SUBSTATION

DESIGN / APPLICATION

GUIDE

BY

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Acknowledgments

i) I would like to express my gratitude to my two retired Chief Engineers at AREVA (then GEC Alsthom), Dr H L Thanawala (Power Systems and Development department) and Mr D Young (Design and Application department), who were very helpful and supportive to me in finding that electrical engineering is an interesting and worthwhile profession for me, having moved from two other occupations, one as a rewarding lecturer, the head of the department of mathematics at St Joseph's College, Colombo in Sri Lanka and the other as a geophysicist, working in North Sea, finding oil and gas and contributing to the United Kingdom economy.

ii) My sincere thanks go to my colleague Mr Philip Flowers for his invaluable help in producing excellent diagrams for this guide.

iii) I am grateful to AREVA for requesting me to write this design/application guide for project application engineers.

iv) The examples provided in this guide are all from multi-million pounds worth of orders for AC substations, SVCs, MSCs and MSCDNs, projects which were successfully carried out by me in the United Kingdom for National Grid and for Overseas electrical utilities in Australia, Canada, Indonesia, Zambia, Pakistan and Sri Lanka.

v) I have also included some illustrations from my presentations I gave in AREVA, IEE in London, the University of Peradeniya in Sri Lanka and CEB in Sri Lanka.

vi) I would like to thank AREVA specially for allowing me to use those examples and illustrations mentioned in this design/application guide.

Contents

1. INTRODUCTION

The purpose of this document is to provide a general guide to the design of an Air Insulated Switchgear (AIS) and a Gas Insulated Switchgear (GIS) of an AC substation. The document is divided into 12 chapters starting from Electrical Arrangement to Lightning and Earthing Protection.

In general this application guide will provide some basic understandings about the HV equipments on substation designs for HVAC and HVDC substation projects.

This guide is written specifically for new electrical graduate engineers who embark on a career on HVAC and HVDC substation projects.

The chapter two covers the electrical arrangements, the basic concepts and factors affecting the design of AC substation.

The chapter three includes the AC substation arrangement. The substation different configurations are characterised by their busbar arrangements and generally any number of circuits can be provided by repeating the pattern. The AC substation comprises three main components and these are classified as primary system, secondary system and auxiliary supply system.

The chapters four and five deal with protection equipment and protection of main components of substation. These chapters will help application engineers to select suitable electrical equipments such as CT's, VT's, relays etc. for the appropriate protection functions. The protection should be done to prevent any disruption of supply and damage to the electrical equipments.

The chapters six and eight cover Compensation and Flexible AC transmission System (FACTS). FACTS is an acronym for Flexible AC Transmission System. The philosophy of FACTS is to use reactive power compensation devices to control power flows in a transmission network, thereby allowing transmission line plant to be loaded to its full capability.

The chapter seven covers Auxiliary System.

The chapter nine covers Wind Farm substation equipments. Electricity generated from renewable sources now accounts for around 4% of the UK's supply, with more planned, including an increase in the amount generated from Offshore and Onshore farms.

The chapters ten and eleven cover Ferro-resonance and Quadrature Booster.

The Chapter twelve includes HVDC equipment/description.

The chapter thirteen covers Lightning and Earthing protections, which prevent any damage to substation equipment and loss of power to public.

2. ELECTRICAL ARRANGEMENT

2.1 FACTORS AFFECTING THE DESIGN

Service Continuity (under fault and maintenance conditions)

– what security of service does the load require, what length of outage can be tolerated and would this cause loss of revenue or endanger plant?

– is insulator pollution going to necessitate more than normal maintenance?

– will outages for maintenance require alternative circuits in the substation or are they available elsewhere in the network?

Cost

– this must be balanced against the facilities desirable

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Protection

– can adequate relay protection be obtained simply?

Operational Facilities

– does the system require splitting under maximum plant conditions to limit fault level?

– will it be necessary to isolate any loads with undesirable characteristics (e.g. rectifier drive rolling mills, arc furnaces) except under emergency conditions?

Extension

– almost invariably required, though not always considered

– what outage can be allowed for extension work?

– if outage to be minimal, may mean extra initial cost

Service Continuity i.e. Strategic Importance

– permissible level of disturbance from a single fault

– extent of circuit disconnection due to busbar outage

– extent of circuit loss due to circuit breaker/plant maintenance

– associated costs of loss supply, PowerGen, NPower etc. vs Domestic user

Operational Flexibility

– duplication of circuits to give alternative routes

– switching of generation for peaks and troughs in demand

Amount of Power to be Transmitted

– sectioning of busbars to cater for large numbers of generators/power modules

Number of Circuits Entering the Substation

– some arrangements are limited to a finite number of circuits

Future System Requirements

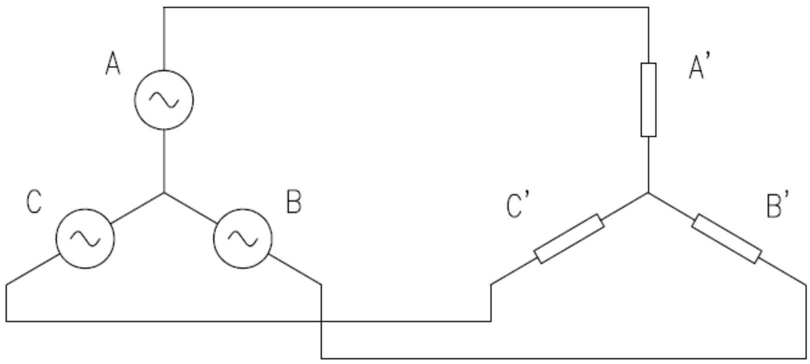
– the need to extend or develop installations for future circuits

Level of Skill of Operating Staff

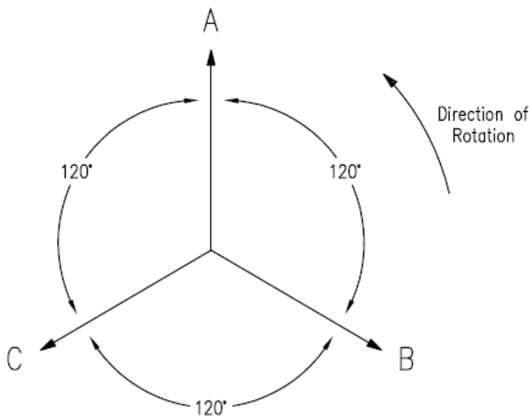
– affects the complexity of installation and maintenance features

2.2 **3-PHASE SYSTEM**

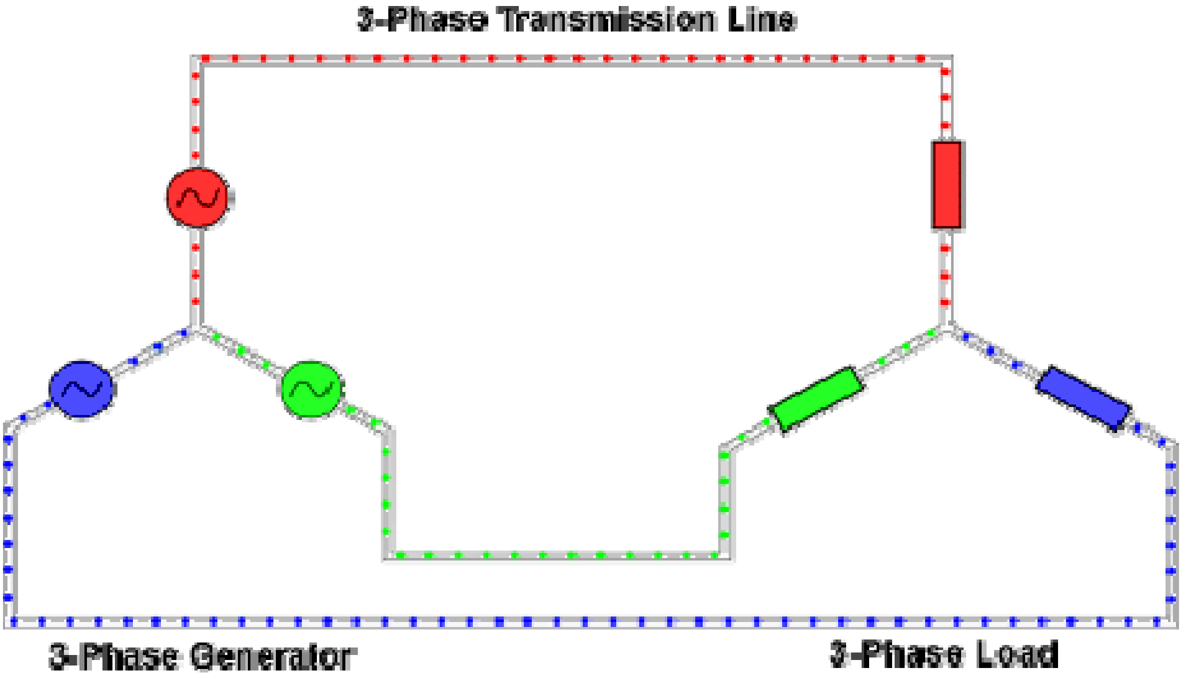
2.3

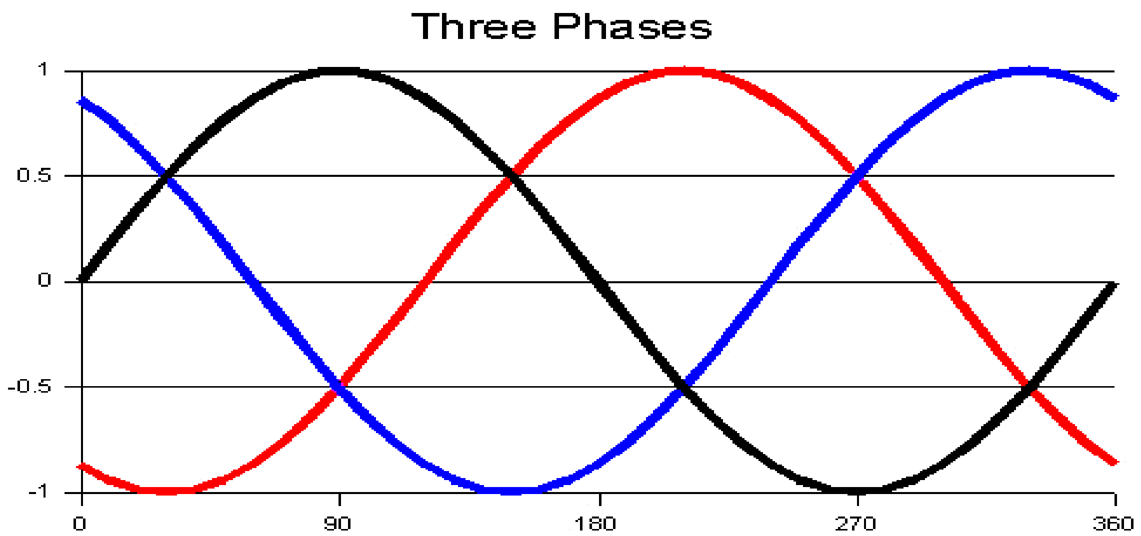


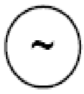
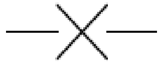
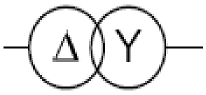
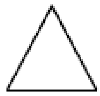
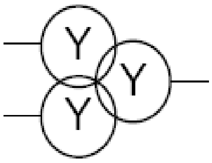
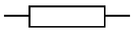
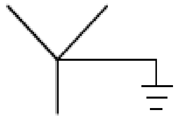
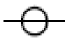
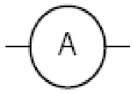
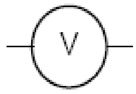
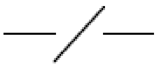
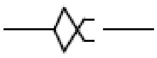
3–phase Balanced Loads

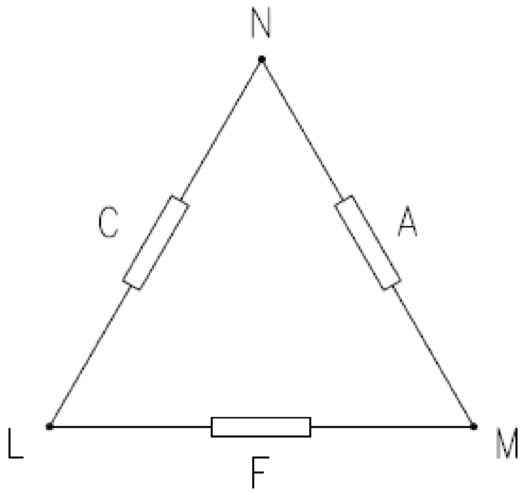


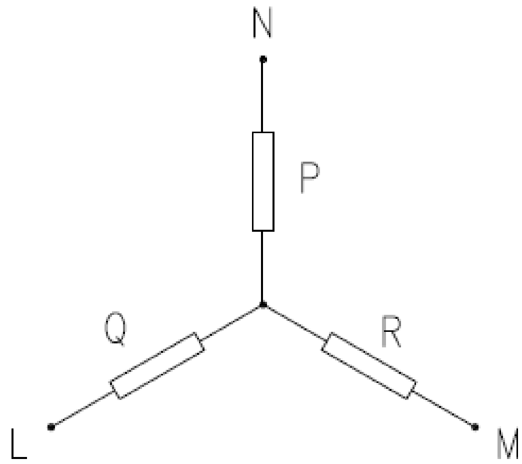
Balanced Vectors


3-Phase Transmission Line
3-Phase Generator
3-Phase Load


Three Phases
1
0.5
0
-0.5
-1
0
90
180
270
360

Machine or rotating armature		Circuit Breaker	
2-Winding power transformer		3-phase Delta connection	
3-Winding power transformer		3-phase Star connection	
Fuse		3-phase Star connection with grounded neutral	
Current transformer	 or 	Ammeter & Voltmeter	 
RCP disconnector		REP disconnector	
Pantograph disconnector		Earth switch	





$$P = \frac{AC}{A + C + F}$$

$$Q = \frac{FC}{A + C + F}$$

$$R = \frac{AF}{A + C + F}$$

AC SYSTEM

3 Phase Voltage = V (Line to Line Voltage) = 400kV say

1 Phase = V/√3 (Line to Neutral) = 400/√3 kV = 230.9 kV

3 Phase Voltage = V (Line to Line Voltage) = 275kV say

1 Phase = V/√3 (Line to Neutral) = 275/√3 kV = 158.8 kV

3 Phase Voltage = V (Line to Line Voltage) = 132kV say

1 Phase = V/√3 (Line to Neutral) = 132/√3 kV = 76.2 kV

3 Phase Voltage = V (Line to Line Voltage) = 415V say

1 Phase = V/√3 (Line to Neutral) = 415/√3 kV = 240 V

3 Phase Voltage = V (Line to Line Voltage) = 110V say

1 Phase = V/√3 (Line to Neutral) = 110/√3 V = 63.5 V

3 Phase Power Transformer Rating = 120 MVA

1 Phase Power Transformer Rating = 120/3 = 40MVA

Current based on 3 phase : Primary Current = 120/√3 x 400 = 173.2 A

Current based on 1 phase : Current = 40/230.9 = 173.2A

WITH A STAR CONNECTED SYSTEM:	WITH A DELTA CONNECTED SYSTEM:
LINE CURRENT = PHASE CURRENT	LINE CURRENT = √3 PHASE CURRENT
LINE VOLTAGE = √3 PHASE VOLTAGE	LINE VOLTAGE = PHASE VOLTAGE

3 Phase Voltage	=	V	(Line to Line Voltage)	=	400kV say
1 Phase	=	V/√3	(Line to Neutral)	=	400/√3 kV = 230.9 kV
3 Phase Voltage	=	V	(Line to Line Voltage)	=	275kV say
1 Phase	=	V/√3	(Line to Neutral)	=	275/√3 kV = 158.8 kV
3 Phase Voltage	=	V	(Line to Line Voltage)	=	132kV say
1 Phase	=	V/√3	(Line to Neutral)	=	132/√3 kV = 76.2 kV
3 Phase Voltage	=	V	(Line to Line Voltage)	=	415V say
1 Phase	=	V/√3	(Line to Neutral)	=	415/√3 kV = 240 V
3 Phase Voltage	=	V	(Line to Line Voltage)	=	110V say
1 Phase	=	V/√3	(Line to Neutral)	=	110/√3 V = 63.5 V

3 Phase Power Transformer Rating = 120 MVA

1 Phase Power Transformer Rating = 120/3 = 40MVA

Current based on 3 phase: Primary Current = 120/√3 x 400 = 173.2 A

Current based on 1 phase: Current = 40/230.9 = 173.2A

TYPICAL DIMENSIONS OF OPEN TERMINAL SWITCHGEAR BAYS

145kV DOUBLE BUSBAR

Distance between Centre Lines of Adjacent Bays	=	10,500 mm
Height of Busbar above Ground	=	10,200 mm
Length of Bay Overall	=	34,500 mm

275kV DOUBLE BUSBAR

Distance between Centre Lines of Adjacent Bays	=	15,500 mm
Height of Busbar Above Ground	=	9,500 mm
Length of Bay Overall	=	57,000 mm
Overall Height of Substation	=	16,000 mm

400kV DOUBLE BUSBAR (BASED ON CEGB MKII)

Distance between Centre Lines of Adjacent Bays	=	19,500 mm
Height of Busbar Above Ground	=	6,300 mm
Length of Bay Overall	=	65,300 mm
Overall Height of Substation	=	16,000 mm

ELECTRICAL CLEARANCES (AREVA DESIGN VALUES) BIL/SIL kV(p)

145kV Substation	650	
Phase to Earth	=	1,350 mm
Phase to Phase	=	1,650 mm
275kV Substation	1050/850	
Phase to Earth	=	2,350 mm
Phase to Phase	=	2,650 mm
400kV Substation	1425/1050	
Phase to Earth	=	3,050 mm
Phase to Phase	=	3,850 mm

SAFETY CLEARANCES

145kV Substation		
Vertical Distance	=	4,050 mm
Horizontal	=	3,150 mm
275kV Substation		
Vertical Distance	=	5,050 mm
Horizontal	=	4,150 mm
400kV Substation		
Vertical Distance	=	5,750 mm
Horizontal	=	4,850 mm

3. SUBSTATION ARRANGEMENT

3.1 INTRODUCTION

Substation provides interconnection of transmission circuits and transformation between network of different voltages.

The substation is connected to the network through overhead lines. In some cases it may not be possible to make connection to the substation directly by the overhead line and cable entry must be considered. The different configurations are characterised by their busbar arrangements and generally any number of circuits may be provided by repeating the pattern.

Substation generally comprises the following :

a) Switchgear
b) Power Transformers
c) Protection, Control and Monitoring of Equipment
d) Busbars and Bays
e) Reactive Power Compensation including Harmonic Filters
f) Substation Lightning Protection System
g) Substation Earthing System

Substation comprises three main components :

These are classified as Primary System, Secondary System and Auxiliary Supply System.

i) Primary System

Primary system comprises all equipments which are in service at the nominal voltage system.

ii) Secondary System

The secondary system comprises all equipments which are used for the control, protection, measurement and monitoring of primary equipment.

iii) Auxiliary Supply System

Auxiliary supply system comprises all equipment such as AC supplies and DC supplies that enable protection, control, measurement and monitoring equipment to operate.

a) DC Supply and Distribution Systems – provided to ensure that a secure supply is available at all times to power protection systems, control equipment and initiate tripping of circuit breakers and comprise :

Batteries – either lead acid or nickel-alkali types at ratings from tens of ampere hours to hundreds of ampere hours at voltages of 30V, 50V, 125V and 250V depending on the application.

Battery Charger – usually constant voltage, current limited types with boost charge facility to supply standing loads and maintain the battery fully charged whilst the auxiliary AC supply is available.

Distribution Board – as the name implies, provides a system of distribution, isolation and protection for DC supplies to all equipment within the substation.

b) LVAC Supplies – an auxiliary AC supply and distribution system which supports the operation of the substation by providing power for cooling fan motors, tap change motors, circuit breaker mechanism charging systems and disconnector drives in addition to the normal heating, lighting and domestic loads.

3.2 SUBSTATION TYPE

Substations are classified as two types of substation, i.e. Air Insulated Switchgear (AIS) 'open terminal' substation and Gas Insulated Switchgear (GIS) 'metalclad' substation.

Open terminal arrangements, as the name suggests, utilises primary equipment whose terminals are in air. Consequently large clearances are required between these terminals and earth and between terminals of different phases. As a result 'open terminal' substations occupy relatively large areas of land.

Metalclad equipment utilises either solid or gaseous (SF6) insulation to allow phase to earth and phase to phase clearance to be drastically reduced.

The space saving advantages of metalclad equipment can be significant particularly for high voltage substations in large cities where space is difficult to obtain and land is very expensive.

Metalclad equipment may also be attractive for other reasons, notably visual impact in environmentally sensitive areas and operation in heavily polluted environments.

Air insulated substations generally cost less than an equivalent gas insulated substation.

Almost all GIS substations are built indoor. GIS can be easily built underground to avoid any environmental concern. The internal GIS insulation is independent of atmospheric pressure.

3.3 SUBSTATION EQUIPMENT

3.3.1 Circuit Breakers

A circuit breaker is a mechanical switching device, capable of making, carrying and breaking currents under normal circuit conditions and also making, carrying for a specified time and breaking currents under specified abnormal circuit conditions such as those of short circuit.

As systems have increased in size and complexity, the circuit breaker has been called upon to have better short circuit interrupting performance, to operate faster and to tolerate higher and higher system voltages.

Initially as fault currents increased circuit breakers become more and more complex to achieve the required performance, particularly when 400kV systems with fault currents of up to 63kA were designed.

Thankfully the introduction of sulphur hexafluoride interrupters led to a reduction in the number of interrupters required in series for a particular voltage to the point where modern designs of SF6 circuit breaker can meet system requirements with a single interrupter up to 245kV 50kA and up to 420kV 63kA with two interrupters in series.

Under special circumstances, such as when switching capacitor banks for power factor correction or arc furnace switching, where circuit breakers may operate many times a day, replacement may be necessary after a shorter period, or point on wave switching (POW) is needed.

Open terminal, phase integrated, dead tank SF6 circuit breaker with porcelain bushings with integral CT accommodation, incorporating puffer type or rotating arc type interrupters and operated by a motor wound spring mechanism.

Open terminal, phase integrated, dead tank SF6 insulated circuit breaker with vandal resistant composite terminal bushings with integral CT accommodation, incorporating vacuum interrupters and operated by a motor wound spring mechanism.

3.3.2 Disconnectors and Earth Switches

Disconnectors (Isolators) are devices which are generally operated off-load to provide isolation of main plant items for maintenance, on to isolate faulted equipment from other live equipment. Open terminal disconnectors are available in several forms for different applications. At the lower voltages single break types are usual with either ‘rocker’ type or single end rotating post types being predominant.

At higher voltages, rotating centre post, double end rotating post, vertical break and pantograph type disconnectors are more common.

Disconnectors are usually interlocked with the associated circuit breaker to prevent any attempt being made to interrupt load current. Disconnectors are not designed to break fault current although some designs will make fault current.

Most disconnectors are available with either a manual drive mechanism or motor operated drive mechanism and the appropriate drive method must be selected for a particular disconnector in a particular substation, e.g. in a remotely controlled unmanned double busbar substation the busbar selector disconnectors would be motor operated to allow ‘on load’ busbar changes without a site visit being required.

Disconnector mechanisms incorporate a set of auxiliary switches for remote indication of disconnector position, electrical interlocking and current transformer switching for busbar protection.

Earthing switches are usually associated and interlocked with disconnectors and mounted on the same base frame. They are driven by a separate, but similar, mechanism to that used for the disconnector. This arrangement avoids the need for separate post insulators for the earth switch and often simplifies interlocking. Normally earth switches are designed to be applied to dead and isolated circuits and do not have a fault making capability, however special designs are available with fault making capability if required.

One practical point worth noting is that line or cable circuit earth switches are normally interlocked with the local line disconnector, but reliance is placed on operating procedures to ensure that the circuit is isolated at the remote end before the earth is applied.

3.3.3 Instrument Transformers

a) Current Transformers – The majority of current transformers used in substations are bar (i.e. single turn) primary type but their method of installation varies considerably. In metalclad switchgear they are usually mounted around the insulated connections between circuit breaker fixed connectors and the cable box terminals, whereas in open terminal substations they may be mounted around the bushings of transformers or dead tank circuit breakers.

b) Alternatively where live tank switchgear is used, the current transformers are mounted in a form known as the post type current transformer where the secondary windings are fitted into a housing insulated from earth by a hollow support insulator. The secondary windings and leads are insulated from the housing and the secondary leads, also heavily insulated, are brought down to a terminal box at the base of the support insulator.

b) Voltage Transformers – The choice is basically between 'wound' voltage transformers and 'capacitor' voltage transformers. Generally where high accuracy metering standard outputs are required the wound voltage transformer is used and where protection and instrumentation outputs only are required a capacitor voltage transformer is often more cost effective at voltages above 145kV. A further advantage of capacitor voltage transformers is that they can be used to provide coupling facilities for power line carrier systems used for protection, signalling, telemetry or telecommunications.

3.3.4 Power Transformers

In any substation the power transformer is probably the most expensive piece of equipment and one of the most inconvenient to replace or repair, due to the sheer size of the equipment particularly at high voltages.

Power transformers are usually of the two winding type. The capacity of the transformers is usually decided by system requirements. Transformers may be designed with all three phases in common tank or as three separate single phase units.

From the power system operator's point of view, a transformer is a simple device. Due to economic considerations, a power transformer generally has auxiliary systems which are essential to its effective operation.

In the smaller sizes, it is quite common for transformers to have off-circuit tap change facilities, natural air cooling and a minimum of protective devices.

In the larger sizes, transformers are fitted with on-load tap change facilities, forced air or forced air/forced oil cooling and in some cases forced oil/liquid cooling systems.

Typically a transformer designed for ONAF (Oil Natural Air Forced) cooling can sustain 65−70% of its ONAF rating without auxiliary supplies, whereas an OFAF (Oil Forced Air Forced) transformer can sustain only 50%.

For OFLC (Oil Forced Liquid Cooling) transformers the output without cooling maybe as low as 30% of the OFLC rating.

The on-load tap changer facility will be designed to match the transformer by the transformer designer but typically would have 19 or 21 tap positions with a tap-step of 1−1.5% possibly giving a range of perhaps +10% −20% i.e. the secondary voltage can be maintained constant for a variation of primary voltage from +10% to −20%. The controls and monitoring circuits for tap changers, particularly when operated automatically, can be quite complex requiring output voltage, load current and tap position of associated transformers to be monitored.

The on-load tap changer is a mechanical switching device and it is usually the tap changer which determines the frequency of maintenance of transformers. After large numbers of operations switching contacts may need to be changed and the oil within the switching chamber be replaced.

Transformers are also protected against excessive temperature as rapid deterioration of insulation can occur if transformers become overheated. The normal method of protection is to monitor the insulating top oil temperature and on large transformers the winding temperature is monitored.

It is not usual to monitor this directly due to risk of insulation failure with devices embedded in the winding; normally oil temperature is monitored and an additional heating element fed from a current transformer measuring load current is used to simulate the winding 'hot spot' temperature within the monitoring device.

3.3.5 Compensation Equipment

There are several forms of compensative equipment, such as :

a) Synchronous Compensators
b) Shunt Reactors
c) Mechanically Switched Shunt Connected Capacitor Banks (MSC)
d) Mechanically Switched Damping Network (MSCDN)
e) Series Capacitor Banks
f) Static Var Compensators (SVC)

3.4 SUBSTATION LAYOUT ARRANGEMENT

3.4.1 Single Bus

The most simple electrical arrangement which, without a bus section, has poor service continuity, no operational facilities and requires a shut down for any extension. It is more common at the lower voltages especially with metalclad switchgear. When fitted with bus section isolators with or without a bus section circuit breaker, the service continuity and operational facilities improve slightly and extensions are possible with only part shut down.

Note that with some circuits (e.g. transformers) the circuit side isolator may be omitted.

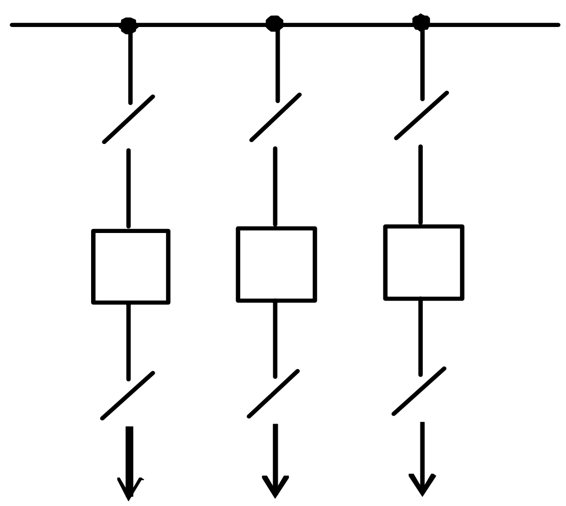


Fig 1 – Single Bus

3.4.2 Double Bus

A very common arrangement nearly always incorporating a bus coupler circuit and often a bus sectionalising arrangement. It has very good service continuity and operational facilities and can be extended with little or no shutdown depending upon the physical arrangement.

Note that circuit side isolators may sometimes be omitted as for the Single Bus.

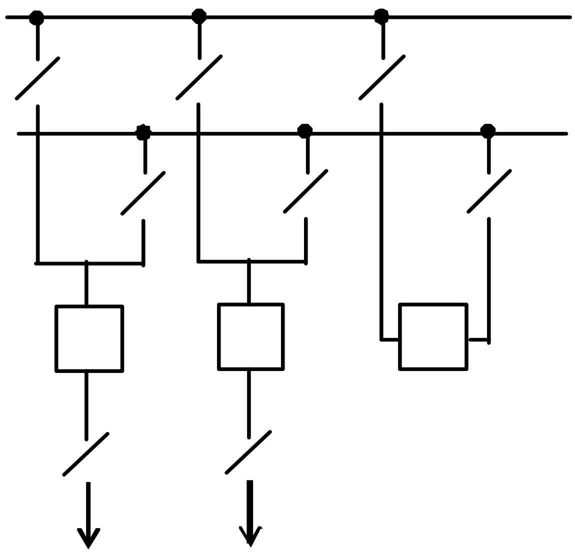


Fig 2 – Double Bus

3.4.3 **Double Breaker**

This is used with double bus arrangements to give improved service continuity. It is normally used only on circuits such as generators where continuity has important economic or operational significance.

A combination of double breaker and single breaker arrangements may be used with a common set of double busbars.

When all circuits have double circuit breakers, a bus coupler circuit breaker is not essential unless it may be required to function as a section circuit breaker. When there is a combination of double breaker and single breaker arrangements, the bus coupler circuit breaker is again not essential as the double breaker can function as a bus coupler circuit but the increased complexity of the protection, interlocking and operation may make the inclusion of a bus coupler circuit preferable.

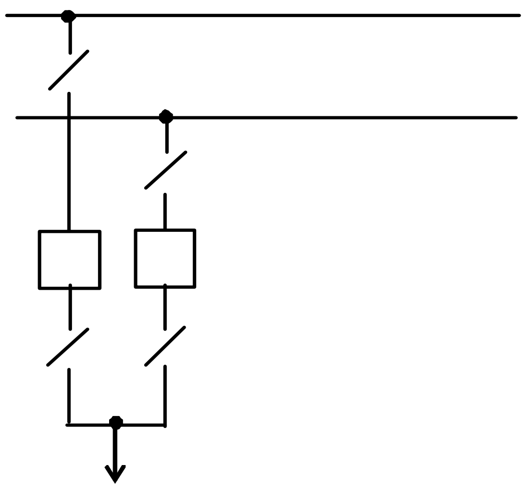


Fig 3 – Double Breaker

3.4.4 Bus Section

This is applicable to both single and double bus arrangements and in the latter each bus may be treated differently. The service continuity, operational facilities and possibility of extension without shut down is increased especially when a bus section circuit breaker is included.

The use of two section isolators enables the bus section isolators to be maintained without a complete shut down.

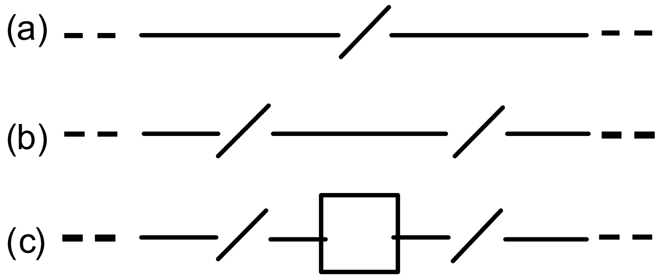


Fig 4 – Bus Sections

3.4.5 Bus Coupler

Apart from providing improved service continuity and improved operational facilities, it has the particular function of enabling the on-load transfer of circuits from one bus to another.

In combination with bus section isolators as in *Figure 5*, it can be used as a bus section to improve the operational facilities.

With by-pass arrangements, it would also function as the “standby” or “transfer” circuit breaker.

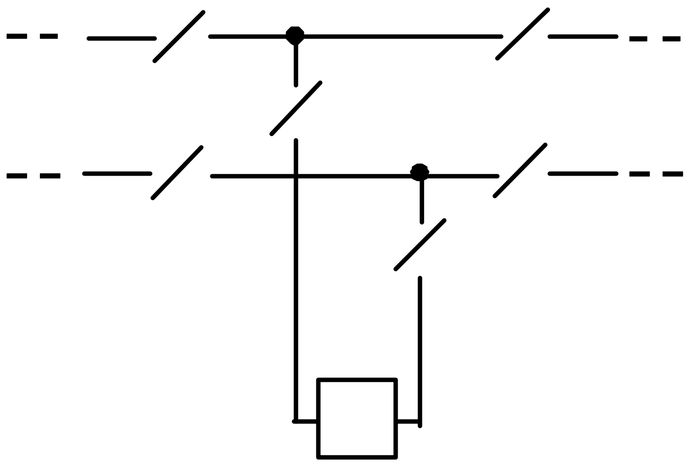


Fig 5 – Bus Coupler with Section Isolators

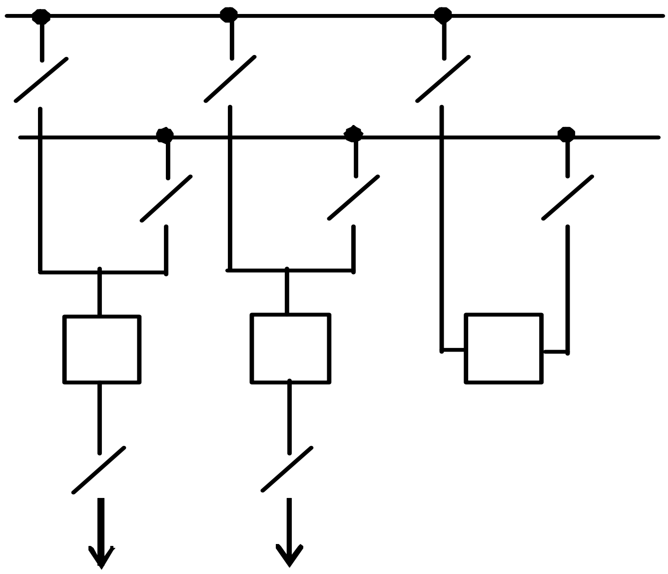


Fig 2 – Double Bus

3.4.6 **Double Bus with Transfer Circuit Breaker**

This is an arrangement generally only used with metalclad switchgear. It is a method of achieving a double bus arrangement when a double bus design is not available. In practice there are two switchboards – one for each bus, with the outgoing circuits connected. To transfer, the circuit breaker truck is moved from one switchboard to the corresponding circuit, on the other switchboard. Such an arrangement is “off-load” transfer. Using a spare circuit breaker truck it may be possible to affect an “on-load” transfer.

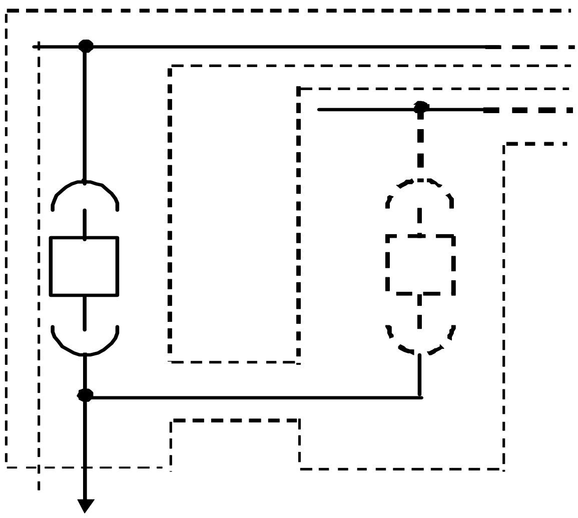


Fig 6 – Double Bus with Transfer Breaker

3.4.7 **Multi-Section Double Bus**

This arrangement has been used by the CEGB to obtain maximum security of supply with generating stations, one generator being connected to each of the four sections of main bus. The other circuits are distributed to the best advantage between the sections of main bus.

Note that there is only one reserve bus divided into two sections.

Normal operation is with all bus sections closed. With the usual arrangement which is shown in *Figure 7* there are only two bus coupler circuits so that on-load transfer of circuits on buses 2 and 3 is only possible when an appropriate bus section is closed.

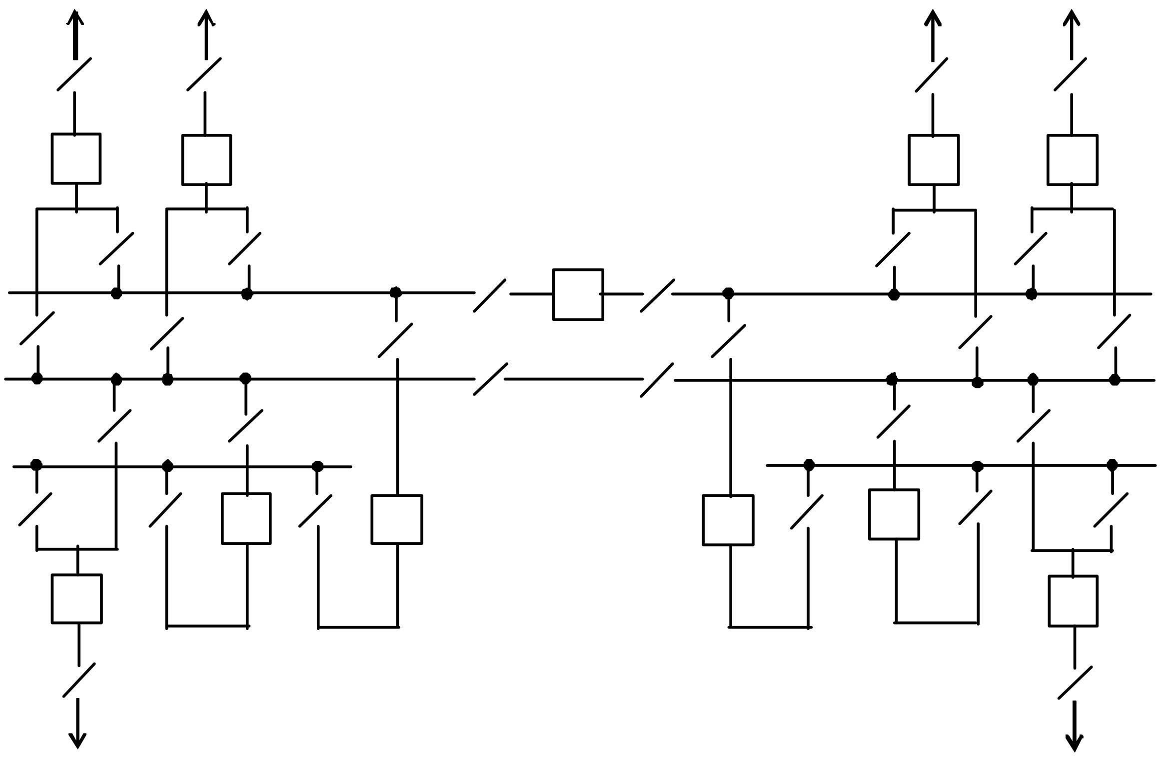


Fig 7 – Multi-Section Double Bus

3.4.8 **Transfer Bus**

Sometimes also known as the “Jack Bus”, this is applicable to both single and double bus arrangements and enables a circuit breaker to be taken out of service for maintenance, the circuit then being under the control of a dedicated “transfer” circuit breaker.

Note that only circuit area can be transferred at any one time and the transfer isolators are to be interlocked to ensure this.

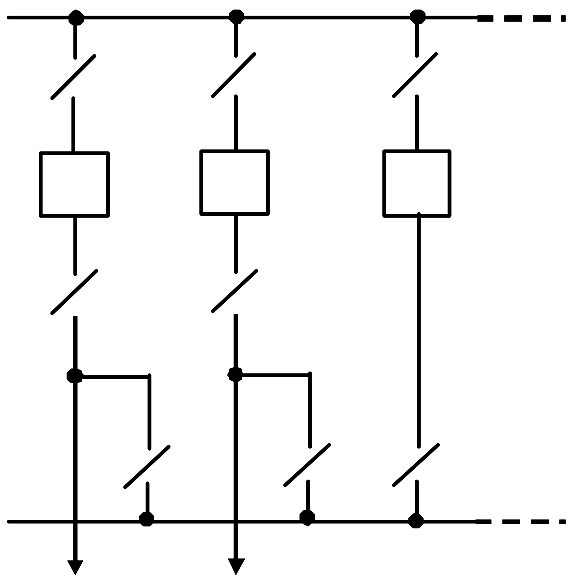


Fig 8 – Single end Transfer Bus

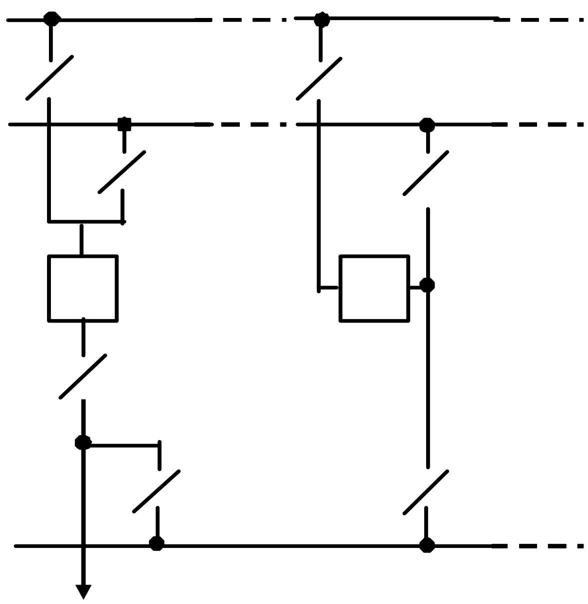


Fig 9 – Double end Transfer Bus

3.4.9 **By-pass**

This is an alternative to the transfer bus and is applicable to both single and double bus arrangements although with the single bus arrangements there is no individual protection for the circuit under by-pass and switching is generally only possible by switching several circuits.

By-pass enables a circuit to continue in operation whilst the circuit breaker is being maintained. Since modern circuit breakers are much more reliable and require less frequent maintenance, the practice of by-pass is rarely used with modern designs.

In some designs economies are made by replacing one or more of the isolators with removable connections but this requires a temporary shutdown of the circuit. The physical arrangement of the substation equipment has to be designed that such connections can be removed (or added) without undue difficulty and that all necessary safety clearances can be obtained.

With the arrangements shown in *Figures 10, 11(a) and 11(b)*, the circuit current transformers are also by-passed with the circuit breaker and the circuit protection is then completely provided by the other current transformers and relays.

(In the case of the double bus, by the bus coupler circuit). *Figure 11(c)* shows an arrangement using a further isolator where the current transformers are not by-passed and the circuit protection remains in service with the tripping transferred to the bus coupler circuit breaker. (Note that any bus coupler protection would still be capable of operating).

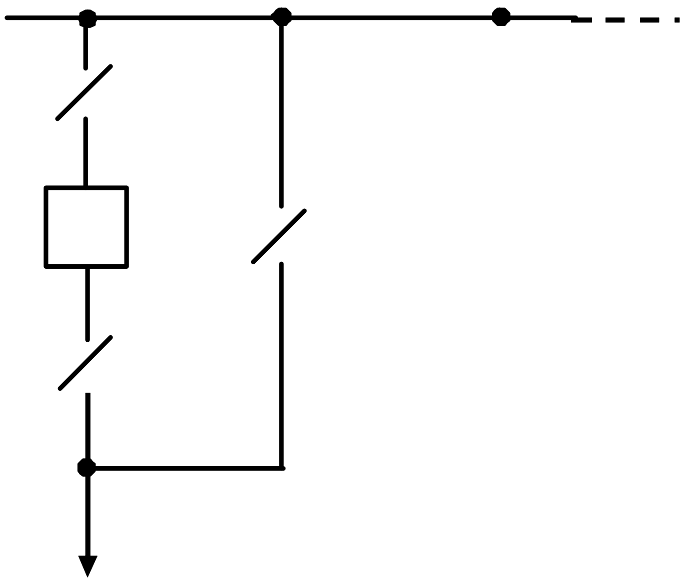


Fig 10 – Single Bus with Bypass

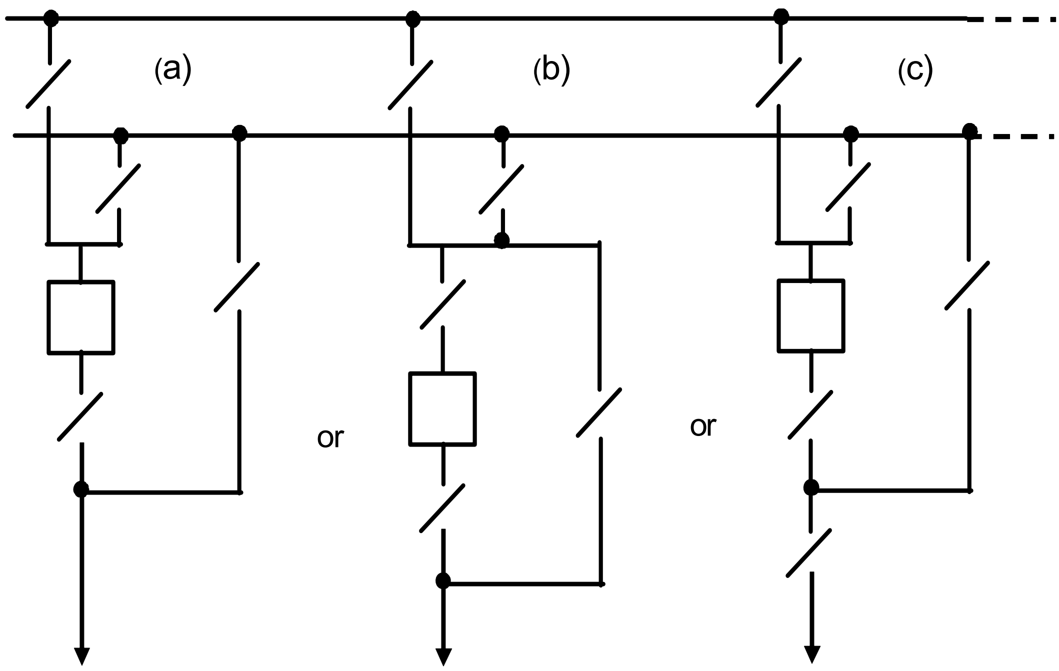


Fig 11 – Double Bus with Bypass

3.4.10 **Mesh**

This arrangement is applicable to four or more circuits with rarely more than six. In practice the physical design of the substation provides for an ultimate even number of circuits, though the initial installation may be for an odd number of circuits.

Note that there can be physical problems in extending a mesh substation if the possibility of future extension was not considered in the initial design stage.

The mesh arrangement permits a circuit breaker to be taken out of service without interrupting the supply to a circuit and therefore gives a good continuity of supply. This is only applicable for one circuit breaker. When the mesh has already been broken, the opening of another circuit breaker could cause serious problems in the continuity of supply. Hence the limitation on the number of circuits connected in a mesh arrangement.

Bus zone protection is not applicable to mesh arrangements. If current transformers are provided on each side of the circuit breaker, these would provide discriminative protection for the elements of the mesh as well as protection for the outgoing circuits.

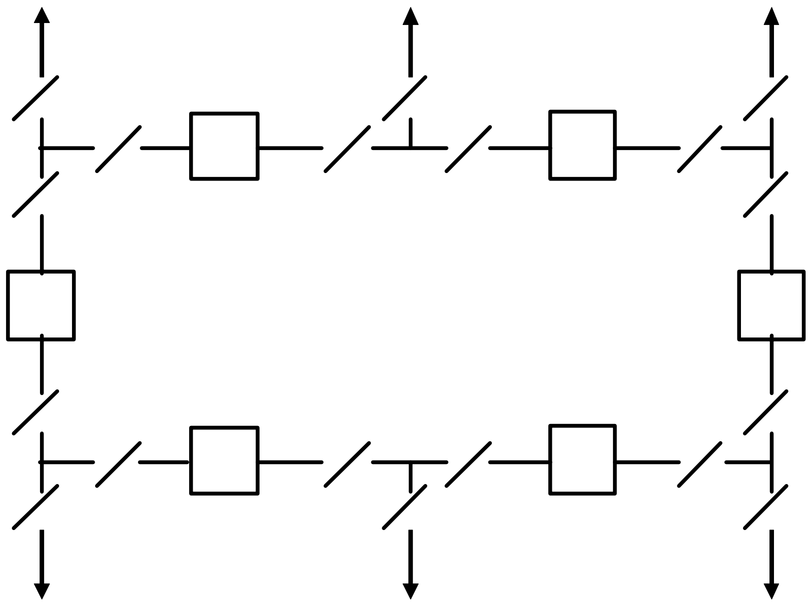


Fig 12 – Mesh

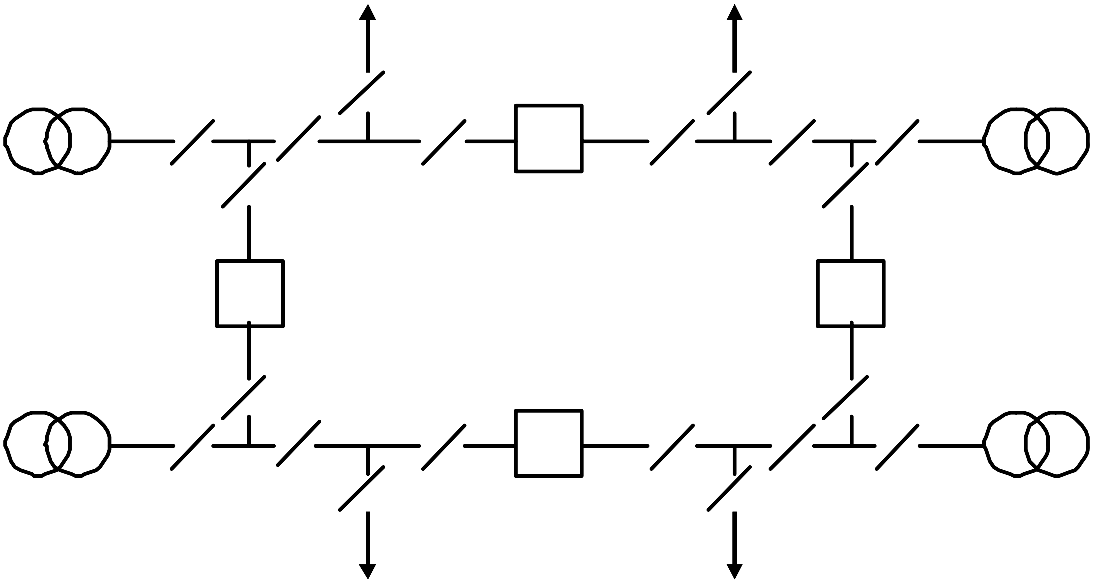


Fig 13 – Mesh with Mesh Opening Isolators

A more economical variation of the mesh arrangement sometimes used by the CEGB incorporates mesh-opening isolators and is shown in *Figure 13*. Normally this is applied to a four-switch mesh and a transformer is paired with an overhead line. It is not essential that all sides of the mesh have mesh-opening isolators.

When it is required to switch a circuit, the mesh must first be complete before the mesh-opening isolator adjacent to the circuit being switched is opened. The circuit can then be switched by the circuit breaker, the circuit isolated, and the mesh then completed.

Under fault conditions both line and transformer are disconnected, the faulty circuit isolated, and the mesh again completed.

3.4.11 **Breaker-and-a-Half**

This arrangement of three circuit breakers in series to give a "diameter" between a pair of busbars gives good service continuity since a circuit breaker can be taken out of service without interrupting the supply to a circuit. It also has better operational facilities than a mesh arrangement.

As in a mesh arrangement, the diameters must be run solid to achieve the best service continuity and operational facilities.

This arrangement with the additional circuit breakers, isolators and current transformers is more costly than the mesh and double bus arrangements.

To obtain discriminative protection for faults on a diameter, current transformers are required each side of the circuit breaker. These current transformers can also be used for the circuit protection.

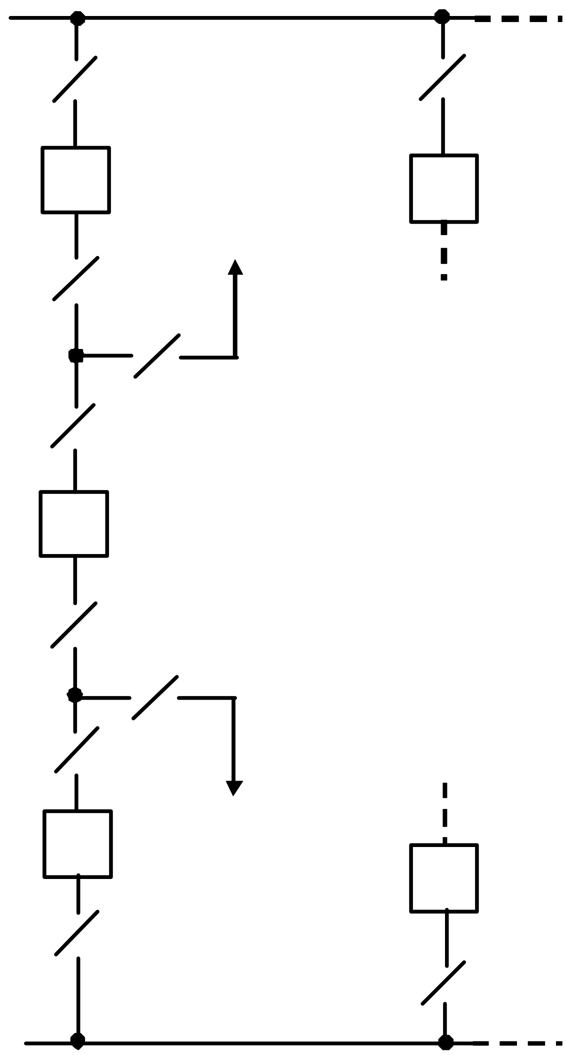


Fig 14 – Breaker and a half

3.4.12 **Breaker-and-a-Third**

This is a lower cost variation of the breaker-and-a-half arrangement. Whilst in the “solid” condition it gives equal service continuity but less operational facilities. When not “solid”, the service continuity is less than that for a breaker-and-a-half arrangement.

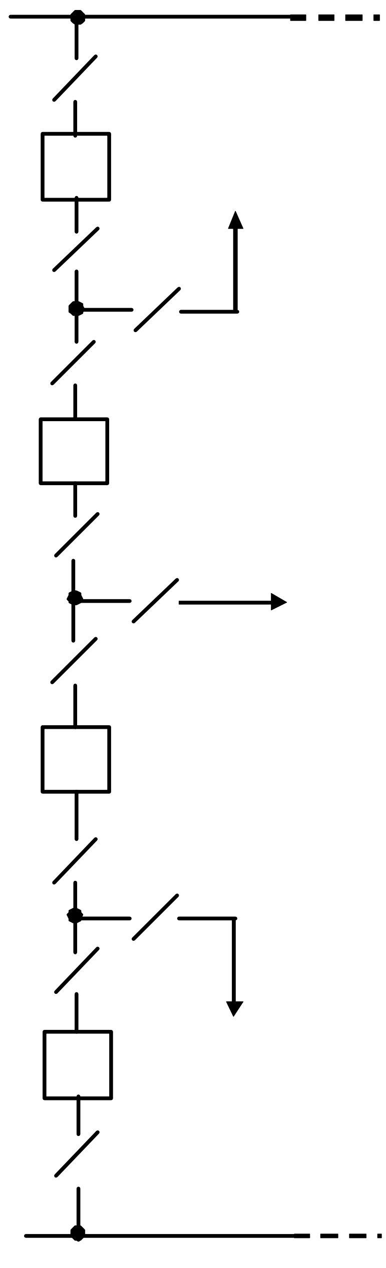


Fig 15 – Breaker and a third

3.4.13 **Four Switch Substation**

This arrangement was introduced into the British Grid system to provide small substations on a ring network.

This arrangement gives good service continuity but negligible operational facilities. The latter can be improved by replacing one of the bus section isolators by a load breaking switch isolator.

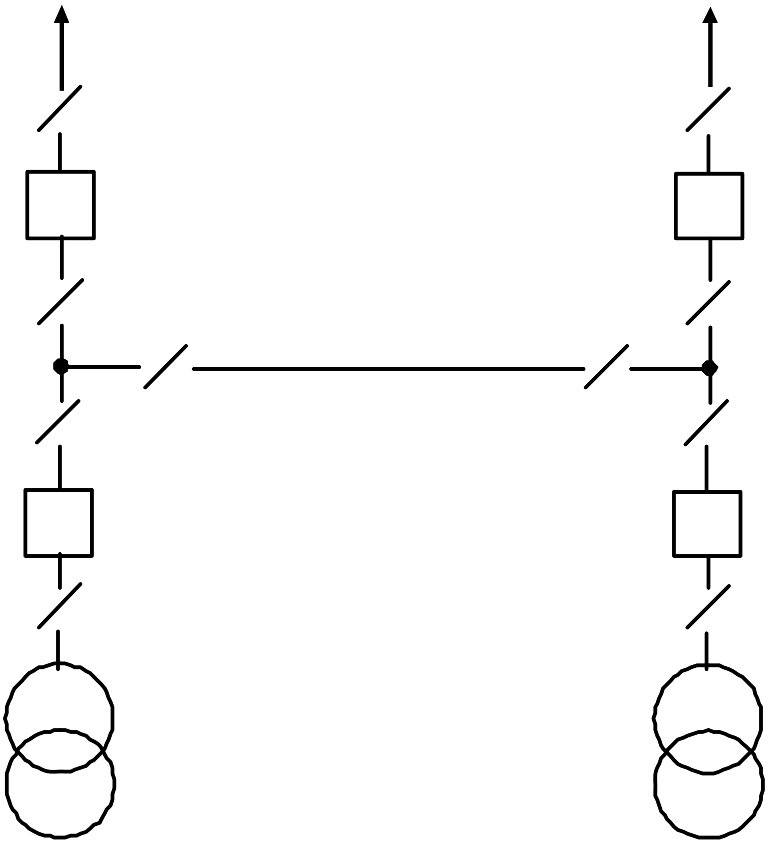


Fig 16 – Four Switch Substation

3.4.14 Three Switch Substation

This developed from the four switch substation and provides almost the same facilities but at a much lower cost. The two normally open isolators connected between the transformers are provided to allow continuity of supply with a circuit breaker out of service.

Note that because they are off-load devices they can only be operated when all the circuit breakers are closed. Note also that it is possible to have an arrangement with the transformers and feeders interchanged.

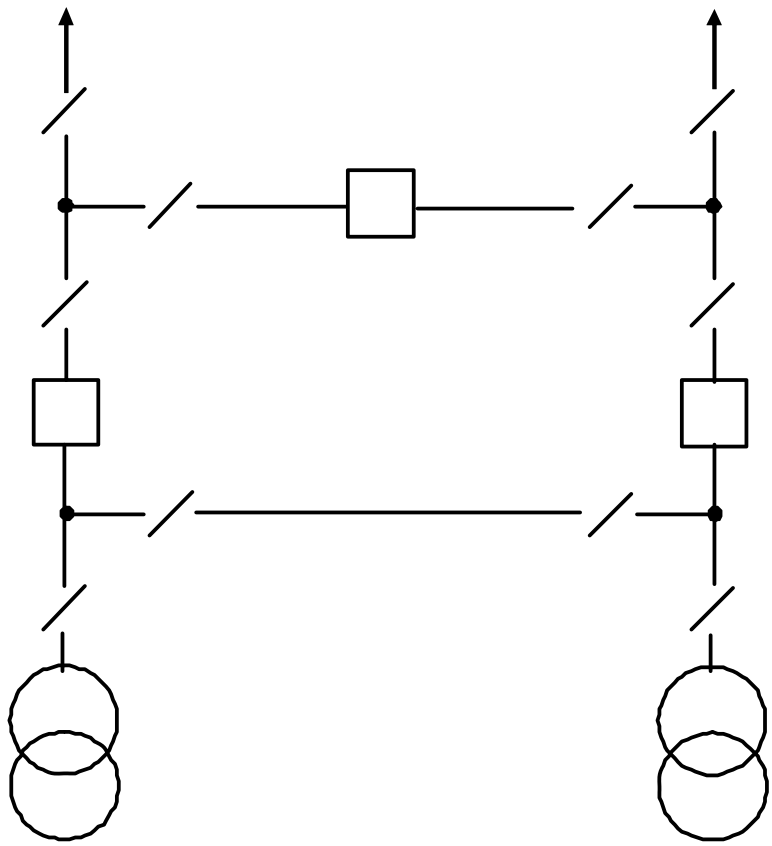


Fig 17 – Three Switch Substation

3.4.15 **Single Switch Substation**

This arrangement is used in place of the three-switch substation at the less important substations. There is a slight reduction in the continuity of supply.

Note that there must be provision for the tripping of the remote circuit breaker on the feeder with transformer faults.

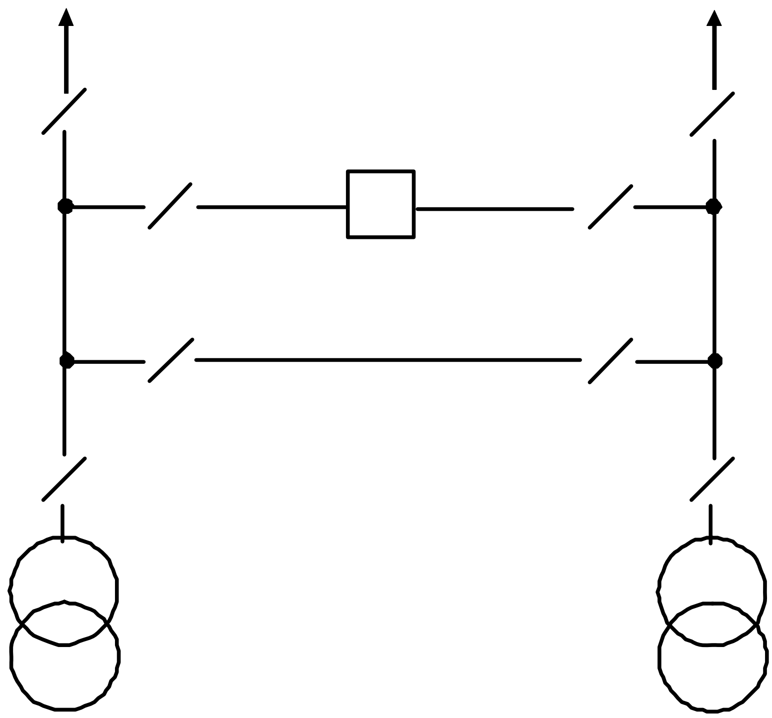


Fig 18 – Single Switch Substation

3.4.16 **Shunt Circuit Breaker**

This was invented by Electricité de France and patented in 1956.

On occurrence of a fault, the shunt circuit breaker closes to clear transient faults with no operation of the circuit isolator and to clear permanent faults with operation of the circuit isolator whilst the circuit breaker is closed, the operation of the isolator is automatic.

The variation in Figure 20 operates in the same manner under fault conditions but the shunt breaker can be used for operational switching by opening the “earthing” isolator, closing the circuit shunt isolator, closing the shunt circuit breaker, opening the circuit busbar isolator, then opening the shunt circuit breaker. The circuit shunt isolator must then be opened and finally the “earthing” isolator closed ready for fault operation.

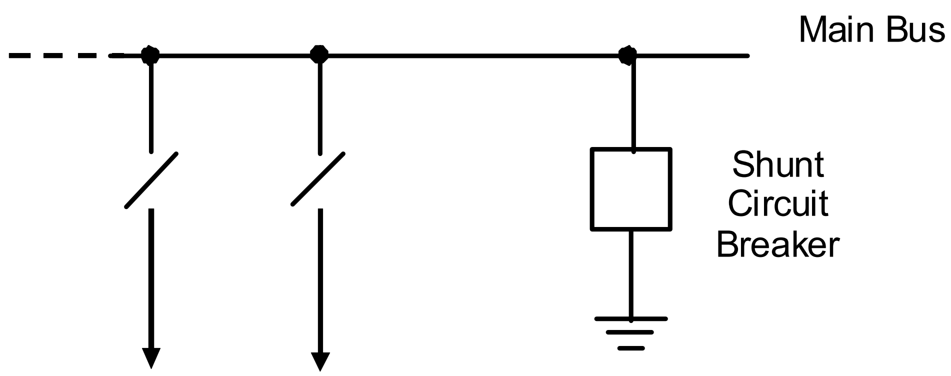


Fig 19 – Shunt Circuit Breaker

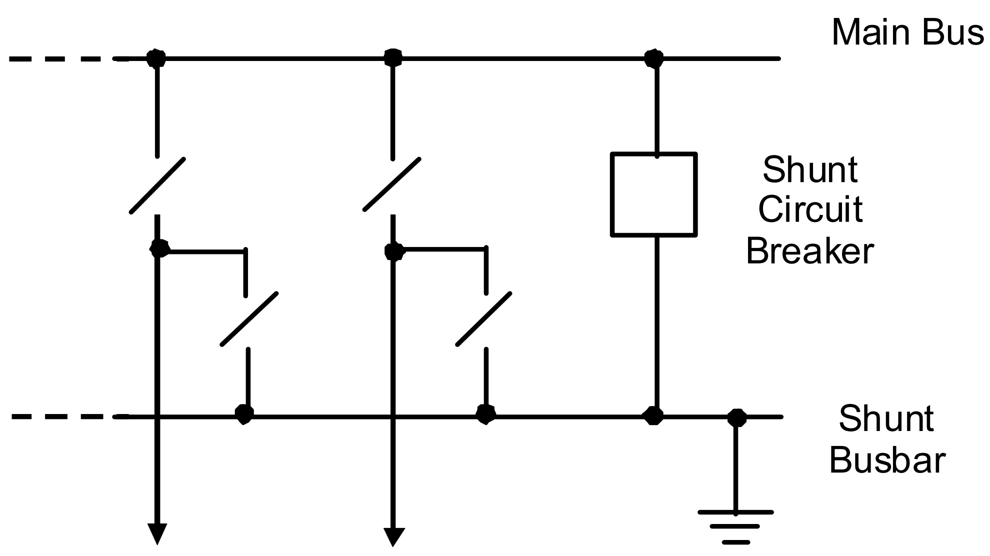


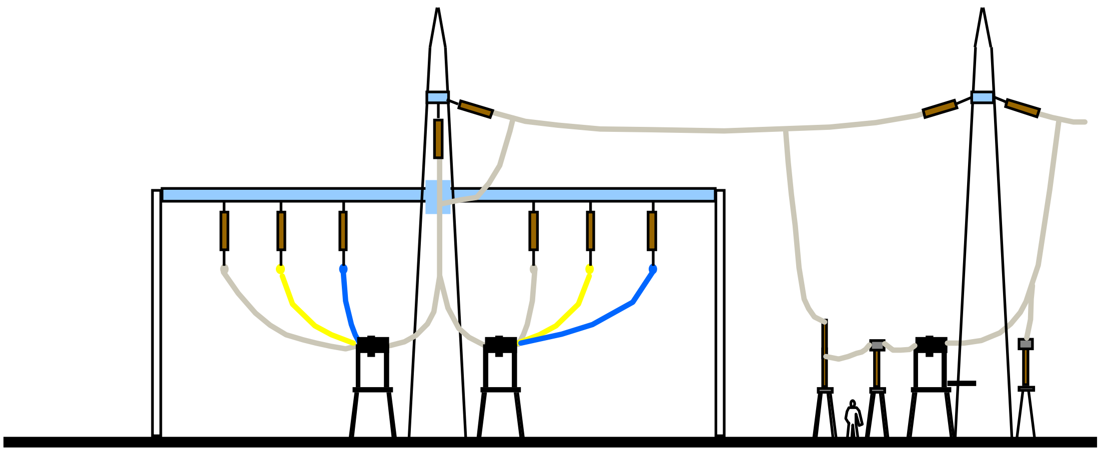
Fig 20 – Shunt Circuit Breaker

3.4.17 **GAS INSULATED SWITCHGEAR (GIS)**

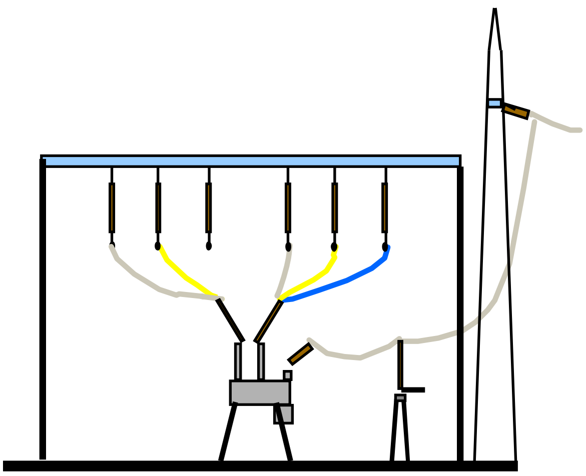
Gas insulated switchgear substations need reduced ground area. These substations can be extended easily. They are environmentally more acceptable. They need reduced civil works & cabling.

Comparison of AIS, Hybrid and GIS Substations

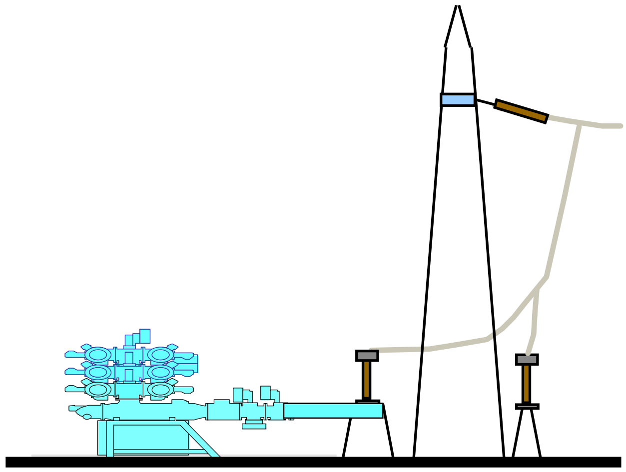
Full AIS



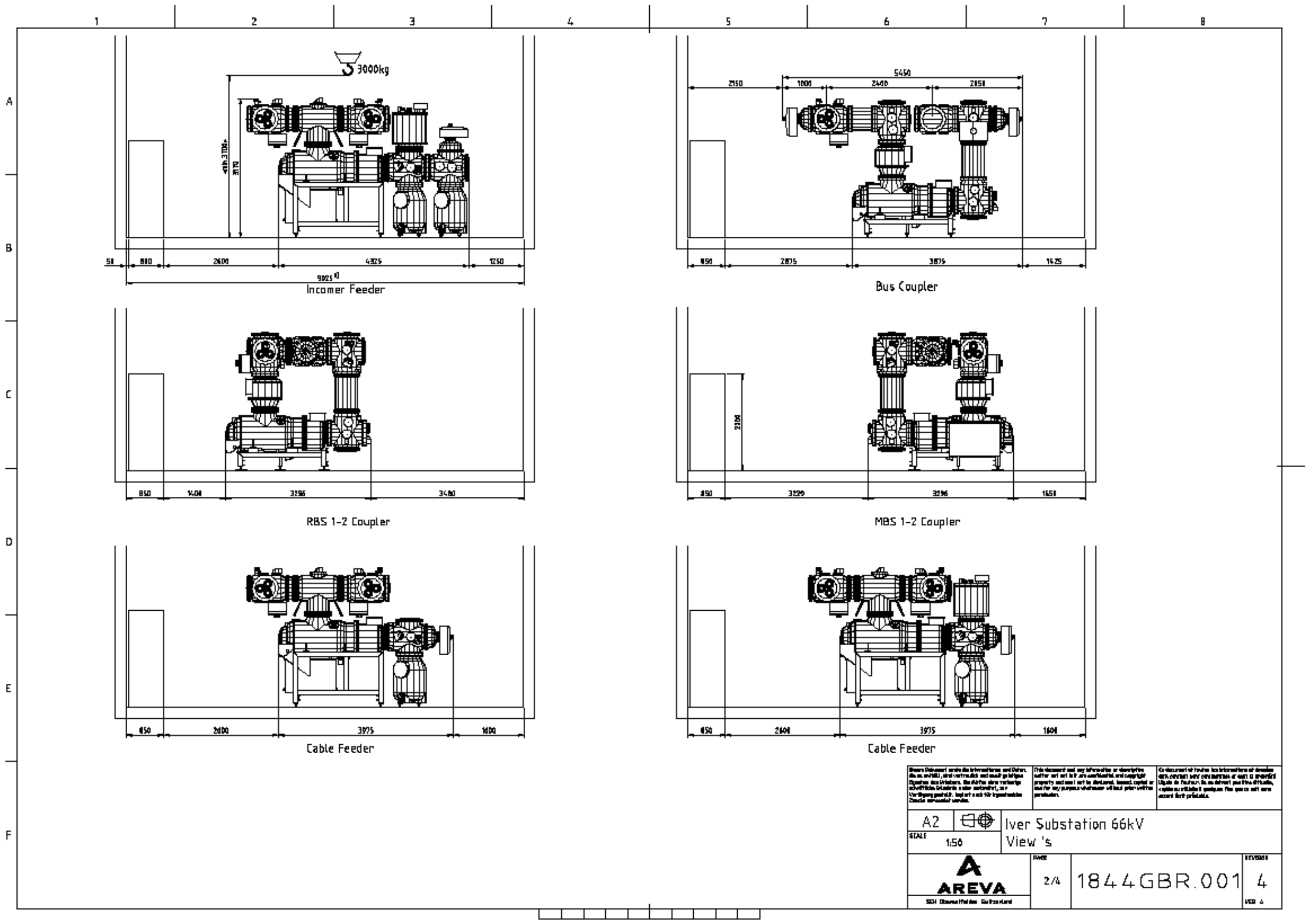
Typical Hybrid



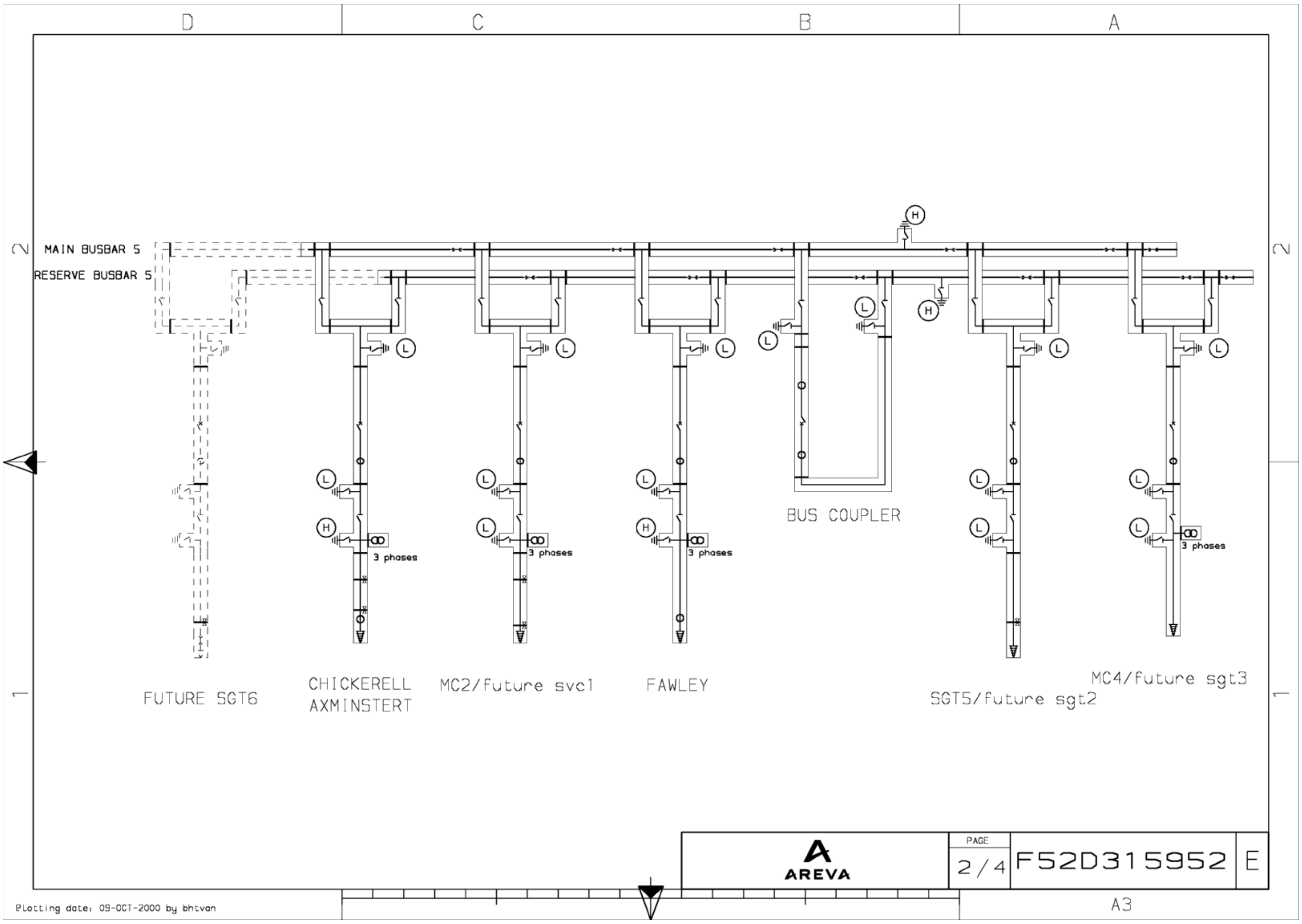
Full GIS



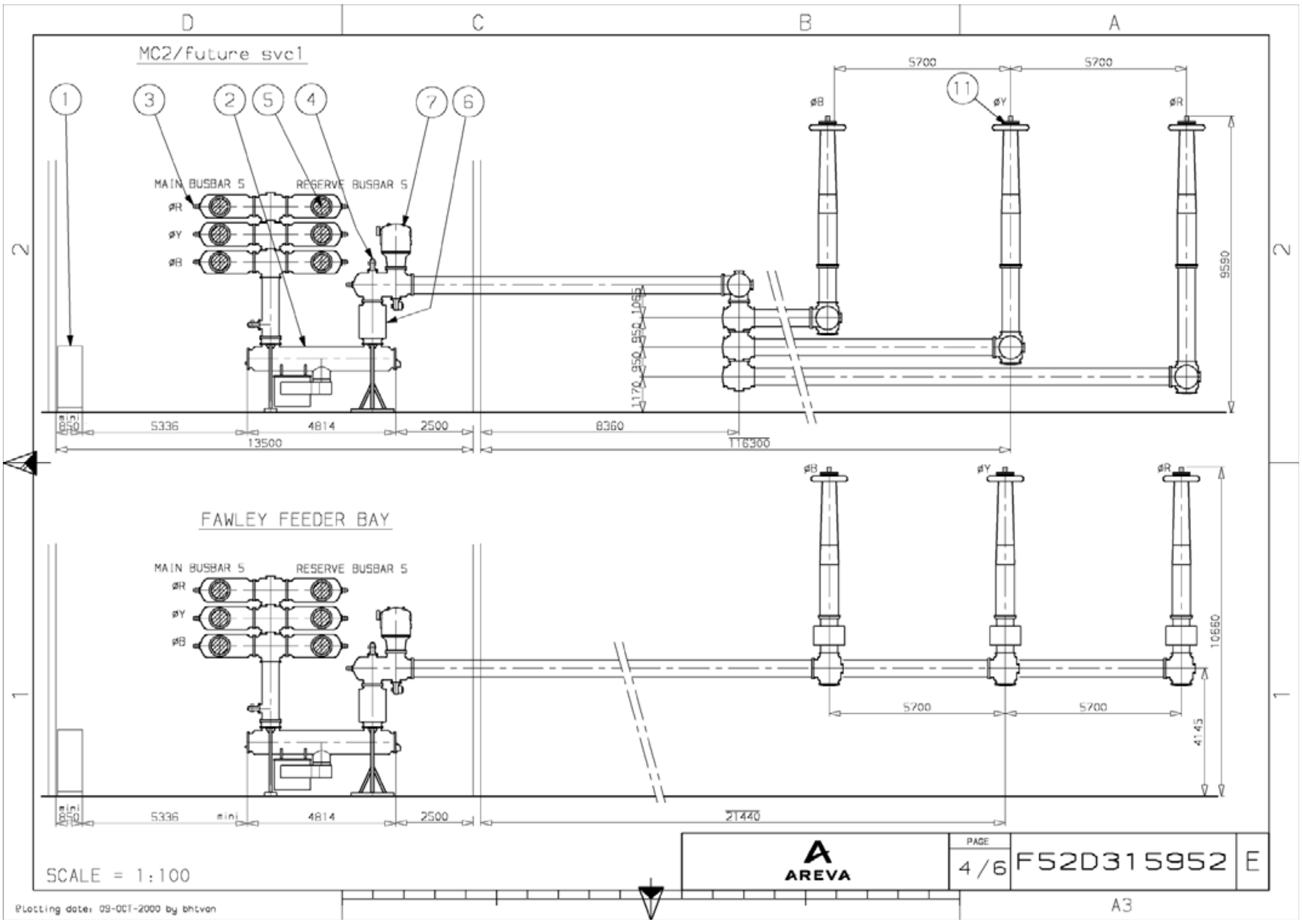
F35 Bays



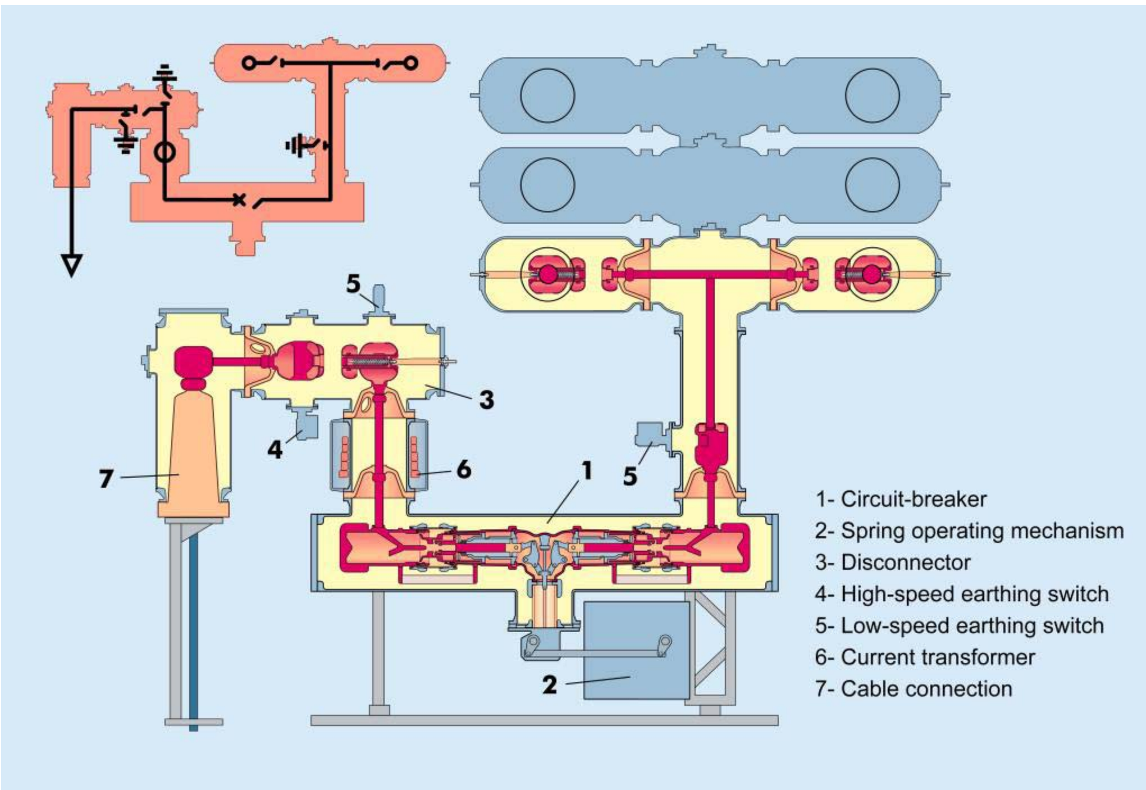
T155 Gas Zones



T155 Bays



T155 Bay Section



T155
Hybrid substation

Hybrid switchgears are ideal equipments to refurbish existing AIS or GIS substations. Engineering application time, civil works and outage time are reduced. All innovative substation layouts are possible with hybrid switchgears.

3.5 Earthing Switches and Portable Earths

Earthing switches which may be integral with isolators or separately mounted, and portable earths are necessary to ensure compliance with Safety Rules, the British safety rules requiring that an earth be applied between a possible point of supply and where a man may work.

To reduce the cost, portable earths are used instead of earthing switches wherever possible. However, the following limitations are important:

(a) They should not be used where there is a risk of the equipment being alive or becoming alive whilst the earth is being applied.

(b) Unless there is already an earth between the point of supply and the point of application, portable earths should be applied using an insulated pole.

It should be noted that earthing switches may or may not have a rated making current. Portable earths have no rated making current.

It follows therefore that earth switches are required to discharge overhead lines and cables, both of which may also have voltages induced in them by the proximity of parallel circuits, and also to provide a discharge path for any lightning strikes. They are also required on transformer circuits where it is impossible to ensure (by locking or interlocking if necessary) that the transformer cannot be energised, and on generator circuits where voltages can be produced by residual magnetism in the excitation circuit. Earth switches may also be used where it is inconvenient to apply portable earths using an insulated pole either because of access or height of the conductor. (At the higher voltages e.g. 400kV earth switches are more extensively used for this reason).

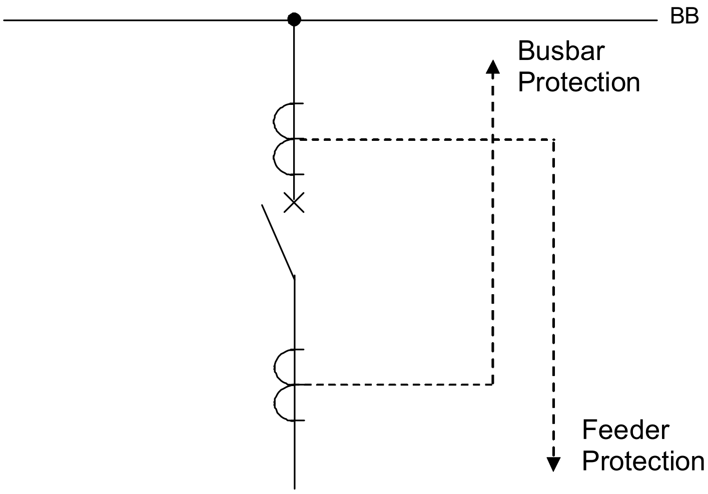
To achieve lower cost earth switches are wherever possible fitted to isolators rather than be separately mounted. They are thus fitted to the line isolators leaving any voltage transformers line traps etc. on the line side of the earthing switch.

3.6 Location of Current Transformers

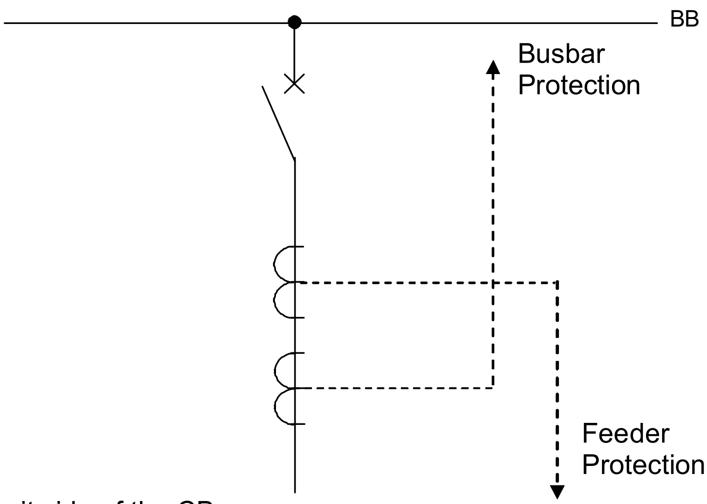
Current transformers are used for protection, instrumentation, metering and control. It is only the first function that has any bearing on the location of the current transformer.

Ideally the current transformers should be on the power source side of the circuit breaker that is tripped by the protection so that the circuit breaker is included in the protective zone. In many circuits the power flow can be in either direction and it then becomes necessary to decide which location of fault is most important or likely and to locate the current transformers on the side of the circuit breaker remote from those faults. In the case of generator (and some transformer) circuits it is necessary to decide whether the protection is to protect against for faults in the generator or to protect the generator against system faults. Current transformers can often be located in the generator phase connections at the neutral end and will then protect the generator from the system faults and to a large degree give protection for faults in the generator.

When current transformers can be accommodated within the circuit breaker, they can in most cases be accommodated on both sides of the circuit breaker and the allocation of the current transformers should give the desired overlapping of protective zones. With some designs of circuit breaker the current transformer accommodation may be on one side only and it may be necessary to consider the implications of the circuit breaker position in the substation before deciding on the electrical location of the current transformers.



CT’s mounted inside the CB (CT’s on both sides of CB)



CT’s are on the circuit side of the CB

However the risk of a fault between the current transformers and the circuit breaker and within the circuit breaker itself is very small and so the economics of accommodating the current transformers may have an important influence on their location.

Where separate current transformer accommodation has to be provided, the cost of separately mounted current transformers and also the extra substation space required almost always results in them being located only on one side of the circuit breaker. In practice this is generally on the circuit side of the circuit breaker. This follows metalclad switchgear practice where this is the easiest place to find accommodation, and is also the optimum position when bus zone protection is required.

Often it may be possible to accommodate current transformers on the power transformer bushings or on through wall bushings. When this is done it is usually for economic reasons to save the cost of, and space for, separately mounted current transformers. Transformer mounted current transformers have minor disadvantages in that a longer length of conductor and, more especially, the bushing is outside the protected zone, and in the event of the transformer being removed then disconnections have to be made to the protective circuits.

Note that the arrangement of the individual current transformers within a unit should preferably be arranged that any protective zones overlap and that current transformers for other functions are included within the protected zone.

Under by-pass conditions (where this is provided) the circuit is switched by the bus coupler circuit breaker. The location of the current transformers is determined by whether the protective relaying and current transformers are provided by the bus coupler circuit, or whether the protective relaying and current transformers of the circuit are used with the tripping signal being routed to the bus coupler circuit breaker during by-pass. If the latter method is used then the current transformers must be separately mounted on the line side of the by-pass isolator. The advantage of this method is that the circuit protection is unchanged to the possibly inferior protection of the bus coupler circuit. On the other hand the circuit would have to be taken out of service to work on the current transformers. The need for continued metering of the by-passed circuit needs also to be considered.

Figures 21 (a), (b) and (c) show possible locations of current transformers in a portion of mesh substation.

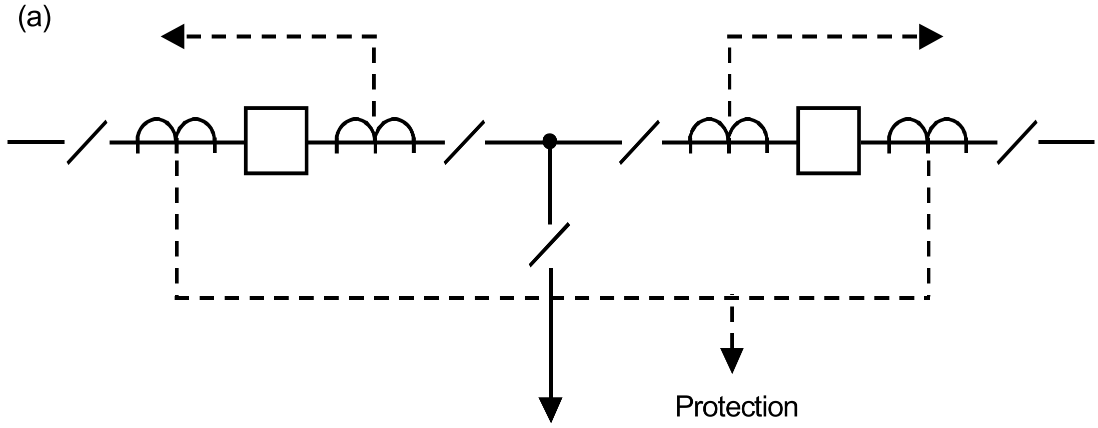
In arrangement *(a)* the current transformers are summed to equate to the feeder current and to operate the circuit protection. The protection also covers a portion of the mesh and, with overlapping current transformers as shown, the whole mesh is included in discriminative protective zones. Because the feeder current may be significantly smaller than the possible mesh current, the ratio of the mesh current transformers may be too high to give the best feeder protection.

In arrangement *(b)* the current transformers are in the feeder circuit and so their ratio can be chosen to give the best protection. However there is now no discriminative protection for the mesh. Note that the current transformers can be located either inboard or outboard of the feeder isolator, the choice being dependent on the ease of shutting down the feeder circuit and the undesirability of opening the mesh if maintenance of the current transformer were required.

The arrangement shown in *(c)* is a combination of *(a)* and *(b)* with, if necessary, different ratio current transformers in the feeder circuit. This arrangement however requires three sets of current transformers as opposed to two and one in arrangements *(a)* and *(b)*.

Similar arrangements are possible with breaker-and-a-half substations with the slight difference that at the end of the diameter the protection becomes protection for the busbar instead of a feeder. All the diameter currents are summed for the bus zone protection.

(a)



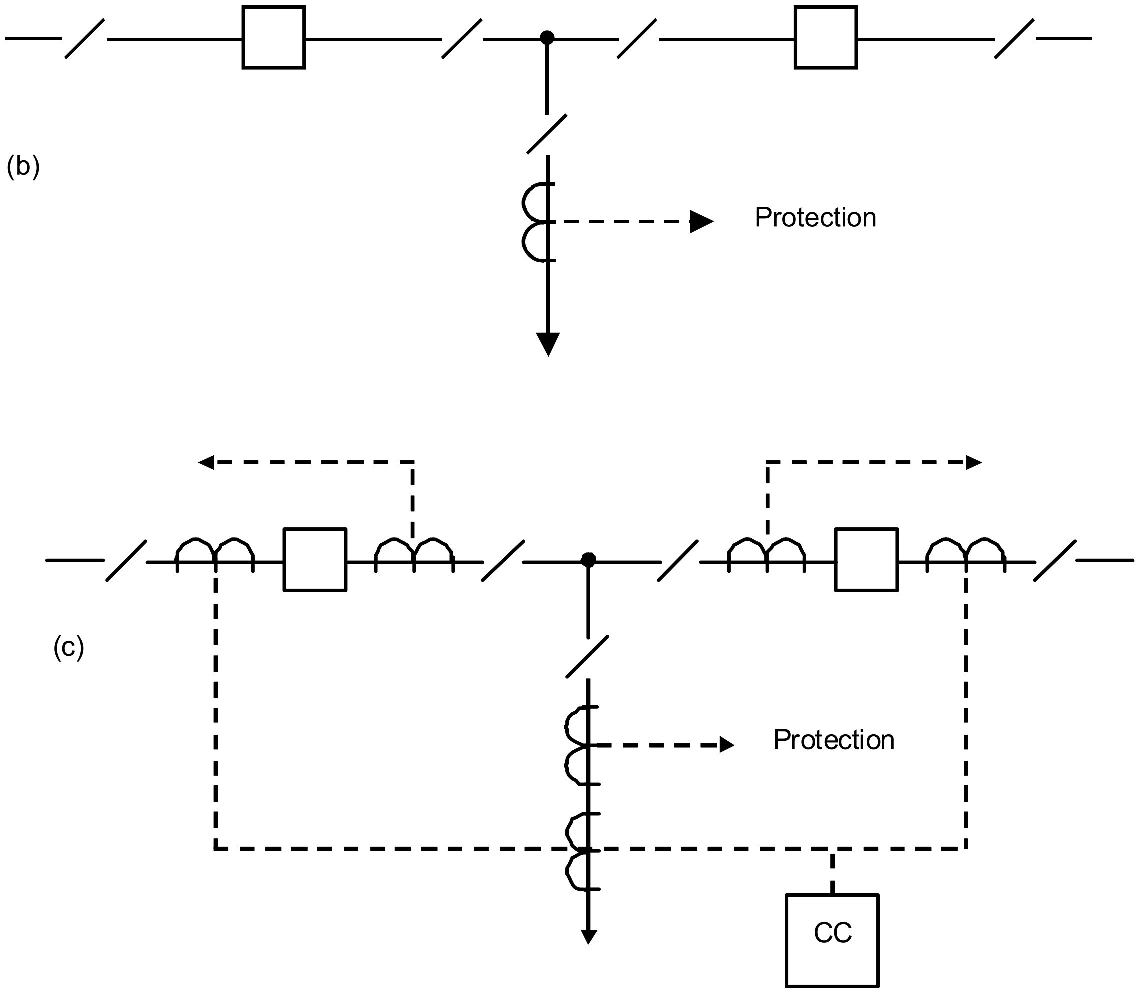


Fig 21 – Mesh Circuit CT's

3.7 Location of Voltage Transformers

Voltage transformers are required to provide an appropriate voltage for protection, instrumentation, metering, synchronising and voltage control. They may be single-phase connected line-to-earth or line-to-line, or three phase. At voltages of 72kV and above they are usually single-phase units connected line-to-earth. Voltage transformers may be required on circuits and busbars.

The need for three-phase voltages will depend upon the requirements of the protection, the instrumentation and the metering. Synchronising and voltage control normally only require a single-phase voltage but with generator control, a three-phase voltage is usually required.

Voltage transformers may be electromagnetic or capacitive, the latter being the lower cost at voltages 72kV and above. Capacitor voltage transformers also have the advantage that they can be used for line coupling with power line carrier signalling. However they do not usually have the very high accuracy required for some special metering functions.

Circuit voltage transformers are usually directly connected on the circuit side of the circuit isolators so that they can indicate whether or not circuit is alive when the isolator is open. They are also required to be in this position if they are the capacitive type and are required for PLC coupling. (If the voltage transformers are electromagnetic, then a separate line coupling capacitor is required for PLC.)

Busbar voltage transformers are often connected to the busbars through isolators and can present problems with the physical design of the substation especially when they have isolators. It is debatable whether the present reliable designs of voltage transformers significantly increase the risk of busbar faults. The need for isolators is also debatable since the maintenance requirements of voltage transformers is minimal and the desirability of operating a busbar without its voltage transformer should be considered. Where busbar voltage transformers are not used, the circuit voltage transformers can be used to give a representation of the busbar voltage by routing the secondary voltage through isolator and circuit breaker auxiliary switches and a voltage selection relay.

Voltage transformers are frequently omitted on outgoing circuits (such as transformers) where there is no need for a synchronising voltage. However, if the protection of the circuit requires a voltage, then voltage transformers are usually fitted rather than have the protection dependent upon auxiliary switches and voltage selection relays.

3.8 Line Traps

These are fitted on the circuits power line carrier communication. They are normally fitted on the line side of the line isolator to enable communication to continue when the isolator is open.

There may be one or two line traps depending upon whether the PLC system is phase-to-earth or phase-to-phase.

3.9 Surge Arresters

Surge arresters are provided to protect equipment from transient overvoltages due to lightning strikes on overhead lines and other exposed connections, and sometimes at the higher system voltages from switching surges. It should be noted that the closer the surge diverter is to the equipment being protected, the better is the protection afforded.

They are normally provided close to the most important and costly items of equipment such as transformers when the earth terminal of the arrester is also directly connected to the transformer tank and, when appropriate, to the transformer neutral.

They can also be provided at the entry of overhead lines to the substation at the line side of the line isolator where they will also protect against the flashover of the gap of the open isolator. When line traps are fitted the arresters are normally on the line side of the line traps since with lightning surges significant voltages can be produced at the relatively high surge impedance of the line trap. Such surge arresters are sometimes considered to give a sufficient protection to any transformers in the substation but it must be recognised that better protection is provided by surge arresters close to the transformers.

Surge arresters may also be at cabled entries to protect the cable against overvoltages produced by the reflection of surges travelling down the cable when they reach the higher surge impedance of the open connections.

Sometimes it is specified that lightning arresters be fitted only to the busbars. This may provide a low cost but less effective solution.

Surge Arrester Parameters

	400kV	**275kV**	**132kV**	**33kV**
Switching Impulse Withstand Voltage (kVp) =	1050	850		
Protection Level (kV) = (IEC)	$\frac{1050}{1.25} = 840$	$\frac{850}{1.25} = 680$	$\frac{550}{1.25} = 440$	$\frac{170}{1.25} = 136$
Lightning Impulse Withstand Voltage (kVp) =	1425	1050	650	170
Protection Level (kV) = (NGC)	$\frac{1425}{1.4} = 1020$	$\frac{1050}{1.4} = 750$	$\frac{650}{1.4} = 464$	$\frac{170}{1.4} = 121$
Maximum Continuous Voltage (kV) =	$\frac{400 \text{ x } 1.23}{\sqrt{3}} = 285$	$\frac{275 \text{ x } 1.23}{\sqrt{3}} = 195$	$\frac{132 \text{ x } 1.23}{\sqrt{3}} = 94$	$\frac{33 \text{ x } 1.23}{\sqrt{3}} = 23$
Rated Surge Arrester Voltage (kV) ≥ (NGC)	$\frac{400 \text{ x } 1.58}{\sqrt{3}} = 366$	$\frac{275 \text{ x } 1.58}{\sqrt{3}} = 250$	$\frac{132 \text{ x } 1.58}{\sqrt{3}} = 120$	$\frac{33 \text{ x } 2.2}{\sqrt{3}} = 42$
Energy Level Class ≥ Normally =	3 4	3 4	3 4	3 4
Nominal Discharge Current =	10–20kA	10–20kA	10kA	

4. PROTECTION EQUIPMENT / DEVICE

4.1 INTRODUCTION

The purpose of an electrical power system is to generate and supply electrical energy to consumers. The system should be designed and managed to deliver energy to the utilisation points with both reliability and economy. Protection should be done to prevent the following:

a) Prevent any disruption of supply
b) Electrical equipment used is very expensive and we should prevent any damage to the equipment
c) Power system should operate in a safe manner at all times
d) How well we design the electrical equipment, fault will occur on power system
e) Fault may represent a risk to life and property

4.2 PROTECTION SYSTEM

a) Protection System – complete arrangement of protection equipment (based on IEC 60255–20)
b) Protection equipment – collection of protection devices i.e. Relays fuse etc.
c) Protection devices – CT's, VT's, CB's
d) Protection scheme – a collection of protection equipment, providing a defined function and protection devices to make the scheme work (i.e. relays, CT's, VT's, CB's, batteries etc.)

4.3 PROTECTION EQUIPMENT

Relays may be classified as follows:

a) Electromechanical Relays
b) Static Relays
c) Digital Relays
d) Numerical Relays

4.4 PROTECTION DEVICES

Current Transformers CTs
Voltage Transformers T'
Circuit Breakers CB's etc.

4.5 CURRENT TRANSFORMERS

Standard: IEC 185, BS3938, TPS 8/2 & NGTs

There are two types of design:

a) Bar Primary Design
b) Hair Pin Design

4.6 SPECIFICATION OF CLASS 5P and 10P TYPE CT's

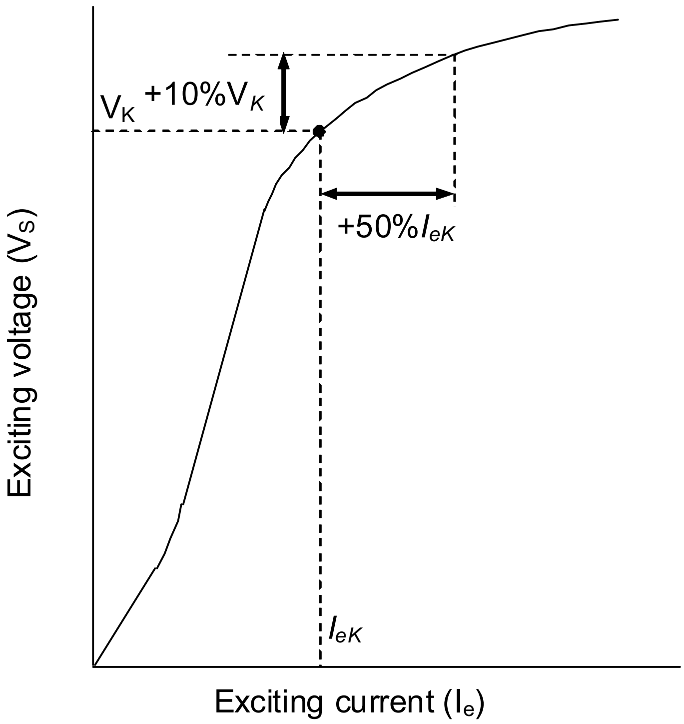
a) CT Ratio: 2000/1000/1A
b) Rated Primary Continuous
c) System frequency 50Hz
d) Class: 5P, Class 10P, Class I, Class 0.5
e) Accuracy Limit Factor 10, 15, 20
f) Burden 10VA, 15VA, 30VA
g) Continuous overload

4.7 SPECIFICATION OF CLASS X TYPE CT's

a) CT turn ratio, e.g. 1/1000/2000
b) Rated primary continuous current
c) Kneepoint voltage
d) Magnetising current
e) Maximum secondary resistance

Definition of knee point Voltage Vk

The 'knee-point' of the excitation curve is defined as 'that point at which a further increase of 10% of secondary emf would require an increment of exciting current of 50%'.



Definition of knee-point

4.8 420kV CURRENT TRANSFORMERS

i) Class X Type A

Turn Ratio 1/1000/2000
Vk ≥ 300 (RCT + 7.5) at 1/2000 tap
Imag = 60 mA at Vk/2
RCT = 3.0 Ω at 75°C

ii) Class X Type B

Turn ratio 1/2000A
Vk ≥ 60 (R CT + 5)
Imag = 40 mA at Vk/2
RCT = 5.0 Ω at 75°C

iii) Class X Special CT Ratio

Turn ratio 1/600/1200
Vk ≥ 82 (RCT + 3)
Imag = 60 mA at Vk/2
RCT = 2.4 Ω at 75°C

iv) a) Type A CT's are used for – Distance Protection
HV Connection Protection
LV Connection Protection

b) Type B CT’s are used for – Busbar Protection
Circulating Current Protection
Trans for Bias Differential
Mesh Corner Protection
HV & LV connections (if the distances are short)

4.9 300kV CURRENT TRANSFORMERS

a)	Protection A	1/600/1200	Vk ≥ 160 (RCT + 7.5) Imag = 60mA at Vk/2 RCT ≤ 2.5 Ω at 75°C at 1200/1 ratio
b)	Protection B	1/600/1200	Vk ≥ 82 (RCT + 3) Imag = 60 mA at Vk/2 RCT ≤ 2.5 Ω at 75°C at 1200/1 ratio
c)	Measurement/Protection	1200/600/1A	Class 5P/10 30VA (at 600/1)

4.10 145kV CURRENT TRANSFORMERS

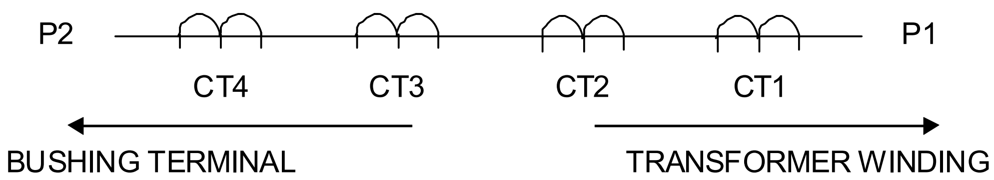
a)	Protection A	1/600/1200 1/500/1200	Vk ≥ 50 (RCT + 17) Vk ≥ 60 (RCT + 12) Imag = 60mA at Vk/2 RCT ≤ 2.5 Ω at 75°C at 1200/1 ratio

b) Protection B 1/500/1000 — Vk ≥ 95 (RCT + 2.5)
Imag = 60mA at Vk/2
RCT ≤ 2.5 Ω at 75°C
at 1000/1 ratio

c) Measurement/Protection 1/600/1200 — Class 1 30VA
Class 5P10 30VA (600/1A)
Class 5P20 30VA (1200/1A)

For tapped current transformers, the knee-point Voltage, magnetising current and secondary resistance are to be specified for the full winding (i.e. top tap)

4.11 **TRANSFORMER BUSHING CT's**



The 132kV Bushing CT's

132kV, 120MVA, SGTs FULL LOAD CURRENT = 530A			*Continuous Current*	*Secondary Current Rating*
CT1	1000 / 500 / 1A	Type A	800A	1A at 1000/1
CT2	1000 / 500 / 1A	Type B	800A	1A at 1000/1
CT3	1200 / 600 / 1A	Class 1 5P10/20 30VA	800A	1A at 1200/1
CT4	1200 / 600 / 1A	Type A	800A	1A at 1200/1
132kV, 180 MVA, SGTs FULL LOAD CURRENT = 790A			*Continuous Current*	*Secondary Current Rating*
CT1	1000 / 500 / 1A	Type A	1200A	1.2A at 1000/1
CT2	1000 / 500 / 1A	Type B	1200A	1.2A at 1000/1
CT3	1200 / 600 / 1A	Class 1 5P10/20 30VA	1200A	1A at 1200/1
CT4	1200 / 600 / 1A	Type A	1200A	1A at 1200/1
132kV, 240 MVA, SGTs FULL LOAD CURRENT = 1050A			*Continuous Current*	*Secondary Current Rating*
CT1	1000 / 500 / 1A	Type A	1600A	1.6A at 1000/1
CT2	1000 / 500 / 1A	Type B	1600A	1.6A at 1000/1
CT3	1200 / 600 / 1A	Class 1 5P10/20 30VA	1600A	1.35A at 1200/1
CT4	1200 / 600 / 1A	Type A	1600A	1.35A at 1200/1

The 275kV Bushing CT's

275kV, 120 MVA, SGTs FULL LOAD CURRENT = 250A			*Continuous Current*	*Secondary Current Rating*
CT1	1200 / 600 / 1A	Type A	450A	1A at 1200/1
CT2	1200 / 600 / 1A	Type A	450A	1A at 1200/1
CT3	1200 / 600 / 1A	Class 1 5P20 30VA	450A	1A at 1200/1
CT4	1200 / 600 / 1A	Type B	450A	1A at 1200/1

275kV, 180 MVA, SGTs FULL LOAD CURRENT = 380A			*Continuous Current*	*Secondary Current Rating*
CT1	1200 / 600 / 1A	Type A	660 A	1A at 1200/1
CT2	1200 / 600 / 1A	Type A	660 A	1A at 1200/1
CT3	1200 / 600 / 1A	Class 1 5P20 30VA	660 A	1A at 1200/1
CT4	1200 / 600 / 1A	Type B	660 A	1A at 1200/1
275kV, 240 MVA, SGTs FULL LOAD CURRENT = 500A			*Continuous Current*	*Secondary Current Rating*
CT1	1200 / 600 / 1A	Type A	870 A	1A at 1200/1
CT2	1200 / 600 / 1A	Type A	870 A	1A at 1200/1
CT3	1200 / 600 / 1A	Class 1 5P20 30VA	870 A	1A at 1200/1
CT4	1200 / 600 / 1A	Type B	870 A	1A at 1200/1

The 275kV Bushing CT's

275kV, 500 MVA, SGTs FULL LOAD CURRENT = 1050A			*Continuous Current*	*Secondary Current Rating*
CT1	1200 / 600 / 1A	Type A	1600 A	1.35A at 1200/1
CT2	1200 / 600 / 1A	Type A	1600 A	1.35A at 1200/1
CT3	1200 / 600 / 1A	Class 1 5P20 30VA	1600 A	1.35A at 1200/1
CT4	1200 / 600 / 1A	Type B	1600A	1.35A at 1200/1
275kV, 750 MVA, SGTs FULL LOAD CURRENT = 1580A			*Continuous Current*	*Secondary Current Rating*
CT1	1200 / 600 / 1A	Type A	2500 A	2.1A at 1200/1
CT2	1200 / 600 / 1A	Type A	2500 A	2.1A at 1200/1
CT3	1200 / 600 / 1A	Class 1 5P20 30VA	2500 A	2.1A at 1200/1
CT4	1200 / 600 / 1A	Type B	2500 A	2.1A at 1200/1
275kV, 1000 MVA, SGTs FULL LOAD CURRENT – 2100A			*Continuous Current*	*Secondary Current Rating*
CT1	1200 / 600 / 1A	Type A	3200A	2.7A at 1200/1
CT2	1200 / 600 / 1A	Type A	3200A	2.7A at 1200/1
CT3	1200 / 600 / 1A	Class 1 5P20 30VA	3200A	2.7A at 1200/1
CT4	1200 / 600 / 1A	Type B	3200A	2.7A at 1200/1

The 400kV Bushing CT's

400kV, 240 MVA, SGTs FULL LOAD CURRENT = 350A			*Continuous Current*	*Secondary Current Rating*
CT1	2000 / 1000 / 1A	Type A	610A	1A at 2000/1
CT2	2000 / 1000 / 1A	Type A	610A	1A at 2000/1
CT3	2000 / 1000 / 1A	Class 1 5P10/20 30VA	610A	1A at 2000/1
CT4	1200 / 600 / 1A	Type B	610A	1A at 2000/1
400kV, 500 MVA, SGTs FULL LOAD CURRENT = 720A			*Continuous Current*	*Secondary Current Rating*
CT1	2000 / 1000 / 1A	Type A	1100 A	1 A at 2000/1
CT2	2000 / 1000 / 1A	Type A	1100 A	1 A at 2000/1
CT3	2000 / 1000 / 1A	Class 1 5P10/20 30VA	1100 A	1.1A at 1000/1A
CT4	1200 / 600 / 1A	Type B	1100 A	1A at 1200

400kV, 1000 MVA, SGTs FULL LOAD CURRENT = 1445A			*Continuous Current*	*Secondary Current Rating*
CT1	2000 / 1000 / 1A	Type A	2200 A	1.1A at 2000/1
CT2	2000 / 1000 / 1A	Type A	2200 A	1.1A at 2000/1
CT3	2000 / 1000 / 1A	Class 1 5P10/20 30VA	2200 A	1.1A at 2000/1
CT4	1200 / 600 / 1A	Type B	2200 A	1.9A at 1200/1

4.12 **145kV, 45 MVA MSCDN's CT's**

1. Main capacitor C1 – H – Type Configuration Unbalance Protection

   3 - Single phase, 20/5A, 30VA, Class 0.5, 50 Hz, 123kV, 550kVp BIL, rating 40A max, 5kA/1 sec S/C current

2. Auxiliary Capacitor C2 – H – Type Configuration Protection

   3 - Single phase, 20/5A, 30VA, Class 0.5, 50 Hz, 36kV, 170kVp BIL, rating 40A max, 5kA/1 sec S/C current

3. Reactor Thermal Overload

   3 - Single phase, 400/1A, 30VA, Class 5P10, 50 Hz, 24kV, 125kVp BIL, rating 480A max, 15kA/1 sec S/C current

4. Resistor Thermal Overload / Open Circuit

   6 - Single phase, 20/1A, type B, Class X, Vkp ≥ 82 (RCT + 3.0) with RCT ≤ 2.4 Ω, i.e. = 60mA at Vk/2, 10kA/1 sec S/C current

5. Circulating Current Protection

   a) HV Side CT's

      3 - Single phase, 600/300/1A, type B, Class X, Vkp ≥ 95 (RCT + 2.5), RCT ≤ 2.5 Ω at 75°C, i.e. = 60mA at Vkp/2 at 600/1 ratio

   b) LV Side CT's

      3 - Single phase, 600/300/1A, type B, Class X, Vkp ≥ 95 (RCT + 2.5), RCT ≤ 2.5 Ω at 75°C, i.e. = 60mA at Vkp/2 at 600/1 ratio

4.13 **145kV, 60 MVAr MSC CT's**

1. Capacitor Split Phase "U" – Type Configuration Unbalanced Protection

   3 x 2 = Single phase, 150/ A, 20VA, Class 0.5, 50 Hz, 40kA/3 secs S/C Current

2. Circulating Current Protection

   a) HV Side CT's

      3 - Single phase, 600/300/1A, Class X, Vk ≥ 95 (RCT + 2.5), i.e. = 60 mA at Vk/2, RCT ≤ 2.5 Ω at 75°C at 600/1A ratio

   b) LV Side CT's

      3 - Single phase, 600/300/1 A, Class X, Vk ≥ 95 (RCT + 2.5), i.e. = 60mA at Vk/2, RCT ≤ 2.5 Ω at 75°C at 600/1A ratio

4.14 145kV, 60 MVAr MSCDN's CT's

1. <u>Capacitor C1 Split Phase "U" – Type Configuration Unbalance Protection</u>

   3 x 2 = Single phase, 150/1A, 20VA, Class 0.5, 50 Hz, 15kA/3 secs S/C current

2. <u>Auxiliary Capacitor C2 Split Phase "U" Type Configuration Unbalance Protection</u>

   3 x 2 = Single phase, 150/1A, 20VA, Class 0.5, 50 Hz, 15kA/3 secs S/C current

3. <u>Reactor Thermal Overload</u>

   3 − Single phase, 400/1A, 30VA, Class 5P10, 50 Hz, 15kA /1 sec S/C current

4. <u>Resistor Thermal Overload / Open Circuit</u>

   6 − Single phase, 20/1A, type Class X, Vk ≥ 82 (RCT + 3.0) with RCT ≤ 2.4 Ω at 75°C, i.e. = 60mA at Vk/2, 10kA/1 sec S/C current

5. <u>Circulating Current Protection</u>

   a) <u>HV Side CT's</u>

      3 − Single phase, 600/300/1A, Class X, Vk ≥ 95 (RCT + 2.5), i.e. = 60mA at Vk/2 at 600/1A ratio, 10kA/1 sec S/C current

   b) <u>LV Side CT's</u>

      3 − Single phase, 600/300/1A, Class X, Vk ≥ 95 (RCT + 2.5), I.e. = 60mA at Vk/2 at 600/1A ratio, 10kA/1 sec S/C current

4.15 400kV, 225 MVAr MSCDN's CT's

1. <u>Main Capacitor C1 Split Phase "U" – Type Configuration Protection</u>

   3 x 2 = Single phase, 200/5A, 25VA, Class 0.5, 72.5kV, 325kVp, 240A maximum primary current, 50 Hz, 15kA/1 sec S/C current

2. <u>Auxiliary Capacitor C2 Split Phase "U" – Type Configuration Protection</u>

   3 x 2 = Single phase, 200/5A, 25VA, Class 0.5, 72.5kV, 325kVp, 240A maximum primary current, 50 Hz, 15kA/1 sec S/C current

3. <u>Main Capacitor C1 – "H" – Type Configuration Unbalance Protection</u>

   3 – Single phase, 20/5A, 30VA, Class 0.5, 50 Hz, 300kV, 1050kVp BIL, 40A maximum primary current, 5kA/1 sec S/C current

4. <u>Reactor Thermal Overload Protection</u>

   CT's specifications are same as other 145kV, MSCDN's Reactor

5. <u>Resistor Thermal Overload Protection</u>

   CT's specifications are same as other MSCDN's resistors

6. Circulating Current Protection

   a) HV Side CT's

   3 – 1200/600/1A, 50 Hz, Class X, Vk ≥ 82 (RCT + 3), with RCT $\leq$ 2.2 Ω at 75°C, 60mA at Vk/2, 10kA/1 sec S/C current

   b) LV Side CT's

   3 – 1200/600/1A, 50 Hz, Class X, Vk ≥ (RCT + 3), with RCT $\leq$ 2.2 Ω at 75°C, 60mA at Vk/2, 10kA/1 sec S/C current

4.16 DISTANCE PROTECTION CT KNEEPOINT VOLTAGE (VK) REQUIREMENT

$$Vk \geq I_f \left(1 + \frac{X}{R}\right) (ZR + RCT + 2RL)$$

ZR = Relay Burden

RCT = CT Secondary resistance

RL = Cable lead resistance

4.17 EARTH FAULT PROTECTION CT KNEEPOINT VOLTAGE (VK) REQUIREMENT

$$Vk \geq I_{fe} \left(1 + \frac{X}{R}\right) (ZRE + RCT + 2RL)$$

ZRE = relay Burden

4.18 CALCULATION OF KNEEPOINT VOLTAGE OF 5P, 10P, CLASS CT's BASED ON BURDEN AND ALF

1) CT parameters are (say) 5P20, 40VA burden
   CT ratio 2000/1 A
   i.e. secondary CT rating 1A

$$Vk = \frac{\text{Rated Burden}}{\text{Rated Current}} \times ALF + RCT \times ALF \times \text{Rated Current} \qquad (1)$$

Rated current = 1 A
RCT = 2.0Ω
ALF = 20
Burden = 40VA

$$\text{Therefore } Vk = \frac{40}{1} \times 20 + 2 \times 20\ 1$$

$$= 800 + 40V$$

$$= 840V$$

OR

2) Vk = ALF x Rated Current x CT Impedance (2)

$$= 20 \times 1 \times \frac{40}{1^2} = 800V$$

3) <u>Voltage Transformers</u>

a) 400kV System

$$\text{VT ratio} = \frac{396kV}{\sqrt{3}} / \frac{110V}{\sqrt{3}} / \frac{110V}{\sqrt{3}}$$

= 228630 / 63.5 / 63.5V, Class = 0.5/3P

Burden 50VA at both windings

b) 132kV System

$$\text{VT ratio} = \frac{132kV}{\sqrt{3}} / \frac{110V}{\sqrt{3}} / \frac{110V}{\sqrt{3}}$$

= 76210 / 63.5V / 63.5V, Class = 0.5/3P

Burden 50VA at both windings

5. PROTECTION

Protection function can be classified as follows :

a) Back up protection
b) Power transformer protection
c) Distance protection
d) Differential protection
e) Busbar protection, etc.

5.1 BACK UP PROTECTION (Overcurrent and Earth Fault)

Overcurrent Protection for Phase and Earth Fault

'Overload' protection is normally making use of the relays that operate in time related in some degree to the thermal capability of the plant to be produced.

'Overcurrent' protection on the other hand is directed entirely to the clearance of faults.

Protection grading is required for Overcurrent and Earth Fault i.e. current and time.

Back up protection is applicable for

a) Power Transformers
b) Line Feeders
c) MSCDN Feeders
d) Capacitor Bank Feeders
e) SVC Feeders

5.2 POWER TRANSFORMER PROTECTION (Unit or Differential Protection)

a)	Transformer Bias Differential 2 windings / 3 windings	(Phase to Phase Fault Phase to Earth Fault)
b)	HV WTI	(Tank Fault, Core Fault
c)	LV WTI	and Internal Fault)
d)	Overcurrent	(Bias Differential)
e)	Buchholz	(Tank Fault)
f)	Thermal Overload	(Overheating)
g)	REF (Primary Winding) REF (Secondary Winding) REF (Tertiary Winding)	

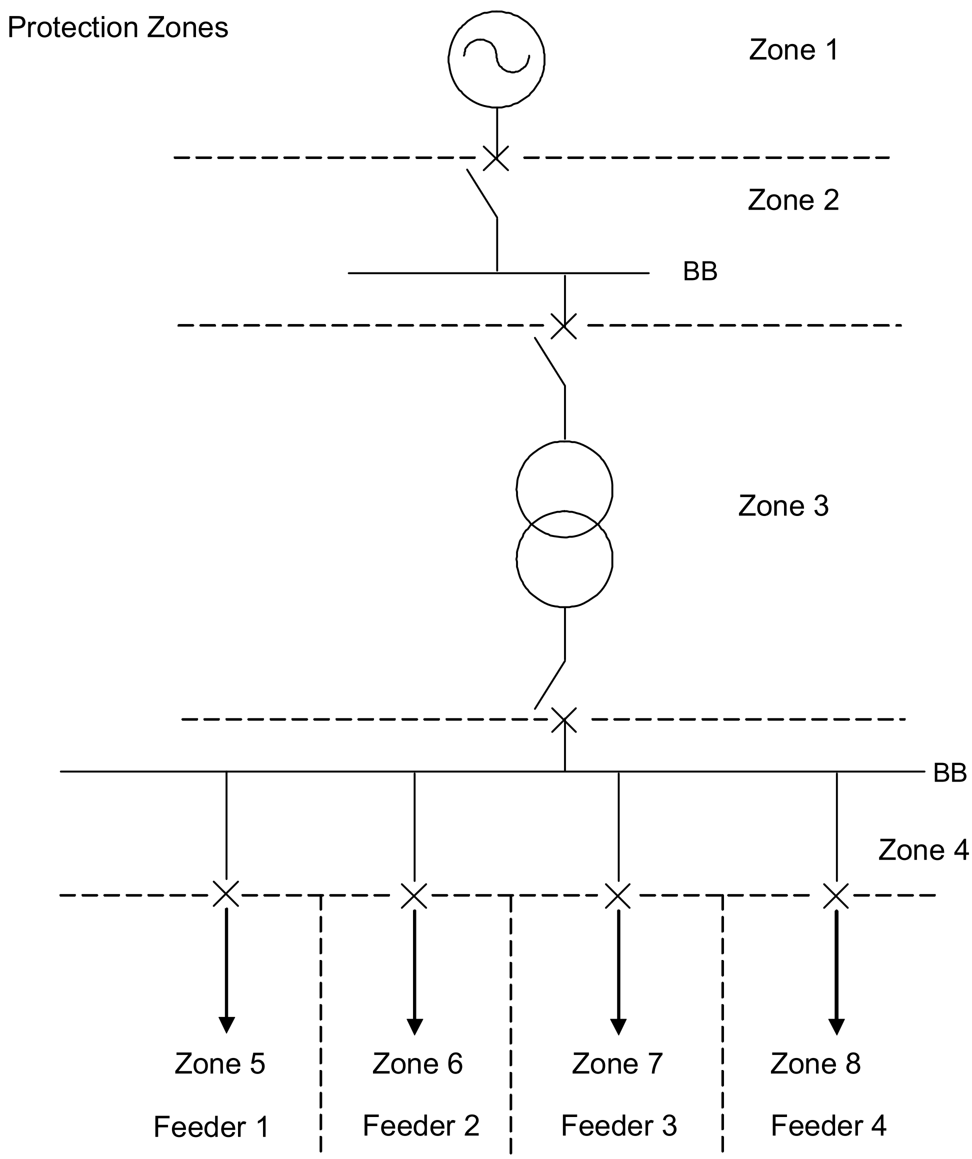
5.3 CAPACITOR BANKS PROTECTION

a) Capacitor Unbalance Protection – Split – Star (Y) Capacitor Bank using CT's

b) Capacitor Unbalance Protection – Delta Connected Capacitor Bank using CT's

c) Capacitor Unbalance Protection – Star Connected Capacitor Bank using VT's

5.4 PROTECTION ZONES



5.4.1 Transformer Bias Differential

Phase correction is needed in the case of STAR / DELTA transformer, by means of CT arrangement or software.

Transformer Connection	Transformer Phase Shift	Clock Factor	Phase Compensation Required
Yyo	0°	0	0°
Yd1	– 30°	1	+ 30°
Yy6	– 180°	6	180°
Yd11	30°	11	– 30°
Dy11	30°	11	– 30°

Where an earthed transformer or an Earthing Transformer is included within the zone of protection, some form of zero sequence current filtering is required. This is because there will be an in-zone source of zero sequence current for an external earth fault. The differential protection will see zero sequence differential current for an external fault and it could **incorrectly** operate as a result.

To avoid this problem, a **Delta** connection of the CT secondary winding is required.

Refer to examples in Appendix.

5.4.2 Distance Protection

Distance protection means measuring voltage and current up to the point of fault and clear the fault very fast, i.e. unlike phase and neutral overcurrent protection, key advantage of distance protection is that its fault coverage of the protected circuit is virtually independent of source impedance variations.

Distance Relay needs CT and VT inputs.

Since the impedance of a transmission line is proportional to its length, i.e. the line impedance 'z'

$$Z = R + jX$$

Basic principle of distance protection involves the division of the voltage at the relaying point by the measured current.

Zone 1 = 80% of the protected line impedance

Zone 2 = 120% of the protected line impedance

Zone 3F = 120% (protected line + longest second line)

Zone 3R = 20% protected line

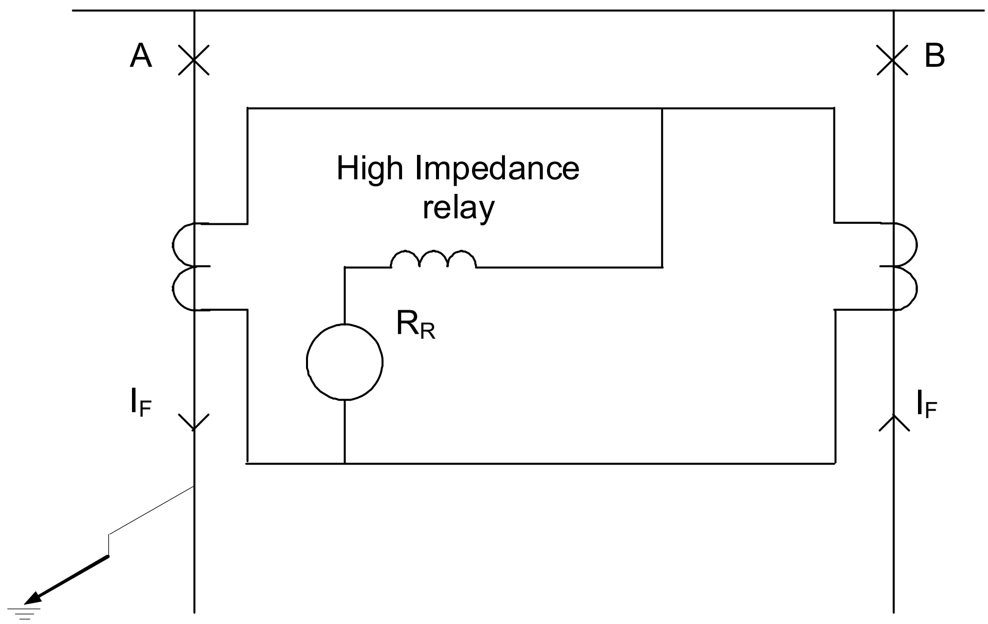
Refer to examples in Appendix.

5.4.3 Differential (Circulating Current) Protection Principles

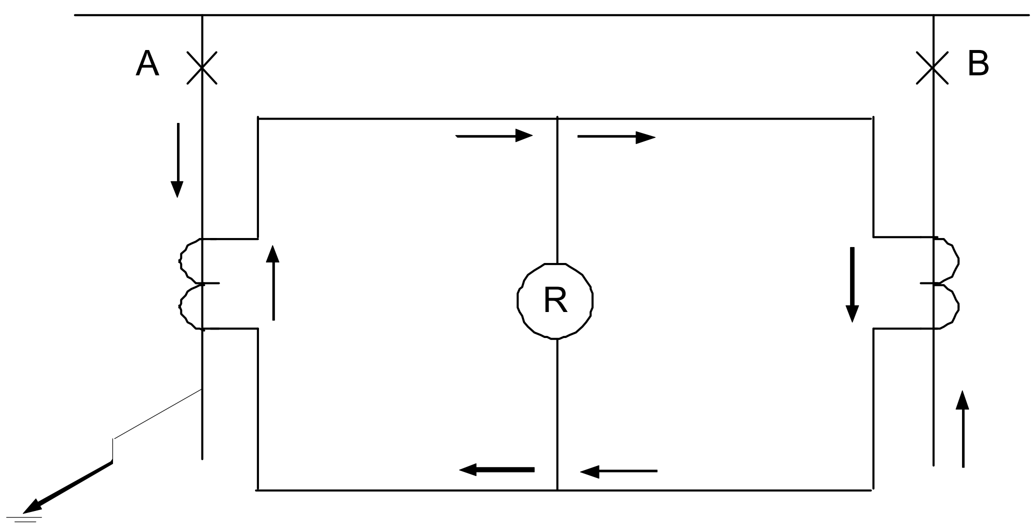
This is a simple form of unit protection which compares the current entering and leaving the busbar as shown in Figure 2. Usually the circulating current arrangement is used, in which the current transformers and interconnections form an analogue of the busbar and circuit connections. A relay connected across the CT bus wires represents a fault path in the primary system in the analogue and hence is not energised until a fault occurs on the busbars, it then receives an input that, in principle at east, represents the fault.

If the current transformers were perfect there would be no current through the relay circuit. In practice there will be spill current through the relay circuit, which must not exceed the relay current setting up to the maximum through fault current.

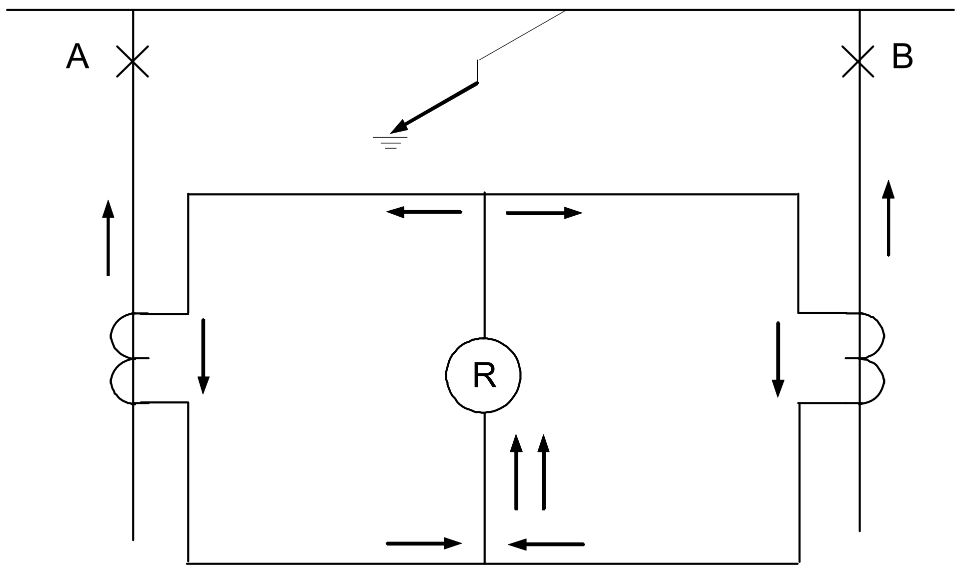
Consider a typical system to protect a zone having only two circuits connected to it.



Let us consider a fault just outside the zone. Maximum fault current enters the zone through one circuit and leaves through the other. One CT, say that on feeder circuit 'A' saturates completely due to asymmetry of the fault current whilst the other CT does not enter saturation and maintains its output as a faithful reproduction of the primary current. Because the CT is saturated by the DC component of the primary current, its magnetising branch can be assumed to have zero impedance. In the absence of a secondary emf the CT on feeder circuit 'A' can produce no output and will behave as a resistor having a value of equal to the resistance of the secondary winding.

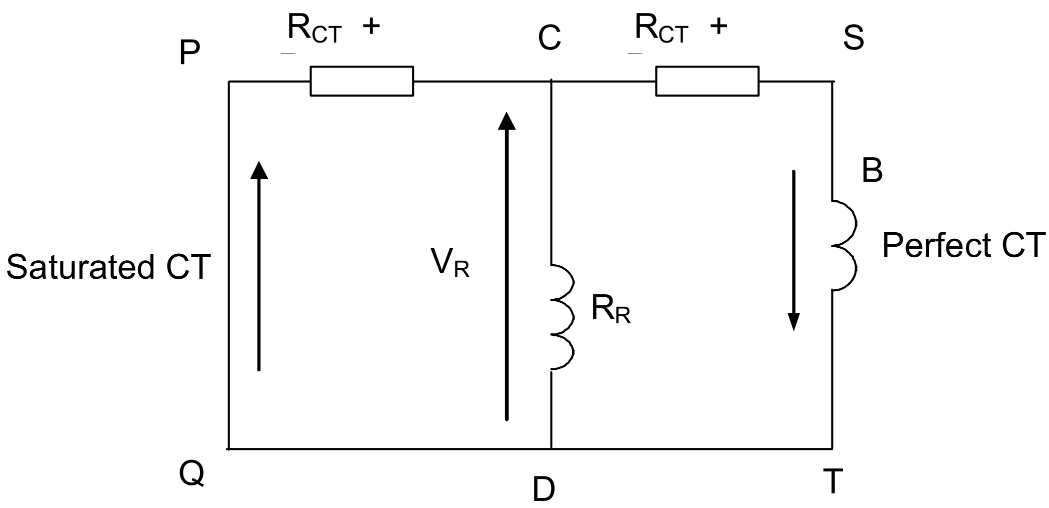


<u>External Fault</u>



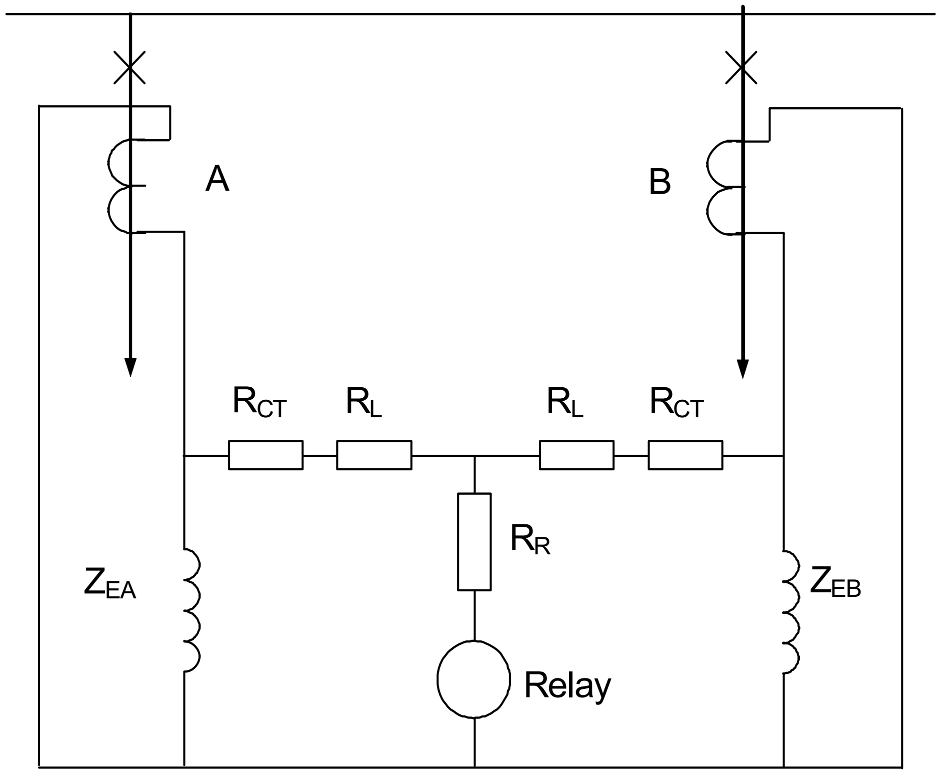
Internal Fault

Figure 2: Basic Circulating Current



Simplified equivalent circuit

The voltage drop 'V_R' appears across the high impedance relay circuit (CD) and must be sufficient to operate the relay if the protection is to remain stable. Since all CT's installed for the circulating current protection of each substation are identical, their secondary winding has the same resistance.



Path of Circulating Current

Busbar Protection

Busbar protection is primarily concerned with

a) Limitation of consequential damage.
b) Removal of busbar faults in less time than could be achieved by back-up line protection with the object of maintaining system stability. Majority of bus faults involve single phase and earth.

In general, busbar protection is required when the system protection does not cover the busbars, or when, in order to maintain power system stability, high speed fault clearance is necessary. Unit busbar protection provides this, with further advantage that if the busbars are sectionalised, one section only needs to be isolated to clear a fault.

The case for unit busbar protection is in fact strongest when there is sectionalisation.

There are three types of busbar protections available such as

a) High Impedance Busbar protection
b) Low Impedance Busbar protection
c) Low Impedance Numerical Busbar Protection

Users have been concerned with reliability issues such as security and availability. The high impedance busbar protection is more reliable and still in common use. Conventional high impedance schemes have been one of the main protection schemes used for busbar protection.

Refer to examples in Appendix.

6. COMPENSATION

6.1 INTRODUCTION

The voltage drop in an A.C. electric power supply system, caused by problem loads which are large compared with the short circuit level of the system, is mainly due to reactive component of the load I_q flowing through the system reactance X_o i.e. $V = I_q X_{o.}$ The variations in loads can cause voltage fluctuations and consequent objectionable or irritating light flicker.

These troublesome loads sometimes produce harmonic currents, which are large enough to cause distortion problems to other consumers whose electricity supply is provided from the same busbar (the point of common coupling). To provide reactive VAr control in order to support the power supply system voltage and to filter the harmonic currents in accordance with Electricity Authority recommendations, which prescribe the permissible voltage fluctuations and harmonic distortions, reactive power (VAr) compensators are required.

These compensators can be grouped into two major groups these are synchronous compensators (condensers) and static VAr compensators. The static VAr compensators having no moving parts. The speed of response of the synchronous compensator is low and the cost is high when compared with the static VAr compensators and hence the latter are the preferred solution.

6.2 WHAT ARE STATIC VAr COMPENSATORS

Static var compensator (SVC) is a shunt connected static var generator or absorber whose output is adjusted to exchange capacitive or inductive current to maintain or control specific parameters of the electrical power system (typically bus voltage).

At least four different types of static Var compensator (SVC) are available. These are saturated reactor type compensators, thyristor controlled reactor compensator and thyristor switched capacitor compensator and STATCOM (Static Compensator).

6.3 SATURATED REACTOR TYPE COMPENSATOR

The Power Transmission Division of GEC, Stafford, was the pioneer of saturated reactor type compensator. The saturated reactor type compensators were first developed in the 1960's by AREVA (then GEC) under the guidance of Dr E Friedlander. These are transformer type devices, which were built in the factory of AREVA (then GEC) Transformers Limited in Stafford. Unlike a synchronous machine the saturated reactor has no rotating parts, no inertia and inherently remains in synchronism with the supply. A saturated reactor can only absorb reactive power. It does not need any external control to force it to absorb reactive power. It does so by the nature of the saturation feature of the magnetising characteristic of its core iron as it operates normally in saturated flux region. The saturated reactor is inherent in its response and the speed of response is fast. The reactive power required for compensation is generated by parallel connected shunt capacitance (often in the form of tuned or damped harmonic filters). The order of harmonic filters depends primarily on the harmonic (number) currents generated by the troublesome loads. There are different types of saturated reactors, namely twin tripler reactor, treble tripler reactor and tapped reactor. AREVA have so far designed, manufactured and commissioned forty nine saturated reactor type compensators all over the world. AREVA are the only Company in the World which produce both the saturated reactor type compensators and the thyristor controlled type compensators.

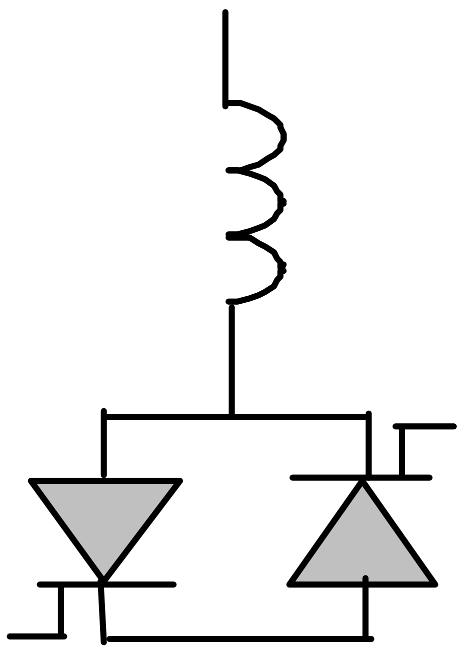
6.4 THYRISTOR CONTROLLED REACTOR COMPENSATOR (TCR)

Thyristor controlled reactor (TCR) is a shunt connected thyristor controlled inductor whose effective reactance is varied in a continuous manner by partial conduction of the thyristor valve.

The thyristor controlled reactor comprises a linear reactor, connected in series with a 'thyristor valve' made up of inverse-parallel (back-to-back) connected pairs of high power, high voltage thyristors.

Unlike saturated reactor (which is inherent, and does not need any external control), the variation of current in the linear VAr reactor (for VAr absorption) is obtained by control of the thyristor conduction duration in each half cycle. The firing angle delay is 90° as measured from the applied voltage zero for full conduction, and can be varied up to 180° delay for no conduction.

In saturated reactor the current is 'switched' by core saturation. In a TCR the current is switched by thyristors. As in the case of a saturated reactor compensator, the reactor power required by the loads is generated by parallel connected shunt capacitance (as mentioned above, often in the form of harmonic filters). During system light load conditions, the excess reactive power from this shunt capacitance is absorbed by thyristor controlled reactor. The design of the harmonic filters depends on the harmonic generated by both the thyristor compensator and the problem loads. The major harmonic frequencies which the TCR produces in the a.c. supply depend on the pulse number p, (e.g. p = 6) in accordance with the formula $h = kp \pm 1$ where h stands for the harmonic number and k is a positive integer. AREVA (then GEC Alstom) have manufactured and commissioned TCR compensators for transmission system applications.

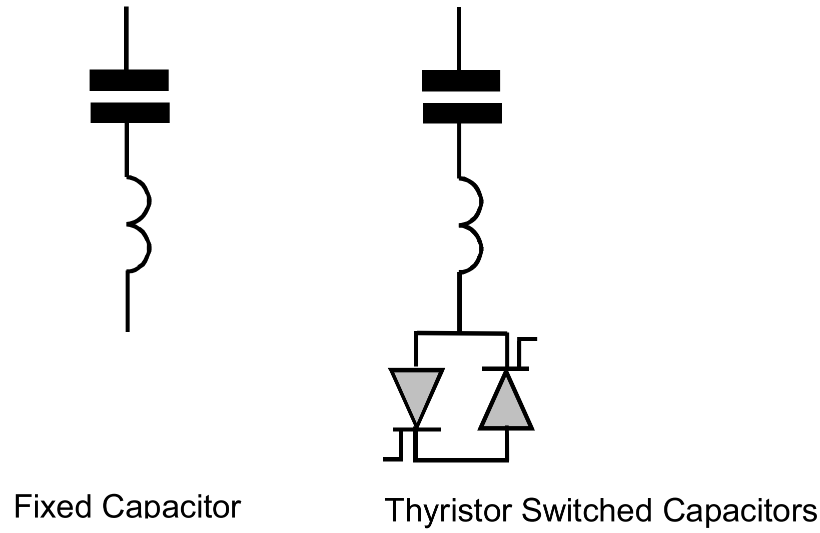


Thyristor Switched Reactor

6.5 THYRISTOR SWITCHED CAPACITORS (TSC)

Thyristor switched capacitor (TSC) is a shunt connected thyristor switched capacitor whose effective reactance is varied in a stepwise manner by full or zero conduction operation of the thyristor valve.

Thyristor valves consisting of inverse-parallel connected thyristors, generally similar to those used for the TCR, are used to give rapid switching of blocks of capacitors. The capacitors are switched in block only, i.e. step-by-step, as they cannot be firing angle controlled, unlike the TCR, as excessive capacitor inrush currents would result. After the capacitor current through the thyristor ceases at current zero, unless re-gating occurs, the capacitors remain charged at peak voltage while the supply voltage peaks in the opposite polarity after a half cycle. The decay of the stored charge takes several minutes and this imposes a doubled voltage stress on the non-conducting thyristor and an increase is necessary in the number of thyristors in series in a TSB.

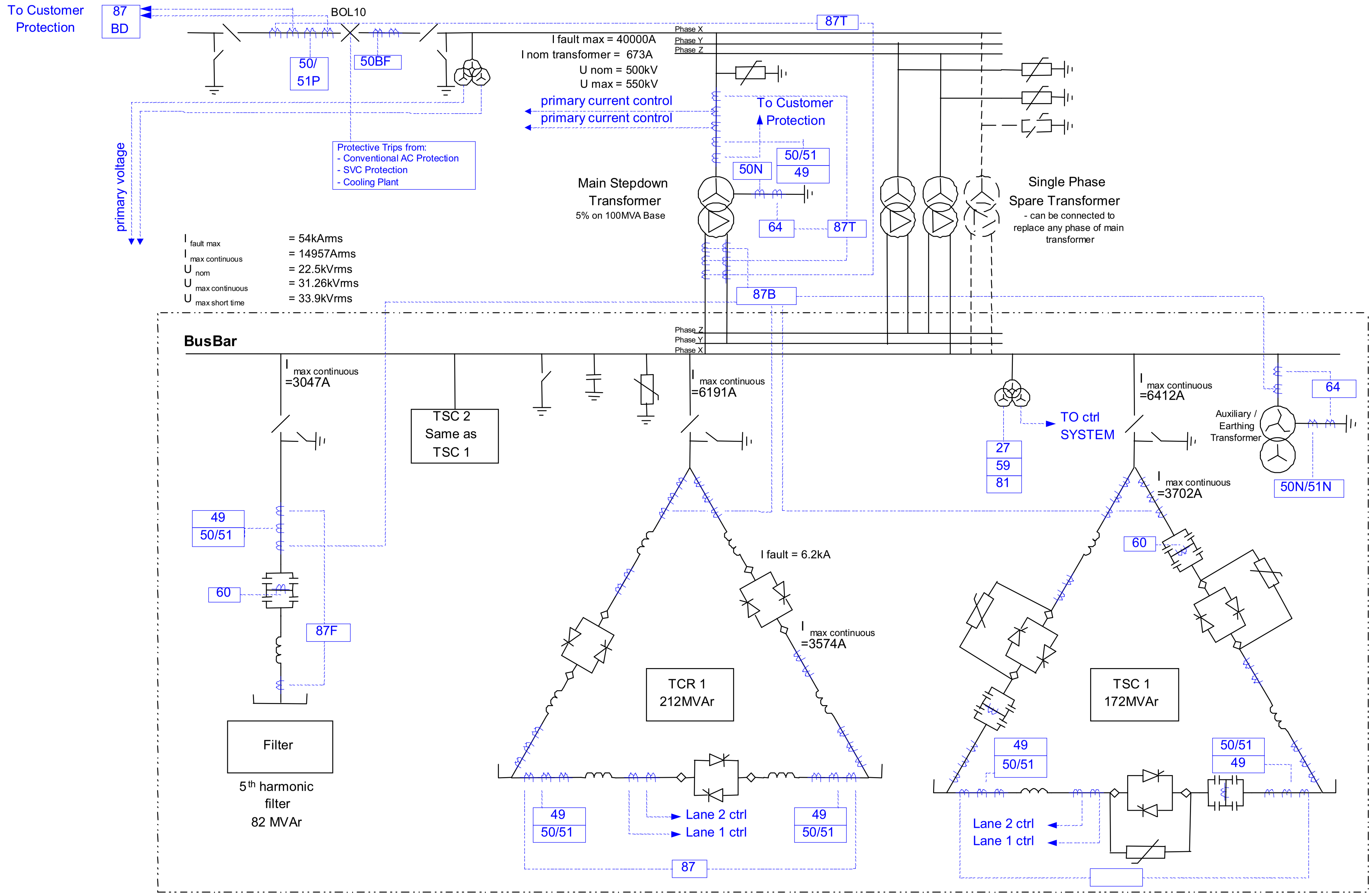


6.6 STATIC VAr COMPENSATOR

The general arrangement of the Static VAr Compensator is shown on the next page. It consists of thyristor controlled reactors (TCR) in parallel with thyristor switched capacitors (TSC). The reactive equipments of the compensator are connected to the transmission line, through a transformer to prevent the equipments having to withstand full system voltage. A control system determines the exact gating instants of reactors according to predetermined strategy. The strategy usually aims to maintain the transmission line voltage at a fixed level.

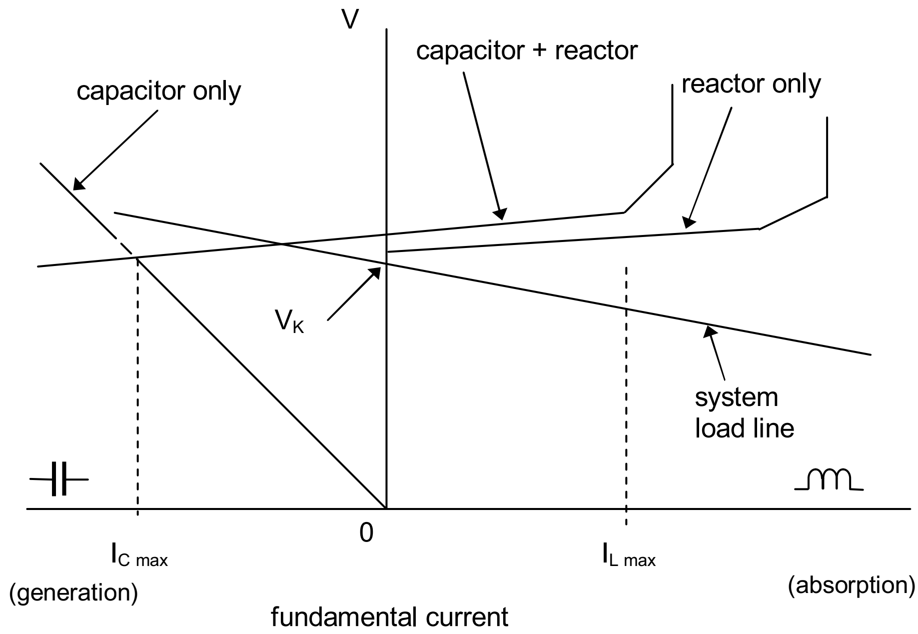
To provide both inductive and capacitive power, the TSCs are included with TCRs. The combined arrangement of TCRs and TSCs is now capable of providing a range of leading and lagging reactive power to support the required operating voltage range.

The continuous variation in the TCR is used in combination with the stepped effect of switching in or out integral capacitor units in the TSC to achieve an effective continuous variation of reactive power over the whole operating range. The typical characteristics of the combined TCR and TSC, the static VAr compensator (SVC) are shown in the figure on the next pagea.



Note : Equipment MVAr is referred to the MV bus at nominal MV bus voltage

Static VAr compensators are used to help power transmission over long A.C. transmission lines by injecting reactive power at points down the line to maintain voltage levels. AREVA (then GEC Alsthom) have designed, manufactured, installed and commissioned SVC's on transmission systems worldwide and are mainly used for dynamic voltage and reactive power support at load centres remote from generating plant.



The figure above shows the typical characteristic of the combined compensator. This arrangement is now capable of providing a range of leading and lagging reactive power support to its operating voltage.

6.7 STATCOM (STATIC COMPENSATOR)

A static synchronous generator operated as a shunt connected static VAr compensator (SVC) whose capacitive or inductive output current can be controlled independently of the A.C. system voltage. STATCOM is based on a voltage source converter. STATCOM has superior dynamic reactive power compensation ability and wider operating voltage range, than a normal SVC. The phases of the STATCOM are independently controlled during system disturbances.

6.8 PROBLEM LOADS

6.8.1 Arc Furnaces

Electric arc furnaces are considered as being one of the worst source of fluctuations on a power supply system. The load cycles of arc furnaces vary widely, depending on size and metallurgical requirements. The first part of the cycle consists of melt-down period when the solid charge is melted and the main energy input needed. The later part of the cycle is known as the refining period; in this, energy supplied has only to make good the heat losses. A considerable movement of the charge occurs during the melt-down period with consequent variations in the arc lengths on each phase. The two main causes of fluctuation are believed to be first, the movement of the arcs as flexible conductors in a magnetic field and in some cases their extinction and restriking; secondly, the short circuiting of the graphite electrodes by scrap movement.

When the fluctuating currents pass through the power supply network impedance, a corresponding fluctuation is set up in the supply voltage at the point of common coupling with other consumers (p.c.c.). Visible light flicker is due to power system voltage fluctuation. The fluctuations in the three phases are, moreover, unbalanced. During melting period the arc furnaces also create harmonics. Arc furnaces are designed to operate at low power factor say 0.7 and 0.8. When the electrode is usually driven into the scrap metal, it produces a dead short circuit on one phase. During arc furnace short-circuit, arc furnace demands larger reactive power from the electricity supply, in turn a larger voltage dip is produced on the system.

To reduce harmonic injection into the system, to improve the power factor of the arc furnace during melting, to support the power supply system for VAr compensation during arc furnace short-circuit, and to balance the three-phases, a reactive VAr compensator is needed. The static VAr compensator should be capable of supporting the system for the dynamic reactive VAr swing requirement due to arc furnaces swing from open circuit to short circuit.

6.8.2 Electric Welding

There are a wide variety of applications for electric welding. The method used can broadly be divided into a) arc welding and b) resistance welding. The control of the welding in both cases can be automatic or manual. Welding is mostly controlled by thyristor control. Most welders operate at low power factor around 0.3 – 0.4 lagging. The welding load employs bursts of power and so creates voltage disturbances and produces harmonic currents, but is generally of smaller magnitude than the other types of fluctuating load considered here.

6.8.3 Mine Winders

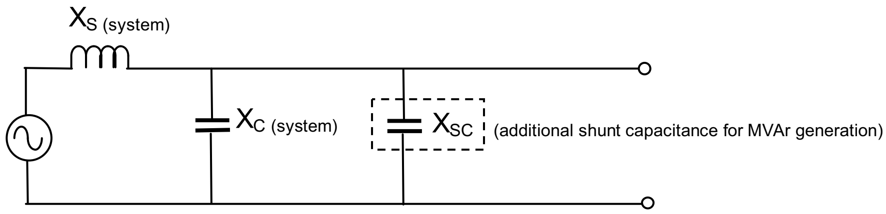
Mine winders (e.g. in the coal industry) are driven by thyristor-fed D.C. drive motors. The duty imposed on the a.c. power supply system is severe due to the varying power demand of the D.C. drives. Every time a winder accelerates it demands a very high amount of reactive power from the system. Because of the thyristor-fed drive, it also generates harmonic currents which need filtering.

6.8.4 Rolling Mills

Rolling mills are driven by D.C. motors fed from thyristor converters. Every time the rolls reverse a large change in reactive power demand occurs in a few cycles. This change in reactive power demand occurs in a short period during acceleration. When compared to an arc furnace, however, overall duty on the power supply system is less severe (as in the case of mine winders) both because the rate of change is slower and the load in the three phases is balanced.

6.8.5 Shunt Capacitor Bank

Shunt capacitor banks are mainly installed to provide capacitive reactive compensation/ power factor correction. Because they are relatively inexpensive, the use of capacitor banks has increased. Shunt capacitor banks are composed of capacitor units mounted on the racks. They can be easily and quickly installed virtually anywhere in the network. Its installation has beneficial effects on the system such as improvement of the voltage at the load, better voltage regulation and reduction of losses.



Mechanically switched capacitor bank (shunt connected) may be installed on transformer tertiaries or connected directly to 132kV, 275kV, 400kV, 500kV or higher grid system. In the case of back-to-back switching of Mechanically Switched Capacitor banks, these shunt capacitor banks are to be connected to grid system via damping reactors (in series with capacitor banks).

Shunt capacitor banks can be arranged in different forms i.e. a) Phase to Neutral - Double Wye, b) Phase to Neutral - Single Wye, c) Ungrounded Wye-connected Banks, d) Delta-connected Banks and e) H connected-configuration Banks.

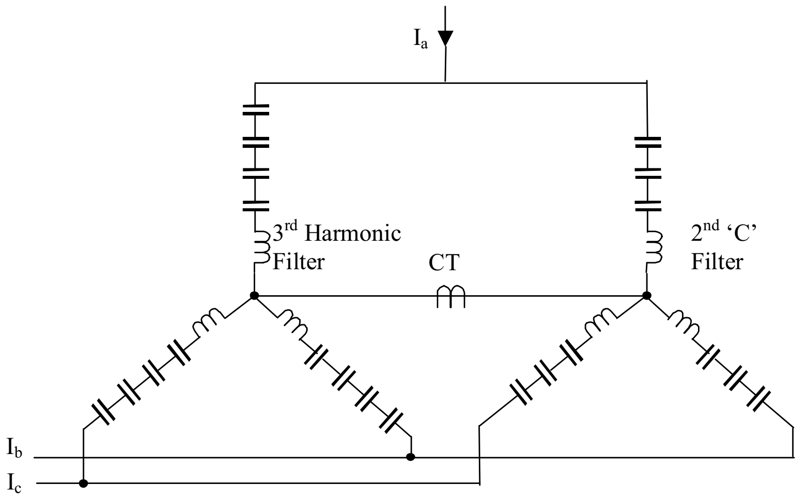
a) Phase to Neutral – Double Wye

Capacitor units with external fuses can be arranged to make up the bank.

When a capacitor bank becomes too large for the maximum 4.5MVAr per group, the bank may be split into two Wye sections, to prevent the parallel energy of a series group becoming too great (above 4500kVAr) for the capacitor units or fuses.

Capacitor Unbalance Calculations

For split-star banks, the unbalance current in the CT interconnecting the star-points is to a first approximation

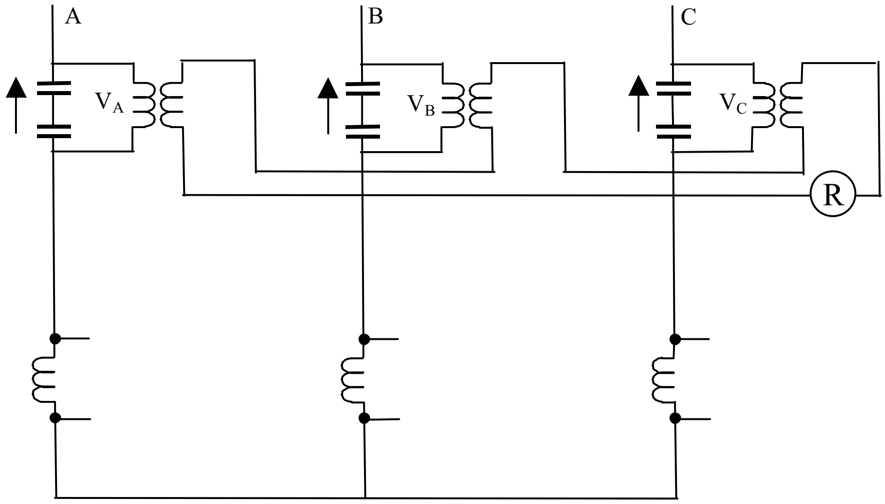


$$I_{UN} = \frac{V_{ll}}{\sqrt{3}} \times \frac{\delta Y}{2}$$

Where V_{ll} is system line to line voltage and δY is the change in admittance of the faulty half phase.

b) Phase to Neutral – Single Wye

Capacitor units with external fuses, internal fuses or fuseless can be arranged to make up the bank.



$\overline{V_a}, \overline{V_b}, \overline{V_c}$ are the capacitor phase voltages and I_a is the current in the faulty phase; if there is an impedance unbalance of δX in one of the phases,

The unbalance voltage is

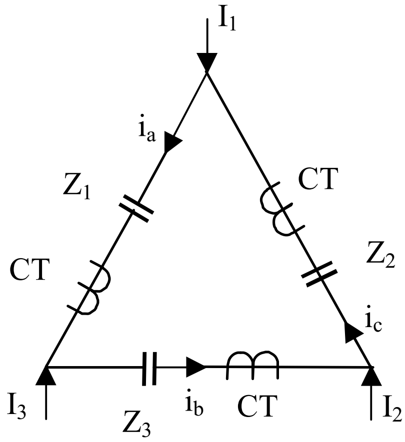
$$\therefore \overline{V_a} + \overline{V_b} + \overline{V_c} = \delta X \overline{I_a}$$

c) Ungrounded Wye-Connected Banks

Capacitor units with internal fuses can be arranged to make up the bank. Ungrounded Wye banks do not permit zero sequence currents, third harmonic currents, or large capacitor discharge currents during system ground faults to flow.

d) Delta-Connected Banks

Capacitor units with internal fuses can be arranged to make up the bank. These banks are generally used at distribution voltages and slope correction for saturated reactor compensators. Capacitors are configured with a single series group of capacitors rated to line to line voltage. As there is only one series group of capacitor units, no voltage stress occurs across the remaining capacitor units from the isolation of a faulted capacitor unit.



Let the nominal impedance of each mesh phase be Z and the unbalance in one phase be δZ.

Unbalance current $= \overline{I_a} + \overline{I_b} + \overline{I_c}$

$$= \frac{\overline{V_a}}{Z} + \frac{\overline{V_b}}{Z} + \frac{\overline{V_c}}{Z + \delta Z}$$

$$= \frac{\left(\overline{V_a} + \overline{V_b}\right)\left(Z + \delta Z\right) + \overline{V_c} Z}{Z\left(Z + \delta Z\right)}$$

$$= \frac{\overline{V_a} + \overline{V_b} + \overline{V_c}}{Z} - \frac{V_c \delta Z}{Z\left(Z + \delta Z\right)}$$

$$= I_c \frac{\delta Z}{Z}$$

Since ($I_c = \dfrac{V_c}{Z + \delta Z}$ and $\overline{V_a} + \overline{V_b} + \overline{V_c} = 0$)

e) H–Configuration Banks

Capacitor units with internal fuses or fuse-less can be arranged to make up the 'H' bank. An 'H' configuration capacitor bank will have in each phase with a current transformer connected between the two legs to compare the current down in each leg. As long as all capacitors are normal, no current will flow through the current transformer. If a capacitor element or elements of a capacitor units fails (i.e. open circuited) some current will flow through the current transformer. This 'H' arrangement is used on large banks with many capacitor units in parallel.

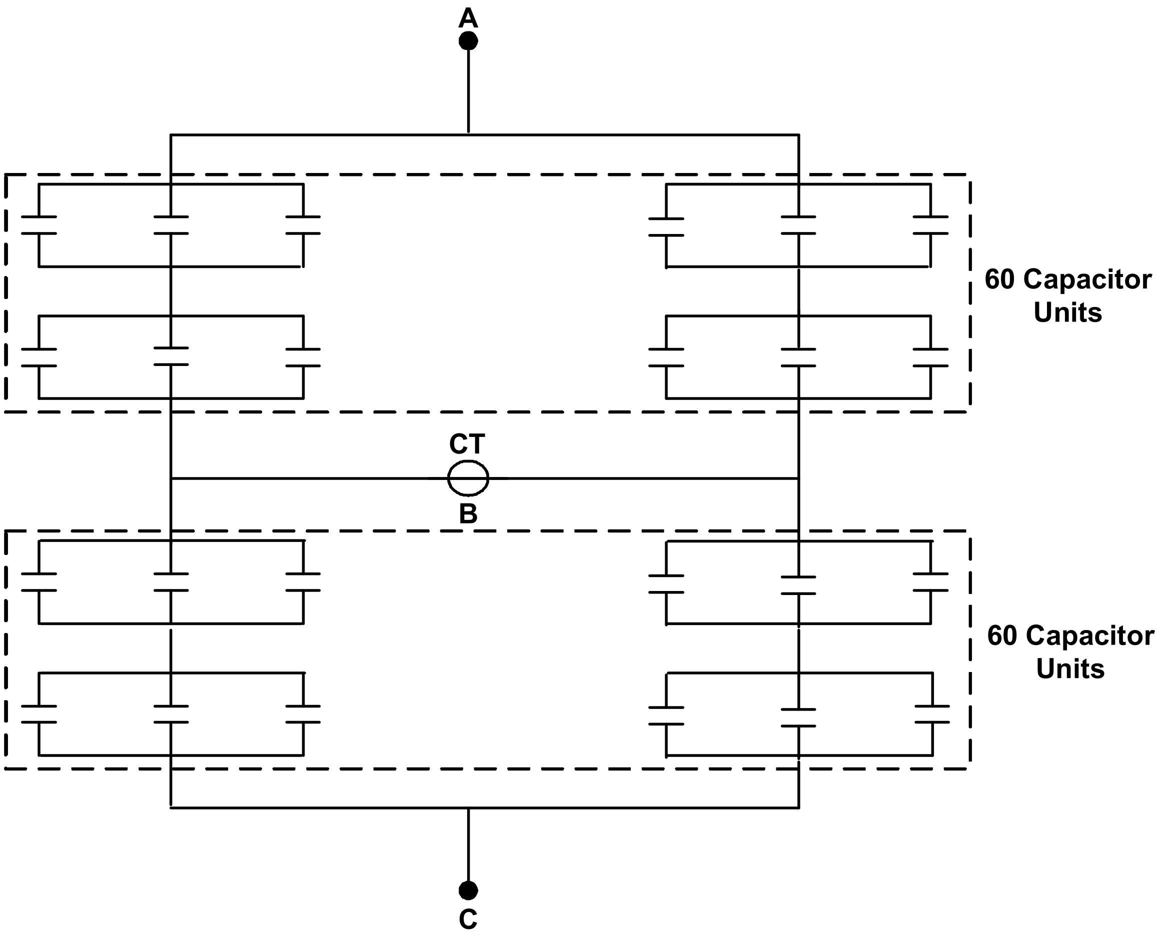


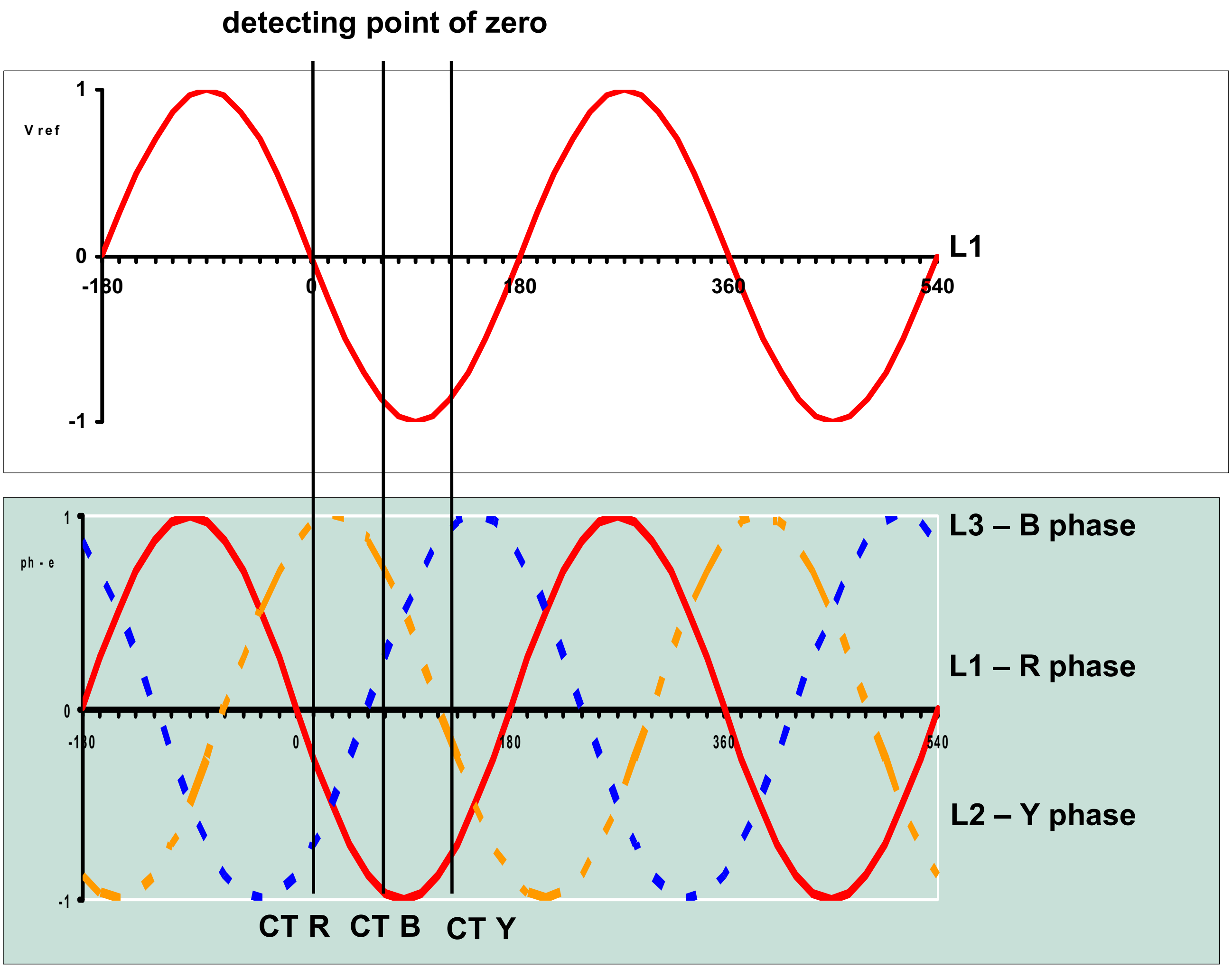
Fig 3 . Single Phase 'H' Type Capacitor Bank

Point On Wave Switching (POW)

These capacitor banks, while reducing the flow of reactive power and improving voltage regulation in the system, constitute a source of transients every time they are switched. Controlled closing of shunt capacitor banks (P O W) is used to minimise the power system and its components by operating each CB pole at the most favourable time instant. A number of P O W control relays are available for this application.

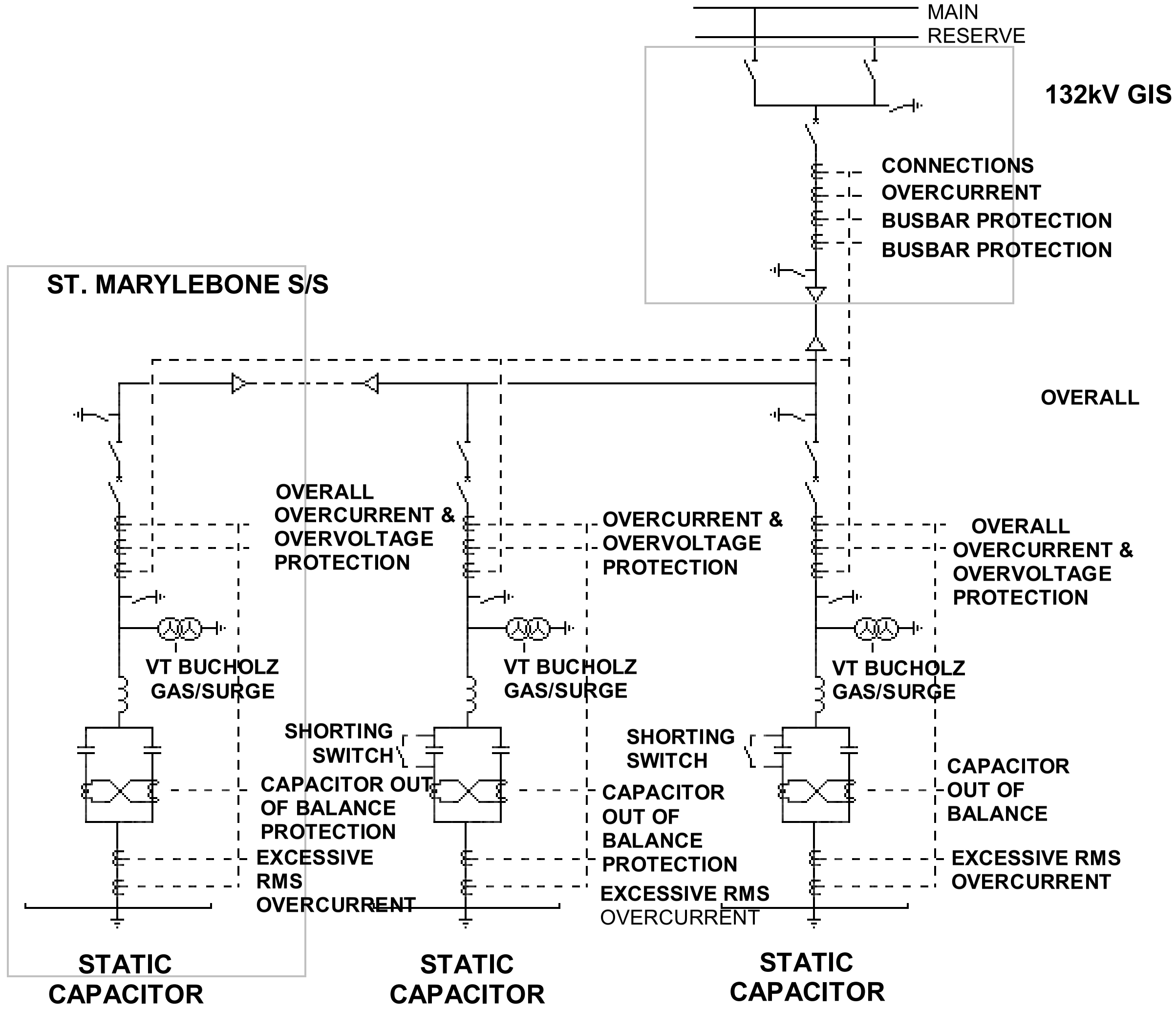
Wye-connected grounded-neutral, shunt capacitor banks are energised when the voltage is equal to zero on each phase. All phases are closed within 120 electrical degrees.

Breaker Pole	A	B	C
Phase	L1 or R phase	L2 or Y phase	L3 or B phase
Operating Instant	0 °	120 °	60°



Back to back switching refers to the conditions where a shunt capacitor bank is energised in the presence of one or more capacitor banks already connected to the system in proximity to the first.

MSC at St. Johns Wood 132kV



MSC Single Line Diagram

6.8.6 The Capacitor Unit and Bank Configuration

The capacitor unit is the building block of a shunt capacitor bank. The capacitor unit is made up of individual capacitor elements, arranged in parallel/series connected groups within a steel enclosure. Each capacitor unit is provided with a discharge resistor that reduces the unit residual voltage to 50V in 5 minutes. Capacitor units are available in variable voltages and sizes.

Capacitors are intended to be operated at or below their rated voltage and frequency as they are very sensitive to these values; the reactive power generated by a capacitor is proportional to both voltage and frequency (kVAr = $2 \pi f v^2$).

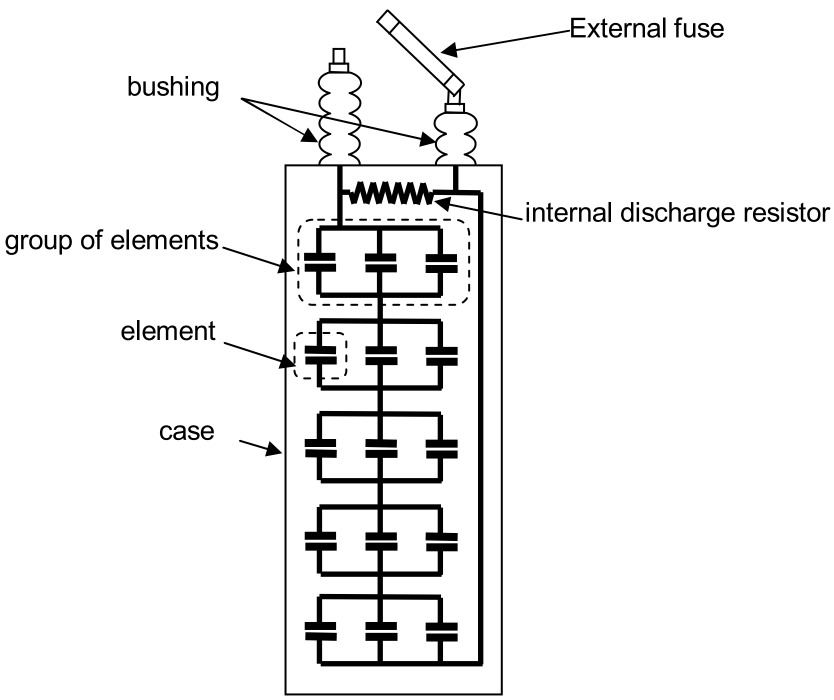
a) Bank Configuration

The use of fuses for protecting the capacitor units and its location (inside the capacitor unit on each element or outside the unit) is an important subject in the design of capacitor banks. They also affect the failure mode of the capacitor unit and influence the design of the bank protection.

b) Externally Fused Capacitor Unit/Bank

An individual fuse, externally mounted between the capacitor unit and the capacitor bank fuse bus, typically protects each capacitor unit.

A failure of a capacitor element welds the foils together and short circuits the other capacitor elements connected in parallel in the same group. The remaining capacitor elements in the unit remain in service with a higher voltage across them than before the failure and an increased capacitor unit current. If a second element fails the process repeats itself resulting in an even higher voltage for the remaining elements. Successive failures within the same unit will make the fuse to operate, disconnecting the capacitor unit and indicating the failed one.



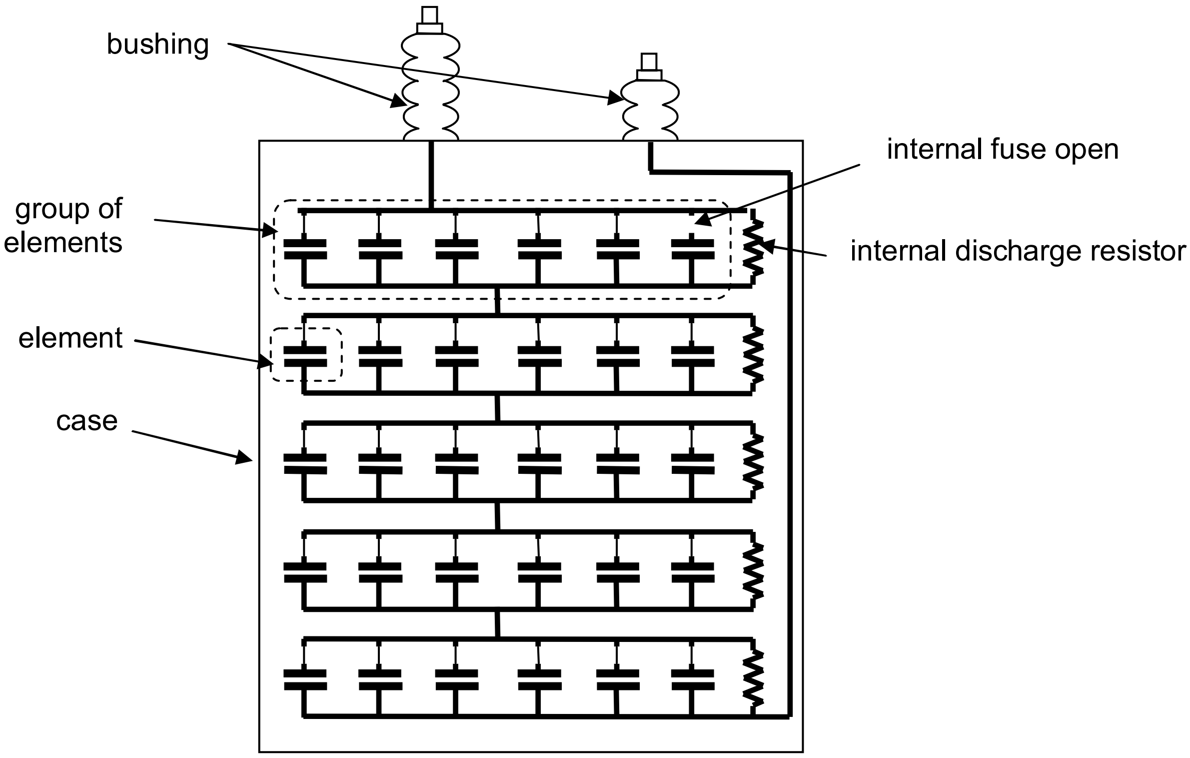
Externally Fused

Externally fused Shunt Capacitor Banks are configured using one or more series groups of parallel-connected capacitor units per phase. The available unbalance signal level decreases as the number of series groups of capacitors is increased or as the number of capacitor units in parallel per series group is increased. However, the kiloVAr rating of the individual capacitor unit may need to be smaller because a minimum of parallel units are required to allow the bank to remain in service with one fuse or unit out.

c) Internally Fused Capacitor Unit/Bank

Each capacitor element is fused inside the capacitor unit. The fuse is a simple piece of wire enough to limit the current and encapsulated in a wrapper able to withstand the heat produced by the arc. Upon a capacitor element failure, the fuse removes the affected element only. The other elements, connected in parallel in the same group, remain in service but with a slightly higher voltage across them.

In general, banks employing internally fuses capacitor units are configured with few capacitor units in parallel and more series groups of units than are used in banks employing externally fused capacitor units. The capacitor units are normally large because a complete unit is not expected to fail.



Internally Fused Capacitor

d) Fuse-less Shunt Capacitor Banks

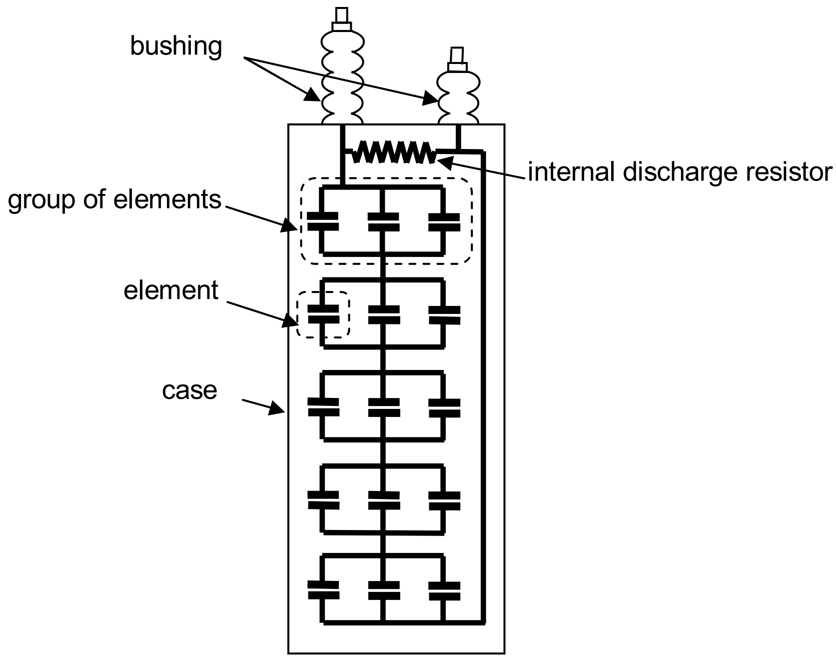
The capacitor units for fuse-less capacitor banks are identical to those for externally fused described above. To form a bank, capacitor units are connected in series strings between phase and neutral.

The protection is based on the capacitor elements (within the unit) failing in a shorted mode, short-circuiting the group. When the capacitor element fails it welds and the capacitor unit remains in service. The voltage across the failed capacitor element is then shared among all the remaining capacitor element groups in the series. For example, if there are 7 capacitor units in series and each unit has 10 element groups in series then there are a total of 70 element groups in series. If one capacitor element fails, the element is shortened and the voltage on the remaining elements is 70/69 or about a 1.5% increase in the voltage. The capacitor bank continues in service; however successive failures of elements will lead to the removal of the bank.

Manufacturer's experience is that for modern capacitor units all element failures result in strong gas-free welded short circuits on the elements.

The key advantages of fuse less capacitors compared to internally fused capacitors may be considered to be :

- No internal fuse losses resulting in heating and loss of life
- No internal fuses to fail
- Improved protection sensitivity since the loss of an element is more detectable
- Simpler internal construction of the units since there is no need for fuses to be wired into the circuit
- Simpler external construction of the bank since there is no need for fuses to be wired into the circuit
- Less likelihood of cascade failures of elements due to overvoltage
- Lower losses due to the absence of fuses

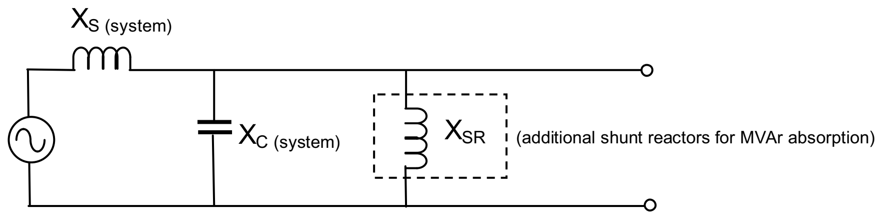


Fuse-less Capacitor

Internally Fused Capacitor Units Damaged

6.8.7 **Shunt Reactors**

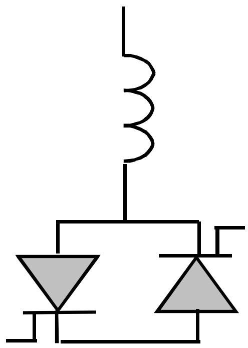
Shunt reactors are used for controlling system voltages .Shunt reactors are either in permanent service or switched daily. Shunt reactors are most electrically stressed equipment in the transmission network system. Some shunt reactors were installed to support system restoration strategies, in particular the need to re-energise the network under a black start condition, following a system shut down. The reactor rating should be chosen to limit the magnitude of the steady state voltage step change during routine switching operation.



There are two kinds of shunt reactors, they are air insulated air core dry type reactors and oil insulated type reactors. Oil insulated reactors can be used at all voltage levels, but the use of air core dry type reactors are limited to MV range.

Air Cored Air Insulated Reactors

Due to magnetic field effect air core reactors need a lot of free fenced space round them. Special attention has to be considered to the location of metallic parts and loops in the vicinity of the air core reactors. The figure below shows using thyristor for switching MV shunt reactor



Thyristor Switched Reactor

Oil Filled Shunt Reactors

The main **use** of shunt reactors is for controlling busbar voltage levels associated with cable under Light load condition. Shunt reactors are used directly on the 400kV (200MVAr), 275kV (100MVAr) and 132kV (60MVAr) busbar systems. Normally 33kV and 13Kv shunt reactors ((60MVAr) are connected to the system via tertiary (delta) winding of the system transformer.

6.8.8 SERIES RACTORS

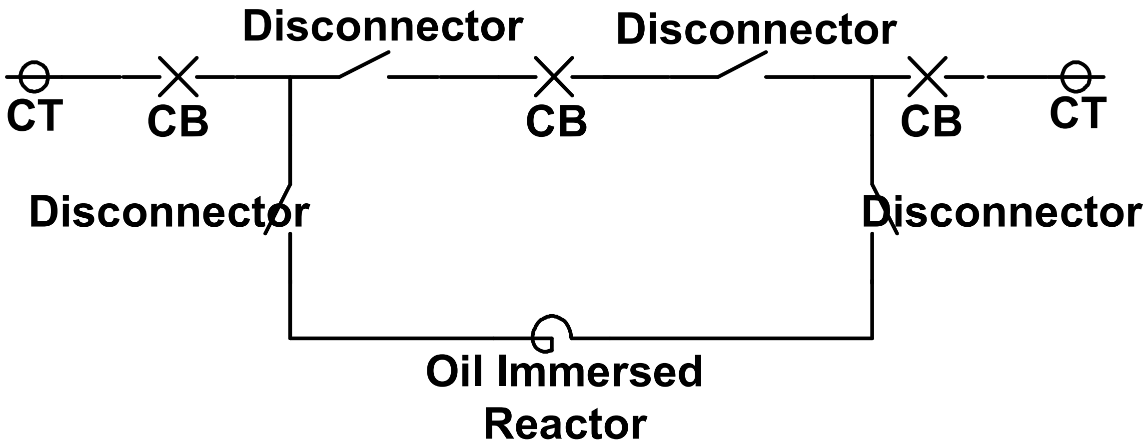
For example in the design of a new system, available switchgear ratings at the higher or lower voltages may be inadequate and it may be uneconomic to install higher voltage equipment to meet the inherent fault levels of the networks. Fault level limitation must therefore be employed to reduce fault currents to within an acceptable level. Alternatively, due to the expansion of an existing system the new fault levels may exceed the capacity of installed circuit breakers. Hence a decision must be made whether to employ fault level limitation or to up-rate the switchgear.

An obvious extension to the choice of major electrical plant impedances to contain fault levels is the incorporation of additional impedances in the form of series current-limiting reactors into a network. However since reactors are by way of extension, they are associated with similar disadvantages and may tend to aggravate problems already existing in a network. Instances actually exist where reactors have been purchased and installed in the system and it has not been possible to retain them in circuit because of the aggravation of a voltage regulation problem or a machine stability problem. Other disadvantages often associated with current-limiting reactors are problems with reactive power demand, power ordering difficulties and loss of system flexibility.

An important consideration when using series reactors is that increasing system reactance this will increase X/R ratios of the system increase the DC time constants. This can have full of implications for circuit breaker duty even with reduced short circuit current levels. The MVA rating of the series reactors is to be co-ordinated with the thermal rating of the adjacent network equipment including switchgear.

Series current-limiting reactors are most often employed where the normal load transfer is low and the required degree of fault level reduction is not great so that a reactor with a small percent impedance on rating is sufficient. The use of small reactors as busbar couplers, for example, has in many cases provided a satisfactory solution to a fault level problem.

AREVA have designed, installed and commissioned series reactors for National Grid 400kV power systems at Kingsnorth, Grain substation and EDFE 132kV power systems at Bankside substation.



When the series reactor wants to be energised, first the line CB should be closed, second the bypass CB to be closed the third outgoing line CB to be closed and then the bypass CB to be Opened to energise the series reactor. However POW switching relays can be used on CBs for particularly for opening.

7. AUXILIARY SUPPLY SYSTEM

7.1 BATTERIES/CHARGERS AND DC DISTRIBUTION

The battery, charger and DC distribution system in any substation is vital as it provides auxiliary power to the protection relays, control equipment and primary plant.

Many modern protection relays rely on an auxiliary DC supply to drive the electronic measuring circuitry and circuit breakers almost invariably have shunt trip coils and closing coils which activate the circuit breaker mechanism.

Most high voltage equipment is designed to operate down to at least 85% of rated control voltage for closing and circuit breakers are required to trip down to 70% volts. At the other end of the scale, equipment will normally tolerate 110% of rated control volts continuously, i.e. for a 125V DC system the voltage ranges are 106.25V to 137.5V (closing) and 87.5V to 137.5V (tripping). These voltages are taken at the equipment terminals not at the battery terminals and therefore the DC distribution system must be carefully designed to avoid excessive volt drops when supplying DC auxiliary power to equipment.

Other common voltages used for control batteries are 34V, 54V and 250V, and quite often a mixture of 125V or 250V and 54V will occur in one substation with the 54V battery system being used for remote control and telecommunications.

The DC system is also used for other purposes where continuity of supply is critical to the operation of the substation e.g. circuit breaker mechanism charging motor drives and motorised disconnector drives.

A typical system would consist of the following equipment :

2 - 30A, 125V output, 415V, 3 phase, 50 Hz input, constant voltage chargers with current limit feature incorporating high voltage, low voltage and charger fail alarms, selection of ‘Float’ or Boost charge facility and suitable instrumentation.

2 - 250Ah, 55 cell lead acid battery on acid resistance (usually wooden) stands.

1 - Distribution board with incoming supplies selectable to either battery by switches or links with outgoing fused ways for various loads including Protection and Control (one per protection panel) Site Ring main, Busbar Protection Panel and Emergency Lighting.

7.2 LVAC DISTRIBUTION SYSTEM

The LVAC system (or more correctly MVAC system) is the main source of auxiliary supplies for the substation, providing power for heating, lighting, battery charging, cooling fan motors, tap changers, AC motor drives for disconnectors, etc.

On most substations the LVAC supplies are derived from two sources to give security. On major substations these two sources may be supplemented by a small diesel or gas turbine driven generator which starts automatically to maintain essential services on loss of the two main supplies.

The usual sources of LVAC are :

a) Local Electricity Area Board 415V or 11kV network

b) Auxiliary supplies transformers fed from 132/11kV or 132/33kV transformer secondaries

c) Auxiliary windings of earthing transformers

d) Tertiary windings of supergrid transformers via auxiliary transformers and voltage regulators

Quite complex automatic changeover schemes are sometimes required, particularly where auxiliary generators are used, which offer selection of Main Supply and Standby Supply and section the distribution board into 'Essential' and 'Non Essential' supplies before starting and switching in the generator on loss of both incoming supplies. On restoration of the main supply the diesel generator will normally be arranged to shut down automatically to conserve fuel.

Auxiliary/Earthing Transformers help to limit the fault current to the LVAC board.

<u>Method 1</u>

Let us consider an auxiliary/earthing transformer with an impedance of 4.5%, on its rating of 250kVA.

If the voltage of the auxiliary/earthing transformer is 33/0.4kV, then the fault limited by the auxiliary earthing transformer is as follows :

Fault limited $= \dfrac{250 \text{ x } 100}{4.5}$ kVA

$= 5556$ kVA

$\therefore$ The fault current on the 400V side (LV side) $= \dfrac{5556 \text{ x } 10^3}{\sqrt{3} \text{ x } 400} = 8.0$ kA

<u>Method 2</u>

Fault current $= \dfrac{100}{4.5}$ x LV current

LV current of the transformer $= \dfrac{250 \text{ x } 10^3}{\sqrt{3} \text{ x } 400} = 360.8$ A

$\therefore$ Fault current $= \dfrac{100 \text{ x } 360.8}{4.5}$

$=$ <u>8.0 kA</u>

This method can be used to adjust any transformer impedance to calculate the required fault current.

Example :

Let us consider a transformer 132/33kV with 15% impedance on its own rating of 120 MVA.

Fault current on the 132kV HV side = 31.5 kA

What is the fault limited on the 33kV side?

Fault Limited $= \dfrac{120}{15} \times 100$ MVA

$= 800$ MVA

$\therefore$ The fault current on the 33kV side (LV side) $= \dfrac{800 \times 10^6}{\sqrt{3} \times 33 \times 10^3}$

$= 13.99$ kA

$\simeq 14$ kA

If we want the fault to be limited to 40kA on the LV side, then the impedance of the transformer has to be reduced.

Rating of the transformer is 120 MVA, current on the LV side i.e. 33kV = 2100A

$\therefore$ Impedance of the transformer $= \dfrac{2100 \times 100}{40 \times 10^3}$

$= 5.25\%$ on its own 120MVA rating

7.3 A.C. SUPPLIES

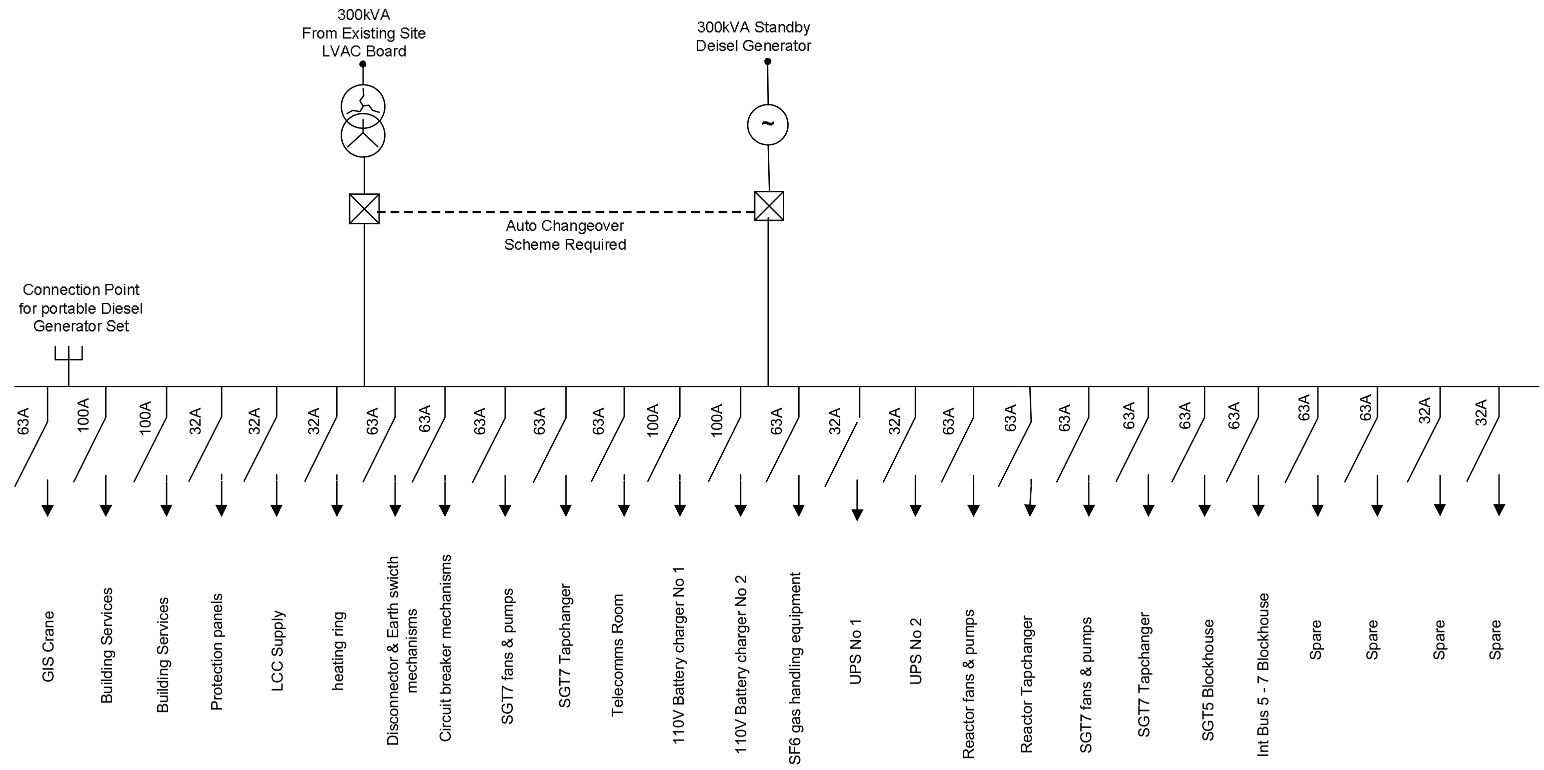
A.C. supplies provide energy for drives, compressors, charging batteries, lighting and heating. Usually two independent sources of supply are used with 100% redundancy and automatic emergency switching. It should be noted that external supplies tend to be less reliable than sources fed through a station transformer from the main substation circuit. If supplies are taken from the MV network it should be ascertained that there is a degree of independence from the HV substation itself.

7.4 DIESEL GENERATION

Diesel Generators are used to provide a back-up LV supply in important substations for loads up to about 800kVA and are activated automatically in the event of failure of the main LVAC supply (or supplies).

A diesel generator would be designed to provide energy for the essential components of the substation for a specified period of time (usually the estimated time it will take to restore the main supply). The components considered to be essential may vary from substation to substation and may include circuit breaker drives (or charging of their energy source), charging of batteries, operation of disconnectors, cooling of transformers and emergency lighting.

LVAC BOARD


300kVA
From Existing Site
LVAC Board
300kVA Standby
Deisel Generator
Auto Changeover
Scheme Required
Connection Point
for portable Diesel
Generator Set
63A
100A
100A
32A
32A
32A
63A
63A
63A
63A
63A
100A
100A
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GIS Crane
Building Services
Building Services
Protection panels
LCC Supply
heating ring
Disconnector & Earth swicth mechanisms
Circuit breaker mechanisms
SGT7 fans & pumps
SGT7 Tapchanger
Telecomms Room
110V Battery charger No 1
110V Battery charger No 2
SF6 gas handling equipment
UPS No 1
UPS No 2
Reactor fans & pumps
Reactor Tapchanger
SGT7 fans & pumps
SGT7 Tapchanger
SGT5 Blockhouse
Int Bus 5 - 7 Blockhouse
Spare
Spare
Spare
Spare

8. FLEXIBLE A.C. SYSTEM

8.1 **FACTS** is an acronym for Flexible AC Transmission System. The philosophy of FACTS is to use reactive power compensation devices to control power flows in a transmission network, thereby allowing transmission line plant to be loaded to its full capability.

All FACTS devices can be fitted to existing AC transmission routes thus providing an economic solution. FACTS technology, however, allows greater throughput over existing routes, thus meeting consumer demand without the construction of new transmission lines.

AREVA Transmission & Distribution has been providing FACTS devices such as Mechanically Switched Capacitors (MSCs), Mechanically Switched Capacitor Damping Networks (MSCDNs), Static VAr Compensators (SVCs) and Short Circuit Limiting Couplings (SLCs) all over the world to be used in transmission networks for many years. MSCs and MSCDNs have generally been connected to the grid system at 132kV, 275kV and 400kV and SVCs have been connected either at 275kV or 400kV via dedicated stepdown transformer.

In England and Wales, the National Grid Company plc (NGC) has identified the need for reactive power plant that can be relocated at short notice, and AREVA T&D Substation Project HV system has been commissioned to design and install relocatable Static VAr Compensators, Mechanically Switched Capacitors and Mechanically Switched Capacitor Damping Networks as an ongoing programme.

Disturbance to the System

The voltage drop in a power supply system, caused by loads which are large compared with the short-circuit level of the system, is mainly due to the reactive component of current, I_q, flowing through the system reactance X_O .i.e.

$$\Delta V = V_S - V_B = I_q X_O$$

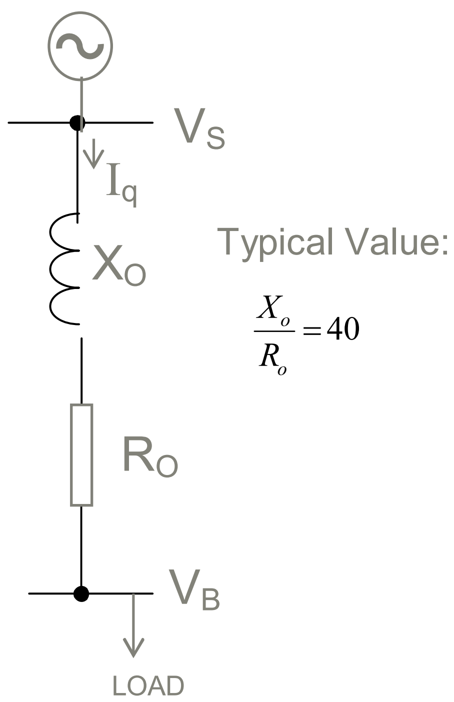


Figure 1: Power System Diagram

Transmission Line

Imaginary Power/reactive Power/Useless Power

The 'concept of real' power, which is unidirectional and 'reactive' power, which alternates but does not produce power in a load, has lead to the concept of 'real' and imaginary power. Because reactive power leads or lags 'real power by 90°, it soon became known as 'imaginary' power. Because reactive has no effect on the power in the load, it may be thought that it has no significance in power networks.

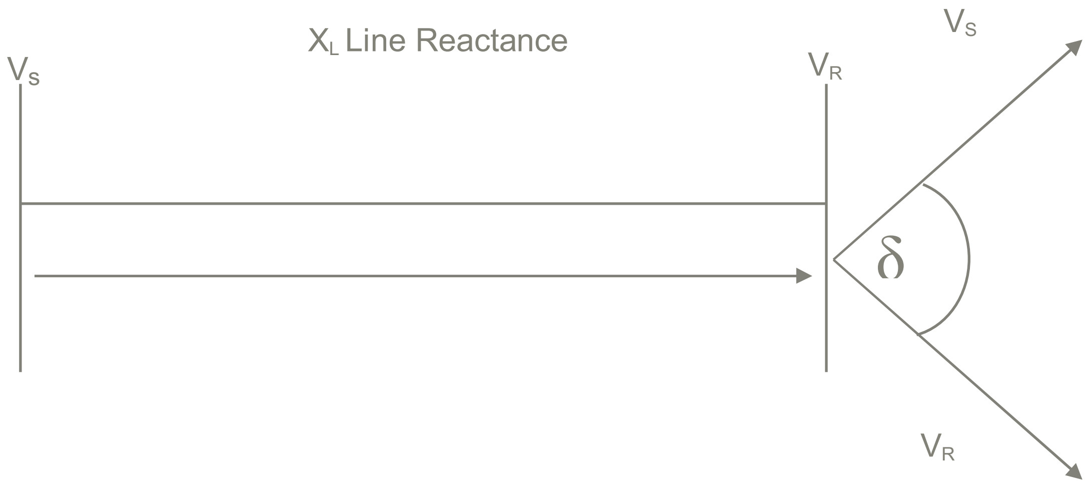


Figure 2: Transmission Line & Voltage Phase Diagram

In a very large transmission system such as the 400kV, 500kV and 750kV system used in America, China and in continental Europe for transmission over very long distances, charging currents due to shunt capacitance can result in a pronounced Ferranti effect, even under local conditions. Such effects can be offset by installing either reactors in shunt at intervals along the line or alternatively, large capacitors in series.

Real power flow along a transmission line is a function of the sending end voltage (V_S) and receiving end voltage (V_R) transmission line reactance X_L and phase angle δ.

$$P = \frac{V_S \, V_R \, \mathrm{Sin}\delta}{X_L}$$

Assuming that busbar magnitudes are maintained at fixed levels, in order to increase power flow, the angle δ between V_S and V_R must increase, However, increasing angle δ increases the risk of transient and voltage stability problems if a fault were to occur along the line.

By increasing the sending end voltage V_S to 220kV, 400kV, 500kV or even to 800kV, more real power can be pushed through a transmission line. However the insulations of the electrical equipment must be increased, which are more expensive.

By increasing phase angle δ up to 90^{o} (Sin 90 = 1) by means of phase shifting transformer i.e. either Quad Booster or phase shifting generator, more real power P can be transmitted along the transmission line. Real power P through the transmission line can be increased by decreasing the transmission line reactance X_L by adding a series capacitor in series with the transmission line as series compensation.

Real power flow P through the transmission lines

$$P = \frac{V_S\, V_R\, \mathrm{Sin}\delta}{X_L}$$

Reactive Power :
(Imaginary Power)

$$Q_L = \frac{V^2{}_{SR}}{X_L} \quad \text{(Absorption)}$$

This equation is a load dependent

V_{SR} equal to the difference line end voltages, thus the line will absorb Reactive Power.

The line shunt capacitance will generate reactive power (imaginary or useless power).

$$X_{SC} = \frac{1}{j\omega c} = \frac{-j}{\omega c}$$

$$Q_C = \frac{V^2}{X_{SC}} = -V^2\ \omega c \quad \text{(Generation)}$$

Thus we see that lightly loaded lines generate reactive power

GENERATION > ABSORPTION

$Q_C > Q_L$

$\therefore\ V_R > V_S$

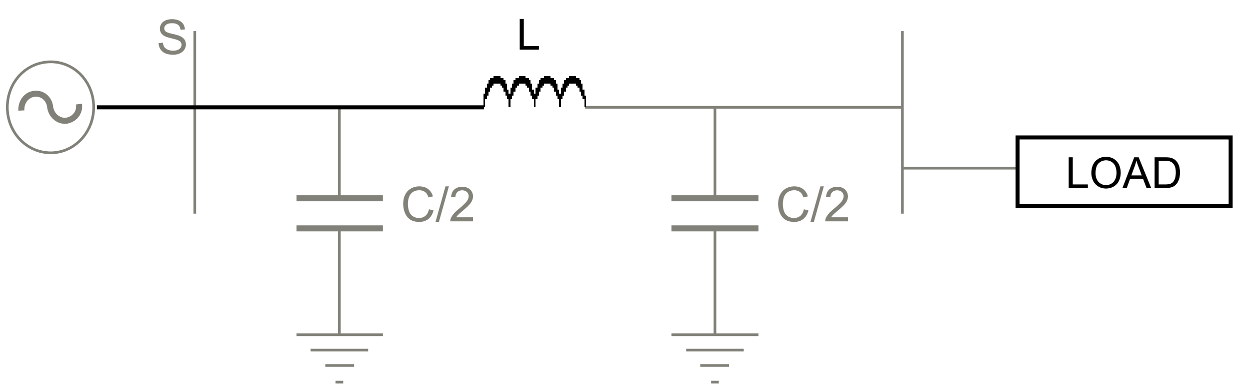


Figure 3: Transmission Line with Line Parameters

Greater line loading leads to greater reactive power absorption. The reactive power must be supplied from the network or some form of reactive power compensation of generation.

For long transmission line we also have to consider the effect of shunt capacitance in the line. If there is no load on the line, then the busbar voltages are in phase and no reactive power is absorbed by the load.

Heavy loading conditions, the reactive power absorbed by the line reactance will be greater than the reactive power generated by the shunt capacitance in the line.

$$Q_L > Q_C$$

$$\therefore \; V_S > V_R$$

Shunt Compensation

Power is being exported along the transmission line from sending busbar ($\mathbf{V_S}$) towards the receiving end busbar ($\mathbf{V_R}$). Under light load condition the receiving end voltage will rise higher than the sending end voltage due to the effect of the line capacitance (Ferranti effect).

The voltage profile of the uncompensated transmission line is a maximum at the line ends, V, and minimum at the mid-point, V_M . If the line is naturally loaded (this means shunt capacitance should be considered), the voltage profile would be flat i.e. the voltage magnitude would be equal at all points along the line. If the shunt capacitance available in the line is good enough to provide voltage magnitude equal at all points along the line, then no compensation is required.

However the shunt capacitance of the transmission line is not big enough to support the flat voltage profile during heavy load condition. Thus the application of line compensations can be seen as a means of approximating a flat voltage profile. This, however, implies that the compensation is distributed along the transmission line, which is clearly impractical. However the next best approach is to provide compensation at the mid-point. It can be seen that the line is divided into two sections.

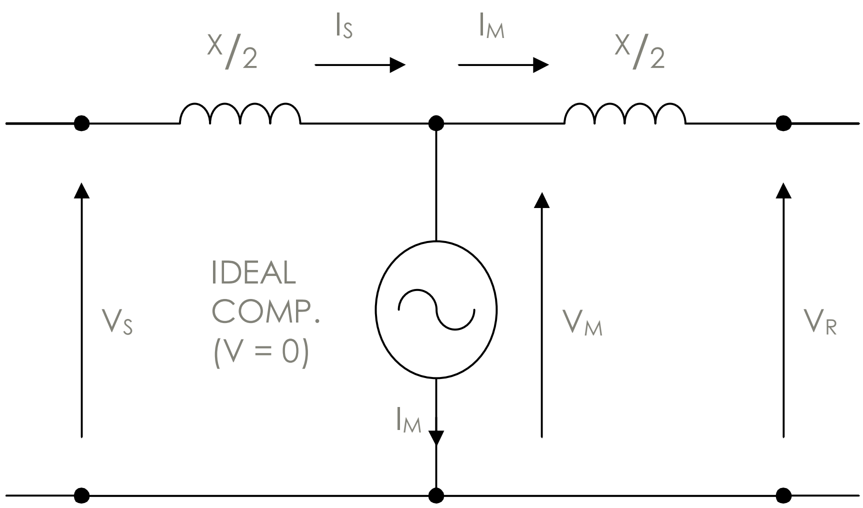


Figure 4: Transmission Line with Compensator at Mid-Point of the Line

The above figure shows the arrangement of an ideal mid-point shunt compensator which maintains a voltage V_M .

Uncompensated Line

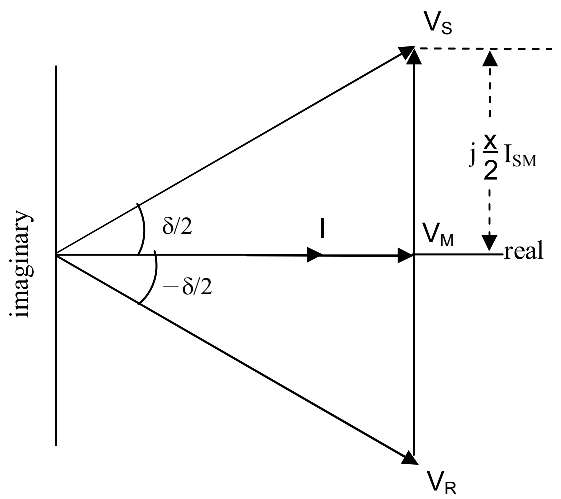
The real power exported along the line is given as :

$$P = \frac{V^2}{X} \operatorname{Sin} \delta$$

Compensated Line

The ideal mid-point shunt compensator i.e. MSC, MSCDN, SVC which maintains voltage Vm equal to the busbar voltage such that

$$|V_S| = |V_R| = |V_M| = |V|$$



Power transferred from S to the mid point is equal to the power transferred from the mid-point to R, and is given by:

$$P = \frac{2V^2}{X} \operatorname{Sin} \frac{\delta}{2}$$

Note: It can be seen that the compensator does not consume real power since the compensator voltage V_M and its current I_M are in quadrature. The reactive power generated by the compensator, Qp = $I_M V_M = I_M V$.

<u>Reactive Power Q Absorbed by the Line</u>

$$\operatorname{Sin} \frac{\delta}{2} = \frac{IX}{2V}$$

$$I = \frac{2V}{X} \sin \frac{\delta}{2}$$

The line absorbs reactive power Q as a function of the line current I

$$\therefore \; Q = I^2 X = \frac{4V^2}{X} \sin \frac{\delta}{2} = \frac{2V^2}{X} (1 - \cos \delta)$$

With long transmission lines a single mid-point compensator may not be adequate to support the line voltage and several shunt compensators (i.e. MSC, MSCDNs or SVCs) connected at intervals down the line may be needed. The line will then be a closer approximation to the fully distributed solution.

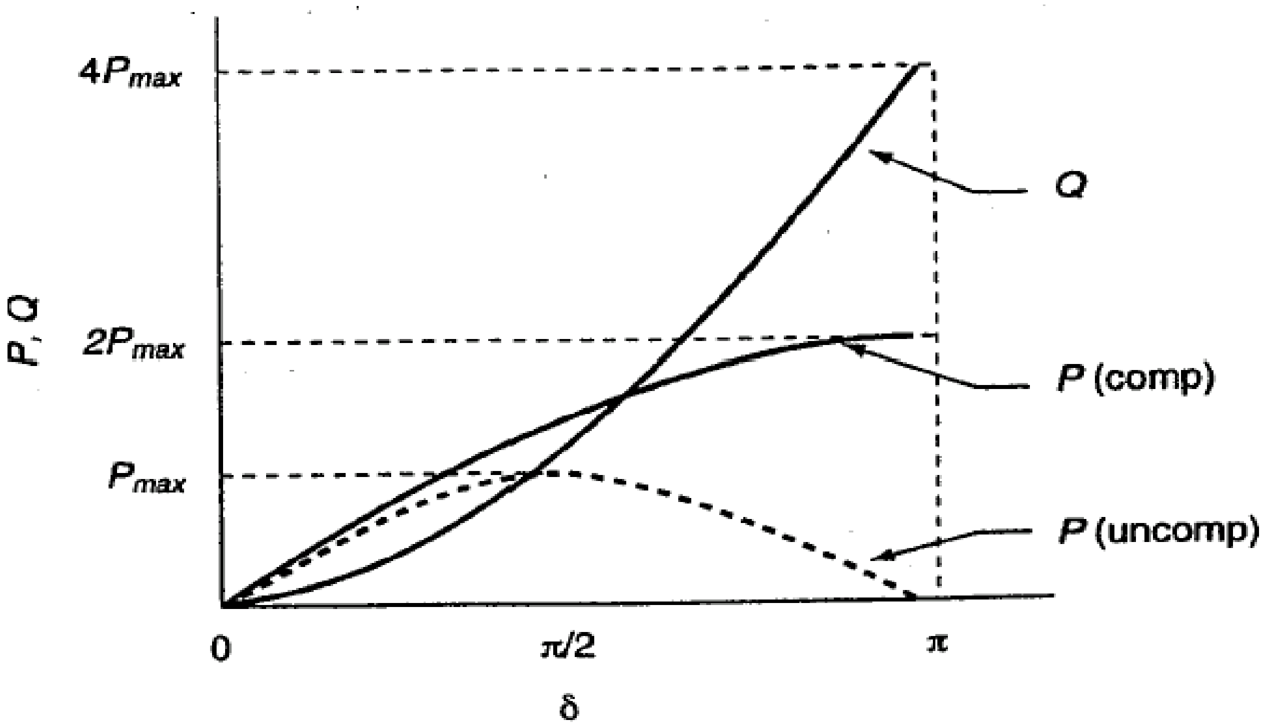


Figure 5: Real power flow P along the line

8.2 SYSTEM RESONANCE CONDITION

Power system study should be carried out to make sure that the Plain Capacitor Bank size selected for compensation/power factor correction does not have any resonance condition with the power system network i.e. system fault level where plain capacitor banks shall be connected. If n is the resonance frequency, Q_S is the system fault level and Q_{SC} is the plain capacitor bank rating then

$$n = \sqrt{(Q_S / Q_{SC})}$$

If Q_S = system fault = 600 MVA at 132kV and Q_{SC} = capacitor bank size = 65 MVAr selected for compensation.

Then the resonance frequency n = 3 harmonic.

So the capacitor bank 65 MVAr cannot be used as a plain Capacitor Bank to connect to the 132kV system, therefore it should be detuned to a 3rd harmonic filter. However the size of the Capacitor Bank should increase in size to include a reactor in series to form 3rd harmonic filter.

$$Q_{3SC} = (n^2 / n^2 - 1)\, Q_{SC}$$

where Q_{3SC} is the 3rd harmonic filter capacitor bank size.

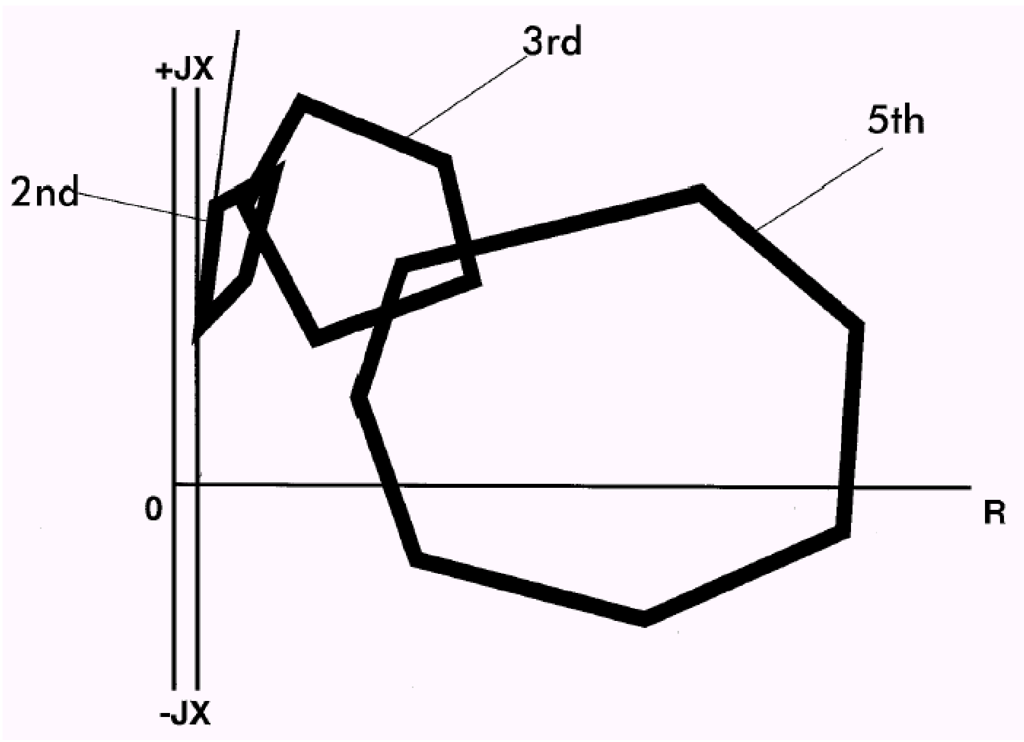
Q_{3SC} = (9 / 8) x 65 = 1.125 x 65 = 73.1 MVAr. Three single phase reactors should be designed and added to the plain capacitor to tune to a 3rd harmonic filter.

If the system fault level is 1625 MVA, then the resonance will be at 5th harmonic.

Q_{5SC} = (25 / 24) x 65 = 1.04 x 65 = 67.7 MVAr. Three single phase reactors should be designed and added to the plain capacitor to tune to a 5th harmonic filter.

However at system frequency 50 Hz, the generation of each filter either 3rd harmonic or 5th harmonic will be 65 MVAr.

Harmonic Impedance Loci



Harmonic Order	Max. Permissible Magnification Factor
2	**3.5**
3	**1.2**
4 to 31	**1.0**

8.3 **MECHANICALLY SWITCHED CAPACITOR DAMPING NETWORK (MSCDN)**

1. Design of the Mechanically Switched Capacitor Damping Network (MSCDN)

AREVA have designed, installed and commissioned MSCDN's for National Grid 400kV, 275kV and 132kV transmission power systems. The MSCDN's are installed at the mid-point (in the nearest substation) of a long transmission line.

The MSCDN comprises main components such as two 3 phase capacitor banks C1 and C2, three single phase air cored air cooled reactor and six single phase air cooled resistors (two resistors are connected in parallel per phase).

Power system study had been carried out to size the required capacitor bank ratings at system (fundamental) frequency 50 Hz, to support the power systems. For a 400kV system, the 3 phase rating of the capacitor bank C1 of the MSCDN is 225 MVAr at fundamental frequency 50 Hz and nominal voltage 400kV. For a 275kV system, the 3 phase rating of the capacitor bank C1 of the MSCDN is 150 MVAr at fundamental frequency 50 Hz and nominal voltage 275kV. For a 132kV system, the 3 phase rating of the capacitor bank C1 of the MSCDN is either 52.2 MVAr or 45 MVAr at fundamental frequency and nominal voltage 132kV in accordance with the 132kV system requirements.

The nominal ratings of the MSCDN's are the ratings of the Main Capacitor Bank C1, at nominal voltage and at fundamental frequency. MSCDN is a 3rd harmonic filter to filter the dominant 3rd harmonic frequency in the NG system.

However when it is tuned to 3rd harmonic filter, the capacitor bank C1 rating at fundamental frequency and nominal voltage should be increased to $\left(\frac{n^2}{n^2-1}\right)$ x C1 rating (minimum), where 'n' is the harmonic number. The total capacitor bank ratings for 400kV MSCDN is 253 MVAr, for 275kV MSCDN is 169 MVAr and for 132kV MSCDN is either 60 MVAr or 50.6 MVAr minimum.

Therefore the rating of the 3 phase Auxiliary capacitor bank C2 of the 400kV MSCDN is (C2 = 253 – C1) 28 MVAr minimum, C2 of the 275kV MSCDN is 19 MVAr minimum and C2 of the 132kV MSCDN is 7.5 MVAr in the case of the 52.5 MVAr MSCDN and is 5.6 MVAr in the case of 45 MVAr MSCDN, at nominal voltage and fundamental frequency.

Figures 1(a), 1(b), 1(c) and 1(d) in the appendix show MSC's and MSCDN's arrangement for different system voltages i.e. 400kV, 275kV and 132Kv.

2. Performance of 400kV MSCDN

The MSCDN has a nominal rating of 225 MVAr at 400kV. In order to meet the performance requirements as stated in section 4.2 of NGTS 2.21, the MSCDN has been configured as a C-type filter tuned at 3rd harmonic. This type of filter was chosen to virtually eliminate fundamental frequency loss in the resistor, whilst providing damping at the harmonic frequencies. The performance of the filter, defined as magnification of pre-existing voltage distortion, is shown in Schedule 10 (2.17) for both one and two MSCDN's. Harmonic studies were performed using AREVA's (then GEC Alsthom) harmonics penetration program (HARP) which modelled a voltage source at harmonics 2 to 31 behind the 400kV impedances defined in NGC drawings 96/29004 and 96/29005. The HARP program automatically searches each impedance area to find the impedance which maximises the voltage at the 400kV busbar.

To allow for possible detuning of the MSCDN, the following factors were taken into account :

a) system frequency variation of 49.5 Hz to 50.5 Hz

b) ambient temperature variation from −25°C to +40°

c) component tolerances

d) capacitor temperature dependence of −0.045% / °C

In order to ensure that the MSCDN will generate the required reactive power output, the tolerance on the capacitor banks is specified as −0% to +4%. To minimise detuning the reactor tolerance is specified as −4% to +0%.

3. Rating

Rating studies were performed using the HARP program which modelled pre-existing voltage distortion as given in Section 3.4 of NGTS 2.21 behind the 400kV impedances defined in NGC drawings 96/29006 and 96/29007. These areas were searched to find the impedance which maximised the component ratings. For continuous ratings the detuning reactors are considered. All rating studies were based on a maximum continuous busbar voltage of 420kV. The studies considered both one and two MSCDN's in service, and ratings were based on the worst case condition.

Details of individual component ratings are as follows :

a) **Capacitors**

NGTS 2.21 section 3.14 indicates that the MSCDN will be in service each day for a period of period of 12 hours. Capacitor banks designed to IEC871-1 have a prolonged overvoltage capability of 110% of rated voltage (Un) for 12 hours in 24. Section 3.5 of NGTS 2.21 requires that Un shall not be less than the maximum continuous fundamental frequency component.

For the main capacitor bank, the maximum continuous fundamental frequency voltage is 420 / √ 3kV = 242.5kV. This value can be chosen as Un unless the worst case maximum voltage, as given in Schedule 10 (2.18), exceeds Un by more than 10%, i.e. is greater than 266.8kV. As shown in the schedule for 2 MSCDN's connected, the maximum voltage is 263.9kV. Thus for the main capacitor bank Un = 242.5kV.

For the auxiliary capacitor bank, the maximum continuous fundamental frequency voltage is 420 / √ 3kV x $\left(\frac{1}{n^2-1}\right)$, where n = 3, i.e. 30.3kV. This value can be chosen as unless the maximum voltage exceeds 33.3kV. As shown in Schedule 10 (2.18) for 2 MSCDN's connected, the maximum voltage is 33.6kV, i.e. 11% above the fundamental frequency voltage. To accommodate this maximum voltage the proposed bank rated voltage Un = 31kV.

b) **Reactors**

As the fundamental frequency current flow in the MSCDN is determined by the impedance of the main capacitor bank, which at extreme tolerance could be 4% below nominal, the reactor fundamental frequency current is increased by 4%. This factor is additional to the detuning effects described above.

The auxiliary capacitor bank C2 is detuned to a fundamental frequency 50 Hz by connecting a series reactor in series with capacitor bank C2 to form a L−C circuit to provide a low impedance path only for fundamental current to flow through and diverting all 3rd, 5th and 7th harmonic currents to flow into the bypass resistor circuit.

By detuning the auxiliary capacitor bank C2 with reactor to a fundamental frequency 50 Hz, the losses in the resistors due to fundamental current is zero. Refer to the single line diagram for MSCDN's components parameter values. However the overall combination of capacitor bank C1, capacitor bank C2 and reactor is a 3rd harmonic filter. For 400kV MSCDN, main capacitor bank capacitance C1 = 4.57 μF, auxiliary capacitor bank capacitance C2 = 36.48 μF and the reactor inductance = 277.2mH.

The combined value of C1 and C2 in series = 4.061 μF.

When the reactor is in series with capacitor C1 and C2, the combination of C1, C2 and reactor forms an L−C circuit with very high resistors in parallel (connected as bypass to L−C circuit).

$$\therefore\ n = \frac{1}{2\pi \int \sqrt{LC}} = \frac{1}{2\,\pi \times 50\sqrt{(LC)}} = 3$$

Similar calculations can be done for 275kV and 132kV MSCDN's to establish they are 3rd harmonic filters. However at fundamental frequency and nominal voltage 400kV, MSCDN will generate 225 MVAr, the 275kV MSCDN will generate 150 MVAr and the 132kV MSCDN will generate either 52.5 MVAr or 45 MVAr in accordance with the design. The function of the resistors is to provide damping and stability to the power system during MSCDN switching and operating. The combination of auxiliary capacitor bank C2 and series reactor tuned at fundamental frequency with resistors connected as bypass to L−C circuit is called Damping Network to Mechanically Switched Capacitor bank C1 (MSC).

Rating of the Main Capacitor bank C1 is the rating of the MSCDN.

c) **Resistors**

The resistor power rating is based on the sum of the small fundamental component which occurs due to detuning of the bypass L−C circuit, and all harmonic components. A maximum voltage based on the arithmetic sum of all fundamental and harmonic components is assigned for insulation design.

4. Electrical Design

As shown on the Single Line Diagrams (SLD's), the main capacitor bank is connected to the 400kV busbar. Each phase of the bank is configured in an 'H' bridge arrangement with a fully insulated mid-point current transformer used for capacitor failure detection. The bank has an insulation level of 1425kVp BIL, both HV-ground and HV−LV. The LV terminal of the main bank, and hence the HV terminal of the auxiliary capacitor bank and damping resistor, has an assigned insulation level of 325kVp. In normal steady state operation the line−ground voltage at this part of the circuit is virtually zero. The assigned insulation level is maintained by the surge arrester shown on the SLD.

The auxiliary capacitor bank is protected from transient voltages arising from switching or fault conditions by the surge arrester connected across its terminals. This maintains a BIL level across the bank of 125kVp. The LV terminal of this bank, and hence the HV terminal of the reactor, has an assigned insulation level of 550kVp BIL.

All of the capacitor units which are externally fused, internally fused or fuse-less and have inbuilt discharge resistors to reduce the voltage to less than 75V in 10 minutes following opening of the circuit breaker, as per IEC871-1. External devices such as discharge VT's are provided for rapid discharge of the capacitor banks.

The reactor is connected at the neutral end of the filter and thus is not exposed to short circuit currents simplifying the reactor design and eliminating the need for expensive short circuit testing. The neutral terminal of the reactor, which is connected to earth, is assigned a nominal 125kVp insulation level.

The damping resistors are connected to the neutral end of the filter. The insulation level across the resistor is 325kVp and the neutral terminal is assigned a nominal 125kVp insulation level.

5. <u>Layout</u>

All of the MSCDN equipment is ground mounted inside an interlocked safety compound.

To minimise ground area the main and auxiliary banks have been accommodated in common structures. Thus the capacitor banks consist of 2 stacks per phase.

The air-cored reactors stand on supports providing electrical and magnetic clearance. However, to a depth of 1200 mm into the concrete plinth reinforcing crossovers will need to be insulated by using fusion bonded epoxy-coated reinforcement systems. The location of the coils is chosen to avoid magnetic effects on adjacent equipment or unacceptable levels of magnetic field at the perimeter fence.

To minimise ground area the damping resistor is arranged in 2 stacks of 2 units. The resistor elements are naturally cooled within an IP23 housing with electrical connections made via through-wall bushings.

All of the MSCDN equipment, including current transformers and surge arresters, are simple and quick to assemble and disassemble for relocation. For this reason, and because of the size of the equipment, it is not considered essential to mount any of the equipment on skids for relocation.

8.4 DESIGN OF THE MECHANICALLY SWITCHED CAPACITOR (MSC) FOR 132kV EAST CLAYDON SUBSTATION

1. <u>Performance</u>

As a result of NGC's assessment of the harmonic conditions around the NG 132kV system, this design for 3 off mechanically switched capacitor banks (MSCs) with a nominal rating of 52.5 MVAr during Stage 1, increasing to 60 MVAr with the addition of a detuning reactor at Stage 2.

Stage 1 is the installation of a non-detuned MSC with a minimum rating of 52.3 MVAr at 132kV for frequencies between 49.5 Hz and 50.5 Hz. The MSC is complete with current limiting reactors and is designed for ease of convention to Stage 2. Stage 2 is the detuning of the capacitor to the third harmonic (nominally 140 Hz) by the addition of a reactor. The affect this addition is to increase the MSC rating to at least 60 MVAr. A harmonic study was performed using AREVA's (then GEC Alsthom) harmonic penetration programme (HARP) to ensure NGC's required performance was met. The study confirmed the suitability of the ratings parameters given in the aforementioned Amendment and hence the equipment offered is in full compliance with NGC's requirements and specifications.

The reactors for Stage 1 are mounted on top of each capacitor stack.

The reactors for Stage 2 are connected at the neutral end of the filter and thus are not exposed to short circuit currents. This simplifies the reactor designs and eliminates the need for expensive short circuit testing.

Only a small voltage is developed across the current limiting reactor of Stage 1 and hence no extra insulation for the capacitor above that which would otherwise be required for a plain capacitor bank is necessary. However the HARP study highlighted the inadequacy of this insulation level when the capacitor is detuned. The voltage across the 133 mH reactor developed by the fundamental current would not, on its own, compel the capacitor insulation level to be increased. However, when harmonic voltages are considered, particularly third, IEC 71 (Insulation Co-ordination) gives an insulation level of up to 170kVp. The proposed capacitor LV to ground and the Stage 2 – 133mH reactors HV to LV and ground are thus rated for a BIL of 170kVp. The capacitor BIL for HV to LV and ground is 650kVp. All remaining BILs are 125kVp.

a) **Capacitors**

   The capacitor units are of the all film dielectric (non PCB) type. A number of windings are connected in series and parallel in order to meet the overall kVAr and voltage rating of the unit. They are then mounted in an insulated, hermetically sealed, stainless steel containers together with discharge resistors. The units are mounted in galvanised steel racks which form three stacks – one per phase. The units within each stack are connected in series and parallel in order to achieve the overall MSC rating.

b) **Reactors**

   The air-cored and air-natural cooled reactor coils are designed for outdoor installation. With an aluminium conductor, they are insulated with epoxy resin and cylindrical in construction.

   During Stage 1 operation a small current limiting reactor is mounted on top of each stack. When converting to Stage 2 the MSC connections are removed and replaced with connections to the much larger ground mounted 133mH reactors.

2. <u>Electrical Design</u>

As shown on NGC drawings 29/6167 and 29/6168, the main capacitor bank is connected to 132kV busbar. Each phase of the bank is split into two halves with a current transformer for each half for capacitor unbalance split phase protection. The bank has an insulation level of 650kVp BIL for HV to LV and ground. The LV terminal of the bank has an assigned insulation level of 170kVp.

3. Layout

All the MSC equipment is mounted inside an interlocked safety compound for Stage 1. A plan of the equipment is shown on NGC drawing numbers 29/6167 and 29/6168. The capacitor banks consist of 1 stack per phase, each stack comprising 4 racks with each rack size 20. External devices such as discharge VT's are provided for rapid discharge of capacitor banks.

During Stage 1 operation the 300μH limiting reactor will be mounted on top of each stack. During Stage 2 when the capacitor bank is detuned at a later stage to 140 Hz, the MSC connections are removed and replaced with connection to the larger ground mounted reactors of 133mH to avoid resonance with the supply system impedance. Hence, sufficient space and access are allowed in the Stage 1 layout for the addition of the floor mounted reactors. Sufficient space for additional equipments are allowed, i.e. surge arresters and current transformers for detuned 2.8 harmonic filter.

8.5 IED-ARS FOR CONTROLLING MSCDN'S, MSC's and REACTOR SWITCHING

The function of the IED-ARS is to switch MSCDN's, MSC's and Reactors in a realistic way to achieve the following objectives without the need for operator intervention :

a) Voltage control under normal system conditions

b) Voltage control under post fault conditions

c) Overvoltage protection of MSC's, achieved by MSC protection mode

SOFTWARE

Data values are obtained from the SCS via a suitable communication media.

COMMUNICATION

A bi-directional communication link is required between the ARS and SCS.

PLANT TO BE CONTROLLED

The IED-ARS can control the following equipment where it exists at a site :

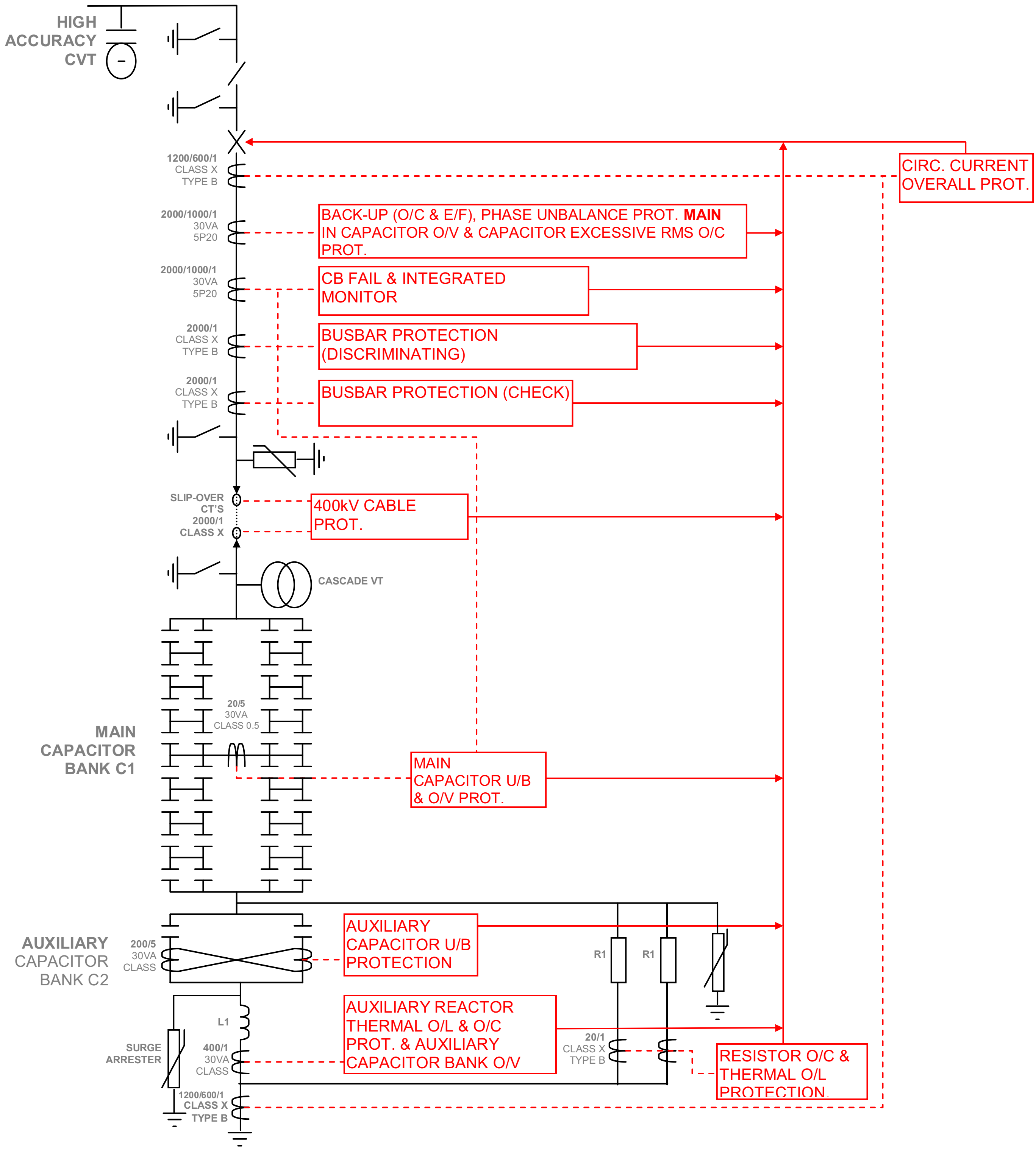
a) MSC's connected to the LV or transformer tertiaries

b) Reactors connected to the LV or transformer tertiaries

c) HV compensation plant MSC's or Reactors connected to the HV if fitted with a dedicated CB

d) The tap stagger facility on the ATCC

Up to 10 LV or tertiary connected MSC's or Reactors and up to 4 items of HV compensation plant can be controlled by the IED-ARS system



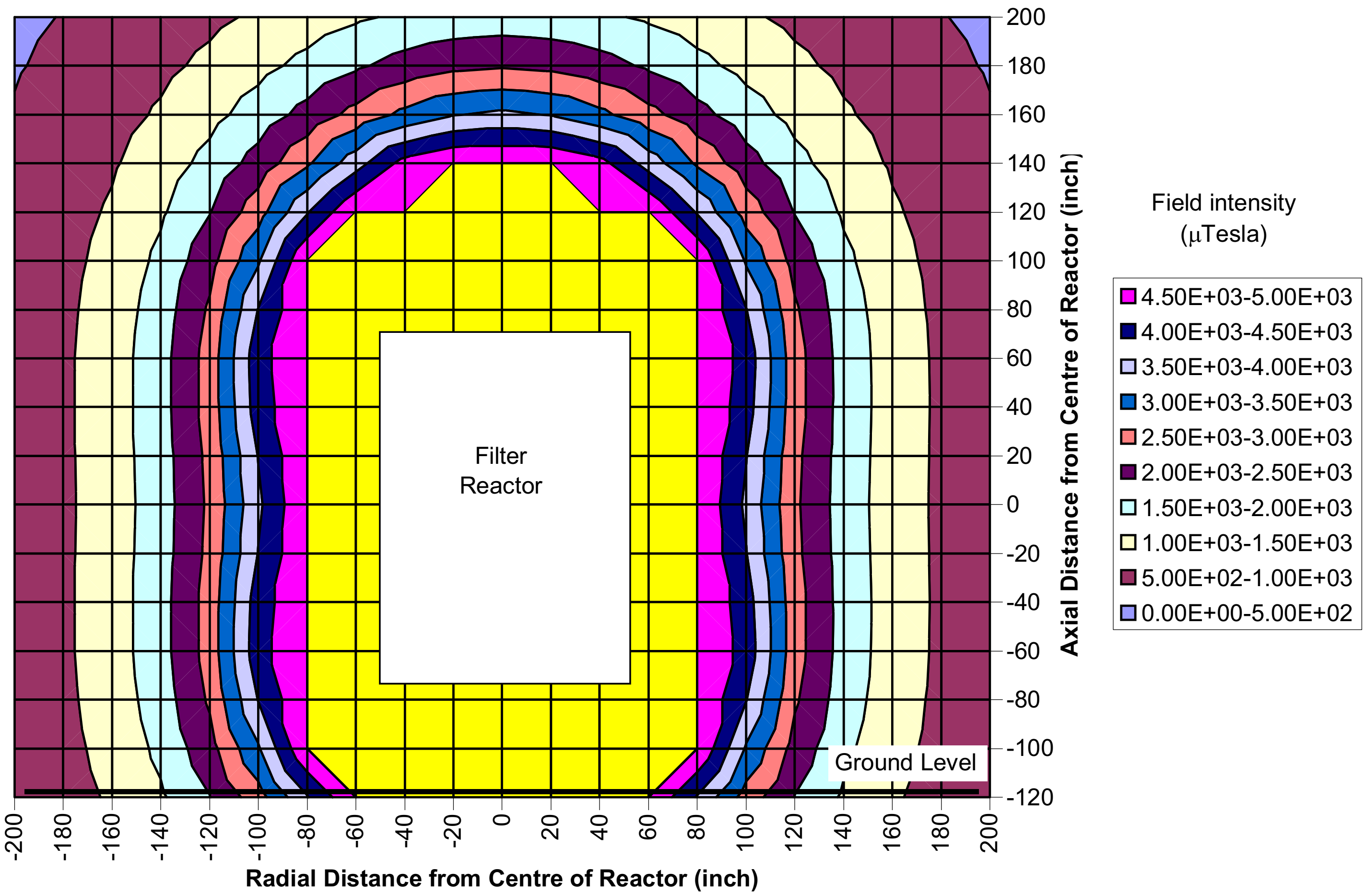
225 MVAr Fuse-less Mechanically Switched Capacitor Damping Network SLD
Fleet 400kVSubstation

8.6 MAGNETIC FIELD DENSITY (mT) CONTOUR PLOT FOR 400kV and 132kV MSCDN REACTORS

1. The reference levels for magnetic field (B) as given in NRPB GS11 are expressed as B = 80,000 / f (μT) where f is the frequency. Thus for 50 Hz fields the limit is 1.6 mT and for 150 Hz the limit is 0.53 mT. As indicated in the magnetic field plots at 50 Hz the 1.6 mT contour lies within the MSCDN compound fence. Similarly for the 150 Hz field component, where the reactor current is considerably lower, typically < 10% of the 50 Hz component the 0.53 mT contour will also lie within the compound fence.

Magnetic Field Plot

400kV, 374A, 277.2mH Filter Reactor



iinformation from the reactor supplier indicates that the 0.1 mT contour will occur at the following distances from the reactor surface

For 400kV	MSCDN distance	=	7.4 m
For 132kV	MSCDN distance	=	5.8 m

2. 400kV MSCDN's

   a) **Compound Fence**

      Distance of the compound fence from the surface of the nearest reactor for the MSCDN = 3.1 m

   b) Radius of the reactor coil = 1.23 m

   c) Distance between two adjacent reactor coils as shown on the site layout = 11.7 m

   d) Distance of the magnetic field density of 1.0 mT (refer to Haefely Trench magnetic field contour plot) from the surface of the reactor coil = 2.9 m

   e) Distance of the NRPB recommended magnetic field density of 1.6 mT (as calculated) from the surface of the reactor coil = 2.4 m
      (falls within the MSCDN compound)

   f) Based on the information provided by Haefely Trench the distance of the magnetic field density of 0.1 mT from the surface of reactor coil = 7.4 m

3. 132kV MSCDN's

   a) **Compound Fence**

      Distance of the compound fence from the surface of the nearest reactor for the MSCDN = 3.1 m

   b) Radius of the reactor coil = 1.1 m

   c) Distance between two adjacent reactor coils as shown on the site layout = 4.3 m

   d) Distance of the magnetic field density of 1.5 mT (refer to Haefely Trench magnetic field contour plot) from the surface of the reactor coil = 1.9 m

   e) Distance of the NRPB recommended magnetic field density of 1.6 mT (as calculated) from the surface of the reactor coil = 1.8 m
      (falls within the MSCDN compound)

   f)Based on the information provided by Haefely Trench the distance of the magnetic field density of 0.1 mT from the surface of reactor coil = 5.8 m

400kV MSCDN at Cellarhead Substation

400kV MSCDN at Grendon Substation

LIST OF MSCs AND MSCDNs DESIGNED, INSTALLED AND COMMISSIONED BY AREVA (then GEC ALSTHOM)

System Voltage	Ph – N Split Wye			Ph – N Single Wye			Ph – N 'H' Wye Arrangements		
	Site	Quantity/Size	Capacitor Type	Site	Quantity/ Size	Capacitor Type	Site	Quantity/ Size	Capacitor Type
400kV	Sundon	1 off - 225MVAr	Externally Fused	Lovedean	1 off – 225MVAr	Externally Fused	Hams Hall	2 off – 225MVAr	Internally Fused
	Grendon	1 off - 225MVAr		Indian Queens	1 off – 225MVAr		Drakelow	1 off – 225MVAr	
	Cellarhead	2 off - 225MVAr		Legacy	1 off – 225MVAr		Fleet	1 off – 225MVAr	Fuseless
				Drakelow	1 off – 225MVAr				
275kV							Blythe	1 off – 150MVAr	Internally Fused
132kV	St Johns Wood	2 off – 60MVAr	Externally Fused						
	Marylebone	1 off – 60MVar							
	East Claydon	3 off – 60MVAr tuned to 3rd harmonic							
	Bradford West	1 off – 60MVAr							
	Abham	2 off – 45MVAr	Internally Fused						
	Bridgwater	2 off – 45MVAr							
	Iron Acton	1 off – 45MVAr							

8.7 SHORT CIRCUIT RATING OF CURRENT LIMITING REACTOR 0.3mH

1. For 132kV system with short circuit current of 31.5kA / 3 sec

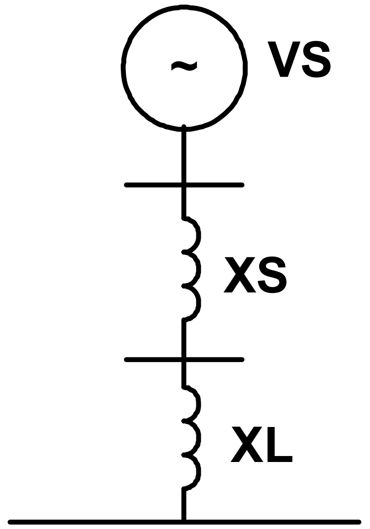


Fig 1 . 132kV System with Current Limiting Reactor

The system impedance $X_S = \dfrac{132 \times 10^3}{\sqrt{3} \times 31.5 \times 10^3} = 2.658\ \Omega$

The current limiting reactor 0.3mH impedance $X_L = jwL$

$$= j\ \frac{2\pi \times 50 \times 0.3}{10^3}$$

$$= 0.094\ \Omega$$

$\therefore$ The short circuit current of the reactor $= \dfrac{132 \times 10^3}{\sqrt{3}\,(2.658 + 0.094)}$

$$I_{SC} = 27.7\text{kA} / 3\text{ sec}$$

2. For 145kV system with short circuit current of 31.5kA/3 sec

The short circuit current of the reactor $I_{SC} = \dfrac{145 \times 10^3}{\sqrt{3}\,(2.658 + 0.094)}$

$$I_{SC} = 30.0\text{kA} / 3\text{ sec}$$

3. For 132kV system with short circuit current of 40kA/3 sec

The system impedance $X_S = \dfrac{132 \times 10^3}{\sqrt{3} \times 40 \times 10^3} = 1.905\ \Omega$

$\therefore$ The short circuit current of the reactor $I_{SC} = \dfrac{132 \times 10^3}{\sqrt{3}\,(1.905 + 0.094)}$

$I_{SC} = 38.1\text{kA} / 3\ \text{sec}$

4. For 145kV system with short circuit current of 40kA/3 sec

The system impedance $X_S = \dfrac{145 \times 10^3}{\sqrt{3} \times 40 \times 10^3} = 2.093\ \Omega$

$\therefore$ The short circuit current of the reactor $I_{SC} = \dfrac{145 \times 10^3}{\sqrt{3}\,(2.093 + 0.094)}$

$I_{SC} = 38.3\text{kA} / 3\ \text{sec}$

8.8 SHORT CIRCUIT RATING OF THE CT FOR 400kV MSCDN 'H' TYPE CAPACITOR BANK C1

Fleet Fuseless Capacitor Bank 'C1'

Capacitance value of each phase	=	4.57 μF
Each capacitor unit capacitance	=	15.23 μF
Each capacitor unit rating	=	712 kVAr
Total capacitor units / phase C1	=	120

Note: The capacitor unbalance protection CT is mounted on the middle point of the capacitor bank C1.

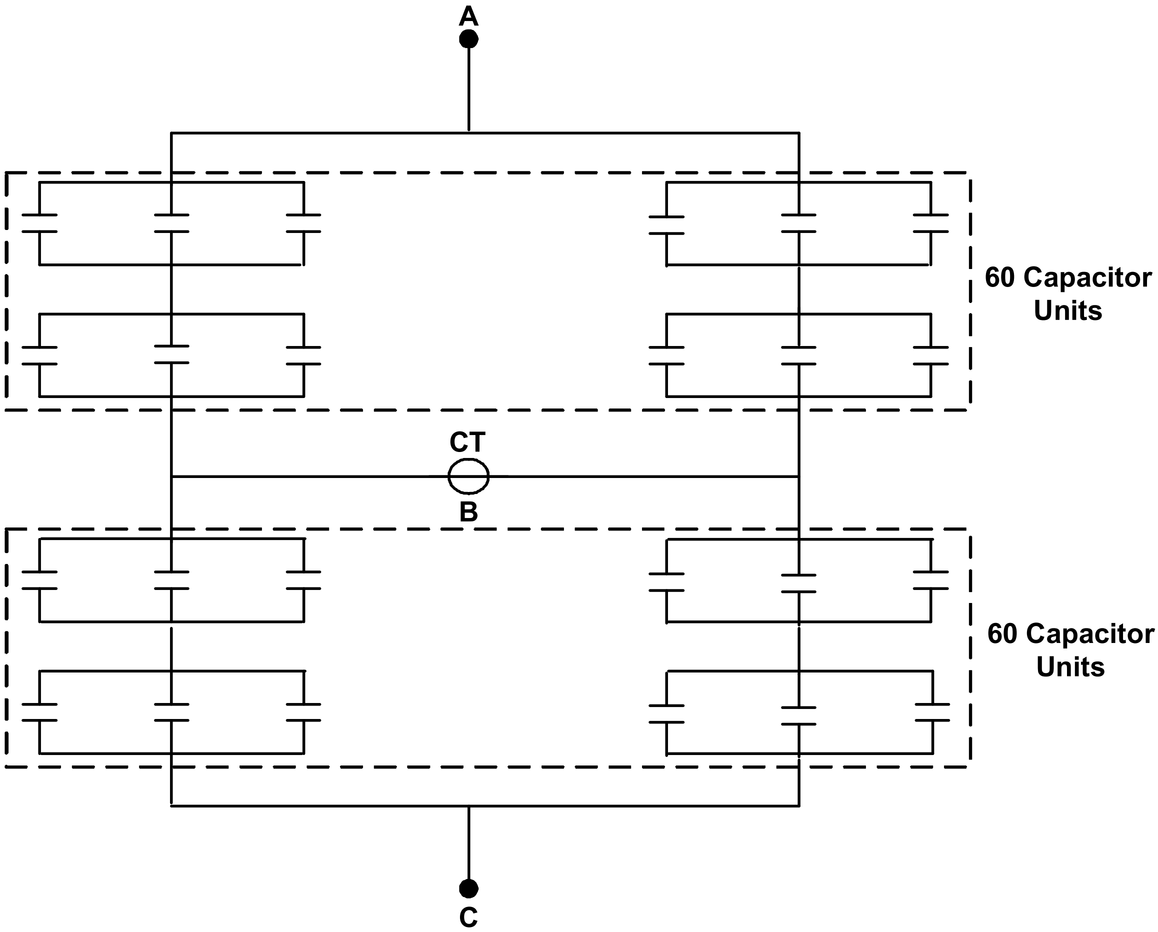


Fig 3 . Single Phase 'H' Type Capacitor Bank

Capacitor impedance (X_{SC}) for 60 units at fundamental frequency = $X_{SC} = -j\dfrac{1}{2\pi fc}$

Total capacitance of units = 9.138 μF

$\therefore$ X_{SC} of 60 capacitor units = $-\,j384.3\ \Omega$

Fleet 400kV fault level = 63kA / 1 sec

$\therefore$ The system impedance X_S = $\dfrac{420}{\sqrt{3} \times 63}$ = $j\,3.85\ \Omega$

Total impedance $X_S + X_{SC}$ at B = $-\,j\,348.3 + j\,3.85$

= $(\,-\,j344.5\ \Omega\,)$

$\therefore$ The short circuit current at the point B, the 'H' connection = $\dfrac{420}{\sqrt{3}\,(-\,j\,348.3 + j\,3.85)}$

$$= \frac{420 \times 10^3}{\sqrt{3} \times 344.5}$$

= 0.704kA

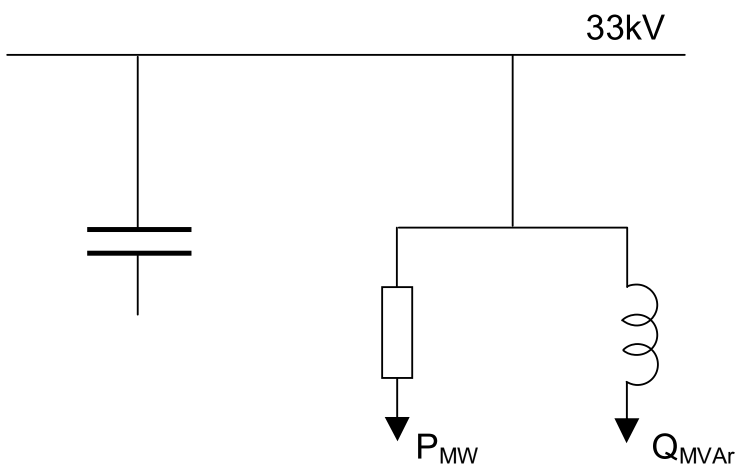
= <u>704A</u>

However the CT is rated for 5kA fault current/1 sec.

8.9 SHUNT CAPACITOR BANKS FOR POWER FACTOR CORRECTION

At 33kV busbar, the rating of the total shunt capacitor bank required to improve the power factor correction from 0.8 lagging to 0.894 lagging at 33kV busbar is 5MVAr with Bus Section closed. What is the rating of the additional shunt capacitor bank required to improve the power factor correction at 33kV busbar from 0.8 lagging to 0.97 lagging, with Bus Section closed?

Let the active power be P and reactive power be Q of all the existing line feeders together are P + jQ.



First the total P and Q of the existing feeders can be calculated.

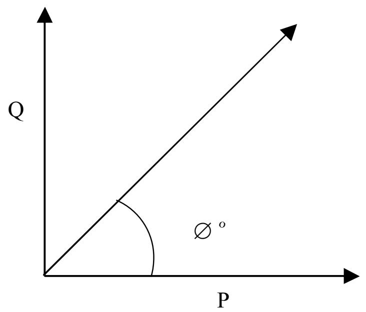
$$\text{Power factor} = 0.8$$

$$\text{i.e. } \cos \varnothing = 0.8$$

$$\varnothing = 36.9^{\circ}$$

$$\tan \varnothing = \frac{Q}{P}$$

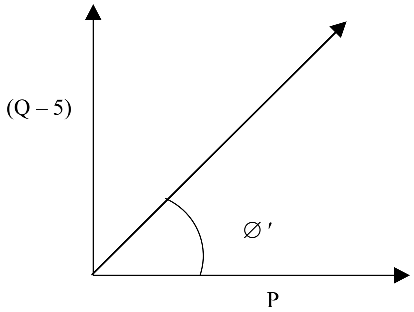
$$\therefore P = \frac{Q}{0.75} = \frac{4}{3} Q \qquad (1)$$



When 5 MVAr shunt capacitor bank is connected to 33kV Busbar with the Bus Section closed the power factor has improved from 0.8 lagging to 0.894 lagging at 33kV busbar.

$$\cos \varnothing^{1} = 0.894$$

$$\varnothing^{1} = 26.61^{\circ}$$



$$\therefore \quad \tan \varnothing^1 = \frac{(Q - 5)}{P}$$

$$\text{But } \tan \varnothing^1 = 0.5$$

$$\therefore \quad P = \frac{(Q - 5)}{0.5} = 2\,(Q - 5) \qquad (2)$$

From equation *(1)*

$$2\,(Q - 5) = \frac{4}{3}\,Q$$

$$Q - 5 = \frac{2}{3}\,Q$$

$$\therefore \quad Q = 15 \text{ MVAr}$$

$$\therefore \quad P = 20 \text{ MW}$$

The total active power of the existing feeders is 20 MW and the reactive power is 15 MVAr.

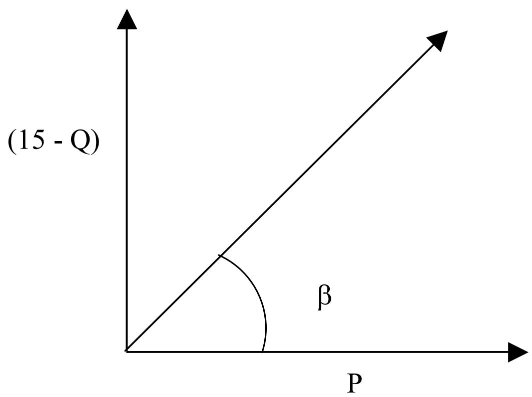
Let the total amount of shunt capacitor required to improve the power factor from 0.8 lagging to 0.97 lagging be Q^{11}.

$$\therefore \text{ Cos } \beta = 0.97$$

$$\beta = 14^o$$

$$\therefore \tan \beta = \frac{(15 - Q^{11})}{20}$$

$$\tan \beta = 0.25$$



$$\therefore \quad \frac{1}{4} = \frac{(15 - Q^{11})}{20}$$

$$Q^{11} = 10 \text{ MVAr}$$

$\therefore$ The total shunt capacitor required to improve the power factor from 0.8 lagging to 0.97 lagging is 10 MVAr.

Therefore the additional shunt capacitor required to improve the power factor from 0.894 lagging to 0.97 lagging (Q^{11} – 5 MVAr) = 5 MVAr.

Refer to the power factor correction diagram, where 5 MVAr capacitor banks are connected to the 33kV busbars A and B.

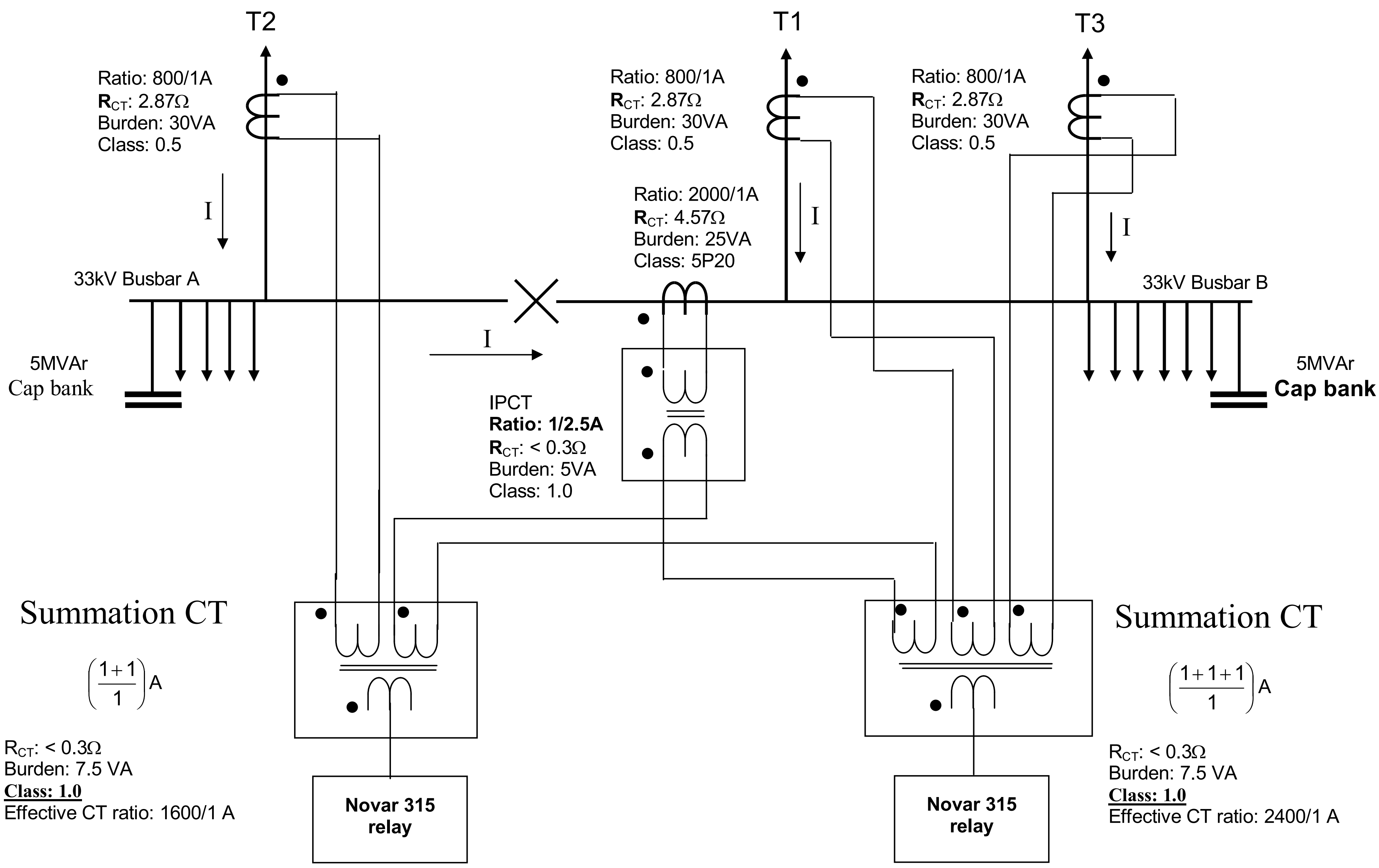
These 5 MVAr shunt capacitor banks are controlled by two NOVAR relays one at each end of the 33kV busbars A and B. These NOVAR relays are set to control the two 5 MVAr shunt capacitor banks with the Bus Section closed to improve the power from 0.8 at 33kV to 0.97 lagging.

It should be checked to make sure that the two 5 MVAr shunt capacitor banks selected do not have any resonance condition with the power system fault level.

$$n = \sqrt{\frac{Q_S}{Q_{SC}}}$$

Where n is the resonance frequency, Q_S is the system fault level at 33kV busbar and Q_{SC} is the total rating of the shunt capacitor banks that are to be connected to the power system. If the shunt capacitor bank has resonance condition with the power system then the shunt capacitor bank cannot be used as a plain capacitor bank, it should be detuned to eliminate the resonance frequency to become a filter to provide a low impedance path for the harmonic number i.e. harmonic frequency current to flow. The shunt capacitor bank should be checked for temperature variation, system frequency variation and capacitance tolerance. However it should be remembered, to make it a filter the size of the shunt capacitor bank should be increased and also a reactor should be added to tune that particular harmonic number to become a filter.

TSDP2 - Lot A - CEB Thulhiriya Substation
Capacitor bank control for Power Factor Correction



8.10 SERIES CAPACITOR COMPENSATOR

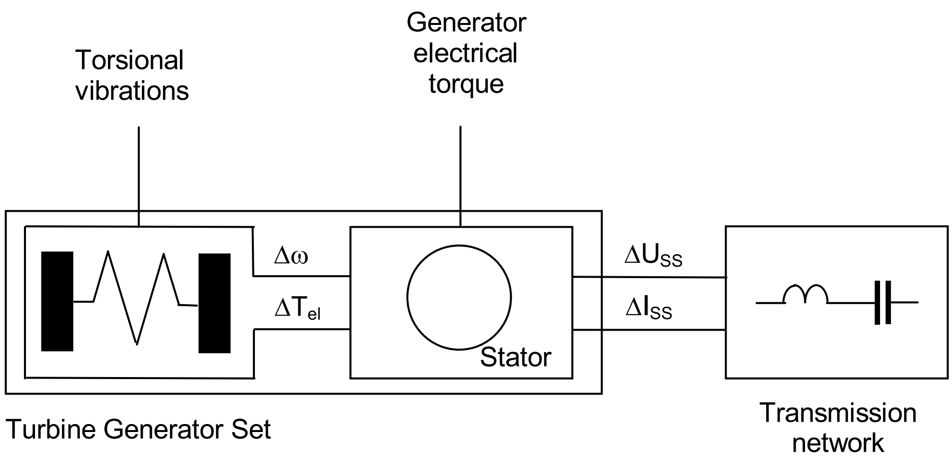
The real power exported along an uncompensated line is given as :

$$P = \frac{V_S \, V_R \sin\delta}{X_L}$$

By looking at the above equation, the real power along the line can be increased by reducing the line reactance X_L by adding capacitance reactance X_C in series with the transmission line. The overall line reactance X, becomes $X_L - X_C$ or alternatively, $X = X_L\,(1-m)$ where m is the degree of compensation given by $m = \frac{X_C}{X_L}$ $0 \le m < 1$.

The real power P, can now be expressed as :

$$P = \frac{V_S \, V_R \sin\delta}{X_L\,(1-m)}$$



The Causes of Sub-synchronous resonance

The figure above shows the combination of series capacitors and transmission line impedance. This combination shows that series capacitor compensates the line and reduces overall line reactance. The length of the line is to be seen as shorter electrically.

The reactive power generated by the series capacitor

Refer to Vector diagram on page 89

$$\text{Sin}\,\delta/_2 = \frac{I_S \dfrac{X_L}{2} - \dfrac{I_S X_C}{2}}{V}$$

$$\text{Sin}\,\delta/_2 = \frac{I_S (X_L - X_C)}{2V}$$

$$\therefore\ I_S = \frac{2V\ \text{Sin}\,\delta/_2}{(X_L - X_C)}$$

$$\text{but} \quad m = \frac{X_C}{X_L}$$

$$\therefore\ I_S = \frac{2V \sin \delta/_2}{X_L\ (1-m)}$$

The reactive power generated by series capacitor $Q_C = I^2{}_S\, X_C$

$$Q_C = \frac{4V^2 \sin^2 \delta/_2}{X^2{}_L\ (1-m)^2}\ .\ m\, X_L$$

$$Q_C = \frac{4V^2 \sin^2 \delta/_2}{X_L\ (1-m)^2}\ .\ m$$

$$\text{but}\ \ \text{Sin}^2\,\delta/_2 = \frac{(1-\text{Cos}\,\delta)}{2}$$

$$Q_C = \frac{2V^2.m\,(1-\text{Cos}\,\delta)}{X_L\ (1-m)^2}$$

8.9.1 Sub-synchronous Resonance (SSR)

The application of series capacitors in power transmission system can create sub-synchronous resonance (SSR). If the SSR is not detected in time it can cause turbine shaft damage in the case of a steam turbine generator, resulting from mechanical torsional vibrations.

<u>Causes of sub-synchronous resonance (SSR)</u>

In cases where the risk of SSR cannot be completely ruled out, the counter measures have to be taken either to bypass the series capacitor when SSR is detected or to trip the generator. There was an incident of turbine shaft damage resulting from a mechanical torsional vibration in steam turbine generator plant in New Mexico in 1970, due to SSR created by series capacitor compensation on a long transmission line. However, it has been established from theoretical investigations and long experience of the use of series capacitors in power system, SSR is not a problem when transmitting hydro power.

Thermal generation is more susceptible to SSR than hydro generation. Large turbo generator units have a large number of rotating masses connected by a long shaft up to 48-50m long. This produces low frequency torsional vibration modes, a greater number of them usually below the system frequency.

On the other hand, hydro generator units are compact. The majority of the hydro generator unit's rotating masses are concentrated at one end of the turbine generator unit. This means the hydro generator unit produces higher mechanical resonance frequencies and better mechanical damping.

SSR is caused by electro-mechanical coupling between the turbo generator shaft and the series compensated network and appears as Torsional Vibration of the shaft. It is even possible for the total circuit resistance to sub-synchronous current to become negative, in this case oscillatory currents due to the induction generator effect may build up to unacceptable levels. Electro-mechanical interaction problem may occur when the electrical resonant frequency is near the complement of one of the torsional resonant frequencies of the shaft system of a generator. If the power system happens to have a characteristic showing Series Resonance at any of the frequencies corresponding to the difference between the system frequency (50 Hz) and the torsional frequency spectrum, the corresponding current component will see a low impedance in its path. Torsional vibration can grow until it results in mechanical damage.

By looking at the equation $P = \frac{V_S \, V_R \sin\delta}{X_L \, (1-m)}$ it can be seen that smaller the degree of compensation 'm' i.e. the ratio of capacitive reactance of the series capacitor applied to the transmission line and the inductive reactance of the transmission line, the lower is the risk of SSR occurring.

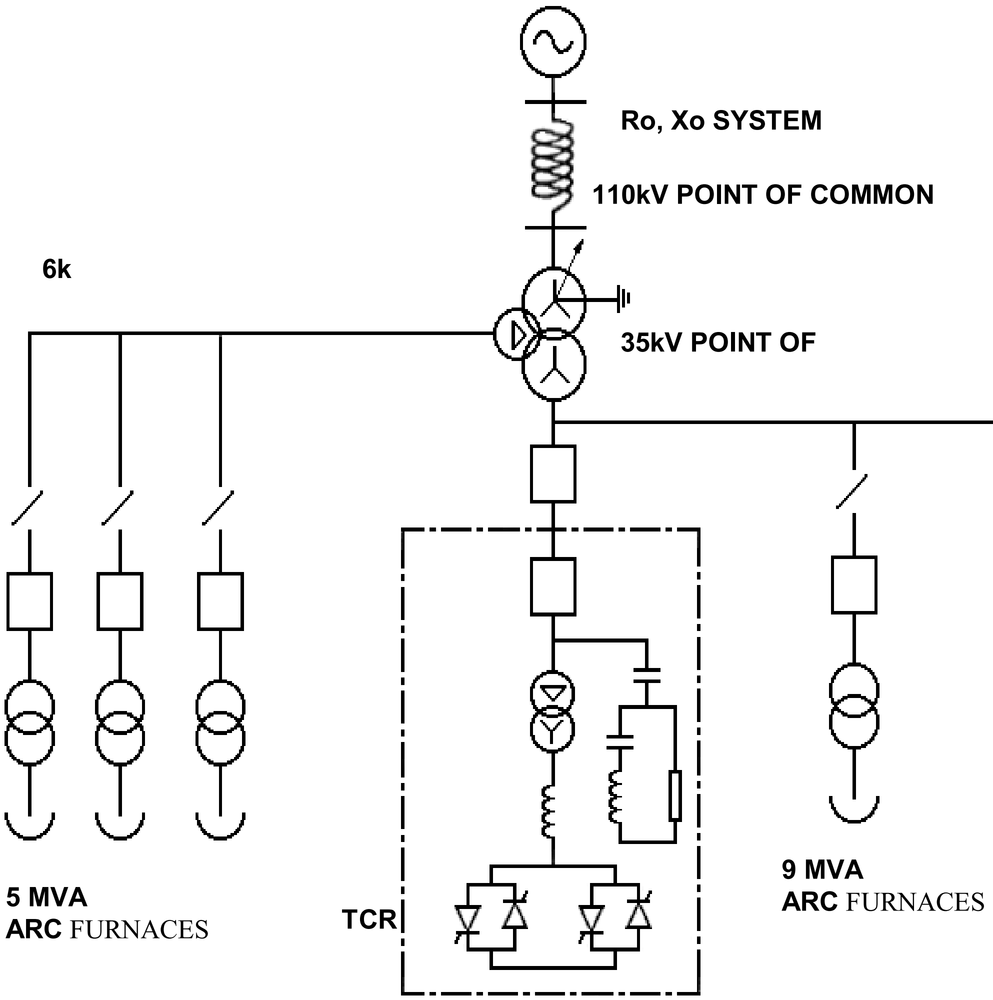
However up to 100% compensation can now be introduced since the thyristor control provides stabilisation. Non thyristor control series compensation is limited to 50 to 55% of line reactance.

Main Benefits and Convenience

SVC's and MSCDN's are the most economic and convenient devices for Transmission problems. Compared to HVDC or six phase-phase Transmission schemes, SVC's and MSCDN's solutions can be provided without wide scale system disruption. Within a reasonable timescale, SVC's and MSCDN's can be fitted to existing AC Transmission lines, i.e. 13kV, 33kV, 132kV, 275kV and 400kV systems.

There is no need to build more and more new Transmission lines. SVC's and MSCDN's technology however allows greater throughput over existing routes (i.e. lines), thus meeting consumer demands without construction of a new transmission line or even a new power station.

8.10 THYRISTOR CONTROLLED REACTOR – STATIC VAR COMPENSATOR FOR INDUSTRIAL APPLICATION



Thyristor Controlled Reactor type Static VAr Compensator for ARC

8.10.1 Principles of operation of a thyristor controlled reactor SVC

In power systems SVC's are often required both to generator and absorb reactive power (VAr's), continuously variable absorption of VAr's can be achieved readily with a variable inductor such as a phase-controlled linear reactor. It is normal practice to achieve continuously variable generation of VAr's by the parallel combination of a fixed capacitor bank and a variable inductor. An additional advantage of this arrangement is that, if required, the fixed capacitor bank can be converted readily into harmonic filtering circuits to cater for the harmonic currents produced by the variable inductor and troublesome loads such as arc furnaces.

A Thyristor Controlled Reactor (TCR) compensator is basically a linear reactor and thyristor switch or 'valve' connected in shunt to the system to provide variable VAr absorption, as shown above. The valve has thyristors connected in anti-parallel, each carrying current in one direction only. By varying the firing angle, i.e. the point-on-wave at which the thyristors are turned on, the compensator control system is capable of varying the reactive current in the linear reactor to any required value between the maximum rated value resulting from continuous conduction and zero when there is no conduction, *Fig.*5

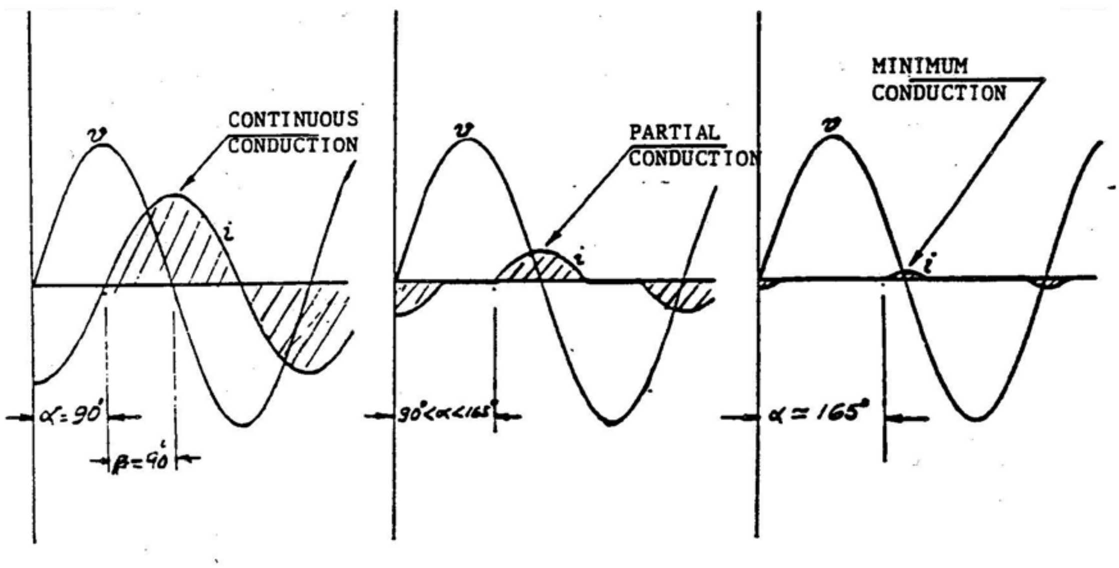


FIGURE 5 EFFECT OF VARYING THE FIRING ANGLE (α)

The firing angle delay, alpha (α), is normally defined from voltage zero, so that full conduction of the (inductive) current occurs at α = 90º and zero conduction at α = 180º. The conduction angle called sigma (σ) is twice β, for an ideal reactor with no resistance. The current will be offset for α between 0 and 90º, *Fig.6*

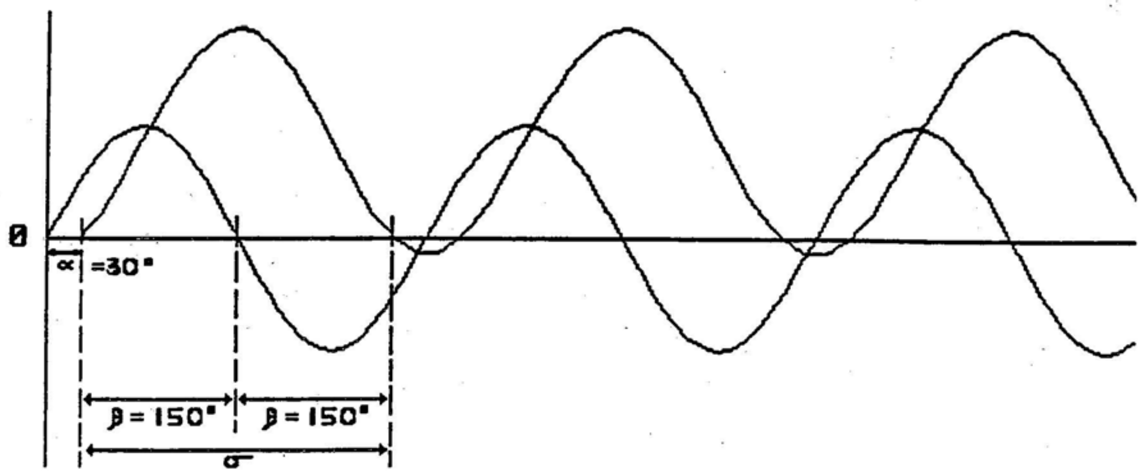
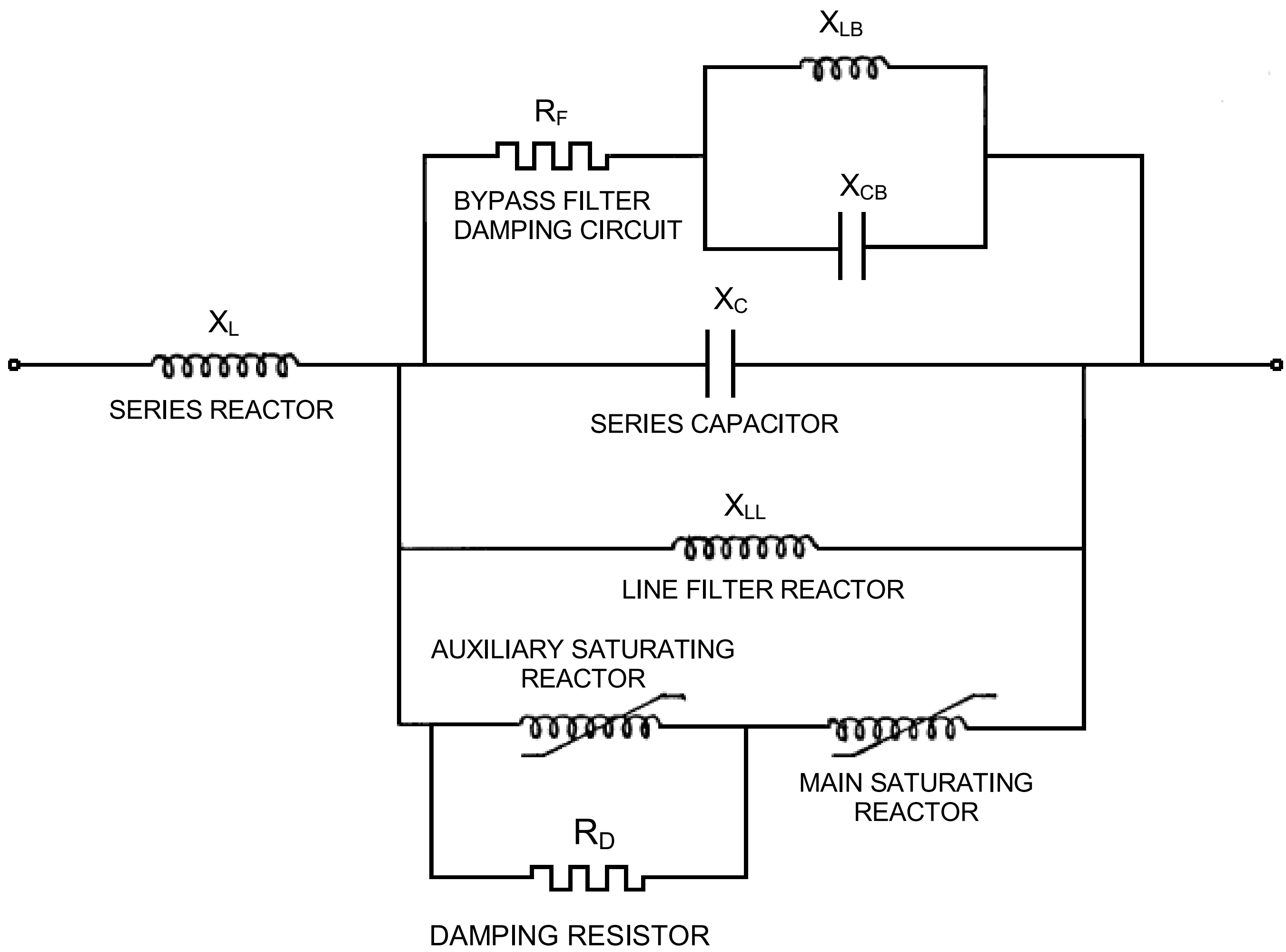


Fig 6 OFFSET REACTOR CURRENT DUE TO FIRING AT α<90^o

This results in a d.c. component and cannot be tolerated on a steady state basis. Transiently it may be acceptable but of no grate advantage.

Therefore α is limited between 90º and 180º.

8.10.2 **Short-circuit Limiting Coupling (SLC)**

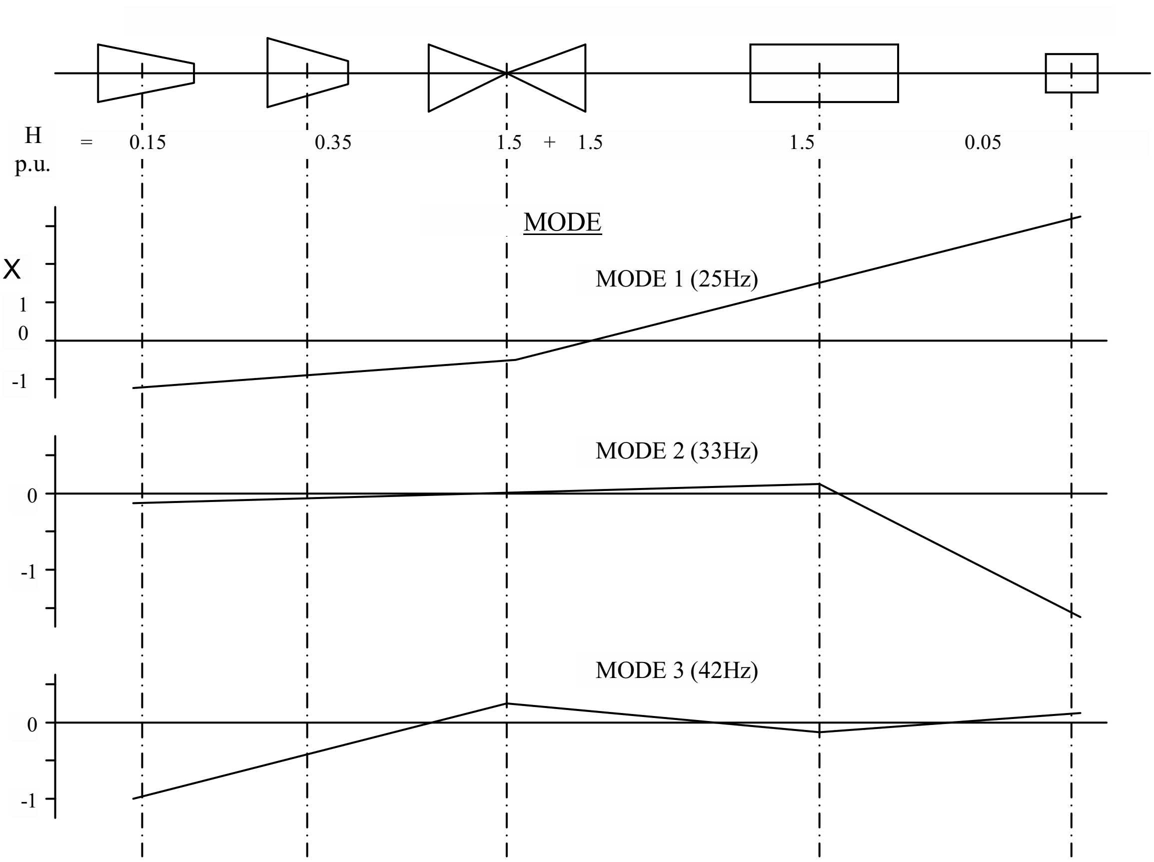


Resonant Link Short-circuit Limiting Coupling Circuit

Series capacitors are included in resonant link circuits (SLC), which are used to limit short circuit fault currents in electrical systems. Figure *above* shows the circuit of a typical SLC. For normal operation, the series reactor is tuned out by means of a series capacitor and the link has low impedance. Across the series capacitor are connected two saturating reactors, which have very high impedance in the normal operating condition and low impedance (due to saturation) under fault conditions, so that the link then has high overall impedance. The damping resistor associated with the auxiliary saturating reactor enables rapid recovery to the low impedance condition when the SLC current reduces after clearance of a system fault. Resonant links are most often used to link private generation in industries to the distribution system, typically at 11kV. Because of the presence of the series capacitor the resonant link is similar to a series capacitor compensated transmission line. The local generators and induction motors connected to the system via the SLC may be subject to instability due to sub-synchronous resonance (SSR) associated with this series capacitor if the damping circuits of the SLC are not designed properly.

8.10.3 Bypass Filter Damping Circuit for Suppression of Electrical SSR

To cancel out the negative resistance due to the induction generator effect, a 'subharmonic' damping filter is connected across the series capacitor. The filter consists of a damping resistor which is connected in series with a parallel combination of a reactor and a capacitor, tuned to provide a very high impedance at system frequency, so as to reduce the power loss in the resistor at the system frequency. At other important frequencies, in particular those in the range from about 20 to 40 Hz, the parallel combination has a reduced impedance and the resistor provides a damping effect. The circuit is designed to give sufficient damping (positive resistance) to cancel out the negative resistance exhibited by the generators and the motors at sub-synchronous frequencies and to cater for the system frequency variation mentioned above for all practical permutations of generators, loads and system configuration.



Typical Torsional Modes of shaft Operation

8.10.4 Line Filter Damping Circuit for Electromechanical Interaction

The series capacitor used in the SLC is itself sometimes used to form blocking filters. A blocking filter is formed by connecting a reactor across the series capacitor (or part of it), giving tuning to a frequency near to the complement of the torsional resonant frequency of the generator shaft system. When a line filter reactor is added to tune the series capacitor for the particular 'mechanical' frequency range, the required total capacitive impedance at 50 Hz is restored by increasing the series capacitor rating.

8.10.5 **Short Circuit Limiting Coupling (SLC) Limits Fault Current**

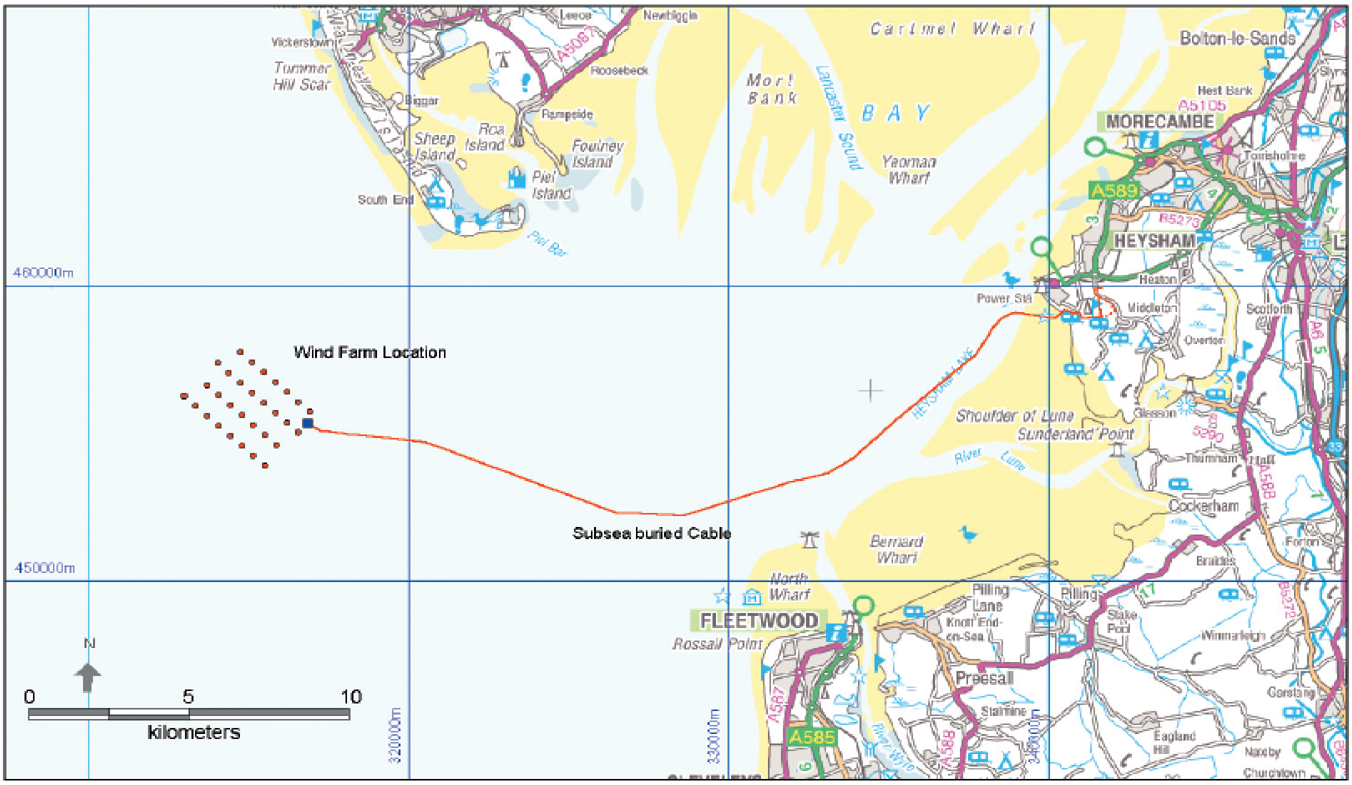
The Short-circuit Coupling or SLC provides a method of fault level reduction which not only has negligible effect on normal system operation but may be employed to greatly enhance the operability and security of an industrial power system. Where alternative methods to SLC may have economic advantages, it is re-emphasised that it can be well worthwhile in the long run to employ technically superior equipment and solutions to problems in industrial systems even at an increase in initial expenditure. It is emphasised that the principles of the SLC method of fault level limitation is applicable in higher voltage systems up to National Grid network level. Thus the SLC makes possible a new concept in power system design in which a high degree of independence between system load growth and associated fault levels greatly reduces the restrictions which were imposed by the increasing short circuit levels of expanding electrical power networks.

Regardless of the method by which detuning is obtained, resonance links possess the basic advantage of having negligible effect on normal system operation and are therefore much superior technically to series current limiting reactors.

The AREVA (then GEC Alsthom) has designed, installed and commissioned SLC's for limiting fault levels on the primary distribution networks of industrial power systems, connecting local generators, generating electricity using waste gasses or process steam to generate their own power and connecting two substations with different fault levels.

9. WIND FARM SUBSTATION

Most wind farms were installed onshore. Since nearly all locations of good wind conditions are used for wind generation, wind farms are being installed offshore. The installed power of the offshore wind farms is intended to be rated to 1000MW. The distance between the wind farm and the substations onshore is estimated to be up to 100km or even more.



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HVAC cables are regarded as a possible solution for the connection of offshore wind farm with the public grid onshore. The connection of the wind farm to the grid is via cables.

Firstly, all the wind turbines in the offshore will be connected to the substation on the offshore platform via 33kV cables, then the substation is connected via power transformer to the grid via high voltage cables either by 132kV, 275kV or 400kV cables (all depend on the voltage of the grid).

9.1 OFFSHORE WIND POWER PLANT

9.1.1 33kV Offshore Cable Rating

The transfer capacity of cables buried in the sea bed depends on the laying depth.

The nominal laying depth for the 33kV cables is 1m, which is the criteria for 100% capacity. However, in order to allow for variations in laying depth and moving sea bed, a margin of at least 5% is added.

For this reason the design criteria used for cable loading is maximum **95%**.

Cable length between wind turbines includes 20 metres at each end from the sea bed to cable connection in turbines.

33kV offshore cable guideline specification

Type	One three core armoured submarine cable
Insulation	Extruded XLPE or similar
Laying Depth	1m
Conductor	Copper
Additional	Longitudinal water block (for main cables) Integrated optical fibres for communication
Termination	Elbow type plugs

At the offshore substation the 33kV submarine cables will be terminated in switchgear. The 33kV submarine cables are lead through J-tubes or ducts in foundation and terminated in the connection point located in the WT.

An optical fibre cable shall be integrated in all the submarine cables to be delivered.

9.1.2 132kV Offshore Cable Rating

The following criteria has been taken into consideration :

1. Nominal laying depth throughout the cable route is 1m
2. Cables would have to be buried deeper in the near shore area, down to 3m

For this reason the design criteria used for cable loading has a current carrying capacity at 3m equal to the max wind farm output.

Offshore cable ratings are for laying depth of 1m. A margin of 5% is however required for the current rating.

132kV offshore cable guideline specification :

Type	Three single core armoured submarine cable
Insulation	Extruded XLPE or similar
Laying depth	1-3m
Conductor	Copper
Additional	Longitudinal water block Integrated optical fibres for communication

9.1.3 Power Transformer

One power transformer is required :

Type	Oil immersed three-winding transformer, totally enclosed
Cooling	ONAN / ONAF – oil / air radiator natural / forced cooling
Tap Changer	On-load automatic controlled
HV Connection	132kV cable box
MV Connection	33kV cable box
Mounting	Oil pan to contain full extent of transformer oil to be provided, including drain pump, oil separator etc. Additional shelter as necessary.

Transformer data guideline :

Data			
S_n	(MVA)	Nominal three-phase apparent power	145
U_{n1}	(kV)	Nominal phase-phase voltage, primary side	132
U_{n2}	(kV)	Nominal phase-phase voltage, secondary side	33
Vector group	−	Vector group / connection	Y n y n 0
Tap Changer	−	Number of taps and additional voltage per tap	+ 8 x 1.25% − 8 x 1.25%
Tap side	−	Tap changer at side	Primary
u_k	(%)	Positive sequence short circuit voltage	13
P_{cu}	(kW)	Copper losses	375
I_0	(%)	No load excitation current	0.1
P_0	(kW)	No load losses (iron losses)	70

The main 132kV cable will be connected directly to the cable box on the transformer. The 132kV cable box shall contain CT cores for the protection and monitoring.

The 132kV cable box data guideline :

Parameter	Unit	Description	Value
U_n	(kV)	Nominal phase-phase stator voltage	132
I_n	(A)	Maximum current rating	700
I_k	(kA)	Maximum short circuit rating	25
I_p	(kA)	Peak short circuit current rating	70

One common transformer and cable protection and control panel, including automatic tap changer control for main transformer. The protection will provide redundant tripping of on-shore 132kV circuit breaker.

The offshore substation shall have an oil collector for the transformer oil in case of leakage.

9.1.4 Medium Voltage Switchgear Module

One offshore container which will have sufficient space for installation of the proposed switchgear.

One 8 panel 33kV Gas Insulated Switchgear (GIS), with single bus section.

Number		
Section A	**Item**	**Description**
1	Transformer feeder	I_N = 2600A Circuit breaker Earthing switch Protection equipment
5	Cable feeder	I_N = 600A Circuit breaker Earthing switch Protection equipment
1	Auxiliary transformer feeder	I_N = 600A Circuit breaker Earthing switch Protection equipment
1	Shunt Reactor feeder	I_N = 600A Circuit breaker Earthing switch Protection equipment

33kV switchgear data guideline :

Parameter	Unit	Description	Value
U_n	(kV)	Nominal phase-phase stator voltage	33
I_n	(A)	Maximum busbar current rating	2600
I_k	(kA)	Maximum symmetrical short circuit current	25
I_p	(kA)	Peak short circuit current rating and making capacity	70

The switchgear and the module shall have pressure relief arrangements.

If SF6 gas is used the pressure shall be monitored and a leak detector be installed.

9.1.5 Auxiliary Transformer

One auxiliary supply transformer 33/0.4kV – 800kVA. Vector group ZNyn. Dry type or completely sealed oil immersed type.

9.1.6 Neutral Earthing and Overvoltage Protection

Earthing system 33kV :

Low impedance earthed by means of a resistor. A disconnector arrangement shall be provided as to switch between the neutral of the auxiliary transformer and the neutral of the main transformer.

Earthing system design criteria is the following :

Limit the earth fault current to approximately 200A. One resistor should be supplied for this purpose. Guideline value for the resistor is 40 ohms.

The 132kV system is solidly earthed. The earthing system of the offshore platform includes provisions for neutral earthing at the primary side of 132/33kV transformers by means of a surge arrester.

9.1.7 Auxiliary Module

One offshore container equipped with :

Local power supply panel including battery backup for protection, control etc.
Local auxiliary power supply panel for light etc.

9.1.8 Shunt Reactor

One oil immersed 33kV shunt reactor, with off-load tap steps, including thermal protection and pressure switch.
The shunt reactor is only used for compensating cable reactive power.

9.1.9 Earthing System

A complete earthing system for the offshore substation shall be provided.

It shall include a main bus, a copper cable ring connection on the platform, main copper cable connections to the main equipment and modules as well as all necessary equipotential bonding conductors to installations and structures.

9.1.10 Diesel Generator

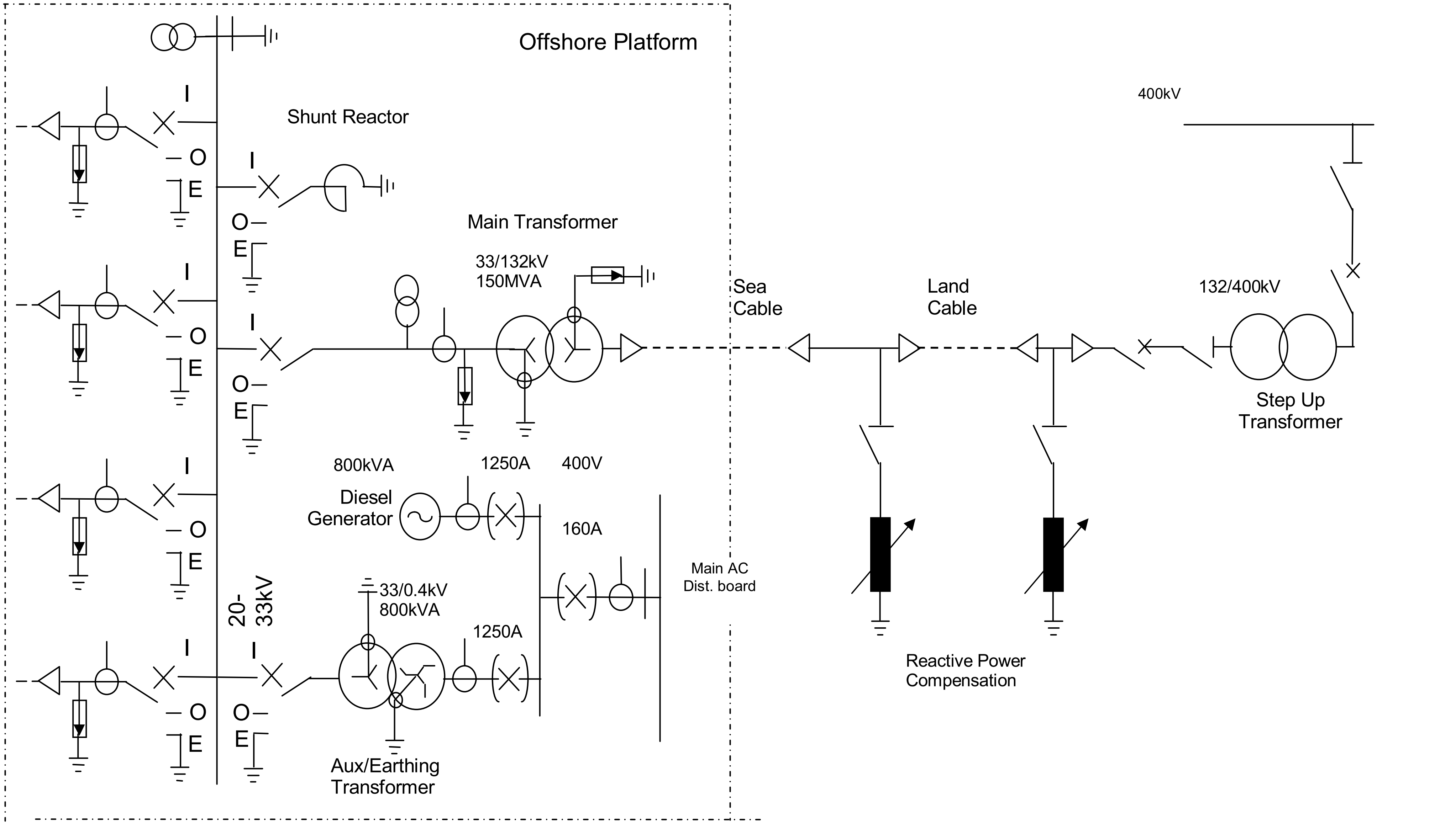
One diesel generator for the auxiliary supply of the platform as well as supplying the wind turbines through the medium voltage grid.

Rated power : 800 kVA, 400V

Diesel generator includes diesel tank. If a diesel generator is used to supply the service platform with electricity during standstill, the offshore substation shall have an oil collector with double bottom tank.

If the offshore substation is equipped with a diesel generator, it shall be provided with an automatic start facility.

A special control for “black-starting” to the 33kV system through the 33/0.4kV auxiliary transformer should be provided. The proposed solution is to connect to a dead system and ramp up voltage.


Offshore Platform
Shunt Reactor
Main Transformer
33/132kV
150MVA
Sea
Cable
Land
Cable
400kV
132/400kV
Step Up
Transformer
800kVA
Diesel
Generator
1250A
400V
160A
Main AC
Dist. board
20-
33kV
33/0.4kV
800kVA
1250A
Aux/Earthing
Transformer
Reactive Power
Compensation
I
O
E

9.1.11 **Transition Joint**

A transition joint is to be constructed at the landfall point containing :

Termination and linking of 132kV offshore cable and 132kV underground cable
Termination and linking of optical fibre cables for communication

At the offshore substation the 132kV submarine cables will be terminated at a 132kV cable box and on land terminated on the onshore substation on the outdoor steel structure including cable sealing end.

An optofibre cable shall be integrated in all the submarine cables to be delivered. On land a separate optical fibre shall be laid together with the underground power cables.


MATADOR 3
BOW
LASTDRAGER 25

9.2 ONSHORE SUBSTATION

Onshore cable ratings are for laying depth < 3m.

132kV onshore cable guideline specification :

Type	Three single core XLPE cables
Insulation	Extruded XLPE or similar
Laying depth	1-3m
Conductor	Aluminium
Additional	Separate optical fibre

1322kV data guideline :

Parameter	Unit	Description	Value
U_n	(kV)	Nominal phase-phase stator voltage	132
I_n	(A)	Maximum busbar current rating	700
I_k	(kA)	Maximum short circuit current	31.5
I_p	(kA)	Peak short circuit current rating and making capacity	79

Protection of cable feeders :

Differential protection covering 132kV cable and 132/33kV transformer
Pilot connection to relay in offshore substation through optic fibre link
Backup overcurrent and earth fault protection

9.2.1 132kV Reactor

For compensation of the reactive power generated by the cables one 132kV reactor is required, including 132kV feeders for reactor.

The reactor should be connected to the 132kV cable rack.

The reactor should be covered by the 132kV cable and transformer protection.

9.2.2 Harmonic Filter

A harmonic filter might be necessary to install in series with the 132kV cable in the onshore substation. The purpose of this filter is to prevent the cable from acting as a sink for harmonics in the 132kV network.

9.2.3 Protection Scheme

<u>132/33kV Transformer</u>

- Differential protection
- Overcurrent protection
- Earth fault protection
- Transformer differential protection
- Overcurrent protection
- Distance protection

<u>Additional transformer protection</u>

- Winding temperature supervision
- Buchholz relay
- Oil temperature

- Oil level

33kV Switchgear in offshore substation

- SF6 density supervision
- Over/undervoltage protection
- Overcurrent protection
- Earth fault protection
- Unidirectional earth fault
- Directional earth fault
- Overload protection

33kV Feeder protection

- Directional earth fault
- Overcurrent protection
- Overload protection

33kV Reactor feeder protection

- Non-directional overcurrent
- Directional earth fault protection

132kV Protection

- SF6 density supervision
- Transformer differential
- Overcurrent protection
- Overload protection
- Reverse power protection
- Frequency protection
- Voltage protection
- Over-fluxing protection

9.2.4 HVAC cables have high demands of charging power. This charging power may lead to a critical voltage condition and also reduces the transmission capability of the cable due to high charging current.

To avoid the problems related to the charging power, compensation devices have to be installed. How much the transmission capacity is reduced depends on the cable design, length, required voltage quality, the compensation scheme and relevant reactive power requirements at the onshore grid connection points.

Voltage control is a key technical condition for connection of wind farms to the grid. Wind farms should be able to assist in control of its local grid voltage, by dynamically varying the reactive power being generated or absorbed during its operation. All the wind farm generators are small induction generators. These have no internal source of excitations and therefore need to draw their magnetising currents from the power system. This causes a voltage drop, but in addition, because of the variable nature of wind, produces large voltage fluctuations. A degree of self-excitation can be provided by fitting capacitors across the terminals of the generator.

A second approach is to use turbines that incorporate their own power electronic converters, and so have the ability to alter their generator excitation in order to change their reactive power import or export. A number of different machines fall into this category; doubly fed induction generators (DFIGs) which have their generator rotor completely decoupled from the grid, or full converter machines, which have both the generator stator and rotor decoupled from the grid.

Such ‘variable speed’ turbines are attractive as they can convert more of the power from the wind into electrical energy than a conventional induction generator. In addition, as rotor speed is decoupled from grid frequency, power spikes arising from wind gusts can also be dampened. Some of the benefit of increased power capture is, however, offset by the losses within the power electronics.

In England, the reference voltage for such control should be at the point of connection (PCC) to the grid for wind farms, while in Scotland it should be at the point of connection or at the wind turbine terminals.
Today however, a wind farm can meet the new voltage control demands in a number of ways. For starters, fast switched capacitances and reactances such as Static Var Compensators (SVC, MSCDN or STATCOMS) can be added to existing or new wind turbines. The voltage control components i.e. SVC’s, can be moved from the low voltage terminals of individual wind turbines to the point of connection, at 33kV or a higher voltage i.e. at grid voltage 132kV or 275kV. The higher voltage compensators are much larger and more expensive than lower voltage compensators. As with the voltage control requirements, wind farm designs will have to include either SVC’s, MSCDN’s, STATCOM’s or wind turbines with power electronic converters to meet the requirements.

Speed of response to voltage fluctuation is a critical aspect of voltage control. However, where voltage control is required at the point of connection, turbines may be required to react to voltage changes, which can be several kilometres away.

The power factor correction is applied at the point of connection. The size of the power factor correction range offered, or SVC, must be calculated taking into account the impedances of all on site equipment such as power transformers and cables on offshore and onshore. To allow despatch of more reactive power from wind farms, the entire sites must be designed for operation between 0.95 lead (generation) to 0.95 lag (absorption).

9.3 THE COMPENSATION SCHEMES

There are two types of compensation devices, the passive and active types.

The passive types are usually not variable coils in tanks. They are very robust and long life components requiring almost no maintenance. They are well suited to offshore application as they have a small footprint, as a transformer. The disadvantage is that they are designed for a single operational mode, usually to compensate the cable at full load. Also they are unable to assist the grid at rapid load variations.

The active Static VAr Compensators use fast thyristor switched coils and condensers. They may help the flicker and voltage variations caused by the statistical nature of the wind power. By monitoring the voltage on the platforms the SVC may ensure the optimal transmission properties at all operational conditions.

Reactive compensation and Grid Code Compliance need to be fulfilled at the power transmission and distribution terminals to ensure power quality for both steady state and transient operating conditions. Reactive power requirements are local and dependent on the actual load flow and voltage profiles in the meshed distribution systems. In most of the cases when the AC cables are operating on their thermal current limits it is desirable not to transport the additional VAr’s needed from the system through the cables. Also transient and switching surge type overvoltages/undervoltages need to be limited by dynamic compensation and avoiding transformer saturation phenomena during fault recovery of severe AC system faults.

9.3.1 Strong AC grid at feed in point

The grid can supply part or all of the necessary charging current and can absorb the changes in the power variations. In this case passive components on both ends, capable to supply the charging current equally, are adequate.

For lengths shorter than approximately 50km, at voltages 72.5kV or lower, the compensation may not be necessary at all.

9.3.2 Weak AC grid at feed in point

In this case the grid cannot supply the necessary reactive power to the cable or it may be unable to alleviate the power variations or both. In this case a complete power flow study in the net is necessary to find the necessary compensation scheme. This is especially necessary if the cable is to transmit a large amount of power over long lengths. Two solutions are possible in this case.

9.3.3 Voltage support is necessary

If voltage support is necessary but otherwise the system is stable, a SVC with its fast response is a good alternative on shore, while the passive compensation is kept on the platform offshore.

9.3.4 Harmonic resonances limitations/resonances for AC – cable transmission

In the past normally such resonance phenomena were not studied in such detail for AC cable transmission. For very long AC cables in conjunction with a step-up transformer on the onshore main substation, a potential magnification of low order harmonic voltage pre-distortion (inherently 3rd, 5th and 7th from the main grid) may occur. Hence AC cables for long distance transmission can be additionally stressed significantly in addition to the fundamental frequency ratings. Also some of these harmonics will amplify and cause significant stresses down to the offshore medium voltage distribution system. This should be avoided and operational harmonic cable stresses need to be analysed and checked carefully.

9.3.5 Lightning Strike on Wind Turbines (WTs)

Lightning tends to strike wind turbines at the blade end. Strikes are more frequent and the WT blades tend to bend in half.

The lightning does not hit the tip of the WT blade (which could provide a path for lightning current to flow to the earth) but in the middle of the WT blade. It flashes water to steam and opens the trailing edge of the blade. After a few days the WT blade tends to bend.

It is being found that slow rotational speeds tend to result in more strikes along the WT blades.

Receptors are being introduced along the blade. Now lightning strike detections are fitted on the WT blades.

9.3.6 **Lightning Strike on Offshore Platform**

One tall lightning tower, fitted with lightning spike, is mounted at the end of the offshore platform to prevent any damage to the offshore substation equipment.

10. FERRO-RESONANCE

10.1 Ferro-resonance suppression Scheme F1

Scheme F1 is designed to initiate an Alarm condition, for use by local and remote systems as required, while the ferro-resonant is present.

10.2 Suppression Schemes F2A and F2B

Schemes F2A and F2B are designed to initiate an Alarm condition, for use by local and remote systems as required, while the ferro-resonant is present.

Scheme F2A will additionally lock out associated local DAR sequences while the ferro-resonant condition is present.

Scheme F2B will additionally lock out local DAR sequences while the ferro-resonant condition is present and inhibit / lockout remote DAR sequences.

10.3 Ferro-resonance suppression Scheme F3

Scheme F3 is designed to initiate an Alarm condition, for local and remote systems as required, while the ferro-resonant condition is present. Scheme F3 will also initiate an automatic switching sequence that will open / and then close (Flapping) the disconnector (only RCP or REP) between the associated Transformers and Feeders, to quench the ferro-resonant condition.

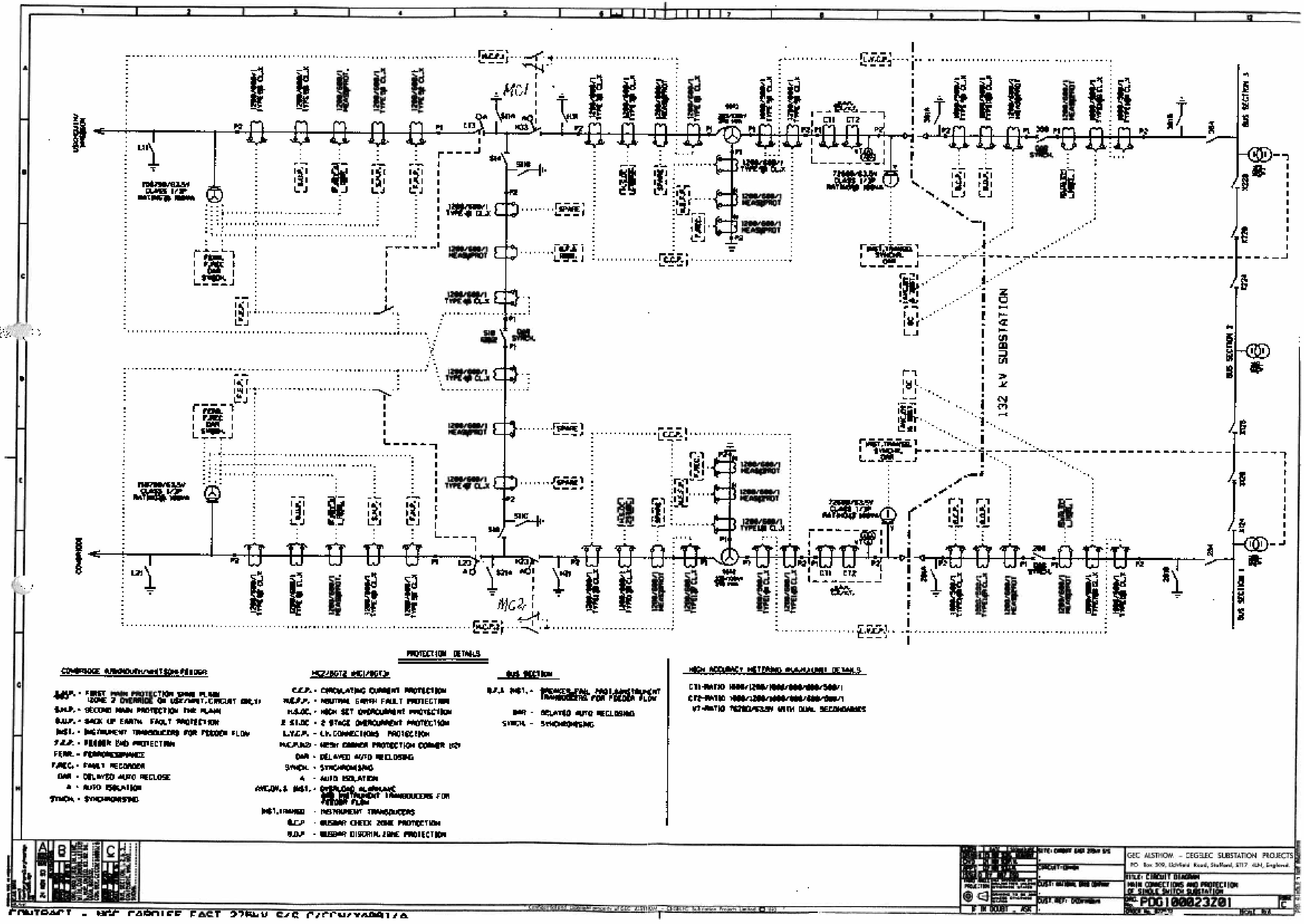
For a Mesh Corner substation the appropriate disconnector would normally be the Transformer HV disconnector(s) associated with the ferro-resonant condition.

In the cases where ferro-resonance is likely to occur due to a banked LV feeder on a 400/275kV transformer then it should be an LV disconnector.

10.4 Ferro-resonance suppression Scheme F4

Where an F3 scheme cannot be applied due to an HV disconnector (Pantograph) switching limitation (cannot be Flapped) in the presence of ferro-resonant condition then scheme F4 may be applied where closure of a suitably rated free standing ferro-resonant quenching earth switch is available for closing and opening (for Flapping).

Once the ferro-resonant condition has been suppressed, the earth switch is opened.


BUS SECTION 1
BUS SECTION 2
BUS SECTION 3
132 kV SUBSTATION
MC1
MC2
C.C.P.
L.V.C.P.
SPARE
PROTECTION DETAILS
C.C.P. - CIRCULATING CURRENT PROTECTION
H.S.OC. - HIGH SET OVERCURRENT PROTECTION
2 ST.OC - 2 STAGE OVERCURRENT PROTECTION
DAR - DELAYED AUTO RECLOSING
SYNCH. - SYNCHRONISING
A - AUTO ISOLATION
INST. TRANSD - INSTRUMENT TRANSDUCERS
B.C.P - BUSBAR CHECK ZONE PROTECTION
B.D.P - BUSBAR DISCRIM. ZONE PROTECTION
BUS SECTION
HIGH ACCURACY METERING DETAILS
F.E.P. - FEEDER END PROTECTION
FERR. - FERRORESONANCE
F.REC. - FAULT RECORDER
DAR - DELAYED AUTO RECLOSE
GEC ALSTHOM - CEGELEC SUBSTATION PROJECTS
TITLE: CIRCUIT DIAGRAM
MAIN CONNECTIONS AND PROTECTION
OF SINGLE SWITCH SUBSTATION
IF IN DOUBT, ASK

Ferro-resonance can occur on circuits with power transformers connected to overhead lines.

Also where wound type electromagnetic voltage transformers are connected to isolate sections of busbars in association with circuit breaker grading capacitors.

Ferro-resonance should not be confused with linear resonance which occurs when inductive and capacitive reactance are equal.

On transformer feeder circuits ferro-resonance conditions can be established between the circuit (overhead line) capacitance and the transformer magnetising inductance.

Power Transformers

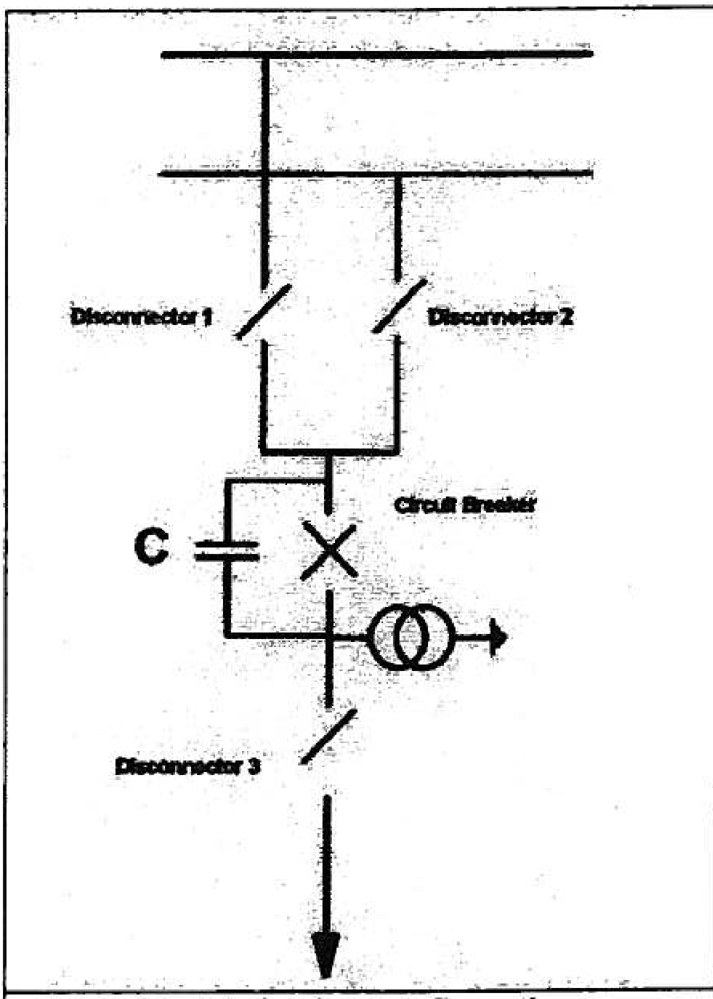
On a transformer feeder associated with a double circuit overhead line route, the ensuing resonance is maintained by energy transferred to the resonance circuit via capacitive mutual coupling from the adjacent circuit(s) on towers, producing the non-linear current and voltage waveforms characteristic of resonance.

Voltage Transformers

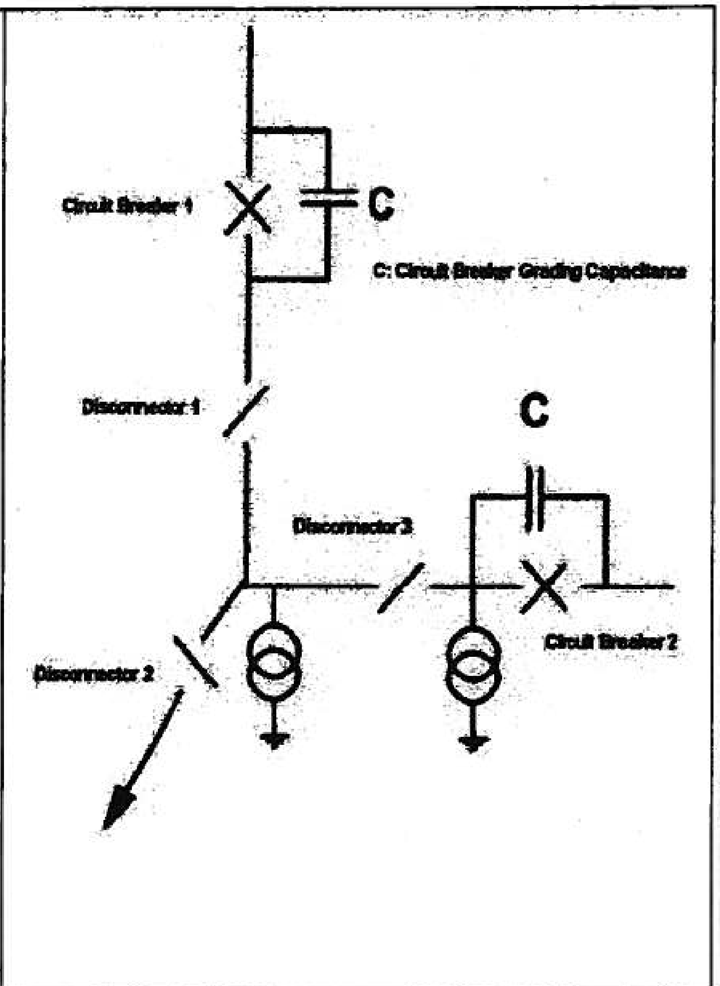
Immediately following de-energisation of a wound VT, an oscillation occurs between the VT inductance and capacitance to earth of any network remaining connected to the VT. These could occur when switching out a wound VT connected by SF_6 circuit breakers which have higher values of grading capacitors and small connected network capacitance.

Capacitor Voltage Transformers (CVTs)

Although CVTs are inherently capable of ferro-resonance, the condition is controlled by the use of integral internal resonance suppression circuits.



Double busbar configuration

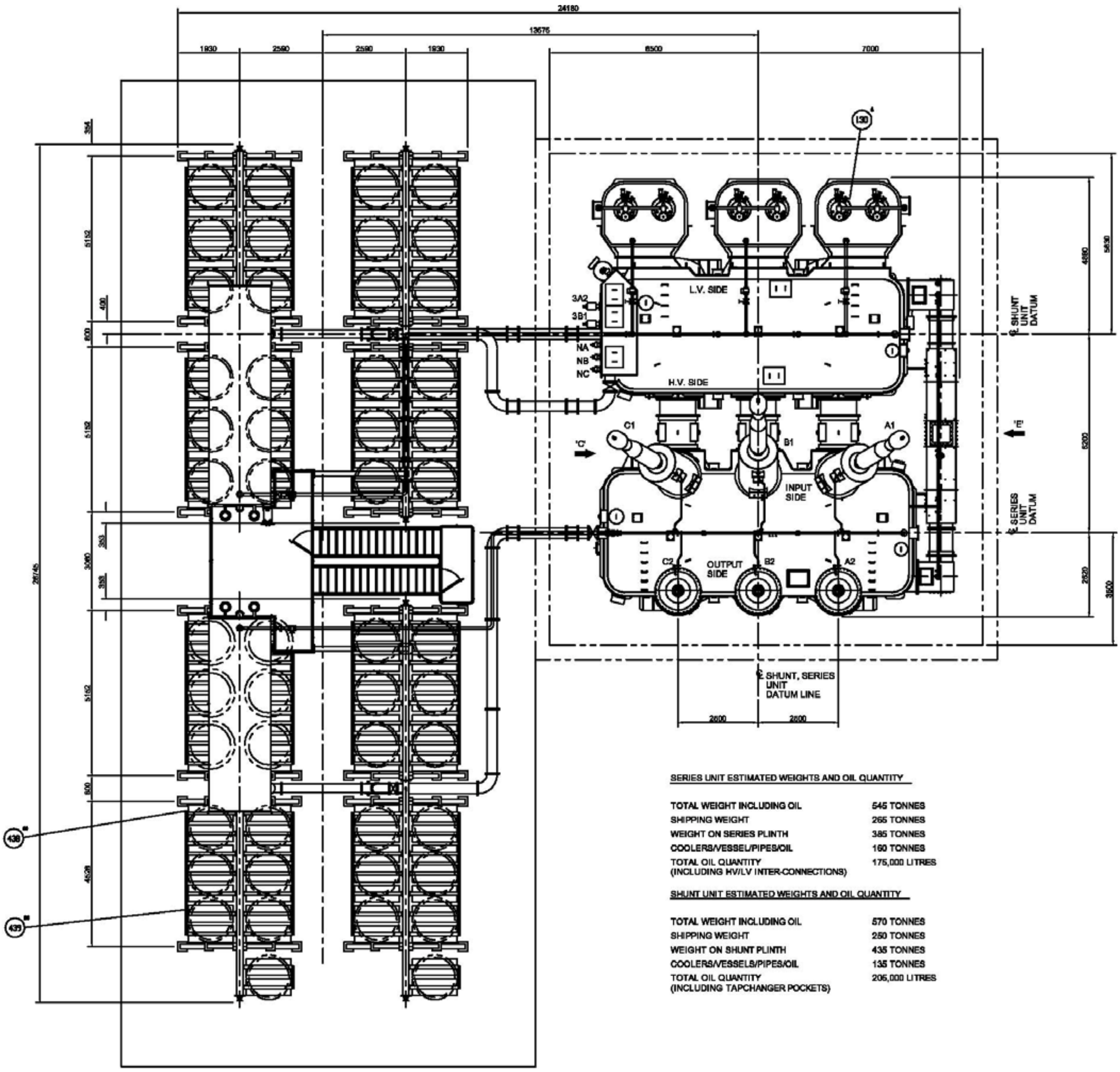


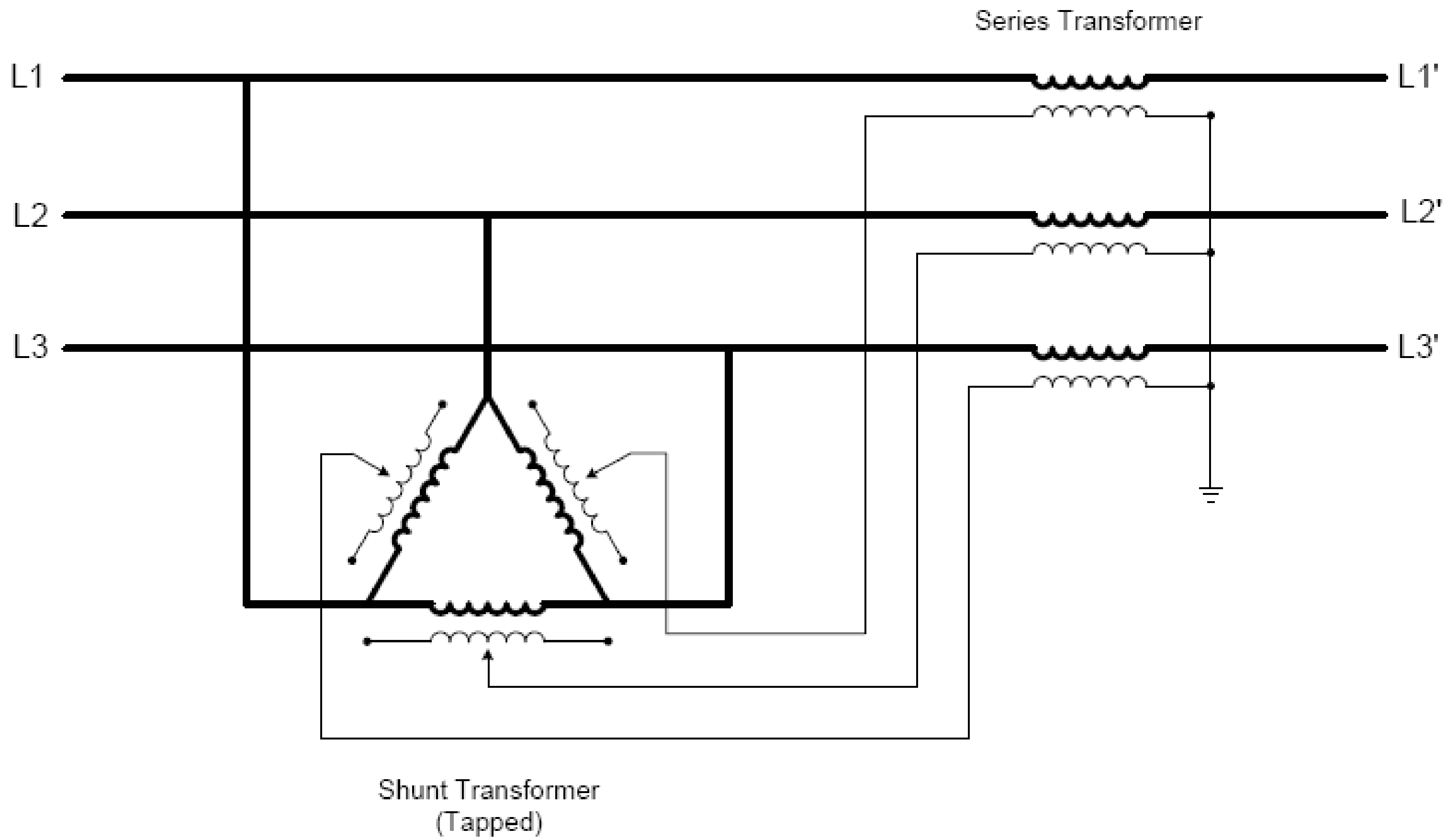
Mesh corner configuration

11. QUADRATURE BOOSTER

Quadrature Booster is a phase shifting Transformer. This is a specialised form of transformer used for controlling the flow of real power on three phase electricity transmission network. These are three single phase quad boosters connected together to form a three phase quad booster unit.

A shunt (exciting) transformer has its primary windings connected in delta across lines L1, L2 and L3. The secondary windings, equipped with tapchanging gear, are connected in Star and supply the primary windings of the quadrature boosting transformer, the latter being connected in Star.





SIMPLIFIED CIRCUIT DIAGRAM OF A THREE PHASE QUADRATURE BOOSTER

The secondary windings of the shunt (exciting) transformer have two independent sets of tappings, one set for the quadrature boost and the other set for the in-phase boost. It will be clear that the primary windings of the in-phase boosting transformer must be connected in delta, in order that the secondary induced voltages shall be in phase with the circuit voltages.

Arrangement

A quadrature booster typically consists of two separate transformers: a shunt unit and a series unit.

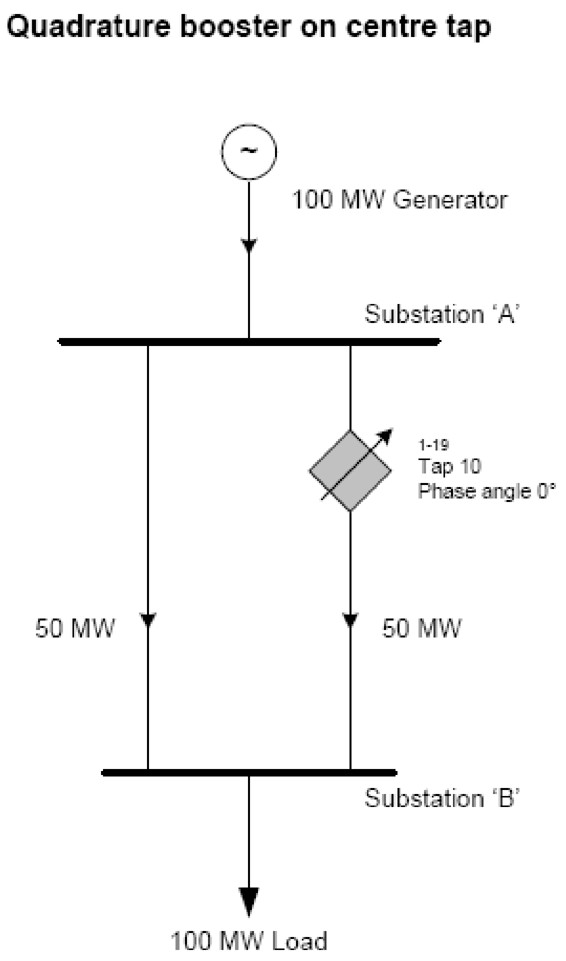
The shunt unit has its winding terminals connected so to shift its output voltage by 90º with respect to the supply voltage. Its output is then applied as input to the series unit. Because its secondary winding is in series with the main circuit, it adds the phase-shifted component. The overall output voltage is hence the vector sum of the supply voltage and the 90º quadrature component.

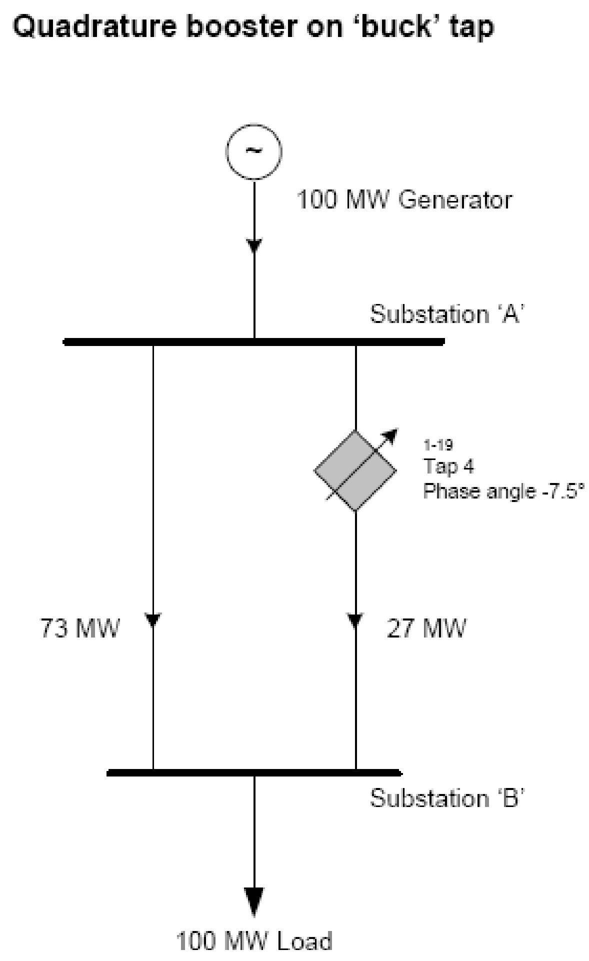
The quad booster shunt unit is normally designed with 1 to 19 taps. The quad booster is controlled to provide negative and positive ranges of flow with magnitude of the phase shift across the quad booster.

The flow on the circuit containing the quad booster may be increased (boost tapping) or reduced (buck tapping).

Method of Operation

By means of a voltage derived from the supply that is first phase-shifted by 90º (hence is in quadrature), and then re-applied to it, a phase angle is developed across the quadrature booster. Quadrature boosters thus provide a means of relieving overloads on heavy laden circuits and re-routing power via more favourable paths.



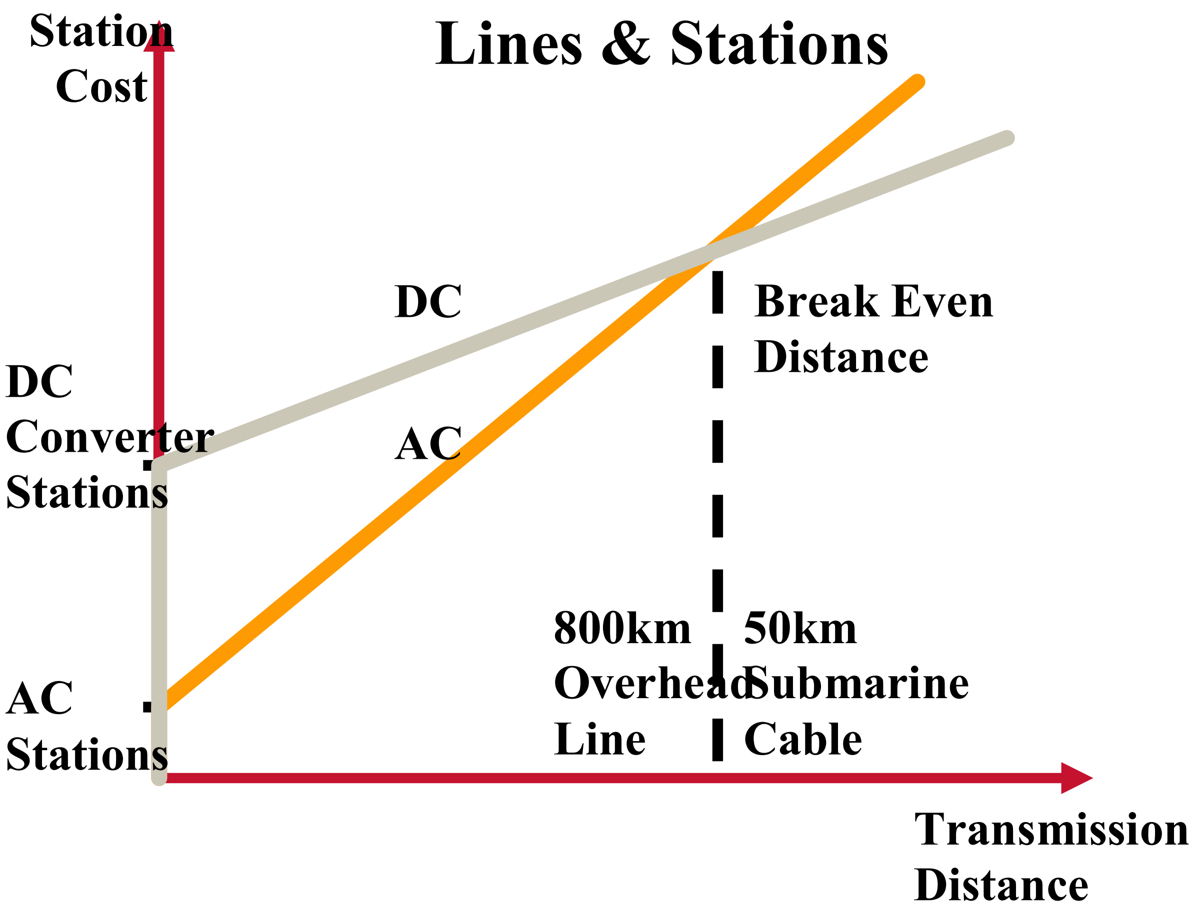


EFFECT OF TAPPING A QUADRATURE BOOSTER

12. HIGH VOLTAGE DIRECT CURRENT (HVDC)

HVDC stands for High Voltage Direct Current
It specifies a system used for transmitting or exchanging electrical power by means of direct current. HVDC transmission is widely recognised as being advantageous for long distance bulk power delivery, asynchronous interconnections and long submarine cable crossings.

HVDC is used to transmit electricity over long or very long distance by overhead transmission lines or submarine cables, because it then becomes economically attractive over a conventional AC transmission lines.

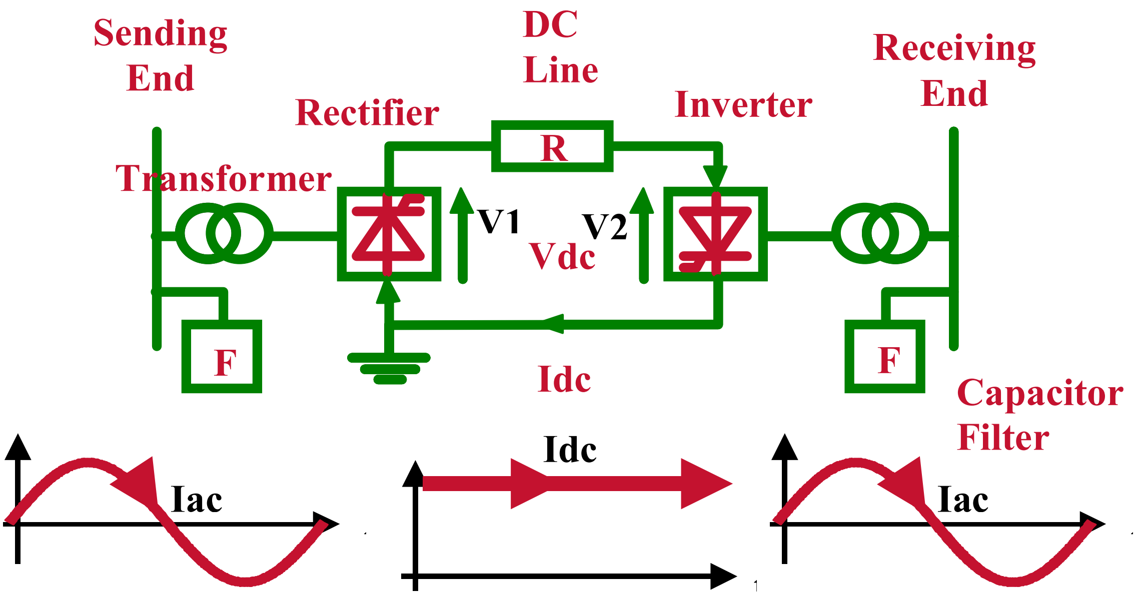


Comparative HVDC & AC Transmission Costs

In a HVDC system, electric power is taken from a three-phase AC network system converted to DC in a converter station, transmitted to the receiving end by a DC cable or a DC overhead line and then inverted back to AC in another converter station and injected in to receiving end AC network system.

HVDC converter station uses thyristor valves to perform the conversion from AC to DC and vice versa. The valves are normally arranged as a 12-pulse converter. The valves are connected to the AC system by means of a converter transformers.

The 12 pulse converter produces odd harmonic currents (h=np ± 1) on the AC side ie 11th, 13th, 23rd, 25th, 35th, 37th ... These harmonics are prevented from entering in to the AC network system by providing AC harmonic filters.

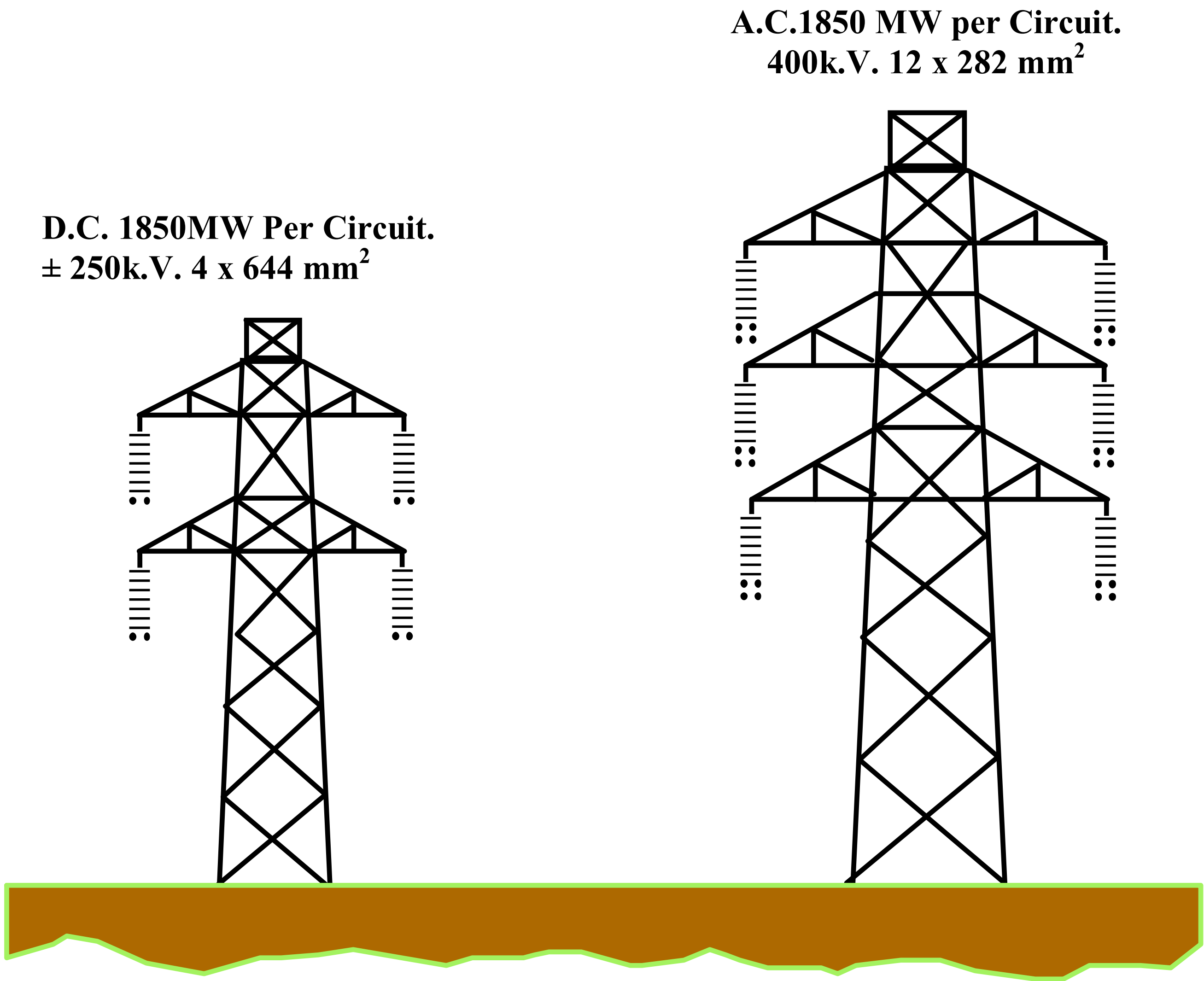


$$I_{dc} = \frac{V1 - V2}{R}$$

The 12 pulse converter produces even harmonic currents on the DC side ie 12th, 24th, 36th. These even harmonics are prevented from entering DC overhead line by providing DC filters. A large smoothing reactor is always installed on the DC side to reduce ripple in the DC current. This large smoothing reactor also filters these harmonics. However for a submarine cable application instead of DC overhead line DC filters are not required.

An HVDC link is two rectifier/inverter stations connected by an overhead line or DC cables. Bipolar HVDC line uses only two insulated sets of conductors rather than three. This results in narrower rights of way, smaller transmission towers. For a given cable conductor area, the line losses with HVDC cables is about 50% of that AC cables. This is due to AC cables requiring more conductors ie three phases, carrying reactive component of current, skin-effect and induce currents in the cable sheath and armour.

Transmitting power over DC lines requires fewer conductors (ie 2 conductors; one is positive another is negative)

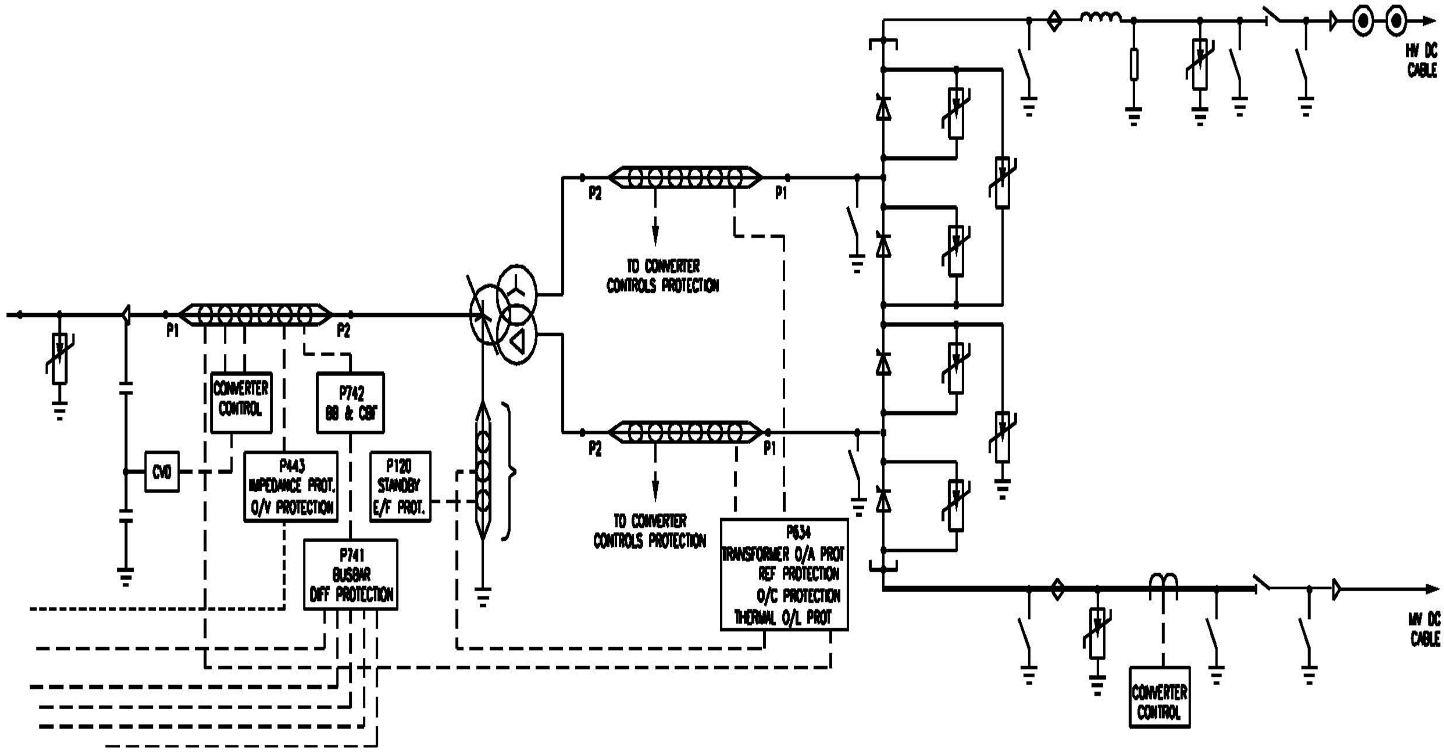


Rectification Station

Converting AC to DC is called rectification and DC to AC called inversion.

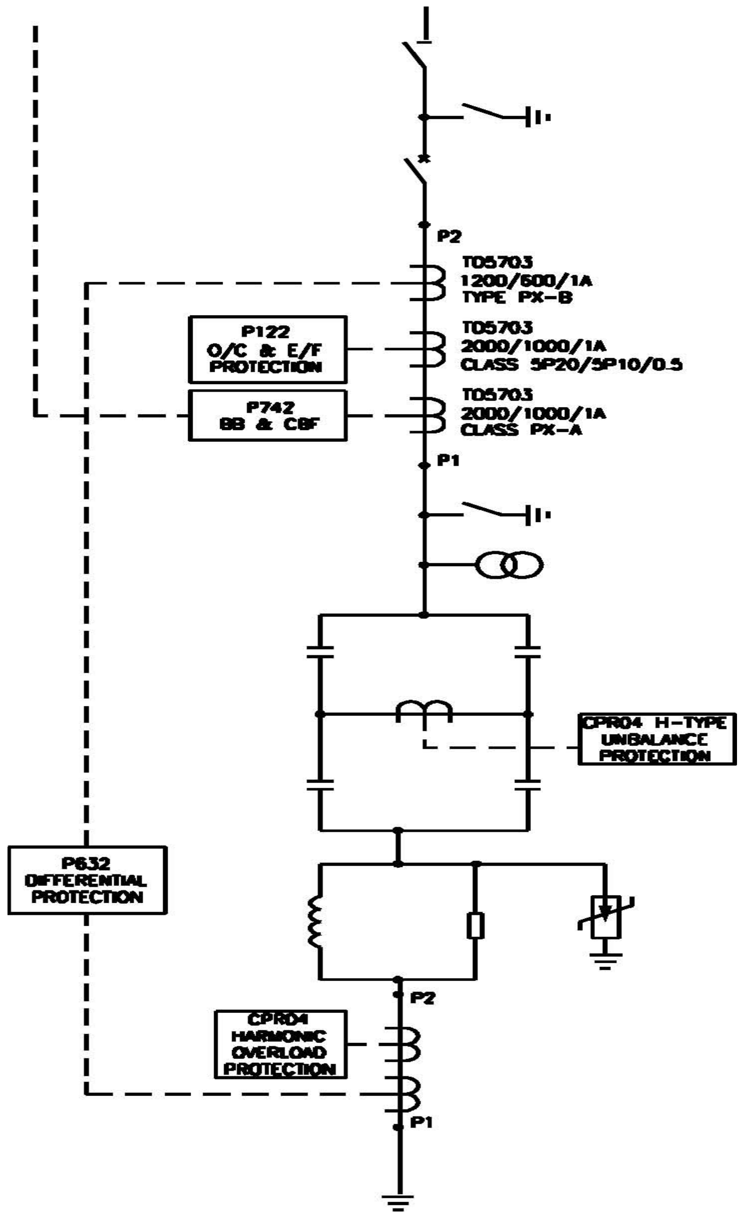
At the rectification station, three single phase converter transformers are used. Each single phase converter transformer consists of one primary winding with Star (Y) Wye arrangement to connect AC system and two secondary windings to split AC into two separate AC supplies. One of the two secondary windings is configured to have a Star (Y) Wye arrangement and the other to have a Delta ( ) arrangement to provide a phase shift of 30 degree between two sets of three phases and to ensure a correct AC voltage for connecting 6 pulse or 12 pulse thyristor valves to convert AC voltage to DC voltage. The valves employ high power thyristor valves, together with associated gating, damping and grading circuits, arranged in 6 pulse or 12-pulse converter groups.

A similar arrangement is provided at the inverter station with three single phase transformers, with the same MVA ratings with one primary and two secondary windings as described above together with associated gating, damping and grading circuits, arranged in 6 pulse or 12-pulse converter groups connected in anti parallel direction to allow DC current to flow in the same direction as the converter station.

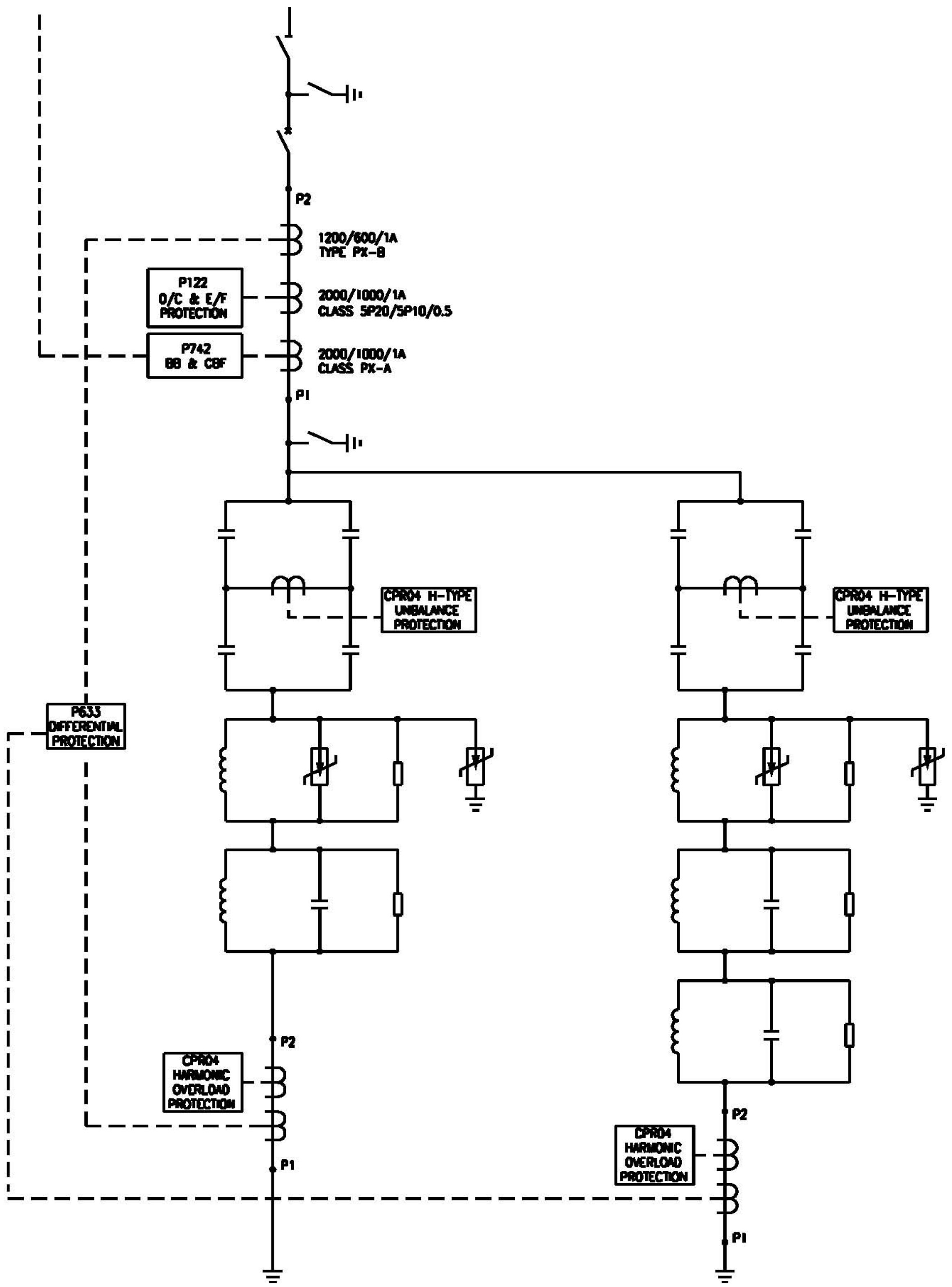


Objectives of the AC filter design

The key objectives of the AC design are to:
Maintain the harmonic distortion within the limits specified in the Technical specification.
Minimise the reactive power imbalance between the converter station and the AC system to the values within the limits specified in the Technical specification.
Minimise filter fundamental frequency losses whilst providing damping (ie harmonic loss) to achieve the performance limits.
Any individual harmonic voltage distortion (Dn) shall be within the limits specified in the Technical specification.
Pre existing harmonic distortion should be taken in to consideration whilst designing the filters.
Line commutated current source converter (CSCs) can only operate with AC current lagging the voltage, so the conversion process demands reactive power. Reactive power is supplied from the AC filters provided for filtering the harmonic currents generated by the thyristor valves. The AC filters are shunt capacitor banks at fundamental frequency.
From power system study, first calculate the total requirements of installed value of shunt capacitor banks to achieve the required generation of reactive power for each side of the converter station.
The performance of the AC harmonic filters and their operational losses were calculated using the network Harmonic Penetration Program HARP



5th HARMONIC FILTER-118MVAr

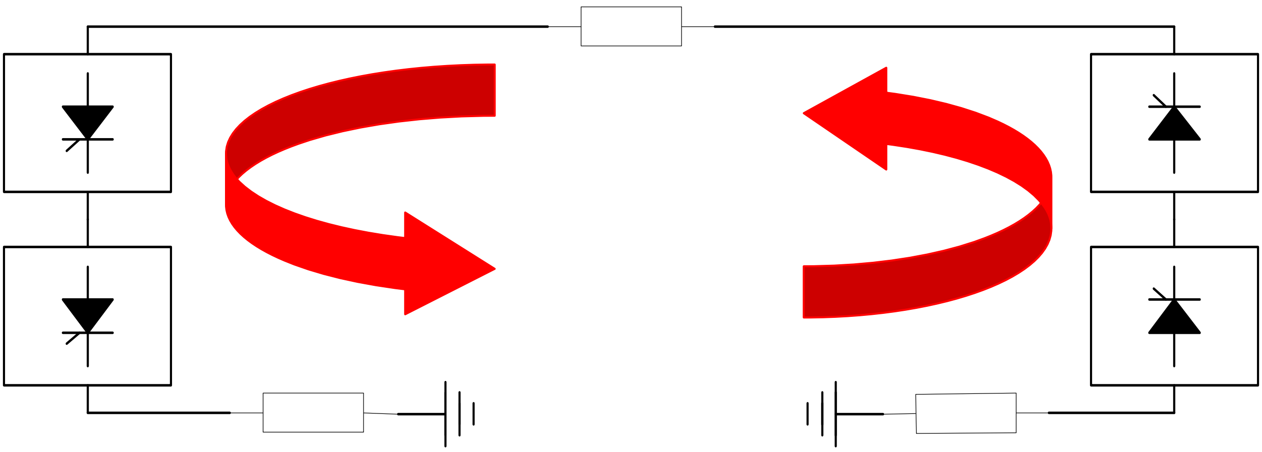


3rd/11th HARMONIC FILTERS- 92MVAr

13th/23rd/35th HARMONIC FILTERS-58MVAr

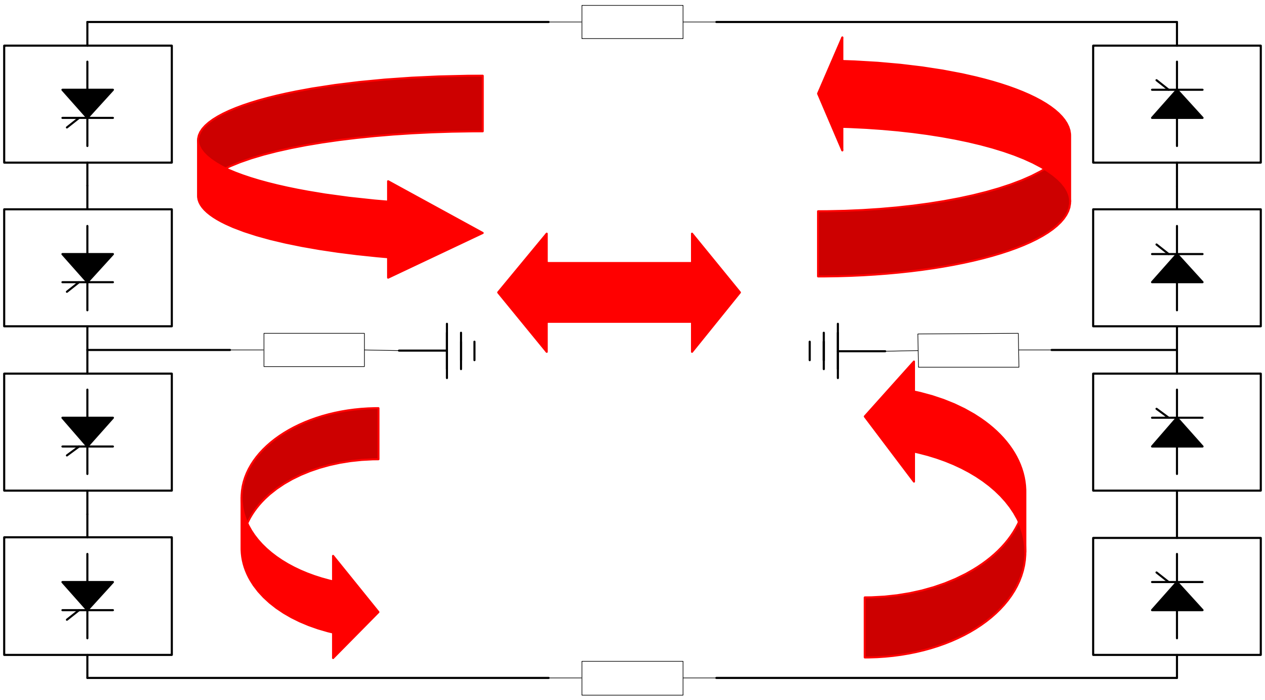
Monopole

In a monopole Configuration, one of the terminals of the rectifier is connected to earth ground and the other terminal which is at high potential, is connected to a transmission line or cable. The earth terminal may or may not be connected to the inverter station by means of a conductor, all depend on where the inverting station is situated. To avoid any electrochemical corrosion, any water pollution or magnetic field disturbance, earth terminal should be connected to the inverting station by a lower insulation conductor. Advantage of monopole configuration is that the monopole configuration can be expanded in to a bipole configuration in the future.
Monopolar systems are the simplest and least expensive systems for moderate power transfers since only two converters and one high-voltage insulated cable or line conductor are required.



Bipole

In a bipole configuration, each terminal of the rectifier is connected at high voltage to each converter terminal. Each terminal will be at high potential and the conductors connecting rectifier and the inverter should be insulated to a high voltage. This clearly indicates that the bipole transmission is more expensive than the monopole DC transmission. However the bipole configuration has more advantages than the monopole configuration. Bipole configuration can be controlled with separate control system or with bipole control system. A bipolar system can also be installed with a metalltalic earth return conductor.



Back-to-Back Scheme

For a back- to-back scheme both the ends of the scheme are at the same location, more typically both converters are located within the same building, known as a valve hall. In this case the transmission link is not 800km of overhead line but is an 8 to 10m of aluminium busbar.

Exchange of Power Between AC Systems which are not Synchronised.

Because power transmitted as DC is asynchronous, ie it is independent of the voltage and phase angle at either end of the link, two AC systems which are not synchronised can still exchange power.

Line Commutated Thyristor Valve For HVDC Applications

AREVA's latest range of thyristor valves for HVDC converter applications is the H400 Series. They use direct liquid cooling which enables a single circuit system with either pure deionised water or a water/glycol mixture, depending on ambient temperature conditions at site. The valves are also air insulated and suspended within a controlled environment. By suspension mounting the valves, the mechanical stresses are reduced, which is of particular importance for applications in seismic areas. The valves employ high power thyristors, together with associated gating, damping and grading circuits, arranged in 6 pulse or 12-pulse converter groups. According to the application type, thyristors with different voltage ratings and diameters can be easily accommodated.

The valves can be configured for either a mono polar or bipolar operation, as a Back-to-Back or a two terminal transmission scheme.
Figure 1 below shows a typical HVDC converter valve arrangement.

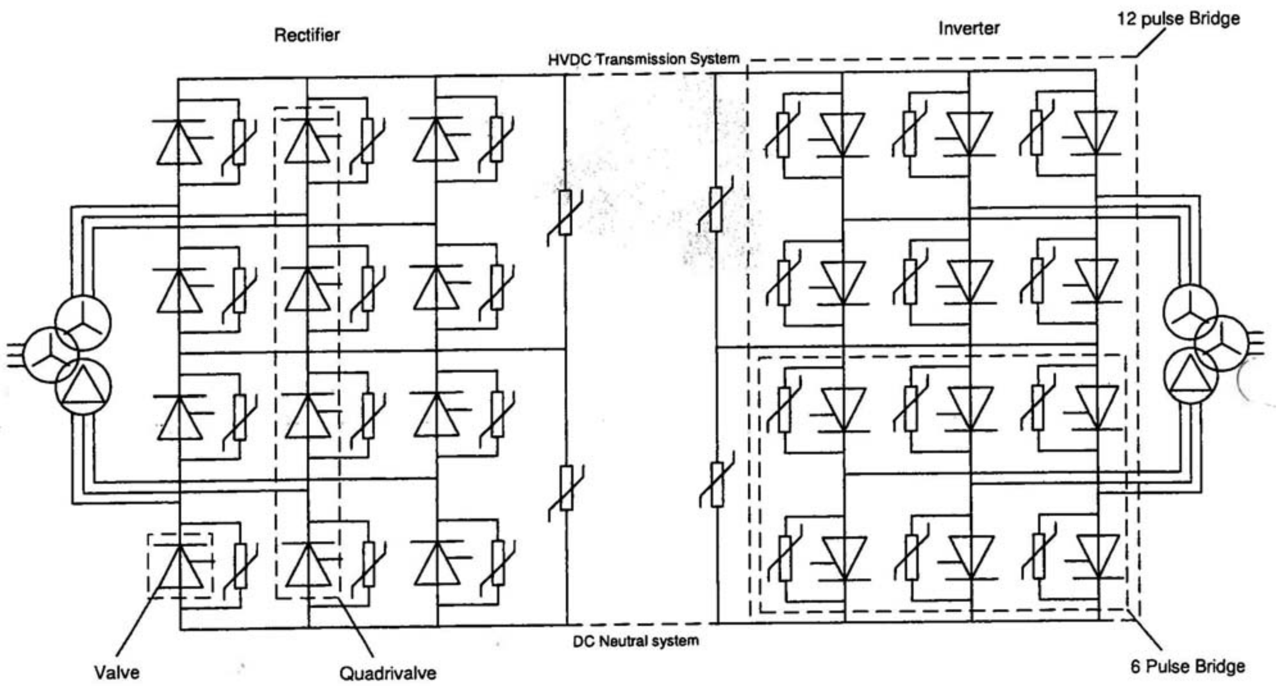


Figure 1 Single Line Diagram of a typical Transmission Scheme

VALVE ELECTRICAL ARRANGEMENT

Thyristor Level

Every valve within a converter group consists of an identical number of ‘thyristor levels’ connected electrically in series. Each level comprises a single thyristor, gate electronics and parallel connected damping and grading circuits.
They also serve to control the voltage and current transients at firing and recovery. The gate electronics provide electrical gating of a thyristor under normal and abnormal operating conditions. The basic circuit representation of a single thyristor level is illustrated in Figure 2.

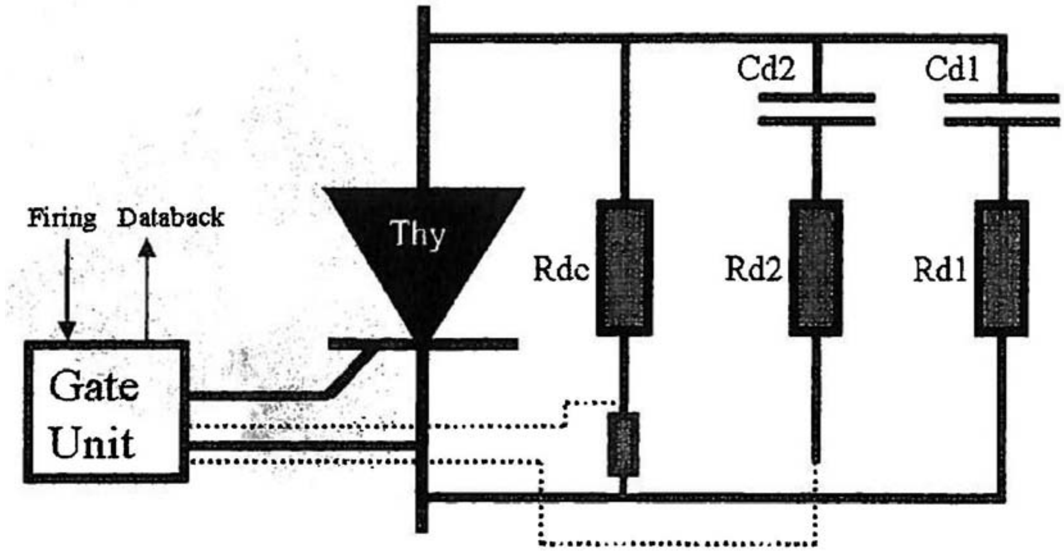


Figure 2 Single Thyristor Level

It is important to aim for a low protective level, but also ensure the rating of the arrester is sufficiently high so that its continuous power dissipation is low. The latter being to avoid thermal runaway in the arrester’s zinc oxide blocks. Therefore preliminary system studies are carried out to estimate the valve arrester coordinating currents and energy inputs during faults and enables the number of arrester columns to be calculated. Once the surge arrester design is confirmed, the number of thyristor levels per valve can then be determined.

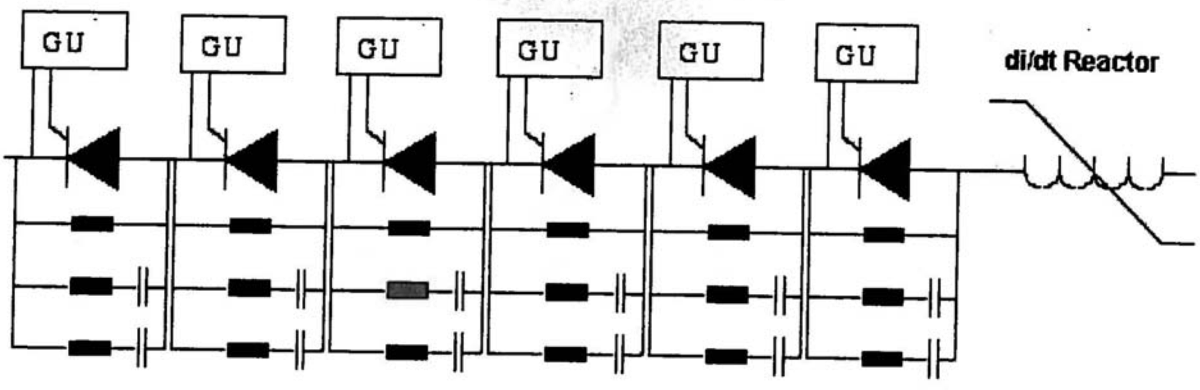


Figure 3 Basic Electrical Circuit of a Thyristor Valve Section

Valve Section and Clamped Assembly
Owing to the number of thyristors connected in series for HVDC converter valve applications, it is convenient to consider a valve, both electrically and mechanically, as divided into a number of ‘valve sections’. A valve section consists of up to 6 thyristor levels connected in series with a saturating reactor to protect against high di/dt at valve turn-on. The 6 thyristors within the valve sections are all held together between high-efficiency liquid cooled heatsinks as one ‘clamped assembly’. Glass-Reinforced Plastic (GRP) tension bands are used to tightly secure the assembly. These provide the high clamping load necessary for good electrical and thermal contact between thyristor and heatsink. The tension bands also maintain adequate dielectric strength support the voltage stresses experienced during the off-state intervals of the valve. The clamping system facilitates replacement of a thyristor without opening any power or coolant connections.

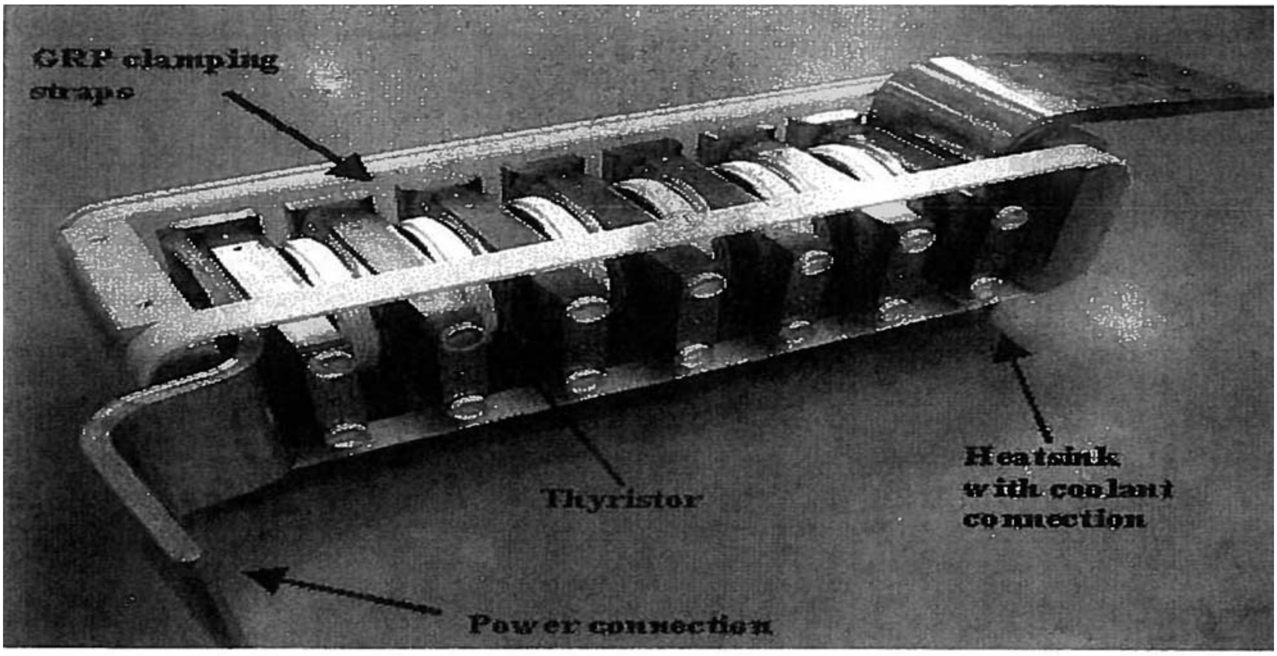


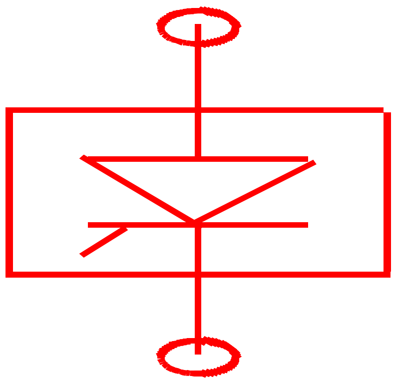
Figure 4 Thyristor Clamped Assembly

Voltage Damping and Grading Circuits
Where two more thyristors are connected in series in a valve, careful attention must be paid to voltage sharing within the valve. This is because the voltage withstand capability of the valve as a whole is invariably less than the sum of the voltage withstand capabilities of the individual thyristors. This arises from variations between series thyristors, of off-state leakage currents and stored charge at turn-off.
As already seen in the above figures 2 and 3, two RC circuits are connected in parallel with each thyristor level, to provide voltage grading under normal operating conditions. The main RC damping circuits also act to control the transient voltage and current stresses during thyristor turn-on and turn-off; furthermore they provide power to the gate electronics at each level.

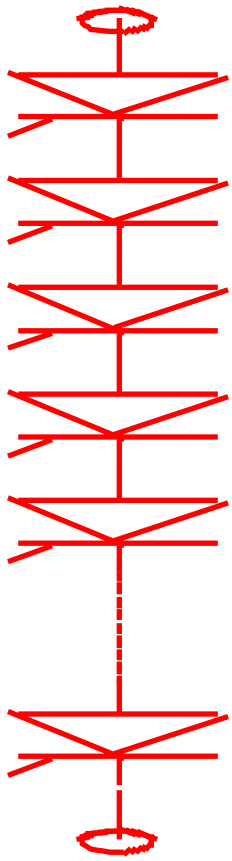
HVDC Control System
For a conventional HVDC transmission, one terminal sets the DC voltage level while the other terminals regulate the its DC current by controlling its output voltage relative to that maintained by the voltage-setting terminal. Since the DC line resistance is low, large changes in current and hence power can be made with relatively small changes in firing angle (alpha).

The control system provides all of the functionality needed to control and protect the HVDC equipment and ensure safe stable real and reactive power flow through the converter and into the connected power systems. The control system controls the valve firing, filter switching, tap changer operation, cooling plant operation and provides protection for thyristor valves and other related DC equipment including the HVDC transmission lines and/or cables. The control system has been designed for use in both manned and unmanned stations.
Station control comprises the followings:
• Station Power Control
• Power Demand Override Control
• Reactive Power
•.Ac Voltage Control
HVDC Protection
Conventional protections are provided for Converter transformers, filters, Busbars and feeders

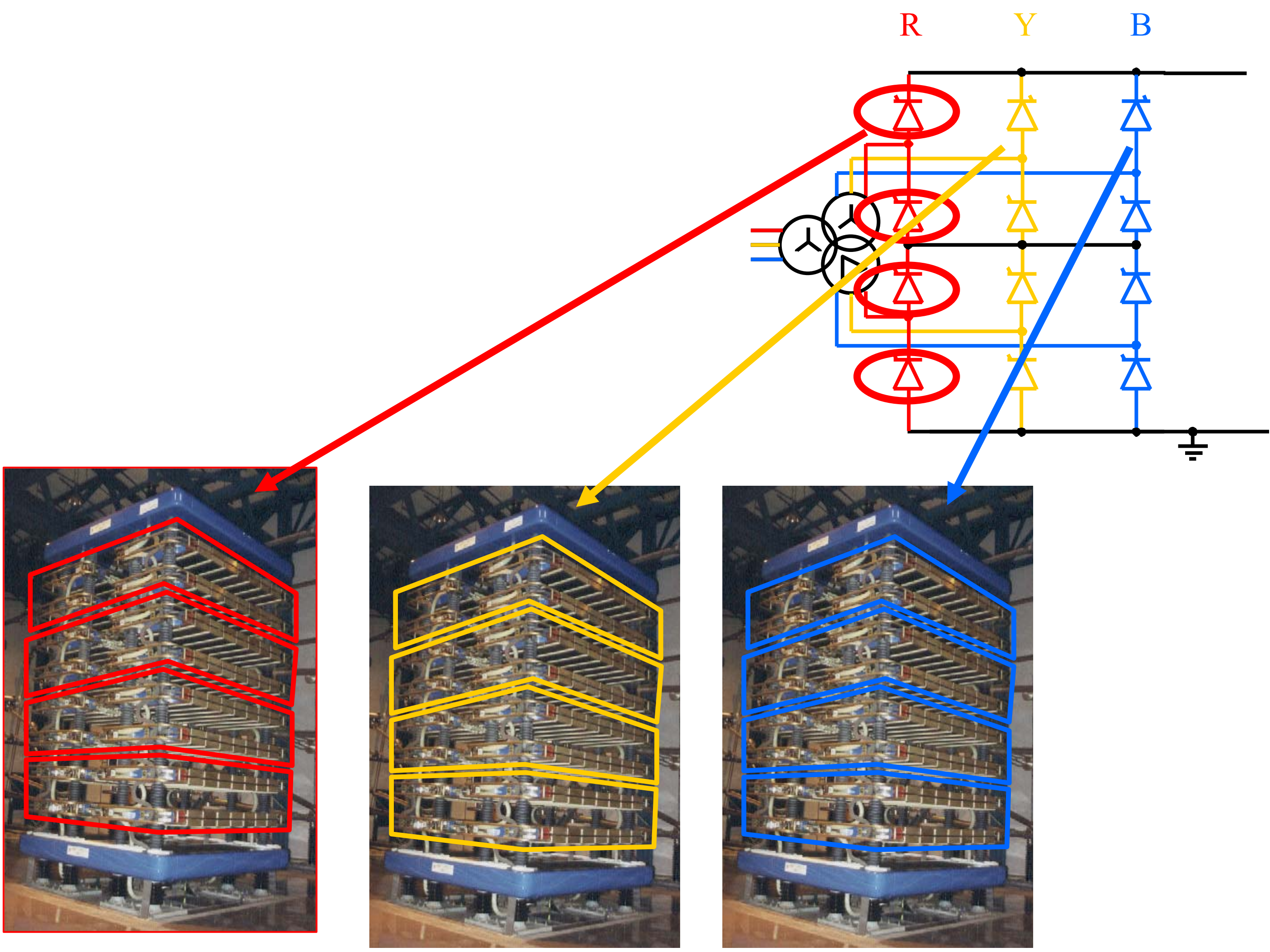
Basic function: a switch
Turns on when instructed by controls
Turns off at current zero



Rapid switching
Zero power losses
Electrically and mechanically robust
Fire-retardant



▸ **Thyristors connected in series**
- voltage grading circuits required
4**Relatively slow switching**
4**Switching not perfectly coherent**
4**Finite losses: typically 0.5%**
- requires forced cooling
4**Vulnerable**
- requires various electronic protections
- care needed to avoid risk of fire



Complete Thyristor Bridge

13 LIGHTNING AND EARTHING

Lightning Protection

Lightning protection should be carried for open terminal substations to prevent the followings:

1. Damage to Substation Equipment
2. Loss of Power to Public

The power equipment in a substation may be exposed to lightning in two ways.

A) By voltage and current waves travelling along the exposed lines leading to the station.

B) By direct lightning strokes to the station.

Outdoor substations and switchyards are shielded against direct lightning strokes by:

i) Earth Wires (Shield Wires)

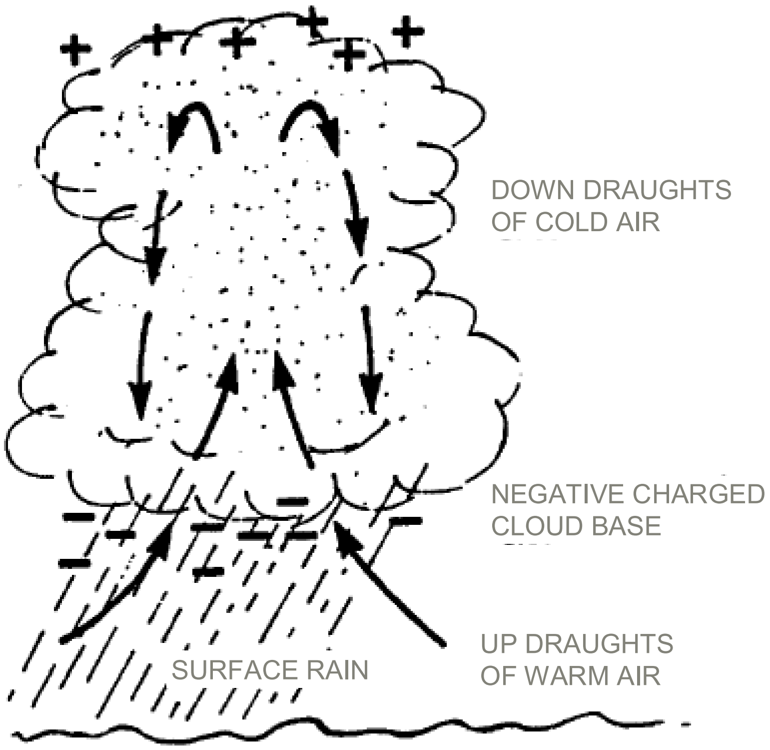
ii) Masts

iii) Earth wires and Masts

Different methods are used to design the shielding of substations against direct lightning.

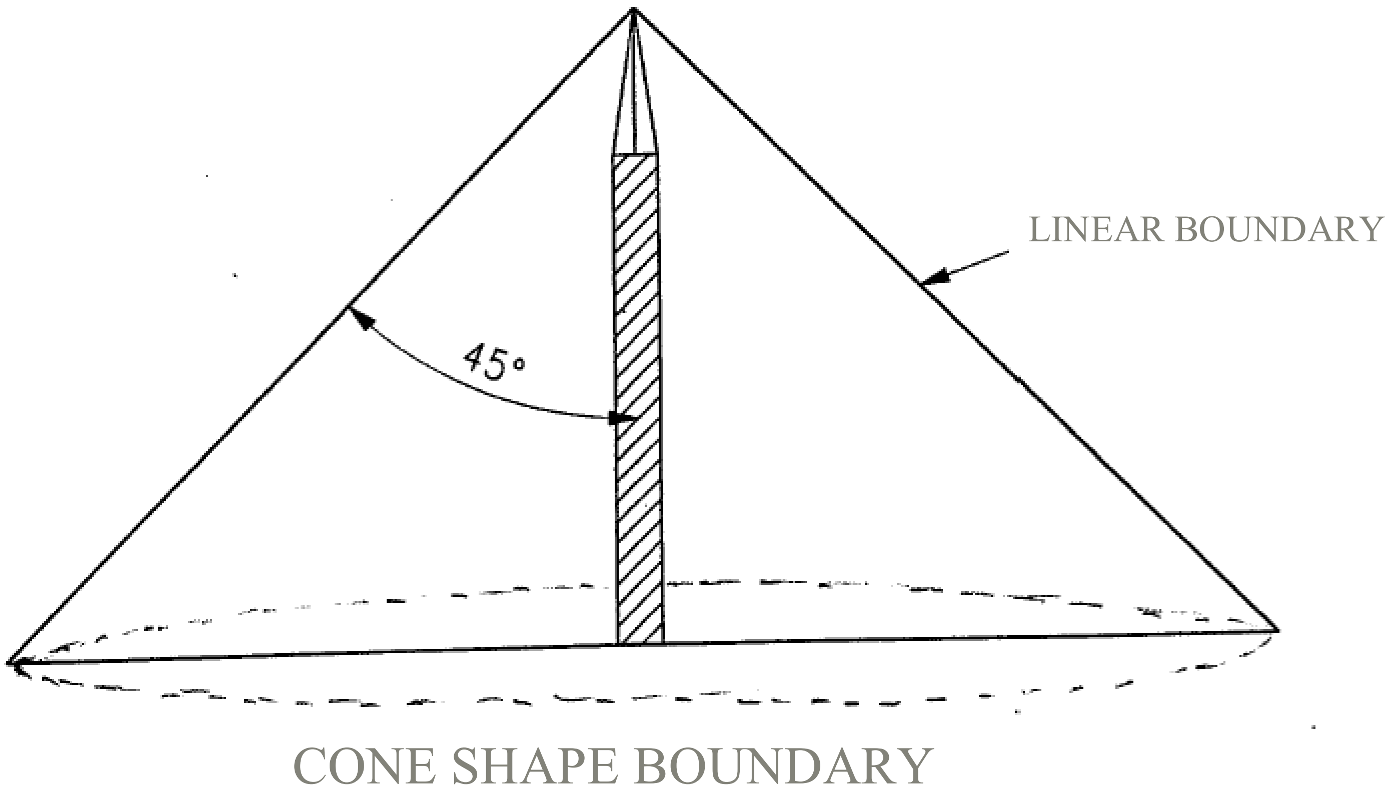
1. Fixed Angles
2. Electrogeometric Models

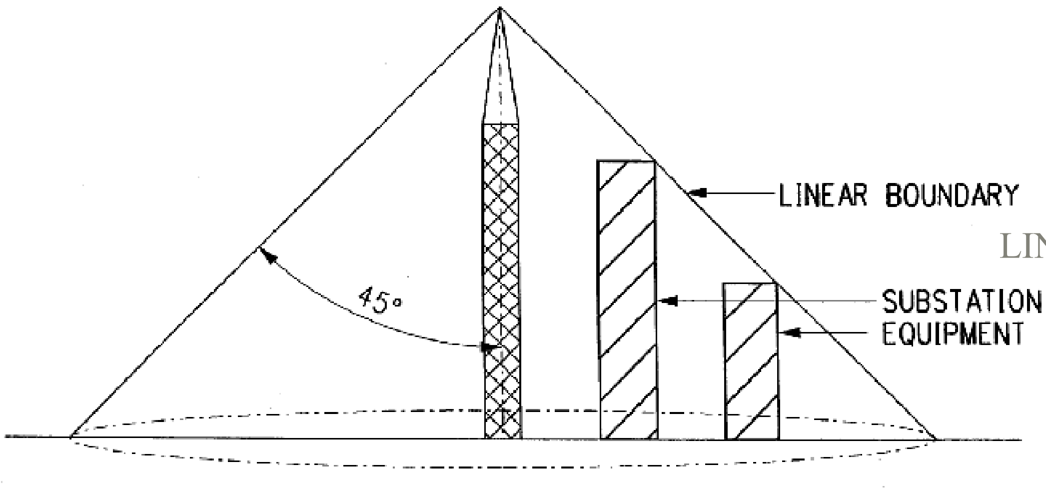
A thunderstorm is formed due to cloud becoming electrically charged.



Method of Estimating Extent of Shielding

Until recently a shielding angle of 45° was used BS (CP 326).





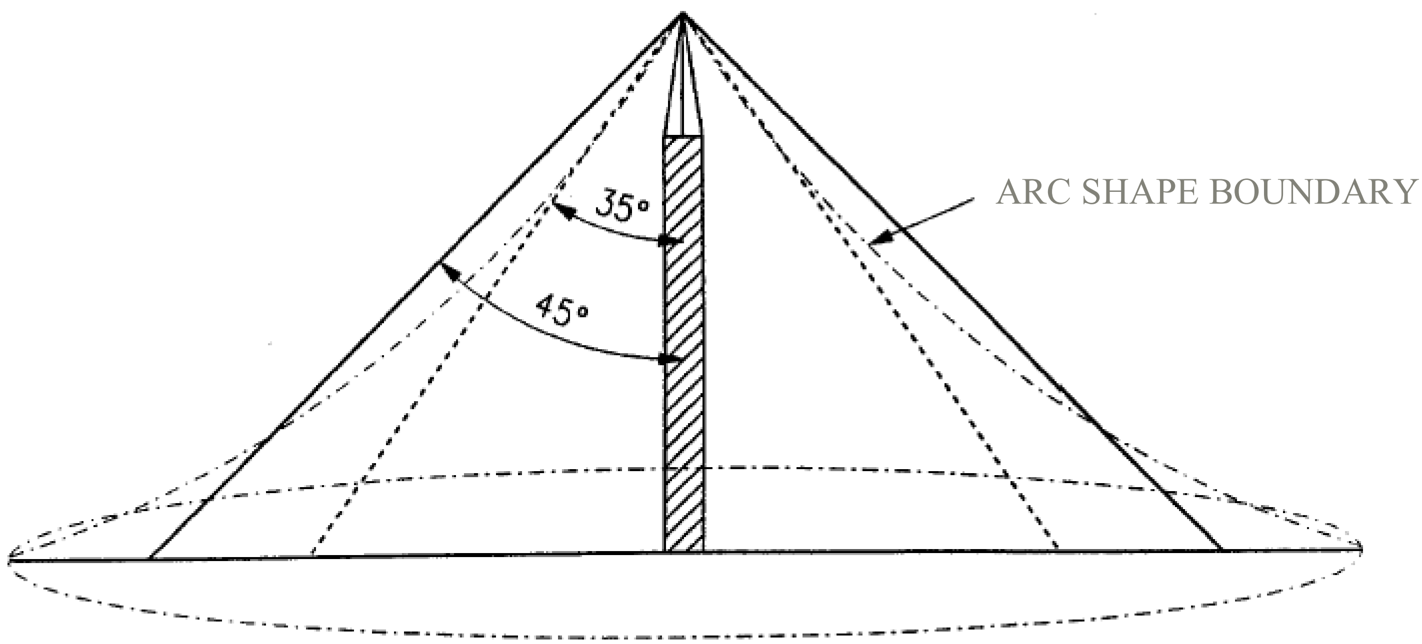
CONE SHAPE BOUNDARY

LINEAR BOUNDARY

SUBSTATION
EQUIPMENT

CONE SHAPE BOUNDARY

Nowadays Arc-shape boundary is considered. This means 32° to 35° shielding angle is used



SHEILDING ZONE HAS 'TENT SHAPE'

The shielding has its centre at twice the height of the mast (shielding wire) and the resulting tent has an Apex Angle of 2 x 30°. This angle agrees closely with that stated formerly of 32° to 35°.

Height or the mast depends on the size of the substation.

Based on electro geometric model, the rolling sphere method was developed. According to this method a sphere is rolled over the contour of the substation. The radius of the sphere is the striking distance corresponding to the critical current of the return stroke.

For overhead lines, critical return stroke current I_C

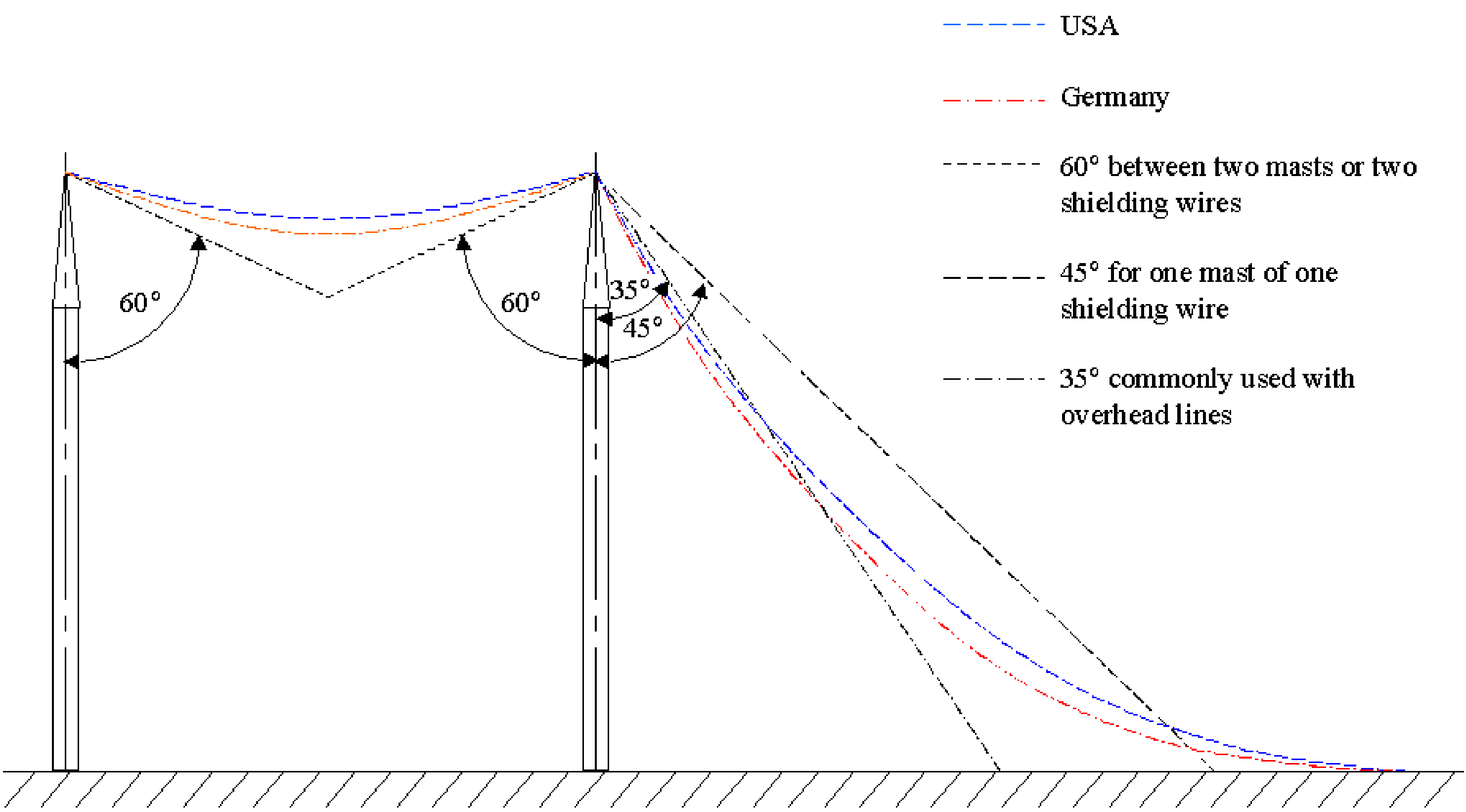
$$I_C = \frac{2 \times BIL}{Z_P}$$

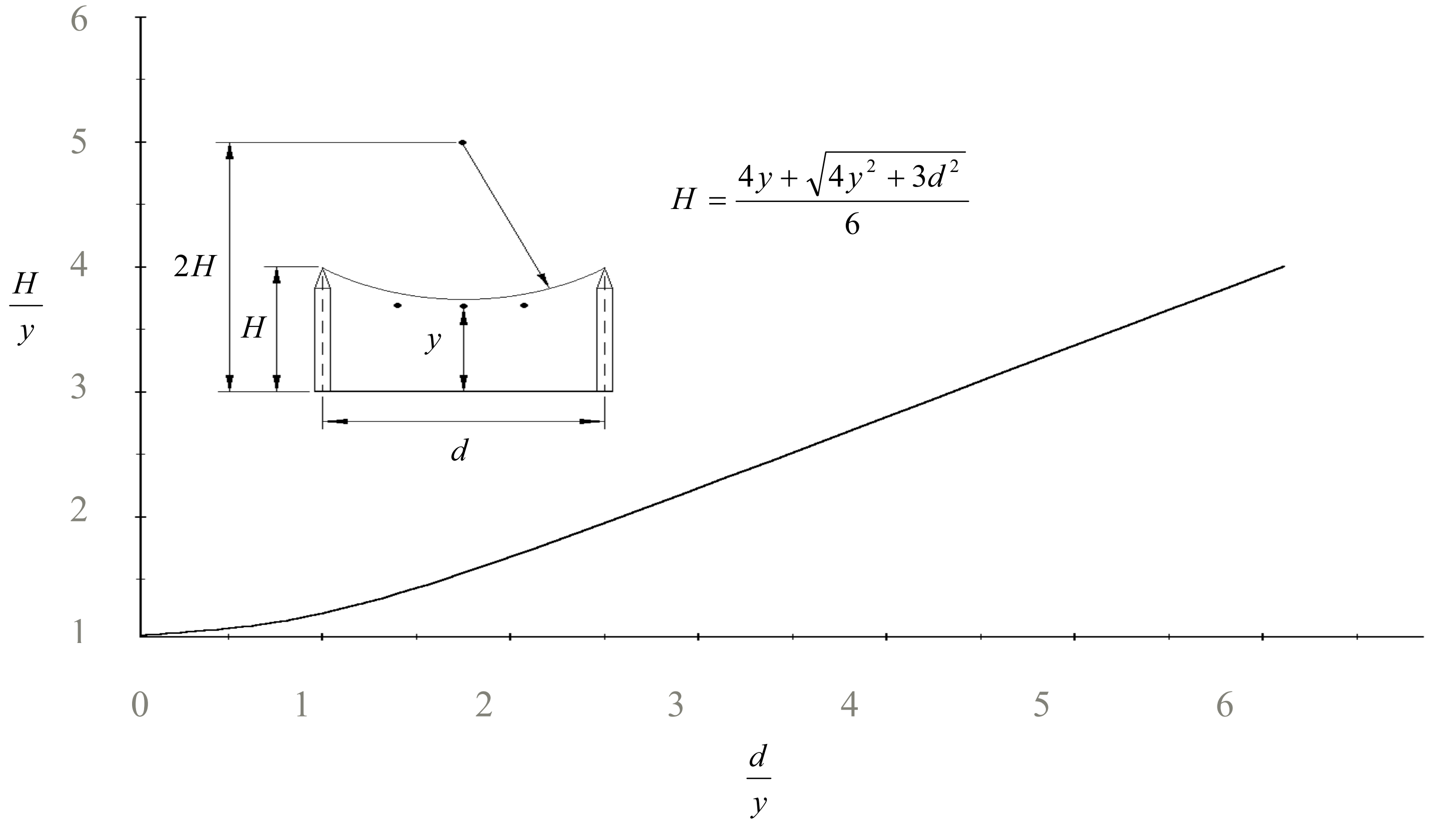
Where Z_P = Surge Impedance

The striking distance $r_S = 8 \times I^{0.65}$(m)

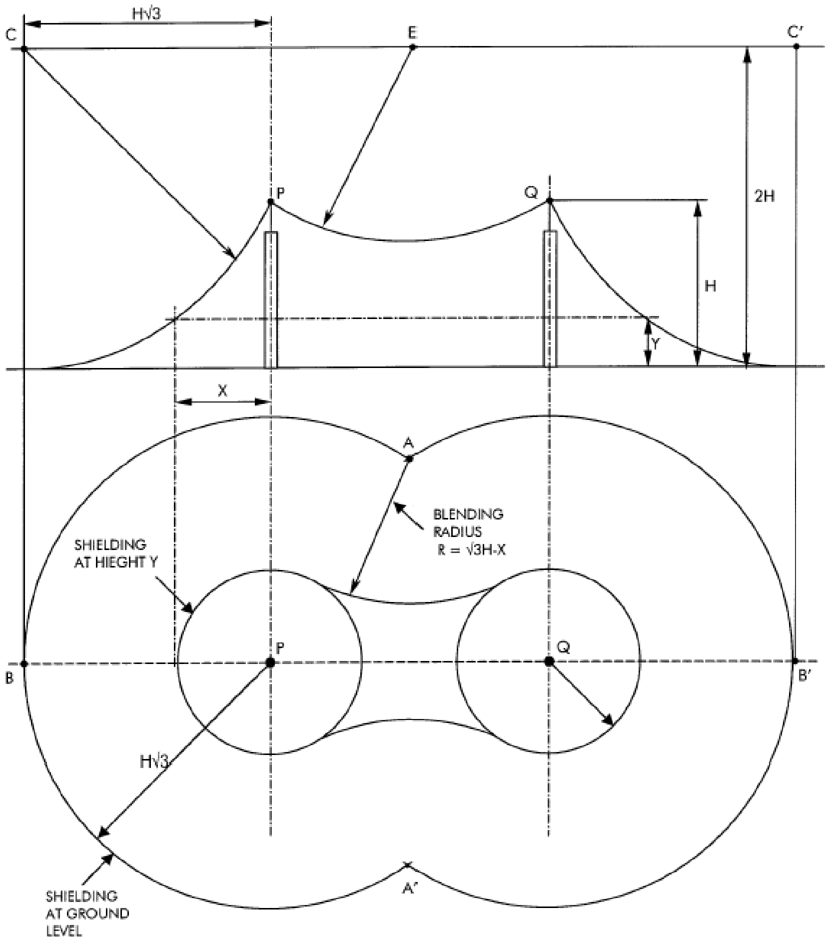
Where I = Return stroke current

Comparison of shielding according to various methods

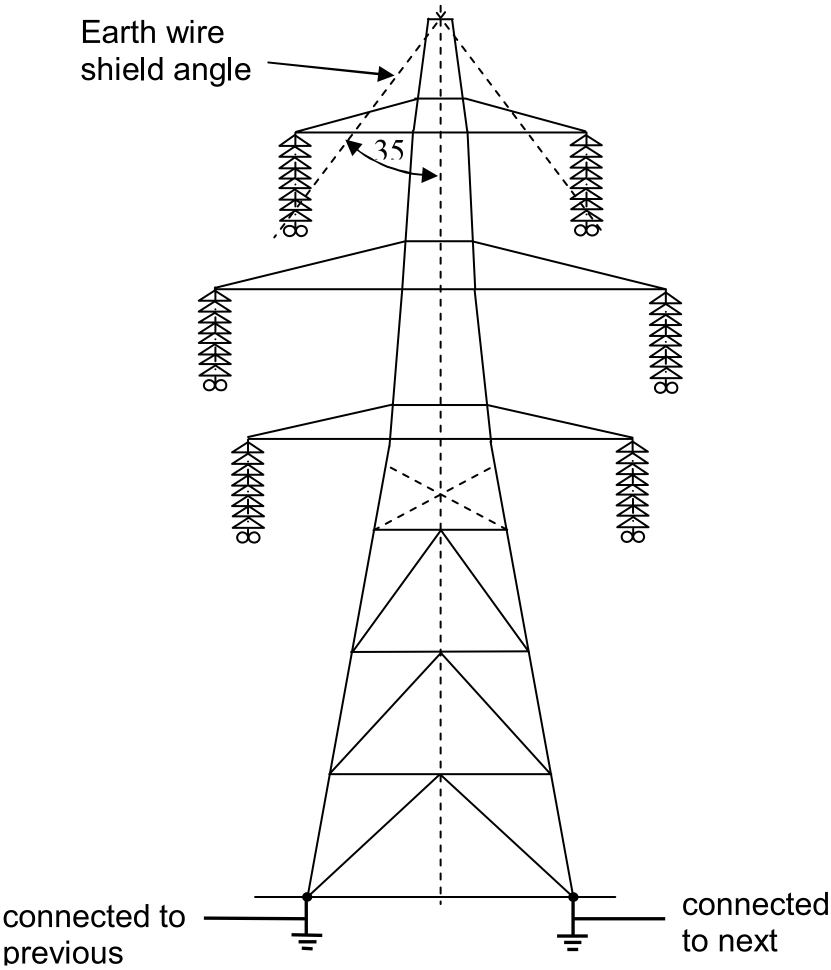




Height of the shielding wires



Shielding Provided by Two Equal Height Masts



Overhead Line Tower Showing Earth Wire Shield at 35 degree to the Vertical Protecting 3 Phase Live conductors.

Offshore Wind Farm Substation Platform

EARTHING

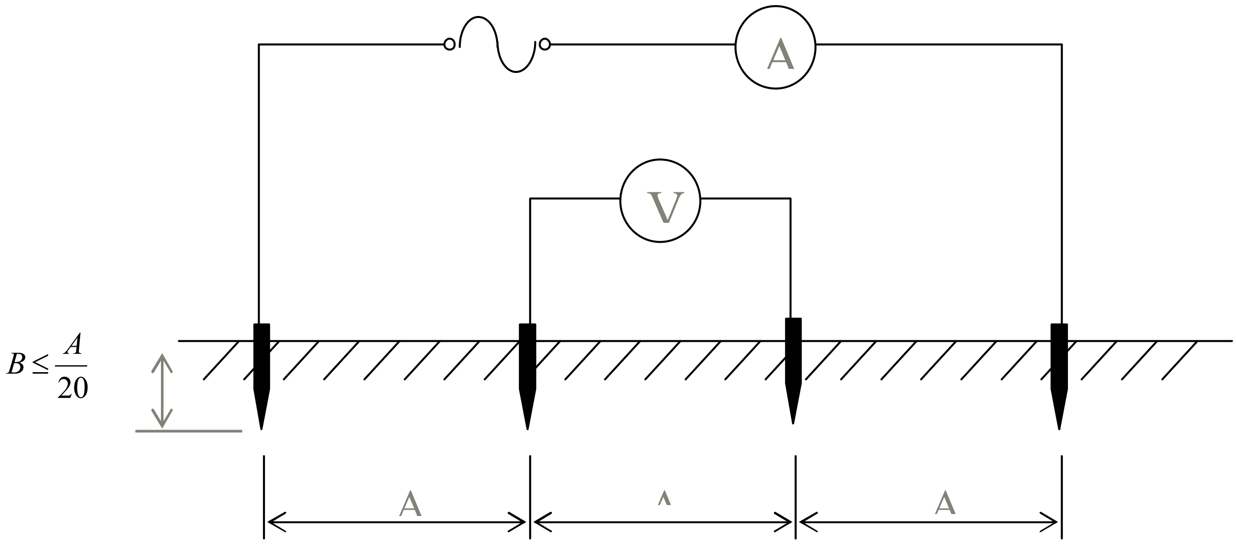
Soil Resistivity Measurement

Measuring Instrument

1 - Megger digital earth tester DET 5/2D and accessory kits.

Setting up the Test Spikes

For soil resistivity measurement, the instrument test leads are connected to spikes which are hammered into the ground as shown.



$$\rho = \frac{4\pi AR}{\dfrac{2A}{1+\sqrt{A^2+4B^2}} - \dfrac{A}{\sqrt{A^2+B^2}}}$$

Where

ρ = Resistivity of the soil in W-m

R = Resistance in Ohms resulting from dividing the voltage between the potential probes by the current flowing between the current electrodes.

A = Distance between adjacent electrodes in m

B = Depth of the electrodes in m

If *B* is small compared to *A*, as is the case of probes penetrating the ground a short distance only, the above equation can be reduced to:-

(*B* not exceeding one twentieth of their separation). Equation 36, ANSI/IEEE80 – 1986

The current tends to flow near the surface for small probe spacings, whereas more of the current penetrates deeper soils for large spacings.

Soil Resistivity Values

Soil	**Resistivity (Ohm/cm)**		
Loams, garden soils, etc	500	-	5,000
Clays	1,000	-	10,000
Chalk	3,000	-	10,000
Clay, Sand and Gravel Mixture	4,000	-	25,000
Marsh, Peat	15,000	-	30,000
Sand	25,000	-	50,000
Slates and Slatey Shales	30,000	-	300,000
Rock	100,000	-	1,000,000

This table sets out typical values of specific soil resistivity but these values vary so greatly, at site testing is the only really satisfactory guide

Minimum Conductor Size

The Addendum No:1 to TS 3.01.02 (Earthing), require 40% derating for duplex or loop connection. As a results of that, all loop connections sizes to be 40% larger.
Prefarred loop conductors shall be: for 63kA 1s - copper strip 50x5mm
for 40kA 1s - copper strip 40x4mm
for 40kA 3s - copper strip 50x6mm
for 31.5IA 3s -copper strip 50x5mm

All conductors which may carry fault point current shall be fully rated.

Selection of Conductors and Joints

Basic Requirements

For grounding system including grid conductors, joints, connecting leads and all primary grounding electrodes:-

l

a) Electrodes should have sufficient conductivity.

b) Electrodes should be mechanically strong enough for most adverse combination of fault current magnitude and duration.

c) Electrodes should be mechanically reliable and rugged to a high degree, especially on locations exposed to corrosion or physical abuse.

-Choice of Material and Related Corrosion Problems

Copper is the most common material used for grounding because it has the following properties:-

a) High Conductivity

b) Being resistant to underground corrosion since copper is cathodic with respect to other metals that are likely to be buried in the vicinity.

The grid burial depth also influences the step and touch voltages significantly. However for very large increases in depth, the touch voltage may actually increase.

Ground Rods Only

For ground rods the current has been found to discharge uniformly, ie at uniform rate along the length of the rod. As in the case of a grid conductor, the current density is greater in the rods near the periphery of the grounding system than that in the centre. The step and touch voltages are higher near outer ground rods.

Increasing the length of the rods is effective in reducing the resistance of the system and therefore reducing the step and touch voltages.

Increasing the number of rods also reduces the resistance until the grounded area is saturated.

Grid and Ground Rod Combination

Combination of grid conductors and ground conductors is used in a grounding.

Current Density

Grid only – for a ground system consisting only of grid conductors the current along any one of the conductors is discharged into the earth in a fairly uniform manner. However a larger portion of the current is discharged into the soil from the outer grid conductor rather than from the conductors at or near the centre of the grid.

An effective way of making the current density more uniform between the inside and periphery conductors is to employ a non uniform spacing.

Touch and Step Voltages

Since most of the current in a uniformly spaced grid is discharged into the earth from outer conductors, therefore the most touch and step voltages occur in the outer meshes especially in the corner meshes. Increasing the number of meshes (decreasing the conductor spacing) tends to reduce the touch and step voltages until a saturation limit is reached.

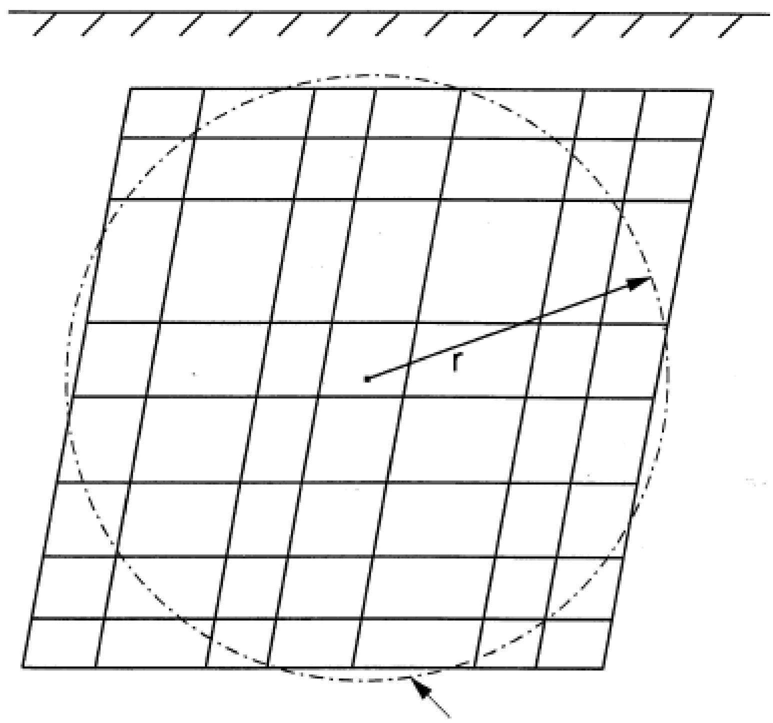
The maximum permitted touch and step potentials as prescribed in TS 3.1.2 (5) are 1.4kV and 4.6kV respectively (with surface chipping cover). Touch potential is defined as the difference between the maximum ROEP and the surface potential 1m from the corner of the earthing system

1.Calculation of the Earth Impedance and Substation Potential Rise

INTRODUCTION

Faults on HV transmission systems are infrequent. Most of the faults occurring on overhead lines are due to lightning. Phase to earth faults in substations are rare, but the current can be large, owing to multiple infeeds from lines and generators.

Buried Earth Grid



EQUIVALENT PLATE ELECTRODE

2. RESISTANCE OF THE SITE EARTH ELECTRODES

2.1 Resistance Due to Earth Mesh

The resistivity to earth of a buried circular plate of radius r in a soil of resistivity ρ is given by:-

$$R = \frac{\rho}{4}\sqrt{\frac{\pi}{A}} = \frac{\rho}{4r} \qquad (1)$$

A very simple method can be employed by using a modification of the circular plate electrode formula equation (1) adding a second term as follows:-

$$R = \frac{\rho}{4r} + \frac{\rho}{L} \qquad (2)$$

Equations 1 and 2 can be used with reasonable accuracy for grid depths less than 0.25m. For grid depths between 0.25 and 2.5m, correction for the grid depth is required. Using Sverak's approximation,

$$R = \rho\left[\frac{1}{L} + \frac{1}{\sqrt{20A}}\left(1 + \frac{1}{1 + h\sqrt{20/A}}\right)\right] \qquad (3)$$

2.2 Resistance Due to Driven Rods

Resistance of a single rod is given by:-

$$R = \frac{\rho}{2\,\pi\,l}\left(1n\,\frac{8l}{d} - 1\right) \qquad (4)$$

Where *l* is the length of the rod, *d* is the diameter of the rod, ρ is the soil resistivity in ohm metres.

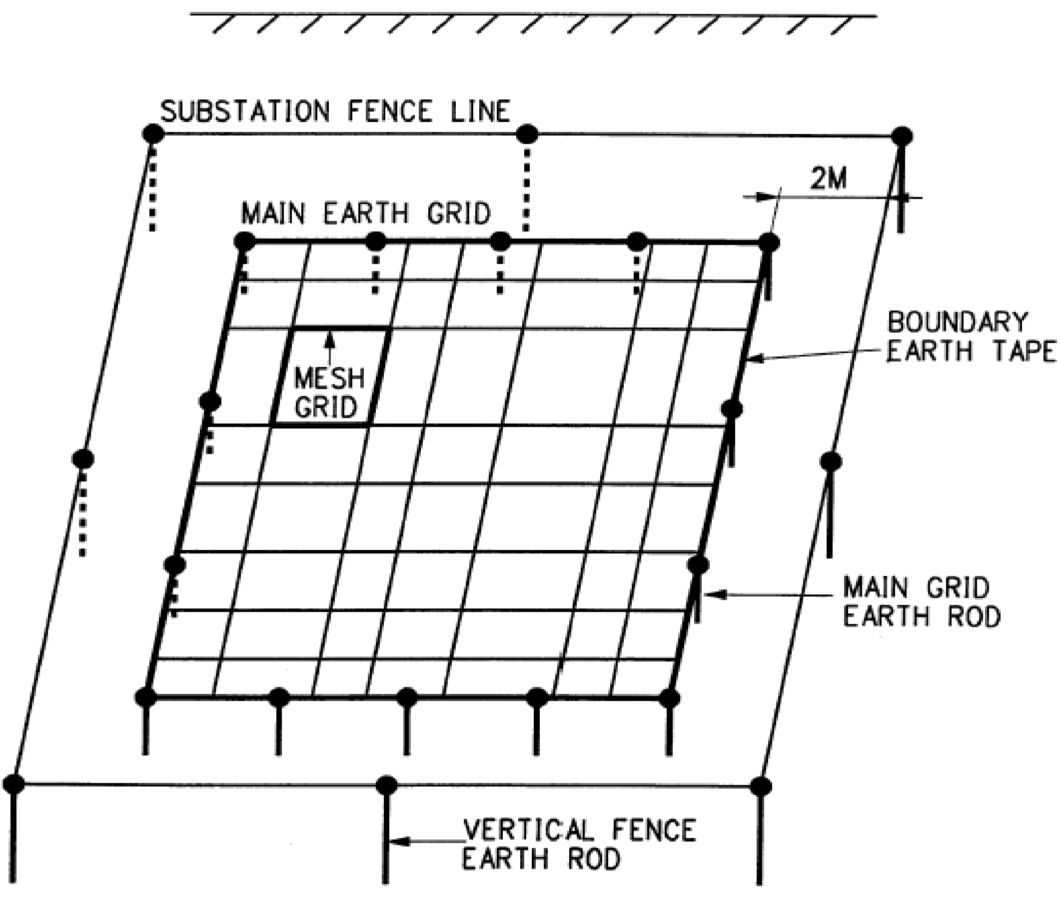
A simplified formula:-

$$R = \frac{\rho}{350}\ ohms \qquad (5)$$

can be used to calculate approximately the resistance of 12ft (3.658m) rod.

Where ρ is the soil resistivity in ohm cm and is relatively independent of the rod diameter. The resistance is approximately inversely proportional to the length of the rod over the range normally used in the substation work (8 to 18ft).

Buried Earth Grid



Where the fence and the attached earth rods are connected to the grid they become the edge of the grid. The area within the fence should be used to determine the radius r. However, the fence should not be taken into account when determining the number of parallel buried conductors, or total length of conductor when determining the resistance.

Where the fence and the associated earth rods are not connected to the grid, (ie normally 2m space between earth grid and the substation fence is allowed), the fence voltage may typically be taken to be 70% of that of the grid potential rise (GPR).

Particular care should be taken with water pipes, cables, etc., and these should be insulated where they pass below or close to the fence.

2.3 Resistance Due to Overhead Earth Wires and Overhead Line Tower Footings

The overhead line towers act as additional earth electrodes in parallel with the site earth electrode system. The overhead line earth wire and tower footing resistances form a “ladder” network with the line terminal tower considered as being part of the site earth electrode. The formula used:-

$$Z_L = \frac{Z_{PE}}{2} + \sqrt{Z_{PE} \times R_T \Omega} \qquad (6)$$

2.4 Current Induced in Overhead Earth Wires

The current induced in overhead earth wire is given by:-

$$I_e = I_f \times \frac{Z_{moe}}{Z_{pe}} \qquad (7)$$

3. MAXIMUM CURRENT IN GROUND

The total earth fault current can return to source by four different paths:-

a) Via transformer neutrals connected to earth mesh.

b) Via cable sheaths due to induction from the unbalanced current in the primary conductors.

c) Via the site earth electrodes by conduction.

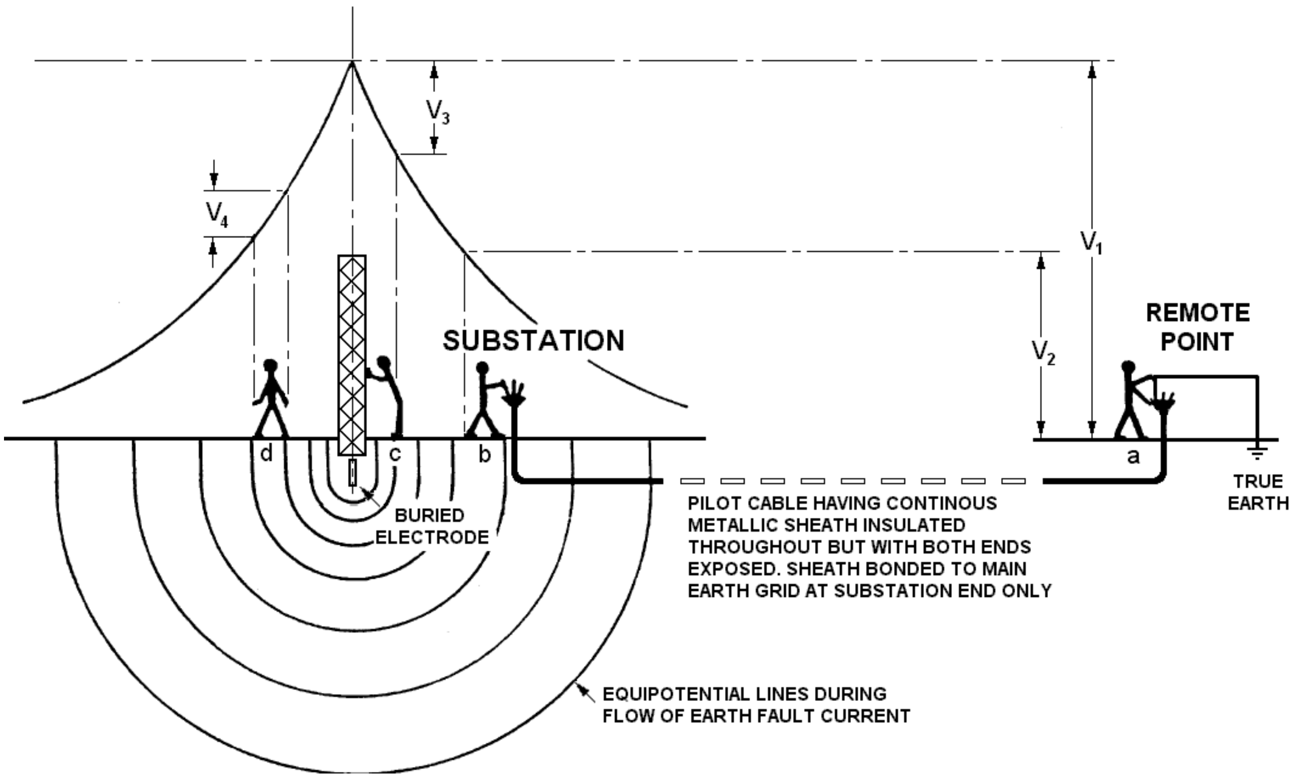
d) Via the overhead line earth wires/tower footings and cable sheaths by conduction.

The latter two paths in parallel form the total size impedance to earth and it is the current flow through this combined path that causes the rise in earth potential.

4. CALCULATION OF MAXIMUM GROUND (GRID) POTENTIAL RISE (GPR OR ROEP)

The maximum rise in potential above remote earth will be V (GPR or ROEP) = IR, where I is the fault current in the grid and R is the ground – grid resistance.

Figure	Current Flow Path	Potential Difference	Type
a	arm-body-arm	V_1	Transferred Potential
b	arm-body-leg	V_2	Transferred Potential
c	arm-body-legs	V_3	Touch Potential
d	leg-leg	V_4	Step Potential



5. CALCULATION OF TOUCH POTENTIAL

Touch potential (E_{touch}) is the tolerable potential difference between any point of the ground where a man may stand and any point which can be touched simultaneously by either hand.

For practical grid arrangements of r > 5m and for depth h > 0.25m and < 1m, a useful approximate expression providing values of V_T within 5% of the full expression is as follows:-

$$V_T = \left[\frac{1n\left(h/d\right)^{0.5} + \frac{1}{2h} + \frac{2}{D}}{2.8\,(n+1)\,K_R} \right] ki \tag{9}$$

Tolerable touch potential (Etouch) can be written as:-

$$E_{touch} = \left(R_B + R_E / 2\right) I_B$$

$$= (1000 + 1.5\rho)\left(\frac{0.116}{\sqrt{t}}\right)$$

$$= \frac{116 + 0.17\rho}{\sqrt{t}} \qquad (10)$$

Assume the high speed protection clears the ground fault in 100ms, but allows 200ms for a second fault due to auto-reclosure. For wet crushed rock surface with resistivity of the order of 3000 ohm-m, the tolerable step and touch voltage can be calculated

6. CALCULATION OF STEP POTENTIAL

Step potential (Estep) is the tolerable potential difference between any two points on the ground surface which can be touched simultaneously by the feet.

For practical grid arrangements and with the same limitations as given in Item 5, a useful approximate expression for step voltage is as follows:-

$$Vs = V\,\frac{\left[\frac{1}{2h} + \frac{2}{D}\right] ki}{2.8\left(n+1\right) K_R} \qquad (12)$$

Tolerable potential difference between two points (ie step potential Estep) can be written as:-

$$E_{step} = \left(R_B + 2\,R_F\right) I_B$$

$$= \left(1000 + 6\rho\right)\left(\frac{0.116}{\sqrt{t}}\right)$$

$$= \frac{116 + 0.7\rho}{\sqrt{t}} \qquad (13)$$

Where t is the duration of the fault current

Assume the high speed protection clears the ground fault in 100ms, but allows 200ms for a second fault due to auto-reclosure. For wet crushed rock surface with resistivity of the order of 3000 ohm-m, the tolerable step and touch voltage can be calculated.

7. CALCULATION OF HOT ZONE RADIUS

The voltage profile around the substation will be developed mainly from the large buried grid with additional, superimposed voltage profiles around the rod electrodes and tower footings.

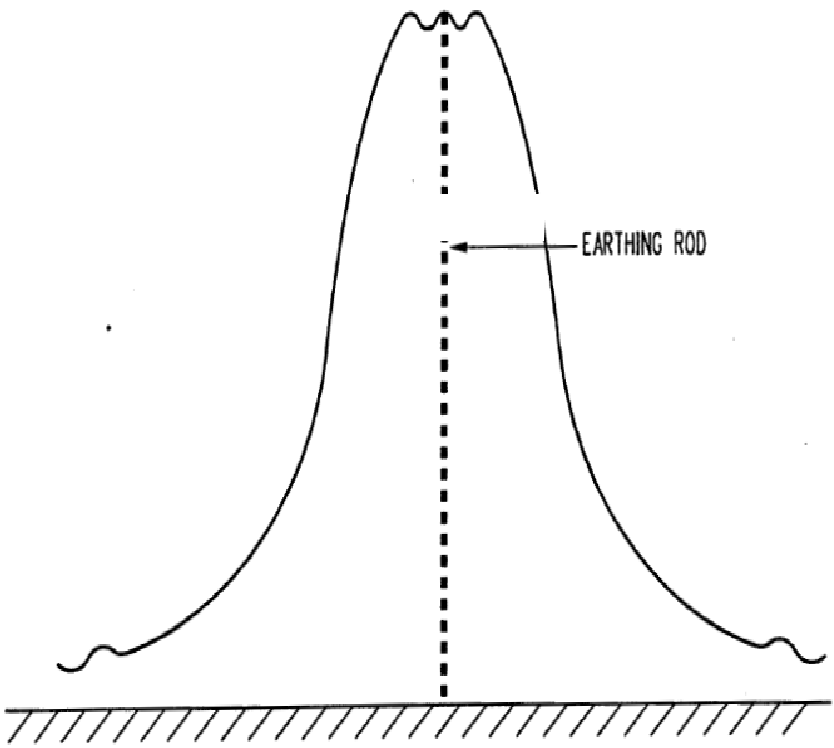
$$Vx = \frac{\rho I}{2 \pi r} \, arc \;\; Sin \, \frac{r}{x} \qquad (14)$$

Where r is the radius of equivalent grid (plate) electrode.

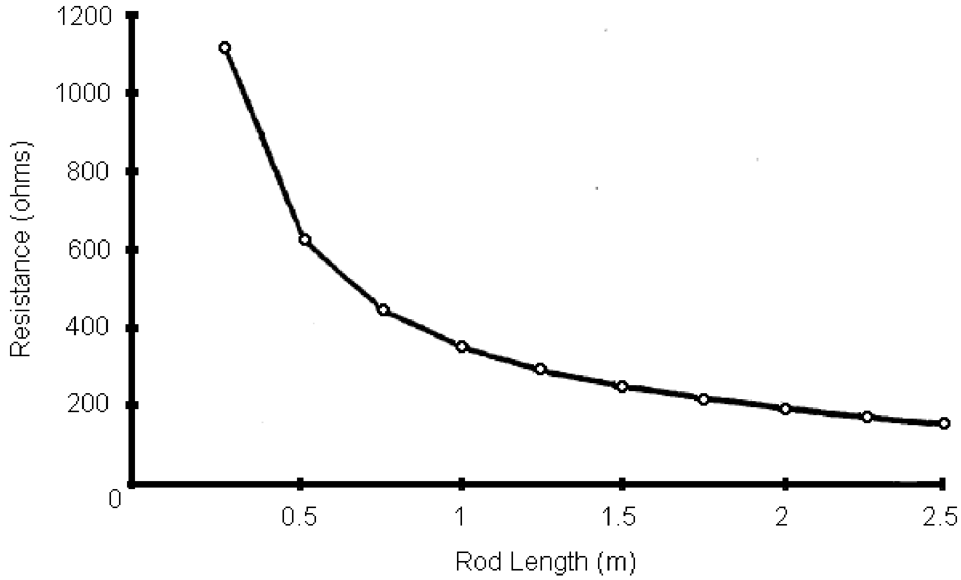
$x = r + X$

Where V*x* is the ground voltage at a distance x metres from the edge of the substation grid electrode.

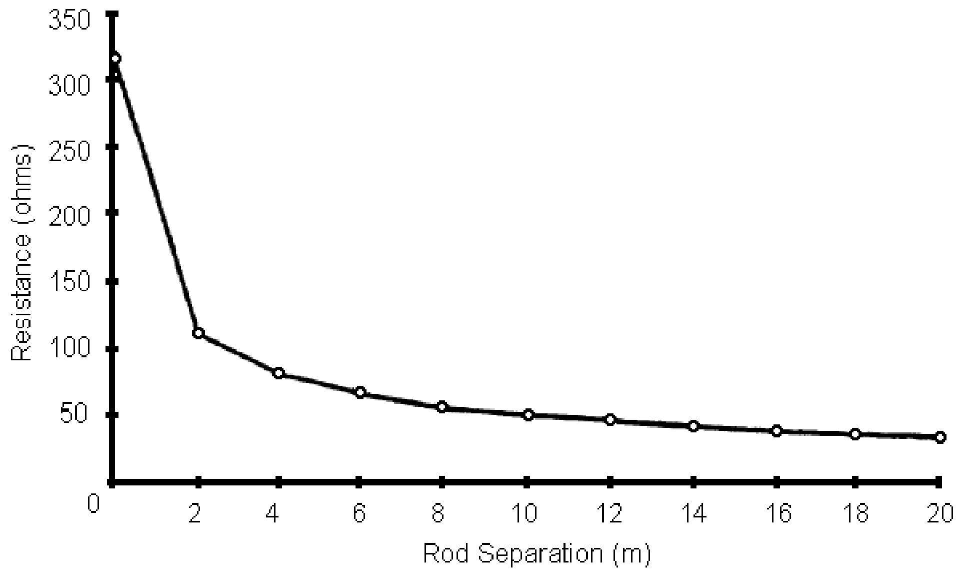
Potential Rise Due to High Frequency Current



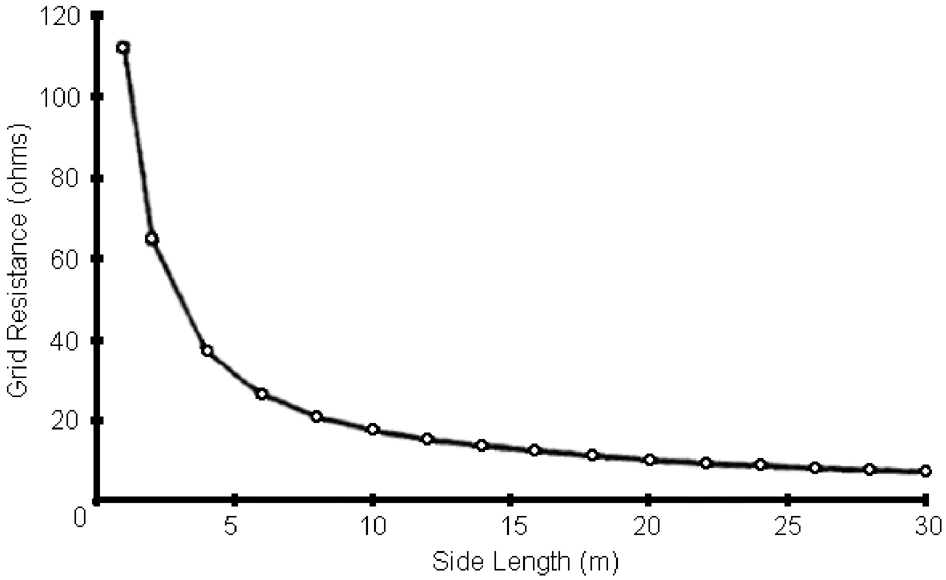
Variation of Resistance With Earth-rod Length



Variation of Resistance With Rod Separation



Variation of Resistance With Grid Side Length



Case Study Earth Grid Design

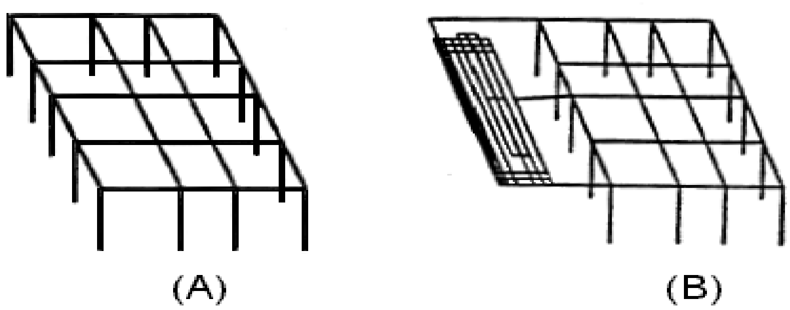
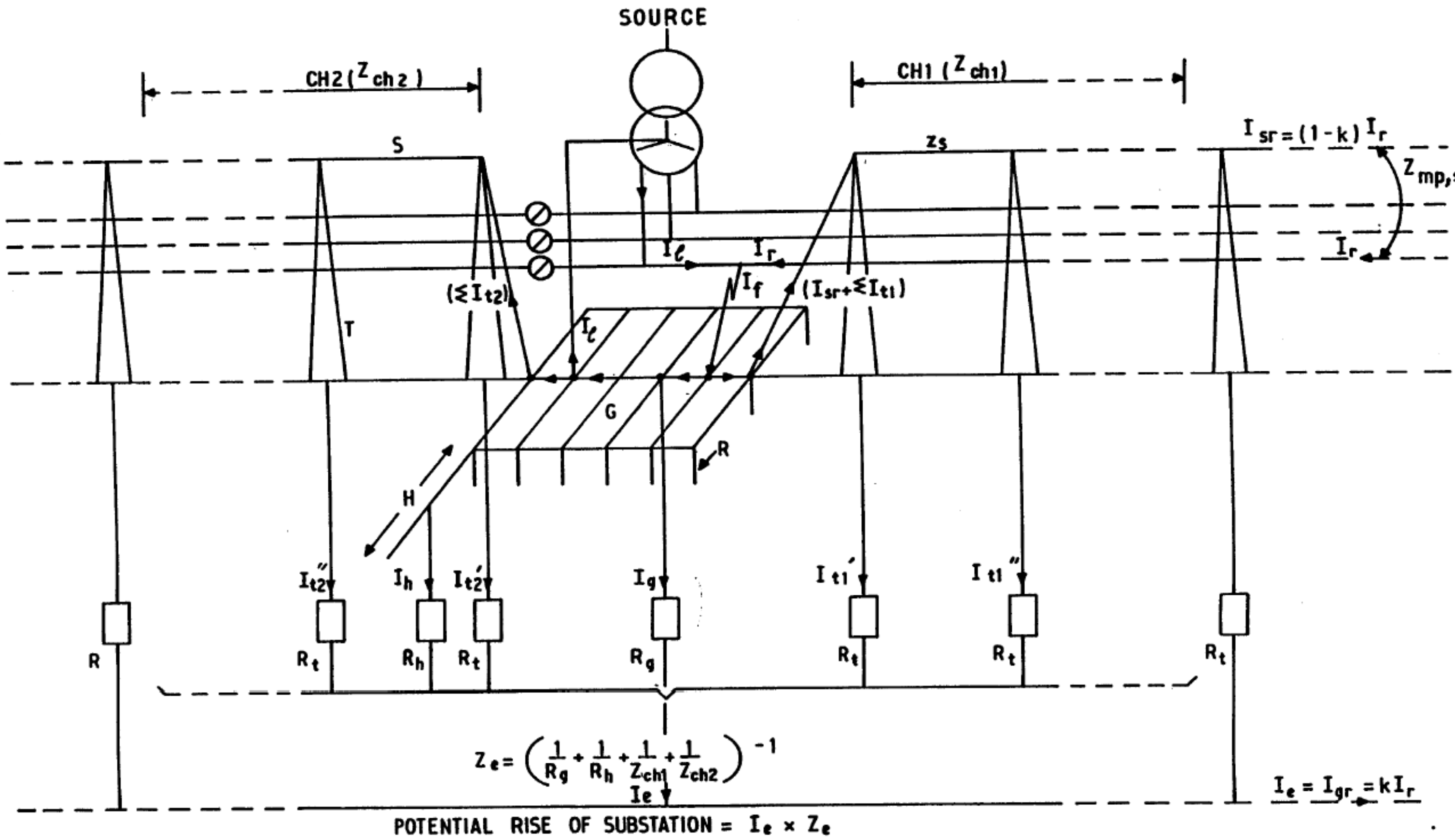
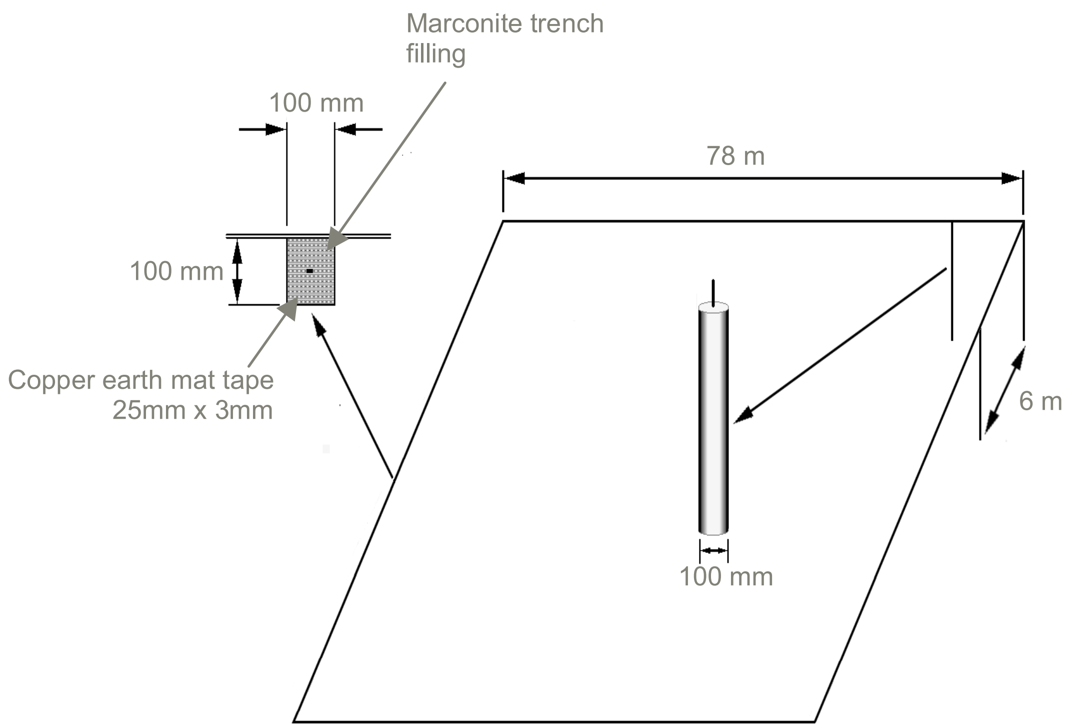


Figure (A) - Basic substation grid
Figure (B) - Substation grid connected to switch room foundation steelwork

Current Distribution Under Earth Fault Conditions





Soil Resistivity = 50 Wm
Bore Hole Depth = 6m
Number of Bores = 52

Resistance of one bore hole:

$$R_1 = \frac{1}{2\pi L}(\rho - \rho_c)\left[1n\left[\frac{8L}{D}\right] - 1\right] + \rho_c\left[1n\left[\frac{8L}{d}\right] - 1\right]$$

$$R_1 = 6.867\ \Omega$$

$$R_{52} = \frac{R_1\left[1 + \lambda\alpha\right]}{n}$$

Where $\lambda = 8.67$ $n = 52$ $\alpha = 0.2$ $R_1 = 6.867\ \Omega$ $R_{52} = 0.353\ \Omega$

With a 100mm square trench of Marconite encapsulating a copper tape connected to the bore holes.

$$R = \frac{\rho}{P\pi L}\left[1n\left[\frac{2L^2}{wh}\right] + Q\right]$$

Assuming the trench is 312m long in a square of approximate dimensiions 78 x 78m, resistance of 2 trenches, each 78m long, connected at right angles.

Assuming the trench is 312m long in a square of approximate dimensiions 78 x 78m, resistance of 2 trenches, each 78m long, connected at right angles.

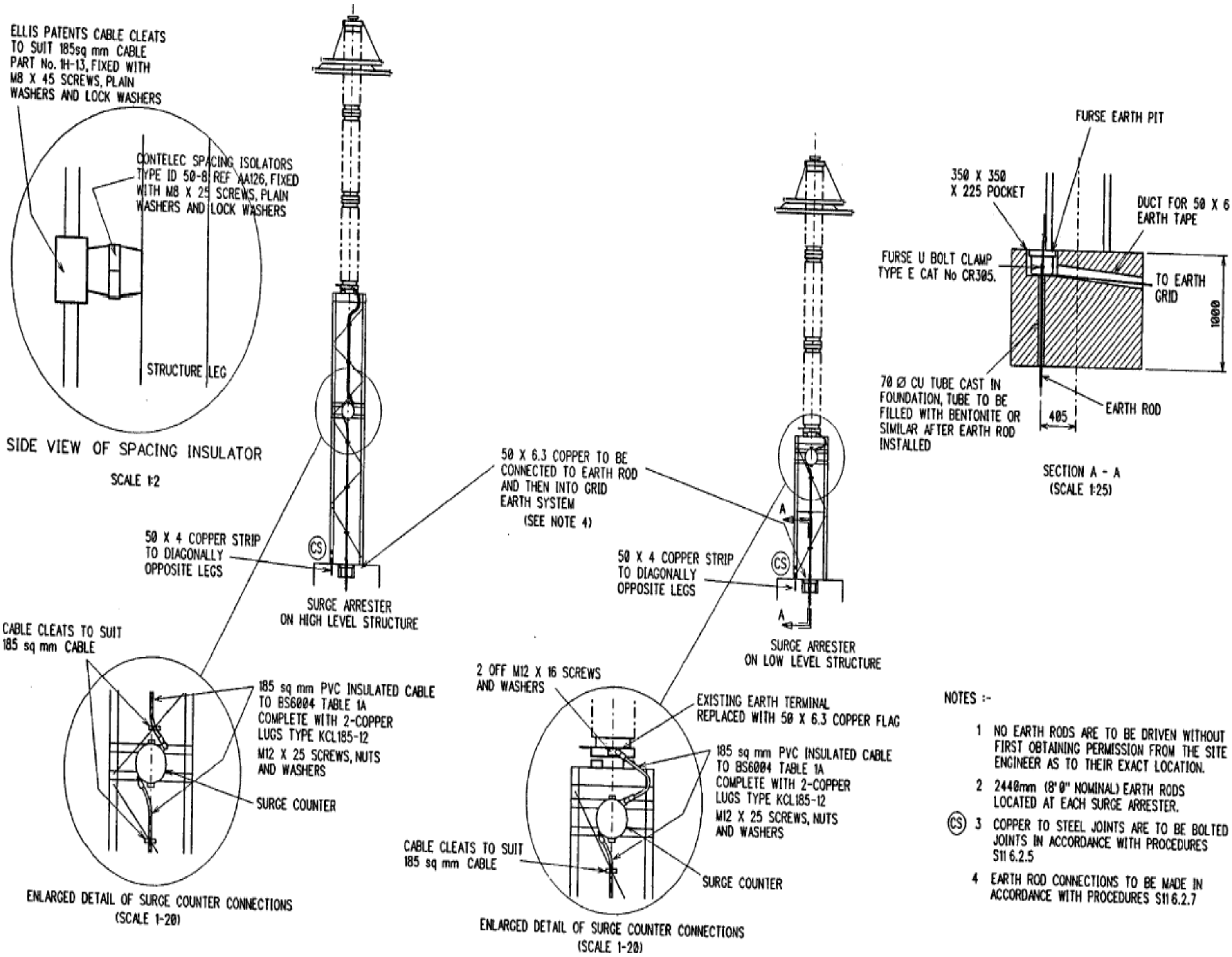
Where soil resistivity r = 150 Wm, P = 4, Q = 0.5, L = 78m, w = 0.1m, h = 1m

R = 1.868 W

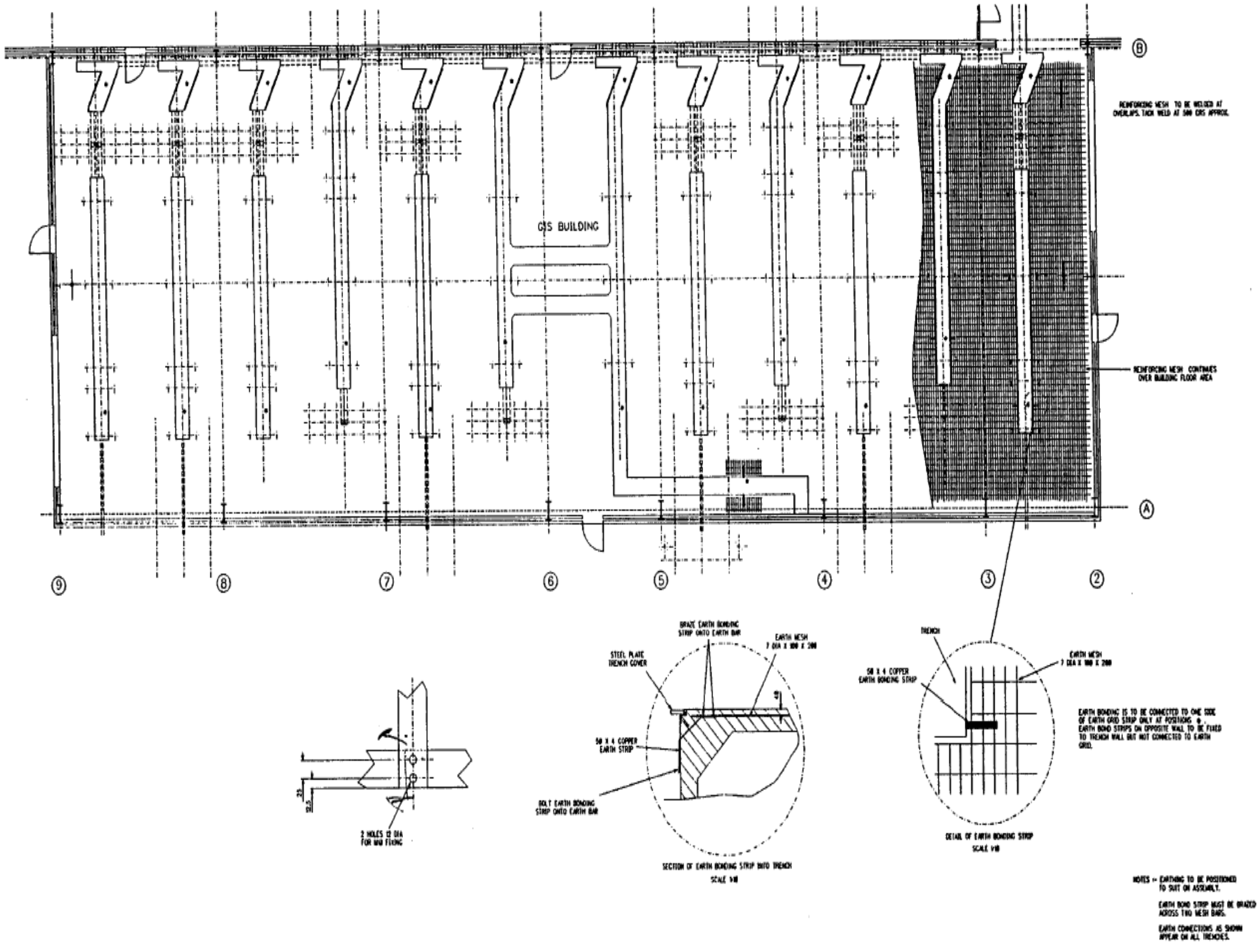
Total resistance of square trench = 0.934 W

Total resistance of earth mat = 0.256 W

Surge Arrester Earthing

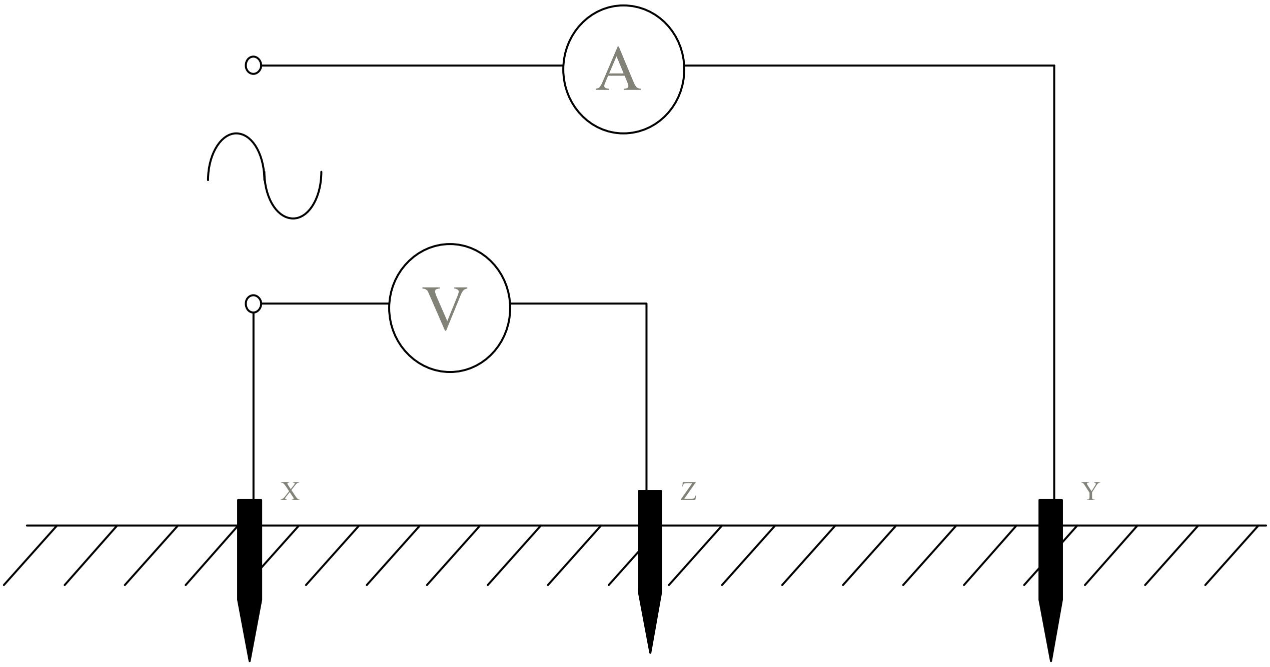


GIS Building Equipotential Earth Plane



Measurement of Earth electrode Resistance

FALL-OF-POTENTIAL METHOD

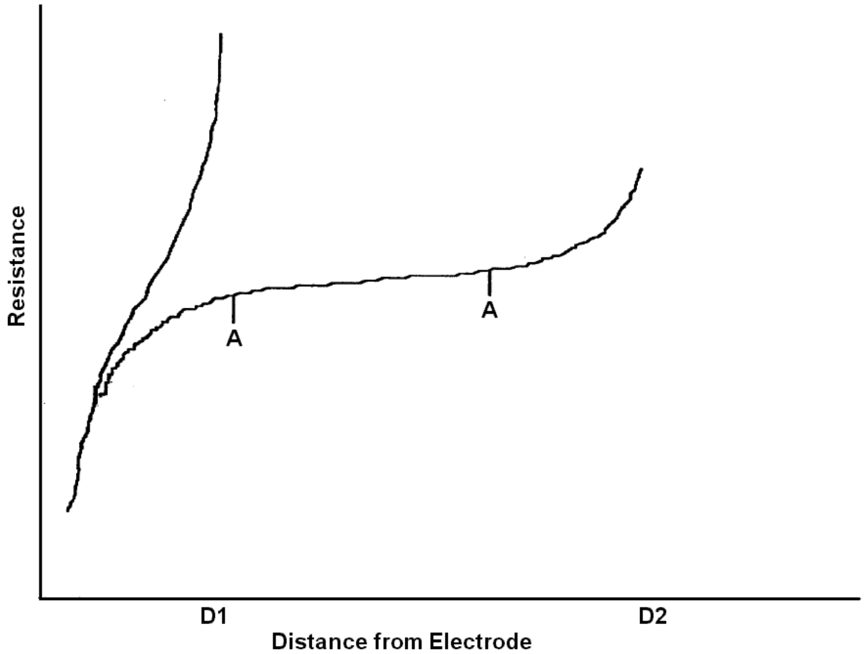


Fall-Of-Potential Method-3 Pin Method BY USING DET3/2 OR DET2/2

1)This is a basic method for measuring the resistance of earth electrode systems. However, it may only be practicable on small, single earth electrodes because of the limitation of the size of the area available to perform the tests.
2)Hammer the Current test spike into the ground some 30m to 50m away from the earth electrode (E) to be tested. Connect this spike to the instrument terminal C2.
3)Hammer the Potential test spike into the ground mid-way between the current test spike and the earth electrode. Connect this spike to the instrument terminal P2.
4) Measure the resistance.
5) It is important , the Current spike ,Potential spike and Earth electrode are in a straight line. Move the Potential spike 3 metres farther away from the earth electrode and make a second resistance measurement. Then move the potential spike 3 metres nearer the earth electrode (than the original position) and make a third resistance measurement.
If the three resistance readings agree with each other, within the required accuracy, then their average may be taken as the resistance to earth of the electrode. If the readings disagree beyond the required accuracy then an alternative method should be used e.g. the 61.8% Rule or Slope method may be used.

6) The ‘True’ resistance of the earth electrode is equal to the measured resistance when the Potential spike is positioned 61.8% of the distance between the earth electrode and the current spike, away from earth electrode. This is the 61.8% Rule and strictly only applies when the earth electrode and both current and potential spikes are in a straight line.

Earth Resistance Curves



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15. APPENDICES

15.1 List of Protection And Earthing Calculations

15.1.1 MSCDN Protection, Fleet substation fuse-less capacitor MSCDN.

15.1.2 Transformer Bias differential protection

15.1.3 LV Connection Protection

15.1.4 Back Up Protection

15.1.5 Over Head Line (Feeder) Protection.

15.1.6 Busbar Protection.

15.1.7 Mesh Corner Protection.

15.2 Design Basis For Mechanically Switched Capacitor (MSC) Banks.

15.3 SLDs For MSCDNs And MSCs At Different System Voltages

15.4 Earthing Design Calculations.

15.5 V Ayadurai and D J Young : 'Reactive Power Compensation for Winders and Conveyors' *GEC Review Vol 1, 1985*

15.6 V Ayadurai : 'Static VAr Compensator for Arc Furnaces, Shaoguan Steelworks in China' *Chinese Society of Electrical Engineering, November 1991*

Appendix 15.1.1 MSCDN Protection, Fleet substation fuse-less capacitor

PROTECTION CALCULATIONS TO

RECOMMEND RELAY SETTINGS

FOR THE

400kV FLEET SUBSTATION

MSCDN1

MAIN PROTECTION WITHOUT 400kV CABLE PROTECTION

FOR

NATIONAL GRID TRANSCO

ENGLAND

By: V AYADURAI

AREVA T&D UK LIMITED

High Voltage Systems

Document No. 123025P / N3416P0020

ISSUE 1 : JULY 2004

CONTENTS

1. INTRODUCTION

This document contains brief calculations to derive the recommended relay settings for the MSCDN2 for 400kV Lovedean substation. Protection setting calculations are based on NGTS 3.6.14 - Copperwork Protection,TGN(T)64 and TGN(E) 181 issue1 Nov 2002-Rating and Setting Resistors and Metrosils for - Instantaneous High Impedance Differential Protection.

The results are tabulated in the final section, together with other relevant data and figures.

1.1 Definitions and Abbreviations

Lead Resistance	=	R_L
CT Ratio	=	N
CT Knee Point Voltage	=	V_k
CT Secondary Resistance	=	R_{CT}
Relay Resistance	=	R_R
Fault Setting Resistor	=	R
CT Magnetising Current	=	I_i
Full Load (Primary) Current	=	I_n
Fault Current (Primary)	=	I_F
Fault Current (Secondary)	=	I_f
Relay Primary Operation Current (POC)	=	I_{OP}
Relay Burden	=	VA
Relay Current	=	I_R
Relay Current Setting	=	I_S
Relay Voltage Setting	=	V_R
Number of CTs in Parallel	=	n
Number of Relays in Parallel	=	m
Turns Ratio of Current Transformers	=	T
Current taken by Peak Voltage Device	=	I_m

Current taken by Fault Setting Resistor = I_{SR}

2. MSCDN1 CIRCULATING CURRENT (OVERALL) PROTECTION

A. Protection Equipment Details

a) CT Location: Post Type CT, Serial Number:

b) CT Ratio: <u>1200</u>/600/1A

Class X Vk ≥ 426V, T = 1/1200

$R_{CT} \leq 1.84\ \Omega$ (HV side), $R_{CT} \leq 2.13\ \Omega$ (LV side)

Cables used for CT connection are 4.0mm^2

Refer Figure 1.

B. Relays

AREVA T&D EAI type high impedance circulating current MFAC 34 relays with metrosils and if applicable fault setting resistor.

C. System Parameters

a) System Voltage: 400kV

b) System design (switchgear) fault current (1∅) = 50kA (1 sec)
System design (switchgear) fault current (3∅) = 50kA (1 sec)

D. Rated Stability Limit (Relay Circuit Setting Voltage)

Consider Table 1 for CTs and Lead Resistances

A, B = Resistance of Leads plus CT Winding, where applicable

C, D = Lead Resistance

V_S = Stability Voltage

I_S = Relay Circuit Current at V_S

I_1 = Secondary Exciting Current of CT at V_S

I_m = Current Taken by Peak Voltage Limiting Device at V_S

I_{SR} = Current Taken by Fault Setting Resistor

I_F = Fault Current Corresponding to Switchgear Rating for Stability Limit

n = Number of CTs in Parallel

m = Number of Relays in Parallel

E. **Primary Fault Setting**

Fault setting shall be 15% of the MSCDN2 rated current (TPS 2.24.3, clause 3.9).

The rated current is the current at rated voltage (422.6kV) = 350A

2.1 Rated Stability Limit

Rated stability is based on switchgear rating, i.e. 50kA single phase current.

Consider an external phase-to-earth short circuit and assume complete saturation of current transformer, then :-

$$V_S \geq I_F \text{ (CT Resistance + lead loop burden)} \qquad (1)$$

If the setting voltage of the circuit is made equal to or greater than this voltage, then the protection will be stable.

The knee point voltage of the CT should be greater than $2 V_S$

It is necessary that the voltage appearing across the relay circuit V_R should be greater than or equal to V_S.

Table 1:

Item No	Lead Length M	Lead Resistance Ω	CT Resistance Ω	Total Ω	Parameters	
1 HV SIDE	60 55 50	0.28 0.25 0.23	1.84 1.84 1.84	2.12 2.09 2.07	R Y B	A
	10 10 10	0.046 0.046 0.046	- - -	0.046 0.046 0.046	R Y B	C
	2	0.0092	-	0.0092	N	E
2 LV SIDE	184 194 204	0.848 0.894 0.940	2.13 2.13 2.13	2.978 3.024 3.07	R Y B	B
	10 10 10	0.046 0.046 0.046	- - -	0.046 0.046 0.046	R Y B	D
	2	0.0092	-	0.0092	N	F

Using Equation 1 :-

$$V_S = \frac{50 \times 1000}{1200}\left(B + D + F\right)$$

$$= \frac{50 \times 1000}{1200}\left(3.07 + 0.046 + 0.0092\right) = 130V$$

A = 2.12 Ω, C = 0.046 Ω, E = 0.0092 Ω

B = 3.07 Ω, D = 0.046 Ω, F = 0.0092 Ω

V_R = 175V (Selected)

2.2 Fault Setting

Fault setting shall be 10-30% of the MSCDN2 rated current.

a) Let the Primary Operating Current (POC) be 15% of MSCDN2 rated current

$\therefore$ POC = 0.15 x 350 = 52.5A

b) Relay circuit current (I_S) at V_S

I_S at (175V) = 0.019A

Fault setting for m relays is :-

$$\text{POC}\left(I_{OP}\right) = N\left(mI_S + I_{1+} I_{2+} I_{SR} + I_m\right) \tag{2}$$

Where m = 2, I_m is very small, I_1 is LV CT and I_2 is HV CT.

I_S = 0.019A I_1 = 0.0035A I_2 = 0.015A

52.5 = 1200 (2 x 0.019 + 0.0185 + I_{SR})

I_{SR} = –0.130A

c) As current I_{SR} is negligible, a Fault Setting Resistor is not applicable, and is not required.

2.3 Peak Voltage Developed Under Internal Fault Condition

For a maximum internal fault, a high voltage may develop across the relay. In that case the insulation of the current transformer secondary winding and relay will not be able to withstand the very high voltage that can be produced.

Where necessary the voltage is limited to less than 3kV peak by use of non-linear resistors called metrosils connected in parallel with the relay circuit.

Assessment of Metrosil requirements

From TGN(T)64, the maximum voltage, V_{pk} across the relay can be calculated using the formula:

$$V_{pk} = 2\sqrt{2.V_k\,(V_f - V_k)}$$

Where V_k = Knee Point Voltage of CTs = 426V

V_{fs} = Value of voltage that would appear if CTs did not saturate, which is given by,

V_{fs} = I_{fs} x $(R_{CCT} + R_L)$

I_{fs} = Value of maximum fault current in CT secondary = 41.7A

R_{CCT} = Resistance of Secondary Circuit

R_L = Lead Burden + CT Resistance = 3.07Ω

R_{MFAC} = V_S / I_{MFAC} = 175/0.019 = 9210 Ω

$R_{metrosil}$ = V_S / $I_{metrosil}$ = 175/0.003 = 58333 Ω

R_{MVTP} = V_S / ($4V_S$ / 600^2) = 90000 Ω

The parallel impedance of the relays R_{CCT} = 4075 Ω

V_{fs} = 41.7 (4075 + 3.07) = 170kV

$$V_{pk} = 2\sqrt{2 \times 426\ (170000 - 426)} = 24040\text{V}$$

V_{pk} is greater than 3000V, so a Metrosil is required

Thermal Rating of Metrosil

The theoretical basis for this method is dealt with in detail in Appendix A.

Power Rating of Metrosil (P) = $\frac{4}{\pi} \times I_{fs} \times V_k$

Maximum Fault Current INCT Secondary (I_{fs}) 41.7A

V_k = 426V

(P) = $\frac{4}{\pi}$ x 41.7 x 426 = 22.62kW

Peak Voltage with Metrosil in Circuit

V_P = $C\, I^{\beta}$

C = 450 or 900

β = 0.25

I = Maximum Current in CT Secondary = 52.5A

V_P = $450 \times (41.7)^{0.25}$ = 1144V

V_P = $900 \times (41.7)^{0.25}$ = 2288V

a) The voltage/current characteristic of a metrosil is given by :-

$V = CI^{\beta}$

Current through the metrosil has an rms current value of 0.52 times the value given by the above formula. This is due to the fact that the current waveform through the metrosil is not sinusoidal but appreciably distorted.

Where voltage V and current I are peak values

$I_{(rms)}$ = $0.52I$, $V = \sqrt{2}\, V_S$

C = A constant depending on the metrosil construction (C can either be 900 or 450)

β = a constant in the range 0.2 to 0.25

$$\therefore \quad \sqrt{2}V_S = C\left[\frac{I_{SL}}{0.52}\right]^{\beta}$$

The values of C and β are chosen so that the voltage across the metrosil is limited to less than 3kV peak at the maximum fault current. The acceptable metrosil currents should be as low as possible, i.e. < 30mA for 1A secondary.

b) Maximum secondary current at fault condition

$$= \frac{50 \times 1000}{1200} = 41.7\text{A (1sec)}$$

$$\sqrt{2} \times 175 = 900 \left[\frac{I_{SL}}{0.52}\right]^{0.25}$$

$I_{SL} = I_m$ = 3.0mA

2.4 Primary Operating Current (POC)

Using Equation (2)

$$\text{POC}\left(I_{OP}\right) = 1200\left(2 \text{ x } 0.019 + 0.0185 + 0.003\right)$$

$$= 71.4\text{A (20.5\% of MSCDN rated current)}$$

In practice the Metrosil current 0.003A is negligible, therefore this can be ignored.

2.5 Supervision of Circulating Current Protection To Cover Open Circulated Current Transformers and Wiring

a) **Bus Wiring Supervision**

Relay: MVTP31

Setting range:2 – 14V

b) **Setting Calculations**

The initial impedance of the current transformer at the bottom bend region
(3–0.17) V / 0.0016 A = 17688 Ω

i) Impedance of 2 (maximum number of circuits = 3) current transformers = 8844 Ω

ii) Impedance of the relay MFAC34

$$\frac{175}{0.019} = 9210 \ \Omega$$

Parallel impedance of current transformers and differential circuit

8844 // 9210 = 4512 Ω

iii) If the desired sensitivity is 10% of total MSCDN rated current = 35A primary

$$\frac{35}{1200} = 0.0291$$

$\therefore$ voltage drop = 0.0291 x 4512

= 131V

Available setting range = 2, 4, 6, 8, 10, 12 and 14

The relay could be set to 14 volts

Choose setting = 14V

Burden of MVTP31 at 14V setting $\underline{\Omega}$ 0.0022A

2.6 **Settings**

a) MFAC 34 relay settings: V_S = 175V (setting range 25 – 325V)

b) Metrosil: 6" metrosil, 3 phase with C = 900 and β = 0.25 of characteristic

c) MVTX31 relay settings: Relay setting = 14V (setting range 2 – 14V)

3. BACK UP PROTECTION

3.1 Filter Bank Two Phase Overcurrent and Earth Fault Protection

3.1.1 Relay Data

Manufacturer: AREVA T&D EAI

Type: MCGG 52

Documentation: R6054

Rated Current: 1A

3.1.2 CT Parameters

CT Location: Post Type

Core No: 2

CT Ratio: 2000/<u>1000</u>/1A

Class: 1/5P/10/20, 30VA

3.1.3 System Parameters

a) System Voltage: 400kV

b) System Design Fault Current: 50kA

c) Fault Withstanding Duration: 1 sec.

d) Fault Level with Maximum Generation (3∅) = 34.177 kA

e) Fault Level with Maximum Generation (1∅) = 30.704 kA

3.1.4 Setting Calculation

a) **Overcurrent Protection**

Rated Current = 350A

Overcurrent setting = 150% of 350A

= 525A

CT Ratio Selected = 1000/1A

Relay Setting Range: 5 – 240% of 1A (5% Steps)

The current to be protected = 525A

∴ current setting (time delayed element) = 52% (on 1000/1A CT ratio)

Proposed relay current setting I_S = 0.5A

The primary current = 0.5 x 1000A

= 500A (346 MVA)

b) **Selection of Time Characteristic**

Standard Inverse	:	(0/0/0)	Very Inverse	:	(1/0/0)
Extremely Inverse	:	(0/0/1)	Long Time Earth Fault	:	(1/1/0)
Definite Time 2s	:	(0/0/1)	Definite Time 4s	:	(1/0/1)
Definite Time 8s	:	(0/1/1)			

Standard Inverse (0/0/0) SI : $t = \dfrac{0.14}{\left(I^{0.02} - 1\right)}$ at $TMS = 1$

c) **Time Multiplier Setting TMS**

Setting Range: 0.05 to 1 in 0.025 steps

The minimum tripping time (calculated with the minimum value between 30 x 1000 x I_S, limit of the curve, and If, the maximum fault current) shall be less than the fault withstanding duration and longer than the main protections tripping time.

Minimum value Ii between 30 x 1000 x I_S and If :

30 x 1000 x 0.50 = 15.5kA and If = 34.177kA

$$I = \frac{34.18 \times 10^3}{0.5 \times 1000} = 68.4$$

Standard Inverse curve reaches Definite time, at I = 30, a minimum time t = 199s at TMS = 1

$$\text{using } t = \frac{0.14}{\left(I^{0.02} - 1\right)} = 1.99 \text{ secs at TMS} = 1$$

Let TMS Setting = 0.50

Minimum tripping time t with TMS = 0.50; 1.99 x 0.50 = 0.995s

3.1.5 Earth Fault Protection

Single phase system fault current = 30.7kA

The fault current to be protected > 50% of 350A

= 175A

∴ Current Setting (I_S) $= \frac{175}{1000} = 0.175$

= 17%

Proposed current setting I_S = 0.2A

Primary operating current (POC) = 0.2 x 1000A = 200A (139 MVA)

Set earth fault curve to standard inverse (SI) IDMT curve from graph, clearance time of less than 1 second for fault at capacitor bank terminals is guaranteed with TMS = 0.50

Where I = 30704 / 200 = 153.5

Standard Inverse curve reaches Definite time, at I = 30, a minimum time t = 199s at TMS = 1

$$\text{using } t = \frac{0.14}{\left(I^{0.02} - 1\right)} \times 0.50 = 0.995 \text{ seconds}$$

Minimum tripping time t, with TMS = 0.50, 1.99 x 0.5 = 0.995s

3.1.6 Instantaneous Element

Setting Range: 1 to 31 in unity steps + ∞

Instantaneous protection is not applicable for MSCDN2 feeder. Therefore, instantaneous feature is rendered inoperative.

Setting: ∞ This function remains unused to maintain selectivity between main protections.

Set I_{INST} ∞ for overcurrent and earth fault

3.1.7 Relay Setting

a) **Overcurrent Element Setting**

Select SI IDMT curve with TMS = 0.50

I_S = 0.5, i.e. set 1st dial left = 0.1
4th dial left = 0.4
other dials right = 0

b) **Earth Fault Element Setting**

Select SI IDMT curve with TMS = 0.50

I_S = 0.2, i.e. set 1st dial left = 0.1
2nd dial left = 0.1
other dials right = 0

c) **Instantaneous Element Setting**

Set I_{INST} = ∞ for overcurrent

Set I_{INST} = ∞ for earth fault

3.2 Phase Unbalanced

3.2.1 Relay Data

Manufacturer: AREVA T&D EAI

Type: MCAG 19 & MVTT 14 (TDR 0.1 to 100 secs.)

Documentation: R6035 & R6012

Rated Current: 1A

3.2.2 CT Parameters

CT Location: Post Type

Core No: 2

CT Ratio: 2000/1000/1A

Class: 1/5P/10/20, 30VA

3.2.3 **System Parameters**

a) System Voltage: 400kV

b) System Design Fault Current: 50kA

c) Fault Withstanding Duration: 1 sec.

d) Fault Level with Maximum Generation (3 ∅) = 34.177 kA

e) Fault Level with Maximum Generation (1 ∅) = 30.704 kA

3.2.4 **Setting Calculation**

a) **Phase Unbalance Alarm**

Rated Current = 350A

CT Ratio Selected = 1000/1A

Relay Setting Range: 20 – 80% of 1A

∴ current setting = 20% (on 1000/1A CT ratio)

Proposed relay current setting I_S = 0.2A

The primary current = 0.2 x 1000A

= 200A (139 MVA)

3.2.5 **Setting**

MCAG 19 relay setting = 20%

MVTT 14 time delay setting = 2 seconds

4. CIRCUIT BREAKER FAIL PROTECTION

4.1 **Circuit Breaker Fail Current Check**

4.1.1 **Relay Data**

Manufacturer: AREVA T&D EAI

Type: MCTI 39

Documentation: R6037

Rated Current: 1A

4.1.2 CT Parameters

CT Location: Post Type

Core No: 3

CT Ratio: 2000/1000/1A

Class: 1/5P/10/20, 30VA

4.1.3 System Parameters

a) System Voltage: 400kV

b) System Design Fault Current: 50kA

c) Fault Withstanding Duration: 1 sec.

d) Fault Level with Maximum Generation (3 ∅) = 34.177 kA

e) Fault Level with Maximum Generation (1 ∅) = 30.704 kA

4.1.4 Setting Calculation

a) **Circuit Breaker Fail Current Check**

Rated Current = 350A

CT Ratio Selected = 1000/1A

CB fail to be set to 50A according to TPS 2.24.3, clause 3.12

Relay Setting Range: 5%, 10%, 20% and 40% of 1A

∴ current setting = 5% (on 1000/1A CT ratio)

Proposed relay current setting I_S = 0.05A

The primary current = 0.05 x 1000A

= 50A (34.7 MVA)

4.2 Circuit Breaker Fail Timing Relay

4.2.1 Relay Data

Manufacturer: AREVA T&D EAI

Type: MVTT14

Documentation: R6012

Rated Current: 1A

4.2.2 CT Parameters

CT Location: Post Type

Core No: 3

CT Ratio: 2000/1000/1A

Class: 1/5P/10/20, 30VA

4.2.3 System Parameters

a) System Voltage: 400kV

b) System Design Fault Current: 50kA

c) Fault Withstanding Duration: 1 sec.

d) Fault Level with Maximum Generation (3 ∅) = 34.177 kA

e) Fault Level with Maximum Generation (1 ∅) = 30.704 kA

4.2.4 Setting Calculation

a) **Circuit Breaker Fail**

Relay Setting Range: 0.01 - 10 seconds (10ms Steps)

Setting = (CB (max) + BFCCKr + 60 + CB inhibit (max) - BFCCKop) ms

CB (max) is maximum circuit breaker trip time to arc extinction = 58 ms.

BFCCKr is maximum relay reset time = 15 ms.

CB inhibit (max) is maximum time from circuit breaker main = 30 ms. (approx)
contacts close to removal of trip to inhibit

BFCCKop is maximum relay pick up time = 10 ms.

Setting = (58 + 15 + 60 + 30 - 10)

= 153 ms.

Choose setting closest = 150 ms

4.3 Settings

Each MCTI 39 relay setting = 5%

Each MVTT 14 timer setting = 150 ms.

5. CAPACITOR EXCESS RMS OVERCURRENT PROTECTION

5.1 Relay Data

Manufacturer: AREVA T&D EAI

Type: MCAG 39 and MVTT 14

Documentation: R6035 and R6012

Rated Current: 1A

5.2 CT Parameters

CT Location: Post Type

Core No: 2

CT Ratio: 2000/<u>1000</u>/1A

Class: 1/5P/10/20, 30VA

5.3 System Parameters

a) System Voltage: 400kV

b) System Design Fault Current: 50kA

c) Fault Withstanding Duration: 1 sec.

d) Fault Level with Maximum Generation (3 ∅) = 34.177 kA

e) Fault Level with Maximum Generation (1 ∅) = 30.704 kA

5.4 Setting Calculation

5.4.1 Excess RMS Overcurrent Alarm

a) **Stage 1**

Rated Current = 350A

CT Ratio Selected = 1000/1A

Relay Setting Range: 50 - 200%

The current to be protected = 130% of 350A

= 455A

∴ current setting = 50% (on 1000/1A CT ratio)

Proposed relay current setting I_S = 0.5A

The primary current = 0.5 x 1000A

= 500A

b) **Alarm Timer**

Timer setting range: = 0.1 – 100s (100ms steps)

Setting selected: = 1 second

5.4.2 **Excess RMS Overcurrent Trip**

a) **Stage 2**

Rated Current = 350A

CT Ratio Selected = 1000/1A

Relay Setting Range: 50 – 200%

The current to be protected = 150% of 350A

= 525A

∴ current setting = 55% (on 1000/1A CT ratio)

Proposed relay current setting I_S = 0.55A

The primary current = 0.55 x 1000A

= 550A

b) **Trip Timer**

Timer setting range: = 0.1 – 100s (100ms steps)

Setting selected: = 1 second

5.5 **Settings**

5.5.1 **Stage 1 Alarm**

a) MCAG39 relay settings: 50% (setting range 50 – 200%)

b) MVTT14 timer settings: 1 second (setting range 0.1 – 100s)

5.5.2 **Stage 2 Trip**

a) MCAG39 relay settings: 55% (setting range 50 – 200%)

b) MVTT14 timer settings: 1 second (setting range 0.1 – 100s)

6. MAIN CAPACITOR BANK PROTECTION

6.1 Main Capacitor H Type Phase Unbalanced Protection

6.1.1 Relay Data

Manufacturer:	Haefely Trench
Type:	CPR 97 H-Bridge Mode Firmware
Documentation:	CPR 97 Operation & Instruction Manual
Rated Current:	1A (5A secondary of the 20/5A CT should be connected to 1A relay input)

6.1.2 CT Parameters

CT Location:	Post Type
CT Ratio:	20/5A
Class:	0.5, 30VA

6.1.3 System Parameters

a) Nominal System Voltage: 400kV (phase to phase)

b) System Design Fault Current: 50kA

c) Fault Withstanding Duration: 1 sec.

d) Fault Level with Maximum Generation (3∅) = 34.177 kA

e) Nominal System Voltage (fund) = 400kV (ph-ph)

f) Nominal System Voltage (fund) = 231kV (ph-neutral)

g) Rated Current (fund) = 350A

h) Main Capacitor

Total capacitance/phase = 4.57 μF

Each capacitor unit = 6.40 μF

Total capacitor units/phase = 140

i.e. (parallel number of units= 10)

(series number of units = 14)

PROTECTION SETTINGS FOR FLEET MSCDN

Failed elements	C1	C2
0	0.00 – 0.00	0.00 – 0.00
1	0.20 – 0.29	1.42 – 2.10
2	0.40 – 0.59	2.98 – 4.41
3	0.61 – 0.90	4.72 – 6.97
4	0.82 – 1.21	6.64 – 9.81
5	1.04 – 1.54	8.79 – 12.99
6	1.27 – 1.88	11.21 – 16.57
7	1.50 – 2.22	13.96 – 20.62
8	1.74 – 2.58	17.10 – 25.26
9	1.99 – 2.95	20.73 – 30.62
10	2.24 – 3.33	24.97 – 36.88

Table 1 – Range of unbalance currents in midpoint CT for 400C1b and current differences between parallel strings of 400C2b of Fleet 400kV MSCDNs

	Elements / current / time	
	400C1b	400C2b
Stage 1	1/0.15A/>5s alarm	1/1.3A/>5s alarm
Stage 2	6/1.25A/1s trip	3/4.5A/1s trip
Stage 3	9/1.95A/<0.1s trip	7/13.8A/<0.1s trip

Table 2 – Suggested capacitor protection settings of Fleet 400kV MSCDNs

6.1.4 **Protection Settings**

<u>400C1b</u>	Elements	Current	Time	
Stage 1	1	0.15A	10 secs	Alarm
Stage 2	6	1.25A	1s	Trip
Stage 3	9	1.95A	< 0.1s	Trip

a) <u>Setting: Stage 1 – Alarm</u>

Spill currrent = 0.15A (primary)

CT Ratio = 20/5A

Current setting = $\frac{0.15}{20} \times 5 = 0.038\text{A (secondary)}$

Relay setting = 4.0%

Time setting = 10s (CPR97 inbuilt timer 0.1 to 600s)

b) Setting: Stage 2 – Trip

Spill currrent = 1.25A (primary)

CT Ratio = 20/5A

Current setting = $\frac{1.25}{20}$ x 5 = 0.31A (secondary)

Relay setting = 31%

Time setting = 1.00s (CPR97 inbuilt timer 1s to 240 mins)

c) Setting: Stage 3 – Trip

Spill currrent = 1.95A (primary)

CT Ratio = 20/5A

Current setting = $\frac{1.95}{20}$ x 5 = 0.49A (secondary)

Relay setting = 49%

Time setting = 90ms (CPR97 inbuilt timer 0 to 60s)

6.1.5 **Settings**

6.1.5.1 Stage 1 – Alarm

a) I_{ub} – al / I_n = 0.04 (setting range 0.01 to 2.0, step = 0.01)

time setting
I_{ub} – al : xt = 10.0s (setting range 0.1 to 600s, step = 0.1s)

6.1.5.2 Stage 2 – Trip

b) I_{ub} > / I_n = 0.31 (setting range 0.01 to 2.0, step = 0.01)

time setting
I_{ub} > : xt = 1.0s (setting range 1s to 240 min, step = 1s)

6.1.5.3 Stage 3 – Trip

c) I_{ub} >> / I_n = 0.49 (setting range 0.05 to 2.0, step = 0.01)

time setting
I_{ub} >> : xt = 0.10 (100ms) (setting range 0s to 60s, step = 0.1s)

6.2 Main Capacitor Overvoltage Protection

6.2.1 Relay Data

Manufacturer: Trench Austria GMBh

Type: CPR 97 Normal Mode Firmware

Documentation:

Rated Current: 1A

6.2.2 CT Parameters

a) **Main CT**

CT Location: Post Type

Core No: 2

CT Ratio: 2000/1000/1A

Class: 1/5P20, 30VA

6.2.3 System Parameters

a) Nominal System Voltage: 400kV (phase to phase)

b) System Design Fault Current: 50kA

c) Fault Withstanding Duration: 1 sec.

d) Fault Level with Maximum Generation (3∅) = 34.177 kA

e) Rated System Voltage (fund) = 422.6kV (ph-ph)

f) Rated System Voltage (fund) = 244.0kV (ph-neutral)

g) Rated Current (fund) = 350A

6.2.4 Setting Calculation

The capacitor overvoltage protection should be set to trip at a level based on the ANSI curve and the value of I_{BC} > set to the current corresponding to the maximum fundamental voltage rating of the bank.

The voltage selected = 422.6kV

The increase in rms voltage across the capacitor banks due to normal system harmonics is negligible.

CT Ratio = 1000/1A

a) I_{CR} / I_N = $\frac{350}{1000}$ = 0.35

Capacitor Overvoltage Settings

b) Stage 1 – Alarm only

Voltage setting = 105% rated V_{CAP} Bank

V_C > / V_{CR} = 1.05

timer setting = 200ms (External Timer MVTT14 setting range 0.1 to 100s)

c) Stage 2 – Trip

Voltage setting = 110% rated V_{CAP} Bank

V_C >> / V_{CR} = 1.1

timer setting = 1.0 second (CPR inbuilt timer setting range 0 to 10s)

6.2.5 **Settings**

6.2.5.1 Stage 1 – Alarm

a) I_{CR} / I_N = 0.35

b) V_C > / V_{CR} = 1.05

timer setting = 200ms (setting range 0.1 to 100s, step = 0.1s)

6.2.5.2 Stage 2 – Trip

c) V_C >> / V_{CR} = 1.1

timer setting
V_C >> : xt = 1.0 second (Inbuilt timer setting range 0.1 to 10s, step = 0.01s)

7. AUXILIARY CAPACITOR BANK PROTECTION

7.1 Filter Capacitor H TYPE Phase Unbalanced Protection

7.1.1 Relay Data

Manufacturer: Trench Austria GMBh

Type: H-Bridge Mode Firmware - CPR 97

Documentation:

Rated Current: 1A (5A secondary of the 200/5A CT should be connected to 1A relay input)

7.1.2 CT Parameters

CT Location: Post Type

CT Ratio: 200/5A

Class: 0.5, 30VA

7.1.3 System Parameters

a) Nominal System Voltage (fund) = 72.5kV (ph-ph)

b) Nominal System Voltage (fund) = 41.85kV (ph-neutral)

c) Rated Current (fund) = 368.5A

d) Filter Capacitor

Total capacitance/phase = 36.56 μF

Each capacitor unit = 7.31 μF

Total capacitor units/phase = 20

i.e. (parallel number of units = 10)

(series number of units = 2)

i) Each capacitor phase is split into two halves

Each half phase consists: 5 units in parallel

2 units in series

7.1.4 Setting Calculation

Healthy Full Phase Current (fund) = 368.5A

Healthy Half Phase Current (fund) = 184.3A

Refer to item 6.1.3 (sheet 22) for Capacitor Unbalance spill current.

400C2b	Elements	Current	Time	
Stage 1	1	1.3A	10 secs	Alarm
Stage 2	3	4.5A	1s	Trip
Stage 3	7	13.8A	≤ 0.1s	Trip

a) Setting: Stage 1 – Alarm

Spill currrent = 1.3A (primary)

CT Ratio = 200/5A

Current setting = $\frac{1.3}{200}$ x 5 = 0.033A (secondary)

Relay setting = 3%

Time setting = 10s (CPR97 inbuilt timer 0.1 to 600s)

b) Setting: Stage 2 – Trip

Spill currrent = 4.5A (primary)

CT Ratio = 200/5A

Current setting = $\frac{4.5}{200}$ x 5 = 0.11 (secondary)

Relay setting = 11%

Time setting = 1.00s (CPR97 inbuilt timer 1s to 240 mins)

c) Setting: Stage 3 – Trip

Spill currrent = 13.8A (primary)

CT Ratio = 200/5A

Current setting = $\frac{13.8}{200}$ x 5 = 0.345A (secondary)

Relay setting = 34%

Time setting = 90ms (CPR97 inbuilt timer 0 to 60s)

7.1.5 Settings

7.1.5.1 Stage 1 – Alarm

a) I_{ub} – al / I_n = 0.03 (setting range 0.01 to 2.0, step = 0.01)

time setting
I_{ub} – al : xt = 10.0s (setting range 0.1 to 600s, step = 0.1s)

7.1.5.2 Stage 2 – Trip

b) I_{ub} > / I_n = 0.11 (setting range 0.01 to 2.0, step = 0.01)

time setting
I_{ub} > : xt = 1.0s (setting range 1s to 240 min, step = 1s)

7.1.5.3 Stage 3 – Trip

c) I_{ub} >> / I_n = 0.34 (setting range 0.05 to 2.0, step = 0.01)

time setting
I_{ub} >> : xt = 0.10 (100ms) (setting range 0s to 60s, step = 0.1s)

7.2 Auxiliary Capacitor Overvoltage Protection

7.2.1 Relay Data

Manufacturer: Trench Austria GMBh

Type: CPR 97 (Reactor Thermal Overload Relay CPR 97 is used for Auxiliary Capacitor Overvoltage)

Documentation:

Rated Current: 1A

7.2.2 CT Parameters

a) **Main CT**

CT Location: Post Type CT Connected to Filter Reactor

CT Ratio: 400/1A

Class: 5P10, 30VA

7.2.3 Setting Calculation

The capacitor overvoltage protection should be set to trip at a level based on the ANSI curve and the value of I_{BC} > set to the current corresponding to the maximum fundamental voltage rating of the bank.

The voltage selected (rated fundamental) = 31.70kV (ph-neutral)

CT Ratio selected = 400/1A

The increase in rms voltage across the capacitor banks due to normal system harmonics is negligible.

a) I_{CR} / I_N = $\frac{368.5}{400}$ = 0.921

Capacitor Overvoltage Settings

b) Stage 1 – Alarm only

Voltage setting = 105% rated V_{CAP} Bank

V_C > / V_{CR} = 1.05

timer setting = 200ms (External Timer MVTT14 setting range 0.1 to 100s)

c) Stage 2 – Trip

Voltage setting = 110% rated V_{CAP} Bank

V_C >> / V_{CR} = 1.1

timer setting = 1.0 second (CPR97 inbuilt timer setting range 0 to 10s)

7.2.4 **Settings**

7.2.4.1 Stage 1 – Alarm

a) I_{CR} / I_N = 0.92

b) V_C > / V_{CR} = 1.05

timer setting = 200ms (setting range 0.1 to 100s, step = 0.1s)

7.2.4.2 Stage 2 – Trip

c) V_C >> / V_{CR} = 1.1

timer setting
V_C >> : xt = 1.0 second (Inbuilt timer, setting range 0.1 to 10s, step = 0.01s)

8. FILTER RESISTOR PROTECTION

8.1 Resistor Thermal Overload Protection

8.1.1 Relay Data

Manufacturer: AREVA T&D EAI
Haefely Trench

Type: MCAG 39 and MVTT 14
CPR 97

Documentation: R6035 and R6012
Operating and Instruction Manual

Rated Current: 1A

8.1.2 CT Parameters

CT Location: Post Type

CT Ratio: 20/1A

Class: Class X, V_k = 426V

8.1.3 Setting Calculation

a) **Thermal Overload Alarm**

Relay:	=	MCAG 39
Timer:	=	MVTT 14
Rated Continuous Current (each leg)	=	18.3A
Resistor heating/cooling time constant τ (supplied by resistor manufacturer)	=	280 secs.
CT Ratio Selected	=	20/1A
Relay Setting Range:	=	50 – 200%
The current to be protected (18.3 x 1.05%)	=	19.2A
∴ current setting	=	96% (on 20/1A CT ratio)
The primary current	=	0.96 x 20A
	=	19.2A

Alarm Timer

Timer setting range:	=	0.1 - 100s (100ms steps)
Setting selected:	=	1 second

b) **Thermal Overload Trip**

Relay:	=	CPR97

Current to be protected: 18.3 x 110% = 20.13A

Current setting: $Ith >$ = 1.0A

$\therefore$ $Ith > / In$ = 1.0

Thermal constant τ selected = 280 secs.

8.1.4 **Settings**

a) MCAG39 relay setting: = 0.96A (96% of 1A)

b) MVTT14 timer setting: = 1 second (setting range 0.1-100s)

c) CPR97 relay current setting: = 1.0A

Thermal time constant τ selected = 280 secs.

8.2 **Resistor Open Circuit Protection**

8.2.1 **Relay Data**

Manufacturer: VA Tech

Type: DCD 314A ARGUS 1 Relay

Documentation: Operating and Instruction Manual

Rated Current: 1A

8.2.2 **CT Parameters**

CT Location: Post Type Connected on the Resistor Legs

CT Ratio: 20/1A

Class: Class X Type B, V_k = 426V

8.2.3 **Setting Calculation**

Resistor Open Circuit calculation

Total combined current = 36.5A

Resistance of each resistor = 792 Ω (hot)

Tolerance when operating = ± 5%

Let us consider that both resistors are at extreme tolerances.

Let one Resistor be at + 5% = 792 x 1.05 = 831.6 Ω

Let the other Resistor be at – 5% = 792 x 0.95 = 752.4 Ω

∴ The current in 1 Resistor = 19.16A

The current in the other Resistor = 17.34A

Spill current to be protected = 1.82A

Current setting = $\frac{1.82}{20}$ = 0.091A

8.2.4 **Settings**

a) DCD314A relay setting: = 0.10A

Definite time characteristic with time delay = 1 second

9. FILTER REACTOR PROTECTION

9.1 Reactor Thermal Overload Protection

9.1.1 Relay Data

Manufacturer: AREVA T&D EAI
Haefely Trench

Type: MCAG 39 and MVTT 14
CPR97

Documentation: R6035 and R6012
Operating and Instruction Manual

Rated Current: 1A

9.1.2 CT Parameters

CT Location: Post Type

CT Ratio: 400/1A

Class: 5P10, 30VA

9.1.3 Setting Calculation

a) **Thermal Overload Alarm**

Relay: MCAG 39

Timer: MVTT 14

Rated Continuous Current = 377A

Resistor heating/cooling time constant = 120 minutes

τ (supplied by reactor manufacturer)		
CT Ratio Selected	=	400/1A
Relay Setting Range:		50 – 200%
The current to be protected 105% $I_{th}>$	=	395.8A
∴ current setting	=	99% (on 400/1A CT ratio)
The primary current	=	0.99 x 400A
	=	396A (32.2 MVA based on reactor voltage 47kV nominal)
Alarm Reset Timer		
Timer setting range:	=	0.1 – 100s (100ms steps)
Setting selected:	=	1 second

b) **Thermal Overload Trip**

Relay:	=	CPR97
Current to be protected: 377 x 110%	=	414.7A
Current setting: $I_{th}>$	=	1.03A
∴ $I_{th}> / I_n$	=	1.03A
Thermal constant τ selected	=	120 minutes (7,200 seconds)

9.1.4 **Settings**

a)	MCAG39 relay setting:	=	0.99A (99% of 1A)
b)	MVTT14 timer setting:	=	1 second (setting range 0.1-100s)
c)	CPR97 relay current setting:	=	1.03A
	Thermal time constant τ selected	=	120 minutes (7,200 seconds)

10. MSCDN1 400kV CABLE CIRCULATING PROTECTION

Refer to separate document.

11. MESH CORNER PROTECTION

Refer to separate document.

12. APPENDIX

12.1 **Protection Circuit Diagrams**

1) Single Line Diagram

2) Circulating Current Diagram

3) CPR97 H Mode Relay Setting Sheet Associated with C1

4) CPR97 Normal Mode Relay Associated with C2

5) CPR97 Normal Mode Relay Associated with C1 Overvoltage

6) CPR97 Normal Mode Relay Associated with Reactor Thermal Overload and C2 Overvoltage

Appendix 15.1.2 Transformer Bias differential protection

2. 132/33kV STAR/DELTA 31.5MVA RATING TRANSFORMER PROTECTION

2.1 Grid Transformer Biased Differential Protection (T2 & T1)

These three transformers are all identical transformers, with the same Voltage Ratio, same Ratings and same Tap steps. Let us consider one Transformer T1 for calculation purposes.

The transformer is a 3 phase, 50 Hz, ONAN/ONAF, oil-immersed, naturally air cooled/oil forced two winding transformer.

Rating kVA : 31,500

Voltage Ratio : 132,000/33,000 between phases at no load

Connections : Star/Delta

Vector Group : Ynd1

No Load Voltage : High Tension: 132kV, + 10%, –15% (17 Steps)

Step (1.5%)

Low Tension: 33kV

2.1.1 CT Data for HV Side

CT Location : Post type Outdoor mounted (Serial No. 0202614-0202616, core 1)

CT Class : 30VA, 5P20

CT Ratio : 200/1A

$V_{KP} \geq 617V$

$R_{CT} = 5{,}0\Omega$

2.1.2 CT Data for LV Side

CT Location : Mounted inside 33kV GIS Transformer feeder (Serial No. 02/103740-02/103748 core 1)

CT Class : 30VA, 5P20

CT Ratio : 800/1A

$V_{KP} \geq 660V$

$R_{CT} = 2.88$

2.1.3 Biased Differential Relay

Manufacturer : AREVA T&D EAI

Type : KBCH120, 3 phase Biased Differential Digital Relay

Protection Features

The protection features offered by the KBCH are listed below :

- Biased differential protection
- Restricted earth fault protection for individual transformer windings
- Overfluxing protection
- Instantaneous high set operation
- Magnetising inrush restraint
- 5th Harmonic Overfluxing blocking
- 8 opto-isolated inputs for alarm/trip indication of external devices

Relay Input Current : 1A

The current setting range available is 0.1 to 0.5 of 1A

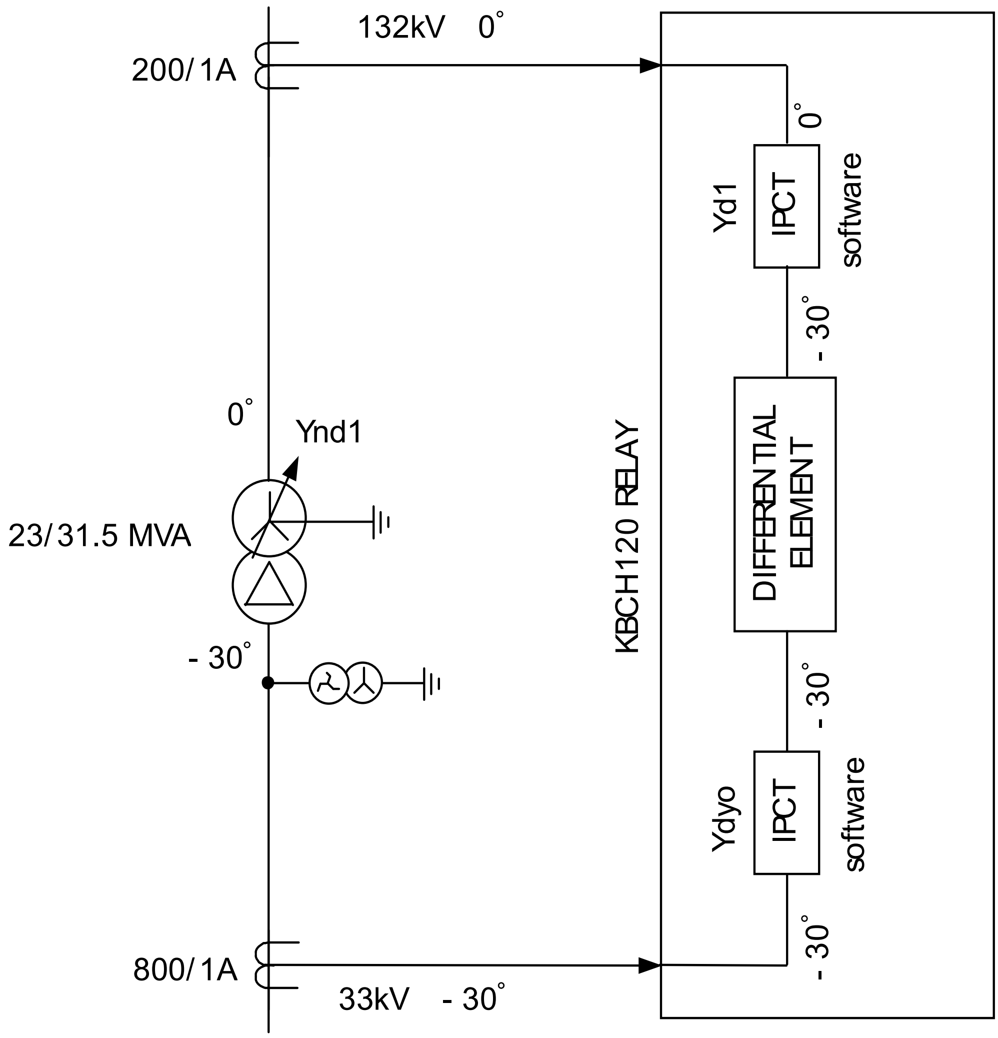


Figure 1 - Single Line Diagram

The transformer connection shows that the delta connected low voltage line current lags the high voltage line current by 30° (–30° phase shift). To ensure that this phase shift does not create a differential current, the same phase shift must be introduced in the secondary circuit. The HV software interposing CT is effectively a winding replica of the main power transformer. It not only provides a –30° phase shift, but also performs the necessary function of filtering out any HV zero sequence current component.

2.1.4 CT Requirements for the Biased Differential Protection

For transformer biased differential protection minimum knee point voltage of the line CT's on the HV side (STAR side) transformer should be

Application	Knee point voltage V_k	Through fault stability limit	
		X/R	If
Transformers	$V_k > 24I_n [R_{ct} + 2R_l + R_B]$	40	$15I_n$

where R_{ct} (CT resistance) = 5.0 Ω

R_l (Lead burden) = 0.346 Ω

R_B (Software Interposing CT resistance = 0

I_n = 1A

R_l = 25 + 50 = 75m, 4.0 sq.mm

R_l = 0.346 Ω

$V_k > 24 \times 1 \times (5.0 + 0.692)$

$V_k > 24 \times 5.692$

$V_k > 136.6V$

Knee point voltage of the Line CTs connected on the LV side (DELTA side) of the transformer, an additional factor must be taken account of in the CT requirements

i.e. $V_k > 24 \sqrt{3} I_n (R_{ct} + 2R_l)$

R_{ct} = 5.0 Ω

R_l = (5.0 + 10.0)m = 15m = 0.069 Ω

$V_k > 24 \times \sqrt{3} \times 1 \times (5.0 + 0.138) = 214V$

Knee point voltage of CT at HV line side

$V_{k\,(HV)}$ = 617V

Knee point voltage of CT at LV line side

$V_{k\,(LV)}$ = 660V

R total HV side = Total burden connected to CT at HV side = 5.69 Ω

R total LV side = Total burden connected to CT at LV side = 5.138Ω

To ensure that the quoted operating times and through fault stability limits are met the ratio of $V_{k\ (HV)}$ / $Rtot_{(HV)}$: $V_{k\ (LV)}$ / $Rtot_{(LV)}$, at biased inputs either side of the protected impedance, should not exceed a maximum disparity ratio of 1 : 3. This ensures that during a through fault condition the flux density in the current transformers is not greatly different.

$$\frac{617}{5.69} : \frac{660}{5.138}$$

1 : 1.2

2.1.5 Transformer HV and LV Currents

To minimise unbalance due to tapchanger operation, current inputs to the differential element should be matched for the mid-tap position.

18 Tap positions = 17 Tap increments   Tap 1 = + 10.5%
Tap 18 = – 15%

$$\text{Tap increment} = \frac{10.5 - (-15)}{17} = \frac{25.5}{17} = 1.5\%$$

$$\text{Mid Tap range} = 132kV \left(\frac{100 + (10.5 - 15) / 2}{100} \right)$$

$$= 132kV \times 97.75\%$$

$$= 129.03kV$$

Tap position 8 = 132.0kV (0%)

Tap position 9 = 130.02kV (–1.5%)

Tap position 10 = 128.04kV (–3.0%)

Mid Tap range = 129.03kV (–2.25%)

This shows that the mid Tap range is between Tap 9 and Tap 10 which is not available.

∴ Tap position 9 is selected as the Mid Tap position

CT Ratio : 200/1A

$$\text{HV FLC on Tap 9} = \frac{31.5 \times 10^3}{130.02 \times \sqrt{3}} = 139.9A \text{ Primary}$$

= 0.7A Secondary

∴ At mid-tap position 9 (–1.5%) primary current = 139.9A Primary
= 0.7A Secondary

See Table 2 for Tap Position, Voltage and Currents.

Tap Range + 7 x 1.5% – 10 x 1.5%

a) **Table 2 : Tap Position, Voltage and Current for Primary Side of the Transformer**

Tap Position Number	HV Volts kV	Tapchanger Ranger	HV Currents A	Secondary (200/1) A	Primary Mid Tap A
1	145.86	10.5%	124.7	0.624	
8	132.0	0%	137.8	0.689	
9	130.02	– 1.5%	139.9	0.70	139.9
10	128.04	– 3.0%	142.0	0.71	
14	120.12	– 9.0%	151.4	0.757	
18	112.2	– 15%	162.1	0.81	

b) **LV Side of the Transformer**

Manufacturer : AREVA T&D EAI

LV Side Voltage : 33kV

LV Full Load Current : $\frac{31.5 \times 10^3}{33 \times \sqrt{3}} = 551\text{A}$ Primary

CT Ratio : 800/1A

LV Side Current : $\frac{551}{800} = 0.689\text{A}$ Secondary

2.1.6 Relay Settings

Required HV ratio compensation factor = 1.0/0.7= 1.428

select = 1.43

Required LV ratio compensation factor = 1.0/0.689 = 1.451

select = 1.45

HV FLC on Tap 1 (10.5%) = 124.7A Primary

= 0.624A Secondary

∴ HV corrected current on Tap 1 = 1.43 x 0.624A

= 0.892A

HV corrected current on Tap 18 = 1.43 x 0.81A

= 1.1583A

LV corrected current = 1.45 x 0.689A

= 0.999A

∴ I diff at Tap 1 = 0.999 – 0.892 = 0.107A

∴ I diff at Tap 18 = 1.1583 – 0.999 = 0.159A

I bias at both extremities (with mid tap correction)

I bias = $(I_{RHV} + I_{RLV}) / 2$

∴ Bias current on Tap 1 = (0.892 + 0.999) / 2

= 0.945A

Bias current on Tap 18 = (1.1583 + 0.999) /2

= 1.0786A

Relay operating current I_{OP}

a) Operating current at Tap 1 with I bias = 0.945A and I_S = 0.2

∴ I_{OP} = I_S + 0.2 I bias

= 0.2 + 0.2 x 0.945 = 0.389A

b) Operating current at Tap 18 with I bias = 1.0786A and I_S = 0.2

I_{OP} = I_S + 0.2 + (I bias – 1.0) x 0.85

= 0.2 + 0.2 + (1.0786 – 1.0) x 0.85 = 0.46681A

Check I diff < I_{OP} by a 10% margin for each tap extremity and adjust I_S as necessary.

Tap 1 : Since I diff = 0.107A and 0.9 I_{OP} at tap 1 = 0.9 x 0.389

= 0.350A

Therefore there is sufficient security with I_S = 0.2

Tap 18: Since I diff = 0.159A and 0.9 I_{OP} at tap 18 = 0.9 x 0.4668

= 0.420A

Therefore there is sufficient security with I_S = 0.2

3. TRANSFORMER RESTRICTED EARTH FAULT PROTECTION

3.1 Grid Transformer T2 HV Restricted Earth Fault Protection

3.1.1 Transformer Data

Primary Voltage (HV Side)	=	132kV
Secondary Voltage (LV Side)	=	33kV
Transformer Rating	=	23/31.5 MVA
Transformer Connection	=	Star / Delta

3.1.2 Rated Stability

a) Rated Primary Current $= \dfrac{31.5 \times 10^6}{\sqrt{3} \times 132 \times 10^3} = 137.8A$

For stability limit the maximum through fault current I_F should be considered.

An estimation of the maximum three phase fault current can be estimated by ignoring source impedance :

I_F = Primary full load current/transformer % impedance = 1350A
I_f = Secondary full load current/transformer % impedance

Transformer impedance = 10.2%

Secondary full load current= $\dfrac{137.8}{200}$ = 0.689A

$$I_f = \frac{0.689}{0.102} = 6.75A$$

It is difficult to accurately predict the maximum anticipated level of inrush current. Typical waveform peak values are of the order of 8–10 x rated current. A worst case estimation of inrush could be made by dividing the transformer full load current by the per unit leakage reactance quoted by the transformer manufacturer.

b) However the customer CEB has declared that the maximum fault level for Ratnapura substation (refer to letter dated 30 January 2003 from Protection Development of CEB).

Fault Level	132kV System	33kV System
Maximum	4.7 kA	7.0 kA

3.1.3 **Relay Setting Calculation for Primary (HV) Side**

3.1.3.1 Restricted Earth Fault Protection for Transformer Star Windings

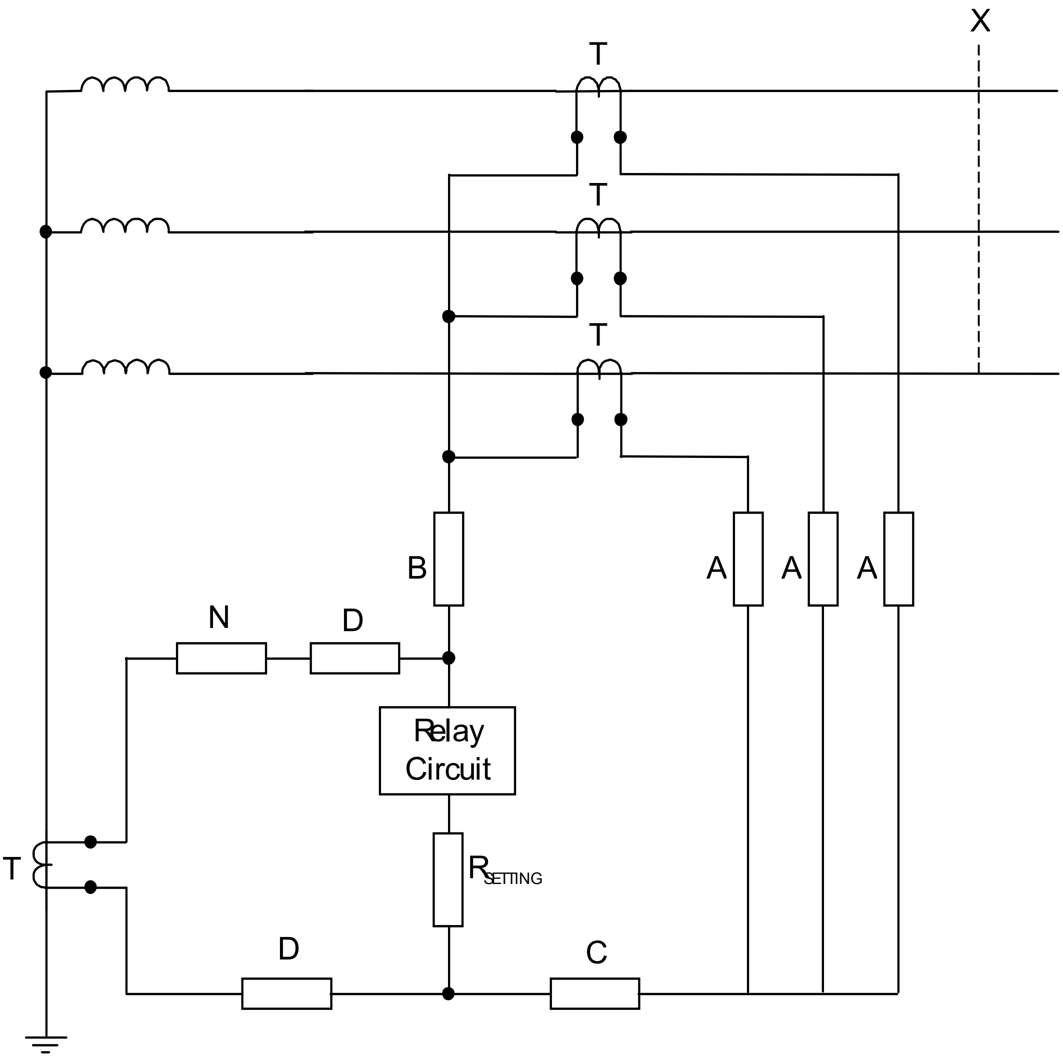


Figure 2 – Restricted Earth Fault Protection (High Impedance Principle)

Let T = turns ratio of line and neutral current transformers

B,C, D = resistance of wiring

A = resistance of wiring plus current transformer winding

N	=	neutral CT resistance plus resistance of wiring
V_S	=	relay circuit setting voltage
I_1	=	secondary exciting current of line current transformer at V_S volts
I_2	=	secondary exciting current of neutral current transformer at V_S volts
I_S	=	relay circuit current at V_S volts
I_F	=	fault current corresponding to the rated stability limit
I_f	=	$I_F \times T$

3.1.3.2 **Rated Stability Limit**

i) Consider a phase-to-earth short circuit at *X* and assume complete saturation of a line current transformer, then V_S shall be not less than:-

$$I_f \quad (A + B + C) \text{ volts} \qquad (1)$$

ii) Consider a phase-to-earth short circuit at *X* and assume complete saturation of the neutral current transformer, then V_S shall be not less than:-

$$I_f \quad (N + 2D) \text{ volts} \qquad (2)$$

3.1.3.3 **General Data**

a) **Line CT Parameters**

CT location	:	Post type CT's (Serial No. 0202616 core 1)
Ratio	:	200/1A
Class	:	30VA, 5P20
Knee Point Voltage	:	617V
Resistance	:	0.8 Ω

b) **Neutral CT (HV Side)**

CT location	:	Post type CTs (Serial No. 0202617)
Ratio	:	200/1A
Class	:	30VA, 5P20

Knee Point Voltage : 616V

Resistance : 0.8 Ω

c) **Lead Length for the Line CTs**

From current transformers to bay marshalling kiosk = 15m

From bay marshalling kiosk to relay panel = 85m

d) **Lead Length for the Neutral CT**

From neutral CT to transformer bay marshalling kiosk = 35m

From transformer bay marshalling kiosk to relay panel = 50m

Table: Lead Resistances and CT Resistances

4.0 sq.mm. cable max resistance/km = 4.61 Ω

Item	Length (m)	Resistance (Ω)	CT (Ω)	Total (Ω)		Parameters
1	15	0.069	0.8	0.869	R_1	A
2	100	0.461		0.461	R_2	B
3	85	0.392	-	0.392	R_3	C
4	85	0.392		0.392	R_4	D
5	35	0.16	0.8	0.96	R_5	N

3.1.3.4 Rated Stability Limit for HV Side

A = 0.869 Ω, B = 0.461 Ω, N = 0.96 Ω

C = 0.392 Ω, D = 0.392 Ω

a) For phase to earth short circuit at *X* and assume line CT saturates using equation (1), then V_S,

$$V_S \geq \frac{4700}{200}\left(0.869 + 0.461 + 0.392\right)$$

$$V_S \geq 40.5\text{V}$$

b) For phase to earth short circuit at *X* and assume neutral CT saturates, using equation (2), then V_S

$$V_S \geq \frac{4700}{200}(0.96 + 2 \times 0.392)$$

$$V_S \geq 41.0V$$

To obtain high speed operation for internal faults, the knee point voltage, V_K, of the CTs must be significantly higher than the stability voltage, V_S. This is essential so that the operating current through the relay is a sufficient multiple of the applied current setting. Ideally a ratio of $V_K \geq 5V_S$ would be appropriate.

The required stability voltage can be calculated as $V_S \geq K\,I_f\,(N + 2D)$

K = a constant affected by the dynamic response of the relay.

$\therefore$ Required relay stability voltage $V_S = 0.5\ I_f\ (N + 2D)$

where K = 0.5

$$V_S \geq 0.5 \times \frac{4700}{200}(0.96 + 2 \times 0.392)$$

$$V_S \geq 20.5V$$

3.1.3.5 Current Setting and Fault Setting Resistor Calculation

a) **Relay Data**

Manufacturer:	AREVA T&D EAI
Type:	KCGG122
Rated Current:	1A

b) **Relay Setting Current**

To achieve the required primary operating current a suitable setting (I_S) must be chosen for the relay.

The recommended primary operating current for REF protection is usually determined by the minimum fault current available for operation.

The primary operating current (I_{op}), in secondary terms, is a function of the CT ratio, the relay operating current (I_S), the number of CTs in parallel with the relay element (n), and the magnetising current of each CT (I_1).

$$I_{op} = \text{CT ratio} \times (I_S + n i_1)$$

I_S < $(I_{OP}/CT\ ratio) - nI_1$ (4)

Assuming that the relay effective setting for a solidly earthed power transformer is approximately 50% of full load current.

Recommended primary fault setting is between 10–60% of HV current

∴ Let us consider 50% of HV current = 0.50 x 137.8 = 68.9A

Total number of CTs = 4

I_1 of one CT = 3mA at V_S = 20.5V

$[I_{OP}/CT\ ratio] = 68.9/200 = 0.3445A$, $nI_1 = 4 \times 3 = 12mA$

using equation (4)

$I_S = 0.3445 - 0.012$

$I_S = 0.3325$

c) **Establishing the Value of Setting Resistors**

Resistor value R is given by :-

$$R = \frac{V_S}{I_S} = \frac{20.5}{0.3285} = 62\ \Omega$$

$$\therefore R_S = \frac{20.5}{0.3325} = 62\ \Omega$$

Let us consider $R_S = 65\ \Omega$

(Adjustable wire-wound resistor of 0–1500 Ω is supplied)

d) **Setting Resistor Dissipation**

i) At setting $= (I_s)^2 R$ or $\frac{V^2_s}{R}$ = 6.5 watts

e) **Check Metrosil requirements**

If the peak voltage appearing across the relay circuit under maximum internal fault conditions exceeds 3000V peak, then a suitable non-linear resistor ("metrosil") externally mounted, should be connected across the relay and stabilising resistor.

The peak voltage can be estimated by the formula :

Where $V_P = 2\sqrt{2V_K\,(V_f - V_K)}$

V_K : actual CT knee point voltage

V_f = If' (N + 2D + Rstab)

Where If' : maximum prospective secondary internal fault current
However the fault current declared by CEB referred to 132kV side = 4.7kA.

If' = 4700 / 200 = 23.5A

V_f = 23.5 (0.96 + 0.784 + 65)

= 1569V

$$V_P = 2\sqrt{2 \times 617 \times (1569 - 617)}$$

= 2168V

This value is below 3000V and therefore Metrosils are not required with the relay.

3.1.3.6 Setting

Protection setting for KCGG122

- Restricted earth fault setting HV, $I_o >$ = 0.3325A
- Stabilising resistor value = 65 Ω
- Adjustable wire-wound resistor of 0–220 Ω or 0–1500 Ω will be supplied with KCGG122 relay.

3.2 Grid Transformer T1 HV Restricted Earth Fault Protection

3.2.1 Transformer Data

Primary Voltage (HV Side)	=	132kV
Secondary Voltage (LV Side)	=	33kV
Transformer Rating	=	23/31.5 MVA
Transformer Connection	=	Star / Delta

3.2.3 Rated Stability

$$\text{Rated Primary Current} = \frac{31.5 \times 10^6}{\sqrt{3} \times 132 \times 10^3} = 137.8\text{A}$$

For stability limit the maximum through fault current I_F should be considered.

An estimation of the maximum three phase fault current can be estimated by ignoring source impedance :

I_F = Primary full load current/transformer % impedance = 1350A

I_f = Secondary full load current/transformer % impedance

Transformer impedance = 10.2%

Secondary full load current = $\frac{137.8}{200}$ = 0.689A

$$I_f = \frac{0.689}{0.102} = 6.75\text{A}$$

It is difficult to accurately predict the maximum anticipated level of inrush current. Typical waveform peak values are of the order of 8–10 x rated current. A worst case estimation of inrush could be made by dividing the transformer full load current by the per unit leakage reactance quoted by the transformer manufacturer.

However the customer CEB has declared that the maximum fault level for Ratnapura substation (refer to letter dated 30 January 2003 from Protection Development of CEB).

Fault Level	132kV System	33kV System
Maximum	4.7 kA	7.0 kA

3.2.3 **Relay Setting Calculation for Primary (HV) Side**

3.2.3.1 Restricted Earth Fault Protection for Transformer Star Windings

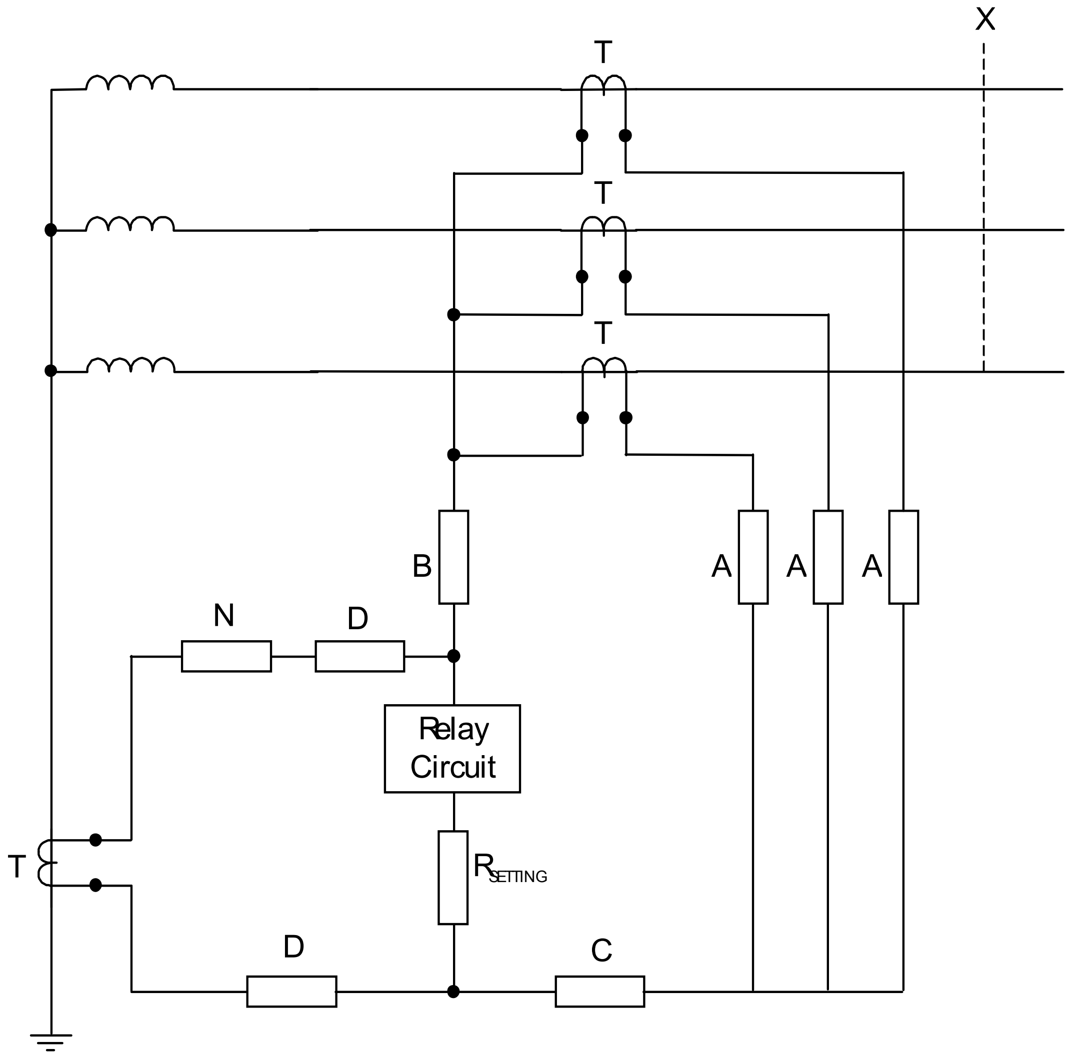


Figure 2 – Restricted Earth Fault Protection (High Impedance Principle)

Let T	=	turns ratio of line and neutral current transformers
B,C, D	=	resistance of wiring
A	=	resistance of wiring plus current transformer winding
N	=	neutral CT resistance plus resistance of wiring
V_S	=	relay circuit setting voltage
I_1	=	secondary exciting current of line current transformer at V_S volts
I_2	=	secondary exciting current of neutral current transformer at V_S volts

I_S	=	relay circuit current at V_S volts
I_F	=	fault current corresponding to the rated stability limit
I_f	=	I_F x T

3.2.3.2 **Rated Stability Limit**

i) Consider a phase-to-earth short circuit at *X* and assume complete saturation of a line current transformer, then V_S shall be not less than:-

$$I_f \ (A + B + C) \text{ volts} \qquad (1)$$

ii) Consider a phase-to-earth short circuit at *X* and assume complete saturation of the neutral current transformer, then V_S shall be not less than:-

$$I_f \ (N + 2D) \text{ volts} \qquad (2)$$

3.2.3.3 **General Data**

a) **Line CT Parameters**

CT location	:	Post type CT's (Serial No. 0202616, core 1)
Ratio	:	200/1A
Class	:	30VA, 5P20
Knee Point Voltage	:	617V
Resistance	:	0.8 Ω

b) **Neutral CT (HV Side)**

CT location	:	Post type CT's (Serial No. 0202617, core 1)
Ratio	:	200/1A
Class	:	30VA, 5P20
Knee Point Voltage	:	616V
Resistance	:	0.8 Ω

c) **Lead Length for the Line CT's**

From current transformers to bay marshalling kiosk = 20m

From bay marshalling kiosk to relay panel = 70m

d) **Lead Length for the Neutral CT**

From neutral CT to transformer bay marshalling kiosk = 30m

From transformer bay marshalling kiosk to relay panel = 50m

Table: Lead Resistances and CT Resistances

4.0 sq.mm. cable max resistance/km = 4.61 Ω

Item	Length (m)	Resistance (Ω)	CT (Ω)	Total (Ω)		Parameters
1	20	0.092	0.8	0.892	R_1	A
2	90	0.415		0.415	R_2	B
3	70	0.323	-	0.323	R_3	C
4	80	0.369		0.369	R_4	D
5	30	0.138	0.8	0.938	R_5	N

3.2.3.4 **Rated Stability Limit for HV Side**

A = 0.892 Ω, B = 0.415 Ω, N = 0.938 Ω

C = 0.323 Ω, D = 0.369 Ω

a) For phase to earth short circuit at *X* and assume line CT saturates using equation (1), then V_S,

$$V_S \geq \frac{4700}{200}(0.892 + 0.415 + 0.323)$$

$$V_S \geq 38.3$$

b) For phase to earth short circuit at *X* and assume neutral CT saturates, using equation (2), then V_S

$$V_S \geq \frac{4700}{200}(0.938 + 2 \times 0.369)$$

$$V_S \geq 39.38 \text{ V}$$

To obtain high speed operation for internal faults, the knee point voltage, V_K, of the CT's must be significantly higher than the stability voltage, V_S. This is essential so that the operating current through the relay is a sufficient multiple of the applied current setting. Ideally a ratio of $V_K \geq 5V_S$ would be appropriate.

The required stability voltage can be calculated as $V_S \geq K I_f (N + 2D)$

K = a constant affected by the dynamic response of the relay.

$\therefore$ Required relay stability voltage $V_S = 0.5\ I_f\ (N + 2D)$

where K = 0.5

$$V_S \geq 0.5 \times \frac{6800}{200} \ (0.938 + 2 \times 0.369)$$

$V_S = 20.0V$

3.2.3.5 Current Setting and Fault Setting Resistor Calculation

a) **Relay Data**

Manufacturer	:	AREVA T&D EAI
Type	:	KCGG122
Rated Current	:	1A

b) **Relay Setting Current**

To achieve the required primary operating current a suitable setting (I_S) must be chosen for the relay.

The recommended primary operating current for REF protection is usually determined by the minimum fault current available for operation.

The primary operating current (I_{op}), in secondary terms, is a function of the CT ratio, the relay operating current (I_S), the number of CTs in parallel with the relay element (n), and the magnetising current of each CT (I_e).

$$I_{op} = \text{CT ratio} \times (I_S + nI_1)$$

$$I_S < [I_{OP}/\text{CT ratio}] - nI_1 \qquad (4)$$

Assuming that the relay effective setting for a solidly earthed power transformer is approximately 50% of full load current.
Recommended primary fault setting is between 10–60% of HV current = 68.9A

$\therefore$ Let us consider 50% of HV current = 0.50 x 137.8 = 68.9A

Total number of CTs = 4

I_1 of one CT = 2mA at V_S = 20V

[I_{OP}/CT ratio] = 68.9/200 = 0.3445A, nI_e = 4 x 2 = 18mA

using equation (4)

I_S = 0.3445 – 0.008

I_S = 0.3365

c) **Establishing the Value of Setting Resistors**

Resistor value R is given by :-

$$R = \frac{V_S}{I_S} = \frac{20.0}{0.3365} = 59\ \Omega$$

$$\therefore\ R_S = \frac{20}{0.3365} = 60\ \Omega$$

Let us consider R_S = 65 Ω

(Adjustable wire-wound resistor of 0–1500 Ω is supplied)

d) **Setting Resistor Dissipation**

i) At setting = $(I_s)^2\ R$ or $\frac{V^2_s}{R}$ = 6.5 watts

e) **Check Metrosil requirements**

If the peak voltage appearing across the relay circuit under maximum internal fault conditions exceeds 3000V peak, then a suitable non-linear resistor (“metrosil”) externally mounted, should be connected across the relay and stabilising resistor.

The peak voltage can be estimated by the formula :

Where $V_P = 2\sqrt{2V_K\ (V_f - V_K}$

V_K : actual CT knee point voltage

V_f = If’ (N + 2D + Rstab)

Where If’ : maximum prospective secondary internal fault current

However the fault current declared by CEB referred to 132kV side = 4.7kA.

If’ = 4700 / 200 = 23.5A

$V_f \quad = \quad 23.5\ (0.938 + 2 \times 0.369 + 65)$

$\quad\quad = \quad 1567V$

$V_P \quad = \quad 2\sqrt{2 \times 617 \times (1567 - 617)}$

$\quad\quad = \quad 2165V$

This value is below 3000V and therefore Metrosils are not required with the relay.

3.2.3.6 **Setting**

Protection setting for KCGG122

- Restricted earth fault setting HV, $Io >\ = 0.3365A$
- Stabilising resistor value = 65 Ω
- Adjustable wire-wound resistor of 0–220 Ω or 0–1500 Ω will be supplied with KCGG122 relay.

3.3 Grid Transformer T2 LV Restricted Earth Fault Protection

3.3.1 Transformer Data

Primary Voltage (HV Side)	=	132kV
Secondary Voltage (LV Side)	=	33kV
Transformer Rating	=	23/31.5 MVA
Transformer Connection	=	Star / Delta

3.3.2 Rated Stability

a) Rated Primary Current $= \dfrac{31.5 \times 10^6}{\sqrt{3} \times 33 \times 10^3} = 551A$

For stability limit the maximum through fault current I_F should be considered.

An estimation of the maximum three phase fault current can be estimated by ignoring source impedance :

$I_F \quad = \quad$ Primary full load current-transformer % impedance

$I_f \quad = \quad$ Secondary full load current/transformer % impedance

Transformer impedance = 10.2%

It is difficult to accurately predict the maximum anticipated level of inrush current. Typical waveform peak values are of the order of 8–10 x rated current. A worst case estimation of inrush could be made by dividing the transformer full load current by the per unit leakage reactance quoted by the transformer manufacturer.

$$\text{Secondary full load current} = \frac{551}{800} = 0.689\text{A}$$

$$I_f = \frac{0.689}{0.102} = 6.75\text{A}$$

b) However the customer CEB has declared that the maximum fault level for Thulhiriya substation (refer to letter dated 30 January 2003 from Protection Development of CEB).

Fault Level	132kV System	33kV System
Maximum	4.7 kA	7.0 kA

3.3.3 **Relay Setting Calculation for Primary (LV) Side**

3.3.3.1 Restricted Earth Fault Protection for Transformer Delta Windings

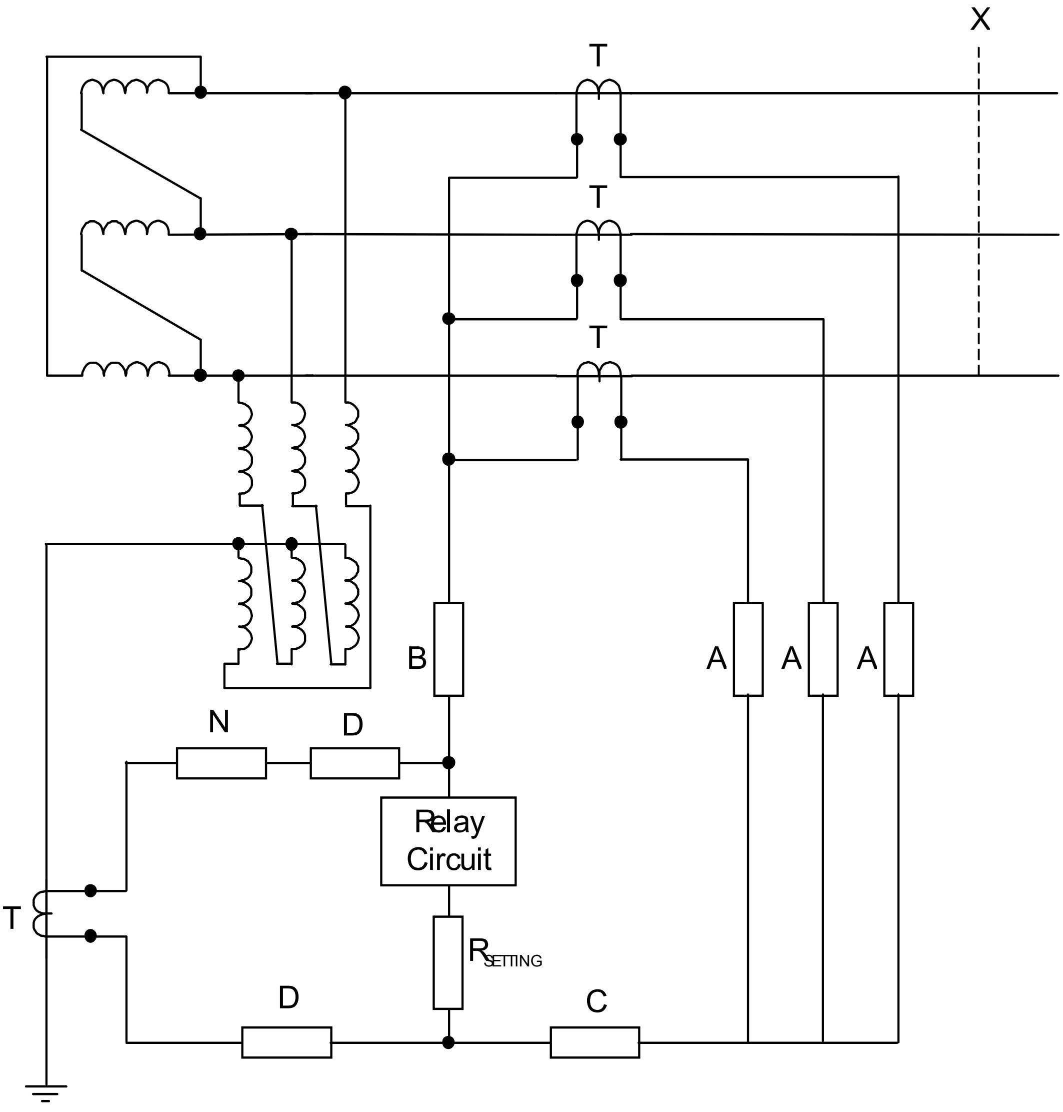


Figure 3 – Restricted Earth Fault Protection (High Impedance Principle)

Let T	=	turns ratio of line and neutral current transformers
B,C, D	=	resistance of wiring
A	=	resistance of wiring plus current transformer winding
N	=	neutral CT resistance plus resistance of wiring
V_S	=	relay circuit setting voltage
I_1	=	secondary exciting current of line current transformer at V_S volts

I_2	=	secondary exciting current of neutral current transformer at V_S volts
I_S	=	relay circuit current at V_S volts
I_F	=	fault current corresponding to the rated stability limit
I_f	=	I_F x T

3.3.3.2 **Rated Stability Limit**

i) Consider a phase-to-earth short circuit at *X* and assume complete saturation of a line current transformer, then V_S shall be not less than:-

$$I_f \ (A + B + C) \text{ volts} \qquad (1)$$

ii) Consider a phase-to-earth short circuit at *X* and assume complete saturation of the neutral current transformer, then V_S shall be not less than:-

$$I_f \ (N + 2D) \text{ volts} \qquad (2)$$

3.3.3.3 **General Data**

a) **Line CT Parameters**

CT location	:	Inside 33kV GIS Transformer feeder (Serial No. 02/103742-44 core 1)
Ratio	:	800/1A
Class	:	30VA, 5P20
Knee Point Voltage	:	660V
Resistance	:	3.0 Ω

b) **Neutral CT (LV Side)**

CT location core 1)	:	Post type Outdoor CTs (Serial No. 0202584
Ratio	:	800/1A
Class	:	30VA, 5P20
Knee Point Voltage	:	680V
Resistance	:	4.9 Ω

c) **Lead Length for the Line CTs**

From (GIS) current transformers to LV relay cubicle = 5m

From GIS to LV relay panel = 10m

d) **Lead Length for the Neutral CT**

From neutral CT to transformer bay marshalling kiosk = 70m

From transformer bay marshalling kiosk to LV relay panel = 45m

Table: Lead Resistances and CT Resistances

4.0 sq.mm. cable max resistance/km = 4.61 Ω

Item	Length (m)	Resistance (Ω)	CT (Ω)	Total (Ω)		Parameters
1	5	0.023	3.0	3.023	R_1	A
2	10	0.046		0.046	R_2	B
3	10	0.046		0.046	R_3	C
4	115	0.530		0.530	R_4	D
5	70	0.323	4.9	5.22	R_5	N

3.3.3.4 **Rated Stability Limit for LV Side**

A = 3.023 Ω, B = 0.046 Ω, N = 5.22 Ω

C = 0.046 Ω, D = 0.530 Ω,

a) For phase to earth short circuit at *X* and assume line CT saturates using equation (1), then V_S,

$$V_S \geq \frac{7000}{800}(3.023 + 0.046 + 0.046)$$

$V_S = 27.3V$

b) For phase to earth short circuit at *X* and assume neutral CT saturates, using equation (2), then V_S

$$V_S \geq \frac{7000}{800}(5.22 + 2 \times 0.530)$$

$V_S = 55V$

To obtain high speed operation for internal faults, the knee point voltage, V_K, of the CTs must be significantly higher than the stability voltage, V_S. This is essential so that the operating current through the relay is a sufficient multiple of the applied current setting. Ideally a ratio of $V_K \geq 5V_S$ would be appropriate.

The required stability voltage can be calculated as $V_S \geq K I_f (N + 2D)$

K = a constant affected by the dynamic response of the relay.

$\therefore$ Required relay stability voltage $V_S = 0.5\ I_f\ (N + 2D)$

where K = 0.5

$$V_S \geq 0.5 \times \frac{7000}{800} (5.22 + 2 \times 0.530)$$

$V_S = 27.5V$

3.3.3.5 Current Setting and Fault Setting Resistor Calculation

a) **Relay Data**

Manufacturer:	ALSTOM T&D EAI
Type:	KCGG122
Rated Current:	1A

b) **Relay Setting Current**

To achieve the required primary operating current a suitable setting (I_S) must be chosen for the relay.

The recommended primary operating current for REF protection is usually determined by the minimum fault current available for operation.

The primary operating current (I_{op}), in secondary terms, is a function of the CT ratio, the relay operating current (I_S), the number of CTs in parallel with the relay element (n), and the magnetising current of each CT (I_1).

$$I_{op} = \text{CT ratio} \times (I_S + nI_1)$$

$$I_S < [I_{OP}/\text{CT ratio}] - nI_1 \quad (4)$$

Assuming that the relay effective setting for a solidly earthed power transformer is approximately 40% of full load current.

Recommended primary fault setting is between 10–60% of LV current

$\therefore$ Let us consider 40% of LV current = 0.4 x 551 = 220A

Total number of CTs = 4

I_1 of one CT = 2mA at V_S = 27.5V

(I_{OP}/CT ratio) = 220/800 = 0.275A, nI_1 = 4 x 2 = 8mA

using equation (4)

I_S = 0.275 – 0.008

I_S = 0.267A

c) **Establishing the Value of Setting Resistors**

Resistor value R is given by :-

$$R = \frac{V_S}{I_S} = \frac{27.5}{0.267} = 103\ \Omega$$

$$\therefore R_S = \frac{27.5}{0.267} = 103\ \Omega$$

Let us consider R_S = 110 Ω

(Adjustable wire-wound resistor of 0-220 Ω is supplied with KCGG122 relay)

b) **Setting Resistor Dissipation**

i) At setting = $(I_s)^2\ R$ or $\frac{V^2{}_s}{R}$ = 7.0 watts

e) **Check Metrosil requirements**

If the peak voltage appearing across the relay circuit under maximum internal fault conditions exceeds 3000V peak, then a suitable non-linear resistor (“metrosil”) externally mounted, should be connected across the relay and stabilising resistor.

The peak voltage can be estimated by the formula :

Where $V_P = 2\sqrt{2V_K\,(V_f - V_K}$

V_K : actual CT knee point voltage

$$V_f = I_f' (N + 2D + R_{stab})$$

Where I_f' = maximum prospective secondary internal fault current

However the fault current declared by CEB referred to 33kV side = 7.0kA.

$$I_f' = 7000 / 800 = 8.75$$

$$V_f = 8.75 \ (5.22 + 1.06 + 110)$$

$$= 1018V$$

$$V_P = 2\sqrt{2 \times 680 \times (1018 - 680)}$$

$$= 1356V$$

This value is below 3000V and therefore Metrosils are not required with the relay.

3.3.3.6 **Setting**

Differential element

- Restricted earth fault setting LV, $I_o >$ = 0.267A
- Stabilising resistor value = 110 Ω
- Adjustable wire-wound resistor of 0–220 Ω or 0–1500 Ω will be supplied with KCGG122 relay.

3.5 Standby Earth Fault Protection for Neutral Earthing Transformers Connected to the LV Side of All 2 Power Transformers T2 and T1

3.5.1 Relay Data

Manufacturer	AREVA T&D EAI
Type	KCGG122
Documentation	R8551
Rated current	1A

3.5.2 CT Parameters

CT Location	Post Type Outdoor CT's (Serial No. 0202584)
Core No.	2
CT Ratio	800/1A
Class	5P20, 30VA

3.5.3 System Parameters

a)	System voltage	33kV	
b)	System Design Fault Current	25kA	
c)	Fault Withstanding Duration	1 sec	
d)	Fault Level (Maximum)	4.7kA	
e)	Fault Level (Minimum)	0.6kA	
f)	Earth Fault Current	per Transformer	245A
	per 2 Transformers	490A	

3.5.4 Setting Calculation

a) **Standby Earth Fault**

The standby earth fault shall be set in order to detect the lowest current available. The tripping curve selected shall be of type "long time earth fault".

CT Ratio Selected = 800/1A
Relay Setting Range 0.098 – 3.2 I_n of 1A (0.01A Steps)

The fault current could nominally be set to 1-30% of relay setting

The current to be protected = 12% of 490A = 0.12 x 490 = 60A of relay setting

$$\therefore \text{ current setting (long time earth fault)} = \frac{60}{800} \times 1 = 0.075A$$

Proposed relay current setting I_s = 0.098A (minimum setting available on
(lowest setting) relay is 0.098)

The primary current (necessary to cause closing of relay contacts)

$= \quad 0.098 \times 800A$

$= \quad 78.5A$

b) **Selection of Time Characteristic**

Inverse definite minimum time (IDMT)

Nine inverse reset time characteristics are available and the general mathematical expression for the curves is :

$$t \quad = \quad TMS \left[\frac{k}{\left(\frac{I}{I_S}\right)^a - 1} + c \right] \text{ seconds}$$

where TMS $=$ Time Multiplier (0.025 to 1.5 in 0.025 steps)

I $=$ Fault current

I_S $=$ Overcurrent setting

k, c, a $=$ Constants specifying curve

Curve No.	Description	Name	IEC Curve	k	c	a
0	Definite Time	DT	-	0	0 to 100	1
1	Standard Inverse	SI30xDT	A	0.14	0	0.02
2	Very Inverse	VI30xDT	B	13.5	0	1
3	Extremely Inverse	EI10xDT	C	80	0	2
4	Long Time Inverse	LTI30xDT	-	120	0	1
5	Moderately Inverse	MI	D	0.103	0.228	0.02
6	Very Inverse	VI	E	39.22	0.982	2
7	Extremely Inverse	EI	F	56.4	0.243	2
8	Short Time Inverse	STI30xDT	-	0.05	0	0.04
9	Rectifier Protection	RECT	-	45900	0	5.6

Although the curves tend to infinity at the setting current value (I_S), the guaranteed minimum operative current is 1.05 $I_S \pm$ 0.05 I_S for all inverse characteristic curves, except curve 10 for which the minimum operating current is 1.61 $I_S \pm$ 0.05 I_S.

Curves numbers 1, 2, 4 and 8 become definite time for currents in excess of 30 x I_S.

Curve 3 becomes definite time for currents above 10 x I_s to give extra time grading steps at high current levels. Curves 1, 2 and 3 are curves A, B & C in IEC 60255-3.
Curves 5, 6 and 7 are slightly different in that they tend to a definite operating time given by the constant (a) at high fault levels. Curves 5, 6 and 7 were proposed by IEEE/ANSI, for inclusion in the IEC Standard IEC 60255-3, as curves D, E and F.

Lone Time Inverse (LTI) : $t = \dfrac{120}{(I - 1)}$ at TMS = 1

$$\text{where} \quad I = \left(\frac{I}{I_s}\right)$$

c) **Time Multiplier Setting TMS**

Setting Range = 0.05 to 1 in 0.025 steps

The minimum tripping time (calculated with the minimum value between 30 x 800 x I_s , limit of the curve, and I_f , the maximum fault current) shall be less than the fault withstanding duration and higher than the main protections tripping time.

Minimum value 1i between 30 x 800 x I_s and I_f :

30 x 800 x 0.098 = 2.16kA and I_f = 7.0kA => I_i = 0.49kA

$$I = \frac{I}{I_s} = \frac{0.49 \times 10^3}{0.098 \times 800} = 6.25$$

$$\text{using} \quad t = \frac{120}{(I - 1)} = 22.8 \text{ secsat TMS} = 1$$

Let TMS setting = 0.5

Minimum tripping time t (with TMS = 0.50) = 22.8 x 0.5 = 11.4s

3.5.5 Instantaneous Element

Instantaneous protection is not applicable for SBEF Protection. Therefore, Instantaneous feature is rendered inoperative.

This function remains unused to maintain selectivity between main protections.

3.5.6.1 Relay Setting for SBEF Relay on All Three Neutral Earth Transformers

a) **Standby Earth Fault Setting**

Select LTI curve with TMS = 0.5

I_S = 0.098A

b) **Instantaneous Element Setting**

Set I_{INST} = ∞ for overcurrent

Set I_{INST} = ∞ for earth fault

3.6 Transformer Back Up Protection

3.6.1 Three Phase Overcurrent and Earth Fault Protection for Two T2 and T1 Transformers

3.6.2 Relay Data

Manufacturer	AREVA T&D EAI
Type	KCGG142
Documentation	R8551
Rated Current	1A

3.6.3 CT Parameters

CT Location	Post Type Outdoor CTs (Serial Nos. 0202614 and 020616 core 2)
Core No.	1
CT Ratio	200/1A
Class	5P20, 30VA
V_{KP}	617V

3.6.4 System Parameters

a)	System Voltage	132kV
b)	System Design Fault Current	25kA
c)	Fault Withstanding Duration	3 secs
d)	Fault Level (Maximum)	4.7kA
e)	Fault Level (Minimum)	0.6kA

3.6.5 Setting Calculation

a) **Overcurrent Protection**

Rated Current	137.8A
CT Ratio	200/1A

Relay Setting Range:

Current Setting $I_S >$ 0.08 – 3.2 I_n (I_n = 1A)

Step = 0.01 I_n

Earth Fault Setting $I_o >$ 0.005 – 0.8 I_n (I_n = 1A)

Step = 0.0025 I_n

The current to be protected $= \frac{137.8}{0.95} = 145A$

$\therefore$ current setting (time delayed element) = 76% (on 200/1A CT ratio)

Proposed relay current setting I_s = 0.76A

The primary current (Transformer shall be overloaded by 10%)

= 0.76 x 200A

= 152A

b) **Selection of Time Characteristic**

Inverse definite minimum time (IDMT)

Nine inverse reset time characteristics are available and the general mathematical expression for the curves is :

$$t = \text{TMS} \left[\frac{k}{\left\langle \frac{I}{I_S} \right\rangle^{a} - 1} + c \right] \text{seconds}$$

where TMS = Time Multiplier (0.025 to 1.5 in 0.025 steps)

I = Fault current

I_s = Overcurrent setting

k, c, a = Constants specifying curve

Standard Inverse SI : $t = \frac{0.14}{(I^{0.02} - 1)}$ at TMS = 1

where $I = \left(\frac{I}{I_s} \right)$

c) **Time Multiplier Setting TMS**

Setting Range = 0.05 to 1 in 0.025 steps

The minimum tripping time (calculated with the minimum value between 30 x 200 x I_s , limit of the curve, and I_f , the maximum fault current) shall be less than the fault withstanding duration and higher than the main protections tripping time.

132kV BC relay operating time (refer to item 5.5) = 1.1 secs.

TMS shall be co-ordinated to operate 33kV feeder relay with 0.35 sec. delay after the 33kV BS relay operating.

$\therefore$ Operation time for 132kV feeder relay = 0.35 + 0.634 = 0.984s

30 x 200 x 0.76 = 4.56kA and I_f = 25kA => I_i = 4.7kA

$$I = \frac{I}{I_s} = \frac{4.7 \times 10^3}{0.76 \times 200} = 30.9$$

Standard Inverse curve reaches a definite time at I = 30

$$\text{using} \quad t = \frac{0.14}{(I^{0.02} - 1)} = 1.988 \text{ secs at TMS} = 1$$

Let TMS setting = 0.984 / 1.988 = 0.495

Minimum tripping time t (with TMS = 0.5) = 1.988 x 0.5 = 0.994s

3.6.6 Earth Fault Protection

Single phase system fault current = 25kA

The fault current to be protected > 60% of 200A

= 120A

$$\therefore \text{ current setting to be protected } (I_s) = \frac{120}{200} = 0.6$$

= 60%

Proposed current setting = 60%

TMS shall be co-ordinated to operate E/F relay with 0.35 sec. delay after the 132kV BC relay operating.

132kV BC operating (refer item 5.5) time = 1.1s

$\therefore$ Operation time for E/F relay $= 0.35 + 1.1 \quad = \quad 1.45s$

Set earth fault curve to standard inverse (SI) IDMT curve

$30 \times 200 \times 0.3 = 1.8kA$ and $I_f = 25kA \Rightarrow I_i = 0.49kA$

$$I = \frac{I}{I_s} = \frac{0.49 \times 10^3}{0.6 \times 200} = 4.08$$

using $$t = \frac{0.14}{(I^{0.02} - 1)} = 4.9 \text{ secs at TMS} = 1$$

Let TMS setting $= 1.45 / 4.9 = 0.296$

Minimum tripping time t (with TMS = 0.30) $= 4.9 \times 0.30 = 1.47s$

$I > 30 \times I_s$ with TMS $= 1.0$

TMS setting $= 0.30$

3.6.7 Instantaneous Element

When applying overcurrent protection to the HV side of a power transformer it is usual to apply a high set instantaneous overcurrent element in addition to the time delayed low-set, to reduce fault clearance times for HV fault conditions. Typically, this should be set to approximately 1.3 times the LV fault level, such that it will only operate for HV faults.

Setting range: 1 to 30 in 0.01 steps + ∞

Transformer impedance (I_s) on its rating (31.5 MVA) = 10.2%

$$\therefore \text{ Maximum through fault} = \frac{31.5}{0.102} = 309 \text{ MVA}$$

$\therefore$ Maximum through fault current at tap 18 (i.e. voltage = 112.2kV) = 1590A current

To operate for an HV side 3ph fault, I_{INST} (overcurrent) to be set $> 1.3 \times 1590 =$ 2067A

$\therefore$ current setting I_{INST} (overcurrent)

$$= \frac{2067}{152} \times I_s$$

$$= 13.6$$

Set I_{INST} (overcurrent) = 13.6 I_S

Set I_{INST} (E/F) = To be disabled

High Set Instantaneous (Definite Time Characteristic)

As proposed by the customer the second stage High Set Overcurrent can be selected to have definite time characteristic. The operation time will be the set time for the time delay t>, plus the operation time of the output relay and the time taken to detect the overcurrent condition.

i) High Set instantaneous setting = $\frac{4 \times 1000}{200}$ = 20A

Time delay setting = 0 sec.

3.6.8 **Relay Setting**

a) **Overcurrent Element Setting**

Select SI IDMT curve with TMS = 0.5

I_S = 0.76

b) **Earth Fault Element Setting**

Select SI IDMT curve with TMS = 0.30

I_S = 0.6

c) **Instantaneous Element Setting**

Set I_{INST} = 13.6 I_S

Set I_{INST} = Earth fault to be disabled

Time = 0s

d) **Definite Time Characteristic (Second Stage)**

i) **High Set Instantaneous Setting**

Current Setting = 20A

Time delay setting = 0 sec.

Appendix 15.1.3 LV Connection Protection

PROTECTION CALCULATIONS TO RECOMMEND RELAY SETTINGS

FOR THE

132kV ABHAM SUBSTATION

SGT1 LV CONNECTION PROTECTION

ASSOCIATED WITH MSCDN1

FOR

THE NATIONAL GRID COMPANY plc
ENGLAND

BY: V AYADURAI

ISSUE 1 : SEPTEMBER 2003

1. INTRODUCTION

This document contains brief calculations to derive the recommended relay settings for the 132kV Abham Substation SGT1 LV connection. Protection setting calculations are based on NGTS 3.6.14 - Copperwork Protection and ESI 48.3 - Instantaneous High Impedance Differential Protection.

The results are tabulated in the final section, together with other relevant data and figures.

1.1 Definitions and Abbreviations

Lead Resistance	=	R_L
CT Ratio	=	N
CT Knee Point Voltage	=	V_k
CT Secondary Resistance	=	R_{CT}
Relay Resistance	=	R_R
Fault Setting Resistor	=	R
CT Magnetising Current	=	I_i
Full Load (Primary) Current	=	I_n
Fault Current (Primary)	=	I_F
Fault Current (Secondary)	=	I_f
Relay Primary Operation Current (POC)	=	I_{OP}
Relay Burden	=	VA
Relay Current	=	I_R
Relay Current Setting	=	I_S
Relay Voltage Setting	=	V_R
Number of CTs in Parallel	=	n
Number of Relays in Parallel	=	m
Turns Ratio of Current Transformers	=	T

2. SGT1 LV CONNECTION PROTECTION

2.1 HV Connection Protection

A. Protection Equipment Details

a) CT Location: Post Type CT for MSC1

b) CT Ratio: <u>1000</u>/1A & IPCT 1.2/1A

Class X Vk ≥ 409V, T = 1/1000, R_{CT} ≤ 1.58 Ω and R_{CT} = 1.09 Ω after IPCT conversion.

c) CT Ratio: 1200/1A Bushing CT

R_{CT} ≤ 3.4 Ω (SGT1 Bushing CTs), R_{CT} ≤ 3.4 Ω (LV side)

d) IPCT R_{CT} Primary = 0.4 Ω, Secondary R_{CT} = 0.5 Ω, Class X, Vk > 480V, R_{CT} = 0.28 Ω after IPCT conversion.

Cables used for CT connection from transformer are 2.5mm^2.

B. Relays

ALSTOM Protection & Control type MFAC34 relays (setting range 25 to 325V) and MVTP31 (setting range 2–14V). Both these relays are existing on the relay panel.

C. System Parameters

a) System Voltage: 132kV

b) System design (switchgear) fault current (1∅) = 31.5kA (3 secs)
System design (switchgear) fault current (3∅) = 31.5kA (3 secs)

D. Rated Stability Limit (Relay Circuit Setting Voltage)

Consider Table 1 for CTs and Lead Resistances

A, B, G = Resistance of Leads plus CT Winding, where applicable

C, D, H = Lead Resistance

V_S = Stability Voltage

I_S = Relay Circuit Current at V_S

I_1 = Secondary Exciting Current of CT at V_S

I_m = Current Taken by Peak Voltage Limiting Device at V_S

I_{SR} = Current Taken by Fault Setting Resistor

I_F = Fault Current Corresponding to Switchgear Rating for Stability Limit

n = Number of CTs in Parallel

m = Number of Relays in Parallel

E. **Primary Fault Setting**

Fault setting shall be 10-30% of the MSCDN1 rated current or Transformer LV rated current.

The MSC rated current on rated voltage (145kV) = 218A

The Transformer rated (240 MVA) on rated voltage (132kV) = 1050A

2.1.1 Rated Stability Limit

Rated stability is based on switchgear rating, i.e. 31.5kA 3 secs. single phase current.

Consider an external phase-to-earth short circuit and assume complete saturation of current transformer, then :-

$$V_S \geq I_F\ (\text{CT Resistance} + \text{lead burden}) \qquad (1)$$

If the setting voltage of the circuit is made equal to or greater than this voltage, then the protection will be stable.

The knee point voltage of the CT should be greater than $2\ V_S$

It is necessary that the voltage appearing across the relay circuit V_R should be greater than or equal to V_S.

Item No	Lead Resistance Ω	CT Resistance Ω	Total Ω	Parameters	
1 SGT2 BUSHING CTs	1.5	3.4	4.9	R	A
	1.5	3.4	4.9	Y	
	1.5	3.4	4.9	B	
	1.5	-	1.5	N	D
2 LV SIDE	1.2	3.4	4.6	R	B
	1.2	3.4	4.6	Y	
	1.2	3.4	4.6	B	
	1.2	-	1.2	N	C
LEAD TO RELAY PANEL	0.07	-	0.07	R	E
	0.07	-	0.07	Y	
	0.07	-	0.07	B	
	0.07	-	0.07	N	F
3	0.205 + 1.778	1.097 + 0.27 + 0.5	3.85	R	G

MSC1 CTs	0.205 + 1.778	1.097 + 0.27 + 0.5	3.85	Y	
	0.205 + 1.778	1.097 + 0.27 + 0.5	3.85	B	
	0.205 + 1.778	-	1.983	N	H

Using Equation 1 :-

$$V_{S1} = \frac{31.5 \times 1000}{1200}(A + D + F + E),\ V_{S2} = \frac{31.5 \times 1000}{1200}(B + C + F + E),\ V_{S3} = \frac{31.5 \times 1000}{1200}(G + H + F + E)$$

$$V_{S1} = \frac{31.5 \times 1000}{1200}(6.6) = 173V,\ V_{S2} = \frac{31.5 \times 1000}{1200}(5.94) = 156V,\ V_{S3} = \frac{31.5 \times 1000}{1200}(5.973) = 157V,$$

A = 4.9 Ω, C = 1.2 Ω, E = 0.07 Ω, G = 3.85 Ω,

B = 4.6 Ω, D = 1.5 Ω, F = 0.07 Ω, H = 1.983 Ω,

V_S = 175V (selected to the existing setting)

2.1.2 Fault Setting

Fault setting shall be 100% of the SGT1 LV full load current.

a) Let the Primary Operating Current (POC) be 100% of the SGT1 LV rated current

$\therefore$ POC = 1050A

b) Fault setting for n circuits and m relays is :-

$$POC\ (I_{OP}) = N\left(mI_S + nI_1 + I_V + I_m + I_{SR}\right) \qquad (2)$$

Where m = 2, n = 3, I_m is very small, I_1 is MSC1 CT, I_2 is SGT1 bushing CT and I_3 is 132kV post CT magnetic currents.

I_1 = 0.0165A, I_2 = 0.0103A, I_3 = 0.0092A, I_V and I_m are small, I_S = 0.019A

1050 = 1200 (2 x 0.019 + 0.036 + I_{SR})

I_{SR} = 0.8A

Let I_{SR} = 0.8A

c) Setting resistor $= \frac{V_S}{I_S} = \frac{175}{0.8} = 218\ \Omega$

Let us consider a stabilising resistor (R) = 220 Ω (selected to the existing setting)

d) Power Rating of the resistors = $\frac{175^2}{220} \geq 140$ watts

2.1.3 Peak Voltage Developed Under Internal Fault Condition

For a maximum internal fault, a high voltage may develop across the relay. In that case the insulation of the current transformer secondary winding and relay will not be able to withstand the very high voltage that can be produced.

Where necessary the voltage is limited to less than 3kV peak by use of non-linear resistors called metrosils connected in parallel with the relay circuit.

a) TGN(T)64 gives the formula $V = 2\sqrt{2.V_k\ (V_f - V_k)}$

Where V_k is CT knee point and V_f is the voltage developed across the relay network assuming CTs do not saturate.

Relay resistance = 175 / 0.019 = 9210 ohm

V_f = 26 x 9210 = 239460V

$\therefore$ V = 13984V, so metrosil is required.

b) The voltage/current characteristic of a metrosil is given by :-

$V = CI^{\beta}$

Current through the metrosil has an rms current value of 0.52 times the value given by the above formula. This is due to the fact that the current waveform through the metrosil is not sinusoidal but appreciably distorted.

Where voltage V and current I are peak values

$I_{(rms)}$ = 0.52I, $V = \sqrt{2}\ V_S$

C = A constant depending on the metrosil construction (C can either be 900 or 450)

β = a constant in the range 0.2 to 0.25

$$\therefore \quad \sqrt{2}V_S = C\left[\frac{I_{SL}}{0.52}\right]^{\beta}$$

The values of C and β are chosen so that the voltage across the metrosil is limited to less than 3kV peak at the maximum fault current. The acceptable metrosil currents should be as low as possible, i.e. < 30mA for 1A secondary.

c) Maximum secondary current at fault condition

$$= \frac{31.5 \times 1000}{1200} = 26A$$

$$\sqrt{2} \times 175 = 900 \left[\frac{I_{SL}}{0.52}\right]^{0.25}$$

$$I_m = 3mA$$

2.1.4 Supervision of Circulating Current Protection to Cover Open Circuited Current Transformers and Wiring

a) **Bus Wiring Supervision**

Relay: MVTP 31

Setting Range: 2 – 14V

b) **Setting Calculations**

The initial impedance of the current transformer at the bottom bend region

$R_1 = 8.5\ k\Omega$, $R_2 = 13\ k\Omega$, $R_3 = 10.3\ k\Omega$,

i) Impedance of 2 (maximum number of circuits = 3) current transformers = 8500 // 10300 = 4657 Ω

ii) Impedance of the relay MFAC 34 circuit = $\frac{175}{0.019}$ = 4605 Ω (2 relays)

Parallel impedance of current transformers and differential circuit

4657 // 4605 // 220 Ω

= 200 Ω

iii) If the desired sensitivity is 10% of total SGT1 LV full load primary current, which = 105A

$$\frac{105}{1200} = 0.0875$$

$\therefore$ voltage drop = 0.0875 x 200

= 17.5V

Available setting range = 2, 4, 6, 8, 10, 12 and 14.

The relay could be set to 14 volts, giving a primary operating current = 84A.

In practice, this value would be tried and adopted provided the steady spill current with system load flowing did not approach the relay setting.

2.1.5 Primary Operating Current (POC)

Using Equation

POC = 1200 (2 x 0.019 + 0.036 + 0.003 + 0.8)

POC = 1052A (100% of SGT1 LV rated current)

2.1.6 Settings

a) Stabilising resistors = 220 Ω (3 off > 140 watts) (existing setting)

b) Metrosil: 6" metrosil, 3 phase with C = 900 and β = 0.25 of characteristic as existing

c) MVTP31 Relay Settings: Relay setting = 14V (setting range 2 – 14V) (existing setting)

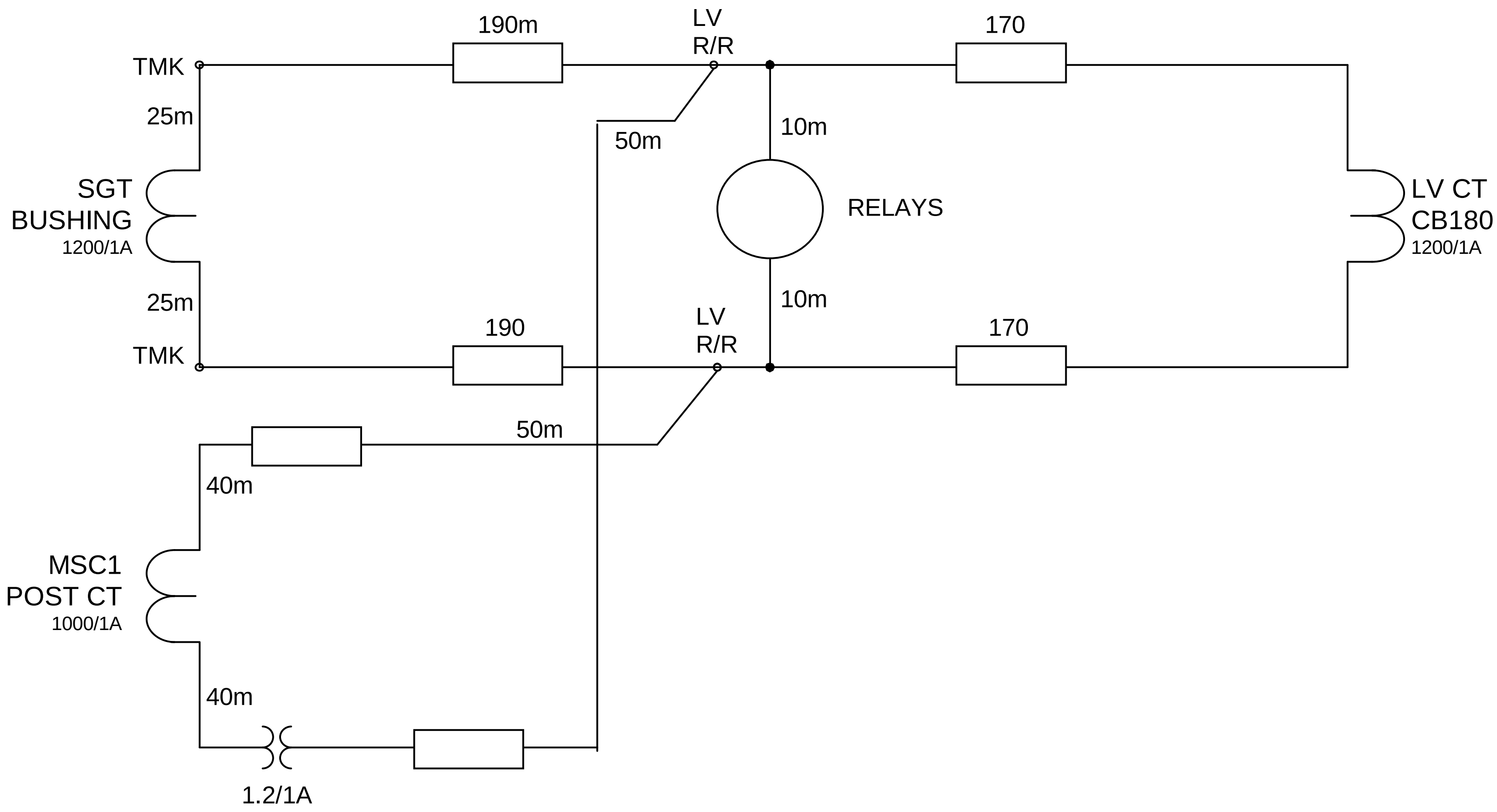
Note: Stabilising resistors should be adjustable resistors of 300 Ω with thermal characteristic greater than 140 watts (existing setting).

3. APPENDIX

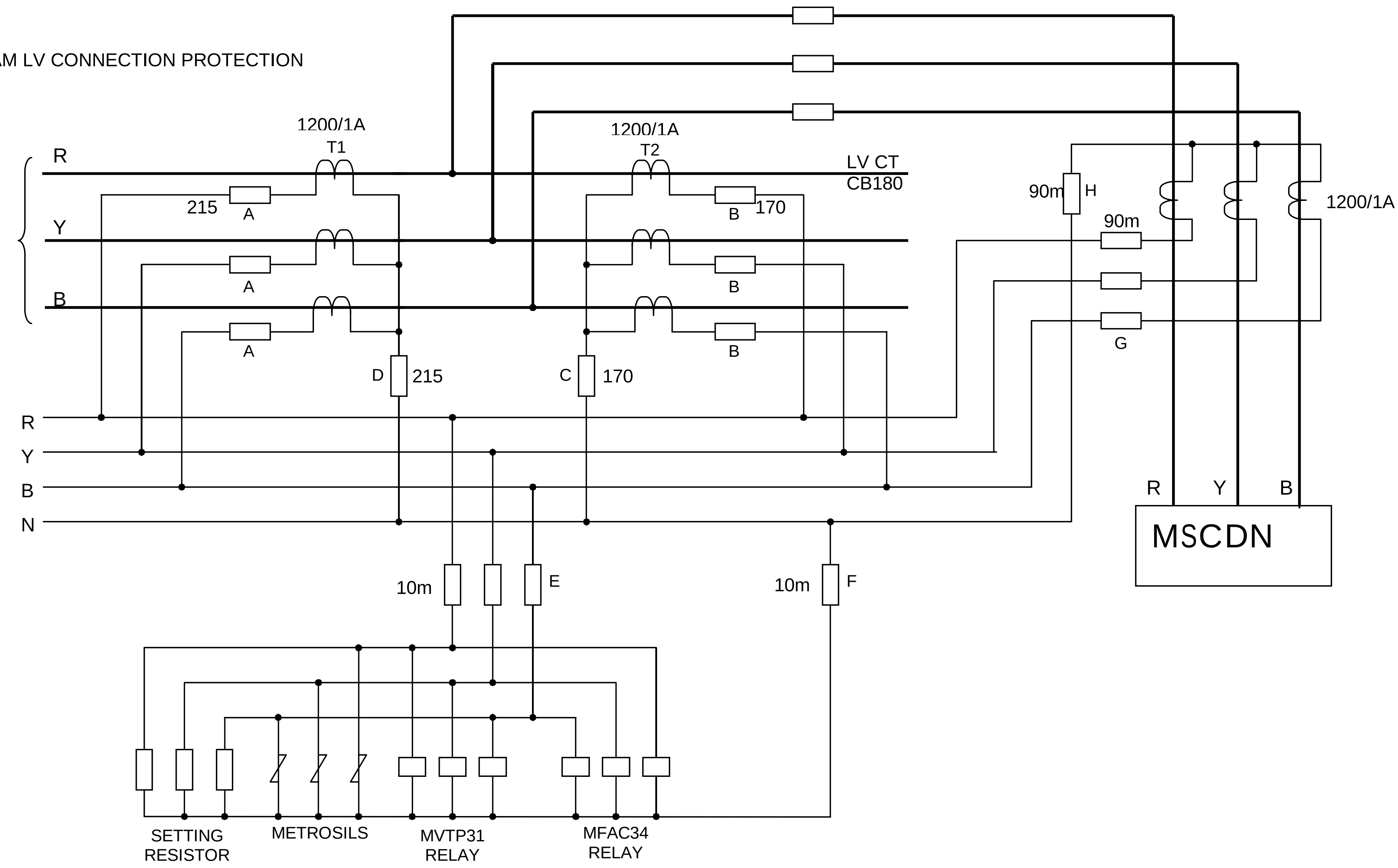
3.1 Protection Circuit Diagrams

a) LV Connection Diagrams 1 & 2

ABHAM LV CONNECTION PROTECTION



ABHAM LV CONNECTION PROTECTION



Appendix 15.1.4 Back Up Protection

6. 132kV FEEDER BACK UP PROTECTIONS (BALANGODA 1 & 2)

6.1 Three Phase Directional Overcurrent and Earth Fault Protection

6.2 Relay Data

Manufacturer	AREVA T&D EAI
Type	KCEG142
Documentation	R8551
Rated Current	1A

6.3 CT Parameters

CT Location	Post Type Outdoor CTs (Serial No. 0202611 core 3)
Core No.	3
CT Ratio	800/1A
Class	5P20, 30VA
V_{KP}	603V

6.4 System Parameters

a)	System Voltage	132kV
b)	System Design Fault Current	25kA
c)	Fault Withstanding Duration	3 secs
d)	Fault Level (Maximum)	4.7kA
e)	Fault Level (Minimum)	0.6kA

6.5 Setting Calculation

It should be noted that in the relay settings I_S is referred to as $I >$ for the Overcurrent setting.

a) **Overcurrent Protection (Inverse Time Characteristic)**

The first stage can be selected to have a current dependent inverse time characteristic

Rated Current	600A
CT Ratio	800/1A

Relay Setting Range:

Current Setting $I_S >$ 0.08 – 3.2 I_n (I_n = 1A)

Step = 0.01 I_n

Earth Fault Setting $I_O >$ 0.005 – 0.8 I_n (I_n = 1A)

Step = 0.0025 I_n

The current to be protected (as proposed by customer) = 600A

The current to be protected $= \frac{600}{0.95} = 632A$

$\therefore$ current setting (time delayed element) = 80% (on 800/1A CT ratio)

Proposed relay current setting I_S = 0.80A

The primary current (overcurrent necessary to cause closing of relay contacts)

= 0.8 x 800A

= 640A

i) **Selection of Time Characteristic**

Inverse definite minimum time (IDMT)

Nine inverse reset time characteristics are available and the general mathematical expression for the curves is :

$$t = TMS \left[\frac{k}{\left\langle \frac{I}{I_S} \right\rangle^{a} - 1} + c \right] \text{seconds}$$

where TMS = Time Multiplier (0.025 to 1.5 in 0.025 steps)

I = Fault current

I_S = Overcurrent setting

k, c, a = Constants specifying curve

Standard Inverse SI :

$$t = \frac{0.14}{\left(I^{0.02} - 1 \right)} \text{ at TMS } = 1 \quad \text{where} \quad I = \left(\frac{I}{I_S} \right)$$

ii) **Time Multiplier Setting TMS**

Setting Range = 0.05 to 1 in 0.025 steps

The minimum tripping time (calculated with the minimum value between 30 x 400 x I_S, limit of the curve, and I_f, the maximum fault current) shall be less than the fault withstanding duration and higher than the main protections tripping time.

30 x 800 x 0.8 = 19.2kA and I_f = 25kA => I_i = 4.7kA

$$I = \frac{I}{I_s} = \frac{4.7 \times 10^3}{0.8 \times 800} = 7.3$$

using $t = \frac{0.14}{(I^{0.02} - 1)} = 3.45$ secs at TMS $= 1$

Let TMS setting = 0.225

Minimum tripping time t (with TMS = 0.33) = 3.45 x 0.225 = 0.78s

Display

3	Drn t >	1	
B	Syn Pol	=	3.2S
060D	Char. Angle (Øc)	+30°	

iii) Earth Fault Protection

It should be noted that in the relay settings I_S is referred to as $I_o >$ for the Earth Fault setting.

Single phase system fault current = 25kA

The fault current to be protected (as proposed by the customer) $>$ 80A

= 80A

$\therefore$ current setting to be protected (I_S) $= \frac{80}{800} = 0.1$

= 10%

Proposed current setting = 10%

30 x 800 x 0.1 = 2.4kA and I_f = 25kA = > I_i = 4.7kA

$$I = \frac{I}{I_s} = \frac{4.7 \times 10^3}{0.1 \times 800} = 58.7$$

Standard Inverse curve reaches a definite time at I = 30

using $t = \frac{0.14}{(I^{0.02} - 1)} = 1.988$ secs at TMS $= 1$

Let TMS setting = 0.40

Minimum tripping time t (with TMS = 0.40) = 1.988 x 0.40 = 0.79s

Set earth fault curve to standard inverse (SI) IDMT curve

$I >$ 30 x I_S with TMS = 1.0

TMS setting = 0.40

iv) Instantaneous Element

Setting range: 1 to 30 in 0.01 steps + ∞

With time delayed protection, directional stability is not usually a problem, but with directionalised instantaneous overcurrent relays it is much more difficult to achieve and momentary operation may occur when the fault is removed.

Instantaneous protection is not applicable for feeders. Therefore, Instantaneous feature is rendered inoperative.

Setting ∞ This function remains unused to maintain selectivity between main protections

Set I_{INST} = Rendered inoperative for overcurrent and earth fault

b) **High Set Overcurrent (Definite Time Characteristic)**

As proposed by the customer the second stage High Set overcurrent can be selected to have definite time characteristic with the following settings :

i) High Set Overcurrent Setting = $\frac{4000}{800}$ = 5A

Time delay setting = 1.4 sec

ii) Earth Fault Current Setting = $\frac{4000}{800}$ = 5A

Time delay setting = 1.4 sec

6.6 Relay Setting

a) **Inverse Time Characteristic (First Stage)**

i) **Directional Overcurrent Element Setting**

Select SI IDMT curve with TMS = 0.225

I_S= 0.8A

Display

Drn t > 1

Syn Pol = 3.2S

Char. Angle (Øc) +30°

ii) **Directional Earth Fault Element Setting**

Select SI IDMT curve with TMS = 0.40

I_S = 0.1A

Char. Angle (Øc) – 45°

iii) **Instantaneous Element Setting**

Set I_{INST} = Overcurrent to be disabled

Set I_{INST} = Earth fault to be disabled

b) **Definite Time Characteristic (Second Stage)**

i) **High Set Overcurrent Setting**

Current setting = 5A

Time delay setting = 0.8 sec

Display

Drn t > 1

Syn Pol = 3.2S

Char. Angle (Øc) +30°

ii) **Earth Fault Setting**

Current setting = 5A

Time delay setting = 0.8 sec

Char. Angle (Øc) – 45°

c) **Definite Time Characteristic (Third Stage)**

i) **High Set Overcurrent Setting**

Current setting = 5A

Time delay setting = 1.4 secs

ii) **Earth Fault Setting**

Current setting = 5A

Time delay setting = 1.4 secs

7. 132kV BUSBAR/BREAKER FAIL/END FAULT PROTECTION

a) Relay Data

CT Location	:	Post Type Outdoor CTs (Serial Nos. 0202611, 0202616, 0202614 – core 4, 0202612 core 1 & 202613)
Manufacturer	:	ABB Switzerland Ltd
Type	:	Busbar Protection System REB500
CT Ratio	:	2000/1A
V_{KP}	:	616V

7.1 Busbar Protection Setting

Refer to Busbar Protection REB500 document HN500765/4000 for Ratnapura Substation.

1) Busbar Protection Function

The functionality consists of Restrained Amplitude comparison along with Phase comparison.

a) For Restrained Amplitude Comparison, the following two parameters are to be set:

I_{kmin} = Pick-up setting for Differential Current

k = Slope, Differential Current/Restrain Current

The following is recommended:

$I_{Lmax} < I_{kmin} < 80\% \; I_{KMS}$

$k = 0.8$

where I_{Lmax} = Maximum load current
I_{KMS} = Maximum fault current on bus

It is presumed that being a solidly grounded system, the fault currents are quite high and several times higher than maximum load current.

The maximum load current is assumed to be 400 Amps and all the feeders have CT ratio as 2000/1A.

Hence, a I_{kmin} of 400 Amps is recommended with a certain safety factor over 400A.
This setting would ensure that no mal-operation would occur with an open circuit in the feeder CT circuit.

It is presumed that all CT cores do not saturate at the minimum fault current through CT adequacy.

If CT saturation is likely, then the procedure adopted in section 5.4.3.1 of the User's Manual would have to be followed depending on the primary system DC time constant.

b) **Low Impedance Busbar protection function (Central Unit)**

Based on the ABB HN500765/3000 Test Record for Ratnapura, the recommended values of parameters are as follows:

Parameter	Range	Unit	Recommended Value
I_{kmin} (phase)	400-1200	Amps	400
k	0.7-0.9		0.8
Diff. I Alarm	5-50	% I_{kmin} (phase)	10
Delay (Diff. Alarm)	5-50	Sec	5
Release Current	0.1-2.5	I_N	0.8

Restrained amplitude comparison - I_{kmin} and k

The "restrained amplitude comparison" algorithm detects and internal fault when the settings for I_{kmin} and k are exceeded. A tripping command is only issued, however, providing the phase comparison function detects an internal fault at the same time.

The pick-up setting for the fault current (I_{kmin}) must be less (80%) than the lowest fault current that can occur on the busbars (I_{KMS}). There is a risk of the protection being too insensitive at higher settings.

2) <u>Breaker Fail Function</u>

a) **Breaker Fail Protection Function**

Requirements from Customer :

- No intentional time delay between timers t1 and t2. Hence, timer t2 shall be set to 120msec.
- Logic type 1 as no special logic required.
- Time setting t1 = 120msec.

Current Pick-up setting recommendation :

Basically, the setting I_E shall be maximum 80% of I_{kmin} (minimum fault current).

R_{CT} = 5 ohms for 2000/1 CT core
Primary system time constant = 80msec.

Assuming minimum fault current is of the order of 0.4Ka, (80% I_{kmin})/I_N = 320/2000 = 0.16.

Time setting :

Minimum setting t1 = Tcb + 58msec.

The required setting of 120msec. Assumes tCB (Breaker interruption time) of about 60msec.

b) **End Fault Protection**

The pick-up delay is recommended at the default value of 400msec.

Current pick-up at the same setting as the BFP function is recommended.

c) **Breaker Fail and End Fault Protection Functions**

Based on the HN500765/3000 for Ratnapura Substation, the recommended values of parameters are as follows :

i) Feeder and Transformer Bays, Lines, = BAL1 = BAL2 = TR1 = TR2 (CT ratio 2000/1A).

Parameter	Range	Unit	Recommended Value

BFP Active			Active
I setting (BFP)	0.1 – 2.0	I_N	0.20 (i.e. 400A primary)
Timer t1 Active			Active / No Remote Trip
Timer t2 Active			Active / Remote Trip
Timer t1	10 – 5000	msec	120
Timer t2	0 – 5000	msec	120
Intertrip Pulse	100 – 2000	msec	System Response *
Logic Type	1 - 4		1
EZP Active			Active
Pick-up delay (EZP)	0.1 – 10.0	sec	0.4
Pick-up I (EZP)	0.1 – 2.0	I_N	0.20 (i.e. 400A primary)
O/c check	0.1 – 4.0	I_N	Not available
Reclaim time	0.1 – 4.0	msec	120

ii) System Response

Parameter	Range	Chosen Value
Diff. Current Alarm	Continue/Block/Selective Block	Selective Block
Isolator Alarm	Continue/Block/Selective Block	Selective Block
Isolator Alarm Delay	0.5 – 90 sec.	15
Remote Trip Imp. Width	100 – 2000 msec.	300

iii) Bus Coupler Bays (CT ratio 2000/1A)

Parameter	Range	Unit	Recommended Value
BFP Active			Active
I setting (BFP)	0.1 – 2.0	I_N	0.20 (i.e. 400A primary)
Timer t1 Active			Active / No Remote Trip

Timer t2 Active			Active / Remote Trip
Timer t1	10 – 5000	msec	120
Timer t2	0 – 5000	msec	120
Intertrip Pulse	100 – 2000	msec	System Response *
Logic Type	1 - 4		1
O/c check	0.1 – 4.0	I_N	Not available

iv) System Response

Parameter	Range	Chosen Value
Diff. Current Alarm	Continue/Block/Selective Block	Selective Block
Isolator Alarm	Continue/Block/Selective Block	Selective Block
Isolator Alarm Delay	0.5 – 90 sec.	15
Remote Trip Imp. Width	100 – 2000 msec.	300

* **System Response**

Isolator Alarm Delay

The busbar protection REB500 has a common alarm circuit and timer for monitoring the operation of all the isolators and bus-tie breakers. The setting of the isolator operating time thus applies for all the isolators and circuit breakers in the system.

Note: The time delay must be set longer than the slowest isolator operating time.

Remote Trip Impulse Switch

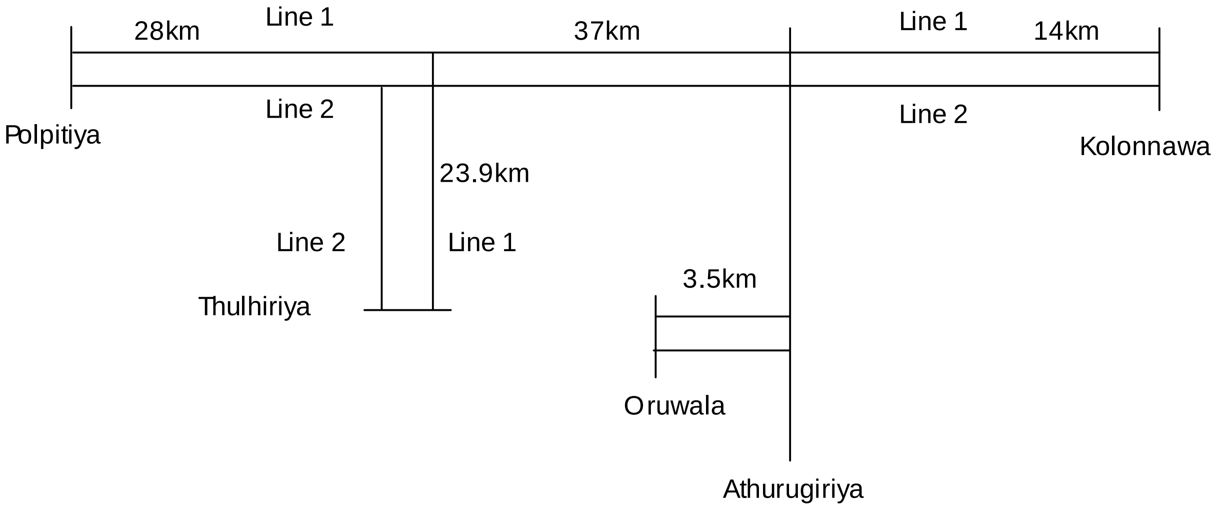
The busbar and where configured, the breaker failure and end fault protection functions can initiate a busbar trip. In case a feeder has no breaker or is bypassed by an isolator, an intertripping signal (REMOTE TRIP) to a remote station via PLC or optical fibre communication channel can be configured.

The duration of the impulse usually has to be limited.

Appendix 15.1.5 Over Head Line (Feeder) Protection.

8. 132kV OVERHEAD LINE FEEDER PROTECTION

All impedance data supplied by the customer is in ohms/km (Ω/km).



8.1 Substation : 132kV Athurugiriya

Feeders : Athurugiriya – Polpitiya 1
Athurugiriya – Polpitiya 2
Athurugiriya – Thulhiriya 1
Athurugiriya – Thulhiriya 2

Substation	Fault current (kA)		132kV Feeder circuit	No. of circuit	Con-ductor type	Positive sequence impedance		Zero sequence impedance		Length (km)
	Min.	Max.				R_1 – Ω/km	X_1 – Ω/km	R_0 – Ω/km	X_0 – Ω/km	
Athurugiriya	0.4kA	14.7kA	Athurugiriya /Polpitiya 1	1	Lynx	0.1780	0.4010	0.39735	1.31149	65.0
			Athurugiriya /Polpitiya 2	1	Lynx	0.1780	0.4010	0.39735	1.31149	65.0
			Athurugiriya /Thulhiriya 1	1	Lynx	0.1780	0.4010	0.39735	1.31149	60.9
			Athurugiriya /Thulhiriya 2	1	Lynx	0.1780	0.4010	0.39735	1.31149	60.9
			Athurugiriya /Oruwala 1	1	Lynx	0.1780	0.4010	0.39735	1.31149	3.4
			Athurugiriya /Oruwala 2	1	Lynx	0.1780	0.4010	0.39735	1.31149	3.4

Note:
1. In the case where a feeder is Teed to two substations the greatest distance will be used in the distance protection settings.
2. The minimum fault level has been assumed as the maximum current carrying capacity of the overhead line (132kV).

8.2 Distance Protection at Athurugiriya Substation End

8.2.1 Distance Relay Type REL316*4

Line Data for Athurugiriya to Thulhiriya 1 & 2

Primary line data: Length: 60.9Km
Total Z1= (10.84 + j 24.42) Ω = 26.72 Ω, ∠ 66.0°
Z0= (24.20 + j 79.87) Ω = 83.46 Ω, ∠ 73.15°

Type of grounding: Solid

Positive sequence impedance:	26.72 Ω/ph	Pos. sequence impedance (Z1) : 0.4387 Ω/km
Angle:	66°	Pos. sequence resistance (R1) : 0.1780 Ω/km Pos. sequence reactance (X1) : 0.4010 Ω/km
Zero sequence impedance:	83.46 Ω/ph	Zero sequence impedance (Z0) : 1.3704 Ω/km
Angle:	73.15°	Zero sequence resistance (R0) : 0.39735 Ω/km Zero sequence reactance (X0) : 1.31149 Ω/km

Line Data for Athurugiriya to Polpitiya 1 & 2

Primary line data: Length: 65.0Km
Total Z1 = (11.57 + j 26.065) Ω = 28.52 Ω, ∠ 66.0°
Z0 = (25.828 + j 85.246) Ω = 89.07 Ω, ∠ 73.15°

Type of grounding: Solid

Positive sequence impedance:	28.52 Ω/ph	Pos. sequence impedance (Z1) : 0.4387 Ω/km
Angle:	66°	Pos. sequence resistance (R1) : 0.1780 Ω/km Pos. sequence reactance (X1) : 0.4010 Ω/km
Zero sequence impedance:	89.07 Ω/ph	Zero sequence impedance (Z0) : 1.3704 Ω/km
Angle:	73.15°	Zero sequence resistance (R0) : 0.39735 Ω/km Zero sequence reactance (X0) : 1.31149 Ω/km

Rated line voltage: 132kV (= 132kV/√ 3)

Rated line current:	400A

P.T./C.T. data

P.T. primary voltage:	76.2kV	(= 132kV/$\sqrt{3}$)
P.T. secondary voltage:	63.5V	(= 110kV/$\sqrt{3}$)
P.T. location:	Post type CVT	
P.T. ratio:	1200	
C.T. primary current:	800A	(800/1A)
C.T. secondary voltage:	1A	
C.T. location:	Post type outdoor CTs (core 2)	
C.T. ratio:	800	
Main VT ratio/main CT ratio	= Impedance ratio: 1.5	

Primary parallel line data

Mutual impedance Zmo = $0.2515 + j\ 0.78757\ \Omega$ /km

Zero sequence compensation factor for parallel line

k0m	=	0.628
k0m Ang	=	$\angle$ 6.23°

8.2.2 Relay Hardware

Relay Code

Nominal voltage:	110V
Nominal current:	1A

AD Channel:	Selections/Comments:	Relay settings of Ref. Values:
Channel 1	VTS 3 ph-R (HV-Dist-U input)	1.000
Channel 2	VTS 3 ph-S	1.000
Channel 3	VTS 3 ph-T	1.000
Channel 4	CT 1 ph (HV-Dist-IO input)	1.000
Channel 5	CT 1 ph (HV-Dist-IOP)	1.000
Channel 6	VT 1 ph	1.000
Channel 7	CT 3 ph-R (HV-Dist I input)	1.000
Channel 8	CT 3 ph-S	1.000
Channel 9	CT 3 ph-T	1.000

Assumptions:

Note:
1. HV distance function use channel 7, 8, 9 for I input.
2. For parallel line compensation channel 5 is used.

8.2.3 General Settings

Parameters	Selections/Comments	Relay settings (secondary):
Ref. Length	Dist. To fault indication shown in km	TBA by CEB
CT Neutral		Line side
k0m		0.628
k0m/Ang		6.23°
Iload	Fixed slope of 7°	2 IN
Umin fault	Conventional VTs	0.1 UN
MemDirMode		Block
DefDirMode		Forward

k0m = $(Z_{m0} / 3 \times Z_1)$ = 0.628
k0mAng = Ang $(Z_{m0} / 3 \times Z_1)$ = 6.23°

8.2.4 V.T. Supervision Settings

Parameters	Selections/Comments	Relay settings (secondary):
VTSupMode		Zero seq.
VTSupBikDel		off
VTSupDebDel	enabled (Grounded system)	on
U0minVTSup	0.2 *UN (setting range 0.01-0.5s)	0.2 UN
I0minVTSup	0.07 *IN (setting range 0.01-0.5s)	0.07 IN
U2minVTSup	0.1 UN (setting range 0.01-0.5s)	0.1 UN
12minVTSup	0.07 IN (setting range 0.01-0.5s)	0.07 IN

8.2.5 O/C Backup Protection

Parameters:	Selections/Comments:	Relaysettings (secondary):
I O/C	Not in use	0
Delay O/C	Not in use	0

8.2.6 Trip Schemes

Parameters:	Selections/Comments:	Relay settings (secondary):
ComMode		POTT
Tripmode		3ph Trip
SOFTMode (Switch on to Fault)		nondir
SOFT10sec (Switch on to Fault)		on
Weak		off
Block		on
Echo		on

Broken Conductor Protection		on
Fault Locator Measurement		on
TransB1		on
t1 block	0.04s (setting range 0-0.25s)	0.04s
t1 TransB1	70 ms (setting range 0-0.25s)	0.07 S
t2 TransB1	100 ms (setting range 0-10s)	0.10 S
t1EvolFaults	100 ms (setting range 0-10s)	0.10 S

8.2.7 **Power Swing Blocking**

Parameters:	Selections/Comments:	Relay settings (secondary):
tPSBlock	on (setting)	10 s

Assumptions:

t1 TransB1 = min. holding time for wrong energy direction signal
= 60 ms + reset time for comm. Channel = 60 + 10 = 70 ms

t2 TransB1 = max. holding time for wrong energy direction signal
= 100 ms (no AR)

i.e. a second directional decision in forward direction is inhibited for 70-100 ms.

8.2.8 **Starting (Athurugiriya to Thulhiriya)**

Parameters:	Selections	Primary values:	Relay settings (secondary):
PhaseSeimode			nonDir
GndFaultMode			I0
Imin	0.55 *IN		0.55 IN
310min	0.10 *IN		0.10 IN
3U0min	0.000 *UN		0 UN
XA	Ω/ph Ω/ph	61.05	40.07
XB	Ω/ph Ω/ph	18.315	12.21
RA	Ω/ph Ω/ph	26.99	17.99
RB	Ω/ph Ω/ph	8.097	5.40
Rload	Ω/ph Ω/ph	26.99	17.99
Angle Load	45°		45°
Uweak	0.7 *UN (UV starters for SOFT, POTT)		0.7 UN
Delay(def)			1.4s

Calculation (assumptions): X_A = 2.5* line reactance of protected line
2.5 x 60.9 x 0.4010 = 61.05 Ω/ph (Athurugiriya to Thulhiriya)

Check: R_A > Zone 3 resistance (+ arc resistance)
$X_B = 0.3^* X_A$
$R_B = 0.3^* R_A$
$R_{Load} = R_A = 0.85 \times 132kV / \sqrt{3} \times 2 \times 1200 = 26.99$ Ω/ph

Factor of 2 is used in calculation of R_{Load} since these are parallel lines

Check: Minimum system voltage = 132kV
Maximum load current I_{Bmax} = 400A
I_A = 800A

Calculated values of Z set with these assumptions:
Zset = 46.75 Ω/ph (primary)
Zset = 31.17 Ω/ph (secondary)

The chosen values for the starting settings have to fulfil the condition of the maximum permissible reach of the starters (see below).

Maximum permissible reach of the starters:

For solidly grounded systems

$Z\ set \leq mod\ (\underline{U}/2^*[I_{Bmax} + I_A]\ )$

$Z\ set \leq mod\ 0.85 \times 132/2\ (400 + 800) = 46.75\ \Omega$

Z set maximum value of the impedance, i.e. the maximum value of the expression

$\underline{U}$ lowest phase voltage of the healthy phases for an E/F on one phase (U = 85* min system voltage

2 factor which takes account of the fact that phase currents and not phase-to-phase currents are used

I_A circulating current, assumption: = C.T. nominal primary current
I_{Bmax} Max. load current

8.2.9 Measuring

First setting group is for when PLC is healthy.

This is configured for Blocking scheme.

Zone 1: 80% of line length (Athurugiriya to Thulhiriya 1 & 2)

Parameters:	Primary values	Secondary values	Relay settings
X(1)	19.536 Ω/ph	13.024 Ω/ph	13.02 Ω/ph
R(1)	8.672 Ω/ph	5.78 Ω/ph	5.78 Ω/ph
RR(1)	23.443 Ω/ph	15.628 Ω/ph	15.63 Ω/ph
RRE(1)	23.443 Ω/ph	15.628 Ω/ph	15.63 Ω/ph
k0(1)			0.711
k0Ang(1)			10.45°
Delay(1)			0s

Zone 2: 120% of line length (Athurugiriya to Polpitiya)

Parameters:	Primary values	Secondary values	Relay settings
X(2)	31.28 Ω/ph	20.85 Ω/ph	20.85 Ω/ph
R(2)	13.88 Ω/ph	9.25 Ω/ph	9.25 Ω/ph
RR(2)	37.54 Ω/ph	25.03 Ω/ph	25.03 Ω/ph
RRE(2)	37.54 Ω/ph	25.03 Ω/ph	25.03 Ω/ph
k0(2)			0.711
k0Ang(2)			10.45°
Delay(2)			70.0s

Zone 3: 150% of line length (Athurugiriya to Thulhiriya)

Parameters:	Primary values	Secondary values	Relay settings
X(3)	36.63 Ω/ph	24.42 Ω/ph	24.42 Ω/ph
R(3)	16.26 Ω/ph	10.84 Ω/ph	10.84 Ω/ph
RR(3)	43.956 Ω/ph	29.30 Ω/ph	29.30 Ω/ph
RRE(3)	43.956 Ω/ph	29.30 Ω/ph	29.30 Ω/ph
k0(3)			0.711
k0Ang(3)			10.45°
Delay(3)			1.0s

Assumptions:

RR (n) = Resistive reach including arc resistance = 1.2* X (n) for phase faults

RRE (n) = Resistive reach including arc resistance = 1.2* X (n) for phase faults

k0 (n) = mod (1/3 [$Z_{OL} - Z_L$] / Z_L)

Zone 4: – 10% of Zone 1 (Athurugiriya to Polpitiya 1 & 2)

Parameters:	Primary values	Secondary values	Relay settings
X(4)	– 2.085 Ω/ph	– 1.39 Ω/ph	– 1.39 Ω/ph
R(4)	– 0.926 Ω/ph	– 0.617 Ω/ph	– 0.617 Ω/ph
RR(4)	– 2.50 Ω/ph	– 1.67 Ω/ph	– 1.67 Ω/ph
RRE(4)	– 2.50 Ω/ph	– 1.67 Ω/ph	– 1.67 Ω/ph
k0(4)			0.711
k0Ang(4)			10.45°
Delay(4)			1.0s

Reverse Zone:	Used for detecting of reversal of fault energy direction 200% of line length (Athurugiriya to Thulhiriya)		
Parameters:	Primary values	Secondary values	Relay settings
X(Back)	48.84 Ω/ph	32.56 Ω/ph	32.56 Ω/ph
R(Back)	21.68 Ω/ph	14.45 Ω/ph	14.45 Ω/ph
RR(Back)	58.61 Ω/ph	39.07 Ω/ph	39.07 Ω/ph
RRE(Back)	58.61 Ω/ph	39.07 Ω/ph	39.07 Ω/ph
k0(Back)			0.711
k0Ang(Back)			10.45°
Delay(Back)			0s

Assumptions:

Note:

1. CEB to conduct a co-ordination study on time settings with other lines in network.

2. CEB to check the values of RR and RRE by calculating arc resistance form Warrington's formula (see operating instruction REL316*4 Pub. IMRB 520050 – Uen page 3.5.2 – 35).

3. Zone 2 and 3 must be checked as to whether they are reaching into the shortest adjacent line or transformer on the bus at the remote end.

8.2.10 Measuring

Second setting group is for when PLC is faulty.

This is configured for Basic Distance Protection.

Zone 1: 80% of line length (Athurugiriya to Thulhiriya 1 & 2)

Parameters:	Primary values	Secondary values	Relay settings
X(1)	19.536 Ω/ph	13.024 Ω/ph	13.02 Ω/ph
R(1)	8.672 Ω/ph	5.78 Ω/ph	5.78 Ω/ph
RR(1)	23.44 Ω/ph	15.628 Ω/ph	15.63 Ω/ph
RRE(1)	23.44 Ω/ph	15.628 Ω/ph	15.63 Ω/ph
k0(1)			0.711
k0Ang(1)			10.45°
Delay(1)			0s

Zone 2: 120% of line length (Athurugiriya to Polpitiya)

Parameters:	Primary values	Secondary values	Relay settings
X(2)	31.28 Ω/ph	20.85Ω/ph	20.85 Ω/ph
R(2)	13.88 Ω/ph	9.25 Ω/ph	9.25 Ω/ph
RR(2)	37.54 Ω/ph	25.03 Ω/ph	25.03 Ω/ph
RRE(2)	37.54 Ω/ph	25.03 Ω/ph	25.03 Ω/ph
k0(2)			0.711
k0Ang(2)			10.45°
Delay(2)			0.5s

Zone 3: 150% of line length (Athurugiriya to Thulhiriya)

Parameters:	Primary values	Secondary values	Relay settings
X(3)	36.63 Ω/ph	24.42 Ω/ph	24.42 Ω/ph
R(3)	16.26 Ω/ph	10.84 Ω/ph	10.84 Ω/ph
RR(3)	43.956 Ω/ph	29.30 Ω/ph	29.30 Ω/ph
RRE(3)	43.956 Ω/ph	29.30 Ω/ph	29.30 Ω/ph
k0(3)			0.711
k0Ang(3)			10.45°
Delay(3)			1.0s

Assumptions:

RR (n) = Resistive reach including arc resistance = 1.2* X (n) for phase faults

RRE (n) = Resistive reach including arc resistance = 1.2* X (n) for phase faults

k0 (n) = mod (1/3 [Z_{OL} – Z_L] / Z_L)

Zone 4: – 10% of Zone 1 (Athurugiriya to Polpitiya 1 & 2)

Parameters:	Primary values	Secondary values	Relay settings
X(4)	– 2.085 Ω/ph	–1.39Ω/p	–1.39 Ω/ph
R(4)	– 0.926 Ω/ph	– 0.617 Ω/ph	– 0.617 Ω/ph
RR(4)	– 2.50 Ω/ph	– 1.67 Ω/ph	– 1.67 Ω/ph
RRE(4)	– 2.5 Ω/ph	– 1.67 Ω/ph	– 1.67 Ω/ph
k0(4)			0.711
k0Ang(4)			10.45°
Delay(4)			1.0s

Reverse Zone: Used for detecting of reversal of fault energy direction
200% of line length (Athurugiriya to Thulhiriya)

Parameters:	Primary values	Secondary values	Relay settings
X(Back)	48.84 Ω/ph	32.56 Ω/ph	32.56 Ω/ph
R(Back)	21.68 Ω/ph	14.45 Ω/ph	14.45 Ω/ph
RR(Back)	58.61 Ω/ph	39.07 Ω/ph	39.07 Ω/ph
RRE(Back)	58.61 Ω/ph	39.07 Ω/ph	39.07 Ω/ph
k0(Back)			0.711
k0Ang(Back)			10.45°
Delay(Back)			0s

Assumptions:

Note:

1. CEB to conduct a co-ordination study on time settings with other lines in network.

2. CEB to check the values of RR and RRE by calculating arc resistance form Warrington's formula (see operating instruction REL316*4 Pub. IMRB 520050 – Uen page 3.5.2 – 35).

3. Zone 2 and 3 must be checked as to whether they are reaching into the shortest adjacent line or transformer on the bus at the remote end.

8.2.11 **Substation : 132kV Polpitiya**

Line Data for Polpitya 1 & 2 to Athurugiriya 1 & 2

Primary line data: Length: 51.9Km
Total Z1=(11.57 + j 26.065) Ω = 28.52 Ω, ∠ 66.0°
Z0=(25.828 + j 85.246) Ω = 89.07 Ω, ∠ 73.15°

Type of grounding: Solid

Positive sequence impedance:		28.52 Ω/ph Pos. sequence impedance (Z1) : 0.4387 Ω/km
Angle:	66°	Pos. sequence resistance (R1) : 0.1780 Ω/km Pos. sequence reactance (X1) : 0.4010 Ω/km
Zero sequence impedance:	89.07 Ω/ph	Zero sequence impedance (Z0) : 1.3704 Ω/km
Angle:	73.15°	Zero sequence resistance (R0) : 0.39735 Ω/km Zero sequence reactance (X0) : 1.31149 Ω/km

Rated line voltage: 132kV (= 132kV/√ 3)
Rated line current: 400A

P.T./C.T. data

P.T. primary voltage: 76.2kV (= 132kV/√ 3)
P.T. secondary voltage: 63.5V (= 110kV/√ 3)
P.T. location: Post type CVT (Serial Nos. 202679, 202680)
P.T. ratio: 1200

C.T. primary current: 800A (800/1A)
C.T. secondary voltage: 1A
C.T. location: Post type outdoor CTs (core 2)
C.T. ratio: 800
Main VT ratio/main CT ratio = Impedance ratio: 1.5

Primary parallel line data

Mutual impedance Zmo = 0.2515 + j 0.78757 Ω /km

Zero sequence compensation factor for parallel line
k0m = 0.628

k0m Ang = ∠ 6.23°

8.2.12 Relay Hardware

Relay Code

Nominal voltage: 110V
Nominal current: 1A

AD Channel:	Selections/Comments:	Relay settings of Ref. Values:
Channel 1	VTS 3 ph-R (HV-Dist-U input)	1.000
Channel 2	VTS 3 ph-S	1.000
Channel 3	VTS 3 ph-T	1.000
Channel 4	CT 1 ph (HV-Dist-IO input)	1.000
Channel 5	CT 1 ph (HV-Dist-IOP)	1.000
Channel 6	VT 1 ph	1.000
Channel 7	CT 3 ph-R (HV-Dist I input)	1.000
Channel 8	CT 3 ph-S	1.000
Channel 9	CT 3 ph-T	1.000

Assumptions:

Note: 1. HV distance function use channel 7, 8, 9 for I input.

2. For parallel line compensation channel 5 is used.

8.2.13 General Settings

Parameters:	Selections/Comments:	Relay settings (secondary):
Ref. Length	Dist. To fault indication shown in km	TBA by CEB
CT Neutral		Line side
k0m		0.628
k0m/Ang		6.23°
Iload	Fixed slope of 7°	2 IN
Umin fault	Conventional VTs	0.1 UN
MemDirMode		Block
DefDirMode		Forward

k0m = $(Z_{m0} / 3 \times Z_1)$ = 0.628
k0mAng = Ang $(Z_{m0} / 3 \times Z_1)$ = 6.23°

8.2.14 V.T. Supervision Settings

Parameters:	Selections/Comments:	Relay settings (secondary):
VTSupMode		Zero seq.
VTSupBlkDel		off

VTSupDebDel	enabled (Grounded system)	on
U0minVTSup	0.2 *UN (setting range 0.01-0.5s)	0.2 UN
I0minVTSup	0.07 *IN (setting range 0.01-0.5s)	0.07 IN
U2minVTSup	0.1 UN (setting range 0.01-0.5s)	0.1 UN
12minVTSup	0.07 IN (setting range 0.01-0.5s)	0.07 IN

8.2.15 **O/C Backup Protection**

Parameters:	Selections/Comments:	Relay settings (secondary):
I O/C	Not in use	0
Delay O/C	Not in use	0

8.2.16 **Trip Schemes**

Parameters:	Selections/Comments:	Relay settings (secondary):
ComMode		POTT
Tripmode		3 ph Trip
SOFTMode		nondir
SOFT10sec		off
Weak		off
Unblock		off
Echo		on
TransB1		on
t1 block	0.04s (setting range 0-0.25s)	0.04s
t1 TransB1	70 ms (setting range 0-0.25s)	0.07 S
t2 TransB1	100 ms (setting range 0-10s)	0.10 S
t1EvolFaults	100 ms (setting range 0-10s)	0.10 S

8.2.17 **Power Swing Blocking**

Parameters:	Selections/Comments:	Relay settings (secondary):
tPSBlock	on (setting)	10 s

Assumptions:

t1 TransB1 = min. holding time for wrong energy direction signal
= 60 ms + reset time for comm. Channel = 60 + 10 = 70 ms

t2 TransB1 = max. holding time for wrong energy direction signal
= 100 ms (no AR)

i.e. a second directional decision in forward direction is inhibited for 70-100 ms.

8.2.18 **Starting (Athurugiriya to Polpitiya)**

Parameters:	Selections:	Primary values:	Relay settings (secondary):
PhaseSeimode			nonDir
GndFaultMode			I0
Imin	0.200 *IN		0.2 IN
310min	0.500 *IN		0.5 IN
3U0min	0.000 *UN		0 UN
XA	Ω/ph	65.16	43.44 Ω/ph
XB	Ω/ph	19.55	13.0 Ω/ph
RA	Ω/ph	26.99	17.99 Ω/ph
RB	Ω/ph	8.097	5.40 Ω/ph
Rload	Ω/ph	26.99	17.99 Ω/ph
Angle Load	45°		45°
Uweak	0.7 *UN (UV starters for SOFT, POTT)		0.7 UN
Delay(def)			1.4s

Calculation (assumptions): X_A = 2.5* line reactance of protected line
2.5 x 65.9 x 0.4010 = 65.16 Ω/ph (Athurugiriya to Polpitiya)

Check: R_A > Zone 3 resistance (+ arc resistance)
X_B = 0.3* X_A
R_B = 0.3* R_A
R_{Load}= R_A=0.85 x 132kV / √3 x 2 x 1200 = 26.99 Ω/ph

Factor of 2 is used in calculation of R_{Load} since these are parallel lines

Check: Minimum system voltage = 132kV
Maximum load current I_{Bmax} = 400A
I_A = 800A

Calculated values of Z set with these assumptions:
Zset = 46.75 Ω/ph (primary)
Zset = 31.17 Ω/ph (secondary)

The chosen values for the starting settings have to fulfil the condition of the maximum permissible reach of the starters (see below).

Maximum permissible reach of the starters:

For solidly grounded systems
Z set ≤ mod (U/2*[I_{Bmax} + I_A])

Z set ≤ mod 0.85 x 132/2 (400 + 800) = 46.75 Ω

Z set maximum value of the impedance, i.e. the maximum value of the expression

U lowest phase voltage of the healthy phases for an E/F on one phase (U = 85* min system voltage

2 factor which takes account of the fact that phase currents and not phase-to-phase currents are used

I_A circulating current, assumption: = C.T. nominal primary current

I_{Bmax} Max. load current

8.2.19 Measuring

First setting group is for when PLC is healthy.

This is configured for Blocking scheme.

Zone 1: 80% of line length (Polpitiya to Athurugiriya)

Parameters:	Primary values	Secondary values	Relay settings
X(1)	20.852 Ω/ph	13.90 Ω/ph	13.90 Ω/ph
R(1)	9.256 Ω/ph	16.17 Ω/ph	16.17 Ω/ph
RR(1)	25.02 Ω/ph	16.68 Ω/ph	16.68 Ω/ph
RRE(1)	25.02 Ω/ph	16.68 Ω/ph	16.68 Ω/ph
k0(1)			0.711
k0Ang(1)			10.45°
Delay(1)			0s

8.2.20 Measuring

Second setting group is for when PLC is faulty.

This is configured for Basic Distance Protection.

Zone 1: 80% of line length (Thulhiriya to Polpitiya)

Parameters:	Primary values	Secondary values	Relay settings
X(1)	20.852 Ω/ph	13.90 Ω/ph	13.90 Ω/ph
R(1)	9.256 Ω/ph	6.17 Ω/ph	6.17 Ω/ph
RR(1)	25.02 Ω/ph	16.68 Ω/ph	16.68 Ω/ph
RRE(1)	25.02 Ω/ph	16.68 Ω/ph	16.68 Ω/ph
k0(1)			0.711
k0Ang(1)			10.45°
Delay(1)			0s
X(Back)	9.775 Ω/ph	6.52 Ω/ph	6.52 Ω/ph
R(Back)	4.048 Ω/ph	2.698 Ω/ph	2.69 Ω/ph
RR(Back)	19.55 Ω/ph	13.03 Ω/ph	13.03 Ω/ph
RRE(Back)	19.55 Ω/ph	13.03 Ω/ph	13.03 Ω/ph

Assumptions:

Note: 1. CEB to conduct a co-ordination study on time settings with other lines in network.

2. CEB to check the values of RR and RRE by calculating arc resistance form Warrington's formula (see operating instruction REL316*4 Pub. IMRB 520050 – Uen page 3.5.2 – 35).

3. Zone 2 and 3 must be checked as to whether they are reaching into the shortest adjacent line or transformer on the bus at the remote end.

4. X(BACK) = 50% X(B)
   R(BACK) = 50% R(B)
   RR(BACK) = RRE(BACK) = 2*X(BACK)

8.3 Distance Protection at Athurugiriya Substation End

8.3.1 Distance Relay Type REL316*4

Line Data for Athurugiriya to Oruwala 1 & 2

Primary line data: Length: 3.5Km
Total Z1 = (0.623 + j 1.404) Ω = 1.536 Ω, ∠ 66.0°
Z0 = (1.391 + j 4.59) Ω = 4.80 Ω, ∠ 73.15°

Type of grounding:	Solid	
Positive sequence impedance:	1.536 Ω/ph	Pos. sequence impedance (Z1) : 0.4387 Ω/km
Angle:	66°	Pos. sequence resistance (R1) : 0.1780 Ω/km Pos. sequence reactance (X1) : 0.4010 Ω/km
Zero sequence impedance:	4.80 Ω/ph	Zero sequence impedance (Z0) : 1.3704 Ω/km
Angle:	73.15°	Zero sequence resistance (R0) : 0.39735 Ω/km Zero sequence reactance (X0) : 1.31149 Ω/km

P.T./C.T. data

P.T. primary voltage:	76.2kV	(= 132kV/√ 3)
P.T. secondary voltage:	63.5V	(= 110kV/√ 3)
P.T. location:	Post type CVT (Serial Nos. 202679, 202680)	
P.T. ratio:	1200	
C.T. primary current:	800A	(800/1A)
C.T. secondary voltage:	1A	
C.T. location:	Post type outdoor CTs (core 2)	

C.T. ratio: 800
Main VT ratio/main CT ratio = Impedance ratio: 1.5

Primary parallel line data

Mutual impedance Zmo = 0.2515 + j 0.78757 Ω /km

Zero sequence compensation factor for parallel line
k0m = 0.628
k0m Ang = ∠ 6.23°

8.3.2 Relay Hardware

Relay Code

Nominal voltage: 110V
Nominal current: 1A

AD Channel:	Selections/Comments:	Relay settings of Ref. Values:
Channel 1	VTS 3 ph-R (HV-Dist-U input)	1.000
Channel 2	VTS 3 ph-S	1.000
Channel 3	VTS 3 ph-T	1.000
Channel 4	CT 1 ph (HV-Dist-IO input)	1.000
Channel 5	CT 1 ph (HV-Dist-IOP)	1.000
Channel 6	VT 1 ph	1.000
Channel 7	CT 3 ph-R (HV-Dist I input)	1.000
Channel 8	CT 3 ph-S	1.000
Channel 9	CT 3 ph-T	1.000

Assumptions:

Note: 1. HV distance function use channel 7, 8, 9 for I input.
3. For parallel line compensation channel 5 is used.

8.3.3 General Settings

Parameters:	Selections/Comments:	Relay settings (secondary):
Ref. Length	Dist. To fault indication shown in km	TBA by CEB
CT Neutral		Line side
k0m		0.628
k0m/Ang		6.23°
Iload	Fixed slope of 7°	2 IN
Umin fault	Conventional VTs	0.1 UN
MemDirMode		Block
DefDirMode		Forward

k0m = $(Z_{m0} / 3 \times Z_1)$ = 0.628
k0mAng = Ang $(Z_{m0} / 3 \times Z_1)$ = 6.23°

8.3.4 V.T. Supervision Settings

Parameters:	Selections/Comments:	Relay settings (secondary):
VTSupMode		Zero seq.
VTSupBikDel		off
VTSupDebDel	enabled (Grounded system)	on
U0minVTSup	0.2 *UN (setting range 0.01-0.5s)	0.2 UN
I0minVTSup	0.07 *IN (setting range 0.01-0.5s)	0.07 IN
U2minVTSup	0.1 UN (setting range 0.01-0.5s)	0.1 UN
12minVTSup	0.07 IN (setting range 0.01-0.5s)	0.07 IN

8.3.5 O/C Backup Protection

Parameters:	Selections/Comments:	Relay settings (secondary):
I O/C	Not in use	0
Delay O/C	Not in use	0

8.3.6 Trip Schemes

Parameters:	Selections/Comments:	Relay settings (secondary):
ComMode		POTT
Tripmode		3 ph Trip
SOFTMode (Switch on to Fault)		nondir
SOFT10sec (Switch on to Fault)		on
Weak		off
Unblock		off
Echo		on
Broken Conductor Protection		on
Fault Locator Measurement		on
TransB1		on
t1 block	0.04s (setting range 0-0.25s)	0.04s
t1 TransB1	70 ms (setting range 0-0.25s)	0.07 S
t2 TransB1	100 ms (setting range 0-10s)	0.10 S
t1EvolFaults	100 ms (setting range 0-10s)	0.10 S

8.3.7 Power Swing Blocking

Parameters:	Selections/Comments:	Relay settings (secondary):
tPSBlock	on (setting)	10 s

Assumptions:

t1 TransB1 = min. holding time for wrong energy direction signal
= 60 ms + reset time for comm. Channel = 60 + 10 = 70 ms

t2 TransB1 = max. holding time for wrong energy direction signal
= 100 ms (no AR)
i.e. a second directional decision in forward direction is inhibited for 70-100 ms.

8.3.8 **Starting (Athurugiriya to Oruwala 1 & 2)**

Parameters:	Selections:	Primary values:	Relay settings (secondary):
PhaseSeimode			nonDir
GndFaultMode			I0
Imin	0.200 *IN		0.2 IN
3I0min	0.500 *IN		0.5 IN
3U0min	0.000 *UN		0 UN
XA	Ω/ph	3.51	2.33 Ω/ph
XB	Ω/ph	1.05	0.7 Ω/ph
RA	Ω/ph	26.99	17.99 Ω/ph
RB	Ω/ph	8.097	5.40 Ω/ph
Rload	Ω/ph	26.99	17.99 Ω/ph
Angle Load	45°		45°
Uweak	0.7 *UN (UV starters for SOFT, POTT)		0.7 UN
Delay(def)			1.4s

Calculation (assumptions): X_A = 2.5* line reactance of protected line
2.5 x 3.5 x 0.4010 = 3.51 Ω/ph (Athurugiriya to Oruwala)

Check: R_A > Zone 3 resistance (+ arc resistance)
X_B = 0.3* X_A
R_B = 0.3* R_A
R_{Load} = R_A = 0.85 x 132kV / √3 x 2 x 1200 = 26.99 Ω/ph

Factor of 2 is used in calculation of R_{Load} since these are parallel lines

Check: Minimum system voltage = 132kV
Maximum load current I_{Bmax} = 400A
I_A = 800A
Calculated values of Z set with these assumptions:
Zset = 46.75 Ω/ph (primary)
Zset = 31.17 Ω/ph (secondary)

The chosen values for the starting settings have to fulfil the condition of the maximum permissible reach of the starters (see below).

Maximum permissible reach of the starters:

For solidly grounded systems

Z set ≤ mod (U/2*[I_{Bmax} + I_A])

Z set ≤ mod 0.85 x 132/2 (400 + 800) = 46.75 Ω

Z set maximum value of the impedance, i.e. the maximum value of the expression

U lowest phase voltage of the healthy phases for an E/F on one phase (U = 85* min system voltage

2 factor which takes account of the fact that phase currents and not phase-to-phase currents are used

I_A circulating current, assumption: = C.T. nominal primary current

I_{Bmax} Max. load current

8.3.10 Measuring

First setting group is for when PLC is healthy.

This is configured for Blocking scheme.

Zone 1: 80% of line length (Athurugiriya to Oruwala 1 & 2)

Parameters:	Primary values	Secondary values	Relay settings
X(1)	1.123 Ω/ph	0.749 Ω/ph	0.749 Ω/ph
R(1)	0.498 Ω/ph	0.332 Ω/ph	0.332 Ω/ph
RR(1)	1.35 Ω/ph	0.90 Ω/ph	0.90 Ω/ph
RRE(1)	1.35 Ω/ph	0.90 Ω/ph	0.90 Ω/ph
k0(1)			0.711
k0Ang(1)			10.45°
Delay(1)			0s

Zone 2: 120% of line length (Athurugiriya to Oruwala 1 & 2)

Parameters:	Primary values	Secondary values	Relay settings
X(2)	1.685 Ω/ph	1.123 Ω/ph	1.123 Ω/ph
R(2)	0.748 Ω/ph	0.499 Ω/ph	0.499 Ω/ph
RR(2)	2.022 Ω/ph	1.348 Ω/ph	1.348 Ω/ph
RRE(2)	2.022 Ω/ph	1.348 Ω/ph	1.348 Ω/ph
k0(2)			0.711
k0Ang(2)			10.45°
Delay(2)			70.0s

Zone 3: 150% of line length (Athurugiriya to Oruwala 1 & 2)

Parameters:	Primary values	Secondary values	Relay settings
X(3)	2.11 Ω/ph	1.407 Ω/ph	1.407 Ω/ph
R(3)	0.935 Ω/ph	0.623 Ω/ph	0.623 Ω/ph
RR(3)	2.532 Ω/ph	1.688 Ω/ph	1.688 Ω/ph
RRE(3)	2.532 Ω/ph	1.688 Ω/ph	1.688 Ω/ph
k0(3)			0.711
k0Ang(3)			10.45°
Delay(3)			1.0s

Assumptions:

RR (n) = Resistive reach including arc resistance = 1.2* X (n) for phase faults
RRE (n) = Resistive reach including arc resistance = 1.2* X (n) for phase faults
k0 (n) = mod (1/3 [Z_{OL} – Z_L] / Z_L)

Zone 4: – 10% of Zone 1 (Athurugiriya to Oruwala 1 & 2)

Parameters:	Primary values	Secondary values	Relay settings
X(4)	– 0.1404 Ω/ph	– 0.0936 Ω/ph	– 0.0936 Ω/ph
R(4)	– 0.0623 Ω/ph	– 0.0415 Ω/ph	– 0.0415 Ω/ph
RR(4)	– 0.1684 Ω/ph	– 0.1123 Ω/ph	– 0.1123 Ω/ph
RRE(4)	– 0.1684 Ω/ph	– 0.1123 Ω/ph	– 0.1123 Ω/ph
k0(4)			0.711
k0Ang(4)			10.45°
Delay(4)			1.0s

Reverse Zone: Used for detecting of reversal of fault energy direction
200% of line length (Athurugiriya to Oruwala 1 & 2)

Parameters:	Primary values	Secondary values	Relay settings
X(Back)	2.8 Ω/ph	1.87 Ω/ph	1.87 Ω/ph
R(Back)	1.246 Ω/ph	0.831 Ω/ph	0.831 Ω/ph
RR(Back)	3.36 Ω/ph	2.24 Ω/ph	2.24 Ω/ph
RRE(Back)	3.36 Ω/ph	2.24 Ω/ph	2.24 Ω/ph
k0(Back)			0.711
k0Ang(Back)			10.45°
Delay(Back)			0s

Assumptions:

Note: 1. CEB to conduct a co-ordination study on time settings with other lines in network.

2. CEB to check the values of RR and RRE by calculating arc resistance form Warrington's formula (see operating instruction REL316*4 Pub. IMRB 520050 – Uen page 3.5.2 – 35).

4. Zone 2 and 3 must be checked as to whether they are reaching into the shortest adjacent line or transformer on the bus at the remote end.

8.3.10 Measuring

Second setting group is for when PLC is faulty.

This is configured for Basic Distance Protection.

Zone 1: 80% of line length (Athurugiriya to Oruwala 1 & 2)

Parameters:	Primary values	Secondary values	Relay settings
X(1)	1.123 Ω/ph	0.749 Ω/ph	0.749 Ω/ph
R(1)	0.498 Ω/ph	0.332 Ω/ph	0.332 Ω/ph
RR(1)	1.35 Ω/ph	0.90 Ω/ph	0.90 Ω/ph
RRE(1)	1.35 Ω/ph	0.90 Ω/ph	0.90 Ω/ph
k0(1)			0.711
k0Ang(1)			10.45°
Delay(1)			0s

Zone 2: 120% of line length (Athurugiriya to Oruwala 1 & 2)

Parameters:	Primary values	Secondary values	Relay settings
X(2)	1.685 Ω/ph	1.123 Ω/ph	1.123 Ω/ph
R(2)	0.748 Ω/ph	0.499 Ω/ph	0.499 Ω/ph
RR(2)	2.022 Ω/ph	1.348 Ω/ph	1.348 Ω/ph
RRE(2)	2.025 Ω/ph	1.348 Ω/ph	1.348 Ω/ph
k0(2)			0.711
k0Ang(2)			10.45°
Delay(2)			0.5s

Zone 3: 150% of line length (Athurugiriya to Oruwala 1 & 2)

Parameters:	Primary values	Secondary values	Relay settings
X(3)	2.11 Ω/ph	1.407 Ω/ph	1.407 Ω/ph
R(3)	0.935 Ω/ph	0.623 Ω/ph	0.623 Ω/ph
RR(3)	2.532 Ω/ph	1.688 Ω/ph	1.688 Ω/ph
RRE(3)	2.532 Ω/ph	1.688 Ω/ph	1.688 Ω/ph
k0(3)			0.711
k0Ang(3)			10.45°
Delay(3)			1.0s

Assumptions:

RR (n) = Resistive reach including arc resistance = 1.2* X (n) for phase faults

RRE (n)	=	Resistive reach including arc resistance = 1.2* X (n) for phase faults
k0 (n)	=	mod (1/3 [$Z_{OL} - Z_L$] / Z_L)

Zone 4: – 10% of Zone 1 (Athurugiriya to Oruwala 1 & 2)

Parameters:	Primary values	Secondary values	Relay settings
X(4)	– 0.1404 Ω/ph	– 0.0936 Ω/ph	– 0.0936 Ω/ph
R(4)	– 0.0623 Ω/ph	– 0.415 Ω/ph	– 0.415 Ω/ph
RR(4)	– 0.1684 Ω/ph	– 0.1123 Ω/ph	– 0.1123 Ω/ph
RRE(4)	– 0.1684 Ω/ph	– 0.1123Ω/ph	– 0.1123 Ω/ph
k0(4)			0.711
k0Ang(4)			10.45°
Delay(4)			1.0s

Reverse Zone: Used for detecting of reversal of fault energy direction 200% of line length (Athurugiriya to Oruwala 1 & 2)

Parameters:	Primary values	Secondary values	Relay settings
X(Back)	2.80 Ω/ph	1.87 Ω/ph	1.87 Ω/ph
R(Back)	1.246 Ω/ph	0.831 Ω/ph	0.831 Ω/ph
RR(Back)	3.36 Ω/ph	2.24 Ω/ph	2.24 Ω/ph
RRE(Back)	3.36 Ω/ph	2.24 Ω/ph	2.24 Ω/ph
k0(Back)			0.711
k0Ang(Back)			10.45°
Delay(Back)			0s

Assumptions:

Note:

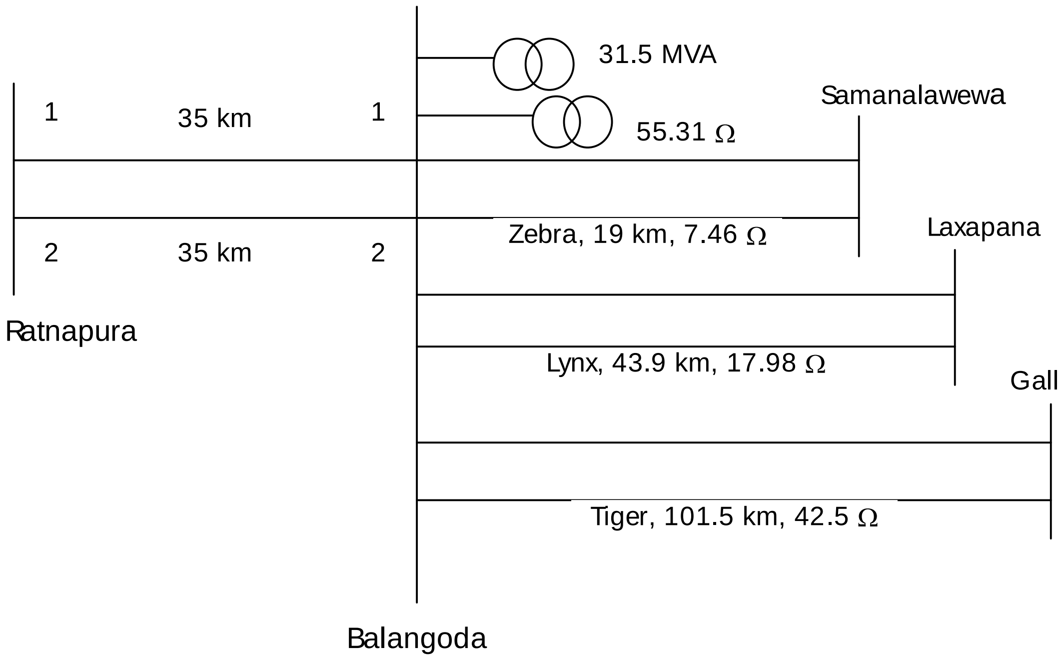
1. CEB to conduct a co-ordination study on time settings with other lines in network.

4. CEB to check the values of RR and RRE by calculating arc resistance form Warrington's formula (see operating instruction REL316*4 Pub. IMRB 520050 – Uen page 3.5.2 – 35).

5. Zone 2 and 3 must be checked as to whether they are reaching into the shortest adjacent line or transformer on the bus at the remote end.

8. 132kV OVERHEAD LINE FEEDER PROTECTION

All impedance data supplied by the customer is in ohms/km (Ω/km).



8.1 Substation : 132kV Ratnapura

Feeders : Ratnapura – Balangoda 1
Ratnapura – Balangoda 2

Substation	Fault current (kA)		132kV Feeder circuit	No. of circuit	Con-ductor type	Positive sequence impedance		Zero sequence impedance		(km)
	Min.	Max.				R_1 – Ω/km	X_1 – Ω/km	R_0 – Ω/km	X_0 – Ω/km	
Ratnapura	0.6kA	4.7kA	Ratnapura / Balangoda 1	1	Zebra	0.0760	0.3870	0.3360	1.18857	35
			Ratnapura / Balangoda 2	1	Zebra	0.0760	0.3870	0.3360	1.18857	35

Note: 1. In the case where a feeder is Teed to two substations the greatest distance will be used in the distance protection settings.

2. The minimum fault level has been assumed as the maximum current carrying capacity of the overhead line (132kV).

8.2 Distance Protection at Ratnapura Substation End

8.2.1 Distance Relay Type LFZR111 (AREVA)

Line Data for Ratnapura to Balangoda

Primary line data: Length: 35 km

Total $Z1 = (2.66 + j\,13.55)\ \Omega = 13.81\ \Omega, \angle 78.9°$

$Z0 = (11.76 + j\,41.60)\ \Omega = 43.23\ \Omega, \angle 74.2°$

Type of grounding: Solid

Positive sequence impedance:	13.81 Ω/ph	Pos. sequence impedance (Z1) : 0.3946 Ω/km
Angle:	78.9°	Pos. sequence resistance (R1) : 0.0760 Ω/km Pos. sequence reactance (X1) : 0.3871 Ω/km
Zero sequence impedance:	43.23 Ω/ph	Zero sequence impedance (Z0) : 1.2350 Ω/km
Angle:	74.2°	Zero sequence resistance (R0) : 0.3360 Ω/km Zero sequence reactance (X0) : 1.1886 Ω/km

$Z_0/Z_1 = 3.130 \angle -4.7°$

Rated line voltage: 132kV (= 132kV/√ 3)
Rated line current: 600A

P.T./C.T. data

P.T. primary voltage: 76.2kV (= 132kV/√ 3)
P.T. secondary voltage: 63.5V (= 110kV/√ 3)
P.T. location: Post type CVT)
P.T. ratio: 1200

C.T. primary current: 800A (800/1A)
C.T. secondary voltage: 1A
C.T. location: Post type outdoor CTs (core 2)
C.T. ratio: 800

$$\text{Ratio of secondary to primary Impedance} = \frac{800\ /\ 1}{132000\ /\ 110} = 0.666$$

Primary parallel line data

Neutral Compensation Factor $KN = \dfrac{Z_{L0} - Z_{L1}}{3Z_{L1}}$

$Z0 - Z1 \quad = 0.3360 + j\,1.18857 - 0.0760 - j\,0.3870$

$\quad = 0.26 + j\,0.8015 = 0.8427 \angle 72.03° \ \Omega / km$

$ZL1 \quad = 0.0760 + j\,0.3870 = 0.3944 \angle 78.88° \ \Omega / km$

$$KN = \frac{0.8427 \angle 72.03^0}{3 \times 0.3944 \angle 78.88^0} = 0.712 \angle -6.85°$$

8.2.2 Relay Settings

The Zone 1 elements of a distance relay should be set to cover as much of the protected line as possible, allowing instantaneous tripping for as many faults as possible. In most applications the Zone 1 reach should not be set to respond to faults beyond the protected line.

Therefore, it is recommended that the reach of the zone 1distance elements is restricted to 80–85% of the protected line impedance, with Zone 2 elements set to cover the final 20% of the line.

8.2.3 Zone 1 Reach Settings

a) It is assumed that only a three-zone scheme is required. Settings on the relay can be performed in primary or secondary quantities and impedances can be expressed as either polar or rectangular quantities (menu selectable). For the purposes of this feeder distance protection secondary quantities are used.

Required Zone 1 forward reach is to be 80% of the line impedance between Ratnapura and Balangoda substations.

Required Zone 1 reach $= 0.8 \times 13.81 \angle 79.4° \times 0.666$

$= 7.358 \angle 79.4° \ \Omega$ secondary

Relay characteristics angle θ ph setting 45° to 85° in 1° steps

Therefore select θ ph = 80°

Therefore actual Zone 1 reach $= 7.358 \angle 80° \ \Omega$ secondary

b) **Zone 1X is set at 120% of the line impedance same as Zone 2** (see calculation below) if needed.

8.2.4 **Zone 2 Reaching Settings**

In the absence of adjacent lines impedance information (shortest adjacent line impedance is missing), the Zone 2 elements should be set to cover the last 20% of the line not covered by Zone 1. Allowing for under-reaching errors, the Zone 2 reach should be set in excess of 120% of the protected line impedance for all fault conditions.

Required Zone 2 forward reach = $1.2 \times 13.81 \angle 79.4° \times 0.666$

= $11.037 \angle 80°\ \Omega$ secondary

$\therefore$ Actual Zone 2 reach setting = $11.037 \angle 80°\ \Omega$ secondary

8.2.5 **Zone 3 Reach Settings**

Zone 3 forward

Zone 3 = 100% of first line + 120% of second longest line

$\therefore$ 120% of second longest line = 120% Balangoda – Galle line

= $120 \times 42.5\ \Omega$

= $51\ \Omega$

However Zone 3 shall not over reach the transformer 33kV side at Balangoda

2 Transformers equivalent

$$\text{Impedance} = \frac{1}{2} \; \frac{132^2 \times 10^6}{31.5 \times 10^6} \times 10\%$$

= $27.65\ \Omega$

Customer CEB has advised us (11/11/03) to select :

Zone 3 = 100% Ratnapura – Balangoda +75% of Transformer equivalent impedance

$\therefore$ Required Zone 3 forward reach = $13.81\ \Omega \angle 78.9° + 75\%\ \ 27.65\ \Omega$

= $2.66 + j\,13.55 + j\,20.625\ \Omega$

= $2.66 + j\,34.18\ \Omega$ primary

= $34.28\angle 85.6 + 0.666\Omega$ secondary

= $22.83 \angle 85.6\ \Omega$ secondary

Actual Zone 3 reach setting = $22.83 \angle 85.6° \Omega$ secondary

Reverse-looking Zone 3 element can be set to provide back-up protection for the local busbars, the offset reach is typically set to 25% of the Zone 1 reach of the relay for short transmission lines (< 30 km) or 10% of the Zone 1 reach for long transmission lines.

$\therefore$ Required Zone 3 reverse offset reach impedance = typically 10% Zone 1 reach

= $0.1 \times 7.358 \angle 79.4° \Omega$ secondary

Zone 3 reverse offset reach setting = $0.7358 \angle 80° \Omega$ secondary

8.2.6 Ground Fault Neutral Compensation Settings

The line impedance characteristics do not change and as such a common KZN factor can be applied to each zone. When a common setting is chosen, this is set in magnitude as KN ratio with ratio with an angle equal to the ground loop impedance angle.

KN = $0.712 \angle -6.85°$ (refer to sheet 68)

KZN settings 0.25 to 4 in steps of 2% or less, θn = 85–45° in 1° step

$\therefore$ Select KZN = 0.71 and θn = 80 – 6.85 = 73°

θn = 73°

KZN = 0.71

8.2.7 Power Swing Blocking

Power swing blocking is a function of continuous operation of the phase selector and as such does not require a setting.

8.2.8 Permissive Overreach Schemes for POR2, POR2 WI trip

Not selected.

8.2.9 Reverse-looking Zone 4 Setting

Not required.

8.2.10 Current Reversal Guard

Not to be used.

8.2.11 **Time Delays**

The following time delays shall be applied :

Zone 1 Phase and Ground – Instantaneous
Zone 1 X (T) Phase and Ground –
Zone 2 (T) Phase and Ground – 500 ms
Zone 3 (T) Phase and Ground – 1.0s

8.2.12 **LFZR Back-up Protection Settings**

The LFZR Back-up protection function (Directional overcurrent/earth fault) will be disabled at Ratnapura and Balangoda substations.

8.2.13 **Loss-of-Load Accelerated trip (LOL)**

Set LOL at 10% of I_n.

8.2.14 **Check on Comparison Voltage at Zone 1 Reach**

The worst condition is with the parallel line out of service and it is assumed that the values of maximum and minimum fault levels at Ratnapura and Balangoda substations are for single infed conditions.

Maximum source positive–sequence impedance $= \frac{132^2}{47.3}$

$= 368.4 \angle 80°$

$= 362.8 + j\,63.97\ \Omega$

Protected line positive–sequence impedance up to zone 1 reach

$= 0.8 \times 13.81 \angle 79.4°$

$= 11.048 \angle 79.4°\ \Omega$

$= 10.86 + j\,2.03\ \Omega$

Overall source to zone 1 positive–sequence impedance =

$$(362.8 + j\,63.97) + (10.86 + j2.03) = 373.66 + j\,66$$

$$= 379.4 \angle 80°\ \Omega$$

Relay voltage for a phase fault at the zone 1 reach

$$= \frac{110 \times 11.048}{379.4} = 3.20\text{V}$$

Ground fault at zone 1 reach

Maximum source zero–sequence impedance is assumed to be equal to the positive– sequence impedance.

Maximum source ground loop impedance = 362.8 + j 63.97 Ω

Protected line zero–sequence impedance up to zone 1 reach

$$= 0.8 \times 43.23 \angle 74.2^\circ$$

$$= 34.58 \angle 74.2^\circ \ \Omega$$

$$= 33.27 + j\,9.42 \ \Omega$$

Protected line ground loop impedance up to zone 1 reach =

$$\frac{2 \times (10.86 + j\,2.03) + (33.27 + j\,9.42)}{3} = 18.33 + j4.49\Omega$$

$$= 18.87 \angle 13.76^\circ \ \Omega$$

Overall source to zone 1 reach ground loop impedance

$$= (362.8 + j\,63.97) + (18.33 + j\,4.49)$$
$$= 387.23 \angle 10.18^\circ \ \Omega$$

Relay voltage for a ground fault at the zone 1 reach

$$= \frac{63.5 \times 18.87}{387.23} = 3.095\text{V}$$

For a $\pm$ 5% reach accuracy with the zone 1 multiplier set to unity, LFZR requires at least 1V.

Both phase and ground fault voltage requirements are met in this application.

Appendix 15.1.6 Busbar Protection

AREVA

BUSBAR PROTECTION CALCULATIONS TO RECOMMEND RELAY SETTINGS

FOR THE

132kV BRIDGWATER SUBSTATION

FOR

NATIONAL GRID TRANSCO

ENGLAND

By: V AYADURAI

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High Voltage Systems

Document No. 123025P / N3416P0020

ISSUE 2 : SEPTEMBER 2004

CONTENTS

1. INTRODUCTION

This document contains brief calculations to derive the recommended relay settings for the Busbar Protection for 132kV Bridgwater substation. Protection setting calculations are based on TPS 2.6.2 issue 3 : 1998, TPS 2.24.3 issue 1 November 2002 and NGTS 3.6.14 - Copperwork Protection and ESI 48.3 - Instantaneous High Impedance Differential Protection.

The busbars are divided into four separate zones of protection each with its own discrimination relay and a common check relay for the substation. This gives the normal two stages of protection for each zone for phase and earth faults, CT ratio 500/1.

When the Reserve Busbar isolators 166 and 169 are both closed the two reserve zones are paralleled both on the CT side and on the tripping side, thus reducing the protection to only three separate zones.

The fault detecting relays are AREVA CAG34 relays fitted with 3000 Ω series stabilising resistors and 70 Ω shunt stabilising resistors. All the fault detecting relays are set to the 0.05 amp plug.

The CT bus wires are supervised by AREVA VTX supervision relays set to 3 volts giving an alarm after a fixed time of 3 seconds.

Please refer to the original busbar protection setting calculation reports SWP55A, SWP55B, SWP55C and revised protection. These calculations are included in this protection setting calculation document.

The results are tabulated in the final section, together with other relevant data and figures.

1.1 Definitions and Abbreviations

Lead Resistance	=	R_L
CT Ratio	=	N
CT Knee Point Voltage	=	V_K
CT Secondary Resistance	=	R_{CT}
Relay Resistance	=	R_R
Fault Setting Resistor	=	R
CT Magnetising Current	=	I_i
Full Load (Primary) Current	=	I_n
Fault Current (Primary)	=	I_F
Fault Current (Secondary)	=	I_f

Relay Primary Operation Current (POC)	=	I_{OP}
Relay Burden	=	VA
Relay Current	=	I_R
Relay Current Setting	=	I_S
Relay Voltage Setting	=	V_R
Number of CTs in Parallel	=	n
Number of Relays in Parallel	=	m
Turns Ratio of Current Transformers	=	T
CT Ratio	=	N
Current taken by Peak Voltage Device	=	I_m
Current taken by the Fault Setting Resistor	=	I_{SR}
Primary Operating Current	=	POC (I_{OP})

2. BUSBAR PROTECTION

A. Protection Equipment Details

MSCDN CTs

a) CT Location = Post Type CT

b) CT Ratio = 1000/500/1A (Type B)

c) CT Resistance = 0.914Ω

Class X Vk ≥ 426V, T = 1/500

Cables used for CT connection are $6.0mm^2$

Cables used for MSCDN MK150 to BC1 MK 130 = $6.0mm^2$ (triple core)

Cables used for MSCDN MK150 to Taunton MK 705 = $6.0mm^2$ (triple core)

Existing CTs

a) CT Location = In the CB

b) CT Ratio = 500/1A (Type B)

c) CT Resistance = 0.88 Ω

Class X Vk ≥ 360V, T = 1/500

B. Relays

a) AREVA type high impedance circulating current CAG34 relays with fault setting resistor for Check and Discriminating zones (existing).

b) AREVA type busbar supervision VTX31 relays (existing).

C. System Parameters

a) System Voltage : 132kV

b) System design (switchgear) fault current (1 Ø) = 21.86kA ≏ 21.9kA (3 secs)
System design (switchgear) fault current (3 Ø) = 21.86kA ≏ 21.9kA (3 secs)

c) Fault level with minimum generation (3Ø) = 15.066 kA

D. Rated Stability Limit (Relay Circuit Setting Voltage)

Consider Figure 1 for Busbar Protection Circuit Diagram

A, B, C = Lead Resistance

V_S = Stability Voltage

I_S = Relay Circuit Current at V_S

I_1 = Secondary Exciting Current of CT at V_S

I_V = Current Taken by Supervision Relay

I_m = Current Taken by Peak Voltage Limiting Device At V_S

I_{SR} = Current Taken by Fault Setting Resistor

I_F = Fault Current Corresponding to Switchgear Rating for Stability Limit

n = Number of CTs in parallel

m = Number of Relays in parallel

E. **Primary Fault Setting**

Fault Setting shall be between 10% to 50% of the minimum fault current available.

a) Minimum fault current (100%) = 15.066kA

Minimum fault current (50%) = 7.53kA

Minimum fault current (10%) = 1506.6A

b) Busbar rating (100%) = 2000A

Busbar rating (50%) = 1000A

2.1 Busbar Main Zone 1 Protection

2.1.1 Rated Stability Limit

Busbar protection rating was based on the original switchgear rating of 15.3kA and then revised for a rating of 21.9kA. As per TPS 2.24.3 issue 1 section 3.2.

Consider an external phase-to-earth short circuit and assume complete saturation of current transformer, then :-

$$V_S \geq I_F \text{ (CT Resistance + Lead Burden) T} \qquad (1)$$

Refer to busbar protection calculation in Appendix with MSCDN included.

<u>CALCULATED VALUES OF Vs</u>

i) <u>Discriminating Zone Main 1</u>

a) $V_{S1} \geq \frac{21900}{500} \times 1.884$ (Refer to sheet 3 in Appendix)

$V_{S1} \geq 43.8 \times 1.884 = 82.5V$

ii) Check Zone

a) $V_{S1} \geq \frac{21900}{500} \times 2.84$ (Refer to sheet 5 in Appendix)

$V_{S1} \geq 43.8 \times 2.84 = 124.4V$

iii) Discriminating Zone (Reserve 2)

a) $V_{S1} \geq \frac{21900}{500} \times 2.82$ (Refer to sheet 7 in Appendix)

$V_{S1} \geq 43.8 \times 2.82 = 123.5V$

All these values are acceptable since the revised busbar protection voltage setting V_S = 170V and current setting I_S = 0.05A. (Refer to revised setting included in Appendix).

$\therefore V_S$ = 170V, I_S = 0.05A (existing)

Stabilising Resistor = R_S

$$R_S = \frac{V_S}{I_S} - \frac{VA}{I_S^2} \quad \text{(VA = Burden)}$$

$$R_S = \frac{170}{0.05} - \frac{1}{0.05^2}$$

$$R_S = 3400 - 400 = 3000\ \Omega$$

However the existing stabilising resistor R_S is 3000 Ω

Dropping resistor R_D = 70 Ω

I_{mag} at 170V = 0.1mA

2.1.2 Supervision of Busbar Protection to Cover Open Circuited Current Transformers and Wiring for Discrimination Zone 1

a) **Bus Wiring Supervision**

Relay: VTX 31 (Existing Relay)

Setting Range: 2 – 14V

b) **Setting Calculations**

The initial impedance of the current transformer at the non-linear portion of the curve (ankle point) of MSCDN CT = 2500 Ω and Existing CT = 3000 Ω (9 CTs)

i) Impedance of 9 (maximum number of circuits = 10) current transformers = 2500 // 333 = 294 Ω

ii) Impedance of relay CAG34 circuit = 8000 Ω (1 relay)

Parallel impedance of current transformers and differential circuit 294 // 70 // 8000

= 56 Ω

iii) If the desired sensitivity is 10% of 138A (GRID 1) primary, which is

$$\frac{13.8}{500} = 0.0276$$

$\therefore$ voltage drop = 0.0276 x 56 = 1.55V

$\triangleq$ 2V

In practice, this value would be tried and adopted provided the steady spill current with system load flowing did not approach the relay setting.

$\therefore$ This is an existing relay and is already set at 3 volts.

Similarly other Zone supervision relay settings can be calculated and proved to be ≤ 3V.

2.1.3 Primary Operating Current (POC)

a) Min POC for 2 circuits

$$POC\ (I_{OP}) = N\ (mI_S + nI_1 + I_{SR} + I_m)$$

Where N = 500, m = 1, n = 2, I_S = 0.5, I_1 = 0.1, I_{SR} = 170/70 and I_m = 0

$$POC\ (I_{OP}) = 500\ \left(0.2 + 0.05 + \frac{170}{70}\right)$$

$$= 1340A$$

b) Min POC for 12 circuits

$$POC\ (I_{OP}) = N\ (mI_S + nI_1 + I_{SR} + I_m)$$

Two relays would be connected (Reserve 1 and 2)

Where N = 500, m = 2, n = 12, I_S = 0.05, I_1 = 0.1, I_{SR} = 170/70 and I_m = 0

$$POC\ (I_{OP}) = 500\ \left(12 \times 0.1 + 2 \times 0.05 + \frac{170}{70}\right)$$

$$= 1864A$$

2.1.4 Setting

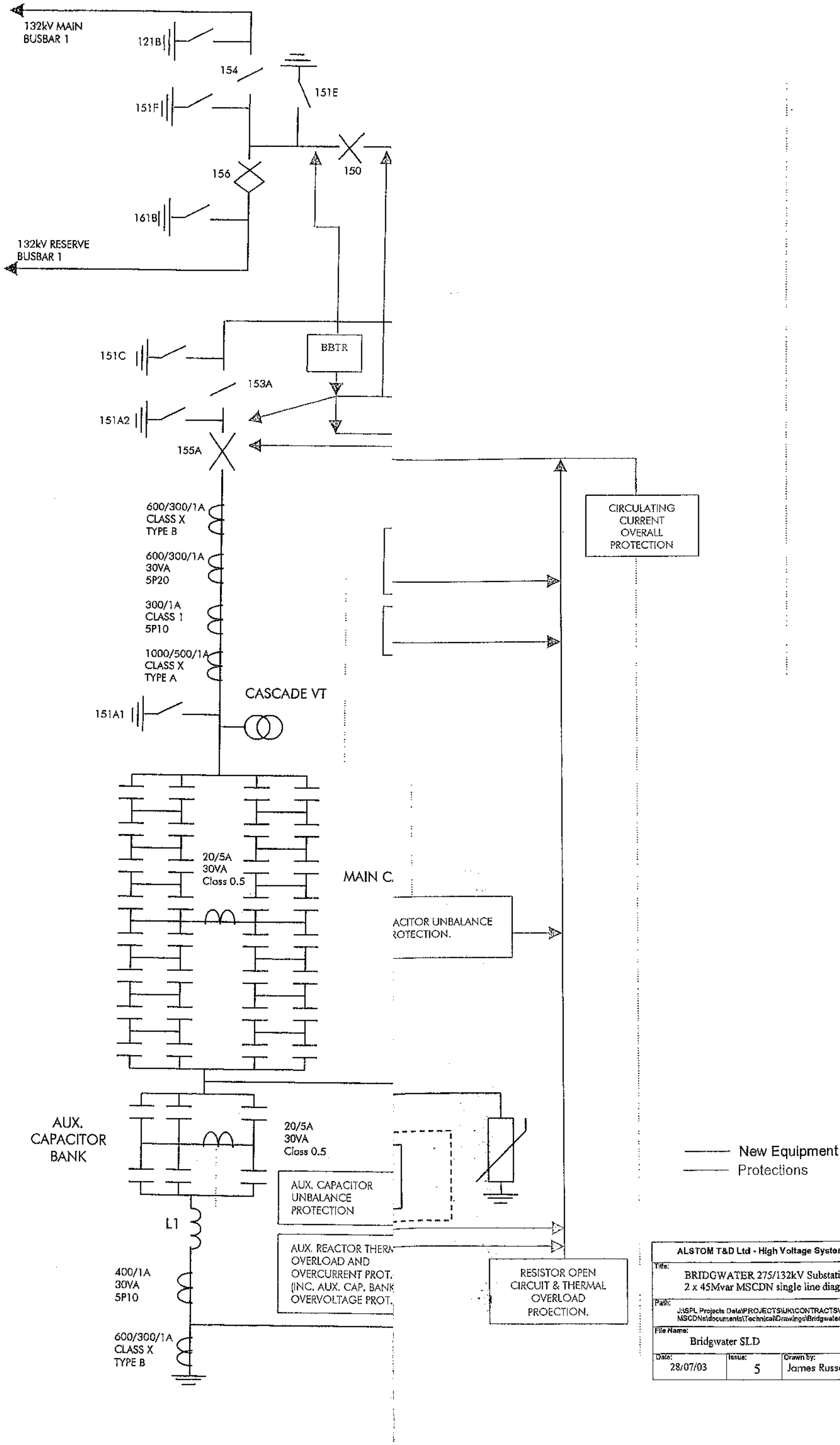
The existing relay settings, the stabilising resistor and shunt resistor are acceptable.

a)	CAG34 relay setting	I_S	=	0.05A (existing)
b)	Shunt resistor value		=	70 Ω (existing)
c)	Stabilising resistor value		=	3000 Ω (existing)

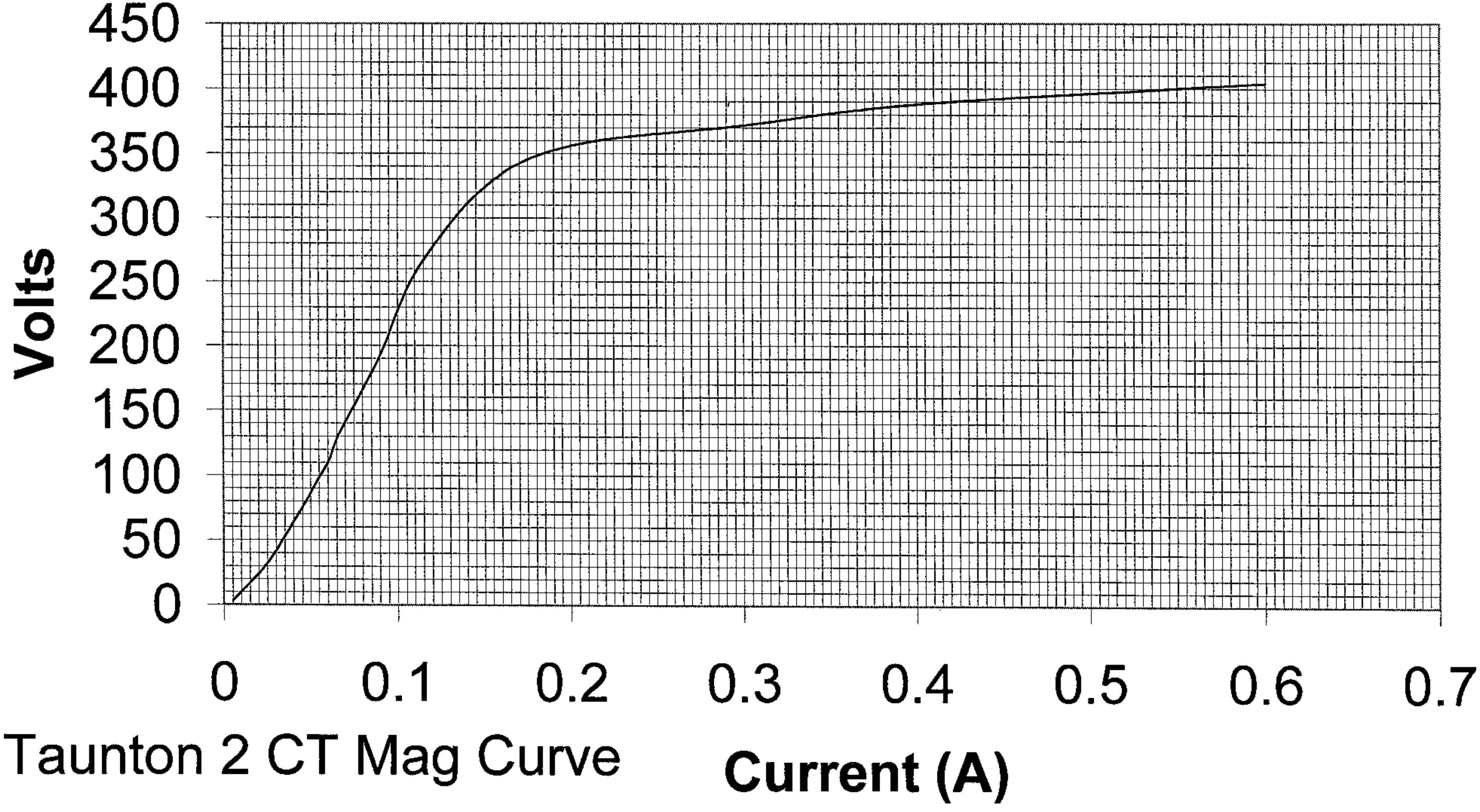
2.1.5 Conclusion

The existing settings do not need any adjustment.

V AYADURAI



ALSTOM T&D Ltd - High Voltage Systems	
Title: BRIDGWATER 275/132kV Substation 2 x 45Mvar MSCDN single line diagram	
Path: J:\SPL Projects Data\PROJECTS\UK\CONTRACTS\23025 – MSCDNs\documents\Technical\Drawings\Bridgwater SLD	
File Name: Bridgwater SLD	
Date: 28/07/03	Issue: 5 — Drawn by: James Russell

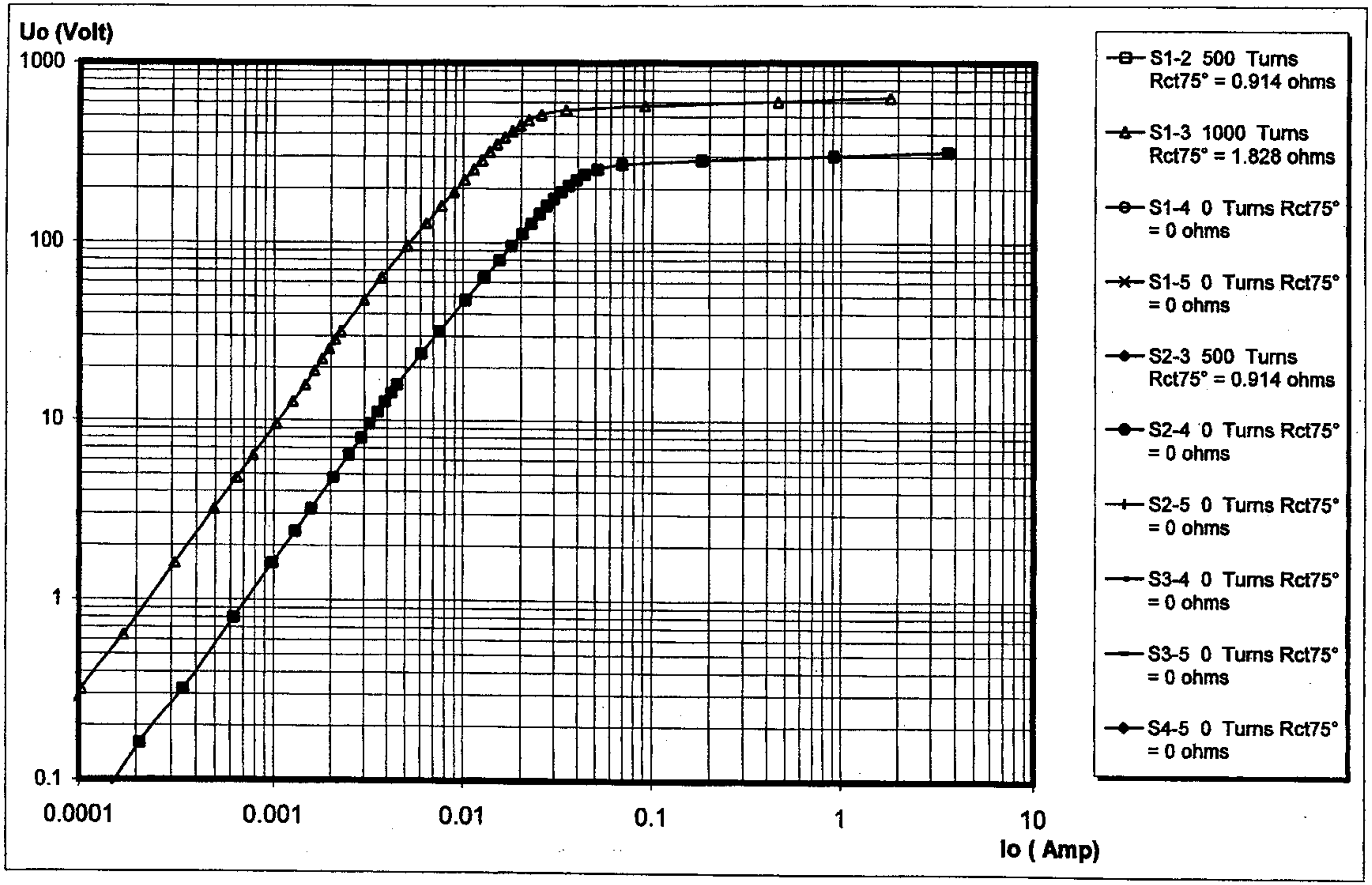


Taunton 2 CT Mag Curve

ALSTOM

Courbes de magnetisation - magnetisation curves

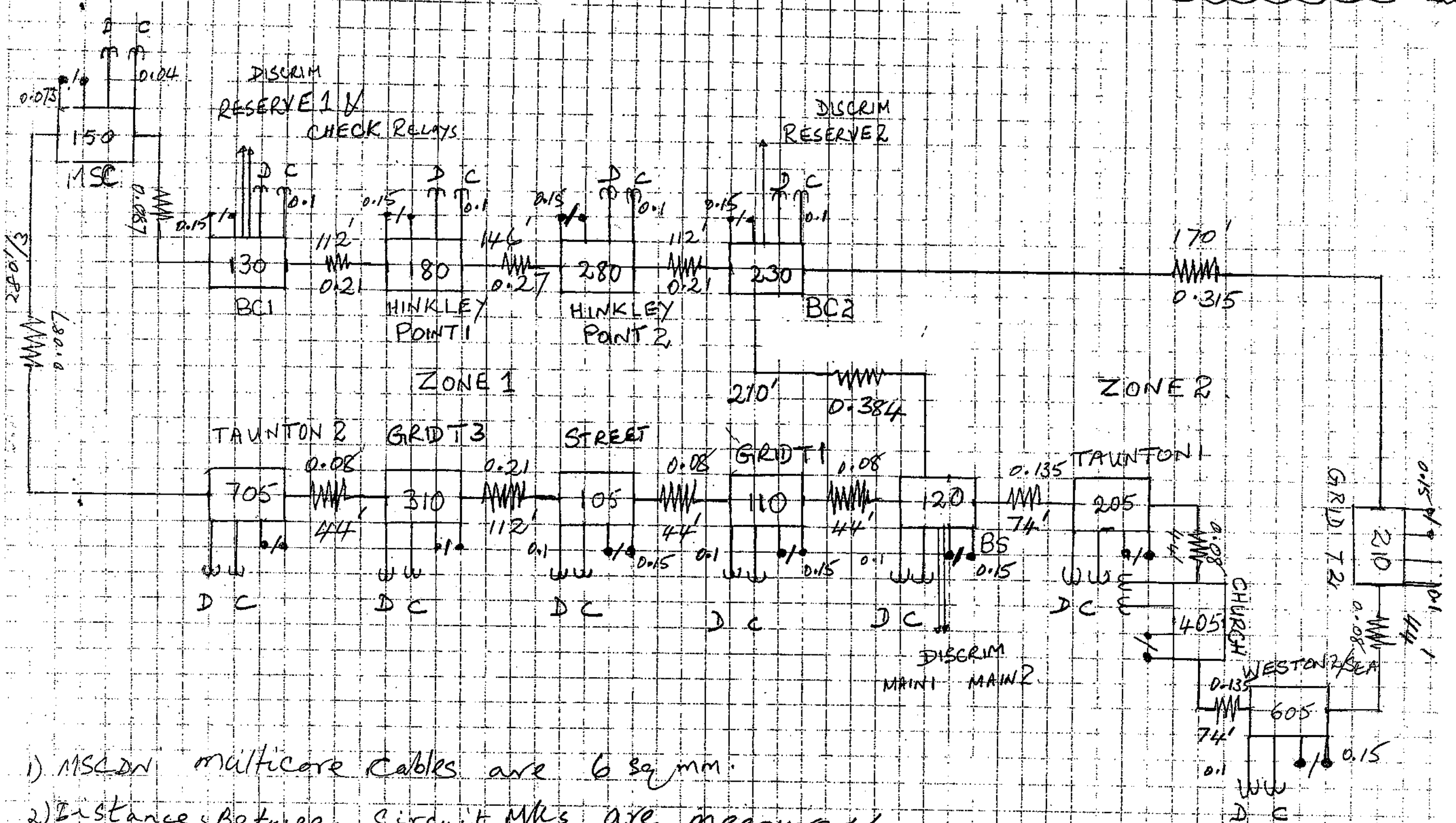
51814- tore-core N°3 (S1-2 S1-3 S2-3) + N°4



Les valeurs indiquées ci dessus sont des valeurs estimées - Aboves mentionned values are typical estimated values

18/11/02

BRIDGWATER BUSBAR PROTECTION



1) MSCDN multicore cables are 6 sq mm.

2) Distances between circuit Mk's are measured/ estimated from existing Layout drawing 21/21221 (2A35815)

3) The existing CT resistances are = 0.88 Ω

4). MSCDN (MSC) BB CT resistance = 0.914 Ω

FIG-1

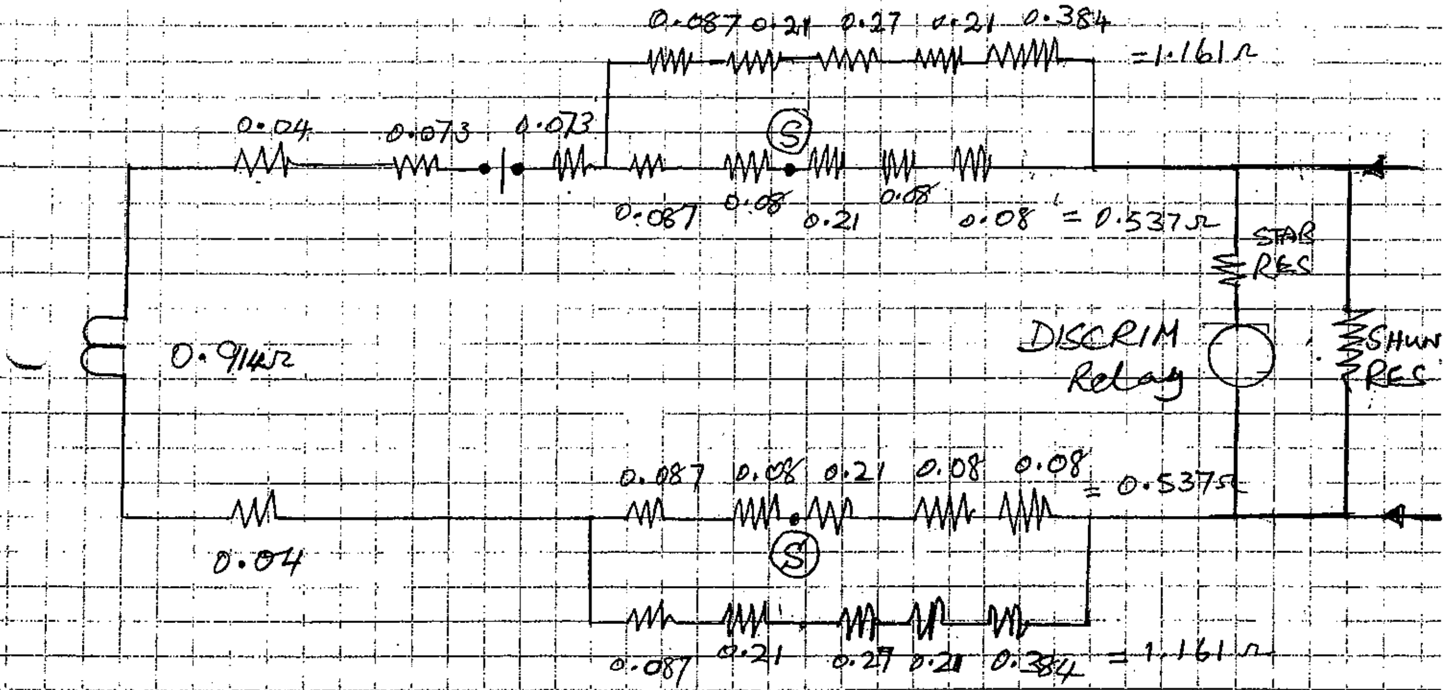
10/09/04 NA

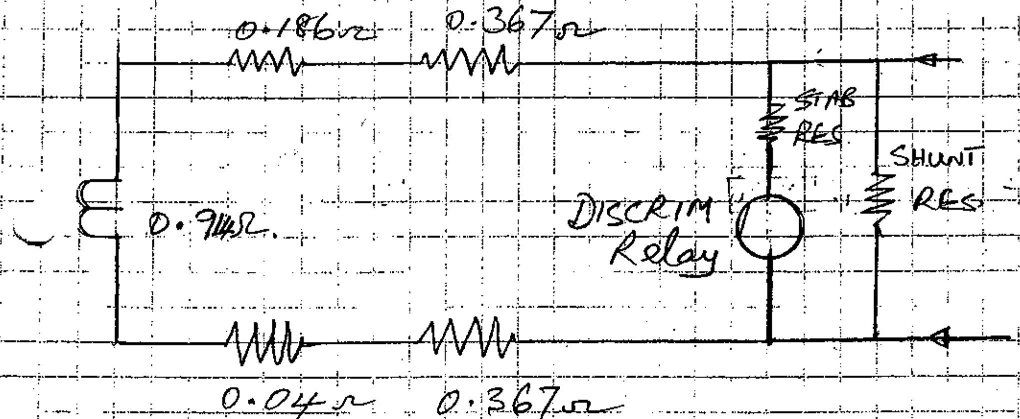
DISCRIM MAIN 1 (ZONE 1) PROTECTION (3)

VOLTAGE STABILITY LEVEL Vs FOR DISCRIM MAIN 1 (ZONE 1)

1) Ring Complete: i) MSC CT Saturates

ii) FAULT FEEDS AT MSC HV SIDE.





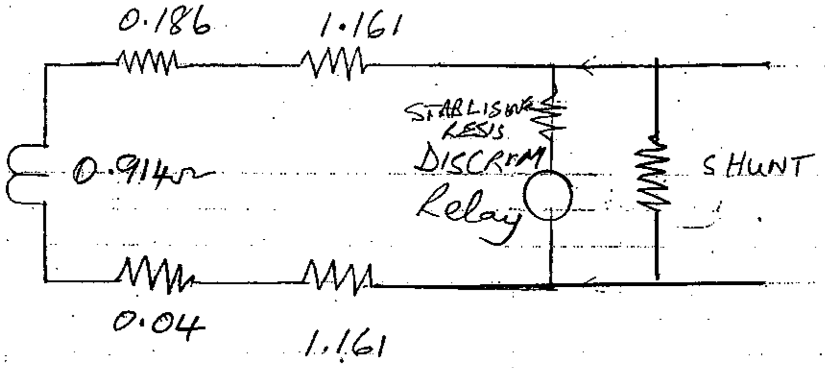
Discrim Main 1 and Main 2 relays are taken from Bus Section MK120.

a) Voltage across Discrim Main 1 Relay in Bus Section with fault current 21.9 kA,

$$V_S \geq \frac{21900}{500}(0.914 + 0.186 + 0.367 + 0.367 + 0.04)$$

$$V_S \geq 43.8 \times 1.884 = 82.5\,V$$

ii) As above with Ring Split

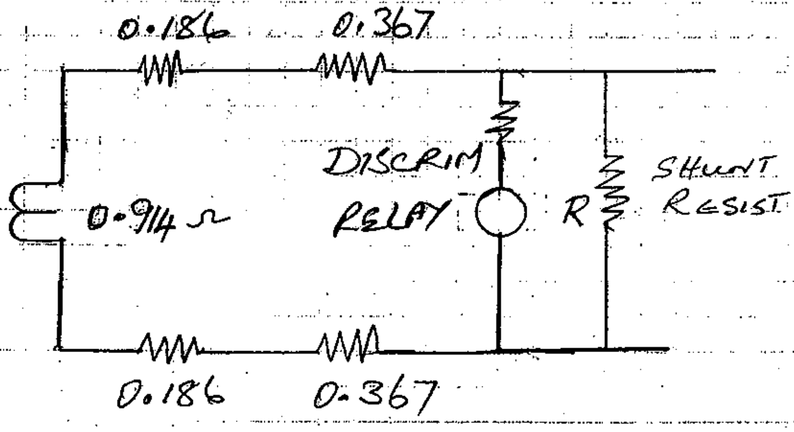


a) Voltage across Discrim Main 1 Relay from BS.

$$V_S \geq \frac{21900}{500}(0.914 + 0.186 + 1.161 + 1.161 + 0.04)$$

$$V_S \geq 43.8 \times 3.46 = 152\,V$$

iii) As Above But with Ring solid phase to phase fault



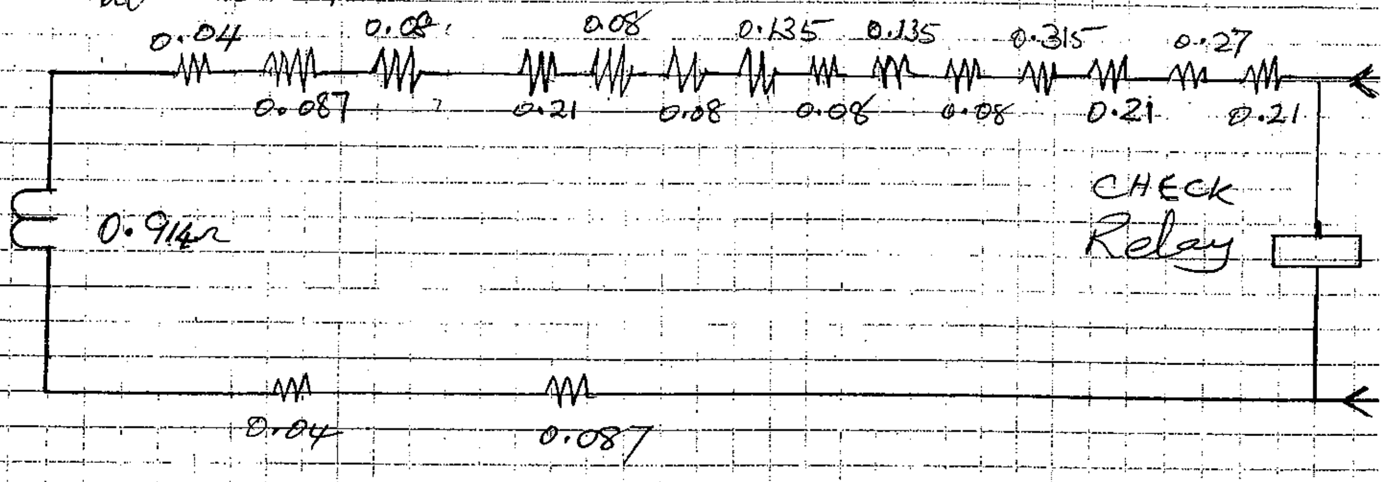
a) Voltage across Discrim Main Relay from Bus Section.

$$V_S \geq \frac{21900}{500} \times (0.914 + 0.186 + 0.367 + 0.367 + 0.186)$$

$$V_S \geq 43.8 \times 2.02 = 88.5V$$

CHECK ZONE PROTECTION

Check zone relay connection is taken from BC1 (MK130) and MSC CT Saturates and Fault feeds ~~at~~ MSC HV side.



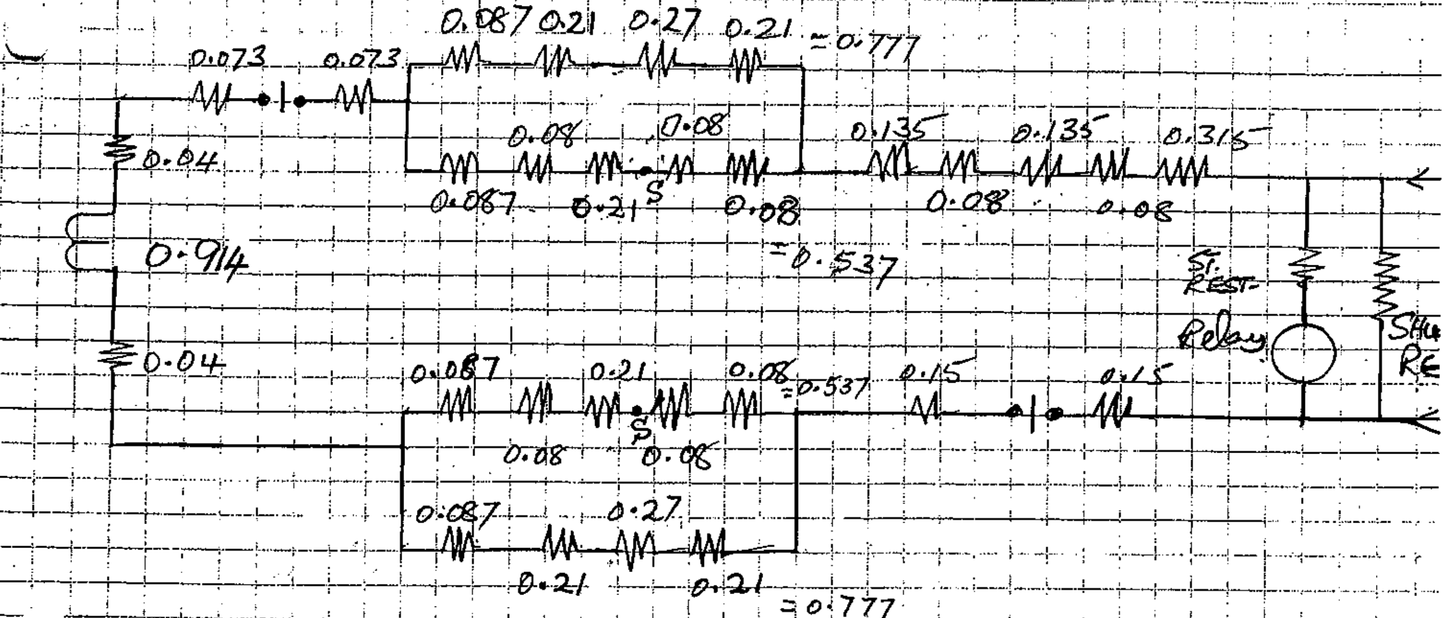
a) Voltage across Check Zone relay from BC1 (MK130)

$$V_s \geq \frac{21900}{500} \times (0.04 + 0.087 + 0.08 + 0.21 + 0.08 + 0.0 + 0.135 + 0.08 + 0.315 + 0.21 + 0.27 + 0.21 + 0.087 + 0.04 + 0.914)$$

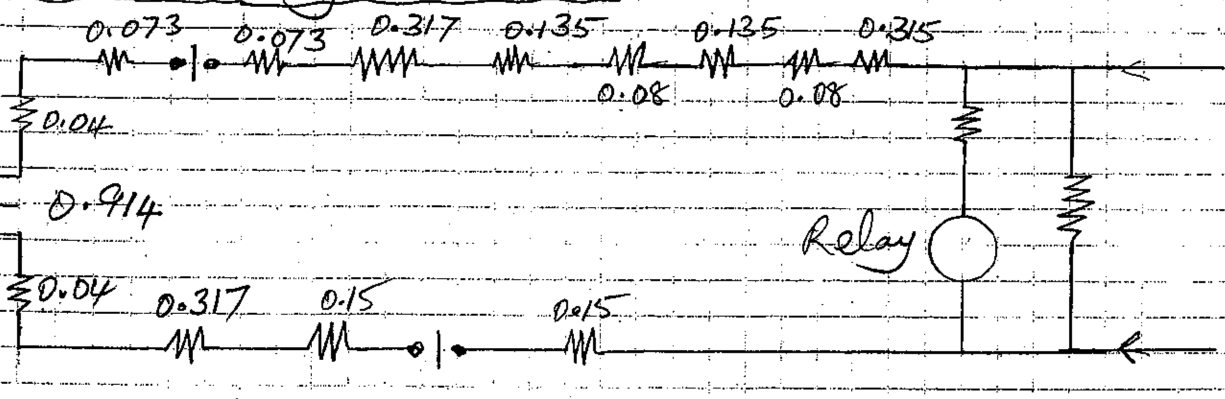
$$V_s \geq 43.8 \times 2.84 = 124.4V$$

DISCRIMINATION (RESERVE 2)

When two sections of Reserve Busbar are connected together with all or great majority of the circuits selected to the reserve busbar, the corresponding discriminating zones being then parallel connected through the Bus section isolator auxiliary switches.



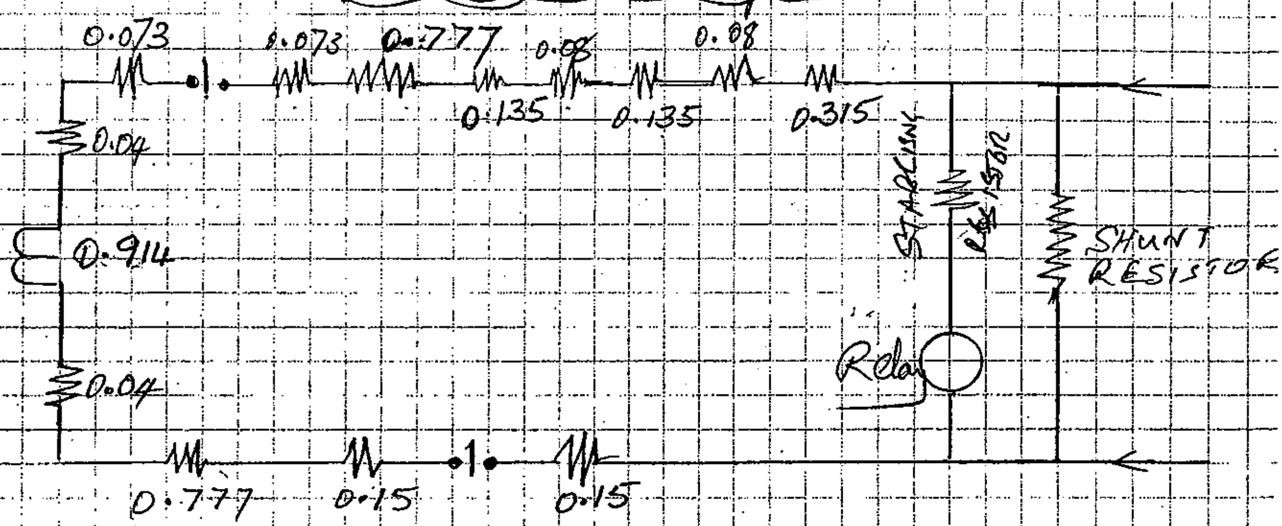
1) When the Ring is Solid



a) Voltage across Discrim Reserve 2 relay from BC2 with fault current of 21900A

$V_S \geq \frac{21900}{500} \times 2.82 = 123.5\ V$

2) When the Ring is split



a) With fault current of 21900A

$V_S \geq \frac{21900}{500} \times 3.75 = 164.2\ V$

10/09/04
[V. AYADURAI]

Appendix 15.1.7 Mesh Corner Protection.

PROTECTION CALCULATIONS TO RECOMMEND RELAY SETTINGS FOR THE 400kV INDIAN QUEENS SUBSTATION MESH CORNER 1 PROTECTION

FOR

NATIONAL GRID TRANSCO

ENGLAND

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High Voltage Systems

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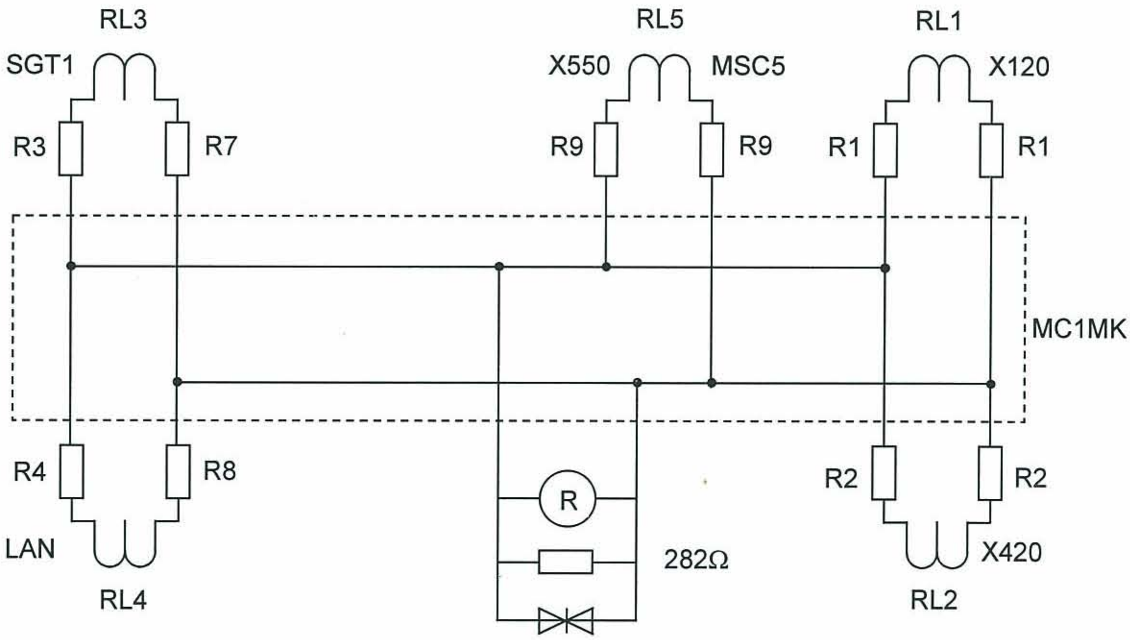
These design calculations have been prepared to investigate whether the existing Mesh Corner protection settings will be affected by the installation of the 225MVAr Re-locatable MSCDN at Indian Queen 400kV Substation.

In order to minimise the lead resistances of the new CT connections, a single core cable of 6.0 mm^2, a total of 90m length (40+50) from CT to PRR Primary Marshalling Field and from PRR to X120 (MK) are used with 75 m (two cores) length of 2.5 mm^2 of cable to the X120 (MK). One single core length includes CT leads from CT to the Portable Relay Room (PRR) Primary Marshalling Field and from the PRR (MK) to the X120 (MK) and two cores of cable length from the X120 (MK) to the Mesh Corner 1 (MC1) MK.

Throughout these calculations reference will be made to the existing Mesh Corner protection calculations ref. C820681&TC/SW/S5516 herewith attached. The existing Mesh Corner 1 protection CT Resistance and Lead Resistance, i.e. Loop Resistance (CT+2R), are available as part of the existing calculation.

Revised Lead Resistance Diagram (25/08/04)



MSC5 Mesh Corner 1

CT ratio = 2000/1 A
CT resistance = 3.58Ω
Knee point voltage $V_k \geq 540V$
Lead length (single way) = 90m (6.0 mm^2)
Single way of 90m = (3.08/1000) x 90 = 0.27Ω
Lead length (single core) = 75m (2.5 mm^2)
Two Cores of 75m = 75/2m = (7.41/1000) x 37.5 = 0.27Ω
Max Loop Resistance = CT resistance + 2 x Lead resistance (ohms)
= R_{CT} + 2R9
= 3.58 + 2(0.27+0.27) = 4.66Ω

∴ The calculated loop resistance for MSC1, 4.66 ohms is lower than 5.24 ohms (existing).

Data for Current Transformers

Current Transformer	Current Transformer Ratio	CT Turns Ratio	Secondary Resistance	Knee Point Voltage	Magnetising Current at Vs
X120 (exist)	2000/1	1/2000	2.8 Ω (RL1)	675	0.014 A
X420 (exist)	2000/1	1/2000	2.8 Ω (RL2)	675	0.014 A
SGT1 (exist)	2000/1	1/2000	2.8 Ω (RL3)	675	0.012 A
FEED (exist)	2000/1	1/2000	2.8 Ω (RL4)	675	0.014 A
MSC5 (new)	2000/1	1/2000	3.58Ω (RL5)	540	0.006 A

Lead Resistances

R1 = 0.67Ω (X120-CT), R2 = 0.39Ω (X420-CT), R3 = 1.17Ω (SGT1-CT), R4 = 0.48Ω (FEED-CT)

R7 = 0.57Ω (SGT1-CT), R8 = 0.19Ω (FEED-CT), R 9 = 0.78Ω (MSC5-CT)

Table of Loop Resistance for Mesh Corner 1 (CT resistance + 2 lead resistance (ohms))

Loop resistance	CT	2 Ways	Loop	Circuit
RL1+2R1	2.8	1.34	4.14	X120
RL2+2R2	2.8	0.78	3.58	X420
RL3+R3+R7	3.5	1.74	5.24	SGT1
RL4+R4+R8	2.8	0.67	3.47	LAND (FEEDER)
RL5+2R9	3.58	1.08	4.66	X550 (MSC5)

There are four FAC34 relays available on Mesh Corner 1 i.e. two relays for Mesh Corner, one relay for Feeder and one relay for SGT1.

a) Main Mesh Corner 1 protection is (existing) High Impedance Voltage relay FAC34

Existing relay setting

FAC34 relay setting	=	175V
Setting resistor	=	282Ω
CT ratio	=	2000/1A
Metrosil		

Calculation

Fault current for stability $= \dfrac{35000 \times 10^3}{\sqrt{3} \times 400}$ A

$= 50.518 \times 10^3$ A

∴ Maximum secondary fault current $= \dfrac{50.52 \times 10^3}{2000}$

$= 25.26$ A

The calculated loop resistance 4.66 ohms is lower than the existing loop resistance 5.24 ohms.

$V_s \geq 25.26 \times 4.66$ (V)

$= 118$V

However, the existing setting on FAC34 relay = 175V

The magnetising current of RL5 at 175V = 0.006A

The Primary operating current with ALL Circuits in service from the existing calculations (1975) = 1906A.

Due to new MSC5, the primary current may increase by 0.006 x 2000 = 12A

<u>Primary Operating Current (P.O.C.)</u>

Magnetising Current of X120 CT at Vs Im1	=	0.014A
Magnetising Current of X420 CT at Vs Im2	=	0.014A
Magnetising Current of SGT1 CT at Vs Im3	=	0.012A
Magnetising Current of FEEDER CT at Vs Im4	=	0.014A
Protective Relay Operating Current at Vs Ir	=	0.02A
Supervision Relay Operating Current at Vs Isr	=	0.01A
Metrosil Surge Diverter Current at Vs Ime	=	0.063A
Magnetising Current of MSC5 CT at Vs Im5	=	0.006A
Shunt Resistor Rsr	=	282 ohms (existing)

Note: Except Im5, other Magnetising Currents are taken from the existing calculation. One copy of the existing calculation is attached with this calculation.

P.O.C. = N (Im1 + Im2 + Im3 + Im4 + Im5 + 4 Ir + Isr + 3 Ime + Vs/ Rsr)

= 2000 (3 x 0.014 + 0.012 + 0.006 + 4 x 0.02 + 0.01 + 3 x 0.063 + 175/282)

= 1918A

Supervision Relay (all circuits energised)

Supervision Relay is set at 10% of the full load current of Transformer circuit i.e. 10% of 1050A = 105A.

With the Supervision Relay VTX 31 settings of 10V (existing):

Magnetising Current of X120 CT	Im1	=	0.002A
Magnetising Current of X420 CT	Im2	=	0.01A
Magnetising Current of SGT1 CT	Im3	=	0.002A
Magnetising Current of FEED CT	Im4	=	0.002A
Magnetising Current of MSC5 CT	Im5	=	0.0008A

Supervision Relay Operating Current	Isr	=	0.0002A
Protective Relay Operating Current	Ir	=	0.00115A
Shunt Resistor (SR) Operating Current	Is	=	0.0334A

POC = 2000 (Im1+ Im2 + Im3 + Im4 + Im5 + Isr +4 Ir + Is)
= 2000 (0.002 + 0.01 +0.002 + 0.002 + 0.0008 + 0.0002 + 4x0.00115 + 0.0334)
= 2000 x 0.055
= 110A

The Recommended Voltage setting = 10V (existing)

Conclusion

The calculations provided above show that the existing Mesh Corner protection settings will not be affected by the connection of MSC5 to Mesh Corner 1. Therefore Mesh Corner 1 protection settings shall therefore remain as per Indian Queens 400kV Substation existing Mesh Corner1 Protection.

Main Protection setting (FAC34)

FAC 34 relays setting	=	175V (existing)
Setting resistor	=	282 ohms (existing)
Current Transformer Ratio	=	2000/1A (existing)
VTX31 Supervision relay setting	=	10V (existing)

Metrosils (existing)

V AYADURAI
25 August 2004

APPENDIX

1) Calculated Performance of Overall Differential Mesh Corner 1 Protection (GEC-AEI Reference C 820681 and TC/SW/S5516)

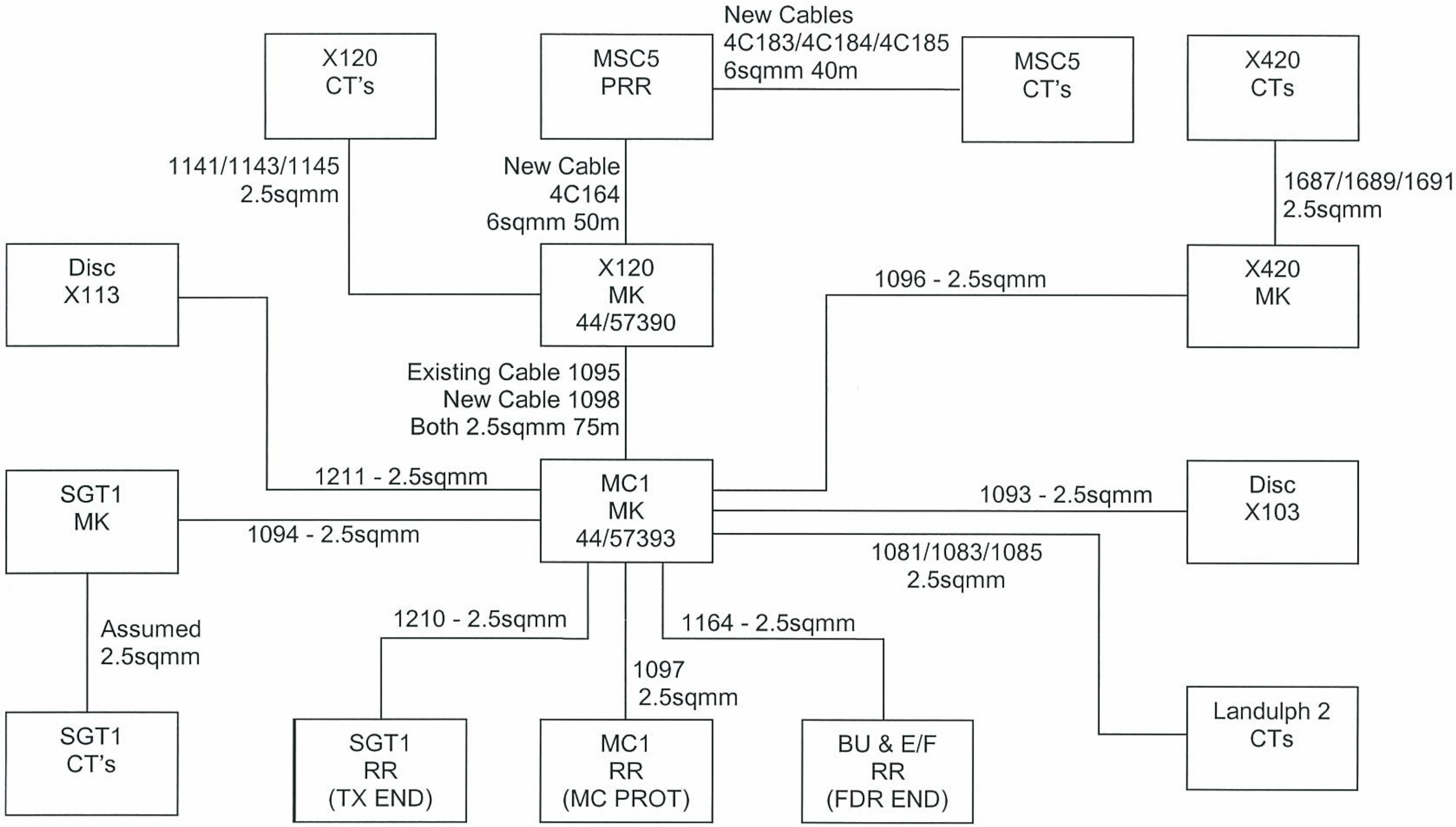
2) Circuit Diagram of Mesh Corner AC Circuits (Drawing No. 42/49431)

3) Current Transformer Name Plate

4) Current Transformer Magnetising Curve

5) SKETCH NUMBER: APB/INDQ4/MCP-Revision A

Indian Queens 400kV Substation – Mesh Corner 1 Circulating Current Protection Cabling Arrangement



SKETCH NUMBER: APB/INDQ4/MCP – Revision A

Appendix 15.2 Design Basis For Mechanically Switched Capacitor (MSC) Banks.

DESIGN BASIS FOR MECHANICALLY SWITCHED CAPACITOR BANKS FOR CEB

The primary requirement is to provide reactive power support to the 33kV system at 5 substations. This consists of :

- 4 x 5 MVAr at Pannipitiya substation
- 4 x 20 MVAr at Pannipitiya substation
- 2 x 10 MVAr at Athurugiriya substation
- 2 x 10 MVAr at Ampara substation
- 2 x 5 MVAr at Chilaw substation
- 2 x 5 MVAr at Thulhiriya substation

Thus there are three different designs for 16 banks.

A simple harmonic assessment was performed. This involved considering the interaction between the various combinations of capacitor banks and the existing harmonic distortion. This enabled components to be rated for the expected duty. Certain assumptions have been made :

- The two 33kV transformer tertiary systems at Pannipitiya are never connected together so the maximum reactive power on one busbar is 50 MVAr.
- The background distortion is considered never to exceed 4%/3rd, 4%/5th and 2%/7th. This is modelled as current sources producing this distortion with a 10MW load and no capacitors on the busbar.
- No other power factor correction or harmonic filters exist on the 33kV network near the substation.
- No other substantial sources of harmonic distortion exist at the local HV system (220kV, 132kV).

Transient switching studies of the capacitor banks has been performed. This has been studied in all combinations. A reactor in series with the capacitors in each phase has been selected to limit high frequency transients from such events.

1) 5.0 MVAr CAPACITOR BANK

Refer to Cooper's drawing number CEB01023N.

Number of capacitor units/per half phase	=	2 in series units
	=	2 units
Total number of capacitor units/phase	=	4 off
Total number of capacitor units/3 phase	=	12 off
Rating of each capacitor unit	=	450 kVAr
Total MVAr output from capacitor bank at	=	450 x 12
33.43kV and 50 Hz (system frequency)	=	5.40 MVAr (3 phase Generation at 50 Hz)

a) Capacitor Unit

Rated voltage (V)	=	9900V = 9.9kV
Rating of each capacitor unit (Q_{SC})	=	450 kVAr

Capacitance of each capacitor unit :

System fundamental frequency 50 Hz

$$Q_{SC} = \frac{V^2}{jX_{SC}}$$

Capacitive reactance at 50 Hz $\quad X_{SC} = \dfrac{-j9.9^2 \times 10^6}{450 \times 10^3} = -j217.79\,\Omega$

$\therefore$ Capacitance (C) of each capacitor unit $= \dfrac{1 \times 10^6}{2 \times \pi \times 50 \times 217.79}$

$$C = 14.615\ \mu F$$

Total capacitance/phase is equivalent to 1 capacitor unit

$$C^1 = 14.615\ \mu F$$

b) Limiting Reactor (Air Insulated)

Refer to Trench drawing number 1-23764

Reactor current rating at 33kV nominal voltage and system frequency 50 Hz = 105A

Reactor Inductance (L) = 0.5mH

Inductive reactance at 50 Hz (X_L) = $j\omega L$

$$X_L = j2 \times \pi \times 50 \times 0.5 \times 10^{-3}\ \Omega$$

$$= j\,0.157\ \Omega \,/\, \text{phase}$$

c) Combination of Capacitor Bank and Reactor

The circuit is a series LC of 0.5mH and 14.615 μF

Capacitance Impedance at fundamental frequency X_{SC} / phase

$$X_{SC} = \frac{-j1 \times 10^6}{2 \times \pi \times 50 \times 14.615} = -j\,217.79\,\Omega$$

$\therefore$ Phase Impedance $= -j\,217.79 + j\,0.157 = -j\,217.64\,\Omega$

$\therefore$ Nominal 50 Hz current at 33kV $= \dfrac{33 \times 10^3}{\sqrt{3}\ \ 217.64}$

$$= 87.5A$$

$\therefore$ Single Phase Capacitor Volts = 87.5 x 217.79V

= 19.06kV

$\therefore$ 3 Phase Capacitor Volts = 33.013kV

$\therefore$ Capacitor 3 phase Output (generation) = $\dfrac{33.013^2 \times 10^6}{217.79}$

= 5.004 MVAr

$\therefore$ Inductor 3 phase (Absorption) = $3 \times 87.5^2 \times 0.157$ VAr

= 0.0036 MVAr

$\therefore$ Net output (Generation) from combined Capacitor Bank with Reactors = 5,004 – 0.0036

= 5.00 MVAr

2) 10.0 MVAr CAPACITOR BANK

Refer to Cooper's drawing number CEB01024N.

Number of capacitor units/per half phase	=	2 in parallel with 2 in series units
	=	4 units
Total number of capacitor units/phase	=	8 off
Total number of capacitor units/3 phase	=	24 off
Rating of each capacitor unit	=	436 kVAr
Total MVAr output from capacitor bank at	=	436 x 24
33.43kV and 50 Hz (system frequency)	=	10.464 MVAr (3 phase Generation at 50 Hz)

a) Capacitor Unit

Rated voltage (V) = 9750V = 9.75kV

Rating of each capacitor unit (Q_{SC}) = 436 kVAr

Capacitance of each capacitor unit :

System fundamental frequency 50 Hz

$$Q_{SC} = \frac{V^2}{jX_{SC}}$$

Capacitive reactance at 50 Hz $\quad X_{SC} = \dfrac{-j9.75^2 \times 10^6}{436 \times 10^3} = -j218.03\Omega$

$\therefore$ Capacitance (C) of each capacitor unit = $\dfrac{1 \times 10^6}{2 \times \pi \times 50 \times 218.03}$

$C = 14.599\ \mu F$

Total capacitance/phase is equivalent to 2 capacitor units in parallel

$$C^{1} = 29.198\ \mu F$$

b) Limiting Reactor (Air Insulated)

Refer to Trench drawing number 1-23764

Reactor current rating at 33kV nominal voltage and system frequency 50 Hz	=	209A
Reactor Inductance (L)	=	0.5mH
Inductive reactance at 50 Hz (X_L)	=	$j\,0.157\Omega$/phase

c) Combination of Capacitor Bank and Reactor

The circuit is a series LC of 0.5mH and 29.198 μF

Capacitance Impedance at fundamental frequency X_{SC} / phase

$$X_{SC} = \frac{-j1 \times 10^6}{2 \times \pi \times 50 \times 29.198} = -j\,109.02\,\Omega$$

$\therefore$ Phase Impedance $= -j\,109.02 + j\,0.157 = -j\,108.86\ \Omega$

$\therefore$ Nominal 50 Hz current at 33kV $= \dfrac{33 \times 10^3}{\sqrt{3}\ \ 108.86}$

$= 175.0\text{A}$

$\therefore$ Single Phase Capacitor Volts $= 175.0 \times 109.02\text{V}$

$= 19.08\text{kV}$

$\therefore$ 3 Phase Capacitor Volts $= 33.05\text{kV}$

$\therefore$ Capacitor 3 phase Output (generation) $= \dfrac{33.05^2 \times 10^6}{109.02}$

$= 10.02$ MVAr

$\therefore$ Inductor 3 phase (Absorption) $= 3 \times 175^2 \times 0.157$ VAr

$= 0.0144$ MVAr

$\therefore$ Net output (Generation) from combined Capacitor Bank with Reactors $= 10.02 - 0.0144$

$= 10.006$ MVAr

3) 20 MVAr CAPACITOR BANK

Refer to Cooper's drawing number CEB01022N.

Number of capacitor units/per half phase	=	3 in parallel with 2 in series units
	=	6 units
Total number of capacitor units/phase	=	12 off
Total number of capacitor units/3 phase	=	36 off
Rating of each capacitor unit	=	568 kVAr
Total MVAr output from capacitor bank at	=	568 x 36
33.43kV and 50 Hz (system frequency)	=	20.448 MVAr (3 phase Generation at 50 Hz)

a) Capacitor Unit

Rated voltage (V) = 9650V = 9.65kV

Rating of each capacitor unit (Q_{SC}) = 568 kVAr

Capacitance of each capacitor unit :

System fundamental frequency 50 Hz

$$Q_{SC} = \frac{V^2}{jX_{SC}}$$

Capacitive reactance at 50 Hz $\quad X_{SC} = \dfrac{-j9.65^2 \times 10^6}{568 \times 10^3} = -j163.948\,\Omega$

$\therefore$ Capacitance (C) of each capacitor unit $= \dfrac{1 \times 10^6}{2 \times \pi \times 50 \times 163.948}$

$$C = 19.415\ \mu F$$

Total capacitance/phase is equivalent to 3 capacitor units in parallel

$$C^1 = 58.246\ \mu F$$

b) Limiting Reactor (Air Insulated)

Refer to Trench drawing number 1-23764

Reactor current rating at 33kV nominal voltage and system frequency 50 Hz = 418A

Reactor Inductance (L) = 0.5mH

Inductive reactance at 50 Hz (X_L) = $j\,0.157\ \Omega$ / phase

d) Combination of Capacitor Bank and Reactor

The circuit is a series LC of 0.5mH and 58.246 μF

Capacitance Impedance at fundamental frequency X_{SC} / phase

$$X_{SC} = \frac{-j1 \times 10^6}{2 \times \pi \times 50 \times 58.246} = -j\,54.649\,\Omega$$

$\therefore$ Phase Impedance $= -j\,54.649 + j\,0.157 = -j\,54.49\,\Omega$

$\therefore$ Nominal 50 Hz current at 33kV $= \dfrac{33 \times 10^3}{\sqrt{3} \quad 54.49}$

$= 349.6A$

$\therefore$ Single Phase Capacitor Volts $= 349.6 \times 54.649V$

$= 19.11kV$

$\therefore$ 3 Phase Capacitor Volts $= 33.10kV$

$\therefore$ Capacitor 3 phase Output (generation) $= \dfrac{33.10^2 \times 10^6}{54.649}$

$= 20.048$ MVAr

$\therefore$ Inductor 3 phase (Absorption) $= 3 \times 349.6^2 \times 0.157$ VAr

$= 0.0575$ MVAr

$\therefore$ Net output (Generation) from combined Capacitor Bank with Reactors $= 20.048 - 0.0575$

$= 19.99$ MVAr

$= 20.00$ MVAr

Three Capacitor Banks are configured as plain capacitors with inrush limiting reactors.

The inrush limiting reactor for all three designs is 0.5mH, but of different current ratings. This results, in the case of 5 MVAr Capacitor Bank in a lowest tuned frequency for the circuit of 37th harmonic, in the case of 10 MVAr Capacitor Bank in a lowest tuned frequency for the circuit of 26th harmonic, and in the case of 20 MVAr Bank in a lowest tuned frequency for the circuit of 18.5th harmonic so that the combination of inrush reactor and capacitor is just a plain capacitor for system analysis purposes.

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PRINCIPAL PROJECT ENGINEER
31 January 2002

Appendix 15.3 SLDs For MSCDNs And MSCs At Different System Voltages

SINGLE LINE DIAGRAM OF 400 KV & 275KV MSCDN'S SHOWING MINIMUM LIGHTING IMPULSE LEVELS

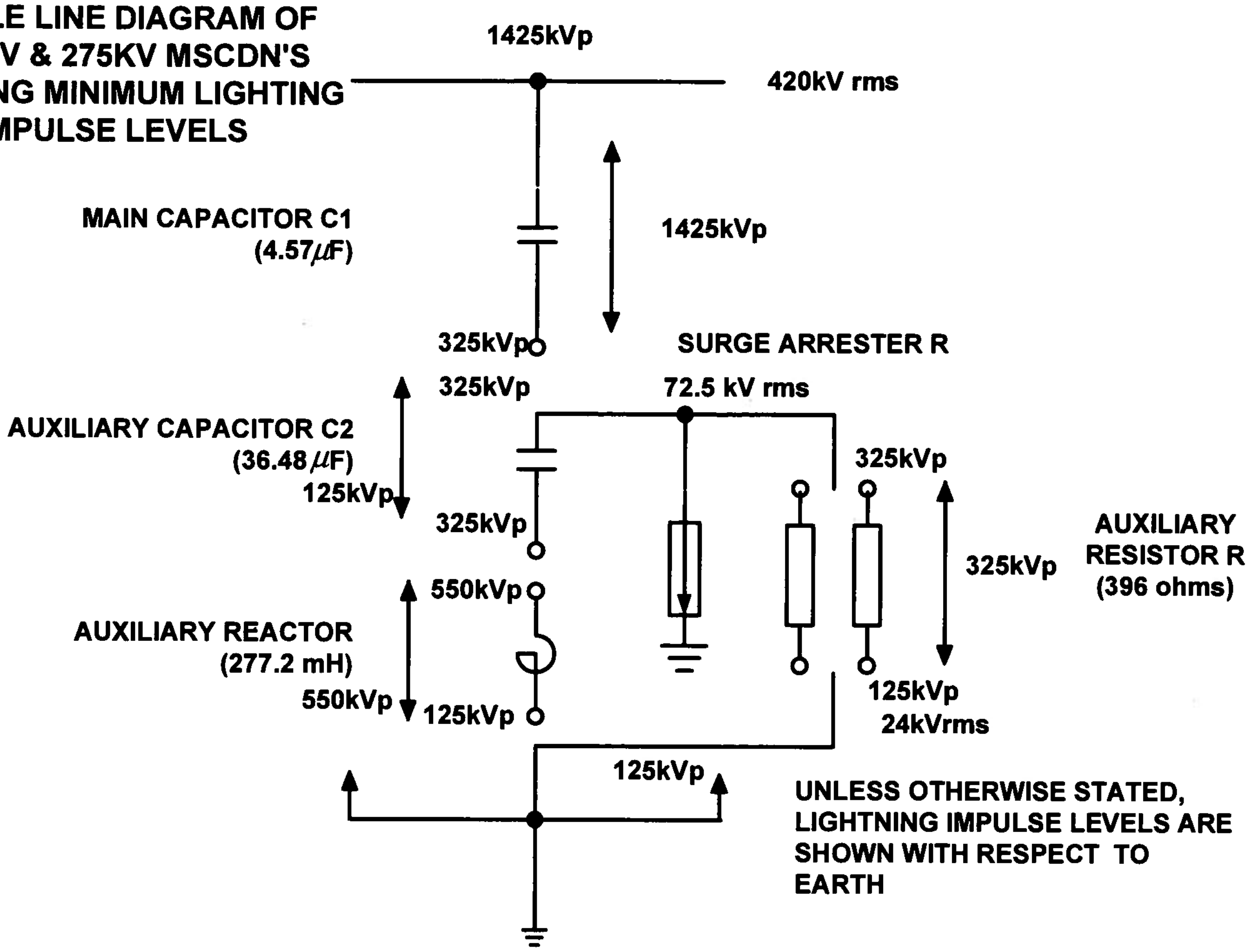


Figure 1 (a) 400 kV,225MVAr MSCDN
Designed / Installed / Commissioned : Typical Fleet...etc

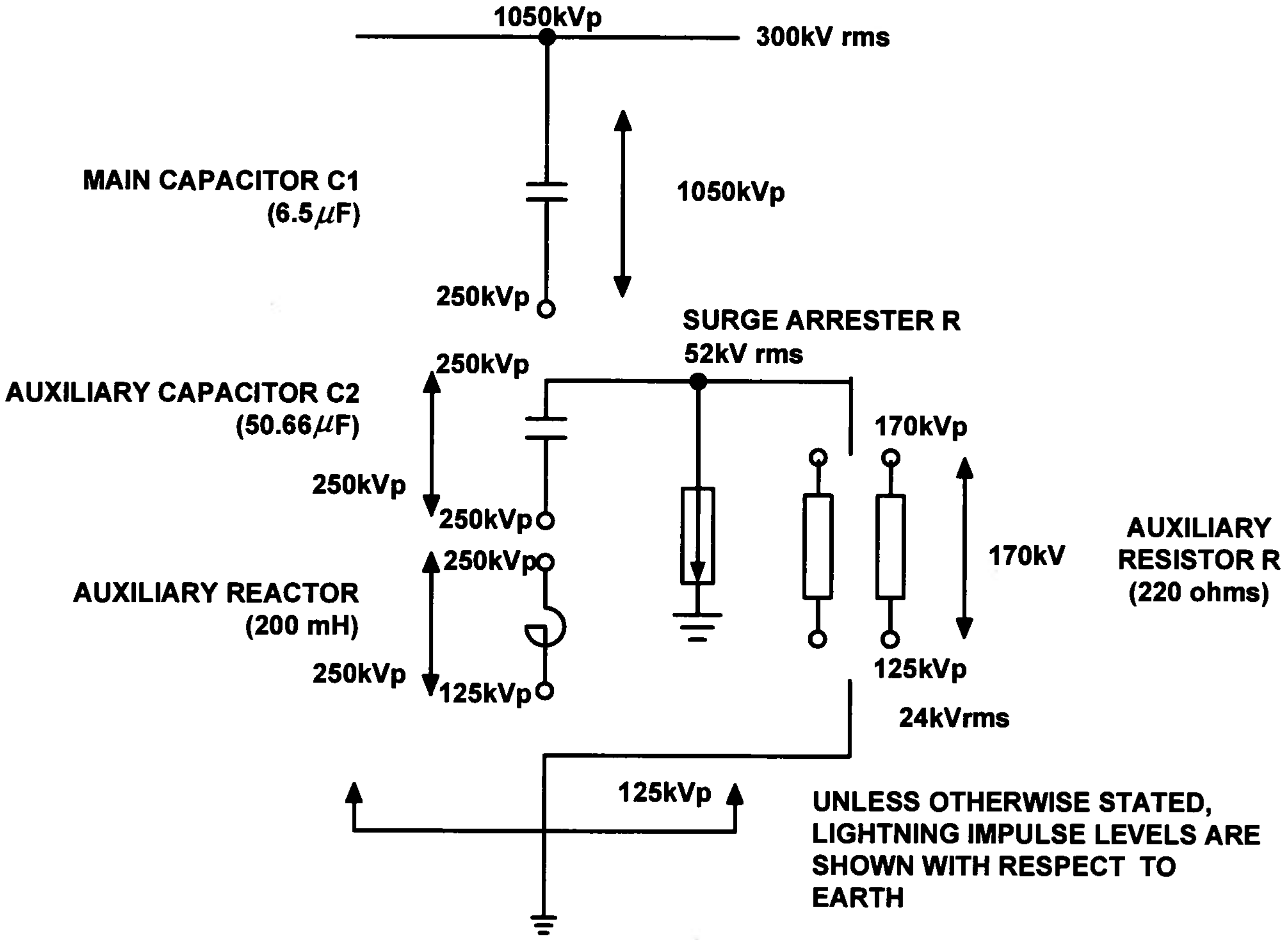


Figure 1 (b) 275kV, 150MVAr MSCDN
Designed / Installed / Commissioned : Typical Blyth...etc

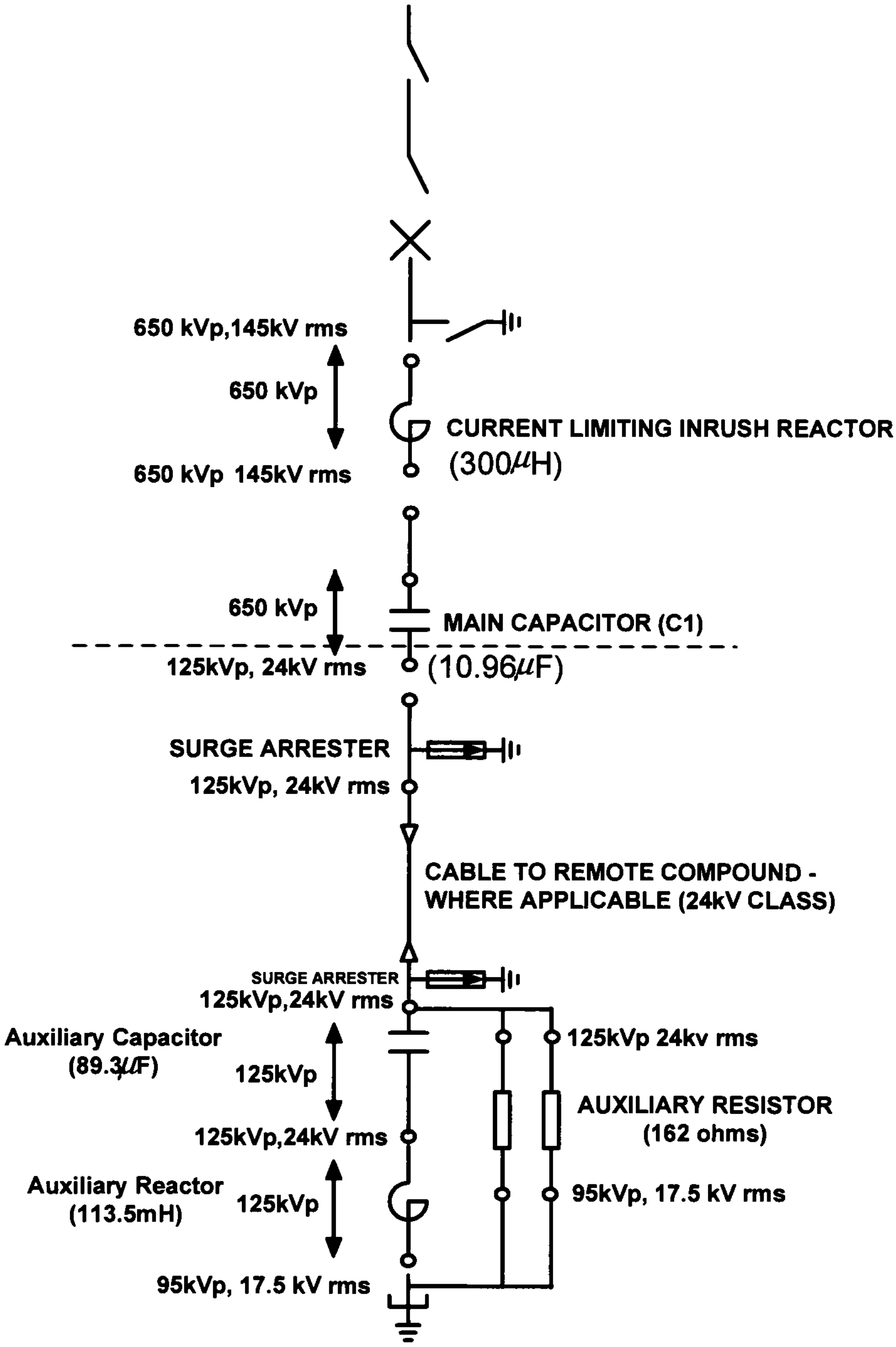


FIG. 1(a)

ADAPTION OF EXISTING 132kV 60/60 MVAr MSC TO MSCDN
Designed / Installed / Commissioned : Typical Bradford West etc

AREVA	AREVA T&D UK Ltd Systems	
Title: Enter the title of the drawing in this box or leave it blank		
Drawing No: Drawing Number	Tender Ref: Tender Number	
Date: Date	Issue Number: Issue No	Sheet: 1 of 1
Drawn By: Drawn By	Checked By: Checked By	

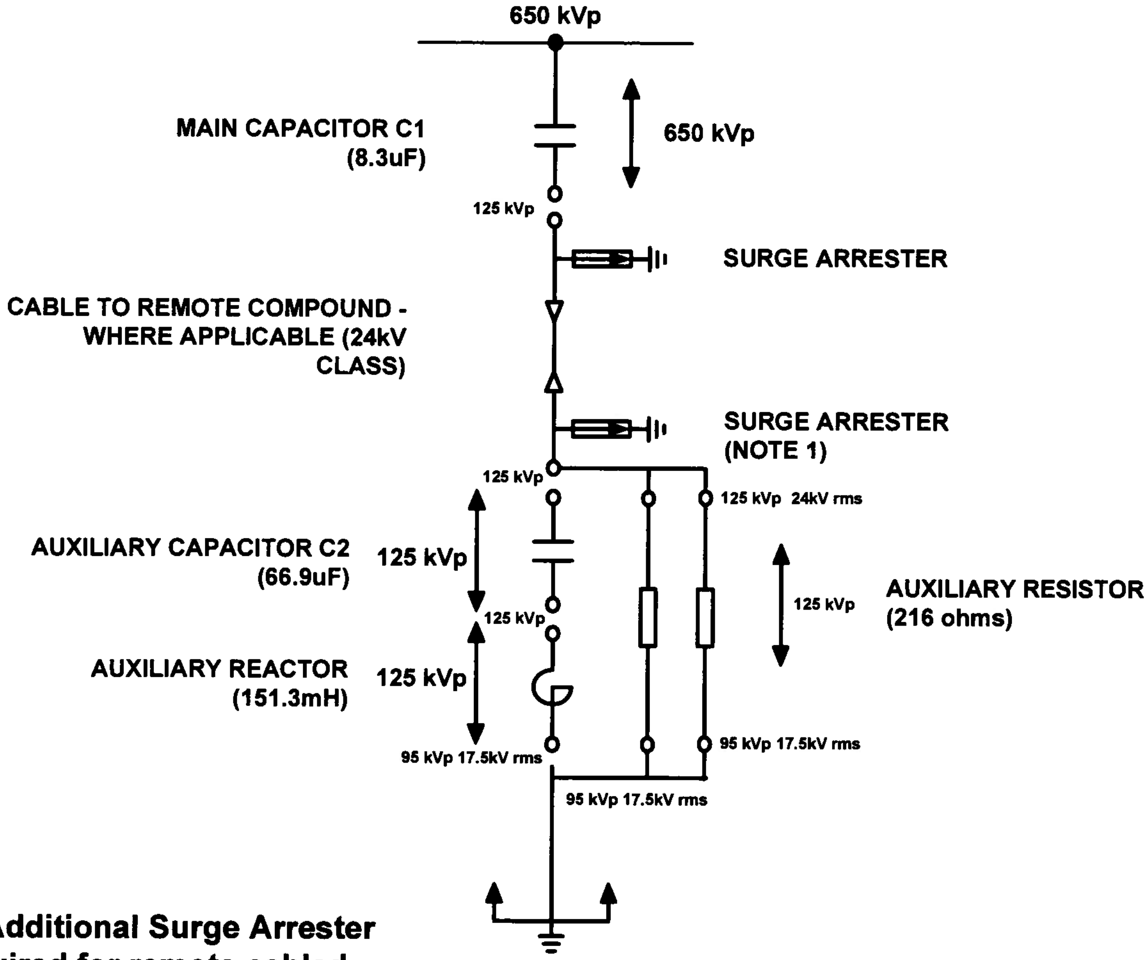
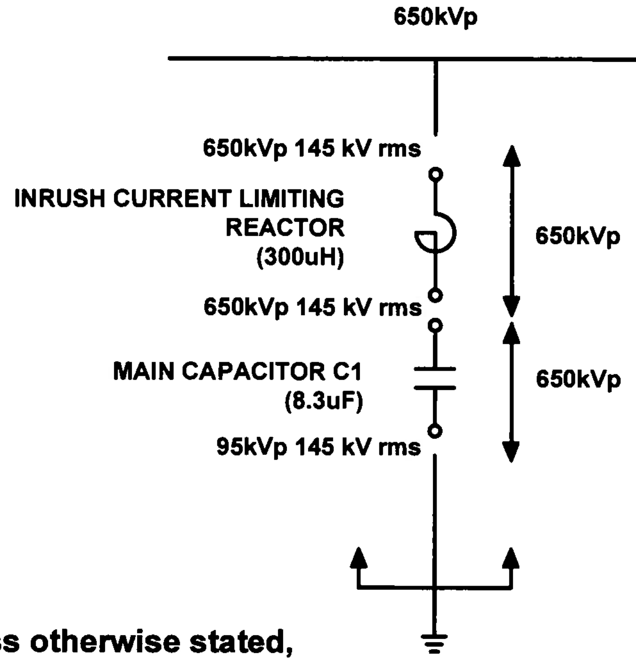


FIG. 1(c)

Note 1: Additional Surge Arrester only required for remote cabled compound.

Note 2: Unless otherwise stated,lighting impulse levels are shown with respect to earth

132kV 45 MVAr MSCDN
Designed / Installed / Commissioned : Typical Abham...etc



Note: Unless otherwise stated, Lighting impulse levels are shown with respect to earth

Figure 1 (d) 132kV 45 MVAr MSC
Design / Install /Commission: Typical Iron Acton ...etc

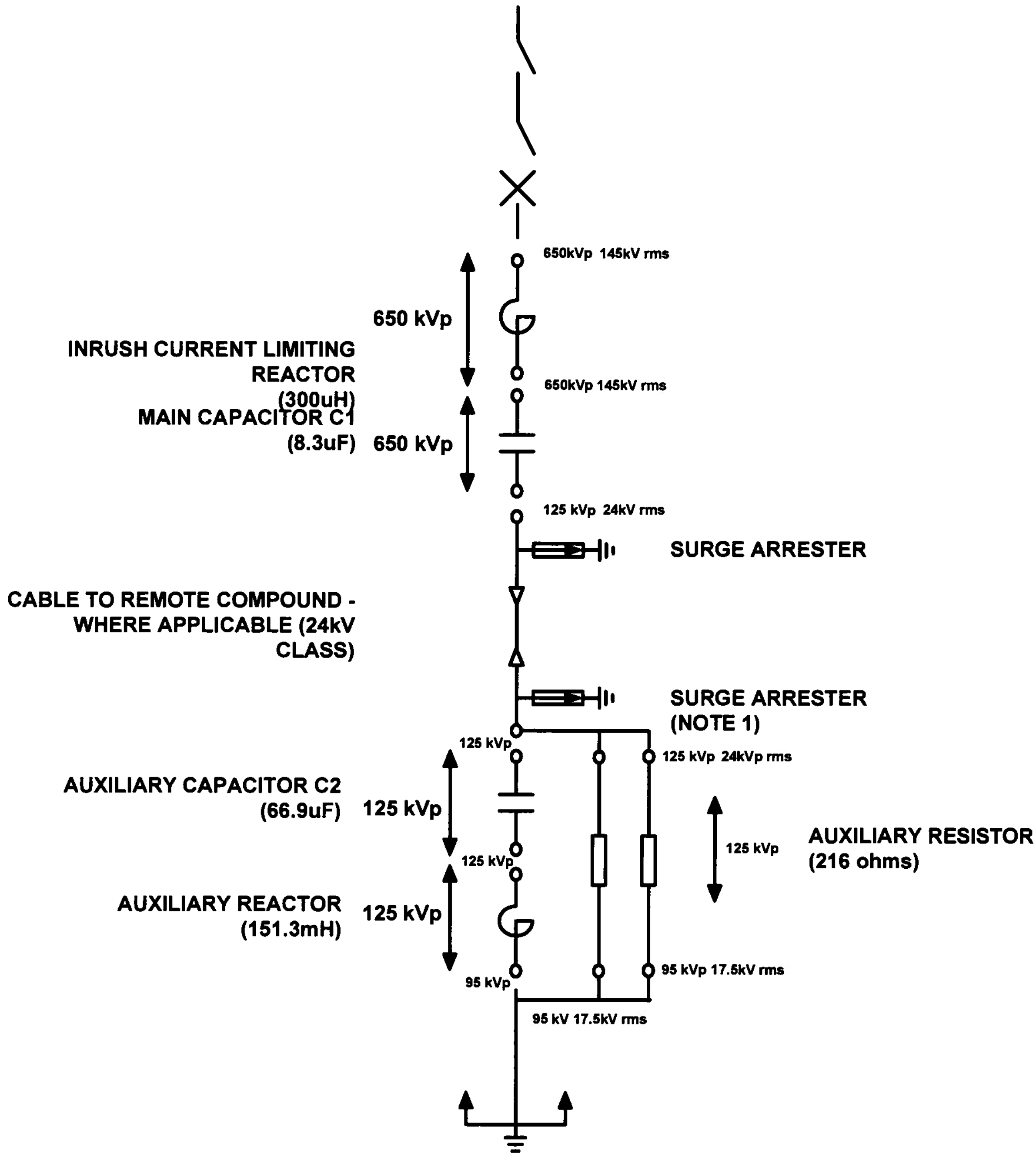


FIG. 1(b)

Adaption of Existing 132kV 45/45 MVAr MSC to MSCDN

Note 1: Additional Surge Arrester only required for remote cabled compound.

Appendix 15.4 Earthing Design Calculations.

DESIGN CALCULATIONS AND SUPPORTING INFORMATION FOR THE SUBSTATION EARTHING SYSTEM AT 400KV NORTON SUBSTATION

FOR

THE NATIONAL GRID COMPANY plc

NORTHERN DIVISION

Report By: V Ayadurai

February 1993

GEC ALSTHOM
T&D SUBSTATION PROJECTS LIMITED

FEBRUARY 1993

DESIGN CALCULATIONS AND SUPPORTING INFORMATION FOR THE SUBSTATION EARTHING SYSTEM AT 400KV NORTON SUBSTATION

FOR

THE NATIONAL GRID COMPANY plc

NORTHERN DIVISION

LIST OF SYMBOLS

The symbols used in this report are as follows:-

E = Phase to Neutral Voltage, V

I_e = Current Induced in Overhead Earth Wire Path, A

I = Current to Earth Buried Conductor, A/m

L = Length of Buried Earthing Conductor, m

N = Total Number of Earth Rods

R = Total Resistance of Electrode or Site Earthing System to Remote Earth, Ω

R_1 = Positive Sequence Resistance, Ω/Phase

R_2 = Negative Sequence Resistance, Ω/Phase

R_0 = Zero Sequence Resistance, Ω/Phase

R_f = Estimated Minimum Resistance of Fault Itself, Ω

R_L = Resistance of an Infinitely Long Overhead Line or Cable Earthing Path as seen from the Station Earth Mesh, Ω

R_T = Average Tower Footing Resistance, Ω

ρ = Specific Soil Resistivity, Ωm

r = Effective Radius of Earth Electrode or System, m

t = Back-Up Protection Fault Clearance Time

X = Total Reactance of Earthing System to Remote Earth, Ω

X_1 = Direct-Axis, Positive-Sequence Reactance (Sub-Transient), Ω/Phase

X_2 = Negative Sequence Reactance, Ω/Phase

X_0 = Zero Sequence Reactance, Ω/Phase

Z_{moe} = Average Mutual Impedance Between Primary Conductors and Earth Wire, Ω/Phase

Z_{pe} = Average Self Impedance of Earth Wire with Earth Return, Ω/km or Ω/Span

l = Length of Earth Rods, m

LIST OF SYMBOLS - Continued . .

A	=	Area Occupied by Grid, m^2
D	=	Spacing Between Parallel Conductors, m
h	=	Depth of Burial of Grid, m
I_L	=	Line Fault Current, A
I_t	=	Tolerable Body Current for Current Duration, A
k_i	=	Current Distribution Factor
K_R	=	Constant Dependent on Number, Position and Length of Earth Rods Connected to the Grid
n	=	Number of Parallel Conductors/Cables/Lines
V	=	Grid Potential Rise (GPR), V
V_S	=	Step Voltage, V
V_T	=	Touch Voltage, V
V_x	=	Voltage at x Metres from Grid Edge
x	=	Distance from Grid, m
Z_L	=	Line Earthwire Chain Impedance to Earth, Ω
Z_T	=	Overall Impedance to Earth, Ω

ASSESSMENT OF RISE OF EARTH POTENTIALS AT 400KV SUBSTATION

A. CALCULATION OF THE EARTH IMPEDANCE AND SUBSTATION POTENTIAL RISE

1. INTRODUCTION

Faults on HV transmission systems are infrequent. Most of the faults occurring on overhead lines are due to lightning. Phase to earth faults in substations are rare, but the current can be large, owing to multiple infeeds from lines and generators.

The earth fault current must return to source via conducting paths including the general body of earth and line earth wires, cable sheaths, etc. These conducting paths can be expressed as an impedance from the substation, of the site earth electrodes in parallel with the tower footings and cable sheaths to the general body of the earth. The total impedance and current flowing determine the total voltage rise.

2. RESISTANCE OF THE SITE EARTH ELECTRODES

2.1 Resistance Due to Earth Mesh

The resistivity to earth of a buried circular plate of radius r in a soil of resistivity ρ is given by

$$R = \frac{\rho}{4r} \qquad (1)$$

The resistance obtainable within a given area will not be less than that obtained from a plate of the same area.

A very simple method can be employed by using a modification of the circular plate electrode formula equation (1) adding a second term as follows:-

$$R = \frac{\rho}{4r} + \frac{\rho}{L} \qquad (2)$$

As explained above 'r' is the radius in metres of a circular plate having the same area as that occupied by the grid; 'L' is the total length of buried conductor in metres and ρ is the resistivity in ohm-metre.

2.2 Resistance Due to Driven Rods

a) Resistance of a single rod is given by (3)

$$R = \frac{\rho}{2 \Pi l} \left(\ln \frac{8l}{d} - 1\right)$$

Where l is the length of the rod, d is the diameter of the rod, ρ is the soil resistivity in ohm-metre.

b) A simplified formula $R = \frac{\rho}{350}\ ohms$ (4)

can be used to calculate approximately the resistance of 12ft (3.658m) rod.

Where ρ is the soil resistivity in ohm cm and is relatively independent of the rod diameter. The resistance is approximately inversely proportional to the length of the rod over the range normally used in the substation work (8 to 18ft).

2.3 Resistance Due to Overhead Earth Wires and Overhead Line Tower Footings

The overhead line towers act as additional earth electrodes in parallel with the site earth electrode system. The impedance to earth of the overhead line earth wires and tower footing resistance should be considered if their values are known. The overhead line earth wire and tower footing resistances form a "ladder" network with the line terminal tower considered as being part of the site earth electrode. The formula used:- (5)

$$Z_L = \frac{Z_{pe}}{2} + \sqrt{Z_{pe} \times R_T}\ \Omega$$

2.4 Current Induced in Overhead Earth Wires

The current induced in overhead earth wire is given by: (6)

$$I_e = I_f \times \frac{Z_{moe}}{Z_{pe}}\ \text{Amps}$$

3. MAXIMUM CURRENT IN GROUND

The total earth fault current can return to source by four different paths:-

a) Via transformer neutrals connected to earth mesh.

b) Via cable sheaths due to induction from the unbalanced current in the primary conductors (as described in 2).

c) Via the site earth electrodes by conduction.

d) Via the overhead line earth wires/tower footings and cable sheaths by conduction.

The latter two paths in parallel form the total site impedance to earth, and it is the current flow through this combined path that causes the rise in earth potential.

4. CALCULATION OF MAXIMUM GROUND (GRID) POTENTIAL RISE (GPR)

The GPR is the maximum voltage that a station grounding grid may attain relative to a distant grounding point assumed to be at the potential of remote earth. The maximum rise in potential above remote earth will be E = IR, where I is the fault current in the grid and R is the ground - grid resistance.

5. CALCULATION OF TOUCH POTENTIAL

Touch potential (E_{touch}) is the tolerable potential difference between any point on the ground where a man may stand and any point which can be touched simultaneously by either hand.

Touch voltage is defined as the sum of the voltage across 1m of surface along a diagonal outside the corner of a grid with the voltage differences of the grid with the ground surface above. The corners are where the maximum voltage gradient occurs.

$$V_T = \frac{\rho V}{\pi R L}\left(\ln\ (h/d)^{0.5} + \left[\frac{1}{2h} + \frac{1}{D+h} + \frac{1-0.5^{n-2}}{D}\right]\right) k_i \tag{7}$$

For practical grid arrangements of r > 5m and for depth h > 0.25m and < 1m, a useful approximate expression providing values of V_T within 5% of the full expression is as follows:-

$$V_T = V\left[\frac{\ln\left((h/d)^{0.5} + \frac{1}{2h} + \frac{2}{D}\right)}{2.8\ (n+1)K_R}\right]k_i \tag{8}$$

Tolerable touch potential (E_{touch}) can be written as

$$E_{touch} = (R_B + R_E/2)\ I_B \tag{9}$$

$$= (1000 + 1.5\rho)\left(\frac{0.116}{\sqrt{t}}\right)$$

$$= \frac{116 + 0.17\rho}{\sqrt{t}}$$

6. CALCULATION OF STEP POTENTIAL

Step potential (E_{step}) is the tolerable potential difference between any two points on the ground surface which can be touched simultaneously by the feet.

Step voltage V_S is the voltage over 1m of surface diagonally outwards from a corner of a grid. The expression used is as follows:

$$V_S = \frac{\rho V}{\pi R L}\left[\frac{1}{2h} + \frac{1}{D + h} + \frac{1 - 0.5^{n-2}}{D}\right] k_i \tag{10}$$

For practical grid arrangements and with the same limitations as given in Item 5, a useful approximate expression for step voltage is as follows:-

$$V_S = V\,\frac{\left[\frac{1}{2h} + \frac{2}{D}\right] K_i}{2.8\ (n + 1) K_R} \tag{11}$$

Tolerable potential difference between two points (ie step potential E_{step}) can be written as

$$E_{step} = (R_B + 2\ R_F)\ I_B \tag{12}$$

$$= (1000 + 6\ \rho)\left(\frac{0.116}{\sqrt{t}}\right)$$

$$= \frac{116 + \overset{0.7}{\cancel{0.07}}\rho}{\sqrt{t}}$$

Where t is the duration of the fault current.

7. CALCULATION OF HOT ZONE RADIUS

The surface potential, created where current passes to or from grid, decays from the edge of the grid to nominal zero as the distance from the grid increases. The voltage profile around the substation will be developed mainly from the large buried grid with additional, superimposed voltage profiles around the rod electrodes and tower footings.

$$V_x = \frac{\rho I}{2\pi r} \text{ arc Sin } \frac{r}{x} \tag{13}$$

Where r is the radius of equivalent grid (plate) electrode.

$x = r + X$, where V_x is the ground voltage at a distance x metre from edge of substation grid electrode.

Substation fences are earthed separately from the earthing system of the substation at 2m from the perimeter of the earthing system.

8. GROUNDING

The function of the grounding system is to provide protection against danger to life and damage to equipment due to installation metalwork being raised to dangerous potentials relative to earth by either ground fault currents or lightning strike currents. The system also provides current carrying paths capable of accepting the rated ground fault current without creating hazards from fire and explosion.

9. CALCULATION OF EARTH CONDUCTOR SIZE

9.1 Below ground Earth Electrodes

For a 1.0 second duration and brazed joints, IEEE 80 recommends 10c mils/amp.

Ground fault current = 50×10^3A

$\therefore$ Required conductor size $= 50 \times 10 \times 10^3$ c mils

$= 500 \times 10^3$ c mils

$= 253\text{mm}^2$

This size is the total cross sectional area required to carry the fault current; because the mesh arrangement provides at least two parallel paths from any equipment earth connection the size of the conductor can be reduced.

However, TPS 3/2, fixed copper earthing connection for 400kV Substations, recommends (refer Table 1) for a maximum single phase fault current of 60kA for 1 second, the strip for single (spur) connections 50 x 6.3mm and strip for duplicate (loop) connections 50 x 4mm.

The declared fault current is 50kA for 1 sec so we have selected 150mm^2 (50 x 3mm) copper conductor for the earth grid conductors which are assumed to carry 60% of the total fault current. This size of conductor will provide more than adequate mechanical strength in the earth grid.

9.2 Above Ground Bonding System

The maximum fault current seen by the above ground bonding system is 50kA. With a fault period of 1 second (and assuming brazed joints) the required conductor size can be calculated as follows:

$$A = \frac{I}{\sqrt{\dfrac{LOG_{10}\left[\dfrac{T_m - T_a}{234 + T_a} + 1\right]}{33S}}} \tag{14}$$

Where

I is the current in ampere

A is copper cross-section in circular mils

S is time in seconds, during which current I is applied

T_m is maximum allowable temperature in °C

T_a is ambient temperature in °C (33°C)

Assumptions

Melting point of copper is 1083°C

Allowable temperature, brazed joints is 450°C (Copper/Copper)

Allowable temperature, bolted joints is 285°C (Aluminium/Copper)

$$A = \frac{50 \times 10^3}{\sqrt{\dfrac{Log_{10}\left[\dfrac{285 - 33}{234 + 33} + 1\right]}{33 \times 1}}} \tag{15}$$

$A = 534.6 \times 10^3$ cmils

$= 271\text{mm}^2$

However TPS 3/3, fixed aluminium earthing connections for 400kV substation recommends (Refer Table 1) for a maximum single phase fault current of 60kA for 1 second, the strip for single (spur) connections 80 x 6mm and strip for duplicate (loop) connections 50 x 6mm.

We have selected 300mm² (50 x 6mm) aluminium conductor for duplicate connections and 80 x 6mm for single (spur) connections.

Copper conductors are provided as "spur" connection to the buried earth grid and therefore must carry the total fault current. These conductors are brazed to the grid conductors to form a 'T' joint, allowing current to flow into the grid conductors in two parallel paths.

B. GAS INSULATED SUBSTATIONS (GIS)

Unlike a conventional open terminal substation, the gas insulated switchgear (GIS) equipment features a metal sheath enclosing a gas insulated switchgear and inner high voltage buses. The gas insulated switchgear equipment installations are basically inside the building with gas insulated trunking connections for feeder circuits passing through the GIS building walls to outside.

Some associated open terminal equipment such as capacitor voltage transformers, surge arresters and earth switches are mounted outside.

Inside the building an earth ring is run around the wall with all building steelwork stanchions bonded on to this ring. (Refer GEC ALSTHOM Drawing ZCEE00196). Bare copper tape spur connections are run inside the multicore trenches. These copper tapes are then connected to aluminium vertical collector tapes available on GIS equipment (Refer BHT Drawing Nos F201275, 276 and 277 , ... Assembly and Earthing Circuits) via a bi-metal joint made in accordance with recommended procedures. Also, GIS support steelwork are bonded to this copper tape system. Copper tape systems available inside the building trenches are then connected to the main earth grid system buried in the soil outside the building.

The earthing installation requirements are met by providing an arrangement of bare copper conductors, buried horizontally in the ground at a depth of 0.6m, which act as an earthing busbar. This is called 'main earth grid'.

The principal function of the earth grid is to connect points on high voltage equipment where earth fault currents originate, but it is also effective in reducing the overall resistance of the installation.

Copper driven (earth) rods are provided around the periphery at 10m intervals in the outdoor substation. Additional copper rods are also provided to earth surge arresters and capacitor voltage transformers (CVT's) associated with feeders to carry fully rated possible power frequency fault currents. These earth rods are connected to the main earth grid.

Bare copper conductors are laid in the trenches provided inside the control room, battery room, PLC room and switchgear room to allow the connection of equipment installed in the building.

This arrangement is connected to the Primary Equipment Earthing system in such a way as to minimise interference to Control and Protection equipment.

1. DESIGN BASIS

1.1 Calculation of Maximum Earth Fault Ground Current for Norton 400kV Substation

The maximum symmetrical rms value of earth fault current is calculated using the formula:-

$$I_f = \frac{3E}{3(R + jx) + 3R_f + (R_1 + R_2 + R_0) + j\,(X_1 + X_2 + X_0)}$$

This gives the total earth fault current, which at the point of fault is equal to the sum of the positive, negative and zero sequence currents.

The unbalanced current in all circuits feeding the fault is controlled entirely by the zero sequence impedance, ie impedance to earth.

The zero sequence currents induce a return current in the overhead earth wires of the circuits concerned.

Assuming fault resistance $R_f = 0$, R and X are very small and the supply resistance and reactance << X, the equation for the fault current can be simplified as:-

$$I_f = \frac{3E}{(R_1 + R_2 + R_3) + j\,(X_1 + X_2 + X_0)} \qquad (17)$$

i) **Norton - Hawthorn Pit (400kV Feeder Circuit)**

27.84km L6: $Z_1 = 0.53 + j\,7.74$ Ohms
$Z_0 = 2.92 + j\,22.05$ Ohms

Base:

Base Voltage = 400kV

Base (MVA) Rating = 100MVA

Base Impedance (Z_b) = $\frac{400^2}{100}$

= 1600 Ohms

Base Current (I_b) = $\frac{100 \times 10^3}{\sqrt{3} \times 400} = 144A$

$Z_1 = Z_2 = 0.00033 + j\,0.00483$ pu

$Z_0 = 0.000183 + j\,0.0138$ pu

ii) **Norton - Osbaldwick (400kV Feeder Circuit)**

$Z_1 = Z_2 = 2.01 + j\ 25.48$ Ohms
$Z_0 = 9.64 + j\ 68.72$ Ohms

$Z_b = 1600$ Ohms & Ib = 144A

$Z_1 = Z_2 = 0.00126 + j\ 0.0159$ pu

$Z_0 = 0.0060 + j\ 0.043$ pu

iii) **Norton - Thornton (400kV Feeder Circuit)**

$Z_1 = Z_2 = 2.33 + j\ 30.17$ Ohms
$Z_0 = 11.41 + j\ 82.08$ Ohms

$Z_b = 1600$ Ohms & Ib = 144A

$Z_1 = Z_2 = 0.00146 + j\ 0.01885$ pu

$Z_0 = 0.00713 + j\ 0.0513$ pu

iv) **Norton - Lackenby (400kV Feeder Circuit)**

$Z_1 = Z_2 = 0.74 + j\ 6.9$ Ohms
$Z_0 = 3.11 + j\ 17.99$ Ohms

$Z_b = 1600$ Ohms & Ib = 144A

$Z_1 = Z_2 = 0.000463 + j\ 0.0043$ pu

$Z_0 = 0.00194 + j\ 0.0112$ pu

v) **Table 1 - Details the Feeder Impedance**

	400kV Overhead Line Feeder Circuits	Positive Seq Negative Seq Imped $Z_1 = Z_2$ Ohm pu	Zero Seq Imped Z_0 Ohm pu
1	Norton - Hawthorn 27.84 km L6	0.53 + j 7.74 0.00033 + j 0.00484	2.92 + j22.05 0.00183 + j 0.0138
2	Norton - Osbaldwick 16.00km L6 52.00km L12 16.19 km L2/2	2.01 + j 25.48 0.00126 + j 0.0159	9.64 + j 68.72 0.0060 + j 0.043
3	Norton - Thornton 16.00km L6 52.00km L12 16.19km L2/2 16.86 km/L6	2.33 + j 30.17 0.00146 + j 0.01885	11.41 + j 82.08 0.00713 + j 0.0513
4	Norton - Lackenby 12.00km L8/2 9.20km L8	0.74 + j 6.90 0.000463 + j 0.0043	3.11 + j 17.99 0.00194 + j0.0112
5	Osbaldwick - Thornton 16.8km L6	0.31 + j 4.67 0.0002 + j 0.00292	1.762 + j 13.306 0.0011 + j 0.0083
6	Lackenby - Thornton 22km L6	0.419 + j 6.116 0.00026 + j 0.0038	2.30 + j 17.42 0.00143 + j 0.0109
7	Lackenby - Thornton 52km - L12	1.705 + j 21.03 0.001 + j 0.0131	7.96 + j 56.05 0.00497 + j 0.035

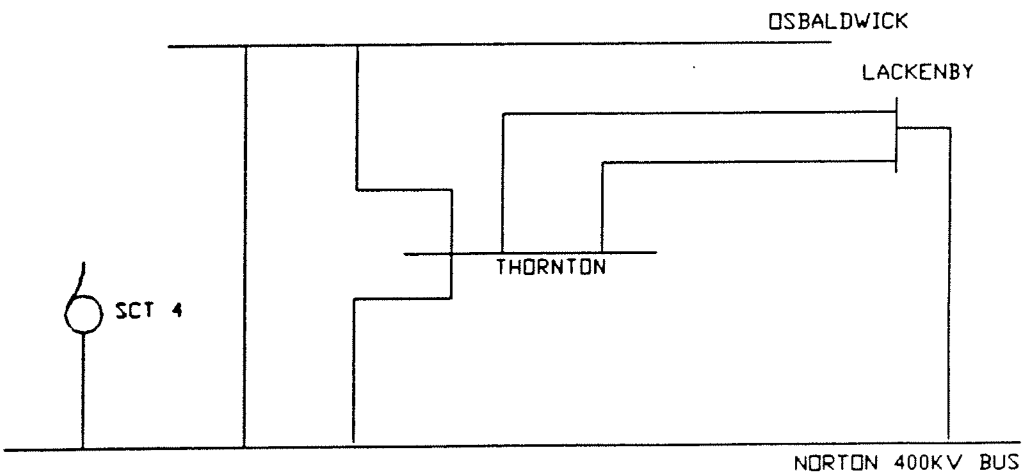


FIG 1. SIMPLIFIED 400 KV NORTON SUBSTATION NETWORK

vi) **System Source at Lackenby**

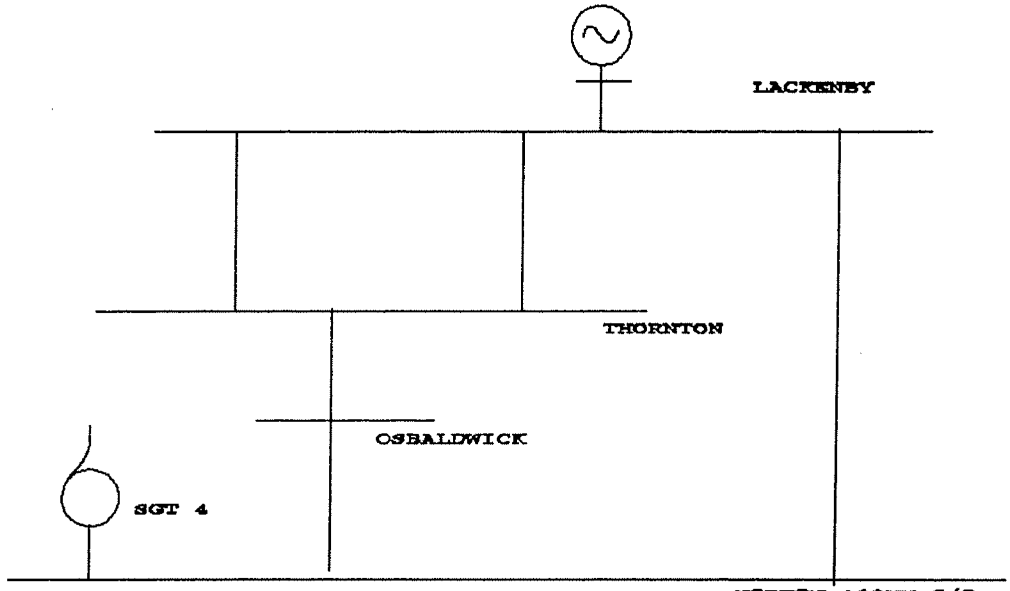


FIG 2 NORTON S/S WITH SYSTEM SOURCE AT LACKENBY

vii) **Total Earth Fault Current Flow**

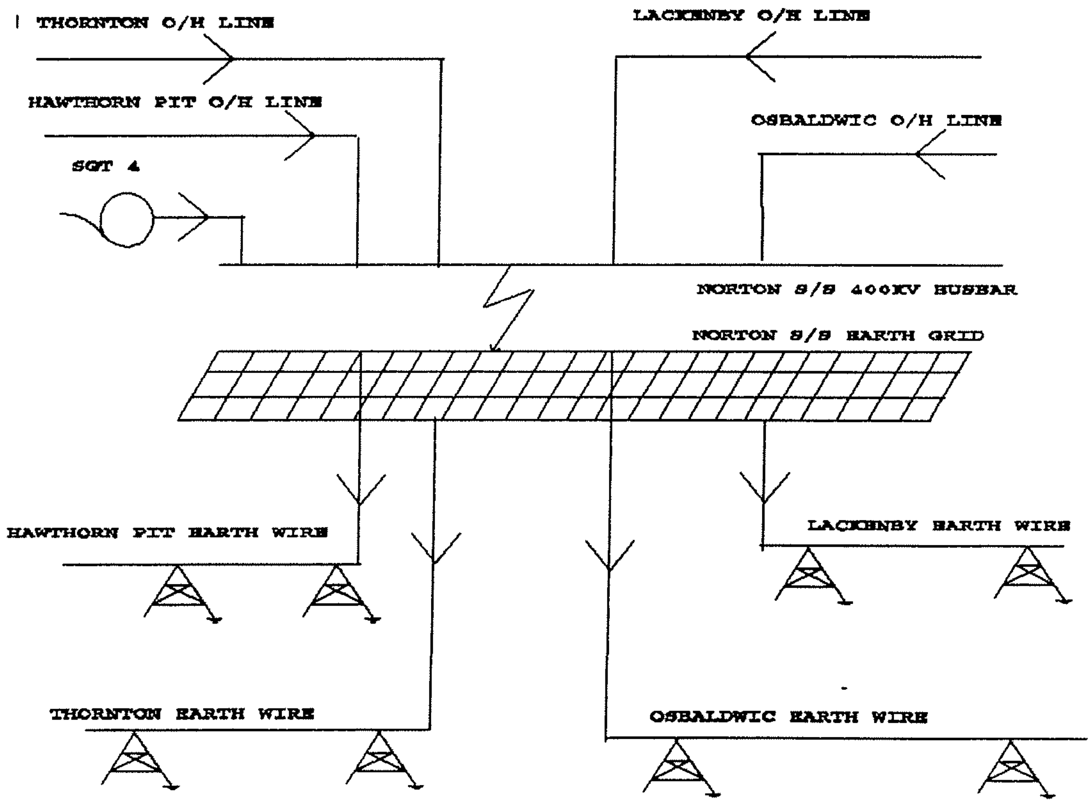


FIG 3. FAULT CURRENT FLOW

Calculated total impedance of the feeders connected to Norton Substation from Lackenby Substation is:

$$Z_1 = Z_2 = 0.0032 \angle 84.3°$$

$$Z_1 = Z_2 = 0.000319 + j\ 0.0032\ pu$$

and

$$Z_0 = 0.00193 + j\ 0.0112\ pu$$

System fault level based on 50kA fault current = 35,000MVA

∴ System Impedance

$$Z_1 = Z_2 = \frac{100}{35,000}\ pu$$

$$Z_S = Z_1 = Z_2 = j\ 0.00286\ pu$$

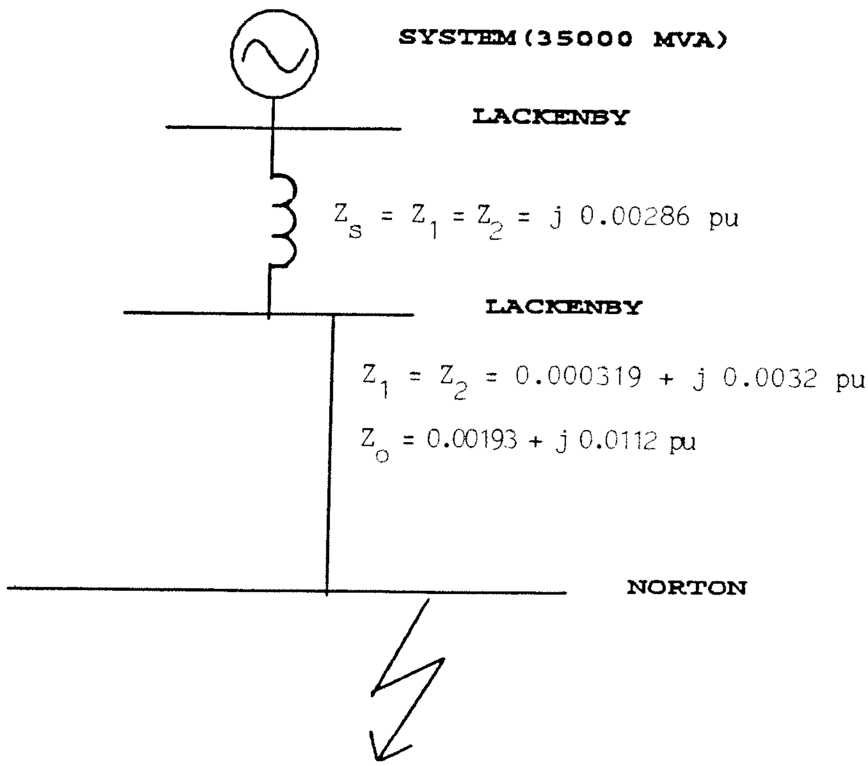


FIG 4.SIMPLIED SYSTEM NETWORK

∴ Fault Current I_f

$$I_f += \frac{3E}{Z_1 + Z_2 + 2\ Z_S + Z_O}$$

$$= \frac{3 \times 1.0}{0.00257 + j\ 0.02332}$$

I_f = 127.9 ∠-83.7° pu

I_f = 127.9 x 144A = 18414 ∠-83.7° A

= 18414 ∠-83.7° A

If the fault is on the HV side of the transformer feeder SGT4, the fault current fed from LV (275kV) side of the transformer feeder to HV side (400kV) = 6360A

∴ Total fault current into the 400kV Norton Substation = 18414 + 6360

= 24774A

2. RESISTANCE DUE TO EARTH MESH (NORTON 400KV SUBSTATION)

Refer Drawing ZCEE00300

Total area of the buried conductor = $12600M^2$

Total amount of earthing conductor buried bare in the soil = 2000M

∴ Radius of the equivalent circular plate = 63.3M

Soil resistivity (ρ) of Norton = 33.9 Ohm-M

Note: Soil resistivity (ρ = 33.9 Ohm-M) was measured at Norton Site by GEC ALSTHOM T&D Substation Projects LImited.

Total resistance to earth R can be calculated as:-

$$R = \frac{33.9}{4 \times 63.3} + \frac{33.9}{2000} = 0.151\ Ohm$$

$$R = 0.151\ Ohms$$

3. CALCULATION OF RESISTANCE DUE TO A DRIVEN ROD

a) Resistance of a Single Rod

$$R_1' = \frac{\rho}{2\pi l}\left(\ln \frac{8l}{d} - 1\right)$$

Length of the rod (l) = 3.658M

Diameter of the rod - 16mm = 0.016M

$$R_1' = \frac{33.9}{2 \times \pi \times 3.658}\left(\ln \frac{8 \times 3.658}{0.016} - 1\right)$$

$$R_1' = 9.63\ Ohms$$

b) Resistance of a single 3.658M (12 ft) rod can be checked by using

$$R_1' = \frac{\rho}{350}\,Ohms$$

$$R_1' = \frac{3390}{350} = 9.68\ Ohms$$

c) **Group of Rods Around (Hollow Square) the Earth Grid**

$$R_2' = \frac{R_1'}{N}(1 + k\,\alpha)$$

N = 50 RODS (Total of 50 Rods are Used)

K from Figure 18 (of S5) = 8.0

$$\alpha = \frac{r_h}{a}$$

a = distance between adjacent rods

r_h = the radius of the equivalent hemisphere for one rod

$$r_h = \frac{\rho}{2\,\pi\,R_1'} = \frac{33.9}{2 \times \pi \times 9.63} = 0.56$$

$$\alpha = \frac{0.56}{10} = 0.056$$

$$\therefore R_2' = \frac{9.63}{50}(1 + 8 \times 0.056) = 0.278\Omega$$

$$R_g = \frac{R\,R_2' - R_{12}{}^2}{R + R_2' - 2\,R_{12}}$$

$$R_{12} = R - \frac{\rho}{\pi \times L}\left(Log_e \frac{l}{b} - 1\right) \quad \text{Where } b = \frac{W}{\pi}$$

W = Width of Strap

$$R_{12} = 0.151 - \frac{33.9}{\pi \times 2000}\left(Log_e \frac{3.658}{0.016} - 1\right)$$

$$R_{12} = 0.151 - 0.0239 = 0.127\ Ohm$$

$$R_g = \frac{0.151 \times 0.278 - (0.127)^2}{0.151 + 0.278 - 2 \times 0.127}$$

$$R_g = 0.147\,Ohm$$

Calculation indicates that by putting more rods will not improve grid resistance very much.

4. EARTHING GRID MESH OF EXISTING NORTON 275KV SUBSTATION AND 132KV SUBSTATION

a) Resistance Due to Earth Mesh (Norton 275kV Substation Existing)

Refer Drawing A2399053

Total area of the buried conductor = $18300M^2$

Total amount of earthing conductor buried bare in the soil = 1800M

$\therefore$ Radius of the equivalent circular plate = 76.3M

Soil resistivity (ρ) of the Substation = 33.9 Ohm-M

Total resistance to earth R can be calculated as:-

$$R = \frac{33.9}{4 \times 76.3} + \frac{33.9}{1800} = 0.130\ Ohm$$

b) **Resistance Due to Earth Mesh (Norton 132kV Substation Existing)**

Refer Drawing LW2403820

Total area of the buried conductor = 4050M^2

Total amount of earthing conductor buried bare in the soil = 1140M

$\therefore$ Radius of the equivalent circular plate = 36M

Soil resistivity (ρ) of the Substation = 33.9 Ohm-M

Total resistance to earth R can be calculated as:-

$$R = \frac{33.9}{4 \times 36} + \frac{33.9}{1140} = 0.265\ Ohm$$

Note:

1) Earthing rods available in the 275kV and 132kV Substations are not considered.

2) As 275kV and 132kV substations are adjacent to 400kV substations, 400kV substation soil resistivity ρ = 33.9 Ohm/m is used for calculating earth grid resistances of 275kV and 132kV substations.

3) Footing resistances of the towers connected to substations are not also considered.

4) Declared combined resistance of the existing 400/275/132kV is 0.11Ω which is in line with our calculated grid resistances value of 0.130Ω (for 275kV Substation) in parallel with 0.265Ω (for 132kV Substation) gives 0.087Ω.

5. **TOWER FOOT RESISTANCE FOR EACH LINE**

It was decided to use the formula for a long line (greater than 7.5km length) with the average footing resistance of the first 20 towers (ie average span is about 350m).

We have used typical CEGB 400kV overhead line parameters for Z_{pe}.

Z_{pe} = 0.077 + j 0.721 Ω/mile (Typical CEGB 400kV O/H Line parameter)

Z_{pe} = 0.123 + 1.1536 Ω/km

$\therefore Z_{pe}$ = 0.043 + j 0.40 Ω/span

R_T (footing resistance) = 2.45 Ω

$$Z_L = \frac{Z_{pe}}{2} + \sqrt{Z_{pe} \times R_T} \;\; \Omega$$

$$Z_L = 0.0215 + j\,0.20 + \sqrt{(0.043 + j\,0.40) \times 2.45}$$

$$= 0.755\;j\,0.858 = 1.143\;\angle 48.6°\Omega$$

Data information for Z_{pe} and R_T were not available for Hawthorn Pit, Osbaldwick, Thornton and Lackenby overhead line feeders connected to Norton Substation. We have used Z_L calculated above for all the overhead lines associated with the Norton 400kV Substation in our calculation to find the combined impedance of earth grid and overhead lines to get overall impedance to earth Z_T.

$$Z_T = \left(\frac{1}{R_g} + \frac{1}{Z_{L1}} + \frac{1}{Z_{L2}} + \frac{1}{Z_{L3}} + \frac{1}{Z_{L4}}\right)^{-1}$$

$$Z_T = \left(\frac{1}{0.147} + \frac{4}{1.143}\;\angle 48.6°\right)^{-1}$$

$$Z_T = 0.10 + j\,0.029 = 0.104\;\angle 16°\Omega$$

$$\therefore \text{Overall Impedance } (Z_T) = 0.104\;\;\angle 16°\Omega$$

Note: In future there will be at least one or two cable feeders. These will reduce the overall grid impedance of the 400kV Substation.

6. INTERCONNECTING 400KV, 275KV AND 132KV SUBSTATIONS

These three substations are situated relatively close to each other. The substations are separated by access roads. If the grids are not directly connected by earthing conductors, there will be a voltage gradient over the ground surface at three substations due to fault current flowing in one of the grids.

These grids should be interconnected and so behave as a single grid with advantage of a correspondingly lower resistance. All three substations will be connected and the combined resistance of the substations

$$Z_{comb} = \left(\frac{1}{Z_T} + \frac{1}{R_{275}} + \frac{1}{R_{132}}\right)^{-1}$$

$$Z_{comb} = \left(\frac{1}{0.104\ \angle 16} + \frac{1}{0.13} + \frac{1}{0.265}\right)^{-1}$$

$$Z_{comb} = 0.048\ \angle 7.4°\ \Omega$$

7. CURRENT INDUCED IN OVERHEAD EARTH WIRES

The current induced in the overhead earth wire is given by:

$$I_e = I_f \times \frac{Z_{moe}}{Z_{pe}}\ Amps$$

$Z_{moe} = 0.045 + j\ 0.275\ \Omega/\text{mile}$

(Typical CEGB 400kV Overhead Line parameter is considered)

$Z_{moe} = 0.072 + j\ 0.44\ \Omega/\text{km}$

$Z_{pe} = 0.123 + j\ 1.1536\ \Omega/\text{km}$

$$\frac{Z_{moe}}{Z_{pe}} = \frac{0.072 + j\ 0.44}{0.123 + j\ 1.1536}$$

$$\frac{Z_{moe}}{Z_{pe}} = 0.384 - j\ 0.0215\ \Omega$$

ie 38.5% of the primary earth fault current being induced in the earth wire at 50Hz.

The earth (Z_{moe}/Z_{pe}) calculation can be carried out for each overhead feeders if Z_{moe} & Z_{pe} of those feeders are known.

The amplitude of the earth current returning to neutrals via line earth wires and towers is 30 to 70% depending on the number of lines and their length.

Let us consider 45% of the fault current return to neutral via line earth wires.

8. FAULT CURRENT

a) Declared Fault Current

Declared short circuit current by the Customer is single phase to earth fault current of 50kA for one second.

We have considered 55% of the fault current will return through to source via ground grid system and the other 45% will return to source via overhead earth wires without entering the ground.

If we consider the declared fault current of 50kA, then the fault current conducted to earth from the substation earth electrode system to be 27.5kA.

b) Calculated Fault Current

When we consider the calculated fault current of 24774A, the fault current conducted to earth from the substation earth electrode system is 13626A.

9. MAXIMUM GROUND POTENTIAL RISE (GPR)

The maximum ground potential rise based on:

$$E = IR$$

$$= 13626 \times 0.048 = 654V$$

$$= 654V$$

If we consider the fault current of 27.5kA, then the ground potential rise E = 1.32kV

10. SUBSTATION GRID PARAMETERS

Number of parallel grid conductors $n = 6$ approximately

Conductor spacing $D = 7M$ approximately

Depth of burial $h = 0.6M$

Diameter of conductor $d = 0.014M$ (equivalent to 50 x 3 flat strip)

11. TOUCH VOLTAGE

a) Using Equation 8

$$V_T = V\left[\frac{\ln\left(\sqrt{\frac{h}{d}} + \frac{1}{2h} + \frac{2}{D}\right)}{2.8\ (n+1)\ K_r}\right]K_i$$

$K_i = (0.15n + 0.17)$

$K_r = (1 + N\ l^2/10r^2)$

N = 50 (number of rods)

l = 3.658M (length of rod)

r = 63.3M (equivalent circular plate radius)

$K_i = 0.15 \times 6 + 0.17 = 1.07$

$K_r = (1 + 50 \times (3.658)^2/10 \times 63.3^2)$

$K_r = 1.017$

V = 654V (grid potential rise GPR)

$$\therefore V_T = 654\left[\frac{\ln\left[\sqrt{\frac{0.6}{0.014}} + \frac{1}{2 \times 0.6} + \frac{2}{7}\right]}{2.8\ (6+1) \times 1.017}\right] 1.07$$

$$V_T = 654\left[\frac{\ln[6.55 + 0.833 + 0.286]}{19.93}\right] 1.07$$

$$V_T = 654 \times \frac{2.037}{19.93} \times 1.07$$

V_T = 71.5V (Based on Calculated Fault Current)

$$V_T' = 1320 \times \frac{2.037 \times 1.07}{19.93}$$

$V_T' = 144V$ (Based on Declared Fault Current)

b) **Tolerable Touch Voltage Using Equation 9**

$$E_{touch} = \frac{116 + 0.17}{\sqrt{t}} \rho = 122V$$

(Based on back-up protection clearance time = 1 second)

E_{touch} = 272V (assume the high speed protection clears the ground fault in 100ms, but allows 200ms for a second fault due to auto-reclosure)

c) For wet crushed rock surfacing with resistivity of the order of 3000 Ohm-M, the tolerable E_{touch} would have been:

$$E_{touch} = \frac{116 + 3000 \times 0.17}{\sqrt{1}} = 626V$$

(based on back up protection time of 1 second)

E_{touch} = 1400V

(based on high speed protection time)

12. **STEP VOLTAGE**

a) **Using Equation 11**

$$V_s = \frac{V\left[\frac{1}{2h} + \frac{2}{D}\right]K_i}{2.8\ (n + 1)K_r}$$

$$V_s = \frac{654\left[\frac{1}{1.2} + \frac{2}{7}\right] \times 1.07}{2.8\ (6 + 1) \times 1.017}$$

$V_s = 39V$ (Based on Calculated Fault Current)

$V_s' = 78V$ (Based on Declared Fault Current)

b) **Using Equation 12**

$$\text{Tolerable } E_{step} = \frac{116 + 0.7\rho}{\sqrt{t}}$$

For natural earth, where ρ = 33.9 Ohm-M then tolerable E_{step} = 140V (based on back up earth fault protection clearing time = 1 second)

Tolerable E_{step} = 312V (assume the high speed protection clears the ground fault in 100ms, but allow 200ms for a second fault due to auto-reclosure).

c) For wet crushed rock surfacing with resistivity of the order of 3000 ohm-M, the tolerable E_{step} would have been:-

$$E_{step} = \frac{116 + 3000 \times 0.7}{\sqrt{1}} = 2216V$$

The calculated step voltage thus falls within the tolerable value as determined above and the ground surface is covered with a layer of crushed rock of 75mm thick.

13. CALCULATION OF HOT ZONE RADIUS

Using Equation 13

$$V_x = \frac{\rho I}{2\pi r} \text{ arc } Sin \frac{r}{x}$$

$$I = I_g = \frac{654}{0.151} = 4330A$$ (Based on Calculated Fault Current GPR)

$$I = I_g^{\prime} = \frac{1320}{0.151} = 8742A$$ (Based on Declared Fault Current GPR)

Radius of Equivalent Plate Electrode

$$r = \frac{\rho}{4 \times R} = \frac{33.9}{4 \times 0.151} \qquad r = 56.1m$$

and

$$x = (r + X)$$

$$V_x = \frac{33.9 \times 4330}{2\pi \times 56.1} \text{ arc } Sin \frac{r}{(r + X)}$$

$$V_x = 416 \text{ arc } Sin \frac{r}{r + X}$$

$$V'_x = 840 \text{ arc } Sin \frac{r}{r + X}$$

$$\text{(ie arc Sin } \frac{r}{(r + X)} \text{ in radians)}$$

Table 2 shows the general voltage profile around the substation.

VOLTAGE PROFILE AROUND THE SUBSTATION

TABLE 2a - Based on Calculated Fault Current

Current I_g A	ρ Ω m	Radius of Equivalent Grid Electrode m	GROUND VOLTAGE (V_x) AT A DISTANCE (X) METRES FROM EDGE OF SUBSTATION GRID ELECTRODE V (VOLTS)												
4330	33.9	56.1	X =	0	1	2	4	5	10	20	40	80	160	320	640
			V_x =	653	575	544	501	484	421	345	259	177	109	62	33

TABLE 2b - Based on Declared Fault Current

Current I_g A	ρ Ω m	Radius of Equivalent Grid Electrode m	GROUND VOLTAGE (V_x) AT A DISTANCE (X) METRES FROM EDGE OF SUBSTATION GRID ELECTRODE V (VOLTS)												
8742	33.9	56.1	X =	0	1	2	4	5	10	20	40	80	160	320	640
			V_x =	1318	1161	1098	1011	977	850	696	523	357	220	125	67

OVERALL DISCUSSION OF CALCULATION

The ground grid and earth rod combinations used for the substation resulted in the substation potential rise, step potentials and touch potentials listed in the Table below

SUBSTATION NORTON	**SUBSTATION POTENTIAL RISE**	**ACTUAL STEP POTENTIAL**	**TOLERABLE STEP POTENTIAL**	**ACTUAL TOUCH POTENTIAL**	**TOLERABLE TOUCH POTENTIAL**
Based on Calculated Current	654V	39V	2216V	71.5V	626V
Based on Declared Current	1320V	78V	2216V	144V	626V

Table 3: Showing Substation Potential Rise, Step Potential and Touch Potential

The calculations are based on parameters given by NGC, typical CEGB parameters or assumed due to lack of information. The assumed parameters are considered to be conservative.

Where touch and step voltages have been calculated on appropriate value of grid mesh conductor, spacing has been used taking into account the irregular layout of conductors required to achieve a practical grid.

Additional Measures if Required

1. Reduce mesh spacing by provision of additional cross connections to reduce mesh spacing.

2. Provide local earth mats beneath operating points buried just below the chipping layer to reduce local foot to hand potentials.

CONCLUSION

Actual step potential and touch potential are within the tolerable step and touch potential. Substation potential rise (GPR) based on calculated current meets the Customer's (NGC plc) required value. Substation potential rise (GPR) based on declared current value is high. We propose to improve the substation potential rise if necessary after installation of the proposed grid as designed and measurements have been taken.

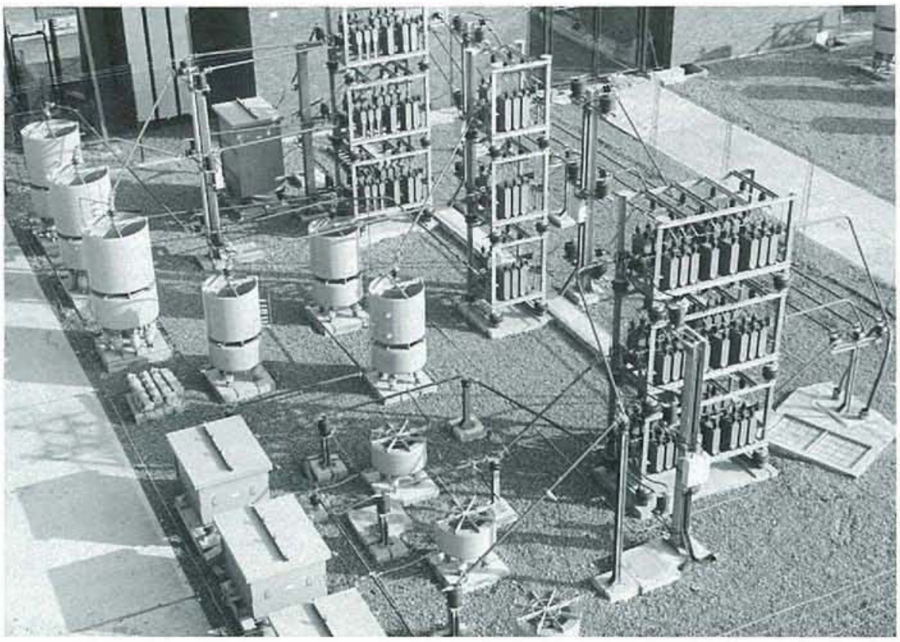
V Ayadurai

V AYADURAI
SENIOR APPLICATION ENGINEER

VA/HJH

Appendix 15.5 V Ayadurai and D J Young : ‘Reactive Power Compensation for Winders and Conveyors’ *GEC Review Vol 1, 1985*

Reactive Power Compensation for Winders and Conveyors



by
V. Ayadurai, B.Sc., C.Eng., M.I.E.E.
and D.J. Young

GEC Transmission and Distribution Projects Limited

Reactive power compensation for mine winders and conveyors

D.J. Young graduated with 1st Class honours from Cambridge University in 1957 and joined GEC as a graduate apprentice. For nine years he assisted the resident Consultant Engineer at Witton, the late Dr. E. Friedlander, in the original development and application of static var compensators using d.c. saturable reactors and a.c. self-saturated reactors. Transferring to Trafford Park in 1968 and Stafford in 1970, he continued to work on static var compensators for industrial and transmission systems. He is now Chief Engineer, A.C. Transmission.

by D.J. YOUNG, B.A., and V. AYADURAI, B.Sc., C. Eng., M.I.E.E.
GEC Transmission and Distribution Projects Ltd.

V. Ayadurai graduated from the University of Ceylon and taught at St. Joseph's College, Colombo, Sri Lanka. He joined Geophysical Services International in England in 1970 as a geophysical engineer. In 1973 he joined GEC Power Transmission Division in Stafford as a design engineer in the A.C. Engineering Department, and is now a senior design and application engineer working on static var compensation and short-circuit current-limiting devices for industrial and transmission systems.

During the past two decades thyristor-fed drives have gained widespread acceptance because of the enormous advantages they offer to the user. However, the power factor of a thyristor drive is often not better than 0.7 to 0.8, and can be much lower at low drive speeds. This low power factor can cause an excessive voltage drop in the power-supply system as well as incurring tariff penalties, so that the installation of shunt power-factor-correction capacitors can often be technically and economically justified.

In addition, thyristor converters have no mechanical inertia or other store of energy to buffer any shock loading of the d.c. motors themselves. These shocks are transformed directly on to the supply system in the form of sudden changes of active and reactive power demand, causing voltage fluctuations. Thyristor drives may also draw harmonic currents of significant amplitude. The permissible limits of disturbances to the supply system, for example voltage fluctuations and harmonic distortion, form the subject of Engineering Recommendations drawn up by the Area Electricity Boards and the Central Electricity Generating Board (CEGB).

Disturbances to the System

The voltage drop in a power-supply system, caused by loads which are large compared with the short-circuit level of the system, is mainly due to the reactive component of current, I_q, flowing through the system reactance, X_o, i.e. $\Delta V = I_q X_o$.

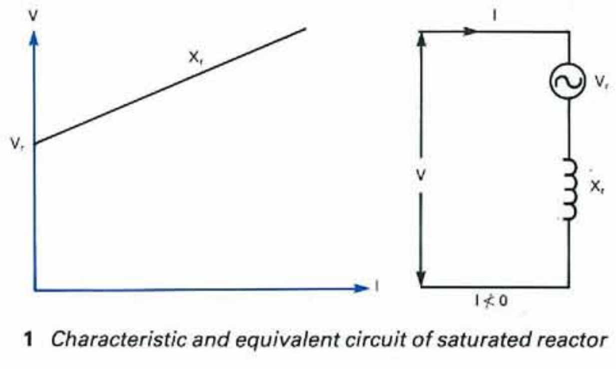
When the voltage drop ΔV is excessive, either the reactive current or the system reactance must be reduced. The reactive load current of thyristor converters can sometimes be reduced by appropriate design modifications. For example, sequence control of two bridges in series reduces the maximum reactive demand by 30%; alternatively, some of the reactive current can be supplied from a compensator connected in parallel with the load. On the other hand the system reactance can be reduced by reinforcing the system, i.e. increasing the system short-circuit level by additional lines and transformers. Strengthening of the system is often a more expensive method of reducing disturbances than the installation of compensators.

The major harmonic frequencies which the thyristor converters produce in the a.c. supply depend on the pulse number p, in accordance with the formula $h = kp \pm 1$, where h stands for the harmonic number and k is an integer, giving 'characteristic harmonics' which are multiples of the frequency. Thus a 6-pulse converter, which is normally used to supply motor fields and sometimes is also used for main drives, produces mainly 5th and 7th harmonic currents and smaller amounts of higher-order harmonics such as 11th and 13th, 17th and 19th etc. The important harmonic currents of a 12-pulse converter are 11th, 13th, 23rd and 25th orders. A 12/24-pulse converter, a type often used for this sort of application, is controlled to produce even smaller levels of 11th and 13th harmonic currents.

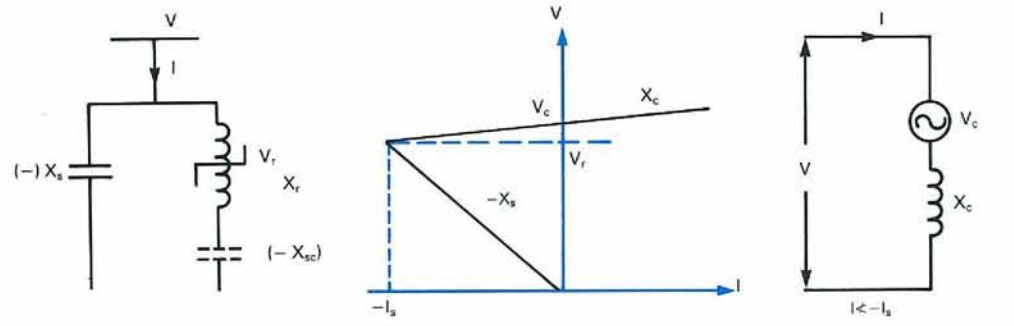
The flow of harmonic currents into the supply system can be reduced by using shunt absorption filters. The generated harmonic currents flow into the harmonic filters and into the supply system in the ratio of their respective admittances. The higher the admittance of a filter at any harmonic frequency, the greater is the proportion of harmonic current absorbed. It is convenient to include the shunt capacitors necessary for the filters as part of any static-compensator installation, because they generate reactive power which will improve the load power factor.

Saturated Reactor Compensators

Saturated reactors were developed by GEC under the guidance of the late Dr. E. Friedlander. They are transformer-type devices which are usually built in the factory of GEC Transformers Ltd in Stafford. Unlike a transformer, a saturated reactor is operated at a sufficiently high terminal voltage to make the core saturate during each half-cycle. In this saturated mode of operation, the magnetizing current becomes very sensitive to voltage changes. Fig. 1 shows



1 *Characteristic and equivalent circuit of saturated reactor*



2 Circuit, characteristic and equivalent circuit of compensator

this magnetizing characteristic, which can be represented as a reactive impedance line, passing through the voltage axis at the voltage at which saturation commences. This characteristic may be thought of in terms of an equivalent 'machine' with reactance X_r and excitation voltage V_r.

Unlike a synchronous machine a saturated reactor has no moving parts, no inertia, and inherently remains in synchronism with the supply. It has a singular value of characteristic reactance, its slope reactance, which is not subject to any delay time constants. A saturated reactor can only absorb reactive power, and this feature must be taken into account when considering the behaviour of its equivalent machine. The reactive power required for compensation is generated by parallel-connected shunt capacitance (often in the form of harmonic filters). Saturated reactors are normally built with six or nine active limbs, and the windings are interconnected in a special zig-zag manner to suppress harmonic currents.

For some applications a lower value of saturated-reactor slope reactance is required than can be economically achieved by natural design. In such cases it is usual to connect capacitors in series with the saturated reactor, to cancel part or all of its slope reactance. This technique makes it possible to obtain a constant-voltage characteristic which can be very useful in many situations.

The overall combination of a saturated reactor with shunt capacitors and also, where appropriate, with series capacitors is known as a saturated-reactor compensator. Fig. 2 shows how this can also be represented as an equivalent machine, together with the overall voltage/current characteristic. In this case the equivalent excitation voltage is:

$$V_c = V_r \quad \frac{X_s}{X_s-(X_r-X_{sc})},$$

and the equivalent reactance is:

$$X_c = \quad \frac{(X_r-X_{sc})X_s}{X_s-(X_r-X_{sc})}.$$

Where X_s is the reactance of the shunt capacitors, and X_{sc} is the reactance of the series capacitors.

By using the representation of the compensator as an equivalent machine, with an excitation voltage V_c and reactance X_c, its compensating action can also be understood as a 'reinforcement' of the supply system. The fluctuating reactive demand of the load current is supplied by the system and the compensator in inverse proportion to their reactive impedances. Thus, by reducing the value of X_c the compensator can be made to absorb more of the fluctuations, and the residual fluctuating voltage can be reduced. In the limit, when $X_c = 0$, the supply system is not disturbed, because the compensator supplies all the reactive fluctuations of the load: as seen from the load, the supply system appears to be infinitely strong when reinforced by the compensator.

Winders for the National Winder Programme

The replacement of old winding engines by new thyristor-fed drives is an important feature of the colliery modernization being carried out by the National Coal Board. The needs of different mines are very diverse, but a number of rationalized ratings of motors and converters were designated under the NCB's National Winder Programme. When the duty of a winder has been determined, the appropriate rationalized rating is selected for the drive motor and converter. Fig. 3 shows one of these new winder drives, many of which have been supplied by GEC Electrical Projects Ltd. The normal duty cycle of a mine winder lasts typically between about 60 and 90 seconds, and fig. 4 shows an idealized example, with the time scale of the build-up of current prior to acceleration exaggerated for clarity.

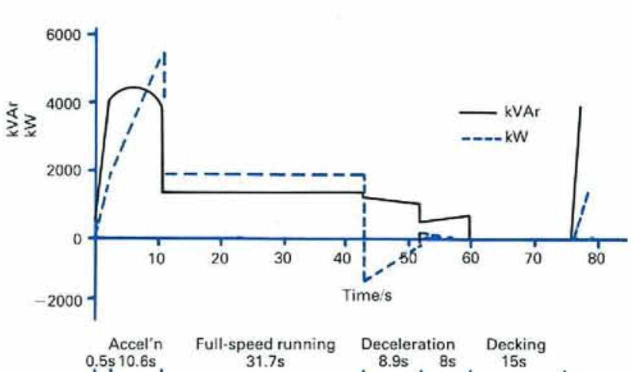
The supply voltage for collieries is sometimes 6.6 kV, but more often 11 kV; the short-circuit level of such 11 kV supplies rarely exceeds 250 MVA and is usually in the range 100 to 200 MVA. The Area Electricity Boards are responsible for the power-supply system and follow the guidelines of Electricity Council Engineering Recommendation P8 ('Supply to Colliery Winders and Rolling Mills') in determining whether the fluctuating load of a mine winder is likely to cause disturbance or annoyance to other consumers fed from the same system. As indicated in fig. 5, this recommendation permits a load to cause step changes of voltage of up to 1% together with slower, ramped, changes of up to 2%, changing at a rate of 1% per second. The maximum permissible change is thus 3% and this change must not take place in less than two seconds. Thus a system with a short-circuit level of 100 MVA could tolerate a maximum cyclic load change of about 3 MVAr. A system short-circuit level of about 150 MVA would be needed to avoid excessive voltage disturbances due to the load cycle illustrated in fig. 4

The smaller winders rarely exceed the limits of permissible voltage fluctuations, but when two large winders are installed at a colliery the combined load demand is often found to be excessive when they accelerate simultaneously, and would be liable to cause unacceptable voltage variations.

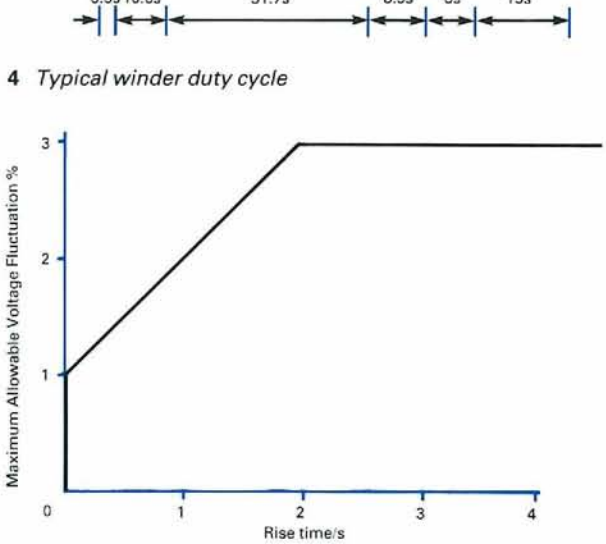
By means of static compensators the supply voltage can be stabilized to a level which avoids disturbance to other consumers. Although the amount of compensation required has varied to some extent from site to site, a rationalized design of compensator was adopted by the NCB for the 11 compensators so far installed in association with new drives under the National Winder Programme, and a twelfth was

3 *Winder motor supplied to NCB (Photo: NCB Doncaster Area, Frickley No 2 Winder)*

ordered late in 1984. This compensator was designed to reduce the voltage disturbances on the system, generally at the colliery 11 kV busbar, to within the limits contained in Recommendation P8. In addition, the harmonic distortion in the supply system must be limited to the values indicated in Recommendation G5/3 ('Limits for Harmonics in the United Kingdom Electricity Supply System'). The major harmonic-frequency currents generated by the 12-pulse converters are 11th and 13th. Smaller levels of 5th and 7th harmonics are also produced, mostly by the 6-pulse converters for the field control of the d.c. motors, and the shunt capacitance of the static compensators is therefore arranged as a harmonic filter.



4 *Typical winder duty cycle*



5 *Maximum allowable voltage fluctuations for colliery winders and rolling mills*

Rationalized Design of Static Compensator

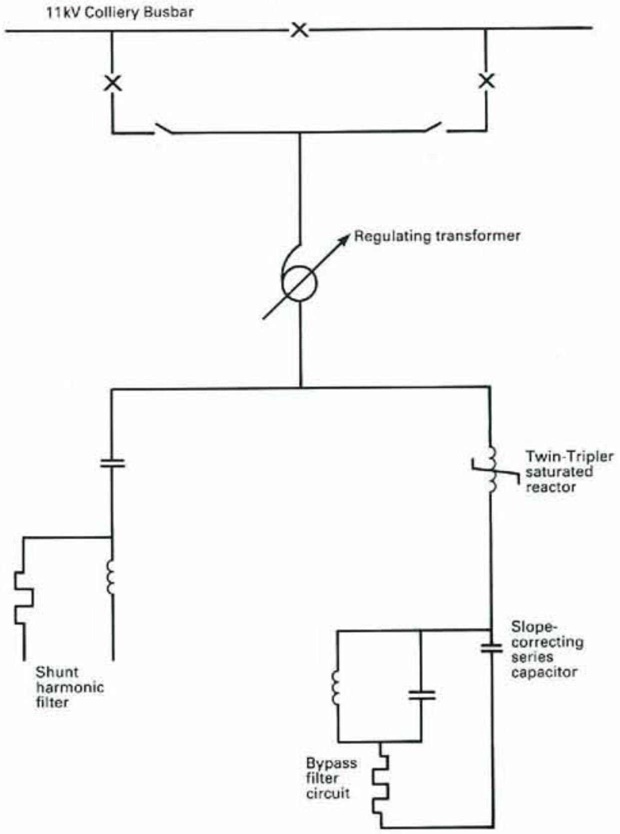
In phase 1 of the National Winder Programme five installations were found to require compensation. For the most critical case the compensator was required to supply almost 5 MVAr in order to prevent excessive voltage changes on the supply system.

By supplying reactive power to reduce voltage dips, the compensators automatically give a substantial improvement to the overall power factor of the converter drives. A particular feature of a saturated-reactor compensator is that it has an inherent response to all voltage changes, whether they are caused by the load to be compensated or by any other loads on the system. It is therefore necessary to include some means of cancelling the effect of longer-term voltage variations coming from the system itself if the action of the compensator is to be restricted to dealing with the particular disturbing load. This is done by connecting the compensator to the system via a regulating transformer and varying its transformation ratio so as to follow the slow variations of supply-system voltage.

None of the seven installations which have subsequently required compensation has necessitated a bigger compensator than the rationalized design. The main items of equipment shown in the compensator power-circuit diagram of fig. 6 are:

a stepless moving-contact Brentford regulating transformer, with on-load voltage regulation of ±7½% on its input side; the rating is 3.25 MVA and natural cooling (ONAN) is used. The turns ratio is controlled by a 'load controller', which is a special device developed by GEC to monitor the current in the saturated reactor. When the load controller detects that the saturated-reactor current is no longer within its correct operating range, and that the compensator may therefore not be able to provide proper compensation for the fluctuating demands of the mine winders, it changes the tapping ratio by an appropriate amount.

a 3-phase Twin-Tripler type saturated reactor with a rating of 6.8 MVAr (320 A at 12.2 kV) and ONAN cooling.



6 *Circuit of static compensator used for winders*

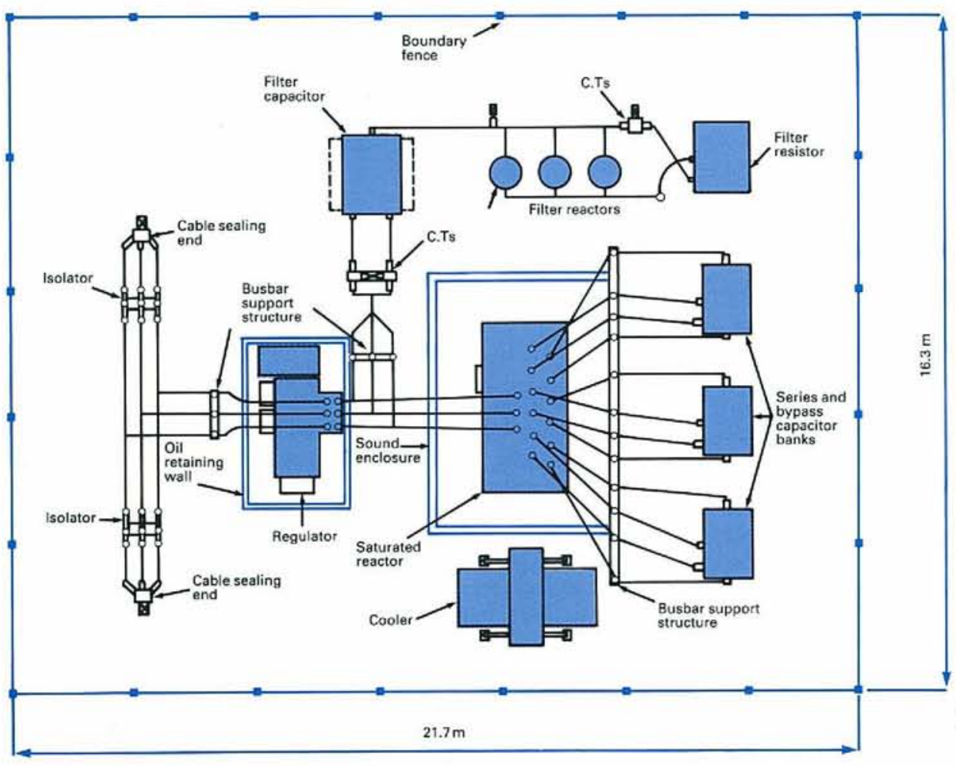
a slope-correcting capacitor bank connected in delta at the neutral terminals of the saturated reactor. A bypass filter is connected across the slope-correcting capacitor to improve the transient response of the compensator. The linear reactor of the bypass filter is of the iron-shrouded type and is mounted inside the saturated-reactor tank. The damping resistor is made up of metallic resistor elements in a naturally air-cooled housing. All the series and bypass capacitor units are internally fused.

a damped harmonic filter rated at 6 MVAr at 11 kV, 50 Hz, to provide a high admittance particularly for 5th, 7th, 11th and 13th harmonics. Three single-phase externally fused capacitor banks, stacked one above the other, are each connected in series with an air-cored, air-cooled linear reactor, shunted by a resistor, the complete filter being in an unearthed-star configuration. The harmonic-filter resistor is of similar construction to the bypass-filter resistor.

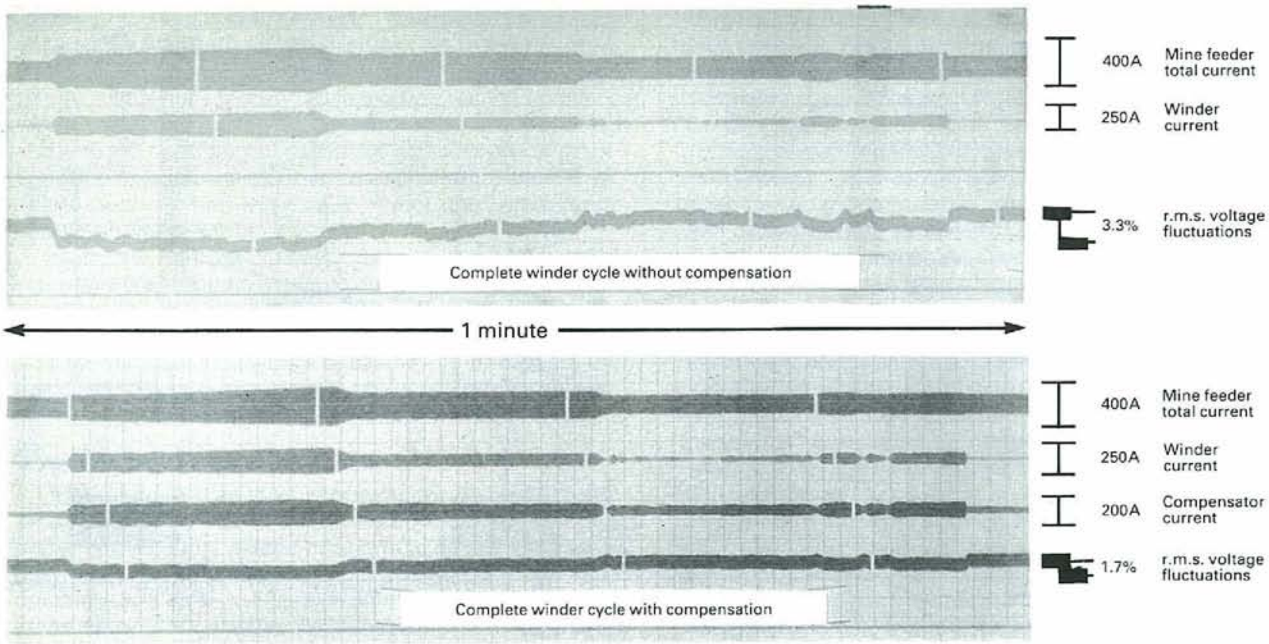
At most collieries the 11 kV busbar is in two sections for security of supply to the winders and other important loads. The static compensator is fed via cables from a dedicated circuit breaker on either busbar and, as indicated in fig. 6, isolators are selected to the in-service circuit breaker. There are no special requirements for these circuit breakers; they are relieved of any capacitor-switching duty by the behaviour of the saturated reactor which discharges the shunt-capacitor banks whenever the compensator is switched off.

All power-frequency components of the static compensators are installed outdoors; the protection and control cubicles are housed indoors. Fig. 7 shows the layout of a static-compensator installation. The compensator compound is fenced, and to reduce its noise level the saturated reactor is surrounded by a brick enclosure.

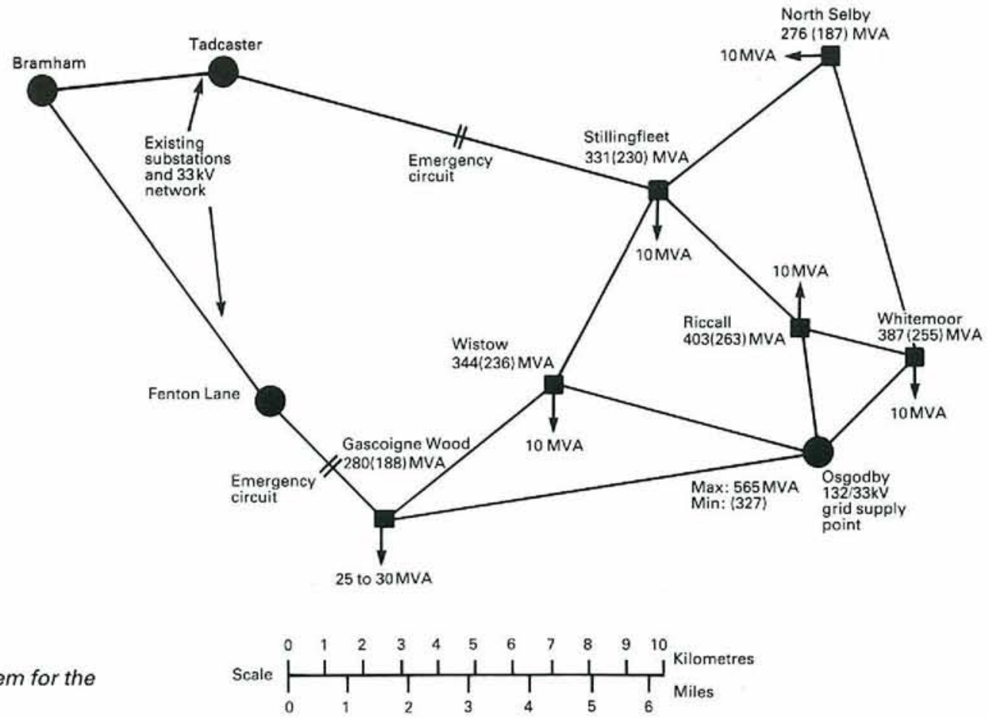
Some of the compensators have now been in service for more than six years and are giving good service, fulfilling very well their intended duty. The oscillograms in fig. 8 were taken at one site with one winder operating through-



7 *Layout of a static compensator installation*



8 *Oscillograms taken during a single winding cycle*



9 *33 kV distribution system for the Selby collieries*

out a single winding cycle, without and with the compensator in service. The current drawn by the winder increases to a maximum during the acceleration period and drops to a constant steady value during full-speed running. The current drawn during the deceleration and decking period is smaller. The voltage trace shows the change of r.m.s. voltage at the point of connection of the compensator and winder; the basic pattern of variation of voltage with time is the same in each case, but it can be seen that the amplitudes of all the voltage variations are approximately halved with the compensator in service. The uncompensated oscillogram shows that there are smaller superimposed voltage disturbances which appear to be due to other loads. The compensator reduces these variations as well.

Selby Coal Mine

The enormous reserves of the new Selby coalfield will be worked from several groups of coal faces which will be serviced by mine winders installed in shafts at five sites. The coal from these faces will be transported by subsidiary conveyors to a main conveyor system, which will then bring the coal to the surface coal-handling plant via a drift mine at Gascoigne Wood.

The electricity supply to all these sites is provided by the Yorkshire Electricity Board via two 132/33 kV stepdown transformers at Osgodby. A new network of 33 kV circuits (see fig. 9) distributes power to the various load centres and in an emergency can be linked to an existing 33 kV network. The supply system is so designed that even with a line outage the minimum short-circuit level at each site is about 200 MVA as shown; because of this, large motor drives such as ventilating fans can be started without any problems. At present the 33 kV system is dedicated to supplying the Selby coalfield complex, apart from when emergency circuits are in use.

Because they have no coal handling duty the thyristor-fed d.c. winders at the five collieries are relatively small. They are supplied at 6.6 kV and have only a small effect on the electricity supply system. Some shunt capacitor banks are installed at 6.6 kV for power-factor correction purposes and the total load on each of these five collieries is of the order of 10 MVA at 0.9 p.f.

Two drift conveyors have been installed at Gascoigne Wood. Each conveyor is capable of transporting to the surface the total coal output of the five collieries of the Selby complex, through a vertical lift of 1000 m. Vertical bunkers are installed at eleven loading stations spaced over the 15 km length of the conveyors.

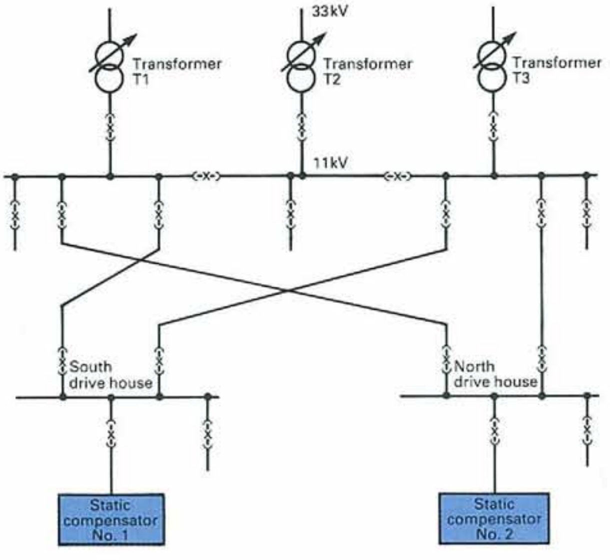
Two 60 rev/min, 1000 V d.c. drive motors, each with 10% sustained overload capability, are used on each drift conveyor. The South Drift conveyor has a full speed of 8.4 m/s and uses 5050 kW shunt-wound d.c. motors with overhung armatures directly coupled to the drive shaft. The North Drift conveyor is of a different design and has a full speed of 7.62 m/s, using two shunt-wound d.c. motors of shafted construction, each rated at 4375 kW. The motor armatures are fed from the 11 kV colliery distribution system via 12/24-pulse single-ended thyristor converters, which are sequence-controlled to reduce the maximum kVAr demand on the supply. The motor fields are connected in series and supplied from 6-pulse, anti-parallel, 'Variflux' thyristor converters. Each drive has a closed-loop control system, having speed- and current-control loops which control the torque applied to the conveyor.

The drive motors and their thyristor converters were supplied by GEC Electrical Projects Ltd and are installed above ground at the top end of the conveyors, respectively in the North and South Drive Houses. In order to minimize the spares requirements, the equipment for the conveyor drives was selected from within the rationalized rating system of the National Winder Programme.

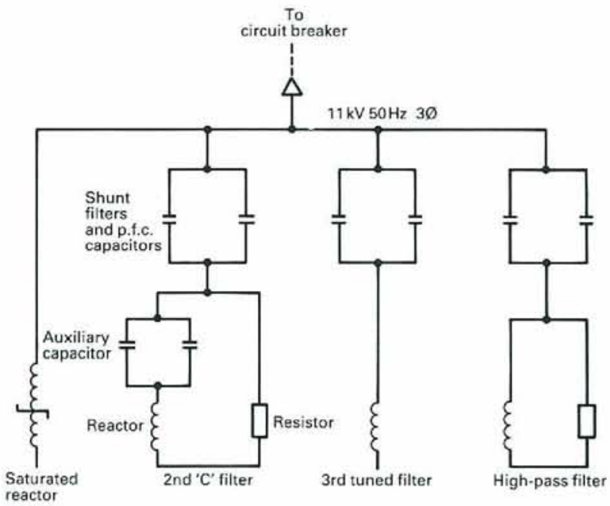
There are no particular 'duty cycles' for the drift conveyor belts. Ideally there should be a steady duty corresponding to a steady winning of coal from the faces. In practice coal production will not be steady and various stoppages will occur to coal-handling equipment, although the underground bunkers will provide some buffering to smooth the variations in the rate of supply of coal. A conveyor belt takes four minutes to reach its full speed by acceleration from zero. A fully loaded conveyor will stop naturally in 30 seconds, but some regeneration is required for an empty or partially loaded conveyor to be stopped in a similar time.

Why Compensation is Needed

Several factors pointed to the need for compensation at Gascoigne Wood. The power factor of the thyristor drives for the drift conveyors needs to be improved. Even if there were no tariff requirement, a reduction of the reactive power demand of the colliery would be required to avoid excessive voltage drops in the supply-system – especially in circuit-outage conditions which give low short-circuit levels at Gascoigne Wood. Also, because of the harmonic current generated by the thyristor converters, harmonic absorption-filter circuits are needed.



10 *Simplified diagram of the 11 kV distribution system*



11 *Single-line diagram of one static compensator*

Although either conveyor is independently capable of handling the complete output of the mine, normally both will be operating, and from time to time they may both be fully loaded. The most severe operating conditions, requiring power-factor correction of the thyristor-converter reactive demand, occur with each conveyor operating at half speed (34.2 rev/min) with full coal load (equivalent to 1800 tonnes per hour at full speed) for which the total demand is 12.2 MW, 17.5 MVAr. There are, of course, many other loads at the colliery, including various auxiliary conveyors, and these loads have been assessed as 16 MVA, 0.7 power factor.

In general the total load levels will change relatively slowly, which could normally permit voltage control and power-factor correction to be achieved satisfactorily by means of tapchanging of the supply transformers and switching of shunt power-factor-correction capacitor banks. However, high-speed dynamic compensation is essential to deal with several anticipated fault and emergency situations, for which both of the main conveyors and some of the auxiliary drives could be stopped or tripped almost simultaneously. Such load rejection conditions would cause excessive voltage rises on the 11 kV busbars and also the possibility of excessive disturbances at possible supply points to other consumers within the 33 kV distribution system, especially when the emergency circuits shown in fig. 9 are in use.

Computer studies showed that, in the absence of compensation, tripping of both conveyor belts would cause a voltage rise in excess of 14%. With both conveyor belts in operation, the power factor would be lower than is desirable and the harmonic distortion in the supply system, in the absence of filtering, would be in excess of Electricity Council Engineering Recommendation G5/3.

The Selby Compensators

It was decided that the compensation equipment should be split into two identical halves, fed from different sections of the 11 kV supply busbar as shown in fig. 10, in order to give some redundancy and increased security. The compensators were specified to limit the voltage rise to 6% at the main 11 kV busbar at Gascoigne Wood when both conveyors are simultaneously switched off from the worst loading condition. In the unlikely event of an outage of one compensator, the voltage rise for this condition must be limited to 8%.

Each compensator consists of a saturated reactor in parallel with harmonic filters, as shown in fig. 11. Each three-phase Twin-Tripler-type saturated reactor has a rating of 16.1 MVAr with a rated current of 800 A at 11.6 kV and is ONAN cooled.

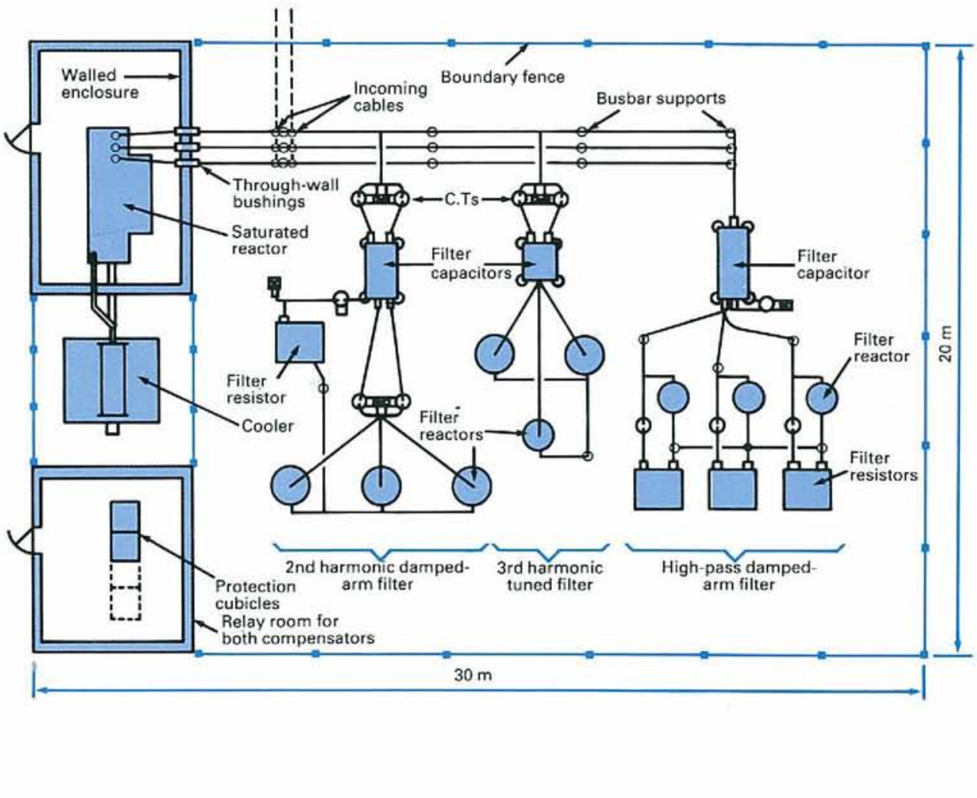
The shunt capacitance required is 14 MVAr at 11 kV, 50 Hz (a total of 28 MVAr for both compensators) to provide the reactive power generation for dynamic swing conditions and for power-factor correction to between 0.95 lagging and unity at the main 11 kV busbar at Gascoigne Wood.

Calculations which took into account the possible range of system harmonic impedance at 11 kV and the alternative connection of one or two 14 MVAr shunt capacitor banks indicated that parallel resonance could occur near to 2nd and 3rd harmonic frequencies. Both of these frequency components are present as pre-existing distortion of the supply voltage. To eliminate any problems due to such resonances, each 14 MVAr shunt capacitor includes separate branches to attenuate 2nd and 3rd harmonics; there is also a broadly tuned, damped-arm filter which provides a high admittance to those harmonic currents (especially in the range between 5th and 19th harmonics) generated by the converters. Each filter is connected with unearthed starpoint.

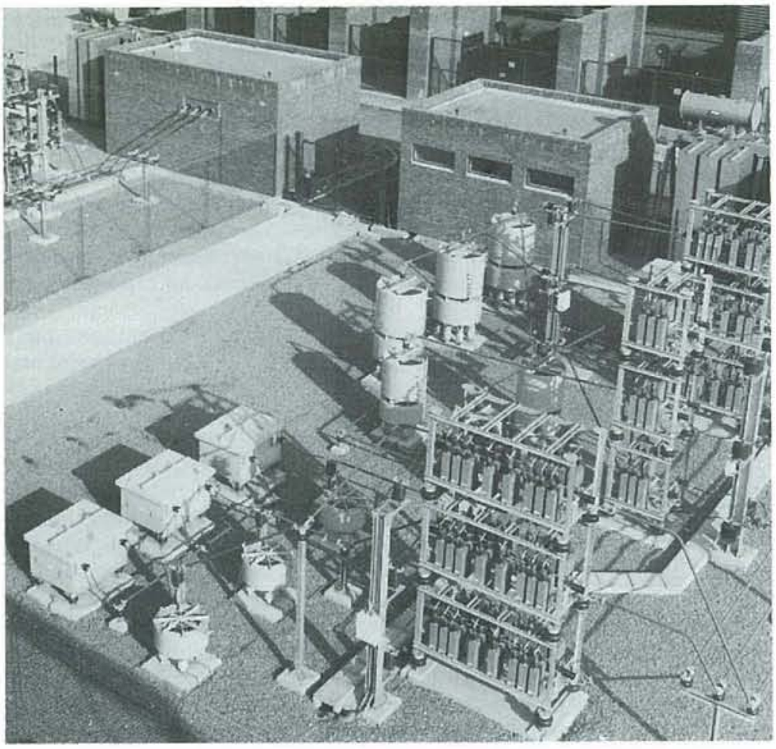
The capacitor units for each filter arm are mounted as a stack of three single-phase banks and are equipped with external expulsion-type fuses. The filter reactors are air-cored and air-cooled. The auxiliary capacitor of the 2nd-harmonic damped-arm filter is connected in series with the reactor, and these are tuned to provide a very low impedance at the system frequency of 50 Hz so that very little fundamental-frequency current flows in the filter resistor. For other frequencies, and especially for 2nd-harmonic currents, the filter resistor provides damping. The 2nd-harmonic filter has a nominal rating of 4 MVAr, the 3rd-harmonic tuned filter is rated at approximately 2 MVAr and the high-pass damped-arm filter at 8 MVAr. Unbalance protection is provided for each filter to detect capacitor unit failure and conventional forms of protection are provided for all other components of the compensators.

The 33/11 kV stepdown transformers are equipped with conventional AVR tapchange control relays, but these do not have suitable response characteristics and flexibility to maintain the necessary operating conditions for the compensated 11 kV busbars. When the compensators are in service a special tapchange control scheme is brought into action to co-ordinate the tapchange controls in a manner that is appropriate to the actual configuration of supply transformers and compensators.

All power-frequency components of the compensators are installed outdoors, except for the saturated reactors which are housed in separate brick buildings, adjacent to



12 *Layout of compensator*



13 *The compensators at Gascoigne Wood*

the compensator compounds, to reduce noise. The protection cubicles for the two compensators are housed in a single building between the saturated-reactor buildings. Fig. 12 shows the layout of one compensator, the other being similar. Simple concrete block foundations are used and interconnections between main components are by tubular copper conductors. The compensator compounds are fenced.

Fig. 13 is a photograph of one compensator, the second being alongside it on the left. It illustrates the implementation of the layout, the three buildings for saturated reactors and for protection cubicles being at the far side of the compounds.

Conclusion

It has been found possible to use a standardized design of static compensator at twelve sites where thyristor-fed mine winders have been installed by the NCB. The compensator was designed to limit voltage variations and harmonic distortion in accordance with Area Board requirements, and its behaviour in service is fully in line with the calculated performance.

It was not a regular operating cycle but an emergency load-rejection condition that necessitated static compensators for the Selby complex. The ratings of the drift-conveyor drives at Selby are much larger than those of any of the compensated winders, and require more compensation and a different operational characteristic. This justified the development of a new tailor-made compensator to meet the specific performance criteria for the application at Selby.

Appendix 15.6 V Ayadurai : 'Static VAr Compensator for Arc Furnaces, Shaoguan Steelworks in China'
Chinese Society of Electrical Engineering, November 1991

CHINESE SOCIETY OF
ELECTRICAL ENGINEERING

"STATIC VAR COMPENSATOR FOR ARC FURNACES OF SHAOGUAN STEELWORKS IN CHINA"

by

V Ayadurai, B.Sc., C.Eng., M.I.E.E.

GEC Transmission and Distribution
Projects Limited

STATIC VAR COMPENSATOR FOR ARC FURNACES SHAOGUAN STEELWORKS IN CHINA

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Senior Design and Application Engineer

GEC Transmission and Distribution Projects Limited

INTRODUCTION

Electric arc furnaces are considered as being one of the worst sources of voltage fluctuation on a power supply system. Electric arc furnaces, because of their rapidly and widely varying demand, cause large rapid changes of unbalanced active and reactive power demand from the power supply system. These can produce a very large voltage fluctuation, causing unpleasant visible light flicker and other objectionable effects to other consumers. The fluctuations in the three phases are, moreover, unbalanced. Unbalance in the power system causes negative sequence component of current which imposes an additional load or heating effect on the electrical machines. Arc furnaces also create harmonics. Sensitive electronic equipments and television receivers can also be affected by harmonics. Arc furnaces are designed to operate at low power factor , say 0.7 and 0.8. Poor power factor creates unnecessary losses in the transmission lines and transformer. To reduce harmonic injection into the power supply system, to improve power factor of the arc furnaces during melting, to support the voltage during arc furnace short-circuit, and to balance the three-phases as well as limit the voltage fluctuations, a rapidly variable reactive var compensator is needed.

DESCRIPTION OF SHAOGUAN STEELWORKS SYSTEM

Initially the Shaoguan Steelworks in Shaoguan, China, had 2 x 5 MVA arc furnaces connected to the 6 kV system by a 20 MVA, 10.5% impedance, two winding system stepdown transformer. The Shaoguan supply system frequency is 50 Hz. The primary winding of the stepdown transformer was connected to 110 kV which was defined as the point of common coupling (pcc) with other consumers. There was a 6 MVAr plain shunt capacitor available on the 6 kV system to improve the power factor during the operation of the arc furnaces. The short circuit level at the point of common coupling was 515 MVA (min) and 925 MVA (max). The Shaoguan company were operating these 2 x 5 MVA arc furnaces with the 6 MVAr plain shunt capacitor on 6 kV without any compensator available on the system for dynamic var swing. Even though the short circuit voltage depression (scvd) at the point of common coupling was approaching 3% during scrap melting, there was hardly any complaint from other customers.

Shaoguan next decided to increase steel production to meet their growing demand. They wanted to bring two additional 9 MVA arc furnaces (altogether 2 x 5 MVA on 6 kV system plus 2 x 9 MVA arc furnaces on a 35 kV system) for improved steel work operation.

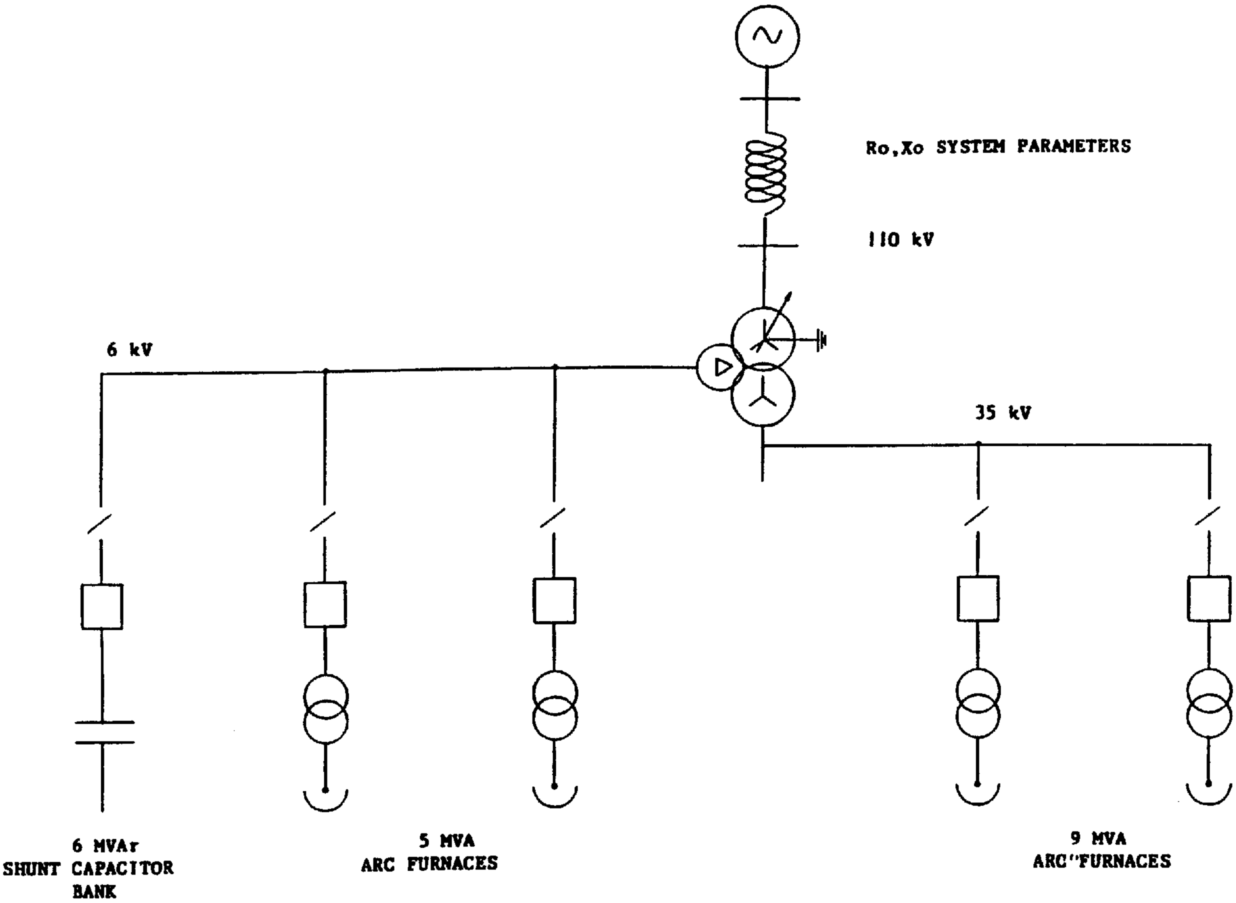

FIGURE 1. SHAOGUAN STEELWORKS SYSTEM

They have decided to modify the existing Shaoguan electrical power supply system to include 31.5 MVA, three winding system step down transformer. The three winding transformer supplying the arc furnaces has the following reactance, i.e. on 31.5 MVA, 110 kV to 6.6 kV; 17.5%, 110 kV to 38.5 kV; 10.5%, 6.6 kV to 38.5 kV; 6.5%. The primary winding of the stepdown transformer is connected to 110 kV, which is once again defined as the point of common coupling. Four electric arc furnaces are to be compensated, 2 x 9 MVA arc furnaces connected to the 35 kV system and 2 x 5 MVA arc furnaces connected to the 6 kV system supplied by the new three-winding stepdown transformer. The operation of these four arc furnaces on Shaoguan's supply system would have exceeded the limit of 3% for scvd and rapidly variable compensation was therefore considered to be essential.

PERFORMANCE CRITERIA

Reduction of Flicker

The short circuit voltage depression (scvd) criterion to be met. This is the voltage dip at the point of common coupling with other consumers, when the three arc furnace electrodes are immersed in a bath of molten steel. This criterion is practised by the National Grid Company and the various

Electricity Companies in the United Kingdom when planning supplies to arc furnace installations (UK Engineering Recommendation P7/2). From the research and field tests carried out by the Electrical Research Association (ERA), it was agreed that the scvd for light flicker networks up to 132 kV should be less than 2% in the United Kingdom. However, on the Shaoguan system it was agreed that performance criteria for scvd should be 3% (using the fourth power law the size of the total equivalent single furnace is about 1.25 times a 9 MVA furnace; the effective scvd for a single 9 MVA furnace is that 2.4% and the gauge point fluctuation voltage (Vfg) = 0.5% as measured with an ERA meter in accordance with UK Engineering Recommendation P7/2). Harmonic voltage distortion at the 110 kV pcc due to the arc furnaces and SVC is to be limited to 1.5 % rss total in accordance with UK Engineering Recommendation G5/3, for harmonic orders 2nd to 19th inclusive. Performance is to be achieved for the weakest supply system impedance condition, (i.e. for a short circuit level of 515 MVA) at 110 kV pcc.

OPERATION OF ARC FURNACES ON A WEAK SUPPLY SYSTEM

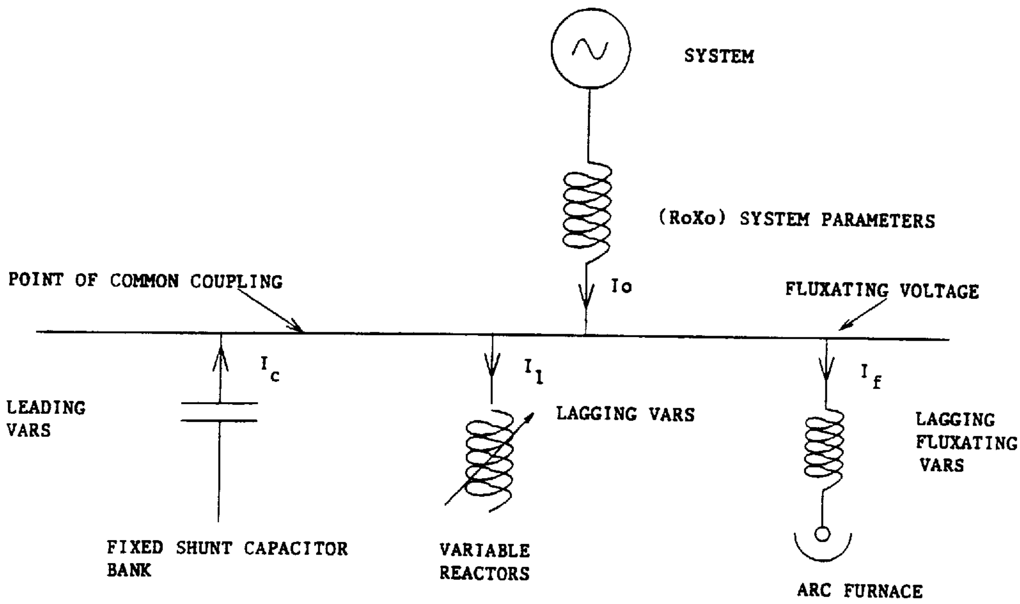

FIGURE 2. BASIC STATIC COMPENSATOR WITH VARIABLE INDUCTOR AND FIXED CAPACITOR

The voltage drop in an a.c. electric power supply system, caused by problem loads such as electric arc furnaces which are large compared with the short-circuit level of the system, is mainly due to reactive component of the load current I_q flowing through the system reactance X_o, i.e. $\Delta V = I_q X_o$. The variations in the electric arc furnace loads can cause voltage fluctuations and consequent objectionable or irritating light flicker, negative phase sequence components, high proportion of harmonic currents and poor power factor.

For a normal supply system impedance, the percentage voltage fluctuation ΔV, at a busbar is given by the following relationship:

$$\frac{\Delta V}{V} = \frac{\Delta Q + \Delta P/\tan\phi}{S_o}$$

Where $\tan\phi = X_0/R_0$ and S_0 short circuit power level at the busbar and P and Q are the active and reactive power of the load flowing through supply system impedance.

The load cycles of arc furnaces vary widely, depending on size and metallurgical requirements. The first part of the cycle consists of melt-down period when the solid charge is melted and the main energy input needed. The later part of the cycle is known as the refining period; in this, energy supplied has only to make good the heat losses. A considerable movement of the charge occurs during melt-down period with consequent variations in the arc lengths on each phase. The two main causes of fluctuation are believed to the first, the movement of the arcs as flexible conductors in a magnetic field and in some cases their extinction and restriking; secondly, the short circuiting of the graphite electrodes by scrap movement.

When the fluctuating currents pass through the power supply network impedance, a corresponding fluctuation is set up in the supply voltage at the point of common coupling with other consumers (pcc). Visible light flicker is due to power system voltage fluctuation. The fluctuations in the three phases are, moreover, unbalanced. During melting period the arc furnaces also create harmonics. Arc furnaces are designed to operate at low power factor say 0.7 and 0.8. When the electrode is driven into the scrap metal, it usually produces a dead short circuit on one phase. During arc furnace short circuit, arc furnace demands larger reactive power from the electricity supply, in turn a larger voltage dip is produced on the system. The static var compensator should be capable of supporting the system for the dynamic reactive var swing requirement due to arc furnace swing from the open circuit to short circuit.

Harmonics

Due to non-linear characteristic of the arc furnace, a high proportion of harmonics is generated by arc furnaces during melting. The typical values of the harmonics (assumed) are as follows:

HARMONIC NUMBER	% OF FULL LOAD CURRENT FOR 9 MVA ARC FURNACE	% OF FULL LOAD CURRENT OF 5 MVA ARC FURNACE
2	6	9
3	7	10
4	4	6
5	7	10
6	2	3
7	4	6
9	2	3

The currents listed above are those averaged over a period of not less than 10 seconds and relate to operation during the melting period (with respect to the 9 MVA furnaces the harmonic currents are those applicable to operation at the 256 V tap). In respect of two furnaces operating together on the same busbar the total harmonic current generated is the quadrature summation (i.e. rss) of the individual currents at each harmonic.

DETERMINATION OF THE SIZE OF THE STATIC VAR COMPENSATOR (SVC)

Studies were carried out using computer to define the 'MVAr generation' (SVC size) and the location of SVC the point of connection (poc) on the Shaoguan electrical system. Load flow studies were carried out to determine the steady-state 'MVAr generation' either on the 35 kV busbar where 2 x 9 MVA arc furnaces are connected or on the 6 kV busbar where 2 x 5 MVA arc furnaces are connected. The most effective location for the 'MVAr generation' for four arc furnaces (2 x 9 MVA arc furnaces connected to the 35 kV system and 2 x 5 MVA arc furnaces connected to 6 kV system supplied by a 31.5 MVA three-winding system stepdown transformer) had been found as the 35 kV bus.

The total circuit reactance of each arc furnace on top tap, which includes arc furnace transformer, secondary busbars, flexibles and electrodes was estimated as 30% on its own rating. This gave short-circuit power of the individual arc furnaces as:

$$S_{f1}(1 \text{ x } 5 \text{ MVA arc furnace}) = \frac{5}{0.3} = 16.7 \text{ MVAr}$$

$$S_{f2}(1 \text{ x } 9 \text{ MVA arc furnace}) = \frac{9}{0.3} = 30 \text{ MVAr}$$

for installations involving more than one arc furnace, a statistical method was derived by Jenkins to determine the rating of that equivalent single arc furnace which would give rise to the same flicker annoyance. Using Jenkins' mathematical analysis the short-circuit power of the total equivalent single furnace giving the same flicker effect as the 4 arc furnaces is 36.5 MVAr

$$.\sqrt[4]{(2 \times 16.7^4 + 2 \times 30^4)}\ .$$

The SVC design philosophy has been to achieve a balance between the following (conflicting) criteria:

- Compliance with disturbing limits;

- Minimisation of steel-making cost:

- Minimisation of capital and loss cost of SVC.

The dynamic swing rating of an SVC is determined by the severe load disturbance. In the case of arc furnace, the swing is from open-circuit to three-phase short circuit. The worst disturbance occurs mainly during the first few minutes of melting down a new charge, and very rarely at other times. The effect of various buffer reactors in line with each arc furnace on 'MVAr generation' requirement where evaluated with all 4 arc furnaces were operating at the top tap (i.e. on the secondary voltage of the arc furnaces, 320V). The introduction of series inductance in the furnace circuit reduces the arc furnace short-circuit current. However, the same effect could be achieved by operating at a lower tap on the furnace transformer. It was agreed by Shaoguan that during the first few minutes of each new charge, melting should commence at the next 256V tap, with top tap (320V) being selected once molten metal has formed. Since the lower tap is obligatory only for a very short proportion of the melt the resulting increase in cycle time will be minimal, but the reduction in furnace short-circuit current and hence SVC rating and cost is very significant.

The SVC is connected to the 35 kV busbar (the point of connection, i.e. poc). Without the SVC the calculated short circuit voltage depression (scvd) at 110 kV is 4.5% approx. for 4 arc furnaces. The scvd is to be corrected to 3% at 110 kV for 4 arc furnaces with the SVC at 35 kV; this represents a reduction factor of 1.5 for the voltage fluctuation.

Two separate designs were produced, one a saturated reactor type SVC and the other a thyristor controlled reactor type SVC.

SELECTION OF SVC AND ITS RATING

The SVCs of the Saturated Reactor (SR) type are particularly important for application to flicker suppression when large reduction factor (greater than 2) must be achieved. For the compensation of the Shaoguan arc furnaces, which required a three phase short circuit voltage depression of 3% but did not require an exceptionally large reduction, the reduction factor required of 1.5 is less than 2 for furnace installation. The SVC supplied to Shaoguan Steelworks is a Thyristor Controlled Reactor (TCR) type.

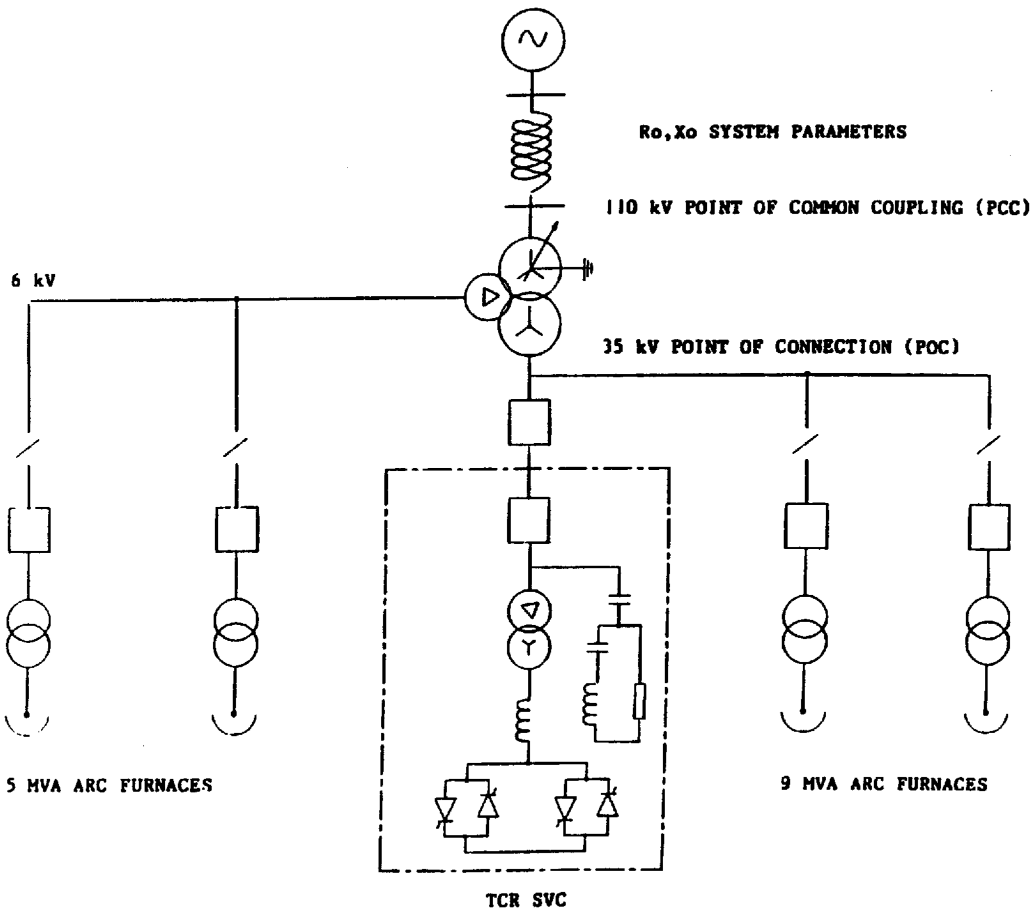

FIGURE 3. THYRISTOR CONTROLLED REACTOR (TCR) TYPE STATIC VAR COMPENSATOR

The thyristor and the Var reactors are connected to the 35 kV steelworks busbars by a two winding (Delta/Star) stepdown transformer with a ratio of 35/2.3 kV, and rating of 12 MVA with an overload capability of 14 MVA. In order to withstand system overvoltage of up to 10% the thyristor valves are rated for a maximum continuous voltage of 2.53 kV rms (corresponding to 38.5 kV) with a maximum current of 3350 rms. The rated voltage of the transformer has been assigned at 36.7 kV (2.43V) in order that it may also withstand continuously an overvoltage of 38.5 kV when carrying rated current, in accordance with IEC70. A harmonic filter of 14.7 MVAr rating at 38.5 kV is connected on the 35 kV busbar to provide the necessary generation of reactive power. The filter is connected with unearthed star points.

PRINCIPLES OF OPERATION OF A THYRISTOR CONTROLLED REACTOR SVC

In power systems, SVCs are often required both to generate and absorb reactive power (VArs); continuously variable absorption of VArs can be achieved readily with a variable inductor such as a phase-controlled linear reactor. It is normal practice to achieve continuously variable generation of VArs by the parallel combination of a fixed capacitor bank and a variable inductor. An additional advantage of this arrangement is that, if required, the fixed capacitor bank can be converted readily into harmonic filtering circuits to cater for the harmonic currents produced by the variable inductor and troublesome loads such as arc furnaces.

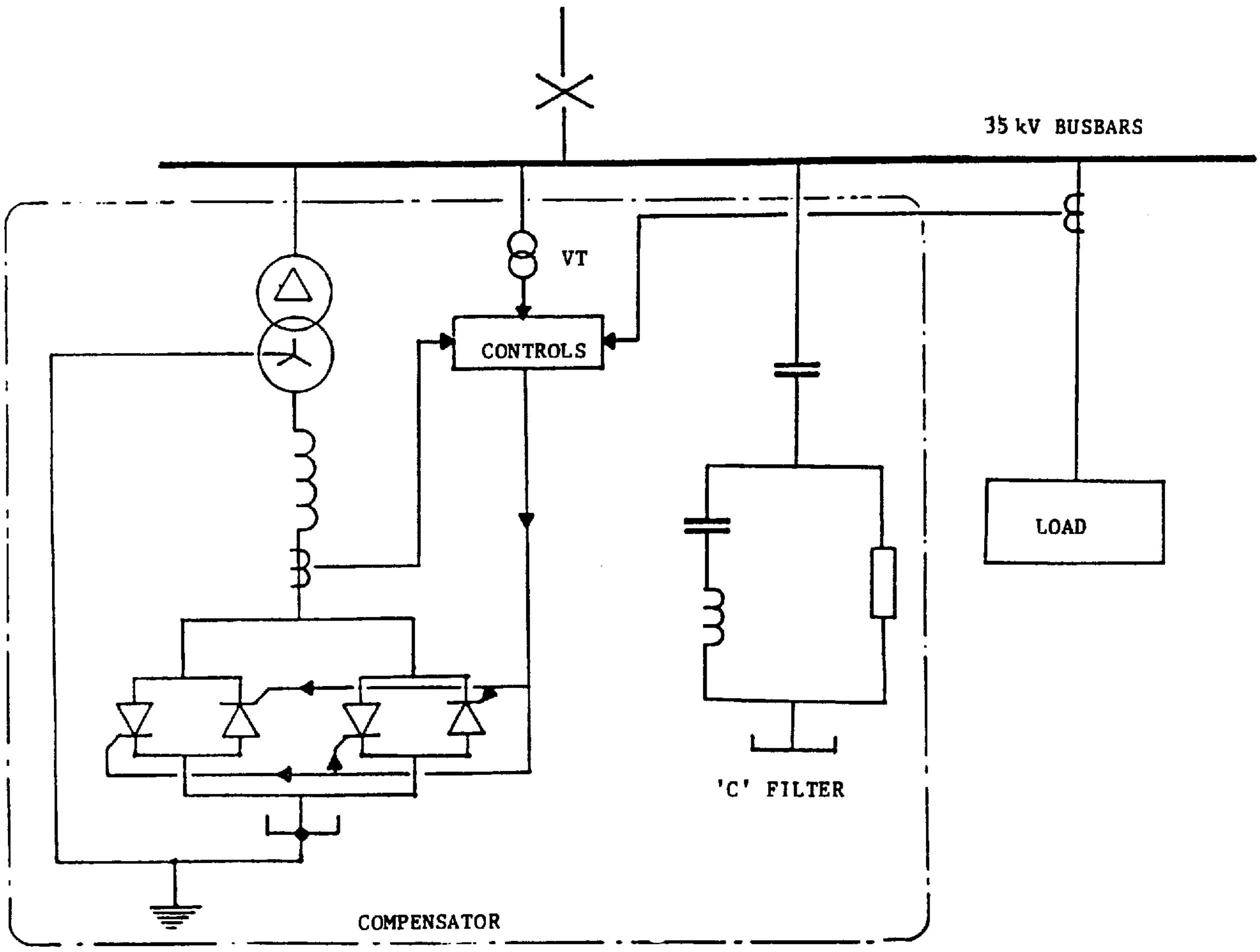

FIGURE 4: SINGLE LINE DIAGRAM OF COMPENSATOR PLUS CONTROL

A Thyristor Controlled Reactor (TCR) compensator is basically a linear reactor and thyristor switch or 'valve' connected in shunt to the system to provide variable Var absorption, Fig 4. The valve has thyristors connected in anti-parallel, each carrying current in one direction only. By varying the firing angle, i.e. the point-on-wave at which the thyristors are turned on, the compensator control system is capable of varying the reactive current in the linear reactor to any required value between the maximum rated value resulting from continuous conduction and zero when there is no conduction, Fig 5.

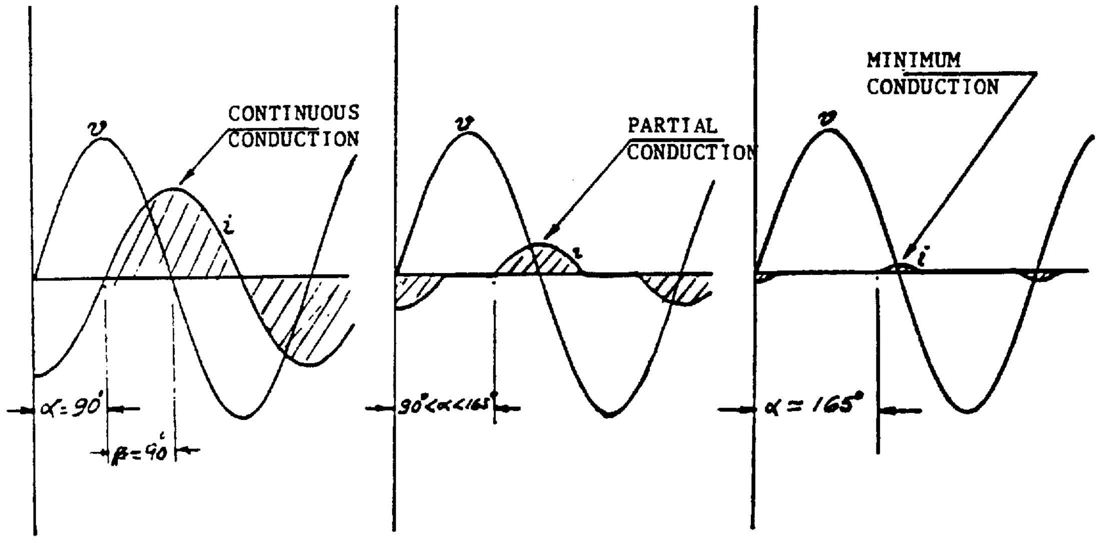

FIGURE 5 EFFECT OF VARYING THE FIRING ANGLE (α)

The firing angle delay, alpha (α) , is normally defined from voltage zero, so that full conduction of the (inductive) current occurs at $\alpha = 90^0$ and zero conduction at $\alpha = 180^0$. The conduction angle called sigma (σ) is twice β , for an ideal reactor with no resistance. The current will be offset for α between 0 and 90^0, Fig 6.

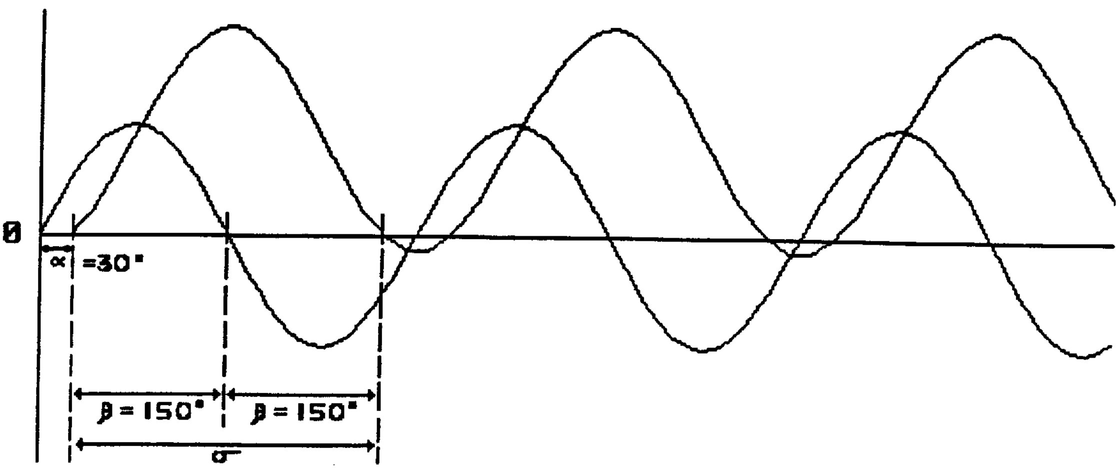

Fig 6 OFFSET REACTOR CURRENT DUE TO FIRING AT $\alpha<90^0$

This results in a d.c. component and cannot be tolerated on a steady state basis. Transiently it may be acceptable but of no great advantage. Therefore α is limited between 90 and 180°.

CIRCUIT ARRANGEMENT OF SVC

All power frequency components, except the thyristor valves of the SVC are installed outdoors. The valve, protection and control cubicles and cooling module are housed inside a building. The SVC is fed from a secondary of a delta/earthed star stepdown transformer of 14 MVA (max) rating (fig 3). The secondary is therefore connected in star in order that each phase may be loaded independently of the others. In this manner the positive and negative sequence system can have their amplitudes individually regulated and all cases of unbalance at the furnace can be compensated. This transformer is mainly for connecting the SVC to 35 kV system (secondary side) of the 3-winding system transformer. The SVC transformer is naturally cooled and filled with oil (ONAN). The thyristor controlled reactors (VAr reactors) are air cored and air cooled connected in series with the transformer. The TCR SVC comprises three-single reactors and thyristor valves connected in star. Since the thyristor switch achieves its active control features by switching action, it produces a discontinuous, non sinusoidal current and shown in fig. 5 and hence generates currents at harmonic frequencies. As a percentage of the full conduction current the largest harmonic currents in a single-phase circuit are approximately 13.5% of 3rd harmonics, 5.0% of 5th, 3.6% of 7th, 1.6% of 9th and 1% of 11th. The triplen harmonics (3rd, 9th etc) only appear in the primary line current of the transformer when the TCR is forced to operate with unequal currents in the three phases. As explained in the previous section substantial harmonic currents are generated by the arc furnaces. The dominant harmonics from the arc furnaces are 2nd, 3rd, 4th and 5th.

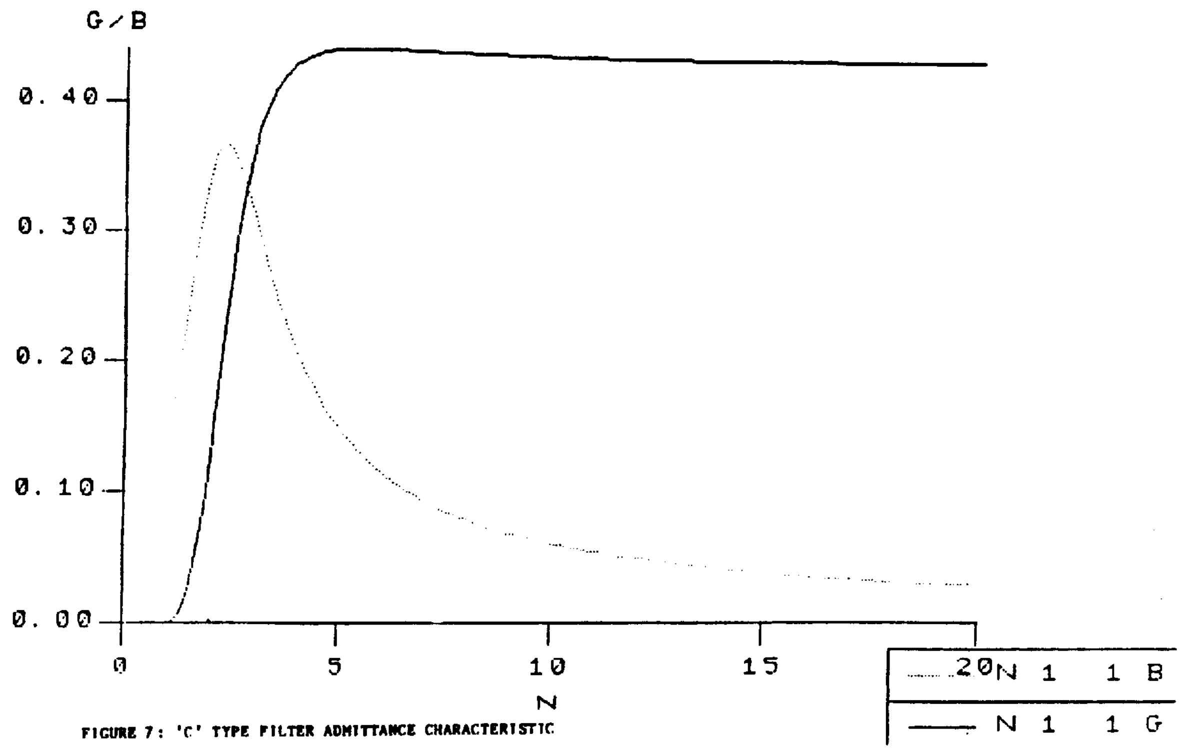

FIGURE 7: 'C' TYPE FILTER ADMITTANCE CHARACTERISTIC

The shunt capacitor bank connected to 35 kV busbar is arranged as low order damped harmonic filter (called 'C' filter) which provides a high admittance to those harmonic currents (especially 2nd and 3rd harmonic) generated by arc furnaces and the TCR. Fig. 7 shows the admittance curve of the 'C' filter, used in Shaoguan SVC. The capacitor units are mounted as a stack of the single phase banks and are internally fused. The filter reactors are air cored and air cooled. The auxiliary capacitor of the filter is connected in series with the reactor, and these are tuned to provide a very low impedance at system frequency 50 Hz so that very little fundamental-frequency current flows in the filter resistor (ref fig. 3). For other frequencies, and specifically for 2nd harmonic currents, the filter resistor provides damping. Unbalance protection is provided to detect capacitor unit failure and conventional forms of protection are provided for all other components of the compensator.

The neutral connection of the secondary star winding of the SVC stepdown transformer and thyristor valves is earthed. Therefore the water-cooled heatsinks are at earth potential, there are no significant electrical potential differences around the cooling circuit and there is no requirement of water-conductivity control to minimise leakage current which would otherwise cause electrolysis of the water. Ordinary clean water may be used for the thyristor value cooling circuit.

A closed-circuit, primary water system is used to cool the thyristor heatsinks, the heat being rejected to secondary water via a water/heat exchanger. The complete cooling plant is located indoors. The primary coolant is fed to the thyristor heatsinks from a ground level pipe and returned to a similar pipe mounted at the same level. The water is circulated round the primary cooling system by means of a pump. A thermometer and a flow switch are provided in the primary coolant path. A thermometer thermostat is provided on each heatsink. A header tank is used to cater for expansion and contraction of the water. The heatsinks are of the 'binocular' type used for industrial rectifiers. They are an aluminium bar extruded with two holes for the cooling fluid. Altogether there are two heatsinks. The thyristor valve design is based on a modular concept. Each module comprises two thyristors of 75 mm diameter, connected in inverse parallel. The module also includes a damping network overvoltage protection and thyristor firing circuits.

There are two modules (mounted on each heat sink) in parallel per phase and altogether 4 thyristors per phase. There is only one such thyristor set in series with each phase because the secondary current is chosen to be sufficiently low and the secondary current necessary to achieve the required rating is within the current rating of the two parallel thyristors.

With a star-connected thyristor valve all the individual thyristors are connected to the star-point and a simple water-cooled heat sink is used to mount the thyristors and to give single-sided cooling.

The thyristor valves are mounted in a conventional steel cubicle with an open back. Busbars interconnect the valves to the Var reactors. The protection and control cubicles are positioned in the middle with the valve cubicle next to control cubicle on one side and the cooler module next to protection cubicle on the other side.

CONTROL OF THYRISTOR CONTROLLED REACTOR SVC

The control is based on measurements of TCR current and arc furnace load current. Currents from the load (arc furnaces) and the TCR are multiplied by busbar voltage to form VAr signals from which an error signal is derived. This controls a phase-locked oscillator to generate firing pulses for the TCR so that the fluctuations of the arc furnace are reduced to the required extent.

As explained earlier, the voltage dip ΔV on the system is mainly due to a change in the flow of the reactive components of the arc furnace currents through the system reactance. Even though the R/X of the Shaoguan system impedance may be small (about 0.1) a provision is available in the control system to measure the real power and to use it in combination with the reactive power to provide additional correction for this system resistance.

Changes in load reactive current are offset by opposite changes of TCR current, which in turn reduce the change of reactive current drawn through the system reactance and hence reduce busbar voltage changes caused by load current changes. With a large TCR the system could be dimensioned to draw a constant reactive current i.e. $I_{load} + I_{TCR} = \text{constant}$. Thus when the load current is zero the TCR current would be controlled to reduce by an equal amount, becoming zero when the load current reached its maximum value.

Thus

$$(I_{TCR})_{max} = (I_{LOAD})_{max}$$

It is not generally necessary to provide full load compensation. In practice the voltage fluctuation at the pcc can be limited to an agreed acceptable value. Normally therefore the change in TCR current is a proportion of the change in load current. Current signals proportional to arc furnace currents are obtained from their conventional CTs and are added together using appropriate summation CTs. Thus $I_{TCR} = k\ I_{LOAD}$ where k is the factor of proportionality. Current signals proportional to current in the TCR are obtained by integrating the signals from differentiating current transformers (DCTs). Similarly differentiating current transformers are used to obtain load current signal fed from the summation CTs. The advantage of DCTs is that, unlike conventional iron-cored CTs, they do not saturate in the event of a current with a substantial d.c. component being passed through them.

Each differentiated current signal is multiplied by its corresponding voltage signal in an electronic multiplier. The d.c. components in the outputs of these multipliers are proportional to the reactive power in each phase of the TCR and to the reactive powers in each phase of the arc furnace load. Arc furnace real power is obtained using conventional CTs summated by the corresponding voltage.

The operation of the 4 arc furnaces will be random, one may be melting scrap metal while others may be refining, or one in two might have been switched off (for tapping the furnace, fettling and recharging etc).

The TCR control is designed so that whatever the value of the time-averaged arc furnace currents the TCR current will operate at an average value of about

0.75 to 0.8 pu, where 1 pu TCR current is defined as 3350A. The TCR therefore always retains the capability for its output to be increased or decreased as necessary in response to the downward and upward fluctuations of load current.

Thus if a furnace is switched off, the TCR current will initially increase to compensate for the reduction of load current. If, after a few seconds, the load current has not been restored, the average current of the TCR will begin to decrease until it reaches the preset average range. When an arc furnace is switched on, the increased load will cause an initial reduction of TCR current, but after a few seconds the control will bring the TCR current back within the preset steady range.

TCR Control

The TCR Control uses the phase-locked oscillator system as incorporated in all GEC designs of Thyristor-Controlled compensators.

The phase-locked oscillator, an independent one for each phase of the TCR, operates at twice the fundamental frequency, generating firing pulses at 180^o spacing in the balanced state to fire the respective "forward" or "reverse" thyristors, in a valve.

The steady-state minimum firing angle is determined by the forward firing interlock at each thyristor level, which is about +30V. The time taken the for thyristor grading network to cross the +30V threshold from start of recovery of the reverse thyristor is much less than 1^o at full conduction, therefore the minimum firing angle can be taken as practically 90^o.

The maximum firing angle is normally 165^o, which corresponds to minimum operating current in the TCR of about 1%. However if a valve has a thyristor continuously firing by its break-over diode overvoltage protection device (indicated by control failure via the databack system), this is reduced to 150^o to ensure that there is sufficient voltage for the valve to fire.

Manual Alpha (α) Control

A manual control mode is available whereby the firing angle, α, can be set by an engineer for test purposes. In this mode α is the feedback quantity and system overvoltage is ignored. This mode is not intended to be used in normal operation.

TCR Valve Firing and Databack

Each TCR valve is fired by gate units, normally connected to two opposite facing thyristors, with cathodes electrically at the same potential. The common cathode connection allows the gate unit to directly trigger the forward thyristor and the reverse thyristor without an isolation stage. Each direction thyristor is, however, controlled independently.

Valve Firing Signals

The gate unit contains two electronic fire latches, one related to each thyristor. The state of both latches is controlled from TCR firing control by start/stop pulses coded onto a single optical fibre ("firing fibre"), as shown in fig 8. If a latch is set, the gate unit will generate a pulse to trigger the thyristor whenever its forward voltage exceeds about 30V. Thus, in effect, the thyristor acts as a diode whenever its fire latch is set.

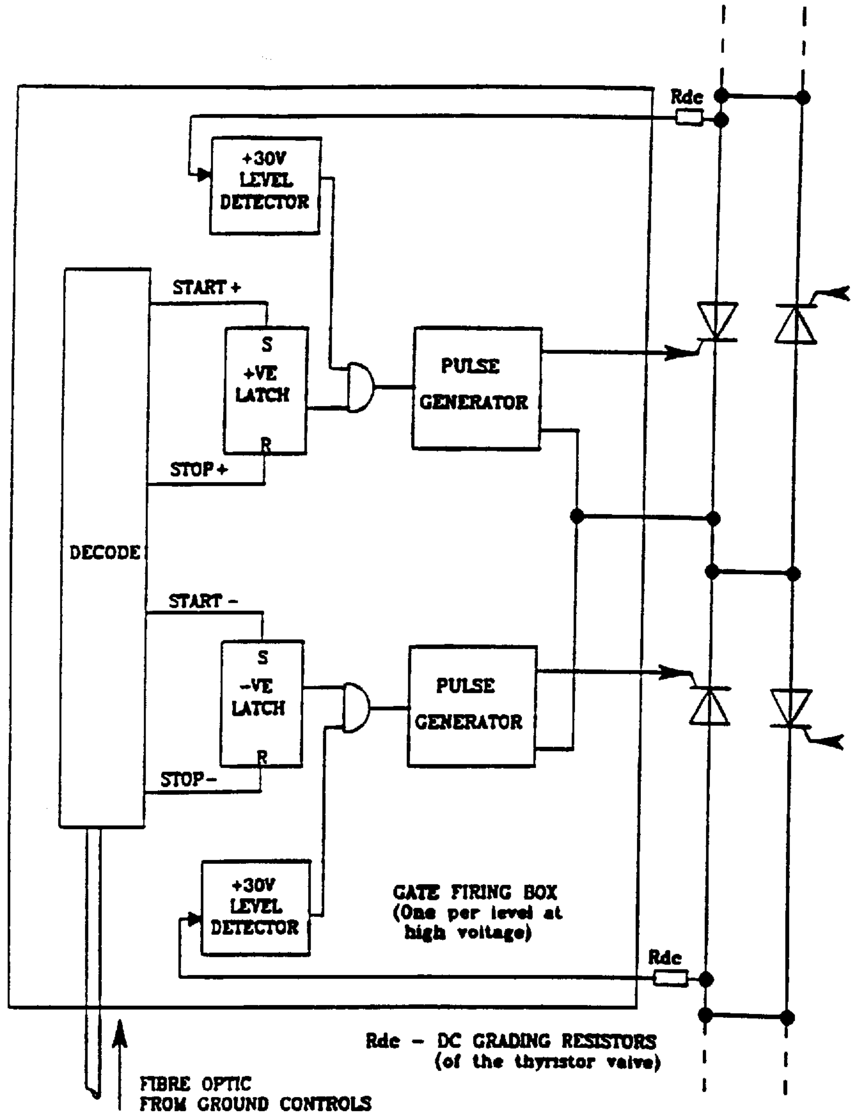

FIGURE 8 THYRISTOR GATE FIRING CIRCUITS (TCR)

CONCLUSION

When electric arc furnaces are operated on a power supply system, to prevent voltage disturbance and harmonic distortion reaching excessive levels, the provision of static var compensation equipment is always worthy of consideration. The static var compensator was designed to limit harmonic injection into the Shaoguan power supply system, to improve power factor of the arc furnaces during melting, to support the voltage during arc furnaces short circuiting, and to balance the three-phases, as well as limit the voltage fluctuations. The action of the static var compensator is to give rapid power factor correction and can make a substantial reduction in overall kVAh demand and an improvement in measured power factor, thus reducing tariff charges.