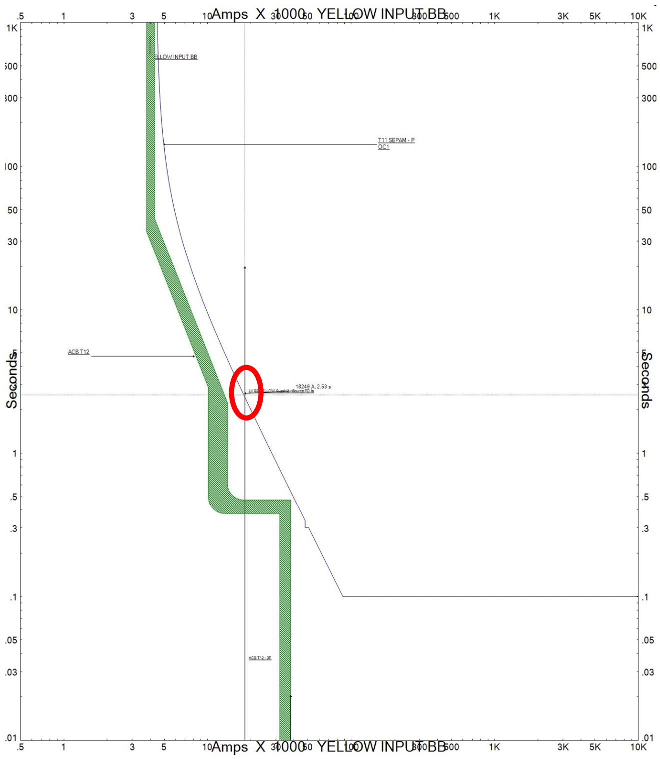
Table 6.2.2 displays a reduction in arc flash incident energy which can be achieved by improving the protection relay curves to clear arc currents as quickly as possible whilst maintaining effective discrimination. Note: DB A1, H1 & yellow/red strings arc energy could not be sufficiently reduced as the other installed LV switchgear, this is due to the ACB protection curve on the LV supply side of the transformers. Typical *ACB* relay curves do not provide the range of curves as the IDMT type. Therefore, a setting could not be provided to reduce arc flash incident levels without compromising on co-ordination of the scheme relays.

Table 6.2.2 Arc Flash Incident Energy Improvements

Reduction of Arc Flash Incident Energy with Improved Protection Relay Settings					
ID	kV	Total Energy (cal/cm²)	AFB (ft-in)	Energy Levels	Final FCT (cycles)
A1 BB LHS	0.415	10.2	8'7"	Level D	13.56
A1 BB RHS	0.415	10.2	8'7"	Level D	13.56
A1 HV	11	7.9	20'10"	Level C	51.82
A1 to A2 Bypass	0.415	10.2	8'7"	Level D	13.56
A2 BB LHS	0.415	21	13'11"	Level D	13.5
A2 BB RHS	0.415	21	13'11"	Level D	13.5
B1 BB LHS	0.415	11.43	9'3"	Level D	25.52
B1 BB RHS	0.415	11.43	9'3"	Level D	25.52
B1 HV	11	7.9	20'10"	Level C	51.82
C1 BB LHS	0.415	18.87	12'12"	Level D	25.1
C1 BB RHS	0.415	18.87	12'12"	Level D	25.1
D1 BB LHS	0.415	11.45	9'3"	Level D	25.91
D1 BB RHS	0.415	11.45	9'3"	Level D	25.91
DBA9	0.415	0.367266	0'11"	Level A	2.57
G1 BB LHS	0.415	14.68	10'9"	Level D	0.34
G1 BB RHS	0.415	14.68	10'9"	Level D	0.34
GEC FBus LHS	11	7.92	20'10"	Level C	51.97
GEC FBus RHS	11	4.21	10'11"	Level C	27.59
GEC RBus	11	1.99	5'0"	Level A	13.5
H1 BB	0.415	17.15	12'2"	Level D	23.5
LV BB DBA1 LHS	0.415	126.74	47'4"	> Level G	200.78
LV BB DBA1 RHS	0.415	126.74	47'4"	> Level G	200.78
LV BB DBB1 LHS	0.415	18.39	12'9"	Level D	35.02
LV BB DBB1 RHS	0.415	18.9	12'12"	Level D	35.41
LV BB DBC1 LHS	0.415	24.78	15'7"	Level D	32.92

ID	kV	Total Energy (cal/cm²)	AFB (ft-in)	Energy Levels	Final FCT (cycles)
LV BB DBC1 RHS	0.415	24.77	15'7"	Level D	32.94
LV BB DBD1 LHS	0.415	18.39	12'9"	Level D	35.02
LV BB DBD1 RHS	0.415	18.8	12'11"	Level D	35.7
LV BB DBG1 LHS	0.415	7.44	3'9"	Level C	5
LV BB DBG1 RHS	0.415	20.73	13'10"	Level D	27.52
LV BB DBH1 Supply1	0.415	162.46	17'5"	> Level G	110.57
LV BB DBH1 Supply2	0.415	162.46	17'5"	> Level G	110.57
LV BB RED Supply1	0.415	162.47	17'5"	> Level G	110.59
LV BB RED Supply2	0.415	162.47	17'5"	> Level G	110.59
LV BB YELLOW Supply1	0.415	172.21	17'12"	> Level G	125.78
LV BB YELLOW Supply2	0.415	172.21	17'12"	> Level G	125.78
PDU A2	0.415	0.323031	0'10"	Level A	0.5
PDU A21	0.415	0.126236	0'5"	Level A	0.5
Rear Bus Ext.	11	1.99	5'0"	Level A	13.5
RED INPUT BB	0.415	17.69	12'5"	Level D	23.63
String 1A	11	7.9	20'10"	Level C	51.82
String 1B	11	7.9	20'10"	Level C	51.82
YELLOW INPUT BB	0.415	14.13	10'8"	Level D	20

Below Figure 6.2.3 & 6.24 *TCC* display the key differences between protection settings on the main LV incoming devices and how these relate to eliminating the arc fault currents and associated incident energy. The goal to improve safety of working operatives and limit damage to the switchgear following a fault of equipment. Therefore, the IDMT relay would provide the best option at the system design stages.

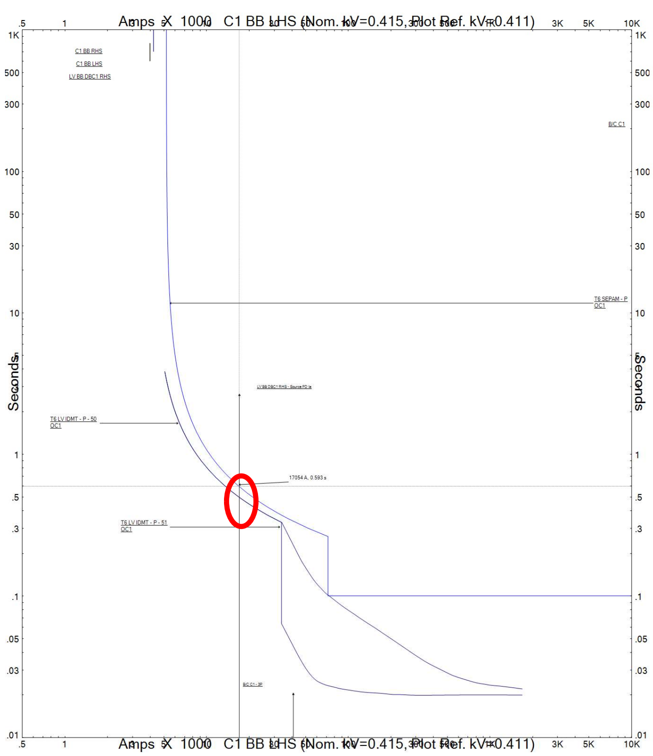


Example 1 – ACB Curve

It can be noted from the Time Current Curve (TCC) the protection device on the HV side of supply transformer is an IDMT relay, with an Extremely Inverse IDMT curve. The LV device is an ACB time/current protection which does not allow for an IDMT curve types, only LT/ST/INST settings.

The issue is limited curve flexibility, with protection clearance time (arcing current) of 2.8s. If the curve type of the IDMT relay is changed to Standard Inverse (SI) the arc current is cleared much quicker although discrimination between the devices is lost. Note below for an improved option.

Figure 6.2.3 *ACB* Protection Curve and Associated Effects on Arc Flash



Example 2 – IDMT Curve

In this example both the HV & LV side of the transformer has IDMT type protections installed, which allows SI curves to be applied at both relays. This IDMT provides flexibility of curve types and ensures effective overload and short circuit protection. Also, more importantly achieving an improved clearance of arc fault current by 2.2 seconds – whilst maintaining time discrimination of devices. Thus, an improved scheme is achievable in comparison to the example above.

Figure 6.2.4 IDMT Protection Curve and Associated Effects on Arc Flash

6.3 A Generalised Approach Flowchart for Improving Operational Availability in a Tier 3 Data Centre

STEPS 1: CARRYING OUT A SYSTEM AUDIT TO CREATE EFFECTIVE MODEL SUB-SECTIONS

STEP 1(A)

COMPLETE A SITE AUDIT AND ESTABLISH THE CURRENT OPERTIONAL PHILOPSOHY AND CONFIGURATION

Carry out an extensive audit of the electrical network and associated documentation, obtaining details for design parameters, load connections, single line diagrams, operational philosophy, and current Tier ratings. Details required as a minimum includes:

Tier rating (Tier 3 or 4), total design capacity (MVA), number of HV supplies provided by the DNO including MVA capacity and nominal voltage ratings (KV), operating configuration for DNO and standby power generators, number of data halls including design load capacity (KA), current connected bus loadings and emergency requirements. Quantity and types of LV & HV switchgear, circuit breakers, and protection relays. Also, details of all Uninterruptible Power Supplies (*UPS*) including types, nominal ratings (KVA & PF), mode of operations and bypass connections. Finally details for all cabling and bus-duct systems (length, cross sectional areas, conductor material and wiring method) and locations of site power metering.

⬇

STEP 1(B)

SPECIFIC DATA COLLECTION OF ELECTRICAL EQUIPMENTS AND OPERATIONAL SETTINGS

Following STEP (1A) the below specific data will be required for construction of the individual simulation components which later compile to the full electrical network construction.

GRID INCOMING FEEDER – L-L-L voltage rating (KV), short circuit capacity (MVA) including L-L-L and L-G values which can be established by enquiry to the network operator, X/R ratio.

STANDBY GENERATOR - L-L-L voltage Rating (KV), power capacity (MVA), Power Factor rating (PF), number of poles, grounding types including resistor value (Ω) or resistor maximum current at L-G voltage (KV), exciter type i.e., salient pole, governor droop mode (%), values for reactance's $Xd'' \leq Xd' \leq Xd$ and associated Time Domains $Td'' \leq Td' \leq Td$.

POWER TRANSFORMER – *IEC* insulation type, power rating (MVA), vector shift i.e., Dyn11, FLC (*A*), percentage impedance (*%Z*), X/R ratio, voltage ratios - Vp/Vs (KV), range of transformer voltage tap settings, grounding configuration i.e., solid or grounding resistor, inrush current (KA), L-L-L symmetrical fault current (KA).

UNINTERRUPTIBLE POWER SUPPLIES (First establish static inverter or rotary construction) - For static inverter: power capacity (KVA), power factor rating (PF), input/output L-L-L voltages (KV), FLC (A), short circuit contribution (KA), grounding configuration i.e., TNC or TNC-S. For rotary construction: power capacity (KVA), power factor rating (PF), input/output voltages (KV), FLC (A), grounding type i.e., TNC or TNC-S, values for reactance's $Xd'' \leq Xd' \leq Xd$ and associated time domains $Td'' \leq Td' \leq Td$.

SWITCHGEAR – Voltage rating (KV), continuous current rating (A), peak current rating (KA), selected conductor materials i.e., copper or aluminium, constructed gaps between conductors L-L and L-G (*mm*).

CIRCUIT BREAKERS - Manufacturer, model class, voltage rating (KA), continuous current rating (A), peak current rating (KA).

PROTECTION RELAYS - Manufacturer, model class, current transformer inputs - type/class, Rated Accuracy Limiting Factor (*RALF*), power rating (KVA), primary current rating (A), secondary current rating (KA). Voltage transformer inputs - primary voltage rating (KV), secondary voltage rating (KV), connection to trip outputs (*LOGIC*), overcurrent settings for both L-L-L and L-G including *IEC* curve type, pick up range, time dial settings.

⬇

STEP 1(B) CONTINUED

SPECIFIC DATA COLLECTION OF ELECTRICAL EQUIPMENTS AND OPERATIONAL SETTINGS

CABLES – Voltage rating (KV), frequency rating (Hz), British standard construction type i.e., BS6622 which is an XLPE multicore, conductor cross sections area CSA (mm^2), Insulation thickness (mm), cable diameter (mm), British standard value for insulation tolerance i.e., ±15% for BS6622.

BUS LOADS – Voltage rating (KV), apparent power (KVA), reactive power (KVAr), active power (KW), Power Factor (PF), characteristics - static or dynamic (%).

RELIABILITY DATA – Applicable for grid incoming feeders, standby generation, power transformers, *UPS*, circuit breakers and cables. Active failure rates expressed as failure per year, Mean Time To Repair (*MTTR*) rate per year, to be noted as per manufacturer guidelines or *IEC* Std.493 (where manufacturer data is not available).

STEP 1(C)

SINGULAR EQUIPMENT MODEL SIMULATIONS AND PROOF OF THEORETICAL CALCULATION

Each of the following data centre equipment are key to the successful system construction and simulation, therefore each model component must be individually simulated, as far as reasonably practical, and proven to be accurate (±2.5%) against the manufacturers literature and theoretical calculations, As detailed below:

GRID SOURCES – Information of grid incoming supplies will firstly be established by enquiry to the *DNO*, calculation of short circuit currents is to be in-line with IEC60909 where L-L-L symmetrical fault currents will be calculated by $\frac{MVA\,rating}{\sqrt{3}.V_L}$ base impedances will also be verified with the following calculation $Z_b = \frac{{V_b}^2}{VA_b}$ and the converted to 100MVA base to compare with the values provided by enquiry and simulation results i.e. $Zpu = Z\,.\frac{MVA\,base}{{V_b}^2}$ IEC60909 values are established at the first system bus connected to the *DNO* feeder.

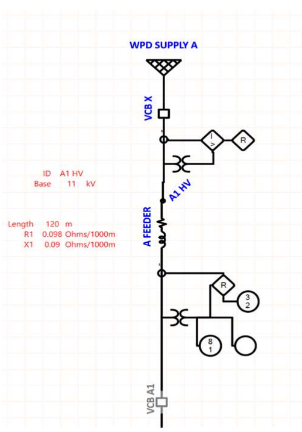


Figure 6.3.1- Example Single Grid Source Model

DISTRIBTUION TRANSFORMERS – Carry out a theoretical calculation of L-L-L symmetrical fault current in-line with the IEC60909, once this value is established it must be converted to a transformer secondary current and subjected to the IEC60909 Cfactor then compared against the manufacturers test data and simulation results for proven accuracy. Calculations utilised; Primary fault current $I_p = \frac{MVA\,rating}{\sqrt{3}.V_L}$ converting primary to secondary current $\frac{Vp}{Vs}.I_p = I_s$ application of IEC factors for symmetrical fault current $I_f = I_s\sqrt{2}$ then utilsing Cfactor i.e $\frac{I_f}{1.05}$ for systems ≤1001 $V_{A.C.}$ Construction of the model for trial simulations must be as the most simplist form with one single input and ouput bus, no load, and cable lengths set to the minimum i.e negating any further system impedances at this proof of concept stage.

(SEE DIAGRAM BELOW)

<u>STEP 1(C) CONTINUED</u>

SINGULAR EQUIPMENT MODEL SIMULATIONS AND PROOF OF THEORETICAL CALCULATION

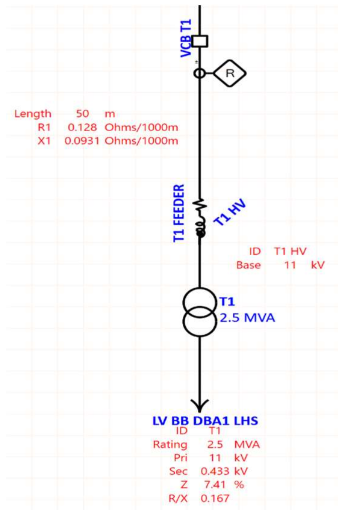


Figure 6.3.2 – Example Single Transformer Model

STANDBY GENERATOR – The generator manufacturers data must be utilised for impedance (Xd’<Xd’<Xd) and time constants (Tdo’’<Tdo’<Tdo) to calculation theoretical fault currents, firstly during open time constants by utilising the following equations:

$$E'' = [\,(1 + Xd''I\,Sin(\theta))^2 + (Xd''I\,Cos(\theta))^2\,]^{\frac{1}{2}}$$
$$E' = [\,(1 + Xd'I\,Sin(\theta))^2 + (Xd'I\,Cos(\theta))^2\,]^{\frac{1}{2}}$$
$$E\ = [\,(1 + Xd\,I\,Sin(\theta))^2 + (Xd\,I\,Cos(\theta))^2\,]^{\frac{1}{2}}$$

$$I'' = \frac{E''}{Xd''}\ \mathrm{x}\ FLC$$

$$I' = \frac{E'}{Xd'}\ \mathrm{x}\ FLC$$

$$I = \frac{E}{Xd}\ \mathrm{x}\ FLC$$

Where: I is the P.u value of 1 at rated MVA, given Cos(θ) is load *PF*, assuming *EMF* = V, *FLC* = Full Load Current (*A*).

Once these values are established further equations can be utilised for calculation of currents during transient time constants, firstly establishing the decay period between *I’* and *I*

During short circuit time constants equations become:

$$\mathrm{Td}'' = \frac{Xd''}{Xd}\,Tdo'' \qquad Td' = \frac{Xd'}{Xd}\,Tdo'$$

Therefore, fault current at a given time constant (t):

$$i = I_d\, e^{-\left(\frac{t}{Td}\right)} + I$$

Where:

$I_d = I' - I$

STEP 1(C) CONTINUED

SINGULAR EQUIPMENT MODEL SIMULATIONS AND PROOF OF THEORETICAL CALCULATION

Construction of the model for trial simulations must be in the most simplist form with a single generator under investigation at anyone time, no load connections, and cable lengths set to the minimum i.e negating any further system impedances at this proof of concept stage. Symmetrical fault currents after trasnient decay should be compared between simulation, theoretical calulation and manufacturers data ensuring an accuary of < ± 2.5%.

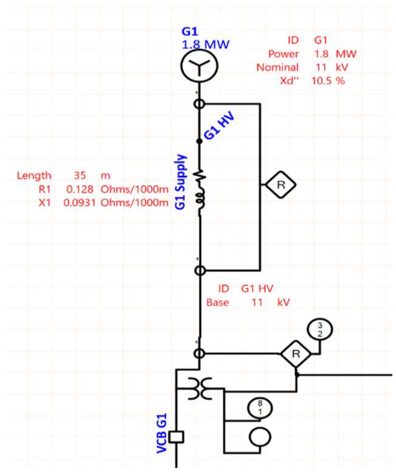


Figure 6.3.3 - Example Single Generator Model

ROTARY UNINTERUPTABLE POWER SUPPLY – Note rotary *UPS* machines shall follow the same proof of concept process as the above synchronous generators, with exception to a synchronous motor at negative Power Factor (*PF*) utilised to represent the transient data of a given *UPS* machine (see below example construction). A static *UPS* construction can be represented as a multiplier of its base rating within the ETAP standard model block i.e. $I_f = I_b \, . x$ (where I_b is the machines base current rating in Amperes). IEC60909 L-L-L symmetrical fault current values between theoretical calculations, manufacturers data and simulation should be within an accuracy limit of < ± 2.5%. Construction of the model for trial simulation must be as the most simplist form with a single *UPS* under investigation at anyone time, no load connections, and cable lengths set to the minimum i.e negating any further system impedances at this proof of concept stage.

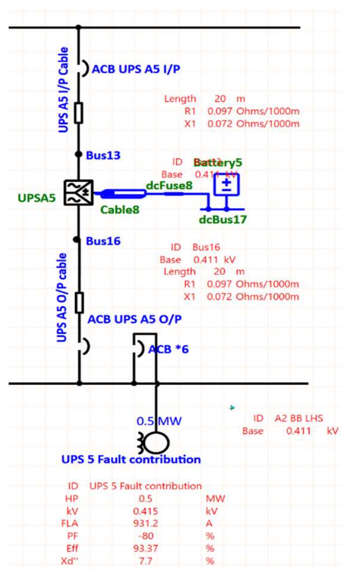


Figure 6.3.4 – Example Rotary *UPS* Model Construction

STEP 1(C) CONTINUED

SINGULAR EQUIPMENT MODEL SIMULATIONS AND PROOF OF THEORETICAL CALCULATION

DISTRIBUTION CABLING – Confirmation of the accuracy of theoretical calculations, simulation, and manufacturers values (*X* P.u) for all the different cable construction types installed within the data centre electrical network must be completed utilising:

$$L = 0.46 \log \frac{d}{r} \ \ \mu H/m$$

Where: d represents the distance between conductors *(mm)*, Re represents conductor geometric mean radius (*mm*) L is the Inductance (*H*)

Once the cable inductance has been established the inductance reactance (X_L) and P.u value can be calculated with application of:

$$\mathrm{X_L} = 2\pi \mathrm{fL}$$

$$\mathrm{X\,P.u} = \frac{\mathrm{MVA}}{\mathrm{KV}^2} \,.\mathrm{X_L}$$

STEP 1(D) CHECKPOINT

Confirm accuracy of singular model components are ± 2.5%of calculated values (and manufacturers data if available)

N → **DO NOT PROCEED TO STEPS 2**

Go to Step 1(B)

Y

STEPS 2: BUILDING A COMPLETE DATA CENTRE ELECTRICAL NETWORK MODEL AND ESTABLISHING STUDY CASE PARAMETERS

STEPS 2(A) – CONSTRUCTING THE COMPLETE ETAP MODEL FROM SINGULAR COMPONENTS

CREATING A BASE MODEL PROJECT - Create an ETAP project file (*Oti), set project standards to IEC 50Hz, utilising the singular model components from steps 1(C) construct the complete electrical network model, ensuring this is an exact replica of the data centre power system and data resourced from the audit and single line diagrams in steps 1(A). Within ETAP 'Data Manager' this model becomes 'BASE 1' and should represent the system in nominal configuration. 'BASE 2' 'BASE 3' etc. can be copied from this original 'BASE 1' network and allow further changes of operational configuration to suit several system loadings or operational configurations. These loadings and site configurations should align with the operational philosophy for a given data centre, as discovered in steps 1(A) i.e., the site audit, design Tier rating and system/literature reviews.

ESTABLISHING PARAMETRES AND INTERNATIONAL STANDARDS FOR STUDY BASE MODELS – Once the base models are constructed and checked for accuracy against the original single line diagrams, a set of international standards are applied to the study case before any simulations commence. These are as noted below:

STEPS 2(A) – CONTINUED

STUDY TYPE	PARAMETRES TO ASSIGN
LOAD FLOW	Calculation method: Adaptive Newton Raphson (Max iterations 99, Precision 0.001) Initial bus voltages: set as normal bus loadings. Loading categories x3: set as normal current system load, also design capacity (as Tier ratings), then emergency (design capacity +10%) Diversity factor: None (unless established as a requirement in Step 1A). Bus Alerts: over voltage 102% (marginal) 105% (critical), under voltage 95% (marginal) 98% critical
SHORT CIRCUIT ANALYSIS	Standard: IEC60909 (X/R Calculation Method C) Cmax Factor 1.05
PROTECTION DEVICE CO-ORDINATION	Standard: IEC60909 Cmax Factor 1.05 Fault values: KA Symmetrical rms Fault types: L-L-L, L-L, L-L-G, L-G consideration of upstream protection devices: value should match data from steps 1(A) i.e., for 3 upstream devices.
ARC FLASH	Arc flash standard: IEC 1584:2002 Bus fault current: Calculated Fault clearing time: Auto select from upstream protection device. Incident energy standard: NFPA 70E 2012:2018

STEP 2(B) CHECKPOINT

Confirm base model(s) are aligned with information from Step 1(A) i.e., audits/ single line diagrams, also all model components utilised are proven as Step 1(C). Plus, model standards have been applied as Steps 2.

N

DO NOT PROCEED TO STEPS 3

Go to Step 1(A)

Y

STEPS 3: BENCHMARKING EXISITNG RELIABILITY PERFORMANCE

STEP 3(A) – SIMULATE THE CURRENT SYSTEM RELIABILITY

Complete a suite of reliability assessment calculations in ETAP power system simulation software, initially on each of the base models. Record each bus bar load point reliability index, expressed as the average annual failure rate hrs/yr (λi).

These steps have modelled the complete data centre electrical network and provided a benchmark reliability index, as per the installed equipment and operational configurations. The result values can be compared to the system design criteria as outlined in the original Tier rating i.e., Tier 3 or 4. The proceeding steps in section 4 will now focus on a sequential methodology of studying and each power system study, with a view to improving the overall system reliability as described in Steps 5 onward.

STEPS 4: APPLYING A SERIES OF POWER SYSTEM SIMULATION SCENERIOS TO THE DATA CENTRE ELECTRICAL NETWORK

STEP 4(A) – LOAD FLOW ANALYSIS

Arrange the complete system model into the correct Tier 3 or Tier 4 configuration (as per original design criteria). Apply the following load values to the 'healthy' system bus bars as three sperate simulations; 1) Normal Operation i.e., to simulate the actual present network loads. 2) Design Operation – 100% load capacity of each system bus bar i.e. to simulate design limits of the electrical network. 3) Emergency Operation - 110% of design capacity i.e., simulation of the worst-case scenario of operation for the electrical network. For each simulation ensure the following simulation values are recorded for each system bus bar. V_{L-L}, KW, KVA_r. Also, where possible during normal operation record the actual system busbar voltages V_{L-L} for comparison with simulation 1.

With these simulated values established, for a healthy network, a Voltage Security Index (Vsi) can be established for each system bus bar, utilising the following:

$$Vsi = \sum_{i=1}^{NB} \frac{1}{2}\left(\frac{|V_i| - |V_i^{sp}|}{0.075}\right)^2$$

Where:

$|V_i|$ represents the calculated magnitude of Voltage rms at busbar i.

$|V_i^{sp}|$ represents the specified Voltage rms of busbar i.

NB represents the number of load buses in System.

With an initial load flow study complete and results captured for the data centres electrical network in nominal configuration the standby power generation must also be considered. Firstly, the complete network model will need to be updated to reflect disconnection of grid supplies and connection on nominal standby generators i.e., the complete network being supplied by temporary power sources (e.g., BASE X). The system is again subjected to the same simulation scenarios as those listed above for the healthy network. For this generator scenario the results captured should focus on the generator capability curves and ISO8528-1 operating limits. Therefore, the following values must be recorded V_{L-L}, KW, KVA_r, PF.

STEP 4(B) – SHORT CIRCUIT ANALYSIS

The complete system model must be subjected to IEC60909 fault analysis with short circuit current values captured at each system bus bar (KA), this is to be inclusive of the electrical network during its varying operational scenarios as defined in Steps 1(A). This study will require multiple simulations with an example Tier 3 data centre system shown below:

STEP 4(B) – CONTINUED

Electrical Power Sources – Example Configurations for Short Circuit Analysis.						
DNO supply 1	✓	✓	✓	×	×	×
DNO supply 2	✓	×	✓	×	×	×
Generator 1	×	×	✓	✓	✓	✓
Generator 2	×	×	✓	✓	✓	✓
Generator 3	×	×	✓	✓	✓	×
Generator 4	×	×	✓	✓	×	×
Generator 5	×	×	✓	×	×	×

Where; ✓ is a Power Source connected to the Network and × is a Power Source Disconnected from the network.

As for generators the *UPS* simulation scenarios will be complex and should include all the below, for a given Tier 3 or Tier 4 data centre.

***UPS* - Mode of operations to be Simulated for Short Circuit Current Analysis, at each system bus bar connected to the *UPS*.**
3 *UPS* in parallel configuration, connected to the network.
4 *UPS* in parallel configuration, connected to the network.
5 *UPS* in parallel configuration, connected to the network.
3 *UPS* synchronised to the site main incoming supplies (i.e. for no break transfer requirements)
4 *UPS* synchronised to the site main incoming supplies (i.e. for no break transfer requirements)
5 *UPS* synchronised to the site main incoming supplies (i.e. for no break transfer requirements)
5 *UPS* during standby battery operation, during loss of main supply.
Bypass mode – All *UPS* offline and disconnected from the network (i.e. during maintenance periods and hard bypass arrangements)

For each of the short circuit simulations above the symmetrical and peak fault currents at every system bus bar should be recorded, including L-L-L, L-L, L-L-G, L-G values (KA).

STEP 4(C) – PROTECTION COORDINATION

Protection assessments are essentially split into two separate investigations, which are Time Current Curve (*TCC*) and Non-Time Current Curve (*NTCC*). For *TCC* protection assessments the following scenarios should be investigated in ETAP star evaluation model (inclusive of all overcurrent and ground faults).

TCC PROTECTION SCENERIOS

Transformer HV to LV grading discrimination.
HV ring system faults during single DNO supply.
HV ring system faults during dual DNO supplies.
Discrimination during islanded generator supply, with downstream devices.
HV faults during synchronised supplies (DNO & synchronous generators) – focus on main ring feeders, interconnectors, and parallel points.
LV Rotary *UPS* co-ordination with both upstream and downstream devices, including bypass mode assessment and transformer incomer circuit breakers.

*Note these *TCC* scenarios must include all operational configurations as defined in Steps 1(A), i.e., 'BASE 1' 'BASE 2' etc.

NTCC protection devices shall also be assessed with ETAP star evaluation module and against manufacturers data defined in Steps 1(A).

STEP 4(C) – CONTINUED

***NTCC* PROTECION SCENERIOS**

G59 synchronised settings for the main High Voltage (HV) ring main incoming circuit breaker protections and generator outputs.
SOLKAR unit protection on any HV ring cable interconnectors.
Restricted L-G (REF) settings on all HV distribution transformers.
Generators ANSI 49RMS, 87M, 46, 32Q, 32P, 81L, 81H, 27, 59, confirmation of settings against manufacturers guidance and international standards.

Any protection setting issues or mis-coordination must be recorded in a *TCC* characteristic curve plot or protection settings table for *NTCC* allowing further investigation and improvement detailed in Steps (5). All installed devices within the network (from main incomer to critical load *PDU* should be investigated) these devices will have been discovered is Steps 1(A).

STEP 4(D) – ARC FLASH ANALYSIS

Utilising ETAP Arc Flash IEEE1584 module a series of operational configurations are to be assessed, providing the established arc incident levels at each system bus bar, simulation values are to be recorded for each system bus bar, which includes Total incident energy (J/cm^2), arc flash boundary levels (m), fault clearing times (s) and required *PPE* rating. Operational scenarios for a Tier 3 data centre must include.

1) Parallel operation of Distribution Network Operator (*DNO*) cable feeders supplying all connected critical loads.
2) Island mode of operation i.e., with standby diesel generators connected to critical loads and removed from grid (*DNO*).
3) Standby generators connected in parallel with distribution network operator (*DNO*) cable feeders, for example as a short term parallel G59, no break transfer of critical load.

STEP 4(E) CHECKPOINT

Confirm simulation results are recorded, for all operational scenarios as defined in Steps 4(A), 4(B), 4(C), 4(D)

N

DO NOT PROCEED TO STEPS 5

Go to Step 4(A)

Y

STEPS 5: ANALYSIS OF SIMULATION RESULTS & OPTIMSING THE ELECTRICAL NETWORK

STEP 5(A) – LOAD FLOW ANALYSIS

Load flow results recorded must be analysed against ANSI C84 and BS7671 specified values, which were set as simulation parameters in Step 2(A), where equipment do not align with these values improvements can be achieved. The three areas and conditions for improving load flow values in-line with International Standard requirements are as below.

STEP 5(A) – CONTINUED

CONDITION 1: DISTRIBUTION TRANSFORMERS

The operational cost of a distribution transformers and system voltage is a function of the transformer tap setting, where at nominal load the installed transformer energy costs align with the below condition, i.e., the optimal tap setting has been obtained for a Tier 3 data centre system.

$$TX\ E_{cost} \leq 0.5428$$

Where;
TX E_{cost} is the total annual energy cost for a distribution transformer, per MVA (£m) and can be calculated at a given loading with unit cost of £0.10 per KWh.

CONDITION 2: SWITCHGEAR VOLTAGE SECUIRITY INDEX

All installed switchgear busbar voltage security indices must comply with the below condition, this will ensure a nominal bus voltage within ANSI C84 and BS7671 specified limits, thus providing sufficient capacity for voltage drops and connecting design loads (as established in Step 1(A)).

$$0.25 \geq 0.5 \left(\frac{V_i - V_{sp}}{V_{lim}}\right)^2$$

Where;
V_i represents the simulated Voltage rms (V_{L-L})
V_{sp} represents the specified Voltage rms (415V_{L-L})
V_{lim} represents the Voltage rms deviation (V_{L-L})

CONDITION 3: GENERATOR VECTOR STABILITY CURVES

During operational simulation scenarios defined in Steps 1(A) the generator vector stability curve should not be exceeded and follow the below condition, ensuring optimal bus voltages throughout the range of system loadings. These load values must be plotted or compared with manufactures curve guidelines.

$$P_n < P_d < P_d \times 1.1$$

Where;
P_n represents the nominal site load power (MW)
P_d represents the system power design capabilities (MW)
P_d x 1.1 is 110% of the system design capacity

STEP 5(B) CHECKPOINT
Confirm all simulation results achieved load flow conditions 1,2 & 3 before proceeding with short circuit analysis.

N

INVESTIGATION REQUIRED BEFORE PROCEEDING TO STEPS 5(C)
Go to Step 4(A) to re-simulate load flow scenarios, investigating range of transformer tap settings, available design loads, cable feeders and standby generator bus voltage set points.
For optimal operational reliability, all 3 conditions should be achieved.

Y

STEP 5(C) – SHORT CIRCUIT ANALYSIS

The data centre electrical network short circuit results must be analysed against the manufacturers guidance and international standards, the following six conditions will ensure compliance with these attributes and optimal management of such faults. Thus, improving the operational availability of the network and support optimal protection operations and arc flash mitigation as described in Steps 5(E) & 5(F)

CONDITION 1: SWITCHGEAR BASE CURRENT RATINGS

Switchgear base current ratings must not exceed the below, note for any input switchgear on *UPS* power strings the battery charge current and Tier 3 configurations must also be considered, these operational philosophies are established in Steps 1(A) & 1(B):

$$I_n \leq 0.95 \times I_b$$

Where;

I_n represents the nominal connected bus load currents (*A*) including any Tier 3 redundant capability.

I_b represents the switchgear continuous current rating (*A*) as specified by ANSI C37.20.2.

CONDITION 2: SWITCHGEAR FAULT CURRENT RATINGS

Each of the installed switchgears must comply with the below condition where the L-L-L fault current value is a criterion from the IEC60909 study in Step 4(B).

$$\text{L-L-L} < \text{IEEE Std. C37.21}$$

Where;

IEEE Std. C37.21 specifies switchgear short circuit current withstand ratings.

CONDITION 3: CONSIDERATION FOR *UPS* STATIC OR ROTARY TYPE FAULT CONTRIBUTIONS

UPS static path fault contribution for model components must align with below optimal condition:

$$K_{ac} = 1200 \text{ to } 1400\%$$

Where;

K_{ac} represents the short circuit current value expressed as percentage of nominal *UPS* current rating.

However, *UPS* rotary construction types must include transient impedances and time constants as below. This will provide a true accurate representation of fault currents and must be considered for equipment fault ratings and associated protection settings.

A synchronous motor (model block) is to be utilised in any simulation, for representation of the rotary *UPS* sub transient components, where transient data is sourced from the *OEM*:

$$X_d'' < X_d' < X_d$$

Where;

OEM is the Original Equipment Manufacturers

Xd'' represents the Sub Transient Impedance, Xd' represents the Transient Impedance, Xd represents the Steady State Impedance

CONDITION 4: GENERATOR STATOR RATING

For all operational scenarios defined in Steps 1(A) the standby generator stator operation must not exceed IEC60034 specified values, which can be plotted in the associated *TCC* curves.

$$2.18 \times FLC \text{ is less than 10seconds load duration}$$

Where; *FLC* = Nominal full load current rating of the generator (A).

STEP 5(C) – CONTINUED

Also, allow consideration for equipment fault ratings i.e. that equipment connected to the generator system must be confirmed as sufficient rating for the fault currents present, these fault current will be proportional to the generator system impedance as shown below.

$$X_d' < X_d$$

Where;
Xd' represents the direct axis transient reactance
Xd represents the direct axis synchronous reactance

CONDITION 5: DISTRIBUTION TRANSFORMERS

For all operational scenarios defined in Steps 1(A), a distribution transformer fault current must satisfy:

$$I_m < In \times 8$$
$$T_m < 6 \text{ cycles}$$

Where;
I_m represents the distribution transformer magnetising current, expressed as multiple of nominal current rating.
T_m represent the time in seconds for transformer inrush to clear i.e., return to steady state conditions.

Faults current scenarios simulated from steps 1(A), on the transformers secondary connections must include all system impedances as:

$$Z = Z_s + Z_t$$

Where;
Z represents the total impedance for a given fault on the transformer secondary.
Z_s represents the upstream system impedances.
Z_t represents the specific transformer impedances.

Short circuit current values obtained for the distribution transformers must comply with both frequent and infrequent values as IEEE C57. This will ensure the magnitude and duration of either fault type will not deteriorate or damage transformer windings, which may lead to future reliability issues.

$$I^2 t = K < \text{IEEE C57.109 specified values}$$

Where;
I represents the symmetrical fault current expressed as a multiple of the transformers nominal current rating.
K represents the constant determined at maximum I when t=2.
t represent the time Seconds (s)

STEP 5(D) CHECKPOINT

Confirm all simulation results achieved short circuit conditions 1,2,3,4 & 5 before proceeding with protection co-ordination.

N

INVESTIGATION REQUIRED BEFORE PROCEEDING TO STEPS 5(E)

Go to Step 4(B) to re-simulate short circuit scenarios.

For optimal operational reliability, all 5 conditions (checkpoint 5D) should be achieved.

Y

STEP 5(E) – PROTECTION CO-ORDINATION

For all the protection devices installed within the data centre electrical network, as defined in steps 1(A), the below outlines optimal protection conditions for each of the critical equipment which are located within such Tier 3 electrical networks.

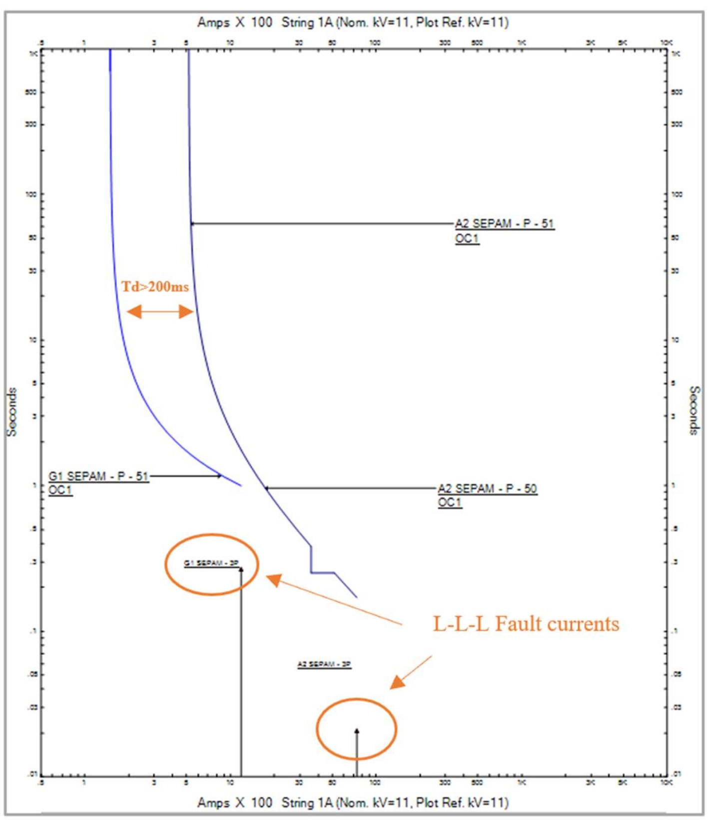
SYNCHRONOUS GENERATORS

Curve type = IEC SI
Phase Overcurrent 50/51: 1.2 x I_n
Earth Fault 50N/51N: 10% of NER rating
Machine Differential 87M: 5 to 10% I_n (stator), 20% I_n (frame faults)
Reverse Active Power 32P: 5 to 20% P_n, $T_d = 3$
Under/Over frequency 81L/H: ± 2Hz, $T_d = 3$
Under voltage 27: 0.75 to 0.85 x U_n, $T_d = 3$
Over voltage 59: 1.1 x U_n, $T_d = 5$

Note: Where settings deviate from those above, for any overcurrent and earth fault settings, time discrimination between protection curves (*TCC*) should be a minimum $T_d > 200$ms, including the output circuit breakers of any generator and HV ring feeder circuit breaker protections.

Where;
I_n represents the nominal current rating (A), for the generator in this case.
P_n represents the generator continuous power rating (MW).
NER represents the neutral earth resistor rating (A).
T_d represents the time delay in seconds (s).
Un represents the L-L Voltage rms (V_{rms}).

Example generator *TCC* with T_n >200ms time discrimination from upstream circuit breaker, important to note system fault levels should also be plotted on the *TCC* graph. In this instance a fault on bus A2 will be cleared by A2 SEPAM before G1 SEPAM.



UNINTERRUPITBLE POWER SUPPLIES (UPS)

Optimal settings for *UPS* online mode: Overcurrent settings for Long Time *(LT)* pick up current $\geq 1.5 \times I_n$, $T_d > 200ms$ - relevant to both the *UPS* input and output circuit breaker protection devices since continuous ratings will be different.

Note: For issues encountered with the time element of *UPS* protection relays, it's possible target for $T_d = 0$, between *UPS* input and output circuit breakers, i.e., no requirement to time grade between either side of the machine connections in terms of improving resiliency or reliability, operation of either protection under fault scenarios will disconnect machine from service.

Where;
LT represents the protection relay long-time pick-up current setting (A).
I_n represents the nominal current rating (A), for the *UPS* in this case.
T_d represents the time delay in seconds (s).

For *UPS* whilst in offline/bypass mode: overcurrent settings must follow: $I_1 > 1.5 \times I_2$ and $T_{d1} > T_{d2} + 200ms$ (for bypass protection against all downstream outgoing power distribution unit (PDU) data hall loads).

Where;
I_1 represents the bypass protection relay current setting (A), I_2 represents the downstream *PDU* relay current setting (A)
T_{d1} represents the time delay on bypass protection relay (S), T_{d2} represents the time delay on downstream *PDU* protection relay (S)

UPS voltage and frequency operational protection settings (listed as *ANSI* codes) must comply with:

81L/81H/27/59 < *ENA G59* limits

Where;
81L/81H are the underfrequency and over frequency relay settings (Hz)
27/59 are the undervoltage and over voltage relay settings (V)

Also, *UPS* input circuit breaker instantaneous protection setting must not exceed:

$$I_{INST} \leq 10 \times I_n$$

Where;
I_n represents the nominal continuous current rating (A), for the *UPS* in this case.
I_{INST} = *UPS* circuit breaker instantaneous current setting, expressed as multiple of machine nominal rating.

DISTRIBTUION TRANSFORMERS

Optimal overcurrent protection settings for the data centre distribution transformers: $LT > 1.25 \times I_n$ & $< 1.5 \times I_n$. Whereas ground fault current settings must align with $Ig = 0.3 \times I_n$. Time delay for both overcurrent and earth fault, between transformer feeder and upstream protection devices must satisfy $T_{d1} > T_{d2} + 200ms$. Definite Time (*DT*) settings must be avoided, also no reliability benefits to time grade either side if the transformer i.e., HV & LV devices. Where *REF* is fitted knee point voltage must comply with $Vk > 2 \times Vs$.

Where;
I_n represents the nominal continuous current rating (A), for the transformer in this case.
LT represents the protection relay long-time pick-up current setting (A).
I_n represents the protection relay ground fault setting current (A).
T_{d1} represent the time delay setting of upstream protection device (s).
T_{d2} represents the time delay setting of the transformer protection device (s).
Vk represents the setting voltage of *REF* relay (V), Vs represent the voltage present at the *REF* relay (V), during an Earth Fault L-G (Ig).

System fault currents simulated in Step 4(B) must comply with the transformer thermal ratings specified by the IEEE C57.109, this will ensure symmetrical fault currents do not damage the transformer winding insulations and can be added to the associated protection *TCC* plot within ETAP i.e., cross referencing both Short Circuit Current (*SCC*) values and relay operating times. Note *IEEE* C57.109 formula below.

⬇

STEP 5(E) – CONTINUED

$$I^2t = K < IEEE \text{ C57.109 specifications}$$

Where;

I represent the symmetrical fault current expressed as a multiple of the transformer continuous current rating (A).
K represents the constant determined at maximum I when t=2.
t represents the time taken for the protection relay to operate, with installed settings (S).

HV & LV MAIN FEEDERS

Optimising settings for HV main incoming supplies, for ground fault L-G and differential protection conditions:

$$Ig\ Td < (Ig_{dno}\ Td_{dno}) + 200ms$$
$$DNO_{dp}\ Td > 200ms + (PNO_{dp}\ Td)$$

Where;

Ig represents the relay ground fault current settings (A), Ig_{dno} represents the DNO relay ground fault current settings (A).
T_d represents the time delay on main feeder protection (s), Td_{dno} represents the time delay DNO circuit breaker (s).
DNO_{dp} represents the *DNO* differential protection setting (A), including time delay (s).
PNO_{dp} represents the *PNO* differential protection setting (A), including time delay (s).

For a Tier 3 data centre network with short term paralleling requirements feeder protection settings should comply with the ENA G59 requirements as outlined below.

$$UV\ \&\ OV\ \pm 6\%\ Un,\ Td = 0.5$$
$$UF\ \&\ OF\ \pm 0.5\ Hz,\ Td = 0.5$$

Where;

UV represents undervoltage (KV), *OV* represents over voltage (KV)
UF represents underfrequency (Hz), *OF* represents over frequency (Hz)
Un represents L-G Voltage rms (KV)
Td represents the time delay (s)

Optimising settings for LV Main feeder protections, pick up and instantaneous currents.

$$INST > 12 \text{ x } I_n < 14 \text{ x } I_n.$$
$$LT > 1.25 \text{ x } I_n.$$

Where;

I_n represents the nominal current (A), for the switchgear in this case.
INST represents the instantaneous current setting of the relay(A).
LT represents the protection relay long-time pick-up setting (A).

OTHER GENERALISED OPERTAIONAL REQUIREMENTS

For continuous improvement of Operational Availability (*Ao*) and to support onsite maintenance engineers the following measures must be applied:

Protection schemes should include operational relays to denote signalling of LV inter-trip received, HV inter-trip send, and vice versa, that is applicable for every distribution transformer within the network. This will support a speedy restoration by engineering operatives should a fault occur (i.e., Improving *MTTR* rates). Single Line Diagrams (*SLD*) and circuit breaker protection records must be periodically updated, as part of preventative maintenance schemes, during audits it was found may records were legacy and did not accurately represent the system settings.

A duplicate copy of all protection relays settings and grading curves (including *TCC* plots) is to be held on secure, on-site electronic storage media with copies of all software and Equipment required to connect with relay devices, this is to support fault investigation and or replacement.

STEP 5(E) – CONTINUED

Critical spares for all protection equipment should be identified, procured, securely stored, and periodically checked for functionality and availability. This can be achieved through the preventative maintenance scheme.

Onsite maintenance teams must be suitably trained for HV network operations, including those tasks associated with the installed protection devices. This will support the safe operation of all electrical network equipment during both normal and fault scenarios.

A suite of Emergency Operational Procedures (*EOPS*) must be created, reviewed, and approved annually. These *EOPS* are to cover disaster scenarios planning i.e., unexpected failures in the electrical network, and for control of standby power machines - including manual controls and synchronising, these can often be the last opportunity to limit network issues and provide uptime of critical equipment, during periods of network issues.

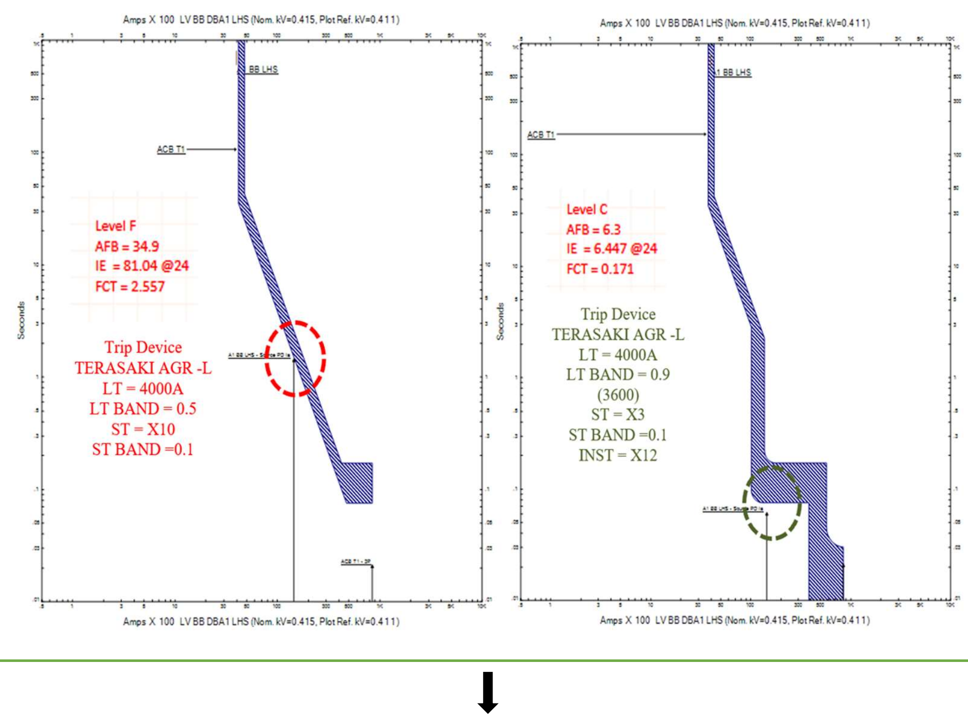
STEP 5(F) – ARC FLASH CONDITIONS

To ensure a reduction of arc flash incident energy to an amount which is significantly less likely, under fault conditions, to permanently damage the equipment and enable the safe use of *PPE* for maintenance operations, the following conditions must be achieved, for each of the switchgears installed within the data centre's electrical network.

$$\mathrm{E} < 30\ \mathrm{J/cm^2}$$
$$\mathrm{FCT} < 35\ \text{cycles}$$
$$\mathrm{INST} < \mathrm{I_n} \times 14$$
$$\text{or}$$
$$\mathrm{RSO} > 25\mathrm{m}\ \text{from the installed switchgear \& equipment}$$

Where;
E represents the arc flash incident energy ($\mathrm{J/cm^2}$).
FCT represents the relay fault clearing time (ms).
INST represents the associated upstream protection relay's instantaneous setting, for any given fault simulated.
RSO is the Remote Switching Operations i.e., an ability to open/close circuit breakers from remote locations.

Below protection relay Time Current Characteristic (*TCC*) displays the important of ensuring the correct instantaneous protection setting of the upstream circuit breaker is achieved, with application of an instantaneous current setting, over and above a short time current setting, it noted the arc fault boundary distance is reduced from 34.9m to 6.3m and incident energy reduced from 81.04 J/cm^2 to 6.447 J/cm^2. This is because the instantaneous setting ensures a quicker clearance of fault current, by over 2.3 seconds in this example.



STEP 5(G) CHECKPOINT

Confirm all simulation results comply with conditions in 5(E) and 5(F) before proceeding to steps 6.

N

INVESTIGATION REQUIRED BEFORE PROCEEDING TO STEPS 6.

Go to steps 5(E) to re-evaluate system protection parameters.

Y

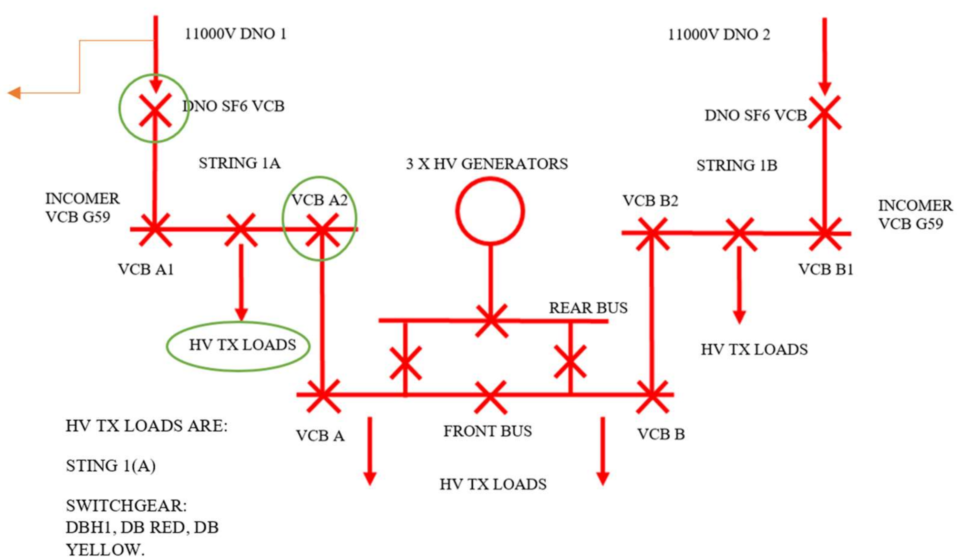
STEPS 6: ESTABLISHING THE IMPROVED RELIABILITY PERFORMANCE

STEP 6(A) – SIMULATE THE IMPROVED SYSTEM RELIABILITY

The final step is to again run the reliability assessment calculations in ETAP power system simulation software, i.e., on the improved base model which has achieved all 5 steps criteria of this flowchart. Simulation results should be recorded for each bus load point reliability index as an average annual failure rate hrs/yr (λi).

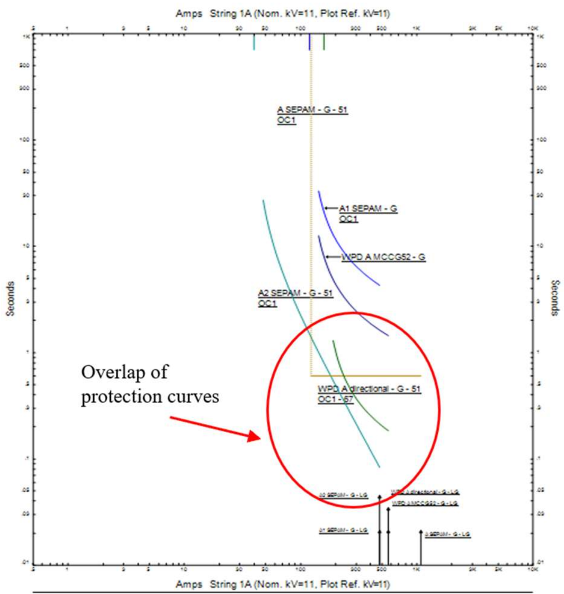
This process will have successful modelled the complete data centre electrical network and provided a new reliability index, as per the installed equipment and operational configurations (improved). These values can be compared to the original design criteria as outlined in the original Tier rating i.e., Tier 3 or 4 (as Step 1A) and the original system performance discovered in Step 3(A) – before improvements were made. The generalised approach will improve electrical network operational issues and lead to improved reliability metric, as the below is one example of many encountered with this Tier 3 system.

In this example a L-G fault was simulated on the *DNO* incoming supply (No.1), whilst the data centre was in parallel i.e., operating their standby generators which is common for no break transfers. Before improvements were made utilising this approach *VCB* A2 protection operated before the *DNO* therefore the critical distribution transformers (STRING 1A) were unnecessarily disconnected.



STEP 6(A) – CONTINUED

PROTECTION CHARACTERISTICS BEFORE AND AFTER APPLICATION OF THIS GENERALISED APPROACH:



Relay ID	L-G fault current (A)	Operating time (s)
VCB A2	485	0.08
DNO 1	572	0.186
VCB A	485	0.59
VCB A1	485	4.27

As it can be seen from the TCC plot, DNO 1 operates within 0.186s whereas VCB A2 operates with 0.08s hence the disconnection of loads connected to the bus 'HV TX LOADS'. With protection settings improved a 400ms time grading margin can be achieved, which removes loss of any critical equipment during a L-G fault. Note below table of before and after protection settings.

Relay ID	CT Ratio	Tap (Pickup)			Time Dial / Mult.		Curve Type
		Range	Setting	Primary	Range	Setting	
A2 SEPAM	400:05:00	0.01 - 1 x CT Sec	0.1	40	0.1-12.5	0.12	SI
A1 SEPAM	400:05:00	0.01 - 1 x CT Sec	0.3	120	0.1-12.5	2.55	SI
WPD A MCCG52	400:05:00	0.05 - 2.4 x CT Sec	0.3	120	0.05-1	0.325	SI
A2 SEPAM	400:05:00	0.01 - 1 x CT Sec	0.1	40	0.01 - 1	0.12	EI
A1 SEPAM	400:05:00	0.01 - 1 x CT Sec	0.3	120	0.01 - 1	2.55	EI
WPD A MCCG52	400:05:00	0.05 - 2.4 x CT Sec	0.4	160	0.01 - 1	0.1	SI

*Required changes are highlighted with the colour red.

CORRESPONDING IMPROVED RELIABILITY BY APPLYING THIS GENERALISED APPROACH:

The below table relates to the reliability indices from the above protection scenario, it can be seen with an effective system the expressed hrs/yr precited outage duration is 5.9, whereas with the original protection settings (before improvements were achieved) the calculated outage duration is 50 hrs/yr, this is an increase of 44 hrs/yr. Yes, a significant 90% improvement which can be achieved through the application of robust operational settings i.e., by following the 6 steps in this new generalised approach. In fact, over 330 protection settings were requiring improvements for a Tier 3 system investigated when it was subjected to this generalised approach.

Example: Protection Scenario 22 (Before & After Reliability Improvements)			
Bus ID's All Connected to HV String 1A (as above diagram)	**Predicted Annual Outage Durations for Connected Load Points, Expressed as (hrs/yr)**		
	'Grading not achieved'. i.e., *VCB* A2 trips, not the *DNO* incomer.	**'Healthy protection grading' i.e., The *DNO* feeder trips and limits removed Equipment.**	**Increased outage from incorrect protection operation.**
LV BB DBH1	50 hrs/yr	5.908 hrs/yr	44.092 hrs/yr
LV BB RED	50 hrs/yr	5.913 hrs/yr	44.087 hrs/yr
LV BB YELLOW	50 hrs/yr	5.903 hrs/yr	44.097 hrs/yr

END

OF PROCESS

6.4 Chapter Summary

Chapter 6.1 provides a recommended range of protection device settings for all twenty-six operational scenarios investigated. Descriptions list Time Current Curves (*TCC*) and display improved time grading margins. The proposed (improved) protection settings comply with both the IEC International Standards and specific equipment manufactures recommendations, reducing the probability of protection grading issues during system faults thus improving system Operational Availability (*Ao*), and limiting predicted downtime of critical equipment. Final protection device settings tables list the recommended 339 changes for the HV devices and 54 for the LV network, respectively. With Chapter 6.1 also listing the associated improved reliability metrics after such protection changes are undertaken.

Chapter 6.2 specifically details further protection setting advancements to improve and limit arc flash incident energy, simulated at each of the system switchgears under network fault scenarios. Such changes also ensure compliance with the IEEE 1584 in terms of limiting arc flash incident energy to an acceptable level, reducing Fault Clearing Times (*FCT*) and ultimately reducing the required Personal Protective Equipment (*PPE*) levels required to safely operate and maintain the switchgear – all of which support the successful Operational Availability (*Ao*) of equipment and infrastructure.

Chapter 6.3 consists of a flowchart which details a new and improved approach 'A Generalised Approach for Improving Operational Availability (*Ao*) of Data Centres'. This methodology provides a step-by-step detailed approach for assessing and improving the *Ao* of data centre electrical networks. The flowchart was constructed from the finding of this research programme and provides an improvement to the current Uptime Tier Classifications approach.

Chapter 7 – Conclusions

Chapter 7.1 consists of a re-evaluation of research methods, detailing why this research programme is important and what challenges its addresses. Listing the key aspects of the current field research, and which areas are suggested to affect the Operational Availability (*Ao*) of data centre electrical networks, and how the author's research continues to build on these findings. Also, within this section a summary is provided for each of the power system studies undertaken in terms of what topologies, international standards and critical assessment methods were applied, and how these methods challenged the current Uptime Institute Tier Classification approach, which considers Inherent Availability (*Ai*) alone and not the operational factors. Chapter 7.1 details the findings of this research programme, which have been listed against each of the power system studies, with emphasis on highlighting weaknesses or issues within the original system and how these can ultimately affect the data centres Operational Availability (*Ao*). This Chapter also summarises the extensive modelling and simulation approach, over one hundred operational scenarios investigated in total, which has allowed a multitude of recommendations, all of which have been proven to positively impact the availability metrics of data centres and build on the current Uptime Institute Tier Classification approach. These findings have produced a new and improved approach to assessing Operational Availability (*Ao*) of the data centre electrical networks, which is presented as a step-by-step flowchart with essential criteria noted against each power system study type and coherent links to improving Operational Availability (*Ao*).

Chapter 7.3 discusses why the author believes Operational Availability (*Ao*) is currently being overlooked in the design and operation of data centres, and why this is detrimental and costly for the data centre owners and success of their operations. The research significance is largely summarised into seven key sections based around each of the separate power system studies undertaken, although more importantly details how these link together and how this research programme had allowed formation of a new 'Generalised Approach' to achieving improved Operational Availability (*Ao*), which is an improvement on the current Uptime Institute Tier Classifications table, or designing and building data centres based on utilising Inherent Availability (*Ai*) metrics alone. Included within this research programme was publication of one UPEC research paper [3] and two *IEEE* industry application papers [1] and [2], along with collaboration with the Industrial Applications Society (*IAS*), or more specifically formation of a new 'Data Centre Working Group'. Alongside challenges this Chapter finishes with an explanation of future works, and the recommendation which involves undertaking other power system studies, such as transient stability during no break transfers and assessment of *CBEMA* power quality, which were not included within this research objectives but would continue to provide contribution of knowledge in this field.

7.0 Methods

As a summary this research programme included completion of an extensive investigation of mission critical electrical infrastructures, more specifically the data centre buildings owned by the Royal Bank of Scotland (*RBS*). The research programme required undertaking a range of power system studies of the actual *RBS* live sites, equipment, and connected loads. A holistic approach was undertaken sequentially studying each section of the electrical networks for load flow, short circuits, protection device co-ordination, Operational Availability (*Ao*), and arc flash mitigation. The findings from this work have provided a 'Generalised approach to achieving improved Operational Availability (*Ao*) of data centre infrastructures', this approach is an advancement on the current Uptime Institutes Tier Classification table and can be utilised for any data centre building.

Background History

Given data centre buildings have been referred to as the 'Modern Industrial Revolution' with an ever-growing dependence on computing, this has driven a requirement for increased resilience and reliability of the data centres infrastructures, these data centre buildings underpin the success of such operations. Often loss of continuous data centre operation can lead to multimillion-pound financial penalties and loss of customer trust. For *RBS* their critical buildings are partnered with The Centre for Protection of National Infrastructure (*CPNI*) which have identified an outage of an *RBS* data centre or part of its operation will negatively impact the wider UK economy and services, highlighting just how important these data centre buildings are.

Therefore, with this in mind i.e., such a significant demand for 100% uptime of equipment the question which soon arises from data centre operators is - what can we do to improve our reliability & resiliency? Or what do we need to investigate to make sure we achieve 100% Uptime of critical services? Unfortunately, although these are simple questions in principle there is certainly no simple answer. For an industry which is so critical to our economy you may be surprised there is currently limited technical standards available to guide building services engineers on how best to design, select and operate what is a vast range of complicated electrical equipment.

Often data centres are power hungry and can consume as much as 80MW, hence the high demand for such a vast range of electrical equipment, such as; multiple high voltage grid connections, standby generators, battery storage, renewable technologies, synchronisers, power transformers, cabling, busbar, switchgear, circuit breakers, power factor correction, active filters, surge suppression, protection relay devices – to name few of many. Over and above the technical challenge of arranging these types of equipment in an optimal way the data centre leadership team also consider; Emergency Operational Procedures (*EOPS*), critical spares, staff training, health & safety of engineers, reducing the recovery duration of any system issues or more specifically the absolute Operational Availability (*Ao)*.

The current guidance within the data centre industry is largely driven by the Uptime Institute with few other organisations providing an alternative view. The Uptime Institute, in brief, provides a table of Tier Classification ratings which indicates the nominal operational philosophies and how reliable the vendors can expect each Tier rating to be in terms of site availability and annual downtime. However, there is little other valuable guidance to support this approach in terms of the effects of the electrical network, in practical terms. For example, in an operational system what happens to downtime or availability if protection grading is not effective? If short circuit currents are more than switchgear ratings? If optimal load flow is not achieved, if arc flash incidents are significant? If load types change or load rejections occur? – just to name a few typically scenarios which occur but appear to be overlooked in current industry guidance, standards, or Tier ratings specifically. After all its the goal of Operational Availability (*Ao*) for live systems which concerns the data centres owners, not merely the Inherent Availability (*Ai*) indicated at the design stages.

However, there is research from Eaton, Schneider and ABB which identified the following six areas and stated they effect *Ao*.

i. Protection Device Grading and Co-ordination.
ii. Critical System Monitoring.
iii. Surge Protection.
iv. Wiring Methods.
v. Earthing & Grounding and System Design.

There are also more specific issues documented with areas of electrical protection co-ordination, dual fed power transformers, standby generator system protections, busbar and cabling designs in high voltage networks and operationally proving Tier 4 systems are Fault Tolerant (*FT*). Other documentation available is generally commercial driven (white papers) and focused on achieving *Ai* at the design stage which is not the most suitable practice for live systems and the operational engineering team.

This research programme investigates and details further the ‘six areas’ of electrical systems in data centres i.e., the areas with a potential of negatively effecting *Ao*, highlighting how to achieve a robust holistic approach to drive out operational weaknesses and categories them in terms of increased outages or negative effects on the electrical networks – i.e., increasing the measurement of success with 100% uptime.

The research was completed on the electrical networks for *RBS* with use of an electrical power software package ETAP. This software allowed the modelling of several system studies providing a holistic approach with respect to the electrical systems investigation. Studies carried out were load flow analysis then followed by short circuit analysis, protection device grading, arc flash mitigation and lastly load point reliability analysis. The below descriptions provide further simulation details, with the overall results and analysis allowing the formation of a new and improved methodology for improving data centre Operational Availability (*Ao*)

Load flow analysis investigated operational equipment within the distribution network at both HV & LV voltage levels. Applied Newton Raphson calculation methods at all major busbars to highlight real and reactive power flows of the entire system, also providing the voltage security index and voltage deviation at each busbar. The electrical network model was studied in three modes of operation, as below.

i. Normal operation with actual site connected loads.
ii. Actual design loads stipulated in the design philosophy documentation, on site.
iii. At emergency load values (design value plus 10%).

Voltage drop of cable feeders and system busbar were crossed referenced to the industry standards, ANSI C84 and BS7671. Consideration was also given to the standby power sources capability curves, tap setting of primary transformers and Uninterruptable Power Supply (*UPS*) machines – with a desire to confirm the optimal configuration of the network before proceeding to short circuit analysis simulation.

Short circuit current analysis investigated the networks with application of the IEC60909 & IEC61368 international standards for short circuit values at all system busbar to establish the below parameters.

i. Equipment strength and capabilities in terms of making, breaking and short time current withstand.
ii. I^2t protection for thermal ratings of equipment.
iii. Maximum and minimum short circuit currents to enable effective protection device co-ordination, and arc flash mitigation.
iv. Phase sequence voltages and currents of unbalanced short circuits, for system protection device evaluation.

Applying both the IEC60909 & IEC61368 standards to the model simulations the following current values were established which provided a detailed assessment of each system busbar to ensure its adequacy for the fault currents present.

i. Initial sub-transient short circuit current (*Ik"*) – Which is the $I_{a.c.}$ r.m.s. value of symmetrical component of prospective current at the instant of short circuit.
ii. Peak SC current (*Ip*) – Which is the maximum possible instantaneous value of the prospective short circuit current.
iii. Symmetrical *SC* breaking current (*Ib*) – Which is the $I_{a.c}$ rms value of symmetrical component of prospective current at the instant of the first pole open of a switch device.
iv. Steady-State SC current (*Ik*) –Which is the rms value of short circuit current after transient decay.

Alongside the system busbar other equipment were considered for fault tolerance. Such as, *UPS* & generator systems which provided significantly different fault current issues than when connected to a grid supply alone. The *UPS* were of a rotary construction which led to a unique model simulation block, ensuring transient elements of the synchronous machines were understood. Over forty operational scenarios were investigated ensuring the actual minimum and maximum values were established, these values are essential for specifying equipment ratings and the application of protection grading studies. Both of which can severely affect the *Ao* if found as incorrect or compromised.

Protection device analysis investigated the safety, selectivity, and reliability of all the electrical network HV & LV protection devices, over twenty-six operational grading scenarios with various upstream and downstream device investigations. The protection devices were assessed in terms of current magnitude and time, in the form of Time Current Curves (*TCC*). Also, a range of Non-Time Current Curves (N*TCC)* investigations for unit protections.

All the data centre specialist equipment such as the rotary *UPS* and standby generators were investigated, including a series of ETAP models created to allow the 113 protection devices and associated settings to be simulated under various operational modes and fault scenarios. Both phase and ground overcurrent settings along with Non-Time Current Curve (*NTCC*) protections such as restricted L-G, generator protection and SOLKAR pilot differential. Examples are detailed below.

i. Transformer HV to LV grading discrimination, six scenarios investigated.
ii. Assessment of HV faults during single DNO supply, five scenarios investigated.
iii. Assessment of HV faults during dual DNO supplies, seven scenarios investigated.

iv. Discrimination during islanded generator supplies, four scenarios investigated.
v. Assessment of HV faults during synchronised supplies (DNO & synchronous generators), one scenario investigated.
vi. Rotary *UPS* co-ordination with both upstream and downstream devices, plus bypass mode assessment.
vii. Non time current curve (*NTCC*) protection investigated was G59, SOLKAR unit, restricted L-G (*REF*), Generators ANSI 49RMS, 87M, 46, 32Q, 32P, 81L, 81H, 27, 59.

All the above protection scenarios included assessment of pick-up currents, transformer damage curves, excitation limit curves, motor acceleration and curve co-ordination assessment.

Arc flash analysis simulations proceeding short circuit current analysis and protection device grading. This is because the arc flash incident energy will have a direct correlation to the short circuit values and associated protection device settings. The model simulations were based on the *IEEE*1584, *NFPA* 70E and *OSHA* 29 guidance, given there is currently no final UK standard. The goal of the model simulations is to obtain the incident energy at any given piece of switchgear, during the following three scenarios.

i. HV & LV network connected to two grid feeders.
ii. HV & LV network connected to one grid feeder.
iii. HV & LV network in island generator mode.

This incident energy is important for addressing Personal Protective Equipment (*PPE*) requirements and applying warning notices to equipment. Also, if the incident energy values can be reduced damage during a fault can be significantly less and reduce downtime of critical data centre power equipment. Results were displayed in a *TCC* so the fault current, protection curve and arc flash incident energy can be assessed holistically.

Load point reliability analysis is the most important and innovative study of the research, after all how can electrical issues encountered during load flow, short circuit or protection grading be expressed in a term or manner which reflects the key metrics of the data centre industry. Given the Uptime Institute provides design availability the operational issues with electrical equipment can also be assessed in a similar manner, allowing the data centre owner to fully understand the operational performance against the proposed design. This approach is a first, as far as the author is aware no current available research has investigated the same technical issues and scenarios.

Often data centre owners will invest tens of millions of pounds to increase the redundancy of equipment or improve the ‘Design Reliability’ without having an actual operational assessment or impact assessment matrix to support such an investment. A drive for a five 9’s (99.999% Availability) system will cost multi-millions of pounds and possibly provide no better Operational Availability (*Ao*) than what can be achieved from undertaking electrical network studies on a lower costing system.

The key benefit of a Load Point Reliability (*LPR*) study is it allows a fault to be assessed in terms of increased downtime in average annual hours per year or load point failure rates. Results from this study highlights just how severe operational issues can be in terms of possible increased outages rather than considering design values alone. Such design availability values form part of manufacture tests in engineering laboratories, not considering site connections as an actual data centre electrical network, the two scenarios are some ways apart. For this research programme, all critical loads were assessed for i) Load point average failure rate ii) Average annual outage duration iii) Annual unavailability.

7.1 Contribution

The below descriptions detail the findings of each simulation and a subsequent summary section to outline the research work in a holistic context i.e. How data centres can benefit from applying these investigations to their Electrical Networks with a section discussing the formation of a new ‘Generalised Approach for improving Data Centre Operational Availability’.

7.1.1 Flowchart for A Generalised Approach

The Generalised Approach Flowchart consists of the complied results from this research programme and can be applied to any other data centre electrical network to improve its Operational Availability (*Ao*). In summary, the flowchart is a six stage, twenty-step detailed process for the simulation of data centre electrical networks, providing an in-depth explanation of how each simulation must be carried out, which international standards are applicable, and what criteria each simulation results must meet. This research programme has proven this approach is an improvement to the current Uptime Tier Classification and predicted downtime can be improved by as much as 50 hrs/yr., at each of the system critical load points. A brief explanation for each of the goals associated with the flowchart stages is as below.

Stages 1: Consisting of an audit of the original system and electrical network design. Investigation into the operational literature, design philosophy and possible operational scenarios for the system. Also, outlining the details for modelling each of the critical equipment in singular format and how to verify accuracy against proven theoretical calculations. This is an important step before building each of the singular model components into a complete electrical network i.e., one which represents the exact live system, which is then subject to further investigations.

Stages 2: Building a complete ‘Base Model’ is detailed in this section i.e., the construction of all the single model components to represent the actual live system. Providing guidance on the necessary ETAP simulation parameters and what international standards should be applied to the model simulations.

Stages 3: Benchmarking the original system, this is a particularly important step. This stage details what is required to obtain the load point reliability data for each critical load point in the system, and how these values should be recorded. This data is subsequently cross referenced after improvements have been made to the base model i.e., providing a tangible before and after reliability metric.

Stages 4: This is one of the larger flowchart stages and provides details for each of the power system simulations required for the data centre electrical network. Including which operational scenarios need to be investigated, which International Standards are applicable and what results need to be documented.

Stages 5: Consists of an analysis of results against a ‘best practice set of parameters’, provides guidance as to where system improvements can be achieved before re-evaluation of complete network reliability performance. This stage will require an update to any base model with a new and improved set of operational configurations of equipment. The set of ’best practice guides’ were constructed from the discoveries of this research and listed in Appendix I.

Stages 6: Re-evaluation of load point reliability, this is applicable to the new and improved network configuration following completion of the previous stages. Results can be compared to stage 3 i.e.; the electrical system improvements can be expressed in terms of how changes have positively impacted system Operational Availability (*Ao*).

Combined these stages produce a robust flowchart which will continue to support the improvement of data centre Operational Availability (*Ao*) through application of optimising electrical networks, with this knowledge continuing to support the field and advancement of the current Uptime Tier Classification approach. Operational scenarios investigated in the electrical network model simulations provided results which indicated annual downtimes were 40 times greater than those listed in the Uptime Institute’s Tier Classification table. Hence, the optimal way to provide high reliability in an electrical infrastructure is to investigate the operational configurations and equipment, rather than relying on design data for Inherent Availability *(Ai).* In this instance the actual system reliability was far worse than the expectations listed in the Uptime tables, despite following the associated design criteria - thus questioning the practical value or limitation of its use.

Such data centre electrical network investigations are to be carried out in significant detail and via the application of power system modelling software, such as ETAP. The author believes this approach was a first and proved to be more effective for highlighting operational issues, also leading to a significantly simplified electrical network and possible reduction in both operational and construction costs. ETAP allowed simulation of scenarios to be undertaken that are just not possible or viable to undertake on a 'live' data centre system, yet these simulations often underpin an understanding of the electrical network during normal operation, fault scenarios or major equipment issues. All of which are key to improving reliability and resiliency.

Whilst the six areas of data centre electrical networks indicated by current research provided a substantiated starting point, it was established these six areas were somewhat randomised with little information detailing the links between each one of the six topics. An example is the electrical power system studies, which must be carried out in a sequential approach i.e., load flow, short circuit, protection device grading, arc flash, reliability assessment. This sequence of modelling is of paramount importance since each proceeding study has the potential to effect subsequent results. These findings are now proposed in a 'Generalised Approach Flowchart' which can be utilised to improve operational reliability of any data centre.

During this research programme substantial issues were recorded in each simulation type, either in terms of potential effects on *Ao* or as non-compliance with current industry standards. The reliability study is most useful to understand the severity of electrical network issues. For example, failure of a protection device can be re-simulated in reliability mode, verifying the significance in the network in terms of increased outage times or *MTTR*. This was a novel approach and not investigated by current available research. Reliability data can also be expressed as a metric for success and understood by the data centre owners, which proves to be useful in a practical application. The stages and steps required to achieve this have also been included in a new generalised approach flowchart which is the author's contribution to a continuation of improvements and knowledge to this field.

Research investigations discovered issues that challenged the conventional methods of specifying data centre electrical systems, by utilising Uptime Tier philosophies and inherent design availabilities. In fact, the system designs with a higher Tier rating often led to significant operational issues due to the range and complexity of equipment and how these had been operationally configured. One could argue the more complex a design the more operational issues may occur, in terms of negatively effecting *Ao* and compliance to engineering standards & industry best practices. The new Generalised

Approach Flowchart in Chapter 6.3 of this report improves on the current approach and adds value to the data centre owners as simulation of their electrical networks by this approach will improve Operational Availability (*Ao*). The flowchart is inclusive of all operational factors, data, standards, and theoretical formula required to achieve such success. Key aspects investigated with the *RBS* buildings through application of new generalised approach flowchart:

i. A Tier 4 system led to network peak fault currents that were in excessive of the installed switchgear rating. Therefore, a fault on the electrical system would extensively damage equipment beyond repair – effecting resiliency (*MTTR*). This is not considered in the Uptime Institutes guidance on data centre design.

ii. Over 30 % of the operational scenarios modelled led to a negative result, in terms of a non-compliance to either international standards or manufactures guidelines. These scenarios when modelled in reliability mode of the software which significantly increased the potential hrs/yr. downtime. Limited research is provided on the importance of operational investigations which supports this work being a first to approach.

iii. Rotary *UPS* model simulations led to peak fault currents above the connected equipment ratings. This has a significant effect on critical power strings within the building's infrastructure. No specific guidance is available on how to effectively model the transient contributions, this research provided an accurate and first solution with details on how to obtain these values which are critical for data centre rotary *UPS* systems.

iv. Protection device grading and co-ordination displayed there is a significant issue given over 30% of HV protection devices installed on site, whether this be a transformer, generator, grid feeder or interconnector were not set correctly and had the potential under fault to cause significant network outages. The LV devices were not as significant as the HV since only 16% had been set incorrectly, although these can still cause issues it appears the complexity of HV networks are a more prominent issue, with respect to protection settings and providing optimal configurations.

v. This research programme has allowed the author to provide a new 'Generalised Approach for improving Data Centre Operational Reliability'. Which continues to improve the predicted outage times by as much as 50hrs/yr., at each critical system load point. This is a significant achievement in comparison to the utilisation of Uptimes Classification table which suggests a predicted outage time of just 1.6 hrs/yr. (Tier 3), which is just not the case when investigated in a practical live operational network i.e., the inherent design values for each Tier have little practical application and or improvement of the operational system, which is the most important factor for the data centre owners.

7.1.2 Load flow

Issues encountered during load flow studies for the LV distribution switchgear, both red & yellow power strings encountered simulation alarms for low busbar voltage outside of the *ANSI* C84 optimal limits. This was the case for any busbar loads above 50% of nominal design value. Such low voltage limits at the intake switchgear, for a given power string, leads to a reduction in voltage drop allowances in the downstream network and is not a best design option. This issue encountered was due to LV cabling (*BS5467 XLPE*) utilised on the secondary side of the distribution transformer, given the remaining power strings in the electrical network utilised a busbar construction which provided an improved resistance to voltage drop and ensured limits were within *ANSI* C84, at any connected load value.

Simulations undertaken for all available transformers tap settings (-5% to +5%), which found only two of the available five settings provided a busbar voltage within *ANSI* C84 limits, at connected loads above 50% of nominal design. The operational cost of the power transformers, with respect to energy consumption, can vary by £300k per annum - between the extreme settings of a transformers tap. A *2N* system also requires adjustment of the transformer tap to ensure optimal busbar voltage. If a transformer is then dis-connected, for maintenance etc, the busbar voltage is too low and leads to simulation alarms. Thus, the N+1 type supply configuration lends to the most appropriate solution for load flow and busbar voltage.

In summary, load flow studies highlighted the requirement for changes to sixteen power transformers tap settings and two from six of the main power strings did not have an equipment designs which could comply to the ANSI C84 limits, for any load above 50% of the associated design capacity.

7.1.3 Short Circuit Analysis

Over 35 operational scenarios were simulated with ETAP for both the HV & LV electrical networks, this included both operational configurations for grid feeders and standby generator supplies. The associated key challenges are:

i. Constant power loads within the network increased associated busbar fault currents by 14.28KA in comparison to constant impedance types, thus must be factored at the design stages to ensure switchgear ratings are adequate.
ii. Given the varied options of standby power supplies and grid connections fault currents within the HV network varied from a possible 9.97KA to 29.98KA which provides a significant

challenge in terms of protection device settings and clearing network faults in a coordinated manner.

iii. Network distribution transformers were solidly grounded which led to L-G currents in-line with L-L-L faults, not as the typical IEC60909 guidance of 0.85 P.u of L-G values. Also connecting distribution transformers in a *2N* paralleled method to the main busbar led to fault currents more than the site's switchgear ratings.

iv. Transient contribution of the rotary *UPS* increased peak busbar fault current (Ip) by 25KA, which led to a value above the switchgear rating. The *UPS* also have mains pathways 1&2, pathway 2 contributes to an input busbar fault i.e., the fault contribution is bi-directional and must be considered in the studies. Typical model blocks in ETAP software do not allow for the transient effects, hence a custom-built model block consisting of a synchronous motor with negative power factor provided a first and an accurate representation required to confirm adequacy of switchgear rating.

In summary, the above points discovered each led to a comprised electrical network given the original equipment were not designed or operational configured to mitigate these issues. Findings were in-line with current research in terms of the potential effect to Operational Availability (*Ao*). The more specific challenges being the HV network fault current variations and transient effect from rotary *UPS*, both of which are discussed further in the protection device grading and arc flash sections below.

7.1.4 Protection Device Grading

Protection device grading issues encountered for this electrical network were arguable the most severe of all the network studies investigated (i.e., load flow, short circuit, protection grading and arc flash etc), in terms of magnitude and quantities. The Mean Time To Repair (*MTTR)* following operation of a protective device can be significant, up to 50 hours, thus optimal protection settings must be obtained. Likewise, if high Operational Availability (*Ao*) is a priority goal for data centres, all network faults must be removed with minimal impact. The findings highlighted over twenty-six simulation issues which are:

I. Distribution transformer protection relay pick up currents were set more than 200% of the transformer current rating, which is not in-line with the IEC standards or manufacturers recommendations. It was also discovered in *TCC's* high pick-up values were present - above the transformers frequent damage point. The transformer L-G settings were also found as low as 3A which is out-with the *IEC* guidelines and likely to cause issue with spurious trips on energisation.

II. Each main LV intake switchgear was connected to two primary transformers, in an N+1 configuration. Whilst the transformer characteristics were identical settings from protection unit to unit varied significantly. This approach did not provide optimal settings for grading and co-ordination.

III. Time delay (T_d) settings on distribution transformers, in several cases, were found more than two seconds which led to failed HV & LV co-ordination, tripping relay indication and further complication with clearing arc flash incident energy. During a network fault this would provide substantial issues to the network with increased service outages and *MTTR*.

IV. The *UPS* output Air Circuit Breaker (*ACB*) protection settings were more than 200% of the nominal current ratings, therefore not compliant to the manufactures recommendations and may significantly damage the machine under overload conditions.

V. A significant number of the Air Circuit Breakers (*ACB*) low voltage protection devices had no Short Time (*ST)* settings applied which led to significant arc fault current clearance issues, problematic for site engineering maintenance and specifying safety equipment. Also, such arc currents during an actual fault would damage the switchgear beyond economical repair, leading to significant outage of critical services.

VI. High voltage ring-main circuit breakers failed protection co-ordination for several possible faults, settings investigated during a site fault disconnected many distribution transformers not relating to the actual fault. Definite Time (*DT*) settings on *VCB* A and *VCB* B created significant issues for the *GEC* busbar.

VII. Ground Fault (*GF*) settings on the main *GEC* busbar were more than the actual L-G currents present in the network, rendering the setting completely ineffective. This also led to issues with the main site feeders and grid incomers during an L-G fault on the *DNO* network.

VIII. Grading margins between circuit feeders and standby generators were found less than 100*ms*. It was also noted the five generators had a range of different settings although units are identical. Issues encountered with generator protection settings:

i) *EF* setting 50N/51N is below the 15% *Io* sum, as outlined by *IEC* standards.
ii) *EF* IDMT settings not in-line with *IEC*, 10% of neutral earth resistor (*NER*).
iii) No protection settings for generator phase imbalance as recommended by *IEC* standards, 15% of *In* with 2-3s time delay.

iv) Under frequency and over frequency not in-line with G59 guidelines.

v) Under voltage and over voltage settings varied between generator protection units, despite being identical units.

IX. SOLKAR pilot differential protection scheme on the HV ring main interconnectors achieved less than 25ms time grading margin against upstream/downstream devices.

X. *UPS* input circuit breakers had no L-G protection settings thus relied on overcurrent values, which causes co-ordination issues for a fault between the *UPS* input and main transformer incomer circuit breakers.

XI. *UPS* power strings, in bypass mode achieved no L-G discrimination between outgoing Power Distribution Units (*PDU's*) and the main incoming bypass circuit breaker. Thus, a fault will disconnect the *UPS* outputs busbar rather than a single *PDU*.

In summary, from 1136 HV protection settings investigated a recommended 339 are to be changed. Likewise, for the LV out of 337 protection settings 54 changes are required. This equates to 18% of the investigated HV systems and 3% of the LV, therefore it could be argued the HV system is more of a significant issue, in comparison to the LV system in this data centre investigation.

7.1.5 Arc Flash

Arc flash studies included all the data centres electrical networks HV & LV switchgear under the following three operational scenarios:

i. Electrical network supplied by two *DNO* supplies in parallel.
ii. Electrical network supplied by a single *DNO* feeder.
iii. Electrical network supplied by standby generators.

IEEE 1584 & National Fire Protection Agency (*NFPA*) standards were applied to all arc flash simulation models, given the UK have no specific legislation available at present. The following quantities were established at every system busbar or Switchgear.

i. Total Incident Energy (*Ie*) of the arc fault.
ii. Recommended safe arc flash boundary distance whilst carrying out service activities, for safety of maintenance personnel etc.
iii. Required *PPE* ratings for a Safe System of Work (*SSOW*).
iv. Total Arc Fault Clearing Times (*AFCT*).

It is important to note the *NFPA* recommend use of *PPE* at levels up to and including 40 cal/cm^2, with specific guidance for values more than this to be reduced with other measures rather than *PPE*. The electrical network studied in this research programme had significant issues with arc flash given 33 from 69 scenarios tested led to values above the *NFPA* recommendations. A significant problem given the site switchgear relies on maintenance activities to support 100% uptime of critical services. Its paramount maintenance work can be safely undertaken – at present this cannot be true for 30% of the installed switchgear. Also, such significant arc fault values and clearing times following a fault would lead to significant equipment outage and extended *MTTR* due to extensive plasma and damages from the arc currents.

It was discovered for this electrical network it was possible to reduce arc faults for all system busbar with exception to eight LV protection devices. The IDMT curves on both HV & LV protection lends to improved settings in terms of arc flash reduction when compared with the nominal LT/ST/INST of a typical LV Air Circuit Breakers (ACB's). This is shown in the results Chapter 5 where IDMT achieve level C and ACB's level F.

7.1.6 Load Point Reliability

To recap the main purpose of load point reliability studies is to discover additional downtime of critical services due to the issues found during the electrical system or protection device grading analysis. This analysis of load point reliability provides a value of downtime expressed as hrs/yr. and can be a utilised as a metric or measurement for success i.e., the less this value the more a data centre electrical network is available for its required operations.

For example, take a protection issue and simulate this in load point reliability before and after a technical solution is established, the two values can be compared with the goal to reduce the downtime metric (hrs/yr.). This is a great way to provide a transferable terminology to express technical operational issues in an electrical network for the data centre owners.

This research programme was a first to discover and express that protection grading issues can increase the data centre annual downtime by as much as 45 hrs/yr. (for a single protection grading issue), with total simulated for this network equating to over 4000 hrs/yr. This is a significant figure when compared with the Uptime Institute Tier Classification table, which outlines only minutes of predicted outage between Tier design options. Therefore, its critical an Operational Assessment (*Ao*) is undertaken. An example of one *ETAP* scenario in this project is DBA1 where the reliability figure for a healthy N+1 network is 1.279 hrs/yr. and then 50 hrs/yr. following protection trip due to grading mis-coordination. Thus, in this case a protection issue has the potential to increase downtime by 44.84 hrs/yr. This type of issue may be mitigated with effective simulation, settings, operational procedures, critical spares, and trained engineering operatives – all further supporting the requirement for operational assessment if the data centre owners want to improve reliability of their electrical network.

Obviously, these conclusions are drawn from this project, but the importance is that this final approach can be utilised by any other data centre building, which is detailed in the generalised approach for improving operational availability of data centres section.

7.2 Challenges

The data centre industry is largely driven by information technology businesses with most industry standards and working groups targeting the advancement of cloud computing, edge computing and supporting the drive for an Internet of Things (*IoT*). Technology industry leaders have evidenced new technology over the last decade has led to a vast growth in demand for data centre buildings. As such these mission critical data centre buildings aim to provide an effective environment for technology equipment and are often significant in scale, requiring a vast range of complex equipment which a high-power demand and operational cost. In real terms the investment and operational cost of engineering equipment can often appear to be a small portion of the overall cost of ownership of the data centre, and the technology business partners have therefore often demanded high reliability and resilient infrastructures for their operations. This has led to an approach where the 'gold standard' is a drive to achieve an Uptime Tier 4 data centre, as outlined by Uptime Institute a Tier 4 standard requires a range of complex equipment and system redundancy to achieve Inherent Availability (*Ai*) design figures. This is likely to cost the data centre owners tens of millions of pounds to achieve, in both capital investments and subsequent operational cost.

Whilst it is true, in general terms, electrical equipment with high design reliability statistics are the most desirable in the mission critical environments, operational scenarios or more specifically Operational Availability (*Ao*) is considerably overlooked. Compared with the more established areas of electrical engineering there is limited research available that provides reports and data on such data centre operational assessments. From the author's searches and reviews it appears Eaton, ABB, Schneider Electric and Microsoft are most of the technical engineering companies that are completing elements of published research on this topic, these publications have too found from facility audits that the high inherent availability designs may not practically achieve the goals of the data centre building. Eaton's research highlighted a generalised six areas of electrical engineering which were found to be a common issue in the data centre environments, in terms of negatively effecting operational availability.

This research programme has continued to build on these areas, with specific investigation of an actual data centre building, utilising advanced ETAP simulation software and being first to challenge the Uptime Tier designs and providing a substantiated, structured, and detailed assessment of why operational scenarios should be of greater concern. Also, this research continues to drive these six areas of the electrical systems, in depth of technical research and expressing availability metrics which can be understood by the system owners. Ultimately, the findings have produced a 'Generalised Approach for improving Data Centre Operational Reliability', which is proven to better the current approach and can be utilised by any other Data Centre system. The flowchart can also be utilised in tandem with the Uptime Institutes Tier Classification table, as evidence in this research programme.

7.3 Significance & Limitations

The author believes this research programme is a first to utilise ETAP for improving Operational Availability (*Ao*), resiliency and redundancy of electrical infrastructures in data centres, via the application of power system modelling and simulation. At present the approach utilised for data centre environments is to specify Tier ratings on design availability figures (Inherent Availability *Ai*), which has been proven to be ineffective when practically configuring the electrical network for optimal performance or reducing the cost of ownership and complexity of designs. The author's research findings have allowed the construction of a 'Generalised Approach for improving Data Centre Operational Reliability' which can significantly improve the predicted Operational Availability (*Ao*) of these infrastructures and can be utilised by any other data centre wanting to simulate its electrical network and improve the critical load point Operational Availability (*Ai*) within the complete system.

List of contributions

i. The research programme findings provided a new 'Generalised Approach for improving Data Centre Operational Reliability' which can be utilised by any other data centre building, for simulation of their electrical networks and achieving tangible improvements to Operational Availability (*Ao*). Up to 50 hrs/yr. reduction of downtime can be achieved with this approach.

ii. Evidenced that operational assessments of data centre electrical networks are critical to assess the potential downtime of the system, which provided a significantly improved approach in comparison to utilising the current inherent availability metrics provided by the Uptime Institutes Tier Classifications table.

iii. Outlined the importance and value of a holistic approach when investigating the electrical network, i.e., given each preceding model simulation can affect subsequent results. To obtain an optimal configuration all aspects of the system should be investigated, which is not detailed in the current approach. These stages have been extensively detailed in the new flowchart i.e. A Generalised Approach for improving Data Centre Operational Availability (Ai), where checkpoints list several conditions for installed equipment, these conditions will lead to improved system availability.

iv. Evidenced arrangements for high voltage protection devices and arc flash mitigation at the low voltage switchgear can have the most significant potential to increase outage times during network faults. This was not previously available in the current research work or Uptime Institutes Tier Classification approach.

v. Highlighted many of the data centre guidelines are becoming legacy, for instance the *CBEMA* power quality guide, which is still utilised as a current approach in industry, despite growth of IT equipment and associated changes since its construction in 2000. Therefore, the author has recommended future works for *CBEMA* power quality investigations.

vi. This research also led to the publication of two *IEEE* papers via the Industry Application Society (*IAS*) who have also indicated a requirement for further research in the field, and recently formed a new Data Centre Working Group (*DCWG*) i.e., this work is timely, topical, and beneficial to the data centre engineering community. The IET are also planning to release a first edition Data Centre Power system guide in 2021.

Given this research programme was a first to utilise ETAP for data centre electrical network studies, the author believes there is no such similar research to support or cross reference the findings. The research was carried out via funding support from the Royal Bank of Scotland (*RBS*) and as such investigations were based on their critical buildings. It could be argued this itself is a limitation and the programme could be built upon, i.e., via investigation of other critical buildings outside of the *RBS* portfolio – either data centres or other such critical facilities. Building types such as hospitals, air traffic control stations, and the ministry of defence buildings etc. These buildings may also have similar issues within their critical electrical infrastructures. At present the identified research is largely produced by Microsoft, Eaton, ABB, and Schneider Electric, who are also working within this area. Any subsequent research publications will continue to support progress in the field. Particularly the review of electrical network protection and improving Vsi, Ao & Ai.

7.4 Future Work

Analysis not covered in this research programme includes transient simulation. This could be investigated in ETAP or PSCAD simulations for standby generators and *UPS*, given both pieces of equipment have a potential to encounter transient stability issues due to the network load demands. Scenarios could include no-break and break transfer operations and connection or removal of system generators and *UPS*, under varying load scenarios i.e., in-line with system design criteria.

Operation of the generator alternator must also adhere to the governor and exciter classifications in terms of the required network voltage and frequency tolerances. This would provide a valuable in-site into standby power system behaviour which is also pivotal to the uptime of a data centre. The Energy Networks Association (*ENA*) G59 guidance has also been revised in 2019 to the G99 which should also be investigated further. Likewise, the *CBEMA* curve outlining power quality standards was last revised in 2000, with such a significant growth and range of new equipment an assessment of these guidelines could provide valuable future improvement of knowledge.

The author is currently collaborating with the *IEEE* Industrial Application Society Data Centre Working Group, to drive technical engagement and publications for the data centre environments. Also, holding the position of joint chair for the subcommittee reliability & uptime, which has a coherent goal to focus on the following four areas of data centre engineering.

i. Power Quality.
ii. Reliability & Uptime.
iii. Power Sources.
iv. Design & Maintenance.

A longer-term drive is to create an IEEE Data Centre Engineering Chapter, working towards subsequent technical standards in the industry covering some of the potential operational gaps, as those areas approached and discussed in this thesis. The author believes this is a continuation to support the industry's engineers to drive operational improvements with what are some of the most important buildings in our society.

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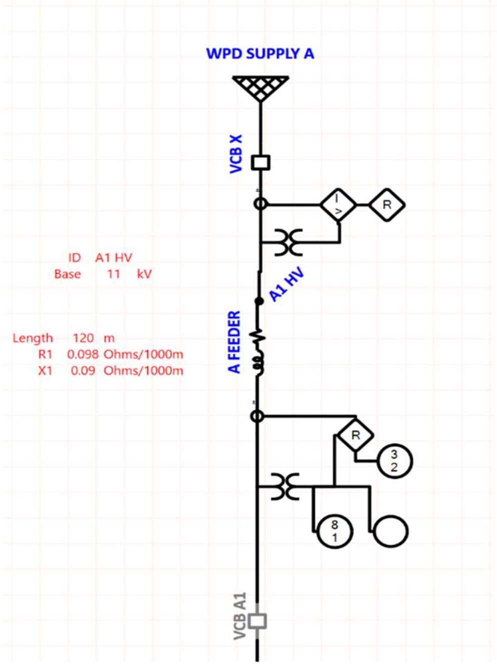
Appendices

Appendices contains:

I. ETAP single model simulations and theoretical calculations completed in-line with T. Davies Protection of Industrial Power Systems.
II. Protection settings table relating to Chapter 5– Original ‘as installed’ site setting.
III. Protection settings table relating to Chapter 6.1 – Optimising for grading co-ordination and *Ao*.
IV. Protection settings table relating to Chapter 6.2 – Optimising for arc flash mitigation.
V. List of optimal conditions for reach of the power systems studies, which were utilised to form the generalised approach flowchart for improving Operational Availability (*Ao*) of data centre electrical networks.

I Individual simulation models with theoretical calculations and cross reference to the Original Equipment Manufacturer (OEM)



GRID FEEDER

Conversion to a P.u system on a 100MVA base is as follows:

$$Zpu = \left(\frac{Z\%}{100}\right) x \left(\frac{\text{MVA base}}{\text{MVA rating}}\right)$$

$$Zpu = (Z)\, x \left(\frac{\text{MVA base}}{V^2}\right)$$

$$Zpu = \left(\frac{Vn}{In}\right) x \left(\frac{\text{MVA base}}{V^2}\right)$$

DNO Grid Source Feeder Model

Data by DNO enquiry	Short circuit current values (rms).	
3-phase system	L-L-L = 58MVA	L-L-L I_{sc}= **3040A**
Swing operation	L-G = 10.98MVA	L-G I_{sc} = 998.32A
Vn = 11KV$_{\text{L-L rms}}$		

Verification by calculation (as single component of no-load busbar L-L-L and L-G fault current rms):

L-L-L

$$I_{sc} = \frac{58\ \text{MVA}}{\sqrt{3}\ X\ 11000} = \mathbf{3044.21A}$$

$$Zf = \frac{V^2}{VA} = \frac{11000^2}{58.10^6} = 2.086\Omega$$ (or 1.72 P.u on 100MVA base)

L-G

$$I_{sc} = \frac{10.98\ \text{MVA}}{\sqrt{3}\ X\ 6350} = 998.32A$$

Simulation results for IEC 60909 L-L-L fault current (rms)

If = **3.044KA**

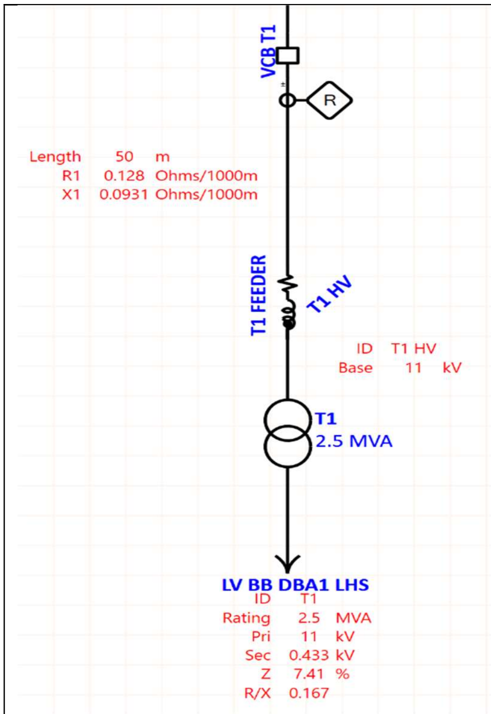
Z P.u = 1.7

OEM	CALC	SIM
3.04KA	3.044KA	3.044KA

Accepatble model simulation tolerance ✓

Where;

SC = Short Circuit, Vn = Nominal Voltage L-L rms, If = Simulation Fault Current rms, Zf = Fault Impedance, Isc = Symetrical short current current rms.



DISTRIBUTION TRANSFORMER

IEC Liquid filled *ONAN* 65°C
2.5MVA *Dyn11* (-30° shift)
Nominal Voltages = 11/0.433KV
FLC = 131.2/3333*A*
Z = 7.41%
X/R = 6
Tap = -5 (0.415KV)
Grounding = *TN-C-S*, Solidly grounded
Current Inrush = 8 I_n
Peak Fault Current $I_p = \sqrt{2}\ .\ 32.62\ KA$ = **46.13KA**

Verification by calculation

$$\text{MVA (fault level)} = \frac{2.5}{0.0741} = 33.72\ \text{MVA}$$

$$Isc = \frac{33.74\ MVA}{\sqrt{3}\ .\ 11000} = 1770A$$

Therefore, current secondary:

$$\left(\frac{\text{Vp}}{\text{Vs}}\right) \text{x (Ip)} = \text{Is}$$

$$\left(\frac{11000}{0.415}\right) \text{x } (1770) = \mathbf{46.91KA}$$

Simulation result:
IEC60909 peak current calulations

$I_{p'}$ = 35.01 x $\sqrt{2}$

$I_{p'}$ = **49.51KA**

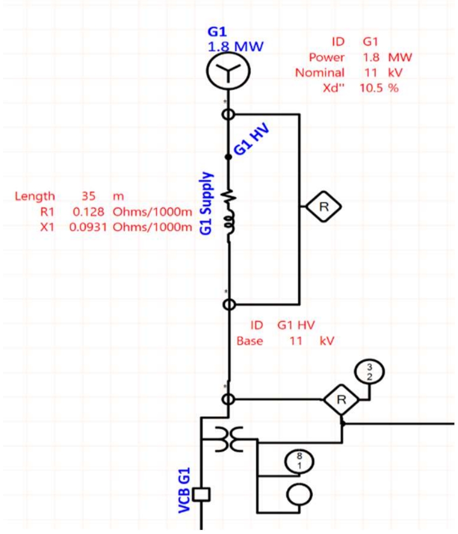
With C-Factor correction for Voltage variation as IEC6090 1.05, for system less than 1001V rms.

$I_{p'}$ = 49.51/1.05 = **47.15 KA**

OEM	CALC	SIM
46.13KA	46.91KA	47.15KA

Accepatble model simulation tolerance ✓
Where;

FLC = Full Load Current, Vp = Primary Voltage, Vs = Secondary Voltage, Ip = Current Primary rms , Is = Current Secondary rms, Ip' = Peak short circuit current.



SYNCHRONOUS GENERATOR

Un = 11KV
MVA = 1.8 %PF = 80
6 poles
Swing operation
Grounding = Resistor 42.33Ω or 150A when Vn = 6.351KV
Sub Transient Impedance Xd''= 0.105 P.u
Transient Impedance Xd'= 0.2 P.u
Synchronous Impedance Xd = 1.36 P.u
Sub Transient Time Constant Tdo''= 0.03 s
Transient Time Constant Tdo'= 5.25 s
Exciter type = Salient Pole
Governor type = droop @ 5%

Verification by calculation

Note: I is the P.u value of 1 at rated MVA, given Cos(θ) is load PF, Assuming EMF = V.

0.8PF Rating (36.87^0) | Cos (36.87^0) = 0.8 | Sin (36.87^0) = 0.6

Equations:

$$E'' = [\,(1 + Xd''I\,Sin(\theta))^2 + (Xd''I\,Cos(\theta))^2\,]^{1/2}$$

$$E' = [\,(1 + Xd'I\,Sin(\theta))^2 + (Xd'I\,Cos(\theta))^2\,]^{1/2}$$

$$E = [\,(1 + Xd\,I\,Sin(\theta))^2 + (Xd\,I\,Cos(\theta))^2\,]^{1/2}$$

$$E'' = [\,(1 + 0.105 \text{ x } 0.6)^2 + (0.105 \text{ x } 0.8)^2\,]^{1/2} = 1.066$$

$$E' = [\,(1 + 0.2 \text{ x } 0.6)^2 + (0.2 \text{ x } 0.8)^2\,]^{1/2} = 1.131$$

$$E = [\,(1 + 1.36 \text{ x } 0.6)^2 + (1.36 \text{ x } 0.8)^2\,]^{1/2} = 2.117$$

Currents under open time constants, where full load current FLC = 118.1A:

$$I'' = \frac{1.066}{0.105} = 10.15 \text{ x FLC} = \mathbf{1198.715A} \qquad Equation: I'' = \frac{E''}{X''}$$

$$I' = \frac{1.131}{0.2} = 5.65 \text{ x FLC} = 676.265A$$

$$I = \frac{2.117}{1.36} = 1.56 \text{ x FLC} = 183.84 \text{ A}$$

During short circuit time constants equations:

$$Td'' = \left(\frac{Xd''}{Xd}\right) \text{x } Tdo'' \qquad Td' = \left(\frac{Xd'}{Xd}\right) \text{x } Tdo'$$

Therefore:

$$I'' = 1198.72A \qquad Td'' = \left(\frac{0.105}{0.2}\right) \text{x } 0.03 = 0.016s$$

$$I' = 667.265A \qquad Td' = \left(\frac{0.2}{1.36}\right) \text{ x } 5.25 = 0.772s$$

Given the time required to decrease to a transient value is 0.03s the following becomes the characteristic curve:

$I' = 5.65 \text{ x FLC} = 676.265A$

$I = 1.56 \text{ x FLC} = 183.84 \text{ A}$

Hence decay period is 676.265 – 183.84 = 483.42A

When t = 0s current is 1198.715A

When t = 0.1s

$i = 483.42\, e^{-\left(\frac{0.1}{0.772}\right)} + 183.84$

$i = 608.53A$

Example decay for given time constant (t):

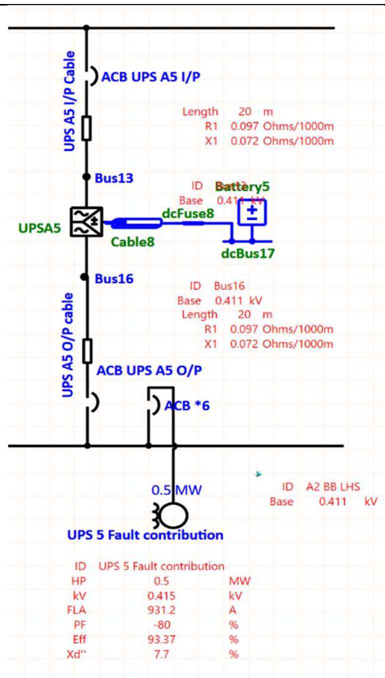
$t\ (s)$	0.1	0.2	0.4	0.6	0.8	Infinity
$i\ (A)$	608	556.9	471.8	406	355	183.84

Simulation result:
If = **1194 A**

CALC	SIM
1198.72A	1194A

Accepatble model simulation tolerance ✓

Where;
PF = Load Power Factor, FLC = Full Load Current, P.u = Per Unit Value



ROTARY *UPS*

Inverter element
Rating = 625KVA, 0.5MW PF = 0.8
Input/Output Voltage Nominal = 0.415KV
FLC = 1225A
SC contribution = 1400% or **12173A**
Grounding = TN-C

Synchronous M/G element
Rating = 625KVA, 0.5MW *PF* = -0.8
Direct axis:
Sub Transient Impedance *Xd″*= 0.077 P.u
Transient Impedance *Xd′*= 0.179 P.u
Synchronous Impedance *Xd*= 1.039 P.u
Sub Transient Time Constant *Td″*= 0.29 s
Transient Time Constant *Td′*= 2.06 s

Note: @0.8PF Rating (36.87^0) | Cos (36.87^0) = 0.8 | Sin (36.87^0) = 0.6

Verification by calculation

$$E'' = [\,(1 + Xd''I\,Sin(\theta))^2 + (Xd''I\,Cos(\theta))^2\,]^{0.5}$$

$$E' = [\,(1 + Xd'I\,Sin(\theta))^2 + (Xd'I\,Cos(\theta))^2\,]^{0.5}$$

$$E = [\,(1 + Xd\,I\,Sin(\theta))^2 + (Xd\,I\,Cos(\theta))^2\,]^{0.5}$$

$$E'' = [\,(1 + 0.077 \times 0.6)^2 + (0.077 \times 0.8)^2\,]^{0.5} = 1.048$$

$$E' = [\,(1 + 0.179 \times 0.6)^2 + (0.179 \times 0.8)^2\,]^{0.5} = 1.117$$

$$E = [\,(1 + 1.039 \times 0.6)^2 + (1.039 \times 0.8)^2\,]^{0.5} = 1.824$$

Currents under open time constants, where full load current FLC = 931.2A:

$$I'' = \frac{1.048}{0.077} = 13.61 \text{ x FLC} = \mathbf{12673.64A} \qquad \text{Equation: } I'' = \frac{E''}{X''}$$

$$I' = \frac{1.117}{0.179} = 6.24 \text{ x FLC} = 5810.69A$$

$$I = \frac{1.824}{1.039} = 1.76 \text{ x FLC} = 1634.76A$$

During short circuit time constants equations:

$$Td'' = \left(\frac{Xd''}{Xd}\right) Tdo'' \qquad Td' = \left(\frac{Xd'}{Xd}\right) Tdo'$$

Therefore:

$$I'' = 12673.64A \qquad Td'' = \frac{0.077}{0.179} \text{ x } 0.29 = 0.125s$$

$$I' = 5810.69A \qquad Td' = \frac{0.179}{1.039} \text{ x } 2.06 = 0.35s$$

Given the time required to decrease to a transient value is 0.29s the following becomes the characteristic curve:

$I' = 6.24 \text{ x FLC} = 5810.69A$

$I = 1.76 \text{ x FLC} = 1634.76\ A$

Hence decay period is 5810.69 – 1634.76 = 4175.93A

When t = 0s current is **12673.64A**

When t = 0.1s

$i = 4175.93\, e^{-\left(\frac{0.1}{0.35}\right)} + 1634.76$

$i = 4772.85A$

Example decay for given time constant (t):

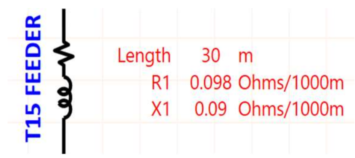
$t\ (s)$	0.1	0.2	0.4	0.8	Infinity
$i\ (A)$	4472	3992	2996	2059	1634.76

Simulation result:
If = **12609A**

CALC	OEM	SIM
12673.64A	12173A	12609A

Accepatble model simulation tolerance ✓

Where;
PF = Load Power Factor, FLC = Full Load Current, P.u = Per Unit Value



CABLE FEEDER

BS6622 11KV/50Hz XLPE 3C 240MM^2
PVC Thickness = 3.4mm Diameter = 17.84mm
(both ±15%)

Verification by calculation

$L = 0.46 \log \frac{d}{r} \ \ \mu H/m$

d= distance between conductors
Re= conductor geometric mean radius
L = Inductance (Henry)

Where equivalent radius (Re):

$Radius = \left(\frac{240}{\pi}\right)^{0.5} = 8.74mm$

Re = 0.78x8.74 = 6.81mm

Utilising worse case for insulation as 3.4mm plus 15% to solve d.

$d = (1.15x8.74)2 + 3.65 = 23.752mm$

Therefore:

$L = 0.46 \log \frac{d2\ \ .752}{6.81} = 0.25\ \mu H/m$

Inductive reactance at 50 Hz

$XL = 2\pi FL = 100\pi. 0.25 = 78.53\ \mu\Omega/m$

Convert to P.u:

$\text{Calculated X P.u} = \left(\frac{10\text{MVA}}{11\text{KV}^2}\right) \text{ x } 78.53 \ \ \frac{\mu\Omega}{\text{m}} = 0.0714 \text{ P.u}$

$\text{Simulated X P.u} = \left(\frac{10\text{MVA}}{11\text{KV}^2}\right) \text{ x } 85.58 \ \ \frac{\mu\Omega}{\text{m}} = 0.077 \text{ P.u}$

CALC	SIM
0.0714 P.u	0.077 P.u

Accepatble model simualtion tolerance ✓

II Complete Protection Settings Table relating to Chapter 5.5, Load Point Reliability Assessments.

HV Relay ID	CT Ratio (A)	Tap Setting (Pickup) Range (x CT rating)	Setting	Primary (A)	Time Dial Range (s)	Setting (s)	Instantaneous Setting Range (x CT rating)	Settings	Primary (A)	Observations
T10 LV IDMT	3500:5	0.05 - 2.4	1.5	5250	0.05-1	0.15				
T10 LV IDMT	3500:5	0.05 - 2.4	0.8	2800	0.05-1	0.2				
T9 LV IDMT	3500:5	0.05 - 2.4	0.35	1225	0.05-1	0.15				
T9 LV IDMT	3500:5	0.05 - 2.4	0.8	2800	0.05-1	0.2				
T3 LV IDMT	1600:5	0.05 - 2.4	1.5	2400	0.05-1	0.3				
T3 LV IDMT	1600:5	0.05 - 2.4	1.5	2400	0.05-1	0.3				
T4 LV IDMT	1600:5	0.05 - 2.4	1.5	2400	0.05-1	0.3				
T4 LV IDMT	1600:5	0.05 - 2.4	1.5	2400	0.05-1	0.3				
T8 LV IDMT	1600:5	0.05 - 2.4	1.5	2400	0.05-1	0.3				Pick up at 2400A, maximum BB FLC is 2000A
T8 LV IDMT	1600:5	0.05 - 2.4	1.5	2400	0.05-1	0.3				
T7 LV IDMT	1600:5	0.05 - 2.4	1.5	2400	0.05-1	0.3				Pick up at 2400A, maximum BB FLC is 2000A
T7 LV IDMT	1600:5	0.05 - 2.4	1.5	2400	0.05-1	0.3				
T6 LV IDMT	3500:5	0.05 - 2.4	1.5	5425	0.05-1	0.3				Pick up at 5250A, maximum BB FLC is 4000A
T6 LV IDMT	3500:5	0.05 - 2.4	1.5	5250	0.05-1	0.3				
T5 LV IDMT	3500:5	0.05 - 2.4	1.5	5250	0.05-1	0.3				Pick up at 5250A, maximum BB FLC is 4000A
T5 LV IDMT	3500:5	0.05 - 2.4	1.5	5250	0.05-1	0.3				
T12 SEPAM	150:5	0.5 - 2.4	1.5	225	0.1-12.5	0.12	0.5 - 24	12	1800	Failed co-ordination with LV side device Pick up more than 200% of FLC capacity
T12 SEPAM	150:5	0.01 - 1	0.2	30	0.1-12.5	0.12	0.01 - 15	3	450	
T14 SEPAM	150:5	0.5 - 2.4	1.5	225	0.1-12.5	0.12	0.5 - 24	12	1800	Failed co-ordination with LV side device Pick up more than 200% of FLC capacity
T14 SEPAM	150:5	0.01 - 1	0.2	30	0.1-12.5	0.12	0.01 - 15	3	450	
T16 SEPAM	150:5	0.5 - 2.4	1.5	225	0.1-12.5	0.12	0.5 - 24	12	1800	Failed co-ordination with LV side device Pick up more than 200% of FLC capacity
T16 SEPAM	150:5	0.01 - 1	0.2	30	0.1-12.5	0.12	0.01 - 15	3	450	
T1 SEPAM	150:5	0.5 - 2.4	1.75	262.5	0.1-12.5	0.93	0.5 - 24	8	1200	Faults exceed transformer damage point at current protection settings Pick up more than 200% of FLC capacity

HV Relay ID	CT Ratio (A)	Tap Setting (Pickup)			Time Dial		Instantaneous Setting			Observations
		Range (x CT rating)	Setting	Primary (A)	Range (s)	Setting (s)	Range (x CT rating)	Settings	Primary (A)	
T1 SEPAM	150:5						0.01 - 15	0.02	3	Failed co-ordination with LV side device, time delay of 0.59s not required GF setting is too low at 3A, increasing chance of spurious trip on energisation
T3 SEPAM	75:5	0.5 - 2.4	1.75	131.25	0.1-12.5	0.89	0.5 - 24	8	600	Failed co-ordination with LV side device Pick up more than 200% of FLC capacity
T3 SEPAM	75:5						0.01 - 15	0.02	1.5	
T5 SEPAM	150:5	0.5 - 2.4	1.75	262.5	0.1-12.5	0.59	0.5 - 24	8	1200	Failed co-ordination with LV side device Pick up more than 200% of FLC capacity
T5 SEPAM	150:5						0.01 - 15	0.02	3	
T7 SEPAM	75:5	0.5 - 2.4	1.75	131.25	0.1-12.5	0.74	0.5 - 24	8	600	Failed co-ordination with LV side device Pick up more than 200% of FLC capacity
T7 SEPAM	75:5						0.01 - 15	0.02	1.5	GF setting @ 1.5A is too low
T9 SEPAM	150:5	0.5 - 2.4	1.25	187.5	0.1-12.5	0.74	0.5 - 24	9	1350	Faults exceed transformer damage point at current protection settings Pick up more than 150% FLC capacity
T9 SEPAM	150:5						0.01 - 15	0.02	3	GF setting is too low at 3A
T2 SEPAM	150:5	0.5 - 2.4	1.75	262.5	0.1-12.5	0.59	0.5 - 24	8	1200	Faults exceed transformer damage point at current protection settings Pick up more than 200% of FLC capacity
T2 SEPAM	150:5						0.01 - 15	0.02	3	Failed co-ordination with LV side device, time delay of 0.59s not required GF setting is too low at 3A
T4 SEPAM	75:5	0.5 - 2.4	1.75	131.25	0.1-12.5	0.74	0.5 - 24	8	600	Failed co-ordination with LV side device Pick up more than 200% of FLC capacity
T4 SEPAM	75:5						0.01 - 15	0.02	1.5	
T6 SEPAM	150:5	0.5 - 2.4	1.75	262.5	0.1-12.5	0.59	0.5 - 24	8	1200	Failed co-ordination with LV side device Pick up more than 200% of FLC capacity
T6 SEPAM	150:5						0.01 - 15	0.02	3	
T8 SEPAM	75:5	0.5 - 2.4	1.75	131.25	0.1-12.5	0.74	0.5 - 24	8	600	Failed co-ordination with LV side device Pick up more than 200% of FLC capacity

HV Relay ID	CT Ratio (A)	Tap Setting (Pickup)			Time Dial		Instantaneous Setting			Observations
		Range (x CT rating)	Setting	Primary (A)	Range (s)	Setting (s)	Range (x CT rating)	Settings	Primary (A)	
T8 SEPAM	75:5						0.01 - 15	0.020	1.5	GF setting @ 1.5A is too low
T10 SEPAM	150:5	0.5 - 2.4	1.5	225	0.1-12.5	0.44	0.5 - 24	9	1350	Exceeds transformer damage point Pick up more than 150% FLC capacity
T10 SEPAM	150:5						0.01 - 15	0.02	3	GF setting is too low at 3A
T15 SEPAM	150:5	0.5 - 2.4	1.5	225	0.1-12.5	0.12	0.5 - 24	12	1800	Failed co-ordination with LV side device Pick up more than 200% of FLC capacity
T15 SEPAM	150:5	0.01 - 1	0.2	30	0.1-12.5	0.12	0.01 - 15	3	450	
T13 SEPAM	150:5	0.5 - 2.4	1.5	225	0.1-12.5	0.12	0.5 - 24	12	1800	Failed co-ordination with LV side device Pick up more than 200% of FLC capacity
T13 SEPAM	150:5	0.01 - 1	0.2	30	0.1-12.5	0.12	0.01 - 15	3	450	
T11 SEPAM	150:5	0.5 - 2.4	1.5	225	0.1-12.5	0.12	0.5 - 24	12	1800	Failed co-ordination with LV side device Pick up more than 200% of FLC capacity
T11 SEPAM	150:5	0.01 - 1	0.2	30	0.1-12.5	0.12	0.01 - 15	3	450	
A2 SEPAM	400:5	0.05 - 2.4	1.5	600	0.1-12.5	0.3				
A2 SEPAM	400:5	0.01 - 1	0.1	40	0.1-12.5	0.12				GF setting does not co-ordinate with *VCB* 'C' thus GEC BB fault will lose all connected busbar loads, not 50% as achievable etc. Whilst in parallel with grid connection *VCB* A2 would operate prior to DNO incomer for supply side cable fault thus loose Energy centre BB loads.
A SEPAM	400:5	0.05 - 24	1.75	700	0.05-300	0.3				DT settings does not grade with *VCB* A2/B2, or VCB C.
A SEPAM	400:5	0.01 - 15	0.31	124	0.05-300	0.6				
B SEPAM	400:5	0.05 - 24	1.75	700	0.05-300	0.30				DT settings does not grade with *VCB* A2/B2, or VCB C.
B SEPAM	400:5	0.01 - 15	0.31	124	0.05-300	0.6				
B2 SEPAM	400:5	0.05 - 2.4	1.5	600	0.1-12.5	0.3				GF setting does not co-ordinate with *VCB* 'C' thus GEC BB fault will lose all connected busbar loads, not 50% as achievable etc. Whilst in parallel with grid connection *VCB* B2 would operate prior to DNO incomer for supply side cable fault thus loose Energy centre BB loads.
B2 SEPAM	400:5	0.01 - 1	0.1	40	0.1-12.5	0.12				GF setting does not co-ordinate with *VCB* 'C' thus GEC BB fault will lose all connected busbar loads, not 50% as achievable etc.
A1 SEPAM	400:5	0.05 - 2.4	1.75	700	0.1-12.5	2.16				Does not grade for O/C with DNO incomer. Trips at grid fault level within 2.4s whereas DNO trips within 0.8s.

HV Relay ID	CT Ratio (A)	Tap Setting (Pickup)			Time Dial		Instantaneous Setting			Observations
		Range (x CT rating)	Setting	Primary (A)	Range (s)	Setting (s)	Range (x CT rating)	Settings	Primary (A)	
A1 SEPAM	400:5	0.01 - 1	0.3	120	0.1-12.5	2.55				G/F protection does not grade with DNO incomer, takes longer than 3s for the relay to operate at the systems maximum L-G current.
B1 SEPAM	400:5	0.05 - 2.4	1.75	700	0.1-12.5	2.16				Does not grade for O/C with DNO incomer. Trips at grid fault level within 2.4s whereas DNO trips within 0.8s.
B1 SEPAM	400:5	0.01 - 1	0.3	120	0.1-12.5	2.55				G/F protection does not grade with DNO incomer, takes longer than 3s for the relay to operate at the systems maximum L-G current.
WPD B MCCG52	400:5	0.05 - 2.4	1.75	700	0.05-1	0.25				
WPD B MCCG52	400:5	0.05 - 2.4	0.3	120	0.05-1	0.325				
WPD A MCCG52	400:5	0.05 - 2.4	1.75	700	0.05-1	0.25				
WPD A MCCG52	400:5	0.05 - 2.4	0.3	120	0.05-1	0.325				
VCB C SEPAM	600:5	0.5 - 2.4	1	600	0.1-12.5	0.59				
VCB C SEPAM	600:5	0.01 - 1	1	600	0.1-12.5	0.32				L-G set at 600A, considerably more than the system fault current.
G1 SEPAM	150:1	0.5 - 2.4	0.9	135	0.1-12.5	0.89				O/C settings as ANSI 51 is <1.2 x FLC of generator capacity. Under/Over frequency setting not in-line with G59 recommendations.
G1 SEPAM	150:1	0.01 - 15	0.05	7.5	0.05-300	1				L-G setting as ANSI 50N is less than 'Io' stability sum.
G2 SEPAM	150:1	0.5 - 2.4	0.9	135.	0.1-12.5	0.89				O/C settings as ANSI 51 is < 1.2 x FLC of generator capacity. Under/Over frequency setting not in-line with G59 recommendations.
G2 SEPAM	150:1	0.01 - 15	0.05	7.5	0.05-300	1				L-G setting as ANSI 50N is < 'Io' stability sum.
G3 SEPAM	150:1	0.5 - 2.4	0.9	135	0.1-12.5	0.89				O/C settings as ANSI 51 is < 1.2 x FLC of generator capacity. Under/Over frequency setting not in-line with G59 recommendations.
G3 SEPAM	150:1	0.01 - 15	0.05	7.5	0.05-300	1				L-G setting as ANSI 50N is less than Io' stability sum.
G4 SEPAM	150:1	0.05 - 2.4	1.86	279	0.1-12.5	0.16				O/C Setting as ANSI 51 is approx. 208A or 200% of generator FLC capacity. Under/Over Voltages or frequency setting not in-line with G59 recommendations.

HV Relay ID	CT Ratio (A)	Tap Setting (Pickup)			Time Dial		Instantaneous Setting			Observations
		Range (x CT rating)	Setting	Primary (A)	Range (s)	Setting (s)	Range (x CT rating)	Settings	Primary (A)	
G4 SEPAM	150:1	0.01 - 1	0.45	67.5	0.1-12.5	0.44				L-G setting has just 100ms grading margin when compared with *upstream VCB* A or *VCB* A2. L-G setting is 67.5A with a non-IEC curve (1.2 x 67.5 =81A), IEC recommends 10% of NER thus 15A
G5 SEPAM	150:1	0.05 - 2.4	1.87	280.5	0.1-12.5	0.16				O/C Setting as ANSI 51 is approx. 208A or 200% of generator FLC capacity. Under/Over Voltages or frequency setting not in-line with G59 recommendations.
G5 SEPAM	150:1	0.01 - 1	0.45	67.5	0.1-12.5	0.44				L-G setting has just 100ms grading time when compared with *VCB* A or *VCB* A2. L-G setting is 67.5A with a non-IEC curve (1.2 x 67.5 =81A), IEC recommends 10% of NER thus 15A

LV CB ID	Manufacturer	Model	CB Rating (A)	Function	Long-Time				Short-Time / Ground				Instantaneous / Maintenance		Observations
					Pickup Setting	Trip (Amps)	Band Label	Band	Pickup Setting	Trip (Amps)	Band Label	Band	Pickup	Trip (Amps)	
B/C A1	Terasaki	AGR-L	2000	Phase											
ACB T1	Terasaki	AGR-L	4000	Phase	1	4000	LT Band	0.5	10	40000	ST Band	0.1			Pick up setting at 4000A, the transformer ampacity is 3333A
ACB T2	Terasaki	AGR-L	4000	Phase	1	4000	LT Band	0.5	10	40000	ST Band	0.1			Pick up setting at 4000A, the transformer ampacity is 3333A
ACB T2	Terasaki	AGR-L	4000	Ground					0.1	400	Ground Band	0.1			
ACB T3	Merlin Gerin	STR 18M	2000	Phase									2	4000	
ACB T15	Terasaki	AGR-L	4000	Phase	1	4000	LT Band	0.5					10	40000	Pick up setting at 4000A, the transformer ampacity is 3333A
ACB T16	Terasaki	AGR-L	4000	Phase	1	4000	LT Band	0.5					10	40000	Pick up setting at 4000A, the transformer ampacity is 3333A
ACB T11	Terasaki	AGR-L	4000	Phase	1	4000	LT Band	0.5					10	40000	Pick up setting at 4000A, the transformer ampacity is 3333A
ACB T12	Terasaki	AGR-L	4000	Phase	1	4000	LT Band	0.5					10	40000	Pick up setting at 4000A, the transformer ampacity is 3333A

LV CB ID	Manufacturer	Model	CB Rating (A)	Function	Long-Time				Short-Time / Ground				Instantaneous / Maintenance		Observations
					Pickup Setting	Trip (Amps)	Band Label	Band	Pickup Setting	Trip (Amps)	Band Label	Band	Pickup	Trip (Amps)	
ACB T14	Terasaki	AGR-L	3200	Phase	1	3200	LT Band	0.5					12	38400	Pick up setting value is < FLC of the transformer.
ACB T13	Terasaki	AGR-L	3200	Phase	1	3200	LT Band	0.5					12	38400	Pick up setting value is < FLC of the transformer.
ACB *UPS* A1 I/P	Terasaki	AGR-L	1600	Phase	1	1600	LT Band	0.5					14	22400	No L-G setting present on the *UPS* input, therefore an opportunity exists to improve L-G grading oppose to relying on phase settings.
ACB *UPS* A1 O/P	Terasaki	AGR-L	1600	Phase	1	1600	LT Band	0.5					14	22400	Pick up for O/C output setting is 1600A whereas the *UPS* machine rating is 900A.
ACB *UPS* A1 O/P	Terasaki	AGR-L	1600	Ground					1	1200	Ground Band	0.1			
ACB *UPS* A2 I/P	Terasaki	AGR-L	1600	Phase	1	1600	LT Band	0.5					14	22400	No L-G setting present on the *UPS* input, therefore an opportunity exists to improve L-G grading oppose to relying on phase settings.
ACB *UPS* A2 O/P	Terasaki	AGR-L	1600	Phase	1	1600	LT Band	0.5					14	22400	Pick up for O/C *UPS* output setting is 1600A whereas the machine rating is 900A.
ACB *UPS* A3 I/P	Terasaki	AGR-L	1600	Phase	1	1600	LT Band	0.5					14	22400	No L-G setting present on the *UPS* input, therefore an opportunity exists to improve L-G grading oppose to relying on phase settings.
ACB *UPS* A3 O/P	Terasaki	AGR-L	1600	Phase	1	1600	LT Band	0.5					14	22400	Pick up for O/C output setting is 1600A whereas the machine rating is 900A.
ACB *UPS* A4 I/P	Terasaki	AGR-L	1600	Phase	1	1600	LT Band	0.5					14	22400	No L-G setting present on the *UPS* input, therefore an opportunity exists to improve L-G grading oppose to relying on phase settings.
ACB *UPS* A4 O/P	Terasaki	AGR-L	1600	Phase	1	1600	LT Band	0.5					14	22400	Pick up for O/C output setting is 1600A whereas the machine rating is 900A.

LV CB ID	Manufacturer	Model	CB Rating (A)	Function	Long-Time				Short-Time / Ground				Instantaneous / Maintenance		Observations
					Pickup Setting	Trip (Amps)	Band Label	Band	Pickup Setting	Trip (Amps)	Band Label	Band	Pickup	Trip (Amps)	
ACB *UPS* A5 I/P	Terasaki	AGR-L	1600	Phase	1	1600	LT Band	0.5					14	22400	No L-G setting present on the *UPS* input, therefore an opportunity exists to improve L-G grading oppose to relying on phase settings.
ACB *UPS* A5 O/P	Terasaki	AGR-L	1600	Phase	1	1600	LT Band	0.5					14	22400	Pick up for O/C output setting is 1600A whereas the machine rating is 900A.

Fuse ID	Manufacturer	Model	Max Voltage	Size (A)	L-L-L fault current (KA)	LG fault current (KA)	Base KV	Observations
LV Fuse T9	Bussmann	GG	0.55 kV	800	47.37	50.632	0.411	Fuses are not required; settings can be achieved on the IDMT incoming relay to maintain effective grading and inter-trip indications.
PDU A2 FUSE	Bussmann	DD	0.415 kV	160	97.413	104.242	0.411	*PDU* fuses do not grade with transformer incomer whilst in *UPS* bypass mode.
PDU A21 FUSE	Bussmann	DD	0.415 kV	160	97.413	104.242	0.411	*PDU* fuses do not grade with transformer incomer whilst in *UPS* bypass mode.

III Complete LV & HV Protection Settings Table relating to Chapter 6.1, Improving *AO* with protection device grading

High Voltage System Settings

Relay ID	CT Ratio	Device Function	Trip Element	Curve	Tap (Pickup)			Time Dial / Mult.		Instantaneous			Inst. Delay	
					Range	Setting	Primary	Range	Setting	Range	Settings	Primary	Range	Setting
T10 LV IDMT	3500:5	Overcurrent	Phase	Standard Inverse	0.05 - 2.4 xCT Sec	1.5	5250	0.05-1	0.15					
T10 LV IDMT	3500:5	Overcurrent	Phase	Very Inverse	0.05 - 2.4 xCT Sec	1.15	4025	0.05-1	0.1	1 - 31 x51 Pickup	9	36225		
T10 LV IDMT	3500:5	Overcurrent	Ground	Standard Inverse	0.05 - 2.4 xCT Sec	0.8	2800	0.05-1	0.2					
T10 LV IDMT	3500:5	Overcurrent	Ground	Very Inverse	0.05 - 2.4 xCT Sec	0.7	2450	0.05-1	0.2					
T9 LV IDMT	3500:5	Overcurrent	Phase	Standard Inverse	0.05 - 2.4 xCT Sec	0.35	1225	0.05-1	0.15					
T9 LV IDMT	3500:5	Overcurrent	Phase	Very Inverse	0.05 - 2.4 xCT Sec	0.35	1225	0.05-1	0.5	1 - 31 x51 Pickup	30	36750		
T9 LV IDMT	3500:5	Overcurrent	Ground	Standard Inverse	0.05 - 2.4 xCT Sec	0.8	2800	0.05-1	0.2					
T9 LV IDMT	3500:5	Overcurrent	Ground	Very Inverse	0.05 - 2.4 xCT Sec	0.6	2100	0.05-1	0.2					
T3 LV IDMT	1600:5	Overcurrent	Phase	Very Inverse	0.05 - 2.4 xCT Sec	1.5	2400	0.05-1	0.3					
T3 LV IDMT	1600:5	Overcurrent	Phase	Very Inverse	0.05 - 2.4 xCT Sec	0.95	1520	0.05-1	0.25	1 - 31 x51 Pickup	10	15200		
T3 LV IDMT	1600:5	Overcurrent	Ground	Very Inverse	0.05 - 2.4 xCT Sec	1.5	2400	0.05-1	0.3					
T3 LV IDMT	1600:5	Overcurrent	Ground	Very Inverse	0.05 - 2.4 xCT Sec	1.25	2000	0.05-1	0.25	1 - 31 x51 Pickup	8	16000		
T4 LV IDMT	1600:5	Overcurrent	Phase	Very Inverse	0.05 - 2.4 xCT Sec	1.5	2400.000	0.05-1	0.3					
T4 LV IDMT	1600:5	Overcurrent	Phase	Very Inverse	0.05 - 2.4 xCT Sec	0.95	1520	0.05-1	0.2	1 - 31 x51 Pickup	10	15200		
T4 LV IDMT	1600:5	Overcurrent	Ground	Very Inverse	0.05 - 2.4 xCT Sec	1.5	2400	0.05-1	0.3					
T4 LV IDMT	1600:5	Overcurrent	Ground	Very Inverse	0.05 - 2.4 xCT Sec	1.25	2000	0.05-1	0.25	1 - 31 x51 Pickup	8	16000		
T8 LV IDMT	1600:5	Overcurrent	Phase	Very Inverse	0.05 - 2.4 xCT Sec	1.5	2400	0.05-1	0.3					
T8 LV IDMT	1600:5	Overcurrent	Phase	Very Inverse	0.05 - 2.4 xCT Sec	0.95	1520	0.05-1	0.25	1 - 31 x51 Pickup	10	15200		
T8 LV IDMT	1600:5	Overcurrent	Ground	Very Inverse	0.05 - 2.4 xCT Sec	1.5	2400	0.05-1	0.3					
T8 LV IDMT	1600:5	Overcurrent	Ground	Very Inverse	0.05 - 2.4 xCT Sec	1.25	2000	0.05-1	0.25	1 - 31 x51 Pickup	8	16000		

Relay ID	CT Ratio	Device Function	Trip Element	Curve	Tap (Pickup)			Time Dial / Mult.		Instantaneous			Inst. Delay	
					Range	Setting	Primary	Range	Setting	Range	Settings	Primary	Range	Setting
T7 LV IDMT	1600:5	Overcurrent	Phase	Very Inverse	0.05 - 2.4 xCT Sec	1.5	2400	0.05-1	0.3					
T7 LV IDMT	1600:5	Overcurrent	Phase	Very Inverse	0.05 - 2.4 xCT Sec	0.95	1520	0.05-1	0.25	1 - 31 x51 Pickup	10	15200		
T7 LV IDMT	1600:5	Overcurrent	Ground	Very Inverse	0.05 - 2.4 xCT Sec	1.5	2400	0.05-1	0.3					
T7 LV IDMT	1600:5	Overcurrent	Ground	Very Inverse	0.05 - 2.4 xCT Sec	1.25	2000	0.05-1	0.25	1 - 31 x51 Pickup		16000		
T6 LV IDMT	3500:5	Overcurrent	Phase	Very Inverse	0.05 - 2.4 xCT Sec	1.55	5425	0.05-1	0.3					
T6 LV IDMT	3500:5	Overcurrent	Phase	Extremely Inverse	0.05 - 2.4 xCT Sec	1.15	4025	0.05-1	0.3	1 - 31 x51 Pickup	8	32200		
T6 LV IDMT	3500:5	Overcurrent	Ground	Very Inverse	0.05 - 2.4 xCT Sec	1.5	5250	0.05-1	0.3					
T6 LV IDMT	3500:5	Overcurrent	Ground	Definite Time 2s	0.05 - 2.4 xCT Sec	0.7	2450	0.05-1	0.2					
T5 LV IDMT	3500:5	Overcurrent	Phase	Very Inverse	0.05 - 2.4 xCT Sec	1.5	5250	0.05-1	0.3					
T5 LV IDMT	3500:5	Overcurrent	Phase	Extremely Inverse	0.05 - 2.4 xCT Sec	1.15	4025	0.05-1	0.3	1 - 31 x51 Pickup	8	32200		
T5 LV IDMT	3500:5	Overcurrent	Ground	Very Inverse	0.05 - 2.4 xCT Sec	1.5	5250	0.05-1	0.3					
T5 LV IDMT	3500:5	Overcurrent	Ground	Definite Time 2s	0.05 - 2.4 xCT Sec	0.7	2450	0.05-1	0.2					
T12 SEPAM	150:5	Overcurrent	Phase	Extremely Inverse	0.5 - 2.4 xCT Sec	1.5	225	0.1-12.5	0.12	0.5 - 24 xCT Sec	12	1800		
T12 SEPAM	150:5	Overcurrent	Phase	IEC - Extremely Inverse	0.5 - 2.4 xCT Sec	1.1	165	0.1-12.5	0.3	0.5 - 24 xCT Sec	12	1800	0.05 - 300	0.2 s
T12 SEPAM	150:5	Overcurrent	Ground	Extremely Inverse	0.01 - 1 xCT Sec	0.2	30	0.1-12.5	0.12	0.01 - 15 xCT Sec	3	450		
T12 SEPAM	150:5	Overcurrent	Ground	Extremely Inverse	0.01 - 1 xCT Sec	0.2	30	0.1-12.5	0.12	0.01 - 15 xCT Sec	3	450		
T14 SEPAM	150:5	Overcurrent	Phase	Extremely Inverse	0.5 - 2.4 xCT Sec	1.5	225	0.1-12.5	0.12	0.5 - 24 xCT Sec	12	1800		
T14 SEPAM	150:5	Overcurrent	Phase	IEC - Extremely Inverse	0.5 - 2.4 xCT Sec	1.1	165	0.1-12.5	0.3	0.5 - 24 xCT Sec	12	1800	0.05 - 300	0.2 s
T14 SEPAM	150:5	Overcurrent	Ground	Extremely Inverse	0.01 - 1 xCT Sec	0.2	30	0.1-12.5	0.12	0.01 - 15 xCT Sec	3	450		
T14 SEPAM	150:5	Overcurrent	Ground	Extremely Inverse	0.01 - 1 xCT Sec	0.2	30	0.1-12.5	0.12	0.01 - 15 xCT Sec	3	450		
T16 SEPAM	150:5	Overcurrent	Phase	Extremely Inverse	0.5 - 2.4 xCT Sec	1.5	225	0.1-12.5	0.12	0.5 - 24 xCT Sec	12	1800		
T16 SEPAM	150:5	Overcurrent	Phase	IEC - Extremely Inverse	0.5 - 2.4 xCT Sec	1.1	165.	0.1-12.5	0.3	0.5 - 24 xCT Sec	12	1800	0.05 - 300	0.2 s

Relay ID	CT Ratio	Device Function	Trip Element	Curve	Tap (Pickup)			Time Dial / Mult.		Instantaneous			Inst. Delay	
					Range	Setting	Primary	Range	Setting	Range	Settings	Primary	Range	Setting
T16 SEPAM	150:5	Overcurrent	Ground	Extremely Inverse	0.01 - 1 xCT Sec	0.2	30	0.1-12.5	0.12	0.01 - 15 xCT Sec	3	450		
T16 SEPAM	150:5	Overcurrent	Ground	Extremely Inverse	0.01 - 1 xCT Sec	0.2	30	0.1-12.5	0.12	0.01 - 15 xCT Sec	3	450		
T1 SEPAM	150:5	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	1.75	262.5	0.1-12.5	0.93	0.5 - 24 xCT Sec	8	1200		
T1 SEPAM	150:5	Overcurrent	Phase	IEC - Extremely Inverse (TMS)	0.5 - 2.4 xCT Sec	1.1	165	0.13-15.47	0.4	0.5 - 24 xCT Sec	18	2700	0.05 - 300	0.1 s
T1 SEPAM	150:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.02	3		
T1 SEPAM	150:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.15	22.5	0.05 - 300	0.1 s
T3 SEPAM	75:5	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	1.75	131.25	0.1-12.5	0.89	0.5 - 24 xCT Sec	8	600		
T3 SEPAM	75:5	Overcurrent	Phase	IEC - Extremely Inverse (TMS)	0.5 - 2.4 xCT Sec	1.1	82.5	0.13-15.47	0.4	0.5 - 24 xCT Sec	18	1350	0.05 - 300	0.1 s
T3 SEPAM	75:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.02	1.5		
T3 SEPAM	75:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.15	11.25	0.05 - 300	0.15 s
T5 SEPAM	150:5	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	1.75	262.5	0.1-12.5	0.59	0.5 - 24 xCT Sec	8	1200		
T5 SEPAM	150:5	Overcurrent	Phase	IEC - Extremely Inverse (TMS)	0.5 - 2.4 xCT Sec	1.1	165	0.13-15.47	0.4	0.5 - 24 xCT Sec	18	2700	0.05 - 300	0.1 s
T5 SEPAM	150:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.02	3		
T5 SEPAM	150:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.15	22.5	0.05 - 300	0.15 s
T7 SEPAM	75:5	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	1.75	131.25	0.1-12.5	0.74	0.5 - 24 xCT Sec	8	600		
T7 SEPAM	75:5	Overcurrent	Phase	IEC - Extremely Inverse (TMS)	0.5 - 2.4 xCT Sec	1.1	82.5	0.13-15.47	0.4	0.5 - 24 xCT Sec	18	1350	0.05 - 300	0.1 s
T7 SEPAM	75:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.02	1.5		
T7 SEPAM	75:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.15	11.25	0.05 - 300	0.15 s
T9 SEPAM	150:5	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	1.25	187.5	0.1-12.5	0.74	0.5 - 24 xCT Sec	9	1350		
T9 SEPAM	150:5	Overcurrent	Phase	IEC - Very Inverse	0.5 - 2.4 xCT Sec	1	150	0.1-12.5	0.4	0.5 - 24 xCT Sec	9	1350	0.05 - 300	0.5 s
T9 SEPAM	150:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.02	3		
T9 SEPAM	150:5	Overcurrent	Ground							0.01 - 15 xCT Sec 0.02	0.25	37.5	0.05 – 300	0.1 s 0.2

Relay ID	CT Ratio	Device Function	Trip Element	Curve	Tap (Pickup)			Time Dial / Mult.		Instantaneous			Inst. Delay	
					Range	Setting	Primary	Range	Setting	Range	Settings	Primary	Range	Setting
T2 SEPAM	150:5	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	1.75	262.5	0.1-12.5	0.59	0.5 - 24 xCT Sec	8	1200		
T2 SEPAM	150:5	Overcurrent	Phase	IEC - Extremely Inverse (TMS)	0.5 - 2.4 xCT Sec	1.1	165	0.13-15.47	0.4	0.5 - 24 xCT Sec	18	2700	0.05 - 300	0.1 s
T2 SEPAM	150:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.02	3		
T2 SEPAM	150:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.15	22.5	0.05 - 300	0.1 s
T4 SEPAM	75:5	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	1.75	131.25	0.1-12.5	0.74	0.5 - 24 xCT Sec	8	600		
T4 SEPAM	75:5	Overcurrent	Phase	IEC - Extremely Inverse (TMS)	0.5 - 2.4 xCT Sec	1.1	82.5	0.13-15.47	0.4	0.5 - 24 xCT Sec	18	1350	0.05 - 300	0.1 s
T4 SEPAM	75:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.02	1.5		
T4 SEPAM	75:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.15	11.25	0.05 - 300	0.15 s
T6 SEPAM	150:5	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	1.7	262.5	0.1-12.5	0.59	0.5 - 24 xCT Sec	8	1200		
T6 SEPAM	150:5	Overcurrent	Phase	IEC - Extremely Inverse (TMS)	0.5 - 2.4 xCT Sec	1.1	165	0.13-15.47	0.4	0.5 - 24 xCT Sec	18	2700	0.05 - 300	0.1 s
T6 SEPAM	150:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.02	3		
T6 SEPAM	150:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.15	22.5	0.05 - 300	0.15 s
T8 SEPAM	75:5	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	1.75	131.25	0.1-12.5	0.74	0.5 - 24 xCT Sec	8	600		
T8 SEPAM	75:5	Overcurrent	Phase	IEC - Extremely Inverse (TMS)	0.5 - 2.4 xCT Sec	1.1	82.5	0.13-15.47	0.4	0.5 - 24 xCT Sec	18	1350	0.05 - 300	0.1 s
T8 SEPAM	75:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.02	1.5		
T8 SEPAM	75:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.15	11.25	0.05 - 300	0.15 s
T10 SEPAM	150:5	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	1.5	225	0.1-12.5	0.44	0.5 - 24 xCT Sec	9	1350		
T10 SEPAM	150:5	Overcurrent	Phase	IEC - Very Inverse	0.5 - 2.4 xCT Sec	1	150	0.1-12.5	0.3	0.5 - 24 xCT Sec	12	1800	0.05 - 300	0.075 s
T10 SEPAM	150:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.02	3		
T10 SEPAM	150:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.2	30	0.05 - 300	0.1 s
T15 SEPAM	150:5	Overcurrent	Phase	Extremely Inverse	0.5 - 2.4 xCT Sec	1.5	225	0.1-12.5	0.12	0.5 - 24 xCT Sec	12	1800		
T15 SEPAM	150:5	Overcurrent	Phase	IEC - Extremely Inverse	0.5 - 2.4 xCT Sec	1.1	165	0.1-12.5	0.3	0.5 - 24 xCT Sec	12	1800	0.05 – 300	0.3 s 0.4

Relay ID	CT Ratio	Device Function	Trip Element	Curve	Tap (Pickup)			Time Dial / Mult.		Instantaneous			Inst. Delay	
					Range	Setting	Primary	Range	Setting	Range	Settings	Primary	Range	Setting
T15 SEPAM	150:5	Overcurrent	Ground	Extremely Inverse	0.01 - 1 xCT Sec	0.2	30	0.1-12.5	0.12	0.01 - 15 xCT Sec	3	450		
T15 SEPAM	150:5	Overcurrent	Ground	Extremely Inverse	0.01 - 1 xCT Sec	0.2	30	0.1-12.5	0.12	0.01 - 15 xCT Sec	3	450		
T13 SEPAM	150:5	Overcurrent	Phase	Extremely Inverse	0.5 - 2.4 xCT Sec	1.5	225	0.1-12.5	0.12	0.5 - 24 xCT Sec	12	1800		
T13 SEPAM	150:5	Overcurrent	Phase	IEC - Extremely Inverse	0.5 - 2.4 xCT Sec	1.1	165	0.1-12.5	0.3	0.5 - 24 xCT Sec	12	1800	0.05 - 300	0.2 s
T13 SEPAM	150:5	Overcurrent	Ground	Extremely Inverse	0.01 - 1 xCT Sec	0.2	30	0.1-12.5	0.12	0.01 - 15 xCT Sec	3	450		
T13 SEPAM	150:5	Overcurrent	Ground	Extremely Inverse	0.01 - 1 xCT Sec	0.2	30	0.1-12.5	0.12	0.01 - 15 xCT Sec	3	450		
T11 SEPAM	150:5	Overcurrent	Phase	Extremely Inverse	0.5 - 2.4 xCT Sec	1.5	225	0.1-12.5	0.12	0.5 - 24 xCT Sec	12	1800		
T11 SEPAM	150:5	Overcurrent	Phase	IEC - Extremely Inverse	0.5 - 2.4 xCT Sec	1.1	165	0.1-12.5	0.3	0.5 - 24 xCT Sec	12	1800	0.05 - 300	0.2 s
T11 SEPAM	150:5	Overcurrent	Ground	Extremely Inverse	0.01 - 1 xCT Sec	0.2	30	0.1-12.5	0.12	0.01 - 15 xCT Sec	3	450		
A2 SEPAM	400:5	Overcurrent	Phase	Very Inverse	0.05 - 2.4 xCT Sec	1.5	600	0.1-12.5	0.3					
A2 SEPAM	400:5	Overcurrent	Phase	IEC - Very Inverse	0.05 - 2.4 xCT Sec	1.3	520	0.1-12.5	0.25	0.05 - 24 xCT Sec	9	3600	0.05 - 300	0.25 s
A2 SEPAM	400:5	Overcurrent	Ground	Extremely Inverse	0.01 - 1 xCT Sec	0.1	40	0.1-12.5	0.12					
A2 SEPAM	400:5	Overcurrent	Ground	IEC - Very Inverse	0.01 - 1 xCT Sec	0.2	80	0.1-12.5	0.4					
A SEPAM	400:5	Overcurrent	Phase											
A SEPAM	400:5	Overcurrent	Ground	Definite Time	0.01 - 15 xCT Sec	0.31	124	0.05-300	0.6					
A SEPAM	400:5	Overcurrent	Ground											
B SEPAM	400:5	Overcurrent	Phase	Definite Time	0.05 - 24 xCT Sec	1.75	700	0.05-300	0.3					
B SEPAM	0:0	Overcurrent	Phase											
B SEPAM	400:5	Overcurrent	Ground	Definite Time	0.01 - 15 xCT Sec	0.31	124	0.05-300	0.6					
B SEPAM	0:0	Overcurrent	Ground											
B2 SEPAM	400:5	Overcurrent	Phase	Very Inverse	0.05 - 2.4 xCT Sec	1.5	600	0.1-12.5	0.3					
B2 SEPAM	400:5	Overcurrent	Phase	IEC - Very Inverse	0.05 - 2.4 xCT Sec	1.3	520	0.1-12.5	0.25	0.05 - 24 xCT Sec	9	3600	0.05 - 300	0.25 s
B2 SEPAM	400:5	Overcurrent	Ground	Extremely Inverse	0.01 - 1 xCT Sec	0.1	40	0.1-12.5	0.12					
B2 SEPAM	400:5	Overcurrent	Ground	IEC - Very Inverse	0.01 - 1 xCT Sec	0.2	80	0.1-12.5	0.3					

Relay ID	CT Ratio	Device Function	Trip Element	Curve	Tap (Pickup)			Time Dial / Mult.		Instantaneous			Inst. Delay	
					Range	Setting	Primary	Range	Setting	Range	Settings	Primary	Range	Setting
A1 SEPAM	400:5	Overcurrent	Phase	Standard Inverse	0.05 - 2.4 xCT Sec	1.75	700	0.1-12.5	2.165					
A1 SEPAM	400:5	Overcurrent	Phase	IEC - Standard Inverse	0.05 - 2.4 xCT Sec	1.75	700	0.1-12.5	0.6	0.05 - 24 xCT Sec	11	4400	0.05 - 300	0.4 s
A1 SEPAM	400:5	Overcurrent	Ground	Standard Inverse	0.01 - 1 xCT Sec	0.3	120	0.1-12.5	2.55					
A1 SEPAM	400:5	Overcurrent	Ground	IEC - Very Inverse	0.01 - 1 xCT Sec	0.25	100	0.1-12.5	0.4					
B1 SEPAM	400:5	Overcurrent	Phase	Standard Inverse	0.05 - 2.4 xCT Sec	1.75	700	0.1-12.5	2.16					
B1 SEPAM	400:5	Overcurrent	Phase	IEC - Standard Inverse	0.05 - 2.4 xCT Sec	1.75	700	0.1-12.5	0.6	0.05 - 24 xCT Sec	11	4400	0.05 - 300	0.4 s
B1 SEPAM	400:5	Overcurrent	Ground	Standard Inverse	0.01 - 1 xCT Sec	0.3	120	0.1-12.5	2.55					
B1 SEPAM	400:5	Overcurrent	Ground	IEC - Very Inverse	0.01 - 1 xCT Sec	0.25	100	0.1-12.5	0.4					
WPD B MCCG52	400:5	Overcurrent	Phase	Standard Inverse	0.05 - 2.4 xCT Sec	1.75	700	0.05-1	0.25					
WPD B MCCG52	400:5	Overcurrent	Phase	Standard Inverse	0.05 - 2.4 xCT Sec	1.75	700	0.05-1	0.35					
WPD B MCCG52	400:5	Overcurrent	Ground	Standard Inverse	0.05 - 2.4 xCT Sec	0.3	120	0.05-1	0.325					
WPD B MCCG52	400:5	Overcurrent	Ground	Standard Inverse	0.05 - 2.4 xCT Sec	0.3	120	0.05-1	0.325					
WPD A MCCG52	400:5	Overcurrent	Phase	Standard Inverse	0.05 - 2.4 xCT Sec	1.75	700	0.05-1	0.25					
WPD A MCCG52	400:5	Overcurrent	Phase	Standard Inverse	0.05 - 2.4 xCT Sec	1.75	700	0.05-1	0.35					
WPD A MCCG52	400:5	Overcurrent	Ground	Standard Inverse	0.05 - 2.4 xCT Sec	0.3	120	0.05-1	0.325					
WPD A MCCG52	400:5	Overcurrent	Ground	Standard Inverse	0.05 - 2.4 xCT Sec	0.3	120	0.05-1	0.325					
VCB C SEPAM	600:5	Overcurrent	Phase	Standard Inverse	0.5 - 2.4 xCT Sec	1	600	0.1-12.5	0.59					
VCB C SEPAM	600:5	Overcurrent	Phase	IEC - Very Inverse	0.5 - 2.4 xCT Sec	0.9	540	0.1-12.5	0.15					
VCB C SEPAM	600:5	Overcurrent	Ground	Standard Inverse	0.01 - 1 xCT Sec	1	600	0.1-12.5	0.32					
VCB C SEPAM	600:5	Overcurrent	Ground	IEC - Very Inverse	0.01 - 1 xCT Sec	0.15	90	0.1-12.5	0.24					
G1 SEPAM	150:1	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	0.9	135	0.1-12.5	0.89					
G1 SEPAM	150:1	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	1	150	0.1-12.5	0.89					

Relay ID	CT Ratio	Device Function	Trip Element	Curve	Tap (Pickup) Range	Tap (Pickup) Setting	Tap (Pickup) Primary	Time Dial / Mult. Range	Time Dial / Mult. Setting	Instantaneous Range	Instantaneous Settings	Instantaneous Primary	Inst. Delay Range	Inst. Delay Setting
G1 SEPAM	150:1	Overcurrent	Ground	Definite Time	0.01 - 15 xCT Sec	0.05	7.5	0.05-300	1					
G1 SEPAM	150:1	Overcurrent	Ground	Definite Time	0.01 - 15 xCT Sec	0.1	15	0.05-300	1					
G2 SEPAM	150:1	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	0.9	135	0.1-12.5	0.89					
G2 SEPAM	0:0	Overcurrent	Phase											
G2 SEPAM	150:1	Overcurrent	Ground	Definite Time	0.01 - 15 xCT Sec	0.05	7.5	0.05-300	1					
G2 SEPAM	0:0	Overcurrent	Ground											
G2 diff	150:1	Overcurrent	Phase											
G2 diff	150:1	Overcurrent	Ground											
G3 SEPAM	150:1	Overcurrent	Phase	Standard Inverse	0.5 - 2.4 xCT Sec	0.9	135	0.1-12.5	0.89					
G3 SEPAM	0:0	Overcurrent	Phase											
G3 SEPAM	150:1	Overcurrent	Ground	Definite Time	0.01 - 15 xCT Sec	0.05	7.5	0.05-300	1					
G3 SEPAM	0:0	Overcurrent	Ground											
G4 SEPAM	150:1	Overcurrent	Phase	Extremely Inverse	0.05 - 2.4 xCT Sec	1.86	279	0.1-12.5	0.16					
G4 SEPAM	150:1	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	1	150	0.1-12.5	0.89					
G4 SEPAM	150:1	Overcurrent	Ground	Very Inverse	0.01 - 1 xCT Sec	0.45	67.5	0.1-12.5	0.44					
G4 SEPAM	150:1	Overcurrent	Ground	Definite Time	0.01 - 15 xCT Sec	0.1	15	0.05-300	1					
G4 diff	150:1	Overcurrent	Ground											
G5 SEPAM	150:1	Overcurrent	Phase	Extremely Inverse	0.05 - 2.4 xCT Sec	1.87	280.5	0.1-12.5	0.16					
G5 SEPAM	150:1	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	1	150	0.1-12.5	0.89					
G5 SEPAM	150:1	Overcurrent	Ground	Very Inverse	0.01 - 1 xCT Sec	0.45	67.5	0.1-12.5	0.44					
G5 SEPAM	150:1	Overcurrent	Ground	Definite Time	0.01 - 15 xCT Sec	0.1	15	0.05-300	1					
G5 diff	150:1	Overcurrent	Phase											
T9 REF	3500:5	Overcurrent	Phase							10 - 40 xCT Sec	10	350	0.01 - 0.01	0.01 s
WPD B directional	400:5	Overcurrent	Phase	Standard Inverse	0.05 - 2.4 xCT Sec	0.5	200	0.1-12.5	0.1					
WPD B directional	400:5	Overcurrent	Ground	Standard Inverse	0.01 - 1 xCT Sec	0.4	160	0.1-12.5	0.1					
WPD A directional	400:5	Overcurrent	Phase	Standard Inverse	0.05 - 2.4 xCT Sec	0.5	200	0.1-12.5	0.1					

Relay ID	CT Ratio	Device Function	Trip Element	Curve	Tap (Pickup)			Time Dial / Mult.		Instantaneous			Inst. Delay	
					Range	Setting	Primary	Range	Setting	Range	Settings	Primary	Range	Setting
WPD A directional	400:5	Overcurrent	Ground	Standard Inverse	0.01 - 1 xCT Sec	0.4	160	0.1-12.5	0.1					
VCB E SEPAM	600:5	Overcurrent	Phase	Standard Inverse	0.5 - 2.4 xCT Sec	1	600	0.1-12.5	0.59					
VCB E SEPAM	600:5	Overcurrent	Phase	IEC - Very Inverse	0.5 - 2.4 xCT Sec	0.8	480	0.1-12.5	0.4					
VCB E SEPAM	600:5	Overcurrent	Ground	Standard Inverse	0.01 - 1 xCT Sec	1	600	0.1-12.5	0.32					
VCB E SEPAM	600:5	Overcurrent	Ground	IEC - Very Inverse	0.01 - 1 xCT Sec	0.17	102	0.1-12.5	0.6					
VCB D SEPAM	600:5	Overcurrent	Phase	Standard Inverse	0.5 - 2.4 xCT Sec	1	600	0.1-12.5	0.59					
VCB D SEPAM	600:5	Overcurrent	Phase	IEC - Very Inverse	0.5 - 2.4 xCT Sec	0.8	480	0.1-12.5	0.4					
VCB D SEPAM	600:5	Overcurrent	Ground	Standard Inverse	0.01 - 1 xCT Sec	1	600	0.1-12.5	0.32					
VCB D SEPAM	600:5	Overcurrent	Ground	IEC - Very Inverse	0.01 - 1 xCT Sec	0.17	102	0.1-12.5	0.6					

Where, Orange coloured cells highlight the proposed protection changes, in comparison to the original scheme (Changes required for the HV scheme 339 of a total 1136 settings).

Low Voltage System Settings

LVCB ID	Manufacturer	Model	Amps	Model	Function	Long-Time					Short-Time / Ground					Instantaneous / Maintenance		
						Pickup Label	Pickup Setting	Trip (Amps)	Band Label	Band	Pickup Label	Pickup Setting	Trip (Amps)	Band Label	Band	Pickup Label	Pickup	Trip (Amps)
B/C A1	Terasaki	AR440S	4000	AGR-L	Phase													
ACB T1	Terasaki	AR440S	4000	AGR-L	Phase	LT Pickup	1	4000	LT Band	0.5	ST Pickup	10	40000	ST Band	0.1			
ACB T1	Terasaki	AR440S	4000	AGR-L	Phase	LT Pickup	0.9	3600	LT Band	0.5						Inst. Pickup	14	56000
ACB T2	Terasaki	AR440S	4000	AGR-L	Phase	LT Pickup	1	4000	LT Band	0.5	ST Pickup	10	40000	ST Band	0.1			
ACB T2	Terasaki	AR440S	4000	AGR-L	Phase	LT Pickup	0.9	3600	LT Band	0.5						Inst. Pickup	14	56000
ACB T2	Terasaki	AR440S	4000	AGR-L	Ground						Ground Pickup	0.1	400	Ground Band	0.1			
ACB T2	Terasaki	AR440S	4000	AGR-L	Ground													
ACB T3	Merlin Gerin	M20 H1	2000	STR 18M	Phase											Inst. Pickup	2	4000
B/C C1	Merlin Gerin	M40 H1	4000	STR 18M	Phase													
B/C G1	Merlin Gerin	M40 H1	4000	STR 18M	Phase													
ACB T15	Terasaki	AR440SB	4000	AGR-L	Phase	LT Pickup	1	4000	LT Band	0.5						Inst. Pickup	10	40000
ACB T16	Terasaki	AR440SB	4000	AGR-L	Phase	LT Pickup	1	4000	LT Band	0.5						Inst. Pickup	10	40000
ACB T11	Terasaki	AR440SB	4000	AGR-L	Phase	LT Pickup	1	4000	LT Band	0.5						Inst. Pickup	10	40000
ACB T11	Terasaki	AR440SB	4000	AGR-L	Phase	LT Pickup	0.9	3600	LT Band	0.5						Inst. Pickup	10	40000
ACB T12	Terasaki	AR440SB	4000	AGR-L	Phase	LT Pickup	1	4000	LT Band	0.5						Inst. Pickup	10	40000
ACB T12	Terasaki	AR440SB	4000	AGR-L	Phase	LT Pickup	0.9	3600	LT Band	0.5						Inst. Pickup	10	40000
ACB T14	Terasaki	AR332H	3200	AGR-L	Phase	LT Pickup	1	3200	LT Band	0.5						Inst. Pickup	12	38400
ACB T13	Terasaki	AR332H	3200	AGR-L	Phase	LT Pickup	1	3200	LT Band	0.5						Inst. Pickup	12	38400
ACB *UPS* A1 I/P	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	1	1600	LT Band	0.5						Inst. Pickup	14	22400

LVCB ID	Manufacturer	Model	Amps	Model	Function	Long-Time					Short-Time / Ground					Instantaneous / Maintenance		
						Pickup Label	Pickup Setting	Trip (Amps)	Band Label	Band	Pickup Label	Pickup Setting	Trip (Amps)	Band Label	Band	Pickup Label	Pickup	Trip (Amps)
ACB *UPS* A1 I/P	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	0.85	1360	LT Band	0.5						Inst. Pickup	10	16000
ACB *UPS* A1 O/P	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	1	1600	LT Band	0.5						Inst. Pickup	14	22400
ACB *UPS* A1 O/P	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	0.85	1360	LT Band	0.5						Inst. Pickup	6	9600
ACB *UPS* A1 O/P	Terasaki	AR316H	1600	AGR-L	Ground						Ground Pickup	1	1200	Ground Band	0.1			
ACB *UPS* A1 O/P	Terasaki	AR316H	1600	AGR-L	Ground						Ground Pickup	1	1200	Ground Band	1			
ACB *	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	1	1600	LT Band	0.5						Inst. Pickup	14	22400
ACB *UPS* A2 I/P	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	1	1600	LT Band	0.5						Inst. Pickup	14	22400
ACB *UPS* A2 I/P	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	0.9	1440	LT Band	0.5						Inst. Pickup	10	16000
ACB *UPS* A2 O/P	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	1	1600	LT Band	0.5						Inst. Pickup	14	22400
ACB *UPS* A2 O/P	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	0.8	1280	LT Band	0.5						Inst. Pickup	6	9600
ACB *UPS* A2 O/P	Terasaki	AR316H	1600	AGR-L	Ground													
ACB *UPS* A2 O/P	Terasaki	AR316H	1600	AGR-L	Ground						Ground Pickup	1	1200	Ground Band	1			
ACB *2	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	1	1600	LT Band	0.5						Inst. Pickup	14	22400
ACB *UPS* A3 I/P	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	1	1600	LT Band	0.5						Inst. Pickup	14	22400
ACB *UPS* A3 I/P	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	0.9	1440	LT Band	0.5						Inst. Pickup	10	16000

LVCB ID	Manufacturer	Model	Amps	Model	Function	Long-Time					Short-Time / Ground					Instantaneous / Maintenance		
						Pickup Label	Pickup Setting	Trip (Amps)	Band Label	Band	Pickup Label	Pickup Setting	Trip (Amps)	Band Label	Band	Pickup Label	Pickup	Trip (Amps)
ACB *UPS* A3 O/P	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	1	1600	LT Band	0.5						Inst. Pickup	14	22400
ACB *UPS* A3 O/P	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	0.8	1280	LT Band	0.5						Inst. Pickup	6	9600
ACB *UPS* A3 O/P	Terasaki	AR316H	1600	AGR-L	Ground													
ACB *UPS* A3 O/P	Terasaki	AR316H	1600	AGR-L	Ground						Ground Pickup	1	1200	Ground Band	1			
ACB *UPS* A4 I/P	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	1	1600	LT Band	0.5						Inst. Pickup	14	22400
ACB *UPS* A4 I/P	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	0.9	1440	LT Band	0.5						Inst. Pickup	10	16000
ACB *UPS* A4 O/P	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	1	1600	LT Band	0.5						Inst. Pickup	14	22400
ACB *UPS* A4 O/P	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	0.8	1280	LT Band	0.5						Inst. Pickup	6	9600
ACB *UPS* A4 O/P	Terasaki	AR316H	1600	AGR-L	Ground													
ACB *UPS* A4 O/P	Terasaki	AR316H	1600	AGR-L	Ground						Ground Pickup	1	1200	Ground Band	1			
ACB *3	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	1	1600	LT Band	0.5						Inst. Pickup	14	22400
ACB *5	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	1	1600	LT Band	0.5						Inst. Pickup	14	22400
ACB *UPS* A5 I/P	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	1	1600	LT Band	0.5						Inst. Pickup	14	22400
ACB *UPS* A5 I/P	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	0.9	1440	LT Band	0.5						Inst. Pickup	10	16000
ACB *UPS* A5 O/P	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	1	1600	LT Band	0.5						Inst. Pickup	14	22400

LVCB ID	Manufacturer	Model	Amps	Model	Function	Long-Time					Short-Time / Ground					Instantaneous / Maintenance		
						Pickup Label	Pickup Setting	Trip (Amps)	Band Label	Band	Pickup Label	Pickup Setting	Trip (Amps)	Band Label	Band	Pickup Label	Pickup	Trip (Amps)
ACB *UPS* A5 O/P	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	0.8	1280	LT Band	0.5						Inst. Pickup	6	9600
ACB *UPS* A5 O/P	Terasaki	AR316H	1600	AGR-L	Ground													
ACB *UPS* A5 O/P	Terasaki	AR316H	1600	AGR-L	Ground						Ground Pickup	1	1200	Ground Band	1			
ACB *6	Terasaki	AR316H	1600	AGR-L	Phase	LT Pickup	1	1600	LT Band	0.5						Inst. Pickup	14	22400
A1 Bypass ACB	Terasaki	AR440S	4000	AGR-L	Phase	LT Pickup	1	4000	LT Band	5	ST Pickup	2	8000	ST Band	0.2	Inst. Pickup	10	40000
A1 Bypass ACB	Terasaki	AR440S	4000	AGR-L	Phase	LT Pickup	1	4000	LT Band	0.5						Inst. Pickup	14	56000
DB A/2 B/C	Terasaki	AR440S	4000	AGR-L	Phase													
A2 Bypass ACB	Terasaki	AR440S	4000	AGR-L	Phase	LT Pickup	1	4000	LT Band	5						Inst. Pickup	4	16000
A2 Bypass ACB	Terasaki	AR440S	4000	AGR-L	Phase													

Where, Orange coloured cells highlight the proposed protection changes, in comparison to the original scheme etc. (Changes required for the LV scheme 54 of a total 337 settings)

IV Protection Settings for Arc Flash Mitigation Table relating to Chapter 6.2

Low Voltage System Settings

LVCB ID	Make	Model	Amps	Model	Sensor/Frame	Function	Long-Time				Short-Time / Ground				Inst	
							Pickup Setting	Trip (Amps)	Band Label	Band	Pickup Setting	Trip (Amps)	Band Label	Band	Pickup	Trip (Amps)
ACB T1	Terasaki	AR440S	4000	AGR-L	4000	Phase	1	4000	LT Band	0.5	10	40000	ST Band	0.1		
ACB T2	Terasaki	AR440S	4000	AGR-L	4000	Phase	1	4000	LT Band	0.5	10	40000	ST Band	0.1		
ACB T2	Terasaki	AR440S	4000	AGR-L	4000	Ground					0.1	400	Ground Band	0.1		
ACB T3	Merlin Gerin	M20 H1	2000	STR 18M	2000	Phase									2	4000
ACB T15	Terasaki	AR440SB	4000	AGR-L	4000	Phase	1	4000	LT Band	0.5					10	40000
ACB T16	Terasaki	AR440SB	4000	AGR-L	4000	Phase	1	4000	LT Band	0.5					10	40000
ACB T11	Terasaki	AR440SB	4000	AGR-L	4000	Phase	1	4000	LT Band	0.5					10	40000
ACB T12	Terasaki	AR440SB	4000	AGR-L	4000	Phase	1	4000	LT Band	0.5					10	40000
ACB T14	Terasaki	AR332H	3200	AGR-L	3200	Phase	1	3200	LT Band	0.5					12	38400
ACB T13	Terasaki	AR332H	3200	AGR-L	3200	Phase	1	3200	LT Band	0.5					12	38400
ACB *UPS* A1 I/P	Terasaki	AR316H	1600	AGR-L	1600	Phase	1	1600	LT Band	0.5					14	22400
ACB *UPS* A1 O/P	Terasaki	AR316H	1600	AGR-L	1600	Phase	1	1600	LT Band	0.5					14	22400
ACB *UPS* A1 O/P	Terasaki	AR316H	1600	AGR-L	1600	Ground					1	1200	Ground Band	0.1		
ACB *UPS* A2 I/P	Terasaki	AR316H	1600	AGR-L	1600	Phase	1	1600	LT Band	0.5					14	22400
ACB *UPS* A2 O/P	Terasaki	AR316H	1600	AGR-L	1600	Phase	1	1600	LT Band	0.5					14	22400
ACB *UPS* A3 I/P	Terasaki	AR316H	1600	AGR-L	1600	Phase	1	1600	LT Band	0.5					14	22400

LVCB ID	Make	Model	Amps	Model	Sensor/Frame	Function	Long-Time				Short-Time / Ground				Inst	
							Pickup Setting	Trip (Amps)	Band Label	Band	Pickup Setting	Trip (Amps)	Band Label	Band	Pickup	Trip (Amps)
ACB *UPS* A3 O/P	Terasaki	AR316H	1600	AGR-L	1600	Phase	1	1600	LT Band	0.5					14	22400
ACB *UPS* A4 I/P	Terasaki	AR316H	1600	AGR-L	1600	Phase	1	1600	LT Band	0.5					14	22400
ACB *UPS* A4 O/P	Terasaki	AR316H	1600	AGR-L	1600	Phase	1	1600	LT Band	0.5					14	22400
ACB *UPS* A5 I/P	Terasaki	AR316H	1600	AGR-L	1600	Phase	1	1600	LT Band	0.5					14	22400
ACB *UPS* A5 O/P	Terasaki	AR316H	1600	AGR-L	1600	Phase	1	1600	LT Band	0.5					14	22400
A1 Bypass ACB	Terasaki	AR440S	4000	AGR-L	4000	Phase	1	4000	LT Band	5	2	8000	ST Band	0.2	10	40000
A2 Bypass ACB	Terasaki	AR440S	4000	AGR-L	4000	Phase	1	4000	LT Band	5					4	16000

High Voltage System Settings

Relay ID	CT Ratio	Device Function	Trip Element	Curve	Tap (Pickup)			Time Dial / Mult.		Instantaneous		
					Range	Setting	Primary	Range	Setting	Range	Settings	Primary
T10 LV IDMT	3500:5	Overcurrent	Phase	Standard Inverse	0.05 - 2.4 xCT Sec	1.5	5250	0.05-1	0.15			
T10 LV IDMT	3500:5	Overcurrent	Ground	Standard Inverse	0.05 - 2.4 xCT Sec	0.8	2800	0.05-1	0.20			
T9 LV IDMT	3500:5	Overcurrent	Phase	Standard Inverse	0.05 - 2.4 xCT Sec	0.35	1225	0.05-1	0.15			
T9 LV IDMT	3500:5	Overcurrent	Ground	Standard Inverse	0.05 - 2.4 xCT Sec	0.8	2800	0.05-1	0.2			
T3 LV IDMT	1600:5	Overcurrent	Phase	Very Inverse	0.05 - 2.4 xCT Sec	1.5	2400	0.05-1	0.3			
T3 LV IDMT	1600:5	Overcurrent	Ground	Very Inverse	0.05 - 2.4 xCT Sec	1.5	2400	0.05-1	0.3			
T4 LV IDMT	1600:5	Overcurrent	Phase	Very Inverse	0.05 - 2.4 xCT Sec	1.5	2400	0.05-1	0.3			
T4 LV IDMT	1600:5	Overcurrent	Ground	Very Inverse	0.05 - 2.4 xCT Sec	1.5	2400	0.05-1	0.3			
T8 LV IDMT	1600:5	Overcurrent	Phase	Very Inverse	0.05 - 2.4 xCT Sec	1.5	2400	0.05-1	0.3			
T8 LV IDMT	1600:5	Overcurrent	Ground	Very Inverse	0.05 - 2.4 xCT Sec	1.5	2400	0.05-1	0.3			
T7 LV IDMT	1600:5	Overcurrent	Phase	Very Inverse	0.05 - 2.4 xCT Sec	1.5	2400	0.05-1	0.3			
T7 LV IDMT	1600:5	Overcurrent	Ground	Very Inverse	0.05 - 2.4 xCT Sec	1.5	2400	0.05-1	0.3			
T6 LV IDMT	3500:5	Overcurrent	Phase	Very Inverse	0.05 - 2.4 xCT Sec	1.55	5425	0.05-1	0.3			
T6 LV IDMT	3500:5	Overcurrent	Ground	Very Inverse	0.05 - 2.4 xCT Sec	1.5	5250	0.05-1	0.3			
T5 LV IDMT	3500:5	Overcurrent	Phase	Very Inverse	0.05 - 2.4 xCT Sec	1.5	5250	0.05-1	0.3			
T5 LV IDMT	3500:5	Overcurrent	Ground	Very Inverse	0.05 - 2.4 xCT Sec	1.5	5250	0.05-1	0.3			
T12 SEPAM	150:5	Overcurrent	Phase	Extremely Inverse	0.5 - 2.4 xCT Sec	1.5	225	0.1-12.5	0.12	0.5 - 24 xCT Sec	12	1800
T12 SEPAM	150:5	Overcurrent	Ground	Extremely Inverse	0.01 - 1 xCT Sec	0.2	30	0.1-12.5	0.12	0.01 - 15 xCT Sec	3	450
T14 SEPAM	150:5	Overcurrent	Phase	Extremely Inverse	0.5 - 2.4 xCT Sec	1.5	225	0.1-12.5	0.12	0.5 - 24 xCT Sec	12	1800
T14 SEPAM	150:5	Overcurrent	Ground	Extremely Inverse	0.01 - 1 xCT Sec	0.2	30	0.1-12.5	0.12	0.01 - 15 xCT Sec	3	450
T16 SEPAM	150:5	Overcurrent	Phase	Extremely Inverse	0.5 - 2.4 xCT Sec	1.5	225	0.1-12.5	0.12	0.5 - 24 xCT Sec	12	1800
T16 SEPAM	150:5	Overcurrent	Ground	Extremely Inverse	0.01 - 1 xCT Sec	0.2	30	0.1-12.5	0.12	0.01 - 15 xCT Sec	3	450
T1 SEPAM	150:5	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	1.75	262.5	0.1-12.5	0.93	0.5 - 24 xCT Sec	8	1200
T1 SEPAM	150:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.02	3
T3 SEPAM	75:5	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	1.75	131.25	0.1-12.5	0.89	0.5 - 24 xCT Sec	8	600
T3 SEPAM	75:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.02	1.5
T5 SEPAM	150:5	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	1.75	262.5	0.1-12.5	0.59	0.5 - 24 xCT Sec	8	1200
T5 SEPAM	150:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.02	3
T7 SEPAM	75:5	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	1.75	131.25	0.1-12.5	0.74	0.5 - 24 xCT Sec	8	600
T7 SEPAM	75:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.02	1.5
T9 SEPAM	150:5	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	1.25	187.5	0.1-12.5	0.74	0.5 - 24 xCT Sec	9	1350
T9 SEPAM	150:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.02	3
T2 SEPAM	150:5	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	1.75	262.5	0.1-12.5	0.59	0.5 - 24 xCT Sec	8	1200
T2 SEPAM	150:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.02	3
T4 SEPAM	75:5	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	1.75	131.25	0.1-12.5	0.74	0.5 - 24 xCT Sec	8	600
T4 SEPAM	75:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.02	1.5
T6 SEPAM	150:5	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	1.75	262.5	0.1-12.5	0.59	0.5 - 24 xCT Sec	8	1200
T6 SEPAM	150:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.02	3
T8 SEPAM	75:5	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	1.75	131.25	0.1-12.5	0.74	0.5 - 24 xCT Sec	8	600
T8 SEPAM	75:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.02	1.5
T10 SEPAM	150:5	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	1.5	225	0.1-12.5	0.44	0.5 - 24 xCT Sec	9	1350
T10 SEPAM	150:5	Overcurrent	Ground							0.01 - 15 xCT Sec	0.02	3
T15 SEPAM	150:5	Overcurrent	Phase	Extremely Inverse	0.5 - 2.4 xCT Sec	1.5	225	0.1-12.5	0.12	0.5 - 24 xCT Sec	12	1800
T15 SEPAM	150:5	Overcurrent	Ground	Extremely Inverse	0.01 - 1 xCT Sec	0.2	30	0.1-12.5	0.12	0.01 - 15 xCT Sec	3	450

	CT				Tap (Pickup)			Time Dial / Mult.		Instantaneous		
Relay ID	Ratio	Device Function	Trip Element	Curve	Range	Setting	Primary	Range	Setting	Range	Settings	Primary
T13 SEPAM	150:5	Overcurrent	Phase	Extremely Inverse	0.5 - 2.4 xCT Sec	1.5	225	0.1-12.5	0.12	0.5 - 24 xCT Sec	12	1800
T13 SEPAM	150:5	Overcurrent	Ground	Extremely Inverse	0.01 - 1 xCT Sec	0.2	30	0.1-12.5	0.12	0.01 - 15 xCT Sec	3	450
T11 SEPAM	150:5	Overcurrent	Phase	Extremely Inverse	0.5 - 2.4 xCT Sec	1.5	225	0.1-12.5	0.12	0.5 - 24 xCT Sec	12	1800
T11 SEPAM	150:5	Overcurrent	Ground	Extremely Inverse	0.01 - 1 xCT Sec	0.2	30	0.1-12.5	0.12	0.01 - 15 xCT Sec	3	450
A2 SEPAM	400:5	Overcurrent	Phase	Very Inverse	0.05 - 2.4 xCT Sec	1.5	600	0.1-12.5	0.3			
A2 SEPAM	400:5	Overcurrent	Ground	Extremely Inverse	0.01 - 1 xCT Sec	0.1	40	0.1-12.5	0.12			
A SEPAM	400:5	Overcurrent	Ground	Definite Time	0.01 - 15 xCT Sec	0.31	124	0.05-300	0.6			
B SEPAM	400:5	Overcurrent	Phase	Definite Time	0.05 - 24 xCT Sec	1.75	700	0.05-300	0.3			
B SEPAM	400:5	Overcurrent	Ground	Definite Time	0.01 - 15 xCT Sec	0.31	124	0.05-300	0.6			
B2 SEPAM	400:5	Overcurrent	Phase	Very Inverse	0.05 - 2.4 xCT Sec	1.5	600	0.1-12.5	0.3			
B2 SEPAM	400:5	Overcurrent	Ground	Extremely Inverse	0.01 - 1 xCT Sec	0.1	40	0.1-12.5	0.12			
A1 SEPAM	400:5	Overcurrent	Phase	Standard Inverse	0.05 - 2.4 xCT Sec	1.75	700	0.1-12.5	2.165			
A1 SEPAM	400:5	Overcurrent	Ground	Standard Inverse	0.01 - 1 xCT Sec	0.30	120	0.1-12.5	2.55			
B1 SEPAM	400:5	Overcurrent	Phase	Standard Inverse	0.05 - 2.4 xCT Sec	1.75	700	0.1-12.5	2.16			
B1 SEPAM	400:5	Overcurrent	Ground	Standard Inverse	0.01 - 1 xCT Sec	0.3	120	0.1-12.5	2.55			
WPD B MCCG52	400:5	Overcurrent	Phase	Standard Inverse	0.05 - 2.4 xCT Sec	1.75	700	0.05-1	0.25			
WPD B MCCG52	400:5	Overcurrent	Ground	Standard Inverse	0.05 - 2.4 xCT Sec	0.3	120	0.05-1	0.325			
WPD A MCCG52	400:5	Overcurrent	Phase	Standard Inverse	0.05 - 2.4 xCT Sec	1.75	700	0.05-1	0.25			
WPD A MCCG52	400:5	Overcurrent	Ground	Standard Inverse	0.05 - 2.4 xCT Sec	0.3	120	0.05-1	0.325			
VCB C SEPAM	600:5	Overcurrent	Phase	Standard Inverse	0.5 - 2.4 xCT Sec	1	600	0.1-12.5	0.59			
VCB C SEPAM	600:5	Overcurrent	Ground	Standard Inverse	0.01 - 1 xCT Sec	1	600	0.1-12.5	0.32			
G1 SEPAM	150:1	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	0.9	135	0.1-12.5	0.89			
G1 SEPAM	150:1	Overcurrent	Ground	Definite Time	0.01 - 15 xCT Sec	0.05	7.5	0.05-300	1			
G2 SEPAM	150:1	Overcurrent	Phase	IEC - Standard Inverse	0.5 - 2.4 xCT Sec	0.9	135	0.1-12.5	0.89			
G2 SEPAM	150:1	Overcurrent	Ground	Definite Time	0.01 - 15 xCT Sec	0.05	7.5	0.05-300	1			
G3 SEPAM	150:1	Overcurrent	Phase	Standard Inverse	0.5 - 2.4 xCT Sec	0.9	135	0.1-12.5	0.89			
G3 SEPAM	150:1	Overcurrent	Ground	Definite Time	0.01 - 15 xCT Sec	0.05	7.5	0.05-300	1			
G4 SEPAM	150:1	Overcurrent	Phase	Extremely Inverse	0.05 - 2.4 xCT Sec	1.86	279	0.1-12.5	0.16			
G4 SEPAM	150:1	Overcurrent	Ground	Very Inverse	0.01 - 1 xCT Sec	0.45	67.5	0.1-12.5	0.44			
G5 SEPAM	150:1	Overcurrent	Phase	Extremely Inverse	0.05 - 2.4 xCT Sec	1.87	280.5	0.1-12.5	0.16			
G5 SEPAM	150:1	Overcurrent	Ground	Very Inverse	0.01 - 1 xCT Sec	0.45	67.5	0.1-12.5	0.44			
VCB E SEPAM	600:5	Overcurrent	Phase	Standard Inverse	0.5 - 2.4 xCT Sec	1	600	0.1-12.5	0.59			
VCB E SEPAM	600:5	Overcurrent	Ground	Standard Inverse	0.01 - 1 xCT Sec	1	600	0.1-12.5	0.32			
VCB D SEPAM	600:5	Overcurrent	Phase	Standard Inverse	0.5 - 2.4 xCT Sec	1	600	0.1-12.5	0.59			
VCB D SEPAM	600:5	Overcurrent	Ground	Standard Inverse	0.01 - 1 xCT Sec	1	600	0.1-12.5	0.32			

V Parameters for Establishing Optimal Network Load Flow Relating to Chapter 5 Simulation Approach

<table>
<tr><th colspan="3">Load flow optimal conditions for a Tier 3 data centre system</th></tr>
<tr>
<td>Condition 1 Switchgear busbar Voltage Security Indices (Vsi) must comply with:

$\mathbf{0.25 \geq 0.5 \left(\frac{V_i - V_{sp}}{V_{lim}}\right)^2}$

Where;
V_i = Simulated busbar voltage
V_{sp} = Specified busbar voltage (Nominal 415V)
V_{lim} = Voltage deviation</td>
<td>Condition 2 Cost parameters of an optimal distribution transformers arrangement must comply with:

TX E_{cost} ≤ 0.5428

Where;
TX E_{cost} is the total annual energy cost for a distribution transformer, per MVA (£m).</td>
<td>Condition 3 Generator vector stability curves should not be exceeded during:

$\mathbf{P_n < P_d < P_d \times 1.1}$

Where;
P_n is the nominal site load power (MW)
P_d is the system power design capabilities (MW)
P_d x 1.1 is 110% of system design capabilities.</td>
</tr>
</table>

VI Parameters for Establishing Optimal Network Short Circuit Analysis Relating to Chapter 5 Simulation Approach

Short circuit analysis optimal conditions for a Tier 3 data centre system						
Load demand and profiles: All simulations must be inclusive of actual site power metering data from devices in accordance to IEC62053 Where accuracy is within tolerances: Voltage (V) and Current (A) ± 0.01% Frequency (Hz) ± 0.005 Hz Power (KW) ± 0.075% Power Factor (PF) ± 0.02% (from 0.5 lag to 0.5 lead). Specify the actual KVA & PF in simulations with details for constant KVA or constant Z type loads to be expressed as a percentage of nominal load. For constant KVA loads LRC values must conform with: $LRC \geq 6 \times I_n$ Where; LRC = lock rotor current I_n = Nominal rated current (A)	**Switchgear:** Base current ratings must not exceed: $I_n \leq 0.95 \times I_b$ Where; I_n = Nominal connected busbar load currents (A) including any Tier 3 redundant capability. I_b = Switchgear continuous current rating (A) as specified by ANSI C37.20.2.	***UPS*:** Static path contribution for model components must include: K_{ac} = 1200 – 1400% Where; K_{ac} is the short circuit expressed as percentage of nominal *UPS* current rating. Internal bypass switch must be closed for all short circuit simulations. A Synchronous motor (model block) is to be utilised for representation of the rotary *UPS* sub transient components, where transient data is sourced from the OEM: Xd'' < Xd' < Xd Where; OEM is the original equipment manufacturers Xd'' = sub transient impedance Xd' = transient impedance Xd = Steady state impedance	**Generator:** Stator operation must not exceed IEC60034: 2.18 x FLC < 10s Where; FLC = Nominal full load current rating of the generator (A). Model components for short circuit analysis must include both dynamic elements: Xd' < Xd Where; OEM data Xd' = direct axis transient reactance Xd = direct axis synchronous reactance	**Transformer:** Model components must satisfy: $I_{mag} < I_n \times 8$ $T_{mag} < 6$ cycles Where; I_{mag} = transformer magnetising current (A) T_{mag} = time in seconds for transformer inrush to clear. Faults simulated on the transformer secondary must include: $Z_s + Z_t$ Where; Z_s = total upstream system impedance Z_t = transformer impedance Short circuit current analysis must include both frequent and infrequent values as IEEE C57. $(I^2t = K) < IEEE\ C57.109$ Where; I= Symmetrical fault current, expressed as times rated current. K= constant determined at maximum I when t=2 seconds.	**Cables:** Model as fixed (Z) passive analysis. Simulations must include cable data for positive, negative and zero sequence resistance and reactance. Construction and insulation type, along with configuration i.e., trefoil, flat or random lay. IEC603664 operating factors must be applied as; $C_g\ C_a\ C_s\ C_t$ Where factors; C_g = grouping with other cables. C_a = ambient temperature exposed to cabling. C_t= Thermal insulation (where cable penetrates) C_s = derating for semi enclosed fuse types BS3036. In x 0.725. (Where In is nominal rating in Amperes). Thermal damage curves as IEC603644 are to be plotted in the TCC for compliance with I^2t. Where; TCC = time current curves	**Short Circuit:** Analysis must determine IEC60909 fault current values at each busbar: L-L-L, L-G, L-L, L-L-G. L-L-L < IEEE Std. C37.21 Where; IEEE Std. C37.21 specifies switchgear short circuit current withstand L-L-L & L-G IEEE Std. C37.21 values are then to be utilised in TCC plots for optimal protection curve assessment.

VII Parameters for Establishing Optimal Electrical Protection Relay Settings Relating to Chapter 5 Simulation Approach

Protection device settings optimal conditions for a Tier 3 data centre system				
Generators: Curve type = IEC SI Phase Overcurrent 50/51: 1.2 x In Earth Fault 50N/51N: 10% of NER rating Machine Differential 87M: 5 to 10% In (stator) 20% In (frame faults) Reverse Active Power 32P: 5 to 20% Pn Td = 3 Under/Over frequency 81L/H: ± 2Hz Td = 3 Undervoltage 27: 0.75 to 0.85 x Un Td = 3 Over voltage 59: 1.1 x Un Td = 5 For O/C & E/F settings: Td > 200ms Between generator outputs and ring feeder circuit breakers. Where; In = nominal current rating Pn = nominal power rating NER = neutral earth resistor Td = time delay in seconds. O/C = relay overcurrent setting E/F = relay earth fault setting	***UPS*:** LT pick-up ≥ 1.5 x In Td > 200ms Relevant between *UPS* input & upstream devices, i.e., Td = 0, between *UPS* input and outputs. Where; LT = Relay long time In = *UPS* nominal current rating (A) Td = Time delay (S) I1 > 1.5 x I2 $Td_1 > Td_2 + 200ms$ For bypass protection against downstream loads. Where; I1 = Bypass relay current setting I2 = Downstream PDU relay current setting Td_1 = Time delay on bypass protection Td_2 = Time delay on downstream PDU *UPS* Voltage and frequency operational settings must comply with: 81l/81h/27/59 < G59 Where; G59 is the Energy Networks Associations short-term requirements for parallel power system connections. *UPS* input INST protection must not exceed: Inst ≤ (In x 10) Where; In = nominal current rating (A) Inst = instantaneous current setting (A)	**Transformer (HV):** LT pick-up > 1.25 x In & < 1.5 x In Where; In = Continuous rating of the transformer LT = Relay long-time pick-up setting (A). Ig = 0.3 x In Where; Ig = Ground fault setting (A) In = Transformer continuous rating (A) Td1 > Td2 + 200ms Where; Td1 = Time delay of upstream protection device. Td2 = time delay of transformer device. Thermal ratings must achieve IEEE C57.109 compliance: $(I^2 t = K) < IEEE\ C57.109$ Where; I = Symmetrical fault current in times rated current. K = Constant determined at maximum I when t=2. t = seconds Note: There is no requirement or benefit to grade HV & LV protections, either side of a Dyn11 vector group transformer.	**HV Main feeder:** Ig < DNO + Td 200ms Td (DNO dp) > 200ms + Td (PNO dp) Where; Ig = Ground current setting (A) Td = Time delay (s) DNO Dp = DNO differential protection setting. PNO Dp = PNO differential protection setting. G59 compliance settings: U/V & O/V ± 6% Un, Td = 0.5 U/F & O/F ± 0.5 Hz, Td = 0.5 Where; U/V = Under voltage O/V = Over voltage U/F = Under frequency O/F = Over frequency Un = Phase to earth Voltage. Td = Time delay (s) Note: Protection system must include an operational relay to denote signalling for LV inter-trip received, or HV inter-trip send.	**LV Main feeder:** INST > 12 x In & < 14 x In Where; In = Continuous current setting (A). INST = Instantaneous current setting (A). LT pick up > 1.25 x In Where; In = Continuous rating of the switchgear (A). LT = Long-time relay setting. Vk > 2 x Vs Where; Vk = Setting voltage of Restricted Earth Fault relay. Vs = Voltage present at the Restricted Earth Fault Relay, during an earth fault. Note: Protection system must include an operational relay to denote signalling for LV inter-trip, or HV inter-trip.

VIII Parameters for Establishing Optimal Arc Flash Mitigation Relating to Chapter 5 Simulation Approach

Arc flash optimal conditions for a Tier 3 data centre system
For each of the installed switchgears within the data centre electrical network, the following three conditions must be obtained. $E <$ 30 cal/cm^2 $FCT <$ 35 cycles $INST <$ In x 14 or $RSO >$ 30m distance from switchgear. Where; $E =$ Incident Energy (J/cm^2) $FCT =$ Fault Clearing Time (s) $INST =$ Instantaneous current setting of incoming switchgear protection relays (KA) $RSO =$ Remote Switching Operations i.e., from an HMI controller or mobile lanyard