

DEP SPECIFICATION

APPLICATION OF PROTECTIVE FUNCTIONS FOR ELECTRICAL SYSTEMS FOR GLOBAL APPLICATION

DEP 33.64.10.17-Gen.

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DESIGN AND ENGINEERING PRACTICE



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PART I INTRODUCTION

1.1 SCOPE

This DEP specifies requirements and gives recommendations for the design, engineering and installation of electrical protection for electrical facilities within a petrochemical or oil and gas operating environment.

The DEP contains requirements for general global use and for use in areas applying North American standards.

This is a revision of the DEP of the same number dated September 2013; see (1.5) regarding the changes.

1.2 DISTRIBUTION, INTENDED USE AND REGULATORY CONSIDERATIONS

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This DEP is intended for use in facilities related to oil refineries, chemical plants, gas plants, exploration and production facilities and supply/distribution installations. This DEP may also be applied in other similar facilities.

When DEPs are applied, a Management of Change (MOC) process shall be implemented; this is of particular importance when existing facilities are to be modified.

If national and/or local regulations exist in which some of the requirements could be more stringent than in this DEP, the Contractor shall determine by careful scrutiny which of the requirements are the more stringent and which combination of requirements will be acceptable with regards to the safety, environmental, economic and legal aspects. In all cases the Contractor shall inform the Principal of any deviation from the requirements of this DEP which is considered to be necessary in order to comply with national and/or local regulations. The Principal may then negotiate with the Authorities concerned, the objective being to obtain agreement to follow this DEP as closely as possible.

1.3 DEFINITIONS

1.3.1 General definitions

The **Contractor** is the party that carries out all or part of the design, engineering, procurement, construction, commissioning or management of a project or operation of a facility. The Principal may undertake all or part of the duties of the Contractor.

The **Manufacturer/Supplier** is the party that manufactures or supplies equipment and services to perform the duties specified by the Contractor.

The **Principal** is the party that initiates the project and ultimately pays for it. The Principal may also include an agent or consultant authorised to act for, and on behalf of, the Principal.

The word **shall** indicates a requirement.

The word **should** indicates a recommendation.

1.3.2 Specific definitions

Term	Definition
Critical Clearance Time	The time within which the protection should operate without impacting the power system stability with reference to voltage, frequency and rotor angle of generators and large motors.
Inverse definite minimum time relay	Dependent-time relay with an operating time that is inversely proportional to the input quantity and with a fixed minimum time at a fixed multiple of the input.

Term	Definition
Protection system	Complete arrangement of protection equipment, including current transformers, voltage transformers, communication links wiring, trip circuit, to achieve a certain protection function.
Relay characteristic	Electrical input quantity that characterises the relay performance in terms of current versus time, i.e., Standard Inverse (SI) or Extremely Inverse (EI) curve.
Relay operating time	The time interval from the occurrence of a specified input condition into a relay until its operation.
Relay operation	The condition attained by a relay when it performs its designated function.
Relay pickup	The condition attained by a relay when its input quantity exceeds the setting.
Relay reset	The condition attained by a relay when it returns to its initial condition.
Relay setting	The threshold value of the input at which the relay operates.
Transient dimensioning factor	The dimensioning factor to consider the increase of the secondary linked flux due to a d.c. component of the primary short circuit current.

1.3.3 Abbreviations

Abbreviation definitions or usages may differ for North American (NA) and outside NA applications. Where that is the case, location specific alternate definitions or usages will be indicated by NA or outside NA.

Term	Definition
ALF	Accuracy Limit Factor
ANSI	American National Standards Institute
ASD	Adjustable Speed Drive
AVR	Automatic Voltage Regulator
BDEP	Basic Design Engineering Package (project phase)
BOD	Basis of Design (project phase)
CB	Circuit Breaker
CBCT	Core Balance Current Transformer
CCT	Critical Clearance Time
CENELEC	European Committee for Electrotechnical Standardisation
CSA	Canadian Standards Association
CT	Current Transformer
EF	Earth Fault (outside NA)
EI	Extremely Inverse Curve
EMF	Electro Motive Force
GIS	Gas insulated switchgear
GUI	Graphical User Interface
HV	High Voltage (Greater than 1000V for outside NA, greater than 38kV for NA)

Term	Definition
IDMT	Inverse Definite Minimum Time
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
ISF	Instrument Security Factor
LV	Low Voltage (less than or equal to 1000V)
MCB	Miniature Circuit Breaker
MESC	Materials and Equipment Standards and Code
MV	Medium Voltage, greater than 1000V, but less than 38kV (NA)
NA	North America
NER	Neutral Earthing Resistor (outside NA)
NGR	Neutral Grounding Resistor (NA)
OC	Overcurrent
OLTC	On Load Tap Changer
PLC	Power Line Carrier
PPE	Personal Protective Equipment
PTP	Precision Time Protocol
RMU	Ring Main Unit
RTD	Resistance Temperature Detector
SI	Standard Inverse Curve
SNTP	Simple Network Time Protocol
TB	Terminal Box
UCP	Unit Control Panel
UL	Underwriters Laboratory
VSD	Variable Speed Drive
VT	Voltage Transformer

1.3.4 ANSI Power System Device Function Numbers

System device function numbers as defined in ANSI/IEEE C37.2 used in this DEP are as follows. Alternate definitions common to NA or outside NA usage are shown in parenthesis.

Abbreviations with * have additional letters detailed in ANSI/IEEE C37.2 section 3.5.

Code	Definition
26OT	Transformer oil temperature element
26WT	Transformer winding temperature element
21	Distance protection
24	Volts per hertz protection (also referred to as overfluxing)
25	Synchro-check
27	Undervoltage protection
32	Reverse power protection
40	Field failure protection

Code	Definition
46	Phase unbalance protection
49	Thermal overload protection
49S/51LR*	Stall protection during starting and running protection
50	Instantaneous overcurrent protection
50G	Instantaneous ground fault protection (NA)
50N*	Instantaneous device connected in the residual of a polyphase circuit, connected across a broken delta or internally derived from the polyphase current or voltage quantities(NA) Instantaneous earth fault protection (outside NA)
51	AC inverse time overcurrent protection
51N*	AC inverse time ground fault protection based on derived quantities (NA) AC inverse time earth fault protection (outside NA)
51S*	Time dependent sensitive earth fault protection
51G*	AC inverse time ground fault protection where the measured quantity is in the path to ground or is the current flowing to ground(NA) AC inverse time Standby earth fault protection (outside NA)
51V	Voltage restrained overcurrent protection
58	Diode failure protection
59	Overvoltage protection
63	Buchholz relay
64	Restricted earth fault protection
66	Excessive number of start protection
67	Directional overcurrent protection
67G*	Directional ground fault protection (NA)
67N*	Directional earth fault protection
74	Trip circuit supervision
78	Pole Slip (Out of step) protection
79	Delayed three-phase auto-reclose
81	Underfrequency and overfrequency protection
86	Lockout relay
87	Differential protection
87G:	generator differential protection
94B*	Buchholz protection
94OT*	Transformer oil temperature element
94WT*	Transformer winding temperature element

1.4 CROSS-REFERENCES

Where cross-references to other parts of this DEP are made, the referenced section or clause number is shown in brackets (). Other documents referenced by this DEP are listed in (Part VII).

1.5 SUMMARY OF MAIN CHANGES

This DEP is a full revision of the DEP of the same number dated September 2013. The changes are too many to list as the DEP has been rewritten to combine global requirements, including protection requirements for North America. Aspects that are unique to particular regulatory regimes defined in separate sections (Part II) and (Part III).

1.6 COMMENTS ON THIS DEP

Comments on this DEP may be submitted to the Administrator using one of the following options:

Shell DEPs Online (Users with access to Shell DEPs Online)	Enter the Shell DEPs Online system at https://www.shelldeps.com Select a DEP and then go to the details screen for that DEP. Click on the "Give feedback" link, fill in the online form and submit.
DEP Feedback System (Users with access to Shell Wide Web)	Enter comments directly in the DEP Feedback System which is accessible from the Technical Standards Portal http://swwww.shell.com/standards . Select "Submit DEP Feedback", fill in the online form and submit.
DEP Standard Form (Other users)	Use DEP Standard Form 00.00.05.80-Gen. to record feedback and email the form to the Administrator at standards@shell.com .

Feedback that has been registered in the DEP Feedback System by using one of the above options will be reviewed by the DEP Custodian for potential improvements to the DEP.

1.7 NON NORMATIVE TEXT (COMMENTARY)

Text shown in italic style in this DEP indicates text that is non-normative and is provided as explanation or background information only.

Non-normative text is normally indented slightly to the right of the relevant DEP clause.

PART II GENERAL

1. BACKGROUND

Part II of this DEP defines general requirements that apply globally.

Part III of this DEP defines protection requirements for application outside North America.

Part IV of this DEP defines protection requirements for application in North America.

Part V of this DEP defines system protection and settings for global application.

For clarification, the sections in Parts II, III and IV follow one numerical sequence from 1 to 10 and section number is not duplicated in the different parts (e.g., there is one section 7).

2. DESIGN AND ENGINEERING PRINCIPLES

2.1 STANDARDS, CODES AND REGULATIONS

This DEP is based on the publications of the International Electrotechnical Commission (IEC), American National Standards Institute (ANSI), Institute of Electrical and Electronics Engineers (IEEE) and the European Committee for Electrotechnical Standardisation (CENELEC). Where relevant, the specific publications are referenced in this DEP.

1. The design and engineering of the protection system for an electrical installation shall satisfy all statutory requirements of the national and/or local authorities of the country in which the electrical installation will be located.
2. The protection system for an electrical installation shall be suitable for the site conditions, including seismic conditions, as specified by the Principal.
3. Electrical equipment and materials shall comply with the relevant DEP specifications, which in turn shall be considered as supplementary to IEC (or applicable North American) equipment standards.
4. CENELEC or national standards of the country in which the installation will be located may be used in lieu of IEC standards for the design and engineering of the electrical installation, provided they are accepted by the Principal.
 - a. Equipment to be installed in the European Union Member States shall have the appropriate 'CE' marking.
 - b. Devices for North American applications shall have Underwriters Laboratory (UL) or Canadian Standards Association (CSA) or equivalent NRTL markings as appropriate for the specific installation location
5. In the event of contradiction between the requirements of DEP specifications and IEC, CENELEC, ANSI, IEEE or national standards, the former shall prevail, provided the statutory obligations in the country of installation are satisfied.
6. Standard Drawings in series S 64, S 66, S 67, S 68 and S 69 shall apply, except where this DEP specifies otherwise.

2.2 OPERATIONAL SAFETY, RELIABILITY AND MAINTENANCE

- 1 The protection system should be designed to operate safely and reliably.
2. The protection system shall be designed to work under all operating conditions, including those associated with start-up and shutdown of plant and equipment, and throughout the intervening shutdown periods.

3. The design of electrical protection systems and equipment shall ensure that all operating and maintenance activities can be performed safely and conveniently and shall permit periods of continuous operation of at least 6 years.
 - a. The design shall not cater for simultaneous failure of two independent pieces of protection equipment.
 - b. The protection devices shall have a design life of 25 years.
4. The relay Manufacturer/Supplier should advise the duration by which the power supply card needs replacement to ensure the reliable operation of the equipment.

3. GENERAL PROTECTION AND SAFEGUARDING REQUIREMENTS

3.1 BACKGROUND

1. Electrical plant, machines, distribution systems and personnel shall be protected against damage which may occur during abnormal conditions such as the following:
 - a. operation outside the design rating due to overloading;
 - b. incorrect functioning of the system;
 - c. fault conditions, for example due to breakdown of some part of the system.
2. Protection of personnel from hazards such as arc flash shall be factored into the design of the electrical installation.

3.2 PROTECTION PHILOSOPHY

This DEP provides the details of the minimum requirements of protection necessary to provide a robust and safe system.

The prime objectives of electrical protection systems are to reliably:

- *identify system faults and automatically initiate action to isolate the affected equipment or section of electrical network whilst minimising disruption to the healthy part of the system;*
- *prevent, or minimise, equipment damage and reduce the arc flash energy by quick identification of fault conditions and rapid disconnection of faulty equipment or section of electrical installation;*
- *maintain the plant availability – i.e., by successfully isolating the faulty section with minimal disruption and returning the system to normal, while at the same time avoiding nuisance trips.*

1. An electrical protection system shall have the following minimum functionality:
 - a. Redundancy or backup sufficient that if a single protection device or circuit fails there shall be an independent secondary method for fault identification and isolation.

In most cases, coordinated upstream protection meets this requirement.

 - i. A single relay shall not be used as both main and back-up protection, e.g., differential and overcurrent.
 - ii. A single relay may be used for two separate main protection functions, e.g., differential and restricted earth (ground) fault protections, which may also share current transformers.
 - iii. The possibility of dormant, un-revealed faults in protection systems shall be minimised by design, e.g., use of trip circuit supervision, self-checking relays.
 - b. Operation for the full range of anticipated system fault levels.

- c. Fault clearance near generator sources shall be cleared within the critical clearing times to ensure system stability.
- d. Stable operation for short time overloads (within the safe limit of equipment) and normal system transients, such as motor starting currents, transformer magnetising inrush currents, switching surges.
- e. To reduce or avoid the damage of electrical equipment.

4. ELECTRICAL SYSTEM STUDIES

4.1 PROTECTION STUDY REPORT

1. A protection co-ordination (grading) study shall be executed for all new installations to ensure the overcurrent and earth (ground) fault relays are well co-ordinated.
2. Overcurrent and earth (ground) fault relays shall be able to isolate the fault as fast as possible maintaining the grading margin requirements to protect equipment and personnel.
3. For all switchgears that have been tested for control of internal arcs, the withstand durations identified in test documents should not be exceeded, for the full range of prospective arc fault current.
4. For all switchgears, potential arc flash energy that could be released shall be assessed as required by DEP 33.64.10.10-Gen. and DEP 33.64.20.10-Gen.
5. Other studies required to complete the co-ordination (grading) study are motor starting and transient stability studies, which shall be used to define the settings for undervoltage/overvoltage and frequency-based relays.
6. Critical clearance time (CCT) shall be calculated for relevant voltage levels in the network to determine the time of fault clearing without losing the system stability.
7. Where the CCT is very short (such as on a generation bus), in the range of 100 ms-200 ms, differential protection or distance protection relays may be required to achieve the required protection timing.
8. A single-line diagram shall be prepared for the complete electrical power system to indicate the types and locations of all protective devices and associated current and voltage transducers.

The single line diagram of the protection system is also known as a protection drawing or protection scheme.

9. Preparation of the protection scheme shall be initiated in the DEFINE phase of the project.
10. The protection study report shall be produced in the EXECUTE phase of the project.
11. The protection study report shall include at least the following:
 - a. a description of the system and of the system operating modes on which the settings have been based;
 - b. relevant short-circuit current calculations for the specified minimum and maximum supply or generation conditions;
 - c. single-line diagrams for each part of the system;
 - d. tabulated settings of the individual devices e.g., setting range, steps, CT ratio, type of relay curve, all relay parameter settings;
 - e. co-ordinated characteristics of the protective devices, fuses, dynamic and thermal withstand curves.

- f. the protection co-ordination (grading) curve shall clearly show the points related to fault current at various bus locations to show the relay operation time for the faults at these locations;
 - g. transformer inrush and motor starting currents;
 - h. generator fault decrement curves plotted in graphical form.
 - 12. The minimum and maximum supply or generation supply capacity conditions shall be representative of those conditions that can arise during normal operation of process units, production facilities and their utilities.
 - 13. The protection of distribution systems during special conditions, such as those occurring at the time of starting up generating plants, shall be ensured by appropriate adjustments of protection settings or selection of protection groups in the relay.
 - 14. Dynamic performance of the system shall be analysed to verify the adequacy of the protection provided in ensuring successful system recovery to stable operation following the incidence of system faults.
 - a. Electrical power systems incorporating their own generation as a means of power supply shall be studied to establish the extent to which re-energisation of essential service loads may be accomplished.
 - 15. The protection of the interconnection with the public utility shall be subject to the Principal's requirements and shall be co-ordinated and agreed with the public utility.
 - 16. The format of the protection report should be such that data is captured and maintained in a logical and efficient manner. As a minimum, the format shall include data on:
 - a. circuit identification;
 - b. protective device application;
 - c. current and voltage transformer rating;
 - d. key device setting parameters;
 - e. logics and interlocks;
 - f. a unique reference to co-ordination graphs with identification of relevant fault currents for ease of identification.
 - 17. Protection settings shall be provided in Manufacturer/Supplier specific parameters for the particular relay.
 - 18. The protection report shall detail the philosophy applied in selecting the relay settings and highlight any areas where necessary compromises are made.
- 4.2 SYSTEM SETTING MANAGEMENT
- 1. In order to maintain the integrity of the electrical protection system, a documented database (spreadsheet and pdf, or database system approved by the Principal) and system narrative shall be produced.
- 4.3 STUDY TIMING
- The timing and content of electrical studies is related to the phase of the project.*
- 1. In the DEFINE phase, system studies and protection schematics shall be produced based upon the S 66 (NA) or S 67 (outside NA) Standard Drawings.
 - a. If the electrical network is complex or contains novel equipment, specific protection schematics shall be produced to describe any unusual features.

2. In the EXECUTE phase, specific protection schematics, wiring diagrams, co-ordination diagrams, setting reports and associated narratives, as described in (4.1), shall be produced and shall be:
 - a. based upon the S 66 (for NA) or S 67 (outside NA) Standard Drawings already provided in the previous phase;
 - b. aligned with Manufacturer/Supplier specific data and engineering requirements to satisfy the project specification and standards.

5. CURRENT AND VOLTAGE TRANSFORMERS

5.1 CURRENT TRANSFORMERS

5.1.1 General

1. Current transformers shall be in accordance with:
 - a. ANSI/IEEE C37.13 for North American applications;
 - b. IEC 61869 for outside North American applications.

5.1.2 Measuring current transformers

The accuracy of measuring CTs is defined in:

- *ANSI/IEEE C57.13 for North American applications;*
- *IEC 61869-2 for outside North American applications.*

1. The accuracy of measuring CTs shall be decided considering the requirement of the particular application, e.g., for tariff metering, accuracy class of 0.2 may be required.
2. Selected measuring accuracy of CTs shall be agreed with Principal.
3. For switchgear applications the Manufacturer/Supplier shall specify the instrument security factor at rated burden of the measuring current transformers to be used.
4. For non-tariff metering application within the plant network protection CTs shall be utilized.

5.1.3 Protective (relaying) current transformers

5.1.3.1 Class P CTs (IEC 61869-2)

This class is applicable for installations outside NA. The performance of this class of CT is defined by accuracy class 5P or 10P.

1. Class P CTs should be used for most protection applications unless otherwise stated in the switchgear requisition. 5P (composite error of 5%) accuracy class of CT shall be used.

5.1.3.2 Class C CTs (ANSI/IEEE C57.13)

This class is applicable for NA installations.

For Class C CTs the allowable error is always 10 %.

A Class C CT with a limiting error of 10 % with the IEEE burden of 60-degree impedance angle has limiting error of 5 % which equates to the IEC Class 5P CT.

5.1.3.3 Rated accuracy limit factor

The rated accuracy limit factor (ALF) indicates a ratio of the primary current up to which the protective transformer, when connected to its rated burden, shall comply with the requirements for composite error defined in IEC 61869-2 or in ANSI/IEEE C57.13.

Typical values of ALF for IEC Class P CTs are 10, 20 and 30.

IEEE Class C CTs always have an ALF of 20.

1. The CT shall have an internal voltage high enough to drive the secondary current, corresponding to the 'rated accuracy limit primary current' (e.g., 20 times of rated current for 5P20), through the CT secondary winding impedance and the rated burden, while maintaining the CT error within the limits to successfully operate the protection relay.
 - a. Based on the application and protection scheme, the switchgear Manufacturer/Supplier shall determine the accuracy limit factor.

5.1.3.4 Class PX CTs

Class PX CTs performance is based on the secondary excitation characteristic (rated knee-point emf and maximum exciting current)-and maximum secondary winding resistance at 75 °C (168 °F)).

5.1.4 Application of Class P and PX CTs for outside NA installations

1. Class P CTs shall be used for general protection applications, e.g., for overcurrent and earth (ground) fault relays.
2. Class PX CTs shall be used for high impedance differential protection schemes or as specified by the relay Manufacturer/Supplier, e.g., for differential protection.
 - a. Where there are no such specific recommendations, the decision to use class P or PX CTs shall be made in consultation with the relay Manufacturer/Supplier.
 - b. For high impedance differential protection the knee-point voltage of the CT shall be at least twice the relay pickup voltage to ensure operation on internal faults.
3. While calculating the CT rating, the transient dimensioning factor suggested by the relay Manufacturer/Supplier for the particular application shall be used.
4. Through short circuit current shall be used for CT dimensioning.

Through fault for a transformer feeder is the short circuit current through the transformer feeder for a short circuit in the secondary side (it is not the prospective short circuit current of the bus).
5. The CT burden shall be selected in such a way that overall performance of the protection is not jeopardized.

Selecting a very low burden might cause severe saturation of the CT if ALF is not selected properly.

 - a. For specific cases, the Manufacturer/Supplier should demonstrate the calculation of CT parameters for a reliable and robust protection function during worst credible case scenario.
6. Wherever possible, the CT and the relay should be designed together; if this is not possible, then the selected CT secondary current shall be within the capability limits of the specified relay.
7. The overcurrent withstand capability of the current inputs of such meters shall comply with the requirements for protection relays to avoid damage by short circuit currents, except if an interposing CT is provided to meet the requirements of the metering equipment.
8. A CT with a high accuracy class, as required by the local grid, shall be used for tariff metering.

5.1.5 Core balanced CTs

1. Core balanced (CB) CTs shall be used for earth (ground) fault protection of transformers and motor feeders.

5.2 VOLTAGE TRANSFORMERS

5.2.1 General

1. Voltage transformers (VTs) shall be in accordance with:
 - a. IEEE for North American applications;
 - b. IEC 61869 for outside North American applications.
2. For VT protection, MCB in secondary shall be used. A primary VT fuse is optional depending on the primary voltage level of the VT.

5.2.2 Measuring and protection VTs

1. For general purposes, a protection VT shall be used for measuring.
2. For tariff metering, a measuring VT with a specified accuracy shall be used in consultation with the grid Supplier.

5.2.3 Earthed and unearthed (grounded/ungrounded) VTs

1. VTs shall be rated for their appropriate Voltage Factor as specified in IEC.
2. In earthed (grounded) VTs, the star point of the primary shall be earthed (grounded). For safety purposes, the secondary star point of the VT shall be earthed (grounded) as well.
3. In the unearthed (ungrounded) VTs, all terminals of the primary winding shall be fully insulated and shall not be earthed (grounded).
4. For protection application, an earthed (grounded) VT shall be used.

5.3 INSTRUMENT TRANSFORMER TEST SWITCHES

1. Test switches meeting the requirements of ANSI/IEEE C37.90 shall be provided for instrument transformers to provide a reliable method to isolate, test and service installed equipment without disturbing the system.
2. Switches shall be mounted on the front of equipment allowing measurements and tests without taking any devices out of service and without the need to access wiring at the rear of the devices.
3. VT test switches shall be of the non-shorting blade type.
4. CTs shall be connected through shorting (make-before break) switches with test jack and blade.

6. INSTALLATION AND DESIGN REQUIREMENTS

6.1 GENERAL REQUIREMENTS

1. Protection relays shall be mounted in the switchgear cubicle or associated relay panel/UCP.
2. All protective relays shall be visible from the front of the panel without having to open the panel door.
3. Relays with LED or LCD displays shall be mounted at such a height that the LED labels and LCD displays can be easily read.
4. The setting / operating parameters and status of the relay should be easily readable and the display should be back-lit.
5. Relays shall be flush or rack mounted in dust and moisture proof cases,
6. For installation outside NA, the minimum protection for the front side of the relay shall be IP 51 in accordance with IEC 60529.

7. The relays with programmable logic capabilities shall be provided with PC based Graphical User Interface.
8. All software and hardware for communication and interfacing with ENMCS, SCADA and computers shall be provided on the relay for local access during commissioning and maintenance.
9. All solid-state equipment shall be designed to withstand impulse and high frequency test requirements in accordance with IEC 60255-26.
10. All safety and emergency trips shall be directly wired to the circuit breaker coil.
11. All protection relays and contacts used in the protection scheme shall be suitable for operating in oil and gas industrial environment without being impacted by corrosion.

6.2 EMISSION REQUIREMENTS FOR PROTECTION RELAYS

1. Electronic protection relays shall comply with generic emission requirements for the industrial environment in accordance with IEC 61000-6-4.
2. For installations in NA electronic protection relays shall comply with generic emission requirements for the industrial environment in accordance with CISPR11 / CISPR22 Class A.

6.3 IMMUNITY REQUIREMENTS FOR PROTECTION RELAYS

6.3.1 General

1. Electronic protection relays installed in a separate control room shall comply with the immunity requirements of IEC 61000-6-5, area G (equipment installed in power stations and MV/ HV substations).
2. Electronic protection relays installed in a High Voltage (HV) switchgear room, back-to-back with switchgear cubicles, shall comply with the immunity requirements of IEC 61000-6-5, area H (equipment installed in HV substations), regardless of the level of the high voltage.
3. Electronic protection relays in Gas Insulated switchgear (GIS) shall comply with the damped oscillatory wave immunity test requirements of IEC 62271-1 and IEC 61000-4-18, with test frequencies of 10 MHz and 30 MHz and test levels as specified in IEC 62271-1.
4. The damped oscillatory wave immunity tests as per IEC 61000-4-18, at oscillatory frequencies of 10MHz and 30MHz, may be replaced by ring wave immunity tests in accordance with IEC 61000-4-12 at frequencies of 10MHz and 50MHz when identical test levels are adhered to.
5. Protection relays shall be able to perform their correct functions in a network subject to harmonic distortion level limits indicated in Table 1 of IEC/TR 61000-3-6.

6.3.2 Performance criteria

1. Protection relays shall withstand each of the immunity tests specified in (6.3) without damage, degradation or malfunction.
2. Where the primary protection and measurement functions of protection relays are concerned, no degradation or temporary loss of function shall be allowed.

This is performance criterion 1 or A of IEC 61000-6-5.

3. Performance criteria for various functions of secondary equipment shall be in accordance with IEC 61000-6-5.

6.4 POWER SUPPLY FOR PROTECTION RELAYS

1. The power supply from the DC distribution board shall be routed independently to protection relays and trip coils through the associated relay and control panel.

2. The auxiliary power supply wiring inside the relay and control panel shall be done by looping in all the equipment supply terminals in parallel, thus forming positive and negative supply buses with as many connection points as required by the number of circuits.
 - a. These supply buses shall end at the terminals of the DC supply supervision relay.

This arrangement ensures 100 % coverage of auxiliary supply wiring for supervision.
 - b. No looping of the power supply shall be made from one relay to another.
3. Where in use, the two breaker trip coils shall be wired to two supplies drawn from two different DC buses. The associated main and back-up protection equipment shall be supplied from two independent DC buses. Each DC supply bus shall be independently supervised by a supply supervision relay.
4. Power to protective devices shall be supplied from a DC supply bus derived from two independent sources connected together by blocking diodes. Refer to standard drawing 67.041
5. In the following cases, the loss of relay power supply should not trip the respective feeder:
 - a. motor feeder (not applicable for Ex 'e' motor);
 - i. Process safety related trips shall not be wired through the relay
 - b. plant distribution feeders where there is upstream protection (co-ordinated as back protection);
 - c. backup generators used for emergency, vital and critical services.
6. Relay power supply failure shall initiate an alarm for immediate operator intervention for the cases listed in (6.4, Item 5).
7. External wiring systems for numerical relays that exit the substation building shall be designed so that electromagnetic interference does not adversely affect the operation of the protection devices
8. For digital inputs that are not time-critical (e.g., temperature, status) a delay of 20 ms should be provided.

6.5 TRIPPING SCHEMES

6.5.1 Tripping and lockout relays

1. A circuit breaker shall be tripped directly or through a tripping relay.
2. The operating time of the tripping relay shall be less than 10 ms.
3. Tripping relays shall have the facility to be programmed to self-reset and be suitable for continuous energisation.
4. The tripping relay should have high burden rated output contact.
5. The tripping contacts shall have sufficient capacity to handle the maximum current that can occur in the circuits controlled by these relays.

These relays contacts are used for trip and close coils of contactors or circuit breakers.
6. Lockout relays shall be used to block the closing of a breaker under faulty conditions.
 - a. To prevent resetting of a lockout relay on failure of auxiliary supply, the latching mechanism of the lockout relay should be mechanical type.

- b. For installations outside of North America, an electronic latching mechanism may be acceptable if it can prevent resetting of a lockout relay on failure of auxiliary supply.
7. Except for locations with separate mechanical lockouts, the reset mechanism of the lockout relay should be electrically operated to facilitate both local and remote resetting.
8. Lockout relays shall be equipped with a pair of normally closed contacts arranged to break their own coil circuit when in the latched position, thus avoiding battery drain.
9. A combined relay performing both trip and lockout functions may be used provided it meets the requirements of both applications. If a varistor or other surge protective device is not provided in the coil of the switching device (contactor, circuit breaker) a lockout relay shall be provided to avoid the damage of relay output contact.
10. For North American installations, the device "86" lock-out relays shall be separate mechanical devices.
 - a. A lockout function as part of a multi-function relay shall not be used.
11. Directional relays should not initiate the trip command on loss of voltage input.
 - a. In case of loss of voltage input (from VT/PT) the relay shall initiate an alarm for immediate operator intervention to bring the protection back in service.

6.5.2 Inter-tripping/ Transfer trip

1. For installations outside North American the power circuits, typically HV transformer or plain feeder circuits to HV systems that have no inherent inter-tripping capability, shall be equipped with a send and receive intertrip relay.
2. For North American installations the power circuits, typically HV and MV transformer or plain feeder circuits to HV and MV systems that have no inherent transfer trip capability, shall be equipped with a transfer trip.
3. The activation of an inter-trip / transfer trip relay shall be indicated at both ends of the circuit.

6.5.3 Trip circuit supervision

1. Trip circuit supervision shall be incorporated in the design of all MV and HV circuit protection schemes.
2. The operation of any trip circuit supervision relay shall activate an alarm.
3. Trip circuit supervision shall be arranged to monitor the tripping coil in both the open and closed conditions.

6.5.4 Breaker fail protection

1. Breaker fail protection should be incorporated in the protection schemes of the outgoing circuits of main intake switchboards, main generation switchboards and other primary distribution switchboards where an upstream bus coupler circuit breaker can operate to reduce the consequences of the outage.
2. Breaker failure protection shall be used if the upstream relay has to trip faster than the normal backup co-ordination time delayed operation.

6.6 NUMERICAL RELAYS

6.6.1 Main features

1. Multifunction numerical protection relays should be applied unless otherwise agreed by the Principal, incorporating the following features:
 - a. self-checking;
 - b. programmable scheme logic;

- c. communications;
 - d. measured value display and disturbance;
 - e. event recording facilities.
2. The self-check feature for multifunction relays shall include the following minimum features for continuous self-monitoring:
- a. auxiliary supply supervision;
 - b. checksum on all protection algorithms;
 - c. memory checks;
 - d. checks on input and output modules including A/D converters and filters;
 - e. watchdog supervision on program execution.

6.6.2 Communications

1. Numerical relays should be equipped with the following means of communications:
- a. with a computer through a modem, RS 232 cable, RS 485 or RJ45 connection;
 - b. with a distributed control system through human-machine interface software;
 - c. with ENMCS (SCADA);
 - d. with a substation control system through a serial interface (RS485 or fibre optic) with protocol IEC 60870-5-103, Modbus RTU or Profibus DP;
Communication protocol IEC 60870-5-103 is not applicable for the For North American installations,
 - e. Ethernet (electrical or fibre optic) with protocol IEC 61850 or Modbus TCP.
 - f. Ethernet Ports for IEC61850 should be redundant and contain two TxRx pairs.
2. The communication link shall be a twisted pair of copper wires or optical fibres and agreed with Principal.

6.6.3 Relay software

Proprietary software is often used to communicate with the relay to download, change, save and upload relay settings.

In addition, the software can also retrieve real time metering data, disturbance and event records and trending data.

Additional software may be required to view the load or fault data in a customised format.

1. Proprietary software for retrieving real time metering data, disturbance and event records and trending data shall be provided to the Principal by the relay Manufacturer/Supplier.

6.6.4 Relay firmware

Relay firmware refers to the software within the relay.

1. All relays shall have facilities to enable upgrading of relay firmware on site.

6.6.5 Time synchronisation

1. Numerical relays shall have a time synchronisation feature to allow the time tagging of measured or fault data, with an accuracy of up to 1 ms:
2. Time synchronisation should be achieved by means of GPS clock through an IRIG-B device.
3. Ethernet based time synchronization such as PTP or SNTP may be used if approved by the Principal.

6.7 APPLICATION OF NUMERICAL RELAYS

1. For installation outside the North America, the design shall be in line with the requirements of the S 67 Standard Drawings.
2. For installation in North America, the design shall be in line with the requirements of the S 66 Standard Drawings.

Duplication of input measuring systems is not generally required.

3. For generators > 100 MW:
 - a. The full duplication of protective devices shall be applied unless otherwise agreed by the Principal.
 - b. Advice shall be taken from a power system protection specialist on the application and design of such a scheme.

PART III APPLICATION OUTSIDE NORTH AMERICA

7. EQUIPMENT PROTECTION SCHEMES

7.1 PROTECTION OF HV CABLES

7.1.1 Summary of features

1. The protection requirements of HV cables shall be as Table 1.

Table 1 Protection Features of HV Cable

Item	Single plain feeder	Parallel plain feeder
Standard Drawing	S 67.054	S 67.053
Voltage	HV	HV
Upstream Switchgear	Circuit breaker	Circuit breaker
Downstream Switchgear	Circuit breaker	Circuit breaker
Upstream Protection	Inverse definite minimum time (IDMT) overcurrent-earthfault protection	1. Differential protection 2. IDMT overcurrent-earth fault protection
Downstream Protection	None	1. Differential protection. (part of upstream differential scheme) 2. Directional IDMT overcurrent and earth fault protection where the downstream bus-section is normally closed.
Others		Intertrip after initial trip from upstream lockout relay to downstream CB.
Meters	Metering function of the relay should be used	Metering function of the relay should be used

2. For two section switchgear operated with 'Bus Coupler' close supplied by parallel plain feeders (each having 100% capacities) the over current (51) and earth fault (51N) protection shall be provided on the bus coupler to split the bus in case the primary protection at downstream feeder fails to operate.

7.1.2 Differential protection

1. For single plain feeder the differential protection may be considered for fast fault clearance requirements. This protection shall be achieved by a current differential based scheme using optic fibre.

7.2 PROTECTION OF OVERHEAD LINES

7.2.1 Summary of features

1. The protection requirements for overhead lines shall be as Table 2.
2. Differential protection shall be applied for short lines (up to 10 Km) where distance protection is not effective.

Auto reclose is applicable for double circuit transmission line operating in normally close configuration.

Table 2 Protection Features of overhead lines

Item	Feeder for Lower Voltages	Feeder for Higher Voltages
Voltage Rating	< 69 kV	≥ 69 kV
Standard Drawing	S 67.059	
Switchgear	Circuit breaker	
Protection	1. IDMT and instantaneous overcurrent and earth fault protection with built-in synchro-check and auto-reclose features. 2. Distance or differential protection, refer (7.2.1, Item 2). 3. Directional earth fault protection.	1. Distance protection with built-in features synchro-check and auto-reclose features, refer (7.2.1, Item 2). 2. IDMT overcurrent and earth fault protection. 3. Directional earth fault protection.
Auto-Reclose Relay	Built-in feature or independent relay	
Synchro-Check Relay	Required for multiple sources	Required for multiple sources
Trip circuit supervision	Provided	Provided
Initiation of auto-reclose	Instantaneous overcurrent-earth fault protection	Distance protection (Z1 and Z2) or current differential relay
Lockout of auto-reclose	IDMT overcurrent-earth fault protection within the reclaim time	Any protection relay operation within the reclaim time
Intertrip signals	Required	Required (via power line carrier (PLC) or optical fibre)
Meters	Metering function of the relay should be used	Metering function of the relay should be used. An alternative is the use of a digital power meter.

7.2.2 Protection of HV (< 69 kV) overhead lines

1. Overhead lines for voltages less than 69 kV shall be protected by the following:
 - a. Instantaneous overcurrent and earth fault relay shall act as the main protection when an auto-reclose scheme is in service.
 - i. This protection shall trip the CB and initiate the auto-reclose.
After initiation, the protection will not be in service until the auto-reclose has completed the reclose cycle, i.e., either at the end of the reclaim time following a successful reclose or a reset following a lockout due to an unsuccessful auto-reclose.
 - ii. The instantaneous protection shall be set to cover the network beyond the line with an adequate factor of safety to ensure operation for faults at the end of the line even under minimum fault current conditions.
 - b. An IDMT over current and earth fault relay shall act as the main protection for both the following:
 - i. during the reclaim time following an auto-reclose attempt, when the instantaneous overcurrent and earth fault protection is not in service;

- ii. when the auto-reclose scheme is not in service.
- 2. The main protection relays shall perform the following functions:
 - a. trip the CB for a line fault and lockout the auto-reclose scheme following an unsuccessful auto-reclose;
 - b. trip the CB for a line fault when the auto-reclose scheme is not in service.
- 3. Line protection shall be coordinated with the other downstream IDMT overcurrent and earth fault protection.
- 4. A distance or current differential protection relay shall be used where the overcurrent and earth fault relays are unable to provide adequate protection during minimum fault levels.
- 5. The main protection for a line shorter than 10 km shall be current differential protection.
- 6. The main protection for a line longer than 10 km shall be either of the following:
 - a. distance protection with permissive under-reach or overreach transfer tripping;
 - b. differential protection.
- 7. The transfer tripping for both short and long lines shall be through power line carrier communication or optical fibres.
- 8. The distance relay shall be provided to protect against phase and earth faults, including high resistance earth faults.

7.2.3 Protection of HV (> 69 kV) overhead lines

- 1. Overhead lines for voltages greater than 69 kV shall be fitted with the following at each end:
 - a. distance relay as the main protection. current differential protection may be used as an alternative to the distance protection;
 - b. directional earth fault protection as the back-up protection to the distance relay for high resistance faults;
 - i. The directional earth fault protection shall be incorporated within the distance relay.
 - c. Back-up IDMT overcurrent and earth fault protection;
 - It is not the practice to use IDMT overcurrent and earth fault relays for lines > 132 kV because of the difficulty of achieving relay grading due to the multiple earth fault current return through the solidly earthed 132 kV neutrals.*
 - i. For lines >132 kV, the back-up protection shall be a distance relay.
 - d. Communication link to ensure fast operation for all faults within the line.
- 2. The main protection for a line shorter than 10 km shall be current differential protection.
- 3. The main protection for a line longer than 10 km shall be either of the following:
 - a. distance protection with permissive under-reach or overreach transfer tripping;
 - b. differential protection.
- 4. The transfer tripping for both short lines shall be through optical fibres.
 - Mode of transfer trip (power line carrier communication or optic fibre) for long lines should be evaluated and selected based economic justification*
- 5. The distance relay shall be provided to protect against phase and earth faults, including high resistance earth faults.