



RP 12-4

**ELECTRICAL SYSTEMS AND
INSTALLATIONS
POWER SYSTEM PROTECTION
AND CONTROL**

August 1994

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BP GROUP RECOMMENDED PRACTICES AND SPECIFICATIONS FOR ENGINEERING											
Doc. No. RP 12-4		Issue Date August 1994	Latest Amendment Date								
Document Title ELECTRICAL SYSTEMS AND INSTALLATIONS POWER SYSTEM PROTECTION AND CONTROL (Replaces BP Engineering CP 17 Pt 4)											
APPLICABILITY Regional Applicability: International											
SCOPE AND PURPOSE The BP Group RP 12 series specifies BP general requirements for electrical systems, equipment, materials and installations. This document is split into two sections, BP Group RP 12-4 Part A and BP Group RP 12-4 Part B. BP Group RP 12-4 Part A specifies those items which apply generally to the selection and application of protective relays to IEC 255, which are supplied to provide electrical system protection for onshore and offshore installations. BP Group RP 12-4 Part B specifies those items which apply generally to the control, instrumentation, metering and alarm annunciation requirements for power system control of onshore and offshore installations.											
AMENDMENTS <table border="0" style="width: 100%;"> <tr> <td style="width: 15%;">Amd</td> <td style="width: 25%;">Date</td> <td style="width: 25%;">Page(s)</td> <td style="width: 35%;">Description</td> </tr> <tr> <td colspan="4"> </td> </tr> </table>				Amd	Date	Page(s)	Description				
Amd	Date	Page(s)	Description								
CUSTODIAN (See Quarterly Status List for Contact) Electrical											
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FOREWORD

Introduction to BP Group Recommended Practices and Specifications for Engineering

The Introductory Volume contains a series of documents that provide an introduction to the BP Group Recommended Practices and Specifications for Engineering (RPSEs). In particular, the 'General Foreword' sets out the philosophy of the RPSEs. Other documents in the Introductory Volume provide general guidance on using the RPSEs and background information to Engineering Standards in BP. There are also recommendations for specific definitions and requirements.

Value of this Recommended Practice

This document identifies the recommended protection and control philosophies, preferred systems and equipment for electrical power systems associated with onshore and offshore applications.

Special consideration has been given to the growing interest in 'smart' protection and control equipment.

Application

Text in *italics* is Commentary. Commentary provides background information which supports the requirements of the Recommended Practice, and may discuss alternative options. It also gives guidance on the implementation of any 'Specification' or 'Approval' actions; specific actions are indicated by an asterisk (*) preceding a paragraph number.

This document may refer to certain local, national or international regulations but the responsibility to ensure compliance with legislation and any other statutory requirements lies with the user. The user should adapt or supplement this document to ensure compliance for the specific application.

Principal Changes from Previous Edition

Generally updated and re-formatted. Additional information has been included for 'smart' protection and control equipment.

Feedback and Further Information

Users are invited to feed back any comments and to detail experiences in the application of BP RPSE's, to assist in the process of their continuous improvement.

For feedback and further information, please contact Standards Group, BP International or the Custodian. See Quarterly Status List for contacts.



1. INTRODUCTION

1.1 Scope

The BP Group RP 12 series specify BP general requirements for electrical systems, equipment, materials and installations.

This document is split into two sections, Part A and Part B. Part A addresses power system protection requirements and Part B addresses power system control, instrumentation and alarm annunciation.

PART A - POWER SYSTEM PROTECTION

2. GENERAL

2.1 Scope

This Part (Part A) specifies those items which apply generally to the selection and application of protective relays to [IEC 255](#) which are supplied to provide electrical power systems protection for onshore or offshore installations.

2.2 Technical Definitions

The technical definitions listed in the referenced Recommended Practices and Guidance for Specification documents shall apply together with the following:-

A protective relay detects faulty apparatus or circuits. It then initiates or permits suitable switching and/or gives an alarm indication.

Relays are designated according to their speed or operation; thus high speed indicates an operating time usually below 50 milliseconds. The term instantaneous used in association with relaying indicates that no time delay has been deliberately introduced into the relay operation.

2.3 Drawing Symbols

Graphical symbols shall be to [IEC 617](#).

2.4 Philosophy

2.4.1 Protective relay application philosophy divides the power system into zones and/or equipment types each having their own relays to determine the existence of faults and to instruct appropriate circuit switches to isolate the fault in the shortest possible time.



2.4.2 The protective system shall be designed to consider the following main criteria:-

- (i) Reliability - Perform correctly when required and avoid unnecessary operation.
- (ii) Speed - Disconnect the fault in the shortest possible time.
- (iii) Selectivity - Ability to locate the fault and trip the minimum number of breakers to isolate only the faulty zone or equipment. Some relays are inherently selective as they only operate for faults within a zone. Others however operate for faults outside their primary zone and therefore need to be made selective by current, voltage and/or time delay co-ordination.
- (iv) Economics - Maximum protection should be provided at minimum cost.
- (v) Simplicity - Minimum equipment and circuitry should be provided to give the required protection.

2.4.3 Overlapping of protected zones shall always be provided to ensure that no part of the power system is ever unprotected.

2.4.4 At least one independent means of back-up protection shall be provided to cater for failure of the primary protection system.

2.5 **Types**

2.5.1 In general solid state protection relays should be used on all distribution systems.

Electromagnetic relays should only be considered for standardisation with an existing distribution system, or where local National Standards dictate their use.

Electromagnetic relays tend to be more expensive than their solid state counterparts, with less features and versatility.

The solid state relays offer a range of benefits over traditional mechanical relays, namely:-

- multiple functions within device
- reduced size
- low burdens

- *increased discrimination*
- *options for remote indication/control*
- *local indication/measurement*
- *data storage*
- *potential for integrating individual relays into a total overall plan protection system.*

2.5.2 Protective relays should be of the 'semi flush' or 'flush' mounting type with 'draw-out' construction. They should be of the automatically self reset type and shall include indicators with hand reset.

2.5.3 Provision shall be made to permit testing of all protection relays whilst in situ. Means shall be provided to ensure that relays are disconnected from their normal circuits during testing, and that all isolated CTs are short circuited.

For solid state protection relays, a test block (socket) is often provided for a group of relays located together to form a composite module. Test plugs facilitate testing.

2.5.4 Consideration should be given to the advantage of selecting a relay type, with sufficient options, to facilitate its interchangeability throughout the distribution system.

This is generally a key advantage of modern solid state relays over electromagnetic types.

2.5.5 Consideration should be given to the use of protection relays which incorporate the means for indication and control remotely via a 'hiway' connection.

It is expected that in the longer term, the availability of information and means of control offered by such dual function relays will provide benefit to the site operators. The information/controls are:-

- *current in each phase*
- *system frequency*
- *operational history of the circuit breaker*
- *record of fault currents broken*
- *event recording (usually time tagged at control operating station)*
- *remote circuit breaker tripping and closing*
- *load shedding and load restoration*
- *operating history of the load distribution*
- *instantaneous 'picture' of the power system operation*

2.6 Current Transformers (CTs) and Voltage Transformers (VTs) for Protection

2.6.1 CTs should be to [IEC 185](#).

2.6.2 VTs should be to [IEC 186](#).

2.6.3 All CTs should have a 1 amp secondary rating.

2.6.4 CTs for high impedance differential and/or restricted earth fault protection shall be exclusively used for that purpose.

CTs for high impedance differential and restricted earth fault protection need to be carefully balanced and of high accuracy. These are class X CTs and require 'matching' in terms of knee-point emf, exciting current at knee point and secondary winding resistance. This is necessary to ensure that through faults do not create an imbalance and cause the unit protection to operate.

2.6.5 Separate CTs shall be used for protection and indication duties.

There is a clear distinction between the requirements of CTs for protection and indication duties. For indication the accuracy within, and a little above, the normal working range is important, but accuracy in the overcurrent and fault ranges of current does not matter. On the other hand, a protective CT must deliver accurate currents in the fault range, whereas accuracy in the working range is unimportant. This gives rise to two different design concepts.

3. MAIN INCOMER PROTECTION

3.1 General

- * 3.1.1 This section specifies the electrical protection requirement for primary substation main incomers. It identifies the protection requirements covered in other sections of this part and specifies the special protection requirements related to main incomers to a site fed from a public utility.

All negotiations with public utilities on protection schemes for main incomers shall be the sole responsibility of BP. Many public utilities have standardised protection arrangement which shall be taken into account together with these recommendations.

In as much as the arrangements with Public Authorities will form part of the long term operational environment for the installation, it is considered necessary that the operator (assumed to be BP in the context of this document) is fully aware and has the sole responsibility for the longer term compliance with the requirements arising from any negotiations. Such responsibility should not be delegated to a third party unless the third party has an ongoing operational responsibility.

It is considered that Contractors may request information from Public Utilities on behalf of BP in pursuit of the determination of options relating to possible installations or changes to existing installations but that in doing so it is made clear that any formal agreement which arises from the information or investigation will be with the operating company (BP).

- 3.1.2 *Special consideration should be given to the responsibility for procurement of all items of equipment in the protection scheme, especially CTs, cabling, glanding etc. Also, locating CT's needs to be addressed and adequate provision made.*

3.2 Single Public Utility Supply and no On-site Generation

3.2.1 Cable Feeder

Where the only power feed to a site is via a single cable feeder from a public utility there should generally be no other main incomer protection relay requirements than that which may be required for busbar protection as specified in Section 5. All overcurrent and earth fault protection should be provided by the public utility. Where there is unit protection on the cable feeder this should be supplied and installed by the public utility.

The cable feeder is normally procured and installed by the Utility Company. The protection devices will be at the cable sending end, i.e. at the utility substation. Installation and procurement of all the protection devices are therefore best left to the utility company. Any duplication of protection devices at the receiving end cannot be justified.

*** 3.2.2 Transformer Feeder**

Where the public utility connection to a site is at the primary terminations of a transformer, but is otherwise as described in 3.2.1 the main incomer relay protection requirements shall be as specified in Section 5 and Section 6. All transformer primary overcurrent and earth fault protection should be provided by the public utility and an intertrip scheme as specified in 6.8.2 may be required to be negotiated by BP with the public utility.

3.3 Parallel Public Utility Supply and no On-site Generation

3.3.1 Cable Feeder

The protection requirements should be as described in 3.2.1 with the addition of directional overcurrent and directional earth fault protection for each site main incomer. If the public utility is supplying and installing unit feeder protection, then directional protection relays may not be required.

The provision of directional relays, in addition to conventional overcurrent and earth fault relays, allows selective tripping of parallel feeders in the event of a fault on one of the public utility feeders. (Unit feeder protection similarly allows selective tripping).



3.3.2 Transformer Feeder

The protection requirements should be as described in 3.2.2 with the addition of directional overcurrent protection for each site main incomer for selective tripping.

The provision of directional relays, in addition to conventional overcurrent and each fault relays, allows selective tripping of parallel feeders in the event of a fault on one of the public utility feeders. (Unit feeder protection similarly allows selective tripping).

3.4 Public Utility Supply in Parallel with On-site Generation

Consideration needs to be given to the [Electricity Association's Engineering Recommendation G.59/1](#) and its companion Engineering Technical Report No. 113 which gives recommendations for the connection of generating plant to the UK regional electricity companies' distribution systems.

3.4.1 Where the on-site generation is not the principal source of power to a site but only a partial supplement to the power drawn from a public utility, main incomer protection requirements shall be as described in 3.2 or 3.3, as appropriate.

3.4.2 Where the on-site generation is the principal source of power to a site the protection requirements appropriate to 3.2 or 3.3 shall be supplemented by means for detecting and clearing external public utility faults to permit uninterrupted operation or minimum downtime of the site power system. The additional protection shall be as follows:-

- (i) Directional overcurrent (and directional earth fault if the site is cable fed) if not already provided.
- (ii) Sensitive reverse power relaying.
- (iii) Frequency relay with a definite time relay.
- (iv) Definite time under voltage relay.

Items (ii), (iii) and (iv) shall be arranged such that during a reverse power (export) condition, tripping of main incomers does not occur unless there is a simultaneous under frequency (iii) or under voltage (iv) condition. The tripping time shall be determined from stability studies as described in BP Group [RP 12-3](#).

The reverse power relay protection should be fitted to each main incomer, but it should only be necessary to provide the under frequency and under voltage protection on each section of busbar of the primary substation main switchboard.

3.5 Tripping Requirements

- 3.5.1 Main incomer protection trips shall be via manual reset lockout relays which may already be provided for busbar or transformer protection as described in Section 5 and Section 6 respectively.

4. GENERATOR PROTECTION

This Section specifies the electrical protection requirements for generators. It does not cover mechanical protective requirements of prime-mover/generator sets. It generally relates to machines rated above 2 MVA but guidance on requirements for smaller sets is covered in specified clauses.

4.1 Method of Connection

- 4.1.1 The recommended neutral earthing system for generators of both the Direct and Unit Connected type is covered in BP Group [RP 12-3](#).

The method of connection of a generator to the electrical power system dictates the type of neutral earthing and protective relaying requirements. There are two methods of connection:-

- (i) *Direct Connected*

In this case, some of the generated power is distributed to loads at the generator voltage from a direct connected busbar.

- (ii) *Unit Connected*

Here all the power generated for the load is supplied through a transformer this being known as the Unit or Generator Transformer.

4.2 Protective Schemes

- 4.2.1 Generators shall be protected against the following internal faults:-

- (i) Stator phase to phase.
- (ii) Stator phase to earth.
- (iii) Rotor earth fault.

- 4.2.2 In addition, generator protective schemes shall consider the following abnormal service conditions:-

- (i) Overcurrent/overload/winding temperature.
- (ii) Overvoltage.
- (iii) Unbalanced loading, (negative phase sequence).
- (iv) Loss of excitation.
- (v) Motoring.
- (vi) Loss of voltage.

- (vii) Field diode failure (above 15 MVA only).
- (viii) Cooling water and air temperature detection.
- (ix) Overexcitation

4.3 Fault Protection

- 4.3.1 Biased or high impedance differential protection shall be provided for all generators above 2 MVA rating to detect both stator phase and earth faults.

High impedance should be used unless it is unstable for the application under consideration.

- 4.3.2 In addition to differential protection, stator earth fault primary protection should be provided where a low impedance earthing scheme is applied to the generator neutral.

Where the neutral earth restricts earth fault currents, the normal differential scheme may prove to be ineffective for this type of fault.

Where direct connected generators are operated in parallel, high impedance REF relays would normally be found to be necessary.

Where there is a single direct connected generator, an inverse definite minimum time (IDMT) relay, supplied from a CT of appropriate ratio in the neutral connection of the generator may replace the REF system, but under these circumstances some winding earth faults may be undetected.

For unit connected generators which may have the neutrals earthed by a high impedance method (E.g. via a distribution transformer), the earth fault detection method may be by a voltage displacement relay connected across the neutral earthing resistor (on the secondary of the single phase earthing transformer).

- 4.3.3 Generator stator earth fault protection shall include a back up relay in addition to the primary protection referred to in 4.4.2. This shall also be capable of detecting uncleared system earth faults.

The purpose of the protection is to act as back-up for the primary protection system. For directly connected machines the back up earth fault relaying shall comprise an IDMT overcurrent relay fed from an appropriate ratio CT connected in the generator neutral if such relaying has not already been provided for primary earth fault protection. In unit connected generators, earthed via a power transformer, the same relay type should be supplied for back up protection but this should be fed by a 1:1 ratio CT in the generator neutral connection. This will only detect earth faults up to and including the generator transformer primary winding.

- 4.3.4 Rotor earth fault protection shall be provided to detect and alarm (not trip) on the occurrence of the first earth fault.

The field circuit of a generator is often an isolated dc circuit which in itself need not be earthed. Thus, if an earth fault occurs, no fault current will flow and the

need for action will not be evident. Danger arises if a second earth fault occurs at a separate point in the winding, causing the current to be diverted, in part at least, from the intervening turns. The field current of a large machine is considerable and, when so diverted, can burn the conductor, causing serious damage very rapidly. Still more damage may be caused mechanically through potentially violent vibrations caused by flux imbalances.

With traditional d.c. exciters the preferred method of detection is to inject a d.c. voltage between rotor and earth and monitor current flow. With some a.c. exciters the main generator field circuit is inaccessible without the provision of special brushes and slip rings and therefore rotor earth faults should be inferred by monitoring the exciter field current using a permanent magnet moving coil relay.

- 4.3.5 Stator phase fault back-up protection shall be provided by overcurrent protection. This is also required to detect uncleared system phase faults. These overcurrent relays shall be of the voltage restrained or controlled type and shall be energised from CTs in the neutral end of the generator.

These relays are not set-up to the thermal characteristics of the generator - but are intended to operate only under fault conditions.

Voltage controlled or restrained overcurrent relays should be set to pick up at about 130% of the generator rated output. They should provide a 0.4 second minimum grading margin with downstream overcurrent protection under the worst single outage condition of any alternative infeed to the downstream protection. Voltages should be set at 90% rated voltage where appropriate.

The need for voltage restrained or controlled type overcurrent relays is to account for the decrement characteristics of the generator and performance of voltage regulator. For a three phase terminal short circuit, the initial high fault current will decay to a value below the relay current setting before the relay completes its full contact travel.

The abnormal service condition of overload or overcurrent as opposed to a fault condition is referred to in 4.4.1.

4.4 Abnormal Service Conditions

- 4.4.1 Overload protection of the stator shall be provided for all generators by embedding temperature measuring elements in the winding.

These should normally only initiate an alarm unless the set is unmanned or unmonitored in which case trip initiation may be desirable.

Overcurrent relays should not be used for overload protection of the generator

- 4.4.2 Where system conditions could cause problematic overvoltages, an overvoltage protection arrangement should be employed.

Overvoltage can be regarded as either high speed transients or sustained conditions at system frequency. Transient overvoltages originate largely in the transmission system because of switching and atmospheric disturbances. The

impact of surges of this type can be dealt with by surge diverters connected to incoming lines or primary substation busbars. Surge diverters may also be connected to generator terminals, depending on the relative capacitance of the generator to transformer interconnections compared with the inter-winding capacitance of the transformer. Generator manufacturer's advice should be sought.

Power frequency overvoltages may be caused by the following:-

- defective voltage regulator.
- sudden variation in VAr load when generator is being operated in manual mode with voltage regulator out of service.

Advice should be sought from the AVR supplier before overvoltage protection is specified.

- 4.4.3 Negative sequence protective relays shall be supplied to detect unbalanced loading of all generators rated above 5 MVA. The relay characteristic should match the negative sequence heating characteristic of the machine. For machines below 5 MVA rating negative sequence relaying should only be considered if the single phase load could exceed 15% could of the total load, or if the operation of a single phase element of a fuse could result in a similar level of unbalance.

A three phase balanced load produces a reaction field which rotates synchronously with the rotor field system. Any unbalanced condition can be resolved into positive, negative and zero sequence components. The positive sequence component is similar to the normal balanced load. The zero sequence component produces no main armature reaction. The negative sequence component is similar to the positive sequence system, except that the resulting reaction field rotates counter to the d.c. field system and hence produces a flux which cuts the rotor at twice the rotational velocity. This induces double frequency currents in the field system and rotor body. The resulting eddy-currents can be very large and can cause severe heating of the rotor.

- 4.4.4 Loss of excitation protection shall be provided.

This should either be a current operated relay in the excitation circuit, or an offset mho relay looking into the machine winding. The offset mho relay should be adjusted to preclude operation on power swings, or loss of synchronisation not accompanied by loss of field. Both relay options should be used with a simple definite time relay set to trip the set after a time delay determined from stability studies as described in BP Group [RP 12-3](#) thereby avoiding unnecessary machine shutdown under transient conditions.

- 4.4.5 Reverse power protection shall be supplied on all generators which could motor in the event of prime mover failure.

It should consist of an IDMT, true wattmetric relay and need only comprise single phase elements. It should be time delayed to avoid operation during power swings or synchronisation.

As the reverse motoring power demand of different prime mover units varies, typically it will require a matched sensitivity varying from 3% for condenser evacuated steam sets to 25% for single shaft gas turbine generators. This relay should not be confused with the forward lower power interlock relay covered under 4.6.1 even though an identical relay may be supplied for both purposes.

The operation of any reverse power protection shall be agreed with the manufacturer of the prime mover.

- 4.4.6 Undervoltage protection shall be supplied to detect loss of supply to voltage transformers (VT). Where a single VT is used to supply both the AVR and protective relays, the undervoltage relay shall incorporate a definite time delay of some 3 seconds to preclude operation under transient conditions.

The undervoltage relay should initiate tripping of the generator only if loss of volts to the AVR would lead to over excitation of the generator. Otherwise, the undervoltage should only alarm.

In most modern installations protective relays are supplied from a separate VT from that which supplies the AVR. Furthermore the AVR supplier may well incorporate undervoltage protection to cater for loss of AVR volts. In such cases undervoltage protection is recommended to prevent maloperation of the voltage controlled or restrained overcurrent relay. Modern microprocessor based relays have built in protection which restricts the overcurrent relay from operating on reduced current operating IDMT curve if voltage is reduced to zero.

4.5 Protection of Generator Transformer and Unit Services Transformer

- 4.5.1 For unit connected generators above 15 MVA rating a separate biased differential relay protecting both the generator and generator transformer should be supplied in addition to the generator differential relay provided under 4.3.1.

This relay shall incorporate an harmonic restraint feature to ensure stability during transformer energisation. For machines between 2 and 15 MVA, a single harmonic restrained biased differential relay to cover both the generator and transformer shall be supplied and the differential relay referred to in 4.3.1 may be omitted.

- 4.5.2 An IDMT earth fault relay supplied from a CT in the neutral of the generator transformer HV winding shall be supplied.

This provides earth fault protection for the transformer HV winding as well as back up earth fault protection for the HV system.

The generator transformer steps up the generator terminal voltage to the distribution voltage. This generator transformer is normally delta primary (generator side, LV winding) and star secondary (distribution side, HV winding).

4.5.3 The unit services transformer, where provided, shall have its own protection as its high impedance precludes it from being adequately protected by differential relaying covered in 4.5.1. This shall consist of:-

- (i) Its own biased differential protection where high speed fault clearance is considered paramount.

The decision whether or not to include differential protection specifically for the unit transformer should be based on the stability of the 'main' system and its importance. Studies should help determine whether faults at the unit transformer need to be cleared rapidly in order to maintain overall supplies to the whole network. If this is the case, and the loss of main supply has significant economic and safety implications, then differential protection should be included.

- (ii) Two stage overcurrent protection initiated from a set of CT's in the unit services transformer HV bushings. The first stage shall only trip the LV unit transformer breaker whilst the second stage trips all the generator breakers and the turbine.
- (iii) Similarly set two stage earth fault IDMT protection initiated by a CT in the neutral connection of the LV unit transformer winding shall also be provided to clear transformer and LV system earth faults.

If a unit services transformer is directly connected at generator voltage, the current taken by the unit transformer must be allowed for by arranging the differential protection as a three-ended scheme. CTs in the unit services transformer leads are connected so that the current circulates with those in the generator neutral conductors.

4.5.4 Guidance on the use of pressure relief and temperature protection devices on transformers is given in BP Group [RP 12-9](#). Where the Generator transformer and Unit Services transformer are provided with alarm and trip Buchholz protection and winding temperature sensing protection, only the Buchholz liquid surge operation and winding temperature trip setting shall result in tripping the main generator and turbine via a separate lock out tripping relay. Alarms should be initiated for all other abnormal conditions.

4.6 Tripping Relays and Functions

4.6.1 Low Forward Power Interlock

For steamdriven turbines the tripping of certain non-severe electrical faults should be delayed by the use of a forward power interlock relay in association with a timing relay. The low forward power relay should be a three phase device to detect unbalanced loads and should be set to close its contacts and energise a timing relay when the generator output

drops below 0.5%. This relay in turn shall energise a tripping relay associated with the electrical circuit breakers. Another separate tripping relay associated with the turbine stop valve shall be initiated to trip the turbine immediately, whether the fault is considered severe or not. Recommended tripping relays and functions are described in 4.6.2 and 4.6.3.

It is desirable to delay tripping of the electrical load on the generator until after the steam has been tripped, so that the steam entrained in the turbine is used in supplying electrical power rather than causing the set to overspeed, that is the generator acts as a 'brake'. This feature is only provided for 'non-urgent' tripping conditions. The contact of the wattmetric relay is associated with a time lag relay whose contact is connected in series with the 'non-urgent' tripping contacts, and with this arrangement the generator is not allowed to trip until the power output of the generator falls below a small preset value.

Operation of the relay at low levels of forward power permits full protection during run up and prior to synchronising, since the relay contacts will be closed during this period.

To provide the highest degree of security under all conditions the relay contacts are arranged to close when the generated power falls to 0.5% of full load output. Such an accurate setting requires the current and voltage transformer to be of high accuracy. Two relays are normally used and have their contacts connected in parallel.

The generator internal fault tripping devices (for example differential protection, etc.) are arranged to trip independently of this sensitive power interlock.

4.6.2 Tripping Relays

At least two generator tripping relays of the lock-out manual reset type shall be provided to effect multiple tripping functions. One shall trip HV field and unit services transformer circuit breakers (where appropriate) and the other, the turbine stop valve. A third relay shall be provided for generator transformer liquid surge and high winding temperature where appropriate.

4.6.3 Tripping Functions

In order to trip a generator, the HV field and unit services transformer circuit breakers (where fitted) require to be opened and the turbine shutdown. Protective relays shall either initiate an alarm or trip plus alarm preferably with a 'first up' trip indication.

The following summarise the generator protective relay actions:-

(i) Alarm only.

Stator winding temperature or overload.

Rotor earth fault.

Generator transformer and unit services transformer winding temperature.

Generator transformer and unit services transformer 'Buchholz' gas.

Cooling water and air temperature.



- (ii) Unit service transformer trip only.
Stage 1 phase fault overcurrent and earth fault.
 - (iii) All circuit breakers, time delayed via low power interlock circuit and immediate trip of turbine.
*Stator earth fault (for maximum current of 10 A).
Negative phase sequence.
Loss of excitation.
Mechanical trips.
Turbine, shutdown.
Emergency stop - manual.*
 - (iv) Immediate trip of all circuit breakers and turbine (for severe faults).
*Generator differential.
Reverse Power.
Overvoltage.
Generator transformer differential, earth fault, Buchholz liquid surge and winding temperature trip setting.
Unit services transformer differential, Buchholz liquid surge and winding temperature trip setting.
Unit services transformer Stage 2 phase fault overcurrent and earth fault.*
- Note: The term immediate means not delayed by low power interlock and does not mean that the protective relay operation is instantaneous. All relays take a finite time to trip.*

4.6.4 Typical arrangement of generator - transformer trips and intertripping is illustrated in Figure 2.

4.7 Protection of Generators below 1250 kVA Rating

- 4.7.1 Protection should normally be provided by machine suppliers as part of a total package and should not be supplemented provided the following minimum requirements are provided:-
- (i) Voltage sensitive overcurrent relays to detect phase faults.
 - (ii) IDMT earth fault relays for sets not normally run in parallel with other earth fault power sources.
 - (iii) Restricted earth fault, high impedance relays, internally looking or directionalised earth fault relays for sets which are run in parallel with other earth fault power sources. An IDMT earth fault relay energised from a CT in the generator neutral shall be provided for system back-up earth fault protection.
 - (iv) Reverse power relay for generators which may be operated in parallel with other power sources.

- (v) A means of indicating overcurrent or overload of emergency supply generators where these may be subjected to overload.
- (vi) Overcurrent protection matched to the generator thermal characteristic for all self excited generators.
- (vii) Where portable self excited generators are provided, they shall all include phase and earth fault and reverse power protection to cover for the possibility of them ever being run in parallel with other power sources.
- (viii) Protection and control circuits shall be segregated and fused to achieve perfect discrimination.

4.8 Special CT and VT Requirements

- 4.8.1 The primary rating of line CTs shall approximate to 150% full load current of the generator. Neutral connection CTs shall have a primary rating at least equal the neutral resistor rating. For generators earthed via a power transformer the neutral connected CT shall have a 1:1 ratio.
- 4.8.2 VTs for the AVR shall be two phase and exclusively used. The same policy shall be adopted for VTs for synchronising.

5. BUSBAR PROTECTION

5.1 General

This Section specifies the main protection of substation busbars including all breakers, switches and instrument transformers connected thereto. It does not include general system phase and earth fault overcurrent relaying.

Main busbar protective schemes fall into two categories. The first employs high impedance differential schemes. The second uses overcurrent relays, arranged either normally on incoming circuits or with differentially connected CTs to give partial differential low impedance protection.

5.2 High Impedance Differential Schemes

High impedance differential relaying schemes require CTs on all incoming and outgoing ways on a switchboard (including bus sections). These schemes therefore tend to be expensive and require special efforts in physically housing the CTs in all the affected switching device cubicles. Because of this, high impedance differential relaying schemes should only be specified where busbar integrity is considered vital to the power supply system, particularly in cases where high speed fault clearance is essential to prevent the risk of a major part of the system cascading out.

For metal clad switchgear, with busbar insulation as specified in BP Group GS 112-9, it is likely that high impedance differential schemes would be difficult to justify.

However, its application should be considered for outdoor primary substations, or primary switchboards without busbar insulation where the integrity of power supplies and plant operation would be seriously impaired by loss of a busbar or section of bar.

5.2.1 Differential busbar protection schemes shall employ high impedance type voltage operated relays with stabilising resistors.

5.2.2 High impedance differential schemes shall have dedicated matched CTs of the same ratio in all incoming and outgoing circuits on the protected busbar or section thereof. Where busbars are sectionalised by breakers each section shall have its own differential scheme with CTs arranged to overlap at sectionalising breakers.

To permit setting of the relay, all CT magnetising characteristics, winding resistances and connecting lead resistances, shall be supplied.

5.2.3 Duplication of busbar differential schemes using overall check zones is not required on BP installations.

Overall differential check zones provide back-up differential protection to the busbars. In order to be effective, a set of CTs separate from those used in the discriminating zones are required. The additional level of protection provided would be costly and introduce further complications, and cannot be justified.

5.2.4 The relays shall be set so as not to operate under maximum external fault conditions, thereby ensuring through fault stability but at the same time giving high sensitivity for in-zone faults. The voltage relays shall be tuned to supply frequency to reduce any prospect of maloperation due to harmonics or d.c. transient components.

5.2.5 High impedance differential relaying may be set to protect busbars against both phase and earth faults. However, for metal clad switchgear with phase segregation, it shall be primarily set to protect against earth faults. The primary effective setting shall not exceed 30% of the fault current associated with minimum plant operating conditions. Where resistance earthing is employed this shall dictate the sensitivity requirements.

5.3 Low Impedance Partial Differential Schemes

Busbar overcurrent protection schemes of the type described in this section, require CTs at the incomer and bus-section circuit breakers only. This form of protection should be applied at all primary and generation busbars where the increased sensitivity and rapid operation associated with high impedance differential relaying is not considered necessary.

Consideration should be given to its use at other 11 kV and 3.3 kV switchboards. The systems allow discrimination of busbar faults on sectionalised switchboards, thereby enabling only faulted busbars to be isolated whilst maintaining supplies to/from healthy sections. It can provide an economic method of maintaining downstream loads, where parallel incomers with closed bus-sections are the normal operating method for the distribution system. However, there is an increase in the number of elements in the system requiring discrimination. This needs specific attention during preliminary protection time-current co-ordination studies.

Subsidiary lower voltage busbars less than 1000V do not require specific busbar protection provided a busbar fault will be cleared by some form of system protection.

- 5.3.1 Single busbar arrangements without bus-section breakers fed by incoming lines or transformers shall have 3 phase overcurrent and residually connected earth fault IDMT relaying fed from CTs located at the incoming switchgear. No instantaneous elements should be used. The pick-up of the phase fault elements shall be set at about 130% of the incoming circuit rating and set to co-ordinate with the slowest downstream relay or fuse.

Special consideration needs to be given to the case where the busbar feeds a motor of comparable rating to the incomer. This requirement leads to unacceptable high relay operating times. In such cases a further overcurrent relay should be provided at the remote end of the incomer or HV side of the incoming transformer and this should be set to form a composite co-ordination curve with the primary busbar protection overcurrent relay. This second remote relay shall be given a higher than normal pick-up but shall be time graded to operate more rapidly under major busbar fault conditions. Consideration should be given to the range of static relays presently on the market. A single composite curve may be obtained from such a relay.

- 5.3.2 Single busbar arrangements with bus-section breakers shall be protected by 3 phase overcurrent and residually connected earth fault IDMT relaying fed from differentially connected CTs in the incoming and bus-section circuits for each section of busbar. These partial differential schemes shall overlap at the bus-section and be of the low impedance type. They shall operate for busbar and external faults on outgoing circuits. No instantaneous elements shall be used. The phase fault elements shall be set to pick-up at about 130% of the incoming rating and shall be time graded to co-ordinate with the slowest outgoing protection.

Special consideration needs to be given to the case where busbars feed motors of comparable rating to the incomers, two sets of phase overcurrent elements driven by the same CTs may be necessary on each partial differential scheme in order to provide high fault current clearance in a reasonable time by using the composite curve referred to in 5.3.1.

An alternative to the partial differential scheme for single busbars with bus-section breakers is to provide separate 3 phase and earth fault relaying at all incomers and

bus-sections and not to connect the CTs differentially. This method is no cheaper and results in slower fault clearance as the bus-section protection has to co-ordinate with incoming circuit relaying. It is therefore not preferred.

5.4 CT and Tripping Requirements

- 5.4.1 All CTs used for differential relaying shall be of the same ratio and matched. The primary current rating shall be slightly greater than the full load rating of the largest circuit within the protected zone. The function point of the CT neutral circuit (i.e. differential relay location) shall be made as central and equidistant as possible to all associated CTs on a differential relaying scheme.
- 5.4.2 Test links shall be provided on all CT circuits to facilitate busbar differential scheme testing.
- 5.4.3 Busbar protection trips shall be via a single dedicated specific hand reset lock out relay which shall be arranged to trip the appropriate busbar breakers.

6. TRANSFORMER PROTECTION

6.1 General

This section specifies protective schemes for power transformers.

Transformer protection schemes normally fall into those employing the following equipment:-

- (i) Fuses.
- (ii) Buchholz or pressure relief protection.
- (iii) Phase fault overcurrent relaying.
- (iv) Earth fault overcurrent relaying.
- (v) Winding Temperature.
- (vi) Differential or circulating current schemes.

Where transformers are operated in parallel and the taps are controlled automatically, consideration should be given to the inclusion of 'out of step' tap protection. As a minimum, where these transformers are operated in parallel and the taps are 'out of step' an alarm should be given. There are microprocessor based devices on the market designed to monitor, control and protect the transformer system integrity when installed with auto-tap changing facilities.

6.2 Fuse Protection

Fuses shall be provided to protect all transformers below 50 kVA. The fuses shall be selected so as not to rupture under magnetising current inrush conditions. They shall be provided on the HV or primary side of the transformer.

The value of transformer inrush current depends on the transformer design, maximum system voltage and system impedance. The value of inrush current, as a proportion of transformer rated current, tends to fall with increase of the kVA rating. On the other hand, the duration of the inrush transient tends to increase with kVA rating. Typically, inrush currents equivalent to 12 times the transformer full load current for a duration of 100 mS may be assumed. It is recommended that manufacturers are requested to provide information on actual values for each specific application.

Often transformers below 50 kVA are only protected by fuses. However, this can cause problems in that they may not operate for earth faults on the secondary winding. If this is the case, then additional earth fault relaying needs to be specified for the secondary side of the transformer to trip the LV breaker.

It should be noted that where transformers are connected in parallel, each individual transformer requires its own primary fuses.

6.3 Buchholz or Pressure Relief Protection

- 6.3.1 All conservator type transformers shall incorporate a Buchholz relay complete with alarm and trip contacts. The slow gas operated element shall initiate an alarm whereas the rapid liquid surge device shall be arranged to disconnect the transformer from the system. Buchholz protection shall include its own dedicated hand reset flag tripping relay located on the respective transformer switchgear nearest to the transformer.

The alarm signal is normally wired back to a marshalling point at the switchgear with the tripping signal and any other control indicating signals from the transformer. The alarm signal would normally then be routed to alarm annunciator panel (within the substation or central control room).

- 6.3.2 All sealed tank transformers shall be fitted with a resetting sudden pressure, spring loaded, relief device with operation contacts. This device shall include its own dedicated hand reset flag tripping relay located on the respective transformer switchgear nearest to the transformer.

All sealed tank transformers should be fitted with a pressure/vacuum gauge incorporating alarm contacts.

The alarm signal is normally wired back to a marshalling point at the switchgear with the tripping signal and any other control indicating signals from the transformer. The alarm signal would normally then be routed to alarm annunciator panel (within the substation or central control room).

6.4 Phase Fault Overcurrent Relays

- 6.4.1 Phase fault overcurrent relays should be supplied on all transformers of 250 kVA rating and above. This relaying shall be fitted on the source side of the transformer.

For transformers below 250 kVA rating, phase overcurrent fault relays may be necessary if HV fuses are not capable of being co-ordinated with LV or load side protection.

It is unlikely that for transformers rated 150 kVA and above adequate co-ordination will be achieved between the HV fuses and LV protection. It should also be noted that fuses, although very fast in operation with large fault currents, are extremely slow with currents of less than three times their rated value. It follows that such fuses will do little to protect the transformer, serving only to protect the system by disconnecting a faulty transformer after the fault has reached an advanced stage.

It should be noted that non-directional overcurrent relays fitted on the load side of the transformer are considered to be busbar or system protection - and not transformer protection relays. Where transformer differential protection is fitted, phase fault overcurrent relays are still required as back-up transformer overcurrent protection.

The IDMT elements provide overload protection and should normally be set at around 125% of the transformer rating. If there is some form of overload protection on the load side of the transformer, then the IDMT pick-up may be set much higher than 125% of the transformer rating, as its function will be to clear the transformer in the event of uncleared load side system fault.

The IDMT element characteristic may be of the inverse, very inverse, extremely inverse, short or long time type but shall be selected to match the load side system protection. This is particularly important where mechanical relays are used, thereby restricting the ability to change characteristics after purchase. Inappropriate selection leads to problems in setting up protection systems with adequate discrimination.

The instantaneous elements provide rapid clearance of faults on the source side transformer winding. They should preferably be designed to be immune to d.c. transients - though simple attracted armature elements are acceptable where the source fault MVA is low, or is not directly connected to generators. The instantaneous elements need to be set at a value above both the magnetising inrush current of the transformer and above the transformer let through fault current. A set trip point of 1.3 times the transformer let through fault current is normally satisfactory. This ensures that faults downstream of the transformer do not cause the upstream instantaneous element to trip, thereby losing the transformer. These relays shall include three IDMT and instantaneous elements.

- 6.4.2 Directional phase overcurrent relays may be required if the load busbar has another infeed.

The provision of two pairs of directionalised relays fed from CTs on either side of the transformer, both looking into the transformer avoids the need for co-ordination of each relay for faults on both the source and load sides. If the other infeed is a parallel operated transformer, the load side overcurrent relay shall be directionalised, the source side one may remain as a conventional non-directionalised element.

- 6.4.3 Where motors of comparable rating to the incoming transformer are supplied, source and load side overcurrent relays shall be supplied to form a composite curve.

The primary side relay is set to have a pick-up above motor starting currents but operates rapidly for high level faults whereas the source side relay operates for transformer overloads but takes a longer time than the motor run-up duration before tripping the transformer. If the transformer is one of a pair of units supplying a comparably rated motor the above composite curve protection shall be achieved by duplicating the partial differential busbar protection. (see also 5.3.1).

- 6.4.4 Where synchronous motors are supplied, a check shall be carried out to ensure that transformer and/or busbar overcurrent relays do not operate in the event of source side faults. If this is likely, appropriate directionalised overcurrent relaying shall be supplied.

6.5 Earth Fault Overcurrent Relays

- 6.5.1 Transformer primary and secondary windings shall be protected against earth faults.

Primary windings for transformers rated 250 kVA and above can be protected most practically by an earth fault overcurrent element in the overcurrent relay proposed in section 6.4.1. For primary windings that are delta or unearthed star, there is no possibility of zero sequence currents being transmitted from the secondary winding to the primary winding. Consequently, for these transformers an earth fault relay on the primary side will only be operative for internal faults on the primary side. The relay can therefore be set low, both regards to current and time. This affords excellent protection to the transformer primary.

For transformers rated below 250 kVA, source side earth fault overcurrent relays should be used in preference to fuses, if the fuses cannot provide adequate protection of the transformer primary winding (see section 6.4.1).

Secondary side earth fault relaying is required wherever the primary side protection is incapable of detecting secondary earth faults.

- 6.5.2 Earth fault relaying may be of the unit type which compares input and output current flow and only operates for in zone faults, or of the non-unit type which may operate for in or out of zone faults dependent on the earth fault source location.

Non-unit type protection comprising overcurrent elements is cheaper and does not always require dedicated CTs, it is therefore preferred for smaller transformers provided it can be satisfactorily graded with external system earth fault relaying.

The unit form of protection becomes necessary where transformers are operated in parallel and high speed and/or discriminatory protection is required.

- 6.5.3 Unearthed transformer windings should be protected by unit type earth fault protection employing overcurrent instantaneous elements.

Where transformer windings are not earthed (e.g. delta winding of a delta/star transformer), a relay in the residual circuit of the line current transformers gives earth fault protection which is fundamentally limited to the feeder and associated

delta-connected transformer winding. The residual connected relay therefore gives unit protection. In such cases, the instantaneous elements can be used - there will be no need for IDMT elements.

Residually connected CTs in the three phase, or a single window CT encompassing all three phases may be used. The high impedance scheme employing a stabilising resistor and a voltage operated relay is preferred as it gives the best through fault stability. In such schemes, the relay should be tuned to the supply frequency to avoid any tendency to operate as a result of d.c. offset or harmonic currents generated under CT saturation conditions with external faults. The simple untuned attracted armature element with a stabilising resistor may be acceptable on less important transformer installations.

- 6.5.4 Earthed transformer windings should be protected by non-unit earth protection employing IDMT elements. The protection relay shall be initiated from a CT located in the neutral transformer connection and consequently provide back-up system earth fault protection. The relay pick-up should be set at 10% of transformer rating or earthing resistor current let through and shall be time graded with system protection. Instantaneous elements shall not be used.

Where the transformer is solidly earthed, the CT primary ratio should approximate to the transformer full load rating. If the transformer is earthed through an impedance, the CT ratio should approximate to the maximum earth fault currently permitted.

This protection is not capable of distinguishing between healthy and faulty parallel connected transformers. It therefore needs to be supplemented by restricted circulating current type protection as described in 6.7 whenever discrimination is required on paralleled transformers.

6.6 Temperature Indicators

- 6.6.1 Temperature indicating devices are specified in BP Group [GS 112-5](#) and detailed guidance on their application is given in BP Group [RP 12-9](#).

- 6.6.2 Winding temperature protection shall include dedicated hand reset flag tripping relays with alarm and trip indication which shall be located at the nearest respective transformer switchgear.

6.7 Differential or Circulating Current Schemes

- 6.7.1 Circulating current schemes shall consist of differential protection for phase faults and restricted earth fault schemes for earth faults of star windings.

These schemes include protection for phase, earth and interturn faults. Differential protection as described in 6.7.2 which compares each phase output against input lacks sensitivity for detecting earth faults on star windings near their star point, and on delta windings for centrally placed faults. In the case of impedance earthed

neutrals, earth faults will, by design, be limited to the full load transformer rating or less and therefore differential protection will cover even less of the transformer star winding.

- 6.7.2 Differential protection for phase faults should be provided on transformers of 10 MVA rating and above. They shall be of the percentage biased type to cater for the maximum transformer tap change ratio and shall include an harmonic restraint feature to avoid maloperation due to magnetising inrush currents. Differential protection CTs shall be dedicated for circulating current schemes. The CTs shall be connected to counteract the main transformer phase changes between primary and secondary windings.

Differential protection schemes of this type provide rapid detection and clearance of faulted transformer. This reduces the damage to the transformer and hence increases its availability. The cost of differential protection schemes in comparison to the reduction in potential damage to the transformer needs to be assessed. Generally a rating of 10 MVA has been taken as a value at which the benefits outweigh the costs.

- 6.7.3 Restricted earth fault unit protection should be provided to cover for star winding faults on all transformers of 10 MVA and above. It should also be supplied for all parallel connected transformers below 10 MVA where discriminating earth fault protection is required on the star windings. The relay shall be a high impedance, instantaneous, low set type incorporating a stabilising resistance to provide through fault stability. CT connections shall compare the resultant current from the three phases with the current flowing in the star winding neutral.

Where differential protection is supplied, the CTs in the phase connections may also be used to drive the restricted earth fault protection by the use of summation CTs.

6.8 Tripping Requirements

- 6.8.1 Transformer protection trips shall be via dedicated hand reset lock-out relays. One lock-out relay shall trip the primary circuit breaker and the other lock-out relay shall trip the secondary circuit breaker.
- 6.8.2 Protection trips associated with a transformer primary shall operate the lock-out relay for the primary circuit breaker, and similarly, protection trips associated with a transformer secondary shall operate the lock-out relay for the secondary circuit breaker.

The following trips should generally operate the relevant lock-out relays.

- (i) Primary lock-out relay.

Phase fault overcurrent.

Primary earth fault.

Directional overcurrent (primary)

(ii) *Secondary lock-out relay*

Restricted earth fault.

Non-unit earth fault.

Liquid surge.

Winding temperature.

Differential protection (including partial differential).

Directional overcurrent (secondary)

High set phase overcurrent (load side).

6.8.3 Where there is no secondary circuit breaker on a single transformer feeder system, the primary and secondary lock-out relay operation shall be combined.

6.8.4 The action of tripping the primary circuit breaker shall also trip the secondary circuit breaker via a contact from the primary lock-out relay in the secondary lock-out relay trip circuit. The action of tripping the secondary circuit breaker shall also trip the primary circuit breaker via a contact from the secondary lock-out relay in the primary circuit breaker tripping circuit (not the primary lock-out relay trip circuit). The secondary lock-out relay should also inhibit closing of the primary circuit breaker.

6.8.5 *Typical arrangement of transformer protection trips and intertripping is shown in Figure 1.*

7. FEEDER PROTECTION

7.1 General

This section covers the cabled power distributed system. Overhead lines are not specifically covered as these are rare on BP networks. However, short route length overhead lines should be protected in the same way as cables.

7.2 Cables Without Load End Switchgear

7.2.1 No additional cable protection should be normally supplied.

Such cables are directly connected to plant such as transformers or motors without switchgear at the remote or load end of the cable. Protection of these cables is afforded by the primary plant (i.e. transformer or motor) protection installed at the source end switchgear.

7.3 Cables with Switchgear at Both Ends

7.3.1 These cables shall have specific protection, catering for both phase and earth faults.



The protection may of the unit type (i.e. inherently selective) or of the overcurrent type which is made selective by current and time delay co-ordination.

7.4 Phase Overcurrent Relaying

Phase overcurrent relaying schemes for protecting cable networks are significantly less expensive than unit type protection. Their use is therefore preferred, when they are effective. The following need to be considered before selection:-

- (i) grading with downstream protection devices must be possible without increasing the slowest operating back-up protection overcurrent relay anywhere on the system to greater than 2.5 seconds under bolted fault conditions.*
- (ii) fault clearance times do not have to be reduced in order to provide overall system (including induction motor) stability under worst conceivable phase fault.*
- (iii) where security of supply demands the need for rapid unit type protection.*

7.4.1 Phase overcurrent relaying should normally be fitted on all three phases and shall incorporate an inverse time and under certain circumstances an instantaneous element.

The inverse time element should normally be of the standard inverse time characteristic but may need to be of the very or extremely inverse time characteristic to co-ordinate with downstream protection. This will generally only be determined following a preliminary co-ordination study. Electronic devices offer a variety of characteristics within a single relay by selection of appropriate switches. This is one of the reasons for their preference over mechanical relays. Use of instantaneous elements should be carefully considered. The concern being that they may operate beyond their required protection zone, in a non co-ordinated condition. Where instantaneous elements are necessary, low transient over-reach characteristics are preferred. Normal attracted armature elements may be supplied provided their setting is increased to 1.8 times the symmetrical sub-transient current for remote end faults to cater for d.c. offset currents.

It is recommended that inverse time elements be set up to pick-up at about 25% above the maximum load condition and to give a 0.4 to 0.5 second co-ordination time with the next downstream relay. This time can be reduced to 0.3 seconds when co-ordination is with a downstream fuse.

7.4.2 Where fault currents may flow in either direction, overcurrent relaying of the directionalised type may be required in order to achieve correct fault discrimination for all conditions. In the case of parallel feeder systems the directional overcurrent relays, where necessary, should be at the receiving end and ordinary non-directionalised relays may be supplied at the source end. Directionalised relays should be applied to those ring fed systems, which are operated 'closed' and which have intermediate circuit breakers. In these instances the source end relays

need not be directionalised provide the ring originates from the same point on the system.

7.5 Earth Fault Overcurrent Relays

- 7.5.1 Earth fault overcurrent relays shall be supplied for all networks where grading is possible without causing unacceptably long earth fault clearing times.

They do not operate for earth faults on both sides of delta winding transformers and therefore only need to co-ordinate with relays on the side of the transformer to which the protected cable is connected. In order to limit the possibility of maloperation they should not normally be set to a sensitivity of less than 20% of cable rating.

- 7.5.2 Earth fault overcurrent relays shall be supplied with phase overcurrent and should be fed from a residual connection of the phase CTs. They shall also include an inverse time (and instantaneous element on solidly earthed systems).

In cases where the distribution system earth fault current is limited by neutral earthing devices, instantaneous elements will not be selective as substantially the same fault current flows wherever the downstream fault is located. Accordingly earth fault relaying shall not use instantaneous elements on impedance earthed systems. Even on solidly earthed systems the use of instantaneous elements should be carefully considered. The concern being that they may operate beyond their required protection zone, in a non co-ordinated condition.

- 7.5.3 Directionalised earth fault relays may be required where currents could flow in either direction. The principal is similar to that covered in 7.4.2 for phase overcurrent directionalised relays.

7.6 Selective or Unit Type Relaying

- 7.6.1 Unit type relaying shall be supplied to protect cables which are controlled by switchgear at both ends when use of a phase and earth fault overcurrent relaying system will either not give satisfactory grading, or leads to maximum tripping times which are too long to prevent excessive disturbance of the power system.

Unsatisfactory grading occurs when tripping times exceed 2.5 seconds with a 0.4 to 0.5 second tolerance between each step. Fault clearing times may well require to be limited to considerably below this time, typically less than 0.5 second, in order to prevent system or induction motor instability which may cause extensive and cascading system shutdowns.

There are a great variety of types of unit type feeder protection systems available. The more common types normally used on BP systems include circulating current schemes using CT leads and circulating current or balanced voltage schemes using pilot wires. The former type are limited to cables not exceeding 1000 metres and should include stabilising resistances. Pilot wire schemes using balanced voltage

systems will be preferred to those using circulating current principles for longer feeders.

**Carrier protection schemes which are inherently selective, and distance protection schemes which are strictly not of the unit type shall only be used in special cases and shall be subject to approval by BP.*

7.7 Tripping Requirements

7.7.1 Feeder protection trips shall be via hand reset lock-out relays located at each circuit breaker on the feeder.

7.7.2 Intertripping schemes will not be required on those feeders protected by directional relays at one or both ends, neither will they be required on feeders protected by pilot wire type unit protection.

7.7.3 Where feeders are serving transformers reference should be made to 6.8 for tripping requirements.

7.7.4 Where feeders have switchgear at both ends and are either protected by non-directional overcurrent relaying or by circulating current type relaying, the tripping of the source end circuit breaker shall cause the load end circuit breaker to trip. Similarly, the tripping of the load end circuit breaker shall trip the source end circuit breaker.

The interconnection of trips shall be similar to that for transformers detailed in section 6.8.4.

8. MOTOR PROTECTION

8.1 General

This section specifies induction motor protection requirements. The protection of synchronous motors and special motors such as those associated with submersible pumps is not covered. Special protection arrangements shall be developed for such special applications.

Induction motor protection schemes fall into the following main categories which are covered in 8.2 to 8.7.

- (i) Overload protection
- (ii) Phase fault protection.
- (ii) Earth fault protection.
- (iv) Unbalanced current protection.
- (v) Undervoltage protection.
- (vi) Miscellaneous protection.

8.2 Overload Protection

- 8.2.1 Single phase motors up to 180 watt rating shall be provided with built-in thermal protection to [BS 4999](#) Part 111 or an equivalent national standard.

Single phase supplies to motors are generally provided without thermal protection devices at the control centre. Requesting single phase motors to have inherent thermal protection within them ensures that these small motors are thermally protected.

- 8.2.2 Three phase motors between 0.18 and 150 kW rating shall be supplied with thermal overload protection and this shall not be built-in. This type of protection shall be three pole, ambient compensated, incorporating single phase protection.

- 8.2.3 Motors rated above 150 kW or those with rated voltages above 1 KV shall include temperature detectors embedded in the stator in accordance with BP Group [GS 112-4](#). These shall be supplied in addition to the thermal overload protection specified in 8.2.2. Between 500 and 2000 kW rating at least the hottest reading resistance temperature detector (RTD) shall be monitored by a temperature relay with adjustable temperature alarmed trip settings which accommodate the maximum permissible stator winding temperature of the motor. For motors above 2000 kW the hottest RTD in each phase shall be monitored separately and each arranged to alarm and trip the motor.

The alarm and trip set points should be selected following discussions with the motor manufacturer. Alarms need to be taken back to a central control area.

- 8.2.4 Where motors are protected by circuit breakers, thermal overload relays may be replaced by magnetic IDMT type relays with a long time characteristic provided such motors also include RTD overload protection as specified in 8.2.3. These relays shall include three pole instantaneous elements for short circuit protection.

- 8.2.5 Dedicated stalling protection should be provided where stalling is likely, where it may cause costly shutdown in the event of motor failure or where the thermal overload relay has an overrun which makes discrimination between normal starting time and safe stall time difficult.

If a motor stalls when running, or is unable to start because of excessive load, it will draw a current from the supply equivalent to the locked rotor current. This locked rotor current will normally be around six times the value of the motor full load current. It is obviously desirable to avoid damage by disconnecting the machine promptly.

It is impossible to distinguish this condition from a healthy start purely on a current magnitude basis - the only way to overcome this problem is to arrange for the

protective device to disconnect the motor if the locked rotor current continues for longer than the normal starting time.

In the majority of cases the starting time of normal induction motors is under ten seconds, while allowable stall time to avoid excessive deterioration of the motor insulation is in excess of 20 seconds. It is therefore relatively easy to discriminate between the two conditions on a time basis, and bimetallic thermal relays can be used to achieve this.

In certain cases, for example motors driving high inertia loads, the starting time may be prolonged, become nearly equal to the safe stall time and making discrimination between the two conditions more difficult. The problem is compounded by the over-run of bimetallic elements. There can be as high as 45% at six times rated current. In such cases dedicated stalling protection may be required. Historically this was provided by an additional single phase thermal unit with an instantaneous undercurrent element which would disconnect the relay trip circuit when the motor current drops below a fixed value, normally three times rated current. Presently electronic relays can provide many options giving ideal locked rotor and stalling protection combined into a complete motor protection relay.

Where the starting time exceeds the safe stall time, a speed switch must be utilised to discriminate between the two conditions.

8.3 Phase Fault Protection

- 8.3.1 Short circuit phase fault protection should normally be provided by the fuses which form part of the starter unit. Where circuit breakers are used, moulded case or otherwise, phase fault protection shall be provided by instantaneous integral magnetic devices or by high set instantaneous relay elements.

The instantaneous relays should be preferably tuned to normal power frequency or time delayed for some 50 ms to prevent maloperation due to high d.c. offset currents. Where this is not possible or available, the devices shall be set to operate at 2.6 times the motor locked rotor current. Wherever possible the instantaneous relay elements shall be included within the thermal overload or IDMT relay case.

8.4 Earth Fault Protection

- 8.4.1 Subject to the limitations of 8.4.2, instantaneous earth fault protection shall be provided on all motors exceeding 30 amp full load current and on all motors with rated voltage above 1 kV.

The value of 30A as a figure for selection of earth fault protection is based on a compromise between the cost of additional protection equipment versus the benefit of damage reduction (cost and downtime) and accident risk.

The preferred instantaneous earth fault protection systems include special dedicated CTs which are commonly of the window type covering all three phases. This avoids any likelihood of maloperation due to CT saturation and consequential spill currents, and therefore permits high sensitivity together with rapid operation. Alternative systems using a simple instantaneous overcurrent relay connected in

the residual circuit of the three line CTs already provided for overload/phase fault protection may be acceptable. However, such systems can only be set to operate at 20% of motor full load current and to ensure stability under motor start conditions the inclusion of a stabilising resistor mounted in series with the relay element may be necessary.

- 8.4.2 Earth fault protection shall be arranged to trip the motor contactor or circuit breaker.

Specific checks need to be made to verify that contactors are rated to clear fault currents when initiated by the instantaneous earth fault relay. In cases where earth fault currents could exceed the contactor rating, tripping time delay relays may be used in order to allow for fault current to decay sufficiently.

8.5 Unbalanced Current Protection

- 8.5.1 For motors installed on systems rated at 3.6 kV and lower voltages, no additional unbalanced current protection beyond that provided by thermal overload devices in all three phase is required.

- 8.5.2 Motors on systems rated above 3.6 kV shall include negative sequence thermal synthesis relays for protection against unbalanced currents.

Such relays may be part of an overall motor protection relay covering thermal overload, single phasing and phase fault protection.

8.6 Under-voltage Protection

- 8.6.1 Motors controlled by circuit breakers, or d.c. operated contactors, or mechanically latched contactors, shall be protected by time delayed under-voltage relays to prevent block restarting of a group of motors in the event of loss of incoming supply and subsequent restoration.

The relay should be set to operate at some 70% of normal voltage after a 2 second time delay and shall be of the fixed time delay variety with a setting range of 0.5 to 3 seconds. Inverse time under-voltage relays to accomplish the same objectives are acceptable and may be used if economically favourable.

Motors controlled by a.c. controlled unlatched contactors are inherently provided with undervoltage tripping as the contactor drops out in less than 50 ms under loss of voltage. Undervoltage relays are therefore very rarely required for motors controlled by a.c. unlatched contactors.

8.7 Miscellaneous Protection

- 8.7.1 Differential protection should not normally be purchased for induction motor protection.

Differential protection is capable of detecting phase to phase faults - which earth fault protection detailed in section 8.4 cannot. However, the vast majority of faults which occur within the motor windings are earth faults caused by a breakdown in

the winding insulation. Because of the relatively greater amount of insulation between phase windings, faults between phases seldom occur. As the stator windings are completely enclosed in grounded metal, the fault would very quickly involve earth, which would then operate the instantaneous earth fault protection described in section 8.4. Provided the motor is connected to an earthed system differential protection does not give any significant benefit if fast acting and sensitive earth fault protection is already provided.

8.7.2 Resistance temperature detectors embedded in hydrodynamic radial bearings shall provide protection against bearing failure. These should generally only be provided in motors 2000 kW and above (in accordance with BP Group [GS 112-4](#)).

8.7.3 Provision for vibration monitoring shall be provided for motors at and above 1500 kW (2 pole) or 3000 kW (4 pole and above) (in accordance with BP Group [GS 112-4](#)) or where vibration may cause significant damage to driven or associated equipment.

9. RELAY SETTING AND SHORT CIRCUIT STUDIES

9.1 General

9.1.1 Relay setting philosophy divides the system into zones covering generators, busbars, transformers, motors and feeders. These shall be adequately protected with the minimum time of system disconnection in the event of a fault.

9.1.2 The choice of protective devices and their settings shall be dictated by the ability to protect without preventing normal operation of the system, and to ensure co-ordination is obtained with other devices that are in the same chain under consideration.

9.2 Studies

9.2.1 Short circuit studies shall be conducted on the system to be protected in order to obtain the necessary data to select the most appropriate relay ranges and to set the relays most effectively.

Power system studies on the distribution network are performed to determine switchgear prospective fault levels for sizing of switchgear. It is recommended that these studies be extended to include calculation of fault current flows at critical points in the network to assist with determination of set points for protection relays.

9.2.2 These studies shall be carried out to determine current flows for three phase, phase to phase and earth faults at all busbars and extremities of the power system.

For relays operating in less than 0.2 seconds, the current flows shall be determined by using either subtransient reactance values or calculated reactance values appropriate to the first half cycle of the fault.

This first half cycle will be 10 m.secs for 50 Hz systems and 8.3 m.secs for 60 Hz systems. These are generally known as fault make currents.

For relays operating in 0.2 seconds and above, the current flows shall be determined by using either transient reactance values or calculated reactance values appropriate to actual circuit break contact parting times plus 10 m.sec.

These are generally known as fault break currents. In most cases computer aided studies are unnecessary for earth fault current flows as earth faults are limited either by neutral earthing equipment or, virtually identical to those obtained from three phase studies on solidly earthed systems.

- 9.2.3 Relay setting and application short circuit studies may adopt a simple approach to motor contributions. In this event induction motor contributions based on locked rotor reactances shall only be used for relays that operate in less than 0.2 seconds and may be ignored for all slower acting relays. Synchronous motor contributions shall be considered for both types of relays.

Induction motor contributions to fault current flows tend to decay very rapidly, becoming negligible after 200 mS. Typical fault current delay time constants for induction motors are 10 mS for 440 V motors, 20 mS for 3.3 KV motors and 60 mS for 11 KV motors.

Power system studies that are performed using computer based models (e.g. IPSA) account fully for the decrement of all components in the network individually. This is obviously preferable.

- 9.2.4 When analysing the results of phase to phase and earth fault studies the effect of delta/star transformer connections on fault currents shall be taken into account when determining 'upstream' relay settings.

Phase to phase faults on the secondary side of such transformers would be 0.866 of the equivalent phase fault current, but on the primary side the line currents would be half the referred phase fault current in two lines and equal to the referred phase fault current in the third line. Phase to earth fault currents on the secondary side of such transformers which are solidly earthed, would be equal to the equivalent phase fault current but on the primary side the line currents would be 0.577 of the referred phase fault current in two lines and zero in the third line.

- 9.2.5 Short circuit studies for relays shall be carried out both under maximum and minimum generation/load. Studies shall also be done with certain pre-selected distribution system outages to ensure satisfactory relay operation. The latter requirement is particularly appropriate on ring fed systems where the first breaker to clear generally leaves the fault fed via a longer or higher impedance route.

Short circuit studies at maximum loadings and generation will establish maximum system fault currents. Under this condition, the protection time-current co-ordination studies should demonstrate adequate discrimination between devices, and provide a check that electrical components in the system are satisfactorily protected. Short circuit studies at minimum loadings and generation will establish minimum system fault currents. Under this condition checks should be made to ensure protection relays will operate satisfactorily under these minimum fault current flow conditions, and that system faults will not remain on the system uncleared.

PART B - POWER SYSTEM CONTROL

10. GENERAL

10.1 Scope

This Part (Part B) defines the minimum facilities required for adequate control of the power system. It does not cover detailed instrumentation equipment specification or the means of transmission of necessary signalling between various control points.

10.2 Technical Definitions

The technical definitions listed in the referenced Recommended Practices and Guidance for Specification documents shall apply.

10.3 Drawing Symbols

Graphical symbols shall be to [IEC 617](#).

10.4 Philosophy

All electrical power and distribution equipment shall include facilities for local control. This should either be located adjacent to the plant or at the switchgear controlling the appropriate equipment. Where specified, additional control facilities shall be provided to permit centralised remote control of equipment, processes or systems. Whenever alternative control locations exist for equipment, padlockable selector switches which preclude control from more than one location shall be provided. Sufficient instrumentation metering, control switches and alarms shall be provided at each location to enable safe control and monitoring to be accomplished.

It should be noted however, that emergency stops shall be active from all locations at all times

11. SWITCHGEAR CONTROLS

11.1 General

This Section specifies the control and instrumentation requirements of substation metal clad switchgear up to 36 kV

Included is the control and instrumentation requirements of incomers, feeders and bus ties. This Section should be read in conjunction with BP Group [GS 112-9](#) and BP Group [GS 112-8](#) and the guidance in BP Group [RP 12-6](#) and BP Group [RP 12-7](#).

11.2 Control

11.2.1 Switchgear on systems with voltages above 17.5 kV shall be remotely controlled. For local control the operating position shall be in a separate room. This operating position shall incorporate control switches and status indication, together with all relevant indication listed in this Section, by means of a hard wired 'mimic' or SCADA system. The relevant protection relaying specified in Part A of this Recommended Practice may be mounted on a separate panel in the same room as the switchgear.

11.2.2 Circuit breakers on switchgear between 1 and 17.5 kV shall not be controlled directly from the front of the circuit breaker panel.

Facilities need to be provided to allow remote operation away from the front of the circuit breaker enclosures. This remote operation may be from a separate control panel within the substation or from a completely separate room. In either case a simple common control switch with a selector plug for circuit selection is sufficient for most applications. For primary substations under SCADA control, facilities in accordance with 11.2.1 may be applied.

11.2.3 Local tripping facilities shall be provided even where remote control is applied.

Tripping devices shall be capable of overriding all remote operating controls. Where circuit breakers are being used for the purpose of earthing, local control facilities shall be provided.

11.3 Instrumentation

11.3.1 Main Incomers

Where a main incomer is directly fed by on-site generation the instrumentation requirements shall be as in 12.3. Incomers from a public utility shall be provided with the following instrumentation.

- (i) Public utility metering.
- (ii) Voltmeter and phase selector switch.
- (iii) Ammeter and phase selector switch.
- (iv) Power factor meter.

In cases where the Public Utility metering is remotely located, consideration should be given to the inclusion of the following for each incoming circuit.

- kWh meter.
- kVArh meter.

Outputs for the kWh and kVArh incoming meters can be summed in a microprocessor based device, which could be programmed to give regular print outs of the plant MW and MVar demand - together with MWh and MVarh for monthly charges. This could be split between various utility charge rates. Such

information is readily available from modern Energy Control Microprocessor Systems - and offers to the operator valuable information for the economic control of his electrical energy consumption. The use should be seriously considered at the onset of all new projects.

Where export of power to the public utility is possible the following additional metering shall be provided subject to agreement between BP and the public utility concerned.

- (v) kW meter (import and export).
- (vi) kWh meter (export).

*

All negotiations with public utilities on metering shall be the responsibility of BP.

11.3.2 Distribution Switchboard Incomers

Distribution switchboard incomers, at area and process substations which are fed from other on site substation switchboards shall be provided with instrumentation to measure the following:-

- (i) Voltage on all phases.
- (ii) Current in all phases.
- (iii) Maximum average demand current.
- (iv) If on load tap changers are fitted to local transformers, tap position indicators shall be provided.

In certain circumstances, internal accounting requirements will require measurements of KWh for incomers.

The maximum average demand ammeter should be of the 'thermal' type. The operation is based on the bimetal strip principle which gives an inherent time lag, thereby eliminating short duration overloads. The integrating periods vary between devices. The shorter the integrating period, generally the cheaper the device. For measurements which are used for internal accounting and efficiency monitoring a simple device with around 8 minute integrating period is satisfactory.

11.3.3 Outgoing Feeders

Outgoing feeders which feed other site switchboards directly or via transformers shall be provided with instrumentation to [IEC 51](#), to measure the following:-

- (i) Current in all phases
- (ii) Maximum average demand current

In certain circumstances, internal accounting requirements will require measurements of KWh for incomers.

Section 11.3.2 commentary gives information on the maximum average demand ammeter.



11.3.4 Bus Ties

Bus ties shall be provided with instrumentation to measure the current in all phases.

12. GENERATOR CONTROLS

12.1 General

12.1.1 This Section specifies the control and instrumentation requirements for generators. It does not cover the instrumentation and control of generator prime movers beyond that equipment which directly influences the electrical system.

The manufacturers propriety system may be used provided it includes the functions detailed in this Section.

12.2 Control

For new installations, it is expected that operational control of the generation functions will be possible from a Central Control Room. For power systems having multiple generators the Central Control Room operator would have the control of the following generator functions:-

- stop/start
- synchronising
- generator loading (frequency/speed control)
- generator excitation (voltage control - possible AVR setting only)

12.2.1 Voltage and frequency control of generator sets shall be as specified in BP Group [GS 112-7](#), guidance being given in BP Group [RP 12-10](#) and BP Group [RP 12-3](#).

12.2.2 Automatic voltage and frequency/loading control systems for generator sets shall include means for manual control of voltage and frequency generally via 'raise' and 'lower' push buttons. These push buttons shall be located at generator control panels and also at switchgear or other control location from which generators are to be controlled.

Guidance on application of synchronising facilities is provided in [RP 12-3](#).

12.2.3 Where automatic synchronising is called for, manual synchronising facilities shall also be provided at the switchgear or control location wherever synchronising is to be carried out.

12.2.4 Manual synchronising facilities shall comprise voltmeters and frequency meters, giving the voltage and frequency on each side of the circuit breaker across which the synchronising is to be done, and a

synchroscope. Check synchronising relaying shall be applied where called for in BP Group [RP 12-3](#).

12.3 Instrumentation

12.3.1 Instrumentation shall be provided at all relevant control location(s) for all generators, to measure the following:-

- (i) kW
- (ii) Power factor
- (iii) kVAr (excluding standby generators)
- (iv) Voltage on all phases
- (v) Current in all phases
- (vi) Frequency
- (vii) Elapsed time
- (viii) kWh

There is preference for measurements (i), (ii) and (iii) to be incorporated into a single vector meter where possible.

13. MOTOR CONTROLS

13.1 General

This Section specifies the control and instrumentation requirements of electric motors of either the induction or synchronous type.

13.2 Control

13.2.1 BP Group [GS 112-8](#) and BP Group [GS 112-9](#) cover the switchgear requirements of LV and HV motor controls and guidance on these requirements is given in BP Group [RP 12-6](#) and [RP 12-7](#).

13.2.2 Motors may be manually or automatically controlled. All motors that are provided with automatic control shall include manual control facilities local to the motor.

13.2.3 The three permissible manual control positions of motor starters shall be:-

- (i) Local to the motor.
- (ii) At a process control station.
- (iii) At the motor starter where this forms part of the switchgear assembly.

In many cases control may be provided at more than one of these locations. The actual selection of control locations shall be dictated by operational philosophy,

manning levels, degree of automation, economics and past practices related to the type of plant.

13.2.4 Where a single location of control is selected this shall be local to the motor.

13.2.5 Every motor control station with a 'start' control shall include a 'stop' control. In addition a 'stop' control shall always be provided at the switchgear starter panel. All 'stop' controls shall be operable at all times and shall be of the hand reset type. The operation of a 'stop' control at any position shall prevent starting the drive at all control locations.

13.2.6 Padlockable selector switches to prevent starting a motor from more than one control location and to select manual/automatic control shall be supplied where more than one control location is required. These selector switches shall be located at the control station local to the motor.

There will be cases where specific plant operational procedures and/or local practices may override this requirement.

13.2.7 Where local control is required for motors which are located in positions which have limited or difficult access, the local control facility should be in an accessible location.

Examples of this would be finfan banks and auxiliary drives within packages.

13.2.8 In all cases a 'stop' control shall be provided at the motor.

Where a 'stop' control is provided local to a motor, without associated start or other control facilities, then its application needs to be considered as 'emergency'. The IEE Regulations require that "the release of the emergency switching device shall not re-energise the equipment concerned." Thus for this special application, release or resetting of the 'stop' should not allow the motor to restart. For situations where automatic control is available, and automatic start may result, special provision will be required to prevent this on release of the 'emergency' stop. A dedicated reset within the switchgear starter panel is one solution.

* 13.2.9 Synchronous motors which are provided with adjustable means for power factor correction, shall have excitation controls located at their respective switchgear or switchgear control panels. The choice of automatic or manual power factor controls shall be subject to approval by BP. Where automatic voltage regulation based on power factor control is provided that control scheme shall be so designed as not to interact detrimentally with other automatic voltage/power control schemes.



13.3 Instrumentation

- 13.3.1 Local control stations for motors rated in excess of 4 kW in process and offsites areas shall incorporate ammeters.

Ammeters may be omitted on local control stations for the following:-

- (i) Motorised valves.
- (ii) Motors driving cranes.
- (iii) Winches.
- (iv) Furnace fans without vane control.
- (v) General domestic items such as HVAC equipment.

- 13.3.2 Subject to the limitations given in 13.3.1, ammeters should be provided at local control stations for motors rated 4 kW and below only when such motors are not visible from the control station location, or when a change in noise level is not easily detectable, or when required for process instrumentation.

- 13.3.3 All ammeters local to motors shall be of 1 amp movement, compressed scale, CT operated type.

The scales should be selected such that the motor full load current appears between 50% and 80% of the full scale deflection.

- 13.3.4 All motor starter/switchgear ways in substation switchboards shall be provided with an ammeter which shall comply with the requirements of BP Group [GS 112-8](#) or BP Group [GS 112-9](#) as appropriate.

- 13.3.5 An elapsed time meter shall be provided on all motor starters/switchgear for motors with ratings of 150 kW and above.

Where maintenance philosophy of the driven equipment is dependent on the hours run, elapsed time meters should be considered for inclusion on a wider range of motor starter/switchgear.

- 13.3.6 The switchgear or switchgear control panels associated with synchronous motors which are capable of power factor correction shall be provided with power factor meters in addition to the instrumentation called for in 12.3.4 and 12.3.5.

Motor starters/switchgear may be provided with kWh meters where internal accountancy dictates.

14. ALARMS AND INDICATIONS

14.1 Alarms

- 14.1.1 Each substation and each on-site generator shall be provided with an alarm annunciation system. This shall comprise an alarm panel which shall collect together all the alarm conditions associated with that particular substation or generator. A common alarm shall be derived from each substation or generator alarm panel for transmission to an emergency control centre.

The 'emergency control centre' is usually the central control room for the plant.

- 14.1.2 Each generator alarm panel shall have an alarm window associated with each separate alarm condition as specified in BP Group [GS 112-7](#).
- 14.1.3 A window shall be provided on the substation alarm panel for each switchboard circuit breaker way which has protective relaying as described in Part A of this document. Where battery charges are provided for closing and tripping supplies a window shall be provided on the substation alarm panel for each battery charger.
- 14.1.4 Each alarm window of a substation alarm panel shall be operated by the combined alarm functions of the equipment the window is supposed to represent. For any circuit breaker each protective relay shall provide a contact into a common alarm circuit which shall operate the appropriate circuit breaker alarm window in the alarm panel. The alarms associated with a battery charger as specified in BP Group [GS 112-11](#) shall form a common alarm to operate the appropriate battery charger alarm window in the alarm panel.

14.2 Indications

- 14.2.1 Local indication of status of circuit breakers on switchgear shall be as specified in BP Group [GS 112-8](#) or BP Group [GS 112-9](#) as appropriate.

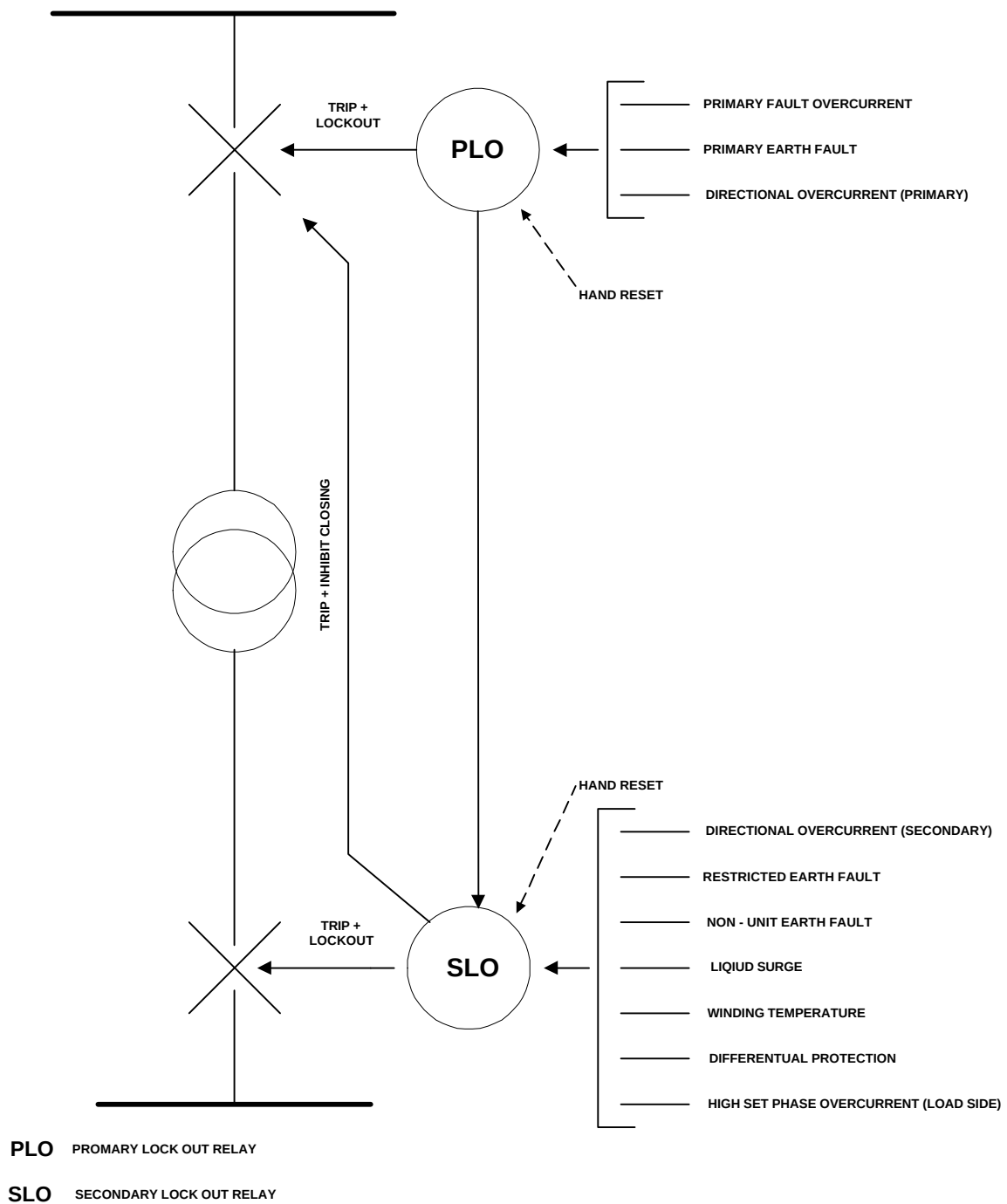


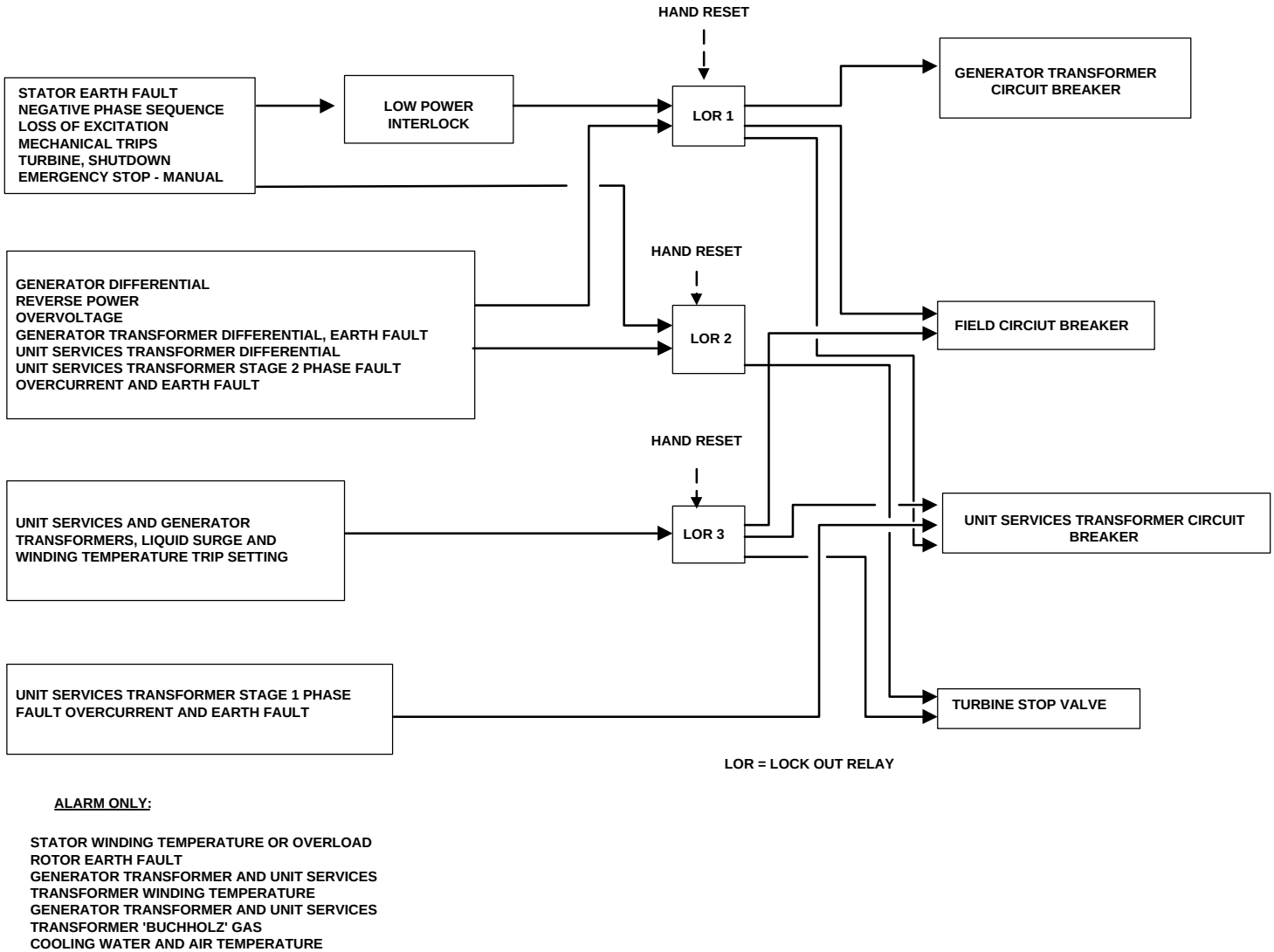
FIGURE 1

TYPICAL ARRANGEMENT OF TRANSFORMER PROTECTION TRIPS AND INTERTRIPPING



TYPICAL ARRANGEMENT OF GENERATOR-TRANSFORMER(S) TRIPS AND INTERRIPPING

FIGURE 2



DEFINITIONS AND ABBREVIATIONS**Definitions**

Standardised definitions may be found in the BP Group RPSEs Introductory Volume.

Abbreviations

AVR	Automatic Voltage regulator
CT	Current Transformer
IDMT	Inverse Definite Minimum Time
IEE	Institution of Electrical Engineers
IEC	International Electro-technical Committee
HV	High Voltage
LV	Low Voltage
REF	Restricted Earth Fault
RTD	Resistance Temperature Detector
SCADA	Supervisory Control and Data Acquisition
VT	Voltage Transformer

LIST OF REFERENCED DOCUMENTS

A reference invokes the latest published issue or amendment unless stated otherwise.

Referenced standards may be replaced by equivalent standards that are internationally or otherwise recognised provided that it can be shown to the satisfaction of the purchaser's professional engineer that they meet or exceed the requirements of the referenced standards.

International Standards

IEC 51	Direct acting indicating analogue electrical measuring instruments and their accessories.
IEC 185	Current transformers.
IEC 186	Voltage transformers.
IEC 255	Electrical relays.
IEC 617	Graphical symbols for diagrams.

British Standards and Codes

BS 4999 (Related to IEC 34-11)	Part 111: Built-in thermal protection for electric motors rated at 660 volts a.c. and below.
G. 59/1	Electricity Association Engineering Recommendations Recommendation for the Connection of Embedded Generating Plant to the Regional Electricity Companies Distribution Systems.
ETR 113	Electricity Association Notes of Guidance for the Protection of Private Generating Sets up to 5 MW for Operation in Parallel with Electricity Boards' Distribution Networks.

BP Group Document

BP Group GS 112-4	High-Voltage Induction Motors (replaces BP Std 220)
BP Group GS 112-5	Transformers and Reactors (replaces BP Std 223)
BP Group GS 112-7	Electrical Requirements for Generation Packages (replaces BP STD 224 Pt 2)
BP Group GS 112-8	Low Voltage Switchgear and Control Gear (replaces BP Std 227)
BP Group GS 112-9	High-Voltage Switchgear and Control Gear (replaces BP Std 225)
BP Group GS 112-11	D.C. Power Supplies (replaces BP Std 228)
BP Group RP 12-3	Power Systems Design (replaces BP CP 12 pt 3)
BP Group RP 12-6	High Voltage Switchgear (replaces BP CP 12 pt 6)
BP Group RP 12-7	Low Voltage Switchgear (replaces BP CP 17 pt 7)
BP Group RP 12-9	Transformers and Reactors (replaces BP CP 17 pt 9)

