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TECHNICAL REPORT

Guidelines for the design of interconnected power systems

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GUIDELINES FOR THE DESIGN OF INTERCONNECTED POWER SYSTEMS

FOREWORD

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IEC/TR 62511, which is a technical report, has been prepared by IEC technical committee 8: Systems aspects for electrical energy supply.

The text of this technical report is based on the following documents:

Enquiry draft	Report on voting
8/1346/DTR	8/1364/RVC

Full information on the voting for the approval of this technical report can be found in the report on voting indicated in the above table.

This publication has been drafted in accordance with the ISO/IEC Directives, Part 2.

The committee has decided that the contents of this publication will remain unchanged until the stability date indicated on the IEC web site under "http://webstore.iec.ch" in the data related to the specific publication. At this date, the publication will be

- reconfirmed,
- withdrawn,
- replaced by a revised edition, or
- amended.

A bilingual version of this publication may be issued at a later date.

GUIDELINES FOR THE DESIGN OF INTERCONNECTED POWER SYSTEMS

1 Scope

The primary objective of this Technical Report is to provide guidelines in planning and design of the interconnected power system (IPS) and consequently achieve the delivery of reliable supply service. The guidelines for the design of interconnected power systems within this document will enhance system reliability, mitigate many of the adverse impacts associated with the loss of a major portion of the system or unintentional separation of a major portion of the system, and will not be consequential because of normal design contingencies.

In the context of this Technical Report, interconnected power system means an entity's (control area or a system operator) high-voltage transmission system that can adversely impact other connected systems due to faults and disturbances within its area. In the case of large areas, the system operator may define a subset of its area to keep the adverse impact contained within a smaller portion of its system.

This Technical Report specifies the recommended techniques for securing an IPS to ensure a high level of reliability. Generally, interconnected power systems are synchronously connected or asynchronously connected through DC interconnections. This document aims to ensure that the interconnections are designed and operated consistently on both ends. The recommendations include design and operation requirements to withstand the primary contingencies specified in this document.

It is recommended that each entity ensures that its portion of the high voltage IPS is designed and operated in unison with these guidelines. This precaution is recommended, otherwise additional system interconnections can cause significant adverse impacts on reliability of the connected entities. Each entity is also encouraged to make use of committees, task forces, working groups, interregional studies and other methods in order to ensure their IPS is constantly updated/enhanced and maintained, in such a way that it is in agreement with these guidelines.

NOTE The application of this guide is for high voltage transmission systems (generally over 50 kV). However, mitigation measures for certain system conditions, such as under frequency load shedding (UFLSh), are frequently required for low voltage distribution systems; hence, for the purpose of this transmission guide, interconnected control areas and/or system operators can establish the voltage level, as required. In addition, the design guidelines in this document are intended only for those elements of the IPS (not the entire high voltage transmission system) that can adversely impact other connected system(s) due to faults and disturbances within an area or a predefined subset of a large area. This document also provides guidance to determine such elements of the IPS.

2 Normative references

The following documents, in whole or in part, are normatively referenced in this document and are indispensable for its application. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

None.

3 Terms and definitions

For the purposes of this document, the following terms and definitions apply.

3.1
adequacy
ability of an electric power system to supply the aggregate electric power and energy required by the customers, under steady-state conditions, with system component ratings not exceeded, bus voltages and system frequency maintained within tolerances, taking into account planned and unplanned system component outages

Note 1 to entry: The ability may be measured by one or several appropriate indices.

[SOURCE: IEC 60050-191:1990, 191-21-01]

3.2
continuous capacity
rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation, transmission, or other electrical equipment

3.3
maximum capacity of a unit
the maximum power that could be generated by a unit, under continuous operation with all of its components in working order

Note 1 to entry: This power may be gross or net.

[SOURCE: IEC 60050-602:1983, 602-03-08]

3.4
contingency
event, usually involving the loss of one or more elements, which affects the IPS at least momentarily

3.5
control area
electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its net interchange schedule with other control areas and contributing to frequency regulation of interconnections

3.6
demand
the magnitude of an electricity supply, expressed in kilowatts or kilovoltamperes

[SOURCE: IEC 60050-691:1973, 691-02-02]

3.7
element of power system
any electric device with terminals that may be connected to other electric devices

EXAMPLE A generator, transformer, circuit breaker, or bus section.

3.8
emergency
any abnormal system condition that requires automatic or manual action to prevent or limit the loss of transmission facilities, or generation supply that could adversely affect the reliability of the electric system

Note 1 to entry: An emergency is considered to exist in a region of an entity where a firm load has to be shed.

3.8.1
emergency limits
limits which can be utilized for the time required to take corrective action

Note 1 to entry: The limiting condition for voltages should recognize that voltages should not drop below that required for suitable system stability performance, and should not adversely affect the operation of the IPS.

Note 2 to entry: The limiting condition for equipment loadings should be such that cascading outages will not occur as a result of the operation of protective devices upon the failure of facilities. (Various definitions of equipment ratings are found in this guide.)

3.8.2
applicable emergency limits
limits which depend on the duration of the occurrence and on the policy of the given entity regarding loss of life to equipment, voltage limitations, etc.

3.9
fault
an unplanned occurrence or defect in an item which may result in one or more failures of the item itself or of other associated equipment

Note 1 to entry: A fault is often the result of a failure of the item itself, but may exist without prior failure.

[SOURCE: IEC 60050-604:1987, 604-02-01, modified – addition of Note 1 to entry]

3.9.1
delayed fault clearing
fault clearing which is consistent with the correct operation of a breaker failure protection group and its associated breakers, or of a backup protection group with an intentional time delay

3.9.2
normal fault clearing
fault clearing which is consistent with the correct operation of the protection system and with the correct operation of all circuit breakers or other automatic switching devices intended to operate in conjunction with that protection system

3.10
generation (of electricity)
a process of producing electrical energy from other forms of energy

Note 1 to entry: The amount of electric energy produced, usually expressed in kilowatt-hours (kWh) or megawatt hours (MWh).

[SOURCE: IEC 60050-601:1985, 601-01-06 modified – modified definition and addition of Note 1 to entry]

3.11
high-voltage d.c. link
HVDC link
an installation for transmitting large quantities of electricity at high-voltage d.c., including the converter substations

[SOURCE: IEC 60050-601:1985, 601-04-01]

3.12
interconnected power system
IPS
interconnected electrical power system within a wide area, comprised of system elements assigned to different local areas within the same operating authority or a different operating authority (e.g. ISOs) on which faults or disturbances can have a significant adverse impact outside of the local area

3.13
interconnection
interconnexion
single or multiple transmission links between transmission systems enabling electric power and energy to be exchanged between these networks by means of electric circuits and/or transformers

Note 1 to entry: In the context of this document interconnection refers to facilities that connect two or more IPSs or control areas. Additionally, interconnection also refers to the facilities that connect a non-utility generator to a control area or IPS.

[SOURCE: IEC 60050-601:1985, 601-01-11, modified – "electricity" replaced by "electric power and energy", "systems" replaced by "networks", "electric" added to "circuits" and addition of Note 1 to entry]

3.14
load
device intended to absorb power supplied by another device or an electric power system

[SOURCE: IEC 6005-151:2001, 151-15-15]

3.14.1
firm load
load that is not an interruptible load **–** load that is served on a guaranteed basis, 100 % of the time

3.14.2
interruptible load
load of particular consumers which, according to contract, can be disconnected by the supply undertaking for a limited period of time

[SOURCE: IEC 60050-603:1986, 603-04-41]

3.15
load relief
reduction in amount of customer load caused by deliberate voltage reduction in response to an abnormal operating condition of the electric power system and/or load shedding

3.16
load shedding
the process of deliberately disconnecting preselected loads from a power system in response to an abnormal condition in order to maintain the integrity of the remainder of the system

[SOURCE: IEC 60050-603:1986, 603-04-32]

3.17
load current
$\boldsymbol{I_{\mathrm{load}}}$
highest continuous ampere on line or other series elements rating, that most closely approximates a 4-hour rating of the line

3.18
native
belonging to the person, place or thing in question

3.19
operating limit
the maximum value of the most critical system operation parameter(s) which meets: (a) pre-contingency criteria as determined by equipment loading capability and acceptable voltage conditions, (b) stability criteria, and (c) post-contingency loading and voltage criteria

3.20
outage
unavailability
the state of an item of being unable to perform its required function

[SOURCE: IEC 60050-603:1986, 603-05-05]

3.20.1
forced outage
unplanned outage whose onset, automatic or manual, cannot be deferred

[SOURCE: IEC 60050-191:1990, 191-24-03]

3.20.2
maintenance outage
the removal of equipment from service to perform work on specific elements that can be deferred

3.20.3
planned outage
outage scheduled in advance, for maintenance or other purposes

[SOURCE: IEC 60050-191:1990, 191-24-01]

3.21
pole (of an equipment)
in certain types of equipment such as switchgear, the part corresponding to one of the phases in a.c. or to one of the polarities in d.c.

Note 1 to entry: According to the number of poles within the equipment, it is called: single-pole equipment, two-pole equipment, etc.

[SOURCE: IEC 60050-601:1985, 601-03-11]

3.22
HVDC terminal
rectifier and an inverter, with associated filter banks and control equipment, tied together by a transmission line or bus

3.23
protection
provisions for detecting faults or other abnormal conditions in a power system, for enabling fault clearance, for terminating abnormal conditions, and for initiating signals or indications

Note 1 to entry: The term “protection” is a generic term for protection equipment or protection systems.

Note 2 to entry: The term “protection” may be used to describe the protection of a complete power system or the protection of individual plant items in a power system e.g. transformer protection, line protection, generator protection.

Note 3 to entry: Protection does not include items of power system plant provided, for example, to limit over voltages on the power system. However, it includes items provided to control the power system voltage or frequency deviations such as automatic reactor switching, load-shedding, etc.

[SOURCE: IEC 60050-448:1995, 448-11-01]

3.23.1
protection system
protection group
an arrangement of one or more protection equipments, and other devices intended to perform one or more specified protection functions

Note 1 to entry: A protection system includes one or more protection equipments, instrument transformer(s), wiring, tripping circuit(s), auxiliary supply(s) and, where provided, communication system(s). Depending upon the principle(s) of the protection system, it may include one end or all ends of the protected section and, possibly, automatic reclosing equipment.

Note 2 to entry: The circuit-breaker(s) are excluded.

[SOURCE: IEC 60050-448:1995, 448-11-04, modified – addition of "**protection group**"]

3.24
element basis
one or more protection groups, including all equipment such as instrument transformers, station wiring, circuit breakers and associated trip/close modules, and communication facilities

Note 1 to entry: It is installed at all terminals of a power system element to provide the complete protection of that element.

3.25
protective relay
protection relay
measuring relay which, either solely or in combination with other relays, is a constituent of a protection equipment

[SOURCE: IEC 60050-448:1995, 448-11-02]

3.26
relay
electrical device designed to produce sudden predetermined changes in one or more electric output circuits, when certain conditions are fulfilled in the electric input circuits controlling the device

[SOURCE: IEC 60050-151:2001, 151-13-31]

3.27
reliability
the ability of an item to perform a required function under given conditions for a given time interval

Note 1 to entry: It is generally assumed that the item is in a state to perform this required function at the beginning of the time interval.

Note 2 to entry: Electric system reliability can be quantified using appropriate measures by considering two basic and functional aspects of the electric system — adequacy and security.

Note 3 to entry: Probability that an electric power system can perform a required function under given conditions for a given time interval.

[SOURCE: IEC 60050-191:1990, 191-02-06, modified – removal of original Note 2 and addition of new Notes 2 and 3 to entry]

3.28
spinning reserve
generating capacity, kept in reserve to compensate for all possible deviations in the power balance that may occur between normal conditions and those which actually occur, and thus to ensure a reliable and economic electricity supply

3.29
resource
any physically or conceptually identifiable entity whose use and state at any time can be unambiguously determined

Note 1 to entry: For this document, refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load.

[SOURCE: IEC 60050-715:1996, 715-02-01, modified – addition of Note 1 to entry]

3.30
security
ability of an electric power system to operate in such a way that credible events do not give rise to loss of load, stresses of system components beyond their ratings, bus voltages or system frequency outside tolerances, instability, voltage collapse, or cascading

Note 1 to entry: This ability may be measured by one or several appropriate indices.

Note 2 to entry: This concept is normally applied to bulk power systems.

Note 3 to entry: In North America, this concept is usually defined with reference to instability, voltage collapse and cascading only.

[SOURCE: IEC 60050-191:1990, 191-21-03]

3.31
short circuit
accidental or intentional conductive path between two or more conductive parts, whether made accidently or intentionally, forcing the electric potential differences between these conductive parts to be equal to or close to zero (relatively low impedance)

Note 1 to entry: The term fault or short-circuit fault used in this document refers to a short circuit.

3.32
significant adverse impact
instability, unacceptable system dynamic response, unacceptable equipment tripping; voltage/frequency levels in violation of applicable emergency limits, and/or loadings on transmission facilities in violation of applicable emergency limits

Note 1 to entry: With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from faults or disturbances shall be deemed as having significant adverse impact:

a) instability
   – any instability that cannot be demonstrably contained to a well-defined local area
   – any loss of synchronism of generators that cannot be demonstrably contained to a well-defined local area
b) unacceptable system dynamic response
   – an oscillatory response to a contingency that is not demonstrated to be clearly positively damped within 30 s of the initiating event
c) unacceptable equipment tripping
   – tripping of an un-faulted IPS element (element that has already been classified as IPS) under planned system configuration due to operation of a protection system in response to a stable power swing
   – special protection system in response to a condition for which its operation is not required

3.33
special protection system
SPS
protection system designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted elements

Note 1 to entry: Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages or power flows. Conventionally switched, locally controlled shunt devices are not SPSs, while Generation Rejection Protection Scheme for system stability is an SPS. As an example, automatic under frequency load shedding to stabilize the system frequency in an area during an event leading to declining frequency is not considered an SPS.

3.34
stability
ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances

Note 1 to entry: Power system stability can be classified as voltage, rotor angle and frequency stability.

3.35
substation (of a power system)
a part of an electrical system, confined to a given area, mainly including ends of transmission or distribution lines, electrical switchgear and control gear, buildings and transformers

Note 1 to entry: A substation generally includes safety or control devices (for example protection).

Note 2 to entry: The substation can be qualified according to the designation of the system of which it forms a part. Examples: switching, transmission, substation (transmission system), distribution substation, 400 kV or 20 kV substations.

[SOURCE: IEC 60050-601:1985, 601-03-02]

3.36
transfer capability
operating limit relating to the permissible power transfer between specified areas of the transmission system

Note 1 to entry: The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). In this context, "area" may be an individual electric system, power pool, control area, sub-region, or region, or a portion of any of these. Transfer capability is directional in nature. That is, the transfer capability from "Area A" to "Area B" is not generally equal to the transfer capability from "Area B" to "Area A".

3.36.1
emergency transfer capability
amount of power transfer allowed between entities or within an entity when operating achieving emergency criteria contingencies

3.37
transmission system
TS
the whole of the means of transmission between two points, comprising the transmission medium, terminal equipment, any necessary intermediate equipment and any equipment provided for such ancillary purposes as power feeding, supervision and testing

[SOURCE: IEC 60050-704:1993, 704-04-10, modified – definition 1 removed]

3.37.1
primary transmission system
PTS
transmission portion of the IPS of an entity, that generally consisting of EHV/HV transmission system

Note 1 to entry: For this document, it can be part of intra-entity and/or inter-entity system connections. Generally connected through auto transformation to connect generation and large load connections. Typical examples are: transmission grid/inter-entity connections (generally > 100 kV), generation (generally > 100 MW), and load consumers (>100 MW).

3.37.2
secondary transmission system
STS
transmission portion of the IPS of an entity that generally consists of HV and MV transmission system

Note 1 to entry: For this document, it can be part of intra-entity and/or inter-entity system connections. Generally connects to primary transmission systems, sub-transmission, generation, and large & medium load connections. Typical examples are: secondary transmission (50 kV< STS < 200 kV), generation (generally 5 MW to 100 MW) and load consumers (20 MW to 100 MW).

3.38
voltage reduction
a relatively small decrease in the system operating voltage used as a means to reduce the demand by lowering the customer's voltage

[SOURCE: IEC 60050-604:1987, 604-01-21, modified – additional text "used as ... voltage" added]

4 General principles

4.1 General requirements

The application of this Technical Report is for high voltage transmission systems (generally over 50 kV). However, mitigation measures for certain system conditions, such as under frequency load shedding (UFLSh), are frequently required for low voltage distribution systems; hence, for the purpose of this transmission guide, interconnected control areas and/or system operators should establish the voltage level, if required. In addition, local conditions may require criteria which are more stringent than those set out herein. Hence, these guidelines should be treated as minimum requirements. Any constraints imposed by the local conditions or more stringent criteria should be adhered to. It is also recognized that these guidelines are not necessarily applicable to those elements of the high voltage transmission system on which disturbances and/or contingencies will not adversely impact the safe, secure and reliable operation of the interconnected power system (IPS), or to those elements which happen to be contained in the portions of a local system where instability and/or overloads will not jeopardize the reliability of the remaining interconnected power system.

The guidelines in this document should be used in the assessment and in the reliability testing of an entity's high voltage transmission system to determine the elements of IPS for enhanced design.

Design studies should assume that power flow conditions utilizing load transfers and generation conditions will stress the system. For example, transfer capability studies should be based on the load and generation conditions which are expected to exist for the period under study followed with sensitivity studies for light load or higher load during extreme weather conditions. All reclosing facilities should be assumed in service, unless it is known that such facilities will be rendered inoperative.

Special protection systems (SPS) may be employed, in the interest of maintaining system security, for facilities which are not available to meet demand. An SPS may also be applied for economic reasons or to preserve system integrity in the event of severe facility outages and extreme contingencies. However, a special protection system (SPS) should be used with caution when employed. It is recommended that SPS be installed consistently with good system design and operating policy. Depending upon the consequences of SPS failure, full redundancy should be considered in its implementation. Generally speaking, SPS may be used to provide protection from infrequent contingencies or from temporary conditions that may exist such as: project delays, unusual combinations of system demand, and equipment outages or availability. The decision to employ an SPS should take into account the complexity of the scheme and the consequences as well as the benefits of correct operation or the risks associated with incorrect operation.

It is not intended to establish operating guidelines in this document. However, it is extremely important to mention that for effective planning and design, coordination among and within interconnected entities operating IPSs is essential to the reliability of interconnected operations. For example, timely information concerning system conditions should be transmitted by the native entities to any other collaborating entities working synchronously or asynchronously through HVDC links with one another.

Where inter-entity reliability is concerned, each native entity (facility owner) should identify the ratings of its equipment; the lowest ratings shall be considered in determining the operating limits of the interconnection facilities. Once the operating limits are determined, the interconnection facilities shall be designed to withstand the contingencies stated in 6.2 and 6.3 without causing a significant adverse impact on the other interconnected entities.

4.2 System analysis and modeling data exchange requirements

For reliability purposes, collaborating entities should arrange to share and coordinate forecast system information, along with real time information, in order to enhance the analysis and modeling of security application software on energy management systems that pertain to interconnected power systems.

It is also strongly recommended that collaborating entities acquire accurate and up-to-date system modeling information and disclose the data required to analyze and model their IPSs. Using the shared data, component facilities can be properly modeled for assessments. Data sharing is also recommended for fault level analysis, as well as for use in interconnected operations and planning studies.

It is recommended that data submitted for analysis pertaining to physical or control characteristics of equipment should be verified through the appropriate methods such as testing and disturbance analysis. System analysis and modeling data should be reviewed at least annually and verified on a periodic basis for consistency. Additionally, generation equipment, and its component controllers, should be tested to verify their conditions.

Entities should install dynamic recording devices and should be able to provide the recorded data necessary to enhance the analysis of system wide disturbances and validate system simulation models.

These recording devices should be time synchronized and should have sufficient data storage to permit several minutes of data to be collected. Information provided by these recordings should be used in tandem with shorter time scale readings from fault recorders, and with sequence of events recorders (SER) when appropriate.

NOTE It is the responsibility of the given entity to protect its proprietary information and to ensure it is used only for the purposes of efficient and reliable system operation and design. Also, should the entity in question report to any other governing bodies, or collaborate with any other entities, it is responsibility of the native entity to ensure that the sharing of such information does not violate any anti-trust laws.

5 Resource adequacy

An entity’s risk of disconnecting a firm load due to resource deficiencies should be, on average, no more than a pre-determined time interval (for example, once every ten years). Compliance with this criterion should be evaluated probabilistically such that the loss of load expectation (LOLE) of disconnecting a firm load is respected. This evaluation should make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with collaborating entities, transmission transfer capabilities and capacity, and/or load reduction from available operating procedures.

Each entity should have procedures in place to schedule outages and deratings of resources in such a manner that the available resources will be adequate to meet the entity’s forecasted load and spinning reserve requirements.

For consistent reporting of resource sufficiency, it is suggested that a measure of the net capability of generating units and loads be utilized as a resource of each entity on a regular basis.

6 Modeling and assessments

6.1 General

Each entity should consider appropriate equipment characteristics, system modeling data, and existing and future interchange schedules in accordance with its respective interconnection for steady-state and dynamic modeling for simulation and assessments. It should also include adequate considerations of interconnected renewable and distributed resources.

Each entity's portion of the high voltage power system should be designed with sufficient transmission capability to serve forecasted loads under the conditions noted in 6.2 and 6.3. These recommended criteria should also hold after any critical generator and/or significant load, transmission circuit, transformer, series or shunt compensating device or HVDC pole has already been lost, assuming that the entity’s generation and power flows are adjusted between outages by the use of a synchronized generation spinning reserve (for example, ten-minute reserve), phase angle regulator control and HVDC control where available.

Anticipated transfers of power from one entity to another, as well as within entities, should be considered in the design of inter-entity and intra-entity transmission facilities. Transmission transfer capabilities should be determined in accordance with the conditions noted in 6.2 and 6.3.

6.2 Stability assessment

The stability of IPSs should be maintained during and following the most severe of design contingencies, with due regard to reclosing. The guidelines for the formulation of the design contingencies are N-1 contingency and credible N-2 contingency. For each of the design contingencies that involve a fault, the stability of the system should be maintained when the simulation is based on fault clearing (times) initiated by each of the protection group(s).

The design contingencies should be identified by each entity for their IPS in coordination with other interconnected entities which may include, for example, the following contingencies:

a) A permanent three-phase fault on any generator, transmission circuit, transformer or bus section with normal fault clearing.

b) Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with normal fault clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed few towers at each station (for example five or a water crossing), then this condition should be seen as an acceptable risk and therefore can be excluded. Other similar situations can be excluded on the basis of acceptable risk, provided that the entity in question deems them acceptable risks, and oversees their exclusions.

c) A permanent phase to ground fault on any transmission circuit, transformer, or bus section with delayed fault clearing.

d) Loss of any element without a fault.

e) A permanent phase to ground fault on a circuit breaker with normal fault clearing. (Normal fault clearing time for this condition may not always be high speed.) Permanent loss of a pole of a direct current bipolar facility without an AC fault.

f) Loss of power infeed from external system.

Depending on the severity of the consequences, consideration may also be given to the failure of a circuit breaker to operate when initiated by a fault or by an SPS.

6.3 Steady state assessment

Each entity should design its system in accordance with its own voltage control criteria, and coordinate these with collaborating and interconnecting entities. Adequate reactive power resources and appropriate controls should be installed in each entity's IPS to retain voltage levels within normal limits for pre- disturbance conditions, and within applicable emergency limits for the system conditions that exist following the contingencies specified in 6.2.

Line and equipment loadings should be within normal limits for pre-disturbance conditions and within applicable emergency limits for the system conditions that exist following the contingencies specified in 6.2.

6.4 Real time system conditions

Scheduled outages of facilities that affect inter-entity reliability should be coordinated sufficiently in advance to permit the affected entities to maintain reliability. Each entity should also notify collaborating entities of scheduled or forced outages of any facility which may impact inter-entity reliability. In addition, entities with facilities that require scheduled or forced outages for maintenance purposes, should ensure the work on these facilities is expedited to the best of their ability to avoid reliability issues as they pertain to inter and intra-entity system connections.

Individual entities should operate in a manner such that the contingencies noted in 6.5 (normal transfers) and 6.6 (emergency transfers) can be resolved swiftly and will not adversely affect other collaborating entities.

Appropriate adjustments should be made to entity operations to accommodate the impact of protection group outages, including the outages of the protection group which are part of a special protection system. For typical periods of forced outages or arranged maintenance on a protection group, it can be assumed, unless there are indications to the contrary, that the remaining protection group will function as designed. If a protection group will be out of service for an extended period of time, additional adjustments to operations and the consequences of possible failures of the remaining protection groups should be considered.

6.5 Normal transfers

Pre-contingency voltages and loadings, both line and equipment should be within normal limits. Unless specific instructions describing alternate actions are in effect, normal transfers should be such that the manual reclosing of a faulted element can be carried out before any manual system adjustment, so long as the stability of the IPS is not affected.

The stability of the IPS should be maintained during and following the most severe of normal design contingencies stated below, with due regard to reclosing. For each of the normal design contingencies below that involve a fault, the stability of the system should be maintained when the simulation of the contingency and assessment is based on fault clearing initiated by the protection group.

Reactive power resources should be maintained in each entity in order to retain voltage levels within normal limits for pre-disturbance conditions and within applicable emergency limits for the system conditions that may exist following the aforementioned contingencies in 6.2.

Adjoining collaborating entities should mutually agree upon procedures of inter-entity voltage control in order to achieve and sustain a higher level of reliability.

Line and equipment loadings should be within normal limits for pre-disturbance conditions and within applicable emergency limits for system conditions that exist following the aforementioned contingencies in 6.2.

The normal design contingencies should be identified by each entity which may include the contingencies listed in 6.2. Since contingencies b, c, and e are not confined to the loss of a single element, individual entities may wish to direct a higher post contingency flow at the remaining facilities, versus contingencies a and d. This is a recommendation which should only be undertaken when: the operating procedures needed to accomplish precise corrective actions have been documented, loadings are sustainable for at least the anticipated time required to complete such actions, and other collaborating entities will not be subjected to the higher flows without prior agreement.

6.6 Emergency transfers

When a firm load cannot be supplied within the normal limits in an entity, or a portion of an entity, the given area in question may wish to increase transfers to the point at which pre-contingency voltages and loadings (line and equipment) are within applicable emergency limits. Emergency transfer levels should require generation adjustments before manually reclosing faulted elements.

Under an emergency transfer, appropriate control measures should be prepared for the occurrence of severe contingencies. The stability of the IPS should be maintained during and following the most severe of the normal design contingencies, and with due regard to reclosing. The voltages and loadings (line and equipment) should all be within applicable emergency limits.

6.7 Post contingency operation

Immediately after the occurrence of a contingency, the status of the IPS should be assessed, transfer levels should be adjusted, and preparation for the next contingency may be necessary. If the readjustment of generation, load resources, phase angle regulators, and direct current facilities are not adequate to restore the system to a secure state, then other measures such as voltage reduction and shedding of firm load may be required. For all cases, following the occurrence of the contingency, system adjustments should be completed as quickly as possible.

Voltage reductions need not be initiated, and firm loads need not be shed to observe a post contingency loading requirement until the contingency occurs, provided: adequate response time for this action is available after the contingency occurs, and other measures have maintained post contingency loadings within applicable emergency limits.

Emergency measures, including the pre-contingency disconnection of a firm load, if necessary, should be implemented to limit transfers to within the aforementioned guidelines of 6.6.

6.8 Operation under high risk conditions

For normal conditions, consideration and preparation for the contingencies listed in 6.5 and 6.6 should provide an acceptable level of IPS security. Under certain unusual conditions, such as severe weather, the expectation of occurrence of some contingencies, and the associated consequences, may be judged to be temporary, but are significantly greater than the long-term average expectation. When these conditions, referred to as high risk conditions, are predicted to exist in/around/above an entity, consideration should be given to operating in a more conservative manner (for example – voltage reduction, additional resources, rotational load shedding, minimize planned outages) than that required by the provisions of 6.5 and 6.6.

6.9 Extreme contingency assessment

Extreme contingency assessment recognizes the situations wherein the IPS can be subjected to events which exceed, in severity, the contingencies listed in 6.2. One of the recommended objectives of extreme contingency assessment is to determine, through planning studies, the effects of extreme contingencies on system performance. This is done in order to obtain an indication of system strength or to determine the extent of a widespread system disturbance, even though extreme contingencies should have low probabilities of occurrence.

The specified extreme contingencies listed below are intended to serve as a means to identify other particular situations that could result in widespread IPS shutdown. It is recommended for each entity to be responsible for the identification of additional extreme contingencies, if any, to be assessed.

Assessment of the extreme contingencies listed below should also include the examination of post contingency steady state conditions, system stability, overload cascading and voltage collapses. Pre-contingency load flows chosen for analysis should attempt to reflect reasonable power transfer conditions with respect to inter-entity or intra-entity connections.

Analytical studies should be conducted for extreme contingencies identified by each entity. Some examples of extreme contingencies are listed below.

a) Loss of the entire capability of a generating station.
b) Loss of all transmission circuits emanating from a generating station, switching station, DC terminal or substation.
c) Loss of all transmission circuits on a common right-of-way.
d) Permanent three-phase fault on any generator, transmission circuit, transformer, or bus section, with delayed fault clearing and with due regard to reclosing.
e) The sudden dropping of a large load or major load center.
f) The effect of severe power swings arising from disturbances outside the areas' interconnected systems.
g) Failure of a special protection system, to operate when required following the normal contingencies listed in 6.2.
h) The operation or partial operation of a special protection system for an event or condition for which it was not intended to operate.
i) Sudden loss of fuel delivery system to multiple plants, (i.e. gas pipeline contingencies, including both gas transmission lines and gas mains.)

NOTE The suggestions in Subclause 6.9 exist to assist in extreme contingency assessments only. In the case where extreme contingency assessment concludes there are serious consequences, an evaluation of implementing a change to design or operating practices to address such contingencies is conducted, and measures are utilized where appropriate to reduce the likelihood of such contingencies or to mitigate the consequences indicated in the assessment of such contingencies.

6.10 Extreme system conditions assessment

The IPS can be subjected to a wide range of abnormal system conditions that have low probability of occurrence. One of the objectives of extreme system condition assessment is to help determine, through planning studies, the impact of these conditions on expected steady-state and dynamic system performance. This is done in order to obtain an indication of system robustness, or to determine the extent of a widespread adverse system response. It is recommended that each entity has the responsibility to incorporate special simulation testing to assess the impact of extreme system conditions.

For example, analytical and simulation studies should be conducted to determine the effect of design contingencies under the following extreme conditions:

a) Peak load conditions resulting from extreme weather conditions with applicable rating of electrical elements.

b) Generating unit(s) fuel shortage, (i.e. gas supply adequacy).

After due assessment of extreme system conditions, measures should be utilized, where appropriate, to mitigate the consequences and as a minimum precaution, relevant stakeholders should be made aware of such system conditions. It is important that extreme contingencies do not result in cascading failures and voltage collapses.

6.11 Fault current assessment

Each entity should establish procedures and implement a system design that ensures its equipment is capable of coping with fault current levels of all transmission and generation facilities in service, for all potential operating conditions, and coordinate these procedures with adjacent collaborating native entities.

7 IPS design guidelines

7.1 General

It is recognized that certain entities for some part of their system may choose to apply more rigid design guidelines because of local considerations. However, in general the reliability of the IPS can be achieved by adequate

- redundancy in transmission system design, and
- protection and control system design.

In light of significant increase in renewable energy resources and distributed resources, entities should develop and/or consider adequate control and protection for these resources to be interconnected to the IPS.

7.2 Redundancy in transmission system design

From a planning and design perspective of transmission system, consideration should be given to equipment redundancy including line, breakers and associated protection that would provide the maximum reliability and security under n-1 contingency. As such, that a single contingency, a failure of an equipment or mis-operation of a protection system with any common mode failure should generally not have any significant adverse impact on the safe, secure and reliable operation of the IPS.

7.3 Protection and control system design

The failures of a protective system and its control to perform its intended mission or a mis-operation of the protective system can not only adversely impact the power system, but also affect other interconnected power systems. For example, a failure of high speed fault clearing could result in wide area system instability and outages. In general, the function of a protection system is to limit the severity and extent of system disturbances and possible damage to system equipment. The intent of these guidelines is to ensure that protection systems are designed to perform its function with adequate reliability and security.

The reliability of transmission system can be enhanced by giving careful attention to the protective relaying schemes and the associated control schemes. The design of the protective scheme should be based on sound protection engineering and operating principles. This includes the following:

a) A single failure in the protective system shall not void the protection system mission.
b) The design of the protective system and its associated control should allow testing and maintenance to be performed without the removal of the equipment being protected.
c) Controlled procedures should be created and followed for checking of drawings against manufacturers' connection diagrams.

d) Controlled procedures should be created and followed for field inspections comparing panel wiring against installation drawings.

e) Written commissioning procedures should be prepared.

f) Testing intervals shall be consistent with the type of protective equipment employed. Protective equipment with self-diagnostics should be employed when possible.

g) Consideration of equipment redundancy and protective schemes.

It is recognized that most portions of the IPS existed prior to such a guideline and may not meet these design guidelines. However, if protection systems or sub-systems of these facilities are replaced as part of a planned renewal or upgrade to the facility, then these guidelines should be considered to the extent practical.

Whenever significant changes are anticipated in generating sources, transmission facilities, or operating conditions, a review should be conducted of the protective schemes, associated control scheme and auxiliary power supplies which can reasonably be expected to be impacted by those changes. Close coordination should be maintained among planning, design, operating, maintenance, and protection functions with the intent that modifications or additions to the IPS will result in facilities that are adequately protected and can be operated and maintained reliably and safely.

The above objectives can be met only if protection systems have a high degree of reliability and security. In this context, reliability relates to the degree of certainty that a protection system will operate correctly when required to operate. Security relates to the degree of certainty that a protection system will not operate when not required to operate.

The relative effect on the IPS of a failure of a protection system to operate when desired versus an unintended operation should be weighed carefully in selecting design parameters. Often increased security (fewer unintended operations) results in decreased reliability (more failures to operate), and vice versa. As an example, there are two types of breaker failure protective schemes: local breaker failure scheme and remote breaker failure scheme. Breaker failures schemes are employed to cover the rare instance where breaker closest to the fault is not able to operate to clear the fault or it operates but cannot interrupt the fault current. In this case, additional breakers behind the compromised breaker have to be opened to isolate the fault. One method is to use what is known as local breaker failure scheme.

For example: If a fault occurs on a line that is comprised of redundant line relaying protection (primary and secondary), this scheme would trip all other sources at that terminal in a finite time after the fault had occurred. This results in a sufficient delay for the line protection to operate and clear the fault. Alternately, the “remote breaker failure scheme” is dependent upon line protection at all of the substations which are one step further away from the faulted line. To achieve this type of remote backup, the protection shall have a zone of protection that can see a fault on a line that is two substations away. For phase to phase fault near the substation, two steps further away from the fault it is necessary to have line protection at the substation behind the location of the failed breaker protected by what is called a third zone of a distance measuring relay. If the third zone is set too wide, it can operate on stable power swings. Thus the reliability of the electric power system is reduced by the remote backup scheme. The local backup scheme is not subjected to mis-operation as that which is experienced by the remote backup scheme.

7.4 Considerations for issues affecting protection systems reliability and dependability

Disregarding identified exceptions, all elements of the IPS should be protected by at least two protection groups: main and backup protection, each of which is independently capable of performing the specified protective function for that element. If possible, both the main and the backup protection should provide high speed fault isolation. Other things to consider are:

a) Preferably, two identical protective relays should not be used in independent protection groups, due to the risk of simultaneous failure of both groups because of design deficiencies or equipment problems.
b) Except if identified otherwise in this guideline, the protection system design should not use components shared by the two protection groups.
c) Areas of common exposure should be kept to a minimum to reduce the risk of both groups being disabled by a single event such as fire, excavation, water leakage, and other such incidents.
d) Means should be provided to trip all necessary local breakers in the event that a breaker fails to clear a fault. This protection need not be duplicated. Third zone protection should not be employed for breaker failure protection, if possible.
e) On installations where free-standing or column-type current transformers are provided on one side of the breaker only, resulting in a protection blind spot, protection should be provided to detect a fault to ground on the primaries of such current transformers. Both of these protections should be designed so as to not be disabled by the same failure but need not be duplicated. Other protections, like breaker failure protection will in fact provide independent protections for the blind spot.
f) Some elements of IPS facility may not themselves be part of the IPS. These portions need not require two protection groups.

7.5 Considerations for issues affecting security

Protection systems should be designed to isolate only the faulted element, except in those circumstances where additional elements are tripped intentionally to preserve system integrity or where isolating additional elements has no impact outside the local area.

For faults external to the protected zone, each protection group should be designed either to not operate, or to operate selectively with other groups and with breaker failure protection.

For planned system conditions, protection systems should not operate to trip for stable power swings.

7.6 Considerations for issues affecting dependability and security

a) Protection systems should be no more complex than required for any given application.
b) The components and software used in protection systems should be of proven quality, as demonstrated either by actual experience or by stringent tests under simulated operating conditions.
c) The thermal capability of all protection system components should be adequate to withstand rated maximum short time and continuous loading of the associated protected elements.
d) Protection systems should be designed to minimize the risk of component failure or malfunction due to electrical transients and interference or external effects such as vibration, shock and temperature.
e) Communication link availability, critical switch positions, and preferably also trip circuit integrity, should be annunciated or monitored.
f) Protection system circuitry and physical arrangements should be designed so as to minimize the risk of incorrect operations due to human error.

g) Protection system automatic self-checking facilities should be designed so as to not degrade the performance of the protection system.

h) Consideration should be given to the consequences of loss of instrument transformer voltage inputs to protection systems.

i) When remote access to protection systems is possible, the design should include security measures to minimize the probability of unauthorized access to the protection systems.

j) Short circuit models used to assess protection scheme design and to develop protection settings should take into account minimum and maximum fault levels and mutual coupling effects of parallel transmission lines. Details of neighboring systems should be modeled wherever they can affect the reliability of protection significantly.

7.7 Protection operating time

a) The calculations and the bases for the calculations of protection settings should be documented appropriately including references used for the calculations. Preferably, all calculations should be independently revised by a second person.

b) Adequate time margin should be provided taking into account study inaccuracies, differences in equipment, and protection operating times. In cases where clearing times are deliberately extended, consideration should be given to the following:

    1) Effect on system stability or reduction of stability margins.

    2) Risk of causing or increasing damage to equipment and subsequent extended repair and/or outage time.

    3) Effect of disturbances on service to customers.

7.8 Protection system testing

a) The design of protection systems both in terms of circuitry and physical arrangement should facilitate periodic testing and maintenance.

b) Test facilities and test procedures should be designed such that they do not compromise the independence of protection groups protecting the same IPS element. Test devices or switches or other suitable means should be provided to eliminate the necessity for removing or disconnecting wires during testing.

c) Each protection group should be functionally tested to verify the dependability and security aspects of the design, when initially placed in service and when modifications are made.

7.9 Analysis of protection performance

a) IPS automatic operations should be analyzed to determine proper protection system performance. Corrective measures should be taken promptly if a protection group fails to operate or operates incorrectly.

b) Event and fault recording capability should be provided to the extent required to permit analysis of system disturbances and protection system performance.

c) Sequence of events to 1 ms resolution and digital fault recording equipment should be time-synchronized to the extent possible.

7.10 Considerations for current and voltage transformers

7.10.1 AC current transformers

a) Current transformers (CTs) associated with protection systems should have adequate steady-state and transient characteristics for their intended function.

b) The output of each current transformer secondary winding should be designed to remain within acceptable limits for the connected loads under all anticipated fault currents to ensure correct operation of the protection system.

c) The thermal and mechanical capabilities of the CT at the operating tap should be adequate to prevent damage under maximum fault conditions and normal or emergency system loading conditions.

d) For protection groups to be independent, they should be supplied from separate current transformer secondary windings.

e) Current transformers should be connected so that adjacent protection zones overlap.

7.10.2 AC voltage transformers (VT), capacitance coupler voltage transformer (CCVT), and fiber optic voltage transducers

a) Voltage transformers and voltage transducer associated with protection systems should have adequate steady-state and transient characteristics for their intended functions.

b) Voltage transformers and voltage transducer should have adequate volt-ampere capacity to supply the connected load while maintaining their relay accuracy over their specified primary voltage range.

c) Each of the two protection groups protecting an element should be supplied from separate voltage sources. The two protection groups may be supplied from separate secondary windings on one transformer or potential device, provided all of the following requirements are met:

   1) Complete loss of one or more phase voltages does not prevent all tripping of the protected element.

   2) Each secondary winding has sufficient capacity to permit fuse protection of the circuit.

   3) Each secondary winding circuit is adequately fuse-protected.

   4) Voltage transformer installations should be designed with due regard to ferroresonance.

7.11 Logic systems

a) The design should efficiently prevent any effects of contact races, spurious operation due to battery grounds, DC transients, radio frequency interference or other such influences.

b) It is recognized that timing is often critical in logic schemes. Operating times of different devices vary. Known timing differences should be accounted for in the overall design.

7.12 Microprocessor-based equipment and software

A protection system may incorporate microprocessor-based equipment. Information from this equipment may support other functions such as power system operations. In such cases, the software and the interface should be designed so as to not degrade the protection system functions. This equipment should comply with IEC 60255-26:2013.

7.13 Batteries and direct current (DC) auxiliary supply

DC auxiliary supplies associated with protection should be designed to have a high degree of dependability as follows:

a) No single battery or DC power supply failure should prevent both independent protection groups from performing the intended function. Based on system impacts and risks, consideration should be given to provide its own charger for each of the battery systems.

b) Each station battery should have sufficient capacity to permit operation of the station, in the event of a loss of its battery charger or the AC supply source, for the period of time necessary to transfer the load to the other station battery or re-establish the supply source. Each station battery and its associated charger should have sufficient capacity to supply the total DC load of the station.

c) A transfer arrangement should be provided to permit connecting the total load to either station battery without creating areas where, prior to failure of either a station battery or a charger, a single event can disable both DC auxiliary supplies.

d) The circuitry between each battery and its first protective device cannot be protected and therefore should be designed so as to minimize the possibility of electrical short circuit.

e) The battery chargers and all DC auxiliary circuits should be protected against short circuits. All protective devices should be coordinated to minimize the number of DC circuits interrupted.

f) The design for the regulation of the DC voltage should be such that, under all anticipated charging and loading conditions, voltage within acceptable limits will be supplied to all devices, while minimizing AC ripple and voltage transients.

g) DC auxiliary systems should be continuously monitored or enunciated to detect abnormal voltage levels (both high and low), DC grounds, and loss of AC to the battery chargers. Protection systems should be continuously monitored or enunciated to detect abnormal power supply.

h) The control batteries should be ungrounded.

i) Selection of batteries and maintenance should be in accordance with IEC and IEEE standard practices.

7.14 Station service AC supply

On IPS facilities, there should be at least two independent sources of station service a.c. supply, each capable of carrying at least all the critical loads associated with protection systems.

7.15 AC circuit breakers

Circuit breaker performance is vital to the reliability and operation of the interconnected electric power system. The operating time of the breaker is critical to the stability of the IPS and to the ability to minimize extensive damage to the IPS in the case of a fault. The following design criteria should be followed:

a) No single trip coil failure should prevent each of the two independent protection groups from performing the intended function. The design of a breaker with two trip coils should be such that the breaker will operate if both trip coils are energized simultaneously. The correct operation of this design should be verified by tests.

b) The indication of the circuit breaker position in protection systems should be designed to reliably mimic the main contact position.

7.16 Teleprotection (communication for protective functions)

Communication facilities required for teleprotection should be designed to have a level of performance consistent with that required of the protection system, and should meet the following:

a) Where each of the two protection groups protecting the same IPS element requires a communication channel, the equipment and channel for each group should be separated physically and designed to minimize the risk of all protection groups being disabled simultaneously by a single event or condition.

b) Teleprotection equipment should be monitored in order to assess equipment and channel readiness.

c) Teleprotection systems should be designed to assure adequate signal transmission during bulk power system disturbances, and should be provided with means to verify proper signal performance.

d) Teleprotection equipment should be powered by the substation batteries or other sources independent from the power system.

e) Except as identified otherwise in these guidelines, the teleprotection system design should not use teleprotection components shared by the two protection groups protecting the same IPS element.

f) Teleprotection systems should be designed to prevent unwanted operations such as those caused by equipment or personnel.

g) Two identical teleprotection equipments should not preferably be used in independent protection groups, due to the risk of simultaneous failure of both groups because of design deficiencies or equipment problems.

NOTE This guideline may be difficult to achieve if the communication system includes a multiplexer. It can be achieved indirectly by selection of a backup protective scheme that is not communication dependent.

h) Areas of common exposure should be kept to a minimum to reduce the possibility of both groups being disabled by a single event such as fire, excavation, water leakage, and other such incidents.

7.17 Control cables and wiring and ancillary control devices

Control cables and wiring and ancillary control devices should be highly dependable and secure. Due consideration should be given to published codes and standards, fire hazards, current-carrying capacity, voltage drop, insulation level, mechanical strength, routing, shielding, grounding and environment.

NOTE See *IEEE Standard 525 Guide for Design and Installation of Cable System in Substations.*

7.18 Environment

Means should be employed to maintain environmental conditions that are favorable to the correct performance of protection systems.

a) Each separate protection group protecting the same system element should be on different non-adjacent vertical mounting assemblies or enclosures. In the event a common raceway is used, cabling for separate groups protecting the same system element should be separated by a fire barrier.

b) The substation shield lightning protective system should be designed to achieve a probability of success against a lightning flashover of the overhead power delivery system of 99,99 % against a lightning flash by-passing the lightning protective system.

c) An audit should be made for the amount of combustible material within the substation building and this should meet acceptable fire code for hazardous locations.

7.19 Grounding

Station grounding is critical for the correct operation of protection systems. The design of the ground grid directly impacts proper protection system operation and the probability of false operation from fault currents or transient voltages. Consideration should be given to establish as part of a substation design procedures or specifications, a mandatory method of designing the substation ground grid, which

- can be traced to a recognized calculation methodology,
- considers cable shielding, and
- considers equipment grounding.

7.20 Specific application considerations

7.20.1 AC transmission line protection

a) The protection system should be designed to limit the effects of faults and disturbances, while itself experiencing a single failure. For faults external to the protected zone, each protection group should be designed either to not operate, or to operate selectively with other groups and with breaker failure protection.

b) For planned system conditions, line protection systems associated with transmission facilities should not operate to trip for stable power swings.

c) Protection system settings should not normally constitute a loading limitation.

d) In the normal case, the tripping relay(s) should not operate at or below I_{Load}, assuming a 0,85 per unit voltage and a current phase angle of 30 degrees lagging. In cases where the above criterion cannot be met, the limits thus imposed should be documented and adhered to as a system operating constraint and should be based on the specific operating conditions.

NOTE The data of item d) are only informative.

e) An audit of power plants under voltage protective equipment and motor contactors should be conducted to determine a low system voltage impact upon the availability of the power generation to remain connected to the grid.

f) A pilot protection (a form of line protection that uses a communication channel as a means to compare electrical conditions at the terminals of a line, e.g. line current differential and directional comparison fall under this category) should be so designed that its failure or misoperation will not affect the operation of any other pilot protection on that same element.

7.20.2 Transmission station protection

a) Each protection system should be designed to limit the effects of faults and disturbances, while itself experiencing a single failure. The protection systems should operate properly for the anticipated range of currents.

b) For planned system conditions, all station protection systems should not operate for load current or stable power swings.

c) In particular, load responsive protective relays applied to transmission autotransformers should allow all possible loads, consistent with equipment protection requirements. Any such relays settings that are identified in studies to be a possible limitation during normal or emergency conditions should be documented and adhered to as a system operating constraint.

d) Pressure relief or Buchholz relays, used on transformers, phase shifters or regulators, should be applied so as to minimize the likelihood of their misoperation due to faults.

7.20.3 AC breaker failure protection

a) Means should be provided to trip all necessary local and remote breakers in the event that a breaker fails to clear a fault.

b) Breaker failure protection should be initiated by each of the protection groups which trip the breaker, with the optional exception of a breaker failure protection in an adjacent zone. It is not necessary to duplicate the breaker failure protection itself.

c) Fault current detectors (alarms) should be considered to determine if a breaker has failed to interrupt a fault. Auxiliary switches may also be required in instances where the fault currents are not large enough to operate the fault current detectors. In addition, auxiliary switches may be necessary for high-speed detection of a breaker failure condition.

NOTE If the primary equipment does not have sufficient number of auxiliary contacts, it may be necessary to either add additional auxiliary contacts or use a contact multiplying relay, normally referred to as an auxiliary relay. Provisions are normally provided to monitor the operating coil of the relay to assure that it is not in a failed condition.

7.20.4 Generating station protection

a) Each protection system should be designed to minimize the effects to the IPS of faults and disturbances, while itself experiencing a single failure.

b) Generators should be protected to limit possible damage to the equipment. The following are some of the abnormal (not necessarily fault) conditions that should be detected:

   1) Unbalanced phase currents, loss of excitation, overexcitation, generator out of step, field ground, and inadvertent energization.

   2) Protection for the above conditions, which are applied for equipment protection, need not be duplicated.

   3) When a directional overcurrent or distance relay is applied to remove the generator for slowly cleared faults on the external system, such protection is a backup and need not be duplicated.

   4) The apparatus should be protected when the generator is starting up or shutting down as well as running at normal speed; this may require additional relays as the normal relays may not function satisfactorily at low frequencies.

c) Generator protection systems should not operate for stable power swings except when that particular generator is out of step with the remainder of the system. This does not apply to special protection systems (SPS) designed to trip the generator as part of an overall plan to maintain stability of the power system.

d) Loss of excitation and out of step relays should be set with due regard to the performance of the excitation system.

e) It is recognized that the overall protection of a generator involves non-electrical considerations that have not been included as a part of these guidelines.

f) All under-frequency, over-frequency, over-voltage and under-voltage protection systems designed to disconnect generators from the power system should be coordinated with automatic under-frequency load shedding programs.

g) Automatic under-frequency load shedding protection systems are not generally located at IPS stations; however, they have a direct effect on the operation of the IPS during major disturbances and emergencies. Automatic under-frequency load shedding protection need not be duplicated.

7.20.5 HVDC system protection

a) Converter stations should be protected to avoid excessive equipment stresses and to minimize equipment damage and outage time. These protections are usually specific to the design of the converter station(s) and should be designed as per manufacturer guidelines.

b) The AC portion, including AC filters/shunt compensation equipment, converter transformers, converters and DC equipment of an HVDC converter station, should be adequately protected, preferably having redundant/duplicated protections.

c) Multiple commutation failures, unexpected power reversals in the converter bridges and the DC portion of the HVDC link which are severe enough to disturb the IPS should have redundant protection groups. For example such failures should be detected by more than one independent control or protection group. Each control or group should be able to initiate appropriate corrective action.

d) The overall protection and control of an HVDC link may also involve the initiation of actions in response to abnormal conditions on the AC interconnected system. The control and protection systems associated with such conditions are not considered part of the HVDC systems protection.

7.20.6 AC capacitor bank protection

a) Each protection system should be designed to minimize the effects of faults and disturbances to the IPS, while itself experiencing a single failure.

b) Capacitor bank protection should be applied with due consideration for capacitor bank transients, power system voltage unbalance, and system harmonics.

c) Protection may be provided to minimize the impact of failures of individual capacitor units on the remaining capacitor units; however, the following types of protections do not need to be duplicated:

   1) overvoltage protection;

   2) individual fuses for each capacitor unit.

7.20.7 Static VAR compensator (SVC) protection

a) The low voltage branch circuits contain the reactive controlling equipment, filters, etc. These may include all or some of the following:

   1) Thyristor controlled reactors (TCR)

   2) Thyristor switched capacitors (TSC)

   3) Switched or fixed capacitors

   4) Harmonic filters

b) Protection for the branch circuits that are not part of the bulk power system need not be duplicated. Consider the following:

   1) Protection for these branch circuits should be applied with due consideration for capacitor bank transients, power system voltage unbalance, and system harmonics.

   2) Protection against abnormal non-fault conditions within the SVC via control of the TSC and TCR valves should be designed so as to not interfere with the proper operation of the SVC.

7.21 Reporting of protection systems

Each system operator should provide others with advance notification of any of the member's new IPS protection facilities, or significant changes in the existing bulk power system protection facilities.

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