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CONSOLIDATED VERSION

TECHNICAL REPORT

Performance of high-voltage direct current (HVDC) systems with line-commutated converters –
Part 2: Faults and switching

colour inside

IEC TR 60919-2:2008-11+AMD1:2015-06+AMD2:2020-04 CSV(en)

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INTERNATIONAL ELECTROTECHNICAL COMMISSION

PERFORMANCE OF HIGH-VOLTAGE DIRECT CURRENT (HVDC) SYSTEMS WITH LINE-COMMUTATED CONVERTERS –

Part 2: Faults and switching

FOREWORD

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This consolidated version of the official IEC Standard and its amendments has been prepared for user convenience.

IEC TR 60919-2 edition 2.2 contains the second edition (2008-11) [documents 22F/160/DTR and 22F/165/RVC], its amendment 1 (2015-06) [documents 22F/344/DTR and 22F/345A/RVC] and its amendment 2 (2020-04) [documents 22F/561/DTR and 22F/575/RVDTR].

In this Redline version, a vertical line in the margin shows where the technical content is modified by amendments 1 and 2. Additions are in green text, deletions are in strikethrough red text. A separate Final version with all changes accepted is available in this publication.

The main task of IEC technical committees is to prepare International Standards. However, a technical committee may propose the publication of a technical report when it has collected data of a different kind from that which is normally published as an International Standard, for example "state of the art".

IEC 60919-2, which is a technical report, has been prepared by subcommittee 22F: Power electronics for electrical transmission and distribution systems, of IEC technical committee 22: Power electronic systems and equipment.

This edition includes the following main changes with respect to the previous edition:

a) this report concerns only line-commutated converters;
b) significant changes have been made to the control system technology;
c) some environmental constraints, for example audible noise limits, have been added;
d) the capacitor coupled converters (CCC) and controlled series capacitor converters (CSCC) have been included.

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

A list of all parts of the IEC 60919 series, under the general title: *Performance of high-voltage direct current (HVDC) systems with line-commutated converters*, can be found on the IEC website.

The committee has decided that the contents of the base publication and its amendments 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
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PERFORMANCE OF HIGH-VOLTAGE DIRECT CURRENT (HVDC) SYSTEMS WITH LINE-COMMUTATED CONVERTERS –

Part 2: Faults and switching

1 Scope

This part of IEC 60919 which is a technical report provides guidance on the transient performance and fault protection requirements of high voltage direct current (HVDC) systems. It concerns the transient performance related to faults and switching for two-terminal HVDC systems utilizing 12-pulse converter units comprised of three-phase bridge (double way) connections but it does not cover multi-terminal HVDC transmission systems. However, certain aspects of parallel converters and parallel lines, if part of a two-terminal system， are discussed. The converters are assumed to use thyristor valves as the bridge arms, with gapless metal oxide arresters for insulation co-ordination and to have power flow capability in both directions. Diode valves are not considered in this report.

Only line-commutated converters are covered in this report, which includes capacitor commutated converter circuit configurations. General requirements for semiconductor line-commutated converters are given in IEC 60146-1-1, IEC 60146-1-2 and IEC 60146-1-3. Voltage-sourced converters are not considered.

The report is comprised of three parts. IEC 60919-2, which covers transient performance, will be accompanied by companion documents, IEC 60919-1 for steady-state performance and IEC 60919-3 for dynamic performance. An effort has been made to avoid duplication in the three parts. Consequently users of this report are urged to consider all three parts when preparing a specification for purchase of a two-terminal HVDC system.

Readers are cautioned to be aware of the difference between system performance specifications and equipment design specifications for individual components of a system. While equipment specifications and testing requirements are not defined herein, attention is drawn to those which could affect performance specifications for a system. Note that detailed seismic performance requirements are excluded from this technical report. In addition, because of the many possible variations between different HVDC systems, these are not considered in detail. Consequently this report should not be used directly as a specification for a specific project, but rather to provide the basis for an appropriate specification tailored to fit actual system requirements for a particular electric power transmission scheme. This report does not intend to discriminate the responsibility of users and manufacturers for the work specified.

Terms and definitions for high-voltage direct current (HVDC) transmission used in this report are given in IEC 60633.

Since the equipment items are usually separately specified and purchased, the HVDC transmission line, earth electrode line and earth electrode are included only because of their influence on the HVDC system performance.

For the purpose of this report, an HVDC substation is assumed to consist of one or more converter units installed in a single location together with buildings, reactors, filters, reactive power supply, control, monitoring, protective, measuring and auxiliary equipment. While there is no discussion of a.c. switching substations in this report, a.c. filters and reactive power sources are included, although they may be connected to an a.c. bus separate from the HVDC substation.

2 Normative references

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

IEC 60146-1-1, *Semiconductor converters – General requirements and line commutated converters – Part 1-1: Specifications of basic requirements*
Amendment 1 (1996)

IEC 60146-1-2, *Semiconductor converters – General requirements and line commutated converters – Part 1-2: Application guide*

IEC 60146-1-3, *Semiconductor converters – General requirements and line commutated converters – Part 1-3: Transformers and reactors*

IEC 60633, *Terminology for high-voltage direct current (HVDC) transmission*

IEC 60071-1, *Insulation co-ordination – Part 1: Terms, definitions, principles and rules*

IEC 60700-1, *Thyristor valves for high-voltage direct current (HVDC) power transmission – Part 1: Electrical testing*

IEC TR 60919-1:~~2005~~2010, *Performance of high-voltage direct current (HVDC) systems with line-commutated converters – Part 1: Steady-state conditions*
Amendment 1:2013

IEC TR 60919-3:2009, *Performance of high-voltage direct current (HVDC) systems with line-commutated converters – Part 3: Dynamic conditions*

3 Outline of HVDC transient performance specifications

3.1 Transient performance specifications

A complete performance specification related to transient performance of an HVDC system during faults and switching should also include fault protection requirements.

These concepts are introduced at the appropriate locations in the following transient performance and related clauses:

– Clause 4 – Switching transients without faults
– Clause 5 – AC system faults
– Clause 6 – AC filter, reactive power equipment and a.c. bus faults
– Clause 7 – Converter unit faults
– Clause 8 – DC reactor, d.c. filter and other d.c. equipment faults
– Clause 9 – DC line faults
– Clause 10 – Earth electrode line faults
– Clause 11 – Metallic return conductor faults
– Clause 12 – Insulation co-ordination - HVDC systems
– Clause 13 – Telecommunication requirements
– Clause 14 – Auxiliary systems

Discussion in the following clauses on the d.c. line, earth electrode line and earth electrode is limited to the relationships between these and either the transient performance or protection of HVDC converter stations.

3.2 General comment

In general, control strategies can be used to minimize the effect of disturbances, but when the safety of equipment depends on their correct performance, this should be identified.

4 Switching transients without faults

4.1 General

This clause deals with the transient behaviour of the HVDC system during and after switching operations both on the a.c. and the d.c. sides of converter substations, and is not related to equipment or line faults which are treated in the following clauses of this report.

Switching operations without faults can be classified as follows:

a) energization and de-energization of a.c. side equipment such as converter transformers, a.c. filters, shunt reactors, capacitor banks, a.c. lines, static var compensators (SVC), and synchronous compensators;
b) load rejection;
c) starting and removal from service of converter units;
d) operation of d.c. breakers and d.c. switches for paralleling of poles and lines; connection or disconnection of d.c. lines (poles), earth electrode lines, metallic return paths, d.c. filters, etc.

4.2 Energization and de-energization of a.c. side equipment

During the operating life of an HVDC transmission system, energization and de-energization of converter transformers, a.c. filters, shunt reactors, capacitor banks, SVCs, and other equipment may occur many times. Depending on the characteristics of the a.c. system and the equipment being switched, resulting current and voltage stresses will be imposed on equipment being switched and generally impinge as well on part of the overall a.c. system.

The overvoltages and overcurrents which are critical for plant design are usually due to faults (Clauses 5 to 9), and not to normal switching operations. Nevertheless, they are discussed here for completeness. They are relevant in consideration of disturbances to a.c. system voltages.

Filter switching will also result in transient distortion of the bus voltage. This could disturb the commutation process and in a weak system could lead to commutation failure.

Thus equipment switching should be investigated to:

– determine critical a.c. network and equipment conditions which may contribute to such abnormal stresses and actions which may be taken to mitigate them;
– design the equipment;
– verify arrester duties.

Transients occur routinely when filters and capacitor banks are switched as necessary to control harmonic interference and steady-state terminal voltages.

Because of the frequency of occurrence of switching overvoltages it is generally desirable that the overvoltage protective devices do not absorb appreciable energy during such operations. For example the amplitudes of overvoltages arising from routine switching operations can be minimized by the use of suitable resistors incorporated in the circuit-breakers associated with filters and capacitor banks or by synchronizing the closing of the circuit-breakers. This can also reduce the possibility of inverter commutation failures. The HVDC control system can also be used effectively to damp certain overvoltages.

Restrike-free switching devices should be used for capacitor switching to avoid onerous overvoltages from restriking which otherwise could occur when disconnecting filters or capacitor banks.

Transformer energization inrush currents can cause an undesirable interaction in the a.c. and d.c. systems. When disconnecting a converter transformer from the a.c. network, the transformer should be disconnected maintaining the a.c. filters connected in parallel if possible, instead of disconnecting the transformer alone or by using synchronizing devices. In that way, residual saturation will be decreased, and inrush currents would be reduced. After some hundreds of milliseconds the filters could be disconnected from the transformer.

To reduce inrush currents, typical control measures include circuit-breaker pre-insertion resistors, using the synchronized circuit-breaker, or setting of the transformer on-load tap changers at their highest tap changer positions. Highest tap changer position refers to the tap changer position with highest number of winding turns. Synchronization requires switching at an optimum instant in each phase, i.e. breaker closing 90 degrees after voltage zero crossing. This implies that the three poles of a circuit-breaker cannot switch simultaneously. For breakers with one-pole operating mechanisms (and thus a separate synchronizing unit), this is not a problem. The synchronizing unit is simply programmed to give switching orders suitably separated in time to the poles. ~~Some breakers with three-pole operating mechanism can also be used for synchronized switching if the operating mechanism can be arranged to give a mechanical time delay.~~ However it should also be noted that saturation of already energized converter transformers can arise from energization of another transformer in the converter station or from switching of an SVC.

Also the application of low order harmonic filters can be helpful in reducing the problems with inrush currents. The effectiveness of such measures depends largely on the system and pertinent equipment characteristics. In addition, the response of the a.c. system can be sensitive to the number of converter transformers already energized, especially if they are not yet loaded as for series connections of multiple converter units.

Energization of capacitor and filter banks changes the system impedance characteristic. In case of system with relatively small short circuit capacity, adding capacitive component shifts high impedance peak of frequency-impedance curve to lower frequency side. If the high impedance peak becomes closer to second harmonic, severe overvoltages could be presumed during faults. To mitigate such situation, damping resister could be added to capacitors.

The energization of capacitor and filter banks produces oscillations between these elements and the rest of the network. Again, depending on the size of the banks and the network characteristics, switching overvoltages can appear along with overcurrents in the already energized a.c. system components.

Attention should be paid to the possibility of damage to the capacitors during re-energization of capacitors because of trapped charges in the capacitors from a preceding opening operation. Measures may be necessary for discharging them before reclosing if their internal discharge resistors are not sufficiently effective within the desired switching time. Alternatively, a longer switching time may be necessary.

Energization of filters excites the frequencies to which they, in combination with the a.c. network, are tuned. Also switching out of filter and capacitor banks can cause the a.c. system voltage to oscillate.

SVCs can be provided to stabilize the voltage and control temporary overvoltages. Energization of SVCs should be such as to produce a light or even no transient in the system voltage. Most of them have an active control which can be used to accomplish this objective.

Connection or disconnection of shunt reactors and capacitors produces change in a.c. voltage. Size and operation of this equipment should be specified so as to limit switching-caused voltage changes to acceptable levels.

Energization and de-energization of a.c. transmission lines connected to HVDC sub-stations generate voltage transients as well, which should be taken into account. These operations change the a.c. harmonic impedances which also influence the transient harmonic effects.

Synchronous compensators can produce voltage transients when started and operated as induction motors, drawing reactive power and reducing the system voltage. This aspect of their performance should be carefully examined.

A table of acceptable levels of temporary or transient overvoltages and overcurrents during switching operations of the various system components or preferably a diagram of the expected transient overvoltage and overcurrent levels versus time should be developed for the specifications.

Related to the foregoing, information about the electrical characteristics of the a.c. system and its future development as complete as possible should also be supplied in the specifications. Relevant operating criteria along with existing and expected a.c. overvoltage levels should also be shown.

The desired performance of the HVDC substations under the transient conditions described in the foregoing subclauses should be stated for both switching in and out of the various components.

Overvoltage performance for the HVDC link should be co-ordinated with the actual performance characteristics of the existing a.c. network with which it is to be integrated.

4.3 Load rejection

Sudden reductions of transmitted power over the HVDC link without occurrence of faults could take place:

– due to unintentional tripping of the a.c. circuit-breakers at either terminal;
– due to blocking and bypass of converter units as a consequence of control system action;
– due to loss of generation and for a multitude of other possible causes.

Voltage levels on the a.c. system would rise primarily because of the consequent excess of reactive power compensation at the HVDC substation. Resonant conditions can be reached due to saturation of the power transformers and resonances between transformers, filters and the a.c. network. These overvoltage effects can be accentuated by frequency deviations in the a.c. system.

Special care ~~shall~~ should be taken for the case that the inverter becomes isolated from the a.c. system with only the filters and shunt capacitor banks connected to it.

For this contingency, the inverter ~~shall~~ should be blocked and bypassed to prevent overvoltage-caused damage to the filter components or the a.c. side arresters or the valve arresters. Opening of the remote end circuit-breakers, for a system with a single or only a few lines connecting the inverter to the a.c. system ~~shall~~ should be taken into account in the design of the protective scheme. It is also helpful to adopt fast and reliable telecommunication system for opening of the remote end circuit breakers.

Load rejection transients following system faults are discussed in 5.3.5.

Acceptable load rejection-caused overvoltages, in terms of amplitudes and durations should be specified particularly if the resulting stresses are expected to be greater than those discussed in 4.2.

Suitable operating strategies to return to normal operating conditions should be developed. Among the procedures for achieving this are controlling the converter units still in service to regulate the system voltage or switching in reactors or by removal of capacitor or filter banks. If capacitor or filter banks are to be switched under overvoltage conditions this ~~shall~~ should be taken into account when fixing the associated circuit-breaker ratings and capabilities. In cases when an existing circuit-breaker of inadequate capacity could be called on to perform this duty, its operation should be inhibited and other means used to reduce overvoltages.

When converters are to be used for voltage control, consideration should be given to the design and manufacture of the valves for operation at large delay angles.

The extent to which converter measures can be used for reducing a.c. system overvoltage will depend on the requirements for continuity of supplied power to satisfy the a.c. system dynamic performance.

Other means, such as switched capacitors or reactors, synchronous compensators, SVCs, special metal oxide (MO) temporary overvoltage absorbers (TOV), etc. may need to be used to limit overvoltages to acceptable levels and to achieve the desired converter performance.

As in most system design decisions, economics will play a major role. However, trade-offs may be necessary between cost and system performance.

4.4 Start-up and shut-down of converter units

Normal operator-initiated start-up and shut-down procedures for an HVDC pole should be established.

Start-up and shut-down of series-connected converter units is performed by the control system sometimes in conjunction with the operation of switching devices in parallel with the converter units. For this purpose normally an automatic sequence is followed in which a valve bypass path within the bridge is activated before the opening or closing of the bypass switch.

For this procedure any special requirements or constraints such as the maximum allowable a.c. bus voltage variation, special interlock requirements or maximum variation in transmitted power, etc., should be specified.

Whether the system is to be operated with a smaller number of converters than in the ultimate configuration, particularly during the development stages of the project, should be noted.

4.5 Operation of d.c. breakers and d.c. switches

Switching devices have been used on the d.c. side of HVDC transmission systems for several functions as follows:

- by-pass and disconnect converter units;
- connect or disconnect the substation pole to the earth electrode line in bipolar links;
- connect poles or bipoles in parallel, including polarity reversal;
- switch the neutral bus-bar;
- connect or disconnect the d.c. line;

– connect or disconnect d.c. filters;
– connect d.c. filters in parallel during monopolar operation.

They can be classified with respect to various aspects. Figure 1 gives an example of switching device arrangements on the d.c. side of a converter substation with the following meanings:

– current commutating switches (S);
– disconnectors (D);
– earthing switches (E).

Distinctions should be made between:

– devices which are used for opening at zero current, even though they may have limited making and breaking capability;
– devices which are able to transfer the current from one current path to a parallel one; such devices shall have an adequate energy absorption capability for the expected current interruption during the transfer;
– and d.c. breakers which are able to interrupt any d.c. current within their ratings and withstand the following recovery voltage.

In the future, d.c. breakers may be used in order to allow an unrestricted paralleling or de-paralleling of substation or d.c. line poles. A special application of the d.c. breaker is the metallic return transfer breaker (MRTB).

Zero current operated switches and d.c. circuit-breakers with a current interrupting capability not exceeding the load current shall be co-ordinated with the control system actions under both fault conditions and during operating sequences. For example, substation or line pole paralleling and de-paralleling operations require the opening and closing of various switches.

These operations initiate a wide variety of voltage and current transients and such functions are performed during established operating sequences as determined by the d.c. controls.

Thus, the transients depend on the control system, on the switch operating times and the a.c. and d.c. system electrical characteristics.

For a two-terminal system where reliability requirements are stringent, the use of d.c. circuit-breakers offers the possibility of enhancing transmission reliability and availability by the use of transmission lines in parallel and sectionalized along their routes. This would permit isolation of one of the parallel lines or line sections either in the case of a permanent fault or for operating needs without even a momentary shut-down of the d.c. transmission.

Thus maximum transmission capability within the thermal limits of the remaining healthy circuit could be maintained. Of course, selective protections as in the case of parallel a.c. lines would need to be used.

The operating characteristics including speed requirements should be determined and specified for all switches and circuit-breakers required for the contemplated HVDC transmission.

When specifying d.c. switching devices, the following duties shall be defined:

– the function within the HVDC substation;
– modes of operation;
– operation time requirements;
– continuous current;

- current on opening;
- current on closing;
- voltage on opening;
- voltage across open contacts;
- voltage to earth in the closed and in the open position;
- maximum energy absorption for one commutation (or for two or more commutations depending on rating criteria);
- lightning impulse withstand level to earth;
- lightning impulse withstand level across open breaker;
- switching impulse withstand level to earth;
- switching impulse withstand level across open breaker.

In the event of a low impedance fault to earth on the d.c. side of one pole, at least one neutral switch should be able to transfer the current injected into the earth from the operating pole.

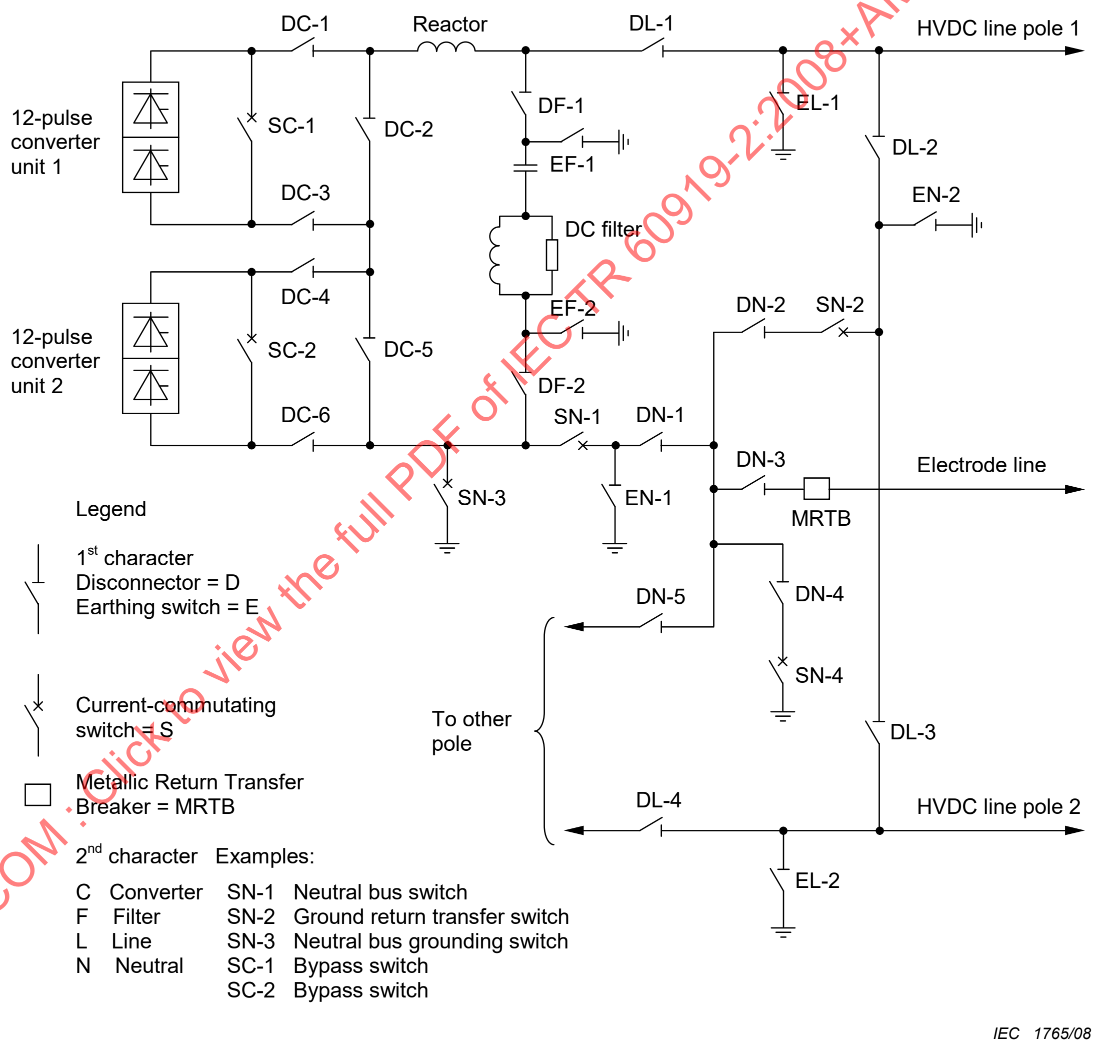


Figure 1 – DC-side switches for an HVDC substation with series-connected converter unit

5 AC system faults

5.1 General

Transient performance of an HVDC system during a.c. system faults and during the recovery period immediately following fault clearing are important considerations in the specification and design of such a system. Recovery performance as influenced by implementation of specific control strategies will directly affect the ratings of the HVDC equipments, the connected a.c. substation facilities and the connected a.c. network response.

5.2 Fault categories

The following a.c. faults should be considered when preparing an HVDC system specification:

– sending end (rectifier) and receiving end (inverter) faults for each power flow direction;
– three-phase to earth and single-phase-to-earth faults at the HVDC substations;
– a.c. faults remote from the HVDC substations; reclosing practices should be considered;
– various faults as above in a.c. or d.c. lines in cases where there is a parallel a.c. line closely coupled to the d.c. line. The extreme case of this type is a flashover from an a.c. to a d.c. conductor where a.c. and d.c. lines cross.

HVDC specifications concerning transient performance during and after a.c. system faults should consider all affected areas of the d.c. and a.c. system operation and equipment ratings. To achieve an optimum balance between total system costs and performance, trade-offs should be considered in the HVDC specifications.

Characteristics that influence transient performance during and after a.c. system faults are discussed in the following paragraphs.

5.3 Specification matters affecting transient performance

5.3.1 Effective a.c. system impedance

In its simplest form effective a.c. system impedance is usually expressed as the short-circuit-ratio (SCR), that is, the ratio of the a.c. system short-circuit MVA to converter d.c. power (MW) rating.

However, SCR is more precisely expressed as a.c. system admittance on a base of rated d.c. power and a.c. voltage. This is defined at system frequency and should include an angle. For many studies the total admittance seen by the converter is relevant, including that of filters and other reactive power elements connected to the HVDC substation a.c. bus; this is known as effective short-circuit ratio (ESCR). Most significant are the impedances at the low-order harmonic frequencies.

SCR as defined here differs from the ratio RSC defined in IEC Publication IEC 60146-1-1 where the base is the rated MVA of the converter.

Transient fault performance factors affected by the SCR are:

a) power transfer during faults to maintain stable operation without commutation failures;
b) recovery time, especially for inverter end faults;
c) control of post-fault recovery voltages within acceptable limits;
d) possible low frequency resonance conditions, i.e., < 5th harmonic;
e) temporary overvoltages.

All of these factors become more pronounced with increases in the a.c. system impedance and phase angle.

5.3.2 Power transfer during faults

The HVDC system may be sensitive to relatively remote a.c. system faults where a.c. voltage changes at the HVDC a.c. buses are not large.

Voltage depression and distortion associated with a.c. faults affect the delay angles of the converters and cause a reduction in the transmitted d.c. power. For remote three-phase faults the power loss is essentially proportional to the a.c. voltage drop, down to a level of d.c. voltage where some form of voltage dependent control possibly needs to be imposed, as discussed in the following paragraphs. A further power reduction can take place as a result of a control mode shift as described in 5.3.8.

Voltage dependent control provides a means to modify the current limits or orders of the converters at each terminal in a co-ordinated manner without loss of current margin. The d.c. voltage at each end represents a common signal to both the rectifier and inverter terminals for co-ordination without the necessity for other communications. There are a variety of such controls; an example characteristic is shown in Figure 2.

In case the converters are used for reactive power control, the input voltage for the voltage dependent control should be the a.c. bus voltage.

System studies should be made to determine optimum settings for d.c. or a.c voltage thresholds, current limits, and time constants or ramp rates, if any, for each system.

For a.c. single phase-to-earth faults to or near the rectifier terminal, the reduction in power transfer for modern converters is also approximately proportional to the average a.c. voltage drop, since delay angle unbalance can be readily incorporated to compensate for large a.c. voltage dissymmetries.

On the other hand, for most inverter control strategies using equidistant firing schemes, the earliest firing time which is set to minimize commutation failures, fixes the firing time for all valves. This control action in conjunction with voltage dependent control normally results in minimum power transfer during a.c. single-phase inverter end faults. Strategies that transfer to individual-phase control operation during inverter end a.c. line-to-earth faults offer one means for increasing the power transfer from the aforementioned minimum without experiencing an excessive number of commutation failures.

To achieve both stable power transfer as much as possible and avoiding commutation failure during faults, optimized control of margin angle can be applied. For example, direct or indirect margin angle detection of the thyristor valve can be implemented and applied to closed loop margin angle control. If system requires, these function can be specified.

Power transfers achievable under a.c. fault conditions depend largely on the characteristics of the HVDC system under consideration and therefore can best be determined by digital and/or simulator studies.

5.3.3 Recovery following fault clearing

The recovery time can be defined as that time required after the fault clearing for the HVDC system to recover to a specified level of the prefault power, typically to 90 %, with the overshoot and settling time being specified.

HVDC system recovery times can be fast, e.g. 50 ms to 100 ms, with modern control systems for all non-permanent a.c. faults at the rectifier or inverter for low impedance a.c. systems. In practice however many HVDC systems being designed or installed are connected to high impedance a.c. systems at either HVDC substation. In such case, recovery times can be several times longer than for HVDC systems connected to low impedance a.c. systems. Long recovery times can also be expected for HVDC systems making use of long d.c. cables and very long d.c. overhead lines.

Recovery time settings shall take into consideration the a.c. system stability characteristics for both primary and possible backup fault clearing times.

However factors such as the necessity to minimize commutation failures or post fault recovery voltages often influence the actual recovery time implemented in a d.c. system control strategy.

Recovery can often be improved by maintaining, if possible, the d.c. current flowing even at a reduced magnitude by firing the valves during severe a.c. single-phase-to-earth and three-phase faults. Valve firing during the period of the fault or resumption of firing immediately upon fault clearing can also reduce the magnitude of recovery voltages and improve stability.

Specifications should indicate the expected duration of single-phase-to-earth and three-phase faults, including most likely backup clearing times, for which fast recovery capability of the HVDC system should be provided. This is important because some valves shall be designed with sufficient energy storage for the gating circuits to ride through expected fault periods.

5.3.4 Reactive power consumption during fault and post-fault recovery periods

Reactive power consumption of the HVDC substation during and after a.c. faults depends on its control strategy. Voltage dependent current limits with tailored characteristics are often utilized to modify the reactive power consumption as a function of voltage and to improve the inverter's ability to recover without commutation failures.

Strategies may be adopted for the remote unfaulted HVDC substation and where practical at the faulted substation to continue reactive power consumption or voltage support at a level to maintain a.c. bus voltages within prescribed limits.

During commutation failures, significant variations occur in reactive power flow. Persistent commutation failure in converters followed by protective action result in reactive power flow being rejected into the a.c. system which can lead to substantial overvoltages on high impedance systems.

HVDC system studies are important to determine the required means to control voltages at the a.c. bus and to maintain commutation as well as stability of the interconnected a.c. networks.

5.3.5 Load rejection due to a.c. faults

Fault conditions which can result in converter blocking, tripping of loads, failures to deblock upon clearing of three-phase faults and severe commutation failures, all result in forms of load rejection which can initiate large temporary overvoltages, ferroresonance, and a.c. system instabilities which can cause system collapse.

In addition on some a.c. systems careful attention shall be given to the possibility of large d.c. load rejections leading to self-excitation of generators or synchronous compensators at or electrically near the HVDC substation.

Load rejection overvoltages will have a direct impact on ratings of the HVDC equipment.

Studies should be carried out to assess:

– the extent to which existing equipment in the a.c. network can withstand these overvoltages and to design necessary corrective measures;
– design requirements for the HVDC substation equipment including any needed a.c. protection to satisfactorily withstand such load rejection overvoltages.

While not blocking, the converter can be used to help limit overvoltages. However consideration shall be given to the possibility of converter blocking during a.c. system faults with subsequent failures to recover. Such contingencies may indicate the need for other measures such as high speed switching devices for reactive power equipment, static var compensators (SVC), low order damped filters or protective energy dissipation devices to control load rejection overvoltages.

The specifications should state the acceptable overvoltage magnitudes and durations for the above contingencies.

5.3.6 Switching of reactive power equipment

Switching of reactive power equipment such as a.c. filters and shunt capacitor and shunt reactor banks is a common strategy at the a.c. terminals of HVDC substations for control of harmonic interference and steady-state terminal voltages, the latter as a function of a.c. system loading or of the primary a.c. system voltage.

When specifying the switching device to switch filters, shunt reactors or shunt capacitor banks, attention shall be given not only to the normal steady-state interrupting capability and speed, but also to the overvoltage requirements which may result from a.c. fault clearing and large load rejection.

Further complications may become apparent if an existing reactive power switching device is inadequate for safe interruption during temporary load rejection overvoltages, in which case provision shall be made for a backup breaker of adequate capacity to enable disconnection of excess reactive power sources.

~~Another consideration is that the use of switching devices can result in objectionably long restart times for the HVDC system if the switched reactive power equipment must be reinserted before the HVDC system may be loaded to prefault levels.~~

5.3.7 Effects of harmonic voltages and current during faults

Multiple cycle commutation failures or misfires occurring during an a.c. fault or the recovery period may cause currents and voltages at low-order non-characteristic harmonics and excite other frequencies, on the a.c. and d.c. sides. These may temporarily excite resonances in the a.c. or d.c. systems, but the resulting currents and voltages normally are not excessive, partly because of the damping provided by modern control systems. However, such effects should be studied to check the effect on, for example, filter transient ratings, and possible misperformance of a.c. system protective relays.

If the d.c. side is resonant at the fundamental frequency, saturation of the converter transformers can occur. This would add to any second harmonic on the primary and cause possible system instability. Also an a.c. single-phase-to-earth fault near the rectifier terminal injects large second harmonic voltages on the d.c. side that will remain as long as firing continues. Because of these considerations it is advisable to study carefully the possibility of any resonance of the d.c. line to this harmonic.

Harmonics generated during faults should be taken into account in the design ratings for the a.c. filters and in determining the inverter's ability to commutate during fault recovery periods.

A further problem which should be carefully examined is possible misoperation of the a.c. protection due to low order harmonics during a.c. faults. In this case that digital type relays were used, misoperation could be prevented for some degree of harmonic component. However, it should be taken into account that existing relays of old type do not have immunity to harmonics.

5.3.8 Shift in control modes of operation

Changes in operating modes, that is, to power or current control mode for example, may be necessary during a.c. fault conditions. Shifts from rectifier current control to inverter current control lead to a power reduction that require a current order adjustment to correct for the power loss. Also co-ordination of current margins with and without end-to-end communications and changes in reactive power demands with current margin correction should be investigated.

In some high impedance a.c. systems, unstable operations during fault-initiated transients can appear in the power control mode unless a switchover is made to current control, or the power control mode is made to assume constant current control mode characteristics.

5.3.9 Power modulation on the HVDC system

AC system transient stability and HVDC fault recovery performance sometimes can be improved by the use of power, direct current or direct voltage modulation. This option will be discussed in IEC 60919-3.

5.3.10 Emergency power reductions

During fault conditions resulting in critical a.c. line outages, capability for emergency power reductions or even power reversals may be required as a contingency option to mitigate a.c. system instability. The specifications should consider the impact of such control actions on:

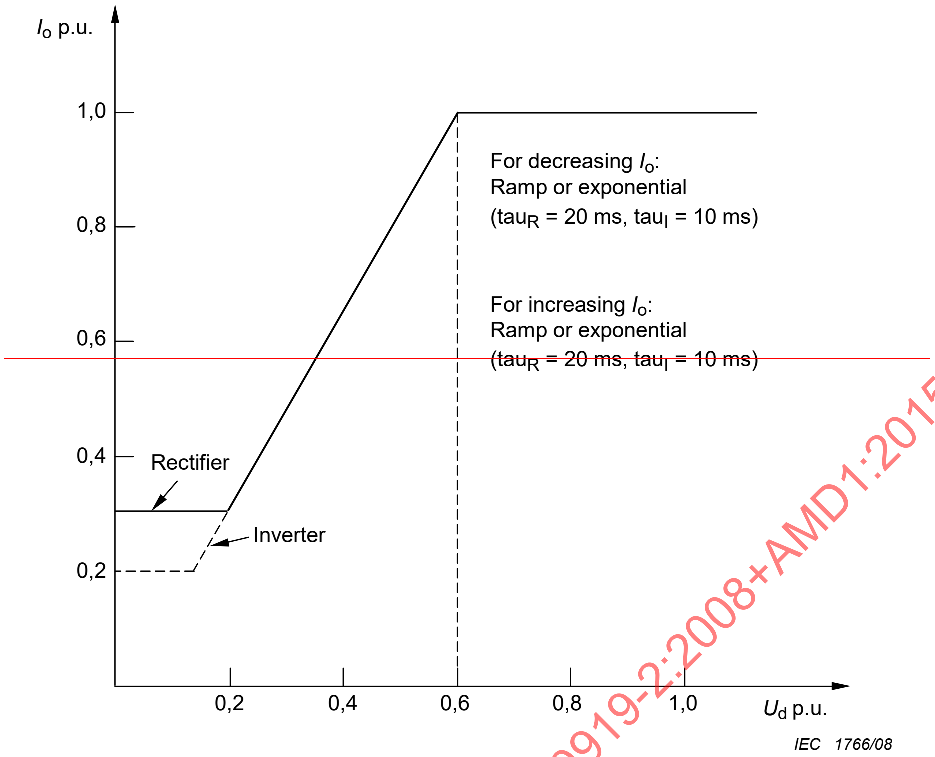
– possible overvoltages or destabilization of the a.c. system connected to the opposite end substation as a result of the partial load rejection;
– communications time requirements to co-ordinate the emergency reductions plus post-fault power increases and the impact of possible communications loss.

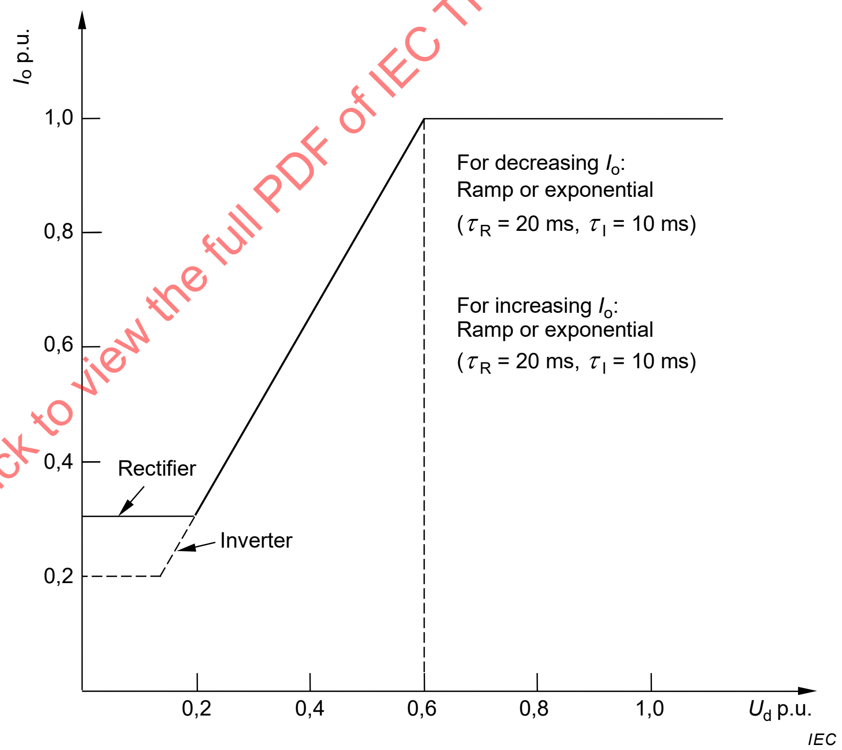
In some cases fault recovery from a.c. faults may permit operation of the d.c. system at a reduced power level until other restorative actions have been accomplished as determined by appropriate system studies.

5.4 Specification impact on control strategy

Because of the wide range of a.c. system conditions that shall be considered in determining optimum transient performance during a.c. faults and during the recovery period following fault clearing, no single control strategy will be appropriate for all cases. Each system shall be optimized around specified reference conditions as determined by digital computer and/or analog simulator studies for that particular system.

Performance specifications should permit d.c. control strategies which achieve an optimum compromise between maintaining power transfer and the prevention of commutation failures, instabilities or excessive recovery voltages, provided that the overall result is a satisfactory solution for the interconnected a.c. system.





Key

U_d	d.c. voltage
I_o	current order
~~tau_R and tau_I~~ τ_R and τ_I	rectifier and inverter time constants, respectively

Figure 2 – Example of voltage dependent control characteristics

6 AC filters, reactive power equipment and a.c. bus faults

6.1 General

This clause discusses faults in a.c. harmonic filters, in reactive power equipment and faults on the a.c. busbar. Relatively high levels of harmonic currents which may appear in these items warrant a discussion of protection aspects. This is included. Specific fault protection aspects of SVCs are not covered in this technical report.

An example of the arrangement of a.c. filters and shunt capacitors for a bipolar HVDC scheme is shown in Figure 3. The individual capacitor, reactor, and filter arms of the banks may be energized and de-energized by means of sub-bank circuit-breakers, the earth faults within the individual arm shall also be cleared by the sub-bank circuit-breakers. The bank circuit-breakers will ~~only~~ operate when sub-bank circuit-breakers fail to open the circuit successfully. An alternative arrangement, sometimes used is to connect the filter and the capacitor and reactor banks via tertiary windings on the converter transformers.

The fundamental and harmonic frequency impedances of the filters and the reactive power banks have a major influence on the amplitude and waveshape of overvoltages occurring at the a.c. busbar. Therefore detailed representation of a.c. harmonic filters and reactive power banks is essential for studies of the busbar voltages during transient conditions.

6.2 Transient overvoltages in filter banks

During normal operating conditions most of the line-to-earth voltage will appear across the main capacitor of the filters, while the voltage across other filter elements is normally a small fraction of the line-to-earth voltage. However under transient conditions the prospective voltage across the filter reactors and resistors can be even higher than the normal line-to-earth voltage. Therefore surge arresters protection should be applied internally in the filters as discussed in Clause 12.

In addition to the overvoltages occurring routinely as a consequence of normal switching (see Clause 4), the filter components are likely to be subjected to lightning-caused over-voltages, switching surges and busbar or external close-in faults.

Since the filter capacitors exhibit low impedances to fast wavefronts such as from lightning discharges, the filter reactors and resistors will be almost directly exposed to any lightning overvoltages appearing on the a.c. busbar.

Switching surge overvoltages appearing on the a.c. busbars may be significantly magnified internally in the filters and the resulting component overvoltages may even exceed the a.c. busbar-to-earth voltage. Therefore the individual component overvoltages should be investigated during overvoltage studies. When the components are not directly protected by surge arresters, as is often the case for the main filter capacitors, they may need to be designed to withstand higher switching surge levels between their terminals than other directly protected equipment connected from the busbar-to-earth.

During unbalanced a.c. system faults, the converters, if not blocked, will generate low order harmonics of substantial amplitude. If filters for low order harmonics are used, the filter surge arresters may be required to absorb considerable energy under these conditions. Another energy stress condition to consider particularly for filter reactor surge arresters of the second or third harmonic filters (when such filters are provided), is during energization of large transformers electrically close to the filter bus such as at recovery from a close a.c. fault.

Severe overvoltages with fast front times can occur across the resistors and reactors within the filters if~~a~~ a flashover from the a.c. busbar-to-earth should take place in the HVDC substation. The prospective voltage amplitudes across these filter elements will be equal to the pre-flashover voltages across the main filter capacitor and the surge arrester energy absorption requirement can be high.

6.3 Transient overcurrents in filter and capacitor banks

Under transient conditions peak currents in the filter components may be several times greater than the normal steady-state values.

In the event of a flashover from busbar-to-earth the capacitor banks will discharge energy into the fault. The current in this discharge will be limited by the stray inductance of the capacitor stack and its busbar connections and by the current limiting inductor if used. Similarly, where surge arresters are provided across reactors and resistors in a.c. harmonic filters, the capacitor discharge current can be high since it is only limited by the back e.m.f. of the protective device and by stray inductance.

Due consideration to these overcurrents should be given in the specifications of the components as well as of the protective circuits and the design of the earthing system. Thus capacitor fuses shall be capable of withstanding the discharge currents, and the operation of current transformers and protective relays should not be adversely affected nor should the protection be incorrectly triggered by transient currents which are within the capabilities of the filter components. These should be designed to withstand such discharges.

The analysis should consider the system configuration, including the filters and shunt capacitors, leading to the most critical stresses.

6.4 Capacitor unbalance protection

To achieve the desired harmonic performance and reactive power balance at all d.c. loadings the capacitor and filter banks are usually divided into a number of switchable arms. This means that the individual banks (arms) may be of relatively low MVar rating, i.e., the number of parallel elements in the capacitor banks would be small.

During the operating life of a capacitor bank, capacitor elements can fail and be disconnected by fuse operation. When internal fuses are used, their operation disconnects the individual internal faulty element, while external fuse operation will disconnect the complete capacitor cell.

Capacitor banks are often designed to have built-in redundancy which means that a limited number of capacitor element failures and the accompanying fuse operations will not overstress the remaining healthy capacitors in the bank. However fuse operations should be detected so redundancy can be restored in the bank at an early convenient opportunity.

One method of such detection is use of current unbalance relay protection. For this scheme each phase of the capacitor bank is connected in a bridge circuit, i.e. “H” connection. If an element fuse blows in one capacitor unit, the capacitance of the bridge arm, that contains this unit will decrease, causing an unbalance current in the bridge arm which is measured by the current transformer.

Another method of such detection is that each capacitor phase is subdivided into two closely equivalent parallel groups of capacitors. Sensitive current unbalance relays responding to the difference in current in the branches are utilized to detect small changes resulting from capacitor element failure and subsequent fuse operation.

An alternative procedure uses voltage sensing devices which measure the voltage at tapping points in each phase of the capacitor bank to detect changes caused by failed capacitor elements and fuse operations. An overvoltage relay is used to monitor the phase or sum of the intermediate tapping voltages.

For some applications two levels of unbalance detection are used. The first gives an alarm and permits manual de-energization of the capacitor bank and replacement of failed capacitor units as necessary to restore redundancy. The second level gives an automatic trip signal to ensure that the safety of the remainder of the capacitor bank is not compromised as a consequence of the loss of a large number of capacitor units or elements. Unbalance protection schemes assume an extremely low probability of the same degree of capacitor element failure simultaneously in two branches of a filter capacitor bank.

6.5 Examples of protection of filters and capacitor banks

Examples of protection arrangements for filters and capacitor banks for an HVDC system are illustrated in Figures 4, 5 and 6. The choice is usually based on individual utility experience and practices.

If redundancy is sufficient to allow a pole to continue to operate even with one filter out of service, it may be desirable to protect the filter arms individually, so that the faulty filter can be disconnected rapidly with minimum loss of transmission capability.

If loss of a filter means that the pole cannot continue operation, it may then be considered economical to provide protection only for the overall bank or to include the filters in the busbar protection zone. As another alternative to individual filter protection, some operational restrictions such as reduction in transmitted power could be considered.

To ensure that the appropriate protection characteristics are applied, contingency operation requirements for partial loss of reactive power sources should be studied and specified.

The presence of an earth or phase-to-earth fault within a given protection zone can be detected by a conventional differential current protection system as shown in Figure 4.

When filters are assigned their own individual protection zones, current transformers shall be provided in each phase on the a.c. busbar side and at the neutral side of the filter. When the filter bank is treated as a single protective zone, only one set of high voltage current transformers need be provided, situated in the a.c. busbar connections.

If tripping of the complete pole should be initiated when the filter bank is tripped, the filter bank could alternatively be incorporated in the overall pole differential protection scheme. However this will have the disadvantage of reduced automatic information for identification of the faulted bank.

Another zone protection scheme is the restricted earth fault protection shown in Figure 5. This uses current transformers in each of the three high voltage phase conductors and in the neutral connections to detect an earth fault in the protected zone.

It should be noted that if the surge arresters inside the filter banks are connected directly to the substation earth mat, the arrester surge current may be registered by the protection system as an unbalance current. The resulting probability of undesirable relay operations can be minimized by proper co-ordination or by including the arresters in the protection zone.

The current in the filter and capacitor banks will depend not only on the amplitude and harmonic content of the a.c. busbar voltage, but on the integrity of the filter and bank components themselves. The differential current schemes described above may not be sufficiently sensitive to detect all internal breakdowns in the filters. Some of these incipient types of failures may need to develop sufficiently so that they can be detected and cleared.

Overcurrents which result from abnormal a.c. busbar voltages often can be tolerated for limited times without excessive penalties in terms of lost equipment life. However the equipment should be monitored so that mitigative steps may be taken before such overloads exceed the limits imposed by the known margins inherent in the equipment. For this, protection can be obtained by measuring the current in each phase and using overcurrent and overload relays. To ensure adequate protection against these problems in an a.c. harmonic filter it is often necessary to provide current transformers for individual elements of the filter as shown in Figure 6.

6.6 Shunt reactor protection

The protection arrangement for a shunt reactor applied at an HVDC substation for reactive power control is similar to that applied to a reactor or transformer as used in an a.c. transmission system.

6.7 AC bus protection

The converter a.c. busbar is normally protected by a differential protection system. Since resonances can exist between the a.c. filters and the a.c. system a high content of harmonic currents may be present in the busbar currents during fault recovery periods. The busbar protection system then shall operate correctly in the presence of these harmonic currents.

Another aspect of this protection which should be examined is its performance during temporary overvoltage conditions. Under some conditions the peak voltages of one polarity may be substantially higher than the other. This can result in unidirectional surge arrester currents. It shall be ensured that the current transformers do not saturate under these conditions since misoperations of the protection can otherwise occur.

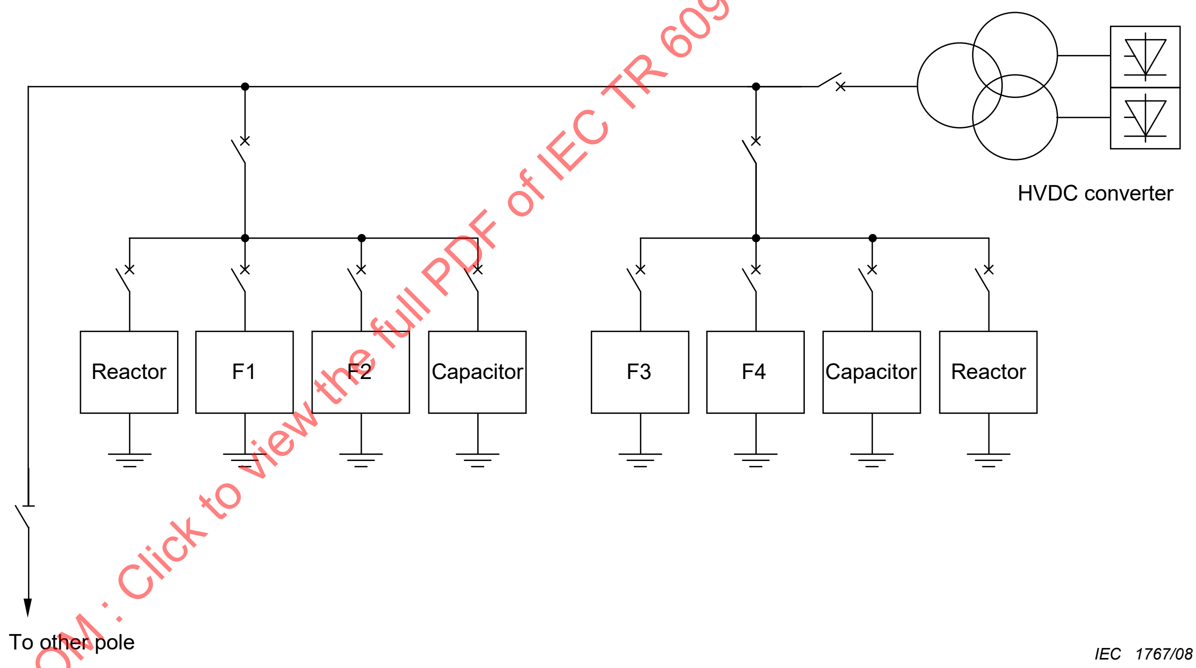


Figure 3 – Example of arrangement of a.c. filters and capacitor and reactor banks for large bipolar HVDC

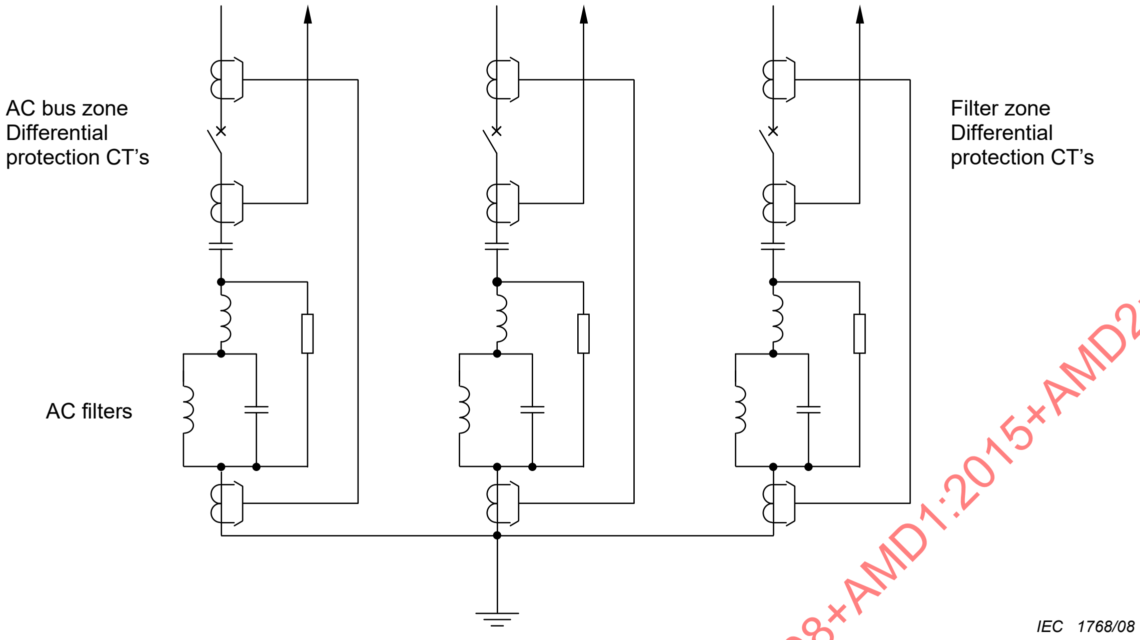


Figure 4 – Example of current transformer arrangements for a.c. filters and a.c. bus differential protections

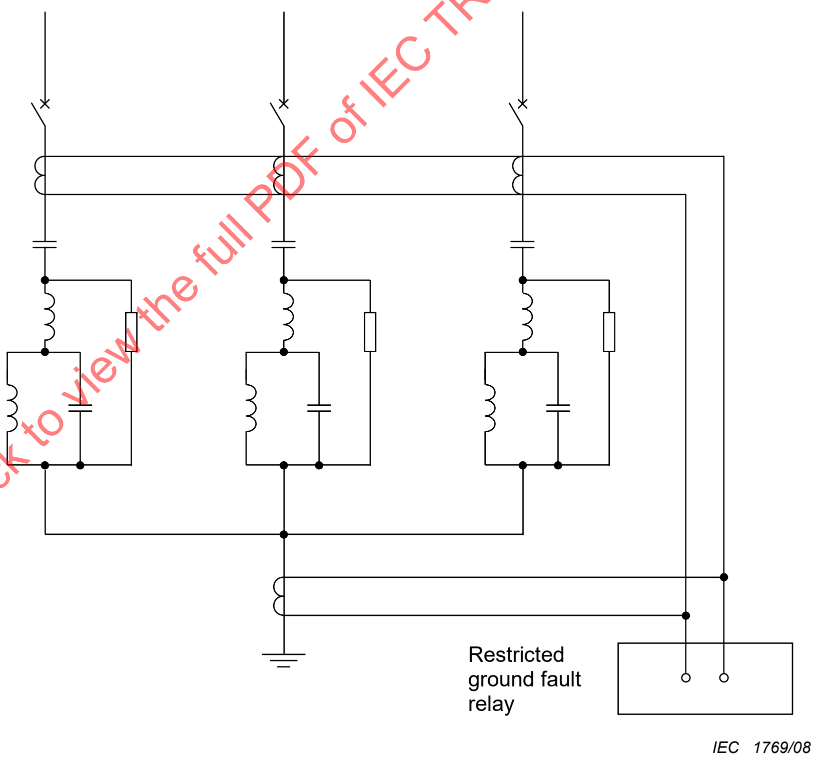


Figure 5 – Example of restricted ground fault protection of filter

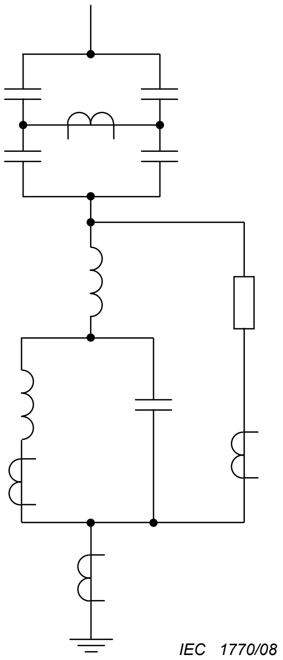


Figure 6 – Example of current transformers arrangement for capacitor bank unbalance protection and overload protection of double tuned filter arm

7 Converter unit faults

7.1 General

This clause discusses converter unit faults, i.e., those which take place between the ~~line~~ valve side of the converter transformers and the valve side of the smoothing reactor.

Electronic equipment external to the converter arms but functionally part of them (see IEC 60633), is included in the discussion as appropriate. Cooling equipment is discussed in Clause 14.

In some applications, converter units can be connected in series or in parallel on the d.c. side within one pole of the HVDC substation. Fault aspects of such configurations are also addressed.

Converter unit faults can be classified as:

a) flashovers or short circuits (see 7.2);

b) failures of the converter unit to perform its intended function (see 7.3).

Various protective circuits are usually built around the converter unit to detect faults and operating conditions that can be detrimental to the safety of the equipment, particularly the thyristor valves. Subclause 7.4 lists typical circuits some of which can be required only for particular valve designs.

7.2 Short circuits

Short circuits can be caused by breakdown of external or internal insulation, by inadvertent operation of switches or from other causes. They call for a shut-down of the affected converter unit because of the high probability of equipment damage and the need for repair or replacement.

In bipolar systems or those comprised of two or more independent converter units per pole, the unaffected converter units and thus the remainder of the HVDC transmission system can remain operative after a short-circuit in a converter unit.

For example, Figure 7, shows a number of possible locations of short circuits within a typical converter unit. Faults within the converter transformer are not shown since they are not unique to the HVDC application. Figure 7 is valid for each individual converter unit in parallel or series-connected converter units.

Usually the most severe fault is a short-circuit of a converter valve while it is in rectifier operation at minimum delay angle and maximum a.c. voltage, e.g., due to a flashover. This would constitute a near-solid line-to-line short-circuit of the valve side winding of the converter transformer and subjects the conducting valve in the same commutating group to the fully offset short-circuit current. The possibility of a flashover of the transformer neutral to earth also shall be considered.

Other short-circuits on the d.c. side include short-circuits of a six-pulse bridge, of a twelve pulse group or from pole-to-earth. However due to the emf's and the impedances involved in these cases, they impose a somewhat reduced short-circuit current stress on the converter valves.

Upon detection of a short-circuit, perhaps by the differential protection within an HVDC thyristor valve converter, common practice requires immediate blocking of all gate pulses to prevent further commutation. The short-circuit current then extinguishes at its first zero crossing, generally within the first cycle following fault initiation. Subsequently the valves are subjected to the recovery voltage including any temporary overvoltages resulting from d.c. load rejection. The a.c. circuit-breaker of the converter unit is tripped simultaneously as a back-up. Due attention should be given to the breaker for operation under these circumstances because of the possibility of delayed current zero.

Stresses are most severe on the valve that has been carrying the short-circuit current because its thyristors have a higher than normal junction temperature when the recovery voltage is applied. The capability of a thyristor valve to withstand such stresses without damage and to block against the recovery voltage is termed fault suppression capability (see IEC 60700-1).

For any given system, the maximum valve fault current and thus the highest thyristor junction temperature are obtained with the maximum a.c. system fault current level including any contribution from the a.c. filters. On the other hand, the maximum recovery voltage including load rejection overvoltage is in general experienced with the minimum a.c. system fault current level.

Valves should be specified to have fault suppression capability for consistent levels of short-circuit current and recovery voltage. Breaker failure should also be considered. If three pole breakers are used and the breaker fails, the backup breaker might be opened after about 400 ms, and that time should be considered for valve design. If single pole breakers are used, and one breaker phase fails, the fault current will be interrupted anyway since most of faults are fed from two phases, and no extra time has to be considered for the valve design. If opening of the converter unit circuit-breaker is intended to provide back-up for fault suppression capability, the valves should be specified to have survival capability for the time period until the breaker clears.

For faults to earth, including fault B1, B2, B3 ~~and B5~~ in Figure 7, valves not stressed by the fault current can experience fast changes of potential. Depending on circuit parameters, this may subject the converter valves to stresses equivalent to steep-fronted voltage surges. Specifications then should require that the converter unit equipment be designed and manufactured to withstand resultant stresses under credible fault conditions, as discussed in the foregoing, without damage.

In the case of CCC, short circuit of the commutation capacitor will not give any decisive short circuit current for dimensioning of the main circuit equipment. For dimensioning of the varistor across the commutation capacitor, valve short circuit and commutation failures / a.c. system single-phase faults should be considered as the decisive fault cases. The number of consecutive commutation failures / a.c. system single-phase faults should be carefully considered as it may be dimensioning for the varistors. 2-phase or 3-phase faults between the CC and the valves would give enormous energy and it is not practically possible to dimension the varistor for such fault cases. If the station layout is such that those 2-phase or 3-phase faults cannot be disregarded, they should be considered for current dimensioning purposes only and not for varistor energy dimensioning.

7.3 Failure of converter unit to perform its intended function

7.3.1 General

The basic function of the converter unit is to cyclically commutate the direct current between the phases of the a.c. system. To perform this function, two conditions shall be fulfilled: sufficient commutation voltage shall be present; and synchronized cyclical gate pulses shall be generated by the converter unit control and transmitted to the valve firing circuits.

7.3.2 Rectifier operation

Usually reduction or distortion of the commutating voltage is of little concern because there is sufficient volt-time area to achieve commutation even for close-in single line-to-earth faults. If the three-phase voltage becomes too low for successful commutation the direct current may be reduced or the converter may be blocked. When the voltage reappears the converter should be able to resume operation with the shortest possible delay. This imposes a requirement on valve designs, where auxiliary energy for gating or thyristor protection is taken from the main circuit, in that the electronic circuits should be designed for fast recharging or have adequate energy storage capability.

Persistent failure of a valve to turn on, perhaps due to missing gate pulses, causes the fundamental a.c. voltage to be injected into the d.c. circuit. Depending on circuit parameters, this can lead to transformer saturation, excite possible resonances on the d.c. line, etc. possibly imposing severe stresses on the affected equipment. The specification should require that such faults be detected and appropriate actions taken (see 8.7).

7.3.3 Inverter operation

During inverter operation the absence of a sufficient commutating voltage-time area or of valve gate pulses results in commutation failure. This subjects the valve to overcurrents and introduces a fundamental a.c. voltage component into the d.c. circuit. Special control strategies such as advancing the delay angle, by-pass pair operation to eliminate fundamental a.c. voltages on the d.c. side, reduction of direct current, etc. are adopted to minimize commutation failures and their effects.

If the commutation failure is caused by insufficient a.c. voltage from an event such as an a.c. system fault (see Clause 5), then normal performance can be expected to resume once the fault has been cleared. To avoid shutdown of the converter, the valves should be designed and manufactured to withstand the stresses resulting from such events for a specified time assisted by the converter unit control. If the specified time is exceeded or if the commutation failure is caused by missing gate pulses then the converter should be blocked.

For valve designs where the auxiliary energy required for gating the thyristors is taken from the main circuit, the pertinent electronic circuits should be designed for fast recharging or they should have sufficient energy storage capability so that the converter can quickly resume normal operation after reappearance of the commutating voltage.

7.4 Converter unit protection

7.4.1 Converter differential protection

By comparing the converter transformer valve side current to the direct current, short-circuits within the converter bridge can be detected. The resulting protective action is to permanently block the converter unit and trip the associated a.c. circuit-breaker.

7.4.2 Overcurrent protection

Evaluating the magnitude of the transformer valve side current makes it possible to protect against overload. This also provides backup for converter differential protection. Protective action is the same as that described in 7.4.1.

7.4.3 AC overvoltage protection

AC overvoltage protection can be included by measuring the a.c. voltage, for example at the valve side of the converter transformer using a capacitive voltage divider as in the transformer bushings or by other means. Protective actions after detecting an undesirable overvoltage might include tripping of capacitor banks, increasing the converter reactive power consumption, permanent blocking of the valves along with tripping of the converter unit a.c. circuit-breaker or an appropriate combination of these actions.

7.4.4 Protection against large delay angle operation

Protection against large delay angle operations can be achieved if required for a particular valve design by measuring the valve delay angles and limiting the duration of such operation in the converter unit control. The limitation should be made dependant on valve side voltage, direct current and the valve coolant temperatures.

7.4.5 Commutation failure protection

Commutation failure detection is usually achieved by a.c./d.c. current differential measurement. If recovery does not occur naturally, this acts after some delay to temporarily increase the inverter angle of advance. If no recovery occurs after a further delay, permanent blocking is applied.

7.4.6 Thyristor valve protections

Thyristor redundancy can be monitored by continuous on-line checking of each thyristor if required. Protective actions can include a warning signal, shut-down and isolation of the converter unit or a combination of these.

Thyristor forward overvoltage protection can be achieved by monitoring the individual thyristor voltages and applying a gating signal if the safe level is exceeded (see also 12.7.3) or by other means.

Forward recovery protection can be used to protect the thyristors against positive high voltage/time differential d*v*/d*t* in the recovery period by applying a gating signal if a safe level is exceeded, or by other means.

7.4.7 Transformer protection

Converter transformer protection is the same as conventionally used for transformers in a.c. transmission systems. It includes differential protection, overcurrent protection, gassing or hot spot detection, etc. Protective action is to trip the converter unit a.c. circuit-breaker. Precautions shall be taken to prevent direct current from flowing in the transformer, for example by bypass-pair operation and thus to assist the circuit-breaker clearing. This can be particularly important for series-connected converter units.

Operation of overall differential protection for valve side earth faults is complicated due to the absence of a direct earth connection. The effects of harmonics upon the operation of the protection should be considered and in particular in the case of biased differential protection with harmonic restraint.

Special attention should be paid to the design and rating of current transformers used because of possible saturation problems. Problems of concern include for example, injection of direct current in conjunction with commutation failures, neutral bus faults, and delayed neutral bus switch operation (see Clause 11).

7.4.8 Transformer tap-changer unbalance protection

Tap-changer unbalance protection may be required to avoid unbalanced operation of the converter unit, in turn leading to generation of excessive non-characteristic harmonics. These can overload filters. Protective response is to give an alarm and initiate a manual or automatic tap changer rebalancing procedure.

7.4.9 AC connection earth fault protection

AC connection earth fault protection may be used to detect earth faults on the connections between the converter transformer and the valves (fault B1 and B2 in Figure 7), when the converter transformer is energized but the valves are blocked. The valve side voltages of the converter transformers can be measured by using capacitive voltage dividers in the transformer bushings or the valve hall bushings or by other means. Protective action can be tripping of the converter unit a.c. circuit-breaker.

7.5 Additional protection aspects of series connected converter units

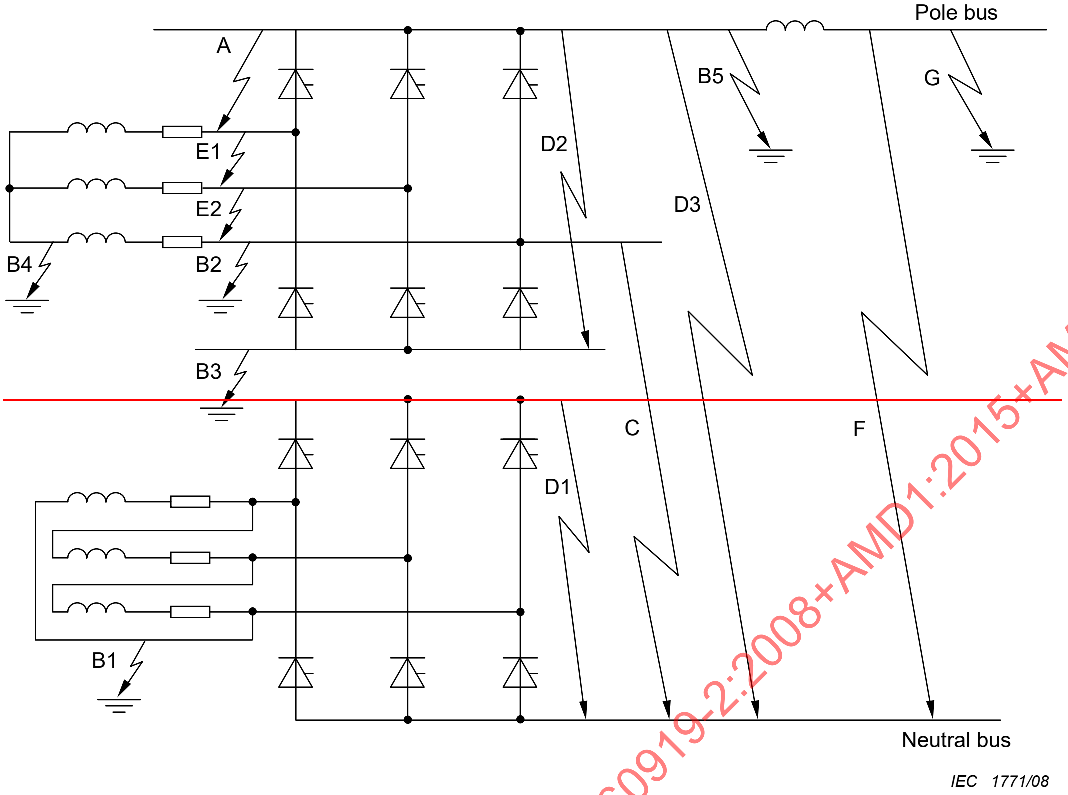
When two or more converter units are connected in series on the d.c. side within one pole of the HVDC substation, protection for the same types of faults apply as for single converter units (see 7.3 and 7.4). One additional differential protection, to cover converter unit faults (type B5 in Figure 7), can be included, comparing the current in the high voltage side and in the low voltage side of the converter unit.

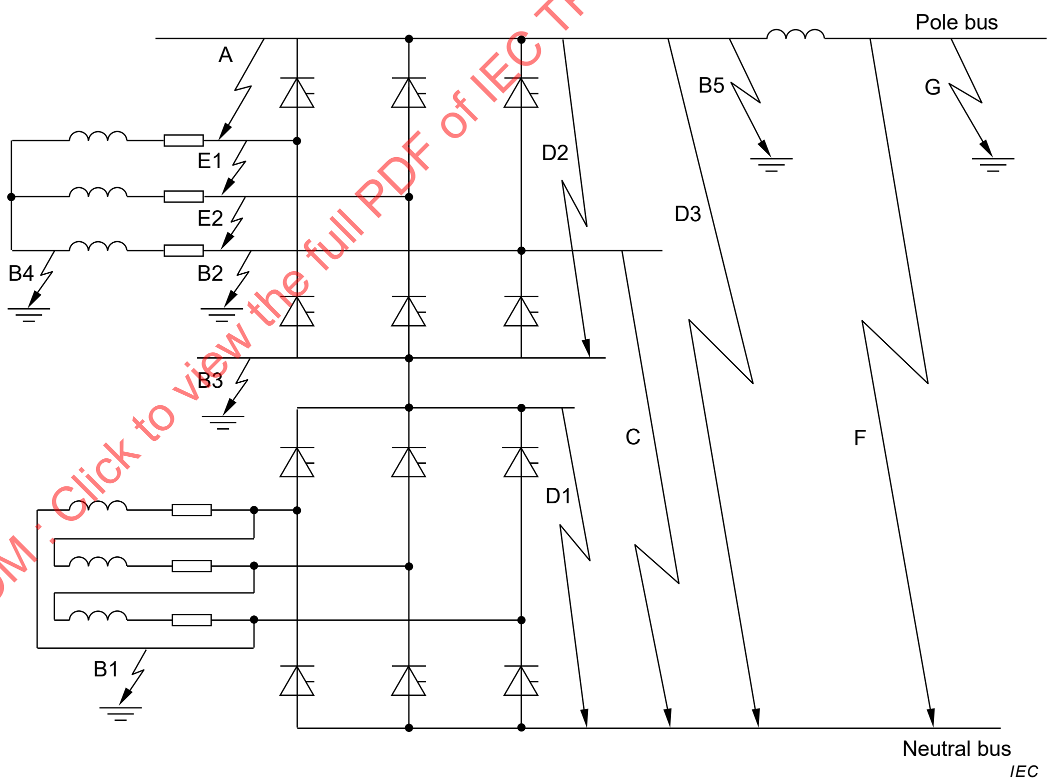
Since both converter units can be operated independently of each other, subdivision of the converter portion of the HVDC substation into protection zones should take this into account (see Figure 8). Protective action for short-circuits would generally include blocking of the pole to remove the direct current. If the fault is within the converter unit 1 or 2 zone, the respective unit then should be isolated and bypassed so that operation can be resumed with the remaining healthy unit. Consideration should also be given to removing one of the converter units from service at the other end of the transmission system to avoid prolonged operation at large delay angle or angle of advance, respectively.

For certain faults occurring only in one of the series connected converter units, such as transformer faults or commutation failures, protective sequences can be used in addition to fault removal to divert the direct current from the affected unit by bypass operation of the converter valves or by closing the bypass switch.

7.6 Additional protection aspects of parallel connected converter units

In general, each of the parallel-connected converter units can be treated independently from the point of view of transient performance and fault protection. However, due consideration should be given to the transient current rating of parallel-connected inverters with respect to commutation failures, especially if the inverters have differing steady-state current ratings. DC breakers may be desirable at the pole bus (see Figure 9), for isolation of faulty converter units, especially inverters, to avoid the need to temporarily block the complete transmission pole.





Fault list

A. Valve short circuit

B. Ground faults on:

1 valve side a.c. phase, D-bridge

2 valve side a.c. phase, Y-bridge

3 bus between 6-pulse bridges

4 neutral point, Y-transformer

5 pole bus connection

C. Short circuit between neutral bus and valve side a.c. phase, Y-bridge

D. Converter short circuit

1 short circuit across lower voltage 6-pulse bridge

2 short circuit across higher voltage 6-pulse bridge

3 short circuit across 12-pulse bridge

E. AC phases short circuit

1 2-phase short circuit

2 3-phase short circuit

F. Pole to neutral bus short circuit outside the d.c. reactor

G. Pole bus to ground fault outside the d.c. reactor

Figure 7 – Examples of a.c. phase short circuits, pole short circuits and faults in a twelve-pulse converter unit

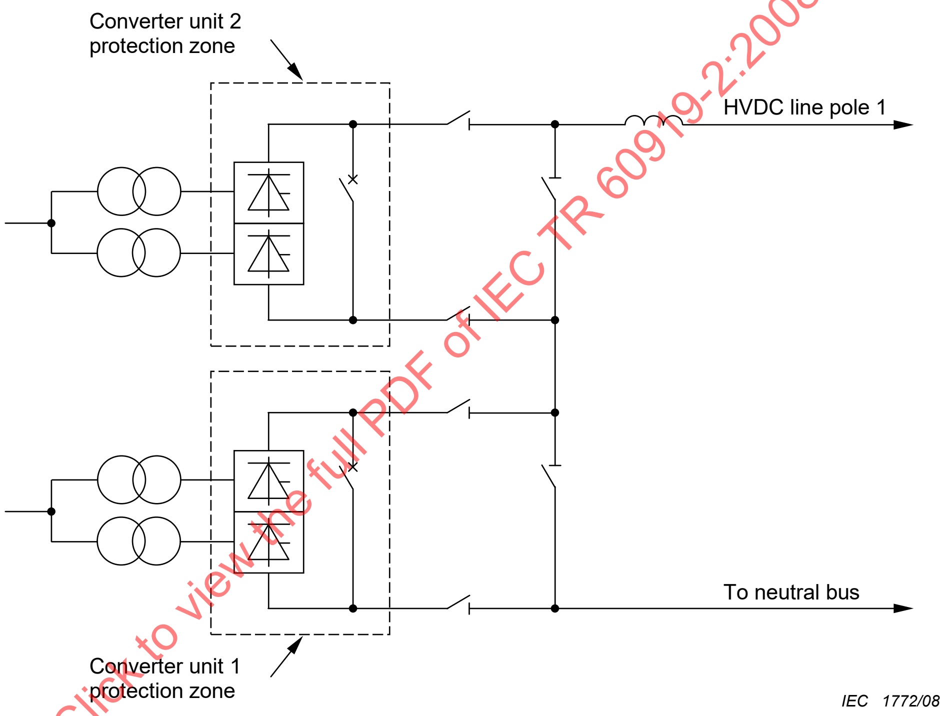


Figure 8 – Protection zones in series-connected converter units

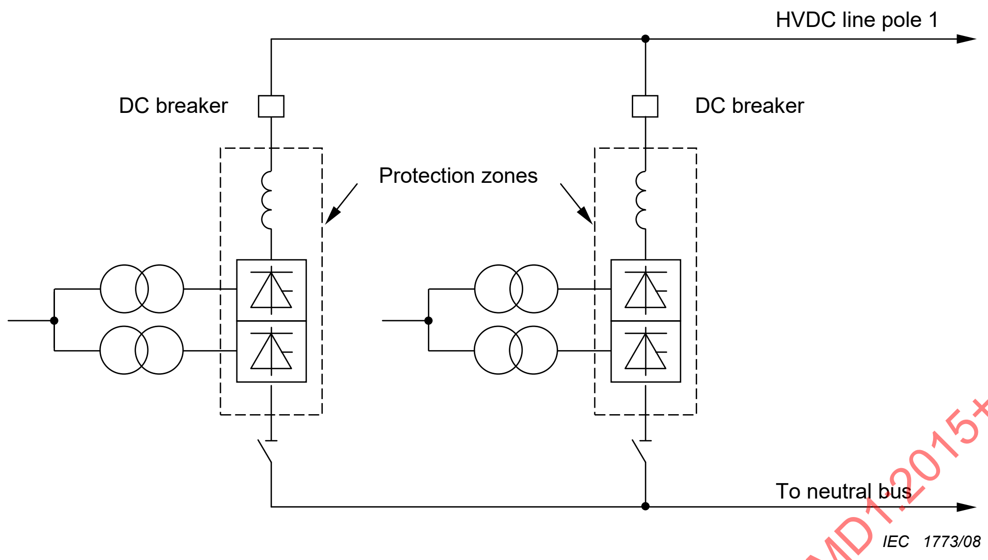


Figure 9 – Protection zones in parallel-connected converter units

8 DC reactor, d.c. filter and other d.c. equipment faults

8.1 General

This clause discusses faults in the HVDC substation for an HVDC transmission system bounded by:

a) the valve side of the d.c. reactor to the d.c. transmission line in each pole;

b) from the neutral side of the converter unit for each pole to the earth electrode line.

8.2 Fault types

Types of faults that should be considered for the protection of the d.c. side equipments and bus sections include:

a) bus-to-earth and bus-to-bus faults;

b) equipment faults;

c) failure of d.c. switching devices to perform their intended switching functions.

8.3 Protection zones

Specifications for HVDC substations should make provision not only for the protection of all d.c. side equipments, but also for the co-ordination of protections.

In HVDC systems the zone protection philosophy and techniques of implementation to achieve zones of protection are in general much the same as with a.c. protection practices. However, in HVDC systems the fault suppression capability of the converter valves (see Clause 7), in addition to the relatively high impedance of d.c. reactors and transformers aids in achieving protection selectively on the d.c. side.

Protection zones of an HVDC substation should be arranged such that all equipment is fully protected by at least one protective function within the HVDC substation. The adjacent zones should be overlapped in actual system in order to eliminate blind spots of protective scheme.

A communication system between substations of the HVDC transmission can be used to optimize recovery from faults and to improve fault protection selectivity for many faults which can take place on an HVDC transmission system. However it should not be necessary for protection of the equipment under discussion in this clause. Figures 10 and 11, show examples of HVDC protection zones and measuring devices for two configurations of HVDC substations.

8.4 Neutral protection

8.4.1 General

In an HVDC system the neutral side protection is generally divided into zones that enable independent fault detection plus selective isolation by pole and a protective zone common to both poles. The latter requires a bipole shutdown to provide corrective maintenance.

8.4.2 Neutral fault detection

In a bipolar configuration operating under balanced conditions, the pole neutral protection zone, the bipole neutral protection zone and the earth electrode line protection zone (see Clause 10) are all essentially at earth potential. An earth fault in any of these zones would therefore not interfere with station operation under balanced bipolar conditions. Any d.c. fault current then would be practically zero.

Faults to earth in these neutral zones would be detectable whenever the poles of the bipole are temporarily unbalanced for any reason such as during startup, shutdown or disturbance on one pole. The HVDC specifications should consider use only of neutral zone alarms if the operation of both poles is expected to be reasonably balanced. This would allow operator decision on corrective actions to be taken based on safety considerations and the power transmission requirements at the time of fault detection.

The pole neutral and bipole neutral zones should be bounded by d.c. current transformers (d.c.-c.t.). A fault within the respective zones can be detected by a differential comparison of the currents as measured by the d.c.-c.t.'s at the zone boundaries during an unbalance operating condition between the two poles.

8.4.3 Neutral bus fault isolation

Faults to earth within the neutral zone or converter zone require a permanent stop of the pole for correction of the faulted condition.

The neutral bus switching device is utilized during the protection sequence to isolate the faulted pole and to transfer any residual pole current to earth return.

Current transfer requirements of the neutral bus switching device should consider the most onerous condition up to and including maximum healthy pole current and location of faults. The switch shall be capable of developing a voltage greater than the IR drop of the earth return to force the current transfer. For systems in which either earth return or on-line transfer to metallic return are not permitted, load break capability of the switching device may not be needed. In this case, a disconnector would be adequate.

In addition, the failure to open the neutral bus switching device of one of the poles will cause a bipole blocking.

8.4.4 Bipolar neutral bus faults

Bus faults within the bipolar neutral protection zone are detectable by differential comparison schemes such as discussed in 8.4.2. A neutral bus fault in this zone requires a bipole shutdown to provide corrective maintenance which could be a scheduled shutdown.

8.5 DC reactor protection

The d.c. reactors of each pole can be either oil-insulated or dry type. Protection of oil type reactors utilizes many of the same techniques as are applied to a.c. transformers with due consideration to the fact that direct current quantities are involved in the operation of the protective devices.

Protection can include:

– pressure relief devices;
– oil temperature monitoring;
– oil level monitoring;
– gas sensing;
– winding temperature sensing;
– loss of cooling detection;
– differential protection.

Differential protection can be specified around the d.c. reactors or these equipments can be included in one of the HVDC substation protection zones as shown in Figures 10 and 11.

Oil type d.c. reactor bushing designs lend themselves to an economic solution to the problem of housing the d.c.-c.t.'s required for differential protection.

When dry type d.c. reactors are employed, separately mounted d.c.-c.t.'s will be needed for reactor fault detection.

8.6 DC harmonic filter protection

8.6.1 General

The d.c. filters associated with HVDC substations are normally specified to limit harmonic interference caused by harmonic currents flowing into the d.c. line (see IEC 60919-1, Clause 17).

Protection design for the d.c. filter arms should take into account the full range of normal and abnormal operating conditions which should be specified for the HVDC substations.

Similarly the protection design for the d.c. filter elements, such as capacitors, reactors, damping resistors, and disconnectors shall consider all expected operational conditions that result in filter elements being overstressed due to harmonic currents which for example can result from operation at large delay angles, angles of advance or from resonant conditions, etc.

8.6.2 Filter bank fault protection

DC filter capacitor bank faults to earth can activate the d.c. line pole protection. However the specifications should require that d.c. line protection operation should not prevent correct identification of any d.c. filter faults and should automatically initiate clearing and isolation of the faulted filter branch.

Any fault within the d.c. filter zone may be detected by a differential comparison between the d.c.-c.t.'s at the boundary of the line side d.c. substation zone as shown in Figures 10 and 11. Other equipment such as line traps, coupling capacitors, d.c. voltage dividers, etc. can also be included in this zone of protection.

Isolation of a faulted filter may require temporary blocking of the affected pole to permit disconnector operation.

If operation is to continue after removal of the faulted d.c. filter branch, the specification should consider the increased d.c. side interference levels expected, possible overloading of other filters and potential resonant conditions.

8.6.3 DC filter capacitor unit protection

Since capacitor banks associated with the d.c. filters normally consist of a combination of series and parallel elements, a variety of protection philosophies may be applied, namely:

– fuse protection (internal or external) if the fuses do provide useful protection;
– unbalance protection within a capacitor bank;
– monitoring of the state of filter tuning by on-line or off-line measurements to locate failures;
– visual or remote indication of failed units or voltage level from earth;
– separate failure alarms to indicate non-critical and critical levels of capacitor failures, including automatic removal of the filter arm if continued operation could result in an avalanche of capacitor failures.

8.7 DC harmonic protection

Protection against fundamental and harmonic frequency components on the d.c. side should be considered in the specification of any HVDC system. Fundamental frequency components on the d.c. side lead to a d.c. and second harmonic frequency component on the a.c. side which can cause transformer saturation or resonant conditions. The fundamental frequency can be detected in the voltage divider or d.c.-c.t. signals. The related harmonic protection normally initiates pole blocking whenever the harmonic component exceeds a given threshold value for a specified time.

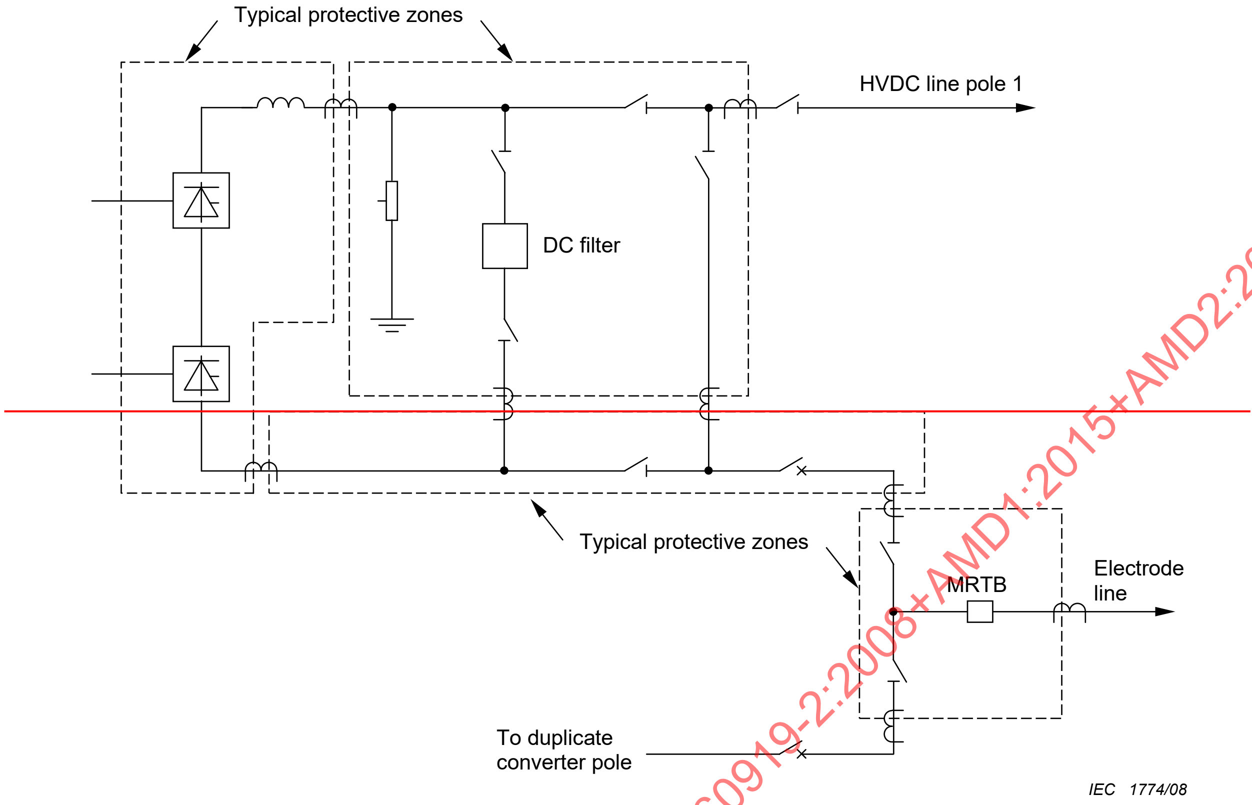
8.8 DC overvoltage protection

Specifications for HVDC substations should consider d.c. side overvoltage protection to assure that all equipments and the d.c. line or cable are protected against steady-state overvoltages. Transient overvoltage protection can be addressed as part of the arrester co-ordination (see Clause 12). Normally converter controls are utilized to implement d.c. system steady state overvoltage protection functions.

8.9 DC side switching protection

Switching devices such as high speed pole circuit-breakers and d.c. side disconnectors, including d.c. filter and pole disconnectors, shall be covered in the specifications. Specification of these switching devices shall consider current interrupting or commutation capability. In addition, permissible switch arcing time without unacceptable equipment damage shall be considered.

The disconnectors usually operate at no-load and their operating supervision should be provided either by the equipment or by other associated protection. The on-load switches, such as the by-pass breakers, should have a dedicated protection.



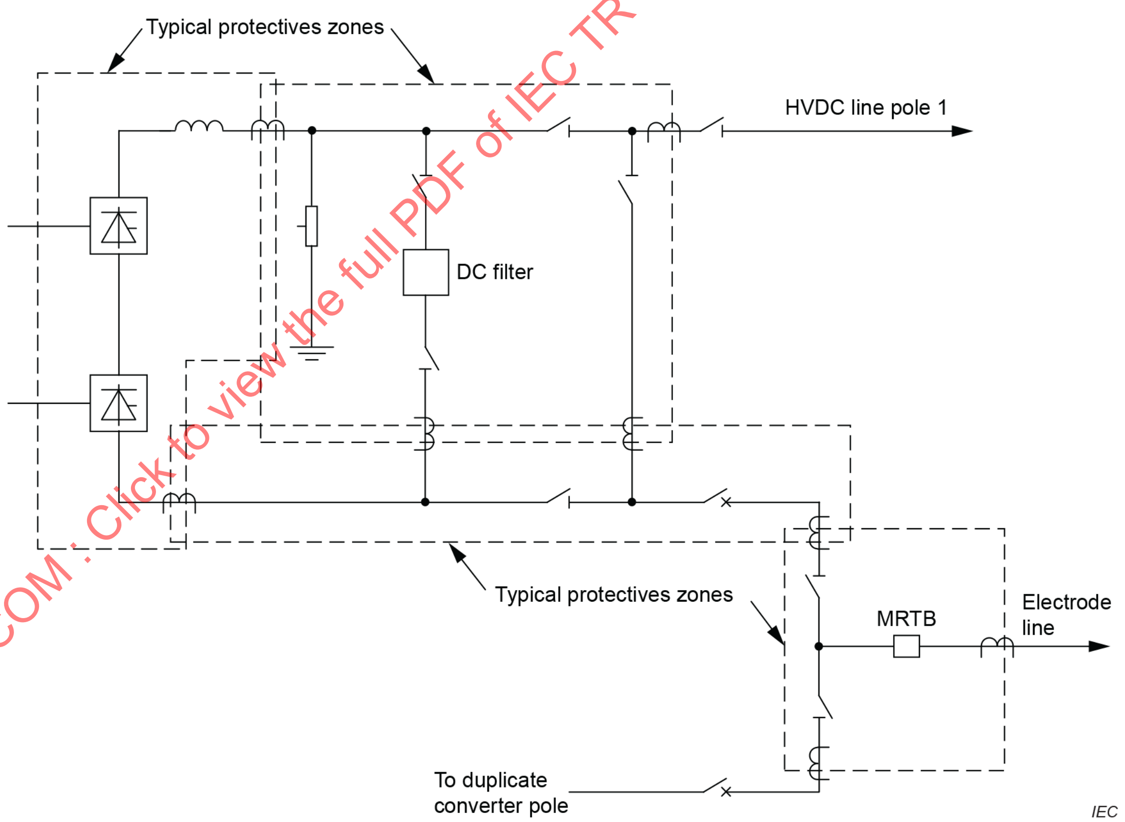
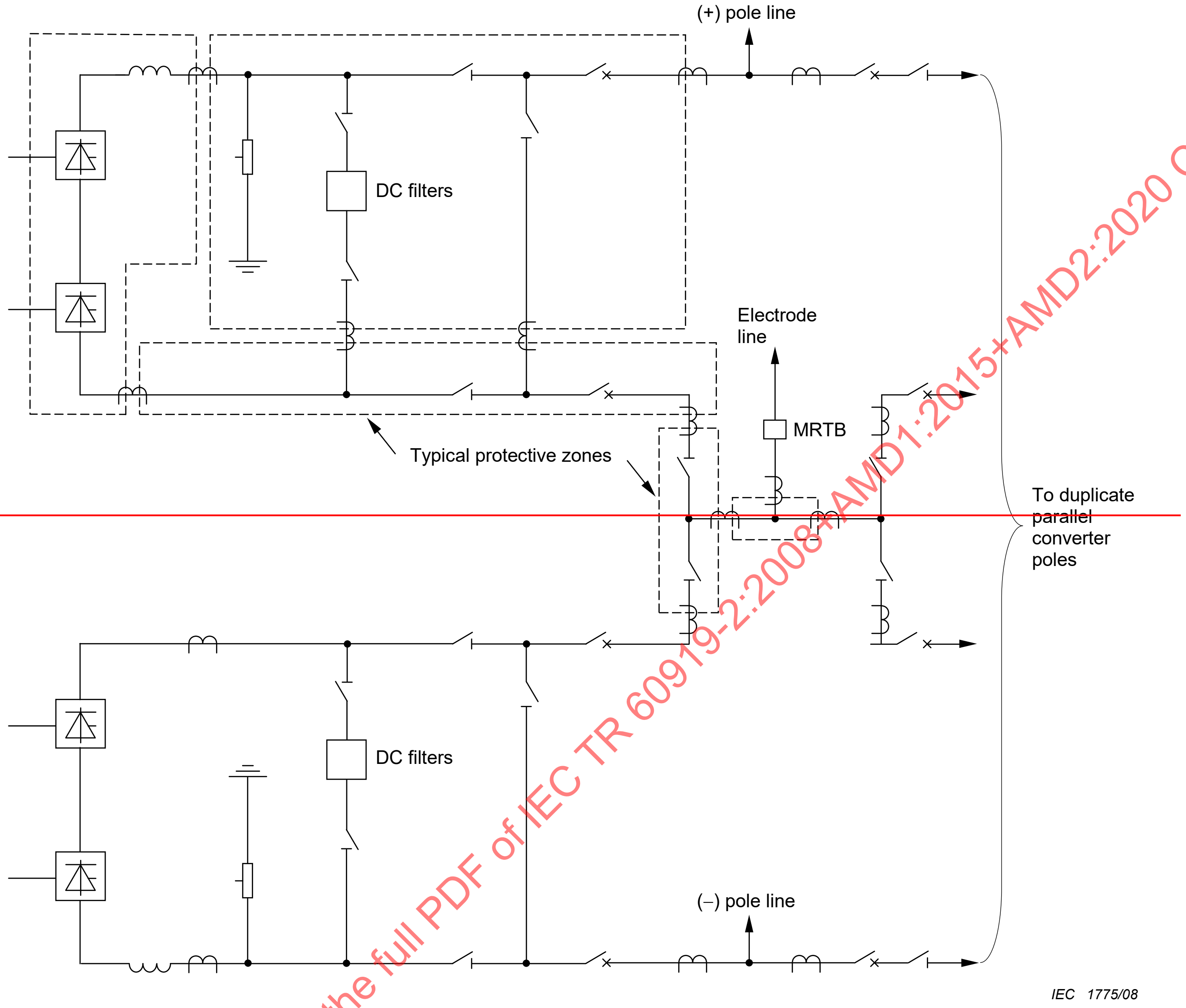


Figure 10 – Example of d.c. protection zones for series-connected converter units


(+) pole line
DC filters
Electrode
line
MRTB
Typical protective zones
To duplicate
parallel
converter
poles
DC filters
(–) pole line
IEC 1775/08

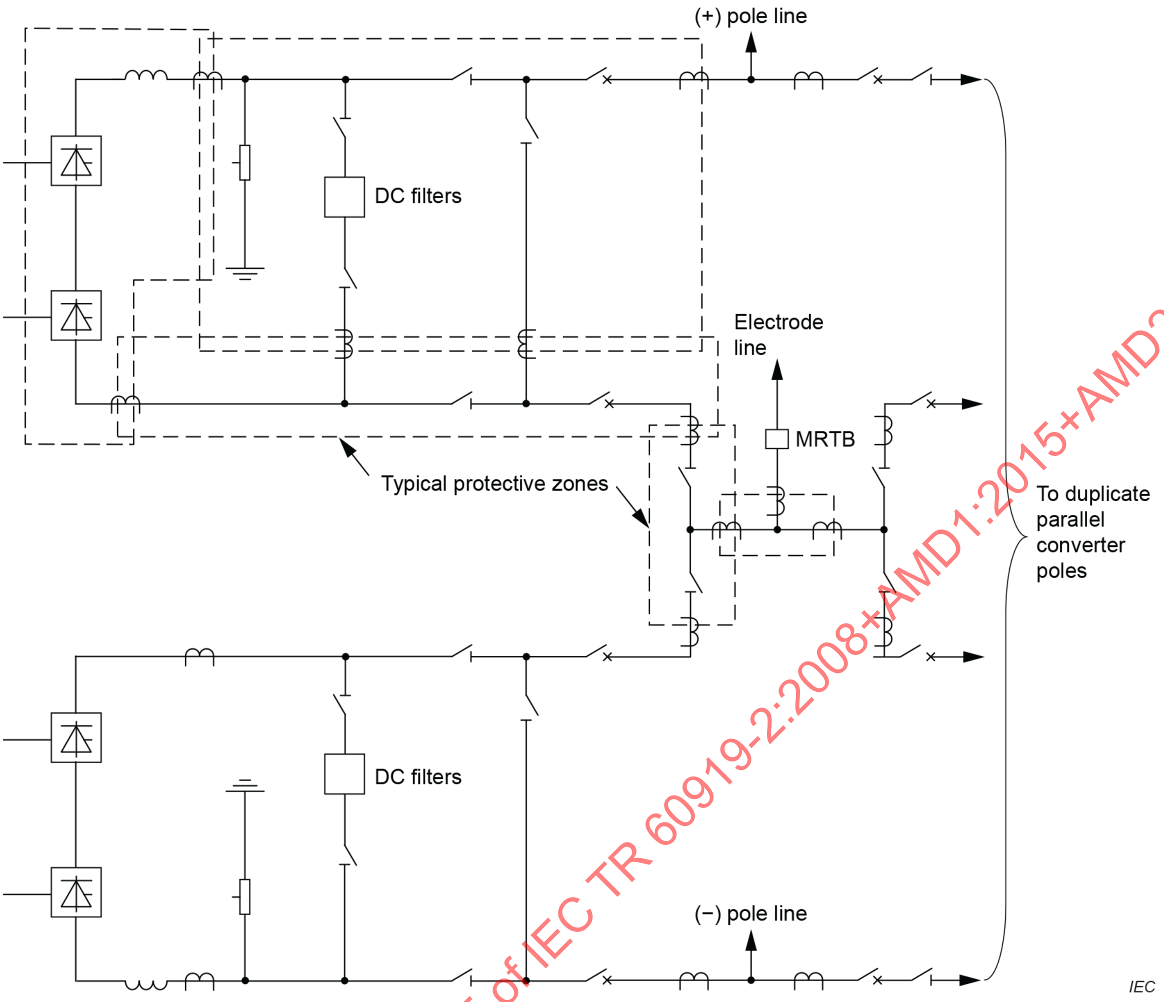


Figure 11 – Example of d.c. protection zones for parallel-connected converter pole

9 DC line faults

9.1 Overhead line faults

An overhead line, particularly if it is very long, may be a source of major disturbances in an HVDC transmission system. The most common fault on an overhead line is a flashover between a line pole and earth. If the line is bipolar the conductors of the two line poles are most often arranged at such a distance from each other that a flashover between poles is excluded for practical purposes.

Overhead line faults are mainly caused by:

– lightning strokes;
– contamination by: salt, industrial pollutants, sand and dust, etc.;
– overvoltages due to faults, control system malfunction, etc.;
– fallen towers;
– other: snow or ice damage, wind, bush fires, tree contacts, etc.

Most d.c. line faults are temporary, i.e. the insulation at the fault location is nearly always restored to its pre-fault level after the fault is cleared. Also since the d.c. fault current is relatively low, it does not usually cause appreciable damage to the conductors and insulators of the line. These considerations mean that in most cases faulted d.c. lines may be restored to service quickly.

For design of an overhead d.c. transmission line the insulation strength of the line against lightning, switching surges, and contamination is selected so that the probability of a single fault to earth is limited to an acceptably low level. Moreover the design should seek to prevent faults to earth due to overvoltages such as those which appear on the healthy pole during a pole-to-earth fault on the opposite pole or those resulting from commutation failure.

In addition to the above line design considerations, the magnitude of overvoltages due to commutation failure, complete loss of valve control pulses, or energization of a d.c. line with the remote terminal open can be limited by proper design of the control system.

The probability that a bipole outage will be caused by lightning or from a single pole-to-earth fault is low.

During d.c. line single pole-to-earth faults, power flow on the faulty pole is temporarily interrupted and a transient overvoltage appears on the healthy pole, d.c. filters, d.c. reactors and metallic return line or the earth electrode line.

The d.c. protection system should be designed and operated to reduce line outage times due to line faults to a minimum.

9.2 Cable faults

Underwater cable faults are the result of mechanical damage by anchoring and trawling, by degradation of cable insulation, or by unexpected overvoltages. Characteristically, cable faults are not self-healing so that a lengthy outage follows for cable repair or replacement.

If high reliability is expected to the HVDC system, laying spare cable is one of the choices for rapid recovery from cable fault.

Proper switchgear configuration around the cable heads will enable swift back up by the spare cable. Also, special consideration for faults should be paid if the system adopts coaxial cables, in which main and return conductors are coaxially arranged in one cable.

9.3 DC fault characteristics

In addition to being essentially unidirectional instead of sinusoidal as in a.c. systems, fault current in a d.c. line is caused to vary by control action in a quite different manner than for a.c. line faults. Initially the rectifier current increases and then after a short time is returned to the preset value or to a lower level as determined by the voltage dependent control action of the rectifier current controller or by other control action. The fault current will continue to flow until it is cleared by control action.

When a d.c. line fault occurs the d.c. voltage for the faulted pole or poles is reduced suddenly to a low level. On the line side of the d.c. reactor, the rate of change of the voltage, dv/dt, is larger than that produced by a commutation failure or by a d.c. bridge fault. These two phenomena, i.e. reduction in pole voltage to a low level and high dv/dt are important for d.c. line protection.

9.4 Functional d.c. fault detection requirements

DC line faults can be detected by utilizing the characteristics of the d.c. side currents and voltages. Detection systems should provide that:

– primary detection be fast;

– detection should be insensitive to normal transient operating conditions such as low voltage operations, system startup and shutdown, power reversal, etc.;
– detection should be insensitive to converter and a.c. system faults but can be actuated by d.c. bus faults;
– in a combined overhead line and cable system, means should be considered for identification of the faulted section;
– in a parallel transmission line system, fault detection should be selective so that the faulted line can be quickly identified.

Fault locators can be utilized to expedite inspection and maintenance of the faulted line.

9.5 Protective sequence

9.5.1 Overhead line faults

Those overhead line faults which are caused by lightning strokes are usually not permanent. When such a d.c. line fault is detected, the fault current is reduced to zero by control action. Inverter backfeed into the fault must be prevented by proper design of the inverter's control system. Figure 15b shows earth current flowing during pole conductor fault to earth.

Following the reduction to zero fault current, a dead time should be provided to allow for deionization of the fault path prior to re-application of voltage and restoration of the faulted line pole to service.

The required dead time is a function of fault current, system voltage, climatic conditions and type of system i.e. monopolar or bipolar. Typical dead time allowance on d.c. overhead transmission lines are in the range 100 ms to 500 ms.

If the first attempt at restart is unsuccessful, additional restart attempts can be made. If so, progressively longer dead times or restart at a lower d.c. voltage would be appropriate to enhance the possibility of a successful restart. The latter option would be particularly attractive if the line insulation is partially damaged at the fault location, or if polluted conditions of a section of the line will not permit operation of the line at full voltage and it is important to continue transmission of power even at reduced capacity.

9.5.2 Faults in cable systems

The cable insulation at the fault location is not self-healing or self-restoring after the fault has been cleared. The current in the faulted pole should be reduced to zero and the converters blocked for cable faults.

9.5.3 Faults in an overhead line/cable system

Identification of whether the fault is in the overhead or cable section of the line is needed only if restart attempts are not to be made for faults in the cable section.

9.5.4 Faults in one of a system of parallel-connected cables

When a fault is detected the faulted cable should be identified and the current in the faulted pole should be reduced to zero as quickly as possible. The faulty cable then should be disconnected and the system restarted using the remaining healthy cable(s).

If a d.c. circuit-breaker with enough current interruption and recovery voltage capability is used in each cable path, it is only necessary to open the d.c. circuit-breakers at both ends of the faulted cable without having to force the pole current to zero. Use of d.c. circuit-breakers in this manner can improve system restoration times.

9.5.5 Fault in a system of parallel overhead lines

The faulted overhead line should be identified and the current in the fault reduced to zero as described above. The restart sequence at full voltage should then be performed. If restart fails, the usual strategy is to leave the pole current at zero and disconnect the faulty line after which the d.c. system can after be restarted. If d.c. circuit-breakers with suitable relaying systems are utilized in each line, the faulted line can be disconnected without forcing the pole current to zero.

9.6 Fault protection schemes

Fault protection for d.c. lines is usually based on measurements of d*v*/d*t* and the d.c. voltage. The use of these two measurements means that usually there is no need for exchange of information between the two line terminals for fault detection and clearing and system restart. However telecommunication may be required between the two HVDC substations for some specific applications and fault conditions.

When a d.c. line fault takes place close to the inverter end, the d.c. voltage level protection at the rectifier end may not achieve line fault clearing as reliably or as quickly as required. Telecommunication from the inverter to the rectifier end may then be necessary to assure fast actuation of the retard function at the rectifier to reduce the current to zero and allow deionization of the fault path followed by re-energization of the faulted line.

Detection of high resistance d.c. line faults or the specified fault clearing times cannot always be achievable using the above protection schemes. In this event, some type of differential current detector arrangement may be needed. This would use telecommunication channels in both directions to allow comparison of the d.c. current at the rectifier and inverter ends of the d.c. line. An alternative approach might be to wait for the fault to develop into a low impedance fault which would then be detected by one of the first two methods described above.

The d.c. transmission line protection cannot always discriminate between blocking and bypassing of the inverter or d.c. line faults. To remedy this weakness and allow for proper discrimination a telecommunication channel from the inverter to the rectifier could be applied to inhibit the line fault protection when the inverter is blocked.

The d.c. transmission line protection, based on voltage level, can misoperate for faults on the a.c. side of the inverter or because of persistent inverter commutation failures. Again, a telecommunication channel may be needed between the inverter and the rectifier to allow the line fault protection to be inhibited under these conditions.

When two d.c. lines are operated in parallel and an automatic line switching sequence is used, telecommunication channels are normally required in both directions between the rectifier and inverter, in order to permit d.c. line isolation sequencing following a fault on one line. If d.c. circuit-breakers with full recovery voltage capability are used to switch the d.c. lines, telecommunication channels would no longer be necessary provided suitable relaying is available to identify the faulted line.

Similarly, telecommunication channels are normally required in both directions between the rectifier and inverter on a per pole basis, where automatic paralleling and deparalleling of poles is to be used after a permanent fault on one of the d.c. lines.

9.7 Open circuit on the d.c. side

Overvoltage may result if a rectifier is started into an open-circuited d.c. pole or a blocked inverter unless appropriate control action is included in the design.

When a restart attempt is made into an open-circuited earth electrode line or neutral conductor the current will be forced through a neutral arrester. Inadvertent opening of the neutral bus switching device also can have the same result. High speed arrester shorting switches can be used to protect this arrester. Provision should be made in the protection system for the detection of these conditions.

9.8 Power line cross protection

When d.c. and a.c. transmission lines cross over one another, there is a risk that the two may come in contact due to collapse of a transmission tower or broken suspension insulators, for example. This undesirable condition is detected by several protections in the HVDC system, normally applied for other purposes. The fastest is d.c. line fault detection, others are d.c. undervoltage detection, and fundamental frequency detection. These block the HVDC but can leave the d.c. conductor energized from the a.c. line. AC line protections may not operate for this condition because of the relatively low current in the fault. Therefore, usually it will be desirable to trip the a.c. line from the appropriate HVDC protection relays.

10 Earth electrode line faults

10.1 General

The earth electrode line is an important part of a d.c. transmission system. It is common to both poles and a fault on the electrode line could seriously influence the HVDC bipole availability. If monopolar operation with earth return is required, the earth electrode line is an essential item of the HVDC transmission system.

The electrode line can be constructed using the d.c. line structures either to support its conductor(s) or by using the conductor to serve as a shield wire. In the latter case, it should be insulated. A technically superior alternative is to build an entirely separate electrode line, as uncoupled as possible from the main d.c. transmission line.

10.2 Specific requirements – Earth electrode line

The electrode line design should minimize the occurrence of permanent faults. In support of this design objective, the following practices are desirable:

– to avoid permanent faults on the electrode line its insulation should be designed so that transient faults resulting from direct or induced lightning surges will tend to be self-extinguishing;

– there should be no flashover across the electrode line insulation under the voltages induced on the earth electrode line during faults on the main d.c. line;

– if it is impossible or impractical to avoid these flashovers, flashover arcs should self-extinguish;

– if the electrode line is constructed separate from the main d.c. line, the risk of insulation flashover is minimized; in any case, arcing horns can be effective in achieving arc self-extinguishment;

– the mechanical design should avoid the possibility of an open circuit in the earth electrode line; one way to achieve this objective would be to use two parallel conductors each supported by an independent insulator string; this will diminish the possibility of an open circuit and offers opportunity to monitor the line by means of a transversal differential protective scheme for comparing the currents in the two conductors for detection of electrode line faults or an open conductor (one of the two conductors);

– the earthing resistance of the electrode line structures should be low for best lightning performance and easier fault detection. However to achieve arc self-extinguishment the tower footing resistance should not be too low, bearing in mind that this may impinge on safety.

10.3 Electrode line supervision

For safety reasons provision may have to be made to recognize a permanently faulted or open earth electrode line. Such a system could give an alarm or order a blocking sequence for the bipole involved. For transient or temporary faults usually no action from the alarm and monitoring will be required.

Implementation of such a supervision system can be based on an impedance monitoring principle either by using the d.c. current, or by additional means. It should be borne in mind that using the direct current is feasible only if the HVDC system operates with unbalanced d.c. pole current. Other methods have been proposed to overcome this problem.

11 Metallic return conductor faults

11.1 Conductor for the return circuit

If metallic return is used during monopolar operation of a bipolar HVDC transmission either a low voltage dedicated conductor (Figure 12), which can be the HVDC line shield wire appropriately insulated, or a high voltage conductor of the other pole, which is temporarily out of service, can be used for the return circuit (Figure 13).

The insulation level for the dedicated conductor can be low as it is normally stressed only by the line voltage drop. Switching devices should be provided to transfer the circuit from earth return to metallic return and vice versa when the pole conductor is used for the metallic return. Requirements for the switching devices would depend mainly on whether the transfers are to be executed on-load or off-load.

11.2 Metallic return faults

Conductor faults on the return circuit will have similar causes to those described in Clause 9. When using a low voltage insulated conductor the number of earth fault occasions can be expected to be large because even an induced lightning surge can break down the lower level insulation. On the other hand the number of flashovers should be much smaller when using the pole conductor for metallic return because of its inherently greater insulation.

Fault current will be distributed in the different return paths in inverse proportion to their resistances as determined by the following factors:

– earth fault location on the line;
– arc resistance;
– soil resistivity;
– tower footing resistance;
– resistance to remote earth at the earthing end (station ground mat or the earth electrode).

If the station ground mat is used for the main d.c. circuit earthing during metallic return operations, a portion of the direct current from earth faults can flow into the a.c. system through power transformer earthed neutrals (see Figure 14).

Protective relays in the a.c. system then may malfunction due to saturation effects in the power transformers and in the current transformers when the direct current flowing into the a.c. system is large enough and sustained. Therefore it is particularly important that any metallic return earth faults be cleared rapidly to mitigate this problem.

On low voltage return circuit conductors, arcing horns capable of clearing earth faults by self-extinguishing or other equally effective means should be provided so that arc damage to the conductor and insulators will be minimal.

An open circuit return conductor fault can cause severe overvoltage at the floating end. A protective relay which will detect this fault as for the electrode line shall be provided for the return circuit together with overvoltage protection.

11.3 Fault detection – Metallic return

During balanced bipolar operation, faults on metallic return conductors are difficult to detect because of the resulting small changes in voltage and current in the main circuits.

However in monopolar or unbalanced bipolar operation a metallic return conductor fault can be detected through changes in current, which can be used for fault sensing. For example, the direct current will flow into the earthing point of the main circuit and the current in the metallic return conductor can be expected to decrease.

Metallic return fault detection examples are illustrated in the following schemes:

– to detect a larger current in the main circuit than in the return circuit (see Figure 15a);

– to detect direct current at the grounding point of the main circuit (see Figure 15b);

– to detect change in alternating current signal superimposed on the return circuit by the a.c. auxiliary power source (see Figure 16).

NOTE It is important to avoid instability on the d.c. circuit, the frequency of superimposed signal should be detuned from harmonics of fundamental frequency.

To shorten the expedited inspection and maintenance time after the faults, a fault locator on the return circuit would be highly desirable. For example, 125 Hz for 50 Hz system and 150 Hz for 60 Hz system can be used.

Detection of an open circuit return conductor should also be considered in the protection scheme.

11.4 Metallic return fault protection systems

Usually, during balanced bipolar operations it is not necessary to initiate protective sequences for metallic return conductor faults as all of them except permanent and open-circuit faults can be cleared by self-extinguishing actions.

However in monopolar and unbalanced bipolar operations, fault clearing by the main d.c. line protection can be required. Under these modes of operation metallic return fault currents can persist for some time (up to 0,5 s), depending on the location of the fault, its current and gap length and wind conditions. Faults near the earthing point can be expected to extinguish rapidly while remote faults will take longer. The self-extinguishing capability of arcing horns becomes more difficult for those faults more distant from the earthed end.

An alternative protection against undesirable long lasting arcs and repeated block-restarts due to frequent faults on the metallic return conductor as can often occur on a low voltage insulated conductor might be considered should the need arise:

– Extinguishing of the arc at a fault without blocking of the converters can be accomplished by closing the d.c. circuit-breaker (MRTB or NBGS) installed at the floating end for a short time so that the main circuit is earthed at both ends (see Figure 17). After the arc quenching, the d.c. circuit-breaker is opened in order to restore d.c. current flowing from earth to metallic conductor.

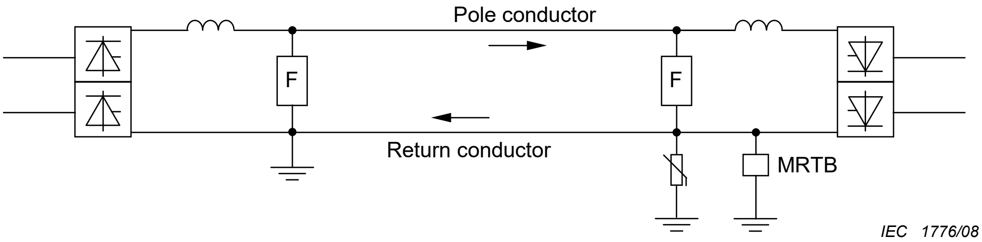


Figure 12 – Monopolar metallic return system showing metallic return transfer breaker (MRTB)

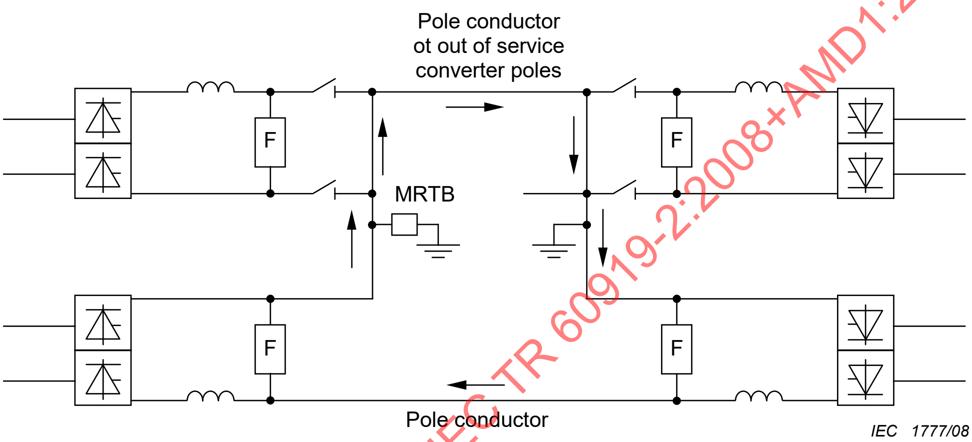


Figure 13 – Monopolar operation of a bipolar system during converter pole outages

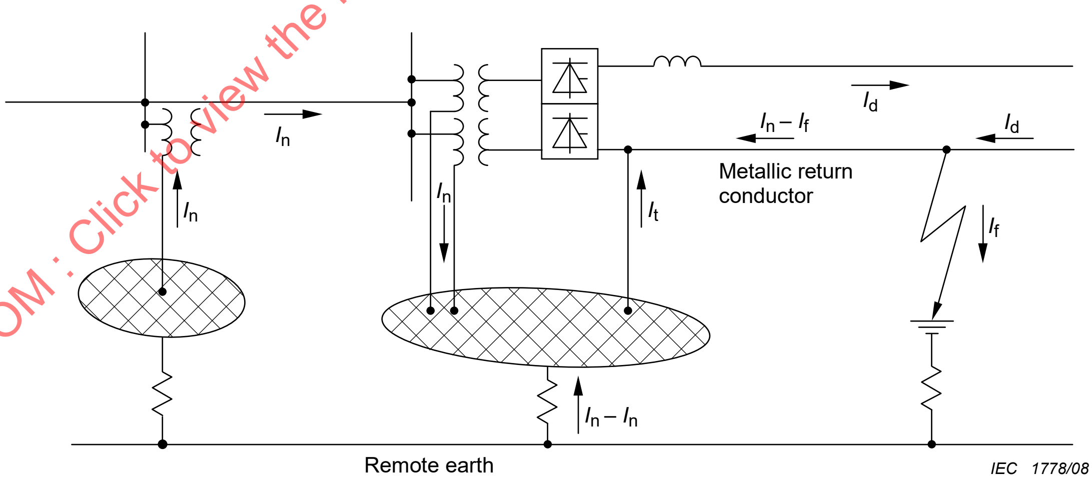


Figure 14 – DC current flowing into an a.c. system during a fault on a metallic return conductor when the HVDC substation mat is used for grounding of the d.c. circuit

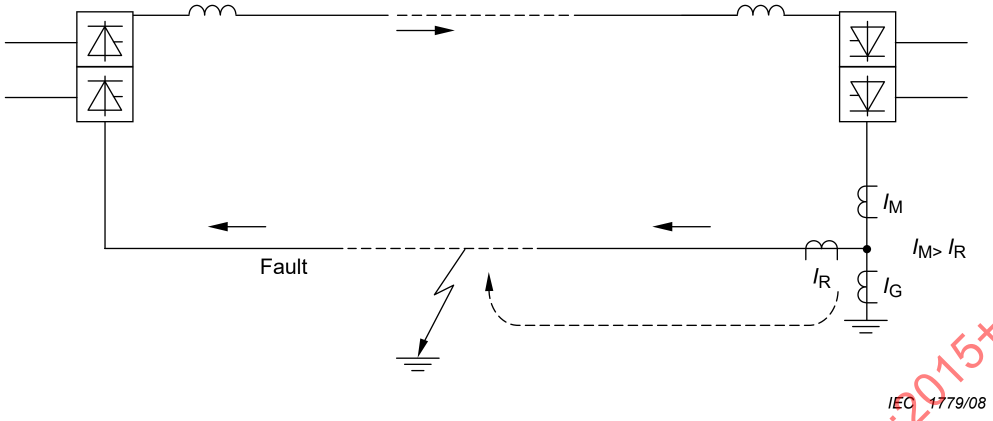
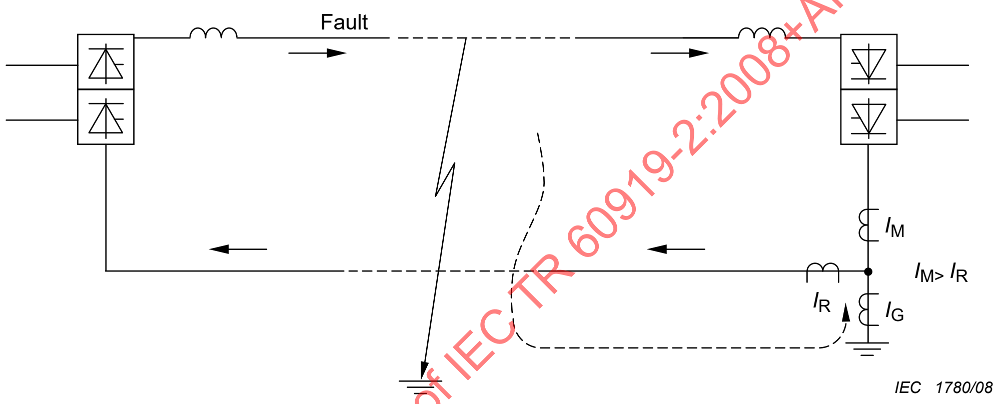


Figure 15a – Metallic return conductor fault to earth



I_M current in ~~main~~ pole conductor

I_R current in return conductor

Figure 15b – ~~Main~~ Pole conductor fault to earth

Figure 15 – Earth current flowing during line faults

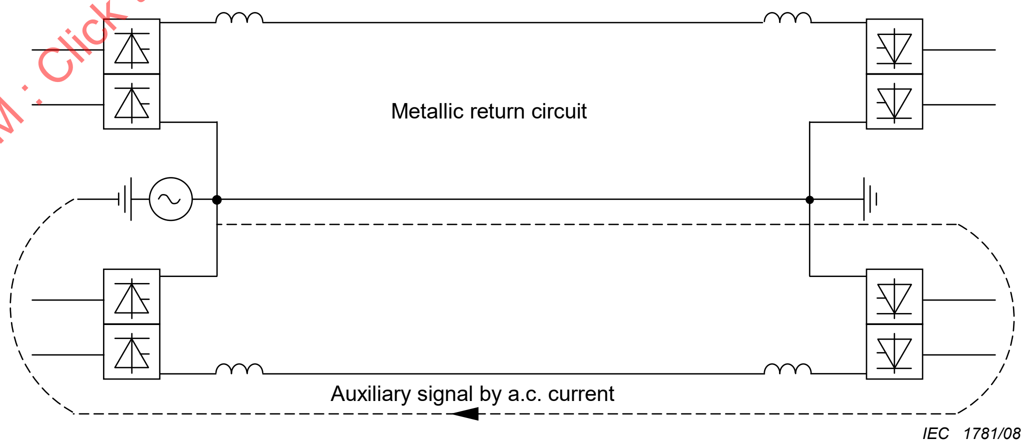


Figure 16 – Example of metallic return fault detection system by means of auxiliary a.c. signal

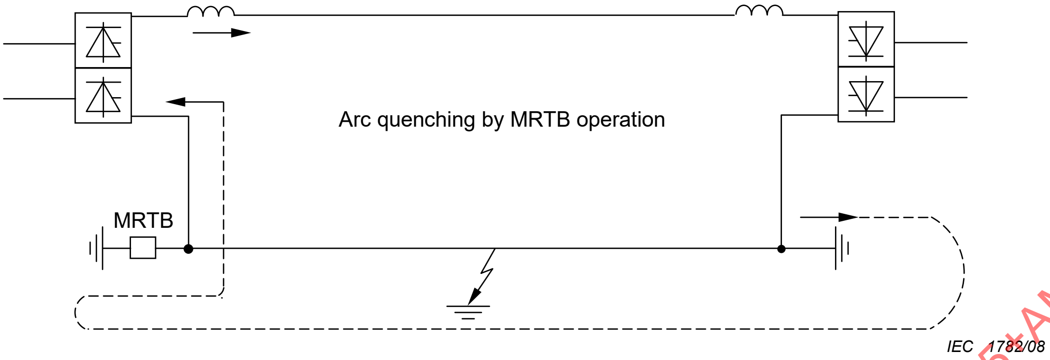


Figure 17 – Example of use of MRTB to quench fault to earth on metallic return conductor

12 Insulation co-ordination – HVDC systems

12.1 General

HVDC substation equipment should be designed to withstand without damage overvoltages that may result from events in the a.c. system or the d.c. line or from malfunctions of the converter equipment.

Insulation co-ordination of an HVDC substation differs from that of a normal a.c. substation, primarily in the need to consider the requirements of series connected equipment involving arresters connected between terminals away from earth potential, and in the use of different insulation levels for different parts of the substation.

The characteristics of the converter valves, including the control of their firing instants, and the installation of very large filters on both the a.c. and d.c. sides are important factors in the generation of overvoltages.

Overvoltages in an HVDC substation may originate from either the a.c. system or from the d.c. line or cable, or from in-station faults. The nature of the a.c. and d.c. systems shall be taken into account as well as the transient and dynamic performance of the valves and the controls and worst case combinations shall be evaluated when studying overvoltages.

12.2 Protection schemes using surge arresters

Only gapless metal-oxide surge arresters are considered in this report for overvoltage protection of HVDC substations. Figure 18 shows an arrester protection scheme for an HVDC substation connected to an overhead d.c. line. Figure 19 shows a similar scheme for protection of a back-to-back substation. Figure 20 shows an arrester scheme for protection of a series capacitor compensated HVDC substation. Figure 21 illustrates arrester protection on the a.c. side including a.c. filter arresters. Figure 22 shows an arrester protection scheme for an HVDC substation with series-connected converters.

The arrester scheme for a series capacitor compensated HVDC substation, including capacitor commutated converter (CCC) and controlled series capacitor converter (CSCC), ~~are~~ is similar with that used for traditional HVDC substation except for the series capacitors which are protected directly by arresters connected in paralleling with them.

For ultra high voltage direct current (UHVDC) substation with series-connected converters, arresters (A_2) ~~will~~ may be installed to protect the valve side winding of the converter transformers located at the upper side (Figure 22). The smoothing reactor is separated into two parts and installed at pole bus and neutral bus respectively per pole at each station. This configuration decreases the overvoltage at transient condition and also decreases the cost for smoothing reactor.

The arresters connected across the valves and on the d.c. side are subjected to different combinations of direct and alternating voltages, to harmonic voltages and to commutation overshoots. They shall be designed to withstand the resulting stresses.

Arrester requirements shall often be determined through an iterative procedure. Energy absorption requirements imposed on the arrester determine its size and characteristics. These in turn affect the overvoltage level and arrester discharge currents. Arrester stresses are discussed further in 12.7.

For detailed specification of arresters in the HVDC system, intensive simulation study could be carried out.

12.3 Switching overvoltages and temporary overvoltages on the a.c. side

Switching overvoltages and temporary overvoltages (see definition in IEC 60071-1) occurring on the a.c. side are important to the study of arrester applications. They determine the overvoltage protection and insulation levels of the a.c. side of the HVDC substation. They also influence valve insulation co-ordination.

For the special case of disconnectors located between the converter transformers and the converter bridge, protection of the converter transformer valve windings shall be provided when these disconnectors are in an open position.

Overvoltages discussed in this subclause are generated by the a.c. side switching operations and fault events described in Clauses 4 and 5 of this report.

12.4 Switching overvoltages and temporary overvoltages on the d.c. side

~~Except for~~ Besides the a.c. side overvoltages transmitted through the converter transformers, the d.c. side insulation co-ordination for switching overvoltages and temporary overvoltages is mainly determined by fault and switching generated overvoltages on the d.c. side.

Events that shall be considered are d.c. line-to-earth faults, d.c. side switching operations, events resulting in an open earth electrode line, generation of superimposed a.c. voltages due to faults in the converter control, misfiring, commutation failures, and earth faults and short-circuits within the converter unit.

In systems involving a combination of d.c. cables and overhead lines, arresters may be needed at the cable terminations to protect them from overvoltages.

12.5 Lightning and steep fronted surges

The different sections of HVDC substations shall be examined in different ways for lightning surges. The sections are:

– a.c. switchyard section from the a.c. line entrance up to the line side terminals of the converter transformers;
– d.c. switchyard section from the line entrance up to the line side terminal of the smoothing reactor;
– converter bridge section between the valve side terminals of the converter transformers and the valve side terminal of the smoothing reactor.

The converter bridge section is separated from the other two sections by series reactances, i.e., at the one end inductance of the smoothing reactor and at the other end, the leakage reactance of the converter transformers. Travelling waves such as those caused by lightning strokes on the a.c. side of the transformer or on the d.c. line outside of the smoothing reactor are attenuated by the combination of series reactance and earth capacitance to a shape similar to switching surges. Consequently they should be considered as part of the switching surge co-ordination.

The a.c. and d.c. switchyard sections have low impedance compared with overhead lines. The differences from most conventional a.c. switchyards are from the presence of a.c. filters, d.c. filters and possibly large shunt capacitor banks, all of which may have attenuating effect.

Steep-fronted surges, other than those caused by lightning, shall also be considered in the equipment design and testing as well as for insulation co-ordination. Such surges, caused by earth faults in the HVDC substation, are important for insulation co-ordination of the valves. These surges typically have a front time of the order 0,5 µs to 1,0 µs and durations up to 10 µs. The values and waveshapes to be specified ~~should~~ can be determined by digital simulation studies.

In the a.c. switchyard section, steep fronted surges with front times of 5 ns to 150 ns may also be initiated by operation of disconnectors in gas-insulated switchgear. Also in the operation of SF_6 power circuit breakers, steep front overvoltages with front times of some tens of nanoseconds can appear.

12.6 Protective margins

Conventional procedures for insulation co-ordination are generally applied for insulation in HVDC substations. Alternatively, a statistical procedure can be used for self-restoring insulation.

In the conventional procedure, the maximum overvoltage to be expected at a specific location is established, based on the characteristics of the overvoltages and the protective devices (the surge arresters).

The maximum current through a surge arrester should be established through a digital computer or an HVDC simulator study. The maximum current or a higher value is defined as the co-ordinating current. The voltage across the arrester that corresponds to this current is the protection level. In the case of switching overvoltage it is referred to as the switching impulse protective level (SIPL). The corresponding quantity for lightning overvoltages is called the lightning impulse protective level (LIPL).

The maximum overvoltage on the equipment is given by the protective level of the arrester or the arrester combination across the equipment, including the influence of the connections between the equipment, the arresters, and the earth.

When the maximum overvoltages have been determined, the corresponding insulation levels, i.e., the switching impulse withstand voltage (SIWV) and the lightning impulse withstand voltage (LIWV) as defined in IEC 60071-1 can be established for the equipment to be protected by the surge arresters, taking into account protective margins.

Different from a.c. substation, it is not necessary to upward rounded off the insulation levels (SIWV, LIWV) to the standard values for HVDC equipment.

The protective margin can be expressed as:

$$\text{Margin} = (\text{safety factor} - 1) \times 100\ \%$$

where the safety factor is defined in IEC 60071-1 as:

$$\text{Safety factor} = \frac{\text{Switching or lightning impulse withstand voltage}}{\text{Maximum overvoltage}}$$

Practice on a.c. systems provides one basis for selecting margins, and the extensive successful experience on existing HVDC systems provides additional data for establishment of criteria for selecting margins. Also the use of metal oxide surge arresters results in more consistent protective levels than was possible with prior arrester technology.

For switching impulse surges, a 15 % margin for the valves has been widely used. However for certain specific applications a 10 % margin has been used.

For lightning impulse surges a 15 % to 20 % margin has been widely used for the valves. Protection of other equipment should apply a 15 % to 20 % margin for switching impulse surges and a 20 % to 25 % margin for lightning impulse surges. Use of these margins in past practice has resulted in successful experience.

For steep front surges with front time less than or equal to 0,5 µs a 20 % to 25 % margin over the maximum overvoltage level is appropriate for valves as well as other equipment. Penetration into the valves of extremely steep front surges should be avoided.

The major reasons for selection of a lower margin or safety factor for the valves than for other equipment are that the valves are usually protected by surge arresters directly connected across them and the ageing process for thyristor valves is different from that of conventional power equipment such as power transformers, because failed thyristors are replaced at the times of regular service inspections. The valves shall be designed such that other insulation than thyristors has higher withstand strength and therefore automatically provides higher margins.

Required levels of protective margins described above should be specified.

12.7 Arrester duties

Figures 18 to 22 should be referred for all arrester designations in this clause.

12.7.1 AC bus arresters (A_1, A_2 and A_3)

The a.c. side of an HVDC substation will usually be protected by arresters at the converter transformers (A_1) and depending on the station configuration at other locations (A_3). For UHVDC substation with series-connected converters, arresters (A_2) ~~will~~ may be installed to protect the valve side of the converter transformers located at the upper side (Figure 22). These arresters are designed according to the criteria for conventional a.c. applications considering network earthing and lightning, switching, and temporary overvoltages. Because of possible saturation of the converter transformers and low frequency resonances between the filters and the a.c. system, in particular at clearing of faults, high overvoltages of long duration may appear. The arresters may then need to be designed for high current and high energy dissipation.

12.7.2 Arrester across filter reactors (FA)

The events to be considered with respect to filter arrester duties are switching and temporary overvoltages on the a.c. bus and discharge of the filter capacitor through the arrester during earth faults on the filter bus. The former determines the required SIPL and the latter the LIPL and the energy discharge requirement. In certain cases, high energy discharge duties may also result from conditions of low order harmonic resonance, or due to low order non-characteristic harmonics generated by unbalanced operation during a.c. system faults (see 5.3.7).

12.7.3 Valve arresters (V)

The events to be considered with respect to valve arrester duties are:

– limitation of switching surge voltages and temporary overvoltages transmitted from the a.c. side;
– discharge of the d.c. line, d.c. filter, and valve hall capacitances during an earth fault between the converter bridge and the high potential converter transformer;
– current extinction in only one commutating group;
– discharge of lightning surges resulting from shielding failures.

The first three types of events determine the arrester stresses of switching surge type. These often lead to high energy absorption capability requirements for the arresters.

The level of forward protective firing of the valves shall be co-ordinated with the protective characteristics of the arresters. When the level of the forward protective firing of the valves shall be greater than the protective characteristics of the arresters, this should be specified.

In the case of parallel connected converter units in rectifier operation, an earth fault between the converter bridge and the high potential converter transformer will impose additional energy absorption requirements on the affected arresters because of the fault currents fed from the parallel connected converter unit.

Valves should be designed to withstand the expected maximum current commutated from the directly parallel connected arresters when the valves turn on during the arrester discharging.

12.7.4 Mid-point d.c. bus arrester (M)

Application of a mid-point d.c. bus arrester is sometimes used to reduce the insulation level requirements on the valve side of the converter transformers.

Its duties are determined by current extinction in the lower six-pulse bridge and by lightning surges resulting from shielding failures. Data for this arrester are of the same order of magnitude as those for the valve arresters.

12.7.5 Converter unit d.c. bus arresters (CB) and converter unit arresters

The high voltage converter unit bus can be directly protected by a converter unit d.c. bus arrester connected between the bus and earth, see Figure 18, arrester CB. For series connected converter units as shown in Figure 22, usually a combination of a converter unit arrester, arrester C, connected between the d.c. terminals of the high voltage converter unit and a converter unit d.c. bus arrester CB2 for the low voltage converter unit is used.

Since the protection levels of both the converter unit d.c. bus arrester and the converter unit arrester are of the order of twice the nominal d.c. voltage, these arresters will normally not be exposed to high discharge currents from switching surges. Their characteristics are determined from the steady-state d.c. voltage levels. In the case of series connected converter units an additional requirement on arresters E_1 and E_2 is the discharge of the d.c. line when one converter unit is short-circuited.

12.7.6 DC bus and d.c. line arresters (DB and DL)

The characteristics of the d.c. bus and d.c. line arresters are determined from consideration of the maximum operating voltage as well as lightning and switching surges. The d.c. bus arrester DB determines the insulation level of the d.c. pole equipment. On HVDC systems incorporating cables, the protective levels of the d.c. line arrester DL may have to be selected based on consideration of the cable withstand characteristics.

When the HVDC line comprises overhead line sections as well as cable sections, consideration should be given to the application of surge arresters at the cable-overhead line junctions to prevent excessive overvoltages on the cable due to reflection of travelling waves.

12.7.7 Neutral bus arresters (E_1 and E_2)

The operating voltage for the neutral bus arresters is normally low. At balanced bipolar operation it will be practically zero. During monopolar operation it will consist mainly of a small d.c. voltage corresponding to the voltage drop in the electrode line or the metallic return conductor.

These arresters are provided to protect equipment from lightning surges entering the neutral bus and to discharge large energies during the following events:

– earth fault on the d.c. pole;
– earth fault between the valves and converter transformer;
– loss of return path during monopolar operation.

Their energy requirements will depend largely on the sequences to clear these faults.

12.7.8 DC reactor arrester (R)

An arrester can be connected in parallel with the d.c. reactor to protect it from subtractive lightning impulses that could otherwise impose excessive overvoltages across the reactor. Its use permits a reduction in the insulation requirements across the reactor winding.

12.7.9 DC filter arresters (FD)

The normal operating voltage of the d.c. filter reactor arrester is low and usually consists of one or more harmonic voltages. Arrester duties are determined mainly by transients resulting from earth faults on the d.c. pole.

12.8 Prevention of protective relay action due to arrester currents

Arrester currents may need to be taken into account when designing the relay protection for HVDC substations. In some cases arresters which carry large discharge currents, as for example the high energy neutral bus arresters, can be located within a differential protection zone. If so, such arrester currents may need to be measured and fed to the protection to avoid unwanted relay operations during events outside the protective relay zone which initiate arrester discharge currents.

12.9 Insulation clearances

Air clearances for outdoor insulation are in general based on the SIWV specified using normal correction factors due to electrode shapes.

Inside the valve buildings great care should be taken to achieve electrode shapes that minimize required clearance distances. Distances used are normally based on tests with the appropriate electrode shape. Inside the valve halls, distances are normally determined so as to achieve a 0,1 % flashover probability.

12.10 Creepage distances for the insulation

12.10.1 Outdoor insulation

The external insulation of outdoor insulators and bushings is determined mainly by its performance under polluted conditions at normal operating voltage. Insulators subjected to d.c. voltage perform differently than those subjected to a.c. voltage. DC insulators tend to become more polluted than a.c. insulators located in the same substation because the d.c. insulators attract charged particles.

Depending on the pollution level, insulator d.c. withstand voltage under polluted conditions is generally lower than the r.m.s. a.c. withstand voltage. The d.c. withstand voltage also seems to be more dependent on insulator shape.

Specific creepage distances in the range of 2,5 cm/kV to 4,6 cm/kV have been used for areas with light to medium pollution. For regions of heavy pollution, creepage values of 4,8 cm/kV and higher have been specified.

Operators of many HVDC installations have found it necessary to use insulator washing, greasing, or application of other coatings to the insulators to improve flashover performance. Also, application of polymer type insulator could be one of the choices besides to above counter measure to the pollution.

Knowledge of station insulator performance under d.c. voltage stress and polluted conditions is limited. Further investigations are needed to establish reliable guidelines for determination of creepage distances.

12.10.2 Indoor insulation

Inside the valve halls except the thyristor valves a minimum specific creepage distance of 1,4 cm/kV to 1,6 cm/kV of nominal d.c. voltage has been widely used. The environment is clean and the humidity is controlled. Creepage distance is therefore not a major consideration.

It should be emphasized that keeping the valve hall environment is very important and the humidity and pollution levels should be controlled within limits.

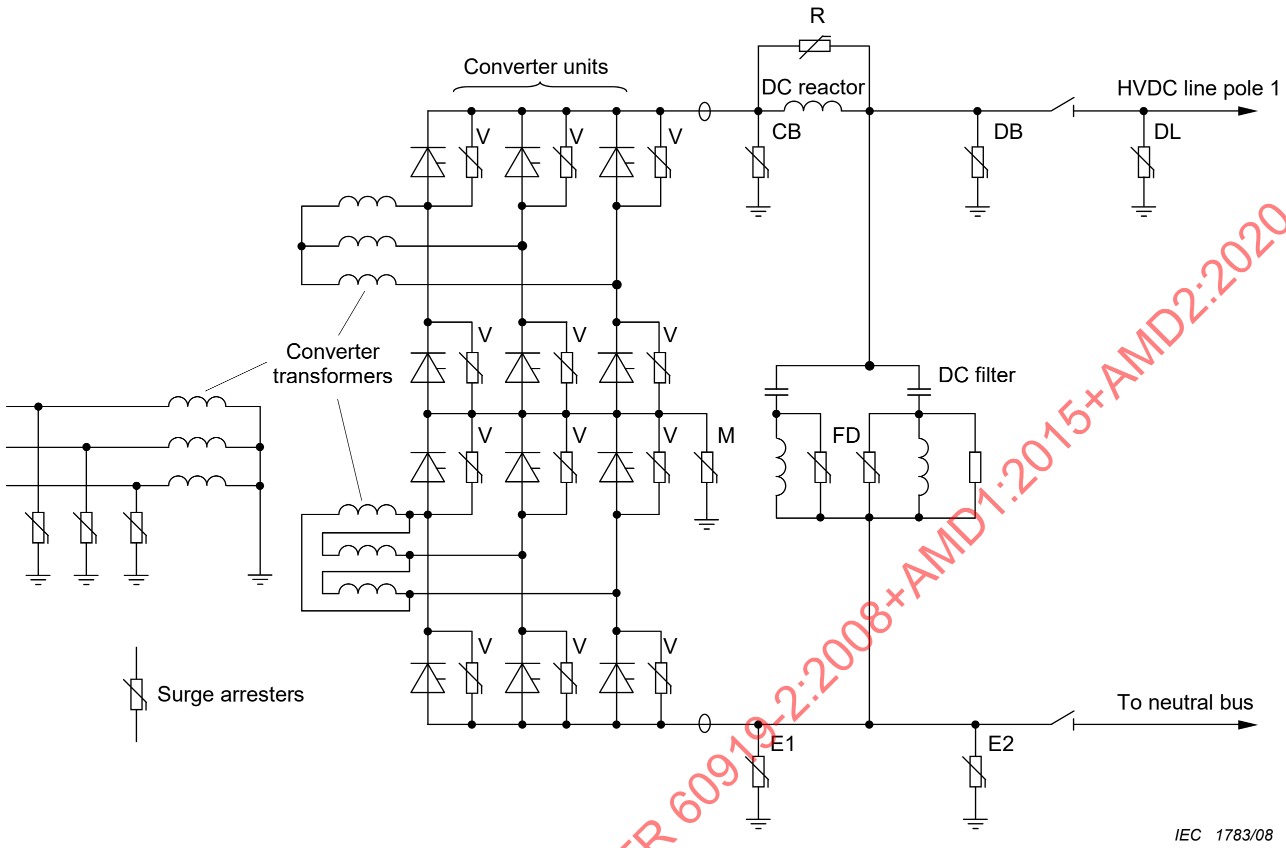


Figure 18 – Example of an arrester protection schene for an HVDC substation

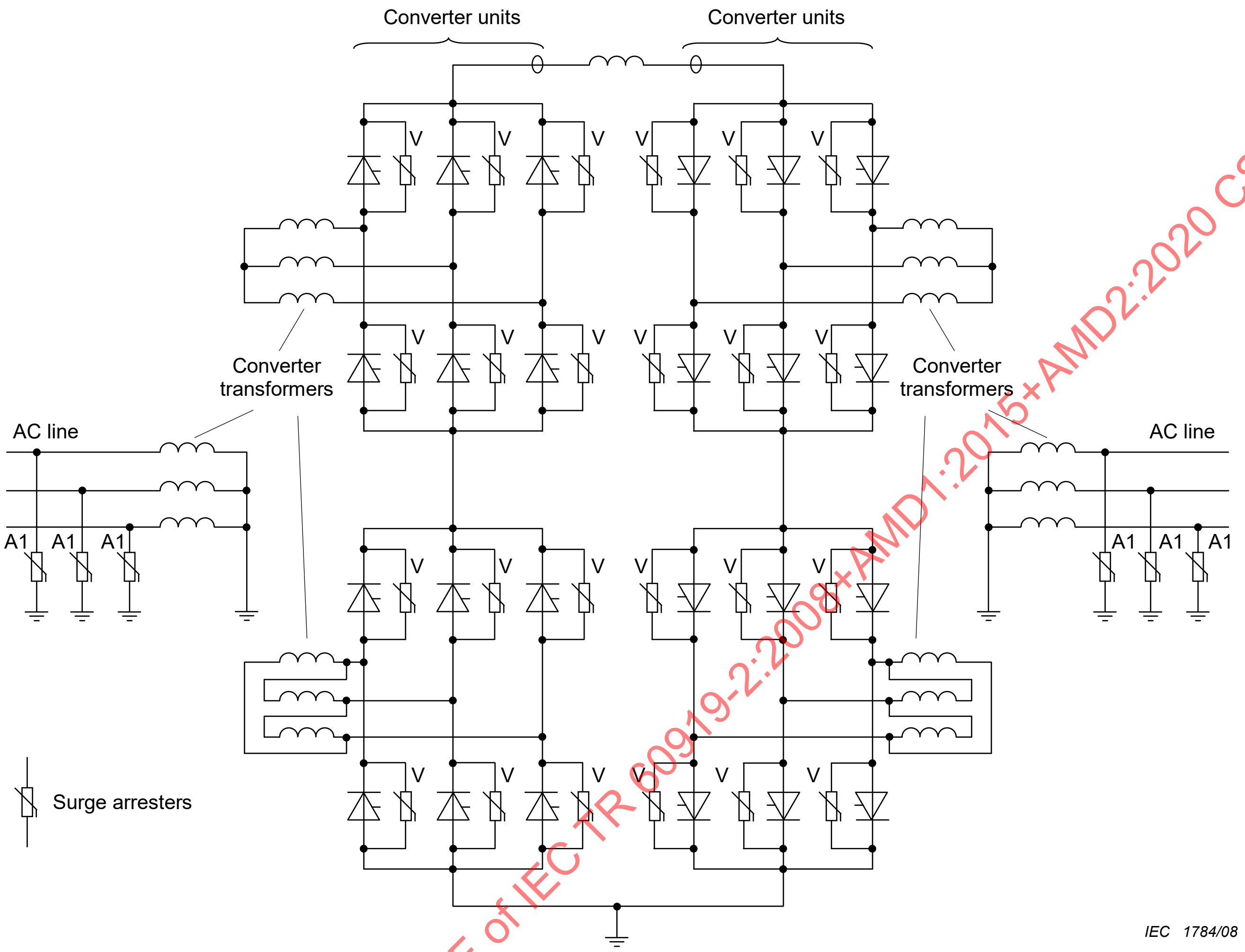


Figure 19 – Example of a d.c. arrester protection scheme for a back to back HVDC substation

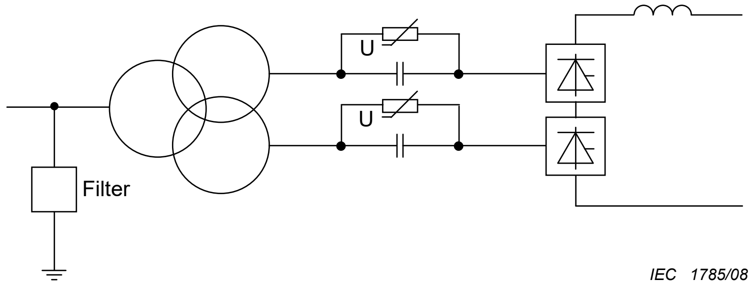


Figure 20a – Capacitor coupled converter (CCC)

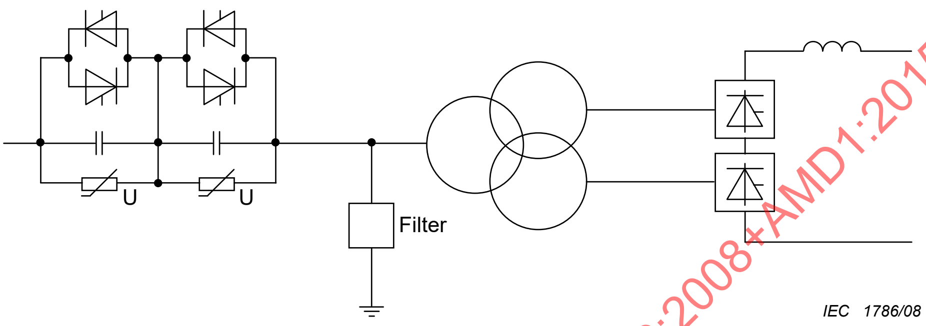


Figure 20b – Controlled series capacitor converter (CSCC)

Figure 20 –Example of an arrester protection arrangement for a capacitor commutated converter HVDC substation

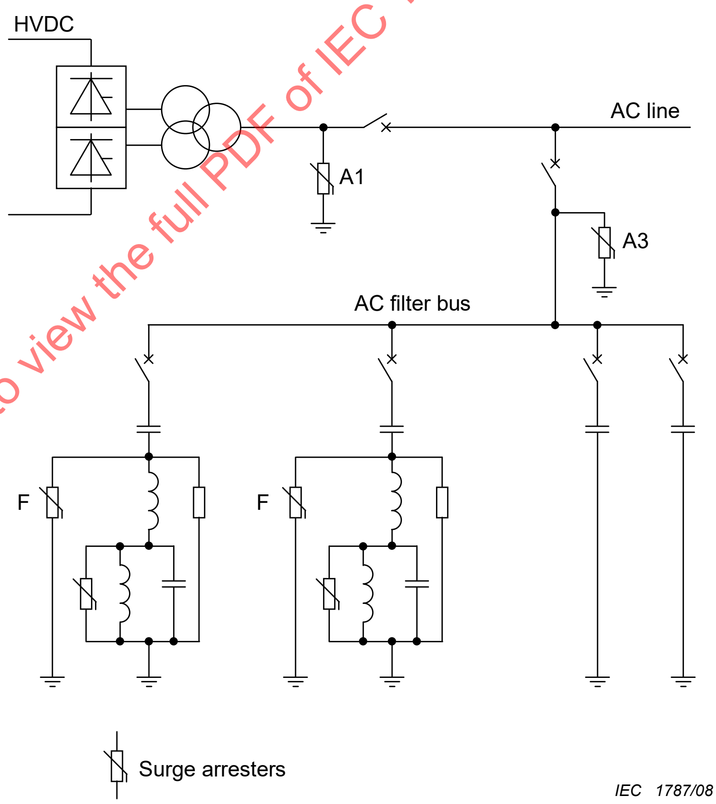


Figure 21 – Example of an a.c. arrester protection arrangement for an HVDC substation

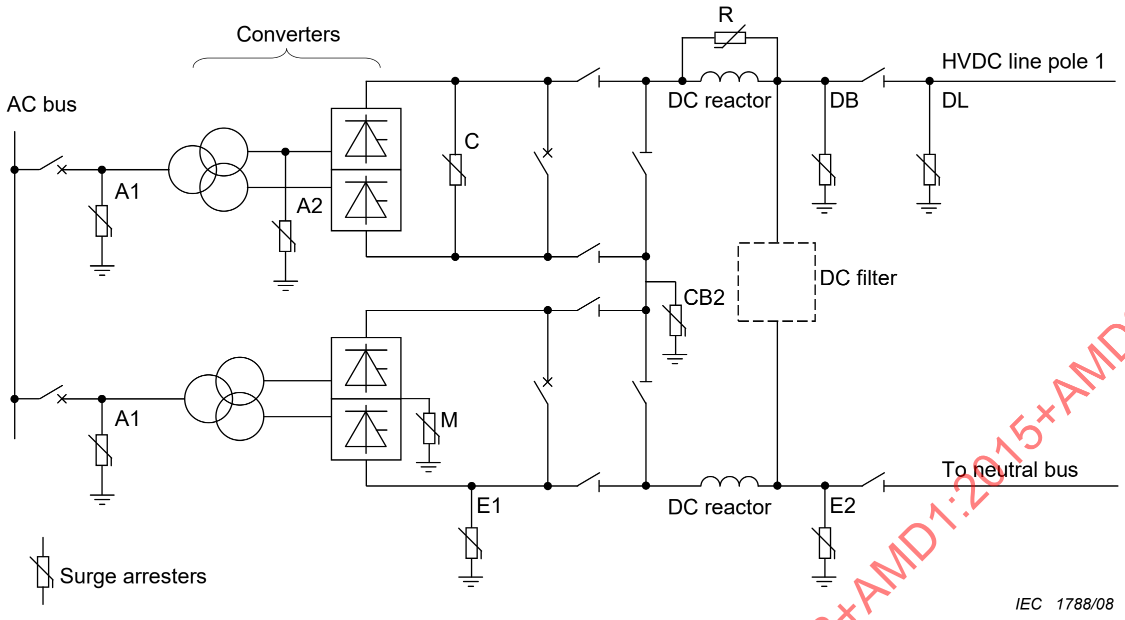


Figure 22 – Example of an arrester protection scheme in a HVDC substation with series-connected converters

13 Telecommunication requirements

13.1 General

As indicated in IEC 60919-1, different types of telecommunication can be used for the operation of an HVDC transmission link.

A main function of telecommunication in the operation of an HVDC link is to transmit control messages such as current or power orders, load and frequency control, etc. In addition it may also be used for supervision, operation and protection. Separate channels could be used for each function; however, often one channel can serve more than one function. In the allocation of channels protection requirements should be given priority.

Fault protection of station equipment and ability to restart after faults within the specified system recovery time should not be dependent on the telecommunication system. However the sending and receiving a.c. systems can be benefited by availability of tele-communication by for example, using it to diminish the impact of sudden changes in active and reactive power at the HVDC substation bus.

Protection of the HVDC substation equipments can be achieved reasonably without telecommunication and without impairing safe operation of the HVDC system. However compliance with requirements for minimum fault durations and short recovery times after faults may not be possible without telecommunication. Time settings that would be required for the protection for selectivity and safe switching sequences probably would not be compatible with the above objectives.

The telecommunication system should use a transmission path which should be secure from the effects of power system faults.

13.2 Specific requirements - Telecommunication systems

As discussed in Clause 9, the basic d.c. line protection criteria, d*v*/d*t*, d.c. voltage and d.c current, need interterminal communication to cope with certain specific fault conditions:

– high resistance line faults;

- to give discrimination between d.c. line faults and inverter side faults including inverter commutation failures;
- for protection without use of d.c. circuit-breakers of d.c. lines operating in parallel to permit automatic switching sequences;
- for automatic paralleling and deparalleling of poles as needed for clearing of permanent pole faults line without using d.c. circuit-breakers.

Protection against inverter commutation failures is usually achieved by increasing the inverter extinction angle. However, some protection strategies order the rectifier to decrease the line current via a telecommunication channel as an alternative to voltage dependent control (Clause 5).

A telecommunication channel in both directions can benefit operation of HVDC systems which use more than one converter unit per pole by maintaining an equal number of converter units in operation at each HVDC substation, following an automatic or manually-initiated unit blocking at each substation.

When a d.c. transmission is tied directly to a power station, the performance of the transmission may require control signals from the rectifier or the inverter to the power station. For example the signals could activate control sequences in the excitation or governing systems of the generators or it could optimize the number and loading of generator units and filter banks.

A telecommunication signal for each pole may be required to limit the current to a preset value following certain types of faults.

Similarly, a control signal for power reversal or change of power level can be used to enhance a.c. system stability for critical a.c. line outages (see Clause 5).

Telecommunication channels for control and protection should be redundant and on a pole basis.

Telecommunication may also be used for line fault location and discrimination between cable fault and overhead fault.

13.3 Consequence of telecommunication system outages

For many of the requirements in 13.2, a lack of telecommunication may not cause trouble other than to increase recovery time after a fault.

However a communication outage could seriously degrade the d.c. system performance, for example by failing to distinguish between an a.c. side inverter fault and an inverter end d.c. line fault. If all telecommunications are involved in the outage, the whole d.c. transmission could be shut down by the d.c. line protection for inverter faults. A partial solution for such an occurrence could come from introduction of a time delay in the d.c. line protection immediately after loss of the telecommunication.

Overall a.c. system voltage control on the rectifier and the inverter end can impose a requirement for telecommunication. Consequences of loss of these communications on a.c. system operation should be carefully considered.

13.4 Special considerations for power line carrier (PLC) systems

Power line carrier (PLC) performance may suffer from transient faults in the pole and shield wire conductors sufficiently to degrade performance of the control and protection systems, thus affecting the HVDC system performance. To minimize such effects the following requirements should be specified for the PLC system:

– for a carrier system using a pole conductor and a shield wire as a communication path, the insulation of the shield wire should be designed to avoid scintillation during normal operation and overvoltage conditions considered in the HVDC system design;
– for a fault on the d.c. line or during a flashover of a shield wire insulator, the degradation of the power line carrier signal should be minimized sufficiently to avoid impairment of the specified HVDC system transmission performance level;
– carrier frequencies chosen for the protection and control channels should be as high as possible to avoid carrier interference produced by the converter stations. A power line carrier filter may be required if the frequency selections do not avoid such effects.

In addition the following sources of transient disturbances on PLC over HVDC transmission lines should be carefully examined:

– interference from noise coupled from the electrode line;
– interference from a.c. lines paralleling or crossing the d.c. transmission line;
– interference due to pole-to-pole coupling on the HVDC line.

14 Auxiliary systems

14.1 General

The auxiliary systems of an HVDC substation are the support sources required to enable the HVDC system to produce its full range of power outputs, to enable the station to be maintained in good running condition and to allow the system to be safely shutdown.

These auxiliary systems can be broadly classified in two major groups, the electrical and the mechanical auxiliary systems.

14.2 Electrical auxiliary systems

14.2.1 General requirements

Steady-state considerations of electrical auxiliary systems were discussed in IEC 60919-1. This Part 2 discussion includes those aspects of electrical auxiliary system performance and requirements related to or which support the performance of HVDC systems during fault and switching-initiated transients.

The electrical auxiliary systems of HVDC substations are nearly always supplied from the a.c. networks to which the rectifier and inverter stations are connected. Consequently, faults in the a.c. networks or on the a.c. feeders which supply auxiliary power to HVDC substations could influence the performance of the auxiliary equipment and as a result the performance of the HVDC transmission. General practice then requires at least two main independent sources.

Although the load on the auxiliary system is usually only 0,2 % to 1 % of the HVDC substation rating, the security of the HVDC system depends vitally upon the correct operation of the auxiliary system during faults and switching transients, and the specification of the electrical auxiliary system should therefore emphasize this greater importance. In consequence it is generally appropriate that the electrical auxiliary system of a large HVDC substation should be much more complex and extensive than for a small HVDC substation.

Station auxiliary power loads can be classified in three categories: essential, emergency and normal loads. Essential loads are those necessary to assure the nominal power transmission capability of the HVDC substation. Emergency loads are those which should be in operation or should be ready to operate with minimum delay in the event of a power failure on the main a.c. bus. The normal or other loads in the station are those which are not closely related to the station's power conversion capability.

In the essential category are those loads such as the control and protection systems which cannot be interrupted or be exposed to transients. They are often described as the first grade auxiliary power loads. They are most often supplied from low voltage a.c. auxiliary power busbars through converters from batteries or uninterruptable power supplies with redundant battery chargers.

To achieve 100 % redundancy and the necessary high degree of reliability, the essential load buses are nearly always supplied from two main independent power sources. They are arranged with automatic changeover to allow one of the primary sources to feed all loads in this category in the event of failure in the other source. Consideration should be given to the simultaneous interruption of both main power sources with respect to the design of the HVDC substation equipment and the auxiliary system.

Design of the automatic transfer might be arranged for normal parallel operation, minimum time delay transfer, or intentional time delay transfer depending on the HVDC substation's requirements as to the allowable interruption time in such power supplies or load synchronization constraints, etc.

Loads which do not require 100 % redundancy are often fed from one of two feeders which can be selected by changeover switches located near the equipment being served.

A special problem for regions subject to freezing temperatures is provision of an alternative power source to avoid freezing of some systems such as, oil lines, diesel fuel supplies, primary water systems, etc., in the event of complete power blackouts.

The auxiliary electrical systems should be designed to operate satisfactorily under full and overload HVDC transmission capacity following disturbances on the a.c. systems. The undervoltage operating limits for the auxiliary systems after a.c. fault clearing should be consistent with the HVDC link low voltage operating criteria.

Design of the auxiliary systems should take into account expected long duration fluctuations in the a.c. supply sources and operate satisfactorily under anticipated operating conditions in the supplying a.c. system.

14.2.2 Specific requirements

Each pole should have its own independent and completely duplicated auxiliary supply for its essential loads. Consideration should also be given to switching and transfer arrangements, during loss of service to one pole, for supplying auxiliary service from the auxiliary service of the other pole.

The auxiliary electrical system should be designed to ensure that after a short temporary interruption, caused by a disturbance in the a.c. system interfacing the HVDC substations, it will not prevent re-establishment of HVDC power transmission within the recovery time specified, after supply to the auxiliary service is re-energized.

The auxiliary electrical system should operate without interruption or shut down of any auxiliary system over the specified range of over and under frequencies for the HVDC link.

Uninterruptible power supplies should maintain output frequency and voltages within the limits required by the auxiliary systems it feeds, so that the operation of valve groups will not be impaired, and to assure continuous protection co-ordination during short time interruptions of up to 2 s of the a.c. power supply to the auxiliary systems.

Control and protection design of auxiliary electrical systems should follow similar practices used for a.c. low voltage industrial or commercial applications, with special regard for the fault clearing speed and protective device selectivity. Particular attention is suggested to:

– avoid paralleling two or more main auxiliary supplies to limit the short-circuit duties of the auxiliary service components;
– provide means for assuring synchronism when two buses are to be paralleled during automatic changeover from one source to another;
– changeover being accomplished within the time requirements of the particular load being supplied with due allowance for the voltage conditions on the buses involved.

14.3 Mechanical auxiliary systems

The mechanical auxiliary systems for an HVDC substation include the following important systems: valve cooling; synchronous compensator cooling; compressed air; fire detection, protection and extinguishing; insulating oil; diesel oil; water supply; drainage and sewage; air conditioning; ventilation; and mechanical load handling facilities.

The above systems are required so that full electric power transmission can be maintained aon the HVDC system. The valve cooling system is probably the most important and critical.

The design of the converters will determine the type of valve cooling system. Generally, it will be either air or liquid cooled. Cooling for a valve group should be dimensioned to handle the power losses from each valve group. Moreover provision should be made for stand-by or spare components so that the failure or shut-down of a fan, cooling pump, heat exchanger, etc. will not cause a reduction of d.c. transmission capacity under any reasonably expected combination of load and ambient conditions (if it is not allowed to utilise the redundant cooling equipment for overload operation).

A supervisory and alarm system may well be included to monitor the auxiliary power functions essential to thyristor valve operation and cooling. Such functions might include:

– air-cooled valves: maximum incoming and outgoing air temperature for the thyristor assemblies; maximum air temperature to and from the heat exchangers; differential pressure across the valves; maximum and minimum temperature in the valve hall; pressure and air flow at critical locations in the air handling facilities; etc.
– water-cooled valves: deionized water temperatures from and to the valves; water level in expansion vessels; water conductivity; pressure drop across the valve cooling pipes; low water flow through a valve; water oxygen content if necessary; if a cooling tower is used, water temperatures and heat exchanger temperatures; and temperature and humidity of the valve hall air and air handling system.

The supervisory system should be arranged to give alarm warnings for low and high limits of the items described above, as well as for loss of pumps or fans, for low reserves of water and the need for refilling of storage vessels, and for water leakage in the thyristor valve structures, etc.

It should also give an alarm signal for such excursions from normal as: high temperature of the deionized water or of the air to and from the valves; low water flow through a valve; or loss of too many pumps or fans, for which a trip signal might be initiated by the supervisory system.

Another mechanical system important for full power transmission is the cooling system for the HVDC transmission's reactive power supplies such as synchronous compensators and static compensators. An independent cooling system should be provided for each such reactive power supply system with sufficient redundancy of major or critical elements in its cooling system to minimize any reduction of transmitted HVDC power resulting from loss of one reactive power source.

Compressed air systems can be important for safe shutdown of the HVDC substation particularly if compressed air is required for operation of switching equipment.

Mechanical equipment in the HVDC substation shall be designed to operate satisfactorily during transients including those which result in over- or underspeed.

Other mechanical auxiliary systems are often provided for maintenance needs or for safety reasons. These are not directly related to the transient performance of an HVDC transmission system.

Moreover provision should be made for standby or spare components so that the failure or shut-down of a fan, cooling pump, heat exchanger, etc. will not cause a reduction of d.c. transmission capacity under any reasonably expected combination of load and ambient conditions, including overload operation (if it is not allowed to utilise the redundant cooling equipment for overload operation).

Bibliography

In addition to the standards referred to in IEC 60919-2, the following publications are considered particularly useful reference materials, but the list may not be complete.

IEC 60044-1: 2003, *Instrument transformers – Part 1: Current transformers*

IEC 60044-5 :2004, *Instrument transformers – Part 5: Capacitor voltage transformers*

IEC 60050-371:1984, *International Electrotechnical Vocabulary (IEV) – Chapter 371: Telecontrol*
Am.1:1997

IEC 60050-421:1990, *International Electrotechnical Vocabulary – Chapter 421: Power transformers and reactors*

IEC 60050-436:1990, *International Electrotechnical Vocabulary – Chapter 436: Power capacitors*

IEC 60050-441:1984, *International Electrotechnical Vocabulary – Chapter 441: Switchgear, controlgear and fuses*
Am.1:2000.

IEC 60050-448:1995, *International Electrotechnical Vocabulary – Chapter 448: Power system protection*

IEC 60050-471:2007, *International Electrotechnical Vocabulary – Part 471 : Insulators*

IEC 60050-521:2002, *International Electrotechnical Vocabulary – Part 521: Semiconductor devices and integrated circuits*

IEC 60050-551:1998, *International Electrotechnical Vocabulary – Part 551: Power electronics*

IEC 60071-1:2006, *Insulation co-ordination – Part 1: Definition, principles and rules*

IEC 60071-2:1996, *Insulation co-ordination – Part 2: Application guide*

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IEC/TS 60071-5:2002, *Insulation co-ordination – Part 5: Procedures for high-voltage direct current (HVDC) converter station*

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IEC 60505: 2004, *Evaluation and qualification of electrical insulation systems*

IEC/TS 60815-1:2008, *Selection and dimensioning of high-voltage insulators intended for use in polluted conditions – Part 1: Definitions, information and general principles*

IEC 60831-1:2002, *Shunt power capacitors of the self-healing type for a.c. systems having a rated voltage up to and including 1 000 V – Part 1: General – Performance, testing and rating – Safety requirements – Guide for installation and operation*

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Performance of high-voltage direct current (HVDC) systems with line-commutated converters –
Part 2: Faults and switching

IEC TR 60919-2:2008-11+AMD1:2015-06+AMD2:2020-04 CSV(en)

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INTERNATIONAL ELECTROTECHNICAL COMMISSION

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PERFORMANCE OF HIGH-VOLTAGE DIRECT CURRENT (HVDC) SYSTEMS WITH LINE-COMMUTATED CONVERTERS –

Part 2: Faults and switching

FOREWORD

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IEC TR 60919-2 edition 2.2 contains the second edition (2008-11) [documents 22F/160/DTR and 22F/165/RVC], its amendment 1 (2015-06) [documents 22F/344/DTR and 22F/345A/RVC] and its amendment 2 (2020-04) [documents 22F/561/DTR and 22F/575/RVDTR].

This Final version does not show where the technical content is modified by amendments 1 and 2. A separate Redline version with all changes highlighted is available in this publication.

The main task of IEC technical committees is to prepare International Standards. However, a technical committee may propose the publication of a technical report when it has collected data of a different kind from that which is normally published as an International Standard, for example "state of the art".

IEC 60919-2, which is a technical report, has been prepared by subcommittee 22F: Power electronics for electrical transmission and distribution systems, of IEC technical committee 22: Power electronic systems and equipment.

This edition includes the following main changes with respect to the previous edition:

a) this report concerns only line-commutated converters;
b) significant changes have been made to the control system technology;
c) some environmental constraints, for example audible noise limits, have been added;
d) the capacitor coupled converters (CCC) and controlled series capacitor converters (CSCC) have been included.

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

A list of all parts of the IEC 60919 series, under the general title: *Performance of high-voltage direct current (HVDC) systems with line-commutated converters*, can be found on the IEC website.

The committee has decided that the contents of the base publication and its amendments 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.

PERFORMANCE OF HIGH-VOLTAGE DIRECT CURRENT (HVDC) SYSTEMS WITH LINE-COMMUTATED CONVERTERS –

Part 2: Faults and switching

1 Scope

This part of IEC 60919 which is a technical report provides guidance on the transient performance and fault protection requirements of high voltage direct current (HVDC) systems. It concerns the transient performance related to faults and switching for two-terminal HVDC systems utilizing 12-pulse converter units comprised of three-phase bridge (double way) connections but it does not cover multi-terminal HVDC transmission systems. However, certain aspects of parallel converters and parallel lines, if part of a two-terminal system， are discussed. The converters are assumed to use thyristor valves as the bridge arms, with gapless metal oxide arresters for insulation co-ordination and to have power flow capability in both directions. Diode valves are not considered in this report.

Only line-commutated converters are covered in this report, which includes capacitor commutated converter circuit configurations. General requirements for semiconductor line-commutated converters are given in IEC 60146-1-1, IEC 60146-1-2 and IEC 60146-1-3. Voltage-sourced converters are not considered.

The report is comprised of three parts. IEC 60919-2, which covers transient performance, will be accompanied by companion documents, IEC 60919-1 for steady-state performance and IEC 60919-3 for dynamic performance. An effort has been made to avoid duplication in the three parts. Consequently users of this report are urged to consider all three parts when preparing a specification for purchase of a two-terminal HVDC system.

Readers are cautioned to be aware of the difference between system performance specifications and equipment design specifications for individual components of a system. While equipment specifications and testing requirements are not defined herein, attention is drawn to those which could affect performance specifications for a system. Note that detailed seismic performance requirements are excluded from this technical report. In addition, because of the many possible variations between different HVDC systems, these are not considered in detail. Consequently this report should not be used directly as a specification for a specific project, but rather to provide the basis for an appropriate specification tailored to fit actual system requirements for a particular electric power transmission scheme. This report does not intend to discriminate the responsibility of users and manufacturers for the work specified.

Terms and definitions for high-voltage direct current (HVDC) transmission used in this report are given in IEC 60633.

Since the equipment items are usually separately specified and purchased, the HVDC transmission line, earth electrode line and earth electrode are included only because of their influence on the HVDC system performance.

For the purpose of this report, an HVDC substation is assumed to consist of one or more converter units installed in a single location together with buildings, reactors, filters, reactive power supply, control, monitoring, protective, measuring and auxiliary equipment. While there is no discussion of a.c. switching substations in this report, a.c. filters and reactive power sources are included, although they may be connected to an a.c. bus separate from the HVDC substation.

2 Normative references

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

IEC 60146-1-1, *Semiconductor converters – General requirements and line commutated converters – Part 1-1: Specifications of basic requirements*
Amendment 1 (1996)

IEC 60146-1-2, *Semiconductor converters – General requirements and line commutated converters – Part 1-2: Application guide*

IEC 60146-1-3, *Semiconductor converters – General requirements and line commutated converters – Part 1-3: Transformers and reactors*

IEC 60633, *Terminology for high-voltage direct current (HVDC) transmission*

IEC 60071-1, *Insulation co-ordination – Part 1: Terms, definitions, principles and rules*

IEC 60700-1, *Thyristor valves for high-voltage direct current (HVDC) power transmission – Part 1: Electrical testing*

IEC TR 60919-1:2010, *Performance of high-voltage direct current (HVDC) systems with line-commutated converters – Part 1: Steady-state conditions*
Amendment 1:2013

IEC TR 60919-3:2009, *Performance of high-voltage direct current (HVDC) systems with line-commutated converters – Part 3: Dynamic conditions*

3 Outline of HVDC transient performance specifications

3.1 Transient performance specifications

A complete performance specification related to transient performance of an HVDC system during faults and switching should also include fault protection requirements.

These concepts are introduced at the appropriate locations in the following transient performance and related clauses:

- Clause 4 – Switching transients without faults
- Clause 5 – AC system faults
- Clause 6 – AC filter, reactive power equipment and a.c. bus faults
- Clause 7 – Converter unit faults
- Clause 8 – DC reactor, d.c. filter and other d.c. equipment faults
- Clause 9 – DC line faults
- Clause 10 – Earth electrode line faults
- Clause 11 – Metallic return conductor faults
- Clause 12 – Insulation co-ordination - HVDC systems
- Clause 13 – Telecommunication requirements
- Clause 14 – Auxiliary systems

Discussion in the following clauses on the d.c. line, earth electrode line and earth electrode is limited to the relationships between these and either the transient performance or protection of HVDC converter stations.

3.2 General comment

In general, control strategies can be used to minimize the effect of disturbances, but when the safety of equipment depends on their correct performance, this should be identified.

4 Switching transients without faults

4.1 General

This clause deals with the transient behaviour of the HVDC system during and after switching operations both on the a.c. and the d.c. sides of converter substations, and is not related to equipment or line faults which are treated in the following clauses of this report.

Switching operations without faults can be classified as follows:

a) energization and de-energization of a.c. side equipment such as converter transformers, a.c. filters, shunt reactors, capacitor banks, a.c. lines, static var compensators (SVC), and synchronous compensators;
b) load rejection;
c) starting and removal from service of converter units;
d) operation of d.c. breakers and d.c. switches for paralleling of poles and lines; connection or disconnection of d.c. lines (poles), earth electrode lines, metallic return paths, d.c. filters, etc.

4.2 Energization and de-energization of a.c. side equipment

During the operating life of an HVDC transmission system, energization and de-energization of converter transformers, a.c. filters, shunt reactors, capacitor banks, SVCs, and other equipment may occur many times. Depending on the characteristics of the a.c. system and the equipment being switched, resulting current and voltage stresses will be imposed on equipment being switched and generally impinge as well on part of the overall a.c. system.

The overvoltages and overcurrents which are critical for plant design are usually due to faults (Clauses 5 to 9), and not to normal switching operations. Nevertheless, they are discussed here for completeness. They are relevant in consideration of disturbances to a.c. system voltages.

Filter switching will also result in transient distortion of the bus voltage. This could disturb the commutation process and in a weak system could lead to commutation failure.

Thus equipment switching should be investigated to:

– determine critical a.c. network and equipment conditions which may contribute to such abnormal stresses and actions which may be taken to mitigate them;
– design the equipment;
– verify arrester duties.

Transients occur routinely when filters and capacitor banks are switched as necessary to control harmonic interference and steady-state terminal voltages.

Because of the frequency of occurrence of switching overvoltages it is generally desirable that the overvoltage protective devices do not absorb appreciable energy during such operations. For example the amplitudes of overvoltages arising from routine switching operations can be minimized by the use of suitable resistors incorporated in the circuit-breakers associated with filters and capacitor banks or by synchronizing the closing of the circuit-breakers. This can also reduce the possibility of inverter commutation failures. The HVDC control system can also be used effectively to damp certain overvoltages.

Restrike-free switching devices should be used for capacitor switching to avoid onerous overvoltages from restriking which otherwise could occur when disconnecting filters or capacitor banks.

Transformer energization inrush currents can cause an undesirable interaction in the a.c. and d.c. systems. When disconnecting a converter transformer from the a.c. network, the transformer should be disconnected maintaining the a.c. filters connected in parallel if possible, instead of disconnecting the transformer alone or by using synchronizing devices. In that way, residual saturation will be decreased, and inrush currents would be reduced. After some hundreds of milliseconds the filters could be disconnected from the transformer.

To reduce inrush currents, typical control measures include circuit-breaker pre-insertion resistors, using the synchronized circuit-breaker, or setting of the transformer on-load tap changers at their highest tap changer positions. Highest tap changer position refers to the tap changer position with highest number of winding turns. Synchronization requires switching at an optimum instant in each phase, i.e. breaker closing 90 degrees after voltage zero crossing. This implies that the three poles of a circuit-breaker cannot switch simultaneously. For breakers with one-pole operating mechanisms (and thus a separate synchronizing unit), this is not a problem. The synchronizing unit is simply programmed to give switching orders suitably separated in time to the poles. However it should also be noted that saturation of already energized converter transformers can arise from energization of another transformer in the converter station or from switching of an SVC.

Also the application of low order harmonic filters can be helpful in reducing the problems with inrush currents. The effectiveness of such measures depends largely on the system and pertinent equipment characteristics. In addition, the response of the a.c. system can be sensitive to the number of converter transformers already energized, especially if they are not yet loaded as for series connections of multiple converter units.

Energization of capacitor and filter banks changes the system impedance characteristic. In case of system with relatively small short circuit capacity, adding capacitive component shifts high impedance peak of frequency-impedance curve to lower frequency side. If the high impedance peak becomes closer to second harmonic, severe overvoltages could be presumed during faults. To mitigate such situation, damping resister could be added to capacitors.

The energization of capacitor and filter banks produces oscillations between these elements and the rest of the network. Again, depending on the size of the banks and the network characteristics, switching overvoltages can appear along with overcurrents in the already energized a.c. system components.

Attention should be paid to the possibility of damage to the capacitors during re-energization of capacitors because of trapped charges in the capacitors from a preceding opening operation. Measures may be necessary for discharging them before reclosing if their internal discharge resistors are not sufficiently effective within the desired switching time. Alternatively, a longer switching time may be necessary.

Energization of filters excites the frequencies to which they, in combination with the a.c. network, are tuned. Also switching out of filter and capacitor banks can cause the a.c. system voltage to oscillate.

SVCs can be provided to stabilize the voltage and control temporary overvoltages. Energization of SVCs should be such as to produce a light or even no transient in the system voltage. Most of them have an active control which can be used to accomplish this objective.

Connection or disconnection of shunt reactors and capacitors produces change in a.c. voltage. Size and operation of this equipment should be specified so as to limit switching-caused voltage changes to acceptable levels.

Energization and de-energization of a.c. transmission lines connected to HVDC sub-stations generate voltage transients as well, which should be taken into account. These operations change the a.c. harmonic impedances which also influence the transient harmonic effects.

Synchronous compensators can produce voltage transients when started and operated as induction motors, drawing reactive power and reducing the system voltage. This aspect of their performance should be carefully examined.

A table of acceptable levels of temporary or transient overvoltages and overcurrents during switching operations of the various system components or preferably a diagram of the expected transient overvoltage and overcurrent levels versus time should be developed for the specifications.

Related to the foregoing, information about the electrical characteristics of the a.c. system and its future development as complete as possible should also be supplied in the specifications. Relevant operating criteria along with existing and expected a.c. overvoltage levels should also be shown.

The desired performance of the HVDC substations under the transient conditions described in the foregoing subclauses should be stated for both switching in and out of the various components.

Overvoltage performance for the HVDC link should be co-ordinated with the actual performance characteristics of the existing a.c. network with which it is to be integrated.

4.3 Load rejection

Sudden reductions of transmitted power over the HVDC link without occurrence of faults could take place:

– due to unintentional tripping of the a.c. circuit-breakers at either terminal;
– due to blocking and bypass of converter units as a consequence of control system action;
– due to loss of generation and for a multitude of other possible causes.

Voltage levels on the a.c. system would rise primarily because of the consequent excess of reactive power compensation at the HVDC substation. Resonant conditions can be reached due to saturation of the power transformers and resonances between transformers, filters and the a.c. network. These overvoltage effects can be accentuated by frequency deviations in the a.c. system.

Special care should be taken for the case that the inverter becomes isolated from the a.c. system with only the filters and shunt capacitor banks connected to it.

For this contingency, the inverter should be blocked and bypassed to prevent overvoltage-caused damage to the filter components or the a.c. side arresters or the valve arresters. Opening of the remote end circuit-breakers, for a system with a single or only a few lines connecting the inverter to the a.c. system should be taken into account in the design of the protective scheme. It is also helpful to adopt fast and reliable telecommunication system for opening of the remote end circuit breakers.

Load rejection transients following system faults are discussed in 5.3.5.

Acceptable load rejection-caused overvoltages, in terms of amplitudes and durations should be specified particularly if the resulting stresses are expected to be greater than those discussed in 4.2.

Suitable operating strategies to return to normal operating conditions should be developed. Among the procedures for achieving this are controlling the converter units still in service to regulate the system voltage or switching in reactors or by removal of capacitor or filter banks. If capacitor or filter banks are to be switched under overvoltage conditions this should be taken into account when fixing the associated circuit-breaker ratings and capabilities. In cases when an existing circuit-breaker of inadequate capacity could be called on to perform this duty, its operation should be inhibited and other means used to reduce overvoltages.

When converters are to be used for voltage control, consideration should be given to the design and manufacture of the valves for operation at large delay angles.

The extent to which converter measures can be used for reducing a.c. system overvoltage will depend on the requirements for continuity of supplied power to satisfy the a.c. system dynamic performance.

Other means, such as switched capacitors or reactors, synchronous compensators, SVCs, special metal oxide (MO) temporary overvoltage absorbers (TOV), etc. may need to be used to limit overvoltages to acceptable levels and to achieve the desired converter performance.

As in most system design decisions, economics will play a major role. However, trade-offs may be necessary between cost and system performance.

4.4 Start-up and shut-down of converter units

Normal operator-initiated start-up and shut-down procedures for an HVDC pole should be established.

Start-up and shut-down of series-connected converter units is performed by the control system sometimes in conjunction with the operation of switching devices in parallel with the converter units. For this purpose normally an automatic sequence is followed in which a valve bypass path within the bridge is activated before the opening or closing of the bypass switch.

For this procedure any special requirements or constraints such as the maximum allowable a.c. bus voltage variation, special interlock requirements or maximum variation in transmitted power, etc., should be specified.

Whether the system is to be operated with a smaller number of converters than in the ultimate configuration, particularly during the development stages of the project, should be noted.

4.5 Operation of d.c. breakers and d.c. switches

Switching devices have been used on the d.c. side of HVDC transmission systems for several functions as follows:

– by-pass and disconnect converter units;
– connect or disconnect the substation pole to the earth electrode line in bipolar links;
– connect poles or bipoles in parallel, including polarity reversal;
– switch the neutral bus-bar;
– connect or disconnect the d.c. line;
– connect or disconnect d.c. filters;
– connect d.c. filters in parallel during monopolar operation.

They can be classified with respect to various aspects. Figure 1 gives an example of switching device arrangements on the d.c. side of a converter substation with the following meanings:

– current commutating switches (S);
– disconnectors (D);
– earthing switches (E).

Distinctions should be made between:

– devices which are used for opening at zero current, even though they may have limited making and breaking capability;
– devices which are able to transfer the current from one current path to a parallel one; such devices shall have an adequate energy absorption capability for the expected current interruption during the transfer;
– and d.c. breakers which are able to interrupt any d.c. current within their ratings and withstand the following recovery voltage.

In the future, d.c. breakers may be used in order to allow an unrestricted paralleling or de-paralleling of substation or d.c. line poles. A special application of the d.c. breaker is the metallic return transfer breaker (MRTB).

Zero current operated switches and d.c. circuit-breakers with a current interrupting capability not exceeding the load current shall be co-ordinated with the control system actions under both fault conditions and during operating sequences. For example, substation or line pole paralleling and de-paralleling operations require the opening and closing of various switches.

These operations initiate a wide variety of voltage and current transients and such functions are performed during established operating sequences as determined by the d.c. controls.

Thus, the transients depend on the control system, on the switch operating times and the a.c. and d.c. system electrical characteristics.

For a two-terminal system where reliability requirements are stringent, the use of d.c. circuit-breakers offers the possibility of enhancing transmission reliability and availability by the use of transmission lines in parallel and sectionalized along their routes. This would permit isolation of one of the parallel lines or line sections either in the case of a permanent fault or for operating needs without even a momentary shut-down of the d.c. transmission.

Thus maximum transmission capability within the thermal limits of the remaining healthy circuit could be maintained. Of course, selective protections as in the case of parallel a.c. lines would need to be used.

The operating characteristics including speed requirements should be determined and specified for all switches and circuit-breakers required for the contemplated HVDC transmission.

When specifying d.c. switching devices, the following duties shall be defined:

– the function within the HVDC substation;
– modes of operation;
– operation time requirements;
– continuous current;
– current on opening;
– current on closing;
– voltage on opening;

- voltage across open contacts;
- voltage to earth in the closed and in the open position;
- maximum energy absorption for one commutation (or for two or more commutations depending on rating criteria);
- lightning impulse withstand level to earth;
- lightning impulse withstand level across open breaker;
- switching impulse withstand level to earth;
- switching impulse withstand level across open breaker.

In the event of a low impedance fault to earth on the d.c. side of one pole, at least one neutral switch should be able to transfer the current injected into the earth from the operating pole.

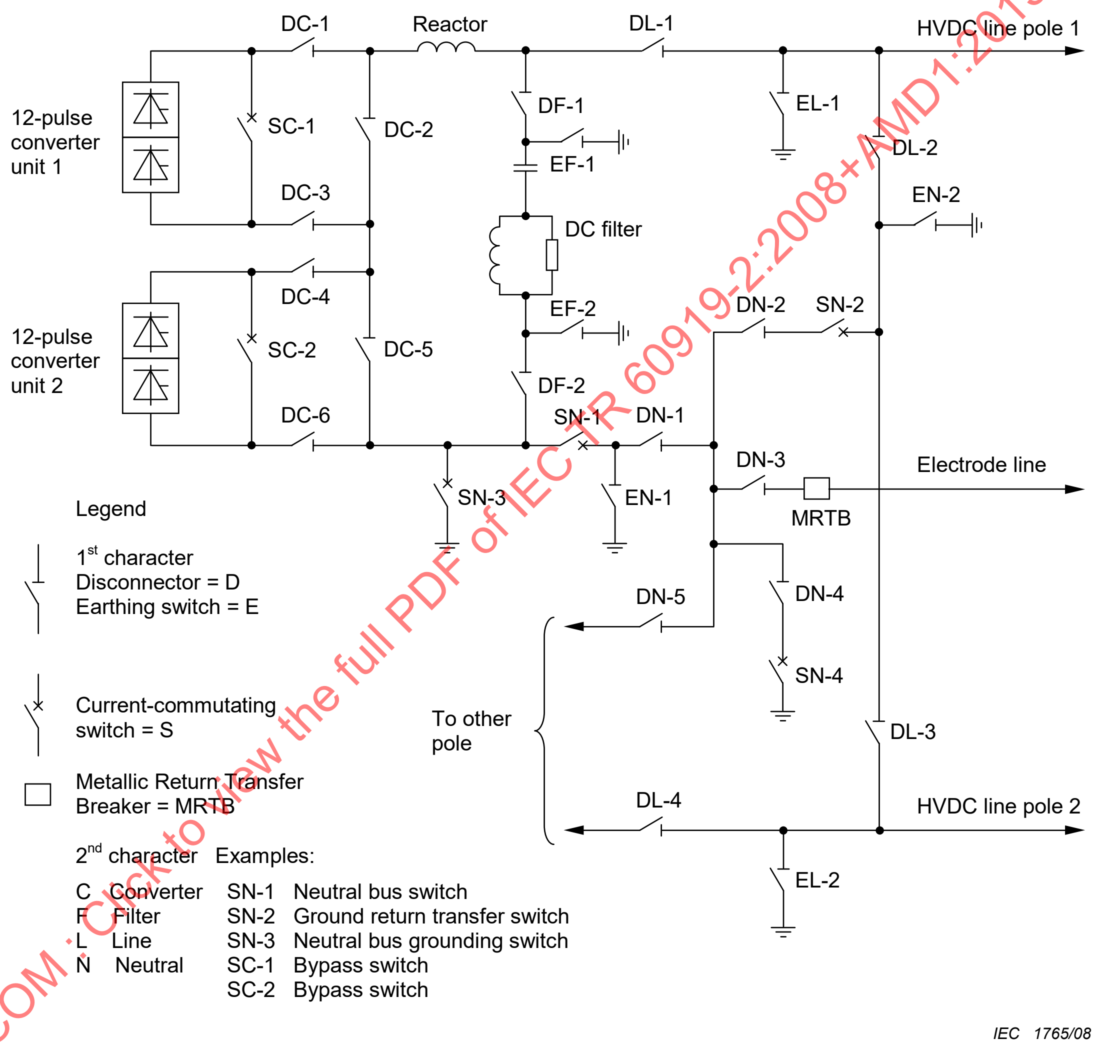


Figure 1 – DC-side switches for an HVDC substation with series-connected converter unit

5 AC system faults

5.1 General

Transient performance of an HVDC system during a.c. system faults and during the recovery period immediately following fault clearing are important considerations in the specification and design of such a system. Recovery performance as influenced by implementation of specific control strategies will directly affect the ratings of the HVDC equipments, the connected a.c. substation facilities and the connected a.c. network response.

5.2 Fault categories

The following a.c. faults should be considered when preparing an HVDC system specification:

– sending end (rectifier) and receiving end (inverter) faults for each power flow direction;
– three-phase to earth and single-phase-to-earth faults at the HVDC substations;
– a.c. faults remote from the HVDC substations; reclosing practices should be considered;
– various faults as above in a.c. or d.c. lines in cases where there is a parallel a.c. line closely coupled to the d.c. line. The extreme case of this type is a flashover from an a.c. to a d.c. conductor where a.c. and d.c. lines cross.

HVDC specifications concerning transient performance during and after a.c. system faults should consider all affected areas of the d.c. and a.c. system operation and equipment ratings. To achieve an optimum balance between total system costs and performance, trade-offs should be considered in the HVDC specifications.

Characteristics that influence transient performance during and after a.c. system faults are discussed in the following paragraphs.

5.3 Specification matters affecting transient performance

5.3.1 Effective a.c. system impedance

In its simplest form effective a.c. system impedance is usually expressed as the short-circuit-ratio (SCR), that is, the ratio of the a.c. system short-circuit MVA to converter d.c. power (MW) rating.

However, SCR is more precisely expressed as a.c. system admittance on a base of rated d.c. power and a.c. voltage. This is defined at system frequency and should include an angle. For many studies the total admittance seen by the converter is relevant, including that of filters and other reactive power elements connected to the HVDC substation a.c. bus; this is known as effective short-circuit ratio (ESCR). Most significant are the impedances at the low-order harmonic frequencies.

SCR as defined here differs from the ratio RSC defined in IEC Publication IEC 60146-1-1 where the base is the rated MVA of the converter.

Transient fault performance factors affected by the SCR are:

a) power transfer during faults to maintain stable operation without commutation failures;
b) recovery time, especially for inverter end faults;
c) control of post-fault recovery voltages within acceptable limits;
d) possible low frequency resonance conditions, i.e., < 5th harmonic;
e) temporary overvoltages.

All of these factors become more pronounced with increases in the a.c. system impedance and phase angle.

5.3.2 Power transfer during faults

The HVDC system may be sensitive to relatively remote a.c. system faults where a.c. voltage changes at the HVDC a.c. buses are not large.

Voltage depression and distortion associated with a.c. faults affect the delay angles of the converters and cause a reduction in the transmitted d.c. power. For remote three-phase faults the power loss is essentially proportional to the a.c. voltage drop, down to a level of d.c. voltage where some form of voltage dependent control possibly needs to be imposed, as discussed in the following paragraphs. A further power reduction can take place as a result of a control mode shift as described in 5.3.8.

Voltage dependent control provides a means to modify the current limits or orders of the converters at each terminal in a co-ordinated manner without loss of current margin. The d.c. voltage at each end represents a common signal to both the rectifier and inverter terminals for co-ordination without the necessity for other communications. There are a variety of such controls; an example characteristic is shown in Figure 2.

In case the converters are used for reactive power control, the input voltage for the voltage dependent control should be the a.c. bus voltage.

System studies should be made to determine optimum settings for d.c. or a.c voltage thresholds, current limits, and time constants or ramp rates, if any, for each system.

For a.c. single phase-to-earth faults to or near the rectifier terminal, the reduction in power transfer for modern converters is also approximately proportional to the average a.c. voltage drop, since delay angle unbalance can be readily incorporated to compensate for large a.c. voltage dissymmetries.

On the other hand, for most inverter control strategies using equidistant firing schemes, the earliest firing time which is set to minimize commutation failures, fixes the firing time for all valves. This control action in conjunction with voltage dependent control normally results in minimum power transfer during a.c. single-phase inverter end faults. Strategies that transfer to individual-phase control operation during inverter end a.c. line-to-earth faults offer one means for increasing the power transfer from the aforementioned minimum without experiencing an excessive number of commutation failures.

To achieve both stable power transfer as much as possible and avoiding commutation failure during faults, optimized control of margin angle can be applied. For example, direct or indirect margin angle detection of the thyristor valve can be implemented and applied to closed loop margin angle control. If system requires, these function can be specified.

Power transfers achievable under a.c. fault conditions depend largely on the characteristics of the HVDC system under consideration and therefore can best be determined by digital and/or simulator studies.

5.3.3 Recovery following fault clearing

The recovery time can be defined as that time required after the fault clearing for the HVDC system to recover to a specified level of the prefault power, typically to 90 %, with the overshoot and settling time being specified.

HVDC system recovery times can be fast, e.g. 50 ms to 100 ms, with modern control systems for all non-permanent a.c. faults at the rectifier or inverter for low impedance a.c. systems. In practice however many HVDC systems being designed or installed are connected to high impedance a.c. systems at either HVDC substation. In such case, recovery times can be several times longer than for HVDC systems connected to low impedance a.c. systems. Long recovery times can also be expected for HVDC systems making use of long d.c. cables and very long d.c. overhead lines.

Recovery time settings shall take into consideration the a.c. system stability characteristics for both primary and possible backup fault clearing times.

However factors such as the necessity to minimize commutation failures or post fault recovery voltages often influence the actual recovery time implemented in a d.c. system control strategy.

Recovery can often be improved by maintaining, if possible, the d.c. current flowing even at a reduced magnitude by firing the valves during severe a.c. single-phase-to-earth and three-phase faults. Valve firing during the period of the fault or resumption of firing immediately upon fault clearing can also reduce the magnitude of recovery voltages and improve stability.

Specifications should indicate the expected duration of single-phase-to-earth and three-phase faults, including most likely backup clearing times, for which fast recovery capability of the HVDC system should be provided. This is important because some valves shall be designed with sufficient energy storage for the gating circuits to ride through expected fault periods.

5.3.4 Reactive power consumption during fault and post-fault recovery periods

Reactive power consumption of the HVDC substation during and after a.c. faults depends on its control strategy. Voltage dependent current limits with tailored characteristics are often utilized to modify the reactive power consumption as a function of voltage and to improve the inverter's ability to recover without commutation failures.

Strategies may be adopted for the remote unfaulted HVDC substation and where practical at the faulted substation to continue reactive power consumption or voltage support at a level to maintain a.c. bus voltages within prescribed limits.

During commutation failures, significant variations occur in reactive power flow. Persistent commutation failure in converters followed by protective action result in reactive power flow being rejected into the a.c. system which can lead to substantial overvoltages on high impedance systems.

HVDC system studies are important to determine the required means to control voltages at the a.c. bus and to maintain commutation as well as stability of the interconnected a.c. networks.

5.3.5 Load rejection due to a.c. faults

Fault conditions which can result in converter blocking, tripping of loads, failures to deblock upon clearing of three-phase faults and severe commutation failures, all result in forms of load rejection which can initiate large temporary overvoltages, ferroresonance, and a.c. system instabilities which can cause system collapse.

In addition on some a.c. systems careful attention shall be given to the possibility of large d.c. load rejections leading to self-excitation of generators or synchronous compensators at or electrically near the HVDC substation.

Load rejection overvoltages will have a direct impact on ratings of the HVDC equipment.

Studies should be carried out to assess:

– the extent to which existing equipment in the a.c. network can withstand these overvoltages and to design necessary corrective measures;
– design requirements for the HVDC substation equipment including any needed a.c. protection to satisfactorily withstand such load rejection overvoltages.

While not blocking, the converter can be used to help limit overvoltages. However consideration shall be given to the possibility of converter blocking during a.c. system faults with subsequent failures to recover. Such contingencies may indicate the need for other measures such as high speed switching devices for reactive power equipment, static var compensators (SVC), low order damped filters or protective energy dissipation devices to control load rejection overvoltages.

The specifications should state the acceptable overvoltage magnitudes and durations for the above contingencies.

5.3.6 Switching of reactive power equipment

Switching of reactive power equipment such as a.c. filters and shunt capacitor and shunt reactor banks is a common strategy at the a.c. terminals of HVDC substations for control of harmonic interference and steady-state terminal voltages, the latter as a function of a.c. system loading or of the primary a.c. system voltage.

When specifying the switching device to switch filters, shunt reactors or shunt capacitor banks, attention shall be given not only to the normal steady-state interrupting capability and speed, but also to the overvoltage requirements which may result from a.c. fault clearing and large load rejection.

Further complications may become apparent if an existing reactive power switching device is inadequate for safe interruption during temporary load rejection overvoltages, in which case provision shall be made for a backup breaker of adequate capacity to enable disconnection of excess reactive power sources.

5.3.7 Effects of harmonic voltages and current during faults

Multiple cycle commutation failures or misfires occurring during an a.c. fault or the recovery period may cause currents and voltages at low-order non-characteristic harmonics and excite other frequencies, on the a.c. and d.c. sides. These may temporarily excite resonances in the a.c. or d.c. systems, but the resulting currents and voltages normally are not excessive, partly because of the damping provided by modern control systems. However, such effects should be studied to check the effect on, for example, filter transient ratings, and possible misperformance of a.c. system protective relays.

If the d.c. side is resonant at the fundamental frequency, saturation of the converter transformers can occur. This would add to any second harmonic on the primary and cause possible system instability. Also an a.c. single-phase-to-earth fault near the rectifier terminal injects large second harmonic voltages on the d.c. side that will remain as long as firing continues. Because of these considerations it is advisable to study carefully the possibility of any resonance of the d.c. line to this harmonic.

Harmonics generated during faults should be taken into account in the design ratings for the a.c. filters and in determining the inverter's ability to commutate during fault recovery periods.

A further problem which should be carefully examined is possible misoperation of the a.c. protection due to low order harmonics during a.c. faults. In this case that digital type relays were used, misoperation could be prevented for some degree of harmonic component. However, it should be taken into account that existing relays of old type do not have immunity to harmonics.

5.3.8 Shift in control modes of operation

Changes in operating modes, that is, to power or current control mode for example, may be necessary during a.c. fault conditions. Shifts from rectifier current control to inverter current control lead to a power reduction that require a current order adjustment to correct for the power loss. Also co-ordination of current margins with and without end-to-end communications and changes in reactive power demands with current margin correction should be investigated.

In some high impedance a.c. systems, unstable operations during fault-initiated transients can appear in the power control mode unless a switchover is made to current control, or the power control mode is made to assume constant current control mode characteristics.

5.3.9 Power modulation on the HVDC system

AC system transient stability and HVDC fault recovery performance sometimes can be improved by the use of power, direct current or direct voltage modulation. This option will be discussed in IEC 60919-3.

5.3.10 Emergency power reductions

During fault conditions resulting in critical a.c. line outages, capability for emergency power reductions or even power reversals may be required as a contingency option to mitigate a.c. system instability. The specifications should consider the impact of such control actions on:

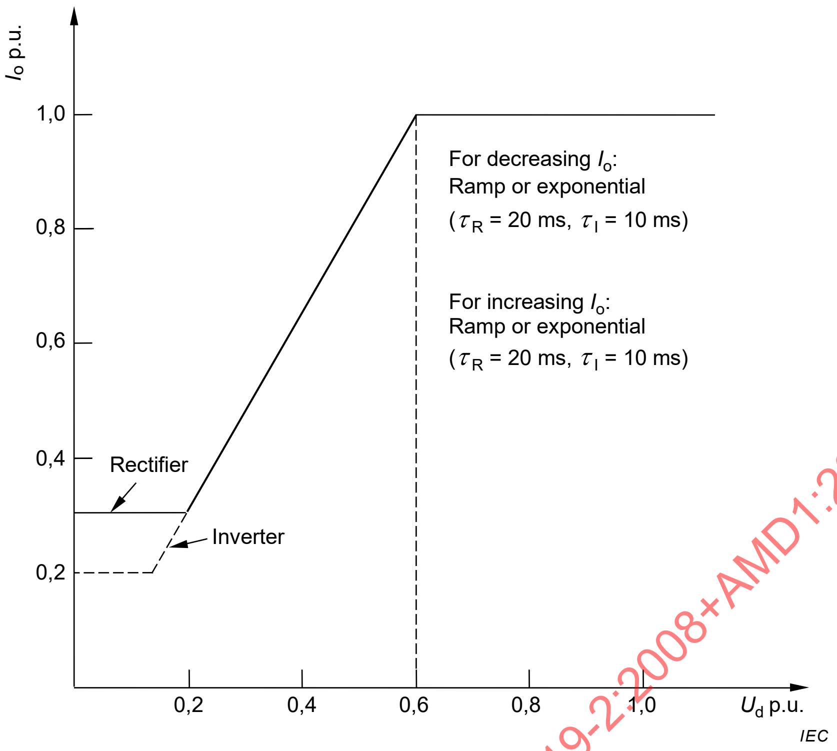
– possible overvoltages or destabilization of the a.c. system connected to the opposite end substation as a result of the partial load rejection;
– communications time requirements to co-ordinate the emergency reductions plus post-fault power increases and the impact of possible communications loss.

In some cases fault recovery from a.c. faults may permit operation of the d.c. system at a reduced power level until other restorative actions have been accomplished as determined by appropriate system studies.

5.4 Specification impact on control strategy

Because of the wide range of a.c. system conditions that shall be considered in determining optimum transient performance during a.c. faults and during the recovery period following fault clearing, no single control strategy will be appropriate for all cases. Each system shall be optimized around specified reference conditions as determined by digital computer and/or analog simulator studies for that particular system.

Performance specifications should permit d.c. control strategies which achieve an optimum compromise between maintaining power transfer and the prevention of commutation failures, instabilities or excessive recovery voltages, provided that the overall result is a satisfactory solution for the interconnected a.c. system.



Key

U_d d.c. voltage

I_o current order

τ_R and τ_I rectifier and inverter time constants, respectively

Figure 2 – Example of voltage dependent control characteristics

6 AC filters, reactive power equipment and a.c. bus faults

6.1 General

This clause discusses faults in a.c. harmonic filters, in reactive power equipment and faults on the a.c. busbar. Relatively high levels of harmonic currents which may appear in these items warrant a discussion of protection aspects. This is included. Specific fault protection aspects of SVCs are not covered in this technical report.

An example of the arrangement of a.c. filters and shunt capacitors for a bipolar HVDC scheme is shown in Figure 3. The individual capacitor, reactor, and filter arms of the banks may be energized and de-energized by means of sub-bank circuit-breakers, the earth faults within the individual arm shall also be cleared by the sub-bank circuit-breakers. The bank circuit-breakers will operate when sub-bank circuit-breakers fail to open the circuit successfully. An alternative arrangement, sometimes used is to connect the filter and the capacitor and reactor banks via tertiary windings on the converter transformers.

The fundamental and harmonic frequency impedances of the filters and the reactive power banks have a major influence on the amplitude and waveshape of overvoltages occurring at the a.c. busbar. Therefore detailed representation of a.c. harmonic filters and reactive power banks is essential for studies of the busbar voltages during transient conditions.

6.2 Transient overvoltages in filter banks

During normal operating conditions most of the line-to-earth voltage will appear across the main capacitor of the filters, while the voltage across other filter elements is normally a small fraction of the line-to-earth voltage. However under transient conditions the prospective voltage across the filter reactors and resistors can be even higher than the normal line-to-earth voltage. Therefore surge arresters protection should be applied internally in the filters as discussed in Clause 12.

In addition to the overvoltages occurring routinely as a consequence of normal switching (see Clause 4), the filter components are likely to be subjected to lightning-caused over-voltages, switching surges and busbar or external close-in faults.

Since the filter capacitors exhibit low impedances to fast wavefronts such as from lightning discharges, the filter reactors and resistors will be almost directly exposed to any lightning overvoltages appearing on the a.c. busbar.

Switching surge overvoltages appearing on the a.c. busbars may be significantly magnified internally in the filters and the resulting component overvoltages may even exceed the a.c. busbar-to-earth voltage. Therefore the individual component overvoltages should be investigated during overvoltage studies. When the components are not directly protected by surge arresters, as is often the case for the main filter capacitors, they may need to be designed to withstand higher switching surge levels between their terminals than other directly protected equipment connected from the busbar-to-earth.

During unbalanced a.c. system faults, the converters, if not blocked, will generate low order harmonics of substantial amplitude. If filters for low order harmonics are used, the filter surge arresters may be required to absorb considerable energy under these conditions. Another energy stress condition to consider particularly for filter reactor surge arresters of the second or third harmonic filters (when such filters are provided), is during energization of large transformers electrically close to the filter bus such as at recovery from a close a.c. fault.

Severe overvoltages with fast front times can occur across the resistors and reactors within the filters if a flashover from the a.c. busbar-to-earth should take place in the HVDC substation. The prospective voltage amplitudes across these filter elements will be equal to the pre-flashover voltages across the main filter capacitor and the surge arrester energy absorption requirement can be high.

6.3 Transient overcurrents in filter and capacitor banks

Under transient conditions peak currents in the filter components may be several times greater than the normal steady-state values.

In the event of a flashover from busbar-to-earth the capacitor banks will discharge energy into the fault. The current in this discharge will be limited by the stray inductance of the capacitor stack and its busbar connections and by the current limiting inductor if used. Similarly, where surge arresters are provided across reactors and resistors in a.c. harmonic filters, the capacitor discharge current can be high since it is only limited by the back e.m.f. of the protective device and by stray inductance.

Due consideration to these overcurrents should be given in the specifications of the components as well as of the protective circuits and the design of the earthing system. Thus capacitor fuses shall be capable of withstanding the discharge currents, and the operation of current transformers and protective relays should not be adversely affected nor should the protection be incorrectly triggered by transient currents which are within the capabilities of the filter components. These should be designed to withstand such discharges.

The analysis should consider the system configuration, including the filters and shunt capacitors, leading to the most critical stresses.

6.4 Capacitor unbalance protection

To achieve the desired harmonic performance and reactive power balance at all d.c. loadings the capacitor and filter banks are usually divided into a number of switchable arms. This means that the individual banks (arms) may be of relatively low MVar rating, i.e., the number of parallel elements in the capacitor banks would be small.

During the operating life of a capacitor bank, capacitor elements can fail and be disconnected by fuse operation. When internal fuses are used, their operation disconnects the individual internal faulty element, while external fuse operation will disconnect the complete capacitor cell.

Capacitor banks are often designed to have built-in redundancy which means that a limited number of capacitor element failures and the accompanying fuse operations will not overstress the remaining healthy capacitors in the bank. However fuse operations should be detected so redundancy can be restored in the bank at an early convenient opportunity.

One method of such detection is use of current unbalance relay protection. For this scheme each phase of the capacitor bank is connected in a bridge circuit, i.e. “H” connection. If an element fuse blows in one capacitor unit, the capacitance of the bridge arm, that contains this unit will decrease, causing an unbalance current in the bridge arm which is measured by the current transformer.

Another method of such detection is that each capacitor phase is subdivided into two closely equivalent parallel groups of capacitors. Sensitive current unbalance relays responding to the difference in current in the branches are utilized to detect small changes resulting from capacitor element failure and subsequent fuse operation.

An alternative procedure uses voltage sensing devices which measure the voltage at tapping points in each phase of the capacitor bank to detect changes caused by failed capacitor elements and fuse operations. An overvoltage relay is used to monitor the phase or sum of the intermediate tapping voltages.

For some applications two levels of unbalance detection are used. The first gives an alarm and permits manual de-energization of the capacitor bank and replacement of failed capacitor units as necessary to restore redundancy. The second level gives an automatic trip signal to ensure that the safety of the remainder of the capacitor bank is not compromised as a consequence of the loss of a large number of capacitor units or elements. Unbalance protection schemes assume an extremely low probability of the same degree of capacitor element failure simultaneously in two branches of a filter capacitor bank.

6.5 Examples of protection of filters and capacitor banks

Examples of protection arrangements for filters and capacitor banks for an HVDC system are illustrated in Figures 4, 5 and 6. The choice is usually based on individual utility experience and practices.

If redundancy is sufficient to allow a pole to continue to operate even with one filter out of service, it may be desirable to protect the filter arms individually, so that the faulty filter can be disconnected rapidly with minimum loss of transmission capability.

If loss of a filter means that the pole cannot continue operation, it may then be considered economical to provide protection only for the overall bank or to include the filters in the busbar protection zone. As another alternative to individual filter protection, some operational restrictions such as reduction in transmitted power could be considered.

To ensure that the appropriate protection characteristics are applied, contingency operation requirements for partial loss of reactive power sources should be studied and specified.

The presence of an earth or phase-to-earth fault within a given protection zone can be detected by a conventional differential current protection system as shown in Figure 4.

When filters are assigned their own individual protection zones, current transformers shall be provided in each phase on the a.c. busbar side and at the neutral side of the filter. When the filter bank is treated as a single protective zone, only one set of high voltage current transformers need be provided, situated in the a.c. busbar connections.

If tripping of the complete pole should be initiated when the filter bank is tripped, the filter bank could alternatively be incorporated in the overall pole differential protection scheme. However this will have the disadvantage of reduced automatic information for identification of the faulted bank.

Another zone protection scheme is the restricted earth fault protection shown in Figure 5. This uses current transformers in each of the three high voltage phase conductors and in the neutral connections to detect an earth fault in the protected zone.

It should be noted that if the surge arresters inside the filter banks are connected directly to the substation earth mat, the arrester surge current may be registered by the protection system as an unbalance current. The resulting probability of undesirable relay operations can be minimized by proper co-ordination or by including the arresters in the protection zone.

The current in the filter and capacitor banks will depend not only on the amplitude and harmonic content of the a.c. busbar voltage, but on the integrity of the filter and bank components themselves. The differential current schemes described above may not be sufficiently sensitive to detect all internal breakdowns in the filters. Some of these incipient types of failures may need to develop sufficiently so that they can be detected and cleared.

Overcurrents which result from abnormal a.c. busbar voltages often can be tolerated for limited times without excessive penalties in terms of lost equipment life. However the equipment should be monitored so that mitigative steps may be taken before such overloads exceed the limits imposed by the known margins inherent in the equipment. For this, protection can be obtained by measuring the current in each phase and using overcurrent and overload relays. To ensure adequate protection against these problems in an a.c. harmonic filter it is often necessary to provide current transformers for individual elements of the filter as shown in Figure 6.

6.6 Shunt reactor protection

The protection arrangement for a shunt reactor applied at an HVDC substation for reactive power control is similar to that applied to a reactor or transformer as used in an a.c. transmission system.

6.7 AC bus protection

The converter a.c. busbar is normally protected by a differential protection system. Since resonances can exist between the a.c. filters and the a.c. system a high content of harmonic currents may be present in the busbar currents during fault recovery periods. The busbar protection system then shall operate correctly in the presence of these harmonic currents.

Another aspect of this protection which should be examined is its performance during temporary overvoltage conditions. Under some conditions the peak voltages of one polarity may be substantially higher than the other. This can result in unidirectional surge arrester currents. It shall be ensured that the current transformers do not saturate under these conditions since misoperations of the protection can otherwise occur.

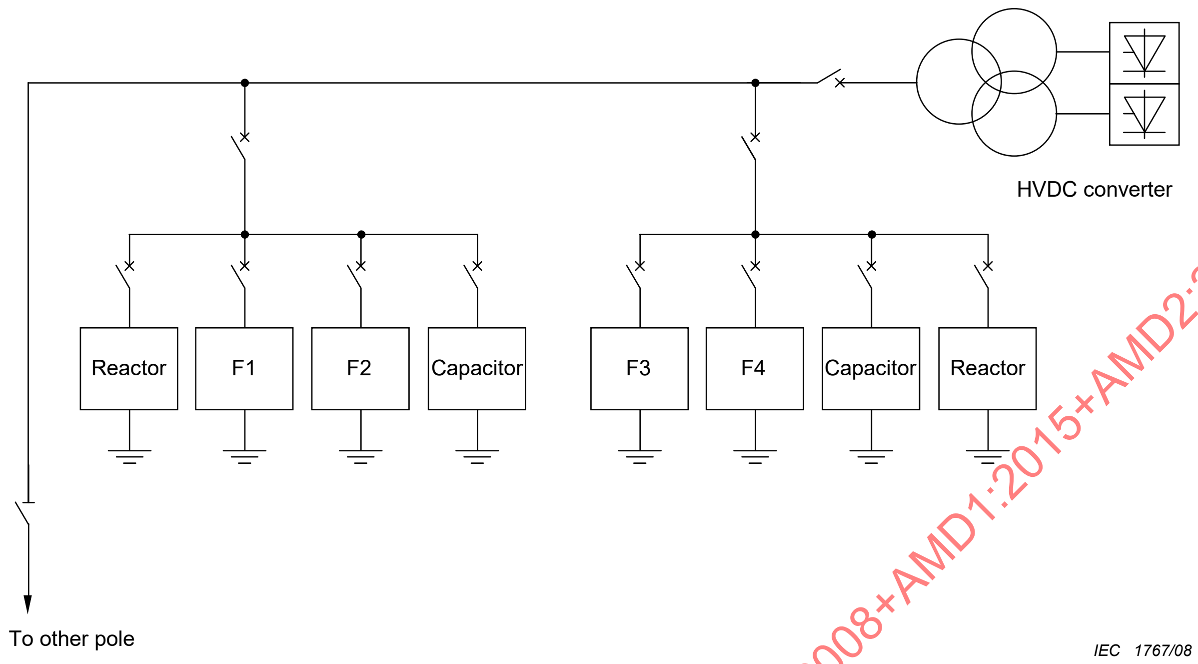


Figure 3 – Example of arrangement of a.c. filters and capacitor and reactor banks for large bipolar HVDC

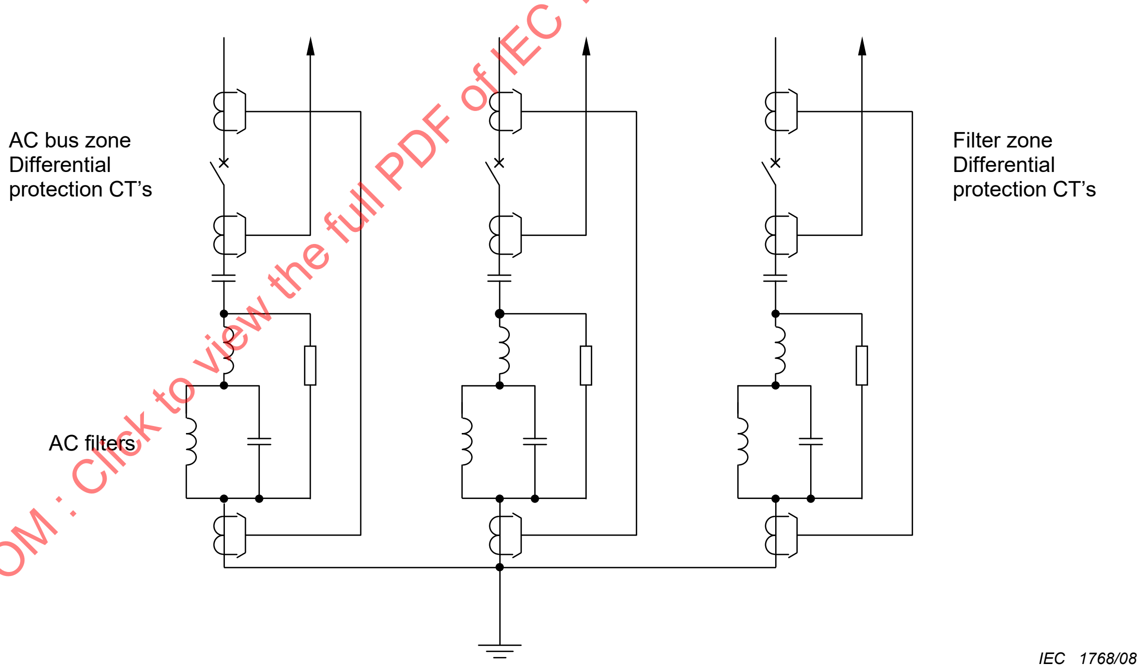


Figure 4 – Example of current transformer arrangements for a.c. filters and a.c. bus differential protections

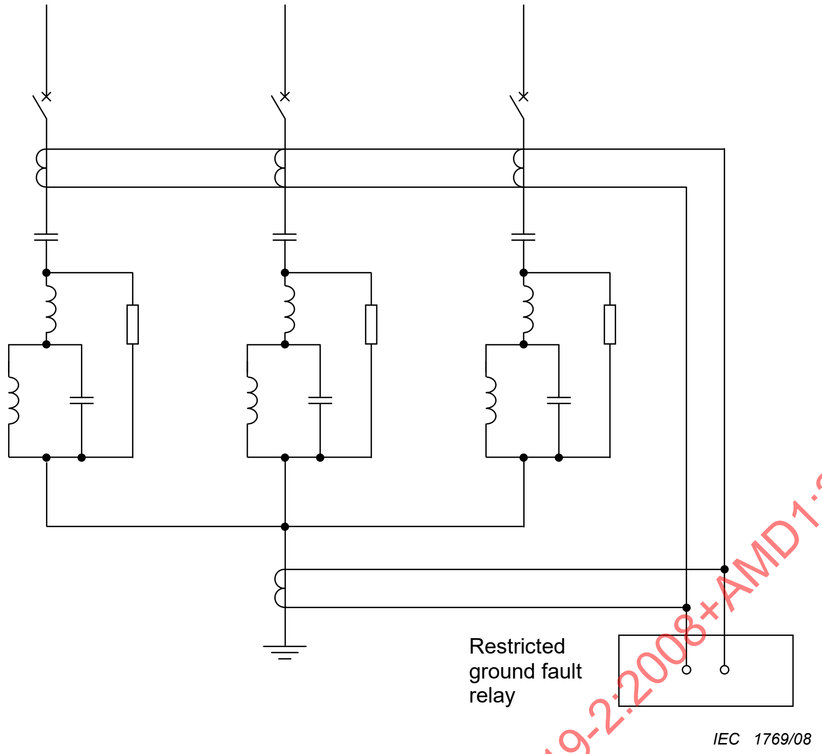


Figure 5 – Example of restricted ground fault protection of filter

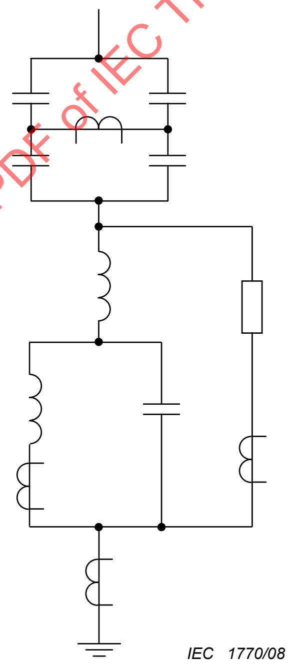


Figure 6 – Example of current transformers arrangement for capacitor bank unbalance protection and overload protection of double tuned filter arm

7 Converter unit faults

7.1 General

This clause discusses converter unit faults, i.e., those which take place between the valve side of the converter transformers and the valve side of the smoothing reactor.

Electronic equipment external to the converter arms but functionally part of them (see IEC 60633), is included in the discussion as appropriate. Cooling equipment is discussed in Clause 14.

In some applications, converter units can be connected in series or in parallel on the d.c. side within one pole of the HVDC substation. Fault aspects of such configurations are also addressed.

Converter unit faults can be classified as:

a) flashovers or short circuits (see 7.2);

b) failures of the converter unit to perform its intended function (see 7.3).

Various protective circuits are usually built around the converter unit to detect faults and operating conditions that can be detrimental to the safety of the equipment, particularly the thyristor valves. Subclause 7.4 lists typical circuits some of which can be required only for particular valve designs.

7.2 Short circuits

Short circuits can be caused by breakdown of external or internal insulation, by inadvertent operation of switches or from other causes. They call for a shut-down of the affected converter unit because of the high probability of equipment damage and the need for repair or replacement.

In bipolar systems or those comprised of two or more independent converter units per pole, the unaffected converter units and thus the remainder of the HVDC transmission system can remain operative after a short-circuit in a converter unit.

For example, Figure 7, shows a number of possible locations of short circuits within a typical converter unit. Faults within the converter transformer are not shown since they are not unique to the HVDC application. Figure 7 is valid for each individual converter unit in parallel or series-connected converter units.

Usually the most severe fault is a short-circuit of a converter valve while it is in rectifier operation at minimum delay angle and maximum a.c. voltage, e.g., due to a flashover. This would constitute a near-solid line-to-line short-circuit of the valve side winding of the converter transformer and subjects the conducting valve in the same commutating group to the fully offset short-circuit current. The possibility of a flashover of the transformer neutral to earth also shall be considered.

Other short-circuits on the d.c. side include short-circuits of a six-pulse bridge, of a twelve pulse group or from pole-to-earth. However due to the emf's and the impedances involved in these cases, they impose a somewhat reduced short-circuit current stress on the converter valves.

Upon detection of a short-circuit, perhaps by the differential protection within an HVDC thyristor valve converter, common practice requires immediate blocking of all gate pulses to prevent further commutation. The short-circuit current then extinguishes at its first zero crossing, generally within the first cycle following fault initiation. Subsequently the valves are subjected to the recovery voltage including any temporary overvoltages resulting from d.c. load rejection. The a.c. circuit-breaker of the converter unit is tripped simultaneously as a back-up. Due attention should be given to the breaker for operation under these circumstances because of the possibility of delayed current zero.

Stresses are most severe on the valve that has been carrying the short-circuit current because its thyristors have a higher than normal junction temperature when the recovery voltage is applied. The capability of a thyristor valve to withstand such stresses without damage and to block against the recovery voltage is termed fault suppression capability (see IEC 60700-1).

For any given system, the maximum valve fault current and thus the highest thyristor junction temperature are obtained with the maximum a.c. system fault current level including any contribution from the a.c. filters. On the other hand, the maximum recovery voltage including load rejection overvoltage is in general experienced with the minimum a.c. system fault current level.

Valves should be specified to have fault suppression capability for consistent levels of short-circuit current and recovery voltage. Breaker failure should also be considered. If three pole breakers are used and the breaker fails, the backup breaker might be opened after about 400 ms, and that time should be considered for valve design. If single pole breakers are used, and one breaker phase fails, the fault current will be interrupted anyway since most of faults are fed from two phases, and no extra time has to be considered for the valve design. If opening of the converter unit circuit-breaker is intended to provide back-up for fault suppression capability, the valves should be specified to have survival capability for the time period until the breaker clears.

For faults to earth, including fault B1, B2, B3 in Figure 7, valves not stressed by the fault current can experience fast changes of potential. Depending on circuit parameters, this may subject the converter valves to stresses equivalent to steep-fronted voltage surges. Specifications then should require that the converter unit equipment be designed and manufactured to withstand resultant stresses under credible fault conditions, as discussed in the foregoing, without damage.

In the case of CCC, short circuit of the commutation capacitor will not give any decisive short circuit current for dimensioning of the main circuit equipment. For dimensioning of the varistor across the commutation capacitor, valve short circuit and commutation failures / a.c. system single-phase faults should be considered as the decisive fault cases. The number of consecutive commutation failures / a.c. system single-phase faults should be carefully considered as it may be dimensioning for the varistors. 2-phase or 3-phase faults between the CC and the valves would give enormous energy and it is not practically possible to dimension the varistor for such fault cases. If the station layout is such that those 2-phase or 3-phase faults cannot be disregarded, they should be considered for current dimensioning purposes only and not for varistor energy dimensioning.

7.3 Failure of converter unit to perform its intended function

7.3.1 General

The basic function of the converter unit is to cyclically commutate the direct current between the phases of the a.c. system. To perform this function, two conditions shall be fulfilled: sufficient commutation voltage shall be present; and synchronized cyclical gate pulses shall be generated by the converter unit control and transmitted to the valve firing circuits.

7.3.2 Rectifier operation

Usually reduction or distortion of the commutating voltage is of little concern because there is sufficient volt-time area to achieve commutation even for close-in single line-to-earth faults. If the three-phase voltage becomes too low for successful commutation the direct current may be reduced or the converter may be blocked. When the voltage reappears the converter should be able to resume operation with the shortest possible delay. This imposes a requirement on valve designs, where auxiliary energy for gating or thyristor protection is taken from the main circuit, in that the electronic circuits should be designed for fast recharging or have adequate energy storage capability.

Persistent failure of a valve to turn on, perhaps due to missing gate pulses, causes the fundamental a.c. voltage to be injected into the d.c. circuit. Depending on circuit parameters, this can lead to transformer saturation, excite possible resonances on the d.c.

line, etc. possibly imposing severe stresses on the affected equipment. The specification should require that such faults be detected and appropriate actions taken (see 8.7).

7.3.3 Inverter operation

During inverter operation the absence of a sufficient commutating voltage-time area or of valve gate pulses results in commutation failure. This subjects the valve to overcurrents and introduces a fundamental a.c. voltage component into the d.c. circuit. Special control strategies such as advancing the delay angle, by-pass pair operation to eliminate fundamental a.c. voltages on the d.c. side, reduction of direct current, etc. are adopted to minimize commutation failures and their effects.

If the commutation failure is caused by insufficient a.c. voltage from an event such as an a.c. system fault (see Clause 5), then normal performance can be expected to resume once the fault has been cleared. To avoid shutdown of the converter, the valves should be designed and manufactured to withstand the stresses resulting from such events for a specified time assisted by the converter unit control. If the specified time is exceeded or if the commutation failure is caused by missing gate pulses then the converter should be blocked.

For valve designs where the auxiliary energy required for gating the thyristors is taken from the main circuit, the pertinent electronic circuits should be designed for fast recharging or they should have sufficient energy storage capability so that the converter can quickly resume normal operation after reappearance of the commutating voltage.

7.4 Converter unit protection

7.4.1 Converter differential protection

By comparing the converter transformer valve side current to the direct current, short-circuits within the converter bridge can be detected. The resulting protective action is to permanently block the converter unit and trip the associated a.c. circuit-breaker.

7.4.2 Overcurrent protection

Evaluating the magnitude of the transformer valve side current makes it possible to protect against overload. This also provides backup for converter differential protection. Protective action is the same as that described in 7.4.1.

7.4.3 AC overvoltage protection

AC overvoltage protection can be included by measuring the a.c. voltage, for example at the valve side of the converter transformer using a capacitive voltage divider as in the transformer bushings or by other means. Protective actions after detecting an undesirable overvoltage might include tripping of capacitor banks, increasing the converter reactive power consumption, permanent blocking of the valves along with tripping of the converter unit a.c. circuit-breaker or an appropriate combination of these actions.

7.4.4 Protection against large delay angle operation

Protection against large delay angle operations can be achieved if required for a particular valve design by measuring the valve delay angles and limiting the duration of such operation in the converter unit control. The limitation should be made dependant on valve side voltage, direct current and the valve coolant temperatures.

7.4.5 Commutation failure protection

Commutation failure detection is usually achieved by a.c./d.c. current differential measurement. If recovery does not occur naturally, this acts after some delay to temporarily increase the inverter angle of advance. If no recovery occurs after a further delay, permanent blocking is applied.

7.4.6 Thyristor valve protections

Thyristor redundancy can be monitored by continuous on-line checking of each thyristor if required. Protective actions can include a warning signal, shut-down and isolation of the converter unit or a combination of these.

Thyristor forward overvoltage protection can be achieved by monitoring the individual thyristor voltages and applying a gating signal if the safe level is exceeded (see also 12.7.3) or by other means.

Forward recovery protection can be used to protect the thyristors against positive high voltage/time differential d*v*/d*t* in the recovery period by applying a gating signal if a safe level is exceeded, or by other means.

7.4.7 Transformer protection

Converter transformer protection is the same as conventionally used for transformers in a.c. transmission systems. It includes differential protection, overcurrent protection, gassing or hot spot detection, etc. Protective action is to trip the converter unit a.c. circuit-breaker. Precautions shall be taken to prevent direct current from flowing in the transformer, for example by bypass-pair operation and thus to assist the circuit-breaker clearing. This can be particularly important for series-connected converter units.

Operation of overall differential protection for valve side earth faults is complicated due to the absence of a direct earth connection. The effects of harmonics upon the operation of the protection should be considered and in particular in the case of biased differential protection with harmonic restraint.

Special attention should be paid to the design and rating of current transformers used because of possible saturation problems. Problems of concern include for example, injection of direct current in conjunction with commutation failures, neutral bus faults, and delayed neutral bus switch operation (see Clause 11).

7.4.8 Transformer tap-changer unbalance protection

Tap-changer unbalance protection may be required to avoid unbalanced operation of the converter unit, in turn leading to generation of excessive non-characteristic harmonics. These can overload filters. Protective response is to give an alarm and initiate a manual or automatic tap changer rebalancing procedure.

7.4.9 AC connection earth fault protection

AC connection earth fault protection may be used to detect earth faults on the connections between the converter transformer and the valves (fault B1 and B2 in Figure 7), when the converter transformer is energized but the valves are blocked. The valve side voltages of the converter transformers can be measured by using capacitive voltage dividers in the transformer bushings or the valve hall bushings or by other means. Protective action can be tripping of the converter unit a.c. circuit-breaker.

7.5 Additional protection aspects of series connected converter units

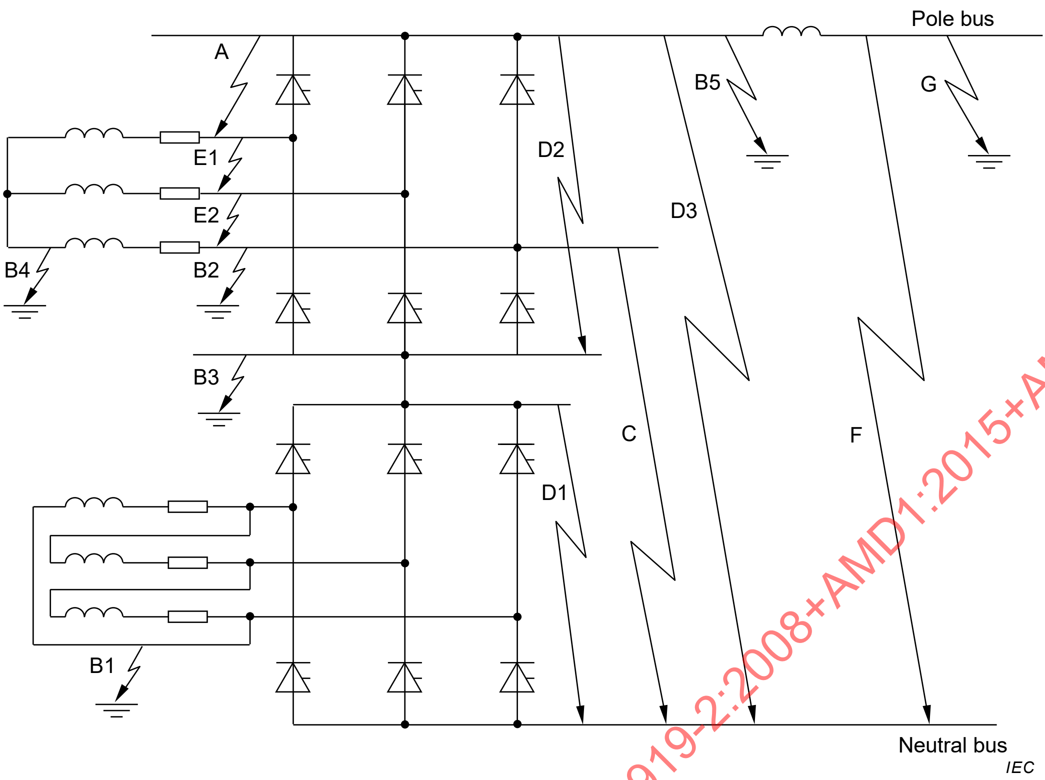
When two or more converter units are connected in series on the d.c. side within one pole of the HVDC substation, protection for the same types of faults apply as for single converter units (see 7.3 and 7.4). One additional differential protection, to cover converter unit faults (type B5 in Figure 7), can be included, comparing the current in the high voltage side and in the low voltage side of the converter unit.

Since both converter units can be operated independently of each other, subdivision of the converter portion of the HVDC substation into protection zones should take this into account (see Figure 8). Protective action for short-circuits would generally include blocking of the pole to remove the direct current. If the fault is within the converter unit 1 or 2 zone, the respective unit then should be isolated and bypassed so that operation can be resumed with the remaining healthy unit. Consideration should also be given to removing one of the converter units from service at the other end of the transmission system to avoid prolonged operation at large delay angle or angle of advance, respectively.

For certain faults occurring only in one of the series connected converter units, such as transformer faults or commutation failures, protective sequences can be used in addition to fault removal to divert the direct current from the affected unit by bypass operation of the converter valves or by closing the bypass switch.

7.6 Additional protection aspects of parallel connected converter units

In general, each of the parallel-connected converter units can be treated independently from the point of view of transient performance and fault protection. However, due consideration should be given to the transient current rating of parallel-connected inverters with respect to commutation failures, especially if the inverters have differing steady-state current ratings. DC breakers may be desirable at the pole bus (see Figure 9), for isolation of faulty converter units, especially inverters, to avoid the need to temporarily block the complete transmission pole.



Fault list

A. Valve short circuit

B. Ground faults on:

1 valve side a.c. phase, D-bridge

2 valve side a.c. phase, Y-bridge

3 bus between 6-pulse bridges

4 neutral point, Y-transformer

5 pole bus connection

C. Short circuit between neutral bus and valve side a.c. phase, Y-bridge

D. Converter short circuit

1 short circuit across lower voltage 6-pulse bridge

2 short circuit across higher voltage 6-pulse bridge

3 short circuit across 12-pulse bridge

E. AC phases short circuit

1 2-phase short circuit

2 3-phase short circuit

F. Pole to neutral bus short circuit outside the d.c. reactor

G. Pole bus to ground fault outside the d.c. reactor

Figure 7 – Examples of a.c. phase short circuits, pole short circuits and faults in a twelve-pulse converter unit

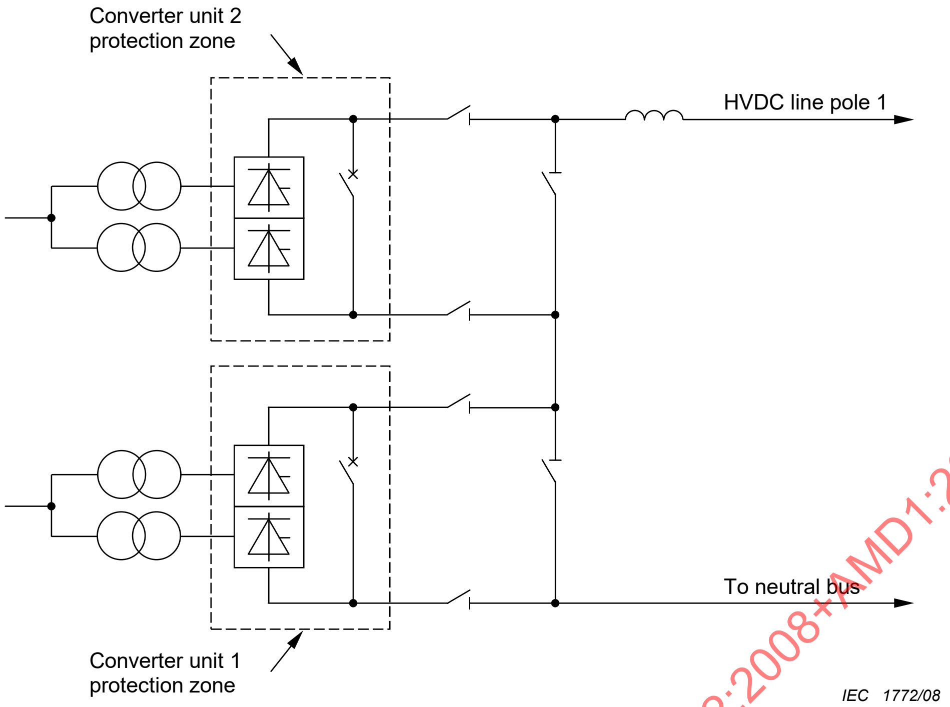


Figure 8 – Protection zones in series-connected converter units

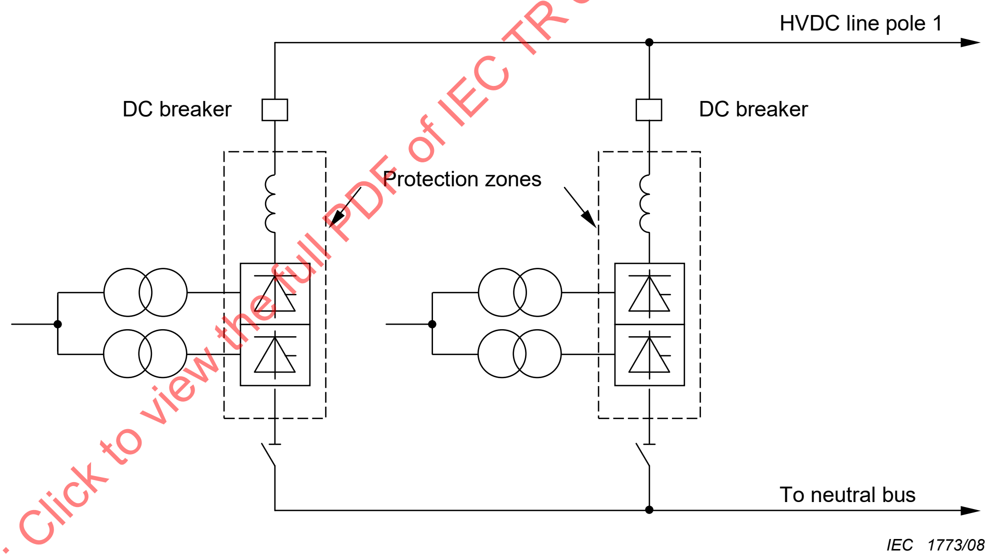


Figure 9 – Protection zones in parallel-connected converter units

8 DC reactor, d.c. filter and other d.c. equipment faults

8.1 General

This clause discusses faults in the HVDC substation for an HVDC transmission system bounded by:

a) the valve side of the d.c. reactor to the d.c. transmission line in each pole;

b) from the neutral side of the converter unit for each pole to the earth electrode line.

8.2 Fault types

Types of faults that should be considered for the protection of the d.c. side equipments and bus sections include:

a) bus-to-earth and bus-to-bus faults;

b) equipment faults;

c) failure of d.c. switching devices to perform their intended switching functions.

8.3 Protection zones

Specifications for HVDC substations should make provision not only for the protection of all d.c. side equipments, but also for the co-ordination of protections.

In HVDC systems the zone protection philosophy and techniques of implementation to achieve zones of protection are in general much the same as with a.c. protection practices. However, in HVDC systems the fault suppression capability of the converter valves (see Clause 7), in addition to the relatively high impedance of d.c. reactors and transformers aids in achieving protection selectively on the d.c. side.

Protection zones of an HVDC substation should be arranged such that all equipment is fully protected by at least one protective function within the HVDC substation. The adjacent zones should be overlapped in actual system in order to eliminate blind spots of protective scheme.

A communication system between substations of the HVDC transmission can be used to optimize recovery from faults and to improve fault protection selectivity for many faults which can take place on an HVDC transmission system. However it should not be necessary for protection of the equipment under discussion in this clause. Figures 10 and 11, show examples of HVDC protection zones and measuring devices for two configurations of HVDC substations.

8.4 Neutral protection

8.4.1 General

In an HVDC system the neutral side protection is generally divided into zones that enable independent fault detection plus selective isolation by pole and a protective zone common to both poles. The latter requires a bipole shutdown to provide corrective maintenance.

8.4.2 Neutral fault detection

In a bipolar configuration operating under balanced conditions, the pole neutral protection zone, the bipole neutral protection zone and the earth electrode line protection zone (see Clause 10) are all essentially at earth potential. An earth fault in any of these zones would therefore not interfere with station operation under balanced bipolar conditions. Any d.c. fault current then would be practically zero.

Faults to earth in these neutral zones would be detectable whenever the poles of the bipole are temporarily unbalanced for any reason such as during startup, shutdown or disturbance on one pole. The HVDC specifications should consider use only of neutral zone alarms if the operation of both poles is expected to be reasonably balanced. This would allow operator decision on corrective actions to be taken based on safety considerations and the power transmission requirements at the time of fault detection.

The pole neutral and bipole neutral zones should be bounded by d.c. current transformers (d.c.-c.t.). A fault within the respective zones can be detected by a differential comparison of the currents as measured by the d.c.-c.t.'s at the zone boundaries during an unbalance operating condition between the two poles.

8.4.3 Neutral bus fault isolation

Faults to earth within the neutral zone or converter zone require a permanent stop of the pole for correction of the faulted condition.

The neutral bus switching device is utilized during the protection sequence to isolate the faulted pole and to transfer any residual pole current to earth return.

Current transfer requirements of the neutral bus switching device should consider the most onerous condition up to and including maximum healthy pole current and location of faults. The switch shall be capable of developing a voltage greater than the IR drop of the earth return to force the current transfer. For systems in which either earth return or on-line transfer to metallic return are not permitted, load break capability of the switching device may not be needed. In this case, a disconnector would be adequate.

In addition, the failure to open the neutral bus switching device of one of the poles will cause a bipole blocking.

8.4.4 Bipolar neutral bus faults

Bus faults within the bipolar neutral protection zone are detectable by differential comparison schemes such as discussed in 8.4.2. A neutral bus fault in this zone requires a bipole shutdown to provide corrective maintenance which could be a scheduled shutdown.

8.5 DC reactor protection

The d.c. reactors of each pole can be either oil-insulated or dry type. Protection of oil type reactors utilizes many of the same techniques as are applied to a.c. transformers with due consideration to the fact that direct current quantities are involved in the operation of the protective devices.

Protection can include:

– pressure relief devices;
– oil temperature monitoring;
– oil level monitoring;
– gas sensing;
– winding temperature sensing;
– loss of cooling detection;
– differential protection.

Differential protection can be specified around the d.c. reactors or these equipments can be included in one of the HVDC substation protection zones as shown in Figures 10 and 11.

Oil type d.c. reactor bushing designs lend themselves to an economic solution to the problem of housing the d.c.-c.t.'s required for differential protection.

When dry type d.c. reactors are employed, separately mounted d.c.-c.t.'s will be needed for reactor fault detection.

8.6 DC harmonic filter protection

8.6.1 General

The d.c. filters associated with HVDC substations are normally specified to limit harmonic interference caused by harmonic currents flowing into the d.c. line (see IEC 60919-1, Clause 17).

Protection design for the d.c. filter arms should take into account the full range of normal and abnormal operating conditions which should be specified for the HVDC substations.

Similarly the protection design for the d.c. filter elements, such as capacitors, reactors, damping resistors, and disconnectors shall consider all expected operational conditions that result in filter elements being overstressed due to harmonic currents which for example can result from operation at large delay angles, angles of advance or from resonant conditions, etc.

8.6.2 Filter bank fault protection

DC filter capacitor bank faults to earth can activate the d.c. line pole protection. However the specifications should require that d.c. line protection operation should not prevent correct identification of any d.c. filter faults and should automatically initiate clearing and isolation of the faulted filter branch.

Any fault within the d.c. filter zone may be detected by a differential comparison between the d.c.-c.t.'s at the boundary of the line side d.c. substation zone as shown in Figures 10 and 11. Other equipment such as line traps, coupling capacitors, d.c. voltage dividers, etc. can also be included in this zone of protection.

Isolation of a faulted filter may require temporary blocking of the affected pole to permit disconnector operation.

If operation is to continue after removal of the faulted d.c. filter branch, the specification should consider the increased d.c. side interference levels expected, possible overloading of other filters and potential resonant conditions.

8.6.3 DC filter capacitor unit protection

Since capacitor banks associated with the d.c. filters normally consist of a combination of series and parallel elements, a variety of protection philosophies may be applied, namely:

- fuse protection (internal or external) if the fuses do provide useful protection;
- unbalance protection within a capacitor bank;
- monitoring of the state of filter tuning by on-line or off-line measurements to locate failures;
- visual or remote indication of failed units or voltage level from earth;
- separate failure alarms to indicate non-critical and critical levels of capacitor failures, including automatic removal of the filter arm if continued operation could result in an avalanche of capacitor failures.

8.7 DC harmonic protection

Protection against fundamental and harmonic frequency components on the d.c. side should be considered in the specification of any HVDC system. Fundamental frequency components on the d.c. side lead to a d.c. and second harmonic frequency component on the a.c. side which can cause transformer saturation or resonant conditions. The fundamental frequency can be detected in the voltage divider or d.c.-c.t. signals. The related harmonic protection normally initiates pole blocking whenever the harmonic component exceeds a given threshold value for a specified time.

8.8 DC overvoltage protection

Specifications for HVDC substations should consider d.c. side overvoltage protection to assure that all equipments and the d.c. line or cable are protected against steady-state overvoltages. Transient overvoltage protection can be addressed as part of the arrester co-ordination (see Clause 12). Normally converter controls are utilized to implement d.c. system steady state overvoltage protection functions.

8.9 DC side switching protection

Switching devices such as high speed pole circuit-breakers and d.c. side disconnectors, including d.c. filter and pole disconnectors, shall be covered in the specifications. Specification of these switching devices shall consider current interrupting or commutation capability. In addition, permissible switch arcing time without unacceptable equipment damage shall be considered.

The disconnectors usually operate at no-load and their operating supervision should be provided either by the equipment or by other associated protection. The on-load switches, such as the by-pass breakers, should have a dedicated protection.

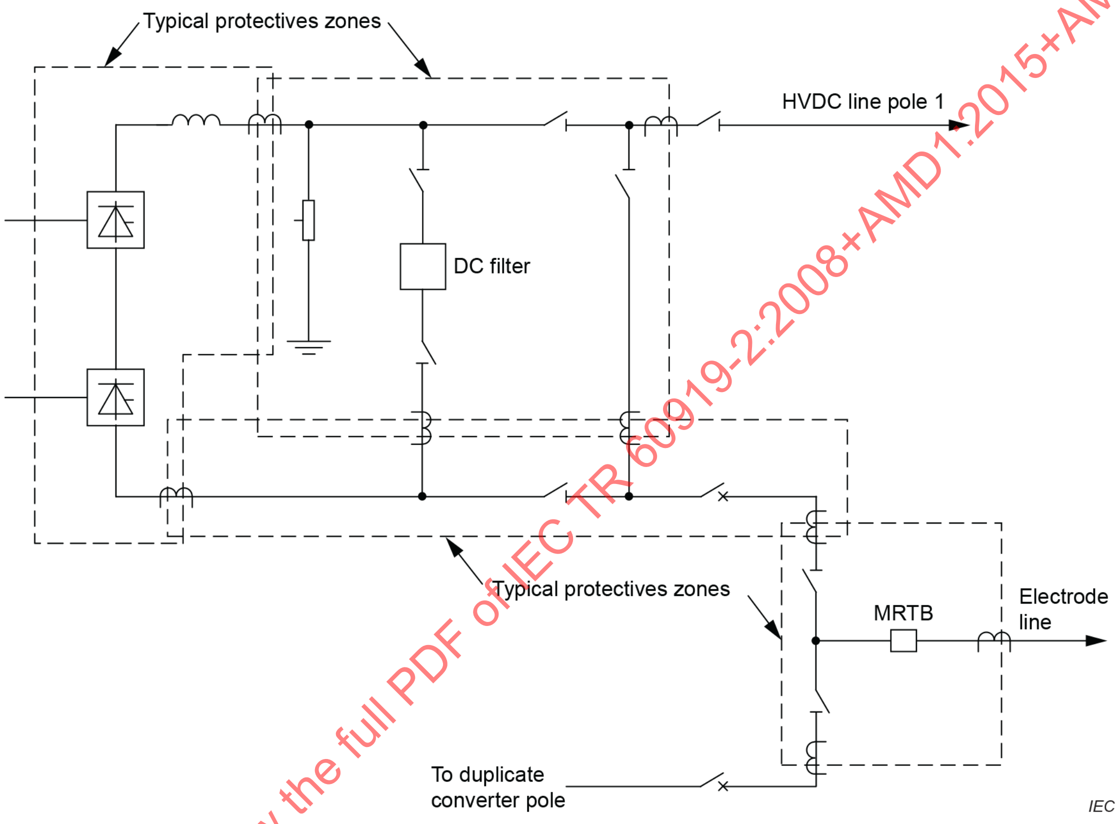


Figure 10 – Example of d.c. protection zones for series-connected converter units

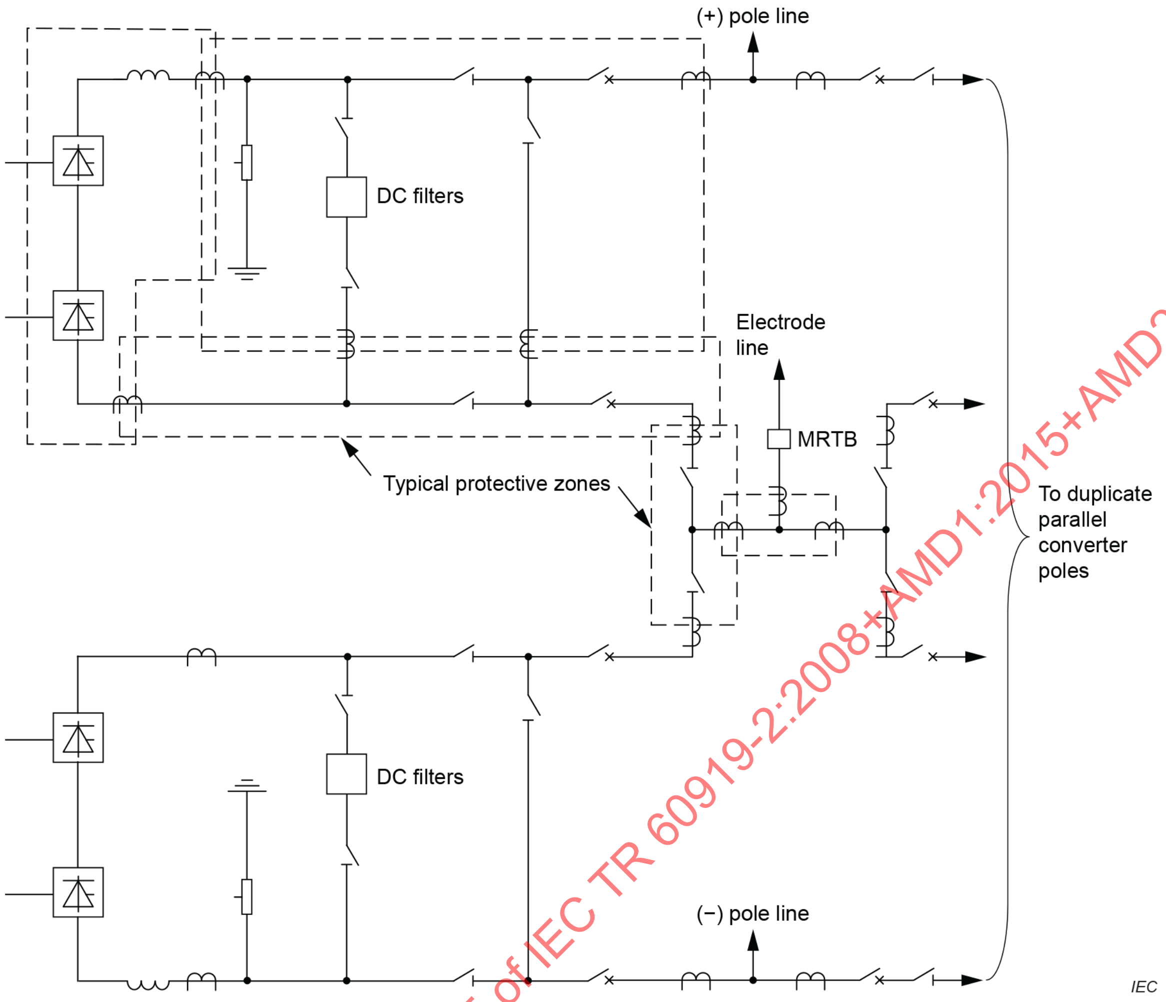


Figure 11 – Example of d.c. protection zones for parallel-connected converter pole

9 DC line faults

9.1 Overhead line faults

An overhead line, particularly if it is very long, may be a source of major disturbances in an HVDC transmission system. The most common fault on an overhead line is a flashover between a line pole and earth. If the line is bipolar the conductors of the two line poles are most often arranged at such a distance from each other that a flashover between poles is excluded for practical purposes.

Overhead line faults are mainly caused by:

– lightning strokes;
– contamination by: salt, industrial pollutants, sand and dust, etc.;
– overvoltages due to faults, control system malfunction, etc.;
– fallen towers;
– other: snow or ice damage, wind, bush fires, tree contacts, etc.

Most d.c. line faults are temporary, i.e. the insulation at the fault location is nearly always restored to its pre-fault level after the fault is cleared. Also since the d.c. fault current is relatively low, it does not usually cause appreciable damage to the conductors and insulators