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TECHNICAL REPORT

Guideline for the system design of HVDC converter stations with line-commutated converters

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Guideline for the system design of HVDC converter stations with line-commutated converters

INTERNATIONAL
ELECTROTECHNICAL
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CONTENTS

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GUIDELINE FOR THE SYSTEM DESIGN OF HVDC CONVERTER STATIONS WITH LINE-COMMUTATED CONVERTERS

FOREWORD

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

IEC TR 63127, which is a Technical Report, has been prepared by IEC technical committee 115: High Voltage Direct Current (HVDC) transmission for DC voltages above 100 kV.

The text of this Technical Report is based on the following documents:

Enquiry draft	Report on voting
115/195/DTR	115/203/RVDTR

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

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

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- withdrawn,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

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

INTRODUCTION

HVDC is an established technology that has been in commercial use for more than 60 years. With the changes in demands due to evolving environmental needs, installation of HVDC systems has increased dramatically in the last 30 years and almost half of HVDC projects were commissioned after the year 2000. HVDC has become a common tool in the design of future global transmission systems.

HVDC systems transmit more electrical power over longer distances than a similar alternating current (AC) transmission system, which means fewer transmission lines are needed, saving both money and land and simplifying permissions. In addition to significantly lowering electrical losses over long distances, HVDC transmission is also very stable and easily controlled, and can stabilize and interconnect AC power networks that are otherwise incompatible. Typically HVDC systems provide unique or superior capabilities in the following aspects:

- long distance bulk power transmission;
- asynchronous interconnections;
- long distance cable;
- controllability;
- lower losses;
- environmental concerns;
- limitation of short-circuit currents.

Simply due to these technical merits, the market demand for HVDC transmission technology is spreading widely over the world. There are many HVDC power transmission systems with a DC voltage from 50 kV up to 660 kV in different countries. In addition, there are several ±800 kV HVDC power transmission systems which have been built or operated or which are under construction in China, India and Brazil. In 2016, one ±1 100 kV HVDC power transmission system project was started in China.

The fast development of the HVDC power transmission and distribution industry has been accompanied by IEC standardization work. More than 40 IEC documents, from DC equipment to DC systems, have been published. Among these, the IEC TR 60919 series, IEC 60633, IEC 60071-5, the IEC TR 62001 series and the IEC 60700 series provide essential information for the design and operation of HVDC power transmission systems.

However, this document provides only a basic guide and refers to typical numbers and examples. Other points and values may also be valid in particular cases and should also be considered accordingly.

GUIDELINE FOR THE SYSTEM DESIGN OF HVDC CONVERTER STATIONS WITH LINE-COMMUTATED CONVERTERS

1 Scope

System design is the basis of construction and operation of HVDC systems. It defines the overall philosophy for the HVDC transmission system and enables the ratings and specifications for the equipment integrated in the project.

This document focuses on the system design of converter stations. It is applicable to point-to-point and back-to-back HVDC systems based on line-commutated converter (LCC) technology.

This document provides guidance and supporting information on the procedure for system design and the technical issues involved in the system design of HVDC transmission projects for both purchaser and potential suppliers. It can be used as the basis for drafting a procurement specification and as a guide during project implementation.

2 Normative references

The following documents are referred to in the text in such a way that some or all of their content constitutes requirements 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 60633, *High-voltage direct current (HVDC) transmission – Vocabulary*

3 Terms and definitions

For the purposes of this document, the terms and definitions given in IEC 60633 apply.

ISO and IEC maintain terminological databases for use in standardization at the following addresses:

- IEC Electropedia: available at http://www.electropedia.org/
- ISO Online browsing platform: available at http://www.iso.org/obp

4 Symbols

4.1 Letter symbols for variables

U_{d} DC voltage between the pole and the neutral bus at the line side of the smoothing reactor

U_{dL} DC voltage of pole line to ground at the measuring point

I_{d} DC current

U_{dmeas} measured DC voltage

P_{ref} power setting at the line side of the smoothing reactor in the rectifier station

X_{t} commutation reactance, including converter transformer reactance and other reactance in the commutation circuit that will affect the commutation process

P_{u} on-load losses of converter transformer and smoothing reactor when a six-pulse converter is operating at rated capacity

R_{th} equivalent resistance of the voltage drop of the thyristor valve (current dependent resistance of the thyristors)

U_{dio} ideal no-load DC voltage of six-pulse converter

U_{k} relative converter transformer inductive voltage drop (short-circuit reactance)

U_{plc} relative voltage drop of AC PLC filter reactors

d_{x} relative inductive DC voltage drop of converter

d_{r} relative resistance DC voltage drop of converter

U_{T} forward voltage drop of converter valve under conducting state

d_{xtotR} total relative inductive DC voltage drop of converter – contains both commutation circuit reactance and the system impedance converted onto valve side

P_{dc} active power of converters

Q_{conv} reactive power consumption of individual converter

Q_{f} reactive power supplied by filters

S_{SC} short-circuit capacity of AC bus

R_{d} total resistance of DC transmission line at each pole

R_{e} resistance of electrode

R_{g} resistance of electrode line

S_{n} rated capacity of a three-phase converter transformer connected to a six-pulse valve group

S_{n3w} rated capacity of a single-phase three-winding converter transformer connected to a 12-pulse valve group

S_{n2w} rated capacity of a single-phase two-winding converter transformer connected to a 12-pulse valve group

U_{v} valve side line voltage of converter transformer

I_{v} valve side line current of converter transformer

U_{l} line voltage of line side of converter transformer

n_{nom} rated ratio of converter transformer at normal tap position

η needed OLTC range of converter transformer

$\Delta\eta$ step size of converter transformer OLTC

L_{d} total inductance from DC side

L_{dr} smoothing reactor inductance

L_{tr} converter transformer inductance per phase

μ overlap angle

α	delay angle
γ	extinction angle
Q_{total}	total reactive power supplied by AC filters and shunt capacitors at normal voltage
Q_{sb}	reactive power supplied by the largest AC filter or shunt capacitor sub-bank at normal voltage
Q_{ac}	reactive power supplied by AC system (negative value means the capability to supply reactive power by AC system)
Q_{dc}	reactive power consumption of converters
K_{v}	voltage correction factor, normally 0,95 to 1,05
Q_{r}	total reactive power absorbed by the shunt reactors of converter station at normal AC voltage
Q_{fmin}	capacity of the minimum filter combination which shall be switched in to meet the harmonic performance requirement at normal AC voltage
ΔU_{AC}	dynamic voltage change because of sub-bank switching
Q_{filter}	reactive power capacity of the filter or shunt capacitor sub-bank to be switched
$\sum Q_{\text{filter}}$	reactive power capacity of the filter or shunt capacitor sub-banks in operation after switching
ΔQ_{dc}	change of reactive power consumption of converters due to sub-bank switching, which sometimes can be ignored

4.2 Subscripts

N	normal value of the variables
R	value of rectifier side
I	value of inverter side
max	maximum value of the variable
min	minimum value of the variable

5 Overview of HVDC system design

5.1 General

In implementing HVDC projects, the purchaser or the supplier will do preliminary system design work to prepare the various required documents needed by the project. Specific studies and simulations are conducted during the system design to find the optimal project schemes and to demonstrate performance. As a minimum, the following main system features should be determined:

- HVDC system ratings;
- HVDC system operation configurations and control modes;
- reactive power compensation and control;
- harmonic filtering;
- AC/DC interaction and control;
- insulation coordination;
- environmental impacts, such as audible noise, electromagnetic fields, etc.

The system design may be conducted in several phases by different parties, such as purchaser or supplier, during planning, bidding, detailed design stages, for example, as shown in Figure 1. Different tools and models may be introduced in the system design because of different targets or designs at each stage. One should be very careful to adopt the tools and models in a coordinated manner.

A functional specification for the project is usually prepared by the purchaser before the detailed design. It may consist of project objectives and conditions, grid codes, targeted system performance requirements and operation regulations, etc. This functional specification should be treated as both providing inputs and the guide for the system design of an HVDC project. Because the final technology solution is undefined before the detail design stage, it is always necessary to reserve adequate space in the functional specification for further optimization. The owner will issue the specification as a document for bidding if this is a turn-key project. After evaluation of bidding for the specific technology solution, especially for HVDC control, the owner may choose the appropriate solution. Thus, the system features listed above will be studied in more detail based on the chosen technology solution and some additional studies and surveys usually need to be performed to finalize the system design. Finally, all the equipment ratings and specifications will be prepared.

The flowchart of an HVDC system design is summarized in Figure 1.

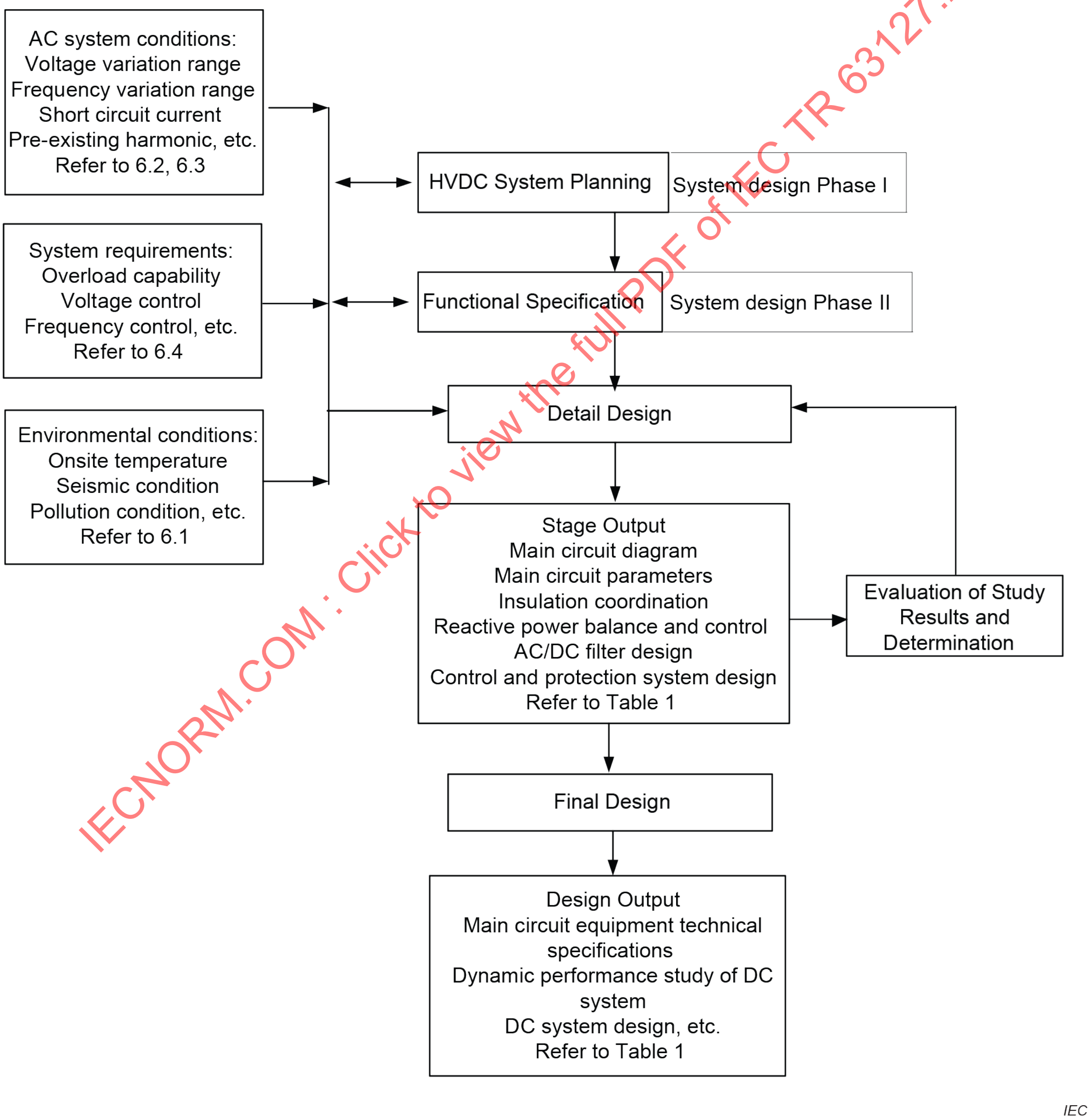


Figure 1 – System design in an HVDC project

5.2 Formulation of system design

5.2.1 HVDC system ratings

HVDC system ratings are defined by transmission capacity, DC voltage and DC current. These ratings are evaluated and selected according to considerations such as the exploitation and the market of energy, the conditions and requirements of power grids, the grid code, the transmission distance, the transportation of bulk equipment, the amount and payback of investment together with the environmental conditions, etc.

The capacity is the first item which the purchaser decides on in the planning stage as well as the DC voltage for a long-distance transmission project. Other ratings can be optimized and finalized in the following design stages.

5.2.2 HVDC system configuration

The HVDC system configuration is normally chosen according to the function and rating of the HVDC system, the environmental requirements, the reliability and availability requirements and other similar high-level functional requirements. A preliminary configuration will be suggested prior to other system design work and the final single line diagram of the converter station will be finalized by the detail design.

5.2.3 Reactive power compensation and control

The converter consumes reactive power in operation. It is necessary to design the reactive power compensation scheme along with the HVDC equipment and control strategy to align with the AC system conditions and requirements. This compensation scheme will be estimated and proposed during planning and then formulated and verified during the detail design together with the related control strategy.

Although most of the reactive power to be compensated is inside the converter station, there will still be some reactive power exchange with the AC system. The capability of the AC system to exchange reactive power needs to be specified in the planning.

5.2.4 AC/DC interaction and control

The AC/DC interaction study should be conducted in different phases to demonstrate stable operation and performance of the power grid after integrating the HVDC link. The power flow and stability study should include at least

- starting and stopping of HVDC system,
- steady-state operation,
- AC system faults, and
- DC system faults.

Especially when the short-circuit ratio (SCR) is low, the commutation failure and recovery procedure of the HVDC system after faults should also be carefully studied. The use of capacitor commutated converters (CCC) or controlled series compensated capacitors (CSCC) may be considered as an option for improvement of HVDC operational performance under low SCR condition. For multi-infeed systems, those converters which will impact the study result should be represented in the studies.

AC/DC interaction is normally studied by digital simulation. In the planning stage a simplified HVDC model may be used when the detailed model is unavailable. This simplified model should have enough precision and the study result should cover all the possible situations in practice. The stable operation and performance of the power grid will be demonstrated and proved by detailed modelling with the actual control in the detailed design. The IEC TR 60919 series provides guidance on specifying the requirements.

Besides the normal power flow and stability study, some special studies may be needed such as a sub-synchronous resonance study, frequency control study, low frequency oscillation damping control study and other such studies. In most cases, mitigation of these resonances or oscillations can be achieved by HVDC control and no extra cost added. Therefore, in the planning stage, some scanning studies may be conducted to check the necessity for further study and solution formulation in the detailed design.

5.2.5 Insulation coordination

Insulation coordination is closely related to the safety and cost of HVDC projects. Thus, it is necessary to predict the insulation level for a HVDC system even in the planning stage. The detail design will formulate the final arrester protection scheme and verify that the predicted insulation level can be achieved by simulations such as

- fundamental frequency overvoltage,
- overvoltage caused by resonance,
- temporary overvoltage, and
- transient overvoltage.

5.2.6 AC/DC harmonic filtering

The converter will produce harmonics on both the AC and the DC sides during operation. These harmonics vary in different operation modes, including different configurations, control modes and transmission powers, etc. AC side harmonics should be mitigated to levels agreed with the connected utilities. DC side harmonics should also be mitigated to levels agreed with the affected telecommunication companies.

The complete filtering solution and component specifications will be provided by AC/DC harmonic filtering study and design. For further information, refer to IEC TR 60919-1 and the IEC TR 62001 series.

5.2.7 Environmental considerations

The HVDC system can impact the environment and vice versa. Audible noise, electromagnetic field, earth current (in some operation configurations) and radio interference are major environmental impacts from the HVDC system. Pollution, earthquake, temperature, etc. are major impacts from the environment. Surveys on environmental effects should be conducted before the system design.

5.3 System studies and simulations

In order to evaluate and determine the system characteristics, applicable quantitative specification and system performances, various kinds of system study and simulation are required during the system design.

A summary of studies and simulations is listed in Table 1.

Table 1 – Studies and simulations in HVDC system design

No.	Study/Simulation	Input	Output
1	Main Circuit Parameter calculation	Capacity and topology of HVDC system, Basic control strategy, DC transmission line and cable parameters, Electrode and electrode line parameters (as applicable), Normal voltage and its steady-state range of AC bus	Steady state characteristics and ratings
2	Reactive Power Compensation	Main circuit parameter calculation, AC network condition	Total amount of compensation, Permissible reactive units and their capacity
3	AC system equivalent	AC network data	Equivalents for relevant simulations such as AC/DC transient/dynamic simulation and fundamental overvoltage study, etc.
4	Temporary overvoltage and ferro-resonance	Main circuit parameters, Reactive power compensation, HVDC equipment characteristics, Control & Protection characteristics, AC network data or equivalent	Overvoltage and depression strategy
5	DC Resonance Study	Main circuit parameters, Reactive power compensation, AC/DC parallel line interaction, HVDC equipment characteristics, Control & Protection characteristics, AC network data or equivalent	Evidence to determine: size of smoothing reactors, size of DC filters, equipment ratings
6	Insulation Coordination	Main circuit parameters, Reactive power compensation, AC/DC harmonic filtering, HVDC equipment characteristics, Control & Protection characteristics AC system equivalent	Arrester protection scheme, LIPL/LIWV and SIPL/SIWV
7	AC system harmonic impedance scan	AC network data	AC system harmonic impedance
8	AC/DC Harmonic Filtering	AC system harmonic impedance, Main circuit parameters, Reactive power compensation, HVDC equipment characteristics, Control & Protection characteristics	AC/DC filter scheme, Component ratings
9	Dynamic performance simulation and verification	AC system equivalent, Main circuit parameters, Reactive power compensation, Control & Protection characteristics	Control & Protection characteristics
10	Power flow and stability study	AC network data, Main circuit parameters, Reactive power compensation, Control & Protection characteristics	Power flow and stability, Required additional control function, such as frequency control, damping control, etc.

No.	Study/Simulation	Input	Output
11	Subsynchronous Torsional Interaction between HVDC & Generator	Main circuit parameters, Reactive power compensation, Control & Protection characteristics, AC network data, Detailed generator characteristics	Confirmation of subsynchronous oscillation (SSO), Subsynchronous damping control (SSDC) specifications[a]
12	AC/DC parallel line interaction study, if applicable	AC and DC line parameters, Main circuit parameters, DC harmonic filtering	Induced fundamental frequency voltage and current on the DC side and influence on the converter transformers
13	Transient current	Main circuit parameters, Reactive power compensation	Transient current ratings
14	AC Breaker /DC Switch study	Main circuit parameters, Reactive power compensation, AC/DC harmonic filtering, HVDC equipment characteristics, Control & Protection characteristics, AC system equivalent	Ratings of breaker
15	Availability & Reliability study	Main circuit arrangement, reactive power compensation and connection scheme, Control & Protection characteristics, auxiliary system, etc. and design target of force outage, rate and schedule outage	Control & protection redundancy requirement, Mandatory spare
[a] SSDC specifications can been designed later if some input is not clear.			

6 Determination of design conditions and requirements

6.1 Environmental conditions and requirements

The meteorological data, such as ambient temperature, atmospheric pressure, humidity, wind direction and velocity, rainfall and snow, and solar radiation intensity, are always needed for HVDC system design. The above data and their intended utilizations are listed in detail in IEC TR 60919-1.

Seismic requirements should be specified for the design of converter station buildings including valve halls as well as for equipment design.

The deposition of contamination particles over insulator surfaces could be more severe under DC voltage than under AC voltage. The pollution condition is ordinarily specified in equivalent salt deposit density (ESDD, mg/cm^2) for the creepage design of HVDC equipment. ESDD will differ according to meteorological conditions, contamination content, type of insulators and other such factors. It is crucial to adopt a reasonable ESDD for an optimized design. Increasingly composite insulators are used in converter stations where the ESDD is very high, for example higher than 0,1 mg/cm^2. Another alternative in a heavy pollution area is to use an indoor DC switchyard especially for ultrahigh-voltage direct current (UHVDC) projects. For more information the designer can refer to IEC TR 60919-2 and CIGRE TB 518.

Altitude correction is needed for the external insulation design of converter station equipment when the station is located at higher than 1 000 m above sea level. Guidance for altitude correction is given in IEC 60060-1, IEC 60071-1 and IEC 60071-5.

The effect of an HVDC system on the environment or surroundings will also influence the scheme of HVDC links, which includes earth current, audible noise, radio interference, etc.

In some countries and states, earth current is strictly limited or prohibited because of risk of interference with underground installations. Thus, the choice of HVDC system configurations and operation modes will be limited.

Audible noise is one of the main concerns in many countries. Audible noise reduction measures might be required for converter transformers, smoothing reactors, AC filters and other noise sources. Further details are given in IEC 61973.

In the case of radio interference and telecommunication interference, RI/PLC filters and DC filter are often designed and installed. An AC filter could diminish the interference to the telephone systems.

6.2 DC transmission line (cable) and earth electrode

6.2.1 Parameters of DC overhead transmission line

The data required for modelling the HVDC transmission line include the following:

a) conductor type;
b) conductor structure, including the respective numbers and diameters (mm) of aluminium and steel strands in pole conductors;
c) cross section (mm^2) of conductor, including respective cross sections of aluminium and steel strands;
d) outer diameter (mm) of conductor;
e) DC resistance of conductor per kilometre at 20 °C (Ω/km);
f) length of transmission line;
g) number of conductor bundles per pole and spacing between bundles;
h) attaching height, horizontal distance and sag of conductors and ground wire on tower.

Owing to the uncertainties of the right of way at system design stage, transmission power and temperature, among others, the total DC resistance of the transmission line can be various. The variation in DC resistance caused by temperature can be calculated for aluminium conductors using Formula (1). For other conductor materials, the resistance calculation can refer to specific specifications.

$$\Delta R = 0{,}004\,1 \times R_{20} \times (T - 20\ °\mathrm{C}) \qquad (1)$$

where

T is the conductor temperature in °C;

R_{20} is the conductor resistance at 20 °C.

Different DC resistances are used in the calculation of main circuit parameters of the HVDC system to define the worst-case scenario. It should be noted that different causes may alter the DC resistance in different directions. For example, the minimum DC resistance at low power and at maximum power may differ substantially for a long HVDC line. The reasonable DC resistance shall be applied in the efficient design.

To carry out the DC filter design and the DC system resonance study, detailed DC line parameters as listed above are required, including shielding wire configuration. For a long-distance DC transmission project, the geographical conditions vary along the line corridor resulting in different towers and earth parameters. It can be difficult to model all the cases one by one. A practical way is to summarize the proportion of each geographical condition along the whole line, such as plains, hills and mountains, and then to calculate the average parameters.

The soil resistivity varies along the HVDC transmission line and the electrode line corridors, which is typically within several hundred Ω·m.

6.2.2 Parameters of DC cable

Historically, several types of cables, including polyethylene (PE), ethylene propylene rubber (EPR), paper-insulated oil filled cables and mass-impregnated cables, have been used in submarine HVDC projects. The choice of cable type is determined by the transmission power and length.

Regardless of the type, the following cable electrical parameters are needed as a minimum for an HVDC system design:

a) inner radius of each conducting layer;
b) outer radius of each conducting layer;
c) resistivity of each conducting layer;
d) relative permeability of each conducting layer;
e) outer radius of each insulation layer;
f) relative permittivity of each insulation layer;
g) relative permeability of each insulation layer.

The IEC 60287 series provides more information.

6.2.3 Parameters of electrode line and ground electrode

When the DC system is allowed to use the ground return operation, the parameters of the ground electrode lines and ground electrodes are an integral part of the DC circuit and therefore are a necessary input for the relevant studies and simulations, such as the main circuit parameter calculation, DC filter design and control and protection system. For specific parameter requirements, refer to 6.2.1 and 6.2.2. IEC TS 62344 provides relevant details about the design of electrode stations. Where several projects share one common electrode, the main circuit arrangement, rated parameters and operation mode of the other projects need to be provided for ground system protection purposes.

6.3 AC system conditions

6.3.1 Operating scenarios of AC/DC system

The operating scenarios of the AC/DC system are defined by the combination of DC transmission powers, generator(s) in service and loads.

The typical operating scenarios of the AC/DC system need to be defined for the project in the system design and study. Some additional scenarios such as emergency operation, commissioning operation or stage operation also need to be considered because they may cause higher stresses on the HVDC equipment if the design of the equipment is based on them. Since these additional scenarios appear just in the early stage of the project or very rarely through the project life, an alternative option for the customer is to design the HVDC system for normal operating conditions and later on verify the design under special scenarios to avoid additional investment. In this case, reduced power or other degradation in performance of the DC system may be acceptable for operation.

6.3.2 AC system modelling

AC system data should generally be provided by the purchaser, which includes all the data necessary for system modelling such as:

a) lines, transformers, reactive power compensators;
b) generators and their regulators such as excitation regulator, prime mover, governor, PSS;

c) unit commitment and load model;

d) configuration, parameters and control model for power electronics based devices (e.g. HVDC, FACTS, STATCOM, SVC, etc.).

AC system modelling should follow the guidance in CIGRE TB 563.

Some special studies, such as the subsynchronous oscillation study, also need the spring mass parameters of the generators.

The configuration of AC lines at various voltage levels in the vicinity of the DC transmission line is needed while performing interaction studies with parallel AC lines.

6.3.3 Relevant AC system protection

The AC system protection scheme is needed for DC system design, including the fault clearing time for normal and backup protection, and the time sequence for single-phase or three-phase auto-reclosing.

The HVDC system design needs to be properly coordinated with the overvoltage protection of AC components. The DC system normally remains in operation and withstands the overvoltages during AC system faults. The overvoltage caused by the sudden loss of complete or partial DC power due to DC faults needs to be depressed to below the level where the AC component overvoltage protection will not operate, by switching sub-banks or other effective methods. Switching banks can also be adopted if it is allowed by the interrupting capability of bank breakers.

The parameters of nearby AC arresters are needed in the insulation coordination study of the converter station, including rated voltage (kV, RMS value), continuous operating voltage (kV, RMS value), and switching impulse protective level (kV, peak value).

6.3.4 Reactive power supply and absorption

Converter stations balance the reactive power demand mainly by on site self-compensation. However nearby generators or reactive power equipment installed in connected grid can also supply or absorb reactive power and the same should also be considered, as appropriate, to reduce the amount of reactive compensation to be provided in the converter station.

The reactive power flow may vary with AC system conditions, which can be determined through power flow studies. The following information needs to be provided:

- permitted steady-state voltage range under different load levels;
- reactive power demand from other nearby loads;
- number of generators in service;
- maintenance of important AC line(s) to power station;
- power factor of feeding unit;
- minimum active power limit of generator;
- self-excitation limit.

Typically the rated power factor of a generator is 0,85 to 0,9. When calculating the reactive power supply of the AC system, a higher power factor for the generator (0,92 to 0,95) is recommended in a more conservative way.

The HVDC power normally remains unchanged after slight AC network contingencies but can run back under emergency conditions to improve network stability. If HVDC power runs back under AC system contingencies, the reactive power supply can be decided according to the conditions before the contingencies, otherwise the conditions after the contingencies should be adopted.

Generators can absorb reactive power in leading phase operation. However the leading phase operation with a lower power factor may result in overheating of the exciting winding, and even destabilize the AC system; therefore it is not recommended unless the generator is specifically designed for such operation. When using generators to absorb excessive reactive power, the power factor of the generator for the leading phase operation will typically not exceed −0,95.

6.3.5 Short-circuit current or capacity

The system strength of interconnected AC systems impacts the HVDC system design. A weak AC system will bring in special requirements and extra cost to the project, like the need for small reactive power sub-banks and an additional synchronous condenser or other static reactive power device, special control strategy, etc.

As one of the alternatives, the CCC or CSCC converters are provided with an extremely favourable behaviour when installed in AC systems having an equivalent short circuit ratio down to 1 at the inverter while introducing the series capacitors in their topology. In addition to this important performance feature, which impacts favourably the economics of the link, such converters present a very robust behaviour in case of commutation failures, as per 5.1.2 of CIGRE TB No.352.

For projects constructed in stages, the short-circuit currents and HVDC power may vary from stage to stage. This can also happen for various scenarios. So SCRs may need to be identified individually.

Both the maximum and the minimum three-phase short-circuit current should be specified for HVDC system design and study. Which short-circuit current will be used for a specific design or study should be decided on a case-by-case basis in order to derive maximum equipment stresses. For example, the maximum short-circuit current is usually used to determine the surge current rating of equipment such as valves and smoothing reactors. The minimum short-circuit current is normally used in studies such as the fundamental frequency overvoltage study and AC side transient overvoltage study.

The calculation of the short-circuit current can be carried out using conventional system stability programs.

6.3.6 AC bus voltage

The steady-state voltage range and short-term voltage range are determined through an AC/DC system study. The steady-state voltage range can be decided through a load flow study on typical operating scenarios and a normal voltage should be defined within this range for HVDC system design. The normal voltage is the most probable voltage on all typical operation scenarios.

A stability study on typical operating scenarios is recommended to decide the short-term voltage range. Generally, the following operation scenarios need to be considered while determining the short-term voltage range:

a) tripping a faulted AC line in the vicinity of the converter station;

b) loss of the maximum generator/load in the vicinity of the converter station;

c) blocking of a monopole in a bipolar HVDC system or blocking of one converter unit or more in a back-to-back station containing several such units;

d) blocking of some or all converters of another HVDC system connected to the same AC system;

e) DC line fault and recovery;

f) commutation failure and response.

The steady-state voltage range is used to determine the tap changer steps of the converter transformer. The normal voltage of the converter station AC bus voltage is mainly used to determine the voltage of the principal tap of the converter transformer and also the rated capacity of the AC filter/shunt capacitor sub-bank. When the converter AC bus voltage varies beyond the steady-state voltage range but is still within the short-term voltage range, the DC system is normally required to start safely and operate reliably, but the requirements of the DC system performance could be lower, for example, operation with reduced power.

6.3.7 AC system frequency

The frequency variation range of the converter station AC bus is an important input condition for the DC side resonance study and the design of main equipment, especially the filters.

The power system operation regulation defines the normal frequency range. Post-disturbance frequency range is normally determined through an AC/DC system study. For HVDC system design, the power systems at the sending end and receiving end have different characteristics of frequency variation if these two systems are asynchronous or split due to some disturbance. The fault cases are listed in 6.3.6 a) to f). The frequency variation range should be compatible with the AC system protection settings, especially for generators and motors.

Normal and post-disturbed frequency range can be represented in the form of the envelope curve. For a 50 Hz system, one example of this curve is given in Figure 2. In this example, the frequency can rapidly rise or fall to the extremes of 50,7 Hz or 49,0 Hz during a fault or serious disturbance, and then recover to 50,5 Hz or 49,5 Hz within 10 min after disturbance clearance, and gradually recover to 50 Hz ± 0,2 Hz within 40 min following the frequency versus time response represented by the two envelopes. Figure 2 is to be interpreted as an envelope encompassing all of the expected transient frequency variations of the AC systems.

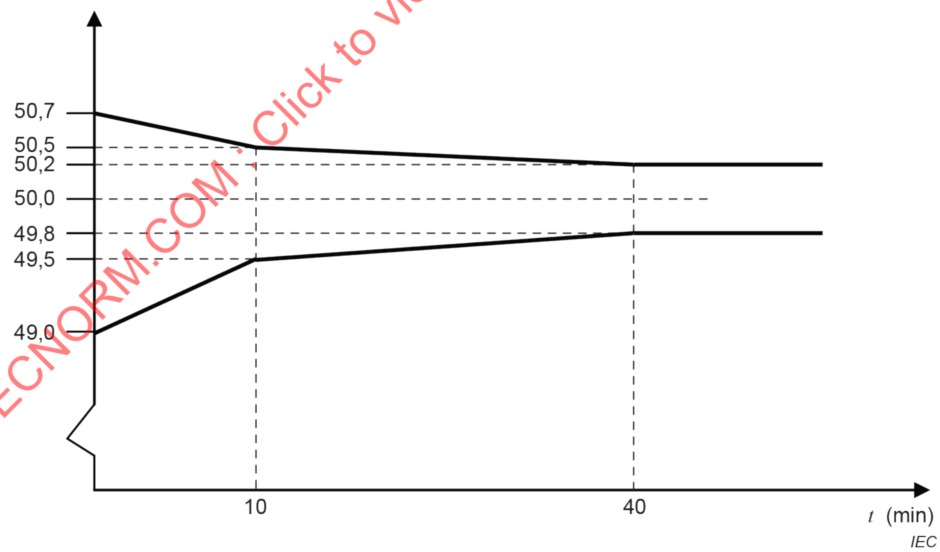


Figure 2 – Example of schematic diagram of AC system frequency variation range

6.3.8 Pre-existing harmonic and negative sequence voltage

The pre-existing harmonics and fundamental frequency's negative sequence component on the AC bus at converter station are basic inputs for AC/DC filter design, which are usually expressed as a percentage of fundamental voltage. Modelling of pre-existing harmonics is discussed in detail in IEC TR 62001-3.

The pre-existing harmonics are generally obtained through on-site harmonic measurement and harmonic power flow calculation. To evaluate the pre-existing harmonic, continuous harmonic measurements covering both relevant substations and AC lines need to be performed. The measurement should be performed on all accessible voltage levels with harmonic sources and include typical scenarios.

Predictive calculation of pre-existing harmonics can be performed on various typical scenarios of the AC system besides the actual test result. The harmonic sources used for the calculation should consider the load growth and planning of specific harmonic producing loads, for example, electric railways, power electronic devices, other HVDC converter stations, domestic and commercial loads. Based on the calculation of harmonic power flow, and suitable margin, the pre-existing harmonics of a converter station can be determined.

The negative sequence voltage from an unbalanced AC system will cause odd triplen harmonics in the converters. A third harmonic AC filter might be required. The negative sequence voltage will lead to an increase of the rating of DC side components, particularly the HV capacitor of DC filters.

Detailed information about pre-existing harmonic influence on the AC filter and DC filter design can be found in the IEC TR 62001 series and CIGRE TB No. 92.

6.4 Requirements for HVDC systems arising from AC/DC interaction

An HVDC system can help to improve the efficiency, safety and stability of the power system when it has well designed functions and performances, such as overload capability, dynamic response requirements, reactive power or voltage control, damping of low-frequency power oscillation, damping of subsynchronous oscillation, frequency control, emergency power control, coordination of parallel AC and DC operation and coordination among multiple DC systems, if applicable. The specification for these functions and performances can arise from an AC/DC interaction study.

In some contingencies, for example, one pole failure in a bipolar system, a generator trip or a loss of parallel AC or DC link, an overload operation is normally expected temporarily, for a short time or continuously. The duration and amount of overload are decided by the capability of the AC system to withstand loss of power through a power flow and stability study.

The HVDC system step response and recovery after interruption of power or fault clearing are crucial to the power system's stability especially for weak AC systems. For example, an optimized VDCL (voltage dependent current order limit) will support the recovery after AC or DC system faults. The requirement for HVDC behaviour can be derived and verified through the power system stability study. Parameters of HVDC controllers should be optimized in the study under given AC system conditions.

The HVDC system can be utilized for damping low-frequency power oscillation by modulation. Through eigenvalue analysis, the necessity and sensitivity of DC modulation can be obtained and a specific controller can be designed and verified when needed.

The HVDC system can also be used to depress subsynchronous oscillation (SSO) which might occur when thermal generators directly feed HVDC converters. The unit interaction factor (UIF) scanning method is recommended in IEC TR 60919-3 to screen for such a possibility. Additional damping control functions can be designed and integrated in the control system if needed.

The DC system may be required to limit large frequency changes of the AC systems through power modulation. This modulation function will be designed and verified by power system simulation. The parameters of frequency control should be optimized considering factors such as the AC network capacity and frequency-dependent characteristics of load and generators. This function can help to stabilize the frequency of some AC systems.

The AC voltage might change due to the HVDC system or the AC system itself. The magnitude and change of the voltage on the AC bus in or near the converter station should always be in accordance with the power system grid code during HVDC operation or after trip. The HVDC system needs to be designed to help maintain the AC voltage at or near the converter station within an acceptable range mainly through its automatic reactive power control.

If multiple HVDC transmission systems or AC/DC parallel transmissions are used to transfer power to and/or from the same region, the dispatching and coordinating of HVDC transmission needs to be studied and designed to ensure power system efficiency during steady operation as well as safety and stability after serious AC or DC faults.

6.5 AC system equivalents

6.5.1 General

Simulations and studies should be carried out according to 5.2. Owing to the limitation of the scale of the simulation tools, an equivalent AC system is usually used instead of the complete AC system. Different AC system equivalents are used for different studies.

6.5.2 Equivalent for AC/DC system dynamic or transient simulation

The equivalent network for AC/DC system dynamic/transient simulation should have similar static and dynamic characteristics as the complete network, including:

- power flow of retained network;
- short-circuit current;
- the recovery characteristics of converter station AC bus voltage after disturbance;
- the power swing of retained generators after disturbance;
- harmonic characteristic.

The equivalent network can be obtained by the static equivalent method more easily than by the dynamic equivalent method. Although the latter can provide a more realistic AC system characteristic, it is usually too complicated to apply. When a complicated power system is simplified, the resistance of mutual impedance in the matrix may appear as negative. The negative impedance needs to be handled through some appropriate measures which are acceptable from the project point of view.

This equivalent network is mainly used for the following purposes:

a) evaluation of DC control and protection functions;
b) evaluation of the performance of the AC/DC system for different DC system control models;
c) evaluation of DC system performance for DC side disturbances such as converter blocking, pole blocking, DC line faults and valve winding faults;
d) demonstration of the DC system response in accordance with the specified response criteria;
e) demonstration of the DC system transient response for reactive bank and sub-bank switching;
f) study of the interaction between the DC system and the local machines during disturbances;
g) factory testing of actual site controls;
h) evaluation of the performance of the DC system during severe AC faults and subsequent fault clearing, when the AC voltages are reduced and distorted;

i) switching overvoltage study of the AC/DC system and ferro-resonance study on the AC side;

j) transient overvoltage study of the DC system caused by unsymmetrical faults in the AC system.

6.5.3 Impedance equivalent for AC filter design

The definition of system harmonic impedance is a compromise between the need to avoid resonance conditions and the need to minimize excessive over-rating of the filter equipment. The harmonic impedance equivalent used for AC filter design can be obtained by scanning the harmonic impedance of the original network. The network scanning is performed using specific tools. System elements such as lines, cables, transformers should be represented by frequency dependent models.

The second to fiftieth harmonic impedances can be represented by a sector diagram (or even several subdivided sectors at a single harmonic) or circle diagram or polygons. For low order harmonics (below the tenth) and characteristic harmonics, it is usually recommended to use a separate diagram to represent system equivalent impedances for each harmonic order. Figure 3 gives an example of a type of sector diagram for a single harmonic order. The impedance of several harmonics can be represented by a single impedance circle, as shown in Figure 4. The impedance circle method tends to result in very conservative and therefore expensive filter designs, so it may not be the most cost-effective method. The polygon diagram method is an alternative to represent system harmonic impedance. Further information is available in the IEC TR 62001 series.

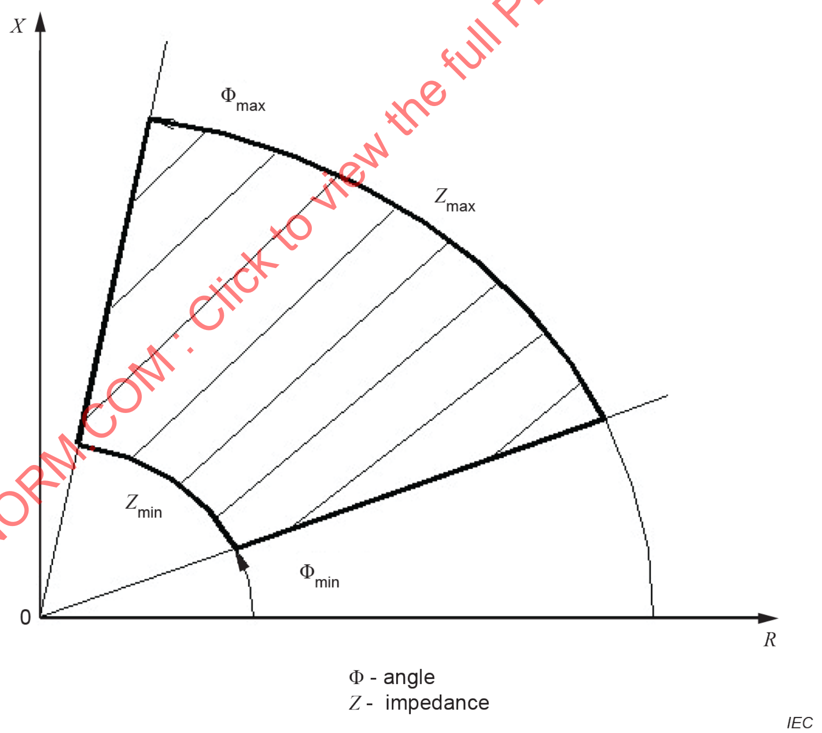


Figure 3 – Sector diagram of system harmonic impedance

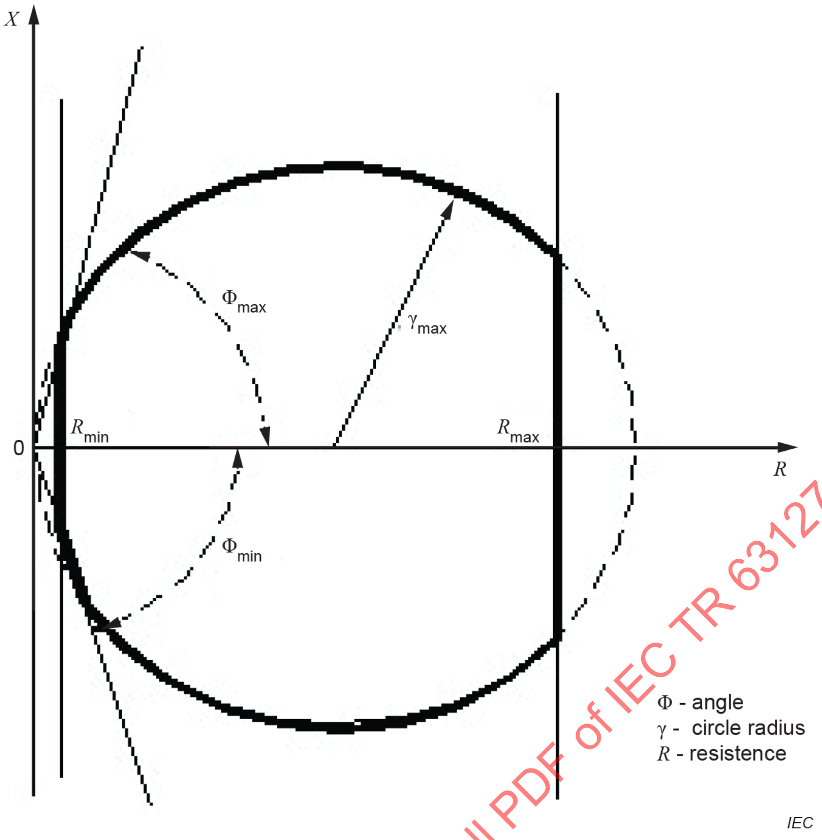


Figure 4 – Circle diagram of system harmonic impedance

The system impedance needs to cover all possible system configurations. The scanning is usually carried out based on the typical operating scenarios of the AC/DC system. The following factors need to be considered:

- different load conditions;
- number of generators in service;
- possible AC lines in service;
- transformers in service;
- nearby filters/shunt capacitor, if applicable.

6.5.4 System equivalent for low order harmonic resonance study

To study the low order harmonic resonance of the AC/DC system, it is necessary to establish a system equivalent. Only the AC bus at the converter station or a portion of the power grid near the converter station may be retained in this equivalent system. This equivalent system needs to meet the following criteria:

a) the converter station AC bus has the same short-circuit current level as the complete network;

b) as observed from the converter AC bus, the equivalent system has the same individual harmonic impedance as the complete network.

The equivalent network may use the structure shown in Figure 5.

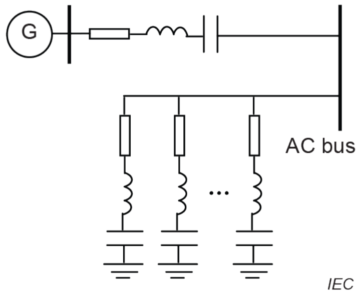


Figure 5 – Structure of equivalent network for low order harmonic resonance study

This system equivalent may be used for the following studies:

- the impact of the control system on the lower order harmonic resonance of the AC system, including the second, third and fifth harmonic resonance;
- low order harmonic resonance of the DC circuit.

7 Main circuit design

7.1 Ratings

7.1.1 Rated power

The nominal power of a project is affected by many aspects as described in 5.1.2 and varies over a wide range. After many years of development, the nominal power of an HVDC system has increased rapidly up to 10 000 MW at ±800 kV. Besides those newly developed large power converters, some traditional power ratings are still chosen for new projects, but some other ratings are no longer chosen.

To date, the highest capacity of a single converter for a back-to-back (BTB) project is 1 000 MW. Higher power rating of BTB is technically feasible but may not be an economical solution due to the high cost of interconnected AC transmission lines especially if long AC lines are required. For cable projects, the power rating limits are most likely decided according to the cable. The two biggest ratings per pole of cable projects are 1 100 MW at 600 kV and 800 MW at 500 kV. These figures relate to a single cable per pole; with parallel cables, higher ratings can be reached.

The power rating limits for long distance overhead HVDC projects are mainly decided according to the converter equipment. Combined with other aspects involved in the determination of the power level, 1 500 MW per converter at 500 kV is a widely used rating for long distance overhead HVDC projects. The highest power capacity of a single converter in a commercial operation is 2 500 MW at present. A higher power rating may require the combination of several converters in parallel or in series as in some UHVDC projects.

When deciding the rating of the converter, consideration should also be given to the maximum permitted loss of transmission capacity due to a single event for the connected AC systems.

The minimum transmitted power is typically 0,1 per unit of the rated capacity in order to avoid intermittent current operation. Lower transmission power is possible with some special design considerations.

An HVDC system design based on rated power may have inherent overload capability. Temporary overload for several seconds will impact the converter valve design, and short-term and continuous overload requirements will impact the design of equipment such as converter transformers, bushings, smoothing reactors.

For more details, refer to 5.1 of IEC TR 60919-1:2010.

7.1.2 Rated voltage

Selection of an HVDC system's rated voltage is decided by the required transmission power and cost of construction and operation. Unlike HVAC systems, there is no standard rated voltage series in HVDC applications. The choice of the transmission voltage depends on a great many factors which can influence the project, including some non-technical factors such as the cost of energy and expected asset life of the scheme. It is a result of the system design, taking into account the following operation scenarios:

a) power flow with high utilization factor;

b) power flow with relatively low utilization factor including high load with limited duration;

c) mainly emergency power exchange;

d) mainly power system quality control operation such as automatic fundamental frequency control.

In scenario a), higher voltage is preferred compared with scenario b) in order to minimize the transmission line losses. However, in other scenarios, selection of DC voltage is mainly determined by AC system requirements.

For a long-distance bulk power transmission project, a higher rated voltage is desired. Table 2 lists the rated voltage ranges selected under various transmission powers and distances.

Table 2 – Preferred rated voltages for overhead line HVDC power transmission

Transmitted power MW	**Rated voltage** kV					
	Transmission distance (km)					
	≤ 200	≤ 500	≤ 1 000	≤ 1 500	< 2 000	≥2 000
≤ 500	250	400	–	–	–	–
≤ 1 000	350	400	500	–	—	–
≤ 3 000	–	500	500 or 600	600 or 800	600 or 800	800
≤ 4 000	–	600	600	800	800	800
> 4 000	–	800	800	800	800	800 or 1 100

For an HVDC cable power transmission project the choice of rated voltage is generally deduced from the required transmission power rating and power capability of the available cable. A higher rated voltage reduces the current rating of the cable. Table 3 lists the rated voltage ranges selected for submarine project under various transmission powers and distances.

Table 3 – Preferred rated voltages for submarine HVDC power transmission

Transmitted power MW	**Rated voltage** kV				
	Transmission distance (km)				
	≤ 50	≤ 100	≤ 200	≤ 300	> 300
≤ 300	250	300	300	400	400
≤ 500	250	400	400 or 500	500	500
≤ 1 000	500	500	500	500	500
≤ 2 000	500	500	500 or 600	500 or 600	–
> 2 000	500	500 or 600	500 or 600	500 or 600	–

For a back-to-back HVDC project the rated voltage is chosen to maximize the utilization of current capability of converter valves/thyristors as substation space saving is a major concern.

7.1.3 Rated current

The choice of rated current is the result of optimization of the transmission capacity demand and rated voltage for a long distance transmission project.

Depending on converter current rating, a higher rated current is of particular interest for back-to-back HVDC applications. For cable projects, the rated current is typically determined by the cable current rating.

The rated current of HVDC converters is mainly determined by the power capacity of thyristors and their cooling systems. Thyristors in four-inch, five-inch and six-inch silicon wafer diameter have been commercially used in HVDC converter valves for different current ratings from 1 500 A up to 6 250 A at 8 500 V blocking voltage. For a given silicon wafer diameter, a higher current rating is available at a lower thyristor blocking voltage.

7.2 Configurations

7.2.1 Pole and return path

The HVDC transmission system can be built as a monopolar or bipolar system. A bipolar system is the most widely chosen for long distance projects due to its having less influence on the environment, lower losses and higher reliability and availability. Various configurations are shown in IEC TR 60919-1.

When two asymmetric monopolar systems are built together, they can share one common return path and thus become a bipolar system. So when the project has several stages for final completion, an optimal implementation scheme is required. For example, a monopolar system can be used as the first phase of a bipolar DC system.

Besides bipolar operation, each independent pole of a bipolar system can operate separately. When a bipolar system operates as a monopole, different pole line configurations can be designed, for example, by using one pole conductor as a pole circuit or by using two pole conductors in parallel to reduce the losses. In the latter configuration some additional switches are needed.

The return (neutral) circuit can consist of metallic return or ground return. The return (neutral) circuit is selected based on the system configurations, electrode site conditions and environmental requirements. For bipolar schemes the design of the return circuit is very flexible for monopole operation. Different solutions can be adopted depending on the individual project requirements:

a) metallic return via a dedicated metallic return (DMR) conductor;
b) earth return via electrodes;
c) metallic return via the pole conductor when the pole converters are out of operation;
d) using a) and c) in parallel.

Earth return is an economic design but long-term operation in this mode is becoming rare due to restrictions on interference with present or future third parties, such as seismic monitoring requirements, underground pipeline corrosion, magnetic compass deviation, etc.

Dedicated metallic return needs higher investment, especially when cables are used. Where long-term monopole operation with earth current is not permitted or high ground resistivity is present, or it is not cost effective to build up ground electrodes and electrode lines, a dedicated metallic return circuit will be employed. The dedicated metallic return lines are generally erected on the same towers with the pole transmission lines.

When one pole of a bipolar system with earth return is blocked, the DC system will transfer to the monopole earth return operation. If monopole earth return operation is permitted only for a limited duration, earth return mode will be transferred to monopole metallic return if the DC line of the other pole is available.

NOTE The change of configuration can lead to a reduction of the total transmitted power capability of the HVDC system.

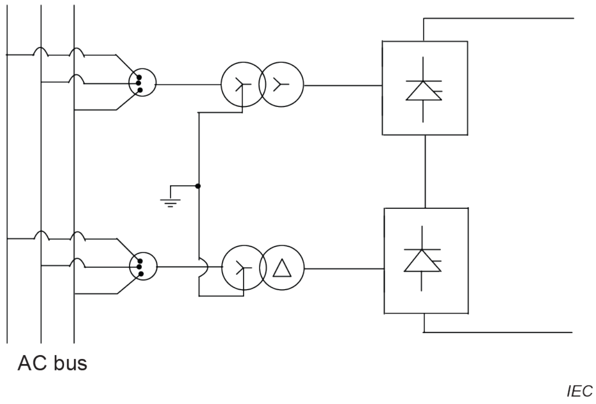
7.2.2 Converter topology

Today in HVDC transmission the most common converter topology used is the twelve-pulse group. The economical and widely applied topology is one converter per pole. However, several criteria may lead to the requirement to install more than one converter for one pole, such as the following:

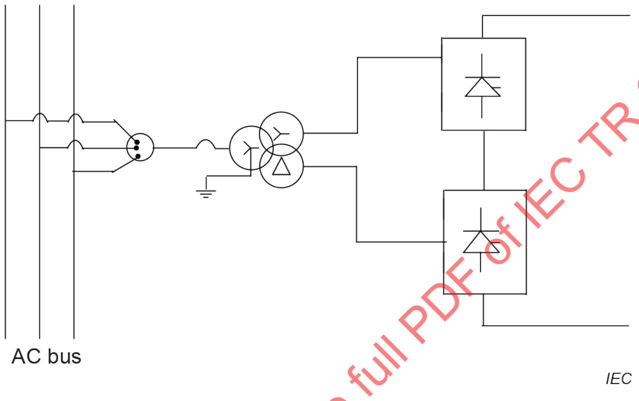
- transport limitations for large equipment to the selected site of one converter station (e.g. converter transformers);
- increased requirements on power availability also in case of outage of one twelve-pulse group;
- stage development project;
- more than one AC bus feeding power to a pole or receiving power from a pole.

When multiple twelve-pulse groups are used in one pole in the converter substation, those twelve-pulse groups can be either connected in series or in parallel to share the pole power. A symmetrical split of converters is preferred as it provides maximum flexibility in case of one twelve-pulse group being out of service. For more details on converter topology, refer to IEC TR 60919-1.

For each twelve-pulse group using two winding converter transformers, the line side windings of Y-Y and Y-Delta transformers are connected in parallel to the converter bus and then to the AC bus of the station, as shown in Figure 6. Where two or more converters are connected in series or parallel, each converter should be separately connected to the AC bus.



a) Two-winding converter transformer connection



b) Three-winding converter transformer connection

Figure 6 – Converter transformer connection topology

Earthing switches need to be installed at the valve side of the converter transformer. There are two alternatives: one is to install the earthing switch on each phase, the other is to install one earthing switch at the neutral point of star-connected windings and the second one at any terminal of the delta-connected windings.

7.2.3 DC switchyard configuration

7.2.3.1 General

For a bipole system which consists of two independent poles, it is recommended to design the main circuit to enable:

a) isolating and earthing one pole or one twelve-pulse converter for maintenance;

b) isolating and earthing the DC transmission line in one pole for maintenance;

c) isolating and earthing the earth electrode(s) and electrode line(s) at one or two converter station(s) or the dedicated metallic return line for maintenance when operating in monopolar metallic return mode;

d) isolating and earthing the earth electrode(s) and electrode line(s) at one or two converter station(s) or the dedicated metallic return line for maintenance when operating in bipole balanced mode. That means bipole balanced operation of the HVDC system with the earthing mat(s) in one or both converter stations as the temporary earthing point of the DC transmission system is possible;

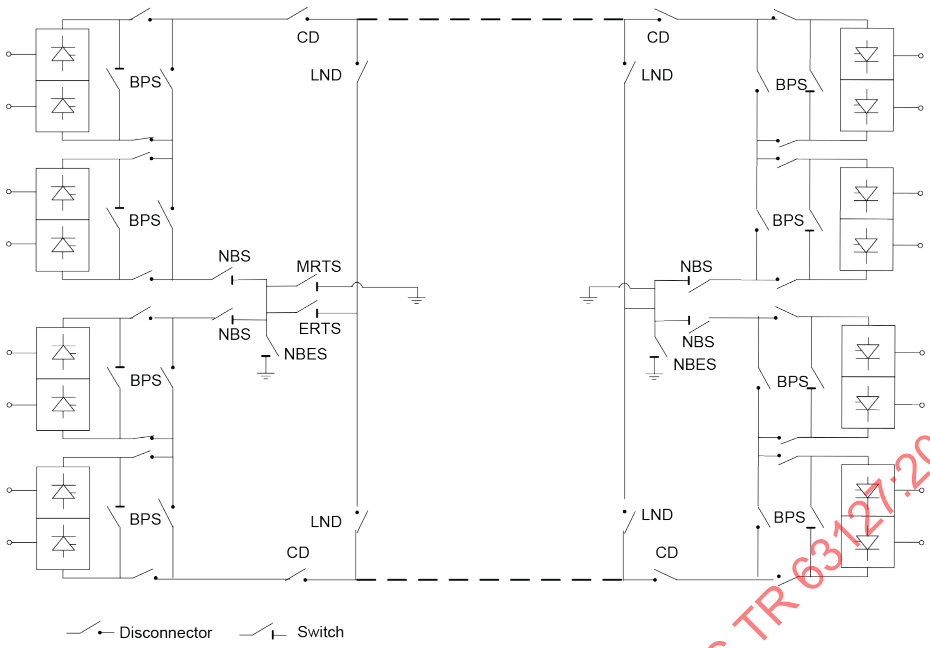
e) clearing of faulted pole or twelve-pulse converter for maintenance without influencing the power transmission of the remaining healthy pole or twelve-pulse converter;

f) switching between different monopolar configurations without interrupting or reducing DC power transfer. The time from initiation to completion of the switching is usually not more than 60 s. Generally, online switching of operation modes is required to increase the availability of DC systems. If the DC current breaking capacity of the switches is lower than the rated DC current, the DC control and protection system can be coordinated to temporarily reduce the DC power and restore it after completion of mode transfer;

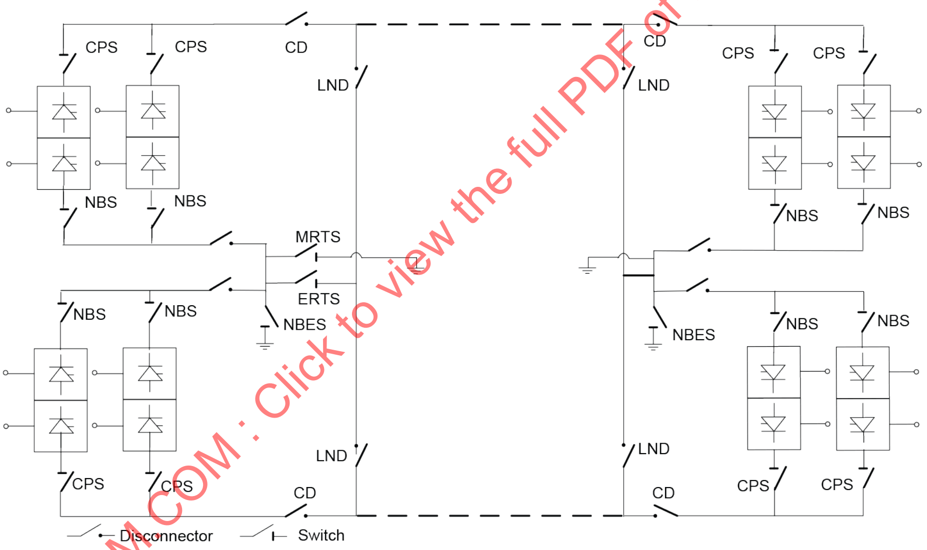
g) connecting, isolating and earthing the DC filter branches for maintenance without interrupting or reducing the DC power transfer of the pole.

For this kind of bipole HVDC system, to transfer between various operation configurations and increase reliability and availability of the whole DC system, it is recommended to use low-voltage high-speed DC switches, such as a neutral bus switch (NBS). For the bipole system with earth as return circuit, a metallic return transfer breaker (MRTS) and an earth return transfer switch (ERTS) are installed. A neutral bus ground switch (NBES) can further increase the reliability and availability of the DC system.

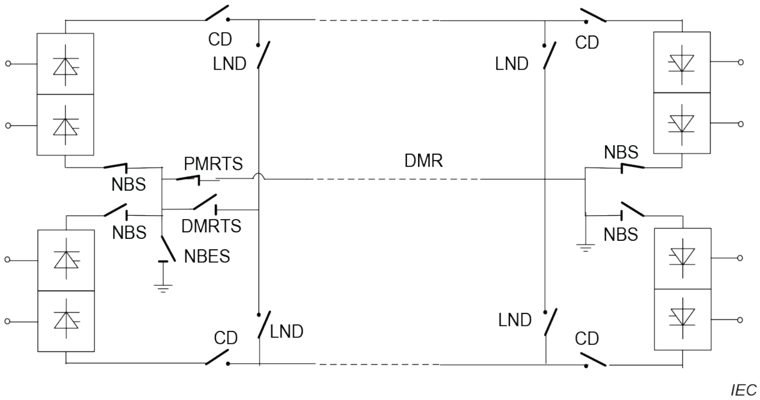
Figures 7 a) and b) give sketch maps of the DC yard switches for series and parallel converter connection in a pole, separately. Figure 7 c) provides a sketch map of DC yard switches when DMR is applied. The switches actually needed depend on the functional requirement of the DC system. Figure 7 shows only the switches which operate to build different configurations.



a) Sketch map with two twelve-pulse valve converters in series connection per pole



b) Sketch map with two twelve-pulse valve converters in parallel connection per pole



c) Sketch map with dedicated metallic return line as return path

Key

CD converter disconnector

LND line to neutral disconnector

NOTE Permanent earthing is shown in the inverter station, but it can be in either station.

Figure 7 – Sketch maps of the DC yard switches of HVDC system

If the commutation current level is beyond the capability of DC switches when switching between configurations, the DC transmission power can be temporarily reduced within the commutation capability of the switches as long as there is no significant disturbance to system operation, and thereafter increased to the maximum as required.

When there are two or more converters in series in one pole, the converters in the different poles can be switched into parallel connection for special purposes, such as de-icing operations. To accomplish the above operation, additional dis-connectors are needed in the DC yard shown in Figure 8.

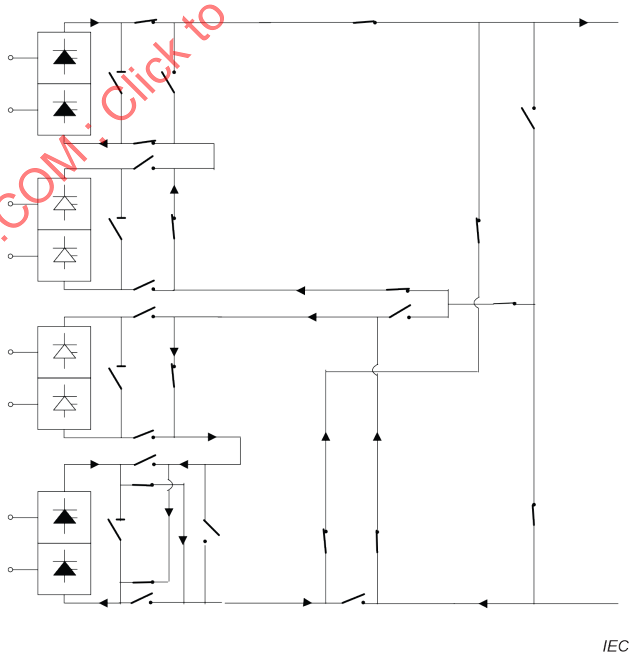


Figure 8 – Schematic diagram of converter parallel connection

A converter can also be operated with two pole lines in parallel connection as shown in Figure 9 if earth return operation is permitted and used as a current path. This can reduce the transmission line losses.

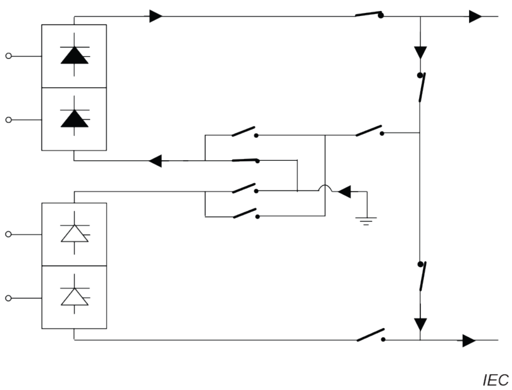


Figure 9 – Schematic diagram of pole line parallel connection

7.2.3.2 Neutral bus switch (NBS)

A DC commutation switch connected in series with the neutral bus on a bipolar HVDC scheme is designed to commutate current from the pole conductor or neutral bus to the electrode line or dedicated metallic return conductor in the event of a pole to earth fault or neutral bus to earth fault during bipolar operation.

When a grounding fault occurs at a pole bus or line, part of the DC current of the other pole will flow to the fault location (1) in Figure 10 through the neutral bus, valve, smoothing reactor and pole bus/pole line of the faulty pole. When a grounding fault occurs to the neutral bus, part of the DC current of the other pole will flow to the fault location (2) through the neutral bus of the faulty pole. See Figure 10.

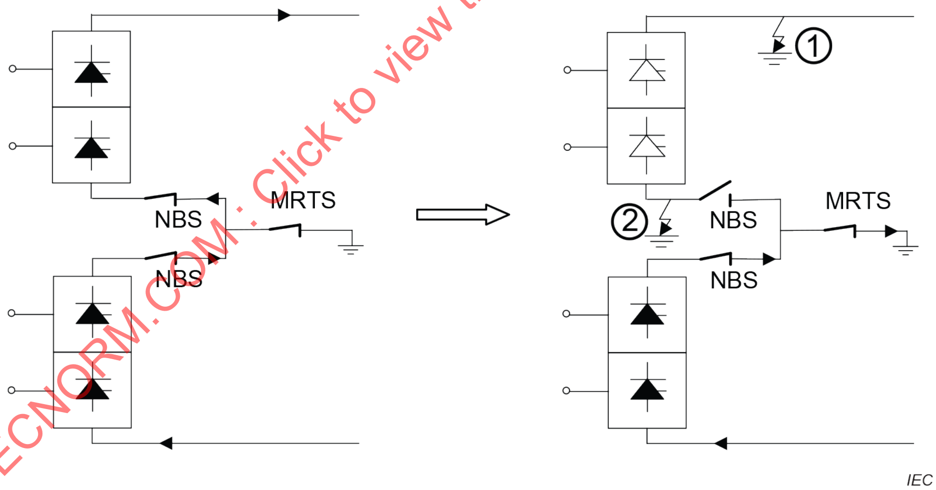


Figure 10 – Procedure of NBS disconnecting DC fault

7.2.3.3 Metallic return transfer switch (MRTS)

For a bipole system using an earth electrode or DMR as return path, one of the converter stations can be equipped with an MRTS. For DMR application, the MRTS is also called the dedicated metallic return transfer switch (DMRTS). The MRTS is used for current transfer from monopole earth return or DMR return to another return circuit, i.e. a pole line without interrupting power transfer when it is needed, as shown in Figure 11.

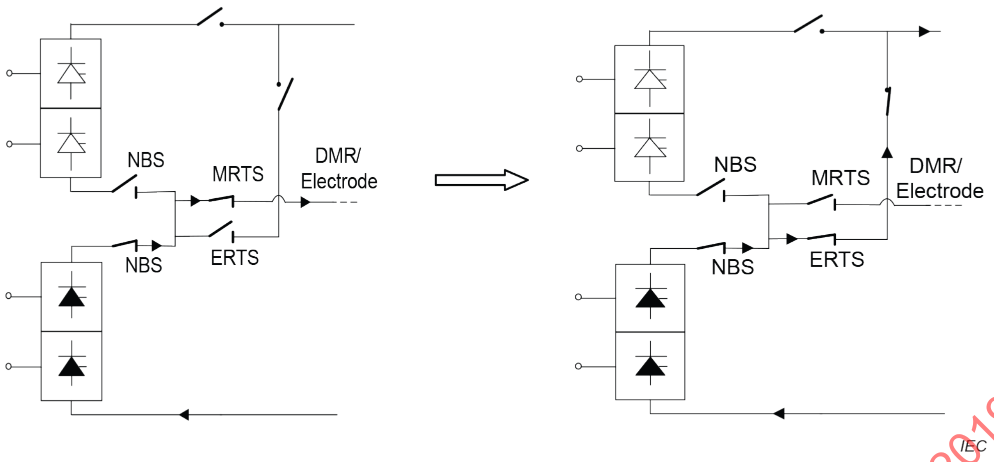


Figure 11 – Current transfer path of the MRTS

7.2.3.4 Earth return transfer switch (ERTS)

One of the converter stations can be equipped with an ERTS or PMRTS (pole metallic return transfer switch) in DMR application when it is necessary to transfer the configuration from a monopole metallic return to an earth return or DMR without interrupting power transfer, as shown in Figure 12. An ERTS or PMRTS transfers the DC current from the pole line return path to the earth return path or DMR path. As the resistance of the earth return is much smaller than that of the metallic return, the transfer of the DC current from the metallic return to earth return will normally not cause a temporary decrease of DC power.

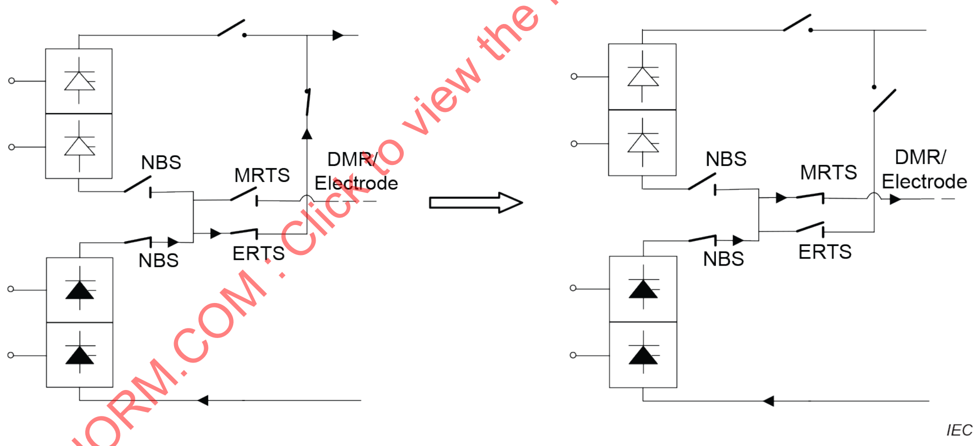


Figure 12 – Current transfer path of ERTS

7.2.3.5 Neutral bus earthing switch (NBES)

As for the earth return applied, the NBES is installed on the neutral bus at both ends and is open in normal operation. NBES can be closed automatically if it is allowed when the earth electrode is out of service in the balanced bipole operation mode, as shown in Figure 13. The switch is not assumed to have a significant current transfer capability, but is capable of opening during bipolar operation hence transferring the unbalanced current to the earth electrode.

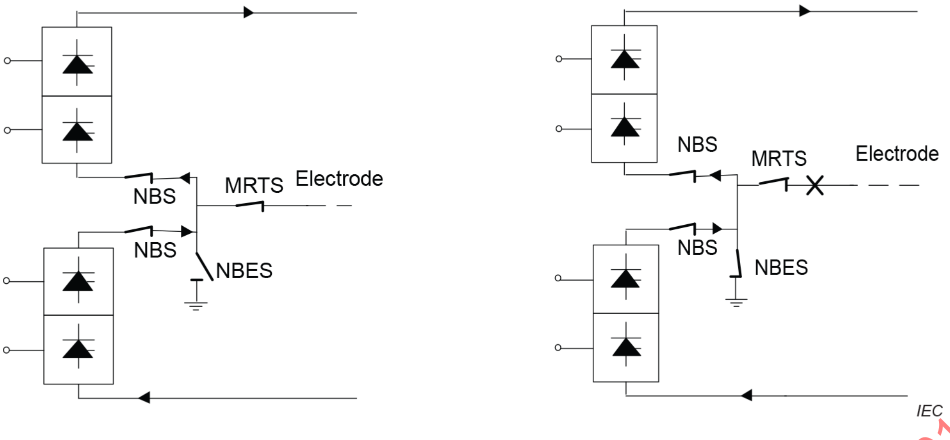
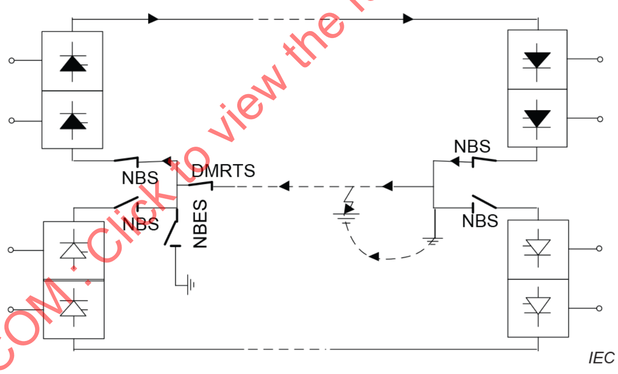
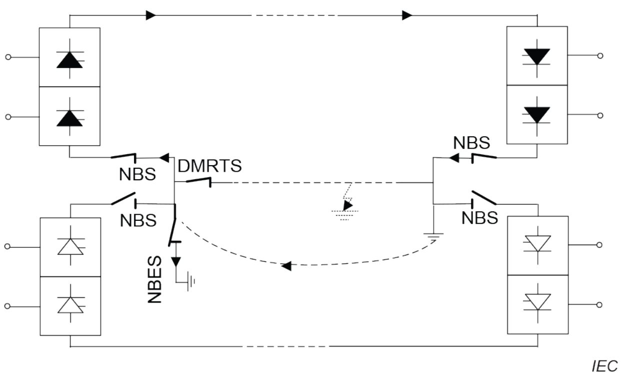


Figure 13 – Connection and function of the NBES

As for the DMR line applied, the NBES is installed at the insulated end of the neutral circuit and is open in normal operation. During bipole operation with balanced current, the NBES can be closed automatically when the DMR is out of service. When a grounding fault occurs at the DMR line, especially in monopole operation, part of the DC current of the DMR line will flow to the fault location. In order to protect insulators, the NBES is closed within several hundred milliseconds to transfer the fault current from the DMR line insulator surface path to the converter station grounding mesh, as shown in Figure 14 b). After the expected time when the fault current is extinguished and deionized, the NBES is opened to commutate the DC current from the path of the grounding mesh to the original neutral circuit. In this application, the NBES is assumed to have a significant current transfer capability.



a) Current transfer path of DMR with a grounding fault



b) Current transfer path of DMR after NBES disconnecting grounding fault

Figure 14 – Commutating process of NBES in case of DMR

7.2.3.6 High speed bypass switch (BPS)

In DC transmission systems with two converters connected in series in each pole, high speed bypass switches (BPS) can be used to decrease the pole contingency rate and increase the system availability. As shown in Figure 15, such switches can isolate faulty converters for maintenance without interrupting DC power transmission when a non-grounding fault occurs in a converter.

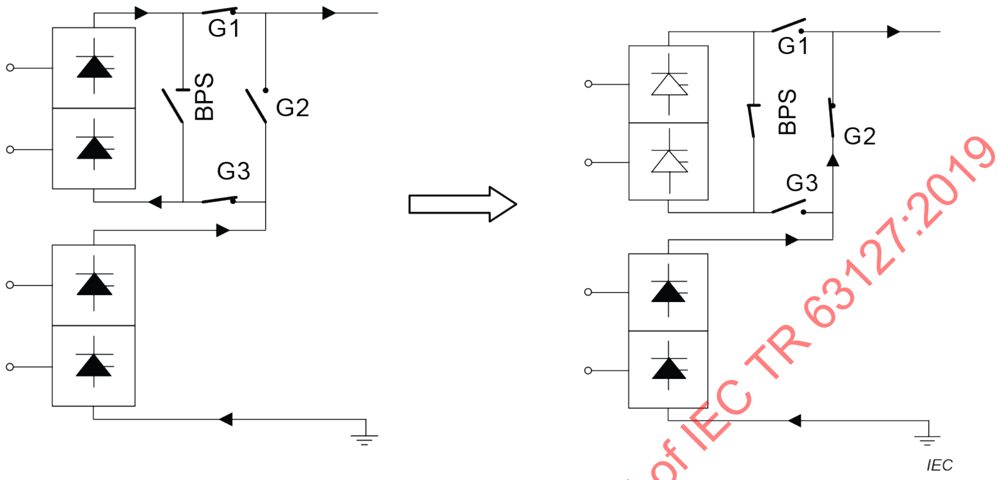


Figure 15 – High speed bypass switch

7.2.3.7 Converter paralleling switches (CPS)

The switches mentioned in 7.2.3.7 are optional. In DC transmission systems with two converters connected in parallel in each pole, converter paralleling switches (CPS) can be used to increase the system availability. As shown in Figure 16, such switches can isolate converters that are faulty or require maintenance without affecting the normal operation of other equipment.

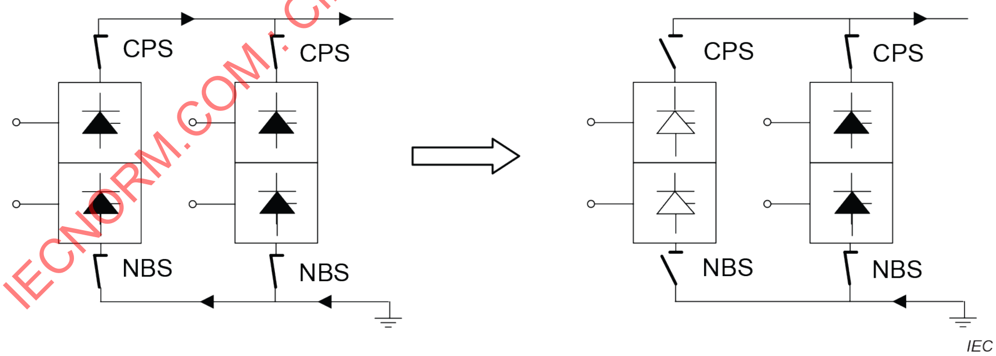


Figure 16 – Converter paralleling switches

7.2.3.8 Smoothing reactors

A smoothing reactor has to be provided in the DC circuit. The smoothing reactor in many projects is located in the pole bus, and in many others it is split in the pole and neutral bus. This depends on the system configuration, converter insulation coordination and smoothing reactor design.

7.2.3.9 DC circuit resonance suppression equipment

When the DC line is long, the DC system may risk a low-order resonance. Studies should be performed to check the resonant frequency and impedance to ensure that the HVDC system has sufficient impedance at the fundamental or second harmonic frequency. This study should cover all normal operation modes, for example bipolar operation, monopole ground return operation, and monopole metallic return operation of the DC system.

If the study indicates that the DC system might suffer a fundamental or second harmonic resonance or both, suitable suppression measures should be adopted. One possible solution is to adjust the parameters of the smoothing reactor to shift the resonance frequency away from the fundamental and second harmonic. If this cannot mitigate the resonance conditions, specific filters should be considered. Insertion of a blocking filter in the neutral bus could make an effective fundamental resonance suppression. A shunt filter is usually used to suppress the second harmonic resonance which is designed in combination with the DC filters. Filters resonant at the second harmonic are vulnerable to AC system single phase events and should be rated appropriately.

7.2.4 Reactive power equipment

The reactive power equipment in a converter station is normally designed as switchable shunt capacitors/reactor sub-banks. Part of the capacitors can be designed as AC filters. Those sub-banks can be grouped into banks and then connected to the AC bus, or directly connected to the AC bus.

A circuit breaker is needed for each sub-bank and bank. All switching operations are executed using circuit breakers (or on-load switching devices). Disconnectors are used only for isolation. Maintenance of each sub-bank and its circuit breaker is possible whilst the remaining sub-banks are energized.

In some projects embedded in a weak AC system, a static var compensator (SVC) or static synchronous compensator (STATCOM) is used for dynamic voltage support. These SVCs or STATCOMs are usually designed for a low voltage level and thus need to be connected to the AC bus through a transformer.

7.3 Determination of main circuit parameters

7.3.1 General

The main circuit parameter calculation should be performed for all possible DC system operation configurations and modes to determine the main equipment parameters and operating parameters.

The main parameters include DC voltage, ideal no-load DC voltage, DC current, control angle, short-circuit current, inductance of smoothing reactor, and the parameters of the converter transformer such as short-circuit impedance, capacity, voltage ratio, winding current, range and step size of tap changer, etc.

To determine the steady-state operating parameters of the HVDC system, calculations need to cover the full transmission power range from the minimum power up to the overload power level applicable at different DC operation configurations, e.g. full and reduced DC voltage, forward and reverse power direction, full AC voltage variation range as well as the DC line resistance range and combinations thereof.

7.3.2 Control strategy

The HVDC system operates in two main control modes as constant DC current control and constant DC power control. For constant DC current control, the DC current reference is directly set, while for constant DC power control, the reference value of DC current is determined using Formula (2):

$$I_d = P_{ref} / U_{dmeas} \quad (2)$$

where U_{dmeas} is the measured DC voltage between the pole and the neutral bus at the line side of the smoothing reactor in the rectifier station.

P_{ref} is the power setting at the line side of the smoothing reactor in the rectifier station.

The DC current is normally controlled by the firing angle α on the rectifier side. The firing angle should be maintained close to the normal value α_N in steady operation, for example $\alpha_N \pm 2{,}5°$ by adjustment of the tap changer position of the converter transformers. If α goes beyond this range, the converter transformer tap changer control will operate to bring it back within that range.

For long distance transmission projects, the DC voltage is generally controlled on the inverter side. There are two main DC voltage control designs: one is constant extinction angle γ control, the other is constant DC voltage U_d control. For back-to-back projects, constant ideal no-load voltage U_{dio} control can be applied.

a) Constant extinction angle control. At steady-state operation, the extinction angle γ remains constant. The DC voltage is maintained within the range through adjustment of converter transformer taps on the inverter side.
b) During dynamic events, constant alpha control is applied at the inverter side. It shows a positive slope at the outer characteristic and then helps to enhance the AC/DC system stability.
c) When there is only one twelve-pulse converter at the inverter side, all converter transformer taps should be set at the same position. When two serial twelve-pulse converter connections are applied, the taps of each converter can be adjusted separately. It is recommended that the difference between the tap positions of the two converters does not exceed one step. Symmetry within converters will help to minimize the un-characteristic harmonic amount.
d) Constant DC voltage control. DC voltage control is achieved through control of extinction angle γ, which is maintained within the required range through adjustment of converter transformer taps at the inverter side. If the extinction angle goes beyond this range, the converter transformer tap control will operate to bring it back within that range.
e) Constant ideal no-load DC voltage U_{dio} control. The converter transformer taps at the inverter side are adjusted to keep the no-load DC voltage at the rated value. Meanwhile, the extinction angle γ on the inverter side is also kept constant. In general, the DC voltage of back-to-back projects does not need to be controlled precisely; therefore, constant ideal no-load DC voltage U_{dio} control can be used so that adjustment of the converter transformer taps is only used to counteract the fluctuations of the AC voltage.

When an HVDC system operates at overload, with the exception of temporary overload, different control strategies can be adopted. One alternative is to keep the U_{dio} at its rated value and the overload ability is achieved by increasing DC current only. The other is to increase U_{dio} under the overload condition. The former strategy needs more current rating, while the latter will lead to higher voltage ratings.

7.3.3 Tolerances and errors

To calculate the extreme value of the main circuit parameters for an HVDC system, some tolerances or errors should be included. Different control strategies described in 7.3.2 will introduce different control tolerance and errors and different manufacturers may also guarantee different values. In particular when purchasers carry out the system design by themselves, it is crucial to choose reasonable values of these tolerances and errors because they will affect equipment rating and hence the cost. Typical values of control parameters and tolerances adopted in this calculation are listed in Annex A, for reference.

The relative resistive voltage drop U_T and inductive voltage drop d_r of the converter valve are also needed for the main circuit parameter calculation. They both depend on the size of the converter and the specific design of various manufacturers. Proper values should be used in the main circuit's parameter calculations.

7.3.4 Determination of converter transformer impedance

The converter transformer impedance will affect the valve and DC side short-circuit current, the reactive power consumption of the converter, the harmonic and losses of the converter transformer.

The short-circuit current in the converter valve during the first cycle can be calculated using Formula (3), while that during the second and third cycles can be calculated using Formula (4).

$$I_{crest} = \frac{I_{dN} \cdot k_r \cdot U_{dio}}{2d_{xtotR} \cdot U_{dioN}} \cdot (1+\cos\alpha) - \frac{I_d}{2} \tag{3}$$

$$I_{crest} = \frac{I_{dN} \cdot k_r \cdot U_{dio}}{2d_{xtotR} \cdot U_{dioN}} \cdot (1+\cos\alpha) \tag{4}$$

The converter transformer impedance is the main factor for limiting the short-circuit current of the converter valve. d_{xtotR} contains not only the converter transformer impedance, but also the system impedance converted onto the valve side. U_{dio} is calculated by the formula given in 7.3.6. k_r is an additional coefficient representing the overvoltage due to load loss of the converter. It can be estimated with Formula (5).

$$k_r = \sqrt{(1+\frac{\Sigma Q_{dc}}{2\times(S_{SC}-Q_{fN})})^2 + (\frac{\Sigma P_{dc}}{2\times(S_{SC}-Q_{fN})})^2} \tag{5}$$

A converter transformer with a certain power rating and voltage has a certain impedance for a minimum dimension. When transportation is limited, the minimum dimension is needed, which will lead to an increase of impedance.

Higher transformer impedance will increase the cost and losses of the converter transformer as well as the reactive power compensation. During the system design, the designer has to discuss with manufacturers to decide on a suitable value of the converter transformer impedance.

7.3.5 Relative inductive voltage drop (d_{xN}) and relative resistive voltage drop (d_{rN})

After determining the transformer impedance, the relative inductive voltage drop d_{xN} and the relative resistive voltage drop d_{rN} can be calculated with Formulas (6) and (7), respectively.

$$d_{xN} = \frac{3}{\pi} \cdot \frac{X_t \cdot I_{dN}}{U_{dioN}} \tag{6}$$

$$d_r = \frac{P_{cu}}{U_{dioN} \cdot I_{dN}} + \frac{2 \cdot R_{th} \cdot I_{dN}}{U_{dioN}} \tag{7}$$

In Formula (7), the coefficient 2 indicates that there are always two thyristor valves conducting in a six-pulse converter. The parameters P_{cu} and R_{th} should be provided by the manufacturers.

7.3.6 Ideal no-load DC voltage

The relationship between the inductive voltage drop of the converter transformer (short-circuit impedance) u_k and the rated relative inductive DC voltage drop d_x is as follows:

$$U_k + U_{plc} \approx 2d_x \tag{8}$$

The rated ideal no-load DC voltage on the rectifier side and inverter side can be calculated using Formula (9) and Formula (10) respectively:

$$\frac{U_{dNR}}{n} = U_{dioNR} \cdot \left(\cos\alpha_N - (d_{xNR} + d_{rNR})\right) - U_T \tag{9}$$

$$\frac{U_{dNI}}{n} = U_{dioNI} \cdot (\cos\gamma_N - (d_{xNI} - d_{rNR})) + U_T \tag{10}$$

U_{dioN} is the no-load DC voltage of the DC system in normal operation. At other power level, U_{dio} may differ from U_{dioN} according to different control strategies. When the inverter DC voltage control is applied, U_{dio} at the rectifier and inverter side can be calculated using Formula (11) and Formula (12):

$$U_{dioR} = \frac{\frac{U_{dR}}{n} + U_T + (d_{xR} + d_{rR}) \cdot \frac{I_d}{I_{dN}} \cdot U_{dioNR}}{\cos\alpha} \tag{11}$$

$$U_{dioI} = \frac{\frac{U_{dR} - R_d \cdot I_d}{n} - U_T + (d_{xI} - d_{rI}) \cdot \frac{I_d}{I_{dN}} \cdot U_{dioNI}}{\cos\gamma} \tag{12}$$

The six-pulse rectifiers are taken as the basis for calculation of the main circuit parameters, so n is the number of six-pulse converters. To calculate the maximum and minimum U_{dio}, the control and measurement errors as well as the manufacturer tolerance need to be included in Formulas (11) and (12).

7.3.7 DC voltage and DC current

The formula for calculation of the DC voltage through the entire power range across a six-pulse rectifier is as follows:

$$\frac{U_{dR}}{2} = U_{dioR} \cdot \left(\cos\alpha - (d_{xR} + d_{rR}) \cdot \frac{I_d}{I_{dN}} \cdot \frac{U_{dioNR}}{U_{dioR}}\right) - U_T \tag{13}$$

From the perspective of the DC circuit, U_{dR} under monopole ground return mode may be calculated as follows:

$$U_{dR} = U_{dLR} + \left(R_{eR} + R_{gR}\right) \cdot I_d \tag{14}$$

The formula for calculation of DC voltage across a six-pulse inverter is as follows:

$$\frac{U_{\text{dI}}}{2} = U_{\text{dioI}} \cdot \left(\cos\gamma - (d_{\text{xI}} - d_{\text{rI}}) \cdot \frac{I_{\text{d}}}{I_{\text{dN}}} \cdot \frac{U_{\text{dioNI}}}{U_{\text{dioI}}} \right) + U_{\text{T}} \tag{15}$$

U_{dI} under monopole ground return operation may be calculated as follows:

$$U_{\text{dI}} = U_{\text{dLI}} - \left(R_{\text{eI}} + R_{\text{gI}} \right) \cdot I_{\text{d}} \tag{16}$$

Under bipolar operation:

$$U_{\text{dR}} = U_{\text{dLR}} \tag{17}$$

$$U_{\text{dI}} = U_{\text{dLI}} \tag{18}$$

The pole line to ground voltage drop between the rectifier and the inverter is defined as follows for a long distance transmission DC system:

$$\Delta U = U_{\text{dLR}} - U_{\text{dLI}} \tag{19}$$

or as

$$\Delta U = R_{\text{d}} \cdot I_{\text{d}} \tag{20}$$

The relationship between U_{dR} and U_{dI} under monopolar ground return operation is as follows:

$$U_{\text{dR}} - U_{\text{dI}} = U_{\text{dLR}} - U_{\text{dLI}} + \left(R_{\text{eR}} + R_{\text{gR}} + R_{\text{eI}} + R_{\text{gI}} \right) \cdot I_{\text{d}} \tag{21}$$

The relationship between U_{dR} and U_{dI} under monopolar metallic return operation is as follows:

$$U_{\text{dR}} - U_{\text{dI}} = 2 \cdot R_{\text{d}} \cdot I_{\text{d}} \tag{22}$$

For bipolar operation,

$$U_{\text{dR}} - U_{\text{dI}} = U_{\text{dLR}} - U_{\text{dLI}} \tag{23}$$

To calculate the maximum and minimum DC voltage, the DC voltage control strategy needs to be considered together with the control and measuring error and the manufacturing tolerances.

DC current can be obtained with Formula (3). To calculate the maximum and minimum continuous DC currents, the current deviation from the reference value caused by DC voltage control errors needs to be considered together with the measuring error.

7.3.8 Rated capacity of converter transformer

The rated capacity of a three-phase converter transformer connected to a six-pulse valve group is calculated as follows:

$$S_n = \sqrt{3} \cdot U_{vN} \cdot I_{vN} = \frac{\pi}{3} \cdot U_{dioN} \cdot I_{dN} \tag{24}$$

The rated capacity of a single-phase three-winding converter transformer connected to a twelve-pulse valve group is calculated as follows:

$$S_{n3w} = \frac{2 \cdot \sqrt{3}}{3} \cdot U_{vN} \cdot I_{vN} = \frac{2 \cdot \pi}{9} \cdot U_{dioN} \cdot I_{dN} \tag{25}$$

The rated capacity of a single-phase two-winding converter transformer connected to a twelve-pulse valve group is half of the rated capacity calculated from Formula (25):

$$S_{n2w} = \frac{S_{n3w}}{2} \tag{26}$$

7.3.9 Converter transformer taps

The rated ratio of the converter transformer at the normal tap position is calculated as follows:

$$n_{nom} = \frac{U_{lN}}{U_{vN}} = \frac{U_{lN}}{\frac{U_{dioN}}{\sqrt{2}} \cdot \frac{\pi}{3}} \tag{27}$$

The maximum ratio of the converter transformer is calculated as follows:

$$n_{max} = \frac{U_{lmax}}{U_{lN}} \cdot \frac{U_{dioN}}{U_{diomin}} \tag{28}$$

The minimum ratio of the converter transformer is calculated as follows:

$$n_{min} = \frac{U_{lmin}}{U_{lN}} \cdot \frac{U_{dioN}}{U_{diomax}} \tag{29}$$

The number of steps of the on-load tap changers is calculated as follows:

$$TC_{step} = \frac{\eta - 1}{\Delta\eta} \tag{30}$$

For long-distance DC transmission projects, if reduced DC voltage operation is required, more steps are needed. The designer can also increase the firing angle. Both methods, increasing tap range or increasing firing angle have an impact on the cost of equipment and thus generally a combination is used. When the converter is connected to an AC grid of 500 kV or lower voltage, the available tap changers can fulfil 80 % of the reduced voltage operation with rated control angles. If the converter is connected to a higher voltage grid, or there is a lower reduced voltage operation requirement, the number of calculated steps may be over the limit, and the designer can increase the firing angle until the target is achieved.

7.3.10 Inductance of smoothing reactor

The smoothing reactors should be designed to limit the rate of rise of DC current during AC system faults at the inverter side, commutation failures and DC line faults. They should also be designed for smoothing the DC current to prevent an intermittent current. When deciding on the size of the inductance of the reactor, due consideration should also be given to the risk of resonance with the DC line close to the fundamental frequency or multiples of it.

One recommendation for smoothing reactor inductance selection is the Si factor (current slope factor). The Si factor describes the rise of the DC current within a millisecond related to normal value, when the normal DC voltage is applied to the DC side inductance. The Si factor is defined as follows.

$$\mathrm{Si} = \frac{U_{\mathrm{dN}}}{L_{\mathrm{d}} \cdot I_{\mathrm{dN}}} \tag{31}$$

where

$L_{\mathrm{d}} = L_{\mathrm{dr}} + 3{,}5\ L_{\mathrm{tr}}$

The Si factor is usually between 0,22 to 1,3. The inductance calculated using the Si factor provides a preliminary value but needs to be further optimized together with DC filter design.

8 Insulation coordination

The primary objectives of insulation coordination are as follows:

- to establish the maximum steady-state, temporary and transient overvoltage levels to which the various components of a system may be subjected in practice;
- to select the insulation strength and characteristics of the equipment, including the protective devices used in order to ensure a safe, economic and reliable installation in the event of overvoltages.

The insulation coordination applied to an HVDC converter station is in principle the same as that of an AC substation. However, essential differences exist which warrant particular consideration when dealing with HVDC converter stations, such as the following:

- series connection of six-pulse and/or twelve-pulse groups which include arresters connected between terminals but not necessarily to earth;
- series connection of equipment between HV busbar and ground with intermediate voltage levels;
- no direct exposure to the external overvoltage since the converter circuit is bounded by the inductances of the converter transformers and smoothing reactors;
- the fault and potential for resonance conditions on the DC side;
- various shapes of operating voltages (e.g. DC voltages, harmonics, overshoots) which might vary during different converter operating conditions;
- existence of a large number of reactive power compensation equipment which can influence resulting overvoltages (e.g. load rejection of the DC link);
- protection characteristics of power electronics which are typically much faster compared to mechanical breaker characteristics as used in AC systems;
- interaction between the AC system and DC system, particularly where the AC system is relatively weak;
- the various operation modes such as monopolar, bipolar.

The study of insulation coordination for an HVDC converter station should follow IEC 60071-5.

9 Filter design

9.1 General

Passive filtering devices are widely used in converter stations. Sometimes the damping of low order harmonic resonance is integrated into the DC filter system.

9.2 AC filter design

Typically AC filters can consist of single tuned filters, double tuned filters and triple tuned filters – all with various levels of damping. The factors determining the design include:

a) performance requirements,
b) reactive power requirements,
c) filter sub-bank size,
d) system harmonic impedance,
e) system frequency variation,
f) system voltage,
g) converter and system harmonics,
h) site area,
i) losses,
j) redundancy requirements,
k) environmental issues such as temperature, and
l) manufacturing tolerances.

For details of AC filter design refer to the IEC TR 62001 series.

9.3 DC filter design

DC filters are generally required where there is a need to protect telecommunication facilities against interference from overhead DC lines and the associated HVDC harmonics. Unlike AC filters there is no requirement for reactive power so the requirement is to reduce the filter size as much as possible. The DC filter acts in conjunction with the DC reactor and is closely associated with the transmission line for which it is required.

As for AC filters, DC filters can consist of single tuned filters, double tuned filters and triple tuned filters – all with various levels of damping, including no damping. The factors determining the design include:

a) performance requirements,
b) DC system characteristics – lines, cables, blocking filters/low frequency filters,
c) DC system resonance issues,
d) system frequency variation,
e) system voltage,
f) converter harmonics,
g) site area,
h) redundancy requirements,
i) environmental issues such as temperature, and
j) manufacturing tolerances.

Generally the DC filters are provided with elements tuned to the characteristic harmonics of the HVDC converter (twelfth, twenty-fourth and possibly thirty-sixth). Occasionally, for DC resonance purposes, low order elements tuned to the fundamental, second harmonic or sixth harmonic may be required to be provided.

Performance requirements are generally expressed in terms of equivalent disturbing current or induced voltage. More detail is available in CIGRE TB 92 and in IEEE Std 1124-2003.

9.4 Power line carrier (PLC) filters

PLC filters are required to protect the communication facilities, if available, on HVAC and HVDC power lines. Today, in many cases PLC communications are superseded by optical ground wire (OPGW) systems. Although DC PLC filters are rare today, such filters might be required on the AC and DC connections to the HVDC converter.

In general, the requirement is to protect a frequency range from as low as 30 kHz to as high as 500 kHz or in some cases the specific frequency bands in use, for example 80 kHz to 100 kHz at the point of coupling to the AC or DC line.

The noise phenomenon being filtered is related to the turn-on characteristics of the thyristor valve similar to the process for radio interference. This requires a detailed high frequency model of a converter transformer to ensure the correct level of filtering is required.

Parameters that have a major impact include:

a) thyristor valve turn-on characteristics,
b) converter transformer high frequency characteristics,
c) performance requirements, and
d) converter and reactive power restrictions on filter size – both series and shunt elements.

9.5 Radio frequency interference (RFI)

Radiated interference is due to the turning-on of the thyristor valve. This causes direct radiation from the valve and also radiation due to high frequency currents imposed on the HV conductor system including adjacent transmission lines.

In general, suppression is by installation of a mesh in the valve hall. In some very rare cases filters are required. Parameters that have a major impact on the design include:

a) thyristor valve turn-on characteristics,
b) converter transformer high frequency characteristics, and
c) performance requirements.

More detail is available in IEC TR 60919-1.

10 Reactive power compensation and control

10.1 General

Reactive power equipment is installed to balance the reactive power consumed by the converter in the converter station during the converter operation from minimum to rated power and overload capacity. Switchable shunt equipment is normally used, which includes AC filters, shunt capacitors/reactors and LV capacitor/reactor. On this occasion, necessary circuit breakers and supplementary control and protection equipment are treated as part of the reactive power equipment. It is preferable that all shunt sub-banks of the same type in the converter station have the same size to decrease the amount of spare parts. Subclause 10.3 gives the capacity of the reactive power supply and absorption equipment. Subclause 10.4 describes the control function of the reactive power equipment.

Synchronous condensers, static var compensators (SVC), and static synchronous compensators (STATCOM) can also be installed in a converter station mainly for voltage control under transient disturbance, or to reduce voltage deviation caused by filter switching in weak AC system.

SVC is sometimes also used as inductive reactive balance equipment for HVDC minimum operation power or during starting. For very weak AC systems, synchronous condensers or STATCOMs are sometimes installed to increase the voltage stability. The synchronous condenser can be of bigger capacity and longer voltage support duration time.

The installation of the above equipment needs further investigation on a range of aspects such as capital expenditure, losses, availability and reliability, and AC switchyard layout.

The reactive power control at both stations is usually achieved through control of AC bus voltage or reactive power exchange with the AC system. The reactive power controls of the two converter stations are independent of each other or coordinated by agreement for back-to-back converters. The reactive power equipment can also contribute to AC system voltage control even after the HVDC system blocks.

10.2 Reactive power consumption

10.2.1 Reactive power consumption calculation

The reactive power consumption of converters increases along with the transmission power. The reactive power consumed by a rectifier (six-pulse converter) can be calculated using Formulas (32), (33) and (34) (for inverters, replace α with γ):

$$Q_{\mathrm{conv}} = I_{\mathrm{d}} \cdot U_{\mathrm{dio}} \frac{2u + \sin 2\alpha - \sin 2(\alpha + u)}{4(\cos\alpha - \cos(\alpha + u))} \qquad (32)$$

$$U_{\mathrm{dio}} = \sqrt{2} \cdot \frac{3}{\pi} \cdot U_{\mathrm{v}} \qquad (33)$$

$$u = \arccos\left(\cos\alpha - 2d_{\mathrm{x}} \cdot \frac{I_{\mathrm{d}}}{I_{\mathrm{dN}}} \cdot \frac{U_{\mathrm{dioN}}}{U_{\mathrm{dio}}}\right) - \alpha \qquad (34)$$

10.2.2 Maximum reactive power consumption

Normally the maximum reactive power consumption is calculated at normal DC voltage, complete configuration and rated or overload transmission power. The calculation should take into account the manufacturing tolerance, control and measurement errors:

a) measurement errors and control errors, including the dead bands of on-load tap changer control of the converter transformer;
b) the maximum commutation reactance of the converter transformer, at the appropriate position of the on-load tap changer, considering the manufacturing tolerances;
c) the minimum DC line resistance to make Q_{dc} at the inverter maximum.

For interconnection projects, to determine the maximum reactive power consumption of each converter station, normal power direction and reverse power direction are considered separately.

10.2.3 Minimum reactive power consumption

The minimum reactive power consumption is calculated at minimum transmission power for all possible configurations. The calculation should take into account the manufacturing tolerance, control and measurement errors:

a) measurement errors and control errors, including the dead-bands of on-load tap changer control of the converter transformer;
b) the minimum possible commutation reactance of the converter transformer, at the appropriate position of the on-load tap changer, considering the manufacturing tolerances;
c) the maximum DC line resistance to achieve the minimum Q_{dc} at the inverter station.

10.3 Determination of reactive power equipment capacity

10.3.1 General

The installed capacity of the capacitive reactive power equipment needs to fulfil the maximum reactive power demand except the part which can be met by AC network. When HVDC operates under low power, excessive reactive power will be injected into the AC system because more filters need to be switched in than those probably needed for reactive power balance due to harmonic performance requirements. Thus inductive reactive power equipment may need to be installed. The minimum reactive power consumption is used to decide the inductive reactive power capacity for each converter station.

10.3.2 Capacity of reactive power supply equipment

The total capacity of the reactive power supply equipment is calculated using Formula (35).

$$Q_{total} \geq \frac{Q_{ac} + Q_{dc}}{{k_v}^2} + Q_{sb} \tag{35}$$

In Formula (35), Q_{sb} is redundancy sub-bank. If it is not required by the system requirement, it can be set to zero. In some cases, the deviation of frequency may also be considered while calculating Q_{total}.

10.3.3 Capacity of reactive power absorption equipment

The capacity of the reactive power absorption equipment is calculated using Formula (36).

$$Q_r \geq Q_{fmin} - \frac{Q_{ac} + Q_{dc}}{{k_v}^2} \tag{36}$$

Usually Q_{dc} reaches its minimum value at the minimum DC power. But it is also possible that Q_r reaches its maximum value at some other power level due to harmonic performance requirements. Therefore, at every power level where a filter is switched in, Q_r calculation needs to be conducted. In some cases, the deviation of frequency may also be considered while calculating Q_r.

10.3.4 Sizing of reactive power sub-bank

As a widely adopted design, the total amount of reactive power consumption is divided into sub-banks which are switched on as the DC power is increased. Each sub-bank should be sized to meet the limits of the dynamic and steady-state AC voltage change. The AC bus voltage change caused by the switching of reactive power sub-banks or banks should meet the requirements of the specific grid code.

a) The dynamic AC bus voltage change caused by sub-bank switching needs to be evaluated and controlled to remain below a specific level. It is typically between 1,5 % and 2 %, depending on the AC system requirements. Higher voltage variation will increase the risk of commutation failure in the inverter side. The steady-state AC voltage change should generally not exceed ~75 % of one step of the on-load tap changer, otherwise this will cause extra tap changer action and increase the difficulties of AC voltage control.

b) Converters can help to depress voltage variation through changing the control angle. But this will add extra stress on the converter, and it is difficult to achieve a satisfactory effect for dynamic voltage change depression because of the coordination between switching and converter control. The maximum dynamic change of DC voltage and current caused by converter control should generally not exceed 5 %.

The reactive power sub-bank size can be estimated by Formula (37).

$$\Delta U_{AC} = \frac{Q_{filter} - \Delta Q_{dc}}{S_{sc} - \sum Q_{filter}} \qquad (37)$$

When the HVDC system transmits high power, the allowed sub-bank size may be bigger than that at low DC power due to there being more generators in operation, especially at the sending end. The filters are always switched in from low DC power, thus the size of filters can be smaller than shunt capacitors to fulfil the voltage deviation requirements. For the receiving end, when the HVDC system transmits larger power, the short-circuit capacity may decrease due to there being fewer generators in operation. So this design may not be applicable for the inverter.

10.3.5 Sizing of reactive power bank

The size of the reactive power bank is influenced by the equipment ability of AC breakers to interrupt the capacitive current as well as the influence on the AC and DC system due to loss of bank. When the AC breaker of a sub-bank fails to open, the breaker of the bank can operate as a back-up measure to clear the fault, thus protecting the system from suffering long-term contingency.

10.4 Reactive power control

10.4.1 General

Reactive power equipment in converter stations should be effectively controlled through a reasonable strategy to meet the requirements of the reactive power exchange and voltage control. Reactive power control (RPC) is integrated into the HVDC control system.

For switchable devices, some sub-banks are designed as filters, thus filter control is also included in the RPC. In this case, RPC usually includes the following functions in descending priority:

a) Filter rating control guarantees the safety of filters. The rating requirement is given the highest priority. Even when the RPC is set to manual mode, the minimum filter combination will be satisfied automatically, while all the other filters can be manually switched in or out by operators.

b) Voltage limitation aims to maintain AC voltage within the permitted limit which is described in 10.4.3.

c) Maximum reactive power limitation defines the maximum quantity of switched-in reactive power sub-banks. It enables the RPC to switch out sub-banks so as to minimize overvoltage protection operations.

d) Filter performance control can guarantee the harmonic performance on the AC bus. It will not switch out filters, but it permits or restrains switching out commands requested by reactive power exchange control/voltage control.

e) Reactive power exchange control/voltage control is the base control function as described in 10.4.2. Reactive power exchange control and voltage control cannot work simultaneously.

Switchable shunt reactive power devices can be controlled automatically or manually. As a good design, each sub-bank is switched in and out only once within a cycle of DC power, i.e. from the minimum power to the normal/overload power then back. Switching of two sub-banks simultaneously or almost at the same time is not allowed under normal control.

10.4.2 Reactive power exchange control/voltage control

The reactive power exchange control should be capable of regulating the reactive power interchange with the AC systems at both stations to the desired schedules within a band defined by the reactive power supply and absorption capability specified. If the band is less than the sub-bank size, a deviation exists because the reactive power control is discontinuous by switching discrete sub-banks. So a tolerance from the scheduled reactive power should be decided in the RPC. The tolerance should not be exceeded for DC power from the minimum to the maximum power in any specified operating mode.

To avoid hunting, the control tolerance should be greater than half of the largest sub-bank capacity plus the reactive power changes of all the connected filters caused by the change of AC voltage in switching. Typically, the value can be set to about 1,5 times the deviation. For a weak AC system, if permitted, this tolerance can be enlarged. An active power hysteresis can also be introduced into the RPC to decrease switching times. The hysteresis corresponds to the reactive power change equal to at least 50 % of the capacity of the maximum sub-bank.

The converter can help to achieve the reactive power balance through an increasing control angle, especially when the AC system has strict limits to reactive power exchange. On this occasion, the designer should check the filter design and the coupling of reactive power control between two stations.

When the converter station operation significantly affects the voltage of nearby AC buses, voltage control is preferred. The design principle of voltage control is similar to that of reactive power exchange control.

10.4.3 Voltage limitation

To avoid the AC bus voltage exceeding the specified range, voltage limitation may be required to prohibit sub-bank switching. In the RPC, there are four voltage levels defined as U_{absmax}, U_{max}, U_{min}, U_{absmin}. These values can be set according to system conditions.

When the AC bus voltage is higher than U_{absmax}, the RPC will switch out the filter/shunt capacitor sub-bank. When the AC bus voltage is higher than U_{max}, the RPC will prohibit the switching in of the sub-bank. To prevent frequent switching of the reactive sub-bank, U_{max} is normally set to $U_{absmax} - 1{,}5\Delta U_{AC}$. Here ΔU_{AC} is the voltage change caused by the switching of the sub-bank.

When the AC bus voltage drops below U_{absmin}, the RPC will switch in the filter/shunt capacitor sub-bank. If the converter station is accessed to the AC system with high short-circuit current, U_{absmin} can be set to a lower value, for example, the extreme minimum voltage; if the AC system is weak, it is recommended that U_{absmin} be set to a higher value to help maintain the voltage stability of the local power grid.

When the AC bus voltage is lower than U_{min}, the RPC will prohibit the switching out of the filter/shunt capacitor sub-bank. U_{min} is usually set to $U_{absmin} + 2\Delta U_{AC}$ to avoid further voltage drop.

10.5 Temporary overvoltage control

When overvoltage occurs on the AC bus and exceeds the protection setting either due to AC system faults or DC load rejection, several AC filter/shunt capacitor sub-banks will be switched off at the same time. The strategy of switching AC filters needs to be optimized to guarantee minimum power loss and equipment safety.

The temporary overvoltage control of the converter station should harmonize with the AC system overvoltage protection, AC lines, transformers and generators close to the converter station (if any).

11 Basic parameters of main equipment

11.1 General

After completion of the design, it is essential to specify the equipment. Requirements and parameters related to the main equipment of converter stations can be determined after the single line diagram, main circuit parameters and insulation coordination scheme are finalized. In this document, attention is only given to converter valves, converter transformers, smoothing reactors, bushings and filters in a converter station.

11.2 Converter valves

11.2.1 General

Converter valves are the core equipment of an HVDC system. The thyristor valve is most widely used in the HVDC system. Thyristors of up to six inches diameter are available for converter valves in terms of current rating in the present state of the art. Converter valves are usually of the air insulated and water cooled type and installed indoors. These are sometimes also installed outdoors in a closed enclosure which is mounted on supported insulators. Depending upon the layout arrangement, a single, double, quadruple or even octuple valve arrangement is used in various projects. Technical data can be specified according to Clause B.1.

For both the rectifier and inverter modes, the thyristor firing circuitry should provide firing pulses to the thyristor gates to safely turn on even under low AC bus voltage conditions or immediately after a solid ground fault has been cleared. The specific low voltage level and duration time should be determined based on system studies.

11.2.2 Valve hall environment

In order to avoid pollution problems, the valve hall is completely enclosed with slightly positive pressure inside. The valve hall air leakage should be controlled to be kept at a minimum.

The indoor temperature is normally controlled within the range from +5 °C to +50 °C, while in some specific zones, for example near the wall bushing, the maximum temperature may temporarily reach +60 °C. If the valve hall is accessible to human beings, +40 °C is treated as the highest temperature.

For the safe operation of converter valves, avoiding condensation inside the valve hall is crucial. The critical parameters for condensation are

- valve hall temperature,
- relative humidity, and
- valve inlet coolant temperature.

It is essential to control the valve hall environment. For the external insulation design of the valve and other equipment inside the valve hall, refer to IEC TR 60919-2 and IEC 60071-5.

11.2.3 Current rating

DC current together with harmonic current will go through each single valve alternately in HVDC system operation. Converter valves are designed to carry normal current, overload current, and various transient surge currents of the HVDC system. IEC TR 60919-1 provides some principles for current rating.

The current rating of the converter valve is mainly decided by the power capacity of the semiconductor device, i.e. thyristor in use. 6 250 A is the state-of-the-art of the six-inch thyristor at 8 500 V blocking voltage.

The overload of converter valves includes continuous overload, short time overload (0,5 h to 2 h), and temporary overload (several seconds).

With respect to transient overcurrent due to faults, the valves have the following capabilities.

a) Short-circuit current withstanding capability with re-applied forward voltage

   As to the maximum short-circuit current caused by any fault in operation, the valve should have the capability to withstand a fully biased asymmetric current wave and maintain a completely blocked state when subject to the maximum fundamental frequency overvoltage immediately after this short-circuit current, so as to avoid damage to the valve.

   For more information, refer to IEC TR 60919 -2.

b) Short-circuit current withstand capability without re-applied forward voltage

   As to the maximum short-circuit current caused by any fault in operation, the converter valves should have the capability to withstand multiple fault current loops if the converter valves are not required to block or fail to do so. Meanwhile, converter valves can also withstand the reverse AC recovery voltage which occurred between two short-circuit current surges. This recovery voltage is equal to the maximum power-frequency overvoltage that appears together with the maximum short-circuit current.

11.2.4 Voltage rating

The converter valve achieves a certain voltage withstanding capability by connecting thyristors in series. A certain number of extra thyristors need to be added for each valve as redundancy for possible damage during intervals between scheduled maintenance.

The converter valve is designed to be able to withstand the normal operating voltage and various overvoltages. For long-distance HVDC transmission systems, the maximum DC voltages can be a few percent, i.e. 1 % to 3 % higher than the normal voltage.

The converter valve is protected directly by the valve arrester as well as by the forward protective firing and du/dt protection during the recovery period. In case the forward protective firing voltage is lower than the protection level of the valve arrester, attention should be paid to the possible system disturbance caused by protective firing.

The insulation level across the valve is directly decided by the valve arrestor. When deciding the insulation level, all the redundant thyristor levels should be excluded.