

TECHNICAL REPORT



**Performance of high-voltage direct current (HVDC) systems with line-commutated converters –
Part 1: Steady-state conditions**

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TECHNICAL REPORT



**Performance of high-voltage direct current (HVDC) systems with line-commutated converters –
Part 1: Steady-state conditions**

INTERNATIONAL
ELECTROTECHNICAL
COMMISSION

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INTERNATIONAL ELECTROTECHNICAL COMMISSION

**PERFORMANCE OF HIGH-VOLTAGE DIRECT CURRENT
(HVDC) SYSTEMS WITH LINE-COMMUTATED CONVERTERS –****Part 1: Steady-state conditions**

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IEC 60919-1, 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 third edition cancels and replaces the second edition, published in 2005. This edition constitutes a technical revision.

This edition includes the following significant technical changes with respect to the previous edition:

- a) the changes have been made to the description of multi 12-pulse groups per pole, especially for a large scale ultra high-voltage direct current (UHVDC) converter arrangement;
- b) the different arrangements of d.c. smoothing reactors have been included;
- c) the figures depicting two 12-pulse groups per pole arrangement have been added.

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

Draft of Technical Report	Report on voting
22F/213/DTR	22F/218/RVC

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

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

A list of all parts of the IEC 60919 series, published 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 this publication will remain unchanged until the stability date indicated on the IEC web site under "<http://webstore.iec.ch>" in the data related to the specific publication. At this date, the publication will be

- reconfirmed;
- withdrawn;
- replaced by a revised edition, or
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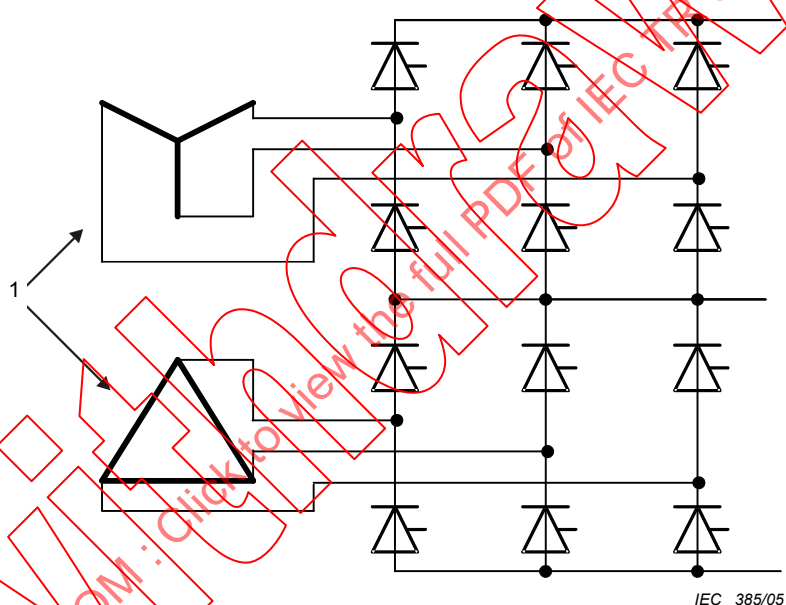
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PERFORMANCE OF HIGH-VOLTAGE DIRECT CURRENT (HVDC) SYSTEMS WITH LINE-COMMUTATED CONVERTERS –

Part 1: Steady-state conditions

1 Scope

This part of the IEC 60919 provides general guidance on the steady-state performance requirements of high-voltage direct current (HVDC) systems. It concerns the steady-state performance of two-terminal HVDC systems utilizing 12-pulse converter units comprised of three-phase bridge (double-way) connections (see Figure 1), but it does not cover multi-terminal HVDC transmission systems. Both terminals are assumed to use thyristor valves as the main semiconductor valves and to have power flow capability in both directions. Diode valves are not considered in this report.



Key

- 1 Transformer valve windings

Figure 1 – Twelve-pulse converter unit

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/TR 60146-1-2 and IEC 60146-1-3. Voltage-sourced converters are not considered.

This technical report, which covers steady-state performance, is followed by additional documents on dynamic performance and transient performance. All three aspects should be considered when preparing two-terminal HVDC system specifications.

The difference between system performance specifications and equipment design specifications for individual components of a system should be realized. Equipment specifications and testing requirements are not defined in this report. Also excluded from this report are detailed seismic performance requirements. In addition, because there are many variations between different possible HVDC systems, this report does not consider these in detail; consequently, it should not be used directly as a specification for a particular project,

but rather to provide the basis for an appropriate specification tailored to fit actual system requirements.

Frequently, performance specifications are prepared as a single package for the two HVDC substations in a particular system. Alternatively, some parts of the HVDC system can be separately specified and purchased. In such cases, due consideration should be given to co-ordination of each part with the overall HVDC system performance objectives and the interface of each with the system should be clearly defined. Typical of such parts, listed in the appropriate order of relative ease for separate treatment and interface definition, are:

- a) d.c. line, electrode line and earth electrode;
- b) telecommunication system;
- c) converter building, foundations and other civil engineering work;
- d) reactive power supply including a.c. shunt capacitor banks, shunt reactors, synchronous and static reactive power (VAR) compensators;
- e) a.c. switchgear;
- f) d.c. switchgear;
- g) auxiliary systems;
- h) a.c. filters;
- i) d.c. filters;
- j) d.c. reactors;
- k) converter transformers;
- l) surge arresters;
- m) series commutation capacitors;
- n) valves and their ancillaries;
- o) control and protection systems.

NOTE The last four items are the most difficult to separate, and, in fact, separation of these four may be inadvisable.

A complete steady-state performance specification for a HVDC system should consider Clauses 3 to 21 of this report.

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 (see Clause 10) 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, as discussed in Clause 16.

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 convertors – General requirements and line commutated convertors – Part 1-1: Specifications of basic requirements*

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

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

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

3 Types of HVDC systems

3.1 General

This part of the specification should include the following basic data:

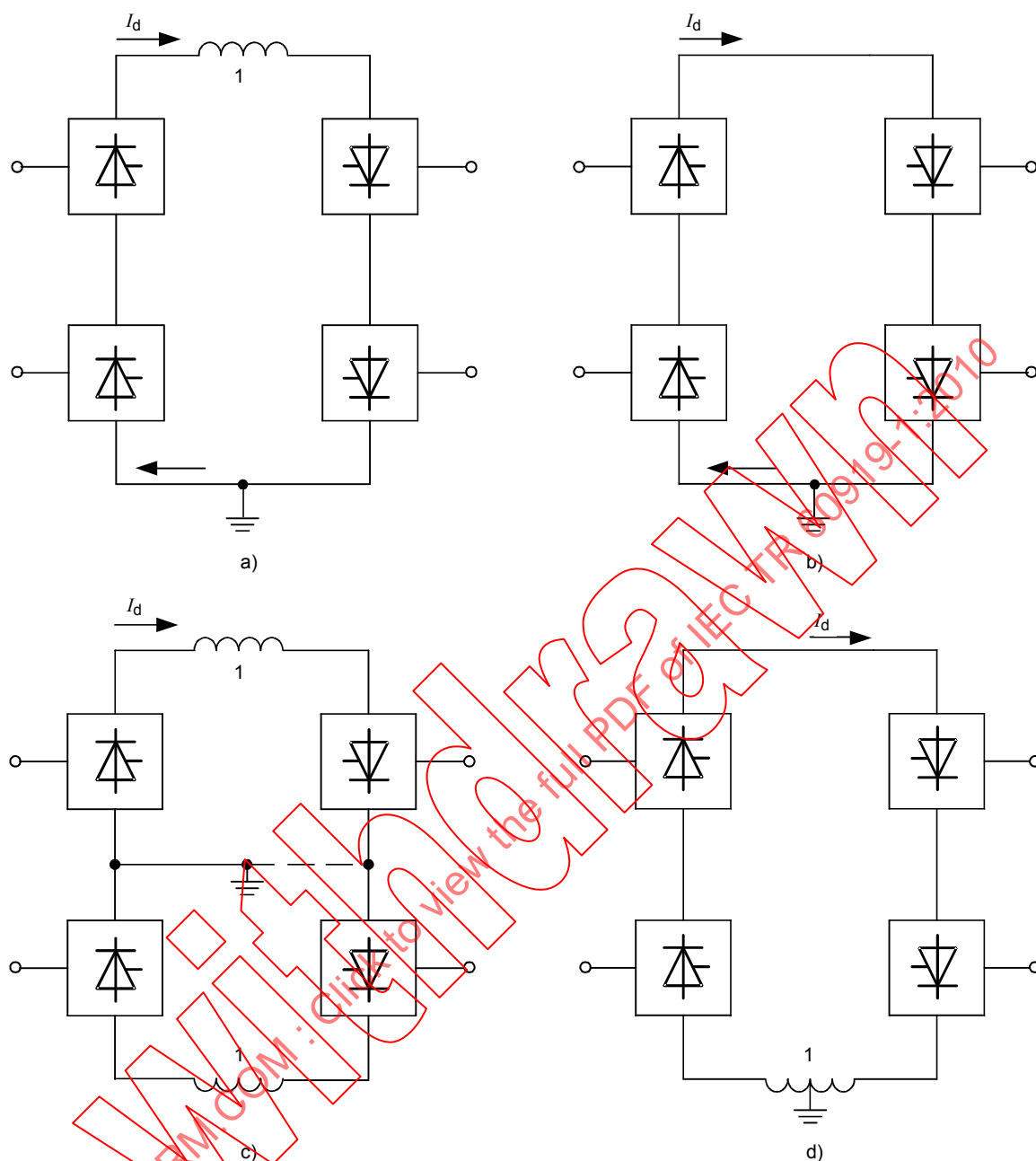
- a) general information on the location of the HVDC substations and the purpose of the project;
- b) type of system needed, including a simple one-line diagram;
- c) number of 12-pulse converter units;
- d) pertinent information derived from the discussion in this section.

Generally, in studies of projects of the types discussed in this report, economic considerations should take into account the capital costs, the cost of losses, cost of outages and other expected annual expenses.

In terms of the type of system, the relatively new development of “capacitor-commutated converter (CCC)” and “controlled series capacitor converter (CSCC)” technology may be suitable alternatives to a conventional HVDC scheme. These are described in 3.10.

3.2 HVDC back-to-back system

In this arrangement there is no d.c. transmission line and both converters are located at one site. The valves for both converters may be located in one valve hall, or even in one integrated structure or separately as outdoor valves. Similarly, many other items for the two converters, such as the control system, cooling equipment, auxiliary system, etc., may be located in one area or even integrated in layout into configurations common to the two converters. Circuit configurations may vary. Examples are given in Figure 2. The performance and economics of these configurations differ and must be evaluated. D.C. filters are not needed.



IEC 386/05

Key

1 DC reactor

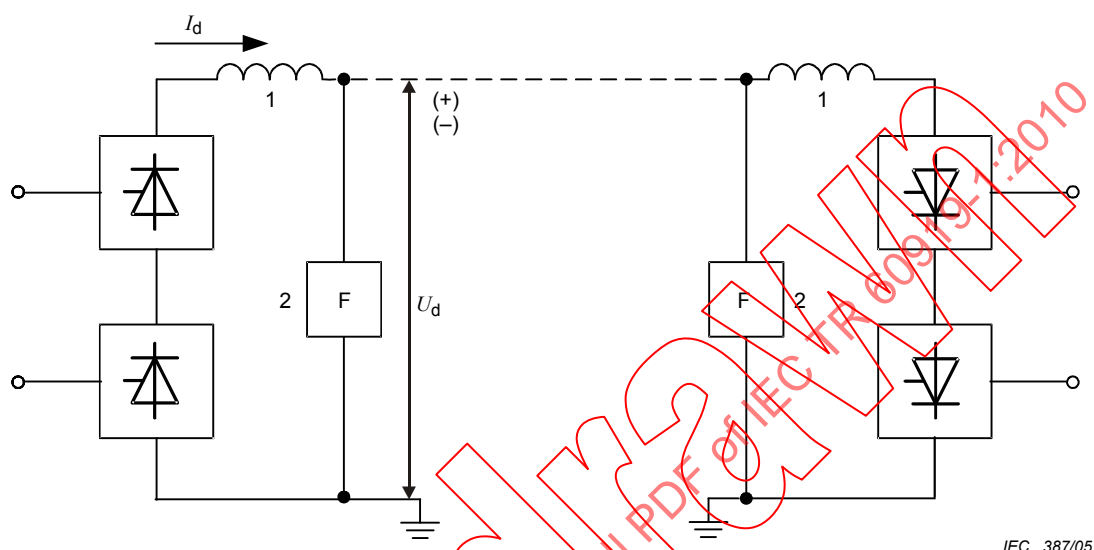
Figure 2 – Examples of back-to-back HVDC systems

The voltage and current ratings for a given power rating should be optimized to achieve the lowest system cost, including the evaluated cost of losses. Ordinarily, the user does not need to specify the direct voltage and current ratings, unless there are specific reasons to do so, for example, for compatibility with an already existing station, to provide for a future extension or for some other reason. Economics dictate that each converter will usually be a 12-pulse converter unit, however it is not mandatory. Where operating criteria require that the loss of one converter unit will not cause loss of full power capability, large HVDC substations could be comprised of two or more back-to-back systems. For this, some of the equipment of the back-to-back systems can, for economic reasons, be located in the same area or even physically integrated, but events which could cause a failure of equipment required by all

back-to-back systems need to be carefully considered and preventive measures taken where appropriate.

3.3 Monopolar earth return HVDC system

Cost considerations often lead to the adoption of a monopolar earth return system (Figure 3), particularly for cable transmission which may be expensive.



IEC 387/05

Key

- 1 DC reactor
- 2 DC filters

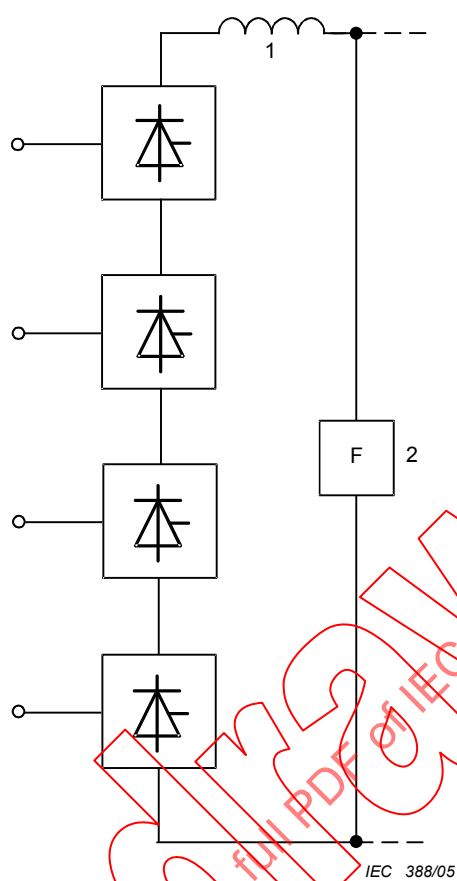
Figure 3 – Monopolar earth return system

The monopolar earth return configuration might also be the first stage in the development of a bipolar scheme. Monopolar arrangements may include one or more 12-pulse units in series or in parallel at the ends of the HVDC transmission (Figures 4 and 5). More than one 12-pulse unit might be used for the following purposes:

- a) to ensure partial transmission capacity during converter unit outages;
- b) to complete the project in stages;
- c) because of the physical limitations of transformer transport.

This arrangement requires one or more d.c. reactors at each end of the HVDC overhead line or cable; these are usually located on the high-voltage side. However, the d.c. reactors may be divided into two parts and located on the high-voltage side and the earth side respectively if the resulting performance is acceptable, especially for a large scale ultra high voltage direct current (UHVDC) converter arrangement.

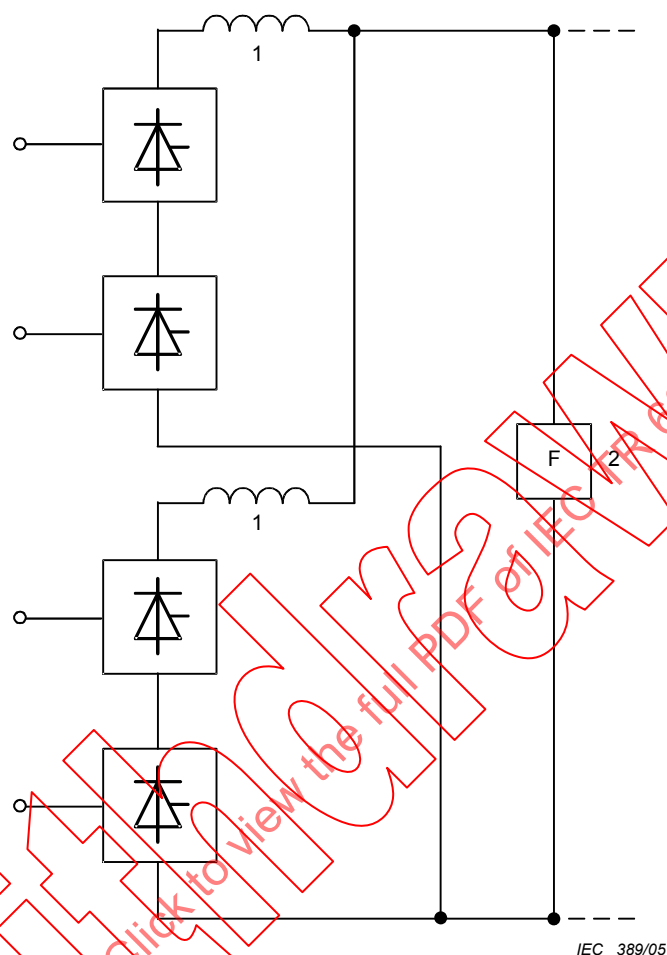
If the line is overhead, d.c. filters are likely to be needed at each end (see Clause 17). It also requires an earth electrode line and a continuously operable earth electrode at the two ends of the transmission which involves consideration of issues such as corrosion, magnetic field effects, etc.



Key

- 1 DC reactor
- 2 DC filter

Figure 4 – Two 12-pulse units in series

**Key**

- 1 DC reactor
- 2 DC filter

Figure 5 – Two 12-pulse units in parallel**3.4 Monopolar metallic return HVDC system**

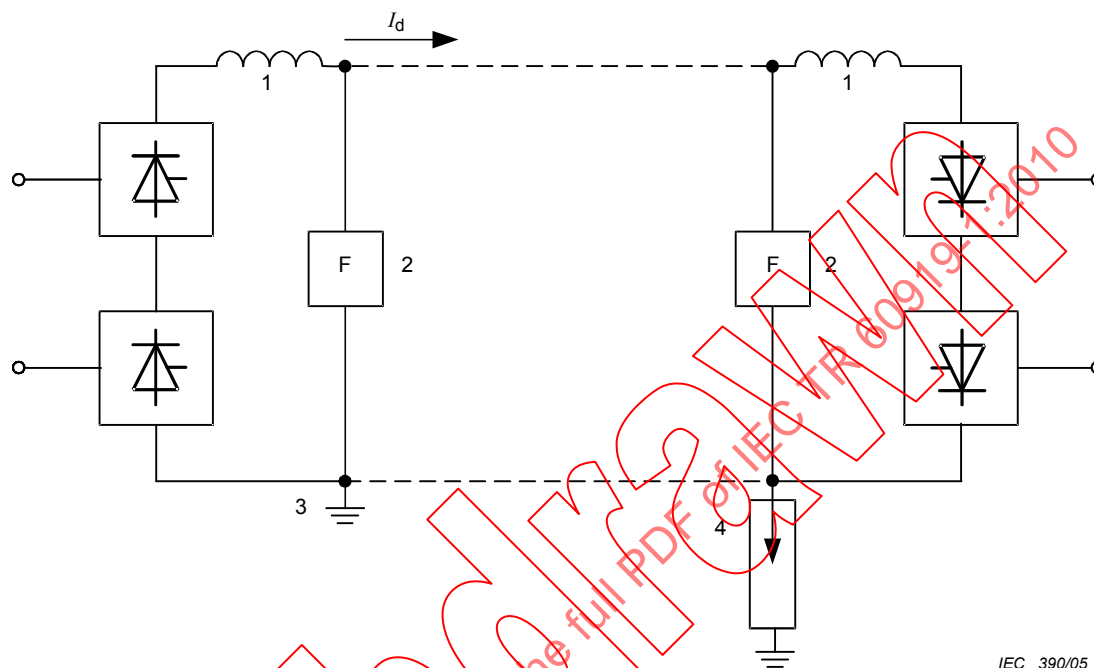
The configuration as illustrated in Figure 6 will generally be used for the following purposes:

- a) as the first stage in the construction of a bipolar system and if long-term flow of earth current is not desirable during the interim period, or
- b) if the transmission line length is short enough to make it uneconomic and undesirable to build earth electrode lines and earth electrodes, or
- c) if the earth resistivity is high enough to impose an unacceptable economic penalty, or
- d) if long-term flow of earth current is unacceptable because of environmental and safety requirements.

This configuration utilizes one high-voltage and one low-voltage conductor. The neutral is connected at one of the two HVDC substations to its station earth or, alternatively, to the associated earth electrode. The other HVDC substation neutral is connected to its station earth through a capacitor or an arrester or both.

DC reactors are needed at both ends of the high-voltage conductor. However, the d.c. reactor may be located on the earth side if the resulting performance is acceptable. DC filters may be needed if the HVDC transmission line is overhead.

If this configuration is the first stage of a bipolar system, its neutral conductor could be insulated for the high voltage at this stage of development.



Key

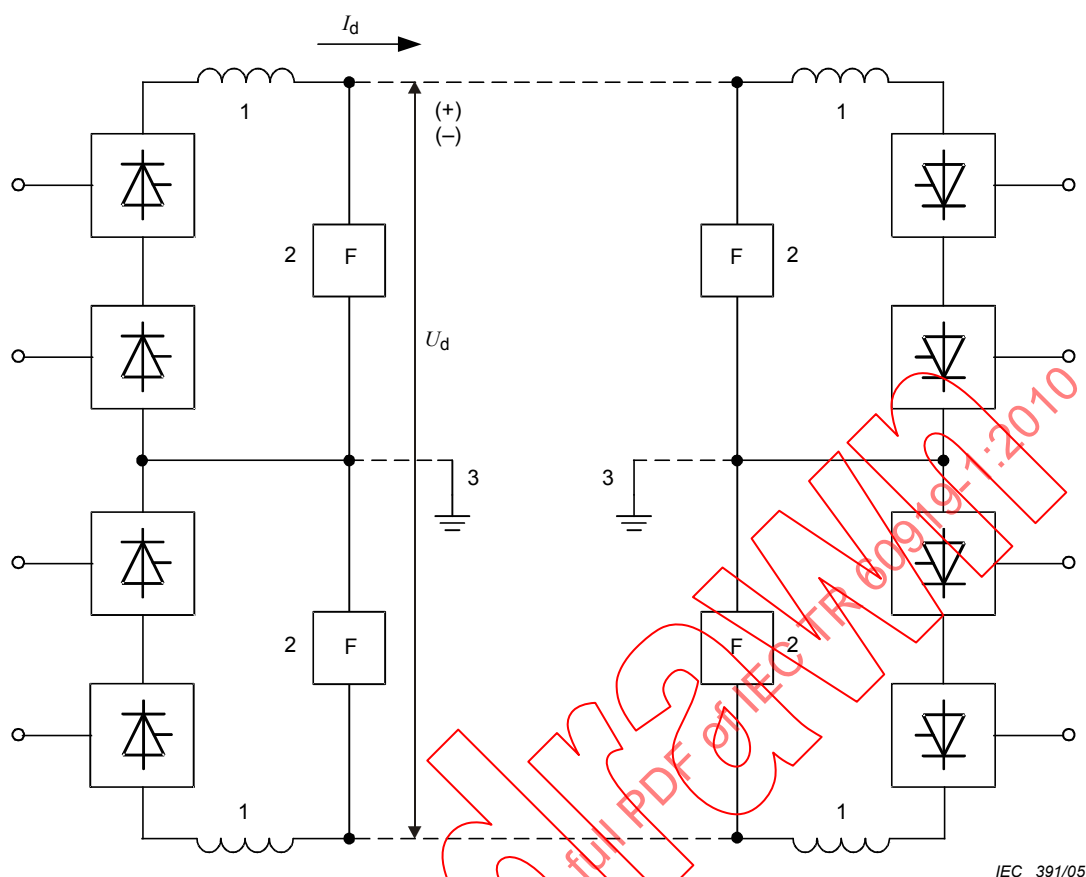
- 1 DC reactor
- 2 DC filter
- 3 Station earth
- 4 Arrester

Figure 6 – Monopolar metallic return system

3.5 Bipolar earth return HVDC system

This is the most commonly used arrangement when a d.c. transmission line connects two HVDC substations and electrodes for earth return operation are provided (Figure 7). It is effectively equivalent to a double-circuit a.c. transmission. It reduces harmonic interference from the d.c. line as compared with monopolar operation and it keeps earth current flow down to a low value. When combined, two monopolar earth return schemes can give a bipolar scheme.

For power flow in one direction, one pole has positive polarity to earth and the other pole has negative polarity to earth. For power flow in the other direction, the two poles reverse their polarities. When both poles are in operation, the unbalance current flowing in the earth path can be kept at a very low value.

**Key**

- 1 DC reactor
- 2 DC filter
- 3 Earth electrodes

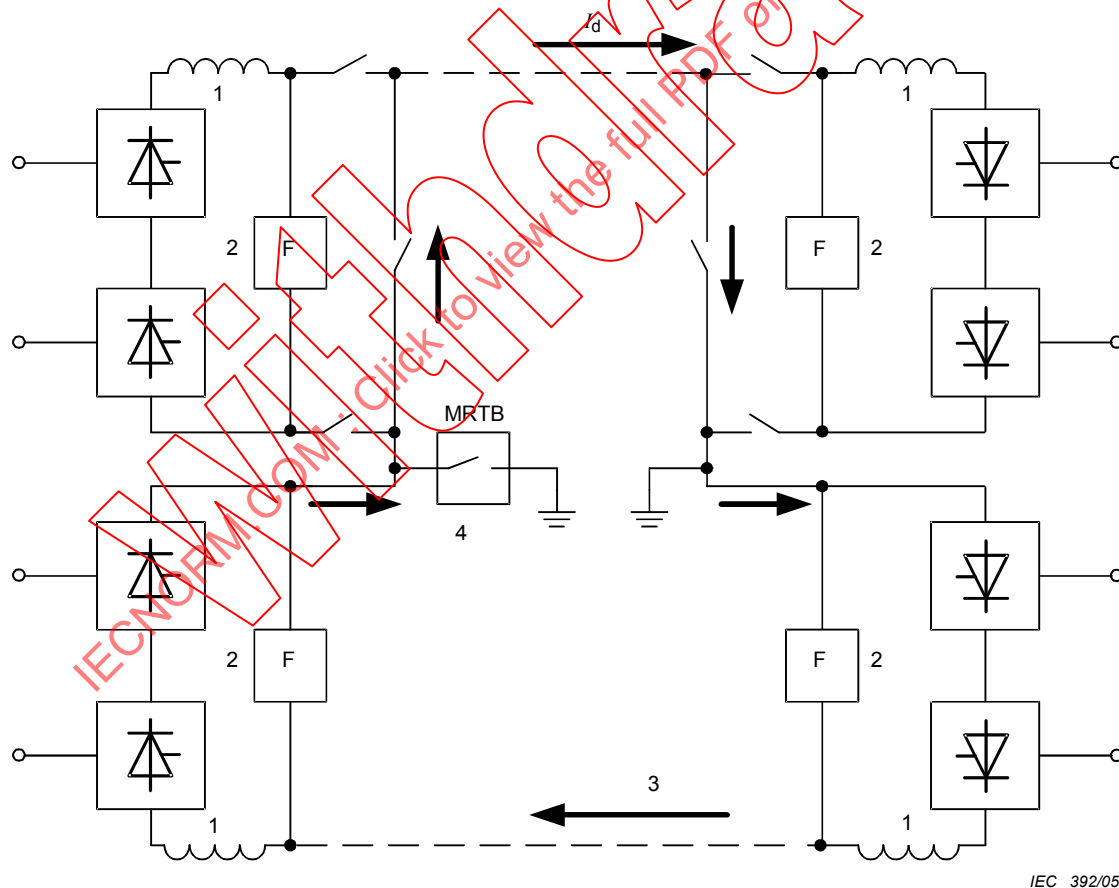
Figure 7 – Bipolar system

This configuration offers a number of emergency operating modes. Consequently, the following requirements should be considered in the specifications.

- a) During an outage of one HVDC transmission line pole, the converter equipment of the other pole should be capable of continuous operation with earth return.
- b) If long-term flow of earth current is undesirable and if the defective line pole still retains some low-voltage insulating capability, the bipolar system should be capable of operation in the monopolar metallic return mode (Figure 8). To switch into this emergency operating mode the conductor of the out-of-service pole is first connected in parallel with the earth path and then the earth path is interrupted to transfer the current to the metallic path (through the conductor of the out-of-service pole). Load transfer without interruption requires a metallic return transfer breaker (MRTB) at one terminal of the d.c. transmission. If a short interruption of power flow is permitted, MRTB would not be necessary. The neutral equipment at the MRTB end of the HVDC transmission system should be insulated from earth for a somewhat higher voltage than at the other end of the system.
- c) During maintenance of the earth electrode(s) or the earth electrode line(s), operation of the bipolar system should be possible with the station neutral(s) connected to the station earth at one or both HVDC substations as long as the unbalance current between the two poles entering the station earth(s) is kept at a very low value. The unbalance current should be kept low to avoid saturation effects in the converter transformers from the flow of part of the unbalance current through the transformer neutrals. In this arrangement when one transmission line of substation pole is lost, both poles should be blocked automatically.

- d) In bipolar operation with both earth electrodes connected, the two poles of the HVDC system should be capable of operation with substantially different currents in each pole. This may be necessary if loss of cooling or some other unusual condition prevents the operation of one pole with full current.
- e) If continuation of operation is required in the case where the line insulation has been partially damaged, the converters should be designed for continuous operation at reduced voltage, so that either pole can be operated at reduced voltage (see 7.3).
- f) In the event of the loss of one transmission line pole, the two substation poles can also be connected in parallel by using appropriate switches for polarity reversal in at least one station pole enabling both poles to operate in the monopolar earth return mode. This, however, requires that the d.c. terminals of each 12-pulse group be insulated for the full pole voltage and the line and the earth electrode shall be thermally capable of carrying a current higher than the normal current.

One or more d.c. reactors is needed at each end of the system in each pole, these are usually located on the high-voltage side. However, the d.c. reactors may be divided into two parts and located on the high-voltage side and the earth side respectively if the resulting performance is acceptable, especially for a large scale ultra high voltage direct current (UHVDC) converter arrangement. If the HVDC system includes an overhead line, d.c. filters would most likely be needed. One 12-pulse unit per pole is most commonly used; however, large capacity systems or staged expansion may require 12-pulse units in series or in parallel (Figures 4 and 5).



Key

- 1 DC reactor
- 2 DC filter
- 3 Operating pole
- 4 MRTB Metallic return transfer breaker

Figure 8 – Metallic return operation of the unfaulted pole in a bipolar system

3.6 Bipolar metallic return HVDC system

If earth currents are not tolerable (as mentioned in 3.4, item d)) or if the distance between the HVDC system terminals is short, or if an earth electrode is not feasible because of high earth resistivity, then the transmission line may be constructed with a third conductor to give a bipolar metallic return HVDC system (Figure 9). The third conductor carries unbalance currents during bipolar operation. It also serves as the return path when one transmission line pole is out of service. This third conductor requires only reduced voltage insulation and, in this case, may also serve as a shield wire if the line is overhead. However, if it is fully insulated, it can serve as a spare conductor. In this case, a separate shield wire is required.

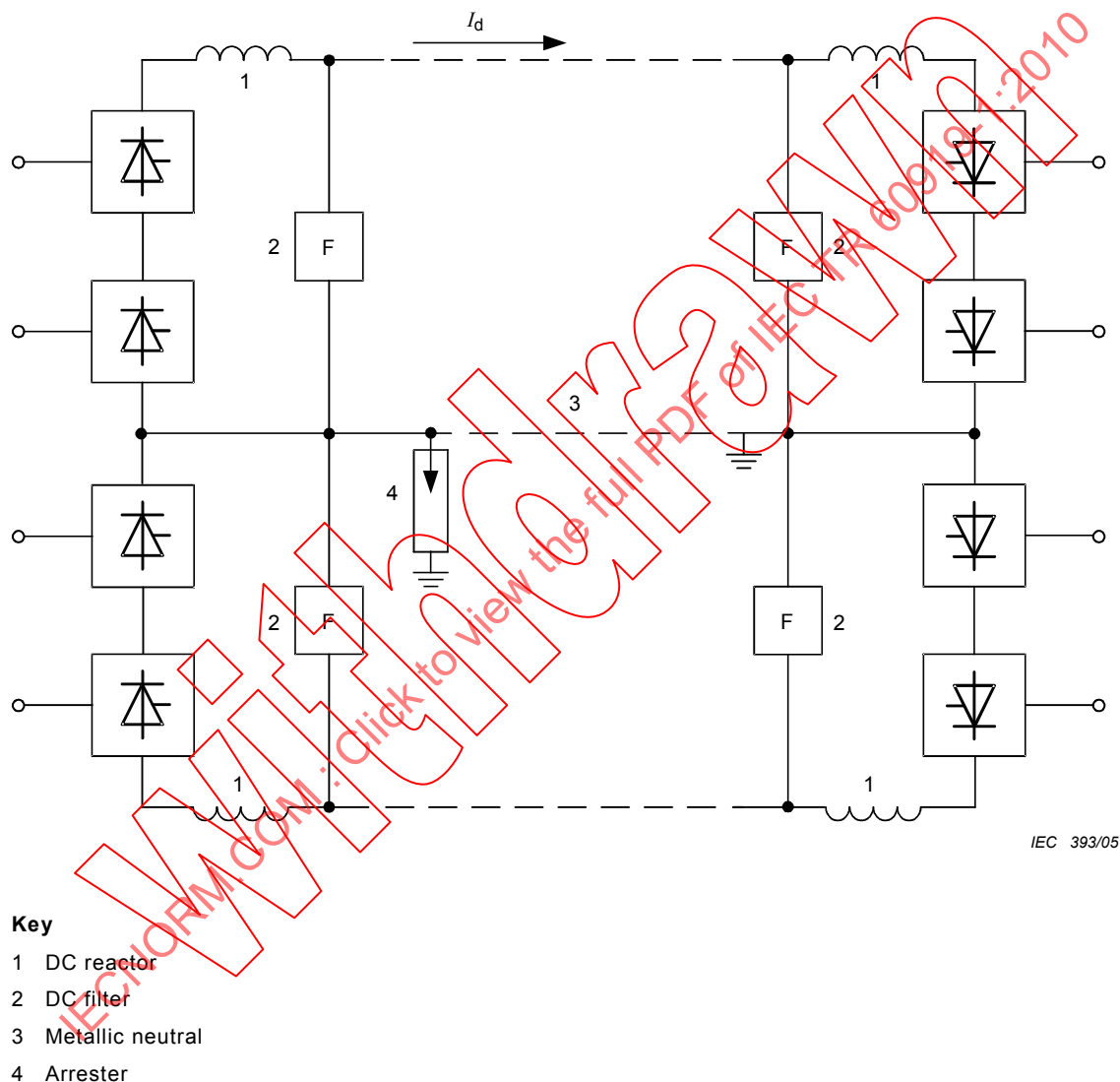


Figure 9 – Bipolar metallic return HVDC system

The neutral of one of the two HVDC substations should be earthed, while the neutral at the other end of the transmission would float or be tied to its station earth through an arrester, a capacitor or both.

With this design, the system can still be operated in the bipolar mode, if one conductor becomes unavailable and the third conductor is fully insulated. Then, the neutrals at both terminals should be connected to their local station earths, and care should be taken to hold the unbalanced current flow to very low values. Loss of one pole will require blocking of the other pole until the necessary switching has taken place for operation of the remaining sound portions of the HVDC transmission system.

If one substation pole becomes unavailable, the system can be operated in monopolar metallic return mode by utilizing the other substation pole.

3.7 Two 12-pulse groups per pole

For a high power ultra high-voltage direct current (UHVDC) converter arrangement, two 12-pulse units per pole may be a better solution to achieve required rating, because the dimension and weight of converter equipment (especially converter transformer) would become too large if only one 12-pulse unit per pole were used.

Two 12-pulse converters can be connected in series (Figure 10) or in parallel (Figure 11), and the selection of converter arrangement depends on the specific requirements of the project. On the other hand, if a project requires reduced voltage operation, for instance, due to occasional salt contamination, then series option should be selected.

Basically series/parallel option has no difference regarding loss of power when a forced or scheduled outage of a 12-pulse converter occurs, only 25 % of the capacity will be lost, assuming the same power rating converters are employed. If sufficient overload capability is available, full power or almost full power can be restored. For series option, the two poles can still operate with balanced current (without earth current) after a forced or scheduled outage of a 12-pulse converter occurs. However, note that by-pass switch is required for each 12-pulse converter in series connected option. For parallel option, the two poles can still operate with unbalanced current when a forced or scheduled outage of a 12-pulse converter occurs, while there is large current flowing through earth.

The cost of two 12-pulse group per pole arrangement, compared to one 12-pulse group per pole for the same total rating, would be expected to be greater, and control system will become more complicated.

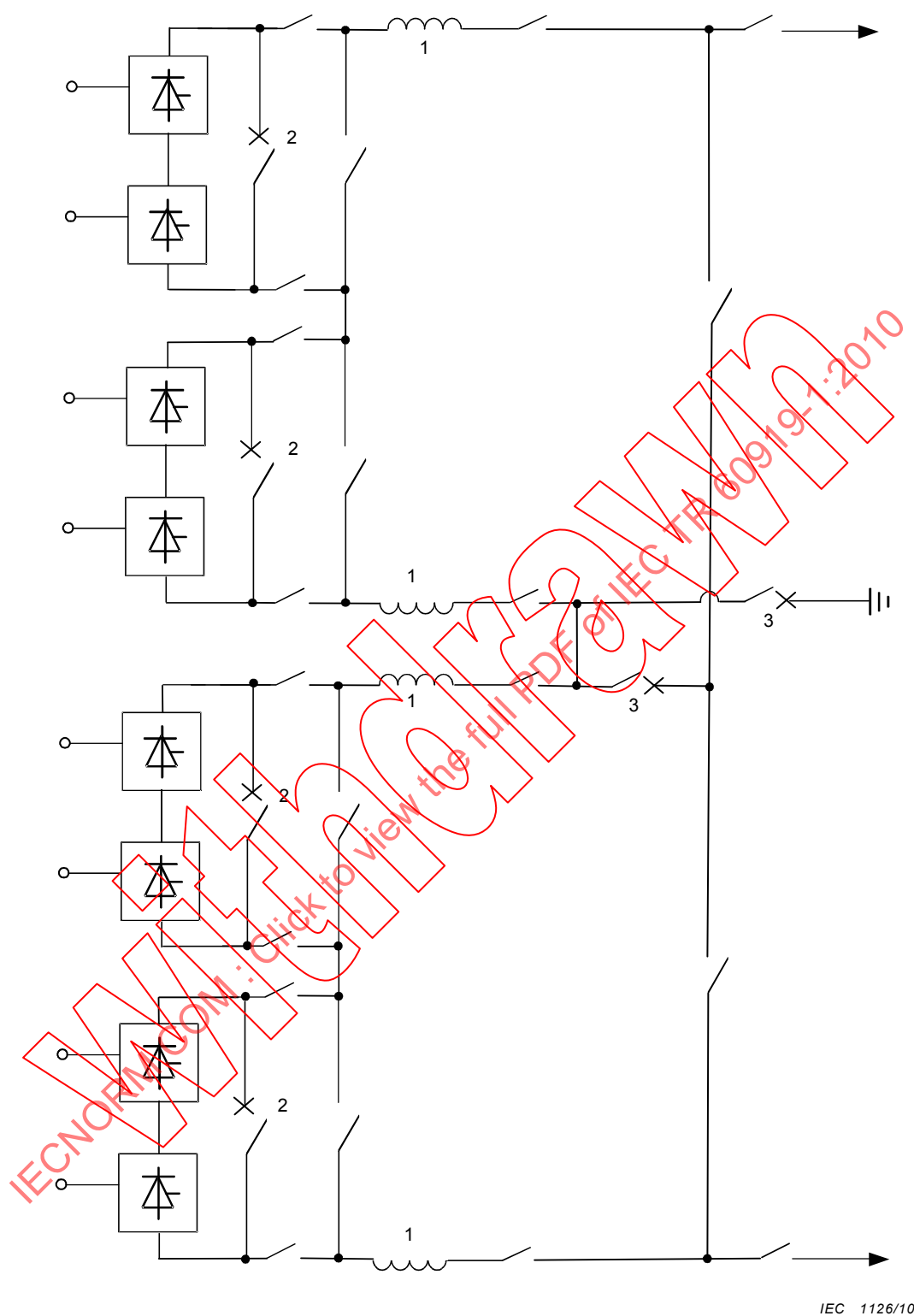
3.8 Converter transformer arrangements

Each 12-pulse converter requires two three-phase transformer valve windings, one star-connected and the other delta-connected. These are provided by either:

- a) one three-phase transformer with two valve windings, or
- b) two three-phase transformers, one connected star-star and the other star-delta, or
- c) three single-phase transformers each with two valve windings, one for star connection and the other for delta connection, or
- d) six single-phase transformers, connected in two three-phase banks, one connected star-star and the other star-delta.

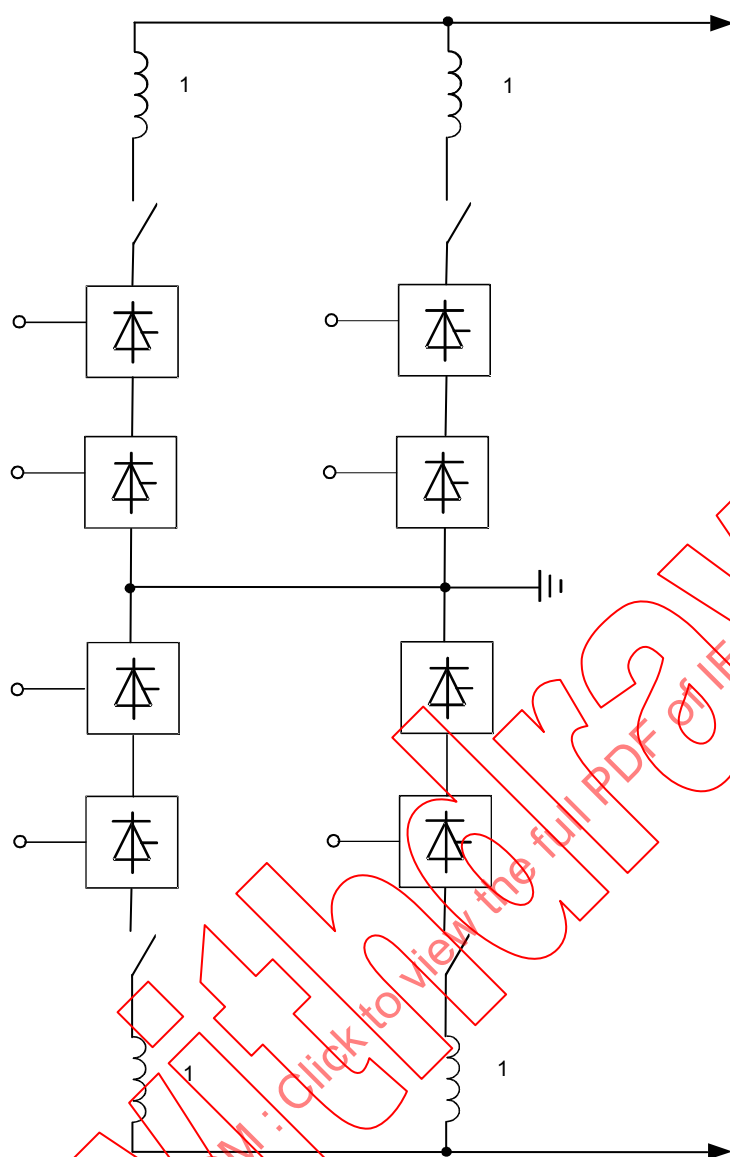
Depending on the HVDC system availability requirements, spare transformers may be needed at one or both ends. If one three-phase transformer with two valve windings is used, only one spare unit would be required. Since the star- and delta-connected three-phase transformers would be of different designs, spares considerations would indicate one spare of each design. Only one spare would be required for the single-phase, double-valve winding transformers since all three would be identical. The last of the above options would suggest two spare transformers, one each for the star- and the delta-valve winding single-phase transformers.

If spare transformers are not employed, alternatives b) and d) above allow for six-pulse operation at half-power in case of a transformer outage, if the HVDC system is designed for this mode of operation and the a.c. and d.c. harmonic conditions would be acceptable. Six-pulse operation is not possible with alternatives a) and c).

**Key**

- 1 DC reactor
- 2 By-pass switch
- 3 DC switch

Figure 10 – Bipolar system with two 12-pulse units in series per pole



IEC 1127/10

Key

1 DC reactor

Figure 11 – Bipolar system with two 12-pulse units in parallel per pole

Converter transformers with a tertiary winding for reactive power and a.c. harmonic filter equipment may also be used.

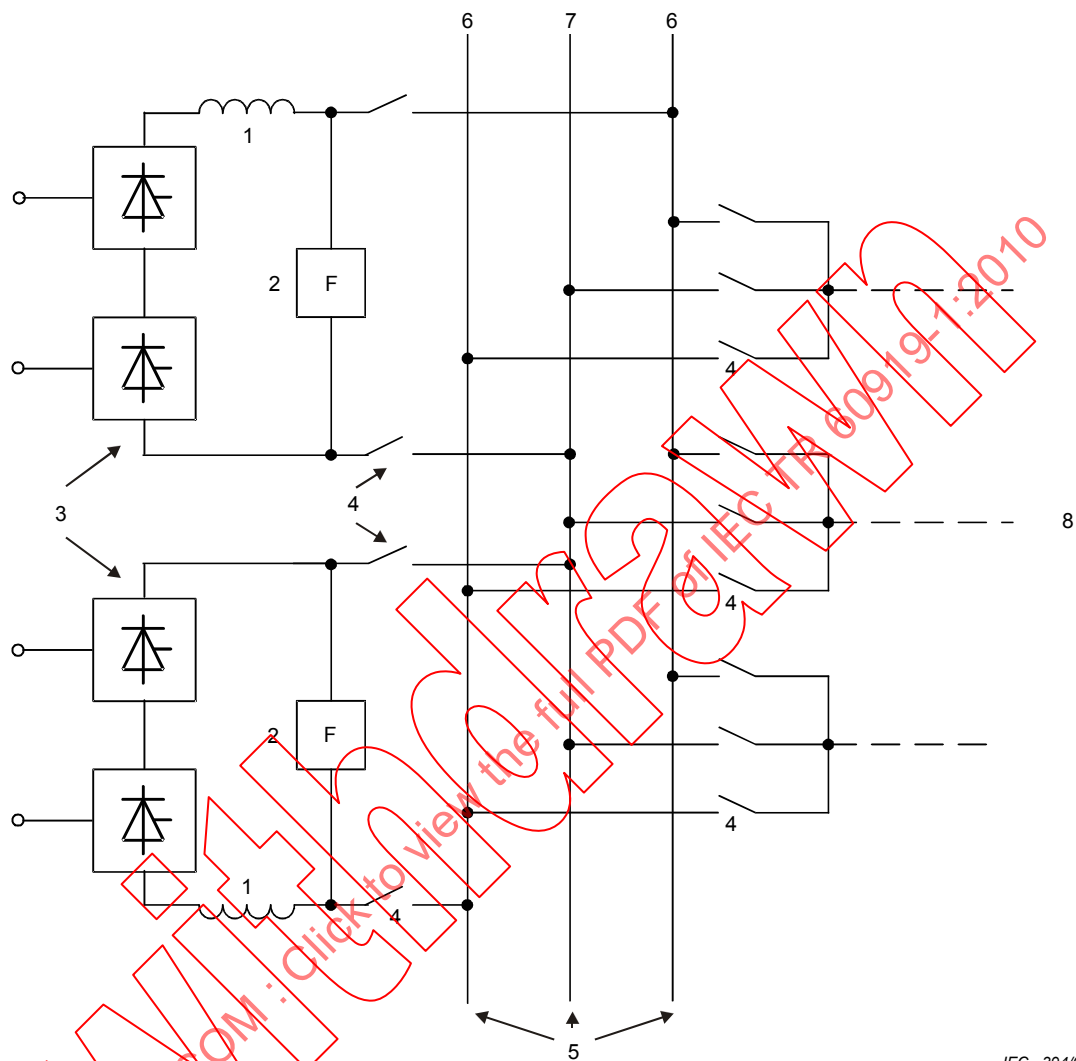
3.9 DC switching considerations

There are a number of possible d.c. switching arrangements intended to increase HVDC system availability.

Monopolar metallic return operation of a bipolar system is discussed in 3.5.

For bipolar systems, d.c. switching may be provided (Figure 12) so as to allow the use of any conductor for connection to any substation pole or to neutral. This arrangement is useful for a scheme involving cables and where a fully insulated spare cable is available or cables are connected in parallel. If one substation pole is out of service, then the cables can be

paralleled to reduce line losses. Generally, d.c. buses are fixed in relation to converters, with two pole buses and a neutral bus. This would preclude connection of the two substation poles in parallel.



IEC 394/05

Key

- | | |
|-----------------------|-----------------|
| 1 DC reactor | 5 DC bus |
| 2 DC filter | 6 Pole |
| 3 Two-converter poles | 7 Neutral |
| 4 DC switches | 8 DC line/cable |

Figure 12 – DC switching of line conductors

However, if flexibility of connecting the two substation poles in parallel is needed, then provision for polarity reversal of at least one substation pole could be made and the neutral end of that substation pole will also have to be insulated for full line voltage. A possible switching arrangement is shown in Figure 13.

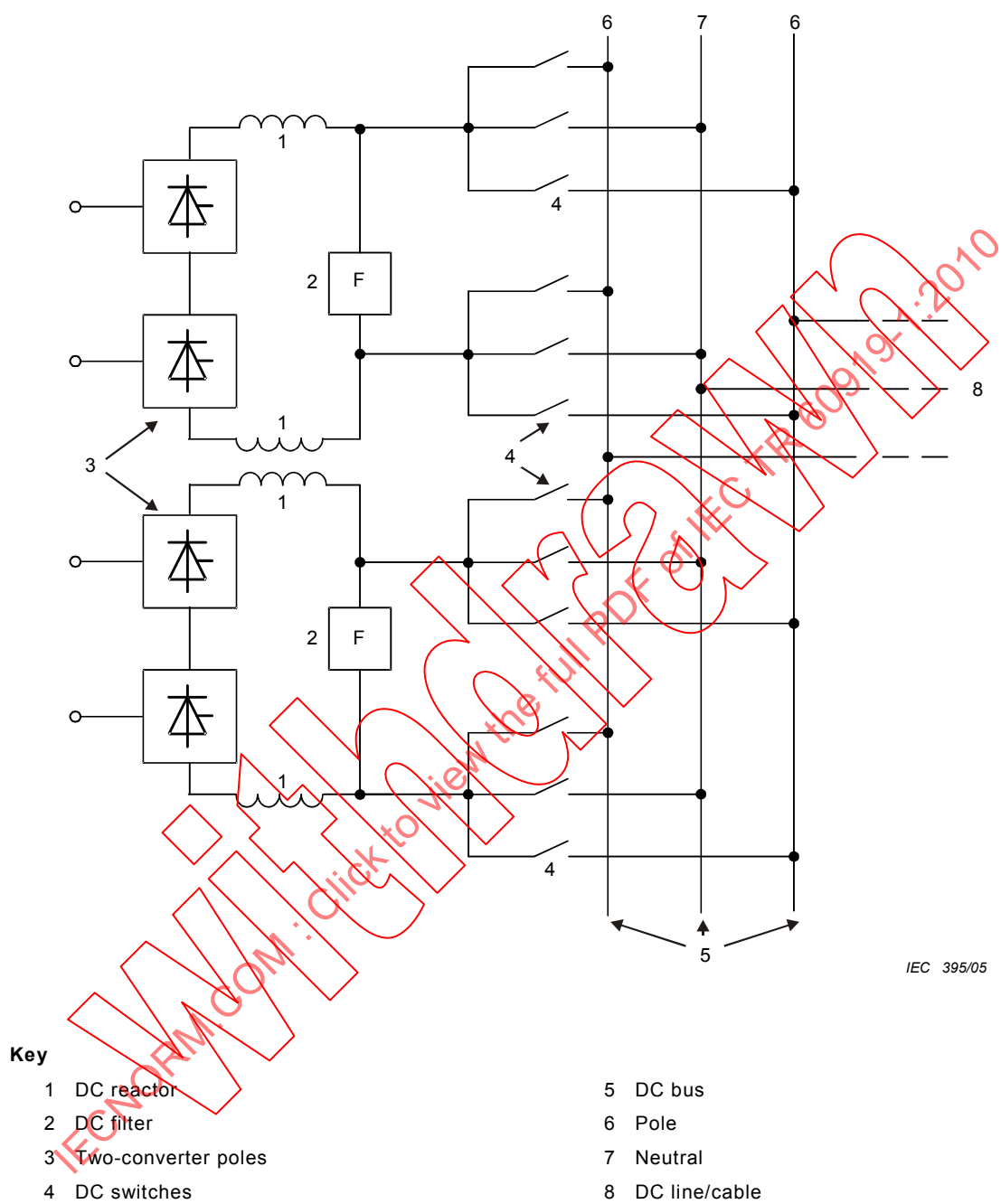
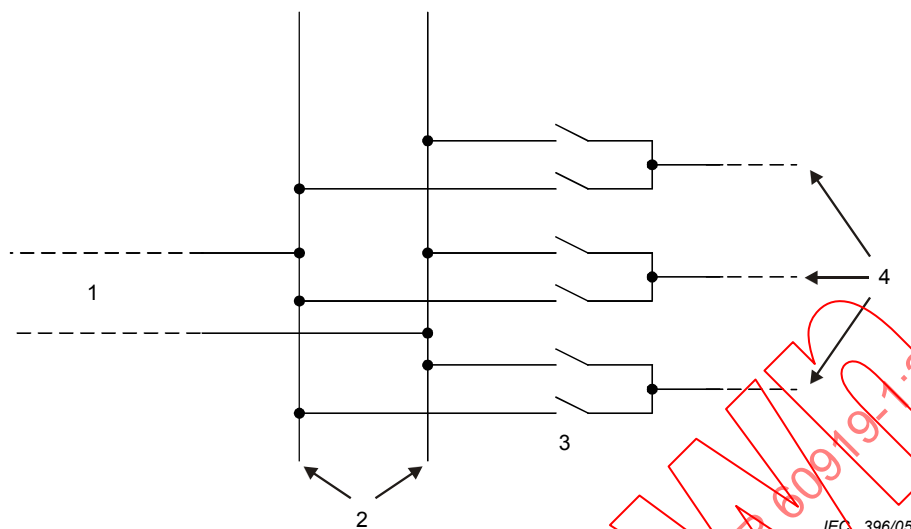


Figure 13 – DC switching of converter poles

If a HVDC transmission system includes both overhead line and cable sections, a d.c. switching arrangement such as in Figure 14 may be used at the junction of the overhead and cable sections.



Key

- 1 Bipolar overhead line
- 2 DC bus
- 3 DC switches
- 4 DC cables (two poles, one spare)

Figure 14 – DC switching – Overhead line to cable

For more than one bipolar line, paralleling of converter poles may be considered, in order to allow restoration of transmission capability (Figure 15) for transmission line outages.

For long bipolar lines in parallel, intermediate switching such as in Figure 16 may be provided.

3.10 Series capacitor compensated HVDC systems

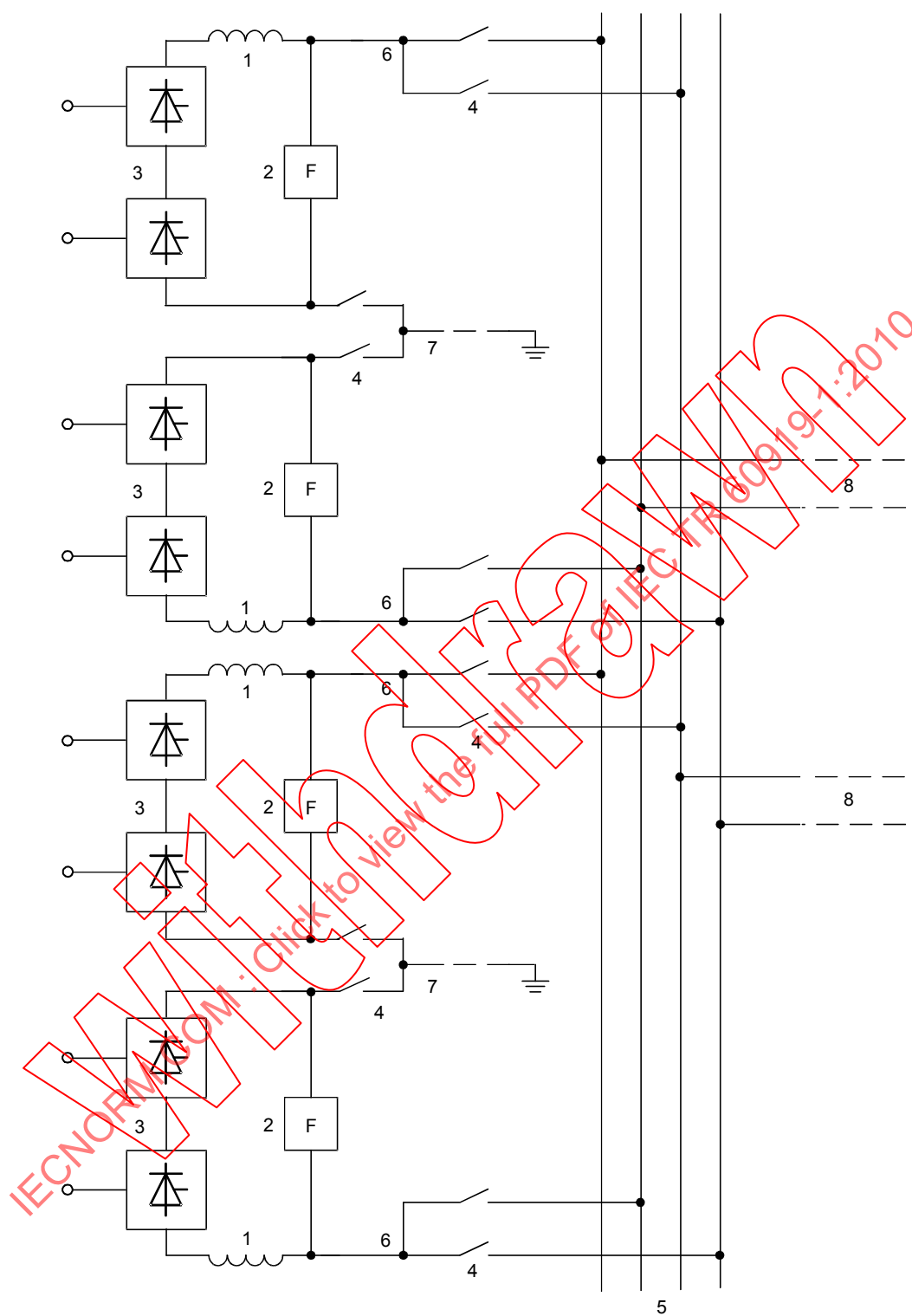
Although the conventional line-commutated converter technology has reached maturity, such converters still have two weaknesses:

- a) a large amount of reactive power consumption, roughly 50 % of its active power;
- b) susceptibility to a.c. side disturbance, commonly observed as commutation failures.

To overcome these weaknesses, further developments have been made using series-capacitor compensation.

Practically, there are two types of series-capacitor compensated HVDC schemes.

- Capacitor-commutated converter (CCC), in which series capacitors are included between the converter transformer and the valves.
- Controlled series capacitor converter (CSCC) is also suggested. In this scheme, the basic topology of the converter is the same as the conventional topology; however, series capacitors are inserted between the a.c. filter bus and the a.c. network. Occurrence of ferro-resonance with the CSCC option is eliminated by controlling the amount of series compensation.

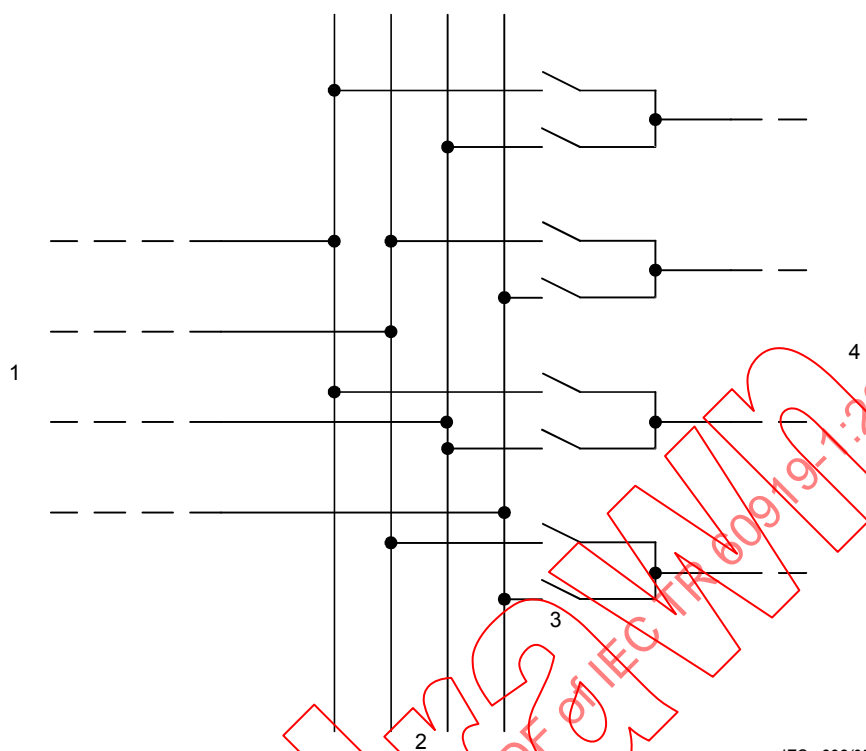


Key

- 1 DC reactor
- 2 DC filter
- 3 Two-converter poles
- 4 DC switches

- 5 DC bus
- 6 Pole
- 7 Neutral
- 8 DC line

Figure 15 – DC switching – Two-bipolar converters and lines



IEC 398/05

Key

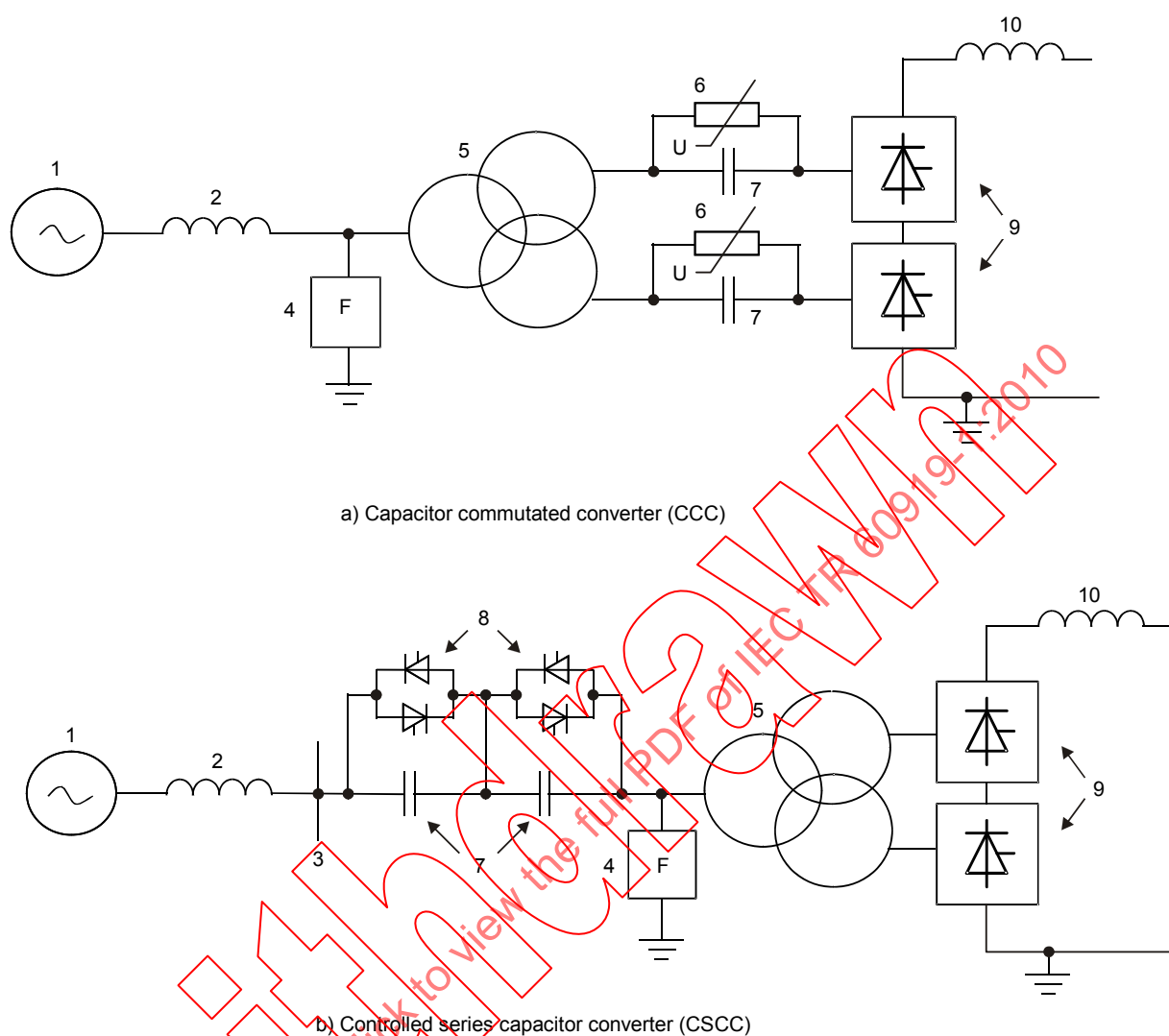
- 1 Two-bipolar lines
- 2 DC bus
- 3 DC switches
- 4 Two-bipolar lines

Figure 16 – DC switching – Intermediate

The CCC circuit shown schematically in Figure 17a) is based on a topology in which series capacitors are included between the converter transformer and the valves. The CSCC circuit has the series capacitors inserted at the connection of the filter bus to the a.c. system as shown in Figure 17b). This provides similar performance to the CCC, with the additional advantage of controllability of the reactive power exchange with the a.c. network.

Both alternatives offer improved immunity from commutation failure, lower load rejection overvoltages and increased stability margins in power control mode, over the conventional HVDC scheme. They are, therefore, suitable candidates for use at the inverter end in long cable systems or in back-to-back ties connected to weak a.c. systems. The performance of the two alternatives is very similar for steady state as well as transient operation.

The maximum valve voltages and also the a.c. current harmonics for the CSCC configuration are lower than for the CCC configuration. On the other hand, the CCC in rectifier operation exhibits a smaller valve short-circuit current. The previously identified problem with ferro-resonance in the CSCC is eliminated through the application of controlled series capacitors.



a) Capacitor commutated converter (CCC)

b) Controlled series capacitor converter (CSCC)

IEC 399/05

Key

- | | |
|-------------------------|-----------------------|
| 1 AC system e.m.f. | 6 Overvoltage limiter |
| 2 AC system impedance | 7 Capacitor |
| 3 AC system bus | 8 Thyristors |
| 4 AC filters | 9 Converters |
| 5 Converter transformer | 10 DC reactor |

Figure 17 – Capacitor commutated converter configurations

The advantages of using CCC in comparison with conventional converter may be summarized as follows:

- significantly less reactive power consumption, which, in combination with sharply tuned filter branches, eliminates the need for switching filter and shunt capacitor banks during power ramps;
- immunity to commutation failure during a.c. side disturbance, which is beneficial with long lines or cables feeding weak a.c. networks;
- stable operation in lower short-circuit capacity systems;

- lower overall installation cost in some cases, due to elimination of switchable filter and shunt capacitor banks or synchronous compensators, in applications associated with weak a.c. network connections;
- robustness in situations of converter-arm short-circuit fault due to lower fault current;
- less variation of reactive power during disturbances, which results in improved power quality and reduced load rejection.

The disadvantages are:

- increased harmonic current;
- slightly increased converter losses;
- requirement for detailed study of transient stresses on equipment;
- reduced inherent overload capability, due to the capacitor connected in series with the converter;
- requirement for shielding against lightning and radio interference between the valve winding, the capacitor and the valve;
- slightly increased valve voltage stress.

When CCC or CSCC is being considered as an HVDC topology for a particular project, it should be emphasized that the selection of optimal system rating is different from conventional HVDC. Therefore, in order to make a selection between conventional HVDC schemes and these alternatives, a detailed analysis is required with respect to economics and technical performance, taking into account losses, installation costs, etc.

4 Environment information

The location and the information listed in Table 1 should be supplied for each HVDC substation.

Table 1 – Information supplied for HVDC substation

Parameter	Unit		Examples of use and comments
Height above sea-level	m		For the design of air-cooling systems and for air clearances
Outdoor air temperature	°C		The maximum temperatures are given for rating purposes and the low temperatures for overload capability requirements. If the user intends to overload the equipment and accept a corresponding loss-of-life expectancy, this should be stated and the necessary information supplied
	For low temperature capability	For rated power capability	If preferred, curves showing how these parameters vary over the year, on a monthly basis, may be provided instead
Maximum dry-bulb temperature	°C	°C	Valve cooling, transformer and reactor design, a.c. and d.c. filter design
Maximum wet-bulb temperature	°C	°C	Evaporative cooling system design and of valve hall relative humidity
Maximum average dry-bulb temperature for a period of 24 h	°C	°C	Transformer and oil insulated reactor design
Minimum average dry-bulb temperature for a period of 24 h	°C	-	Transformer, reactor and disconnector switch design and building heating needs
Minimum dry-bulb temperature	°C	-	Transformer, reactor and disconnector switch design and building heating needs, a.c. and d.c. filter design

Table 1 (continued)

Parameter	Unit		Examples of use and comments
Maximum and minimum indoor air temperatures and relative humidity	°C	°C	Usually determined by the valve designer for the valve hall and by the control designer for the control room
	%	%	
Indoor air temperatures and relative humidity during maintenance and maximum transition time after shutdown	°C	°C	Specified if indoor temperature extremes are too great for maintenance personnel
	%	%	
Maximum incident solar radiation			Building cooling, ratings of transformers, reactors, buses, etc.
Horizontal surface	W/m ²		
Vertical surface	W/m ²		
Wind conditions			
Maximum continuous velocity	m/s		Equipment support and building design
Maximum gust velocity	m/s		Equipment support and building design
Maximum velocity at a minimum temperature °C	m/s		Conductor, strain insulator and tower design
Ice and snow covering load			
Maximum ice thickness with no wind	mm		Equipment and structure design, for example, disconnect/switch, conductor, etc.
Maximum ice thickness with a maximum wind speed ofm/s	mm		Equipment and structure design, for example, disconnect/switch, conductor, etc.
Maximum snow load	N/m ²		Building design
Maximum depth of snow	mm		Equipment height above snow for safety purposes
Rainfall			Building and site drainage
Annual average	mm		
Maximum in a period of 1 h	mm		
Maximum in a period of 5 min	mm		
Fog and contamination			To determine requirements for insulation and air-cooling system filter design. An estimated equivalent salt deposit density level should be specified for insulator design
Utility practice for insulator washing and greasing			
Keraunic level at the station and the first 5-10 km of the line	Strokes/km ² /year (substation) Strokes/100 km/year		Station lightning protection design
Seismic conditions			Equipment, structure and foundation design
Maximum horizontal acceleration frequency range of horizontal oscillations	m/s ² Hz		
Maximum vertical acceleration frequency range of vertical oscillations	m/s ² Hz		
Duration of seismic event	Hz Cycles		
Cooling water available at the site (if used for secondary cooling)			Secondary cooling water may be used either for make-up and blow-down of evaporative coolers or for once-through cooling. Evaporative cooling towers can be a source of high humidity for the insulators and should be carefully located

Table 1 (continued)

Parameter	Unit		Examples of use and comments
Source of water			Reservoir, well, etc. If preferred, curves showing how these parameters vary over the year on a monthly basis may be provided instead.
	For low temperature capability	For rated power capability	
Maximum continuous flow rate	m ³ /s	m ³ /s	Required for cooling system design
Maximum flow rate for a period of 24 h	m ³ /s	m ³ /s	Required for cooling system design
Minimum continuous flow rate	m ³ /s	m ³ /s	Required for cooling system design
Minimum flow rate for a period of 24 h	m ³ /s	m ³ /s	Required for cooling system design
Maximum water temperature	-	°C	Required for cooling system design
Minimum water temperature	°C	-	Required for cooling system design
Maximum allowable dump temperature	°C	°C	Required for cooling system design
pH level			Design of water treatment plant
Conductivity of water	μ Siemens/m		Design of water treatment plant
Type of dissolved solids			Design of water treatment plant
Quantity of dissolved solids	g/m ³		Design of water treatment plant
Type of undissolved solids			Design of water treatment plant
Quantity of undissolved solids	g/m ³		Design of water treatment plant
Maximum earth resistivity at the HVDC substation	Ωm		Station earth design
- Depth of water table	m		Foundation design
- Site soil conditions			Bore hole information (for example, rocks) and any special conditions, such as maximum frost depths, foundation design
- Site accessibility			To determine installation and delivery costs
- Weight and size limitations for transportation	kg, m		Equipment design – especially transformers and d.c. reactors
- Local profile limitations on equipment and buildings			Influence on equipment, bus and building design
- Environmental considerations			Audible noise limits, aesthetic requirements – architectural treatment, landscaping, etc.
Any special conditions not listed above, for instance, related regulations, which influence system performance should be given.			

5 Rated power, current and voltage

5.1 Rated power

5.1.1 General

Rated power is the active power which the HVDC system shall be able to transmit continuously, over the range of ambient conditions specified, with all equipment in service, but without the need to utilize redundant components; the HVDC system voltage and frequency as well as the converter firing angle and the extinction angle being in their steady-state range.

Because an HVDC transmission system in general consists of three sections, that is the two HVDC substations and the transmission line, each of which produces losses, the point of measurement of rated power should be specified.

5.1.2 Rated power of an HVDC system with transmission line

The rated power of an HVDC transmission system on a per pole basis is defined as the product of rated direct voltage times rated direct current.

For a given direct current, transmission line losses vary with ambient conditions, which can be non-uniform along the length of the line. Therefore, it is customary to specify rated power at the rectifier d.c. bus. If the required transmission capability is defined at some other location, that is sending-end a.c. bus, receiving-end a.c. bus, or somewhere along the HVDC transmission line, then the rated d.c. voltage should be defined and the rated direct current should be chosen through design optimization of the HVDC system.

Rated power and voltage at the inverter d.c. bus are derived values from rectifier quantities, and line losses are usually based on defined conductor parameters and uniform conductor temperature assumptions along the line.

Long distance HVDC systems may be monopolar or bipolar. Rated power should be specified on a per pole basis stating the number of poles.

5.1.3 Rated power of an HVDC back-to-back system

With system ties in a back-to-back configuration, there is no transmission line. Therefore, the rated d.c. voltage and current are chosen through design optimization of the HVDC system. Moreover, rectifier and inverter are solidly connected at the d.c. side, operating as one unit. Rated power of such a system can, therefore, be defined as the product of rated direct voltage times the rated direct current.

5.1.4 Direction of power flow

If the same power rating is required in each direction, such as with system ties for power exchange, this should be stated.

Where power flow is primarily in one direction, such as with systems fed from remote generation, rated power may be specified only for that direction to minimize the inverter cost. Then a lower inherent transmission capability should be accepted for reversal of power flow.

5.2 Rated current

Rated direct current is the mean value of the direct current that the system should be able to transmit continuously for all ambient conditions specified and without time limitations. The rated current should not be specified for back-to-back systems as detailed in 5.1.3 above, unless there are specific reasons for doing so.

5.3 Rated voltage

The rated voltage is the mean value of the required direct voltage to transmit rated power at rated direct current. It is measured between the high-voltage bus at the line side of the d.c. reactor and the low-voltage bus at the HVDC substation, excluding the earth electrode line. The rated voltage is defined at nominal a.c. system voltage and nominal converter firing angle while operating at rated direct current.

For long distance HVDC transmission systems, the rated voltage should be specified at the sending end. If the voltage capability of the transmission line is higher than the rated voltage, then this shall be stated. The rated voltage need not be specified for back-to-back systems as detailed in 5.1.3 above, unless there are specific reasons for doing so.

6 Overload and equipment capability

6.1 Overload

Overload in an HVDC substation usually refers to direct current flow above its rated value. For this, consideration may be given to acceptable reduction in life expectancy of equipment (for example, due to thermal ageing), use of redundancy, and low ambient temperatures.

Overload may be specified in terms of power. Voltage regulation in the converter including the transformer normally causes an increase in current somewhat more than an amount proportional to the increase in power. If rated voltage is to be maintained under overload conditions, then the following measures may be adopted, at additional cost.

- a) The converter should be designed for a higher no-load voltage. This results in a higher MVA rating, if overload is required over the full range of a.c. bus voltage.

NOTE This may not be necessary, if overload is required only for the upper range of the steady-state a.c. system voltage.

- b) The voltage rating of the converter valves, which is based on transformer no-load voltage, should be increased.
- c) The on-load tap changer range should be increased, if the converter firing angle is to be maintained at its nominal value. Alternatively, the converter may be designed for a higher nominal firing angle at rated power. This will increase reactive power consumption, harmonics and losses, as well as the internal stresses on valve components.

As a consequence, if rated direct voltage is to be maintained under overload conditions, oversizing of equipment will be necessary.

For a more economical design, an overcurrent rating may be specified, without regard for direct voltage regulation. Basic converter equations then permit determination of the maximum current, beyond which further increase would be offset by excessive voltage regulations.

When the converter is operated in overload it will absorb more reactive power. Unless this increased reactive power absorption can be compensated by filters/shunt capacitors, for example, from another pole, then the a.c. busbar voltage will reduce. When the a.c. system short-circuit level is low, this effect may limit the achievable overload.

The required duration of HVDC substation overloading is most often determined by a.c. system needs, especially following contingencies in either the a.c. or HVDC system.

However, some constraints should be observed for the HVDC substation equipment. Thermal time constants range from 1 s to some hours, as detailed in 6.2. Longer duration overload requirements of high magnitude may, therefore, result in an effectively increased rating of equipment and thus impose a greater cost or a reduction of life expectancy. These factors should be weighed against system benefits when specifying overload.

EXAMPLE A practical value may be a 1,2 per unit overload for 1 h which does not result in loss of life expectancy of oil-cooled transformers and reactors but may have to be designed into thyristor valves. Also depending on the particular design, the 1 h overload may be converted to continuous if cooling redundancy is utilized. Other examples include oscillatory overloads at a frequency of up to 1 Hz for durations of several seconds, and 5 s overloads to counteract temporary overvoltage or frequency changes.

The frequency and the time intervals between such overload cycles should be specified.

6.2 Equipment capability

6.2.1 General

This is defined as the ability of the HVDC substation equipment to permit transmission of greater than rated power, without loss of equipment life expectancy. It depends on operating

conditions as well as on the design criteria for individual components. Implications resulting from the latter are discussed in subsequent subclauses with respect to their bearing on overload specifications.

Ambient temperature is an important factor. Power equipment is designed to perform at rated loading under the most adverse ambient conditions specified. However, these conditions normally prevail for only limited time periods. At low ambient temperatures, some margin is available for increased capability, if the constraints listed in 6.2.4 can be overcome. This margin depends on the design chosen for the particular equipment and would differ for various HVDC substation components. An enveloping curve of transmission capability versus ambient temperature can be specified along with the a.c. system conditions to be met. This should be specified in terms of wet-bulb and dry-bulb ambient temperatures.

6.2.2 Converter valve capability

The thermal time constant of the thyristor heat sink combination in a thyristor valve is rather small (several seconds up to a few minutes). Overloads following continuous operation at rated current and at maximum ambient temperatures increase the thyristor junction temperature. This should be considered with respect to the specified fault suppression capability of the valve. Consequently, thyristor valve cooling should be designed so that safe operating temperatures are not exceeded even during specified overload operation.

Redundancy is provided as a general practice in the valve cooling circuit. Valves are designed such that the specified rating will be met under the most adverse ambient conditions and loss of thyristor cooling equipment redundancy. If additional capability is needed when redundant cooling is not available, this should be explicitly specified.

On the other hand, with all redundant cooling equipment in service, extra thermal capability is available. The resulting greater-than-normal current capabilities depend on the thermal design of the valve and on the cooling system.

In view of the above, converter overload specifications should state the magnitude and duration of overload, frequency of oscillatory overloads for modulation purposes, as well as the cooling equipment status to be assumed at maximum ambient temperatures.

6.2.3 Capability of oil-cooled transformers and reactors

The thermal time constant of the transformer or reactor windings is approximately 15 min and ranges from one to several hours for their oil circuits, depending on the design.

Consequently, for short time overloads in the 5 s range, oil-cooled equipment is not the limiting factor on HVDC substation overloads. For overloads lasting longer than 1 h, it should be specified whether loss-of-life expectancy is permitted. The expected frequency of occurrence of such overloads should be specified.

6.2.4 AC harmonic filter and reactive power compensation equipment capability

HVDC substation overloads will usually generate increased harmonic currents. These in turn increase harmonic loading, losses in filters and harmonic interference levels. The specifications should state whether the interference performance under rated conditions should be met under overload conditions or to what extent degradation of performance is permitted.

Also, since overload increases the converter reactive power consumption, the specifications should state how this is to be taken into account when designing reactive power compensation equipment. If additional reactive power is drawn from the system under HVDC substation overload conditions, excessive a.c. bus voltage regulation and a consequent reduction in power flow may take place. For this reason, the expected a.c. bus voltage under overload conditions should be specified.

6.2.5 Switchgear and buswork capability

Switchgear and buswork normally do not impose limits on HVDC substation overloads unless paralleling of converters is planned. However, special attention should be paid to the overload capabilities of current transformers and bushings.

7 Minimum power transfer and no-load stand-by state

7.1 General

With HVDC substations there exists a minimum steady-state direct current limit. This is due to the fact that at some low level the current becomes discontinuous and is the principal criterion for a minimum power limit.

7.2 Minimum current

Since the direct voltage output of an HVDC converter is made of sections of the sinusoidal bus voltage, direct current would not be a smooth or constant quantity by itself. Rather, it is made continuous by the d.c. reactor connected in series with the converter. Assuming a constant average direct voltage, the direct current would become discontinuous, at low power, depending on the commutating reactance of the converters, the inductance of the d.c. reactor, the number of valve groups in service, where series connection of groups is used, and converter firing angle, as well as the negative sequence component of the a.c. system voltages. Discontinuous current should be avoided in steady-state operation, unless the converter equipment is designed for this mode of operation.

Since the d.c. reactor inductance is usually determined by other criteria and the firing angle can be of any value, a minimum current limited shall be specified. A value of 5 % to 10 % of rated current is commonly used. This minimum direct current can further be reduced by choosing a larger value of d.c. reactor inductance.

7.3 Reduced direct voltage operation

Under contamination conditions, often in combination with unfavourable weather conditions, operation of an overhead d.c. transmission line may not be possible at its rated voltage. However, the control system of the HVDC substation offers various means to achieve continuation of power flow at reduced transmission voltages.

One possibility is to move the transformer tap changer to the position resulting in the lowest a.c. voltage for the valves. In addition, a further decrease of transmission voltage can be achieved through operation at an increased firing angle.

This requirement could mean a special valve design and thus increase valve costs. Furthermore, since operation at large firing angles causes an increased harmonic generation and reactive power consumption, operation at reduced direct voltage then requires a reduction of the direct current, if the filtering and compensation equipment is not rated for these conditions.

Other possibilities are to increase the tap changer range, or where the HVDC system is fed from an isolated power station, a reduction of a.c. bus voltage can also be considered.

Practical values for reduced direct voltage operation are at 70 % to 80 % of rated voltage, perhaps, at reduced current. It is reasonable to expect continuous operating capability at approximately rated current at 75 % voltage with use of redundant cooling, provided that somewhat higher harmonic interference level is acceptable; this in turn depends on expected frequency and duration of such operations.

Where two series-connected 12-pulse converter units are used, one unit might be switched out, resulting for example in a 50 % voltage reduction when both have the same rating, thus

eliminating the necessity to operate at increased converter firing angle or reduced direct current.

To arrive at an economic design of the equipment, the a.c. voltage levels should be specified for expected direct voltage operations.

7.4 No-load stand-by state

7.4.1 General

In this mode, the HVDC substation is ready for immediate pick-up of load without the need for a lengthy start-up procedure. A definition of the status of various equipment shall be specified to determine the no-load losses of the HVDC substation, if operation in the no-load stand-by state is planned.

7.4.2 Converter transformers – No-load stand-by

The converter transformers may remain energized or de-energized, depending on the user's policies with respect to losses. In the latter case, account should be taken of the time required for inrush currents to decay. Oil pumps and coolers should be in operation on a minimum level, as appropriate to the design of the transformers.

7.4.3 Converter valves – No-load stand-by

The converter valves should be blocked condition. There will be small losses in the voltage grading circuits, if the converter transformers are energized. Primary, secondary and valve hall cooling should be in operation at a sufficient level to permit immediate pick-up of load.

7.4.4 AC filters and reactive compensation – No-load stand-by

The a.c. filters and reactive compensation may be connected or disconnected depending on reactive power control strategy within the a.c. system. However, for the sake of no-load loss determinations, they should be considered disconnected.

7.4.5 DC reactors and d.c. filters – No-load stand-by

The d.c. reactors and d.c. filters should be connected. DC reactors, pumps and coolers should be in operation on a minimum level, as appropriate to the design of the reactors.

7.4.6 Auxiliary power system – No-load stand-by

The auxiliary power system should be fully operative and ready to pick-up rated load, for example, all station service transformers energized, battery chargers in operation, etc.

7.4.7 Control and protection – No-load stand-by

All control and protection circuits should be operative.

8 AC system

8.1 General

The following should be specified for a.c. systems at both ends for each stage of development as well as for expected future changes. Different values may be specified for performance and rating purposes.

The arrangement of the a.c. switchgear to which the converter units and filters are to be connected, including a.c. lines, should be described. This should also be done for the planned operating schemes of the switchyard.

Specific data should be made available for generators in the close vicinity, particularly if the major load for the generators is served through the rectifier. Often all data pertinent to load flow and short-circuit studies are also needed.

8.2 AC voltage

8.2.1 Rated a.c. voltage

Rated a.c. voltage is the r.m.s. phase-to-phase fundamental frequency voltage for which the system is designed and to which certain characteristics of the a.c. equipment are related, such as a.c. switchgear, a.c. filters, reactive power compensation equipment, primary windings of converter transformers, etc.

Rated voltage may be used to define the rated power of such a.c. equipment.

8.2.2 Steady-state voltage range

8.2.2.1 General

The steady-state voltage range is the range over which the HVDC system should be able to transmit rated power and over which all performance requirements are to be met, unless stated otherwise.

Any special performance requirements beyond the limits of the steady-state range should be specified. These may affect the design of main equipment, converter transformers, filters, auxiliary equipment, etc.

8.2.2.2 Short-term voltage range

There may be situations under which the voltage exceeds the normal steady-state operating range but the HVDC system may be required to remain in operation. Under these conditions the HVDC system may be designed to operate in a manner whereby no equipment should be at risk of damage, but the performance limits of the system may be acceptably degraded (for harmonics, losses, etc.).

The acceptable degraded performance limits should be specified since these will have an effect upon the ratings of equipment.

The HVDC control system may even be specified to assist in the restoration of the voltage to within the normal operating range (through either HVDC control action or addition/removal of filters and reactors) if this is appropriate.

8.2.2.3 Voltage variation during emergency

Dynamic overvoltages could determine ratings and protection strategies.

Under extreme circumstances, the a.c. voltage may exceed even the short term range, in which case it may be desirable to remove the HVDC system from operation in order to protect the equipment. Alternatively, it may be possible to rate the HVDC converter equipment to operate within these limits, although this will probably require higher cost equipment and degraded performance.

The HVDC control system may even be specified to assist in the restoration of the voltage to within the normal operating range (through either HVDC control action or addition/removal of filters and reactors), if this is appropriate.

8.2.3 Negative sequence voltage

The negative sequence component of a.c. voltage calculated according to the method of symmetrical components is that balanced set of three-phase voltages whose maxima occur in the opposite order to that of the positive sequence voltages. It is generally expressed as a percentage of the rated voltage.

Although it is difficult to obtain an actual value for this parameter, the maximum to be used in determination on non-characteristic harmonics of the current on the a.c. side and the non-characteristic harmonic voltages on the d.c. side should be specified. These harmonic currents and voltages are respectively used for the design of the a.c. filter, d.c. filter and d.c. reactor (see Clauses 16, 17, and 20).

8.3 Frequency

8.3.1 Rated frequency

The frequency of an a.c. system should be specified to give the basis of rating of the a.c. equipment, converter transformer, etc, as well as converter bridges and control.

The design of the d.c. filters is also influenced by the a.c. system frequency.

8.3.2 Steady-state frequency range

Steady-state frequency range is the range, in conjunction with the a.c. voltage steady-state range, over which the rated power may be transmitted and all performance requirements are to be met.

8.3.3 Short-term frequency variation

Limits and duration of short-term frequency excursions for which system performance is required should be specified. This can be a sensitive parameter for a.c. and d.c. filter design. Filtering performance during such variations may be specified.

8.3.4 Frequency variation during emergency

During an emergency the a.c. system frequency may reach extreme values for limited periods. These values and their expected durations should be specified. In this condition, the equipment should remain in service without damage, but should not be required to meet the performance specified. For excursions beyond the specified operating frequency limits, it may be permissible to automatically disconnect the equipment.

8.4 System impedance at fundamental frequency

For the purpose of analysis of commutation conditions in the converter, the system impedance at fundamental frequency should be stated. Maximum and minimum values of the subtransient impedance at the a.c. bus, without any filter or compensating equipment, are needed for such analysis.

Subtransient impedance is the positive sequence impedance of the a.c. system as determined by the subtransient reactance of synchronous machines, leakage reactance of induction machines and positive sequence impedance of connecting lines.

Additionally, a detailed a.c. system impedance or a suitable equivalent should be specified, in order to optimize the d.c. control.

8.5 System impedance at harmonic frequencies

System impedance at all harmonic frequencies from the 2nd up to the 50th is needed for a.c. filter design and performance calculations.

This impedance may be calculated using the parameters of the lines, transformers and generators up to five to eight HVDC substation buses. However, this impedance may change considerably under different load conditions and extension stages of the system. Therefore, it is usually more convenient to use an R - X diagram and to plot the envelope of the locus of the system harmonic impedance under expected system conditions. The values of $R_{\min}$ and $X_{\min}$ should be included in the diagram.

In practice, this diagram may take various forms such as a circular plot, limited by constant R/X ratio or the combination of both.

8.6 Positive and zero-sequence surge impedance

The positive and zero-sequence surge impedance is needed for all a.c. lines going into the station for evaluation of interference from converters in the carrier frequency band and for design of appropriate filters.

8.7 Other sources of harmonics

Other sources of harmonics electrically close to the HVDC substation should be identified. Their influence should be taken into account in a.c. filter and capacitor bank ratings. Generated harmonic currents should be stated for the static reactive power compensators connected to the converter substation bus or to nearby a.c. substations.

8.8 Subsynchronous torsional interaction (SSTI)

If subsynchronous torsional interaction (SSTI) problems are expected, all related information from the pertinent studies should be provided (see also Clause 9).

9 Reactive power

9.1 General

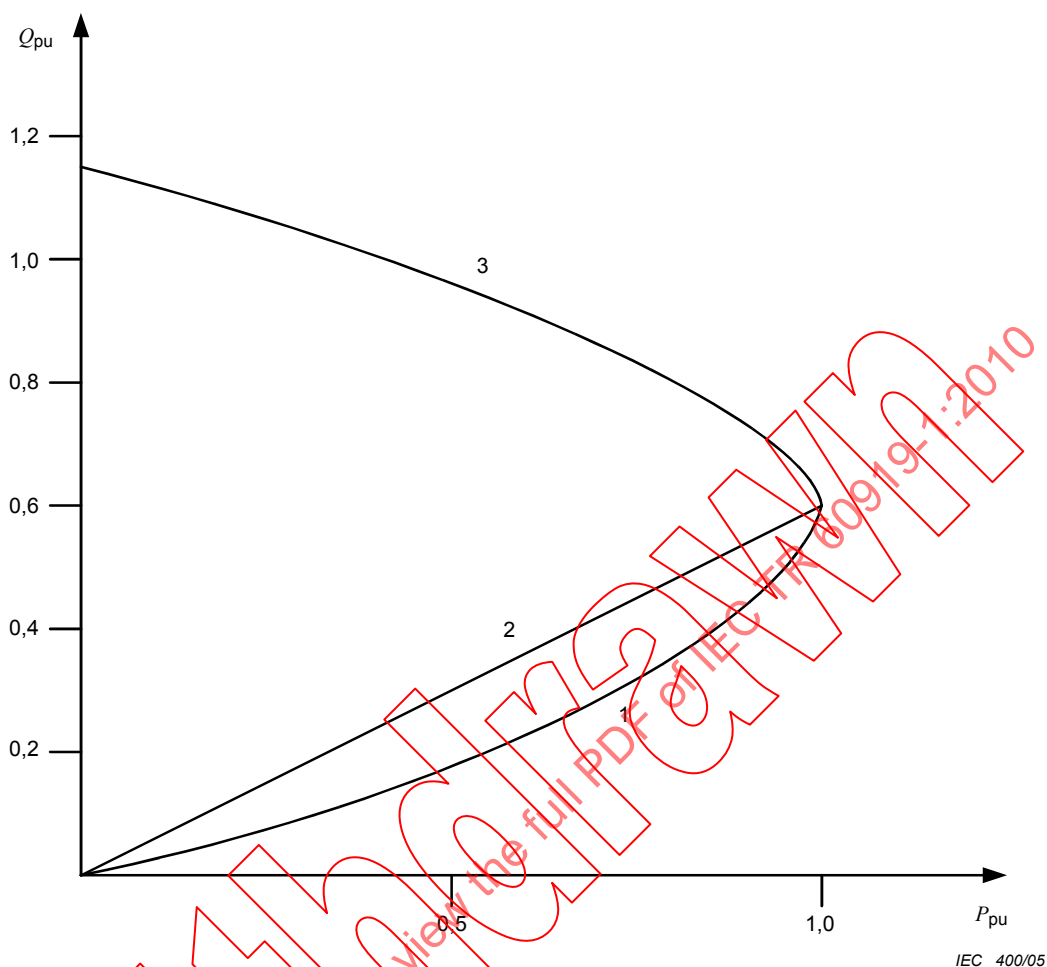
This clause identifies the considerations relevant to reactive power.

9.2 Conventional HVDC systems

Line commutation of converter bridges, as used in conventional HVDC systems, requires a consumption of reactive power in both rectifier and inverter operation. At full load, this consumption represents 50 % to 60 % of rated power for commonly used values of transformer impedance and firing angle or extinction angle.

At partial load reactive power consumption can be varied according to a.c. system requirements by using an appropriate control strategy. A control strategy which is often adopted, is to maintain the delay angle α in the rectifier, or the extinction angle γ in the inverter, within narrow limits by means of the tap changer of the converter transformer. Under this strategy, the variation of reactive power versus real power is shown in Figure 18, curve 1, for constant direct voltage and constant extinction angle γ . As an alternative, a linear variation may be obtained, as shown on Figure 18, curve 2, which involves maintaining constant no-load direct voltage U_{d0} by means of an increase of the delay angle α in the rectifier and extinction angle γ in the inverter, when the load is reduced.

If the direct current is kept constant and partial load is achieved by increasing the delay angle and thus reducing the direct voltage, reactive power consumption is increased at partial load according to curve 3 in Figure 18. Any characteristic between curves 1) and 3) can be implemented to meet specific a.c. system requirements.



Key

- 1 Constant d.c. voltage – Constant γ
- 2 Constant d.c. voltage – Constant U_{d0}
- 3 Constant d.c. current

Figure 18 – Variations of reactive power Q with active power P of an HVDC converter

Combined changes of the valve firing angle and the load tap changer of the converter transformer may be used to control the reactive power demand of a HVDC substation. However, since this requires an increase of the firing angle, it leads to an increased generation of harmonic currents and voltages and increased losses in the damping circuits of the valves.

Looked at another way, filtering of a.c. current is obtained through harmonic filters, which also generate reactive power. However, the fundamental frequency reactive power generated by the filters as determined by the a.c. filtering requirements at full load is generally less than the reactive power consumption of the converter bridges. Therefore, additional capacitor banks are usually provided to meet the total reactive power demand of the converter.

The net reactive power of the converters and filters, taking into account filtering consideration, may be controlled within certain limits, by switching of capacitor banks and also part of the filter banks, if needed.

To define a suitable strategy of reactive power control, the aspects described in 9.4 to 9.7 should be specified.

9.3 Series capacitor compensated HVDC schemes

Reactive power requirements of conventional HVDC schemes are addressed by adding shunt devices such as shunt capacitors and filters.

Conversely, both CCC and CSCC treat this differently, as instead of connecting capacitor banks in parallel to the converter bus, they are inserted between the transformers and valves (CCC) or between the transformers and the a.c. network (CSCC). By these configurations, the voltage across the series capacitor adds to the commutation voltage resulting in a wide range of trigger delay angle (α) and extinction angle (γ). This brings about less overlap angle (μ) and thus less reactive power consumption. AC filters are required only for harmonic elimination and not for reactive power support. This reduces the MVAR rating of the filter to small values. Unlike the conventional case, neither the CCC or CSCC configuration requires filter-bank switching for variations in the load over the full range of operation.

9.4 Converter reactive power consumption

The reactive power consumption should be determined for the different operating conditions for the rectifier and inverter under partial load, full load and overload conditions. The method of calculation and the parameters used in the calculations should also be specified.

The operating conditions to be considered include: direction of power flow, monopolar earth return, monopolar metallic return, bipolar and reduced direct voltage operation over the specified range of steady-state a.c. bus voltage.

Also at minimum power transfer with a minimum number of a.c. filters connected, the ability of the converter valves to operate with increased firing angle/extinction angle can be utilized to minimize the reactive power flow to the a.c. systems.

9.5 Reactive power balance with the a.c. system

To determine the reactive power sources to be installed, an overall balance of reactive power has to be known. To determine the appropriate reactive power balance load flow studies may need to be performed. Apart from the reactive power needs of the converters, consideration should be given to the following:

- the power factor range to be maintained in the a.c. lines for all operating conditions;
- the operating voltage ranges under light and peak load conditions of the a.c. system;
- reactive power available from nearby generators;
- redundancy requirements.

In case the rectifier is directly connected to a power station, the following points should also be considered:

- generator capability over the maximum and minimum permissible operating voltage range;
- tap changer range available in the step-up transformer, and the tap to be used for each development stage;
- reactive power requirement of other loads;
- minimum permissible active power for the generators;
- self-excitation limit of the generators;
- minimum number of generators to be connected.

9.6 Reactive power supply

The sources of reactive power supply to meet the set of requirements should include the most economical combination of filters, shunt capacitors, shunt reactors, series capacitors, synchronous and static reactive power compensators that meets the performance criteria. Much of the reactive power should be supplied in the form of filters to meet the harmonic performance. Under light load conditions, minimum size of available filter bank connected may lead to surplus reactive power and consequently excessive steady-state voltage. This may require provision of shunt reactors or use of converter capability to consume greater reactive power.

Shunt capacitor banks are the most economical source for the required remaining reactive power. Synchronous and static reactive power compensators should be considered only if there is a dynamic voltage and/or stability problem (see Clause 8). There may be additional requirements associated with the adjacent a.c. systems.

9.7 Maximum size of switchable VAR banks

Filters and capacitor banks may be divided into small switchable banks. The size of switchable banks depends on

- a) voltage control requirements over the whole operating range from no load to full load and overload;
- b) acceptable regulation step per switching operation. It should be noted that the regulating effect from switching reactive power banks can be modulated with the help of converter control;
- c) frequency of switching.

When considering combinations of filters and shunt capacitors with synchronous compensators, the filters and shunt capacitors should be limited in size to avoid self-excitation of the synchronous machines.

10 HVDC transmission line, earth electrode line and earth electrode

10.1 General

This section identifies those characteristics of the HVDC transmission line, the earth electrode and the earth electrode line that are relevant to the specification of the steady-state performance of the converter, including power line carrier performance and design requirements. It does not provide the information that should be specified for the design of the HVDC transmission line, earth electrode lines or earth electrodes themselves.

Key performance specification data for the HVDC transmission line, the earth electrode line and the earth electrode should be determined in advance.

10.2 Overhead line(s)

10.2.1 General

The total length of the line should be given, including details concerning any overhead and cable sections. Details should be provided of any right-of-way joint uses. Particulars of all crossings and parallelisms need to be given to enable assessment of possible electrical interactions and interference. In case the exact length is not known, the expected range for this length should be stated.

For bipole and multi-pole lines, information on the spacings between poles and bipoles along the complete route will be needed.

10.2.2 Electrical parameters

The electrical parameters are the following:

- 1) resistance – maximum positive and zero-sequence d.c. values at minimum current, rated current, maximum overload current with due consideration of the ambient conditions (temperature, radiation, wind velocity, etc.) prevailing during the load condition considered. Curve of frequency dependence up to 100 Hz for rated current;
- 2) capacitance – positive and zero-sequence capacitance (C_1 and C_0);
- 3) inductance – positive and zero-sequence inductance (L_1 and L_0), curve of frequency dependence up to 100 kHz for these.

If the above information is not available, as an alternative, the necessary data to enable its calculation could be given. To calculate these parameters, the following data will be required:

- a) conductor size, type, geometry (including the shield wire);
- b) tower outlines, spacing and sag profiles;
- c) soil resistivity along the route;
- d) tower footing resistance;
- e) the worst-case maximum conductor surface gradients to permit calculation of corona effects, for example, if a carrier is to be used;
- f) critical impulse flashover level of insulation.

It is strongly recommended that the HVDC transmission line be adequately shielded from direct lightning strokes for the first 10 km from the HVDC substation and for the HVDC transmission line tower footing resistance to be sufficiently low, for example, less than 10 Ω up to 25 Ω .

As a third alternative, in place of sequence components, the information could be provided in the form of self- and mutual impedance between conductors and earth.

10.3 Cable line(s)

10.3.1 General

Length of sections or total length should be specified as appropriate. Any restrictions on service conditions imposed by the cable supplier should be stated.

Examples of such restrictions might include:

- a) limitations on polarity reversal;
- b) limitations on discharge rate;
- c) limiting voltage and current ripple level;
- d) limitations on overvoltages and overcurrents.

10.3.2 Electrical parameters

The electrical parameters are the following:

- 1) d.c. resistance of conductor, maximum value at rated current and at maximum overload current, minimum value at minimum current;
- 2) conductor resistance frequency dependence up to 5 kHz;
- 3) cable sheath resistance and frequency dependence up to 5 kHz;
- 4) inductance and frequency dependence up to 20 kHz;
- 5) capacitance of conductor to sheath;

- 6) capacitance of sheath to earth (armour);
- 7) surge impedance of cable conductor to sheath;
- 8) attenuation characteristics up to 50 kHz.

10.4 Earth electrode line

To evaluate possible transformer saturation effects due to direct current flowing via the station earthing system and earthed neutrals, the earth electrode line length, as well as the length of any part of it which is on the HVDC transmission line towers should be specified.

The earth electrode line resistance – maximum value and ambient temperature assumptions – should be stated.

10.5 Earth electrode

The maximum resistance of the earth electrode relative to the remote earth should be indicated. It should be noted that this resistance may increase with time and environmental and/or load conditions.

11 Reliability

11.1 General

The reliability of a HVDC system is the ability to transmit a defined energy within a defined time under specified system and environmental conditions.

The purpose and scope of this clause is for writing specifications and evaluating reliability. This clause defines reliability calculations during the acceptance period of an HVDC system. Reference is made to the CIGRE Brochure 346 which deals with a reporting procedure of specific failures and overall availability of HVDC systems in operation. Although the scope of the CIGRE Brochure 346 is different from this report, the basic terms used and their definitions are common to both documents.

Terms and definitions applicable to the reliability of HVDC systems are given below.

11.2 Outage

11.2.1 General

An outage of the HVDC system is an event when the transmission capability falls to a level below the maximum rated power. This may be caused by defects of components of parts of the equipment, human errors, switching-out of equipment for maintenance and repair, switching-out caused by an operation of protection equipment, external fault, etc. (see 11.3.3). Consideration should be given to defining which of these or other causes should be included in the availability and annual number of forced outages. An outage will be included in the calculations either as a scheduled outage or a forced outage (11.2.2 and 11.2.3, respectively).

11.2.2 Scheduled outage

A scheduled outage is an outage where the transmission capability falls below the rated power level, and is planned in advance to allow part or all of the HVDC system to be taken out of service for a scheduled maintenance period or for equipment repair.

11.2.3 Forced outage

A forced outage is an unscheduled outage, which is initiated either by automated protection equipment action or through operator intervention (i.e. taking a decision to shut down all or part of the HVDC system in a situation where continued operation may cause damage to

personnel or equipment and the shutdown cannot be deferred until the next scheduled outage).

11.3 Capacity

11.3.1 General

The capacity terms defined below are normally defined at one point in the HVDC system (such as the sending-end a.c. terminals, the receiving-end a.c. terminals, or the sending-end d.c. terminals). In cases where each of the HVDC converter terminals are under separate ownership, it may be appropriate to define the rating of each station individually.

11.3.2 Maximum continuous capacity P_m

This is defined as the maximum power value (in MW) for which the HVDC system is rated for continuous operation, excluding any additional capacity available through the presence of redundant equipment.

11.3.3 Outage capacity P_o

For the duration of the outage the power available is reduced from the maximum rating by an amount (in MW) called the outage capacity P_o .

11.3.4 Outage derating factor (ODF)

The outage derating factor is defined as the ratio of the outage capacity P_o to the maximum capacity P_m :

$$ODF = \frac{P_o}{P_m} \quad (1)$$

11.4 Outage duration terms

11.4.1 Actual outage duration (AOD)

The actual outage duration is defined as the time elapsed in decimal hours between the start and the end of the outage. The outage is typically started when a switching event takes place to interrupt the main circuit power flow, or to initiate the reduction to the outage power level. The outage is typically completed when a switching event takes place to restore the equipment to a state where it is ready for operation, although not necessarily put into operation, i.e. the equipment is made available for service operation.

The actual outage durations may be segregated into forced and scheduled, such that the figure of AOD for each outage becomes either Actual Forced Outage Duration (AFOD) or Actual Scheduled Outage Duration (ASOD).

11.4.2 Equivalent outage duration (EOD)

To take into account the partial loss of capacity, the equivalent outage duration is defined as the actual outage duration multiplied by the outage derating factor

$$EOD = AOD \times ODF \quad (2)$$

Similarly to the creation of forced and scheduled actual outage durations, it is possible to segregate the equivalent outage durations into forced and scheduled to give Equivalent Forced Outage Duration (EFOD) and Equivalent Scheduled Outage Duration (ESOD).

11.4.3 Period hours (PH)

The period hours is the total number of hours in the period covered by the analysis and is typically one year or 8 760 h.

11.4.4 Actual outage hours (AOH)

The actual outage hours are the sum of the individual actual outage durations for the period of the analysis.

$$AOH = \sum AOD \quad (3)$$

It is possible to subdivide the AOH figure into forced and scheduled outage hours, by summing the AFOD and ASOD values rather than the summation of the AOD values.

11.4.5 Equivalent outage hours (EOH)

This is defined as the sum of the individual equivalent outage durations within the period of the analysis.

$$EOH = \sum EOD \quad (4)$$

It is possible to subdivide the EOH figure into forced and scheduled outage hours by summing the EFOD and ESOD values, rather than the summation of the EOD values.

11.5 Energy unavailability (EU)

11.5.1 General

This is a measure of energy which could not have been transmitted due to outages.

Energy unavailability is determined from the equivalent outage hours figure, as follows:

$$EU\% = \left(\frac{EOH}{PH} \right) \times 100 \quad (5)$$

It is usually expressed in percentage values.

For reliability studies, it is essential to distinguish between the effects of line faults on monopolar and on multipolar (bipolar) transmission systems.

In a monopolar system, a line fault causes a complete collapse of the transmission. In a bipolar system for most cases, a line fault only affects one pole of the transmission system, so that line faults would, in general, reduce energy transmission by 50 %. However, if the remaining transmission line pole is designed for some degree of overcurrent capability and if the converter groups on the HVDC substation can be connected in parallel, then more than 50 % of the energy may be transmitted after necessary switching for paralleling the converters has been performed.

In the case of a fault in a converter unit, the affected unit may have to be switched out. The percentage loss of transmission capacity is given by the number of converter groups taken out of service related to the total number of converter units.

There may be other contingencies, such as partial loss of filters, faulted earth electrode line, etc. Their impact on availability should be defined.

11.5.2 Forced energy unavailability (FEU)

There is a measure of the energy which could not have been transmitted due to forced outages:

$$FEU\% = \left(\frac{EFOH}{PH} \right) \times 100 \quad (6)$$

11.5.3 Scheduled energy unavailability (SEU)

This is a measure of the energy which could not have been transmitted due to scheduled outages:

$$SEU\% = \left(\frac{ESOH}{PH} \right) \times 100 \quad (7)$$

11.6 Energy availability (EA)

This is a measure of the energy which could have been transmitted by an HVDC system:

$$EA \% = 100 - EU \% \quad (8)$$

11.7 Maximum permitted number of forced outages

Not all the forced outages are to be counted. The maximum permitted number of such forced outages for the period hours PH should be defined.

11.8 Statistical probability of outages

11.8.1 Component faults

In addition to the availability of the overall system, the reliability of some individual components may also be considered.

Every component in the system can be characterized by its failure rate λ . It is well to distinguish between statistical failures (random outages) and failures at the end of the component lifetime (for example, outages of luminescent diodes because of ageing). To stock spare parts, good practice differentiates between these two kinds of failures, since at the end of their lifetime all of the concerned components should be replaced.

11.8.2 External faults

The expected number of a.c. system faults and their duration, which may detrimentally influence the behaviour of an HVDC system, should be stated. The probability of the occurrence of such faults should be considered when stating the permitted number of HVDC system forced outages.

12 HVDC control

12.1 Control objectives

The advantages of an HVDC system very much depend on the utilization of its controllability in ensuring maximum flexibility, reliability and adaptability for different system requirements.

The objective of an HVDC control system should be to provide efficient operation and maximum flexibility of power control in magnitude, rate of change and direction without

compromising the safety of the equipment, while maintaining the maximum independence of each pole. The control system should be suitable for high-speed control in such a way that it can effectively respond to disturbances in the a.c. and HVDC systems. It is recognized that long-distance transmission requires a high-speed telecommunication system for the most effective operation. However, the HVDC system should be operable without telecommunication, and, for this case, the performance should be maximized to the extent possible.

The control system should be adaptable for:

- 1) control of the reactive power exchange with the a.c. system including reduced or increased reactive power consumption;
- 2) a.c. voltage control;
- 3) frequency control;
- 4) active power modulation;
- 5) combined active and reactive power modulation;
- 6) subsynchronous torsional interaction damping;
- 7) remote operation.

12.2 Control structure

12.2.1 General

The various control circuits of an HVDC substation are generally structured in a hierarchical manner. They normally operate fully automatically. For long-distance HVDC transmission systems, a telecommunication link is needed to coordinate between the rectifier and the inverter. The various levels are described subsequently, starting with the lowest level (Figure 19).

12.2.2 Converter unit firing control

The converter unit firing control is essentially an open loop control. Its outputs are the firing pulses to the individual valves in a 12-pulse converter unit. These are synchronized to the a.c. system voltage. The input is the delay angle α or the trigger advance angle β , as provided by the next higher level.

There are mainly two types of converter unit firing control principles which have been used for HVDC:

- equal delay angle control;
- equidistant firing control.

Equal delay angle control is a method of timing the valve control pulses so that the delay angles of the valves in the converter unit are essentially equal, regardless of unbalances in the a.c. system voltage.

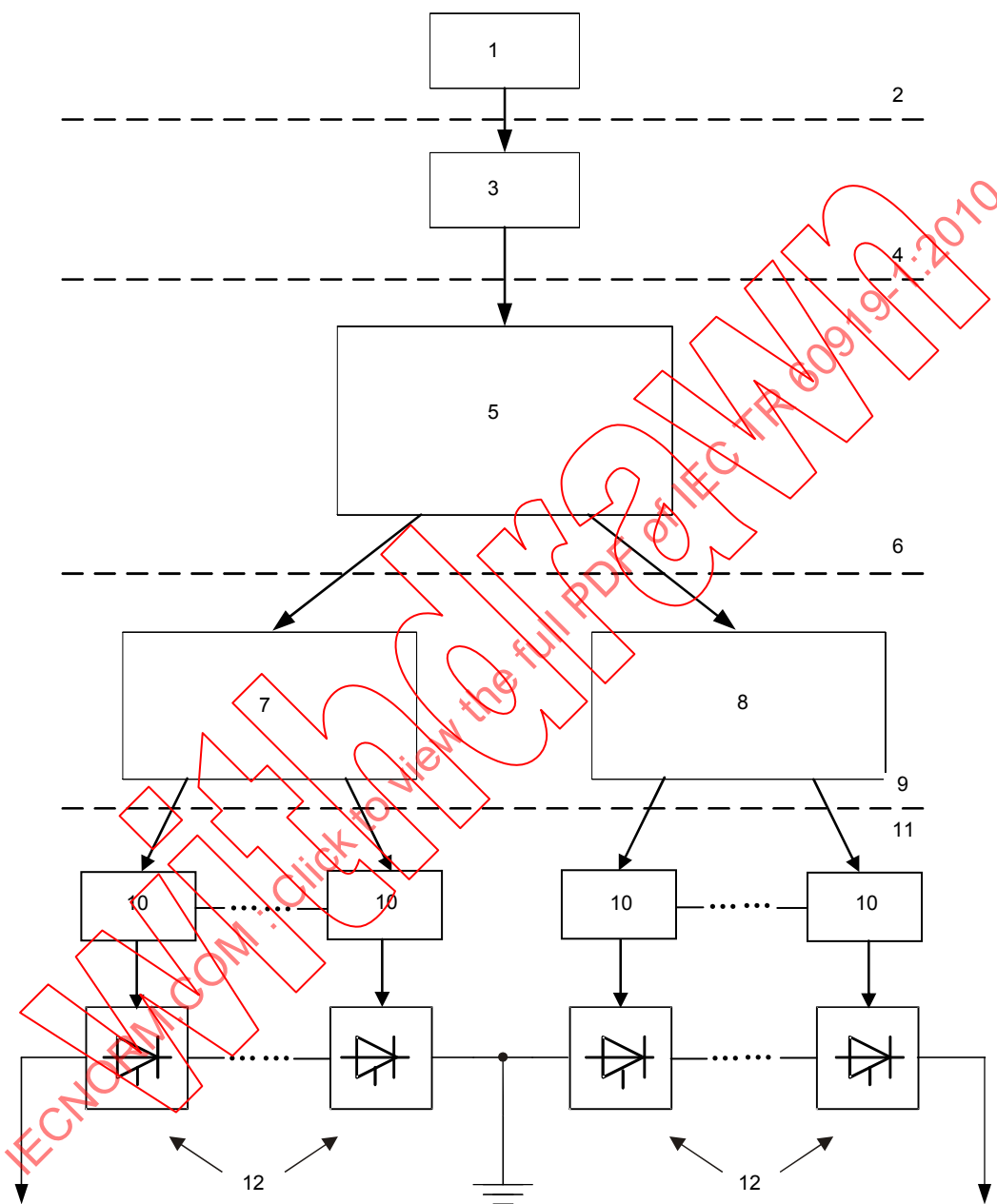
Equidistant firing control is a method of timing the valve control pulses in such a way that they are essentially equidistant in time, regardless of unbalances or distortion in the a.c. system voltage.

The function requirements of the converter unit firing control are:

- a) operation down to low values (i.e. less than 3) of the ratio between the short-circuit capacity of the a.c. network and the transmitted d.c. power;
- b) that the permitted deviation from equidistant firing should be $\pm\Delta^\circ$, i.e. each firing during conditions specified shall occur $30 \pm \Delta^\circ$ after the preceding firing (for a 12-pulse converter unit). It should be noted that the conditions are different with regard to a reasonable value

for Δ° for different converter modes of operation, i.e. operation with minimum α , current control or minimum extinction angle control.

Deviation from equidistant firing gives rise to non-characteristic harmonics transferred to the a.c. network as well as to the HVDC transmission line. A typical permitted maximum value of Δ° is $0,2^\circ$, assuming that the a.c. system voltage and impedances are balanced.



IEC 401/05

Key

- | | | | |
|---|---|----|--|
| 1 | Integrated a.c./d.c. system control | 8 | Pole 2 (d.c. protection, pole sequencing, pole power control, tap changer control, pole power capability calculator) |
| 2 | AC/d.c. system level | 9 | HVDC substation (pole level) |
| 3 | HVDC system/master control | 10 | Valve base electronics (thyristor firing control, thyristor status reporting, thyristor protection) |
| 4 | Area level (or local substation level) | 11 | Converter unit level |
| 5 | Bipole/substation control (substation sequencing, substation power control, substation power capability calculator, reactive power control, a.c. voltage control) | 12 | Converters |
| 6 | HVDC substation (bipole level) | | |
| 7 | Pole 1 (d.c. protection, pole sequencing, pole power control, tap changer control, pole power capability calculator) | | |

Figure 19 – Control hierarchy**12.2.3 Pole control**

The pole control provides the reference values per pole for all series-connected converter units, if any.

Pole control is a closed loop control and includes the basic control functions that are required for stable operation of the HVDC system, such as current control, voltage control, extinction angle control, power control, tap changer control. All these control functions have a reference value and an actual value. Some of these reference values may be provided by the pole control (for example, the current reference value, which is calculated out of the requested transmission power), others can be provided by the operator (for example, d.c. voltage, d.c. power).

Generally, each substation pole is provided with a pole control (Figure 19) that controls the d.c. voltage output of the converter by determining the firing instant of the valves. The pole control senses the difference between the order and the response and adjusts the converter d.c. output voltage accordingly. If the current order in the rectifier is larger than the current response, the firing control increases the direct voltage by decreasing the delay angle, thus increasing the direct current. The direct voltage is increased until the current response equals the current order or the maximum voltage is reached when firing at minimum delay angle, (minimum voltage across the valve capable to fire it). On the other hand, if the current response is larger than the current order, the direct voltage is correspondingly decreased. The decreasing action is limited when the converter operation has been transferred from rectification to inversion and firing given the least permitted extinction angle (to assure safe valve recovery).

The voltage current characteristics of a rectifier and an inverter are shown in Figures 20a and 20b.

Normally, the maximum voltage limit in the inverter is lower than that of the rectifier, and the current will be controlled by the rectifier. That is, the inverter will maintain the voltage, and the rectifier will adjust its voltage until the current becomes equal to the order input, and a stable working point A is established (Figure 20a).

If the inverter voltage limit is larger than the rectifier voltage limit, the inverter controls the current and the rectifier maintains a maximum voltage. As Figures 20a and 20b show the control characteristic in a simplified form, typical examples of more detailed characteristics are shown in Figure 20c.

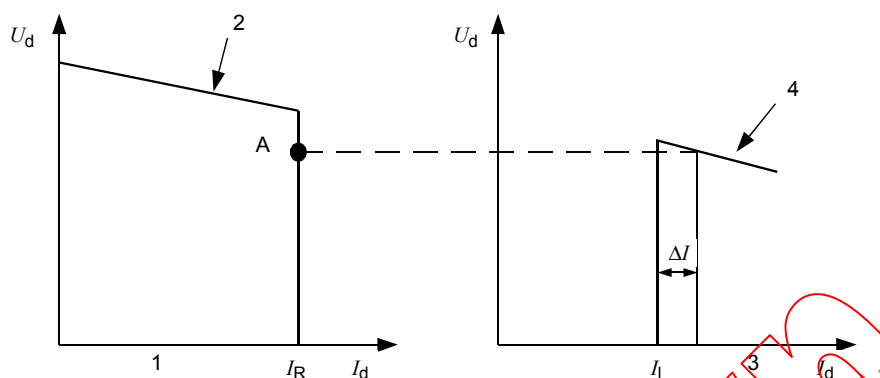
As noted, the rectifier usually controls the current and the inverter determines the voltage. The inverter current order equals the rectifier current order less the “current margin” ($\Delta I = I_R - I_I$) (Figure 20a). The inverter is forced to fire at the lowest allowed trigger advance angle β keeping the extinction angle constant at $\gamma_{\min}$, and, accordingly, the inverter establishes the voltage on the HVDC transmission line.

For long-distance transmission, the d.c. voltage at the inverter is usually kept constant by appropriate control of the inverter transformer tap changers.

In other systems, the inverter is controlled in such a way as to keep the HVDC transmission line voltage constant. In this case, the transformer tap changer is used to keep the extinction angle γ within a certain range.

The delay angle in the rectifier is kept within a narrow band (nominal $\alpha \pm \Delta\alpha$) by means of adjustment of the tap changers of the converter transformers. DC voltage variation by changing the delay angle by $\Delta\alpha$ normally corresponds to one tap-changer step. Alternatively,

the converter no-load direct voltage may be kept constant by means of adjustment of the tap changers.

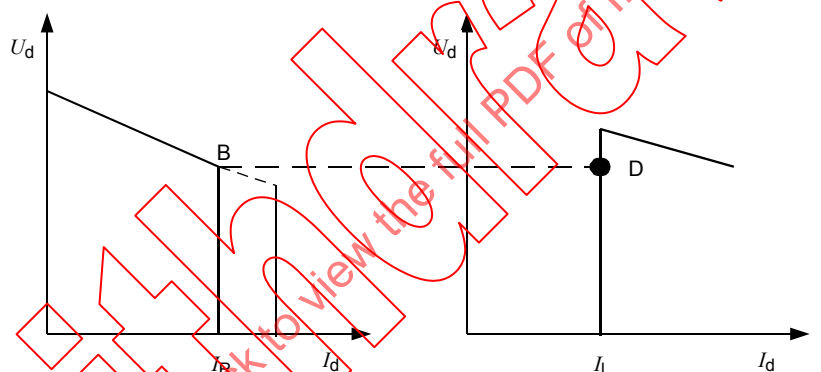


Key

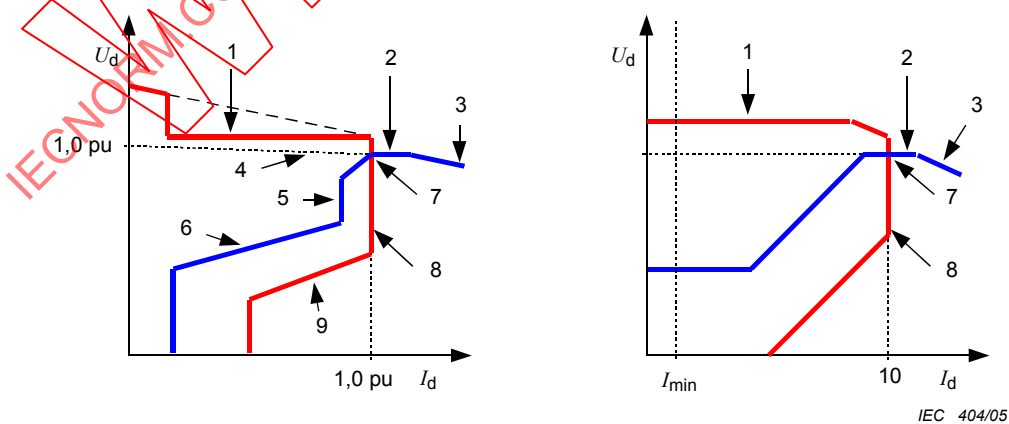
1 Rectifier
2 Rectifier firing at $\alpha = \alpha_{\min}$

3 Inverter
4 Inverter firing at $\gamma = \gamma_{\min}$

a) Normal operation, rectifier controls the current



b) Inverter controls the current



c) Examples of HVDC control characteristic

Key

1 Rectifier U_d control
2 Inverter U_d control (voltage order)
3 Inverter γ control
4 DC line drop

6 Inverter VDCL (voltage dependent current limit)
7 Normal operating point
8 Rectifier I_d control
9 Rectifier VDCL (voltage dependent current limit)

5 Inverter I_d control

10 Current order

Figure 20 – Converter voltage-current characteristic

Reduced d.c. voltage may be needed, for example, at times of reduced voltage withstand capability of the HVDC transmission line. This can be accomplished in the rectifier as well as in the inverter by tap change in the converter transformer, by adjustment of the delay angle or by switching off one series connected converter groups, if any.

12.2.4 HVDC substation control

The HVDC substation control is normally implemented as a closed loop control system. One major design criteria for HVDC systems is normally to minimize the equipment at the station level as much as possible, in order to minimize the impact on the bipole in case of a fault at that level. Referring to station level functions, these could also be realized within pole level hardware, and may include:

- a) coordination of current orders between the two ends via the telecommunication link, most likely on a per pole basis;
- b) power control;
- c) coordination between the poles of a HVDC substation (if there is more than one pole);
- d) more sophisticated control strategies.

Examples of the more sophisticated control strategies are described below.

The reactive power consumption of a HVDC substation is dependent upon the firing angle and the direct current flowing. Thus the d.c. link can be used for control of reactive power or for voltage control in the a.c. network.

The HVDC substation control can be coordinated with control external to the HVDC substation, for example, the turbine governor of a generator station. The HVDC substation can also be provided with controls to avoid subsynchronous torsional interaction (SSTI) of a turbine-generator.

Pole current balance control can be specified to minimize earth electrode line current (equal to the unbalance current between two poles of a bipolar earth return HVDC system), to avoid corrosion problems from earth current flow through underground structures. A typical unbalance current limit between the two poles of a bipolar system without balance control might be 3 % of rated current.

It should be specified which control strategies are intended to be used and at which priority they should be operable under different operating and a.c. system conditions.

The power control tolerance is dependent upon the accuracy of the voltage divider, the current sensor and the resolution of the power order. A typical tolerance value is about 1,5 % at rated power.

12.2.5 Master control

Master control is usually integrated into the HVDC station control. However, if two or more HVDC substations are connected to the same a.c. bus, the master control would be a separate level above the station control and include more sophisticated control strategies. It would interface with the a.c. system and coordinate the various substations. Master control can also be provided remotely, for example, at a dispatch centre. In this case, telecommunication must be provided from the dispatch centre to the HVDC substation.

12.3 Control order settings

Generally, both converters of an HVDC system are equipped with identical control equipment since most HVDC systems are designed to transmit power in both directions.

Only the station control in one location can be in the lead at one time. Generally, the setting of the station control order and rate of change are provided manually at the lead station. The changes in order are then executed in the other substation(s) via the telecommunication. Capability of the lead station for setting can also be transferred to a remote location, for example, a dispatch centre.

In the current control mode the current order can be set manually in both substations, if voice communication is available for coordination purposes. Current control can also be provided remotely, for example, at a dispatch centre.

Switching from power to current control mode may be ordered automatically after failure of the telecommunication channel or by command from the station control.

The resolution in the power order setting may be specified (typically 10 MW at a rated power of 1 000 MW). Its rate of change may be specified as well (for example, between 1 MW/min and 99 MW/min in steps of 1 MW/min).

Change in power direction is normally initiated from the lead substation, but could also be ordered automatically, if emergency reversal is called for, for example, after a disturbance in one of the a.c. systems.

12.4 Current limits

Various limits can be applied to the current order. The main objective of these is to optimize the permissible current with respect to main circuit components and cooling conditions. Examples of such limits are:

- a) overload of limited duration – permits overload for a fixed duration per 24 h period, for example, to take account of transformer temperature-rise limits;
- b) winter overload – permits overload when valve cooling conditions are favourable during low ambient temperature periods;
- c) dynamic overload – permits overload for short times based on transient thermal properties of thyristors and their coolers;
- d) other current limitation – because of loading limits for generators connected to the rectifier substation or for operation with reduced d.c. voltage or other system dynamic performance requirements;
- e) minimum current limitation – normally 0,05 to 0,1 per unit.

The limited current order can be transmitted between the two substations and synchronizing equipment ensures that the two substations at any particular time will be given identical current orders.

12.5 Control circuit redundancy

The user requirements for availability of the HVDC scheme may form the basis for specifying the reliability of the control system. Typically, to achieve a minimum possible bipolar outage rate, the control system incorporates redundancy or main and backup subsystems.

12.6 Measurements

Items of interest which are normally measured in an HVDC system are as follows:

- d.c. current;

- d.c. voltage and polarity;
- reactive power consumed by the converters;
- net reactive power including VAR banks and filters;
- a.c. current;
- a.c. voltage;
- a.c. power;
- energy;
- earth current;
- delay angle;
- extinction angle;
- tap-changer positions.

A decision should be made on which of these measurements is required, and whether they should be made on a per pole basis, and at what accuracy.

The accuracy or tolerance requirements will be different according to the function for which the measurement is being made (control, protection, metering, indication, recording, etc.). As an example, the deviation between the set current order and the actual current is dependent upon the tolerance of the current control system and the current sensor. In this case, a typical tolerance requirement is less than 1 % at rated current.

13 Telecommunication

13.1 Types of telecommunication links

When the two terminals of a HVDC system are located a considerable distance apart, it is necessary to have a telecommunication system to exchange information between the two terminals. The most basic information to be exchanged relates to coordination of the two terminals during start and stop sequences. Fast communication between the two terminals can be used to enhance the performance of the HVDC system.

Alternative types of telecommunication can be used for control and operation of an HVDC transmission:

- a) telephone;
- b) power line carrier (PLC);
- c) microwave;
- d) radio link;
- e) optical fibre communication.

More than one system may be used.

13.2 Telephone

A public telephone network is one alternative communication link for HVDC transmission control. The basic need for voice communication between the stations for the correct timing of measures to be taken in the stations at operational changes can be satisfied by a dial-up connection. For the operation of the HVDC transmission from a dispatch centre with unmanned HVDC substations and to make use of the inherent HVDC system speed of response for control of transmitted power, a permanent telephone line is needed.

13.3 Power line carrier (PLC)

PLC is one means of communication for an HVDC transmission with overhead lines; however, its capabilities may be insufficient to meet the requirements of high-speed modulation control.

For an HVDC cable system, the transmission capacity of a PLC will be reduced for longer cable distances. A cable distance of about 150 km is the approximate limit for one duplex PLC channel.

When allocating frequencies for a PLC system which utilizes the HVDC transmission line for its carrier signal transmission, consideration should be given to the frequency coordination with other PLC systems of interconnected a.c. networks to avoid interference.

PLC over the HVDC transmission line might well use a higher carrier frequency close to the HVDC substations to achieve a satisfactory signal-to-noise ratio with respect to possible converter interference. Lower carrier frequencies may be used at some distance from the HVDC substations because the lower frequencies have lower attenuation. Due consideration should also be given to possible interference at crossings between the HVDC and a.c. transmission lines.

13.4 Microwave

While not necessarily essential for control of HVDC transmission, a microwave link may be the correct alternative for fast transmission of the large amounts of information needed to complement a more sophisticated control and protection of HVDC systems.

However, the signal levels of microwave telecommunication can be affected by weather conditions, such as heavy rain and fog since they absorb or scatter the microwave signal.

Proper selection of the microwave channel route is necessary for reliable and economical installation. Because of its line-of-sight characteristic, the system requires several reflection towers depending on geographical situation and repeater station(s) for intermediate signal boost to compensate for this attenuation.

Satellite telecommunication may be another choice for very long distance HVDC transmission schemes although it inevitably has communication delay time.

13.5 Radio link

A radio link may be considered at long sea crossings with HVDC cable transmissions, when PLC does not provide sufficient speed.

13.6 Optical fibre telecommunication

A fibre-optic communication link may be used for control and protection of HVDC systems and may be an economic alternative for fast transmission of large amounts of information with high immunity from interference.

This communication system is very fast (comparable to microwave systems) and reliable. Therefore, in addition to the basic requirements for operation of the HVDC system, sufficient additional bandwidth may exist to allow enhanced performance of the control and protection systems. Also, information capacity is sufficiently high that a variety of detailed operational data can be transmitted almost instantaneously. The data channels usually incorporate multiplexer technology for efficient utilization of the system.

Optical fibre can be laid for sea crossings; however, careful route selection is important since they are easily damaged by mechanical stress. Using composite d.c. power cables, in which optical fibres are enclosed, is another choice. If these cables are used, the reliability of the

fibre optic communication in terms of mechanical stress can be compatible with conventional power cable and the total laying cost can be reduced.

13.7 Classification of data to be transmitted

A list of classes of the different types of information to be transmitted between the HVDC substations is given below. For each of these classes, the different requirements should be identified such as speed, resolution and reliability:

- a) order signals for continuous control:
 - power order;
 - current order;
 - frequency control;
 - damping control;
- b) operation orders:
 - change of control mode of operation;
 - interlocking of protection;
 - operation of switches;
 - block/deblock;
 - power system security control;
- c) state indications:
 - position of switches;
 - number of converters in operation;
- d) measured value;
- e) alarm signals;
- f) voice communication;
- g) d.c. line fault location.

Usually, these signals are transmitted in accordance with certain data format, such as cyclic digital telemeter data format. Each data item is assigned to a group of bits sized according to the data format. In some cases, it may be undesirable to resend old data if an error is detected, for example, when sending power orders during swing damping.

13.8 Fast response telecommunication

Several types of control may require a fast telecommunication such as microwave or optical fibre channel (greater than 1 200 bit per second (bps), (for example, 64 kbps)), for example:

- a) damping control of a.c. systems;
- b) frequency control of a.c. systems;
- c) fast power control of a.c. and HVDC systems;
- d) HVDC transmission line fault location;
- e) HVDC transmission line protection;
- f) power system security control.

The performance requirements of the telecommunications system(s) will depend on the specific demands placed on it by the HVDC control system, remote control facilities, etc. Since these vary widely between HVDC schemes, the telecommunications system specification shall be determined through detailed analysis of the particular HVDC system.

13.9 Reliability

Generally, a telecommunication system can be provided with an automatic self-checking system.

If a redundant (stand-by) telecommunication system is available, automatic switch-over should be provided, thus maintaining the full degree of control of the HVDC system. If a redundant system is not available, then, after loss of communication, the operation of the HVDC system should continue uninterrupted under the defined control strategy not requiring telecommunication.

For microwave channels, signal fading is inevitable; however, the interruption period of a typical communication channel is around 10 ms. It is normally possible for the HVDC system to maintain the control signal data during the interruption, so it should be able to recover without interruption of the power flow.

Further high reliability can be achieved if several of the above mentioned communication channels are combined. For example, combination of microwave and fibre-optic communication channel enables uninterruptible, more reliable communication and flexible maintenance of these facilities. Also, dislocated installation of two sets of microwave system (space diversity scheme) can mitigate a signal-fading problem across the sea.

14 Auxiliary power supplies

14.1 General

Auxiliary power supplies, which usually have a total rating equivalent from 0,2 % to 1 % of the HVDC substation, are needed for cooling pumps and fans, control, protection and motorized drives of disconnectors, etc. and for general substation service needs. To ensure adequate security of supply and freedom from interruption, these supplies are usually derived directly from the high-voltage a.c. network at the substation.

Where a separately and independently energized distribution network supply is available, this should be utilized as a back-up source to give added protection against failure of medium- and low-voltage switchgear and supply transformers.

14.2 Reliability and load classification

Short (for example, less than 5 s) interruptions in the auxiliary supply to the converter station should not disturb the HVDC power flow. Safe controlled shutdown of the HVDC substation should take place in the event that the a.c. bus has been tripped by the protection. (Since HVDC converters are line-commutated there can be no sustained transmission if the a.c. system generation is lost, although protection may be needed to prevent pseudo-commutation by filters or reactive power compensators).

Control, protection and data recording systems are not usually able to accommodate even a very short interruption in their power supplies. Accordingly, they are supplied from station batteries or, when a.c. supplies are needed, from an uninterruptible power system (UPS). Duplication of batteries is not always necessary, but full redundancy of the battery chargers and the UPS may be required to meet the desired reliability criteria. All breakers and disconnectors essential to the safe shutdown following a fault should be operated by stored energy, for example, compressed air or battery supplies.

Different considerations apply to the operation of disconnect switches and the closing of breakers to reinstate the transmission capability following a fault-caused shutdown perhaps at a lower capacity. If the requirement for a restart from a totally dead bus can be expected, a diesel generator may be necessary when adequate battery capacity is unrealistic.

Only brief interruptions in power for valve cooling fans and pumps can be allowed because of the short thermal time constant of thyristor valves. Automatic changeover between two independently derived supplies is preferable; but if one is dependent upon the distribution network, it shall be recognized that the security of such a supply will be rather low and the changeover should be such that reconnection to the primary system source is automatically accomplished as quickly as possible.

Since HVDC power transmission is possible only when the a.c. system bus is energized, the loss of auxiliary supplies during an a.c. system disturbance or converter disconnection does not cause a further loss of availability, unless the subsequent restart of auxiliary loads is delayed.

A lower security of supply can be accepted for those general station services the loss of which does not directly jeopardize the power flow. Even so, changeover capability between alternative and independent supplies should be regarded as the norm, but may not necessarily be automatic.

An emergency supply that will be maintained even when the HVDC substation is isolated from the a.c. network may be needed. Typically, this emergency supply will be from diesel generators and apart from supplying general services may be arranged to power the battery chargers, particularly if the possibility of prolonged outages can be anticipated.

14.3 AC auxiliary supplies

The total auxiliary load of the HVDC substation and the number and rating of motors larger than 30 kW should be established, at first to define approximately the overall auxiliary bus requirements. Secondly, details of possible sources of supply and the capacity, fault level and relationship to the point of coupling of the converter to the a.c. network need to be defined. This should be augmented with the aid of a single line diagram. From these data, it will be possible to specify security of supplies, duration of interruptions due to fault clearance, distortion, voltage and frequency limits. A voltage stability analysis should be carried out on any design proposal to ensure that changeover times and phase differences between alternative supplies, voltage reductions on motor starting and fault clearance are within acceptable limits.

Induction motors particularly may be sensitive to the amplitude of negative sequence voltage, low voltage or extreme frequency excursions. Finally, an accurate figure will be needed for loss guarantee purposes.

14.4 Batteries and uninterruptible power supplies (UPS)

It is usual to have separately assigned batteries to limit mutual interference for at least:

- HVDC system control for each pole;
- other substation control and protection;
- telecommunication equipment.

These batteries will usually be of different rated voltages. The time for which each battery can supply its rated load, within the rated voltage range in the event of failure of the charger or its supply, should be specified. A typical time is 6 h. The charging time, while the charger is supplying the rated load and the recharge current for the battery, should also be specified. A typical recharge time is 10 h to achieve a minimum state of charge of the battery of not less than 90 %. In addition, the acceptable ripple voltage and the superimposed ripple current shall be considered. A room should be set aside for batteries and chargers, but with modern equipment there is no justification for separating the two items.

For batteries, it is necessary to consider and specify the following:

- nominal voltage;

- load profile and/or rated capacity;
- voltage range from charge (when boost is necessary) to discharge;
- kind of battery and/or type;
- temperature conditions;
- ventilation requirements.

The charging system should meet the requirements of the battery and the load.

The UPS for a.c. loads can be based upon dedicated units or a common system for the HVDC substation. The latter is usually preferred because it makes the provision of adequate redundancy more realistic. Usually, the UPS will include its own assigned battery.

The following should be specified for the UPS:

- rated voltage, number of phases and permissible distortion;
- voltage frequency and tolerance;
- rated and maximum load;
- type of load;
- maximum allowable interruption for which the UPS should function.

Special consideration should be given to the last three items. UPS are often very sensitive to overload and surge starting conditions of induction motors, large storage capacitors or any other type of load having a substantial non-linear type characteristic. With many UPS the continuity of supply is only within the specified limits for the equipment and is not generally uninterruptible in an absolute sense. Care should therefore be taken that the UPS is correctly specified for the system requirements.

Reliability of the UPS shall also be carefully assessed. Many commercial quality systems suitable for enhancing the quality of distribution system supplies may actually degrade the security of the auxiliary supply in a converter where this is derived direct from the high-voltage system and is therefore inherently very secure, but non-interruptible.

14.5 Emergency supply

If a diesel generator is necessary, then consideration should be given to the following when preparing its specification:

- how much of the total auxiliary load should be supplied?
- should start-up, changeover and/or shutdown be automatic?
- if automatic, care should be taken to ensure that conditions causing frequent restarting cannot occur, otherwise the starting battery might become fully discharged,
- how much fuel should be stored on-site?

To ensure reliable operation when required by emergency conditions, it is desirable that the generator is started and loaded so that it reaches correct operating conditions periodically on a systematic basis. The auxiliary system should be designed to achieve this without in any way putting the transmission at risk by the failure of auxiliary supply equipment to make a correct changeover.

15 Audible noise

15.1 General

Noise from the HVDC substation could be troublesome and might incur prescriptive mandatory sanctions which may be difficult to resolve once the station is built. Therefore,

limiting specifications should be prepared at the start of the project taking into account requirements of any applicable regulations or codes of practice. The effects of noise are generally treated as those concerning nuisance to the public outside the boundary of the HVDC substation and noise effects in the working environment. While the latter are important, public nuisance limits are often more difficult to specify.

15.2 Public nuisance

15.2.1 General

The impact of HVDC substation noise on the public outside the confines of the substation, and whether or not it is seen as a nuisance, depends upon the noise level, the pre-existing level, the nature of the surrounding area and the nearness of residential property.

As a first step the acceptable noise level at the boundary shall be specified having regard to the relevant factors. ISO 1996-1 gives a method for determination of an acceptable level. Next, the level and spectrum of noise expected from each major source should be defined. These can then be summed to decide whether or not the total noise will be acceptable. The location of equipment, that is the distance from the property line, is of particular importance. Special noise abatement measures may need to be used to keep the total to an acceptable figure.

Other noise-producing equipment may be installed at the same location and, if so, should also be considered, for example, a.c. system transformers and reactive power compensators. Typical HVDC substation plant items most likely to produce significant noise are discussed below. When very low audible noise levels are specified at the boundary, the noise from other equipment, such as a.c. filter capacitors, diesel generators, etc. may also be significant.

15.2.2 Valves and valve coolers

The noise associated with indoor valves can usually be disregarded so far as the public is concerned, since in most cases the attenuation introduced by the valve hall will adequately suppress it. A main source of noise will probably be from the fans of outdoor coolers. These will usually be closed-cycle evaporative coolers or forced air coolers drawn from a standard product range and, as such, the cooling equipment manufacturer should be able to supply noise spectrum and level data. Evaporative coolers are generally less noisy. In both types, the noise level can be reduced by using larger, lower-speed fans. Substantial noise reduction can also be achieved by using screen walls to deflect the noise upwards.

15.2.3 Converter transformers

Converter transformer noise level is likely to be comparable to similarly sized a.c. system transformers; but, because of the effects of the harmonic currents, principally of orders 5, 7, 11 and 13 and the small residual direct current in the converter transformer valve windings, its noise spectrum will be different in actual operation and may be about 10 dB higher than would be measured in factory a.c. tests. The tank and cooler noise levels can be reduced by conventional means, if necessary, for example, enclosure, mufflers and lower speed fans.

15.2.4 DC reactors

In the case of oil-immersed d.c. reactors, noise will come from the core, structure and coolers of the d.c. reactors. Core and structure noise can be expected to have peaks at ripple frequencies corresponding to the harmonic orders of 6 and 12. It is probably not practicable to carry out valid factory tests of d.c. reactor noise. The noise level can be reduced, if necessary, by some of the same measures as are applicable to transformers, for example, enclosures.

For air-cored d.c. reactors, and where low noise levels are required, special designs including the use of additional sound absorbent shields should be considered.

15.2.5 AC filter reactors

Filter reactors are usually air-cored, and modern manufacturing methods are available which may be used to reduce the amount of noise produced. Other measures may be taken to reduce the amount of noise propagated, such as careful consideration of the location within the converter station, sound absorbent barrier walls, or even locating the equipment inside buildings.

15.3 Noise in working areas

The noise level to which persons within the boundary of the HVDC substation may be subjected should be considered with regard to safety, hearing impairment, and the effects noise can have on working efficiency.

Many countries have established codes or mandatory regulations which seek to safeguard the hearing of those exposed to high noise levels and these should be examined and incorporated within the specification as appropriate. Problems of this kind are unlikely in HVDC substations other than during maintenance procedures and in the immediate vicinity of certain types of cooling fans or diesel generators. In most cases, it will be possible to meet the requirements of the regulations if maintenance personnel wears hearing protectors as necessary.

The general noise level within the building will be determined primarily by the valves and the indoor part of their cooling systems, any rotating machinery and by the d.c. reactors (and transformers) where these are partially or fully enclosed within the building. Low noise levels should be specified where mental concentration is routinely expected, as in control rooms.

16 Harmonic interference – AC

16.1 AC side harmonic generation

Converter systems of all types are sources of voltage and current harmonics. To an a.c. network, the HVDC substation acts as a source of harmonic currents. These harmonic currents flowing into the a.c. system impedance give rise to harmonic voltage distortion. In addition, they can propagate throughout the a.c. system giving rise to local resonances or telephone interference.

If a converter is fed from a balanced three-phase source of voltage, if the impedances of the three phases are equal, and if the converter control angles are equal, characteristic a.c. side harmonics are generated of an order, determined by the pulse number, p , of the converter, $kp \pm 1$, where k is an integer. For the ideal case, the amplitude and phase of the generated characteristic harmonics in relation to the fundamental component depend solely on the control angle (α or β) and the overlap angle μ .

However, in practice, a.c. systems that are coupled with HVDC converters are not perfectly balanced in voltage or phase. This leads to negative sequence voltage system typically in the range 0,25 % to 1 % of the positive sequence system. Other sources of unbalance include converter transformer commutation inductance differences (typically ± 2 % to ± 5 %), and control angle unbalances (typically $0,1^\circ$ to $0,25^\circ$ in steady state for modern HVDC control systems). These unbalances result in the generation of non-characteristic harmonics, thus added to the harmonic interference from the converter.

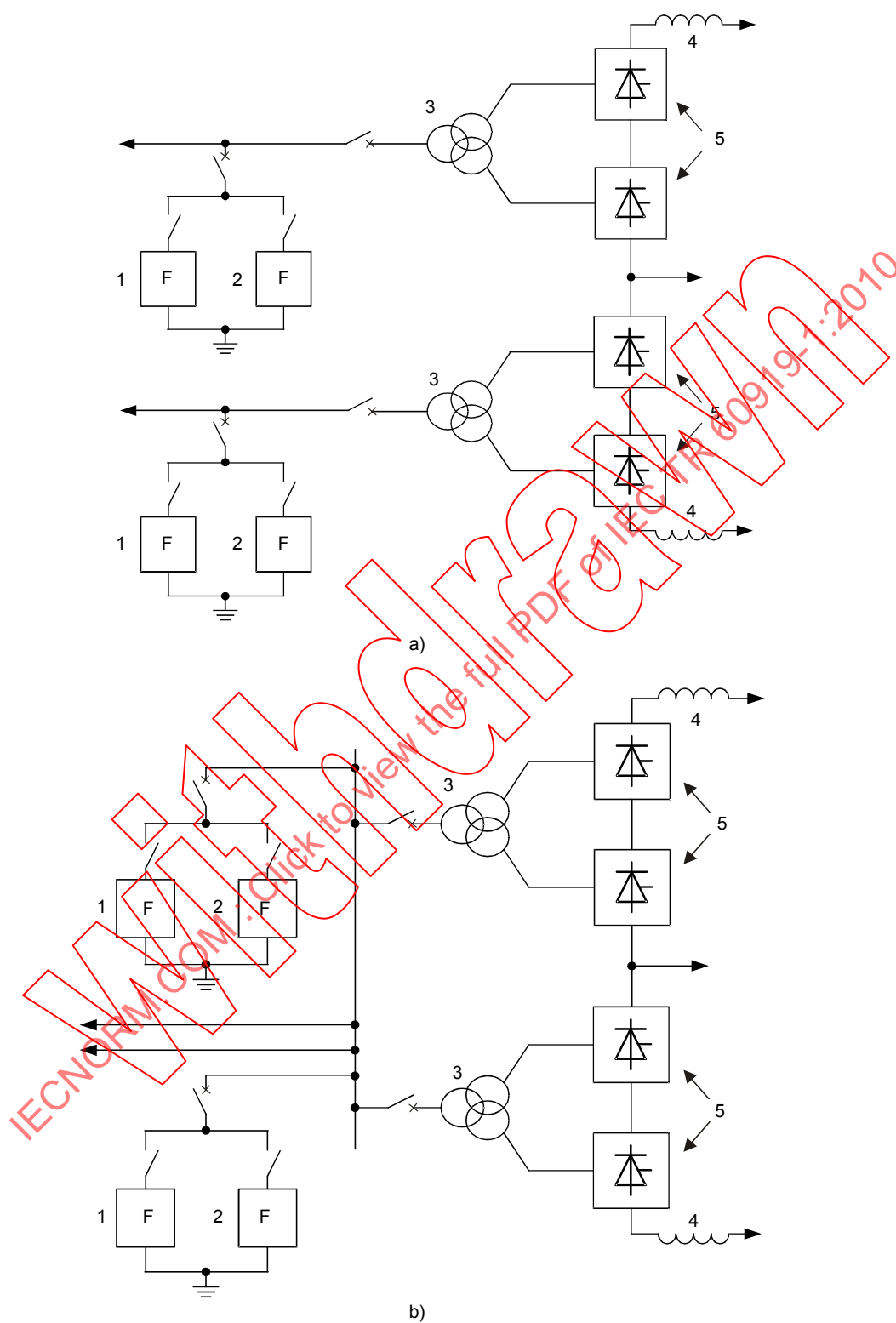
16.2 Filters

AC harmonic filters are generally provided at HVDC substations for absorbing the harmonics generated by the converters, and in addition for reactive power compensation (see Clause 9). An example of a.c. harmonic filters connected to the a.c. feeders for a bipolar HVDC system is shown in Figure 21.

In order that the loss of any filter will not prevent system operation at full power, two filter arms of each type may be specified. The filter arms may be made switchable on the basis of individual arms on each pole. Sizing the individual filter to be switchable should take into consideration:

- reactive power and voltage regulation requirements;
- reduced and light load conditions;
- possible resonances between the filters and the a.c. network impedance with each switched;
- reliability criteria;
- economic constraints.

Filters of either the series-resonant RLC or the damped high-pass type are generally used on HVDC systems. Examples of the most frequently used filter types are shown in Figure 22.



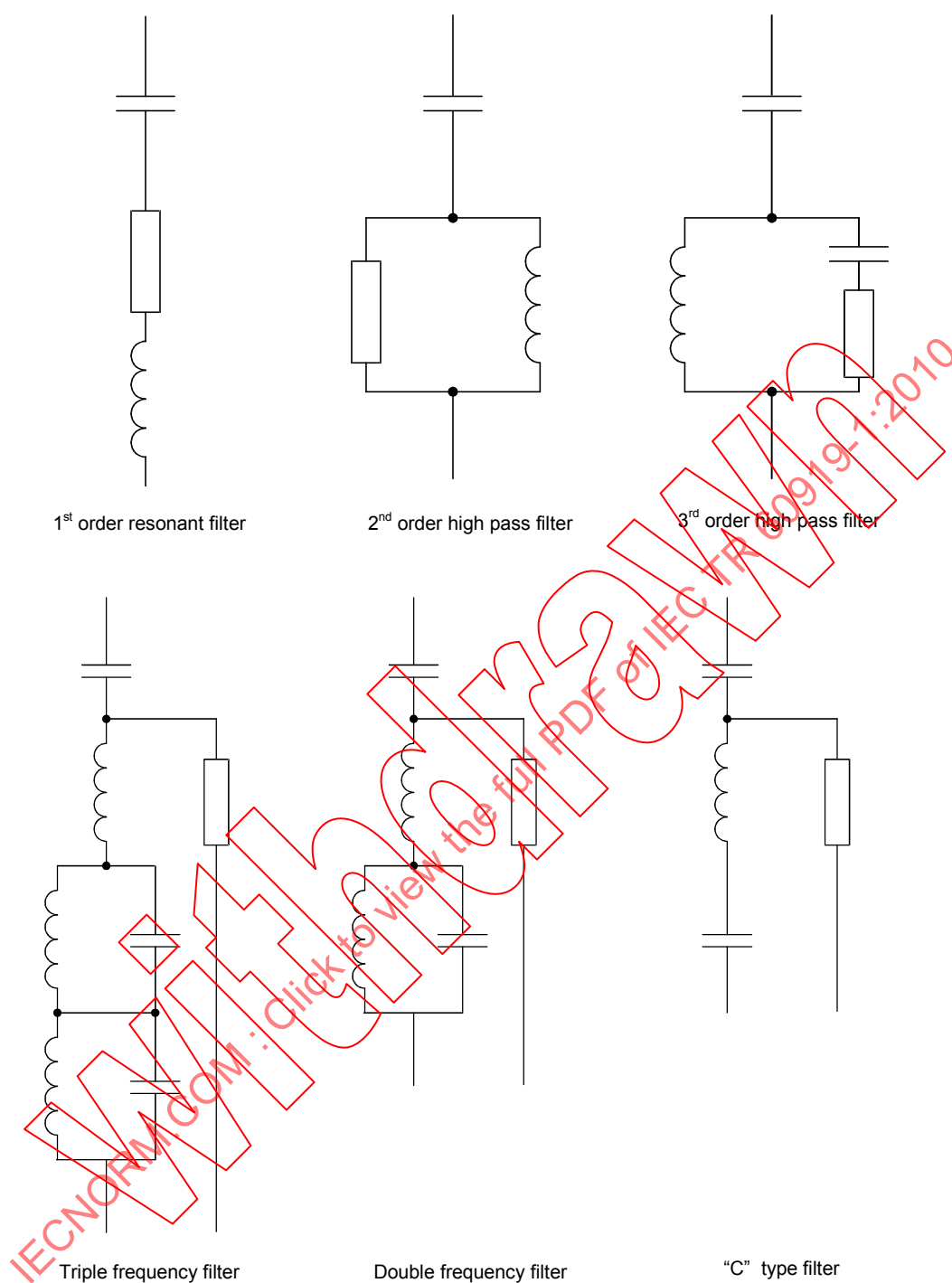
IEC 405/05

Key

1 11th and 13th harmonic filter
 2 High pass filter
 3 Converter transformer

4 DC reactor
 5 Converters

Figure 21 – Examples of a.c. filter connections for a bipole HVDC system



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Figure 22 – Circuit diagrams for different filter types

For optimum harmonic filter design, the system impedance at harmonic frequencies should be known over the frequency range of interest. The a.c. system impedance of the HVDC substation may be specified by an impedance (R/X) circle diagram over the frequency range from fundamental to the 50th harmonic.

Alternatively, the system may be specified in detail by harmonic impedances of lines and generators, etc., normally extending to five to eight buses from the HVDC substation, as discussed in Clause 8. The design of a.c. harmonic filters should also take into account any harmonics that may flow into the filters from other harmonic sources.

Where stringent a.c. harmonic performance requirements are specified, or in combination with CCC/CSCC HVDC circuit topologies, active a.c. filters are a suitable measure. Each active a.c. filter consists of a conventional passive filter connected in series with an active voltage source. The active parts are typically designed to mitigate harmonic voltages at several frequencies in order to improve the harmonic performance of the passive part. Alternatively, active parts can be designed to mitigate the harmonic currents flowing in the a.c. lines which connect to the converter station.

AC filtering aspects including a.c. side harmonic generation, a.c. filter design, interference criteria and levels, filter performance and technical specification as well as monitoring issues are described and discussed in more detail in IEC/TR 62001.

16.3 Interference disturbance criteria

Interference performance is defined in terms of individual harmonic distortion D_n , total effective harmonic distortion D_{eff} , telephone interference factor TIF, telephone harmonic form factor THFF and weighted IT product. For telephone interference, two systems of weighting are used. These take into account the response of telephone equipment and the sensitivity of the human ear, namely, psophometric weighting as recommended by the International Telegraph and Telephone Consultative Committee (CCITT) and “C” – message weighting developed by Bell Telephone Systems (BTS) and the Edison Electric Institute (EEI). Each of the above terms is defined as follows.

Individual harmonic distortion according to CCITT or BTS:

$$D_n \% = \frac{U_n \times 100}{U_1} \quad (9)$$

U_1 refers to rated fundamental r.m.s. voltage and U_n to the n^{th} harmonic r.m.s. voltage considered.

Total effective harmonic distortion:

$$D_{\text{eff}} \% = \sqrt{\sum_{n=2}^{n=50} \left(\frac{U_n \times 100}{U_1} \right)^2} \quad (10)$$

The telephone harmonic form factor (THFF in the CCITT system) and the telephone interference factor (TIF in the BTS system) are both used to describe the interference influence of a power transmission line on a telephone line, and serve as guidelines for specifying interference performance. THFF and TIF are defined in the same way with the only difference being the weighting factor:

$$TIF = \sqrt{\sum_{n=1}^{n=\infty} \left(\frac{U_n \times F_n}{U_1} \right)^2} \quad (11)$$

where

F_n is the weighting factor for each harmonic n according to IEC/TR 62001.

$$THFF = \sqrt{\sum_{n=1}^{n=\infty} \left(k_f \times P_f \times \frac{U_n}{U_1} \right)^2} \quad (12)$$

where